ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

September 1, 2021

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

RE: **Docket No. 21-035-09 PacifiCorp's 2021 Integrated Resource Plan**

Please find enclosed PacifiCorp's 2021 Integrated Resource Plan ("2021 IRP"). Copies of the 2021 IRP are also available electronically on PacifiCorp's ("the Company") website, at www.pacificorp.com/irp. As with the 2019 IRP, the Company will provide data discs for the 2021 IRP that will contain supporting information for the analyses included in the 2021 IRP. The Company plans to file these data discs by September 15, 2021, which will contain both non-confidential and confidential work papers.

PacifiCorp plans to supplement its filing with results of its 2021 IRP sensitivity studies no later than September 30, 2021. A post-IRP filing public input meeting has been scheduled for October 1, 2021 to provide an opportunity for stakeholder discussion on the organization of the work papers contained on the data discs and results of the sensitivity studies.

Confidential information in the 2021 IRP and workpapers will be available to state regulators and any party who has intervened in this Docket and certified that it agrees to be bound by the Public Service Commission of Utah's ("Commission") confidentiality rules, R746-100-16.

PacifiCorp submits the 2021 IRP to the Commission pursuant to the Commission's 1992 Report and Order on Standards and Guidelines for Integrated Resource Planning, Docket No. 90-2035-01. The 2021 IRP contains information outlining how PacifiCorp has addressed each of the procedural and substantive elements of the Commission's rules, set forth in "Appendix B – IRP Regulatory Compliance".

PacifiCorp respectfully requests that the Commission acknowledge the 2021 IRP in accordance with its rules and fully support the 2021 IRP conclusions, including the proposed action plan.

All formal correspondence and data requests regarding this filing should be addressed as follows:

By E-mail (preferred): datarequest@pacificorp.com
irp@pacificorp.com
Jana.saba@pacificorp.com
emily.wegener@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

Informal inquiries, including requests to receive a copy of the 2019 IRP filing, may be directed to Jana Saba, Utah Regulatory Affairs Manager, at (801) 220-2823.

PacifiCorp appreciates the time and effort Utah participants have dedicated to helping the Company develop its 2021 IRP.

Sincerely,

Joelle Steward
Vice President, Regulation

Enclosures

CERTIFICATE OF SERVICE

Docket No. 21-035-09

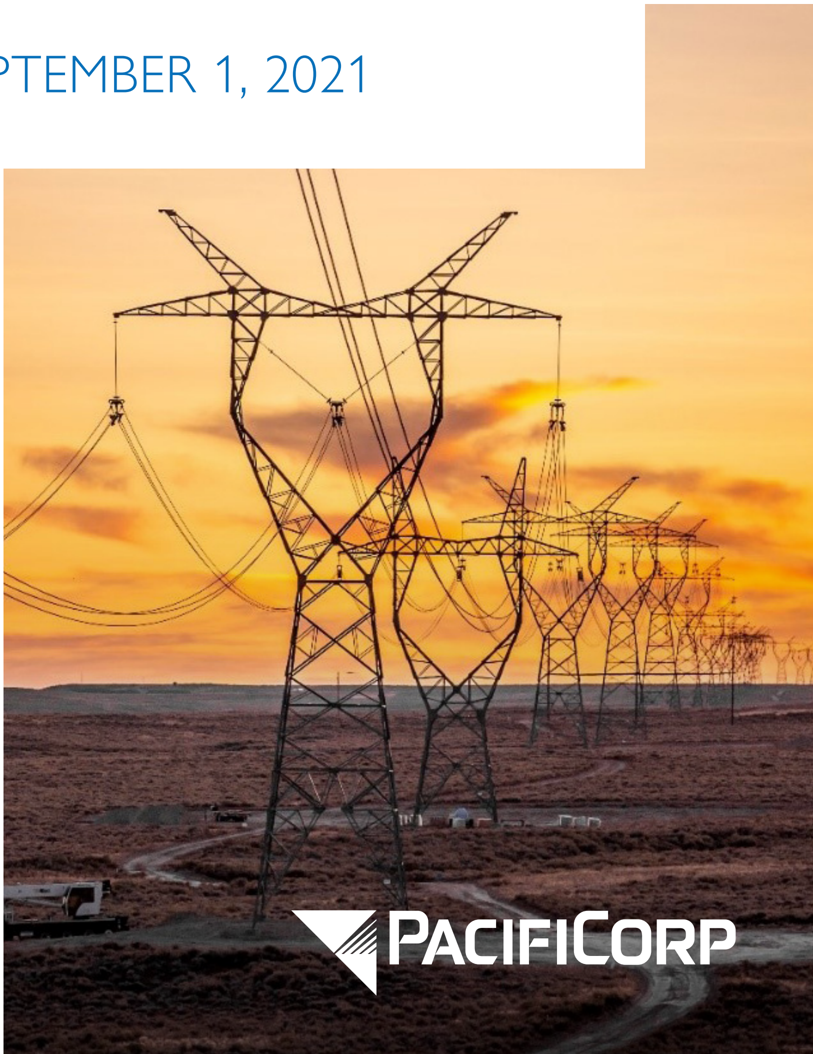
I hereby certify that on September 1, 2021, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services	
Michele Beck	mbeck@utah.gov
Alyson Anderson	Akanderson@utah.gov
Bela Vastag	bvastag@utah.gov
Alex Ware	aware@utah.gov
ocs@utah.gov	
Division of Public Utilities	
dpudatarequest@utah.gov	
Assistant Attorney General	
Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Robert Moore	rmoore@agutah.gov
Victor Copeland	vcopeland@agutah.gov
Rocky Mountain Power	
Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com utahdockets@pacificorp.com
Western Resource Advocates	
Sophie Hayes (C)	Sophie.hayes@westernresources.org
Nancy Kelly (C)	nkelly@westernresources.org
Steven S. Michel (C)	smichel@westernresources.org

Mary Penfield
Adviser, Regulatory Operations

2021 Integrated Resource Plan

VOLUME I | SEPTEMBER 1, 2021



PACIFICORP

This 2021 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.

For more information, contact:
PacifiCorp Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
www.pacificorp.com

Cover Photos (Top to Bottom):
Pavant III Solar Plant
Marengo Wind Project
Transmission Line - Wyoming
Panguitch Solar & Battery Storage

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CHAPTER 1 – EXECUTIVE SUMMARY

PacifiCorp's 2021 Integrated Resource Plan (IRP) was developed through comprehensive analysis and an extensive public-input process spanning over a year and a half resulting in the selection of a least-cost, least-risk preferred portfolio. With accelerated coal retirements, no new fossil-fueled resources, continued growth in energy efficiency programs, and incremental renewable resources, the 2021 IRP preferred portfolio results in a greater reduction in greenhouse gas emissions relative to the 2019 IRP. Reliable service will be maintained with investment in transmission infrastructure, the conversion of two coal units to natural gas peaking units, growth in demand response programs, the addition of advanced nuclear resources, the addition of energy storage resources, and over the long term, the addition of non-emitting peaking resources.

PacifiCorp's Vision

The time is now

At PacifiCorp, we share a vision with our customers and communities in which clean energy from across the West powers jobs and innovation. This bold vision has guided our work for years. Most recently, it took shape in our 2017 and 2019 IRPs, in which we outlined an ambitious path to substantially increase our renewable energy capacity, evolving our existing portfolio and connecting supply with demand through an expanded, modernized transmission system.

Now is the time for further action.

Delivering on our promise

The power of the West lies in its diversity: windswept plains and high deserts, the sun-soaked Great Basin, and rivers fed by rain and mountain snow. Taken together, these reserves of wind, solar and hydro power can help meet the growing and changing needs of homes and businesses throughout the West, cleanly, reliably and affordably.

Yet, capturing this power alone is not enough. To unlock the full promise of these abundant resources, we must add transmission and storage capacity, unlock customer demand response resources with a modernized grid, and replace retiring thermal resources with non-emitting resources like advanced nuclear, to connect the West to its energy future—built on a resilient, hardened, adaptable grid that safely delivers power when and where it's needed.

PacifiCorp's 2021 IRP is a roadmap for action. It sets forth a path to build upon our significant progress toward the goals laid out in the 2017 and 2019 IRPs and identifies critical investments in expanded and modernized transmission, renewable energy, storage, demand response and advanced nuclear resources.

Our integrated system connects and brings new opportunities to the West, building on a foundation of infrastructure designed to handle extreme weather and enhance the energy resilience of communities from the Pacific Coast to the Rocky Mountains, all while continuing to deliver energy solutions for our customers at prices that are below national and regional averages.

As our 2021 IRP shows, this expanded, modernized transmission will connect supply with demand from east to west and from north to south, serving as the backbone of the West for the hundreds of energy providers that serve our region alongside PacifiCorp.

Putting our customers at the center of everything we do

At PacifiCorp, we're committed to meeting the demands of our customers and communities throughout the West to deliver safe, affordable, clean energy and a resilient, modern grid.

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

Our customer-centered vision embodies four core themes:

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

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

Affordable Prices: PacifiCorp is proud to be one of the lowest-cost electricity providers in the nation and the region. As we plan for our next generation of resources, we are prioritizing resources that add value and keep customer prices low.

Clean Energy: Through strategic, customer-focused investments in a diversity of resources, PacifiCorp is on a path to reduce carbon emissions, system-wide, by 74 percent from 2005 levels by 2030. Our resource plan includes continued significant new renewable additions among other diverse, advanced technologies to keep us on that path and achieve even deeper decarbonization beyond 2030.

2021 IRP Roadmap

The 2021 IRP outlines PacifiCorp's bold vision for the West between now and 2040 and sets us on the path to achieve a clean, resilient and affordable energy future that leverages the abundant, diverse, clean energy resources that the West can offer through a modernized and expanded grid.

- **Continue our growth into a grid powered by clean energy (incremental to projects already online and projects with executed agreements that will come online through 2023)**:
    - 4,290 MW from energy efficiency programs
    - 5,628 MW of new solar resources (most paired with storage)
    - 3,628 MW of new wind resources
    - 6,181 MW of storage resources, including battery storage co-located with solar, standalone battery storage and pumped hydro storage resources
    - 2,448 MW of direct load control programs

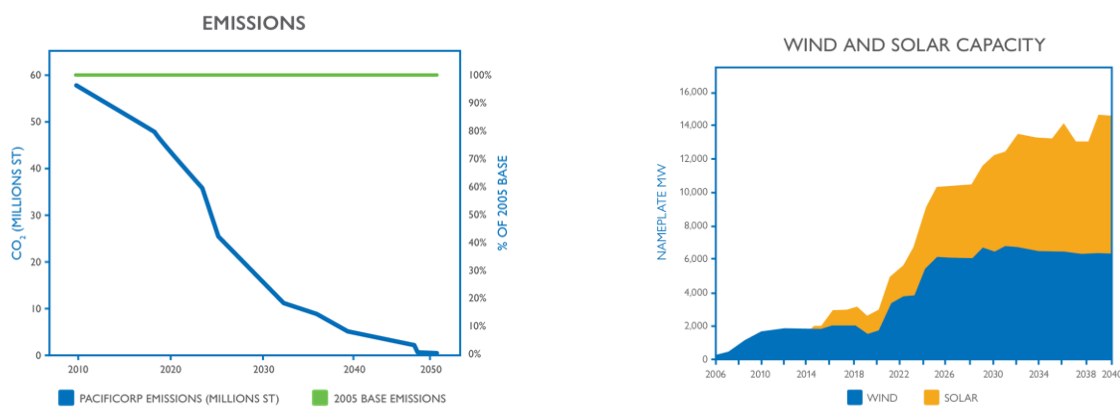
    - 500 MW of advanced nuclear (the Natrium TM reactor demonstration project) in 2028, with an additional 1,000 MW of advanced nuclear over the long-term

- **Connect and optimize these diverse, clean resources across the West with a strengthened and modernized transmission network that ensures resilient service, reduces costs and creates maximum opportunities for our communities to thrive (incremental to projects already online)**:
    - 416 miles of new transmission from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South)
    - 59 miles of new transmission from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming (Energy Gateway West Sub-Segment D.1)
    - 290 miles of new transmission from the Boardman substation in north central Oregon to the Hemingway substation in south central Idaho

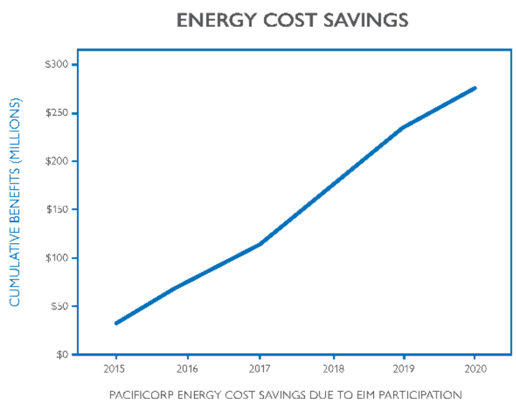
Meeting our goals. Accelerating our progress.

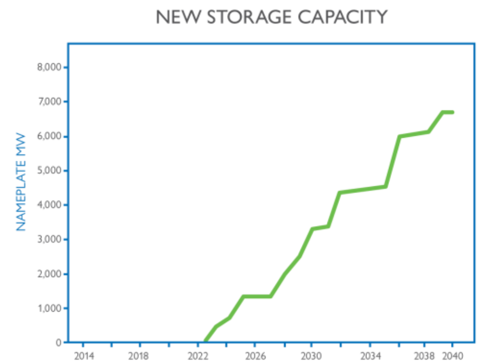
Our 2021 IRP positions PacifiCorp to rapidly expand its supply of clean energy while increasing our storage capacity and delivering cost savings to our customers.[1]

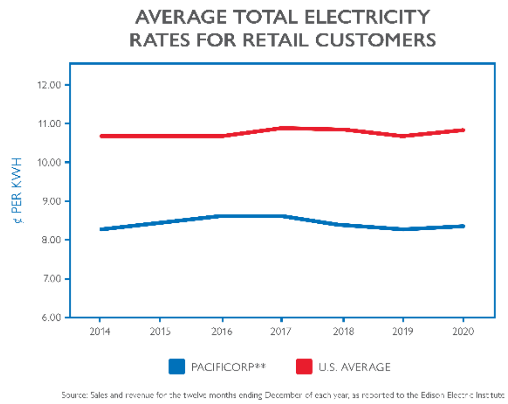
Figure 1.1 – IRP preferred portfolio metrics and trajectory



[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.







Evolving Our Portfolio

Working in close partnership with our communities, we are making significant progress in our evolution to an increasingly low-carbon portfolio. Over the past two years, our progress toward those goals has included:

- A completed coal-to-gas peaker conversion of Naughton Unit 3 in Kemmerer, Wyoming
- Retirement of the Cholla Unit 4 coal-fired generator in Joseph City, Arizona

Our resource strategy in the 2021 IRP continues that progress, and within the next four years will:

- Begin the process of retiring or divesting Colstrip Units 3 and 4 in Colstrip, Montana
- Begin the process of a coal-to-gas peaker conversion of Jim Bridger Units 1 and 2 in Rock Springs, Wyoming
- Begin the process of retirement or sale of Naughton Units 1 and 2

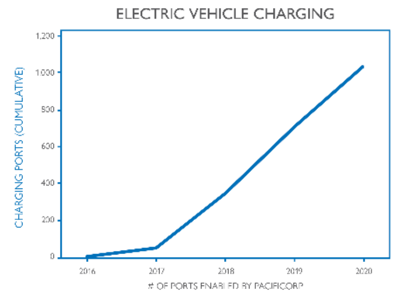
Throughout, we are collaborating closely with affected communities and with state leadership to support a successful transition for our employees and their communities.

Co-creating energy solutions with customers and communities

The communities PacifiCorp serves are why we exist, so we're working in close collaboration with them to build the opportunities and infrastructure that enables communities to thrive.

Clean transportation infrastructure

There are good things ahead for electric transportation in the West. In addition to the more than 2,100 new electric vehicle charging ports that we have already helped install, we're expanding workplace charging, supporting regional solutions to electrify interstates for cleaner freight transportation, and making electric vehicle ownership more accessible for rural and underserved communities.



Solar + Storage in our communities

PacifiCorp is partnering with the communities throughout its service area to leverage grid-scale battery storage and solar projects to help meet community energy needs. In Panguitch Utah, a one-megawatt peak capacity, five megawatt-hour energy storage system anticipates and responds to peak electricity consumption and levels demand on the local grid. This enables PacifiCorp to employ batteries as an alternative to traditional grid poles-and-wires infrastructure. The 650-kilowatt solar photovoltaic component of this project was funded through a grant from the company's Blue Sky renewable energy program.

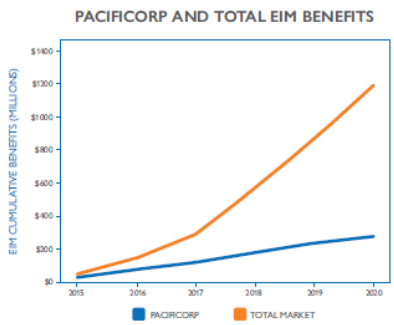
Similarly, through a partnership with the Oregon Institute of Technology in Klamath Falls, Oregon, PacifiCorp is installing a two-megawatt peak capacity, six megawatt-hour energy storage system that will partner with the existing geothermal and solar resources on the campus to provide increased local grid stability. PacifiCorp will also facilitate the interconnection of 64 megawatts of small community based solar systems over the next four years through the Oregon Community Solar Program. These projects are designed to provide an opportunity for residential and low-income customers to share in the benefits of local solar energy production.

Advanced nuclear demonstration project

A developer of an advanced nuclear reactor, TerraPower, has received support from the Department of Energy to construct a demonstration plant for its Natrium™ technology. TerraPower is investigating the opportunity to site Natrium at a retiring coal plant in Wyoming. The project promises many benefits to PacifiCorp including a 24/7 reliable source of clean energy with embedded storage, safety, cost and reduced spent fuel advantages while providing an employment transition opportunity for our existing coal employees and an economic boost to the community where they reside. Using safety features that take advantage of natural forces and do not require human intervention, this reactor will be able to shut down safely and independently, greatly reducing the risks associated with earlier nuclear reactors. TerraPower has not yet identified the specific site for this facility. For modeling purposes in the 2021 IRP, the Natrium™ demonstration project is placed at the Naughton facility. However, a modeling assumption does not equate to the selection of a site. Should TerraPower's site selection ultimately identify a different location than what was modeled in the 2021 IRP, updated analysis of portfolio implications will be made in a future IRP or IRP update.

Delivering resilience and reliability through a connected West

The diversity of the West's landscape—including its abundant clean energy resources—are the key to our strategy for delivering least-cost, least-risk, resilient power to our customers. We have already collaborated with utilities from across the region to form the Western Energy Imbalance Market (EIM),



which allows utilities to trade surplus power in near-real time. The EIM leverages diverse clean energy resources from across the West to dramatically lower greenhouse gas emissions, while increasing the grid's resilience and lowering costs for our customers.

In our 2019 IRP, we expanded our plans stemming from the 2017 IRP to significantly increase our transmission capacity to integrate new renewable resources more effectively into the grid and to deliver the full benefit of the EIM to our customers. We are on target with all benchmarks established by that IRP.

- Completed reinforcements of high-voltage transmission in the Utah Valley, northern Utah, southern Utah, and Yakima, Washington. These projects will allow the company to respond to interconnection requests and accommodate the renewable resources identified in the 2019 IRP.
- Continuing the regulatory process to construct Energy Gateway South and Energy Gateway West Sub-Segment D.1, which will connect eastern Wyoming to central Utah, enhance system reliability and provide access to more generation resources.

Expanded conservation measures

We're championing technical innovations that use fast-acting residential demand response resources to support the bulk power system. Our approach moves beyond peak-load management to create a grid-scale solution that turns demand response resources into frequency-responsive operating reserves. With over 100,000 customers participating in our program, more than 200 MW of operating reserve are available every day and can be dispatched in a matter of seconds. This reduces our need to buy reserve power on the market, and it's only used in emergencies, minimizing inconvenience to customers.

Our partnership with The Wasatch Group enabled us to develop and manage a first-of-its-kind battery demand response solution at an all-electric apartment building. That success has shaped a new battery demand response option for any Utah customer with on-site solar generation. The network of renewable energy stored in customer-owned batteries will enable greater use of renewable power, improves overall grid resiliency, and helps keep prices down.

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

- 603 MW of energy efficiency between 2021-2024
- 549 MW of demand response[2] between 2021-2024

Putting our shared vision to work for our customers

Our 2021 IRP is grounded in our commitment to deliver reliable, affordable power to all our customers through a dynamic, connected grid. It is the roadmap for a future of clean energy and strengthened infrastructure to support the delivery of this essential service. It's shaped by our customers and communities, and new technologies and programs, like demand response. And it's

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

bolstered by innovations in power generation and storage that will help decarbonize our portfolio while lowering costs and increasing reliability.

This is the vision, with clear, measurable steps that will connect the region to its massive energy generating potential and leverage our transmission infrastructure across our six-state area to enhance reliability and resilience throughout the West.

By investing in resilience, through expanded and modernized transmission, a hardened grid, and a diverse, increasingly clean portfolio, we are delivering on our commitment to ensuring safe, reliable, affordable power for our customers, now and for generations to come.

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 2021 IRP presents the company's plans to continue to make significant advancements in this vision. The 2021 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 2021 IRP, PacifiCorp presents a preferred portfolio that builds on its vision to deliver energy affordably, reliably and responsibly through near-term investments in transmission infrastructure that will facilitate continued growth in new renewable resource capacity while maintaining substantial investment in energy efficiency and demand response programs. All of this can be achieved by maintaining reliable service with incremental investments in transmission infrastructure and other non-emitting flexible resources capable of shaping and responding to changes in energy from an increasing supply of wind and solar resources.

The primary objective of the IRP is to identify the best mix of resources to serve customers in the future. The best 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 2021 IRP was developed through an open and extensive public process, with input from an active and diverse group of stakeholders, including customer advocacy groups, community members, regulatory staff, and other interested parties. The public-input process began with the first public-input meeting in January 2020. Over the subsequent year and a half, PacifiCorp met with stakeholders 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 2021 IRP.

As depicted in Figure 1.2, PacifiCorp's 2021 IRP was developed by working through five fundamental planning steps that began with development of key inputs and assumptions to inform the modeling and portfolio-development process. The portfolio-development process is where PacifiCorp produced a range of different resource portfolios that meet projected gaps in the load and resource balance, each uniquely characterized by the type, timing, and location of new resources in PacifiCorp's system. The resource portfolios produced for the 2021 IRP were created considering a wide range of potential coal retirement dates, options to convert to gas or to retrofit for carbon capture utilization and sequestration for certain coal units, and other planning uncertainties.

PacifiCorp then developed variants of the top performing resource portfolio to further analyze impacts of specific resource actions within the top performing portfolio. In the resource portfolio analysis step, PacifiCorp conducted targeted reliability analysis to ensure portfolios had sufficient flexible capacity resources to meet reliability requirements. PacifiCorp then analyzed these different resource portfolios to measure the comparative cost, risk, reliability, and emission levels. This resource portfolio analysis ultimately informed selection of the least-cost and least-risk portfolio, the 2021 IRP preferred portfolio and development of the associated near-term resource action plan. Throughout this process, PacifiCorp considered a wide range of factors to develop key planning assumptions and to identify key planning uncertainties, with input from its stakeholder group. Supplemental studies were also done to produce specific modeling assumptions.

Figure 1.2 – Key Elements of PacifiCorp's 2021 IRP Approach

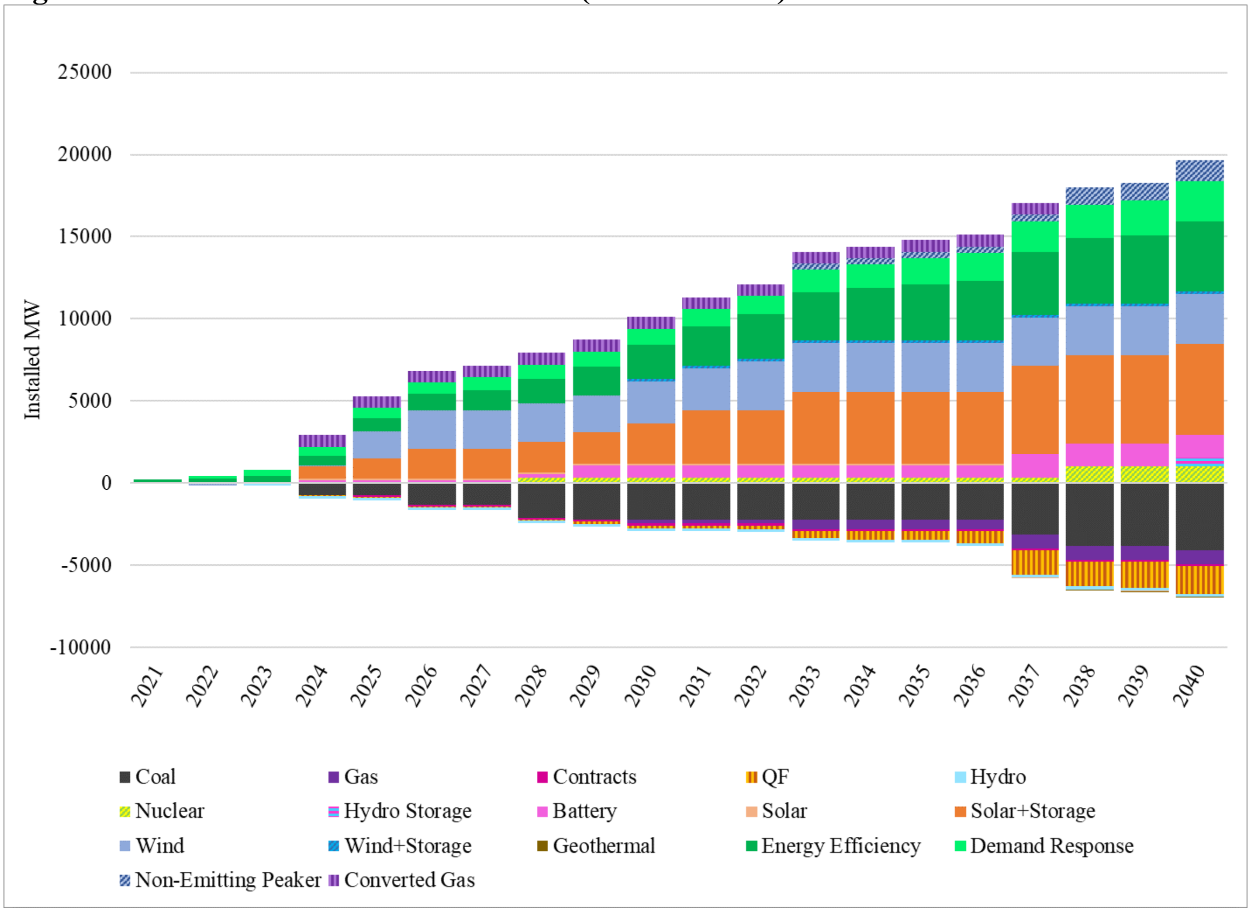
Preferred Portfolio Highlights

PacifiCorp's selection of the 2021 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 1.3 shows that PacifiCorp's 2021 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, significant storage resources, and for the first time, advanced nuclear.

By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source Request for Proposals (RFP) final shortlist resources. These projects include 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity—497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage. The 2021 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, which will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Over the 20-year planning horizon, the 2021 IRP preferred portfolio includes 3,628 MW of new wind and 5,628 MW of new solar co-located with storage.

Figure 1.3 – 2021 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile, high-voltage (230-kilovolt) transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2021 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway, which connects those respective substations in Oregon and Idaho, which will come online in 2026. Further, the 2021 IRP preferred portfolio further includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. Table 1.1 summarizes the incremental transmission projects in the 2021 IRP preferred portfolio.

Table 1.1 – Transmission Projects Included in the 2021 IRP Preferred Portfolio[1,2,*]

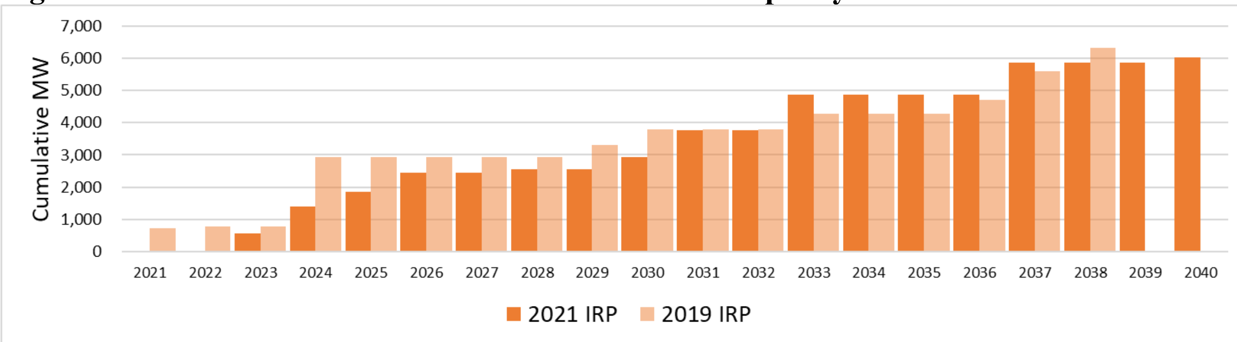
Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

The 2021 IRP preferred portfolio includes 1,302 MW of new solar by the end of 2024 and 1,902 MW by the end of 2026. Through 2040, more than 5,600 MW of new solar is online as shown in Figure 1.4.

Figure 1.4 – 2021 IRP Preferred Portfolio New Solar Capacity*

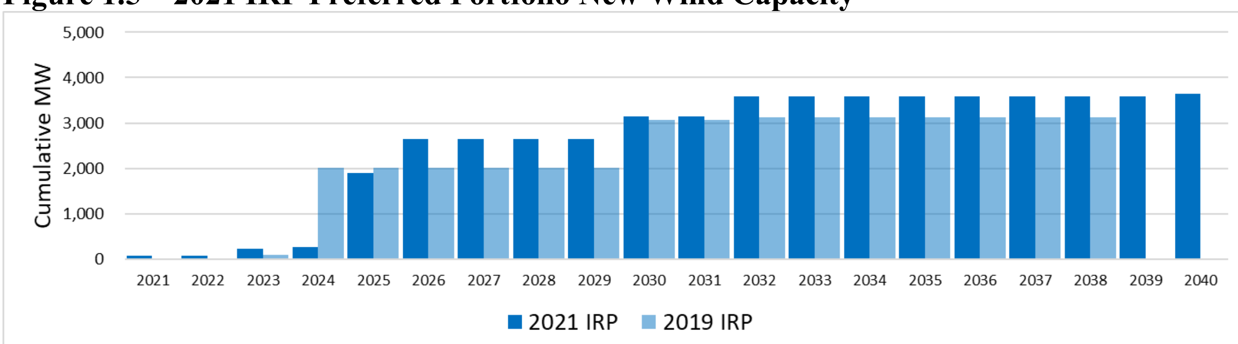


*Note: 2021 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates).

New Wind Resources

As shown in Figure 1.5, by the end of 2024, PacifiCorp's 2021 IRP preferred portfolio includes 1,792 MW of new wind generation resulting from the 2020 AS RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of new wind and more than 3,700 MW of new wind by 2040.

Figure 1.5 – 2021 IRP Preferred Portfolio New Wind Capacity*

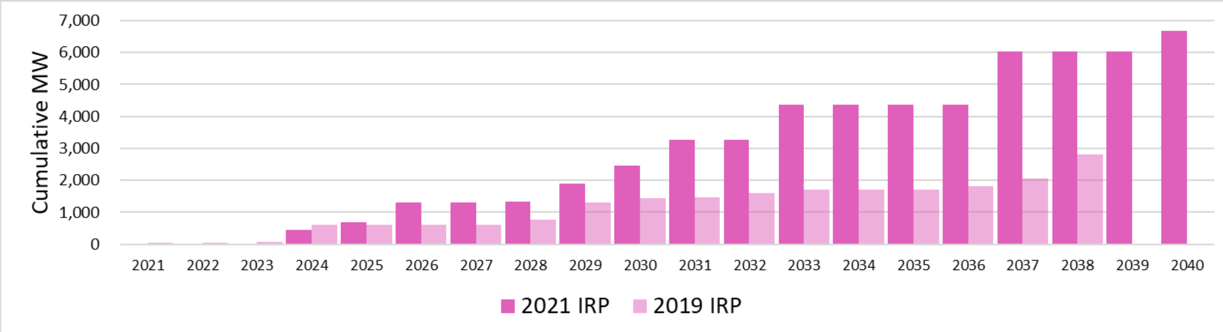


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2021 IRP preferred portfolio are summarized in Figure 1.6. The 2021 IRP preferred portfolio includes nearly 700 MW of battery storage by the end of 2024 – 200 MW of which is a standalone battery and the remaining portion paired with solar resources resulting from the 2020 All-Source RFP. Through 2040, the 2021 IRP includes 4,781 MW of storage co-located with solar resources,1,400 MW of standalone battery, and 500 MW of pumped hydro.

Figure 1.6 – 2021 IRP Preferred Portfolio New Storage Capacity*

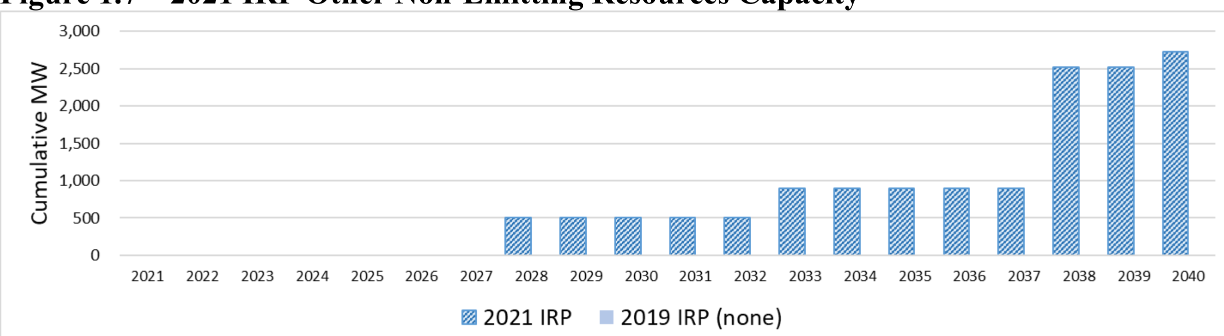


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

This is the first PacifiCorp IRP that includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in Figure 1.7, the 500 MW advanced nuclear Natrium™ demonstration project will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Figure 1.7 – 2021 IRP Other Non-Emitting Resources Capacity*

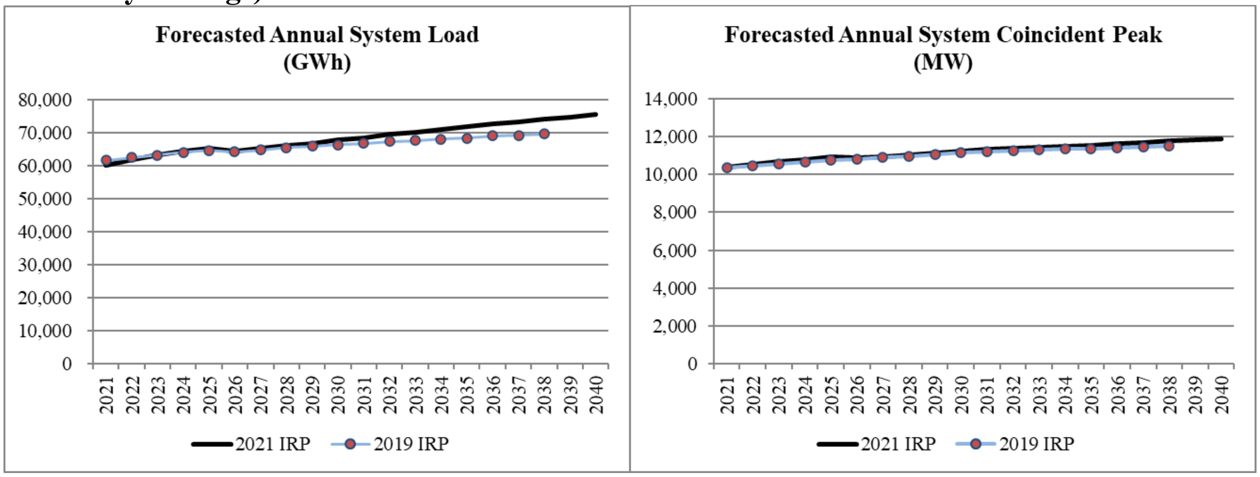


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and 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 1.8 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2019 IRP. On average, forecasted system load is up 2.2 percent and forecasted coincident system peak is up 1.1 percent when compared to the 2019 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.21 percent for load and 0.73 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 increased residential forecast.

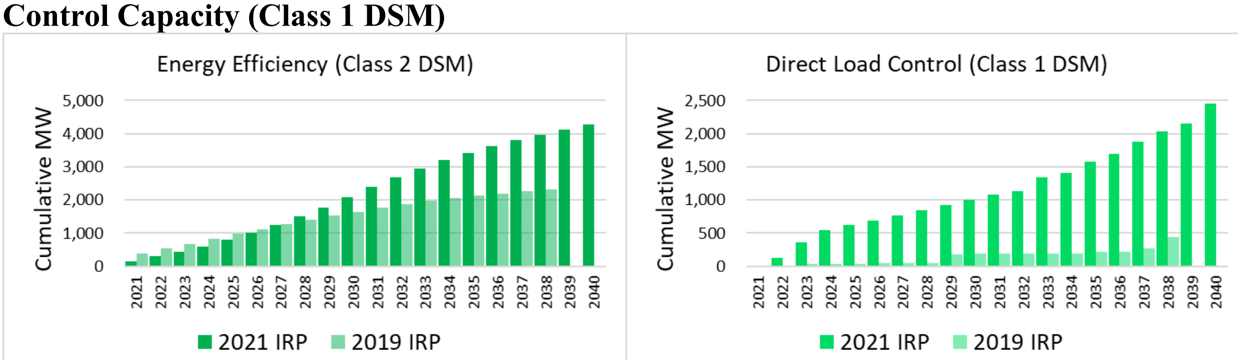
Figure 1.8 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. The chart to the left in Figure 1.9 compares total energy efficiency capacity savings in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and includes 4,290 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows an increasing role for incremental direct load control programs. The chart to the right in Figure 1.9 compares cumulative capacity of direct load control program capacity in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and does not include capacity from existing programs. In the 2021 IRP, direct load control resources previously identified in the 2019 IRP and solicited via a demand response RFP, were modeled in addition to resources from the CPA assessing the upper limit of demand response opportunities and value within the IRP. This allowed for the evaluation of real-time resources as a substitute for front office transactions. The 2021 IRP has a cumulative capacity of direct load control programs reaching 2,448 MW by 2040 – an over 400% increase over the planning horizon from the 2019 IRP.

Figure 1.9 – 2021 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 1.10 shows that the 2021 IRP's base case forecast for natural gas prices has decreased along with a decrease in wholesale power prices for most years relative to those in the 2019 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The lower power prices observed in the 2021 IRP are primarily driven by the assumption of lower natural gas prices-than what was assumed in the 2019 IRP. Wholesale power prices are higher in 2027 to 2031 because of higher inflation impacting new resource costs. Moreover, the 2021 IRP assumed lower natural gas prices than the 2019 IRP as Henry Hub in particular, is softened by limited pipeline expansion lowering liquefied natural gas exports. While not shown in the figure below, the 2021 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 1.10 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

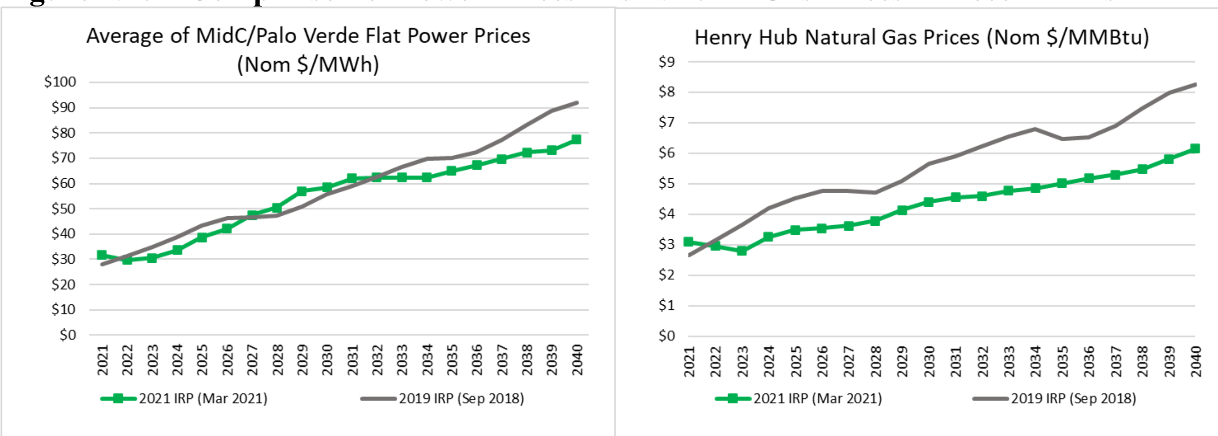
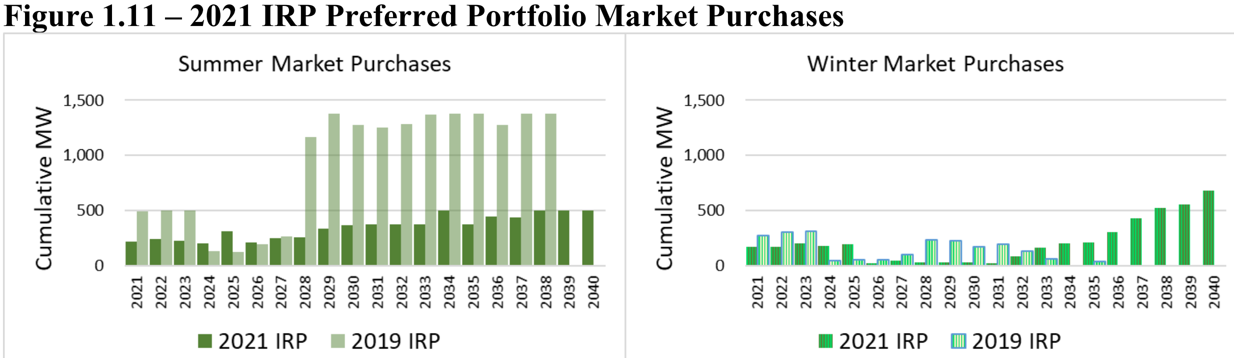


Figure 1.11 shows an overall decline in reliance on wholesale power market firm purchases in the 2021 IRP preferred portfolio relative to the wholesale power market purchases included in the 2019 IRP preferred portfolio. In particular, reliance on wholesale power market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from wholesale power market purchases identified in the 2019 IRP preferred portfolio. This reduction in wholesale power market purchases coincides with the period over which there are resource adequacy concerns in the region. While wholesale power 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 1.11 – 2021 IRP Preferred Portfolio Market Purchases



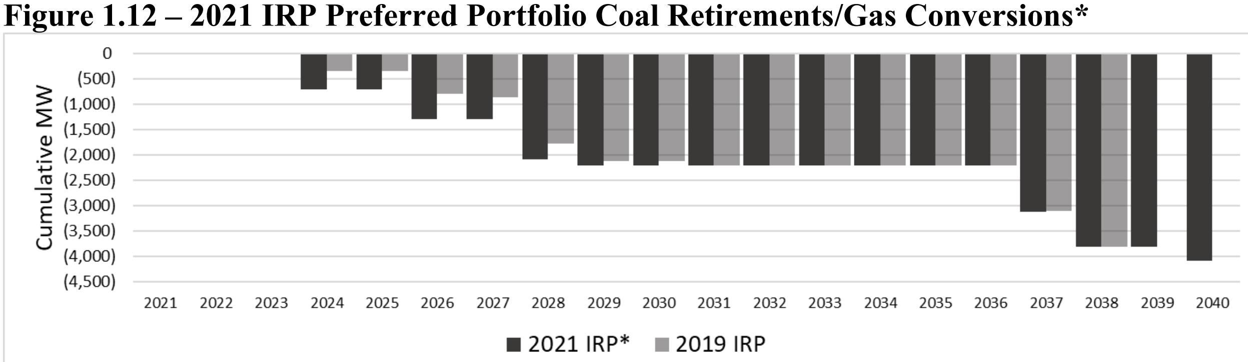
Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. As shown in Figure 1.12, coal unit retirements/gas peaker conversions in the 2021 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 4,000 MW by 2040.

Coal unit retirements scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas peakers in 2024 (same retirement year for Jim Bridger 1 in 2019 IRP and instead of 2028 for Jim Bridger 2 in the 2019 IRP).
- 2025 = Naughton Units 1-2 (same as 2019 IRP)
- 2025 = Craig Unit 1 (same as 2019 IRP)
- 2025 = Colstrip Units 3-4 (instead of 2027 in the 2019 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2019 IRP)
- 2027 = Hayden Unit 2 (instead of 2030 in the 2019 IRP)
- 2028 = Craig Unit 2 (instead of 2026 in the 2019 IRP)
- 2028 = Hayden Unit 1 (instead of 2030 in the 2019 IRP)
- 2036 = Huntington Units 1-2 (same as 2019 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2019 IRP)
- 2039 = Wyodak (same as 2019 IRP but outside of 2019 IRP planning horizon)

Figure 1.12 – 2021 IRP Preferred Portfolio Coal Retirements/Gas Conversions*



* 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.

In addition to the coal unit retirements outlined above, the preferred portfolio reflects 1,554 MW natural gas retirements through 2040. This includes Naughton Unit 3 at the end of 2029, Gadsby at the end of 2032, Hermiston at the end of 2036, and Jim Bridger Units 1 and 2 at the end of 2037.

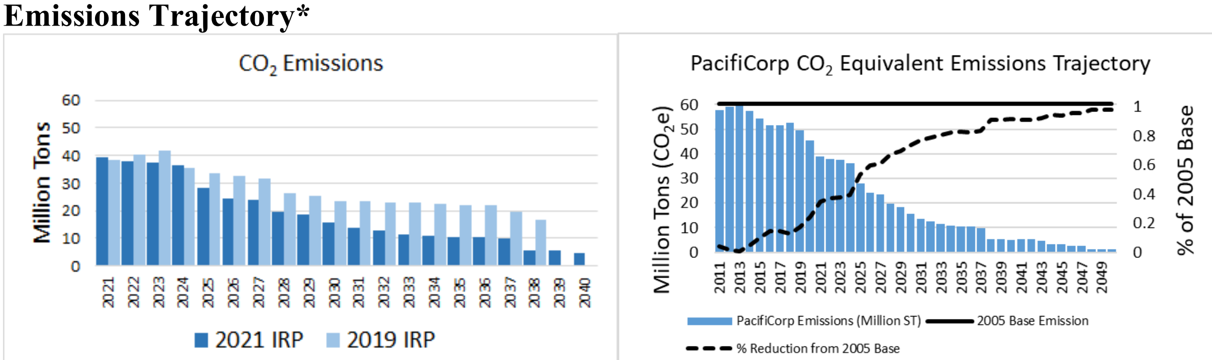
Carbon Dioxide Emissions

The 2021 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 related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 1.13 compares projected annual CO_2 emissions between the 2021 IRP and 2019 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2026, annual CO_2 emissions are down 26 percent relative to the 2019 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2019 IRP preferred portfolio, and down 52 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.1 million tons in 2021 to 4.8 million tons in 2040—a reduction of 88 percent.

The chart on the right in Figure 1.13 includes historical data, assigns emissions at a rate of 0.4708 tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, system CO_2 equivalent emissions are down 53 percent in 2025, 74 percent in 2030, 83 percent in 2035, 92 percent in 2040, 94 percent in 2045, and 98 percent in 2050.

Figure 1.13 – 2021 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2021 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.4708 short tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

Renewable Portfolio Standards

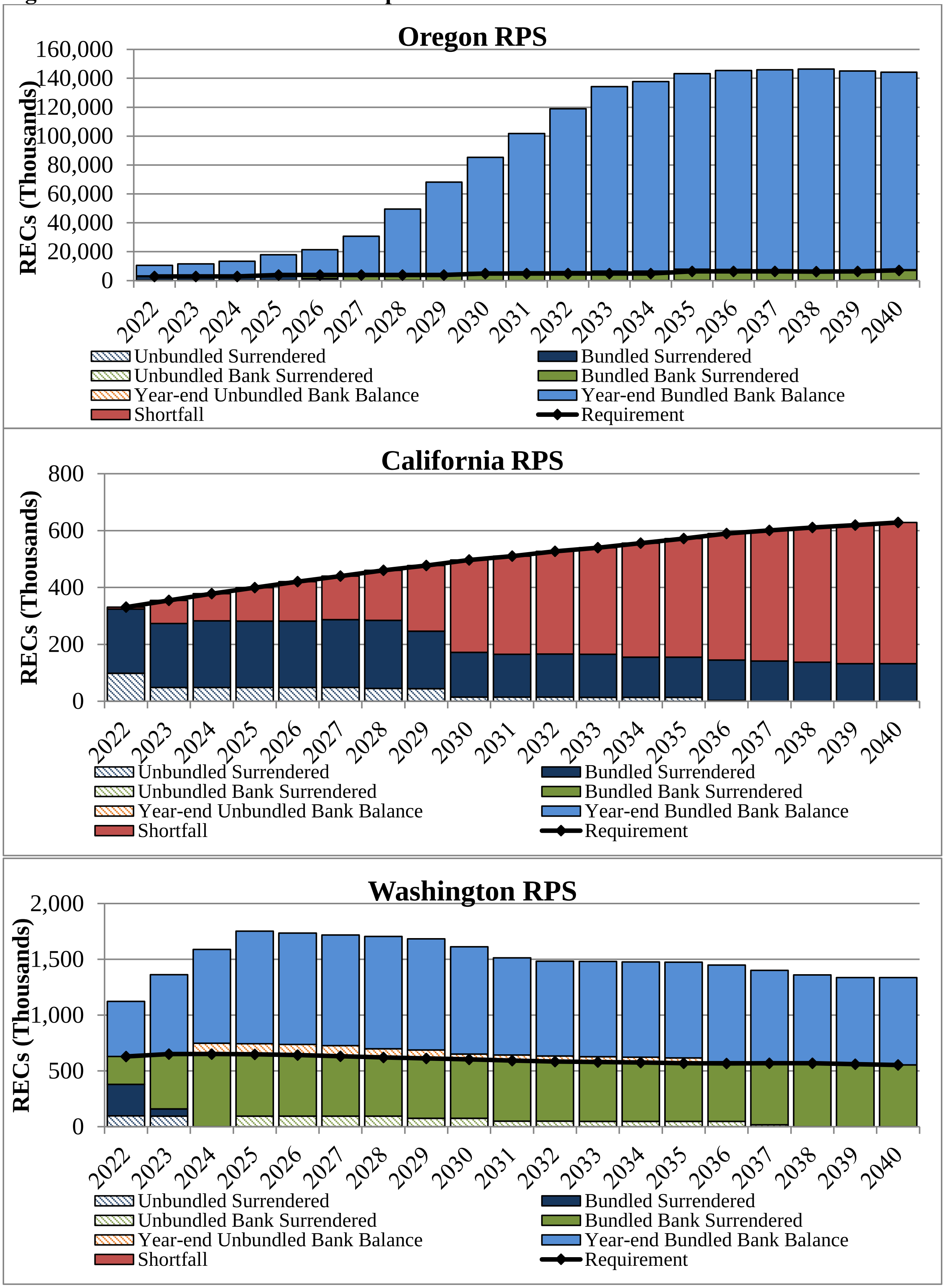
Figure 1.14 shows PacifiCorp's renewable portfolio standard (RPS) compliance forecast for California, Oregon, and Washington after accounting for new renewable resources in the preferred portfolio. While these resources are included in the preferred portfolio as cost-effective system resources and are 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 2040 with the addition of new renewable resources and transmission in the 2021 IRP preferred portfolio. Washington RPS compliance is achieved with the benefit of increased system renewable resources beginning 2021 as well as additional resources procured that meet the state's Clean Energy Transformation Act. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2021 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in 2021-2040. New renewable resources and transmission in the 2021 IRP preferred portfolio mitigate that shortfall, but the company may need to purchase approximately 200,000 RECs in compliance periods 4 and 5, 2021-2024 and 2025-2028, respectively. Beyond 2028, the company may need to purchase 200,000-300,000 RECs per year to meet the ramping RPS.

While not shown in Figure 1.14, 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 2021 IRP preferred portfolio.

Figure 1.14 – Annual State RPS Compliance Forecast



2021 IRP Advancements and Supplemental Studies

IRP Advancements

During each IRP planning cycle, PacifiCorp identifies and implements advancements to continuously improve the IRP for its customers, other stakeholders, and regulatory commissions. Some of the key advancements implemented in the 2021 IRP include:

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

- Endogenous Modeling of Resources
  As part of it 2021 IRP, the Plexos model was able to endogenously consider coal retirement timing options along with other specified options such as gas conversion or carbon capture utilization and sequestration retrofit for a coal unit. In addition, the Plexos model had 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. Endogenous transmission modeling capabilities include the consideration of 1) new incremental transmission options tied to resource selections, 2) existing transmission rights tied to the use of post-retirement brownfield sites, and 3) incorporation of costs associated with these transmission options, and 4) transmission options that interact with multiple or complex elements of the IRP transmission topology. Endogenous modeling of standalone and co-located battery resources was also improved with the Plexos model over the 2019 IRP. In the 2019 IRP, optimization of dispatch, charging and reserves for batteries was modeled using an external tool, and the results brought back into the primary model. In the 2021 IRP, Plexos allows for the endogenous treatment of the entirety of battery optimization. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Targeted Portfolio Reliability Analysis
  In the 2021 IRP, PacifiCorp further advanced its approach for assessing the reliability of resource portfolios and the ability of each unique resource portfolio to meet reliability requirements. This IRP incorporates operating reserves in the LT model for capacity expansion and optimizes available resources to meet requirements in all periods, not just the system peak. With significant levels of economic renewable resource being selected in every resource portfolio, PacifiCorp found that subsequent modeling of these resource portfolios using the Short-Term (ST) hourly dispatch model, which considers more granularity and an explicit accounting of operating reserve requirements, consistently identified capacity shortfalls needed to maintain reliable operation of the system. PacifiCorp ran 20-year ST studies to evaluate shortfalls on a portfolio-specific basis across each year of the 20-year planning horizon. From the results of these hourly deterministic ST runs PacifiCorp developed a process

to remedy the incremental need for reliability resources through cost-effective resource additions to a portfolio to ensure there is sufficient flexible capacity to meet reliability requirements. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Improvements in Modeling Assumptions
  In the 2021 IRP, PacifiCorp improved several modeling assumptions including weather-adjusted energy efficiency, wind and solar to better align with the load forecast, re-bundling energy efficiency supply-side resource options on a net cost of capacity basis, optimizing battery dispatch that adheres to charging constraints within the Plexos model, and multipath endogenous transmission modeling options. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for more information.

- Stakeholder Requests and Feedback
  In its 2021 IRP, in addition to PacifiCorp's stakeholder feedback form process of posting the forms received from stakeholders as well as PacifiCorp's response throughout the public-input process, PacifiCorp has also summarized the stakeholder feedback forms received and how feedback was considered as part of the 2021 IRP document. PacifiCorp received and responded to over 450 stakeholder feedback forms in the 2021 IRP. PacifiCorp was able to accommodate numerous stakeholder requests to develop additional scenarios and sensitivities during the public-input process. PacifiCorp and stakeholders collaborated to identify potential scenarios, and scenarios selected for inclusion included an analysis of accelerated coal retirements, variations of "business-as-usual" cases, alternate DSM bundling methodologies, and other updates to modeling inputs. A full summary of requests received and considered can be found in Volume II, Appendix C (Public Input Process).

- Public-Input Meetings
  PacifiCorp began its public-input process for the 2021 IRP development cycle much earlier than prior IRP development cycles with a series of three public-input meetings that were technical workshops on the Conservation Potential Assessment to inform development of PacifiCorp's demand-side management planning assumptions. In addition, due to the pandemic that emerged during the 2021 IRP development cycle, PacifiCorp was able to pivot and continue robust stakeholder participation throughout its public-input meeting process by holding the meetings via Microsoft Teams platform and phone conference. This enabled the option for video connectivity when available and simultaneous viewing of meeting material via the online platform. See Volume II, Appendix C (Public Input Process) for more information.

Supplemental Studies

PacifiCorp's 2021 IRP relies on numerous supplemental studies that support the derivation of specific modeling assumptions critical to development of its long-term resource plan. A description of these studies, discussed in more detail in 2021 IRP and appendices filed with the 2021 IRP, is provided below. Additional source files and information may also be located for some studies on PacifiCorp's IRP webpage at the following location:
www.pacificorp.com/energy/integrated-resource-plan.html

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

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

- Energy Storage Potential Evaluation
  Energy storage resources can provide a variety of grid services since they are highly flexible, with the ability to respond to dispatch signals and act as both a load and a resource. This evaluation, refreshed for the 2021 IRP, provides details on these grid services and on how energy storage resources can be configured and sited to maximize the benefits they provide.

- Flexible Reserve Study
  This study, updated for the 2021 IRP, evaluates the need for flexible resources resulting from the variability and uncertainty in load, wind, solar, and other generation resources. The study produces an estimate of flexible reserve needs for each hour that accounts for the specific load, wind, and solar resources being evaluated. Reserve costs associated with meeting these flexible reserve needs are also estimated.

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

- Private Generation Resource Assessment
  This supplemental study, prepared by Guidehouse (formerly Navigant Consulting, Inc.), was refreshed for the 2021 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.

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

- Stochastic Parameter Update
  PacifiCorp's preferred portfolio-selection process relies, in part, on stochastic risk analysis using Monte Carlo random sampling of stochastic variables. Stochastic variables include natural gas and wholesale electricity prices, load, hydro generation, and unplanned thermal outages. For the 2021 IRP, PacifiCorp updated its stochastic parameter input assumptions with more current historical data.

- Renewable Resources Assessment
  A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2021 Integrated Resource Plan (IRP). The 2020 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.

Action Plan

The 2021 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 2021 IRP, and other resource activities described in the 2021 IRP. Table 1.2 details specific 2021 IRP action items by category.

Table 1.2 – 2021 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**<u>Colstrip Units 3 and 4:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**<u>Craig Unit 1:</u>** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**<u>Naughton Units 1 and 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 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

1c	**<u>Jim Bridger Units 1 and 2 Gas Conversion:</u>** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. • By the end of Q4, 2023, PacifiCorp will remove units 1 and 2 from Washington's allocation of electricity.
1d	**<u>Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:</u>** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly. • PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.
1e	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.

<table>
<tr><th>Action Item</th><th>2. New Resource Actions</th></tr>
<tr><td>2a</td><td><u>Customer Preference Request for Proposals:</u>
• Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window.</td></tr>
<tr><td>2b</td><td><u>Acquisition and Repowering of Foote Creek II-IV and Rock River I:</u>
• In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date.
• In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.</td></tr>
<tr><td>2c</td><td><u>Natrium™ Demonstration Project:</u>
• PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable.
• By the end of 2022, PacifiCorp will finalize commercial agreements for the Natrium™ project.
• Q1 2022, PacifiCorp will develop a community action plan in coordination with community leaders.
• By 2025, PacifiCorp will begin training operators.
• PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.</td></tr>
</table>

2d	**<u>2022 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 2026. • In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window. • In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.
2e	**<u>2020 All-Source Request for Proposals:</u>** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist.
Action Item	**3. Transmission Action Items**
3a	**<u>Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):</u>** • By Q2 2022, obtain Utah and Wyoming Certificates of Public Convenance and Necessity. • By the end of Q1 2022, Bureau of Land Management notice to proceed to construct Energy Gateway South. • In Q3 2024, construction of Energy Gateway South is expected to be completed and placed in service.
3b	**<u>Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):</u>** • By Q2 2022, obtain conditional Wyoming Certificate of Public Convenance and Necessity • By Q3 2022 complete ROW easement acquisition and option full Wyoming CPCN • In Q3 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.

3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids
3e	Continue permitting support for Gateway West segments D.3 and E.
Action Item	**4. Demand-Side Management (DSM) Actions**

4a	**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 is provided in Appendix D in Volume II of the 2021 IRP. • PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

Year	Annual 1st Year Energy (GWh)	Annual Incremental Capacity (MW)
2021	510	157
2022	492	138
2023	486	144
2024	529	164

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

Year	Annual Incremental Capacity (MW)
2021	0
2022	123
2023	242
2024	184

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

Action Item	5. Market Purchases

5a	**<u>Market Purchases:</u>** • Acquire short-term firm market purchases for on-peak delivery from 2021-2023 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	**6. Renewable Energy Credit (REC) Actions**
6a	**<u>Renewable Portfolio Standards (RPS):</u>** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2024.
6b	**<u>Renewable Energy Credit Sales:</u>** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

CHAPTER 2 – INTRODUCTION

PacifiCorp files an Integrated Resource Plan (IRP) on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. This IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. 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 2021 IRP preferred portfolio is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. PacifiCorp's 2021 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, demand-side management (DSM) resources, and for the first time, significant battery storage resources and advanced nuclear. By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source RFP final shortlist resources including 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River 1 (49 MW) and Foote Creek II-IV (43 MW) wind projects. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional solar co-located with storage.

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes the construction of a 416-mile 500-kilovolt (kV) transmission line known as Gateway South connecting southeastern Wyoming and northern Utah, the 59-mile 230 kV transmission line in eastern Wyoming known as Gateway West Segment D.1, and the 500 kV, 290-mile transmission line across eastern Oregon and southwestern Idaho known as Boardman to Hemingway (B2H).

Other significant studies conducted to support analysis in the 2021 IRP include:

- An updated demand-side management resource conservation potential assessment;
- A private generation study for PacifiCorp's service territory;
- A renewable resources assessment;
- An assessment of smart grid technologies;
- Updated stochastic parameters; and
- An updated load and resource balance.

This chapter outlines the components of the 2021 IRP, summarizes the role of the IRP, and provides an overview of the public-input process.

2021 Integrated Resource Plan Components

The basic components of PacifiCorp's 2021 IRP include:

- 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).
- Discussion of PacifiCorp's commitment to serve customers reliably, and summary of the company's actions to ensure all-weather resource adequacy, wildfire mitigation planning, and transmission planning to support power flow reliability. (Chapter 5)
- Load and resource balance on a capacity and energy basis and determination of the load and energy positions for the front ten years of the twenty-year planning horizon (Chapter 6).
- Profile of resource options considered for addressing future capacity and energy needs (Chapter 7).
- Description of the IRP modeling, including a description of the portfolio development process, cost and risk analysis, and preferred portfolio selection process (Chapter 8).
- Presentation of IRP modeling results and selection of PacifiCorp's preferred portfolio (Chapter 9).
- Presentation of PacifiCorp's 2021 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 10).

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 (Volume II, Appendix C),
- Demand Side Management Resources (Volume II, Appendix D),
- Smart Grid (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),
- Plant Water Consumption Study (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Capacity Expansion Results (Volume II, Appendix I)
- Stochastic Simulation Results (Volume II, Appendix J),
- Capacity Contribution (Volume II, Appendix K),
- Private Generation Study (Volume II, Appendix L),
- Renewable Resources Assessment (Volume II, Appendix M),
- Energy Storage Potential Evaluation (Volume II, Appendix N),
- Washington Clean Energy Action Plan (Volume II, Appendix O),
- RFP Overview (Volume II, Appendix P); and
- Acronyms (Volume II, Appendix Q)

To promote transparency PacifiCorp is also providing data discs for the 2021 IRP. These discs support and provide additional details for the analysis described within the document. Data 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 establishes a plan that will deliver adequate and reliable electricity supply at a reasonable cost and in a manner "consistent with the long-run public interest."[1] In this way, the IRP serves as a roadmap for determining and implementing PacifiCorp's long-term resource strategy. In doing so, it accounts for state commission IRP requirements, the current view of the planning environment, corporate business goals, and uncertainty. As a business planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including supporting request for proposal bid evaluation efforts. As an external communications tool, the IRP engages numerous stakeholders in the planning process and guides them through the key decision points leading to PacifiCorp's preferred portfolio of generation, demand-side, and transmission resources.

Public-Input Process

The IRP standards and guidelines for certain states require PacifiCorp to have a public-input process allowing stakeholder involvement in all phases of plan development. PacifiCorp organized five state meetings and held 18 public-input meetings, some of which spanned two days to facilitate information sharing, collaboration, and expectations for the 2021 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.

[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.

Table 2.1 – IRP Public-Input Meetings

Meeting Type	Date	Main Agenda Items
State Meeting	7/22/20	Utah state stakeholder comments
State Meeting	7/22/20	Washington state stakeholder comments
State Meeting	7/23/20	Wyoming state stakeholder comments
State Meeting	7/24/20	Oregon state stakeholder comments
CPA Technical Workshop	1/21/20	Conservation Potential Assessment (CPA) Overview, Key Changes and Updates for the 2021 CPA, Market Characterization and Baseline Development, Measure Characterization and Potential Estimation, 2021 CPA Work Plan
CPA Technical Workshop	2/18/20	Energy Efficiency, Measure List Changes, Demand Response, Resource Options and Examples
CPA Technical Workshop	4/16/20	Conservation Potential Assessment Schedule and Milestones, Stakeholder Feedback, Recap of Key Discussion Topics From Prior Workshops, Drivers of difference in Forecasted Potential by State
General Meeting (2-Day)	6/18/20	Stakeholder Feedback Form Update, CPA Update, Optimization Modeling and Modeling Update, Modeling Energy Storage
	6/19/20	2019 IRP Highlights/ 2021 IRP Topics and Timeline, Request for Proposal Update, Transmission Overview and Update
General Meeting (2-Day)	7/30/20	Load Forecast Update, Distribution System Planning, Supply-side Resource Study Efforts, Coal Studies Discussion
	7/31/20	Environmental Policy, Renewable Portfolio Standards, DMS Bundling Portfolio Methodology, Private Generation Study, Stakeholder Feedback Form Recap
CPA Technical Workshop	8/28/20	2021 CPA Process Review, Energy Efficiency Potential Draft Results, Demand Response Potential Draft Results
General Meeting	9/17/20	Supply-side Resources, Portfolio Development Discussion, State Policy Update, Conservation Potential Assessment Update, Stakeholder Feedback Form Recap
General Meeting	10/22/20	General Updates, Summary of Oregon Energy Efficiency Analysis Results
General Meeting	11/16/20	Plexos Benchmark and Modeling Assumptions
General Meeting	12/3/20	Conservation Potential Assessment, DSM Bundling Methodology, Updated Portfolio Matrix and Analysis
General Meeting	1/29/21	Energy Efficiency Bundling Methodology, Renewable Shaping, Stakeholder Feedback Form Recap
General Meeting	2/10/21	Discussion of current status of IRP, proposed updates to schedule.
General Meeting	4/23/21	Portfolio Modeling process update, Stakeholder Feedback Form Recap
General Meeting	6/25/21	Update on Key Activities and Presentation of Indicative Case
General Meeting	7/30/21	Discussion of Portfolio Optimization and Modeling Discussion
General Meeting	8/6/21	Continued Discussion of Portfolio Results
General Meeting	8/27/21	Presentation of 2021 IRP results

In addition to the public-input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP process. The IRP webpage can be found at the following location: www.pacificorp.com/energy/integrated-resource-plan.html, an e-mail "mailbox" (irp@pacificorp.com), 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 2021 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 2020, Appalachia was producing over 35 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 2020 Henry Hub prices averaged $2.03/Million British thermal units (MMBtu), down 77 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 likely dominate U.S. capacity additions for the next decade. To better integrate these resources into the larger grid requires more flexible generation, transmission, new storage technologies, and market design changes.
- In 2019, the Washington Legislature approved the Clean Energy Transformation Act (CETA), which requires that 100% of electricity sales in Washington be 100% renewable and non-emitting by 2045. The Phase I rulemakings – governing the planning processes – were completed as of December 2020, and this IRP meets the requirements outlined in the law and subsequent rules.
- In 2021, Washington passed the Climate Commitment Act, which establishes a cap-and-trade program to be implemented by no later than 2023 through the regulatory rulemaking process. The Climate Commitment Act does not modify any of PacifiCorp's obligations under CETA, and utility allowances within the cap-and-trade program are aligned with the CETA renewable energy requirements. The legislation allows – but does not require – linkage with cap-and-trade programs in jurisdictions outside of Washington State.
- In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. PacifiCorp's 2023 IRP will include modeling to support House Bill 2021.
- 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 ($1.42 billion total footprint-wide benefits as of August 2, 2021). A significant contributor to EIM benefits is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area.
- Beginning in early 2019, PacifiCorp along with other Northwest Power Pool (NWPP) member entities and the Northwest Power Pool itself engaged in the development and implementation of a regional Resource Adequacy (RA) Program as a mechanism to assure a high likelihood of adequate supply to meet customer demand under a wide array of scenarios. This program includes two components, a Forward Showing (FS) planning

mechanism and an Operational Program (Ops Program) to help Participants that are experiencing extreme events meet customer demand. The program is designed to be supplemental and complementary to those processes and requirements. Program planning is scheduled to continue throughout 2022, with a proposed implementation date in 2024.

- Near-term procurement activities focused on three areas—the purchase and sale of renewable energy credits, and the purchase or procurement of new renewable and battery resources, and the procurement of new demand response resources.

Introduction

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

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

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

Wholesale Electricity Markets

PacifiCorp's system 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 ensuring that resources with the lowest operating cost are serving demand throughout the region and by providing reliability benefits that arise from a larger portfolio of resources.

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

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

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

Similarly, several transmission projects propose to provide east-to-west transfer capability to allow greater integration of intermittent resources. Gateway West – a series of transmission projects currently in the permitting process – would add east-to-west transfer capability on PacifiCorp's system.[1] Boardman-to-Hemingway (B2H), a joint effort with Idaho Power Company, a 290-mile high-voltage 500-kilovolt transmission between the Hemingway substation in southwestern Idaho and the Pacific Northwest with an online date by the end of 2026. Additionally, TransWest Express, a 730-mile line high-voltage 500-kilovolt transmission line from southwest Wyoming through Colorado and Utah to Nevada's Hoover Dam is anticipated to begin construction in once the Bureau of Land Management issues a notice to proceed, with a projected online date in the mid-2020s.

The intermittency of renewable generation has also given rise to a greater need for fast-responding and long-duration storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option and there are multiple projects being developed throughout the West. Of remaining mechanical, thermal, and chemical storage options, lithium-ion (Li-ion) batteries have shown the most promise in terms of cost and performance improvement. In 2013, the California Public Utility Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement has been satisfied. Utility-scale four-hour battery storage modules have fallen considerably in price, and costs are expected to continue to decline as electric vehicle manufacturing drives further innovation. To date, nine states have implemented energy storage targets or mandates, with another one state seriously considering implementation.[2] In California, the world's largest Li-ion battery, 400 MW, is scheduled to go online at Pacific Gas & Electric (PG&E)'s Moss Landing Power Plant in 2021.[3] Hybrid co-located solar photovoltaic (SPV) and battery systems are now in Hawaii, Arizona, Nevada, California, and Texas. In March 2019, Florida Power & Light Company announced a plan to build the world's largest solar-powered battery system with 409 MW of capacity serving the customers in late 2021.

In 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the

[1] Additional information on Gateway West projects can be found in Volume I, Chapter 4 (Transmission).
[2] California, New Jersey, New York, Massachusetts, Oregon, Nevada, Virginia, Connecticut, and Maine have either mandated or set energy storage targets, while Arizona is considering the implementation of targets.
[3] Phase II of Moss Landing is expected to reach a capacity of 1,600MWh/400MW in Fall 2021.

participation of energy storage in wholesale energy, capacity, and ancillary services markets[4]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. Later, in May 2019, the FERC issued an order generally affirming the earlier order to establish reforms to remove barrier to the participation of electric storage resources in certain organized wholesale markets. As part of its 2021 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.[5]

Increased renewable generation has also contributed to the need for balancing sub-hourly demand and supply across a broader and more diverse market. For balancing purposes, PacifiCorp combined its resources with those of the CAISO through the creation of the EIM. The EIM became operational November 1, 2014, and as of August 2021 has seen NV Energy, Puget Sound Energy, Arizona Public Service, Portland General Electric, Powerex, Idaho Power, Balancing Authority of Northern California, Salt River Project, Seattle City Light, Los Angeles Department of Water and Power, Northwestern Energy, and Public Service Company of New Mexico join the EIM. Avista Utilities, Tucson Electric Power, Tacoma Power, and Bonneville Power Administration plan to join 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 part of other EIM participant entities, PacifiCorp is also participating in the CAISO stakeholder process to establish and Expanded Day-Ahead Market (EDAM), tentatively targeted to go-live in 2022.

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

Market participants routinely study demand uncertainties driven by weather and overall economic conditions. The North American Electric Reliability Corporation (NERC) publishes an annual assessment of regional power reliability and any number of data services are available that track the status of new resource additions[6]. In its latest assessment, published December 2020, the NERC indicates that WECC region has adequate resources through 2030. However, the NERC's probabilistic studies indicate that in each of the WECC's sub-regions' (except Alberta), resource adequacy is at risk during off peak hours, starting as early as 2021.[7]

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

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

[6] 2020 Long-term Reliability Assessment, December 2020, North American Electric Reliability Assessment

[7] A discussion of regional resource adequacy efforts can be found in Volume I, Chapter 5 (Reliability and Resiliency)

In addition to reliability planning, there are externalities that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. 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 2021 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[8].

Natural Gas Uncertainty

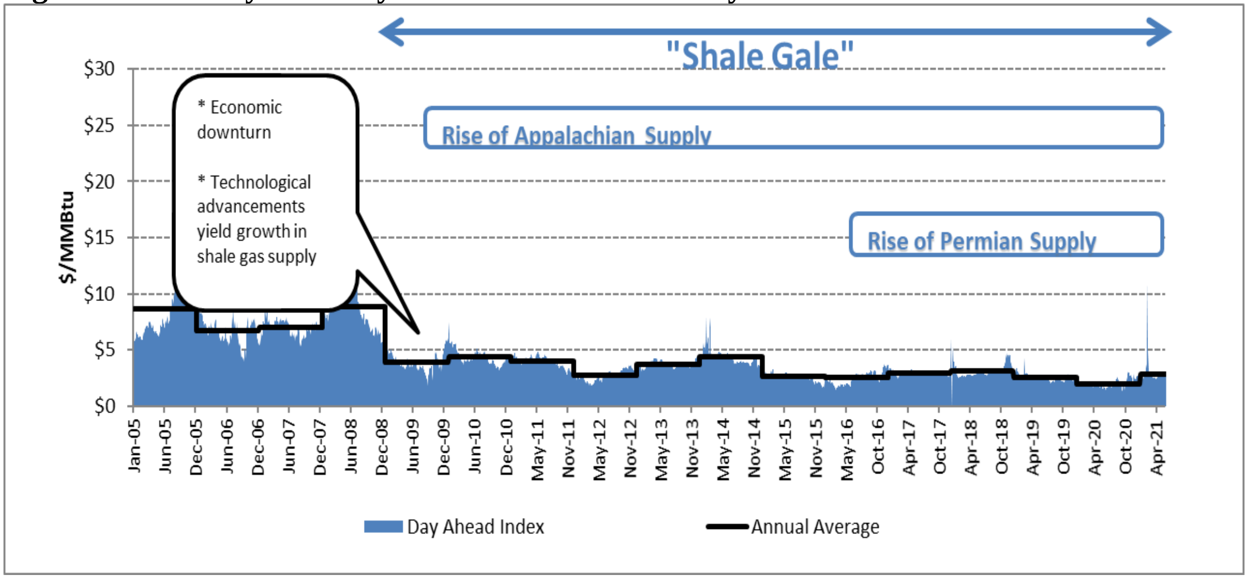
Since 2008, North American natural gas markets have undergone a remarkable paradigm shift. As shown in Figure 3.1, Henry Hub day-ahead gas prices hit a high of $13.31/MMBtu on July 2, 2008 and a low of $1.49/MMBtu on March 4, 2016. Day-ahead prices averaged $8.86/MMBtu in 2008, dropped to $3.94 in 2009, and have averaged $2.72 since 2015. Day-ahead 2020 Henry Hub prices averaged $2.03/MMBtu, down 77 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[9].

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 2020, Appalachia was producing over 35 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.

[8] 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.

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

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.

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

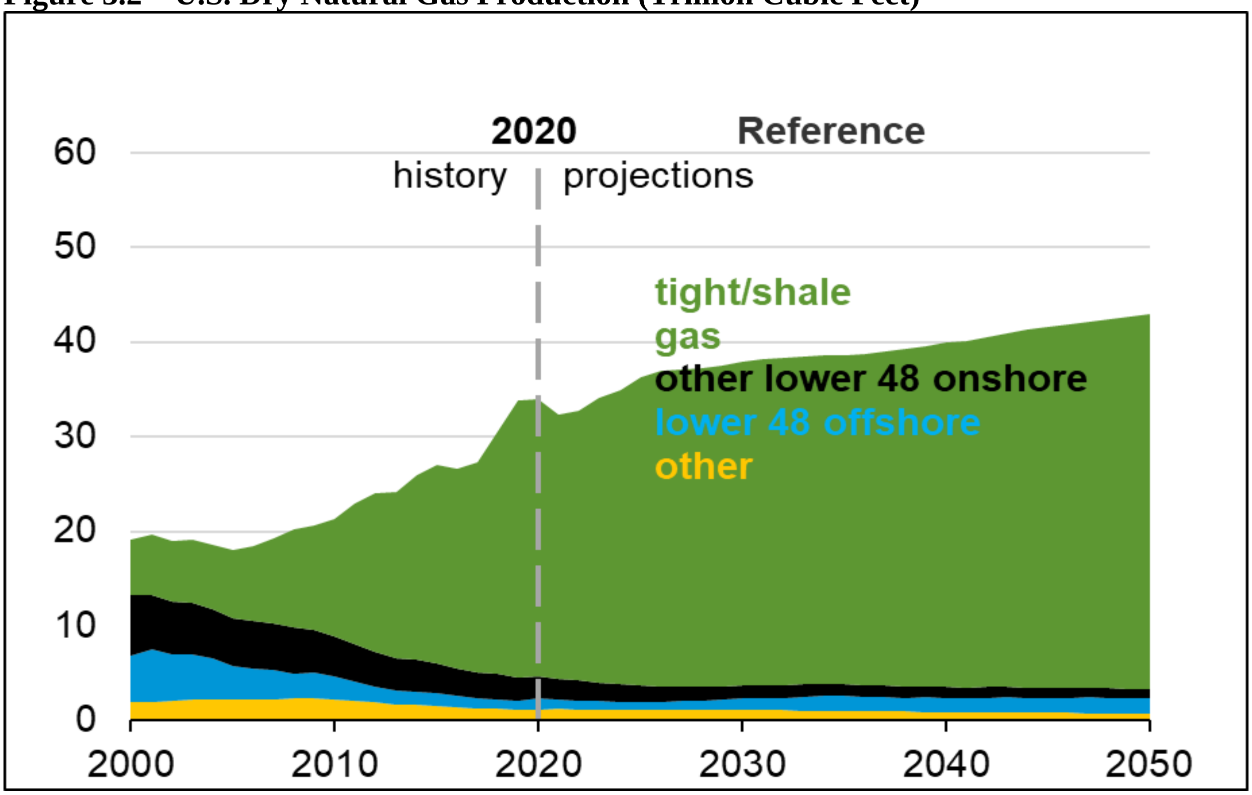
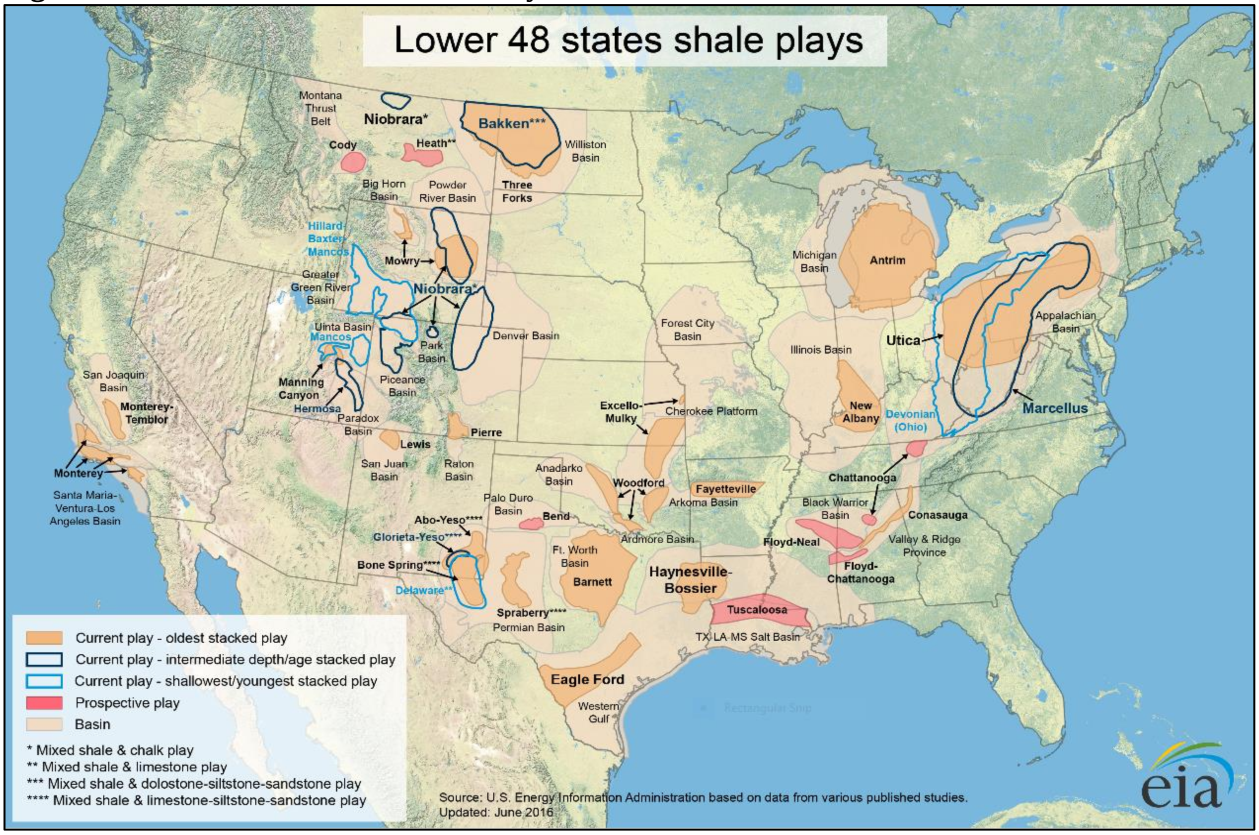
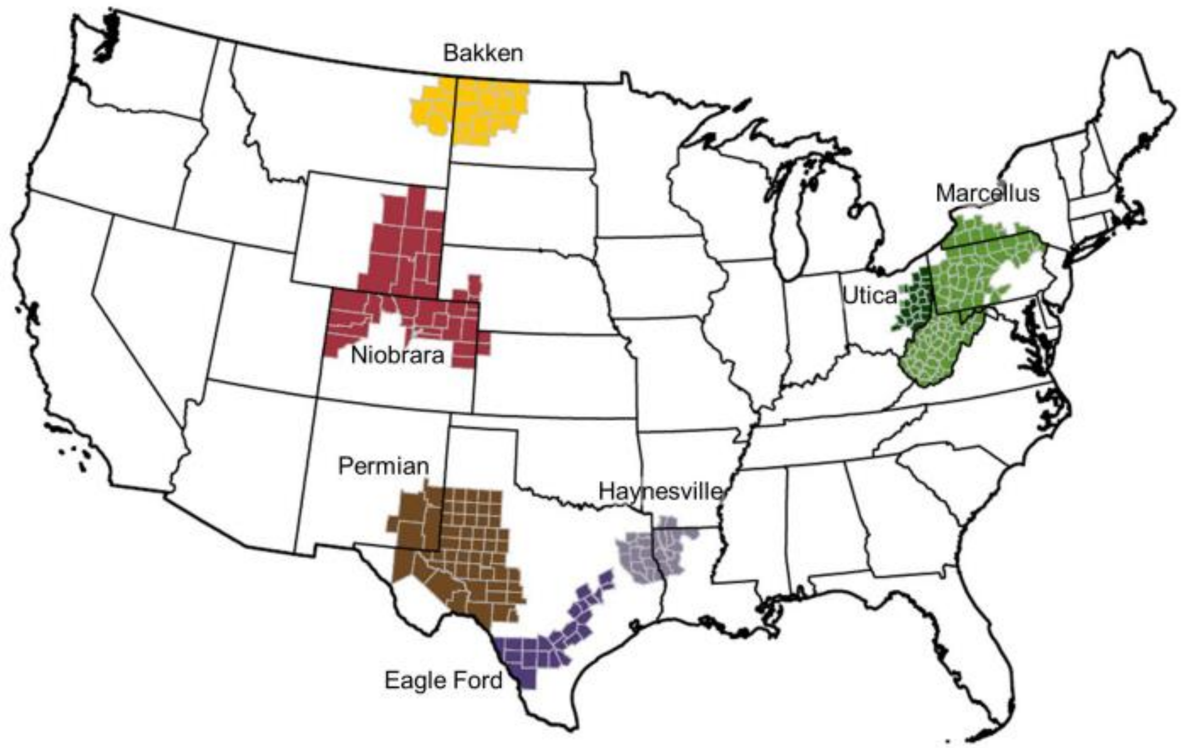


Figure 3.3 – Lower 48 States Shale Plays



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

Figure 3.4 – Plays Accounting for Natural Gas Production Growth 2011 -2020



Source: *Drilling Productivity Report*, May 17, 2021, U.S. Department of Energy, Energy Information Administration

Figure 3.5 shows Henry Hub NYMEX futures, as of June 30, 2021. Natural gas futures show a high price, \$3.17/MMBtu in 2022, which offers the "signal-to-drill" to the natural gas producers. But as producers chase production efficiencies the "signal-to-drill" price becomes lower. While the futures decline in the short term to reflect the ramp-up in the natural gas production, the annual futures rise after 2024 due to export and domestic demand growth.

But, for the next decade low-cost natural gas will come from oil-targeted plays, especially in the Permian Basin. West Texas Intermediate two-year futures are currently hovering around \$72/barrel, 68% more than 2020, reflecting the increasing demand as global economy continues to recover. It is 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.[10] This is especially true of Permian Basin oil wells, whose output naturally contains 20 to 50 percent natural gas. Permian Basin production had peaked at 12.8 Bcf/d in March 2020, following several years of rapid growth. Output from the basin then fell due to the oil price collapse and the onset of the COVID-19 pandemic in early 2020. Since then, production has started to rebound.

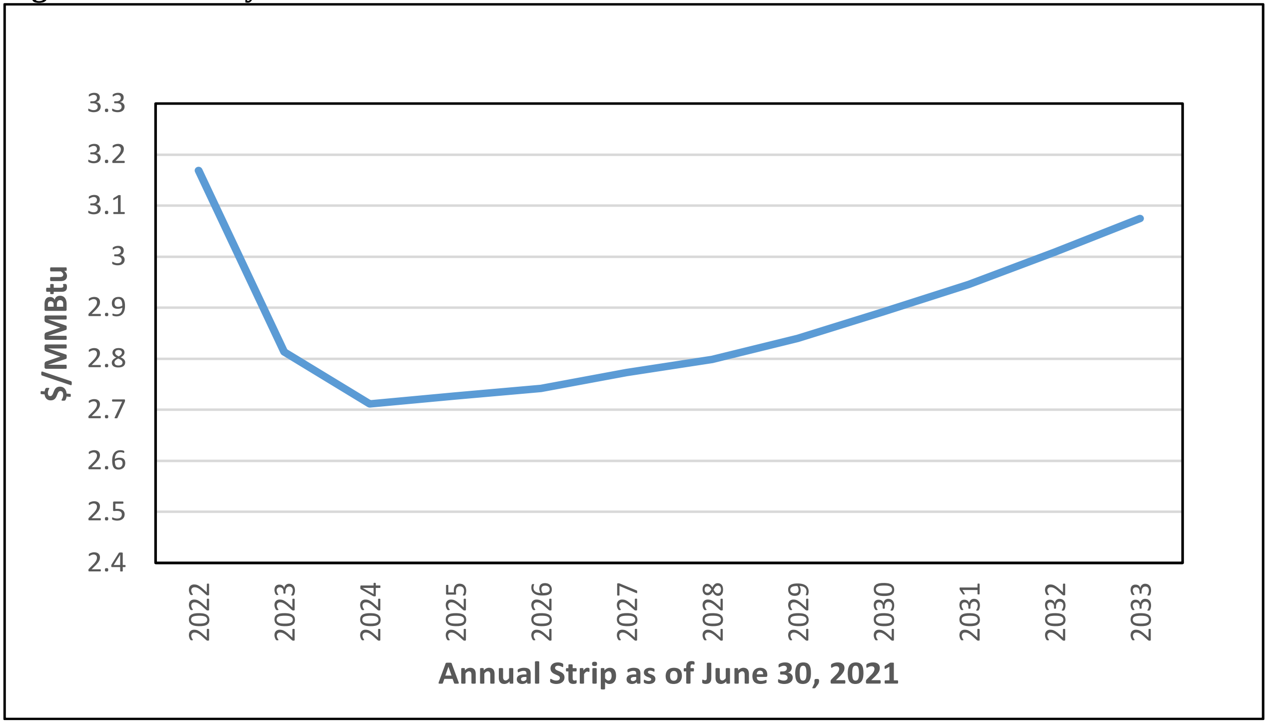
[10] Note that while front-loading increases initial production it often shortens productive well life.

In 2016, following crude's price collapse, U.S. production fell to 8.8 million barrels of oil per day (MMbpd[11]) 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. In 2020, the COVID-19 pandemic triggered an unprecedented demand shock in the oil industry, leading to a historic market collapse in oil prices. In addition, an oil price war between Russia and Saudi Arabia erupted in March when the two nations failed to reach a consensus on oil production levels. The oversupply of oil led to an unprecedented collapse in oil prices in April 2020, forcing the contract futures price for West Texas Intermediate (WTI) to plummet from $18 a barrel to around -$37 a barrel. By the summer of 2020, oil prices began to rebound as nations emerged from lockdown and OPEC agreed to significant cuts in crude oil production. Since the end of 2020, as optimism over the possible rollout of multiple COVID-19 vaccines buoyed the market, the global demand recovery has led the oil prices increasing continuously, which led to the increased oil production. Moreover, the EIA estimated that as of May 2021, 6,521 wells remain drilled but uncompleted; these wells can be put into production quickly and represent a significant source of supply[12]. 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[13]. US LNG exports have recovered from the summer 2020 weakness after global fundamentals tightened in winter 2020/21. Summer feed gas normally bound for liquefaction would then be diverted onto the U.S. market, depressing prices. The summer 2021 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. U.S. LNG exports are projected to increase in 2022 because of commissioning of additional LNG trains at Sabine Pass and Calcasieu Pass. 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.

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

Figure 3.5 – Henry Hub NYMEX Futures



Stronger oil prices and a recovering economy should enable the natural gas production to return to strong growth in 2022-2023. Associated and Appalachian gas production rebounded faster than expected in late 2020, following price-induced shut-ins earlier that year. However, as pipeline projects become increasingly difficult to build in the Appalachian region, supply growth there will be constrained after 2026, with strong associated gas and Haynesville production growth keeping prices low. 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.

PacifiCorp's Multi-State Process

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

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

In December 2019, PacifiCorp filed the most recent inter-jurisdictional cost-allocation methodology, known as the 2020 Protocol. Five of PacifiCorp's six retail states agreed that the methodology outlined in the 2017 protocol should continue, with certain modifications.[14] The guiding principles underlying the 2020 Protocol are as follows:

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

Under those principles, the 2020 Protocol represented a fundamental shift in how the company proposed to address inter-jurisdictional cost allocation, with the ultimate goal of moving away from the concept of a common generation resource portfolio with dynamic allocation factors and toward a cost-allocation protocol with fixed allocation factors for generation resources and state-specific resource portfolios. In support of that change, the 2020 Protocol used a gradual transition approach that relies on the continuation of historic protocols during an interim period (January 1, 2020 through December 31, 2023 or upon the resolution of all remaining cost-allocation issues), with a series of modifications:

- Cost-allocation procedures that will be implemented during the interim period (implemented issues);
- Cost-allocation procedures that are agreed to but that will not take effect until after the Interim Period (resolved issues); and
- Cost-allocation procedures that parties to the 2020 Protocol will continue to work to resolve during the interim period (framework issues).

Before the end of the interim period, assuming the resolution of all framework issues, a new cost allocation method – incorporating implemented issues, resolved issues and the final resolution of the framework issues – will be presented to state commissions for approval. This is anticipated to occur no later than year-end 2023.

[14] California, Idaho, Oregon, Utah, and Wyoming parties agreed to the extension of the methodology. As part of the agreement, Washington signed a Memorandum of Understanding that would continue negotiations toward Washington joining a common cost allocation methodology amongst all six states.

List of Implemented Issues

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

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

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

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

List of Resolved Issues

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

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

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

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

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

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

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

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

Update on 2020 Protocol and Status of Framework Issues

Following the filing of PacifiCorp's 2020 Protocol, Oregon, Idaho, Wyoming, Utah, and Washington have issued approval. Quarterly MSP meetings continue for parties to work through the framework issues in advance of the 2023 timeframe. The current framework issues as agreed upon in the 2020 Protocol are as follows:

1. **Resource Planning and New Resource Assignment –** The continued operation, planning, and dispatch of the Company's system as an integrated six-state system will likely be beneficial to PacifiCorp customers. However, as state energy policy continues to evolve, requiring the exclusion of certain generating resources, it appears infeasible to continue serving customers with a common generation portfolio and dynamically allocated system costs. As such, PacifiCorp will work to meet its legal requirements as a public utility in each state in a risk-adjusted, least-cost manner, while striving to mitigate cost impacts in other states. Parties to the MSP are working to develop a planning process that 1) optimizes risk-adjusted, least-cost resource portfolios on a system basis to the extent practicable while meeting individual state requirements and maintaining reliability; and 2) assigns benefits and allocates costs of specific new resources added to meet an individual state's needs. As of September 2021, these discussions are ongoing as part of the MSP framework process.

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

3. **Special Contracts** – PacifiCorp will work directly with special contract customers to develop one or more proposals for consideration of parties. PacifiCorp will make best efforts to present a proposal to parties by September 1, 2021, with the intention of incorporating a proposal into the post-interim period method.

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

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

Analysis of "Outstanding Material Disagreements"

In compliance with Wyoming Public Service Commission Order in Docket No. 9000-144-XI-19 (Record No. 15280), PacifiCorp includes this analysis of any material disagreements regarding cost allocation at the time of the preparation and filing of the 2021 IRP.

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

The Future of Federal Environmental Regulation and Legislation

The inauguration of a new federal administration and the convening of the 117th U.S. Congress in January 2021 provides a backdrop of potentially changing federal energy policy within PacifiCorp's 2021 IRP cycle. Although the exact nature of these potential changes is not known at the time of filing, the company notes that changes to energy policy may impact the portfolio selection process in the 2021 IRP and in future IRPs. PacifiCorp actively monitors federal legislative requirements and participates in rulemaking processes by filing comments on various proposals, participating in scheduled hearings, and providing assessments of proposals.

Among potential federal legislative priorities under consideration, PacifiCorp notes that there have been some emerging themes:

- **The extension and/or expansion of production and investment tax credits:** In February 2021, California Representative Mike Thompson introduced the Growing Renewable Energy and Efficiency Now (GREEN) Act, which would increase the federal solar investment tax credit and provide investment tax credits for battery storage and electric vehicles.

  In April 2021, Oregon Senator Ron Wyden introduced the Clean Energy for America Act (CEAA), which proposed to provide tax incentives for clean electricity technologies and grid improvements, including transportation electrification and energy efficiency.

  In Spring 2021, the Biden Administration released the American Jobs Plan, a $2 trillion infrastructure plan that included proposals that would expand the investment tax credit to incentivize the buildout of high-voltage capacity power lines and potentially extend the investment and production tax credits for clean energy generation and storage.

- **A federal clean energy standard and/or renewable portfolio standard:** In addition to the potential expansion and extension of tax credits, the American Jobs Plan included provisions to set a national clean electricity standard, which would transition the electricity sector to be carbon-pollution free by 2035.

  In March 2021, the House Committee on Energy and Commerce introduced the Climate Leadership and Environmental Action for our Nation's (CLEAN) Future Act, which would require electricity suppliers to provide 100 percent clean energy by 2035 as part of a national clean electricity standard.

As of August 2021, these potential policy decisions continue to be discussed, details continue to evolve, and to date no new comprehensive federal energy policy requirements have been implemented. Most recently, the United States Congress has continued negotiations a bipartisan infrastructure bill, which may contain a federal clean energy standard, production and investment tax credits, or both. PacifiCorp will continue to closely monitor emerging federal legislation and requirements.

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. In January 2021, the EPA issued the final rule. However, in April 2021, at the request of the EPA as directed by the Biden Administration, the D.C. Circuit vacated and remanded the January 2021 final rule.

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

On August 3, 2015, EPA issued a final rule, referred to as the Clean Power Plan (CPP), regulating CO_2 emissions from existing power plants.

On February 9, 2016, the U.S. Supreme Court issued a stay of the CPP suspending implementation of the rule pending the outcome of the merits of litigation before the D.C. Circuit Court of Appeals. On October 10, 2017, EPA proposed to repeal the CPP and on August 21, 2018, proposed the Affordable Clean Energy (ACE) rule to replace the CPP. The ACE rule sets forth a list of "candidate technologies" that states can use to reduce greenhouse gas emissions at coal-fueled power plants. The ACE rule was finalized June 19, 2019, replacing the CPP. On January 19, 2021, the D.C. Circuit vacated the ACE rule and directed the EPA to proceed with new rulemaking for the control of carbon emissions from electric utility coal-fired boilers.

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

In 2008, the Internal Revenue Service issued a tax credit for carbon oxide sequestration under section 45Q to incentivize carbon capture and sequestration (CCS) investments. The tax credit is computed per metric ton (tonne) of qualified carbon oxide captured and sequestered.[15] Carbon oxide can either be permanently disposed of in secure geological storage or the carbon oxide can be utilized – typically as a tertiary injectant in enhanced oil recovery (EOR).

The Bipartisan Budget Act of 2018 reformed 45Q for carbon capture equipment that is placed in service on or after February 9, 2018, increasing the credit amount from $10/tonne to $35/tonne for utilization and from $20/tonne to $50/tonne for storage.[16] This Act also removed the limit on the amount of tax credits that could be awarded for CCS, and, instead, requires a minimum amount of carbon oxide to be capture annually and is available for 12 years from the date the carbon capture equipment is originally placed into service.[17]

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 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 gas facilities are located as "Marginal Nonattainment." A marginal designation is the least stringent classification for a nonattainment area and does not require a formal State Implementation Plan (SIP).Utah submitted its strategy for meeting the standard to EPA in May of 2021.

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

[15] Before February 9, 2018, the tax credit was strictly for CO_2.
[16] The tax credit reaches $35/tonne and $50/tonne in 2026.
[17] For an electric generating facility, a minimum of 500,000 tonnes of qualified carbon oxide must be captured per year to receive the 45Q tax credit. Construction of the qualified facility must begin before January 1, 2026.

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 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 to 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. The regulated pollutants include fine particulate matter (PM), nitrogen oxide (NO_X), sulfur dioxide (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 an effective long-term strategy for achieving reasonable progress toward visibility goals. In January 2017 EPA issued a final rule updating requirements for the first periodic update to the state implementation plans (SIP). EPA required states to submit their second periodic SIP update by July 31, 2021, unless granted an extension.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are in the western United States where PacifiCorp owns and operates several coal-fired generating units (Utah, Wyoming, Colorado and Montana as well as Arizona, where a PacifiCorp-owned coal unit ceased operating in 2020).

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

Utah Regional Haze

In May 2011, the state of Utah issued a regional haze SIP requiring the installation of SO2, NOx and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO2 portion of the Utah regional haze SIP and disapproved the NOX and PM portions. EPA's approval of the SO2 SIP was appealed by environmental advocacy groups to the Tenth Circuit Court of Appeals (Tenth Circuit). In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NOX and PM SIP. PacifiCorp and the state's appeals were dismissed, and the SO2 appeal was denied by the Tenth Circuit. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an alternative BART NOx analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, crediting NOX controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove Utah's regional haze SIP and propose a federal implementation plan (FIP). The FIP required the installation of selective catalytic reduction (SCR) controls by August 4, 2021, at four of PacifiCorp's units in Utah, including Hunter Units 1 and 2 and Huntington Units 1 and 2. On September 2, 2016, the state of Utah and PacifiCorp filed petitions for administrative and judicial review of EPA's final rule, followed by a motion to stay the effective date of the final rule.

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

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

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

Environmental advocacy groups filed a petition for review objecting to the revised Utah regional haze SIP on January 20, 2021, in the Tenth Circuit. At EPA's request, the Tenth Circuit abated the petition on February 4, 2021, while EPA considers the petition under the new Biden administration's guidelines. The state of Utah, PacifiCorp and co-owners of the Hunter plant filed motions to intervene, which remain under advisement until the abatement is lifted.

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 level of 10 to determine which sources will be evaluated for reasonable progress controls under the rule. On April 21, 2020, PacifiCorp submitted a Regional Haze Reasonable Progress Analysis for the second planning period to the Utah Department of Environmental Quality for PacifiCorp's Huntington and Hunter plants. The analysis was requested by the State as part of its Second Planning Period SIP development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for NOx and SO2 on the Hunter and Huntington units to meet second planning period requirements. On October 20, 2020, PacifiCorp submitted a follow-up letter in response to questions from the Utah Department of Environmental Quality (Utah DEQ) about proposed emission reductions and costs for control technology. Utah DEQ and PacifiCorp are engaged in ongoing discussions regarding evaluations and requirements for emission reductions and control technologies.

Wyoming Regional Haze

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

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

Wyodak – PacifiCorp and the state of Wyoming petitioned EPA's final action several requiring SCR at Wyodak. PacifiCorp and other parties successfully requested a stay of EPA's final rule relating to the Wyoming SIP pending resolution of the petition. PacifiCorp subsequently submitted a request for reconsideration to EPA and is currently engaged in a settlement process with EPA and Wyoming. The EPA, state of Wyoming and PacifiCorp signed a Settlement Agreement for Wyodak on December 16, 2020. EPA published the Settlement Agreement in the Federal Register requesting public comment on January 4, 2021. PacifiCorp submitted formal comments to the EPA on March 5, 2021, in support of the Wyodak Settlement Agreement. The public comment period was extended through July 6, 2021. EPA did not proceed with final approval of the Settlement Agreement and has engaged Wyoming and PacifiCorp regarding paths for resolution.

Naughton - In its 2014 rule, EPA approved Wyoming's determination that BART for Units 1 and 2 was LNB/OFA. EPA also indicated support for the conversion of the Naughton Unit 3 to natural gas in lieu of retrofitting the unit with SCR and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its Regional Haze SIP amendment regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit for Unit 3's conversion to natural gas, which allowed operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019, as required by the permit. EPA's final rule approval of Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the *Federal Register* on March 21, 2019, with an effective date of April 22, 2019. Naughton Unit 3 currently operates on natural gas. Environmental groups petitioned EPA's approval of LNB/OFA as BART for Units 1 and 2 in the Tenth Circuit. Like the Wyodak petition, that petition was stayed by the court and remains stayed.

Jim Bridger - SCR was installed on Jim Bridger Units 3 and 4 by the dates required by Wyoming in state law and by EPA in the 2014 final rule. On February 5, 2019, PacifiCorp submitted to Wyoming an application and proposed SIP revision instituting plant-wide variable average monthly-block pound per hour NOx and SO_2 emission limits, in addition to an annual combined NOx and SO_2 limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. The proposed SIP revision demonstrates that the proposed limits are more cost effective while leading to better modeled visibility than the SCR installation on Units 1 and 2 required in the federally approved SIP.

Wyoming's proposed approval of the SIP revision was published for public comment July 20, 2019, through August 23, 2019. On May 5, 2020, the Wyoming Department of Environmental Quality issued permit P0025809 with PacifiCorp's proposed monthly and annual NOx and SO_2 emission limits. Under the permit, the new emission limits become effective January 1, 2022. Wyoming submitted a corresponding regional haze SIP revision to EPA on May 14, 2020. EPA has not taken formal action responding to the SIP revision. Discussions between EPA, Wyoming, and PacifiCorp regarding the SIP revision and regional haze compliance at Jim Bridger are ongoing.

WRAP performed the modeling that the state will use for the implementation of the second planning period. On March 31, 2020, PacifiCorp submitted a four-factor reasonable progress analysis to Wyoming which analyzed PacifiCorp's Naughton, Jim Bridger, Dave Johnston, and Wyodak plants. The four-factor analyses will be used by the state in its development of the SIP for the regional haze second planning period.

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

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

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

In February 2015, 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, to convert the unit to natural gas by August 31, 2023. The Colorado Air Quality Board approved the agreement on December 15, 2016. Colorado submitted the corresponding SIP amendment to EPA Region 8 on May 17, 2017. EPA approved the SIP on July 5, 2018.

Mercury and Hazardous Air Pollutants

The Mercury and Air Toxics Standards (MATS) became effective April 16, 2012. The MATS rule required that new and existing coal-fueled facilities achieve emission standards for mercury, acid gases and other non-mercury hazardous air pollutants. Existing sources were required to comply with the new standards by April 16, 2015. However, individual sources may have been granted up to one additional year, at the discretion of the Title V permitting authority, to complete installation of controls or for transmission system reliability reasons. By April 2015, PacifiCorp had taken the required actions to comply with MATS across its generation facilities. On April 25, 2016, the EPA published a Supplemental Finding that determined that it is appropriate and necessary to regulate under the MATS rule which addressed 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. In May 2020, the EPA published its decision to repeal the appropriate and necessary findings in the MATS rule regarding regulation of electric utility steam generating units, and to retain the rule's current emission standards. The rule took effect in July 2020. Several petitions for review were filed in the D.C. Circuit by parties challenging and supporting the EPA's decision to rescind the appropriate and necessary finding. Until litigation over the rule is exhausted, PacifiCorp cannot fully determine the potential impacts of the changes to the MATS rule.

Coal Combustion Residuals

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

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

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

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

Separately, on August 10, 2017, the EPA issued proposed permitting guidance on how states' coal combustion residuals permit programs should comply with the requirements of the final rule as authorized under the December 2016 Water Infrastructure Improvements for the Nation Act. To date, none of the states in which PacifiCorp operates has submitted an application to the EPA for approval of state permitting authority. The state of Utah adopted the federal final rule in September 2016, which required PacifiCorp to submit permit applications for two of its landfills by March 2017. It is anticipated that the state of Utah will submit an application to EPA for approval of its coal combustion residuals permit program prior to the end of 2022. In 2019, the state of Wyoming proposed to adopt state rules which incorporate the final federal rule by reference. Wyoming finalized its rule in late 2020 and is waiting on legislative approval, likely in 2022, before submitting an application to the EPA to implement a state permit program.

Water Quality Standards

Cooling Water Intake Structures

The federal Water Pollution Control Act ("Clean Water Act") establishes the framework for maintaining and improving water quality in the United States through a program that regulates, among other things, discharges to and withdrawals from waterways. The Clean Water Act requires that cooling water intake structures reflect the "best technology available for minimizing adverse environmental impact" 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 and subsequent issuance of a draft permit for public notice, the Water Quality Division has indicated that PacifiCorp may be required to select and implement an approved 316(b) impingement mortality compliance option by December 31, 2023. As the final Dave Johnston Wyoming Pollutant Discharge Elimination System permit has yet to be issued which is expected to include 316(b) impingement mortality (IM) compliance requirements, it is anticipated that the December 31, 2023 IM technology implementation date will be adjusted to compensate for the actual permit issuance date.

Effluent Limit Guidelines

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

On April 5, 2017, a request for reconsideration and administrative stay of the guidelines was filed with the EPA. EPA granted the request for reconsideration and extended certain compliance dates for flue gas desulfurization wastewater and bottom ash transport water limits until November 1, 2020.

On November 22, 2019, EPA proposed updates to the 2015 rule, specifically addressing flue gas desulfurization wastewater and bottom ash transport water. Those proposals were formalized in rule when the EPA administrator signed the Reconsideration Rule, and it was published in the Federal Register on October 13, 2020. The rule eases selenium limits on flue gas desulfurization wastewater, eases the zero-discharge requirements on bottom ash transport water associated with blowdown of ash handling systems, allows a two-year time extension to meet flue gas desulfurization wastewater requirements, and includes additional subcategories to both wastewater categories.

Most of the issues raised by this rule are already being addressed at PacifiCorp facilities through compliance with the coal combustion residuals rule and are not expected to impose significant additional requirements on the facilities. The Dave Johnston plant anticipates achieving compliance with the rule by issuing a notice of planned participation for subcategorization, or by installation and operation of a bottom ash recycle system that would enable long-term compliance with the Reconsideration Rule.

Renewable Generation Regulatory Framework

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

The wind projects constructed as part of PacifiCorp’s Energy Vision 2020 initiative for example, (TB Flats, Ekola Flats, and Cedar Springs) were required to obtain permits from the State of

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

Tax Extender Legislation

On Dec. 27, 2020, President Trump signed into law the Taxpayer Certainty and Disaster Relief Act of 2020. Among other things, the bill extended and expanded certain alternative energy tax credits. Notable as relating to the 2021 IRP, the renewable electricity production tax credit (PTC) was extended by one year for certain qualifying facilities; for wind facilities that begin construction during 2021, the credit continues to be equal to 60% of the full value of the PTC. The energy tax credit (ITC) was extended by two years for certain qualifying facilities; the bill extends the 26% ITC for solar energy property that begins construction during 2021 and 2022, before being phased down further.

The energy tax credit was expanded to cover offshore wind facilities; generally, any offshore wind project that on which construction after December 31, 2017, and before January 1, 2026, will qualify for a 30% ITC. And, finally, the credit for carbon dioxide sequestration was extended to cover facilities that begin construction by the end of 2025. Additional schedules detailing the phase-out of the wind PTC and solar ITC are provided as follows:

Table 3.1 – Tax Extender Legislation and Phaseout of PTC and ITC

Phaseout of Wind PTC		
Date Construction Begins	In-Service Date*	% of Full PTC Rate
Before 12/31/2015	Before 01/01/2020	100%
01/01/2016 - 12/31/2016	Before 01/01/2022	100%
01/01/2017 - 12/31/2017	Before 01/01/2023	80%
01/01/2018 - 12/31/2018	Before 01/01/2023	60%
01/01/2019 - 12/31/2019	Before 01/01/2024	40%
01/01/2020 - 12/31/2020	Before 01/01/2025	60%
01/01/2021 - 12/31/2021	Before 01/01/2026	60%
On or After 01/01/2022	Any	0%

* In-Service date assumes the use of the Continuity Safe Harbor which is 4 years after the calendar year during which construction, 5 years for projects beginning construction in 2016 and 2017.

Phaseout of Solar ITC		
Date Construction Begins	In-Service Date	ITC Rate
Before 01/01/2020	Before 01/01/2026	30%
01/01/2020 - 12/31/2020	Before 01/01/2026	26%
01/01/2021 - 12/31/2021	Before 01/01/2026	26%
01/01/2022 - 12/31/2022	Before 01/01/2026	26%
01/01/2023 - 12/31/2023	Before 01/01/2026	22%
Before 01/01/2024	On or After 01/01/2026	10%
On or After 01/01/2024	Any	10%

State Policy Update

California

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

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by

2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target.

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

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

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

In 2021, Oregon passed House Bill 2021, which directs utilities to reduce emissions levels below 2010-2012 baseline levels by 80% by 2030, 90% by 2035, and 100% by 2040. Utilities will also convene a Community Benefits and Impacts Advisory Group. PacifiCorp's 2023 IRP will include modeling to support House Bill 2021.

Washington

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

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

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

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

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

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.

On March 11, 2020, the Utah Legislature passed HB 396, Electric Vehicle Charging Infrastructure Amendments, that enables PacifiCorp to create an Electrical Vehicle Infrastructure Program, with a maximum funding from customers of $50 million for all costs and expenses. The legislation allows PacifiCorp to own and operate electric vehicle charging stations and to provide investments in make-ready infrastructure to interested customers.

Wyoming

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

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

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

In March 2020, the Wyoming legislature passed House Bill 200 (HB 200), Reliable and Dispatchable Low-Carbon Energy Standards. HB 200 requires the Wyoming Public Service Commission to put in place a standard for each public utility specifying a percentage of electricity to be generated from coal-fired generation utilizing carbon capture technology by 2030. The requirement would only apply to generation allocated to Wyoming customers. HB 200 will require each public utility to demonstrate in its IRP the steps taken to achieve the electricity generation standard established by the Commission and will allow rate recovery of costs incurred by a public utility that utilizes coal-fired generation with carbon capture technology installed.

Greenhouse Gas Emission Performance Standards

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

Renewable Portfolio Standards

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

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

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.2, with additional discussion below.

Table 3.2 – State RPS Requirements

	California	Oregon	Washington	Utah
Legislation	• Senate Bill 1078 (2002) • Assembly Bill 200 (2005) • Senate Bill 107 (2006) • Senate Bill 2 First Extraordinary Session (2011) • Senate Bill 350 (2015) • Senate Bill 100 (2018)	• Senate Bill 838 Oregon Renewable Energy Act (2007) • House Bill 3039 (2009) • House Bill 1547-B (2016)	• Initiative Measure No. 937 (2006) • SB 5400 (2013)	• Senate Bill 202 (2008)
Requirement or Goal	• 20% by December 31, 2013 • 25% by December 31, 2016 • 33% by December 31, 2020 • 44% by December 31, 2024 • 52% by December 31, 2027 • 60% by December 31, 2030 and beyond • Planning target of 100% renewable and zero-carbon by 2045 * Based on the retail load for a three-year compliance period	• 5% by December 31, 2011 • 15% by December 31, 2015 • 20% by December 31, 2020 • 27% by December 31, 2025 • 35% by December 31, 2030 • 45% by December 31, 2035 • 50% by December 31, 2040 * Based on the retail load for that year	• 3% by January 1, 2012 • 9% by January 1, 2016 • 15% by January 1, 2020 and beyond * Annual targets are based on the average of the utility's load for the previous two years	• Goal of 20% by 2025 (must be cost effective) • Annual targets are based on the adjusted[18] retail sales for the calendar year 36 months before the target year

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

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.[19] 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.[20] 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 3.3 below.

Table 3.3 – California Compliance Period Requirements

Compliance Period	Procurement Quantity Requirement Calculation
Compliance Period 1 (2011-2013)	(20% * 2011 Retail Sales) + (20% * 2012 Retail Sales) + (20% * 2013 Retail Sales)
Compliance Period 2 (2014-2016)	(21.7% * 2014 Retail Sales) + (23.3% * 2015 Retail Sales) + (25% * 2016 Retail Sales)
Compliance Period 3 (2017-2020)	(27% * 2017 Retail Sales) + (29% * 2018 Retail Sales) + (31% * 2019 Retail Sales) + (33% * 2020 Retail Sales)
Compliance Period 4 (2021-2024)	(35.8% * 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;[11] or
>
> Have an agreement to dynamically transfer electricity to a California balancing

[19] www.leginfo.ca.gov/pub/11-12/bill/sen/sb_0001-0050/sbx1_2_bill_20110412_chaptered.pdf
[20] leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350

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.[21]

Additionally, the CPUC established the balanced portfolio requirements for contracts executed after June 1, 2010. The balanced portfolio requirements set minimum and maximum levels for the Procurement Content Category products that may be used in each compliance period as shown in Table 3.4.

Table 3.4 – California Balanced Portfolio Requirements

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

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

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

[21] 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.

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.[22] 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,[23] 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.
- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[24]

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.

[22] www.leg.state.or.us/07reg/measpdf/sb0800.dir/sb0838.en.pdf
[23] olis.leg.state.or.us/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled
[24] 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.

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.

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.[25]

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

Eligible renewable resources include electricity from a facility or upgrade that becomes operational on or after January 1, 1995, that derives its energy from wind, solar photovoltaic, solar thermal electric, wave, tidal or ocean thermal, certain types of biomass and biomass products, landfill gas or municipal solid waste, geothermal, waste gas and waste heat capture or recovery, and efficiency upgrades to hydroelectric facilities if the upgrade occurred after January 1, 1995. Up to 50 average megawatts from a certified low-impact hydro facility and in-state geothermal

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

and hydro generation without regard to operational online date may also be used toward the target. To assist solar development in Utah, solar facilities located in Utah receive credit for 2.4 kilowatt-hours of qualifying electricity for each kWh of generation.

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

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

In 2027, the legislation requires a commission report to the Utah Legislature, which may contain any recommendation for penalties or other action for failure to meet the 2025 target. The legislation 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.[27] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

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

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[28]

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.

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

REC Management Practices

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

Clean Energy Standards

Washington

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

Oregon

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

California

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

Wyoming

In March 2020, the Wyoming governor signed House of Representatives Enrolled Act No. 79, which requires the WPSC to adopt a low-carbon standard to specify a percentage of an electric utility's electricity to be generated from coal-fueled generation utilizing carbon capture technology by no later than 2030. The bill allows electric utilities to implement a surcharge not to exceed 2% of customer bills to recover costs to comply with the standard. The WPSC is establishing the standard and requirements to implement the law through a rulemaking process expected to be completed before the end of 2021.

Transportation Electrification

The electric transportation market is in an emerging state,[29] and plug-in electric vehicles (EV) currently comprise a negligible share of PacifiCorp's load. This rapidly evolving market represents a potential driver of future load growth and those impacts managed proactively, provide an opportunity to increase the efficiency of the electrical system and provide benefits for all PacifiCorp customers. In addition, increased adoption of electric transportation has the ability to improve air quality, reduce noise pollution, reduce greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low- and moderate-income populations.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing to support EV fast chargers along key corridors, develop workplace charging programs, research new rate designs and implement time-of-use pricing pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities. Our investments include the Oregon Clean Fuels programs as well as pilot programs approved and filed with the OPUC equaling over $12 million in TE investment. This includes infrastructure, education and outreach and innovative e mobility projects. As of the end of 2020, PacifiCorp had supported installation of over 2,100 EV ports throughout the territory

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

Hydroelectric Relicensing

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

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

[29] As of June 2019, the market share of plug-in electric vehicles was two percent: www.nada.org/WorkArea/DownloadAsset.aspx?id=21474858563

of the license are consistent with the Commission's previous environmental analysis. Pursuant to the new license, PacifiCorp will implement increased minimum flows downstream of the diversion dam, replace the project's wood-stave flowline and sag-pipe, upgrade and construct new wildlife crossings over the waterway, and prepare and implement various monitoring and management plans.

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

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, 2020, PacifiCorp had incurred approximately $5 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work- in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Cutler and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. Much of these relicensing and settlement costs relate to PacifiCorp’s 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 Volume I, Chapter 7 (Resource Options).

PacifiCorp’s Approach to Hydroelectric Relicensing

PacifiCorp continues to manage the hydroelectric relicensing process by pursuing interest-based resolutions or negotiated settlements as part of relicensing. PacifiCorp believes this proactive approach, which involves meeting agency and others’ interests through creative solutions, is the best way to achieve environmental 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. As of Spring 2021, less than one percent of customers have opted to participate in the time-of-day rate option.

Changes in residential rate design include a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs will be discussed in more detail in Volume I, Chapter 7 (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.

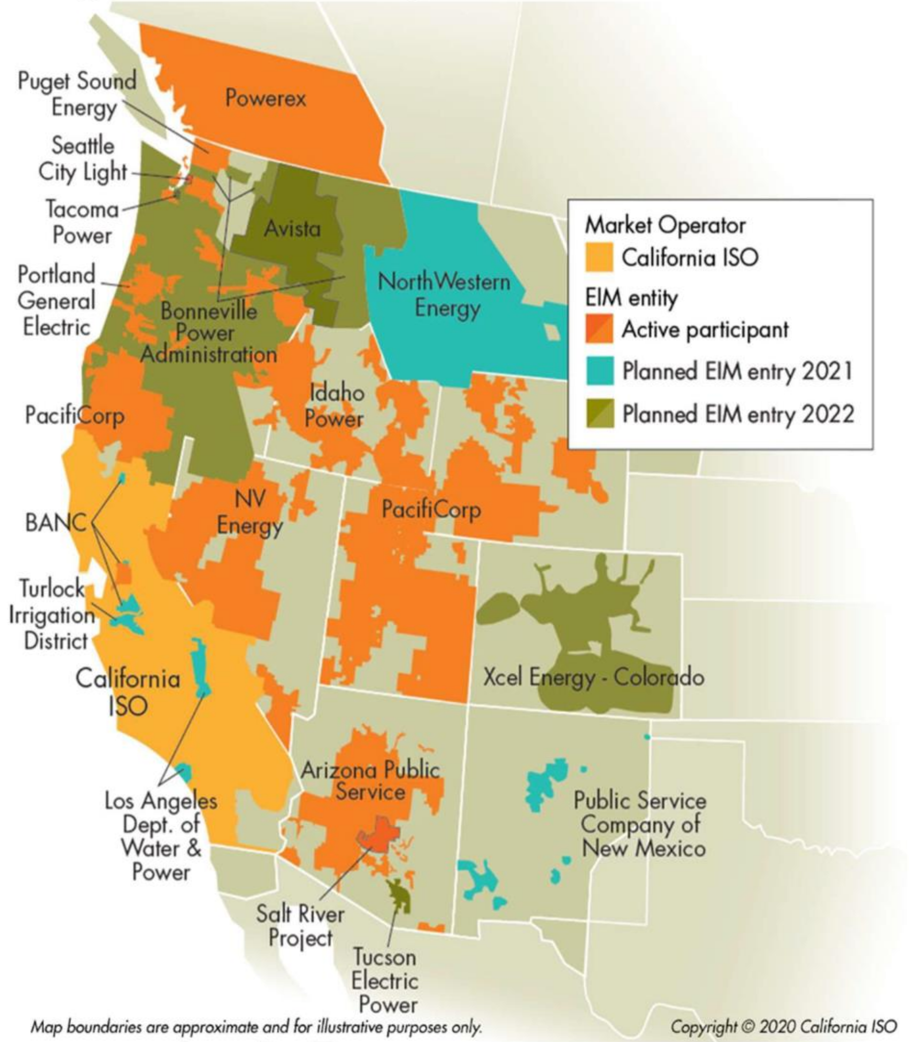
Irrigation Rate Design

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. NV Energy began participating in December 2015, Arizona Public Service and Puget Sound Energy began participating in October 2016, and Portland General Electric began participating in October 2017. Idaho Power and Powerex began participating in April 2018, and the Balancing Authority of Northern California (BANC)[1] began participating in April 2019. Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020, and 2021 saw the addition of NorthWestern Energy, Los Angeles Department of Water & Power, Public Service Company of New Mexico, and Turlock Irrigation District. The EIM footprint now includes portions of Arizona, California, Idaho, Nevada, Oregon, Utah, Washington, Wyoming, and extends to the border with Canada. 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 ($1.42 billion total footprint-wide benefits as of August 2021), 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 is transfers across balancing authority areas, providing access to lower-cost supply, while factoring in the cost of compliance with greenhouse gas emissions regulations when energy is transferred into the CAISO balancing authority area to serve California load. The transfer volumes are therefore a good indicator of a portion of the benefits attributed to the EIM. Transfers can take place in both the five and 15-minute market dispatch intervals.

After development and expansion of the 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. The concept of extending day-ahead market services is a current CAISO stakeholder initiative, which also aligns with the CAISO's day-ahead market enhancement stakeholder initiative. The Extended Day-Ahead Market (EDAM) stakeholder initiative is expected to continue working through transmission utilization, resource sufficiency, governance and congestion management in 2021.

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 3.5 summarizes recent RFP activities.

Table 3.5 – PacifiCorp's Requests for Proposal Activity

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
2019R Utah RFP	Purchase new renewable energy for specific customers under Utah Schedule 32 or 34	Ongoing	March 2019	Fall 2019
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
2020 All-Source RFP	Seeking resources consistent with the 2019 IRP's least cost resource portfolio	Ongoing	July 2020	Ongoing
2021 DR RFP	Oregon compliance and purchase of cost-effective flexible capacity	On-going	January 2021	Ongoing

2020 All-Source RFP

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

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

PacifiCorp is finalizing both build and transfer and power purchase agreement updated drafts that will be forwarded to all final shortlisted participants prior to September 1, 2021. Contract negotiations are expected to proceed into early Q1 2022. All necessary final state regulatory approvals and proceedings are expected to be complete by Q2 2022.

2021 DR RFP

PacifiCorp's 2019 IRP identified the addition of 178 MW of DR system wide by 2029 as resource additions of a least cost least risk long term resource plan. To acquire the DR resource needs identified in the 2019 IRP, the company issued a DR RFP for cost effective DR resources. Successful initial short list bids from this DR RFP joined final bids from the AS 2020 RFP for a combined analysis in the 2021 IRP to determine the optimal acquisition of resources to meet system needs. On February 8, 2021, PacifiCorp issued an RFP soliciting proposals from implementation contractors for Demand Response (DR) resources. Although a variety of programs were eligible for consideration, of most interest to PacifiCorp were programs located in Oregon and/or Washington with the following focus:

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

The final shortlist of bids was identified in June 2021 and includes over 600 MW of capacity during the planning horizon. PacifiCorp is finalizing the procurement and negotiation of demand response resources following the completion of 2021 IRP. Contract negotiations and program filings are expected to conclude in Q4 of 2021. All necessary state regulatory approvals and proceedings are expected to be complete in the winter and spring of 2022.

CHAPTER 4 – TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects help facilitate a transitioning resource portfolio and comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit, and construct new transmission lines, these projects need to be planned well in advance of resource additions.
- PacifiCorp's transmission planning and benefits evaluation efforts adhere to regulatory and compliance requirements and respond to commission and stakeholder requests for a robust evaluation process and clear criteria for evaluating transmission additions.
- The 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59-mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.
- The 2021 IRP preferred portfolio also includes the Boardman to Hemingway line - an approximately 290-mile high-voltage 500-kilovolt transmission line and associated infrastructure running from the proposed Longhorn substation near Boardman, Oregon and the Hemingway substation near Melba, Idaho, which will come online in 2026.
- Further, the 2021 IRP preferred portfolio 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 resources needed to serve our customers. While construction of the balance of future Energy Gateway segments (i.e., Gateway West segments D.3, and E 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 a high-value asset that is designed to reliably transport electric energy from a broad array of generation resources (owned or contracted generation including market purchases) to load centers. There are many benefits associated with a robust transmission network, some of which are set forth below:

1. Reliable delivery of diverse energy supply to continuously changing customer demands under a wide variety of system operating conditions.
2. Ability to always meet aggregate electrical demand and customers' energy requirements, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. Ability to meet changing regulatory requirements as states move towards a renewable energy future.

4. Economic dispatch of resources within PacifiCorp's diverse system.
5. Economic transfer of electric power to and from other systems as facilitated by the company's participation in the market, which reduces net power costs and provides opportunities to maintain resource adequacy at a reasonable cost.
6. Access to some of the nation's best wind and solar resources, which provides opportunities to develop geographically diverse low-cost renewable assets.
7. Protection against market disruptions where limited transmission can otherwise constrain energy supply.
8. Ability to meet obligations and requirements of PacifiCorp's Open Access Transmission Tariff (OATT).

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

Regulatory Requirements

Open Access Transmission Tariff

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

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

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

Reliability Standards

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

This chapter provides:

- Justification supporting acknowledgement of PacifiCorp's plan to construct the Gateway South, Gateway West segment D.1 and Boardman-to-Hemingway transmission lines. Support for PacifiCorp's plan to continue permitting the balance of Gateway West;
- Key background information on the evolution of the Energy Gateway Transmission Expansion Plan; and
- An overview of PacifiCorp's investments in recent short-term system improvements that have improved reliability, helped to maximize efficient use of the existing system, and enabled the company to defer the need to invest in larger-scale transmission infrastructure.

Generation Interconnection Queue Reform

In 2019, PacifiCorp initiated a public stakeholder process to review possible generation interconnection tariff reform transitioning from a serial queue process to a cluster study process.

[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.

In May of 2020 the Federal Energy Regulatory Commission (FERC) issued an order approving the transition and in the same year PacifiCorp initiated the first cluster study process, the "transitional cluster study". The transitional study was initiated in October of 2020 and completed in March of 2021, the first annual cluster study process was initiated in April of 2021 and is planned to complete in November of 2021. Subsequent study processes will be initiated annually beginning in April.

PacifiCorp's serial queue interconnection process, based on the *pro forma* tariff generation interconnection procedures, presented significant challenges in meeting the goals of FERC Order No. 2003 due to a large number of Interconnection Requests in the company's queue competing to serve PacifiCorp load. There was additional concern at the state commission level that the serial process inhibited wholesale competition. The main feature the interconnection cluster approach is its prioritization of commercial readiness over queue position in the interconnection process—i.e., a change from a "first-come, first-served" to a "first-ready, first-served" approach. To do this, generator developers are required to demonstrate sufficient progress toward commercial operation before submitting a formal Interconnection Request and entering a Cluster. This process of increasing the requirements for obtaining a queue position in this way increases the likelihood that only projects that are likely to be commercially viable enter the interconnection process.

In the transition cluster study 56 requests totaling approximately 4260 megawatts were entered into the process and evaluated, of those 24 projects moved beyond the initial cluster study phase. These requests represented a mix of solar, hydro, solar and storage, battery storage, wind, geothermal and nuclear resources. In the first annual cluster study, under process now, 59 requests were received totaling approximately 12,037 megawatts with 52 currently remaining in the process. These requests represent a mix of solar, solar and storage, battery storage, pumped storage, wind, wind and storage and geothermal resources.

Aeolus to Bridger/Anticline

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 was completed in October 2020 and energized in November 2020.

Aeolus-to-Mona (Gateway South)

The 2021 PacifiCorp IRP preferred portfolio includes the Aeolus-to-Mona (Clover substation) transmission segment (Energy Gateway South or Segment F).

To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes significant transmission investment. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South transmission line - a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project - a new 59 mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines come online by the end of 2024.

Timing of construction is driven by the phase-out schedule of federal production tax credits (PTCs), particularly the 2024 in-service requirements for 60 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.

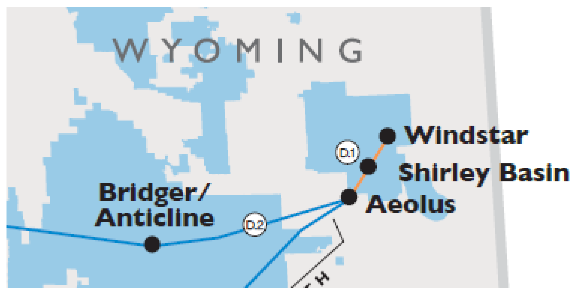
Gateway West – Continued Permitting

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). 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:

Figure 4.1 - Segment D



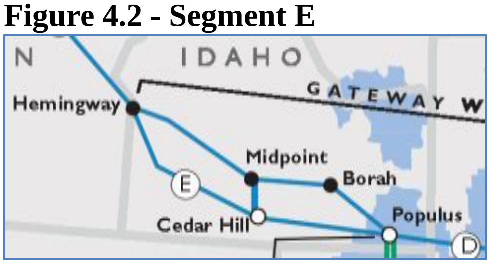
- D1—A single-circuit 230-kV line that will run approximately 59 miles between the existing Windstar substation in eastern Wyoming and the Aeolus substation near Medicine Bow, Wyoming, which includes a loop-in to the existing Shirley Basin 230-kV substation;

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

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

Populus 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 performance of the transmission system performance (i.e., reduce line losses), improve reliability, and enable access to a diverse range of new resource alternatives over the long term.

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

Request for Acknowledgement for Boardman-to-Hemingway

The 2021 IRP preferred portfolio also includes an approximately 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway to come online by 2026. Further, the 2021 IRP 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.

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

Idaho Power's 2019 IRP 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.

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

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 project has been issued a Proposed Order approving the project, with the next step the completion of the Contested Case proceeding, which is expected to conclude in 2022.

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.

Factors Supporting Acknowledgement

PacifiCorp's existing transmission path between the two balancing areas (PACW and PACE) consists of a single line (Midpoint Idaho to Summer Lake Oregon) 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. 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 2030. Coupled with renewable additions 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. To support the addition of the new renewable resources typically located remotely from load centers and retirement of coal resources requires continued investment in a robust transmission system required to move resources across and between both PacifiCorp balancing areas.
- **Regional Benefit**: PacifiCorp, as a past member of the regional planning entity Northern Tier Transmission Group (NTTG), supported the inclusion of B2H in the NTTG 2018-2019 regional plan. PacifiCorp as a current member of the regional planning organization NorthernGrid has supported the inclusion of B2H into the 2020-2021 regional plan. From a regional perspective, the B2H project is a cost-effective investment that will provide regional solutions to identified regional needs. The project resolves possible system issues as identified in the NTTG 2018-2019 draft regional plan. This plan shows system issues depicted by heat maps, refer to figure 33, for the regional transmission line without B2H and with B2H, refer to figure 34 in the NTTG report. Figure 34 in the NTTG report shows the removal of system issues graphically.
- **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.
- **Energy Imbalance Market (EIM)**: PacifiCorp was a leader in implementing the western 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.
- **Grid Reliability**: The loss of the Hemingway–Summer Lake 500-kV transmission line, the only 500-kV connection between the Pacific Northwest and Idaho Power, during peak summer load is one of the most severe possible contingencies the Idaho Power transmission system can experience. Once Hemingway–Summer Lake 500-kV disconnects, the transfer capability of the Idaho to Northwest path is reduced by over 700 MW in the west-to-east direction. After the addition of B2H, there will be two major 500-kV connections between the Pacific Northwest and Idaho Power. The Hemingway–Summer Lake 500-kV outage would become much less severe to Idaho Power's transmission system. Additionally, loss of the Hemingway–Summer Lake 500-kV line with heavy east-to-west power transfer out of Idaho to the Pacific Northwest results in significant system impacts. In this disturbance, an existing remedial action scheme (power system logic used to protect power system equipment) will disconnect over 1,000 MW of generation at the Jim Bridger Power Plant to reduce path transfers and protect bulk transmission lines and apparatus. Due to the magnitude of the generation loss, recovery from this disturbance can be extremely difficult. After the addition of B2H, this enormous amount of generation shedding will no longer be required. With two 500-kV lines between Idaho and the Pacific Northwest, the loss of one can be absorbed by the other. Keeping 1,000 MW of generation on the system for major system outages is important for grid stability.

Next Steps

Given the extensive list of benefits noted above, PacifiCorp is committed to participating in the Boardman-to-Hemingway project in accordance with the terms of the Joint Funding Permitting Agreement through Oregon's permitting process and will continue to work with Idaho Power in the development and negotiations of the definitive agreement for the construction and ownership of the new line. PacifiCorp continues to evaluate the benefits to PacifiCorp's customers prior to commitment of entering into a project construction agreement. Additionally, PacifiCorp will continue to review possible benefits of the project as it continues to participate in project development activities, including moving forward with preliminary construction and construction agreement negotiations.

Energy Gateway Transmission Expansion Plan

Introduction

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

Background

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

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

Planning Initiatives

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

- ***Rocky Mountain Area Transmission Study***
  Recommended transmission expansions overlap significantly with Energy Gateway configuration, including:
  - Bridger system expansion similar to Gateway West.
  - Southeast Idaho to southwest Utah expansion akin to Gateway Central 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 2018-2019 NTTG Draft Regional Transmission Plan, sub segments of Energy Gateway (both Gateway West and Gateway South) were listed as necessary to provide acceptable system performance. The study also established that the amount of new Wyoming wind generation that is added over time can impact the transmission system reliability west of Wyoming. Additionally, three interregional projects were included in the study the Southwest Inter-tie Project (SWIP North), Cross Tie and TransWest Express, which showed that all three projects relied on Energy Gateway to attain their full transfer capability rating.

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

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

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

Energy Gateway Configuration

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

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

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

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

Energy Gateway's Continued Evolution

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

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

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

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

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

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

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

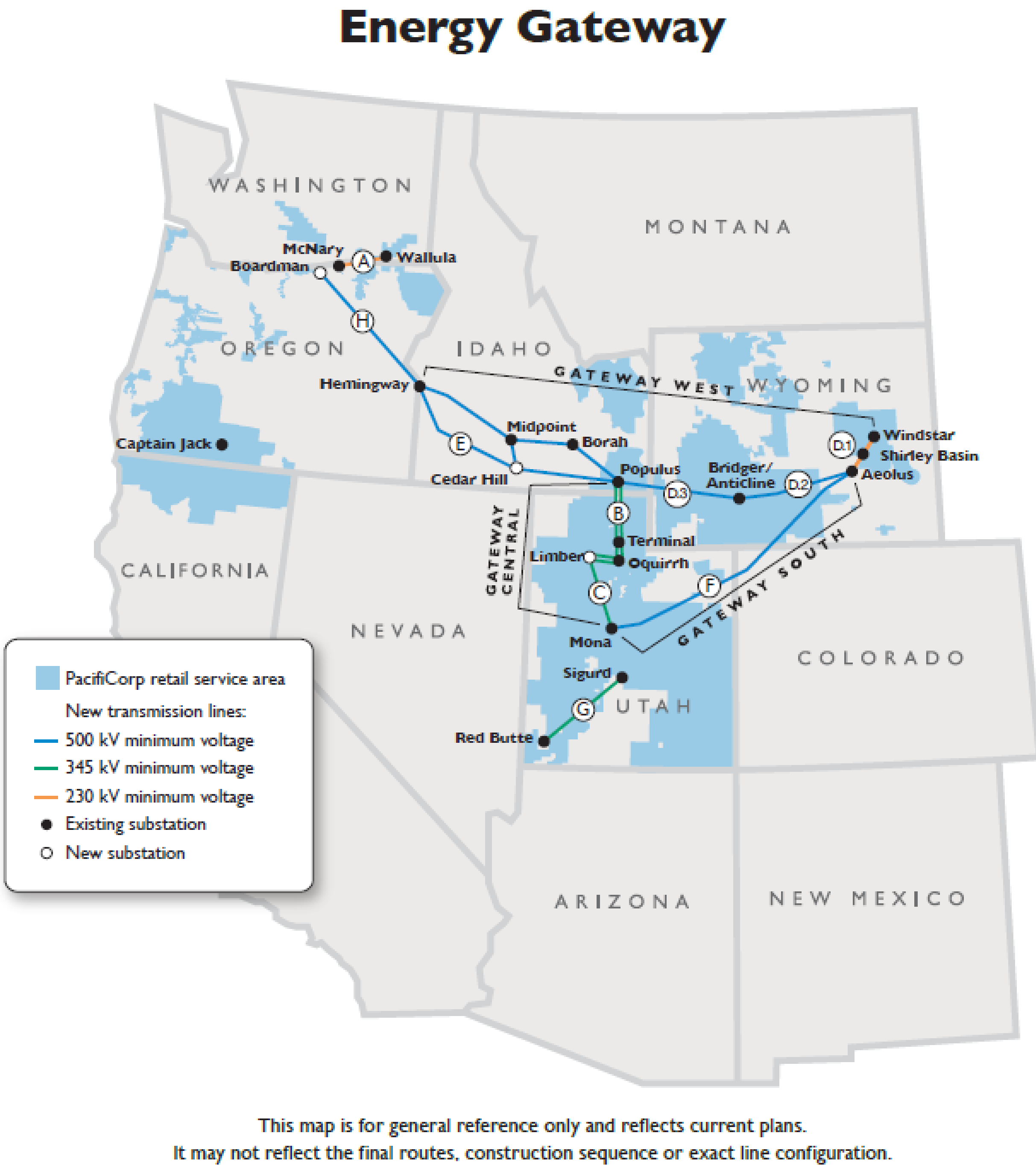


Table 4.1 – Energy Gateway Transmission Expansion Plan

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: completed • Placed in-service: January 2019
(B) Populus-Terminal	345 kV, double circuit	135 mi	• Status: completed • Placed in-service: November 2010
(C) Mona-Oquirrh	500 kV single circuit 345 kV double circuit	100 mi	• Status: completed • Placed in-service: May 2013
Oquirrh-Terminal	345 kV double circuit	14 mi	• Status: rights-of-way acquisition underway • Scheduled in-service: 2026
(D1) Windstar-Aeolus	New 230 kV single circuit Re-built 230 kV single circuit	59 mi	• Status: permitting underway • Scheduled in-service: 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: completed • Placed in-service: November 2020
(D3) Bridger/Anticline-Populus	500 kV single circuit	200 mi	• Status: permitting underway • Scheduled in-service: 2027 earliest
(E) Populus-Hemingway	500 kV single circuit	500 mi	• Status: permitting underway • Scheduled in service: 2030 earliest
(F) Aeolus-Mona	500 kV single circuit	416 mi	• Status: permitting underway • Scheduled in-service: 2024
(G) Sigurd-Red Butte	345 kV single circuit	170 mi	• Status: completed • Placed in-service: May 2015
(H) Boardman-Hemingway	500 kV single circuit	290 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in-service: 2026

Efforts to Maximize Existing System Capability

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

System-wide, PacifiCorp has instituted more than 155 grid operating procedures and 17 remedial action schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the Energy Imbalance Market since November 2014. By August 2021, 15 participants have joined the EIM. By broadening the pool of lower-cost resources that can be accessed to balance load system requirements, enhances reliability and reduces costs across the entire EIM Area. In addition, the automated system is able to identify and use available transmission capacity to transfer the dispatched resources, enabling more efficient use of the available transmission system.

Transmission System Improvements Placed In-Service Since the 2019 IRP

PacifiCorp East (PACE) Control Area

1. Salt Lake Valley Area
   - Install a new circuit switcher in series with the bus-tie circuit breaker at 90th South substation
     - 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.
2. Utah Valley Area
   - Upgrade the 345-138 kV transformer at Spanish Fork substation
     - 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.
3. Goshen Idaho Area
   - Install a new 161-kV line from Goshen to Sugarmill substations
     - 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.
4. East Utah Area
   - Construct the new Naples 138-12.5 kV substation
     - 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.

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
     - 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.

2. Yreka California Area

   - Install an additional 115-69 kV transformer at Yreka substation located
     - 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.

3. 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
     - 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.

Planned Transmission System Improvements

PacifiCorp East (PACE) Control Area

1. Central Wyoming Area

   - Upgrade the 345-230 #2 transformer at Jim Bridger substation
     - 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 result in thermal overload of existing Jim Bridger 345-230 kV #2 transformer.

    - Benefits include mitigating the risk of thermal overloads and resolution of the NERC TPL-001-4 Category P1 and P3 deficiencies.

2. Goshen Idaho Area

- Install a third 345-161 kV transformer at Goshen substation
    - 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 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 (completed) and then from Sugarmill to Rigby substation (still to complete) to allow a looped configuration during heavy summer load conditions.
    - Benefits include mitigating the risk of thermal overloads and voltage issues and eliminating the loss of up to 150 MW of load for N-1 outages and up to 300 MW for N-1-1 outages.

3. Utah & Idaho – Upgrade Program – Backup Bus Differential Relays

- 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.

4. 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.

5. Goshen Idaho Area

- 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.

6. 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.

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

PacifiCorp West (PACW) Control Area

1. 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.
        - 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.
2. Medford Oregon Area
    - Construct one new 500-230 kV substation called Sams Valley
        - Project driver is to correct NERC Standard TPL-002-4 deficiencies for the loss of a single 230-kV line and for N-1-1 and N-2 outages to 230-kV lines that were initially identified in PacifiCorp's 2010 NERC TPL Assessment and supported

through subsequent NERC TPL Assessments, and to provide a second 500-kV source to address load growth in the Southern Oregon region.

- Benefits include adding a second source of 500-kV capacity, adding a new 230-kV line, improving reliability of the 230-kV network, mitigates the risk of thermal overloads and low voltage, mitigates the risk of shedding load in preparation of the second contingency for N-1-1 outages, and resolves the NERC TPL-001-4 deficiencies.

- Expand the RAS at Meridian substation
  - 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.

3. Yakima Washington Area
   - Construct a new 115-kV transmission line from Outlook substation to Punkin Center substation
     - 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.
4. Oregon – Upgrade Program – Replace Over-dutied Circuit Breakers
   - Replace breakers identified as over-dutied with higher-capability breakers at Lone Pine Substation
     - 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 North American Electric Reliability Corporation and Western Electricity Coordinating Council reliability standards.

CHAPTER 5 – RELIABILITY AND RESILIENCY

CHAPTER HIGHLIGHTS

- Regional resource adequacy assessments highlight that there are resource adequacy risks through the mid-2020s. The addition of variable energy resources replacing traditional "baseload" resources may act to tighten market supply.
- PacifiCorp's wildfire mitigation plans, which outline a risk-based, balanced and integrated approach, contain six critical focus areas of planning and execution for a reliable and resilient energy future: (1) Risk analysis and drivers, (2) Situational awareness, (3) Inspection and correction, (4) Vegetation management, (5) System hardening, and (6) Operational practices.
- The 2021 IRP preferred portfolio includes the Energy Gateway South (GWS), Energy Gateway West Subsegment D.1 (D.1), and Boardman-to-Hemingway (B2H) transmission lines. The preferred portfolio also includes other transmission upgrades that support the transition to renewable energy by providing access to low-cost, location-specific renewable resources, and additional transfer capability, which enables greater use of other low-cost resource options and relieves stress on current assets.

Introduction

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

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

Supply-Based Reliability

Regional Resource Adequacy

As part of its 2021 IRP, PacifiCorp has conducted a review and evaluation of western resource adequacy studies and information, including evaluating the Western Electricity Coordinating Council (WECC) Power Supply Assessment (PSA) to glean trends and conclusions from the supporting analysis.

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

WECC Western Assessment of Resource Adequacy Report

The WECC Western Assessment of Resource Adequacy was published on December 18, 2020 and was developed based on data collected from balancing authorities describing their own demand and supply projections over the next 10 years. The analysis is probabilistic and represents an hourly assessment of resource adequacy over the study period. The region-wide projections included in the study were categorized into two scenarios: one in which the region is required to meet its own demand without assumed reliance on imports, and a second scenario in which the region can assume that imports will help meet the demand needs of the future. Each scenario was further sub-divided into three variations:

- Variation 1: Existing Resources (EX) – Includes resources that are in-service and can be expected to run in future forecasts.
- Variation 2: Tier 1 Resources (T1) – Existing resources including those under construction and expected to be in-service in the forecasted year.
- Variation 3: Tier 1 and Tier 2 Resources (T12) – Existing and Tier 1 resources including those in licensing, siting, etc. but not yet in construction.

To inform the study, WECC has developed peaking assumptions and ramp need estimates on both an interconnection-wide basis, as well as for each planning subregion within the WECC. A summary of the planning regions and peak assumptions is shown in Table 5.1.

Table 5.1 – Planning Subregions and Peaking Assumptions underlying analysis

Designation	Subregion	Peaking Assumption	Ramp[1]	Peak Load
NWPP-NW[2]	Northwest Power Pool - Northwest	January	51%	39,300MW
NWPP-NE[3]	Northwest Power Pool – Northeast	February	30%	14,800MW
NWPP-C[4]	Northwest Power Pool – Central	July	104%	36,400MW
CAMX[5]	California and Mexico	August	81%	51,300MW
DSW[6]	Desert Southwest	July	100%	25,700MW

PacifiCorp serves load primarily in the NWPP-NW, NWPP-NE, and NWPP-C planning subregions.

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

NWPP-NW

- Expected availability of peak-hour resources in 2021: 44,000 MW to meet an expected peak of 39,300 MW. However, in low-availability scenarios (5% probability), the region could have only 29,200 MW of resources available to meet peak.

- One Day in Ten Years (ODITY) planning threshold: WECC determines that a planning reserve margin of 15%is likely sufficient to maintain the median ODITY resource adequacy threshold. However, as more variable resources continue to be added to the grid, a larger planning reserve margin may be needed to compensate. WECC estimates that in the spring, when variability in energy supply and demand is highest, a planning reserve margin of 40%+ may be appropriate.

- Scenario findings for NWPP-NW generally identify that the subregion may need imports to ensure system reliability as early as 2021, and the scenario outputs identify hours at risk of not being able to maintain ODITY threshold of resource adequacy:

  Stand-alone:
  - Existing Resources: 208 hours
  - T1: 195 hours
  - T2: 194 hours

  Imports:

  - Existing Resources: 0 hours
  - T1: 0 hours
  - T2: 0 hours

NWPP-NE

- Expected availability of peak-hour resources in 2021: 19,600 MW to meet an expected peak of 14,800 MW. However, in low-availability scenarios (5 percent probability), the region could have 16,700 MW available, which is still sufficient to meet peak demand.

- ODITY planning threshold: WECC determines that a planning reserve margin of 15% is likely sufficient to maintain the median ODITY resource adequacy threshold. WECC's highest reserve margin is estimated to be approximately 20% to account for potential limited availability in baseload resources.

- Scenario findings for NWPP-NE identifies that the subregion needs imports to maintain resource adequacy thresholds. From 2021-2024, WECC finds that in each stand-alone scenario there are over 4,000 hours per year in which 100+ MW of demand is at risk of being unserved. The number of hours increase as there is less baseload availability.

Stand-alone

- Existing Resources: 4,200 hours
- T1: 4,200 hours
- T2: 4,200 hours

Imports

- Existing Resources: 0 hours
- T1: 0 hours
- T2: 0 hours

NWPP-C

- Expected availability of peak-hour resources in 2021: 19,600 MW to meet an expected peak of 14,800 MW. However, in low-availability scenarios (5 percent probability), the region could have 16,700 MW available, which is still sufficient to meet peak demand.

- ODITY planning threshold: WECC determines that a planning reserve margin of 15% is likely sufficient to maintain the median ODITY resource adequacy threshold. WECC's highest reserve margin is estimated to be approximately 20% to account for potential limited availability in baseload resources.

- Scenario findings for NWPP-NE identifies that the subregion needs imports to maintain resource adequacy thresholds. From 2021-2024, WECC finds that in each stand-alone scenario there are over 4,000 hours per year in which 100+ MW of demand is at risk of being unserved. The number of hours increase as there is less baseload availability.

  Stand-alone

  - Existing Resources: 4,200 hours
  - T1: 4,200 hours
  - T2: 4,200 hours

  Imports

  - Existing Resources: 0 hours
  - T1: 0 hours
  - T2: 0 hours

Resource Assumptions

The WARA analysis includes all currently operating resource, with planned retirements included in the calculation.

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

> **Recommendation 1:** *Planning entities and their regulatory authorities should consider moving away from a fixed planning reserve margin to a probabilistically determined margin. As variability grows, a dynamic planning reserve margin will better ensure resource adequacy for all hours.*
>
> - PacifiCorp's 2019 IRP and its 2021 IRP both evaluate the performance of the selected portfolio of resources in all hours to ensure resource adequacy beyond the coincident peak.
> - PacifiCorp's 2021 IRP calculates the planning reserve margin for every hour and identifies the lowest hourly margin by season and year, allowing for greater focus on the periods and types of conditions that lead to the greatest risk. As portfolios evolve over time, this automatically identifies the changing periods of risk.
> - PacifiCorp's stochastic reliability modeling has identified that reliability risks exist in both the summer and the winter under a range of conditions.
>
> **Recommendation 2:** *Planning entities should consider not only how much additional capacity is needed to mitigate variability, but also the expected availability of the resource. Understanding the differences in resource type availability is crucial to performing resource adequacy studies.*
>
> - PacifiCorp recognizes that the conditions with the greatest risk can be addressed with targeted solutions, for instance solar combined with storage is very helpful for meeting summer requirements.
> - PacifiCorp also recognizes that widespread adoption of a targeted solution will cause risks to evolve, and solutions will need evolve or change to target other conditions. To help retain flexibility for evolving needs, PacifiCorp increased the level of storage in its hybrid solar and storage resources to 100% of the solar nameplate with four-hour duration. But even this results in diminishing returns for winter needs.
> - While four-hour storage provides significant flexibility, for instance to fill in gaps in typical renewable resource output, uncertainty remains about expected renewable resource availability under extreme conditions, which are relatively uncommon. To address this issue, additional analysis of renewable resource variability and correlation with load will be needed in future IRPs.
>
> **Recommendation 3:** *Planning entities should coordinate their resource planning efforts on an interconnection-wide basis each year to help ensure they are not all relying on the*

same imports to maintain resource adequacy. This coordination will help subregions make assumptions about import availability in the context of the entire interconnection.

- PacifiCorp evaluates its planning assumption around availability of markets and interconnection-wide imports, and has adjusted its forecasted maximum liquidity at the Mid-Columbia, California-Oregon Border, Nevada-Oregon Border, and Mona trading hubs as a result. Chapter 7 (Resource Options), as well as the section in this chapter addressing market availability, include a discussion of PacifiCorp's assumed maximum seasonal values for front-office transactions.

NERC Long-Term Resource Adequacy (LTRA)

Resources

As part of the regional reliability assessment to support the 2021 IRP, PacifiCorp reviewed and incorporated learnings from the NERC LTRA, published in December 2020. The NERC LTRA organizes resources into two broad categories in 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
- Non-firm 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 the difference between resources less demand, divided by demand, as a percentile.

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

- Adequate: 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 shortfall

- Inadequate: Anticipated reserve margin is significantly less than reference margin level and load interruption is likely

WECC Subregions

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

Table 5.2 – WECC Subregion Descriptions

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

Table 5.3 – NERC LTRA Anticipated Reserve Margin

Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	25.9%	24.6%	23.4%	21.6%	20.8%	17.7%	16.5%	13.5%	11.7%	10.4%
SRSG	Summer	18.1%	17.3%	17.0%	14.7%	15.5%	16.8%	16.0%	15.4%	14.4%	13.6%
CAMX	Summer	21.4%	27.8%	27.3%	26.8%	22.5%	21.0%	20.6%	19.6%	19.2%	19.2%

Table 5.4 – NERC LTRA Prospective Reserve Margin

Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	25.9%	24.8%	24.0%	22.2%	21.5%	18.4%	17.2%	14.2%	12.3%	11.0%
SRSG	Summer	18.1%	18.1%	19.5%	17.2%	17.9%	19.2%	18.3%	17.6%	16.6%	15.7%
CAMX	Summer	21.4%	35.3%	40.8%	41.7%	37.3%	35.7%	35.2%	34.1%	33.6%	34.8%

Table 5.5 – NERC LTRA Reference Reserve Margin

Reference Planning Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	15.4%	16.1%	15.2%	15.1%	15.0%	14.9%	14.8%	15.6%	14.7%	14.5%
SRSG	Summer	10.9%	11.9%	11.0%	10.8%	10.7%	10.6%	10.5%	11.1%	10.4%	10.3%
CAMX	Summer	18.2%	15.8%	19.1%	19.1%	19.1%	19.0%	18.9%	15.7%	18.9%	19.0%

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 5.6 reports the reserve margin differential based on anticipated resources, whereas Table 5.7 reports the reserve margin differential assuming prospective resources are achieved during the study period. In either table, a positive percentage represents a margin of overage where WECC is expected to have resources above the reference margin target; a negative number (highlighted for emphasis) represents a year where a given subregion is at risk of falling below the reference margin.

Based on this evaluation, potential shortfalls in planning reserve margin show up in the back three years of the study period and only in the NWPP/RMRG subregion of WECC.

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

Shortfalls Assuming Anticipated Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	10.5%	8.5%	8.2%	6.5%	5.8%	2.8%	1.7%	**-2.1%**	**-3.0%**	**-4.1%**
SRSG	Summer	7.2%	5.4%	6.0%	3.9%	4.8%	6.2%	5.5%	4.3%	4.0%	3.3%
CAMX	Summer	3.2%	12.0%	8.2%	7.7%	3.4%	2.0%	1.7%	3.9%	0.3%	0.2%

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

Shortfalls Assuming Prospective Reserve Margin											
U.S. WECC Subregion	Peaking Assumption	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
NWPP/RMRG	Summer	10.5%	8.7%	8.8%	7.1%	6.5%	3.5%	2.4%	**-1.4%**	**-2.4%**	**-3.5%**
SRSG	Summer	7.2%	6.2%	8.5%	6.4%	7.2%	8.6%	7.8%	6.5%	6.2%	5.4%
CAMX	Summer	3.2%	19.5%	21.7%	22.6%	18.2%	16.7%	16.3%	18.4%	14.7%	15.8%

Prior Measures

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

Pacific Northwest Resource Adequacy Forum's Adequacy Assessment

As in the 2019 IRP, the Pacific Northwest Resource Adequacy Forum (later replaced by the Resource Adequacy Advisory Committee) issued resource adequacy standards in April 2008, which were subsequently adopted by the Northwest Power and Conservation Council. The standard calls for assessments three and five years out, conducted every year, and including only existing resources and planned resources that are already sited and licensed. The current assessment (issued October 2019) concludes that power supply is expected to be adequate through 2020, with energy and capacity surplus becoming a deficit in 2021 and 2022 at a loss of load probability of 10%. This deficit is primarily driven by the retirement of the Boardman and Centralia coal plants. The assessment includes approximately 550 MW of new capacity scheduled to come online in 2021.

2021 Northwest Power Plan

The Northwest Power and Conservation Council is currently in the process of finalizing the 2021 Northwest Power Plan, which is expected to be final in early 2022. Although preliminary, PacifiCorp has been actively participating in the planning process to date, and notes that the draft findings are similar to what the company has observed through the WECC Western Assessment of Resource Adequacy and the NERC LTRA, primarily:

- There is a resource adequacy need in the next few years, with up to 1,600 MW of capacity need by 2023;
- After 2023, even with additional coal-fired generation retirements, adequacy can be maintained through a high level of expected renewable resource buildout and the optimization of the existing hydro and gas-fired resource fleet; and
- There is inherent uncertainty driven by the possibility of accelerated loads due to electrification programs and the uncertainty of WECC-wide resource buildout.

NWPP Resource Adequacy Program

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

The program will focus on creating a capacity RA program with a demonstration of deliverability. Additional adequacy programs may also be necessary following the implementation of the capacity program. The region may also benefit from other forms of coordination, and while the structure and process associated with the program may serve as foundational building blocks to additional regional coordination, the NWPP and its participants are only working to implement the capacity RA program at this time. The proposed RA program does not replace or supplant the resource planning processes used by states or provinces or the regulatory requirements of the Federal Energy Regulatory Commission (FERC), North America Electric Reliability Corporation (NERC) or Western Electricity Coordinating Council (WECC). The program is designed to be supplemental and complementary to those processes and requirements. Program planning is scheduled to continue throughout 2022, with a proposed implementation date in 2024.

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

Reliable Service through Unpredictable Weather and Challenging Market Liquidity

As described in Volume I, Chapter 7 (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 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 2021 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 2021 IRP FOT limits are 1,000 MW in the winter, and 500 MW in the summer, reduced from 1,425 MW in the 2021 IRP. These reductions are due to an assumption of zero summer liquidity at COB, NOB, and Mona, as well as decreased liquidity at Mid-C in both Flat Annual and Heavy Load Hour. Table 5.8 details the assumed market availability limits.

Table 5.8 – Maximum Available Front Office Transactions by Market Hub

Market Hub/Proxy FOT Product Type	Availability Limit (MW)			
	2021		2019	
	Summer (July)	Winter (December)	Summer (July)	Winter (December)
Mid-Columbia (Mid-C)				
Flat Annual or Heavy Load Hour	350	350	Reduced from 400	
Heavy Load Hour	150	0	Reduced from 375	
California Oregon Border (COB)				
Flat Annual or Heavy Load Hour	0	250	Removed in summer only	
Nevada Oregon Border (NOB)				
Heavy Load Hour	0	100	Removed in summer only	
Mona				
Heavy Load Hour	0	300	Removed in summer only	
Total	**500**	**1,000**	**1,425**	**1,425**

PacifiCorp's historical market purchases at times exceeded its 2019 IRP FOT planning limits, indicating that it was able to find sellers in the market to meet capacity needs. While PacifiCorp expects to continue to use its transmission access to access markets whenever it is economic to do so, planning to rely exclusively on markets and imports at the same levels is becoming riskier as western resource mix evolves and there is greater reliance on variable and short-duration resources.

Aligned with review of the regional studies discussed above, and the historical market purchases and transactions, PacifiCorp has selected a peak-season FOT limit of 1,000 MW in the winter and 500 MW for the summer in the 2021 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 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results).

Planning for Load Changes as a Result of Climate Change

Recent weather-based reliability events throughout the United States have underscored the need for utilities to consider the potential for increasingly extreme weather and the underlying reliability challenges that may be caused as part of its planning process. PacifiCorp has prepared a climate change scenario within the 2021 IRP to assess the ways in which climate change may impact planning assumptions (See Chapter 8, Volume I, Modeling and Portfolio Evaluation Approach). The following section provides an overview on the load assumptions associated with climate change projections.

PacifiCorp consulted with the Northwest Power and Conservation Council to collaboratively align on how to model future peak load need based on changing temperatures throughout PacifiCorp's service area. Further, a literature review of various climate change research was performed to determine a basis for temperatures informing the 2021 IRP climate change scenario. Ultimately, PacifiCorp's 2021 IRP climate change scenario relies on projected temperatures as determined by the United States Bureau of Reclamation (Reclamation) in the West-Wide Climate Risk Assessments: Hydroclimate Projections Study (Study).[8] In addition to temperature projections, the Reclamation study also provides hydrological projections for waterways throughout PacifiCorp's six-state service territory.

Table 5.9 below provides the projected range of temperature change for select sites within PacifiCorp's service territory, which were used to model projected temperatures in the 2021 IRP Washington-required scenario to include the effects of climate change.

[8] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

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

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F)	
		2020s	2050s
Klamath River near Klamath	California	1.4 to 2.4	2.6 to 4.4
Snake River Near Heise	Idaho	1.6 to 3.1	3.1 to 5.6
Klamath River near Seiad Valley	Oregon	1.4 to 2.5	2.7 to 4.5
Green River near Greendale	Utah	1.7 to 3.1	3.1 to 5.7
Yakima River at Parker	Washington	1.5 to 2.6	2.7 to 5.0
Green River near Greendale	Wyoming	1.7 to 3.1	3.1 to 5.7

PacifiCorp used these temperature projections to calculate change in peak loads and energy driven by temperature change over the next three decades.[10]

As illustrated in Table 5.10, relative to the 2021 IRP forecast, the climate change scenario results in summer peaks being higher by approximately 50 MW (<1% higher) over the 2021-2025 timeframe. By 2040, summer peaks are projected to be 318 MW (2.7%) higher than the 2021 IRP Base.

As illustrated in Table 5.11, increasing winter temperatures results in less heating load, which drive lower winter peaks. By 2040, winter peaks are projected to be 259 MW (2.3%) lower than the 2021 IRP Base.

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

[9] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

[10] Additional information on methodology behind the peak-load calculation can be found in Volume I, Chapter 6 (Load and Resource Balance) of the 2021 IRP.

Table 5.10 – Change in Summer Coincident Peak Climate Change Scenario vs 2021 IRP Base (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	53	10	1	(0)	17	17	8
2022	53	11	1	(0)	17	17	8
2023	54	11	1	(0)	17	17	8
2024	55	11	1	(0)	17	17	8
2025	53	11	1	(0)	17	17	7
2026	71	16	3	(0)	26	18	8
2027	89	22	4	(0)	35	18	10
2028	107	28	5	(0)	44	19	11
2029	126	34	7	(0)	53	19	13
2030	139	41	8	-	63	14	14
2031	158	47	10	0	73	14	15
2032	178	54	11	0	82	14	16
2033	198	60	13	0	92	15	18
2034	218	67	14	0	103	15	19
2035	239	74	16	0	113	16	21
2036	245	80	17	0	119	16	14
2037	273	86	19	0	128	16	24
2038	291	91	20	0	137	17	26
2039	301	97	21	0	139	16	28
2040	318	103	22	0	146	16	30

Table 5.11 – Change in Winter Coincident Peak Climate Change Scenario vs 2021 IRP Base (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	(126)	(90)	(10)	(3)	(15)	(4)	(4)
2022	(127)	(90)	(10)	(3)	(16)	(4)	(4)
2023	(127)	(90)	(10)	(3)	(16)	(4)	(4)
2024	(128)	(90)	(10)	(3)	(16)	(4)	(4)
2025	(130)	(92)	(10)	(2)	(17)	(5)	(4)
2026	(137)	(95)	(12)	(3)	(18)	(5)	(4)
2027	(143)	(97)	(14)	(3)	(19)	(6)	(5)
2028	(150)	(101)	(15)	(3)	(20)	(6)	(5)
2029	(158)	(104)	(17)	(3)	(21)	(8)	(5)
2030	(162)	(107)	(19)	(3)	(22)	(6)	(5)
2031	(167)	(109)	(20)	(3)	(23)	(7)	(6)
2032	(175)	(112)	(22)	(3)	(24)	(8)	(6)
2033	(182)	(115)	(23)	(3)	(25)	(9)	(6)
2034	(189)	(118)	(25)	(3)	(26)	(10)	(6)
2035	(194)	(121)	(27)	(3)	(27)	(10)	(7)
2036	(201)	(124)	(28)	(4)	(28)	(12)	(7)
2037	(247)	(449)	(105)	(14)	290	24	7
2038	(256)	(461)	(106)	(14)	294	24	8
2039	(261)	(472)	(107)	(15)	300	25	8
2040	(259)	(484)	(109)	(15)	310	30	9

Table 5.12 – Change in Annual Energy Climate Change Scenario vs 2021 IRP Base (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	(129,280)	(171,850)	(38,220)	(13,050)	76,330	(16,180)	33,690
2022	(129,790)	(172,660)	(38,030)	(13,070)	76,800	(16,410)	33,580
2023	(131,060)	(173,320)	(37,820)	(13,050)	76,400	(16,710)	33,440
2024	(131,500)	(173,790)	(37,630)	(13,050)	76,560	(16,930)	33,340
2025	(131,870)	(174,200)	(37,470)	(13,060)	76,780	(17,130)	33,210
2026	(126,270)	(175,670)	(37,980)	(13,430)	83,670	(17,590)	34,730
2027	(120,520)	(177,100)	(38,480)	(13,790)	90,660	(18,060)	36,250
2028	(114,500)	(178,480)	(38,950)	(14,170)	97,840	(18,520)	37,780
2029	(107,870)	(179,490)	(39,360)	(14,550)	105,200	(18,950)	39,280
2030	(101,020)	(180,590)	(39,720)	(14,920)	112,780	(19,370)	40,800
2031	(93,880)	(181,720)	(40,060)	(15,310)	120,630	(19,750)	42,330
2032	(86,310)	(182,800)	(40,350)	(15,700)	128,740	(20,090)	43,890
2033	(78,250)	(183,760)	(40,570)	(16,080)	137,110	(20,380)	45,430
2034	(69,710)	(184,630)	(40,750)	(16,460)	145,750	(20,640)	47,020
2035	(60,710)	(185,420)	(40,880)	(16,850)	154,690	(20,850)	48,600
2036	(54,280)	(186,550)	(41,010)	(17,150)	161,400	(21,080)	50,110
2037	(47,420)	(187,620)	(41,090)	(17,450)	168,420	(21,280)	51,600
2038	(40,300)	(188,630)	(41,130)	(17,760)	175,600	(21,470)	53,090
2039	(32,870)	(189,600)	(41,140)	(18,070)	182,980	(21,640)	54,600
2040	(25,190)	(190,540)	(41,110)	(18,380)	190,520	(21,810)	56,130

Weather-Related Impacts to Variable Generation

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

Wildfire Impacts

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

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

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

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

PacifiCorp outlines its wildfire mitigation strategies later in this document.

Extreme Weather Impacts

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

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

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

Impacts on wind and solar energy

The impact on renewable energy generation due to extreme weather events and climate change is an evolving topic. For conclusive trends of climate change impact, data collection specific to geographic locations is critical. Climate impacts both the demand and supply side of energy. Due to daily or seasonal changes the demand for energy patterns is changing. On the supply side due to increasing temperatures and variability in climate parameters it impacts estimated energy outputs of projects as well as operational costs. However, there are limited studies in the North American region that quantitatively document the impact of a climate parameter on the future of wind and solar energy.[11] Some broad impacts anticipated from climate change are noted below:[12]

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

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

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

Solar Energy

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

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

Wildfire Risk Mitigation

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

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

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

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

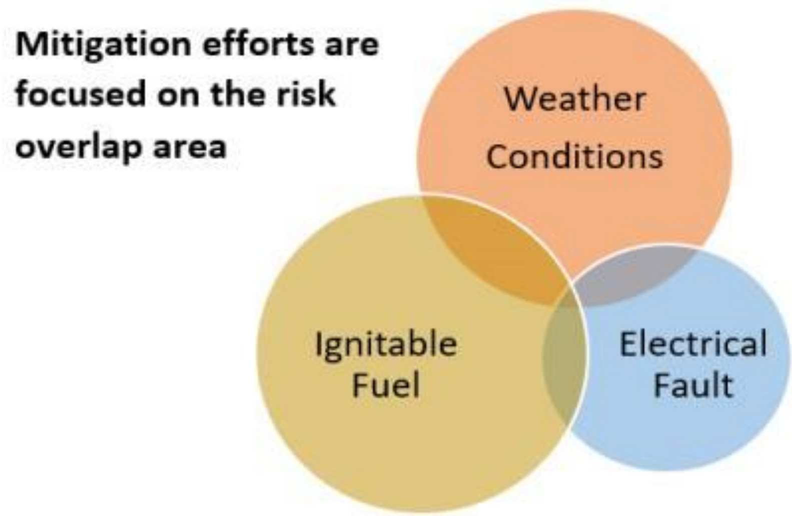
The company continues to build on over a century of wildfire mitigation experience and three decades of information gathering and analysis. PacifiCorp's planning focus areas above are intended to ensure that we continue to serve customers safely and reliably. As new analyses, technologies, practices,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

Risk Analysis and Drivers

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

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

Figure 5.1 – Wildfire Risk Mitigation Focus Areas



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

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

Situational Awareness

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

Weather Stations

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

Meteorology

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

Inspection and Correction

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

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

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

Vegetation Management

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

System Hardening

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

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

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

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

Line Rebuild Program

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

<u>Covered Conductor</u>

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

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

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

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

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

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

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

Non-Wooden Poles

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

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

Non-Expulsion Fuses

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

Operational Practices

System Operations

The manner in which an electrical system is operated can also help mitigate wildfire risk. PacifiCorp has specific procedures addressing system operations during fire season. These procedures are designed to reduce the potential for ignition of a fire from sparks emitted when a line is re-energized with a disturbance still on the line. Recognizing the increasing magnitude of the wildfire risk, PacifiCorp significantly augmented operating procedures in June 2018 to incorporate a more conservative approach designed to reduce the potential of fault-based ignitions on PacifiCorp's electrical network. From a practical perspective, the procedures implicate two primary subject areas: (a) settings for automatic reclosers and (b) line testing after lock-out.

Automatic reclosers are currently deployed on various transmission lines and distribution circuits throughout PacifiCorp's service territory. When a line trips open, an automatic recloser may operate to close the circuit very quickly, so long as the cause of a momentary trip has cleared. The reclosing function allows PacifiCorp to maintain service on a line that had tripped, rather than opening the circuit and de-energizing the line. In general, automatic recloser operation is beneficial because it reduces outages and improves customer reliability. The actual operation of recloser equipment does not directly present wildfire risk, as the recloser equipment itself does not emit sparks or otherwise pose an ignition risk.

The operation of automatic reclosers, however, indirectly implicates some degree of ignition risk. When a fault is detected on the line, a recloser will trip and reclose based on predetermined settings in an attempt to re-energize the line. If the cause of the fault is no longer present when the device recloses, the line will re-energize resulting in limited impact to customers. If the cause of the original fault still remains when the device recloses, however, the original fault may persist and, depending on the circumstances, potentially result in arcing or an emission of sparks. As a result, in some limited circumstances, the second fault scenario could lead to a fire ignition. Accordingly, automatic recloser settings can have a significant impact on wildfire mitigation.

The risk associated with line-testing on overhead lines is very similar. If a breaker has “locked-out”, meaning that it has opened and no longer conducts electricity, a system operator will sometimes “test” the line. To test the line, the system operator will close the device, thereby allowing the line to be re-energized. If the fault has cleared, then the system will run normally. If the fault has not cleared, the device will lock out again. If the device locks out again, the system operator then knows that additional investigation or work will be required before the line can be successfully re-energized. Because faults are often temporary, line-testing can be an efficient tool to maintain customer reliability. At the same time, line-testing can result in the emission of sparks if a fault has not yet cleared when the line is tested. Accordingly, a “no-test” policy reduces the risk of ignition, and a “no-test” policy is applicable in certain circumstances during fire season.

In general, these system operating procedures are more restrictive when wildfire conditions are elevated. The specific circumstances in which automatic reclosers are disabled and no-test applies, on both transmission and distribution lines, are fully detailed in the procedures.

Field Operations

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

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

<u>Work Restrictions</u>

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

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

- **Hot Work Restrictions.** Field operations managers are encouraged to evaluate whether work should be performed during a planned interruption, rather than while a line is energized.
- **Time of Day Restrictions.** Field operations managers are encouraged to consider using alternate work hours to accommodate evening and night work when there may be less risk of ignition.
- **Wind Restrictions.** Field personnel are encouraged to defer work, if feasible, when there are windy conditions at a particular work site.
- **Driving Restrictions.** Field personnel are encouraged to keep vehicles on designated roads whenever operationally feasible.

Worksite Preparation

If wildland vegetation posing an ignition risk is prevalent at a worksite, and the work to be performed involves the potential emission of sparks from electrical equipment, field personnel working during fire season are encouraged to remove vegetation at the work site where allowed in accordance with land management/agency permit requirements, especially when there is dry or tall wildland grass. In addition to clearing work, the water truck resources, discussed below, are strategically assigned to sometimes accompany field personnel working in a wildland area during fire season, especially in high-risk locations. Depending on local conditions, dry vegetation in the immediate vicinity may be sprayed with water before work as a preventative measure.

Vehicles

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

Additional Labor Resources

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

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

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

Basic Personal Suppression Equipment

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

Mobile Generators

PacifiCorp has a mobile generator to assist with emergency response efforts. In short, when power on the electrical network is lost, either proactively or as the result of wildfire damage, a mobile generator unit can be dispatched to provide power. The generator is transported via tractor trailer to a specific location based on real-time circumstances. For example, a mobile generator may be dispatched by the Emergency Operations Center to mitigate the impact of a proactive de-energization, as discussed in greater detail in the Public Safety Power Shutoff section below. There are constraints in connecting the generator, and each deployment is examined on a case-by-case basis.

Water Truck Resources

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

Transmission-Based Reliability

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

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

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

Federal Reliability Standards

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

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

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

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

Power Flow Analyses and Planning for Generator Retirements

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

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

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

The 2021 IRP includes the 416-mile long 500-kV GWS transmission line from the Aeolus substation near Medicine Bow, WY to Clover substation near Mona, Utah. The construction of GWS directly connects eastern Wyoming to central Utah while enhancing the reliability throughout the PacifiCorp-served regions. Connecting into the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah to serve customer load.

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

In addition to the GWS, PacifiCorp is also planning to construct the 56-mile-long 230-kV D.1 transmission line from Windstar substation near Glen Rock, WY to Shirley Basin substation near Medicine Bow, WY. This line provides a new transmission path allowing for renewable resources development in the area. The addition of this line improves the reliability of the transmission system during certain identified outage conditions (Dave Johnston to Amasa 230-kV outage or Amasa – Shirley Basin 230-kV outage). Current generation interconnections with large generator interconnection agreements (LGIA) in eastern Wyoming show that the D.1 is a prerequisite for connecting these new resources. Information for those resources can be found on PacifiCorp's OASIS web site, under queue numbers; Q0713, 0783, 0784, 0785, 0801, 0802, 0807, 0835 and 0836.

CHAPTER 6 – 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 across all hours in both the summer and winter.
- Capacity assessment across more than the coincident peak is necessary due to the evolution of the company's portfolio to include more wind, solar, and storage resources. Solar in particular provides significant output during the summer coincident peak, but no output in many other summer hours. As a result, summer risks cannot easily be identified by looking at load alone. Instead, PacifiCorp evaluated the resources available relative to the expected load in every hour, and the hour with the lowest resources as a percentage of the hourly load in each season determines the planning reserve margin (PRM) achieved for that season in that year.
- The company's load obligation is calculated based on projected load less private generation, energy efficiency savings, and demand response, including interruptible load.
- A 2020 Private Generation Long-Term Resource Assessment (2021-2040) study prepared by Guidehouse 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 2021 IRP load and resource balance treats base case private generation penetration levels as a reduction in load.
- After accounting for a minimum 13 percent PRM target, load growth, coal unit retirements from the preferred portfolio, plus accounting for the level of potential market purchases (front office transactions, or FOTs) assumed in the 2021 IRP, and after incorporating future energy efficiency savings from the preferred portfolio, PacifiCorp's system is capacity deficient (before adding proxy resources) over both the summer and winter peaks throughout the twenty-year planning period.
- The uncertainty in the company's load and resource balance is increasing as PacifiCorp's resource portfolio and customer demand evolve over time. While PacifiCorp took steps to better reflect the relationship between renewable resources and load in the 2021 IRP, uncertainty remains, particularly with regard to the frequency and characteristics of the relatively extreme conditions that are most likely to trigger reliability shortfalls.

Introduction

This chapter presents PacifiCorp's assessment of its load and resource balance. PacifiCorp's long-term load forecasts (both energy and coincident peak load) for each state and the system 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 2021 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 2021 IRP relies on PacifiCorp's June 2020 load forecast. Table 6.1 shows the annual summer coincident peak load stated in megawatts (MW) as reported in the capacity load and resource balance before any load reductions from energy efficiency and private generation. The system summer peak load grows at a compound growth rate (CAGR) of 0.85 percent over the period 2021 through 2040.

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

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
System	10,447	10,646	10,824	10,947	11,089	11,022	11,107	11,227	11,338	11,470
	2031	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
System	11,615	11,748	11,879	12,005	12,141	12,094	12,206	12,345	12,148	12,270

Existing Resources

Thermal Plants

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

Table 6.2 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	Gas Conversion/ Retirement Year	Nameplate Capacity (MW)
Colstrip 3	10	Montana	2025	74
Colstrip 4	10	Montana	2025	74
Craig 1	19	Colorado	2025	82
Craig 2	19	Colorado	2028	79
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	2028	44
Hayden 2	13	Colorado	2027	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	2024/2037	354
Jim Bridger 2	67	Wyoming	2024/2037	359
Jim Bridger 3	67	Wyoming	2037	349
Jim Bridger 4	67	Wyoming	2037	351
Naughton 1	100	Wyoming	2025	156
Naughton 2	100	Wyoming	2025	201
Wyodak	80	Wyoming	2039	268
TOTAL – Coal				**5,246**

Table 6.3 – 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 1	100	Utah	2047	551
Lake Side 2	100	Utah	2054	644
Naughton 3	100	Wyoming	2029	247
TOTAL – Natural Gas				**3,070**

Renewable Resources

Wind

PacifiCorp either owns or purchases under contract 3,811 MW of wind resources.
Table 6.4 shows existing wind facilities owned by PacifiCorp, while Table 6.5 shows existing wind power-purchase agreements (PPAs).

Table 6.4 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Cedar Springs II	WY	200
Dunlap 1	WY	111
Ekola Flats 1	WY	250
Foote Creek I	WY	41
Glenrock I	WY	99
Glenrock III	WY	39
Goodnoe Hills East	WA	94
High Plains	WY	99
Leaning Juniper	OR	101
Marengo I	WA	156
Marengo II	WA	78
McFadden Ridge 1	WY	29
Pryor Mountain	MT	240
Rolling Hills	WY	99
Seven Mile Hill	WY	99
Seven Mile Hill II	WY	20
TB Flats	WY	500
TOTAL – Owned Wind		**2,255**

Table 6.5 – Non-Owned Wind Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Big Top ORWF	QF	OR	2.0
BLM Rawlins	QF	WY	0.1
Butter Creek Power ORWF	QF	OR	5.0
Cedar Springs III	PPA	WY	133.0
Cedar Springs PPA	PPA	WY	199.0
Chopin	QF	OR	10.0
Combine Hills	PPA	OR	41.0
Four Corners ORWF	QF	OR	10.0
Four Mile Canyon ORWF	QF	OR	10.0
J Bar Ranch	QF	WY	0.1
Latigo	QF	UT	60.0
Meadow Creek Project - North Point	QF	ID	80.0
Meadow Creek Project Five Pine	QF	ID	40.0
Mountain Power I	QF	WY	61.0
Mountain Power II	QF	WY	80.0
Orchard Wind 1	QF	OR	10.0
Orchard Wind 2	QF	OR	10.0
Orchard Wind 3	QF	OR	10.0
Orchard Wind 4	QF	OR	10.0
Oregon Trail ORWF	QF	OR	10.0
Pacific Canyon ORWF	QF	OR	8.0
Pioneer Park I	QF	WY	80.0
Power County Park North	QF	ID	23.0
Power County Park South	QF	ID	23.0
Rock River I	PPA	WY	50.0
Sand Ranch ORWF	QF	OR	10.0
Spanish Fork Park 2	QF	UT	19.0
Stateline	Exchange	WA	175.0
Three Buttes Power (Duke)	PPA	WY	99.0
Three Mile Canyon	QF	OR	10.0
Tooele	QF	UT	1.5
Tooele	QF	UT	1.7
Top of the World	PPA	WY	200.0
Wagon Trail ORWF	QF	OR	3.0
Ward Butte ORWF	QF	OR	7.0
Wolverine Creek	PPA	ID	65.0
TOTAL - Purchased Wind			**1,556.4**

Solar

PacifiCorp has a total of 73 solar projects under contract representing 2,340 MW of nameplate capacity.

Table 6.6 – Non-Owned Solar Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Adams	QF	OR	10.0
Appaloosa Solar IA	PPA	UT	120.0
Appaloosa Solar IB	PPA	UT	80.0
BC Solar	QF	OR	8.0
Bear Creek	QF	OR	10.0
Beryl	QF	UT	3.0
Black Cap	PPA	OR	2.0
Bly	QF	OR	8.0
Buckhorn	QF	UT	3.0
Captain Jack	QF	OR	3.0
Castle Solar (Retail 1)	PPA	UT	20.0
Castle Solar (Retail 2)	PPA	UT	20.0
Cedar Valley	QF	UT	3.0
Chiloquin	QF	OR	10.0
Cove Mountain	PPA	UT	58.0
Cove Mtn II	PPA	UT	122.0
eBay	QF	UT	0.5
Elbe	QF	OR	10.0
Elektron Solar 20Yr	PPA	UT	10.0
Elektron Solar 25Yr	PPA	UT	70.0
Enterprise	QF	UT	80.0
Escalante I	QF	UT	80.0
Escalante II	QF	UT	80.0
Escalante III	QF	UT	80.0
Granite Mountain - East	QF	UT	80.0
Granite Mountain - West	QF	UT	50.0
Granite Peak	QF	UT	3.0
Graphite	PPA	UT	80.0
Greenville	QF	UT	2.0
Horseshoe Solar	PPA	UT	75.0
Hunter	PPA	UT	100.0
Iron Springs	QF	UT	80.0
Klamath Falls Solar 1	QF	UT	1.0
Klamath Falls Solar 2	QF	UT	3.0
Laho	QF	UT	3.0
Milford	PPA	UT	99.0
Milford2	QF	UT	3.0
Milford Flat	QF	UT	3.0
Millican Solar Energy, LLC	PPA	OR	60.0
NW2_Neff	QF	OR	10.0
NW4_Bonanza	QF	OR	6.0
NW7_EaglePoint	QF	OR	10.0
NW9_Pendleton	QF	OR	6.0
Old Mill	PPA	OR	5.0
OR2_AgateBay	QF	OR	10.0
OR3_TurkeyHill	QF	OR	10.0

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
OR5_Merrill	QF	OR	8.0
OR6_Lakeview	QF	OR	10.0
OR8_Dairy	QF	OR	10.0
OSLH Collier	QF	OR	10.0
Pavant	QF	UT	50.0
Pavant II LLC	QF	UT	50.0
Pavant III LLC	PPA	UT	20.0
Prineville	PPA	OR	40.0
Quichapa I	QF	UT	3.0
Quichapa II	QF	UT	3.0
Quichapa III	QF	UT	3.0
Red Hills	QF	UT	80.0
Rocket	PPA	UT	80.0
Sage I	QF	WY	20.0
Sage II	QF	WY	20.0
Sage III	QF	WY	18.0
Sigurd	PPA	UT	80.0
Skysol	QF	OR	55.0
Solarize Rogue LLC (OR Community Solar)	QF	OR	0.1
South Milford	QF	UT	3.0
SunE1	QF	UT	3.0
SunE2	QF	UT	3.0
SunE3	QF	UT	3.0
Sweetwater	QF	WY	80.0
Three Peaks	QF	UT	80.0
Tumbleweed	QF	OR	10.0
Woodline	QF	OR	8.0
TOTAL – Purchased Solar			**2339.6**

Geothermal

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

Biomass/Biogas

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

Renewables Net Metering

Table 6.7 provides a breakdown of net metered capacity and customer counts from data collected as of August 16, 2021.

Table 6.7 – Net Metering Customers and Capacity

Fuel	Solar	Wind	Gas[1/]	Hydro	Mixed[2/]
Nameplate (kW)	570,106	853	884	965	1,217
Capacity (percentage of total)	99.32%	0.15%	0.15%	0.17%	0.21%
Number of customers	65,582	194	4	21	62
Customer (percentage of total)	99.57%	0.29%	0.01%	0.03%	0.09%

[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. 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 snowpack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, 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 6.8.

Table 6.8 – Hydroelectric Contracts

Hydroelectric Contracts by Load and Resource Balance Category		L&R Balance Capacity at System Peak (MW)
Hydroelectric		193
Qualifying Facilities - Hydroelectric		88
Total Contracted Hydroelectric Resources		**280**

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

Table 6.9 – PacifiCorp Owned Hydroelectric Generation Facilities –Capacities

Plant	River System	State	Capacity (MW)
East			
Ashton	Bear	UT	8
Cutler	Bear	UT	30
Grace	Bear	UT	33
Lifton	Bear	UT	1
Oneida	Bear	UT	30
Soda	Bear	UT	14
PCM - North*	-	UT	9
PCM - South**	-	UT	1
West			
Bend	-	OR	4
Bigfork	Lewis	MT	4
Swift 1	Lewis	WA	240
Swift 2	Lewis	WA	70
Yale	Lewis	WA	134
Merwin	Lewis	WA	136
Copco 1	Klamath	OR/CA	20
Copco 2	Klamath	OR/CA	27
Iron Gate	Klamath	OR/CA	18
JC Boyle	Klamath	OR/CA	98
Clear Water 1	Umpqua	OR	15
Clear Water 2	Umpqua	OR	26
Fish Creek	Umpqua	OR	11
Lemolo 1	Umpqua	OR	29
Lemolo 2	Umpqua	OR	33
Slide Creek	Umpqua	OR	18
Soda Springs	Umpqua	OR	11
Toketee	Rogue	OR	43
Eagle Point	Rogue	OR	3
Prospect 1	Rogue	OR	5
Prospect 2	Rogue	OR	36
Prospect 3	Rogue	OR	7
Prospect 4	Rogue	OR	1
Fall Creek	-	OR	4
Wallowa Falls	-	OR	1
TOTAL – Hydroelectric before contracts			**1118**
Hydroelectric Contracts			**280**
TOTAL – Hydroelectric			**1398**

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

Demand-Side Management

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

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

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

Table 6.10 – Existing DSM Resource Summary

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2021-2040 Period
1	Residential/small commercial air conditioner load control	124 MW summer peak	Yes.
	Irrigation load management	205 MW summer peak	Yes.
	Interruptible contracts	191 MW summer peak	Yes.
2	PacifiCorp and Energy Trust of Oregon programs	0 MW[1/]	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	Energy and capacity impacts are not available/measured	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	Energy and capacity impacts are not available/measured	No. Historical savings from customer response to pricing structure is reflected in load forecast.
4	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

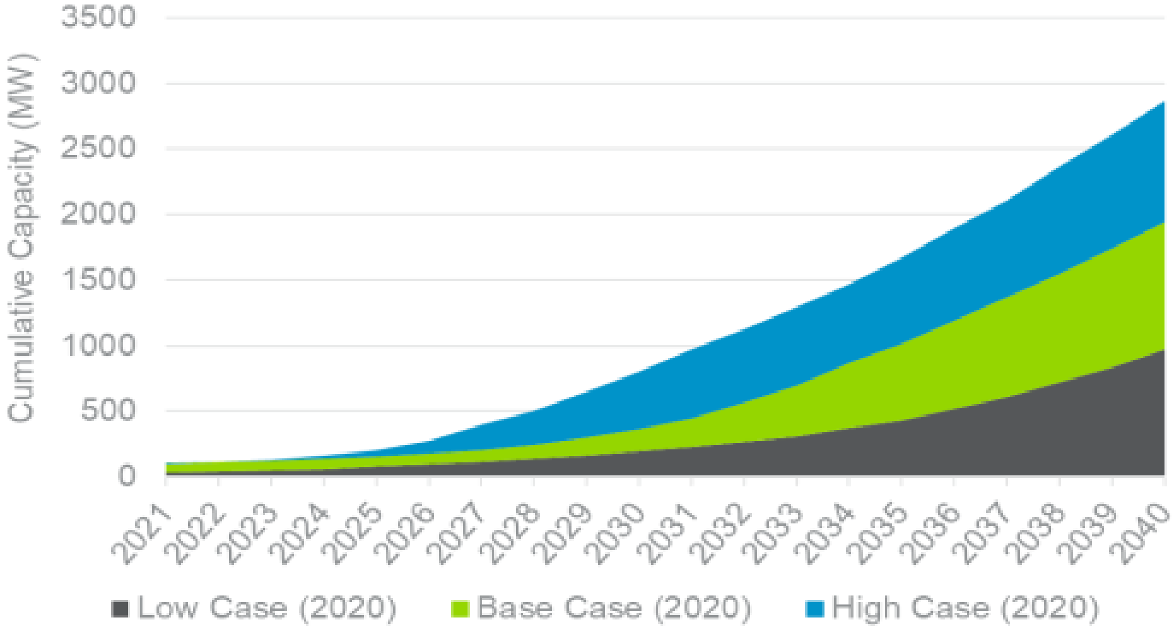
[1/] Due to the timing of the 2021 IRP load forecast, there is a small amount (68 MW) of existing Class 2 DSM in Table 6.12 (System Capacity Loads and Resources without Resource Additions).

Private Generation

For the 2021 IRP, PacifiCorp contracted with Guidehouse to update the assessment of private generation (PG) penetration performed for the 2021 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.

Guidehouse estimates approximately 1.74 gigawatts (GW) of PG capacity will be installed in PacifiCorp's territory from 2021-2040 in the base case scenario. As shown in **Figure 6.1**, the low and high scenarios project a cumulative installed capacity of 0.82 GW and 2.66 GW by 2040, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions. The Guidehouse study identifies expected levels of customer-sited private generation, which is applied as a reduction to PacifiCorp's forecasted load for IRP modeling purposes.

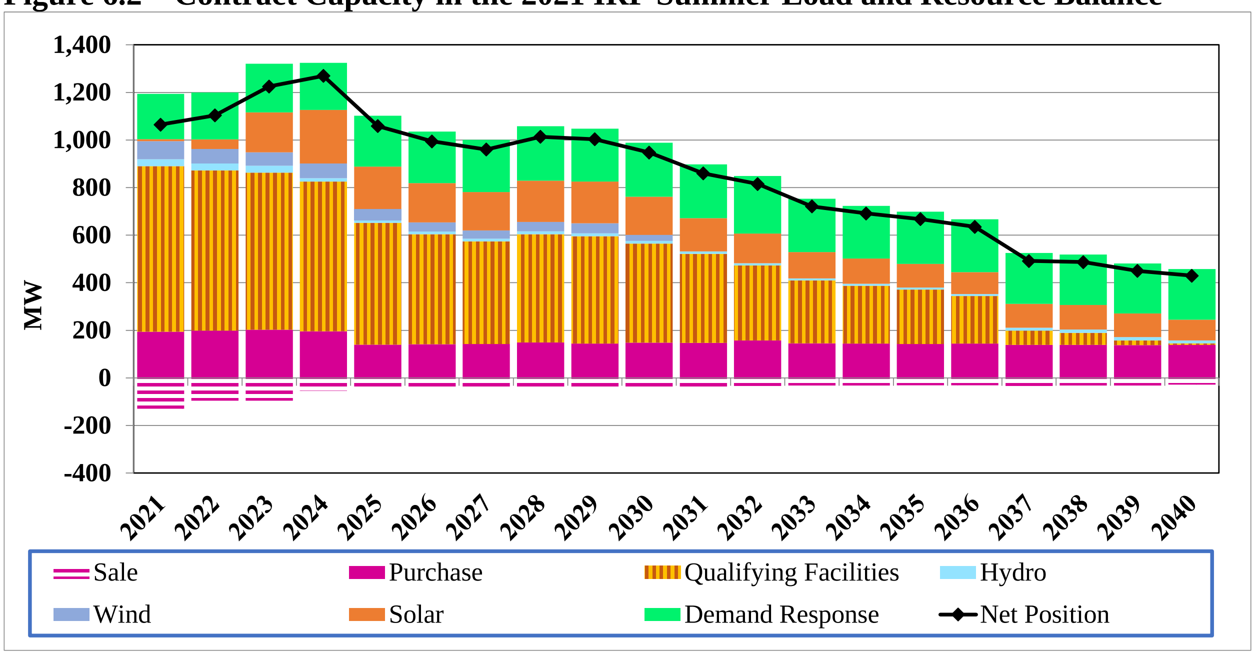
Figure 6.1 – Private Generation Market Penetration (MWAC), 2021-2040



Power-Purchase Agreements

PacifiCorp obtains the remainder of its capacity and energy requirements through long-term firm contracts, short-term firm contracts, and spot market purchases. Figure 6.2 presents the contract capacity in place for 2021 through 2040. 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 6.2 – Contract Capacity in the 2021 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 to load obligations across both summer and winter. In the past, the coincident peak load hour was almost always the hour with the lowest margin, because the available resource output was comparable in the peak load hour and in other hours. With the significant penetration of solar resource in PacifiCorp's portfolio, the hour with the lowest margin is no longer readily identifiable from load alone, as solar resources have high availability during the peak load hour but no availability a few hours later when loads are slightly lower. Wind, storage, hydro, and other resources further complicate the calculation. In light of this, for the 2021 IRP, PacifiCorp evaluated the balance of generating capability and load obligations not just during the coincident peak load hour, but across all hours, to identify the winter and summer hours in each year with the lowest margin as a percentage of load. Under this method, the reported planning reserve margin is necessarily met in the coincident peak load hour, but the hour with the lowest margin generally coincides with a period of relatively high load and relatively low renewable resource output.

For reporting purposes, the capacity balance summarized in this chapter is developed by first reducing the hourly system load by hourly private generation projections to determine the net system coincident peak load for each of the first ten years (2021-2030) 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 capacity reserve margin (13% for the 2021 IRP) and then subtracting the result from existing resources. This view is presented both without and with uncommitted FOTs.

The energy balance shows the average monthly surplus or deficit of energy over the first ten years of the planning horizon (2021-2030). 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. 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 8 (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, and sales. 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 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) weighted based on the expected timing of resource shortfalls during summer or winter periods. 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. Presently, these thermal resources account for roughly two thirds of the firm capacity available in the PacifiCorp system.

All Other 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 2021 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, in particular the level of storage capability. 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. PacifiCorp also recognizes that other resources whose expected output varies over the course of each year are also impacted by portfolio changes.

For the purpose of reporting the capacity contribution of all other resources in the load and resource balance, PacifiCorp first calculated the contribution of long-duration dispatchable resources in the portfolio, using the methodologies described above. The remaining capacity in the load and resource balance, up to PacifiCorp's thirteen percent planning reserve margin, is attributable to the rest of the resources in PacifiCorp's portfolio. This remaining capacity was allocated based on each resource's hourly available generation during the hours in each winter or summer season when load exceeded the availability of long-duration dispatchable resources, and was allocated pro-rata among all resources delivering during such hours. It should be noted that while allocation of capacity among resources as described in this section is helpful for presenting a load and resource balance, the allocation to specific resources has no bearing on the reliability or economics of the preferred portfolio, which reflects the coordinated dispatch of all available resources in every hour of the year. The economics of resource additions are more closely aligned with marginal or "last-in" capacity contribution estimates, which are generally lower for resources whose output is positively correlated with other resources already present in the portfolio. For estimates of marginal capacity contribution values, please refer to Volume II, Appendix K (Capacity Contribution).

Sales

Contracts for the sale of firm capacity and energy are treated the same as all other resources, except that they have a negative capacity value. The energy balance counts them by expected model dispatch.

Obligation

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

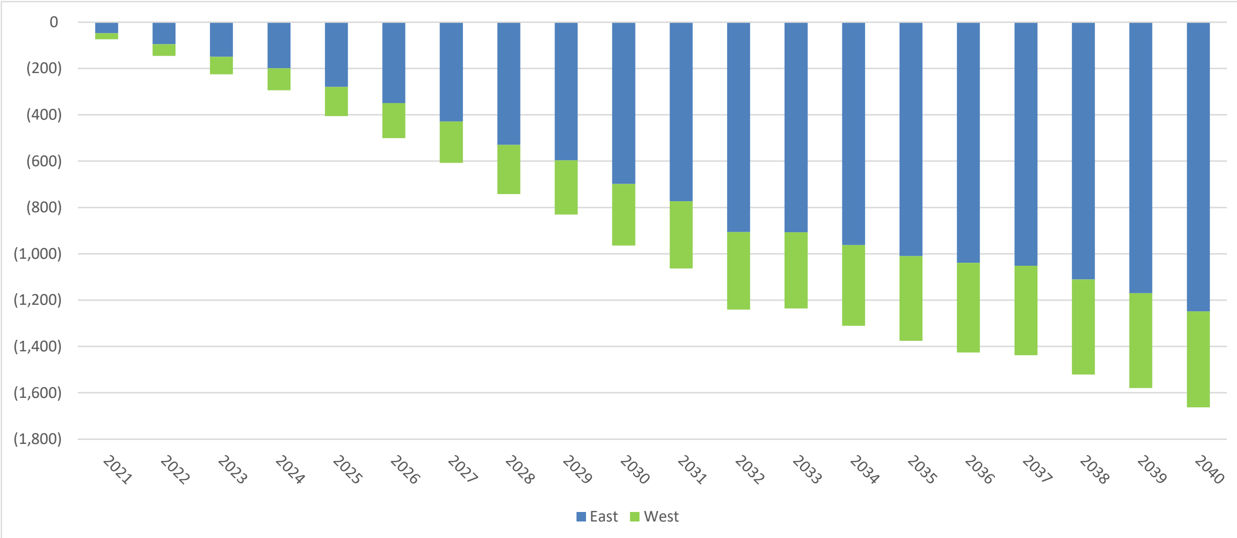
Load Net of Private Generation

The largest component of the obligation is retail load. In the 2021 IRP, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year and season. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer and winter peaks. The energy balance counts the average load on a monthly basis. For simplicity, load net of private generation is referred to as load in the following sections.

Energy Efficiency (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 2020 energy efficiency that is not incorporated in the forecast. The 2020 energy efficiency forecast (73 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 2021 IRP preferred portfolio. Figure 6.3 shows the energy efficiency for the east and west control areas in the 2021 IRP preferred portfolio.

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



Demand Response (Class 1 DSM)

Existing demand response program capacity is categorized as a reduction to peak load. Also included in the demand response category are interruptible contracts. PacifiCorp has had interruptible contracts for approximately 177 MW of load interruption capability for many years. These contracts are a key aspect of the retail service provided to the associated customers, and absent these contracts their demand would likely be different from that included in the load forecast. To maintain an alignment with the load forecast, these contracts are assumed to continue indefinitely under their current structure.

Planning Reserve Margin

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

Position

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

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 – Demand Response – 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 PRM adopted for the 2021 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 + Planning Reserves)

Capacity Balance Results

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

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

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,466	5,429	5,425	5,459	5,044	5,002	4,293	4,182	3,953
Hydroelectric	86	86	85	69	56	52	51	56	57	52
Renewable	668	690	815	912	709	676	661	718	743	676
Purchase	193	197	202	195	138	141	142	148	143	147
Qualifying Facilities	537	521	515	488	396	357	344	364	372	346
Sale	(20)	(20)	(20)	0	0	0	0	0	0	0
East Existing Resources	**6,943**	**6,940**	**7,026**	**7,090**	**6,758**	**6,271**	**6,201**	**5,580**	**5,498**	**5,174**
Load	7,096	7,246	7,380	7,475	7,583	7,492	7,550	7,643	7,728	7,833
Private Generation	(51)	(72)	(81)	(84)	(87)	(90)	(96)	(106)	(119)	(136)
Existing - Demand Response	(520)	(538)	(558)	(538)	(583)	(592)	(598)	(623)	(604)	(619)
Existing - Energy Efficiency	(43)	(45)	(46)	(45)	(49)	(49)	(50)	(52)	(50)	(52)
New Energy Efficiency	(48)	(95)	(149)	(199)	(280)	(349)	(429)	(529)	(597)	(698)
East Total obligation	**6,434**	**6,495**	**6,546**	**6,609**	**6,586**	**6,411**	**6,377**	**6,333**	**6,358**	**6,328**
Capacity Reserve Margin (13%)	836	844	851	859	856	833	829	823	827	823
East Obligation + Reserves	7,271	7,340	7,397	7,468	7,442	7,244	7,206	7,157	7,185	7,151
East Position	(327)	(400)	(371)	(378)	(684)	(974)	(1,005)	(1,577)	(1,687)	(1,977)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Thermal	2,139	2,165	2,168	2,144	2,149	2,019	2,015	2,014	2,036	2,035
Hydroelectric	577	567	521	508	407	386	380	420	423	390
Renewable	194	177	185	184	148	139	140	144	144	134
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	158	153	145	141	116	105	87	91	79	71
Sale	(109)	(76)	(76)	(54)	(44)	(42)	(41)	(44)	(44)	(41)
West Existing Resources	**2,961**	**2,986**	**2,945**	**2,924**	**2,777**	**2,608**	**2,582**	**2,626**	**2,638**	**2,591**
Load	3,351	3,400	3,443	3,472	3,506	3,530	3,557	3,584	3,610	3,638
Private Generation	(23)	(39)	(51)	(56)	(60)	(65)	(71)	(78)	(86)	(96)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(24)	(25)	(26)	(25)	(27)	(28)	(28)	(29)	(28)	(29)
New Energy Efficiency	(26)	(51)	(76)	(95)	(126)	(152)	(178)	(213)	(234)	(266)
West Total obligation	**3,278**	**3,286**	**3,290**	**3,297**	**3,293**	**3,286**	**3,280**	**3,264**	**3,262**	**3,247**
Capacity Reserve Margin (13%)	426	427	428	429	428	427	426	424	424	422
West Obligation + Reserves	3,704	3,713	3,718	3,725	3,721	3,713	3,707	3,689	3,686	3,669
West Position	(743)	(726)	(773)	(801)	(943)	(1,105)	(1,125)	(1,063)	(1,048)	(1,078)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
System										
Total Resources	9,904	9,927	9,971	10,014	9,535	8,879	8,783	8,206	8,136	7,764
Obligation	9,712	9,781	9,836	9,906	9,878	9,697	9,657	9,598	9,620	9,575
Planning Reserves (13%)	1,263	1,272	1,279	1,288	1,284	1,261	1,255	1,248	1,251	1,245
Obligation + Reserves	10,975	11,053	11,115	11,193	11,162	10,958	10,912	10,845	10,871	10,820
System Position	(1,071)	(1,126)	(1,144)	(1,179)	(1,627)	(2,079)	(2,130)	(2,639)	(2,735)	(3,056)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
Uncomitted FOTs to meet remaining Need	1,071	1,126	1,144	500	500	500	500	500	500	500
Net Surplus/(Deficit)	0	0	0	(679)	(1,127)	(1,579)	(1,630)	(2,139)	(2,235)	(2,556)

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

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,945	3,955	3,629	3,607	3,613	3,613	2,765	2,759	2,757	2,491
Hydroelectric	47	43	40	40	40	40	57	63	64	58
Renewable	582	525	471	465	465	465	587	595	586	539
Purchase	146	157	145	144	142	144	138	137	136	138
Qualifying Facilities	310	266	220	204	192	162	34	29	12	0
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**5,031**	**4,947**	**4,505**	**4,459**	**4,452**	**4,424**	**3,582**	**3,583**	**3,555**	**3,226**
Load	7,938	8,041	8,138	8,232	8,336	8,343	8,413	8,520	8,390	8,488
Private Generation	(160)	(189)	(218)	(251)	(291)	(181)	(205)	(230)	(119)	(132)
Existing - Demand Response	(615)	(660)	(609)	(604)	(598)	(607)	(582)	(579)	(574)	(581)
Existing - Energy Efficiency	(51)	(55)	(51)	(50)	(50)	(51)	(48)	(48)	(48)	(48)
New Energy Efficiency	(773)	(906)	(907)	(962)	(1,009)	(1,039)	(1,052)	(1,111)	(1,170)	(1,248)
East Total obligation	**6,339**	**6,231**	**6,353**	**6,364**	**6,388**	**6,465**	**6,526**	**6,552**	**6,478**	**6,478**
Capacity Reserve Margin (13%)	824	810	826	827	830	840	848	852	842	842
East Obligation + Reserves	7,163	7,041	7,179	7,192	7,219	7,306	7,374	7,404	7,320	7,321
East Position	(2,132)	(2,094)	(2,674)	(2,732)	(2,767)	(2,882)	(3,792)	(3,821)	(3,766)	(4,094)
Available Front Office Transactions	0	0	0	0	0	0	0	0	0	0
West										
Thermal	2,027	2,021	2,024	2,023	2,023	2,031	1,807	456	456	456
Hydroelectric	355	323	301	299	296	298	435	483	485	446
Renewable	117	108	105	92	92	100	129	142	143	128
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	64	49	45	39	37	38	25	22	9	6
Sale	(38)	(34)	(32)	(32)	(32)	(31)	(34)	(32)	(32)	(28)
West Existing Resources	**2,527**	**2,468**	**2,443**	**2,422**	**2,417**	**2,435**	**2,364**	**1,072**	**1,061**	**1,009**
Load	3,676	3,707	3,740	3,773	3,805	3,752	3,793	3,825	3,758	3,782
Private Generation	(118)	(158)	(205)	(258)	(316)	(263)	(305)	(351)	(195)	(225)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(29)	(31)	(28)	(28)	(28)	(28)	(27)	(27)	(27)	(27)
New Energy Efficiency	(289)	(334)	(329)	(348)	(366)	(388)	(386)	(410)	(409)	(414)
West Total obligation	**3,241**	**3,184**	**3,178**	**3,138**	**3,095**	**3,073**	**3,075**	**3,038**	**3,127**	**3,115**
Capacity Reserve Margin (13%)	421	414	413	408	402	399	400	395	407	405
East Obligation + Reserves	132	80	84	60	36	12	14	(15)	(2)	(9)
East Position	2,395	2,388	2,359	2,362	2,381	2,423	2,350	1,087	1,064	1,018
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
System										
Total Resources	7,558	7,415	6,948	6,881	6,869	6,859	5,946	4,655	4,616	4,235
Obligation	9,580	9,415	9,531	9,502	9,483	9,538	9,601	9,590	9,606	9,593
Planning Reserves (13%)	1,245	1,224	1,239	1,235	1,233	1,240	1,248	1,247	1,249	1,247
Obligation + Reserves	10,825	10,639	10,770	10,737	10,716	10,778	10,849	10,836	10,854	10,841
System Position	(3,267)	(3,225)	(3,821)	(3,856)	(3,847)	(3,919)	(4,903)	(6,182)	(6,239)	(6,606)
Available Front Office Transactions	500	500	500	500	500	500	500	500	500	500
Uncomitted FOTs to meet remaining Need	500	500	500	500	500	500	500	500	500	500
Net Surplus/(Deficit)	(2,767)	(2,725)	(3,321)	(3,356)	(3,347)	(3,419)	(4,403)	(5,682)	(5,739)	(6,106)

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

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,383	5,540	5,364	5,550	5,057	5,143	4,229	4,140	3,835
Hydroelectric	50	52	46	43	30	31	29	39	42	42
Renewable	765	929	885	860	546	676	639	796	843	802
Purchase	173	169	167	158	115	116	120	125	110	113
Qualifying Facilities	204	225	192	213	105	136	123	208	227	233
Sale	(16)	(17)	(15)	0	0	0	0	0	0	0
East Existing Resources	**6,654**	**6,741**	**6,815**	**6,638**	**6,346**	**6,016**	**6,054**	**5,397**	**5,362**	**5,025**
Load	5,538	5,678	5,800	5,860	5,943	5,874	5,915	6,008	6,081	6,161
Private Generation	(0)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Existing - Demand Response	(239)	(251)	(255)	(252)	(255)	(258)	(267)	(277)	(246)	(251)
Existing - Energy Efficiency	(32)	(33)	(34)	(33)	(34)	(34)	(35)	(37)	(33)	(33)
New Energy Efficiency	(39)	(74)	(109)	(143)	(181)	(213)	(259)	(309)	(308)	(356)
East Total obligation	**5,229**	**5,320**	**5,400**	**5,429**	**5,470**	**5,366**	**5,349**	**5,379**	**5,488**	**5,512**
Capacity Reserve Margin (13%)	680	692	702	706	711	698	695	699	713	717
East Obligation + Reserves	5,908	6,011	6,102	6,135	6,181	6,064	6,045	6,079	6,202	6,229
East Position	746	730	713	504	165	(48)	10	(682)	(839)	(1,203)
Available Front Office Transactions	300	300	300	300	300	300	300	300	300	300
West										
Thermal	2,205	2,211	2,186	1,930	2,203	2,064	2,060	1,982	2,010	1,991
Hydroelectric	497	518	434	456	320	330	317	410	439	439
Renewable	105	75	69	86	56	63	52	84	92	95
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	53	50	45	54	37	36	19	39	36	33
Sale	(88)	(71)	(59)	(45)	(32)	(33)	(32)	(38)	(41)	(40)
West Existing Resources	**2,773**	**2,784**	**2,675**	**2,482**	**2,585**	**2,461**	**2,418**	**2,478**	**2,536**	**2,519**
Load	3,318	3,358	3,397	3,421	3,449	3,479	3,516	3,550	3,585	3,615
Private Generation	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(3)	(3)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(23)	(24)	(24)	(24)	(24)	(24)	(25)	(26)	(23)	(24)
New Energy Efficiency	(25)	(48)	(69)	(86)	(105)	(124)	(149)	(176)	(176)	(200)
West Total obligation	**3,270**	**3,286**	**3,304**	**3,311**	**3,319**	**3,329**	**3,340**	**3,345**	**3,384**	**3,387**
Capacity Reserve Margin (13%)	425	427	430	430	431	433	434	435	440	440
West Obligation + Reserves	400	379	3,734	3,741	3,750	3,761	3,774	3,780	3,824	3,828
West Position	2,373	2,404	(1,058)	(1,260)	(1,165)	(1,301)	(1,356)	(1,302)	(1,287)	(1,309)
Available Front Office Transactions	700	700	700	700	700	700	700	700	700	700
System										
Total Resources	9,427	9,525	9,490	9,120	8,930	8,477	8,472	7,875	7,898	7,544
Obligation	8,498	8,605	8,704	8,740	8,789	8,695	8,689	8,725	8,872	8,900
Planning Reserves (13%)	1,105	1,119	1,132	1,136	1,143	1,130	1,130	1,134	1,153	1,157
Obligation + Reserves	9,603	9,724	9,836	9,876	9,931	9,825	9,819	9,859	10,025	10,056
System Position	(176)	(199)	(345)	(756)	(1,001)	(1,348)	(1,347)	(1,984)	(2,127)	(2,512)
Available Front Office Transactions	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncomitted FOTs to meet remaining Need	176	199	345	756	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	0	0	0	0	(1)	(348)	(347)	(984)	(1,127)	(1,512)

Table 6.13 (cont.) – Winter Peak System Capacity Loads and Resources without Resource Additions

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,901	3,947	3,646	3,554	3,677	3,411	2,830	2,643	2,783	2,421
Hydroelectric	36	36	34	37	38	43	47	48	52	49
Renewable	665	662	620	668	703	752	782	756	832	778
Purchase	129	129	131	119	109	111	136	133	134	119
Qualifying Facilities	186	178	133	124	119	80	15	13	4	0
Sale	0	0	0	0	0	0	0	0	0	(0)
East Existing Resources	**4,917**	**4,952**	**4,563**	**4,501**	**4,647**	**4,397**	**3,811**	**3,592**	**3,806**	**3,368**
Load	6,240	6,328	6,415	6,517	6,595	6,672	6,407	6,504	6,589	6,682
Private Generation	(9)	(10)	(12)	(13)	(14)	(16)	(33)	(37)	(41)	(45)
Existing - Demand Response	(288)	(287)	(291)	(264)	(243)	(247)	(303)	(295)	(299)	(267)
Existing - Energy Efficiency	(38)	(38)	(39)	(35)	(32)	(33)	(40)	(39)	(40)	(35)
New Energy Efficiency	(446)	(480)	(513)	(494)	(481)	(504)	(659)	(695)	(758)	(726)
East Total obligation	**5,459**	**5,513**	**5,560**	**5,711**	**5,824**	**5,872**	**5,372**	**5,438**	**5,451**	**5,609**
Capacity Reserve Margin (13%)	710	717	723	742	757	763	698	707	709	729
East Obligation + Reserves	6,169	6,230	6,283	6,453	6,581	6,636	6,070	6,145	6,160	6,338
East Position	(1,252)	(1,277)	(1,720)	(1,952)	(1,935)	(2,239)	(2,260)	(2,553)	(2,354)	(2,970)
Available Front Office Transactions	300	300	300	300	300	300	300	300	300	300
West										
Thermal	2,076	2,053	2,032	2,080	2,072	2,025	1,808	489	490	490
Hydroelectric	373	374	351	388	406	448	481	487	536	503
Renewable	79	79	70	78	78	91	101	104	111	107
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	25	23	19	19	19	19	17	16	13	8
Sale	(35)	(34)	(32)	(34)	(36)	(38)	(32)	(29)	(32)	(30)
West Existing Resources	**2,519**	**2,496**	**2,442**	**2,531**	**2,540**	**2,545**	**2,376**	**1,068**	**1,119**	**1,078**
Load	3,643	3,681	3,721	3,760	3,797	3,826	4,271	4,322	4,375	4,425
Private Generation	(4)	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(13)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
Existing - Energy Efficiency	(27)	(27)	(28)	(25)	(23)	(23)	(29)	(28)	(28)	(25)
New Energy Efficiency	(252)	(271)	(293)	(283)	(276)	(293)	(372)	(385)	(409)	(369)
West Total obligation	**3,360**	**3,378**	**3,395**	**3,446**	**3,491**	**3,502**	**3,861**	**3,898**	**3,925**	**4,018**
Capacity Reserve Margin (13%)	437	439	441	448	454	455	502	507	510	522
East Obligation + Reserves	185	168	148	165	178	163	130	121	101	153
East Position	2,334	2,328	2,294	2,366	2,362	2,382	2,246	947	1,018	925
Available Front Office Transactions	700	700	700	700	700	700	700	700	700	700
System										
Total Resources	7,436	7,449	7,005	7,033	7,186	6,942	6,187	4,660	4,925	4,445
Obligation	8,819	8,891	8,955	9,157	9,315	9,374	9,234	9,336	9,377	9,627
Planning Reserves (13%)	1,146	1,156	1,164	1,190	1,211	1,219	1,200	1,214	1,219	1,251
Obligation + Reserves	9,966	10,047	10,119	10,347	10,526	10,593	10,434	10,550	10,595	10,878
System Position	(2,530)	(2,599)	(3,115)	(3,314)	(3,340)	(3,651)	(4,247)	(5,889)	(5,670)	(6,433)
Available Front Office Transactions	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Uncomitted FOTs to meet remaining Need	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000	1,000
Net Surplus/(Deficit)	(1,530)	(1,599)	(2,115)	(2,314)	(2,340)	(2,651)	(3,247)	(4,889)	(4,670)	(5,433)

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

Figure 6.4 – Summer System Capacity Position Trend

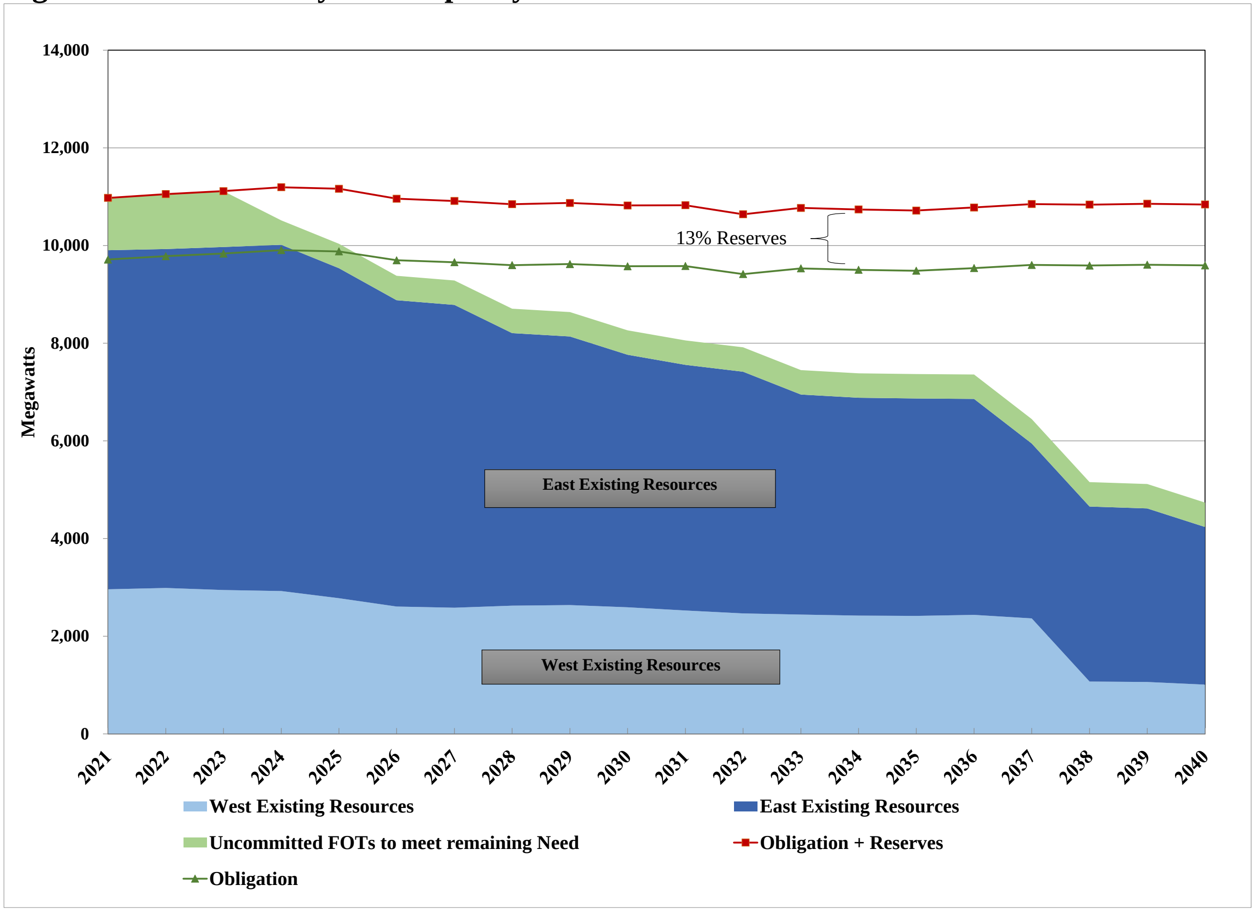


Figure 6.5 – Winter System Capacity Position Trend

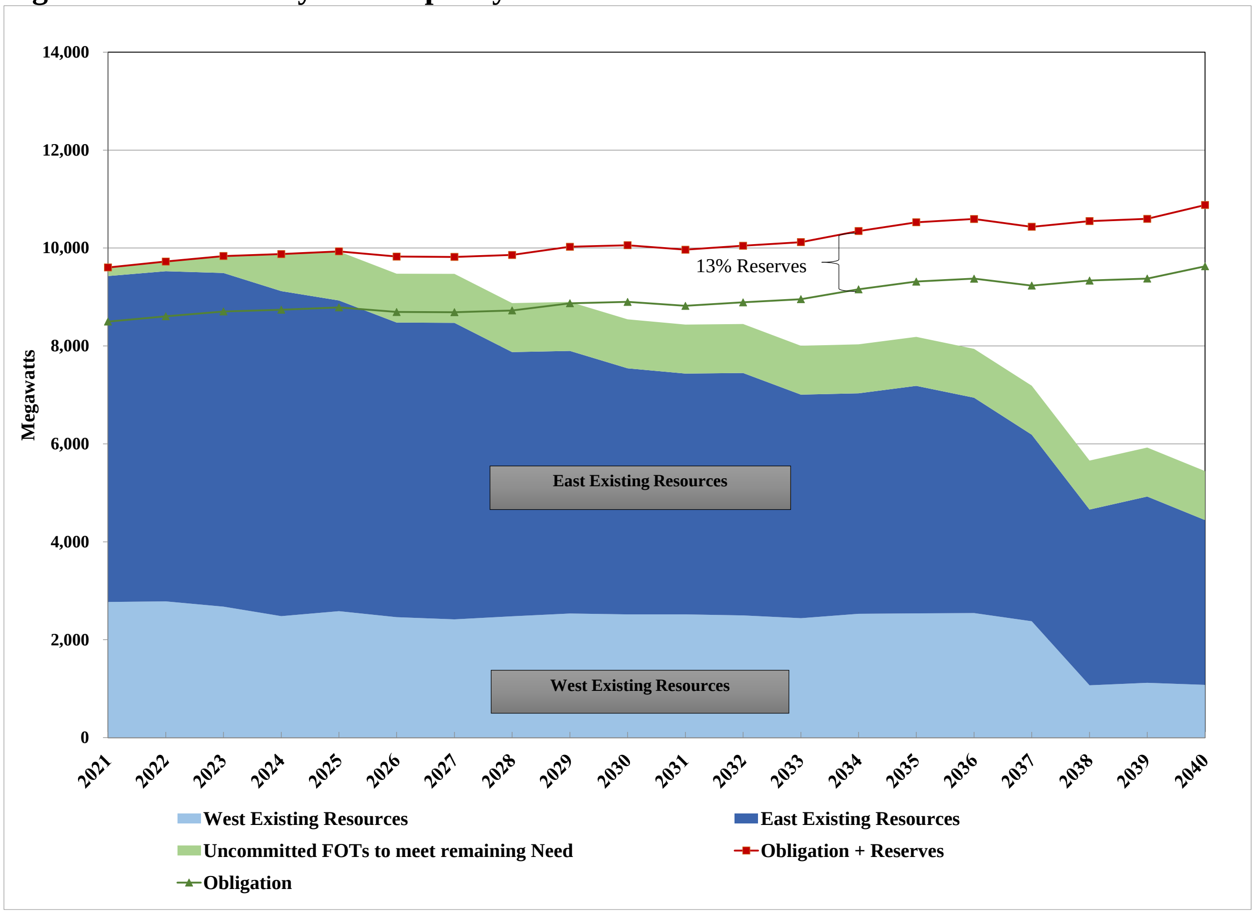


Figure 6.6 – East Summer Capacity Position Trend

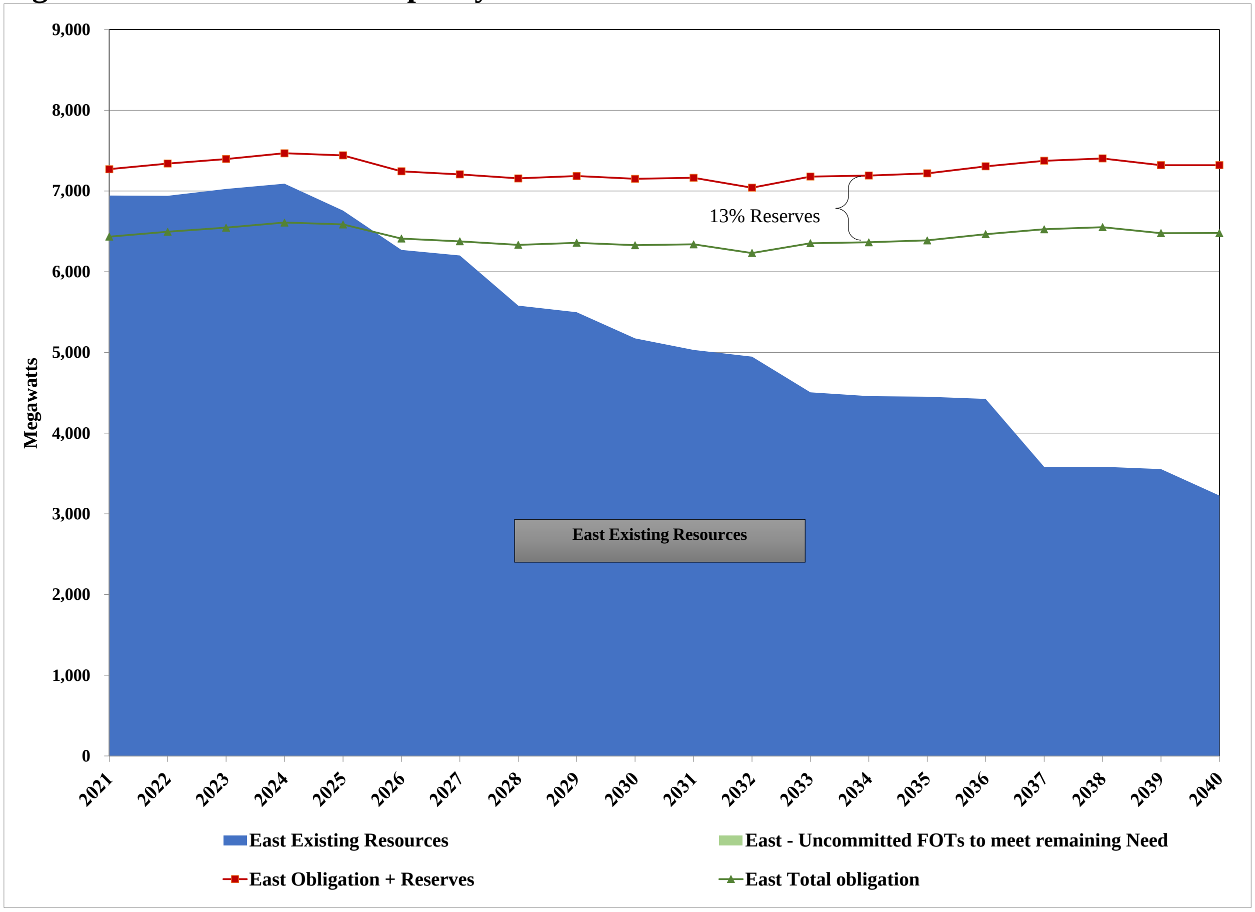
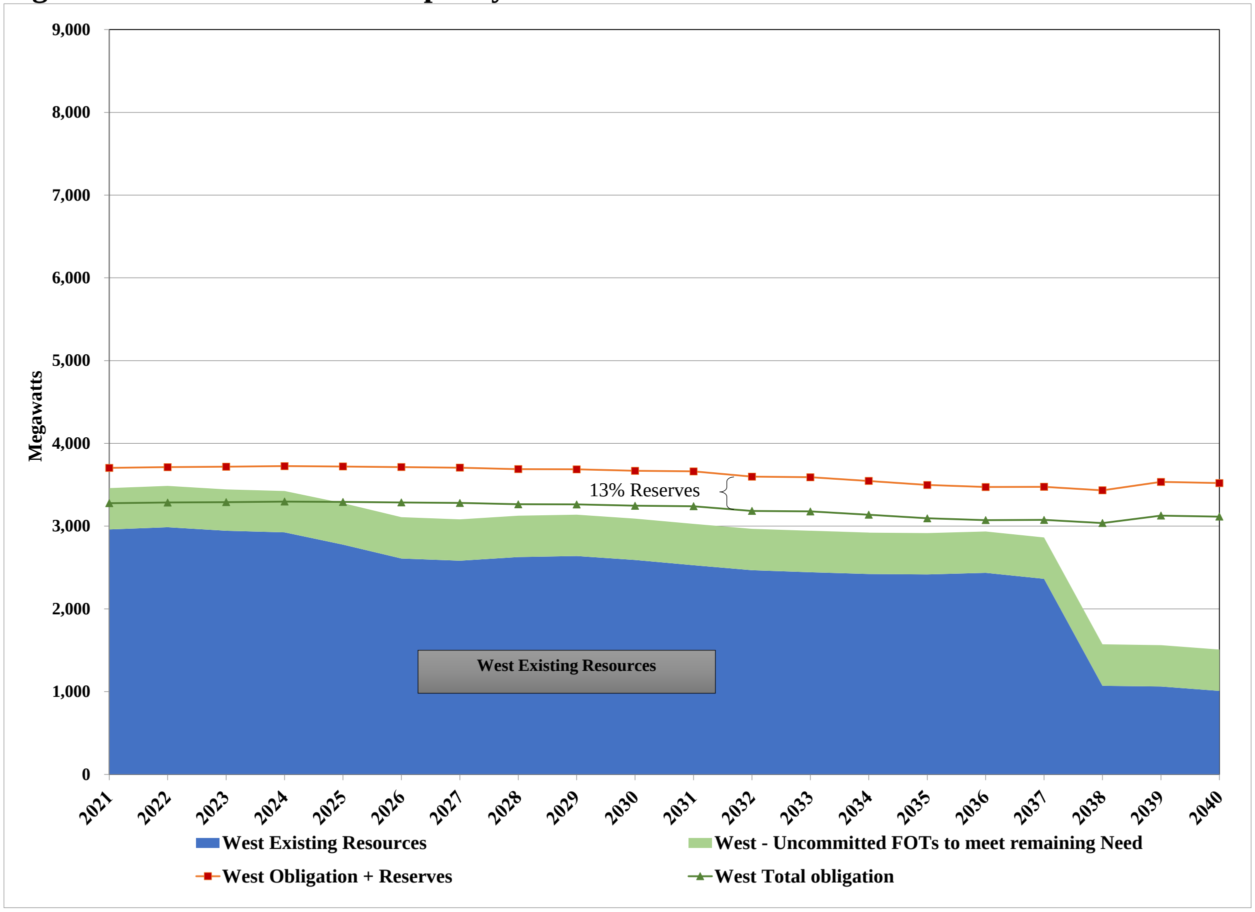


Figure 6.7 – West Summer Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the monthly surplus or (deficit) of energy. 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 + Renewable + Firm Purchases + QF – Sales

The average obligation is computed using the following formula:

Obligation = Load + Firm Sales

The energy position by month is then computed as follows:

Energy Position = Existing Resources – Obligation – Operating Reserve Requirements

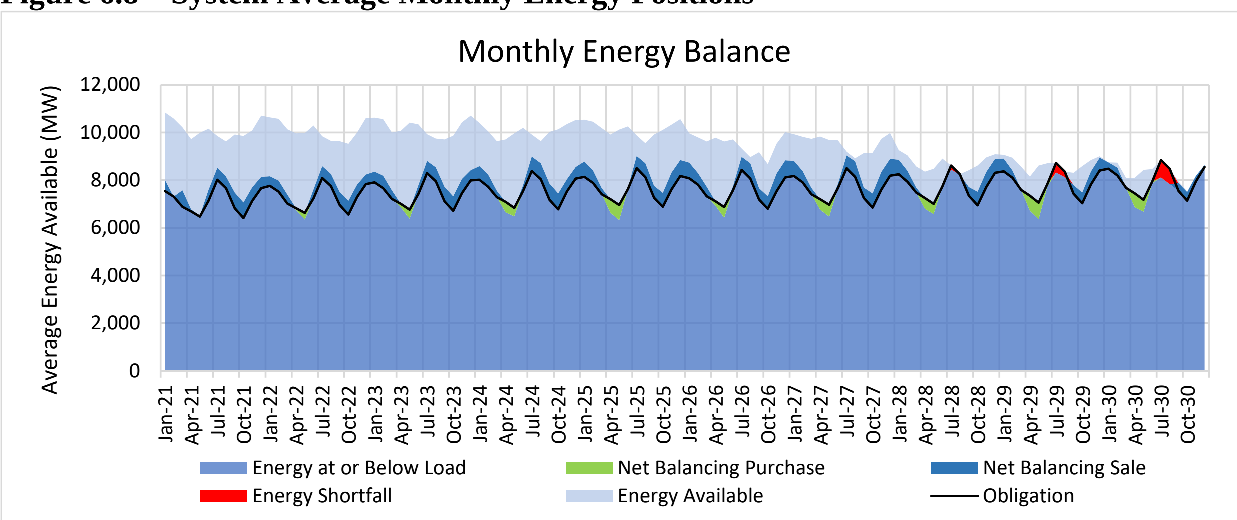
Operating Reserve Requirements include spinning and non-spinning reserves, but not regulation reserves, which are expected to be close to energy neutral over time. As duration-limited resources such as batteries become a larger portion of the Company's portfolio, less of the potential output of thermal resources is likely to be needed to meet Operating Reserve requirements. In addition, energy storage resources represent a net load, due to their roundtrip efficiency. For the 2021 IRP, storage resources are not included in the energy balance.

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 6.8 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 6.8 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 6.8 – System Average Monthly Energy Positions



CHAPTER 7 – 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.
- 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.
- The Plexos model is able to endogenously model transmission upgrades.
- PacifiCorp continued to apply cost reduction credits to energy efficiency, reflecting risk mitigation benefits, transmission and distribution investment deferral benefits, and a ten percent market price credit for Washington and Oregon as allowed by the Northwest Power Act.

Introduction

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

Supply-Side Resources

The list of supply-side resource options reflects the realities evidenced through permitting, internally generated studies and externally commissioned studies undertaken to better understand details of available generation resources. Capital costs for some resource options have declined while others have remained stable compared to the 2019 IRP. Wind and transmission resources were updated based upon market and performance data gained from construction of the Energy Vision 2020 project that came out of the 2017 IRP. 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 were updated to include 100 MW and 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. Combustion turbine types and configurations remained unchanged because the market continued to improve the ability of existing technology to provide firming for variable energy resources. The capital and operating costs of simple and combined-cycle gas turbine plants have remained relatively low in recent years, with a flat to slightly decreasing cost trend.[1] carbon capture and sequestration (CCS) retrofit costs were updated using cost data from existing carbon capture facilities, studies and CCS developers. New super critical pulverized coal-fueled 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 2019 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 (2020) third-party engineering cost and performance estimates;
- Original equipment manufacturers operation and maintenance estimates;
- Developer cost and performance estimates;
- Publicly available cost and performance estimates;
- Actual PacifiCorp or electric utility industry installations, providing current construction/maintenance costs and performance data with similar resource attributes; and
- Projected PacifiCorp or electric utility industry installations, providing projected construction/maintenance costs and performance data of similar or identical resource options.

Black and Veatch and original equipment manufacturers provided estimated capital costs, operating and maintenance costs, performance, operating characteristics and planned outage cycles for simple cycle and combined cycle resources. Carbon capture, utilization and sequestration (CCUS) costs, revenues, and performance were estimated from existing carbon capture facilities, studies and CCUS developers. For this IRP cycle, Burns & McDonnell provided information for solar, wind, and energy storage resources. The Burns & McDonnell study builds upon prior 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

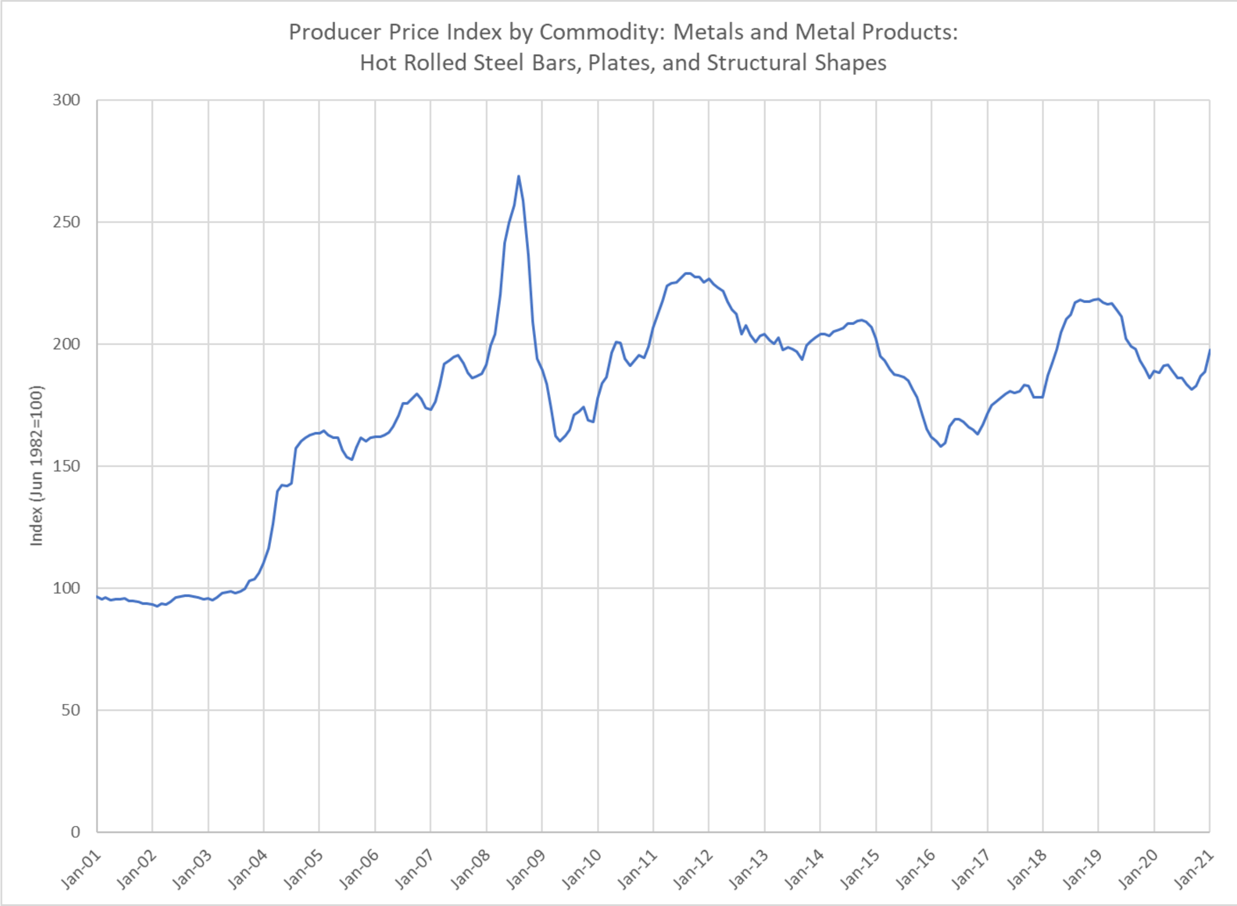
[1] While cost-and-performance metrics for gas-fired resources are presented in this chapter, PacifiCorp ultimately did not allow new gas-fired resources in its portfolio selection process. Please refer to Chapter 8 for a discussion of the risks PacifiCorp considered when making this planning assumption. A sensitivity case will be developed that enables new gas-fired proxy resources.

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

Handling of Technology Improvement Trends and Cost Uncertainties

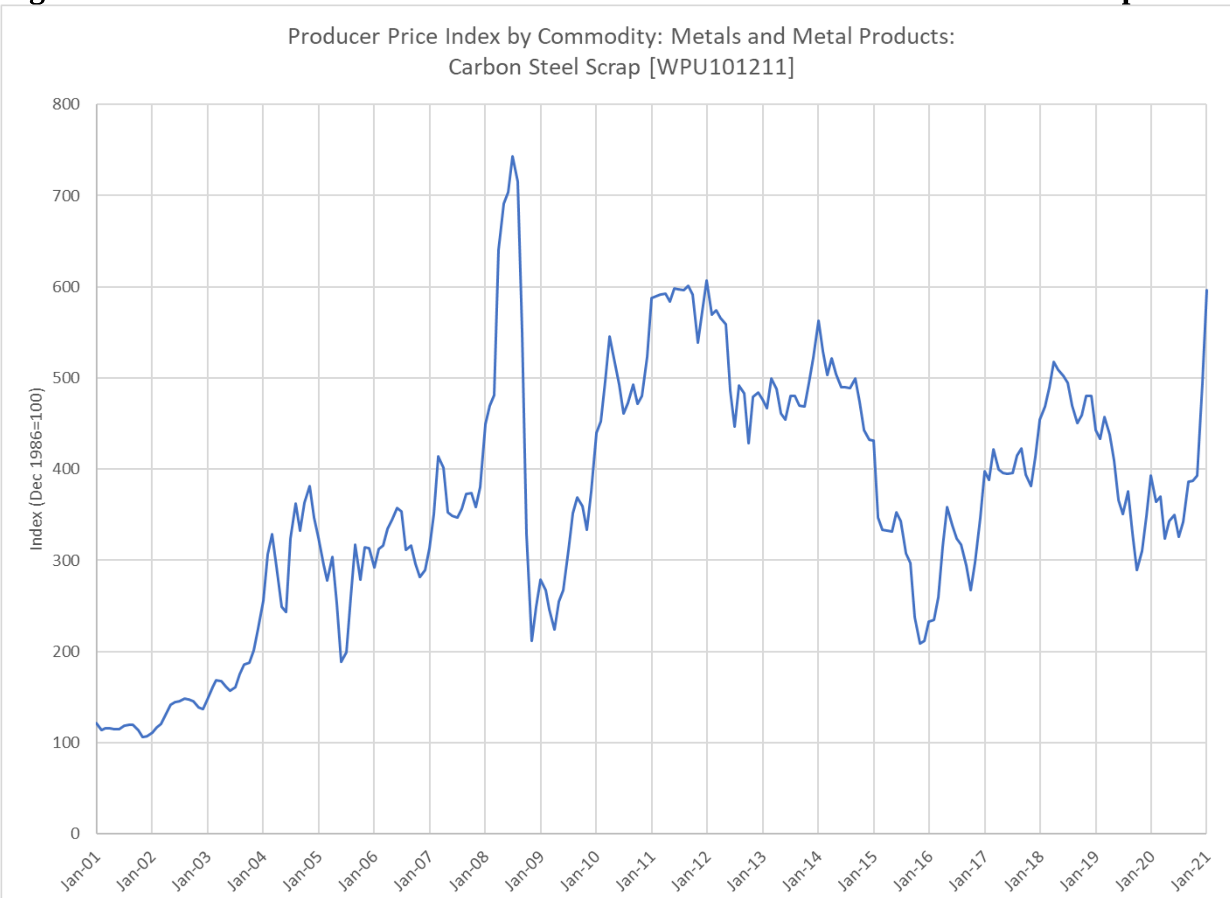
The capital cost uncertainty for some generation technologies is relatively high. Various factors contribute to this uncertainty including limited quantity and quality of data sets for new and emerging technologies that have been demonstrated at utility scale. Despite this uncertainty, the cost profile between the 2019 IRP and the 2021 IRP has not changed significantly. For example, Figure 7.1 shows the trend in U.S. steel prices over the period from January 2001 through January 2021. This figure illustrates changes in capital costs of generation resources. The 2021 IRP includes demolition costs for the first time. Demolition costs are impacted by the salvage of metals, including steel. Figure 7.2 shows the trend in U.S. carbon steel scrap and illustrates the uncertainty in demolition costs.

Figure 7.1 – Producer Price Index: Hot Rolled Steel Bars, Plates, and Structural Shapes[2]



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

Figure 7.2 – Producer Price Index: Metals and Metal Products: Carbon Steel Scrap[3]



Prices for solar PV modules and balance of plant costs have been re-baselined since the 2019 IRP as described later in this chapter. 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 2021 IRP anticipates the cost of new solar projects to decline approximately five percent per year during next ten 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), as well as CCUS technologies, have shown significant cost uncertainty because only a few units have been built and operated. For example, experience with significant cost overruns on IGCC projects, such as Southern Company's Kemper County IGCC plant, illustrate the difficulty in accurately estimating capital costs of these resource options. Where carbon capture is dependent on revenues from enhanced oil recovery (EOR) to offset costs, the volatility in the price of oil adds an additional level of uncertainty. For example, declining oil prices caused NRG Energy's Petra Nova carbon capture facility to cease operation. The loss of revenue at Petra Nova illustrates the added uncertainty of recovering costs through carbon dioxide sales. As these technologies mature and more facilities are proven at commercial scale, the associated costs may decrease.

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

The potential to provide reduced, reliable capital and operating cost estimates is limited by the number of installed and successfully operated resources. Reliable cost and performance estimates are not expected to be realized until the next generation of new plants are built and successfully operated. As such, future IRPs will be better able to incorporate the potential benefits of future cost reductions. Given the current emphasis on construction and operating experience associated with renewable generation, PacifiCorp anticipates the cost benefits for these technologies to be available sooner. The estimated capital costs are displayed in the SSR along with expected availability of each technology for commercial utilization.

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 recent RFPs.

Wind annual capital cost escalation rates are based on estimates provided by Burns and McDonnell and costs and market information obtained by PacifiCorp during the development and construction of recent wind projects. All other resources are assumed to escalate at inflation.

Resource Options and Attributes

Table 7.1 lists the cost-and-performance attributes for supply-side resource options designated by generic, elevation-specific regions where resources could potentially be located:

- 0 feet elevation: international organization for standardization (ISO) conditions (sea level and 59 degrees F); this is used as a reference for certain modeling purposes.
- 1,500 feet elevation: eastern Oregon/Washington.
- 3,000 feet elevation: southern/central Oregon.
- 4,500 feet elevation: northern Utah, specifically Salt Lake/Utah/Tooele/Box Elder counties.
- 5,050 feet elevation: central Utah, southern Idaho, central Wyoming.
- 6,500 feet elevation: southwestern Wyoming.

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (Continued)

Description		Resource Characteristics				Costs				Operating Characteristics			
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 (%)	Wa
Solar + Storage + Wind	Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	5,000	200	2023	25	$ 3,364	$ 268	$ -	$ 81.45	85%	(b)	(b)	
Solar + Storage + Wind	Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	6,400	200	2023	25	$ 3,364	$ 268	$ -	$ 81.45	85%	(b)	(b)	
Solar + Storage + Wind	Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	1,000	200	2023	25	$ 3,424	$ 268	$ -	$ 81.45	85%	(b)	(b)	
Storage	Pumped Hydro, Swan Lake. 3600 MWh	N/A	400	2027	60	$ 3,095	$ 485	$ -	$ 12.50	78%	0.0	0.0	
Storage	Pumped Hydro, Goldendale, 14400 MWh	N/A	1,200	2028	60	$ 2,833	$ 485	$ -	$ 12.50	78%	0.0	0.0	
Storage	Pumped Hydro, Seminoe, 7500 MWh	N/A	750	2029	80	$ 3,461	$ 485	$ 0.37	$ 16.00	80%	0.0	0.0	
Storage	Pumped Hydro, Badger Mountain, 4000 MWh	N/A	500	2027	80	$ 2,621	$ 485	$ 0.37	$ 28.00	80%	0.0	0.0	
Storage	Pumped Hydro, Owyhee, 4800 MWh	N/A	600	2029	80	$ 3,203	$ 485	$ 0.37	$ 20.00	80%	0.0	0.0	
Storage	Pumped Hydro, Flat Canyon, 1800 MWh	N/A	300	2029	80	$ 4,046	$ 485	$ 0.37	$ 53.33	80%	0.0	0.0	
Storage	Pumped Hydro, Utah PS2, 4000 MWh	N/A	500	2027	80	$ 3,237	$ 485	$ 0.37	$ 28.00	80%	0.0	0.0	
Storage	Pumped Hydro, Utah PS3, 4800 MWh	N/A	600	2029	80	$ 3,371	$ 485	$ 0.37	$ 20.00	80%	0.0	0.0	
Storage	Pumped Hydro, Banner Mountain, 3400 MWh	N/A	400	2028	50	$ 3,276	$ 485	$ 0.00	$ 28.50	81%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	150	2024	50	$ 1,954	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	150	2024	50	$ 2,189	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	150	2024	50	$ 2,445	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	300	2024	50	$ 1,557	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	300	2024	50	$ 1,692	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	300	2024	50	$ 2,016	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	500	2024	50	$ 1,549	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	500	2025	50	$ 1,762	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	
Storage	Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	500	2025	50	$ 2,010	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	
Storage	Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	1	2023	20	$ 1,948	$ 55	(a)	$ 40.00	85%	0.0	0.0	
Storage	Li-Ion Battery, , 1 MW, 1 MWh	N/A	1	2023	20	$ 2,058	$ 110	(a)	$ 50.00	85%	0.0	0.0	
Storage	Li-Ion Battery, , 1 MW, 4 MWh	N/A	1	2023	20	$ 3,167	$ 440	(a)	$ 70.00	85%	0.0	0.0	
Storage	Li-Ion Battery, , 1 MW, 8 MWh	N/A	1	2023	20	$ 4,622	$ 880	(a)	$ 100.00	85%	0.0	0.0	
Storage	Li-Ion Battery, , 50 MW, 200 MWh	N/A	50	2023	20	$ 1,820	$ 440	(a)	$ 27.60	85%	0.0	0.0	
Storage	Flow Battery, , 1 MW, 1 MWh	N/A	1	2023	20	$ 4,719	$ 12	(a)	$ 13.00	70%	0.0	0.0	
Storage	Flow Battery, , 1 MW, 4 MWh	N/A	1	2023	20	$ 5,051	$ 12	(a)	$ 13.00	70%	0.0	0.0	
Storage	Flow Battery, , 1 MW, 8 MWh	N/A	1	2023	20	$ 7,291	$ 12	(a)	$ 27.00	70%	0.0	0.0	
Storage	Flow Battery, , 20 MW, 160 MWh	N/A	20	2023	20	$ 4,190	$ 12	(a)	$ 30.50	70%	0.0	0.0	
Nuclear	Small Modular Reactor	5,000	854	2028	60	$ 5,396	$ 722	$ 6.72	$ 65.03	N/A	5.0	5.0	
Hydrogen	Non-Emitting Peaker	5,050	206	2030	30	$ 959	$ 2,414	$ 21.29	$ -	9936	2.7	3.9	

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (Continued)

Description		Resource Characteristics				Costs				Operating Characteristics			
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 (%)	Wa
CCUS for Coal Plants	Naughton 2 PC CCUS Retrofit	6,500	155	2026	20	$ 3,930	$ 37	$ 7.30	$ 39.90	1437200%	5.0	5.0	
CCUS for Coal Plants	Johnston 2 PC CCUS Retrofit	6,500	82	2026	20	$ 5,314	$ 37	$ 6.10	$ 40.58	1437200%	5.0	5.0	
CCUS for Coal Plants	Johnston 4 PC CCUS Retrofit	6,500	254	2026	20	$ 3,877	$ 37	$ 5.69	$ 37.88	1437200%	5.0	5.0	
CCUS for Coal Plants	Wyodak PC CCUS Retrofit	6,500	206	2026	20	$ 3,935	$ 37	$ 7.31	$ 39.95	1437200%	5.0	5.0	
CCUS for Coal Plants	Bridger 1 PC CCUS Retrofit	6,500	273	2026	20	$ 3,934	$ 37	$ 7.31	$ 39.94	1437200%	5.0	5.0	
CCUS for Coal Plants	Bridger 3 PC CCUS Retrofit	6,500	269	2026	20	$ 3,873	$ 37	$ 5.69	$ 37.83	1437200%	5.0	5.0	
CCUS for Coal Plants	Bridger 4 PC CCUS Retrofit	6,500	270	2026	20	$ 3,876	$ 37	$ 5.69	$ 37.86	1437200%	5.0	5.0	

Table 7.2 and Table 7.3 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 2020 dollars. Similar to the approach taken in previous IRPs, it is not currently envisioned that new combined cycle resources could be economically permitted in northern Utah, specifically Salt Lake, Utah, Davis, and Box Elder counties due to state implementation plans for these counties regarding particulate matter of 2.5 microns and less ($PM_{2.5}$).

A Glossary of Terms and a Glossary of Acronyms from the SSR is summarized in Table 7.4 and Table 7.5.

Table 7.1 – 2021 Supply-Side Resource Table (2020$)

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Natural Gas	SCCT Aero x3	0	169	2025	30	$ 1,463	$ 10	$ 7.44	$ -	9350	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	0	227	2025	30	$ 1,126	$ 10	$ 5.03	$ -	8800	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	0	239	2025	35	$ 699	$ 10	$ 14.16	$ -	9913	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	0	239	2025	35	$ 674	$ 10	$ 14.16	$ -	9913	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	0	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8286	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	0	422	2026	40	$ 1,396	$ 10	$ 1.77	$ -	6343	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	0	51	2026	40	$ 470	$ -	$ 0.05	$ -	8838	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	0	842	2027	40	$ 1,019	$ 10	$ 1.71	$ -	6361	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	0	102	2027	40	$ 357	$ -	$ 0.05	$ -	8665	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	0	842	2027	40	$ 1,019	$ 10	$ 1.08	$ -	6610	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	0	615	2026	40	$ 1,065	$ 10	$ 1.48	$ -	6264	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	0	63	2026	40	$ 397	$ -	$ 0.06	$ -	8769	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	0	1,232	2027	40	$ 787	$ 10	$ 1.43	$ -	6251	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	0	126	2027	40	$ 309	$ -	$ 0.06	$ -	8704	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	1,500	159	2025	30	$ 1,551	$ 14	$ 7.89	$ -	9362	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	1,500	215	2025	30	$ 1,188	$ 14	$ 5.31	$ -	8802	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	1,500	227	2025	35	$ 738	$ 14	$ 14.94	$ -	9916	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	1,500	227	2025	35	$ 711	$ 14	$ 14.94	$ -	9916	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	1,500	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8286	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	1,500	397	2026	40	$ 1,484	$ 14	$ 1.88	$ -	6384	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	1,500	51	2027	40	$ 470	$ -	$ 0.05	$ -	8789	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	1,500	797	2027	40	$ 1,077	$ 14	$ 1.81	$ -	6367	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	1,500	102	2026	40	$ 357	$ -	$ 0.05	$ -	8713	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	1,500	797	2026	40	$ 1,077	$ 14	$ 1.14	$ -	6633	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	1,500	582	2027	40	$ 1,125	$ 14	$ 1.57	$ -	6264	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	1,500	63	2027	40	$ 397	$ -	$ 0.06	$ -	8816	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	1,500	1,166	2026	40	$ 832	$ 14	$ 1.51	$ -	6249	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	1,500	126	2026	40	$ 309	$ -	$ 0.06	$ -	8742	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	3,000	150	2025	30	$ 1,645	$ 11	$ 8.37	$ -	9380	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	3,000	203	2025	30	$ 1,260	$ 11	$ 5.63	$ -	8811	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	3,000	214	2025	35	$ 779	$ 11	$ 15.79	$ -	9928	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	3,000	214	2025	35	$ 751	$ 11	$ 15.78	$ -	9928	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	3,000	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8286	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	3,000	376	2026	40	$ 1,569	$ 11	$ 1.99	$ -	6387	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	3,000	51	2027	40	$ 470	$ -	$ 0.05	$ -	8816	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	3,000	750	2027	40	$ 1,144	$ 11	$ 1.92	$ -	6400	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	3,000	102	2026	40	$ 357	$ -	$ 0.05	$ -	8756	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	3,000	750	2026	40	$ 1,144	$ 11	$ 1.21	$ -	6682	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	3,000	550	2027	40	$ 1,189	$ 11	$ 1.66	$ -	6270	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	3,000	63	2027	40	$ 397	$ -	$ 0.06	$ -	8837	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	3,000	1,103	2026	40	$ 879	$ 11	$ 1.60	$ -	6256	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	3,000	126	2026	40	$ 309	$ -	$ 0.06	$ -	8763	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	5,050	139	2025	30	$ 1,777	$ 12	$ 9.04	$ -	9400	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	5,050	187	2025	30	$ 1,363	$ 12	$ 6.09	$ -	8816	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	5,050	199	2025	35	$ 841	$ 12	$ 17.04	$ -	9936	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	5,050	199	2025	35	$ 811	$ 12	$ 17.03	$ -	9936	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	5,050	111	2026	40	$ 1,938	$ 12	$ 10.39	$ -	8292	2.5	5.0	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	5,050	350	2026	40	$ 1,687	$ 12	$ 2.14	$ -	6362	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	5,050	51	2026	40	$ 470	$ -	$ 0.05	$ -	8545	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	5,050	686	2027	40	$ 1,252	$ 12	$ 2.10	$ -	6487	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	5,050	102	2027	40	$ 358	$ -	$ 0.05	$ -	9470	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	5,050	686	2027	40	$ 1,251	$ 12	$ 1.33	$ -	6874	2.5	3.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	5,050	504	2026	40	$ 1,299	$ 12	$ 1.81	$ -	6352	2.5	3.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	5,050	63	2026	40	$ 397	$ -	$ 0.06	$ -	9452	2.5	3.8	20.1033	0.0006	0.0072	0.2550	117.0000

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (Continued)

Description		Resource Characteristics				Costs				Operating Characteristics				Environmental			
Fuel	Resource	Elevation (AFSL)	Net Capacity (MW)	Commercial Operation Year	Design Life (yrs)	Base Capital ($/KW)	Demolition Cost ($/kW)	Var O&M ($/MWh)	Fixed O&M ($/KW-yr)	Average Full Load Heat Rate (HHV Btu/KWh)/Efficiency	EFOR (%)	POR (%)	Water Consumed (Gal/MWh)	SO2 (lbs/MMBtu)	NOx (lbs/MMBtu)	Hg (lbs/TBTu)	CO2 (lbs/MMBtu)
Natural Gas	CCCT Dry "J", 2x1	5,050	1,004	2027	40	$ 966	$ 12	$ 1.76	$ -	6373	2.5	3.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	5,050	126	2027	40	$ 309	$ -	$ 0.06	$ -	9456	2.5	3.8	17.8427	0.0006	0.0072	0.2550	117.0000
Natural Gas	SCCT Aero x3	6,500	126	2025	30	$ 1,957	$ 13	$ 9.96	$ -	9314	2.6	3.9	43.6234	0.0006	0.0090	0.2550	117.0000
Natural Gas	Intercooled SCCT Aero x2	6,500	179	2025	30	$ 1,427	$ 13	$ 6.37	$ -	8786	2.9	3.9	27.0223	0.0006	0.0090	0.2550	117.0000
Natural Gas	SCCT Frame "F" x1	6,500	189	2025	35	$ 886	$ 13	$ 17.95	$ -	9930	2.7	3.9	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	Brownfield SCCT Frame "F" x1	6,500	189	2025	35	$ 854	$ 13	$ 17.95	$ -	9930	2.7	5.0	28.4484	0.0006	0.0090	0.2550	117.0000
Natural Gas	IC Recips x 6	6,500	111	2026	40	$ 1,937	$ 12	$ 10.39	$ -	8333	2.5	3.8	27.1363	0.0006	0.0288	0.2550	117.0000
Natural Gas	CCCT Dry "H", 1x1	6,500	335	2026	40	$ 1,761	$ 13	$ 2.23	$ -	6390	2.5	3.8	23.5973	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 1x1	6,500	51	2027	40	$ 470	$ -	$ 0.05	$ -	8857	2.5	3.8	22.9547	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", 2x1	6,500	669	2027	40	$ 1,283	$ 12	$ 2.15	$ -	6399	2.5	3.8	20.1038	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "H", DF, 2x1	6,500	102	2026	40	$ 357	$ -	$ 0.05	$ -	8852	2.5	4.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	6,500	669	2026	40	$ 1,283	$ 12	$ 1.36	$ -	6724	2.5	5.8	19.7926	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 1x1	6,500	490	2027	40	$ 1,337	$ 12	$ 1.86	$ -	6273	2.5	6.8	20.3774	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 1x1	6,500	63	2027	40	$ 397	$ -	$ 0.06	$ -	8864	2.5	7.8	20.1033	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", 2x1	6,500	981	2026	40	$ 988	$ 12	$ 1.80	$ -	6259	2.5	8.8	17.8997	0.0006	0.0072	0.2550	117.0000
Natural Gas	CCCT Dry "J", DF, 2x1	6,500	126	2026	40	$ 309	$ -	$ 0.06	$ -	8789	2.5	9.8	17.8427	0.0006	0.0072	0.2550	117.0000
Coal	SCPC with CCS	4,500	526	2028	40	$ 6,488	$ 127	$ 7.00	$ 72.22	13087	5.0	5.0	1,004.2373	0.0085	0.0700	0.0222	20.5352
Coal	IGCC with CCS	4,500	466	2028	40	$ 6,282	$ 60	$ 11.77	$ 58.20	10823	8.0	7.0	394.0678	0.0085	0.0500	0.3333	20.5352
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	4,500	-115	2026	20	$ 2,971	$ 37	$ 3.29	$ 28.18	14372	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
Coal	SCPC with CCS	6,500	692	2028	40	$ 7,348	$ 127	$ 7.58	$ 67.09	13242	5.0	5.0	1,004.2373	0.0085	0.0700	0.0222	20.5352
Coal	IGCC with CCS	6,500	456	2028	40	$ 7,113	$ 60	$ 14.11	$ 63.40	11047	8.0	7.0	394.0678	0.0085	0.0500	0.3333	20.5352
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	6,500	-115	2026	20	$ 2,971	$ 37	$ 3.29	$ 28.18	14372	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	$ 5,708	$ 127	$ 1.16	$ 103.85	N/A	5.0	5.0	10.0000	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	$ 5,973	$ 127	$ 1.16	$ 103.85	N/A	5.0	5.0	270.0000	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	$ -	$ -	$ 77.34	$ -	N/A	5.0	5.0	270.0000	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 200 MW Wind, CF: 37.1% (100% PTC)	4,500	200	2024	30	$ 1,365	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	200	2024	30	$ 1,315	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 200 MW Wind, CF: 29.5% (100% PTC)	4,500	200	2024	30	$ 1,306	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100%PTC)	6,500	200	2024	30	$ 1,356	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	200	2024	30	$ 1,390	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 200 MW Wind, CF: 37.1% (60% PTC)	4,500	200	2024	30	$ 1,365	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 200 MW Wind, CF: 37.1% (60% PTC)	1,500	200	2024	30	$ 1,315	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 200 MW Wind, CF: 29.5% (60% PTC)	4,500	200	2024	30	$ 1,306	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	6,500	200	2024	30	$ 1,356	$ 13	$ 0.65	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 200 MW Wnd, CF: 37.1% (60% PTC)	1,500	200	2024	30	$ 1,390	$ 13	$ -	$ 24.74	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Pocatello, ID, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	$ 2,152	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Arlington, OR, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	$ 2,086	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Monticello, UT, 200 MW Wind, CF: 29.5% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	$ 2,061	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	200	2024	30	$ 2,136	$ 233	$ 0.65	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Wind + Storage	Goldendale, WA, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	$ 2,211	$ 233	$ -	$ 37.59	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 100 MW Solar, CF: 26.1% (30% ITC)	4,700	100	2023	25	$ 1,429	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 200 MW Solar, CF: 26.1% (30% ITC)	4,700	200	2023	25	$ 1,302	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 100 MW Solar, CF: 27.6% (30% ITC)	4,800	100	2023	25	$ 1,444	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 200 MW Solar, CF: 27.6% (30% ITC)	4,800	200	2023	25	$ 1,330	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (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)
Solar	Milford, UT, 100 MW Solar, CF: 30.2% (30% ITC)	5,000	100	2023	25	$ 1,422	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 200 MW Solar, CF: 30.2% (30% ITC)	5,000	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 100 MW Solar, CF: 27.9% (30% ITC)	6,400	100	2023	25	$ 1,423	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 200 MW Solar, CF: 27.9% (30% ITC)	6,400	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 100 MW Solar, CF: 24.2% (30% ITC)	1,000	100	2023	25	$ 1,486	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 200 MW Solar, CF: 24.2% (30% ITC)	1,000	200	2023	25	$ 1,357	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 100 MW Solar, CF: 26.1% (10% ITC)	4,700	100	2023	25	$ 1,429	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Idaho Falls, ID, 200 MW Solar, CF: 26.1% (10% ITC)	4,700	200	2023	25	$ 1,302	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 100 MW Solar, CF: 27.6% (10% ITC)	4,800	100	2023	25	$ 1,444	$ 35	$ -	$ 16.20	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 200 MW Solar, CF: 27.6% (10% ITC)	4,800	200	2023	25	$ 1,330	$ 35	$ -	$ 16.10	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 100 MW Solar, CF: 30.2% (10% ITC)	5,000	100	2023	25	$ 1,422	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	5,000	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 100 MW Solar, CF: 27.9% (10% ITC)	6,400	100	2023	25	$ 1,423	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	6,400	200	2023	25	$ 1,297	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 100 MW Solar, CF: 24.2% (10% ITC)	1,000	100	2023	25	$ 1,486	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 200 MW Solar, CF: 24.2% (10% ITC)	1,000	200	2023	25	$ 1,357	$ 35	$ -	$ 17.60	N/A	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	100	2023	25	$ 2,351	$ 255	$ -	$ 30.00	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	200	2023	25	$ 2,161	$ 255	$ -	$ 28.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	100	2023	25	$ 2,329	$ 255	$ -	$ 30.00	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	200	2023	25	$ 2,154	$ 255	$ -	$ 28.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	100	2023	25	$ 2,283	$ 255	$ -	$ 31.40	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	200	2023	25	$ 2,102	$ 255	$ -	$ 30.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	100	2023	25	$ 2,312	$ 255	$ -	$ 31.40	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	200	2023	25	$ 2,128	$ 255	$ -	$ 30.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	100	2023	25	$ 2,405	$ 255	$ -	$ 31.40	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	200	2023	25	$ 2,217	$ 255	$ -	$ 30.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Idah Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,700	200	2023	25	$ 3,395	$ 268	$ -	$ 82.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,800	200	2023	25	$ 3,424	$ 268	$ -	$ 82.95	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (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)
Solar + Storage + Wind	Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	5,000	200	2023	25	$ 3,364	$ 268	$ -	$ 81.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	6,400	200	2023	25	$ 3,364	$ 268	$ -	$ 81.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	1,000	200	2023	25	$ 3,424	$ 268	$ -	$ 81.45	85%	(b)	(b)	n/a	n/a	n/a	n/a	n/a
Storage	Pumped Hydro, Swan Lake. 3600 MWh	N/A	400	2027	60	$ 3,095	$ 485	$ -	$ 12.50	78%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Goldendale, 14400 MWh	N/A	1,200	2028	60	$ 2,833	$ 485	$ -	$ 12.50	78%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Seminoe, 7500 MWh	N/A	750	2029	80	$ 3,461	$ 485	$ 0.37	$ 16.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Badger Mountain, 4000 MWh	N/A	500	2027	80	$ 2,621	$ 485	$ 0.37	$ 28.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Owyhee, 4800 MWh	N/A	600	2029	80	$ 3,203	$ 485	$ 0.37	$ 20.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Flat Canyon, 1800 MWh	N/A	300	2029	80	$ 4,046	$ 485	$ 0.37	$ 53.33	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Utah PS2, 4000 MWh	N/A	500	2027	80	$ 3,237	$ 485	$ 0.37	$ 28.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Utah PS3, 4800 MWh	N/A	600	2029	80	$ 3,371	$ 485	$ 0.37	$ 20.00	80%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Pumped Hydro, Banner Mountain, 3400 MWh	N/A	400	2028	50	$ 3,276	$ 485	$ 0.00	$ 28.50	81%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	150	2024	50	$ 1,954	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	150	2024	50	$ 2,189	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	150	2024	50	$ 2,445	$ 12	$ 6.50	$ 12.67	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	300	2024	50	$ 1,557	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	300	2024	50	$ 1,692	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	300	2024	50	$ 2,016	$ 12	$ 6.50	$ 9.33	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	500	2024	50	$ 1,549	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	500	2025	50	$ 1,762	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	500	2025	50	$ 2,010	$ 12	$ 6.50	$ 6.60	60%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	1	2023	20	$ 1,948	$ 55	(a)	$ 40.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 1 MWh	N/A	1	2023	20	$ 2,058	$ 110	(a)	$ 50.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 4 MWh	N/A	1	2023	20	$ 3,167	$ 440	(a)	$ 70.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 1 MW, 8 MWh	N/A	1	2023	20	$ 4,622	$ 880	(a)	$ 100.00	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Li-Ion Battery, , 50 MW, 200 MWh	N/A	50	2023	20	$ 1,820	$ 440	(a)	$ 27.60	85%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 1 MW, 1 MWh	N/A	1	2023	20	$ 4,719	$ 12	(a)	$ 13.00	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 1 MW, 4 MWh	N/A	1	2023	20	$ 5,051	$ 12	(a)	$ 13.00	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 1 MW, 8 MWh	N/A	1	2023	20	$ 7,291	$ 12	(a)	$ 27.00	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Storage	Flow Battery, , 20 MW, 160 MWh	N/A	20	2023	20	$ 4,190	$ 12	(a)	$ 30.50	70%	0.0	0.0	0.0000	0.0000	0.0000	0.0000	0.0000
Nuclear	Small Modular Reactor	5,000	854	2028	60	$ 5,396	$ 722	$ 6.72	$ 65.03	N/A	5.0	5.0	N/A	0.0000	0.0000	0.0000	0.0000
Hydrogen	Non-Emitting Peaker	5,050	206	2030	30	$ 959	$ 2,414	$ 21.29	$ -	9936	2.7	3.9	218.0000	0.0000	0.0000	0.0000	0.0000

Table 7.1 – 2021 Supply-Side Resource Table (2020$) (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)
CCUS for Coal Plants	Naughton 2 PC CCUS Retrofit	6,500	155	2026	20	$ 3,930	$ 37	$ 7.30	$ 39.90	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Johnston 2 PC CCUS Retrofit	6,500	82	2026	20	$ 5,314	$ 37	$ 6.10	$ 40.58	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Johnston 4 PC CCUS Retrofit	6,500	254	2026	20	$ 3,877	$ 37	$ 5.69	$ 37.88	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Wyodak PC CCUS Retrofit	6,500	206	2026	20	$ 3,935	$ 37	$ 7.31	$ 39.95	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Bridger 1 PC CCUS Retrofit	6,500	273	2026	20	$ 3,934	$ 37	$ 7.31	$ 39.94	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Bridger 3 PC CCUS Retrofit	6,500	269	2026	20	$ 3,873	$ 37	$ 5.69	$ 37.83	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352
CCUS for Coal Plants	Bridger 4 PC CCUS Retrofit	6,500	270	2026	20	$ 3,876	$ 37	$ 5.69	$ 37.86	1437200%	5.0	5.0	450.0000	0.0050	0.0700	1.2000	20.5352

Table 7.2 - Total Resource Cost for Supply-Side Resource Options

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
SCCT Aero x3	No	0	$1,463	$10	7.497%	$110.43	$0.00	1.262%	$0.00	$31.94	$31.94	$142.37
Intercooled SCCT Aero x2	No	0	$1,126	$10	7.497%	$85.14	$0.00	1.135%	$0.00	$30.03	$30.03	$115.17
SCCT Frame "F" x1	No	0	$699	$10	7.049%	$49.97	$0.00	0.273%	$0.00	$33.77	$33.77	$83.74
Brownfield SCCT Frame "F" x1	No	0	$674	$10	7.049%	$48.20	$0.00	0.273%	$0.00	$33.77	$33.77	$81.97
IC Recips x 6	No	0	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$28.47	$28.47	$165.92
CCCT Dry "H", 1x1	No	0	$1,396	$10	6.886%	$96.84	$0.00	0.146%	$0.00	$23.57	$23.57	$120.41
CCCT Dry "H", DF, 1x1	No	0	$470	$0	6.886%	$32.34	$0.00	0.000%	$0.00	$23.57	$23.57	$55.91
CCCT Dry "H", 2x1	No	0	$1,019	$10	6.886%	$70.86	$0.00	0.146%	$0.00	$23.62	$23.62	$94.48
CCCT Dry "H", DF, 2x1	No	0	$357	$0	6.886%	$24.60	$0.00	0.000%	$0.00	$23.62	$23.62	$48.22
Brownfield CCCT Dry "H", DF, 2x1	No	0	$1,019	$10	6.886%	$70.83	$0.00	0.000%	$0.00	$23.36	$23.36	$94.19
CCCT Dry "J", 1x1	No	0	$1,065	$10	6.886%	$73.99	$0.00	0.000%	$0.00	$23.36	$23.36	$97.35
CCCT Dry "J", DF, 1x1	No	0	$397	$0	6.886%	$27.36	$0.00	0.000%	$0.00	$23.36	$23.36	$50.73
CCCT Dry "J", 2x1	No	0	$787	$10	6.886%	$54.88	$0.00	0.146%	$0.00	$23.36	$23.36	$78.25
CCCT Dry "J", DF, 2x1	No	0	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$23.36	$23.36	$44.66
SCCT Aero x3	No	1,500	$1,551	$14	7.497%	$117.36	$0.00	1.262%	$0.00	$31.76	$31.76	$149.12
Intercooled SCCT Aero x2	No	1,500	$1,188	$14	7.497%	$90.12	$0.00	1.135%	$0.00	$29.91	$29.91	$120.03
SCCT Frame "F" x1	No	1,500	$738	$14	7.049%	$52.98	$0.00	0.273%	$0.00	$33.71	$33.71	$86.68
Brownfield SCCT Frame "F" x1	No	1,500	$711	$14	7.049%	$51.11	$0.00	0.273%	$0.00	$33.71	$33.71	$84.82
IC Recips x 6	No	1,500	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$28.47	$28.47	$165.92
CCCT Dry "H", 1x1	No	1,500	$1,484	$14	6.886%	$103.13	$0.00	0.146%	$0.00	$23.37	$23.37	$126.49
CCCT Dry "H", DF, 1x1	No	1,500	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$23.37	$23.37	$55.71
CCCT Dry "H", 2x1	No	1,500	$1,077	$14	6.886%	$75.15	$0.00	0.146%	$0.00	$23.41	$23.41	$98.56
CCCT Dry "H", DF, 2x1	No	1,500	$357	$0	6.886%	$24.60	$0.00	0.000%	$0.00	$23.41	$23.41	$48.01
Brownfield CCCT Dry "H", DF, 2x1	No	1,500	$1,077	$14	6.886%	$75.11	$0.00	0.000%	$0.00	$23.17	$23.17	$98.29
CCCT Dry "J", 1x1	No	1,500	$1,125	$14	6.886%	$78.43	$0.00	0.000%	$0.00	$23.17	$23.17	$101.61
CCCT Dry "J", DF, 1x1	No	1,500	$397	$0	6.886%	$27.37	$0.00	0.000%	$0.00	$23.17	$23.17	$50.54
CCCT Dry "J", 2x1	No	1,500	$832	$14	6.886%	$58.24	$0.00	0.146%	$0.00	$23.17	$23.17	$81.41
CCCT Dry "J", DF, 2x1	No	1,500	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$23.17	$23.17	$44.47
SCCT Aero x3	No	3,000	$1,645	$11	7.497%	$124	$0.00	1.262%	$0.00	$16.94	$16.94	$141.12
Intercooled SCCT Aero x2	No	3,000	$1,260	$11	7.497%	$95	$0.00	1.135%	$0.00	$15.94	$15.94	$111.26
SCCT Frame "F" x1	No	3,000	$779	$11	7.049%	$56	$0.00	0.273%	$0.00	$17.98	$17.98	$73.70
Brownfield SCCT Frame "F" x1	No	3,000	$751	$11	7.049%	$54	$0.00	0.273%	$0.00	$17.98	$17.98	$71.73

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
IC Recips x 6	No	3,000	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$15.18	$15.18	$152.62
CCCT Dry "H", 1x1	No	3,000	$1,569	$11	6.886%	$108.80	$0.00	0.146%	$0.00	$23.28	$23.28	$132.08
CCCT Dry "H", DF, 1x1	No	3,000	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$23.28	$23.28	$55.62
CCCT Dry "H", 2x1	No	3,000	$1,144	$11	6.886%	$79.55	$0.00	0.146%	$0.00	$12.43	$12.43	$91.98
CCCT Dry "H", DF, 2x1	No	3,000	$357	$0	6.886%	$24.60	$0.00	0.000%	$0.00	$12.43	$12.43	$37.03
Brownfield CCCT Dry "H", DF, 2x1	No	3,000	$1,144	$11	6.886%	$79.51	$0.00	0.000%	$0.00	$12.27	$12.27	$91.78
CCCT Dry "J", 1x1	No	3,000	$1,189	$11	6.886%	$82.65	$0.00	0.000%	$0.00	$12.27	$12.27	$94.92
CCCT Dry "J", DF, 1x1	No	3,000	$397	$0	6.886%	$27.37	$0.00	0.000%	$0.00	$12.27	$12.27	$39.64
CCCT Dry "J", 2x1	No	3,000	$879	$11	6.886%	$61.29	$0.00	0.146%	$0.00	$12.28	$12.28	$73.57
CCCT Dry "J", DF, 2x1	No	3,000	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$12.28	$12.28	$33.58
SCCT Aero x3	No	5,050	$1,777	$12	7.497%	$134.18	$0.00	1.262%	$0.00	$14.06	$14.06	$148.23
Intercooled SCCT Aero x2	Yes	5,050	$1,363	$12	7.497%	$103.10	$0.00	1.135%	$0.00	$13.22	$13.22	$116.32
SCCT Frame "F" x1	Yes	5,050	$841	$12	7.049%	$60.13	$0.00	0.273%	$0.00	$14.93	$14.93	$75.07
Brownfield SCCT Frame "F" x1	Yes	5,050	$811	$12	7.049%	$58.00	$0.00	0.273%	$0.00	$14.93	$14.93	$72.94
IC Recips x 6	Yes	5,050	$1,938	$12	7.049%	$137.45	$0.00	0.136%	$0.00	$12.61	$12.61	$150.06
CCCT Dry "H", 1x1	Yes	5,050	$1,687	$12	6.886%	$116.98	$0.00	0.146%	$0.00	$9.91	$9.91	$126.89
CCCT Dry "H", DF, 1x1	Yes	5,050	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$9.91	$9.91	$42.26
CCCT Dry "H", 2x1	No	5,050	$1,252	$12	6.886%	$87.04	$0.00	0.146%	$0.00	$9.93	$9.93	$96.97
CCCT Dry "H", DF, 2x1	No	5,050	$358	$0	6.886%	$24.63	$0.00	0.000%	$0.00	$9.93	$9.93	$34.56
Brownfield CCCT Dry "H", DF, 2x1	Yes	5,050	$1,251	$12	6.886%	$87.00	$0.00	0.000%	$0.00	$9.84	$9.84	$96.84
CCCT Dry "J", 1x1	Yes	5,050	$1,299	$12	6.886%	$90.28	$0.00	0.000%	$0.00	$9.84	$9.84	$100.13
CCCT Dry "J", DF, 1x1	Yes	5,050	$397	$0	6.886%	$27.36	$0.00	0.000%	$0.00	$9.84	$9.84	$37.21
CCCT Dry "J", 2x1	No	5,050	$966	$12	6.886%	$67.34	$0.00	0.146%	$0.00	$9.85	$9.85	$77.19
CCCT Dry "J", DF, 2x1	No	5,050	$309	$0	6.886%	$21.29	$0.00	0.000%	$0.00	$9.85	$9.85	$31.15
SCCT Aero x3	No	6,500	$1,957	$13	7.497%	$147.74	$0.00	1.262%	$0.00	$9.13	$9.13	$156.86
Intercooled SCCT Aero x2	Yes	6,500	$1,427	$13	7.497%	$107.96	$0.00	1.135%	$0.00	$8.62	$8.62	$116.58
SCCT Frame "F" x1	Yes	6,500	$886	$13	7.049%	$63.37	$0.00	0.273%	$0.00	$9.70	$9.70	$73.06
Brownfield SCCT Frame "F" x1	Yes	6,500	$854	$13	7.049%	$61.12	$0.00	0.273%	$0.00	$9.70	$9.70	$70.82
IC Recips x 6	Yes	6,500	$1,937	$12	7.049%	$137.42	$0.00	0.136%	$0.00	$8.24	$8.24	$145.66
CCCT Dry "H", 1x1	Yes	6,500	$1,761	$13	6.886%	$122.11	$0.00	0.146%	$0.00	$20.66	$20.66	$142.77

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($) Resource Description	Modeled IRP	Elevation (AFSL)	Capital Cost $/kW Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	Fixed Cost Fixed O&M $/kW-Yr O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
CCCT Dry "H", DF, 1x1	Yes	6,500	$470	$0	6.886%	$32.35	$0.00	0.000%	$0.00	$20.66	$20.66	$53.01
CCCT Dry "H", 2x1	No	6,500	$1,283	$12	6.886%	$89.23	$0.00	0.146%	$0.00	$6.71	$6.71	$95.94
CCCT Dry "H", DF, 2x1	No	6,500	$357	$0	6.886%	$24.61	$0.00	0.000%	$0.00	$6.71	$6.71	$31.32
Brownfield CCCT Dry "H", DF, 2x1	Yes	6,500	$1,283	$12	6.886%	$89.18	$0.00	0.000%	$0.00	$6.62	$6.62	$95.80
CCCT Dry "J", 1x1	Yes	6,500	$1,337	$12	6.886%	$92.91	$0.00	0.000%	$0.00	$6.62	$6.62	$99.53
CCCT Dry "J", DF, 1x1	Yes	6,500	$397	$0	6.886%	$27.36	$0.00	0.000%	$0.00	$6.62	$6.62	$33.98
CCCT Dry "J", 2x1	No	6,500	$988	$12	6.886%	$68.90	$0.00	0.146%	$0.00	$6.62	$6.62	$75.53
CCCT Dry "J", DF, 2x1	No	6,500	$309	$0	6.886%	$21.30	$0.00	0.000%	$0.00	$6.62	$6.62	$27.92
SCPC with CCS	No	4,500	$6,488	$127	6.822%	$451.29	$72.22	5.541%	$4.00	$0.00	$76.23	$527.52
IGCC with CCS	No	4,500	$6,282	$60	7.389%	$468.60	$58.20	0.000%	$0.00	$0.00	$58.20	$526.80
PC CCS retrofit @ 500 MW pre-retrofit basis	Yes	4,500	$2,971	$37	6.822%	$205.19	$28.18	5.541%	$1.56	$0.00	$29.74	$234.92
SCPC with CCS	No	6,500	$7,348	$127	6.822%	$509.92	$67.09	5.541%	$3.72	$0.00	$70.80	$580.72
IGCC with CCS	No	6,500	$7,113	$60	7.389%	$530.01	$63.40	0.000%	$0.00	$0.00	$63.40	$593.41
PC CCS retrofit @ 500 MW pre-retrofit basis	Yes	6,500	$2,971	$37	6.822%	$205.19	$28.18	5.541%	$1.56	$0.00	$29.74	$234.92
Blundell Dual Flash 90% CF	Yes	4,500	$5,708	$127	6.273%	$366.02	$103.85	0.875%	$0.91	$0.00	$104.76	$470.77
Greenfield Binary 90% CF	Yes	4,500	$5,973	$127	6.273%	$382.70	$103.85	0.000%	$0.00	$0.00	$103.85	$486.55
Generic Geothermal PPA 90% CF	Yes	4,500	$0	$0	6.273%	$0.00	$0.00	0.000%	$0.00	$0.00	$0.00	$0.00
Pocatello, ID, 200 MW Wind, CF: 37.1% (100% PTC)	Yes	4,500	$1,365	$13	6.979%	$96.14	$24.74	0.000%	$0.00	$0.00	$24.74	$120.88
Arlington, OR, 200 MW Wind, CF: 37.1% (100% PTC)	Yes	1,500	$1,315	$13	6.979%	$92.67	$24.74	0.000%	$0.00	$0.00	$24.74	$117.41
Monticello, UT, 200 MW Wind, CF: 29.5% (100% PTC)	Yes	4,500	$1,306	$13	6.979%	$92.05	$24.74	0.000%	$0.00	$0.00	$24.74	$116.79
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100%PTC)	Yes	6,500	$1,356	$13	6.979%	$95.54	$24.74	0.000%	$0.00	$0.00	$24.74	$120.28
Goldendale, WA, 200 MW Wind, CF: 37.1% (100% PTC)	Yes	1,500	$1,390	$13	6.979%	$97.89	$24.74	0.000%	$0.00	$0.00	$24.74	$122.63
Pocatello, ID, 200 MW Wind, CF: 37.1% (60% PTC)	Yes	4,500	$1,365	$13	6.979%	$96.14	$24.74	0.000%	$0.00	$0.00	$24.74	$120.88
Arlington, OR, 200 MW Wind, CF: 37.1% (60% PTC)	Yes	1,500	$1,315	$13	6.979%	$92.67	$24.74	0.000%	$0.00	$0.00	$24.74	$117.41
Monticello, UT, 200 MW Wind, CF: 29.5% (60% PTC)	Yes	4,500	$1,306	$13	6.979%	$92.05	$24.74	0.000%	$0.00	$0.00	$24.74	$116.79
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	Yes	6,500	$1,356	$13	6.979%	$95.54	$24.74	0.000%	$0.00	$0.00	$24.74	$120.28
Goldendale, WA, 200 MW Wnd, CF: 37.1% (60% PTC)	Yes	1,500	$1,390	$13	6.979%	$97.89	$24.74	0.000%	$0.00	$0.00	$24.74	$122.63
Pocatello, ID, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	Yes	4,500	$2,152	$233	6.979%	$166.45	$37.59	2.902%	$1.09	$0.00	$38.68	$205.13
Arlington, OR, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	Yes	1,500	$2,086	$233	6.979%	$161.82	$37.59	2.902%	$1.09	$0.00	$38.68	$200.50
Monticello, UT, 200 MW Wind, CF: 29.5% + BESS: 50% pwr, 4 hours	Yes	4,500	$2,061	$233	6.979%	$160.06	$37.59	2.902%	$1.09	$0.00	$38.68	$198.74
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	Yes	6,500	$2,136	$233	6.979%	$165.29	$37.59	2.902%	$1.09	$0.00	$38.68	$203.97
Goldendale, WA, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	Yes	1,500	$2,211	$233	6.979%	$170.52	$37.59	2.902%	$1.09	$0.00	$38.68	$209.20
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (30% ITC)	Yes	4,700	$1,429	$35	6.839%	$100.09	$16.20	1.379%	$0.22	$0.00	$16.42	$116.52
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (30% ITC)	Yes	4,700	$1,302	$35	6.839%	$91.44	$16.10	1.379%	$0.22	$0.00	$16.32	$107.77
Lakeview, OR, 100 MW Solar, CF: 27.6% (30% ITC)	Yes	4,800	$1,444	$35	6.839%	$101.18	$16.20	1.379%	$0.22	$0.00	$16.42	$117.61
Lakeview, OR, 200 MW Solar, CF: 27.6% (30% ITC)	Yes	4,800	$1,330	$35	6.839%	$93.38	$16.10	1.379%	$0.22	$0.00	$16.32	$109.70
Milford, UT, 100 MW Solar, CF: 30.2% (30% ITC)	Yes	5,000	$1,422	$35	6.839%	$99.67	$17.60	1.379%	$0.24	$0.00	$17.84	$117.51
Milford, UT, 200 MW Solar, CF: 30.2% (30% ITC)	Yes	5,000	$1,297	$35	6.839%	$91.11	$17.60	1.379%	$0.24	$0.00	$17.84	$108.95
Rock Springs, WY, 100 MW Solar, CF: 27.9% (30% ITC)	Yes	6,400	$1,423	$35	6.839%	$99.70	$17.60	1.379%	$0.24	$0.00	$17.84	$117.55
Rock Springs, WY, 200 MW Solar, CF: 27.9% (30% ITC)	Yes	6,400	$1,297	$35	6.839%	$91.07	$17.60	1.379%	$0.24	$0.00	$17.84	$108.91
Yakima, WA, 100 MW Solar, CF: 24.2% (30% ITC)	Yes	1,000	$1,486	$35	6.839%	$104.04	$17.60	1.379%	$0.24	$0.00	$17.84	$121.88
Yakima, WA, 200 MW Solar, CF: 24.2% (30% ITC)	Yes	1,000	$1,357	$35	6.839%	$95.20	$17.60	1.379%	$0.24	$0.00	$17.84	$113.04
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (10% ITC)	Yes	4,700	$1,429	$35	6.839%	$100.09	$16.20	1.379%	$0.22	$0.00	$16.42	$116.52
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (10% ITC)	Yes	4,700	$1,302	$35	6.839%	$91.44	$16.10	1.379%	$0.22	$0.00	$16.32	$107.77
Lakeview, OR, 100 MW Solar, CF: 27.6% (10% ITC)	Yes	4,800	$1,444	$35	6.839%	$101.18	$16.20	1.379%	$0.22	$0.00	$16.42	$117.61
Lakeview, OR, 200 MW Solar, CF: 27.6% (10% ITC)	Yes	4,800	$1,330	$35	6.839%	$93.38	$16.10	1.379%	$0.22	$0.00	$16.32	$109.70
Milford, UT, 100 MW Solar, CF: 30.2% (10% ITC)	Yes	5,000	$1,422	$35	6.839%	$99.67	$17.60	1.379%	$0.24	$0.00	$17.84	$117.51
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	Yes	5,000	$1,297	$35	6.839%	$91.11	$17.60	1.379%	$0.24	$0.00	$17.84	$108.95
Rock Springs, WY, 100 MW Solar, CF: 27.9% (10% ITC)	Yes	6,400	$1,423	$35	6.839%	$99.70	$17.60	1.379%	$0.24	$0.00	$17.84	$117.55
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	Yes	6,400	$1,297	$35	6.839%	$91.07	$17.60	1.379%	$0.24	$0.00	$17.84	$108.91

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	No	Elevation (AFSL)	Total Capital Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,700	$2,351	$255	6.839%	$178.25	$30.00	1.379%	$0.41	$0.00	$30.41	$208.66
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,700	$2,161	$255	6.839%	$165.25	$28.95	1.379%	$0.40	$0.00	$29.35	$194.60
Yakima, WA, 100 MW Solar, CF: 24.2% (10% ITC)	Yes	1,000	$1,486	$35	6.839%	$104.04	$17.60	1.379%	$0.24	$0.00	$17.84	$121.88
Yakima, WA, 200 MW Solar, CF: 24.2% (10% ITC)	Yes	1,000	$1,357	$35	6.839%	$95.20	$17.60	1.379%	$0.24	$0.00	$17.84	$113.04
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,800	$2,329	$255	6.839%	$176.71	$30.00	1.379%	$0.41	$0.00	$30.41	$207.12
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	4,800	$2,154	$255	6.839%	$164.74	$28.95	1.379%	$0.40	$0.00	$29.35	$194.09
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	5,000	$2,283	$255	6.839%	$173.58	$31.40	1.379%	$0.43	$0.00	$31.83	$205.41
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	5,000	$2,102	$255	6.839%	$161.21	$30.45	1.379%	$0.42	$0.00	$30.87	$192.08
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	6,400	$2,312	$255	6.839%	$175.57	$31.40	1.379%	$0.43	$0.00	$31.83	$207.40
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	6,400	$2,128	$255	6.839%	$163.01	$30.45	1.379%	$0.42	$0.00	$30.87	$193.88
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	1,000	$2,405	$255	6.839%	$181.91	$31.40	1.379%	$0.43	$0.00	$31.83	$213.74
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	1,000	$2,217	$255	6.839%	$169.05	$30.45	1.379%	$0.42	$0.00	$30.87	$199.92
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,700	$2,351	$255	6.839%	$178.25	$30.00	1.379%	$0.41	$0.00	$30.41	$208.66
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,700	$2,161	$255	6.839%	$165.25	$28.95	1.379%	$0.40	$0.00	$29.35	$194.60
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,800	$2,329	$255	6.839%	$176.71	$30.00	1.379%	$0.41	$0.00	$30.41	$207.12
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	4,800	$2,154	$255	6.839%	$164.74	$28.95	1.379%	$0.40	$0.00	$29.35	$194.09
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	5,000	$2,283	$255	6.839%	$173.58	$31.40	1.379%	$0.43	$0.00	$31.83	$205.41
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	5,000	$2,102	$255	6.839%	$161.21	$30.45	1.379%	$0.42	$0.00	$30.87	$192.08
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	6,400	$2,312	$255	6.839%	$175.57	$31.40	1.379%	$0.43	$0.00	$31.83	$207.40
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	6,400	$2,128	$255	6.839%	$163.01	$30.45	1.379%	$0.42	$0.00	$30.87	$193.88
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	1,000	$2,405	$255	6.839%	$181.91	$31.40	1.379%	$0.43	$0.00	$31.83	$213.74
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	Yes	1,000	$2,217	$255	6.839%	$169.05	$30.45	1.379%	$0.42	$0.00	$30.87	$199.92
Idah Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	4,700	$3,395	$268	6.839%	$250.50	$82.95	1.379%	$1.14	$0.00	$84.09	$334.59
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	4,800	$3,424	$268	6.839%	$252.44	$82.95	1.379%	$1.14	$0.00	$84.09	$336.53
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	5,000	$3,364	$268	6.839%	$248.37	$81.45	1.379%	$1.12	$0.00	$82.57	$330.95
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	6,400	$3,364	$268	6.839%	$248.33	$81.45	1.379%	$1.12	$0.00	$82.57	$330.90
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	No	1,000	$3,424	$268	6.839%	$252.46	$81.45	1.379%	$1.12	$0.00	$82.57	$335.04
Pumped Hydro, Swan Lake. 3600 MWh	Yes	N/A	$3,095	$485	6.251%	$223.78	$12.50	0.000%	$0.00	$0.00	$12.50	$236.28
Pumped Hydro, Goldendale, 14400 MWh	Yes	N/A	$2,833	$485	6.251%	$207.43	$12.50	0.000%	$0.00	$0.00	$12.50	$219.93
Pumped Hydro, Seminoe, 7500 MWh	Yes	N/A	$3,461	$485	6.111%	$241.13	$16.00	0.000%	$0.00	$0.00	$16.00	$257.13
Pumped Hydro, Badger Mountain, 4000 MWh	Yes	N/A	$2,621	$485	6.111%	$189.78	$28.00	0.000%	$0.00	$0.00	$28.00	$217.78
Pumped Hydro, Owyhee, 4800 MWh	Yes	N/A	$3,203	$485	6.111%	$225.33	$20.00	0.000%	$0.00	$0.00	$20.00	$245.33
Pumped Hydro, Flat Canyon, 1800 MWh	Yes	N/A	$4,046	$485	6.111%	$276.88	$53.33	0.000%	$0.00	$0.00	$53.33	$330.22
Pumped Hydro, Utah PS2, 4000 MWh	Yes	N/A	$3,237	$485	6.111%	$227.44	$28.00	0.000%	$0.00	$0.00	$28.00	$255.44
Pumped Hydro, Utah PS3, 4800 MWh	Yes	N/A	$3,371	$485	6.111%	$235.63	$20.00	0.000%	$0.00	$0.00	$20.00	$255.63
Pumped Hydro, Banner Mountain, 3400 MWh	Yes	N/A	$3,276	$485	6.479%	$243.64	$28.50	0.000%	$0.00	$0.00	$28.50	$272.14
Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	No	N/A	$1,954	$12	7.497%	$147.40	$12.67	0.000%	$0.00	$0.00	$12.67	$160.06
Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	No	N/A	$2,189	$12	7.497%	$165.01	$12.67	0.000%	$0.00	$0.00	$12.67	$177.67
Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	No	N/A	$2,445	$12	7.497%	$184.22	$12.67	0.000%	$0.00	$0.00	$12.67	$196.89
Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	No	N/A	$1,557	$12	7.497%	$117.65	$9.33	0.000%	$0.00	$0.00	$9.33	$126.98
Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	No	N/A	$1,692	$12	7.497%	$127.79	$9.33	0.000%	$0.00	$0.00	$9.33	$137.12
Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	No	N/A	$2,016	$12	7.497%	$152.05	$9.33	0.000%	$0.00	$0.00	$9.33	$161.38
Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	Yes	N/A	$1,549	$12	7.497%	$117.06	$6.60	0.000%	$0.00	$0.00	$6.60	$123.66
Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	Yes	N/A	$1,762	$12	7.497%	$132.99	$6.60	0.000%	$0.00	$0.00	$6.60	$139.59
Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	Yes	N/A	$2,010	$12	7.497%	$151.61	$6.60	0.000%	$0.00	$0.00	$6.60	$158.21
Li-Ion Battery, , 1 MW, 0.5 MWh	No	N/A	$1,948	$55	8.676%	$173.74	$40.00	0.000%	$0.00	$0.00	$40.00	$213.74
Li-Ion Battery, , 1 MW, 1 MWh	No	N/A	$2,058	$110	8.676%	$188.13	$50.00	0.000%	$0.00	$0.00	$50.00	$238.13
Non-Emitting Peaker	Yes	5,050	$959	$2,414	7.497%	$252.85	$0.00	0.000%	$0.00	$0.00	$0.00	$252.85
Li-Ion Battery, , 50 MW, 200 MWh	Yes	N/A	$1,820	$440	8.676%	$196.05	$27.60	0.000%	$0.00	$0.00	$27.60	$223.65
Flow Battery, , 1 MW, 1 MWh	No	N/A	$4,719	$12	8.676%	$410.44	$13.00	0.000%	$0.00	$0.00	$13.00	$423.44
Flow Battery, , 1 MW, 4 MWh	No	N/A	$5,051	$12	8.676%	$439.29	$13.00	0.000%	$0.00	$0.00	$13.00	$452.29
Flow Battery, , 1 MW, 8 MWh	No	N/A	$7,291	$12	8.676%	$633.58	$27.00	0.000%	$0.00	$0.00	$27.00	$660.58
Flow Battery, , 20 MW, 160 MWh	Yes	N/A	$4,190	$12	8.676%	$364.59	$30.50	0.000%	$0.00	$0.00	$30.50	$395.09
Small Modular Reactor	Yes	5,000	$5,396	$722	6.733%	$411.88	$65.03	5.687%	$3.70	$0.00	$68.73	$480.61
Non-Emitting Peaker	Yes	5,050	$959	$2,414	7.497%	$252.85	$0.00	0.000%	$0.00	$0.00	$0.00	$252.85

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)			Capital Cost $/kW				Fixed Cost					
							Fixed O&M $/kW-Yr					
Resource Description	Modeled IRP	Elevation (AFSL)	Total Capital and Environmental Cost 1/	Demolition Cost	Payment Factor 1/	Annual Payment ($/kW-Yr)	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Gas Transportation 1/	Total	Total Fixed ($/kW-Yr)
Brownfield Site												
Utah (Hunter, Huntington)												
Brownfield SCCT Frame "F" x1	Yes	5,050	$811	$12	7.049%	$58.00	0.00	0.273%	$0.00	$14.93	$14.93	$72.94
Intercooled SCCT Aero x2	Yes	5,050	$1,363	$12	7.497%	$103.10	0.00	1.135%	$0.00	$13.22	$13.22	$116.32
Brownfield CCCT Dry "H", DF, 2x1	Yes	5,050	$1,251	$12	6.886%	$87.00	0.00	0.000%	$0.00	$9.84	$9.84	$96.84
CCCT Dry "J", 1x1	Yes	5,050	$1,299	$12	6.886%	$90.28	0.00	0.000%	$0.00	$9.84	$9.84	$100.13
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	Yes	5,000	$1,297	$35	6.839%	$91.11	17.60	1.379%	$0.24	$0.00	$17.84	$108.95
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	5,000	$2,102	$255	6.839%	$161.21	30.45	1.379%	$0.42	$0.00	$30.87	$192.08
Wyoming (Bridger, Johnston, Wyodak)						0						
Brownfield SCCT Frame "F" x1	Yes	6,500	$854	$13	7.049%	$61.12	0.00	0.273%	$0.00	$9.70	$9.70	$70.82
Intercooled SCCT Aero x2	Yes	6,500	$1,427	$13	7.497%	$107.96	0.00	1.135%	$0.00	$8.62	$8.62	$116.58
Brownfield CCCT Dry "H", DF, 2x1	Yes	6,500	$1,283	$12	6.886%	$89.18	0.00	0.000%	$0.00	$6.62	$6.62	$95.80
CCCT Dry "J", 1x1	Yes	6,500	$1,337	$12	6.886%	$92.91	0.00	0.000%	$0.00	$6.62	$6.62	$99.53
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	Yes	6,500	$1,356	$13	6.979%	$95.54	24.74	0.000%	$0.00	$0.00	$24.74	$120.28
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	Yes	6,500	$2,136	$233	6.979%	$165.29	37.59	2.902%	$1.09	$0.00	$38.68	$203.97
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	Yes	6,400	$1,297	$35	6.839%	$91.07	17.60	1.379%	$0.24	$0.00	$17.84	$108.91
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	Yes	6,400	$2,128	$255	6.839%	$163.01	30.45	1.379%	$0.42	$0.00	$30.87	$193.88
Naughton 1 PC CCUS Retrofit	Yes	6,500	$3,939	$37	8.920%	$354.70	39.99	5.541%	$2.22	$0.00	$42.21	$396.91
Naughton 2 PC CCUS Retrofit	Yes	6,500	$3,930	$37	8.920%	$353.83	39.90	5.541%	$2.21	$0.00	$42.11	$395.94
Johnston 2 PC CCUS Retrofit	Yes	6,500	$5,314	$37	8.920%	$477.27	40.58	5.541%	$2.25	$0.00	$42.83	$520.10
Johnston 4 PC CCUS Retrofit	Yes	6,500	$3,877	$37	8.920%	$349.16	37.88	5.541%	$2.10	$0.00	$39.97	$389.13
Wyodak PC CCUS Retrofit	Yes	6,500	$3,935	$37	9.010%	$357.86	39.95	5.541%	$2.21	$0.00	$42.16	$400.02
Bridger 1 PC CCUS Retrofit	Yes	6,500	$3,934	$37	8.920%	$354.24	39.94	5.541%	$2.21	$0.00	$42.15	$396.39
Bridger 3 PC CCUS Retrofit	Yes	6,500	$3,873	$37	9.010%	$352.29	37.83	5.541%	$2.10	$0.00	$39.93	$392.22
Bridger 4 PC CCUS Retrofit	Yes	6,500	$3,876	$37	9.010%	$352.56	37.86	5.541%	$2.10	$0.00	$39.96	$392.52

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh											
					Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 2/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
SCCT Aero x3	0	33%	$49.25	N/A	$ 2.97	$ 27.77	$ 7.44	11.48%	$ 0.85	$ -	$85.32	$ -	$85.32
Intercooled SCCT Aero x2	0	33%	$39.84	N/A	$ 2.97	$ 26.13	$ 5.03	11.48%	$ 0.58	$ -	$71.58	$ -	$71.58
SCCT Frame "F" x1	0	33%	$28.97	N/A	$ 2.97	$ 29.44	$ 14.16	13.23%	$ 1.87	$ -	$74.44	$ -	$74.44
Brownfield SCCT Frame "F" x1	0	33%	$28.36	N/A	$ 2.97	$ 29.44	$ 14.16	13.23%	$ 1.87	$ -	$73.83	$ -	$73.83
IC Recips x 6	0	33%	$57.40	N/A	$ 2.97	$ 24.61	$ 10.39	8.73%	$ 0.91	$ -	$93.30	$ -	$93.30
CCCT Dry "H", 1x1	0	78%	$17.62	N/A	$ 2.97	$ 18.84	$ 1.77	10.21%	$ 0.18	$ -	$38.41	$ -	$38.41
CCCT Dry "H", DF, 1x1	0	12%	$53.19	N/A	$ 2.97	$ 26.25	$ 0.05	0.00%	$ -	$ -	$79.49	$ -	$79.49
CCCT Dry "H", 2x1	0	78%	$13.83	N/A	$ 2.97	$ 18.89	$ 1.71	10.79%	$ 0.18	$ -	$34.61	$ -	$34.61
CCCT Dry "H", DF, 2x1	0	12%	$45.87	N/A	$ 2.97	$ 25.73	$ 0.05	0.00%	$ -	$ -	$71.65	$ -	$71.65
Brownfield CCCT Dry "H", DF, 2x1	0	78%	$13.78	N/A	$ 2.97	$ 19.63	$ 1.08	10.21%	$ 0.11	$ -	$34.61	$ -	$34.61
CCCT Dry "J", 1x1	0	78%	$14.25	N/A	$ 2.97	$ 18.60	$ 1.48	10.21%	$ 0.15	$ -	$34.49	$ -	$34.49
CCCT Dry "J", DF, 1x1	0	12%	$48.26	N/A	$ 2.97	$ 26.05	$ 0.06	0.00%	$ -	$ -	$74.36	$ -	$74.36
CCCT Dry "J", 2x1	0	78%	$11.45	N/A	$ 2.97	$ 18.57	$ 1.43	10.79%	$ 0.15	$ -	$31.60	$ -	$31.60
CCCT Dry "J", DF, 2x1	0	12%	$42.48	N/A	$ 2.97	$ 25.85	$ 0.06	0.00%	$ -	$ -	$68.39	$ -	$68.39
SCCT Aero x3	1,500	33%	$51.59	N/A	$ 2.97	$ 27.81	$ 7.89	11.48%	$ 0.91	$ -	$88.19	$ -	$88.19
Intercooled SCCT Aero x2	1,500	33%	$41.52	N/A	$ 2.97	$ 26.14	$ 5.31	11.48%	$ 0.61	$ -	$73.58	$ -	$73.58
SCCT Frame "F" x1	1,500	33%	$29.99	N/A	$ 2.97	$ 29.45	$ 14.94	13.23%	$ 1.98	$ -	$76.36	$ -	$76.36
Brownfield SCCT Frame "F" x1	1,500	33%	$29.34	N/A	$ 2.97	$ 29.45	$ 14.94	13.23%	$ 1.98	$ -	$75.71	$ -	$75.71
IC Recips x 6	1,500	33%	$57.40	N/A	$ 2.97	$ 24.61	$ 10.39	8.73%	$ 0.91	$ -	$93.30	$ -	$93.30
CCCT Dry "H", 1x1	1,500	78%	$18.51	N/A	$ 2.97	$ 18.96	$ 1.88	10.21%	$ 0.19	$ -	$39.54	$ -	$39.54
CCCT Dry "H", DF, 1x1	1,500	12%	$53.00	N/A	$ 2.97	$ 26.10	$ 0.05	0.00%	$ -	$ -	$79.15	$ -	$79.15
CCCT Dry "H", 2x1	1,500	78%	$14.42	N/A	$ 2.97	$ 18.91	$ 1.81	10.79%	$ 0.19	$ -	$35.34	$ -	$35.34
CCCT Dry "H", DF, 2x1	1,500	12%	$45.67	N/A	$ 2.97	$ 25.88	$ 0.05	0.00%	$ -	$ -	$71.60	$ -	$71.60
Brownfield CCCT Dry "H", DF, 2x1	1,500	78%	$14.38	N/A	$ 2.97	$ 19.70	$ 1.14	10.21%	$ 0.12	$ -	$35.35	$ -	$35.35
CCCT Dry "J", 1x1	1,500	78%	$14.87	N/A	$ 2.97	$ 18.60	$ 1.57	10.21%	$ 0.16	$ -	$35.20	$ -	$35.20
CCCT Dry "J", DF, 1x1	1,500	12%	$48.08	N/A	$ 2.97	$ 26.18	$ 0.06	0.00%	$ -	$ -	$74.32	$ -	$74.32
CCCT Dry "J", 2x1	1,500	78%	$11.91	N/A	$ 2.97	$ 18.56	$ 1.51	10.79%	$ 0.16	$ -	$32.15	$ -	$32.15
CCCT Dry "J", DF, 2x1	1,500	12%	$42.30	N/A	$ 2.97	$ 25.96	$ 0.06	0.00%	$ -	$ -	$68.32	$ -	$68.32
SCCT Aero x3	3,000	33%	$48.82	N/A	$ 3.21	$ 30.11	$ 8.37	11.48%	$ 0.96	$ -	$88.26	$ -	$88.26
Intercooled SCCT Aero x2	3,000	33%	$38.49	N/A	$ 3.21	$ 28.28	$ 5.63	11.48%	$ 0.65	$ -	$73.05	$ -	$73.05
SCCT Frame "F" x1	3,000	33%	$25.49	N/A	$ 3.21	$ 31.87	$ 15.79	13.23%	$ 2.09	$ -	$75.24	$ -	$75.24
Brownfield SCCT Frame "F" x1	3,000	33%	$24.81	N/A	$ 3.21	$ 31.87	$ 15.78	13.23%	$ 2.09	$ -	$74.55	$ -	$74.55

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)*

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	Total Fixed ($/MWh)	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
IC Recips x 6	3,000	33%	$52.80	N/A	$ 3.21	$ 26.60	$ 10.39	8.73%	$ 0.91	$ -	$90.69	$ -	$90.69
CCCT Dry "H", 1x1	3,000	78%	$19.33	N/A	$ 3.21	$ 20.50	$ 1.99	10.21%	$ 0.20	$ -	$42.02	$ -	$42.02
CCCT Dry "H", DF, 1x1	3,000	12%	$52.92	N/A	$ 3.21	$ 28.30	$ 0.05	0.00%	$ -	$ -	$81.26	$ -	$81.26
CCCT Dry "H", 2x1	3,000	78%	$13.46	N/A	$ 3.21	$ 20.55	$ 1.92	10.79%	$ 0.21	$ -	$36.13	$ -	$36.13
CCCT Dry "H", DF, 2x1	3,000	12%	$35.23	N/A	$ 3.21	$ 28.11	$ 0.05	0.00%	$ -	$ -	$63.39	$ -	$63.39
Brownfield CCCT Dry "H", DF, 2x1	3,000	78%	$13.43	N/A	$ 3.21	$ 21.45	$ 1.21	10.21%	$ 0.12	$ -	$36.22	$ -	$36.22
CCCT Dry "J", 1x1	3,000	78%	$13.89	N/A	$ 3.21	$ 20.13	$ 1.66	10.21%	$ 0.17	$ -	$35.84	$ -	$35.84
CCCT Dry "J", DF, 1x1	3,000	12%	$37.71	N/A	$ 3.21	$ 28.37	$ 0.06	0.00%	$ -	$ -	$66.14	$ -	$66.14
CCCT Dry "J", 2x1	3,000	78%	$10.77	N/A	$ 3.21	$ 20.08	$ 1.60	10.79%	$ 0.17	$ -	$32.62	$ -	$32.62
CCCT Dry "J", DF, 2x1	3,000	12%	$31.94	N/A	$ 3.21	$ 28.13	$ 0.06	0.00%	$ -	$ -	$60.13	$ -	$60.13
SCCT Aero x3	5,050	33%	$51.28	N/A	$ 3.13	$ 29.42	$ 9.04	11.48%	$ 1.04	$ -	$90.78	$ -	$90.78
Intercooled SCCT Aero x2	5,050	33%	$40.24	N/A	$ 3.13	$ 27.59	$ 6.09	11.48%	$ 0.70	$ -	$74.62	$ -	$74.62
SCCT Frame "F" x1	5,050	33%	$25.97	N/A	$ 3.13	$ 31.10	$ 17.04	13.23%	$ 2.25	$ -	$76.36	$ -	$76.36
Brownfield SCCT Frame "F" x1	5,050	33%	$25.23	N/A	$ 3.13	$ 31.10	$ 17.03	13.23%	$ 2.25	$ -	$75.62	$ -	$75.62
IC Recips x 6	5,050	33%	$51.91	N/A	$ 3.13	$ 25.95	$ 10.39	8.73%	$ 0.91	$ -	$89.16	$ -	$89.16
CCCT Dry "H", 1x1	5,050	78%	$18.57	N/A	$ 3.13	$ 19.91	$ 2.14	10.21%	$ 0.22	$ -	$40.84	$ -	$40.84
CCCT Dry "H", DF, 1x1	5,050	12%	$40.21	N/A	$ 3.13	$ 26.75	$ 0.05	0.00%	$ -	$ -	$67.00	$ -	$67.00
CCCT Dry "H", 2x1	5,050	78%	$14.19	N/A	$ 3.13	$ 20.31	$ 2.10	10.79%	$ 0.23	$ -	$36.82	$ -	$36.82
CCCT Dry "H", DF, 2x1	5,050	12%	$32.88	N/A	$ 3.13	$ 29.64	$ 0.05	0.00%	$ -	$ -	$62.57	$ -	$62.57
Brownfield CCCT Dry "H", DF, 2x1	5,050	78%	$14.17	N/A	$ 3.13	$ 21.51	$ 1.33	10.21%	$ 0.14	$ -	$37.15	$ -	$37.15
CCCT Dry "J", 1x1	5,050	78%	$14.65	N/A	$ 3.13	$ 19.88	$ 1.81	10.21%	$ 0.18	$ -	$36.53	$ -	$36.53
CCCT Dry "J", DF, 1x1	5,050	12%	$35.39	N/A	$ 3.13	$ 29.58	$ 0.06	0.00%	$ -	$ -	$65.03	$ -	$65.03
CCCT Dry "J", 2x1	5,050	78%	$11.30	N/A	$ 3.13	$ 19.95	$ 1.76	10.79%	$ 0.19	$ -	$33.19	$ -	$33.19
CCCT Dry "J", DF, 2x1	5,050	12%	$29.63	N/A	$ 3.13	$ 29.60	$ 0.06	0.00%	$ -	$ -	$59.28	$ -	$59.28
SCCT Aero x3	6,500	33%	$54.26	N/A	$ 3.09	$ 28.78	$ 9.96	11.48%	$ 1.14	$ -	$94.14	$ -	$94.14
Intercooled SCCT Aero x2	6,500	33%	$40.33	N/A	$ 3.09	$ 27.15	$ 6.37	11.48%	$ 0.73	$ -	$74.58	$ -	$74.58
SCCT Frame "F" x1	6,500	33%	$25.27	N/A	$ 3.09	$ 30.68	$ 17.95	13.23%	$ 2.38	$ -	$76.29	$ -	$76.29
Brownfield SCCT Frame "F" x1	6,500	33%	$24.50	N/A	$ 3.09	$ 30.68	$ 17.95	13.23%	$ 2.38	$ -	$75.51	$ -	$75.51
IC Recips x 6	6,500	33%	$50.39	N/A	$ 3.09	$ 25.75	$ 10.39	8.73%	$ 0.91	$ -	$87.43	$ -	$87.43
CCCT Dry "H", 1x1	6,500	78%	$20.89	N/A	$ 3.09	$ 19.75	$ 2.23	10.21%	$ 0.23	$ -	$43.10	$ -	$43.10
CCCT Dry "H", DF, 1x1	6,500	12%	$50.43	N/A	$ 3.09	$ 27.37	$ 0.05	0.00%	$ -	$ -	$77.85	$ -	$77.85

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh											Credits	
					Levelized Fuel									
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
CCCT Dry "H", 2x1	6,500	78%	$14.04	N/A	$ 3.09	$ 19.77	$ 2.15	10.79%	$ 0.23	$ -	$36.20	$ -	$36.20
CCCT Dry "H", DF, 2x1	6,500	12%	$29.79	N/A	$ 3.09	$ 27.35	$ 0.05	0.00%	$ -	$ -	$57.20	$ -	$57.20
Brownfield CCCT Dry "H", DF, 2x1	6,500	78%	$14.02	N/A	$ 3.09	$ 20.78	$ 1.36	10.21%	$ 0.14	$ -	$36.30	$ -	$36.30
CCCT Dry "J", 1x1	6,500	78%	$14.57	N/A	$ 3.09	$ 19.38	$ 1.86	10.21%	$ 0.19	$ -	$36.00	$ -	$36.00
CCCT Dry "J", DF, 1x1	6,500	12%	$32.32	N/A	$ 3.09	$ 27.39	$ 0.06	0.00%	$ -	$ -	$59.77	$ -	$59.77
CCCT Dry "J", 2x1	6,500	78%	$11.05	N/A	$ 3.09	$ 19.34	$ 1.80	10.79%	$ 0.19	$ -	$32.38	$ -	$32.38
CCCT Dry "J", DF, 2x1	6,500	12%	$26.56	N/A	$ 3.09	$ 27.16	$ 0.06	0.00%	$ -	$ -	$53.78	$ -	$53.78
SCPC with CCS	4,500	90%	$66.91	N/A	$ 1.96	$ 25.65	$ 7.00	0.00%	$ -	$ -	$99.56	$ -	$99.56
IGCC with CCS	4,500	86%	$69.93	N/A	$ 1.96	$ 21.21	$ 11.77	11.52%	$ 1.36	$ -	$104.27	$ -	$104.27
PC CCS retrofit @ 500 MW pre-retrofit basis	4,500	90%	$29.80	N/A	$ 1.96	$ 28.17	$ 3.29	0.00%	$ -	$ -	$61.26	$ -	$61.26
SCPC with CCS	6,500	90%	$73.66	N/A	$ 1.96	$ 25.95	$ 7.58	0.00%	$ -	$ -	$107.19	$ -	$107.19
IGCC with CCS	6,500	86%	$78.77	N/A	$ 1.96	$ 21.65	$ 14.11	11.52%	$ 1.63	$ -	$116.15	$ -	$116.15
PC CCS retrofit @ 500 MW pre-retrofit basis	6,500	90%	$29.80	N/A	$ 1.96	$ 28.17	$ 3.29	0.00%	$ -	$ -	$61.26	$ -	$61.26
Blundell Dual Flash 90% CF	4,500	90%	$59.71	N/A	$ -	$ -	$ 1.16	0.00%	$ -	$ -	$60.87	$ (16.12)	$44.75
Greenfield Binary 90% CF	4,500	90%	$61.71	N/A	$ -	$ -	$ 1.16	0.00%	$ -	$ -	$62.88	$ (16.12)	$46.75
Generic Geothermal PPA 90% CF	4,500	90%	$0.00	N/A	$ -	$ -	$ 77.34	0.00%	$ -	$ -	$77.34	$ (16.12)	$61.22
Pocatello, ID, 200 MW Wind, CF: 37.1% (100% PTC)	4,500	37%	$37.19	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.12	$ (16.12)	$22.00
Arlington, OR, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	37%	$36.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$37.05	$ (16.12)	$20.93
Monticello, UT, 200 MW Wind, CF: 29.5% (100% PTC)	4,500	30%	$45.20	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$46.13	$ (16.12)	$30.00
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (100%PTC)	6,500	44%	$31.49	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$32.42	$ (16.12)	$16.30
Goldendale, WA, 200 MW Wind, CF: 37.1% (100% PTC)	1,500	37%	$37.73	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.66	$ (16.12)	$22.54
Pocatello, ID, 200 MW Wind, CF: 37.1% (60% PTC)	4,500	37%	$37.19	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.12	$ (9.67)	$28.45
Arlington, OR, 200 MW Wind, CF: 37.1% (60% PTC)	1,500	37%	$36.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$37.05	$ (9.67)	$27.38
Monticello, UT, 200 MW Wind, CF: 29.5% (60% PTC)	4,500	30%	$45.20	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$46.13	$ (9.67)	$36.45
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	6,500	44%	$31.49	N/A	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$33.07	$ (9.67)	$23.40
Goldendale, WA, 200 MW Wnd, CF: 37.1% (60% PTC)	1,500	37%	$37.73	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$38.66	$ (9.67)	$28.99
Pocatello, ID, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	4,500	37%	$63.12	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$64.05	$ (16.12)	$47.92
Arlington, OR, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	37%	$61.69	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$62.62	$ (16.12)	$46.50
Monticello, UT, 200 MW Wind, CF: 29.5% + BESS: 50% pwr, 4 hours	4,500	30%	$76.90	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$77.83	$ (16.12)	$61.71
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	44%	$53.40	85%	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$54.98	$ (16.12)	$38.86
Goldendale, WA, 200 MW Wind, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	37%	$64.37	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.93	$65.30	$ (16.12)	$49.18
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (30% ITC)	4,700	26%	$50.96	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$51.67	$ (10.96)	$40.70
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (30% ITC)	4,700	26%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$47.84	$ (9.99)	$37.85
Lakeview, OR, 100 MW Solar, CF: 27.6% (30% ITC)	4,800	28%	$48.64	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$49.35	$ (10.48)	$38.86
Lakeview, OR, 200 MW Solar, CF: 27.6% (30% ITC)	4,800	28%	$45.37	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$46.08	$ (9.66)	$36.42
Milford, UT, 100 MW Solar, CF: 30.2% (30% ITC)	5,000	30%	$44.42	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.12	$ (9.43)	$35.69
Milford, UT, 200 MW Solar, CF: 30.2% (30% ITC)	5,000	30%	$41.18	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$41.89	$ (8.60)	$33.28
Rock Springs, WY, 100 MW Solar, CF: 27.9% (30% ITC)	6,400	28%	$48.10	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$48.80	$ (10.21)	$38.58
Rock Springs, WY, 200 MW Solar, CF: 27.9% (30% ITC)	6,400	28%	$44.56	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.27	$ (9.31)	$35.96
Yakima, WA, 100 MW Solar, CF: 24.2% (30% ITC)	1,000	24%	$57.49	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$58.20	$ (12.30)	$45.90
Yakima, WA, 200 MW Solar, CF: 24.2% (30% ITC)	1,000	24%	$53.32	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$54.03	$ (11.23)	$42.80
Idaho Falls, ID, 100 MW Solar, CF: 26.1% (10% ITC)	4,700	26%	$50.96	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$51.67	$ (0.52)	$51.15
Idaho Falls, ID, 200 MW Solar, CF: 26.1% (10% ITC)	4,700	26%	$47.13	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$47.84	$ (0.47)	$47.36
Lakeview, OR, 100 MW Solar, CF: 27.6% (10% ITC)	4,800	28%	$48.64	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$49.35	$ (0.50)	$48.85
Lakeview, OR, 200 MW Solar, CF: 27.6% (10% ITC)	4,800	28%	$45.37	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$46.08	$ (0.46)	$45.62
Milford, UT, 100 MW Solar, CF: 30.2% (10% ITC)	5,000	30%	$44.42	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.12	$ (0.45)	$44.67
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	5,000	30%	$41.18	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$41.89	$ (0.41)	$41.48
Rock Springs, WY, 100 MW Solar, CF: 27.9% (10% ITC)	6,400	28%	$48.10	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$48.80	$ (0.48)	$48.31
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	6,400	28%	$44.56	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.27	$ (0.44)	$44.82
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	26%	$91.26	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$91.97	$ (18.04)	$73.92

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh			Levelized Fuel							Credits	
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (30% ITC)	4,700	26%	$85.11	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.82	$ (16.59)	$69.23
Yakima, WA, 100 MW Solar, CF: 24.2% (10% ITC)	1,000	24%	$57.49	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$58.20	$ (0.58)	$57.61
Yakima, WA, 200 MW Solar, CF: 24.2% (10% ITC)	1,000	24%	$53.32	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$54.03	$ (0.53)	$53.50
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	28%	$85.67	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$86.37	$ (16.90)	$69.47
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (30% ITC)	4,800	28%	$80.28	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.98	$ (15.63)	$65.35
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	30%	$77.65	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$78.35	$ (15.14)	$63.21
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	30%	$72.60	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$73.31	$ (13.94)	$59.37
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	28%	$84.86	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.56	$ (16.60)	$68.96
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	28%	$79.33	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.03	$ (15.28)	$64.75
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	24%	$100.83	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$101.53	$ (19.90)	$81.62
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (30% ITC)	1,000	24%	$94.31	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$95.01	$ (18.35)	$76.66
Idaho Falls, ID, 100 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	4,700	26%	$91.26	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$91.97	$ (0.86)	$91.11
Idaho Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours (10% ITC)	4,700	26%	$85.11	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.82	$ (0.79)	$85.03
Lakeview, OR, 100 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	4,800	28%	$85.67	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$86.37	$ (0.80)	$85.57
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours (10% ITC)	4,800	28%	$80.28	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.98	$ (0.74)	$80.24
Milford, UT, 100 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	5,000	30%	$77.65	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$78.35	$ (0.72)	$77.63
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (10% ITC)	5,000	30%	$72.60	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$73.31	$ (0.66)	$72.65
Rock Springs, WY, 100 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	6,400	28%	$84.86	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$85.56	$ (0.79)	$84.78
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (10% ITC)	6,400	28%	$79.33	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.03	$ (0.73)	$79.31
Yakima, WA, 100 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	1,000	24%	$100.83	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$101.53	$ (0.94)	$100.59
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours (10% ITC)	1,000	24%	$94.31	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$95.01	$ (0.87)	$94.14
Idah Falls, ID, 200 MW Solar, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,700	26%	$146.34	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$147.05	$ -	$147.05
Lakeview, OR, 200 MW Solar, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,800	28%	$139.19	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$139.90	$ -	$139.90
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	5,000	30%	$125.10	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$125.80	$ -	$125.80
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	6,400	28%	$135.39	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$136.10	$ -	$136.10
Yakima, WA, 200 MW Solar, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	1,000	24%	$158.04	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$158.75	$ -	$158.75
Pumped Hydro, Swan Lake. 3600 MWh	N/A	38%	$71.93	78%	$ -	$ -	$ -	0.00%	$ -	$ -	$71.93	$ -	$71.93
Pumped Hydro, Goldendale, 14400 MWh	N/A	50%	$50.21	78%	$ -	$ -	$ -	0.00%	$ -	$ -	$50.21	$ -	$50.21
Pumped Hydro, Seminoe, 7500 MWh	N/A	42%	$70.45	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$70.82	$ -	$70.82
Pumped Hydro, Badger Mountain, 4000 MWh	N/A	33%	$74.58	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$74.95	$ -	$74.95
Pumped Hydro, Owyhee, 4800 MWh	N/A	33%	$84.02	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$84.39	$ -	$84.39
Pumped Hydro, Flat Canyon, 1800 MWh	N/A	25%	$150.78	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$151.15	$ -	$151.15
Pumped Hydro, Utah PS2, 4000 MWh	N/A	33%	$87.48	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$87.85	$ -	$87.85
Pumped Hydro, Utah PS3, 4800 MWh	N/A	33%	$87.54	80%	$ -	$ -	$ 0.37	0.00%	$ -	$ -	$87.91	$ -	$87.91
Pumped Hydro, Banner Mountain, 3400 MWh	N/A	35%	$87.72	81%	$ -	$ -	$ 0.00	0.00%	$ -	$ -	$87.72	$ -	$87.72
Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	17%	$109.63	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$116.13	$ -	$116.13
Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	33%	$60.85	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$67.35	$ -	$67.35
Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	50%	$44.95	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$51.45	$ -	$51.45
Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	17%	$86.97	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$93.47	$ -	$93.47
Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	33%	$46.96	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$53.46	$ -	$53.46
Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	50%	$36.84	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$43.34	$ -	$43.34
Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	17%	$84.70	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$91.20	$ -	$91.20
Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	33%	$47.81	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$54.31	$ -	$54.31
Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	50%	$36.12	60%	$ -	$ -	$ 6.50	0.00%	$ -	$ -	$42.62	$ -	$42.62

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh										Credits	
					Levelized Fuel								
Resource Description	Elevation (AFSL)	Capacity Factor 3/	l Fixed($/MW	Storage Efficiency	$/mmBtu	$/MWh	O&M 1/	Capitalized Premium	O&M Capitalized 1/	Integration Cost 1/	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	2%	$1,171.19	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$1,171.19	$ -	$1,171.19
Li-Ion Battery, , 1 MW, 1 MWh	N/A	4%	$652.41	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$652.41	$ -	$652.41
Li-Ion Battery, , 1 MW, 4 MWh	N/A	17%	$262.28	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$262.28	$ -	$262.28
Li-Ion Battery, , 1 MW, 8 MWh	N/A	33%	$197.73	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$197.73	$ -	$197.73
Li-Ion Battery, , 50 MW, 200 MWh	N/A	17%	$153.19	85%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$153.19	$ -	$153.19
Flow Battery, , 1 MW, 1 MWh	N/A	4%	$1,160.11	70%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$1,160.11	$ -	$1,160.11
Non-Emitting Peaker	5,050	33%	$87.47	0%	$ 26.72	$ 265.54	$ 21.29	0.00%	$ -	$ -	$374.30	$ -	$374.30
Flow Battery, , 20 MW, 160 MWh	N/A	33%	$135.30	70%	$ -	$ -	cluded in FO	0.00%	$ -	$ -	$135.30	$ -	$135.30
Small Modular Reactor	5000	86%	$ 64.12	N/A	$ -	$ -	$ 6.72	0.00%	$ -	$ -	$70.84	$ -	$70.84
Non-Emitting Peaker	5050	33%	$ 87.47	0%	$ 26.72	$ 265.54	$ 21.29	0.00%	$ -	$ -	$374.30	$ -	$374.30

Table 7.2 – Total Resource Cost for Supply-Side Resource Options (Continued)

Supply Side Resource Options Mid-Calendar Year 2020 Dollars ($)		Convert to $/MWh					Variable Costs ($/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 / CO2 Revenues	Total Resource Cost	PTC Tax Credits / ITC (Solar Only) / 45Q Tax Credits (CCUS Only)	Total Resource Cost - with PTC / ITC / 45Q Credits
Brownfield Site													
Utah													
Brownfield SCCT Frame "F" x1	5050	33%	$25.23	N/A	$ 3.13	$ 31.10	$ 17.03	13.23%	$ 2.25	$ -	$75.62	$ -	$75.62
Intercooled SCCT Aero x2	5050	33%	$40.24	N/A	$ 3.13	$ 27.59	$ 6.09	11.48%	$ 0.70	$ -	$74.62	$ -	$74.62
Brownfield CCCT Dry "H", DF, 2x1	5050	78%	$14.17	N/A	$ 3.13	$ 21.51	$ 1.33	10.21%	$ 0.14	$ -	$37.15	$ -	$37.15
CCCT Dry "J", 1x1	5050	78%	$14.65	N/A	$ 3.13	$ 19.88	$ 1.81	10.21%	$ 0.18	$ -	$36.53	$ -	$36.53
Milford, UT, 200 MW Solar, CF: 30.2% (10% ITC)	5000	30%	$41.18	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$41.89	$ (0.41)	$41.48
Milford, UT, 200 MW Solar, CF: 30.2% + BESS: 50% pwr, 4 hours (30% ITC)	5,000	30%	$72.60	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$73.31	$ (13.94)	$59.37
Wyoming													
Brownfield SCCT Frame "F" x1	6500	33%	$24.50	N/A	$ 3.09	$ 30.68	$ 17.95	13.23%	$ 2.38	$ -	$75.51	$ -	$75.51
Intercooled SCCT Aero x2	6500	33%	$40.33	N/A	$ 3.09	$ 27.15	$ 6.37	11.48%	$ 0.73	$ -	$74.58	$ -	$74.58
Brownfield CCCT Dry "H", DF, 2x1	6500	78%	$14.02	N/A	$ 3.09	$ 20.78	$ 1.36	10.21%	$ 0.14	$ -	$36.30	$ -	$36.30
CCCT Dry "J", 1x1	6500	78%	$14.57	N/A	$ 3.09	$ 19.38	$ 1.86	10.21%	$ 0.19	$ -	$36.00	$ -	$36.00
Medicine Bow, WY, 200 MW Wind, CF: 43.6% (60% PTC)	6,500	44%	$31.49	N/A	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$33.07		$33.07
Medicine Bow, WY, 200 MW Wind, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	44%	$53.40	85%	$ -	$ -	$ 0.65	0.00%	$ -	$ 0.93	$54.98		$54.98
Rock Springs, WY, 200 MW Solar, CF: 27.9% (10% ITC)	6400	28%	$44.56	N/A	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$45.27	$ (0.44)	$44.82
Rock Springs, WY, 200 MW Solar, CF: 27.9% + BESS: 50% pwr, 4 hours (30% ITC)	6,400	28%	$79.33	85%	$ -	$ -	$ -	0.00%	$ -	$ 0.70	$80.03	$ (15.28)	$64.75
Naughton 1 PC CCUS Retrofit	6,500	85%	$53.31	0%	$ 2.28	$ 32.77	$ 7.32	0.00%	$ -	$ (12.28)	$81.12	$ (25.79)	$55.33
Naughton 2 PC CCUS Retrofit	6,500	85%	$53.17	0%	$ 2.28	$ 32.77	$ 7.30	0.00%	$ -	$ (12.28)	$80.97	$ (25.79)	$55.18
Johnston 2 PC CCUS Retrofit	6,500	85%	$69.85	0%	$ 0.99	$ 14.23	$ 6.10	0.00%	$ -	$ (12.28)	$77.90	$ (25.79)	$52.11
Johnston 4 PC CCUS Retrofit	6,500	85%	$52.26	0%	$ 0.99	$ 14.23	$ 5.69	0.00%	$ -	$ (12.28)	$59.91	$ (25.79)	$34.12
Wyodak PC CCUS Retrofit	6,500	85%	$53.72	0%	$ 1.14	$ 16.38	$ 7.31	0.00%	$ -	$ (12.28)	$65.14	$ (25.79)	$39.35
Bridger 1 PC CCUS Retrofit	6,500	85%	$53.24	0%	$ 2.12	$ 30.47	$ 7.31	0.00%	$ -	$ (12.28)	$78.74	$ (25.79)	$52.95
Bridger 3 PC CCUS Retrofit	6,500	85%	$52.68	0%	$ 2.12	$ 30.47	$ 5.69	0.00%	$ -	$ (12.28)	$76.56	$ (25.79)	$50.77
Bridger 4 PC CCUS Retrofit	6,500	85%	$52.72	0%	$ 2.12	$ 30.47	$ 5.69	0.00%	$ -	$ (12.28)	$76.60	$ (25.79)	$50.81

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 7.3 shows the total resource cost results for this analysis.

Table 7.3 - 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 7.4 - 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 ($/kW-year)	Includes labor costs, combustion turbine fixed maintenance fees, contracted services fees, office equipment and training.
Demolition Cost ($/kW)	Total cost to decommission and demolish the generating unit at the end of life in dollars per kilowatt ($/kW).
Full Load Heat Rate HHV (Btu/kWh)	Net efficiency of the resource to generate electricity for a given heat input in a "new and clean" condition on a higher heating value basis.
EFOR (%)	Estimated Equivalent Forced Outage Rate, which includes forced outages and derates for a given resource at the given site.
POR (%)	Estimated Planned Outage Rate for a given resource at the given site.
Water Consumed (gal/MWh)	Average amount of water consumed by a resource for make-up, cooling water make-up, inlet conditioning and pollution control.
SO_2 (lbs/MMBtu)	Expected permitted level of sulfur dioxide (SO_2) emissions in pounds of sulfur dioxide per million Btu of heat input.
NOx (lbs/MMBtu)	Expected permitted level of nitrogen oxides (NO_x) (expressed as NO_2) in pounds of NOx per million Btu of heat input.
Hg (lbs/TBtu)	Expected permitted level of mercury emissions in pounds per trillion Btu of heat input.
CO_2 (lbs/MMBtu)	Pounds of carbon dioxide (CO_2) emitted per million Btu of heat input.

Table 7.5 - 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
CCUS	Carbon Capture Utilization 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 7.1.

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.

Brownfield SCCT Frame "F" x1 - a resource located at an existing generating facility 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 "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 "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 7.1: CCCT Dry "G/H", DF, 2x1; CCCT Dry "J/HA.02", DF, 1x1; CCCT Dry "J/HA.02", DF, 2x1.

Natural Gas, CCCT Dry "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.

Brownfield CCCT Dry "H", DF, 2X1 - a resource located at an existing generating facility based on a combined cycle resource using two frame-type General Electric 7HA.01 combustion turbines, two 3-pressure heat recovery steam generators with duct firing 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", 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", 2x1 - a combined cycle resource based on two frame-type General Electric 7HA.02 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 CCUS – 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 CCUS to reduce carbon dioxide emissions by 90 percent.

Coal, PC CCUS pre-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 CCUS – an advanced IGCC resource to facilitate lower CCUS 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 SCR 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, 4.0 MW turbine 37 percent Net Capacity Factor (NCF) WA/OR/ID – a wind resource based on 4.0 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, 4.0 MW turbine 29 percent NCF UT – a wind resource based on 4.0 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, 4.0 MW turbine 43 percent NCF WY – a wind resource based on 4.0 MW wind turbines located in Wyoming with an estimated annual net capacity factor of 43 percent.

Wind + Energy Storage – a wind resource as described above paired with a 4-hour battery with 50% of the power capacity of the wind resource. The batteries paired with wind resources in the previous IRP had 25% of the power of the wind resources.

Solar, PV Single Axis Tracking in ID, OR, UT, WA, and WY with NCF between 24.2 and 30.2 percent depending upon location (1.30 MWdc/MWac) – a large utility scale (100 MW or 200 MW) solar photovoltaic resource using crystalline silica solar panels in a single axis tracking system located in Idaho Falls, Idaho; Lakeview, Oregon; Milford, Utah; Rock Springs, WY; and Yakima, Washington.

Solar + Energy Storage – a solar resource as described above paired with a 4-hour battery with 50% of the power capacity of the solar resource. The batteries paired with solar resources in the previous IRP had 25% of the power of the solar resources.

Storage, Pumped Hydro Storage – a range (300 - 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 8 to 12 hours. Total development time is estimated at 6 –to 8 years due to various progress on permitting. The recharge ratio for this resource is 78 to 81 percent. Actual pumped hydro storage projects within PacifiCorp's territory were analyzed.

Storage, Lithium Ion Battery – a battery technology of lithium ion batteries located on PacifiCorp owned property. 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 85 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 70 percent.

Storage, CAES – compressed air energy storage (CAES) system consists of air storage reservoir pressurized by a compressor similar to a conventional gas turbine compression section but driven by an electric motor coupled with an adiabatic power generation turbine. The compressed air powers the adiabatic turbine. Off-peak energy is used to compress air into the storage reservoir. A system size of 500 MW is assumed. The air storage reservoir is assumed to be solution mined to size. No natural gas is required to generate power. The recharge ratio for this storage resource is 55 percent . The CAES resource modeled in the 2019 and prior IRP's was a diabatic system which differed from this resource in that it required burning fuel in the power generation turbine similar to a gas turbine engine.

Nuclear, Advanced Fission – removed from the list of resource options due to lack of progress by the developers.

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 884 MW concept is included. It is recognized that this concept is still in the design and licensing stage and is not commercially available requiring approximately 7 years for availability.

Resource Types

Renewables

PacifiCorp retained Burns & McDonnell Engineering Company (BMcD) to evaluate various renewable energy resources in support of the development of the 2021 IRP and associated resource acquisition portfolios and/or products. The 2020 Renewable Resources Assessment and Summary Tables (Assessment) (See Volume II, Appendix M) is screening-level in nature and includes a comparison of technical capabilities, capital costs, and O&M costs that are representative of renewable energy and storage technologies listed below. The Assessment contains preliminary information in support of the long-term power supply planning process. Any technologies of interest to PacifiCorp shall be followed by additional detailed studies during procurement proposal evaluation to further investigate each technology and its direct application within the owner's long-term plans.

- 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 PacifiCorp:

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

Solar

The BMcD Assessment includes 100 MW, and 200 MW single axis tracking (SAT), PV options evaluated at five locations within the PacifiCorp services area. The 2021 IRP differs from the previous IRP in the following ways:

- Idaho, Washington and Wyoming solar resource costs were extrapolated from the previous IRP to scale similarly to the Oregon and Utah solar resource cost changes.

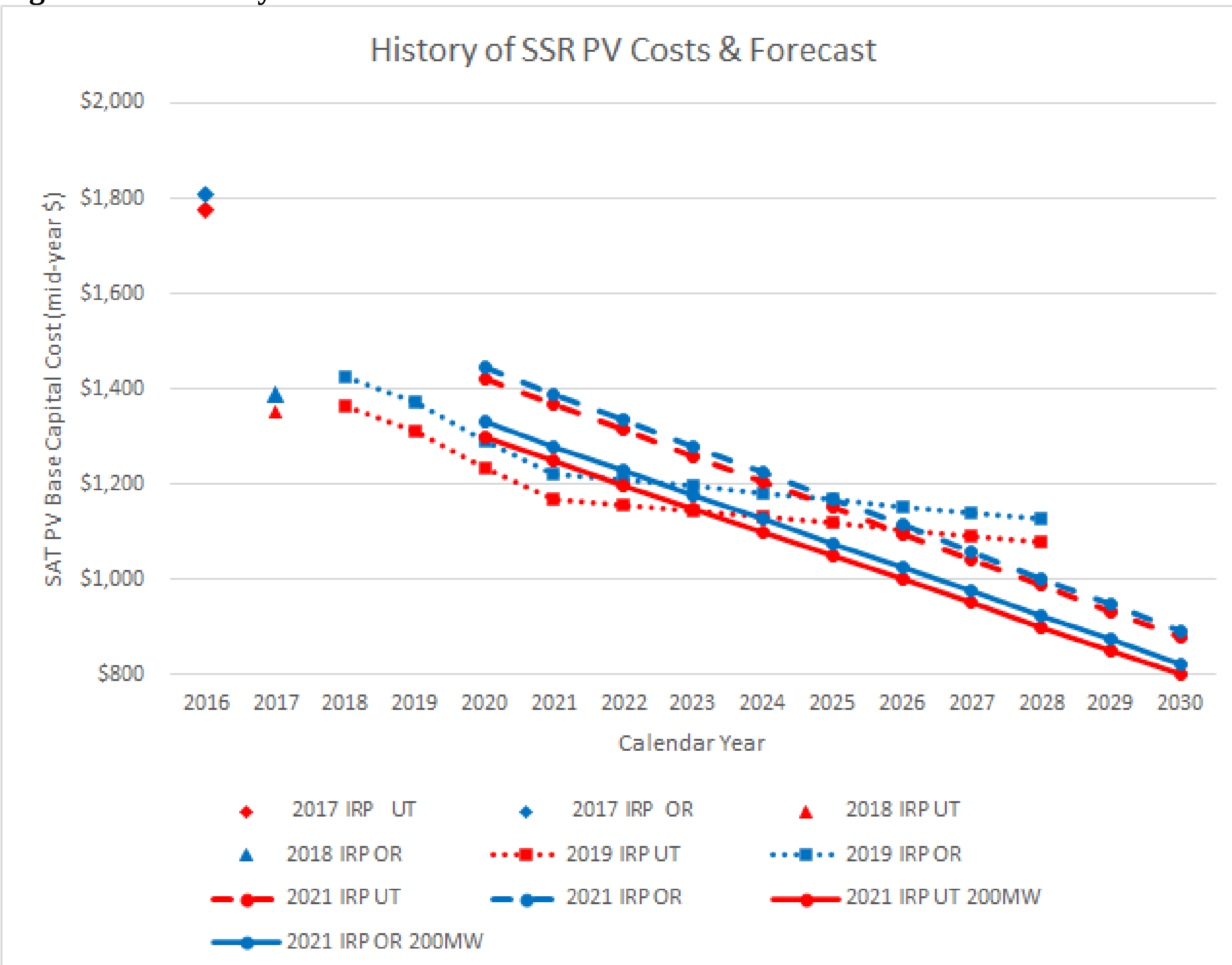
- The 5 MW option was removed and the 50 MW option for each of the five locations was increased to 100 MW based upon industry trends of building larger solar facilities.
- The DC to AC ratio was reduced from 1.46 to 1.30 based upon industry trends.

Solar costs (including forecasted costs) used for the 2021 IRP closely match the forecasted costs from the 2019 IRP through 2024 at which point the new linear forecast indicates costs may continue to decrease more rapidly than forecasted in the 2019 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 7.3 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 PV costs were provided via NREL data on an annual basis. The dotted lines show the forecast from the 2019 IRP. The NREL forecast has changed to a linear decline over the next ten years. The data from prior IRP's was based on a 50 MW scale; however, the 50 MW scale is no longer included as a resource option. The dashed lines show the costs for 100 MW, while the solid line indicates the price forecast at the 200 MW scale. It appears that the economy of scale has shifted to the larger (200 MW) scale plants.

Figure 7.3 – History of SSR PV Cost & Forecast



Wind

Wind energy has been one of the most cost-effective new generation resources for PacifiCorp's customers in recent IRPs and led to PacifiCorp's Energy Vision 2020 initiative. Energy Vision 2020 included the repowering of existing wind facilities, 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 added 1,150 MW of new wind power to PacifiCorp's generation resources. The wind market knowledge gained by PacifiCorp during the construction of the Energy Vision 2020 wind projects has been combined with the information in the BMcD Assessment to inform the wind costs in the 2021 IRP. Changes in the federal production tax credits (PTCs) for wind projects will also impact the market conditions for wind project in the coming years.

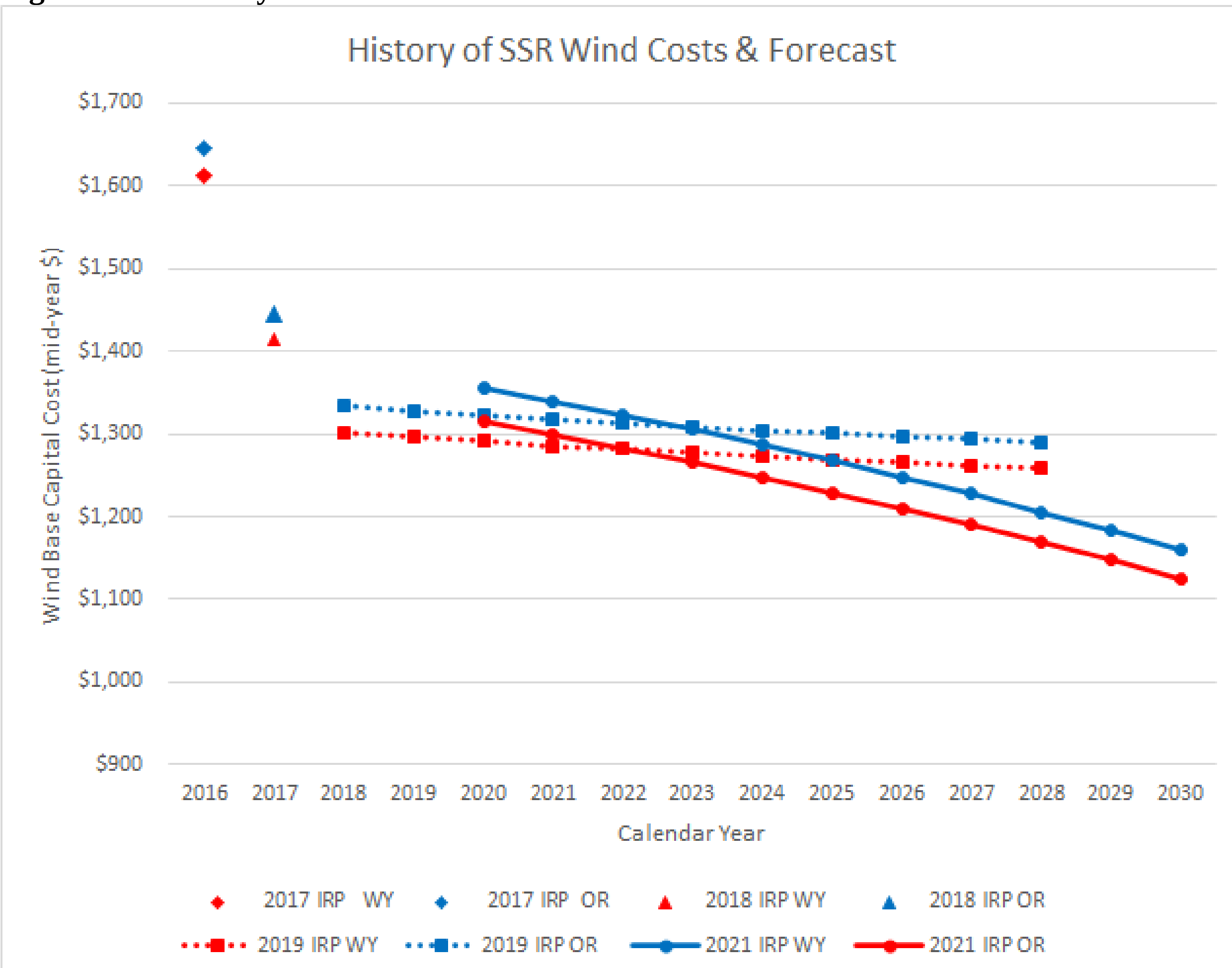
The BMcD Assessment uses a 200 MW project size that can be realized within most wind development areas in PacifiCorp's service territory and large enough to achieve economies of scale. Multiple 200 MW projects can be selected within the IRP models to meet larger generation needs. The net capacity factors for onshore wind generating facilities in the states of Idaho, Oregon, Utah, Washington, and Wyoming reflect strong wind resources that are achievable within or near PacifiCorp's service areas. 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. Although the size of wind turbines in the SSR has increased from 3.6 MW to 4.0 MW the cost for utility scale wind farms in the 2021 IRP is very similar to the costs in the 2019 IRP.

Federal PTCs were extended in December 2020 to allow wind projects that begin construction in 2021 and complete construction before December 31, 2024 to qualify for a 60% of the full tax credit amount. Wind projects that started construction in 2016 and 2017 were granted an extra year to complete construction and qualify for production tax credits due to Covid 19. The 2016 and 2017 projects must now be completed by 2021 and 2022 respectively. Wind construction activity is expected to remain strong through 2024 due to the PTC extensions. Burns & McDonnell estimates the cost of wind projects will decrease by approximately 15 percent over the next ten years as shown in Figure 7.4, while other estimates indicate the levelized cost of energy for wind production could decline as much as 20 percent over the next ten years. The progressive national goals for renewable energy being put in place by the Biden administration could help sustain growth in the wind industry over the next decade and beyond.

Offshore Wind

Offshore wind holds the promise of high production capacity but faces various risks and costs that are higher than onshore wind projects. The most promising offshore wind regimes are located approximately 10 to 20 miles from the coast and will require underwater electric transmission lines to connect to the shore. New offshore wind projects will have to bear the cost of underwater transmission lines and any land-based transmission upgrades that are required to interconnect the project to the grid. Offshore wind turbines along the Pacific coast will need to be built on floating bases due to water depths that are hundreds of meters deep, as compared to offshore wind developments in shallower waters along the Atlantic coast. Floating offshore wind turbines are much less common than seabed-mounted offshore wind turbines that can be built in ocean waters up to 60 meters deep. Interest in offshore wind along the Pacific coast has increased during the past year and the advancement of two areas for offshore wind development along the coast of California by the US Department of the Interior was a significant step forward in the development process. PacifiCorp is reviewing offshore wind studies and reports and may include offshore wind as a resource in the SSR for the 2023 IRP.

Figure 7.4 – History of SSR Wind Costs & Forecast



<u>Solar and Wind Capital Costs</u>

Capital cost estimates for wind resources in the IRP are based upon a combination of information sources including the Burns & McDonnell study, communications with wind equipment suppliers and construction companies, and from PacifiCorp's experience with active and recently completed 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.

<u>Solar and Wind Resource Capacity Factors and Energy Shapes</u>

Resource options in the topology bubbles are assigned capacity factors based upon historic or expected project performance. Assigned capacity values for solar resources are 24% in Washington, 26% in Idaho, 27% in Oregon and Wyoming, and 30% in Utah. 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 used in IRP modeling The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

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, publicly available capital costs from the Geothermal Resources Council and publicly available prices for energy supplied under power purchase agreements.

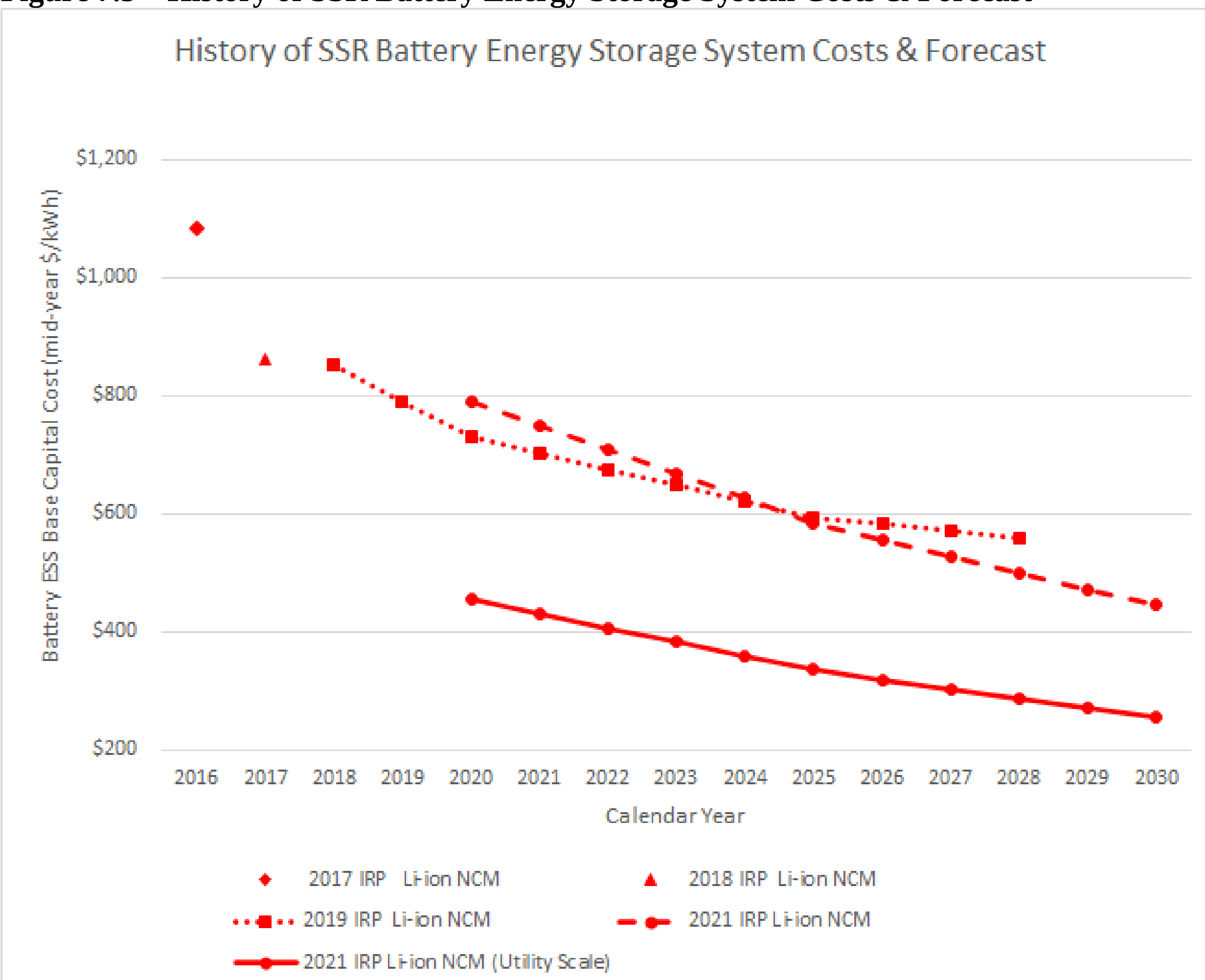
The cost recovery mechanisms currently available to PacifiCorp as a regulated electric utility are not compatible with the inherent risks associated with the development of geothermal resources for power generation. The primary risks of geothermal development are dry holes, well integrity and insufficient 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 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 Burns and McDonnell 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, despite the change technology change from an adiabatic system to a diabatic system. 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. **Error! Reference source not found.** shows a history of capital costs and a forecast used in the SSR for Li-Ion and flow battery resources. The dotted lines show the forecast from the 2019 IRP. The data from prior IRP's was based on a 1 MW scale; however, the 1 MW scale is no longer included as a resource option. The dashed lines show the 2020 costs for 100 MW scale, while the solid line indicates the price forecast at the 50 MW scale, indicating a significant economy-of-scale benefit. 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.

Figure 7.5 – History of SSR Battery Energy Storage System Costs & Forecast



PacifiCorp and its Berkshire Hathaway Energy affiliates continuously monitor and evaluate technical developments in the utility power industry, including energy storage technologies (lithium-ion and flow batteries, pumped storage hydro and hybrid energy-storage solutions), nuclear and carbon capture technologies. With the ever-advancing technological developments, market conditions, and regulatory environment, it is critical that PacifiCorp understand when developing technologies and other opportunities become sufficiently established in the marketplace that they can be implemented with minimal risk to PacifiCorp's system customers.

Fortune Business Insights estimates the global battery energy storage market size stood at $7.06 billion in 2019 and is anticipated to reach $19.74 billion by 2027, at a CAGR of 20.4%. The growth and technological advancements in lithium-ion batteries for the electric vehicle markets have resulted in technological advancements and cost reductions that also stand to benefit the electric utility market. PacifiCorp has monitored the use of lithium-ion battery storage in the electric utility market and believes based on its analysis and experience that the technology is mature enough for large scale deployment.

PacifiCorp has experience in all aspects of battery storage project development and execution including, budgeting, proforma, tax credits, siting, permitting, interconnection, engineering, equipment procurement, construction, project controls, quality assurance, commissioning, operation, and maintenance. PacifiCorp has utilized this expertise in 1) the development of proxy resources for the integrated resource plans since 2009, 2) the development of the use cases and specifications outlined in the 2020 all source request for proposal and 3) in the execution and construction of two battery storage demonstration projects and a third of which is in design development.

PacifiCorp has included consideration of battery storage in its IRP as a system resource since 2009. Since then, PacifiCorp actively monitored developments in battery storage and its cost, use, and application to our system resource planning. By 2015 battery storage became a more viable resource alternative, and PacifiCorp assigned an internal subject matter expert to track, review and evaluate ongoing and emerging developments in the battery storage market and the value that energy storage could provide to our customers.

PacifiCorp also leverages the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy to collaborate and share experiences and lessons learned regarding battery energy storage technology and capturing the value of energy storage. NV Energy has been a leader in battery storage implementation having signed contracts for more than 1 gigawatt of solar and 100 MW of storage in 2018 and an additional 1.2 gigawatts of solar and 590 MW of batteries contracted in 2019, and having further implemented residential, small and large commercial and industrial energy storage customer programs,[1] and having installed several transmission and distribution pilot projects.

In addition to leveraging the experience of its peer utilities, PacifiCorp has engaged the expertise of market-leading 3rd party technical experts including WSP, Black & Veatch, Power Engineers, FlexGen, Tesla and other leading battery consultants and suppliers to develop its proxy resource assumptions, develop its procurement specifications, evaluate bidders and design and construct utility-owned transmission and distribution facilities.

In 2019, PacifiCorp's IRP process identified approximately 700 megawatts of battery storage as a part of its least-cost portfolio and 2019 IRP action plan and worked to incorporate battery storage resources into the resulting 2020 all-source request for proposal. Leading up to the inclusion of battery storage in the 2020 all-source request for proposal, PacifiCorp developed a preferred supplier list, standard specifications, and system control schemes for battery storage facilities. In

[1] https://www.nvenergy.com/cleanenergy/energy-storage/storage-faqs

the request for proposal, PacifiCorp outlined battery storage use cases and required functionality to ensure battery storage proposals value was captured through battery energy storage bids. Finally, PacifiCorp engaged outside legal expertise in the structuring of contracting terms and conditions to mitigate any remaining delivery risk to its customers. Such outside legal expertise brings in battery storage contracting knowledge and experience from both within and outside the Berkshire Hathaway Energy.

PacifiCorp procurement and operational experience with battery storage projects

PacifiCorp completed the Panguitch Solar and Battery Storage project in Utah in 2020 as a utility-owned and operated transmission and distribution upgrade deferral project. In 2019-2020, PacifiCorp partnered with Sonnen, Inc. and the Wasatch Group to complete The Soleil Lofts Residential Apartment Project, a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. PacifiCorp is currently completing the development and design for a second transmission and distribution upgrade deferral project in Oregon to install a battery storage project at the Oregon Institute of Technology in Klamath Falls, which is scheduled for completion in 2022. These three projects demonstrate the capability and validate the value battery storage provides to the electrical grid through peak shifting in order to defer the cost to upgrade regional transmission and distribution lines. PacifiCorp had complete turnkey responsibility for the Panguitch Solar and Battery Storage facility and will similarly be responsible for the Oregon Institute of Technology facility. The Soleil Lofts facilities were developed, constructed and owned by a 3rd party, but are being dispatched by PacifiCorp's Energy Supply Management Group for the benefit of PacifiCorp's system.

Panguitch Solar and Battery Storage Project

To correct voltage issues experienced during peak loading conditions on a portion of PacifiCorp's system in southern Utah, a stationary battery system and photovoltaic solar array was installed on a distribution circuit out of the Panguitch substation located in Garfield County, Utah. This project will alleviate peak loading on the power transformer, improve voltage conditions, and defer costs associated with upgrading the upstream 69-kV sub-transmission system under a traditional poles and wires build-out. The Panguitch project was a 650-kilowatt photovoltaic solar field and one megawatt, five-hour battery system in central Utah. PacifiCorp with Black & Veatch and battery supplier FlexGen developed multiple operating modes to demonstrate the full range and capabilities of 684 Samsung lithium-ion batteries and how different control modes affect energy system operation.

The Utah Public Service Commission approved the Panguitch battery storage project (1 MW, 5 MWh) under the Sustainable Transportation and Energy Plan/Utah Innovative Technologies (STEP/UIT) program December 29, 2016. The solar photovoltaic component (650 kW) of the project was separately funded by the company's Blue Sky program. PacifiCorp completed the purchase of a ten-acre project site in October 2017. Construction began in July 2019 and was completed in late 2019. Commercial operations began in 2020.

Since commercial operations began, the company has worked with the battery provider to refine the control algorithms to enable charging of the battery only from the on-site solar generation facility. The company is currently collecting solar and battery charge/discharge data from the site to further optimize operational performance.

Soleil Lofts Residential Apartment Project

Soleil Lofts, located in Herriman, Utah is an all-electric, net-zero development, that will generate as much electricity as it uses through rooftop solar panels backed up with battery storage. PacifiCorp collaborated with the Soleil Lofts residential apartment project to develop a behind the meter application of battery systems. This project is the largest utility-managed residential battery demand response solution in the United States. PacifiCorp with Sonnen, Inc. and the Wasatch Group completed a network of solar powered battery storage systems for the benefit of the apartment community and PacifiCorp's customers. The project features over 630 individuals Sonnen ecoLinx batteries, totaling 12.6 MWh of solar energy storage that is managed by PacifiCorp. The batteries provide emergency back-up power, daily management of peak energy use, and demand response for the overall management of the electric grid and demonstrating a way to expand residential renewable power capacity.

Oregon Institute of Technology

Oregon House Bill (HB) 2193, passed in June of 2015 directed electric companies in Oregon to identify and evaluate potential energy storage technologies. PacifiCorp has commenced a project to engineer, design, procure, interconnect, and commission a 2 MW (6 MWh) battery storage project on the campus of the Oregon Institute of Technology ("OIT") in Klamath Falls, Oregon. Design and procurement activities are underway in parallel with the generation interconnection review process. The project is expected to go into service in early 2023. PacifiCorp has contracted Kiewit Engineering as the Owner's engineer, Power Engineers as the Engineer of Record, and is working with supply vendors to secure a final purchase agreement. Once the design is complete a construction contractor will be selected via competitive bid. PacifiCorp's engineering and management team are also working with OIT to provide a student learning experience by partnering with OIT student groups who will be working with the project team during the design and construction of the project.

Outside Engineering Support for Battery Storage Procurement and Operations

In preparation for the 2020 all-source request for proposal which resulted from the resource need action items in the 2019 IRP process, PacifiCorp engaged WSP to 1) develop preferred use case and technical specifications for collocated and stand-alone storage resource bids, 2) evaluate the technical bid responses, and 3) update the generating-resource power purchase agreements to include battery storage terms and conditions and relevant exhibits needed for a collocated resource and storage power purchase agreement.

WSP is a globally recognized professional services firm with a 130-year history. WSP's primary inputs have been in a supporting role, assisting in the development of revised specification specific to wind and solar farm equipment and installations including accompanying battery storage facilities. Specific to battery storage, WSP has been influential in assisting PacifiCorp in the development of Li-battery specifications and has participated in the development of operating and contractual parameters that will become part of our revised power purchase agreement contract template in the 2020AS RFP contracting process.

A summary of WSP team members, their role and years of experience is provided in Table 7.6.

Table 7.6 – WSP Team Roles and Years of Experience

Role	# Years of Experience
Principal-In-Charge	19
Project Manager	27
BESS / SCADA Expert	7
BESS Constructability and Operations	29
BESS / Electrical Engineering (US)	9
BESS / Electrical Engineering (CAN)	7
BESS Systems Engineer	6

As stated above, PacifiCorp has been actively monitoring developments in battery storage since 2009 with support through the broader Berkshire Hathaway Energy platform of companies including NV Energy and MidAmerican Energy and through the engagement of market-leading companies like WSP, Black & Veatch, Power Engineers, FlexGen, Tesla. Further, PacifiCorp is actively evaluating and pursuing new control systems that will both integrate and optimize battery storage, and other electronically controlled distributed assets, to further assure both maximum customer benefit and improved system flexibility and stability for years to come. With each new battery storage resource added to on our system, we gain additional depth and experience that we then apply to the next cycle of integrated resource planning and subsequent resource procurement.

Natural Gas

A variety of natural gas-fueled generating resources are included in the SSR. The variety of natural gas resources were selected to provide for generating performance and services essential to safe and reliable operation of the energy grid. Performance, cost and operating characteristics for each resource were provided at elevations of 1,500, 3,000, 5,050 and 6,500 feet above mean sea level, representative of geographic areas in which the resource could be located. Performance, cost and operating characteristics were also provided at zero feet above mean sea level and 59 °F (ISO conditions) as a reference. The essential services provided by the resource are firming for variable energy resources, intermediate and base generation.

Three simple cycle combustion turbine options and one reciprocating engine option could provide peaking generating services. Peaking generating services require the ability to start and reach near full output in less than ten minutes. Peaking generating services also require the ability in increase (ramp up) and decrease (ramp down) very quickly in response to sudden changes in power demand as well as increases and decreases in production from intermittent power sources. Peaking generation provide the ability to meet peak power demand that exceed the capacity of intermediate and base generation. Peak generation also provide reserves to meet system upsets.

Options for firming and 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 9,936 Btu/kW-hr for the SCCT Frame “F” to 8,286 Btu/kW-hr for the 18V50SG engines. Installation of high temperature oxidation catalysts for carbon monoxide (CO) control and a selective catalytic reduction (SCR) system for NOx control would be available for these resources.

Eight combined cycle combustion turbine options could provide firming, intermediate and base generating service. Firming generating service requires resources that can increase and decrease generation to replace decreases and increases in generation from variable energy resources. Intermediate generating service requires resources that 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 “H” size was represented by a GE HA.01. The “J” 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 6,352 to 6,487 Btu/kW-hr. Installation of oxidation catalysts for CO control and SCR systems for 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 SSR 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 SSR 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 SSR table, more than one manufacturer produces these types of equipment. The costs and performance used here is representative of the cost and performance that would be expected from any of the manufacturers. Final selection of a manufacturer’s equipment would be made based on a bid process.

Coal

Coal resources are shown in the SSR table as new supercritical pulverized coal (PC) boilers and IGCC located in Utah and Wyoming at an existing site. Both resource types include CO_2 capture and compression needed for transportation. The standard design technology for PC boilers is supercritical technology (compared to subcritical). Supercritical technology is generally more cost-effective because it has a higher efficiency (resulting in a lower overall emissions intensity), has better load following capability, faster ramp rates, uses less water and requires less steel for construction. As such, there is a greater competitive marketplace for large supercritical boilers than for subcritical boilers, and large boiler manufacturers only offer supercritical boilers in the 500-plus MW sizes. A new coal-fueled generating facility would be subject to carbon dioxide emissions limits (1,400 lbs per megawatt-hour gross) under the Federal New Source Performance Standards

(NSPS) for Greenhouse Gases (GHG). These emission limits are only achievable if a coal-fueled generating facility is equipped with CCUS technology; however, this imposes a significant cost for both new and existing coal resources. Based on this requirement, only coal resource options that include CCUS technology are included in the SSR table. The capital and O&M costs for new coal-fuel generation options were updated by escalating corresponding costs used in the 2019 IRP. The CCUS retrofit costs were updated using information from existing carbon capture facilities, relevant studies and CCUS developers.

Carbon Capture Utilization and Sequestration

There are a limited number of commercial-scale carbon capture projects in operation around the world. Most have been installed in conjunction with a planned carbon dioxide end use of injection for EOR. There are only two major utility-scale CCUS retrofit projects on coal plants in North America that have been operated commercially. SaskPower's Boundary Dam Power Station Unit 3 (115 MW net), located in Saskatchewan, Canada, was retrofitted with an amine-based carbon capture system and entered commercial operation in October 2014. The captured carbon dioxide is piped 41 miles to the Weyburn field to be used for EOR. Any carbon dioxide not used for EOR is sequestered at the Aquistore research project. The total cost of the project was approximately $1.24 billion (including approximately $200 million through federal grants). In July 2016, the plant reached a major milestone when it demonstrated that over 1,100,000 tons of carbon dioxide had been captured.

NRG Energy installed a 240 MW equivalent flue gas slipstream amine-based carbon capture system on W.A. Parish Generating Station Unit 8 that went into commercial operation in January 2017. The project, named the Petra Nova Project, was a joint venture between NRG Energy and JX Nippon Oil & Gas Exploration, and cost approximately $1 billion. Approximately $195 million of federal funding in grants was awarded to the project as part of the Clean Coal Power Initiative Program (CCPI), a cost-shared collaboration between the federal government and private industry. The Petra Nova Project included a retrofit of an existing coal-fueled plant using amine-based system and captured approximately 5,200 short tons per day when operating at full capacity.[4] Captured carbon dioxide was transported through an 81-mile pipeline and used for EOR at the West Ranch Oilfield, located on the Gulf Coast of Texas. It is the largest carbon capture retrofit of a pulverized coal plant in the world. The amine-based capture system utilizes Mitsubishi's proprietary KM CDR Process® and uses its KS-1™ amine solvent. Due to low demand for and price of oil in 2020, NRG Energy announced Petra Nova would be placed in a reserve shutdown effective May 1, 2020.[5] In January 2021, the Electric Reliability Council of Texas received a Notification of Suspension of Operations (NSO) for Petra Nova Power.[6] The NSO stated the resource would be mothballed indefinitely as of June 26, 2021.[7]

To address the availability and viability of commercial sequestration near PacifiCorp coal generation resources, three PacifiCorp power plants participated in federally funded research to conduct a Phase I pre-feasibility study, which was awarded in 2016, for carbon capture and storage.

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[4] W.A. Parish Post-Combustion CO_2 Capture and Sequestration Demonstration Project Final Scientific/Technical Report; March 31, 2020.

[5] Petra Nova status update | NRG Energy

[6] W-A012721-01 Notification of Suspension of Operations (NSO) for Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

[7] A March 2021 notice was issued, moving up the date to suspend operations to June 1, 2021. W-A012721-03 Date of suspension of operations changed - Indefinite Mothball Status of Petra Nova Power I LLC (PNPI_GT2) (ercot.com)

A grant from the U.S. Department of Energy (DOE) to the University of Wyoming was used to assess the storage of carbon dioxide in the Rock Springs Uplift, a geologic formation located adjacent to the Jim Bridger Plant in southwest Wyoming. Similar funding was allocated to the University of Utah to study the feasibility of long-term carbon dioxide storage in the San Rafael Swell near the Hunter and Huntington plants in central Utah. Both projects showed that geological formations exist near the plants that may support carbon sequestration, though further studies would be required. Neither site was selected by the U.S. DOE for an advanced study in the Phase II of the grant program.

PacifiCorp issued a request for expression of interest to potential CCUS counterparties on September 7, 2018. The request focused on possible deployment of CCUS technologies at PacifiCorp's Dave Johnston generating facility, including utilization of EOR. On February 28, 2019, PacifiCorp received Phase I feasibility studies from three respondent parties. On April 23, 2019, the participants were notified they could opt to progress to a Phase II front-end engineering and design (FEED) study at their discretion. Only one of the parties expressed intent to complete a FEED study. No participants received DOE funds to support Phase II studies. PacifiCorp remains open to evaluate any CCUS project proposal that may arise from these efforts. As part of its ongoing CCUS evaluation, PacifiCorp issued a new request for expression of interest (REOI) for CCUS on June 29, 2021 to identify and engage with any interested parties to explore the feasibility and design of CCUS facilities to remove carbon dioxide from exhaust gases for PacifiCorp's Wyoming coal-fueled generation, and subsequently utilize and/or sequester all removed carbon dioxide. Responses to the REOI will be a precursor to a PacifiCorp issuing a request for proposal (RFP) for CCUS projects.

PacifiCorp continues to monitor and evaluate current and emerging CCUS 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 carbon dioxide at an existing coal-fired unit has been included in the SSR. Due to the high capital cost of implementing CCUS on coal-fueled generation (both on a retrofit basis and for new resources) and applicable tax credits, CCUS was not considered viable in previous IRPs. Capital cost, transportation infrastructure, availability of commercial sequestration (non-EOR) sites, long-term liabilities for sequestration, and the lack of availability of federal funding continue to contribute to the risk and uncertainty of CCUS.

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 the NuScale Small Modular Reactor (SMR), but used nth-of-a-kind pricing rather than the 1st-of-a-kind pricing previously used for the plant being developed for construction at the Idaho National Lab site. 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. Blue Castle Holdings (BCH) again did not provide updated pricing, therefore the advanced reactor option based on the AP1000 design was eliminated from the resource options.

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 lack of maturity for the technology. 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 NuScale resource.

PacifiCorp's 2021 IRP includes the Natrium™ advanced nuclear demonstration project: a molten sodium-cooled nuclear reactor paired with a molten salt thermal energy storage tank. Both the reactor and the molten salt energy storage generate power through a single steam turbine.

At this time, the specific cost and performance assumptions for the Natrium™ advanced nuclear demonstration project are confidential and are not summarized in the SSR. The demonstration project has three primary elements: a nuclear reactor that produces heat, a steam generator to convert heat to electricity, and a molten salt tank to store heat. Operating characteristics of this facility are summarized as follows:

- 345 MW of baseload energy production at a 92.5% capacity factor
- Maximum output of 500 MW
- Minimum output of 100 MW
- A ramp rate of approximately 40 MW per minute from min to max
- Molten salt storage supports maximum output of 500 MW for a 5.5-hour duration (max output then drops to 345 MW until output is reduced and more heat can be stored)
- Maximum storage efficiency is 99%

Demand-Side Resources

Resource Options and Attributes

Source of Demand-Side Management Resource Data

PacifiCorp conducted a Conservation Potential Assessment (CPA) with for 2021-2040, which provided DSM resource opportunity estimates for the 2021 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.[8] 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 2021 IRP planning and modeling, PacifiCorp had established, funded and begun acquiring 2021 DSM program acquisition targets. To ensure that the 2021 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 2021. Beyond 2021, 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.

<u>Demand Response: DSM Capacity Supply Curves</u>

The potential and costs for demand response resources were provided at the state level, with impacts specified separately for summer and winter peak periods. To acquire resource needs identified in the 2019 IRP, the company issued the All Source (AS) 2020 RFP for large scale resources and subsequently issued a demand response (DR) RFP for DR resources. Successful initial short list bids from this DR RFP joined final bids from the AS 2020 RFP for a combined analysis in the 2021 IRP to determine the optimal acquisition of resources to meet system needs.

[8] The 2021 Conservation Potential Study is available on PacifiCorp's demand-side management web page. www.pacificorp.com/energy/integrated-resource-plan/support.html.

In 2022, where competitive bids overlapped with measures in the conservation potential assessment (CPA), competitive bids were substituted for demand response measures identified in the CPA to avoid double counting of demand response resources in the IRP and reflect resource characteristics and current pricing. In 2023 and beyond RFP and CPA resources were modeled together to assess the upper limit on demand response opportunities and value within the IRP given limitations on front office transactions. 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.

Table 7.7 and Table 7.8 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 2021 CPA.[9] Potential shown is incremental to the existing DSM resources identified in Table 7.7 For existing program offerings, it is assumed that the PacifiCorp could begin acquiring incremental potential in 2021. For resources representing new product offerings, it is assumed PacifiCorp could begin acquiring potential in 2022, accounting for the time required for program design, regulatory approval, vendor selection, etc.

Table 7.7 – Demand Response Program Attributes West Control Area[10],*

Product	Summer		Winter	
	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)	20-Year Potential (MW)	Average Levelized Cost ($/kW-yr)
Res - EV DLC	14	$144	15	$145
Res - Home Energy Management System	14	$84	5	$166
Res – HVAC DLC	11	$181	58	$61
Res – Pool Pump DLC	0.3	$521	0.3	$524
Res – Water Heater DLC	1	$62	2	$29
Res – Smart Thermostat	63	$31	23	$65
Res – Grid Interactive Water Heaters	18	$141	60	$61
Res –Battery DLC	50	$69	50	$69
C&I –Battery DLC	47	$48	47	$48
C&I – Grid Interactive Water Heaters	4	$93	8	$51
C&I – HVAC DLC	4	$141	8	$51
C&I – Pool Pump DLC	4	$330	2	$364
C&I – Smart Thermostats	0	$20	0	$301
C&I – Water Heater DLC	8	$48	5	$43
C&I – Third Party	62	$273	56	$335
Ag – Irrigation DLC	8	$51	0	$0

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

[9] The CPA can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.
[10] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.

Table 7.8 – Demand Response Program Attributes East Control Area[11]

Product	Summer 20-Year Potential (MW)	Summer Levelized Cost ($/kW-yr)	Winter 20-Year Potential (MW)	Winter Levelized Cost ($/kW-yr)
Res - EV DLC	210	$62	210	$62
Res - Home Energy Management System	1	$971	1	$1,020
Res – HVAC DLC	42	$94	63	$192
Res – Pool Pump DLC	0.3	$585	0.3	$585
Res – Water Heater DLC	2	$142	6	$63
Res – Grid Interactive Water Heaters	16	$288	54	$124
Res –Battery DLC	210	$62	210	$62
C&I –Battery DLC	92	$61	92	$61
C&I – Grid Interactive Water Heaters	7	$201	12	$140
C&I – HVAC DLC	4	$313	9	$355
C&I – Pool Pump DLC	0	$247	0	$225
C&I – Smart Thermostats	9	$50	5	$177
C&I – Water Heater DLC	1	$92	1	$65
C&I – Third Party	146	$217	117	$304
Ag – Irrigation DLC	13	$65	0	$0

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

Energy Efficiency DSM, Energy Supply Curves

The 2021 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[12]
- **Measure:**
  - 98 residential measures
  - 138 commercial measures
  - 96 industrial measures
  - 25 irrigation measures

[11] Demand response resources derived from the demand response RFP are not included to protect confidential 3rd party pricing information.
[12] Oregon's DSM potential was assessed in a separate study commissioned by the Energy Trust of Oregon.

- **Facility type:**[13]
  - Six residential facility types
  - 28 commercial facility types
  - 34 industrial facility types
  - Two irrigation facility type

The 2021 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 15.1 million MWh.[14] 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 10.8 million MWh for all five states. The technical achievable potential for all six states for modeling consideration is 13.8 million MWh. The technical achievable potential, representing available potential at all costs, is provided to the IRP model for economic screening relative to supply-side alternatives.

Despite the granularity of DSM energy efficiency resource information available, it was impractical to model the resource supply curves at this level of detail. The combination of measures by building type and state generated almost 30,000 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 and net cost of capacity to reduce the number of combinations to a more manageable number.

Bundle development began with the energy efficiency technical potential identified by the 2021 CPA. To account for the practical limits associated with acquiring all available resources in any given year, the technical potential by measure was adjusted to reflect the amount that is realistically achievable over the 20-year planning horizon. Consistent with the Northwest Power and Conservation Council's achievability assumptions in the Draft 2021 Power Plan as, which typically assume that 85% of the technical potential could be acquired over the 20-year period.[15]

[13] Facility type includes such attributes as existing or new construction, single or multi-family. Facility types represent a combination of market segment and vintage and are more fully described in in the Analysis Approach in Volume 1, Chapter 2, of the2021 CPA.
[14] 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.
[15] 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.

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 2021 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 7.9 shows the 20-year MWh potential for DSM energy efficiency levelized cost bundles, designated by ranges of $/MWh.

Table 7.9 – 20-Year Total Incremental Energy Efficiency Potential by Cost Bundle (MWh)

Bundle	California	Idaho	Oregon	Utah	Washington	Wyoming
Annual Measures 1 (Best)	14,907	117,483	663,976	3,046,586	257,744	953,035
Annual Measures 2	4,243	44,907	505,973	433,935	48,147	111,397
Annual Measures 3 - Weather	1,719	24,887	52,257	119,916	30,747	17,654
Annual Measures 3 - Non-Weather	536	15,254	72,949	60,729	7,632	18,527
Annual Measures 4 - Weather	8,277	17,602	-	292,054	52,506	20,573
Annual Measures 4 - Non-Weather	1,342	3,696	54,515	69,006	10,602	11,610
Annual Measures 5 - Weather	3,011	22,106	22,753	42,323	26,355	4,037
Annual Measures 5 - Non-Weather	2,199	5,247	82,199	32,067	16,103	7,847
Annual Measures 6 - Weather	1,009	10,212	-	258,334	16,538	10,418
Annual Measures 6 - Non-Weather	141	1,251	18,600	37,860	57,595	20,163
Summer Measures 7 - Weather	2,894	16,837	121,477	150,336	26,229	8,448
Summer Measures 7 - Non-Weather	255	3,401	64,074	11,160	3,073	7,642
Summer Measures 8 - Weather	7,927	18,140	22,924	256,041	37,761	10,953
Summer Measures 8 - Non-Weather	2,519	5,038	120,418	98,283	11,727	24,612
Summer Measures 9 - Weather	10,299	11,455	6,642	267,252	31,988	8,213
Summer Measures 9 - Non-Weather	3,025	2,590	25,851	24,055	21,127	17,602
Summer Measures 10 - Weather	6,237	11,849	48,133	185,206	37,902	9,705
Summer Measures 10 - Non-Weather	796	1,013	35,465	57,507	10,818	12,551
Summer Measures 11 - Weather	7,184	9,700	12,889	237,866	26,380	12,295
Summer Measures 11 - Non-Weather	1,967	9,487	12,737	173,013	59,880	43,670
Highest Cost Measures	76,185	162,172	270,159	1,196,598	320,867	279,849
Winter Measures 6	3,170	12,130	166,645	96,308	16,389	6,885
Winter Measures 5	4,291	2,895	215,250	111,172	21,021	24,665
Winter Measures 4	15,298	2,583	195,188	35,337	7,507	7,734
Winter Measures 3	550	5,466	79,514	77,771	5,149	15,857
Winter Measures 2	105	7,864	106,755	45,286	6,320	19,939
Winter Measures 1 (Best)	-	3,215	33,265	34,164	406	5,647

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

- A state-specific transmission and distribution investment deferral cost credit (Table 7.10)
- Stochastic risk reduction credit of $3.59/MWh[16]
- Northwest Power Act 10-percent credit (Oregon and Washington resources only)[17]

Table 7.10 – State-specific Transmission and Distribution Credits

State	Transmission Deferral Value ($/KW-year)	Distribution Deferral Value ($/KW-year)	Total
California	$6.34	$11.06	$17.40
Oregon	$6.34	$13.38	$19.72
Washington	$6.34	$16.86	$23.20
Idaho	$6.34	$16.72	$23.06
Utah	$6.34	$13.20	$19.54
Wyoming	$6.34	$7.48	$13.82

The bundle is split by weather dependent and non-weather dependent measures and their net cost of capacity ($/kw-yr) cost for the group of measures in the cost bins. 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.

PacifiCorp relies on simulated load shapes tied to weather stations in PacifiCorp's service territory. Weather is a major driver of PacifiCorp's load and in any given month weather results in a range of high and low load conditions. Weather also impacts the hourly timing of energy efficiency savings particularly for measures that are weather dependent. For the 2021 IRP, PacifiCorp chose to reshape daily energy efficiency volumes to better align with seasonal variations in the load forecast. The highest demand for weather-sensitive end use loads is expected to occur at the time of the winter and summer peaks in PacifiCorp's service territory. For weather dependent measures, the highest daily simulated savings were mapped to the highest to lowest load days to align with the load forecast. To capture the time-varying impacts of energy efficiency resources, each bundle uses an annual 8,760 hourly load shape specifying the portion of the maximum capacity available in any hour of the year. These shapes are created by spreading measure-level annual energy savings over 8,760 load shapes, differentiated by state, sector, market segment, and end use accounting for the hourly variance of energy efficiency impacts by measure. These hourly impacts are then aggregated for all measures in a given bundle to create a single weighted average load shape for that bundle.

[16] 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.

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

Distribution Efficiency

PacifiCorp continues to develop its CYME CYMDIST® (power flow software) investment in ways that improve engineering response time and, indirectly, distribution system efficiency. In the last biennial period, more than 300 large (Level 2 and Level 3) distributed energy resource (DER) applications were studied in CYME. This resulted in more than 29 MW (nameplate) of approved private generation across the company. Any energy savings resulting from these approvals across the service territory has not been determined.

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

Transmission Resources

In developing resource portfolios for the 2021 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and amount of new resources as well as any assumed resource retirements, as applicable, in any given portfolio. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).

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 2021 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 7.11 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 I, Chapter 5 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 8 (Modeling and Portfolio Evaluation Approach).

Table 7.11 - 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")	350	350
Heavy Load Hour ("6X16")	150	0
California Oregon Border (COB)		
Flat Annual ("7x24") or Heavy Load Hour ("6X16")	0	250
Nevada Oregon Border (NOB)		
Heavy Load Hour ("6X16")	0	100
Mona		
Heavy Load Hour ("6X16")	0	300

CHAPTER 8 – 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.
- PacifiCorp used the Plexos Long-Term planning model (LT model) to produce unique resource portfolios across a range of different planning cases. Informed by the public-input process, PacifiCorp identified case assumptions that were used to produce optimized resource portfolios, each one unique regarding the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years.
- PacifiCorp used the Plexos Medium-Term schedule (MT model) to perform stochastic risk analysis of the portfolios. Each portfolio was evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide (CO_2) price scenarios (zero, medium, high). An additional CO_2 policy scenario was developed to evaluate performance assuming a price signal that aligns with the social cost of greenhouse gases (SC-GHG). Taken together, there are five distinct price-policy scenarios (medium gas/medium CO_2, medium gas/zero CO_2, high gas/high CO_2, low gas/zero CO_2, and the social cost of greenhouse gases).
- A primary function of the MT model is to calculate an optimized risk-adjustment, representing the relative risk of a portfolio under unfavorable stochastic conditions for that portfolio.
- Each portfolio was evaluated in the Short-Term model (ST model) to establish system costs for each portfolio over the entire 20-year planning period. The ST model accounts for resource availability and system requirements at an hourly level, producing reliability and resource value outcomes as well as a present-value revenue requirement (PVRR) which serves as the basis for selecting least-cost least-risk portfolios.
- The MT model risk-adjustment was added to the system cost determined by the ST model to calculate a final "risk-adjusted" PVRR measure of system cost.
- A selection of portfolios were analyzed using the other four price-policy scenarios in the ST and MT models to evaluate how each portfolio performs under differing market/policy conditions.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp produced additional studies that examine the potential impact of portfolio options on the system.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from the ST and MT models, comparing resource portfolios based on expected costs, low-probability high-cost outcomes, reliability, CO_2 emissions and other criteria.

Introduction

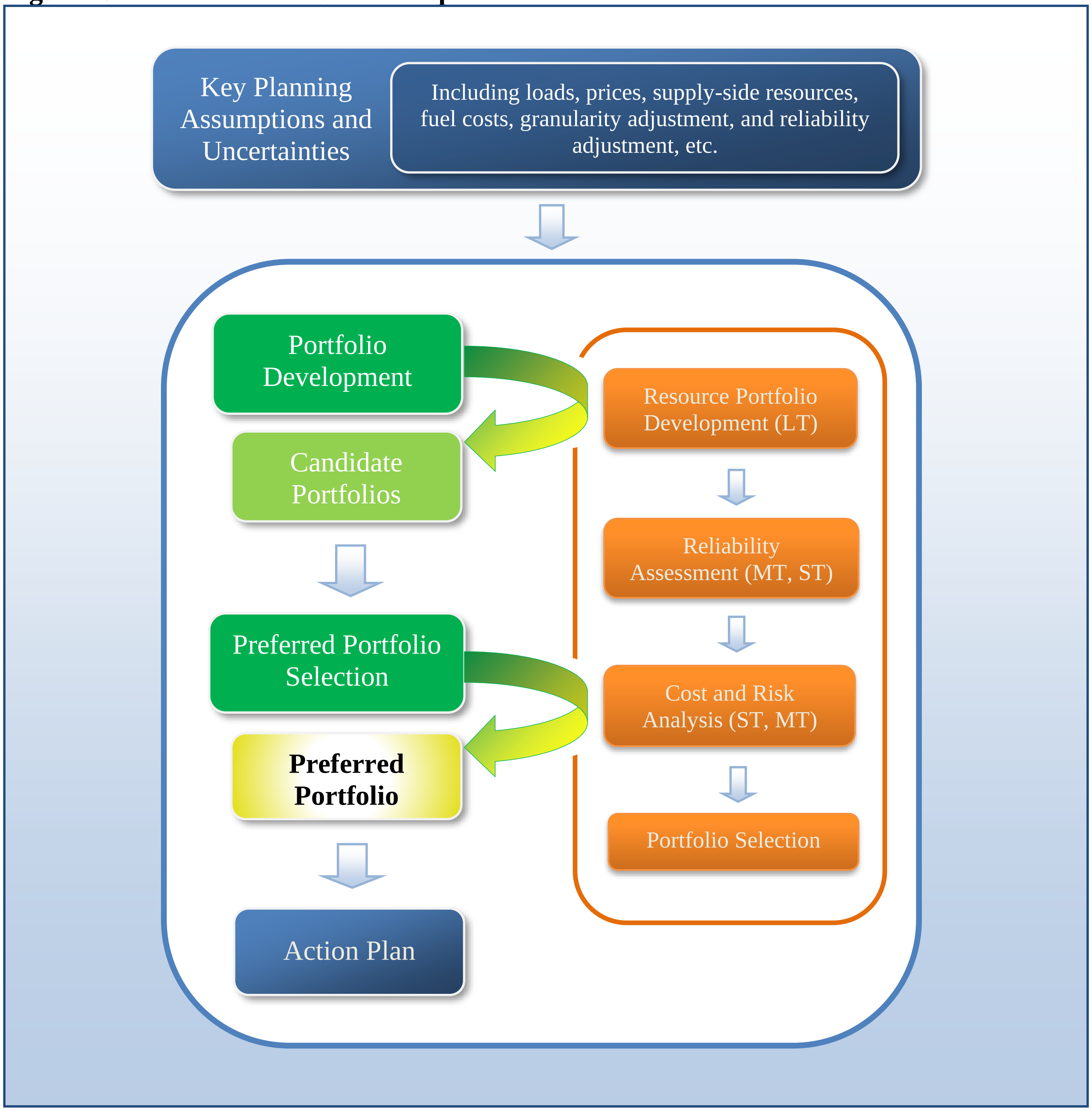
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

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

Modeling and Evaluation Steps

Figure 8.1 summarizes the modeling and evaluation steps for the 2021 IRP, highlighted in green. The steps are (1) portfolio development, and (2) portfolio screening. The result of the final screening step is selection of the preferred portfolio.

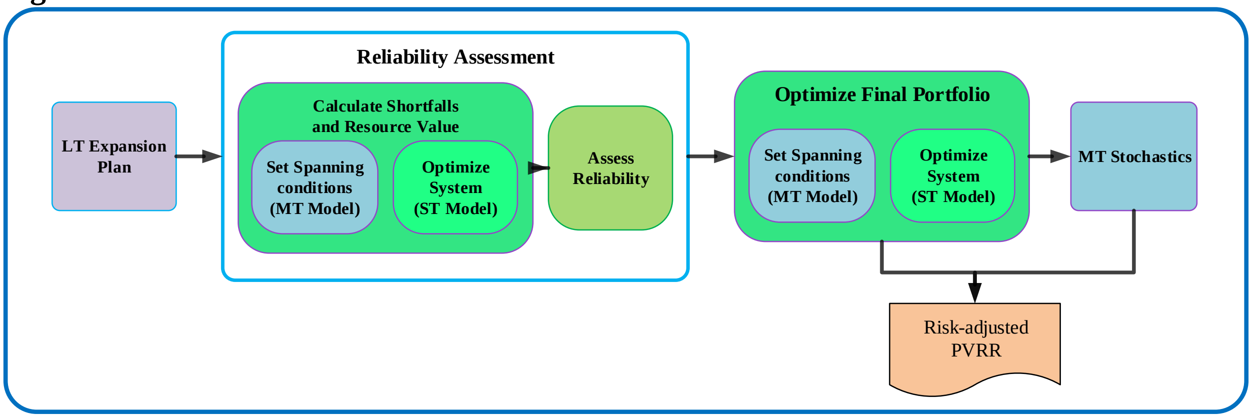
Figure 8.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp developed unique resource portfolios, analyzed deterministic cost and stochastic risk metrics for each portfolio, and selected, based on comparative cost and risk metrics, the specific portfolios considered in the next modeling and evaluation step. The outcomes of each can inform the need for additional studies to test or refine assumptions in a subsequent screening analysis.

Figure 8.2 provides additional process detail regarding these portfolio processing elements, followed by descriptions of each element.

Figure 8.2 – Portfolio Production Process



Resource Portfolio Development
All IRP models are configured and loaded with the best available information at the time a model run is produced. This information is fed into the LT model, which is used to produce resource portfolios with sufficient capacity to be reliable on a 20-year aggregated granularity basis.

Reliability Assessment
Resource portfolios developed by the LT model are simulated in the ST model to quantify reliability shortfalls at an hourly level. The ST model also supports the assessment of each resource's net system value, inclusive of resources that are not part of the specific portfolio being examined. This allows for the refinement of each portfolio according to a highly granular view of its needs and at the same time provides the data necessary to optimally select additional resources when needed to resolve shortfalls. The reliability-adjusted portfolio is then rerun through the ST model to create an optimal dispatch which considers all resource availability and system requirements at an hourly level, inclusive of individual resource operations and market purchases.

Cost and Risk Analysis
Resource portfolios developed by the LT model and adjusted for reliability by the ST model are simulated in the MT model to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed using Monte Carlo sampling of stochastic variables across the 20-year study horizon, which include load, natural gas and wholesale electricity prices, hydro generation, and unplanned thermal outages. The MT results are used to calculate a risk adjustment which is combined with ST model system costs to achieve a final risk-adjusted PVRR to guide portfolio selection.

Portfolio Selection
The portfolio selection process is based on modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the PVRR of system costs, assessed across a range of price-policy scenarios on a deterministic basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the deterministic PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other

supplemental modeling results, including reliability and CO_2 emissions data as an indicator of risks associated with greenhouse gas emissions.

Resource Portfolio Development

Resource expansion plan modeling, performed with the LT model, is used to produce resource portfolios with sufficient capacity to achieve reliability over the 20-year study horizon. Each resource portfolio is refined for reliability at an hourly granularity during the reliability assessment development step. Each subsequent 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 management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks. New to this IRP is using the LT model to consider the retirement of coal endogenously.

Long-Term (LT) Capacity Expansion Model

In the 2021 IRP, the LT model is used to establish an initial portfolio under expected conditions (medium gas, medium CO_2), and then modified for each case, based on study parameters, to eliminate shortfalls and maintain reliability. The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability, and other constraints.[1] Over the 20-year planning horizon, the model optimizes resource additions subject to resource costs and load constraints. These constraints include seasonal loads, operating reserves and regulation reserves plus a minimum capacity reserve margin for each load area represented in the model.

The initial resource portfolio developed with the LT model is appropriately reliable to its granularity and performance limitations. Operating reserve requirements include contingency reserves, which are calculated as 3% of load and 3% of generation. The capacity reserve margin in the 2021 IRP is set at a "floor" of 13% at each load area in the topology, as provided in Figure 8.3.

In the event that an early retirement of an existing generating resource is assumed or selected for a given planning scenario, the LT model will select additional resources as required to meet loads plus reliability requirement in each period and location.

To accomplish these optimization objectives, the LT model performs a least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on representative data blocks for each of the 12 months of every year. 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

[1] LT model performance limits the granularity at which the model can be run. For the 2021 IRP there is an additional reliability assessment performed in the ST model to ensure that final portfolios meet reliability requirements.

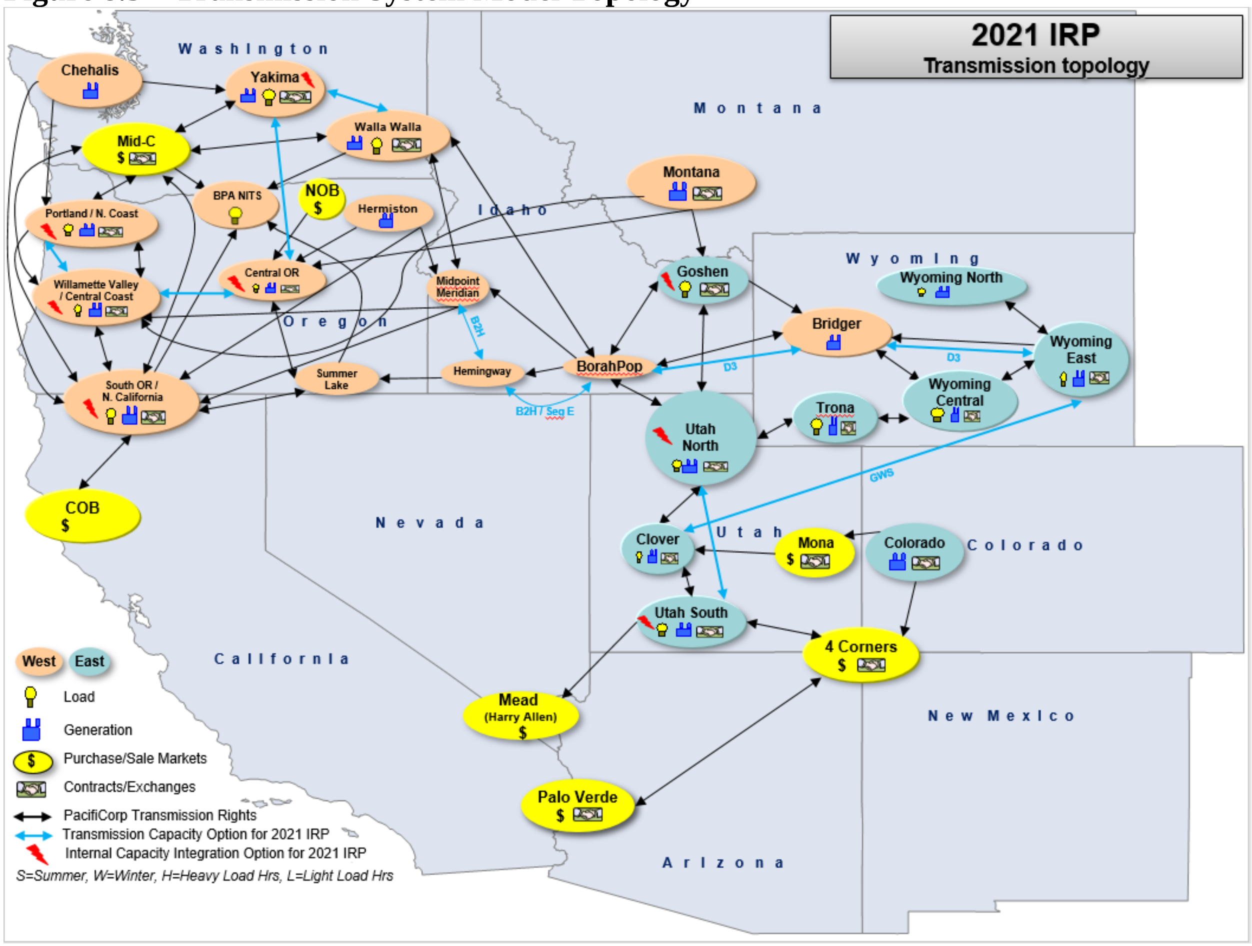
cost of existing contracts, market purchase costs, market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

Key modeling elements and inputs for the LT capacity expansion model include the following:

Transmission System

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

Figure 8.3 – Transmission System Model Topology



Transmission Costs

In developing resource portfolios for the 2021 IRP, PacifiCorp included modeling to endogenously select transmission options, in consideration of relevant costs and benefits. These costs are influenced by the type, timing, location, and amount of new resources as well as any assumed resource retirements, as applicable, in any given portfolio.

Resource Adequacy

In its 2021 IRP, PacifiCorp used the Plexos capacity reserve margin (CRM) setting in the LT model to establish a minimum 13% requirement for each topology location containing load. The capacity reserve margin applies in all periods and must be met by available resources within that area or imports from adjacent areas with excess resources available, subject to transmission constraints. This treatment is an improvement on a traditional planning reserve margin which accounts only for peak load capacity met by an estimated firm capacity contribution. Additionally, the 2021 IRP directly modeled operating reserve requirements in expansion plan model runs, which ensures that expansion resources selected to CRM requirements will also meet operating contingency spin and non-spin reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

Granularity and Reliability Adjustments

As detailed during the 2021 IRP public-input process, the granularity adjustment reflects the difference in economic value between an hourly 8760 cost calculation in ST modeling, and the four-block per month representation used in the LT model.

This adjustment is needed because resources with high variable costs that are rarely dispatched may provide a large value in a few intervals in the ST study, while not dispatching in any of the 4 LT model blocks. Also, storage resources allow for arbitrage among high value and low value hours in each day; however, the four-block granularity smooths out many of the storage arbitrage opportunities.

In parallel with the granularity adjustment, the reliability adjustment addresses unmet capacity needs by hour in the LT model portfolio selection. Much of the peak load hour requirements in mid-afternoon in the summer are adequately met by solar resources. However, resource requirements are driven by portfolio-dependent *net* load peaks (load less renewable resource output), which are harder for the LT model to identify.

While the granularity and reliability adjustments help direct the LT model to more cost-effective resources and a more reliable portfolio, the LT model cannot guarantee reliability at an hourly operational level. Marginal benefits decline as any resource type becomes a larger share of a portfolio, as it saturates the need in the hours it is available. A similar effect occurs with storage, where each incremental MW of system storage capacity must cover a longer duration.

As a consequence of the performance limitations of capacity expansion optimization, the ST model is leveraged to refine the portfolio to achieve a final balanced and reliable mix of resources, as described under the Cost and Risk Analysis section of this analysis, further below.

New Resource Options

Demand-Side Management

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). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

Wind and Solar Resources

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 represent expected monthly generation levels such that half of the time actual monthly generation would fall below expected levels, and half of the time actual monthly generation would be above expected levels assuming no curtailments.

The ability for wind and solar resources, to reliably meet demand over time is impacted by the forecasted profiles, along with mix of other resources in the portfolio. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Non-Emitting Resources

Two non-CO_2-emitting thermal resources are considered: advanced nuclear projects and non-emitting peaking units. Advanced nuclear resources are characterized by continuous operation and substantial storage in the form of heat stored as molten salt. In contrast, non-emitting peaking resources are designed to run infrequently to support system reliability by dispatching only when needed to meet shortfalls. The non-emitting peaking resource is assumed to use a non-CO_2 emitting fuel such as hydrogen.

Energy Storage Resources

Energy storage resources are distinguished from other resources by the following three attributes:

- Energy take – generation or extraction of energy from a storage reservoir for a specified period;
- Energy return – energy used to fill (or charge) a storage reservoir; and
- Storage cycle efficiency – an indicator of the energy loss involved in storing and extracting energy over the course of the take-return cycle.

Modeling energy storage resources requires specification of the size of the storage reservoir, defined in gigawatt-hours. The model dispatches a storage resource to optimize energy used by the resource subject to constraints such as storage-cycle efficiency, the daily balance of take and return energy, and variable costs (for example, the cost of natural gas for expanding air with gas turbine expanders).

Market Purchases

Market purchases are transactions by the company's front office represent short-term firm agreements for physical delivery of power. PacifiCorp is active in the western wholesale power markets and routinely makes short-term firm market purchases for physical deliveries on a forward basis (i.e., future months or quarters, balance of month, day-ahead, and hour-ahead). These transactions are used to balance PacifiCorp's system as market and system conditions become more certain when the time between an effective transaction date and real time delivery is reduced. Balance of month and day-ahead physical firm market purchases are most routinely acquired through a broker or an exchange, such as the Intercontinental Exchange (ICE). Hour-ahead transactions can also be made through an exchange. For these types of transactions, the broker or the exchange provides a competitive price. Non-brokered transactions can also be used to make firm market purchases among a wide range of forward delivery periods.

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, 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 contribution of short-term firm market purchases is accounted for in the portfolio-development process. For capacity expansion optimization modeling, market purchases contribute capacity toward meeting the 2021 IRP's capacity reserve margin and supply energy to meet system needs.

Capital Costs

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. All capital costs evaluated in the IRP are converted to nominal levelized revenue requirement costs. Use of nominal levelized revenue requirement costs is an established methodology for analyzing capital-intensive resource decisions among resource alternatives that have unequal lives and/or when it is not feasible to capture operating costs and benefits over the entire life of any given resource. To achieve this, the nominal levelized revenue requirement method spreads the return of investment (book depreciation), return on investment (equity and debt), property taxes and income taxes over the life of the investment. The result is an annuity or annual payment that remains constant such that the PVRR is identical to the PVRR of the nominal requirement when using the same nominal discount rate.

General Assumptions

Study Period and Date Conventions

PacifiCorp executes its 2021 IRP models for a 20-year period beginning January 1, 2021 and ending December 31, 2040. Future IRP resources reflected in model simulations are given an in-service date of January 1st of a given year, except for coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period.

Inflation Rates

The 2029 IRP simulations and cost data reflect PacifiCorp's corporate inflation rate schedule unless otherwise noted. A single annual escalation rate value of 2.155 percent is assumed. This escalation rate reflects the average of annual inflation rate projections for the period 2021 through 2040, using PacifiCorp's September 2020 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 2021 IRP is 6.88 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.[2] PVRR figures reported in the 2021 IRP are reported in 2021 dollars.

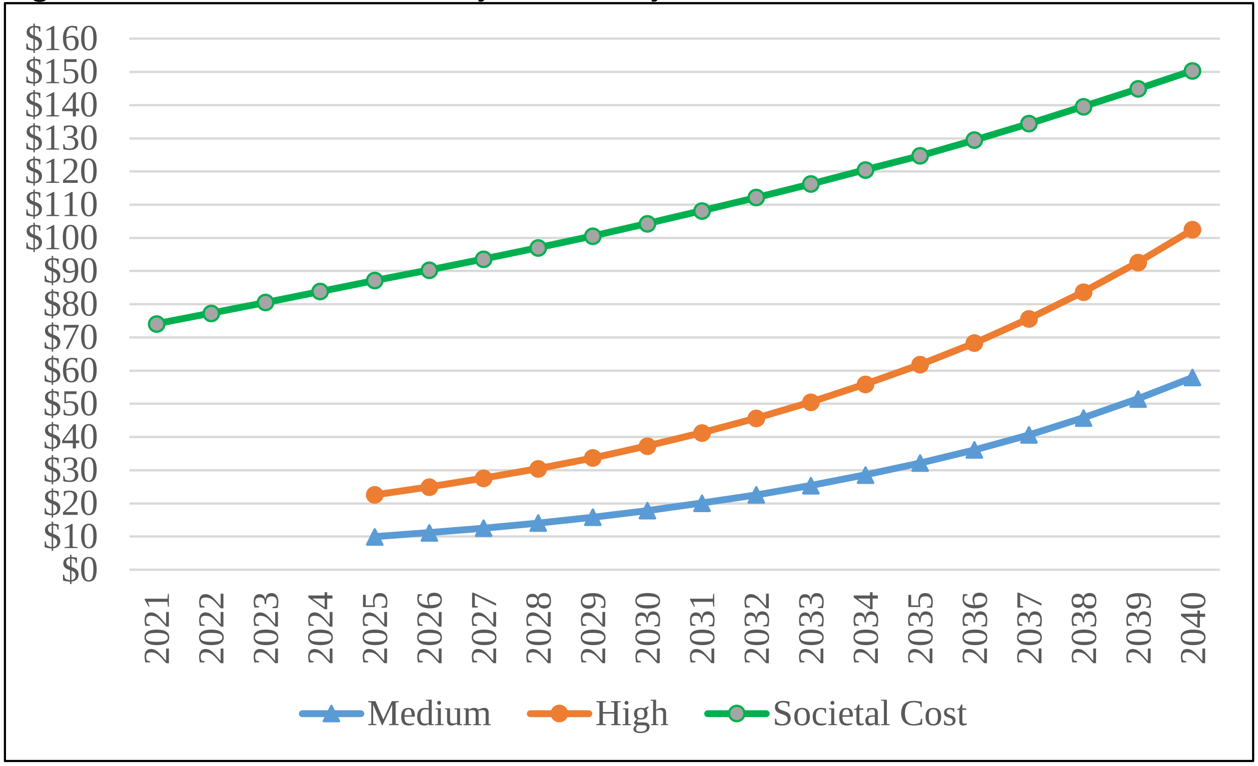
CO_2 Price Scenarios

PacifiCorp used four different CO_2 price scenarios in the 2021 IRP—zero, medium, high, and a price forecast that aligns with the social cost of greenhouse gases. The medium and high scenario are derived from expert third-party multi-client "off-the-shelf" subscription services. Both scenarios apply a CO_2 price as a tax beginning 2025.

PacifiCorp also incorporated the social cost of greenhouse gas in compliance with RCW 19.280.030. Social cost of greenhouse gas emissions are assumed to start in 2021. The social cost of greenhouse gases is applied such that the price for the SC-GHG is reflected in market prices and dispatch costs for the purposes of developing each portfolio (i.e., incorporated into capacity expansion optimization modeling). Aligned with Washington staff suggested treatment, system operations also include the SC-GHG once the portfolios are determined, presenting the risk that this operational assumption will not be aligned with actual market forces (i.e., market transactions at the Mid-Columbia market do not reflect the social cost of greenhouse gases and PacifiCorp does not directly incur emission costs at the price assumed for the social cost of greenhouse gases).

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

Figure 8.4 – CO_2 Prices Modeled by Price-Policy Scenarios



<u>Wholesale Electricity and Natural Gas Forward Prices</u>

For 2021 IRP modeling purposes, five electricity price forecasts were used: the official forward price curve (OFPC) and four scenarios. Unlike scenarios, which are alternative spot price forecasts, the OFPC represents PacifiCorp's official quarterly outlook. The OFPC is compiled using market forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

At the time PacifiCorp's 2021 IRP modeling inputs were prepared, the March 2021 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.[3] As such, these 36 months are market forwards as of March 2021. 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[4] (Aurora), a WECC-wide market model. Aurora uses the expert third-party natural gas price forecast to produce a consistent electricity price forecast for market hubs in which PacifiCorp participates. PacifiCorp updates its natural gas price forecasts each quarter for the OFPC and, as a corollary, the electricity OFPC is also updated.

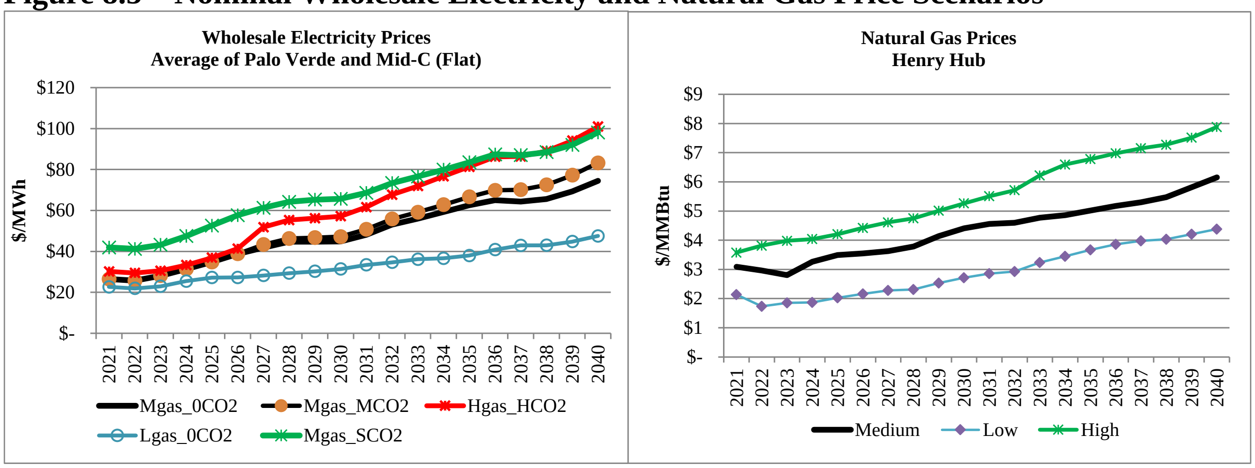
[3] The March 2021 OFPC prompt month is May 2021; April 2021 would be traded as "balance of month" when the OFPC is released.
[4] AURORAXMP is a proprietary production cost simulation model, developed by Energy Exemplar, LLC.

Scenarios pairing medium gas prices with alternative CO_2 price assumptions reflect OFPC forwards through April 2024 before transitioning to a pure fundamentals forecast. Scenarios using high or low gas prices, regardless of CO_2 price assumptions, do not incorporate any market forwards since scenarios are designed to reflect an alternative view to that of the market. As such, the low and high natural gas price scenarios are purely fundamental forecasts. Low and high natural gas price scenarios are also derived from expert third-party multi-client "off-the-shelf" subscription services.

PacifiCorp's OFPC for electricity and each of its five scenarios were developed from one of three (medium, low, high) underlying expert third-party natural gas price forecasts in conjunction with one of four CO_2 price scenarios.[5] The OFPC used in the 2021 IRP does not assume any CO_2 policy or tax in conjunction with its medium gas price forecast. However, PacifiCorp's 2021 IRP "medium case" price forecast is not the OFPC but a scenario that couples medium gas with a medium CO_2 price, applied for forecasting purposes as a tax. Thus, the 2021 IRP medium case differs from that of the March 2021 OFPC by assuming a medium CO_2 price starting in 2025. This medium CO_2 price serves as a proxy for a potential future CO_2 policy.

Figure 8.5 summarizes the five wholesale electricity price forecasts and three natural gas price forecasts used in the base and scenario cases for the 2021 IRP.

Figure 8.5 – Nominal Wholesale Electricity and Natural Gas Price Scenarios



Cost and Risk Analysis

Short-Term (ST) Schedule Model

The ST model uses the same common input assumptions described for the LT model with additional data provided by two other Plexos models. The LT model results provide the initial capacity expansion plan, and the MT model provides an optimized set of spanning conditions.

Spanning conditions are constraints that must be observed across periods of time that extend beyond the ST model's ability to "see" as it chronologically optimizes several days of hourly data at a time (e.g., an annual emissions limit). The MT model is able to determine for each month how each spanning condition is allocated for the ST model's use. The result is that even though the ST

[5]Zero CO2, medium CO2 price, high CO2 price, and a social based cost of CO2.

model is focused on hourly details and cannot simultaneously account for limitations that span across every hour in a year, the model will nonetheless appropriately adhere to an annual constraint.

Reliability Assessment and System Cost

The ST model begins with an portfolio from the LT model that has not yet been refined to reflect the reliability needs of a particular study (e.g., a particular sensitivity or price-policy scenario). The ST model is first run at an hourly level for 20 years in order to retrieve two critical pieces of data: 1) shortfalls by hour, and 2) the value of every potential resource to the system.

This information is used to determine the most cost-effective resource additions needed to meet reliability shortfalls, leading to a reliability-modified portfolio. The ST model is then run again with the modified portfolio to calculate an initial PVRR which is risk-adjust by outcomes of MT model stochastics.

<u>Resource Value</u>

Plexos calculates a locational marginal price (LMP) specific to each area in each hour that is based on supply and demand in that area and available imports and exports on transmission links to adjacent areas. This is also known as a shadow price. Plexos also calculates the marginal price specific to ancillary services (i.e., operating reserves) in each hour. Plexos then multiplies these prices by a generator's energy and operating reserve provision for each hour and reports the total as a resource's estimated revenue. In an organized market, this would represent the expected payments based on market-clearing prices.

When variable costs (such as fuel, emissions, and VOM) are subtracted out, the result is a resource's "net revenue". Net revenue provides a clear model-optimized assessment of every resource's value to the system, which is then used to assess resource additions needed to preserve reliable operation of the system.

While the net revenue approach is demonstrably superior to past resource value measures, especially as it is evaluated simultaneously for all potential resources, modeling capabilities, net revenue has limitations that should be acknowledged. Net revenue represents the value of the last MW of capacity from a given resource – as resources grow larger, the average value from the first MW of capacity to the last MW of capacity will tend to be somewhat higher than the reported marginal value. Conversely, adding more of a particular resource will result in declining values. While marginal prices will be very high in hours with supply shortfalls, this only indirectly contributes to reliable operation by helping to identify beneficial replacement resources. Once sufficient resources are added, shortfalls will mostly be eliminated and marginal prices will again reflect the variable cost of an available resource.

<u>Portfolio Refinements</u>

While a large number of resource options are evaluated, new generation resources are mostly restricted to two circumstances: replacement resources at retiring generators, and new resources at locations with interconnection or transmission upgrade options.

These interconnection and transmission upgrade options are limited and can be expensive. Replacing existing thermal generators with resources that provide only a portion of their interconnection capacity in "firm" capacity creates a need for additional interconnection capacity elsewhere, and a key strategy is maximizing the "firmness" of each MW of interconnection capacity to provide greater value. For this reason, the modeling of combined solar and storage resources now reflects storage with capacity equal to 100% of solar nameplate, and four-hour duration—up from 25% of solar capacity in the 2019 IRP, and 50% of capacity as discussed early in the 2021 IRP public-input process. This allows a collocated solar resource to shift more energy accumulated during periods of high solar radiance, increasing its effective capacity contribution.

Portfolio Cost

The second run of the ST model optimizes the reliability-adjusted portfolio to reflect least-cost operations while meeting all requirements and adhering to modeled constraints. The ST model's hourly granularity means that this system cost will be highly accurate, taking into account operational nuances that are obscured in the less granular LT and MT models. This in turn means that when evaluating the constellation of all competitive portfolios, the comparison will be based on appropriate relationships among all system components to yield an accurate PVRR.

Additional Measures

- Annual and energy not served (ENS)
- Annual CO_2 emissions.

Medium-Term (MT) Schedule Model

The MT model uses the same common input assumptions described for LT and ST models with additional data provided by the LT and ST model results (e.g., the capacity expansion portfolio). While the LT and ST models supply an optimized portfolio for each case, the MT model is able to bring the advantages of stochastic-driven risk metrics to the evaluation of the studies. While deterministic ST system cost results are the most precise available due the hourly granularity, the MT model provides the necessary data to calculate a stochastic risk metric for each case, which is then added to the ST system cost outcomes to produce the risk-adjusted PVRR for each case.

Cost and Risk Analysis

Once unique resource portfolios are developed using the LT and ST models, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with the MT model.

The stochastic simulation in the MT model produces a dispatch solution that accounts for chronological commitment and dispatch constraints. The MT simulation incorporates stochastic risk in its production cost estimates by using the Monte Carlo sampling of stochastic variables, which include load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages.

The stochastic parameters used in the MT model for the 2021 IRP are developed with a short-run mean reverting process, whereby mean reversion represents a rate at which a disturbed variable returns to its expected value. Stochastic variables may have log-normal or normal distribution as appropriate. The log-normal distribution is often used to describe prices because such distribution is bounded on the low end by zero and has a long, asymmetric "tail" reflecting the possibility that prices could be significantly higher than the average. Unlike prices, load generally does not have such skewed distribution and is generally better described by a normal distribution. Volatility and mean reversion parameters are used for modeling the volatilities of the variables, while accounting for seasonal effects. Correlation measures how much the random variables tend to move together.

Stochastic Model Parameter Estimation

Stochastic parameters are developed with econometric modeling techniques. The short-run seasonal stochastic parameters are developed using a single period auto-regressive regression equation (commonly called an AR(1) process). The standard error of the seasonal regression defines the short run volatility, while the regression coefficient for the AR(1) variable defines the mean reversion parameter. Loads and commodity prices are mean-reverting in the short term. For instance, natural gas prices are expected to hover around a moving average within a given month and loads are expected to hover near seasonal norms. These built-in responses are the essence of mean reversion. The mean reversion rate tells how fast a forecast will revert to its expected mean following a shock. The short-run regression errors are correlated seasonally to capture inter-variable effects from informational exchanges between markets, inter-regional impacts from shocks to electricity demand and deviations from expected hydroelectric generation performance. The stochastic parameters are used to drive the stochastic processes of the following variables:

- Representative natural gas prices for PacifiCorp’s east and west balancing authority areas;
- Electricity market prices for Mid-C, COB, Four Corners, and Palo Verde;
- Loads for California, Idaho, Oregon, Utah, Washington and Wyoming regions; and
- Hydro generation.

Volume II, Appendix H – Stochastic Parameters discusses the methodology for developing the stochastic parameters for the 2021 IRP.

For unplanned thermal outages, PacifiCorp assumes a uniform distribution around an expected rate. For existing units, the expected unplanned outage rates by unit are based on its historical performance. For new resources, the unplanned outage rates are as specified for those resources as listed in the supply-side resource table in Volume I, Chapter 7 – Resource Options. Table 8.1 through Table 8.8 summarize updated stochastic parameters and seasonal price correlations for the 2021 IRP.

Table 8.1 – Short-Term Load Stochastic Parameters

Short-Term Volatility	CA/OR without Portland	Portland	ID	UT	WA	WY
Winter 2021 IRP	0.045	0.041	0.038	0.023	0.052	0.016
Spring 2021 IRP	0.039	0.038	0.066	0.030	0.039	0.018
Summer 2021 IRP	0.043	0.059	0.057	0.051	0.053	0.017
Fall 2021 IRP	0.041	0.037	0.045	0.033	0.042	0.018
Short-Term Mean Reversion	**CA/OR without Portland**	**Portland**	**ID**	**UT**	**WA**	**WY**
Winter 2021 IRP	0.154	0.165	0.177	0.281	0.147	0.226
Spring 2021 IRP	0.214	0.242	0.258	0.519	0.157	0.272
Summer 2021 IRP	0.197	0.265	0.148	0.307	0.212	0.234
Fall 2021 IRP	0.290	0.277	0.198	0.202	0.234	0.241

Table 8.2 – Short-Term Gas Price Parameters

Short-Term Volatility	East Gas	West Gas
Winter 2021 IRP	0.115	0.166
Spring 2021 IRP	0.091	0.203
Summer 2021 IRP	0.099	0.131
Fall 2021 IRP	0.101	0.171
Short-Term Mean Reversion	**East Gas**	**West Gas**
Winter 2021 IRP	0.061	0.031
Spring 2021 IRP	0.160	0.140
Summer 2021 IRP	0.503	0.287
Fall 2021 IRP	0.046	0.022

Table 8.3 – Short-Term Electricity Price Parameters

Short-Term Volatility	Four Corners	COB	Mid-Columbia	Palo Verde
Winter 2021 IRP	0.132	0.163	0.198	0.121
Spring 2021 IRP	0.172	0.288	0.630	0.138
Summer 2021 IRP	0.220	0.339	0.260	0.202
Fall 2021 IRP	0.174	0.173	0.160	0.150
Short-Term Mean Reversion	**Four Corners**	**COB**	**Mid-Columbia**	**Palo Verde**
Winter 2021 IRP	0.089	0.070	0.090	0.086
Spring 2021 IRP	0.180	0.258	0.461	0.151
Summer 2021 IRP	0.312	0.395	0.196	0.146
Fall 2021 IRP	0.197	0.178	0.120	0.163

Table 8.4 – Winter Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.413	1.000				
COB	0.377	0.620	1.000			
Mid - Columbia	0.320	0.540	0.757	1.000		
Palo Verde	0.492	0.791	0.586	0.564	1.000	
Natural Gas West	0.344	0.235	0.302	0.288	0.248	1.000

Table 8.5 – Spring Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.197	1.000				
COB	0.141	0.339	1.000			
Mid - Columbia	0.102	0.424	0.638	1.000		
Palo Verde	0.223	0.630	0.327	0.276	1.000	
Natural Gas West	0.563	0.195	0.215	0.168	0.097	1.000

Table 8.6 – Summer Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.066	1.000				
COB	0.161	0.224	1.000			
Mid - Columbia	0.116	0.233	0.797	1.000		
Palo Verde	0.056	0.440	0.453	0.542	1.000	
Natural Gas West	0.674	0.035	0.103	0.075	-0.003	1.000

Table 8.7 – Fall Season Price Correlation

	Natural Gas East	Four Corners	COB	Mid - Columbia	Palo Verde	Natural Gas West
Natural Gas East	1.000					
Four Corners	0.207	1.000				
COB	0.251	0.289	1.000			
Mid - Columbia	0.225	0.279	0.596	1.000		
Palo Verde	0.165	0.609	0.401	0.435	1.000	
Natural Gas West	0.359	0.129	0.203	0.226	0.160	1.000

Table 8.8 – Hydro Short-Term Stochastic

	Short Term Volatility	Short-Term Mean Reversion
Winter 2021 IRP	0.274	0.722
Spring 2021 IRP	0.189	0.433
Summer 2021 IRP	0.210	1.149
Fall 2021 IRP	0.298	0.368

Figure 8.6 and
Figure **8.7** 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 8.6 – Simulated Annual Mid-C Electricity Market Prices

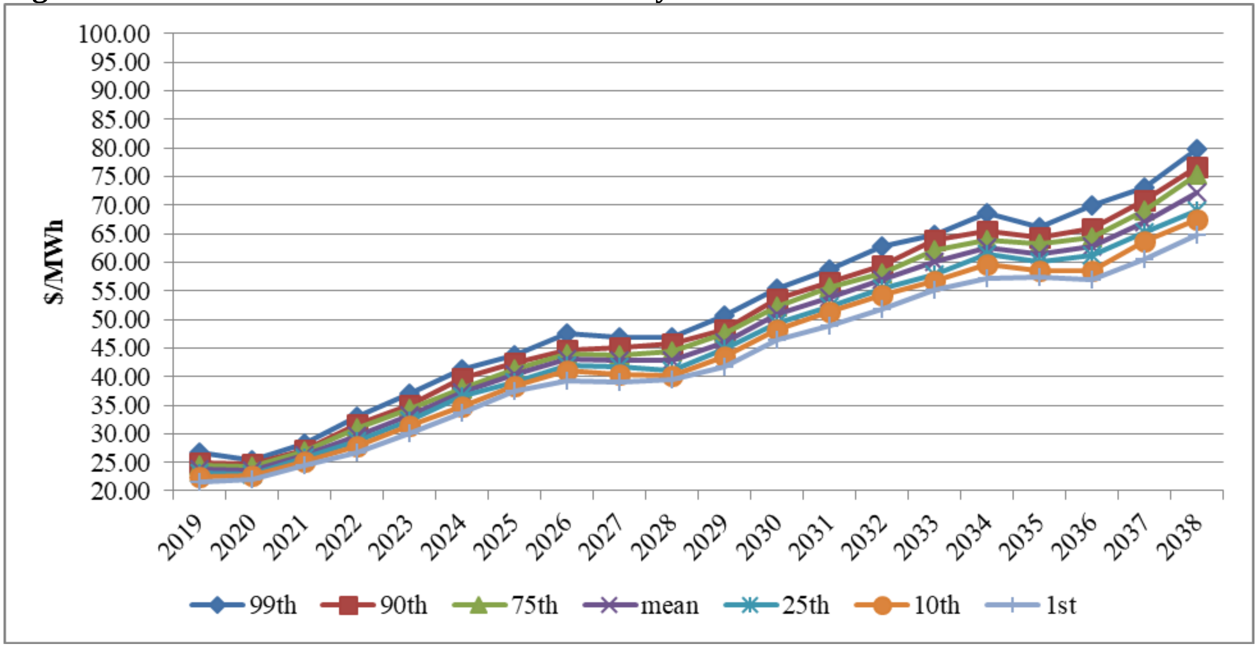


Figure 8.7 – Simulated Annual Palo Verde Electricity Market Prices

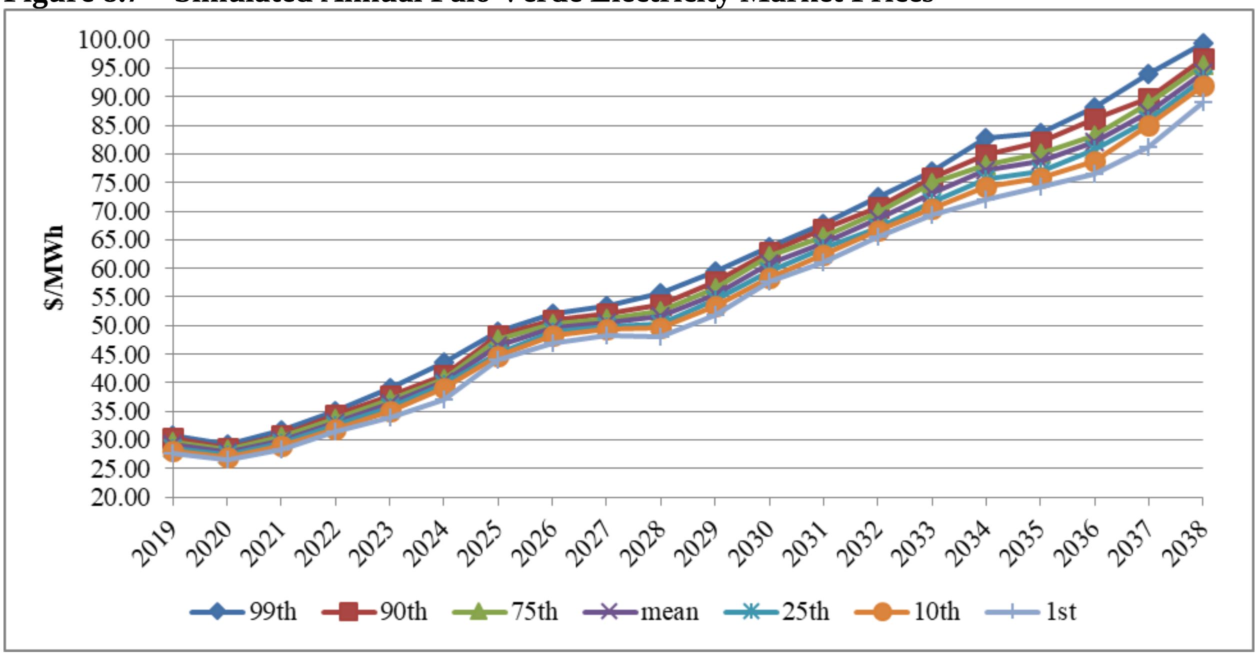


Figure 8.8 and Figure 8.9 show annual electricity prices at the first, 10^{th}, 25^{th}, 50^{th}, 75^{th}, 90^{th}, and 99^{th} percentiles for west and east natural gas prices. For west natural gas prices, differences between the first and 99^{th} percentiles range from $1.85/ Million British thermal units (MMBtu) to $7.22/MMBtu during the 20-year study period. For east natural gas prices, differences between the first and 99^{th} percentiles range from $2.00/MMBtu to $7.64/MMBtu.

Figure 8.8 – Simulated Annual Western Natural Gas Market Prices

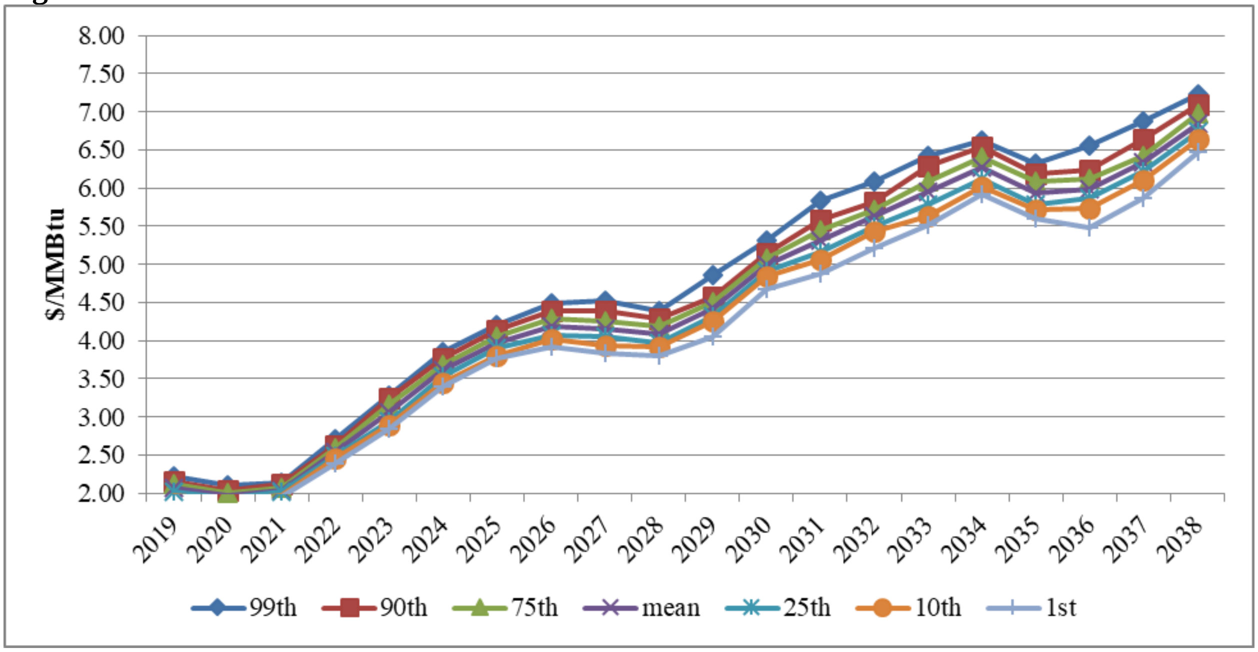


Figure 8.9 - Simulated Annual Eastern Natural Gas Market Prices

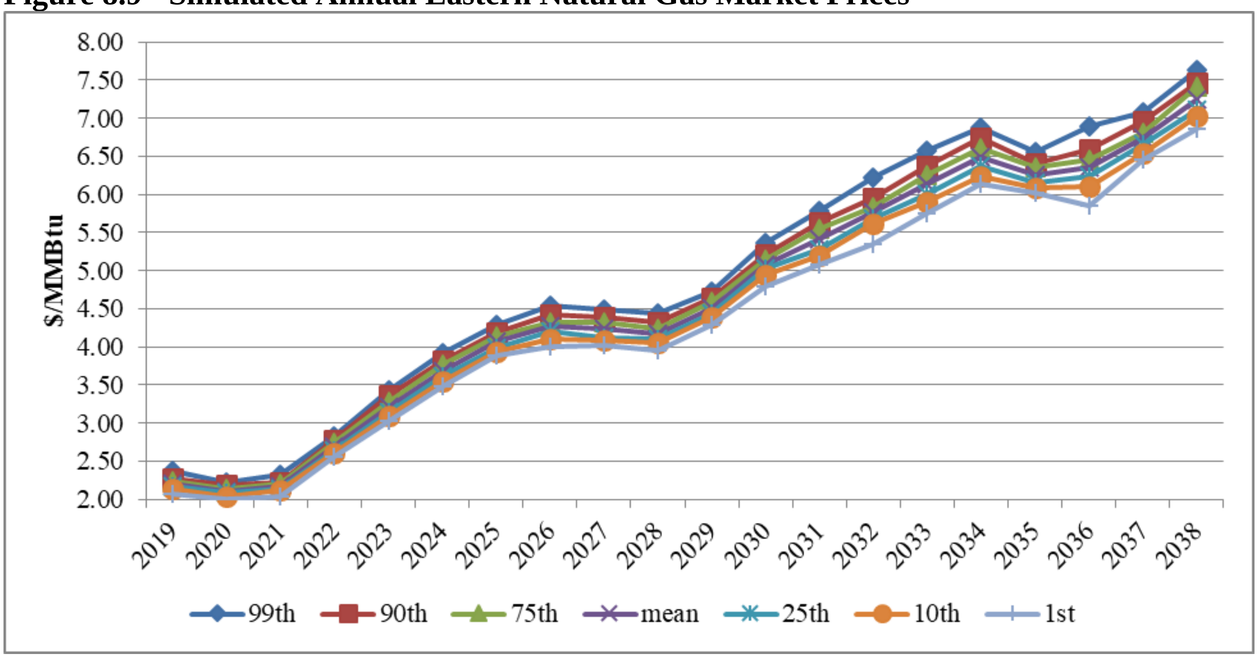


Figure 8.10 through

Figure 8.15 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 ranges 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 8.10 - Simulated Annual Idaho (Goshen) Load

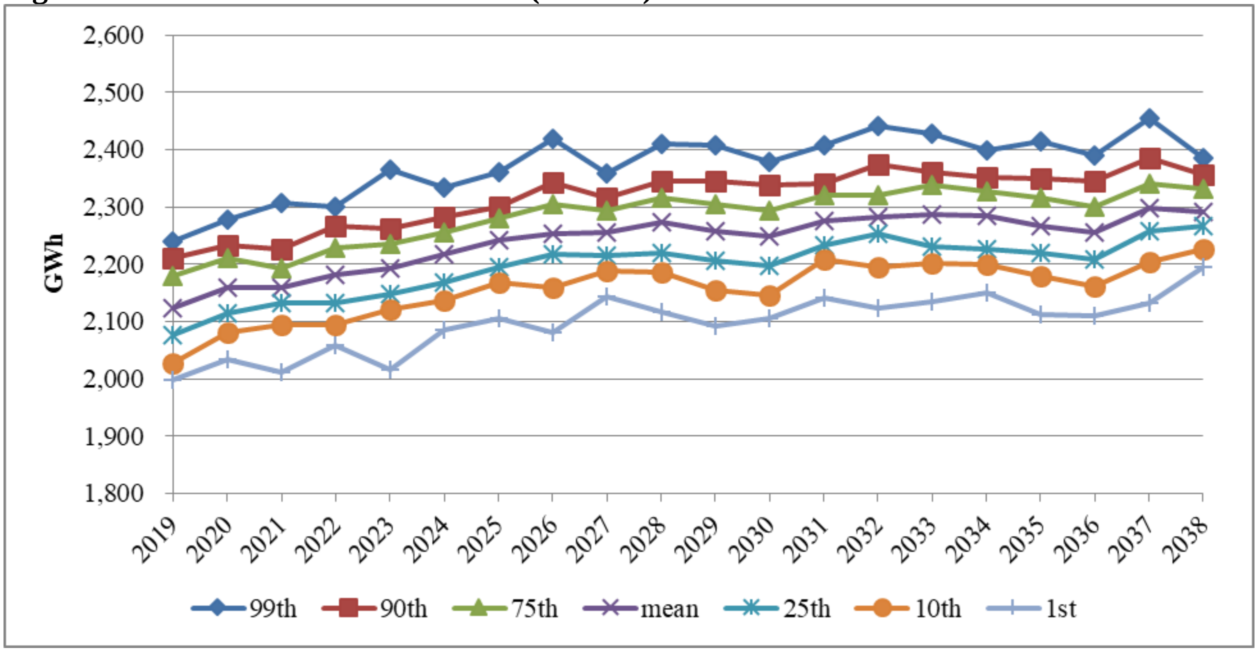


Figure 8.11 - Simulated Annual Utah Load

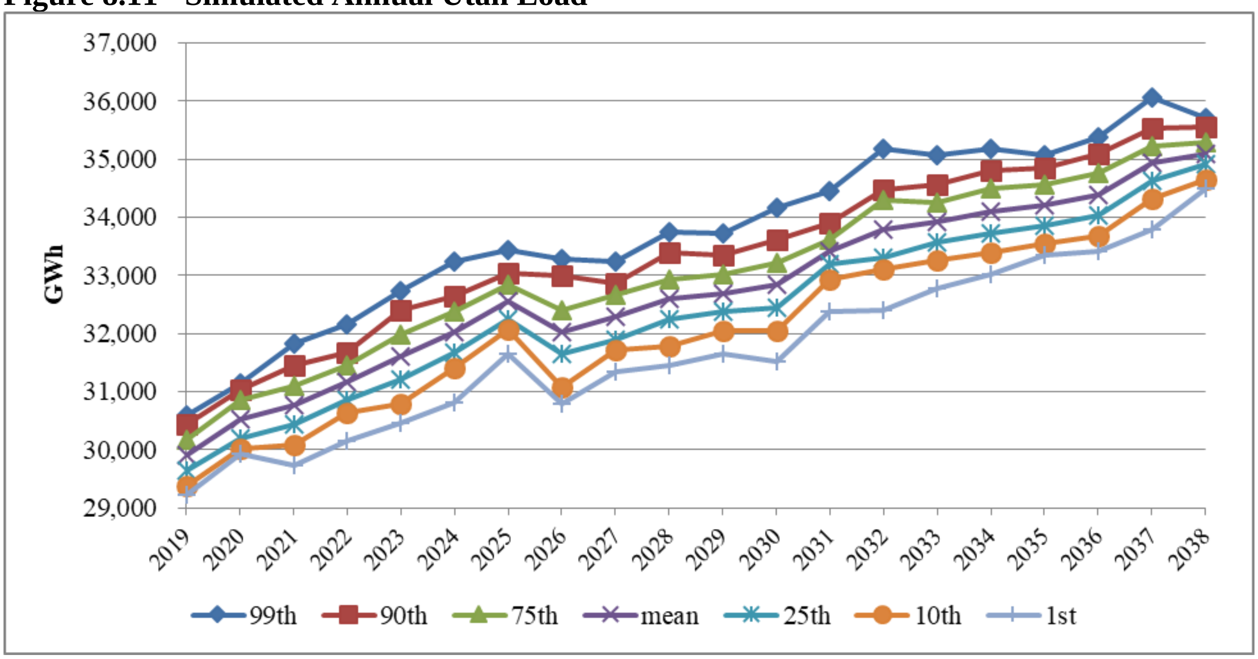


Figure 8.12 - Simulated Annual Wyoming Load

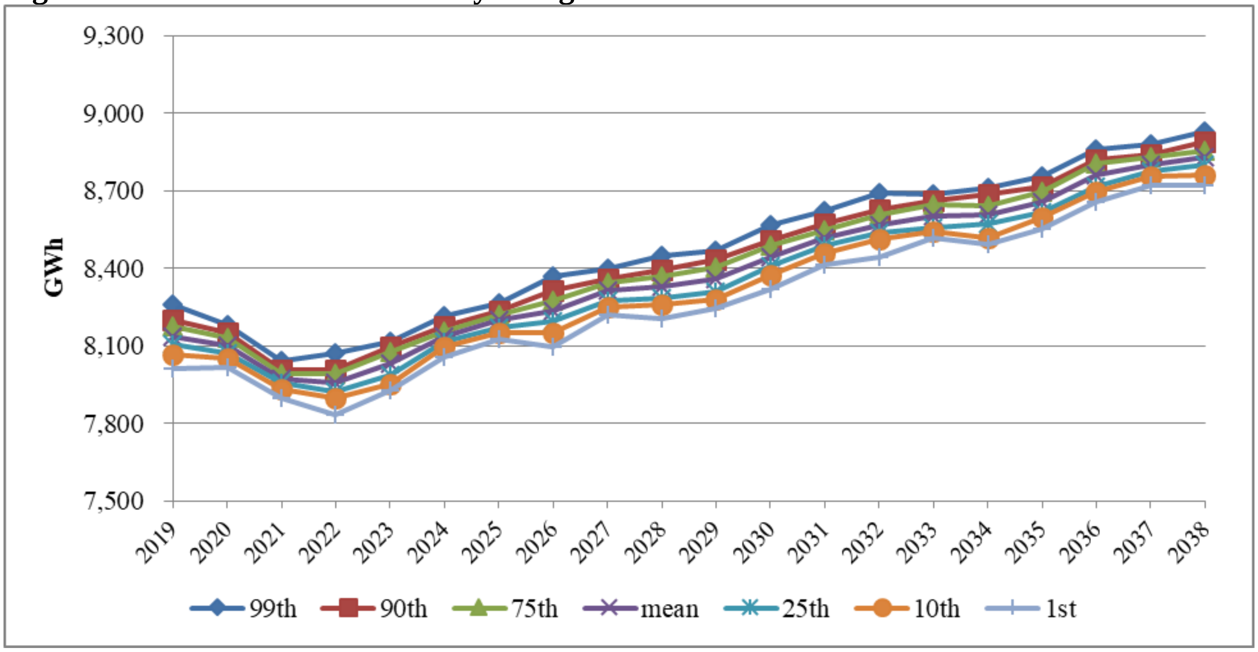


Figure 8.13 - Simulated Annual Oregon/California Load

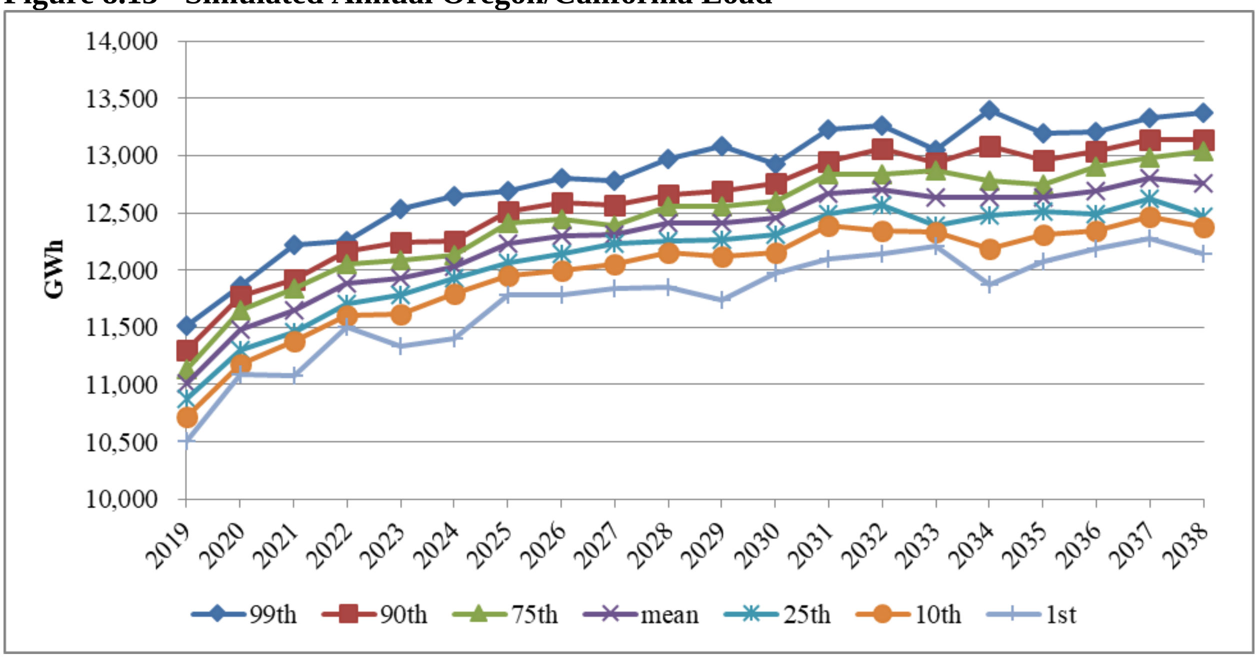


Figure 8.14 - Simulated Annual Washington Load

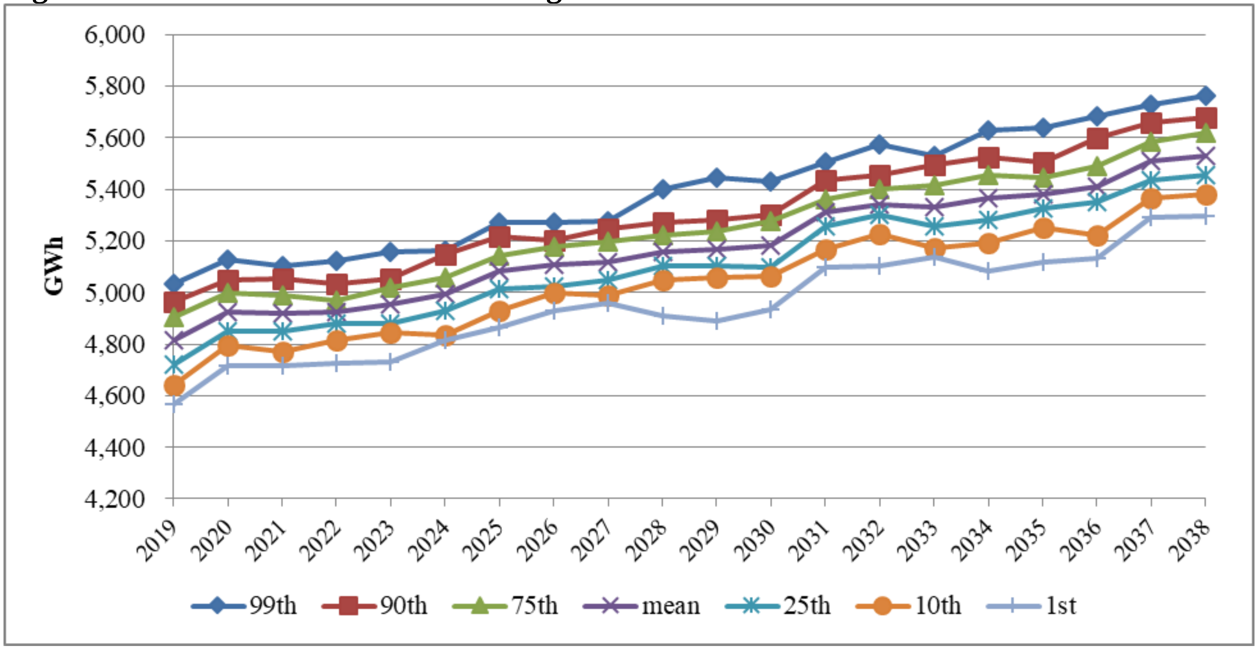


Figure 8.15 - Simulated Annual System Load

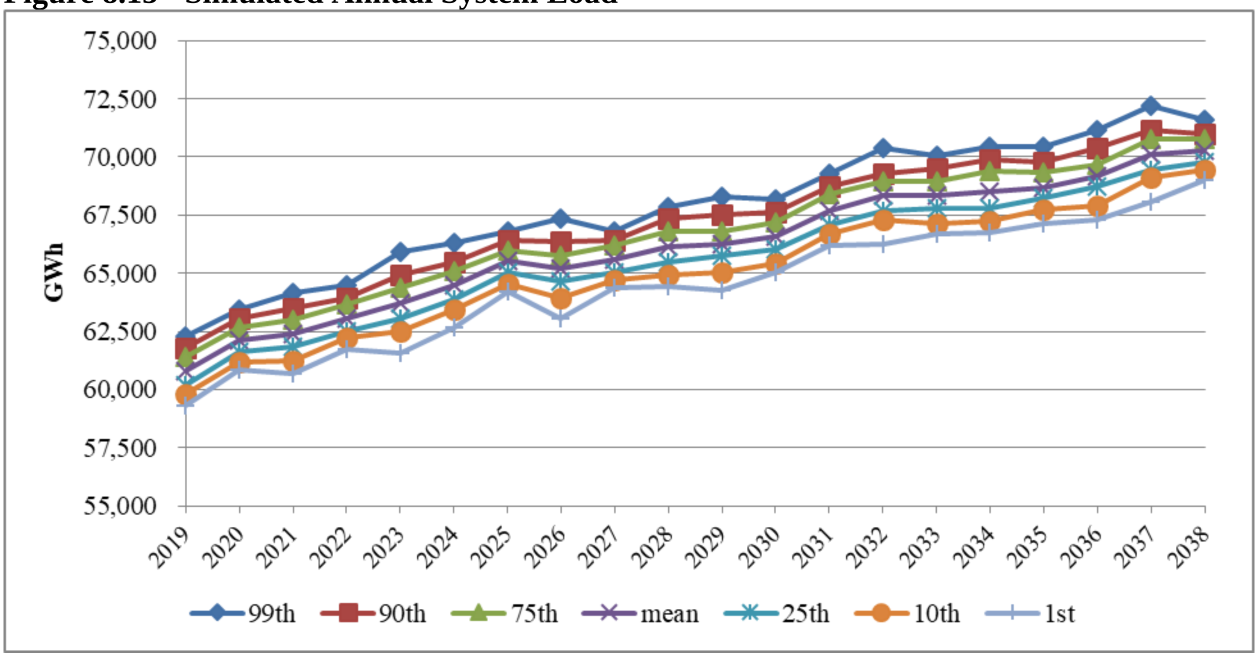
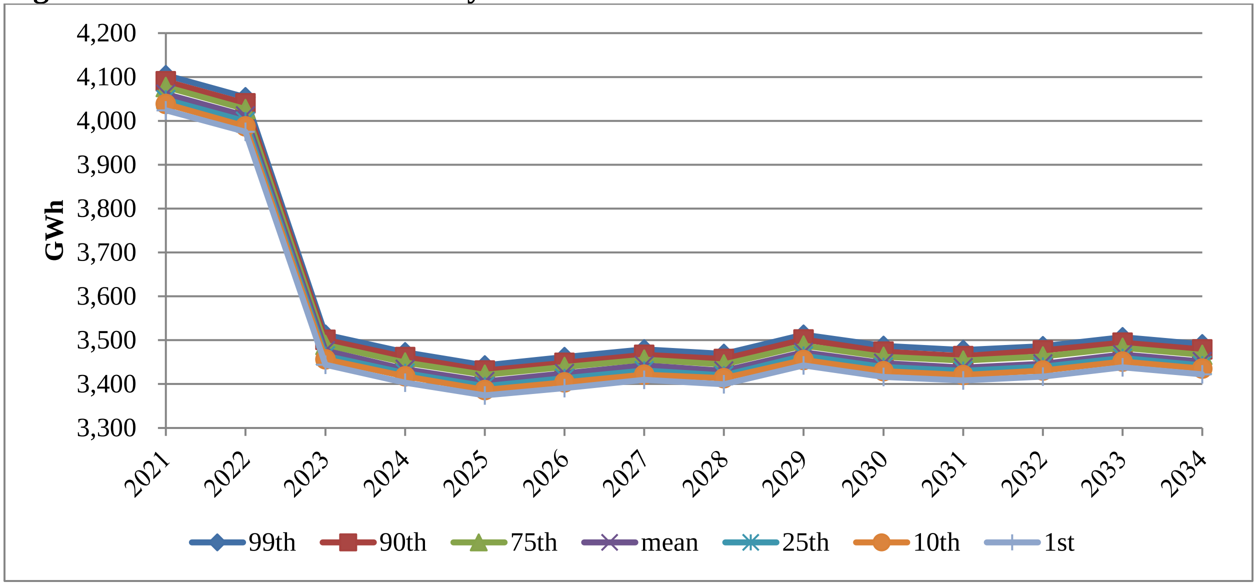


Figure 8.16 shows hydro generation at the first, 10^{th}, 25^{th}, 50^{th}, 75^{th}, 90^{th}, and 99^{th} percentiles based on a Monte Carlo simulation using short-term volatility and mean reversion parameters. PacifiCorp can dispatch its hydro generation on a limited basis to meet load and reserve obligations. 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 99^{th} percentiles range from 253 GWh to 512 GWh.

Figure 8.16 - Simulated Annual Hydro Generation



Monte Carlo Simulation

During model execution, the MT model makes time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the MT model applies Monte Carlo draws on a daily basis. In the case of hydroelectric generation, Monte Carlo draws are applied on a weekly basis.

Stochastic Portfolio Performance Measures

Stochastic simulation results for each unique resource portfolio are summarized, enabling direct comparison among resource portfolio results during the preferred portfolio selection process. The cost and risk stochastic measures reported from the MT model include:

- Stochastic mean PVRR
- Upper-tail Mean PVRR
- 5th, 90th and 95th percentile PVRR
- Standard deviation
- Risk-adjustment (5% of the 95th percentile)

<u>Stochastic Mean PVRR</u>

The stochastic mean PVRR is the average of system net variable operating costs among 50 iterations, combined with the nominal levelized capital costs and fixed costs corresponding to the LT model for any given resource portfolio. The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, long term contracts, system balancing market purchase expenses and sales revenues, reserve deficiency costs, and ENS costs applicable when available resources fall short of load obligations. Capital costs for new and existing resources are calculated on a nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2 emission costs for any scenarios that include a CO_2 price assumption. The stochastic mean PVRR, limited by performance constraints of the MT model, is not used directly in portfolio selection; instead, the more granular ST PVRR serves as the base measure of net system cost, modified appropriately by stochastic risk.

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's fixed costs, taken from the LT model, are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

5th and 95th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 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 2021 through 2040. This measure meets Oregon IRP guidelines to report a stochastic measure that addresses the variability of costs in addition to a measure addressing the severity of bad outcomes.

Risk-Adjustment

The MT model outcomes of the 50 stochastic samples are used to calculate a risk-adjustment measuring the relative risk of low-probability, high-cost outcomes. This measure is calculated as five percent of system variable costs from the 95th percentile. This metric expresses a low-probability portfolio cost outcome as a risk premium based on 50 Monte Carlo simulations for each resource portfolio and applied to the hourly-granularity deterministic PVRR. The rationale behind the risk-adjusted PVRR is to have a consolidated cost indicator for portfolio ranking, combining the most precise available system cost and high-end cost-risk concepts.

Forward Price Curve Scenarios

Preferred portfolio variants developed during the portfolio-development process are analyzed in the MT model with up to five price-policy scenarios. Price assumptions for each of these scenarios are subject to short-term volatility and mean reversion stochastic parameters when used in the MT model. The approach for producing wholesale electricity and natural gas price scenarios used for MT model simulations is identical to the approach used to develop price scenarios for the portfolio-development process.

Other Plexos Modeling Methods and Assumptions

Transmission System

The base transmission topology shown in Figure 8.3 is used in each of the three Plexos models, LT, ST and MT. Any transmission upgrades selected by LT and ST model processes that provide incremental transfer capability among bubbles in this topology are part of the portfolio and thus included in the MT stochastics and final ST optimizations.

Resource Adequacy

The CRM is a portfolio selection driver adequate to the capabilities of the LT model. Consistent with past IRPs use of a PRM, the CRM is not used once the initial portfolio is established. This is because ST reliability modifications to the portfolio rely on hourly resource availability and system requirements to directly determine reliability shortfalls and any additional resource need at the hourly level. MT stochastic model runs optimize unit commitment and dispatch logic on the resulting fixed portfolio to meet all requirements, including operating reserve and regulation reserves.

Energy Storage Resources

Storage resources such as battery energy storage systems (BESS), compressed air energy storage (CAES), and flow storage have many potential advantages, including storage for frequency regulation, grid stabilization, transmission loss reduction, reduced transmission congestion, renewable energy smoothing, spinning reserve, peak-shaving, load-levelling, transmission and distribution deferral, and asset utilization.

Each of the Plexos models (LT/MT/ST) dispatch storage resources endogenously, subject to their constraints, for example requirements to charge from onsite solar or for the combined solar and storage output and reserves to remain within a single interconnection limit. The model can deploy energy storage for the most cost-effective uses, including any combination of load ramping and leveling, reserve carrying, and to complement the benefits of renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing the risk-adjustment, ENS, and CO_2 emissions data, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity

PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and market purchases.

Customer Rate Impacts

To derive a rate impact measure, PacifiCorp computes the change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the risk adjusted PVRR results from the models and capital costs on a nominal levelized basis. While this approach provides a reasonable representation of relative differences in projected total system revenue requirement among portfolios, it is not a prediction of future revenue requirement for rate-making purposes.

Market Reliance

To assess market reliance risk, PacifiCorp quantifies market purchases for each portfolio allowing comparisons among cases in Chapter 9 – modeling and Portfolio Selection Results. In the 2021 IRP market purchase become increasingly constricted compared to past IRPs, as described in Volume I, Chapter 7 – Resource Options.

Portfolio Selection

Portfolios are measured for relative performance with regard to system costs, risk-adjusted system costs, ENS and CO_2 emissions. The risk adjusted PVRR accounts for relative upper tail stochastic risk among portfolios.

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

Additional quantitative analysis can be performed to further assess the relative differences among top-performing portfolios; qualitative analysis can also be considered where appropriate during portfolio selection on the basis of known factors that could not be readily captured in models.

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps. For the 2021 IRP this includes additional analysis to assess the impacts of new natural gas resources, and energy efficiency methodologies based on levelized cost of energy (LCOE) bundling as compared to capacity contribution bundling.

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

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2021 IRP, organized here into major development categories:

- Initial Portfolios
  - P02 (optimized coal retirements)
  - P03 (coal retired by 2030)
  - BAU1 (end-of-life coal retirements)
  - BAU2 (2019 IRP coal retirements)
- Preferred Portfolio Selection
  - Top Performing Portfolio
  - Preferred Portfolio Variants
- Washington Required Portfolios and Sensitivities[6]

Additional portfolio detail can be found in Volume II, Appendix I – Capacity Expansion Results.

Initial Portfolios

Informed by the public-input process, these cases build diversity around varying key retirement dates. These portfolios explore potentially significant interactions among retirement options including the potential to convert coal units to natural gas operations, retire units prior to end-of-life, install carbon-capture equipment on coal-fired facilities, retire units at end-of-life, or cease all coal-fired operations by year 2030. Potential trade-offs among these options are captured in the relative strengths of each unique portfolio in how it interacts with the optimized selection of proxy resources throughout the planning horizon. 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 rely on the combined capabilities of three optimization models within Plexos, the LT model, MT model and ST model, new to PacifiCorp in the 2021 IRP cycle.

There are considerable stranded-cost risks associated with planning a system that is reliant on new natural gas resources with depreciable lives ranging between 30 to 40 years (i.e., a new gas-fired resource placed in service in 2030 would be depreciated as late as 2070). Further, when considering current state policies, it is not feasible to assume new natural gas resources can obtain the permits needed to site and operate such a facility in many parts of PacifiCorp's service territory. Finally, PacifiCorp has observed that there is very limited development activity for new natural gas facilities. This was most recently evident in the 2020AS RFP, which did not result in a single bid for new natural gas resources. Therefore, new natural gas proxy resources were not made available for selection in any of Initial Portfolios.

Portfolios generated with SCGHG price-policy assumptions are consistent with RCW19.280.030 in Washington.

[6] Informational portfolios that are not eligible for selection as the preferred portfolio.

Table 8.9 provides the initial portfolio definitions for this IRP. Additional information, including coal unit retirement assumptions, are provided for each case in Volume II, Appendix I – Capacity Expansion Results.

Table 8.9 – Initial Portfolio Case Definitions

Case Type[a]	Price-Policy	Existing Coal[b]	Existing Gas[b]	Other Existing Resources[b]	Proxy Resources[c]
P02	MM	Optimized	End of Life	End of Life	No New Gas
P02	MN	Optimized	End of Life	End of Life	No New Gas
P02	LN	Optimized	End of Life	End of Life	No New Gas
P02	HH	Optimized	End of Life	End of Life	No New Gas
P02	SCGHG	Optimized	End of Life	End of Life	No New Gas
P03	MM	Retired by 2030	End of Life	End of Life	No New Gas
P03	MN	Retired by 2030	End of Life	End of Life	No New Gas
P03	LN	Retired by 2030	End of Life	End of Life	No New Gas
P03	HH	Retired by 2030	End of Life	End of Life	No New Gas
P03	SCGHG	Retired by 2030	End of Life	End of Life	No New Gas
BAU1	MM	End of Life	End of Life	End of Life	No New Gas
BAU1	MN	End of Life	End of Life	End of Life	No New Gas
BAU1	LN	End of Life	End of Life	End of Life	No New Gas
BAU1	HH	End of Life	End of Life	End of Life	No New Gas
BAU1	SCGHG	End of Life	End of Life	End of Life	No New Gas
BAU2	MM	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	MN	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	LN	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	HH	2019 IRP	2019 IRP	2019 IRP	No New Gas
BAU2	SCGHG	2019 IRP	2019 IRP	2019 IRP	No New Gas

(a) "P" refers generically to "portfolio"; "BAU" refers to "business as usual", a designation derived from stakeholder feedback recommending the BAU1 and BAU2 series of cases.
(b) Aligned with the intent of the BAU2 study requests, the designation "2019 IRP" means that existing resources maintain 2019 retirement assumption except where updated information has changed known planning.
(c) Optimized proxy portfolio selections exclude new gas proxy resources except for gas-conversion of specific existing coal resources.

All initial portfolios consider variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or CCUS retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing.

P02 (optimized coal retirements)

P02 portfolios are fully optimized using the best available input data and assumptions regarding requirements and constraints. The P02-MM case represents a reasonably likely future that assumes medium gas prices and a medium CO_2 price proxy for future federal policy. In this series, coal retirement timing is optimized, whereas other existing resources are assumed to operate through end of life; contracts expire at the end of their term. Proxy resource selections exclude new gas-fueled additions except in the case of a coal-to-gas conversion of an existing resource. Based on the logic of optimization modeling, P02 cases are expected to perform well compared to other case types within the same price-policy environment assumptions given that the models will have the most latitude to find a low-cost portfolio solution. The P02 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

P03 (coal retired by 2030)
These P03 cases feature the retirement of all coal resources by 2030 using an optimized retirement strategy within the first nine years of the planning horizon. Other existing resources are assumed to operate through end of life; contracts expire at the end of their term. Proxy resource selections exclude new gas-fueled additions except in the case of a coal-to-gas conversion of an existing coal resource. In contrast to the P02 series, described above, the P03 series is expected to be relatively costly as the pre-2030 retirement strategy prevents the models from optimizing coal retirements in the last half of the planning horizon. The P03 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

Business as Usual Cases
During the 2021 IRP public input process, four stakeholder feedback forms requested specific "Business as Usual" (BAU) Cases:

Table 8.10 – Business as Usual Study Requests

Requesting Party	Requested Case Summary
Wyoming Office of Consumer Advocate (Form 037)	Begin with current generation and transmission portfolio and reflect analysis on customer impacts of changes to portfolio to accommodate load growth and environmental compliance obligations. Exclude early coal retirement as that is analyzed elsewhere in the IRP.
Wyoming Public Service Commission (Form 045)	Carry forward the 2019 IRP preferred portfolio, with updates due to regulatory changes, no additional assumed early retirements, and exclude externalities that are not currently required by law to be evaluated.
Renewable Northwest (Form 046)	Include a BAU case that incorporates reliability issues in California, Front Office Transaction assumptions and state energy policy.
Joint Parties (Utah Association of Energy Users, Utah Division of Public Utilities, Wyoming Industrial Energy Consumers, and Wyoming Office of Consumer Advocate (Form 058)	Two BAU cases – one based on the 2019 IRP preferred portfolio and one based on the 2017 IRP Update preferred portfolio with all commitments since the 2019 IRP included in BAU case.

Based on this feedback, PacifiCorp planned to develop two stakeholder-defined BAU case series, termed "BAU1" and "BAU2".

<u>BAU1 (end-of-life coal retirements)</u>

The retirement strategy for BAU1 cases assumes existing assets will operate through the end of their life operating life (no early retirement), including coal and non-coal resources; contracts expire at the end of their term. Proxy resource selections exclude new gas-fueled additions except in the case of a coal-to-gas conversion of an existing coal resource. The BAU1 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

BAU2 (2019 IRP coal retirements)

BAU2 cases target portfolios that are reasonably aligned with the 2019 IRP preferred portfolio. Existing resource assumptions will differ from the 2019 IRP retirement assumption only where required to align with updated information, such as anticipated retirement dates for the minority-owned Colstrip and Hayden facilities. Proxy resources can change to optimally meet load, ensuring sufficient capacity and energy to accommodate changes in load from the 2019 IRP. Such proxy resource selections exclude new gas-fueled additions and new coal-to-gas conversions are disallowed. The BAU2 series of cases includes a unique portfolio developed under each of the five price-policy scenarios.

Preferred Portfolio Selection Cases

Certain additional cases were developed directly from the top-performing case (P02-MM) based on analysis of portfolios from the twenty initial cases as described above to evaluate the impacts of specific future scenarios not considered elsewhere, but which may be adopted into the preferred portfolio if the analysis warrants their inclusion. In the 2021 IRP, there are eight preferred portfolio selection cases referred to as the "P02 Variants" as shown in Table 8.11:

Table 8.11 – Preferred Portfolio Variants

Portfolio	Description
P02a-JB1-2 GC	Excludes gas conversion of Jim Bridger Units 1 and 2
P02b-No B2H	Excludes Boardman-to-Hemingway transmission segment
P02c-No GWS	Excludes the Energy Gateway South transmission segment
P02d-No RFP	Excludes 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment
P02e-No NUC	Excludes the Natrium™ advanced nuclear demonstration project
P02f-No NAU25	Excludes the early retirement of Naughton Units 1 and 2
P02g-CCUS	Includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4 in response to Wyoming House Bill 200
P02h-JB3-4 RET	Includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback

Each variant case begins with inputs and assumptions identical to the preferred portfolio (P02-MM-CETA), which is the top performing portfolio (P02-MM) with adjustments required for Washington's Clean Energy Transformation Act (CETA).

P02a-JB1-2 GC
Starting with the assumption of the P02-MM-CETA portfolio, this portfolio is re-optimized with added assumption that coal-to-gas conversions are disallowed, requiring an alternate strategy to maintain system reliability.

P02b-No B2H
In this sensitivity the transmission segments associated with the Boardman-to-Hemingway project are removed along with 600 MW (nameplate) of enabled resources. The portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

P02c-No GWS
The Energy Gateway South and associated D.1[7] projects enable 1,930 MW (nameplate) of interconnected resources; approximately 1,641 MW of this interconnection capability is occupied by projects identified in the All-Source 2020 RFP. In the P02c-No GWS case, both the transmission project and enabled final shortlist wind bids from the All-source 2020 RFP are removed. The portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

P02d-No RFP
Similar to P02c-No GWS, the 'No RFP' case eliminates the Energy Gateway South and D.1 transmission projects, but also removes all final shortlist bids from the All-source 2020 RFP (not just the wind bids enabled by GWS and D.1). The portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

P02e-No NUC
The 'No Nuc' case removes the Natrium™ demonstration project in 2028 from the preferred portfolio and re-optimizes proxy resources to maintain reliability. As the purpose of the sensitivity is evaluate the system value of the Natrium™ demonstration project, proxy nuclear resources are still allowed in the later years of the planning horizon in order to meet load and reliability requirements at a reasonable cost. This results in a portfolio that targets the system value contribution of the individual demonstration project.

P02f-No NAU25
The retirements of Naughton unit 1 and Naughton unit 2 in 2025 are assumed in the preferred portfolio. This sensitivity evaluates the cost and risk merits of this strategy by disallowing these two early retirements, re-optimizing the portfolio, and comparing outcomes.

P02g-CCUS
In response to Wyoming House Bill 200, this sensitivity includes the CCUS retrofit of Dave Johnston Unit 4. The CCUS installation is assumed to occur in 2026 and also assumes the life of Dave Johnston Unit 4 could be extended beyond the end of the planning horizon.

P02h-JB3-4 RET
The P02h-JB3-4 RET sensitivity tests the potential system cost or benefit of retiring Jim Bridger unit 3 and Jim Bridger unit 4 prior to end-of-life. Based on the selected early retirement dates, the portfolio is re-optimized in the absence of these projects, requiring an alternate strategy to maintain system reliability.

[7] Refer to Volume I, Chapter 4 – Transmission for details regarding these projects.

Washington Required Portfolios

Washington's CETA legislation requires utilities to conduct three scenarios:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. This sensitivity including the requirement to use the social cost of greenhouse gases (SCGHG) price-policy assumption in the resource acquisition decision. In Chapter 9 – Modeling and Portfolio Selection Results, the company will analyze this portfolio in the context of both CETA and non-CETA complaint outcomes.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." Please see Appendix A for additional detail regarding the climate change scenario.

- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals." The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario and includes all available Washington energy efficiency and demand response.

Sensitivity Case Definitions

PacifiCorp identified eight sensitivities outlined in Table 8.12 and discussed further in Volume I, Chapter 9 – Modeling and Portfolio Selection Results.

Table 8.12 – Sensitivity Case Definitions

Case	Description	Load Forecast	Private Generation	Resources	CO_2 Policy
S-01	High Load	High	Base	Optimized	Medium gas / Medium CO_2
S-02	Low Load	Low	Base	Optimized	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth	1 in 20	Base	Optimized	Medium gas / Medium CO_2
S-04	New Proxy Gas Allowed	Base	Base	Optimized	Medium gas / Medium CO_2
S-05	Business Plan	Base	Base	Align first three years	Medium gas / Medium CO_2
S-06	Levelized Cost of Energy Efficiency Bundles	Base	Base	Optimized	Medium gas / Medium CO_2
S-07	High Private Generation	Base	High	Optimized	Medium gas / Medium CO_2
S-08	Low Private Generation	Base	Low	Optimized	Medium gas / Medium CO_2

Load Sensitivities (S01, S02, S03)

PacifiCorp includes three different load forecast sensitivities. The high load forecast sensitivity (S01) reflects optimistic economic growth assumptions from IHS Global Insight and high Utah and Wyoming industrial loads. The low load forecast sensitivity (S02) 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 and high industrial load forecast is taken from 5th and 95th percentile.

The third load forecast sensitivity (S03) is a 1-in-20 (5 percent probability) extreme weather scenario. The 1-in-20 peak weather scenario is defined as the year for which the peak has the chance of occurring once in 20 years. This sensitivity is based on 1-in-20 peak weather for July in each state. Figure 17 compares the low, high, and 1-in-20 load sensitivities, net of base case private generation levels, alongside the base case load forecast.

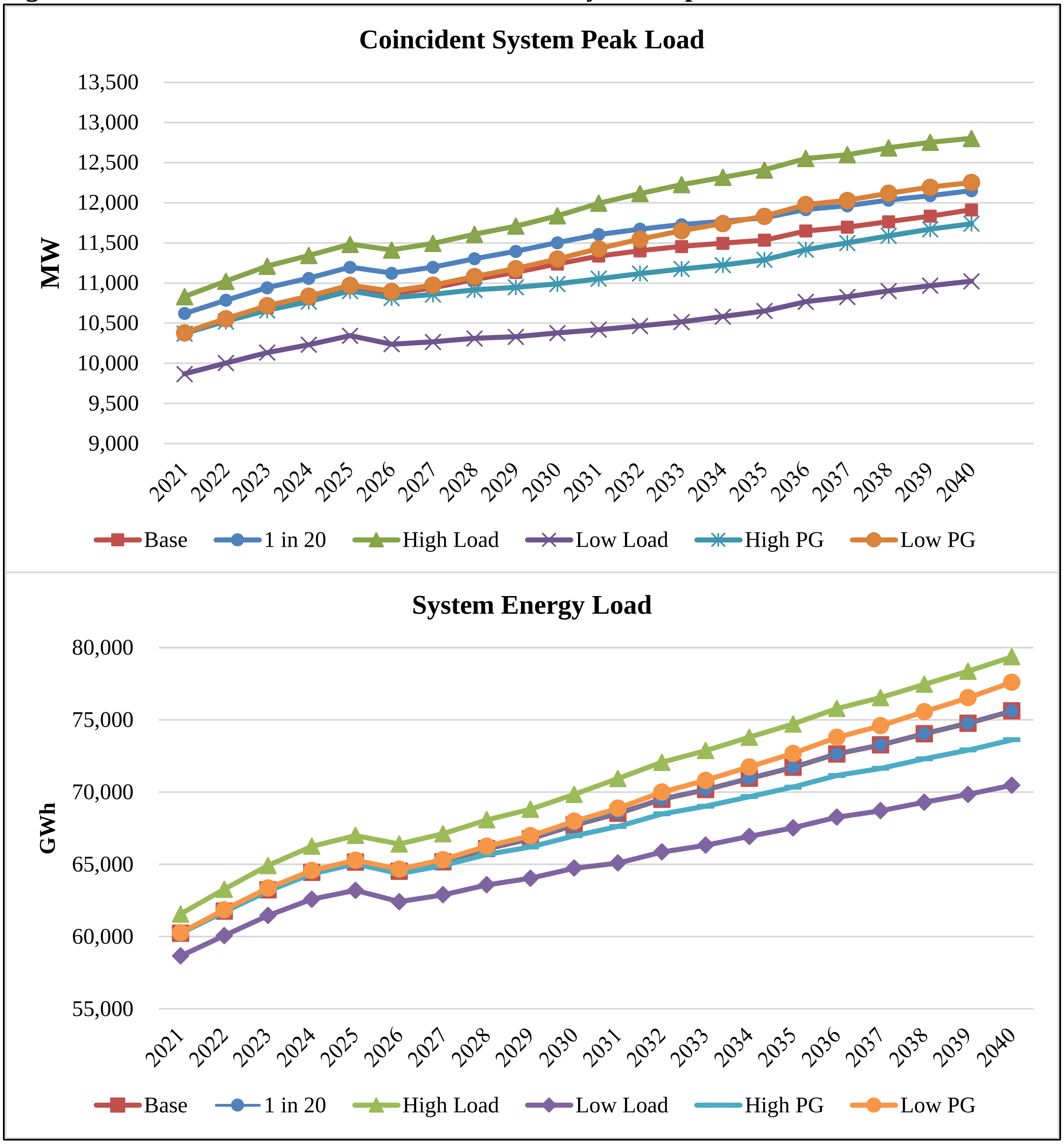
New Proxy Gas (S04)

In this sensitivity, new gas peaking resources replace non-emitting peaking resources and new combined cycle combustion turbines replace advanced nuclear resources.

Business Plan Sensitivity (S05)

Case S05 complies with the Utah requirement to perform a business plan sensitivity consistent with the commission’s order in Docket No. 15-035-04. Over the first three years, resources align with those assumed in PacifiCorp’s 2020 Business Plan. Beyond the first three years of the study period, unit retirement assumptions are aligned with those identified in the preferred portfolio. All other resource selections are optimized using the Plexos models.

Figure 17 - Load and Private Generation Sensitivity Assumptions



Levelized Cost of Energy Efficiency Bundles (S06)

For the 2021 IRP, PacifiCorp reshaped the daily volumes from energy efficiency to better align with the load forecast. This creates a realistic representation of the relationship between load and weather-sensitive energy efficiency resource options. This sensitivity tests the effectiveness of this methodology change in terms of efficiency and as measured by cost and risk metrics.

Private Generation Sensitivities (S07, S08)

Two private generation sensitivities are analyzed. As compared to base private generation penetration levels that incorporated annual reductions in technology costs, the high private generation sensitivity (S07) reflects more aggressive technology cost reduction assumptions, greater technology performance levels, and higher retail electricity rates. In contrast, the low private generation sensitivity (S08) reflects lesser reductions in technology costs, reduced technology performance levels, and lower retail electricity rates.

CHAPTER 9 – MODELING AND PORTFOLIO SELECTION RESULTS

CHAPTER HIGHLIGHTS

- Using cost and risk metrics to evaluate a wide range of resource portfolios, PacifiCorp selected a preferred portfolio reflecting a bold vision shared with our customers for a future where energy is delivered affordably, reliably and with increasingly reduced greenhouse gas emissions.
- By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source RFP final shortlist resources including 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River 1 (49 MW) and Foote Creek II-IV (43 MW) wind projects. and 4,290 MW of incremental energy efficiency and 2,448 MW of new direct load control resources.
- To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes significant transmission investments. Specifically, the 2021 IRP preferred portfolio includes the Energy Gateway South (GWS) transmission line—a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the Energy Gateway West Subsegment D.1 project (D.1)—a new 59-mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines come online by the end of 2024.
- The 2021 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt transmission line known as Boardman-to-Hemingway (B2H) to come online in 2026.
- Further, the 2021 IRP preferred portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to reliably serve our customers.
- This is the first PacifiCorp IRP that includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. The 500 MW advanced nuclear Natrium™ demonstration project will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.
- Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. Coal-fueled generation capacity is reduced by 1,300 MW by the end of 2025, 2,211 MW by 2030, and over 4,000 MW by 2040. The preferred portfolio also reflects 1,554 MW of natural gas retirements through 2040.
- In the 2021 IRP preferred portfolio, Jim Bridger Units 1 and 2 are converted to natural gas-fueled peaking units in 2024, providing a low-cost reliable resource for meeting load and reliability requirements. There are no new natural gas resources in the preferred portfolio.
- The preferred portfolio shows an overall decline in reliance on wholesale market firm purchases in the 2021 IRP preferred portfolio relative to the market purchases included in the 2019 IRP preferred portfolio.

- The 2021 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 2019 IRP, projected CO_2 emissions in 2026 are down 26 percent. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2019 IRP preferred portfolio, and down 52 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.1 million tons in 2021 to 4.8 million tons in 2040—a reduction of 88 percent.

Introduction

This chapter reports modeling and portfolio selection results for the resource portfolios developed with a broad range of input assumptions informed by the Plexos modeling. Using model data from the portfolio-development process and subsequent cost and risk analysis of unique portfolio alternatives, the following discussion describes PacifiCorp's preferred portfolio selection process and presents the 2021 IRP preferred portfolio.

This chapter is organized around the portfolio development, modeling and evaluation steps identified in the previous chapter and covers the portfolio, cost and risk analysis for the: (1) initial portfolios; (2) the variants of the top performing initial portfolio and (3) the preferred portfolio selection. The final preferred portfolio selection is informed by all relevant modeling results. This chapter also presents modeling results for additional scenarios required under Washington's Clean Energy Transformation Act (CETA) that, while informative, were not considered eligible for selection as the preferred portfolio.

Results of resource portfolio cost and risk analysis from each step are presented in the following discussion of PacifiCorp's portfolio evaluation processes. Stochastic modeling results are also summarized in Volume II, Appendix J – Stochastic Simulation Results.

Initial Portfolio Development

The following discussion begins with an examination of initial portfolios exploring variations in retirement timing, the impact of regional haze compliance operating limits and options for gas conversion or carbon capture utilization and sequestration (CCUS) retrofit for certain units. The initial portfolios differ based on planning assumptions around coal unit retirement options and retirement timing. This includes a fully optimized view of potential retirements (P02), a partially optimized view of early retirements that requires all coal units to be retired by 2030 (P03), fixed retirements based on end-of-life operating assumptions (BAU1) and forced retirements consistent with the 2019 IRP preferred portfolio (BAU2).

Following the initial portfolios, PacifiCorp examined variants of the top-performing case with eight additional portfolios referred to as the P02-MM variants. All portfolios are examined with a granular assessment of reliability requirements through the production of hourly deterministic ST studies for every year over the 20-year planning horizon. Similar to the initial portfolios, this provides twenty years of hourly ST reliability assessment data used to inform the portfolios and ensure they are reliable.

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), PacifiCorp evaluated eight variants of the top-performing P02-MM initial portfolio. Final selection of the top-performing portfolio and preferred portfolio selection also included an assessment of compliance with CETA.

Initial Portfolio Development

The following tables and figures present resource additions and system costs for the initial portfolios. Additional information is provided for all cases in Volume II, Appendix I (Capacity Expansion Results), including resource portfolio results showing new resource capacity and changes to existing resource capacity by year.

Initial Portfolios Thermal Retirements

Figure 9.1 summarizes the cumulative nameplate coal and gas retirements, including retirement of units converted or converting to gas-fueled peaking resources by case over the near-term, mid-term, and long-term among the initial portfolio cases. Note, in reporting cumulative capacity in this figure, 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 I (Capacity Expansion Results).

Through 2026, coal unit retirement capacity ranges from 230 MW (BAU1 portfolios which assume end-of-life retirements) to 2,909 MW (P03 that assumes all coal units retire by 2030 and specifically, the P03-HH and P03-SCGHG portfolios). By the end of the planning horizon, coal retirements are similar among nearly all cases with exception of P03 which includes the early retirement of Hunter Units 1-3 as part of the planning assumption to retire all units by 2030. There is slight variation in timing of coal retirements among P02 and P03. Coal retirement timing assumptions with the BAU1 and BAU2 cases are fixed based on the planning assumption end-of-life (BAU1) and the 2019 IRP preferred portfolio retirement timing (BAU2). By the end of the planning horizon, coal retirements are the same among P02, BAU1 and BAU2 cases with a total of over 4,000 MW retired by 2040 (19 of PacifiCorp's 22 units). P03 includes retirement of Hunter Units 1-3 that are accelerated from end-of-life in 2042 to a 2029 retirement.

Not shown on the chart below, gas retirements are the same among all cases and include retirement of the gas-fueled Naughton Unit 3 at the end of 2029, Gadsby Units 1-6 at the end of 2032, Hermiston at the end of 2036, and the gas-fueled Jim Bridger Units 1 and 2 at the end of 2037. This represents a total of 1,554 MW of gas retirements through 2040.

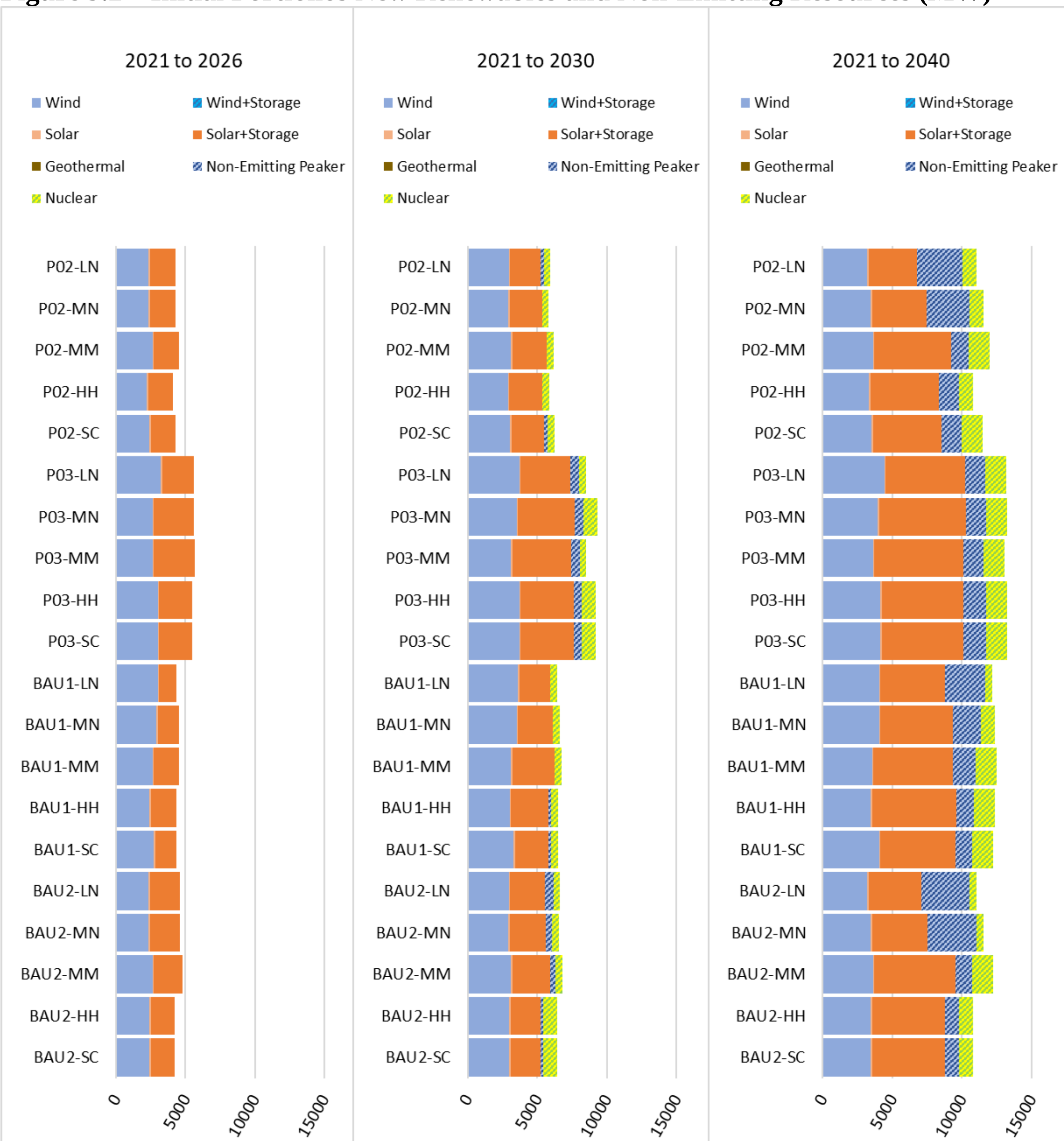
Figure 9.1 – Initial Portfolios Thermal Retirements (MW)

Initial Portfolios New Renewables and Non-Emitting Resources

Figure 9.2 reports the nameplate capacity of new renewables and non-emitting resource additions for each initial portfolio. Through 2025, all portfolios include the 2020 All-Source RFP final shortlist resources including 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. They also include the acquisition and repowering of Rock River 1 (49MW) and Foote Creek II-IV (43 MW) wind projects. In 2026, all cases include an additional 745 MW of wind and additional solar and storage ranging from 600 MW up to 1,090 MW. All cases include GWS and D.1 in 2024 along with 1,641 MW of new wind in eastern Wyoming.

All cases include B2H in 2026 along with 600 MW of new co-located solar and storage. All cases include the 500 MW Natrium™ demonstration project in 2028. Through 2040, total new renewable capacity including new wind, new solar and new solar collocated with storage ranges between 6,794 MW and 10,306 MW. Through 2040, total new nuclear and non-emitting peaking resource capacity ranges between 2,010 MW and 4,277 MW.

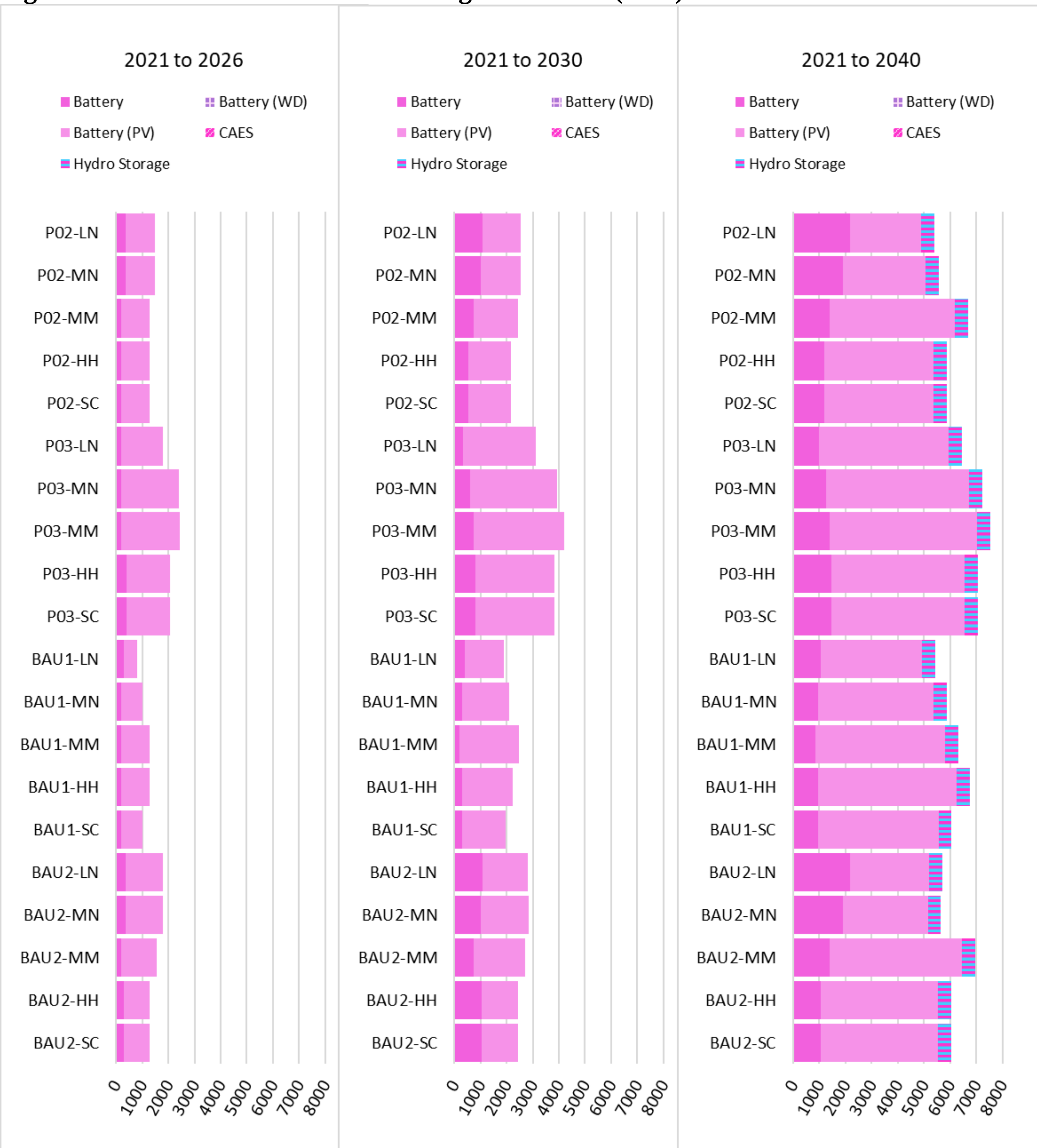
Figure 9.2 – Initial Portfolios New Renewables and Non-Emitting Resources (MW)



Initial Portfolios New Storage Resources

Figure 9.3 summarizes cumulative nameplate capacity of new storage resources for each initial portfolio. Through 2025, all cases include the 2020 All-Source RFP final shortlist resources including 697 MW of battery storage capacity – 497 MW paired with solar and a 200 MW standalone battery. More storage resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements. Through 2040, total storage selections range between 5,404 MW (P02-LN) and 7,531 MW (P03-MM) including storage co-located with solar, standalone battery and a 500 MW pumped storage project selected in all cases in 2040.

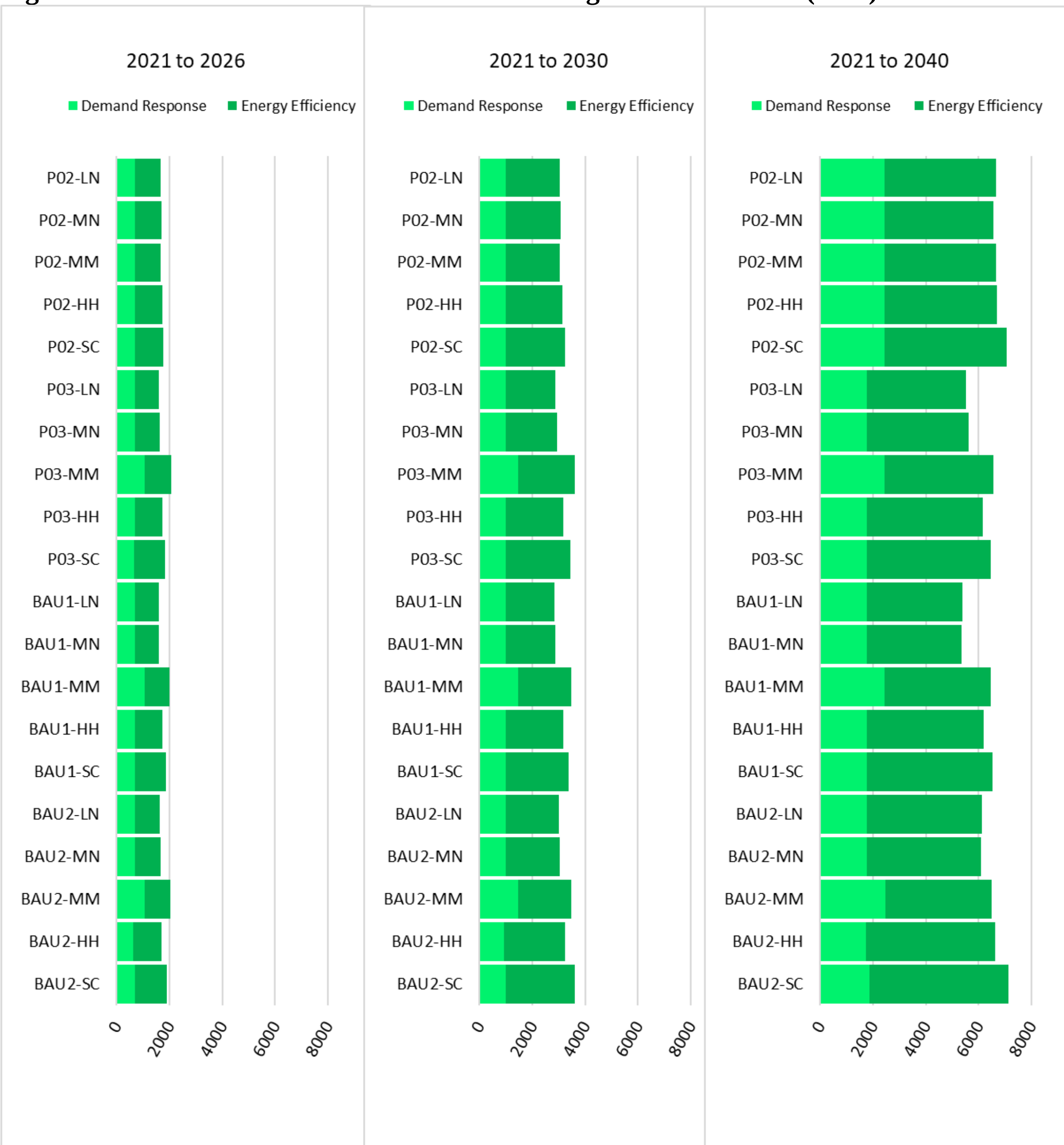
Figure 9.3 – Initial Portfolios New Storage Resources (MW)



Initial Portfolios Demand-Side Management (DSM) Resources

Figure 9.4 summarizes aggregated Demand-Side Management (DSM) selections by case. DSM selections continue to be relatively stable among all cases however, variations do occur among price-policy assumptions relative to CO_2. Through 2030, energy efficiency selections range between 1,845 MW (Case BAU1-LN) and 2,589 (Case BAU2-SC); demand response selections range between 918 MW (Case BAU2-HH) and 1,469 MW (Cases BAU-1 MM, BAU-2 MM, P-03 MM). More demand response resources are accelerated into the mid-term among those cases that have higher levels of accelerated coal and gas retirements. Through 2040, energy efficiency selections range between 3,605 MW (Case BAU1-MN) and 5,249 (Case BAU2-SC); demand response selections range between 1,752 MW (Case BAU2-HH) and 2,458 MW (Case BAU2-MM).

Figure 9.4 – Initial Portfolios Demand-Side Management Resources (MW)



CO_2 Emissions

Figure 9.5 reports cumulative CO_2 emissions for each initial portfolio. Total CO_2 emissions across the initial portfolios are stable under the medium gas, medium CO_2 (MM) price policy conditions, averaging 372 million tons over the 20-year planning period. Emissions are generally higher in cases with no CO_2 price, averaging 427 million tons in low gas, no CO_2 (LN) and medium gas, no CO_2 (MN) price-policy conditions. Under high gas, high CO_2 (HH) price environments, emissions average 323 million tons. The lowest emissions are reported under the social cost of greenhouse gas (SCGHG) price-policy portfolios, averaging 195 million tons. Emissions across all cases range from 171 million tons (P03-SCGHG) to 550 million tons (P02-MN).

Figure 9.5 – Initial Portfolios CO_2 Emissions (Million Tons)

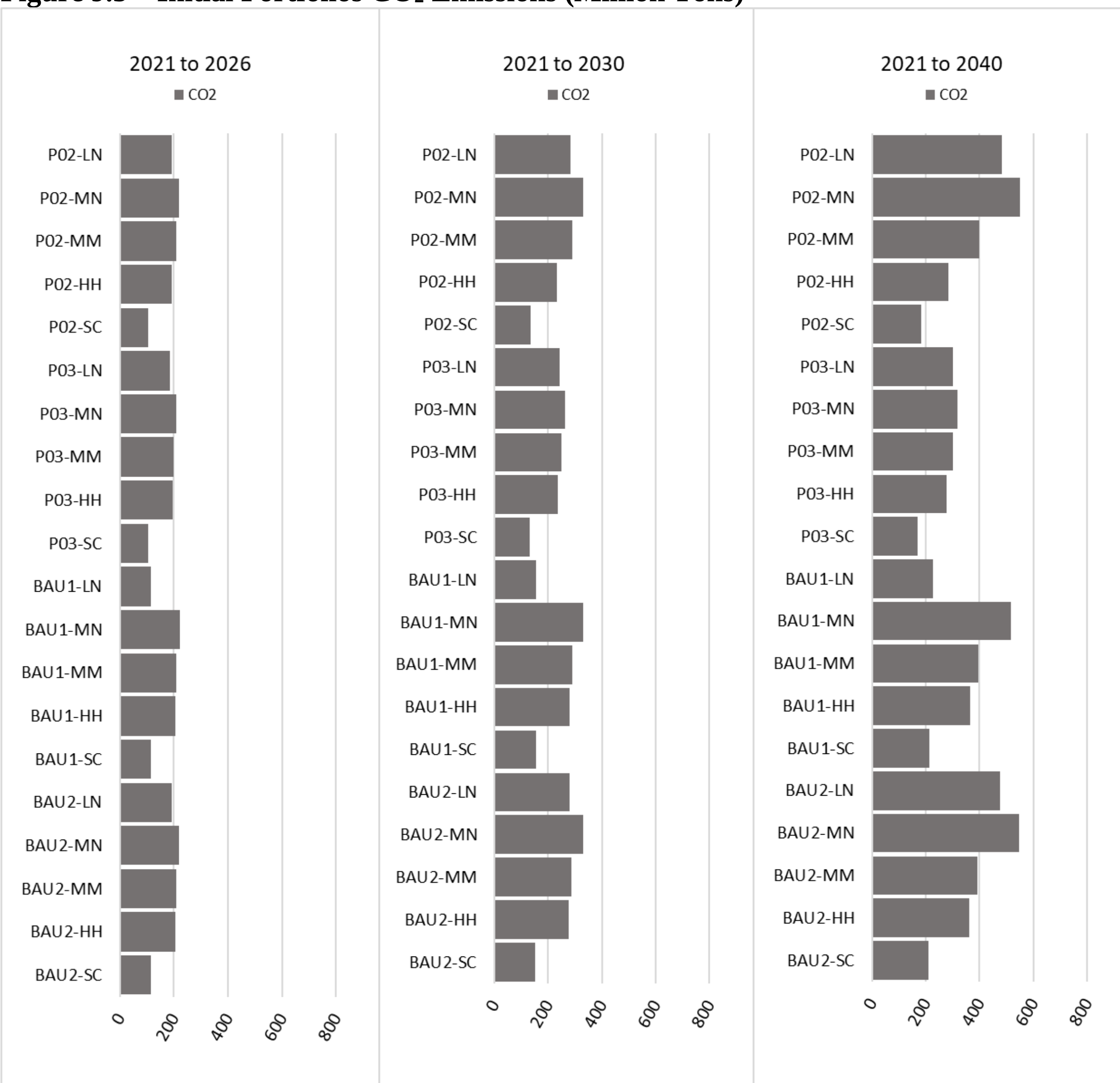


Table 9.1 to Table 9.**5** present cost and risk results for the initial portfolios across five price-policy scenarios, including the deterministic present value revenue requirement (PVRR), the risk-adjusted PVRR, the amount of energy not served (ENS) as a percentage of load, and total CO_2 emissions.

As shown in Table 9.1, the medium gas/medium CO_2 price-policy scenario, P02 outperforms other cases on a PVRR basis, risk-adjusted PVRR, and ENS. While P02 has higher cumulative CO_2 emissions, P03 has a risk-adjusted cost that is $1.7b higher than P02. Emissions levels are similar among the P02, BAU1, and BAU2 portfolios.

Table 9.1 – Initial Portfolios Cost and Risk Results Summary (Medium Gas/Medium CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MM	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	25,794	$0	1	26,151	$0	1	0.0049%	0.00000%	1	398,953	97,568	4
P03	27,566	$1,772	4	27,848	$1,696	4	0.0051%	0.00021%	2	301,385	0	1
BAU1	26,839	$1,045	3	27,172	$1,021	3	0.0051%	0.00021%	3	395,123	93,738	3
BAU2	26,691	$897	2	27,026	$875	2	0.0053%	0.00037%	4	391,900	90,515	2

As shown in Table 9.2, In the low gas/no CO_2 price-policy scenario, P02 outperforms other cases on cost and ENS and has comparable emissions to BAU1 and BAU2. P02 cumulative CO_2 emissions are higher than in P03, driven by P03 retirement assumptions of retiring all coal by 2030, which has a risk-adjusted cost that is $2.5b higher than P02. Emissions levels are similar among the P02, BAU1, and BAU2 portfolios.

Table 9.2 – Initial Portfolios Cost and Risk Results Summary (Low Gas/No CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - LN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	21,973	$0	1	22,224	$0	1	0.0053%	$0	1	472,867	172,908	4
P03	24,582	$2,609	4	24,744	$2,520	4	0.0055%	$0	2	299,959	0	1
BAU1	22,426	$453	2	22,635	$411	2	0.0058%	$0	4	447,378	147,419	2
BAU2	22,452	$479	3	22,707	$483	3	0.0057%	$0	3	466,064	166,105	3

As shown in Table 9.**3**, In the medium gas/no CO_2 price-policy scenario, P02 outperforms other cases on costs and ENS and has comparable emissions to BAU1 and BAU2. P02 cumulative CO_2 emissions are higher than in P03, driven by P03 retirement assumptions of retiring all coal by 2030, which has a risk-adjusted cost that is $3.5b higher than P02.

Table 9.3 **– Initial Portfolios Cost and Risk Results Summary (Medium Gas/No CO_2)**

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - MN	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	21,994	$0	1	22,228	$0	1	0.0049%	$0	1	540,688	224,270	4
P03	25,588	$3,594	4	25,752	$3,523	4	0.0053%	$0	3	316,418	0	1
BAU1	22,471	$477	3	22,649	$420	2	0.0052%	$0	2	517,882	201,464	2
BAU2	22,432	$439	2	22,674	$445	3	0.0055%	$0	4	537,670	221,252	3

As shown in Table 9.**4**, In the high gas/high CO_2 price-policy scenario, P02 outperforms other cases on costs and ENS and has comparable emissions to P03, the case with lowest emissions, which has a risk-adjusted cost that is $1.0b higher than P02.

Table 9.4 – Initial Portfolios Cost and Risk Results Summary (High Gas/High CO_2)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - HH	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	27,464	$0	1	27,965	$0	1	0.0056%	$0	1	283,845	5,527	2
P03	28,643	$1,179	2	29,002	$1,037	2	0.0059%	$0	3	278,317	0	1
BAU1	29,280	$1,815	4	29,776	$1,810	4	0.0056%	$0	2	365,205	86,888	4
BAU2	28,856	$1,391	3	29,356	$1,391	3	0.0060%	$0	4	363,367	85,050	3

In the medium gas/social cost of greenhouse gas scenario, P02 outperforms other cases on cost except for P03, outperforms P03 and BAU2 on ENS, and ties BAU1 on ENS. P02 emissions are comparable to P03 emissions, the case with lowest emissions. P03 retires all coal by 2030 and has a risk-adjusted cost that is $178m lower than P02.

Table 9.5 – Initial Portfolios Cost and Risk Results Summary (Med Gas/Social Cost and Greenhouse Gas)

	ST Value			Risk Adjusted			ENS Average Percent of Load			CO2 Emissions		
Case - SCGHG	PVRR ($m)	Change from Lowest Cost Portfolio ($m)	Rank	ST PVRR plus 5% of 95th Stochastic ($m)	Change from Lowest Cost Portfolio ($m)	Rank	Average Annual ENS, 2021-2040 % of Average Load	Change from Lowest ENS Portfolio	Rank	Total CO2 Emissions, 2021-2040 (Thousand Tons)	Change from Lowest Emission Portfolio	Rank
P02	38,371	$80	2	39,290	$178	2	0.0068%	$0	1	184,121	13,417	2
P03	38,291	$0	1	39,112	$0	1	0.0110%	$0	3	170,704	0	1
BAU1	40,356	$2,065	4	41,393	$2,281	4	0.0102%	$0	2	214,365	43,662	4
BAU2	40,154	$1,863	3	41,196	$2,084	3	0.0137%	$0	4	209,299	38,595	3

Based on these findings, PacifiCorp identified P02-MM as the top-performing portfolio at this stage of the portfolio-development process. PacifiCorp developed and analyzed additional portfolios as variants of P02-MM, as described in the following section.

P02 Variant Portfolios

Eight P02 variant portfolios were developed from the top-performing P02-MM portfolio to analyze key resources and in response to stakeholder interest. The P02 variant portfolios are summarized in the Table 9.6.

Table 9.6 – P02 Variant Portfolios

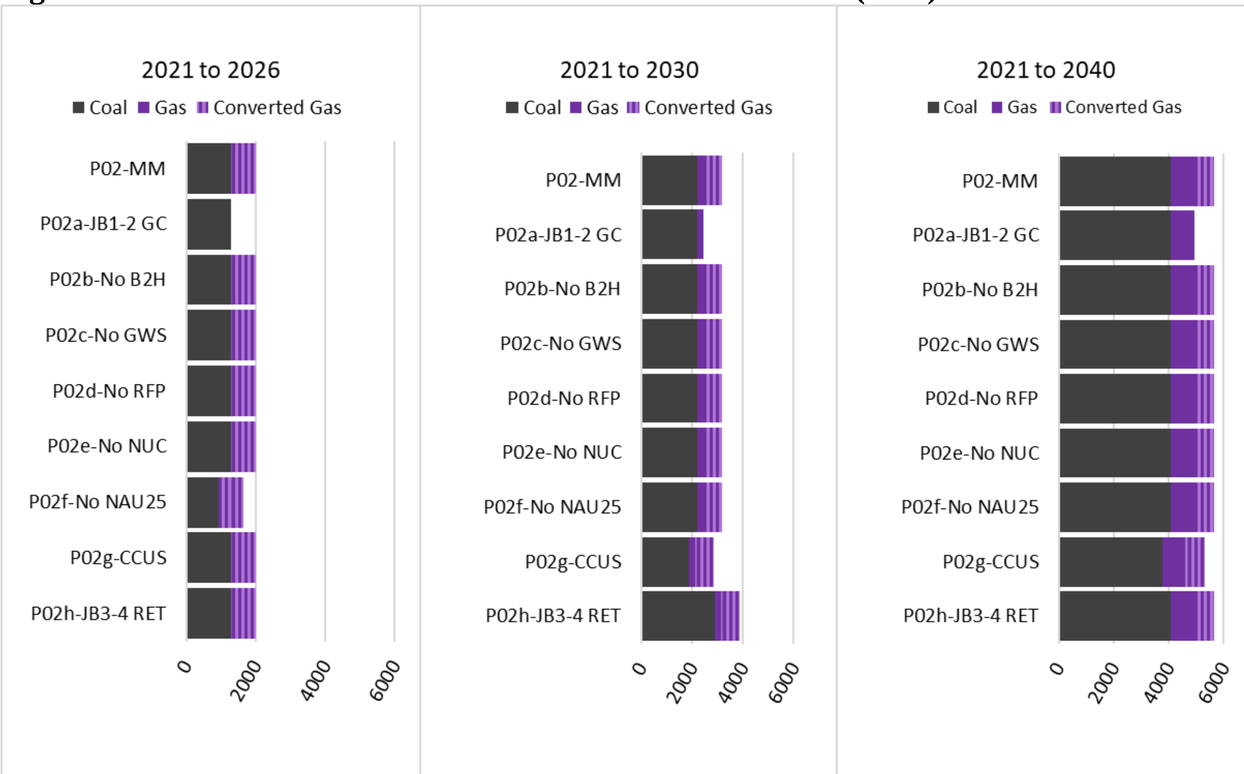
Case	Description
P02a – JB1-2 No GC	Excludes gas conversion of Jim Bridger Units 1 and 2
P02b – No B2H	Excludes Boardman-to-Hemingway transmission segment
P02c – No GWS	Excludes the Energy Gateway South transmission segment
P02d – No RFP	Excludes 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment
P02e – No Nuc	Excludes the Natrium™ advanced nuclear demonstration project
P02f – No Nau 25	Excludes the early retirement of Naughton Units 1 and 2
P02g – CCUS	Includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4 in response to Wyoming House Bill 200
P02h – JB 3-4 Retire	Includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback

P02 Variant Portfolios Portfolio Summary

Coal and Gas Retirements

Figure 9.6 summarizes cumulative nameplate coal and gas retirements for the P02 variant portfolios 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 I (Capacity Expansion Results). Through 2026, total coal retirements range between 944 MW (P02e – No Nau 25) and 1,302 MW (P02-MM and all other P02 variant portfolios). Through the end of 2030, coal retirements range between 1,882 MW (P02g – CCUS) and 2,911 MW (P02h – JB 3-4 Retire). Through 2040, total coal retirements are 4,088 MW in each case with exception of P02g – CCUS, which totals 3,758 MW resulting from the CCUS retrofit of Dave Johnston Unit 4.

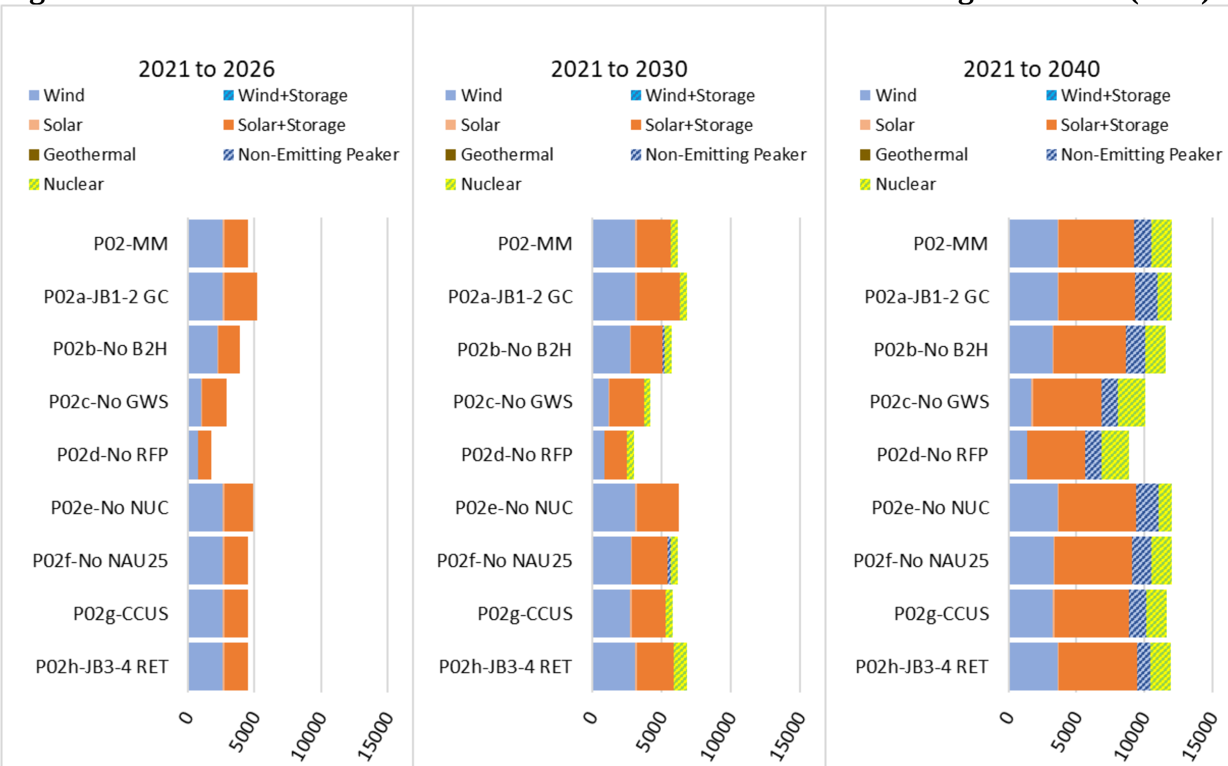
Figure 9.6 – P02 Variant Portfolios Coal and Gas Retirements (MW)



New Renewable and Non-Emitting Resources

Figure 9.7 summarizes the capacity of new renewables and non-emitting resource additions for each of the P02 variant portfolios. P02b excludes B2H in 2026 along with 600 MW of new co-located solar and storage. P02c (no GWS or D.1) excludes 1,641 MW of new wind in eastern Wyoming. P02d (no RFP bids, no GWS, and no D.1) results in the lowest new renewable additions, excluding 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity. P02e excludes the 500 MW Natrium™ demonstration project in 2028, resulting in the lowest nuclear resource additions across the horizon at 1,000 MW in 2038; P02e also has the highest non-emitting peaking additions, at 1,638 MW.

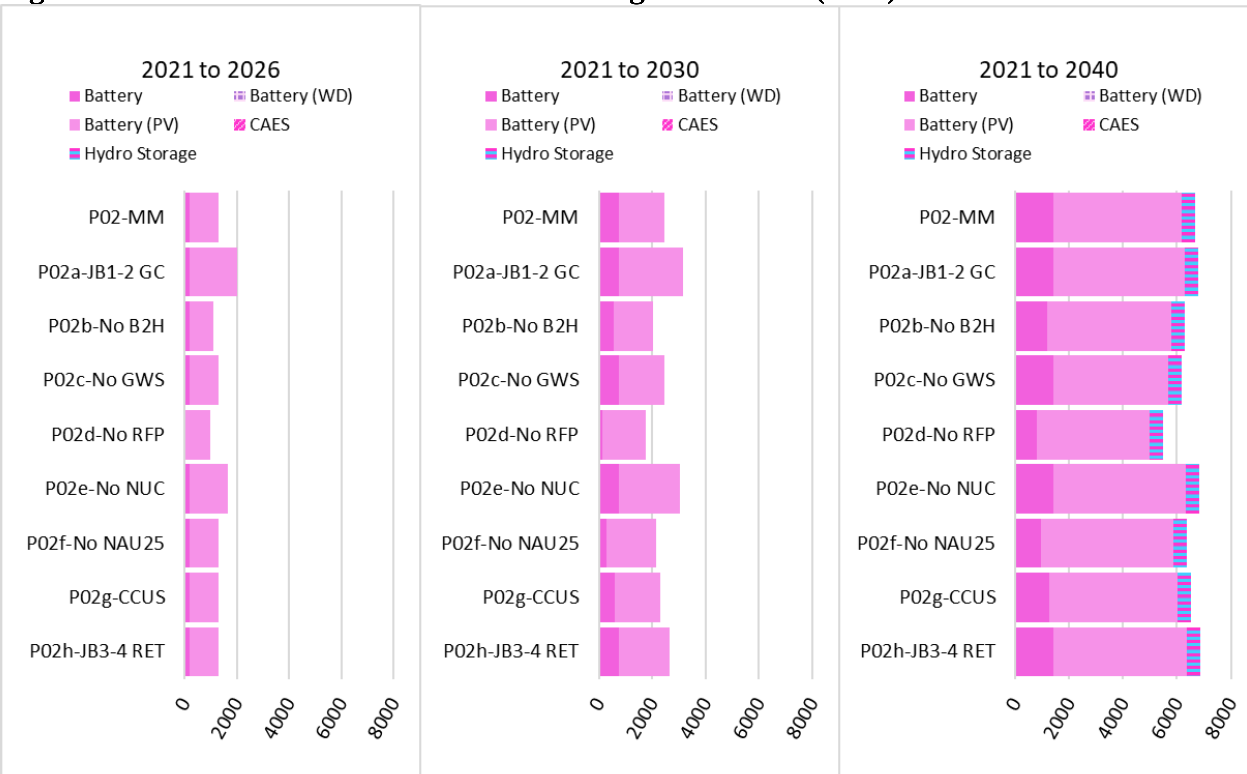
Figure 9.7 – P02 Variant Portfolios New Renewables and Non-Emitting Resources (MW)



New Storage Resources

Figure 9.8 summarizes the capacity of new storage resource additions for each of the P02 variant portfolios. P02d-No RFP adds the least total battery resource in the absence of the All-Source RFP resources, and the GWS and D.1 transmission lines. This is due to larger additions of advance nuclear and non-emitting peaking units needed to meet system requirements. With the removal of large dispatchable resources, such as the Natrium™ demonstration project (P02e-No Nuc) or the Jim Bridger plant (P02h-JB 3-4 Retire), there are higher selections of storage to maximize the value of renewable additions.

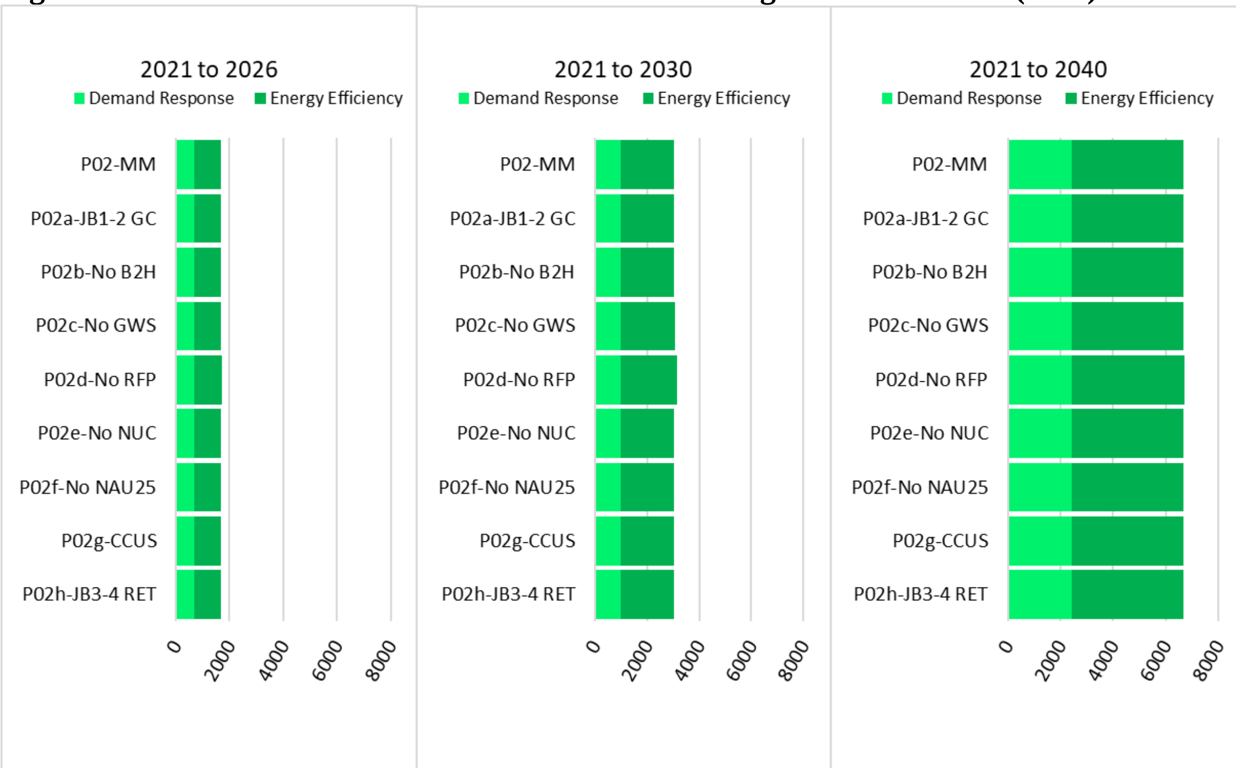
Figure 9.8 – P02 Variant Portfolios New Storage Resources (MW)



P02 Variant Portfolios Demand-Side Management Resources

Figure 9.9 summarizes aggregated DSM selections by case. DSM selections remain relatively consistent among P02 variants and range between 1,669 MW and 1,709 MW through 2026. Through 2040, energy efficiency selections and demand response total investments are consistent among the P02 variant portfolios.

Figure 9.9 – P02 Variant Portfolios Demand-Side Management Resources (MW)



CO_2 Emissions

Figure 9.10 reports cumulative CO_2 emissions for each of the P02 variant portfolios. Total CO_2 emissions through 2026 are very stable, ranging between 205 million tons (P02a-JB1-2 GC) and 220 million tons (P02d-No RFP). Through 2040, cumulative CO_2 emissions range between 369 million tons (P02h-JB3-4 Retire) and 476 (P02d-No RFP GWS) million tons.

Figure 9.10 – P02 Variant Portfolios CO_2 Emissions Summary (Million Tons)

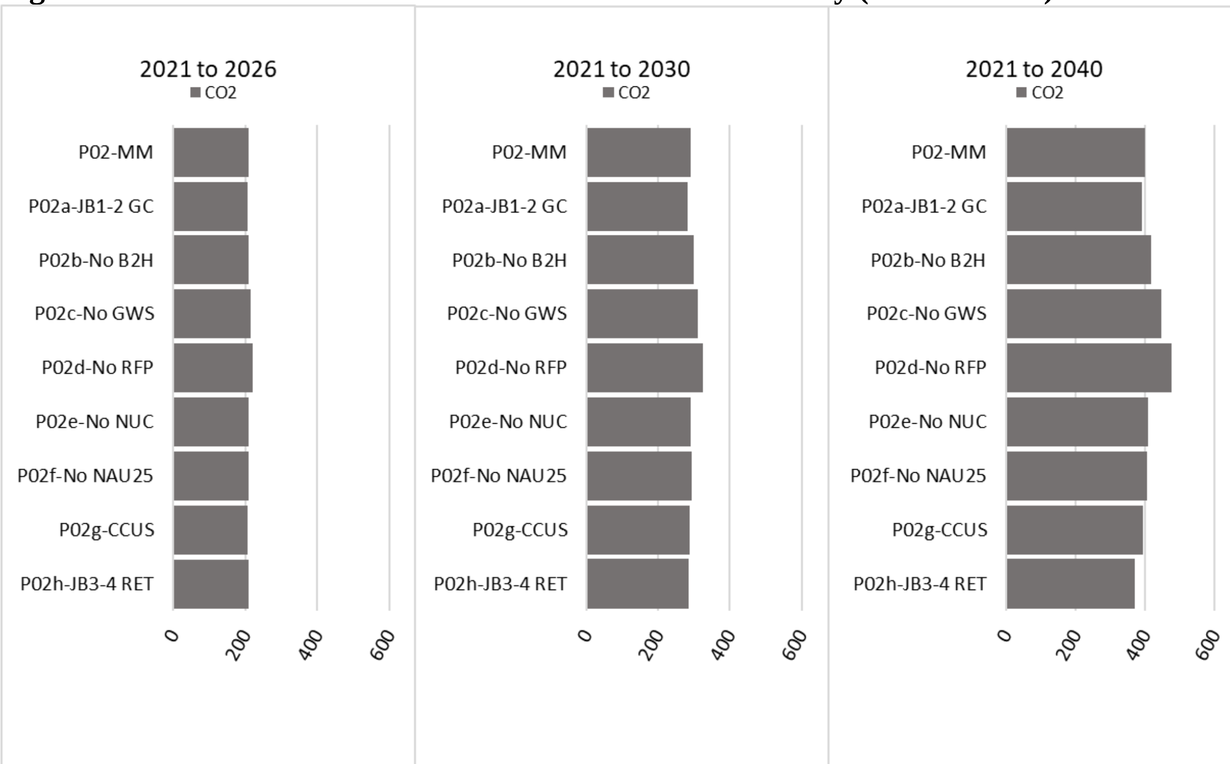
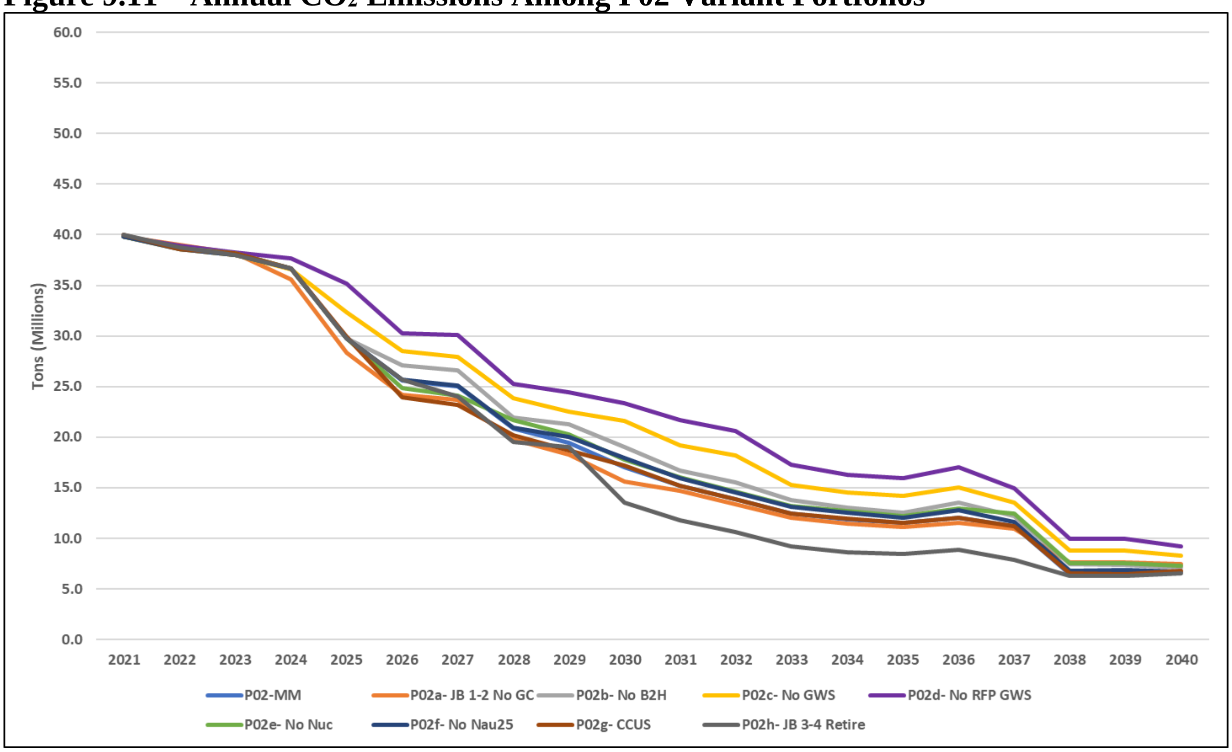


Figure 9.11 shows the annual emissions profile for the P02-MM portfolio and the eight P02 variant portfolios through the end of the planning period in 2040.

Figure 9.11 – Annual CO_2 Emissions Among P02 Variant Portfolios



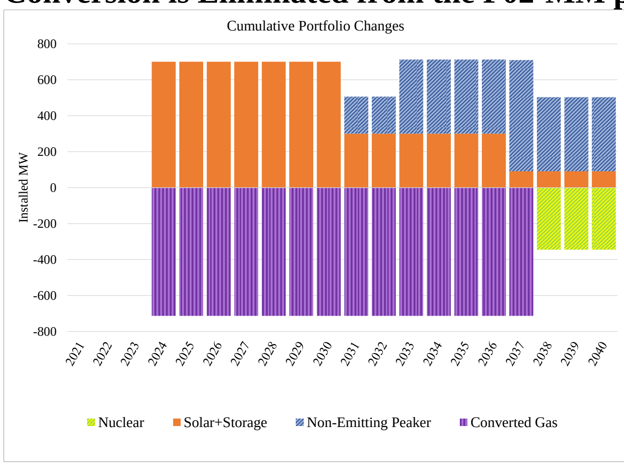
P02 Variants Portfolio Discussion

Jim Bridger Unit 1 and Unit 2 Gas Conversion Variant (P02a-JB 1-2 GC)

The P02a-JB 1-2 No GC portfolio is a variant of the P02-MM portfolio that eliminates the gas conversion of Jim Bridger Units 1 and 2. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the gas conversion of Jim Bridger Units 1 and 2 can be isolated.

Figure 9.12 shows the cumulative (at left) and incremental (at right) portfolio changes when the gas conversion of Jim Bridger Units 1 and 2 is eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the conversion is eliminated. Without the gas conversion, the model optimizes the next-best selection and indicates that Jim Bridger Units 1 and 2 retire at the end of 2023 and an additional 700 MW of solar co-located with storage is added in 2024. Over 600 MW of non-emitting peakers displace a similar amount of solar co-located with storage over the 2031-2037 timeframe. In 2038, considering Jim Bridger Units 1 and 2 were already retired at the end of 2023, the case without gas conversion avoids an advanced nuclear resource and non-emitting peaker resources that are required in the P02-MM portfolio when the converted units would have otherwise retired.

Figure 9.12 – Increase/(Decrease) in Proxy Resources when the Jim Bridger Gas Conversion is Eliminated from the P02-MM portfolio.



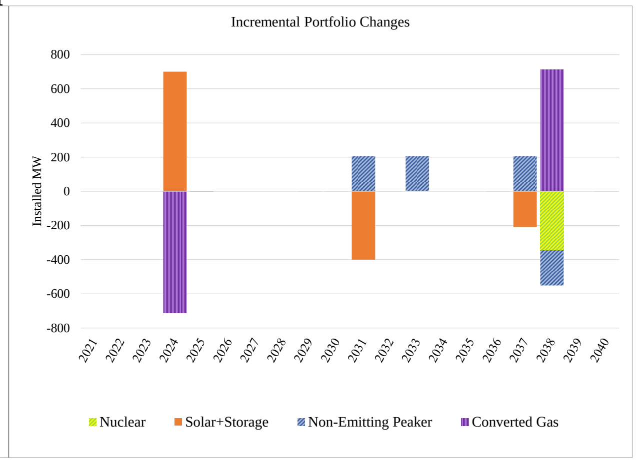


Figure 9.13 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the gas conversion of Jim Bridger Units 1 and 2 is eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative present-value revenue requirement differential (PVRR(d)) over time (the dashed black line).[1] Through 2040, the PVRR(d) shows that the portfolio without gas conversion of Jim Bridger Units 1 and 2 is $447 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without gas conversion is $469 million higher cost than the P02-MM portfolio.

The key drivers to this result are consistent with changes in resources between the two portfolios. The portfolio without gas conversion retires Jim Bridger Units 1 and 2 at the end of 2023 (the next

[1] The PVRR(d) represents the differential in revenue requirement costs relative to the P02-MM portfolio.

best alternative to gas conversion), which triggers the addition of 700 MW of solar co-located with storage in 2024. The initial capital associated with the 700 MW solar resource paired with 700 MW of 4-hour storage is $2,890/kW. The initial capital required to convert Jim Bridger Units 1 and 2 to natural gas is about $25/kW.

Figure 9.13 – Increase/(Decrease) in System Costs when the Jim Bridger Gas Conversion is Eliminated from the P02-MM portfolio.

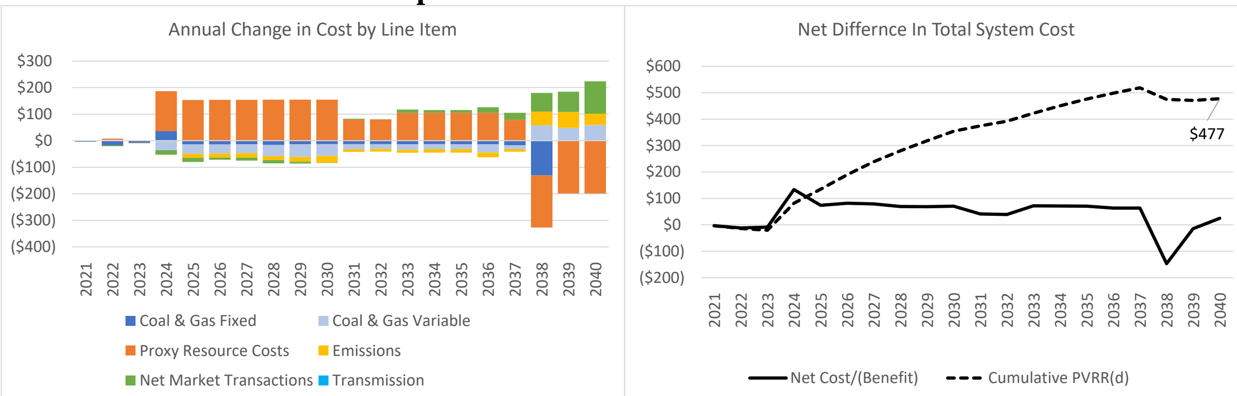


Table 9.7 summarizes the PVRR(d) of the P02a-JB 1-2 No GC portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. The portfolio that eliminates gas conversion for Jim Bridger Units 1 and 2 is significantly higher cost than the P02-MM portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable among all price-policy scenarios. Emissions are slightly higher when Jim Bridger Units 1 and 2 are converted to natural gas (approximately 1-2 percent relative to the case without gas conversion). In aggregate, these results support the inclusion of the Jim Bridger Unit 1 and 2 gas conversion in the preferred portfolio.

Table 9.7 – PVRR(d) of the P02a-JB 1-2 No GC Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02a-MM-MM	$26,271	$26,620	0.0049%	390,206
P02a-MM-LN	$23,126	$23,322	0.0051%	427,277
P02a-MM-MN	$22,916	$23,095	0.0049%	504,386
P02a-MM-HH	$29,198	$29,684	0.0050%	360,636
P02a-MM-SCGHG	$39,991	$41,000	0.0097%	206,732
Change from P02-MM-MM	$477	$469	0.0000%	(8,747)
Change from P02-MM-LN	$534	$529	-0.0003%	(8,857)
Change from P02-MM-MN	$495	$486	0.0000%	(6,982)
Change from P02-MM-HH	$418	$404	0.0001%	(7,915)
Change from P02-MM-SCGHG	$353	$335	0.0003%	(1,918)

Boardman-to-Hemingway Variant (P02b-No B2H)

The P02b-No B2H portfolio is a variant of the P02-MM portfolio that eliminates the B2H transmission line. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the B2H transmission line can be isolated.

Figure 9.14 shows the cumulative (at left) and incremental (at right) portfolio changes when the B2H transmission line is eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission line is eliminated. Without B2H, 405 MW of wind and 200 MW of solar co-located with storage is removed from the portfolio in 2026. Approximately 200 MW of storage capacity is removed from eastern Wyoming in 2029, which must be replaced by just over 200 MW of non-emitting peaking capacity in 2030.

Figure 9.14 – Increase/(Decrease) in Proxy Resources when the B2H Transmission Line is Eliminated from the P02-MM portfolio.

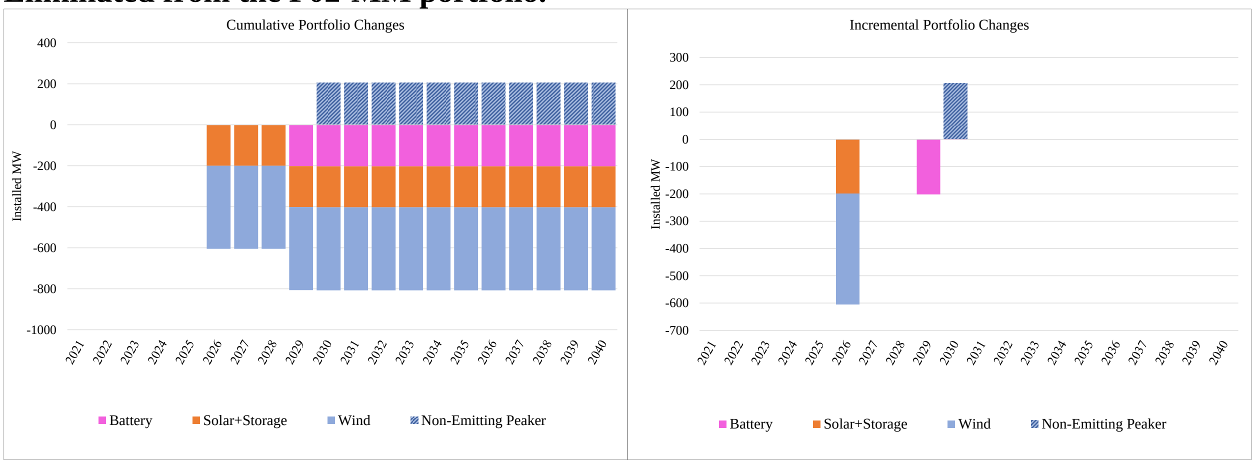


Figure 9.15 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the B2H transmission line is eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the B2H transmission line is $388 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without B2H is $453 million higher cost than the P02-MM portfolio.

Without the B2H transmission line, the cost for proxy resources is reduced consistent with the changes in the resource portfolio. However, the reduction in resources results in an increase in net market costs, indicating that without the B2H transmission line, the system would be more dependent on the market. With fewer renewable resources, output from coal and gas resources increase, emissions increase, and the associated costs from higher fossil-fueled generation and emissions also increase. The increase in transmission costs is driven by the incremental costs to reliably serve increasing load in central Oregon. The B2H transmission line provides more flexibility and increased load-serving capability on the 500-kV transmission system into the central Oregon load pocket. Without the B2H transmission line, additional resources would need to be sited in southern Oregon that could be called upon to maintain reliable operations of the broader transmission system in the region. The analysis assumes that 725 MW of incremental 4hour battery resources and other transmission upgrades would be needed in southern Oregon if the B2H transmission line is not built. The transmission cost savings reflect the fact that these investments would be avoided if B2H is built.

Figure 9.15 – Increase/(Decrease) in System Costs when the B2H Transmission Line is Eliminated from the P02-MM portfolio.

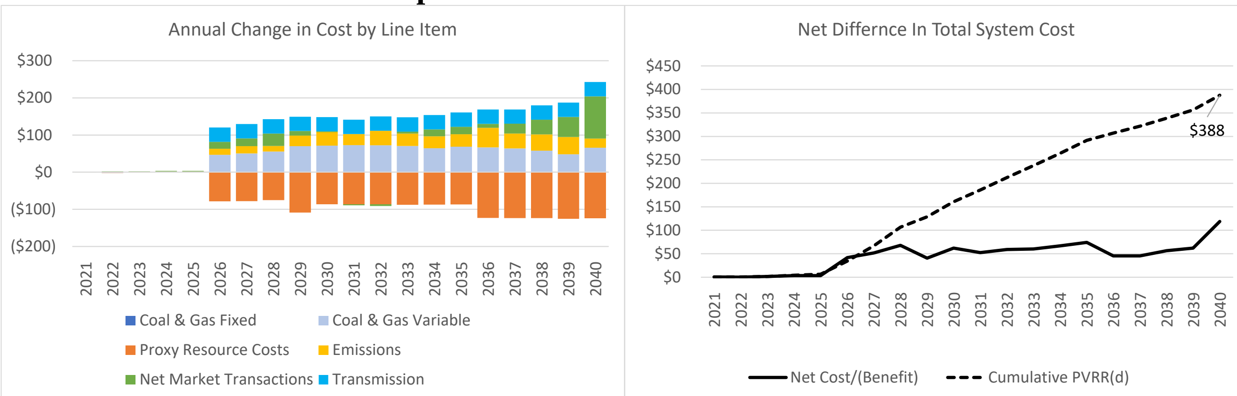


Table 9.8 summarizes the PVRR(d) of the P02b-No B2H portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. Eliminating the B2H transmission line increases the ST PVRR and the risk-adjusted PVRR all price-policy scenarios Removal of B2H also results in higher emissions (emissions increase by approximately 5 percent in the MM price-policy scenario). Note, that both portfolios, as measured by ENS results, are very reliable among all price-policy scenarios. While the cost increase from B2H in the LN price-policy scenario is low relative to other price-policy scenarios, it is more likely than not that there will be some form of policy that will impute a cost on greenhouse gas emissions. It is also unlikely that gas prices will remain low for decades to come. In aggregate, these results support the inclusion of the B2H transmission line in the preferred portfolio.

Table 9.8 – PVRR(d) of the P02b-No B2H Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02b-MM-MM	$26,181	$26,605	0.0050%	418,015
P02b-MM-LN	$22,622	$22,874	0.0054%	456,553
P02b-MM-MN	$22,575	$22,822	0.0050%	527,710
P02b-MM-HH	$29,521	$30,102	0.0050%	387,960
P02b-MM-SCGHG	$41,089	$42,223	0.0117%	228,728
Change from P02-MM-MM	$388	$453	0.0001%	19,062
Change from P02-MM-LN	$30	$81	0.0001%	20,419
Change from P02-MM-MN	$154	$213	0.0000%	16,342
Change from P02-MM-HH	$742	$822	0.0001%	19,408
Change from P02-MM-SCGHG	$1,450	$1,557	0.0023%	20,078

Energy Gateway South and Sub-Segment D.1 Variant (P02c-No GWS)

The P02c-No GWS portfolio is a variant of the P02-MM portfolio that eliminates the GWS and D.1 transmission lines. Because wind bids selected to the 2020AS RFP final shortlist that are located in eastern Wyoming cannot interconnect without these two transmission lines,[2] these resources are also eliminated from the P02c-No GWS portfolio. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the GWS and D.1 transmission lines can be isolated.

Figure 9.16 shows the cumulative (at left) and incremental (at right) portfolio changes when the GWS and D.1 transmission line are eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the transmission lines are eliminated. Without GWS and D.1, 2020AS RFP wind resources are removed from the portfolio in 2024 (shown as a reduction in 2025, the first full year these resources would be online). An additional 289 MW of wind is eliminated in 2030. In 2034, the absence of the new wind resources triggers the addition of an additional advanced nuclear plant that displaces solar co-located with storage resources. The lack of resource additions with the removal of wind resources in the portfolio without GWS and D.1 signals an increase in market reliance.

Figure 9.16 – Increase/(Decrease) in Proxy Resources when the GWS and D.1 Transmission Lines are Eliminated from the P02-MM portfolio.

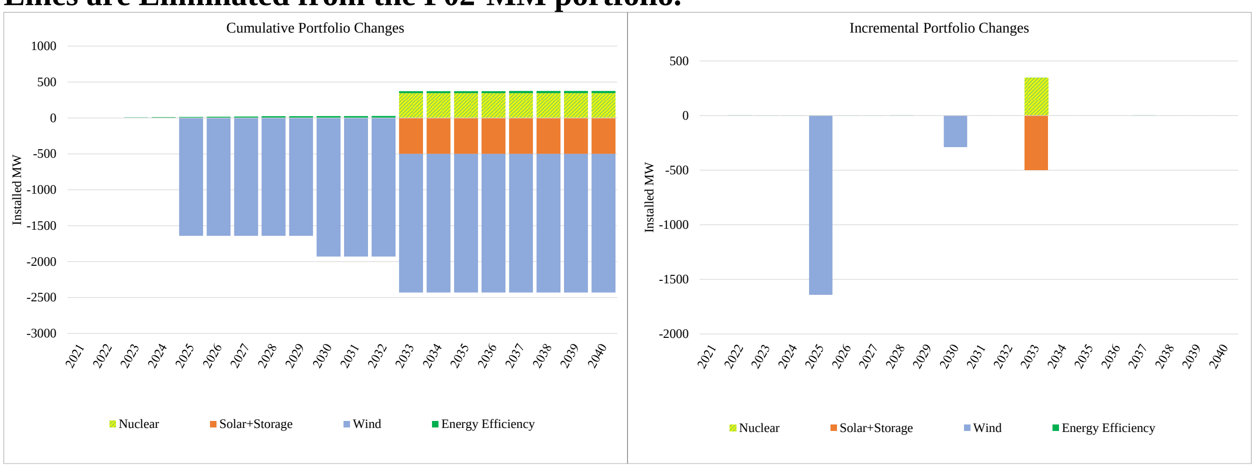
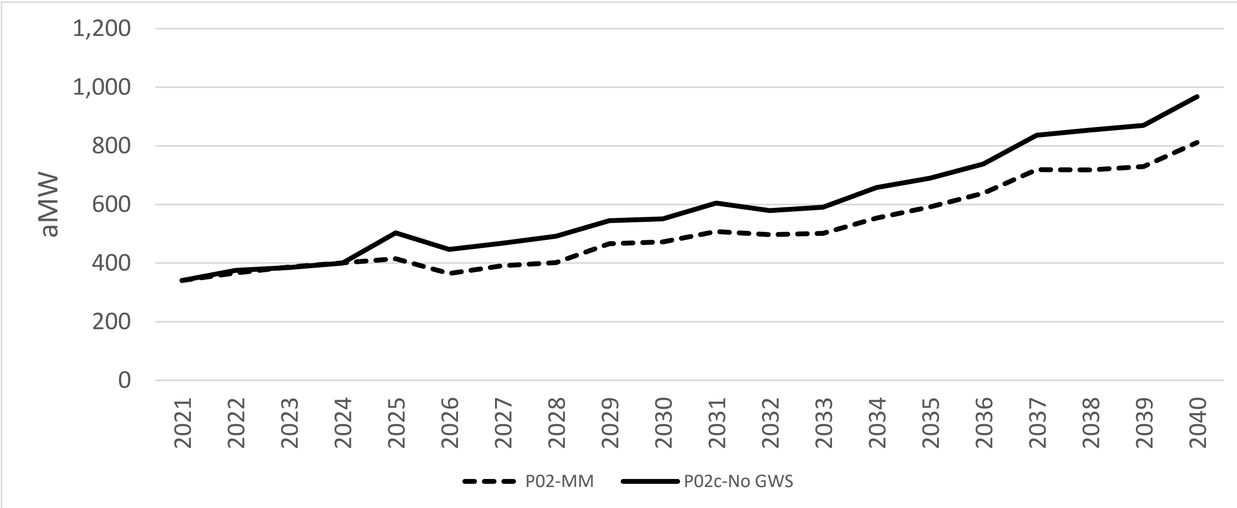


Figure 9.17 shows how market purchases change when the GWS and D.1 transmission lines are removed from the portfolio. With fewer resources, market purchases on an annual basis increase by nearly 20% if GWS and D.1 are removed from the portfolio. Consequently, there is elevated market-reliance risk if the GWS and D.1 transmission lines are not built.

[2] Examination of this variant focuses on the estimated impacts to resource procurement, market purchases, and system costs, but ignores the elimination of GWS and D.1 transmission lines would interfere with PacifiCorp transmission's ability to provide nearly 2,500 MW of requests for transmission and interconnection service governed by multiple FERC-jurisdictional executed contracts.

Figure 9.17 – Increase/(Decrease) Market Purchases in the P02-MM and P02c-No GWS Portfolios.

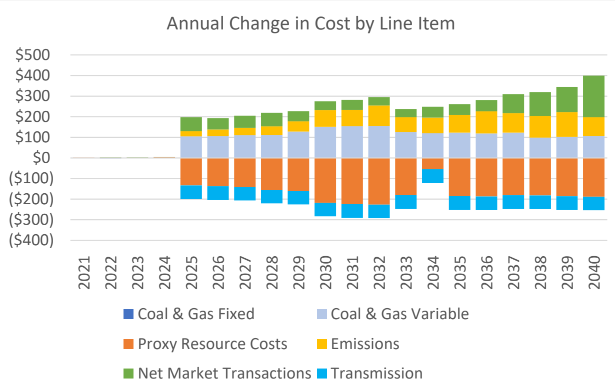


When GWS, D.1, and the associated 2020AS RFP wind resources are removed from the portfolio, the costs associated with new resources decline. The cost for transmission is also reduced. This reduction in transmission cost is net of the cost required to build a new 230-kV line to accommodate PacifiCorp's obligation to provide firm point-to-point transmission service to a third-party transmission customer. The 230-kV alternative is not avoidable if GWS is not built. Further, the $1.4 billion cost assumed for this alternative is the minimum cost for the alternative considering that it includes only the upgrades required to grant a single transmission service request. Additional costs would be incurred to accommodate additional requests for interconnection service. To accommodate all of these requests, it is likely the alternative would be to construct GWS.

When the GWS and D.1 transmission lines are removed from the portfolio, coal and gas generation is increased, which increases variable costs for existing fossil-fired resources and the associated cost for increased emissions. Further, the system becomes more reliant on the market as shown by increased market costs. As noted above, this not only increases costs to the system, but it also introduces incremental market-reliance risk, which is not captured in PVRR results. The increase in system costs that occurs in 2034 coincides with the period where production tax credits associated with new wind in the P02-MM portfolio roll off and when there is a shift in the resource mix between the two cases (without GWS, D.1, and the associated 2020AS RFP wind, an additional advanced nuclear facility is required).

Figure 9.18 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the GWS and D.1 transmission lines are eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the GWS and D.1 transmission lines is $156 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the GWS and D.1 transmission lines is $288 million higher cost than the P02-MM portfolio. The risk-adjusted results indicate that the GWS and D.1 transmission lines add significant risk mitigation benefits associated with volatility in market prices, loads, hydro generation, and unplanned outages.

Figure 9.18 – Increase/(Decrease) in System Costs when the GWS and D.1 Transmission Lines are Eliminated from the P02-MM portfolio.



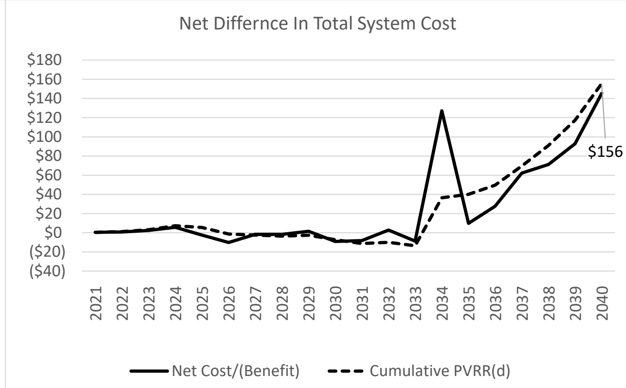


Table 9.9 summarizes the PVRR(d) of the P02c-No GWS portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when GWS and D.1 are removed from the portfolio in MM, HH, and SCGG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. Without GWS and D.1, emissions from PacifiCorp's fossil-fueled resources increase considerably—ranging from 8.4% in the MN price-policy scenario to 17.8% in the SCGG price-policy scenario. As discussed earlier, it is more likely than not that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions. It is also unlikely gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not building these transmission lines should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under HH and SCGG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios. Considering the removal of GWS and D.1 increases system costs among the MM, HH, and SCGG price-policy scenarios, significantly increases emissions and associated costs and risks, and significantly increases market-reliance risk, this analysis supports including GWS, D.1, and the associated 2020AS RFP wind resources in the preferred portfolio.

Table 9.9 – PVRR(d) of the P02c-No GWS Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02c-MM-MM	$25,949	$26,439	0.0052%	445,607
P02c-MM-LN	$21,864	$22,151	0.0005%	484,784
P02c-MM-MN	$22,056	$22,349	0.0051%	554,193
P02c-MM-HH	$29,739	$30,408	0.0051%	413,739
P02c-MM-SCGHG	$42,235	$43,512	0.0157%	245,883
Change from P02-MM-MM	$156	$288	0.0002%	46,654
Change from P02-MM-LN	($727)	($642)	-0.0048%	48,650
Change from P02-MM-MN	($365)	($261)	0.0002%	42,825
Change from P02-MM-HH	$960	$1,128	0.0002%	45,187
Change from P02-MM-SCGHG	$2,596	$2,847	0.0063%	37,233

2020AS RFP Variant (P02d-No RFP)

The P02d-No RFP GWS portfolio is a variant of the P02-MM portfolio that eliminates all 2020AS RFP resources, including the GWS and D.1 transmission lines. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the 2020AS RFP resources can be isolated.

Figure 9.19 shows the cumulative (at left) and incremental (at right) portfolio changes when the 2020AS RFP resources are eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the 2020AS RFP resources and the GWS and D.1 transmission lines are eliminated. Without 2020AS RFP resources, an additional 400 MW of solar co-located with storage is added to the portfolio in 2026. In 2029, 549 MW of storage is removed. In 2030, 149 MW of storage is added concurrent with the removal of 389 MW of wind. In 2033, an additional advanced nuclear resource displaces 500 MW of solar co-located with storage. The lack of resource additions with the removal of 2020AS RFP resources signals an increase in market reliance.

Figure 9.19 – Increase/(Decrease) in Proxy Resources when 2020AS RFP Resources are Eliminated from the P02-MM portfolio.

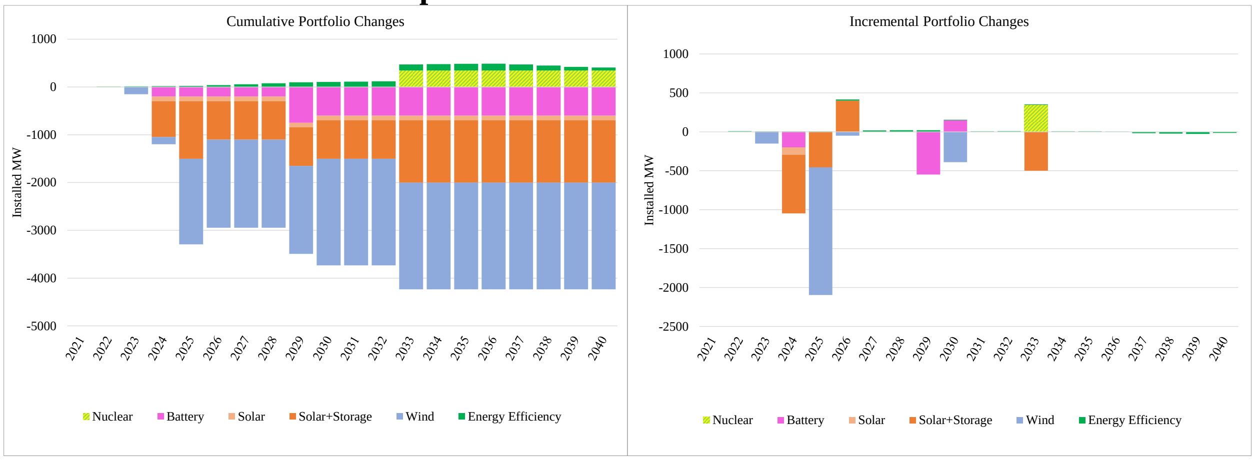


Figure 9.20 shows how market purchases change when the 2020AS RFP resources are removed from the portfolio. With fewer resources, market purchases on an annual basis increase by as much as 45% in 2025. From 2025 through 2040, market purchase volumes are, on average, 30% higher than the market purchases in the P02-MM portfolio. Consequently, there is elevated market-reliance risk without the 2020AS RFP resources.

Figure 9.20 – Increase/(Decrease) Market Purchases in the P02-MM and P02d-No RFP Portfolios.

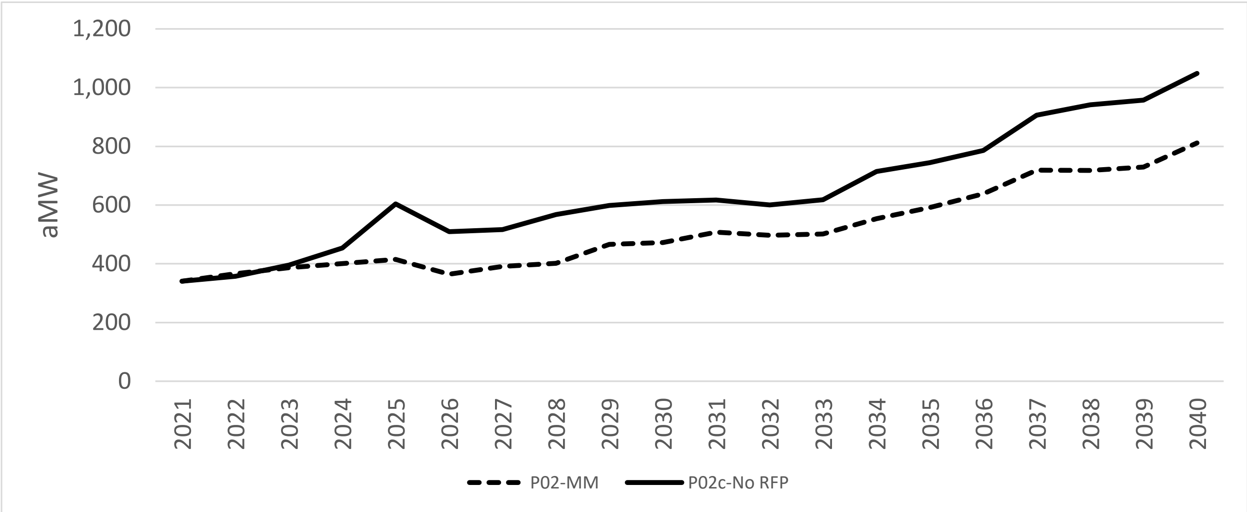


Figure 9.21 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when 2020AS RFP resources are eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without 2020AS RFP resources is $1,063 billion higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the 2020AS RFP resources is $1,293 billion higher cost than the P02-MM portfolio.

When the 2020AS RFP resources are removed from the portfolio, the costs associated with new resources decline. The cost for transmission is also reduced. As is the case in the portfolio that removes GWS and D.1 (but retains all 2020AS RFP resources not dependent upon these transmission lines), this reduction in transmission cost is net of the cost required to build a new 230-kV line to accommodate PacifiCorp's obligation to provide firm point-to-point transmission service to a third-party transmission customer. The 230-kV alternative is not avoidable if GWS is not built, and the $1.4 billion cost assumed for this alternative is the minimum cost considering that it focuses on the upgrades required to grant a single transmission service request. Additional costs would be incurred to accommodate additional requests for interconnection service. To accommodate all of these requests, it is likely the alternative would be to construct GWS.

When the 2020AS RFP bids are removed from the portfolio, coal and gas generation is increased, which increases variable costs for existing fossil-fired resources and the associated cost for increased emissions. Further, the system becomes more reliant on the market as shown by increased market costs. As noted above, this not only increases costs to the system, but it also introduces incremental market-reliance risk, which is not captured in PVRR results. The increase in costs in 2025 reflect a sizeable deficiency that would need to be covered with additional market purchases. The deficiency cost is grouped with the proxy resource costs in the chart at left, which essentially offsets new resource cost savings in that year.

Figure 9.21 – Increase/(Decrease) in System Costs when 2020AS RFP Resources are Eliminated from the P02-MM portfolio.

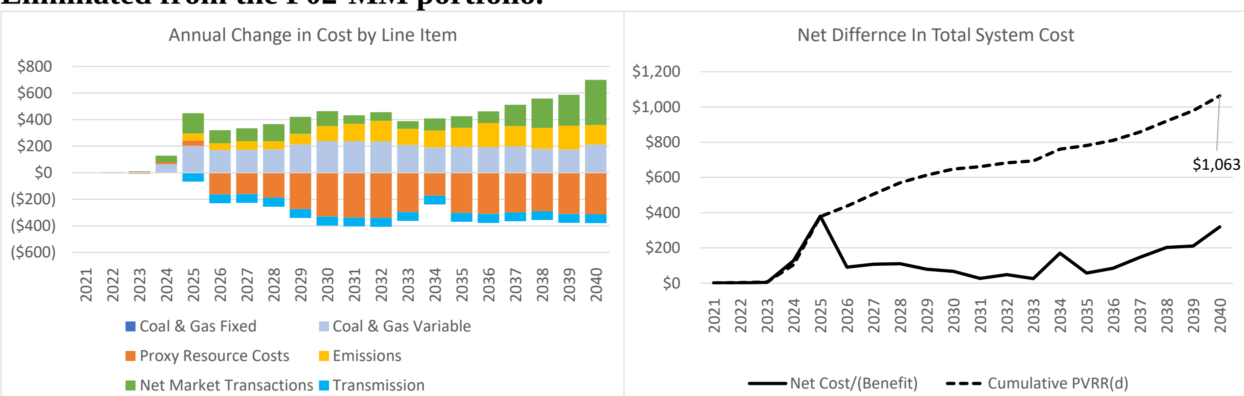


Table 9.10 summarizes the PVRR(d) of the P02d-No RFP GWS portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase significantly when 2020AS RFP resources are removed from the portfolio in all but the LN price-policy scenario. Without the RFP resources, emissions from PacifiCorp's fossil-fueled resources increase considerably—ranging from 12.5% in the MN price-policy scenario to 34.7% in the SCGG price-policy scenario. As discussed earlier, it is more likely than not that there will be policy actions taken to impute a cost or penalty on greenhouse gas emissions. It is also unlikely that gas prices will be suppressed for many decades to come, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of not pursuing the RFP resources along with the associated investments in the GWS and D.1 transmission lines should policies develop impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under HH and SCGG price-policy scenarios relative to the size of cost reductions in the unlikely LN price-policy scenario. Further, each of cases that remove 2020AS RFP resources show a more notable decline in reliability, as measured by the ENS metric. Considering the removal of 2020AS RFP bids and the associated investment in the GWS and D.1 transmission

lines increases system costs among all but the LN price-policy scenario, significantly increases emissions and associated costs, and significantly increases market-reliance risk, this analysis supports including 2020AS RFP resources in the preferred portfolio.

Table 9.10 – PVRR(d) of the P02d-No RFP GWS Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02d-MM-MM	$26,857	$27,445	0.0208%	476,318
P02d-MM-LN	$22,246	$22,605	0.0265%	515,934
P02d-MM-MN	$22,655	$23,036	0.0208%	575,308
P02d-MM-HH	$31,178	$31,973	0.0206%	445,220
P02d-MM-SCGHG	$45,770	$47,228	0.0537%	281,014
Change from P02-MM-MM	$1,063	$1,293	0.0159%	77,364
Change from P02-MM-LN	($346)	($188)	0.0211%	79,800
Change from P02-MM-MN	$234	$426	0.0159%	63,939
Change from P02-MM-HH	$2,399	$2,693	0.0157%	76,669
Change from P02-MM-SCGHG	$6,131	$6,563	0.0443%	72,364

Natrium™ Demonstration Project Variant (P02e-No Nuc)

The P02e-No Nuc portfolio is a variant of the P02-MM portfolio that eliminates the Natrium™ advanced nuclear demonstration project. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the demonstration project can be isolated.

Figure 9.22 shows the cumulative (at left) and incremental (at right) portfolio changes when the Natrium™ demonstration project is eliminated from the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. Without the Natrium™ demonstration project, 348 MW of solar co-located with storage is added to the portfolio in 2026 and an additional 240 MW is added in 2030. In 2037, a non-emitting peaker displaces solar+battery resource capacity.

Figure 9.22 – Increase/(Decrease) in Proxy Resources when the Natrium™ Demonstration Project is Eliminated from the P02-MM portfolio.

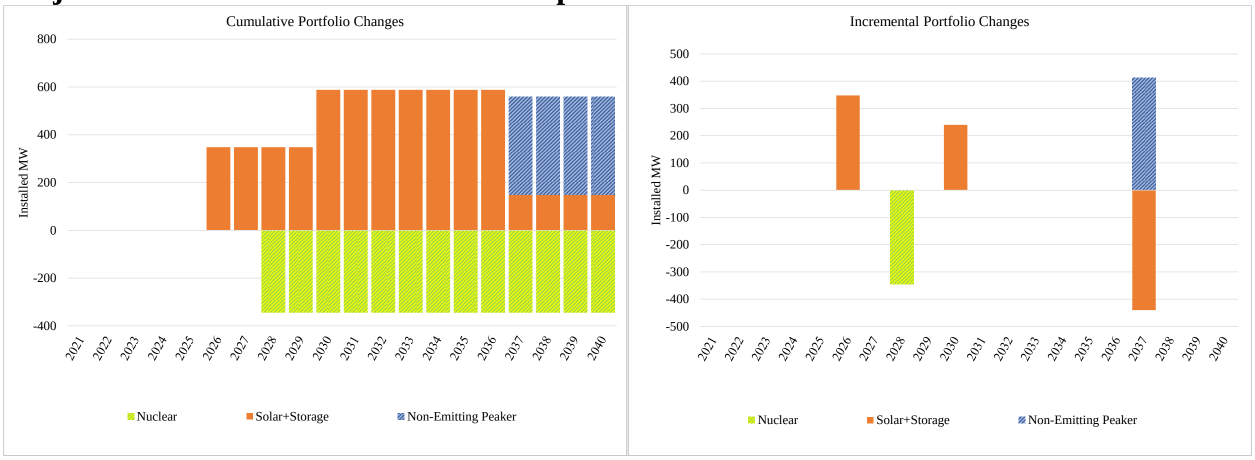


Figure 9.23 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when the Natrium™ demonstration project eliminated from the P02-MM portfolio. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio without the demonstration project is $133 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio without the demonstration project is $158 million higher cost than the P02-MM portfolio.

When the Natrium™ advanced nuclear demonstration project is removed from the portfolio, the cost for new proxy resources increases in 2026 with the addition of more solar+battery resources. Over this period, fossil-fueled generation decreases, which reduced operating costs and emissions costs. Beginning 2028, removing the Natrium™ demonstration project reduces new proxy resource costs. More than offsetting these cost savings are increased costs from fossil-fueled generation, emissions, and net market transactions.

Figure 9.23 – Increase/(Decrease) in System Costs when the Natrium™ Demonstration Project is Eliminated from the P02-MM portfolio.

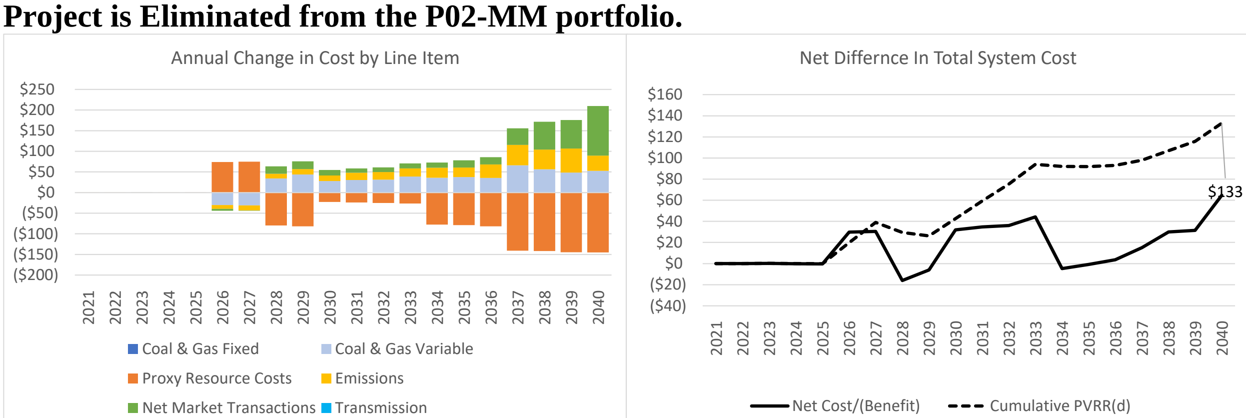


Table 9.11 summarizes the PVRR(d) of the P02e-No Nuc portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when the

Natrium™ demonstration project is removed from the portfolio in all but the LN and MN price-policy scenarios, which show an incremental reduction in costs on a deterministic basis. The cost reduction for the LN price-policy erodes by $12 million on a risk-adjusted basis, while the MN price-policy scenario breaks even with P02-MM when adjusted for risk. Without the demonstration project, emissions from PacifiCorp's fossil-fueled resources increase by about 2% to 3%, depending upon the price-policy scenario. Both portfolios, as measured by ENS results, are very reliable among all price-policy scenarios. In aggregate, these results support the inclusion of the Natrium™ advanced nuclear demonstration project in the preferred portfolio.

Table 9.11 – PVRR(d) of the P02e-No Nuc Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02e-MM-MM	$25,927	$26,309	0.0049%	408,473
P02e-MM-LN	$22,510	$22,723	0.0054%	446,547
P02e-MM-MN	$22,404	$22,609	0.0049%	521,098
P02e-MM-HH	$29,112	$29,644	0.0049%	377,010
P02e-MM-SCGHG	$40,139	$41,203	0.0090%	215,640
Change from P02-MM-MM	$133	$158	0.0000%	9,520
Change from P02-MM-LN	($82)	($70)	0.0000%	10,413
Change from P02-MM-MN	($17)	($0)	0.0000%	9,730
Change from P02-MM-HH	$333	$364	0.0000%	8,459
Change from P02-MM-SCGHG	$501	$537	-0.0004%	6,990

Naughton Units 1 and 2 Retirement Variant (P02f-No Nau 25)

The P02f-No Nau 25 portfolio is a variant of the P02-MM portfolio that maintains continued coal-fueled operation of Naughton Units 1 and 2 through the end of 2029. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the removal of the demonstration project can be isolated.

Figure 9.24 shows the cumulative (at left) and incremental (at right) portfolio changes when Naughton Units 1 and 2 continue operating as coal-fueled resources through 2029. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. With continued coal-fueled operations at Naughton Units 1 and 2, 549 MW of 4-hour storage capacity is removed from the portfolio in 2029. When Naughton Units 1 and 2 subsequently retire at the end of 2029, 339 MW of wind is removed from the portfolio, a non-emitting peaker is added to the portfolio along with additional solar co-located with storage and standalone storage.

Figure 9.24 – Increase/(Decrease) in Proxy Resources when Naughton Units 1 and 2 Continue Operating as Coal-Fueled Resources through 2029.

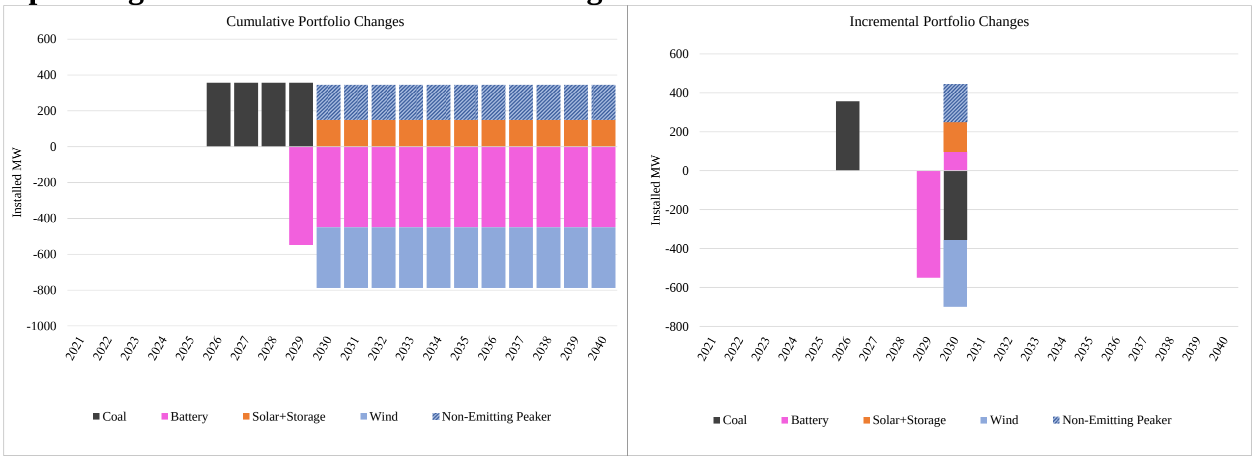


Figure 9.25 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Naughton Units 1 and 2 continue operating as coal-fueled resources through 2029. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio that operates Naughton Units 1 and 2 through 2029 is $54 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio that operates Naughton Units 1 and 2 through 2029 is $66 million higher cost than the P02-MM portfolio.

When Naughton Units 1 and 2 continue operating as coal-fueled resources through 2029, changes in system costs are largely tied to changes in the operating cost of these two units through 2028. In 2029, the reduction in proxy resource costs is caused by the displacement of incremental solar co-located with storage. This is partially offset by increased costs from fossil-fueled resources and emissions. Beyond 2030, changes in the resource mix lead to reduced proxy resource costs. However, over this time, fossil-fueled resource costs increase, emissions costs increase, and the net cost of market transactions increase.

Figure 9.25 – Increase/(Decrease) in System Costs when Naughton Units 1 and 2 Continue Operating as Coal-Fueled Resources through 2029.

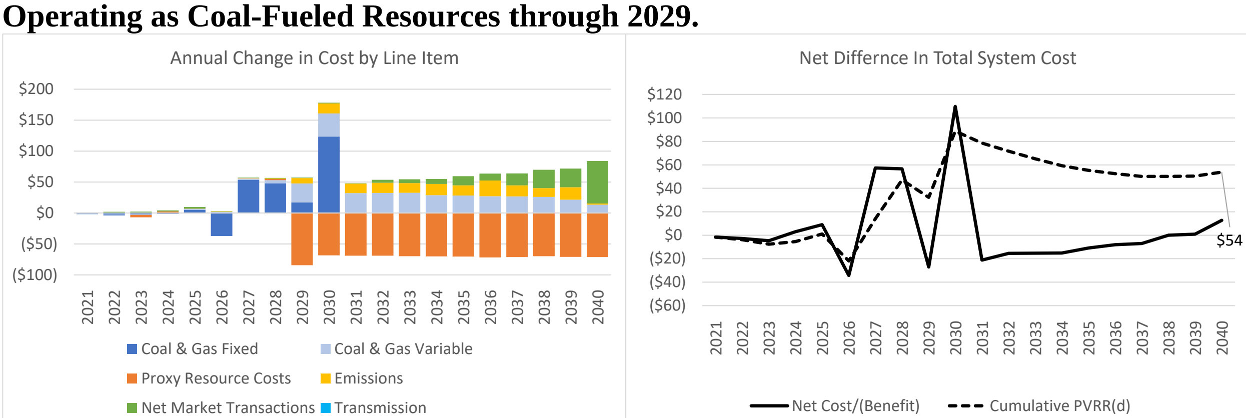


Table 9.12 summarizes the PVRR(d) of the P02f-No Nau 25 portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when Naughton Units 1 and 2 continue to operate as coal-fueled resources through 2029 in the MM, HH, and SCGG price-policy scenarios. Conversely, costs decrease in the LN and MN price-policy scenarios. If Naughton Units 1 and 2 do not retire at the end of 2025, emissions from PacifiCorp's fossil-fueled resources increase by about 2%. It is more likely than not that there will be some form of policy action taken to impute a cost or penalty on greenhouse gas emissions, even when considered through the 2029 time frame. It is also unlikely gas prices will be suppressed for the next decade, as assumed in the LN price-policy scenario. Further, cost-and-risk results indicate that there is a tremendous opportunity cost of continuing to operate Naughton Units 1 and 2 as coal-fueled resources should policies develop that impose costs on greenhouse gas emissions. This is seen with the disproportionate increase in costs under HH and SCGG price-policy scenarios relative to the size of cost reductions in the unlikely LN and MN price-policy scenarios. Considering the continued coal operations of Naughton Units 1 and 2 increases system costs among the MM, HH, and SCGG price-policy scenarios, significantly increases emissions and associated costs and risks, this analysis supports retiring Naughton Units 1 and 2 at the end of 2025.

Table 9.12 – PVRR(d) of the P02f-No Nau Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02f-MM-MM	$25,848	$26,217	0.0050%	405,395
P02f-MM-LN	$22,503	$22,710	0.0054%	442,821
P02f-MM-MN	$22,372	$22,565	0.0049%	518,642
P02f-MM-HH	$28,968	$29,484	0.0049%	374,781
P02f-MM-SCGHG	$40,017	$41,068	0.0098%	213,910
Change from P02-MM-MM	$54	$66	0.0001%	6,442
Change from P02-MM-LN	($89)	($83)	0.0001%	6,687
Change from P02-MM-MN	($49)	($45)	0.0000%	7,274
Change from P02-MM-HH	$189	$204	0.0000%	6,230
Change from P02-MM-SCGHG	$378	$402	0.0004%	5,260

Dave Johnston Unit 4 CCUS Variant (P02g-CCUS)

The P02g-CCUS portfolio is a variant of the P02-MM portfolio that forces a CCUS retrofit on Dave Johnston Unit 4 in 2026 to enable the project to qualify for existing tax credits. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the CCUS retrofit can be isolated. Because CCUS was not selected as a least-cost resource option in the P02-MM portfolio, this variant was produced to evaluate a means to comply with Wyoming House Bill 200 (HB 200). HB 200 was passed by the Wyoming Legislature in March 2020, and it requires the Wyoming Public Service Commission to establish a standard that specifies a percentage of electricity that must be generated from coal-fired generation using carbon capture technology by 2030, subject to an incremental cost limitation of 2% of Wyoming customers' total bill to comply with the standard.

For modeling purposes, PacifiCorp chose to force a CCUS retrofit (amine based post-combustion + enhanced oil recovery) at Dave Johnston Unit 4 for the following reasons:

- There are no complications with co-ownership as would be the case with Wyodak or the Jim Bridger units
- CCUS at Dave Johnston Unit 4 would not require a new lined coalcombustion residual impoundment as would be the case at the Naughton coal units
- Expectation of lower costs associated with necessary inlet NO_X and SO_2 controls relative to Dave Johnston Units 1 and 2
- Dave Johnston Unit 3 has a federal closure commitment under EPA's regional haze rule. Installation of CCUS at Dave Johnston Unit 4 would be expected to meet preliminary HB 200 targets

This modeling assumption does not mean PacifiCorp has determined Dave Johnston Unit 4 is the only site for a CCUS retrofit. As described in the 2021 IRP action plan, PacifiCorp is engaged in a request for expressions of interest process and will soon be issuing a request for proposals that will help identify candidates for potential CCUS retrofits and help refine cost-and-performance assumptions.

Figure 9.26 shows the cumulative (at left) and incremental (at right) portfolio changes when the CCUS retrofit is installed on Dave Johnston Unit 4 relative to the P02-MM portfolio. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the CCUS retrofit is installed. With the installation of CCUS in 2026, there is a net reduction of capacity due to the parasitic load associated with the carbon capture equipment.[3] Beyond 2027, when Dave Johnston is retired in the P02-MM portfolio, there is an increase in coal capacity through the remainder of the study period. The extended life of Dave Johnston Unit 4, with a CCUS retrofit installed, displaces 149 MW of standalone storage in 2029 and 359 MW of wind in 2030.

[3] Upon installation of the carbon capture equipment, Dave Johnston Unit 4's rating is 254 MW. As a coal-fired facility without carbon capture equipment, Dave Johnston Unit 4's rating is 330 MW.

Figure 9.26 – Increase/(Decrease) in Proxy Resources when CCUS is Installed on Dave Johnston Unit 4 in 2026.

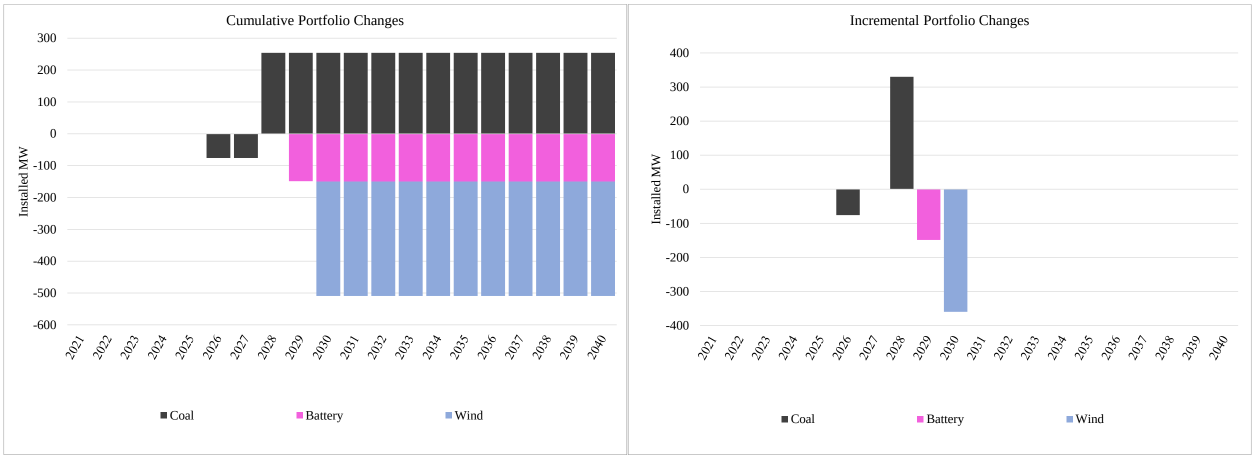


Figure 9.27 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when CCUS is installed on Dave Johnston Unit 4 in 2026. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio with CCUS installed on Dave Johnston Unit 4 project is $271 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the Dave Johnston Unit 4 CCUS retrofit is $235 million higher cost than the P02-MM portfolio.

On an ST PVRR basis, capital cost assumptions for the CCUS retrofit at Dave Johnston Unit 4 would need to decrease by approximately 33% to achieve break-even economics in the MM price-policy scenario—initial capital would need to drop from $1.14 billion to $761 million. Alternatively, the enhanced-oil recovery revenue stream assumed in this analysis (from a credit-worthy counterparty) would need to increase by approximately 84% to achieve break-even economics under the MM price-policy scenario. Prices for enhanced-oil recovery in the company's analysis start at $19.25/ton in 2026 and grow to $27.51 by 2040.

When the CCUS retrofit is installed in 2026, the carbon capture technology increases the costs associated with Dave Johnston Unit 4. This shows up as increased fixed costs for coal and gas resources in the chart at left. This is partially offset by reduced emissions costs. Beginning in the 2029-to-2030-time frame, avoided proxy resource costs add to the emissions cost savings.

Figure 9.27 – Increase/(Decrease) in System Costs when CCUS is Installed on Dave Johnston Unit 4 in 2026.

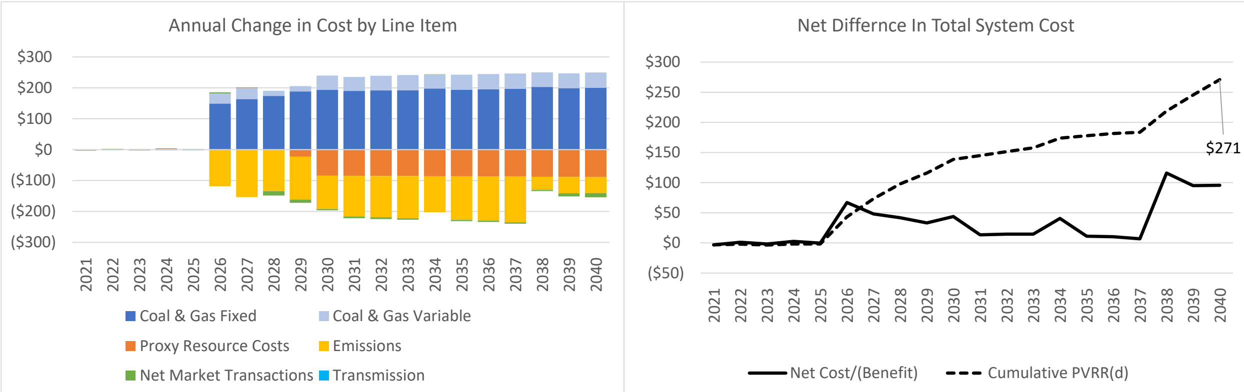


Table 9.13 summarizes the PVRR(d) of the P02g-CCUS portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. The portfolio that includes the CCUS retrofit at Dave Johnston Unit 4 is higher cost than the P02-MM portfolio across each of the price-policy scenarios. This trend holds true for both the ST PVRR and the risk-adjusted PVRR results. Both portfolios, as measured by ENS, are very reliable among all price-policy scenarios. Emissions are slightly lower when CCUS is installed on Dave Johnston Unit 4 (approximately 1% relative to the P02-MM portfolio). The magnitude of the increased cost in the portfolio that includes a CCUS retrofit on Dave Johnston Unit 4 in 2026, which would be situs-assigned to Wyoming customers, is expected to exceed the cost containment language set forth in HB 200, and for this reason, it is not included in the preferred portfolio. Nonetheless, PacifiCorp recognizes that this analysis is driven by a wide range of assumptions specific to the cost and commercial structure of CCUS opportunities. Consequently, PacifiCorp has established an action plan with a CCUS action item to continue with the on-going request for expressions of interest process initiated this year and to proceed with a request for proposals process that will help identify potential sites, costs, and commercial structures that will allow us to update this analysis in the 2023 IRP.

Table 9.13 – PVRR(d) of the P02g-CCUS Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02g-MM-MM	$26,065	$26,387	0.0048%	394,448
P02g-MM-LN	$22,860	$23,025	0.0054%	431,634
P02g-MM-MN	$22,741	$22,894	0.0048%	506,715
P02g-MM-HH	$28,932	$29,389	0.0049%	364,436
P02g-MM-SCGHG	$39,763	$40,744	0.0091%	207,527
Change from P02-MM-MM	$271	$235	-0.0001%	(4,506)
Change from P02-MM-LN	$269	$232	0.0000%	(4,500)
Change from P02-MM-MN	$320	$285	-0.0001%	(4,654)
Change from P02-MM-HH	$153	$109	0.0000%	(4,115)
Change from P02-MM-SCGHG	$124	$79	-0.0003%	(1,122)

Jim Bridger Units 3 and 4 Retirement Variant (P02h-JB3-4 Retire)

The P02h-JB3-4 Retire portfolio is a variant of the P02-MM portfolio that forces Jim Bridger Units 3 and 4 to retire before 2030 with the most optimal timing as determined by the Plexos model. When this variant is compared to the P02-MM portfolio, changes in proxy resources and system costs driven by the early retirement of Jim Bridger Units 3 and 4 can be isolated.

Figure 9.28 shows the cumulative (at left) and incremental (at right) portfolio changes when Jim Bridger Units 3 and 4 are retired early. A positive value indicates an increase in resources and a negative value indicates a decrease in resources when the project is eliminated. When required to choose the most economic retirement date before 2030 for Jim Bridger Units 3 and 4, the portfolio with the early retirements retires Jim Bridger Unit 3 at the end of 2026 and retires Jim Bridger Unit 4 at the end of 2029. When Jim Bridger Unit 3 retires, 200 MW of solar co-located with storage is added to the portfolio. When Jim Bridger Unit 4 retires, an additional advanced nuclear resource is added in 2030. These additions displace a 2038 advanced nuclear resource and a 2038 non-emitting peaker, which are included in the P02-MM portfolio. Note, the chart at right does not indicate there is an increase in coal capacity. This bar indicates that the loss of coal capacity that would otherwise occur in the P02-MM portfolio with the retirement of Jim Bridger Units 3 and 4 at the end of 2037 does not occur in the P02h-JB3-4 Retire portfolio because those retirements already occurred at the end of 2026 and 2029.

Figure 9.28 – Increase/(Decrease) in Proxy Resources when Jim Bridger Units 3 and 4 are Forced to Retire before 2030.

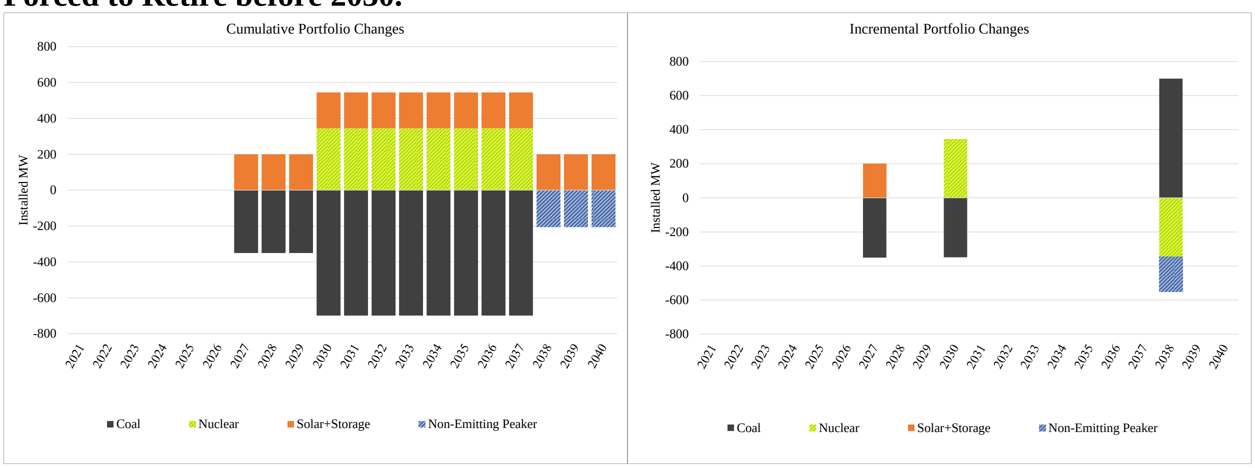


Figure 9.29 summarizes changes in system costs, based on ST model results using MM price-policy assumptions, when Jim Bridger Units 3 and 4 are forced to retire before 2030. The graph on the left shows annual changes in cost by category and the graph on right shows annual net changes in total costs (the solid black line) and the cumulative PVRR(d) of changes to net system costs over time (the dashed black line). Through 2040, the PVRR(d) shows that the portfolio with the accelerated retirement of Jim Bridger Units 3 and 4 is $95 million higher cost than the P02-MM portfolio. On a risk-adjusted basis, which factors in the risk associated with low-probability, high-cost events through stochastic simulations, the portfolio with the early retirement of Jim Bridger Units 3 and 4 is $60 million higher cost than the P02-MM portfolio.

When Jim Bridger Units 3 and 4 retire early, there is a reduction in system costs associated with reduced fixed and variable expenses from fossil-fueled generation and reduced emissions expenses. These cost savings are more than offset by higher proxy resource costs from incremental solar co-located with storage and incremental advanced nuclear resources.

Figure 9.29 – Increase/(Decrease) in System Costs when Jim Bridger Units 3 and 4 are Forced to Retire Before 2030.

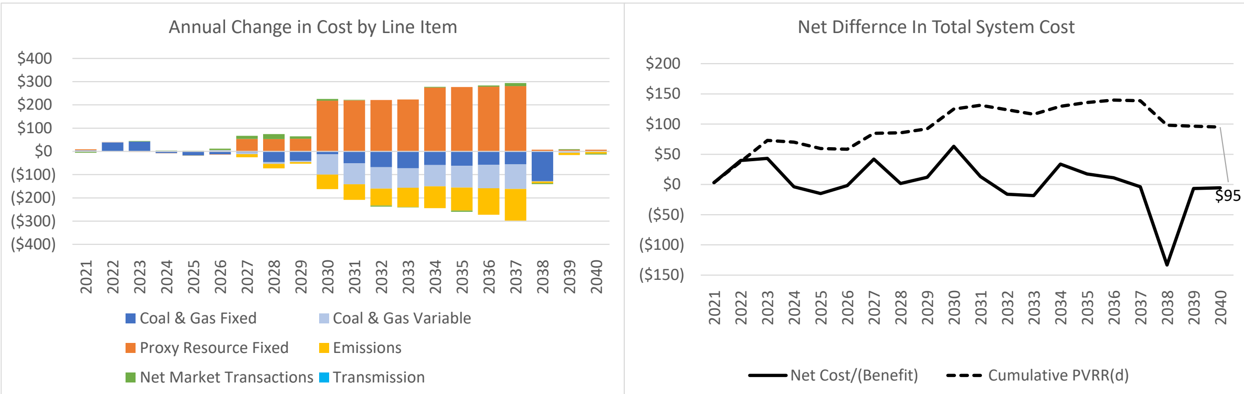


Table 9.14 summarizes the PVRR(d) of the P02h-JB3-4 Retire portfolio relative to the P02-MM portfolio under a range of different price-policy scenarios. System costs increase when Jim Bridger Units 3 and 4 retire early in the MM, LN, and MN price-policy scenarios. Conversely, costs decrease in the HH and SCGHG price-policy scenarios. If Jim Bridger Units 3 and 4 retire early, emissions from PacifiCorp's fossil-fueled resources are reduced by about 7%. While it is more likely than not that there will be some form of policy taken to impute a cost or penalty on greenhouse gas emissions, the company's analysis captures this risk in its MM price policy assumptions. In this case, early retirement of Jim Bridger Units 3 and 4 increases system costs by $60 million on a risk-adjusted basis. And while emissions costs and risks are higher with continue operation of Jim Bridger Units 3 and 4, there are many resource choices in the P02-MM portfolio that greatly mitigate this risk. Further, considering that the early retirements were selected in 2026 (Jim Bridger Unit 3) and 2029 (Jim Bridger Unit 4), there is sufficient time to continue to evaluate the potential early retirement of these two units in the 2023 IRP. This would be particularly important if base case carbon prices are projected to increase from current levels. For these reasons, the early retirement of Jim Bridger Units 3 and 4 is not included in the preferred portfolio.

Table 9.14 – PVRR(d) of the P02h-JB3-4 Retire Portfolio Relative to the P02-MM Portfolio Under Varying Price-Policy Scenarios.

	PVRR ($m)	ST PVRR + 5% of 95th Stochastic ($m)	ENS Average % of Load	CO2 Emissions 2021-2040 (Thousand Tons)
P02-MM-MM	$25,794	$26,151	0.0049%	398,953
P02-MM-LN	$22,592	$22,793	0.0054%	436,134
P02-MM-MN	$22,421	$22,609	0.0049%	511,369
P02-MM-HH	$28,779	$29,280	0.0049%	368,551
P02-MM-SCGHG	$39,639	$40,665	0.0094%	208,650
P02h-MM-MM	$25,889	$26,212	0.0050%	369,493
P02h-MM-LN	$22,972	$23,152	0.0054%	405,192
P02h-MM-MN	$22,873	$23,044	0.0050%	472,422
P02h-MM-HH	$28,604	$29,057	0.0051%	341,025
P02h-MM-SCGHG	$39,376	$40,349	0.0103%	201,974
Change from P02-MM-MM	$95	$60	0.0001%	(29,460)
Change from P02-MM-LN	$380	$359	0.0000%	(30,942)
Change from P02-MM-MN	$452	$435	0.0001%	(38,947)
Change from P02-MM-HH	($175)	($223)	0.0002%	(27,527)
Change from P02-MM-SCGHG	($262)	($317)	0.0009%	(6,676)

Portfolio Development Conclusions

P02-MM remains the top performing portfolio among the P02 variant portfolios and was further assessed relative to CETA requirements, described further in a later section.

Preferred Portfolio Selection

Final Preferred Portfolio Selection

P02-MM entered the final evaluations as the top-performing portfolio for preferred portfolio selection.

P02-MM was subsequently evaluated using the targets established by CETA[4]. CETA establishes specific targets for utilities serving customers in Washington including:

- By 2025, utilities remove coal-fueled generation from Washington's allocation of electricity;[5]
- By 2030, Washington retail sales are carbon-neutral;
    - 80 percent from long-term system resources[6]
    - 20 percent from alternative compliance using purchase of Unbundled Renewable Energy Credits (REC)[7]s;
- By 2045, Washington's retail sales are 100 percent renewable and non-carbon-emitting

[4] RCW 19.405
[5] RCW 19.405.030(1)(a)
[6] RCW 19.405.040(1)(a)(ii) requires utilities to "use electricity from renewable resources and non-emitting electric generation in an amount equal to one hundred percent of the utilities retail electric loads over each multiyear compliance period."
[7] RCW 19.405.020(38)

Evaluation of the P02-MM portfolio against the CETA targets required certain modeling assumptions to account for uncertainties related to the future of interjurisdictional cost allocation among the PacifiCorp states and resolution of outstanding CETA implementation issues. PacifiCorp currently allocates costs and benefits, including resource costs and benefits, to Washington according to the Washington Inter-Jurisdictional Allocation Methodology (WIJAM). The WIJAM expires December 31, 2023, and negotiations are underway among all six states to determine the next inter-jurisdictional allocation methodology. In addition to future inter-jurisdictional uncertainty, certain CETA implementation issues remain unresolved. [8, 9]

In addition to assumptions regarding how energy is allocated across PacifiCorp's six-state system, PacifiCorp also made assumptions regarding the amount of renewable and non-emitting resources that is eligible to apply toward the 80 percent "primary" compliance obligation. For purposes of meeting primary compliance, PacifiCorp assumed that eligible generation was limited to energy generated from long-term resources located on PacifiCorp's system where both the energy and RECs were: 1) acquired at the same time; and 2) allocated to Washington customers under the applicable interjurisdictional allocation mechanism.

By 2025, PacifiCorp will remove all coal-fired generation from Washington's allocation of electricity. By 2030, the Chehalis natural gas-fueled plant is the only Washington-located thermal resource operating on the system; all other existing and new resources in the P02-MM top-performing portfolio are renewable or non-emitting. Thus, all system energy allocated to Washington from a renewable or non-emitting resource contributes to meeting the CETA targets.[10] This includes the renewable and non-emitting resources in the P02-MM top-performing portfolio.

Upon evaluation relative to the 2030 CETA target, a shortfall of roughly 69 MW of annual capacity was identified in 2030 (the highest shortfall year), with significantly smaller shortfalls identified in the years between 2030-2033. Under a four-year compliance window for the time period 2030 – 2033, an average annual shortfall of 49 MW was identified. This shortfall is addressed with a Washington-situs assigned 160 MW wind and solar resource co-located with storage located in Yakima, Washington.

This shortfall includes lower capacity requirements from incremental demand-side management resources specific to Washington identified from the P02-SCGHG portfolio. In 2030, there was a reconfiguration of 160 MW of system solar collocated with storage located in Yakima, Washington in P02-MM, the top-performing portfolio, to become a Washington-situs assigned 160 MW resource that also includes wind, collocated with the solar and storage resource. This Washington-situs assigned resource maximizes usage of transmission interconnection availability at this location.

[8] PacifiCorp is a multi-state utility, serving customers in California, Idaho, Oregon, Utah, Washington, and Wyoming. PacifiCorp operates and plans its system on an integrated, six-state basis.

[9] For existing resources and new resources added through the end of 2023, the energy from system resources was allocated to states consistent with the 2020 Protocol and Washington Inter-Jurisdictional Allocation Methodology. For resources added to the system in 2024 and beyond, assignment of energy, costs and benefits followed a potential framework, subject to the ongoing Multi-State Process discussions, that enables compliance with CETA (and Oregon law) through reassignment of certain thermal resources. These resource allocation assumptions are used to assess the generation and allocation of Renewable Energy Credits (REC) state Renewable Portfolio Standard (RPS) compliance.

[10] This is limited to system energy where Washington is also allocated the associated RECs.

These portfolio differences to P02-MM to meet the requirements of CETA result in the 2021 IRP preferred portfolio, P02-MM-CETA. As CETA establishes a target in 2045 that retail sales are 100 percent renewable or non-emitting that is outside of the 20-year IRP planning horizon, extrapolation was done that shows the P02-MM-CETA preferred portfolio meets the requirements. The P02-MM-CETA results in a PVRR(d) relative to P02-MM, the top-performing portfolio is $164m.

Table 9.15 - PVRR(d) of the P02-MM-CETA Portfolio Under Varying Price-Policy Scenarios below shows the PVRR and risk-adjusted PVRR, ENS as a percentage of load, and CO_2 emissions for the 2021 IRP preferred portfolio under five price-policy scenarios.

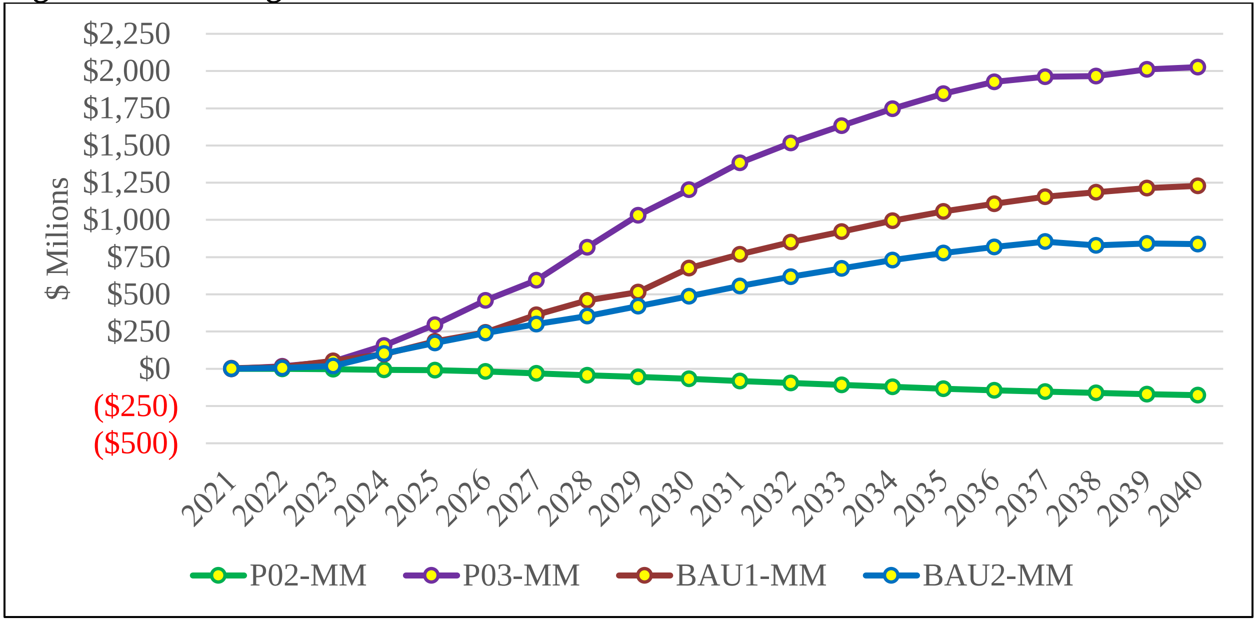
Table 9.15 - PVRR(d) of the P02-MM-CETA Portfolio Under Varying Price-Policy Scenarios

Case	ST PVRR ($m)	Risk-Adjusted PVRR ($m)	ENS Average Percent of Load	CO2 Emissions (Thousand Tons)
P02-MM-CETA-LN	22,773	22,974	0.0054%	436,414
P02-MM-CETA-MN	22,605	22,793	0.0049%	510,115
P02-MM-CETA	25,963	26,315	0.0049%	398,597
P02-MM-CETA-HH	28,951	29,448	0.0049%	368,927
P02-MM-CETA-SC	39,910	40,934	0.0103%	213,233

Customer Rate Pressure

Figure 9.30 shows the difference in the cumulative PVRR, as an indicator of rate pressure over time, among the initial portfolios discussed earlier in this chapter relative to the 2021 IRP preferred portfolio, P02-MM-CETA applying medium gas, medium CO_2 price-policy assumptions. All Portfolios P03, BAU1 and BAU2 trend higher in costs over the planning horizon relative to P02-MM-CETA whereas P02 trends lower in costs notably, as it does not include Washington-situs assigned resources relative to the requirements of CETA.

Figure 9.30 – Change in the Cumulative PVRR relative to P02-MM-CETA



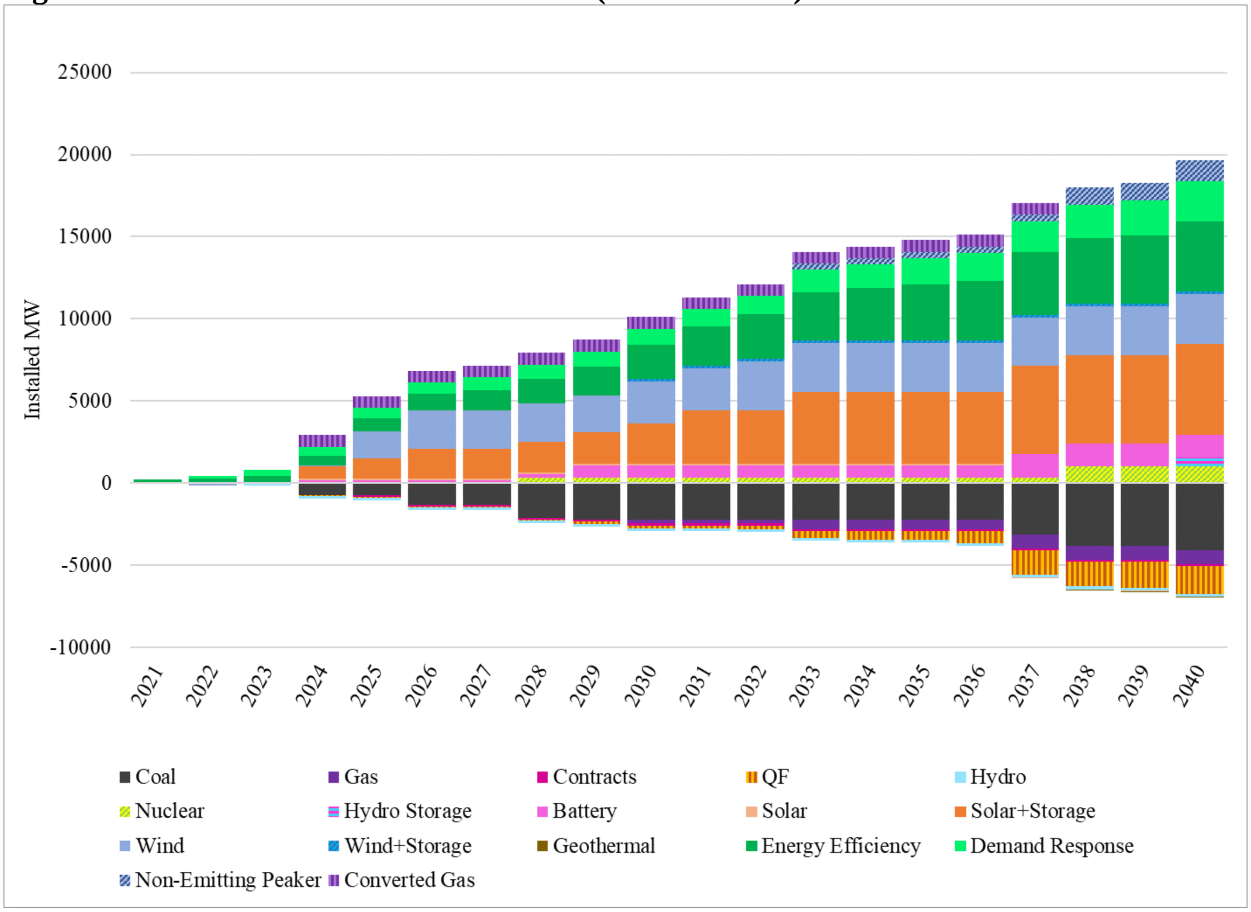
The 2021 IRP Preferred Portfolio

PacifiCorp's selection of the 2021 IRP preferred portfolio, P02-MM-CETA, is supported by comprehensive data analysis and an extensive public-input process, described in the chapters that follow. Figure 9.31 shows that PacifiCorp's 2021 preferred portfolio continues to include substantial new renewables, facilitated by incremental transmission investments, DSM resources, significant storage resources, and for the first time, advanced nuclear.

By the end of 2024, the 2021 IRP preferred portfolio includes the 2020 All-Source RFP final shortlist resources. These projects include 1,792 MW of wind, 1,302 MW of solar additions, and 697 MW of battery storage capacity—497 MW paired with solar and a 200 MW standalone battery. During this time, the preferred portfolio also includes the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW) wind projects located in Wyoming. Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of wind and an additional 600 MW solar co-located with storage. The 2021 IRP preferred portfolio includes the 500 MW advanced nuclear Natrium™ demonstration project, which will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Over the 20-year planning horizon, the 2021 IRP preferred portfolio includes 3,628 MW of new wind and 5,628 MW of new solar co-located with storage.

Figure 9.31 – 2021 IRP Preferred Portfolio (All Resources)



To facilitate the delivery of new renewable energy resources to PacifiCorp customers across the West, the preferred portfolio includes additional transmission investment. Specifically, the 2021 IRP preferred portfolio includes the GWS—a new 416-mile, high-voltage 500-kilovolt transmission line and associated infrastructure running from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah. The 2021 preferred portfolio also includes the D.1 transmission line—a new 59-mile high-voltage 230-kilovolt transmission line from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming. Both transmission lines will come online by the end of 2024.

The 2021 IRP preferred portfolio also includes a 290-mile high-voltage 500-kilovolt B2H transmission line, which connects Boardman in Oregon to Hemming in Idaho. B2H is expected to come online in 2026. Further, the 2021 IRP preferred portfolio includes near-term and long-term transmission upgrades across the system that will facilitate continued and long-term growth in new resources needed to serve our customers. Table 9.16 summarizes the incremental transmission projects included in the 2021 IRP preferred portfolio.

Table 9.16 – Transmission Projects Included in the 2021 IRP Preferred Portfolio[1,2,*]

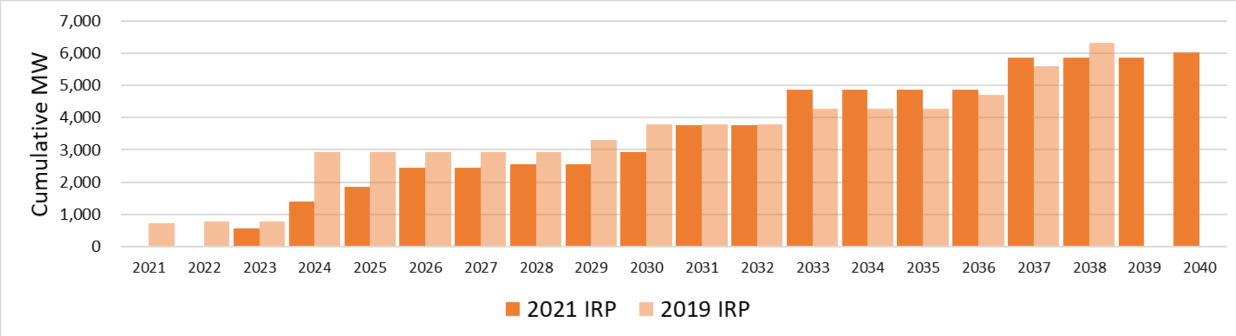
Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.
2 - Energy Gateway South is modeled in the 2021 IRP as a contingent option with bids in the 2020 All-Source Request for Proposals. Other transmission options prior to 2026 are not modeled as transmission requirements and costs are accounted for in the 2020 All-Source Request for Proposals transmission cluster study for all other resource bids.
* - Reclaimed transmission is committed with resources with a commercial operation date later than the date of retirement.

New Solar Resources

The 2021 IRP preferred portfolio includes 1,302 MW of new solar by the end of 2024 and 1,902 MW by the end of 2026. Through 2040, more than 5,600 MW of new solar is online as shown in Figure 9.32.

Figure 9.32 – 2021 IRP Preferred Portfolio New Solar Capacity*

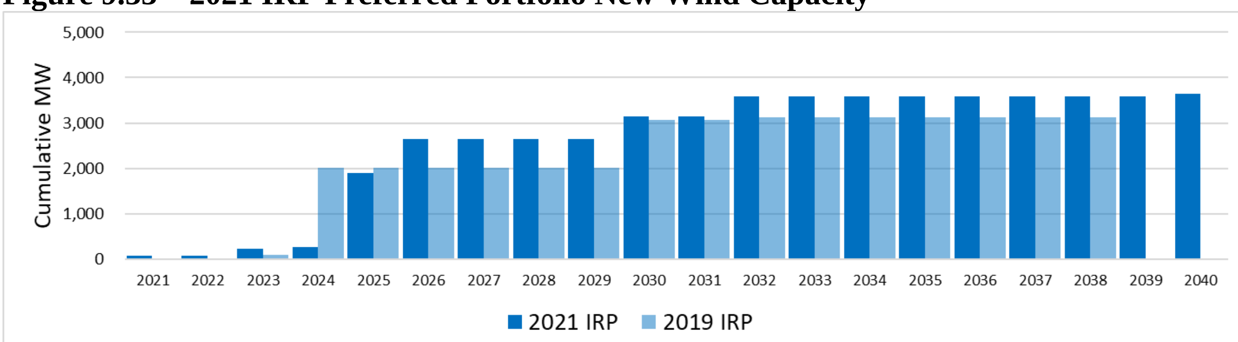


*Note: 2021 IRP solar capacity shown in the figure includes solar resources coming via the 2020 All-Source Request for Proposals by the end of 2024. Resources are shown in the first full year of operation (the year after the year-online dates).

New Wind Resources

As shown in Figure 9.33, by the end of 2024, PacifiCorp's 2021 IRP preferred portfolio includes 1,792 MW of new wind generation resulting from the 2020 All-Source RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of new wind and more than 3,700 MW of new wind by 2040.

Figure 9.33 – 2021 IRP Preferred Portfolio New Wind Capacity*

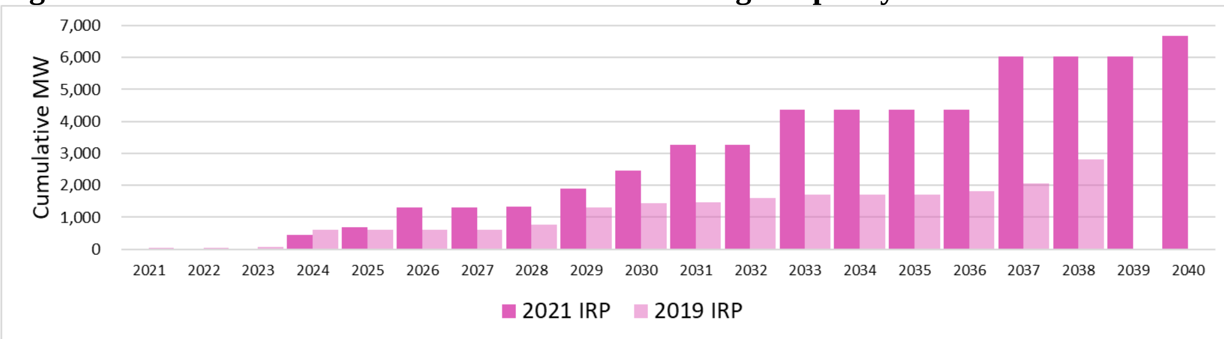


*Note: Wind additions shown are incremental to Energy Vision 2020 and other projects that have come online over the past few years. Resources are shown in the first full year of operation (the year after year-end online dates).

New Storage Resources

New storage resources in the 2021 IRP preferred portfolio are summarized in Figure 9.34. The 2021 IRP preferred portfolio includes nearly 700 MW of battery storage by the end of 2024 – 200 MW of which is a standalone battery and the remaining portion paired with solar resources resulting from the 2020 All-Source RFP. Through 2040, the 2021 IRP includes 4,781 MW of storage co-located with solar resources,1,400 MW of standalone battery, and 500 MW of pumped hydro.

Figure 9.34 – 2021 IRP Preferred Portfolio New Storage Capacity*

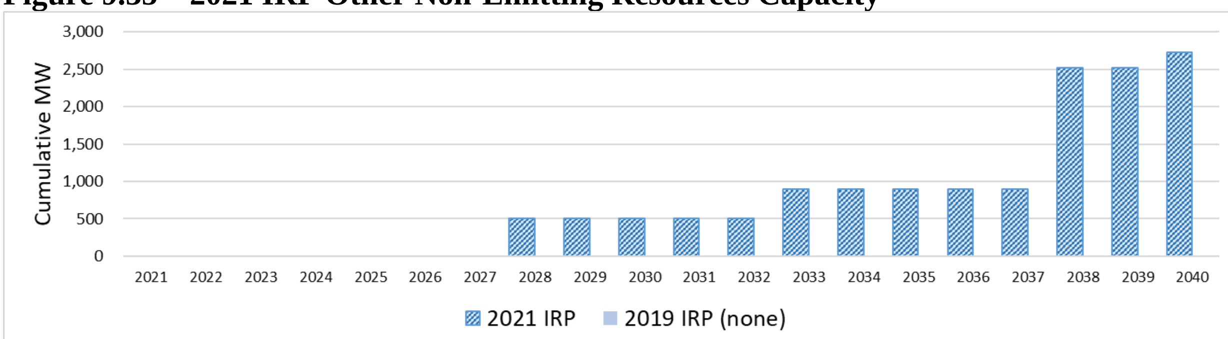


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Other Non-Emitting Resources

This is the first PacifiCorp IRP that includes new advanced nuclear and non-emitting peaking resources as part of its least-cost, least-risk preferred portfolio. As shown in Figure 9.35, the 500 MW advanced nuclear Natrium™ demonstration project will come online by summer 2028. Through 2040, the 2021 IRP preferred portfolio includes 1,000 MW of additional advanced nuclear resources and 1,226 MW of non-emitting peaking resources.

Figure 9.35 – 2021 IRP Other Non-Emitting Resources Capacity

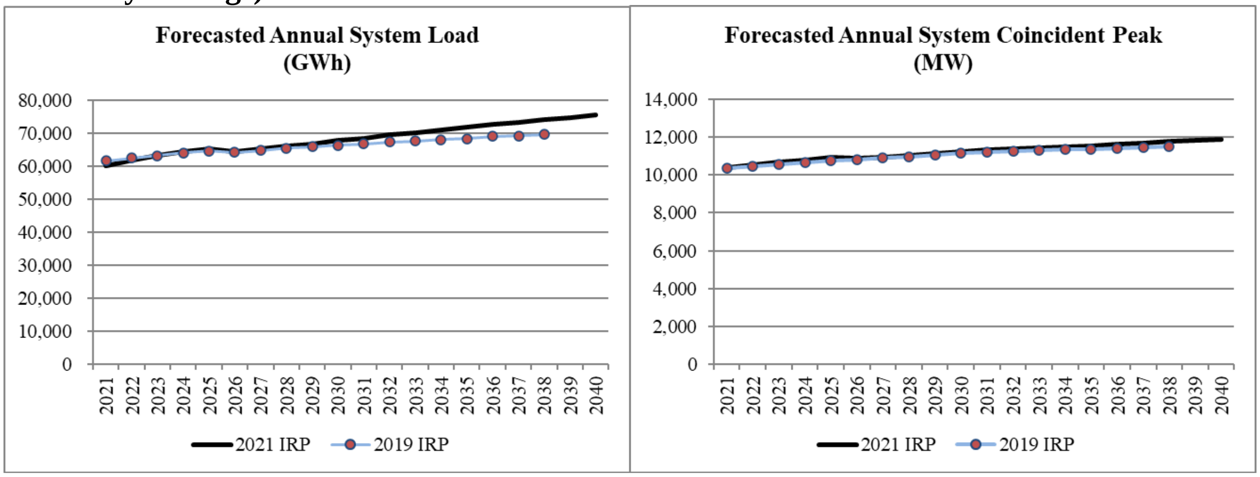


*Note: Resources are shown in the first full year of operation (the year after the year-end online dates).

Demand-Side Management

PacifiCorp evaluates new DSM opportunities, which includes both energy efficiency and 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 9.36 shows that PacifiCorp's load forecast before incremental energy efficiency savings has increased relative to projected loads used in the 2019 IRP. On average, forecasted system load is up 2.2 percent and forecasted coincident system peak is up 1.1 percent when compared to the 2019 IRP. Over the planning horizon, the average annual growth rate, before accounting for incremental energy efficiency improvements, is 1.21 percent for load and 0.73 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 increased residential forecast.

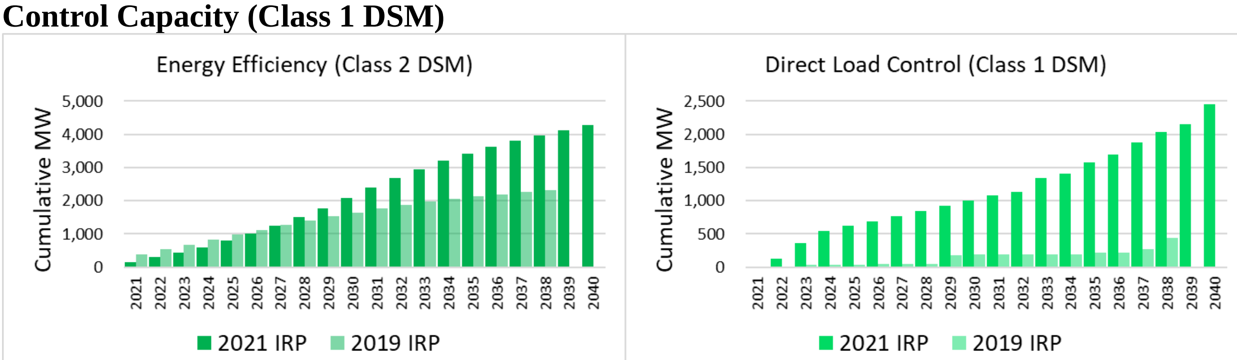
Figure 9.36 – Load Forecast Comparison between Recent IRPs (Before Incremental Energy Efficiency Savings)



DSM resources continue to play a key role in PacifiCorp's resource mix. Figure 9.37 compares total energy efficiency capacity savings in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and includes 4,290 MW by the end of the planning period.

In addition to continued investment in energy efficiency programs, the preferred portfolio shows an increasing role for incremental direct load control programs. The chart to the right in Figure 9.37 compares cumulative capacity of direct load control program capacity in the 2021 IRP preferred portfolio relative to the 2019 IRP preferred portfolio and does not include capacity from existing programs. In the 2021 IRP, direct load control resources previously identified in the 2019 IRP and solicited via a demand response RFP, were modeled in addition to resources from the CPA assessing the upper limit of demand response opportunities and value within the IRP. This allowed for the evaluation of real-time resources as a substitute for front office transactions. The 2021 IRP has a cumulative capacity of direct load control programs reaching 2,448 MW by 2040—an over 400% increase over the planning horizon from the 2019 IRP.

Figure 9.37 – 2021 IRP Preferred Portfolio Energy Efficiency (Class 2 DSM) and Direct Load Control Capacity (Class 1 DSM)



Wholesale Power Market Prices and Purchases

Figure 9.38 shows that the 2021 IRP's base case forecast for natural gas prices has decreased along with a decrease in wholesale power prices for most years relative to those in the 2019 IRP. These forecasts are based on prices observed in the forward market and on projections from third-party experts. The lower power prices observed in the 2021 IRP are primarily driven by the assumption of lower natural gas prices-than what was assumed in the 2019 IRP. Wholesale power prices are higher in 2027 to 2031 because of higher inflation impacting new resource costs. Moreover, the 2021 IRP assumed lower natural gas prices than the 2019 IRP as Henry Hub in particular, is softened by limited pipeline expansion lowering liquefied natural gas exports. While not shown in the figure below, the 2021 IRP also evaluated low and high price scenarios when evaluating the cost and risk of different resource portfolios.

Figure 9.38 – Comparison of Power Prices and Natural Gas Prices in Recent IRPs

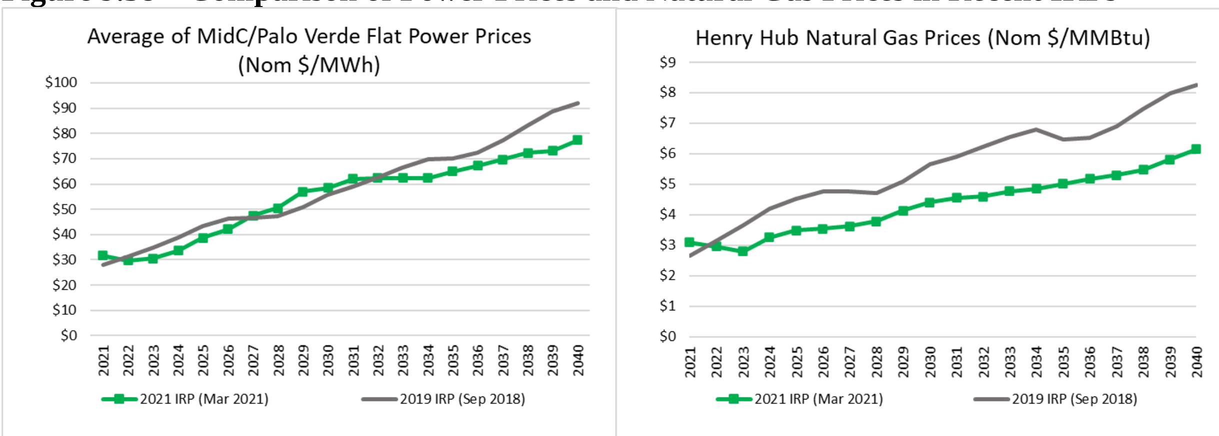
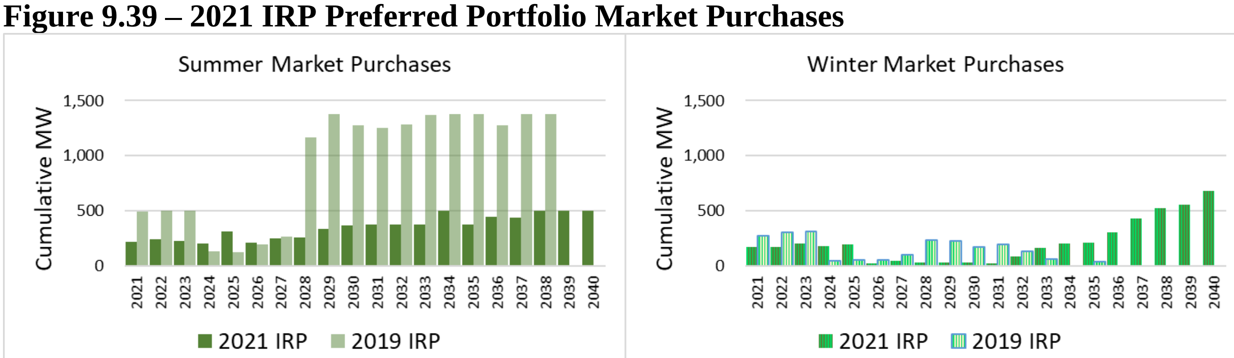


Figure 9.39 shows an overall decline in reliance on wholesale power market firm purchases in the 2021 IRP preferred portfolio relative to the wholesale power market purchases included in the 2019 IRP preferred portfolio. In particular, reliance on wholesale power market purchases during summer peak periods averages 366 MW per year over the 2020-2027 timeframe—down 60 percent from wholesale power market purchases identified in the 2019 IRP preferred portfolio. This reduction in wholesale power market purchases coincides with the period over which there are resource adequacy concerns in the region. Further, PacifiCorp is actively participating in regional efforts to develop day-ahead markets and a resource adequacy program that will help unlock regional diversity and facilitate market transactions over the long term.

Figure 9.39 – 2021 IRP Preferred Portfolio Market Purchases



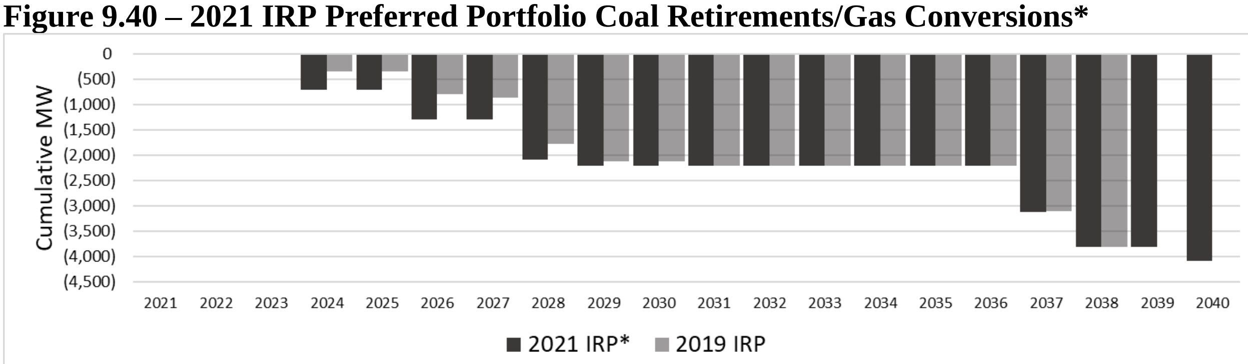
Coal and Gas Retirements/Gas Conversions

Coal resources have been an important resource in PacifiCorp's resource portfolio for many years. However, there have been material changes in how PacifiCorp has been operating these assets (i.e., by lowering operating minimums and optimizing dispatch through the EIM) that has enabled the company to reduce fuel consumption and associated costs and emissions, and instead buy increasingly low-cost, zero-emissions renewable energy from market participants across the West, which is accessed by our expansive transmission grid. PacifiCorp's coal resources will continue to play a pivotal role in following fluctuations in renewable energy as the remaining coal units approach retirement dates. Driven in part by ongoing cost pressures on existing coal-fired facilities and dropping costs for new resource alternatives, of the 22 coal units currently serving PacifiCorp customers, the preferred portfolio includes retirement of 14 of the units by 2030 and 19 of the units by the end of the planning period in 2040. As shown in Figure 9.40, coal unit retirements/gas peaker conversions in the 2021 IRP preferred portfolio will reduce coal-fueled generation capacity by 1,300 MW by the end of 2025, over 2,200 MW by 2030, and over 4,000 MW by 2040.

Coal unit retirements scheduled under the preferred portfolio include:

- 2023 = Jim Bridger Units 1-2, converted to natural gas peakers in 2024 (same retirement year for Jim Bridger 1 in 2019 IRP and instead of 2028 for Jim Bridger 2 in the 2019 IRP).
- 2025 = Naughton Units 1-2 (same as 2019 IRP)
- 2025 = Craig Unit 1 (same as 2019 IRP)
- 2025 = Colstrip Units 3-4 (instead of 2027 in the 2019 IRP)
- 2027 = Dave Johnston Units 1-4 (same as 2019 IRP)
- 2027 = Hayden Unit 2 (instead of 2030 in the 2019 IRP)
- 2028 = Craig Unit 2 (instead of 2026 in the 2019 IRP)
- 2028 = Hayden Unit 1 (instead of 2030 in the 2019 IRP)
- 2036 = Huntington Units 1-2 (same as 2019 IRP)
- 2037 = Jim Bridger Units 3-4 (same as 2019 IRP)
- 2039 = Wyodak (same as 2019 IRP but outside of 2019 IRP planning horizon)

Figure 9.40 – 2021 IRP Preferred Portfolio Coal Retirements/Gas Conversions*



* 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.

In addition to the coal unit retirements outlined above, the preferred portfolio reflects 1,554 MW natural gas retirements through 2040. This includes Naughton Unit 3 at the end of 2029, Gadsby at the end of 2032, Hermiston at the end of 2036, and Jim Bridger Units 1 and 2 at the end of 2037.

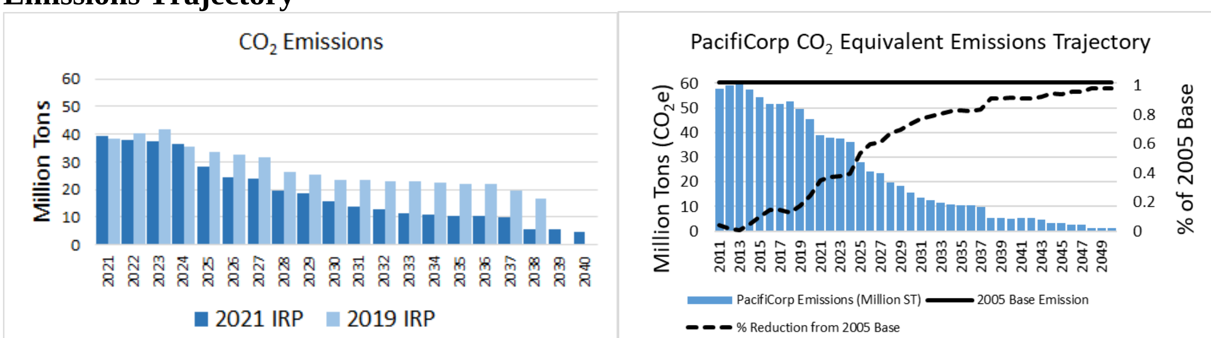
Carbon Dioxide Emissions

The 2021 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 related to several factors including PacifiCorp's participation in the EIM, which reduces customer costs and maximizes use of clean energy; PacifiCorp's on-going transition to clean-energy resources including new renewable resources, new advanced nuclear resources, new non-emitting resources, storage, transmission, and Regional Haze compliance that capitalizes on flexibility.

The chart on the left in Figure 9.41 compares projected annual CO_2 emissions between the 2021 IRP and 2019 IRP preferred portfolios. In this graph, emissions are not assigned to market purchases or sales, and in 2026, annual CO_2 emissions are down 26 percent relative to the 2019 IRP preferred portfolio. By 2030, average annual CO_2 emissions are down 34 percent relative to the 2019 IRP preferred portfolio, and down 52 percent in 2035. By the end of the planning horizon, system CO_2 emissions are projected to fall from 39.1 million tons in 2021 to 4.8 million tons in 2040—a reduction of 88 percent.

The chart on the right in Figure 9.41 includes historical data, assigns emissions at a rate of 0.4708 tons CO_2 equivalent per MWh to market purchases (with no credit to market sales), includes emissions associated with specified purchases, and extrapolates projections out through 2050. This graph demonstrates that relative to a 2005 baseline, system CO_2 equivalent emissions are down 53 percent in 2025, 74 percent in 2030, 83 percent in 2035, 92 percent in 2040, 94 percent in 2045, and 98 percent in 2050.

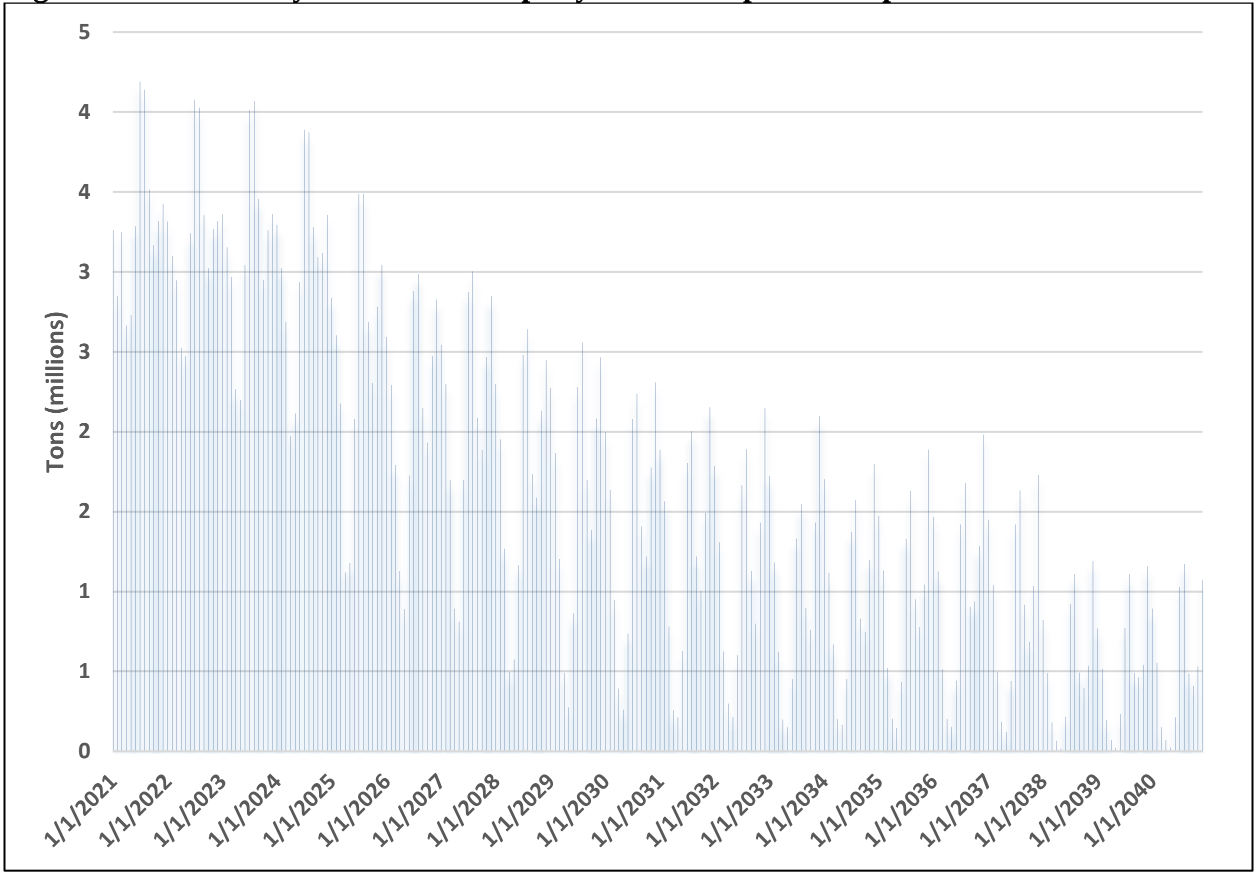
Figure 9.41 – 2021 IRP Preferred Portfolio CO_2 Emissions and PacifiCorp CO_2 Equivalent Emissions Trajectory*



*Note: PacifiCorp CO_2 equivalent emissions trajectory reflects actual emissions through 2020 from owned facilities, specified sources and unspecified sources. From 2021 through the end of the twenty-year planning period in 2040, emissions reflect those from the 2021 IRP preferred portfolio with emissions from specified sources reported in CO_2 equivalent. Market purchases are assigned a default emission factor (0.4708 short tons CO_2e/MWh) – emissions from sales are not removed. Beyond 2040, emissions reflect the rolling average emissions of each resource from the 2021 IRP preferred portfolio through the life of the resource. The emissions trajectory does not incorporate clean energy targets set forth in Oregon House Bill 2021 or any other state-specific emissions trajectories. PacifiCorp expects these targets, and an Oregon-specific emissions trajectory, to be incorporated following the 2023 integrated resource plan when PacifiCorp is required under the bill to file a Clean Energy Plan.

Monthly CO_2 emissions are available for the preferred portfolio as shown in Figure 9.42 below.

Figure 9.42 – Monthly CO_2 emissions per year for the preferred portfolio



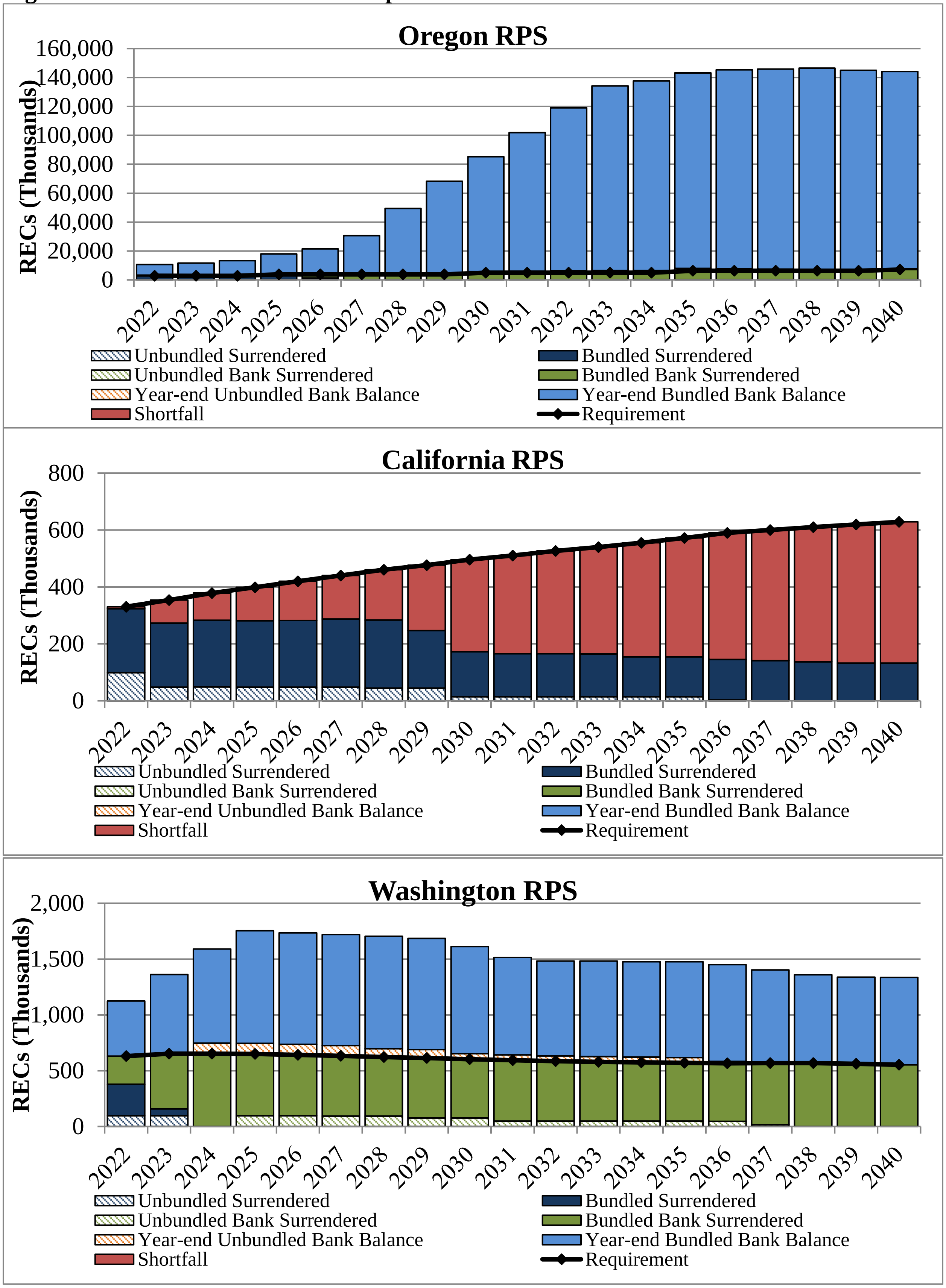
Renewable Portfolio Standards

Figure 9.43 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 2040 with the addition of new renewable resources and transmission in the 2021 IRP preferred portfolio. Washington RPS compliance is achieved with the benefit of increased system renewable resources beginning 2021 as well as additional resources procured that meet the state's Clean Energy Transformation Act. Under PacifiCorp's 2020 Protocol, and the Washington Interjurisdictional Allocation Methodology, Washington's RPS position is improved by receiving a system share of renewable resources across the PacifiCorp's system.

The California RPS compliance position will be met with owned and contracted renewable resources, as well as REC purchases throughout the 2021 IRP study period. The ramping RPS requirement results in an increased need for unbundled REC purchases to meet the annual and compliance period targets in 2021-2040. New renewable resources and transmission in the 2021 IRP preferred portfolio mitigate that shortfall, but the company may need to purchase approximately 200,000 RECs in compliance periods 4 and 5, 2021-2024 and 2025-2028, respectively. Beyond 2028, the company may need to purchase 200,000-300,000 RECs per year to meet the ramping RPS.

While not shown in Figure 9.43, 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 2021 IRP preferred portfolio.

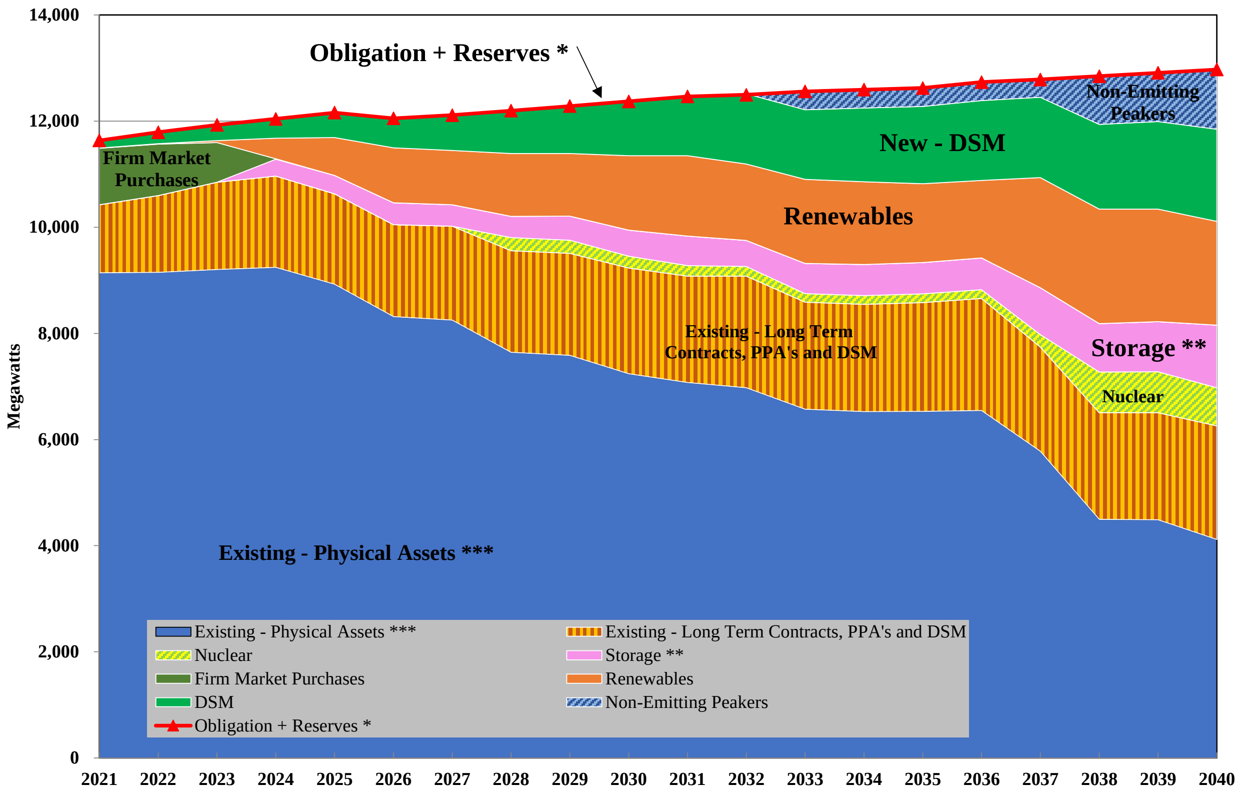
Figure 9.43 – Annual State RPS Compliance Forecast



Capacity and Energy

Figure 9.44 displays how preferred portfolio resources meet PacifiCorp's capacity needs over time. Through 2040, PacifiCorp meets its capacity needs, including a 13% planning reserve margin, through incremental acquisition of wind and solar resources and hybrid renewables (with storage) enabled by investment in transmission infrastructure, nuclear resources, strand alone storage resources, new DSM, non-emitting peaker resources, and wholesale power market purchases.

Figure 9.44 – Meeting PacifiCorp's Capacity Needs with Preferred Portfolio Resources



* Includes 13% Capacity Reserve Margin, Sales and Non-Owned Reserves
** Includes the storage component of wind and solar collocated with storage
*** Includes retirements, and gas conversions

Figure 9.45 and Figure 9.46 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.[11] On an energy basis, coal generation drops to 25 percent by 2027, falls to 9 percent by 2032, and declines to only 1 percent by the end of the planning period. On a capacity basis, coal resources drop to 18 percent by 2027, fall to 11 percent by 2032, and decline to 3 percent by the end of the

[11]The projected PacifiCorp 2021 IRP preferred portfolio "energy mix" is based on energy production and not resource capability, capacity or delivered energy. All or some of the renewable energy attributes associated with wind, biomass, geothermal and qualifying hydro facilities in PacifiCorp's energy mix may be: (a) used in future years to comply with renewable portfolio standards or other regulatory requirements; (b) sold to third parties in the form of renewable energy credits or other environmental commodities; or (c) excluded from energy purchased. PacifiCorp's 2021 IRP preferred portfolio energy mix includes owned resources and purchases from third parties.

planning period. Reduced energy and capacity from coal is offset primarily by increased energy and capacity from renewable and storage resources, nuclear resources, DSM resources, and to a smaller extent later in the plan, non-emitting peaker resources.

Figure 9.45 – Projected Energy Mix with Preferred Portfolio Resources.

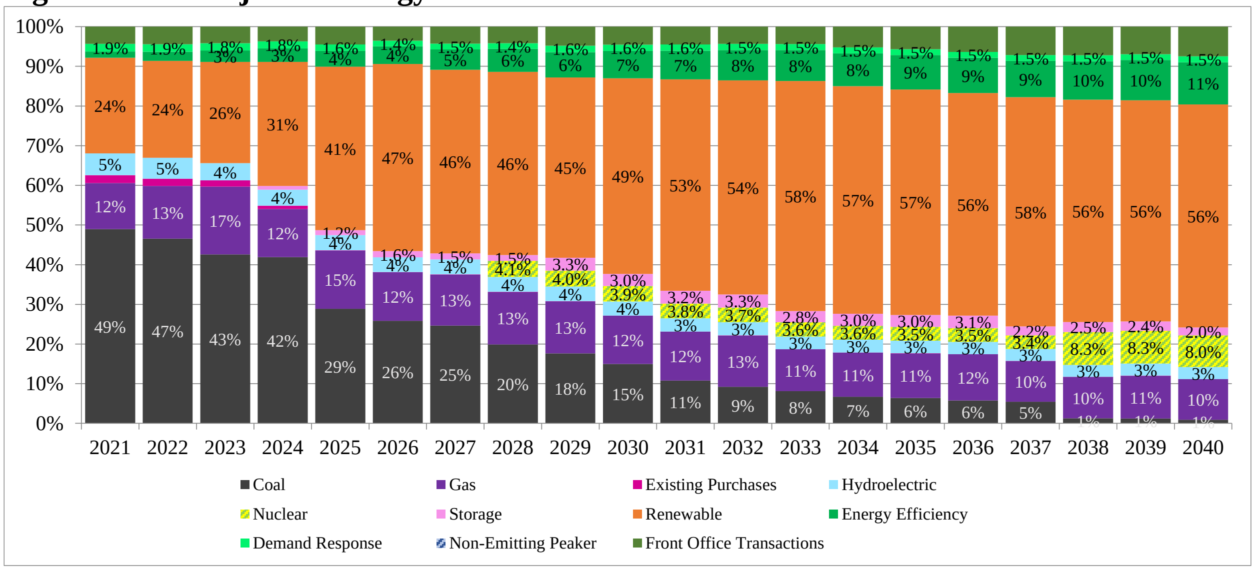
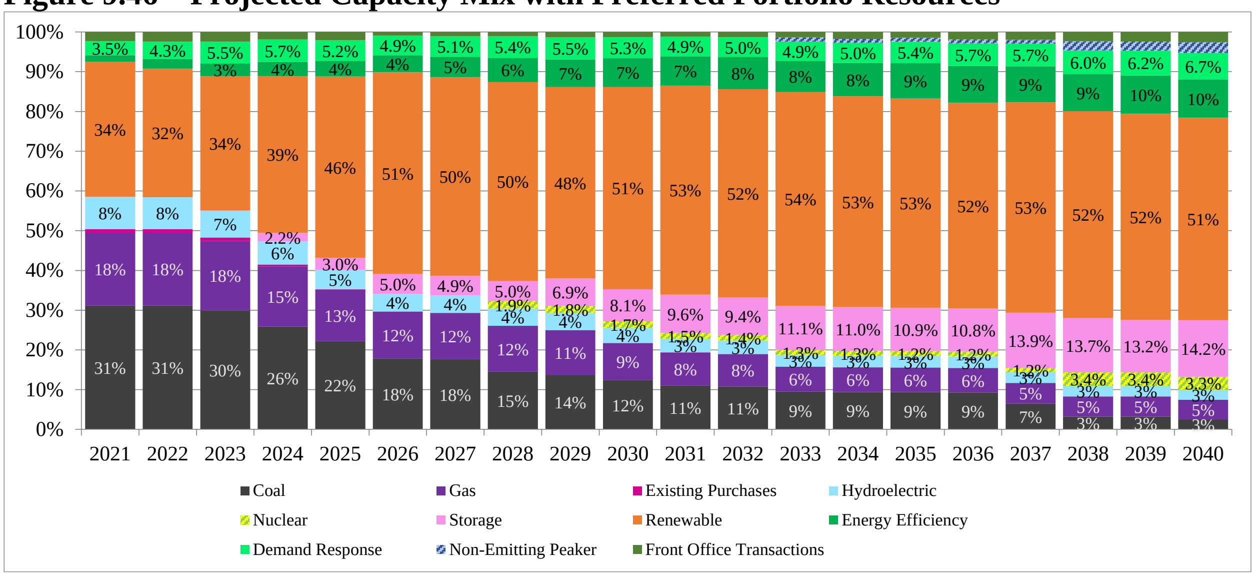


Figure 9.46 – Projected Capacity Mix with Preferred Portfolio Resources



Detailed Preferred Portfolio

Table 9.17 provides line-item detail of PacifiCorp's 2021 IRP preferred portfolio showing new resource capacity along with changes in existing resource capacity through the 20-year planning horizon. Table 9.18 shows line-item detail of PacifiCorp's peak load and resource capacity balance for summer, including preferred portfolio resources, over the 20-year planning horizon. Table 9.19 shows line-item detail of PacifiCorp's peak load and resource capacity balance for winter, including preferred portfolio resources, over the twenty-year planning horizon.

Table 9.17 – PacifiCorp's 2021 IRP Preferred Portfolio

Summary Portfolio Capacity by Resource Type and Year, Installed MW

	Installed Capacity, MW																				
Resource	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**Total**
Expansion Options																					
Gas - CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Gas- Peaking	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
NonEmitting Peaker	-	-	-	-	-	-	-	-	-	-	-	-	402	-	-	-	-	618	-	206	1,226
DSM - Energy Efficiency	157	138	144	164	186	211	238	263	279	304	301	293	272	249	221	195	189	171	160	156	4,290
DSM - Demand Response	-	123	242	184	79	63	69	80	78	77	82	50	213	70	160	125	183	159	108	302	2,448
Renewable - Wind	49	-	151	43	1,641	745	-	-	-	489	-	450	-	-	-	-	-	-	-	60	3,628
Renewable - Wind+Storage	-	-	-	-	-	-	-	-	-	160	-	-	-	-	-	-	-	-	-	-	160
Renewable - Utility Solar	-	-	-	95	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	95
Renewable - Utility Solar+Storage	-	-	-	752	455	600	-	83	-	558	820	-	1,100	-	-	-	1,009	-	-	156	5,533
Renewable - Battery, Wind+Storage	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Renewable - Battery, Solar+Storage	-	-	-	239	258	600	-	42	-	558	820	-	1,100	-	-	-	1,009	-	-	156	4,781
Renewable - Geothermal	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Battery - Stand Alone	-	-	-	200	-	-	-	-	549	1	-	-	-	-	-	-	650	-	-	-	1,400
Storage - CAES	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Storage - Pumped Hydro	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	500	500
Nuclear	-	-	-	-	-	-	-	345	-	-	-	-	-	-	-	-	-	690	-	-	1,035
Nuclear Storage	-	-	-	-	-	-	-	155	-	-	-	-	-	-	-	-	-	310	-	-	465
Front Office Transactions	385	412	427	383	498	231	287	285	363	394	395	459	538	703	578	747	863	1,025	1,052	1,176	560
Existing Unit Changes																					
Coal Plant End-of-life Retirements	-	-	-	-	-	(230)	-	(788)	(123)	-	-	-	-	-	-	-	(909)	(699)	-	(268)	(3,018)
Coal Early Retirements	-	-	-	-	-	(357)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(357)
Coal - CCUS	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Coal - Gas Conversions	-	-	-	713	-	-	-	-	-	-	-	-	-	-	-	-	-	(713)	-	-	-
Coal Plant ceases running as Coal	-	-	-	(713)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(713)
Gas Plant End-of-life Retirements	-	-	-	-	-	-	-	-	-	(247)	-	-	(356)	-	-	-	(237)	-	-	-	(840)
Retire - Hydro	-	-	(163)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(163)
Retire - Wind	-	(10)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(10)
Expire - Wind PPA	-	-	-	(41)	-	(65)	-	-	(99)	(200)	-	-	-	-	-	-	-	-	-	-	(405)
Retire - Solar	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(18)	-	-	-	(18)
Expire - Solar PPA	-	-	-	-	-	-	-	(2)	-	-	-	(8)	-	-	-	-	(73)	-	-	-	(83)
Expire - QF	-	(2)	-	(50)	-	-	(29)	-	(83)	(0)	-	(81)	(181)	(91)	(19)	(208)	(744)	(30)	(100)	(92)	(1,712)
Retire - Other	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(32)	-	-	(32)
Expire - Other	-	11	-	32	(91)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	(49)
Total	**591**	**673**	**802**	**2,001**	**3,025**	**1,798**	**565**	**463**	**964**	**2,094**	**2,419**	**1,162**	**3,088**	**931**	**940**	**858**	**1,923**	**1,497**	**1,220**	**2,350**	

Table 9.18 – Preferred Portfolio Summer Capacity Load and Resource Balance (2021-2030)

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,466	5,429	5,425	5,459	5,044	5,002	4,293	4,182	3,953
Hydroelectric	86	86	85	69	56	52	51	56	57	52
Renewable	668	690	815	912	709	676	661	718	743	676
Purchase	193	197	202	195	138	141	142	148	143	147
Qualifying Facilities	537	521	515	488	396	357	344	364	372	346
Sale	(20)	(20)	(20)	0	0	0	0	0	0	0
East Existing Resources	**6,943**	**6,940**	**7,026**	**7,090**	**6,758**	**6,271**	**6,201**	**5,580**	**5,498**	**5,174**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	6	6	35	47	298	280	283	331	328	387
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	32	25	24	24	27	27	25
Solar+Storage	0	0	0	334	513	388	377	401	397	350
Storage	1	1	1	148	104	58	56	50	162	126
Nuclear	0	0	0	0	0	0	0	248	250	224
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**7**	**7**	**36**	**561**	**940**	**750**	**740**	**1,056**	**1,164**	**1,112**
East Total Resources	**6,950**	**6,947**	**7,062**	**7,651**	**7,698**	**7,020**	**6,940**	**6,636**	**6,661**	**6,286**
Load	7,096	7,246	7,380	7,475	7,583	7,492	7,550	7,643	7,728	7,833
Private Generation	(51)	(72)	(81)	(84)	(87)	(90)	(96)	(106)	(119)	(136)
Existing - Demand Response	(520)	(538)	(558)	(538)	(583)	(592)	(598)	(623)	(604)	(619)
New Demand Response	0	(86)	(192)	(231)	(274)	(301)	(329)	(375)	(397)	(438)
Existing - Energy Efficiency	(43)	(45)	(46)	(45)	(49)	(49)	(50)	(52)	(50)	(52)
New Energy Efficiency	(48)	(95)	(149)	(199)	(280)	(349)	(429)	(529)	(597)	(698)
East Total obligation	**6,434**	**6,410**	**6,353**	**6,378**	**6,311**	**6,110**	**6,048**	**5,958**	**5,961**	**5,890**
East Reserve Margin	8%	8%	11%	20%	22%	15%	15%	11%	12%	7%
West										
Thermal	2,139	2,165	2,168	2,144	2,149	2,019	2,015	2,014	2,036	2,035
Hydroelectric	577	567	521	508	407	386	380	420	423	390
Renewable	194	177	185	184	148	139	140	144	144	134
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	158	153	145	141	116	105	87	91	79	71
Sale	(109)	(76)	(76)	(54)	(44)	(42)	(41)	(44)	(44)	(41)
West Existing Resources	**2,961**	**2,986**	**2,945**	**2,924**	**2,777**	**2,608**	**2,582**	**2,626**	**2,638**	**2,591**
Front Office Transactions	1,064	972	747	8	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	177	177	211	194	189
Wind+Storage	0	0	0	0	0	0	0	0	0	39
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	147	119	522	511	564	526	775
Storage	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**1,064**	**972**	**747**	**154**	**119**	**699**	**688**	**775**	**720**	**1,003**
West Total Resources	**4,025**	**3,959**	**3,691**	**3,079**	**2,897**	**3,307**	**3,270**	**3,401**	**3,358**	**3,594**
Load	3,351	3,400	3,443	3,472	3,506	3,530	3,557	3,584	3,610	3,638
Private Generation	(23)	(39)	(51)	(56)	(60)	(65)	(71)	(78)	(86)	(96)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	0	(45)	(127)	(179)	(238)	(276)	(310)	(355)	(369)	(411)
Existing - Energy Efficiency	(24)	(25)	(26)	(25)	(27)	(28)	(28)	(29)	(28)	(29)
New Energy Efficiency	(26)	(51)	(76)	(95)	(126)	(152)	(178)	(213)	(234)	(266)
West Total obligation	**3,278**	**3,241**	**3,163**	**3,117**	**3,054**	**3,010**	**2,970**	**2,910**	**2,893**	**2,835**
West Reserve Margin	23%	22%	17%	-1%	-5%	10%	10%	17%	16%	27%
System										
Total Resources	10,975	10,905	10,753	10,730	10,595	10,328	10,210	10,037	10,020	9,880
Obligation	9,712	9,651	9,516	9,495	9,366	9,120	9,017	8,868	8,854	8,726
Capacity Reverve Margin (13%)	1,263	1,255	1,237	1,234	1,218	1,186	1,172	1,153	1,151	1,134
Obligation + Reserves	10,975	10,905	10,753	10,730	10,583	10,306	10,190	10,021	10,005	9,860
System Position	0	0	0	0	12	22	21	16	15	20
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**

Table 9.18 (cont'd) – Preferred Portfolio Summer Capacity Load and Resource Balance (2031-2040)

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,945	3,955	3,629	3,607	3,613	3,613	2,765	2,759	2,757	2,491
Hydroelectric	47	43	40	40	40	40	57	63	64	58
Renewable	582	525	471	465	465	465	587	595	586	539
Purchase	146	157	145	144	142	144	138	137	136	138
Qualifying Facilities	310	266	220	204	192	162	34	29	12	0
Sale	0	0	0	0	0	0	0	0	0	0
East Existing Resources	**5,031**	**4,947**	**4,505**	**4,459**	**4,452**	**4,424**	**3,582**	**3,583**	**3,555**	**3,226**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	369	369	368	371	373	375	374	562
Wind	360	322	308	326	307	305	419	461	463	439
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	22	20	18	17	16	15	19	20	19	17
Solar+Storage	677	604	951	929	906	870	1,364	1,377	1,383	1,228
Storage	131	115	99	99	99	104	119	124	93	86
Nuclear	198	181	161	166	163	165	231	260	262	242
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**1,388**	**1,242**	**1,906**	**1,906**	**1,859**	**1,829**	**2,525**	**2,615**	**2,594**	**2,573**
East Total Resources	**6,419**	**6,189**	**6,411**	**6,365**	**6,311**	**6,253**	**6,107**	**6,199**	**6,149**	**5,799**
Load	7,938	8,041	8,138	8,232	8,336	8,343	8,413	8,520	8,390	8,488
Private Generation	(160)	(189)	(218)	(251)	(291)	(181)	(205)	(230)	(119)	(132)
Existing - Demand Response	(615)	(660)	(609)	(604)	(598)	(607)	(582)	(579)	(574)	(581)
New Demand Response	(468)	(521)	(570)	(593)	(627)	(673)	(705)	(740)	(771)	(849)
Existing - Energy Efficiency	(51)	(55)	(51)	(50)	(50)	(51)	(48)	(48)	(48)	(48)
New Energy Efficiency	(773)	(906)	(907)	(962)	(1,009)	(1,039)	(1,052)	(1,111)	(1,170)	(1,248)
East Total obligation	**5,871**	**5,710**	**5,784**	**5,771**	**5,762**	**5,792**	**5,820**	**5,812**	**5,707**	**5,630**
East Reserve Margin	9%	8%	11%	10%	10%	8%	5%	7%	8%	3%
West										
Thermal	2,027	2,021	2,024	2,023	2,023	2,031	1,807	456	456	456
Hydroelectric	355	323	301	299	296	298	435	483	485	446
Renewable	117	108	105	92	92	100	129	142	143	128
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	64	49	45	39	37	38	25	22	9	6
Sale	(38)	(34)	(32)	(32)	(32)	(31)	(34)	(32)	(32)	(28)
West Existing Resources	**2,527**	**2,468**	**2,443**	**2,422**	**2,417**	**2,435**	**2,364**	**1,072**	**1,061**	**1,009**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	573	573	577
Wind	168	241	230	239	228	248	338	371	374	348
Wind+Storage	39	32	31	31	33	33	45	49	50	47
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	670	594	515	503	489	484	576	584	587	583
Storage	0	0	0	0	0	0	78	84	95	387
Nuclear	0	0	0	0	0	0	0	508	509	475
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**877**	**868**	**775**	**773**	**750**	**765**	**1,038**	**2,168**	**2,188**	**2,417**
West Total Resources	**3,404**	**3,336**	**3,219**	**3,195**	**3,166**	**3,200**	**3,401**	**3,240**	**3,249**	**3,426**
Load	3,676	3,707	3,740	3,773	3,805	3,752	3,793	3,825	3,758	3,782
Private Generation	(118)	(158)	(205)	(258)	(316)	(263)	(305)	(351)	(195)	(225)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	(441)	(485)	(461)	(469)	(488)	(519)	(512)	(531)	(544)	(594)
Existing - Energy Efficiency	(29)	(31)	(28)	(28)	(28)	(28)	(27)	(27)	(27)	(27)
New Energy Efficiency	(289)	(334)	(329)	(348)	(366)	(388)	(386)	(410)	(409)	(414)
West Total obligation	**2,800**	**2,699**	**2,717**	**2,669**	**2,607**	**2,554**	**2,563**	**2,507**	**2,584**	**2,521**
West Reserve Margin	22%	24%	18%	20%	21%	25%	33%	29%	26%	36%
System										
Total Resources	9,823	9,524	9,630	9,560	9,477	9,453	9,509	9,438	9,398	9,225
Obligation	8,671	8,410	8,500	8,440	8,369	8,346	8,383	8,319	8,291	8,150
Capacity Reverve Margin (13%)	1,127	1,093	1,105	1,097	1,088	1,085	1,090	1,081	1,078	1,060
Obligation + Reserves	9,798	9,503	9,605	9,537	9,457	9,431	9,473	9,400	9,369	9,210
System Position	25	22	25	23	21	22	35	38	29	15
Reserve Margin	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**	**13%**

Table 9.19 – Preferred Portfolio Winter Capacity Load and Resource Balance (2021-2030)

East	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Thermal	5,478	5,383	5,540	5,364	5,550	5,057	5,143	4,229	4,140	3,835
Hydroelectric	50	52	46	43	30	31	29	39	42	42
Renewable	765	929	885	860	546	676	639	796	843	802
Purchase	173	169	167	158	115	116	120	125	110	113
Qualifying Facilities	204	225	192	213	105	136	123	208	227	233
Sale	(16)	(17)	(15)	0	0	0	0	0	0	0
Transfers	(277)	(267)	(247)	(535)	(275)	(79)	(99)	(588)	(561)	(369)
East Existing Resources	**6,378**	**6,474**	**6,568**	**6,104**	**6,071**	**5,937**	**5,955**	**4,809**	**4,802**	**4,657**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	12	14	52	69	362	398	406	499	533	686
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	0	0	0	17	6	9	8	14	16	16
Solar+Storage	0	0	0	201	205	178	169	235	247	242
Storage	1	1	1	128	83	55	52	51	179	153
Nuclear	0	0	0	0	0	0	0	217	231	233
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**13**	**15**	**53**	**415**	**657**	**640**	**636**	**1,017**	**1,206**	**1,331**
East Total Resources	**6,391**	**6,489**	**6,621**	**6,518**	**6,728**	**6,577**	**6,591**	**5,825**	**6,008**	**5,987**
Load	5,538	5,678	5,800	5,860	5,943	5,874	5,915	6,008	6,081	6,161
Private Generation	(0)	(1)	(2)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Existing - Demand Response	(239)	(251)	(255)	(252)	(255)	(258)	(267)	(277)	(246)	(251)
New Demand Response	0	(76)	(164)	(198)	(218)	(239)	(268)	(304)	(293)	(323)
Existing - Energy Efficiency	(32)	(33)	(34)	(33)	(34)	(34)	(35)	(37)	(33)	(33)
New Energy Efficiency	(39)	(74)	(109)	(143)	(181)	(213)	(259)	(309)	(308)	(356)
East Total obligation	**5,229**	**5,244**	**5,237**	**5,231**	**5,251**	**5,127**	**5,081**	**5,076**	**5,195**	**5,189**
East Reserve Margin	22%	24%	26%	25%	28%	28%	30%	15%	16%	15%
West										
Thermal	2,205	2,211	2,186	1,930	2,203	2,064	2,060	1,982	2,010	1,991
Hydroelectric	497	518	434	456	320	330	317	410	439	439
Renewable	105	75	69	86	56	63	52	84	92	95
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	53	50	45	54	37	36	19	39	36	33
Sale	(88)	(71)	(59)	(45)	(32)	(33)	(32)	(38)	(41)	(40)
Transfers	277	267	247	535	275	79	99	588	561	369
West Existing Resources	**3,049**	**3,051**	**2,922**	**3,017**	**2,860**	**2,540**	**2,517**	**3,066**	**3,097**	**2,887**
Front Office Transactions	163	62	5	0	0	0	0	0	0	0
NonEmitting Peaker	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	85	79	120	125	135
Wind+Storage	0	0	0	0	0	0	0	0	0	30
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	0	0	0	46	22	252	232	325	315	479
Storage	0	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**163**	**62**	**5**	**46**	**22**	**337**	**311**	**445**	**441**	**643**
West Total Resources	**3,212**	**3,113**	**2,927**	**3,063**	**2,882**	**2,878**	**2,828**	**3,511**	**3,538**	**3,530**
Load	3,318	3,358	3,397	3,421	3,449	3,479	3,516	3,550	3,585	3,615
Private Generation	(0)	(0)	(1)	(1)	(1)	(1)	(2)	(2)	(3)	(3)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	0	(33)	(91)	(129)	(159)	(186)	(216)	(248)	(238)	(263)
Existing - Energy Efficiency	(23)	(24)	(24)	(24)	(24)	(24)	(25)	(26)	(23)	(24)
New Energy Efficiency	(25)	(48)	(69)	(86)	(105)	(124)	(149)	(176)	(176)	(200)
West Total obligation	**3,270**	**3,253**	**3,213**	**3,182**	**3,160**	**3,142**	**3,123**	**3,098**	**3,146**	**3,124**
West Reserve Margin	-2%	-4%	-9%	-4%	-9%	-8%	-9%	13%	12%	13%
System										
Total Resources	9,603	9,602	9,548	9,581	9,609	9,454	9,419	9,336	9,546	9,518
Obligation	8,498	8,497	8,450	8,412	8,411	8,269	8,205	8,174	8,341	8,314
Capacity Reverve Margin (13%)	1,105	1,105	1,098	1,094	1,093	1,075	1,067	1,063	1,084	1,081
Obligation + Reserves	9,603	9,602	9,548	9,506	9,505	9,344	9,271	9,236	9,425	9,394
System Position	0	0	0	75	105	110	148	100	120	123
Reserve Margin	**13%**	**13%**	**13%**	**14%**	**14%**	**14%**	**15%**	**14%**	**14%**	**14%**

Table 9.19 (cont'd) – Preferred Portfolio Winter Capacity Load and Resource Balance (2031-2040)

East	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Thermal	3,901	3,947	3,646	3,554	3,677	3,411	2,830	2,643	2,783	2,421
Hydroelectric	36	36	34	37	38	43	47	48	52	49
Renewable	665	662	620	668	703	752	782	756	832	778
Purchase	129	129	131	119	109	111	136	133	134	119
Qualifying Facilities	186	178	133	124	119	80	15	13	4	0
Sale	0	0	0	0	0	0	0	0	0	(0)
Transfers	(415)	(387)	(518)	(468)	(504)	(416)	(541)	(472)	(804)	(382)
East Existing Resources	**4,502**	**4,566**	**4,045**	**4,034**	**4,142**	**3,981**	**3,270**	**3,120**	**3,002**	**2,986**
Front Office Transactions	0	0	0	0	0	0	0	0	0	0
NonEmitting Peaker	0	2	378	378	379	375	376	376	381	567
Wind	595	570	555	619	654	706	736	725	807	778
Wind+Storage	0	0	0	0	0	0	0	0	0	0
Solar	12	13	11	11	11	12	13	13	13	12
Solar+Storage	429	427	629	689	699	776	969	942	1,008	936
Storage	142	140	120	138	147	157	125	113	88	83
Nuclear	202	197	182	202	209	236	241	240	265	249
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
East Planned Resources	**1,380**	**1,349**	**1,875**	**2,036**	**2,099**	**2,263**	**2,459**	**2,408**	**2,563**	**2,626**
East Total Resources	**5,882**	**5,915**	**5,920**	**6,070**	**6,241**	**6,244**	**5,729**	**5,528**	**5,565**	**5,612**
Load	6,240	6,328	6,415	6,517	6,595	6,672	6,407	6,504	6,589	6,682
Private Generation	(9)	(10)	(12)	(13)	(14)	(16)	(33)	(37)	(41)	(45)
Existing - Demand Response	(288)	(287)	(291)	(264)	(243)	(247)	(303)	(295)	(299)	(267)
New Demand Response	(398)	(414)	(483)	(461)	(449)	(488)	(654)	(669)	(713)	(705)
Existing - Energy Efficiency	(38)	(38)	(39)	(35)	(32)	(33)	(40)	(39)	(40)	(35)
New Energy Efficiency	(446)	(480)	(513)	(494)	(481)	(504)	(659)	(695)	(758)	(726)
East Total obligation	**5,061**	**5,099**	**5,078**	**5,250**	**5,375**	**5,384**	**4,718**	**4,769**	**4,738**	**4,904**
East Reserve Margin	16%	16%	17%	16%	16%	16%	21%	16%	17%	14%

West										
Thermal	2,076	2,053	2,032	2,080	2,072	2,025	1,808	489	490	490
Hydroelectric	373	374	351	388	406	448	481	487	536	503
Renewable	79	79	70	78	78	91	101	104	111	107
Purchase	1	1	1	1	1	1	1	1	1	1
Qualifying Facilities	25	23	19	19	19	19	17	16	13	8
Sale	(35)	(34)	(32)	(34)	(36)	(38)	(32)	(29)	(32)	(30)
Transfers	415	387	518	468	504	416	541	472	804	382
West Existing Resources	**2,934**	**2,883**	**2,960**	**2,999**	**3,044**	**2,961**	**2,917**	**1,541**	**1,923**	**1,459**
Front Office Transactions	0	0	0	0	0	0	0	560	59	420
NonEmitting Peaker	0	0	0	0	0	0	15	581	582	571
Wind	111	176	164	182	178	209	232	246	266	254
Wind+Storage	24	24	23	25	24	29	32	34	37	35
Solar	0	0	0	0	0	0	0	0	0	0
Solar+Storage	359	355	294	317	325	357	364	358	385	394
Storage	0	0	0	0	0	1	94	88	111	399
Nuclear	0	0	0	0	0	0	13	480	531	487
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
West Planned Resources	**494**	**555**	**480**	**524**	**527**	**597**	**748**	**2,347**	**1,970**	**2,561**
West Total Resources	**3,428**	**3,438**	**3,441**	**3,523**	**3,571**	**3,557**	**3,666**	**3,887**	**3,893**	**4,020**
Load	3,643	3,681	3,721	3,760	3,797	3,826	4,271	4,322	4,375	4,425
Private Generation	(4)	(4)	(5)	(6)	(7)	(8)	(9)	(11)	(12)	(13)
Existing - Demand Response	0	0	0	0	0	0	0	0	0	0
New Demand Response	(327)	(336)	(350)	(328)	(331)	(354)	(449)	(458)	(480)	(460)
Existing - Energy Efficiency	(27)	(27)	(28)	(25)	(23)	(23)	(29)	(28)	(28)	(25)
New Energy Efficiency	(252)	(271)	(293)	(283)	(276)	(293)	(372)	(385)	(409)	(369)
West Total obligation	**3,033**	**3,042**	**3,045**	**3,118**	**3,160**	**3,148**	**3,412**	**3,440**	**3,445**	**3,558**
West Reserve Margin	13%	13%	13%	13%	13%	13%	7%	13%	13%	13%

System										
Total Resources	9,310	9,353	9,360	9,593	9,812	9,801	9,395	9,415	9,458	9,632
Obligation	8,095	8,141	8,122	8,368	8,536	8,532	8,131	8,209	8,183	8,462
Capacity Reverve Margin (13%)	1,052	1,058	1,056	1,088	1,110	1,109	1,057	1,067	1,064	1,100
Obligation + Reserves	9,147	9,200	9,178	9,455	9,645	9,641	9,188	9,276	9,247	9,562
System Position	163	153	182	138	167	160	207	139	211	70
Reserve Margin	**15%**	**15%**	**15%**	**15%**	**15%**	**15%**	**16%**	**15%**	**16%**	**14%**

Washington Clean Energy Transformation Act Required Scenarios

Washington's CETA legislation requires utilities to conduct three scenarios:

- **Alternative Lowest Reasonable Cost** - WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards.

- **Climate Change** - WAC 480-100-620(10)(b) instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."

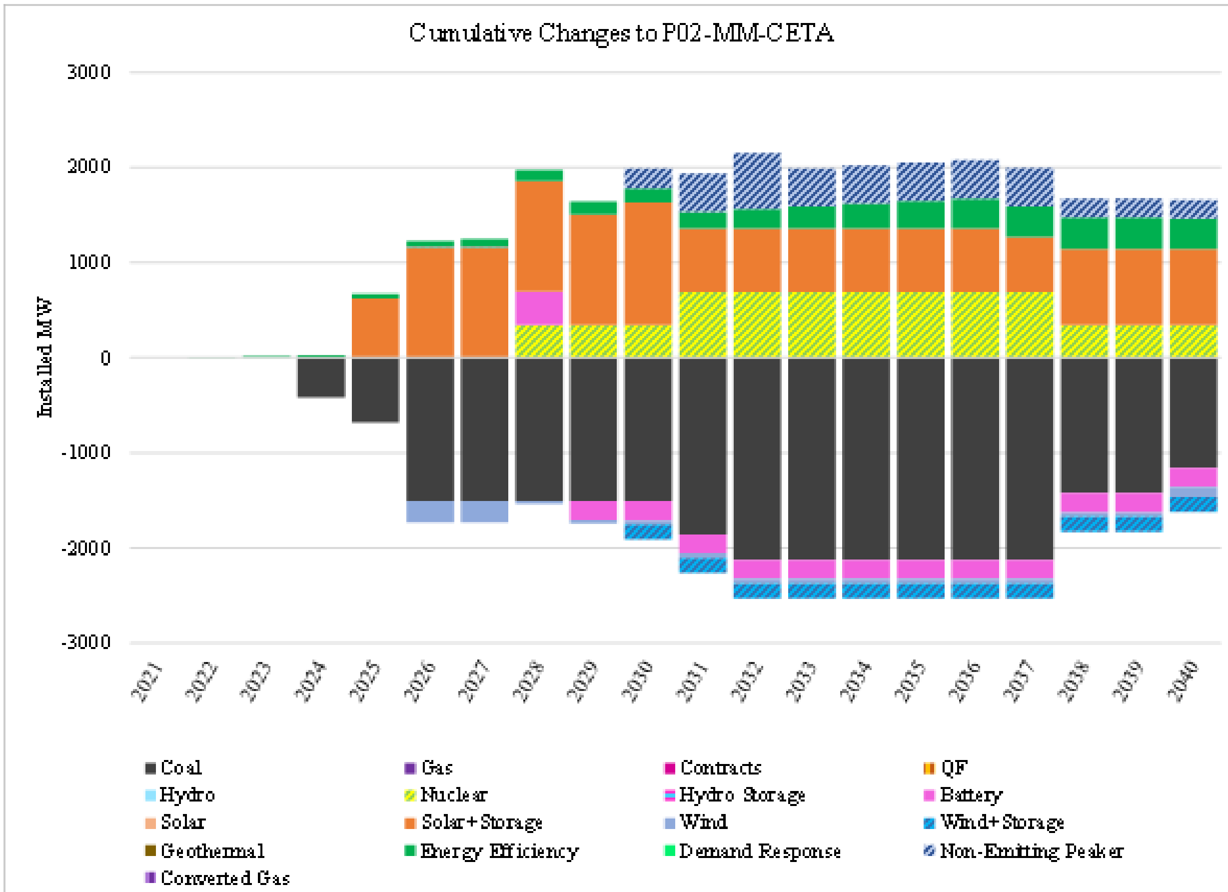
- **Maximum Customer Benefit** - WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals."

In this section, PacifiCorp discusses each of these portfolio outcomes relative to the preferred portfolio P02-MM-CETA. Note, that the Alternative Lowest Reasonable Cost scenario is also discussed relative to the P02-MM portfolio.

Alternative Lowest Reasonable Cost

WAC 480-100-620(10)(a) instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards and must include the social cost of greenhouse gases (SCGHG) in the resource acquisition decision. In the absence of a requirement to assume SCGHG during portfolio development, the alternative lowest reasonable cost portfolio is P02-MM, and what we would have implemented but for CETA requirements. The preferred portfolio, P02-MM-CETA, adds a present value revenue requirement of $164m compared to P02-MM to meet CETA requirements. Accounting for the requirement to include the SCGHG price-policy assumption in portfolio development, the alternate scenario becomes the same as an SCGHG portfolio run under the medium gas, medium CO_2 price-policy scenario. Comparing this Alternative Lowest Reasonable Cost case to the preferred portfolio (P02-MM-CETA) yields a PVRR(d) system cost of $182m.

Figure 9.47 – Cumulative Portfolio Resource Changes P02-SCGHG Compared to the 2021 IRP Preferred Portfolio

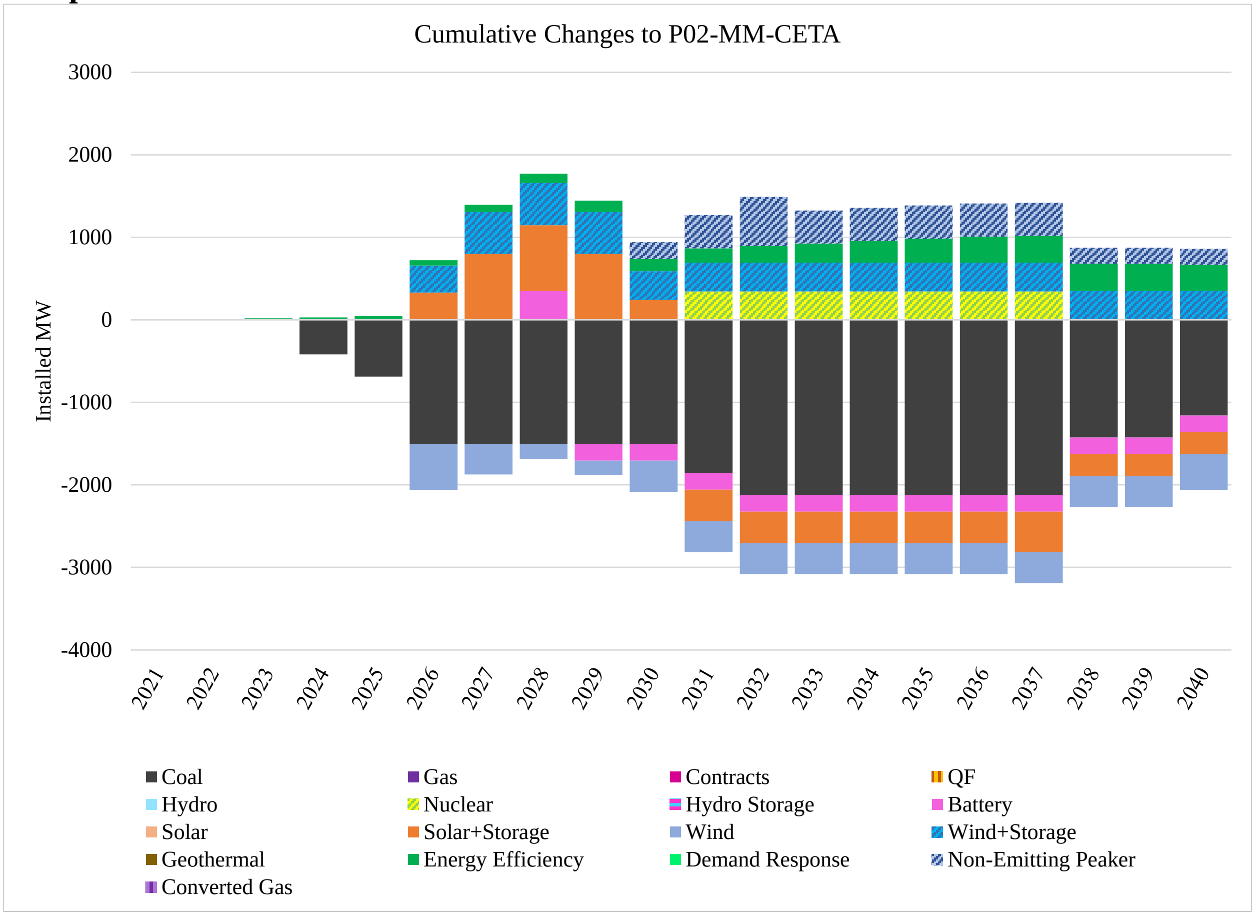


Climate Change

The Washington climate change scenario includes an updated load forecast to incorporate regional studies on potential temperature change (and associated impact to demand and energy). Relative to the 2021 IRP forecast, the climate change scenario results in summer peaks being higher by approximately 50 MW (<1% higher) over the 2021-2025 timeframe. By 2040, summer peaks are projected to be 318 MW (2.7%) higher than the 2021 IRP Base. Higher winter temperatures result in less heating load, which are driving lower winter peaks. By 2040, winter peaks are projected to be 259 MW (2.3%) lower than the 2021 IRP Base. Please see Appendix A for additional detail regarding the climate change scenario.

The scenario also includes analysis of impacts from climate change (precipitation, streamflow, etc.) on Lewis River hydroelectric generating facilities, resulting in a reduction of approximately 7% in energy production, relative to the 2021 IRP base. Compared to the preferred portfolio, the climate change scenario increases system costs by $14.6 billion, driven in large part by the SCGHG price-policy assumption.

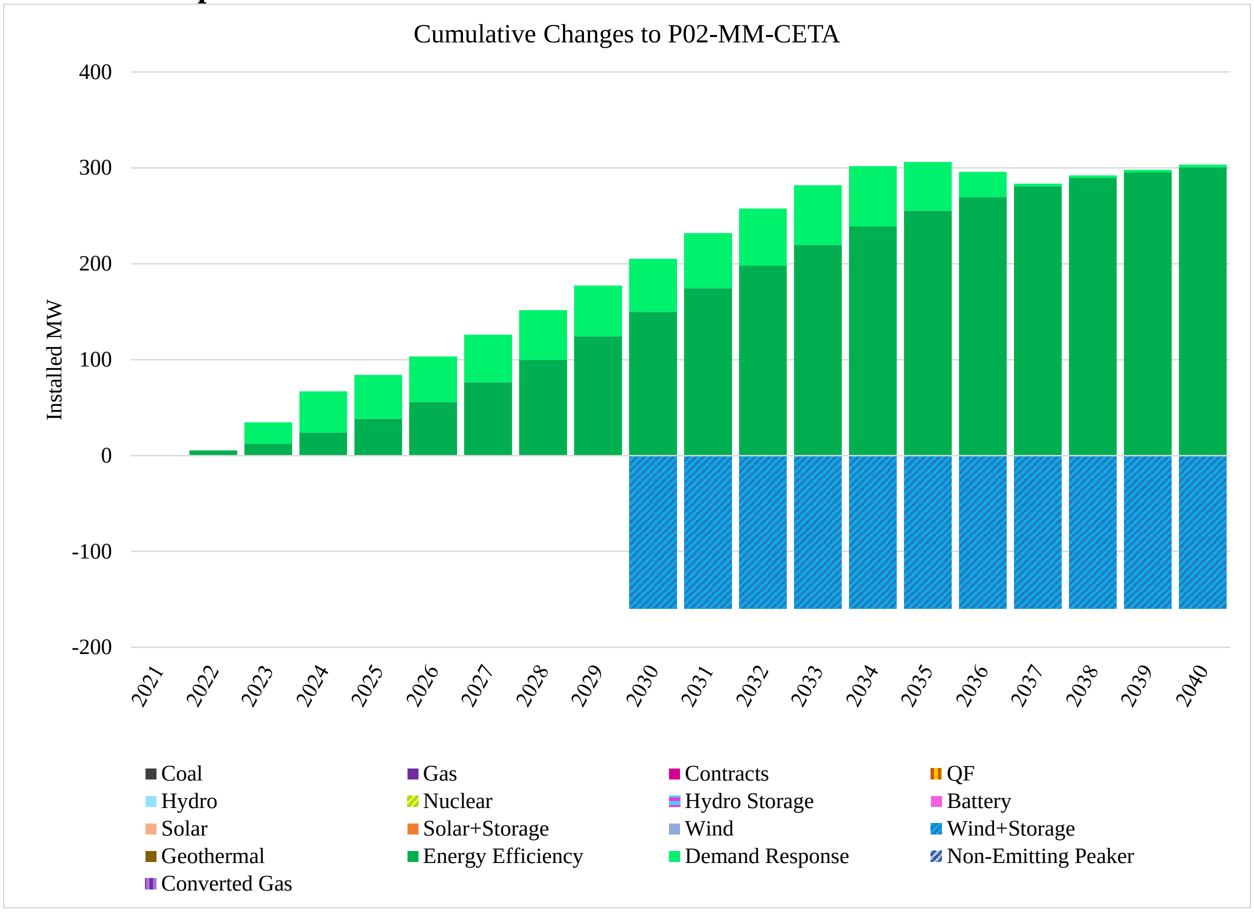
Figure 9.48 – Cumulative Portfolio Resource Changes, Climate Change Portfolio Compared to the 2021 IRP Preferred Portfolio



Maximum Customer Benefit

The maximum customer benefit scenario focuses on adding distributed generation, demand response, and energy efficiency in Washington, as well as avoiding high-voltage transmission upgrades in PacifiCorp's Yakima and Walla Walla communities to minimize burdens and maximize benefits to Washington customers. Washington load forecast reflects the high private generation forecast. The portfolio assumes the social cost of greenhouse gas price-policy scenario, and includes all available Washington energy efficiency and demand response. 335 MW of needed Yakima resource is assumed to be small scale PVS, adjusting operating costs and mitigating transmission costs. Due to higher DSM selections, it was not necessary to create a hybrid Yakima resource by adding 160 MW of co-located wind to the selected PVS resource in year 2030. As a result, a 160 MW reduction in wind capacity is visible in the cumulative changes graph beginning 2030 relative to the preferred portfolio. The Maximum customer benefits sensitivity increases costs by $16.9 billion relative to the preferred portfolio, driven primarily by the SCGHG price-policy assumption and the inclusion of all available DSM.

Figure 9.49 – Cumulative Portfolio Resource Changes, Maximum Customer Benefit Portfolio Compared to the 2021 IRP Preferred Portfolio



Additional Sensitivity Analysis

In addition to the resource portfolios developed and studied as part of the portfolio-development process that supports selection of the preferred portfolio, sensitivity cases will be completed to better understand how certain modeling assumptions influence the resource mix and timing of future resource additions. These sensitivity cases are useful in understanding how PacifiCorp's resource plan would be affected by changes to uncertain planning assumptions and to address how alternative resources and planning paradigms affect system costs and risk.

Table 9.20 lists additional sensitivity studies to be performed for the 2021 IRP. To isolate the impact of a given planning assumption, all sensitivity cases will be evaluated as a variant of the BAU1 and BAU2 portfolios along with the preferred portfolio (P02-MM-CETA).

Table 9.20 – Summary of Additional Sensitivity Cases

Case	Description	Risk-Adjusted PVRR ($m)	Load	Private Gen	CO_2 Policy
S-01	High Load		High	Base	Medium gas / Medium CO_2
S-02	Low Load		Low	Base	Medium gas / Medium CO_2
S-03	1 in 20 Load Growth		1 in 20	Base	Medium gas / Medium CO_2
S-04	New Proxy Gas Allowed		Base	Base	Medium gas / Medium CO_2
S-05	Business Plan		Base	Base	Medium gas / Medium CO_2
S-06	Levelized Cost of Energy Efficiency Bundles		Base	Base	Medium gas / Medium CO_2
S-07	High Private Generation		Base	High	Medium gas / Medium CO_2
S-08	Low Private Generation		Base	Low	Medium gas / Medium CO_2

PacifiCorp will file a supplemental filing to its 2021 IRP filing that includes discussion and results of these sensitivities. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

CHAPTER 10 – ACTION PLAN

CHAPTER HIGHLIGHTS

- The 2021 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 2021 IRP action plan includes action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases, and the purchase and sale of renewable energy credits (RECs).
- The 2021 IRP acquisition path analysis provides insight on how changes in the planning environment might influence future resource procurement activities. Key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and carbon dioxide (CO_2) emission polices.
- PacifiCorp further discusses how it can mitigate procurement delay risk, summarizes planned procurement activities tied to the action plan, assesses trade-offs between owning or purchasing third-party power, discusses its hedging practices, and identifies the types of risks borne by customers and the types of risks borne by shareholders.

Introduction

PacifiCorp's 2021 IRP action plan identifies the steps the company will take over the next two-to-four years to deliver its preferred portfolio, with a focus on the front ten years of the planning horizon. Associated with the action plan is an acquisition path analysis that anticipates potential major regulatory actions and other trigger events during the action plan time frame that could materially impact resource acquisition strategies.

The 2021 IRP action plan is based on the latest and most accurate information available at the time portfolios are being developed and analyzed on cost and risk metrics. PacifiCorp recognizes that the preferred portfolio, upon which the action plan is based, is developed in an uncertain and evolving planning environment and that resource acquisition strategies need to be regularly evaluated as planning assumptions change.

Resource information used in the 2021 IRP, such as capital and operating costs, are based upon recent cost-and-performance data. However, it is important to recognize that resources identified in the plan include proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost, and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and requirements, and commission orders.

In addition to presenting the 2021 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2021 IRP acquisition path analysis, This chapter also includes discussion of the following resource procurement topics:

- Procurement delays;
- IRP action plan linkage to the business plan;
- Resource procurement strategy;

- Assessment of owning assets vs. purchasing power;
- Managing carbon risk for existing plants;
- Purpose of hedging; and
- Treatment of customer and investor risks.

The 2021 IRP Action Plan

The 2021 IRP action plan identifies specific actions PacifiCorp will take over roughly the next two-to-four years to deliver its preferred portfolio. Action items are based on the size, type and timing of resources in the preferred portfolio, findings from analysis completed over the course of portfolio modeling, and feedback received by stakeholders in the 2021 IRP public-input process. Table 10.1 details specific 2021 IRP action items by resource category.

Table 10.1 – 2021 IRP Action Plan

Action Item	1. Existing Resource Actions
1a	**Colstrip Units 3 and 4:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**Craig Unit 1:** • PacifiCorp will continue to work closely with co-owners to seek the most cost-effective path forward toward the 2021 IRP preferred portfolio target exit date of December 31, 2025.
1b	**Naughton Units 1 and 2:** • PacifiCorp will initiate the process of retiring Naughton Units 1-2 by the end of December 2025, including completion of all required regulatory notices and filings. • By the end of Q2 2023, PacifiCorp will confirm transmission system reliability assessment and year-end 2025 retirement economics in 2023 IRP filing. • By the end of Q4 2023, PacifiCorp will initiate the process with the Wyoming Public Service Commission for approval of a reverse request for proposals for a potential sale of Naughton Units 1 and 2. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements.

1c	**Jim Bridger Units 1 and 2 Gas Conversion:** • PacifiCorp will initiate the process of ending coal-fueled operations and seeking permitting for a natural-gas conversion by 2024, including completion of all required regulatory notices and filings. • By the end of Q2 2022, PacifiCorp will finalize an employee transition plan. • By the end of Q2 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By the end of Q4 2023, PacifiCorp will administer termination, amendment, or close-out of existing permits, contracts, and other agreements. • By the end of Q4, 2023, PacifiCorp will remove units 1 and 2 from Washington's allocation of electricity.
1d	**Carbon Capture, Utilization, and Sequestration/Wyoming House Bill 200 Compliance:** • PacifiCorp issued a carbon capture, utilization, and sequestration (CCUS) request for expression of interest (REOI) on June 29, 2021. PacifiCorp will complete the 2021 CCUS REOI process and utilize any new relevant information. Additional model sensitivities will be run accordingly. • PacifiCorp will issue a CCUS Request for Proposals (RFP) in 2022. The 2021 CCUS REOI responses will inform the scope of the CCUS RFP. • A completed CCUS Front End Engineering & Design Study (FEED Study) based on a new CCUS technology was submitted to PacifiCorp in July 2021 for Dave Johnston Unit 2. Third-party review of the FEED Study will be completed by Q1 2022, and model sensitivities will subsequently be run as needed, with FEED Study assumptions and inputs as appropriate. • Subject to finalization of rules by the Wyoming Public Service Commission (WPSC) to implement House Bill 200 (HB 200), the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), by March 31, 2022, PacifiCorp will file with the WPSC an initial CCUS application to establish intermediate CCUS standards and requirements. • Subject to finalization of rules by the WPSC to implement HB 200, the Wyoming Low Carbon Energy Standard (anticipated by Q4 2021), PacifiCorp will submit for WPSC approval a final plan with its proposed energy portfolio standard for dispatchable and reliable low-carbon electricity, its plan for achieving the standard, and a target date of no later than July 1, 2030.

1e	**<u>Regional Haze Compliance:</u>** • Following the resolution of first planning period regional haze compliance disputes, and the submission of second planning period regional haze state implementation plans, PacifiCorp will evaluate and model any emission control retrofits, emission limitations, or utilization reductions that are required for coal units. • PacifiCorp will continue to engage with the Environmental Protection Agency, state agencies, and stakeholders to achieve second planning period regional haze compliance outcomes that improve Class I visibility, provide environmental benefits, and are cost effective.
Action Item	**2. New Resource Actions**
2a	**<u>Customer Preference Request for Proposals:</u>** • Consistent with Utah Community Renewable Energy Act, PacifiCorp continues to work with eligible communities to develop program to achieve goal of being net 100 percent renewable by 2030; PacifiCorp anticipates filing an application for approval of the program with the Utah Public Service Commission in 2022, which may necessitate issuance of a request for proposals to procure resources within the action plan window.
2b	**<u>Acquisition and Repowering of Foote Creek II-IV and Rock River I:</u>** • In Q3 2021, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Foote Creek II-IV in order to issue repowering contracts in Q1 2022 in support of a late 2023 in-service date. • In Q1 2022, PacifiCorp will pursue necessary regulatory approvals to authorize the acquisition and repowering of Rock River I following the expiration of the existing power purchase agreement in order to issue repowering contracts in Q3 2022 to support a late 2024 in-service date.
2c	**<u>Natrium™ Demonstration Project:</u>** • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable. • By the end of 2022, PacifiCorp will finalize commercial agreements for the Natrium™ project. • Q1 2022, PacifiCorp will develop a community action plan in coordination with community leaders. • By 2025, PacifiCorp will begin training operators. • PacifiCorp will continue to monitor key TerraPower milestones for development and will make regulatory filings, as applicable, including, but not limited to, a request for the Oregon Public Utility Commission to explicitly acknowledge an alternative acquisition method consistent with OAR 860-089-0100(3)(c), and a request for a waiver of a solicitation for a significant energy resource decision consistent with Utah statute 54-17-501.

2d	**2022 All-Source Request for Proposals:** • PacifiCorp will issue an all-source Request for Proposals (RFP) to procure resources that can achieve commercial operations by the end of December 2026. • In September 2021, PacifiCorp will notify the Public Utility Commission of Oregon, the Public Service Commission of Utah, and the Washington Utilities and Transportation Commission, of PacifiCorp's need for an independent evaluator. • In October 2021, PacifiCorp will file a draft all-source RFP with applicable state utility commissions. • In January 2022, PacifiCorp expects to receive approval of the all-source RFP from applicable state utility commissions and issue the RFP to the market. • In Q2 2022, PacifiCorp will identify an initial shortlist in advance of annual Cluster Request Window. • In Q1 2023, PacifiCorp will identify a final shortlist from the all-source RFP, and file for approval of the final shortlist in Oregon, file, certificate of public convenience and necessity (CPCN) applications, as applicable. • By Q2 2023 PacifiCorp will execute definitive agreements with winning bids from the all-source RFP. • By Q4 2025-2026, winning bids from the all-source RFP are expected to achieve commercial operation. Resources must have commercial operation date of December 31, 2026, or earlier.
2e	**2020 All-Source Request for Proposals:** • PacifiCorp filed for approval of the final shortlist in Oregon in June 2021. • In September 2021, PacifiCorp will file CPCN applications in Wyoming, as applicable, for final shortlist. • In Q4 2021, PacifiCorp will make a filing in Utah for significant energy resources on final shortlist.
Action Item	**3. Transmission Action Items**
3a	**Energy Gateway South Segment F (Aeolus-Clover 500 kV transmission line):** • By Q2 2022, obtain Utah and Wyoming Certificates of Public Convenance and Necessity. • By the end of Q1 2022, Bureau of Land Management notice to proceed to construct Energy Gateway South. • In Q3 2024, construction of Energy Gateway South is expected to be completed and placed in service.
3b	**Energy Gateway West, Segment D.1 (Windstar-Shirley Basin 230 kV transmission line):** • By Q2 2022, obtain conditional Wyoming Certificate of Public Convenance and Necessity • By Q3 2022 complete ROW easement acquisition and option full Wyoming CPCN • In Q3 2024, construction of Energy Gateway West segment D.1 to be completed and placed in service.

3c	**<u>Boardman-to-Hemingway (500 kV transmission line):</u>** • Continue to support the project under the conditions of the Boardman-to-Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue to participate in "pre-construction" activities in support of the 2026 in-service date. • Continue negotiations for plan of service post B2H for parties to the permitting agreement.
3d	Initiate Local Reinforcement Projects as identified with the addition of new resources per the preferred portfolio, and follow-on requests for proposal successful bids
3e	Continue permitting support for Gateway West segments D.3 and E.
Action Item	**4. Demand-Side Management (DSM) Actions**

4a	**Energy Efficiency Targets:**

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 is provided in Appendix D in Volume II of the 2021 IRP.
- PacifiCorp will pursue cost-effective energy efficiency resources as summarized in the table below:

Year	Annual 1st Year Energy (GWh)	Annual Incremental Capacity (MW)
2021	510	157
2022	492	138
2023	486	144
2024	529	164

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

Year	Annual Incremental Capacity (MW)
2021	0
2022	123
2023	242
2024	184

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
2A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

Action Item	5. Market Purchases

5a	**Market Purchases:** • Acquire short-term firm market purchases for on-peak delivery from 2021-2023 consistent with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices. These short-term firm market purchases will be acquired through multiple means: Balance of month and day-ahead brokered transactions in which the broker provides a competitive price. • Balance of month, day-ahead, and hour-ahead transactions executed through an exchange, such as the Intercontinental Exchange, in which the exchange provides a competitive price. • Prompt-month, balance-of-month, day-ahead, and hour-ahead non-brokered bi-lateral transactions.
Action Item	**6. Renewable Energy Credit (REC) Actions**
6a	**Renewable Portfolio Standards (RPS):** • PacifiCorp will pursue unbundled REC RFPs and purchases to meet its state RPS compliance requirements. • As needed, issue RFPs seeking then current-year or forward-year vintage unbundled RECs that will qualify in meeting California RPS targets through 2024.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous action plan items documented in the 2019 IRP filed with state commissions on October 18, 2019. Many of these action items have been superseded in some form by items identified in the 2021 IRP action plan. The status for all action items from the 2019 IRP is summarized in Table 10.2.

Table 10.2 – 2019 IRP Action Plan Status Update

Action Item	3. Existing Resource Actions	Status
1a	**Naughton Unit 3:** • PacifiCorp will complete the gas conversion of Naughton Unit 3, including completion of all required regulatory	This action is complete. PacifiCorp filed an amended certificate of public convenience and necessity (CPCN) notice with the Wyoming Public Service Commission on 11/21/2019. The notice requested a determination that a

	notices and filings, in 2020. Initiate procurement of materials in Q4 2019. Conversion completed in 2020.	CPCN was not required to convert the unit to natural gas. The Commission approved the notice by a letter order issued on 11/27/2019. Gas conversion was complete in July 2020.
1b	**<u>Cholla Unit 4:</u>** • 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.	Cholla Unit 4 regulatory, compliance, environmental, transmission, permits, operations, and other associated closure communications and requirements were performed throughout 2020. Cholla Unit 4 was retired on 12/31/2020. PacifiCorp continues to work with the operator on joint-owner obligations, transition, and decommissioning plans.

1c	**<u>Jim Bridger Unit 1:</u>** • 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.	Finalizing plans for the process of retiring Jim Bridger Unit 1 are dependent on the preferred portfolio of the 2021 IRP, which will be filed by September 1, 2021. Jim Bridger regulatory, compliance, environmental, permits, operations, and other associated closure impacts will be addressed as required by state laws. The request to study Jim Bridger Unit 1 retirement was received in Q1 2021 by PacifiCorp transmission. The results are posted to OASIS. The employee transition plan and community action plan are ongoing. The initiation of a process for approval of a reverse request for proposals for potential sale of Jim Bridger 1 is dependent on the preferred portfolio of the 2021 IRP. If the outcome of the 2021 IRP continues to show customer benefits to retire the unit at the end of 2023, PacifiCorp will file an application with the Wyoming Public Service Commission in Q4 2021 to initiate the process to solicit a buyer for the unit, in accordance with the administrative rules adopted by the commission to implement Wyo. Stat. 37-2-133 and 37-3-117.
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.	PacifiCorp is proceeding with this action item on schedule. Additional information on this action item is included in the 2021 action plan.

	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.	PacifiCorp is proceeding with this action item on schedule.
Action Item	**4. New Resource Actions**	**Status**
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 megawatt (MW) Power	PacifiCorp signed a long-term 80 MW PPA for six Utah Schedule 34 customers.

	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.	PacifiCorp signed four long-term PPAs (75 MW, 80 MW, 120 MW & 80 MW) for a large Utah Schedule 34 customer. PacifiCorp signed a long-term 20 MW PPA for a large Utah Schedule 32 customer. Rules for Utah HB 411 were finalized by the Public Service Commission of Utah providing a path forward for development of a program to meet the communities' goals. PacifiCorp is currently working with the consortium of customers to develop the program.
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.	A draft of PacifiCorp's 2020 All-Source RFP ("2020AS RFP") was filed for approval with the Utah PSC and the Oregon PUC in April 2020. In July 2020, the Utah PSC and the Oregon PUC approved the 2020AS RFP, and PacifiCorp issued the 2020AS RFP to market. The 2020AS RFP sought bids for resources capable of coming online by the end of 2024 up to the level of resources identified in PacifiCorp's 2019 IRP. Bids were submitted in August 2020. An initial shortlist was identified in October 2020. The initial shortlist included a total of 6,982 MWs of new generation and storage capacity. Of the total, 5,652 MWs are new generation resources (represented by 3,173 MWs of solar generation and 2,479 MWs of wind generation) and an additional 1,330 MWs of new battery storage assets, which includes 1,130 MWs of solar collocated battery storage and 200 MWs of stand-alone battery storage. The final shortlist of winning bids was filed in Oregon in June 2021. PacifiCorp is finalizing

	• 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.	both build and transfer and power purchase agreement updated drafts that will be forwarded to all final shortlisted participants prior to September 1, 2021. Contract negotiations are expected to proceed into early Q1 2022. All necessary final state regulatory approvals and proceedings are expected to be complete by Q2 2022. On January 31, 2020, as amended March 13, 2020, PacifiCorp submitted revisions to its Open Access Transmission Tariff (OATT) to implement revisions to its interconnection process. PacifiCorp proposed revisions to its Large Generator Interconnection Procedures, Small Generator Interconnection Procedures, and associated appendices, including the Large Generator Interconnection Agreement and Small Generator Interconnection Agreement. On May 12, 2020, the FERC issued an order accepting the proposed Tariff revisions, subject to condition. As a result of the acceptance, PacifiCorp's interconnection process changed from a serial, first =-come, first-served process, to a first-ready, first-served interconnection process. The prospective interconnection processes use cluster studies, under which interconnection requests received during an annual "Cluster Request Window" are studied in groups (as opposed to serially and individually). The revised interconnection process should allow commercially-ready projects to proceed on a more accelerated basis while allowing less-developed projects to have access to non-binding estimates of cost responsibility and time to construct to assist with preliminary siting decisions.

Action Item	3. Transmission Action Items	
3a	**Energy Gateway South:** • 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.	Energy Gateway South has been moved to a target in-service date of Q4 2024. This action item has been superseded by the Energy Gateway South Action in the 2021 action plan.
3b	**Utah Valley Reinforcements:** • 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.	In-service dates have been revised based on current project schedules as follows: • In Q1 2021, PacifiCorp completed the Spanish Fork 345 kV/138 kV transformer upgrade. The completion date for the transformer upgrade was shifted to 2021 due to outage constraints on the line. The remaining scope to complete improvements at a third-party owned substation will be completed in fall 2021. • In Q2 2021, PacifiCorp will complete rebuild of approximately five miles of the Spanish Fork-Timp138 kV line in the Utah Valley. The completion of this project shifted to 2021 due to delays in steel pole deliveries.

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 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.	Transmission cluster studies are underway and final short list RFP results will be available no later than June 2021 which could impact final project schedules. The rebuild of two miles of the Morton Court –Fifth West 138 kV line is scheduled for Q4 2023. The project to loop existing Populus Terminal 345 kV line into both Bridger and Ben Lomond; build 345 kV yard with 345/138 transformer and 138 kV yard buildout at Bridger plus ancillary 345 kV and 230 kV circuit breakers at Ben Lomond is now scheduled for Q4 2023.
3d	**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).	In-service dates have been revised based on current project schedules. Cluster studies continue and final short list RFP results will be available no later than June 2021 which could impact final project schedules. Washington action items are addressed in PacifiCorp's response to item 3e below. In Q3 2024 PacifiCorp is scheduled complete rebuild of the Mona –Clover #1 & #2 345 kV lines. In Q2 2026 PacifiCorp is scheduled to identify route and terminals for new approximately 70-mile 345 kV line in southern/central Utah.

	• By Q2 2022, establish the type and location of new resources and finalize project scope, as necessary.	
3e	**<u>Yakima Washington Reinforcements:</u>** • To facilitate interconnection of preferred portfolio resources in the Yakima area, PacifiCorp will proceed with protection system and remedial action scheme upgrades to local 230 kV and 115 kV substations not otherwise included in 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.	The cluster studies are underway and final short list RFP results will be available no later than June 2021 which could impact final project schedules. The Vantage-Pomona Heights 230kV line was completed in Q3 2020.
3f	**<u>Boardman to Hemmingway:</u>** • Continue to support the project under the conditions of the Boardman to Hemingway Transmission Project (B2H) Joint Permit Funding Agreement. • Continue to participate in the development and negotiations of the construction agreement. • Continue 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.	Negotiations with partners are ongoing. PacifiCorp continues to study this transmission segment as part of its 2021 IRP.
3g	**<u>Energy Gateway West:</u>**	Energy Gateway West Segment D.2 was completed in Q4 2020. The other action items remain on schedule.

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

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><td>This action item has been superseded by the Energy Gateway West Action in the 2021 action plan.</td></tr>
<tr><th>Action Item</th><th>4. Demand-Side Management (DSM) Actions</th><th>Status</th></tr>
<tr><td>4a</td><td>
<u>Energy Efficiency 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

</td><td>
In October 2020, the Utah PSC approved a new Wattsmart battery demand response program. With the addition of this new program and program modifications occurring with Cool Keeper and Irrigation Load Control, the Company is currently on track to achieve the incremental capacity.

Energy Efficiency Targets

2019 reporting indicates the company acquired 506 GWh of energy efficiency system wide. This equates to 113 MW of capacity reductions.

Preliminary 2020 reporting indicates the company acquired 561 GWh of energy efficiency system wide. This equates to 138 MW of capacity reductions.
</td></tr>
</table>

	targeting approximately 29 MW of incremental capacity from 2020 through 2023.	Coupling preliminary 2020 reporting with 2019 actuals, acquired 1,067 GWh of energy efficiency over the two years. This equates to capacity reductions of 251 MW (using the same GWh/MW relationship) PacifiCorp continues to evaluate alternative bundling methodologies as part of the 2021 IRP process, and presented its methodology at the January 29, 2021 IRP public-input meeting. At the end of January 2021, PacifiCorp issued a demand response RFP to identify the potential acquisition of cost-effective flexible capacity. The final shortlist of bids was identified in June 2021 and includes over 600 MW of capacity during the planning horizon. PacifiCorp is finalizing the procurement and negotiation of demand response resources following the completion of 2021 IRP. Contract negotiations and program filings are expected to conclude in Q4 of 2021. All necessary state regulatory approvals and proceedings are expected to be complete in the winter and spring of 2022.
Action Item	**5. Front Office Transactions**	**Status**
5a	**<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	Market purchases, inclusive of day-ahead, balance of month, prompt, and forward hedging transactions, but not accounting for any offsetting hedging sales, were made for on peak delivery in the following periods and at the following quantities:

Action Item	Action	Status
	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.	2019: 350 to 2561 MW 2020: 650 to 2720 MW 2021: 125 to 1150 MW Market purchases are made in accordance with the Risk Management Policy and Energy Supply Management Front Office Procedures and Practices and include a mix of the transaction types identified in item 5a.
Action Item	**6. Renewable Energy Credit Actions**	**Status**
6a	**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.	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 and Washington. Most recently, PacifiCorp issued an RFP for RECs in 2019 to meet its state RPS compliance requirements.
6b	**Renewable Energy Credit Sales:** • Maximize the sale of RECs that are not required to meet state RPS compliance obligations.	PacifiCorp issued reverse RFPs in April 2019, March 2020, and February 2021. PacifiCorp will continue to engage in bilateral REC sales and issue reverse RFPs to maximize the sale of RECs that are not required to meet state RPS compliance obligations.

Acquisition Path Analysis

Resource and Compliance Strategies

PacifiCorp worked with stakeholders to define its portfolio development process and cost and risk analysis in the 2021 IRP. This analysis reflects a combination of specific planning assumptions related to key uncertainties addressed in the acquisition path analysis include load, private generation, changes in available resources, and CO2 emission polices. PacifiCorp will further analyze sensitivity cases on planning assumptions related primarily to the load forecasts and private generation penetration levels. The array of planning assumptions that define the studies used to develop resource portfolios provides the framework for a resource acquisition path analysis by evaluating how resource selections are impacted by changes to planning assumptions.

Given current load expectations, portfolio modeling performed for the 2021 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, market purchases, and energy efficiency and demand response resources are consistently selected. Further, the procurement processes associated with these resource actions are well underway. With regard to renewable resource acquisition, the portfolio development modeling performed in the 2021 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 2021 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 (2021-2030) and long-term (2031-2040) resource strategies.

Acquisition Path Decision Mechanism

The Public Service Commission of Utah requires that PacifiCorp provide "[a] plan of different resource acquisition paths with a decision mechanism to select among and modify as the future unfolds."[1] PacifiCorp's decision mechanism is centered on the IRP process and ongoing updates to the IRP modeling tools between IRP cycles. The same modeling tools used in the IRP are also used to evaluate and inform the procurement of resources. The IRP models are used on a macro-level to evaluate alternative portfolios and futures as part of the IRP process, and then on a micro-level to evaluate the economics and system benefits of individual resources as part of the supply-side resource procurement and demand-side management target-setting/valuation processes. PacifiCorp uses the IRP development process, and the IRP modeling tools to serve as decision support tools to guide prudent resource acquisition paths that maintain system reliability at a reasonable cost. Table 9.3 summarizes PacifiCorp's 2021 IRP acquisition path analysis, which provides insight on how changes in the planning environment might influence future resource procurement activities. Changes in procurement activities driven by changes in the planning environment will ultimately be reflected in future IRPs and resource procurement decisions.

[1] Public Service Commission of Utah, In the Matter of Analysis of an Integrated Resource Plan for PacifiCorp, Report and Order, Docket No. 90-2035-01, June 1992, p. 28.

Table 10.3 – Near-term and Long-term Resource Acquisition Paths

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
Higher sustained load growth	High economic drivers accounting for 95% prediction interval.	• In 2026, there is an increase of 5 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 545 MW increasing further to nearly 600 MW in 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. • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements.	• In 2040, there is an increase of 7 percent higher sustained load growth than the base case forecast, resulting in an increase in peak capacity requirements of 890 MW. • The higher peak capacity requirements relative to the base case forecast results in additional resource need, increased market reliance and/or shifts in timing of planned resources or coal unit retirements.
Lower sustained load growth	Low economic drivers accounting for 95% prediction interval.	• In 2026, there is 6 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 628 MW decreasing further 861 MW in 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. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.	• In 2040, there is a 7 percent lower sustained load growth than the base case forecast, resulting in a decrease in peak capacity requirements of 890 MW. • The lower peak capacity requirements relative to the base case forecast results in a reduction in resource need, decreased market reliance and/or shifts in timing of planned resources or coal unit retirements.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
Higher sustained private generation penetration levels	More aggressive technology cost reductions, improved technology performance, and higher electricity retail rates	• In 2026, peak capacity requirements are lower by 53 MW due to higher sustained private generation levels relative to the base case forecast. • In 2030, peak capacity requirements are lower by 249 MW due to higher sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2040, peak capacity requirements are lower by 172 MW due to higher sustained private generation levels relative to the base case forecast. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.
Lower sustained private generation penetration levels	Less aggressive technology cost reductions, reduced technology performance, and lower electricity retail rates	• In 2026, peak capacity requirements are higher by 31 MW due to lower sustained private generation levels relative to the base case forecast. • In 2030, peak capacity requirements are higher by 61 MW due to lower sustained private generation levels relative to the base case forecast. • Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Small changes to the portfolio would require minimal changes to the resource acquisition strategy.	• In 2040, peak capacity requirements are higher by 342 MW due to lower sustained private generation levels relative to the base case forecast. • Timing differences in resource capacity would need to be assessed in procurement processes to achieve the appropriate balance of energy and capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
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 $102.48/ton by 2040 that drives all coal to be retired by 2030	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Accelerate timing of new resource additions including an advanced nuclear resource from 2038 to 2030 and 1,009 MW of solar co-located with storage from 2037 to 2024 through 2028 with an additional 330 MW added over that time period. Accelerate a non-emitting peaking unit from 2040 to 2030 with two additional non-emitting peaking units added in that year. • Increase procurement of market purchases with the potential for accelerated coal retirements. • Increase procurement of energy efficiency: energy efficiency capacity is accelerated and increases by 108 MW by 2030.	• Through 2040, new non-emitting peaking capacity is increased by 412 MW. • Through 2040, energy efficiency is increased by 111 MW and solar co-located with solar capacity is increased by over 330 MW. • Through 2040, market purchases increase by an average of 381 MW.
No Natrium™ Advanced Nuclear Demonstration Project in 2028	See Volume 1, Chapter 9, Modeling and Portfolio Selection Results, P02e-No Nuc portfolio	• Without the NatriumTM demonstration project, 348 MW of solar co-located with storage is added to the portfolio in 2026 and an additional 240 MW is added in 2030. • Higher costs and emissions result from increased fossil-fueled generation, emissions and net market transactions.	• In 2037, a non-emitting peaker displaces solar co-located with storagesolar co-located with storage resource capacity.

Trigger Event	Planning Scenario(s)	Near-Term Resource Acquisition Strategy (2021-2030)	Long Term Resource Acquisition Strategy (2031-2040)
No Boardman-to-Hemingway (B2H) transmission segment in 2026	See Volume 1, Chapter 9, Modeling and Portfolio Selection Results, P02b-No B2H portfolio	• Within the action plan window, there would be no change to the resource procurement strategy focused on an all-source RFP and incremental transmission upgrades. • Without B2H, 405 MW of wind and 200 MW of solar co-located with storage is removed from the portfolio in 2026. Approximately 200 MW of storage capacity is removed from eastern Wyoming in 2029, which must be replaced by just over 200 MW of non-emitting peaking capacity in 2030. • A reduction in resources results in increased reliance on the market and higher emissions from an increase in coal and gas generation. • Reduced flexibility and load-serving capability of the transmission system.	• 725 MW of incremental 4-hour battery resources and other transmission upgrades would be needed in southern Oregon if the B2H transmission line is not built.

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 its planning reserve margin.
- Implement load control initiatives, including calls for load curtailment via existing load curtailment contracts.

IRP Action Plan Linkage to Business Planning

The 2021 IRP includes a sensitivity that complies with the Utah requirement to perform a business plan sensitivity case consistent with the commission's order in Docket No. 15-035-04. This order sets forth the following parameters for this sensitivity case:

- Over the first three years, resources align with those assumed in PacifiCorp's December 2020 Business Plan.
- Beyond the first three years of the study period, unit retirement assumptions are aligned with the preferred portfolio.
- All other resources are optimized.

PacifiCorp will file a supplemental filing to its 2021 IRP filing that includes discussion and results of the sensitivities outlined in Volume I, Chapter 9 – Modeling and Portfolio Selection Results, including a discussion of this business plan sensitivity case summarizing portfolio differences between the business plan sensitivity case and the 2021 IRP preferred portfolio, including changes to the resource mix, present value revenue requirement of system costs, and implications on the near-term action plan. The supplemental filing will also be posted to PacifiCorp's IRP webpage at the following location: www.pacificorp.com/energy/integrated-resource-plan.

Resource Procurement Strategy

To acquire resources outlined in the 2021 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 2021 IRP action plan.

Renewable Resources, Storage Resources, and Dispatchable Resources

PacifiCorp will use a competitive RFPs to procure supply-side resources consistent applicable laws, rules, and/or guidelines in each of the states in which PacifiCorp operates. In Oregon and Utah, these state requirements involve the oversight of an independent evaluator. In Washington, an independent evaluator may be used if benchmark resources (PacifiCorp built and owned resources) are being considered after consultation with Washington staff and stakeholders. The all-source RFPs outline the types of resources being pursued, defines specific information required of potential bidders and details both price and non-price scoring metrics that will be used to evaluate proposals.

Renewable Energy Credits

PacifiCorp uses shelf RFPs as the primary mechanism under which REC RFPs and reverse REC RFPs will be issued to the market. The shelf RFPs are updated to define the product definition, timing, and volume and further provide schedule and other applicable criteria to bidders.

Demand-Side Management

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 continue to 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 was implemented with the wind repower project), use the site for additional resources in the future, change fueling strategies or sources (as was implemented for the Naughton Unit 3 gas conversion and as planned for Jim Bridger Units 1 and 2), efficiently address plant modifications that may be required as a result of changes in environmental or other laws and regulations, and use the plant at embedded cost as long as it remains economic. In addition, by owning a plant, PacifiCorp can hedge itself against the uncertainty of third-party performance consistent with the terms and conditions outlined in a power-purchase agreement over time.

Alternately and depending on contractual terms, purchasing power from a third party in a long-term contract may help mitigate and may avoid liabilities associated with closure of a plant. A long-term power-purchase agreement relinquishes control of construction cost, schedule, ongoing costs and environmental and regulatory compliance. Power-purchase agreements can also protect and cap the buyer's exposure to events that may not cover actual seller financial impacts. However, credit rating agencies can impute debt associated with long-term resource contracts that may result from a competitive procurement process, and such imputation may affect PacifiCorp's credit ratios and credit rating.

Managing Carbon Risk for Existing Plants

CO_2 reduction regulations at the federal, regional, or state levels could prompt PacifiCorp to continue to look for measures to lower CO_2 emissions of fossil-fired power plants through cost-effective means. The cost, timing, and compliance flexibility afforded by CO_2 reduction rules will impact what types of measures might be cost effective and practical from operational and regulatory perspectives. As evident in the 2021 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. As mentioned above, plant CO_2 emission risk may also be addressed by acquiring offsets or other environmental attributes that could become available in the market under certain regulatory frameworks. PacifiCorp's compliance strategies will evolve and continue to be reassessed in future IRP cycles as market forces and regulatory outcomes evolve.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits and power volume hedge limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of short positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas and power at fixed prices in gradual stages in advance of when it is required to reduce the size of short positions and associated customer risk.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within power volume hedge limits and natural gas percent hedge volume limits.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total generation capacity relative to customer load requirements at a given point in time.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 2021 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.

2021 Integrated Resource Plan

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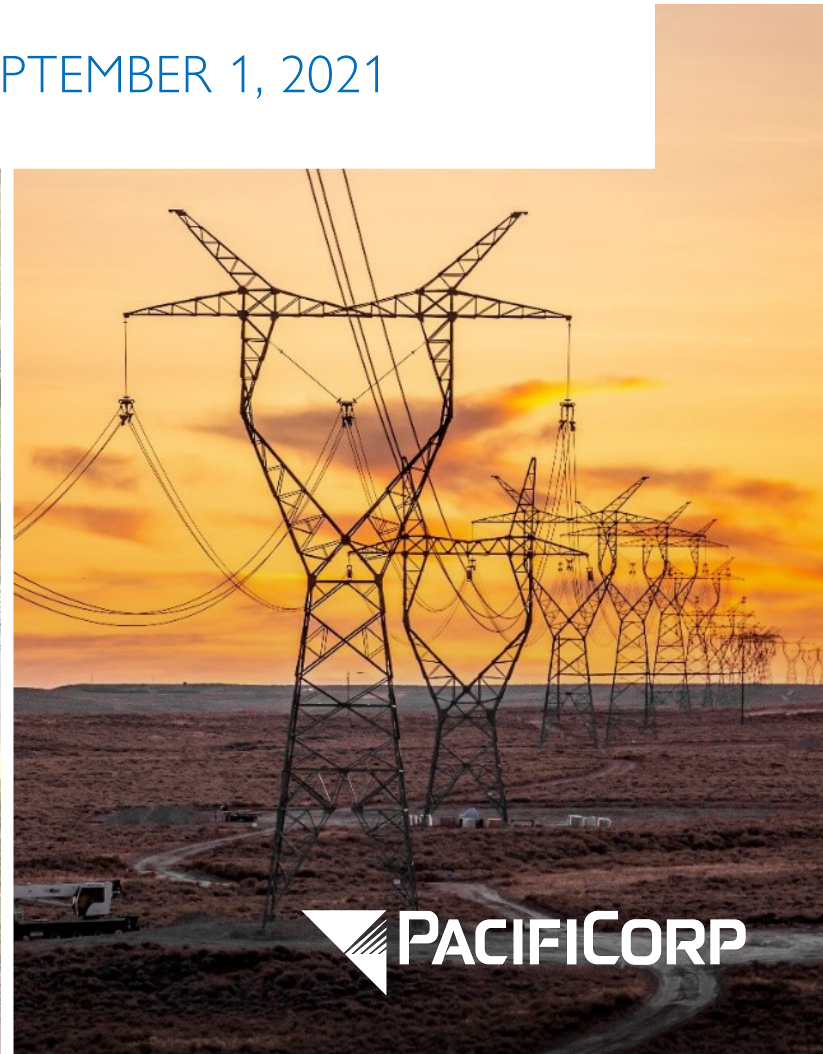


PACIFICORP

This 2021 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.

For more information, contact:
PacifiCorp Resource Planning
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232
(503) 813-5245
irp@pacificorp.com
www.pacificorp.com

Cover Photos (Top to Bottom):
Pavant III Solar Plant
Marengo Wind Project
Transmission Line - Wyoming
Panguitch Solar & Battery Storage

APPENDIX A – LOAD FORECAST DETAILS

Introduction

This appendix reviews the load forecast used in the modeling and analysis of the 2021 Integrated Resource Plan ("IRP"), including scenario development for case sensitivities. The load forecast used in the IRP is an estimate of the energy sales and peak demand over a 20-year period. The 20-year horizon is important to anticipate electricity demand to develop a timely response of resources.

In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. These separate customer classes include residential, commercial, industrial, irrigation, and lighting customer classes. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, air conditioning, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions and various other end use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

Summary Load Forecast

The Company updated its load forecast in June 2020. The compound annual load growth rate for the 10-year period (2021 through 2030) is 1.31 percent. Relative to the load forecast prepared for the 2019 IRP, PacifiCorp's 2030 forecast load requirement decreased in all jurisdictions other than Utah and California, while PacifiCorp system load requirement increased approximately 2.06 percent. Figure A.1 has a comparison of the load forecasts from the 2021 IRP to the 2019 IRP.

Figure A.1 – PacifiCorp System Energy Load Forecast Change, at Generation, pre-DSM

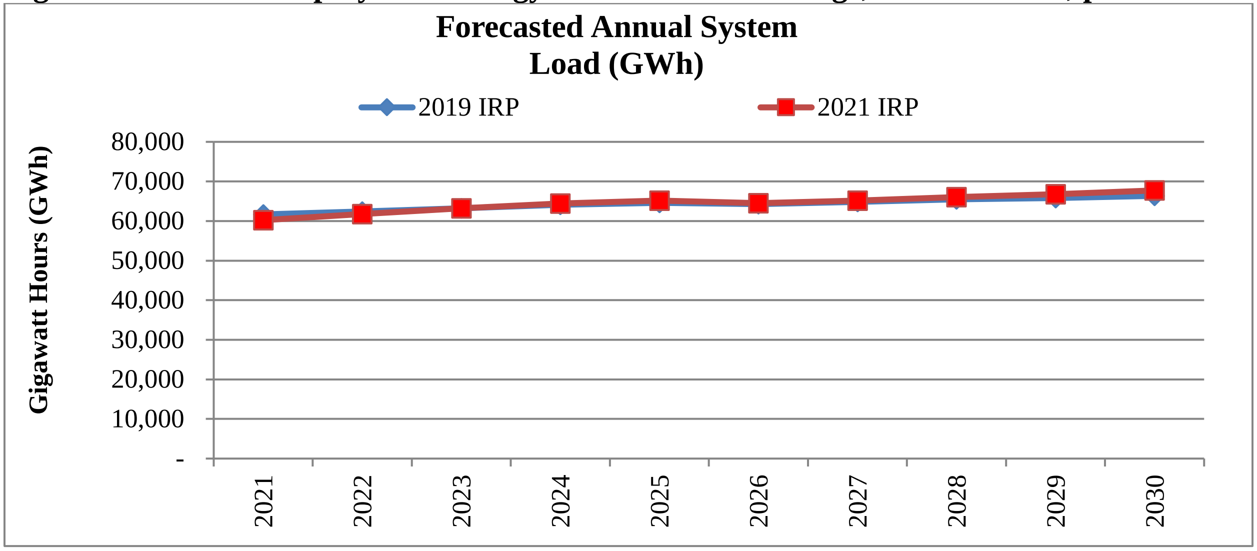


Table A.1 and Table A.2 show the annual load and coincident peak load forecast when not reducing load projections to account for new energy efficiency measures (Class 2 DSM).[1] Tables A.3 and A.4 show the forecast changes relative to the 2019 IRP load forecast for loads and coincident system peak, respectively.

Table A.1 – Forecasted Annual Load, 2021 through 2030 (Megawatt-hours), at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	60,221,570	15,052,100	4,508,140	873,350	26,683,220	9,151,270	3,953,490
2022	61,760,910	15,406,270	4,591,020	879,260	27,444,090	9,467,940	3,972,330
2023	63,242,990	15,758,680	4,656,030	882,500	28,210,380	9,756,470	3,978,930
2024	64,451,310	16,106,120	4,710,640	888,170	28,792,180	9,963,260	3,990,940
2025	65,162,260	16,239,510	4,730,240	888,890	29,341,030	9,957,000	4,005,590
2026	64,527,030	16,418,820	4,760,890	891,130	28,352,920	10,079,510	4,023,760
2027	65,178,400	16,609,250	4,796,190	892,410	28,700,930	10,140,050	4,039,570
2028	66,083,420	16,856,640	4,850,400	896,280	29,192,860	10,227,820	4,059,420
2029	66,768,660	17,037,100	4,879,900	895,370	29,609,850	10,278,220	4,068,220
2030	67,723,210	17,268,040	4,923,100	898,610	30,155,750	10,393,670	4,084,040
Compound Annual Growth Rate							
2021-30	**1.31%**	**1.54%**	**0.98%**	**0.32%**	**1.37%**	**1.42%**	**0.36%**

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

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

Year	Total	OR	WA	CA	UT	WY	ID
2021	10,374	2,421	768	140	5,054	1,223	768
2022	10,535	2,442	779	140	5,158	1,247	768
2023	10,691	2,462	788	142	5,255	1,280	765
2024	10,808	2,480	795	141	5,326	1,300	765
2025	10,942	2,500	804	142	5,419	1,302	775
2026	10,867	2,513	810	142	5,308	1,314	779
2027	10,940	2,527	816	142	5,351	1,321	782
2028	11,043	2,540	823	143	5,426	1,329	783
2029	11,133	2,551	831	142	5,490	1,335	784
2030	11,238	2,562	837	142	5,563	1,348	786
Compound Annual Growth Rate							
2021-30	**0.89%**	**0.63%**	**0.96%**	**0.19%**	**1.07%**	**1.09%**	**0.25%**

Table A.3 – Annual Load Change: June 2020 Forecast less September 2018 Forecast (Megawatt-hours) at Generation, pre-DSM

Year	Total	OR	WA	CA	UT	WY	ID
2021	(1,446,650)	(710,630)	(188,810)	(12,870)	193,120	(693,260)	(34,200)
2022	(669,210)	(667,350)	(133,820)	(4,040)	554,880	(383,170)	(35,710)
2023	53,140	(467,730)	(100,410)	650	851,120	(178,640)	(51,850)
2024	352,250	(316,440)	(92,170)	5,990	915,480	(94,950)	(65,660)
2025	600,950	(283,400)	(91,260)	11,470	1,120,660	(95,750)	(60,770)
2026	291,170	(250,470)	(94,560)	17,670	705,630	(31,000)	(56,100)
2027	351,380	(211,750)	(96,000)	24,810	756,540	(70,940)	(51,280)
2028	639,990	(160,230)	(94,050)	32,590	937,330	(32,350)	(43,300)
2029	926,340	(91,430)	(91,890)	40,000	1,125,640	(21,450)	(34,530)
2030	1,368,710	18,030	(84,790)	49,670	1,407,610	530	(22,340)

Table A.4 – Annual Coincident Peak Change: June 2020 Forecast less September 2018 Forecast (Megawatts) at Generation, pre-DSM

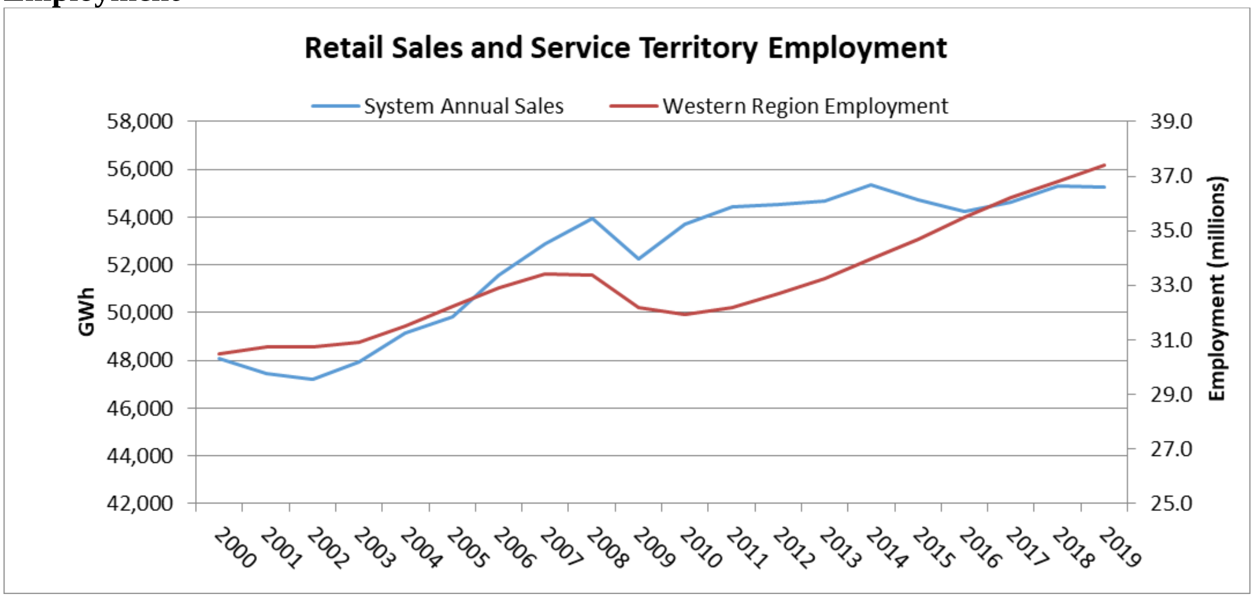
Year	Total	OR	WA	CA	UT	WY	ID
2021	17	(71)	(11)	(5)	192	(68)	(20)
2022	67	(84)	(6)	(4)	230	(46)	(23)
2023	111	(81)	(4)	(4)	250	(22)	(29)
2024	121	(75)	7	0	238	(25)	(26)
2025	157	(80)	(5)	(1)	264	(13)	(8)
2026	49	(82)	(5)	(0)	165	(7)	(20)
2027	45	(85)	(6)	2	165	(11)	(18)
2028	58	(89)	(6)	3	175	(8)	(16)
2029	70	(92)	(6)	5	183	(7)	(12)
2030	98	(89)	(6)	7	199	(4)	(9)

Load Forecast Assumptions

Regional Economy by Jurisdiction

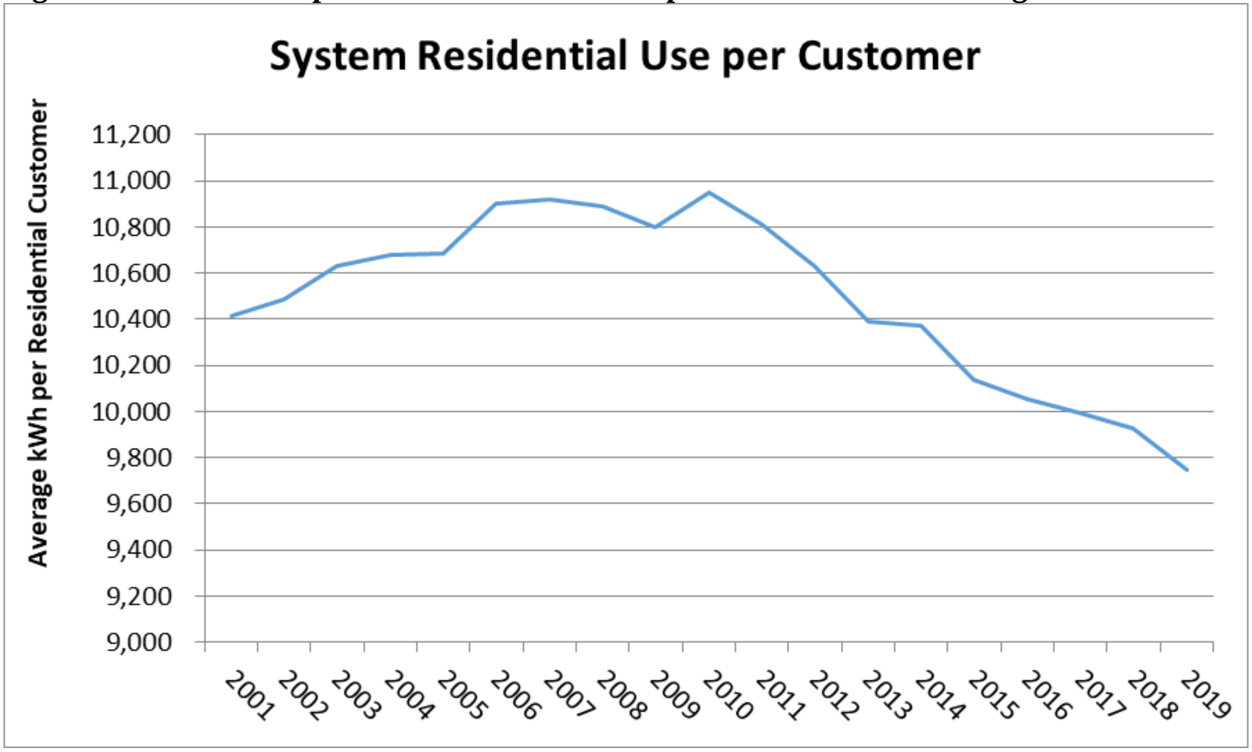
The PacifiCorp electric service territory is comprised of six states and within these states the company serves customers in a total of 90 counties. The level of retail sales for each state and county is correlated with economic conditions and population statistics in each state. PacifiCorp uses both 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 2019, 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 2019 and Western Region Employment



The 2021 IRP forecast utilizes the October 2019 release of IHS Markit economic driver forecast; whereas the 2019 IRP relies on the September 2018 release from IHS Markit. Figure A.3 shows the weather normalized average system residential use per customer.

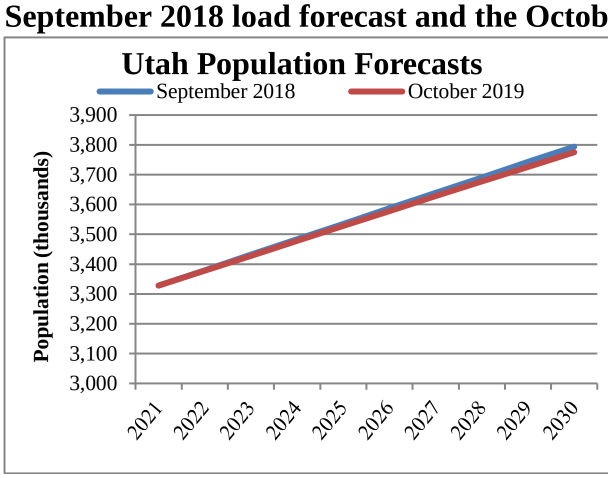
Figure A.3 – PacifiCorp Annual Residential Use per Customer 2001 through 2019

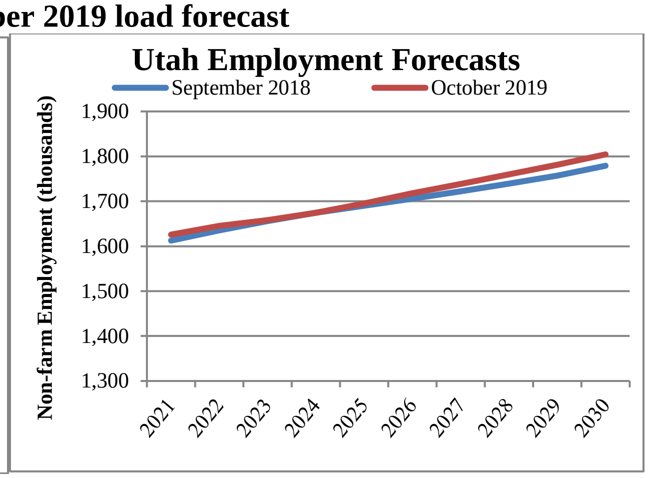


Utah

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 1.16 percent in non-farm employment over the next 10 years. Figure A.4 shows the change in population and employment forecasts between the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the population forecast is relatively unchanged, but slightly lower. The employment forecast is also relatively unchanged, but slightly higher over the 2021 through 2030 timeframe.

Figure A.4 – IHS Global Insight Utah Population and Employment Forecasts from the September 2018 load forecast and the October 2019 load forecast

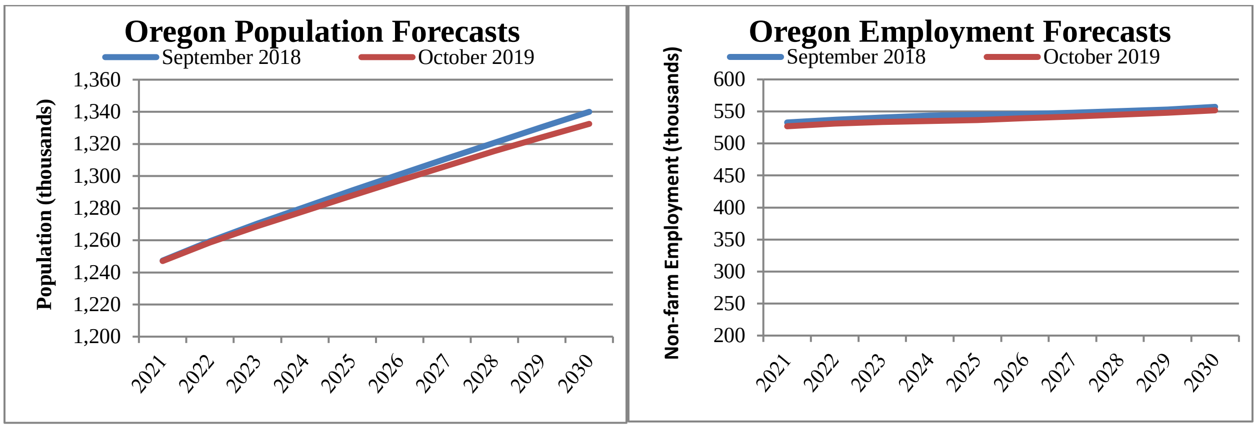




Oregon

PacifiCorp serves 25 of the 36 counties in Oregon, but provided only 26.2 percent of electric retail sales in the state of Oregon in 2018.[2] Figure A.5 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the Oregon population and employment forecasts have remained relatively unchanged, but have decreased slightly.

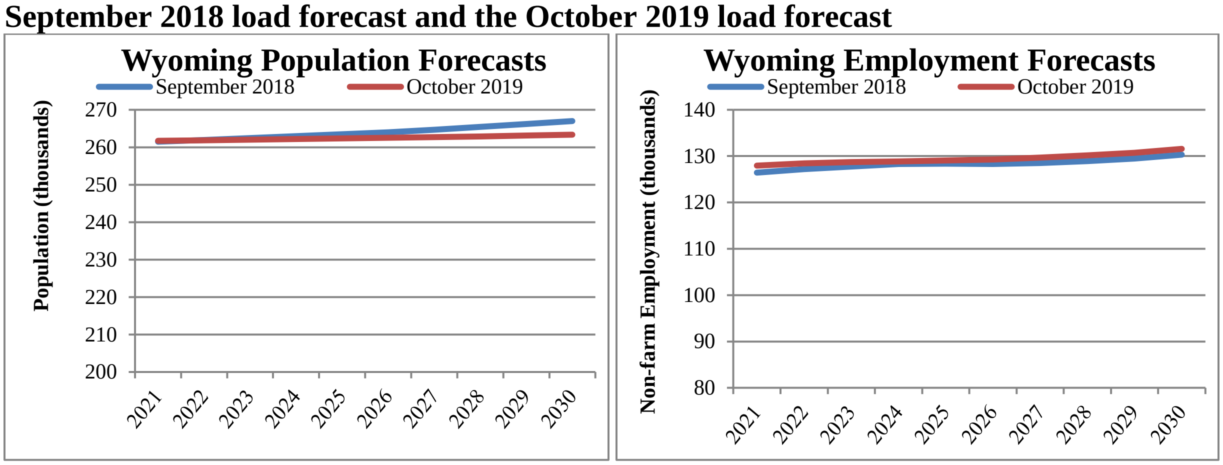
Figure A.5 - IHS Global Insight Oregon Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



Wyoming

The Company 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% of the Company's Wyoming sales. Figure A.6 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the Wyoming population and employment forecasts used in the 2021 IRP forecast has remained relatively unchanged to the 2019 IRP.

Figure A.6 - IHS Global Insight Wyoming Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast

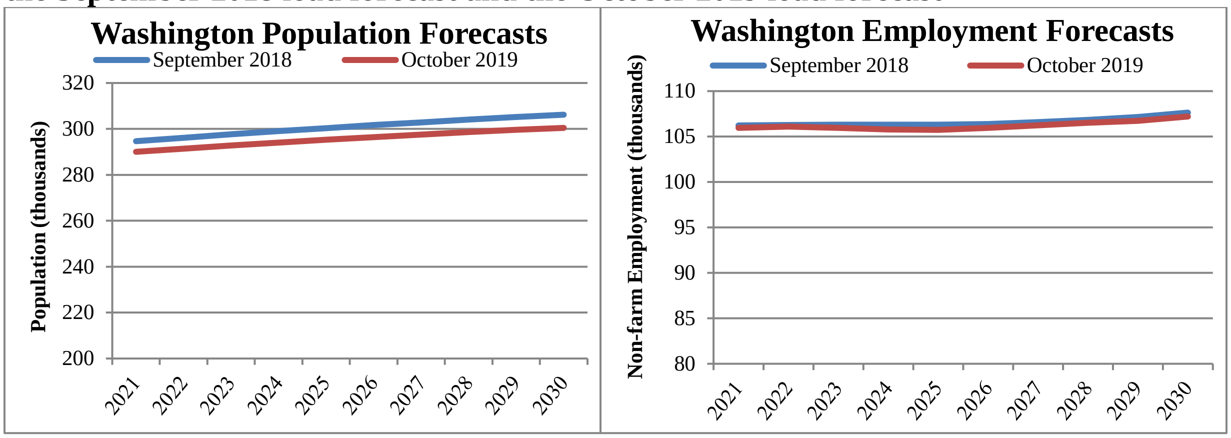


[2] Source: Oregon Public Utility Commission, 2018 Oregon Utility Statistics.

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 the Company's Washington sales. Figure A.7 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the population forecast is lower, while the employment forecast is unchanged.

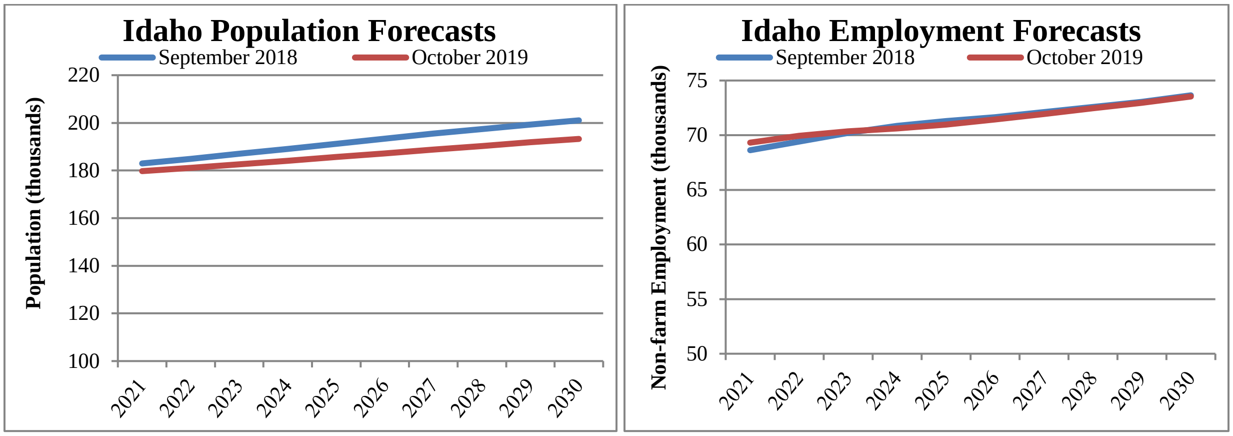
Figure A.7 – IHS Global Insight Washington Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



Idaho

The Company 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 47% of the Company's Idaho sales. Figure A.8 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the forecast for population has decreased, while the employment forecast has remained consistent over the 2021 to 2030 timeframe.

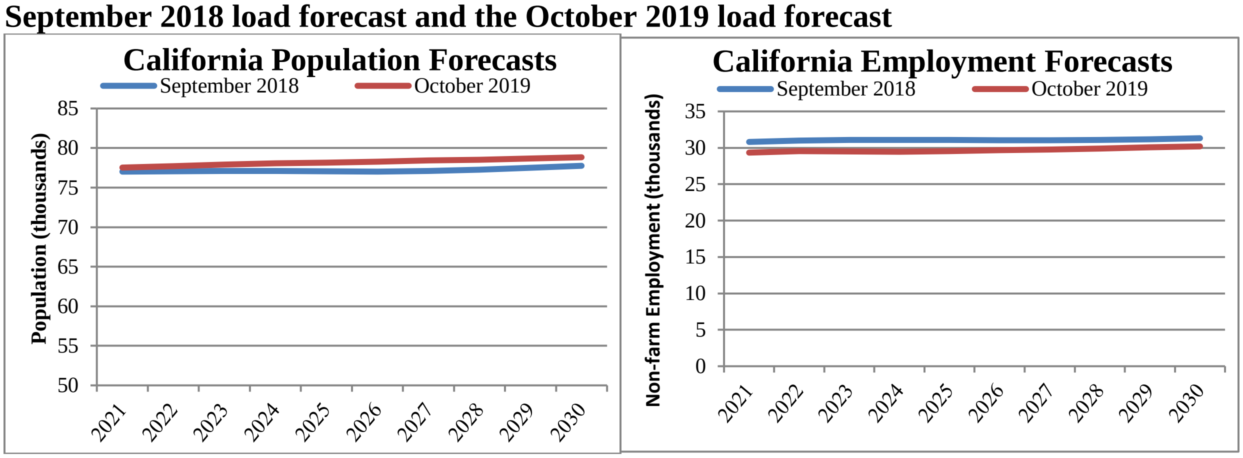
Figure A.8 – IHS Global Insight Idaho Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



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 48 percent of the Company's California sales. Figure A.9 shows the change in population and employment forecasts for the 2021 IRP relative to the 2019 IRP forecast. This figure illustrates that the population forecast has increased, while the employment forecast has decreased.

Figure A.9 – IHS Global Insight California Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast

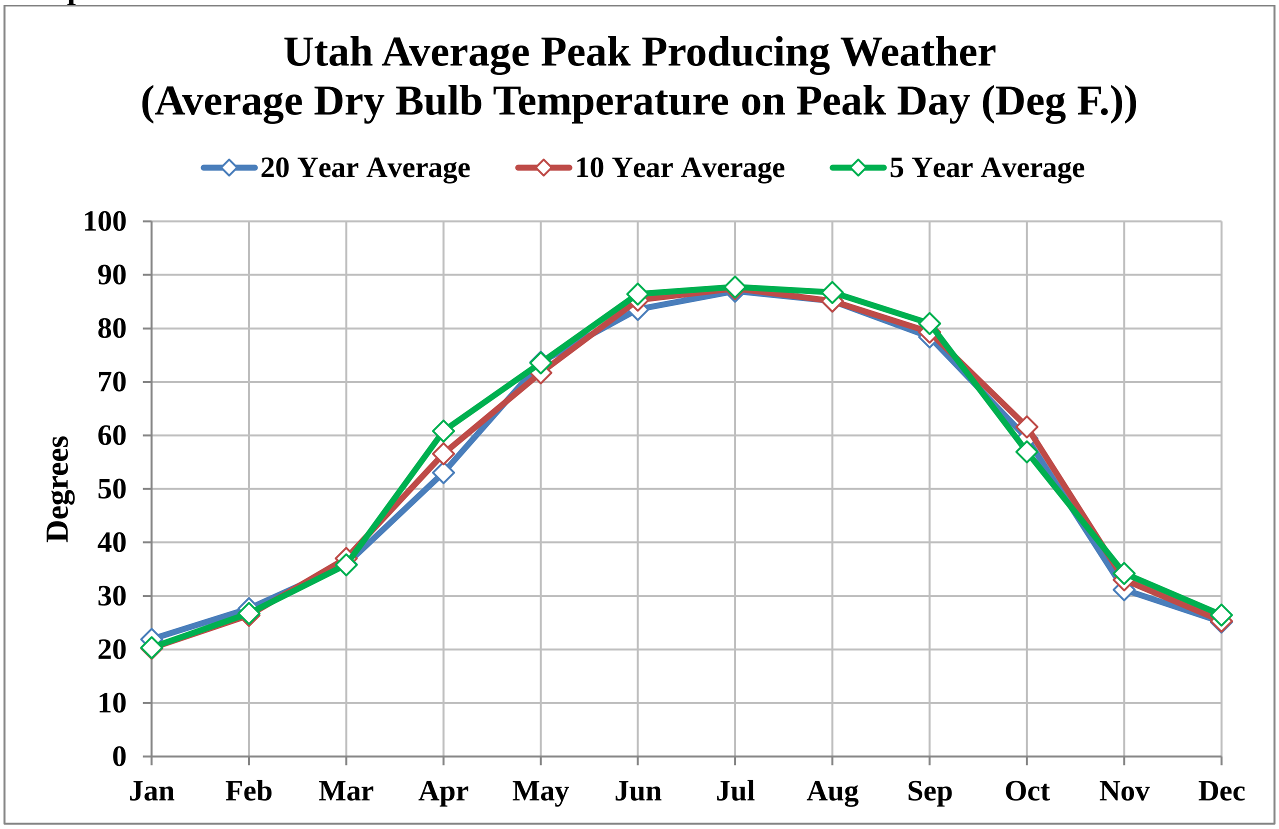


Weather

The Company's load forecast is based on normal weather defined by the 20-year time period of 2000-2019. The Company updated its temperature spline models to the five-year time period of October 2014 – September 2019. The Company's spline models are used to model the commercial and residential class temperature sensitivity at varying temperatures.

The Company 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")

The Company models sales per customer for the residential class using the SAE model, which combines the end-use modeling concepts with traditional regression analysis techniques. Major drivers of the SAE-based residential model are heating and cooling related variables, equipment shares, saturation levels and efficiency trends, and economic drivers such as household size, income and energy price. The Company uses ITRON for its load forecasting software and services, as well as the SAE. To predict future changes in the efficiency of the various end uses for the residential class, an excel spreadsheet model obtained from ITRON was utilized; the model includes appliance efficiency trends based on appliance life as well as past and future efficiency standards. The model embeds all currently applicable laws and regulations regarding appliance efficiency, along with life cycle models of each appliance. The life cycle models, based on the decay and replacement rate are necessary to estimate how fast the existing stock of any given appliance turns over, i.e. newer more efficient equipment replacing older less efficient equipment. The underlying efficiency data is based on estimates of energy efficiency from the US Department of Energy's Energy Information Administration (EIA). The EIA estimates the efficiency of appliance stocks and the saturation of appliances at the national level and for individual Census Regions.

Individual Customer Forecast

The Company updated its load forecast for a select group of large industrial customers, self-generation facilities of large industrial customers, and data center forecasts within the respective jurisdictions. Customer forecasts are provided by the customer to the Company through a regional business manager ("RBM").

Actual Load Data

With the exception to the industrial class, the Company uses actual load data from January 2000 through January 2020. The historical data period used to develop the industrial monthly sales forecast is from January 2000 through January 2020 in Utah, Wyoming, and Washington, January 2002 through January 2020 in Idaho, and January 2003 through January 2020 in California and January 2008 through January 2020 in Oregon.

The following tables are the annual actual retail sales, non-coincident peak, and coincident peak by state used in calculating the 2021 IRP retail sales forecast.

Table A.5 – Weather Normalized Jurisdictional Retail Sales 2000 through 2019

System Retail Sales - Megawatt-hours (MWh)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	775,192	3,089,288	13,955,787	18,744,308	4,105,482	7,414,678	**48,084,734**
2001	776,422	2,980,497	13,516,606	18,504,774	4,021,390	7,668,756	**47,468,446**
2002	799,842	3,230,347	13,099,087	18,604,385	4,018,756	7,445,204	**47,197,621**
2003	815,011	3,247,459	13,085,666	19,273,299	4,073,691	7,440,948	**47,936,073**
2004	844,695	3,308,170	13,199,227	19,866,036	4,104,202	7,804,357	**49,126,687**
2005	835,299	3,261,932	13,201,375	20,282,194	4,216,649	8,006,549	**49,803,998**
2006	858,510	3,340,635	13,915,186	21,098,318	4,135,813	8,220,696	**51,569,159**
2007	874,531	3,408,616	14,021,185	21,999,896	4,080,890	8,517,002	**52,902,119**
2008	866,199	3,420,524	13,780,706	22,599,294	4,077,495	9,216,788	**53,961,007**
2009	829,274	2,954,023	13,113,340	22,024,520	4,060,707	9,269,845	**52,251,710**
2010	841,107	3,439,999	13,177,771	22,508,996	4,055,511	9,664,424	**53,687,809**
2011	803,543	3,464,119	13,032,607	23,295,557	4,023,385	9,809,825	**54,429,035**
2012	785,008	3,515,467	13,043,196	23,640,249	4,051,450	9,487,492	**54,522,863**
2013	775,368	3,558,468	13,087,558	23,643,822	4,068,821	9,551,446	**54,685,482**
2014	775,046	3,548,642	13,152,703	24,147,318	4,117,170	9,602,358	**55,343,237**
2015	746,165	3,506,314	13,117,689	23,873,791	4,111,291	9,374,355	**54,729,605**
2016	755,863	3,467,134	13,216,931	23,535,056	4,055,967	9,207,677	**54,238,627**
2017	760,480	3,580,973	13,164,823	23,661,450	4,088,797	9,351,510	**54,608,034**
2018	742,614	3,614,740	13,104,102	24,528,017	4,069,834	9,258,202	**55,317,509**
2019	744,447	3,504,257	13,168,919	24,435,035	4,059,165	9,333,539	**55,245,362**
Compound Annual Growth Rate							
2000-19	**-0.21%**	**0.67%**	**-0.30%**	**1.41%**	**-0.06%**	**1.22%**	**0.73%**

*System retail sales do not include sales for resale

Table A.6 – Non-Coincident Jurisdictional Peak 2000 through 2019

Non-Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	176	686	2,603	3,684	785	1,061	**8,995**
2001	162	616	2,739	3,480	755	1,124	**8,876**
2002	174	713	2,639	3,773	771	1,113	**9,184**
2003	169	722	2,451	4,004	788	1,126	**9,260**
2004	193	708	2,524	3,862	920	1,111	**9,317**
2005	189	753	2,721	4,081	844	1,224	**9,811**
2006	180	723	2,724	4,314	822	1,208	**9,970**
2007	187	789	2,856	4,571	834	1,230	**10,466**
2008	187	759	2,921	4,479	923	1,339	**10,609**
2009	193	688	3,121	4,404	917	1,383	**10,705**
2010	176	777	2,552	4,448	893	1,366	**10,213**
2011	177	770	2,686	4,596	854	1,404	**10,486**
2012	159	800	2,550	4,732	797	1,337	**10,376**
2013	182	814	2,980	5,091	886	1,398	**11,351**
2014	161	818	2,598	5,024	871	1,360	**10,831**
2015	157	843	2,598	5,226	837	1,326	**10,986**
2016	155	848	2,584	5,018	819	1,300	**10,724**
2017	177	830	2,920	4,932	943	1,354	**11,156**
2018	158	830	2,608	5,091	849	1,319	**10,854**
2019	151	793	2,632	5,163	895	1,363	**10,997**
Compound Annual Growth Rate							
2000-19	**-0.79%**	**0.77%**	**0.06%**	**1.79%**	**0.69%**	**1.33%**	**1.06%**

*Non-coincident peaks do not include sales for resale

Table A.7 – Jurisdictional Contribution to Coincident Peak 2000 through 2019

Coincident Peak - Megawatts (MW)*							
Year	California	Idaho	Oregon	Utah	Washington	Wyoming	**System**
2000	154	523	2,347	3,684	756	979	**8,443**
2001	124	421	2,121	3,479	627	1,091	**7,863**
2002	162	689	2,138	3,721	758	1,043	**8,511**
2003	155	573	2,359	4,004	774	1,022	**8,887**
2004	120	603	2,200	3,831	740	1,094	**8,588**
2005	171	681	2,238	4,015	708	1,081	**8,895**
2006	156	561	2,684	3,972	816	1,094	**9,283**
2007	160	701	2,604	4,381	754	1,129	**9,730**
2008	171	682	2,521	4,145	728	1,208	**9,456**
2009	153	517	2,573	4,351	795	987	**9,375**
2010	144	527	2,442	4,294	757	1,208	**9,373**
2011	143	549	2,187	4,596	707	1,204	**9,387**
2012	156	782	2,163	4,731	749	1,225	**9,806**
2013	156	674	2,407	5,091	797	1,349	**10,474**
2014	150	630	2,345	5,024	819	1,294	**10,263**
2015	152	805	2,472	5,081	833	1,259	**10,601**
2016	139	575	2,462	4,940	817	1,201	**10,135**
2017	152	593	2,547	4,911	787	1,306	**10,296**
2018	126	741	2,526	5,037	790	1,295	**10,514**
2019	122	731	2,276	5,158	761	1,248	**10,297**
Compound Annual Growth Rate							
2000-19	**-1.20%**	**1.77%**	**-0.16%**	**1.79%**	**0.04%**	**1.29%**	**1.05%**

*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, 2019.

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 Plexos capacity expansion optimization model,. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM; Plexos 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 Plexos, 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 forecasted number of customers.

The customer forecasts are based on a combination of regression analysis and exponential smoothing techniques using historical data from January 2000 to January 2020. For the residential class, the Company forecasts the number of customers using IHS Markit's forecast of each state's population or number of households as the major driver.

The Company uses a differenced model approach in the development of the residential customer forecast. Rather than directly forecasting the number of customers, the differenced model predicts the monthly change in number of customers.

The Company models sales per customer for the residential class using the SAE model discussed above, which combines the end-use modeling concepts with traditional regression analysis techniques.

For the commercial class, the Company forecasts sales using regression analysis techniques with non-manufacturing employment and non-farm employment designated as the major economic drivers, in addition to weather-related variables. Monthly sales for the commercial class are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers. The development of the forecast of monthly commercial sales involves an additional step; to reflect the addition of a large "lumpy" change in sales such as a new data center, monthly commercial sales are increased based on input from the Company's RBM's. The treatment of large commercial additions is similar to the methodology for large industrial customer sales, which is discussed below.

Monthly sales for irrigation and street lighting are forecast directly from historical sales volumes, not as a product of the use per customer and number of customers.

The majority of industrial sales are modeled using regression analysis with trend and economic variables. Manufacturing employment is used as the major economic driver in all states with exception of Utah, in which an Industrial Production Index is used. For a small number of the very largest industrial customers, the Company prepares individual forecasts based on input from the customer and information provided by the RBM's.

After the Company develops the forecasts of monthly energy sales by customer class, a forecast of hourly loads is developed in two steps. First, monthly peak forecasts are developed for each state. The monthly peak model uses historical peak-producing weather for each state and incorporates the impact of weather on peak loads through several weather variables that drive heating and cooling usage. The weather variables include the average temperature on the peak day and lagged average temperatures from up to two days before the day of the forecast. The peak forecast is based on average monthly historical peak-producing weather for the 20-year period, 2000 through 2019. Second, the Company develops hourly load forecasts for each state using hourly load models that include state-specific hourly load data, daily weather variables, the 20-year average temperatures 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.

COVID-19 Adjustments

For the 2021 IRP, the Company incorporated the expected impacts of COVID-19 on forecasted electricity demand. These impacts include stay-at-home impacts, longer-term economic impacts and commodity price impacts.

Stay-at-home impacts were assumed to last over the March 2020 through June 2020 timeframe. Stay-at-home period impacts were based on observed class level load impacts over the March through April 2020 timeframe. Longer-term COVID-19 impacts based on IHS Markit economic driver data released March 2020 was incorporated into the forecast. The Wyoming industrial class forecast was adjusted to account for COVID-19 commodity price impacts based on observed load changes, commodity price projections, and Regional Business Manager input. Commodity price impacts were projected to last from March 2020 through June 2023 timeframe and are expected to improve over the period.

Electrification Adjustments

The load forecast used for 2021 IRP portfolio development includes the Company’s expectations for transportation electrification based on current and expected electric-vehicle adoption trends. These projections were incorporated as a post-model adjustment to the residential and commercial sales forecasts. The load forecast also incorporates the Company’s expectations for building electrification initiatives. Given the status of building electrification initiatives in PacifiCorp’s service territory, only the expected impact of these programs for Utah have been incorporated into the sales forecast.

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 2021 through 2030, post-DSM

System Retail Sales – Megawatt-hours (MWh)						
Year	Residential	Commercial	Industrial	Irrigation	Lighting	**Total**
2021	16,389,484	18,613,139	18,287,179	1,441,875	107,253	**54,838,930**
2022	16,384,868	19,324,611	18,589,219	1,415,430	98,411	**55,812,538**
2023	16,439,913	19,905,826	18,898,932	1,398,288	91,221	**56,734,180**
2024	16,589,964	20,276,728	19,037,799	1,385,557	85,970	**57,376,018**
2025	16,654,511	20,413,589	19,030,766	1,376,104	81,656	**57,556,626**
2026	16,825,236	20,444,277	17,767,848	1,369,039	78,667	**56,485,067**
2027	16,999,818	20,438,006	17,824,694	1,356,979	76,390	**56,695,887**
2028	17,265,999	20,525,328	17,905,345	1,340,301	74,749	**57,111,722**
2029	17,418,800	20,482,093	17,921,770	1,321,831	72,892	**57,217,386**
2030	17,613,925	20,436,176	18,102,483	1,298,520	71,383	**57,522,487**
Compound Annual Growth Rate						
2021-30	0.80%	1.04%	-0.11%	-1.16%	-4.42%	**0.53%**

Residential

The average annual growth of the residential class sales forecast increased from -0.29 percent in the 2019 IRP to 0.80 percent in the 2021 IRP. The number of residential customers across PacifiCorp's system is expected to grow at an annual average rate of 1.22 percent, reaching approximately 1.93 million customers in 2030, with Rocky Mountain Power states adding 1.49 percent per year and Pacific Power states adding 0.80 percent per year.

Commercial

Average annual growth of the commercial class sales forecast increased from 0.87 percent annual average growth in the 2019 IRP to 1.04 percent in the 2021 IRP. The number of commercial customers across PacifiCorp's system is expected to grow at an annual average rate of 0.99 percent, reaching approximately 240,000 customers in 2030, with Rocky Mountain Power states adding 1.23 percent per year and Pacific Power states adding 0.66 percent per year.

Industrial

Average annual growth of the industrial class sales forecast increased from -0.52 percent annual average growth in the 2019 IRP to -0.11 percent expected annual growth in the 2021 IRP. A portion of the Company's industrial load is in the extractive industry in Utah and Wyoming; therefore, changes in commodity prices can impact the Company's load forecast.

State Summaries

Oregon

Table A.9 – Forecasted Retail Sales Growth in Oregon, post-DSM 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**
2021	5,708,962	5,767,210	1,491,973	312,674	34,484	**13,315,304**
2022	5,733,105	5,954,746	1,487,633	291,620	32,284	**13,499,389**
2023	5,754,277	6,145,533	1,485,094	280,748	30,277	**13,695,929**
2024	5,812,675	6,293,686	1,487,735	275,951	28,624	**13,898,671**
2025	5,841,879	6,290,798	1,482,175	275,724	27,104	**13,917,680**
2026	5,895,695	6,298,198	1,479,349	278,168	25,962	**13,977,372**
2027	5,957,709	6,306,969	1,475,887	280,047	25,082	**14,045,694**
2028	6,048,834	6,330,610	1,475,301	279,611	24,491	**14,158,847**
2029	6,112,862	6,328,312	1,465,503	278,532	23,929	**14,209,138**
2030	6,204,688	6,337,488	1,459,048	275,343	23,572	**14,300,139**
Compound Annual Growth Rate						
2021-30	**0.93%**	**1.05%**	**-0.25%**	**-1.40%**	**-4.14%**	**0.80%**

Washington

Table A.10 – Forecasted Retail Sales Growth in Washington, post-DSM 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**
2021	1,571,875	1,526,929	746,477	156,438	5,334	**4,007,054**
2022	1,560,893	1,581,253	748,392	155,784	4,806	**4,051,128**
2023	1,557,071	1,610,608	749,236	155,057	4,621	**4,076,594**
2024	1,561,217	1,621,511	752,126	152,198	4,577	**4,091,630**
2025	1,552,484	1,611,943	750,699	149,416	4,545	**4,069,088**
2026	1,546,197	1,604,724	750,620	146,710	4,540	**4,052,790**
2027	1,538,962	1,601,382	748,971	143,453	4,538	**4,037,306**
2028	1,538,642	1,607,169	748,585	140,015	4,551	**4,038,963**
2029	1,529,991	1,602,860	745,385	136,236	4,537	**4,019,009**
2030	1,528,793	1,596,229	751,976	132,505	4,537	**4,014,041**
Compound Annual Growth Rate						
2021-30	**-0.31%**	**0.49%**	**0.08%**	**-1.83%**	**-1.78%**	**0.02%**

California

Table A.11 - Forecasted Retail Sales Growth in California, post-DSM 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**
2021	375,063	236,324	53,093	89,705	1,428	**755,613**
2022	375,655	237,999	54,023	89,502	1,300	**758,478**
2023	376,478	239,115	53,642	89,408	1,190	**759,834**
2024	378,596	240,418	53,510	89,397	1,102	**763,023**
2025	378,233	240,052	52,933	89,382	1,027	**761,626**
2026	379,038	239,998	52,015	89,250	971	**761,272**
2027	379,772	239,453	50,400	89,020	929	**759,574**
2028	381,554	239,392	48,763	88,708	900	**759,319**
2029	380,801	237,792	46,909	88,360	875	**754,736**
2030	381,404	236,731	47,316	88,038	859	**754,348**
Compound Annual Growth Rate						
2021-30	**0.19%**	**0.02%**	**-1.27%**	**-0.21%**	**-5.49%**	**-0.02%**

Utah

Table A.12 – Forecasted Retail Sales Growth in Utah, post-DSM 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**
2021	7,053,764	9,280,716	7,951,967	221,290	51,501	**24,559,238**
2022	7,067,147	9,707,481	8,002,444	216,942	45,608	**25,039,622**
2023	7,119,606	10,048,998	8,092,662	211,493	40,843	**25,513,603**
2024	7,213,987	10,280,843	8,077,013	206,050	37,505	**25,815,398**
2025	7,280,042	10,478,187	8,091,621	199,545	35,095	**26,084,490**
2026	7,416,655	10,562,626	6,729,247	193,084	33,644	**24,935,256**
2027	7,551,739	10,608,971	6,752,477	183,304	32,760	**25,129,251**
2028	7,734,200	10,718,474	6,783,092	171,698	32,328	**25,439,792**
2029	7,852,413	10,741,666	6,785,091	159,400	31,925	**25,570,495**
2030	7,977,046	10,753,325	6,871,983	144,262	31,745	**25,778,360**
Compound Annual Growth Rate						
2021-30	**1.38%**	**1.65%**	**-1.61%**	**-4.64%**	**-5.23%**	**0.54%**

Idaho

Table A.13 - Forecasted Retail Sales Growth in Idaho, post-DSM 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**
2021	707,725	498,044	1,785,159	636,507	2,557	**3,629,993**
2022	696,381	512,893	1,787,439	636,356	2,506	**3,635,575**
2023	695,209	522,820	1,773,920	636,379	2,453	**3,630,781**
2024	703,628	528,557	1,760,259	636,762	2,406	**3,631,612**
2025	706,280	527,074	1,758,834	636,846	2,344	**3,631,379**
2026	710,983	525,924	1,757,288	636,646	2,289	**3,633,130**
2027	715,049	524,117	1,753,296	636,000	2,234	**3,630,697**
2028	721,463	524,558	1,748,147	635,141	2,187	**3,631,496**
2029	721,451	520,988	1,741,166	634,212	2,128	**3,619,945**
2030	720,891	518,341	1,739,423	633,313	2,078	**3,614,045**
Compound Annual Growth Rate						
2021-30	**0.21%**	**0.44%**	**-0.29%**	**-0.06%**	**-2.28%**	**-0.05%**

Wyoming

Table A.14 – Forecasted Retail Sales Growth in Wyoming, post-DSM 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**
2021	972,095	1,303,915	6,258,509	25,261	11,950	**8,571,729**
2022	951,688	1,330,238	6,509,288	25,226	11,907	**8,828,346**
2023	937,271	1,338,751	6,744,378	25,202	11,836	**9,057,438**
2024	919,862	1,311,712	6,907,156	25,198	11,756	**9,175,684**
2025	895,593	1,265,534	6,894,504	25,191	11,541	**9,092,363**
2026	876,667	1,212,808	6,999,330	25,181	11,262	**9,125,247**
2027	856,587	1,157,113	7,043,662	25,156	10,846	**9,093,365**
2028	841,305	1,105,125	7,101,457	25,127	10,292	**9,083,306**
2029	821,282	1,050,476	7,137,716	25,091	9,497	**9,044,063**
2030	801,102	994,062	7,232,736	25,060	8,593	**9,061,553**
Compound Annual Growth Rate						
2019-28	**-2.13%**	**-2.97%**	**1.62%**	**-0.09%**	**-3.60%**	**0.62%**

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 and varying economic conditions.

The June 2020 forecast is the baseline scenario. For the high and low load growth scenarios, optimistic and pessimistic economic driver assumptions from IHS Markit were applied to the economic drivers in the Company's load forecasting models. These growth assumptions were extended for the entire forecast horizon. Further, the high and low load growth scenarios also incorporate the standard error bands for the energy and the peak forecast to determine a 95% prediction interval around the base IRP forecast.

The 95% prediction interval is calculated at the system level and then allocated to each state and class based on their contribution to the variability of the system level forecast. The standard error bands for the jurisdictional peak forecasts were calculated in a similar manner. The final high load growth scenario includes the optimistic economic forecast 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, the Company used 1-in-20 year peak weather for summer (July) months for each state. The 1-in-20 year peak weather is defined as the year for which the peak has the chance of occurring once in 20 years.

The climate change scenario relies on projected temperature increases over 1990 average temperatures as determined by the United States Bureau of Reclamation (Reclamation) in the West-Wide Climate Risk Assessments: Hydroclimate Projections Study (Study).[3] The Company determined daily average temperatures and peak producing temperatures that correspond to the midpoint of the projected temperature increase ranges in the study. The Company used those temperatures to project the jurisdictional energy and jurisdictional peaks in the scenario.

Table A.15 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s below provides the projected range of temperature change for select sites within PacifiCorp's service territory, which were ultimately used to model projected temperatures in the 2021 IRP climate change scenario.

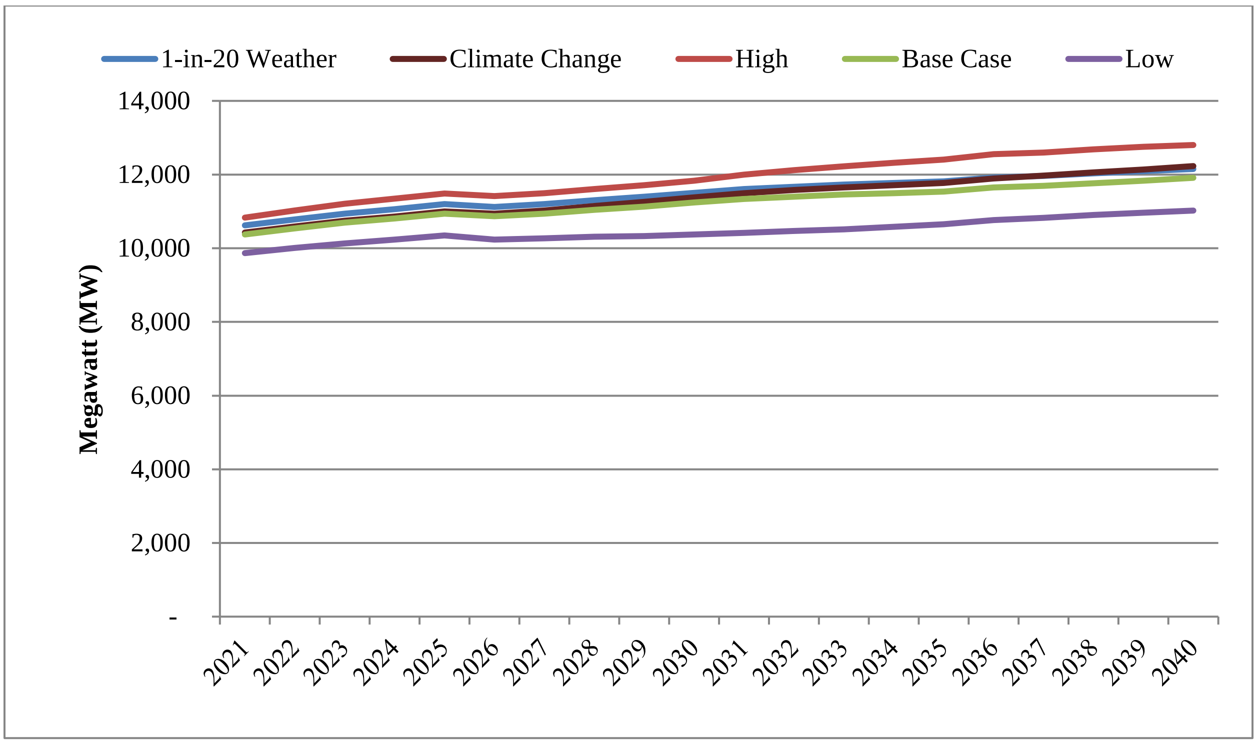
[3] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

Table A.15 – Projected Range of Temperature Change in the 2020s and 2050s relative to the 1990s[4]

Bureau of Reclamation Site	PacifiCorp Jurisdiction Assumption	Projected Range of Temperature Change (°F) 2020s	2050s
Klamath River near Klamath	California	1.4 to 2.4	2.6 to 4.4
Snake River Near Heise	Idaho	1.6 to 3.1	3.1 to 5.6
Klamath River near Seiad Valley	Oregon	1.4 to 2.5	2.7 to 4.5
Green River near Greendale	Utah	1.7 to 3.1	3.1 to 5.7
Yakima River at Parker	Washington	1.5 to 2.6	2.7 to 5.0
Green River near Greendale	Wyoming	1.7 to 3.1	3.1 to 5.7

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, Climate Change, High, Base Case and Low, pre-DSM



[4] United States Bureau of Reclamation, March 2016, Managing Water in the West, Technical Memorandum No. 86-68210-2016-01, West-Wide Climate Risk Assessments: Hydroclimate Projections. https://www.usbr.gov/climate/secure/docs/2016secure/wwcra-hydroclimateprojections.pdf

APPENDIX B - IRP REGULATORY COMPLIANCE

Introduction

This appendix describes how PacifiCorp's 2021 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 2019 Integrated Resource Plan, and other ongoing IRP acknowledgement order requirements as applicable, and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 - Provides an overview and comparison of the rules in each state for which IRP submission is required.[33]
- Table B.2 - Provides a description of how PacifiCorp addressed the 2019 IRP acknowledgement order requirements and other commission directives.
- Table B.3 - Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 - Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 - Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Transportation Commission IRP rules issued in December 2020 in WAC 480-100-620.
- Table B.6 - Provides an explanation of how this plan addresses each of the items contained in the Wyoming Public Service Commission IRP guidelines updated in March 2016.

General Compliance

PacifiCorp prepares the IRP on a biennial basis and files the IRP with state commissions. The preparation of the IRP is done in an open public process with consultation from all interested parties, including commissioners and commission staff, customers, and other stakeholders. This open process provides parties with a substantial opportunity to contribute information and ideas in the planning process, and also serves to inform all parties on the planning issues and approach. The public input process for this IRP will be described in Volume I, Chapter 2 – Introduction, as well as Volume II, Appendix C – Public Input fully complies with IRP standards and guidelines.

[33] California Public Utilities Code Section 454.5 allows utility with less than 500,000 customers in the state to request an exemption from filing an IRP. However, PacifiCorp files its IRP and IRP supplements with the California Public Utilities Commission to address the company plan for compliance with the California RPS requirements.

The IRP provides a framework and plan for future actions to ensure PacifiCorp continues to provide reliable and least-cost electric service to its customers. The IRP evaluates, over a twenty-year planning period, the future load of PacifiCorp customers and the resources required to meet this load.

To fill any gap between changes in loads and existing resources, while taking into consideration potential early retirement of existing coal units as an alternative to investments that achieve compliance with environmental regulations, the IRP evaluates a broad range of available resource options, as required by state commission rules. These resource options include supply-side, demand-side, and transmission alternatives. The evaluation of the alternatives in the IRP, as detailed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results) meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur. To perform the analysis and evaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP standards and guidelines, and is described in detail in Volume I, Chapter 8 – Modeling and Portfolio Evaluation 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 9 – Modeling and Portfolio Selection Results.

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan in Volume I, Chapter 10 – Action Plan. The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. The Action Plan also provides a progress report on action items contained in the 2019 IRP.

The 2021 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 October 18, 2019, PacifiCorp submitted its 2019 IRP in compliance with D.18-02-018.

On April 6, 2020, the CPUC issued D.20-03-028, which reiterated PacifiCorp’s ability to file an alternative IRP.

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 2021, 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[34]). Consistent with the earlier guidelines (Order 89-507), the Oregon PUC notes that acknowledgment does not guarantee favorable ratemaking

34 Public Utility Commission of Oregon, Order No. 12-013, Docket No. 1461, January 19, 2012.

treatment, only that the plan seems reasonable at the time acknowledgment is given. Table B provides detail on how this plan addresses each of the requirements.

Utah

This IRP is submitted to the Public Service Commission of Utah in compliance with its 1992 Order on Standards and Guidelines for Integrated Resource Planning (Docket No. 90-2035-01, "Report and Order on Standards and Guidelines"). Table B documents how PacifiCorp complies with each of these standards.

Washington

This IRP is submitted to the Washington Utilities and Transportation Commission (WUTC) in compliance with its rule requiring 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. provides detail on how this IRP addresses each of the rule requirements.

Regulatory implementation of the planning sections of the Clean Energy Transformation Act (CETA) through Docket UE- 190698 specified the development, timing, and required content of an IRP and Clean Energy Action Plan (CEAP). Commission General Order R-601 adopted the amended IRP and CETA compliance rules. PacifiCorp's 2021 IRP was designed to be compliant with the rules in WAC 480-100-600 through WAC 480-100-665.

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.1 provides detail on how this plan addresses the rule requirements.

> ***Section 33. Integrated Resource Plan (IRP).***
> *Each utility serving in Wyoming that files an IRP in another jurisdiction shall file that IRP with the Commission. The Commission may require any utility to file an IRP.*

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

Topic	Oregon	Utah	Washington	Idaho	Wyoming
Source	Order No. 07-002, *Investigation Into Integrated Resource Planning*, January 8, 2007, as amended by Order No. 07-047. Order No. 08-339, *Investigation into the Treatment of CO2 Risk in the Integrated Resource Planning Process*, June 30, 2008. Order No. 09-041, New Rule OAR 860-027-0400, implementing Guideline 3, "Plan Filing, Review, and Updates". Order No. 12-013, "Investigation of Matters related to Electric Vehicle Charging", January 19, 2012.	Docket 90-2035-01 *Standards and Guidelines for Integrated Resource Planning* June 18, 1992.	WAC 480-100-251 Least cost planning, May 19, 1987, and as amended from WAC 480-100-238 *Least Cost Planning Rulemaking*, January 9, 2006 (Docket # UE-030311). Commission General Order R-601 further adopted IRP rules compliant with CETA.	Order 22299 *Electric Utility Conservation Standards and Practices* January, 1989.	Wyoming Electric, Gas and Water Utilities, Chapter 3, Section 33, March 21, 2016.
Filing Requirements	Least-cost plans must be filed with the Oregon PUC.	An IRP is to be submitted to commission.	Submit a least cost plan to the WUTC. Plan to be developed with consultation of WUTC staff, and with public involvement.	Submit Resource Management Report on planning status. Also file progress reports on conservation, low-income programs, lost opportunities and capability building.	Each utility serving in Wyoming that files and IRP in another jurisdiction, shall file the IRP with the commission.

Frequency	Plans filed biennially, within two years of its previous IRP acknowledgment order. An annual update to the most recently acknowledged IRP is required to be filed on or before the one-year anniversary of the acknowledgment order date. While informational only, utilities may request acknowledgment of proposed changes to the action plan.	File biennially.	Unless otherwise ordered by the commission, each electric utility must file an integrated resource plan (IRP) with the commission by January 1, 2021, and every four years thereafter. At least every two years after the utility files its IRP, beginning January 1, 2023, the utility must file a two-year progress report.	RMR to be filed at least biennially. Conservation reports to be filed annually. Low income reports to be filed at least annually. Lost Opportunities reports to be filed at least annually. Capability building reports to be filed at least annually.	The commission may require any utility to file an IRP.
Commission Response	Least-cost plan (LCP) *acknowledged* if found to comply with standards and guidelines. A decision made in the LCP process does not guarantee favorable rate-making treatment. The OPUC may direct the utility to revise the IRP or conduct additional analysis before an acknowledgment order is issued. Note, however, that Rate Plan legislation allows pre-approval of near-term resource investments.	IRP acknowledged if found to comply with standards and guidelines. Prudence reviews of new resource acquisitions will occur during rate making proceedings.	The plan will be considered, with other available information, when evaluating the performance of the utility in rate proceedings. WUTC sends a letter discussing the report, making suggestions and requirements and acknowledges the report.	Report does not constitute pre-approval of proposed resource acquisitions. Idaho sends a short letter stating that they accept the filing and acknowledge the report as satisfying commission requirements.	Commission advisory staff reviews the IRP as directed by the Commission and drafts a memo to report its findings to the commission in an open meeting or technical conference.

Process	The public and other utilities are allowed significant involvement in the preparation of the plan, with opportunities to contribute and receive information. Order 07-002 requires that the utility present IRP results to the Oregon PUC at a public meeting prior to the deadline for written public comments. Commission staff and parties should complete their comments and recommendations within six months after IRP filing. Competitive secrets must be protected.	Planning process open to the public at all stages. IRP developed in consultation with the commission, its staff, with ample opportunity for public input.	In consultation with WUTC staff, develop and implement a public involvement plan. Involvement by the public in development of the plan is required. PacifiCorp is required to submit a work plan for informal commission review not later than 15 months prior to the due date of the plan. The work plan is to lay out the contents of the IRP, resource assessment method, and timing and extent of public participation.	Utilities to work with commission staff when reviewing and updating RMRs. Regular public workshops should be part of process.	The review may be conducted in accordance with guidelines set from time to time as conditions warrant. The Public Service Commission of Wyoming, in its Letter Order on PacifiCorp's 2008 IRP (Docket No. 2000-346-EA-09) adopted commission Staff's recommendation to expand the review process to include a technical conference, an expanded public comment period, and filing of reply comments.
Focus	20-year plan, with end-effects, and a short-term (two-year) action plan. The IRP process should result in the selection of that mix of options which yields, for society over the long run, the best combination of expected costs and variance of costs.	20-year plan, with short-term (four-year) action plan. Specific actions for the first two years and anticipated actions in the second two years to be detailed. The IRP process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	20-year plan, with short-term (two-year) action plan. The plan describes mix of resources sufficient to meet current and future loads at "lowest reasonable" cost to utility and ratepayers. Resource cost, market volatility risks, demand-side resource uncertainty, resource dispatchability, ratepayer risks, policy impacts, environmental risks, and equitable distribution of benefits must be considered.	20-year plan to meet load obligations at least-cost, with equal consideration to demand side resources. Plan to address risks and uncertainties. Emphasis on clarity, understandability, resource capabilities and planning flexibility.	Identification of least-cost/least-risk resources and discussion of deviations from least-cost resources or resource combinations.

			As part of the IRP, utilities must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.		
Elements	Basic elements include: • All resources evaluated on a consistent and comparable basis. • Risk and uncertainty must be considered. • The primary goal must be least cost, consistent with the long-run public interest. • The plan must be consistent with Oregon and federal energy policy. • External costs must be considered, and quantified where possible. OPUC specifies environmental adders (Order No. 93-695, Docket UM 424). • Multi-state utilities should plan their generation and transmission systems on an integrated-system basis. • Construction of resource portfolios over the range of	IRP will include: • Range of forecasts of future load growth • Evaluation of all present and future resources, including demand side, supply side and market, on a consistent and comparable basis. • Analysis of the role of competitive bidding • A plan for adapting to different paths as the future unfolds. • A cost effectiveness methodology. • An evaluation of the financial, competitive, reliability and operational risks associated with resource options, and how the action plan addresses these risks. • Definition of how risks are allocated between ratepayers and shareholders	The plan shall include: • A range of forecasts of future demand using methods that examine the effect of economic forces on the consumption of electricity and that address changes in the number, type and efficiency of electrical end-uses. • An assessment of commercially available conservation, including load management, as well as an assessment of currently employed and new policies and programs needed to obtain the conservation improvements. • Assessment of a wide range of conventional and commercially available nonconventional generating technologies • An assessment of transmission system capability and reliability.	Discuss analyses considered including: • Load forecast uncertainties; • Known or potential changes to existing resources; • Equal consideration of demand and supply side resource options; • Contingencies for upgrading, optioning and acquiring resources at optimum times; • Report on existing resource stack, load forecast and additional resource menu.	Proposed Commission Staff guidelines issued July 2016 cover: • Sufficiency of the public comment process • Utility strategic goals, resource planning goals and preferred resource portfolio • Resource need over the near-term and long-term planning horizons • Types of resources considered • Changes in expected resource acquisitions and load growth from the previous IRP • Environmental impacts considered • Market purchase evaluation • Reserve margin analysis • Demand-side management and conservation options

	identified risks and uncertainties. • Portfolio analysis shall include fuel transportation and transmission requirements. • Plan includes conservation potential study, demand response resources, environmental costs, and distributed generation technologies. • Avoided cost filing required within 30 days of acknowledgment.		• A comparative evaluation of energy supply resources (including transmission and distribution) and improvements in conservation using "lowest reasonable cost" criteria. • An assessment and determination of resource adequacy metrics. • An assessment of energy and nonenergy benefits and reductions of burdens to vulnerable populations and highly impacted communities; long-term and short-term public health and environmental benefits, costs, and risks; and energy security risk • Integration of the demand forecasts and resource evaluations into a long-range (at least 10 years) plan. • All plans shall also include a progress report that relates the new plan to the previously filed plan. • Must develop a ten-year clean energy action plan for implementing RCW 19.405.030 through 19.405.050.		

			• The IRP must include a summary of substantive changes to modeling methodologies or inputs that result in changes to the utility's resource need, as compared to the utility's previous IRP. • The IRP must include an analysis and summary of the avoided cost estimate for energy, capacity, transmission, distribution, and greenhouse gas emissions costs. The utility must list nonenergy costs and benefits addressed in the IRP and should specify if they accrue to the utility, customers, participants, vulnerable populations, highly impacted communities, or the general public. • The utility must provide a summary of public comments received during the development of its IRP and the utility's responses, including whether issues raised in the comments were addressed and incorporated into the		

			final IRP as well as documentation of the reasons for rejecting any public input		

Table B.2 – Handling of 2021 IRP Acknowledgment and Other IRP Requirements

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Idaho		
Case No. PAC-E-19-16, Order No. 34780, p. 13	The Commission expects the Company to actively consider the concerns raised in comments submitted in this case as it plans, and to continue evaluating all resource options and the best interests of customers when developing the 2021 IRP.	PacifiCorp has included a full description of comments received and considered within Volume II, Appendix C (Public Input Process).
Case No. PAC-E-19-16, Order No. 34780, p. 13	The Commission encourages the Company to fully study the costs and benefits of additional transmission resources in its 2021 IRP.	A discussion of the transmission resources studied by the company in the 2021 IRP is included in Volume I, Chapter 4 (Transmission), as well as the chapters addressing resource selection and the Action Plan.
Case No. PAC-E-19-16, Order No. 34780, p. 13	Additionally, the Commission is encouraged by the Company's development of DSM resources and continues to encourage the study, development, and implementation of economical DSM programs.	The implementation of economical DSM programs is described in PacifiCorp's resource selection and action plan chapters (Volume I, Chapters 9 and 10). Studies underlying the DSM resources are posted to the company's IRP website.
Case No. PAC-E-19-16, Order No. 34780, p. 13	The Commission looks forward to observing and working with the Company as it continues to develop time-of-use pricing policies to help shift peak demand in its service territory.	PacifiCorp continues to develop time-of-use pricing and the impact of programs is included in the company's load forecast, included in Volume II, Appendix A (Load Forecast).
Case No. PAC-E-19-16, Order No. 34780, p. 13	Finally, the Commission expects the Company to continue refining and enhancing its forecasting methodologies by analyzing a broad and diverse range of measures to avoid disadvantageous or unfair forecasting treatment of certain resources over others.	PacifiCorp continues to refine and enhance forecasting methodologies as described in Volume II, Appendix A (Load Forecast).
Oregon		
Order No. 20-186, p. 9	Adopt Staffs condition for updated coal analysis (direct PacifiCorp to include in its 2021 IRP development and updated economic study of retirement dates for all the coal units on PacifiCorp's system) on a timeline that informs the 2021 IRP because we view the coal analysis as a fundamental input to the IRP portfolios. Do not require a special coal update prior to the 2021 IRP. We leave this condition flexible, with the direction that PacifiCorp is to include in its 2021 IRP development process an updated analysis identifying the	PacifiCorp held an initial discussion of coal retirement analysis options as part of the December 3, 2020 IRP Public Input meeting. PacifiCorp's modeling system provided multiple retirement options for each relevant coal-fueled generator, modified for the case requirements of each portfolio. Specific retirement dates were optimized as part of the Short-term deterministic analysis. Further discussion of these processes can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	most cost-effective coal retirements individually and in combination.	
Order No. 20-186, p. 10	PacifiCorp is to work with stakeholders on the judgement calls where SCR can be reasonably avoided or not.	PacifiCorp led a discussion on SCRs as part of the December 3, 2020 public input meeting.
Order No. 20-186, p. 10	PacifiCorp is to update its inputs for correct Jim Bridger cost assumptions, as well as update its assumptions to reflect changes to the economy associated with COVID-19.	This input has been corrected and the updated cost assumptions were included in the IRP modeling described in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach). Volume II, Appendix A (Load Forecast) provides additional information on COVID-19's impact on the economy.
Order No. 20-186, p. 10	PacifiCorp is to provide a workshop or update for the Oregon Commission on PacifiCorp's timeline and sequence for incorporating nodal pricing and other MSP issues and EDAM into its IRP process.	PacifiCorp filed the required update with the Oregon Public Utility Commission on December 11, 2020 in Docket No. LC 70.
Order No. 20-186, p. 12-13	We ask PacifiCorp to bring its capacity needs and the economics of its energy position into greater focus through updates and analysis in the RFP docket. We require additional sensitivity analysis and request additional explanation of how PacifiCorp has balanced the near-term cost and optionality benefits of relying on available FOTs against the reliability gains and projected long-term economic benefits of new resource additions.	PacifiCorp provided the sensitivity analyses and requested explanation of how the company has balanced near-term cost and optionality benefits of relying on FOTs against the reliability gains and projected long-term economic benefits of new resource additions as part of the workpapers provided on June 10, 2021 and supplemented on July 25, 2021.
Order No. 20-186, p. 13	Direct PacifiCorp to provide a workshop or presentation on how it calculates the capacity contribution of renewables (including solar and wind co-located with battery storage) for its 2019 and 2021 IRPs.	PacifiCorp provided a workshop on the capacity contribution of renewable resources (including solar and wind co-located with battery storage) as part of the January 2021 IRP Public Input Meeting.
Order No. 20-186, p. 13	Regarding the QF issues, we accept PacifiCorp's commitment to produce a sensitivity or other explanation of the impact of renewing QFs on its load resource balance and direct PacifiCorp to include this in its 2021 IRP.	PacifiCorp has included an explanation of the impact of renewing QFs on its load resource balance as part of Volume I, Chapter 6 (Load and Resource Balance).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 14	We adopt Staff's condition with flexibility for PacifiCorp to conduct a workshop anytime in 2020 and for information sharing to occur between parties in a format convenient for participants. (Staff requests PacifiCorp provide a presentation to Staff, Commissioners, and any interested stakeholders who have signed the protective order in this docket regarding the coal mine costs at Jim Bridger and the drivers for the Jim Bridger coal price forecast within 120 days of this docket's acknowledgment order.) During our deliberations we questioned whether this information exchange could occur in an already planned workshop on net power costs. That workshop has since been held, however, and we note that it did not address the specific issue of Jim Bridger fuel price forecasts applicable to the planning timeframe.	PacifiCorp held a workshop to discuss this issue on October 20, 2020.
Order No. 20-186, p.14	We find that PacifiCorp reasonably allowed for additional flexible reserves, given its initial reliability analysis in this IRP, but we also agree with Staff and stakeholders that, for future IRPs, PacifiCorp needs to improve the analytical foundations for incorporating additional reliability resources into the IRP.	PacifiCorp's move to the Plexos modeling system provides a greater analytical foundation for incorporating reliability resources into the IRP. PacifiCorp further discussed compliance with this requirement during the June 25, 2021 and July 30, 2021 public input meetings.
Order No. 20-186, p. 17	We acknowledge Action Item 2a subject to the condition that PacifiCorp files all relevant workpapers for resource acquisition and rate setting in any customer preference RFP with the Oregon Commission in this docket at the time it files a request for waiver or notice of exception under the competitive bidding rules or within 30 days of acquisition of the resource, whichever occurs first.	PacifiCorp acknowledges this requirement.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 18	We acknowledge this action item with conditions based on Staff's recommendations. Our conditions on this action item include: Updated load and market forecasts, Off-system sales sensitivities, and customer impacts/ revenue requirement analysis.	PacifiCorp provided materials to Staff and the Independent Evaluator on June 10, 2021, and supplemented information provided on July 25, 2021.
Order No. 18-138, p. 21	Regarding conditions relating to non-wires alternatives, we accept PacifiCorp's offer of a Commission workshop before the 2021 IRP is filed. The workshop should address how PacifiCorp's IRP relates to its long-term transmission plan.	PacifiCorp held a workshop on non-wires alternatives on February 4, 2021.
Order No. 20-186, p. 23	PacifiCorp should work with stakeholders and Staff in the 2021 IRP development process to select two to four bundling strategies in an effort to identify the highest level of cost- effective energy efficiency by state and across the system. The collaborative decision process should consider bundling energy efficiency measures by energy cost, capacity contribution cost and measure type, as well as potentially by other metrics. The company should report on the collaborative process, bundling methods chosen, and any results in a filing before the filing of the 2021 IRP. PacifiCorp may hire a third party to conduct this analysis if needed due to resource constraints, but should coordinate with stakeholders on the scope of the work and timing.	PacifiCorp worked with Staff and stakeholders to select bundling strategies throughout 2020. Energy Efficiency bundles were presented as part of the January 29, 2021 public input meeting.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 23	Adopted Staffs conditions, including a modified condition that: PacifiCorp pursue demand response acquisition with a demand response RFP. To the extent practicable, the demand response bids may considered with bids from the all-source RFP. PacifiCorp should work with non-bidding stakeholders from Oregon and other interested states to determine whether PacifiCorp should move forward with cost-effective demand response bids, or with a demand response pilot, or both. PacifiCorp and/or Staff are to provide an update on demand response efforts at a regular public meeting before the 2021 IRP is filed.	PacifiCorp issued a demand response RFP in January 2021 and provided updates as part of the April 23, 2021 public input meeting. PacifiCorp provided an update on demand response efforts on August 16, 2021 and the informational filing was on the consent agenda for the August 24, 2021 regular public meeting.
Order No. 20-186, p. 23	Staff recommends that PacifiCorp conduct a Class 3 DSM workshop. PacifiCorp agreed to provide a stakeholder workshop during 2021 IRP development. We ask that the 2021 IRP summarize the timeframes and participation rates of any existing or planned Class 3 DSM pilots or schedules.	PacifiCorp held Conservation Potential Assessment workshop on August 28, 2020 in compliance with this requirement. A summary of DSM programs and pilots can be found in Volume II, Appendix D (DSM Resources).
Order No. 20-186, p. 24	We acknowledge this action item (6, sale of RECs) and accept PacifiCorp's agreement to add detail to this language in the 2021 IRP to more clearly explain its REC management for states with and without RPS requirements management of RECs.	PacifiCorp has added detail as directed as part of Volume I, Chapter 3 (Planning Environment).
Order No. 20-186, p. 24	Require PacifiCorp include a proposal for the scope of a potential climate adaptation study in its 2021 IRP. This will also allow PacifiCorp to use its next IRP process to solicit stakeholder feedback on the scope of its plan. Additional discussion in the 2021 IRP of adaptation actions already taking place in the course of normal business, such as changes to modeling inputs such as heating and cooling days or water constraints, is encouraged in the meantime.	PacifiCorp has developed a scope for a potential climate adaptation study and the scope is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation). The company has also prepared a “future climate change” sensitivity that takes into account streamflow, snowpack, rainfall, and changes in heating and cooling degree days. The future climate change scenario is also included in Chapter 8.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order No. 20-186, p. 25-26	As an IRP housekeeping matter, we seek to reduce the Oregon compliance items that PacifiCorp carries forward in each IRP. We ask PacifiCorp and Staff to review the Oregon compliance list, to determine which items they both agree are no longer relevant or necessary, and to provide an update on the list in the 2021 IRP docket. If certain items are not agreed upon or require our review, we ask Staff to bring those to a public meeting before the 2021 IRP.	PacifiCorp and Commission Staff met during the second quarter of 2021 to discuss opportunities to streamline filing requirements. Following discussions, parties agreed on proposed changes to the reporting process to drive efficiencies, and Staff proposed to recommend the agreed-upon changes for Commission acknowledgement as part of the 2021 IRP Staff Report.
Utah		
Order, Docket No. 19-035-02, p.12	The PTC issue demonstrates the dynamic nature of IRP processes generally, and we find PacifiCorp's treatment of the PTC in the 2019 IRP is consistent with the Guidelines. Because resource approval is a separate process from IRP acknowledgment, though, we fully expect that dockets related to resource approval or a certificate of public convenience and necessity would include adequate evaluation of the PTC extension. We also expect those dockets to give meaningful attention to potential future increases in the Wyoming wind tax.	PacifiCorp acknowledges this requirement.
Order, Docket No. 19-035-02, p.13	Any FERC queue reform will certainly impact some of the issues addressed by the 2019 IRP, but the ongoing nature of that process does not impact whether PacifiCorp substantially complied with the Guidelines in the development of the 2019 IRP. Other dockets, including future integrated resource planning, are appropriate	PacifiCorp acknowledges this requirement and has included a summary of queue reform in Volume I, Chapter 4 (Transmission). PacifiCorp acknowledges that the implications of queue reform will be evaluated in future dockets, including potentially through the Integrated Resource Planning process.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	venues to evaluate the implications of the results of queue reform.	
Order, Docket No. 19-035-02, p.15	Reliability assessments will only become more crucial as PacifiCorp's resource mix changes in the future, and those assessments must become an increasingly core aspect of future IRP processes.	PacifiCorp has included a chapter on reliability and resiliency as part of the 2021 IRP. Additional information can be found in Volume I, Chapter 5 (Reliability and Resiliency).
Order, Docket No. 19-035-02, p.18	We find PacifiCorp has reasonably evaluated DSM in the 2019 IRP considering all appropriate factors necessary to comply with the requirement in Guideline 4.b for a consistent and comparable evaluation of resources, including DSM. In addition, since it appears that many of UCE/SWEEP's concerns stem from the CPA, we find that PacifiCorp has appropriately addressed that issue with a commitment to work with stakeholders to identify potential improvements to the CPA methodology and other modeling changes during the upcoming 2021 IRP process.	PacifiCorp has worked extensively with stakeholders throughout the development of the 2021 IRP. The company held four CPA-specific workshops (January 21, 2020, February 18, 2020, April 16, 2020, and August 28, 2020) and responded to questions/recommendations through the stakeholder feedback form process. Additional information on DSM resources can be found in Volume II, Appendix D (DSM Resources), and information on the recommendations received through the stakeholder feedback process can be found in Volume II, Appendix C (Public Input Process).
Order, Docket No. 19-035-02, p.19-20	We conclude that PacifiCorp's commitment to provide materials three business days in advance of meetings generally satisfies Guideline 3. If a party can demonstrate, in the future, a pattern of unwillingness to provide meeting materials far enough in advance of meetings to allow parties to reasonably prepare, we could consider re-opening the Guidelines to make them more specific.	PacifiCorp acknowledges this ongoing requirement.
Order, Docket No. 19-035-02, p.20-21	We decline to modify the Guidelines at this time to make them more specific in connection with these requests of OCS (requirement of a customer rate impact analysis) and DPU (separate EV forecasts, and trends in the observed forecast overestimation). If a party can demonstrate, in the future, a pattern of unwillingness to provide reasonable responses to information requests, we could consider re-opening the Guidelines to make them more specific.	PacifiCorp acknowledges this requirement.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order, Docket No. 19-035-02, p. 26	PacifiCorp filed extensive documentation and workpapers with the 2019 IRP. The level of detail is useful and the information provided is well-organized. We commend PacifiCorp for making this information readily available and encourage PacifiCorp to continue to provide such detailed back-up data and workpapers in future IRPs.	PacifiCorp acknowledges this requirement.
Washington		
UE-180259, Order 03 Granting Petition, p.1	A CEIP must be based on an IRP that complies with the new statutory requirements. Specifically, the CEIP must "be informed by the investor-owned utility's clean energy action plan" (CEAP), which is one of the new legislative requirements for electric IRPs. (RCW 19.405.060(1)(b)(i); RCW 19.280.030.)	PacifiCorp acknowledges this requirement and has worked with Commission Staff to ensure that the 2021 IRP is compliant with the new legislative requirements for electric IRPs per RCW 19.405 and RCW 19.280.
UE-180259, Order 03 Granting Petition, p.1	Subsequent electric IRP filings must, therefore, be fully compliant with the new statutory requirements and be filed timely to allow incorporation of the CEAP into the CEIP. (See Chapter 19.405 RCW (Clean Energy Transformation Act (CETA)); RCW 19.280.030; RCW 80.28.405; RCW 19.405.060.)	PacifiCorp's 2021 IRP is compliant with each requirement under CETA as detailed in Table B.5 below.
UE-180259, Order 03 Granting Petition, p.6	Pacific Power & Light Company's next draft IRP must be submitted by January 4, 2021, and its next final IRP must be submitted by April 1, 2021.	In UE-200420, Order 01, the Commission granted PacifiCorp's Petition for Exemption, allowing additional time to complete necessary analysis. PacifiCorp has filed a compliant IRP by September 1, 2021, as directed in Order 01.
UE-200420, Order 02 Requiring Compliance	1(a) Integrate the demand forecasts and resource evaluations into a long-range IRP solution describing the mix of resources that meet current and projected resource needs, abiding by a variety of constraints pursuant to statute and per Commission rule.	PacifiCorp's portfolio modeling process meets this requirement. Inputs are discussed in Volume I, Chapter 6 (Load and Resource Balance) and Chapter 7 (Resource Options). The modeling process and portfolio selection is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	1(b) Provide a narrative illustrating step-by-step how the social cost of greenhouse gas emissions (SCGHG) cost adder is applied throughout its modeling logic. The SCGHG impact on the Company's modeling and portfolio analyses should be addressed in numerous variables, including PacifiCorp's imports and contracts and forward price curves.	PacifiCorp has included a step-by-step discussion of how SCGHG is applied to the portfolio modeling process as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation). The summary includes a description of how the SCGHG is included in the model, and which variables are impacted.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	1(c) Include an assessment of battery and pumped storage for integrating renewable resources. The assessment may consider ancillary services at the appropriate granularity required to model such resources.	PacifiCorp's 2021 IRP portfolio modeling process included battery and pumped storage as capacity options to integrate renewables. A description of the resources can be found in Volume I, Chapter 7 (Resource Options), and a description of the portfolio selection can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	1(d) Provide precise analyses and an explanatory narrative describing the alternative lowest reasonable cost and reasonably available portfolio in the absence of CETA. Staff encourages PacifiCorp to exercise its professional judgment regarding many scenario details. However, for additional guidance, PacifiCorp could consider how its peer Washington investor-owned utilities have approached this scenario. For example, Puget Sound Energy's counterfactual scenario has decidedly fewer transmission capacity constraints to serve Washington load since the utility would not need to meet GHG neutral nor 100 percent clean energy targets in 2030 and 2045, respectively. The Commission expects this CETA counterfactual scenario will yield a baseline portfolio that includes the SCGHGs and differs from the CETA-compliant preferred portfolio according to rule.	PacifiCorp's alternative lowest reasonable cost and reasonably available portfolio is described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation). Chapter 8 includes a narrative describing the portfolio, as well as other scenario details.
UE-200420, Order 02 Requiring Compliance	1(e) Include a future climate change scenario as proposed in the company's IRP	A description and narrative of PacifiCorp's future climate change scenario is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
UE-200420, Order 02 Requiring Compliance	1(f) Adjust variables specific to its Washington service territory to develop a more robust maximum customer benefit sensitivity. For example, the Company could consider what level of distributed energy resource penetration within PacifiCorp's Washington service territory would be sufficient to preclude – or at least postpone – high-voltage transmission buildout between Walla Walla and Yakima and/or between Yakima and Southern Oregon. Forgoing constructing such transmission could significantly reduce eminent domain actions that can disproportionately impact vulnerable	A description and narrative of PacifiCorp's maximum customer benefit scenario is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	populations. This modeling exercise intends to maximize the hypothetical benefit for PacifiCorp's Washington customers. For the 2021 IRP, this sensitivity's primary result is additional data and analyses the utility could further refine for its 2022 CEIP and subsequent planning cycles.	
UE-200420, Order 02 Requiring Compliance	1(g) Assess its regional transmission future needs and the extent transfer capability limitations may affect the future siting of resources.	PacifiCorp assesses its regional transmission future needs throughout the IRP process, and additional information on the interaction between transmission availability and future resources can be found in Volume I, Chapter 4 (Transmission), Chapter 8 (Modeling and Portfolio Evaluation), Chapter 9 (Modeling and Portfolio Selection), and Chapter 10 (Action Plan).
UE-200420, Order 02 Requiring Compliance	2(a) [Clean Energy Action Plan (CEAP)] must be at the lowest reasonable cost	PacifiCorp's CEAP is based on the IRP preferred portfolio, which represents the lowest reasonable cost portfolio that serves customers reliably. A broader discussion of portfolio cost is available in Volume I, Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	2(b) [CEAP] must identify and be informed by the utility's ten-year cost effective conservation potential assessment (CPA) as determined in RCW 19.285.040	PacifiCorp's ten-year CPA provides the inputs to PacifiCorp's IRP modeling that selects cost effective conservation resources.
UE-200420, Order 02 Requiring Compliance	2(c) [CEAP] must identify how the utility will meet the requirements in WAC 480-100-610(4)(c)	A discussion of CETA's clean energy transformation standards – including a narrative of how PacifiCorp's preferred portfolio sets the path to compliance – is part of the "Resource Adequacy" section of Volume II, Appendix O (Washington Clean Energy Action Plan)
UE-200420, Order 02 Requiring Compliance	2(d) [CEAP] must establish a resource adequacy requirement	PacifiCorp sets the resource adequacy requirement through the IRP modeling process, which includes Washington customers. The full-system resource adequacy assessment is included in Volume I, Chapter 6 (Load and Resource Balance), and the planning reserve margin is included for the sake of convenience in the Volume II, Appendix O (Clean Energy Action Plan) as part of the "Resource Adequacy" section.
UE-200420, Order 02 Requiring Compliance	2(e) [CEAP] must identify the potential cost-effective demand response (DR) and load management programs that may be acquired	Volume II, Appendix O (Clean Energy Action Plan) includes a discussion of DR and load management programs as part of the "Resource Adequacy" section.
UE-200420, Order 02 Requiring Compliance	2(f) [CEAP] must identify renewable resources, non-emitting electric generation, and distributed energy resources that may be acquired and evaluate how each identified resource may reasonably be expected to	PacifiCorp discusses these resources at a system level in Volume I, Chapter 9 (Modeling and Portfolio Selection) and Chapter 10 (Action Plan). PacifiCorp also includes a list of the renewable and non-emitting resources in Volume II, Appendix R (Clean Energy Action Plan) within the "Resource Adequacy"

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
	contribute to meeting the utility's resource adequacy requirement.	section.
UE-200420, Order 02 Requiring Compliance	2(g) [CEAP] must identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities.	PacifiCorp has fully complied with this requirement. Additional details can be found in Volume I, Chapter 10 (Action Plan) and Volume II, Appendix O (Clean Energy Action Plan).
UE-200420, Order 02 Requiring Compliance	2(h) [CEAP] must identify the nature and possible extent to which the utility may need to rely on an alternative compliance option identified under RCW 19.405.040(1)(b), if appropriate; and	PacifiCorp's preferred portfolio – included in Volume I, Chapter 9 (Modeling and Portfolio Selection) – meets the requirements under CETA's clean energy standards. A high-level discussion of compliance risk is also included in Volume II, Appendix O (Clean Energy Action Plan).
UE-200420, Order 02 Requiring Compliance	2(i) [CEAP] must incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW 19.280.030(3).	PacifiCorp included social cost of greenhouse gas as a cost adder throughout the modeling process – including in portfolios that were considered to ultimately inform Volume II, Appendix O (Clean Energy Action Plan). Additional discussion of how the social cost of greenhouse gas emissions was incorporated into the modeling can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).
UE-200420, Order 02 Requiring Compliance	3(a) Identify an appropriate resource adequacy requirement and complete the assessment, as required by WAC 480-100-620(8)	PacifiCorp's assessment and determination of resource adequacy metrics is included in Volume I, Chapter 6 (Load and Resource Balance) and Chapter 8 (Modeling and Portfolio Evaluation). A discussion of regional resource adequacy is included in Volume I, Chapter 5 (Reliability and Resiliency).
UE-200420, Order 02 Requiring Compliance	3(b) Provide resource assumptions and market forecasts used in the utility's schedule of estimated avoided costs required in WAC 480-106-040 including, but not limited to: 1)cost assumptions; 2)production estimates; 3)peak capacity contribution estimates and annual capacity factor estimates	PacifiCorp will include these assumptions as part of the data disk process.
UE-200420, Order 02 Requiring Compliance	3(c) develop a detailed narrative describing the logic used in the Plexos LTCE and medium-term model that determine whether low-cost energy efficiency or demand response are developed or dispatched.	The logic underlying the Plexos LTCE will be included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	3(d) compare and evaluate all identified resources and potential changes to existing resources for achieving the clean energy transformation standards in WAC 480-100-610 at the lowest reasonable cost, including a narrative of the decisions it has made.	A discussion of PacifiCorp's portfolio selection parameters is included in Volume I, Chapter 9 (Modeling and Portfolio Selection) as well as in Volume I, Chapter 10 (Action Plan).
UE-200420, Order 02 Requiring Compliance	4(a) Augment its load forecasting chapter and supporting appendices with significantly more details. Staff expect to see the data inputs used in the calculation and estimated regression results in native file format	PacifiCorp will provide the data inputs and estimated regression results along with the IRP data disks sent shortly after filing. Volume II, Appendix A (Load Forecast) has been updated where possible.
UE-200420, Order 02 Requiring Compliance	4(b) Address WAC 480-100-620(2), including more information and discussion regarding treatment of: 1)alternative load forecast scenarios, including climate change impacts; 2) "optimistic" and "pessimistic" assumptions in the low and high growth models and how these alternative forecasts differ from the base forecast; and 3) electrification adjustments made to the load forecast.	PacifiCorp included narrative to discuss the climate change scenario, electrification adjustments, and assumptions in low and high load growth models within Volume II, Appendix A (Load Forecast). The climate change load forecast is further discussed in Volume I, Chapter 5 (Reliability and Resiliency) and Chapter 8 (Modeling and Portfolio Evaluation).
UE-200420, Order 02 Requiring Compliance	5(a) file the conservation potential assessment (CPA) as an appendix or attachment to the final IRP and specifically provide the: 1) CPA model and underlying data; 2) DR potential model and underlying data	PacifiCorp has included the CPA as part of the IRP filing. Underlying data will be provided as part of the data disk process.
UE-200420, Order 02 Requiring Compliance	5(b) identify the DSM grid benefits, explaining benefits: 1) Endogenous within LTCE portfolio optimization 2) Separately determined during the CPA process	Grid benefits endogenously determined within the long-term capacity expansion portfolio optimization process are discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
UE-200420, Order 02 Requiring Compliance	5(c) Describe how the Plexos LTCE model harmonizes differences in technical achievable potential when the optimization process applies different load growth forecasts.	The description of the Plexos long-term capacity expansion process and the selection of DSM is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	6(a) demonstrate consideration of a wider incorporation of non-energy impacts (NEIs) in addition to NEI applications during CPA development.	A narrative consideration of NEIs is discussed in Volume II, Appendix O (Clean Energy Action Plan). NEIs by energy efficiency measure included in the CPA are found in Appendix G of the 2021 CPA. A review of NEIs for demand response is found Appendix J of the 2021 CPA PacifiCorp IRP team applied NEI proxy in the 2021 IRP. Proxy will be the EPA EE NEI value for public health benefits, •Applied to WA EE resources in Social Cost of Carbon cases. •Value is 2.8 c/kWh in 2017$ (Table ES-1, high value of Pacific NW for Uniform EE). It will be grossed up to 2020 dollars to be consistent with the rest of the IRP model assumptions. •Link to study: https://www.epa.gov/statelocalenergy/public-health-benefits-kwh-energy-efficiency-and-renewable-energy-united-states
UE-200420, Order 02 Requiring Compliance	6(b) Attribute NEIs considered, indicating whether nonenergy costs and benefits accrue to the utility, customers, participants, vulnerable populations, highly-impacted communities, or the general public.	Accrual of NEIs is discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
UE-200420, Order 02 Requiring Compliance	6(c) Specifically address vulnerable populations and quantify disparate impacts existing within PacifiCorp's Washington service territory in its current-state assessment of economic, health, and environmental impacts.	A preliminary list identifying vulnerable populations and a quantification of disparate impacts within PacifiCorp's Washington service area is discussed in Volume II, Appendix O (Clean Energy Action Plan).
UE-200420, Order 02 Requiring Compliance	7(a) summarize public comments received during the 2021 IRP development rather than providing a download of stakeholder feedback forms received to date.	A summary of public comments and PacifiCorp responses – including whether/how the feedback was incorporated into the 2021 IRP – is included in Volume II, Appendix C (Public Input Process).
UE-200420, Order 02 Requiring Compliance	7(b) Summarize utility's corresponding responses to public comments; and	A summary of public comments and PacifiCorp responses – including whether/how the feedback was incorporated into the 2021 IRP – is included in Volume II, Appendix C (Public Input Process).
UE-200420, Order 02 Requiring Compliance	7(c) Summarize whether and how final plan addresses and incorporates comments received.	A summary of public comments and PacifiCorp responses – including whether/how the feedback was incorporated into the 2021 IRP – is included in Volume II, Appendix C (Public Input Process).

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
UE-200420, Order 02 Requiring Compliance	8(a) provide all data input files to the Commission in native format with appropriate context as appendices or attachments to the final filing or via accompanying data disks. Data made available in this accessible manner will facilitate understanding of why PacifiCorp took the actions it did and assist in the independent review of such actions	PacifiCorp will provide all data input files as part of the data disk process in the week(s) following the filing of the IRP on September 1, 2021.
UE-200420, Order 02 Requiring Compliance	8(b) include complete data sets informing the Company's preferred portfolio. Supporting data and workpapers should allow a 2019-to-2021 comparison of resource need	PacifiCorp will provide all data input files as part of the data disk process in the week(s) following the filing of the IRP on September 1, 2021.
UE-200420, Order 02 Requiring Compliance	8(c) Ensure supporting data is easily accessible to interested parties by including contextual aids with the given information. At minimum, the company should organize its final IRP deliverable by including a master table of contents, readme files, and categorically grouping related data.	PacifiCorp will provide all data input files as part of the data disk process in the week(s) following the filing of the IRP on September 1, 2021.
Wyoming		
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include a Reference Case based on the 2017 IRP Updated Preferred Portfolio, incorporating updated assumptions, such as load and market prices and any known changes to system resources and using environmental investments or costs only required by current law. For example, the reference case will not include an estimate or assumed price or cost for carbon emissions absent an existing legal requirement	PacifiCorp has complied with this requirement. Additional information on the specified reference case can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Conduct a more extensive analysis of the impact of alternative price-policy scenarios on the resource plan	The impact of price-policy scenarios on the resource plan is summarized in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Conduct a sensitivity analysis on top performing portfolio cases and the reference case.	PacifiCorp has complied with this requirement. Additional information on sensitivity analyses can be found within Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results).
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Investigate alternative methodologies to integrate different reliability analyses including regional analysis of resource adequacy; analysis of power flow issues caused by retiring coal units; study of potential weather-related outages on intermittent generation; and an analysis of wildfire risk.	PacifiCorp has introduced a new chapter into this IRP – Reliability and Resiliency – which includes regional analyses of resource adequacy, a discussion of power flow issues caused by baseload resource retirements and how PacifiCorp Transmission is planning for those retirements, an assessment of weather-related outages, and a discussion of wildfire risk and mitigation.

Reference	IRP Requirement or Recommendation	How the Guideline is Addressed in the 2021 IRP
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include additional analysis on operational experience, if any, with battery acquisition and operations and include a review of capabilities learned from other utilities.	PacifiCorp has included a description of procurement and operational experience with battery acquisition and operations as part of Volume I, Chapter 7 (Resource Options).
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include an analysis that demonstrates how the Company will maximize the use of dispatchable and reliable low-carbon electricity pursuant to HB200.	PacifiCorp has included Carbon Capture Utilization and Sequestration analysis within the portfolio modeling process. Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection) provide additional detail.
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Incorporate an analysis of any agreed upon change to the MSP and to the extent there are outstanding material disagreements regarding cost allocation at the time of filing, quantify those risks and potential impact to Wyoming ratepayers.	PacifiCorp has included a discussion of the current status of the MSP within Volume I, Chapter 3 (Planning Environment). As there are no agreed-upon changes or outstanding material disagreements, PacifiCorp did not quantify potential impacts. To the extent that there are changes and/or material disagreements in future IRP cycles, the company will include the required quantified risk.
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include a broader analysis of all generation types including nuclear and natural gas.	PacifiCorp has expanded the generation types included in the supply-side table as part of the 2021 IRP. Advanced nuclear and natural gas resources have both been included in the supply-side table and analyzed in the 2021 IRP.
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include a narrative discussing impacts and regulatory framework for renewable generation in the Planning Environment discussion (chapter 3).	PacifiCorp has added this narrative analysis to the Planning Environment discussion in Volume I, Chapter 3 (Planning Environment).
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include an acknowledgement that each of these requirements are addressed in the 2021 IRP to ensure compliance.	PacifiCorp acknowledges these requirements and has addressed each within the 2021 IRP.

Table B.3 – Oregon Public Utility Commission IRP Standard and Guidelines

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
Guideline 1. Substantive Requirements		
1.a.1	All resources must be evaluated on a consistent and comparable basis: All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, power purchases, thermal resources, and transmission. Volume I, Chapter 4 (Transmission Planning), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation Approach) document how PacifiCorp developed these resources and modeled them in its portfolio analysis. All these resources were established as resource options in the company's capacity expansion optimization model, Plexos, and selected by the model based on load requirements, relative economics, resource size, availability dates, and other factors.

1.a.2	All resources must be evaluated on a consistent and comparable basis: Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations and locations in portfolio risk modeling.	All portfolios developed with Plexos were subjected to Monte Carlo production cost simulation. These portfolios contained a variety of resource types with different fuel types (coal, gas, biomass, nuclear fuel, "no fuel" renewables), lead-times (ranging from front office transactions to nuclear plants), in-service dates, operational lives, and locations. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), Chapter 9 (Modeling and Portfolio Selection Results), and Volume II, Appendix I (Capacity Expansion Results) and Appendix J (Stochastic Simulation Results).
1.a.3	All resources must be evaluated on a consistent and comparable basis: Consistent assumptions and methods should be used for evaluation of all resources.	PacifiCorp fully complies with this requirement. The company developed generic supply-side resource attributes based on a consistent characterization methodology. For demand-side resources, the company used the Applied Energy Group's supply curve data developed for this IRP for representation of DSM resources. The study was based on a consistently applied methodology for determining technical, market, and achievable DSM potentials. All portfolio resources were evaluated using the same sets of price and load forecast inputs. These inputs are documented in Volume I, Chapter 6 (Load and Resource Balance), Chapter 7 (Resource Options), and Chapter 8 (Modeling and Portfolio Evaluation 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 6.88 percent to discount all cost streams.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
1.b.1	Risk and uncertainty must be considered: At a minimum, utilities should address the following sources of risk and uncertainty: 1. Electric utilities: load requirements, hydroelectric generation, plant forced outages, fuel prices, electricity prices, and costs to comply with any regulation of greenhouse gas emissions.	Each of the sources of risk identified in this guideline is treated as a stochastic variable in PacifiCorp's production cost simulation with the exception of CO2 emission compliance costs, which are treated as a scenario risk and evaluated as part of a CO2 price assumption and a no CO2, a high CO2, and a social cost of carbon price-policy scenario for specific studies. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	Resource risk mitigation is discussed in Volume I, Chapter 10 (Action Plan). Regulatory and financial risks associated with resource and transmission investments are highlighted in several areas in the IRP document, including Volume I, Chapter 3 (Planning Environment), Chapter 4 (Transmission), Chapter 8 (Modeling and Portfolio Evaluation Approach), and Chapter 9 (Modeling and Portfolio Selection Results).
1.c	The primary goal must be the selection of a portfolio of resources with the best combination of expected costs and associated risks and uncertainties for the utility and its customers ("best cost/risk portfolio").	PacifiCorp evaluated cost/risk tradeoffs for each of the portfolios considered. See Volume I, Chapter 9 (Modeling and Portfolio Selection Results), Chapter 10 (Action Plan), and Volume II, Appendix I (Capacity Expansion Results) and Appendix H (Stochastic Parameters) for the company's portfolio cost/risk analysis and determination of the preferred portfolio.
1.c.1	The planning horizon for analyzing resource choices should be at least 20 years and account for end effects. Utilities should consider all costs with a reasonable likelihood of being included in rates over the long term, which extends beyond the planning horizon and the life of the resource.	PacifiCorp used a 20-year study period (2021-2040) for portfolio modeling, and a real levelized revenue requirement methodology for treatment of end effects.
1.c.2	Utilities should use present value of revenue requirement (PVRR) as the key cost metric. The plan should include analysis of current and estimated future costs for all long-lived resources such as power plants, gas storage facilities, and pipelines, as well as all short-lived resources such as gas supply and short-term power purchases.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) provides a description of the PVRR methodology.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
1.c.3.1	To address risk, the plan should include, at a minimum: 1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	PacifiCorp uses the standard deviation of stochastic production costs as the measure of cost variability. For the severity of bad outcomes, the company calculates several measures, including stochastic upper-tail mean PVRR and the 95th percentile stochastic production cost PVRR.
1.c.3.2	To address risk, the plan should include, at a minimum: 2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	A discussion on hedging is provided in Volume I, Chapter 10 (Action Plan).
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) summarizes the results of PacifiCorp's cost/risk tradeoff analysis, and describes what criteria the company used to determine the best cost/risk portfolios and the preferred portfolio.
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	PacifiCorp considered both current and potential state and federal energy/pollutant emission policies in portfolio modeling. Volume I, Chapter 7 (Modeling and Portfolio Evaluation 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 9 (Modeling and Portfolio Selection Results) provides the results. Volume I, Chapter 10 (Action Plan) presents an acquisition path analysis that describes resource strategies based on regulatory trigger events.
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Oregon PUC for resolution.	PacifiCorp fully complies with this requirement. Volume II, Appendix C (Public Input) provides an overview of the public input process, all public-input meetings held for the 2021 IRP, and summarizes public input received throughout the 2021 IRP cycle. 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.	2021 IRP Volumes I and II provide non-confidential information used for portfolio evaluation, as well as other data requested by stakeholders. PacifiCorp also provided stakeholders with non-confidential information to support public meeting discussions via email and in response to Stakeholder Feedback Forms. Data discs will be available with public data. Additionally, data discs with confidential data will be provided to

		appropriate parties through use of a general protective order.
2.c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Oregon PUC.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public input meetings and solicited/and received feedback at various times when developing the 2021 IRP. The materials shared with stakeholders at these meetings, outlined in Volume II, Appendix C (Public Input Process), is consistent with materials presented in Volumes I and II of the 2021 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 2021 IRP complies with this requirement.
3.b	The utility must present the results of its filed plan to the Oregon PUC at a public meeting prior to the deadline for written public comment.	This activity will be conducted following the filing of this IRP.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted following the filing of this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted following the filing of this IRP.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Oregon PUC, unless the utility is within six months of filing its next IRP. The utility must summarize the update at an Oregon PUC public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	Not applicable to this filing; this activity will be conducted following the filing of this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	Not applicable to this filing; this activity will be conducted following the filing of this IRP.
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		
No.	**Requirement**	**How the Guideline is Addressed in the 2021 IRP**
4.a	An explanation of how the utility met each of the substantive and procedural requirements.	The intent of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	PacifiCorp developed low, high, and extreme peak temperature (one-in-twenty probability) load growth forecasts for scenario analysis using the Plexos model. Stochastic variability of loads was also captured in the risk analysis. See Volume I, Chapters 6 (Load and Resource Balance) and Chapter 8 (Modeling and Portfolio Evaluation Approach), and Volume II, Appendix A (Load Forecast Detail) for load forecast information.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
4.c	For electric utilities, a determination of the levels of peaking capacity and energy capability expected for each year of the plan, given existing resources; identification of capacity and energy needed to bridge the gap between expected loads and resources; modeling of all existing transmission rights, as well as future transmission additions associated with the resource portfolios tested.	See Chapter 6 (Load and Resource Balance) for details on annual capacity and energy balances. Existing transmission rights are reflected in the IRP model topologies. Future transmission additions used in analyzing portfolios are summarized in Volume I, Chapter 4 (Transmission) and Chapter 8 (Modeling and Portfolio Evaluation 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 7 (Resource Options) identifies the resources included in this IRP and provides their detailed cost and performance attributes. Additional information on energy efficiency resource characteristics is available in Volume II, Appendix D (Demand-Side Management Resources) referencing additional information on PacifiCorp's IRP website.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	In addition to incorporating a planning reserve margin for all portfolios evaluated, as supported by an updated Stochastic Loss of Load Study in Volume II, Appendix J (Stochastic Simulation Results), the company used several measures to evaluate relative portfolio supply reliability. These measures (Energy Not Served and Loss of Load Probability) are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation 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 8 (Modeling and Portfolio Evaluation Approach) describes the key assumptions and alternative scenarios used in this IRP. Volume II, Appendix I (Capacity Expansion Detail) includes summaries of assumptions used for each case definition analyzed in the 2021 IRP.
4.h	Construction of a representative set of resource portfolios to test various operating characteristics, resource types, fuels and sources, technologies, lead times, in-service dates, durations and general locations – system-wide or delivered to a specific portion of the system.	This IRP documents the development and results of portfolios designed to determine resource selection under a variety of input assumptions in Volume I, Chapters 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results).
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) 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 9 (Modeling and Portfolio Selection Results) provides tables and charts with performance measure results, including rank ordering.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	See responses to 1.b.1 and 1.b.2 above.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	See 1.c above.
4.m	Identification and explanation of any inconsistencies of the selected portfolio with any state and federal energy policies that may affect a utility's plan and any barriers to implementation.	This IRP is designed to avoid inconsistencies with state and federal energy policies therefore none are currently identified.
4.n	An action plan with resource activities the utility intends to undertake over the next two to four years to acquire the identified resources, regardless of whether the activity was acknowledged in a previous IRP, with the key attributes of each resource specified as in portfolio testing.	Volume I Chapter 10 (Action Plan) presents the 2019 IRP action plan.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
Guideline 5: Transmission		
5	Portfolio analysis should include costs to the utility for the fuel transportation and electric transmission required for each resource being considered. In addition, utilities should consider fuel transportation and electric transmission facilities as resource options, taking into account their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PacifiCorp evaluated four sensitivities on Energy Gateway transmission project configurations on a consistent and comparable basis with respect to other resources. Where new resources would require additional transmission facilities the associated costs were factored into the analysis. Fuel transportation costs were factored into resource costs.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PacifiCorp's conservation potential study is available on the company's webpage, and the most recent results from the conservation potential assessment have been incorporated into the IRP modeling process.
6.b	To the extent that a utility controls the level of funding for conservation programs in its service territory, the utility should include in its action plan all best cost/risk portfolio conservation resources for meeting projected resource needs, specifying annual savings targets.	PacifiCorp's energy efficiency supply curves incorporate Oregon resource potential. Oregon potential estimates were provided by the Energy Trust of Oregon. See the demand-side resource section in Volume I, Chapter 7 (Resource Options), the results in Volume I, Chapter 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.
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		
No.	**Requirement**	**How the Guideline is Addressed in the 2021 IRP**
8.a	Base case and other compliance scenarios: The utility should construct a base-case scenario to reflect what it considers to be the most likely regulatory compliance future for carbon dioxide (CO_2), nitrogen oxides, sulfur oxides, and mercury emissions. The utility should develop several compliance scenarios ranging from the present CO_2 regulatory level to the upper reaches of credible proposals by governing entities. Each compliance scenario should include a time profile of CO_2 compliance requirements. The utility should identify whether the basis of those requirements, or "costs," would be CO_2 taxes, a ban on certain types of resources, or CO_2 caps (with or without flexibility mechanisms such as an allowance for credit trading as a safety valve). The analysis should recognize significant and important upstream emissions that would likely have a significant impact on resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach). In the 2021 IRP, PacifiCorp modeled a price on CO2 starting in 2021 within the Social Cost of Greenhouse Gas price-policy scenarios.
8.b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value revenue requirement (PVRR) costs and risk measures, over at least 20 years, for a set of reasonable alternative portfolios from which the preferred portfolio is selected. The utility should incorporate end-effect considerations in the analyses to allow for comparisons of portfolios containing resources with economic or physical lives that extend beyond the planning period. The utility should also modify projected lifetimes as necessary to be consistent with the compliance scenario under analysis. In addition, the utility should include, if material, sensitivity analyses on a range of reasonably possible regulatory futures for nitrogen oxides, sulfur oxides, and mercury to further inform the preferred portfolio selection.	Volume II, Appendix J (Stochastic Simulation Results) provides the stochastic mean PVRR versus upper tail mean less stochastic mean PVRR scatter plot diagrams that for a broad range of portfolios developed with a range of compliance scenarios as summarized in 8.a above. The company considers end-effects in its use of Real Levelized Revenue Requirement Analysis, as summarized in Volume I, Chapter 8 (Modeling and Portfolio Evaluation 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 point" scenario, which, if anticipated now, would lead to, or "trigger" the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio's expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO2 compliance scenarios. The utility should provide its assessment of whether a CO2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) for a description of initial portfolio-development definitions. Comparative analysis of these case results is included in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
8.d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including state goals for reducing greenhouse gas emissions) as those policies are applied to the utility, the utility should construct the best cost/risk portfolio that achieves that consistency, present its cost and risk parameters, and compare it to those in the preferred and alternative portfolios.	Several portfolios yield system emissions aligned with state goals for reducing greenhouse gas emissions. These cases are summarized in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
Guideline 9: Direct Access Loads		
9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Oregon Docket UE 267 established a long-term opt out option for eligible PacifiCorp customers. Going forward PacifiCorp will cease planning for customers who elect direct-access service on a long-term basis (i.e. five-year opt out customers).
Guideline 10: Multi-state Utilities		
10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated system basis that achieves a best cost/risk portfolio for all their retail customers.	The 2021 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 9 (Modeling and Portfolio Selection Results) walks through the role of reliability, cost, and risk measures in determining the preferred portfolio. Scatter plots of portfolio cost versus risk at different CO2 cost levels were used to inform the cost/risk tradeoff analysis.
Guideline 12: Distributed Generation		
12	Electric utilities should evaluate distributed generation technologies on par with other supply-side resources and should consider, and quantify where possible, the additional benefits of distributed generation.	PacifiCorp contracted with Guidehouse to provide estimates of expected private generation penetration. The study was incorporated in the analysis as a deduction to load. Sensitivities looked at both high and low penetration rates for private generation. The study is included in Volume II, Appendix L (Private Generation Study).
Guideline 13: Resource Acquisition		

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
13.a	An electric utility should, in its IRP: 1. Identify its proposed acquisition strategy for each resource in its action plan. 2. Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party. 3. Identify any Benchmark Resources it plans to consider in competitive bidding.	Volume I, Chapter 10 (Action Plan) outlines the procurement approaches for resources identified in the preferred portfolio. A discussion of the advantages and disadvantages of owning a resource instead of purchasing it is included in Chapter 10 (Action Plan). PacifiCorp has not at this time identified any specific benchmark resources it plans to consider in the competitive bidding process summarized in the 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 Guideline is Addressed in the 2021 IRP
Procedural Issues		
1	The Commission has the legal authority to promulgate Standards and Guidelines for integrated resource planning.	Not addressed; this is a Public Service Commission of Utah responsibility.
2	Information Exchange is the most reasonable method for developing and implementing integrated resource planning in Utah.	Information exchange has been conducted throughout the 2021 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 8 (Modeling and Portfolio Evaluation Approach) for a description of the methodology employed, including how CO2 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 10 (Action Plan) describes the linkage between the 2021 IRP preferred portfolio and December 2020 business plan resources. Significant resource differences are highlighted. The business plan portfolio was run consistent with requirements outlined in the Order issued by the Utah Public Service Commission on September 16, 2016, Docket No. 15-035-04.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
Standards and Guidelines		
1	Definition: Integrated resource planning is a utility planning process which evaluates all known resources on a consistent and comparable basis, in order to meet current and future customer electric energy services needs at the lowest total cost to the utility and its customers, and in a manner consistent with the long-run public interest. The process should result in the selection of the optimal set of resources given the expected combination of costs, risk and uncertainty.	Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) outlines the portfolio performance evaluation and preferred portfolio selection process, while Chapter 9 (Modeling and Portfolio Selection Results) chronicles the modeling and preferred portfolio selection process. This IRP also addresses concerns expressed by Utah stakeholders and the Utah commission concerning comprehensiveness of resources considered, consistency in applying input assumptions for portfolio modeling, and explanation of PacifiCorp's decision process for selecting top-performing portfolios and the preferred portfolio.
2	The company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on October 18, 2019, and filed this IRP on September 1, 2021, meeting the requirement. PacifiCorp requested and was granted an extension of time to file the 2019 IRP in Docket No. 21-035-09.
3	IRP will be developed in consultation with the Commission, its staff, the Division of Public Utilities, the Committee of Consumer Services, appropriate Utah state agencies and interested parties. PacifiCorp will provide ample opportunity for public input and information exchange during the development of its Plan.	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction). A record of public meetings and a summary of feedback and public comments is provided in Volume II, Appendix C (Public Input).
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load growth, including both capacity (kW) and energy (kWh) requirements.	PacifiCorp implemented a load forecast range for both capacity expansion optimization scenarios as well as for stochastic variability, covering both capacity and energy. Details concerning the load forecasts used in the 2021 IRP are provided in Volume I, Chapter 7 (Resource Options) and Volume II, Appendix A (Load Forecast 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 6 (Load and Resource Balance) 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	Volume II, Appendix A (Load Forecast Details) documents how demographic and price factors are used in PacifiCorp's load forecasting methodology.

	loads.	

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
4.b	An evaluation of all present and future resources, including future market opportunities (both demand-side and supply-side), on a consistent and comparable basis.	Resources were evaluated on a consistent and comparable basis using the 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 9 (Modeling and Portfolio Selection Results). Resource options are summarized in Volume I, Chapter 7 (Resource Options).
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	PacifiCorp included supply curves for Demand Response (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 7 (Resource Options).
4.b.ii	An assessment of all technically feasible generating technologies including: renewable resources, cogeneration, power purchases from other sources, and the construction of thermal resources.	PacifiCorp considered a wide range of resources including renewables, cogeneration (combined heat and power), power purchases, thermal resources, energy storage, and Energy Gateway transmission configurations. Volume I, Chapters 7 (Resource Options) and 8 (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.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	A description of the role of competitive bidding and other procurement methods is provided in Volume I, Chapter 10 (Action Plan).
4.d	A 20-year planning horizon.	This IRP uses a 20-year study horizon (2021-2040).
4.e	An action plan outlining the specific resource decisions intended to implement the integrated resource plan in a manner consistent with the company's strategic business plan. The action plan will span a four-year horizon and will describe specific actions to be taken in the first two years and outline actions anticipated in the last two years. The action plan will include a status report of the specific actions contained in the previous action plan.	The IRP action plan is provided in Volume I, Chapter 10 (Action Plan). A status report of the actions outlined in the previous action plan (2019 IRP Update) is provided in Volume I, Chapter 10 (Action Plan). In Volume I, Chapter 10 (Action Plan) Table 9.1 identifies actions anticipated in the next two-to-four years.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
4.f	A plan of different resource acquisition paths for different economic circumstances with a decision mechanism to select among and modify these paths as the future unfolds.	Volume I, Chapter 10 (Action Plan) includes an acquisition path analysis that presents broad resource strategies based on regulatory trigger events, change in load growth, extension of federal renewable resource tax incentives and procurement delays.
4.g	An evaluation of the cost-effectiveness of the resource options from the perspectives of the utility and the different classes of ratepayers. In addition, a description of how social concerns might affect cost effectiveness estimates of resource options.	PacifiCorp provides resource-specific utility and total resource cost information in Volume I, Chapter 7 (Resource Options). The IRP document addresses the impact of social concerns on resource cost-effectiveness in the following ways: ● Top performing portfolios were evaluated using a range of CO2 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 9 (Modeling and Portfolio Selection Results). ● Volume II, Appendix G (Plant Water Consumption) reports historical water consumption for PacifiCorp's thermal plants.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
4.h	An evaluation of the financial, competitive, reliability, and operational risks associated with various resource options and how the action plan addresses these risks in the context of both the Business Plan and the 20-year Integrated Resource Plan. The company will identify who should bear such risk, the ratepayer or the stockholder.	The handling of resource risks is discussed in Volume I, Chapter 10 (Action Plan), and covers managing environmental risk for existing plants, risk management and hedging and treatment of customer and investment risk. Transmission expansion risks are discussed in Chapter 4 (Transmission). Resource capital cost uncertainty and technological risk is addressed in Volume I, Chapter 7 (Resource Options). For reliability risks, the stochastic simulation model incorporates stochastic volatility of forced outages for new thermal plants and hydro availability. These risks are factored into the comparative evaluation of portfolios and the selection of the preferred portfolio upon which the action plan is based. Identification of the classes of risk and how these risks are allocated to ratepayers and investors is discussed in Volume I, Chapter 10 (Action Plan).
4.i	Considerations permitting flexibility in the planning process so that the company can take advantage of opportunities and can prevent the premature foreclosure of options.	Flexibility in the planning and procurement processes is highlighted in Volume I, Chapter 10 (Action Plan).
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	PacifiCorp examined the trade-off between portfolio cost and risk, taking into consideration a broad range of resource alternatives defined with varying levels of dispatchability. This trade-off analysis is documented in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
4.k	A range, rather than attempts at precise quantification, of estimated external costs which may be intangible, 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.	PacifiCorp incorporated environmental externality costs for CO2 and costs for complying with current and proposed U.S. EPA regulatory requirements. For CO2 externality costs, the company used scenarios with various compliance requirements to capture a reasonable range of cost impacts. These modeling assumptions are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation 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 7 (Resource Options).
5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	PacifiCorp distributed draft IRP materials for external review throughout the process prior to each of the public-input meetings and solicited/and received feedback at various times when developing the 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.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
7	Acknowledgment of an acceptable Plan will not guarantee favorable ratemaking treatment of future resource acquisitions.	Not addressed; this is not a PacifiCorp activity.
8	The Integrated Resource Plan will be used in rate cases to evaluate the performance of the utility and to review avoided cost calculations.	Not addressed; this refers to a post-filing activity.

Table B.5 – Washington Utilities and Transportation Commission IRP Standard and Guidelines to Implement CETA Rules (RCW 19.280.030 and WAC 480-100-620 through WAC 480-100-630) per Commission General Order R-601.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-625(1) and (4)	Integrated resource plan updated every four years, with a progress report at least every two years.	The PacifiCorp IRP is published every two years with updates in the off cycles. This exceeds Washington State requirements.
WAC 480-100-620(1)	Unless otherwise stated, all assessments, evaluations, and forecasts comprising the plan should extend over the long-range (e.g., at least ten years; longer if appropriate to the life of the resources considered) planning horizon.	PacifiCorp's 2021 (and prior) IRPs span a 20 year long-term planning horizon. Additional analysis may extend beyond the 20-year horizon but not in the form of optimization modeling runs, as sufficient data is unavailable, resources insufficient and run times are impractical.
WAC 480-100-620(2)	Plan includes range of forecasts of projected customer demand that reflect effect of economic forces on electricity consumption.	Variant load forecast cases will include High/low load, 1-in-20 load, High/low private generation, and High/no customer preference. Other load variants will be considered on the basis of stakeholder feedback and model outcomes. A discussion of load forecasts will be included in a Load and Resource Balance chapter.
WAC 480-100-620(2)	Plan includes range of forecasts of projected customer demand that address changes in the number, type, and efficiency of electrical end-uses.	PacifiCorp has provided detail on load forecasts in Volume II, Appendix A (Load Forecast Details). Information can also be found in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(3)(a)	Plan includes load management assessments that are cost-effective and commercially available, including current and new policies and programs to obtain:	The IRP is informed by the company’s current conservation potential assessment, which is available on PacifiCorp’s website. Additional information on the load management assessments can be found in Volume II, Appendix D (Demand-Side Management Programs).
WAC 480-100-620(3)(a)	- all cost-effective conservation, efficiency, and load management improvements;	IRP modeling optimally selects all cost-effective energy efficiency and demand response in each case portfolio as a part of core model functionality. Results are reported for all portfolios in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-109-100(2)	- ten-year conservation potential used in the concurrent biennial conservation plan consistent with RCW 19.285.040(1);	The IRP is informed by the current conservation potential assessment, which is available on PacifiCorp’s website. Volume I, Chapter 6 (Load and Resource Balance) provides additional detail.
	- identification of opportunities to develop combined heat and power as an energy and capacity resource; and	Combined heat and power are addressed as a component of the Private Generation Study, which is included in Volume II, Appendix L (Private

		Generation Study).
No.	**Requirement**	**How the Guideline is Addressed in the 2021 IRP**
WAC 480-100-620(3)(b)	- all demand response (DR) at the lowest reasonable cost (LRC).	IRP modeling optimally selects all cost-effective energy efficiency and demand response in each case portfolio as a part of core model functionality. Results are reported for all portfolios in Volume II, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(3)(b)	Plan includes assessments of distributed energy programs and mechanisms pertaining to energy assistance and progress toward meeting energy assistance need, including but not limited to the following: - Energy efficiency and CPA, - Demand response potential, - Energy assistance potential	IRP modeling considers and selects energy efficiency and demand response potential, and distributed energy programs. Evaluation is detailed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(3)(b)	Plan assesses a forecast of distributed energy resources (DER) that may be installed by the utility's customers via a planning process pursuant to RCW 19.280.100(2).	PacifiCorp has worked with Guidehouse Consulting to prepare a Private Generation Study, which assesses distributed and customer-sited resources. Customer preference resources are also assessed as part of the portfolio selection process. Additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(3)(b)	Plan includes effect of DERs on the utility's load and operations.	The impacts of DERs on PacifiCorp's utility load and operations are assessed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach). Inputs are assessed as part of Volume II, Appendix L (Private Generation Study).
WAC 480-100-620(3)(b)	If utility engages in a DER planning process, which is strongly encouraged, IRP should include a summary of the process planning results.	PacifiCorp understands this requirement and will include a summary in future integrated resource plans, if applicable.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(4)	Plan assesses wide range of conventional generating resources.	PacifiCorp considered a wide range of resources including renewables, demand-side management, energy storage, distributed energy resources, power purchases, thermal resources, and transmission. Volume I, Chapter 7 (Resource Options) provides relevant detail on conventional generating resources.
WAC 480-100-620(5)	In making new investments, plan considers acquisition of existing and new renewable resources at LRC.	Cost and performance data for all resource types is evaluated and entered as a model input for the optimal selection of resources. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
See **WA-UTC energy storage policy statement** (UE-151069 & UE-161024 consolidated)	Plan assesses energy storage resources.	Energy storage resources are considered as part of the supply-side resource table, found in Volume I, Chapter 7 (Resource Options). Energy storage potential is assessed as part of Volume II, Appendix N.
WAC 480-100-620(5)	Plan assesses nonconventional generating, integration, and ancillary service technologies.	Compressed air storage and modular nuclear resources are represented in the Supply Resource Table, which is posted on PacifiCorp's IRP website and included as Volume I, Chapter 7 (Resource Options). All resource types are appropriately subject to integration and ancillary services determination, including transmission upgrade costs, reserve holding capability and additional reserve requirements that are particular to technologies. These factors are inherent to every portfolio optimization run.
WAC 480-100-620(6)	Plan assesses the availability of regional generation and transmission capacity for purposes of delivery of electricity to customers.	Regional generation is incorporated into market availability and price forecasts, which are described and analyzed in Volume I, Chapter 3 (Planning Environment), Chapter 5 (Reliability and Resiliency), and
WAC 480-100-620(6)	Plan assesses utility's regional transmission future needs and the extent	Regional transmission is represented through markets and region-based price forecasting, while PacifiCorp's transmission system is represented by firm

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
	transfer capability limitations may affect the future siting of resources.	transmission rights and endogenous transmission upgrade options. These factors will be discussed in the Resource Options, and Modeling and Portfolio Evaluation chapter of the IRP.
WAC 480-100-620(7)	Plan compares benefits and risks of purchasing power or building new resources.	As a component of core modeling functionality, all competing resources are evaluated to determine each optimal portfolio. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results)
WAC 480-100-620(7)	Plan compares all identified resources according to resource costs, including:	The comparison of resources on a cost-risk basis is core functionality of PacifiCorp's optimization modeling. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(7)	- transmission and distribution delivery costs;	PacifiCorp's transmission system is represented by firm transmission rights and endogenous transmission upgrade options. Transmission dependencies implying additional resource costs are included in the optimization, resulting in a reasonable comparison of resource costs. Additional information can be found in Volume I, Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation), and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(7)	- risks, including environmental effects and the social cost of GHG emissions;	The Company has conducted five core SC-GHG cases, each to be evaluated under a range of price-policy conditions and which will compete with other cases for CETA compliance and preferred portfolio selection. The cases evaluated are described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(7)	- benefits accruing to the utility, customers, and program participants (when applicable); and	Benefits are characterized by present value revenue requirement differentials, emissions, reserve and load deficiencies, robustness across stochastic variances and additional factors as may emerge from modeling results. A summary of benefits accruing is included as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(7)	- resource preference public policies adopted by WA State or the federal government.	The preferred portfolio selected in the 2021 IRP process is compliant with all policy requirements. A summary of the policy environment is included as Volume I, Chapter 3 (Planning Environment), and a description of the portfolio runs in compliance with policy is included as Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(7)	Plan includes methods, commercially available technologies, or facilities for integrating renewable resources, including but not limited to battery storage and pumped storage, and addressing overgeneration events.	IRP modeling endogenously considers "overgeneration" in dispatch and curtails resources appropriately. These curtailments are an inherent component of the cost and risk valuation of each portfolio, and is a driver for the optimal size, type and location of selected resources.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(8)	Plan assesses and determines resource adequacy metrics.	For the 2021 IRP, resource adequacy is evaluated as a core model function, where each portfolio is obligated to meet reliability requirements including varying degrees of quality of operating reserves. This is described in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(8)	Plan identifies an appropriate resource adequacy requirement.	PacifiCorp has addressed this requirement as described in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(8)	Plan measures corresponding resource adequacy metric consistent with prudent utility practice in eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030), attaining GHG neutrality by 1/1/2030 (RCW 19.405.040), and achieving 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050).	PacifiCorp has addressed this requirement as described in Volume I, Chapter 6 (Load and Resource Balance), Chapter 8 (Modeling and Portfolio Evaluation Approach), and Chapter 9 (Modeling and Portfolio Selection Results). Additional information on the Washington-specific portfolio view is available in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(9)	Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:	PacifiCorp has incorporated information from the Cumulative Impact Analysis, the Washington Tracking Network, and the US Census. Information derived from the Cumulative Impact Analysis is included in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(9)	- energy and nonenergy benefits;	PacifiCorp analyzes energy benefits within selection of the preferred portfolio. Non-energy benefits are included with DSM measures, and additional nonenergy benefits are qualitatively discussed within Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(9)	- reduction of burdens to vulnerable populations and highly impacted communities;	A preliminary identification of burdens to vulnerable populations and highly-impacted communities has been made through data publicly available through the Cumulative Impacts Analysis, Washington Tracking Network, and the US Census, and included in Volume II, Appendix O (Washington Clean Energy Action Plan). PacifiCorp will continue to refine this data in consultations with the public and advisory groups moving forward.
WAC 480-100-620(9)	- long-term and short-term public health and environmental benefits, costs, and	A preliminary identification of burdens to vulnerable populations and highly-impacted communities has been made through data publicly available through the Cumulative Impacts Analysis, Washington Tracking Network, and the US Census, and included in Volume II, Appendix O (Washington Clean Energy Action Plan). PacifiCorp will continue to refine this data in consultations with the public and advisory groups moving forward.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(9)	- long-term and short-term public health and environmental risks; and	A preliminary identification of burdens to vulnerable populations and highly impacted communities has been made through data publicly available through the Cumulative Impacts Analysis, Washington Tracking Network, and the US Census, and included in Volume II, Appendix O (Washington Clean Energy Action Plan). PacifiCorp will continue to refine this data in consultations with the public and advisory groups moving forward.
WAC 480-100-620(9)	- energy security and risk.	PacifiCorp addresses energy security and risk throughout the IRP, and specifically addresses this in Volume I, Chapter 5 (Reliability and Resiliency) and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(10)	Utility should include a range of possible future scenarios and input sensitivities for testing the robustness of the utility's resource portfolio under various parameters, including the following required components:	A wide range of cases and sensitivities under various price-policy futures have been included, as discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(10)	*CETA counter factual scenario* - describe the alternative LRC and reasonably available portfolio that the utility would have implemented if not for the requirement to comply with RCW 19.405.040 and RCW 19.405.050, as described in WAC 480-100-660(1).	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(10)	*Climate change scenario* - incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(10)	*Maximum customer benefit sensitivity* - model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(11)	Plan must integrate demand forecasts and resource evaluations into a long-range IRP solution.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(11)	IRP solution or preferred portfolio must describe the resource mix that meets current and projected needs.	PacifiCorp has met this requirement – additional detail can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(11)(a)	Preferred portfolio must include narrative explanation of the decisions made, including how the utility's long-range IRP solution:	
WAC 480-100-620(11)(a)	- achieves requirements for eliminating coal-fired generation by 12/31/2025 (RCW 19.405.030);	PacifiCorp will remove coal-fired generation from Washington's allocation of electricity by 2025 and will continue to analyze this pending further resolution of interpretive issues by the Commission. Additional information can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(11)(a)	- attains GHG neutrality by 1/1/2030 (RCW 19.405.040); and	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection Results).
WAC 480-100-620(11)(a)	- achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050) at LRC,	This is outside of the 2021 IRP timeline, but generally may be addressed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(11)(a)	- achieves 100 percent clean electricity WA retail sales by 1/1/2045 (RCW 19.405.050), considering risk.	This is outside of the 2021 IRP timeline, but the pathway to 2045 is generally addressed as part of Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(11)(c)	Consistent with RCW 19.285.040(1), preferred portfolio shows pursuit of all cost-effective, reliable, and feasible conservation and efficiency resources, and DR.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(11)(d) and (e)	Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, insofar as doing so is at LRC,	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(11)(d) and (e)	Preferred portfolio considers acquisition of existing renewable new resources and relies on renewable resources and energy storage, considering risks.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(11)(f)	Preferred portfolio maintains and protects the safety, reliable operation, and balancing of the utility's electric system, including mitigating over-generation events and achieving identified resource adequacy requirements.	PacifiCorp has met this requirement. Additional information can be found in Volume I, Chapter 6 (Load and Resource Balance).

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(11)(g)	Preferred portfolio ensures all customers are benefiting from the transition to clean energy through the:	
WAC 480-100-620(11)(g)	- equitable distribution of energy and nonenergy benefits; reduction of burdens to vulnerable populations and highly impacted communities;	This is discussed as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(11)(g)	- long-term and short-term public health and environmental benefits; reduction of costs and risks; and	This is discussed as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(11)(g)	- energy security and resiliency.	This is discussed as part of Volume I, Chapter 5 (Reliability and Resiliency), Chapter 6 (Load and Resource Balance), and Chapter 9 (Modeling and Portfolio Evaluation Results).
WAC 480-100-620(11)(h)	Preferred portfolio: assesses the environmental health impacts to highly impacted communities,	This is discussed as part of Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(11)(i)	- analyzes and considers combinations of DER costs, benefits, and operational characteristics (incl. ancillary services) to meet system needs,	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(11)(j)	- incorporates the social cost of GHG emissions as a cost adder.	Detail is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(12)	Utility must develop a ten-year **clean energy action plan** (CEAP) for implementing RCW 19.405.030 through 19.405.050 at LRC, and at an acceptable resource adequacy standard. The CEAP will:	
WAC 480-100-620(12)(b)	- identify and be informed by utility's ten-year CPA per RCW 19.285.040(1);	The Washington Clean Energy Action Plan is informed by the 10-year CPA, which can be found on PacifiCorp's website.
WAC 480-100-620(12)(c)	- demonstrate that all customers are benefiting from the transition to clean energy;	This requirement is included in Volume II, Appendix O (Washington Clean Energy Action Plan), which discusses vulnerable populations and highly-impacted communities and a discussion of benefits from the preferred portfolio.
WAC 480-100-620(12)(d)	- establish a resource adequacy requirement;	PacifiCorp establishes resource adequacy at a system level, and the resource adequacy requirement is explained in Volume I, Chapter 6 (Load and Resource Balance).
WAC 480-100-620(12)(e)	- identify the potential cost-effective DR and load management programs that may be acquired;	This requirement is met in Volume I, Chapter 9 (Modeling and Portfolio Selection Results). A summary of DR and load management programs in Washington are included in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(12)(f)	- identify renewable resources, nonemitting electric generation, and DERs that may be acquired and evaluate how each identified resource may be expected to contribute to meeting the utility's resource adequacy requirement;	This is described at the system-level as part of PacifiCorp's resource planning process. Volume I, Chapter 7 (Resource Options), Chapter 8 (Modeling and Portfolio Evaluation Approach), and Chapter 9 (Modeling and Portfolio Selection) provide additional detail.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(12)(g)	- identify any need to develop new, or expand or upgrade existing, bulk transmission and distribution facilities; and	This is described at the system level in Volume I, Chapter 4 (Transmission) and also within PacifiCorp's action plan (Volume I, Chapter 10).
WAC 480-100-620(12)(h)	- identify the nature and possible extent to which the utility may need to rely on alternative compliance options, if appropriate.	This requirement is addressed in Volume II, Appendix O (Washington Clean Energy Action Plan).
WAC 480-100-620(12)(i)	Plan (both IRP and CEAP) considers cost of greenhouse gas emissions as a **cost adder** equal to the cost per metric ton of carbon dioxide emissions, using the two and one-half percent discount rate, listed in Table 2, Technical Support Document: Technical update of the social cost of carbon (SCC) for regulatory impact analysis under Executive Order 12866, published by the interagency working group on social cost of greenhouse gases of the United States government, August 2016, as adjusted by the Commission to reflect the effect of inflation.	This requirement will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section. For the IRP, this requirement will be included as part of the "Modeling and Portfolio Evaluation Approach" section.
WAC 480-100-620(13)	Plan must include an analysis and summary of the estimated avoided cost for each supply- and demand-side resource, including (but not limited to):	
WAC 480-100-620(13)	- energy,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- capacity,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- transmission,	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- distribution, and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(13)	- GHG emissions.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-100-620(13)	Listed energy and non-energy impacts should specify to which source party they accrue (e.g., utility, customers, participants, vulnerable populations, highly impacted communities, general public).	PacifiCorp provides a preliminary determination of accrual of energy and non-energy benefits within Volume II, Appendix O (Washington Clean Energy Action Plan).

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
WAC 480-106-040	Plan provides information and analysis used to inform annual purchases of electricity from qualifying facilities, including a description of the:	
WAC 480-106-040	- avoided cost calculation methodology used;	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-106-040	- avoided cost methodology of energy, capacity, transmission, distribution, and emissions averaged across the utility; and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-106-040	- resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost, including (but not limited to): cost assumptions, production estimates, peak capacity contribution estimates, and annual capacity factor estimates.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(14)	To maximize transparency, the utility should submit data input files supporting the plan in native file format (e.g., supporting spreadsheets in Excel, not PDF file format).	PacifiCorp will make data available in the native file format consistent with practice in prior IRPs.
WAC 480-100-620(15)	Information relating to purchases of electricity from qualifying facilities. Each utility must provide information and analysis that it will use to inform its annual filings required under chapter 480-106 WAC. The detailed analysis must include, but is not limited to, the following components:	
WAC 480-100-620(15)(a)	A description of the methodology used to calculate estimates of the avoided cost of energy, capacity, transmission, distribution and emissions averaged across the utility; and	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(15)(b)	(b) Resource assumptions and market forecasts used in the utility's schedule of estimated avoided cost required in WAC 480-106-040 including, but not limited to, cost assumptions, production estimates, peak capacity contribution estimates and annual capacity factor estimates.	The estimated avoided cost will be based on the values determined through the IRP modeling process. Values can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).
WAC 480-100-620(16)	Plan must summarize substantive changes to modeling methodologies or inputs that change the utility's resource need, as compared to the utility's previous IRP.	An assessment of modeling methodology is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
WAC 480-100-620(17)	Utility must summarize:	
WAC 480-100-620(17)	- public comments received on the draft IRP,	This is included in Volume II, Appendix C (Public Input).

WAC 480-100-620(17)	- utility's responses to public comments, and	This is included in Volume II, Appendix C (Public Input).
WAC 480-100-620(17)	- whether final plan addresses and incorporates comments raised.	This is included in Volume II, Appendix C (Public Input).

Table B.6 – Wyoming Public Service Commission Guideline

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
A	The public comment process employed as part of the formulation of the utility's IRP, including a description, timing and weight given to the public process;	PacifiCorp's public process is described in Volume I, Chapter 2 (Introduction) and in Volume II, Appendix C (Public Input).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 9 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 10 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 6 (Load and Resource Balance).
D	A study detailing the types of resources considered;	Volume, I Chapter 7 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.
E	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2021 IRP is presented in Volume I, Chapter 10 (Action Plan). A chart comparing the peak load forecasts for the 2019 IRP, and 2021 IRP is included in Volume II, Appendix A (Load Forecast Details).
F	The environmental impacts considered;	Portfolio comparisons for CO2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection) as well as Volume II, Appendix J (Stochastic Simulation Results).
G	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in the 2021 IRP.
H	Reserve Margin analysis; and	Reserve margin analysis is included in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).
I	Demand-side management and conservation options;	See Volume I, Chapter 7 (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 2021 IRP from the beginning. The public-input meetings held beginning in January 2020 were the cornerstone of the direct public- input process, and there have been a total of 18 public-input meetings held as part of the 2021 IRP development cycle. Due to restrictions and concerns surroundings COVID-19, all meetings have been held via phone conference, with no in-person participation.

The IRP public-input process also included state-specific stakeholder dialogue sessions held in July 2020. The goal of these sessions was to capture key IRP issues of most concern to each state, as well as to discuss how to tackle these issues from a system planning perspective. PacifiCorp wanted to ensure stakeholders understood IRP planning principles. These meetings continued to enhance interaction with stakeholders in the planning cycle and provided a forum to directly address stakeholder concerns regarding equitable representation of state interests during public- input meetings.

PacifiCorp solicited agenda item recommendations from stakeholders in advance of the state meetings. There was additional open time to ensure participants had adequate opportunity for dialogue.

PacifiCorp's integrated resource plan website houses feedback forms included in this filing. This standardized form allows stakeholders to provide comments, questions, and suggestions. PacifiCorp also posts its responses to the feedback forms at the same location. Feedback forms and PacifiCorp's responses can be found via the following link: https://www.pacificorp.com/energy/integrated-resource-plan/comments.html.

Participant List

PacifiCorp's 2021 IRP continues to be a robust process involving input from many parties. Participants included commissions, stakeholders, and industry experts. Among the organizations that have been represented and actively involved in this collaborative effort are:

Commissions

- California Public Utilities Commission
- Idaho Public Utilities Commission
- Oregon Public Utility Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission

- Wyoming Public Service Commission

Stakeholders and Industry Experts

- 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
- 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
- Renewable 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 Counsel 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 continued time and energy that participants have given to the IRP process. Their participation has contributed significantly to the quality of this plan.

Public-Input Meetings

As mentioned above, PacifiCorp has hosted 10 public-input meetings, as well as six state meetings during the public-input process, with two additional public-input meeting scheduled for early 2021. During the 2021 IRP public-input process presentations and discussions have covered various issues regarding inputs, assumptions, risks, modeling techniques, and analytical results. Below are the agendas from the public-input meetings; the presentations can be located at:

https://www.pacificorp.com/energy/integrated-resource-plan/public-input-process.html

General Meetings

January 21, 2020 – Conservation Potential Assessment (CPA) Technical Workshop 1 (Conference Call)

- Conservation Potential Assessment Overview
- Key Changes and Updates for the 2021 CPA
- Market Characterization and Baseline Development
- Measure Characterization and Potential Estimation
- 2021 CPA Work Plan

February 18, 2020 – CPA Technical Workshop 2 (Conference Call)

- Energy Efficiency
- Measure List Changes
- Demand Response
- Resource Options and Examples

April 16, 2020 – CPA Technical Workshop 3 (Conference Call)

- CPA Schedule and Milestones
- Stakeholder Feedback
- Recap of Key Discussion Topics From Prior Workshops
- Drivers of difference in Forecasted Potential by State

June 18-19, 2020 – General Public Meeting (Conference Call)

Day One

- Stakeholder Feedback Form Update
- CPA Update
- Optimization Modeling and Modeling Update
- Modeling Energy

Storage Day Two

- 2019 IRP Highlights/ 2021 IRP Topics and Timeline
- Request for Proposal (RFP) Update
- Transmission Overview and Update

July 30-31, 2020 – General Public Meeting (Conference Call)

Day One

- Load Forecast Update
- Distribution System Planning
- Supply-side Resource Study Efforts
- Endogenous Retirement

Discussion Day Two

- Environmental Policy
- Renewable Portfolio Standards
- DMS Bundling Portfolio Methodology
- Private Generation Study
- Stakeholder Feedback Form Recap

August 28, 2020 – CPA Technical Workshop 4 (Conference Call)

- 2021 CPA Process Review
- Energy Efficiency Potential Draft Results
- Demand Response Potential Draft Results

September 17, 2020 – General Public Meeting (Conference Call)

- Supply-side Resources
- Portfolio Development Discussion
- State Policy Update
- Conservation Potential Assessment Update
- Stakeholder Feedback Form Recap

October 22, 2020 – General Public Meeting (Conference Call)

- Supply-Side Resource Table Results
- Conservation Potential Assessment Final Results
- Energy Efficiency Bundling Methodology

- Market Reliance Assessment
- PLEXOS Benchmark Update
- Environmental Policy: Regional Haze Update
- Stakeholder Feedback Form Recap

November 16, 2020 – General Public Meeting (Conference Call)
- PLEXOS Benchmark Update
- Modeling Assumptions Update
- All Source Request for Proposals Update
- Stakeholder Feedback Form Recap

December 3, 2020 – General Public Meeting (Conference Call Only)
- Portfolio Development
- Carbon Capture Supply-Side Resource Table
- Price Curve and Customer Preference Update
- Transmission Modeling Assumptions
- Stakeholder Feedback Form Recap

January 29, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Energy Efficiency Bundling Methodology
- Multi-State Process and Extended Day-Ahead Market Update
- Stakeholder Feedback Form Recap

February 10, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Discussion of current IRP status
- Stakeholder Feedback Form Recap

April 22-23, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Update on IRP filing extension regulatory process
- Discussion of RFP status
- Stakeholder Feedback Form Recap

June 25, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Discussion of portfolios due to incorporation of AS RFP final short list results, discussion of cost and risk portfolio analysis; opportunity for stakeholder feedback.

July 30, 2021 – General Public Meeting (Conference Call and Teams Meeting)
- Discuss selection of portfolio optimization and portfolio modeling progress, update on state energy policy; opportunity for stakeholder feedback.

August 6, 2021 – General Public Meeting (Conference Call and Teams Meeting)

- Discussion of portfolio modeling – including sensitivities and scenario runs.

August 27, 2021 – General Public Meeting (Conference Call and Teams Meeting)

- Review portfolio modeling, portfolio development process, and preferred portfolio.

State-Specific Input Meetings

July 22, 2020 – Utah State Stakeholder Meeting
July 22, 2020 – Washington State Stakeholder Meeting
July 23, 2020 – Wyoming State Stakeholder Meeting
July 24, 2020 – Oregon State Stakeholder Meeting

Stakeholder Comments

For the 2021 IRP, PacifiCorp offered a Stakeholder Feedback Form which provided stakeholders a direct opportunity to provide comments, questions, and suggestions in addition to the opportunities for discussion at public-input meetings. PacifiCorp recognizes the importance of stakeholder feedback to the IRP public-input process. A blank form, as well as those submitted by stakeholders and PacifiCorp's response, can be located on the PacifiCorp website at the IRP comments webpage at: www.pacificorp.com/energy/integrated-resource-plan/comments.html.

As of August 31, 2021, PacifiCorp has received 91 Stakeholder Feedback Forms with over 480 questions, comments, and recommendations. The Stakeholder Feedback Forms have allowed the company to review and summarize issues by topic as well as identify specific recommendations that were provided. Information collected is used to inform the 2021 IRP development process, including feedback related to process improvements and input assumptions, as well as responding directly to stakeholder questions. So far, Stakeholder Feedback Forms have been received from the following stakeholders:

- Able Grid Energy Solutions
- City of Kemmerer, Wyoming
- Cadmus Group
- Idaho Conservation League
- Idaho Public Utility Commission Staff
- Individual Stakeholders
- Interwest Energy Alliance
- Northwest Energy Coalition
- Oregon Citizens' Utility Board
- Oregon Public Utility Commission Staff
- Powder River Basin Resource Council
- Renewable Northwest
- Sierra Club
- Southwest Energy Efficiency Project

- Utah Clean Energy
- Utah Valley Earth Forum
- Washington Utilities and Transportation Commission Staff
- Western Resource Advocates
- Wyoming Industrial Energy Consumers
- Wyoming Office of Consumer Advocate

A discussion of topics included in the stakeholder feedback forms and how those topics were considered in the IRP are as follows:

Carbon Price

Sierra Club requested additional information on carbon pricing (which PacifiCorp subsequently presented as part of the November 16, 2020 IRP public-input meeting) and a scenario where carbon pricing would be applied in only some of the company's jurisdictions. PacifiCorp included carbon price sensitivities, but the price was applied across all jurisdictions.[1]

Coal Analysis

Washington Utilities and Transportation Commission Staff asked for more information about the cost and physical supply risk of coal fuel to the Colstrip plant. PacifiCorp responded that the IRP modeling considers fuel price in dispatch decisions, and while fuel-supply risk is not explicitly modeled in the IRP, the modeling does consider operational characteristic for heat rates, minimum-up and maximum-down times, ramp rates, and minimum capacity for dispatch decisions.[2]

Washington Utilities and Transportation Commission staff asked about supply-risk of fuel and potential market alternatives to the continued operation of the Jim Bridger mine. PacifiCorp responded that IRP modeling considers fuel price in dispatch decisions, and the dispatch cost of a facility is compared to the sales market price to determine whether the operation or sale is economic and providing a net benefit to customers.[3]

The City of Kemmerer asked that PacifiCorp include carbon capture and coal gasification technology be included in the 2021 IRP. PacifiCorp has included consideration in the 2021 IRP, and discussed these technologies specifically in the September 17, 2020 public input meeting.[4]

Washington Utilities and Transportation Commission Staff requested an economic analysis of closing/divesting Colstrip units 3 and 4 earlier than 2025. PacifiCorp and staff agreed to a "bookend" approach by developing cases that would close/divest Colstrip as early as the end of 2022 and as late as 2027.[5]

Sierra Club requested additional information on the cost assumptions for major coal unit overhauls, whether those overhauls include pollution control technology, coal operating limits, and operating

[1] Feedback Form 052; October 19, 2020
[2] Feedback Form 013; June 26, 2020
[3] Feedback Form 013; June 26, 2020
[4] Feedback Form 025; August 28, 2020
[5] Feedback Form 069; December 11, 2020

variant assumptions. PacifiCorp provided the requested detail in the feedback form response.[6] Sierra Club asked a follow up requesting more information on the definitions of operating limits, which PacifiCorp provided.[7] Sierra Club further requested information on pricing tiers and how fuel considerations were modeled within Plexos.[8]

Catriona Buhayar expressed concern regarding ongoing investment into coal power plants over the next ten years rather than focusing on retirement and investment in renewables. PacifiCorp responded that all options were being considered and the supply-side table provides additional information regarding potential resources for future investment.[9]

Wyoming Public Service Commission Staff requested additional information regarding what would be considered in the coal-fueled resource decommissioning studies and reassignment filings and the extent to which those inputs would be included in the 2021 IRP. PacifiCorp provided the requested detail as part of the feedback form response.[10]

Conservation Potential Assessment (CPA)/Energy Efficiency/Demand Response

Utah Valley Earth Forum requested that the company provide more attention for renewable-fuel power generation or for conventional cogeneration for the purposes of improving grid efficiency and resilience.[11]

Utah Valley Earth Forum provided a list of potential additions to the 20221 Residential Measure list. PacifiCorp provided explanations of which were currently included, and which could be considered in the 2021 CPA.

Southwest Energy Efficiency Project and Utah Clean Energy jointly made multiple recommendations as part of the CPA process:

- The CPA should look at the potential for demand response to expand potential beyond capacity and consider how it could offer services such as frequency regulation and contingency reserves. PacifiCorp addressed this recommendation at the February 18, 2020 IRP Public-Input meeting and noted that in the 2019 IRP, there was a credit applied for operating reserves for DR, which also tried to capture grid services benefits through "ancillary services."

- The CPA should assess the potential for DR to shift load on a daily basis to help integrate renewables. PacifiCorp responded that it was open to exploring ways of adapting modeling tools to provide this functionality but noted that DR was not as controllable as battery storage.

- The 2021 CPA should not assign the full cost of DR enabling technologies to the

[6] Feedback Form 071; December 18, 2020
[7] Feedback Form 078; April 13, 2021
[8] Feedback Form 085; August 3, 2021
[9] Feedback Form 072; January 19, 2021
[10] Feedback Form 076; February 10, 2021

levelized cost of DR. PacifiCorp committed to revisiting the costs for all measures and will consider cost assumption recommendations through the CPA stakeholder engagement process.

- The CPA should consider the impacts of interactive effects between energy efficiency and DR in all states, including those that use the Utility Cost Test. PacifiCorp noted that in the 2019 CPA, the company discounted participant costs in California, Oregon, Washington, and Wyoming to account for DR and energy efficiency interactions. For the 2021 CPA, the company committed to investigating the treatment of cost proxies in all states.

- Additional information should be provided regarding the methodology to treat interactive effects between DR and pricing and rates measures (as pricing and rates potential is not included in the IRP modeling process). PacifiCorp responded that DR is included in the IRP model, and pricing and rates programs are accounted for in the IRP load forecast.

- The CPA should include a low, medium, and high case for Technically Achievable Potential. PacifiCorp responded that it would consider this request as the 2021 CPA progress progressed.

- Request for transparency regarding assumptions for Market Adoption Rates and any corrections. PacifiCorp committed to providing stakeholders an opportunity to review measure adoption rates during the CPA development process and any "outside" the model changes that could affect the technical potential.

- Requested analysis for measure-level levelized cost and supply assumptions from 2019, 2017, and 2015 CPAs with historical measure-level cost and program achievements in each jurisdiction. PacifiCorp committed to conducting a subset of that analysis as part of the 2021 CPA.

Utah Clean Energy sought additional information regarding how "emerging" CPA and DSM measures were treated compared to standard DSM measures. PacifiCorp noted that there is no inherent difference (save for potentially a faster ramp rate), but that the company would work with Utah Clean Energy and Southwest Energy Efficiency Project to explore the possibility of modeling declining cost within the 2021 IRP for emerging technologies.

Utah Clean Energy provided recommendations on which measures should be considered "emerging." PacifiCorp considered this feedback and ultimately removed the "emerging" distinction from a number of measures.

Utah Clean Energy requested additional information regarding technical achievable potential, data underlying light-emitting diode market adoption, and other conservation potential assumptions. PacifiCorp responded to all questions and provided data as requested.[12]

The Oregon Citizen's Utility Board made a number of recommendations regarding low-income assistance, moving the Oregon Irrigation Load Control beyond a pilot program, and pricing and

[12] Feedback Form 036; September 18, 2020

rates recommendations. PacifiCorp noted that it was extending the Oregon program and appreciated the suggestion for low-income assistance. PacifiCorp referred pricing recommendations to the (then) ongoing general rate case.

Staff of the Washington Utilities and Transportation Commission provided recommendations that would increase the accessibility of reviewing CPA measures, including a "crosswalk" that would allow comparison of approaches, measures grouped by program option, ability to save spreadsheets locally, and expanded abbreviations. PacifiCorp removed password protection on the online copies of the workbooks so that they could be saved, provided an "introduction" spreadsheet within each list that defines terms, and provided an explanation of how a "crosswalk" could be derived from materials on the PacifiCorp website.

Staff of the Oregon Public Utility Commission requested additional information regarding whether the costs for a residential smart thermostat have been updated with advanced metering infrastructure deployment complete. PacifiCorp responded that projects that were reliant on advanced metering infrastructure were only analyzed after the advanced metering infrastructure was assumed to be deployed. Additional information is included in the 2019 CPA.[13][14][15] Staff further recommended that the company follow the California Public Utilities Commission's methodology for program incentives and recommended participant cost values. PacifiCorp incorporated all recommendations.[16]

Southwest Energy Efficiency Project and Utah Clean Energy also provided feedback on the Conservation Potential Assessment workplan process in general, including providing all inputs, assumptions, and draft output tables be provided to stakeholders in Excel format by year, as well as considering ways to make scheduling more accessible. PacifiCorp

Cadmus Group requested the conservation supply curves generated in support of the IRP. PacifiCorp provided the requested data in the feedback form response.[17]

Southwest Energy Efficiency Project and Utah Clean Energy provided a number of recommendations to update conservation potential assessments results for actual program performance. PacifiCorp requested any workpapers underlying the recommendations and engaged with parties to implement any needed changes. [18]

Oregon Public Utility Commission Staff requested additional information regarding why Direct Load Control demand response programs have not been proposed as pilots in PACW, requested information regarding why the "large project adder" was removed from the Oregon projection, and requested information on other modeling inputs. PacifiCorp responded that Direct Load Control pilots have not been identified as cost-effective in PACW, and provided other information requested as part of the stakeholder feedback form response.[19]

[13] Feedback Form 010; May 4, 2020
[14] Feedback Form 011; May 4, 2020
[15] Feedback Form 012; May 4, 2020
[16] Feedback Form 034; September 15, 2020
[17] Feedback Form 048; October 4, 2020
[18] Feedback Form 049; October 9, 2020
[19] Feedback Form 050; October 16, 2020

Washington Utilities and Transportation Commission Staff requested additional information regarding costs, total resource cost tests, and resource acquisition levels to be included in the IRP. PacifiCorp provided the requested detail in the feedback form response.[20]

Southwest Energy Efficiency Project raised questions with the energy efficiency measure results and achievable technical potential. PacifiCorp provided additional detail in the feedback form response.[21]

Consultant Reports

The Wyoming Public Service Commission asked whether/how the 2021 IRP would include the costs and reliability effects of the Kiewit decommissioning studies (including the other items to consider and contingency percentage). PacifiCorp responded that the 2021 IRP will include base estimate demolition costs from the 2019 decommissioning study for the coal-fueled generating units, will include “take-or-pay” provisions, and will not include contingency reserves as they cannot reliably be estimated at an acceptable level of granularity at this time.

Customer Preference

Sierra Club requested additional detail regarding the incremental costs or savings from customer preference resources, a list of what actions “customer preference” includes, and detail on the customer preference slides shown during the December 3, 2020 IRP public input meeting. PacifiCorp responded with the requested detail within the feedback form.[22]

Distributed Energy Resources

Washington Utilities and Transportation Commission Staff requested additional detail regarding how PacifiCorp plans for allowable levels of distributed energy resources on the system, including quantifying benefits of distributed resources. PacifiCorp held a call with Staff on December 7, 2020 to discuss the questions and provide responses.[23]

Energy Efficiency

City of Kemmerer requested a technical conference to discuss “supply-side energy efficiency” of various technology types, as well as analysis of costs and subsidies. PacifiCorp responded that resource efficiency as described in the request is roughly equivalent to levelized cost of energy per resource type, which is included in Chapter 6 of the IRP.[24]

Oregon Public Utility Commission Staff requested confirmation that there would be an opportunity to discuss bundling methodologies in accordance with Oregon Order No. 20-186. PacifiCorp addressed the topic during the October 2020 public input meeting.[25]

[20] Feedback Form 056; November 3, 2020
[21] Feedback Form 068; December 4, 2020
[22] Feedback Form 071; December 18, 2020
[23] Feedback Form 056; November 3, 2020
[24] Feedback Form.021; August 28, 2020
[25] Feedback Form 041; September 28, 2020

Oregon Public Utility Commission Staff requested additional information regarding energy efficiency bundling methodology. PacifiCorp provided information in response to the stakeholder feedback form and held a follow-up discussion as part of the January IRP public-input meeting.[26]

Washington Utilities and Transportation Commission Staff provided recommendations and requests for detail regarding energy efficiency, energy efficiency and renewable energy shaping, and load shapes. PacifiCorp responded to requests for information through the feedback form process, and recommendations for energy efficiency and renewable energy shaping will be considered in future planning cycles.[27]

Energy Storage

Utah Valley Earth Forum recommended that PacifiCorp avoid lithium batteries to facilitate development of the market for the construction of electric vehicles. PacifiCorp responded that lithium-ion batteries are the most competitive energy storage technology (as of the 2019 IRP), but that IRP modeling does not focus on specific battery chemistry. PacifiCorp has commissioned a study of cost and performance characteristics of renewable resources as well as energy storage.[28]

Renewable Northwest emphasized that co-located energy storage and renewables provided flexibility and regional grid benefits, and that co-location should be encouraged. Renewable Northwest also encouraged an independent analysis at the balancing authority level to evaluate whether battery storage systems can provide benefits for peak hours in a year. PacifiCorp replied that the company currently evaluates alternative solutions to planned transmission and distribution upgrades, and battery storage is a potential alternative.[29]

Oregon Citizen's Utility Board requested additional information regarding how battery storage will be modeled in the IRP and whether the IRP will account for interactive effects of Direct Load Control and Price-based Demand Response programs. PacifiCorp responded that battery storage is modeled on a state-by-state basis, and that Direct Load Control is taken into account. While not a direct modeling input, the effects of Price-based Demand Response programs are included in the load forecast.[30]

Oregon Public Utility Commission Staff requested additional information on the solar plus storage constraints presented during the June 2020 public input meeting, as well as whether there are any constraints that would prevent the company from adding storage capacity to variable energy resources. PacifiCorp responded to these requests and discussed how the IRP's aggregated topology eliminates the need to co-locate as long as the resources are in the same transmission bubble. A discussion of constraints was discussed in the feedback form response.[31]

Able Grid Energy Solutions provided recommendations and data to support the inclusion of energy storage in the supply-side resource table and within portfolio modeling.[32]

[26] Feedback Form 063; November 17, 2020
[27] Feedback Form 074; February 4, 2021
[28] Feedback Form 014; June 27, 2020
[29] Feedback Form 015; June 29, 2020
[30] Feedback Form 031; September 9, 2020
[31] Feedback Form 032; September 10, 2020
[32] Feedback Form 055; October 26, 2020

Environmental Policy

Powder River Basin Resource Council requested a follow-up to the October 2020 discussion on regional haze, including a discussion of what the "baseline" case is for regional haze. PacifiCorp held a follow-up discussion as part of the November 16, 2020 IRP public-input meeting.[33]

Powder River Basin Resource Council requested additional data on how risk, cost, and benefits regarding water use and water rights would be incorporated for coal-fired generation. PacifiCorp provided the additional detail requested in the feedback form response.[34]

IRP Public-Input Meeting Process/General Comments

Utah Association of Energy Users requested more detail on how the company planned to allow opportunities for stakeholder feedback, given the extension of IRP filing to September 1, 2021 and the cancellation of the May public input meetings. PacifiCorp subsequently added a public-input meeting date in August to provide greater opportunity for feedback.[35]

Derek Sawaya provided a recommendation to transition to net-zero [emitting] energy as quickly as possible. PacifiCorp considered this feedback as part of the portfolio modeling process, and the preferred portfolio shows CO2 emissions reductions of 98% from 2005 levels by 2050.[36]

Utah Office of Consumer Services recommended the inclusion of customer rate impacts analysis within the IRP. PacifiCorp analyzes the present value revenue requirement of different portfolios as part of the portfolio selection process.[37]

Legislation

Utah Association of Energy Users asked for additional detail on Oregon House Bill 2021 and how it may impact the 2021 IRP. PacifiCorp discussed HB 2021 during the July 30, 2021 IRP public-input meeting.[38]

Load Forecasting

Utah Clean Energy asked for additional information on the electric vehicle and building electrification forecasts used to estimate increased sales. PacifiCorp responded that EV growth projections are unique to each state (and provided more information as an attachment) and clarified that the building electrification projections were based on the outcome of HB 421 in Utah.[39]

Oregon Public Utility Commission Staff requested to review the company's load forecast methodology, which is included in the 2019 IRP, Appendix A. The company further responded to

[33] Feedback Form 053; October 24, 2020
[34] Feedback Form 054; October 24, 2020
[35] Feedback Form 080; May 25, 2021
[36] Feedback Form 086; August 3, 2021
[37] Feedback Form 089; August 12, 2021
[38] Feedback Form 082; June 28, 2021
[39] Feedback Form 019; August 6, 2020

Staff's request for more information on low and high private generation load forecast sensitivities, and explained that the underlying load forecast methodology underlying the IRP and Oregon Docket UE 374 (Oregon 2020 General Rate Case) is the same.[40]

Oregon Public Utility Commission Staff requested more detail on how renewable load correlation method considers differences on the west and east sides of PacifiCorp's system. PacifiCorp provided the requested detail in the feedback form response.[41]

Market Reliance Assessment

Sierra Club requested additional information regarding what types of transactions are considered as part of "market reliance," which delivery points for market purchases and sales are available on the PacifiCorp system, and any planned assessments of the overall supply and availability of market resources over time. PacifiCorp responded that market reliance assumes short-term firm front office transactions which are assumed in planning to meet capacity needs. PacifiCorp provided additional information as requested by Sierra Club as part of the stakeholder feedback form response.[42]

Washington Utilities and Transportation Commission Staff requested additional information on the market reliance assessment, including how climate change is considered and what risk analyses have been incorporated to measure market liquidity trends. PacifiCorp provided the requested detail in the feedback form response.[43]

Oregon Public Utility Commission Staff requested additional information regarding the applicability of front-office transaction limits across all hours. PacifiCorp provided the requested information as part of the feedback form response.[44]

Modeling Assumptions

The Wyoming Public Service Commission recommended modeling scenarios that consider the possibility that all Rocky Mountain Power states decline the additional load and costs within the reassignment filings. PacifiCorp responded that it would be considered for inclusion in the 2021 IRP modeling process and may also be considered through the multi-state process in advance of the reassignment filings.

Washington Utilities and Transportation Commission Staff provided recommendations for the calculation of the three required scenarios under Washington's Clean Energy Transformation Act. PacifiCorp consulted the recommendations when planning the scenario runs to comply with the legislation.[45]

[40] Feedback Form 033; September 10, 2020
[41] Feedback Form 077; April 9, 2021
[42] Feedback Form 052; October 19, 2020
[43] Feedback Form 056; November 3, 2020
[44] Feedback Form 057; November 6, 2020
[45] Feedback Form 056; November 3, 2020

Washington Utilities and Transportation Commission Staff provided a reminder that regardless of the preferred portfolio, coal-fired resources cannot be included in Washington's allocation of electricity after 2025.[46]

Natrium Demonstration Project

Sierra Club requested additional detail about the Natrium demonstration project and evaluation within the 2021 IRP. PacifiCorp responded through the stakeholder feedback form process.[47]

Western Resource Advocates requested additional detail regarding the technology involved in the Natrium demonstration project. PacifiCorp's response included the requested information.[48]

Green Energy Institute requested additional information about the project, including siting considerations and fuel considerations. PacifiCorp's response included the requested information.[49]

Natural Gas

Utah Association of Energy Users noted that natural gas price forecasts have been consistently higher than actual realized pricing since 2008 and recommended that the low-price forecast take into account the reality of flat-to-declining natural gas price futures. PacifiCorp noted that if Utah Association of Energy Users had a specific price forecast or methodology that it recommended, that PacifiCorp could include it as a potential scenario. The company otherwise will continue to rely on third-party experts to provide natural gas price forecasting due to the complexity.[50]

Operating Limits

Sierra Club requested information regarding the definition of "operating limits" including whether operating limits referred to a reduction in thermal capacity factor. PacifiCorp clarified that operating limits were plant-wide emissions limits and could be achieved through numerous measures.

Sierra Club requested information on coal operations, including what constraints PacifiCorp applies to the operation of coal units, and whether the company would consider a model run that specified all coal units retired by 2030. PacifiCorp has implemented portfolio P-02, which specifies all coal units retired by 2030.[51]

Plexos

Washington Utilities and Transportation Commission Staff requested additional information regarding how Plexos would be used for stochastic risk analysis, how loss of load probability would be incorporated into the modeling, how social cost of greenhouse gas would be

[46] Feedback Form 069; December 11, 2020
[47] Feedback Form 081; June 11, 2021
[48] Feedback Form 083; July 9, 2021
[49] Feedback Form 084; July 15, 2021
[50] Feedback Form 018; July 28, 2020
[51] Feedback Form 052, October 19, 2020

incorporated, price forecasts, and other potential risks to quantify within the model. PacifiCorp provided the requested information as part of the feedback form response.[52][53]

Oregon Administrative Hearings Division asked for additional data (production costs) that is input into the IRP for existing generators. Administrative Hearings Division further asked for explanation on how the Plexos optimization model inputs are treated. PacifiCorp clarified that production costs are an input regardless of the modeling process, and that the slides discussed during the public input meeting referred generally to linear optimization modeling (but not specifically to Plexos or the 2021 IRP).[54]

Idaho Public Utilities Commission Staff asked for additional explanation on how the Plexos optimization simulation model is validated. PacifiCorp responded that the company is performing a benchmark test of Plexos against the 2019 IRP preferred portfolio to ensure that similar results are reached given similar inputs.[55]

Washington Utilities and Transportation Commission Staff requested additional information on the Plexos modeling progress and the inclusion of the social cost of greenhouse gas for the 2021 IRP. PacifiCorp provided the requested data in the feedback form response.[56]

Western Resource Advocates requested additional information regarding how Plexos would consider certain coal analysis components (take-or-pay, fuel plans of company-owned mines, fuel cost forecasts, etc.). PacifiCorp provided the requested detail as part of the feedback form response.[57]

Utah Association of Energy Users asked if the 2020 all source request for proposals results would be incorporated into the 2021 IRP. PacifiCorp responded that results of the final short list would be included, and that the results would be discussed at the June public-input meeting.[58]

Private Generation Study

Oregon Public Utility Commission Staff requested that the private generation study outline the policy driver assumptions. PacifiCorp responded that existing regulatory structures and known incentives are used to develop the forecast, but no future regulatory/incentive regimes are assumed.[59]

Procurement

Sierra Club requested anonymized median bid price data from PacifiCorp's 2020 all source request for proposals initial short list. PacifiCorp provided the requested detail.[60]

[52] Feedback Form 056; November 3, 2020
[53] Feedback Form 065; November 25, 2020
[54] Feedback Form 016; July 23, 2020
[55] Feedback Form 051; October 22, 2020
[56] Feedback Form 074; February 4, 2021
[57] Feedback Form 079; April 27, 2021
[58] Feedback Form 080; May 25, 2021
[59] Feedback Form 041; September 28, 2020
[60] Feedback Form 071; December 18, 2020

Oregon Public Utility Commission Staff provided a reminder of Oregon's competitive bidding rules.[61]

Reliability Assessment

Wyoming Office of Consumer Advocate forwarded WECC's Western Assessment of Resource Adequacy and recommended that PacifiCorp incorporate the report's recommendations. PacifiCorp has reviewed the report and included a summary of its findings in Volume I, Chapter 5 (Reliability and Resiliency).[62]

Renewable Energy Resources

Oregon Public Utility Commission Staff asked why PacifiCorp does not compare the generation shapes of all resources to the load shape of the system – including why east and west resources were divided. PacifiCorp responded that local weather conditions are likely to drive correlation, and that west/east load and generation shapes were most closely correlated.

Utah Valley Earth Forum asked that for solar installations considered, that the company model horizontal turning panels by each panel pivoting about a vertical axis. PacifiCorp responded that single axis tracking solar photovoltaic systems were modeled in the 2019 IRP and would be modeled again in the 2021 IRP. Further, a wide range of technologies and configurations can be offered into procurement processes downstream from the IRP, as applicable.[63]

Resource Adequacy

Wyoming Office of Consumer Advocate sent the Western Electric Coordinating Council Western Assessment of Resource Adequacy report and recommended that PacifiCorp include recommendations in the 2021 IRP. PacifiCorp considered the report and recommendations within Volume I, Chapter 5 (Reliability and Resiliency).

Sensitivity Studies

The City of Kemmerer requested a sensitivity that would eliminate all hydroelectric generation from the grid and would add back coal-fueled generation. PacifiCorp responded that the requested sensitivity would be considered.[64]

The City of Kemmerer requested a sensitivity that eliminated all tax credits and subsidies are eliminated. PacifiCorp responded that the requested sensitivity would be considered.[65][66]

Wyoming Office of Consumer Advocate provided the framework for a business as usual case which would begin from the current portfolio and would quantify customer impacts that would

[61] Feedback Form 077; April 9, 2021
[62] Feedback Form 075; February 9, 2021
[63] Feedback Form 017; July 25, 2020
[64] Feedback Form 026; August 28, 2020
[65] Feedback Form 027; August 28, 2020
[66] Feedback Form 028; August 28, 2020

result from incremental changes from the portfolio. PacifiCorp incorporated this recommendation into the BAU1 and BAU2 studies.[67]

Wyoming Office of Consumer Advocate requested a sensitivity focused on system reliability throughout the summer, in light of non-resource adequacy resources being deemed as emergency capacity resources to support weather-related reliability challenges. This feedback is included in PacifiCorp's climate change scenario.[68]

Wyoming Office of Consumer Advocate requested a Wyoming House Bill 200 sensitivity as part of the 2021 IRP. PacifiCorp responded that the company would evaluate the potential impacts of the bill.[69]

Wyoming Public Service Commission Staff requested the following sensitivities[70]:

- A model run showing the PVRR with no early coal or gas retirements to compare the preferred portfolio (all other assumptions remaining the same). This is included through the company's business as usual cases.
- A model run that assumes carbon capture on all Wyoming coal plants with assumptions of CCUS with zero capital costs (assuming third party pays capital costs) and the inclusion of 45Q tax credits retained by Company. Carbon capture utilization and sequestration technology was included for analysis in the 2021 IRP.
- Rerun the IRP model without Washington Clean Energy Transformation Act (CETA) to compare against the preferred portfolio. This is included through the CETA alternative lowest reasonable cost scenario.
- Implementation of SF0159 where the Company purchases coal generation at avoided cost for all Wyoming units past the retirement date. To model how new generation needs change when coal generation in Wyoming is purchased at the Company's avoided cost.
- Various sensitivity analysis related to prolonged extreme weather events sensitivity ran on the preferred portfolio, such as: 3 days of record high temperatures and more A/C load, 3 days of record low temperatures with additional heating load, 15% reduction in solar generation due to cloudy weather paired with a 15% reduction in wind generation due to reduced wind. This is included through the company's climate change sensitivity.
- A sensitivity analysis on how electrification affects load growth and the Company's ability to meet reliability standards when EVs adoption rates increase exponentially in 2023. EV adoption and electrification cases are included in the load forecast.

Wyoming Public Utility Commission Staff provided the framework for a business as usual case. This framework informed the company's two planned business as usual scenarios.[71]

Renewable Northwest recommended that a business as usual case consider relevant state policy objectives and continue to make economic retirement decisions and the growing scale of energy

[67] Feedback Form 037; September 23, 2020
[68] Feedback Form 039; September 23, 2020
[69] Feedback Form 040; September 23, 2020
[70] Feedback Form 044; September 29, 2020
[71] Feedback Form 045; September 30, 2020

efficiency and demand response. Renewable Northwest's recommendations informed the company's two planned business as usual scenarios.[72]

Washington Utilities and Transportation Commission Staff and Oregon Public Utility Commission Staff jointly provided a set of sensitivity runs that are CETA compliant and apply a social cost of carbon cost adder. The cases informed the P01, P02, and P03 cases planned by the company, and were factored into the development of CETA required cases (such as maximum customer benefit and climate change).[73]

Wyoming Industrial Energy Consumers emailed a joint party recommendation for two business as usual cases for modeling in the 2021 IRP. PacifiCorp consulted the requested cases when building the "business as usual" portfolios.[74]

Oregon Public Utility Commission Staff requested a low market price, high volatility sensitivity to determine the optimal portfolio in a high-renewable and no-gas buildout throughout the WECC. PacifiCorp considered this request when developing portfolios.[75]

Wyoming Industrial Energy Consumers requested a stochastic sensitivity that took into account weather-related extended outage risks within the 2021 IRP. PacifiCorp included a climate-change sensitivity in the 2021 IRP that included the best available science on climate change and potential risks.[76]

Powder River Basin Resource Council, National Parks Conservation Association, and HEAL Utah requested a sensitivity that incorporates selective catalytic reduction controls at Jim Bridger units 1 and 2, Wyodak, Naughton units 1 and 2, and all 5 units at Hunter and Huntington. PacifiCorp considered this request as part of the portfolio construction process.[77]

Utah Division of Public Utilities requested an additional sensitivity to allow the model to select new proxy natural gas units as a resource option. PacifiCorp added this requested sensitivity to the portfolio modeling process as a result of this feedback.[78]

Utah Clean Energy and other parties requested an additional sensitivity to study potential retirement dates for Jim Bridger Units 3 & 4. PacifiCorp added this requested sensitivity to the portfolio modeling process as a result of this feedback.[79]

PacifiCorp included discussions on requested and required sensitivities in Chapter 7 – Portfolio Modeling and presented sensitivities as part of the August 6, 2021 IRP public-input meeting.

State Energy Policy

[72] Feedback Form 046; October 2, 2020
[73] Feedback Form 047; October 2, 2020
[74] Feedback Form 058; November 10, 2020
[75] Feedback Form 061; November 17, 2020
[76] Feedback Form 067; December 4, 2020
[77] Feedback Form 070; December 17, 2020
[78] Feedback Form 087; August 3, 2021
[79] Feedback Form 088; August 3, 2021

Washington Utilities and Transportation Commission Staff asked for additional information regarding how PacifiCorp would show compliance with the legislative requirements of RCW 19.405.030(1)(a). PacifiCorp responded that it would comply with the method directed in rule, once adopted. PacifiCorp is continuing to work with Staff and Commissioners to ensure compliance.[80]

Washington Utilities and Transportation Commission requested additional data on how key components of the Clean Energy Transformation Act – including the required Climate Change scenario – would be modeled as part of the IRP. PacifiCorp provided additional information regarding the modeling process for heating and cooling degree days, a 1-in-20 year scenario, and the availability of differing modeling timescales.[81][82]

The City of Kemmerer asked that Wyoming's Senate File 159 and House Bill 200 be included in the 2021 IRP. Both are included and have been addressed at the September 17, 2020 public input meeting.[83]

Oregon Public Utility Commission Staff recommended a preliminary House Bill 2021 assessment as part of the 2021 IRP and requested additional information/confirmation on baseline emissions. PacifiCorp will work with Staff to determine the best path forward on HB 2021 compliance.[84]

Supply-side Resource Costs/Supply-side Resource Table

The City of Kemmerer requested that small nuclear reactors be included in the supply-side table, as well as carbon capture coal technology. Both have been added to the supply-side table for 2021.[85]

The City of Kemmerer requested additional elevations to be included in the efficiency study for natural gas resources. PacifiCorp responded that the elevations currently included in the study represented a reasonable range across the system, and that specific elevations by site were not feasible for a proxy study.[86][87]

Oregon Public Utility Commission Staff asked if any potential economies of scale were potentially being missed as part of the current supply-side resource table solar selection and asked for additional information on solar and wind profiles that may be used in the IRP. PacifiCorp responded that above 200MW of solar, economies of scale are marginal. The company also provided additional detail for the solar and wind profiles.[88]

Wyoming Office of Consumer Advocate requested that carbon capture utilization and sequestration technology and small modular nuclear reactors should be included in the supply-side resource table. Both have been included for the 2021 IRP.[89]

[80] Feedback Form 013; June 26, 2020
[81] Feedback Form 013; June 26, 2020
[82] Feedback Form 020; August 7, 2020
[83] Feedback Form 024; August 28, 2020
[84] Feedback Form 090; August 9, 2021
[85] Feedback Form 022; August 28, 2020
[86] Feedback Form 023; August 28, 2020
[87] Feedback Form 035; September 17, 2020
[88] Feedback Form 033; September 10, 2020
[89] Feedback Form 038; September 23, 2020

Wyoming Public Service Commission Staff provided a number of questions and recommendations with regard to the supply-side table, price-policy scenarios, and optimization of retirement dates. PacifiCorp responded to the questions through the feedback form, and subsequently discussed optimized retirement dates as part of the portfolio discussions in June and July 2021.[90]

Wyoming Public Service Commission Staff requested that carbon capture utilization and sequestration technology be included in the supply-side resource table and asked for additional information on the 2019 supply side resource tables and underlying data. PacifiCorp included carbon capture utilization and sequestration technology in the 2021 IRP and provided the data requested through the feedback form.[91]

Oregon Public Utility Commission Staff requested that offshore wind be included in the supply-side table after the 2021 IRP. In response to this feedback, PacifiCorp included a discussion of offshore wind potential in the 2021 IRP, and plans to include off-shore wind in the 2023 IRP supply-side table.[92]

Oregon Public Utility Commission Staff requested additional information on carbon capture utilization and sequestration inputs and coal take-or-pay provisions in the supply-side resources table. PacifiCorp provided the requested information in the stakeholder feedback form response.[93][94]

Transmission

Oregon Administrative Hearings Division requested explanation of the target in-service assumptions for Gateway West Segment D1 in the 2019 IRP. PacifiCorp responded that Gateway West Segment D1 was not modeled in the 2019 IRP but is necessary to comply with FERC order and to achieve the level of new resources in eastern Wyoming included in the preferred portfolio at the end of 2023.[95]

Oregon Public Utility Commission Staff requested additional detail regarding how the Boardman to Hemingway line would be modeled in the 2021 IRP and how the upgrade/financing would be conducted. PacifiCorp provided information regarding the company's east-to-west share of the line and the asset swap agreement but had not yet determined the modeling approach for the line.[96]

Western Resource Advocates requested that once the transmission topology was complete, that PacifiCorp provide the incremental transmission capacity as compared to the 2019 IRP. Discussion of transmission capacity is included in Chapter 4 – Transmission, Chapter 7 – Portfolio Modeling, and Chapter 8 – Portfolio Selection.[97]

[90] Feedback Form 042; September 29, 2020
[91] Feedback Form 043; September 29, 2020
[92] Feedback Form 073; January 19, 2021
[93] Feedback Form 073; January 19, 2021
[94] Feedback Form 077; April 9, 2021
[95] Feedback Form 016; July 23, 2020
[96] Feedback Form 029; September 3, 2020
[97] Feedback Form 060; November 17, 2020

Interwest Energy Alliance requested additional detail on when network service transmission capacity from retiring assets is made available for interconnection – including more information on the process and notification to transmission customers. PacifiCorp provided the requested detail in the feedback form response.[98] Interwest further requested information on legal needed for approval of the 2021 IRP projects, import capacity assumed, and requested additional clarity on how transmission projects were selected.[99]

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

[98] Feedback Form 064; November 25, 2020
[99] Feedback Form 091; August 4, 2021

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 2021 Integrated Resource Plan (IRP). In addition, it provides information on the economic DSM selections in the 2021 IRP's Preferred Portfolio, a summary of existing DSM program services and offerings, and an overview of the DSM planning process in each of PacifiCorp's service areas.

Conservation Potential Assessment (CPA) for 2021-2040

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 2021-2040,[1] conducted by Applied Energy Group (AEG) on behalf of PacifiCorp, primarily seeks to develop reliable estimates of the magnitude, timing, and costs of DSM resources likely available to PacifiCorp over the IRP's 20-year planning horizon. The study focuses on resources realistically achievable during the planning horizon, given normal market dynamics that may hinder or advance resource acquisition. Study results were incorporated into PacifiCorp's 2021 IRP and will be used to inform subsequent DSM planning and program design efforts. This study serves as an update of similar studies completed since 2007.

For resource planning purposes, PacifiCorp classifies DSM resources into four categories, differentiated by two primary characteristics: reliability and customer choice. These resource classifications can be defined as: demand response (e.g., a firm, capacity focused resource such as direct load control), energy efficiency (e.g., a firm energy intensity resource such as conservation), demand side rates (DSR) (e.g., a non-firm, capacity focused resource such as time of use rates), and behavioral-based response (e.g., customer energy management actions through education and information).

From a system-planning perspective, demand response resources can be considered the most reliable, as they can be dispatched by the utility. In contrast, behavioral-based resources are the least reliable due to the resource's dependence on voluntary behavioral changes. With respect to customer choice, demand response and energy efficiency resources should be considered

[1] PacifiCorp's Demand-Side Resource Potential Assessment for 2021-2040, completed by AEG, can be found at: www.pacificorp.com/energy/integrated-resource-plan/support.html.

involuntary in that, once equipment and systems have been put in place, savings can be expected to occur over a certain period of time. DSR and behavioral-based activities involve greater customer choice and control. This assessment estimates potential from demand response, energy efficiency, and DSR.

The CPA excludes an assessment of Oregon's energy efficiency resource potential, as this work is performed by Energy Trust of Oregon, which provides energy efficiency potential in Oregon to PacifiCorp for resource planning purposes.

Current DSM Program Offerings by State

Currently, PacifiCorp offers a robust portfolio of DSM programs and initiatives, most of which are offered in multiple states, depending on size of the opportunity and the need. Programs are reassessed on a regular basis. PacifiCorp has the most up-to-date programs on its website.[2] Demand response and energy efficiency program services and offerings are available by state and sector. Energy efficiency services listed for Oregon, except for low-income weatherization services, are provided in collaboration with Energy Trust of Oregon.[3]

Table D.1 provides an overview of the breadth of demand response and energy efficiency program services and offerings available by Sector and State.

PacifiCorp has numerous DSR offerings currently available. They include metered time-of-day and time-of-use pricing plans (in all states, availability varies by customer class), and residential seasonal rates (Idaho and Utah). System-wide, approximately 17,200 customers were participating in metered time-of-day and time-of-use programs as of December 31, 2019.

Savings associated with rate design are captured within the company's load forecast and are thus captured in the integrated resource planning framework. PacifiCorp continues to evaluate DSR programs for applicability to long-term resource planning.

PacifiCorp provides behavioral based offerings as well. Educating customers regarding energy efficiency and load management opportunities is an important component of PacifiCorp's long-term resource acquisition plan. A variety of channels are used to educate customers including television, radio, newspapers, bill inserts and messages, newsletters, school education programs, and personal contact. Load reductions due to behavioral activity will show up in demand response and energy efficiency program results and non-program reductions in the load forecast over time.

Table D.2 provides an overview of DSM related ***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.html and programs for Pacific Power can be found at www.pacificorp.com/environment/demand-side-management.html.
[3] Funds for low-income weatherization services are forwarded to Oregon Housing and Community Services.

Table D.1– Current Demand Response and Energy Efficiency Program Services and Offerings by Sector and State

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Residential Sector						
Air Conditioner Direct Load Control					√	
Lighting Incentives	√	√	√	√	√	√
New Appliance Incentives	√	√	√	√	√	√
Heating And Cooling Incentives	√	√	√	√	√	√
Weatherization Incentives - Windows, Insulation, Duct Sealing, etc.	√	√	√	√	√	√
New Homes	√	√	√	√	√	√
Low-Income Weatherization	√	√	√	√	√	√
Home Energy Reports		√	√	√	√	√
School Curriculum		√	√		√	
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						
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		√			√	
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.

In 2019, Washington passed the Clean Energy Transformation Act (CETA), which requires utilities to meet three primary clean energy standards: remove coal-fueled generation from Washington's allocation of electricity by 2025, serve Washington customers with greenhouse gas neutral electricity by 2030, and to serve customers in Washington with 100% renewable and non-emitting electricity by 2045. The conservation stakeholder group and the demand-side management advisory group inform the CETA planning process.

California

On January 13, 2021, the Commission issued Decision 20-11-032, approving the company's Annual Budget Advice Letter (ABAL) Filing 637E to continue administering its energy efficiency programs through 2021. PacifiCorp submitted an application for the continuation of energy efficiency programs for program years 2022-2026 on December 31, 2020.

Oregon

Energy efficiency programs for Oregon customers are planned for and delivered by Energy Trust of Oregon in collaboration with PacifiCorp. Energy Trust's planning process is comparable to PacifiCorp's other states, including establishing resource acquisition targets based on resource assessment and integrated resource planning, developing programs based on local market conditions, and coordinating with stakeholders and regulators to ensure efficient and cost-effective delivery of energy efficiency resources.

Preferred Portfolio DSM Resource Selections

The following tables show the economic DSM resource selections by state and year in the 2021 IRP preferred portfolio.

Table D.3 –First Year Demand Response Resource Selections (2021 IRP Preferred Portfolio)[4]

State/Product Category by Year (MW)	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
DR Summer - ID	-	-	0.5	9.5	1.9	0.5	1.3	4.3	5.9	2.0
DR Summer - UT	-	-	29.4	26.4	7.6	3.5	5.5	9.9	9.2	8.0
DR Summer - WY	-	-	0.9	1.1	0.8	0.6	0.9	1.0	0.9	0.8
DR Winter - ID	-	-	0.5	0.9	0.3	0.5	1.2	1.8	1.9	2.0
DR Winter - UT	-	-	35.5	41.2	2.6	2.7	3.9	5.9	9.7	7.0
DR Winter - WY	-	-	0.2	0.6	0.4	0.6	0.7	0.9	0.9	0.9
RFP DR - ID	-	5.0	6.4	2.8	2.8	2.8	2.8	2.8	2.8	2.8
RFP DR - UT	-	54.7	59.3	9.1	9.1	9.1	9.1	9.1	9.1	9.1
RFP DR - WY	-	17.0	2.0	2.7	2.7	2.7	2.7	2.7	2.7	2.7
DR Summer - CA	-	-	1.1	2.0	0.5	0.4	0.5	0.7	0.6	0.7
DR Summer - OR	-	-	15.9	16.4	5.9	5.1	7.1	8.3	2.3	8.4
DR Summer - WA	-	-	3.9	4.9	2.0	1.1	1.8	2.2	1.5	1.4
DR Winter - CA	-	-	1.1	1.4	0.4	0.3	0.4	0.6	0.6	0.7
DR Winter - OR	-	-	13.7	15.4	2.8	3.1	3.2	4.3	4.3	4.7
DR Winter - WA	-	-	2.8	3.7	0.6	0.7	0.8	0.9	1.0	0.8
RFP DR - CA	-	1.8	2.1	0.6	0.6	0.6	0.6	0.6	0.6	0.6
RFP DR - OR	-	33.9	48.0	28.8	24.5	18.9	18.0	18.2	18.9	19.5
RFP DR - WA	-	11.0	19.2	16.2	13.3	10.3	8.5	6.1	5.3	5.3
Total by Year	**0**	**123.41**	**242.39**	**183.61**	**78.83**	**63.46**	**68.98**	**80.18**	**77.84**	**77.50**

[4] A portion of cost-effective demand response resources identified in the 2021 preferred portfolio are expected to be acquired through a previously issued demand response RFP soliciting resources identified in the 2019 IRP. PacifiCorp will pursue all cost-effective demand response resources identified as incremental to resources subsequently procured under the previously issued RFP in compliance with state level procurement requirements.

State/Product Category by Year (MW)	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Total MW
DR Summer - ID	2.4	2.1	2.7	2.3	14.6	2.0	2.6	4.7	3.4	4.6	67.0
DR Summer - UT	9.9	11.1	104.8	19.7	29.7	29.5	66.3	33.8	28.6	42.3	475.0
DR Summer - WY	1.0	1.0	1.9	1.1	1.0	1.4	1.2	1.4	3.7	36.5	57.0
DR Winter - ID	1.8	2.1	3.5	2.3	2.4	2.0	2.6	2.1	7.1	7.7	42.7
DR Winter - UT	8.3	12.1	72.6	22.2	24.1	33.9	58.9	24.0	26.6	74.2	465.3
DR Winter - WY	1.0	1.0	2.8	1.1	1.0	1.4	1.1	1.4	5.9	30.2	51.7
RFP DR - ID	2.8	-	-	-	-	-	-	-	-	-	33.6
RFP DR - UT	9.1	-	-	-	-	-	-	-	-	-	186.5
RFP DR - WY	2.7	-	-	-	-	-	-	-	-	-	40.8
DR Summer - CA	0.8	0.9	1.0	0.7	1.3	1.0	2.0	3.5	2.3	3.2	23.0
DR Summer - OR	8.4	9.9	13.8	8.9	25.8	11.0	9.9	25.1	13.1	52.6	248.0
DR Summer - WA	1.8	0.6	2.2	1.1	4.3	14.3	6.2	2.6	2.2	1.2	55.3
DR Winter - CA	0.7	0.9	0.9	0.7	1.2	1.0	2.0	7.6	2.2	3.3	25.9
DR Winter - OR	5.0	7.8	6.0	9.9	43.7	15.4	9.4	51.3	11.2	44.7	255.8
DR Winter - WA	0.6	0.9	0.6	0.5	11.4	12.3	21.5	1.2	1.4	1.1	62.9
RFP DR - CA	0.6	-	-	-	-	-	-	-	-	-	8.7
RFP DR - OR	20.2	-	-	-	-	-	-	-	-	-	248.9
RFP DR - WA	5.2	-	-	-	-	-	-	-	-	-	100.4
Total by Year	**82.26**	**50.10**	**212.64**	**70.31**	**160.37**	**125.23**	**183.45**	**158.65**	**107.60**	**301.50**	**2448.30**

Table D.4 – First Year Energy Efficiency Resource Selections (2021 IRP Preferred Portfolio)

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
CA	2,272	2,621	1,702	2,055	2,412	2,863	3,415	4,488	4,791	4,571
OR	174,321	141,069	124,676	123,006	118,508	126,414	131,318	136,237	145,519	145,561
WA	41,184	34,003	37,231	39,530	45,254	50,201	53,928	55,500	55,259	55,204
UT	230,790	257,465	266,500	271,227	298,181	286,714	306,600	316,691	316,193	342,228
ID	17,590	12,824	12,000	12,512	15,102	17,289	19,353	20,682	22,741	23,669
WY	43,877	44,467	44,204	80,727	83,706	88,708	94,174	96,827	94,700	94,876
Total System	510,034	492,450	486,314	529,058	563,163	572,189	608,788	630,425	639,204	666,108

Energy Efficiency Energy (1st Year Savings MWh) Selected by State and Year										
State	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
CA	3,995	4,339	3,849	3,414	2,968	3,261	3,780	3,304	3,332	3,124
OR	141,456	137,369	127,089	119,104	103,538	98,182	88,424	98,235	101,704	93,476
WA	52,754	47,873	42,479	37,700	33,324	26,190	24,150	21,300	19,555	17,219
UT	327,804	307,520	279,091	256,780	234,795	198,053	200,602	193,179	189,052	200,875
ID	22,897	21,643	20,077	18,466	17,391	14,208	13,228	12,732	11,518	11,123
WY	85,470	75,314	63,065	55,559	47,916	35,267	30,062	27,784	25,797	27,026
Total System	634,375	594,059	535,650	491,023	439,932	375,161	360,245	356,534	350,958	352,843

For the 20-year assumed nameplate capacity contributions (MW impacts) by state and year associated with the energy efficiency resource selections above, see Volume I, Chapter 9 (Modeling and Portfolio Selection).

APPENDIX E – SMART GRID

Introduction

Smart grid is the application of advanced communications and controls to the electric power system. As such, a wide array of applications can be defined under the smart grid umbrella. PacifiCorp has identified specific areas for research that include technologies such as dynamic line rating, phasor measurement units, distribution automation, advanced metering infrastructure (AMI), automated demand response and other advanced technologies. PacifiCorp has reviewed relevant smart grid technologies for transmission and distribution systems that provide local and system benefits. When considering these technologies, the communications network is often the most critical infrastructure decision. This network must have relevant speed, reliability, and security and be scalable to support the entire service territory and interoperable for many device types, manufacturers, and generations of technology.

PacifiCorp has focused on those technologies that present a positive benefit for customers and has implemented functions such as advanced metering, dynamic line rating, and distribution automation. This will optimize the electrical grid when and where it is economically feasible, operationally beneficial and in the best interest of customers. PacifiCorp is committed to consistently evaluating the value of emerging technologies for integration when they are found to be appropriate investments. The company is working with state commissions to improve reliability, energy efficiency, customer service, and integration of renewable resources by analyzing the total cost of ownership, performing thorough cost-benefit analyses, and reaching out to customers concerning smart grid applications and technologies. As technology advances and development continues, PacifiCorp is able to improve cost estimates and benefits of smart grid technologies that will assist in identifying the best suited technologies for implementation.

Transmission Network and Operation Enhancements

Dynamic Line Rating

Dynamic line rating is the application of sensors to transmission lines to indicate the real-time current-carrying capacity of the lines in relation to thermal restrictions. Transmission line ratings are typically based 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. The Standpipe-Platte project was implemented in 2014 and has delivered positive results as windy days are directly linked to increased wind power generation and increased transmission ratings. A dynamic line rating system is used to determine the resulting cooling effect of the wind on the line. The current carrying capacity is then updated to a new weather dependent line rating. The Standpipe-Platte 230 kilovolt (kV) transmission line is one of three lines in the TOT4A transmission corridor and had been one of the limits of the corridor power transfer. As a result of this project, the TOT4A Western Electricity Coordinating Council (WECC) non-simultaneous path rating was increased. The DLR system on the Platte – Standpipe 230 kV line is currently being upgraded with a Transmission Line Monitoring (TLM) system manufactured by Lindsay Industries, which has been put in-service in January 2021.

Additionally, a new DLR system is being implemented on the existing Dave Johnston- Amasa – Difficulty – Shirley Basin 230 kV line as part of the Gateway Segment D.2 Project. The Dave Johnston- Amasa – Difficulty – Shirley Basin 230 kV line connects two areas with a high penetration of wind generation resources and implementation of the DLR system will improve the link between those two areas to reduce the need for operational curtailments when wind patterns result in a variation in generation between the two areas, such as high winds in the northeast area and moderate to low winds in the southeast area. The DLR system will increase the transmission line steady-state rating under increased wind conditions and reduce instances and duration of associated generation curtailments.

Dynamic line rating will be considered for all future transmission needs as a means for increasing capacity in relation to traditional construction methods. Dynamic line rating is only applicable for thermal constraints and only provides additional site-dependent capacity during finite time periods, and it may or may not align with expected transmission needs of future projects. PacifiCorp will continue to look for opportunities to cost-effectively employ dynamic line rating systems similarly to the one deployed on the Standpipe – Platte 230 kV transmission line...

Digital Fault Recorders / Phasor Measurement Unit Deployment

To meet compliance with the North American Electric Reliability Corporation (NERC) MOD-033-1 and PRC-002-2 standards, PacifiCorp has installed over 100 multifunctional digital fault recorders (DFR) which include phasor measurement unit (PMU) functionality. The installations are at key transmission and generation facilities throughout the six-state service territory, generally placed on WECC identified critical paths. PMUs provide sub-second data for voltage and current phasors, which can be used for MOD-033-1 event analysis and model verification. DFRs have a shorter recording time with higher sampling rate to validate dynamic disturbance modelling per PRC-002-2. The DFR/PMUs will deliver dynamic PMU data to a centralized phasor data concentrator (PDC) storage server where offline analysis can be performed by transmission operators, planners, and protection engineers. Installation of the communications and data transfer systems between the individual PMUs and the PDC is underway and planned for completion by the end of 2021. Additionally, transient DFR data can be downloaded manually at substations.

Transmission planners will use the phasor data quantities from actual system events to benchmark performance of steady-state and transient stability models of the interconnected transmission system and generating facilities. Using a combination of phasor data from the PMUs and analog quantities currently available through Supervisory Control and Data Acquisition System (SCADA), transmission planners can set up the system models to accurately depict the transmission system prior to, during, and following an event. Differences in simulated versus actual system performance will then be evaluated to allow for enhancements and corrections to the system model.

Model validation procedures are being evaluated, in conjunction with data and equipment availability to fulfill MOD-033-1. Creation of a documented process to validate data that includes the comparison of a planning power flow model to actual system behavior and the comparison of the planning dynamic model to actual system response is ongoing. PacifiCorp will continually evaluate potential benefits of PMU installation and intelligent monitoring as the industry considers PMU in special protection, remedial action scheme and other roles that support transmission grid operators. PacifiCorp will continue to work with the California Independent System Operator (CAISO)'s Reliability Coordinator West to share data as appropriate.

Distribution Automation and Reliability

Distribution Automation

Distribution automation encompasses a wide field of smart grid technology and applications that focus on using sensors and data collection on the distribution system, as well as automatically adjusting the system to optimize performance. Distribution automation can also provide improved outage management with decreased restoration times after failure, operational efficiency, and peak load management using distributed resources and predictive equipment failure analysis using complex data algorithms. PacifiCorp is working on distribution automation initiatives focused on improved system reliability through improved outage management and response.

In Oregon, PacifiCorp identified 40 circuits on which cost benefit analyses were performed. From this analysis two circuits in Lincoln City, Oregon were selected to have a fault location, isolation and service restoration (FLISR) system installed. The project was installed through 2019 and commissioning of the automation scheme conducted through 2020. While the automation scheme's effectiveness was able to be validated, persistent issues with the security and reliability of the piloted communication technology occurred throughout 2020 and resulted in exploring alternate technology. Based on that experience additional two additional automation projects were initiated in Portland and Medford, relying on private fiber optic communications (in a manner very similar to how transmission assets would be monitored) Engineering and construction are in progress and commissioning during 2022 is anticipated.

Wildfire Mitigation

In response to concerns of wildfire danger to customers, PacifiCorp began developing communication systems and practices to improve system reliability in at risk areas. Selected substations in Siskiyou County, California and Wasatch County, Utah are preliminary sites that will have remote communication installed to allow dispatch operators to modify re-closer settings.

Distribution Substation Metering

Substation monitoring and measurement of various electrical attributes were identified as a necessity due to the increasing complexity of distribution planning driven by growing levels of primarily solar generation as distributed energy resources. Enhanced measurements improve visibility into loading levels and generation hosting capacity as well as load shapes, customer usage patterns, and information about reliability and power quality events.

In 2017, an advanced substation metering project was initiated to provide an affordable option for gathering required substation and circuit data at locations where SCADA is unavailable and/or uneconomical. SCADA has been the preferred form of gathering load profile data from distribution circuits, however SCADA systems can be expensive to install and additional equipment is required to provide the data needed to perform distribution system and power quality analysis. When system data rather than data and control is important, SCADA is no longer the best option.

The advanced substation metering project was intended to provide an affordable option for gathering required distribution system data. The Company's work plan included:

- Finalize installation of advanced substation meters at distribution substations and document installations
- Ensure all substation meters installed as part of this program are enabled with remote communication capabilities

- Refine a data management system (PQView) to automatically download, analyze and interpret data downloaded from all installed substation meters

The advanced substation metering project enabled installation of enhanced monitors at more than fifty distribution circuits in the state of Utah. The Company also deployed PQView software, a data analytics tool that provides users with a refined view of power quality information gathered from substation meters.

Distributed Energy Resources

Energy Storage Systems

In 2017, PacifiCorp filed the Energy Storage Potential Evaluation and Energy Storage Project proposal with the Public Utilities Commission or Oregon. This filing was in alignment with PacifiCorp's strategy and vision regarding the expansion and integration of renewable technologies. The company proposed a utility-owned targeted energy storage system (ESS) pilot project. In 2019 PacifiCorp began project development and is progressing to build an ESS on a Hillview substation distribution circuit in Corvallis, Oregon. Due to issues finding a suitable location in Corvallis the company located a different location. The new location for the ESS is the Lakeport Substation in Klamath Falls. The intent of this project is to integrate the ESS into the existing distribution system with the capability and flexibility to potentially advance to a future micro grid system.

In 2020, PacifiCorp developed Community Resiliency programs in Oregon and California to expand customer understanding of how the use of ESS equipment might increase the resilience of critical facilities. The initial pilot programs provided technical support and evaluation of potential options. In the future, the Company will evaluate opportunities to develop programs and partner with facilities that move forward with the installation of ESS infrastructure.

Demand Response

In 2018, PacifiCorp transitioned to the automatic dispatch of the residential air conditioner (A/C) program in Utah, utilizing two-way communication devices to respond to frequency dispatch signals. Known as Cool Keeper this frequency dispatch innovation is a grid-scale solution using fast-acting residential demand response resources to support the bulk power system. Some utilities use generating resources to perform this function, but as higher levels of wind and solar resources are added, additional balancing resources are required. The Cool Keeper system provides over 200 MWs of operating reserves to the system through the control of more than 108,000 A/C units.

In 2021, PacifiCorp released a Request for Proposals for Demand Response resources. The Company is currently at the early stages of reviewing those proposals. The Company has used the responses to incorporate the cost of Demand Response programs more accurately in the 2021 Integrated Resource Plan.

Dispatchable Customer Resources

PacifiCorp partnered with a developer in 2018 to make an innovative solar and battery solution possible at a 600-unit multi-family community in Utah. Known as Soleil Lofts, this project provides a unique opportunity for the company to implement an innovative solution using solar and battery storage integration along with demand response and advanced management of the grid through daily energy load shaping. The project includes the development of a company-owned utility data and dispatch portal with direct access to 621 Sonnen batteries, each rated at 8kW, for a total of 4.8 MWs of capacity and 12 MWh of energy within the project area. In addition to the cost savings with leveraging the Soleil community partnership, the project creates opportunity to develop and test new programs related demand response, load shaping and rate design.

At this time, approximately 450 of the 600 units have been deployed. PacifiCorp has integrated the control system into the energy management system and continues to test different use cases for the aggregated capacity.

In learning from Rocky Mountain Power's partnership with Soleil Lofts. The Company developed the Wattsmart Battery Program which was approved in October 2020 through the Utah Public Service Commission. This innovative demand response program allows Rocky Mountain Power to control behind the meter customer batteries. The Company will have the ability to control customer batteries for real time grid needs such as peak load management, contingency reserves and frequency response. Customer controlled batteries will allow the Company to maximize renewable energy when it's needed to support the electrical gird.

Advanced Metering Infrastructure

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that provide interval data available on a daily basis. This infrastructure can also provide advanced functionalities including remote connect/disconnect, outage detection and restoration signals, and support distribution automation schemes. In 2016, PacifiCorp identified economical AMI solutions for California and Oregon that delivered tangible benefits to customers while minimizing the impact on consumer rates.

In 2019, PacifiCorp completed installation of the Itron Gen5 AMI system across the Company's Oregon and California service territories. The AMI system consists of head-end software, FANs and approximately 656,000 meters. Interval energy usage data is provided to customers via the Pacific Power website and mobile app. The project was completed on schedule and on budget.

In 2018, PacifiCorp awarded a contract to Itron for their OpenWay Riva AMI system in the states of Idaho and Utah. In early 2020, Itron proposed a change for the information technology (IT) and network systems, using their Gen5 system rather than the OpenWay system, while still deploying the more advanced Riva meter technology. Itron's Gen5 system has the same IT and network used in PacifiCorp's Oregon and California service territories. This solution aligns with Itron's future road map and provides PacifiCorp with a single operational system that will reduce cybersecurity issues and operating costs associated with maintaining separate systems. This solution provides a stronger, more flexible network coupled with a high-end metering solution.

The Utah/Idaho project involves upgrading the head-end software and installation of the FAN and approximately 240,000 new Itron Riva AMI meters for most customer classification and 20,000 Aclara AMI meters for the Utah rate schedule 136 private generation accounts. This solution will utilize over 80% of the existing AMR meters in Utah to provide hourly interval data for residential customers as well as outage detection and restoration messaging. The project will replace all current meters in Idaho with new Itron Riva AMI meters as AMR was not fully deployed there. Furthermore, the project will leverage the customer communication tools developed for the Oregon and California AMI projects.

The project is expected to be completed by the end of 2022. Costs and benefits associated with the AMI project will be tracked and analyzed and will be evaluated against the business case projections after completion.

Financial analyses to extend AMI solutions to Washington and Wyoming were performed in 2019 and 2020, respectively. These states utilize the same AMR meter technology as Utah and can be leveraged to provide extended functionality and value. The analyses determined that moving these states to an AMI solution is not cost effective at this time but has improved slightly over previous analyses. The Company will continue to review and evaluate the business case and cost effectiveness for these states routinely over the next few years.

Outage Management Improvements

PacifiCorp advanced a new module in its OMS which allows for field responders to update outage data as they complete their work, using Mobile Workforce Management tools; this functionality is restricted to service transformer and customer meter devices, which comprise approximately half of the outages to which the company responds. This ensures more rapid, accurate and efficient updates to outage data, but still maintains the OMS topology as the method to manage line worker safety by having real-time access to elements that are energized and those which may be in an abnormal state.

In Utah, PacifiCorp has initiated a project to enhance the ability to receive outage notifications from intelligent line sensors, smart meters and existing AMR meters. The intelligent line sensors will be installed on distribution circuits that will provide service to critical facilities. For the purpose of this project, critical facilities have been defined as major emergency facility centers such as hospitals, trauma centers, police and fire dispatch centers, etc. The information provided by the line sensors will allow control center operators to target restoration at critical facilities during major outages sooner than is currently possible. Full implementation of the project is expected to be completed by December 2021, concurrent with the completion of the AMI project.

Future Smart Grid

The Company continues to develop a strategy to attain long-term goals for grid modernization and smart grid-related activities to continually improve system efficiency, reliability and safety, while providing a cost-effective service to our customers. The Company will continue to monitor smart grid technologies and determine viability and applicability of implementation to the system, and as tipping points to broader implementation occur it’s expected these will be communicated through a variety of methods, including this IRP as well as other regulatory mechanisms relevant to that state.

APPENDIX F – FLEXIBLE RESERVE STUDY

Introduction

The 2021 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 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 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 2018 through December 2019 for load, wind, solar, and Non-VERs. PacifiCorp's primary analysis focuses on the actual

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 2018-2019. A supplemental analysis discusses how the total variability of the PacifiCorp system changes with varying levels of wind and solar capacity. The estimated regulation reserve amounts determined in this study represent the incremental capacity needed to ensure compliance with BAL-001-2 for a particular operating hour. The regulation reserve requirement covers variations in load, wind, solar, and Non-VERs, while implicitly accounting for the diversity between the different classes. An explicit adjustment is also made to account for diversity benefits realized 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 2019 IRP but has been enhanced in two areas.[5] First, the historical period evaluated in the study has been expanded to include two years, rather than one, to capture a larger sample of system conditions. Second, the methodology for extrapolating results for higher renewable resource penetration levels has been modified to better capture the diversity between growing wind and solar portfolios.

The FRS results produce an hourly forecast of the regulation reserve requirements for each of PacifiCorp's BAAs that is sufficient to ensure the reliability of the transmission system and compliance with NERC and WECC standards. This regulation reserve forecast covers the combined deviations of the load, wind, solar and Non-VERs on PacifiCorp's system and varies as a function of the wind and solar capacity on PacifiCorp's system, as well as forecasted levels of wind, solar and load.

The regulation reserve requirement methodologies produced by the FRS are applied in production cost modeling to determine the cost of the reserve requirements associated with incremental wind and solar capacity. After a portfolio is selected, the regulation reserve requirements specific to that portfolio can be calculated and included in the study inputs, such that the production cost impact of the requirements is incorporated in the reported results. As a result, this production cost impact is dependent on the wind and solar resources in the portfolio as well as the characteristics of the dispatchable resources in the portfolio that are available to provide regulation reserves.

Overview

The primary analysis in the FRS is to estimate the regulation reserve necessary to maintain compliance with NERC Standard BAL-001-2 given a specified portfolio of wind and solar resources. The FRS next calculates the cost of holding regulation reserve for incremental wind and solar resources. Finally, the FRS compares PacifiCorp's overall operating reserve requirements over the IRP study period, including both regulation reserve and contingency reserve, to its flexible resource supply.

The FRS estimates regulation reserve based on the specific requirements of NERC Standard BAL-001-2. It also incorporates the current timeline for EIM market processes, as well as EIM resource deviations and diversity benefits based on actual results. The FRS also includes adjustments to regulation reserve requirements to account for the changing portfolio of solar and wind resources on PacifiCorp's system and accounts for the diversity of using a single portfolio of regulation

[5] 2019 Flexible Reserve Study, Appendix F in Volume II of PacifiCorp's 2019 IRP report: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2019_IRP_Volume_II_Appendices_A-L.pdf

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 2019 IRP is shown in Table F.1 and Table F.2. Flexible resource costs are portfolio dependent and vary over time. For more details please refer to Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs.

Table F.1 - Portfolio Regulation Reserve Requirements

Case	Wind Capacity (MW)	Solar Capacity MW	Stand-alone Regulation Requirement (MW)	Portfolio Diversity Credit (%)	Regulation Requirement with Diversity (MW)
CY2017 (2019 IRP)	2,750	1,021	994	47%	531
2018-2019 (2021 IRP)	2,745	1,080	1,057	49%	540

Table F.2 - 2021 FRS Flexible Resource Costs as Compared to 2019 Costs, $/MWh

	Wind 2019 FRS (2018$)	Solar 2019 FRS (2018$)	Wind 2021 FRS (2020$)	Solar 2019 FRS (2018$)
Study Period	2018-2036	2018-2036	2023-2040	2023-2040
Flexible Resource Cost	$1.11	$0.85	$1.30	$1.09

Flexible Resource Requirements

PacifiCorp's flexible resource needs are the same as its operating reserve requirements over the planning horizon for maintaining reliability and compliance with NERC regional reliability standards. Operating reserve generally consists of three categories: (1) contingency reserve (i.e., spinning and supplemental reserve), (2) regulation reserve, and (3) frequency response reserve. Contingency reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC regional reliability standard BAL-002-WECC-2a.[6] Regulation reserve is capacity that PacifiCorp holds available to ensure compliance with the NERC Control Performance Criteria in BAL-001-2.[7] Frequency response reserve is capacity that PacifiCorp holds available to ensure compliance with NERC standard BAL-003-1.[8] 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.

[6] NERC Standard BAL-002-WECC-2a – Contingency Reserve: www.nerc.com/files/BAL-002-WECC-2a.pdf
[7] NERC Standard BAL-001-2 – Real Power Balancing Control Performance: www.nerc.com/files/BAL-001-2.pdf
[8] NERC Standard BAL-003-1 — Frequency Response and Frequency Bias Setting: www.nerc.com/pa/Stand/Reliability%20Standards/BAL-003-1.pdf

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.[9]

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…*

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 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.

[9] 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

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 2020 frequency response obligation was 19.4 MW/0.1Hz for PACW, and 49.1 MW/0.1Hz for PACE.[10] PacifiCorp's combined obligation amounts to 68.5 MW for a frequency drop of 0.1 Hz, or 205.5 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

[10] NERC. 2020 Frequency Bias Settings Effective 6/2/2020: www.nerc.com/comm/OC/Documents/BAL-003_Frequency_Bias_Settings_02Jun2020.pdf
[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

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, 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.

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

[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

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 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 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 study period includes an average of 2,745 megawatts of wind and 1,080 megawatts of solar.

Non-VER Data

The Non-VER class is a mix of thermal and hydroelectric resources and includes all resources which are not VERs, and which do not provide either contingency or regulation reserve. Non-VERs, in contrast to VERs, are often more stable and predictable. Non-VERs are thus easier to plan for and maintain within a reliable operating state. For example, in Order No. 764, FERC

[13] Order No. 764 at P 281; Order No. 764-B at P 210.
[14] Order No. 764 at P 20 (emphasis added).

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 in the study.

Regulation Reserve Data Analysis and Adjustment

Overview

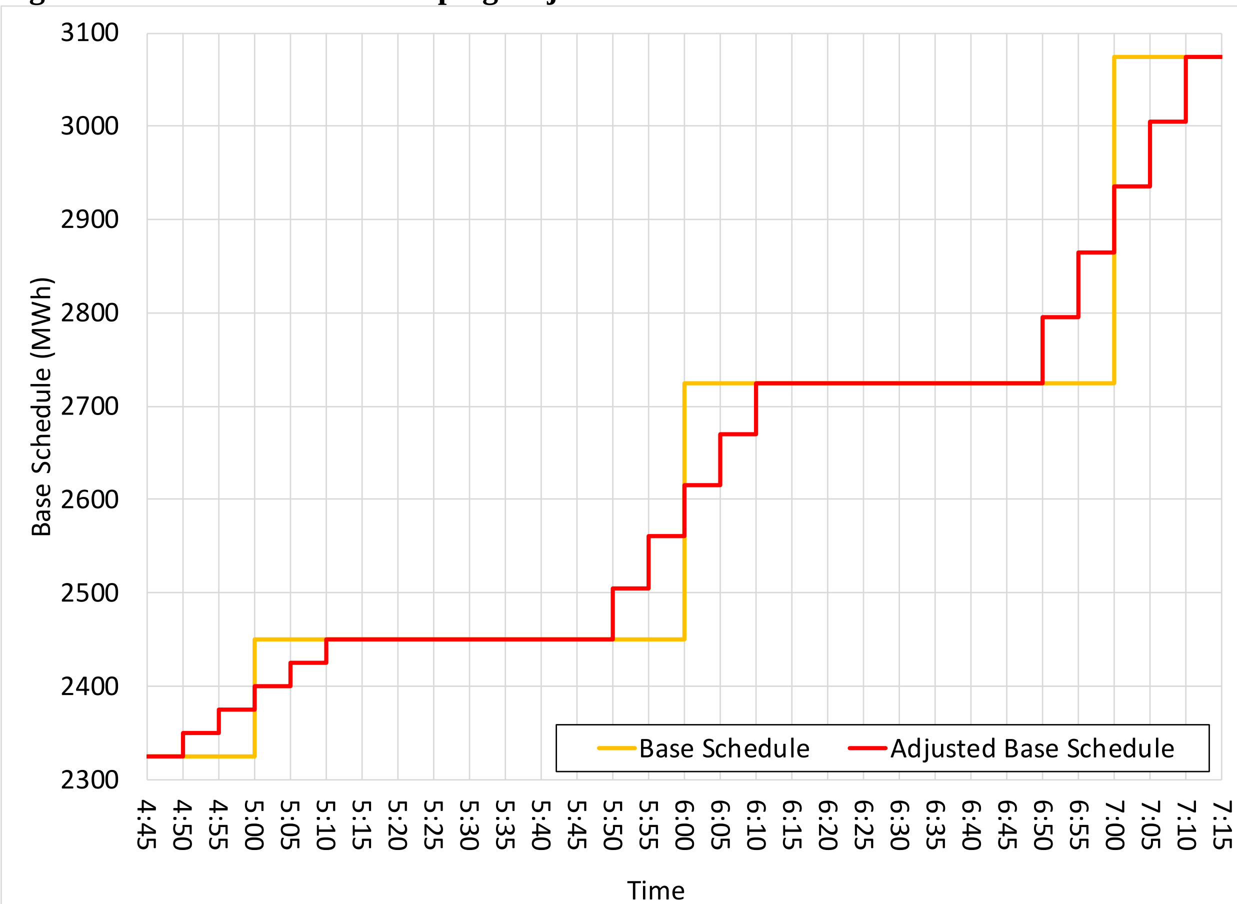
This section provides details on adjustments made to the data to align the ACE calculation with actual operations, and address data issues.

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 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.

[15] *Id.* at P 92.

Figure F.1 - Base Schedule Ramping Adjustment



Data Corrections

The data extracted from PacifiCorp's systems for, wind, solar and Non-VERs was sourced from CAISO settlement quality data. This data has already been verified for inconsistencies as part of the settlement process and needs minimal cleaning as described below. Regarding five-minute interval load data from the PI Ranger system, intervals were excluded from the FRS results if any five-minute interval suffered from at least one of the data anomalies that are described further below:

Load:

- Telemetry spike/poor connection to meter
- Missing meter data
- Missing base schedules

VERs:

- Curtailment events

Load in PacifiCorp's BAAs changes continuously. While a BAA could potentially maintain the exact same load levels in two five-minute intervals in a row, it is extremely unlikely for the exact same load level to persist over longer time frames. When PacifiCorp's energy management system

(EMS) load telemetry fails, updated load values may not be logged, and the last available load measurement for the BAA will continue to be reported.

Rapid spikes in load telemetry either up or down are unlikely to be the result of conditions which require deployment of regulation reserve, particularly when they are transient. Such events could be a result of a transmission or distribution outage, which would allow for the deployment of contingency reserve, and would not require deployment of regulation reserve. Such events are also likely to be a result of a single bad load measurement. Load telemetry spike irregularities were identified by examining the intervals with the largest changes from one interval to the next, either up or down. Intervals with inexplicably large and rapid changes in load, particularly where the load reverts back within a short period, were assumed to have been covered through contingency reserve deployment or to reflect inaccurate load measurements. Because they do not reflect periods that require regulation reserve deployment, such intervals are excluded from the analysis. During the study period, in PACW 15 minutes' worth of telemetry spikes were excluded while no telemetry spikes were observed in PACE. There were also 10 minutes' worth of missing load meter data, and 82 hours of missing load base schedules.

The available VER data includes wind curtailment events which affect metered output. When these curtailments occur, the CAISO sends data, by generator, indicating the magnitude of the curtailment. This data is layered on top of the actual meter data to develop a proxy for what the metered output would have been if the generator were not curtailed. Regulation reserve requirements are calculated based on the shortfall in actual output relative to base schedules. By adding back curtailed volumes to the actual metered output, the shortfall relative to base schedules is reduced, as is the regulation reserve requirement. This is reasonable since the curtailment is directed by the CAISO or the transmission system operator to help maintain reliable operation, so it should not exacerbate the calculated need for regulation reserves.

After review of the data for each of the above anomaly types, and out of 210,216 five-minute intervals evaluated, approximately 1,000 five-minute intervals, or 0.5% of the data, was removed due to data errors. While cleaning up or replacing anomalous hours could yield a more complete data set, determining the appropriate conditions in those hours would be difficult and subjective. By removing anomalies, the FRS sample is smaller but remains reflective of the range of conditions PacifiCorp experiences, including the impact on regulation reserve requirements of weather events experienced during the study period.

Regulation Reserve Requirement Methodology

Overview

This section presents the methodology used to determine the initial regulation reserve needed to manage the load and resource balance within PacifiCorp's BAAs. The five-minute interval load and resource deviation data described above informs a regulation reserve forecast methodology that achieves the following goals:

- Complies with NERC standard BAL-001-2;
- Minimizes regulation reserve held; and

- Uses data available at time of EIM base schedule submission at T-40.[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. 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:

[16] *See* footnote 12 above for explanation of PacifiCorp's use of the T-40 base schedule time point in the FRS.
[17] NERC Standard BAL-001-2, www.nerc.com/files/BAL-001-2.pdf

> *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 circumstances, rather than acquiring resources for extremely unlikely events. The reliability target balances the cost of additional capacity against the benefit of incrementally more reliable operation. By planning to curtail firm load in the rare event of a regulation reserve shortage, PacifiCorp can maintain the required 100 percent compliance with the BAL-001-2 standard and the Balancing Authority ACE Limit. This balances the cost of holding additional regulation reserve against the likelihood of regulation reserve shortage events.

The FRS assumes that a regulation reserve forecasting methodology that results in 0.50 loss of load hours per year due to regulation reserve shortages is appropriate for planning and ratemaking purposes. This is in addition to any loss of load resulting from transmission or distribution outages, resource adequacy, or other causes. The FRS applies this reliability target as follows:

- If the regulation reserve available is greater than the regulation reserve need for an hour, the LOLP is zero for that hour.
- If the regulation reserve held is less than the amount needed, the LOLP is derived from the Balancing Authority ACE Limit probability distribution as illustrated below.

Balancing Authority ACE Limit: Allowed Deviations

Even if insufficient regulation reserve capability is available to compensate for a thirty-minute sustained deviation, a violation of BAL-001-2 does not occur unless the deviation also exceeds the Balancing Authority ACE Limit.

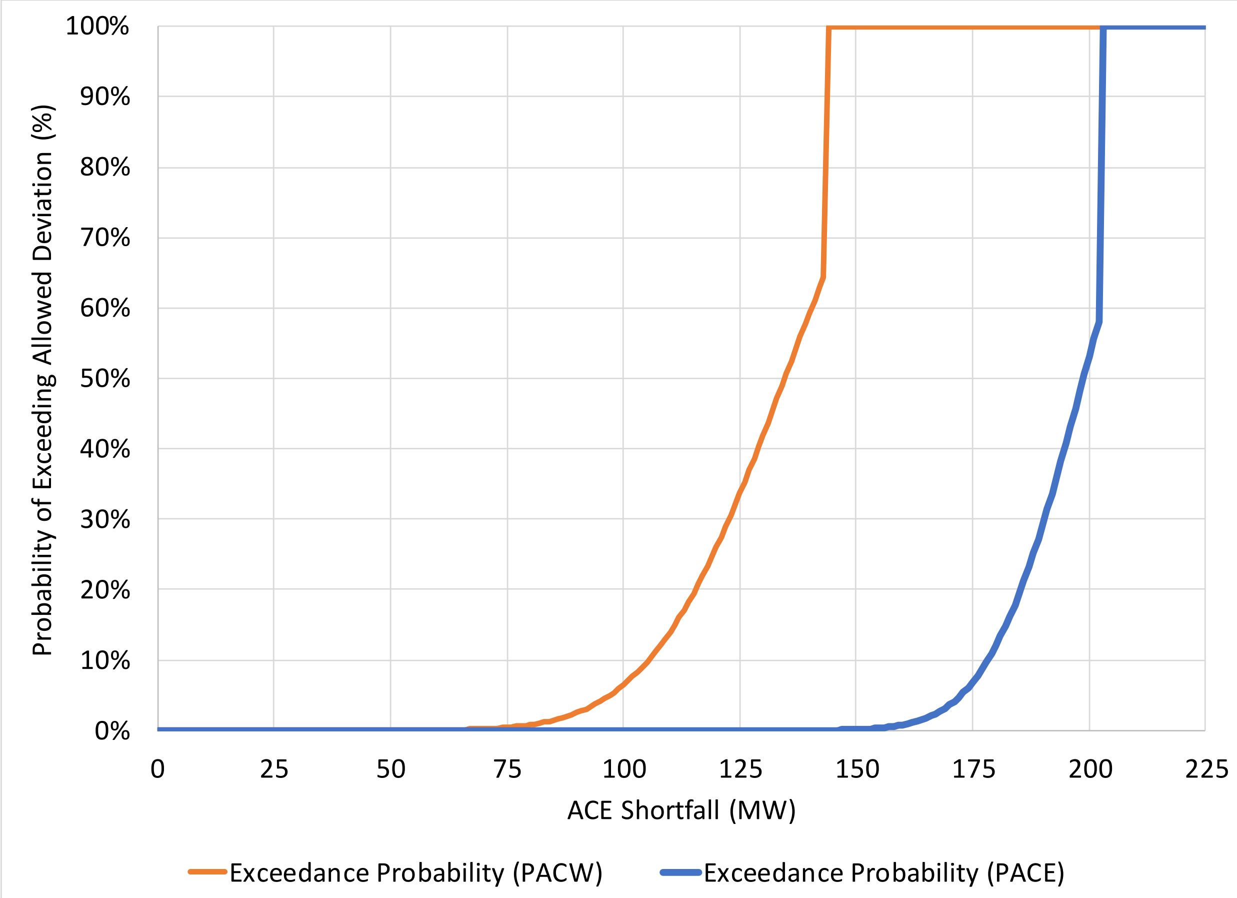
The Balancing Authority ACE Limit is specific to each BAA and is dynamic, varying as a function of interconnection frequency. When WECC frequency is close to 60 Hz, the Balancing Authority ACE Limit is large and large deviations in ACE are allowed. As WECC frequency drops further and further below 60 Hz, ACE deviations are increasingly restricted for BAAs that are contributing to the shortfall, *i.e.* those BAAs with higher loads than resources. A BAA commits a BAL-001-2 reliability violation if in any thirty-minute interval it does not have at least one minute when its ACE is within its Balancing Authority ACE Limit.

While the specific Balancing Authority ACE Limit for a given interval cannot be known in advance, the historical probability distribution of Balancing Authority ACE Limit values is known. Figure F.2 below shows the probability of exceeding the allowed deviation during a five-minute interval for a given level of ACE shortfall. For instance, an 82 MW ACE shortfall in PACW has a one percent chance of exceeding the Balancing Authority ACE Limit. WECC-wide frequency can change rapidly and without notice, and this causes large changes in the Balancing Authority ACE Limit over short time frames. Maintaining ACE within the Balancing Authority ACE Limit under those circumstances can require rapid deployment of large amounts of operating reserve. To limit the size and speed of resource deployment necessitated by variation in the Balancing Authority ACE Limit, PacifiCorp's operating practice caps permissible ACE at the lesser of the Balancing Authority ACE Limit or four times L_{10}. This also limits the occurrence of transmission flows that exceed path ratings as result of large variations in ACE.[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 2018-2019, PacifiCorp's deviations and Balancing Authority ACE Limits were uncorrelated, which indicates that PacifiCorp's contribution to WECC-wide frequency is small. PacifiCorp's deviations and Balancing Authority ACE Limits were also uncorrelated when periods with large deviations were examined in isolation. If PacifiCorp's large deviations made distinguishable contributions to the Balancing Authority ACE Limit, ACE shortfalls would be more likely to exceed the Balancing Authority ACE Limit during large deviations. Since this is not the case, the probability of exceeding the Balancing Authority ACE Limit is lower, and less regulation reserve is necessary to comply with the BAL-001-2 standard.

Regulation Reserve Forecast: Amount Held

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. Quantile regression is a type of regression analysis. Whereas the typical method of ordinary least squares results in estimates of the conditional mean (50^{th} percentile) of the response variable given certain values of the predictor variables, quantile regression aims at estimating other specified percentiles of the response variable. Eight regressions were prepared, one for each class (load/wind/solar/non-VER) and area (PACE/PACW). Each regression uses the following variables:

- Response Variable: the error in each interval, in megawatts;
- Predictor Variable: the forecasted generation or load in each interval, expressed as a percentage of area capacity;

The forecasted generation or load in each interval used as the predictor variable contributes to the regression as a combination of linear, square, and higher order exponential effects. Specifically, the regression identifies coefficients that correspond to the following functions for each class:

Load Error: Load Forecast^1 + Constant
Wind Error: Wind Forecast^2 + Wind Forecast^1
Solar Error: Solar Forecast^4 + Solar Forecast^3 + Solar Forecast^2 + Solar Forecast^1
Non-VER Error: Non-VER Forecast^2 + Non-VER Forecast^1

The instances requiring the largest amounts of regulation reserve occur infrequently, and many hours have very low requirements. If periods when requirements are likely to be low can be distinguished from periods when requirements are likely to be high, less regulation reserve is necessary to achieve a given reliability target. The regulation reserve forecast is not intended to compensate for every potential deviation. Instead, when a shortfall occurs, the size of that shortfall determines the probability of exceeding the Balancing Authority ACE Limit and a reliability violation occurring. The forecast is adjusted to achieve a cumulative LOLP that corresponds to the annual reliability target.

Regulation Reserve Forecast

Overview

The following forecasts are polynomial functions that cover a targeted percentile of all historical deviations. These forecasts are stand-alone forecasts, based on the difference between hour-ahead base schedules and actual meter data, expressing the errors as a function of the level of forecast. The stand-alone reserve requirement shown achieves the annual reliability target of 0.5 hours per year, after accounting for the dynamic Balancing Authority ACE Limit. The combined diversity error system requirements are discussed later on in the study. Figure F.3- Figure F.8 illustrate the relationship between the regulation reserve requirements during 2018-2019 and the forecasted level of output, for each resource class and control area. Both the regulation reserve requirements and the forecasted level of output are expressed as a percentage of resource nameplate (*i.e.*, as a capacity factor). Figure F.9 and Figure F.10 illustrate the same relationship between the regulation reserve requirements during 2018-2019 and the forecasted load for each control area. Both the regulation reserve requirements and the forecasted load are expressed as a percentage of the annual peak load (*i.e.*, as a load factor).

Figure F.3 - Wind Regulation Reserve Requirements by Forecast - PACE

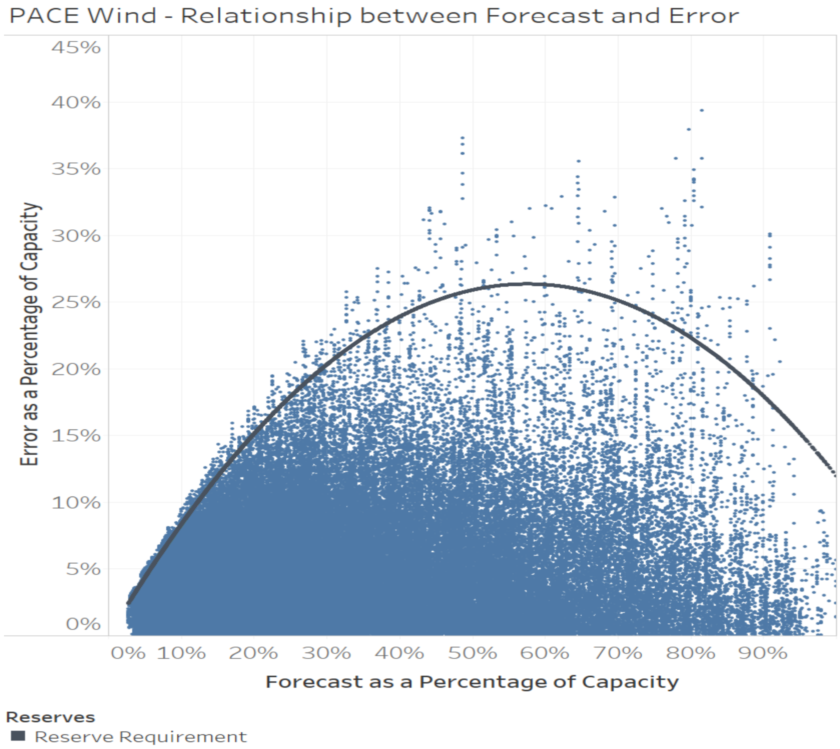


Figure F.4 - Wind Regulation Reserve Requirements by Forecast Capacity Factor - PACW

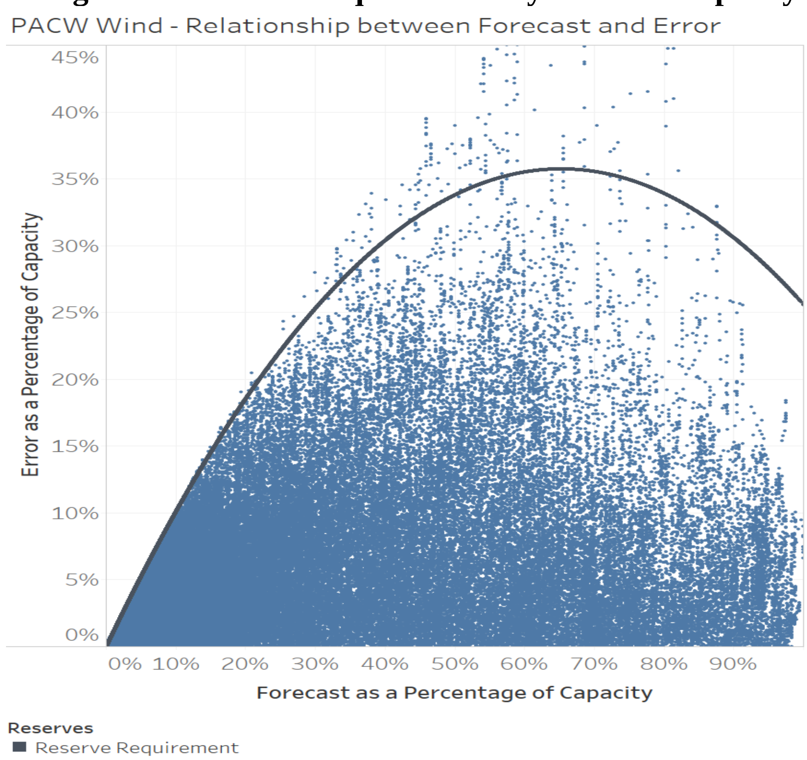


Figure F.5 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACE

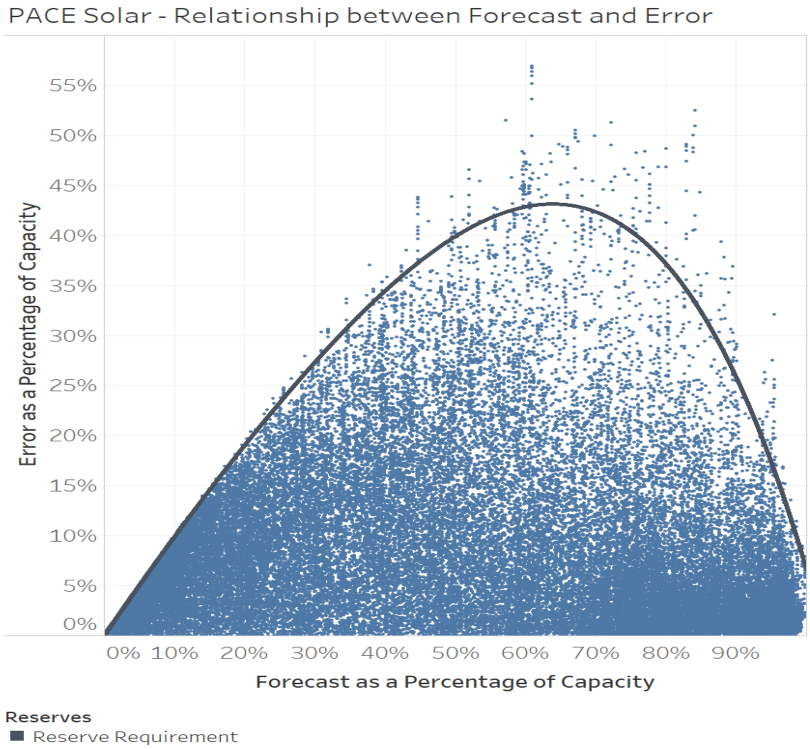


Figure F.6 - Solar Regulation Reserve Requirements by Forecast Capacity Factor - PACW

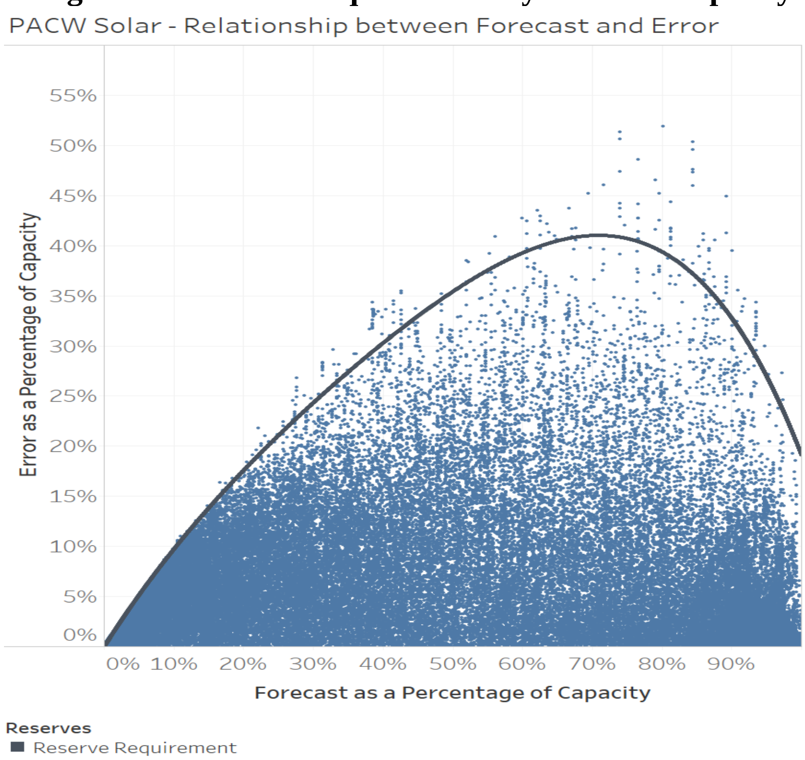


Figure F.7 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACE

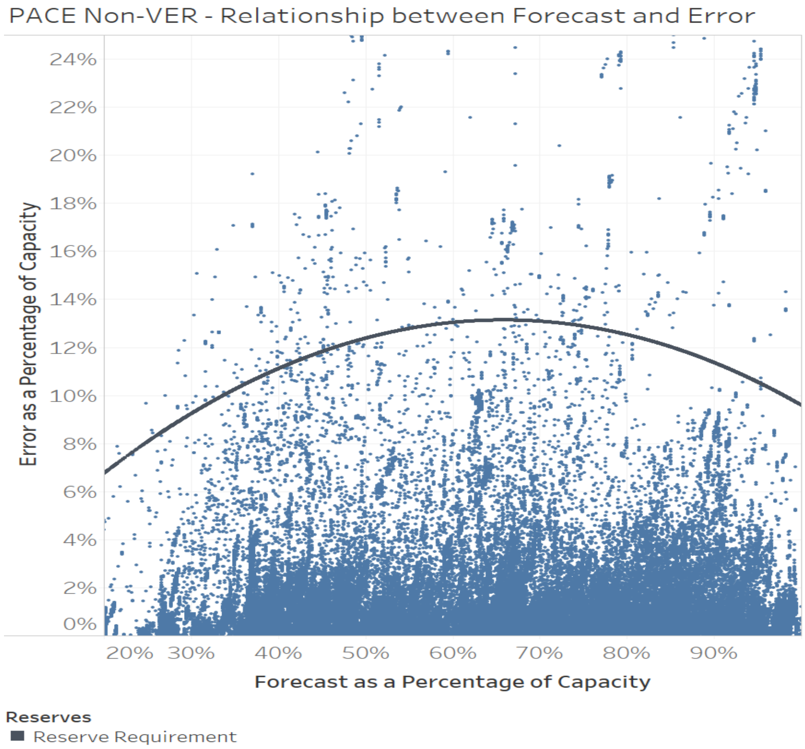


Figure F.8 – Non-VER Regulation Reserve Requirements by Capacity Factor - PACW

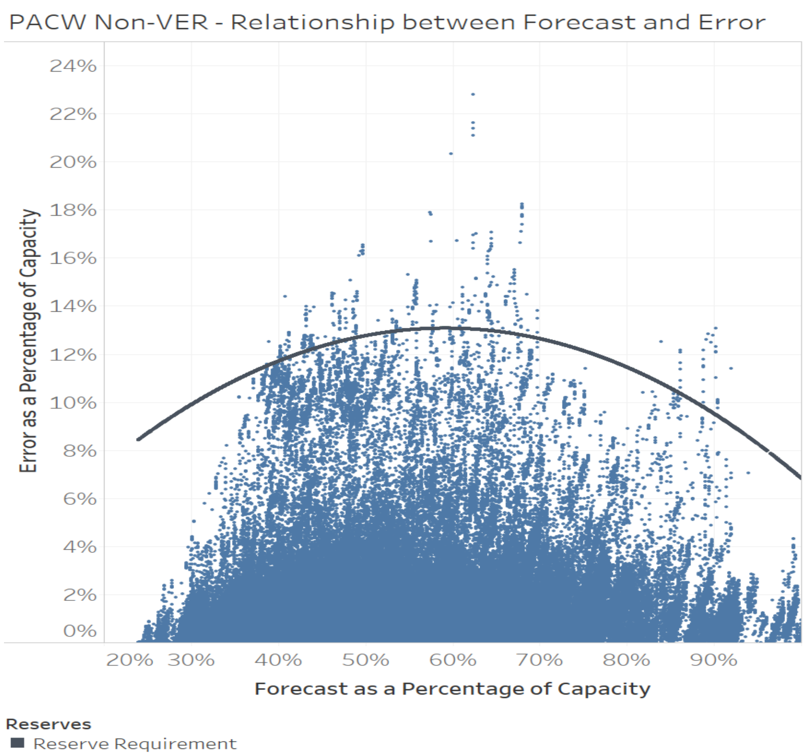


Figure F.9 – Stand-alone Load Regulation Reserve Requirements - PACE

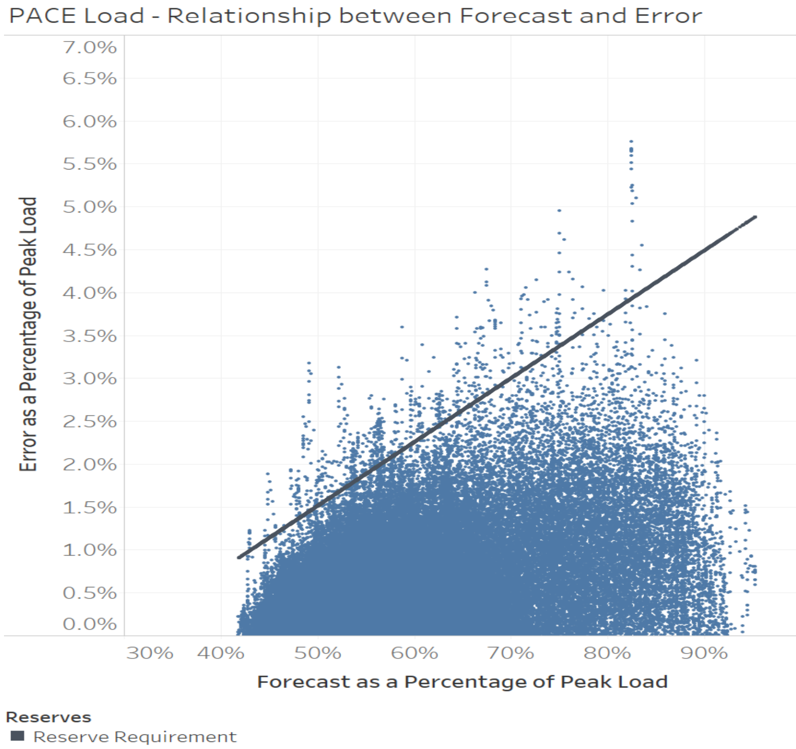
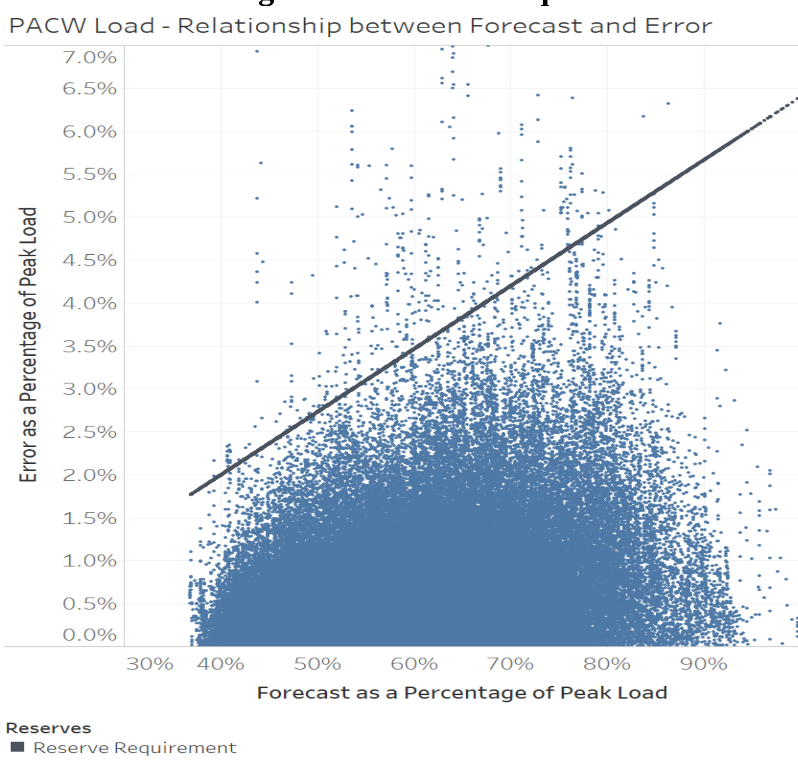


Figure F.10 – Stand-alone Load Regulation Reserve Requirements - PACW



The results of the analysis are shown in Figure F.3 below.

Table F.3 – Summary of Stand-alone Regulation Reserve Requirements

Scenario	Stand-alone Regulation Forecast (aMW)	Capacity (MW)	Stand-alone Regulation Forecast (%)
Non-VER	106	1,304	8.2%
Load	334	10,094	3.3%
VER - Wind	457	2,745	16.7%
VER - Solar	159	1,080	14.8%
Total	**1,057**		

Portfolio Diversity and EIM Diversity Benefits

The EIM is a voluntary energy imbalance market service through the CAISO where market systems automatically balance supply and demand for electricity every fifteen and five minutes, dispatching least-cost resources every five minutes.

PacifiCorp and CAISO began full EIM operation on November 1, 2014. 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. In the historical period, portfolio diversity from the interactions between the various classes results in a regulation reserve requirement that is 36% lower than the sum of the stand-alone requirements, or approximately 679 MW.

EIM Diversity Benefit

In addition to the direct benefits from EIM's increased system visibility and improved intra-hour operational performance described above, the participation of other entities in the broader EIM footprint provides the opportunity to further reduce the amount of regulation reserve PacifiCorp must hold.

By pooling variability in load and resource output, EIM entities reduce the quantity of reserve required to meet flexibility needs. The EIM also facilitates procurement of flexible ramping capacity in the fifteen-minute market to address variability that may occur in the five-minute market. Because variability across different BAAs may happen in opposite directions, the flexible ramping requirement for the entire EIM footprint can be less than the sum of individual BAA requirements. This difference is known as the "diversity benefit" in the EIM. This diversity benefit reflects offsetting variability and lower combined uncertainty. This flexibility reserve (uncertainty requirement) is in addition to the spinning and supplemental reserve carried against generation or transmission system contingencies under the NERC standards.

The CAISO calculates the EIM diversity benefit by first calculating an uncertainty requirement for each individual EIM BAA and then by comparing the sum of those requirements to the uncertainty requirement for the entire EIM area. The latter amount is expected to be less than the sum of the uncertainty requirements from the individual BAAs due to the portfolio diversification effect of forecasting a larger pool of load and resources using intra-hour scheduling and increased system visibility in the hypothetical, single-BAA EIM. Each EIM BAA is then credited with a share of the diversity benefit calculated by CAISO based on its share of the stand-alone requirement relative to the total stand-alone requirement.

The EIM does not relieve participants of their reliability responsibilities. EIM entities are required to have sufficient resources to serve their load on a standalone basis each hour before participating in the EIM. Thus, each EIM participant remains responsible for all reliability obligations. Despite these limitations, EIM imports from other participating BAAs can help balance PacifiCorp's loads and resources within an hour, reducing the size of reserve shortfalls and the likelihood of a Balancing Authority ACE Limit violation. While substantial EIM imports do occur in some hours, it is only appropriate to rely on PacifiCorp's diversity benefit associated with EIM participation, as these are derived from the structure of the EIM rather than resources contributed by other participants.

Table F.4 below provides a numeric example of uncertainty requirements and application of the calculated diversity benefit.

Table F.4 – EIM Diversity Benefit Application Example

	a	b	c	d	e =a+b+c+d	f	g = e-f	h = g / e	i = c * h	j = c - i
Hour	CAISO req't. before benefit (MW)	NEVP req't. before benefit (MW)	PACE req't. before benefit (MW)	PACW req't. before benefit (MW)	Total req't. before benefit (MW)	Total req't. after benefit (MW)	Total diversity benefit (MW)	Diversity benefit ratio (MW)	PACE benefit (MW)	PACE req't. after benefit (MW)
1	550	110	165	100	925	583	342	37.00%	61	104
2	600	110	165	100	975	636	339	34.80%	57	108
3	650	110	165	110	1,035	689	346	33.40%	55	110
4	667	120	180	113	1,080	742	338	31.30%	56	124

While the diversity benefit is uncertain, that uncertainty is not significantly different from the uncertainty in the Balancing Authority ACE Limit previously described. In the FRS, PacifiCorp has credited the regulation reserve forecast based on a historical distribution of calculated EIM diversity benefits. While this FRS considers regulation reserve requirements in 2018-2019, the CAISO identified an error in their calculation of uncertainty requirements in early 2018. CAISO's published uncertainty requirements and associated diversity benefits are now only valid for March 2018 forward. To capture these additional benefits for this analysis, PacifiCorp has applied the historical distribution of EIM diversity benefits from the 12 months beginning March 2018. In the historical study period, EIM diversity benefits used in the FRS would have reduced regulation reserve requirements by approximately 140 MW.

The inclusion of EIM diversity benefits in the FRS reduces the magnitude, and thus probability, of reserve shortfalls and, in doing so, reduces the overall regulation reserve requirement. This allows PacifiCorp's forecasted requirements to be reduced. As shown in Table F.5 below, the resulting regulation reserve requirement is 540 MW, which is a 49 percent reduction (including the portfolio diversity benefit) compared to the stand-alone requirement for each class. This portfolio regulation forecast is expected to achieve an LOLP of 0.5 hours per year.

Table F.5 – 2018-2019 Results with Portfolio Diversity and EIM Diversity Benefits

Scenario	Stand-alone Regulation Forecast (aMW)	Stand-alone Rate (%)	Portfolio Regulation Forecast w/EIM (aMW)	Portfolio Rate (%)	Capacity (MW)	Rate Determinant
Non-VER	106	8.2%	55	4.2%	1,304	Nameplate
Load	334	3.3%	172	1.7%	10,094	12 CP
VER - Wind	457	16.7%	237	8.6%	2,745	Nameplate
VER - Solar	159	14.8%	76	7.1%	1,080	Nameplate
Total	**1,057**		**540**			

Fast-Ramping Reserve Requirements

As previously discussed, Requirement 1 of BAL-001-2 specifies that PacifiCorp's CPS1 score must be greater than equal to 100 percent for each preceding 12 consecutive calendar month period, evaluated monthly. The CPS1 score compares PacifiCorp's ACE with interconnection frequency during each clock minute. A higher score indicates PacifiCorp's ACE is helping interconnection frequency, while a lower score indicates it is hurting interconnection frequency. Because CPS1 is averaged and evaluated on a monthly basis, it does not require a response to each and every ACE event, but rather requires that PacifiCorp meet a minimum aggregate level of performance in each month.

The Regulation Reserve Forecast described above is evaluating requirements for extreme deviations that are at least 30 minutes in duration, for compliance with Requirement 2 of BAL-001-2. In contrast, compliance with CPS1 requires reserve capability to compensate for the majority of conditions over a minute-to-minute basis. These fast-ramping resources would be deployed frequently and would also contribute to compliance with Requirement 2 of BAL-001-2, so they are a subset of the Regulation Reserve Forecast described above.

To evaluate CPS1 requirements, PacifiCorp compared the net load change for each five-minute interval in the study period to the corresponding value for Requirement 2 compliance in that hour from the Regulation Reserve Forecast, after accounting for diversity (resulting in a 540 MW average requirement). Resources may deploy for Requirement 2 compliance over up to 30 minutes, so the average requirement of 540 MW would require ramping capability of at least 18.0 MW per minute (540 MW / 30 minutes).

Because CPS1 is averaged and evaluated 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 CPS1 and given that ACE may deviate in either a positive or negative direction, the 97.5th percentile of incremental requirements versus Requirement 2 in that interval was evaluated. At the 97.5th percentile, fast ramping requirements for PACE and PACW are 1.7 MW/minute and 0.8 MW/minute higher than the Requirement 2 ramp rate, respectively; however, if dynamic transfers between the BAAs are available, the 97.5th percentile for system as a whole is 0.6 MW / minute lower than the Requirement 2 value. When viewed on a system basis, this means that 30-minute ramping capability held for Requirement 2 would be sufficient to cover an adequate portion of the fast-ramping events to ensure CPS1 compliance.

Note that resources must respond immediately to ensure compliance with Requirement 1, as performance is measured on a minute-to-minute basis. As a result, resources that respond after a delay, such as quick-start gas plants or certain interruptible loads, would not be suitable for Requirement 1 compliance, so these resources cannot be allocated the entire regulation reserve requirement. However, because Requirement 1 compliance is a small portion of the total regulation reserve requirement, these restrictions on resource type are unlikely to be a meaningful constraint.

In addition, CPS1 compliance is weighted toward performance during conditions when interconnection frequency deviations are large. The largest frequency deviations would also result in deployment of frequency response reserves, which are somewhat larger in magnitude, though they have a less stringent performance metric under BAL-003-1, 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 requirement beyond what is necessary to comply with those standards.

Portfolio Regulation Reserve Requirements

The IRP portfolio optimization process contemplates the addition of new wind and solar capacity as part of its selection of future resources, as well as changes in peak load due to load growth and energy efficiency measure selection. These load and resource changes are expected to drive changes in PacifiCorp's regulation reserve requirements that will vary from portfolio to portfolio.

The 2019 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 was quantified and used to extrapolate portfolio regulation results for larger quantities of VERs. While extrapolating beyond existing data could be reasonable to a certain extent, significant wind and solar capacity additions have already been committed and have entered service since 2019 or will enter service in the next few years, and very large amounts of wind and solar additions were identified in future years in the 2019 IRP portfolio, as shown in Table F.6. Given the magnitude of the increases, the trendlines used in the 2019 FRS may not adequately represent aggregate reserve requirements.

Table F.6 – Pending and Projected Wind and Solar Capacity Additions

Case	Wind Capacity (MW)	Solar Capacity (MW)	Wind Increase (%)	Solar Increase (%)
2018-2019 (Actual)	2,745	1,080		
Actual + Signed contracts through 12/31/21	4,312	1,937	+57%	+79%
Actual + Signed contracts through 12/31/23	4,312	2,427	+57%	+125%
Actual + Signed + 19IRP Pref. Port 2024	6,232	4,581	+127%	+324%
Actual + Signed + 19IRP Pref. Port 2030	7,282	5,440	+165%	+404%

The locations that have been identified as likely sites for future wind and solar additions are in relatively close proximity to existing wind and solar resources: wind mostly in eastern Wyoming and solar mostly in southern Utah and southern Oregon. The trendline analysis performed in the 2019 FRS assumed that incremental resources continue to provide increasing levels of diversity; however, future resources added in close proximity to existing resources are likely to have lower than average diversity for that class of resources. Given the sizeable sample of existing wind and solar resources in PACE and PACW, maintaining the existing level of diversity as a class of resources doubles or quadruples is a more likely outcome than the continuing improvements assumed in the 2019 FRS. With that in mind, the incremental regulation reserve analysis for the

2021 FRS assumes that wind, solar, and load deviations scale linearly with capacity increases from the actual data in the 2018-2019 historical period.

While diversity within each class is not expected to change significantly, there is the opportunity for greater diversity among the wind, solar, and load requirements. These portfolio-related benefits are inherently tied to the portfolio as a whole, so it is appropriate that they vary with the portfolio. To that end, for the 2021 FRS PacifiCorp has calculated the portfolio diversity benefits specific to a wide variety of wind and solar capacity combinations, rather than relying upon the historical portfolio diversity value.

As part of the portfolio diversity calculation, the analysis assumes that minimum EIM flexible reserve requirements and EIM diversity benefits scale with changes in portfolio capacity. EIM minimum flexible reserve requirements are tied to the uncertainty in PacifiCorp's requirements, which grow with changes portfolio capacity, so it would be impacted directly. EIM diversity benefits reflect PacifiCorp's share of stand-alone requirements relative to those of the rest of the BAA's participating in EIM. All else being equal, increases in PacifiCorp's portfolio capacity would result in a greater proportion of the EIM diversity benefits being allocated to PacifiCorp.

Portfolio diversity is driven by interplay among the deviations by wind, solar, and load, so it is not a single number, but rather is dependent on the specific conditions. The 2021 FRS incorporates two mechanisms to better account for these interactions. First, a portfolio diversity value is calculated specific to each hour of the day in each season. Second, rather than applying an equal percentage reduction to all hours, diversity benefits are assumed to be highest when stand-alone requirements are highest. For example, there is more opportunity for offsetting requirements when load, wind, and solar all have significant stand-alone requirements. With that in mind, diversity is applied as an exponent to the incremental requirement in excess of the EIM minimum requirement. The result of this calculation is a diversity benefit which is highest for large reserve requirements, and which approaches zero as the requirement approaches the EIM minimum, as illustrated in Table F.7.

Table F.7 – Portfolio Diversity Exponent Example

			Incremental Requirement w/ Diversity (MW) By Diversity Exponent			Portfolio Diversity (%) By Diversity Exponent		
Stand-alone Reserve Req. (MW)	EIM Floor (MW)	Stand-alone Incremental Req. (MW)	d = c ^ 75%	e = c ^ 85%	f = c ^ 95%	g = 1 - (b + d)/a	h = 1 - (b + e)/a	i = 1 - (b + f)/a
a	b	c = a - b	75%	85%	95%	75%	85%	95%
200	200	0	0	0	0	0%	0%	0%
250	200	50	19	28	41	12%	9%	4%
300	200	100	32	50	79	23%	17%	7%
350	200	150	43	71	117	31%	23%	9%
400	200	200	53	90	153	37%	27%	12%
450	200	250	63	109	190	42%	31%	13%
500	200	300	72	128	226	46%	34%	15%

For each combination of wind and solar capacity, the hourly portfolio diversity exponents for each season are increased in a stepwise fashion until the risk of regulation reserve shortfalls during an interval is sufficiently low and the overall risk of regulation reserve shortfalls achieves the target

of 0.5 hours per year. The resulting portfolio diversity is maximized for a combination of wind and solar as summarized in Table F.8 and Table F.9 for PacifiCorp East and PacifiCorp West, respectively.

Table F.8 – PacifiCorp East Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

East Wind Capacity MW	%								
8,224	548%	17.2%	18.8%	20.6%					*Not enough interconnection*
7,184	472%	19.2%	21.5%	23.0%	25.5%	26.5%			*capacity in 2021 IRP*
6,144	395%	22.9%	24.1%	25.6%	27.9%	28.5%	29.0%		*to reach*
5,104	319%	26.0%	27.3%	29.2%	30.7%	30.7%	30.5%	29.5%	*these*
4,064	242%	30.4%	31.6%	32.9%	33.8%	32.7%	32.8%	32.8%	*levels*
3,024	166%	35.0%	36.2%	38.5%	37.1%	37.6%	36.2%	33.9%	31.9%
1,575	100%		**48.0%**	45.8%	43.1%	39.5%	35.8%	32.2%	29.4%
788	50%			46.4%	40.3%	36.4%	33.0%	30.0%	27.3%
East Solar Capacity	%	50%	100%	166%	329%	493%	656%	820%	983%
	MW	428	855	1,462	2,502	3,542	4,582	5,622	6,662

☐ 2018-2019 Actual Wind and Solar Capacity

Table F.9 – PacifiCorp West Diversity by Portfolio Composition

(% Reduction vs. Stand-alone Requirements)

West Wind Capacity MW	%								
4,389	548%	21.1%	22.4%	22.9%					*Not enough interconnection*
3,669	472%	23.4%	24.8%	25.4%	29.0%	33.0%			*capacity in 2021 IRP*
2,949	395%	26.2%	26.7%	27.6%	32.1%	34.8%	38.1%		*to reach*
2,229	319%	29.6%	30.6%	31.4%	36.2%	39.5%	42.7%	42.7%	*these*
1,509	242%	33.8%	34.5%	36.3%	40.8%	45.2%	46.2%	43.9%	*levels*

789	**166%**	38.8%	41.6%	43.1%	47.6%	48.4%	47.7%	45.0%	44.3%	
726	**100%**		42.4%	42.9%	48.6%	49.3%	47.7%	46.2%	44.4%	
363	**50%**			41.7%	47.1%	49.8%	47.4%	45.0%	43.2%	
		50%	**100%**	**166%**	**329%**	**493%**	**656%**	**820%**	**983%**	**%**
		111	**221**	**321**	**1,041**	**1,761**	**2,481**	**3,201**	**3,921**	**MW**

West Solar Capacity

2018-2019 Actual Wind and Solar Capacity

After portfolio selection is complete, regulation reserve requirements are calculated specific to a portfolio's load, wind, and solar resources in each year. The hourly regulation reserve requirement varies as a function of annual peak load net of energy efficiency selections as well as total wind and solar capacity. The regulation reserve requirement also varies based on the hourly load net of energy efficiency and hourly wind and solar generation values. Diversity exponents specific to the wind and solar capacity in each year are applied by hour and season, by interpolating among the scenarios illustrated in Tables F.8 and F.9. For example, the diversity exponent for hour five in the spring for a PACW study with 1,000 MW of wind and 1,000 MW of solar would reflect a weighting of diversity exponents in hour five in the spring from four scenarios. The highest weighting would apply to the 789 MW wind/1,041 MW solar scenario, and successively lower weightings would apply to 1,509 MW wind/1,041 MW solar, 789 MW wind/321 MW solar, and 1,509 MW wind/321 MW solar, with the total weighting for all four scenarios summing to 100%.

Finally, an adjustment is made to account for the ability of resources that are combined with storage to offset their own generation shortfalls beyond what is already captured by the model. For example, combined solar and storage resources can offset their own generation shortfalls, up to their interconnection limit. In actual operation, a reduction in solar generation would enable additional storage discharge. However, within the Plexos model, there are no intra-hour variations in load or renewable resource output and thus no potential increase in storage discharge. Note that combined storage can only be discharged when there is a generation shortfall at the adjacent resource, so it cannot cover all shortfalls across the system. For example, many solar resources do not have co-located storage, and their errors would continue to need to be met with incremental reserves. Nonetheless, combined solar and storage can cover a portion of their own shortfalls, and that portion increases as more combined storage resources are added to the system. This adjustment reduces the hourly regulation reserve requirement that is entered in the model.

Regulation Reserve Cost

The Plexos model reports marginal reserve prices on an hourly basis. So long as the change in reserve obligations or capability from what was input for a study is relatively small, this reserve price can provide a reasonable estimate of the impact of changes in reserves, without requiring additional model runs.

To estimate wind and solar integration costs from the 2021 IRP, PacifiCorp prepared a Plexos scenario that reflected the final regulation reserve requirements, consistent with the Company's existing wind and resources plus selections in the P02-MM portfolio. Hourly regulation reserve prices were reported from this study.

Wind Integration

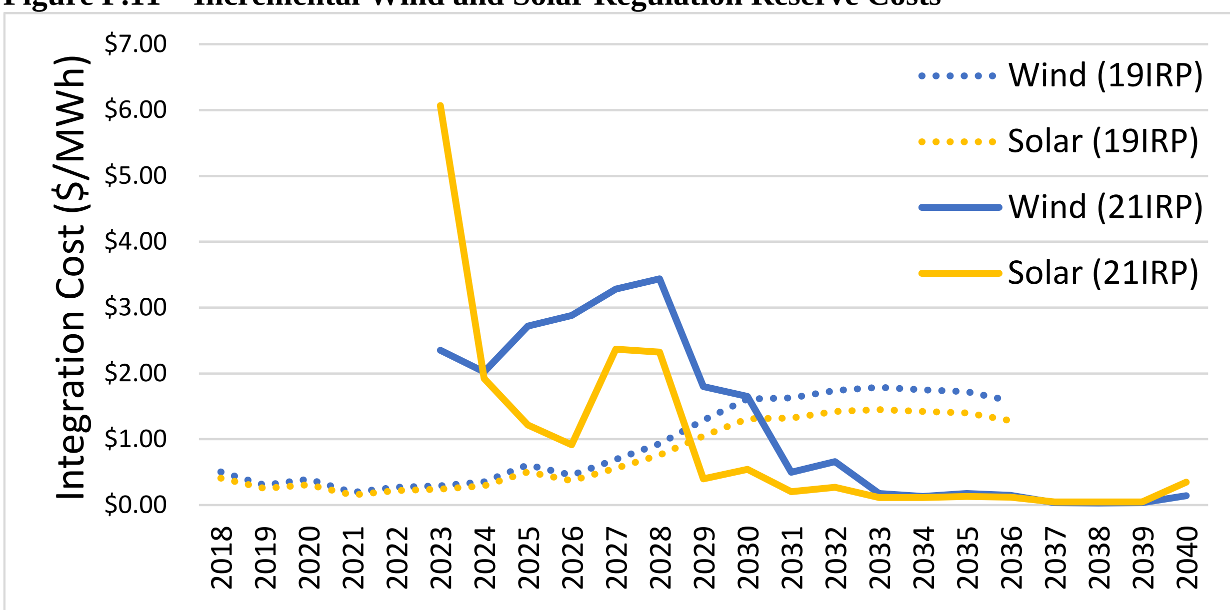
The wind reserve case uses the 2021 FRS methodology to recalculate the wind reserve requirement for a portfolio with 100 MW fewer wind resources in each year of the IRP study horizon (2021-2040). The reduction in resources is applied equally between PACE and PACW, and is allocated pro-rata among all wind resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. Removing this wind capacity decreases regulation reserve requirements by an average of 14 MW. Wind integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental wind generation over the year.

Solar Integration

The solar reserve case uses the 2021 FRS methodology to recalculate the solar reserve requirement for a portfolio with 100 MW fewer solar resources in each year of the IRP study horizon (2021-2040). The reduction in resources is applied equally between PACE and PACW, and is allocated pro-rata among all solar resources in the area, such that the aggregate hourly capacity factor is not impacted by the change in capacity. Removing this solar capacity decreases regulation reserve requirements by an average of 19 MW. Solar integration costs are calculated by multiplying the hourly change in reserve requirements (in MW) by the hourly regulation reserve price in each hour of the year, and then dividing that total by the incremental solar generation over the year.

The incremental regulation reserve cost results for wind and solar are shown in Figure F.11. The comparable regulation reserve costs from the 2019 FRS are also shown.

Figure F.11 – Incremental Wind and Solar Regulation Reserve Costs



Solar generation is highest in the summer, when market prices and the cost of holding incremental reserves is relatively high. The impact of the reduced summer market purchase limit in the 2021 IRP is likely a contributing factor in the 2023 solar integration value. However, as solar resources become more prevalent, they tend to cause backdown of thermal generation in an increasing number of hours, and reductions in marginal prices, instead of impacting higher cost market transactions. As a result, many hours can have low or zero regulation reserve costs as solar penetration gets high. Hybrid solar and storage resources also drive down regulation reserve costs from the supply side, as storage resources are well suited for providing reserves. Due to their high flexibility and limited energy capacity storage resources can respond quickly if needed, but would otherwise be unlikely to dispatch until marginal costs are expected to be highest. This results in many hours with an excess of regulation reserve capability at no cost. As storage becomes increasingly prevalent in the Company's portfolio after 2030, integration costs drop to under $0.20/MWh for both wind and solar. In the 2019 IRP, solar combined with storage only included storage equivalent to 25% of the solar nameplate, so it had a much small impact on regulation reserve supply, and costs remained relatively high.

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 2021 through 2040, and the calculation method used to estimate those requirements. PacifiCorp then identifies its supply of flexible capacity from its generation resources, in accordance with the Western Electricity Coordinating Council (WECC) operating reserve guidelines, demonstrating that PacifiCorp has sufficient flexible resources to meet its requirements.

Forecasted Reserve Requirements

Since contingency reserve and regulation reserve are separate and distinct components, PacifiCorp estimates the forward requirements for each separately. The contingency reserve requirements are derived from the Plexos model. The regulating reserve requirements are part of the inputs to the Plexos model and are calculated by applying the methods developed in the Portfolio Regulation Reserve Requirements section. The contingency and regulation reserve requirements include three distinct components and are modeled separately in the 2021 IRP: 10-minute spinning reserve requirements, 10-minute non-spinning reserve requirements, and 30-minute regulation reserve requirements. The average reserve requirements for PacifiCorp's two balancing authority areas are shown in Table F.10 below.

Table F.10 - 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)
2021	136	136	562	70	70	228
2022	140	140	572	71	71	213
2023	144	144	623	73	73	214
2024	146	146	624	74	74	200
2025	148	148	914	75	75	200
2026	145	145	905	76	76	329
2027	147	147	909	76	76	330
2028	148	148	912	77	77	327
2029	151	151	884	78	78	313
2030	153	153	931	79	79	298
2031	155	155	934	80	80	299
2032	157	157	936	81	81	393
2033	159	159	902	82	82	394
2034	161	161	890	82	82	392
2035	163	163	892	83	83	392
2036	164	164	870	84	84	393
2037	166	166	866	85	85	396
2038	168	168	869	85	85	396
2039	170	170	872	86	86	397
2040	171	171	882	86	86	387

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.11 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.

[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.

Table F.11 - Flexible Resource Supply Forecast (MW)

Year	East Supply (10-Minute)	West Supply (10-Minute)	East Supply (30-Minute)	West Supply (30-Minute)
2021	705	268	1,455	525
2022	791	327	1,412	462
2023	863	375	1,521	429
2024	1,312	473	1,770	395
2025	1,625	515	2,325	368
2026	1,653	1,062	2,247	949
2027	1,662	1,086	2,232	939
2028	1,777	1,146	2,226	973
2029	2,316	1,167	2,398	921
2030	2,299	1,677	2,378	1,305
2031	3,006	1,705	3,055	1,319
2032	3,011	1,714	3,053	1,453
2033	3,667	1,720	3,830	1,480
2034	3,691	1,732	3,811	1,476
2035	3,714	1,760	3,784	1,465
2036	3,750	1,782	3,742	1,468
2037	4,610	2,465	4,418	2,039
2038	4,661	2,716	4,413	2,272
2039	4,510	2,715	4,246	2,256
2040	4,553	3,243	4,275	2,449

Figure F.12 and Figure F.13 graphically display the balances of reserve requirements and capability of spinning reserve resources in PacifiCorp's East and West balancing authority areas respectively. The graphs demonstrate that PacifiCorp's system has sufficient resources to serve its reserve requirements throughout the IRP planning period.

Figure F.12 - Comparison of Reserve Requirements and Resources, East Balancing Authority Area (MW)

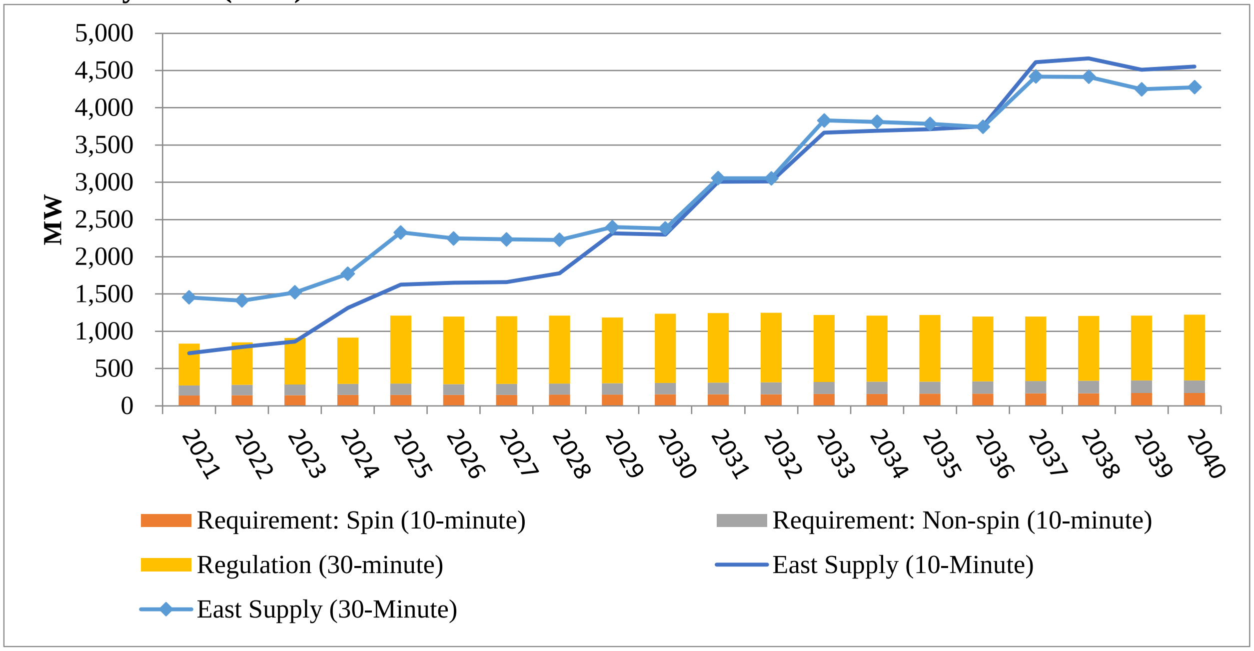
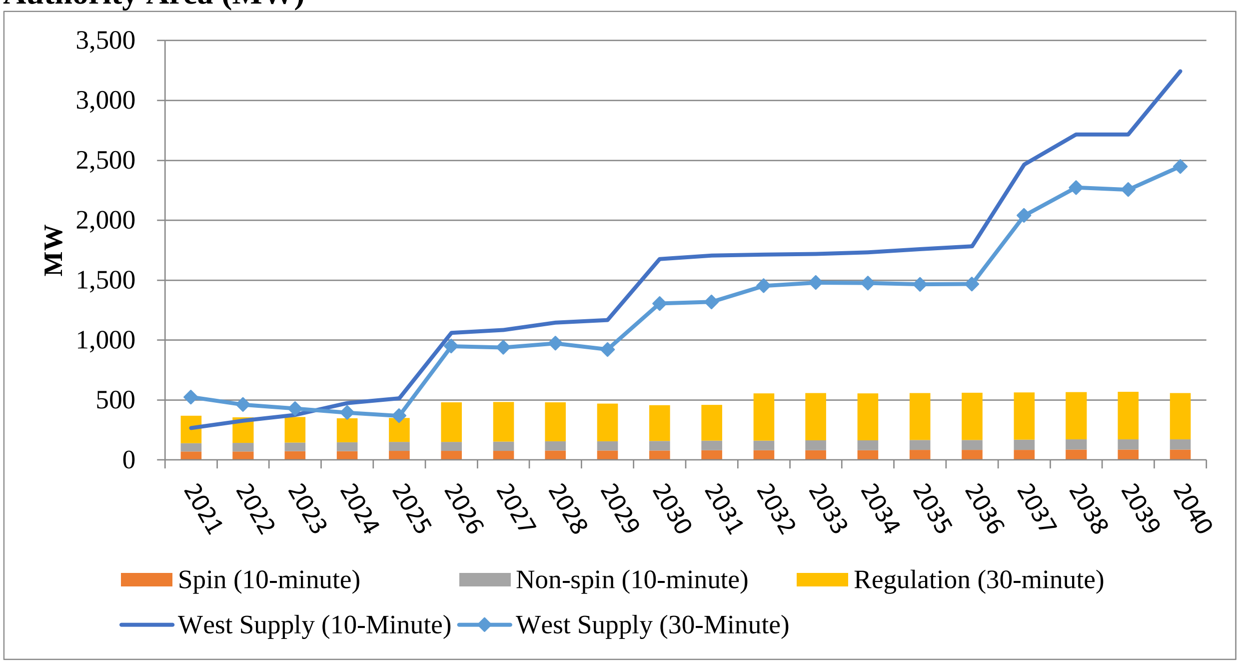


Figure F.13 - Comparison of Reserve Requirements and Resources, West Balancing Authority Area (MW)



Flexible Resource Supply Planning

In actual operations, PacifiCorp has been able to serve its reserve requirements and has not experienced any incidents where it was short of reserve. PacifiCorp manages its resources to meet its reserve obligation in the same manner as meeting its load obligation – through long term planning, market transactions, utilization of the transmission capability between the two balancing authority areas, and operational activities that are performed on an economic basis.

PacifiCorp and the California Independent System Operator Corporation implemented the energy imbalance market (EIM) on November 1, 2014, and participation by other utilities has expanded significantly with more participants scheduled for entry through 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 STUDY

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					Net MWhs Per Year					4-year Average	
Plant Name	Zero Discharge	Cooling Media	2016	2017	2018	2019	4-year Average	2016	2017	2018	2019	2020	Gals/ MWH	GPM/ MW
Chehalis		Air	48	54	33	63	49	1,462,659	1,758,799	1,741,969	2,431,536	2,407,519	9	0.1
Currant Creek	Yes	Air	124	116	110	101	113	1,513,522	1,193,242	2,418,275	2,917,279	2,335,426	18	0.3
Dave Johnston		Water	8,864	8,231	8,325	8,485	8,476	5,088,505	4,519,908	4,800,371	4,686,381	4,325,604	579	9.6
Gadsby		Water	262	100	205	281	212	120,903	92,814	59,682	134,182	133,410	678	11.3
Hunter	Yes	Water	14,225	15,383	14,751	15,808	15,042	8,161,219	8,582,142	8,293,966	8,681,784	7,988,203	581	9.7
Huntington	Yes	Water	9,189	9,653	9,804	9,028	9,418	5,503,890	5,399,777	5,087,824	4,897,541	4,515,305	588	9.8
Jim Bridger	Yes	Water	18,000	19,047	20,067	19,893	19,252	11,688,747	11,642,810	10,966,745	11,254,989	10,458,575	551	9.2
Lake Side		Water	3,619	2,698	3,648	3,894	3,465	5,885,802	3,340,561	4,861,169	5,063,816	5,560,112	236	3.9
Naughton	Yes	Water	6,896	6,927	9,916	10,195	8,483	4,871,839	4,740,158	4,740,078	2,840,374	2,659,033	643	10.7
Wyodak	Yes	Air	329	332	319	292	318	2,054,311	2,565,053	2,254,203	1,852,094	1,732,784	48	0.8
TOTAL			**61,557**	**62,541**	**67,178**	**68,040**	**64,829**	**46,351,397**	**43,835,264**	**45,224,282**	**44,759,976**	**42,115,971**	**472**	**7.9**

Gadsby includes a mix of both Rankine steam units and Brayton peaking gas turbines.

1 acre-foot of water is equivalent to 325,851 Gallons or 43,560 Cubic Feet.

Table G.2 – Plant Water Consumption by State (acre-feet)

UTAH PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Currant Creek	84	92	78	124	116	110	101
Gadsby	610	367	1,022	262	100	205	281
Hunter	17,001	16,662	16,386	14,225	15,383	14,751	15,808
Huntington	10,643	10,240	9,888	9,189	9,653	9,804	9,028
Lake Side	1,361	2,960	4,533	3,619	2,698	3,648	3,894
TOTAL	**29,699**	**30,320**	**31,906**	**27,419**	**27,950**	**28,518**	**29,112**

Percent of total water consumption = 42.9%

WYOMING PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Dave Johnston	8,941	9,474	9,736	8,864	8,231	8,325	8,485
Jim Bridger	25,059	23,936	22,493	18,000	19,047	20,067	19,893
Naughton	9,622	7,484	9,160	6,896	6,927	9,916	10,195
Wyodak	319	332	228	329	332	319	292
TOTAL	**43,941**	**41,225**	**41,617**	**34,090**	**34,537**	**38,627**	**38,865**

Percent of total water consumption = 57.1%

Table G.3 – Plant Water Consumption by Fuel Type (acre-feet)

COAL FIRED PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Dave Johnston	8,941	9,474	9,736	8,864	7,721	8,941	9,474
Hunter	17,001	16,662	16,386	14,225	18,266	17,001	16,662
Huntington	10,643	10,240	9,888	9,189	10,423	10,643	10,240
Jim Bridger	25,059	23,936	22,493	18,000	23,977	25,059	23,936
Naughton	9,622	7,484	9,160	6,896	8,745	9,622	7,484
Wyodak	319	332	228	329	322	319	332
TOTAL	**71,585**	**68,127**	**67,891**	**57,504**	**69,454**	**71,585**	**68,127**

Percent of total water consumption = 94.7%

NATURAL GAS FIRED PLANTS							
Plant Name	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**
Currant Creek	84	92	78	124	116	110	101
Chehalis	86	150	93	48	54	33	63
Gadsby	610	367	1,022	262	100	205	281
Lake Side	1,361	2,960	4,533	3,619	2,698	3,648	3,894
TOTAL	**2,141**	**3,568**	**5,725**	**4,053**	**2,968**	**3,996**	**4,339**

Percent of total water consumption = 5.3%

Table G.4 – Plant Water Consumption for Plants Located in the Upper Colorado River Basin (acre-feet)

Plant Name	2013	2014	2015	2016	2017	2018	2019
Hunter	17,001	16,662	16,386	14,225	15,383	14,751	15,808
Huntington	10,643	10,240	9,888	9,189	9,653	9,804	9,028
Naughton	9,622	7,484	9,160	6,896	6,927	9,916	10,195
Jim Bridger	25,059	23,936	22,493	18,000	19,047	20,067	19,893
TOTAL	**62,325**	**58,322**	**57,927**	**48,311**	**51,010**	**54,537**	**54,924**

Percent of total water consumption = 81.1%

APPENDIX H – STOCHASTIC PARAMETERS

Introduction

For the 2021 IRP, PacifiCorp updated and re-estimated the stochastic parameters provided in the 2019 IRP for use in the development of the 2021 IRP preferred portfolio.

Plexos, as used by PacifiCorp, develops portfolio cost scenarios via computational finance in concert with production simulation. The model stochastically shocks the case-specific underlying electricity price forecast as well as the corresponding case-specific key drivers (e.g., natural gas, loads, and hydro) and dispatches accordingly. Using exogenously calculated parameters (i.e., volatilities, mean reversions, and correlations), Plexos develops scenarios that bracket the uncertainty surrounding a driver; statistical sampling techniques are then employed to limit the number of representative scenarios to 50. The stochastic model used in Plexos is a two-factor (short- and long-run) mean reverting model.

PacifiCorp used short-run stochastic parameters for this Integrated Resource Plan (IRP); long-run parameters were set to zero since Plexos cannot re-optimize its capacity expansion plan. This inability to re-optimize or add capacity can create a problem when dispatching to meet extreme load and/or fuel price excursions, as often seen in long-term stochastic modeling. Such extreme out-year price and load excursions can influence portfolio costs disproportionately while not reflecting plausible outcome. Thus, since long-term volatility is the year-on-year growth rate, only the expected yearly price and/or load growth is simulated over the forecast horizon[1].

Key drivers that significantly affect the determination of prices tend to fall into two categories: loads and fuels. Targeting only key variables from each category simplifies the analysis while effectively capturing sensitivities on a larger number of individual variables. For instance, load uncertainty can encompass the sensitivities of weather, transmission availability, unit outages, and evolving end-uses. Depending on the region, fuel price uncertainty (especially natural gas) can encompass the sensitivities of weather, load growth, emissions, and hydro availability. The following sections summarize the development of stochastic process parameters and describe how these uncertain variables evolve over time.

Overview

Long-term planning demands specification of how important variables behave over time. For the case of PacifiCorp's long-term planning, important variables include natural gas and electricity prices, regional loads, and regional hydro generation. Modeling these variables involves not only a description of their expected value over time as with a traditional forecast, but also a description of the spread of possible future values. The following sections summarize the development of stochastic process parameters to describe how these uncertain variables evolve over time[2].

[1] Mean reversion is assumed to be zero in the long run.

[2] A stochastic or random process is the counterpart to a deterministic process. Instead of dealing with only one possible reality of how the variables might evolve over time, there is some indeterminacy in the future evolution described by probability distributions.

Volatility

The standard deviation[3](σ) is a measure of how widely values are dispersed from the average value:

$$\sigma = \sqrt{\frac{\sum_{i=1}^{n}(x_i - \mu)^2}{(n-1)}}$$

where μ is the average value of the observations {x1, x2,…,xn}, and n is the number of observations.

Volatility (σ_T) incorporates a time component so a variable with constant volatility has a larger spread of possible outcomes two years in the future than one year in the future:

$$\sigma_T = \sigma\sqrt{T}$$

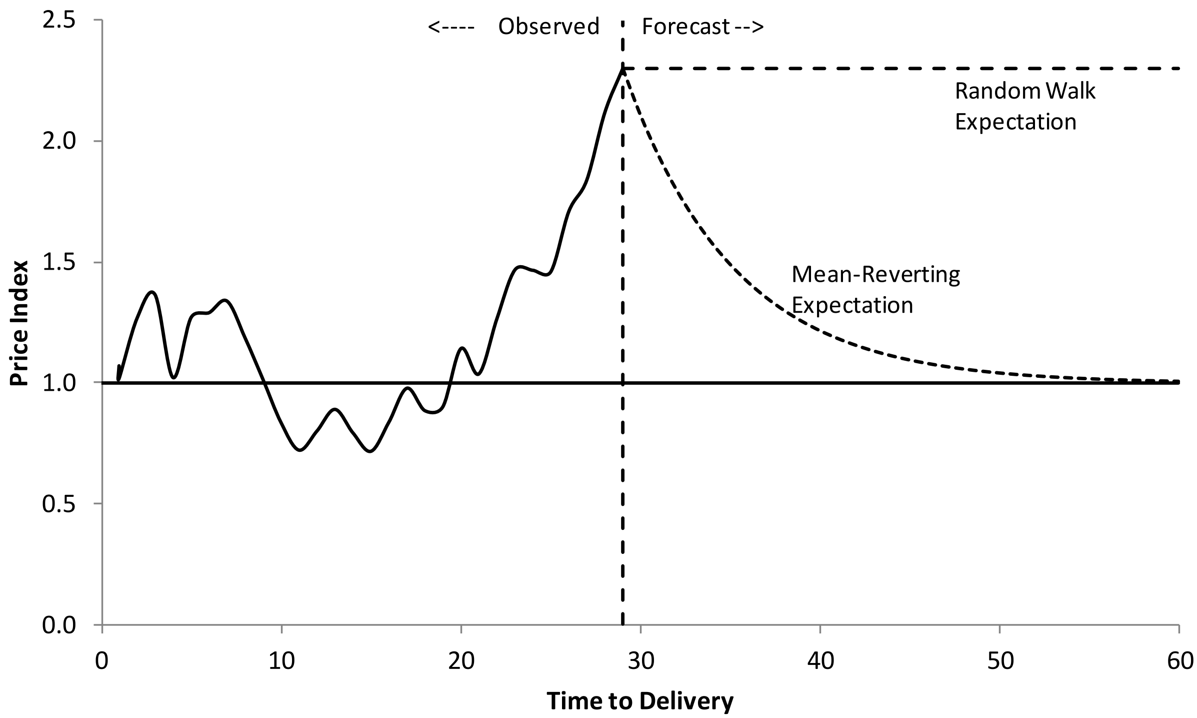
Volatilities are typically quoted on an annual basis but can be specified for any desired time period (T). Suppose the annual volatility of load is two percent. This implies that the standard deviation of the range of possible loads a year from now is two percent, while the standard deviation four years 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.

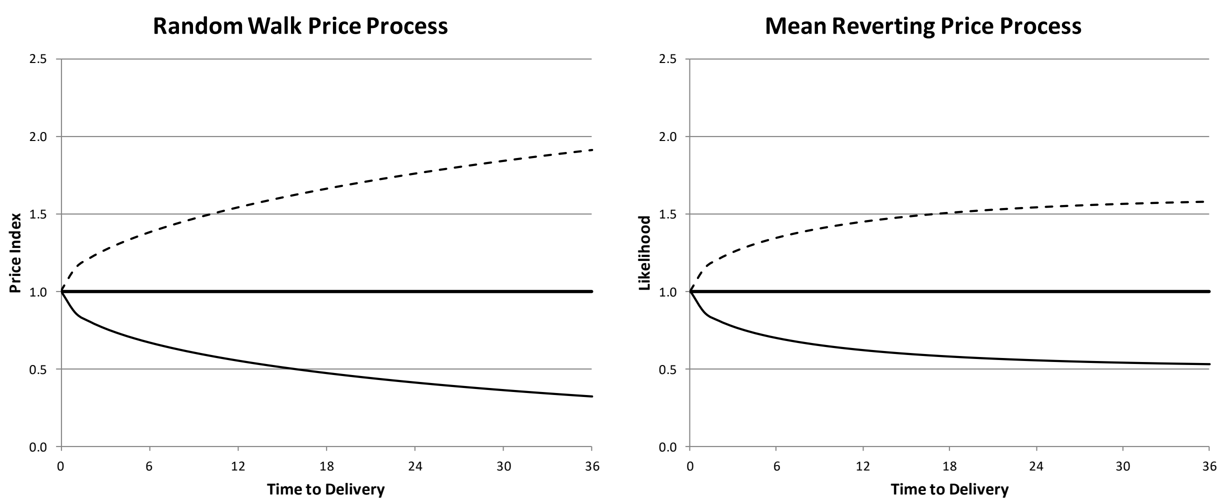
[3] "Standard Deviation" and "Variance" are standard statistical terms describing the spread of possible outcomes. The Variance equals the Standard Deviation squared.

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.

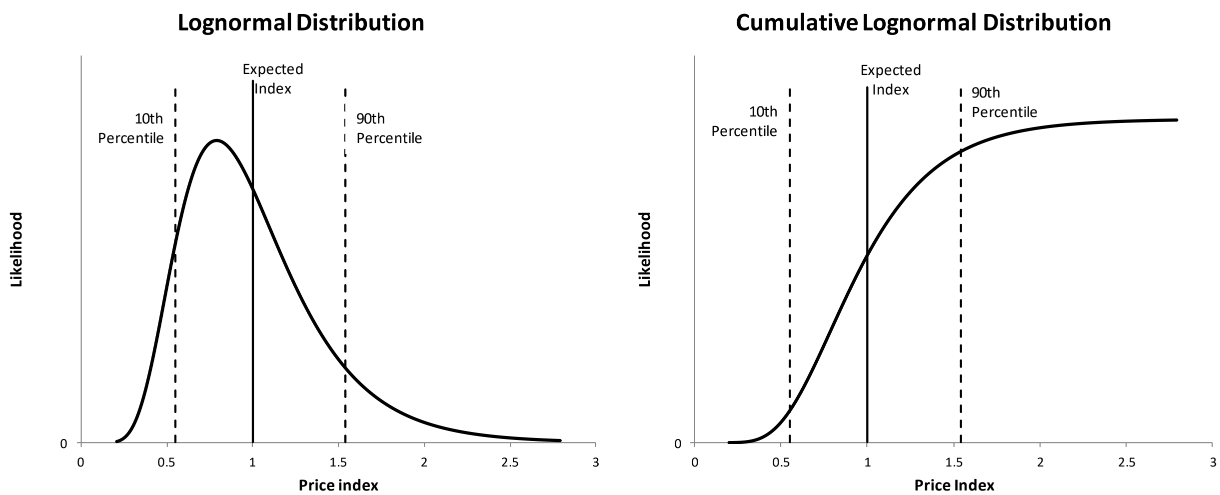
Estimating Short-term Process Parameters

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:

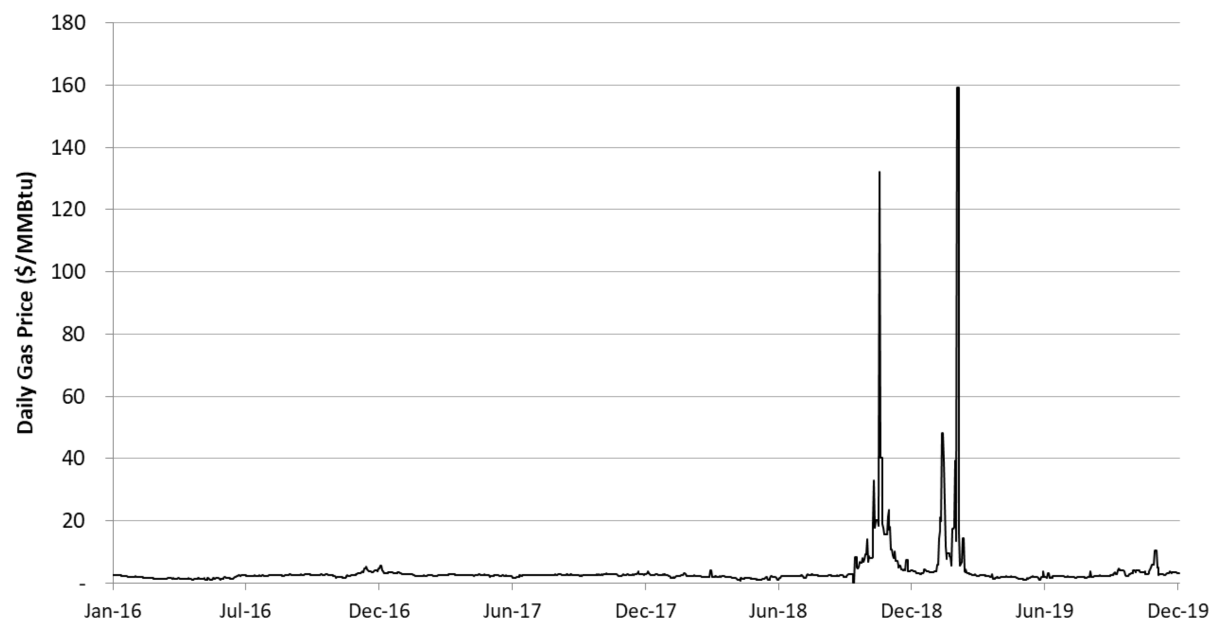
Table H.1 - Seasonal Definitions

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 2016 to 2019 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, 2016-2019



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:

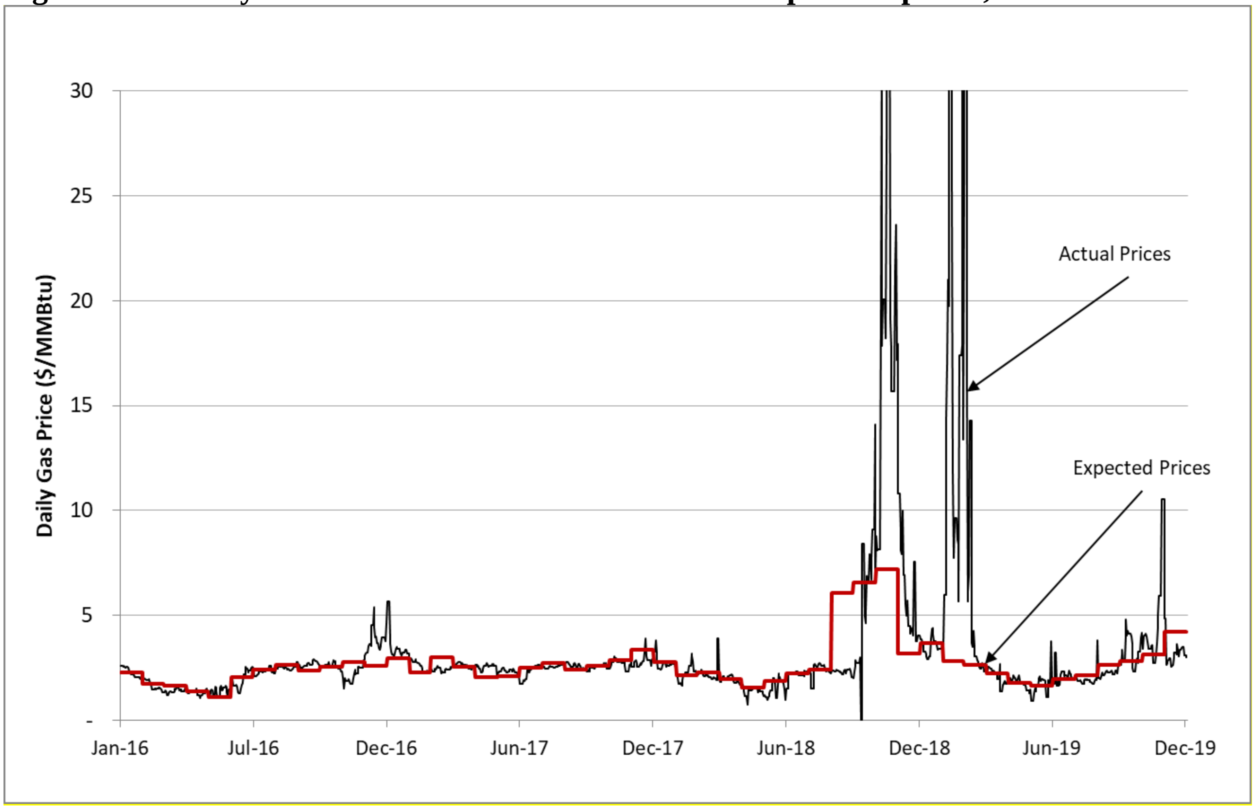
> Seasonal Median: The level of gas prices may be different from one year to the next. While this can be attributed to random movements or shocks in the gas markets, it is not a short-term event and should not be included in the short-term uncertainty process. In order to account for this possible difference in the level of gas prices, the median gas price for each season and year is calculated. For example, Sumas prices in the winter of 2016 average $2.21/MMBtu.
>
> Monthly Median: Within a season, there are different expected prices by month. For instance, within the fall season, November gas prices are expected to be much higher than September and October prices as winter is just around the corner. A monthly factor representing the ratio of monthly prices to the seasonal median price is calculated. For example, February prices in Sumas are 79 percent of the winter median price.
>
> Weekly Shape: Many variables exhibit a distinct shape across the week. For instance, loads and electricity prices are higher during the middle of the week and lower on the weekends. The expected shape of gas prices across the week was calculated and found to be insignificant (expected variation by weekday did not exceed two percent of the weekly average).

These three components – seasonal median, monthly shape, and weekly shape – combine to form an expected price for each day. For example, the expected price of gas in Sumas on February 1, 2016 was $1.75/MMBtu, the product of the seasonal median and the monthly shape factor

$$Expected\ Gas\ Price\ = Seasonal\ Median.Price * Monthly\ Shape\ within\ the\ Season$$

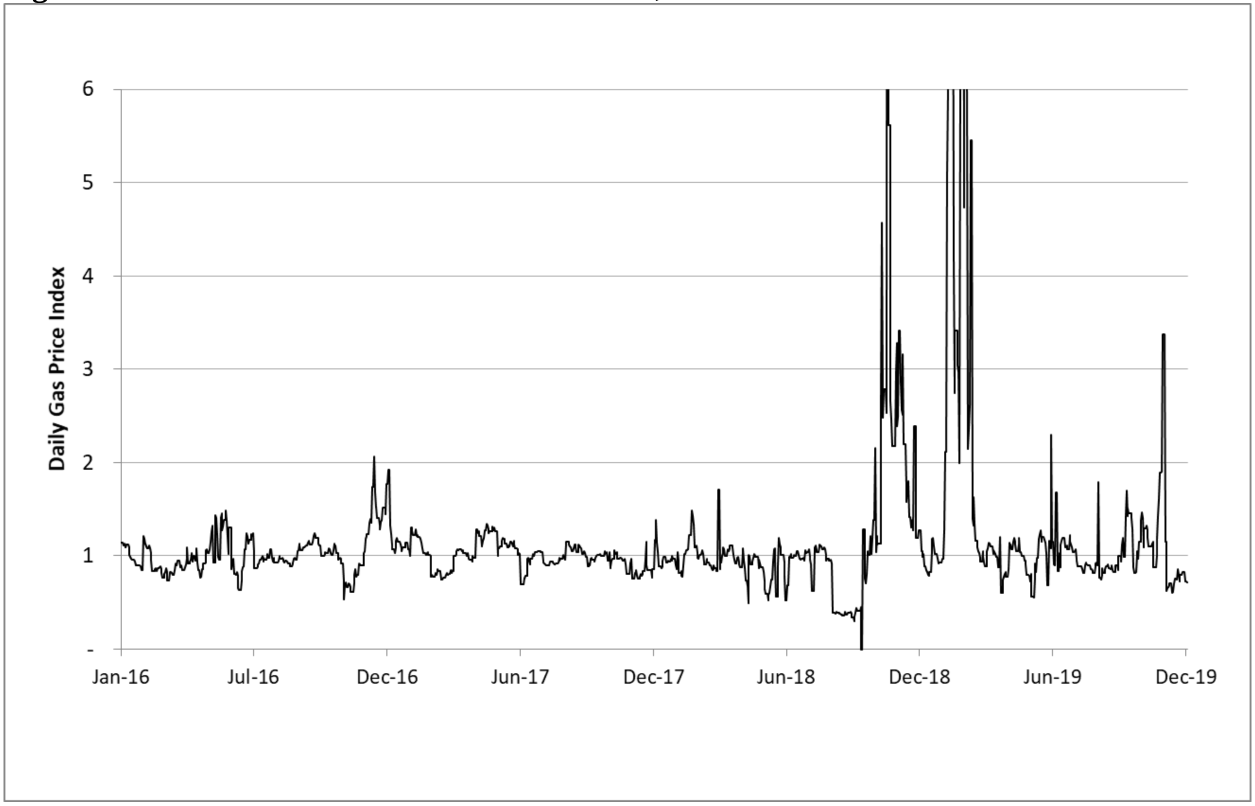
The following chart shows the comparison of the actual Sumas prices with the "expected" prices:

Figure H.5 – Daily Gas Prices for SUMAS Basin with "expected" prices, 2016-2019



Dividing the actual gas prices by the expected prices forms a price index with a median of one. This index, illustrated by the chart below, captures only the random component of price movements—the portion not explained by expected seasonal, monthly, and weekly shape.

Figure H.6 – Gas Price Index for SUMAS Basin, 2016-2019



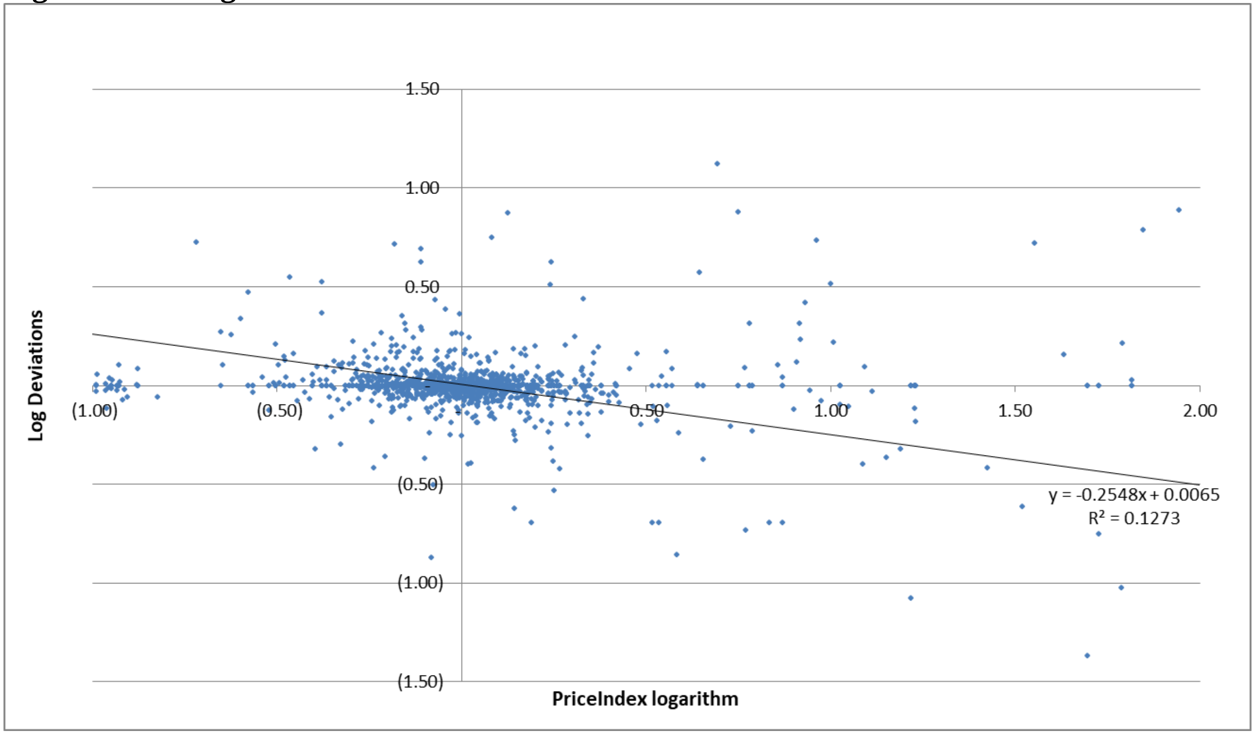
Parameter Estimation – Autoregressive Model

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	11.48%	9.05%	9.91%	10.07%
Daily Mean Reversion Rate	0.061	0.160	0.503	0.046
SUMAS				
Daily Volatility	16.65%	20.30%	13.06%	17.14%
Daily Mean Reversion Rate	0.031	0.140	0.287	0.022

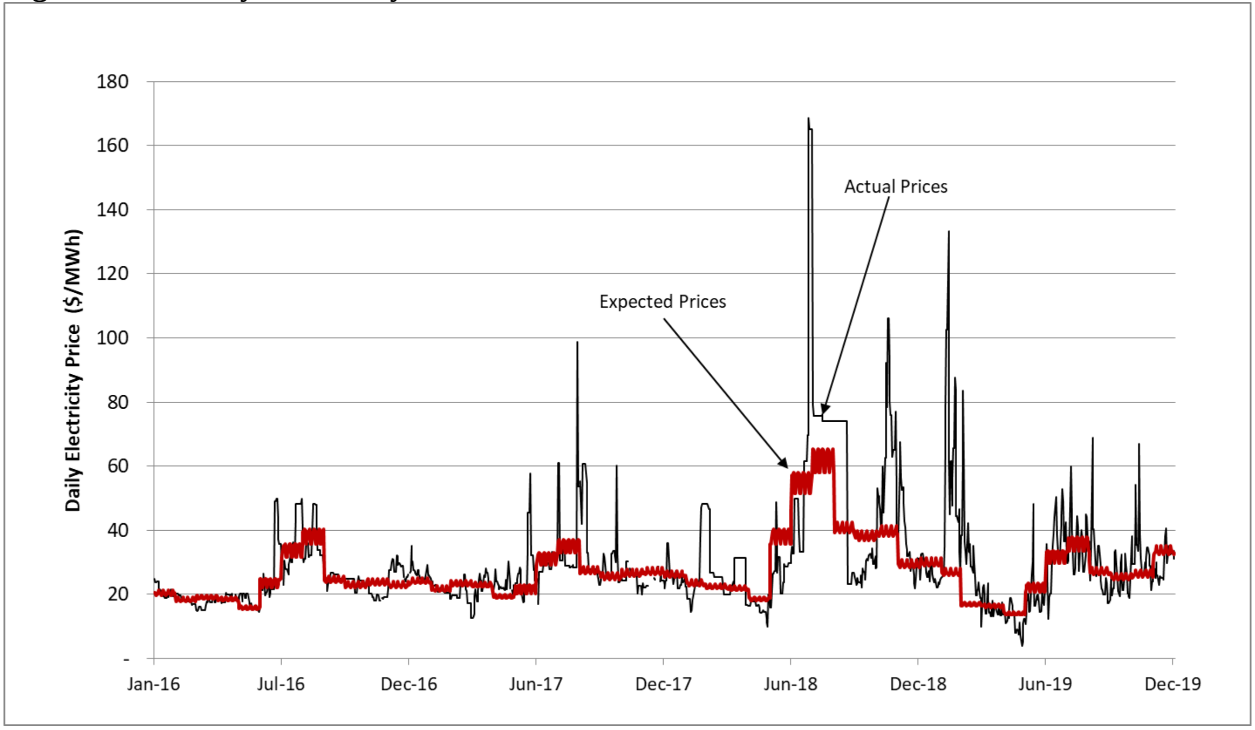
Electricity Price Process

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 2016 through 2019 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 median, monthly shape and weekly shape. For instance, the expected price for January 2, 2016 in the Four Corners region was $20.45/megawatt hours (MWh). This price incorporates the 2016 winter median price of $20.33/MWh times the monthly shape factor for January of 99 percent and the weekday index for Saturday of 101 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, 2016-2019



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.

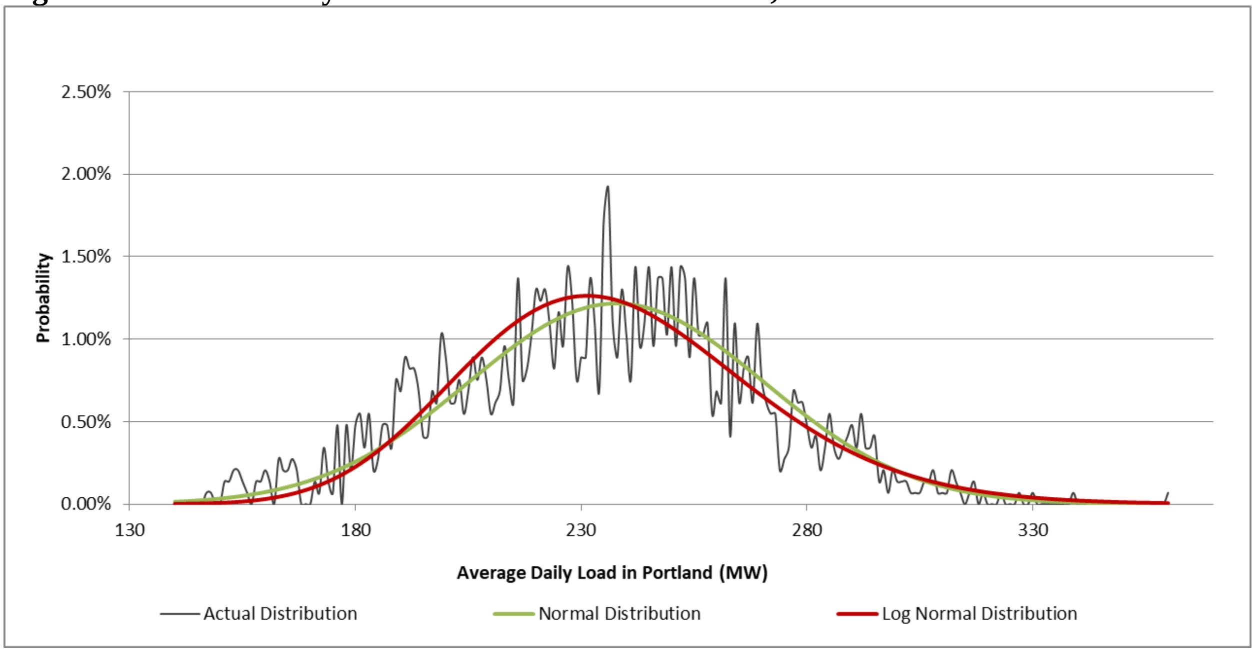
Table H.3 - Uncertainty Parameters for Electricity Regions

	Winter	Spring	Summer	Fall
Four Corners				
Daily Volatility	13.22%	17.19%	21.99%	17.41%
Daily Mean Reversion Rate	0.089	0.180	0.312	0.197
CA-OR Border				
Daily Volatility	16.31%	28.78%	33.94%	17.32%
Daily Mean Reversion Rate	0.070	0.258	0.395	0.178
Mid-Columbia				
Daily Volatility	19.81%	63.03%	25.97%	16.00%
Daily Mean Reversion Rate	0.090	0.461	0.196	0.120
Palo Verde				
Daily Volatility	12.11%	13.81%	20.17%	15.02%
Daily Mean Reversion Rate	0.086	0.151	0.146	0.163

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.

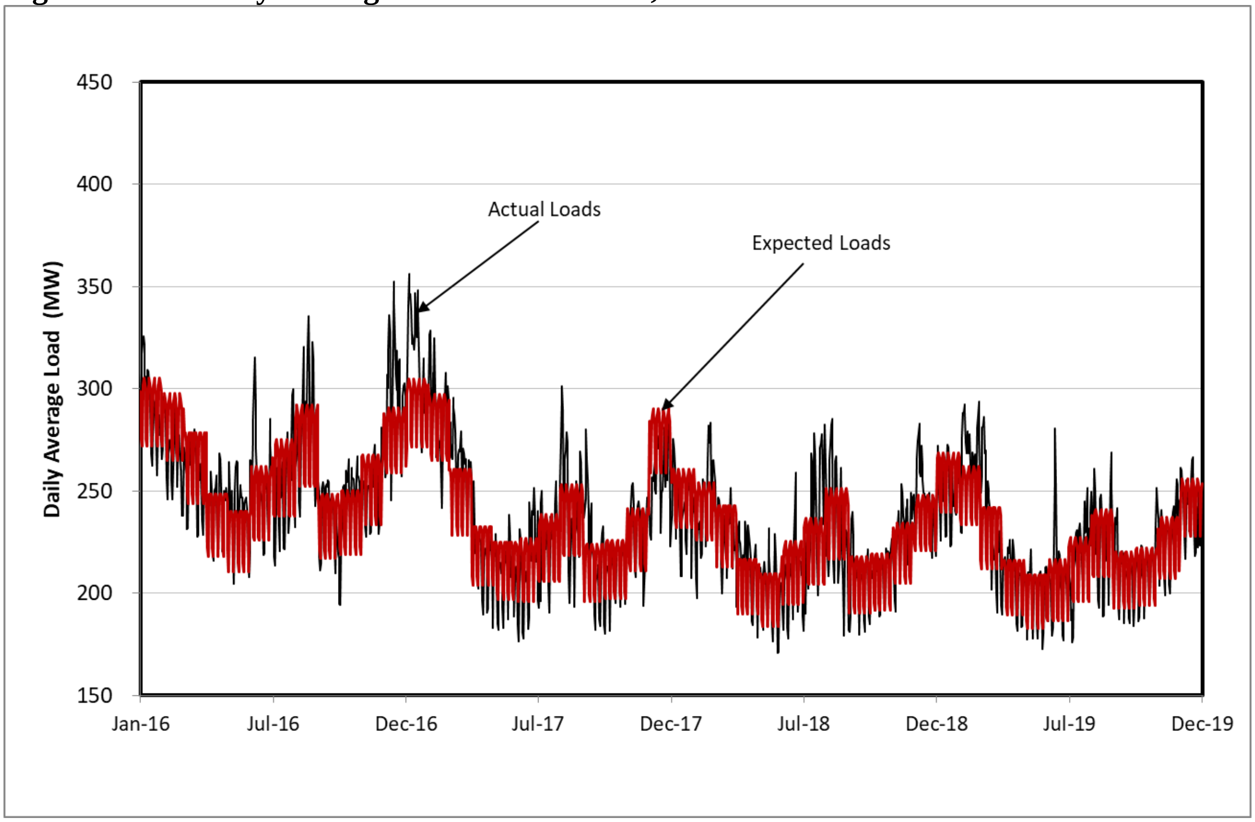
Figure H.9 – Probability Distribution for Portland Load, 2016-2019



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, 2016 in Portland was 276 megawatts (MW). This load incorporates the 2016 winter average load of 286 MW times the monthly shape factor for January of 102 percent and the weekday index for Saturday also of 94 percent. The following chart shows the Portland actual and expected loads over the analysis time period.

Figure H.10 – Daily Average Load for Portland, 2016-2019



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

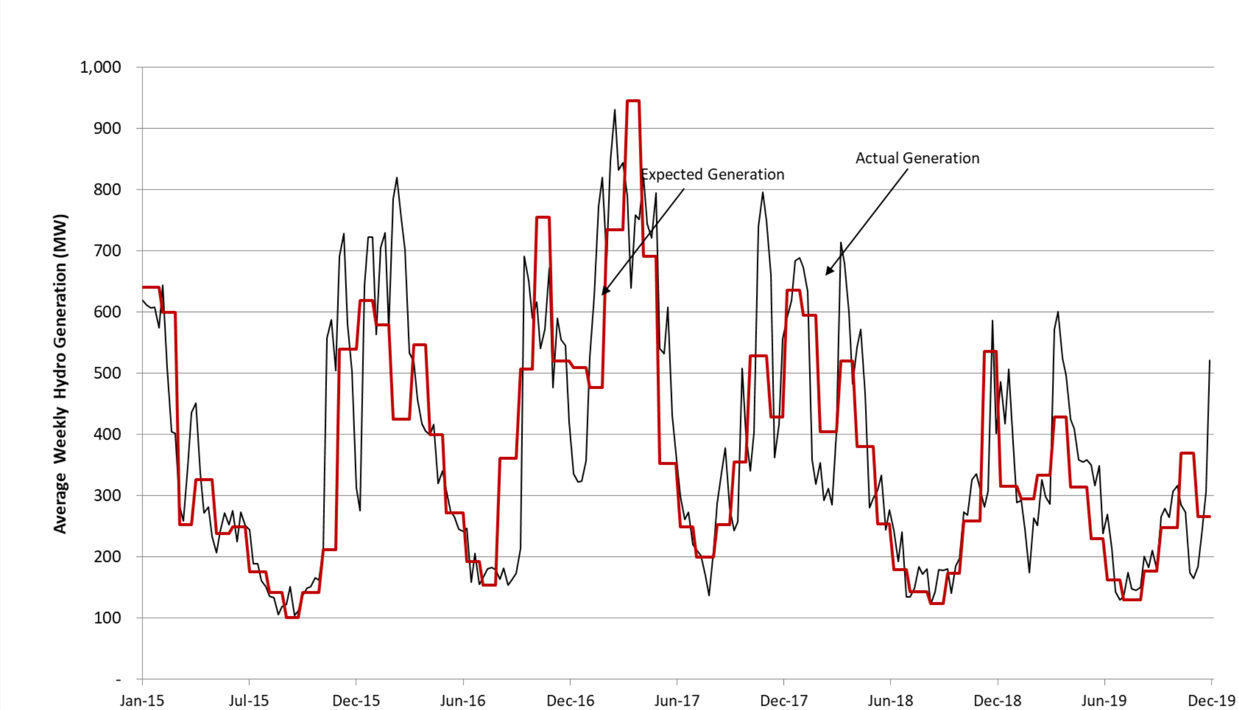
	Winter	Spring	Summer	Fall
California				
Daily Volatility	4.8%	4.4%	3.8%	4.5%
Daily Mean Reversion Rate	0.208	0.193	0.223	0.238
Idaho				
Daily Volatility	3.6%	6.4%	5.3%	4.2%
Daily Mean Reversion Rate	0.179	0.271	0.135	0.184
Portland				
Daily Volatility	3.8%	3.5%	5.5%	3.6%
Daily Mean Reversion Rate	0.157	0.225	0.258	0.285
Oregon Other				
Daily Volatility	4.4%	3.6%	4.1%	4.0%
Daily Mean Reversion Rate	0.152	0.249	0.190	0.294
Utah				
Daily Volatility	2.3%	3.0%	4.7%	3.2%
Daily Mean Reversion Rate	0.278	0.535	0.296	0.203
Washington				
Daily Volatility	5.0%	3.9%	5.0%	4.1%
Daily Mean Reversion Rate	0.149	0.179	0.191	0.226
Wyoming				
Daily Volatility	1.6%	1.8%	1.7%	1.7%
Daily Mean Reversion Rate	0.226	0.270	0.224	0.232

Hydro Generation Process

There are two differences between the uncertainty analysis for hydro generation and natural gas prices. Hydro generation varies on a slower time frame than other variables analyzed. As such, median hydro generation is calculated and analyzed on a weekly, rather than daily, basis. Generation is calculated as the median hourly generation across the 168 hours in a week. The hydro analysis covers the 2015 through 2019 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, 2015 through January 7, 2015 in the Western Region was 641 MW. This generation incorporates the 2015 winter median generation of 594 MW times the monthly shape factor for January of 108 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, 2015-2019



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	27.40%	18.91%	20.97%	29.81%
Weekly Mean Reversion Rate	0.72	0.43	1.15	0.37

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:

$$Correlation(X,Y) = \frac{\sum_i^n[(x_i - x_{avg.}) * (y_i - y_{avg.})]}{\sqrt{\sum_i^n(x_i - x_{avg.})^2 * \sum_i^n(y_i - y_{avg.})^2}}$$

There are a few things to note about the correlation calculations. First, correlation data must always be organized so that the same 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%	34%	41%	38%	32%	49%	10%	2%	17%	16%	17%	20%	3%	-1%
SUMAS	34%	100%	24%	30%	29%	25%	13%	13%	12%	12%	15%	19%	9%	-2%
4C	41%	24%	100%	62%	54%	79%	16%	-8%	17%	20%	23%	25%	5%	-3%
COB	38%	30%	62%	100%	76%	59%	17%	-5%	21%	25%	23%	33%	8%	4%
Mid-C	32%	29%	54%	76%	100%	56%	15%	0%	26%	32%	21%	36%	9%	6%
PV	49%	25%	79%	59%	56%	100%	13%	-8%	11%	15%	16%	19%	6%	-4%
CA	10%	13%	16%	17%	15%	13%	100%	12%	32%	70%	30%	35%	19%	2%
ID	2%	13%	-8%	-5%	0%	-8%	12%	100%	19%	20%	34%	29%	24%	-5%
Portland	17%	12%	17%	21%	26%	11%	32%	19%	100%	69%	43%	65%	23%	-6%
OR Other	16%	12%	20%	25%	32%	15%	70%	20%	69%	100%	44%	64%	20%	8%
UT	17%	15%	23%	23%	21%	16%	30%	34%	43%	44%	100%	45%	40%	-5%
WA	20%	19%	25%	33%	36%	19%	35%	29%	65%	64%	45%	100%	28%	13%
WY	3%	9%	5%	8%	9%	6%	19%	24%	23%	20%	40%	28%	100%	-3%
Hydro	-1%	-2%	-3%	4%	6%	-4%	2%	-5%	-6%	8%	-5%	13%	-3%	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 negative five 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%	56%	20%	14%	10%	22%	7%	7%	13%	14%	12%	13%	9%	1%
SUMAS	56%	100%	19%	21%	17%	10%	1%	6%	12%	13%	10%	17%	8%	-6%
4C	20%	19%	100%	34%	42%	63%	8%	11%	27%	21%	22%	23%	18%	1%
COB	14%	21%	34%	100%	64%	33%	14%	1%	28%	24%	13%	31%	14%	9%
Mid-C	10%	17%	42%	64%	100%	28%	12%	3%	21%	15%	8%	27%	11%	8%
PV	22%	10%	63%	33%	28%	100%	10%	13%	21%	17%	24%	23%	16%	-1%
CA	7%	1%	8%	14%	12%	10%	100%	16%	35%	68%	24%	40%	12%	-7%
ID	7%	6%	11%	1%	3%	13%	16%	100%	6%	17%	46%	20%	20%	-18%
Portland	13%	12%	27%	28%	21%	21%	35%	6%	100%	69%	19%	60%	25%	1%
OR Other	14%	13%	21%	24%	15%	17%	68%	17%	69%	100%	30%	67%	23%	-3%
UT	12%	10%	22%	13%	8%	24%	24%	46%	19%	30%	100%	21%	32%	-22%
WA	13%	17%	23%	31%	27%	23%	40%	20%	60%	67%	21%	100%	22%	0%
WY	9%	8%	18%	14%	11%	16%	12%	20%	25%	23%	32%	22%	100%	-17%
Hydro	1%	-6%	1%	9%	8%	-1%	-7%	-18%	1%	-3%	-22%	0%	-17%	100%

Similarly, the spring season shows a very low correlation of 12 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%	67%	7%	16%	12%	6%	-2%	1%	5%	4%	0%	9%	0%	0%
SUMAS	67%	100%	4%	10%	8%	0%	-12%	-4%	2%	-3%	-3%	2%	-1%	3%
4C	7%	4%	100%	22%	23%	44%	25%	13%	23%	28%	29%	23%	17%	-8%
COB	16%	10%	22%	100%	80%	45%	14%	7%	37%	31%	10%	27%	6%	5%
Mid-C	12%	8%	23%	80%	100%	54%	21%	8%	48%	41%	12%	30%	2%	1%
PV	6%	0%	44%	45%	54%	100%	27%	16%	34%	33%	27%	26%	16%	0%
CA	-2%	-12%	25%	14%	21%	27%	100%	44%	37%	66%	35%	52%	18%	-9%
ID	1%	-4%	13%	7%	8%	16%	44%	100%	13%	27%	51%	22%	24%	-10%
Portland	5%	2%	23%	37%	48%	34%	37%	13%	100%	79%	10%	62%	-1%	8%
OR Other	4%	-3%	28%	31%	41%	33%	66%	27%	79%	100%	21%	80%	8%	2%
UT	0%	-3%	29%	10%	12%	27%	35%	51%	10%	21%	100%	22%	48%	-15%
WA	9%	2%	23%	27%	30%	26%	52%	22%	62%	80%	22%	100%	5%	-1%
WY	0%	-1%	17%	6%	2%	16%	18%	24%	-1%	8%	48%	5%	100%	-12%
Hydro	0%	3%	-8%	5%	1%	0%	-9%	-10%	8%	2%	-15%	-1%	-12%	100%

In the summer season, six 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%	36%	21%	25%	23%	17%	19%	3%	7%	18%	7%	11%	6%	-11%
SUMAS	36%	100%	13%	20%	23%	16%	16%	-4%	10%	17%	5%	6%	6%	-13%
4C	21%	13%	100%	29%	28%	61%	14%	5%	16%	12%	23%	13%	7%	-6%
COB	25%	20%	29%	100%	60%	40%	21%	3%	26%	24%	19%	23%	13%	-13%
Mid-C	23%	23%	28%	60%	100%	43%	22%	6%	29%	30%	18%	29%	9%	-7%
PV	17%	16%	61%	40%	43%	100%	10%	5%	17%	8%	18%	10%	10%	0%
CA	19%	16%	14%	21%	22%	10%	100%	26%	56%	80%	38%	64%	31%	-4%
ID	3%	-4%	5%	3%	6%	5%	26%	100%	18%	20%	39%	21%	28%	-12%
Portland	7%	10%	16%	26%	29%	17%	56%	18%	100%	80%	46%	71%	35%	4%
OR Other	18%	17%	12%	24%	30%	8%	80%	20%	80%	100%	46%	81%	40%	1%
UT	7%	5%	23%	19%	18%	18%	38%	39%	46%	46%	100%	43%	41%	-2%
WA	11%	6%	13%	23%	29%	10%	64%	21%	71%	81%	43%	100%	36%	4%
WY	6%	6%	7%	13%	9%	10%	31%	28%	35%	40%	41%	36%	100%	-2%
Hydro	-11%	-13%	-6%	-13%	-7%	0%	-4%	-12%	4%	1%	-2%	4%	-2%	100%

In the fall, a low correlation of nine percent has been observed between Mid-C market price deviations and Wyoming load deviations. Market deviations are due to deviations in northwest weather patterns and resource mix while Wyoming loads are mostly dictated by planned or unplanned outages of industrial customer class.

APPENDIX I – CAPACITY EXPANSION RESULTS

Portfolio-Development Cases Quick Reference Guide

This appendix provides a reference guide to portfolio capacity expansion results for each portfolio in the 2021 IRP. Capacity expansion result information is further described in Volume I, Chapter 8 – Modeling and Portfolio Evaluation Approach and Volume I, Chapter 9 – Modeling and Portfolio Selection Results.

Table I.1 –Preferred Portfolio

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
P02-MM-CETA	P02-MM (top-performing portfolio) with WA-situs resources relative to CETA requirements.	$26,315	Med Gas, Med CO_2	Base	Base

Table I.2 – Initial Portfolios

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
P02-LN	Existing coal and new proxy resources optimized	$22,224	Low Gas, No CO_2	Base	Base
P02-MN	Existing coal and new proxy resources optimized	$22,228	Med Gas, No CO_2	Base	Base
P02-MM	Existing coal and new proxy resources optimized	$26,151	Med Gas, Med CO_2	Base	Base
P02-HH	Existing coal and new proxy resources optimized	$27,965	High Gas, High CO_2	Base	Base
P02-SCGHG	Existing coal and new proxy resources optimized	$39,290	Med Gas, Social Cost of Greenhouse Gas	Base	Base
P03-LN	Existing coal retired by 2030, new proxy resources optimized	$24,744	Low Gas, No CO_2	Base	Base
P03-MN	Existing coal retired by 2030, new proxy resources optimized	$25,752	Med Gas, No CO_2	Base	Base
P03-MM	Existing coal retired by 2030, new proxy resources optimized	$27,848	Med Gas, Med CO_2	Base	Base
P03-HH	Existing coal retired by 2030, new proxy resources optimized	$29,002	High Gas, High CO_2	Base	Base
P03-SCGHG	Existing coal retired by 2030, new proxy resources optimized	$39,112	Med Gas, Social Cost of Greenhouse Gas	Base	Base
BAU1-LN	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$22,635	Low Gas, No CO_2	Base	Base
BAU1-MN	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$22,649	Med Gas, No CO_2	Base	Base
BAU1-MM	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$27,172	Med Gas, Med CO_2	Base	Base
BAU1-HH	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$29,776	High Gas, High CO_2	Base	Base
BAU1-SCGHG	Business-as-usual scenario - existing coal retires end-of-life, new proxy resources optimized	$41,393	Med Gas, Social Cost of Greenhouse Gas	Base	Base
BAU2-LN	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$22,707	Low Gas, No CO_2	Base	Base
BAU2-MN	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$22,674	Med Gas, No CO_2	Base	Base
BAU2-MM	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$27,026	Med Gas, Med CO_2	Base	Base
BAU2-HH	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$29,356	High Gas, High CO_2	Base	Base

BAU2-SCGHG	Business-as-usual scenario - existing coal 2019 IRP retirements, new proxy resources optimized	$41,196	Med Gas, Social Cost of Greenhouse Gas	Base	Base

Table I.3 – P02 Variant Portfolios

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
P02a-JB 1-2 No GC	Variant of P02-MM (top-performing portfolio) excludes gas conversion of Jim Bridger Units 1 and 2	$26,620	Med Gas, Med CO_2	Base	Base
P02b-No B2H	Variant of P02-MM (top-performing portfolio) excludes Boardman-to-Hemingway transmission segment	$26,605	Med Gas, Med CO_2	Base	Base
P02c-No GWS	Variant of P02-MM (top-performing portfolio) excludes the Energy Gateway South transmission segment	$26,439	Med Gas, Med CO_2	Base	Base
P02d-No RFP	Variant of P02-MM (top-performing portfolio) excludes the 2020 All-Source Request for Proposals Final Shortlist and the Energy Gateway South transmission segment	$27,445	Med Gas, Med CO_2	Base	Base
P02e-No Nuc	Variant of P02-MM (top-performing portfolio) excludes the Natrium™ advanced nuclear demonstration project	$26,309	Med Gas, Med CO_2	Base	Base
P02f-No Nau 25	Variant of P02-MM (top-performing portfolio) excludes the early retirement of Naughton Units 1 and 2	$26,217	Med Gas, Med CO_2	Base	Base
P02g-CCUS	Variant of P02-MM (top-performing portfolio) includes Carbon Capture Utilization and Sequestration (CCUS) retrofit of Dave Johnston Unit 4	$26,387	Med Gas, Med CO_2	Base	Base
P02h-JB 3-4 Retire	Variant of P02-MM (top-performing portfolio) includes early retirement of Jim Bridger Units 3 and 4 in response to stakeholder feedback	$26,212	Med Gas, Med CO_2	Base	Base

Table I.4 – Washington Clean Energy Transmission Act (CETA) Required Scenarios

Case	Description	Risk-Adjusted PVRR ($m)	Price-Policy	Load	Private Gen
Alternative Lowest Reasonable Cost	Describes the alternative lowest reasonable cost and reasonably available portfolio that that would have been implemented if not for the requirement to comply with CETA.	$26,497	Med Gas, Med CO_2	Base	Base
Climate Change	A scenario that assesses the impacts of climate change.	$40,876	Med Gas, Med CO_2	Base	Base
Maximum Customer Benefit	A scenario that maximizes customer benefits prior to balancing against other goals.	$43,282	Med Gas, Med CO_2	Base	Base

Preferred Portfolio Fact Sheet

PORTFOLIO ASSUMPTIONS

Description

The preferred portfolio P02-MM-CETA, is based on P02-MM, the top-performing portfolio and includes Washington-situs resources relative to requirements of Washington's Clean Energy Transformation Act (CETA).

PORTFOLIO SUMMARY

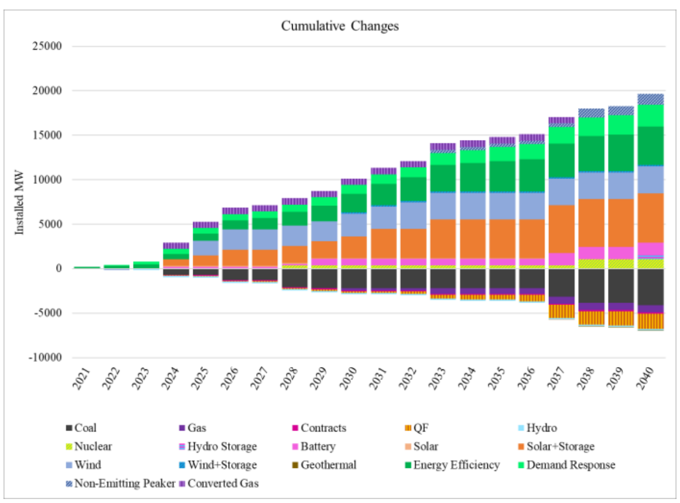
Risk-Adjusted PVRR ($m) ***$26,315***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*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.



Retirement Assumptions

Thermal retirement assumptions for P02-MM-CETA are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (P02-LN)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

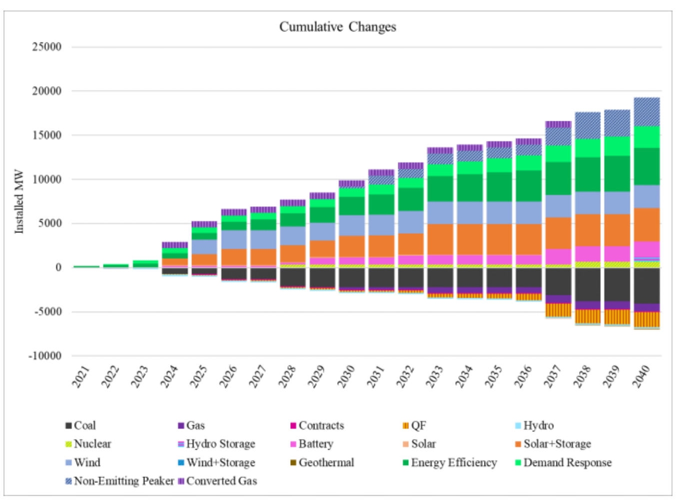
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$22,224***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*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.



Retirement Assumptions
Thermal retirement assumptions for P02-LN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

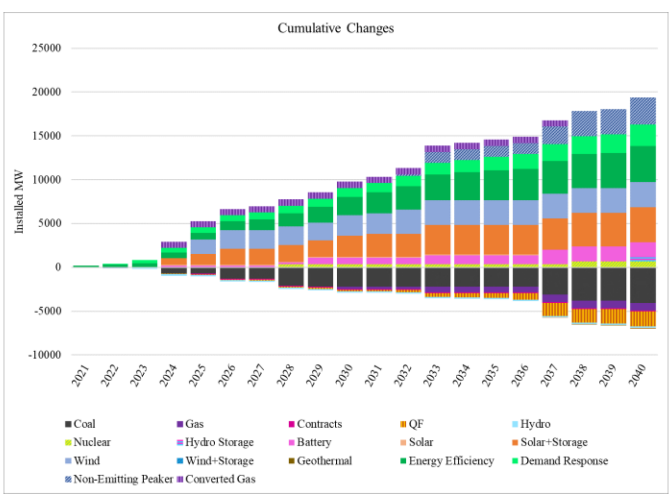
Risk-Adjusted PVRR ($m) $22,228

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

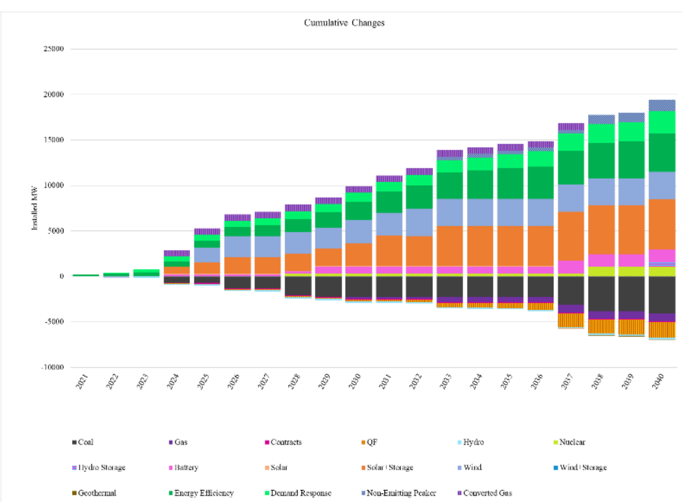
Risk-Adjusted PVRR ($m) $26,151

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

PORTFOLIO SUMMARY

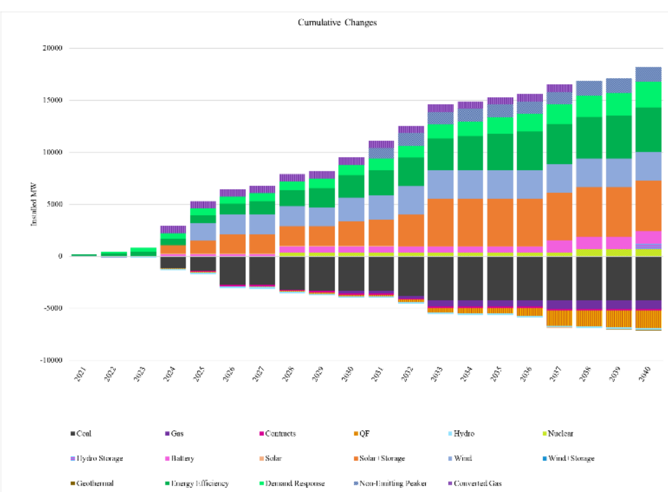
Risk-Adjusted PVRR ($m) $27,965

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02-HH are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	CCUS 2026
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2031
Huntington 2	Retire 2032
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	CCUS 2026
Jim Bridger 4	CCUS 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	CCUS 2026

CCUS = carbon capture and sequestration
GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P02 is a set of initial portfolios where existing coal and new proxy resources are optimized. P02 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P02-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

PORTFOLIO SUMMARY

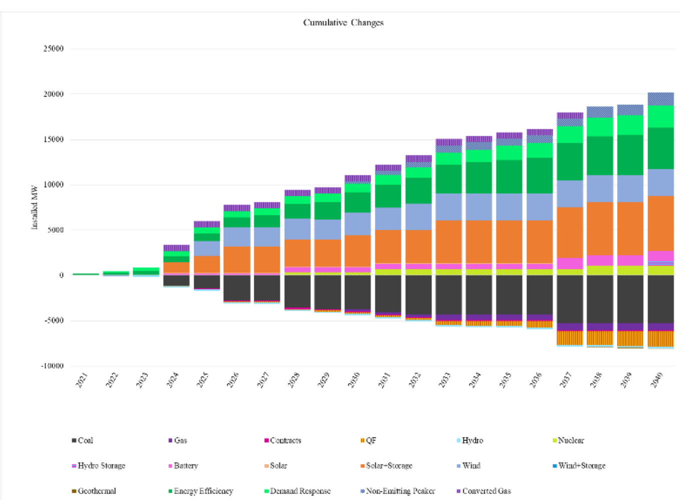
Risk-Adjusted PVRR ($m) ***$39,290***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02-SCGHG are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2031

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

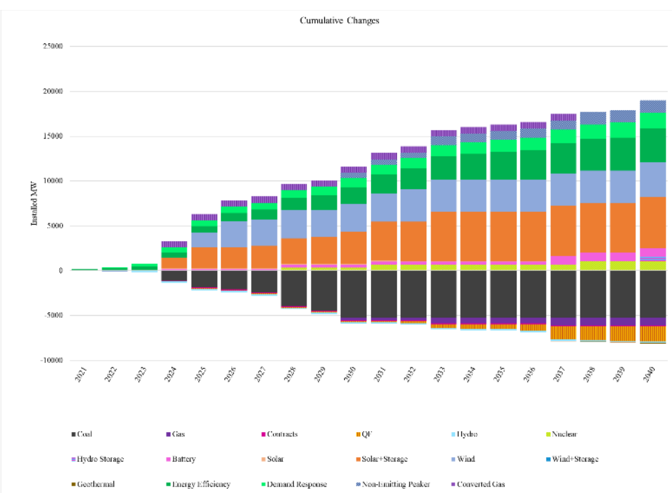
Risk-Adjusted PVRR ($m) $24,744

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P03-LN are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2029
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2028
Naughton 2	Retire 2028
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

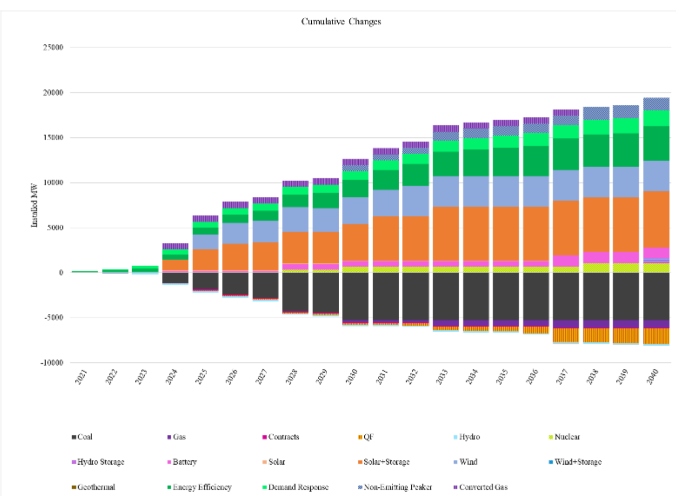
Risk-Adjusted PVRR ($m) ***$25,752***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P03-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2029
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

Portfolio Summary

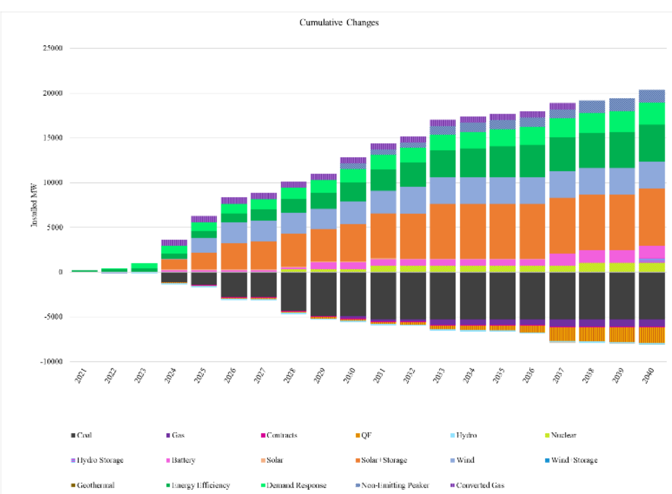
Risk-Adjusted PVRR ($m) ***$27,848***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P03-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2027
Huntington 2	Retire 2028
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

PORTFOLIO SUMMARY

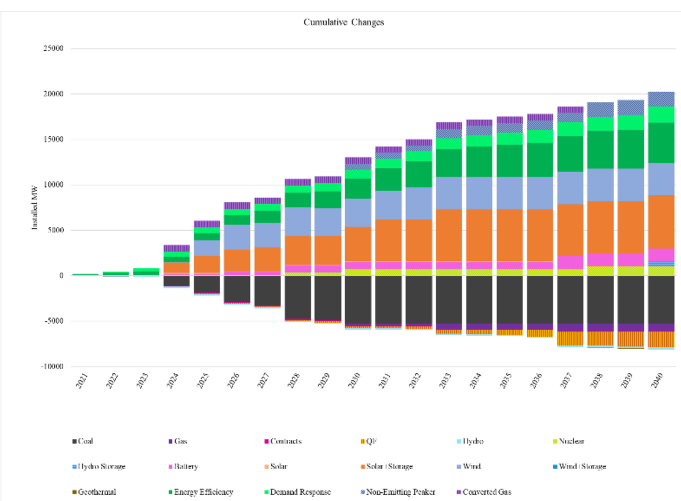
Risk-Adjusted PVRR ($m) $29,002

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P03-HH are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Portfolio: Initial Portfolios (P03-SCGHG)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

P03 is a set of initial portfolios where all existing coal units are assumed to retire by 2030. New proxy resources are optimized. P03 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for P03-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

PORTFOLIO SUMMARY

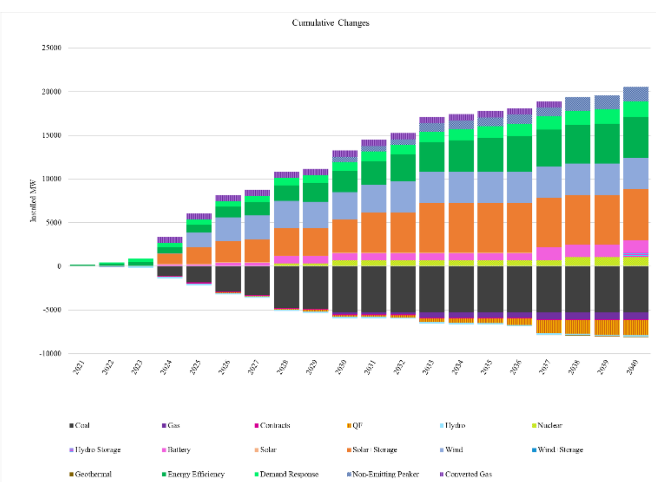
Risk-Adjusted PVRR ($m) ***$39,112***

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P03-SCGHG are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2027
Huntington 2	Retire 2024
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2027

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

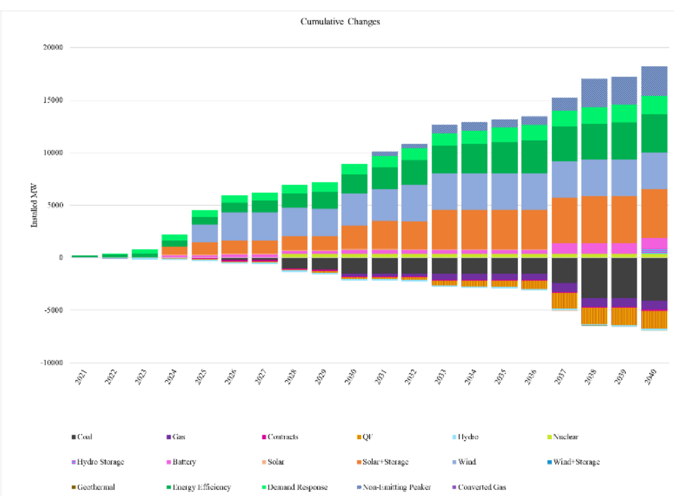
Risk-Adjusted PVRR ($m) $22,635

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU1-LN are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

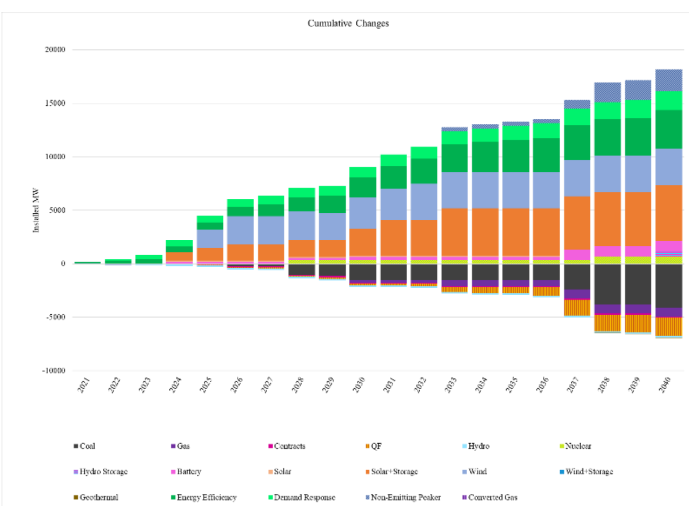
Risk-Adjusted PVRR ($m) ***$22,649***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU1-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

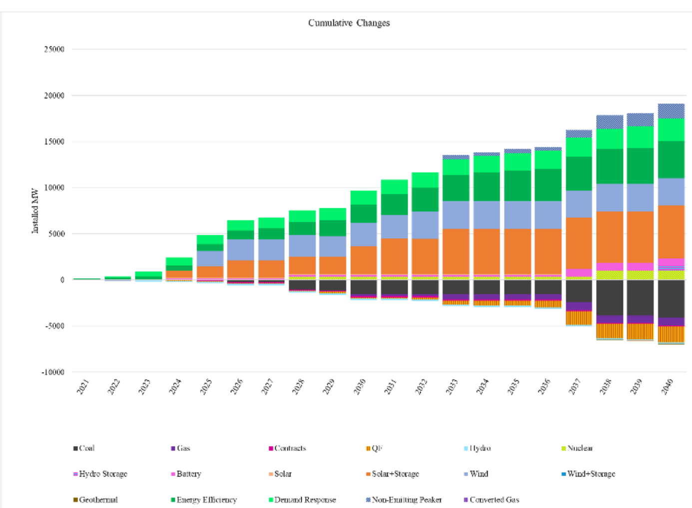
Risk-Adjusted PVRR ($m) ***$27,172***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU1-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU1-HH)

Initial Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

Portfolio Summary

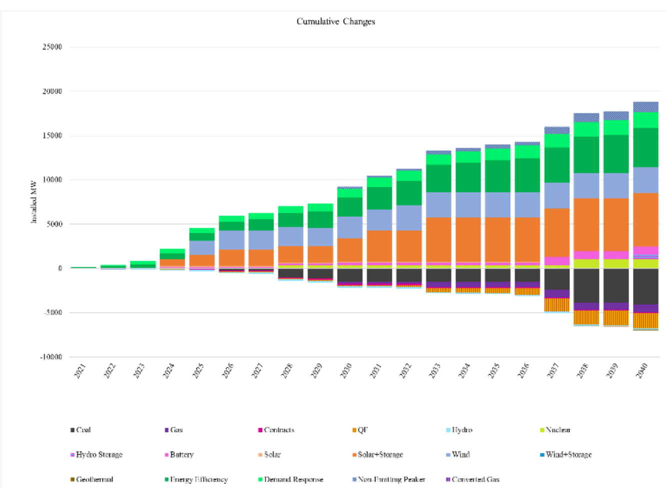
Risk-Adjusted PVRR ($m) $29,776

Incremental Transmission Upgrades

Description	***Year***	***Capacity***
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU1-HH are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
BAU1 is a set of initial portfolios where all existing coal units are assumed to retire at end-of-life. New proxy resources are optimized. BAU1 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU1-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

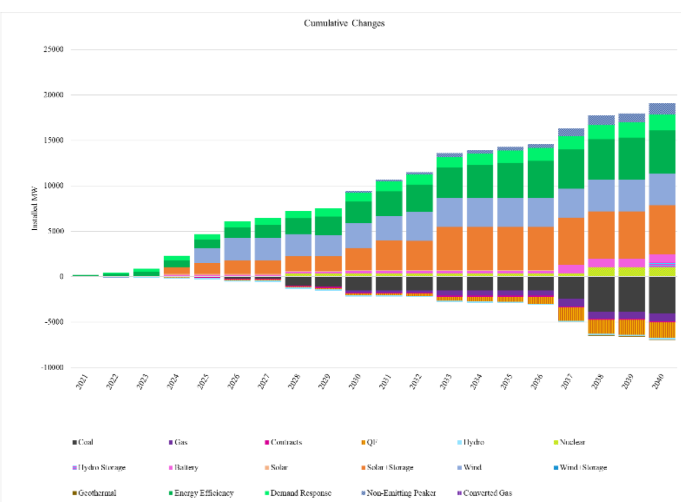
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$41,393***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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
Thermal retirement assumptions for BAU1-SCGHG are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU2-LN)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-LN, the portfolio developed under a low gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

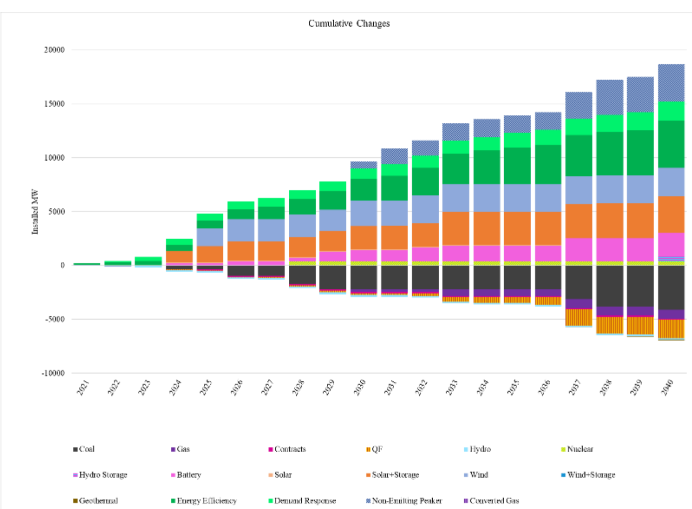
Risk-Adjusted PVRR ($m) ***$22,707***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU2-LN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-MN, the portfolio developed under a medium gas / no CO_2 price-policy assumption.

PORTFOLIO SUMMARY

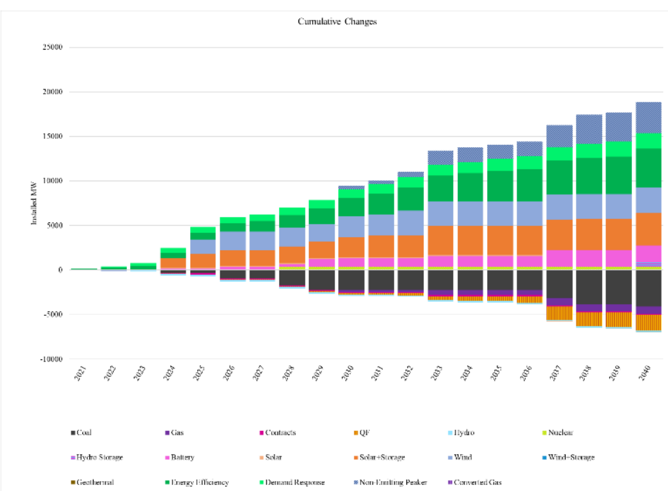
Risk-Adjusted PVRR ($m) ***$22,674***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU2-MN are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolio (BAU2-MM)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-MM, the portfolio developed under a medium gas / medium CO_2 price-policy assumption.

PORTFOLIO SUMMARY

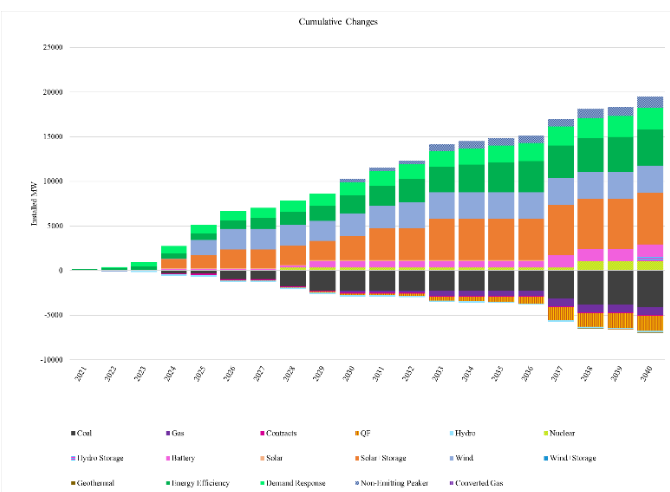
Risk-Adjusted PVRR ($m) ***$27,026***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU2-MM are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-HH, the portfolio developed under a high gas / high CO_2 price-policy assumption.

PORTFOLIO SUMMARY

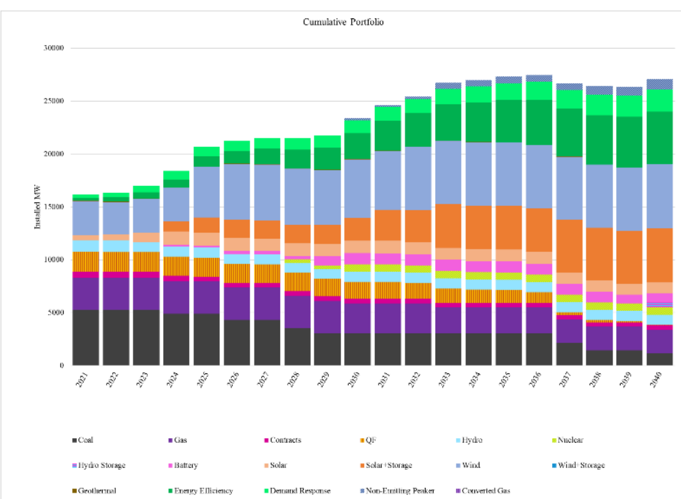
Risk-Adjusted PVRR ($m) ***$29,356***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU2-HH are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Initial Portfolios (BAU2-SCGHG)

Initial Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

BAU2 is a set of initial portfolios where all existing coal units are assumed to retire consistent with the 2019 IRP preferred portfolio. New proxy resources are optimized. BAU2 initial portfolios were developed under each of the five price-policy scenarios. This portfolio fact sheet presents high-level information for BAU2-SCGHG, the portfolio developed under a medium gas / social cost of greenhouse gas price-policy assumption.

PORTFOLIO SUMMARY

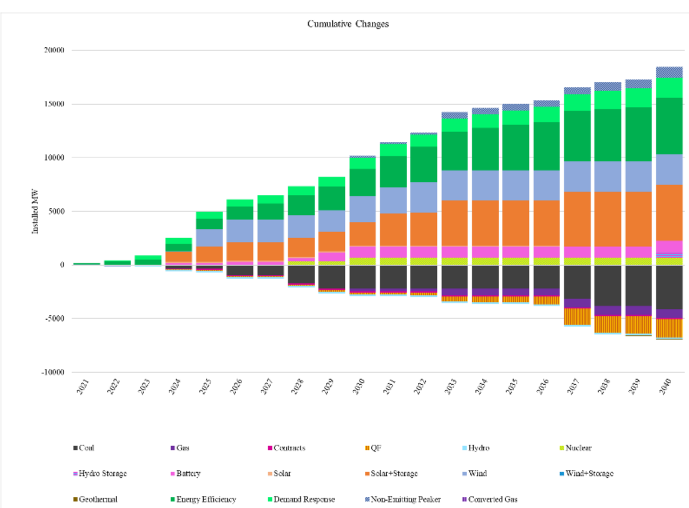
Risk-Adjusted PVRR ($m) ***$41,196***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for BAU2-SCGHG are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Jim Bridger 1 & 2 No GC (P02 Variants P02(a))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02a-JB 1-2 No GC portfolio is a variant of the P02-MM portfolio that eliminates the gas conversion of Jim Bridger Units 1 and 2.

PORTFOLIO SUMMARY

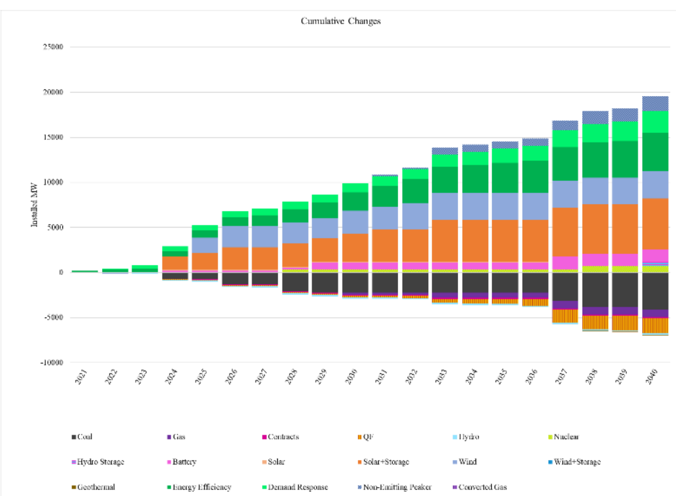
Risk-Adjusted PVRR ($m) ***$26,620***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02a-JB 1-2 No GC are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
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 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
The P02b-No B2H portfolio is a variant of the P02-MM portfolio that eliminates the Boardman-to-Hemingway transmission line.

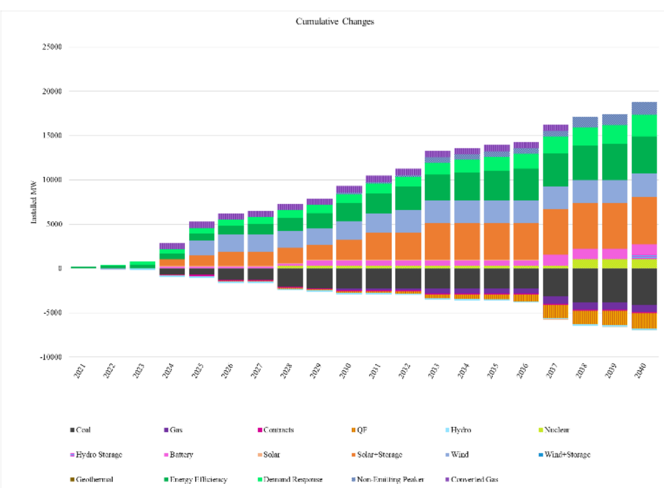
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$26,605***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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
Thermal retirement assumptions for P02b-No B2H are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02c-No GWS portfolio is a variant of the P02-MM portfolio that eliminates the Energy Gateway South (GWS) and D.1 transmission lines.

PORTFOLIO SUMMARY

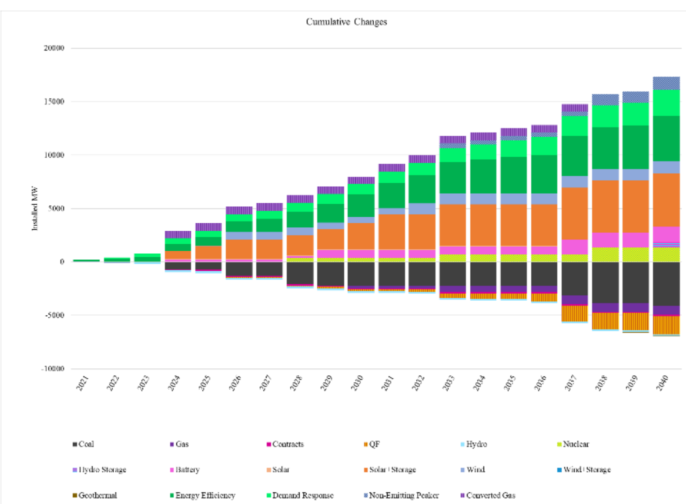
Risk-Adjusted PVRR ($m) ***$26,439***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02c-No GWS are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: No RFP Bids (P02 Variants P02(d))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
The P02d-No RFP portfolio is a variant of the P02-MM portfolio that eliminates all 2020 All-Source Request for Proposals final shortlist resources, including the Energy Gateway South (GWS) and D.1 transmission lines.

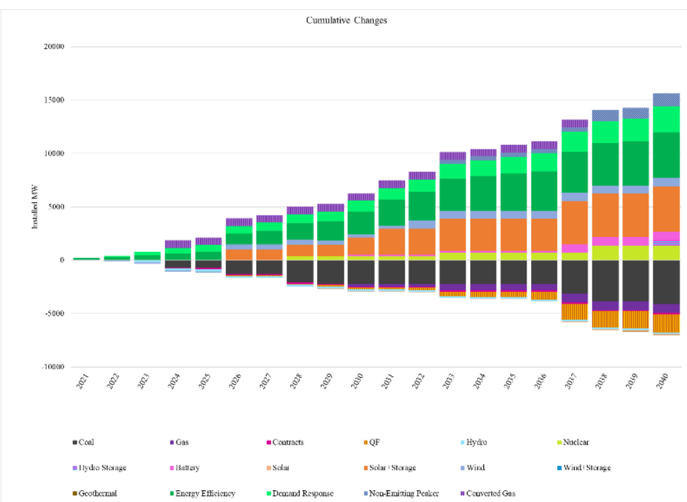
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$27,445***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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
Thermal retirement assumptions for P02d-No RFP are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: No Natrium Nuclear Project (P02 Variants P02(e))

P02 Variant Portfolio-Development Fact Sheets

Portfolio Assumptions

Description

The P02e-No Nuc portfolio is a variant of the P02-MM portfolio that eliminates the Natrium™ advanced nuclear demonstration project.

Portfolio Summary

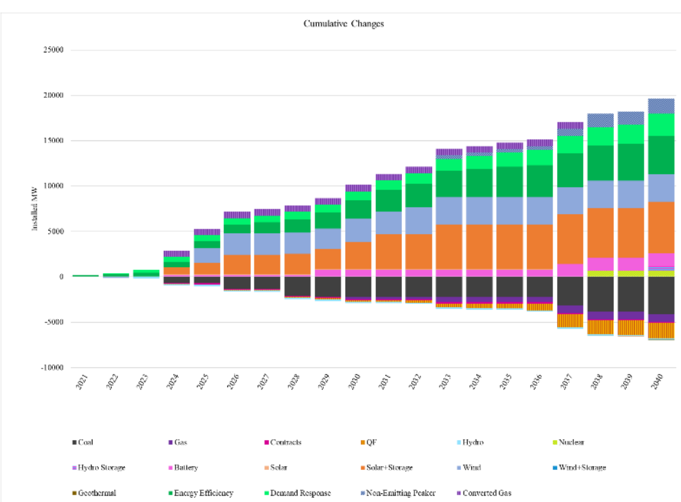
Risk-Adjusted PVRR ($m) ***$26,309***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02e-No Nuc are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: No Naughton 2025 Retirement (P02 Variants P02(f))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description
The P02f-No Nau 25 portfolio is a variant of the P02-MM portfolio that maintains continued coal-fueled operation of Naughton Units 1 and 2 through the end of 2029, rather than retiring in 2025.

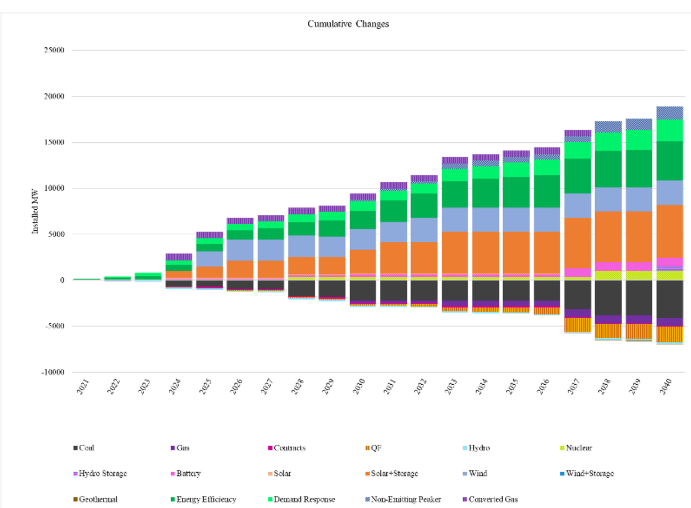
PORTFOLIO SUMMARY

Risk-Adjusted PVRR ($m) ***$26,217***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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
Thermal retirement assumptions for P02f-No Nau 25 are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2029
Naughton 2	Retire 2029
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Dave Johnston 4 CCUS Conversion (P02 Variants P02(g))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02g-CCUS portfolio is a variant of the P02-MM portfolio that forces a Carbon Capture Utilization and Sequestration (CCUS) retrofit on Dave Johnston Unit 4 in 2026, rather than retiring in 2027.

PORTFOLIO SUMMARY

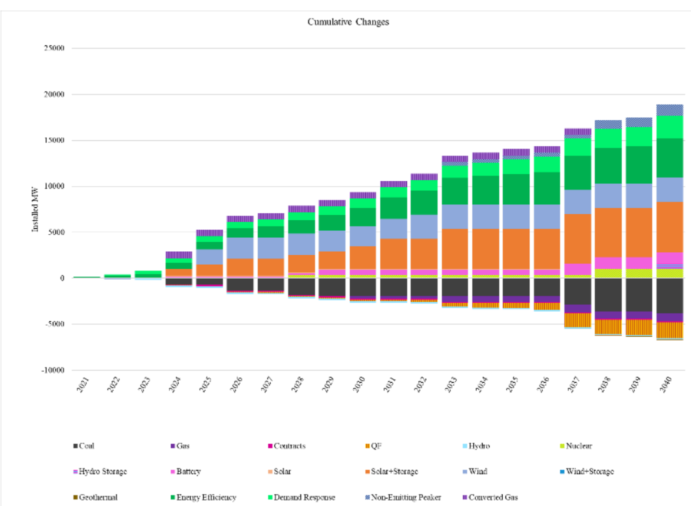
Risk-Adjusted PVRR ($m) ***$26,387***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02g-CCUS are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
Dave Johnston 1	Retire 2027
Dave Johnston 2	Retire 2027
Dave Johnston 3	Retire 2027
Dave Johnston 4	CCUS 2026
Gadsby 1	Retire 2032
Gadsby 2	Retire 2032
Gadsby 3	Retire 2032
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

CCUS = carbon capture and sequestration
GC = gas conversion

Portfolio: Jim Bridger 3 & 4 Early Retirement (P02 Variants P02(h))

P02 Variant Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

The P02h-JB3-4 Retire portfolio is a variant of the P02-MM portfolio that forces Jim Bridger Units 3 and 4 to retire before 2030 with the most optimal timing as determined by the Plexos model.

PORTFOLIO SUMMARY

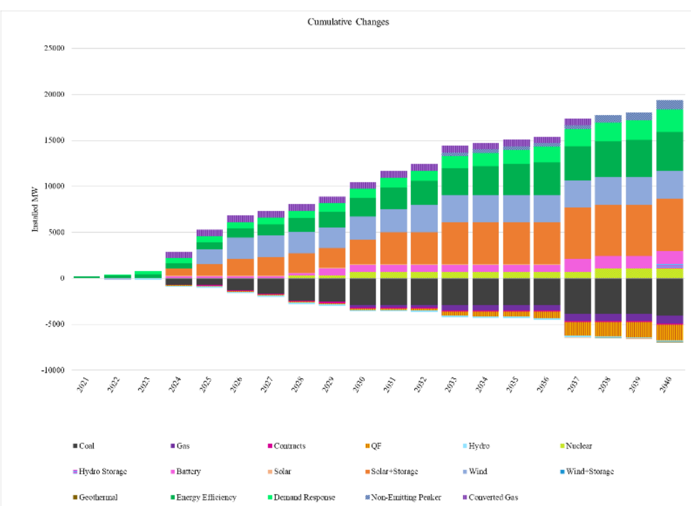
Risk-Adjusted PVRR ($m) ***$26,212***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02h-JB 3-4 Retire are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2029
Jim Bridger 4	Retire 2026
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

Portfolio: Alternative Lowest Cost Washington Required Portfolio

Washington CETA Required Scenarios Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Washington's Clean Energy Transformation Act (CETA) requires utilities to conduct specific scenarios as part of its integrated resource planning process. The Alternative Lowest Reasonable Cost scenario is required under WAC 480-100-620(10)(a) that instructs utilities to "describe the alternative lowest reasonable cost and reasonably available portfolio that the utility would have implemented if not for the requirement to comply" with CETA's Clean Energy Transformation Standards. Accounting for the retirement to include the social cost of greenhouse gas price policy in portfolio development, this is the alternative lowest cost portfolio, run under a medium gas / medium CO_2 price scenario.

PORTFOLIO SUMMARY

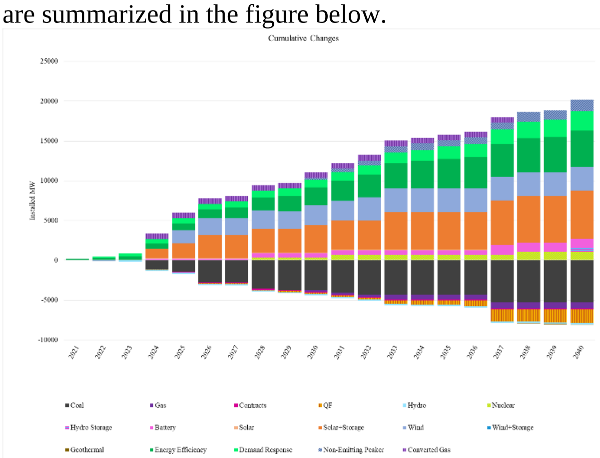
Risk-Adjusted PVRR ($m) $26,497

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for P02-SCGHG are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2023, Retire 2037
Jim Bridger 2	GC 2023, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2031

GC = gas conversion

In the absence of a requirement to assume the social cost of greenhouse gas price policy during portfolio development, the alternative lowest reasonable cost portfolio is P02-MM (Initial Portfolio-Development Fact Sheet: P02-MM).

Portfolio: Climate Change Washington Required Portfolio

Washington CETA Required Scenarios Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Washington's Clean Energy Transformation Act (CETA) requires utilities to conduct specific scenarios as part of its integrated resource planning process. The Climate Change scenario is required under WAC 480-100-620(10)(b) that instructs utilities to "incorporate the best science available to analyze impacts including, but not limited to, changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change."

PORTFOLIO SUMMARY

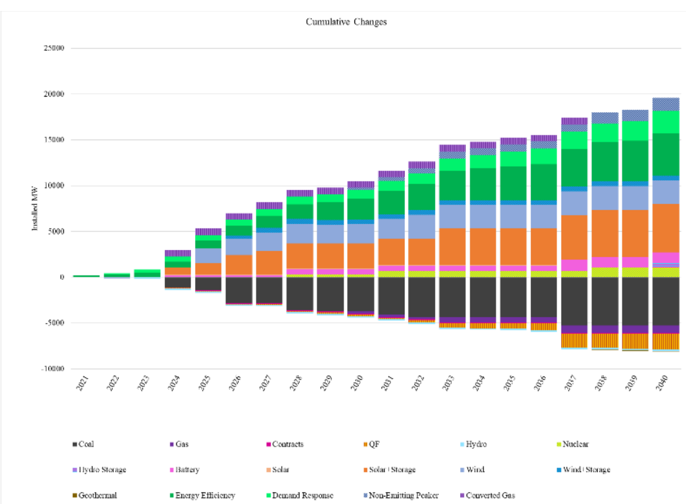
Risk-Adjusted PVRR ($m) ***$40,876***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for the Climate Change scenario are summarized in the following table.

Unit	**Description**
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2023
Hunter 2	Retire 2024
Hunter 3	Retire 2025
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2025
Jim Bridger 4	Retire 2030
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2031

GC = gas conversion

Portfolio: Maximum Customer Benefit Washington Required Portfolio

Washington CETA Required Scenarios Portfolio-Development Fact Sheets

PORTFOLIO ASSUMPTIONS

Description

Washington's Clean Energy Transformation Act (CETA) requires utilities to conduct specific scenarios as part of its integrated resource planning process. The Maximum Customer Benefit scenario is required under WAC 480-100-620(10)(c) instructs utilities to "model the maximum amount of customer benefits described in RCW 19.405.040(8) prior to balancing against other goals."

PORTFOLIO SUMMARY

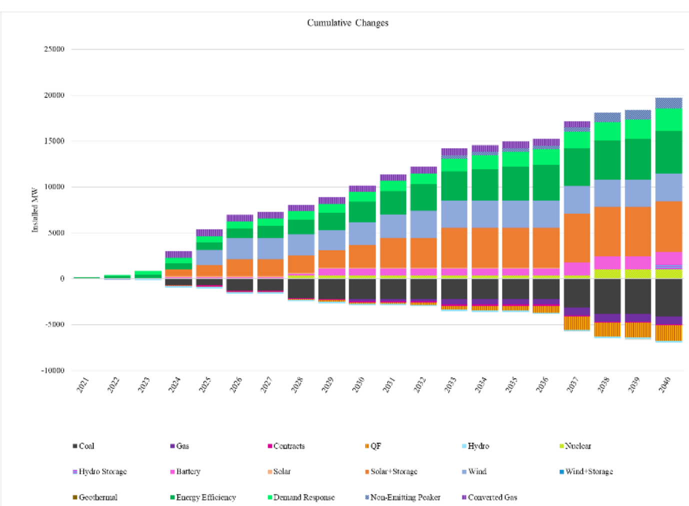
Risk-Adjusted PVRR ($m) ***$43,282***

Incremental Transmission Upgrades

Description	*Year*	*Capacity*
Wyoming East > Clover	*2025*	*1200*
B2H Borah > Hemingway	*2026*	*600*
B2H Hemingway > Midpoint	*2026*	*455*
B2H Walla Walla – WA > Borah	*2026*	*300*
Portland North Coast > Willamette Valley	*2032*	*450*
Utah South > Utah North	*2033*	*800*
Portland North Coast > Southern OR	*2037*	*1500*
Central OR > Willamette Valley	*2040*	*1500*

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

Thermal retirement assumptions for the Maximum Customer Benefit scenarios are summarized in the following table.

Unit	Description
Colstrip 3	Retire 2025
Colstrip 4	Retire 2025
Craig 1	Retire 2025
Craig 2	Retire 2028
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
Gadsby 4	Retire 2032
Gadsby 5	Retire 2032
Gadsby 6	Retire 2032
Hayden 1	Retire 2028
Hayden 2	Retire 2027
Hermiston	Retire 2036
Hunter 1	Retire 2042
Hunter 2	Retire 2042
Hunter 3	Retire 2042
Huntington 1	Retire 2036
Huntington 2	Retire 2036
Jim Bridger 1	GC 2024, Retire 2037
Jim Bridger 2	GC 2024, Retire 2037
Jim Bridger 3	Retire 2037
Jim Bridger 4	Retire 2037
Naughton 1	Retire 2025
Naughton 2	Retire 2025
Naughton 3 GC	Retire 2029
Wyodak	Retire 2039

GC = gas conversion

APPENDIX J – STOCHASTIC SIMULATION RESULTS

Introduction

This appendix reports additional results for the Monte Carlo production cost simulations conducted with the stochastic model. The results presented in Table J.1 through Table J.4 include stochastic results from the Medium Term (MT) model for the 2021 IRP preferred portfolio presented under five price-policy scenarios, four initial portfolios run through five price-policy scenarios, eight variant cases run through five price-policy scenarios and three Washington-required scenarios in accordance with WAC 480-100-620(10)(a)-(c).

Table J.5 and Figure J.1 present a 10-year incremental customer rate impact. Table J.6 and Figure J.2 present a 20-year incremental customer rate impact. Rate implications are more relevant over the near-term given biennial updates to the long-term 20-year planning horizon. During this time frame, portfolios and their associated costs are similar. Portfolio level system costs are a key factor in the portfolio selection process therefore, rate implications are not the primary key for portfolio selection. Distribution of costs among different classes is established in rate proceedings and nothing in the preferred portfolio would explicitly alter cost impacts among different classes of rate payers.

Table J.1 – MT Stochastic Mean PVRR, Preferred Portfolio

MT Stochastic PVRR ($ millions)					2021 to 2040		
Case	MT Stochastic Average	5th Percentile	90th Percentile	95th Percentile	Upper Tail	Upper Tail No Fixed Cost	Standard Deviation
P02-MM-CETA	25,205	24,911	25,457	25,476	25,538	7,106	178

Table J.2 – MT Stochastic Mean PVRR, Initial Portfolios

MT Stochastic PVRR ($ millions)					2021 to 2040		
Case	MT Stochastic Average	5th Percentile	90th Percentile	95th Percentile	Upper Tail	Upper Tail No Fixed Cost	Standard Deviation
P02-MM	25,185	24,881	25,419	25,460	25,505	7,198	178
P02-MM-CETA	25,205	24,911	25,457	25,476	25,538	7,106	178
P02-MM	26,875	26,516	27,158	27,203	27,235	5,677	210
BAU1-MM	25,838	25,554	26,071	26,112	26,152	6,715	174
BAU2-MM	25,899	25,603	26,134	26,171	26,213	6,744	176
P02-LN	21,480	21,209	21,684	21,737	21,805	5,093	160
P02-MM-LN	22,162	21,972	22,318	22,330	22,348	4,042	114
P02-MM-CETA-LN	22,268	22,085	22,433	22,440	22,459	4,026	114
P02-LN	24,041	23,772	24,236	24,270	24,360	3,327	152
BAU1-LN	21,929	21,721	22,104	22,120	22,142	4,206	126
BAU2-LN	21,959	21,648	22,175	22,239	22,324	5,188	177

Table J.2 Continued – MT Stochastic Mean PVRR, Initial Portfolios

P02-MN	21,284	20,989	21,544	21,571	21,625	4,745	181
P02-MM-MN	21,846	21,599	22,051	22,072	22,085	3,779	149
P02-MM-CETA-MN	21,977	21,736	22,198	22,203	22,227	3,795	149
P02-MN	24,790	24,483	25,027	25,065	25,100	3,310	179
BAU1-MN	21,834	21,592	22,042	22,060	22,069	3,568	149
BAU2-MN	21,805	21,466	22,079	22,117	22,198	4,904	200
P02-HH	27,642	27,256	27,950	28,011	28,094	10,098	235
P02-MM-HH	27,953	27,567	28,261	28,322	28,405	10,098	235
P02-MM-CETA-HH	28,004	27,617	28,334	28,369	28,473	10,041	234
P02-HH	27,874	27,451	28,258	28,270	28,355	7,267	259
BAU1-HH	28,237	27,850	28,544	28,610	28,685	9,998	231
BAU2-HH	27,964	27,573	28,289	28,342	28,428	10,094	241
P02-SC	37,161	36,587	37,731	37,763	38,034	18,649	405
P02-MM-SC	38,247	37,647	38,812	38,840	39,144	20,838	419
P02-MM-CETA-SC	38,288	37,697	38,841	38,898	39,209	20,777	415
P02-SC	36,924	36,371	37,454	37,494	37,734	16,668	386
BAU1-SC	38,661	38,048	39,245	39,278	39,560	21,035	426
BAU2-SC	38,536	37,940	39,123	39,171	39,449	21,115	430

Table J.3 – MT Stochastic Mean PVRR, P02 Variant Cases

MT Stochastic PVRR ($ millions)					2021 to 2040		
Case	**MT Stochastic Average**	**5th Percentile**	**90th Percentile**	**95th Percentile**	**Upper Tail**	**Upper Tail No Fixed Cost**	**Standard Deviation**
P02a-JB 1-2 No GC-MM	25,683	25,382	25,923	25,955	26,009	7,042	179
P02b-No B2h-MM	25,409	25,091	25,659	25,689	25,742	8,522	186
P02c-No GWS-MM	25,108	24,793	25,356	25,391	25,465	9,863	189
P02d-No RFP-MM	26,090	25,734	26,398	26,413	26,499	11,833	219
P02e-No Nuc-MM	25,308	24,996	25,546	25,585	25,636	7,703	180
P02f-No Nau 25-MM	25,150	24,839	25,382	25,428	25,474	7,435	179
P02g-CCUS-MM	25,321	25,016	25,558	25,592	25,634	6,482	177
P02h-JB 3-4 Retire-MM	25,229	24,922	25,475	25,508	25,557	6,510	181
P02a-JB 1-2 No GC-LN	22,714	22,529	22,876	22,886	22,911	3,943	114
P02b-No B2h-LN	22,079	21,883	22,251	22,262	22,280	5,060	120
P02c-No GWS-LN	21,153	20,957	21,324	21,333	21,366	5,764	120
P02d-No RFP-LN	21,604	21,350	21,801	21,842	21,900	7,234	149
P02e-No Nuc-LN	22,025	21,839	22,188	22,195	22,217	4,284	115
P02f-No Nau 25-LN	22,006	21,827	22,166	22,176	22,192	4,152	112
P02g-CCUS-LN	22,274	22,100	22,433	22,440	22,463	3,311	111

P02h-JB 3-4 Retire-LN	22,476	22,290	22,642	22,647	22,668	3,621	115

Table J.3 Continued – MT Stochastic Mean PVRR, P02 Variant Cases

P02a-JB 1-2 No GC-MN	22,317	22,085	22,536	22,544	22,573	3,606	148
P02b-No B2h-MN	21,915	21,659	22,141	22,156	22,180	4,960	157
P02c-No GWS-MN	21,208	20,953	21,443	21,450	21,493	5,890	157
P02d-No RFP-MN	21,958	21,637	22,221	22,273	22,329	7,663	191
P02e-No Nuc-MN	21,799	21,557	22,021	22,029	22,053	4,120	150
P02f-No Nau 25-MN	21,664	21,433	21,885	21,889	21,908	3,868	147
P02g-CCUS-MN	21,979	21,751	22,196	22,206	22,226	3,074	146
P02h-JB 3-4 Retire-MN	22,237	21,995	22,460	22,467	22,493	3,445	151
P02a-JB 1-2 No GC-HH	28,331	27,946	28,650	28,698	28,802	9,835	232
P02b-No B2h-HH	28,468	28,075	28,809	28,839	28,954	11,734	241
P02c-No GWS-HH	28,596	28,210	28,940	28,972	29,109	13,507	244
P02d-No RFP-HH	30,147	29,741	30,542	30,562	30,692	16,026	273
P02e-No Nuc-HH	28,201	27,818	28,529	28,573	28,670	10,737	236
P02f-No Nau 25-HH	27,982	27,598	28,300	28,349	28,439	10,400	233
P02g-CCUS-HH	27,922	27,536	28,249	28,289	28,389	9,237	231
P02h-JB 3-4 Retire-HH	27,726	27,342	28,059	28,094	28,199	9,151	235
P02a-JB 1-2 No GC-SC	38,511	37,911	39,088	39,142	39,438	20,471	425
P02b-No B2h-SC	39,261	38,656	39,823	39,890	40,216	22,996	427
P02c-No GWS-SC	40,504	39,876	41,068	41,151	41,519	25,917	442
P02d-No RFP-SC	43,140	42,478	43,758	43,833	44,196	29,530	471
P02e-No Nuc-SC	38,581	37,976	39,135	39,198	39,505	21,572	422
P02f-No Nau 25-SC	38,433	37,838	39,000	39,048	39,345	21,306	420
P02g-CCUS-SC	38,171	37,581	38,729	38,783	39,080	19,928	411
P02h-JB 3-4 Retire-SC	37,901	37,324	38,437	38,495	38,792	19,744	403

Table J.4 – MT Stochastic Mean PVRR, Washington Clean Energy Transmission Act (CETA) Required Scenarios Cases

MT Stochastic PVRR ($ millions)					2021 to 2040		
Case	MT Stochastic Average	5th Percentile	90th Percentile	95th Percentile	Upper Tail	Upper Tail No Fixed Cost	Standard Deviation
P02-MM-Alt Low Cost	25,621	25,281	25,918	25,931	25,999	6,614	203
P02-MM-Climate	37,363	36,753	37,963	38,032	38,271	20,010	426
P02-MM-Maximum Cust Benefit	40,640	40,049	41,200	41,252	41,553	23,189	414

Table J.5 – 10-year Incremental Customer Rate Impact

$ Millions	10-year Incremental Customer Rate Impact (2021 - 2030) Medium Gas, Medium CO2	
	Difference from Top Portfolio	Rank
P02	0	1
P02-CETA	23	2
P03	304	5
BAU1	208	4
BAU2	132	3

Figure J.1 – 10-year Incremental Customer Rate Impact

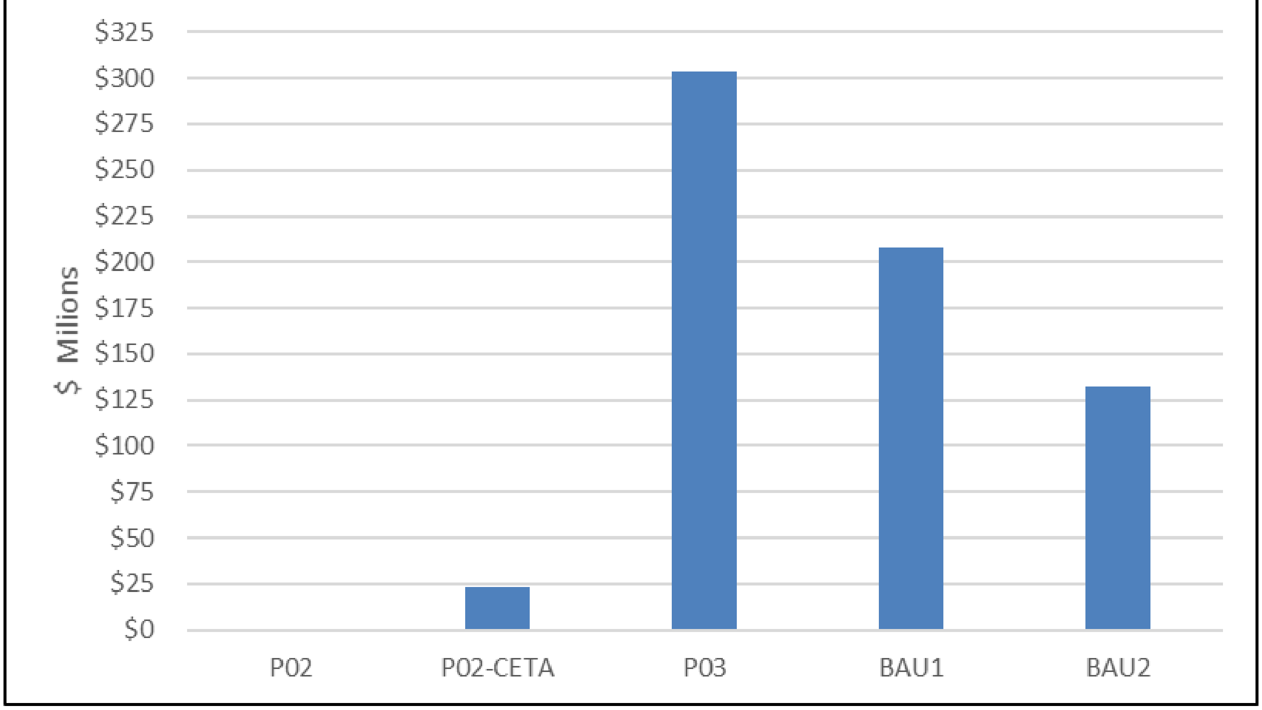
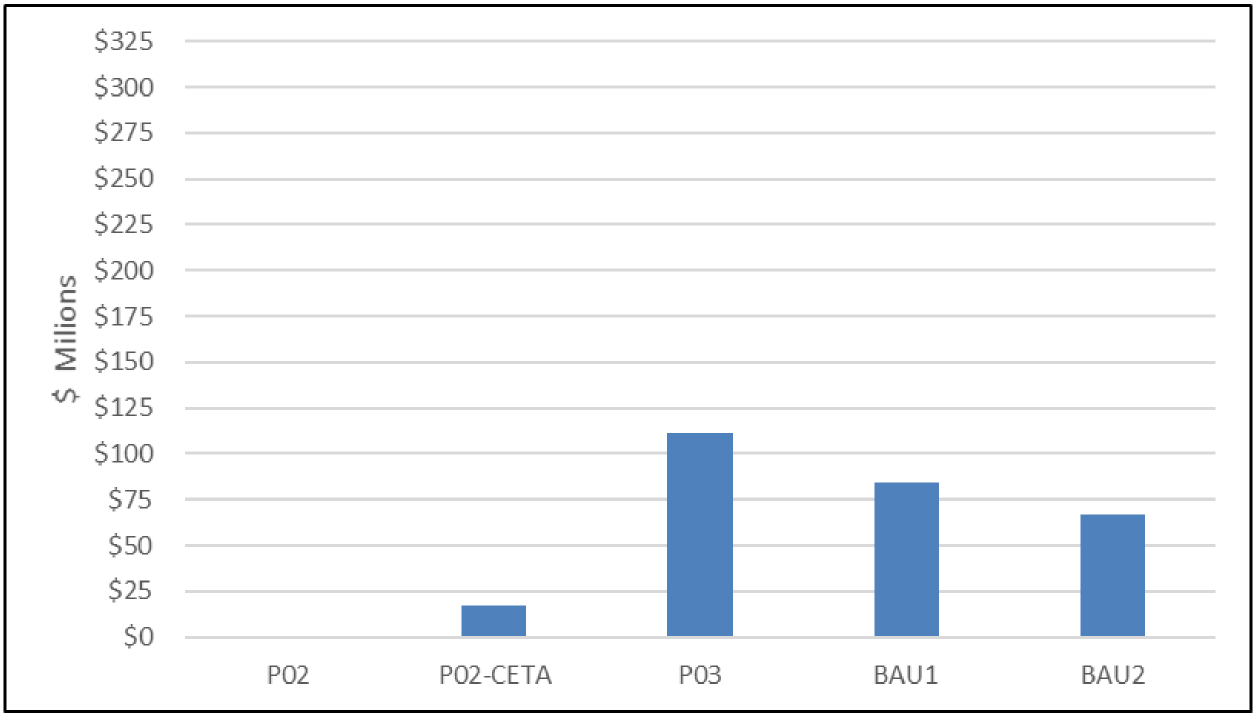


Table J.6 – 20-year Incremental Customer Rate Impact

$ Millions	**20-year Incremental Customer Rate Impact (2021 - 2040) Medium Gas, Medium CO2**	
	Difference from Top Portfolio	**Rank**
P02	0	1
P02-CETA	17	2
P03	111	5
BAU1	85	4
BAU2	67	3

Figure J.2 – 20-year Incremental Customer Rate Impact


$325
$300
$275
$250
$225
$200
$175
$150
$125
$100
$75
$50
$25
$0
$ Milions
P02
P02-CETA
P03
BAU1
BAU2

APPENDIX K – CAPACITY CONTRIBUTION

Introduction

The capacity contribution of a resource is represented as a percentage of that resource's nameplate or maximum capacity and is a measure of the ability of a resource to reliably meet demand. This capacity contribution affects PacifiCorp's resource planning activities, which are intended to ensure there is sufficient capacity on its system to meet its load obligations inclusive of a planning reserve margin. Because of the increasing penetration of variable energy resources (such as wind and solar) and energy-limited resources (such as storage and demand response), planning for coincident peak loads is no longer sufficient to determine the necessary amount and timing of new resources. To ensure resource adequacy is maintained over time, all resource portfolios evaluated in the integrated resource plan (IRP) have sufficient capacity to meet PacifiCorp's load obligations and a planning reserve margin in all hours of each year. Because all resources provide both energy and capacity benefits, identifying the resource that can provide additional capacity at the lowest incremental cost to customers is not straightforward. A resource's energy value is dependent on its generation profile and location, as well as the composition of resources and transmission in the overall portfolio. Similarly, a resource's capacity value (or contribution to ensuring reliable system operation) is also dependent on both its characteristics and the composition of the overall portfolio. To further complicate the analysis, PacifiCorp's portfolio composition changes dramatically over time, as a result of retirements and expiring contracts.

In the 2019 IRP, PacifiCorp developed initial capacity contribution estimates for wind and solar capacity that accounted for expected declining contributions as the level of penetration increased. A key assumption in this analysis was that only a single variable was modified, for example, when evaluating solar penetration level, the capacity from wind and energy storage resources in the portfolio were held constant. As the preparation of the 2019 IRP continued, PacifiCorp identified that these initial estimates did not adequately account for the interactions between solar, wind, and energy storage and thus did not ensure that each portfolio was adequately reliable. Therefore, as part of the 2019 IRP PacifiCorp assessed each portfolio to verify that it would support reliable operation in each hour of the year.

At the conclusion of the 2019 IRP, PacifiCorp recalculated the capacity contribution values for wind and solar resources using the capacity factor approximation method (CF Method) as outlined in a 2012 report produced by the National Renewable Energy Laboratory (NREL Report)[1]. The CF Method calculates a capacity contribution based on a resource's expected availability during periods when the risk of loss of load events is highest, based on the loss of load probability (LOLP) in each hour. This final CF Method analysis was performed using a portfolio that was very similar to the 2019 IRP preferred portfolio. For the reasons discussed above, this final CF Method analysis provides a reasonable estimate of capacity contribution value so long as the changes relative to the preferred portfolio are small, since in effect, the CF Method calculates the marginal capacity contribution of a one megawatt resource addition. Changes to the locations and quantities of wind, solar, and energy storage are key drivers of the marginal capacity contribution results.

[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 capacity contribution analysis for the 2021 IRP is comparable to that in PacifiCorp's 2019 IRP in two key ways. First, rather than assigning a capacity contribution at the start of the analysis, the hourly reliability of portfolios was assessed to identify periods of shortfalls. Second, a final CF Method analysis was performed using a portfolio that is similar to the 2021 IRP preferred portfolio. The final CF Method analysis for the 2021 IRP is presented in this Appendix.

CF Methodology

The NREL Report summarizes several methods for estimating the capacity value of renewable resources that are broadly categorized into two classes: 1) reliability-based methods that are computationally intensive; and 2) approximation methods that use simplified calculations to approximate reliability-based results. The NREL Report references a study from Milligan and Parsons that evaluated capacity factor approximation methods, which use capacity factor data among varying sets of hours, relative to a more computationally intensive reliability-based metric. As discussed in the NREL Report, the CF Method was found to be the most dependable technique in deriving capacity contribution values that approximate those developed using a reliability-based metric.

As described in the NREL Report, the CF Method "considers the capacity factor of a generator over a subset of periods during which the system faces a high risk of an outage event." When using the CF Method, hourly LOLP is calculated and then weighting factors are obtained by dividing each hour's LOLP by the total LOLP over the period. These weighting factors are then applied to the contemporaneous hourly capacity factors to produce a capacity contribution value.

The weighting factors based on LOLP are defined as:

$$w_i = \frac{LOLP_i}{\sum_{j=1}^{T} LOLP_j}$$

where w_i is the weight in hour i, $LOLP_i$ is the LOLP in hour i, and T is the number of hours in the study period, which is 8,760 hours for the current study. These weights are then used to calculate the weighted average capacity factor as an approximation of the capacity contribution as:

$$CV = \sum_{i=1}^{T} w_i C_i,$$

where C_i is the capacity factor of the resource in hour i, and CV is the weighted capacity value of the resource.

For fixed profile resources, including wind, solar, and energy efficiency, the average LOLP values across all iterations are sufficient, as the output of these resources is the same in each iteration. To determine the capacity contribution of fixed profile resources using the CF Method, PacifiCorp implemented the following three steps:

1. A 50-iteration hourly Monte Carlo simulation of PacifiCorp's system was produced using the Plexos Short-Term (ST) model. The key stochastic variables assessed as part of this analysis are loads, thermal outages, and hydro conditions. The LOLP for each hour in the

year is calculated by counting the number of iterations in which system load and/or reserve obligations could not be met with available resources and dividing by the total number of iterations.[2] For example, if in hour 19 on December 22nd there are three iterations with shortfalls out of a total of 50 iterations, then the LOLP for that hour would be 6 percent.[3]

2. Weighting factors were determined based upon the LOLP in each hour divided by the sum of LOLP among all hours within the same summer or winter season. In the example noted above, the sum of LOLP among all winter hours is 58 percent.[4] The weighting factor for hour 19 on December 22nd would be 1.0417 percent.[5] This means that 1.0417 percent of all winter loss of load events occurred in hour 19 on December 22nd and that a resource delivering in only in that single hour would have a winter capacity contribution of 1.0417 percent.

3. The hourly weighting factors are then applied to the capacity factors of fixed profile resources in the corresponding hours to determine the weighted capacity contribution value in those hours. Extending the example noted, if a resource has a capacity factor of 41.0 percent in hour 19 on December 22nd, its weighted winter capacity contribution for that hour would be 0.4271 percent.[6]

For resources which are energy limited, such as energy storage or demand response programs, the LOLP values in each iteration must be examined independently, to ensure that the available storage or control hours are sufficient. Continuing the example of December 22nd described above, consider if hour 18 and hour 19 both have three hours with energy or reserve shortfalls out of 500 iterations. If all six shortfall hours are in different iterations, a 1-hour energy storage resource could cover all six hours. However, if the six shortfall hours are in the same three iterations in hour 18 and hour 19 (i.e. 2-hour duration events), then a 1-hour storage resource could only cover three of the six shortfall hours.

Additional considerations are also necessary for hybrid resources which share an interconnection and cannot generate their maximum potential output simultaneously.

Final 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. Please note that marginal capacity contribution values reported herein are applicable to small incremental or

[2] In the past, PacifiCorp assumed that the first hour of any shortfall would be covered as part of its 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. While this reserve sharing remains in effect, shortfalls in the 2021 IRP are much more likely to result from changes in load, renewable resource output, or energy storage limitations, and not in the first hour after a contingency event occurs. In light of this, PacifiCorp's 2021 IRP analysis no longer excludes the first hour of every shortfall event.
[3] 0.6 percent = 3 / 500.
[4] For each hour, the hourly LOLP is calculated as the number of iterations with ENS divided by the total of 500 iterations. There are 288 winter ENS iteration-hours out of total of 5,832 winter hours. As a result, the sum of LOLP for the winter is 288 / 500 = 58 percent. There are 579 summer ENS iteration-hours out of total of 2,928 summer hours. As a result, the sum of LOLP for the summer is 579 / 500 = 116 percent.
[5] 1.0417 percent = 0.6 percent / 58 percent, or simply 1.0417 percent = 3 / 288.
[6] 0.4271 percent = 1.0417 percent x 41.0 percent.

decremental changes relative to the composition of the IRP preferred portfolio in 2030 and do not represent the average capacity contribution for each of the megawatts of a given resource type included in the preferred portfolio. In general, wind, solar, and energy storage have declining marginal capacity contribution values as the quantity of a given resource type increases. This results in average capacity contribution values that exceed the marginal capacity contribution values reported herein.

Table K.1 – 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%	14%	7%
Lakeview, OR	29%	13%	18%
Milford, UT	32%	15%	7%
Yakima, WA	25%	9%	4%
Rock Springs, WY	30%	14%	13%
Wind			
Pocatello, ID	37%	33%	39%
Arlington, OR	37%	46%	17%
Monticello, UT	29%	14%	42%
Goldendale, WA	37%	47%	21%
Medicine Bow, WY	44%	30%	32%
Stand-alone Storage			
2-hour duration		49%	75%
4-hour duration		74%	90%
9-hour duration		90%	96%

Table K.2 – Final CF Method Capacity Contribution Values for Solar Combined with Storage

	Capacity Factor (%)	Capacity Contribution (%)	
Summer/Winter:	**Annual**	**S**	**W**
Solar & 100% x 4-hour Storage			
Idaho Falls, ID	28%	81%	92%
Lakeview, OR	29%	82%	93%
Milford, UT	32%	80%	95%
Yakima, WA	25%	79%	91%
Rock Springs, WY	30%	80%	94%

The above CF Method results are from a one-year study period (2030) and shortfall 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. The study includes specific wind and solar volumes by resource for each hour in the period, and includes the effects of calm and cloudy days on resource output. Where data was available, the modeled generation profiles for proxy resources are derived from calendar year 2018 hourly generation profiles of existing resources, adjusted to align with the expected annual output of each proxy resource.

The use of correlated hourly shapes produces variability across each month and a reasonable correlation between resources of the same type that are located in close proximity. It also results in days with higher generation and days with lower generation in each month. As one would expect, days with lower renewable generation are more likely to result in shortfall events. As a result, basing CF Method capacity contribution calculations on an average or 12-month by 24-hour forecast of renewable generation will tend to overstate capacity contribution, particularly if there is a significant quantity of similarly located resources of the same type already in the portfolio, or if an appreciable quantity of resource additions are being contemplated. Even if an hourly renewable generation forecast is used, capacity contributions can be overstated if the weather underlying the forecast is not consistent with that used for similarly located resources used to develop the CF Method results. Because similarly located resources of the same type would experience similar weather in actual operations, a mismatch in the underlying weather conditions used in renewable generation forecasting will create diversity in the generation supply than would not occur in actual operations.

Because they are both influenced by weather, a relationship between renewable output and load is expected. To assess this relationship, PacifiCorp gathered information on daily wind and solar output from 2016-2019, and compared it to the load data from that period, the same load data that was used to determine stochastic parameters.

Each of the days in the historical period was assigned to a tier based on the rank of its daily average load within that month. This was done independently for the east and west sides of the system. The seven tiers were defined as follows:

Tier 1: The peak load day

Tier 2: 2nd – 5th highest load days

Tier 3: Days 6-10

Tier 4: Days 11-15

Tier 5: Days 16-20

Tier 6: Days 21-25

Tier 7: Days 26-31

The average wind and solar generation on the days in each tier was then compared to the average wind and solar generation for the entire month. The results indicated that west-side wind is often below average during the highest load days in a month, and above average during the lowest load days in a month. The results for other resource types were less pronounced, but do exhibit some patterns, as shown in Figure K.1 and Figure K.2.

Figure K.1 – Renewable Resources vs. High Load Conditions

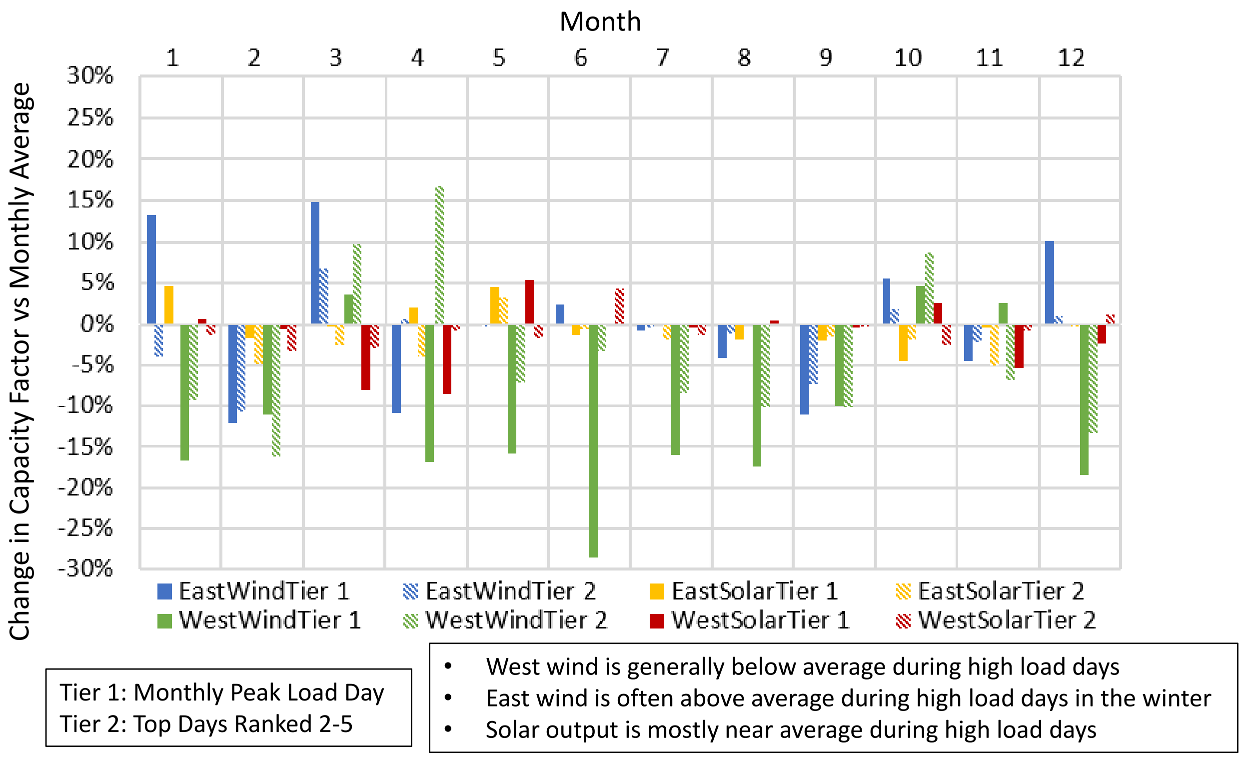
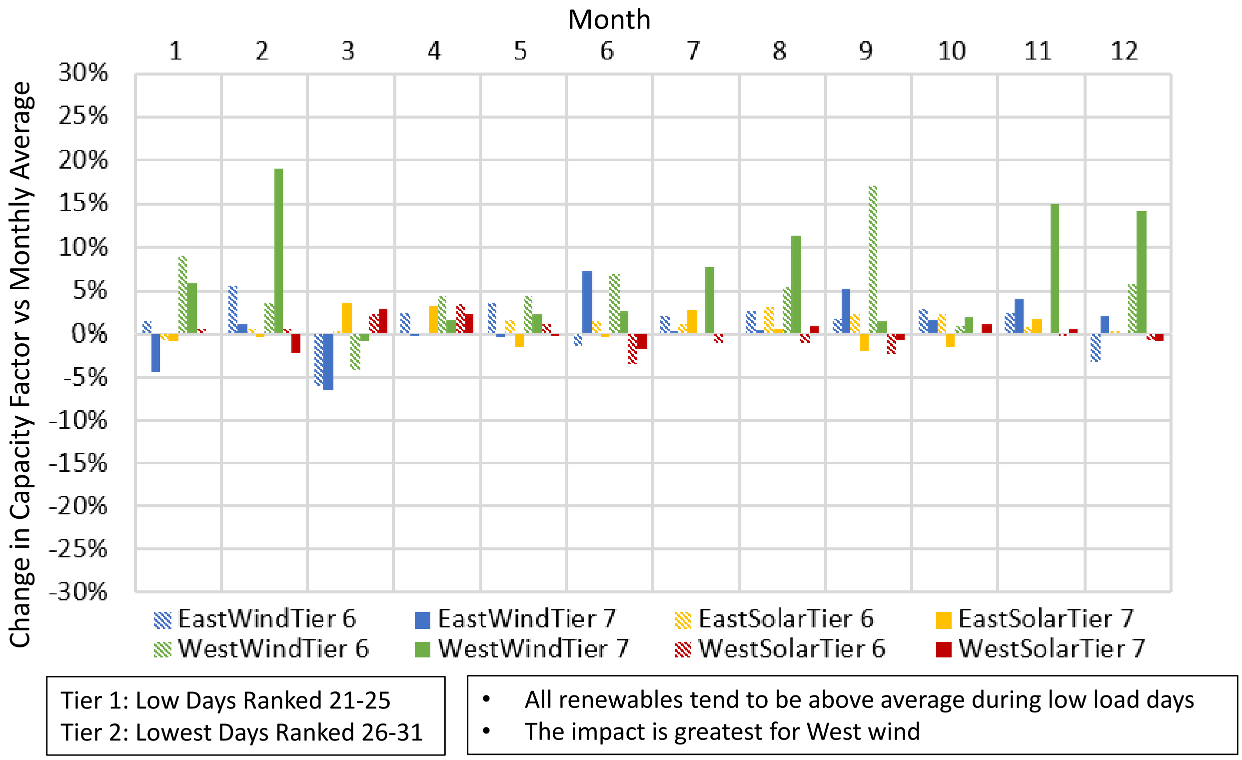


Figure K.2 – Renewable Resources vs. Low Load Conditions



Standard stochastic evaluation of prices, loads, etc. is based on standard deviations and mean reversion statistics. The results indicate that wind and solar output does exhibit relationships with load, but they are poorly represented by standard deviations – a different modeling technique is necessary.

Because of the complexity of the data, PacifiCorp did not attempt to develop wind and solar generation that varies by stochastic iteration for the 2021 IRP. Instead, PacifiCorp developed a technique using the existing input framework: a single 8760 profile for each wind and solar resource that repeats every year. Because the load forecast rotates with the calendar, such that the peak load day moves to different calendar days, this creates differences in the alignment of load and renewable output across the IRP study horizon.

The order of the 2018 historical days was rearranged so that the forecasted intra-month variation in renewable output was reasonably aligned with the intra-month variation observed in the historical period for the days in the same load tier. Each day of renewable resource output derived from the 2018 history is mapped to a specific day for modeling purposes – only the order of the days changes. To maintain correlations within wind and solar output, all wind and solar resources across the entire system are mapped using the same days.

While this technique builds on previous modeling and produces a reasonable forecast that captures some of the relationships between wind, solar, and load, additional work is needed in future IRPs to explore the variation and diversity of solar and wind output and further relationships with load.

APPENDIX L – PRIVATE GENERATION STUDY

Introduction

Guidehouse, formerly known as Navigant Consulting, Inc., prepared the Private Long-Term Resource Assessment for PacifiCorp. A key objective of this research is to assist PacifiCorp in developing private generation resource penetration forecasts to support its 2021 Integrated Resource Plan. The purpose of this study is to project the level of private generation resources PacifiCorp's customers might install over the next twenty years under low, base and high penetration scenarios.

2020 Renewable Resources Assessment

PacifiCorp

2020 Renewable Resources Assessment
Project No. 125017

Revision 1
August 2020

2020 Renewable Resources Assessment

prepared for

PacifiCorp
2020 Renewable Resources Assessment
Salt Lake City, Utah

Project No. 125017

Revision 1
August 2020

prepared by

Burns & McDonnell Engineering Company, Inc.
Kansas City, Missouri

TABLE OF CONTENTS

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 2020 Integrated Resource Plan (IRP) and associated resource acquisition portfolios and/or products. The 2020 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. The level of detail in this study is sufficient to provide screening level data required for the IRP planning process. Past the IRP modeling and selection, technologies of interest to the Owner should be further investigated in order to refine design, major equipment selection, value engineering, and specific project scope adjustments.

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-2020 dollars for a fixed price, turn-key resource implementation. The Summary Tables can be found in Appendix A: Summary Tables.

This report compiles the assumptions and methodologies used by BMcD 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-2020 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 costs were included for technology options with a shorter life cycle (Li-Ion, Solar, and Wind). Costs were developed based on Burns & McDonnell experience as well as published information. Recycling costs are included in the demolition figures; however, re-sale value of materials is excluded as that can vary significantly depending on metals pricing and competition in the currently expanding recycling market.

The current market is being impacted by various trade tariffs on materials as well as on solar modules. Predicting future trends or impacts of these tariffs is beyond the scope of this study. This 2020 study has based costs on recent bids that have accounted for the additional costs associated with current tariffs when available. While these costs are intended to represent a snapshot of 2020 pricing, additional volatility could occur when looking at future pricing of these options. These factors may also change the declining costs curves presented in the appendices.

Energy storage technologies evaluated in this assessment are expected to take advantage of less expensive, off-peak power to charge the system to later be used for generation during periods of higher demand. These storage options provide the ability to optimize the system for satisfying monthly, or even seasonal, energy needs. Energy stored off-peak and delivered on-peak can help reduce on-peak prices and is therefore beneficial to consumers. Additionally, energy storage has a direct benefit to renewable resources as it 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. Costs and options shown in this assessment represent storage technologies that are designed for one full cycle per day in a scheduled use case. Other use cases such as frequency regulation, voltage regulation, renewable smoothing, renewable firming, and black starting are not accounted for in the options presented in this study. Different use cases will impact the capital cost, O&M, and performance of the various technologies. 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

2.3 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: Summary Tables.

2.4 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
- Salvage values

2.5 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-2020 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 100 MW, and 200 MW single axis tracking photovoltaic (PV) options evaluated at two 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
100 MW	1.30
200 MW	1.30

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: Solar PVSYST Model Output (5MW) shows the PVSYST model output for a 4.2 MW block with the input assumptions, losses, and output summary. Appendix C: Solar Output Summary 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: Generation Cash Flows.

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: Summary Tables. The project scope assumes a high voltage interconnection for both the 100 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.

Demolition costs for PV are included in the IRP Inputs and are meant to reflect the end of life decommissioning efforts. PV recycling in the U.S. is led by the Solar Energy Industries Association (SEIA), which has developed a national PV recycling program. This program works with several recycling companies along with regulators in order to abide by the Federal Resource Conservation and Recovery Act (RCRA), which is the governing legislation for the disposal of PV equipment. SEIA advises system owners to consider reuse and refurbishment when possible. However, when demolition and recycling is required, PV panels contain several materials that can be recovered. By weight, 80% of the panel consists of glass and aluminum. Other valuable materials include copper, silver, and semiconductor materials. Similar to the Li-Ion storage industry, many PV sites have not yet reached their end of useful life and therefore the recycling and materials resale market is still in its infancy.

The 2020 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 2020 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 9.0. The battery storage size is set at approximately 50% of the total nominal output of the base solar options, with four 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: Wind Performance Information 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 V150-4.0 wind turbine model 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 V150-4.0. 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 V150-4.0
Name Plate Capacity, MW	4.0
Rotor Diameter, meters	150
Hub Height, meters	105

Using the NREL wind resource maps, the mean annual hub height wind speed at each potential project location was estimated and then extrapolated using the wind profile power law 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: Generation Cash Flows. Cost estimates assume an EPC project plus typical Owner’s costs. Costs are based on a 200 MW plant with 4.0 MW turbines (50 total turbines) and 105-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 161 kV.

- Land costs are excluded from the EPC and Owner's cost. For the 2020 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.

Demolition costs shown on the IRP Input Table are meant to represent the efforts to return the project site back to native conditions (i.e. re-grading the site to achieve suitable drainage and seeding disturbed areas consistent with surrounding areas). This includes the decommissioning and demolition of all wind turbines as well as the associated infrastructure (i.e. buildings, turbine foundations, access roads, transmission lines, etc.). Also included is the transportation cost associated with moving the turbines off-site to recycling or landfill locations. Demolishing turbine blades can be a difficult as they are made of tough resin and fiberglass. One method of decommissioning is to cut the blades up into 3 or more parts to make them easier to transport to landfills. Another method involves grinding the blades into small pellets that can used for decking, pallets, and piping. Along with PV and li-ion storage, wind turbines contain valuable components such as steel, copper, and other metals that ideally can be resold as part of the recycling process.

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

A summary of the suggested planned maintenance activities for a utility-scale wind energy facility are presented in Table 4-2 below. These represent the minimum activities that Burns & McDonnell suggests to be performed on a recurring basis and represent a minimum standard of performance if high availability and/or extended useful life are required. For the avoidance of doubt, the frequencies noted in Table 4-2 represent a minimum recurrence interval; trending results, condition-based monitoring data, supplier recommendations, or other similar items may necessitate more frequent planned maintenance.

Table 4-2: Minimum Wind Farm Planned Maintenance Activities

Component	Activity	Min. Frequency
General	Visual inspection of exterior components (e.g., nacelle, tower, blades)	Semi-annual
	Tower weld inspections	3-year rotation
	External paint touch-up	As required
	Fastener inspections and re-torque	3-year rotation
	Condition monitoring system set-point review	Annual
	Supplier-recommended semi-annual maintenance	Semi-annual
	Monitoring via SCADA	24/7
Nacelle	Visual inspection of internal components	Per supplier manuals
	Functional tests of major components	Per supplier manuals
	Gearbox borescope inspections	3-year rotation
	Gearbox oil sampling and trending	Annual
	Gearbox oil and filter replacement	Per supplier manuals
	Bearing grease sampling and trending (e.g., main bearing, yaw bearings, blade bearings)	Per supplier manuals
	Lubrication flush and filter replacement	Per supplier manuals
	Inspection of emergency equipment	Annual
Foundations	Visual inspection of exterior components (including bolts, nuts, washers, concrete, and surroundings)	Semi-annual
	Re-application of anti-corrosion protective coating	As required
BOP	Visual inspection of infrastructure (e.g., roads, collection routes, gen-tie routes, substation)	Annual
	Visual inspection of electrical equipment (e.g., transformers, breakers)	Semi-annual
	Maintain drainage away from foundations / structures	As required
	Transformer oil testing and trending	Annual
	Infrared scanning on all transformers	Annual
	De-energized substation maintenance	3 years
	Revenue meter test / calibration	Semi-annual
	Visual inspection of met towers (including tower, instruments, and guys)	Annual
	Met tower instrument calibration	Bi-annual

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 4-3 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 4-3: 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 $25/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 2020, 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 received reduced credits:

- 2017: 80% of the full PTC value
- 2018: 60% of the full PTC value
- 2019: 40% of the full PTC value
- 2020: 40% of the full PTC value (extended through Dec 31st, 2020)

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 9.0. The battery storage size is set at approximately 50% of the total nominal output of the base solar options, with four 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. The costs were aligned 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. CAES has two primary application methods: diabatic and adiabatic. To utilize CAES, the project needs a suitable storage site, either a salt cavern or mined hard-rock cavern. Salt caverns are the most preferred due to the low cavern construction costs, however mined hard-rock caverns are now a viable option in areas that do not have salt formations with the use of hydrostatic compensation to increase energy storage density and reduce the cavern volume required. 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, and generating power as the heated air travels through an expander.

6.1.1 Diabatic CAES

The difference between diabatic and adiabatic compressed air energy storage is in the method that the air is heated during generation. Diabatic CAES uses natural gas firing during generation via a gas turbine expansion train. Expansion train technology is also currently allowing for 30% H2 co-firing today and there are plans to develop the technology to support 100% H2. Round-trip efficiencies for diabatic CAES plants account for the energy input of the compressors as well as the energy input of the gas turbine. The energy input of the compressors is a design choice that will be made to balance cost and benefit. The round-trip efficiencies represented in this technology assessment are the efficiencies that can be reached at the cost that is shown. The heat input of the gas turbine during generation takes into account the heat rate of the turbine. The total energy output of the CAES plant is divided by the combination of these two figures (compressor energy and natural gas heat input) to calculate the round-trip efficiency. 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. Diabatic CAES was removed from the evaluated options due to a shift in focus from developers to adiabatic CAES, which offers zero emissions storage.

6.1.2 Adiabatic CAES

A second application of compressed air energy storage is adiabatic, which uses no natural gas firing. Heat is recovered in a Thermal Energy Storage (TES) system while air is being compressed and this energy is released to heat the air during expansion and generation. During compression, air temperatures can reach up to 1000°F. The use of a TES (with oil, molten salt, etc..) to capture and release this heat allows the adiabatic CAES technology to work free of any fuel. This trait can decrease operating and construction costs. The absence of a gas turbine makes the calculation for round-trip efficiency the total energy output of the plant divided by the energy input of the compressors. Again, the size and energy requirements of the compressors is a design choice and the efficiencies represented in the technology assessment table are in conjunction with the costs also represented for each option. This technology is currently in service or in construction at 3 plants in Canada and Australia that total 25 MWh of storage capacity.

6.2 CAES Cost Estimates

The CAES cost estimates are shown in the Summary Tables. The costs were developed using generic Siemens and Hydrostor 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 diabatic 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. Adiabatic CAES is an emissions-free operation and does not require an emissions control system.

7.0 LIQUID AIR ENERGY STORAGE

7.1 General Description

Liquid air energy storage (LAES) uses electricity to drive a compression/refrigeration system that cools ambient air to approximately -320 °F, at which point it becomes a liquid. Liquefying air is advantageous because it achieves a volume reduction of approximately 700:1, meaning that large quantities of air can be stored in a significantly smaller volume. The liquid air is stored is until it is ready for use. Energy is then recaptured by re-vaporizing the liquid air and generating power as the heated air travels through a series of heat exchangers and expanders. The overall system is optimized by taking advantage of waste heat and "waste cold" in the process to reduce the amount of power required to liquefy the air.

LAES is a relatively new application in the energy storage market, however, the major equipment components and technologies used to liquefy, store, and re-vaporize the air have been widely used in many other industry applications for decades. Highview Power is one of the major LAES technology licensors in the market, having completed a LAES pilot plant in Heathrow, UK in 2011. This operational facility uses 350 kW to liquefy the air and provides 2.5 MWh of energy storage.

One of the major similarities between LAES and CAES is that the LAES technology also offers the ability to take advantage of off-peak power to charge the system that can then be later discharged during peak demand hours as described in Section 6.1.

Another similarity LAES shares with adiabatic CAES is a zero emissions process. When coupled with a renewable energy source to provide power for the system, LAES is considered a completely green technology, meaning that it does not have any emissions associated with the process. The system utilizes motor-driven equipment, as opposed to a gas turbine, for the main air compressors and other auxiliary equipment, so there are no emissions generated from combustion. Additionally, there are no hydrocarbons used in the process at all – only air – so fugitive emissions are also non-existent.

The LAES technology can be broken down into three (3) major systems; system charging (air liquefaction), energy storage (liquid air storage), and system discharge (power generation). Each of these systems are relatively independent of one another and therefore can be designed for different amounts of capacity, depending on the specific application and use case. For example, the charging section of the facility (air liquefaction) could be designed to produce liquid air at a rate sufficient enough to utilize any excess energy generated from renewable sources that otherwise would need to be curtailed due to transmission constraints. However, the discharge system could be designed to generate power at the rate required to meet the demand during peak times; this rate may or may not be the same as the charging rate.

The number of hours of available storage can be easily modified by adding additional liquid air storage tanks.

The following sections describe each of these three systems in more detail.

7.1.1 System Charging – Air Liquefaction

Ambient air is used as the source of air for the process. The air is sent through a series of compressors and heat exchangers to increase the pressure from atmospheric to approximately 850 psig. This initial air compression requires the largest amount of power usage for the entire process; there are other users within the process, but they are significantly smaller the main air compressor.

Contaminants in the air such as carbon dioxide, water, and particulates must be removed prior to the liquefaction process. Carbon dioxide and water will freeze at the cryogenic temperatures and could clog the piping, valves, or equipment. The air flows through a set of molecular-sieve beds that adsorb the water and CO_2 from the air – this technology is very similar to the process used in liquefied natural gas (LNG) facilities. Once saturated, the molecular-sieve is regenerated with dry air and ready to be used again.

A common process used to liquefy air is the Claude cycle. In the Claude cycle, the air acts as the process fluid to be cooled as well as the refrigerant. The high pressure air is let-down across an expander and/or valve to low pressure. This rapid reduction in pressure creates a cooling effect, known the Joule-Thompson (JT) effect, and a portion of the air becomes the liquid air product. Any air that is not liquefied is used as a refrigerant to further cool the system and is recycled to go through the process again. This is a well-known and widely industry-recognized process for liquefying air.

7.1.2 Energy Storage – Liquid Air Storage

Once the air is liquefied, it must be stored until ready for use. A benefit that LAES provides over CAES is that a specialized storage site, such as a salt cavern, is not required. Liquid air is stored in field-erected, insulated, cryogenic, storage tanks. These tanks are very similar to the storage tanks used to store other cryogenic liquids (such as liquid nitrogen or liquefied natural gas) and are widely utilized the in the oil, gas, and chemicals industry. By not depending on the geological formations of the site for storage, LAES facilities can be built in any location in which sufficient space is available.

Although the tanks are very well insulated, there will be some amount of the liquid air that “boils-off” as the system sits stagnant. Fortunately, since the contents of the storage system are only air (nitrogen, oxygen, argon, etc.), this “boil-off” vapor can be vented directly to atmosphere with no additional handling equipment required.

Depending on the amount of storage duration desired (i.e. hours of storage), the volume and quantities of storage tanks can be modified. Additional storage duration requires additional storage volume. When determining the size/capacity of the charging system, it is important to consider how long it will take to fill the storage tanks. If the charging duration is too long, it may be advantageous to increase the charging system capacity.

7.1.3 System Discharge – Power Generation

When ready to use to generate power, the liquid air is pumped from the storage tanks to a heat exchanger in which it is re-vaporized. The warm air then flows through series of heat exchangers and expanders, similar to CAES, in order to generate power via the expander. The rate in which power is generated is determined by the pumping capacity and the expander capacity. The higher discharge rate required, the larger the expander required.

Once the air is fully expanded, it is released back into the atmosphere.

8.0 GRAVITY ENERGY STORAGE

8.1 General Description

Gravity energy storage (GES) offers a technique of storing off peak generation that can be dispatched during peak demand hours. Like Pumped Hydro Storage, GES takes advantage of kinetic and potential energy via mass transfer between different elevations. This developing storage technology presents unique advantages in performance with round-trip efficiencies of approximately 80-90%. GES's largest competing technology is pumped-hydro storage due to similarities in fundamental design. However, GES has little to no site restrictions and can be integrated into any high voltage transmission grid while maintaining an insignificant environmental impact over the storage system's lifespan. Currently, storage capabilities range from 6-14 hours. In addition, gravity storage caries a small land footprint per kWh, thus increasing storage capability per acre.

GES technology is currently in small-scale international operation but is not yet available on a commercial scale. However, due to the growing global demand for large-scale storage options, there is burgeoning interest in the use of GES as a commercial storage solution. CapEx for GES depends on the design of the system and is customizable to balance the economic and performance goals of the project. GES has a large upfront capital cost but does not require as much ongoing CapEx throughout the life of the project due to minimal degradation. The future success of GES systems will depend on their ability to compete with other emerging energy storage methods in the long term.

8.1.1 Vertical Shaft Gravity Energy Storage

Vertical shaft (VS) GES systems consist of a shaft of large diameter, a piston, and other common operational components such as a pump-turbine, generator, etc. The water that fills the large shaft below the piston serves as a medium for energy transfer. The system operates on the simple function of pumping water to hydraulically lift a piston fitted within the large shaft. The steel piston is filled with reinforced rock and concrete materials. A reversible pump-turbine essentially creates a closed-circuit and converts grid power to potential energy by pumping water into the large shaft to raise the piston. During peak demand, the stored potential energy can be converted back into electrical energy by the descending piston that then allows the water under pressure to transfer back through the turbine, and ultimately back onto the grid.

In 2013 a Santa Barbara, California based company, Gravity Power, planned to construct its first commercial GES demonstration in Penzberg, Germany designed with a power shaft depth of 500-m and a 30-m diameter. These parameters produce an equivalence of 160 MWh (40 MW for 4 hours of bulk energy storage and requires a power consumption of 40 MW for a charge time of approximately 5 hours). This project is expected to have a lifetime of at least 50 years. The total cost estimate of this system was estimated at $1,100/kWh or $4,400 kW. Because general planning for a GES can take 2+ years with an additional 3-4 years of construction, this GES project is expected to be operational within the next few years.

8.1.2 Crane-Lift Gravity Energy Storage

A second application of GES employs the elevation of rock or concrete masses by crane to create a tower where potential energy is stored via elevation gain. Electric motors power the lifting of blocks to various levels that then create a tower. The total allowable energy storage is relative to tower height mass of the blocks, and the quantity of the blocks that can fit under the cranes. Energy from the grid is used to lift blocks and during hours of peak demand, energy is returned to the grid when the cranes lower the blocks. The force of gravity pulls the blocks downward, maintaining a constant speed of descent which creates kinetic energy that is converted to electrical energy by turning the electric generator. Since the mass of the blocks affects the CapEx of the cranes, the most cost effective way to increase power and energy capacity for this system is to increase the height of the tower and the velocity at which the blocks descend.

Energy Vault, a Swiss-based company specializing in utility-scale gravity-based energy storage, partnered with Indian energy provider, Tata Power, to deploy a 35-MW system in 2018. Energy Vault has developed a six-arm crane with capability to lift 35T (5,000 concrete blocks) to a height of ~30 stories. The system holds a round-trip efficiency between 80-90%. The storage system’s capability maintains ranges of 20-35-80 MWh storage capacity and a 4-8MW of power discharge for 8-16 hours. A 30+ year lifespan is expected for this size GES system. Though this system is small-scale when considering the possible capabilities of its technology, its appeal has propelled Energy Vault and other companies to push the boundaries of crane-lift GES systems. This GES system may be more commonly utilized in the coming years due to large storage capacities, efficiency, low O&M costs, and sparse site restrictions. However, the technology is new, and the concern of its ability to compete with other new storage proposals produced in the long term remains.

8.1.3 Rail Energy Storage

Rail energy storage (RES) similarly takes advantage of potential energy to store and kinetic energy to discharge energy like Pumped Hydro Storage and the other GES technologies, with a simpler approach and less infrastructure. RES does not require water as a working fluid like pumped hydro and does not involve intensive extraction of materials during the construction process. RES has the potential to have lower CapEx and O&M expenses than other current energy storage options in certain topographical areas. RES storage facilities perform at approximately 80% round-trip operating efficiency while continuously delivering energy for up to 8 hours.

This storage solution utilizes rail cars that haul large masses (typically concrete or rock masses) back and forth between storage yards to store excess energy in times of low demand and easily disperse that energy during peak demand. RES uses surplus electrical energy from nearby renewable plants to power the increase in elevation of rail cars during hours of low demand, which creates potential energy. During hours of peak demand, the rail cars descend back downhill via gravity. This process converts the stored potential energy back into kinetic energy through regenerative braking, a technology commonly seen in electric vehicles. Regenerative braking utilizes the motor as a generator and converts lost kinetic energy from deceleration back into electrical that can be returned to the grid.

In April of 2016, Advanced Rail Energy Storage (ARES), a Santa-Barbara, California based energy startup had its first commercial-scale project approved on behalf of the Bureau of Land Management. The small-scale project, called ARES Nevada, planned for development on ~100 acres of public land near Pahrump, Nevada, has a 50-MW power capacity and can produce 12.5 MWh of energy. The estimated cost of the project is $55 million (at approximately $4,400/kWh) with an expected lifespan of 40 years. Though the project was scheduled to be in operation by late 2019 to early 2020, its success is still in question as it has not been in commercial use for an extended period. ARES is currently working on new designs to enable the storage system to perform on much steeper slopes along shorter distances which would allow the technology to be operable in more densely populated regions.

9.0 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 30-minute, 1-hour, 4-hour, and 8-hour storage capacities as well as a 50 MW option with 4-hours of storage. A 1 MW, 1-hour, 4-hour, and 8-hour flow cell battery options were also included, along with a 20MW, 8-hour option. Additionally, the solar and wind summary tables include optional costs for adding Li-Ion battery capacity of 50% of the nominal renewable output to the site with 4-hours of storage.

9.1 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.

9.1.1 Flow Batteries

Vanadium Redox batteries (VRB) and Zinc-Bromide (ZnBr) batteries are representative of commercially available flow battery technologies, but other technologies, such as iron flow batteries, are also available. Generally, flow batteries have lower round-trip efficiencies than Li-Ion batteries, however their theoretical performance does not degrade. This allows flow batteries to exhibit longer life spans than Li-Ion batteries without augmentation.

Developed in the early 1990’s by the University of New South Wales in Australia, VRBs employ a two tank, two pump system that contains vanadium-based electrolyte solutions on each side. Electrons are passed between the two solutions via an ion-permeable membrane to charge and discharge the battery. VRBs may be attractive for grid-scale applications due to their long lifetime and potential to scale power and energy capacity independently as needed for a given application. However, commercially available VRBs are generally modular in design, so the electrolyte volumes and discharge durations are limited by the form factor. As products and markets develop further, decoupled designs may arrive with greater design flexibility. The vanadium in the electrolyte does not degrade, so it can be reused/recycled after the useful life of the battery.

Zinc-Bromide batteries were developed in the 1970's by Exxon and are often referred to as "hybrid" flow batteries. ZnBr batteries use pumped liquid electrolyte in a single pump, single tank system. During charging, energy is stored by plating electrode surfaces with zinc. Discharging causes the zinc to oxidize and dissolve into the aqueous solution, which releases electrons to do work in the external circuit. The capacity of ZnBr batteries (and other plating style technologies) is dependent on electrode area as well as electrolyte volume. Commercially available units are modular designs with fixed power and energy ratings

9.1.2 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 20-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.

9.1.3 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 98°C and 113°C, respectively. To maintain the electrolytes in liquid form and for optimal performance, the NaS battery systems are typically operated and stored at around 300°C, 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.

9.2 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.

9.3 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.

9.4 Regulatory Trends

Two (2) Federal Energy Regulatory Commission (FERC) Orders released in 2018 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.

Tariffs are a popular concern in the solar and storage market. With recent tariffs, uncertainty of how manufacturing abroad and nationally will be affected has crept into the industry. The “Section 301” tariffs are comprised of four lists of Chinese products that have been selected for tariffs between 15% and 30%. Raw materials used to create Li-Ion batteries and solar modules are already impacted by the Section 301 tariffs in affect and were set to increase from 25% to 30% in late Fall 2020 but has since been delayed. While these tariffs are beginning to increase, manufacturers in China have started to react and move production of solar and storage products outside of China to Mexico and India to avoid paying some of the tariffs.

9.5 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 options are based on iron flow battery technology. This is a modular design in which the OEM scope includes the tanks, electrolyte storage, and associated pumps and controls in a factory assembled package. The EPC scope includes the inverters, switchgear, MV transformer, and installation.

Demolition costs are meant to reflect the end of life decommissioning efforts. This includes discharging the batteries to the greatest extent possible, shutting the system down, final inspections, and physically disconnecting all electrical equipment. Following this, battery modules will need to be removed from the racks and placed on pallets for shipment to a recycling facility. Lithium-ion batteries are considered Class 9 hazardous waste and is currently treated like e-waste. Once at the recycling facility, a dissembler will break the module down into major subcomponents like steel, cells, copper, printed circuit boards, plastics, etc. The cells are then sent through either a shredding or smelting process to recover valuable metals. Once the cells go through this process, any remaining waste is not considered hazardous. Battery recycling costs vary significant depending on chemistry. Cobalt-based battery chemistries have higher recovery value and because they are more energy dense, typically involve handling less material. In all cases, the cost of disassembly and freight to the recycling facility is estimated to account for 70-90% of the total cost for recycling. Estimates, though, can vary significantly depending on metals pricing and competition in the battery recycling market.

9.6 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 20 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 portions of performance guarantees and augmentation from recent BMcD project experience. The 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.

Previously represented as variable O&M, estimates for Li-ion options account for cycling degradation fees are now also included in the fixed O&M section due to how the industry is now utilizing service agreements. 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 augmentation 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 an augmentation 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.

10.0 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. For specific project development efforts beyond IRP planning, PacifiCorp should pursue additional engineering studies to define project scope, budget, and timeline.

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. While PHES currently has the most installed capacity for energy storage as a whole, Li-Ion technology is achieving the greatest market penetration in the battery storage sector. This is 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

APPENDIX B – SOLAR PVSYST MODEL OUTPUT (5MW)

APPENDIX C – SOLAR OUTPUT SUMMARY

APPENDIX D – WIND PERFORMANCE INFORMATION

APPENDIX E – DECLINING COST CURVES

APPENDIX F – GENERATION CASHFLOWS

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Burns & McDonnell
9785 Maroon Circle, Suite 400
Centennial, CO 80112
O 303-721-9292
F 303-721-0563
www.burnsmcd.com

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
ENERGY STORAGE

PROJECT TYPE	Pumped Hydro								
BASE PLANT DESCRIPTION	**Swan Lake**	**Goldendale**	**Seminoe**	**Badger Mountain**	**Owyhee**	**Flat Canyon**	**Utah PS2**	**Utah PS3**	**Banner Mountain**
Nominal Output, MW	400	400	750	500	600	300	500	600	400
Nominal Output, MWh	3800	3800	7500	4000	4800	1800	4000	4800	3400
Capacity Factor (%)	31%	39%	40%	32%	32%	24%	32%	32%	34%
Startup Time (Cold Start), minutes	1.5	1.5	1.8	1.8	1.8	1.8	1.8	1.8	1.5
Full Pumping to Full Gen, minutes	4	4	3.5	3.5	3.5	3.5	3.5	3.5	0.67
Transition Time from Charging to Discharging, minutes	6	6	3.5	3.5	3.5	3.5	3.5	3.5	N/A
Availability Factor, %	90%	90%	95%	95%	95%	95%	95%	95%	95%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature	Mature
Life Cycle, yrs	60	60	80	80	80	80	80	80	50+
Permitting & Construction Schedule, year (note 1)	6	10	8	6	8	8	6	8	7
ESTIMATED PERFORMANCE									
Base Load Performance @ (Annual Average)									
Net Plant Output, kW	400,000	400,000	750,000	500,000	600,000	300,000	500,000	600,000	400,000
Total Plant Storage, kWh (note 2)	3,800,000	4,800,000	7,500,000	4,000,000	4,800,000	1,800,000	4,000,000	4,800,000	3,400,000
Time for Full Discharge, hours	9.5	12.0	10	8	8	6	8	8	8.5
Time for Full Charge, hrs	9.5	14.0	12	9.5	9.5	7.2	9.5	9.5	10
Compression Power, MW (note 11)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Round-Trip Efficiency (%) (note 3)	78%	78%	80%	80%	80%	80%	80%	80%	81%
ESTIMATED CAPITAL AND O&M COSTS (Note 8)									
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$814**	**$2,146**	**$1,625**	**$897**	**$1,203**	**$760**	**$1,108**	**$1,266**	**$900**
Owner's Costs, 2020 MM$	**$163**	**$429**	**$249**	**$137**	**$184**	**$116**	**$169**	**$194**	**$77**
Owner's Project Development	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Engineer	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Project Management	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Legal Costs	Included	Included	Included	Included	Included	Included	Included	Included	Included
Permitting and Licensing Fees	Included	Included	Included	Included	Included	Included	Included	Included	Included
Generation Switchyard (note 4)	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included
Transmission to Interconnection Point (note 4)	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included
Training/Testing	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in O&M
Land (note 6)	Included in Project Costs	Included in Project Costs	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included
Permanent Plant Equipment and Furnishings	Included	Included	Included	Included	Included	Included	Included	Included	Included in Project Cost
Builders Risk Insurance (0.45% of Project Cost)	$3.7	$9.7	$7.3	$4.0	$5.4	$3.4	$5.0	$5.7	$4.1
Owner's Contingency (5% of Total Project Cost)	$40.9	$107.8	$88.9	$49.0	$65.8	$41.5	$60.6	$69.2	$46.3
Total Screening Level Project Costs, 2020 MM$	**$977**	**$2,575**	**$1,874**	**$1,034**	**$1,387**	**$876**	**$1,277**	**$1,460**	**$977**
EPC Project Costs, 2020 $/kWh	**$214**	**$447**	**$217**	**$224**	**$251**	**$422**	**$277**	**$264**	**$265**
Total Screening Level Project Costs, 2020 $/kWh	**$257**	**$536**	**$250**	**$259**	**$289**	**$487**	**$319**	**$304**	**$287**
Demolition Costs (end of life cycle) 2020$/kWh (note 10)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
O&M Cost, 2020 MM$/yr									
Fixed O&M Cost, 2020 MM$/yr	$5	$15	$12	$14	$12	$16	$14	$12	$11.4
Variable O&M Cost, 2020 $/MWh	$0	$0	$0.37	$0.37	$0.37	$0.37	$0.37	$0.37	$0

PROJECT TYPE	ADIABATIC CAES								
BASE PLANT DESCRIPTION	**Hydrostor**								
Nominal Output, MW	150	150	150	300	300	300	500	500	500
Nominal Output, MWh	600	1200	1800	1200	2400	3600	2000	4000	6000
Capacity Factor (%)	16%	32%	24%	16%	32%	24%	16%	32%	24%
Startup Time (Cold Start), minutes	5	5	5	5	5	5	5	5	5
Full Pumping to Full Gen, minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transition Time from Charging to Discharging, minutes	10	10	10	10	10	10	10	10	10
Availability Factor, %	95%	95%	95%	95%	95%	95%	95%	95%	95%
Technology Rating	Developing	Developing	Developing	Developing	Developing	Developing	Developing	Developing	Developing
Life Cycle, yrs	50+	50+	50+	50+	50+	50+	50+	50+	50+
Permitting & Construction Schedule, year (note 1)	2.5	2.5	2.5	2.5	2.5	3.0	3.0	3.5	3.5
ESTIMATED PERFORMANCE									
Base Load Performance @ (Annual Average)									
Net Plant Output, kW	150,000	150,000	150,000	300,000	300,000	300,000	500,000	500,000	500,000
Total Plant Storage, kWh (note 2)	600,000	1,200,000	1,800,000	1,200,000	2,400,000	3,600,000	2,000,000	4,000,000	6,000,000
Time for Full Discharge, hours	4	8	12	4	8	12	4	8	12
Time for Full Charge, hrs	7	13	20	7	13	20	7	13	20
Compression Power, MW (note 11)	90	90	90	180	180	180	300	300	300
Round-Trip Efficiency (%) (note 3)	60%	60%	60%	60%	60%	60%	60%	60%	60%
ESTIMATED CAPITAL AND O&M COSTS (Note 8)									
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$235**	**$261**	**$290**	**$374**	**$402**	**$439**	**$572**	**$644**	**$700**
Owner's Costs, 2020 MM$	**$39**	**$46**	**$53**	**$63**	**$73**	**$84**	**$98**	**$118**	**$135**
Owner's Project Development	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Engineer	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Project Management	Included	Included	Included	Included	Included	Included	Included	Included	Included
Owner's Legal Costs	Included	Included	Included	Included	Included	Included	Included	Included	Included
Permitting and Licensing Fees	Included	Included	Included	Included	Included	Included	Included	Included	Included
Generation Switchyard (note 4)	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Transmission to Interconnection Point (note 4)	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Training/Testing	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Land (note 6)	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Permanent Plant Equipment and Furnishings	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost	Included in Project Cost
Builders Risk Insurance (0.45% of Project Cost)	$1	$1	$1	$2	$2	$2	$3	$3	$3
Owner's Contingency (5% of Total Project Cost)	$11.8	$13.1	$14.6	$18.8	$20.2	$22.0	$28.7	$32.3	$35.2
Total Screening Level Project Costs, 2020 MM$	**$274**	**$307**	**$343**	**$437**	**$475**	**$523**	**$670**	**$762**	**$835**
EPC Project Costs, 2020 $/kWh	**$392**	**$218**	**$161**	**$312**	**$168**	**$122**	**$286**	**$161**	**$117**
Total Screening Level Project Costs, 2020 $/kWh	**$457**	**$256**	**$191**	**$364**	**$198**	**$145**	**$335**	**$191**	**$139**
Demolition Costs (end of life cycle) 2020$/kWh (note 10)	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**	**N/A**
O&M Cost, 2020 MM$/yr									
Fixed O&M Cost, 2020 MM$/yr	$1.9	$1.9	$1.9	$2.8	$2.8	$2.8	$3.3	$3.3	$3.3
Variable O&M Cost, 2020 $/MWh	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50	$6.50

PROJECT TYPE	Li-Ion Battery					Flow Battery			
BASE PLANT DESCRIPTION									
Nominal Output, MW	1	1	1	1	50	1	1	1	20
Nominal Output, MWh	0.5	1	4	8	200	1	4	8	160
Capacity Factor (%)	2%	4%	16%	32%	16%	4%	16%	32%	32%
Startup Time (Cold Start), minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Full Pumping to Full Gen, minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Transition Time from Charging to Discharging, minutes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Availability Factor, %	97%	97%	97%	97%	97%	97%	97%	97%	97%
Technology Rating	Mature	Mature	Mature	Mature	Mature	Commercial	Commercial	Commercial	Commercial
Life Cycle, yrs	20	20	20	20	20	20	20	20	20
Permitting & Construction Schedule, year (note 1)	1.5	1.5	1.5	1.5	2	1.5	1.5	1.5	2
ESTIMATED PERFORMANCE									
Base Load Performance @ (Annual Average)									
Net Plant Output, kW	1,000	1,000	1,000	1,000	50,000	1,000	1,000	1,000	20,000
Total Plant Storage, kWh (note 2)	500	1,000	4,000	8,000	200,000	1,000	4,000	8,000	160,000
Time for Full Discharge, hours	0.5	1	4	8	4	1	4	8	8
Time for Full Charge, hrs	0.6	1.2	4.6	9.2	4.6	1.3	5.2	10.4	10.4
Compression Power, MW (note 11)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Round-Trip Efficiency (%) (note 3)	85%	85%	85%	85%	85%	70%	70%	70%	70%
ESTIMATED CAPITAL AND O&M COSTS (Note 8)									
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$1.1**	**$1.2**	**$2.2**	**$3.5**	**$68.0**	**$3.6**	**$3.9**	**$5.9**	**$70.0**
Owner's Costs, 2020 MM$	**$0.8**	**$0.8**	**$0.8**	**$0.9**	**$13.7**	**$0.9**	**$0.9**	**$1.0**	**$13.8**
Owner's Project Development	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Owner's Engineer	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1	$0.1	$0.1	$0.2
Owner's Project Management	$0.1	$0.1	$0.1	$0.1	$0.2	$0.1	$0.1	$0.1	$0.2
Owner's Legal Costs	$0.1	$0.1	$0.1	$0.1	$0.5	$0.1	$0.1	$0.1	$0.5
Permitting and Licensing Fees	$0.1	$0.1	$0.1	$0.1	$0.3	$0.1	$0.1	$0.1	$0.3
Generation Switchyard (note 4)	$0.1	$0.1	$0.1	$0.1	$4.6	$0.1	$0.1	$0.1	$4.6
Transmission to Interconnection Point (note 4)	N/A	N/A	N/A	N/A	$3.5	N/A	N/A	N/A	$3.5
Training/Testing	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1	$0.1
Land (note 6)	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located	Assumes Co-located
Permanent Plant Equipment and Furnishings	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Builders Risk Insurance (0.45% of Project Cost)	$0.00	$0.01	$0.01	$0.02	$0.31	$0.02	$0.02	$0.03	$0.32
Owner's Contingency (5% of Total Project Cost)	$0.1	$0.1	$0.1	$0.2	$3.9	$0.2	$0.2	$0.3	$4.0
Total Screening Level Project Costs, 2020 MM$	**$1.9**	**$2.0**	**$3.0**	**$4.4**	**$82**	**$4**	**$5**	**$7**	**$84**
EPC Project Costs, 2020 $/kWh	**$2,200**	**$1,200**	**$550**	**$438**	**$340**	**$3,600**	**$975**	**$738**	**$438**
Total Screening Level Project Costs, 2020 $/kWh	**$3,706**	**$1,959**	**$753**	**$548**	**$408**	**$4,490**	**$1,202**	**$864**	**$524**
Demolition Costs (end of life cycle) 2020$/kWh (note 10)	**$110**	**$110**	**$110**	**$110**	**$110**	**N/A**	**N/A**	**N/A**	**N/A**
O&M Cost, 2020 MM$/yr									
Fixed O&M Cost, 2020 MM$/yr	$0.04	$0.05	$0.07	$0.10	$1.38	$0.013	$0.013	$0.027	$0.61
Variable O&M Cost, 2020 $/MWh	Included in FOM	Included in FOM	Included in FOM	Included in FOM	Indluded in FOM	Included in FOM	Included in FOM	Included in FOM	Indluded in FOM

Notes
Note 1. Permitting & Construction Schedule is based on earliest COD date for some of the pumped hydro options
Note 2. 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 3. 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 4. 1MW battery options (Li-Ion and Flow) assume interconnection at distribution voltage and therefore excludes GSU and switchyard. Larger options include GSU and switchyard costs as well as a standalone transmission cost. Also assumes co-located with existing asset and therefore excludes land costs.
Note 5. Battery O&M assumes the site is remotely controlled and that batteries cycle once per day. 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 6. 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 7. Battery capacity factor and annual O&M is based on one full cycle per day.
Note 8. EPC and Owner's Cost estimates exclude AFUDC, Sales Tax, Insurance and Property Tax During Construction
Note 9. Compression Capacity Ratio is defined as the relationship of the MWh of charging to the MWh of generation.
Note 10. Demolition costs are not shown for longer life cycle storage options (pumped hydro, CAES, and flow batteries). Li-Ion storage includes the cost to recycle the modules but does not include any resale of raw materials.
Note 11. Compressors can be sized to meet most charging duration requirments. A representative size has been chosen for the options shown.

PACIFICORP RENEWABLE TECHNOLOGY ASSESSMENT SUMMARY TABLE
SOLAR GENERATION

PROJECT TYPE				
PROJECT LOCATION	**Lakeview, OR**		**Milford, UT**	
BASE PLANT DESCRIPTION	**100 MW**	**200 MW**	**100 MW**	**200 MW**
Nominal Output, MW	100	200	100	200
Annualized Energy Production, MWh (Yr 1)	242,000	484,000	264,900	529,700
AC Capacity Factor at POI (%) (Note 1)	27.6%	27.6%	30.2%	30.2%
Availability Factor, % (Note 2)	99%	99%	99%	99%
Assumed Land Use, Acres	800	1600	800	1600
PV Inverter Loading Ratio (DC/AC)	1.30	1.30	1.30	1.30
PV Degradation, %/yr (Note 3)	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year	1st year: 2% After 1st Year: 0.5% per year	2nd year: 2% After 1st Year: 0.5% per year
Technology Rating	Mature	Mature	Mature	Mature
Permitting & Construction Schedule, year	2	2	2	2
ESTIMATED PERFORMANCE				
Base Load Performance @ (Annual Average)				
Net Plant Output, kW	100,000	200,000	100,000	200,000
ESTIMATED CAPITAL AND O&M COSTS (Note 7)				
EPC Project Capital Costs, 2020 MM$ (w/o Owner's Costs)	**$113**	**$222**	**$111**	**$216**
Modules	$48	$91	$48	$91
Racking w/ Piles	$16	$31	$16	$31
Inverter & MV Transformer	$4	$8	$4	$8
Labor, Materials, and BOP Equiment	$29	$59	$27	$53
Project Indirects, Fee, and Contingency	$16	$33	$16	$33
Owner's Costs, 2020 MM$	**$24**	**$31**	**$24**	**$31**
Owner's Project Development	$0.3	$0.3	$0.3	$0.3
Owner's Project Management	$0.1	$0.1	$0.1	$0.1
Owner's Legal Costs	$0.3	$0.3	$0.3	$0.3
Permitting and Licensing Fees	$0.5	$0.6	$0.5	$0.6
Interconnection Switchyard (Note 5)	$2.0	$2.0	$2.0	$2.0
Transmission Interconnection (Note 8)	$3.5	$3.5	$3.5	$3.5
Transmission Interconnection Application and Upgrades (Note 9)	$9.8	$9.8	$9.8	$9.8
Land (Note 4)	$0.0	$0.0	$0.0	$0.0
Operating Spare Parts	$0.8	$1.6	$0.8	$1.6
Builders Risk Insurance (0.45% of Project Cost)	$0.5	$1.0	$0.5	$1.0
Owner's Contingency	$6.5	$12.1	$6.4	$11.8
Total Screening Level Project Costs, 2020 MM$	**$137**	**$253**	**$135**	**$247**
EPC Project Costs, 2020 $/kW	**$1,130**	**$1,110**	**$1,110**	**$1,080**
Total Screening Level Project Costs, 2020 $/kW	**$1,372**	**$1,266**	**$1,351**	**$1,234**
Demolition Costs (end of life cycle) 2020$/kW	**$35**	**$35**	**$35**	**$35**
O&M Cost, 2020 MM$/yr	**$1.7**	**$3.2**	**$1.9**	**$3.5**
Third Party LTSA, 2020$MM/Yr	$0.7	$1.3	$0.7	$1.3
BOP and Other Cost, 2020$MM/Yr	$0.2	$0.3	$0.2	$0.3
Land Lease Allowance, 2020$MM/Yr	$0.4	$0.8	$0.6	$1.1
Capital Replacement Allowance, 2020$/MWh (Notes 3-5)	$0.4	$0.8	$0.4	$0.8
O&M Cost, 2020 $/kWac-yr	**$16.20**	**$16.10**	**$17.60**	**$17.60**
Co-Located Energy Storage - 4 hr Capacity				
Add-On Costs				
Capital Costs, 2020 MM$	$70	$133	$68	$130
Owner's Costs, 2020 MM$	$6.9	$10.3	$6.8	$10.1
Incremental O&M Cost, 2020 MM$/Yr	$1.38	$2.57	$1.38	$2.57
Co-Located Energy Storage - 4 hr Capacity + 200MW Wind				
Add-On Costs				
Capital Costs, 2020 MM$	N/A	$365	N/A	$361
Owner's Costs, 2020 MM$	N/A	$34	N/A	$33
Incremental O&M Cost, 2020 MM$/Yr	N/A	$13.37	N/A	$12.77

Notes

Note 1. Solar capacity factor accounts for typical losses. 100 and 200 MW options have AC capacity overbuilt for high voltage losses.
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
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. Solar project substation included in EPC cost. Interconnection switchyard assumes additional position on existing ring bus.
Note 6. Oregon 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 3 miles of transmission line at 161 kV. 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	50 x 4 MW	50 x 4 MW	50 x 4 MW	50 x 4 MW	50 x 4 MW
Capacity Factor (Note 1)	43.0%	43.0%	36.1%	48.6%	43.0%
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, 2020 MM$ (w/o Owner's Costs)	**$231**	**$232**	**$231**	**$231**	**$232**
Wind Turbine Generators	$155	$156	$155	$155	$156
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	$61	$61	$61	$61	$61
Owner's Costs, 2020 MM$	**$73**	**$73**	**$72**	**$72**	**$73**
Project Development (Note 3)	$24.4	$24.4	$23.4	$23.4	$24.4
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)	$3.5	$3.5	$3.5	$3.5	$3.5
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 (5% of Total Project Cost)	$14.5	$14.5	$14.4	$14.4	$14.5
Total Screening Level Project Costs, 2020 MM$	**$304**	**$305**	**$303**	**$303**	**$305**
EPC Project Costs, 2020 $/kW	**$1,155**	**$1,160**	**$1,155**	**$1,155**	**$1,160**
Total Screening Level Project Costs, 2020 $/kW	**$1,519**	**$1,524**	**$1,513**	**$1,513**	**$1,524**
Demolition Costs (end of life cycle) 2020$/kW	**$13**	**$13**	**$13**	**$13**	**$13**
O&M Cost, 2020 MM$/yr	$10.6	$10.8	$10.2	$9.6	$10.8
O&M Cost, 2020 $/kW-yr	$53.0	$54.0	$51.0	$48.0	$54.0
Co-Located Energy Storage - 4 hr Capacity					
Add-On Costs					
Capital Costs, 2020 MM$	$130	$133	$130	$130	$133
Owner's Costs, 2020 MM$	$11.2	$11.3	$11.2	$11.2	$11.3
Incremental O&M Cost, 2020 MM$/Yr	$2.57	$2.57	$2.57	$2.57	$2.57

Notes
Note 1. Wind capacity factor based on NREL 80 meter wind speed maps used to convert wind speeds to 105 meter hub height.
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 3 miles of transmission line at 161 kV. 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.

Grid-Connected System: Simulation parameters

Project : **Pacificorp20-LakeviewOR**

Geographical Site		**Lakeview**	Country	**United States**
Situation	Latitude	42.17° N	Longitude	-120.40° W
Time defined as	Legal Time	Time zone UT-8	Altitude	1441 m
	Albedo	0.20		
Meteo data:	**Lakeview**	NREL: TMY3 hourly DB (1991-2005) - TMY		

Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Simulation date 30/06/20 10h33

Simulation parameters	System type	**Trackers single array, with backtracking**		
Tracking plane, tilted axis	Axis Tilt	0°	Axis azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
	Tracking algorithm	Irradiance optimization		
Backtracking strategy	Nb. of trackers	100	Single array	
	Tracker Spacing	10.00 m	Collector width	4.26 m
Inactive band	Left	0.02 m	Right	0.02 m
Backtracking limit angle	Phi limits	+/- 79.9°	Ground Cov. Ratio (GCR)	42.6%
Models used	Transposition	Perez	Diffuse	Imported
			Circumsolar	separate
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
User's needs :	Unlimited load (grid)			

PV Array Characteristics

PV module Si-poly	Model	**CS3W-400P HE**		
Custom parameters definition	Manufacturer	Canadian Solar Inc.		
Number of PV modules	In series	28 modules	In parallel	488 strings
Total number of PV modules	nb. modules	13664	Unit Nom. Power	400 Wp
Array global power	Nominal (STC)	**5466 kWp**	At operating cond.	4961 kWp (50°C)
Array operating characteristics (50°C)	U mpp	982 V	I mpp	5049 A
Total area	Module area	**30186 m²**	Cell area	27114 m²
Inverter	Model	**Solar Ware 840 - PVU-L0840ER(PRERELEASE)**		
Custom parameters definition	Manufacturer	TMEIC		
Characteristics	Unit Nom. Power	**840 kWac**	Oper. Voltage	915-1300 V
Inverter pack	Total power	**4200 kWac**	Pnom ratio	1.30
	Nb. of inverters	5 units		
Total	Total power	**4200 kWac**	Pnom ratio	1.30

PV Array loss factors

Array Soiling Losses			Loss Fraction	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.	3.2 mΩ	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.5 %
Module mismatch losses			Loss Fraction	2.0 % at MPP
Strings Mismatch loss			Loss Fraction	0.10 %

Grid-Connected System: Simulation parameters

Incidence effect (IAM): User defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.000	1.000	1.000	0.990	0.990	0.970	0.920	0.760	0.000

System loss factors

AC wire loss inverter to transfo	Inverter voltage	630 Vac tri		
	Wires: 3 x 4000 mm²	1 m	Loss Fraction	0.0 % at STC

MV transfo	Grid Voltage	34.5 kV		
One MV transfo				
Operating losses at STC	Iron loss (24/24 Connexion)	10.70 kW	Loss Fraction	0.2 % at STC
	Copper (resistive) loss	3 x 1.03 mΩ	Loss Fraction	1.4 % at STC

Grid-Connected System: Horizon definition

Project : **Pacificorp20-LakeviewOR**

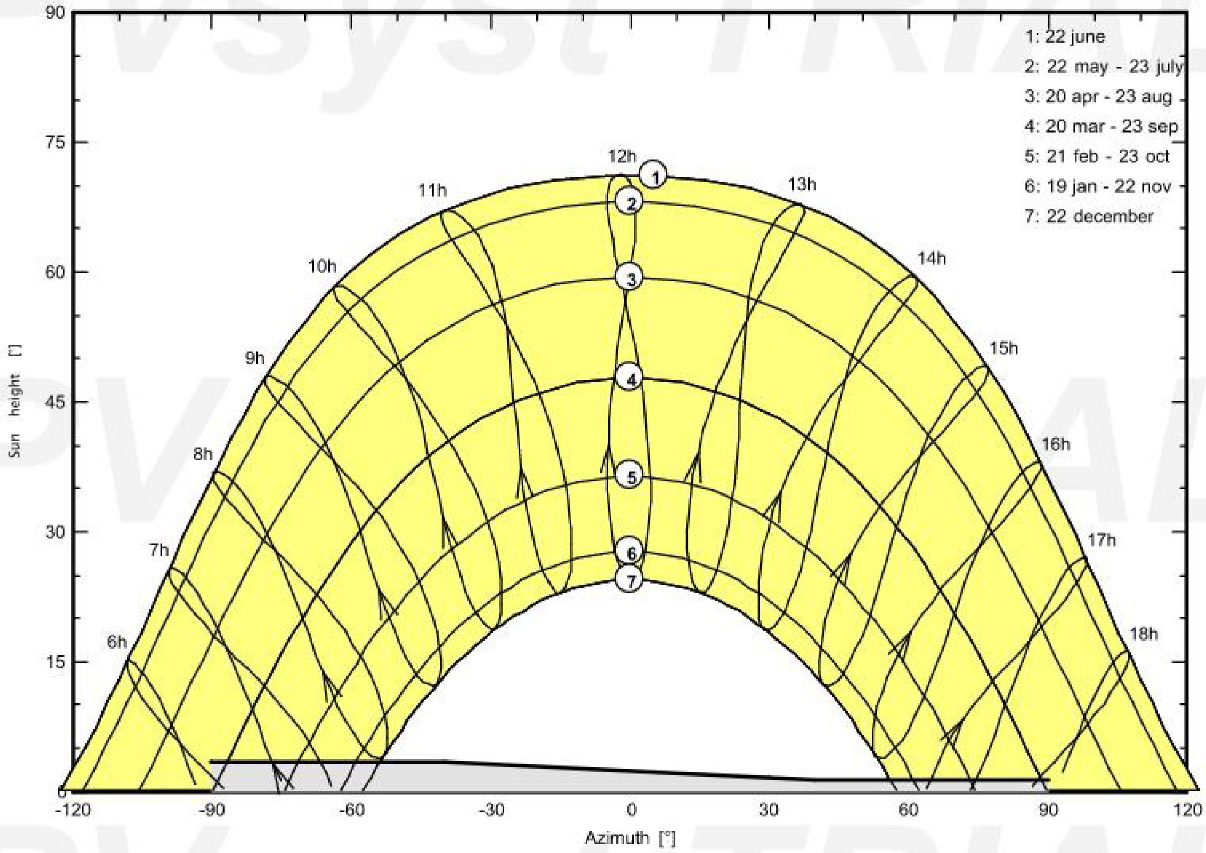
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 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 line at LakeviewOR_NSRDB



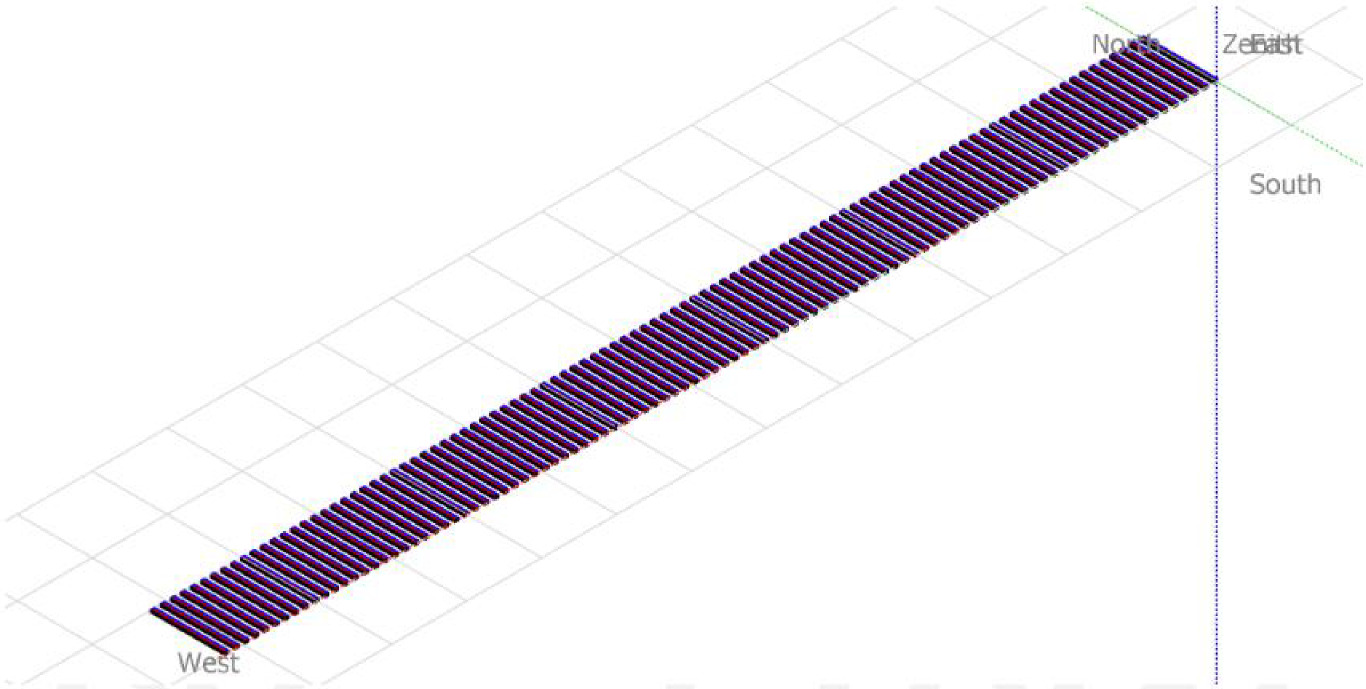
Grid-Connected System: Near shading definition

Project : **Pacificorp20-LakeviewOR**

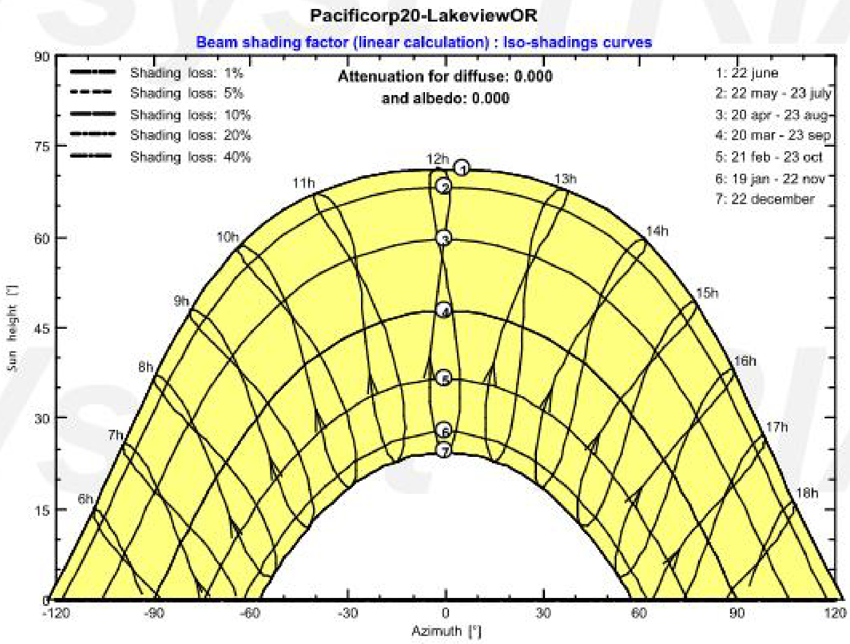
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram



Grid-Connected System: Main results

Project : **Pacificorp20-LakeviewOR**

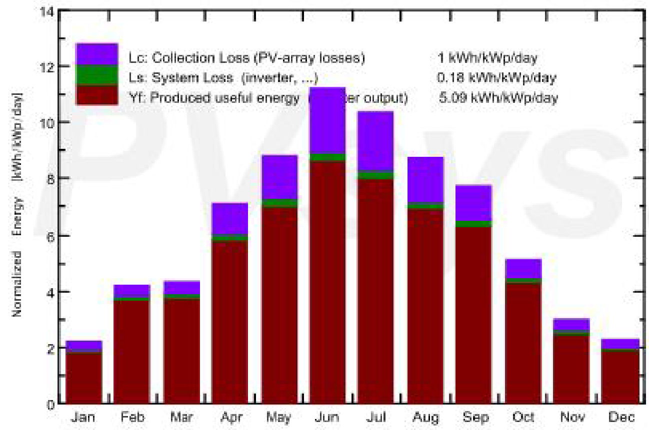
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

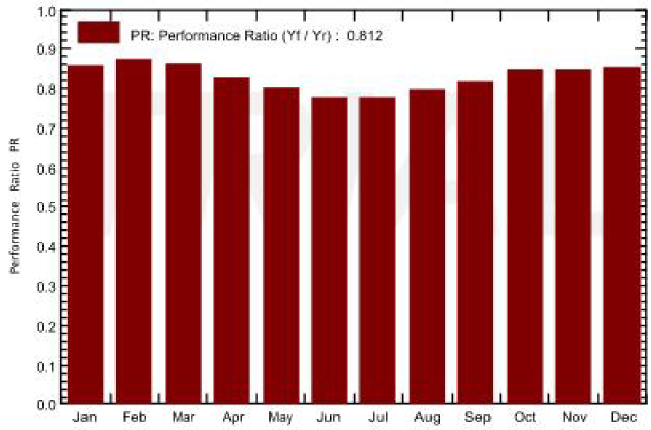
Main simulation results

System Production	**Produced Energy**	**10146 MWh/year**	Specific prod.	1856 kWh/kWp/year
	Performance Ratio PR	81.15 %		

Normalized productions (per installed kWp): Nominal power 5466 kWp



Performance Ratio PR



PC20_VC0_LakeviewOR_SAT

Balances and main results

	GlobHor kWh/m²	DiffHor kWh/m²	T_Amb °C	GlobInc kWh/m²	GlobEff kWh/m²	EArray MWh	E_Grid MWh	PR ratio
January	52.8	28.22	-1.22	67.9	62.0	334	317	0.854
February	85.1	27.99	-0.46	118.6	109.9	587	565	0.872
March	106.7	50.37	2.86	135.8	126.4	665	640	0.862
April	163.1	61.22	5.42	212.8	200.2	994	960	0.825
May	209.3	67.48	9.94	273.8	258.5	1235	1195	0.799
June	251.2	49.77	16.42	336.8	319.7	1471	1425	0.774
July	242.7	54.01	20.83	321.4	304.8	1404	1360	0.774
August	198.5	46.36	17.73	270.3	256.0	1215	1176	0.796
September	167.3	37.18	14.61	232.3	218.7	1069	1035	0.815
October	114.2	35.81	6.91	158.2	147.4	759	733	0.847
November	63.8	22.84	1.73	89.2	81.8	432	413	0.847
December	49.6	20.66	-0.87	70.4	64.1	344	328	0.851
Year	1704.3	501.91	7.87	2287.5	2149.6	10512	10146	0.812

Legends:				
	GlobHor	Global horizontal irradiation	GlobEff	Effective Global, corr. for IAM and shadings
	DiffHor	Horizontal diffuse irradiation	EArray	Effective energy at the output of the array
	T_Amb	T amb.	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	PR	Performance Ratio

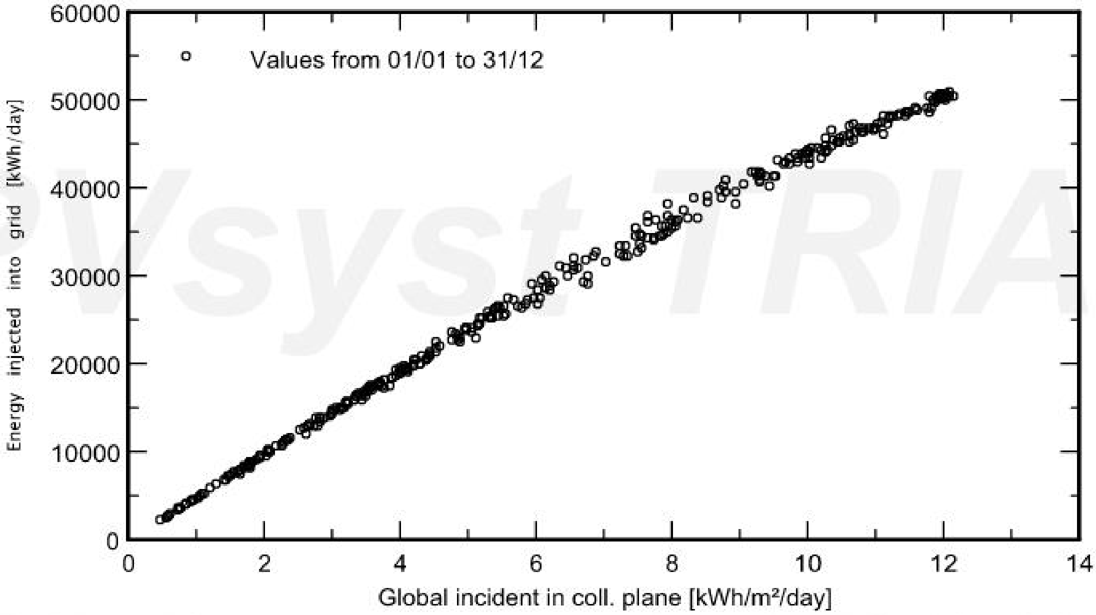
Grid-Connected System: Special graphs

Project : **Pacificorp20-LakeviewOR**

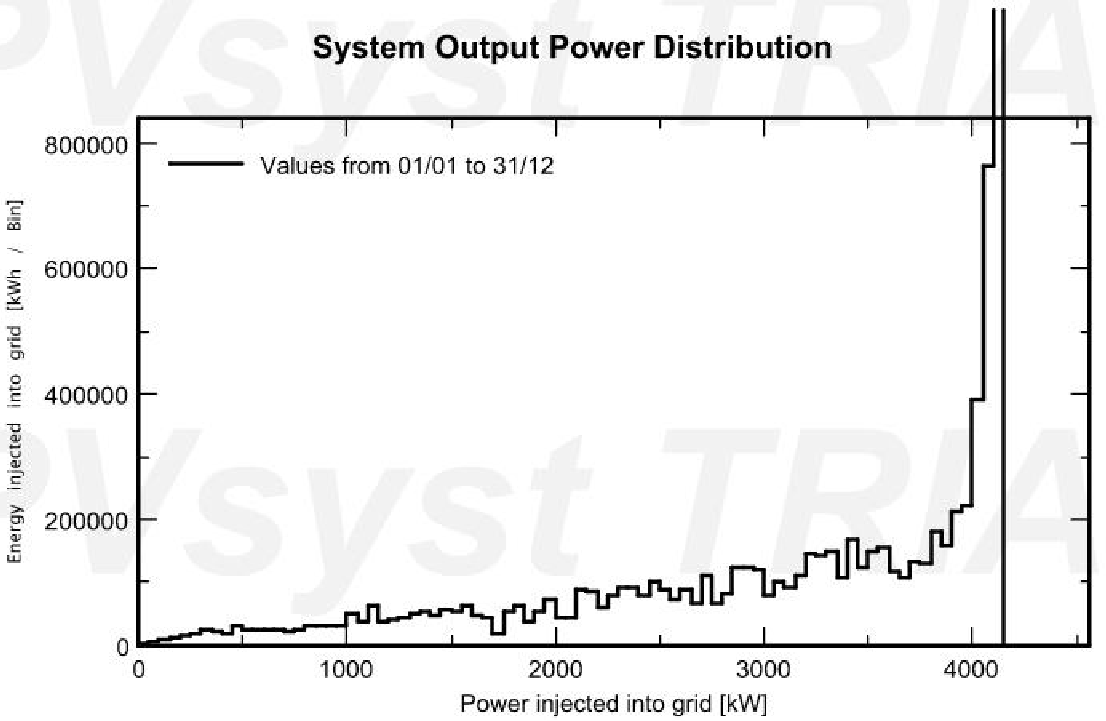
Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Daily Input/Output diagram



System Output Power Distribution



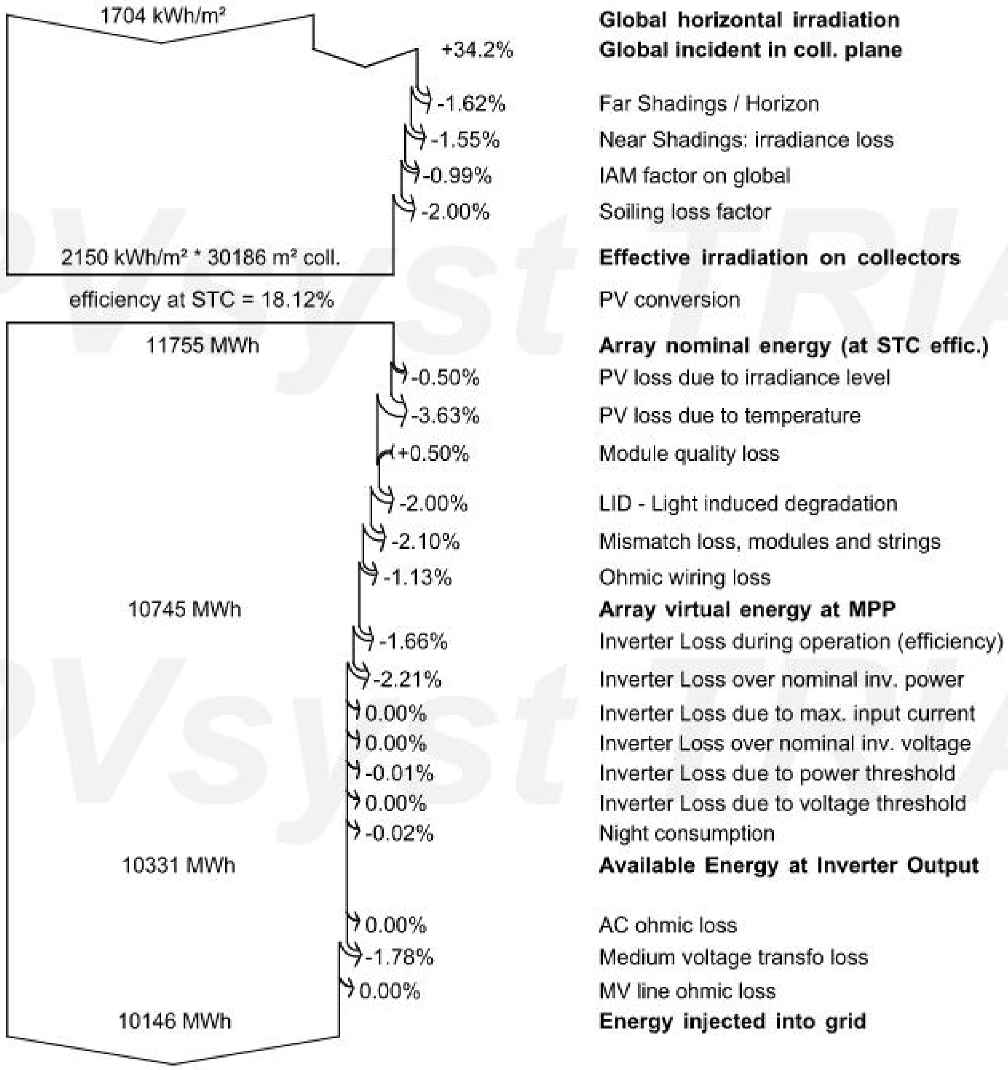
Grid-Connected System: Loss diagram

Project : **Pacificorp20-LakeviewOR**

Simulation variant : **PC20_VC0_LakeviewOR_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	2.4°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



Grid-Connected System: Simulation parameters

Project : **Pacificorp20-MilfordUT**

Geographical Site	**MilfordUT_NSRDB**		Country	**United States**
Situation	Latitude	38.41° N	Longitude	-113.02° W
Time defined as	Legal Time	Time zone UT-7	Altitude	0 m
	Albedo	0.20		
Meteo data:	**MilfordUT_NSRDB**	NREL: TMY3 hourly DB (1991-2005) - TMY		

Simulation variant : **MilfordUT_SAT**

Simulation date 23/06/20 14h56

Simulation parameters	System type	**Trackers single array, with backtracking**		
Tracking plane, tilted axis	Axis Tilt	0°	Axis azimuth	0°
Rotation Limitations	Minimum Phi	-60°	Maximum Phi	60°
	Tracking algorithm	Irradiance optimization		
Backtracking strategy	Nb. of trackers	100	Single array	
	Tracker Spacing	10.00 m	Collector width	4.26 m
Inactive band	Left	0.02 m	Right	0.02 m
Backtracking limit angle	Phi limits	+/- 79.9°	Ground Cov. Ratio (GCR)	42.6%
Models used	Transposition	Perez	Diffuse	Imported
			Circumsolar	separate
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
User's needs :	Unlimited load (grid)			

PV Array Characteristics

PV module	Si-poly	Model	**CS3W-400P HE**		
Custom parameters definition		Manufacturer	Canadian Solar Inc.		
Number of PV modules		In series	28 modules	In parallel	488 strings
Total number of PV modules		nb. modules	13664	Unit Nom. Power	400 Wp
Array global power		Nominal (STC)	**5466 kWp**	At operating cond.	4961 kWp (50°C)
Array operating characteristics (50°C)		U mpp	982 V	I mpp	5049 A
Total area		Module area	**30186 m²**	Cell area	27114 m²
Inverter		Model	**Solar Ware 840 - PVU-L0840ER(PRERELEASE)**		
Custom parameters definition		Manufacturer	TMEIC		
Characteristics		Unit Nom. Power	**840 kWac**	Oper. Voltage	915-1300 V
Inverter pack		Total power	**4200 kWac**	Pnom ratio	1.30
		Nb. of inverters	5 units		
Total		Total power	**4200 kWac**	Pnom ratio	1.30

PV Array loss factors

Array Soiling Losses			Loss Fraction	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.	3.2 mΩ	Loss Fraction	1.5 % at STC
LID - Light Induced Degradation			Loss Fraction	2.0 %
Module Quality Loss			Loss Fraction	-0.5 %
Module mismatch losses			Loss Fraction	2.0 % at MPP
Strings Mismatch loss			Loss Fraction	0.10 %

Grid-Connected System: Simulation parameters

Incidence effect (IAM): User defined profile

10°	20°	30°	40°	50°	60°	70°	80°	90°
1.000	1.000	1.000	0.990	0.990	0.970	0.920	0.760	0.000

System loss factors

AC wire loss inverter to transfo — Inverter voltage 630 Vac tri

Wires: 3 x 4000 mm² 1 m — Loss Fraction 0.0 % at STC

MV transfo — Grid Voltage 34.5 kV

One MV transfo

Operating losses at STC — Iron loss (24/24 Connexion) 10.73 kW — Loss Fraction 0.2 % at STC

Copper (resistive) loss 3 x 1.03 mΩ — Loss Fraction 1.4 % at STC

Grid-Connected System: Horizon definition

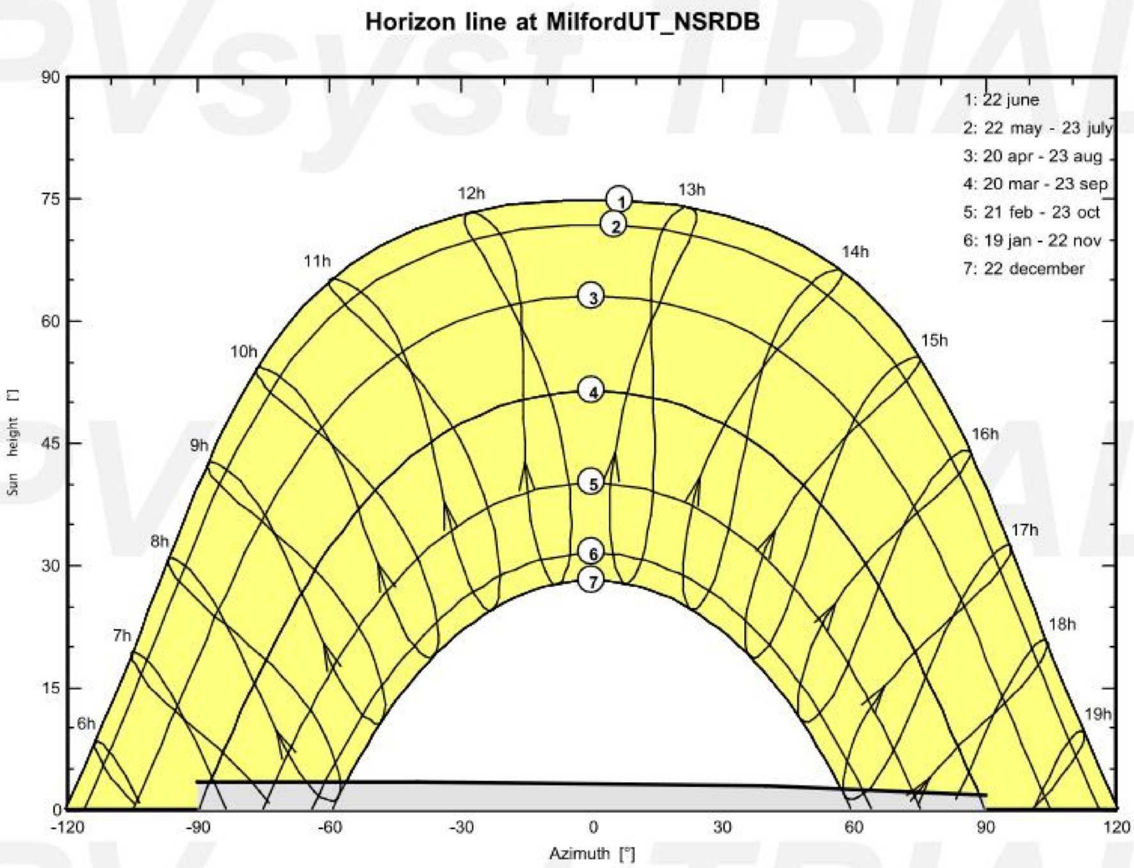
Project : **Pacificorp20-MilfordUT**

Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 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



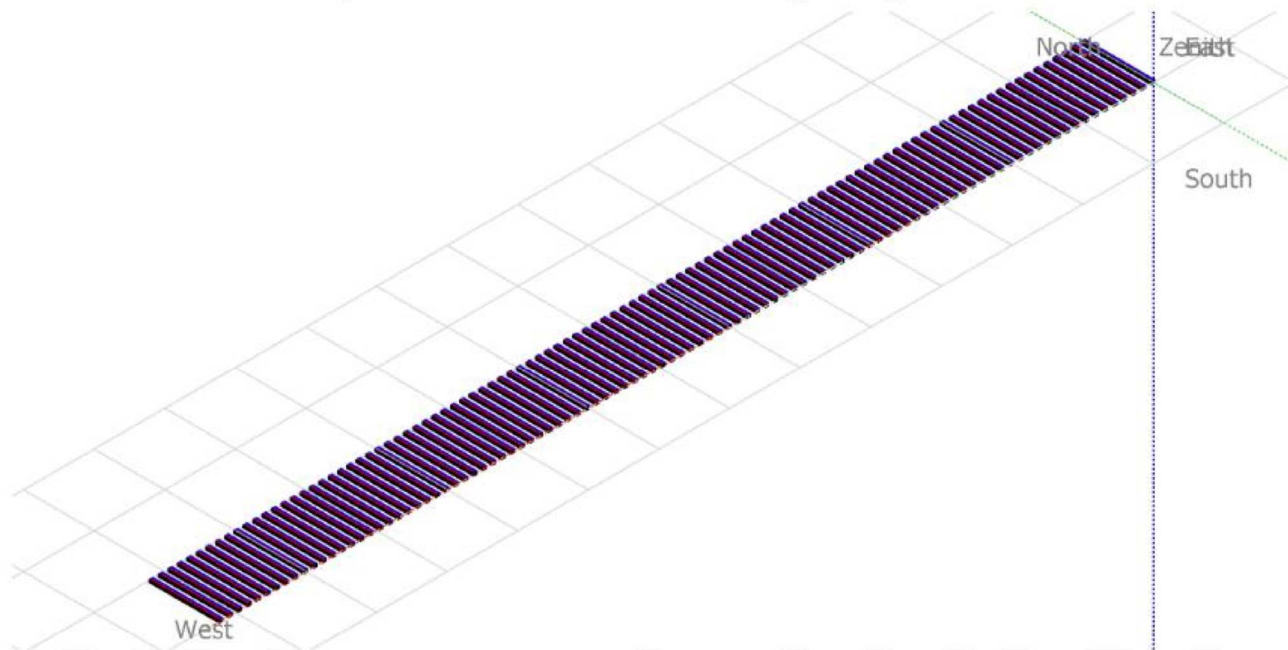
Grid-Connected System: Near shading definition

Project : **Pacificorp20-MilfordUT**

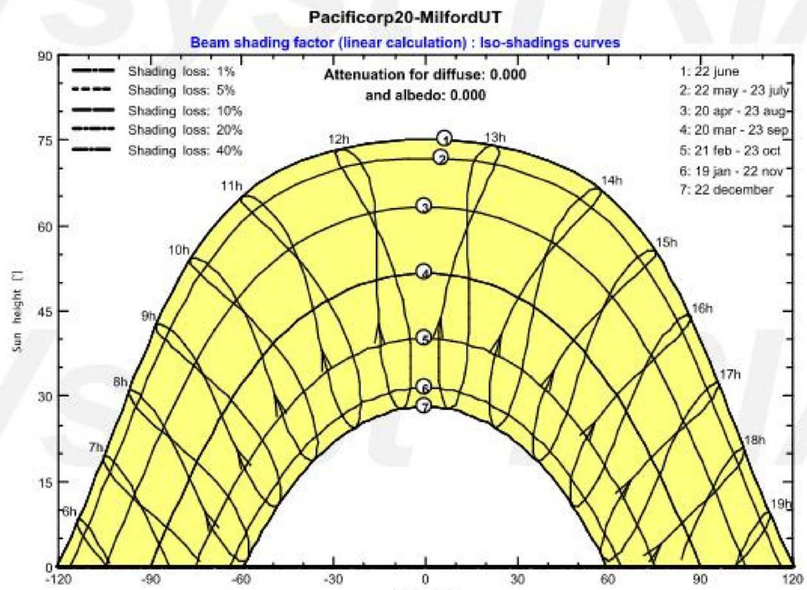
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Perspective of the PV-field and surrounding shading scene



Iso-shadings diagram



Grid-Connected System: Main results

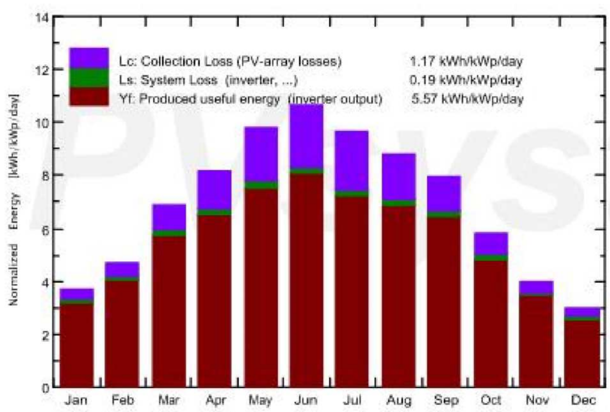
Project : **Pacificorp20-MilfordUT**

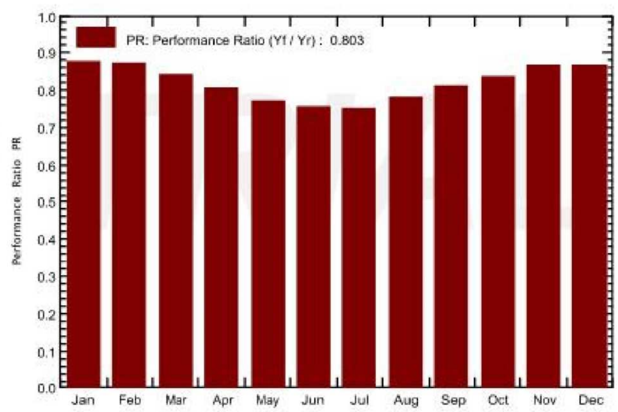
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Main simulation results

System Production	**Produced Energy**	**11113 MWh/year**	Specific prod.	2033 kWh/kWp/year
	Performance Ratio PR	80.32 %		





MilfordUT_SAT

Balances and main results

	GlobHor	DiffHor	T_Amb	GlobInc	GlobEff	EArray	E_Grid	PR
	kWh/m²	kWh/m²	°C	kWh/m²	kWh/m²	MWh	MWh	ratio
January	83.0	25.95	-1.63	114.6	105.9	571	549	0.876
February	97.2	34.43	0.96	130.7	122.0	647	623	0.872
March	158.1	47.64	2.97	213.0	200.6	1014	980	0.841
April	188.5	62.38	7.14	244.2	231.0	1113	1076	0.806
May	233.1	62.75	15.67	303.5	288.3	1323	1281	0.772
June	243.9	56.57	19.11	320.3	304.5	1365	1322	0.755
July	230.2	57.42	23.97	299.1	284.3	1269	1229	0.752
August	207.6	52.71	23.16	274.0	260.1	1204	1166	0.778
September	175.2	38.23	15.35	238.3	225.7	1093	1057	0.812
October	132.0	32.68	11.70	180.3	168.9	851	822	0.835
November	86.8	26.42	1.58	120.3	111.6	591	568	0.865
December	67.8	23.58	-1.75	93.4	85.6	461	442	0.865
Year	1903.4	520.77	9.92	2531.7	2388.6	11502	11113	0.803

Legends:				
	GlobHor	Global horizontal irradiation	GlobEff	Effective Global, corr. for IAM and shadings
	DiffHor	Horizontal diffuse irradiation	EArray	Effective energy at the output of the array
	T_Amb	T amb.	E_Grid	Energy injected into grid
	GlobInc	Global incident in coll. plane	PR	Performance Ratio

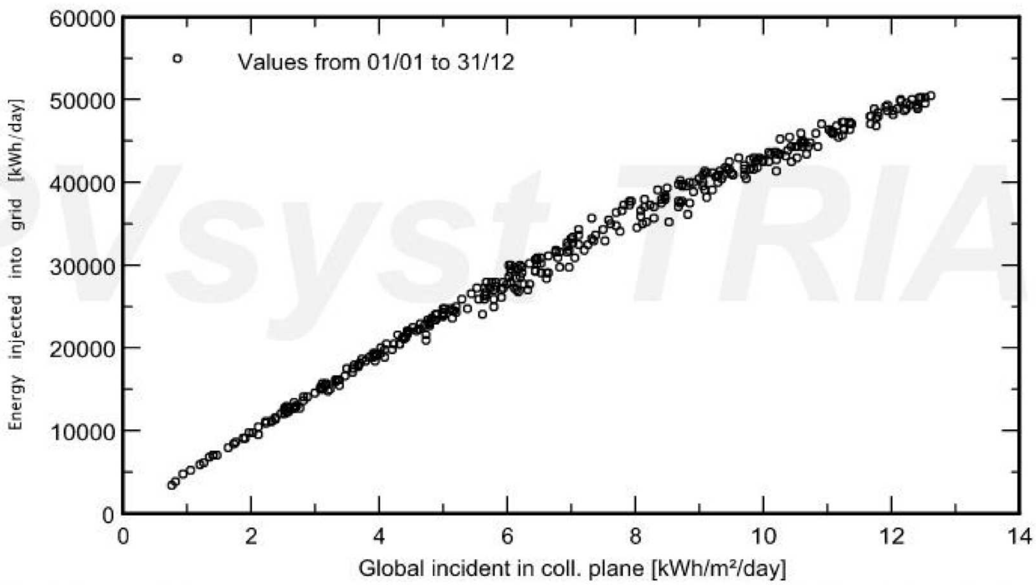
Grid-Connected System: Special graphs

Project : **Pacificorp20-MilfordUT**

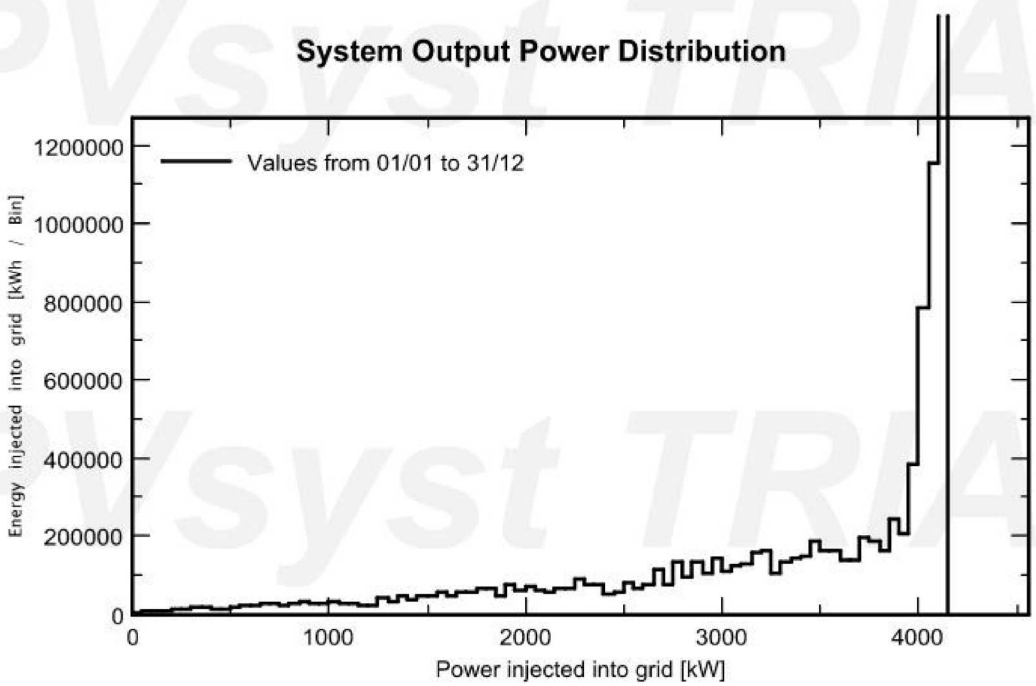
Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Daily Input/Output diagram



System Output Power Distribution



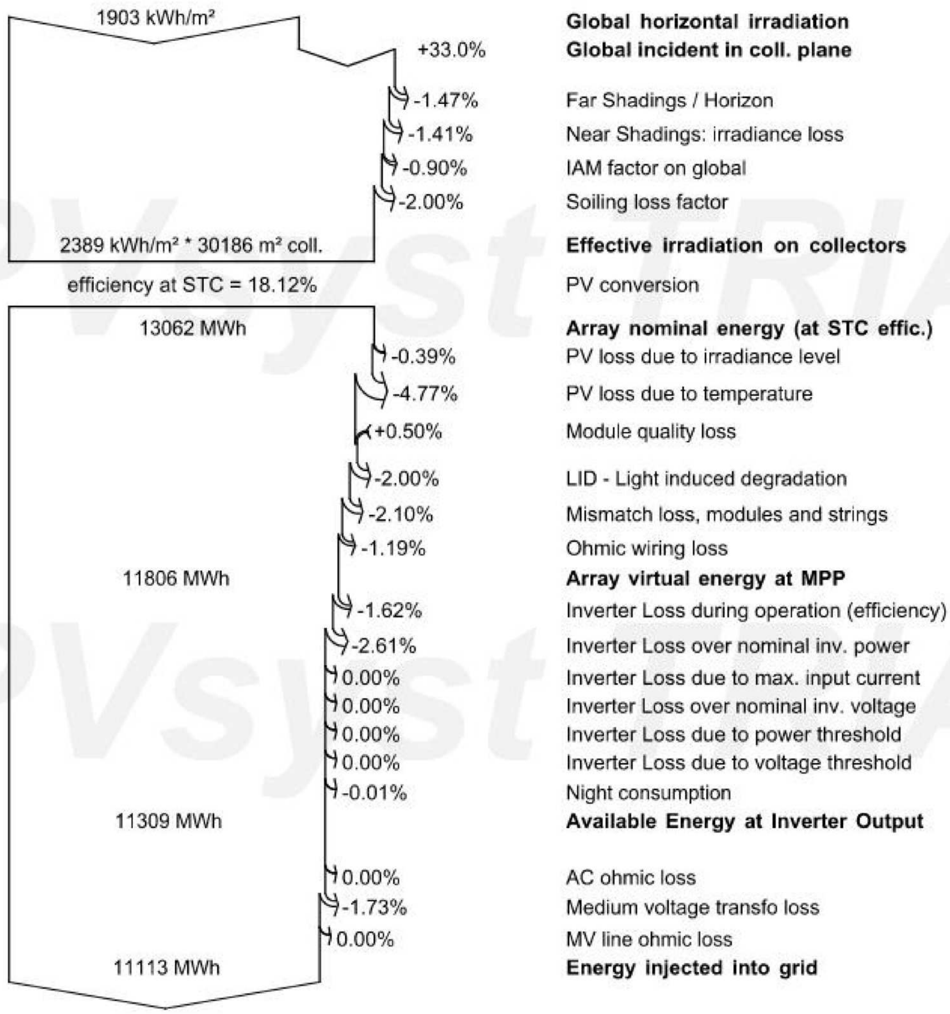
Grid-Connected System: Loss diagram

Project : **Pacificorp20-MilfordUT**

Simulation variant : **MilfordUT_SAT**

Main system parameters	System type	**Trackers single array, with backtracking**		
Horizon	Average Height	3.0°		
Near Shadings	Linear shadings			
PV Field Orientation	tracking, tilted axis, Axis Tilt	0°	Axis azimuth	0°
PV modules	Model	CS3W-400P HE	Pnom	400 Wp
PV Array	Nb. of modules	13664	Pnom total	**5466 kWp**
Inverter	Solar Ware 840 - PVU-L0840ER(PRERELEASE)		Pnom	840 kW ac
Inverter pack	Nb. of units	5.0	Pnom total	**4200 kW ac**
User's needs	Unlimited load (grid)			

Loss diagram over the whole year



BURNS McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information	
City / State:	Lakeview, OR
Latitude (N):	42.17 °
Longitude (W):	-120.4 °
Altitude	1441 m
ASHRAE Cooling DB Temp.	32.2 °C
ASHRAE Extreme Mean Min. Temp.	-22.6 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	42.6 %
Row spacing	10 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	400 W
# Modules per string	28
Strings in parallel	488
Total number of modules	13664
DC capacity	5466 kW
Inverter rating	4200 kW
DC/AC ratio - Inv Rating	1.301

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)	241986.6 MWh
AC capacity factor - Inv Rating	27.62%
AC capacity factor - POI Rating	27.62%
DC capacity factor	21.23%
Specific Production	1860 kWh/kWp/yr
Performance Ratio PR	81.15%
Night time losses	-407.2 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**130.13 MWDC**
Number of modules	325333
Nameplate Capacity	**100.00 MWAC**
Number of arrays	24
Interconnection Limit	**100.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.301

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2287.5 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.45 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.61 m/s

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
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 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information		
City / State:	Lakeview, OR	
Latitude (N):	42.17	°
Longitude (W):	-120.4	°
Altitude	1441	m
ASHRAE Cooling DB Temp.	32.2	°C
ASHRAE Extreme Mean Min. Temp.	-22.6	°C

Estimated Annual Energy Production	
P50 net production (yr-1)	483973.1 MWh
AC capacity factor - Inv Rating	27.62%
AC capacity factor - POI Rating	27.62%
DC capacity factor	21.23%
Specific Production	1860 kWh/kWp/yr
Performance Ratio PR	81.15%
Night time losses	-814.4 MWh
Plant Output Limitations	0.00%

Design Parameters		
System DC Voltage	1500	VDC
GCR	42.6	%
Row spacing	10	m
Mounting	Tracker	
Tilt angle or rotation limits	60	°
Azimuth	0	°
Tracking strategy	TRUE	
Availability	100.0	%
Degradation	0.5	%/yr

Facility Level Information	
Nameplate Capacity	**260.27 MWDC**
Number of modules	650667
Nameplate Capacity	**200.00 MWAC**
Number of arrays	48
Interconnection Limit	**200.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.301

Array Level Information		
Module rating	400	W
# Modules per string	28	
Strings in parallel	488	
Total number of modules	13664	
DC capacity	5466	kW
Inverter rating	4200	kW
DC/AC ratio - Inv Rating	1.301	

Weather	
Source	TMY3
GHI	1704.3 kWh/m2
DHI	kWh/m2
Global POA	2287.5 kWh/m2
Average Temp.	7.87 °C
Average Temp. (Generation)	12.45 °C
Average Wind	3.33 m/s
Average Wind (Generation)	3.61 m/s

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	%

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
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%

BURNS & McDONNELL

Energy Production Summary

Burns & McDonnell, Energy Division

Project Name: **Pacificorp 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information	
City / State:	Milford, UT
Latitude (N):	38.41 °
Longitude (W):	-113.02 °
Altitude	0 m
ASHRAE Ext. Max Mean Temp	38.1 °C
ASHRAE 99.6% Heating DB	-19.8 °C

Design Parameters	
System DC Voltage	1500 VDC
GCR	42.6 %
Row spacing	10 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	400 W
# Modules per string	28
Strings in parallel	488
Total number of modules	13664
DC capacity	5466 kW
Inverter Rating	4200 kW
DC/AC ratio - Inv Rating	1.301

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*	2.0 %
Light induced degradation	2.0 %
DC wiring loss	1.5 %
Module quality loss	-0.5 %
Module mismatch loss	1.0 %
DC health loss	1.0 %
Albedo*	1.0 %

Estimated Annual Energy Production	
P50 net production (yr-1)	264852.0 MWh
AC capacity factor - Inv Rating	30.23%
AC capacity factor - POI Rating	30.23%
DC capacity factor	23.23%
Specific Production	2035 kWh/kWp/yr
Performance Ratio PR	80.39%
Night time losses	-398.3 MWh
Plant Output Limitations	0.00%

Facility Level Information	
Nameplate Capacity	**130.13 MWDC**
Number of modules	325333
Nameplate Capacity	**100.00 MWAC**
Number of arrays	24
Interconnection Limit	**100.00 MWAC**
Inteconnection Voltage	34.5 kV
DC/AC ratio - POI Rating	1.301

Weather	
Source	TMY3
GHI	1903.4 kWh/m2
DHI	kWh/m2
Global POA	2531.7 kWh/m2
Average Temp.	9.92 °C
Average Temp. (Generation)	14.87 °C
Average Wind	2.11 m/s
Average Wind (Generation)	2.81 m/s

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
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 2020 Renewables Technology Assessment**

Variant: VC0 Date: 26-Jun-20

Site Information		
City / State:	Milford, UT	
Latitude (N):	38.41	°
Longitude (W):	-113.02	°
Altitude	0	m
ASHRAE Ext. Max Mean Temp	38.1	°C
ASHRAE 99.6% Heating DB	-19.8	°C

Estimated Annual Energy Production		
P50 net production (yr-1)	529704.0	MWh
AC capacity factor - Inv Rating	30.23%	
AC capacity factor - POI Rating	30.23%	
DC capacity factor	23.23%	
Specific Production	2035	kWh/kWp/yr
Performance Ratio PR	80.39%	
Night time losses	-796.6	MWh
Plant Output Limitations	0.00%	

Design Parameters		
System DC Voltage	1500	VDC
GCR	42.6	%
Row spacing	10	m
Mounting	Tracker	
Tilt angle or rotation limits	60	°
Azimuth	0	°
Tracking strategy	TRUE	
Availability	100.0	%
Degradation	0.5	%/yr

Facility Level Information		
Nameplate Capacity	**260.27**	**MWDC**
Number of modules	650667	
Nameplate Capacity	**200.00**	**MWAC**
Number of arrays	48	
Interconnection Limit	**200.00**	**MWAC**
Inteconnection Voltage	230	kV
DC/AC ratio - POI Rating	1.301	

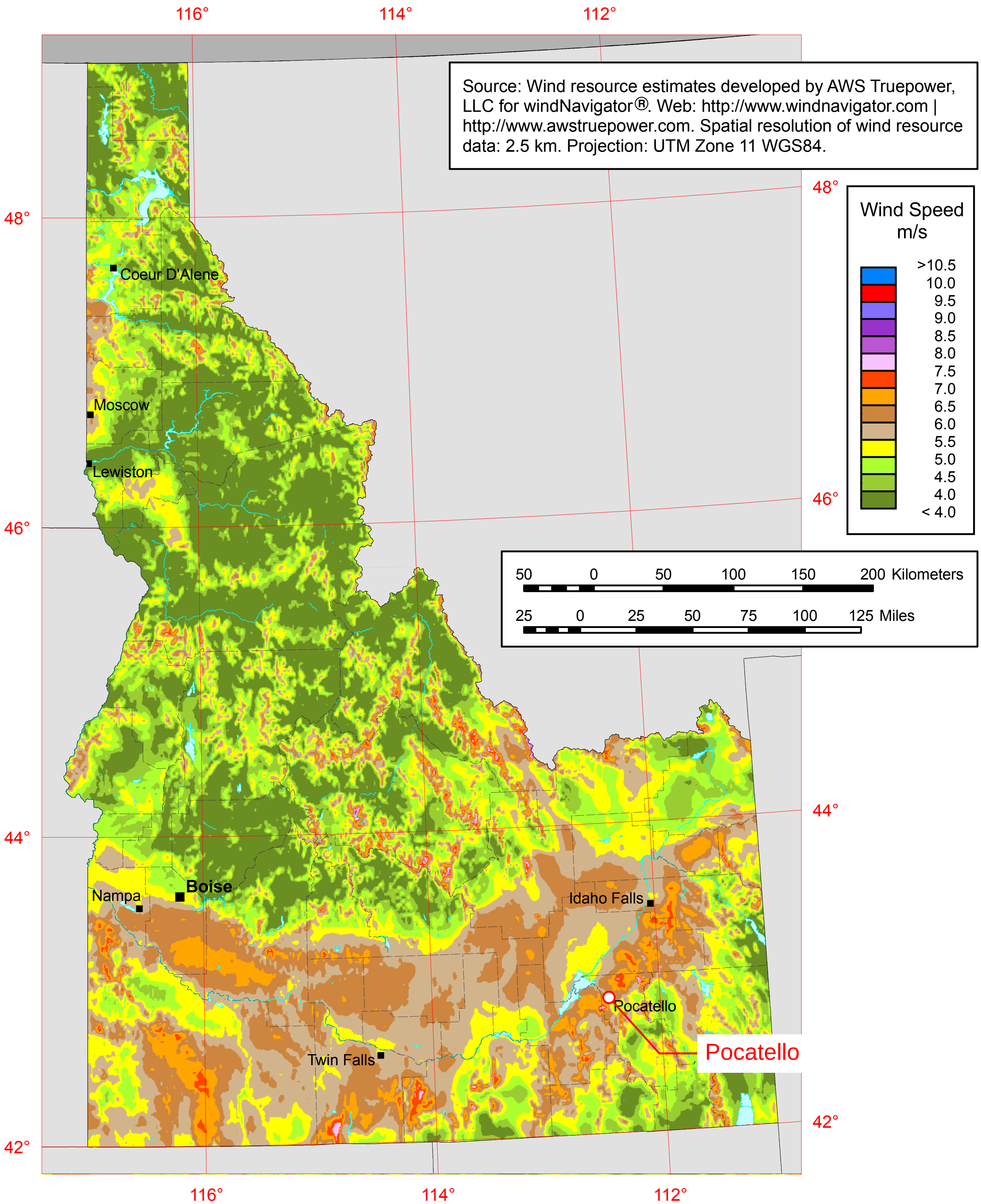
Array Level Information		
Module rating	400	W
# Modules per string	28	
Strings in parallel	488	
Total number of modules	13664	
DC capacity	5466	kW
Inverter Rating (Max Temp & 95% pf)	4200	kW
DC/AC ratio - Inv Rating	1.301	

Weather		
Source	TMY3	
GHI	1903.4	kWh/m2
DHI		kWh/m2
Global POA	2531.7	kWh/m2
Average Temp.	9.92	°C
Average Temp. (Generation)	14.87	°C
Average Wind	2.11	m/s
Average Wind (Generation)	2.81	m/s

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*	2.0	%
Light induced degradation	2.0	%
DC wiring loss	1.5	%
Module quality loss	-0.5	%
Module mismatch loss	1.0	%
DC health loss	1.0	%
Albedo*	1.0	%

AC System Losses	
MV transformer no-load losses	0.00%
MV transformer full load losses	0.00%
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%

Idaho - Annual Average Wind Speed at 80 m



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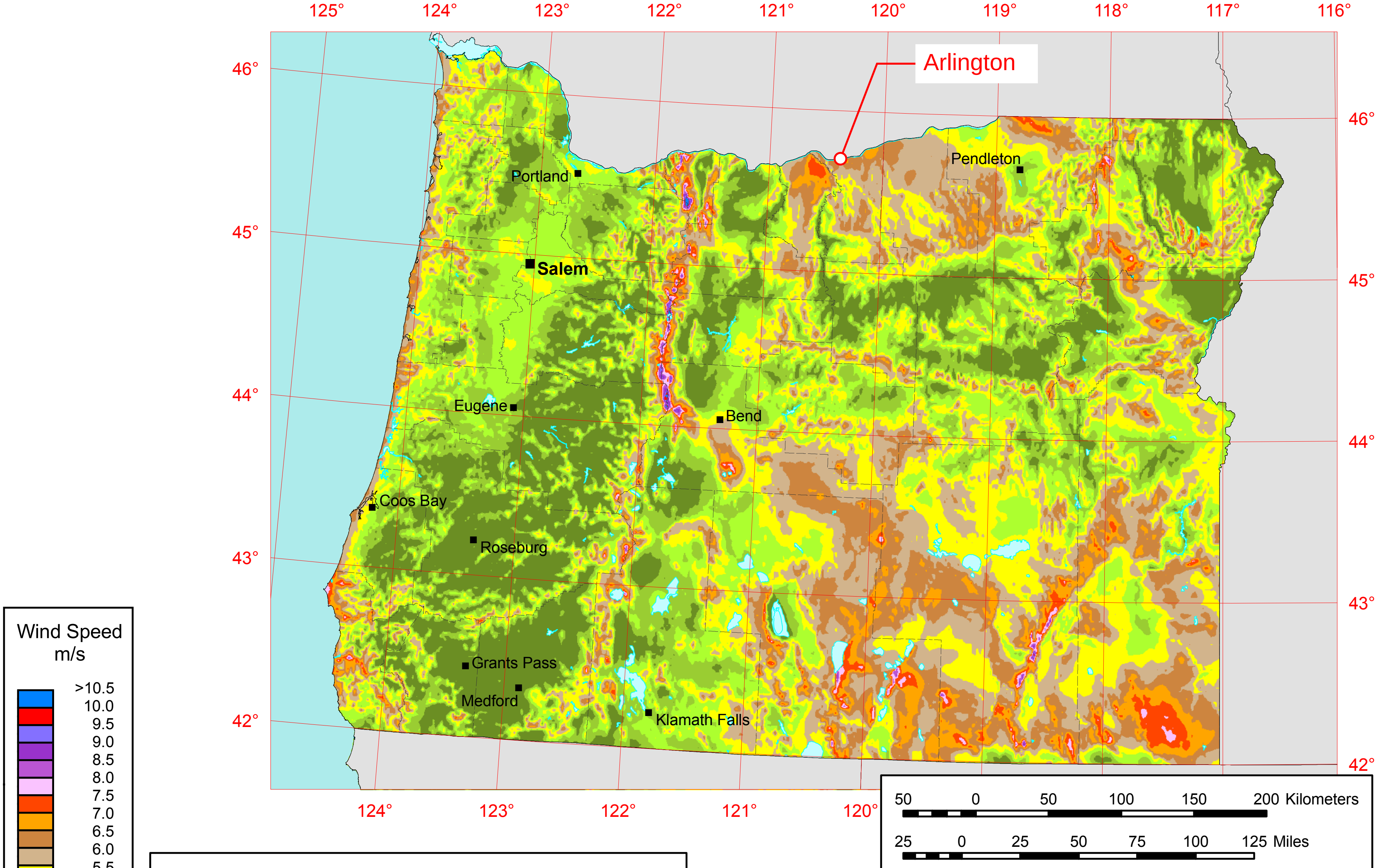
06-OCT-2010 1.1.1

Oregon - Annual Average Wind Speed at 80 m



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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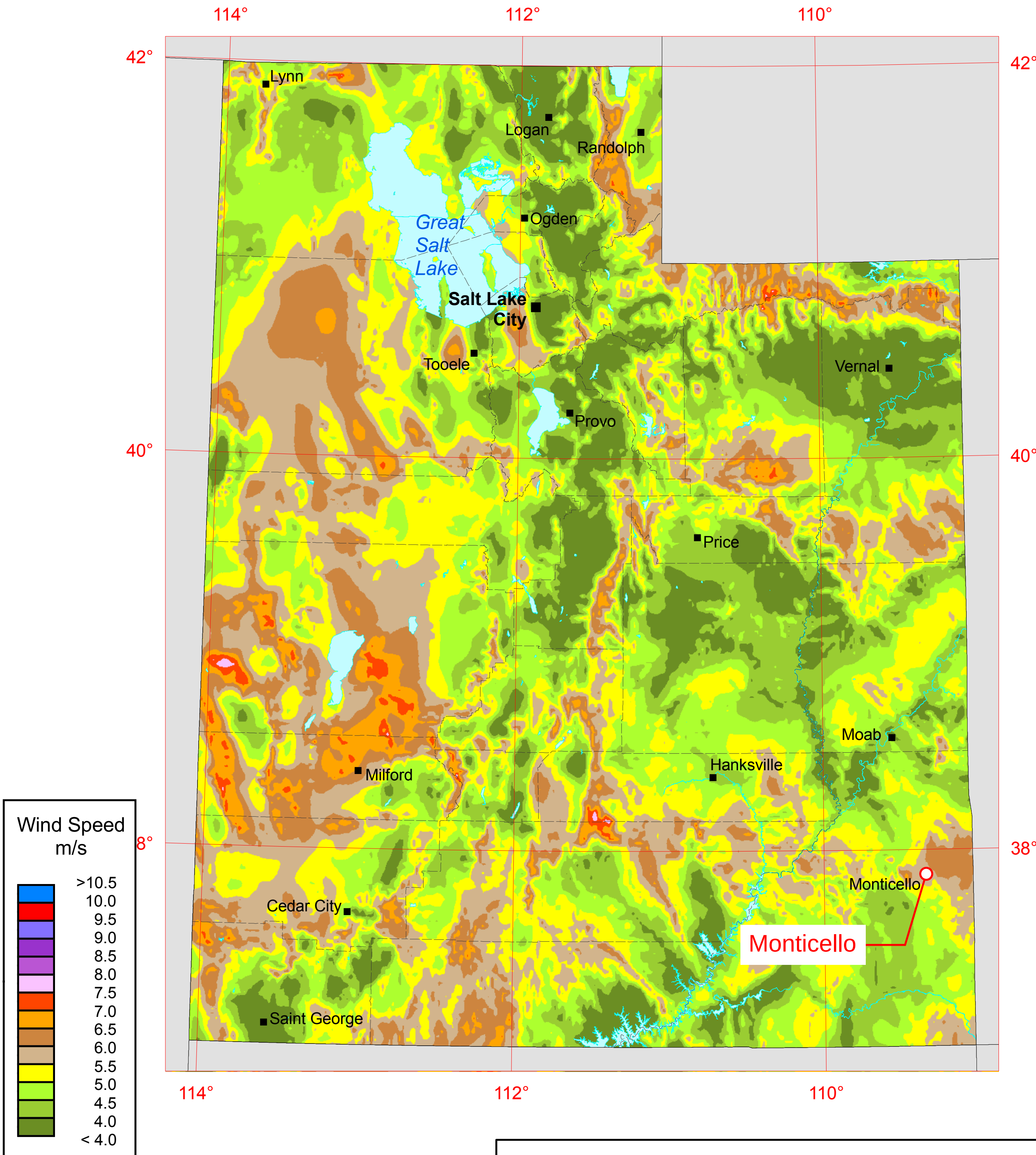
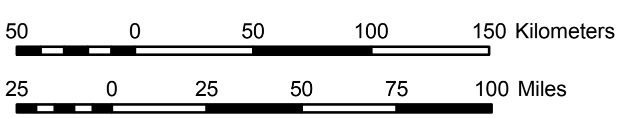
Utah - Annual Average Wind Speed at 80 m





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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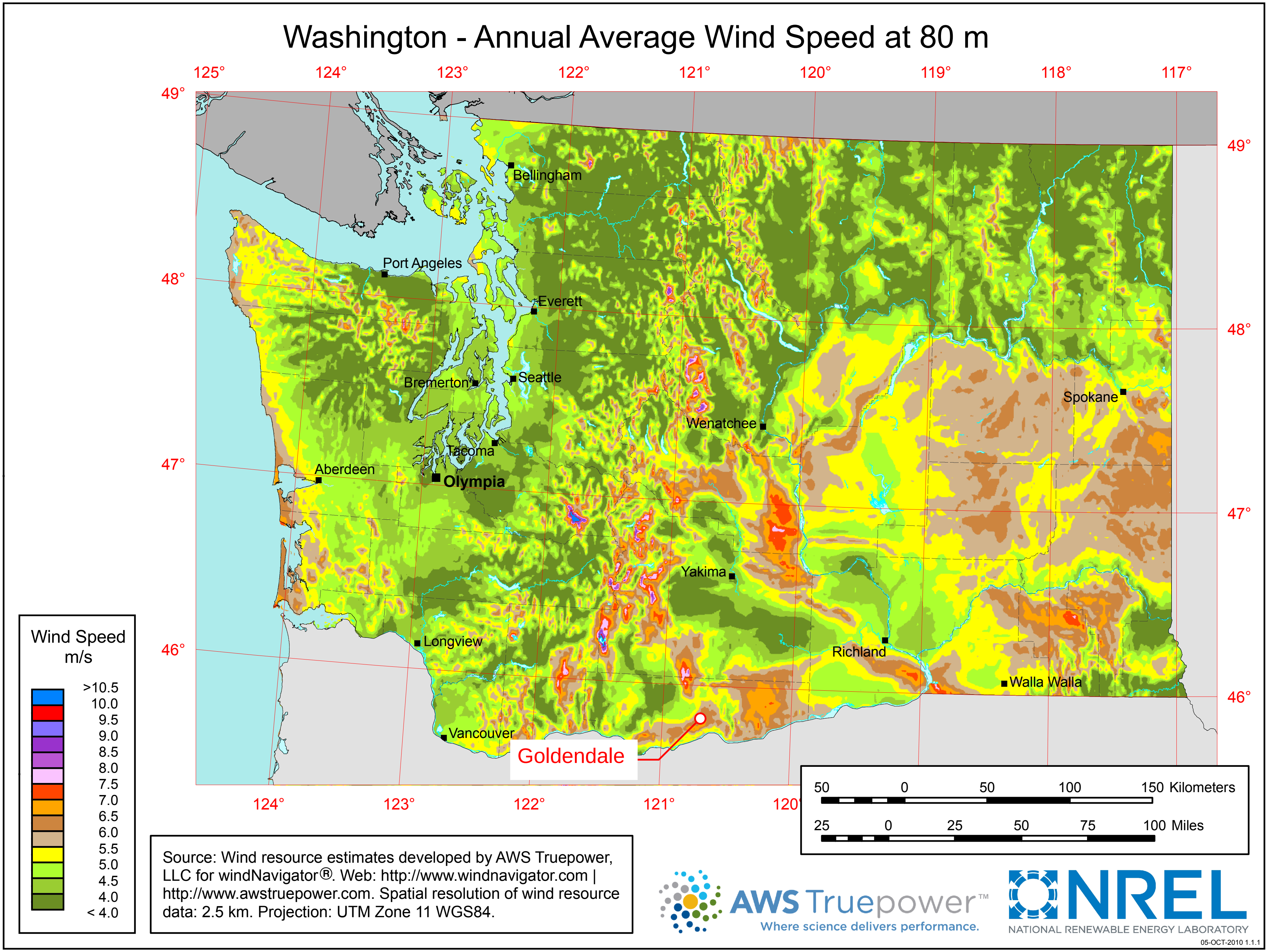
Washington - Annual Average Wind Speed at 80 m
125° 124° 123° 122° 121° 120° 119° 118° 117°
49° 48° 47° 46°
Bellingham
Port Angeles
Everett
Seattle
Bremerton
Tacoma
Aberdeen
Olympia
Wenatchee
Spokane
Yakima
Richland
Walla Walla
Longview
Vancouver
Goldendale
Wind Speed
m/s
>10.5
10.0
9.5
9.0
8.5
8.0
7.5
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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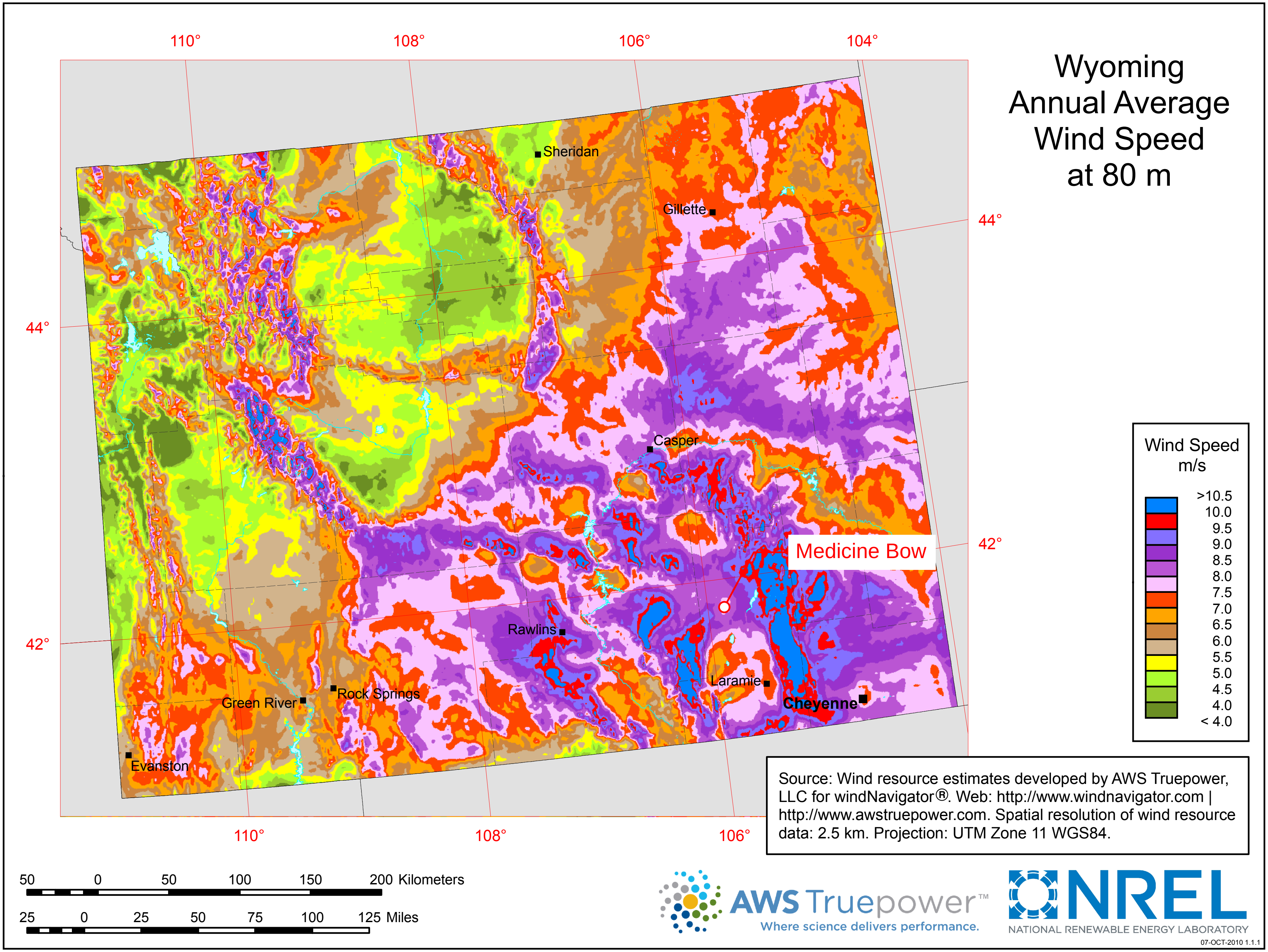
05-OCT-2010 1.1.1



Wyoming
Annual Average
Wind Speed
at 80 m
110°
108°
106°
104°
44°
42°
Sheridan
Gillette
Casper
Medicine Bow
Rawlins
Laramie
Cheyenne
Green River
Rock Springs
Evanston
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
AWS Truepower™
Where science delivers performance.
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
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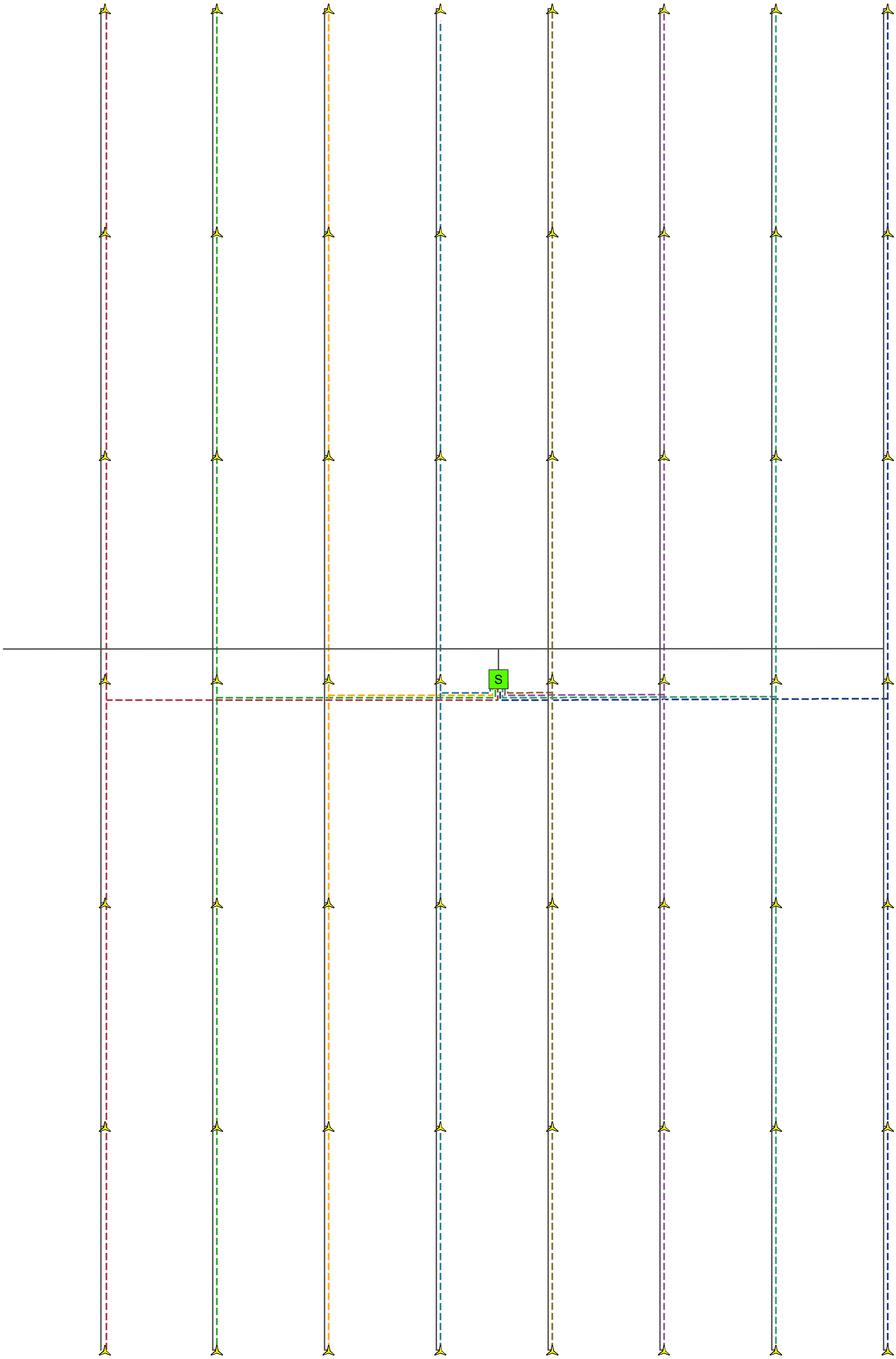


Drawing Notes:
1. Layout is intended to be generic / conceptual and not necessarily representative of a site that would be constructed. Layout based upon generic turbine model with approx. 414m by 828m gridded spacing. Final turbine model, project size, and site conditions will alter layout.

PRELIMINARY
NOT FOR CONSTRUCTION

GENERIC SITE LAYOUT
200 MW Wind Farm

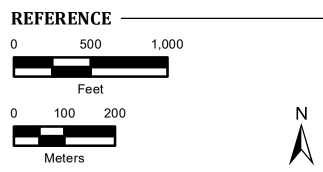
LOCATION:	Generic
CLIENT:	Pacificorp
PROJ. NO.:	109571
CREATED:	09/06/2018

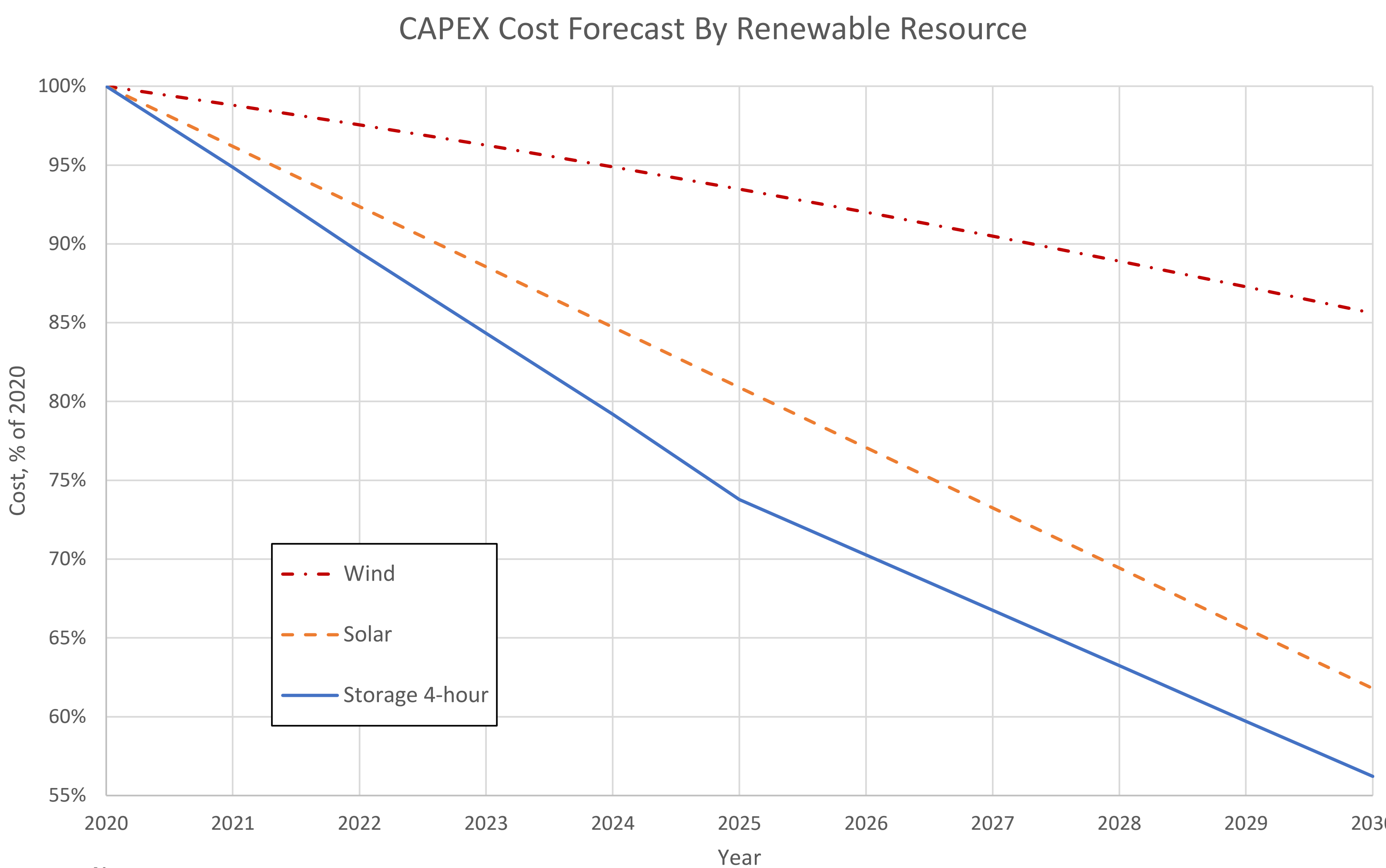
BURNS McDONNELL
www.burnsmcd.com

LEGEND

Proposed Turbine
Collector Substation
Access Roads
Circuit 1
Circuit 2
Circuit 3
Circuit 4
Circuit 5
Circuit 6
Circuit 7
Circuit 8

REFERENCE



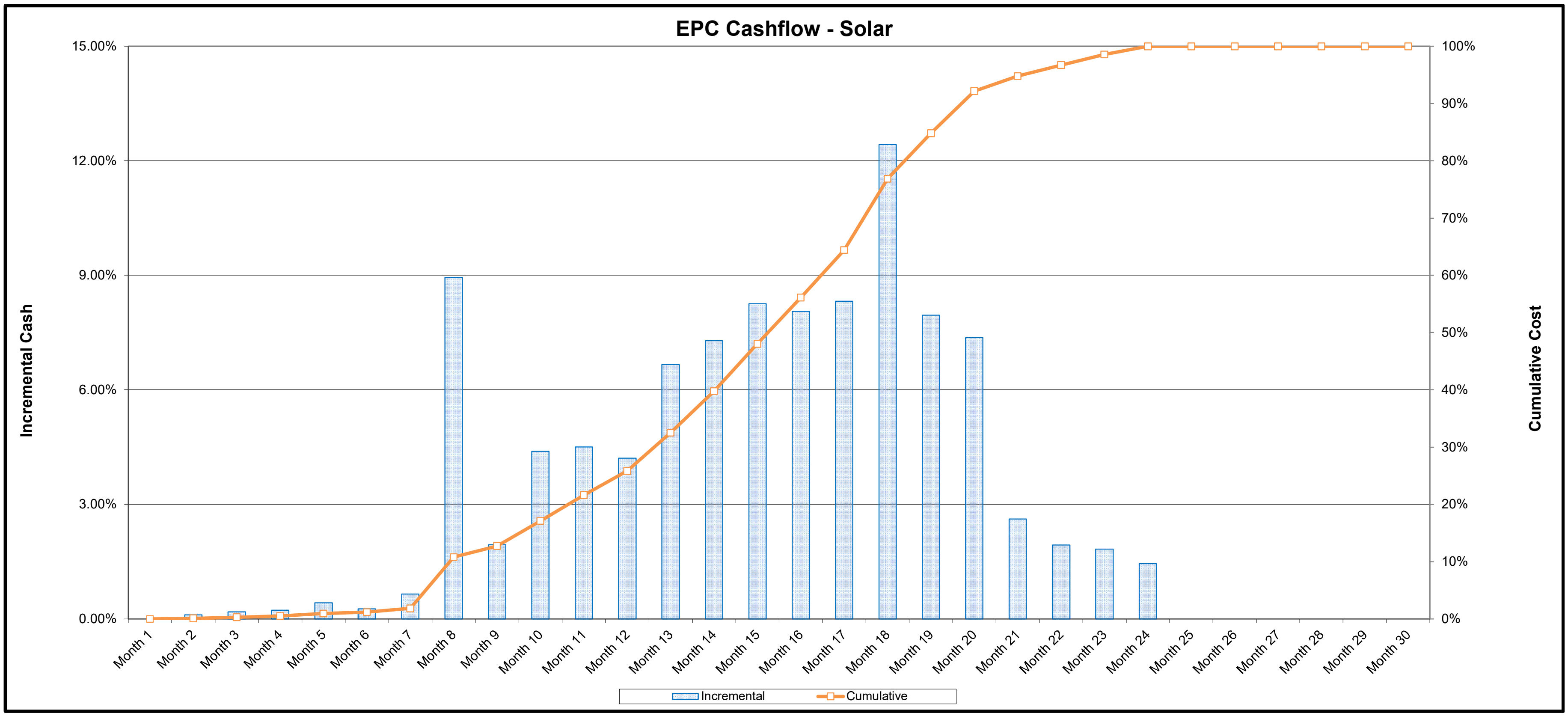


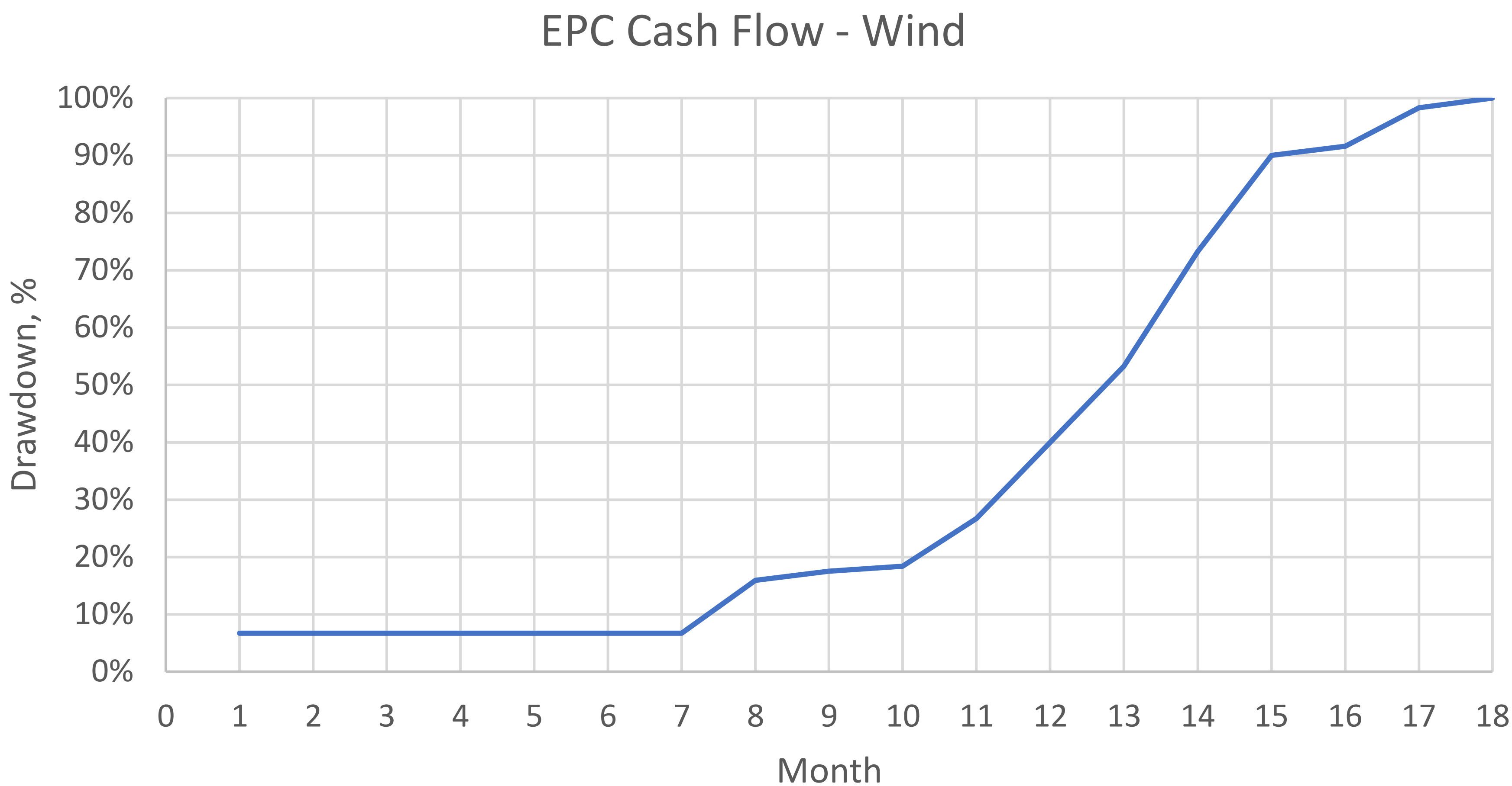
Notes:
1. The declining cost curve for onshore wind was developed using NREL Land-Based Wind Classes (Class) moderate overnight cost inforamtion. The costs for Class 2, Class 6, and Class 8 were averaged to represent the Pacificorp identified sites based on average wind speed.

2. The declining cost curve for utility solar photovoltaic was developed using NREL mid overnight cost inforamtion.

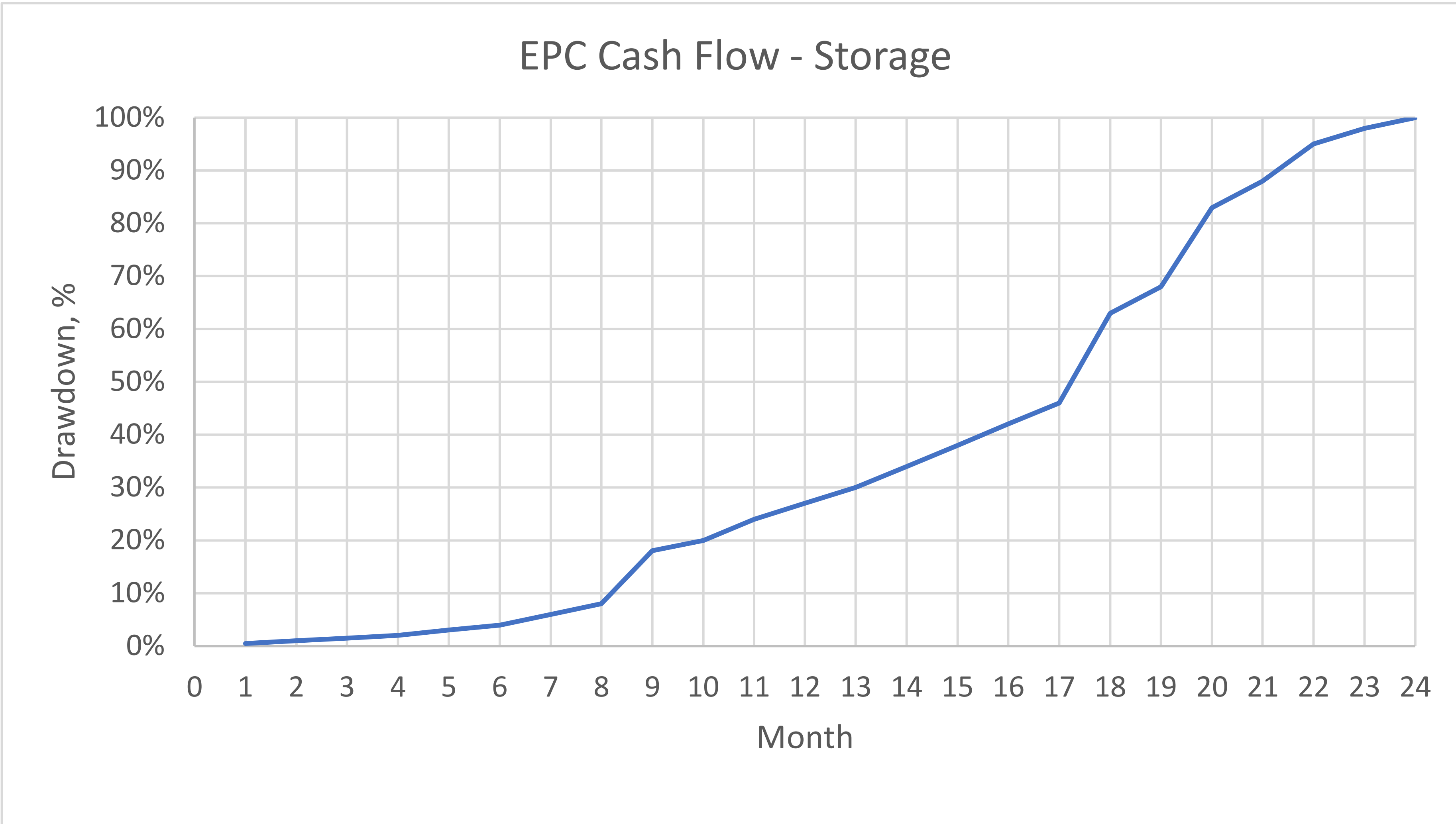
3. The declining cost curve for battery storage was developed using NREL mid overnight CAPEX cost information for a storage device with 15-year life and 85% round-trip efficiency for 4- hour storage.

Overnight Cost Forecast ($/kW)											
Technology	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**
Wind	$1,684.96	$1,664.76	$1,643.66	$1,621.65	$1,598.74	$1,574.92	$1,550.20	$1,524.58	$1,498.05	$1,470.62	$1,442.28
Percentage of 2020	100.00%	98.80%	97.55%	96.24%	94.88%	93.47%	92.00%	90.48%	88.91%	87.28%	85.60%
Solar	$1,324.76	$1,274.15	$1,223.53	$1,172.91	$1,122.30	$1,071.68	$1,021.06	$970.45	$919.83	$869.22	$818.60
Percentage of 2020	100.00%	96.18%	92.36%	88.54%	84.72%	80.90%	77.08%	73.25%	69.43%	65.61%	61.79%
Storage ($/kWh)	$370.00	$351.00	$331.00	$312.00	$293.00	$273.00	$260.00	$247.00	$234.00	$221.00	$208.00
Percentage of 2020	100.00%	94.86%	89.46%	84.32%	79.19%	73.78%	70.27%	66.76%	63.24%	59.73%	56.22%


EPC Cashflow - Solar
Incremental Cash
Cumulative Cost
15.00%
12.00%
9.00%
6.00%
3.00%
0.00%
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
Month 1
Month 2
Month 3
Month 4
Month 5
Month 6
Month 7
Month 8
Month 9
Month 10
Month 11
Month 12
Month 13
Month 14
Month 15
Month 16
Month 17
Month 18
Month 19
Month 20
Month 21
Month 22
Month 23
Month 24
Month 25
Month 26
Month 27
Month 28
Month 29
Month 30
Incremental
Cumulative



Notes: 200 MW project was assumed.



EPC Cash Flow - Storage
Drawdown, %
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0 1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24
Month

25 - Year Cashflows

200 MW UT Solar

Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Capital Cost, $MM:	$ 216.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 11.59	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
O&M, $MM:	$ -	$ 3.59	$ 3.68	$ 3.77	$ 3.86	$ 3.96	$ 4.06	$ 4.16	$ 4.26	$ 4.37	$ 4.48	$ 4.59	$ 4.71	$ 4.82	$ 4.95	$ 5.07	$ 5.20	$ 5.33	$ 5.46	$ 5.60	$ 5.74	$ 5.88	$ 6.03	$ 6.18	$ 6.33	$ 6.49

200 MW UT Wind

Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
Capital Cost, $MM:	$ 231.00	$ -	$ -	$ 0.44	$ 0.45	$ 0.46	$ 0.89	$ 0.91	$ 0.93	$ 0.96	$ 0.98	$ 1.67	$ 1.72	$ 1.76	$ 1.80	$ 1.85	$ 1.89	$ 1.94	$ 1.99	$ 2.04	$ 2.09	$ 3.00	$ 3.07	$ 3.15	$ 3.23	$ 3.31
O&M, $MM:	$ -	$ 10.46	$ 10.72	$ 10.98	$ 11.26	$ 11.54	$ 11.83	$ 12.12	$ 12.43	$ 12.74	$ 13.06	$ 13.38	$ 13.72	$ 14.06	$ 14.41	$ 14.77	$ 15.14	$ 15.52	$ 15.91	$ 16.31	$ 16.71	$ 17.13	$ 17.56	$ 18.00	$ 18.45	$ 18.91

50 MW 200 MWh Storage

Year:	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
Capital Cost, $MM:	$ 68.00	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4.71	$ -	$ -	$ -	$ -	$ -
O&M, $MM:	$ -	$ 1.41	$ 1.45	$ 1.49	$ 1.52	$ 1.56	$ 1.60	$ 1.64	$ 1.68	$ 1.72	$ 1.77	$ 1.81	$ 1.86	$ 1.90	$ 1.95	$ 2.00	$ 2.05	$ 2.10	$ 2.15	$ 2.21	$ 2.26

Guidehouse

PacifiCorp: Private Generation Resource Assessment for long term planning

Updated Analysis Including ITC Changes

Jan 22, 2021

Introduction

Updated ITC Schedule

- Guidehouse prepared a Long-term Private Generation Resource Assessment on behalf of PacifiCorp.
- The purpose of this study is to support PacifiCorp's 2021 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 built on Guidehouse's previous assessment which supported PacifiCorp's 2015, 2017, 2019, and 2021 IRP, incorporating updated load forecasts, market data, technology cost and performance projections.
- The study includes projections for PacifiCorp's six state territories: UT, OR, ID, WY, CA, WA.
- Navigant evaluated five private generation resources in detail in this report: Photovoltaic Solar, Small Scale Wind, Small Scale Hydro, Combined Heat and Power Reciprocating Engines, Combined Heat and Power Micro-turbines
- The Federal Investment Tax Credit (ITC) rules were changed in December 2020 as part of the US coronavirus relief package. We have updated the analysis to include the impacts of the new ITC rules. No other changes were made to the analysis inputs.

Federal Incentives

Updated ITC Schedule

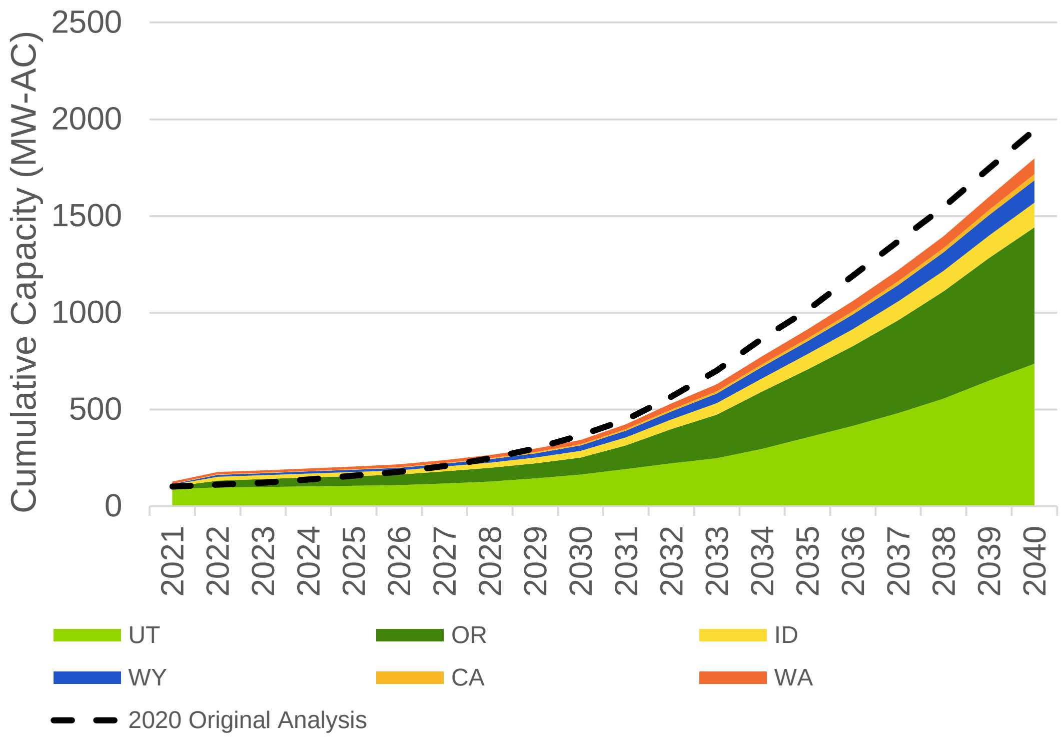
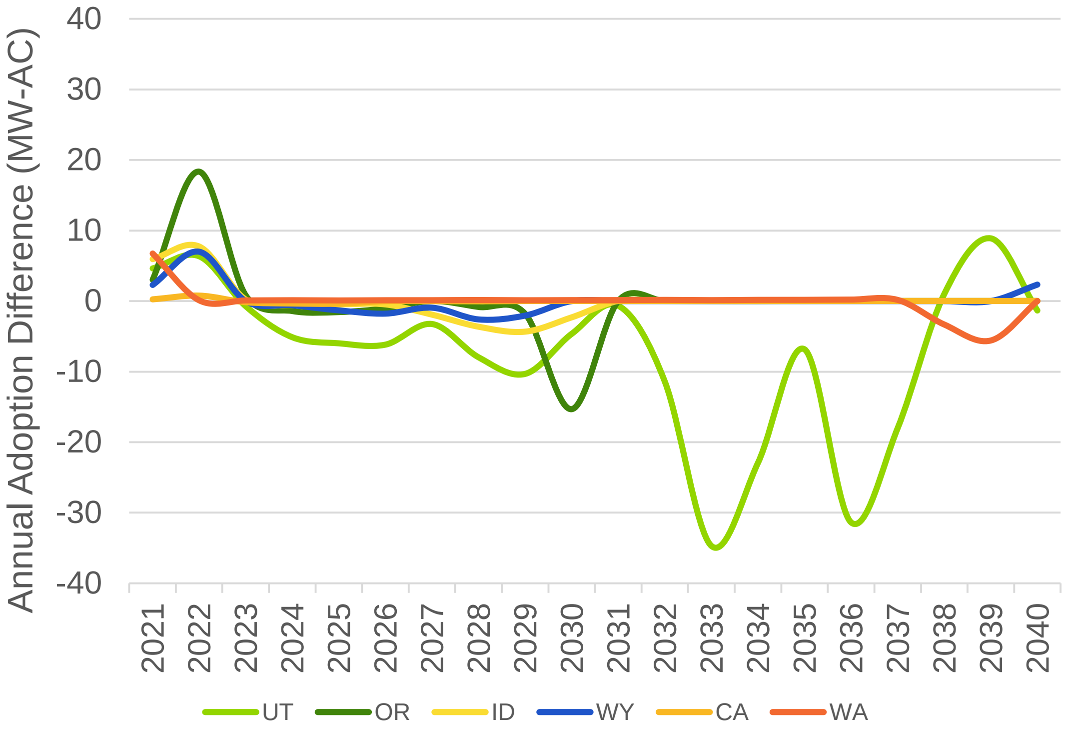
Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	10%	10%	10%	0%	0%	0%
Micro Turbines	10%	10%	10%	0%	0%	0%
Small Hydro	0%	0%	0%	0%	0%	0%
PV - Com	30%	26%	26%	26%	22%	10%
PV - Res	30%	26%	26%	26%	22%	0%
Wind - Com	12%	0%	0%	0%	0%	0%
Wind - Res	30%	26%	26%	26%	22%	0%

Federal Investment Tax credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc

Guidehouse

Private Generation – Base Case

Updated ITC Schedule

Cumulative Capacity Installations, 2021-2040, Base Case	Annual Adoption Difference – Updated 2020 Analysis vs. Original 2020 Analysis
	

Contact

Shalom Goffri
Director
617.460.2731
shalom.goffri@guidehouse.com

Guidehouse

APPENDIX M – RENEWABLE RESOURCES ASSESSMENT

A study on renewable resources and energy storage was commissioned to support PacifiCorp's 2021 Integrated Resource Plan (IRP). The 2020 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.

Private Generation Long-Term Resource Assessment (2021-2040)

Prepared for:

PacifiCorp

Prepared by:
Shalom Goffri
Ryan Auker

June 19th, 2020

Navigant Consulting, Inc.
1375 Walnut Street, Suite 100
Boulder, CO 80302

415.356.7100
navigant.com

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June 19th, 2020

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, 2017, and 2019 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.

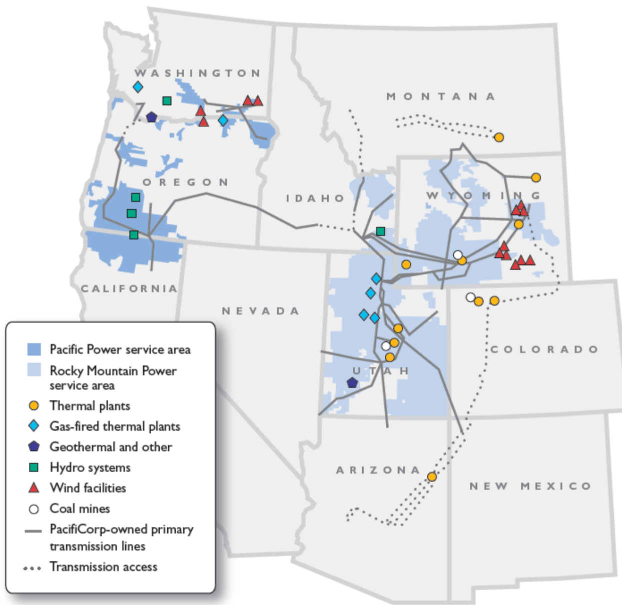
[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[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.

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 2021 to 2040. This analysis was performed for typical commercial, irrigation, industrial and residential PacifiCorp customers in each state.

In the base scenario, Navigant estimates approximately 1.9 GW AC of PG capacity will be installed in PacifiCorp's territory from 2021-2040.[7] As shown in Figure 2, the low and high scenarios project a cumulative installed capacity of 1.0 GW AC and 2.9 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.

Figure 2 Cumulative Market Penetration Results (MW AC), 2021 – 2040

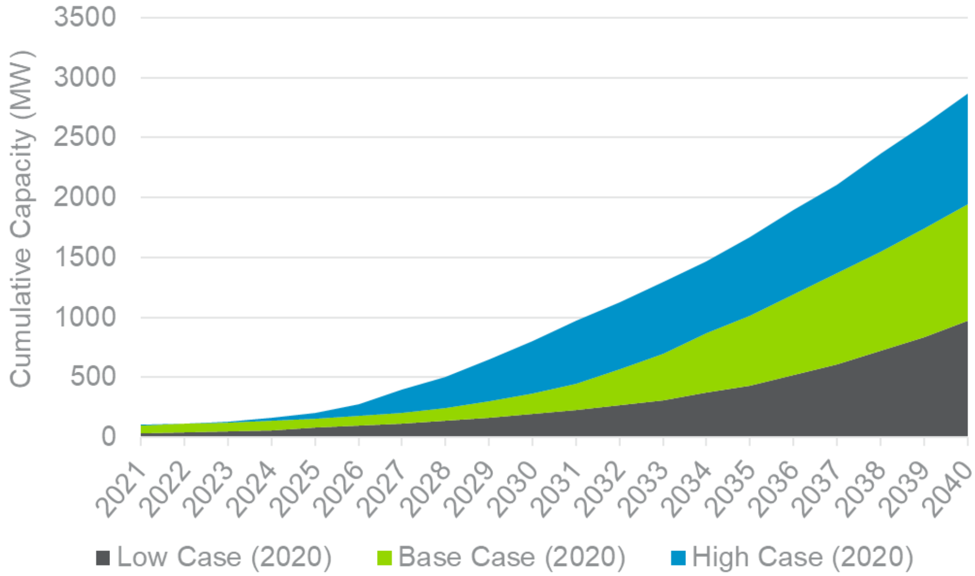


Figure 3 indicates that Utah and Oregon will drive most PG installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales[8]. Reference APPENDIX A for detailed state-specific customer data. In both states, PG installations are 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 2018 report. The two main factors that impacted the adoption results from 2018 to 2020 include: customer count and electric rate and policy.

Reference

Table 1 for a detailed comparison of the 2018 and 2020 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 2038, the latest common year in the last two studies, cumulative adoption in the base case is around 1,500 MW in the 2020 study and around 1,300 MW in the 2018 study.

[8] The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114)

Figure 3 Cumulative Market Penetration Results by State (MW AC), 2021 – 2040, Base Case

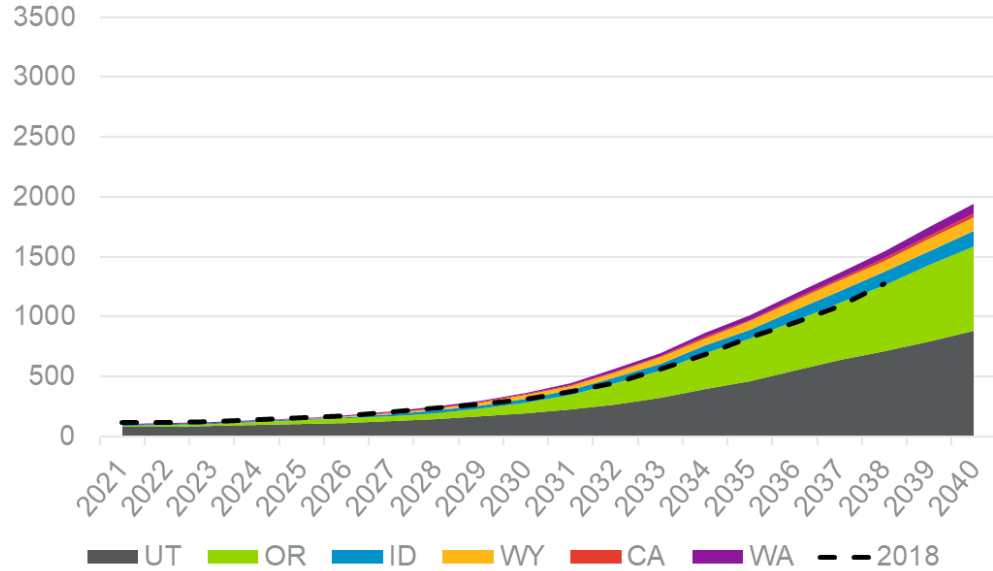
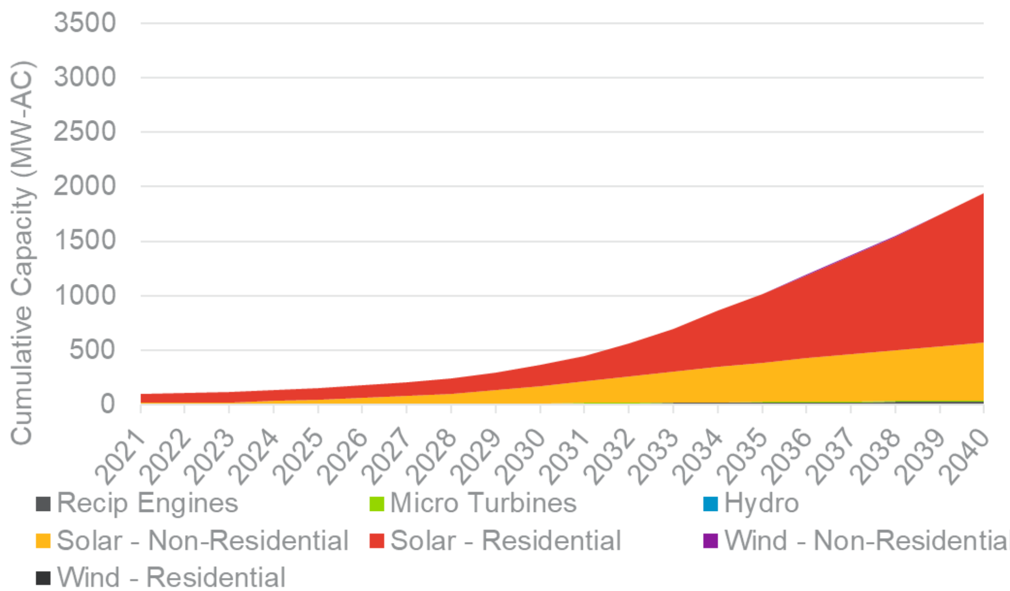


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2021 – 2040, Base Case



The main factors that impacted the adoption results from 2018 to 2020 include: growth in customer count, retail rates, system cost and policy. In general, the rates used in this study changed relative to the 2018 study as PacifiCorp's ability to calculate more accurate offset rates has increased. For example, changes to California's net billing framework are captured in the offset rates. The technology cost and performance forecasts have not changed substantially since 2018. Solar PV policies in key states have not fluctuated as much as in previous studies, but policy changes in CA, UT and WA had a marginal impact on expected near-term and long-term adoption. These changes between the 2018 and 2020 analysis are detailed in

Table 1.

Table 1. Adoption Change from Electric Rate, System Cost and Policy Changes from 2018 to 2020

State	Estimated Adoption Change	Key Adoption Drivers
CA	**2038** – Market decreased from 48 MW to 22 MW	• Rates: Decrease (residential significantly, commercial and industrial marginally) • Solar PV Cost: Declines in the later years are more sustained • Policy: Change to net billing framework (captured in the offset rates) • Customer Count: increased 3%
ID	**2038** – Market remained consistent	• Rates: Decrease (residential, commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: No change • Customer Count: increased 10%
OR	**2038** – Market increased from 435 MW to 554 MW, with adoption shifting to later years which seems reasonable given incentive declines offset by cost declines in future years	• Rates: Decrease (commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: No change from Energy Trust incentives previously included. • Customer Count: increased 7.5%
UT	**2038** – Market increased from 560 MW to 646 MW. Key drivers include customer count increase, manual adjustment for 2021, and increase in commercial offset rates.	• Rates: Decrease (Residential, Industrial), Increase (Commercial); NEM reduction to around 90% of full rates • Solar PV Cost: Declines in the later years are more sustained • Policy: Incentive for residential solar PV declines to $400 in 2024 and $0 beyond; • The report reflects the regulatory modifications to the PG program in Utah, as included in Schedule 136 (Utah Docket 14-035-114) • Customer Count: increased 12%
WA	**2038** – Market increased from 60 MW to 76 MW	• Rates: Decrease (commercial, industrial) • Solar PV Cost: Declines in the later years are more sustained • Policy: Solar and wind FiT reduced rate for an 8-year period • Customer Count: increased 5.5%
WY	**2038** – Market decreased from 114 MW to 96 MW	• Rate: Small changes only • Solar PV Cost: Declines in the later years are more sustained • Policy: None • Customer Count: increased 2%

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 sustained declines in solar PV system costs in later years result in increased adoption over time. In 2036, the latest year in all three studies, cumulative adoption in the base case is around 1,200 MW in the 2020 study, around 1,000 MW in the 2018 study and around 1,200 in 2016. The consistency in cumulative adoption across all three studies indicates that the long-term adoption factors have not experienced significant, unexpected changes. In 2038, the latest year in the latest two studies, cumulative adoption in the base case is around 1,500 MW in the 2020 study and around 1,300 MW in the 2018 study, primarily driven by growth in PacifiCorp's customer count and changes to offset rates.

Figure 5 Cumulative Market Penetration Results by Scenario (MW AC), 2020 and 2018 Studies, 2021-2038

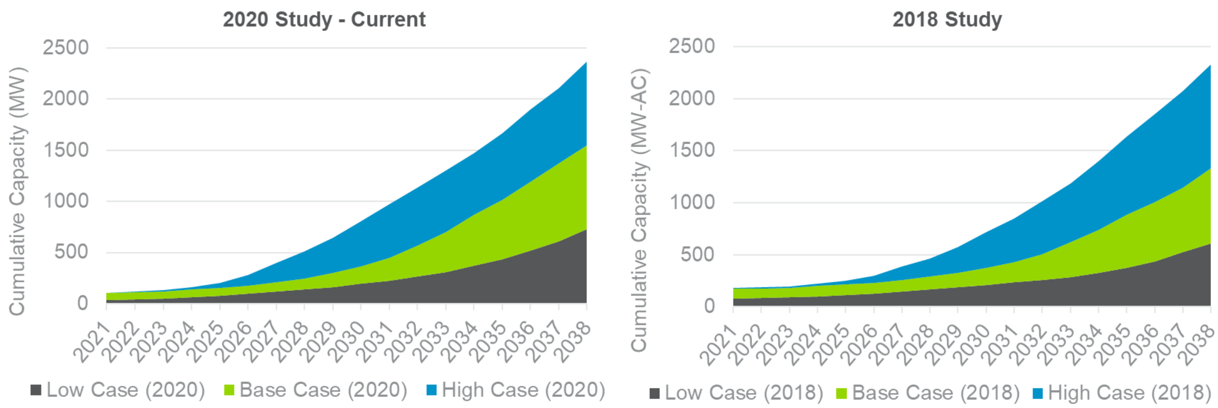
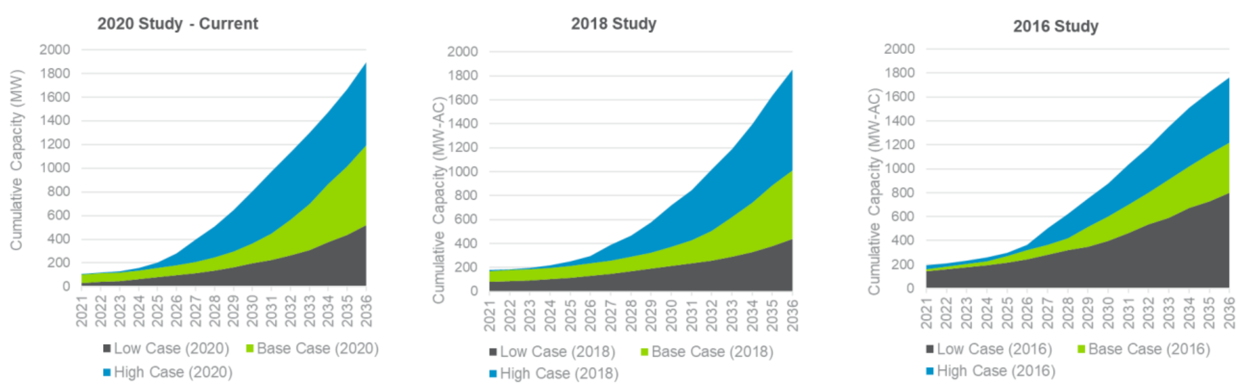


Figure 6 Cumulative Market Penetration Results by Scenario (MW AC), 2020, 2018 and 2016 Studies, 2021-2036



Report Organization

The report is organized as follows:

- Private Generation Market Penetration Methodology
- Results
- APPENDIX A: Customer Data
- APPENDIX B: System Capacity Assumptions
- APPENDIX C: Detailed Numeric Results

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)

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]

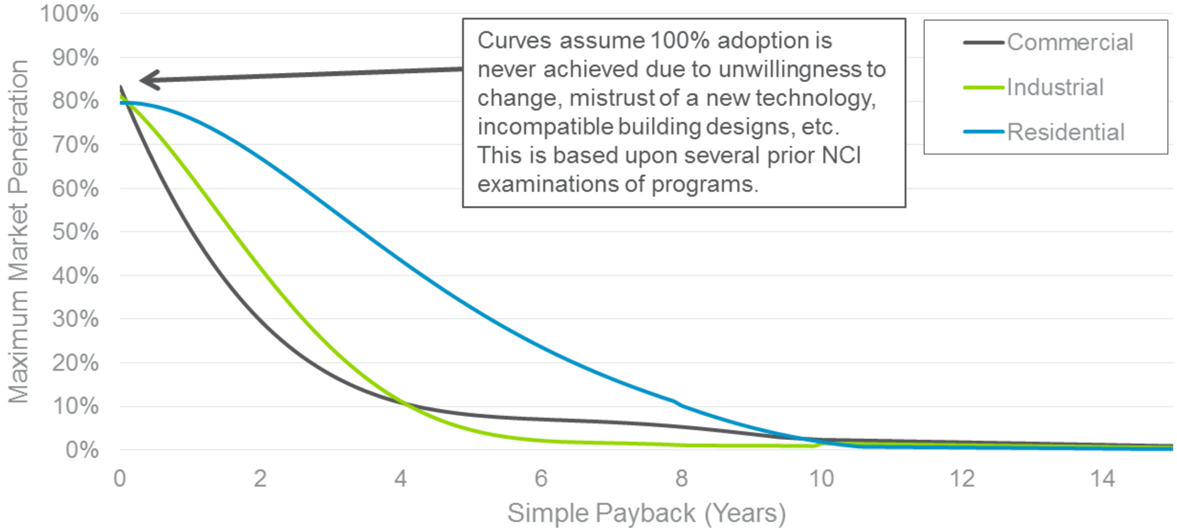
- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *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.

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 7 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 2020 thru 2040. 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

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 7 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.

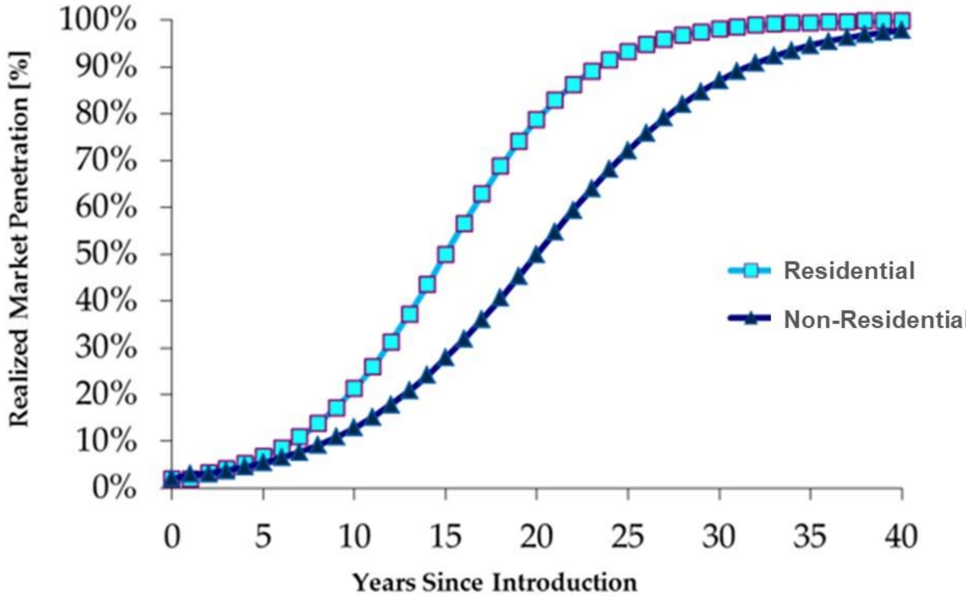
The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other 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.

Figure 8 **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 **8**) 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 7). A technology that was introduced 10 years ago will have realized about 20 percent of its maximum market penetration (Figure **8**), having a market penetration of about seven percent of the technical potential.

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	2021 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.

The system was sized 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

Table 3 Micro-turbines Assumptions[16]

PG Resource Costs	Units	2021 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.

Table 4 Small Hydro Assumptions[18]

PG Resource Costs	Units	2021 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, 2016 and 2018 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.

Table 5 Solar Assumptions

PG Resource Costs	Units	2021 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 9 and
Figure 10, 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.

Figure 9. Non-Residential Solar System Costs, 2021-2040

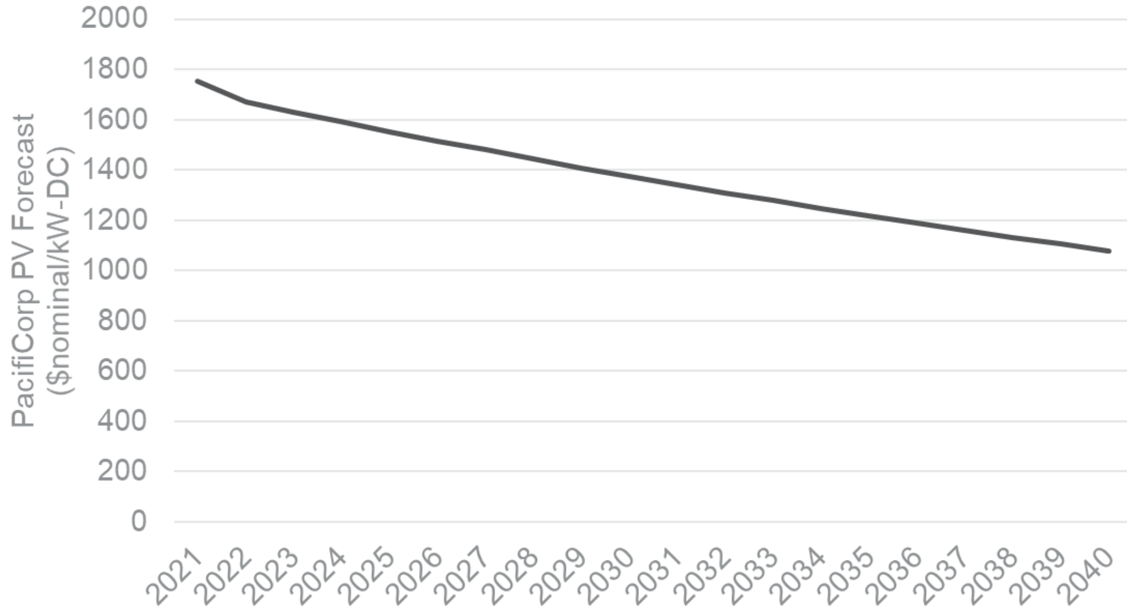
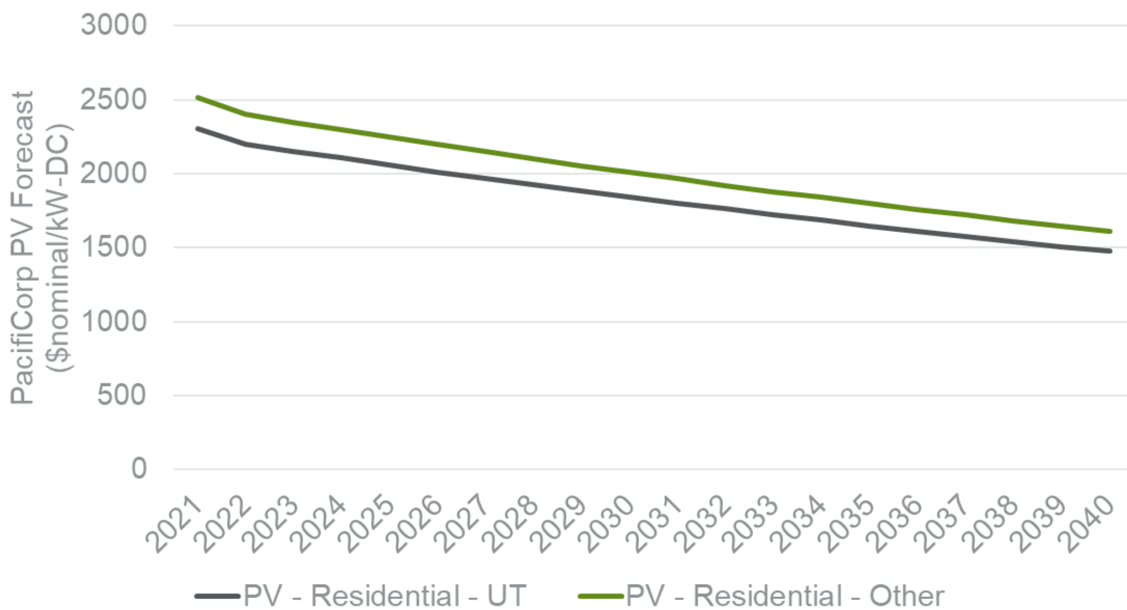


Figure 10 Residential Solar System Costs, 2021-2040



The solar capacity factors (Table 5) were calculated using NREL's System Advisory Model for each state territory.

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 same access factors used in the 2014, 2016 and 2018 studies were used for this study.

The following cost and performance assumptions were used in the analysis.

Table 7 Wind Assumptions

PG Resource Costs	Units	2021 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%	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%.

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.

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[21] Business Energy Investment Tax Credit, http://energy.gov/savings/business-energy-investment-tax-credit-itc.

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. Utah and Idaho also have local state residential personal tax deduction for solar and wind projects, while Oregon has a performance based incentive for residential and commercial solar PV. Currently, state incentives do not exist in California[22], Washington or Wyoming.

The report continues to incorporate the PG program outlined in Schedule 136[23], as first introduced in the 2018 study. 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

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

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

Table 13 Idaho Incentives

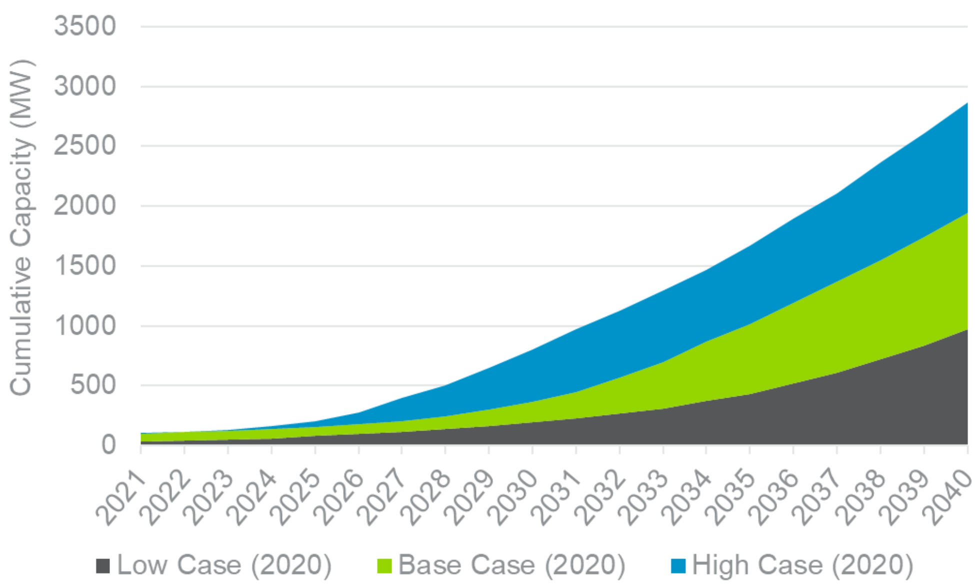
Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	**0**	**0**	**0**	**0**	**0**	**0**
Micro Turbines	**0**	**0**	**0**	**0**	**0**	**0**
Small Hydro	**0**	**0**	**0**	**0**	**0**	**0**
PV - Com	**0**	**0**	**0**	**0**	**0**	**0**
PV – Res (%)*	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**40,20,20,20**	**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.

RESULTS

Navigant estimates approximately 1.9 GW of PG capacity will be installed in PacifiCorp's territory from 2021-2040 in the base case scenario. As shown in Figure 11, the low and high scenarios project a cumulative installed capacity of 1.0 GW and 2.9 GW by 2040, respectively. The main drivers between the different scenarios include variation in technology costs, system performance, and electricity rate assumptions.

Figure 11. Cumulative Market Penetration Results (MW AC), 2021 – 2040



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 31 MW of capacity over the next two decades in the base case, averaging about 1.5 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. However, cumulative residential PG adoption in California decreased significantly compared to the 2018 study due to a 47% decline in the residential offset rates used in the 2020 study (changes to the net billing framework were incorporated in the offset rates). 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.

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 12. The 31 MW from the base case decreases by 54% to 14 MW in the low case and increases by 71% to 53 MW in the high case. Compared to the 2018 study, California is expected to have less residential solar PV adoption in the long-run due a notable reduction in offset rates in California.

Figure 12. Cumulative Capacity Installations by Scenario (MW AC), California

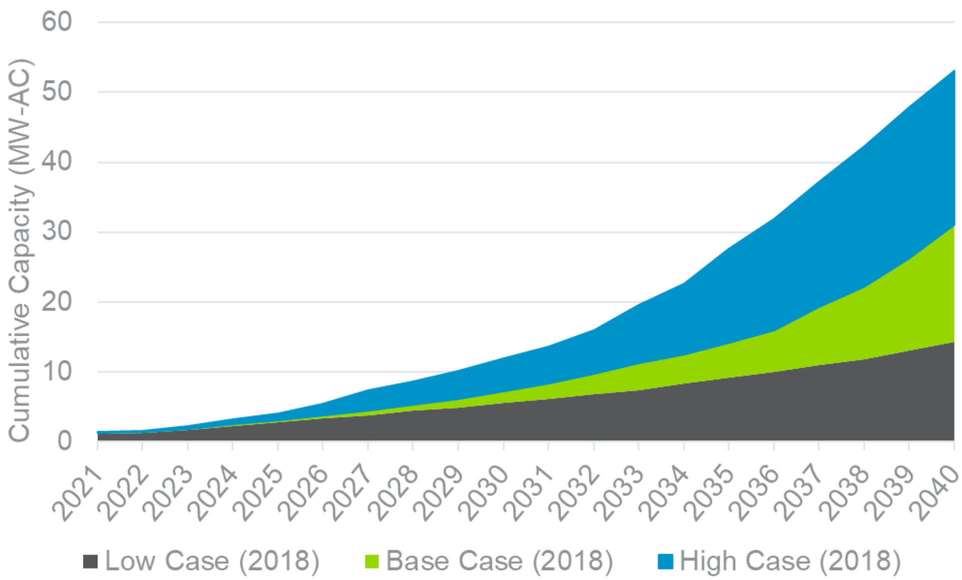


Figure 13. Cumulative Capacity Installations by Technology (MW AC), California Base Case

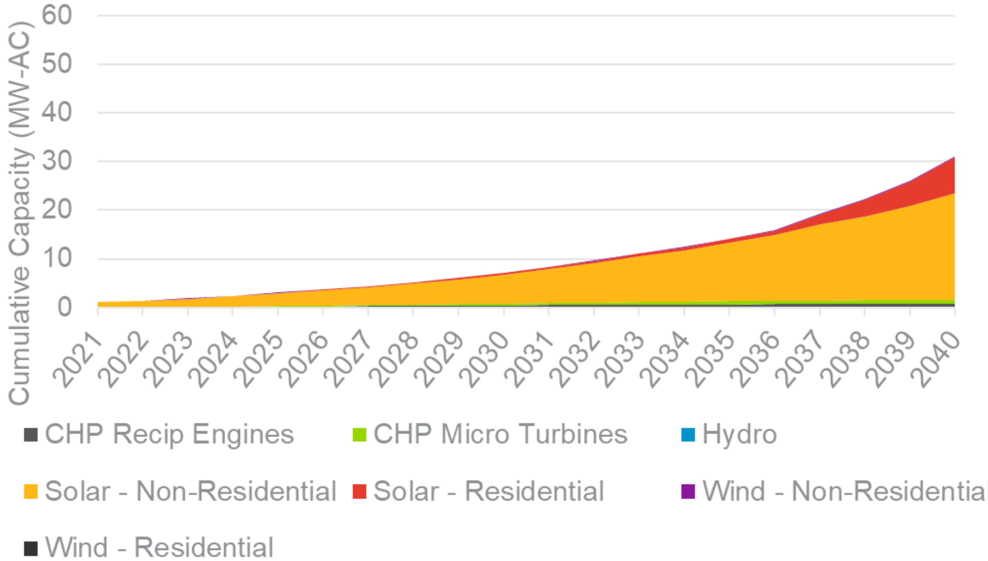


Figure 14. Cumulative Capacity Installations by Technology (MW AC), California High Case

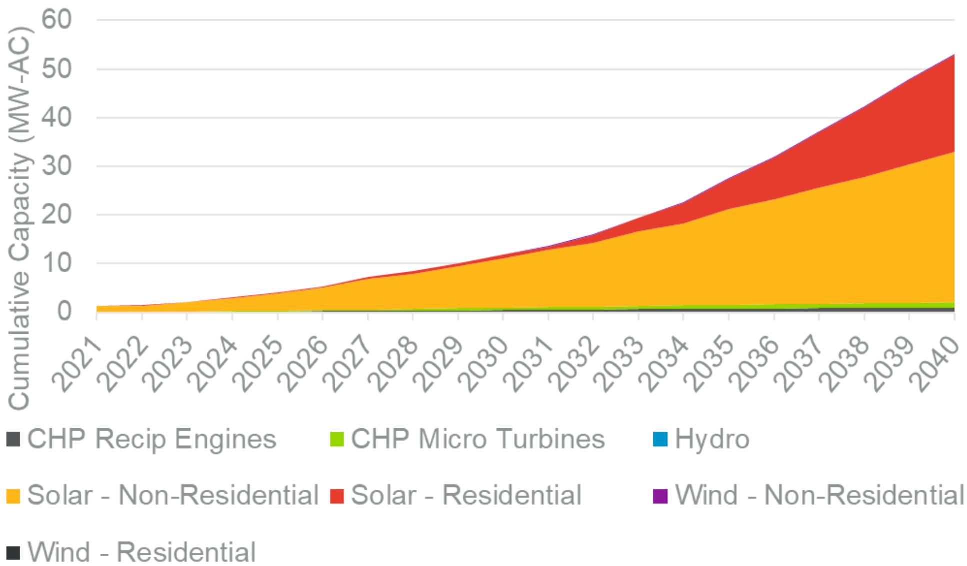
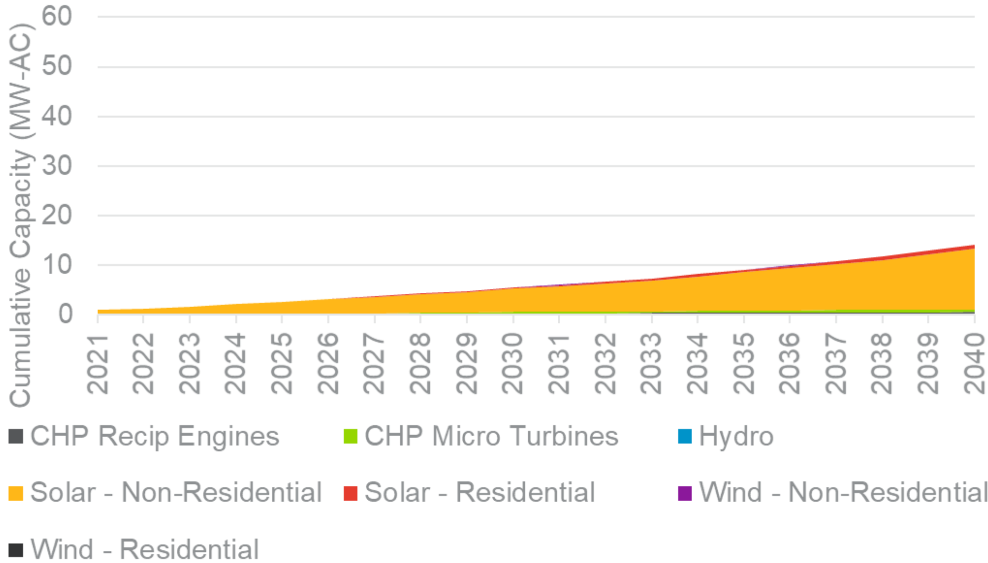


Figure 15. Cumulative Capacity Installations by Technology (MW AC), California Low Case



1.8.2 Idaho

PacifiCorp's Idaho customers are projected to install about 127 MW of capacity over the next two decades in the base case, averaging about 6 MW annually. Idaho currently has a Residential 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. A 10% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

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 16. The 127 MW from the base case decreases by 37% to 80 MW in the low case and increases by 32% to 168 MW in the high case.

[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.

Figure 16. Cumulative Capacity Installations by Scenario (MW AC), Idaho

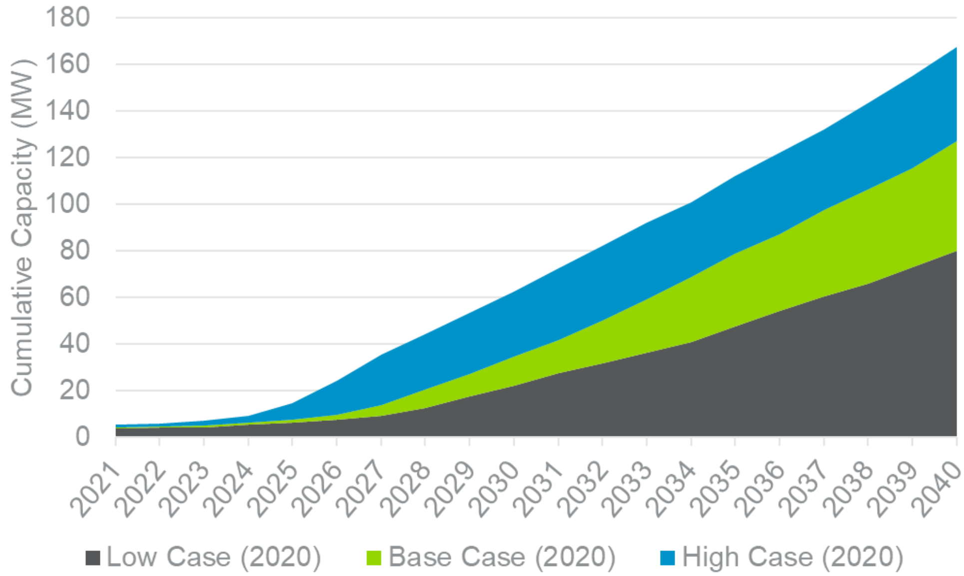


Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

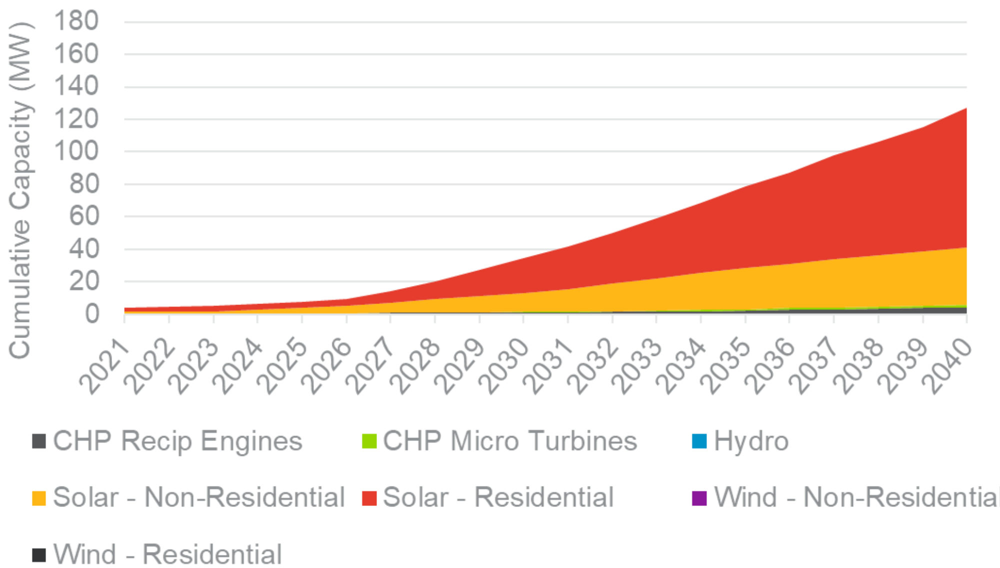


Figure 18. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case

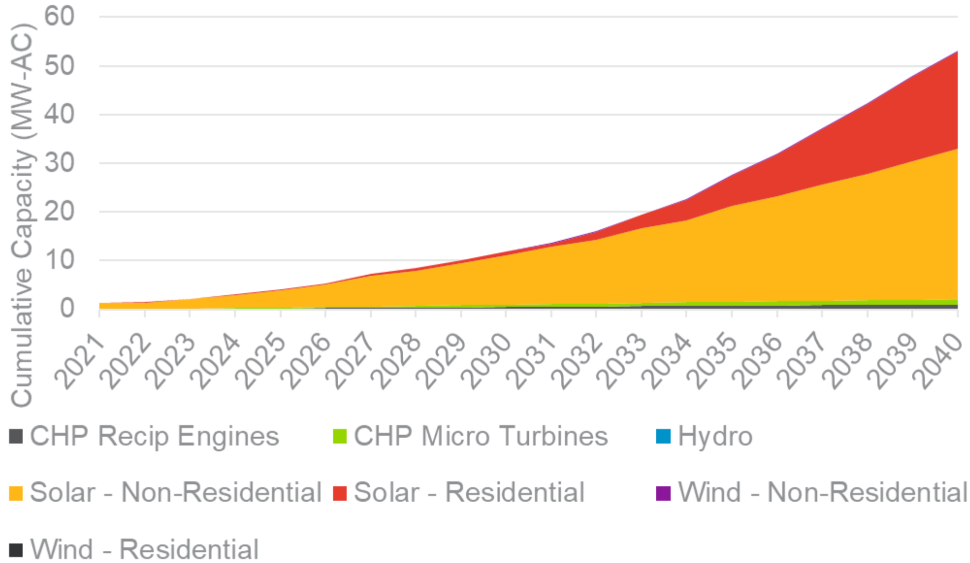
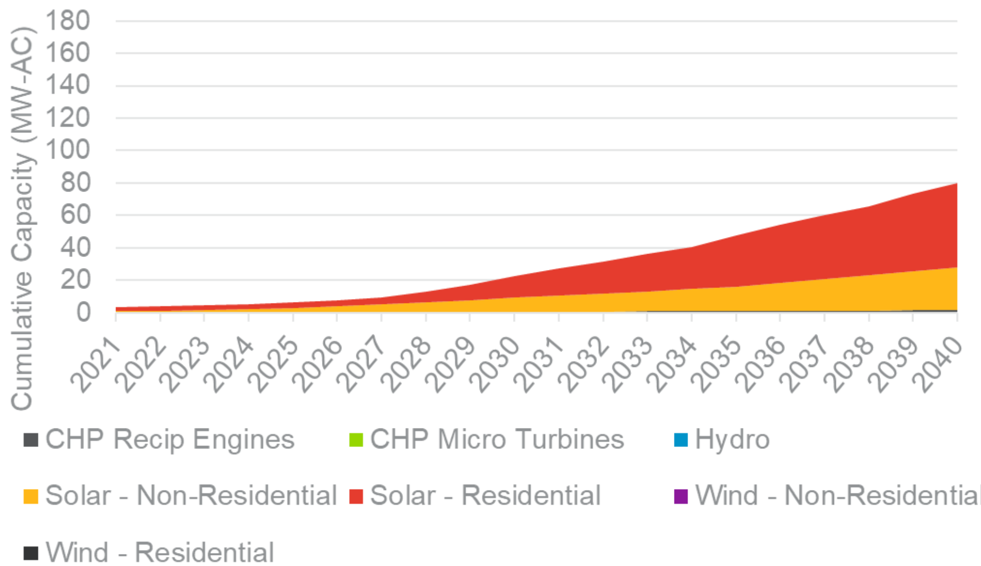


Figure 19. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



1.8.3 Oregon

PacifiCorp's Oregon customers are projected to install about 706 MW of PG capacity over the next two decades in the base case, averaging about 34 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. A 7.5% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

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 20. The 706 MW from the base case decreases by 49% to 360 MW in the low case and increases by 45% to 1,026 MW in the high case.

Figure 20. Cumulative Capacity Installations by Scenario (MW AC), Oregon

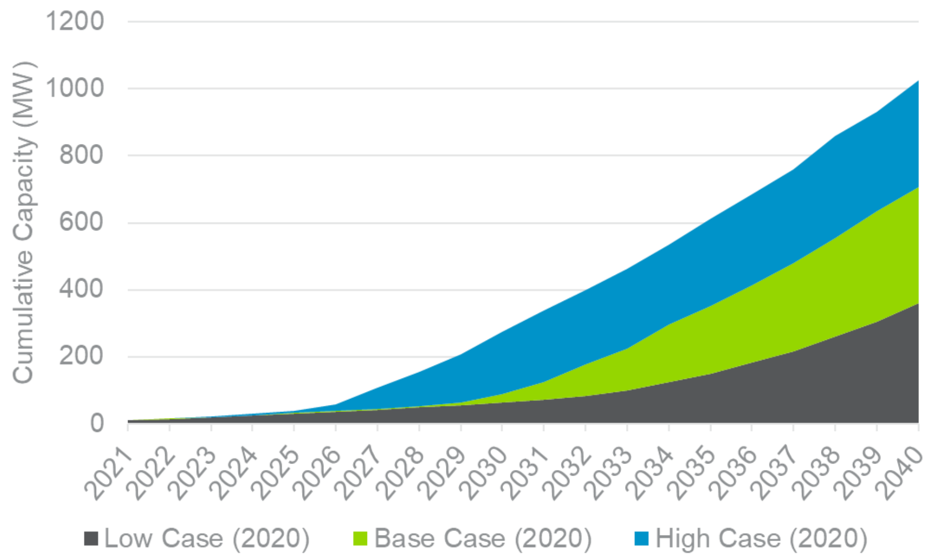


Figure 21. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case

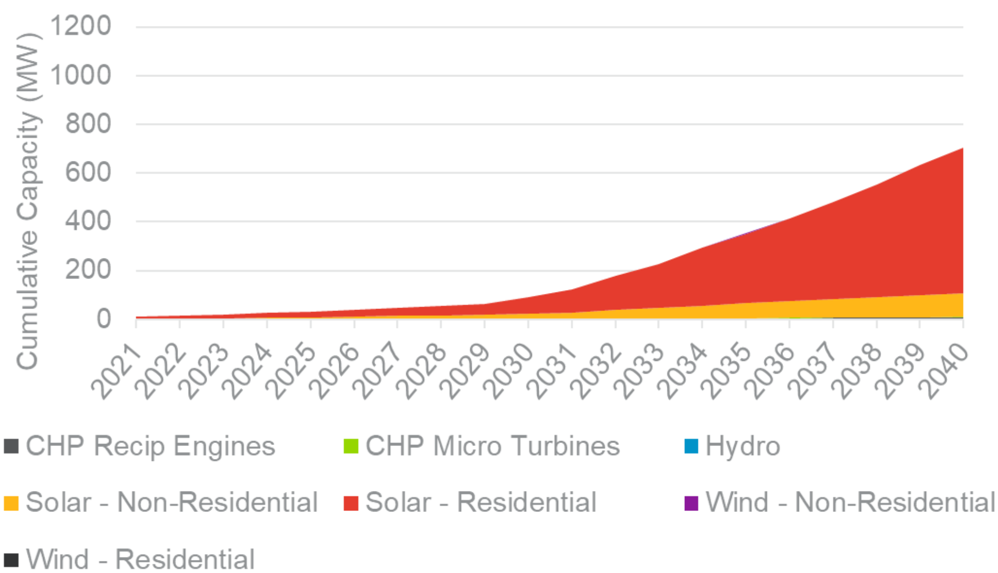


Figure 22. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

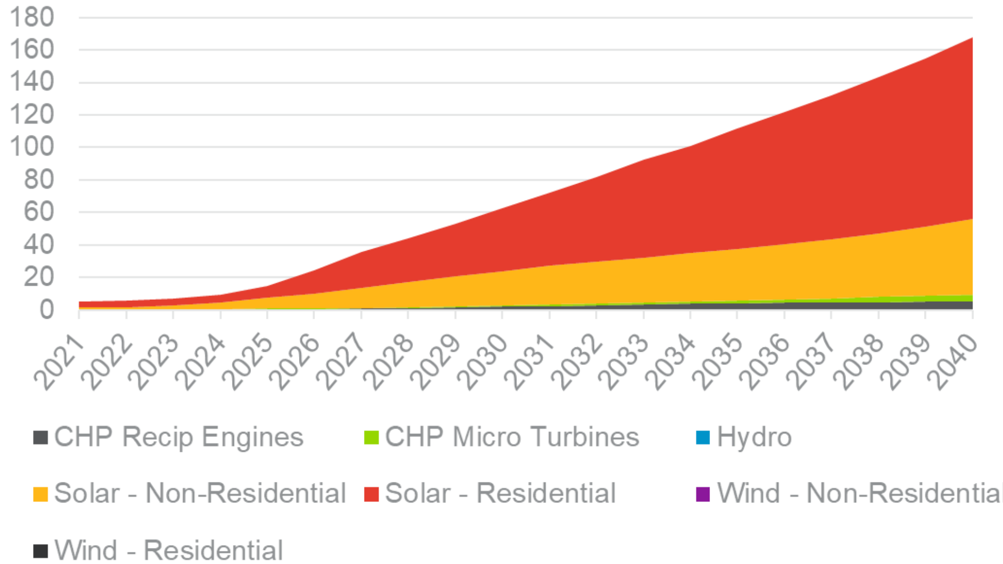
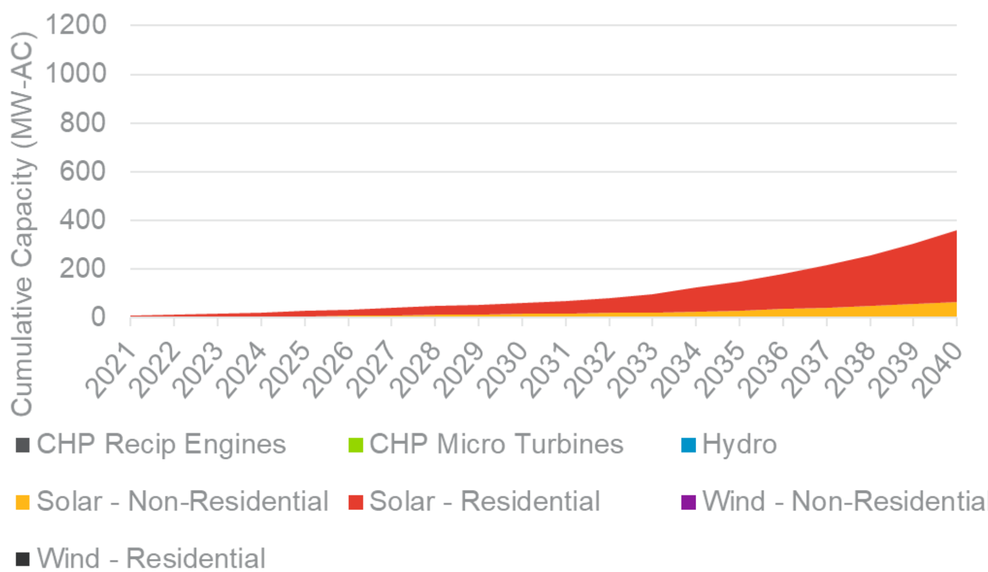


Figure 23 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



1.8.4 Utah

PacifiCorp's Utah customers are projected to install about 885 MW of PG capacity over the next two decades in the base case, averaging 42 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. 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. Compared to the 2018 study, commercial offset rates in Utah increased nearly 40%, driving additional PG adoption in the commercial sector.

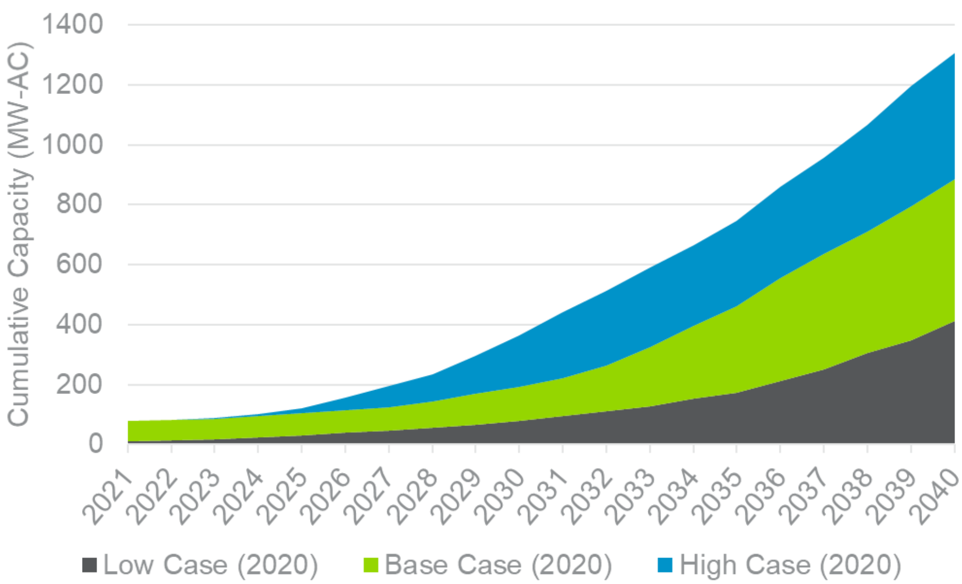
Additionally, a 12% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

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 continues to incorporate the regulatory modifications Schedule 136[25] brought to the PG program in Utah, as first introduced in the 2018 study. The value of generated energy takes into consideration the recently approved compensation for exported energy included in the tariff. Additionally, the forecast installations for year 2021 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 24. The 885 MW from the base case decreases by 53% to 413 MW in the low case and increases by 48% to 1,308 MW in the high case.

Figure 24. Cumulative Capacity Installations by Scenario (MW AC), Utah



[25] Utah Docket 14-035-114

Figure 25. Cumulative Capacity Installations by Technology (MW AC), Utah Base Case

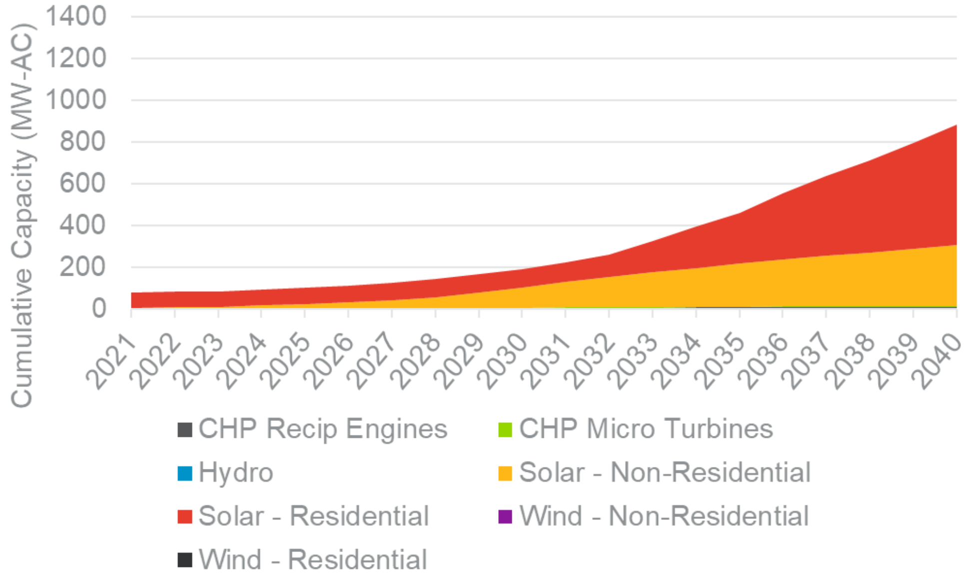


Figure 26. Cumulative Capacity Installations by Technology (MW AC), Utah High Case

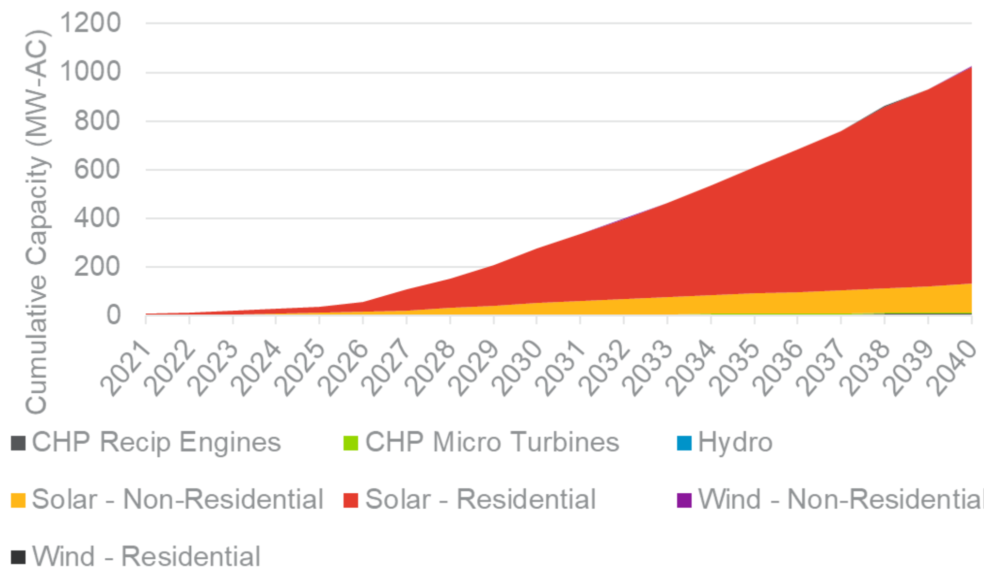
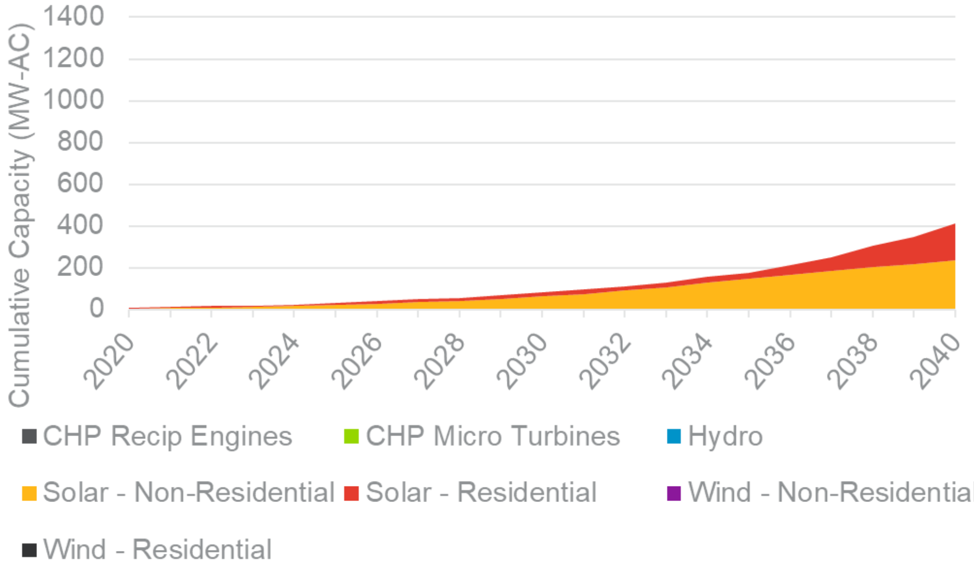


Figure 27. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



1.8.5 Washington

PacifiCorp's Washington customers are expected to install about 80 MW of PG capacity over the next two decades in the base case, averaging 4 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). A 5.5% increase in customer count contributed a positive impact on the cumulative installations over the forecast horizon.

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 28. The 80 MW from the base case decreases by 53% to 38 MW in the low case and increases by 72% to 139 MW in the high case.

Figure 28. Cumulative Capacity Installations by Scenario (MW AC), Washington

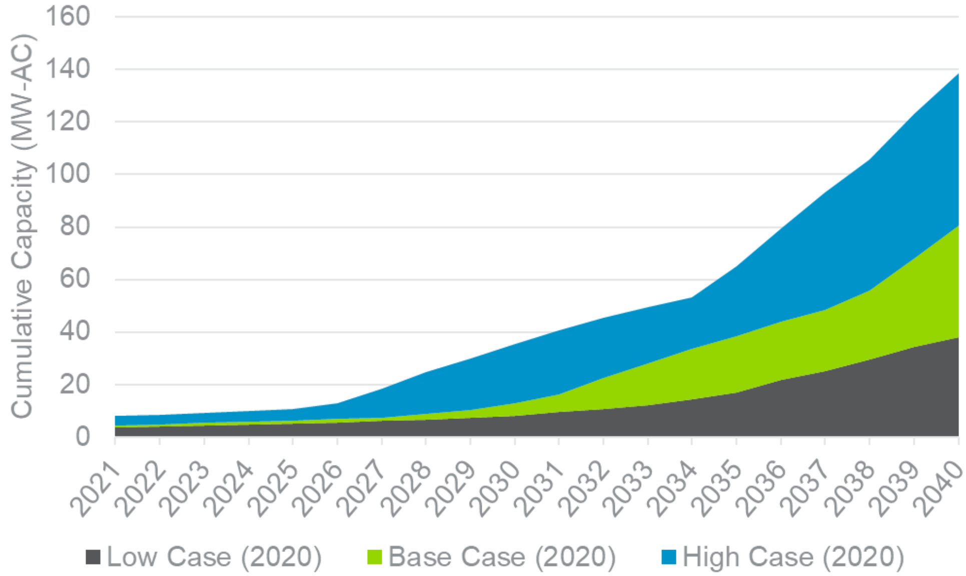


Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case

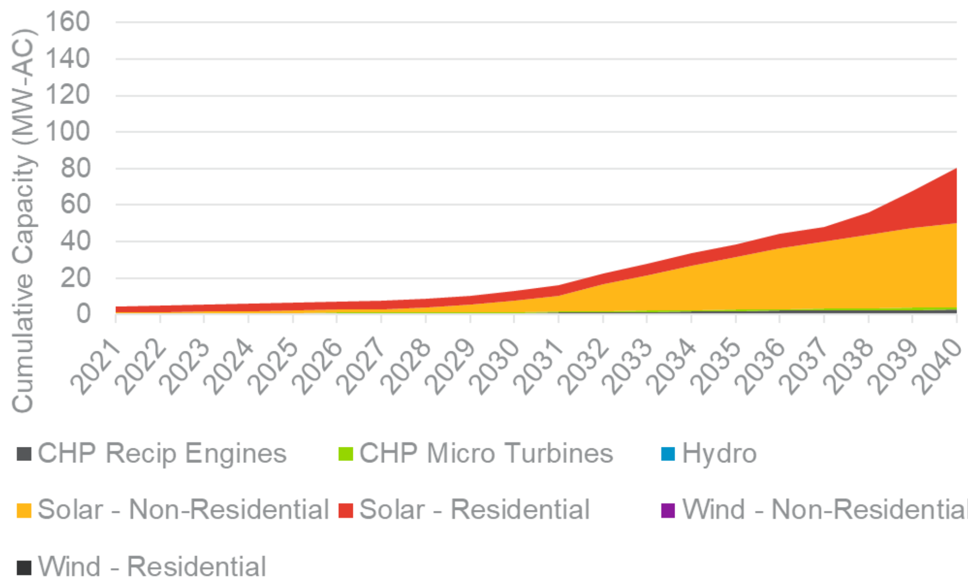


Figure 30. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

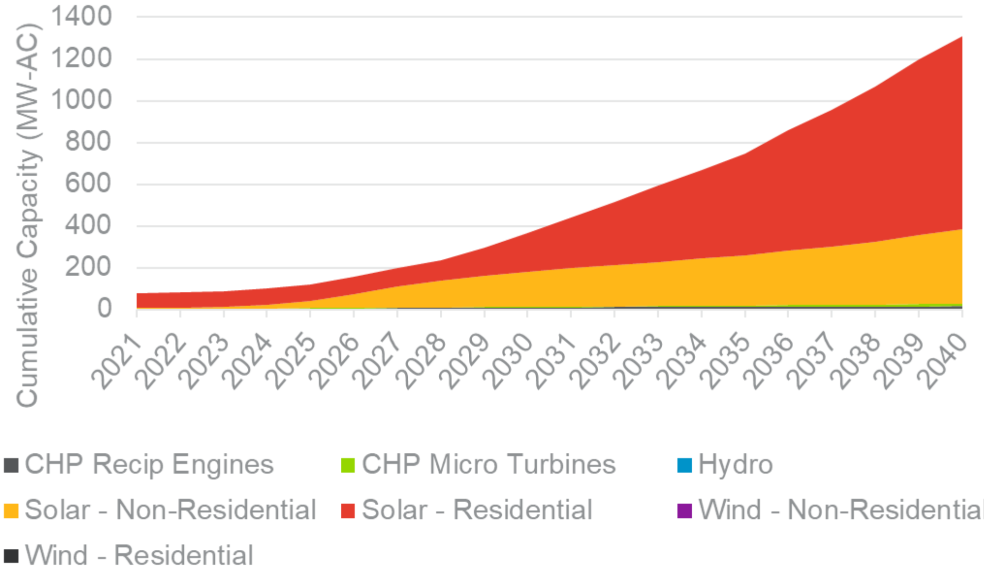
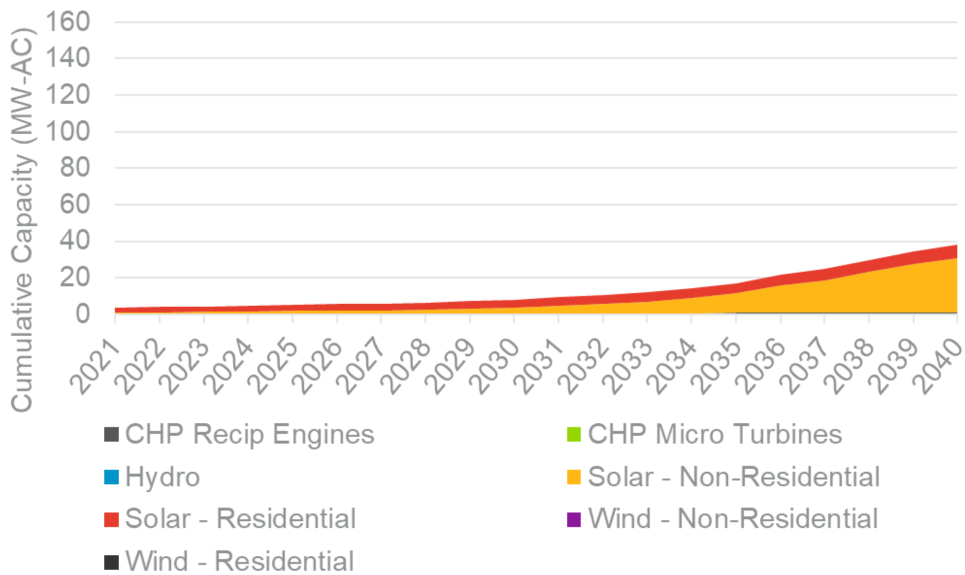


Figure 31. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



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 5.4 MW annually. Solar is responsible for most PG 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 32. The 114 MW from the base case decreases by 43% to 65 MW in the low case and increases by 50% to 171 MW in the high case.

Figure 32. Cumulative Capacity Installations by Scenario, Wyoming

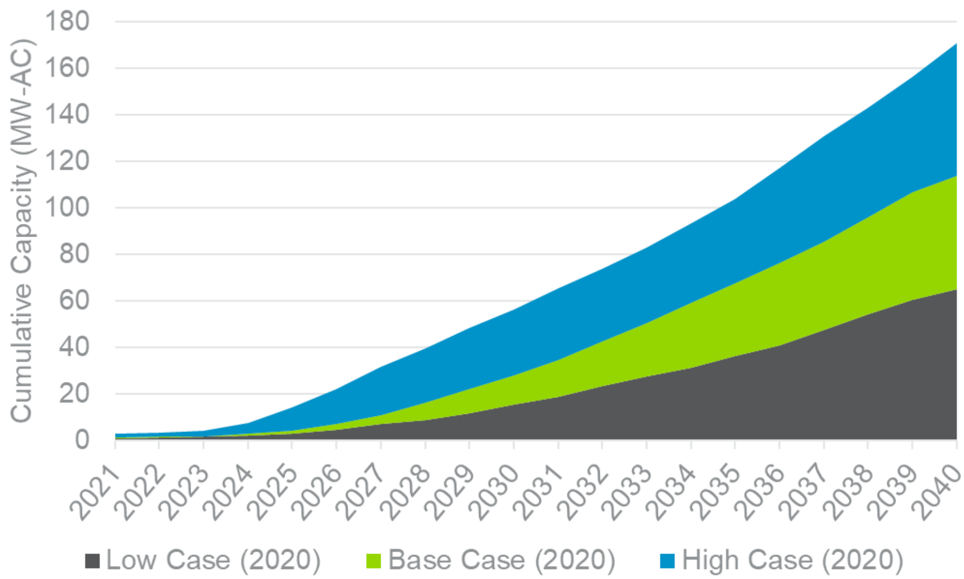


Figure 33. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

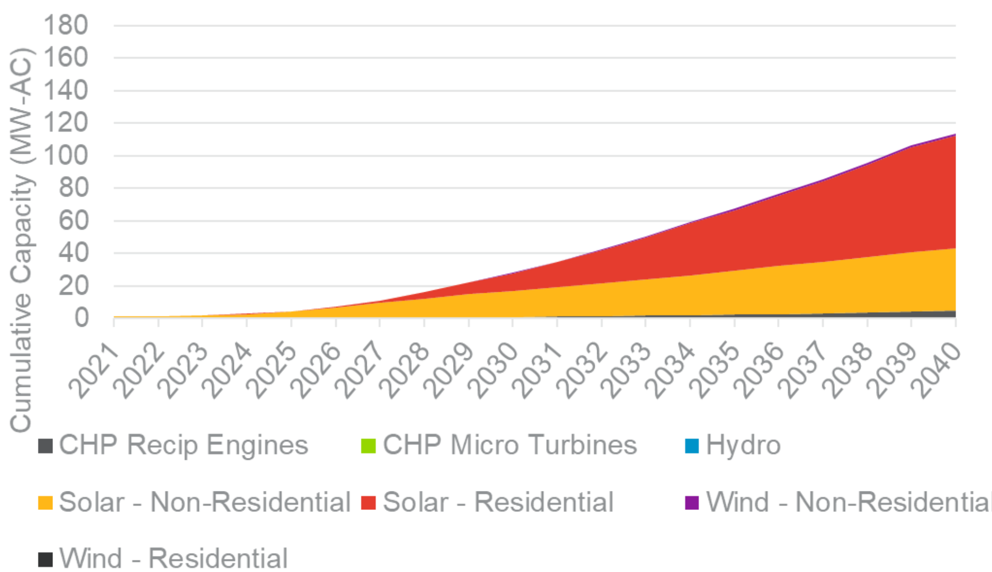


Figure 34. Cumulative Capacity Installations by Technology, Wyoming High Case

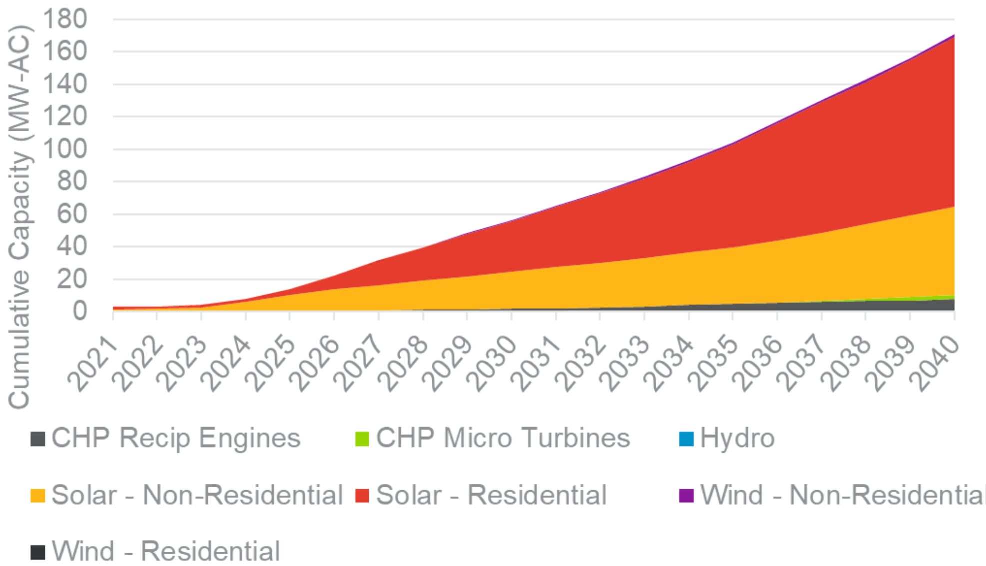
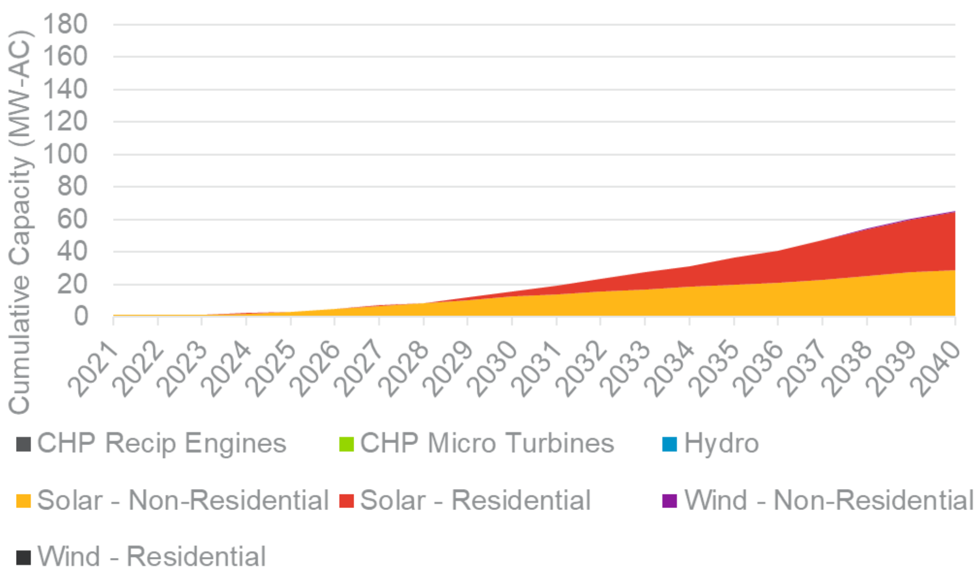


Figure 35. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



APPENDIX A. CUSTOMER DATA

Table 14 California

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	36,081	381,625	0.088
Commercial	7,360	244,248	0.149
Industrial	111	58,758	0.136
Irrigation	1,830	87,802	0.136

Table 15 Idaho

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	67,442	735,925	0.131
Commercial	9,277	513,544	0.085
Industrial	592	11,828,179	0.068
Irrigation	5,084	640,198	0.068

Table 16 Oregon

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	519,457	5,676,002	0.104
Commercial	69,373	5,858,774	0.089
Industrial	1,525	1,693,832	0.076
Irrigation	7,637	333,940	0.076

Table 17 Utah

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	852,304	7,267,347	0.103
Commercial	90,773	9,335,173	0.081
Industrial	4,768	8,045,765	0.059
Irrigation	3,438	231,548	0.059

Table 18 Washington

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	110,627	1,591,155	0.101
Commercial	16,446	1,596,374	0.079
Industrial	477	805,295	0.069
Irrigation	5,020	159,179	0.069

Table 19 Wyoming

Rate Class	# Customers	2020 MWh Sales	Avg. Rates ($/kWh)
Residential	116,338	959,613	0.116
Commercial	23,057	1,401,596	0.085
Industrial	1,991	6,940,902	0.062
Irrigation	792	24,978	0.062

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

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

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

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

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	2021	2030	2040	Notes
Installed System Cost	$/W	$2.69/W	$2.79/W	$2.91/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

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[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

Table 28 Micro-turbines LCOE – Key Assumptions[28]

DG Resource Costs	Units	2019 2021	2028 2030	2038 2040	Notes
Installed System Cost	$/W	$2.55/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 ~$93/MWh to ~$119/MWh over the forecast period, varying by year and technology.

Table 29 LCOE Results – Electric Component Only

Technology	Units	2021	2030	2040
Reciprocating Engines	$/MWh	93.4	106.3	118.7
Microturbines	$/MWh	93.8	104.4	114.6

[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

APPENDIX D. DETAILED NUMERIC RESULTS

D.1 Utah

Table 30. Utah – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.5	0.6	0.5	0.6	0.6	0.7	0.7	0.6	0.5	0.6	0.5	0.5	1.0	0.4	0.7	0.9	0.3	0.6	0.5	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	0.2	0.0	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.2	0.1	0.1	0.4	0.2	0.3	0.4	0.2	0.2	0.3	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	32.2	1.7	1.7	2.0	1.7	2.0	2.2	2.4	2.0	1.8	1.8	18.7	39.8	48.8	44.2	71.3	66.3	59.0	65.6	73.1
PV	Commercial	3.2	1.2	1.2	4.9	5.4	5.8	7.9	14.2	22.8	20.5	25.3	19.5	17.9	17.6	16.4	16.0	14.4	12.2	15.0	13.6
PV	Industrial	0.3	0.1	0.1	0.5	0.8	0.8	0.8	0.8	0.9	0.8	1.3	1.8	3.2	4.1	3.2	2.5	2.7	2.1	2.3	1.8
PV	Irrigation	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	0.2	0.2	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 31. Utah – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	3781	4150	3761	4127	4115	5267	5466	4207	3372	4339	3932	3703	7133	3204	4938	6867	2409	4248	4040	1344
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	1441	349	980	1023	1125	1547	1368	804	792	1199	1087	1024	2784	1328	2104	2610	1192	1640	2566	444
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	67855	3514	3501	4123	3566	4249	4570	5115	4247	3833	3876	39333	83838	102798	93138	150280	139691	124172	138081	153905
PV	Commercial	6687	2598	2588	10226	11306	12118	16587	30004	48111	43142	53214	41140	37728	37106	34613	33767	30332	25665	31694	28595
PV	Industrial	615	181	181	1101	1675	1619	1724	1642	1842	1636	2660	3750	6807	8636	6800	5256	5734	4339	4746	3873
PV	Irrigation	23	23	23	43	121	130	123	146	174	286	289	310	315	291	306	331	333	353	369	324
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 32. Utah – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.4	0.4	0.2	0.1	0.0	0.3	0.2	0.1	0.2	0.2	0.1	0.2	0.2	0.1	0.2	0.3	0.1	0.1	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	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	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	1.3	1.4	1.4	1.6	1.4	1.6	1.8	2.0	1.6	1.5	1.5	1.7	1.5	1.9	2.0	19.0	20.9	35.0	28.2	45.6
PV	Commercial	3.2	1.2	1.2	3.3	6.0	5.6	5.1	5.4	8.3	11.3	11.3	14.9	15.2	22.4	16.5	17.0	16.2	16.2	11.2	15.9
PV	Industrial	0.1	0.1	0.1	0.3	0.8	0.7	0.7	0.6	0.6	0.6	0.5	0.7	0.5	0.6	0.9	1.6	2.0	3.0	3.1	2.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	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	0.0
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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	3248	2843	1697	530	220	2201	1333	723	1406	1349	1069	1247	1710	912	1161	2001	407	487	1260	491
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	1143	38	36	54	80	359	126	84	53	39	39	56	39	66	68	85	66	74	75	78
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	2824	2873	2862	3370	2915	3474	3736	4181	3472	3134	3168	3662	3259	4036	4160	39949	44112	73716	59475	96128
PV	Commercial	6665	2526	2517	6868	12589	11895	10757	11460	17383	23782	23754	31474	31985	47088	34668	35859	34158	34159	23559	33550
PV	Industrial	210	160	159	637	1616	1557	1458	1355	1331	1334	1070	1405	1157	1299	1948	3325	4292	6263	6484	4787
PV	Irrigation	22	23	23	27	107	128	121	114	94	91	69	194	196	215	226	244	246	261	212	284
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 34. Utah – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.5	0.6	0.6	0.7	0.8	0.8	1.0	0.9	0.8	0.9	0.8	0.8	0.7	0.7	0.8	0.6	0.5	0.5	0.6	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	0.2	0.1	0.2	0.2	0.3	0.3	0.4	0.3	0.3	0.3	0.3	0.3	0.9	0.6	1.3	1.7	1.0	0.9	1.2	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	32.2	2.2	2.2	2.6	2.2	2.6	2.8	11.8	39.6	46.8	60.7	56.3	62.6	56.9	63.4	91.9	79.8	89.0	97.8	79.2
PV	Commercial	1.3	1.3	2.2	7.9	15.6	30.9	33.7	23.3	17.0	15.2	13.0	12.8	11.6	13.1	11.8	16.9	15.0	17.7	27.7	26.4
PV	Industrial	0.5	0.1	0.3	1.1	1.0	1.0	1.5	2.4	3.7	3.0	3.3	2.5	1.7	2.0	1.6	2.0	1.8	2.1	2.0	3.1
PV	Irrigation	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.3	0.6	0.6	0.8	0.6
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 35. Utah – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	3865	4664	4117	5163	6141	6035	7114	6519	5959	6458	6040	5820	5055	5014	5610	4536	3855	3744	4551	2447
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	1657	628	1579	1809	1915	2491	2691	2329	2426	2592	2502	2485	6542	4426	9622	12824	7164	7057	9102	1882
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	67855	4600	4582	5396	4668	5561	5981	24880	83475	98667	127926	118638	131777	119847	133595	193610	168113	187490	206101	166741
PV	Commercial	2736	2784	4544	16582	32930	65103	70999	49148	35809	31996	27364	26955	24525	27593	24906	35582	31687	37387	58408	55545
PV	Industrial	967	211	627	2259	2175	2160	3224	4985	7820	6362	6893	5174	3646	4259	3411	4206	3755	4507	4286	6625
PV	Irrigation	24	25	25	159	180	331	454	314	314	271	315	289	289	321	459	694	1260	1316	1704	1313
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

D.2 Oregon

Table 36. Oregon – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	0.0	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.2	0.2	0.4	0.4	0.7	1.0	0.8	0.5	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	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.4	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	3.7	3.7	3.8	3.8	3.9	3.8	4.5	5.5	6.4	24.1	29.0	44.3	38.1	60.4	46.6	52.7	57.7	65.6	73.5	64.8
PV	Commercial	1.3	0.3	0.3	1.9	2.0	1.8	2.1	2.0	2.2	1.7	4.7	8.5	8.5	8.3	7.7	5.8	6.0	4.5	4.3	4.1
PV	Industrial	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.6	0.8	0.8	0.8	0.7	0.5
PV	Irrigation	0.1	0.0	0.1	0.1	0.1	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.5	1.0	1.3	1.3	1.2	1.1	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	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	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 37. Oregon – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	480	203	649	733	1388	1414	1734	1783	1861	1954	1997	1835	1732	2867	3233	5016	7467	5739	3918	5101
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	503	1704	1531	1388	1365	1252	1063	2930	2446	2489
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	5956	5981	6072	6119	6199	6113	7143	8775	10307	38613	46499	71061	61170	96910	74791	84455	92527	105180	154919	136517
PV	Commercial	2023	484	490	3101	3148	2824	3394	3153	3560	2790	7468	13620	13597	13363	12355	9222	9695	7294	8952	8691
PV	Industrial	89	27	57	135	123	212	309	328	293	307	263	283	280	501	981	1311	1286	1232	1461	1048
PV	Irrigation	143	43	92	217	197	341	496	527	471	493	423	454	449	805	1575	2106	2067	1979	2347	1684
Wind	Residential	2	37	1	0	0	-3	1	1	0	1	1	1	23	27	22	28	22	41	24	25
Wind	Commercial	0	0	0	0	0	-1	0	0	0	0	0	180	191	242	216	227	187	235	171	143
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	9	9

Table 38. Oregon – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	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	0.0	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	3.7	3.7	3.8	3.8	3.9	3.8	4.1	4.7	5.0	5.1	5.2	9.3	14.8	22.8	22.3	26.0	29.4	33.6	37.8	49.0
PV	Commercial	1.2	0.3	0.2	1.3	1.9	1.7	2.1	1.4	1.6	1.7	1.3	1.4	1.7	2.2	3.8	5.1	5.0	7.5	7.5	5.3

PV	Industrial	0.1	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.4
PV	Irrigation	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.6
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	0.1	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 39. Oregon – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	263	7	214	474	555	583	717	758	801	781	799	825	792	1300	1325	1635	1334	1373	1380	1382
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	5925	5947	6042	6095	6180	6113	6501	7604	7988	8210	8418	14862	23770	36615	35738	41771	47201	53931	79676	103168
PV	Commercial	1898	430	392	2145	3044	2779	3296	2170	2546	2657	2104	2290	2702	3547	6047	8159	8063	11993	15756	11174
PV	Industrial	84	25	29	131	119	102	177	239	202	211	251	225	179	237	247	218	211	276	310	774
PV	Irrigation	136	40	46	210	191	163	284	384	324	339	403	362	288	381	397	351	339	443	498	1244

Wind	Residential	1	2	1	0	0	-1	0	0	0	0	0	1	0	0	0	3	26	22	16	16
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	91	156
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 40. Oregon – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	0.0	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.5	0.7	1.0	1.0	0.7	0.7	0.6	0.5	0.5	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
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	0.2	0.2	0.2	0.2	0.2	0.4	0.4	0.4	0.3	0.4	0.4	1.3	1.2	1.1
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	3.9	3.8	3.8	3.8	4.3	17.1	44.2	36.9	44.4	55.8	53.8	51.5	56.4	64.2	71.9	64.7	67.8	94.1	60.9	85.6
PV	Commercial	1.4	0.3	1.4	3.0	2.9	2.3	5.8	8.8	7.9	9.2	6.5	4.9	5.0	4.6	3.7	4.1	4.2	5.3	6.7	6.3
PV	Industrial	0.1	0.0	0.1	0.2	0.3	0.2	0.3	0.2	0.2	0.4	0.7	0.9	0.7	0.6	0.6	0.5	0.4	0.4	0.4	0.4
PV	Irrigation	0.1	0.0	0.1	0.3	0.4	0.4	0.4	0.3	0.3	0.7	1.2	1.5	1.1	1.0	0.9	0.8	0.6	0.7	0.6	0.7
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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	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 41. Oregon – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	885	156	1239	1441	1713	1706	2076	2126	2172	4073	5486	7251	7113	5515	5083	4681	3869	3484	3068	2208
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	1266	1453	1380	1413	1383	2619	3053	2728	2555	2651	3275	9370	9300	8504
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	6248	6031	6118	6154	6834	27400	70853	59229	71179	89439	86306	82512	90454	102880	115322	103709	108653	150872	128240	180351
PV	Commercial	2173	549	2200	4848	4576	3760	9351	14155	12737	14705	10467	7796	8061	7355	5958	6557	6763	8543	14175	13246
PV	Industrial	104	30	120	326	445	392	412	321	278	661	1158	1453	1108	1027	906	811	565	671	771	863
PV	Irrigation	166	47	193	523	715	630	662	516	447	1063	1860	2335	1781	1650	1456	1303	907	1078	1239	1387
Wind	Residential	9	41	2	1	0	-3	1	1	0	3	31	27	36	40	41	42	33	43	25	26
Wind	Commercial	1	1	1	0	0	-1	0	0	202	205	228	250	260	274	244	253	206	254	183	184
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	4	16	14	15	15	11	10

D.3 Washington

Table 42. Washington – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	0.0	0.1	0.1	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.3	0.2	0.2	0.2	0.2	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	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	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	1.4	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.2	0.3	0.3	0.4	0.3	0.4	0.4	0.4	0.4	3.9	8.4	9.9
PV	Commercial	0.1	0.1	0.1	0.2	0.1	0.2	0.2	1.0	1.0	1.8	2.5	5.7	4.6	4.4	3.2	3.7	2.5	2.4	2.7	1.8
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	0.4	0.5	0.6	0.6	0.5	0.5	0.3
PV	Irrigation	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	0.3	0.4	0.5	0.5	0.5	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	0.0
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 43. Washington – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	1109	216	775	670	516	445	371	350	516	757	748	1134	2090	1457	1426	1441	1284	1261	1178	626
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	459	-4	209	306	263	360	285	251	267	232	265	204	873	682	578	828	471	608	616	281
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	2551	396	349	458	341	461	468	582	451	520	530	651	504	669	675	805	639	7117	17701	20867
PV	Commercial	251	267	235	309	230	311	316	1722	1779	3220	4457	10392	8255	7968	5773	6730	4521	4327	5633	3814
PV	Industrial	23	24	21	28	21	28	29	36	222	239	213	229	223	659	915	1070	1009	943	971	691
PV	Irrigation	20	21	19	24	18	25	25	31	193	208	185	199	193	572	795	929	876	819	843	600
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	1	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 44. Washington – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040

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	0.1	0.1	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	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	0.1	0.0	0.0	0.1	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	1.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3
PV	Commercial	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.5	0.7	0.9	0.8	0.7	2.0	2.1	3.9	2.8	4.1	4.0	2.8
PV	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	0.1	0.1	0.2	0.3
PV	Irrigation	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	0.1	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 45. Washington – Incremental Annual Adoption (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	906	-15	155	398	201	351	205	191	144	141	241	258	335	148	367	285	251	275	279	53
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	406	261	303	420	9
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	2174	302	267	350	261	352	358	445	344	397	405	497	385	511	516	615	489	571	676	675
PV	Commercial	242	258	227	299	222	300	305	379	874	1237	1575	1403	1324	3658	3864	7136	5063	7370	8389	5876
PV	Industrial	22	23	21	27	20	27	28	35	27	31	163	183	178	158	201	180	171	185	437	561
PV	Irrigation	19	20	18	24	18	24	24	30	23	27	141	159	154	137	174	156	148	160	379	487
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 46. Washington – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.2	0.0	0.1	0.1	0.2	0.2	0.2	0.3	0.2	0.3	0.2	0.2	0.1	0.1	0.2	0.1	0.1	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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.4	0.4	0.3	0.3	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	3.2	0.3	0.3	0.4	0.3	0.4	0.4	0.5	0.4	0.4	0.4	0.5	0.4	0.6	8.6	11.3	10.0	8.7	12.5	10.9
PV	Commercial	0.1	0.2	0.1	0.2	0.4	1.4	4.3	5.4	4.2	3.9	3.4	3.1	2.5	2.0	2.0	2.3	2.4	3.1	4.0	3.7
PV	Industrial	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	0.4	0.5	0.6	0.5	0.4	0.4	0.3	0.3	0.2	0.3	0.3
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.1	0.2	0.1	0.2	0.3	0.5	0.6	0.4	0.4	0.3	0.2	0.3	0.2	0.2	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	0.0
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 47. Washington – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	1556	65	845	818	1324	1315	1529	2215	1423	1988	1253	1734	978	983	1236	855	665	688	664	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	569	122	466	430	390	611	805	711	676	680	676	594	663	1093	2205	2926	2766	2558	2209	1034

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	5703	579	511	671	500	675	686	853	660	761	777	953	738	1154	15564	20409	18063	15823	26389	22939
PV	Commercial	261	278	245	322	685	2544	7702	9685	7537	7033	6207	5546	4445	3642	3609	4147	4330	5610	8368	7769
PV	Industrial	24	26	23	30	22	215	324	212	391	717	943	1158	844	777	671	515	522	449	559	642
PV	Irrigation	21	22	20	26	19	187	281	184	340	622	819	1006	733	675	583	447	453	390	486	557
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3
Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	36	65	66	51	43
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

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Table 48. Idaho – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.3	0.2	0.4	0.5	0.3	0.3	0.3	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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	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	2.1	0.3	0.2	0.2	0.3	0.3	2.5	4.3	4.9	5.5	4.7	5.3	5.7	6.3	6.9	5.5	7.9	6.2	6.6	9.6
PV	Commercial	0.2	0.0	0.2	0.3	0.3	0.8	1.1	1.3	1.2	1.1	0.9	0.7	0.6	0.7	0.6	0.5	0.6	0.8	0.7	0.9
PV	Industrial	0.1	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.7	0.7	0.7	0.6	0.4	0.5	0.3	0.3	0.3
PV	Irrigation	0.2	0.0	0.0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.9	1.7	1.7	1.6	1.5	1.1	1.2	0.8	0.8	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	0.0
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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	597	121	603	760	871	972	952	1096	970	1074	910	1018	1959	1514	3027	3599	2485	2437	2327	2178
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	49	405	479	432	523	533	566	642	602	569	729	1454	1133	1156	1167	823
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	4289	586	446	507	580	659	5206	8859	10087	11334	9763	10872	11699	13096	14310	11364	16377	12867	13902	20219
PV	Commercial	476	97	323	636	572	1655	2286	2650	2531	2329	1954	1406	1218	1409	1146	1012	1317	1641	1560	1826
PV	Industrial	203	29	27	352	329	345	312	373	324	332	722	1399	1398	1366	1251	910	972	708	670	645
PV	Irrigation	501	72	68	869	810	850	770	919	798	820	1779	3449	3447	3369	3085	2245	2397	1746	1653	1590
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1
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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	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	0.1	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	1.1	0.2	0.2	0.2	0.2	0.3	0.3	2.3	3.6	3.3	3.8	2.9	3.1	3.4	5.1	4.1	4.2	2.8	4.8	5.2

PV	Commercial	0.2	0.0	0.1	0.3	0.3	0.3	0.7	0.7	0.7	1.0	1.0	0.7	0.9	0.6	0.6	0.8	0.5	0.5	0.5	0.5
PV	Industrial	0.1	0.0	0.0	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.4	0.4	0.6	0.6	0.4
PV	Irrigation	0.2	0.0	0.0	0.3	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.7	1.0	1.0	1.4	1.4	1.0
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	0.0
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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	373	14	288	324	381	413	400	583	473	717	594	590	856	566	704	707	504	670	663	130
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	2215	483	368	418	478	544	669	4718	7358	6812	7801	6059	6334	6981	10630	8426	8772	5729	10190	10859
PV	Commercial	393	92	220	620	557	661	1397	1467	1454	2105	2021	1433	1859	1322	1267	1610	1089	1074	1062	1034
PV	Industrial	159	26	20	254	318	334	302	270	217	271	210	223	271	357	612	821	816	1207	1225	855
PV	Irrigation	391	64	49	627	783	824	746	665	536	668	519	549	669	881	1509	2023	2011	2975	3021	2108

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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.1	0.0	0.1	0.1	0.1	0.1	0.2	0.3	0.3	0.5	0.4	0.5	0.5	0.4	0.3	0.4	0.2	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	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.4	0.8	0.6	0.5
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	2.0	0.3	0.3	0.3	2.3	6.9	8.2	5.1	5.5	6.0	6.5	7.2	7.6	6.0	8.8	6.9	7.0	7.4	7.7	8.0
PV	Commercial	0.2	0.1	0.3	0.9	1.9	1.8	1.2	0.9	0.7	0.6	0.5	0.6	0.6	0.9	0.8	1.4	1.2	1.5	1.7	2.1
PV	Industrial	0.1	0.0	0.1	0.2	0.2	0.2	0.5	0.7	0.6	0.6	0.6	0.4	0.4	0.4	0.3	0.3	0.3	0.4	0.4	0.6
PV	Irrigation	0.3	0.0	0.3	0.5	0.6	0.5	1.2	1.8	1.6	1.5	1.6	0.9	1.0	0.9	0.7	0.7	0.8	1.0	0.9	1.5
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 53. Idaho – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	653	231	790	869	1063	1107	1500	2013	2510	3447	2765	3633	3438	3244	2268	2689	1736	1587	1826	868
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	290	27	332	392	464	585	614	650	997	1374	1467	1404	1413	1301	1139	2424	3005	5680	4440	3991
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	4028	721	550	624	4847	14231	16830	10542	11250	12341	13421	14783	15603	12392	18081	14292	14401	15335	16307	16814
PV	Commercial	500	103	586	1933	3991	3771	2417	1778	1478	1154	1038	1181	1335	1758	1639	2800	2480	3014	3666	4333
PV	Industrial	217	33	242	451	475	456	985	1483	1333	1274	1322	769	811	733	580	626	666	829	789	1286
PV	Irrigation	536	82	596	1113	1172	1125	2428	3656	3285	3142	3259	1896	2000	1808	1430	1543	1642	2045	1945	3171
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1
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.5 California

Table 54. California – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.0	0.1	0.1	0.0	0.1	0.0	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	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	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	0.0	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	1.0	1.4	1.8	2.2
PV	Commercial	0.3	0.1	0.3	0.3	0.4	0.3	0.4	0.5	0.5	0.6	0.7	0.8	0.9	0.6	1.2	0.8	1.5	1.0	1.1	2.1
PV	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.3	0.3	0.2	0.4	0.2
PV	Irrigation	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.1	0.2	0.2	0.2	0.2	0.3	0.2	0.4	0.4	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	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 55. California – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	196	19	226	268	299	339	369	269	383	397	401	203	373	394	127	397	81	383	396	60
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	160	63	196	232	320	305	331	360	362	375	378	393	373	394	395	129	378	407	420	63
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	48	4	4	11	55	51	51	110	186	192	167	206	173	152	188	384	2149	2977	3774	4653
PV	Commercial	600	131	557	721	773	734	823	984	1071	1278	1419	1742	1942	1318	2573	1737	3212	2104	2230	4349
PV	Industrial	131	38	146	127	137	157	142	221	188	224	247	308	343	427	278	566	631	419	805	509
PV	Irrigation	196	56	219	190	204	235	211	330	281	335	369	460	513	638	415	845	943	626	1202	760
Wind	Residential	0	2	0	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1
Wind	Commercial	7	8	11	13	13	15	15	17	15	15	14	16	12	17	22	23	30	38	21	11
Wind	Industrial	0	1	1	1	1	1	2	2	2	2	2	2	1	2	3	3	3	2	2	1
Wind	Irrigation	1	3	3	4	4	5	5	5	5	5	5	4	5	4	4	4	4	3	4	4

Table 56. California – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040

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	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1
PV	Commercial	0.3	0.1	0.3	0.3	0.3	0.3	0.3	0.4	0.2	0.4	0.3	0.3	0.3	0.7	0.4	0.5	0.5	0.6	0.6	0.7
PV	Industrial	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.1	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.2	0.1
PV	Irrigation	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	0.2	0.1	0.1	0.2	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	0.0
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 57. California – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	127	67	150	202	223	250	200	276	274	281	159	275	113	255	255	90	242	60	254	264
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	120	61	145	192	189	210	223	238	234	239	237	244	227	240	239	256	242	60	254	264
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	45	4	4	4	34	49	44	39	31	56	129	136	104	142	146	122	152	127	129	131
PV	Commercial	575	129	569	664	545	610	667	791	529	933	587	691	671	1409	935	1087	1084	1246	1329	1433
PV	Industrial	129	29	132	144	109	138	121	138	94	153	98	190	119	145	269	198	195	226	426	280
PV	Irrigation	193	44	197	215	163	206	181	207	141	228	147	283	178	217	401	296	291	338	636	419
Wind	Residential	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	1	1	1
Wind	Commercial	3	7	9	10	10	13	12	13	13	12	12	12	10	10	9	10	8	8	3	4
Wind	Industrial	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Wind	Irrigation	1	2	2	2	3	3	4	4	4	5	4	4	3	4	3	3	3	3	1	1

Table 58. California – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.0	0.1	0.1	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.1	0.0	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	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	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	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.8	1.2	1.6	1.9	2.4	2.7	2.9	3.1	2.7
PV	Commercial	0.3	0.1	0.4	0.6	0.6	0.7	1.2	0.5	0.9	1.1	1.2	0.8	1.5	1.0	1.9	1.2	1.2	1.4	1.5	1.6
PV	Industrial	0.1	0.0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.2	0.1	0.3	0.3	0.2	0.4	0.3	0.5	0.3	0.3	0.3
PV	Irrigation	0.1	0.0	0.1	0.2	0.1	0.2	0.3	0.2	0.3	0.3	0.2	0.4	0.4	0.3	0.6	0.4	0.7	0.4	0.5	0.5
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 59. California – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	206	100	263	313	351	400	299	450	454	472	478	238	446	471	472	151	451	101	471	485
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	186	96	237	351	333	378	413	450	454	472	478	498	472	499	500	531	106	512	527	541

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	56	5	4	69	107	290	274	201	169	174	177	1700	2540	3339	4151	5068	5872	6169	6581	5585
PV	Commercial	633	153	905	1187	1204	1553	2594	1148	1965	2308	2553	1689	3150	2068	4045	2665	2668	3000	3163	3371
PV	Industrial	136	38	170	227	199	323	451	344	379	448	272	560	621	412	807	537	994	644	680	726
PV	Irrigation	203	56	254	340	298	483	674	513	567	670	407	837	928	616	1207	802	1485	962	1016	1084
Wind	Residential	0	2	0	0	0	0	0	0	0	1	1	1	1	2	2	2	2	2	1	1
Wind	Commercial	8	10	12	14	15	17	18	17	18	16	32	26	47	41	40	40	37	36	18	16
Wind	Industrial	1	1	1	1	2	2	2	2	2	2	4	4	3	3	3	3	3	3	1	2
Wind	Irrigation	2	3	4	5	5	5	6	6	6	5	6	6	4	7	8	11	13	14	7	10

D.6 Wyoming

Table 60. Wyoming – Incremental Annual Market Penetration (MW AC) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.6	0.6	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

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	0.1	0.0	0.0	0.0	0.0	0.0	1.1	2.7	3.0	3.7	4.5	5.4	5.5	6.1	5.2	5.9	6.3	7.1	7.8	4.6
PV	Commercial	0.4	0.2	0.3	0.6	1.2	2.3	2.3	2.3	2.0	1.5	1.6	1.2	1.0	1.0	1.1	1.3	1.1	1.8	1.7	1.3
PV	Industrial	0.2	0.0	0.0	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.6	1.2	1.3	1.3	1.3	1.1	0.8	0.7	0.5
PV	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	0.1	0.1	0.1	0.1	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	0.0
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	0.1	0.1	0.1	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 61. Wyoming – Incremental Annual Market Penetration (MWh) – Base Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	239	2154	2107	2234	2276	2274	2119	2024	2043	2107	3050	4193	4258	4091
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	111	100	49	61	46	74	2282	5938	6430	8058	9750	11658	11910	13200	11352	12767	13611	15308	16380	9765
PV	Commercial	781	350	568	1329	2609	4953	5013	4935	4418	3238	3368	2525	2123	2239	2339	2792	2328	3824	3478	2794
PV	Industrial	325	83	41	583	712	671	682	717	713	650	634	1272	2499	2916	2865	2719	2332	1706	1506	1105
PV	Irrigation	15	4	2	26	32	30	31	33	32	30	29	58	114	132	130	124	106	77	68	50
Wind	Residential	1	7	0	0	0	0	0	0	0	0	4	3	4	5	5	5	5	5	3	2
Wind	Commercial	-2	1	0	0	0	0	0	0	0	222	234	257	268	284	293	305	248	309	133	157
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 62. Wyoming – Incremental Annual Market Penetration (MW AC) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.2	0.3	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	0.0	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	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	1.1	1.6	2.0	2.5	2.9	2.3	3.8	3.0	4.7	4.7	3.6	3.1
PV	Commercial	0.3	0.2	0.2	0.6	0.5	1.3	1.8	1.3	1.8	1.8	1.2	1.7	1.1	1.1	1.1	1.1	1.2	0.9	0.9	0.2

PV	Industrial	0.1	0.0	0.1	0.1	0.3	0.3	0.3	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.4	0.6	0.8	1.2	0.7
PV	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	0.1	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	0.0
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	0.1	0.1	0.1	0.1	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 63. Wyoming – Incremental Annual Market Penetration (MWh) – Low Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	1257	2149	2170
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	58	93	46	57	43	58	182	245	2296	3461	4373	5386	6299	5049	8266	6593	10274	10192	7667	6594
PV	Commercial	755	332	364	1294	1084	2871	3881	2885	3989	3979	2662	3619	2341	2389	2287	2319	2558	2051	1983	464
PV	Industrial	155	74	110	249	692	650	664	511	406	525	511	447	528	471	487	779	1272	1720	2425	1433
PV	Irrigation	7	3	5	11	31	30	30	23	18	24	23	20	24	21	22	35	58	78	110	65
Wind	Residential	0	4	0	0	0	0	0	0	0	0	0	0	0	2	3	3	3	2	2	1

Wind	Commercial	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	141	213	221	184	148
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 64. Wyoming – Incremental Annual Market Penetration (MW AC) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.5	0.6	0.7	0.6	0.6	0.6	0.5	0.5	1.0
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	0.2	0.7	0.6	0.5	0.5
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	0.8	0.1	0.0	0.1	2.2	4.4	7.0	5.2	6.3	4.5	6.4	5.7	6.0	6.8	7.5	8.4	8.8	7.1	7.5	8.8
PV	Commercial	0.7	0.2	0.8	2.9	3.5	2.7	1.9	1.4	1.0	1.2	1.0	1.0	1.4	1.9	1.8	3.1	2.7	3.3	3.9	3.6
PV	Industrial	0.2	0.0	0.2	0.5	0.5	0.4	0.4	0.7	1.2	1.5	1.2	1.1	0.9	0.8	0.6	0.7	0.6	0.7	0.8	0.5
PV	Irrigation	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	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	0.0
Wind	Commercial	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.2	0.1	0.1	0.1	0.1	0.1	0.1	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 65. Wyoming – Incremental Annual Market Penetration (MWh) – High Case

Technology	Sector	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
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	237	1784	1997	2071	2419	2524	2436	2383	4072	4680	5489	4456	4607	4454	3956	3949	7331
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	1816	5383	4325	3802	3545
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	1678	192	95	118	4683	9609	15199	11165	13664	9692	13912	12282	13006	14753	16223	18222	19133	15327	15832	18617
PV	Commercial	1422	387	1635	6285	7626	5907	4126	3053	2185	2634	2208	2135	2966	4073	3798	6636	5742	7061	8142	7678
PV	Industrial	346	97	443	987	1012	902	916	1531	2673	3329	2519	2332	1936	1731	1275	1525	1214	1450	1702	954
PV	Irrigation	16	4	20	45	46	41	42	70	121	151	114	106	88	79	58	69	55	66	77	43
Wind	Residential	2	9	0	0	0	0	0	0	1	6	6	6	4	6	5	6	5	5	3	2
Wind	Commercial	-3	2	0	0	-1	0	114	265	269	302	284	348	352	320	274	333	320	276	215	198
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	3	4

APPENDIX N – 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 2021 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 line 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. For example, 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.

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 marginal cost in any given interval.

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, evaluating decisions that span multiple time steps (such as when to charge or discharge a battery, or when to start or shutdown a thermal resource) requires the evaluation of multiple timesteps at once, resulting in a larger more complicated problem that can take longer to solve. In addition, maintaining inputs to represent smaller 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 modeling for the 2021 IRP uses the Plexos model and reflects system dispatch at an hourly granularity. While the IRP modeling uses the hourly market prices from the OFPC as inputs, a distributed resource's energy value will depend on its location and other 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

[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.

the resource included, and one with the resource excluded. This explicitly identifies the marginal resources dispatched in the absence of the resource being evaluated. The Plexos model offers an alternative in that it reports the value of energy produced by each resource, by multiplying that resource's output by the marginal price in that resource's location for each hour. A comparable calculation is performed for operating reserves. This provides an estimate of the marginal benefits from any resource in the portfolio, without the need for with and without studies. However, for large resources or significant portfolio changes, with and without studies may still be necessary, as the reported results reflect the marginal cost of the last increment of generation, rather than the average across all of the resource's output.

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.

Table N.1 contains nominal levelized energy margin values for various energy storage technologies in 2024-2040, and reflects marginal values reported by the Plexos model for specific resources in the preferred portfolio.

Table N.1 - Energy Margin by Energy Storage Technology

Technology	Hours of Storage	Efficiency (%)	Levelized Energy Margin (2024-2040) ($/kw-yr)
Lithium Ion	4	85%	$31.34
Lithium Ion (combined with solar)	4	85%	$21.89
Molten Salt (Nuclear)	5.5	99%	$53.45

These energy values will vary by location, volume, and operating reserve requirements, as well as with changes in the portfolio.

The Plexos model identifies resources to carry operating reserves for each hour, but does 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. Furthermore, 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. While intra-hour dispatch is a key aspect of reliable system operation, and potentially an additional source of revenue for flexible resources, it is difficult to represent the interactions between hourly dispatch in Plexos and sub-hourly dispatch in EIM – since they have finite storage capability, a battery that is discharged in response to high prices in EIM is likely to forego dispatch at relatively high prices in a later interval. In addition, imbalance in the EIM is finite in both duration and magnitude and the battery resources added in PacifiCorp's preferred portfolio could easily move the market thereby drastically reducing the frequency of price excursions and the associated intra-hour revenue. For these reasons, PacifiCorp has not quantified the costs or benefits of intra-hour dispatch for the 2021 IRP, but expects to continue evaluating them as its portfolio and the market itself continue to evolve.

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.

[2] NERC Glossary of Terms: http://www.nerc.com/files/glossary_of_terms.pdf, updated May 13, 2019.

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 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 reported in Volume II, Appendix F (Flexible Reserve Study), PacifiCorp assessed the cost of holding incremental operating reserves. That study identified a cost of approximately $29/kw-yr (2020$), based on a 2023-2040 study period. This value would be applicable to any resource that provided operating reserves uniformly throughout the year. Similar to reporting on energy values, the Plexos model also reports operating reserve revenues specific to each modeled resource, accounting for availability, location, and use for energy dispatch (during which a resource could not also provide reserves with any portion of its capacity that was generating energy). As with the annual wind and solar costs shown in Appendix F, operating reserve value is projected to be highest in the near term and decline across the study horizon as the amount of battery resources on the system increases.

Transmission and Distribution Capacity

The 2021 IRP included endogenous 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, because energy efficiency and load control are customer-sited, they are not subject to these constraints, placing them at an advantage relative to both thermal and renewable resource options. For some sizes and locations, distributed resources can also potentially avoid significant transmission upgrades and may help to defer distribution system investments. 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 2021 IRP, and amounts to $6.34/kw-year (2020$). 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 substation's 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 N.2 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 N.2 – Share of Distribution Load by State with Potential Upgrade Deferral

	Threshold	CA	OR	WA	ID	UT	WY	Total
High	Above 90% Utilization	5%	8%	19%	14%	12%	1%	10%
Medium	Within 20 years	5%	25%	27%	46%	34%	18%	29%
Low	Beyond 20 years	90%	68%	54%	41%	54%	81%	61%

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 N.3 illustrates the distribution load growth by state that may trigger distribution upgrades during the IRP planning period. The forecasted distribution capacity deferral value averages approximately $26/kw-yr (2020$) 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 N.3 - Forecasted Distribution Load Growth Above 90 Percent Planning Threshold (MW)

Year	CA	ID	OR	UT	WA	WY	Total
2021	0	15	24	151	13	3	206
2022	1	15	31	161	16	3	227
2023	1	16	40	198	16	3	274
2024	1	20	46	242	20	3	333
2025	2	23	63	272	26	20	405
2026	2	28	71	317	26	20	464
2027	2	28	77	339	28	25	499
2028	2	32	78	343	28	28	511
2029	2	34	83	385	28	28	559
2030	2	38	83	423	28	35	608
2031	2	38	84	437	32	52	645
2032	2	38	93	453	37	52	674
2033	2	38	96	465	40	57	699
2034	2	39	99	483	40	59	721
2035	2	39	99	506	40	61	747
2036	2	42	104	571	40	61	819
2037	2	43	107	577	40	75	845
2038	2	44	108	581	40	99	874
2039	2	50	112	589	43	99	895
2040	2	54	116	595	43	99	909

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. For the 2021 IRP, PacifiCorp identified a planning reserve margin of 13 percent over its hourly loads throughout the year. The planning reserve margin does not translate directly into either resources or need.

All resources contribute to a reliable portfolio, but they do so in ways that are not straightforward to measure and are dependent on the composition of the portfolio. 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. For more details on capacity contribution, please refer to Volume II, Appendix K (Capacity Contribution).

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 small or 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 2021 IRP preferred portfolio includes stand-alone four-hour lithium-ion battery storage resources starting in 2029. These resources have annual fixed costs (capital recovery and fixed operations and maintenance) of approximately $109/kw-yr in 2029. After netting out energy and operating reserve values as described above, the remainder is approximately $89/kw-yr for 2029. This represents the net cost of the battery's nameplate capacity. To put this on an equivalent footing with resources of different types, it can be converted to a net cost of "pure" capacity, by dividing by its capacity contribution. The summer capacity contribution for 4-hour duration storage is 74%, as discussed in Appendix K (Capacity Contribution). This would result in a 2029 cost of $115/kw-yr for "pure" summer capacity from four-hour lithium-ion storage.

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 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 2021 IRP supply-side table shows that on a per kilowatt basis, the fixed costs for a fifty-megawatt, four-hour lithium-ion battery are roughly half that 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. To the extent discharging is aligned with periods with higher load, and charging is aligned with periods with lower load, the benefits will be proportionately higher. 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

Under current tax law, solar resources can qualify for an increased federal investment tax credit (ITC) if they come online prior to the end of 2025. 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 reduces the cost of storage combined with solar 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, combining storage with solar resources provides greater benefits than portfolios that included new solar resources without storage. In the 2021 IRP, storage resources that are combined with solar are sized equivalent to 100 percent of the solar nameplate and have four hours of storage. These sizing parameters will evolve as PacifiCorp goes out to procure specific resources, based on both the costs and effective capabilities of different configurations.

Cost-Effectiveness Results

Table N.4 provides details on the year-by-year benefits of various lithium-ion battery applications.

Since a stand-alone battery is included in the preferred portfolio starting in 2029, it is assumed to be cost effective and providing benefits equal to its costs starting in that year. Additional benefits applicable to distributed resources are also identified.

Table N.4 – Energy Storage Applications - Annual Benefits Stream

					Potential Benefits from Distributed Resources				
$/kw-yr	**Stand-alone Li-Ion 4hr Fixed Cost**	**Energy Value**	**Operating Reserve**	**Utility-scale Resource**	**Primary Losses Energy**	**Primary Losses Gen Capacity**	**Total Primary Losses**	**T&D Deferral**	**Primary Losses + T&D Deferral**
2029	109.22	9.25	11.38	**109.22**	0.51	5.30	**115.03**	30.91	**145.94**
2030	111.21	12.85	11.59	**111.21**	0.71	5.19	**117.12**	31.58	**148.69**
2031	113.40	13.75	2.42	**113.40**	0.76	5.82	**119.98**	32.26	**152.24**
2032	115.73	17.57	4.08	**115.73**	0.98	5.63	**122.34**	32.95	**155.29**
2033	118.11	18.60	1.36	**118.11**	1.03	5.87	**125.02**	33.66	**158.68**
2034	120.54	19.08	1.28	**120.54**	1.06	5.99	**127.59**	34.39	**161.98**
2035	123.02	21.25	1.40	**123.02**	1.18	6.01	**130.21**	35.13	**165.34**
2036	125.56	35.96	1.62	**125.56**	2.00	5.26	**132.82**	35.88	**168.70**
2037	128.14	16.52	0.54	**128.14**	0.92	6.65	**135.71**	36.66	**172.37**
2038	130.79	112.38	0.59	**130.79**	6.24	1.07	**138.10**	37.45	**175.54**
2039	133.49	81.42	1.06	**133.49**	4.52	3.05	**141.06**	38.25	**179.32**
2040	136.24	87.26	1.23	**136.24**	4.85	2.86	**143.95**	39.08	**183.03**

APPENDIX O – WASHINGTON CLEAN ENERGY ACTION PLAN

Introduction

The Clean Energy Transformation Act (CETA) was passed by the Washington State Legislature and signed into law by Governor Jay Inslee in May 2019. The legislation combines directives for utilities to pursue a clean energy future with assurances that benefits from a transformation to clean power are equitably distributed among all Washingtonians.

The Washington Utilities and Transportation Commission began rulemakings to implement CETA in June 2019, and the first phase concluded in December 2020. As directed by the legislation and the new CETA rules, Washington electric utilities must file the following long-term planning documents:

> **Clean Energy Action Plan:** The Clean Energy Action Plan (CEAP) is a ten-year planning document that is derived from the IRP and included as an appendix to the IRP. The CEAP provides a Washington-specific view of how PacifiCorp is planning for a clean and equitable energy future that complies with CETA.
>
> **Integrated Resource Plan:** The IRP is a comprehensive decision support tool and roadmap for meeting the company's objective of providing reliable and least-cost electric service to its customers. The plan is developed through open, transparent and extensive public involvement from state utility commission staff, state agencies, customer and industry advocacy groups, project developers, and other stakeholders.
>
> The key elements of the IRP include: an assessment of resource need, focusing on the first 10 years of a 20-year planning period; the preferred portfolio of supply-side and demand-side resources to meet this need; and an action plan that identifies the steps that will be taken over the next two-to-four years to implement the plan.
>
> **Clean Energy Implementation Plan:** The Clean Energy Implementation Plan (CEIP) is a plan that lists the specific actions PacifiCorp will take over the next four years to move toward the 2030 and 2045 clean energy directives. PacifiCorp's first CEIP will be filed in October 2021.

The CEAP included in the 2021 IRP provides a Washington-specific roadmap of how PacifiCorp is planning for a clean and equitable energy future relative to the requirements of CETA.

Part 1: PacifiCorp in Washington

PacifiCorp is a multi-jurisdictional, vertically integrated utility that serves nearly two million customers in six western states: California, Idaho, Oregon, Utah, Washington, and Wyoming. In Washington, PacifiCorp serves approximately 137,000 customers throughout Yakima, Walla Walla, Columbia, Benton, Cowlitz, and Garfield Counties. The company's generation and transmission systems span the west and connect customers to safe, reliable, affordable, and increasingly renewable electricity. Our integrated transmission system connects thermal, hydroelectric, wind, solar, and geothermal generating facilities with markets and loads. The diversity of this integrated system benefits all of PacifiCorp's customers in all six states. PacifiCorp owns approximately 11,500 megawatts (MW) of generating capacity and about 16,500 miles of transmission lines.

PacifiCorp's large regional footprint enables delivery of low-cost generation from some of the best wind and solar sites in the country reducing power costs and emissions. PacifiCorp is proud to operate one of the lowest-cost systems in the country, and we remain actively engaged in finding ways to leverage the benefits of geographic diversity for our customers as we develop and implement plans to deliver the targets set forth in CETA.

Over the past 13 years, PacifiCorp has successfully reduced its greenhouse gas emissions and improved reliability while simultaneously delivering energy cost savings to our customers. The company has achieved these results by collaborating with others, and through the visionary and collaborative efforts of our own generation, transmission, information technology and energy supply management teams, PacifiCorp has been a key player in the creation of an open and connected Western grid.

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 is positioned to harness it and transport it instantly across the company's 16,500-mile grid.

PacifiCorp's Energy Vision 2020 initiative accelerated that commitment to greenhouse gas reduction, adding 1,150 MW of new wind projects, and repowering our existing wind resources. In total, Energy Vision 2020 projects are able to power the annual energy needs of approximately 400,000 homes, in addition to creating hundreds of construction jobs and adding millions in tax revenue to rural economies.

PacifiCorp is also proud to be involved in the communities the company serves. In Washington, for over 20 years, PacifiCorp has hosted the Merwin Special Kids Day. The Merwin Special Kids Day is a unique annual event held at the company's Merwin hydro generation facility that provides kids, that would not otherwise have the opportunity to go fishing, an opportunity to visit the Merwin facility and fish for trout. More than 100 kids and their families attended the 2019 event. PacifiCorp's employees and families look forward to hosting this event each year.

In June 2019, PacifiCorp hosted an energy fair in Yakima and hosted an energy education booth at the Walla Walla Sweet Onion Festival. The participation at these events allowed PacifiCorp to provide information about energy efficiency offerings, local reliability upgrades, account services, renewable energy options, electric vehicle charging station grants, and an electric vehicle ride and drive opportunity.

PacifiCorp is also proud to have completed light emitting diode (LED) street lighting upgrades for 18 communities in Washington. The project was a partnership with the Washington State Transportation Improvement Board (TIB) and Pacific Power's Wattsmart program. The project resulted in the 18 cities saving an average of 30% on their street light costs. Walla Walla and Yakima did not qualify for the TIB program, but Pacific Power—using the Wattsmart program incentives—was able to partner with the two communities to upgrade their streetlights. This means every community in Pacific Power's Washington service territory has been upgraded to LED.

Part 2: Resource Adequacy

PacifiCorp's CEAP is planning toward a future in Washington that balances a rapid transition to renewable and non-emitting energy as directed under CETA, with our continued commitment to ensure that we are serving customers affordably, safely, and reliably. To meet reliability standards in a future that includes an increasing number and type of variable resources, PacifiCorp has carefully analyzed the way our programs, generation resources, customer load obligations, cost-effective conservation potential fit together to ensure reliability.

The company's long-term load forecasts (both energy and coincident peak load) for each state and for the system as a whole are summarized in Volume I, Chapter 6 (Load and Resource Balance) as well as in 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 2021 IRP preferred portfolio, before adding new generating resources.

Resource Portfolio Development

As discussed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach), PacifiCorp uses the Plexos LT model to produce resource portfolios with sufficient capacity to meet all load and operating reserves requirements over the 20-year study horizon appropriate to achievable granularity. Each of these portfolios is uniquely characterized by variables on PacifiCorp's system, including type, timing, location, and resources needed to achieve reliable operation. The portfolio modeling and selection process ultimately leads to an optimized, lowest reasonable cost six-state portfolio to serve PacifiCorp's customers.

These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices (also applicable to CO_2 equivalent emissions, or "CO_2e"), wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side management (DSM) resources. Changes to these input variables cause changes to the resource mix, which influences system costs and risks. The Plexos LT model is also used to consider the retirement of coal endogenously—a methodological improvement that is new to the 2021 IRP.

In its 2021 IRP, PacifiCorp applies a capacity reserve margin (CRM) to ensure resource adequacy, modeled minimum 13 percent requirement calculated at each topology location carrying load. Additionally, the 2021 IRP will directly model operating reserve requirements in expansion plan model runs which ensures that expansion resources selected to meet CRM requirements will also meet operating reserve requirements. Taken together, these reliability requirements ensure that PacifiCorp has sufficient resources to meet load in all periods, recognizing the uncertainty for load fluctuation and extreme weather conditions, fluctuation of variable generation resources, a possibility for unplanned resource outages, and reliability requirements to carry sufficient contingency and regulating reserves.

PacifiCorp's study period to select the preferred portfolio in the IRP is a 20-year period beginning January 1, 2021 and ending December 31, 2040. The CEAP represents an allocation of the optimized portfolio to Washington over a ten-year horizon ending in 2030. The following resources were considered as part of the long-term expansion model at the system level to ensure resource adequacy

Dispatchable Thermal Resources:
These resources include dispatch costs for fuel, non-fuel VOM, and the costs of greenhouse emissions, as applicable. 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 locations as defined in the transmission topology of the model.

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.

Demand-Side Management:
Energy efficiency resources are characterized with supply curves that represent achievable technical potential of the resource by state, by year, and by measures specific to PacifiCorp's service territory. For modeling purposes, these data are aggregated into cost bundles. Each cost bundle of the energy efficiency supply curves specifies the aggregate

energy savings profile of all measures included within the cost bundle. Each cost bundle has both a summer and winter capacity contribution based on aggregate energy savings during on-peak hours in July and December aligning with periods where PacifiCorp is most likely to exhibit capacity shortfalls.

Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). Operating characteristics include variables such as total number of hours per year and hours per event that the demand response resource is available.

Wind and Solar Resources:
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 contribution of wind and solar resources, determined by forecast profiles, determine the ability for these resources to reliably meet demand over time. The use of resource availability to meet requirements in all periods allows the model to endogenously account for declining capacity contribution due to the increasing penetration of resources with similar dispatch patterns.

Preferred Portfolio Results

PacifiCorp's preferred portfolio reflects the company's ongoing vision in which clean energy from across the West powers jobs and innovation. This bold vision took shape in the 2017 and 2019 IRPs, in which an ambitious path was outlined to substantially increase renewable energy capacity, evolving the existing portfolio, and connecting supply with demand through an expanded, modernized transmission system. The 2021 preferred portfolio builds on that vision and was evaluated against the requirements of CETA. The 2021 preferred portfolio:

- **Continues the transition to a low-carbon portfolio:**
    - Begin the process of retiring or divesting Colstrip Units 3 and 4 in Colstrip, Montana
    - Begin the process of a coal-to-gas peaker conversion of Jim Bridger Units 1 and 2 in Rock Springs, Wyoming
    - Begin the process of retirement or sale of Naughton Units 1 and 2

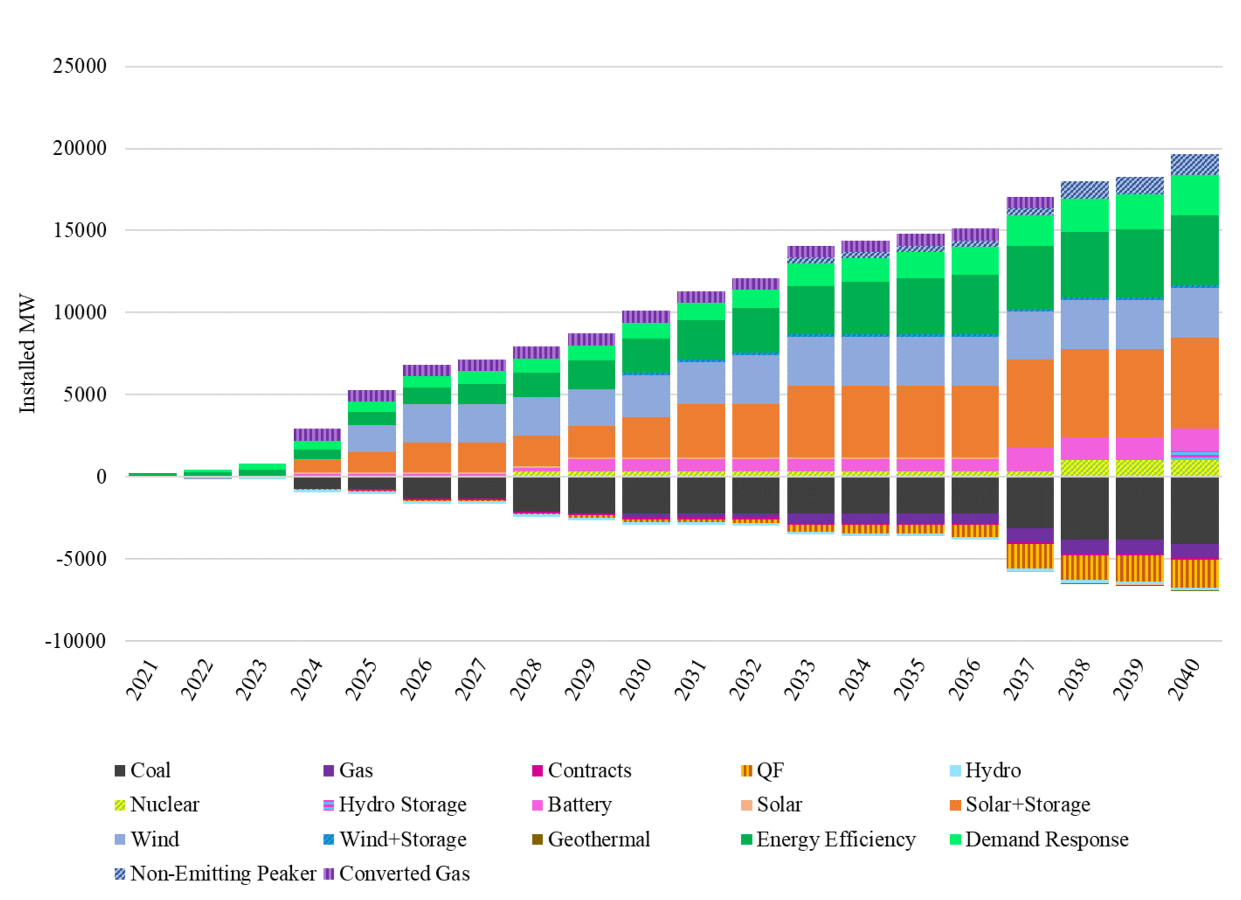
- **Continues growth into a grid powered by clean energy (incremental to projects already online and projects with executed agreements that will come online through 2023)**:

  - 4,290 MW of incremental savings through energy efficiency programs
  - 5,628 MW of new solar resources (most paired with storage)
  - 3,628 MW of new wind resources
  - 6,181 MW of storage resources including battery storage co-located with solar, standalone battery storage and pumped hydro storage resources
  - 2,448 MW of direct load control programs
  - 500 MW of advanced nuclear (the Natrium TM reactor demonstration project) in 2028, with an additional 1,000 MW of advanced nuclear over the long term

- **Connects and optimizes the diverse, clean resources across the West with a strengthened and modernized transmission network that ensures resilient service, reduces costs, and creates maximum opportunities for our communities to thrive (incremental to projects already online)**:
  - 416 miles of new transmission from the new Aeolus substation near Medicine Bow, Wyoming, to the Clover substation near Mona, Utah (Energy Gateway South)
  - 59 miles of new transmission from the Shirley Basin substation in southeastern Wyoming to the Windstar substation near Glenrock, Wyoming (Energy Gateway West Sub-Segment D.1)
  - 290 miles of new transmission from the Boardman substation in north central Oregon to the Hemingway substation in south central Idaho

PacifiCorp's IRP preferred portfolio selections are summarized in Figure O.1.

Figure O.1 – PacifiCorp 2021 IRP Preferred Portfolio



The methodology behind PacifiCorp's preferred portfolio selection – as well as additional detail on the supply-side and demand-side resources selected as part of the portfolio – is detailed in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach) and Chapter 9 (Modeling and Portfolio Selection).

PacifiCorp's IRP preferred portfolio is optimized to serve the company's six-state service area on a lowest reasonable cost basis. As part of portfolio construction, PacifiCorp takes into account planning reserve margin and resource adequacy considerations, as well as the availability of regional generation and transmission. Additional detail on resource adequacy and the availability of regional resources can be found in Volume I, Chapter 5 (Reliability and Resiliency).

In compliance with WAC 480-100-620(12)(i), the social cost of greenhouse gas (SCGHG) was considered as part of the selection of PacifiCorp's preferred portfolio and was the basis of multiple price-policy scenarios and other required and requested sensitivities. As the SCGHG was an important part of considering and ultimately selecting a lowest reasonable cost optimized portfolio, the impacts of SCGHG on portfolio modeling are included in the Washington allocation of the portfolio discussed in this appendix. Additional detail on how SCGHG was considered in PacifiCorp's portfolio modeling can be found in Volume I, Chapter 8 (Modeling and Portfolio Evaluation Approach).

PacifiCorp preferred portfolio 2021-2030

Based on the resources in P02-MM-CETA PacifiCorp's generation portfolio will substantially increase renewable generation and will add new non-emitting resources. Coal-fueled generation will be removed from Washington rates by the end of 2023. Chehalis Generation Station (Chehalis) is projected to be the only thermal resource serving Washington customers after 2024 and will retire in 2043.

Under the preferred portfolio the share of renewable and non-carbon-emitting resources as a percentage of Washington retail load will have increased from 28% in 2021, to around 81% in 2030. Additionally, PacifiCorp is on track to meet the 100% renewable and non-emitting standard in Washington by 2045.

Coal-fueled resources

Washington is currently served by two coal-fired facilities within PacifiCorp's resource portfolio: Colstrip Unit 4 in Colstrip, Montana, and Jim Bridger Units 1 and 2 in Point of Rocks, Wyoming. The allocation of resources to Washington – in accordance with WAC 480-100-610(1) – will no longer include both resources by December 31, 2023.

Following the removal of these resources from Washington's allocation of energy, PacifiCorp will pursue the retirement or divestiture of Colstrip from the company's portfolio by the end of 2025. The company will begin steps to convert Jim Bridger Units 1 and 2 from coal-fueled to natural gas fueled; PacifiCorp does not anticipate allocating any of the converted Jim Bridger units to Washington.

Other thermal resources

PacifiCorp's Washington allocation of energy currently includes generation from the Chehalis Generating Station (Chehalis) – a natural-gas fired resource in Chehalis, Washington – and from the Hermiston Generating Station (Hermiston) – a natural-gas fired resource in Hermiston, Oregon. On an energy basis, Hermiston currently serves approximately one third of the gas-fueled power serving Washington. Hermiston will be removed from Washington's allocation of electricity by the end of 2023.

Chehalis is currently forecast to serve Washington customers through the end of the IRP study period and will be retired at the technical end-of-life in 2043. Following the removal of coal-fueled resources from Washington's allocation of electricity at the end of 2023, Chehalis will be the only thermal unit serving Washington customers until its retirement.

Non-emitting resources

PacifiCorp's non-emitting resources serving Washington currently consists of generation from 35 hydroelectric facilities throughout the company's six-state service area.

PacifiCorp's preferred portfolio also includes nuclear. The portfolio selects a 500 MW advanced nuclear Natrium™ demonstration project to come online by summer 2028. This resource will serve as an additional non-emitting capacity resource.

Renewable Resources

The 2021 IRP preferred portfolio includes 1,302 MW of new solar by the end of 2024 and 1,902 MW by the end of 2026. Through 2040, more than 5,600 MW of new solar is scheduled to come online system wide. PacifiCorp's 2021 IRP preferred portfolio also includes 1,792 MW of new wind generation resulting from the 2020 All-Source RFP and the acquisition and repowering of Rock River I (49 MW) and Foote Creek II-IV (43 MW). Through the end of 2026, the 2021 IRP preferred portfolio includes an additional 745 MW of new wind and more than 3,700 MW of new wind by 2040.

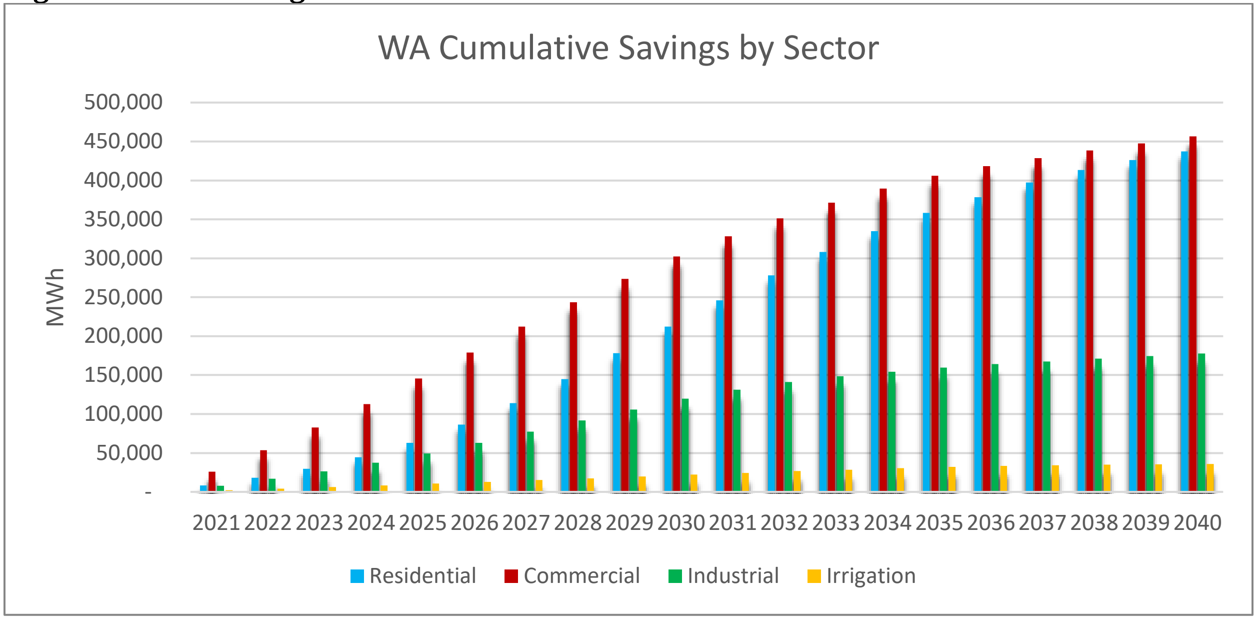
Additionally, during the portfolio development process, upon evaluation relative to the 2030 CETA target, a shortfall of roughly 69 MW of annual capacity was identified in 2030 (the highest shortfall year), with significantly smaller shortfalls identified in the years between 2030-2033. Under a four-year compliance window for the time period 2030 – 2033, an average annual shortfall of 49 MW was identified. This shortfall is addressed with a Washington-situs assigned 160 MW wind and solar resource co-located with storage located in Yakima, Washington. A further discussion of how the preferred portfolio was evaluated relative to the requirements of CETA can be found in Volume I, Chapter 9 (Modeling and Portfolio Selection).

Conservation Potential

New cost-effective energy efficiency measures and programs are among the new resource selections that are present in every portfolio described in the process above. These resources are first identified through the development of a conservation potential assessment (CPA) which identifies the magnitude and cost of all technically achievable energy savings opportunities in PacifiCorp's service territory over the next 20 years. Several measures include quantified non energy impacts netted against measure cost. Examples include health benefits from avoided woodsmoke with installation of ductless heat pumps, operations and maintenance cost savings with new lighting, and water savings for measures which conserve water use as well as electricity use. For the past several IRP cycles, PacifiCorp has contracted with Applied Energy Group (AEG) to conduct this assessment. A comprehensive description of the study methodology, underlying assumptions, and results can be found on PacifiCorp's website[1]. Figure O.2 shows cumulative technical achievable potential results from the CPA for the Washington service territory.

[1] Available online at https://www.pacificorp.com/energy/integrated-resource-plan/support.html

Figure O.2 – Washington CPA Technical Achievable Potential



The study results in over 3,000 individual efficiency measures which are then bundled into 27 groups for each of PacifiCorp's six states. In past years, these groups were characterized only by the total levelized cost of each measure. For the 2021 IRP, a new bundling approach based on net value of efficiency resources will be employed as described at the January 2021 public-input meeting.

The output from the CPA serves as an input to the Plexos model which selects the optimal mix of resources from the defined bundles to provide system adequacy in a least cost least risk manner. The conservation resources which are selected in the preferred portfolio become the cost-effective conservation potential.

Demand Response and Load Management Programs

Cost-effective demand response and load management resources are identified and selected in a manner similar to conservation resources. The scope of the CPA also includes identification of the technical potential for direct load control (DLC) demand response opportunities and for potential new pricing programs. The methodology and all underlying assumptions and results for these resources can also be found on PacifiCorp's website.

Direct load control resources are differentiated by customer, technology, and duration. Sustained duration resources are available for more than 20 minutes while short duration reflects load which can be curtailed in greater quantity but for shorter duration such as for frequency response over 5-minute increments where the customer is less likely to be impacted by the disruption.

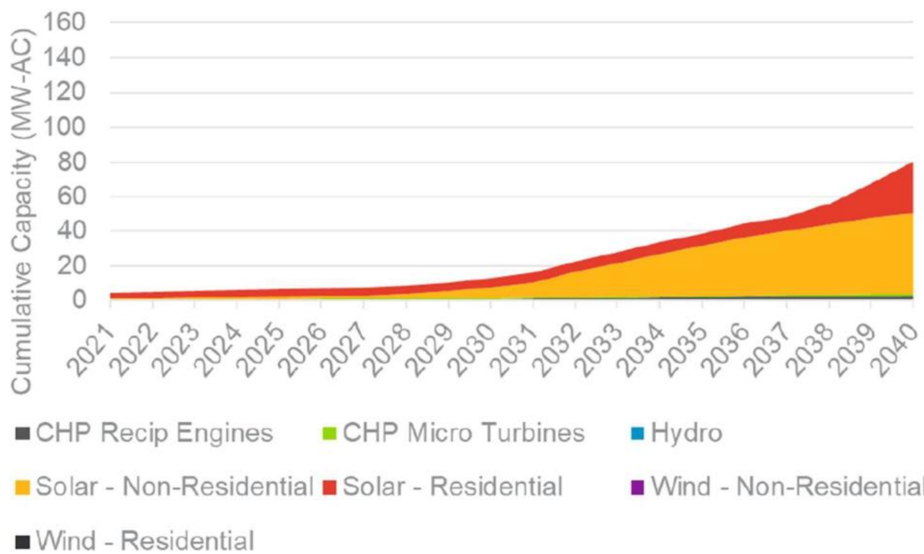
The amount and cost of load curtailment or shift is characterized by customer type and type of end use that is being controlled. The technical achievable potential is input to the IRP model as a resource option to be selected to meet system adequacy. Demand response selections by the model are cost effective potential to be acquired as a part of the preferred portfolio.

Pricing programs include time-of-use rates, critical-peak pricing and other behavioral pricing tools. The third focus of the CPA is to quantify the technical potential and magnitude of demand impacts possible through these pricing designs. The results are used to inform future rate design concepts that are proposed with rate cases but the IRP model is not used to determine the type and amount of pricing programs as a part of the preferred portfolio. This is because all pricing programs are designed to be cost effective to the system but may not be cost effective for the individual customer to select. Therefore, setting targets for programs that only benefit the utility system but not customers is not appropriate for the IRP but is analyzed and designed through other stakeholder and regulatory processes.

Distributed Energy Resources

Distributed energy resources include energy conservation, demand response and load management, and distributed generation. Energy conservation and demand response and load management are characterized in the CPA as described above. New customer-sited generation is forecasted within the Private Generation Long Term Resource Assessment, which will be included as an appendix to the 2021 IRP). This assessment was conducted by Guidehouse Consulting for all states and for each distributed generation resource type including solar PV, small scale wind, small scale hydro, reciprocating engines and micro-turbines. The resource costs and state specific policies and incentives are integrated in the forecast of customer adoption of these resources across low, base, and high case scenarios. The base case results are netted against each state's load forecast. Washington private generation assumptions are shown in Figure O.3.

Figure O.3 – Washington Private Generation Assumptions



Transmission

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

In support of the significant renewable resource additions identified in the 2021 preferred portfolio, PacifiCorp has identified a number of transmissions and upgrades that will reinforce existing transmission paths, allow for increased east-west transfer capability, and will support the interconnection of new renewables. A summary of PacifiCorp's identified transmission additions is shown in Figure O.4 below:

Figure O.4 - Transmission Projects Included in the 2021 IRP Preferred Portfolio

Year	Resource(s)	From	To	Description
2025	1,641 MW RFP Wind (2025)	Aeolus WY	Clover	Enables 1,930 MW of interconnection with 1700 MW of TTC: Energy Gateway South
2026	615 MW Wind (2026)	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany OR area reinforcement
2026	130 MW Wind (2026) 450 MW Wind (2032) 650 MW Battery (2037)	Portland North Coast	Willamette Valley Southern Oregon	Enables 2080 MW of interconnection with 1950 MW TTC; Portland Coast area reinforcement, Willamette Valley and Southerm Oregon
2026	600 MW Solar+Storage (2026)	Borah-Populous	Hemingway	Enables 600 MW of interconnection with 600 MW of TTC: B2H Boardman-Hemingway
2028	41 MW Solar+Storage (2028) 377 MW Solar+Storage (2030)	Within Southern OR Transmission Area		Enables 460 MW of interconnection: Medford area reinforcement
2030	160 MW Solar+Wind+Storage (2030) 20 MW Solar+Storage (2030)	Yakima WA Transmission Area		Enables 180 MW of interconnection: Yakima local area reinforcement
2031	820 MW Solar+Storage (2031) 206 MW Non-Emitting Peaker (2033)	Northern UT Transmission Area		Enables 1040 MW of interconnection: Northern UT 345 kV reinforcement
2033	400 MW Non-Emitting Peaker (2033) 1100 MW Solar+Storage (2033)	Southern UT	Northern UT	Enables 1500 MW of interconnection with 800 MW TTC: Spanish Fork - Mercer 345 kV; New Emery – Clover 345 kV
2040	156 MW Solar+Storage (2040) 500 MW Pumped Storage (2040)	Central OR	Willamette Valley	Enables 980 MW of interconnection with 1500 MW of TTC
2028*	500 MW Adv Nuclear (2028)	Southwest Wyoming Transmission Area		Reclaimed transmission upon retirement of Naughton 1 & 2
2029*	549 MW Battery (2029)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Dave Johnston Plant
2037	909 MW Solar+Storage (2037)	Southern Utah Transmission Area		Reclaimed transmission upon retirement of Huntington 1 & 2
2038	412 MW Non-Emitting Peaker (2038) 1000 MW Adv Nuclear (2038)	Bridger WY Transmission Area		Reclaimed transmission upon retirement of Jim Bridger Plant
2040	206 MW Non-Emitting Peaker (2040) 60 MW Wind (2040)	Eastern Wyoming Transmission Area		Reclaimed transmission upon retirement of Wyodak

Part 3: Working Toward an Energy Future that Benefits All Customers

WAC 480-100-610(4)(c) and WAC 480-100-620(12) direct PacifiCorp to ensure that all customers are benefiting from the transition to clean energy by:

(1) describing the specific actions the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities (HICs) and vulnerable populations;

(2) estimating the degree to which such benefits will be equitably distributed, and burdens reduced over the CEAP's ten-year horizon; and

(3) describing how the specific actions are consistent with its long-term strategy.
To comply with these directives, PacifiCorp plans to conduct a multi-step stakeholder engagement process that will rely heavily on public participation and community input.

This section represents the first step in that effort. To support future stakeholder engagement, it:

1. Identifies highly impacted communities within the two main population centers of PacifiCorp's Washington service territory: Yakima and Walla Walla, drawing from DOH's Washington Tracking Network (WTN) Environmental Health Disparities map;

2. Discusses the historic and anticipated non-energy and energy-related burdens these HICs face;

3. Describes existing programs available to these HICs and possible benefits to these communities from the transition to clean energy.

Identifying Highly Impacted Communities

PacifiCorp's service area in Washington can be categorized into two distinct population centers: Yakima and the surrounding area, and Walla Walla and the surrounding area. In total, PacifiCorp's Washington service area covers or partially covers sixty-one census tracts. PacifiCorp's service area in the Yakima and the surrounding area covers or partially covers forty-seven separate census tracts, while Walla Walla and the surrounding area covers or partially covers fourteen census tracts. Based on information from the U.S Census Bureau's, American Community Survey the population of these sixty-one census tracts is 259,228.

- The Washington Department of Health (DOH) defines a HIC as a census tract that meets at least one of the following two criteria:

    - The census tract is covered or partially covered by "Indian Country" as defined and designated by statue (RCW 19.405.020), or

- The census tract ranks a nine or ten on the WTN Environmental Health Disparities Map, as designated by the Washington DOH.

Through a collaborative effort, the DOH's Washington Tracking Network (WTN) developed a ranking of environmental, health and socioeconomic themes and measures for each census tract throughout the state using deciles (1 decile = 10%). Each decile represents 10% of the values in the data set. As an example of how to interpret the WTN rankings, a census tract with a rank of nine for poverty would mean that 10% of other census tracts throughout the state have a higher proportion of their population living below the poverty level, while 80% of census tracts throughout the state have a lower proportion of their population living below the poverty level.

To determine the presence of HICs, PacifiCorp relied on geospatial analysis of WTN data for Tribal Lands, Environmental Health Disparities (EHD), Environmental Exposures, Environmental Effects, Socioeconomic Factors and Sensitive Populations. Additional detail on these themes and measures are provided below.

- **Indian Country:** Except as otherwise provided in sections 1154 and 1156 of 18 US Code, the term "Indian country", as used in 18 US Code Section 1151 and RCW 19.405.020, means (a) all land within the limits of any Indian reservation under the jurisdiction of the United States Government, notwithstanding the issuance of any patent, and, including rights-of-way running through the reservation, (b) all dependent Indian communities within the borders of the United States whether within the original or subsequently acquired territory thereof, and whether within or without the limits of a state, and (c) all Indian allotments, the Indian titles to which have not been extinguished, including rights-of-way running through the same.

- **Environmental Health Disparities (EHD):** The DOH uses the EHD data to designate highly impacted communities under the CETA-Cumulative Impact Analysis (CIA). It is the overall ranking of each of the nineteen WTN measures within the EHD, which are grouped into the following four themes:

- **Environmental Exposures:** includes Nitrous-Oxide diesel emissions (annual tons/Km2), ozone concentration, PM 2.5 concentration, populations near heavy-traffic roadways, and toxic releases from facilities

- **Environmental Effects:** which includes lead risk from housing, proximity to hazardous waste treatment and disposal facilities, proximity to national priorities list facilities (superfund sites), proximity to risk management plan facilities, and wastewater discharge

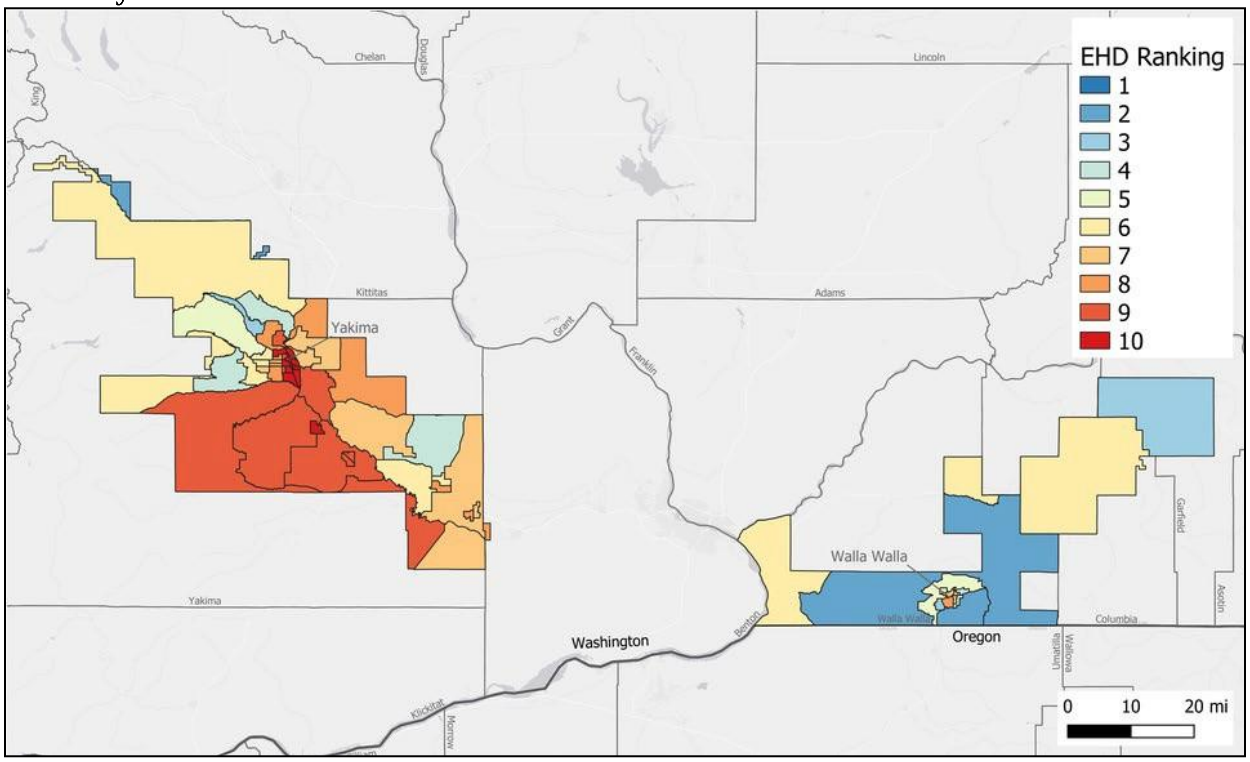
- **Socioeconomic factors:** including limited English, no high school diploma, race/ethnicity, population living in poverty, transportation expense, unaffordable housing, and unemployed

- **Sensitive Populations:** includes deaths from cardiovascular disease and low birthweight

Pacific Power Territory Specific Mapping of WTN Data by Census Tract

This section provides a geospatial analysis of communities within PacifiCorp's Washington service territory. Further, this analysis also incorporates DOH rankings for communities throughout the territory, with discussion focused on HICs with a ranking of 9 or greater.

Figure O.5 – WTN Data – Environmental Health Disparities (Overall) in Pacific Power Territory



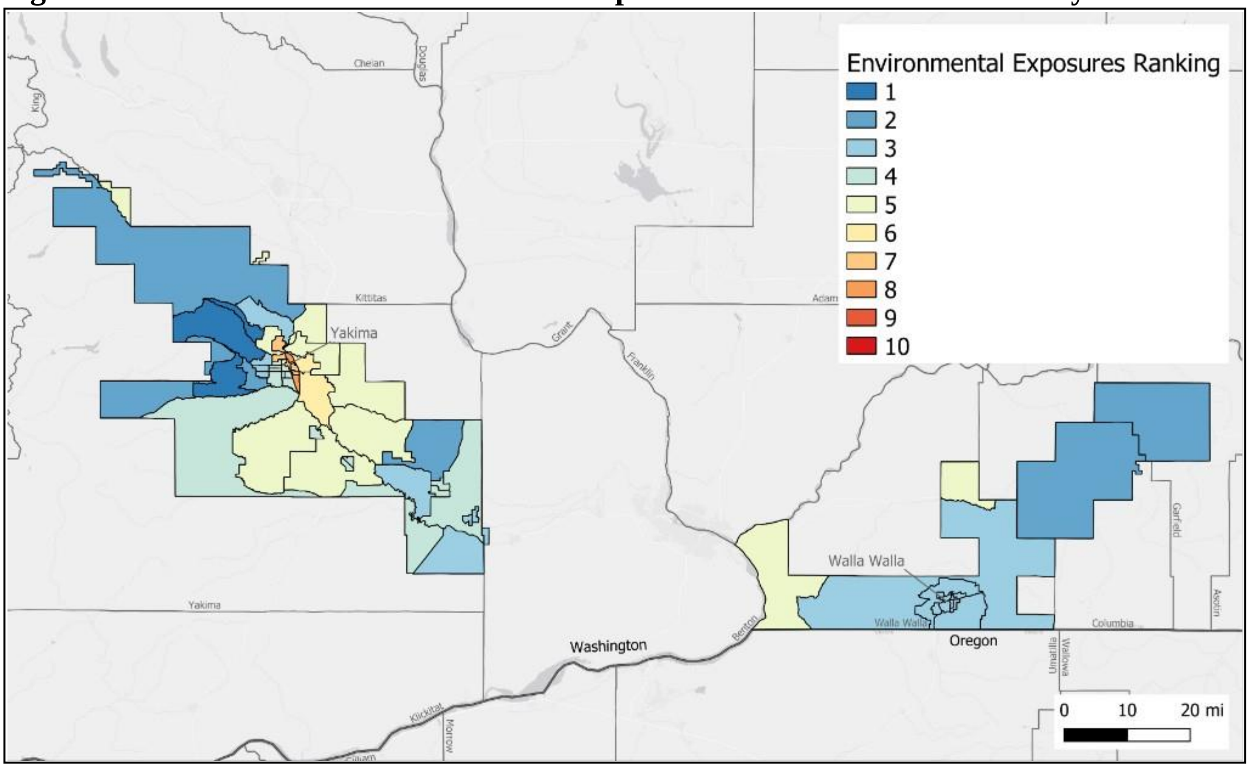
Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Health Disparities (EHD)	
Yakima	19
Walla Walla	0

Within the Yakima area, 19 census tracts have an Environmental Health Disparities ranking of 9 or greater. The Walla Walla area includes no census tracts with an Environmental Health Disparities ranking of 9 or greater. Additional information on Environmental Health Disparities ranking in the Washington service territory are provided below.

Yakima and Surrounding Area
The Yakima area includes 19 census tracts (40.4%) with an Environmental Health Disparities ranking of 9 or greater, with Socioeconomic Factors and Environmental Effects as the leading factors in this category.

Walla Walla and Surrounding Area
The Walla Walla area includes no census tracts with an Environmental Health Disparities ranking of 9 or greater.

Figure O.6 – WTN Data – Environmental Exposures in Pacific Power Territory



Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Exposures	
Yakima	0
Walla Walla	0

No census tracts within the Yakima area or the Walla Walla area have Environmental Exposures ranking of 9 or greater. Additional information on Environmental Exposures ranking in the Washington service territory are provided below.

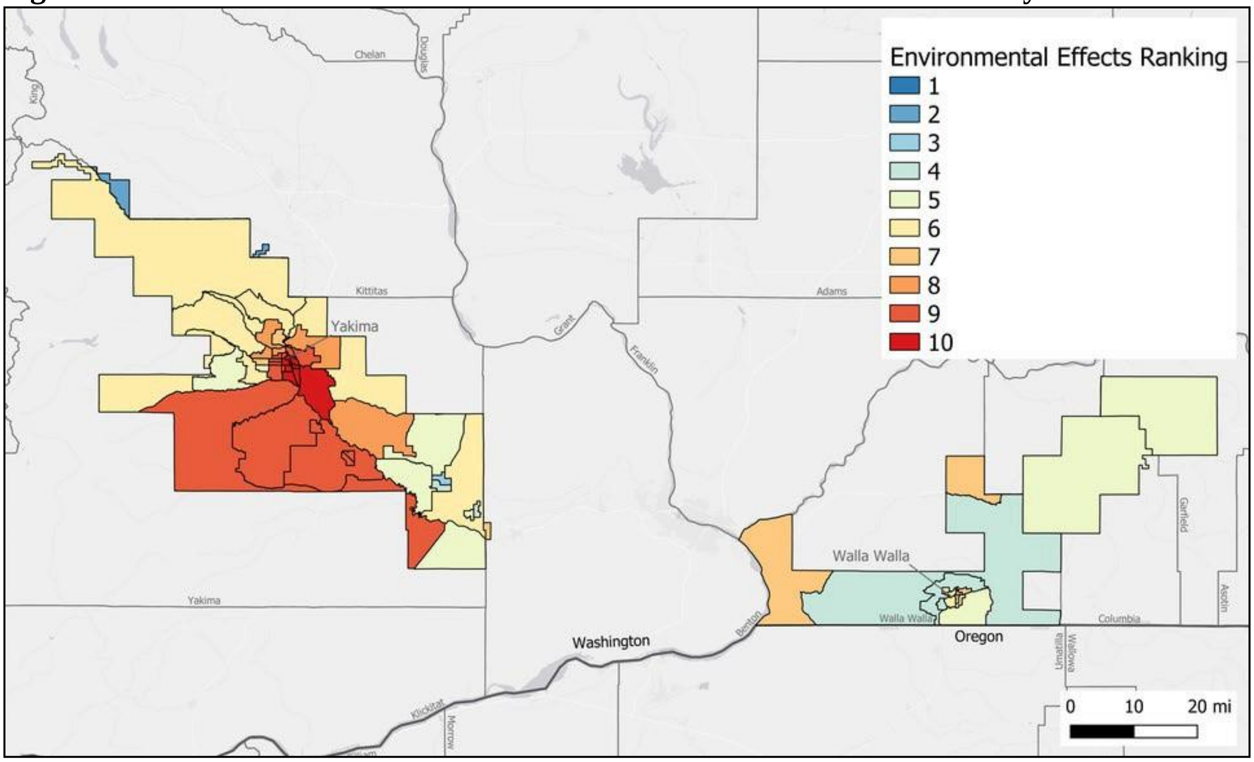
Yakima and Surrounding Area

For measures of Environmental Exposures, the Yakima area includes no census tracts with ranking of 9 or greater.

Walla Walla and Surrounding Area

The Walla Walla area does not have a census tract with a ranking above 5 for Environmental Exposures, with many census tracts ranking in the 2-3 range.

Figure O.7 – WTN Data – Environmental Effects in Pacific Power Territory



Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Effects	
Yakima	22
Walla Walla	0

Within the Yakima area, 22 census tracts have Environmental Effects ranking of 9 or greater. The Walla Walla area includes no census tracts with an Environmental Effects ranking of 9 or greater. Additional information on Environmental Effect ranking in the Washington service territory are provided below.

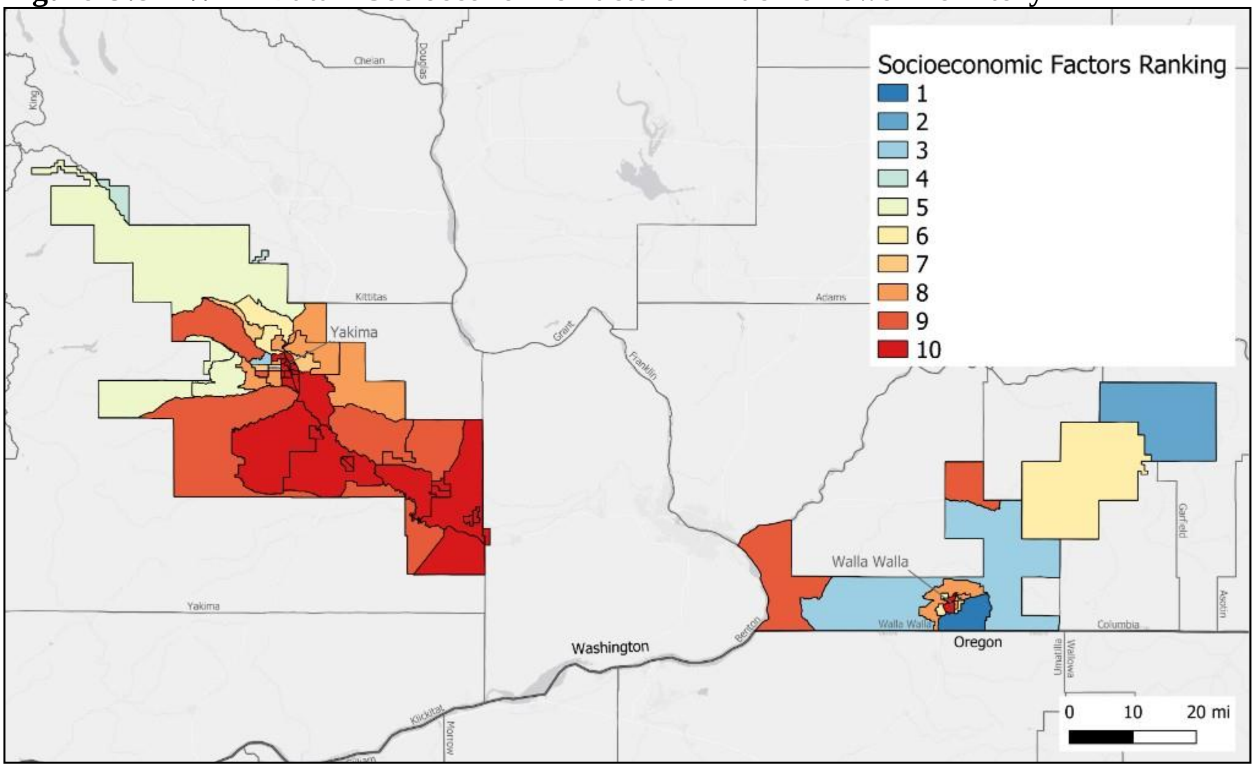
Yakima and Surrounding Area

The Yakima area includes 22 census tracts (46.8%) with Environmental Effects ranking of 9 or greater, with lead risk from housing, proximity to hazardous waste treatment storage and disposal facilities, proximity to superfund sites and proximity to Risk Management Plan facilities as leading factors in this category.

Walla Walla and Surrounding Area

The Walla Walla area includes no census tracts with an Environmental Effects ranking of 9 or greater.

Figure O.8 – WTN Data – Socioeconomic Factors in Pacific Power Territory



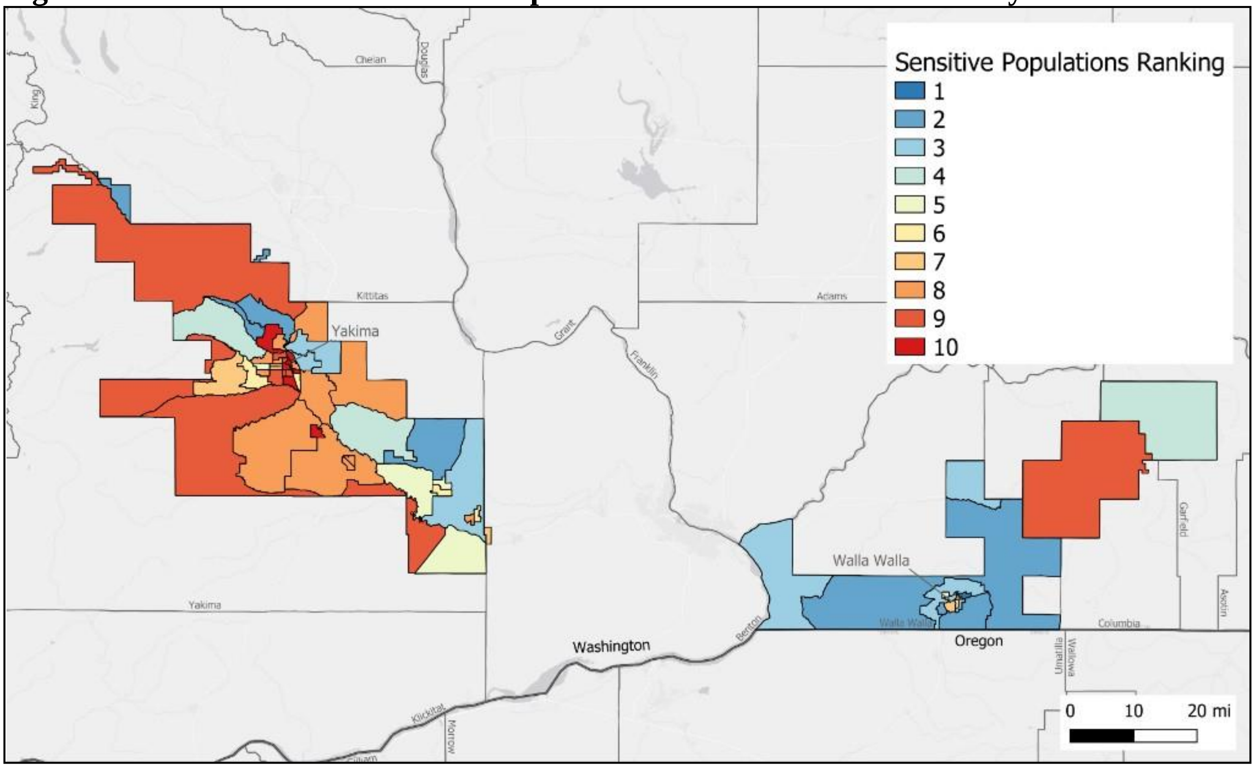
Location	Count of WTN 9/10 Scoring Census Tracts
Socioeconomic Factors	
Yakima	30
Walla Walla	3

Within the Yakima area, 30 census tracts have Socioeconomic Factors ranking of 9 or greater. The Walla Walla area includes 3 census tracts with Socioeconomic Factors ranking of 9 or greater. Additional information on Socioeconomic Factors ranking in the Washington service territory are provided below.

Yakima and Surrounding Area
The Yakima area includes 30 census tracts (63.8%) with Socioeconomic Factors ranking 9 or greater, with major factors being the prevalence of people of color, population living in poverty and high transportation expense.

Walla Walla and Surrounding Area
The Walla Walla area includes 3 census tracts with Socioeconomic Factors ranking of 9 or greater, with major factors being the prevalence of populations with limited English proficiency and populations living in poverty.

Figure O.9 – WTN Data – Sensitive Populations in Pacific Power Territory



Location	Count of WTN 9/10 Scoring Census Tracts
Sensitive Populations	
Yakima	14
Walla Walla	1

Within the Yakima area, 14 census tracts have Sensitive Populations ranking of 9 or greater. The Walla Walla area has 1 census tract with Sensitive Populations ranking of 9 or greater.
Additional information on Sensitive Populations ranking in the Washington service territory are provided below.

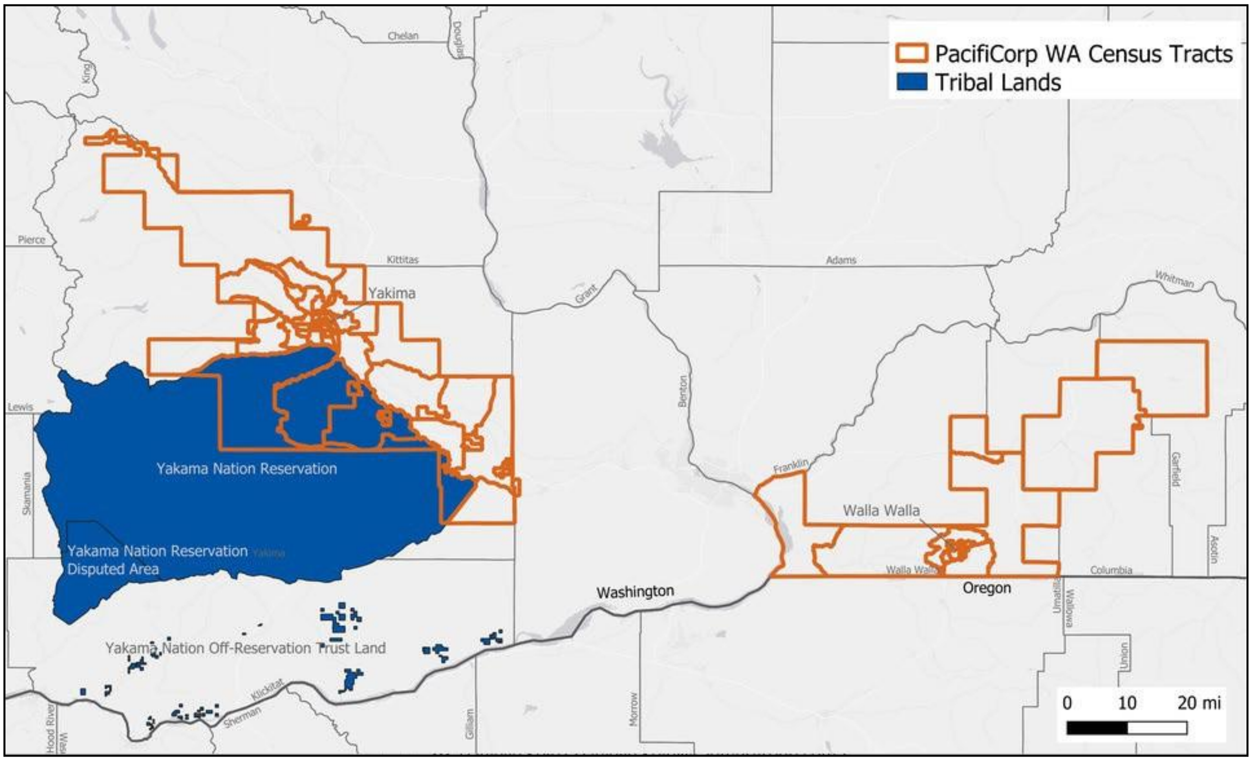
Yakima and Surrounding Area

The Yakima area includes 14 census tracts (29.8%) with Sensitive Populations ranking of 9 or greater, with the major factor being death from cardiovascular disease.

Walla Walla and Surrounding Area

The Walla Walla area includes 1 census tract with Sensitive Populations ranking of 9 or greater, with the major factor being low birth weight.

Figure O.11 – Tribal Land and Pacific Power Territory Map



Location	Number of Census Tracts
Tribal Lands	
Yakima	6
Walla Walla	0

Within the Yakima area, 6 census tracts are located on Tribal Lands. The Walla Walla area has no census tracts located on Tribal Lands. Additional information on Tribal Lands within the Washington service territory are provided below.

Yakima and Surrounding Area

For the Yakima area 6 census tracts are located on the Yakama Nation Reservation.

Walla Walla and Surrounding Area
The Walla Walla area includes no census tracts located on tribal lands.

Identifying Vulnerable Populations

In addition to determining HICs, it is necessary to identify vulnerable populations within the Washington service territory. To that end, PacifiCorp engaged with its external Equity Advisory Group (EAG) to advise on equity issues including vulnerable population designation (WAC 480-100-655). PacifiCorp initially gathered input on vulnerable populations from its EAG members on June 16, 2021, which was further updated on July 21, 2021. The list of those initial vulnerable populations identified by PacifiCorp's EAG is presented in Table O.1 below.

Table O.1 – Initial List of Vulnerable Populations within PacifiCorp Service Territory

Students
Adults 65 years old and above
Young children
People who are hard of hearing
People with a disability
People with medical equipment at home
Diverse supplier business owners
Energy burdened
Asset Limited, Income Constrained, Employed (ALICE)
Low-income migrants
Low income
Immigration status (outside of US citizen)
People who speak limited English
Renters
Multi-generational households
Multi-family households
People experiencing homelessness
People living in rural areas
People living in different land statuses (such as land trust vs. fee patent that have different regulatory requirements)
Agricultural and/or farm workers
Gas-heated homes
Single parents

Table O.2 below provides additional insight on the proportion of PacifiCorp's Washington Service territory customers who belong to a vulnerable population relative to the state of Washington overall. The table shows the average (mean) values of each vulnerable population across all Census tracts in Washington and in PacifiCorp's service territory, respectively, weighted by households or population counts. This average therefore represents the proportion of households or individuals who belong to each vulnerable population across all of Washington and across all of PacifiCorp's Washington service territory.

Table O.2 – Proportion of Vulnerable Populations within Washington and PacifiCorp Service Territory

Vulnerable Population	Washington Statewide Proportions	PacifiCorp Service Territory Proportions
Total population 65 years and over[a]	15.1%	14.6%
Total population under 5 years[a]	6.1%	7.6%
Total civilian noninstitutionalized population with a disability[b]	12.7%	13.7%
Total population foreign born[b]	14.3%	16.9%
Percentage of families and people whose income in the past 12 months is below the poverty level[c]	7.2%	12.1%
Language spoken at home by population 5 years and over: Language other than English[b]	19.1%	32.8%
Number of grandparents living with own grandchildren under 18 years[b]	1.8%	2.8%
Population in households living with other nonrelatives[b]	4.8%	2.9%
Occupied housing units using utility gas for house heating fuel[d]	34.5%	25.1%
Civilian employed population 16 years and over: Agriculture, forestry, fishing and hunting, and mining[c]	2.9%	15.1%
Total households: male or female householder, no spouse/partner present, living alone with own children[b]	15.9%	17.0%
Mean Energy Burden[e]	2.0%	2.8%
School enrollment: Population 3 years and over enrolled in school[b]	23.6%	27.1%
Occupied housing units that are renter-occupied[f]	37.0%	36.1%
Households located in rural areas[g]	5.2%	6.6%
Asset Limited, Income Constrained, Employed[h]	24.7%	30.8%
Minority & Women's Business Enterprises[i] (*total* certified)	2,363	26

[a] US Census Bureau, ACS, 2019, Table DP05
[b] US Census Bureau, ACS, 2019, Table DP02
[c] US Census Bureau, ACS, 2019, Table DP03
[d] US Census Bureau, ACS, 2019, Table S2504
[e] US Department of Energy, Low-Income Energy Affordability Data Tool
[f] US Census Bureau, ACS, 2019, Table DP04
[g] US Department of Agriculture, 2010, Rural-Urban Commuting Areas
[h] United Way Washington: ALICE Project
[i] Washington Office of Minority & Women's Business Enterprises, Directory of Certified Firms. Note: this figure represents the *total* counts of certified MWBEs, as opposed to *percentages*.

In some cases, it was not possible to find an appropriate dataset for vulnerable populations at the needed level of granularity. Vulnerable populations for which PacifiCorp was unable to locate adequate data include people that are hard of hearing, people with medical equipment at home, low-income migrants, people experiencing homelessness, and people living in different land statuses.

Existing Community Programs in Washington

PacifiCorp offers a variety of programs which can be beneficial to customers that are living in a HIC or designated as a vulnerable population (referred to as a Named Communities) such as providing low-cost electricity, which positively impacts housing expenditures and lessens the cost burden for impoverished households. Further, utility programs such as electric vehicle incentive programs impact HIC Environmental Exposures, by lowering NOx from diesel emissions. Below are some additional details regarding a select number of PacifiCorp programs which beneficially impact Washington Named Communities.

- **Low-income Weatherization Program:** Provides energy efficiency services through a partnership between the Company and local non-profit agencies to low-income eligible households residing in single family homes, manufactured homes and multi-unit residential housing. Services are provided at no cost to participants.

- **Project Help – Fuel Fund** provides energy assistance to customers in need with funds donated by customers and employees which PacifiCorp matches 2 to 1 - up to $34k annually in Washington. Donated funds are provided to Project Help in Washington, a non-profit program providing energy assistance with donated funds.

- **Low Income Bill Assistance (LIBA) Program:** Provides a bill discount to income eligible households year-round. A three-tiered bill discount based on the income and monthly billing include a discount on each kWh usage in excess of 600 kWh. The program is administered through partner Low Income Home Energy Assistance Program (LIHEAP) agencies for income certification services.

- **Time-of-Use Pilot Program:** Provides a time of use pilot program which can lower bills for participating customers who can shift usage to off-peak periods of time. This pilot program is limited to the first 500 residential customers that enroll.

- **Energy Efficiency Programs:** Discounts and cash back incentives for qualifying home energy improvements and appliance upgrades.

- **Electric-vehicle Program:** Electric vehicle charging station grants and an electric vehicle ride and drive opportunity.

Analysis of how the 2021 preferred portfolio may help reduce burden and increase benefit

PacifiCorp's 2021 IRP preferred portfolio continues the company's investment in clean energy, affordable service, safety, and reliability. PacifiCorp's initial assessment of how the preferred portfolio actions may impact Washington customers is shown in the table below and will be subsequently refined through the development of Customer Benefit Indicators as part of the development of the 2022 Clean Energy Implementation Plan.

Table O.3 – PacifiCorp Assessment of Preferred Portfolio Impact

Identified Impact or Benefit	How it's addressed in 2021 IRP/CEAP
Energy Benefits	Including the fundamental transition to decarbonize PacifiCorp's system, additional energy benefit is anticipated for Named Communities through participation in company energy electrification and efficiency programs.
Non-energy Benefits	In an effort to prioritize diverse suppliers, PacifiCorp is expanding the non-price scoring criteria associated with utility procurement. Additional information can be found in Volume II, Appendix P (RFP Overview).
Reduction of Burdens	Through the programs identified in the 2021 IRP preferred portfolio – including energy efficiency and demand response – PacifiCorp has the opportunity to deliver programs with an increased equity focus utilizing more effective communication strategies to reach its Named Communities.
Environment/Public Health	Although PacifiCorp does not currently own any generation in its Washington service area, the company's continued investment in clean and non-emitting resources – and the associated retirement of thermal generators – will help reduce environmental exposures across the region. Over time, these investments will reduce environmental exposures and improve air quality.
Reduction in Cost	Washington's allocation of the 2021 preferred portfolio selects resources, programs, locations, and timing meant to lead to the lowest present value revenue requirement compared to overall portfolio risk.
Energy Security/Resiliency	PacifiCorp's preferred portfolio has selected transmission resources that increase east-west transfer capability, harden the system against weather-based threats, and provide the ability to integrate renewable resources.

Public Participation

2021 IRP Stakeholder Meetings

PacifiCorp's long-term planning processes are designed to be transparent, collaborative, and accessible, with a number of meetings held throughout 2020 and 2021.

The development of the 2021 IRP and CEAP began with a public-input meeting in January 2020, which kicked off a total of 18 public-input meetings, with some lasting two days. Due to restrictions and concerns surroundings COVID-19, all meetings were held virtually via phone and the Microsoft Teams platform.

The 2021 public-input process also included state-specific stakeholder meetings held in July and October of 2020. The goal of these sessions were to capture key issues of most concern to each state that PacifiCorp serves, as well as discuss how to address these issues from a system planning perspective. PacifiCorp wanted to ensure stakeholders understood IRP planning principles and its development process. These meetings continued to enhance interaction with stakeholders in the planning cycle and provided a forum to directly address state-specific items of stakeholder interest.

Demand-side Management (DSM) Advisory Group Meetings
PacifiCorp uses its DSM Advisory Group to meet the requirements of WAC 480-109-110. The DSM Advisory Group was initially created under the June 16, 2000, Comprehensive Stipulation in docket UE-991832, which the Commission approved in the August 9, 2000, Third Supplemental Order in that docket, and its IRP public input process created under WAC 480-100-238.

On June 23, 2021, PacifiCorp presented details regarding CETA, the EAG and HICs within the Washington Service Territory to the DSM Advisory Group. Further, on July 21, 2021, PacifiCorp provided details regarding vulnerable populations, draft CBIs, and requested the DSM Advisory Group to complete the Clean Energy Benefit Survey.

CEIP Public Participation Plan
PacifiCorp is working closely with Washington Commission Staff and stakeholders to further expand the participation opportunities within the communities that the company serves in Washington. Detailed public participation methods are outlined in the revised Public Participation Plan for the 2022 CEIP that Pacific Power filed with the Commission on July 3, 2021. As described in the plan, PacifiCorp formed an Equity Advisory Group, and has held four meetings over the May – August 2021 timeframe with another four scheduled through December 2021. PacifiCorp is also seeking input from the public through various other avenues as described in detail in the CEIP Public Participation Plan including upcoming public meetings.

PacifiCorp and Washington Department of Commerce (the Department)
In accordance with RCW 19.405.120, all electric utilities in Washington are required to report data on energy assistance programs to the Department to inform current program adoption and to ensure that programs are meeting the need of Washington customers. As part of this process, PacifiCorp has presented detail on the company's low-income programs and participated in subsequent workshops to provide further input on low-income programs.

In accordance with CETA requirements, PacifiCorp has also provided program statistics to the Department on the Low-income Weatherization Program, Project Help – Fuel Fund Services and Low-income Bill Assistance (LIBA) Program. PacifiCorp will continue to evaluate options to overlay this work with public data sources to recommend actions to reduce barriers to equitable distribution of benefits.

Part 4: Compliance Pathways

RCW 19.405.040 and 19.405.050 set the 2025, 2030, and 2045 goals for electric utilities in Washington to meet. Specifically, utilities must show that by December 31, 2025 all coal-fired generation has been removed from Washington's allocation of electricity. By January 1, 2030, utilities must be greenhouse gas neutral, and by 2045, Washington's electric utilities must be 100% renewable.

PacifiCorp's 2021 IRP sets the company on the path to meet each of Washington's Clean Energy Transformation Standards. As detailed in Volume I, Chapter 1 (Executive Summary) of PacifiCorp's 2021 IRP, the company is investing in a diverse portfolio that includes investment in renewable and non-emitting resources. The discussion in the Resource Adequacy section of this CEAP describes the ways in which those renewable and non-emitting resources will be allocated to Washington and will help build a clean and reliable portfolio that is fully CETA compliant.

RCW 19.405.090 sets out four alternative compliance pathways that can be used to meet up to 20% of the carbon neutrality standards that begin in 2030 and run through 2044:

> (i) Making an alternative compliance payment under RCW 19.405.090(2);
>
> (ii) Using unbundled renewable energy credits, provided that there is no double counting of any nonpower attributes associated with renewable energy credits within Washington or programs in other jurisdictions, subject to conditions outlined in CETA;
>
> (iii) Investing in energy transformation projects, including additional conservation and efficiency resources beyond what is otherwise required under this section, provided the projects meet the requirements of subsection (2) of this section and are not credited as resources used to meet the standard under (a) of this subsection; or
>
> (iv) Using electricity from an energy recovery facility using municipal solid waste as the principal fuel source, where the facility was constructed prior to 1992, and the facility is operated in compliance with federal laws and regulations and meets state air quality standards.

Based on the 2021 preferred portfolio, PacifiCorp currently forecasts that it will be on track to meet the compliance requirement by using unbundled renewable energy credits in addition to the renewable and non-emitting electric generation to serve Washington customers. At this time, PacifiCorp does not expect to use the alternative compliance payment, energy transformation project, or energy recovery facility pathway to meet the standards under RCW 19.405.090.

APPENDIX P – DRAFT BID EVALUATION AND SELECTION PROCESS FOR 2022 ALL SOURCE REQUEST FOR PROPOSALS

Introduction

The chapter fulfills two state regulatory requirements. First, it fulfills Oregon regulation OAR 860-089-0250(2) requiring a utility to describe its initial scoring and associated modeling in its Integrated Resource Plan or in its Independent Evaluator selection docket. Second, it satisfies Washington regulation WAC 480-107-035 which stipulates that RFP ranking criteria must also be consistent with the avoided cost methodology developed in the IRP the utility uses to support its determination of its resource need.

The 2021 Integrated Resource Plan (IRP) establishes an Action Item to conduct an all-source request for proposals (2022AS RFP) and acquire new resources. The 2021 IRP preferred portfolio includes the following new, incremental resources:

- 1,345 megawatts (MW) of new proxy supply-side generation resources with 600 MW co-located energy storage resources with commercial operation date ("COD") by December 31, 2026.

- 274 megawatts (MW) of new proxy demand-side resources by December 31, 2026[1].

The 2022AS RFP will accept and evaluate all resource types[2] which meet the minimum criteria of this RFP. Prior to the determination of the final shortlist targeted in January 2023, the 2022AS RFP will conduct due diligence and score supply-side and a demand-side resources separately, before dovetailing the processes to evaluate both supply-side and demand-side resource types in parallel using the IRP portfolio optimization models. PacifiCorp will use the results of the RFP to fulfil resource needs for system customers and state compliance obligations.

PacifiCorp is subject to procurement rules in California, Utah, Washington, and Oregon. This chapter begins with a summary of procurement rules in each of the states as they apply to the scoring, evaluation and selection process. The chapter concludes with the proposed bid evaluation and selection process to be used by the 2022 All Source RFP for supply-side resources including the non-price scorecard and equity questionnaire.

[1] Capacity impacts for demand response include both summer and winter impacts within a year.
[2] WAC 480-107-009 107-009 Required all-source RFPs and conditions for targeted RFPs. (1) All-source RFP requirements. All-source RFPs must allow bids from different types of resources that may fill all or part of the characteristics or attributes of the resource need. Such re-source types include, but are not limited to, unbundled renewable energy credits, conservation and efficiency resources, demand response or other distributed energy resources, energy storage, electricity from qualifying facilities, electricity from independent power producers, or other resources identified to contribute to an equitable distribution of energy and nonenergy benefits to vulnerable populations and highly impacted communities.

Review of State Regulatory Requirements

Oregon Regulatory Requirements

In 2016, the Commission initiated the rule making process to develop competitive bidding rules that allow for diverse ownership of renewable energy sources that generate qualifying electricity, consistent with Section 6 of 2016 Senate Bill 1547.[3] After multiple workshops and rounds of comments, the Commission adopted competitive bidding rules in their Order 18-324.[4] Each RFP must demonstrate that it can satisfy these Rules before receiving approval and, after the RFP has taken place, must demonstrate compliance with the Rules in order to receive acknowledgment of a final shortlist.[5]

Oregon's competitive bidding rules describe a two-step process to ensure the Commission and stakeholders are engaged early and often in RFP design. The first step is when a utility describes its initial scoring and associated modeling in its IRP or in its IE selection docket;[6] and the second step is full RFP design and Commission review for approval, conditional approval, or disapproval. This chapter fulfills the first step. The Commission's Rules provide that by including the initial scoring and modeling as part of a utility's IRP filing with the Commission, the Commission acknowledges a resource need as part of the utility's IRP and simultaneously approves the associated RFP scoring methodology and associated modeling process. This RFP scoring and modeling is then incorporated into the complete RFP that is drafted with input from the independent evaluator and stakeholders.

860-089-0100 Applicability of Competitive Bidding Requirements

OAR 860-089-0100 requires PacifiCorp to issue an RFP for all major resource acquisitions meeting specific thresholds including resource sizes greater than 80 MW or contract term length greater than five years. PacifiCorp established an action item out of PacifiCorp's 2021 IRP to conduct an all-source RFP in 2022 to procure 600 MW of new proxy solar resources co-located with 600 MW battery storage capacity, 745 MW of new proxy wind resources, and 274 MW of new proxy demand response resources by the end of 2026. PacifiCorp will also allow bids from nuclear and pumped storage hydro (PSH) resources requiring longer lead time beyond the 2026 deadline to develop and construct and a to be determined amount of new generating resources (including battery storage) in other geographic regions not specified in the 2021 IRP action plan but subject to the results of PacifiCorp Transmission's 2022 cluster study. PacifiCorp's issuance of the 2022AS RFP for its all-source resource additions will satisfy 860-089-0100.

860-089-0350 Benchmark Resource Score

OAR 860-089-0350 applies to the evaluation process and scoring of any utility submitted self-build assets or benchmark bids. In the event benchmark bids are included in the RFP, the following rules apply and have therefore been incorporated into the evaluation and scoring methodology below:

> (1) Prior to the opening of bidding on an approved RFP, the electric company must file with the Commission and submit to the IE, for review and comment, a detailed score for any benchmark resource with supporting cost information, any transmission arrangements,

[3] Codified in Oregon Laws 2016, Chapter 28, Section 6.
[4] Docket No. AR 600, Order 18-324, August 30, 2018.
[5] OAR 860-089-0500 (1).
[6] OAR 860-089-0250(2).

and all other information necessary to score the benchmark resource. The electric company must apply the same assumptions and bid scoring and evaluation criteria to the benchmark bid that are used to score other bids.
(2) If, during the course of the RFP process, the Commission or the IE determines that it is appropriate to update any bids, the electric company must also make the equivalent update to the score of the benchmark resource.
(3) Before the IE provides the electric company an opportunity to score other bids, the electric company must file with the Commission and submit via a method that protects confidentiality the following information:
(a) The final benchmark resource score developed in consultation with the IE, and
(b) Cost information and other related information shared under this rule.

860-089-0400 Bid Scoring and Evaluation by Electric Company

OAR 860-089-0400 provides that the utility must provide all scoring criteria and metrics in its draft and final RFPs filed with the Commission. The initial-shortlist bids must be based on both price and non-price factors, and non-price factors should be converted to price factors where practicable. The non-price score "should be based on resource characteristics identified in the utility's acknowledged IRP Action Plan.... and conformance to the standard form contracts attached to the RFP."[7] Final shortlist bids are then to be based, at least in part, on the bid resources' overall system costs and risks, and the independent evaluator must have full access to the production cost and risk models.

The 2022AS RFP evaluation process will use both price and non-price scoring to determine the initial shortlist. Non-price scoring will involve three weighted factors: (1) bid submittal completeness, (2) contracting progress and viability, and (3) project readiness and deliverability as shown in the non-price scoring matrix at the end of this appendix. Bidders will be required to self-score and provide the results of their scoring to PacifiCorp for its audit and final non-price score determination. As such, bidders will have full transparency to the non-price scoring metrics being used. The non-price scorecard is comprised of three parts. First, to assess bid submittal completeness, bidders will be evaluated upon whether bids provided complete, accurate and consistent information and were in compliance with technical specifications. Second, to assess contracting progression, bidders will be evaluated upon whether the bidder had provided contract issues list, a mark-up of the pro-forma contract, or both and whether certain bid and bidder attributes are consistent with the requirements of the pro forma contracts. Third, to assess project deliverability, bids will be evaluated based on their development maturity, whether they fulfil certain resource attributes consistent with the IRP resource need and are able to achieve a December 31, 2026, commercial operation date, and finally, bidders will be evaluated based upon the extent of previous development-and-construction experience.

This non-price scoring is consistent with PacifiCorp's 2021 IRP Action Plan. PacifiCorp's non-price scoring will also conform to the standard contracts included in the following RFP.

PacifiCorp's price scoring is also consistent with the 2019 IRP analysis because it will use the similar economic models and methodology to evaluate the system impact and costs associated with each bid, as described in the section below, titled "BID EVALUATION AND SELECTION."

[7] OAR 860-089-0400(2)(b).

Upon selection of the initial shortlist, PacifiCorp will engage a third-party engineering firm, to complete an assessment of the resource energy performance reports as submitted by bidders as well as providing additional technical review of the bids for completeness and alignment with technical specifications.

In summary, Oregon has several competitive bidding rules related to an RFP evaluation and scoring, including minimum eligibility requirements for bidders and modeling/scoring uncertainties.[8] This chapter is being provided to address PacifiCorp's conformance with those rules.

Utah Regulatory Requirements

Utah Admin. Code R746-420-1(1)(d) requires a soliciting utility filing for approval of a proposed solicitation and solicitation process in accordance with the Energy Resource Procurement Act (Act) to provide as part of its request for approval filing descriptions of the criteria and the methodology, including any weighting and ranking factors, to be used to evaluate bids.

Utah Admin. Code R746-420-3(2) and (5) requires the 2022AS RFP provide descriptions of the proposed screening and evaluation criteria and the methodology, including any weighting and ranking factors to be used to evaluate bids. Screening, evaluation criteria, ranking factors and evaluation methodologies must be reasonably designed to ensure that the Solicitation Process is fair, reasonable and in the public interest. Reasonable initial screening criteria may include, but are not necessarily limited to, reasonable and nondiscriminatory evaluation of and initial rankings based upon the following factors:[9] (i) Cost to utility ratepayers; (ii) Timing of deliveries; (iii) Point of delivery; (iv) Dispatchability/flexibility; (v) Credit requirements; (vi) Level of change to pro forma contracts included in an approved Solicitation Process; (vii) Transmission, Interconnection and Integration costs and benefits; (viii) Commission-approved consideration of impacts of direct or inferred debt; (ix) Feasibility, including project timing and the process for obtaining necessary rights and permits; (x) Adequacy and flexibility of fuel supplies; (xi) Choice of cooling technology and adequacy of water resources; (xii) Systemwide benefits of transmission infrastructure investments associated with a project; (xiii) Allocation of project development risks, including capital cost overruns, fuel price risk and environmental regulatory risk among project developer, utility and ratepayers; and (xiv) Environmental impacts.

In developing the initial screening and evaluation criteria, the Soliciting Utility shall consider the assumptions included in the Soliciting Utility's most recent Integrated Resource Plan (IRP), any recently filed IRP Update, any Commission order on the IRP or IRP Update and in its Benchmark Option.[10]

Reasonable RFQ screening criteria may include, but are not necessarily limited to, reasonable and nondiscriminatory evaluation of the following factors:[11] (i) Credit requirements and risk; (ii) Non-performance risk; (iii) Technical experience; (iv) Technical and financial feasibility; and (v) Other reasonable screening criteria that are applied in a fair, reasonable and nondiscriminatory manner.

[8] OAR 860-089-0250(3).
[9] R746-420-3(2)(b)
[10] R746-420-3(2)(c)
[11] R746-420-3(3)(c)

For Solicitations which include a Benchmark Option, Utah Admin. Code R746-420-3 (4)(c) requires that the Solicitation shall include at least the following a description and examples of the manner in which resources of differing characteristics or lengths will be evaluated, and Utah Admin. Code R746-420-3 (5)(a) requires that the Solicitation shall include a clear and complete description and explanation of the methodologies to be used in the evaluation and ranking of bids, including a complete description of all evaluation procedures, factors and weights to be considered in the RFQ, initial screening and final evaluation of bids.

Utah Admin. Code R746-420-3 (7)(c) provides that the Solicitation Process must include clear descriptions of qualification requirements, price and non-price factors and weights, and Utah Admin. Code R746-420-3 (7)(d) requires the Solicitation Process must utilize an evaluation methodology for resources of different types and lengths which is fair, reasonable and in the public interest.

Utah Admin. Code R746-420-3 (8) outlines Process Requirements for Benchmark Option. In a Solicitation Process involving the possibility of a Benchmark Option, (h) All relevant costs and characteristics of the Benchmark Option must be audited and validated by the Independent Evaluator prior to receiving any of the bids and are not subject to change during the Solicitation except as provided within the rules; (i) All bids must be considered and evaluated against the Benchmark Option on a fair and comparable basis; and (j) Environmental risks and weight factors must be applied consistently and comparably to all bid responses and the Benchmark Option.

Section 6 (Bid Evaluation and Selection) of the draft 2022AS RFP is included in this chapter and provides a detailed description of the bid scoring, modeling and selection process including assumptions, criteria and methodology that will be used to evaluate, rank, and shortlist bids. As described in the draft 2022AS RFP, the screening and evaluation criteria meet the requirements of the Utah Commission's rule.

Utah Admin. Code R746-420-3(10)(a) requires bids be "blinded;" however, PacifiCorp is recommending that bids not be "blinded." PacifiCorp will request a waiver of this requirement, consistent with similar requests in past RFPs. The Utah Commission has approved such requests previously based, in part, on recommendations by the IE and the Division of Public Utilities, who have questioned the value of blinding the bids. As in past solicitation processes, blinding bids will provide limited value because the detailed information that will be included in each bid will effectively disclose the bidder's identity. Therefore, blinding bids will create an administrative burden on the IE and the Company, with no commensurate value.

Washington Regulatory Requirements

Washington's WAC 480-107 procurement of energy rules (ELECTRIC COMPANIES—PURCHASES OF RESOURCES) requires the following procurement rules with respect to evaluation and scoring processes.

WAC 480-107-009 Required all-source RFPs and conditions for targeted RFPs. (1) All-source RFP requirements. All-source RFPs must allow bids from different types of resources that may fill all or part of the characteristics or attributes of the resource need. Such resource types include, but are not limited to, unbundled renewable energy credits, conservation and efficiency resources, demand response or other distributed energy resources, energy storage, electricity from qualifying facilities, electricity from independent power producers, or other resources identified to contribute to an equitable distribution of energy and nonenergy benefits to vulnerable populations and highly impacted communities.

WAC 480-107-025 Contents of RFP solicitations. (2) The RFP must request information identifying energy and nonenergy benefits or burdens to highly impacted communities and vulnerable populations, short-term and long-term public health impacts, environmental impacts, resiliency and energy security impacts, or other information that may be relevant to identifying the costs and benefits of each bid, such as a bidder's past performance utilizing diverse businesses and a bidder's intent to comply with the labor standards in RCW 82.08.962 and 82.12.962. After the commission has approved the utility's first clean energy implementation plan (CEIP), requested information must contain, at a minimum, information related to indicators approved in the utility's most recent CEIP, including customer benefit indicators, as well as descriptions of all indicators.

(3) The RFP must document that the size and operational attributes of the resource need requested are consistent with the range of estimated new resource needs identified in the utility's IRP.

(4) The RFP must explain the specific ranking procedures and assumptions that the utility will use in accordance with WAC 480-107-035. The RFP must include a sample evaluation rubric that quantifies, where possible, the weight the utility will give each criterion during the bid ranking procedure, and provides a detailed explanation of the aspects of each criterion that would result in the bid receiving higher priority.

(7) The RFP must identify any minimum bidder requirements, including for financial security requirements and the rationale for such requirements, such as proof of a bidder's industry experience and capabilities.

(10) All RFPs must clearly state the scope of the solicitation and the types of bids that the utility will accept consistent with WAC 480-107-024.

WAC 480-107-035 Bid ranking procedure. (1) At a minimum, a utility's RFP ranking criteria must recognize resource cost, market-volatility risks, demand-side resource uncertainties and benefits, resource dispatchability, resource effect on system operation, credit and financial risks to the utility, the risks imposed on ratepayers, public policies regarding resource preference, and Washington state or federal government requirements. The ranking criteria must recognize differences in relative amounts of risk and benefit inherent among different technologies, fuel sources, financing arrangements, and contract provisions, including risks and benefits to vulnerable populations and highly impacted communities. The ranking criteria must also be consistent with the avoided cost methodology developed in the IRP the utility uses to support its determination of its resource need. The utility must consider the value of any additional net benefits that are not directly related to the specific need requested.

(2) In choosing to remove a bid during any stage of its evaluation process, the utility may not base its decision solely on the project's ability to only meet a portion of the resource need.

(3) The utility may not discriminate based on a bidder's ownership structure in the ranking process.

(4) The utility and any independent evaluator selected by the utility will each score and rank the qualifying bids using the RFP's ranking criteria and methodology. If bids include unexpected content, the utility may modify the ranking criteria but must notify all bidders of the change, describe the change, and provide an opportunity for bidders to modify their bids.

(5) Within thirty days after the close of the bidding period, the utility must post on its public website a summary of each bid the utility has received. Where use of confidential data prohibits the utility from identifying specifics of a bid, a generic but complete description is sufficient.

(6) The utility may reject any bids that do not comply with the minimum requirements of the RFP or identify the costs of complying with environmental, public health, or other laws, rules, and regulations in effect at the time of the bid.

(7) Within thirty days after executing an agreement for acquisition of a resource, the utility must file the executed agreement and supporting documents with the commission.

(8) The commission may review any acquisitions resulting from the RFP process in the utility's general rate case or other cost recovery proceeding.

(9) The commission will review, as appropriate, a utility's finding that no proposal adequately serves ratepayers' interests, together with evidence filed in support of any acquisition made outside of the RFP process, in the utility's general rate case or other cost recovery proceeding.

California Regulatory Requirements[12]

California's R.18-07-003 5.10. RPS Plan Section IV.A. Portfolio Supply and Demand states: "The retail seller's RPS Plan must also explain how the quantitative analysis provided in response to Section 5.8 of the ACR supports the assessment. Lastly, it should describe how procurement or sales planned for the period covered by the 2021 RPS Plans is consistent with the evaluation of supply and demand.

R.18-07-003 5.10. RPS Plan Section X: Bid Solicitation Protocol, Including Least-Cost Best-Fit (LCBF) Methodologies - § 399.13(a)(6)(C), D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044

> R.18-07-003 5.10. X.B. Bid Selection Protocols: The bid solicitation protocols for procuring and selling should include an overview of the solicitation process, a solicitation schedule, and pro forma agreement(s). All retail sellers should include a detailed description of their bid selection process and evaluation methodology, which should be consistent with D.04-07-029, D.11-04-030, D.12-11-016, D.14-11-042, and D.16-12-044. Retail sellers stated bid selection criteria should align with all sections of their RPS Plan, especially regarding stated needs, goals, and preferences retail seller. Retail sellers should describe how their solicitations and procurement decisions will give preference to

[12] Rulemaking 18-07-003, Assigned Commissioner and Assigned Administrative Law Judges' Ruling Identifying Issues and Schedule for Review for 2021 Renewables Portfolio Standard Procurement Plans, dated March 30, 2021, which sets forth the general requirements for 2021 RPS Procurement Plans.

renewable energy resources located in specific communities, such as those identified as disadvantaged communities, pursuant to Pub. Util. Code § 399.13(a)(8).[13]
R.18-07-003 5.10. X.C. Least Cost Best Fit (LCBF) Criteria: The LCBF methodology used must be consistent with relevant Commission decisions.[14] In particular, retail sellers shall include a detailed description of their bid evaluation methodologies and "best fit" attributes considered, pursuant to § 399.13(a)(9),[15] and how bids will be valued and evaluated based on their evaluation methodology. When evaluating bids in their solicitations, retail sellers should consider at a minimum the following attributes: energy and capacity value, congestion cost, locational preference, potential for curtailment, and operational flexibility and how bids will be valued and evaluated based on their evaluation methodology. Any qualitative measures in the LCBF methodology should also be described, both in terms of the criteria and application.[16] If the retail seller's LCBF criteria does not include system reliability considerations then the retail seller's RPS Plan will be rejected.

Bid Evaluation and Selection

Overview of the Evaluation Process

PacifiCorp's bid evaluation and selection process is designed to identify the combination and amount of new resources that will maximize customer benefits through the selection of bids that will satisfy projected capacity and energy needs while maintaining reliability. The same method will be used to evaluate benchmark resources and market bids. Based on proxy resource cost assumptions used in the 2021 IRP, energy and capacity needs were best satisfied by the resource selections summarized in Table P.2. The models that PacifiCorp will use to evaluate and select the best combination and amount of bids are similar to the models that were used to evaluate proxy resources in PacifiCorp's 2021 IRP. PacifiCorp uses 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.

The bid evaluation process incorporates PacifiCorp Transmission's interconnection cluster study process steps. At a high level, the 2022AS RFP evaluation process involves three phases:

[13] Pub. Util. Code § 399.13(a)(8)(A) requires that in soliciting and procuring eligible renewable energy resources for California-based projects, each electrical corporation shall give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and GHG.
[14] See D.04-07-029, Opinion Adopting Criteria for the Selection Least-Cost and Best-Fit Renewable Resources (July 8, 2004); D.11-04-030, Decision Conditionally Accepting 2011 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Supplements (Apr. 14, 2011); D.12-11-016, Decision Conditionally Accepting 2012 Renewables Portfolio Standard Procurement Plans and Integrated Resource Plan Off-Year Supplement (Nov. 8, 2012); D.14-11-042, Decision Conditionally Accepting 2014 Renewables Portfolio Standard Procurement Plans and an Off-Year Supplement to 2013 Integrated Resource Plan (Nov. 20, 2014); D.16-12-044, Decision Accepting Draft 2016 Renewables Portfolio Standard Procurement Plans (Dec. 15, 2016).
[15] Pub. Util. Code § 399.13(a)(9) requires that in soliciting and procuring eligible renewable energy resources, each retail seller consider the best-fit attributes of resource types that ensure a balanced resource mix to maintain the reliability of the electrical grid.
[16] As noted in the November 9, 2018 Assigned Commissioner's Scoping Memo and Ruling issued in R.18-07-003, the Commission is revising and updating the least-cost best-fit methodology for evaluating RPS-eligible procurement. Parties submitted comments on the staff paper on LCBF reform and further Commission action will follow. Thus, parties should limit comments on this Ruling to the particulars of proposed LCBF methodologies in 2021 RPS Procurement Plans in relation to the current rules

1. Initial shortlist
2. Interconnection cluster study, and
3. Final shortlist

The 2022AS RFP evaluation process is shown in Figure P.1 and Figure P.2.

Figure P.1 – Bid Evaluation and Selection Process – Supply-side Resources

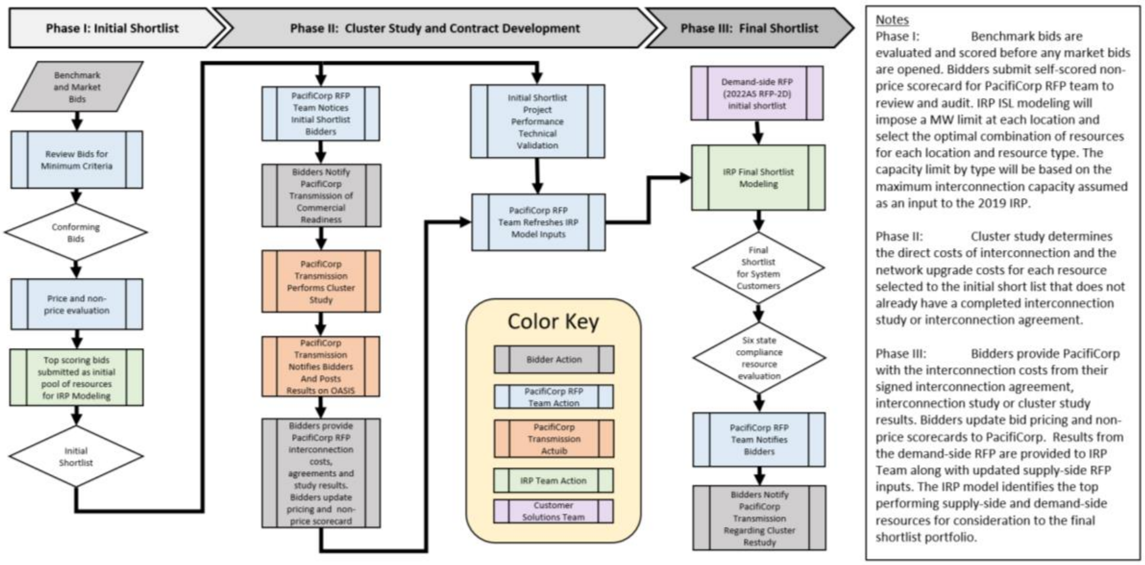
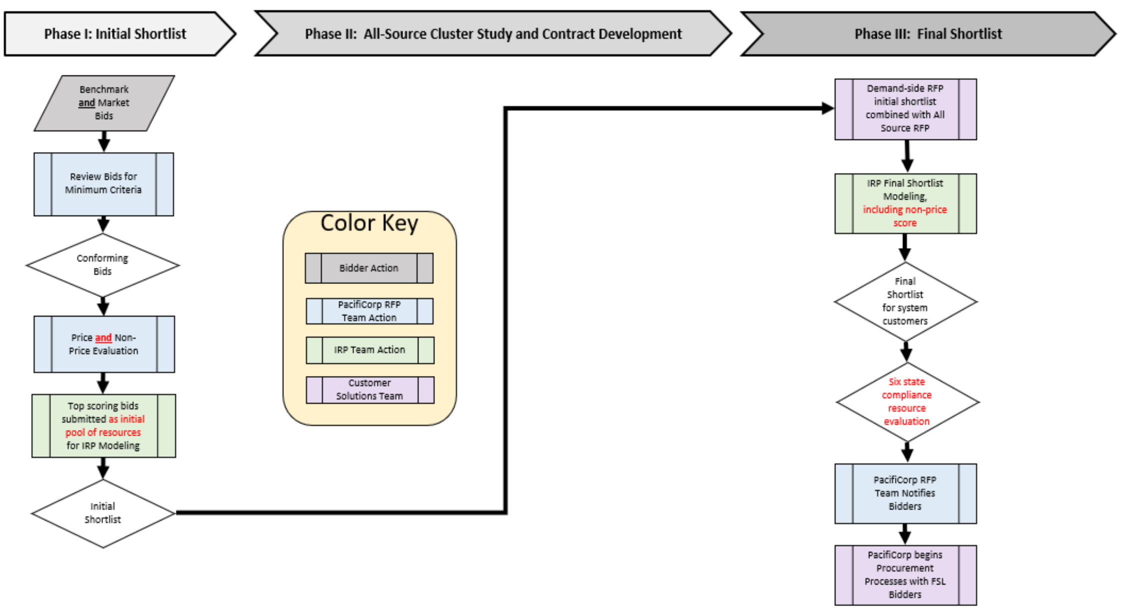


Figure P.2 – Bid Evaluation and Selection Process – Demand-side Resources



Phase I – Initial Shortlist

Phase I of the bid evaluation and selection process includes the due diligence, evaluation and ranking steps leading up to selection of the initial shortlist: i) bid eligibility screening to ensure conformance with the minimum requirements (Section 3.I); ii) price and non-price scoring to rank bids for inclusion in IRP portfolio optimization models; and iii) IRP modeling used to select the lowest cost bids for inclusion to the initial shortlist. During this phase of the bid evaluation process, PacifiCorp will not ask for, or accept, updated pricing or updates to any other bid components. PacifiCorp will rely on the pricing and other inputs as submitted into the 2022AS RFP for each benchmark and market resource to evaluate and rank bids. However, PacifiCorp will contact bidders to confirm and clarify information presented in each proposal. The pricing model will be made available to the IE, but not to bidders or stakeholders.

1. Conformance to Minimum Requirements

Benchmark and market bids will initially be screened after receipt against minimum requirements to determine RFP conformance and eligibility. After IE review and consultation, non-conforming bids will be notified to correct their bid within two (2) business days or be removed from the RFP. Consistent with OR 860-089-0400 (2), non-price score criteria that seek to identify minimum thresholds for a successful bid have been converted into minimum bidder requirements.

2. Price and Non-Price Scoring and Ranking

After PacifiCorp has screened for eligibility, conforming bids will be evaluated and given price and non-price scores. Each benchmark resource and market bid will be ranked based on the sum of their price and non-price bid score. A maximum of 75 points are allocated to price scoring and a maximum of 25 points for non-price scoring for a total maximum score of 100 points. Bids are then ranked, and the top performing bids are chosen to be the initial pool of resources to be considered as alternatives by the IRP model in selecting the initial shortlist.

Table P.1 – Scoring to Determine Initial Pool of Resources for IRP Modeling

	Maximum Score
1. Price	75 points
2. Non-price score	25 points

Price scores are determined using PacifiCorp's proprietary pricing models. Non-price scores are determined using a non-proprietary tool. Developers will be asked to grade themselves as part of their bid package, which PacifiCorp will audit before determining a final non-price score for each bid. More detail on the price and non-price score methodology is provided below.

The sum of the price and non-price scores will be ranked and compared against bids in similar geographic regions of PacifiCorp's territory. The 2021 IRP preferred portfolio selected cost-effective resources in three areas of PacifiCorp's territory where transmission upgrades prior to the 2026 COD deadline enabled additional resources to interconnect to PacifiCorp's transmission system and be transmitted to load (Table P.2). PacifiCorp may also consider a to-be-determined amount of new generating resources (including battery storage) in other geographic regions not specified in the 2021 IRP action plan but subject to the results of PacifiCorp Transmission's 2022 cluster study.

Table P.2 – PacifiCorp preferred portfolio transmission selections

Year	MW	Type	From	To	Description
2026	615	Wind	Within Willamette Valley OR Transmission Area		Enables 615 MW of interconnection: Albany, OR area reinforcement
2026	130	Wind	Portland North Coast	Willamette Valley	Enables 2080 MW of interconnection with 1950 MW TTC. Portland Coast area reinforcement, Willamette Valley and Southern Oregon
2026	600	Solar plus storage	Borah-Populous	Hemingway	Enables 600 MW interconnection with 600 MW TTC: B2H Boardman-Hemingway

1 - TTC = total transfer capability. The scope and cost of transmission upgrades are planning estimates. Actual scope and costs will vary depending upon the interconnection queue, the transmission service queue, the specific location of any given generating resource and the type of equipment proposed for any given generating resource.

For the purposes of selecting a pool of resources to be considered by the IRP model for the initial shortlist, PacifiCorp will rank the sum of price and non-price score for each resource type in each geographic region. For the locations listed in Table P.2, PacifiCorp will choose up to 150% of the MW capacity selected in the preferred portfolio for the IRP model to choose from in the initial shortlist process. For all other regions not represented in the preferred portfolio, PacifiCorp will choose up to a to-be-determined amount of installed MW bids in other geographic areas of PacifiCorp system to be included in the pool of resources from which the IRP model may select the initial shortlist.

If PacifiCorp determines that there is a distinct change in bid scores at a level of capacity that falls short or exceeds this capacity limit, the company will coordinate with the IE to establish a limit by resource type that could either fall below or exceed the maximum total capacity for a given location.

- **Price Score (up to 75 points).** PacifiCorp's proprietary price scoring model will calculate the delivered revenue requirement cost of each bid, inclusive of any applicable carrying cost and net of tax credit benefits, as applicable. In developing the revenue requirement cost for each bid, PacifiCorp requires certain cost data as inputs to the price score model. Table P.3 contains a summary of the cost and benefit component which are required and included in PacifiCorp's valuation analysis broken by bid structure.

Table P.3 – Summary of Cost/Benefit Components by Bid Structure

Component	PPA Option	BTA Option	Toll Option
Initial Capital Revenue Requirements (net of ITC, if solar)	-	(X)	-
Ongoing Capital Revenue Requirements	-	(X)	-
PTC Benefit (if wind)	-	Z	-
Terminal Value	-	Z	-
O&M, Lease/Royalty, Insurance	-	(X)	-
Property Taxes	-	(X)	-
State Generation Tax (if Wyoming or Montana)	-	(X)	-
Network Upgrade Revenue Requirements	(X)	(X)	(X)
Transmission Wheeling and Losses (if off-system)	(X)	(X)	(X)
PPA Price	(X)	-	-
Storage Costs	(X)	(X)	(X)
Energy Arbitrage and Operating Reserve Storage Value[17]	Z	Z	Z

[17] Energy Arbitrage and Operating Reserve Storage Value are only calculated for PPA and BTA bids include a dispatchable (e.g. battery storage) component.

Generation Energy Value (net of balancing area reserve obligation)	Z	Z	Z
Integration Cost	(X)	(X)	(X)

Z	Benefit
(X)	Cost

Any internal assumptions for key financial inputs (*i.e.*, inflation, discount rates, marginal tax rates, asset lives, AFUDC rates, *etc.*) and PacifiCorp carrying costs (*i.e.*, integration costs, owner's costs, *etc.*) will be applied consistently to all bids, as applicable. PacifiCorp anticipates that it will receive some bids which have an executed LGIA and other bids which will not yet have been studied by PacifiCorp Transmission. To ensure there is a fair comparison among bids, bidders shall not include the cost for any direct assigned interconnection costs in their bids, and PacifiCorp will not include the cost of transmission network upgrades associated with the proposed project in the initial shortlist price evaluation. As described in greater detail below, at the conclusion of the cluster study phase, as part of updating bid pricing, bidders will add interconnection costs to their refreshed prices for final shortlist evaluation.[18]

PacifiCorp's proprietary price scoring model scores each bid based on its net benefit to the system. The model uses system-value curves, which are developed and locked down with the IE in advance of receiving bids. The system-value curves are developed by the IRP Team using Plexos, which calculates the hourly marginal system energy value of a flat energy profile and the hourly marginal operating reserve value of a flat operating reserve profile, for each location in PacifiCorp's territory. The proprietary model also incorporates regional reserve values (PACE and PACW) provided by the IRP team.

The proprietary pricing model nets bid costs against the applicable system-value curve. Then, it calculates an inflation-adjusted real-levelized net cost or net benefit expressed in "$/MWh" for each bid. Finally, each bid's nominal net benefit is force ranked to determine the bid's price score. For each technology (resource type) in each transmission cluster bubble location, a maximum score of 75 points is assigned to the bid with the highest calculated net benefit and a minimum of zero (0) points to the evaluated bid with the lowest calculated net benefit. The remaining bids of that same technology[19] and location are scored on a 0-to-75-point scale according to their relative relationship (respective net benefits) to those of the highest and lowest performing bids.

- Non-Price Score (Up To 25 points). The non-price evaluation rubric is included at the end of this appendix and will be included in an RFP issued to market.[20] For each non-price factor, proposals will be assigned a one or a zero. PacifiCorp's non-price scoring model evaluates whether bids are thorough and comprehensive, whether the proposed resource is viable, and whether the bidder is likely to achieve commercial operation by December 31, 2026. The non-price rubric is designed to be objective, intuitive, and self-scoring. As a bid requirement, bidders are required to score themselves based on the completeness of RFP

[18] We will not accept price increases (exclusive of direct assigned and network upgrade costs) greater than ten percent above original bid.
[19] Technology means…. Generating facilities inclusive of batteries are considered different technology from facilities that only have the generating facility and no battery storage option.
[20] OAR 860-089-400-2(b).

bid requirements, the ability to contract with the project, and the maturity of the project and ability to deliver the project by the commercial operation deadline.

Table P.4 – Non-Price Factor Weighting

Non-Price Factor	Maximum Non-Price Factor Points
1. Bid Submittal Completeness	5 points
2. Contracting Progress and Viability	5 points
3. Project Readiness and Deliverability	15 points

The first section of non-price scoring model is similar to a checklist and grades bids based on completion of bid requirements such as providing complete, thorough and consistent responses. The second section grades bidders based on the ability to contract the resource bid. The third section of the non-price scoring model assesses each bid's development status and viability. Points are earned based on degree of site control, permit attained, completed equipment sourcing strategy and other operational characteristics such as dispatchability and having a reasonable construction schedule.

In compliance with OR 860-089-0400 (2), non-price factors have been converted to price factors where practicable. Non-price scores primarily relate to resource characteristics identified in the electric company's most recent acknowledged IRP Action Plan and reflect standard form contracts. Non-price scoring criteria is objective and reasonably subject to self-scoring analysis by bidders. Finally, non-price score criteria that seek to identify minimum thresholds for a successful bid have been converted into minimum bidder requirements.

All resources are required to complete the equity questionnaire included with the RFP. When considering California-located resources and resources allocated to Washington customers, PacifiCorp has a preference for projects that provide environmental and economic benefits to disadvantaged communities. For resources located in California, PacifiCorp has a supplier diversity target of 23% women-owned, minority-owned, disabled veteran-owned and LGBT-owned business enterprises and we encourage the bidder to register with California's supplier clearing house. When considering resources to be allocated to Washington customers, equity questionnaire responses will be used in Phase III of the evaluation process to measure Washington community benefit indicators as part of Washington's Clean Energy Transformation Act ("CETA"). Oregon-located resources should be able to demonstrate their ability to meet the requirements of HB2021, including but not limited to apprenticeship and workforce requirements.

- **Final Ranking (up to 100 points) to determine the Initial Resource Pool to be evaluated using the IRP models.** PacifiCorp will use the combined price and non-price results to rank each benchmark resource and market bid. Based on these rankings, PacifiCorp will identify an initial pool of resources by location and resource type based on the total bid score (maximum at 100 points, with a maximum of 75 points for price and a maximum of 25 points for non-price factors). This initial pool of resources will be made available as resource alternatives for IRP modeling.[21]

[21] Note, in instances where bidders offer a bid alternative for the same resource type in the same location, only the highest scoring bid alternative for that location and resource type will be included in the initial pool of resources.

When considering tiebreakers for inclusion in the initial pool of resources to be evaluated by the IRP model and considered for the initial shortlist, PacifiCorp will give preference to renewable energy projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants, and greenhouse gases when ranking projects.[22]

3. IRP Modeling and Selection of the Initial Shortlist

Following the Price and Non-Price Scoring, PacifiCorp will submit the initial pool of resources to the IRP team to select resources for the initial shortlist. The IRP team will evaluate the initial pool of resources using Plexos, the same production cost models used in the 2021 IRP. PacifiCorp will first process bid costs for IRP modeling; consistent with the treatment of capital revenue requirement in PacifiCorp's IRP modeling, PacifiCorp will convert any calculated revenue requirement associated with capital costs, as applicable (i.e., return on investment, return of investment, and taxes, net of tax credits, as applicable) to first-year, real-levelized costs. All other benchmark resource and market bid costs will be summarized in nominal dollars and formatted for input into to the IRP models, consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling. Projected renewable resource performance data (expected hourly capacity factor information) will also be processed for input into the IRP models. The IRP production cost models will then select the optimized portfolio of resources.

The IRP modeling tools will select the least cost resource types by location based on bid cost and performance data. PacifiCorp's initial shortlist may also include high-scoring bids in excess of the identified capacity limits if those projects have completed interconnection studies and will not be participating in PacifiCorp Transmission's interconnection cluster study process commencing in May 2022.

PacifiCorp will not make any of the IRP evaluation models available to the IE, bidders, or stakeholders. However, PacifiCorp will summarize for the IE how the IRP evaluation models function, and the IE will be provided with the inputs and outputs of all IRP models used during the evaluation process.

4. Initial Shortlist Notification by PacifiCorp

PacifiCorp will notify bidders that were selected to the initial shortlist in Phase I.

5. Bidder Notification to PacifiCorp Transmission

Immediately upon their selection to the initial shortlist, bidders will be required to notify PacifiCorp Transmission to demonstrate they have met the OATT's "commercial readiness" criteria. Bidders shall be responsible for also having satisfied any other PacifiCorp Transmission defined requirements established in the OATT. There should be no discrepancy between the facility characteristics bid into the RFP and what bidders have communicated to PacifiCorp Transmission as part of the cluster study application process. Bidders will be

[22] Pub. Util. Code § 399.13(a)(5)(7)(A) requires the following: "In soliciting and procuring renewable energy resources for California based projects, each electrical corporation shall give preference to renewable projects that provide environmental and economic benefits to communities afflicted with poverty or high unemployment, or that suffer from high emission levels of toxic air contaminants, criteria air pollutants and greenhouse gas emissions."

responsible to ensure that their bid(s) submitted to PacifiCorp in response to the 2022AS RFP are in compliance with and represent their interconnection service requests and/or existing contracts between Bidder and PacifiCorp Transmission.

Bidders assume the risk, and PacifiCorp will not be held liable, in the event that a bid selected to the initial shortlist in the 2022AS RFP is deemed ineligible for PacifiCorp's cluster study due to deviations between the submitted project bid and the LGIA, study documentation, or application associated with such project as submitted to PacifiCorp Transmission, or due to a Bidder's failure to satisfy any other requirement of PacifiCorp's OATT. Bidders will be required to meet all requirements of PacifiCorp Transmission's cluster study process including deposits, payments, milestones and any penalties associated with withdrawals from the cluster process and could be subject to disqualification from the 2022AS RFP for any violation during the cluster study process.

Phase II – Interconnection Cluster Study

Phase II is composed of the following tasks: cluster study report issued by PacifiCorp Transmission, resource capacity factor and storage performance verification performed by third-party consultants for PacifiCorp, and finally, bid updates by the initial shortlist bidders.

1. Interconnection Cluster Study Report

PacifiCorp will screen each benchmark and market bid and confirm that it is consistent with available interconnection documentation.[23] The cluster study report is expected to take approximately six months and will be performed by PacifiCorp Transmission in accordance with the OATT.

2. Resource Capacity Factor Verification

PacifiCorp will engage a third-party subject matter expert to verify the capacity factor of the proposed wind and solar resources selected to the initial shortlist consistent with Oregon rule 860-089-0400 5(a). This task will be done in parallel with the cluster study.

3. Bid Update

At the conclusion of the interconnection cluster study process, results of the cluster study will be posted to Open Access Same-time Information System (OASIS) and participating parties including the initial shortlist bidders will be notified of their results. Bidders will be required to provide PacifiCorp with their cluster study results or any updates to their existing interconnection studies and interconnection agreements and a summary of the direct assigned interconnection costs and network upgrade portions from their respective studies and agreements. Bidders will also be required to provide updated non-price scorecards and equity questionnaires. Finally, bidders will be required to provide updated bid prices which shall now include the direct assigned portion of their interconnection costs in their prices for PacifiCorp's analysis and evaluation. Best and final pricing must be provided for the same site and same interconnection proposed and studied as their original bid, with same or similar project equipment so that there is no material modification required with PacifiCorp Transmission,

[23] PacifiCorp Transmission customers retain the right to downsize the Project up to 60 percent prior to the return of the executed Cluster Study Agreement, per PacifiCorp OATT Volume 11 (2020.07.10), Section 39.4.1.

and on the same COD timeline as originally proposed. With the exception of price increases attributed to the direct interconnection costs assigned by PacifiCorp Transmission, Bidders may only increase bid price by 110% of what was originally offered or be subject to disqualification.

Phase III – Final Shortlist

Phase III is the selection of the final shortlist. In Phase III, PacifiCorp will review the cluster study results and any amended LGIAs and re-run Phase I price models to confirm bid conformance with minimum criterial. PacifiCorp will then process updated pricing, verified capacity factors and storage inputs, for inclusion in the IRP production cost models. Plexos (the same model used by PacifiCorp to develop resource portfolios in the 2021 IRP) will be rerun to develop a resource portfolio. As was done in the 2021 IRP and in Phase I, PacifiCorp will perform a reliability assessment to ensure that the selected portfolio of resources can meet all hourly load and operating reserve requirements with sufficient cushion to account for other system uncertainties such as non-normal weather events. Should incremental flexible resource capacity be required to maintain system reliability, additional resources will be selected from the initial shortlist of bids that are capable of providing incremental flex capacity or remove resources to hit the targeted reliability requirements. PacifiCorp will not update the non-price portion of the bid evaluation from Phase I. However, cost and risk analysis, along with any other factors not expressly included in the formal evaluation process, but required by applicable law or commission order, will be used by PacifiCorp, in consultation with the IE, to establish the final shortlist.

1. Cluster Study Results

PacifiCorp will analyze the results of the cluster study as well as any updated and amended LGIAs to determine any limits to available transmission capacity which might prevent bidders from meeting the December 31, 2026 COD deadline. PacifiCorp will then utilize the same proprietary models used in the Phase I initial ranking to ensure bidders have updated their pricing according to the requirements of the 2022AS RFP and not increased their pricing more than 110% apart from increases resulting from the inclusion of interconnection costs. In this way, PacifiCorp will reconfirm bidder eligibility with minimum criteria of the RFP.

2. Processing of Bid Updates

Similar to the Phase I pricing evaluation, PacifiCorp uses its proprietary models to process bid updates. The models are refreshed with updated bid prices, including interconnection costs from cluster study results and any LGIA updates, verified capacity factors and storage inputs. Consistent with the treatment of capital revenue requirement in PacifiCorp's IRP modeling, PacifiCorp converts any calculated revenue requirement associated with capital costs (i.e., return on investment, return of investment, and taxes, net of tax credits, as applicable) to first-year-real-levelized costs. Consistent with the treatment of non-capital revenue requirement in PacifiCorp's IRP modeling, all other bid costs are summarized in nominal dollars and formatted for input into to the IRP models. Projected renewable resource performance data (expected hourly capacity factor information) is also processed for input into the IRP models.

3. Combining of Supply-Side and Demand-Side RFPs Prior to Final Shortlist

At the same time initial shortlist bidders are updating their prices, and prior to the final evaluation and selection of the final shortlist, the shortlist bidders from the demand-side RFP will be available for incorporation and inclusion to the IRP models.

4. Bid Resource Portfolio Development

After initial shortlist bidders update their pricing to include interconnection costs and it is processed for inclusion in the IRP model, and after the demand-side RFP resources have been incorporated into the IRP model, the IRP team uses the Plexos model to optimize the portfolio of resources and select the final shortlist. PacifiCorp uses Plexos to develop and evaluate the cost of multiple resource portfolios.

PacifiCorp evaluates portfolios under a range of different environmental policy and market price scenarios (policy-price scenarios).[24] In this way, PacifiCorp uses Plexos to optimize its selection of bid resources to identify the lowest cost, reliable portfolio under multiple scenarios prior to undergoing additional stochastic risk analysis and further consideration as part of the final shortlist process.

5. Stochastic Risk Analysis

PacifiCorp next uses Plexos to evaluate each portfolio and its ability to perform under dynamic weather and market conditions. Plexos measures the stochastic risk of each portfolio through its production cost estimates. By holding a resource portfolio fixed and using Monte Carlo simulations of stochastic variables, including load, wholesale electricity and natural gas prices, hydro generation, and thermal unit outages, Plexos can measure the expected cost of each portfolio in an uncertain future.

6. Identifying Top-Performing 2022AS RFP Renewable Resource Portfolios

PacifiCorp then summarizes and analyzes the portfolios to identify the specific bid resources that are most consistently selected among the policy-price scenarios. Based on these data, as well as certain qualitative criteria, and in consultation with the IE, PacifiCorp may select one or more 2022AS RFP resource portfolios for further scenario risk analysis.

7. Scenario Risk Analysis

Plexos will be used to calculate the stochastic mean PVRR and the risk-adjusted PVRR for various policy-price scenarios.[25] This step of the evaluation process will help identify whether top-performing portfolios exhibit especially poor performance under the range of scenarios.

PacifiCorp takes the information from the prior steps and develops new system resource portfolios based on the top-performing resource portfolios in the prior steps. For each, it then

[24] Policy-price scenarios will be conceptually consistent with those used in the 2021 IRP (i.e., alternative environmental policy assumptions among low, medium, and high price scenarios), but updated to reflect PacifiCorp's assessment of the most current information. Policy-price scenario assumptions will be established and reviewed with the IE before updated bids with updated pricing are received and opened.

[25] The stochastic mean metric is the average of system net variable operating costs among 50 iterations, combined with the real-levelized capital costs and fixed costs taken from Plexos. The risk-adjusted metric adds 5% of system variable costs from the 95th percentile to the stochastic mean. The risk-adjusted metric incorporates the expected value of low-probability, high-cost outcomes.

calculates a stochastic mean PVRR and a risk-adjusted PVRR for each policy price-scenario before recommending a lowest cost, lowest risk portfolio from which to draw the final shortlist.

8. Other Factors: Applicable Law and Statutory Requirements

Before establishing a final shortlist, PacifiCorp may take into consideration, in consultation with the IE, other factors that are not expressly or adequately factored into the evaluation process outlined above, particularly any factor required by applicable law or Commission order to be considered.[26]

9. Final Shortlist Selection

PacifiCorp will summarize and evaluate the results of its scenario risk analysis, considering PVRR results, to identify the specific least-cost, least-risk bids. Based on these data and certain other factors as described above, and in consultation with the IE, PacifiCorp may establish a final shortlist.

Selection of the final shortlist will not be conditioned on the results of any future restudy arising out of the applicable PacifiCorp Transmission cluster study process.

After the final shortlist is established and approved, PacifiCorp will re-engage in negotiations with the selected bidders to finalize their contract and prepare the contract for execution. Selection of a bid to the final shortlist does not constitute a winning bid. Only execution of a definitive agreement between PacifiCorp and the bidder, on terms acceptable to PacifiCorp, in its sole and absolute discretion, will constitute a winning bid proposal.

10. Additional State Requirements

Following the final shortlist selection, PacifiCorp may consider resources additions and changes required for state compliance purposes. For example, to address Washington's CETA, in consultation with the IE, PacifiCorp will evaluate the final shortlist bids designated in part to serve Washington customers. In accordance with WAC 480-107-035, PacifiCorp will review the Equity Questionnaire for each resource and evaluate the associated risks and benefits to vulnerable populations and highly impacted communities associated with those bids. PacifiCorp, in consultation with the IE, may add or replace resources allocated to Washington customers in order to meet CETA goals with the understanding that the incremental cost associated with those resources would later be assigned to Washington customers.

Minimum Eligibility Requirements for Bidders (RFP Section 3.I)

Bidders may be disqualified for failure to comply with the RFP if any of the requirements outlined in this RFP are not met to the satisfaction of PacifiCorp, as determined in its sole discretion. If proposals do not comply with these requirements, PacifiCorp has the option to deem the proposal non-conforming and eliminate it from further evaluation. Reasons for rejection of a bidder or its proposal include, but are not limited to:

1. Receipt of any proposal after the bid submittal deadline.
2. Failure to submit the required Bid Fee when due.

[26] Footnote to UT, OR, WA, CA requirements.

3. Failure to meet the requirements described in this RFP and provide all information requested in Appendix C-2 - Bid Summary and Pricing Input Sheet of this RFP.
4. Failure to adequately demonstrate the viability of a COD on or before December 31, 2026 with the exception of long-lead resources as described in Section 1.C.
5. Failure to permit disclosure of information contained in the proposal to PacifiCorp's agents, contractors, regulators, or non-bidding parties to regulatory proceedings consistent with terms of executed confidentiality agreement.
6. Any attempt to influence PacifiCorp in the evaluation of the proposals outside the solicitation process.
7. Failure to provide a firm offer through the bid validity date outlined in Section 3.E. of this RFP.
8. Between date of initial cover letter accompanying bid and the bid validity date, failure to disclose to PacifiCorp at any time bidder has committed their project to another entity.
9. Failure to disclose the real parties of interest in any submitted proposal.
10. Failure to clearly specify all pricing terms for each base proposal and alternative(s).
11. Failure to offer unit contingent (as generated) or system firm capacity and energy to Company's network transmission system in either its PACE and PACW balancing areas.
12. For any bid that is proposing to interconnect to a third-party transmission system and secure transmission service to deliver the output of the resource to PacifiCorp at PACE or PACW, failure to provide a system impact study by the third-party transmission provider as well as satisfactory evidence that firm transmission rights are already secured in bidder or project owner's name or readily obtainable by bidder. Evidence of transmission rights must demonstrate that bidder can deliver the full output of the resource to PacifiCorp on or before December 31, 2026 and must detail all actual or estimated transmission costs.
13. Failure to materially comply with technical specification requirements in Appendix A -Technical Specifications for BTA proposals involving potential PacifiCorp ownership or operational control.
14. Failure to demonstrate a process to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long lead time equipment.
15. Failure to demonstrate that it can meet the credit security requirements for the resource proposed.
16. Failure to submit information required by PacifiCorp to evaluate the price and non-price factors described herein.
17. Failure or inability to abide by the applicable safety standards.
18. Failure to submit an acceptable contract structure.
19. A determination by PacifiCorp that collusive bidding or any other anticompetitive behavior has occurred.
20. Bidder or proposed project being bid is involved in bankruptcy proceedings.
21. Failure of the bidder's authorized officer to sign the proposal cover letter as required in this document and without edits.
22. Misrepresentation or failure to abide by Federal Trade Commission Green guidelines for renewable projects, if applicable.
23. Any change in law or regulatory requirements that make the bidder's proposal non-conforming.

24. Any matter impairing the bidder, the specified resource, or the generation of power or, if applicable, environmental attributes from the specified resource.
25. Failure to provide the minimum resource performance estimate information as described in Section 5.B. of the RFP.
26. Failure to provide a performance model output including hourly output values as identified in Appendix C-3 - Energy Performance Report.
27. Failure to provide Appendix D - Bidder's Credit Information.
28. Any bid that includes a requirement that PacifiCorp provide credit assurances.
29. In the case of a BTA bid, failure to submit an operations and maintenance proposal materially compliant with Appendix K - General Services Contract - Operations & Maintenance Services for Project.
30. Failure to provide documentation of binding, exclusive site control for the project including the facility but excluding right-of-way or easements for interconnection or transmission, roads, or access to the site.
31. Failure of the bid interconnection description and capacity to be consistent with the interconnection request and/or executed LGIA with PacifiCorp Transmission.
32. Failure to complete Appendix P - Equity Questionnaire
33. Any bid that increases its bid price in the final shortlist process by more than 110% of what was originally offered beyond price increases attributed to the direct interconnection costs.
34. In the case of a demand-side bid, failure to meet the requirements of PacifiCorp's 2021 Demand Response RFP included in Appendix S – 2020 Demand Response RFP - Requirements for Demand-side Bids.

Non-Price Scorecard

ALL BIDDERS ARE REQUIRED TO COMPLETE AND SELF-SCORE THE NON-PRICE SCORING MATRIX. PACIFICORP WILL COMPLETE DUE DILIGENCE, AUDIT AND EVALUATE BIDDER'S RESPONSES.

Bidder Company	
Project / Facility Name	
Assigned Bid Number	
PPA or BTA	
County/State	
MW	

Non-Price Score:

Bid Submittal Completeness	5
Contracting Progress and Viability	5
Project Readiness and Deliverability	15
Total Non Price Score	**25**

Non-Price Factor

I. Bid Submittal Completeness - Bidder completed each of following items accurately and in a manner consistent with the RFP requirements.	**Response**	**Bid Score**	**Comments**
· Appendix A-2 Interconnection plan including studies, agreements and confirmation of material modification, as applicable. Off-system bids have provided a system impact or facilities study with 3rd party transmission provider and demonstrated transmission availability to a POD on PacifiCorp's transmission system.	Yes	1	
· Appendix A-3 Permit Matrix	Yes	1	
· Appendix A-5 Project One-Line Drawing and Layout	Yes	1	
· Appendix A-6 Division of Responsibility (BTAs only)	Yes	1	
· Appendix A-7 Demonstration of Conformance with Owners Standards and Specifications (BTA)	Yes	1	
· Appendix A-9 Product Data-Equipment Supply Matrix	Yes	1	
· Appendix A-10 Plant Performance Guarantee/Warranties (BTAs only)	Yes	1	
· Appendix B-1 Notice of Intent to Bid - Summary of Bids	Yes	1	
· Appendix B-2 Signed Cover Letter without modification	Yes	1	
· Appendix B-2 Bid Proposal in compliance with the proposal format and requirements outlined in Appendix B-2	Yes	1	
· Appendix C-2 Bid Summary and Pricing Input Sheet provided without modification, including milestong payment schedule for BTAs	Yes	1	
· Appendix C-3 3rd Party Energy Performance Report. For wind submittals, one (1) electronic and hard copy of an independent third-party or in-house wind assessment analysis/report supported by a minimum of (a) two years of wind data for BTA proposals from the proposed site or (b) one year of wind data for PPA proposals from the proposed site. Wind data shall support the capacity factor. For solar proposals, one (1) electronic and hard copy of the PVSyst report, including the complete set of modeling input files in Microsoft Excel format that PacifiCorp can use to replicate the performance using PVSyst, PacifiCorp's preferred solar performance model, and two years of solar irradiance satellite data provided by Solargis, SolarAnyway or on-site met data.	Yes	1	
· Appendix D Bidder's Credit Information including a clear description of ownership and/or corporate structure, a letter from the entity providing financial assurances stating that it will provide financial assurances on behalf of the bidder	Yes	1	
· Appendix G-1 Confidentiality Agreement	Yes	1	
· Appendix J PacifiCorp Transmission Waiver	Yes	1	
· Appendix K General Services Contract-O&M Services (BTAs only)	Yes	1	
· Appendix P - Equity Questionnaire	Yes	1	
· Critical Issues Analysis (BTA) or sufficent narrative summary (PPA and Toll)	Yes	1	
· Permits including Conditional Use Permit and Conditional Use Permit, or equivalent (BTA)	Yes	1	
· Geotechnical report (BTA)	Yes	1	
· Environmental studies (endangered species, wetlands, Phase I ESA) (BTA)	Yes	1	
· Cultural studies (BTA)	Yes	1	
· Evidence of wire transfer provided prior to bid deadline in the correct amount for the correct number of bids	Yes	1	

II. Contracting Progress and Viability	Response	Bid Score	Comments
· A contract redline was provided including redline of Appendices.	Yes	1	
· A contract issues list was provided identifying bidder's top priority commercial terms.	Yes	1	
· Bidder redlines and issues lists are based on a lawyer's review of the proforma contract documents.	Yes	1	
· Bidder has the legal authority to enter into a contract for the output of the facility.	Yes	1	
· Bidder provided fixed and firm pricing for a contract term length between 5 and 30 years.	Yes	1	
· Bidder has offered a dispatchable product and agrees to PacifiCorp's ability to issue dispatch notices as defined in contract proforma.	Yes	1	
· Bidder has demonstrated it can meet the credit security requirements for the resource proposed.	Yes	1	
· Binding and exclusive site control documentation matches legal site description included in contract redline.	Yes	1	
· Appendix C-2 inputs (product, price, term, 8760, capacity factor, depreciation, degradation, storage specifications, BTA milestone payments, etc) are consistent with contract redlines.	Yes	1	
· BTA bids include list of assets to be transferred to PacifiCorp. Project documents with same legal entity as bidder. Studies and other contracts may be assigned and relied upon by PacifiCorp.	Yes	1	
III. Project Readiness and Deliverability	**Response**	**Bid Score**	**Comments**
· Schedule includes development and construction milestones (major equipment procurement and delivery on site, EPC execution and notice to proceed, interconnection backfeed, mechanical completion) which support the commercial operations date.	Yes	1	
· BTA assets (permits, leases, interconnection agreements, other contracts, resource assessments etc) support commercial operation date, 8760 resource estimates and net capacity factor through operating life.	Yes	1	
· Bidder has experience with (developing, constructing and/or operating) the same technology as being proposed.	Yes	1	
· Bidder has sufficient development experience (prior to construction) for size of project proposed (has completed at least one project 50% of proposed size).	Yes	1	
· Bidder has appropriate construction experience for the project size as proposed (has completed at least one project 50% of proposed size).	Yes	1	
· Bidder's Financing Plan demonstrates ability to finance project construction and ongoing operations.	Yes	1	
· Bidder has executed and recorded lease or warranty deed of ownership.	Yes	1	
· Required easements have been identified including project site and any gentie line up to point of interconnection.	Yes	1	
· Required easements have been secured including project site and any gentie line up to point of interconnection.	Yes	1	
· Bidder has signed LGIA with PacifiCorp Transmission which demonstrates ability to interconnect before proposed commercial operations date.	Yes	1	
· Met stations have been installed - and are functional - on site.	Yes	1	
· 50% Engineering designs are complete.	Yes	1	
· Proposed equipment is consistent with bid narrative, Appendix C-3 (8760), Appendix A-7 Technical Specifications and Appendix A-9.	Yes	1	
· EPC/Supply chain plan demonstrates bidder's ability to secure materials and complete construction, including securing safe harbor equipment, if applicable. Bidder has demonstrated a process to adequately acquire or purchase major equipment (i.e., wind turbines, solar photovoltaic panels, inverters, tracking system, generator step-up transformers, batteries) and other critical long lead time equipment.	Yes	1	
· Major equipment has been procured, EPC or construcution contractor agreements have been signed, and/or Master Service Agreement in place.	Yes	1	
· Wetlands are not present, or mitigation plans are in place.	Yes	1	
· Endangered species are not present on site or mitigations plans are in place.	Yes	1	
· One or more year of avian studies are available for proposed wind resources.	Yes	1	
· Cultural resources are not present, or mitigation plans are in place.	Yes	1	
· Site is zoned for proposed use.	Yes	1	
· Permitting is complete (i.e. project is shovel ready).	Yes	1	
· Proposal meets PacifiCorp's workforce diversity goal of 23% women-owned, minority-owned, disabled veteran-owned and LGBT-owned business enterprises.	Yes	1	

· If located in California, proposal is a renewable generating facility located in a community afflicted with poverty or high unemployment or that suffers from high emission levels according to California Office of Environmental Health Hazard Assessment (OEHHA)'s California Communities Environmental Health Screening Tool: CalEnviroScreen 4.0. (https://oehha.ca.gov/calenviroscreen/report/draft-calenviroscreen-40)	N/A	1	
· If located in Washington state, facility is located in a highly impacted community or in proximity to a vulnerable population according to Washington State Department of Health's Environmental Public Health Data website and Environmental Health Disparities V 1.1 tool (https://fortress.wa.gov/doh/wtn/WTNIBL/)	N/A	1	
· If located in Oregon state, facility meets HB2021 requirements including but not limited to apprenticeship and workforce requirements	N/A	1	
· Proposal is a renewable generating facility or non-emitting resource.	Yes	1	

Equity Questionnaire

All bidders are required to complete the equity questionnaire. Washington-sited, Oregon-sited and California-sited bidders will be required to complete a second set of questions specific to rules in each of those states.

Appendix P - Equity Questionnaire

Facility proximity to community			
Census track in which facility is located			https://geocoding.geo.census.gov/geocoder/geographies/address?form
Distance from facility to nearest residential home		miles	
Number of residential homes within 1 mile of facility		residences	
Number of residential homes within 6 miles of facility		residences	
Distance to nearest existing generation sources by fuel source within 6 miles of proposed facility;		miles	
Will the proposed facility replace/supplant identified generation sources?			
If "yes," provide estimated reduction in air pollutants/toxics in the community over life of the project/contract due to the facility (when/how much megawatt-hour ("MWh")/year), and avoided emissions released into the community (within 6 miles of the project).			

Population characteristics of community where facility is proposed				
To be completed based on census track in which facility is located				
Race and ethnicity			https://data.census.gov/cedsci/advanced	Table: DP05
White (%)		% of population white alone		
Black or African American (%)		% of population Black or African American alone		
Amercian Indian and Alaska Native (%)		% of population American Indian and Alaska Native alone		
Asian (%)		% of population Asian alone		
Native Hawaiian and Other Pacific Islander (%)		% of population Native Hawaiian and Other Pacific Islander alone		
Two or More Races (%)		% of population two or more races		
Hispanic or Latino (%)		% of population Hispanic or Latino		
Population 25 years and over with no high school diploma		% of population 25 years and older	https://data.census.gov/cedsci/advanced	Table DP02
Unaffordable housing		% of households (with and without mortgages and rentals) spending greater than 30% of income on housing	https://data.census.gov/cedsci/advanced	Table DP04
Population five years and older that speak English less than "very well" and "not at all"		% of people that speak English at home (5 years old or older)	https://data.census.gov/cedsci/advanced	Table B16004
Population with income 185% below poverty		% of total population with income 185% below poverty	https://data.census.gov/cedsci/advanced	Table S1701
Population 16 years and older unemployed		% of population 16 years or older	https://data.census.gov/cedsci/advanced	Table S2301

Facility Job Creation	Construction	Ongoing Operations	CA GO-156 Procurement Goal	
Total hires (number of jobs)			N/A	
Will there be an apprenticeship or training program?			N/A	
Projected local hires from nearby communities (number of jobs)			N/A	
Duration of work (months of construction / years of operation)			N/A	hours, days, months
Projected direct and indirect economic benefits to the local economy (annual $ from payroll taxes, property taxes, other taxes, services)			N/A	Check source
Minority-owned businesses (percentage of contractors and subcontractors)			15%	
Woman-owned businesses (percentage of contractors and subcontractors)			5%	
Service-disabled veteran-owned businesses (percentage of contractors and subcontractors)			1.5%	
LGBT firms (percentage of contractors and subcontractors)			N/A	
Unionized/represented labor (percentage of contractors and subcontractors)			N/A	
Average annual wage or hourly rate ($)			N/A	

Local Impacts		
Is Facility a distributed energy resource?		yes/no
Duration of construction		months
Source of water used during construction		
Source of water used during operations		
Is water a permitted or public source		public/private
Site disturbance - amount of disturbed soil during construction		acres
Tree and pollinator seed re-planting after construction		acres

Pollution Burden	Estimated Amount During Construction	Ongoing Operations
Environmental Exposures		
Annual amount of greenhouse gas emissions		
Diesel Emission Levels of NOx (tons per year)		
Particulate Matter 2.5 (PM2.5) (tons per year)		
Will the facility be required by the EPA to have a Risk Management Plan (Y/N)		
Estimated number of vehicles on site (daily average)		
Environmental Effects		
Will the facility have a transportation plan? (Y/N)		
Will the facility require a hazardous waste permit (Y/N)		
Will the facility have a dust mitigation plan (Y/N)		
Will the facility require a wastewater discharge permit (Y/N)		
Water use (gallons per year)		
Will the facility request an incidental take permit (Y/N)		

APPENDIX Q – ACRONYMS

AB = Assembly Bill

AC = alternating current

ACE = Affordable Clean Energy Rule

ACE = Area Control Error

AEG = applied energy group

AFSL = average feet (above) sea level

AFUDC = allowance for funds used during construction

AGC = Automatic Generation Control

AH = Ampere hour

A/m = Amperes per Meter

AMI = Advance Metering Infrastructure

AMR = Automated Meter Reading

ARO = asset retirement obligation

ATC = Available Transmission Capacity (Available Transfer Capacity?)

AVR = Automatic Voltage Regulator

AWEA = American Wind Energy Association

BA – Balancing Authority

BAA = Balancing Authority Area

BART = Best Available Retrofit Technology

BCF/D = billion cubic feet per day

BES = Bulk Electric System

BLM = Bureau of Land Management

BMcD = Burns and McDonnell

BPA = Bonneville Power Administration

BSER = best system of emission reduction

Btu = British thermal unit

CAES = compressed air energy storage

CAGR = compounded annual average growth rate

CAIDI = Customer Average Interruption Duration Index

CAISO = California Independent System Operator

CAP = Community Action Program

CARB = California Air Resources Board

CARI = Control Area Reliability Issues

CCCT = Combined Cycle Combustion Turbine

CCGT = Combined Cycle Gas Turbine

CCR = coal combustion residual

CCS = carbon capture and sequestration / Utah Committee of Consumer Services

CEC = California Energy Commission

CETA = Clean Energy Transformation Act

CF = capacity factor

CFL = Compact Fluorescent Light Bulb

CIPS = Critical Infrastructure Protection Standards

CIS = Corporate Information Security

CO = carbon monoxide

CO_2 = carbon dioxide

Cogen = Cogeneration

COMPASS = Coordinated Outage Management Planning and Scheduling System?

CPA = Conservation Potential Assessment

CPU = Clark Public Utilities / cost per unit

CPUC = California Public Utilities Commission

CREA = Columbia Rural Electric Association

CSP = concentrated solar power

CTG = Combustion Turbine Generator

CUB = (Oregon) Citizen's Utility Board

DC = direct current

DF = duct firing

DG = Distributed Generation

DOE = Department of Energy

DPU = Utah Division of Public Utilities / Distribution Protection Unit (relay)

DR = Demand Response

DRA = Division of Ratepayer Advocates

DSM = demand-side management

EBIT = Earnings before Interest and Taxes

EDAM = extended day-ahead market

EE = Energy Efficiency

EEI = Edison Electric Institute

EIA = Energy Information Administration

EIM = Energy Imbalance Market

ELCC = Effective Load Carrying Capacity

EPA = Environmental Protection Agency

EPC = engineering, procurement, and construction

EPM = Energy Portfolio Management System

ERC = emission rate credit

ETO = Energy Trust of Oregon

EUBA = Electric Utility Benchmarking Association

EUI = Energy Utilization Index

EUL = effective useful life

EV = Electric Vehicle

FCC = Federal Communications Commission

FCRPS = Federal Columbia River Power System

FERC = Federal Energy Regulatory Commission

FIP = federal implementation plan

FIT = Feed-In Tariff

FLPMA = Federal Land Policy Management Ace

FOTs = Front Office Transactions

FRAC = Flexible Resource Adequacy Capacity

GAAP = Generally Accepted Accounting Principles

GBP = Great Britain Pound

GE = General Electric

GFCI = Ground Fault Circuit Interrupter

GHG = Greenhouse Gas

GIC = Generation Interconnection Contract

GIS = Geographic Information System

GPS = Global Positioning System

GRC = General Rate Case

GRID = Generation and Regulation Decision Model (used for net power cost pricing calc and QF avoided cost calc)

GT = Gas Turbine

GW = Gigawatt

GWh = gigawatt-hours (gigawatt)

H = Hour

HB = House Bill

HCC = Hydro Control Center

HRSG = Heat Recovery Steam Generator

HVAC = heating, ventilation, and air conditioning

Hz = Hertz

IBEW = International Brotherhood of Electrical Workers

IC = internal combustion

ICE = Intercontinental Exchange

IECC = International Energy Conservation Code

IEEE = Institute of Electrical and Electronic Engineers

IGCC = integrated gasification combined cycle

IHS = Information Handling Services

ILR = Inverter Loading Ratio

IOU = Investor Owned Utility

IPC = Idaho Power Company

IPP = Independent Power Producer

IPOC = Idaho Power Company

IPUC = Idaho Public Utility Commission

IRP = Integrated Resource Plan

IS = Information Systems

ISO = international organization for standardization / Independent System Operator

IT = Information Technology

ITC = Investment Tax Credit

K = kilo (thousand)

Kv = kiloVolt

kW = kilowatt

kWh = kilowatt-hour

kW-yr = Kilowatt-Year

kV = kilovolt

kVa = kilovolt-ampere

kVAr = kilovolt-ampere-reactive

kVArh = kilovolt-ampere-reactive-hour

Lb = Pound

LCOE = Levelized Cost of Energy

LED = light emitting diode

Li-Ion = lithium-ion battery

Lm = lumens

LNG = Liquefied Natural Gas

LOLH = loss of load hour

LRA = Local Regulatory Authority

LSE = load serving entities

MATS = Mercury and Air Toxics Standards

MEHC = MidAmerican Energy Holdings Company

MMBpd = Million barrels of oil per day

MMBtu = Million British thermal units

MSP = Balancing Authority Area / Multi-State Process

MVA = megavolt-ampere

MVAr = megavolt-ampere-reactive

MVA LTC = megavolt-ampere, load tap changing

MW = Megawatt

MWh = megawatt hour

$MWh = dollars per megawatt hour

NAAQS = National Ambient Air Quality Standards

NAPEE = National Action Plan for Energy-Efficiency

NCM = nickel cobalt manganese (sub-chemistry of Li-Ion)NEEA = Northwest Energy Efficiency Alliance

NEEP = Northeast Energy Efficiency Partnerships

NEMA = National Electrical Manufacturer’s Association

NEMS = National Energy Modeling System

NERC = North American Electric Reliability Corporation

NH_3 = Ammonia

NOAAF = National Oceanic and Atmospheric Administration Fisheries

NRC = Nuclear Regulatory Commission

NOx = Nitrogen Oxides

NPV = net present value

NQC = Net Qualifying Capacity

NSPS = new source performance standards

NTTG = Northern Tier Transmission Group

NWEC = NW Energy Coalition

NWPCC = Northwest Power and Conservation Council

O&M = operations and maintenance

OAR = Oregon Administrative Rules

OASIS = Open Access Same Time Information System

OATT = Open Access Transmission Tariff

ODOE = Oregon Department of Energy

ODOT = Oregon Department of Transportation

OE = Owner’s Engineer

OEM = Original Equipment Manufacturer

OFPC = Official Forward Price

OMS = Outage Management System / Operations Mapping System

OPUC = Oregon Public Utility Commission

ORS = Oregon Revised Statutes

PAC = PacifiCorp

PACE = PacifiCorp East?

PaR = Planning and Risk Model

PC = pulverized coal

PCB = Polychlorinated Biphenyls

PC CCS = pulverized coal equipped with carbon capture and sequestration

PDDRR = Partial displacement differential revenue requirement methodology (OR QF)

PG&E = Pacific Gas & Electric

PGE = Portland General Electric

PHES = pumped hydro energy storage

PJM = no definition

PM = particulate matter

$PM_{2.5}$ = Particulate Matter 2.5 microns and larger

PM_{10} = Particulate Matter 10 microns and larger

PNUCC = Pacific Northwest Utility Coordinating Council

POU = Publicly Owned Utility

PP = Pacific Power

PPA = Power Purchase Agreement

Ppb = parts per billion

PP&L = Pacific Power & Light Co.

ppmvd@15%02 = parts per million, dry-volumetric basis, corrected to 15% Oxygen (O_2)

PRM = Planning Reserve Margin

PSC = Public Service Commission

PSE = Purchasing-Selling Entity

Psia = Pounds per Square Inch-Absolute

PTC = Production tax credit

PTO = Participating Transmission Owner

PTP = point to point

PUC = Public Utility Commission

PURPA = Public Utility Regulatory Policies Act

PV = photovoltaic

PVRR(d) = present value revenue requirement (delta)

PWC = PricewaterhouseCoopers

QC = Qualifying Capacity

RA = Resource Adequacy

RCRA = Resource Conservation and Recovery Act

RCW = Revised Code of Washington

REA = Rural Electrical Administration / Rural Electrification Administration

REC = renewable energy credit (certificate) / Rural Electric Cooperative

RFI = request for information

RFM = Rate Forecasting Model

RFP = Request for Proposal

RH = Relative humidity

RICE = Reciprocating Internal Combustion Engine

RMP = Rocky Mountain Power / Resource Management Plan

RPS = Renewable Portfolio Standard

RTO = Regional Transmission Organization

RTF = Regional Technical Forum

RTP = real-time pricing

RVOS = Resource Value of Solar

SAIDI = System Average Interruption Duration Index

SAIFI = System Average Interruption Frequency Index

SB = Senate Bill

SCCT = Simple Combined Cycle Turbine

SCPC = Super-critical pulverized coal

SCPPA = Southern California Public Power Authority

SCR = selective catalytic reduction system

SEC = Securities and Exchange Commission

SEEM = Simple Energy Enthalpy Model

SEPA = Solar Electric Power Association

SIP = state implementation plan

SF = Senate File

SF6 = Sulfur Hexafluoride

SNCR = selective non-catalytic reduction

SO = System Optimizer

SO_2 = Sulfur Dioxide

SO_x = Sulfur Oxide / Sarbanes-Oxley Act

SRSG = Southwest reserve sharing group

SSR = supply side resource (table)

STEP = Sustainable Transportation and Energy Plan

STG = Steam turbine generator

SWEEP = Southwest Energy Efficiency Project

T&D = Transmission & Distribution

th = Therm

TPL = transmission planning assessment

UAE = Utah Association of Energy Consumers

UDOT = Utah Department of Transportation

UMPA = Utah Municipal Power Agency

UNIDO = United Nations Industrial Development Organization

UP&L = Utah Power & Light Co.

UPC = Use per Residential Customer

UCE = Utah Clean Energy

UCT = Utility Cost Test

VERs = Variable Energy Resources

V = volt

VA = Volt-ampere

VDC = Volts Direct Current

VOC = volatile organic compounds

W = Watts

WAC = Washington Administrative Code

WACC = weighted average cost of capital

WAPA = Western Area Power Administration

WCA = West Control Area

WECC = Western Electricity Coordinating Council

Wh = Watt-hour

WIEC = Wyoming Industrial Energy Council

WPSC = Wyoming Public Service Commission

WRA = Western Resource Advocates

WREGIS = Western Renewable Generation Information System

WSEC = Washington State Energy Code 2015

WSPP = Western Systems Power Pool

WTG = wind turbine generator

WUTC = Washington Utilities and Transmission Commission