Attachment A

PacifiCorp 2021 Integrated Resource Plan
April 1 Interim Filing

PACIFICORP DRAFT IRP OVERVIEW

PacifiCorp files an IRP on a biennial basis with the state utility commissions of Utah, Oregon, Washington, Wyoming, Idaho, and California. The IRP fulfills the company's commitment to develop a long-term resource plan that considers cost, risk, uncertainty, and the long-run public interest. The IRP is 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.

PacifiCorp's IRP establishes a long-term plan to ensure it can reliably serve its customers at a reasonable cost and in a manner "consistent with the long-run public interest." The main role of the IRP is to serve 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 planning tool, it supports informed decision-making on resource procurement by providing an analytical framework for assessing resource investment tradeoffs, including the evaluation of bids submitted into request for proposal (RFP) processes. 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.

The Company began the 2021 IRP process in January 2020 and has held a robust and inclusive public input process that has to date included 13 public input meeting in addition to state-specific and topic-specific technical meetings. As the company continues the analytical work related to the IRP in advance of the final IRP filing no later than September 1, 2021, the stakeholder process will continue to ensure timely opportunities for feedback. Additional information regarding the public input process throughout the summer can be found in Appendix C – Public Input Process. This filing provides the following updates to the January 4, 2021 draft filing (April 1 Filing), which are not contingent on the IRP modeling process and demonstrate progress to date in development of the 2021 IRP:

- Draft Chapter 4 – Transmission
- Draft Appendix A – Load Forecast appendix updated to include the impact of new legislation on the Private Generation Study and results that are not dependent on the IRP portfolio outputs Draft Appendix B – IRP regulatory compliance appendix updated to reflect adopted rules under WAC 480-100
- Draft Appendix C – Public-input process appendix updated to include a schedule from April1 2021 to PacifiCorp's filing of the final IRP no later than September 1, 2021
- Draft Appendix D – Demand-side management appendix describing programs and analysis
- Draft Appendix O – Private Generation Study updated to include the effects of tax legislation passed in late 2020
- Draft Appendix R – Clean Energy Action Plan (CEAP) updated to include additional community analysis and preliminary identification of vulnerable and highly-impacted communities per WAC 480-100-620(9)

PacifiCorp plans to include the following in its final 2021 IRP to be filed no later than September 1, 2021:

- Summary of PacifiCorp's approach to integrated resource planning, preferred portfolio highlights, load and resource balance, 2021 IRP advancements and supplemental studies, and the 2021 IRP action plan (Chapter 1 – Executive Summary)
- Summary of the components of PacifiCorp's IRP, the role of an IRP and integrated resource planning process, and the public-input process (Chapter 2 – Introduction)
- Assessment of the planning environment, market trends and fundamentals, legislative and regulatory developments, and current procurement activities (Chapter 3 – Planning Environment)
- Description of PacifiCorp's transmission planning efforts and activities (Chapter 4 – Transmission)
- Load and resource balance on a capacity and energy basis based on the preferred portfolio and determination of the load and energy positions for the first ten years of the twenty-year planning horizon (Chapter 5 – Load and Resource Balance)
- Cost-and-performance assumptions for proxy resource options considered for addressing future capacity and energy needs (Chapter 6 – Resource Options)
- Description of the IRP modeling, including a description of the resource portfolio development process, cost and risk analysis, and preferred portfolio selection process (Chapter 7 – Modeling and Portfolio Evaluation Approach)
- Discussion of PacifiCorp's commitment to reliability and actions to support reliability: regional resource adequacy efforts, wildfire mitigation planning, and other efforts to ensure the customers can be served reliably and safely (Chapter 8 – Reliability)
- Presentation of IRP modeling results, and selection of top-performing resource portfolios and PacifiCorp's preferred portfolio including sensitivities (Chapter 9 – Modeling and Portfolio Selection Results)
- 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 – Action Plan and Resource Procurement)

Presented within these chapters will be a large volume of figures and tables to present the information and resulting analysis and results. Please see the following list of tables and figures from the 2019 IRP included herein as reference to the type of information that will be included in final filing to be made no later than September 1, 2021.

It is anticipated that the appendices filed with the 2021 IRP on September 1, 2021, will likely contain the items listed below.

- Load Forecast Details (Volume II, Appendix A)(draft included herein),
- IRP Regulatory Compliance (Volume II, Appendix B)(draft included herein),

- Public Input Process (Volume II, Appendix C)(draft included herein),
- Demand Side Management Resources (Volume II, Appendix D)(draft included herein),
- Smart Grid discussion (Volume II, Appendix E),
- Flexible Reserve Study (Volume II, Appendix F),
- Plant Water Consumption data (Volume II, Appendix G),
- Stochastic Parameters (Volume II, Appendix H),
- Reliability Assessment (Volume II, Appendix I),
- Western Resource Adequacy Evaluation (Volume II, Appendix J),
- Capacity Expansion Results Detail (Volume II, Appendix K),
- Stochastic Simulation Results (Volume II, Appendix L),
- Case Study Fact Sheets (Volume II, Appendix M),
- Private Generation Study (Volume II, Appendix O)(draft included herein),
- Renewable Resources Assessment (Volume II, Appendix P),
- Energy Storage Potential Evaluation (Volume II, Appendix Q)
- Clean Energy Action Plan (Volume II, Appendix R)(draft included herein), and
- Acronym Guide (Volume II, Appendix S)(draft included herein)

PacifiCorp will also provide data discs for the 2021 IRP with the final filing that include the associated workpapers and modeling inputs and outputs.

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 has held four state-specific meetings and 14 public-input meetings to date, some of which spanned two days to facilitate information sharing, collaboration, and understanding for the 2021 IRP. The topics covered many topics, ranging from specific input assumptions to the portfolio modeling approach and risk analysis that will be implemented. Table 2.1 lists the public-input meetings and highlights key topics covered. Volume II, Appendix C (Public-Input Process) provides more detail around the public-input process.

Table 2.1 – 2021 IRP Public Input Meetings

Meeting Type	Date	Key Topics
CPA Technical Workshop	1/21/20	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
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 (RFP) Update, Transmission Overview and Update
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

Meeting Type	Date	Key Topics
State Meeting	7/24/20	Oregon state stakeholder comments
General Meeting (2-Day)	7/30/20	Load Forecast Update, Distribution System Planning, Supply-side Resource Study Efforts, Endogenous Retirement 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, Conservation Potential Assessment Final Results
General Meeting	11/16/20	Plexos Benchmark Result, Modeling Assumptions, All-source Request for Proposals Update.
General Meeting	12/3/20	Portfolio Development, Transmission Modeling, Customer Preference, Carbon Capture Use and Sequestration Supply Side Update.
General Meeting	1/29/21	Energy Efficiency Bundling Methodology and Renewables Shaping
General Meeting	2/25/21	Update on PacifiCorp IRP process
General Meeting (2-Day)	4/22/2021	Initial discussion of modeling results; opportunity for stakeholder feedback.
	4/23/2021	Initial discussion of modeling results; opportunity for stakeholder feedback.
General Meeting (2-Day)	5/27/2021	Continued discussion of modeling results and stakeholder feedback.
	5/28/2021	Continued discussion of modeling results and stakeholder feedback.
General Meeting (2-Day)	6/24/2021	Discussion of portfolios due to incorporation of AS 2020 RFP final short list results, discussion of cost and risk portfolio analysis; opportunity for stakeholder feedback.
	6/25/2021	Discussion of portfolios due to incorporation of AS 2020 RFP final short list results, discussion of cost and risk portfolio analysis; opportunity for stakeholder feedback.
General Meeting (2-Day)	7/29/2021	Discuss selection of preferred portfolio/cost and risk analysis; opportunity for stakeholder feedback.
	7/30/2021	Discuss selection of preferred portfolio/cost and risk analysis; opportunity for stakeholder feedback.
General Meeting	8/12/2021	If needed.

In addition to the public-input meetings, PacifiCorp used other channels to facilitate resource planning-related information sharing and stakeholder input throughout the IRP development process. The company maintains a public website: (www.pacificorp.com/energy/integrated-resource-plan.html), an e-mail “mailbox” (irp@pacificorp.com), and a dedicated IRP phone line (503-813-5245) to support communications and inquiries among participants. Additionally, a stakeholder feedback form was used to provide opportunities for stakeholders to submit additional input and ask questions throughout the 2021 IRP development process. The submitted forms, as well as PacifiCorp’s responses to these feedback forms are located on 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 and is provided as Attachment B to this filing

PLANNING ENVIRONMENT

Introduction

Chapter 3 profiles the major external influences that affect PacifiCorp's long-term resource planning and recent procurement activities. External influences include events and trends affecting the economy, wholesale power and natural gas prices, and public policy and regulatory initiatives that influence the environment in which PacifiCorp operates.

Major issues in the power industry market include capacity resource adequacy and associated standards for the Western Electricity Coordinating Council (WECC). Future natural gas prices, the role of gas-fired generation and the falling costs and increasing efficiencies of renewables 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 significant issue facing PacifiCorp continues to be planning for an eventual, but highly uncertain, climate change regulatory regime. This chapter provides discussion on climate change regulatory initiatives as well as a review of significant policy developments for currently regulated pollutants.

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

Wholesale Electricity Markets

PacifiCorp's system does not operate in an isolated market. Operations and costs are tied to a larger electric system known as the Western Interconnection which functions, on a day-to-day basis, as a geographically dispersed marketplace. Each month, millions of megawatt-hours of energy are traded in the wholesale electricity market. These transactions yield economic efficiency by ensuring that resources with the lowest operating cost are serving demand in a region and by providing reliability benefits that arise from a larger portfolio of resources.

PacifiCorp actively participates in the wholesale market by making purchases and sales to keep its supply portfolio in balance with customers' constantly varying needs. This interaction with the market takes place on time scales ranging from sub-hourly to years in advance. Without the wholesale market, PacifiCorp or any other load serving entity would need to construct or own an unnecessarily large margin of supply that would not be used to serve load in all but the most unusual circumstances and that would substantially diminish its capability to cost effectively match delivery patterns to the profile of customer demand.

The benefits of access to an integrated wholesale market have grown with the increased penetration of intermittent generation such as solar and wind. Intermittent generation tends to come online and go offline abruptly in congruence with changing weather conditions. Federal and state (where applicable) tax credits, declining capital costs, and improved technology performance have contributed to positive economics for wind and solar particularly in areas of high potential. To effectively integrate these resources requires more flexible generation, new storage technologies, market design changes, and a robust transmission system that links everything together.

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

The intermittency of renewable generation has also given rise to a greater need for fast-responding storage, which is essential for grid stability and resiliency. Pumped storage has been the traditional storage option but large-scale expansion can be limited due to geography. That said, there are several opportunities to further expand pumped storage capacity in the WECC. 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 Utilities Commission (CPUC) required investor-owned utilities to procure 1,325 MW of storage by 2020; that requirement is now close to being met. Costs are expected to continue to decline as electric vehicle manufacturing drives further innovation. To date, five states have implemented energy storage targets or mandates, with another two states seriously considering implementation.[2] In California, the world's largest Li-ion battery, 300 MW, is scheduled to go online at Pacific Gas & Electric (PG&E)'s Moss Landing Power Plant in 2021. Hybrid co-located solar photo voltaic (SPV) and battery systems are now in Hawaii, Arizona, Nevada, California, and Texas. In February 2019, Arizona Public Service announced it would pair existing solar with 200 MW of battery storage while Nevada Energy has contracted for 100 MW of battery storage to be paired with solar. But, perhaps most importantly, in 2018, the Federal Energy Regulatory Commission (FERC) directed regional transmission organizations (RTO) and independent system operators (ISO) to develop market rules for the participation of energy storage

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

in wholesale energy, capacity, and ancillary services markets[3]. The FERC gave operators nine months to file tariffs and another year to implement – essentially opening wholesale markets to energy storage. Operators' proposed tariffs have varied substantially among regions with PJM requiring a 10-hour continuous discharge capability while New England requires a continuous 2-hour capability. An initial shortlist was identified in October 2020 for PacifiCorp's 2020 All Source RFP. The initial shortlist includes 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. 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.[4]

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 California Independent System Operator (CAISO). The resulting energy imbalance market (EIM) became operational November 1, 2014. By December 2015, Nevada Energy had joined as did Puget Sound Energy and Arizona Public Service in 2016. Portland General Electric joined in 2017, followed by Powerex and Idaho Power in 2018, Balancing Authority of Northern California in 2019, and Salt River Project and Seattle City Light in 2020. Los Angeles Department of Water & Power, Northwestern Energy, and Public Service Company of New Mexico are anticipated to join in 2021, followed by Avista and Tucson Electric Power in 2022. The multi-service area footprint brings greater resource and geographical diversity allowing for increased reliability and cost savings in balancing generation with demand using 15-minute interchange scheduling and five-minute dispatch. CAISO's role is limited to the sub-hourly scheduling and dispatching of participating EIM generators. CAISO does not have any other grid operator responsibilities for PacifiCorp's service areas.

PacifiCorp has been an active participant in stakeholder efforts to develop a voluntary day-ahead market referred to as the Extended Day Ahead Market (EDAM), at the CAISO. This stakeholder effort began in September of 2019 and is currently in the design phase. PacifiCorp recently submitted comments as part of the Joint EIM Entities (EIM Entities) in response to the CAISO's straw proposal that outlines participation in the EDAM.[5] The EIM Entities reiterated the importance and support for achieving key principles and elements that include ensuring a voluntary market design, ensuring equity and "no leaning" for Balancing Authority Areas, and consistency with obligations of the Open Access Transmission Tariff. The EDAM is targeted for implementation in October 2022. However, due to recent weather and wildfire related events this summer in California, stakeholder efforts on the EDAM have been delayed. It is unclear at this time how that may ultimately affect achievement of the target implementation date however, PacifiCorp will continue to be an active participant in and proponent of this effort as it progresses.

As with all markets, electricity markets are faced with a wide range of uncertainties. However, some uncertainties are easier to evaluate than others. Market participants are routinely studying

[3] 162 FERC ¶ 61,127 United States of American Federal Energy Regulatory Commission, 18 CFR Part 35 [Docket Nos. RM16-23-000; AD16-20-000; Order No. 841] *Electric Storage Participation in Markets Operated by Regional Transmission Organizations and Independent System Operator* (Issued February 15, 2018)
[4] Solar or wind resources coupled with battery storage.
[5] https://stakeholdercenter.caiso.com/StakeholderInitiatives/AllComments/45a5a15c-c5c9-407a-9f59-4e7ce97a8544#org-94cd20c1-84ba-4261-bedd-58e03168ac43

demand uncertainties driven by weather and overall economic conditions. Similarly, there is a reasonable amount of data available to gauge resource supply developments. The North American Electric Reliability Corporation (NERC) and Western Electric Coordinating Council (WECC) 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] The outputs of those studies may be included in PacifiCorp's analysis as part of the final filing made no later than September 1, 2021.

There are other uncertainties that are more difficult to analyze that can heavily influence the direction of future prices. One such uncertainty is the evolution of natural gas prices over the course of the IRP planning horizon. Given the increased role of natural gas-fired generation, gas prices are a critical determinant of western electricity prices, and this trend is expected to continue over the term of this plan's decision horizon. Another critical uncertainty that weighs heavily on the 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.[7]

Natural Gas Uncertainty

Please see discussion in the 2019 IRP, Volume I, Chapter 3 – Planning Environment, under this section for an example of the type of information that will be updated and included in the company's final IRP filing no later than September 1, 2021.

The Future of Federal Environmental Regulation and Legislation

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

Federal Climate Change Legislation

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

Federal Renewable Portfolio Standards

Since 2010, there has been no significant activity in the development of a federal renewable portfolio standard (RPS). Accordingly, PacifiCorp's 2021 IRP assumes no federal RPS requirement over the course of the planning horizon.

[6] 2018 Long-term Reliability Assessment, December 2018, North American Electric Reliability Assessment
[7] A forecast of California carbon allowance prices is used as a proxy for future cap-and-trade allowance auction

prices.

Federal Policy Update

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

New Source Performance Standards (NSPS) are established under the Clean Air Act for certain industrial sources of emissions determined to endanger public health and welfare. On August 3, 2015, the United States Environmental Protection Agency (EPA) issued a final rule limiting CO_2 emissions from coal-fueled and natural-gas-fueled power plants. New natural-gas-fueled power plants can emit no more than 1,000 pounds of CO_2 per megawatt-hour (MWh). New coal-fueled power plants can emit no more than 1,400 pounds of CO_2/MWh. The final rule largely exempts simple cycle combustion turbines from meeting the standards. On December 6, 2018, the EPA proposed to revise the NSPS for greenhouse gas emissions from new, modified, and reconstructed fossil fuel-fired power plants. EPA's proposal would replace EPA's 2015 determination that carbon capture and storage technology was the best system of emissions reduction for new coal units. The comment period for the proposed revisions closed in March 2019.

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

On August 3, 2015, 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.

Clean Air Act Criteria Pollutants – National Ambient Air Quality Standards

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

In October 2015, EPA issued a final rule modifying the standards for ground-level ozone from 75 parts per billion (ppb) to 70 ppb. On November 16, 2017, the EPA designated all counties where PacifiCorp's coal facilities are located (Lincoln, Sweetwater, Converse and Campbell Counties in Wyoming; and Emery County in Utah) as "Attainment." On June 4, 2018, the EPA designated Salt

Lake County and part of Utah County where the PacifiCorp Lake Side and Gadsby facilities are located as “Marginal Nonattainment.” A marginal designation is the least stringent classification for a nonattainment area and does not require a formal State Implementation Plan (SIP), however Utah has until 2021 to develop ways to meet the standard.

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

Regional Haze

EPA's regional haze rule, finalized in 1999, requires states to develop and implement plans to improve visibility in certain national park and wilderness areas. On June 15, 2005, EPA issued final amendments to its regional haze rule. These amendments related to provisions that require emission controls known as the Best Available Retrofit Technology (BART) for industrial facilities meeting certain regulatory criteria with emissions that have the potential to affect visibility. The regulated pollutants include fine PM, NO_X, SO_2, certain volatile organic compounds, and ammonia. The 2005 amendments included final guidelines, known as BART guidelines, for states to use in determining which facilities must install controls and the type of controls the facilities must use. States were given until December 2007 to develop their implementation plans, in which states were responsible for identifying the facilities that would have to reduce emissions under BART guidelines, as well as establishing BART emissions limits for those facilities. States are also required to periodically update or revise their implementation plans to reflect current visibility data and an effective long-term strategy for achieving reasonable progress toward visibility goals. In January 2017 EPA issued a final rule updating requirements for periodic updates in state implementation plans. States are currently required to submit the next periodic update by July 31, 2021.

The regional haze rule is intended to achieve natural visibility conditions by 2064 in specific National Parks and Wilderness Areas, many of which are located in Utah and Wyoming where PacifiCorp operates generating units, as well as Arizona where PacifiCorp owns a coal unit that has ceased operations, and in Colorado and Montana where PacifiCorp has partial ownership in generating units operated by others, but are nonetheless subject to the regional haze rule.

On August 20, 2019, EPA issued a final guidance document to support states with the technical aspects of developing regional haze state implementation plans for the second implementation period of the Regional Haze Program.

<u>Utah Regional Haze</u>
In May 2011, the state of Utah issued a regional haze state implementation plan (SIP) requiring the installation of SO_2, NO_x and PM controls on Hunter Units 1 and 2 and Huntington Units 1 and 2. In December 2012, the EPA approved the SO_2 portion of the Utah regional haze SIP and disapproved the NO_X and PM portions. EPA's approval of the SO_2 SIP was appealed to federal circuit court. In addition, PacifiCorp and the state of Utah appealed EPA's disapproval of the NO_X

and PM SIP. PacifiCorp and the state's appeals were dismissed, and the SO_2 appeal was denied by the court. In June 2015, the state of Utah submitted a revised SIP to EPA for approval with an updated BART analysis incorporating a requirement for PacifiCorp to retire Carbon Units 1 and 2, crediting NO_X controls previously installed on Hunter Unit 3, and concluding that no incremental controls (beyond those included in the May 2011 SIP and already installed) were required at the Hunter and Huntington units. On June 1, 2016, EPA issued a final rule to partially approve and partially disapprove the Utah's regional haze SIP and propose a federal implementation plan (FIP). The FIP required the installation of selective catalytic reduction (SCR) controls by August 4, 2021, at four of PacifiCorp's units in Utah: Hunter Units 1 and 2, and Huntington Units 1 and 2. On September 2, 2016, PacifiCorp filed petitions for administrative and judicial review of EPA's final rule, 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, and EPA sent letters to Utah and PacifiCorp on July 14, 2017, indicating its intent to reconsider its FIP. EPA also filed a motion with the 10th Circuit Court of Appeals to stay EPA's FIP and hold the litigation in abeyance pending the rule's reconsideration. On September 11, 2017, the 10th Circuit Court granted the petition for stay and the request for abatement. The compliance deadline of the FIP and the litigation were stayed pending EPA's reconsideration, and EPA was required to file periodic status reports with the Court.

Utah and PacifiCorp worked with EPA to develop CAMx air quality modeling, and final CAMx modeling reports were delivered by PacifiCorp to Utah on September 21, 2018. On March 6, 2019, Utah Division of Air Quality staff presented a revised Utah Regional Haze SIP, based on the new CAMx modeling, to the Utah Air Quality Board. The Utah Air Quality Board voted in favor of sending the revised SIP out for public comment. On April 1, 2019, the SIP revision was released for a 45-day public comment period, which closed on May 15, 2019.

On June 24, 2019, the Utah Air Quality Board unanimously voted to approve the Utah Regional Haze SIP Revision, which incorporated and adopted the BART Alternative into Utah's Regional Haze SIP. The BART Alternative makes the shutdown of PacifiCorp's Carbon Plant enforceable under the SIP and removes the requirement to install SCR on Hunter Units 1 and 2, and Huntington Units 1 and 2. The state's final rule was published in the Utah Bulletin on July 15, 2019 and had an effective date of August 15, 2019. The Utah Division of Air Quality submitted the SIP Revision to EPA for review on July 3, 2019. On December 3, 2019, submitted a supplement to EPA with a minor SIP revision relating to particulate matter (PM).

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 nitrogen oxide emission controls at the Hunter and Huntington plants as well as nitrogen oxide and particulate matter 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 control technology on Hunter Units 1 and 2 and Huntington Units 1 and 2. On December 29, 2020, Utah, PacifiCorp, and EPA filed a motion to withdraw the Utah regional haze petitions in the 10th Circuit Court.

The Western Regional Air Partnership (WRAP) is currently developing the modeling that the state will use for the implementation of the second planning period. Utah will use a 'Q/d' screening of 10 to determine which sources will be subject to the rule. 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 State Implementation Plan development process. PacifiCorp's analysis included a proposal to implement reasonable progress emission limits for nitrogen oxides (NOx) and sulfur dioxide (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 about proposed emission reductions and costs for control technology.

<u>Wyoming Regional Haze</u>

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

- 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 - Aspects of EPA's final action were appealed by a number of entities. PacifiCorp appealed EPA's action requiring SCR at Wyodak. PacifiCorp successfully requested a stay of EPA's action pending resolution of the appeals. PacifiCorp subsequently submitted a request for reconsideration to EPA and is currently engaged in litigation and appeal settlement processes with EPA and Wyoming.

Naughton - In its 2014 rule, EPA indicated support for the conversion of the Naughton Unit 3 to natural gas in lieu of retrofitting and stated that it would expedite consideration of the gas conversion once the state of Wyoming submitted the requisite SIP amendment. Wyoming submitted its Regional Haze SIP revision regarding Naughton Unit 3 to EPA on November 28, 2017. On March 7, 2017, Wyoming issued PacifiCorp a permit which allowed for adjusted emission limits upon Unit 3's conversion to natural gas; and allowed for operation of Unit 3 on coal through January 30, 2019. PacifiCorp ceased coal operation on Unit 3 on January 30, 2019 as required by the permit. EPA's final rule approving Wyoming's SIP revision for Naughton Unit 3 gas conversion was published in the *Federal Register* on March 21, 2019, with an effective date of April 22, 2019, On May 24, 2019, PacifiCorp provided Wyoming with a notice of commencement of construction for upgrades supporting Unit 3's conversion to natural gas, along with a notice of initial startup on natural gas firing in accordance with state permits and EPA's approval of the Wyoming SIP. Naughton Unit 3 currently operates on natural gas.

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 which would institute plant-wide variable average monthly-block pound per hour NOx and SO_2 emission limits, in addition to an annual combined NOx and SO_2 limit, on all four Jim Bridger boilers in lieu of the requirement to install SCR on Units 1 and 2. The application demonstrates that the proposed limits are more cost effective, result in less overall environmental impacts, and lead to better modeled visibility than SCR installation on Units 1 and 2.

Wyoming's proposed approval of the application 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 which approved PacifiCorp's proposed monthly and annual NOx and SO2 emission limits included in the Jim Bridger application. The new emission limits will become effective January 1, 2022. Wyoming submitted a corresponding regional haze SIP revision to EPA on May 14, 2020. The SIP revision grants approval of PacifiCorp's Jim Bridger application and incorporates PacifiCorp's proposed emission limits in lieu of the requirement to install SCR on Jim Bridger Units 1 and 2. EPA's proposed approval, including public comment period for of the SIP revision is forthcoming.

WRAP is currently developing the modeling that the state will use for the implementation of the second planning period. Wyoming has not determined which sources will be subject to the rule. 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, which is due to EPA in July of 2021.

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 but operated by Arizona Public Service. EPA approved in part and disapproved in part the Arizona SIP and issued a FIP requiring the installation of SCR equipment on Cholla Unit 4. PacifiCorp filed an appeal regarding the FIP as it relates to Cholla Unit 4, and the Arizona Department of Environmental Quality and other affected Arizona utilities filed separate appeals of the FIP as it relates to their interests. For the Cholla FIP requirements, the court stayed the appeals while parties attempt to agree on an alternative compliance approach.

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

Colorado Regional Haze

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

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

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. A number of 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 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 the respective Registrant's coal combustion rule compliance data and information websites in March 2018. Based on the results in those reports, additional action may be required under the rule. At the time the rule was published in April 2015, PacifiCorp operated 18 surface impoundments and seven landfills that contained CCRs. Before the effective date in October 2015, nine surface impoundments and three landfills were either closed or repurposed to no longer receive CCRs and hence are not subject to the final rule.

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 reclassifies compacted-soil lined surface impoundments from "lined" to "unlined," establishes a deadline of April 11, 2021, by which all unlined surface impoundments must initiate closure, and revises 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 with a commitment to close the coal-fueled operating unit and complete closure of unlined impoundments by a date certain. The Part A rule also revises 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.

(2) On October 16, 2020, the EPA released the pre-publication version of the final Holistic Approach to Closure: Part B rule ("Part B rule"). The Part B rule finalizes a two-step process, as set forth in the March 2020 proposal, allowing facilities to request approval to continue operating an existing unlined CCR surface impoundment with an alternate liner system. The other provisions that were contained in the Part B proposal, including (1) options to use CCR during closure of a CCR unit, 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 2021. In 2019, the state of Wyoming proposed to adopt state rules which incorporate the final federal rule by reference. It is anticipated that Wyoming will finalize its rule in late 2020 and submit an application to the EPA to implement a state permit program in early 2021.

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. It is anticipated that a final Wyoming Pollutant Discharge Elimination System permit containing 316(b) compliance conditions will be issued in the first quarter of 2021.

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. It is expected that subcategorization through the new rule will allow for continued operation of certain PacifiCorp facilities through their anticipated retirement dates.

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 oxide 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:

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 amount of allowances necessary to meet its compliance obligations.

In May 2014, CARB approved the first update to the Assembly Bill (AB) 32 Climate Change scoping plan, which defined California's climate change priorities for the next five years and set the groundwork for post-2020 climate goals. In April 2015, Governor Brown issued an executive order to establish a mid-term reduction target for California of 40 percent below 1990 levels by 2030. CARB has subsequently been directed to update the AB 32 scoping plan to reflect the new interim 2030 target and previously established 2050 target.

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

Oregon

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

In 2007, Oregon enacted 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 (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. The Executive Order also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

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.

Utah

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

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

Wyoming

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

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 0159 electric public utilities, other than cooperative electric utilities, shall be obligated to purchase electricity generated from a coal fired electric generation facility purchased under agreement approved by the Commission, provided the otherwise retiring coal fired electric generation facility offers to sell some or all of the electricity from the facility to an electric public utility, the electricity is sold at a price that is no greater than the purchasing electric utility's avoided cost, the electricity is sold under a power purchase agreement, and the Commission approves a 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.

House Bill (HB 200) – Reliable and Dispatchable Low-Carbon Energy Standards was passed in March 2020. In the Bill, The Wyoming Public Service Commission is required to put in place a standard specifying a percentage of PacifiCorp's 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 all adopted greenhouse gas emission performance standards applicable to all electricity generated in the state or delivered from outside the state that is no higher than the greenhouse gas emission levels of a state-of-the-art combined cycle natural gas generation facility. The standards for Oregon and California are currently set at 1,100 lb CO_2/MWh, which is defined as a metric measure used to compare the emissions from various greenhouse gases based on their global warming potential. In September 2018, the Washington Department of Commerce issued a new rule lowering the emissions performance standard to 925 lb CO_2/MWh.

Renewable Portfolio Standards

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

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

In PacifiCorp's service territory, California, Oregon, and Washington have each adopted a mandatory RPS, and Utah has adopted a RPS goal. Each of these states' legislation and requirements are summarized in Table 3.2, 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[8] retail sales for the calendar year 36 months before the target year

California

California originally established its RPS program with passage of SB 1078 in 2002. Several bills that have since been passed into law to amend the program. In the 2011 First Extraordinary Special Session, the California Legislature passed SB 2 (1X) to increase California's RPS to 33 percent by 2020.[9] 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.[10] 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

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

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 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.[12]

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.

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

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

Table 3.4 – 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).

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.[13] 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,[14] 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.

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

- A requirement that by 2025, at least eight percent of the aggregate electric capacity of the state's investor-owned utilities must come from small-scale renewable projects under 20 megawatts.
- Creates new eligibility for pre-1995 biomass plants and associated thermal co-generation. Under the previous law, pre-1995 biomass was not eligible until 2026.
- Direction to the state's investor-owned utilities to propose plans encouraging greater reliance on electricity in all modes of transportation, in order to reduce carbon emissions.
- Removal of the Oregon Solar Initiative mandate.[15]

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

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

To qualify as eligible, the RECs must be from a resource certified as Oregon RPS eligible by the Oregon Department of Energy and tracked in WREGIS.

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

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

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

PacifiCorp files an annual RPS compliance report by June 1 of every year and a renewable implementation plan on or before January 1 of even-numbered years, unless otherwise directed by the Public Utility Commission of Oregon. These compliance reports and implementation plans are available on PacifiCorp's website.[16]

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

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

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

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

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

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

Washington

In November 2006, Washington voters approved I-937, a ballot measure establishing the Energy Independence Act, which is an RPS and energy efficiency requirement applied to qualifying electric utilities, including PacifiCorp.[18] The law requires that qualifying utilities procure at least three percent of retail sales from eligible renewable resources or RECs by January 1, 2012 through 2015; nine percent of retail sales by January 1, 2016 through 2019; and 15 percent of retail sales by January 1, 2020, and every year thereafter.

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

PacifiCorp is required to file an annual RPS compliance report by June 1 of every year with the Washington Utilities and Transportation Commission (WUTC) demonstrating compliance with the Energy Independence Act. PacifiCorp's compliance reports are available on PacifiCorp's website.[19]

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.

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.

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

The other states in which PacifiCorp operates have not enacted clean energy standards beyond their state renewable portfolio standards or renewable portfolio goals. Certain local governments within PacifiCorp's service territories have also adopted clean energy standards.[20]

Transportation Electrification

The electric transportation market is in an emerging state,[21] 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 greenhouse gas emissions, improve public health and safety, and create financial benefits for drivers, which can be a particular benefit for low and moderate income populations.

To help manage and understand the potential future load growth impacts of electric transportation PacifiCorp is investing $26 million to support EV fast chargers along key corridors, develop workplace charging programs, research new rate designs and implement time-of-use pricing pilots, create partnerships for smart mobility programs and develop opportunities for customers in our rural communities. Our investments include a $4 million partnership award from the U.S. Department of Energy to research and develop electric transportation and $3 million as part of the Oregon Clean Fuels Program.

Given the emerging state of electric transportation a forecast explicitly identifying the load associated with electric transportation on PacifiCorp's system is currently unavailable. Electric vehicle load is, however, reflected in the Company's load forecast. PacifiCorp continues to actively engage with local, regional, and national stakeholders and participate in state regulatory processes that can inform future planning and load forecasting efforts.

Hydroelectric Relicensing

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

The value of relicensing hydroelectric facilities is continued availability of energy, capacity, and ancillary services associated with hydroelectric generation. Hydroelectric projects can often provide unique operational flexibility because they can be called upon to meet peak customer demands almost instantaneously and back up intermittent renewable resources such as wind. In addition to operational flexibility, hydroelectric generation does not have the emissions concerns

[20] The City of Portland Climate Action Plan, Salt Lake City 100% Renewable Energy Community Goal, and the Park City Renewable Energy Pledge represent a small subset of the local government clean energy standards.
[21] As of June 2019, the market share of plug-in electric vehicles was two percent: www.nada.org/WorkArea/DownloadAsset.aspx?id=21474858563

of thermal generation and can also often provide important ancillary services, such as spinning reserve and voltage support, to enhance the reliability of the transmission system.

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

PacifiCorp will provide an update on current hydroelectric relicensing efforts as part of the September 1, 2021 filing.

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

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

Potential Impact

Relicensing hydroelectric facilities involves significant process costs. The FERC relicensing process takes a minimum of five years and may take longer, depending on the characteristics of the project, the number of stakeholders, and issues that arise during the process. As of December 31, 2016, PacifiCorp had incurred approximately $16 million in costs for license implementation and ongoing hydroelectric relicensing, which are included in construction work- in-progress on PacifiCorp's Consolidated Balance Sheet. As current or upcoming relicensing and settlement efforts continue for the Weber, Cutler and other hydroelectric projects, additional process costs are being or will be incurred that will need to be recovered from customers. Hydroelectric relicensing costs have and will continue to have a significant impact on overall hydroelectric generation cost. Such costs include capital investments and related operations and maintenance costs associated with fish passage facilities, recreational facilities, wildlife protection, water quality, cultural and flood management measures. Project operational and flow-related changes, such as increased in-stream flow requirements to protect aquatic resources, can also directly result in lost generation. The majority of these relicensing and settlement costs relate to PacifiCorp's three largest hydroelectric projects: Lewis River, Klamath River, and North Umpqua.

Treatment in the IRP

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

PacifiCorp's Approach to Hydroelectric Relicensing

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

Utah Rate Design Information

Current rate designs in Utah have evolved over time based on orders and direction from the Public Service Commission of Utah and settlement agreements between parties during general rate cases. Most recently, current rates and rate design changes were adopted in Docket No. 13-035-184. The goals for rate design are (generally) to reflect the cost to serve customers and to provide price signals to encourage economically efficient usage. This is consistent with resource planning goals that balance consideration of costs, risk, and long-run public policy goals. PacifiCorp currently has a number of rate design elements that take into consideration these objectives, in particular, rate designs that reflect cost differences for energy or demand during different time periods and that support the goals of acquiring cost-effective energy efficiency.

Residential Rate Design

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

Changes in residential rate design that might facilitate IRP objectives include a critical peak pricing program or an expansion of time-of-use rates. These types of rate designs will be discussed in more detail in Volume I, Chapter 6 (Resource Options). As part of the STEP legislation enacted in SB 115, the company developed a pilot time-of-use program to encourage off-peak charging of electric vehicles for residential customers. The results of this pilot may inform future rate design offerings. Any changes in standard residential rate design or institution of optional rate options to support energy efficiency or time-differentiated usage should be balanced with the recovery of fixed costs to ensure price signals are economically efficient and do not unduly shift costs to other customers.

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

Commercial and Industrial Rate Design

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

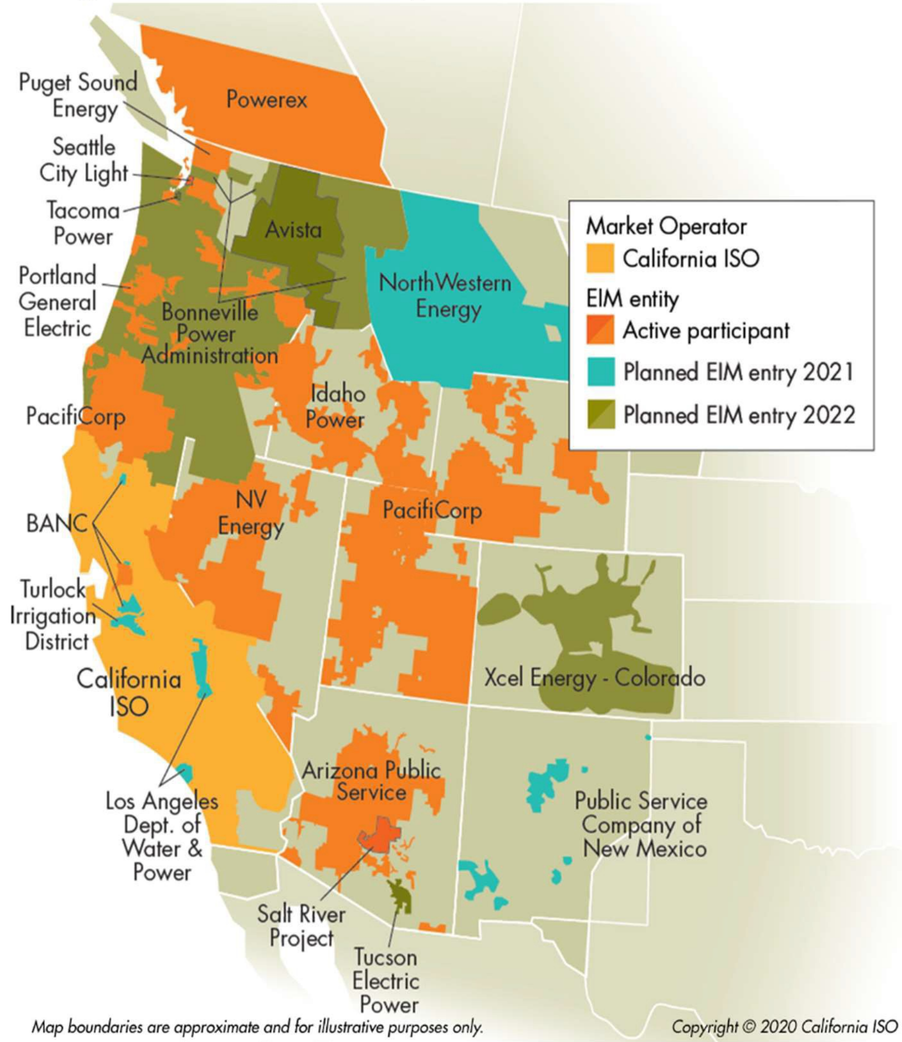
Irrigation Rate Design

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. Most recently, Seattle City Light (SCL) and Salt River Project (SRP) began participating in April 2020. 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 ($1.2 billion total footprint-wide benefits as of September 30, 2020), 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 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 Request for Proposal Activities

RFP	RFP Objective	Status	Issued	Completed
2017 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2017	September 2017
2017 Renewable RFP	Purchase new or repowered wind renewable energy	Closed	September 2017	November 2018
2017 Solar RFP	Purchase solar renewable energy	Closed	November 2017	March 2018
2017 Market Resource RFP	Purchase firm power for PacifiCorp's western balancing authority	Closed	November 2017	November 2017
2018 Oregon Community Solar RFP	Purchase solar energy or Oregon Community Solar	Ongoing	July 2018	On hold pending final program rules
2018 Renewable Energy Credits RFP	Purchase renewable energy credits for Oregon Schedule 272 participation	Closed	August 2018	September 2018
2019R Utah RFP	Purchase new renewable energy for specific customers under Utah Schedule 32 or 34	Ongoing	March 2019	Ongoing
Renewable energy credits (Sale)	Excess system RECs	Ongoing	Based on specific need	Ongoing
2019 Capacity and Energy Supply RFP	Purchase capacity and energy supply	Ongoing	June 4, 2019	Ongoing
Renewable energy credits (Purchase)	Oregon compliance needs	Ongoing	Based on specific need	Ongoing
Renewable energy credits (Purchase)	Washington compliance needs	Ongoing	Based on specific need	Ongoing

RFP	RFP Objective	Status	Issued	Completed
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	Planned	Targeting end of January 2021	TBD

Demand Side Management (DSM) Resources

In 2018, the Company issued a Request for Proposals to re-procure services for the outsourced portion of Wattsmart Business currently performed by Nexant and Cascade Energy as described below. The Request for Proposal also included *Home Energy Savings* to allow for potential economies of a single contractor delivering for both programs. Selection and contracting with Nexant and Cascade Energy was complete in 2019. Nexant is now also delivering the *Home Energy* Savings program allowing consolidation of some administrative functions and the residential and non-residential trade ally networks.

In December 2018, the Company issued a Request for Proposals to potentially outsource the project manager portion of Wattsmart Business. The decision was made in 2019 to outsource this work and selection and contracting with Cascade Energy was complete in 2019. The transition from an in-house project manager working with a pre-contracted network of consultants (including Cascade Energy and others) took place starting in August 2019.

2017 Renewable Energy Credits RFP

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

2017 Renewable RFP

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

2017 Solar RFP

PacifiCorp issued a 2017 Solar Resource RFP in November 2017 seeking cost-competitive bids for solar energy interconnecting with or delivering to PacifiCorp's system that will reduce system costs and provide net benefits for customers. At the conclusion of the final shortlist evaluation process, PacifiCorp decided not to select any of the bids under this RFP.

2017 Market Resource RFP

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

2018 Oregon Community Solar RFP

PacifiCorp issued a 2018 Oregon Community Solar RFP in July 2018 seeking cost-competitive bids for individual projects up to 3.0 MW of new greenfield, alternating current (AC) solar photovoltaic resources directly interconnecting with PacifiCorp's distribution or transmission system and located in PacifiCorp's Oregon service territory. The RFP is currently on hold while Oregon Community Solar Program rules, guidelines and timelines are furthered clarified and established within Public Utility Commission of Oregon proceedings.[22]

2018 Renewable Energy Credits RFP

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

2019 Renewable RFP - Utah

PacifiCorp issued a Renewable RFP in March 2019 on behalf of a select group of customers seeking cost-competitive bids for renewable projects constructed in Utah meeting the criteria established by the participating customers to meet their annual energy requirements. Projects must interconnect or be capable of delivery to PacifiCorp's system. Customers will contract for the project output through Utah's Schedule 32 or 34.[23] The 2019 Renewable RFP – Utah was completed in the fall of 2019, with the final power purchase agreement signed in the fall of2020.

Renewable Energy Credits RFP (Sale)

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

[22] See Public Utility Commission of Oregon, Community Solar Program Implementation, Docket No. UM 1930, for more information.
[23] This Utah schedule information for Rocky Mountain Power can be found at: www.rockymountainpower.net/about/rates-regulation/utah-rates-tariffs.html

Renewable Energy Credits RFP (Purchase)

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

2020 All-Source RFP

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 was seeking 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 will be identified by June 2021.

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TRANSMISSION

CHAPTER HIGHLIGHTS

- PacifiCorp's planned transmission projects will facilitate a transitioning resource portfolio and will comply with reliability requirements, while providing sufficient flexibility necessary to ensure existing and future resources can meet customer demand cost effectively and reliably.
- Given the long lead time needed to site, permit and construct 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.

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 meet aggregate electrical demand and customers' energy requirements at all times, taking into account scheduled outages and the ability to maintain reliability during unscheduled outages.
3. 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.

[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.

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 meet aggregate electrical demand for customers at all times. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities in order to meet NERC reliability criteria.

This chapter provides:

- An update of PacifiCorp's plan to construct Gateway South.
- Will include information supporting acknowledgement of transmission action plan items once known in the 2021 IRP.
- 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.

Aeolus to Bridger/Anticline Update

In 2018 PacifiCorp received the necessary state regulatory approvals, state and local permits, and private rights-of-way to construct the Aeolus-to-Bridger/Anticline sub-segment D.2 of Gateway West. Construction began in April 2019 and was completed in October 2020 and energized in November 2020.

Update of Aeolus to Mona (Gateway South)

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

The 500 kV transmission segment extends 416 miles between the Aeolus substation near Medicine Bow, Wyoming, and Clover substation located near Mona, Utah. PacifiCorp, with stakeholder involvement, has pursued permitting of the Energy Gateway South transmission project since 2008. In May 2016 the Bureau of Land Management (BLM) released its final Environmental Impact Statement (EIS) and issued their Record of Decision (ROD) in December of the same year.

In May 2018 the U.S. Forest Service issued its ROD, completing the permitting on federal lands and providing a right-of-way grant for federal properties.

The current plan for the Aeolus-to-Mona transmission segment will be to place the segment into service by the end of 2024, subject to completion of local permitting and private rights-of-way acquisitions.

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.

Completion of the new transmission segment realizes the full 1,700 MW rating of Gateway South allowing the addition of up to 1,920 MW of renewable resources added to the system. Connecting into the Mona/Clover market hub provides additional flexibility in the use of least-cost resources from eastern Wyoming or southern Utah to serve customer load.

PacifiCorp's portfolio outputs as part of the final filing made no later than September 1, 2021 will provide additional details on the portfolio effects of these projects.

Gateway West – Continued Permitting

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

Windstar to Populus (Segment D)

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

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

Figure 4.1 - Segment D

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

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

Populus to Hemingway (Segment E)

Figure 4.2 - Segment E

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

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

Under the National Environmental Policy Act, the BLM has completed the EIS for the Gateway West project. The BLM released its final EIS on April 26, 2013, followed by the ROD on November 14, 2013, providing a right-of-way grant for all of Segment D and most of Segment E of the project. The BLM chose to defer its decision on the western-most portion of Segment E of the project located in Idaho in order to perform additional review of the Morley Nelson Snake River Birds of Prey Conservation Area. Specifically, the sections of Gateway West that were deferred for a later ROD include the sections of Segment E from Midpoint to Hemingway and Cedar Hill to Hemingway. A ROD for these final sections of Segment E was issued on January 19, 2017 and a right-of-way grant was issued on August 8, 2018.

Plan to Continue Permitting – Gateway West

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

Energy Gateway Transmission Expansion Plan

Introduction

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

Background

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

The Energy Gateway Transmission Expansion Plan, formally announced in May 2007, has origins in numerous local and regional transmission planning efforts discussed further below. Energy Gateway was designed to ensure a reliable, adequate system capable of meeting current and future customer needs. Importantly, given the changing resource picture, its design supports multiple future resource scenarios by connecting resource-rich areas and major load centers across PacifiCorp's multi-state service area. In addition, the ability to use these resource-rich areas helps position PacifiCorp to meet current state renewable portfolio requirements. Please refer to the regional maps of wind, solar, biomass, and geothermal potential available on PacifiCorp's Energy Gateway project website to see an overlay of the Energy Gateway project and renewable resource potential.[2] Energy Gateway has since been included in all relevant local, regional and interconnection-wide transmission studies.

Planning Initiatives

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

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

- ***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.[3]

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

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

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

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

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

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

In 2011, PacifiCorp announced the indefinite postponement of the Gateway South 500-kV segment between the Mona substation in central Utah and Crystal substation in Nevada. This extension of

Gateway South, like the double-circuit configuration discussed above, was a component of the upsized system to address regional needs if supported by queue customers or partnerships. However, despite significant third-party interest in the Gateway South segment to Nevada, there was a lack of financial commitment needed to support the upsized configuration.

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

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

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

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

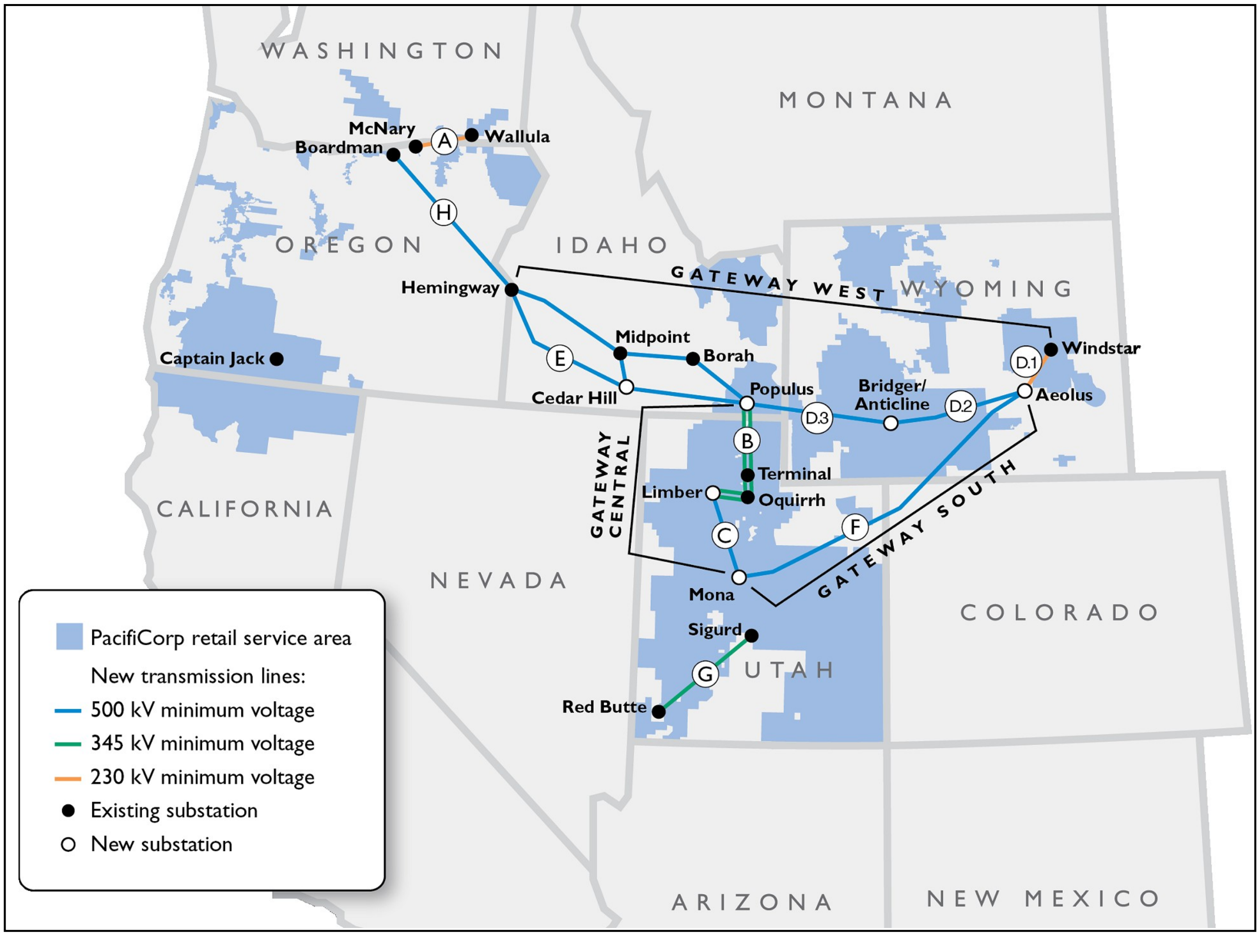
In December 2016, the BLM issued its ROD and right-of-way grant for the Gateway South project.

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

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

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

Figure 4.3 – Energy Gateway Transmission Expansion Plan



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

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
(A) Wallula-McNary	230 kV, single circuit	30 mi	• Status: Construction complete • 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	75 mi	• Status: permitting underway • Scheduled in service: 2024
(D2) Aeolus-Bridger/Anticline	500 kV single circuit	140 mi	• Status: under construction • 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)	500 kV single circuit	400 mi	• Status: permitting underway

Segment & Name	Description	Approximate Mileage	Status and Scheduled In-Service
Aeolus-Mona			• 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	500 mi	• Status: pursuing joint-development and/or firm capacity opportunities with project sponsors • Scheduled in service: sponsor driven

Efforts to Maximize Existing System Capability

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

System-wide, PacifiCorp has instituted more than 155 grid operating procedures and 17 remedial action schemes to maximize the existing system capability while managing system risk. In addition, PacifiCorp has been an active participant in the EIM since November 2014. The California Independent System Operator's (CISO) Energy Imbalance Market (EIM) is a real-time energy market. The EIM's advanced market system automatically finds low-cost energy to serve real-time consumer demand across the west. Since its launch in 2014, the EIM has enhanced grid reliability and generated cost savings for its participants. Besides its economic advantages, the EIM improves the integration of renewable energy, which leads to a cleaner, greener grid. The EIM provides for more efficient dispatch of participating resources in real-time through an automated system that dispatches generation across the EIM footprint (collectively, EIM Area), which currently includes:

- PacifiCorp east and west balancing authority areas
- NV Energy
- Puget Sound Energy
- Arizona Public Service
- Portland General Electric
- Idaho Power Company
- Powerex Corporation in the BC Hydro balancing authority area
- Balancing Authority of Northern California with its member the Sacramento Municipal Utility District
- CAISO balancing authority area (collectively, EIM Area)
- Seattle City Light
- Salt River Project

Pending participants include:
Los Angeles Department of Water & Power – entry 2021
Public Service of New Mexico – entry 2021
NorthWestern Energy – entry 2021
Turlock Irrigation District – entry 2021
Balancing Authority of Northern California (Phase 2) – entry 2021

Avista – entry 2022
Tucson Electric Power – entry 2022
Tacoma Power – entry 2022
Avangrid – entry 2022
Bonneville Power Administration – entry 2022
Xcel Energy – Colorado – entry 2022

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.
   - Construct a new 138 kV transmission line from the Terminal–Grow and extend it to the new State of Utah prison facility
     - Project driver is to provide infrastructure to supply customer load and accommodate future load growth in the area identified in the area master plan.
     - Benefits include a transmission line to serve the new load at the Utah State Prison and infrastructure that can be used for future load that is expected to develop in the Northwest Quadrant of Salt Lake City.
   - Rebuild 1.6 miles of the Gadsby – Rose Park West Tap 46 kV line for Chevron USA, Inc.
     - Project driver is to correct N-1 overload and low voltage issues caused by Chevron USA, Inc.'s increased load. The load addition will cause a N-1 overload on the Gadsby - Rose Park West Tap 46 kV line segment and a N-1 low voltage issue at Centerville, Lagoon and Woods Cross substations.
     - Benefits include mitigating the risk of thermal overloads and low voltage, adding additional capacity to address Chevron USA Inc.'s increased load, and improved transmission reliability.
   - Rebuild the 90th South – Dumas 138 kV transmission line and tap Highland – Bull River connecting it to Lone Peak for C7 Data Centers

    - Project driver is to provide infrastructure to strengthen the local transmission system to serve the additional 13 MW of load during N-1 contingencies and improve system reliability for other customers.
    - Benefits include infrastructure to accommodate C7's load increase, mitigate N-1 issues on the local 138 kV transmission system, and increases capacity and reliability in the area.

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.
- Install 345 kV point of delivery substation for Stadion, LLC
    - Project driver is to provide infrastructure to supply customer load according to the terms in the Master Electric Service Agreement.
    - Benefits include a new 345 kV substation to serve Stadion, LLC's new load and infrastructure that can be used for future load that is expected to develop in Eagle Mountain.

1. 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.

3. 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 results in thermal overload of existing Jim Bridger 345-230 kV #2 transformer.

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

2. Goshen Idaho Area

- Install a third 345-161 kV transformer at Goshen substation
    - 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.

  - o 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
     - o 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.
     - o 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
     - o Project drivers are projected load growth and reliability improvements which required of extension of the 138-kV line from Jordanelle-to-Midway substation.
     - o 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
     - o 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.
     - o 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.
     - o 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.
     - o 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.

- Construct a new 69 kV tie line tapping off the line from Bonneville Power Administration's Santiam substation to the Santiam Switching station and tapping into the line from Lyons to Scio substation (Kingston line)
    - Project drivers are projected load growth and reliability improvements.
    - The proposed construction allows Lyons, Scio and Evergreen Biomass to be supplied directly from BPA Santiam substation, bypassing the Santiam Switching Station and the Santiam Switching Station to Lyons line section allowing either facility to be maintained or repaired without customer or generation curtailment, at all times. With this project, full service to Lyons substation and the industrial customers it supplies could be restored prior to line repair.

2. Bend Oregon Area
    - Replace conductor on the 69-kV between Cleveland Avenue and Bond Street substations.
        - Project drivers are projected load growth and reliability improvements.
        - Benefits will provide this line section relief for 20 years at a 2% growth rate and will allow the entire Bend loop to be restored during an outage of Pilot Butte to Overpass without load transfers or the risk of damaging equipment.

3. 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.

4. 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.

5. 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 NERC and WECC reliability standards.

LOAD AND RESOURCE BALANCE

CHAPTER HIGHLIGHTS

- On both a capacity and energy basis, PacifiCorp calculates load and resource balances from existing resources, forecasted loads and sales, and reserve requirements. The capacity balance compares existing resource capability at the time of the coincident system summer and winter peak periods.
- For capacity expansion planning, PacifiCorp is developing its target planning reserve margin (PRM) applied to the company's obligation, which is calculated as projected load less private generation, less energy efficiency savings (Class 2 demand-side management (DSM)), and less interruptible load.

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 will be summarized in Volume II, Appendix A (Load Forecast Details) as part of the September 1, 2021 filing. 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 will be 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

Tables and figures to be incorporated in the final IRP filing no later than September 1, 2021.

Existing Resources

On a system coincident basis, PacifiCorp is a summer-peaking utility. For the forecasted 2021 summer coincident peak, PacifiCorp owns or contracts for resources to meet expected system summer peak capacity. Note that capacity ratings in the following tables provide resource capacity value at nameplate, rounded to the nearest megawatt.

Thermal Plants

Table 5.6 lists PacifiCorp's existing coal-fueled plants and

Table 5.7 lists existing natural-gas-fueled plants. End of life year dates reflect those assumed in the 2019 preferred portfolio. All tables will be updated as part of the final filing no later than September 1, 2021..

Table 5.6 – Coal-Fueled Plants

Plant	PacifiCorp Percentage Share (%)	State	End of Life Year	Nameplate Capacity (MW)
Colstrip 3	10	Montana	2027	74
Colstrip 4	10	Montana	2027	74
Craig 1	19	Colorado	2025	82
Craig 2	19	Colorado	2026	82
Dave Johnston 1	100	Wyoming	2027	99
Dave Johnston 2	100	Wyoming	2027	106
Dave Johnston 3	100	Wyoming	2027	220
Dave Johnston 4	100	Wyoming	2027	330
Hayden 1	24	Colorado	2030	44
Hayden 2	13	Colorado	2030	33
Hunter 1	94	Utah	2042	418
Hunter 2	60	Utah	2042	269
Hunter 3	100	Utah	2042	471
Huntington 1	100	Utah	2036	459
Huntington 2	100	Utah	2036	450
Jim Bridger 1	67	Wyoming	2023	354
Jim Bridger 2	67	Wyoming	2028	359
Jim Bridger 3	67	Wyoming	2037	349
Jim Bridger 4	67	Wyoming	2037	353
Naughton 1	100	Wyoming	2025	156
Naughton 2	100	Wyoming	2025	201
Naughton 3*	100	Wyoming	2019	0
Wyodak	80	Wyoming	2039	268
TOTAL – Coal				**5,638**

* Naughton 3 coal generation ended January 30, 2019 and was converted to gas in 2020 through 2029.
* This table is currently being updated as part of the 2021 IRP development process and is subject tochange.

Table 5.7 – Natural-Gas-Fueled Plants

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

* This table is currently being updated as part of the 2021 IRP development process and is subject to change.

Renewable Resources

Wind

Table 5.8 shows existing wind facilities owned by PacifiCorp, while Table 5.9 shows existing wind power purchase agreements. Both tables are subject to update as part of the final filing no later than September 1, 2021.

Table 5.8 – Owned Wind Resources

Utility-Owned Wind Projects	State	Capacity (MW)
Foote Creek I *	WY	41
Leaning Juniper	OR	101
Goodnoe Hills East Wind	WA	94
Marengo	WA	140
Marengo II	WA	70
Glenrock Wind I	WY	99
Glenrock Wind III	WY	39
Rolling Hills Wind	WY	99
Seven Mile Hill Wind	WY	99
Seven Mile Hill Wind II	WY	20
High Plains	WY	99
McFadden Ridge 1	WY	29
Dunlap 1	WY	111
Pryor Mountain **	MT	240

Cedar Springs II***	WY	200
Ekola Flats ***	WY	250
TB Flats ***	WY	500
TOTAL – Owned Wind		**2,222**

* Net total capacity for Foote Creek 1 is 40 MW.
** Wind facility not part of EV 2020. In service December 31, 2020.
*** EV 2020 in service by December 31, 2020.
This table is currently being updated as part of the 2021 IRP development process and is subject to change.

Table 5.9 – Non-Owned Wind Resources

Power Purchase Agreements / Exchanges	State	PPA or QF	Capacity (MW)
Cedar Springs Wind ***	WY	PPA	200
Cedar Springs III *	WY	PPA	120
Combine Hills	OR	PPA	41
Foote Creek IV	WY	PPA	17
Rock River I	WY	PPA	50
Stateline Wind	OR / WA	PPA	175
Three Buttes Wind Power (Duke)	WY	PPA	99.0
Top of the World	WY	PPA	200
Wolverine Creek	ID	PPA	65
Chopin	WA	QF	10
Foote Creek II	WY	QF	2
Foote Creek III	WY	QF	25
Latigo Wind	UT	QF	60
Mariah Wind	OR	QF	10
Meadow Creek Project – Five Pine	ID	QF	40.0
Meadow Creek Project – North Point	ID	QF	80
Monticello Wind	UT	QF	79
Mountain Wind Power I	WY	QF	61
Mountain Wind Power II	WY	QF	80
Orchard Wind	WA	QF	40
Oregon Wind Farms I & II	OR	QF	65
Orem Family Wind	OR	QF	10.0
Pioneer Wind Park I	WY	QF	80
Power County Wind Park North	ID	QF	23
Power County Wind Park South	ID	QF	23
Spanish Fork Wind Park 2	UT	QF	19
Three Mile Canyon	WA	QF	10
Toole Army Depot	UT	QF	3
Small QF	WY	QF	0.2
TOTAL – Purchased Wind			**1,686**

* Wind facility not part of EV 2020. New since 2017 IRP Update.
** EV 2020 in service by December 31, 2020.
*** This table is currently being updated as part of the 2021 IRP development process and is subject to change.

Solar

Table 5.10 shows solar projects under contract. This table will be updated as necessary as part of the final filing no later than September 1, 2021.

Table 5.10 – Non-Owned Solar Resources

Power Purchase Agreements / Exchanges	PPA or QF	State	Capacity (MW)
Black Cap	PPA	OR	2
Utah Solar PV Program	PPA	UT	2
Old Mill	PPA	OR	5
Oregon Solar Incentive Projects (OSIP)	PPA	OR	10
Milford *	PPA	UT	99
Hunter *	PPA	UT	100
Sigurd *	PPA	UT	80
Cove Mountain *	PPA	UT	58
Cove Mountain II *	PPA	UT	122
Prineville *	PPA	OR	40
Millican *	PPA	OR	60
Small Solar	QF	UT	0.5
Adams Solar Center	QF	OR	10
Bear Creek Solar Center	QF	OR	10
Beryl Solar	QF	UT	3
Black Cap Solar II	QF	OR	8
Bly Solar Center	QF	OR	9
Buckhorn Solar	QF	UT	3
Cedar Valley Solar	QF	UT	3
Chiloquin Solar	QF	OR	10
Collier Solar	QF	OR	10
Elbe Solar Center	QF	OR	10
Enterprise Solar	QF	UT	80
Escalante Solar I	QF	UT	80
Escalante Solar II	QF	UT	80
Escalante Solar III	QF	UT	80
Ewauna Solar	QF	OR	1
Ewauna Solar 2	QF	OR	3
SunF Solar XVII Project 1-3	QF	UT	9
Granite Mountain - East	QF	UT	80
Granite Mountain - West	QF	UT	50
Granite Peak Solar	QF	UT	3
Greenville Solar	QF	UT	2
Iron Springs	QF	UT	80
Laho Solar	QF	UT	3
Merrill Solar	QF	OR	10
Milford Flat Solar	QF	UT	3
Milford Solar 2	QF	UT	3
Norwest Energy 2 (Neff)	QF	OR	10
Norwest Energy 4 (Bonanza)	QF	OR	6
Norwest Energy 7 (Eagle Point)	QF	OR	10
Norwest Energy 9 Pendleton	QF	OR	6
OR Solar 2, LLC (Agate Bay)	QF	OR	10
OR Solar 3, LLC (Turkey Hill)	QF	OR	10
OR Solar 5, LLC (Merrill)	QF	OR	8
OR Solar 6, LLC (Lakeview)	QF	OR	10
OR Solar 7, LLC (Jacksonville)	QF	OR	10

OR Solar 8, LLC (Dairy)	QF	OR	10
Pavant Solar	QF	UT	50
Pavant Solar II LLC	QF	UT	50
Pavant Solar III LLC	QF	UT	20
Quichapa Solar 1- 3	QF	UT	9
Sage I Solar	QF	WY	20
Sage Il Solar	QF	WY	20
Sage Ill Solar	QF	WY	18
South Milford Solar	QF	UT	3
Sweetwater Solar	QF	WY	80
Three Peaks Solar	QF	UT	80
Tumbleweed Solar	QF	OR	10
Utah Red Hills Renewable Park	QF	UT	80
Woodline Solar	QF	OR	8
TOTAL – Purchased Solar			**1,759**

* This table is currently being updated as part of the 2021 IRP development process and is subject to change.

Geothermal

PacifiCorp owns and operates the Blundell geothermal plant in Utah, which uses naturally created steam to generate electricity. The plant has a net generation capacity of 34 MW. Blundell is a fully renewable, zero-discharge facility. The bottoming cycle, which increased the output by 11 MW, was completed at the end of 2007. The Oregon Institute of Technology added a new small qualifying facility (QF) using geothermal technologies to produce renewable power for the campus that is rated at 0.28 MW. PacifiCorp has a six-year power purchase agreement with a 3.65 MW QF geothermal project near Lakeview, Oregon, which became operational September 2016.

Biomass/Biogas

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

Renewables Net Metering

Installation rates for net metering facilities have been relatively consistent for the last few years in the Pacific Power States. While in the Rocky Mountain Power states the net metering installation rates have declined approximately 40 percent from the peak installed in 2017. PacifiCorp will provide an updated breakdown of net metered capacity and customer counts as part of the September 1, 2021 filing.

Hydroelectric Generation

Hydroelectric resources provide operational benefits such as flexible generation, spinning reserves and voltage control. PacifiCorp-owned hydroelectric plants are located in California, Idaho, Montana, Oregon, Washington, Wyoming, and Utah.

The amount of electricity PacifiCorp is able to generate or purchase from hydroelectric plants is dependent upon a number of factors, including the water content of snow pack accumulations in the mountains upstream of its hydroelectric facilities and the amount of precipitation that falls in its watershed. Operational limitations of the hydroelectric facilities are affected by varying water levels, licensing requirements for fish and aquatic habitat, and flood control, which lead to load and resource balance capacity values that are different from net facility capacity ratings.

Hydroelectric purchases are categorized into two groups, as shown in Table 5.11, which shows 2019 capacity. The table will be updated as part of the final filing no later than September 1, 2021.

Table 5.11 – Hydroelectric Contracts

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

Table 5.12 provides the capacity for each of PacifiCorp's owned hydroelectric generation facilities. This table will be updated as part of the September 1, 2021 filing.

Table 5.12 – PacifiCorp Owned Hydroelectric Generation Facilities –Capacities

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

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

Hydroelectric Relicensing Impacts on Generation

Table 5.13 lists the estimated impacts to average annual hydro generation from expected Federal Energy Regulatory Commission (FERC) orders and relicensing settlement commitments. PacifiCorp assumes that the Klamath hydroelectric facilities will be decommissioned in accordance with the Klamath Hydroelectric Settlement Agreement in the year 2022 and that other projects currently in relicensing will receive new operating licenses, but that additional operating restrictions will be imposed in new licenses, such as higher bypass flow requirements, that will reduce generation available from these facilities. This table will be updated as part of the final filing no later than September 1, 2021.

Table 5.13 – Estimated Impact of FERC License Renewals and Relicensing Settlement Commitments on Hydroelectric Generation

Years	Incremental Lost Generation (MWh)	Cumulative Lost Generation (MWh)
2021-2036	628,000	639,116

Demand-Side Management

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

- **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.

- **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.

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

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

PacifiCorp has been operating successful DSM programs since the late 1970s. While the company's DSM focus has remained strong over this time, since the 2001 western energy crisis, PacifiCorp's DSM pursuits have expanded to new heights in terms of investment level, state presence, breadth of DSM resources pursued and resource planning considerations. Work continues on the expansion of cost-effective program portfolios and savings opportunities in all states while at the same time adapting programs and measure baselines to reflect the impacts of advancing state and federal energy codes and standards. In Oregon, PacifiCorp continues to work closely with the Energy Trust of Oregon to help identify additional resource opportunities, improve delivery and communication coordination, ensure adequate funding, and provide company support in pursuit of DSM resource targets.

Table 5.14 summarizes PacifiCorp's existing DSM programs, their assumed impact, and how they are treated for purposes of incremental resource planning. Note that since incremental energy efficiency is determined as an outcome of resource portfolio modeling and is characterized as a new resource in the preferred portfolio, existing energy efficiency in Table 5.14 is shown as having zero MW.[25] For a summary of current DSM program offerings in each state, refer to Volume II, Appendix D (Demand-Side Management Resources).

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

Table 5.14 – Existing DSM Resource Summary

Program Class	Description	Energy Savings or Capacity at Generator	Included as Existing Resources for 2021-2040 Period
Demand Response	Residential/small commercial air conditioner load control	122 MW summer peak	Yes.
	Irrigation load management	205 MW summer peak[1/]	Yes.
	Interruptible contracts	177 MW Year-round availability	Yes.
Energy Efficiency	PacifiCorp and Energy Trust of Oregon programs	0 MW[2/]	No. Class 2 DSM programs are modeled as resource options in the portfolio development process and included in the preferred portfolio.
Demand-Side Rates	Time-based pricing	98 MW summer peak	No. Historical savings from customer responses to pricing signals are reflected in the load forecast.
	Inverted rate pricing	55-149 GWh (capacity impacts are unavailable due to lack of information on end use loads being saved	No. Historical savings from customer response to pricing structure is reflected in load forecast.
Education / Information	Energy education	Energy and capacity impacts are not available/measured	No. Historical savings from customer participation are reflected in the load forecast.

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

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

Private Generation

For the 2021 IRP, PacifiCorp contracted with Navigant Consulting to update the assessment of private generation (PG) penetration performed for the 2019 IRP with new market and incentive developments. 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 builds on Navigant's previous assessments, which supported PacifiCorp's 2015, 2017, and 2019 IRPs. 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

The updated Navigant study has been included in this draft filing as Appendix O..

Power Purchase Contracts

An update of PacifiCorp's current power purchase contracts will be provided as part of the final filing no later than September 1, 2021.

Load and Resource Balance

Capacity and Energy Balance Overview

The analysis and narrative on Capacity and Energy Balance will be included as part of the final filing no later than September 1, 2021.

Load and Resource Balance Components

Existing Resources
A description of each of the resource categories follows:

<u>Thermal</u>
This category includes all thermal plants that are wholly owned or partially owned by PacifiCorp. The capacity balance counts these plants at their expected availability (after derating for forced outages and maintenance) during summer or winter hours with loss of load events in the final capacity factor methodology analysis.[26] The energy balance also counts them at expected availability, but includes all hours in the year. This includes the existing fleet of coal-fueled units, and six natural-gas-fueled plants. These thermal resources account for roughly two thirds of the firm capacity available in the PacifiCorp system.

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

<u>Renewable</u>
This category is comprised of geothermal and variable (wind and solar) renewable energy capacity. The capacity balance counts the geothermal plant using the same methodology applied to thermal resources. The capacity contribution of wind and solar resources, represented as a percentage of resource capacity, is a measure of the ability for these resources to reliably meet demand. During the 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. To account for these effects, PacifiCorp performed a reliability analysis on every portfolio that was developed to ensure that the combination of resources achieved a targeted level of reliability. For the purpose of reporting the capacity contribution of wind and solar resources in

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

the load and resource balance, PacifiCorp first calculated the contribution of all other resources in the portfolio, using the methodologies described in this section. The remaining capacity in the load and resource balance, up to PacifiCorp's thirteen percent planning reserve margin, is attributable to wind and solar.

Purchase

This includes all major purchase contracts for firm capacity and energy in the PacifiCorp system.[27] The capacity balance counts these by the maximum contract availability at time of system summer peak. The energy balance counts contracts at optimal economic model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

Qualifying Facilities

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

Demand Response (Class 1 DSM)

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

Sales

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

Non-owned Reserves

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

Obligation

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

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

Load Net of Private Generation
The largest component of the obligation is retail load. In the 2019 IRP, the hourly retail load at a location is first reduced by hourly private generation at the same location. The system coincident peak is determined by summing the net loads for all locations (topology bubbles with loads) and then finding the highest hourly system load by year. Loads reported by east and west BAAs thus reflect loads at the time of PacifiCorp's coincident system summer peak. The energy balance counts the load on monthly basis by on-peak and off-peak hours. The net load is simply referred to as load in the context of load and resources balances and portfolio selection and evaluation.

Energy Efficiency
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 (83 MW) has been accounted for by adding an existing energy efficiency resource in the load and resource balance. The energy efficiency line also includes the selected energy efficiency from the 2019 IRP preferred portfolio.

Interruptible Contracts
Interruptible resources directly curtail load and thus full planning reserves are not held for the load that may be curtailed. As with demand response, this resource is categorized as a decrease to the peak load.

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

Position
The position is the resource surplus or deficit after subtracting obligation plus required reserves from total resources. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Capacity Balance Determination

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

> **Existing Resources** = Thermal + Hydro + Renewable + Firm Purchases + Qualifying Facilities + Existing Demand Response – Firm Sales – Non-owned Reserves

The peak load, interruptible contracts, existing Energy Efficiency, and new Energy Efficiency from the preferred portfolio are netted together for each of the annual system summer and winter peaks, as applicable, to compute the annual peak obligation:

> **Obligation** = Load – Interruptible Contracts – New and Existing Energy Efficiency

The amount of reserves to be added to the obligation is then calculated. This is accomplished by the net system obligation calculated above multiplied by the 13 percent target PRM adopted for the 2019 IRP. The formula for this calculation is:

Planning Reserves = Obligation x PRM

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

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

Current Status of 2021 IRP Cycle Load Resource Balance updates

PacifiCorp has provided updates to stakeholders related to the current transmission planning efforts during the 2021 IRP development cycle that may be included in additional discussion in this chapter for final IRP filing, which will be made no later than September 1, 2021.

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.

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.

PacifiCorp's current supply-side resource tables are included as follows:

Table - 2021 Supply Side 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	10.00	7.44	0.00	9,350	2.6	3.9	43.6	0.0006	0.0090	0.255	117
Natural Gas	Intercooled SCCT Aero x2	0	227	2025	30	1,126	10.03	5.03	0.00	8,800	2.9	3.9	27.0	0.0006	0.0090	0.255	117
Natural Gas	SCCT Frame "F" x1	0	239	2025	35	699	10.09	14.16	0.00	9,913	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	Brownfield SCCT Frame "F" x1	0	239	2025	35	674	10.09	14.16	0.00	9,913	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	IC Recips x 6	0	111	2026	40	1,938	12.14	10.39	0.00	8,286	2.5	5.0	27.1	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "H", 1x1	0	422	2026	40	1,396	10.05	1.77	0.00	6,343	2.5	3.8	23.6	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 1x1	0	51	2026	40	470	0.00	0.05	0.00	8,838	2.5	3.8	23.0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", 2x1	0	842	2027	40	1,019	9.89	1.71	0.00	6,361	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 2x1	0	102	2027	40	357	0.00	0.05	0.00	8,665	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	0	842	2027	40	1,019	9.89	1.08	0.00	6,610	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 1x1	0	615	2026	40	1,065	9.95	1.48	0.00	6,264	2.5	3.8	20.4	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 1x1	0	63	2026	40	397	0.00	0.06	0.00	8,769	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 2x1	0	1,232	2027	40	787	9.90	1.43	0.00	6,251	2.5	3.8	17.9	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 2x1	0	126	2027	40	309	0.00	0.06	0.00	8,704	2.5	3.8	17.8	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	1,500	159	2025	30	1,551	13.91	7.89	0.00	9,362	2.6	3.9	43.6	0.0006	0.0090	0.255	117
Natural Gas	Intercooled SCCT Aero x2	1,500	215	2025	30	1,188	13.93	5.31	0.00	8,802	2.9	3.9	27.0	0.0006	0.0090	0.255	117
Natural Gas	SCCT Frame "F" x1	1,500	227	2025	35	738	13.84	14.94	0.00	9,916	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	Brownfield SCCT Frame "F" x1	1,500	227	2025	35	711	13.84	14.94	0.00	9,916	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	IC Recips x 6	1,500	111	2026	40	1,938	12.14	10.39	0.00	8,286	2.5	5.0	27.1	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "H", 1x1	1,500	397	2026	40	1,484	13.80	1.88	0.00	6,384	2.5	3.8	23.6	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 1x1	1,500	51	2027	40	470	0.00	0.05	0.00	8,789	2.5	3.8	23.0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", 2x1	1,500	797	2027	40	1,077	14.11	1.81	0.00	6,367	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 2x1	1,500	102	2026	40	357	0.00	0.05	0.00	8,713	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	1,500	797	2026	40	1,077	14.11	1.14	0.00	6,633	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 1x1	1,500	582	2027	40	1,125	14.02	1.57	0.00	6,264	2.5	3.8	20.4	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 1x1	1,500	63	2027	40	397	0.00	0.06	0.00	8,816	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 2x1	1,500	1,166	2026	40	832	14.10	1.51	0.00	6,249	2.5	3.8	17.9	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 2x1	1,500	126	2026	40	309	0.00	0.06	0.00	8,742	2.5	3.8	17.8	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	3,000	150	2025	30	1,645	11.24	8.37	0.00	9,380	2.6	3.9	43.6	0.0006	0.0090	0.255	117
Natural Gas	Intercooled SCCT Aero x2	3,000	203	2025	30	1,260	11.23	5.63	0.00	8,811	2.9	3.9	27.0	0.0006	0.0090	0.255	117
Natural Gas	SCCT Frame "F" x1	3,000	214	2025	35	779	11.25	15.79	0.00	9,928	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	Brownfield SCCT Frame "F" x1	3,000	214	2025	35	751	11.25	15.78	0.00	9,928	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	IC Recips x 6	3,000	111	2026	40	1,938	12.14	10.39	0.00	8,286	2.5	5.0	27.1	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "H", 1x1	3,000	376	2026	40	1,569	11.30	1.99	0.00	6,387	2.5	3.8	23.6	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 1x1	3,000	51	2027	40	470	0.00	0.05	0.00	8,816	2.5	3.8	23.0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", 2x1	3,000	750	2027	40	1,144	11.10	1.92	0.00	6,400	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 2x1	3,000	102	2026	40	357	0.00	0.05	0.00	8,756	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	3,000	750	2026	40	1,144	11.10	1.21	0.00	6,682	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 1x1	3,000	550	2027	40	1,189	11.12	1.66	0.00	6,270	2.5	3.8	20.4	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 1x1	3,000	63	2027	40	397	0.00	0.06	0.00	8,837	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 2x1	3,000	1,103	2026	40	879	11.05	1.60	0.00	6,256	2.5	3.8	17.9	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 2x1	3,000	126	2026	40	309	0.00	0.06	0.00	8,763	2.5	3.8	17.8	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	5,050	139	2025	30	1,777	12.14	9.04	0.00	9,400	2.6	3.9	43.6	0.0006	0.0090	0.255	117
Natural Gas	Intercooled SCCT Aero x2	5,050	187	2025	30	1,363	12.14	6.09	0.00	8,816	2.9	3.9	27.0	0.0006	0.0090	0.255	117
Natural Gas	SCCT Frame "F" x1	5,050	199	2025	35	841	12.14	17.04	0.00	9,936	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	Brownfield SCCT Frame "F" x1	5,050	199	2025	35	811	12.14	17.03	0.00	9,936	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	IC Recips x 6	5,050	111	2026	40	1,938	12.14	10.39	0.00	8,292	2.5	5.0	27.1	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "H", 1x1	5,050	350	2026	40	1,687	12.14	2.14	0.00	6,362	2.5	3.8	23.6	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 1x1	5,050	51	2026	40	470	0.00	0.05	0.00	8,545	2.5	3.8	23.0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", 2x1	5,050	686	2027	40	1,252	12.14	2.10	0.00	6,487	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 2x1	5,050	102	2027	40	358	0.00	0.05	0.00	9,470	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	5,050	686	2027	40	1,251	12.14	1.33	0.00	6,874	2.5	3.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 1x1	5,050	504	2026	40	1,299	12.14	1.81	0.00	6,352	2.5	3.8	20.4	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 1x1	5,050	63	2026	40	397	0.00	0.06	0.00	9,452	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 2x1	5,050	1,004	2027	40	966	12.14	1.76	0.00	6,373	2.5	3.8	17.9	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 2x1	5,050	126	2027	40	309	0.00	0.06	0.00	9,456	2.5	3.8	17.8	0.0006	0.0072	0.255	117
Natural Gas	SCCT Aero x3	6,500	126	2025	30	1,957	13.37	9.96	0.00	9,314	2.6	3.9	43.6	0.0006	0.0090	0.255	117
Natural Gas	Intercooled SCCT Aero x2	6,500	179	2025	30	1,427	12.72	6.37	0.00	8,786	2.9	3.9	27.0	0.0006	0.0090	0.255	117
Natural Gas	SCCT Frame "F" x1	6,500	189	2025	35	886	12.80	17.95	0.00	9,930	2.7	3.9	28.4	0.0006	0.0090	0.255	117
Natural Gas	Brownfield SCCT Frame "F" x1	6,500	189	2025	35	854	12.80	17.95	0.00	9,930	2.7	5.0	28.4	0.0006	0.0090	0.255	117
Natural Gas	IC Recips x 6	6,500	111	2026	40	1,937	12.14	10.39	0.00	8,333	2.5	3.8	27.1	0.0006	0.0288	0.255	117
Natural Gas	CCCT Dry "H", 1x1	6,500	335	2026	40	1,761	12.68	2.23	0.00	6,390	2.5	3.8	23.6	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 1x1	6,500	51	2027	40	470	0.00	0.05	0.00	8,857	2.5	3.8	23.0	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", 2x1	6,500	669	2027	40	1,283	12.45	2.15	0.00	6,399	2.5	3.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "H", DF, 2x1	6,500	102	2026	40	357	0.00	0.05	0.00	8,852	2.5	4.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	Brownfield CCCT Dry "H", DF, 2x1	6,500	669	2026	40	1,283	12.45	1.36	0.00	6,724	2.5	5.8	19.8	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 1x1	6,500	490	2027	40	1,337	12.50	1.86	0.00	6,273	2.5	6.8	20.4	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 1x1	6,500	63	2027	40	397	0.00	0.06	0.00	8,864	2.5	7.8	20.1	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", 2x1	6,500	981	2026	40	988	12.43	1.80	0.00	6,259	2.5	8.8	17.9	0.0006	0.0072	0.255	117
Natural Gas	CCCT Dry "J", DF, 2x1	6,500	126	2026	40	309	0.00	0.06	0.00	8,789	2.5	9.8	17.8	0.0006	0.0072	0.255	117

Table - 2021 Supply Side 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)
Coal	SCPC with CCS	4,500	526	2028	40	6,488	127.00	7.00	72.22	13,087	5.0	5.0	1,004	0.0085	0.070	0.022	20.5
Coal	IGCC with CCS	4,500	466	2028	40	6,282	60.00	11.77	58.20	10,823	8.0	7.0	394	0.0085	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	4,500	-115	2026	20	2,971	37.00	3.29	28.18	14,372	5.0	5.0	450	0.0050	0.070	1.200	20.5
Coal	SCPC with CCS	6,500	692	2028	40	7,348	127.00	7.58	67.09	13,242	5.0	5.0	1,004	0.0085	0.070	0.022	20.5
Coal	IGCC with CCS	6,500	456	2028	40	7,113	60.00	14.11	63.40	11,047	8.0	7.0	394	0.0085	0.050	0.333	20.5
Coal	PC CCS retrofit @ 500 MW pre-retrofit basis	6,500	-115	2026	20	2,971	37.00	3.29	28.18	14,372	5.0	5.0	450	0.0050	0.070	1.200	20.5
Geothermal	Blundell Dual Flash 90% CF	4,500	35	2021	40	5,708	127.00	1.16	103.85	n/a	5.0	5.0	10.0	n/a	n/a	n/a	n/a
Geothermal	Greenfield Binary 90% CF	4,500	43	2023	40	5,973	127.00	1.16	103.85	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Geothermal	Generic Geothermal PPA 90% CF	4,500	30	2021	20	0		77.34	0.00	n/a	5.0	5.0	270	n/a	n/a	n/a	n/a
Wind	Pocatello, ID, 200 MW, CF: 37.1%	4,500	200	2024	30	1,365	12.50	0.00	24.74	N/A	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind	Arlington, OR, 200 MW, CF: 37.1%	1,500	200	2024	30	1,315	12.50	0.00	24.74	N/A	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind	Monticello, UT, 200 MW, CF: 29.5%	4,500	200	2024	30	1,306	12.50	0.00	24.74	N/A	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind	Medicine Bow, WY, 200 MW, CF: 43.6%	6,500	200	2024	30	1,356	12.50	0.00	24.74	N/A	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind	Goldendale, WA, 200 MW, CF: 37.1%	1,500	200	2024	30	1,390	12.50	0.00	24.74	N/A	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind + Storage	Pocatello, ID, 200 MW, CF: 37.1% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	2,152	232.50	0.00	37.59	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind + Storage	Arlington, OR, 200 MW, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	2,086	232.50	0.00	37.59	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind + Storage	Monticello, UT, 200 MW, CF: 29.5% + BESS: 50% pwr, 4 hours	4,500	200	2024	30	2,061	232.50	0.00	37.59	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind + Storage	Medicine Bow, WY, 200 MW, CF: 43.6% + BESS: 50% pwr, 4 hours	6,500	200	2024	30	2,136	232.50	0.00	37.59	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Wind + Storage	Goldendale, WA, 200 MW, CF: 37.1% + BESS: 50% pwr, 4 hours	1,500	200	2024	30	2,211	232.50	0.00	37.59	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Idah Falls, ID, 100 MW, CF: 26.1%	4,700	100	2023	25	1,429	35.00	0.00	16.20	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Idah Falls, ID, 200 MW, CF: 26.1%	4,700	200	2023	25	1,302	35.00	0.00	16.10	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 100 MW, CF: 27.6%	4,800	100	2023	25	1,444	35.00	0.00	16.20	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Lakeview, OR, 200 MW, CF: 27.6%	4,800	200	2023	25	1,330	35.00	0.00	16.10	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 100 MW, CF: 30.2%	5,000	100	2023	25	1,422	35.00	0.00	17.60	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Milford, UT, 200 MW, CF: 30.2%	5,000	200	2023	25	1,297	35.00	0.00	17.60	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 100 MW, CF: 27.9%	6,400	100	2023	25	1,423	35.00	0.00	17.60	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Rock Springs, WY, 200 MW, CF: 27.9%	6,400	200	2023	25	1,297	35.00	0.00	17.60	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 100 MW, CF: 24.2%	1,000	100	2023	25	1,486	35.00	0.00	17.60	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar	Yakima, WA, 200 MW, CF: 24.2%	1,000	200	2023	25	1,357	35.00	0.00	17.60	n/a	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idah Falls, ID, 100 MW, CF: 26.1% + BESS: 50% pwr, 4 hours	4,700	100	2023	25	2,351	255.00	0.00	30.00	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Idah Falls, ID, 200 MW, CF: 26.1% + BESS: 50% pwr, 4 hours	4,700	200	2023	25	2,161	255.00	0.00	28.95	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 100 MW, CF: 27.6% + BESS: 50% pwr, 4 hours	4,800	100	2023	25	2,329	255.00	0.00	30.00	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Lakeview, OR, 200 MW, CF: 27.6% + BESS: 50% pwr, 4 hours	4,800	200	2023	25	2,154	255.00	0.00	28.95	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 100 MW, CF: 30.2% + BESS: 50% pwr, 4 hours	5,000	100	2023	25	2,283	255.00	0.00	31.40	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Milford, UT, 200 MW, CF: 30.2% + BESS: 50% pwr, 4 hours	5,000	200	2023	25	2,102	255.00	0.00	30.45	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 100 MW, CF: 27.9% + BESS: 50% pwr, 4 hours	6,400	100	2023	25	2,312	255.00	0.00	31.40	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Rock Springs, WY, 200 MW, CF: 27.9% + BESS: 50% pwr, 4 hours	6,400	200	2023	25	2,128	255.00	0.00	30.45	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 100 MW, CF: 24.2% + BESS: 50% pwr, 4 hours	1,000	100	2023	25	2,405	255.00	0.00	31.40	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage	Yakima, WA, 200 MW, CF: 24.2% + BESS: 50% pwr, 4 hours	1,000	200	2023	25	2,217	255.00	0.00	30.45	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Idah Falls, ID, 200 MW, CF: 26.1% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,700	200	2023	25	3,395	267.50	0.00	82.95	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Lakeview, OR, 200 MW, CF: 27.6% + BESS: 50% pwr, 4 hours + 200 MW Wind	4,800	200	2023	25	3,424	267.50	0.00	82.95	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Milford, UT, 200 MW, CF: 30.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	5,000	200	2023	25	3,364	267.50	0.00	81.45	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Rock Springs, WY, 200 MW, CF: 27.9% + BESS: 50% pwr, 4 hours + 200 MW Wind	6,400	200	2023	25	3,364	267.50	0.00	81.45	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Solar + Storage + Wind	Yakima, WA, 200 MW, CF: 24.2% + BESS: 50% pwr, 4 hours + 200 MW Wind	1,000	200	2023	25	3,424	267.50	0.00	81.45	85%	Included with CF		n/a	n/a	n/a	n/a	n/a
Storage	Pumped Hydro, Swan Lake	N/A	400	2027	60	3,095	2,600.00	0.00	12.50	78%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Goldendale	N/A	1,200	2028	60	2,833	2,600.00	0.00	12.50	78%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Seminoe	N/A	750	2029	80	3,461	2,600.00	0.37	16.00	80%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Badger Mountain	N/A	500	2027	80	2,621	2,600.00	0.37	28.00	80%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Owyhee	N/A	600	2029	80	3,203	2,600.00	0.37	20.00	80%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Flat Canyon	N/A	300	2029	80	4,046	2,600.00	0.37	53.33	80%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Utah PS2	N/A	500	2027	80	3,237	2,600.00	0.37	28.00	80%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Utah PS3	N/A	600	2029	80	3,371	2,600.00	0.37	20.00	80%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Pumped Hydro, Banner Mountain	N/A	400	2028	50	3,276	2,600.00	0.00	28.50	81%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 150 MW, 600 MWh	N/A	150	2024	50	1,954	12.14	6.50	12.67	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1200 MWh	N/A	150	2024	50	2,189	12.14	6.50	12.67	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 150 MW, 1800 MWh	N/A	150	2024	50	2,445	12.14	6.50	12.67	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 300 MW, 1200 MWh	N/A	300	2024	50	1,557	12.14	6.50	9.33	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 300 MW, 2400 MWh	N/A	300	2024	50	1,692	12.14	6.50	9.33	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 300 MW, 3600 MWh	N/A	300	2024	50	2,016	12.14	6.50	9.33	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 500 MW, 2000 MWh	N/A	500	2024	50	1,549	12.14	6.50	6.60	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 500 MW, 4000 MWh	N/A	500	2025	50	1,762	12.14	6.50	6.60	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Adiabatic CAES, Hydrostor, 500 MW, 6000 MWh	N/A	500	2025	50	1,930	12.14	6.50	6.60	60%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Li-Ion Battery, , 1 MW, 0.5 MWh	N/A	1	2023	20	1,948	55.00	Included in FOM	40.00	85%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Li-Ion Battery, , 1 MW, 1 MWh	N/A	1	2023	20	2,058	110.00	Included in FOM	50.00	85%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Li-Ion Battery, , 1 MW, 4 MWh	N/A	1	2023	20	3,167	440.00	Included in FOM	70.00	85%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Li-Ion Battery, , 1 MW, 8 MWh	N/A	1	2023	20	4,608	880.00	Included in FOM	100.00	85%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	**Li-Ion Battery, , 50 MW, 200 MWh**	**N/A**	**50**	**2023**	**20**	**1,828**	**440.00**	**Included in FOM**	**27.60**	**85%**	**0.0**	**0.0**	**n/a**	**0.0000**	**0.000**	**0.000**	**0**
Storage	Flow Battery, , 1 MW, 1 MWh	N/A	1	2023	20	4,719	12.14	Included in FOM	13.00	70%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Flow Battery, , 1 MW, 4 MWh	N/A	1	2023	20	5,051	12.14	Included in FOM	13.00	70%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Flow Battery, , 1 MW, 8 MWh	N/A	1	2023	20	7,268	12.14	Included in FOM	27.00	70%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Storage	Flow Battery, , 20 MW, 160 MWh	N/A	20	2023	20	4,686	12.14	Included in FOM	30.50	70%	0.0	0.0	n/a	0.0000	0.000	0.000	0
Nuclear	Small Modular Reactor	5,000	854	2028	60	6,257	721.53	16.14	180.53	N/A	5.0	5.0	767	0.0000	0.000	0.000	0

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 uses 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 has identified case assumptions that will be used to produce optimized resource portfolios, each one unique with regard to the type, timing, location, and amount of new resources that could be pursued to serve customers over the next 20 years.
- PacifiCorp uses the PLEXOS Medium-Term schedule (MT Model) to perform stochastic risk analysis of the portfolios. Each portfolio will be evaluated for cost and risk among three natural gas price scenarios (low, medium, and high) and three carbon dioxide equivalent (CO_2e) price scenarios (zero, medium, high). An additional CO_2e 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_2e, medium gas/zero CO_2e, high gas/high CO_2e, low gas/zero CO_2e, and the social cost of greenhouse gases).
- Each LT model portfolio developed under one of the five price-policy scenarios will also be analyzed using the other four scenarios in the MT model to evaluate how it performs under differing market/policy conditions. The resulting cost and risk metrics will then be used to compare portfolio alternatives and inform selection of the preferred portfolio.
- Taking into consideration stakeholder comments and regulatory requirements, PacifiCorp will produce additional sensitivities/scenarios/cases that examine the potential impact/benefits of portfolio options on the system. Included in this are the Clean Energy Transformation Act (CETA) scenarios specified by rule in Washington: maximum customer benefit, CETA alternative portfolio, and climate change portfolio.
- Informed by comprehensive modeling, PacifiCorp's preferred portfolio selection process involves evaluating cost and risk metrics reported from the MT model, comparing resource portfolios on the basis of expected costs, low-probability high-cost outcomes, reliability, CO_2e emissions and other criteria.

Introduction

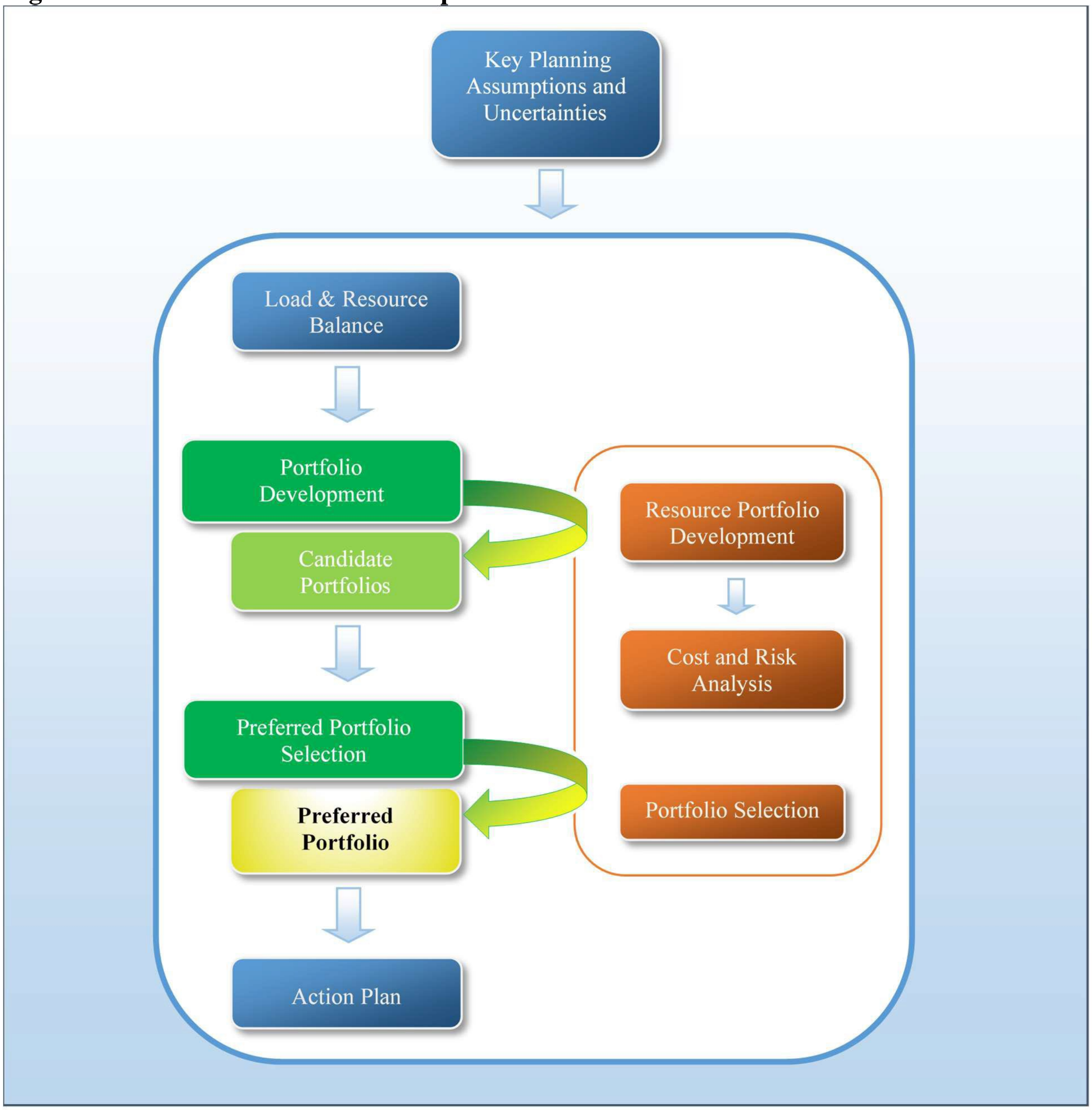
IRP modeling is used to assess the comparative cost, risk, and reliability attributes of different resource portfolios, each meeting target reliability requirements. These portfolio attributes form the basis of an overall quantitative portfolio performance evaluation.

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. When completed, the results of PacifiCorp's modeling and portfolio analysis will be summarized in the chapter, "Modeling and Portfolio Selection Results".

Modeling and Evaluation Steps

Figure 7.1 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 7.1 – Portfolio Evaluation Steps within the IRP Process



For each modeling and evaluation step, PacifiCorp develops unique resource portfolios, analyzes cost and stochastic risk metrics for each portfolio, and selects, based on comparative cost and risk metrics, the specific portfolios considered in the next modeling and evaluation step. The outcomes of each can inform the need for additional studies to test or refine assumptions in a subsequent screening analysis. The basic portfolio evaluations within each step are highlighted in orange in Figure 7.1 above and include:

Resource Portfolio Development

All IRP models are configured and loaded with the best available information at the time a model run is produced. This information is fed into the LT model, which is used to produce resource portfolios with sufficient capacity to be reliable, measured against accepted industry standards. Each resource portfolio is uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system over time.

- Cost and Risk Analysis
  Resource portfolios developed by the LT 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.

- Portfolio Selection
  The portfolio selection process is based upon modeling results from the resource portfolio development and cost and risk analysis steps. The screening criteria are based on the present value revenue requirement (PVRR) of system costs, assessed across a range of price-policy scenarios on an expected-value basis and on an upper-tail stochastic risk basis. Portfolios are ranked using a risk-adjusted PVRR metric, a metric that combines the expected value PVRR with upper-tail stochastic risk PVRR. The final selection process considers cost-risk rankings, robustness of performance across pricing scenarios and other supplemental modeling results, including reliability and CO_2e emissions data.

Resource Portfolio Development

Resource expansion plan modeling, performed with the PLEXOS LT model, is used to produce resource portfolios with sufficient capacity to achieve a target loss of load probability over the 20-year study horizon. Each resource portfolio is uniquely characterized by the type, timing, location, and amount of new resources in PacifiCorp's system over time. These resource portfolios reflect a combination of planning assumptions such as resource retirements, CO_2 prices (also applicable to CO_2 equivalent emissions), wholesale power and natural gas prices, load growth net of assumed private generation penetration levels, cost and performance attributes of potential transmission upgrades, and new and existing resource cost and performance data, including assumptions for new supply-side resources and incremental demand-side resources (DSM). Changes to these input variables cause changes to the resource mix, which influences system costs and risks. New to this IRP is using the PLEXOS LT model to consider the retirement of coal endogenously.

Long-Term (LT) Capacity Expansion Model

The LT model operates by minimizing operating costs for existing and prospective new resources, subject to system load balance, reliability and other constraints. Over the 20-year planning horizon, it optimizes resource additions subject to resource costs and load constraints (seasonal loads, LOLP target, operating reserves, plus a target capacity reserve margin for each load area represented in the model). 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 time-of-day least-cost dispatch for existing and potential planned generation, while considering cost and performance of existing contracts and new DSM alternatives within PacifiCorp's transmission system. Resource dispatch is based on 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 cost of existing contracts, spot market purchase costs, spot market sale revenues, generation costs (fuel, fixed and variable operation and maintenance, decommissioning, emissions, unserved energy, and unmet capacity), costs of DSM resources, amortized capital costs for existing coal resources and potential new resources, and costs for potential transmission upgrades.

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.

Transmission Costs
In developing resource portfolios for the 2021 IRP, PacifiCorp will include 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
Resource adequacy is modeled in the portfolio-development process by ensuring each portfolio meets a target loss of load probability (LOLP). In its 2021 IRP, PacifiCorp will also apply a capacity reserve margin (CRM), modeled minimally as a 13 percent requirement calculated at each topology location carrying load. The capacity reserve margin applies in all periods and must be met on the basis of resource availability. 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 will directly model operating reserve requirements in expansion plan model runs which ensures that expansion resources selected to meet LOLP and 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.

New Resource Options

Dispatchable Thermal Resources

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

Front Office Transactions

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

From a modeling perspective, it is not feasible to incorporate all of the short-term firm physical power products, which differ by delivery pattern and delivery period, that are available through brokers, exchanges, and non-brokered transactions. However, considering that PacifiCorp routinely uses these types of firm transactions, which obligate the seller to back the transaction with reserves when balancing its system, it is important that the contribution of short-term firm market purchases are accounted for in the portfolio-development process. For capacity expansion optimization modeling, short-term firm forward transactions are represented as FOTs and configured in the LT model with either an annual flat, summer-on-peak (July), or winter on-peak (December) delivery pattern in every year of the twenty-year planning horizon. As configured, FOTs contribute capacity toward meeting the 2021 IRP's capacity reserve margin and supply system energy consistent with the assumed FOT delivery pattern.

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

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 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.

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 of time;
- 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 fuel costs (for example, the cost of natural gas for expanding air with gas turbine expanders).

Capital Costs and End-Effects

Annual capital recovery factors are used to convert capital investment dollars into nominal levelized revenue requirement costs. The Plexos model is able to address end-effects that arise with capital-intensive projects that have different lives which may extend beyond the study period, and different in-service dates. 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 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 real annual requirement that grows with inflation when using the same nominal discountrate.

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, with the exception of coal unit natural gas conversions, which are given an in-service date of June 1st of a given year, recognizing the desired need for these alternatives to be available during the summer peak load period.

Inflation Rates

The 2021 IRP model simulations and cost data will reflect PacifiCorp's corporate inflation rate schedule of 2.155% unless otherwise noted.

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.[28] PVRR figures reported in the 2021 IRP will be reported in January 1, 2021 dollars.

CO2E Price Scenarios

PacifiCorp will use four different CO_2e 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 of these scenarios apply a CO_2e price as a tax beginning 2025. PacifiCorp will incorporate the social cost of greenhouse gas in compliance with RCW 19.280.030.

Wholesale Electricity and Natural Gas Forward Prices

For 2021 IRP modeling purposes, five electricity price forecasts will be 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

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

forwards, followed by a market-to-fundamentals blending period that transitions to a pure fundamentals-based forecast.

Cost and Risk Analysis

Medium-Term (MT) Schedule Model

The MT model uses the same common input assumptions described for LT model with additional data provided by the LT model results (e.g., the capacity expansion portfolio). While the LT model supplies 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 MT model cost-risk metrics are ultimately used in the preferred portfolio selection, the LT model results can be informative, especially in their role as a magnitude and direction indicator to compare to MT modeloutcomes.

Cost and Risk Analysis
Once unique resource portfolios are developed using the LT model, additional modeling is performed to produce metrics that support comparative cost and risk analysis among the different resource portfolio alternatives. Stochastic risk modeling of resource portfolio alternatives is performed with 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 LT 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.

Monte Carlo Simulation

During model execution, the MT model will make time-path-dependent Monte Carlo draws for each stochastic variable based on input parameters. The Monte Carlo draws are percentage deviations from the expected forward value of each variable. The Monte Carlo draws of the stochastic variables among all resource portfolios modeled are the same, which allows for a direct comparison of stochastic results among all of the resource portfolios being analyzed. In the case of natural gas prices, electricity prices, and regional loads, the 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;
- Risk-adjusted mean PVRR;
- Upper-tail Mean PVRR;
- 5th and 95th percentile PVRR;
- Average annual mean and upper-tail energy not served (ENS);
- Loss of load probability; and
- Cumulative CO_2e emissions.

Stochastic Mean PVRR

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.[29] The net variable cost from stochastic simulations, expressed as a net present value, includes system costs for fuel, variable O&M, unit start-up, long term contracts, system balancing market purchases 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 an nominal-levelized basis. Other components in the stochastic mean PVRR include CO_2e emission costs for any scenarios that include a CO_2e price assumption.

Risk-Adjusted PVRR

The risk-adjusted PVRR incorporates the expected-value cost of low-probability, high cost outcomes. This measure is calculated as the PVRR of stochastic mean system variable costs plus

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

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

Upper-Tail Mean PVRR

The upper-tail mean PVRR is a measure of high-end stochastic cost risk. This measure is derived by identifying the Monte Carlo iterations with the three highest production costs on a net present value basis. The portfolio's nominal levelized fixed costs are added to these three production costs, and the arithmetic average of the resulting PVRRs is computed.

95th and 5th Percentile PVRR

The 5th and 95th percentile PVRRs are also reported from the 50 Monte Carlo iterations. These measures capture the extent of upper-tail (high cost) and lower-tail (low cost) stochastic outcomes. As described above, the 95th percentile PVRR is used to derive the high-end cost risk premium for the risk-adjusted mean PVRR measure. The 5th percentile PVRR is reported for informational purposes.

Production Cost Standard Deviation

To capture production cost volatility risk, PacifiCorp uses the standard deviation of the stochastic production cost from the 50 Monte Carlo iterations. The production cost is expressed as a net present value of annual costs over the period 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.

Average and Upper-Tail Energy Not Served

Certain iterations of a stochastic simulation will have ENS, a condition where there are insufficient resources, inclusive of system balancing purchases, available to meet load or operating reserve requirements because of physical constraints. This occurs when Monte Carlo draws of stochastic variables result in a load obligation that is higher than the capability of the available resources in the portfolio. For example, this might occur in Monte Carlo draws with large load shocks concurrent with a random unplanned plant outage event. Consequently, ENS, when averaged across all 50 iterations, serves as a measure of reliability that can be compared among resource portfolios.

Loss of Load Probability

Loss of load probability (LOLP) reports the probability and extent to which available resources of a portfolio cannot serve load during the 20-year period. PacifiCorp reports LOLP statistics, which are calculated from ENS events that exceed threshold levels. The actual level of LOLP reported is distinct from the aforementioned LOLP *target*, which is used to ensure that all portfolio produced by the LT model meet the "1 day in 10 years" industry standard threshold for reliability.

Cumulative CO_{2e} Emissions

Annual CO_2e emissions from each portfolio will be reported from the MT model and summed for the twenty year planning period. Comparison of total CO_2e emissions is used to identify potential outliers among resource portfolios that might otherwise be comparable with regard to expected cost, upper-tail cost risk, and/or ENS.

Forward Price Curve Scenarios

Top-performing resource portfolios developed with the LT model 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

Any transmission upgrades selected by the LT model that provide incremental transfer capability among bubbles in this topology are also included in the MT model.

Resource Adequacy

The resource portfolio developed with the LT model, which will meet an assumed LOLP target, operating reserves requirement and capacity reserve margin, is fixed in all MT simulations. While the LOLP target and capacity reserve margin are portfolio selection drivers, the MT model assumes the fixed portfolio inherited from the LT model. The MT therefore optimizes unit commitment and dispatch logic on the fixed portfolio to meet operating reserve requirements. These operating reserve requirements include contingency reserves, which are calculated as 3 percent of load and 3 percent of generation. In addition, MT reserve requirements account for regulation reserves.

Energy Storage Resources

Storage resources such as 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.

Given the size and complexity of PacifiCorp's system, and the necessary aggregation of data that occurs in a 20-year capacity expansion planning model, the company will model these types of storage systems primarily for load ramping and leveling, reserves carrying, and to support renewable resource additions, particularly co-located renewables.

Other Cost and Risk Considerations

In addition to reviewing stochastic PVRR, ENS, and CO_2e emissions data from the MT model, PacifiCorp considers other cost and risk metrics in its comparative analysis of resource portfolios. These metrics include fuel source diversity, and customer rate impacts.

Fuel Source Diversity
PacifiCorp considers relative differences in resource mix among portfolios by comparing the capacity of new resources in portfolios by resource type, differentiated by fuel source. PacifiCorp also provides a summary of fuel source diversity differences among top performing portfolios based on forecasted generation levels of new resources in the portfolio. Generation share is reported among thermal resources, renewable resources, storage resources, DSM resources and FOTs.

Customer Rate Impacts
To derive a rate impact measure, PacifiCorp computes the percentage change in nominal annual revenue requirement from top performing resource portfolios (with lowest risk adjusted mean PVRRs) relative to a benchmark portfolio selected during the final preferred portfolio screening process. Annual revenue requirement for these portfolios is based on the stochastic production cost results from the LT model 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.

Portfolio Selection

The final action in each modeling and evaluation step is portfolio selection. In the first step, top performing portfolios are identified based on their relative performance with regard to mean system costs, risk-adjusted system costs, which account for upper tail stochastic risk, reliability metrics and cumulative CO_2e emissions.

Additional analysis can be performed to further assess the relative differences among top-performing portfolios.

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

Final Evaluation and Preferred Portfolio Selection

Due to the lengthy nature of the IRP cycle, the final step is the last opportunity to consider whether top-performing portfolios merit additional study based on observations in the model results across all studies, additional sensitivities, possible updates driven by recent events, and additional stakeholder feedback. Additional sensitivities may refine the portfolio selection based on portfolio optimization and cost and risk analysis steps.

During the final screening process, the results of any further resource portfolio developments will be ranked by risk-adjusted mean 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 mean 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 stochastic metrics from the MT model looking to identify if expected and ENS results and CO_2e emissions results can be used to differentiate portfolios that might be closely ranked on a risk-adjusted mean PVRR basis.

Case Definitions

Case definitions specify a combination of planning assumptions used to develop each unique resource portfolio analyzed in the 2021 IRP. The following presents preliminary cases to be analyzed as part of the 2021 IRP (as presented during the December 3, 2020 public input meeting):

Oregon Required Cases and Sensitivities

Requirement	Summary
Cost-effective Coal Retirements (Order 20-186)	Include in the 2021 development process an updated analysis – identifying the most cost-effective coal retirements individually and in combination.

Washington Required Cases and Sensitivities

Requirement	Summary
Alternative Lowest Reasonable Cost (CETA Draft Rules)	Analysis of lowest reasonable cost portfolio that the utility would have implemented if not for compliance with CETA requirements.
Future Climate Change (CETA Draft Rules)	Analysis should incorporate best available science on impacts of snowpack, streamflow, rainfall, heating/cooling degree days, and load changes from climate change.
Maximum Customer Benefit (CETA Draft Rules)	Scenario should model customer benefit (per RCW 19.405.040(8)) prior to balancing against other goals.

Preliminary Set of 2021 IRP Portfolio Development Cases

Case "Name"	Price-Policy	Existing Coal	Existing Gas	Other Existing Resources	Proxy Resources
BAU1-MM	MM	End of Life	End of Life	End of Life	Optimized
BAU1-MN	MN	End of Life	End of Life	End of Life	Optimized
BAU1-LN	LN	End of Life	End of Life	End of Life	Optimized
BAU1-HH	HH	End of Life	End of Life	End of Life	Optimized

BAU1-SC-GHG	SC-GHG	End of Life	End of Life	End of Life	Optimized
BAU2-MM	MM	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-MN	MN	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-LN	LN	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-HH	HH	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
BAU2-SC-GHG	SC-GHG	2019 IRP	2019 IRP	2019 IRP	2019 IRP+
P01-MM	MM	Optimized	End of Life	End of Life	Optimized
P01-MN	MN	Optimized	End of Life	End of Life	Optimized
P01-LN	LN	Optimized	End of Life	End of Life	Optimized
P01-HH	HH	Optimized	End of Life	End of Life	Optimized
P01-SC-GHG	SC-GHG	Optimized	End of Life	End of Life	Optimized

Case "Name"	Price-Policy	Existing Coal	Existing Gas	Other Existing Resources	Proxy Resources
P02-MM	MM	Optimized	End of Life	End of Life	No New Gas
P02-MN	MN	Optimized	End of Life	End of Life	No New Gas
P02-LN	LN	Optimized	End of Life	End of Life	No New Gas
P02-HH	HH	Optimized	End of Life	End of Life	No New Gas
P02-SC-GHG	SC-GHG	Optimized	End of Life	End of Life	No New Gas
P03-MM	MM	Retired by 2030	End of Life	End of Life	No New Gas
P03-MN	MN	Retired by 2030	End of Life	End of Life	No New Gas
P03-LN	LN	Retired by 2030	End of Life	End of Life	No New Gas
P03-HH	HH	Retired by 2030	End of Life	End of Life	No New Gas
P03-SC-GHG	SC-GHG	Retired by 2030	End of Life	End of Life	No New Gas

Additional Case Requirements

Washington Clean Energy Transformation Act Portfolio Requirements – SC-GHG

In accordance with the draft Clean Energy Implementation Plan and Integrated Resource Plan rules, PacifiCorp will consider the social cost of greenhouse gas emissions (SC-GHG) in compliance with RCW19.280.030(1)(a), which states utilities will "consider the social cost of greenhouse gas emissions, as determined by the commission for investor-owned utilities pursuant to RCW 80.28.405 and the department for consumer-owned utilities, when:

(i) Evaluating and selecting conservation policies, programs, and targets;
(ii) Developing integrated resource plans and clean energy action plans; and
(iii) Evaluating and selecting intermediate term and long-term resource options."

Provisions of the law are met by:

(i) Evaluating and selecting conservation policies, programs, and targets;

The 2021 IRP incorporates a robust conservation potential assessment (CPA), which in response to stakeholder interest and policy direction included three stakeholder feedback meetings beginning five months before the 2021 IRP planning cycle "kick-off" on June 18-19, 2020, and included an additional a CPA-specific workshop held on August 28, 2020. In addition, discussion of energy efficiency and demand response evaluation and application have been ongoing through the Company's 2021 IRP public-input meetings, including the topics of the CPA, related stakeholder feedback and responses, energy efficiency bundling methodologies, and non-energy impacts (NEIs).

(ii) Developing integrated resource plans and clean energy action plans; and

The SC-GHG will be considered in 2021 IRP analysis, and also specifically in the CEAP of the published IRP document.[30] PacifiCorp plans to develop cases that include five SC-GHG portfolios that will be evaluated under five price-policy scenarios as described in materials and discussion on portfolio development at the 2021 IRP public-input meeting on December 3, 2020.

For these five SC-GHG cases, 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 the LT model capacity expansion optimization modeling). Specifically, the SC-GHG will be modeled as dispatch adder on emissions, levied on a dollars-per-pound ($/lb.) dispatch cost rate and applicable to a pounds-per-MMBtu (lb./MMBtu) emissions rate in the model. The further assumption is made that system operations will not include the SC-GHG once the portfolios are determined, as the dispatch adder is not 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).

[30] WAC 480-100-620(12)(i) instructs utilities to "Incorporate [into the CEAP] the social cost of greenhouse gas emissions as a cost adder as specified in RCW 19.280.030(3)."

The Company plans to run at least one sensitivity that does model the impact of an operational cost component of the SC-GHG. In this case, the dispatch adder and market effects are applied in the cost and risk MT model assessment as well as in the capacity expansion phases of the analysis.

The published 2021 IRP will include a narrative description of the SC-GHG cases highlighting similarities and differences in assumptions and modeling and emphasizing important analytical outcomes.

(iii) Evaluating and selecting intermediate-term and long-term resource options.
The 2021 IRP modeling includes a 20-year long-term analysis of each portfolio eligible for selection as the Company's least-cost, least risk preferred portfolio. This analysis includes an assessment of the 2-to-4-year action plan window which informs potential immediate and intermediate next steps and will be detailed in the Action Plan chapter of the published IRP.

In each case, greenhouse gas emissions will be estimated and reported based on factors of generation or fuel usage consistent with direction provided in RCW 80.28.405. Emissions costs will also be included in price-policy scenarios with include an emissions policy cost component, such as the "MM" medium-gas price, medium CO_2e expected case scenario.

Oregon and Washington Requirements – plans for a Climate Change Scenario

As part of the order acknowledging PacifiCorp's 2019 IRP, the Oregon Public Utilities Commission directed the company to include a proposal for the scope of a potential climate adaptation study in its 2021 IRP. This proposed scope proposes a study that examines the impact of climate change on PacifiCorp's system in ways that the company is aware of and preparing for, as well as aligning with Oregon state policy that encourages the consideration of climate change impacts.

Structure of Proposed Study

I. Background and current knowledge on climate science

a. PacifiCorp would conduct a secondary literature review, combined with statewide policy and the company's own knowledge of climate impacts to produce a summary of the current state of climate science, as well as projections on where global, regional, and local forecasts project us to be in the future

II. Future Climate Scenarios

a. As part of the analysis on future climate scenarios, the company would include current best data from global climate models (GCMs) that simulate atmospheric and ocean circulation, land surface processes, clouds, atmospheric chemistry, aerosols, land and sea ice, vegetation, and carbon cycling. These simulations are conducted as part of the Intergovernmental Panel on Climate Change and would be used to project the future climate scenarios.

b. The data used from the Intergovernmental Panel would allow PacifiCorp to include simulation scenarios that analyze emissions variables (known as representative concentration pathways).
c. PacifiCorp would also include either an analysis or a discussion of the feasibility of downscaling analysis to move from GCMs to regional models, and the inherent benefit/uncertainty that arises from this approach.

III. Primary Variables Relevant to the IRP

a. Temperature
   i. Observed trends
   ii. Future projections
   iii. Impact on PacifiCorp service area and energy production (maximum and minimum temperature, precipitation, wind speed, and specific humidity)
b. Precipitation
   i. Observed trends
   ii. Future projections
   iii. Impact of low or extreme precipitation events on PacifiCorp service area and energy production
c. Streamflow
   i. Observed trends
   ii. Future projections
   iii. Impact of snow-pack disruption or changes in watershed on PacifiCorp service area and energy production
d. Changes in severe weather duration
   i. Observed trends
   ii. Future projections
   iii. Impact on fire weather, population growth, and air conditioning load in service area

IV. Other Variables

a. Wind speed
b. Cloud cover
c. Wildfire risk

V. Potential Mitigation Strategies

a. Discussion of two degrees Celsius threshold and RCP emissions scenarios
b. Discussion of decarbonization and carbon-free energy sources
c. Specifically discuss adaptation strategies for risk of population growth, and air conditioning penetration
d. Discussion of solar radiation management and carbon dioxide removal

As part of the implementation of the Clean Energy Transformation Act in Washington, WAC 480-100-620(10)(b) directs utilities to run a "climate change" scenario; the requirements are as follows:

> "(b) At least one scenario must be a future climate change scenario. This scenario should incorporate the best science available to analyze impacts including, but not limited to,

changes in snowpack, streamflow, rainfall, heating and cooling degree days, and load changes resulting from climate change." From WAC 480-100-620(10)(b)

Scenario Details

To comply with this required scenario, an analysis similar to the proposed outline in Oregon may be required. The following study plan is directed at achieving compliance with this scenario:

I. Background and current knowledge on climate science

a. PacifiCorp would conduct a secondary literature review, combined with statewide policy and the company's own knowledge of climate impacts to produce a summary of the current state of climate science, as well as projections on where global, regional, and local forecasts project us to be in the future.

II. Future Climate Scenarios

b. As part of the analysis on future climate scenarios, the company would include current best data from global climate models (GCMs) that simulate atmospheric and ocean circulation, land surface processes, clouds, atmospheric chemistry, aerosols, land and sea ice, vegetation, and carbon cycling. These simulations are conducted as part of the Intergovernmental Panel on Climate Change and would be used to project the future climate scenarios.
c. The data used from the Intergovernmental Panel would allow PacifiCorp to include simulation scenarios that analyze emissions variables (known as representative concentration pathways).
d. PacifiCorp would also include either an analysis or a discussion of the feasibility of downscaling analysis to move from GCMs to regional models, and the inherent benefit/uncertainty that arises from this approach.

III. Primary Variables Relevant to the IRP

a. Snowpack
    i. Observed trends
    ii. Future projections
    iii. impact
b. Streamflow
    i. Observed trends
    ii. Future projections
    iii. impact
c. Rainfall
    i. Observed trends
    ii. Future projections
    iii. impact
d. HDD and CDD
    i. Observed trends
    ii. Future projections
    iii. impact
e. Population growth, AC use, and other load changes

i. Observed trends
ii. Future projections
iii. Impact

IV. Impact of Scenario on Portfolio Outcome

a. Discussion of SC-GHG
b. Discussion of no coal in allocation of electricty after 12/31/2025
c. Portfolio outcome and required assumptions

Among the broad range of portfolios created and analyzed under the strategies described in this draft chapter, and responsive to many regulatory requirements and stakeholder interests, many or all may be determined to meet CETA objectives. Any deficiencies in meeting CETA objectives will be addressed based on analysis and ongoing stakeholder and regulatory guidance.

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 may include action items for existing resources, new resources, transmission, demand-side management (DSM) resources, short-term firm market purchases (front office transactions or FOTs), and the purchase and sale of renewable energy credits (RECs).
- The 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, distributed generation, carbon dioxide (CO_2) emission polices, Regional Haze outcomes, and availability of purchases from the market.
- PacifiCorp will further discuss 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.

Resources included in the 2021 IRP preferred portfolio help define the actions included in the action plan, focusing on the size, timing, type, and amount of resources needed to meet load obligations, and current and potential future state regulatory requirements.

The 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 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 the resources identified in the plan are proxy resources, which act as a guide for resource procurement and not as a commitment. Resources evaluated as part of procurement initiatives may vary from the proxy resources identified in the plan with respect to resource type, timing, size, cost and location.

PacifiCorp recognizes the need to support and justify resource acquisitions consistent with then-current laws, regulatory rules and commission orders.

In addition to presenting the 2021 IRP action plan, reporting on progress in delivering the prior action plan, and presenting the 2021 IRP acquisition path analysis, Chapter 9 will cover the following resource procurement topics as part of the final IRP filing no later than September 1, 2021:

- 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.

Purpose of Hedging

While PacifiCorp focuses every day on minimizing net power costs for customers, the company also focuses every day on mitigating price risk to customers, which is done through hedging consistent with a robust risk management policy. For years PacifiCorp has followed a consistent hedging program that limits risk to customers, has tracked risk metrics assiduously and has diligently documented hedging activities. PacifiCorp's risk management policy and hedging program exists to achieve the following goals: (1) ensure reliable sources of electric power are available to meet PacifiCorp's customers' needs; (2) reduce volatility of net power costs for PacifiCorp's customers. The purpose is solely to reduce customer exposure to net power cost volatility and adverse price movement. PacifiCorp does not engage in a material amount of proprietary trading activities. Hedging is done solely for the purpose of limiting financial losses due to unfavorable wholesale market changes. Hedging modifies the potential losses and gains in net power costs associated with wholesale market price changes. The purpose of hedging is not to reduce or minimize net power costs. PacifiCorp cannot predict the direction or sustainability of changes in forward prices. Therefore, PacifiCorp hedges, in the forward market, to reduce the volatility of net power costs consistent with good industry practice as documented in the company's risk management policy.

Risk Management Policy and Hedging Program

PacifiCorp's risk management policy and hedging program were designed to follow electric industry best practices and are periodically reviewed at least annually by the company's risk oversight committee. The risk oversight committee includes PacifiCorp representatives from the front office, finance, risk management, treasury, and legal department. The risk oversight committee makes recommendations to the president of Pacific Power, who ultimately must approve any change to the risk management policy. PacifiCorp's current policy is also consistent with the guidelines that resulted from collaborative hedging workshops with parties in Utah, Oregon, Idaho and Wyoming that took place in 2011 and 2012.

The main components of PacifiCorp's risk management policy and hedging program are natural gas percent hedged volume limits, value-at-risk (VaR) limits and time to expiry VaR (TEVaR) limits. These limits force PacifiCorp to monitor the open positions it holds in power and natural gas on behalf of its customers on a daily basis and limit the size of these open positions by prescribed time frames in order to reduce customer exposure to price concentration and price volatility. The hedge program requires purchases of natural gas at fixed prices in gradual stages in advance of when it is required to reduce the size of this short position and associated customer risk. Likewise, on the power side, PacifiCorp either purchases or sells power in gradual stages in advance of anticipated open short or long positions to manage price volatility on behalf of customers.

Since 2003, PacifiCorp's hedge program has employed a portfolio approach of dollar cost averaging to progressively reduce net power cost risk exposure over a defined time horizon while adhering to best practice risk management governance and guidelines. PacifiCorp's current portfolio hedging approach is defined by increasing risk tolerance levels represented by progressively increasing percentage of net power costs across the forward hedging period. PacifiCorp incorporated a time to expiry value at risk (TEVaR) metric in May 2010. In May 2012, as a result of multiple hedging collaboratives, the company reintroduced natural gas percent hedge volume limits of forecast requirements into its policy. There has been no conflict to-date between the new volume limits and PacifiCorp's VaR and TEVaR limits, although the volume limits would supersede in such conflict, consistent with the guidelines from the hedging collaboratives.

The primary governance of PacifiCorp's hedging activities is documented in the company's Risk Management Policy. In May 2010, PacifiCorp moved from hedging targets based on volume percentages to targets based on the "to expiry value-at-risk" or TEVaR metric. The primary goal of this change was to increase the transparency of the combined natural gas and power exposure by period. It enhances the progressive approach to hedging that PacifiCorp has employed for many years and provides the benefit of a more sophisticated measure of risk that responds to changes in the market and changes in open natural gas and power positions. Importantly, the TEVaR metric automatically reduces hedge requirements as commodity price volatility decreases and increases hedge requirements as correlations among commodities diverge, all the while maintaining the same customer risk exposure.

Dollar cost averaging is the term used to describe gradually hedging over a period of time rather than all at once. This method of hedging, which is widely used by many utilities, captures time diversification and eliminates speculative bursts of market timing activity. Its use means that at times PacifiCorp buys at relatively higher prices and at other times relatively lower prices, essentially capturing an array of prices at many levels. While doing so, PacifiCorp steadily and adaptively meets its hedge goals through the use of this technique while staying within VaR and TEVaR and natural gas percent hedge volume limits.

The result of these program changes in combination with changes in the market (such as reduced volatility to which PacifiCorp's program automatically responds), has been a significant decrease in PacifiCorp's longer-dated hedge activity, *i.e.*, four years forward on a rolling basis.

As a result of the hedging collaboratives, PacifiCorp made the following material changes to its policy in May 2012: (l) a reduction in the standard hedge horizon from 48 months to 36 months and (2) a percent hedged range guideline for natural gas for each of the three forward l2-month periods, which includes a minimum natural gas open position in each of the forward 12-month periods. The percent hedged range guideline is greater for the first rolling twelve months and gradually smaller for the second and third rolling twelve-month periods. PacifiCorp also agreed to provide a new confidential semi-annual hedging report.

Cost Minimization

While hedging does not minimize net power costs, PacifiCorp takes many actions to minimize net power costs for customers. First, the company is engaged in integrated resource planning to plan resource acquisitions that are anticipated to provide the lowest cost resources to our customers in the long-run. PacifiCorp then issues competitive requests for proposals to assure that the resources we acquire are the lowest cost resources available on a risk-adjusted basis. In operations, PacifiCorp optimizes its portfolio of resources on behalf of customers by maintaining and operating a portfolio of assets that diversifies customer exposure to fuel, power market and emissions risk and utilize an extensive transmission network that provides access to markets across the western United States. Independent of any natural gas and electric price hedging activity, to provide reliable supply and minimize net power costs for customers, PacifiCorp commits generation units daily, dispatches in real time all economic generation resources and all must-take contract resources, serves retail load, and then sells any excess generation to generate wholesale revenue to reduce net power costs for customers. PacifiCorp also purchases power when it is less expensive to purchase power than to generate power from our owned and contracted resources.

Hedging cannot be used to minimize net power costs. Hedging does not produce a different expected outcome than not hedging and therefore cannot be considered a cost minimization tool. Hedging is solely a tool to mitigate customer exposure to net power cost volatility and the risk of adverse price movement. However, PacifiCorp does minimize the cost of hedging by transacting in liquid markets and utilizing robust protections to mitigate the risk of counterparty default. In addition, PacifiCorp reduces the amount of hedging required to achieve a given risk tolerance through its portfolio hedge management approach, which takes into account offsetting exposures when these commodities are correlated, as opposed to hedging commodity exposures to natural gas and power in isolation without regard for offsets.

Portfolio

PacifiCorp has a short position in natural gas because of its ownership of gas-fired electric generation that requires it to purchase large quantities of natural gas to generate electricity to serve its customers. PacifiCorp may have short or long positions in power depending on the shortfall or excess of the company's total economic generation relative to customer load requirements at a given point in time.

PacifiCorp hedges its net energy (combined natural gas and power) position on a portfolio basis to take full advantage of any natural offsets between its long power and short natural gas positions. Analysis has shown that a "hedge only power" or "hedge only natural gas" approach results in higher risk (*i.e.,* a wider distribution of outcomes). There is a natural need for an electric company with natural gas fired electricity generation assets to have a hedge program that simultaneously manages natural gas and power open positions with appropriate coordinated metrics. PacifiCorp's risk management department incorporates daily updates of forward prices for natural gas, power, volatilities and correlations to establish daily changes in open positions and risk metrics which inform the hedging decisions made every day by company traders.

PacifiCorp's hedge program does not rely on a long power position. However, the company's hedge program takes into account its full portfolio and utilizes continuously updated correlations of natural gas and power prices and thereby takes advantage of offsetting natural gas and power positions in circumstances when prices are correlated and a forecast long power position offsets a forecast short natural gas position. This has the effect of reducing the amount of natural gas hedging that PacifiCorp would otherwise pursue. Ignoring this correlation would instead result in the need for more natural gas hedges to achieve the same level of customer risk reduction.

PacifiCorp's customers have benefited from offsetting power and natural gas positions. Power and natural gas prices are closely related because natural gas is often the fuel on the margin in efficient dispatch, as is practiced throughout the western U.S. This means power sales tend to be more valuable in periods when natural gas is high cost, producing revenues that are a credit or offset to the high cost fuel. If spot natural gas prices depart from prior forward prices, power prices will tend to do so in the same direction, thereby naturally hedging some of the unexpected cost variance.

Effectiveness Measure

The goal of the hedging program is to reduce volatility in PacifiCorp's net power costs primarily due to changes in market prices. The goal is not to "beat the market" and, therefore, should not be measured on the basis of whether it has made or lost money for customers. This reduction in volatility is calculated and reported in the company's confidential semi-annual hedging report which it began producing as a result of the hedging collaborative.

Instruments

PacifiCorp's hedging program allows the use of several instruments including financial swaps, fixed price physical and options for these products. PacifiCorp chooses instruments that generally have greater liquidity and lower transaction costs. The company also considers, with respect to options, the likelihood of disallowance of the option premium in its six jurisdictions. There is no functional difference between financial swaps and fixed price physical transactions; both instruments are equally effective in hedging the PacifiCorp's fixed price exposure.

Treatment of Customer and Investor Risks

The IRP standards and guidelines in Utah require that PacifiCorp "identify which risks will be borne by ratepayers and which will be borne by shareholders." This section addresses this requirement. Three types of risk are covered: stochastic risk, capital cost risk, and scenario risk.

Stochastic Risk Assessment

Several of the uncertain variables that pose cost risks to different IRP resource portfolios are quantified in the IRP production cost model using stochastic statistical tools. The variables addressed with such tools include retail loads, natural gas prices, wholesale electricity prices, hydroelectric generation, and thermal unit availability. Changes in these variables that occur over the long-term are typically reflected in normalized revenue requirements and are thus borne by customers. Unexpected variations in these elements are normally not reflected in rates, and are therefore borne by investors unless specific regulatory mechanisms provide otherwise. Consequently, over time, these risks are shared between customers and investors. Between rate cases, investors bear these risks. Over a period of years, changes in prudently incurred costs will be reflected in rates and customers will bear the risk.

Capital Cost Risks

The actual cost of a generating or transmission asset is expected to vary from the cost assumed in the IRP. State commissions may determine that a portion of the cost of an asset was imprudent and therefore should not be included in the determination of rates. The risk of such a determination is borne by investors. To the extent that capital costs vary from those assumed in this IRP for reasons that do not reflect imprudence by PacifiCorp, the risks are borne by customers.

Scenario Risk Assessment

Scenario risk assessment pertains to abrupt or fundamental changes to variables that are appropriately handled by scenario analysis as opposed to representation by a statistical process or expected-value forecast. The single most important scenario risks of this type facing PacifiCorp continues to be government actions related to emissions and changes in load and transmission infrastructure. These scenario risks relate to the uncertainty in predicting the scope, timing, and cost impact of emission and policies and renewable standard compliance rules.

To address these risks, PacifiCorp evaluates resources in the IRP and for competitive procurements using a range of CO_2 policy assumptions consistent with the scenario analysis methodology adopted for PacifiCorp's 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.

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 in order to develop a timely response of resources.

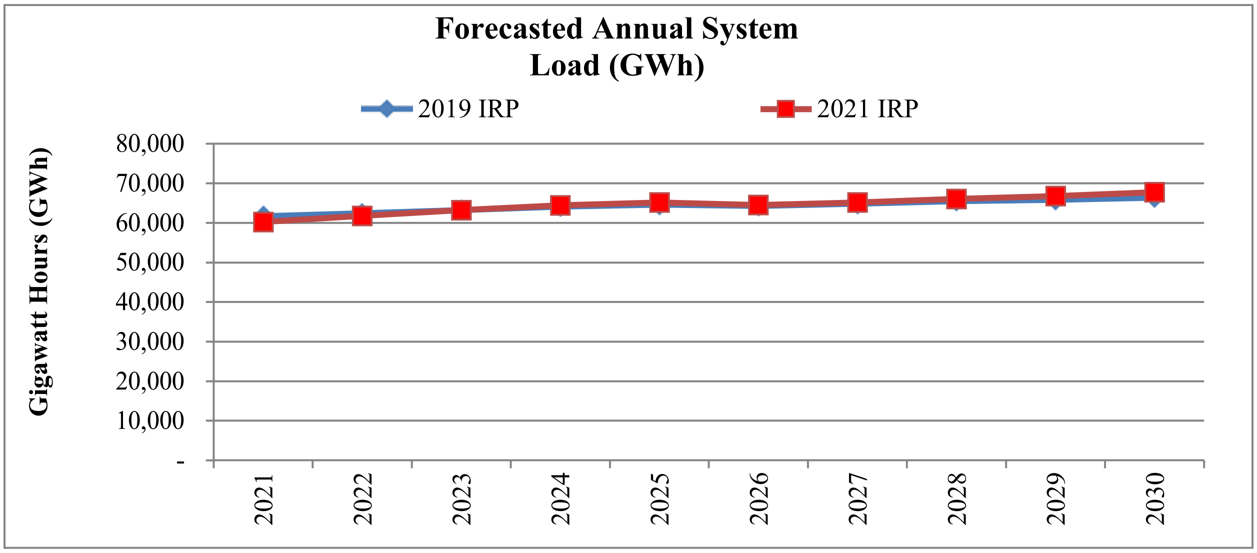
In the development of its load forecast PacifiCorp employs econometric models that use historical data and inputs such as regional and national economic growth, weather, seasonality, and other customer usage and behavior changes. The forecast is divided into classes that use energy for similar purposes and at comparable retail rates. These separate customer classes include residential, commercial, industrial, irrigation, and lighting customer classes. The classes are modeled separately using variables specific to their usage patterns. For residential customers, typical energy uses include space heating, air conditioning, water heating, lighting, cooking, refrigeration, dish washing, laundry washing, televisions and various other end use appliances. Commercial and industrial customers use energy for production and manufacturing processes, space heating, air conditioning, lighting, computers and other office equipment.

Jurisdictional peak load forecasts are developed using econometric equations that relate observed monthly peak loads, peak producing weather and the weather-sensitive loads for all classes. The system coincident peak forecast, which is used in portfolio development, is the maximum load required on the system in any hourly period and is extracted from the hourly forecast model.

Summary Load Forecast

The Company updated its load forecast in November 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 increased in all jurisdictions other than Washington and Idaho, 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



Tables A.1 and 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							
2021-2030	**1.31%**	**1.54%**	**0.98%**	**0.32%**	**1.37%**	**1.42%**	**0.36%**

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

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

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							
2021-2030	**0.89%**	**0.63%**	**0.96%**	**0.19%**	**1.07%**	**1.09%**	**0.25%**

Table A.3 – Annual Load Change: November 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: November 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

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Figure A.2 – PacifiCorp Annual Retail Sales 2000 through 2019 and Western Region Employment

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

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.

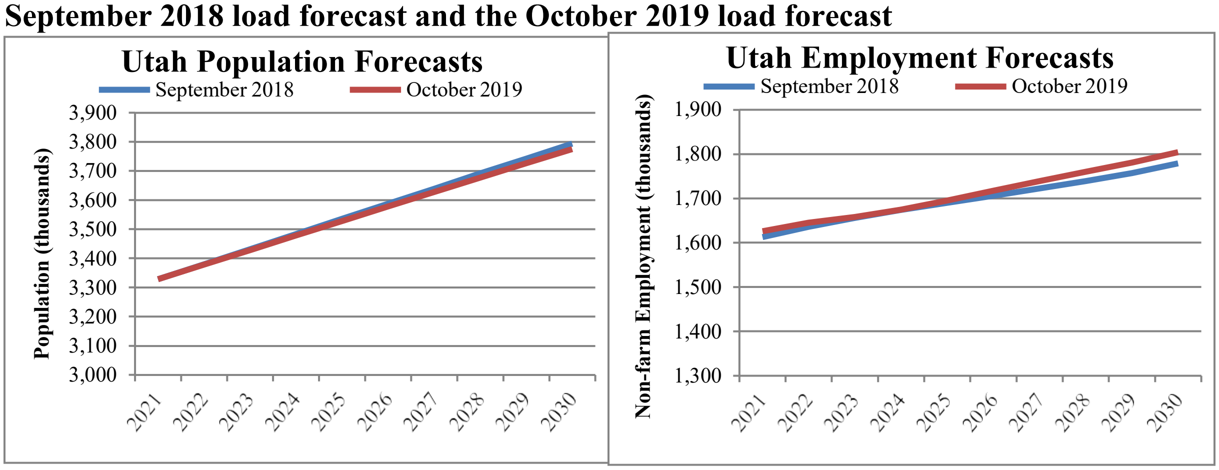
Figure A.3 – PacifiCorp Annual Residential Use per Customer 2001 through 2019

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

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.

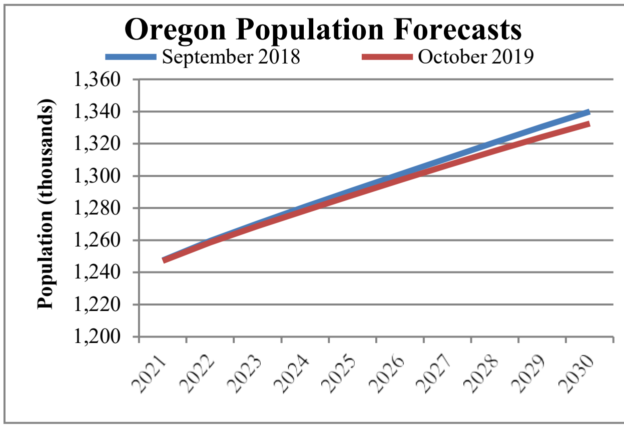
Figure A.4 – IHS Global Insight Utah Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast

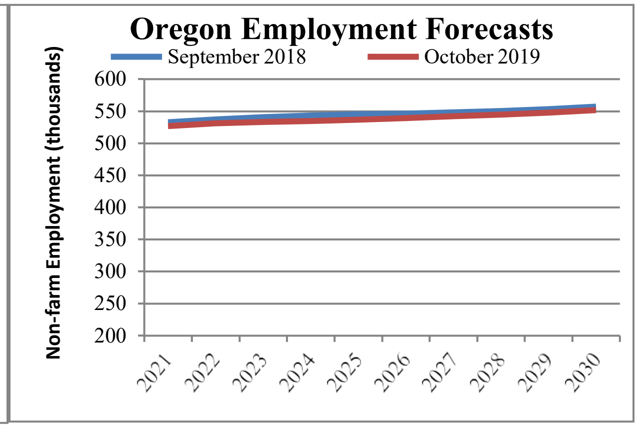


Oregon

PacifiCorp serves 25 of the 36 counties in Oregon, but provided only 26.2 percent of ultimate 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

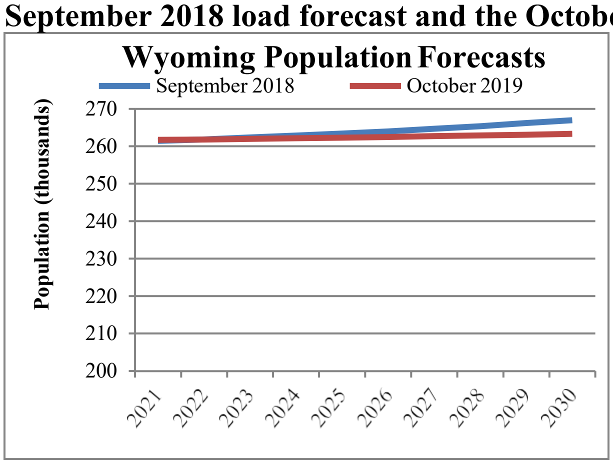


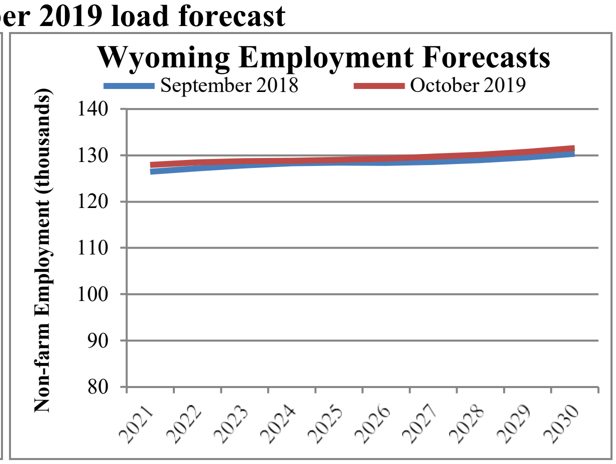


Wyoming

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



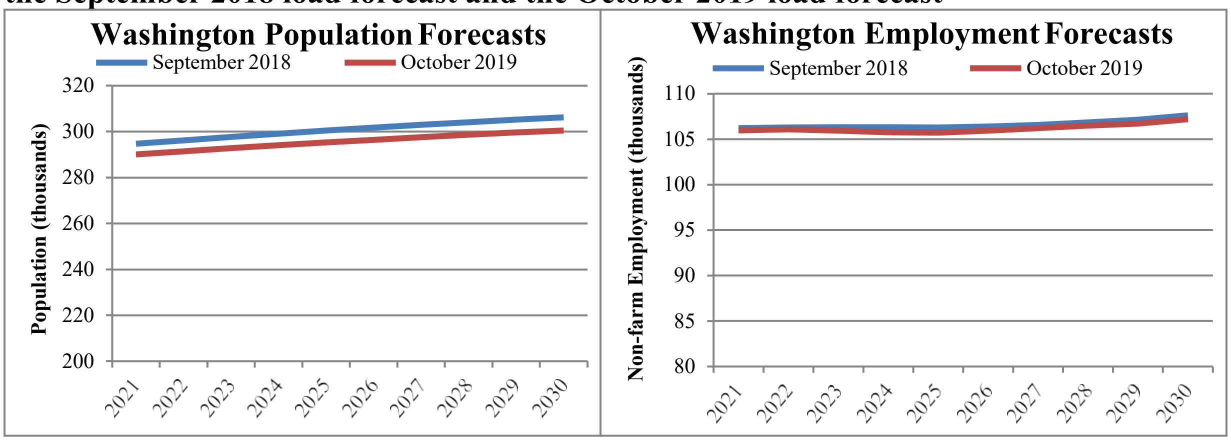


[2] Source: Oregon Public Utility Commission, 2018 Oregon Utility Statistics.

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.

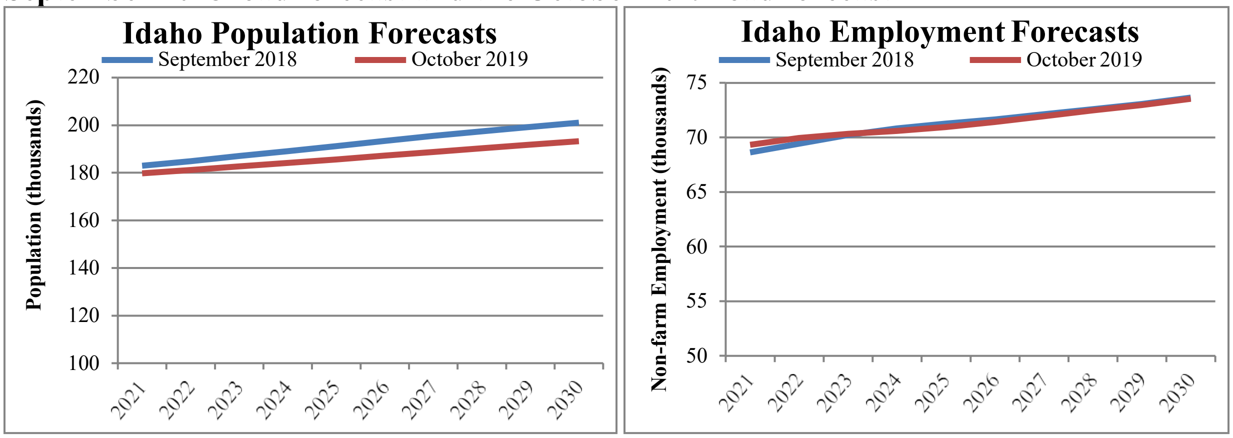
Figure A.7 – IHS Global Insight Washington Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



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.

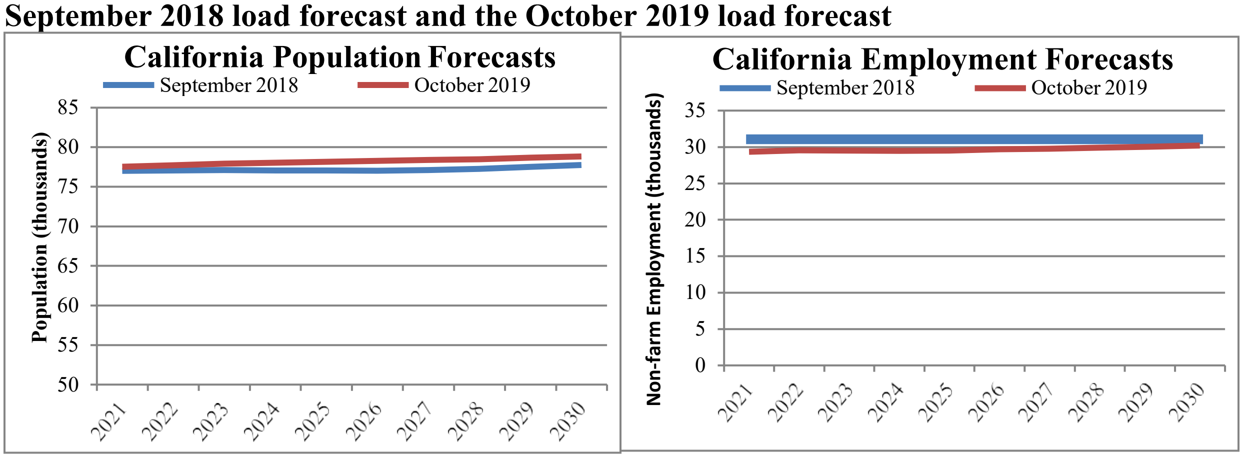
Figure A.8 – IHS Global Insight Idaho Population and Employment forecasts from the September 2018 load forecast and the October 2019 load forecast



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

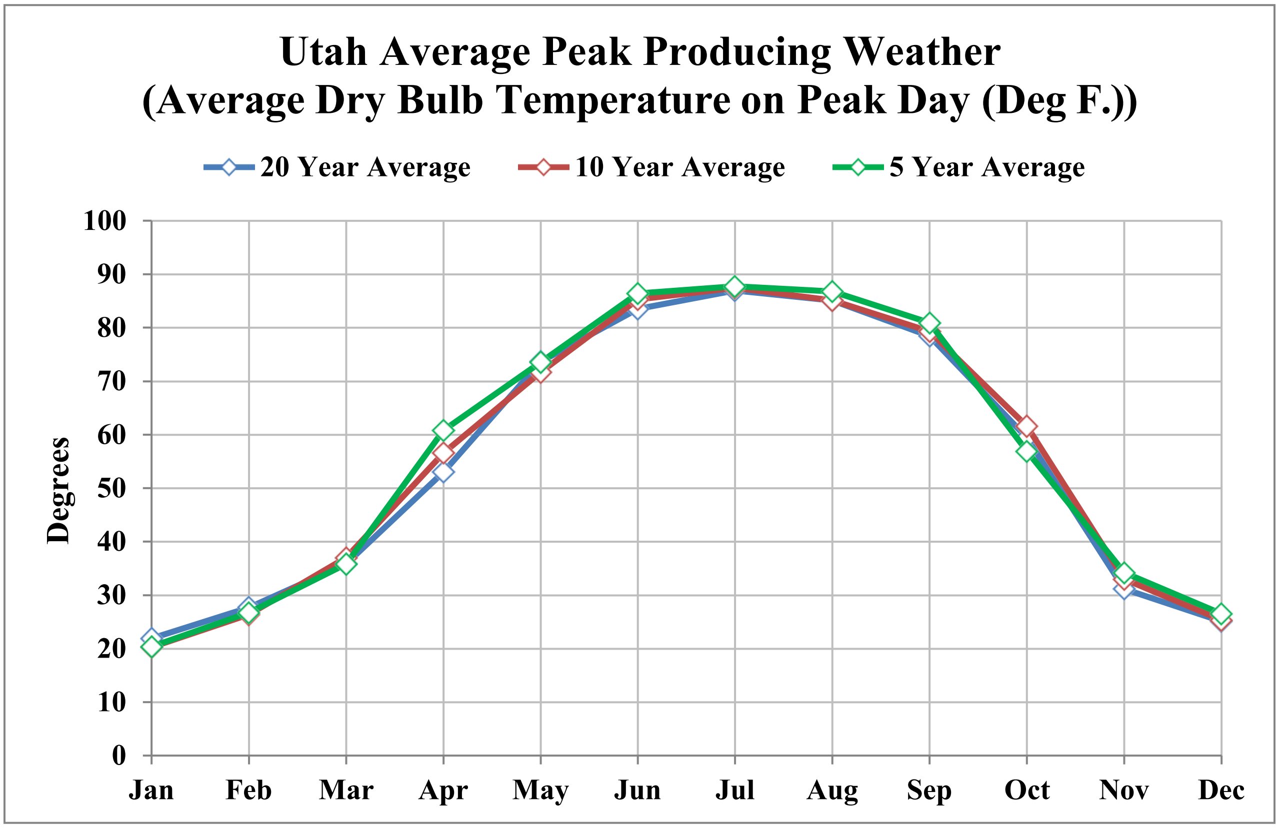


Weather

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 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

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Table A.6 Non-Coincident Jurisdictional Peak 2000 through 2019

Non-Coincide nt 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							
2000-2019	**-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	726	2,276	5,163	761	1,248	**10,297**
Compound Annual Growth Rate							
2000-2019	**-1.20%**	**1.74%**	**-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 capacity expansion optimization model, System Optimizer. The load forecast used for IRP portfolio development excluded forecasted load reductions from Class 2 DSM; System Optimizer then determines the amount of Class 2 DSM—expressed as supply curves that relate incremental DSM quantities with their costs—given the other resource options and inputs included in the model. The use of Class 2 DSM supply curves, along with the economic screening provided by System Optimizer, determines the cost-effective mix of Class 2 DSM for a given scenario.

Modeling overview

The load forecast is developed by forecasting the monthly sales by customer class for each jurisdiction. The residential sales forecast is developed as a use-per-customer forecast multiplied by the 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 Global Insight'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

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Residential

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Commercial

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Industrial

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

State Summaries

Oregon

Table A.9 summarizes Oregon state forecasted retail sales growth by customer class.

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

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Washington

Table A.10 summarizes Washington state forecasted retail sales growth by customer class.

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

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

California

Table A.11 summarizes California state forecasted sales growth by customer class.

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

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Utah

Table A.12 summarizes Utah state forecasted sales growth by customer class.

Table A.12 – Forecasted Retail Sales Growth in Utah, post-DSM

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Idaho

Table A.13 summarizes Idaho state forecasted sales growth by customer class.

Table A.13 – Forecasted Retail Sales Growth in Idaho, post-DSM

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Wyoming

Table A.14 summarizes Wyoming state forecasted sales growth by customer class.

Table A.14 – Forecasted Retail Sales Growth in Wyoming, post-DSM

This analysis is ongoing and will be updated as part of the September 1, 2021 Integrated Resource Plan filing.

Alternative Load Forecast Scenarios

The purpose of providing alternative load forecast cases is to determine the resource type and timing impacts resulting from a change in the economy or system peaks as a result of higher than normal temperatures.

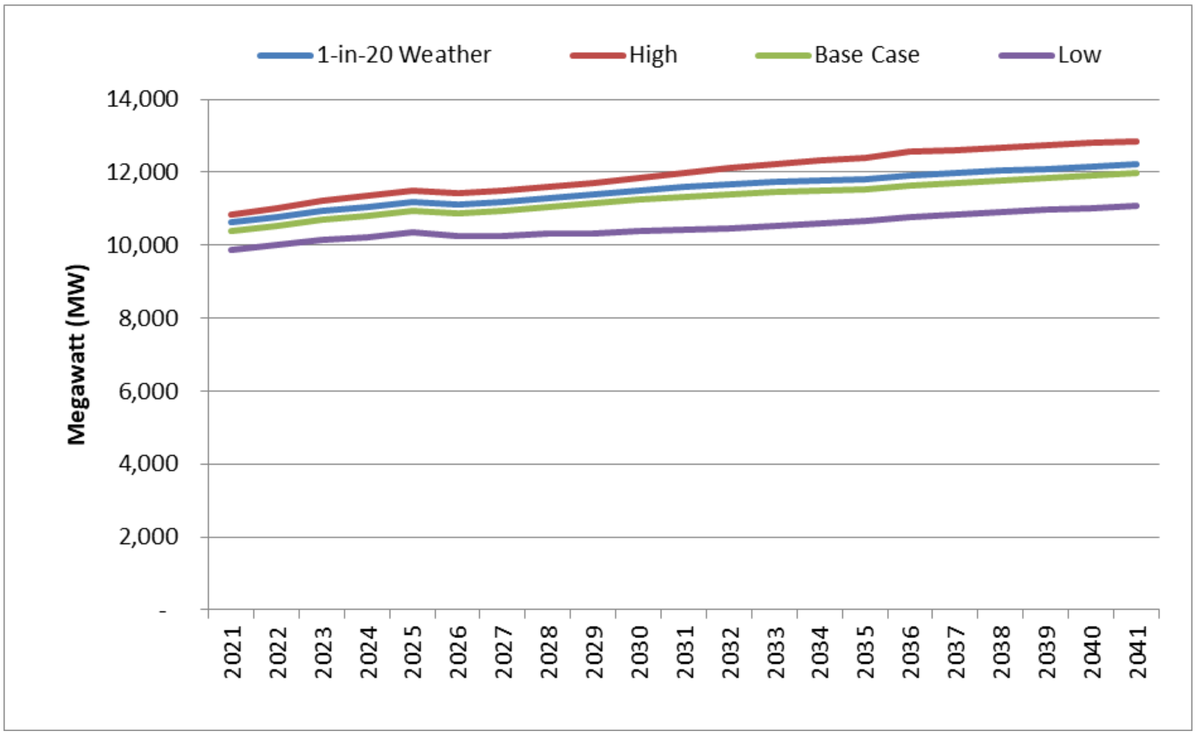
The November 2020 forecast is the baseline scenario. For the high and low load growth scenarios, optimistic and pessimistic economic driver assumptions from IHS Markit were applied to the economic drivers in the Company's load forecasting models. These growth assumptions were extended for the entire 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.

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 (analysis ongoing), High, Base Case and Low, pre-DSM



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 (2017 IRP) and other ongoing IRP acknowledgement order requirements as applicable, and (3) state commission IRP requirements stemming from other regulatory proceedings.

Included in this appendix are the following tables:

- Table B.1 - Provides an overview and comparison of the rules in each state for which IRP submission is required.[33]
- Table B.2 - Provides a description of how PacifiCorp addressed the 2017 IRP acknowledgement order requirements and other commission directives.
- Table B.3 - Provides an explanation of how this plan addresses each of the items contained in the Oregon IRP guidelines.
- Table B.4 - Provides an explanation of how this plan addresses each of the items contained in the Public Service Commission of Utah IRP Standard and Guidelines issued in June 1992.
- Table B.5 - Provides an explanation of how this plan addresses each of the items contained in the Washington Utilities and Transportation Commission IRP rules issued in December 2020.
- 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 Process) 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 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection Results) meets this requirement and includes the impact to system costs, system operations, supply and transmission reliability, and the impacts of various risks, uncertainties and externality costs that could occur. To perform the analysis andevaluation, PacifiCorp employs a suite of models that simulate the complex operation of the PacifiCorp system and its integration within the Western interconnection. The models allow for a rigorous testing of a reasonably broad range of commercially feasible resource alternatives available to PacifiCorp on a consistent and comparable basis. The analytical process, including the risk and uncertainty analysis, fully complies with IRP standards and guidelines, and is described in detail in Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach).

The IRP analysis is designed to define a resource plan that is least-cost, after consideration of risks and uncertainties. To test resource alternatives and identify a least-cost, risk adjusted plan, portfolio resource options were developed and tested against each other. This testing included examination of various tradeoffs among the portfolios, such as average cost versus risk, reliability, customer rate impacts, and average annual carbon dioxide (CO_2) emissions. This portfolio analysis and the results and conclusions drawn from the analysis are described in Volume I, Chapter 8 (Modeling and Portfolio Selection Results).

Consistent with the IRP standards and guidelines of Oregon, Utah, and Washington, this IRP includes an Action Plan in Volume I, Chapter 9 (Action Plan). The Action Plan details near-term actions that are necessary to ensure PacifiCorp continues to provide reliable and least-cost electric service after considering risk and uncertainty. The Action Plan also provides a progress report on action items contained in the 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 2019, and fully addresses the above report components.

Oregon

This IRP is submitted to the Oregon Public Utility Commission (OPUC) in compliance with its planning guidelines issued in January 2007 (Order No. 07-002). The Oregon PUC's IRP guidelines consist of substantive requirements (Guideline 1), procedural requirements (Guideline 2), plan filing, review, and updates (Guideline 3), plan components (Guideline 4), transmission (Guideline 5), conservation (Guideline 6), demand response (Guideline 7), environmental costs (Guideline 8, Order No. 08-339), direct access loads (Guideline 9), multi-state utilities (Guideline 10), reliability (Guideline 11), distributed generation (Guideline 12), resource acquisition (Guideline 13), and flexible resource capacity (Order No. 12-013[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 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 601 adopted the amended IRP and CETA compliance rules. PacifiCorp's compliance with the requirements of General Order 601 are included in this draft filing as part of Appendix C – Compliance Matrix.

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 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 Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
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.	
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.	
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.	
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.	
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.	
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	

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
	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.	
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.	
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.	
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.	
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.	
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.	
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	

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
	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.	
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.	
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.	
Order No. 20-186, p. 18	We acknowledge this action item with conditions based on Staffs recommendations. Our conditions on this action item include: Updated load and market forecasts, Off-system sales sensitivities, and customer impacts/ revenue requirement analysis.	
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.	
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	

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
	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.	
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.	
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.	
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.	

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
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.	
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.	
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.	
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	

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
	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.	
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.	
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.	
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 anlaysis) and DPU (seperate EV forecasts, and trends in the observed forecast overstimation). 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.	

Reference	IRP Requirement or Recommendation	How the Requirement or Recommendation is Addressed in the 2021 IRP (This Column will be updated as part of the September 1, 2021 Filing)
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.	
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.)	
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.)	
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.	
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	
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	

Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Conduct a sensitivity analysis on top performing portfolio cases and the reference case.	
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.	
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.	
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.	
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.	
Order, Docket No. 9000-144-XI-19 (Record No. 15280)	Include a broader analysis of all generation types including nuclear and natural gas.	
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).	
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.	

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,	

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
	purchase and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	
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.	
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.	
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.	
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.	
1.b.2	Risk and uncertainty must be considered: Utilities should identify in their plans any additional sources of risk and uncertainty.	
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").	
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.	
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.	

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.	
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.	
1.c.4	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	
1.d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	
Guideline 2. Procedural Requirements		
2.a	The public, which includes other utilities, should be allowed significant involvement in the preparation of the IRP. Involvement includes opportunities to contribute information and ideas, as well as to receive information. Parties must have an opportunity to make relevant inquiries of the utility formulating the plan. Disputes about whether information requests are relevant or unreasonably burdensome, or whether a utility is being properly responsive, may be submitted to the Oregon PUC for resolution.	PacifiCorp fully complies with this requirement. Volume I, Chapter 2 (Introduction) will provide an overview of the public process, all public-input meetings held for the 2021 IRP, which will also be documented in Volume II, Appendix C (Public Input Process). PacifiCorp also made use of a Stakeholder Feedback Form for stakeholders to provide comments and offer suggestions. Stakeholder Feedback Forms along with the public-input meeting presentations are available on PacifiCorp's webpage at: www.pacificorp.com/energy/integrated-resource-plan.html
2.b	While confidential information must be protected, the utility should make public, in its plan, any non-confidential information that is relevant to its resource evaluation and action plan. Confidential information may be protected through use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Oregon PUC.	This will be addressed in PacifiCorp's September 1, 2021 filing.
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. 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	The 2021 IRP complies with this requirement.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
	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.	
3.b	The utility must present the results of its filed plan to the Oregon PUC at a public meeting prior to the deadline for written public comment.	This activity will be conducted subsequent to filing this IRP.
3.c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	This activity will be conducted subsequent to filing this IRP.
3.d	The Commission will consider comments and recommendations on a utility's plan at a public meeting before issuing an order on acknowledgment. The Commission may provide the utility an opportunity to revise the IRP before issuing an acknowledgment order.	This activity will be conducted subsequent to filing this IRP.
3.e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	Not applicable.
3.f	(a) Each energy utility must submit an annual update on its most recently acknowledged IRP. The update is due on or before the acknowledgment order anniversary date. Once a utility anticipates a significant deviation from its acknowledged IRP, it must file an update with the Oregon PUC, unless the utility is within six months of filing its next IRP. The utility must summarize the update at an Oregon PUC public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	Not applicable to this filing; this activity will be conducted subsequent to filing this IRP.
3.g	Unless the utility requests acknowledgment of changes in proposed actions, the annual update is an informational filing that: • Describes what actions the utility has taken to implement the plan; • Provides an assessment of what has changed since the acknowledgment order that affects the action plan to select best portfolio of resources, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and • Justifies any deviations from the acknowledged action plan.	Not applicable to this filing; this activity will be conducted subsequent to filing this IRP.
Guideline 4. Plan Components: At a minimum, the plan must include the following elements		

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 purpose of this table is to comply with this guideline.
4.b	Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
4.f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs.	This will be addressed in PacifiCorp's September, 2021 filing.
4.g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered.	This will be addressed in PacifiCorp's September, 2021 filing.
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 will be addressed in PacifiCorp's September, 2021 filing.
4.i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties.	This will be addressed in PacifiCorp's September, 2021 filing.
4.j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results.	This will be addressed in PacifiCorp's September, 2021 filing.
4.k	Analysis of the uncertainties associated with each portfolio evaluated.	This will be addressed in PacifiCorp's September, 2021 filing.
4.l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers.	This will be addressed in PacifiCorp's September, 2021 filing.
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 will be addressed in PacifiCorp's September, 2021 filing.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
Guideline 6: Conservation		
6.a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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 will evaluate 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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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	This will be addressed in PacifiCorp's September, 2021 filing.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
	cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent that the identified trigger point will be mandated.	
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
13.b	For gas utilities only.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.

Table B.4 – Utah Public Service Commission IRP Standard and Guidelines

No.	Requirement	How the Standards and Guidelines are 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	PacifiCorp's public process will be described in Volume I, Chapter 2 (Introduction). A description of public-input meetings will be provided in Volume II,

No.	Requirement	How the Standards and Guidelines are Addressed in the 2021 IRP
	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.	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.	This will be addressed in PacifiCorp's September, 2021 filing.
6	The integrated resource plan must evaluate supply-side and demand-side resources on a consistent and comparable basis.	This will be addressed in PacifiCorp's September, 2021 filing.
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 will be developed in consultation with parties from all state jurisdictions, and will meet all formal state IRP guidelines.
9	The company's Strategic Business Plan must be directly related to its Integrated Resource Plan.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
2	The company will submit its Integrated Resource Plan biennially.	The company submitted its last IRP on October 18, 2019, and will file this IRP on September 1, 2021, meeting the requirement.
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 will be described in the September 1, 2021 IRP filing. A record of public meetings will be provided as an appendix to the September 1, 2021 filing.
4.a	PacifiCorp's integrated resource plans will include: a range of estimates or forecasts of load	This will be addressed in PacifiCorp's September, 2021 filing.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2021 IRP
	growth, including both capacity (kW) and energy (kWh) requirements.	
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.	This will be addressed in PacifiCorp's September, 2021 filing.
4.a.ii	Analyses of how various economic and demographic factors, including the prices of electricity and alternative energy sources, will affect the consumption of electric energy services, and how changes in the number, type and efficiency of end-uses will affect future loads.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
4.b.i	An assessment of all technically feasible and cost-effective improvements in the efficient use of electricity, including load management and conservation.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
4.c	An analysis of the role of competitive bidding for demand-side and supply-side resource acquisitions	This will be addressed in PacifiCorp's September, 2021 filing.
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	This will be addressed in PacifiCorp's September, 2021 filing.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2021 IRP
	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.	
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
4.j	An analysis of tradeoffs; for example, between such conditions of service as reliability and dispatchability and the acquisition of lowest cost resources.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
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.	This will be addressed in PacifiCorp's September, 2021 filing.
5	PacifiCorp will submit its IRP for public comment, review and acknowledgment.	This will be addressed in PacifiCorp's September, 2021 filing.
6	The public, state agencies and other interested parties will have the opportunity to make formal comment to the Commission on the adequacy of	Not addressed; this is a post-filing activity.

No.	Requirement	How the Standards and Guidelines are Addressed in the 2021 IRP
	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.	
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 Standards and Guidelines will be 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 spans 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.	Will be addressed within the load/resource balance chapter
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 will be informed by robust analysis via Conservation Potential Assessment and related efforts in conjunction with extensive stakeholder participation. This subject is covered in the Load/Resource Balance chapter of the IRP.

WAC 480-100-620(3)(a)	- all cost-effective conservation, efficiency, and load management improvements;	IRP modeling will optimally select 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 the Modeling and Portfolio Selection Results Chapter.
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 will be informed by robust analysis via Conservation Potential Assessment and related efforts in conjunction with extensive stakeholder participation. This subject is covered in the Load/Resource Balance chapter of the IRP.
	- 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, covered in the IRP in the Private Generation Study Appendix.
WAC 480-100-620(3)(b)	- all demand response (DR) at the lowest reasonable cost (LRC).	IRP modeling will optimally select 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 the Modeling and Portfolio Selection Results Chapter.
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,	IRP modeling will optimally select 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 the Modeling and Portfolio Selection Results Chapter.

No.	Requirement	How the Standards and Guidelines will be addressed in the 2021 IRP
	- Demand response potential, - Energy assistance potential	
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).	IRP modeling will optimally select 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 the Modeling and Portfolio Selection Results Chapter.
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 will likely be discussed in the Modeling and Portfolio Selection Results Chapter, as well as load/resource balance chapter and in the 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 if applicable.
WAC 480-100-620(4)	Plan assesses wide range of conventional generating resources.	PacifiCorp's IRP will include a broad range of technologies as proxy resource options in its portfolio optimizations, including solar, storage, wind, natural gas, nuclear, energy efficiency, demand response, pumped storage, co-located facilities and front office transactions, with appropriate variants for each. A comprehensive supply side resource table with more than 100 potential resources will be provided in the Resource Options chapter.
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, and will be reported in the Supply Resource Table in the Resource Options Chapter.
See **WA-UTC energy storage policy statement** (UE-151069 & UE-161024 consolidated)	Plan assesses energy storage resources.	Energy storage will be represented with multiple options in the Supply Resource Table in the Resource Options Chapter.
WAC 480-100-620(5)	Plan assesses nonconventional generating, integration, and ancillary service technologies.	Compressed air storage and modular nuclear resources will be represented in the Supply Resource Table in the Resource Options Chapter. 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 will be examined in chapters covering The Planning Environment, Resource Options, and Modeling and Portfolio Evaluation.
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 Standards and Guidelines will be 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.
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, which will be described in the chapter on Modeling and Portfolio Evaluation.
WAC 480-100-620(7)	- transmission and distribution delivery costs;	PacifiCorp's transmission system is represented by firm transmission rights and endogenoustransmission upgrade options. Transmission dependencies implying additional resource costs are included in the optimization, resulting in a reasonable comparison of resource costs. These factors will be discussed in the Resource Options, and Modeling and Portfolio Evaluation chapter of the IRP.
WAC 480-100-620(7)	- risks, including environmental effects and the social cost of GHG emissions;	The Company will conduct a minimum of five 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 will be described in the Modeling and Portfolio Analysis chapter and detailed further in Appendices.
WAC 480-100-620(7)	- benefits accruing to the utility, customers, and program participants (when applicable); and	Benefits will be 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. Results will be covered in the chapter Modeling and Portfolio Selection Results, with additional detail provided in IRP appendices.
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 will be compliant with all policy requirements. Policy discussion will be included in chapters on The Planning Environment and Modeling and Portfolio Selection Results.
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.	Please refer to responses above numbered 7 and 16-19. IRP modeling endogenously considers "overgeneration" in dispatch and curtails resources appropriately. These curtailments are an inherent component of the cost and risk valuation of each portfolio, and is a driver for the optimal size, type and location of selected resources.
WAC 480-100-620(8)	Plan assesses and determines resource adequacy metrics.	For the 2021 IRP, resource adequacy will be evaluated as a core model function, where each portfolio is obligated to meet reliability requirements including varying degrees of quality of operating reserves. This will be described in the chapter Modeling and Portfolio Evaluation.
WAC 480-100-620(8)	Plan identifies an appropriate resource adequacy requirement.	Addressed within Load/Resource Balance chapter

No.	Requirement	How the Standards and Guidelines will be addressed in the 2021 IRP
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).	This is addressed within Load/Resource Balance, Modeling/Portfolio Evaluation, and Modeling/Portfolio Selection
WAC 480-100-620(9)	Plan reflects the cumulative impact analysis conducted under RCW 19.405.140, and includes an assessment of:	As the cumulative impact analysis is in progress and not available as of January 4, 2021, PacifiCorp has used alternative data sources such as the Washington Tracking Network and the US Census. The cumulative Impact Analysis will be included when available.
WAC 480-100-620(9)	- energy and nonenergy benefits;	PacifiCorp will analyze energy benefits within selection of the preferred portfolio. Non-energy benefits are included with DSM measures, and additional nonenergy benefits may be qualitatively discussed as part of the environmental cost/benefit section and the public health risk section
WAC 480-100-620(9)	- reduction of burdens to vulnerable populations and highly impacted communities;	A preliminary identification of burdens to vulnerable and highly-impacted communities has been made through data publicly available through the Washington Tracking Network and the US Census. PacifiCorp will conduct future outreach and consult the cumulative impact analysis to continue to refine this data.
WAC 480-100-620(9)	- long-term and short-term public health and environmental benefits, costs, and	A preliminary identification of public health and environmental benefits has been made through data publicly available through the Washington Tracking Network and the US Census. PacifiCorp will conduct future outreach and consult the cumulative impact analysis to continue to refine this data.
WAC 480-100-620(9)	- long-term and short-term public health and environmental risks; and	A preliminary identification of public health and environmental risks has been made through data publicly available through the Washington Tracking Network and the US Census. PacifiCorp will conduct future outreach and consult the cumulative impact analysis to continue to refine this data.
WAC 480-100-620(9)	- energy security and risk.	PacifiCorp addresses energy security and risk throughout the IRP, and specifically will address this through the discussion of the preferred portfolio, the planning environment, and throughout the discussion on transmission.
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 will be explored as discussed at the December 3, 2020 public input meeting. These cases will be fully explored in the Modeling/Portfolio Evaluation chapter.
WAC 480-100-620(10)	*CETA counter factual scenario* - describe the alternative LRC and reasonably available portfolio that the utility would	This will be addressed as part of the Modeling/Portfolio Evaluation chapter.

No.	Requirement	How the Standards and Guidelines will be addressed in the 2021 IRP
	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).	
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.	This will be addressed as part of the Modeling/Portfolio Evaluation chapter.
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.	This will be addressed as part of the Modeling/Portfolio Evaluation chapter.
WAC 480-100-620(11)	Plan must integrate demand forecasts and resource evaluations into a long-range IRP solution.	This is addressed as part of the Load/Resource Balance chapter.
WAC 480-100-620(11)	IRP solution or preferred portfolio must describe the resource mix that meets current and projected needs.	This is addressed as part of the Modeling/Portfolio Selection chapter.
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 rates by 2025 and will continue to analyze this pending further resolution of interpretive issues by the Commission.
WAC 480-100-620(11)(a)	- attains GHG neutrality by 1/1/2030 (RCW 19.405.040); and	This will be addressed within the Modeling/Portfolio Evaluation and Modeling/Portfolio Selection chapters.
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 the Modeling/Portfolio Evaluation and Modeling/Portfolio Selection Chapters.
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 generally may be addressed as part of the Modeling/Portfolio Evaluation and Modeling/Portfolio Selection Chapters.
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.	Addressed in Modeling/Portfolio Evaluation chapter.
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,	Addressed in Modeling/Portfolio Evaluation chapter.
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.	Addressed in Modeling/Portfolio Evaluation chapter.
WAC 480-100-620(11)(f)	Preferred portfolio maintains and protects the safety, reliable operation, and	Addressed in Load/Resource balance chapter.

No.	Requirement	How the Standards and Guidelines will be addressed in the 2021 IRP
	balancing of the utility's electric system, including mitigating over-generation events and achieving identified resource adequacy requirements.	
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 will be addressed as part of the Planning Environment chapter and the 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 will be addressed as part of the Planning Environment chapter and the Clean Energy Action Plan
WAC 480-100-620(11)(g)	- energy security and resiliency.	This will be addressed as part of the Load/Resource Balance chapter, the Transmission Chapter, and the Clean Energy Action Plan
WAC 480-100-620(11)(h)	Preferred portfolio: assesses the environmental health impacts to highly impacted communities,	Addressed in 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,	Included in Modeling/Portfolio Evaluation Chapter
WAC 480-100-620(11)(j)	- incorporates the social cost of GHG emissions as a cost adder.	Included in Modeling/Portfolio Evaluation Chapter
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);	This requirement will be included in Appendix R - Clean Energy Action Plan, within the "resource adequacy" section.
WAC 480-100-620(12)(c)	- demonstrate that all customers are benefiting from the transition to clean energy;	This requirement will be included in Appendix R - Clean Energy Action Plan, within the "Working Toward an Energy Future that Benefits All Customers" section.
WAC 480-100-620(12)(d)	- establish a resource adequacy requirement;	This requirement will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section.
WAC 480-100-620(12)(e)	- identify the potential cost-effective DR and load management programs that may be acquired;	This requirement will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section.
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 requirement will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section.

No.	Requirement	How the Standards and Guidelines will be 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 requirement will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section.
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 will be included in Appendix R - Clean Energy Action Plan, within the "Resource Adequacy" section.
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,	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
WAC 480-100-620(13)	- capacity,	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
WAC 480-100-620(13)	- transmission,	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
WAC 480-100-620(13)	- distribution, and	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
WAC 480-100-620(13)	- GHG emissions.	This will be addressed in the September 1 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
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).	This requirement will be addressed in the September 1, 2021 IRP filing.
WAC 480-106-040	Plan provides information and analysis used to inform annual purchases of	

No.	Requirement	How the Standards and Guidelines will be addressed in the 2021 IRP
	electricity from qualifying facilities, including a description of the:	
WAC 480-106-040	- avoided cost calculation methodology used;	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
WAC 480-106-040	- avoided cost methodology of energy, capacity, transmission, distribution, and emissions averaged across the utility; and	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
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.	This will be addressed in the September 1, 2021 IRP filing, and the methodology will be consistent with Commission Order within docket UE-190666 and other applicable avoided cost decisions
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(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.	This is addressed within the Planning Environment chapter and the Portfolio Evaluation chapter
WAC 480-100-620(17)	Utility must summarize:	
WAC 480-100-620(17)	- public comments received on the draft IRP,	This will be addressed as part of Appendix C - Public Input Process
WAC 480-100-620(17)	- utility's responses to public comments, and	This will be addressed as part of Appendix C - Public Input Process
WAC 480-100-620(17)	- whether final plan addresses and incorporates comments raised.	This will be addressed as part of Appendix C - Public Input Process

Table B.15 – Wyoming Public Service Commission Guidelines Regarding Electric IRP

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 Process).
B	The utility's strategic goals and resource planning goals and preferred resource portfolio;	Volume I, Chapter 8 (Modeling and Portfolio Selection Results) documents the preferred resource portfolio and rationale for selection. Volume I, Chapter 9 (Action Plan) constitutes the IRP action plan and the descriptions of resource strategies and risk management.
C	The utility's illustration of resource need over the near-term and long-term planning horizons;	See Volume I, Chapter 5 (Resource Needs Assessment).
D	A study detailing the types of resources considered;	Volume, I Chapter 6 (Resource Options), presents the resource options used for resource portfolio modeling for this IRP.

No.	Requirement	How the Guideline is Addressed in the 2021 IRP
F	Changes in expected resource acquisitions and load growth from that presented in the utility's previous IRP;	A comparison of resource changes relative to the 2017 IRP Update is presented in Volume I, Chapter 9 (Action Plan). A chart comparing the peak load forecasts for the 2017 IRP, 2017 IRP Update, and 2019 IRP is included in Volume II, Appendix A (Load Forecast Details).
G	The environmental impacts considered;	Portfolio comparisons for CO_2 and a broad range of environmental impacts are considered, including prospective early retirement and gas conversions of existing coal units as alternatives to environmental investments. See Volume I, Chapter 7 (Modeling and Portfolio Evaluation Approach) and Chapter 8 (Modeling and Portfolio Selection) as well as Volume II, Appendix L (Stochastic Simulation Results).
H	Market purchases evaluation;	Modeling of firm market purchases (front office transactions) and spot market balancing transactions is included in the 2019 IRP.
I	Reserve Margin analysis; and	Reliability target will be discussed in an Appendix to the 2021 IRP.
J	Demand-side management and conservation options;	See Volume I, Chapter 6 (Resource Options) for a detailed discussion on DSM and energy efficiency resource options. Additional information on energy efficiency resource characteristics is available on the company's website.

DRAFT 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 10 public-input meetings, with two more scheduled in early 2021. 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

- Idaho Public Utilities Commission
- Oregon Public Utilities Commission
- Public Service Commission of Utah
- Washington Utilities and Transportation Commission
- Wyoming Public Service Commission

Stakeholders and Industry Experts

- Alliance of Western Energy Consumers
- Applied Energy Group
- Avangrid
- Black & Veatch
- Breathe Utah
- Burns & McDonnell Engineering Company
- Cascade Natural Gas
- City of Kemmerer Wyoming
- Clarke Investments, LLC
- Enel Green Power
- Energy Trust of Oregon
- First Solar
- Gardner Energy
- Glenrock Energy
- Heal Utah
- Holladay United Church of Christ
- Idaho Conservation League
- Idaho Power Company
- Idaho Public Utility Commission Staff
- Individual Customers
- Industrial Customers of Northwest Utilities
- Intermountain Wind
- Lincoln County Commission
- Magnum Development
- National Grid Ventures
- Natural Resources Defense Council
- Navigant Consulting, Inc.
- Northwest Pipeline GP
- Oregon Department of Energy
- Oregon Department of Justice
- Oregon Public Utility Commission Staff
- Portland General Electric
- Power Quip
- Renewables Northwest
- Sierra Club
- Utah Clean Energy
- Utah Division of Public Utilities
- Utah Office of Consumer Services
- Utah Office of Energy Development
- Washington Office of Attorney General, Public Council Unit
- Western Resource Advocates
- Westmoreland

- Wyoming Coalition of Local Governments & Lincoln County
- Wyoming Department of Workforce Services
- Wyoming House District 18
- Wyoming Infrastructure Authority
- Wyoming Liberty Group
- Wyoming Office Of Consumer Advocate

PacifiCorp extends its gratitude for the continued time and energy that participants have given to the IRP process thus far. Their participation has contributed significantly to the quality of this plan and their continued participation will help PacifiCorp as it works toward the September 1, 2021 filing date.

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 Only)

- 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 Only)

- Discussion of current IRP status
- Stakeholder Feedback Form Recap

April 22-23, 2021 – General Public Meeting (Indicative schedule, subject to change)

- Portfolio Development initial outputs

May 27-28, 2021 – General Public Meeting (Indicative schedule, subject to change)

- Continue discussion of portfolio development initial outputs

June 24-25, 2021 – General Public Meeting (Indicative schedule, subject to change)

- 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 29-30, 2021 – General Public Meeting (Indicative schedule, subject to change)

- Discuss selection of preferred portfolio/cost and risk analysis; opportunity for stakeholder feedback.

August 12, 2021 – General Public Meeting (Indicative schedule, subject to change)

- If needed

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 March 31, 2020, PacifiCorp has received 76 Stakeholder Feedback Forms with a combined 435 questions. 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

Some topics of note addressed in the forms include:

- Capacity Factors
- Coal Analysis
- Coal Combustion Residuals
- Endogenous Retirement
- Conservation Credit
- Conservation Potential Assessment
- Consultant Reports
- Demand Response
- Demand-Side Management
- Demand-Side Management Modeling
- Distribution System Planning
- Energy Efficiency
- Energy Storage
- Environmental Policy
- Flexible Reserve Study
- General Comments
- Inflation Assumption
- Initial Sensitivity Studies
- Intra-hour Dispatch Credits
- IRP Filing Date
- IRP Public-Input Meeting Process
- Legislation
- Levelized Cost Curves
- Load Forecasting
- Market Purchases
- Market Reliance Assessment
- Modeling Assumptions
- Modeling Improvements
- Planning Reserve Margin
- Portfolio Analysis
- Private Generation Study
- Reliability Assessment
- Renewable Energy Resources
- Sensitivity Studies
- Supply-side Resource Costs
- Supply-side Resource Table
- Transmission
- Unit Specific Questions

Contact Information

PacifiCorp's IRP website: www.pacificorp.com/energy/integrated-resource-plan.html.

PacifiCorp requests any informal request be sent to the following address or email.

PacifiCorp
IRP Resource Planning Department
825 N.E. Multnomah, Suite 600
Portland, Oregon 97232

Email Address:
IRP@PacifiCorp.com

Phone Number:
(503) 813-5245

APPENDIX D – DEMAND-SIDE MANAGEMENT RESOURCES

Introduction

This appendix reviews the studies and reports used to support the demand-side management (DSM) resource information used in the modeling and analysis of the 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 2019-2038, 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.

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								

[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.

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Air Conditioner Direct Load Control	√	√	√	√	√	√
Lighting Incentives	√	√	√	√	√	√
New Appliance Incentives	√	√	√	√	√	√
Heating And Cooling Incentives	√	√	√	√	√	√
Weatherization Incentives - Windows, Insulation, Duct Sealing, etc.	√	√	√	√	√	√
New Homes	√	√	√	√	√	√
Low-Income Weatherization	√	√	√	√	√	√
Home Energy Reports			√	√	√	√
School Curriculum		√	√		√	
Energy Saving Kits	√	√	√	√	√	√
Financing Options With On-Bill Payments		√				
Trade Ally Outreach	√	√	√	√	√	√

Program Services & Offerings by Sector and State	California	Oregon	Washington	Idaho	Utah	Wyoming
Non-Residential Sector						
Air Conditioner Direct Load Control		√		√	√	
Irrigation Load Control		√		√	√	
Standard Incentives	√	√	√	√	√	√
Energy Engineering Services	√	√	√	√	√	√
Billing Credit Incentive (offset to DSM charge)		√			√	√
Energy Management	√	√	√	√	√	√
Energy Profiler Online	√	√	√	√	√	√
Business Solutions Toolkit	√	√	√	√	√	√
Trade Ally Outreach	√	√	√	√	√	√
Small Business Lighting	√	√	√	√	√	√
Lighting Instant Incentives	√	√	√	√	√	√
Small to Mid-Sized Business Facilitation	√	√	√	√	√	√
DSM Project Managers Partner With Customer Account Managers	√	√	√	√	√	√

Table D.2 – Current wattsmart Outreach and Communications Activities

Wattsmart Outreach & Communications (incremental to program specific advertising)	California	Oregon	Washington	Idaho	Utah	Wyoming
Advertising		√	√	√	√	√
Sponsorships		√			√	
Social Media	√	√	√	√	√	√
Public Relations	√	√	√		√	√
Business Advocacy (awards at customer meetings,	√	√	√	√	√	√

Wattsmart Outreach & Communications (incremental to program specific advertising)	California	Oregon	Washington	Idaho	Utah	Wyoming
sponsorships, chamber partnership, university partnership)						
Wattsmart Workshops and Community Outreach	√	√	√	√	√	√
Be wattsmart, Begin at Home - in school energy education			√	√	√	√

State-Specific DSM Planning Processes

A summary of the DSM planning process in each state is provided below.

Utah, Wyoming and Idaho

The company's biennial IRP and associated action plan provides the foundation for DSM acquisition targets in each state. Where appropriate, the company maintains and uses external stakeholder groups and vendors to advise on a range of issues including annual goals for conservation programs, development of conservation potential assessments, development of multi-year DSM plans, program marketing, incentive levels, budgets, adaptive management and the development of new and pilot programs.

Washington

The company is one of three investor-owned utilities required to comply with the Energy Independence Act (also referred to as I-937) approved in November 2006. The Act requires utilities to pursue all conservation that is cost-effective, reliable, and feasible. Every two years, each utility must identify its 10-year conservation potential and two-year acquisition target based on its IRP and using methodologies that are consistent with those used by the Northwest Power and Conservation Council. Each utility must maintain and use an external conservation stakeholder group that advises on a wide range of issues including conservation programs, development of conservation potential assessments, program marketing, incentive levels, budgets, adaptive management and the development of new and pilot programs. PacifiCorp works with the conservation stakeholder group annually on its energy efficiency program design and planning.

California

On 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 2019 IRP preferred portfolio, P45CNW.

Table D.3 – Incremental Demand Response Resource Selections (2019 IRP Preferred Portfolio)

State/Product by Year	2019	2021	2023	2025	2026	2029	2030	2032	2035	2036	2037	2038	Total/Products (MW)
California-3rd Party Contracts												1.1	1.1
California-Cool/WH												1.5	1.5
California-Irrigate											4.8		4.8
California-Thermostat											5.8		5.8
Oregon-3rd Party Contracts												10.9	10.9
Oregon-Ancillary Services						7.5							7.5
Oregon-Irrigate											13.3		13.3
Washington-3rd Party Contracts												10.9	10.9
Washington-Ancillary Services						1.9							1.9
Washington-Cool/WH												7.7	7.7
Washington-Irrigate											8.3		8.3
Washington-Thermostat											16.6		16.6
Utah-3rd Party Contracts												76.7	76.7
Utah-Ancillary Services			8.3	5.3							3.2		16.7
Utah-Cool/WH	4.1	7.0	9.9		7.2	6.7		6.8	7.0			7.2	55.9
Utah-Irrigate												1.9	1.9
Utah-Thermostat						116.7	8.2		8.3			5.1	138.3
Idaho-Irrigate								5.2		3.7		1.8	10.6
Wyoming-3rd Party Contracts												37.3	37.3
Wyoming-Ancillary Services				3.0									3.0
Wyoming-Cool/WH												5.2	5.2
Wyoming-Irrigate											1.8		1.8
Wyoming-Thermostat											5.5	1.2	6.7
Total by Year	**4.1**	**7.0**	**18.1**	**8.2**	**7.2**	**132.7**	**8.2**	**12.0**	**15.3**	**3.7**	**48.7**	**166.0**	**431.2**

Table D.4 – Incremental Energy Efficiency Resource Selections (2019 IRP Preferred Portfolio)

Energy Efficiency Energy (MWh) Selected by State and Year										
State	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
CA	5,130	5,710	5,270	5,540	6,240	6,180	6,760	6,830	6,710	6,900
OR	182,370	168,410	165,580	177,040	170,830	175,640	163,960	158,100	152,370	144,500
WA	42,090	39,900	40,550	44,450	46,490	46,420	45,300	43,710	42,870	41,510
UT	255,470	254,270	254,120	254,590	260,140	256,810	252,620	244,500	244,770	236,870
ID	18,100	17,190	17,590	18,410	20,920	20,580	20,450	20,740	20,400	20,020
WY	59,320	50,960	54,960	71,250	79,200	83,290	84,430	91,700	91,270	88,540
Total System	562,480	536,440	538,070	571,280	583,820	588,920	573,520	565,580	558,390	538,340

Energy Efficiency Energy (MWh) Selected by State and Year										
State	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**
CA	6,690	6,400	6,220	5,890	5,380	4,110	4,440	3,660	3,040	2,640
OR	130,550	122,100	118,120	113,420	98,860	99,240	96,100	95,190	87,690	84,090
WA	37,970	36,610	34,390	32,040	30,230	22,700	22,740	18,190	15,620	15,330
UT	216,320	213,380	200,900	198,880	184,760	135,510	122,290	93,920	80,230	87,710
ID	19,410	18,210	17,480	17,400	15,760	12,850	11,930	9,810	8,370	8,640
WY	81,230	75,380	66,490	61,490	56,140	43,140	40,520	35,180	25,690	25,880
Total System	492,170	472,080	443,600	429,120	391,130	317,550	298,020	255,950	220,640	224,290

For the 20-year assumed nameplate capacity contributions (MW impacts) by state and year associated with the Energy Efficiency resource selections above, see Table 8.18 – PacifiCorp's 2019 IRP Preferred Portfolio, in Volume I of the 2019 IRP.

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. The DLR system on the Dave Johnston – Amasa – Difficulty – Shirley Basin 230 kV line is scheduled to be completed by the 2Q2021

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 is on track to be installed by the end of 2019. This pilot is intended to provide field validation of lab tested solutions for outage management and automated restoration, and will identify improvements to the operating systems and drive implementation of FLISR throughout the service territory.

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. Development of standards for re-closers to enable the remote communication have been completed and the pilot implementation will be provided to at risk substations by the conclusion of 2019. The ability to integrate legacy systems to various communication networks will allow PacifiCorp to improve its response to failures in remote locations.

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 will use the responses to more accurately include the cost of Demand Response programs in the 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

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.

APPENDIX O – PRIVATE GENERATION STUDY

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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

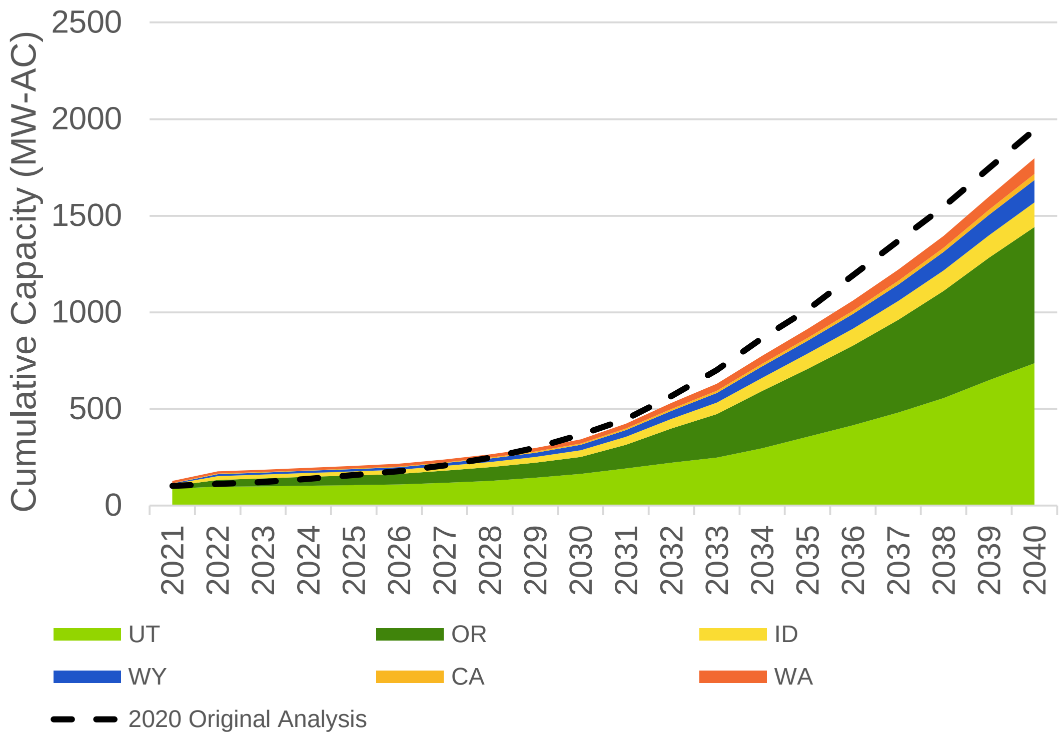
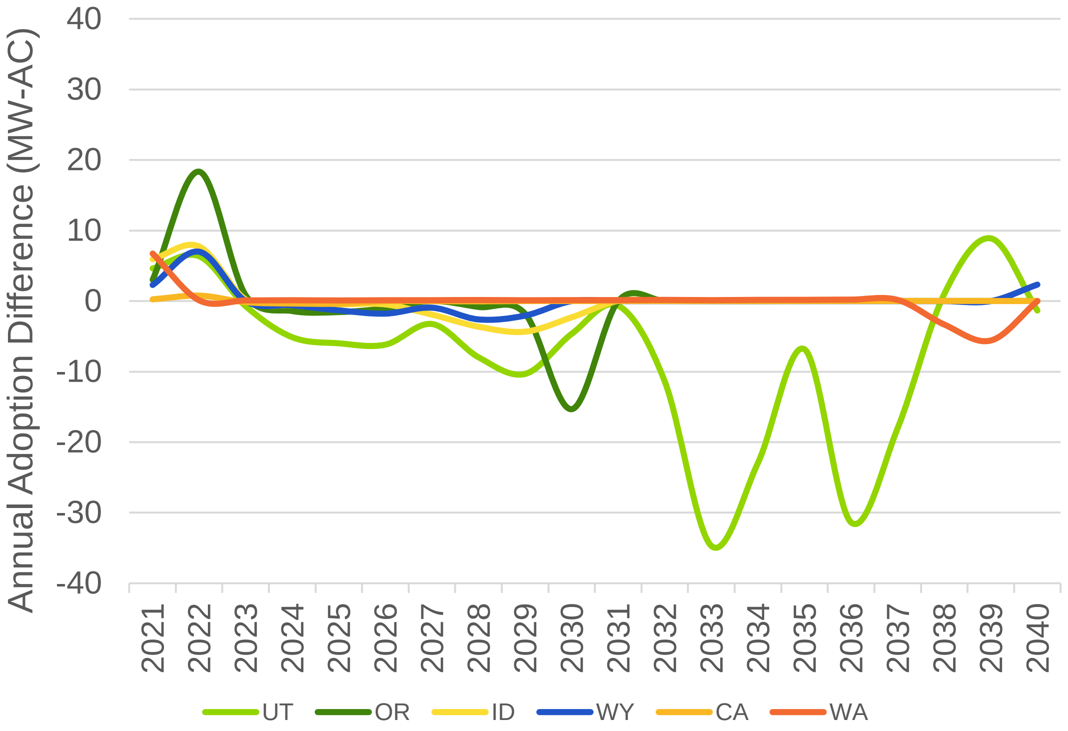
Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	10%	10%	10%	0%	0%	0%
Micro Turbines	10%	10%	10%	0%	0%	0%
Small Hydro	0%	0%	0%	0%	0%	0%
PV - Com	30%	26%	26%	26%	22%	10%
PV - Res	30%	26%	26%	26%	22%	0%
Wind - Com	12%	0%	0%	0%	0%	0%
Wind - Res	30%	26%	26%	26%	22%	0%

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
	

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Guidehouse

Private Generation Long-Term Resource Assessment (2021-2040)

Prepared for:

PacifiCorp

Prepared by:
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June 19th, 2020

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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.

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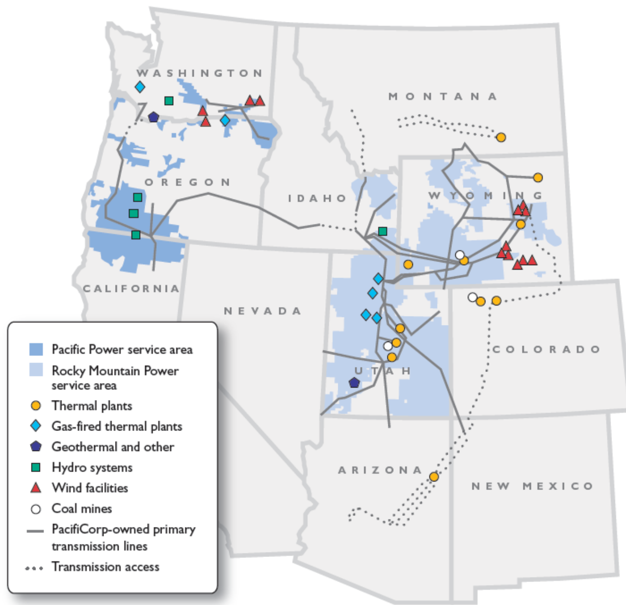
[1] Navigant, Distributed Generation Resource Assessment for Long-Term Planning Study, http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/2015IRPStudy/Navigant_Distributed-Generation-Resource-Study_06-09-2014.pdf.

[2] Navigant, Private Generation Long-Term Resource Assessment (2017-2036), http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/PacifiCorp_IRP_PG_Resource_Assessment_Final.pdf.

[3] Total resource potential factoring out resources that cannot be accessed due to non-economic reasons (i.e. land use restrictions, siting constraints and regulatory prohibitions), including those specific to each technology. Technical potential does not vary by scenario.

[4] Based on economic potential (technical potential that can be developed because it's not more expensive than competing options), estimates the timeline associated with the diffusion of the technology into the marketplace, considering the technology's relative economics, maturity, and development timeline.

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

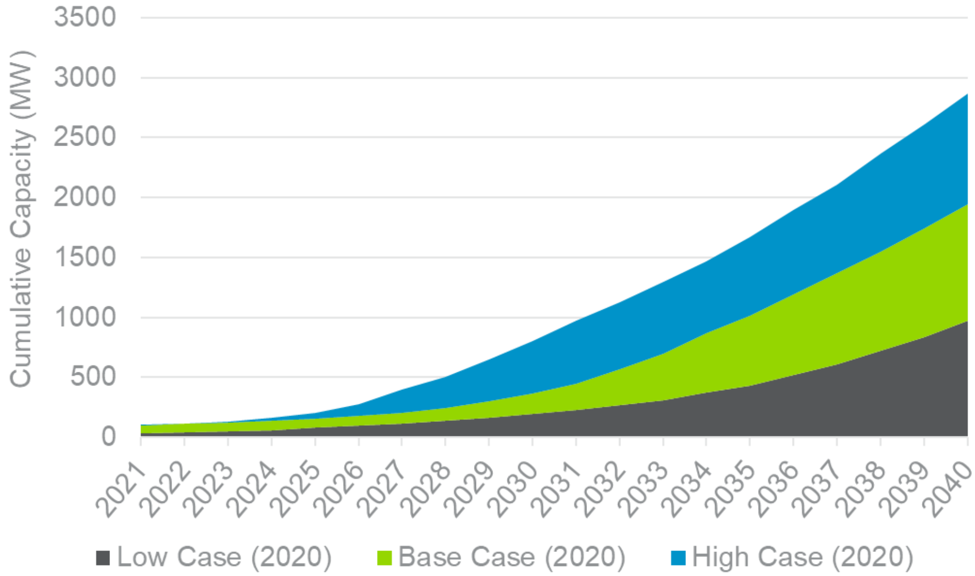


Figure 3 indicates that Utah and Oregon will drive most PG installations over the next two decades, largely because these two states are PacifiCorp's largest markets in terms of customers and sales[8]. Reference APPENDIX A for detailed state-specific customer data. In both states, PG installations are 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

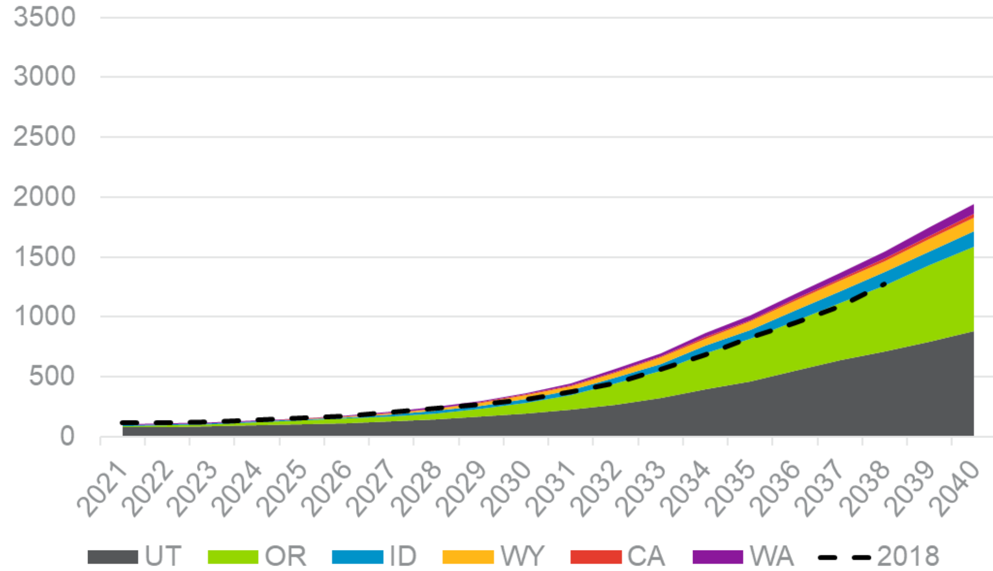
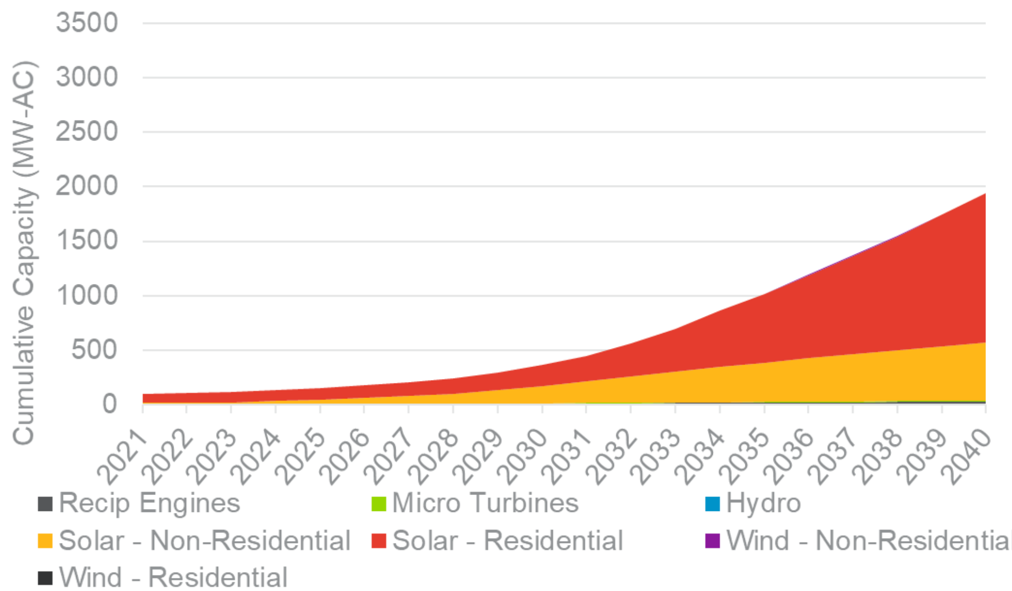


Figure 4 Cumulative Market Penetration Results by Technology (MW AC), 2021 – 2040, Base Case



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

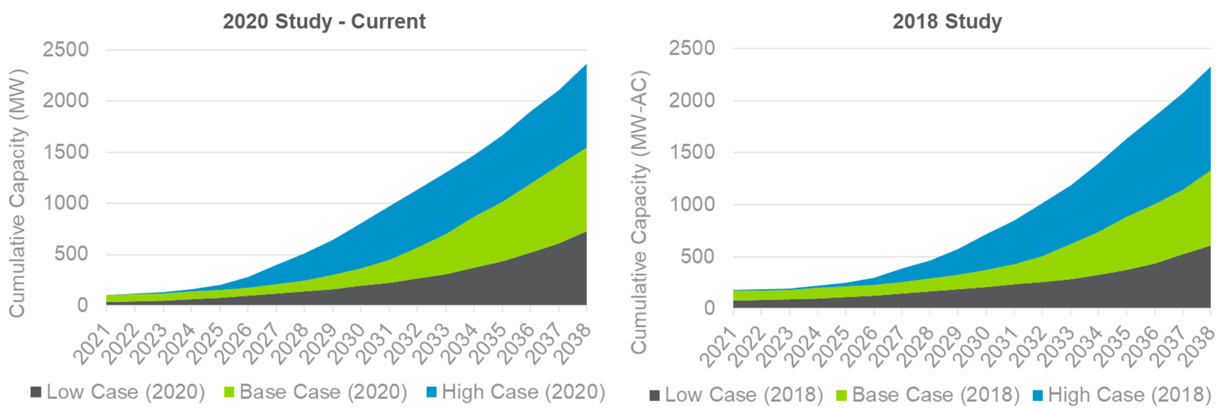
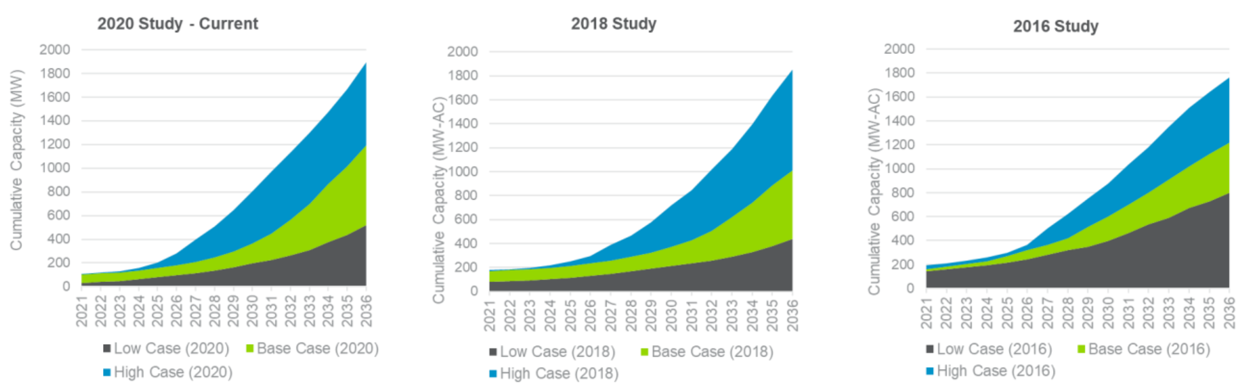


Figure 6 Cumulative Market Penetration Results by Scenario (MW AC), 2020, 2018 and 2016 Studies, 2021-2036



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]

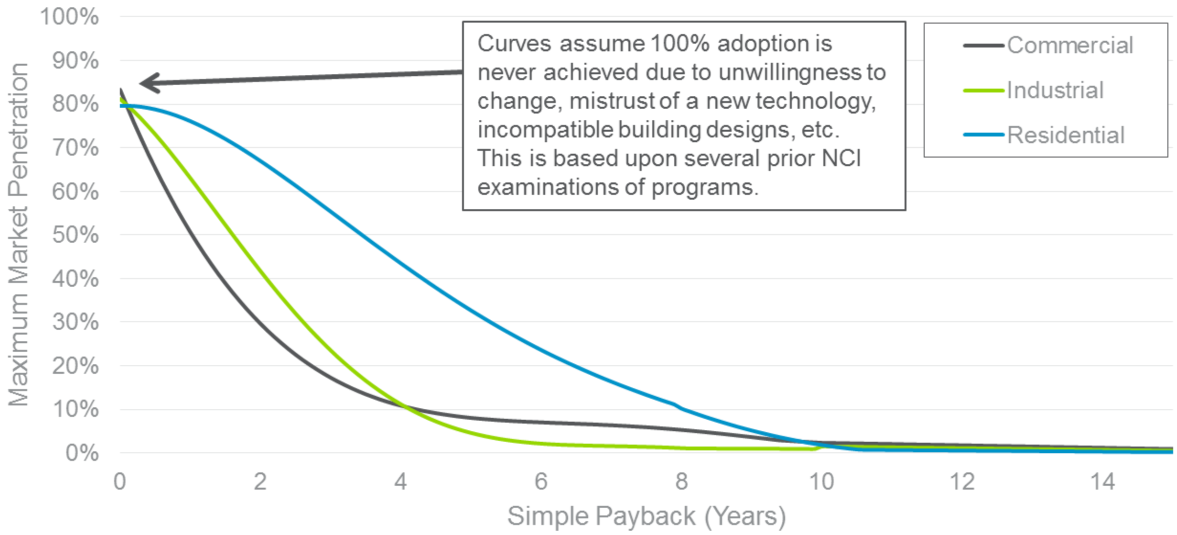
- *Federal tax credits can be taken against a system's full value if other (i.e. utility or state supplied) capacity-based or performance-based incentives are considered taxable.*
- *Navigant's Market Penetration model calculates first year simple payback assuming new installations for each year of analysis.*
- *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.

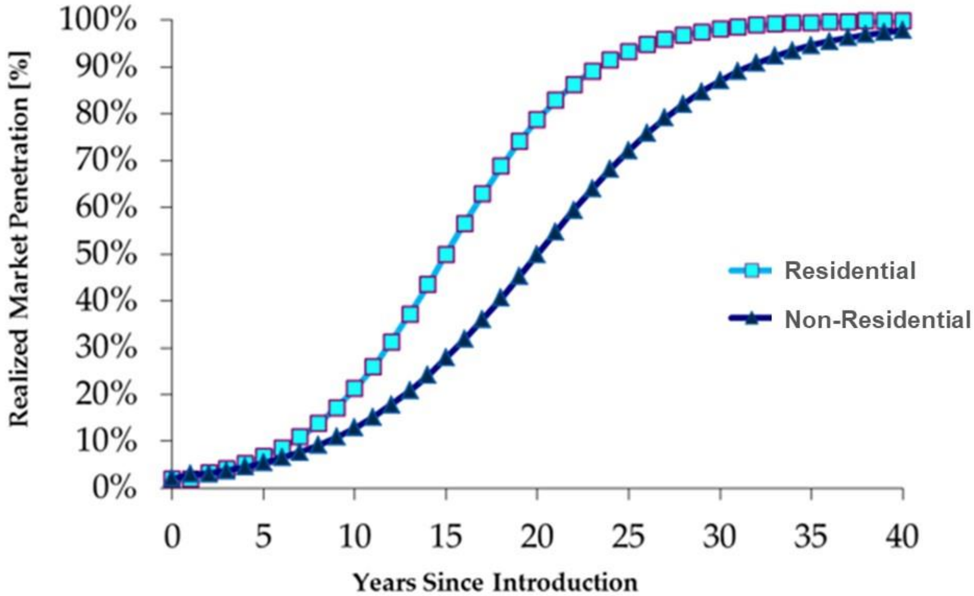
The model uses these factors to determine market growth instead of relying on individual assumptions about annual market growth for each technology or various supply and/or demand curves that may sometimes be used in market penetration modeling. With this approach, the model does not account for other 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.

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[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

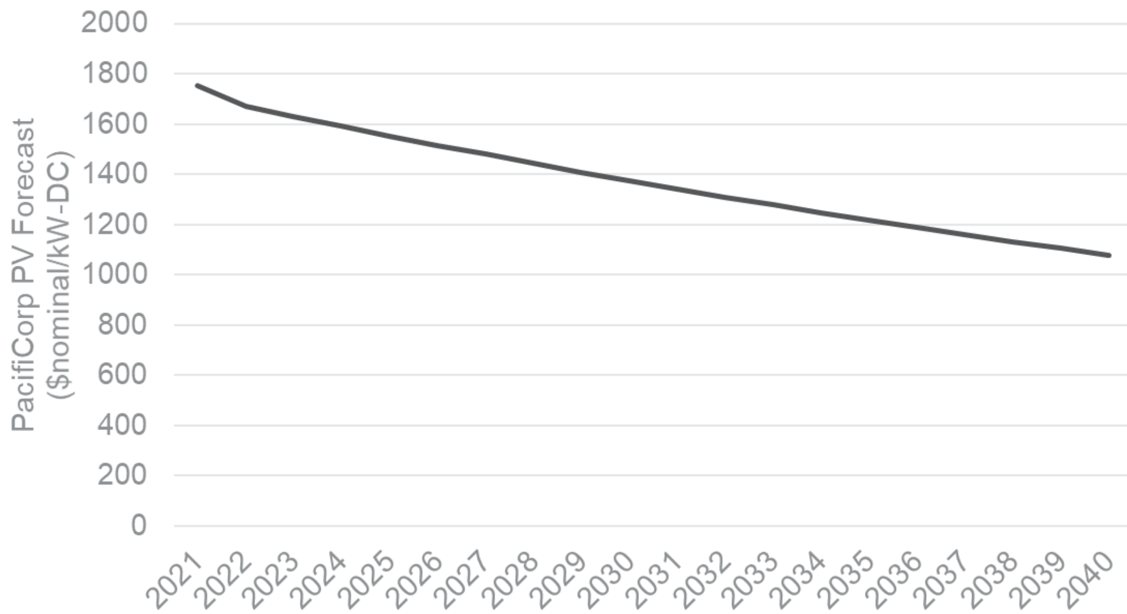
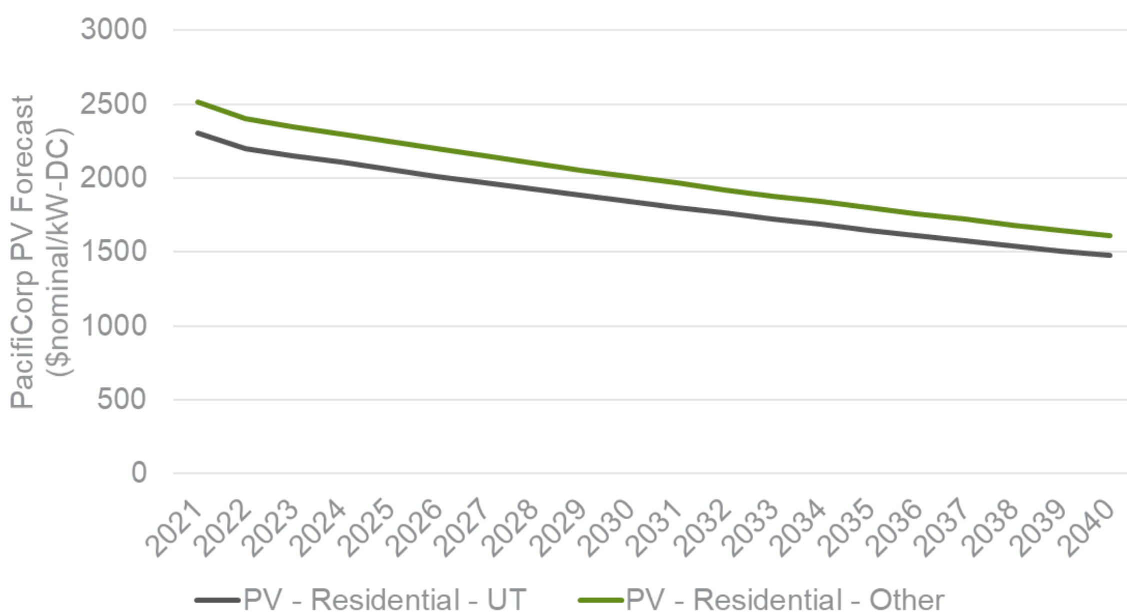


Figure 10 Residential Solar System Costs, 2021-2040



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.

[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

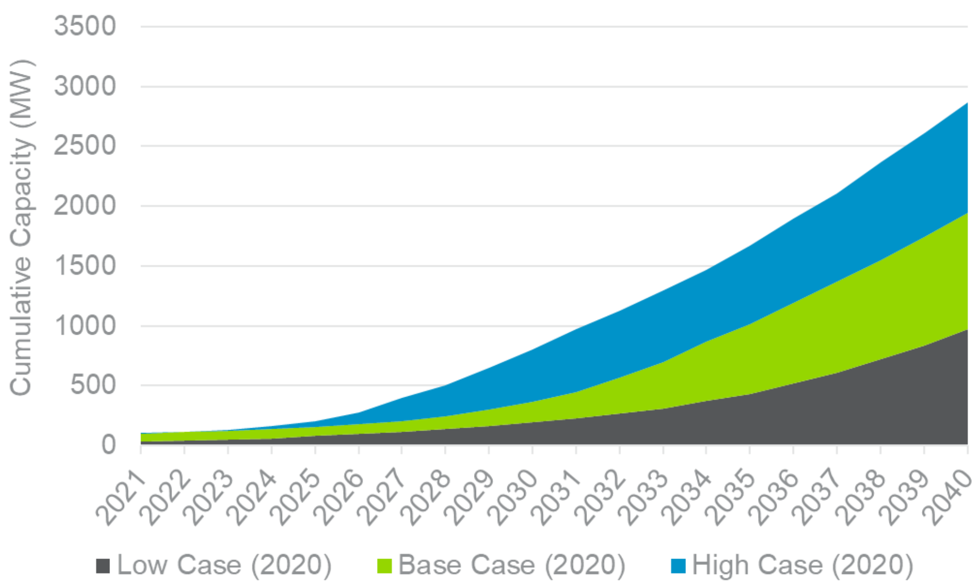
Technology	2019	2020	2021	2022	2023	>2023
Recip. Engines	0	0	0	0	0	0
Micro Turbines	0	0	0	0	0	0
Small Hydro	0	0	0	0	0	0
PV - Com	0	0	0	0	0	0
PV – Res (%)*	40,20,20,20	40,20,20,20	40,20,20,20	40,20,20,20	40,20,20,20	40,20,20,20
Wind – Com	0	0	0	0	0	0
Wind – Res (%)*	40,20,20,20	40,20,20,20	40,20,20,20	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

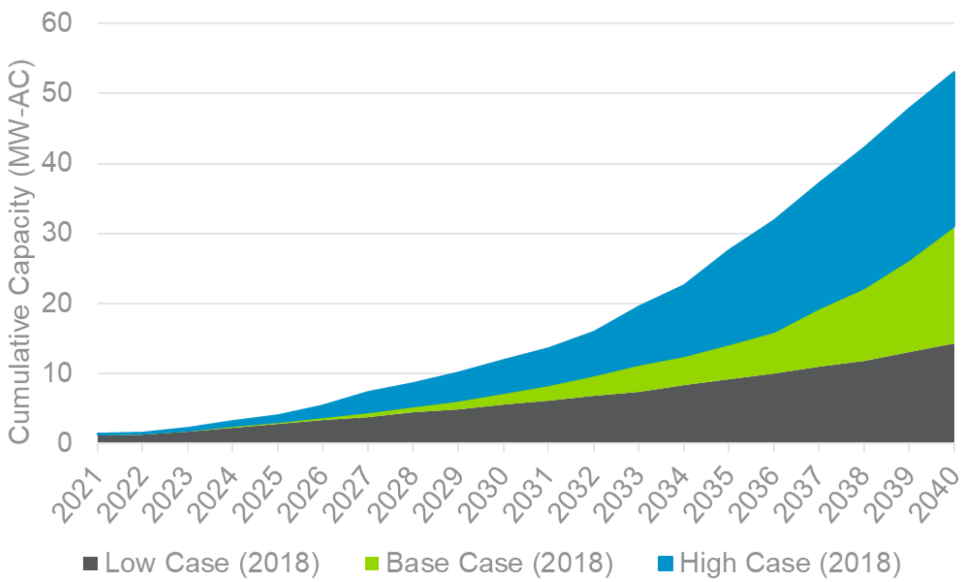


Figure 13. Cumulative Capacity Installations by Technology (MW AC), California Base Case

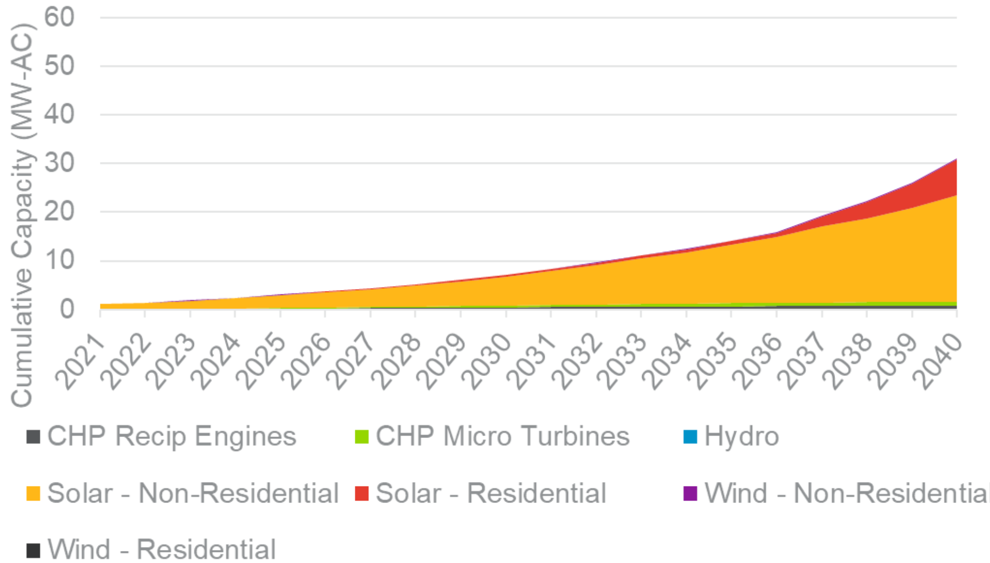


Figure 14. Cumulative Capacity Installations by Technology (MW AC), California High Case

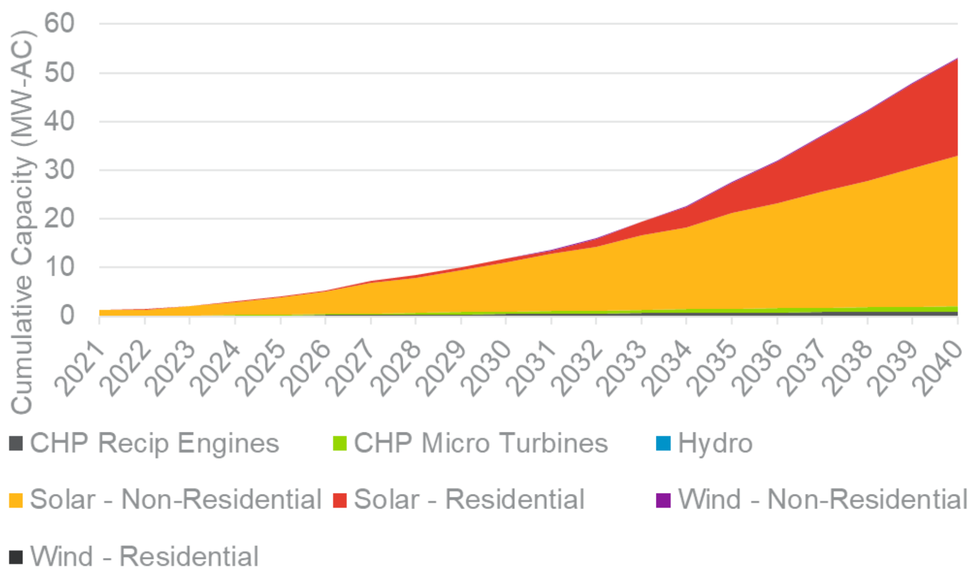
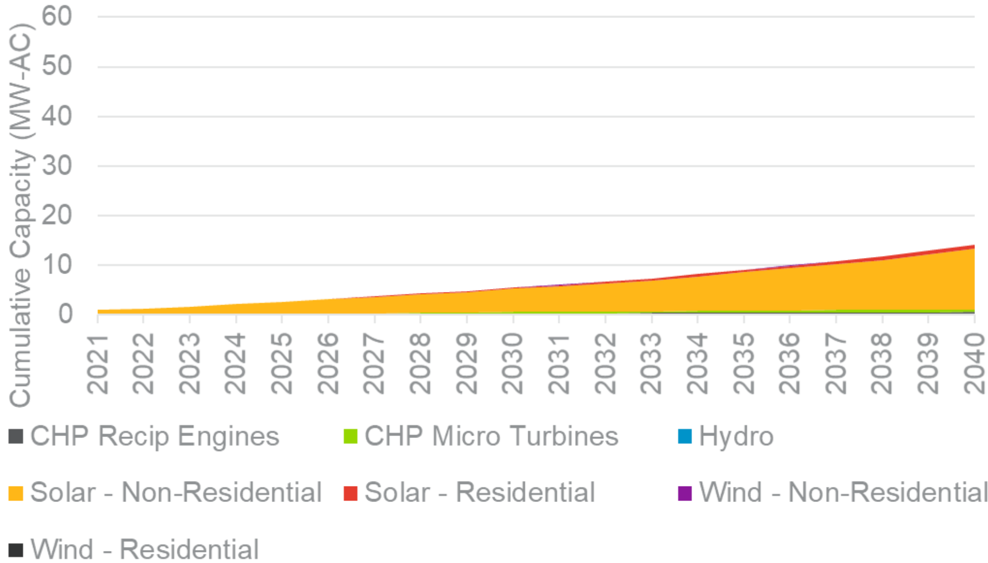


Figure 15. Cumulative Capacity Installations by Technology (MW AC), California Low Case



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

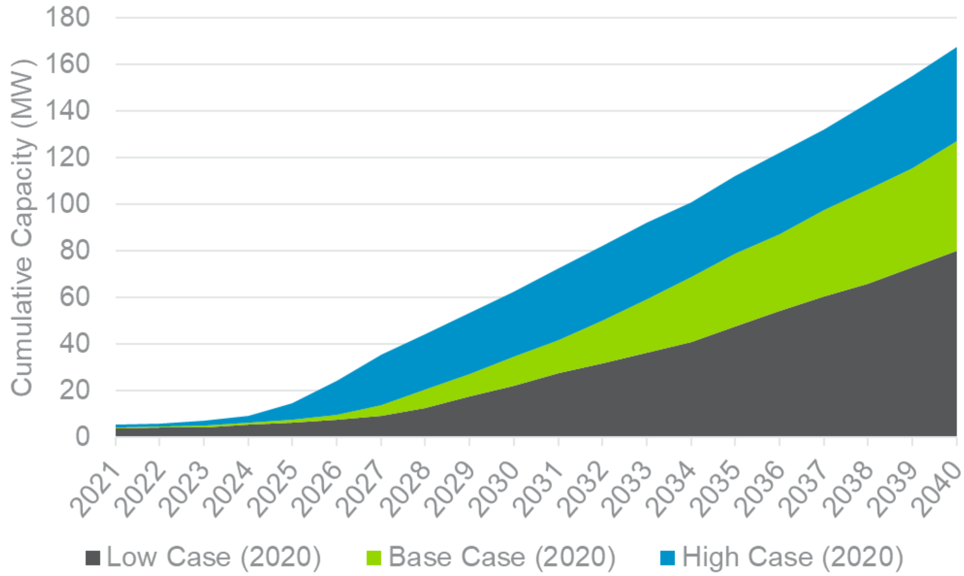


Figure 17. Cumulative Capacity Installations by Technology (MW AC), Idaho Base Case

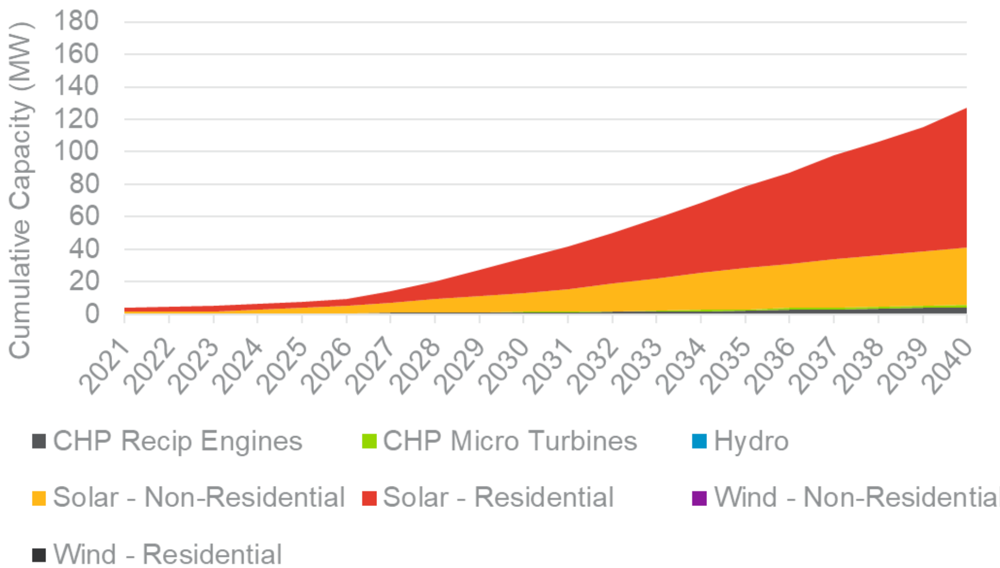


Figure 18. Cumulative Capacity Installations by Technology (MW AC), Idaho High Case

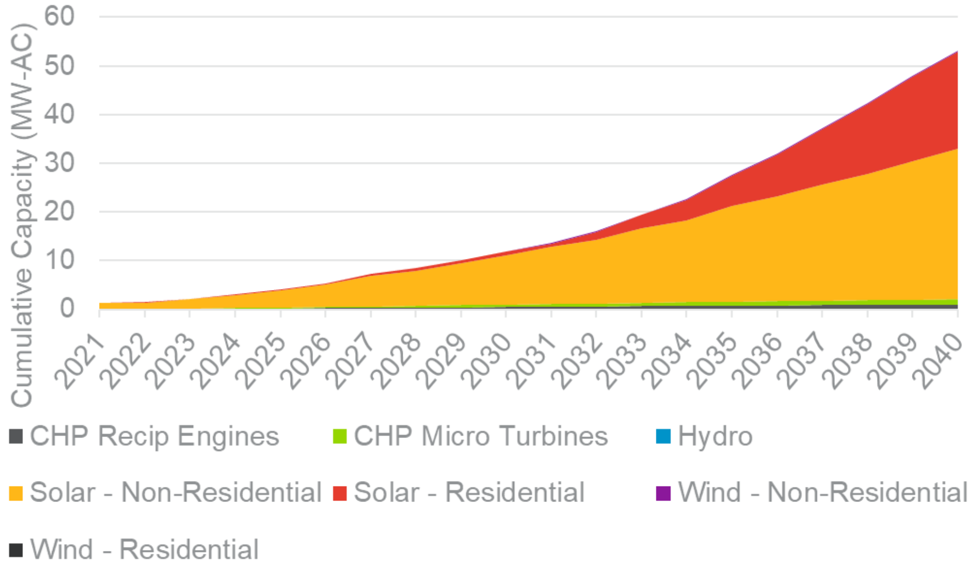
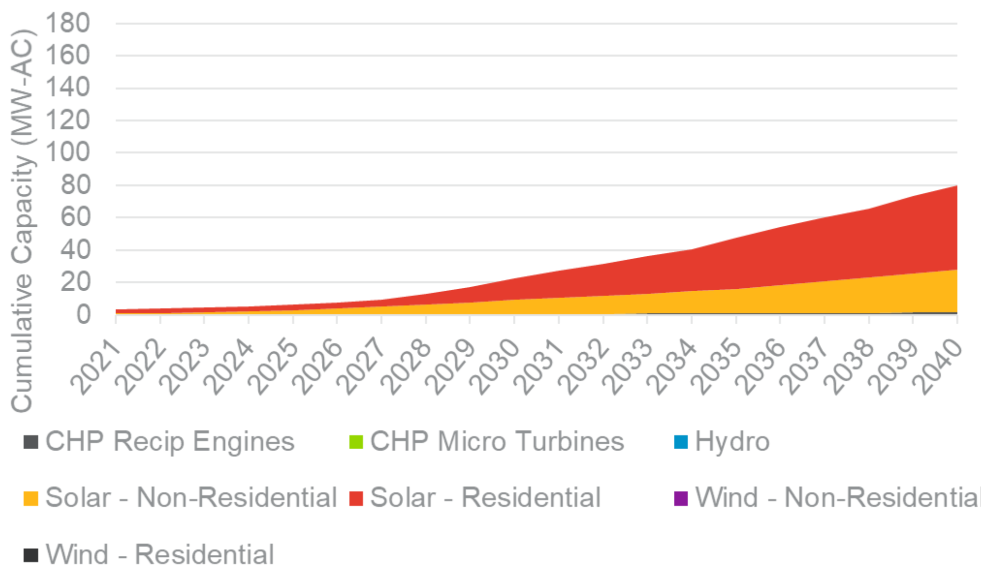


Figure 19. Cumulative Capacity Installations by Technology (MW AC), Idaho Low Case



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

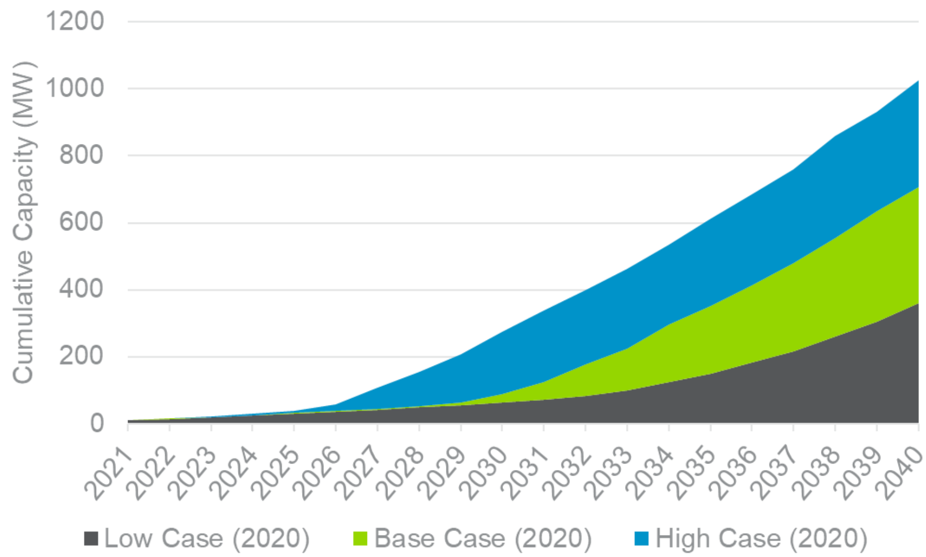


Figure 21. Cumulative Capacity Installations by Technology (MW AC), Oregon Base Case

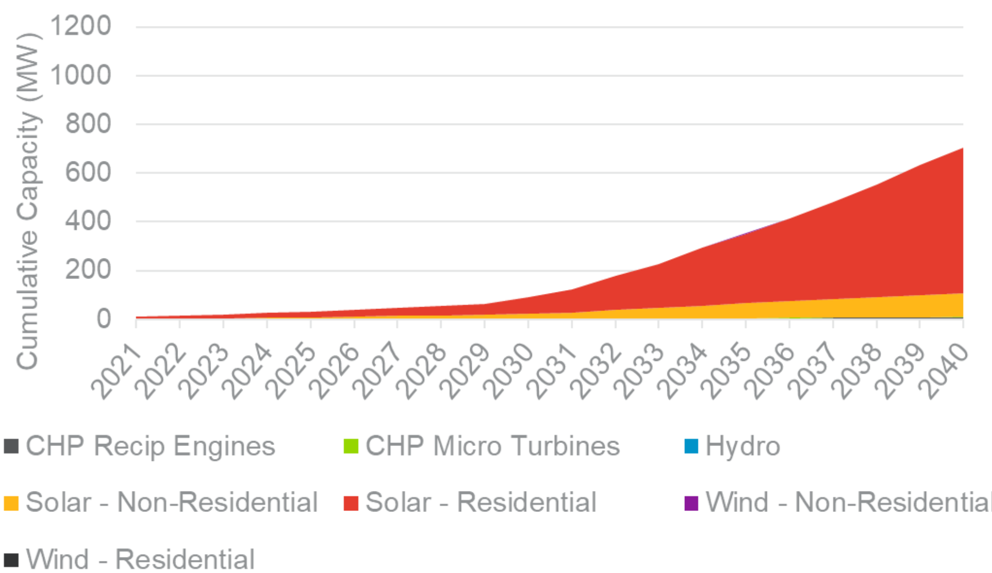


Figure 22. Cumulative Capacity Installations by Technology (MW AC), Oregon High Case

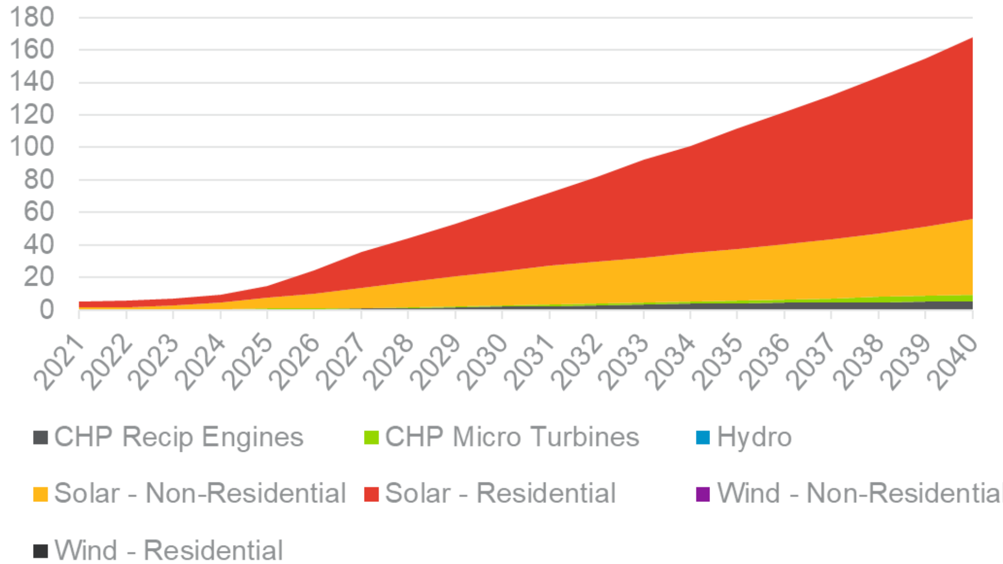
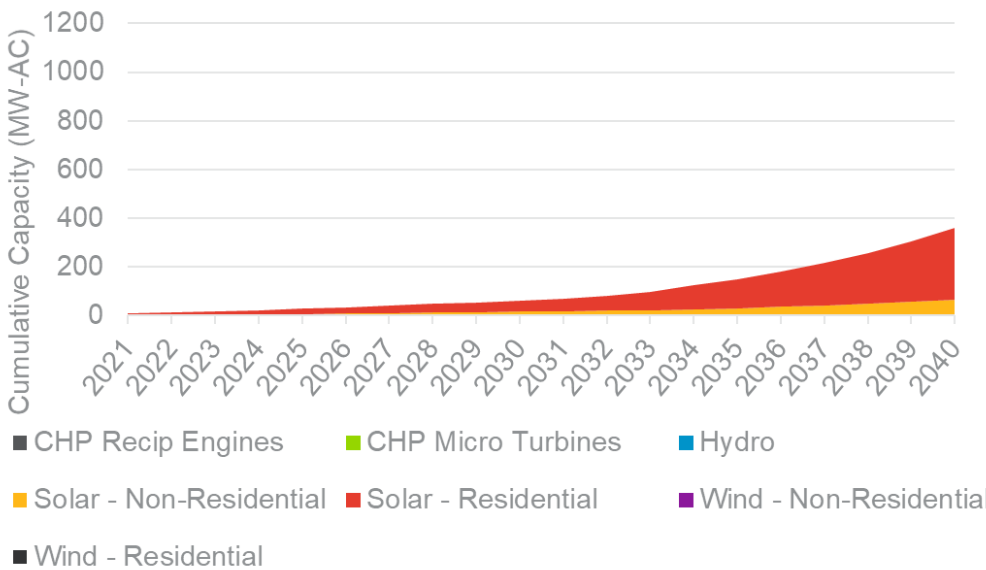


Figure 23 Cumulative Capacity Installations by Technology (MW AC), Oregon Low Case



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.

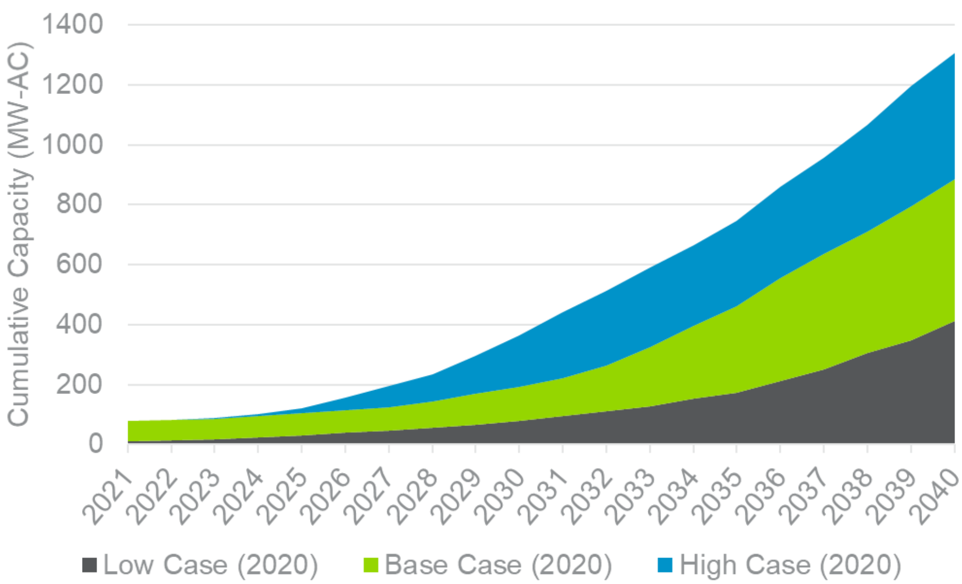
Additionally, a 12% increase in customer count contributed a positive impact on the cumulative installations over the planning horizon.

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

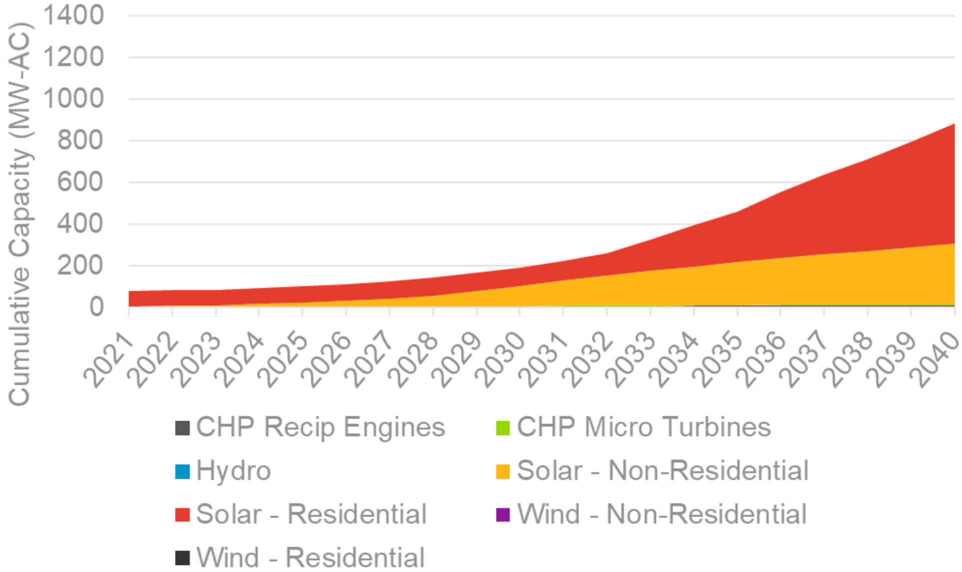


Figure 26. Cumulative Capacity Installations by Technology (MW AC), Utah High Case

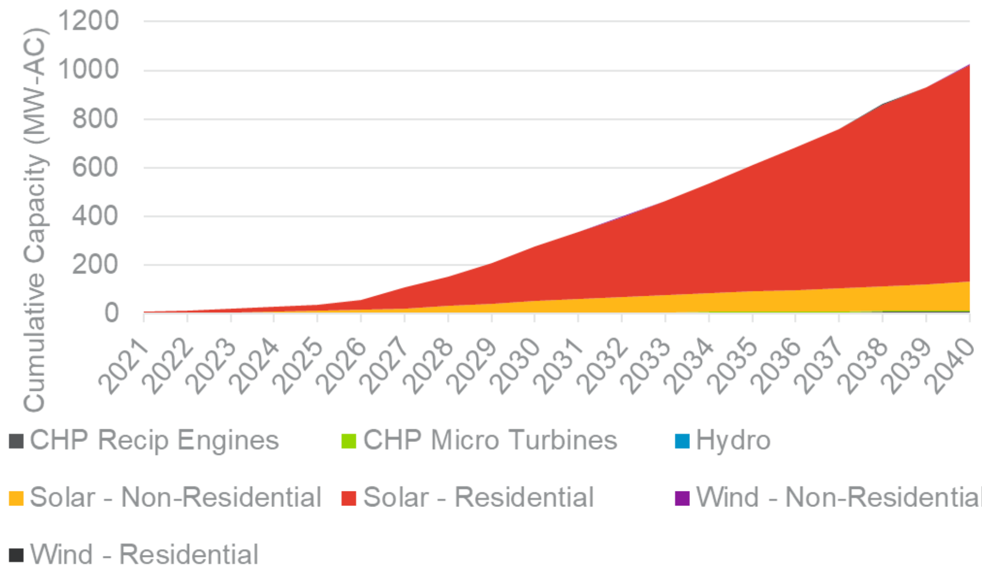
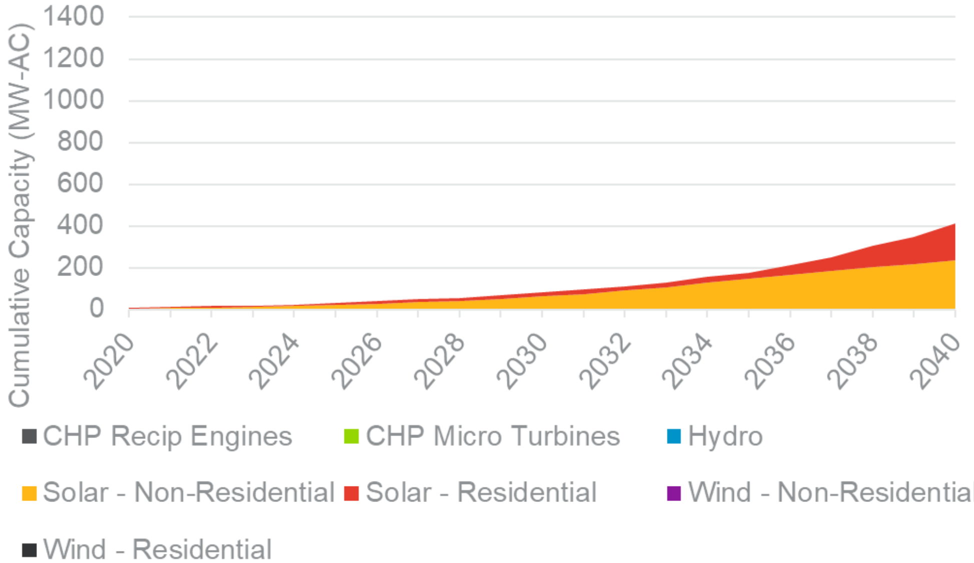


Figure 27. Cumulative Capacity Installations by Technology (MW AC), Utah Low Case



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

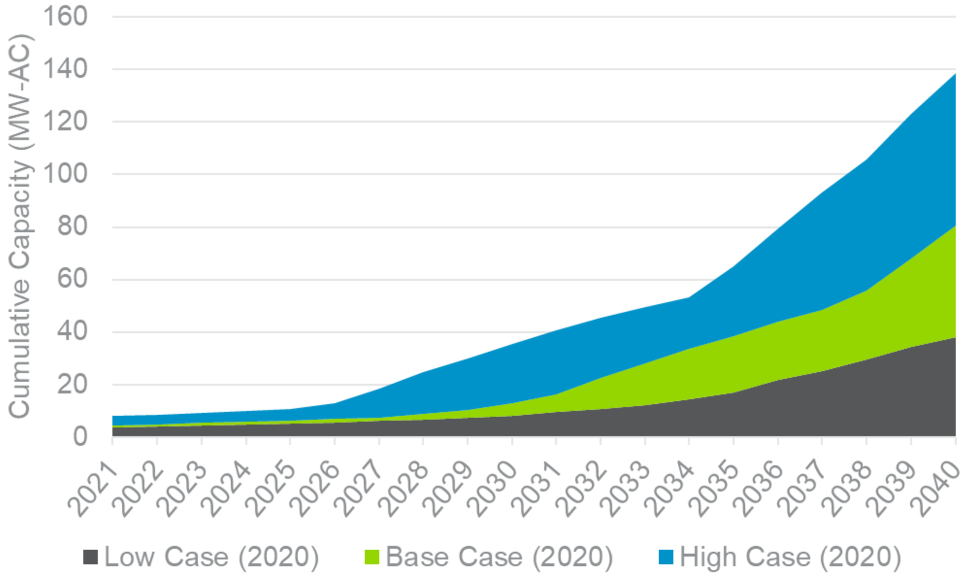


Figure 29. Cumulative Capacity Installations by Technology (MW AC), Washington Base Case

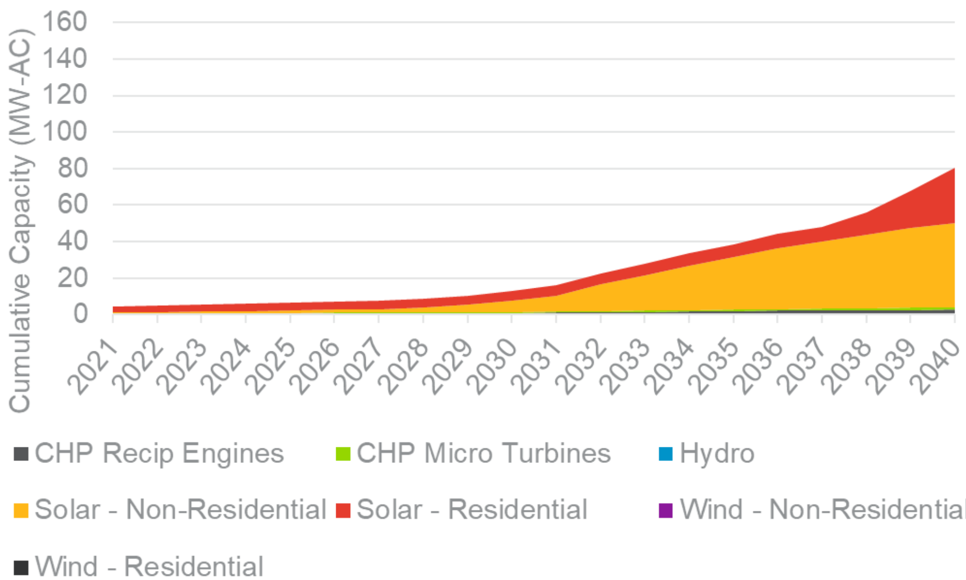


Figure 30. Cumulative Capacity Installations by Technology (MW AC), Washington High Case

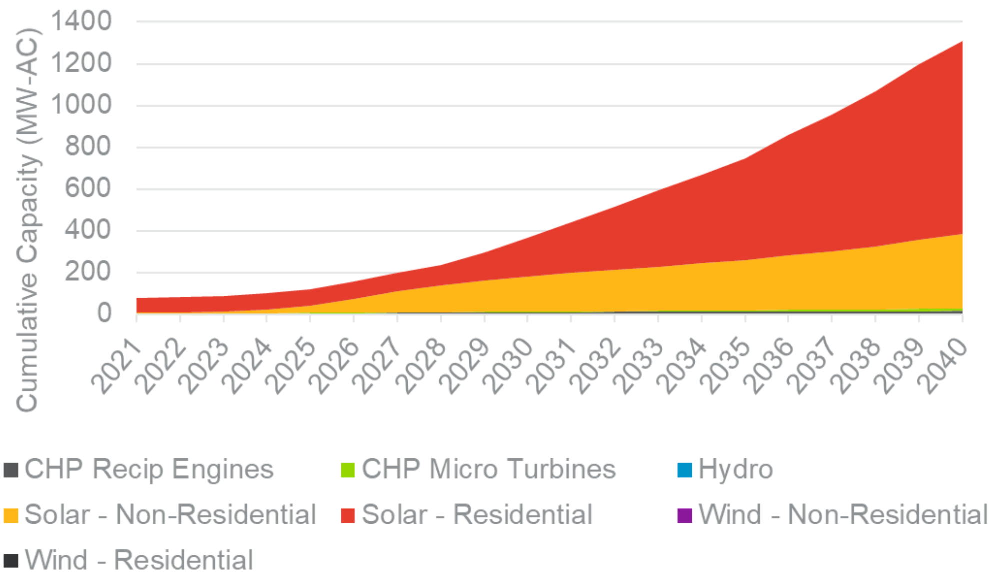
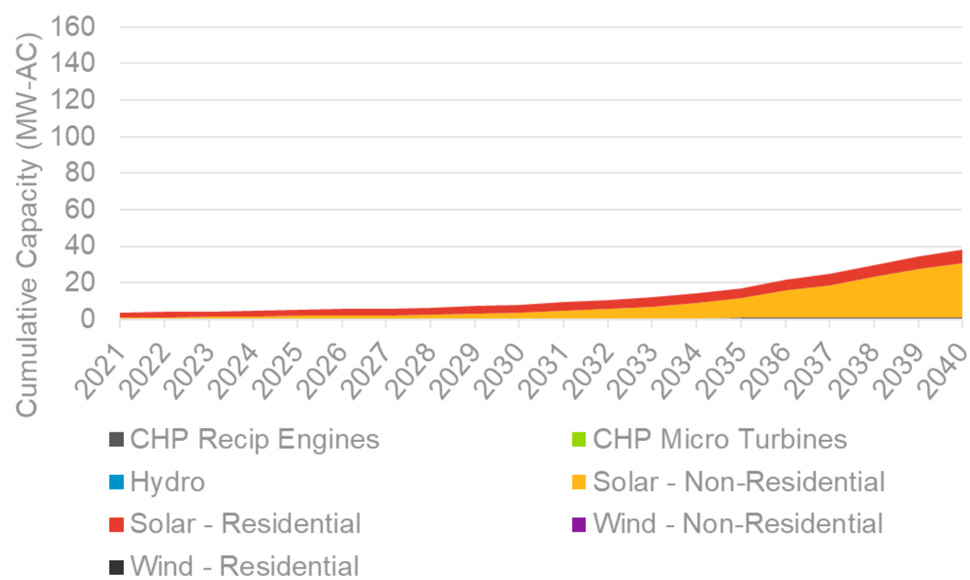


Figure 31. Cumulative Capacity Installations by Technology (MW AC), Washington Low Case



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

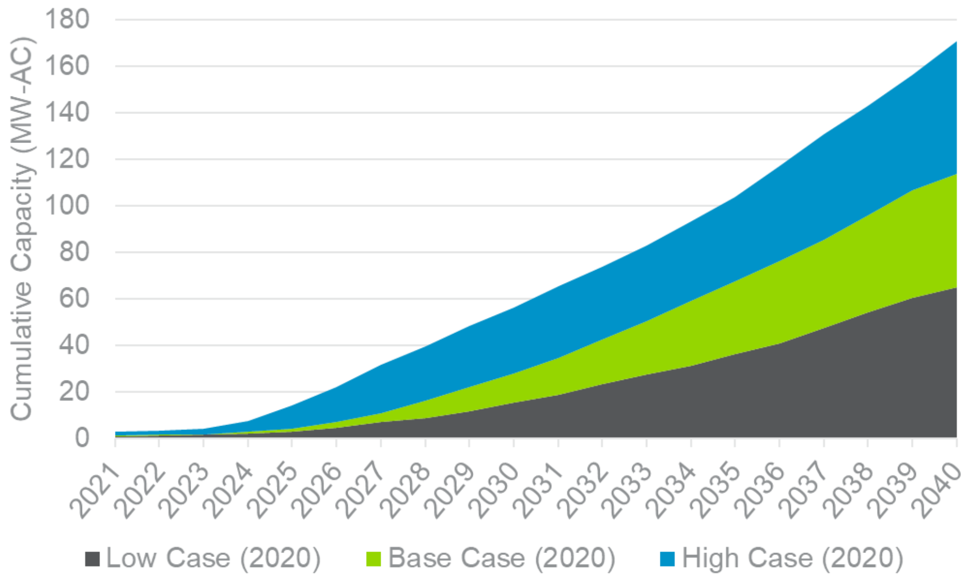


Figure 33. Cumulative Capacity Installations by Technology (MW AC), Wyoming Base Case

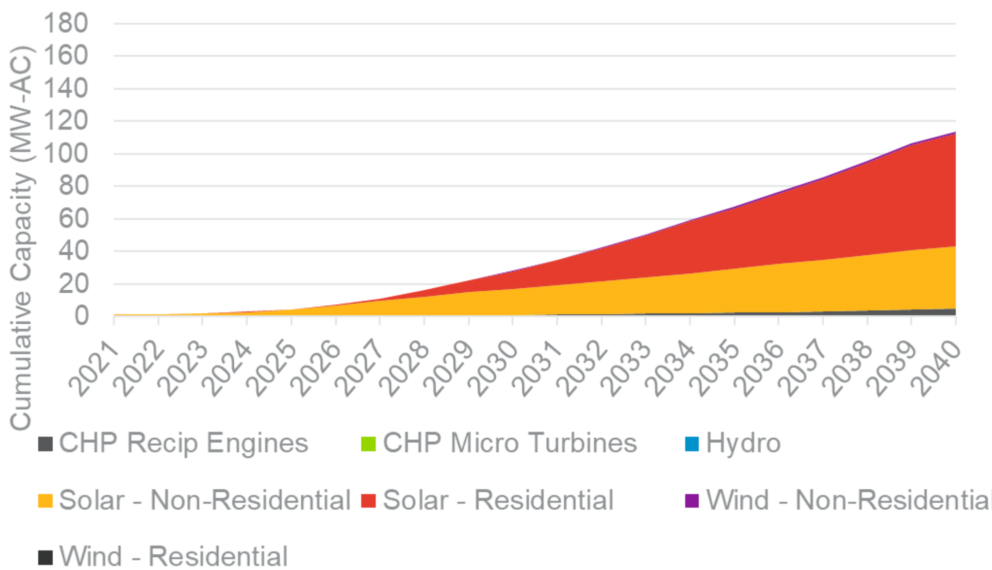


Figure 34. Cumulative Capacity Installations by Technology, Wyoming High Case

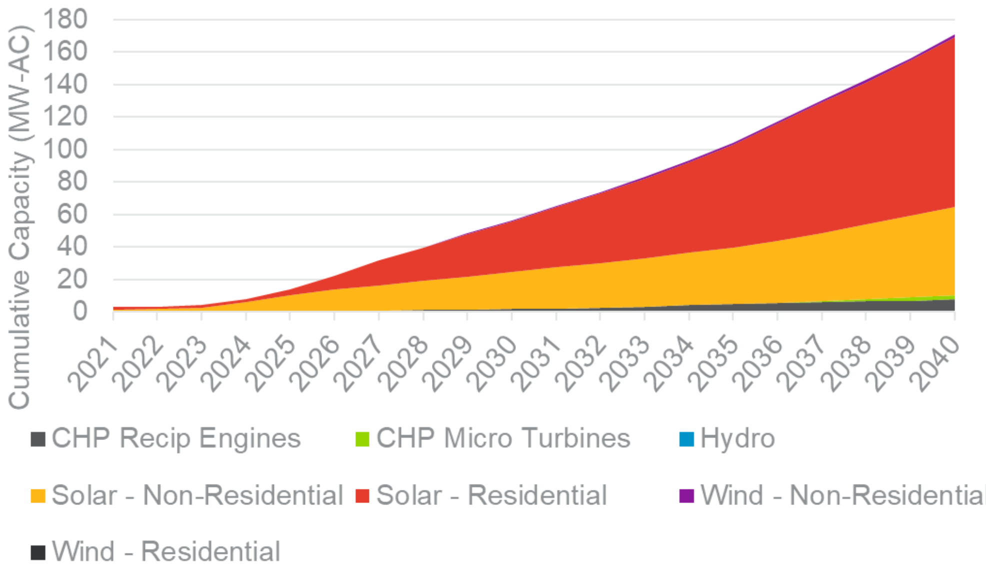
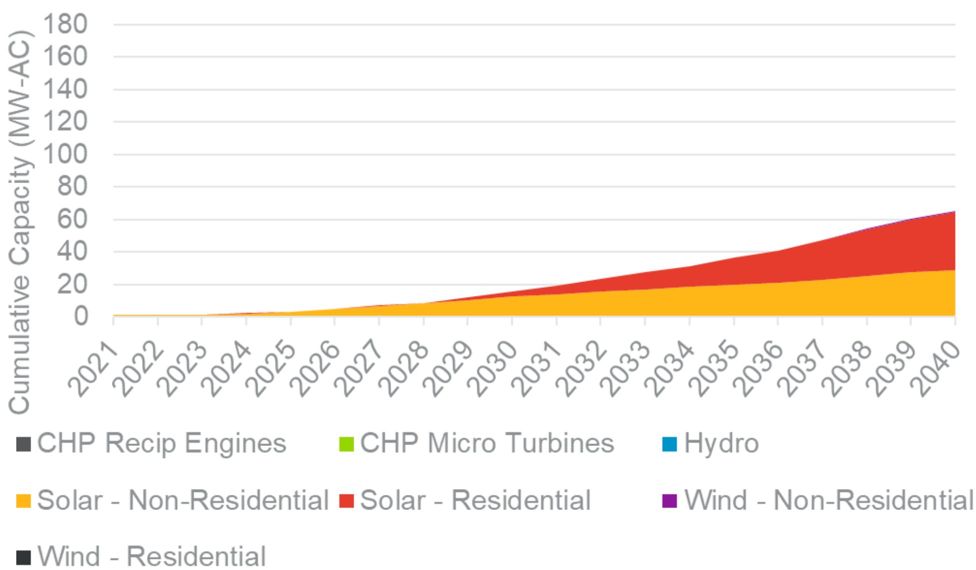


Figure 35. Cumulative Capacity Installations by Technology (MW AC), Wyoming Low Case



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

[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 R – 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. TheCEAP 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 later in 2021.

The CEAP included in the 2021 IRP serves to provide PacifiCorp's initial forecast of how it plans to meet the requirements set forth in CETA. The highlights of PacifiCorp's 2021 CEAP include:

[This section will detail highlights of preferred portfolio actions specific to PacifiCorp's Washington jurisdiction as of the September 1, 2021 filing.]

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, 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 11,000 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 decade, PacifiCorp has reduced its carbon 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 carbon 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 streetlight 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

The following requirements are per WAC 480-100-620(12) and provide an indication of what requirements will be met in this section as part of the 2021 IRP filing no later than September 1, 2021.

(a) Be at the lowest reasonable cost;
(b) Identify and be informed by the utility's ten-year cost-effective conservation potential assessment as determined under RCW 19.285.040;
(d) Establish a resource adequacy requirement; management programs that may be acquired;
(e) Identify the potential cost-effective demand response and load management programs that may be acquired;
(f) 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 contribute to meeting the utility's resource adequacy requirement;
(g) Identify any need to develop new, or to expand or upgrade existing, bulk transmission and distribution facilities;
(h) Identify the nature and possible extent to which the utility may need to rely on an alternative compliance option identified under RCW 19.405.090, if appropriate; and
(i) Incorporate the social cost of greenhouse gas emissions as a cost adder as specified in RCW

PacifiCorp's CEAP is planning toward a future in Washington that balances a rapid transition to renewable energy as directed under CETA, with our continued commitment to ensure that we are serving customers affordably, safely, and reliably. In order 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 resource adequacy.

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 the chapter addressing 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 7 (Modeling and Portfolio Evaluation Approach), PacifiCorp uses the PLEXOS LT model to produce resource portfolios with sufficient capacity to achieve a target a loss of load probability (LOLP) over the 20-year study horizon. Each of these portfolios is uniquely characterized by variables on PacifiCorp's system, including type, timing, location, and resources needed to achieve reliable operation.

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.

Resource adequacy is modeled in the portfolio-development process by ensuring each portfolio meets a target LOLP which is new for the 2021 IRP. PacifiCorp will also apply a capacity reserve margin (CRM), modeled minimally as a 13 percent requirement calculated on load at each topology location. Additionally, the 2021 IRP will directly model operating reserve requirements, also new, in expansion plan model runs which ensures that expansion resources selected to meet LOLP and CRM requirements will also meet operating reserve requirements. Considered 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, the 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. For the CEAP, the action plan period begins January 1, 2021 and ends December 31, 2030. The following resources are considered as part of the long-term expansion model to ensure resource adequacy

- **Dispatchable Thermal Resources:**
  These resources include dispatch costs for fuel, non-fuel VOM, and the costs of 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 attimes 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:**
  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.

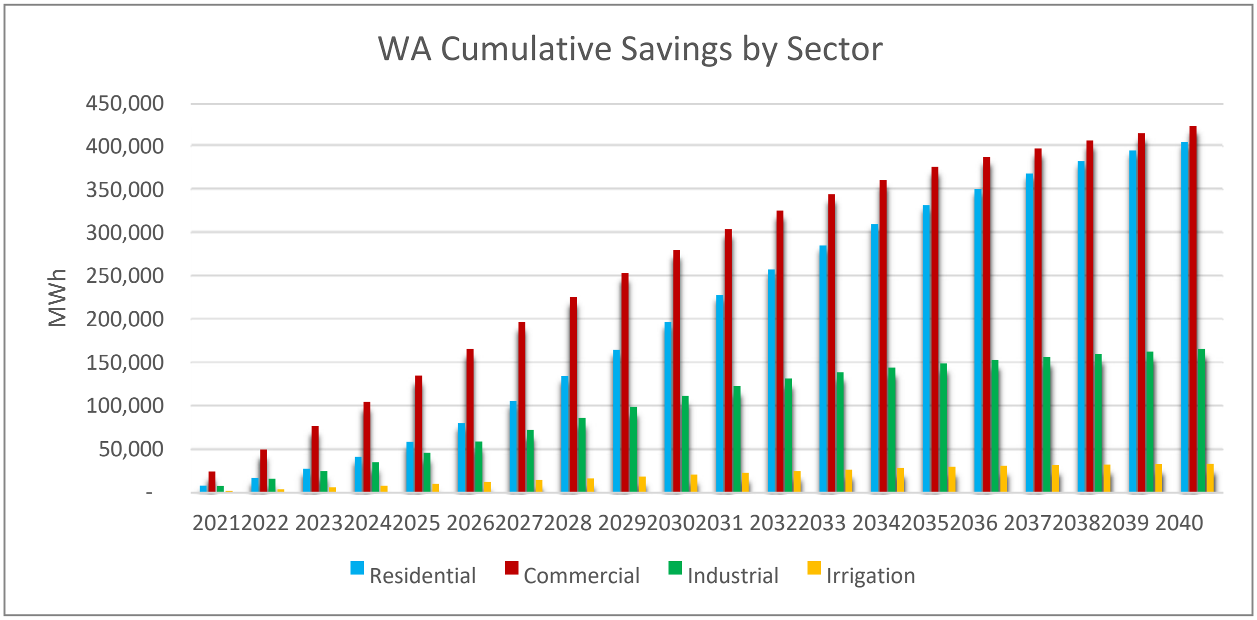
  Demand response resources, representing direct load control capacity resources, are also characterized with supply curves representing achievable technical potential by state and by year for specific direct load control program categories (i.e., air conditioning, irrigation, and commercial curtailment). 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.

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 wateruse 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 will be included in an appendix to the 2021 IRP. The figure below shows cumulative technical potential results from the CPA for the Washington service territory.



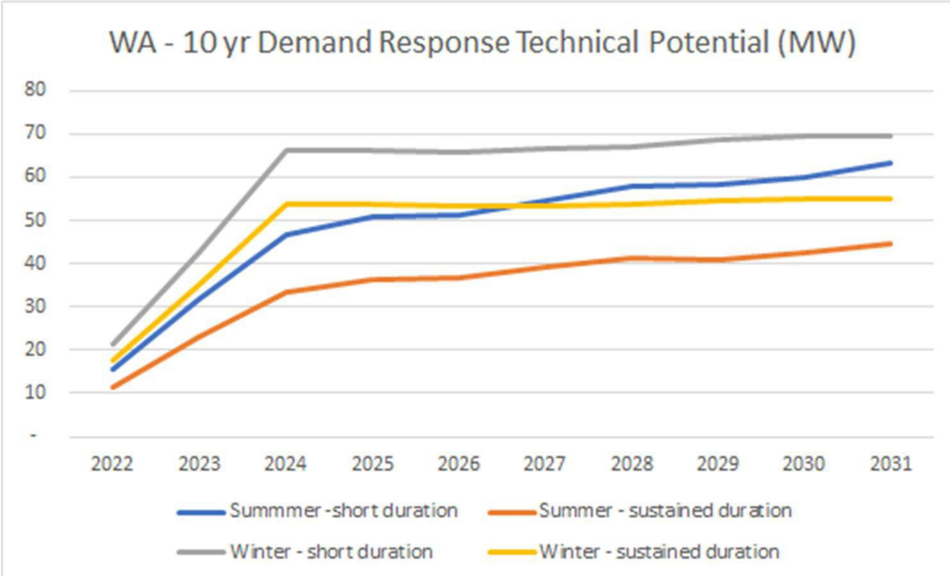
The study results in over 3,000 individual efficiency measures which are then bundled into 27 groups for each of PacifiCorp's six states. In past years, these groups were characterized only by the total levelized cost of each measure. For the 2021 IRP, a new bundling approach based on net value of efficiency resources will be employed as described at the December 2020 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 will also be included in an appendix to the 2021 IRP. PacifiCorp issued a Demand Response request for proposals in January 2021 to pursue the acquisition of cost-effective flexible capacity.

The figure below shows cumulative technical potential for new demand response resources, including customer-sited battery storage, through 2031. 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.

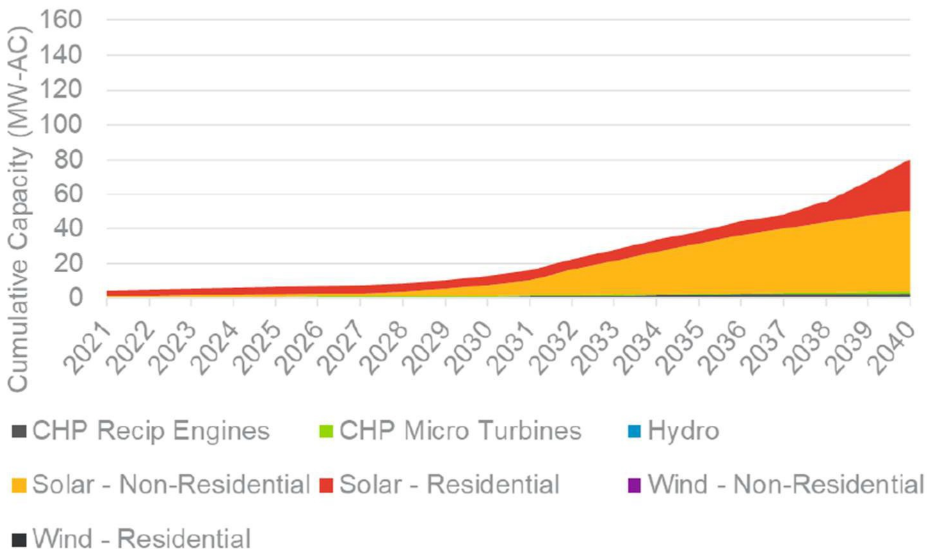


The amount and cost of load curtailment or shift is characterized by customer type and type of end use that is being controlled. This technical achievable potential is input to the IRP model as a resource option to be selected to meet system adequacy. Demand response selections by the model are cost 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 the figure below.



Transmission and Distribution

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.

Preferred Portfolio Results

[This will be available as part of the final IRP filing made no later than September 1, 2021]

Part 3: Working Toward an Energy Future that Benefits All Customers

The following requirements are per WAC 480-100-620(12) and provide an indication of what requirements will be met in this section as part of the filing of the September 1, 2021 IRP.

(c) Identify how the utility will meet the requirements in WAC 480-100-610 (4)(c) including, but not limited to:
(i) Describing the specific actions the utility will take to equitably distribute benefits and reduce burdens for highly impacted communities and vulnerable populations;
(ii) Estimating the degree to which such benefits will be equitably distributed and burdens reduced over the CEAP's ten-year horizon; and
(iii) Describing how the specific actions are consistent with the long-term strategy described in WAC 480-100-620 (11)(g).

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 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. When PacifiCorp's preferred portfolio is available as part of the September 1, 2021 filing, it will also describe preliminary actions that the utility could take to address identified disparities, for further discussion amongst stakeholders.

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 Highly Impacted Community (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 Nitrus-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

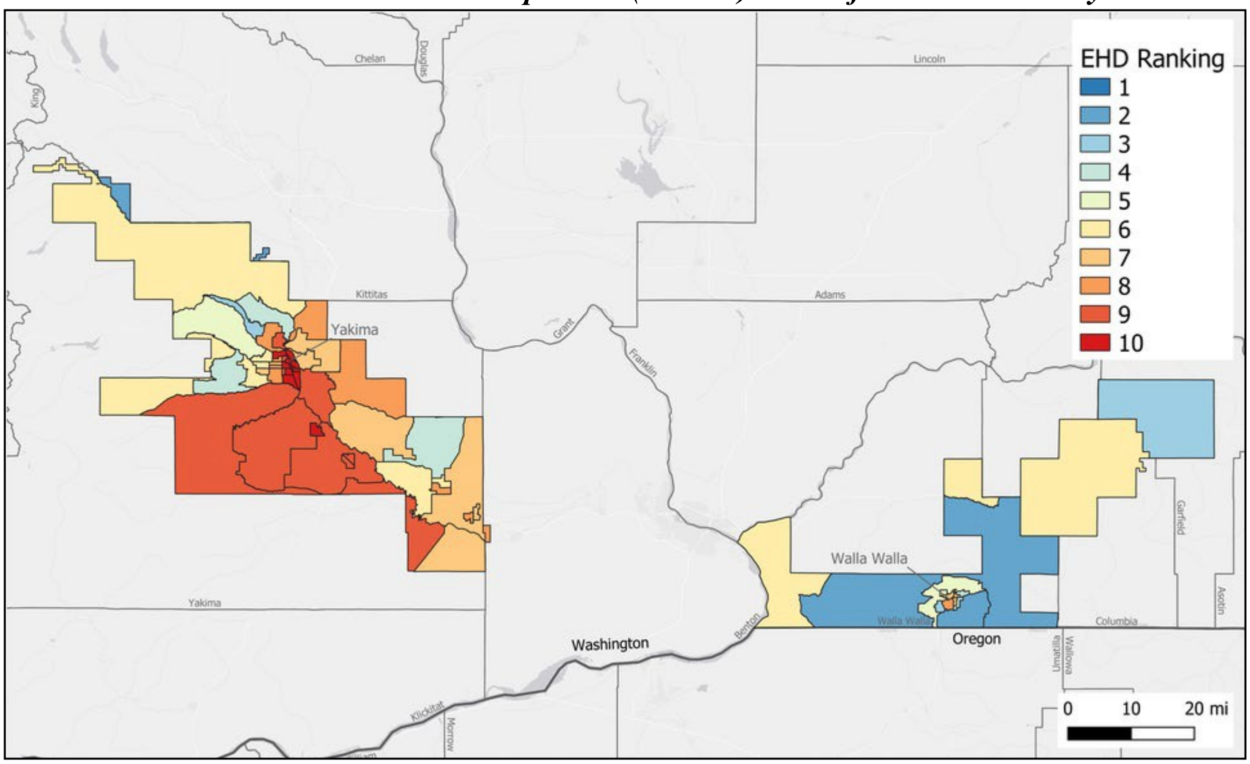
- **Socioeconomic factors:** including limited English, no high school diploma, race/ethnicity, population living in poverty, transportation expense, unaffordable housing, and unemployed

- **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.

WTN Data – Environmental Health Disparities (Overall) in Pacific Power Territory



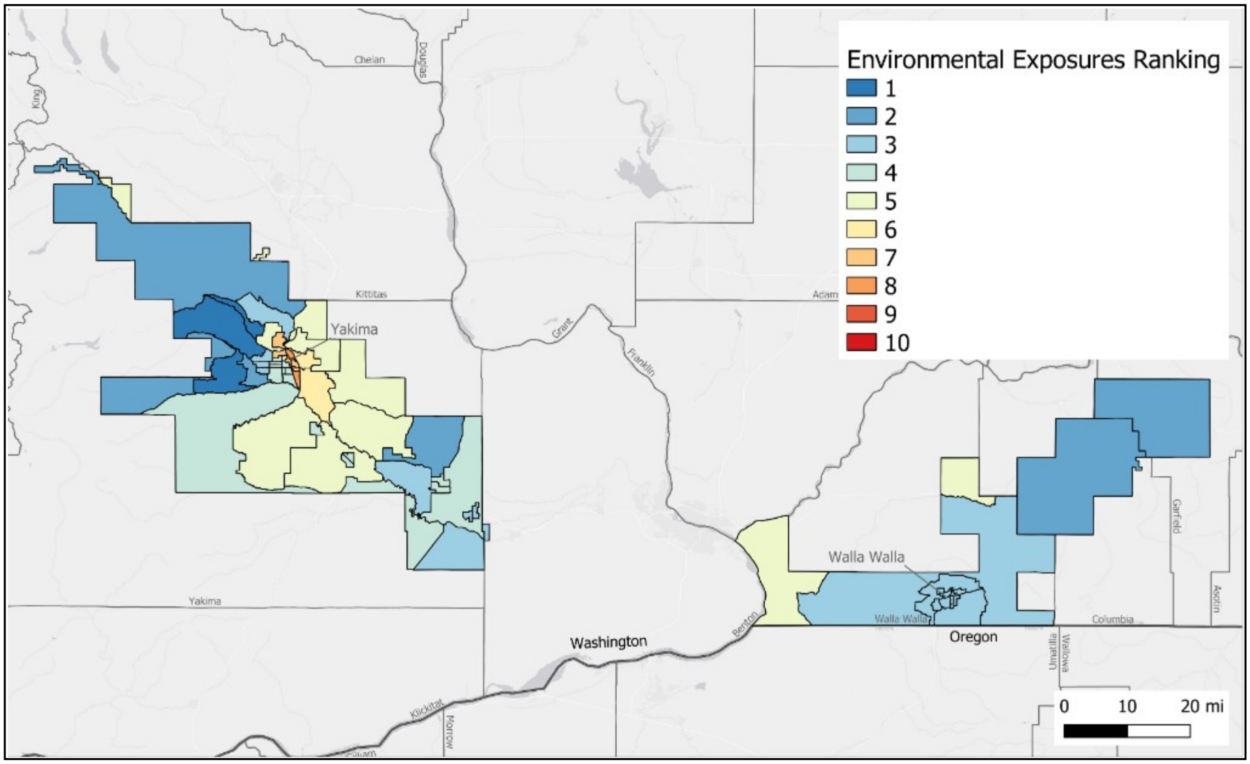
Location	Count of WTN 9/10 Scoring Census Tracts
Environmental Health Disparities (EHD)	
Yakima	19
Walla Walla	0

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.

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.

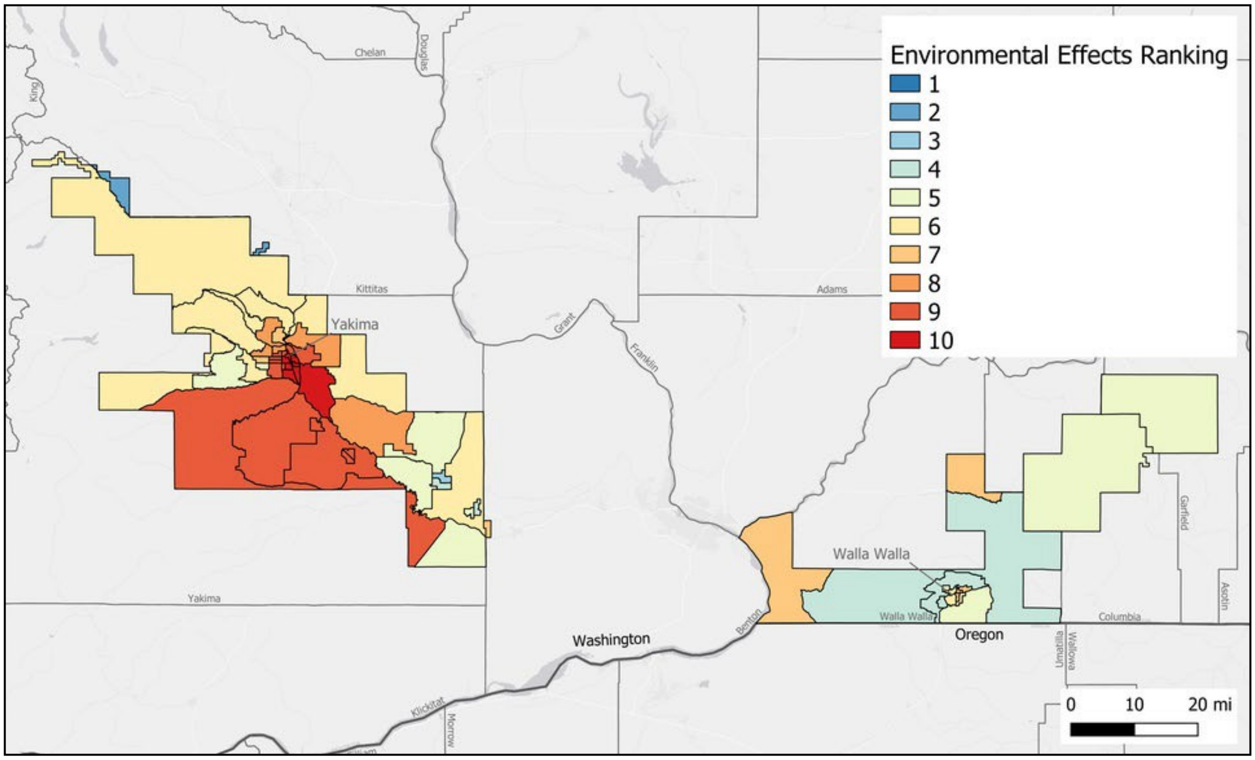
Yakima and Surrounding Area

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.

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.

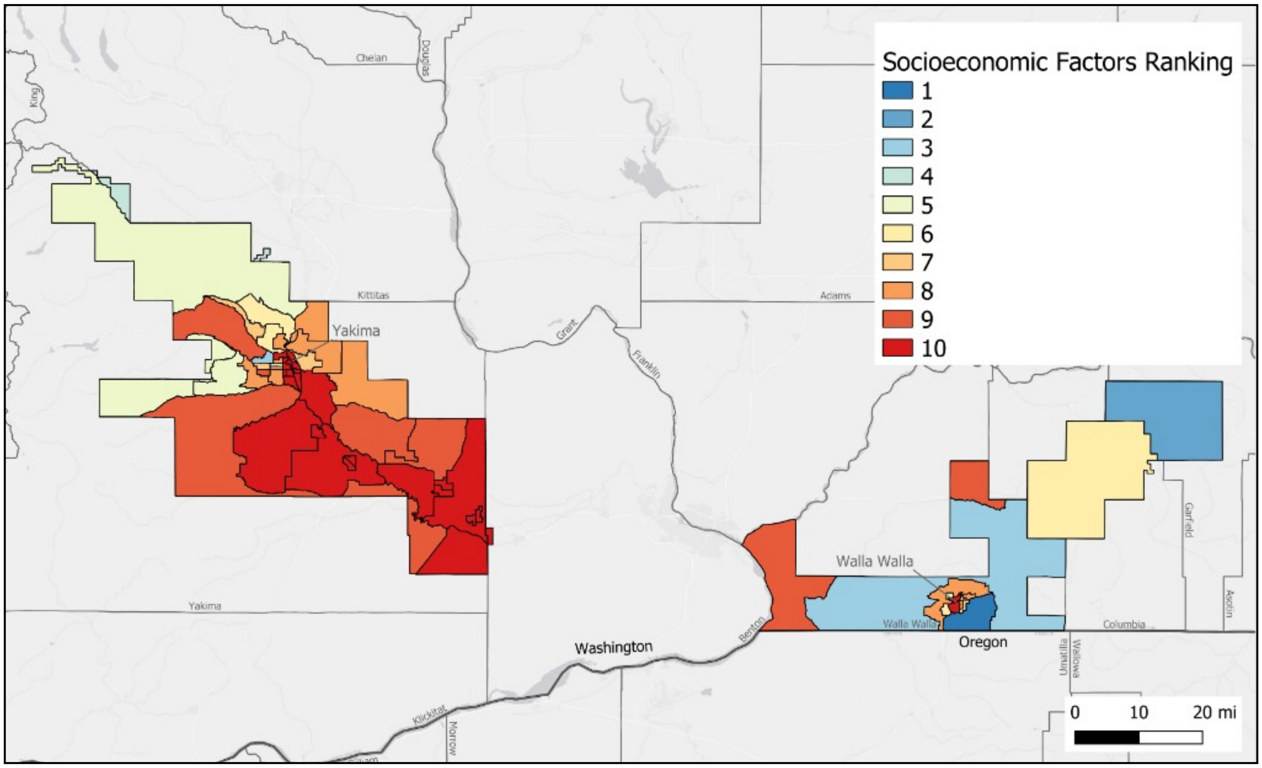
Yakima and Surrounding Area

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.

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.

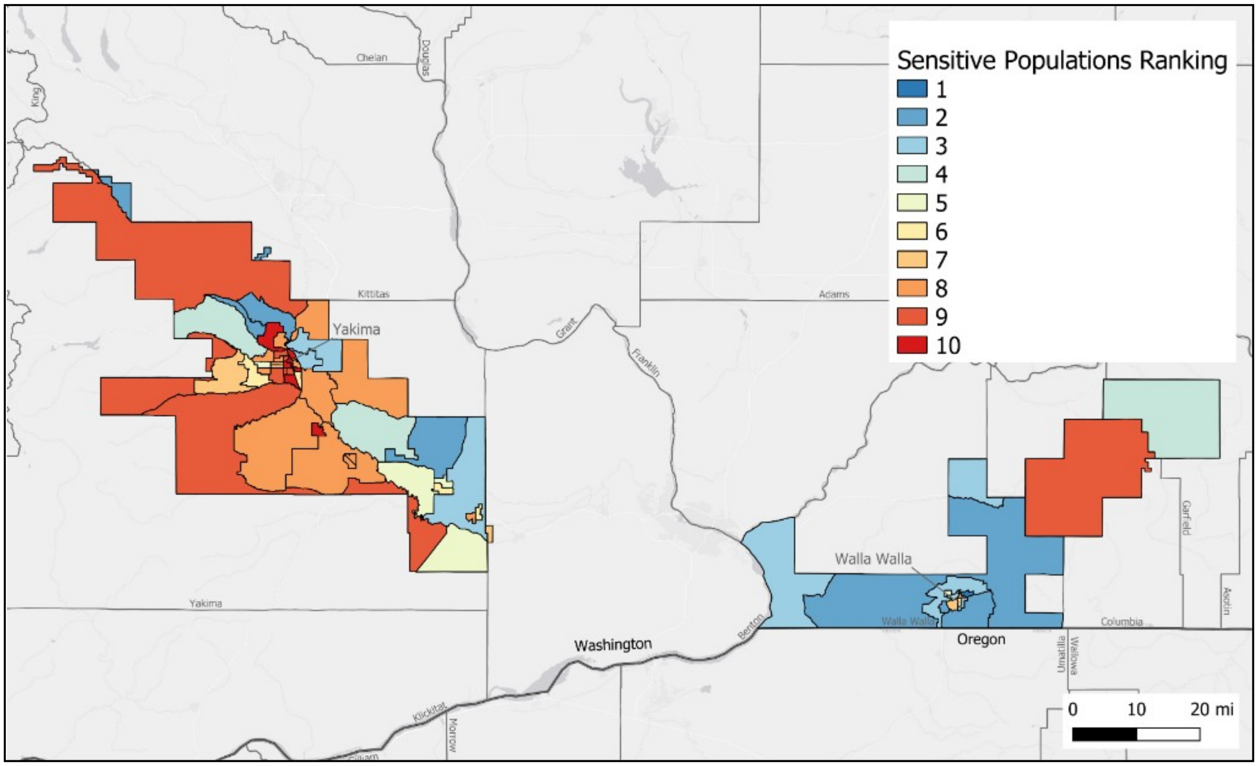
Yakima and Surrounding Area

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.

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.

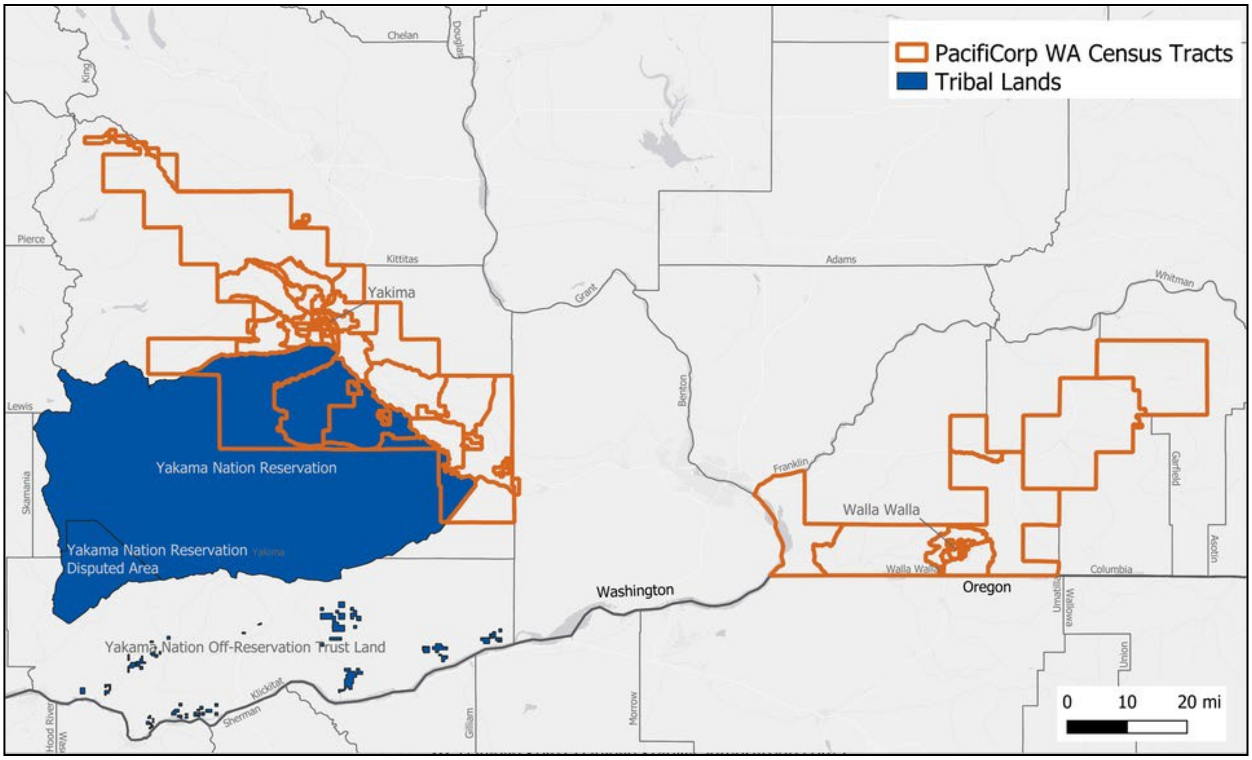
Yakima and Surrounding Area

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.

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.

Existing Community Programs in Washington

PacifiCorp offers a variety of programs which have ultimately been designed to benefit customer Socioeconomic Factors, 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 HIC populations.

- 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.

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 12 public-input meetings, with some lasting two days. Due to restrictions and concerns surroundings COVID-19, all meetings were held virtually via phone conference.

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.

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. PacifiCorp is currently putting together an Equity Advisory Group, with the first meeting to be held no later than June 30, 2021. PacifiCorp will continue to seek additional opportunities for community involvement in the IRP and CEAP.

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.

Specific Actions to help address barriers to equitable distribution of benefits

[hold for completion once additional information on the Preferred Portfolio is known]

Proposed Structure of this section within the September 1, 2021 filing:

-
- Additional detail on potential specific actions that PacifiCorp's preferred portfolio is recommending to ensure an equitable transition to clean energy for all Washington customers.
-

Part 4: Compliance Pathways

The following requirement is per WAC 480-100-620(12) and provide an indication of what requirements will be met in this section as part of the filing of the 2021 IRP filing no later than September 1, 2021.

(h) Identify the nature and possible extent to which the utility may need to rely on an alternative

Proposed Structure of Section:

RCW 19.405.040 and 19.405.050 set the 2025, 2030, and 2050 goals for electric utilities in Washington to meet. Specifically, utilities must show that by December 31, 2025 all coal-fired generation has been eliminated from Washington's allocation of electricity. By January 1, 2030, all retail sales of electricity to Washington retail electric customers must be greenhouse gas neutral, and by 2045, all sales of electricity to Washington retail electric customers must be supplied by non-emitting electric generation and electricity from renewable resources.

PacifiCorp's 2021 IRP, and corresponding "resource adequacy" and "working toward an energy future that benefits all customers" sections of this CEAP, set the company on the path toward meeting those objectives for the benefit of all customers. Specifically, PacifiCorp's preferred portfolio included in Chapter 8 of the IRP filed no later than September 1, 2021 will be CETA compliant and will outline the least-cost, risk-adjusted path forward for PacifiCorp's system. The CEAP will use this preferred portfolio to give a Washington-specific view of the next 10 years, and to identify any risks or needed alternative compliance mechanisms between 2021 and 2031.

This section will be expanded as part of the September 1, 2021 filing once PacifiCorp's preferred portfolio is known.