Clean Energy Plan and Integrated Resource Plan 2023

This document contains forward-looking statements, including those regarding implementation of our business plans, technology transitions, our business, strategies and financial performance, our offerings of new services, and other statements that are not historical fact, and actual results could differ materially from these forward-looking statements. Risk factors that could cause actual results to differ are set forth in the “Risk Factors” section, as well as other sections of our 2022 Annual Report on Form 10-K, available on our website at investors.portlandgeneral.com/financial information/sec-filings, as well as, or in addition to, other filings with the SEC. All forward-looking statements are based on management’s estimates, projections, and assumptions as of the date of filing, and we undertake no obligation to update any such statements.

Portland General Electric Company
Integrated Resource Planning
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Table of Contents

Figures

Tables

CEO Message

At Portland General Electric (PGE), we take pride in providing safe, reliable, affordable and increasingly clean power to homes, businesses and communities. Delivering this essential service is a responsibility that we have embraced for more than 130 years, and today, one that reflects evolving values and expectations.

For decades, customers have made clean energy a top priority. Echoing that sentiment, today many customers have aggressive climate goals and communities we serve have comprehensive climate action plans. In 2021, the Oregon Legislature passed landmark public policy that affirmed and mandated PGE's goals for decarbonization. This inaugural Clean Energy Plan, filed in conjunction with our 2023 Integrated Resource Plan, is a comprehensive roadmap detailing how we will meet customers' energy needs and greenhouse gas emissions targets while maintaining reliability, safety and affordability.

These targets are also in line both with the science-driven United Nations 6th IPCC Report, and with the policy of the federal government, which is providing significant financial resources to states, communities, utilities and customers through the Inflation Reduction Act and the Infrastructure Investment and Jobs Act.

Meeting our targets and decarbonizing our system will require significant investment in diverse resources, as well as investments in new transmission infrastructure, technology and innovation, as well as wider regional collaboration. We will invest in a full range of clean energy resources and tools, including large-scale wind and solar projects, battery storage, energy efficiency, demand response, customer-sited resources and community based renewable energy.

This is a significant undertaking, requiring us to try new things as well as adopt and evolve when new technologies, opportunities and challenges present themselves.

Importantly, we cannot implement this Clean Energy Plan and Integrated Resource Plan alone. Success depends on the commitment of customers as well as leaders and partners throughout the community. This plan calls for community-based renewable energy and customer participation in energy efficiency and demand response programs. We rely on key partners, ranging from community colleges and labor unions who enable well-trained workers, to suppliers and contractors of various types and sizes who provide reliable sources of materials and equipment.

In the pages that follow, we outline how we will meet future energy and capacity needs while achieving emissions targets, reliably and affordably. Central to this plan is PGE's commitment to diversity, equity and inclusion. We must decarbonize in ways that benefit everyone, with an attentive eye to historically underserved communities.

Thank you for your interest, partnership and willingness to think differently as we work together in building a clean energy future.

Maria Pope

President and CEO, PGE

Introduction

Portland General Electric (PGE, or the Company) is proud to submit our combined, 2023 Clean Energy Plan and Integrated Resource Plan (CEP/IRP) for consideration by our customers, stakeholders, communities and the Public Utility Commission of Oregon (OPUC, or the Commission).

PGE's purpose is to power the advancement of society. We have served our customers with safe, reliable and affordable power for over 130 years. We engage in robust planning, analysis, stakeholder and community engagement to inform our investments in resources, customer programs and the grid. We are committed to balancing affordability, reliability and reductions in greenhouse gas (GHG) emissions across all of our planning efforts.

As Oregon's largest electricity supplier, we recognize our unique role in addressing climate change and leading an equitable clean energy transition in Oregon. We reflect this commitment in our climate-related goals and detailed disclosures of our progress in our annual environmental, social and governance (ESG) report. We also see it aligned with the climate and clean energy goals of many of the customers and communities we serve. This CEP/IRP represents a continuation of our clean energy journey, which began years ago in response to customer demands, climate science, emerging technologies and market opportunities.

Oregon's landmark clean energy legislation, HB 2021, and unprecedented federal government support for clean energy, is now transforming how PGE provides excellent service to customers. The 2023 IRP is PGE's first long-term resource plan since the passage of HB 2021, which established PGE's climate goals into law with firm targets for reducing emissions associated with Oregon retail sales. HB 2021 requires PGE to file a CEP, detailing our plans to achieve annual progress toward achieving emissions targets with consideration for the benefits for local communities.

These emissions targets and the expectations outlined in the pursuant Commission orders inherently change PGE's approach to long-term resource planning. Emissions targets are now an integral component of PGE's IRP modeling. At the same time, PGE cannot demonstrate a balanced, feasible path toward emissions targets without also estimating future energy and capacity needs and identifying an optimal portfolio of resources to meet those needs, subject to emissions constraints. Our CEP and IRP are tightly integrated and as such, PGE is submitting the CEP and IRP as a single planning document, responsive to the OPUC's requirements, guidelines and expectations for both planning documents. The CEP serves as our accessible roadmap to the clean energy transition. The IRP functions as the detailed analytical foundation. Both share common methodologies and recommendations.

Our CEP/IRP details a pathway to meeting future energy and capacity needs and emissions targets, given what we know today, and acknowledges the significant change and uncertainty confronting our industry in the coming decades. We propose measured, near-term actions to serve our customers with reliable, affordable and increasingly clean power consistent with achieving our 2030, 2035 and 2040 emissions targets. Those near-term actions represent specific steps PGE intends to take with acknowledgement by the OPUC.

This filing is the result of continued and iterative planning and analysis, during which, we have emphasized and evolved our venues for stakeholder and community input. As has been underscored throughout this process, diverse stakeholders will view the document through their own lens. To aid in reviewing this first CEP/IRP submission, we highlight the following navigational tips:

- Chapter 1 details the company's strategies, planned actions and forecasted emissions in response to HB 2021 requirements. Chapter 1, combined with Chapters 7, 13 and 14 address the bulk of CEP guidelines and expectations outlined in HB 2021 and the Commission's orders;
- Chapters 2-6 and Chapters 8-12 serve as the more traditional components of the IRP. As noted above, HB 2021 and Commission orders necessitated changes in IRP methodology and analysis. As a result, there are CEP expectations addressed in some of the IRP chapters. For example, community-based renewable energy (CBRE) resources are included in the IRP's set of Resource Options;
- Chapters 11 and 12 provide a single Preferred Portfolio and Action Plan that reflect the near-term actions we intend to pursue to satisfy energy and capacity needs and emissions reduction requirements; and
- Appendix B provides a crosswalk for the reader to identify where each particular IRP guideline or CEP expectation from HB 2021 or Commission orders are met.

Our goal throughout the planning process was to produce a CEP/IRP that provides clarity on our priorities and values, responds to feedback, and aligns with the public policy goals of Oregon. We set out to mitigate risks for customers while balancing affordability and emissions reduction during a highly dynamic period of change for our industry. We sought to create a plan that was flexible and could be adapted as we continue to learn and as conditions change and new technologies and market opportunities arise.

Importantly, we wanted a plan that would invite further conversations with our customers, communities, stakeholders and the Commission. We would like to acknowledge the time, work, valued inputs and contributions of so many participants to this process over the course of many workshops and other venues. Moving forward, it will take all of us working together to implement the actions identified in this filing and successfully navigate an equitable clean energy transition for Oregon. We share the incredible sense of urgency and look forward to working together to implement next steps.

Summary of key findings from the 2023 CEP/IRP

- PGE has already reduced emissions from power sold to Oregon retail customers by 25 percent below 2010-2012 baseline emissions.
- Electrification of vehicles, homes and businesses will accelerate load growth in the years ahead. This CEP/IRP anticipates and plans for that load as PGE decarbonizes.
- PGE will need to add non-emitting energy resources and capacity at an accelerated pace in order to maintain system reliability while it systematically reduces fossil fuel purchases and generation to achieve emissions targets.
- PGE's planned path to emissions targets features a linear decline in emissions associated with sales to Oregon retail customers from 2026-2030 and 2030-2040. Actual reductions may vary year-by-year due to variables that impact emissions that are beyond PGE's control and/or the pace of clean energy acquisition and integration.
- Achieving emissions targets reliably and affordably will require access to a wider geographic diversity of resources and the transmission solutions to access them. Participation in regional markets and partnerships that allow PGE to pool resources and source clean energy from across the West can increase reliability and lower costs for our customers.
- Significant transmission constraints drive a greater role for customer-sited resources, including demand response and energy efficiency, and community-based renewable energy resources in this CEP/IRP. PGE plans to pursue all cost-effective energy efficiency and demand response during the Action Plan window. PGE establishes a target for CBRE resources of 155 MW by 2030 with plans to pursue at least 66 MW by 2026.
- The growing role of customer-sited and community-based renewable energy resources in PGE's decarbonization efforts underscores the importance of PGE's ongoing efforts to enhance the capacities of distributed energy resources to provide local and system value when managed as a Virtual Power Plant.

- PGE forecasts a significant capacity need of 1136 MW in summer, 1004 MW in winter, and a significant energy need of 905 MWa (~2,500 MW nameplate) by 2030.
- Policy and market changes could change PGE's estimated future energy and capacity needs but the near-term actions proposed during the Action Plan window are the same: conduct one or more Request for Proposals (RFPs) for an additional 181 MWa (~520 MW nameplate) of non-emitting generation and sufficient capacity to remain resource adequate each year.
- 2030 emissions targets can be met with technologies and resources that are currently known and commercially available.
- Pathways to 2040 emissions targets will require further development of non-emitting resources and transmission to meet the region's energy and capacity needs.
- PGE's natural gas plants will continue to play a role in helping to meet our resource adequacy needs during the clean energy transition. PGE will continue to invest in the efficiency, safety and emissions controls of those facilities as appropriate.
- Efforts to specify the sources of generation for resources currently procured through short-term market purchases will reduce PGE's reported emissions and future energy needs.
- Utilizing federal, state and local funding opportunities to support decarbonization on our system will mitigate customer price pressure during the transition.
- PGE's success will require deep and continued collaboration with our customers, communities and stakeholders and with a wide range of leaders at all levels of government.

Chapter 1. Clean energy plan

House Bill (HB) 2021 is a transformative public policy setting Portland General Electric (PGE) on a path to decarbonizing the power supply for Oregon retail customers.[1] To inform our approach to meeting the greenhouse gas (GHG) emissions targets specified by HB 2021, we have engaged in robust planning, analysis, stakeholder and community engagement. Throughout our planning, we remain committed to balancing affordability for customers, the reliability of the grid and GHG reductions.

We begin this chapter by describing our vision for a clean energy future and our role in leading an equitable clean energy transition across our service territory. Before discussing our decarbonization strategies, we provide an overview of our system emissions and historic progress. Notably, in this chapter, we summarize the results of Integrated Resource Plan (IRP) modeling and portfolio analysis developed over subsequent chapters, which form the basis of our Clean Energy Plan (CEP) and detail our path to compliance with HB 2021 emissions targets.

Chapter highlights

- To meet our emissions targets, we have identified a significant need to procure non-emitting resources and capacity to keep pace with new customer demands.
- Achieving emissions targets reliably and affordably requires systematically replacing fossil fuel generation and purchases with non-emitting energy and capacity resources.
- Transmission is a significant factor impacting the economics and timing of resource additions to meet HB 2021 targets. Transmission solutions are integral to meeting our targets.
- Significant transmission constraints will drive a greater role for customer-sited resources such as demand response (DR), energy efficiency (EE), distributed solar/storage and community-based renewable energy (CBRE) resources, highlighting the importance of PGE's efforts to improve our utilization of these resources through a virtual power plant (VPP).

[1] House Bill (HB) 2021 codified as ORS 469A.400 to 469A.475, effective 09/25/2021.

- 2030 emissions targets can be met by technologies and resources that are currently known and commercially available.
- Decarbonization pathways to 2040 will require further technological advancement of non-emitting resources and transmission to meet the region's energy and capacity needs.

At PGE, we are privileged to serve Oregon communities with an essential service foundational to the well-being and vitality of society. Our responsibilities are significant, and we are continuously evolving our ambitions and best practices to advance social equity and environmental sustainability in the communities we serve. We are firmly committed to a future in which all Oregonians can thrive.

We have supported Oregon communities with reliable, affordable and safe power for over 130 years. While many things have changed over that time, our core responsibility to power Oregon homes and businesses has not. It has become increasingly apparent that climate change poses significant risks to the power sector across all regions of the country. Extreme weather and natural disasters threaten utility infrastructure, contribute to energy market volatility and render the balancing of energy supply and demand more challenging. At PGE, we have witnessed the impacts of climate change first-hand in the form of record-breaking winter and summer energy peaks, damaging and disruptive storms, and wildfire risk.

Importantly, climate change threatens the health and well-being of the communities we serve, and our most vulnerable communities, including Black, Indigenous and People of Color (BIPOC) and communities experiencing economic hardship, are often the most negatively impacted. As the state's largest electricity provider, we have a unique responsibility to address the challenges of climate change head-on and lead the transition to cleaner, non-emitting sources of energy. Integral to this work is our commitment to diversity, equity and inclusion and to supporting everyone's opportunity to participate in and benefit from a clean and reliable energy future.

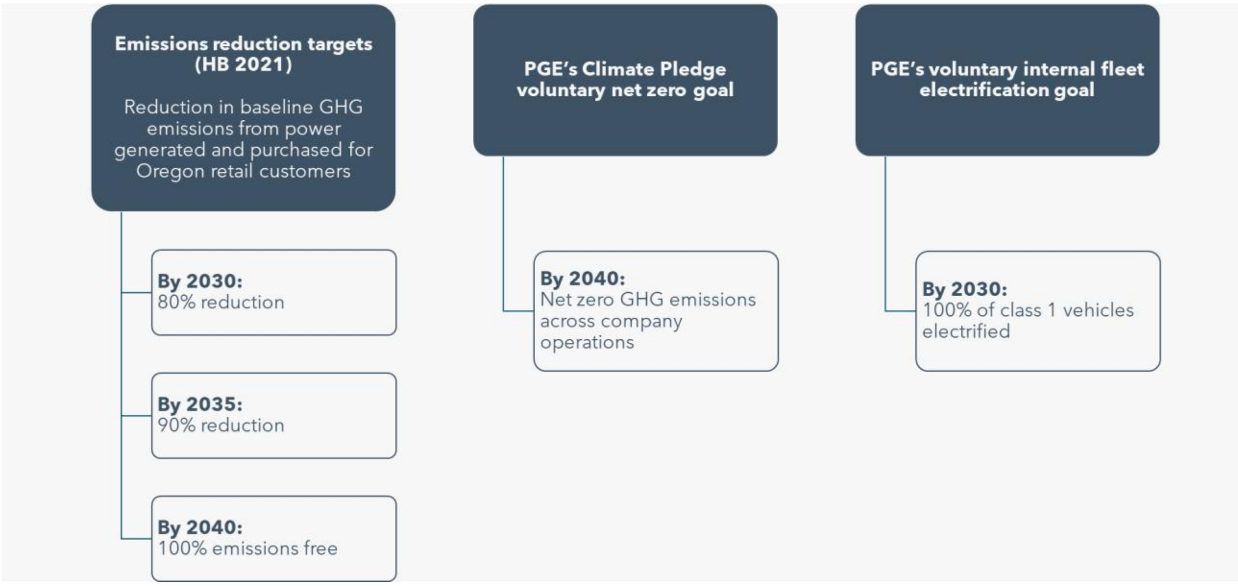
Our commitment to equity is important across all areas of our business, but especially as we acknowledge the disproportionate impacts of climate change on vulnerable communities. We seek to decarbonize our system in ways that can benefit traditionally underserved communities across our service territory. In **Chapter 7, Community benefits indicators and community-based renewable energy**, we describe our efforts to apply an equity lens to our resource and decarbonization planning. In **Chapter 14, Community equity lens** we describe our efforts throughout our planning process to create an inclusive process in which all the diverse communities we serve can participate and be heard.

We also seek to ground our resource and decarbonization planning efforts in the best available climate science, including the United Nations Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report and the Oregon Climate Change Research Institute's Sixth Oregon Climate Assessment.[2,3] We see this reflected in climate-related goals that the company has set in recent years (described in **Figure 1**), as well as our detailed disclosures of environmental, social and governance (ESG) metrics and progress in our annual ESG report.[4] We view our responsibility to address climate change as broad, including decarbonizing the power we generate and purchase for customers; reducing emissions associated with other areas of our company's operations, such as our own vehicle fleets and buildings; and preparing our system for, and working with customers to support, their continued electrification of vehicles, homes, buildings and industrial systems.

PGE has been committed to reducing emissions for many years and in 2020 announced its voluntary goal to achieve company-wide net zero carbon emissions by 2040. PGE then became the first US utility to sign The Climate Pledge in 2021, joining what is now more than 385 companies worldwide in committing to net zero emissions by 2040, 10 years ahead of the Paris Accords.[5] Having established these emissions reduction goals, PGE then welcomed the opportunity to collaborate with community groups, policy makers and other stakeholders around the potential for state mandated targets for emissions for power generated and purchased for Oregon retail customers, in what eventually became House Bill 2021 (HB 2021).

[2] United Nations Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report available at: https://www.ipcc.ch/assessment-report/ar6/
[3] Oregon Climate Change Research Institute's Sixth Oregon Climate Assessment available at: https://blogs.oregonstate.edu/occri/oregon-climate-assessments/
[4] PGE's ESG report is available at: https://portlandgeneral.com/about/who-we-are/sustainability
[5] Information about The Climate Pledge is available at: https://www.theclimatepledge.com/us/en

Figure 1. PGE's climate goals and targets



House Bill 2021 sets PGE on a course to providing Oregon retail customers with energy from generation and power purchases that is 100 percent GHG emissions-free by 2040, with important emissions milestones required along the way.[6] As described in **Chapter 14, Community equity lens**, **Chapter 13, Resilience**, and **Chapter 7, Community benefits indicators and community-based renewable energy**, HB 2021 also requires PGE to meaningfully include equity, resilience and CBRE resources as part of its decarbonization efforts, and to begin to evolve its resource planning approach to include a broader range of community benefits. The inclusion of community benefits marks a change in how utilities like PGE evaluate resources and other system investments to serve customers. We have taken some important initial steps in this combined filing of our CEP and IRP to identify community benefits indicators and adapt our IRP methods to begin including them. We look forward to future improvements as we continue our engagement with communities.

Filing this inaugural CEP with our 2023 IRP is an important first step in charting a course to achieving emissions targets in 2030, 2035 and 2040 that balances affordability and reliability for customers. Our utility has learned much in this process, and we will continue to learn more and adapt our strategies as the market, technologies and the needs of customers continuously evolve. As described in the following sections, the path to the 2030 emissions target is predicated on technologies and resources that are currently known and commercially feasible and available. But as we look beyond the initial 2030 target, there are still important unknowns regarding technology, resource economics and regulation.

[6] ORS 469A.405.

But this is what we do know. Our ability to serve load in the future will hinge on our ability to plan for and procure the best combination of resources that balances costs and risks for customers to meet our emissions targets safely and reliably. Decarbonizing our power supply will require resource acquisition and integration at a pace and scale unprecedented in our utility's history. It will require changes in how we procure resources for our system, how we operate our system, how we participate in energy markets, how we collaborate with other regional energy players, and ultimately, how we provide exceptional electricity service to customers. These changes will be informed by science, market research, rigorous modeling, data analytics, guidance from our regulators and policy makers, and importantly, from robust engagement with customers and communities.

Decarbonizing our system will require significant new investment in energy resources and distribution and transmission infrastructure to prepare for the smart, clean energy grid of the future. Our commitment to energy access and affordability is more important now than ever before. Customers already rely on us for their essential electricity needs. As we look to the future, customers will rely on us further as they electrify their vehicles, homes and businesses. Affordability drives us to continuously innovate, deploy new technologies, launch new programs, simplify processes and reduce costs while delivering exceptional customer experiences.

We will continue to actively manage costs for customers as we transition to an energy mix that meets our emissions targets. This includes careful and inclusive planning through our Clean Energy Plan, Integrated Resource Plan and Distribution System Plan processes, competitive procurement through our Requests for Proposals (RFPs) for resources, and our continuous efforts to improve operational efficiency, safety, system and equipment reliability. We are also actively pursuing federal and state grant funding opportunities to offset investment costs and support key decarbonization initiatives on behalf of customers, including infrastructure upgrades. We are also supporting efforts to connect customers with the unprecedented federal tax incentives and rebates available, ranging from electric vehicles to heat pumps to rooftop solar.

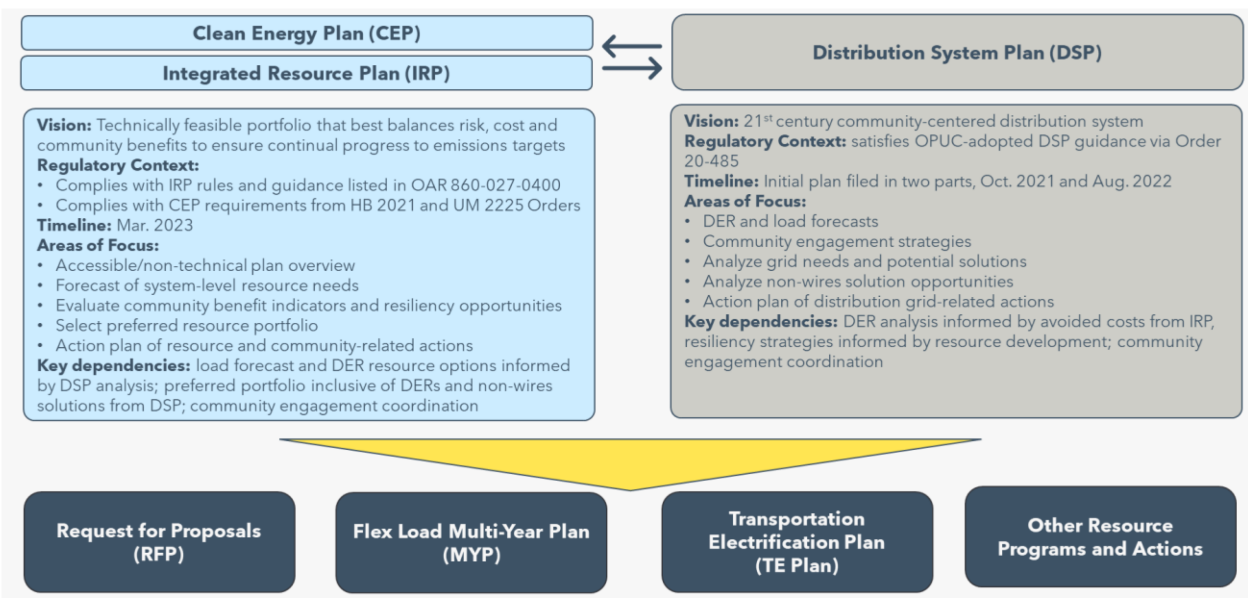
We remain committed to supporting customers with the tools to manage their own energy costs. This includes expanding systems that give customers insights into their energy use and supporting customers in paying their electricity bills through access to federal and state energy assistance programs, and PGE's Income Qualified Bill Discount (IQBD) Program. At the close of 2022, there were more than 47,000 households enrolled in PGE's IQBD program. We also recognize that managing costs also involves addressing societal barriers that make it harder for people to access energy savings, clean energy and energy assistance and collaborating with community groups to support state and federal legislation that helps low-income and vulnerable communities meet their energy needs.

1.1 Aligned planning

The combined filing of the CEP and IRP is the cornerstone of PGE's vision for a balanced, comprehensive, collaborative and streamlined planning process to achieve emission targets. It is situated within an evolving utility regulatory planning landscape where connectivity and alignment across planning strategies are increasingly complex and necessary, sharing our journey toward decarbonization clearly and concisely. As a result, it connects the dots for our regulators, policymakers, customers, stakeholders and communities between multiple planning requirements.

The combined plans are informed by data and outputs from other planning processes; references are provided throughout the plan accordingly. Notably, load and distributed energy resource (DER) adoption forecasts and hosting capacity analysis from the Distribution System Plan (DSP) inform IRP analysis of system needs and preferred resource options. The CEP and IRP Action Plan then provides the need and key inputs for successive planning activities presented through RFP materials, the Flexible Load Multi-Year Plan (MYP) and Transportation Electrification (TE) Plan, as depicted in **Figure 2**.

Figure 2. Coordination between planning activities [7] [8]



[7] OAR 860-027-0400, available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=221555.

[8] See *In the Matter of Public Utility Commission of Oregon, Consideration for Adoption Staff Proposed Guidelines for Distribution System Planning*, Docket No. UM 2005, Order 20-485 (Dec 23, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

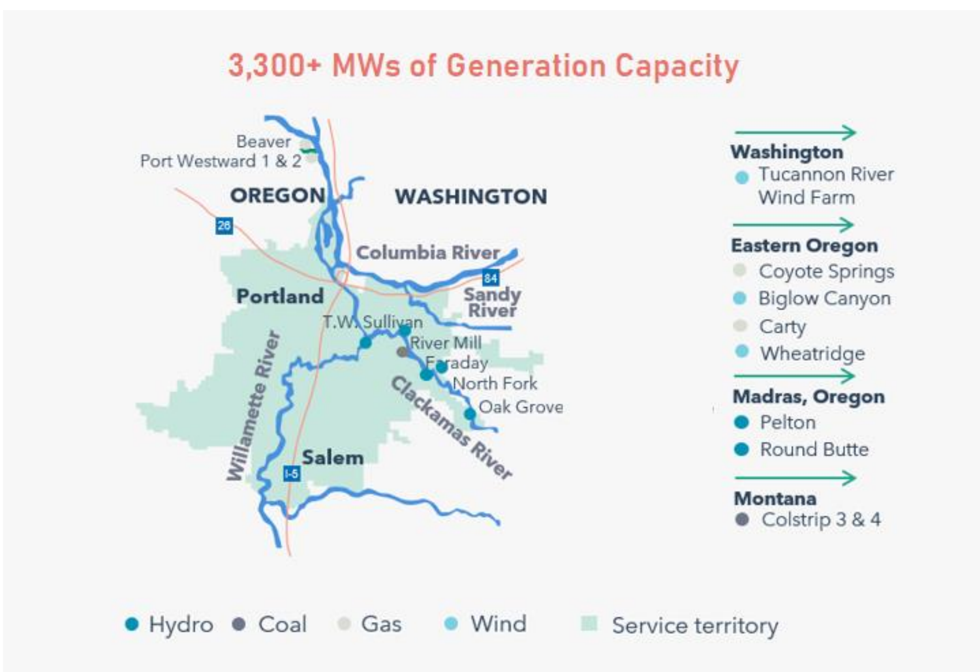
PGE also has sought to promote alignment of engagement processes, as discussed in **Chapter 14, Community equity lens**. Coordinated engagement strategies between the CEP, IRP, DSP and other venues seek to reduce workload wherever possible. Going forward, these engagement activities will also seek to align with new processes related to PGE's Community Benefits and Impacts Advisory Group (CBIAG). The result of these proceedings must meaningfully reflect stakeholder and community input.

This new landscape requires thoughtful and ongoing discussion. For example, there are still many outstanding questions on how CEP guidance will impact existing DSP guidelines and inform resource acquisition actions and proactive investments in the distribution system to accelerate decarbonization as envisioned in HB 2021. We look forward to working with the Public Utility Commission of Oregon (OPUC or the Commission), stakeholders and community members to further develop and refine the DSP guidelines.

1.2 Historical emissions trends and resource mix

PGE is a vertically integrated electric utility encompassing generation, transmission and distribution. PGE is Oregon's largest electricity provider, serving over 900,000 retail customers within a service area of 1.9 million residents. Roughly half of Oregon's population lives within PGE's service area, encompassing 51 incorporated cities entirely within the State of Oregon. Seventy-five percent of Oregon's commercial and industrial activity occurs in PGE service area.

Figure 3. PGE's service area and generation capacity



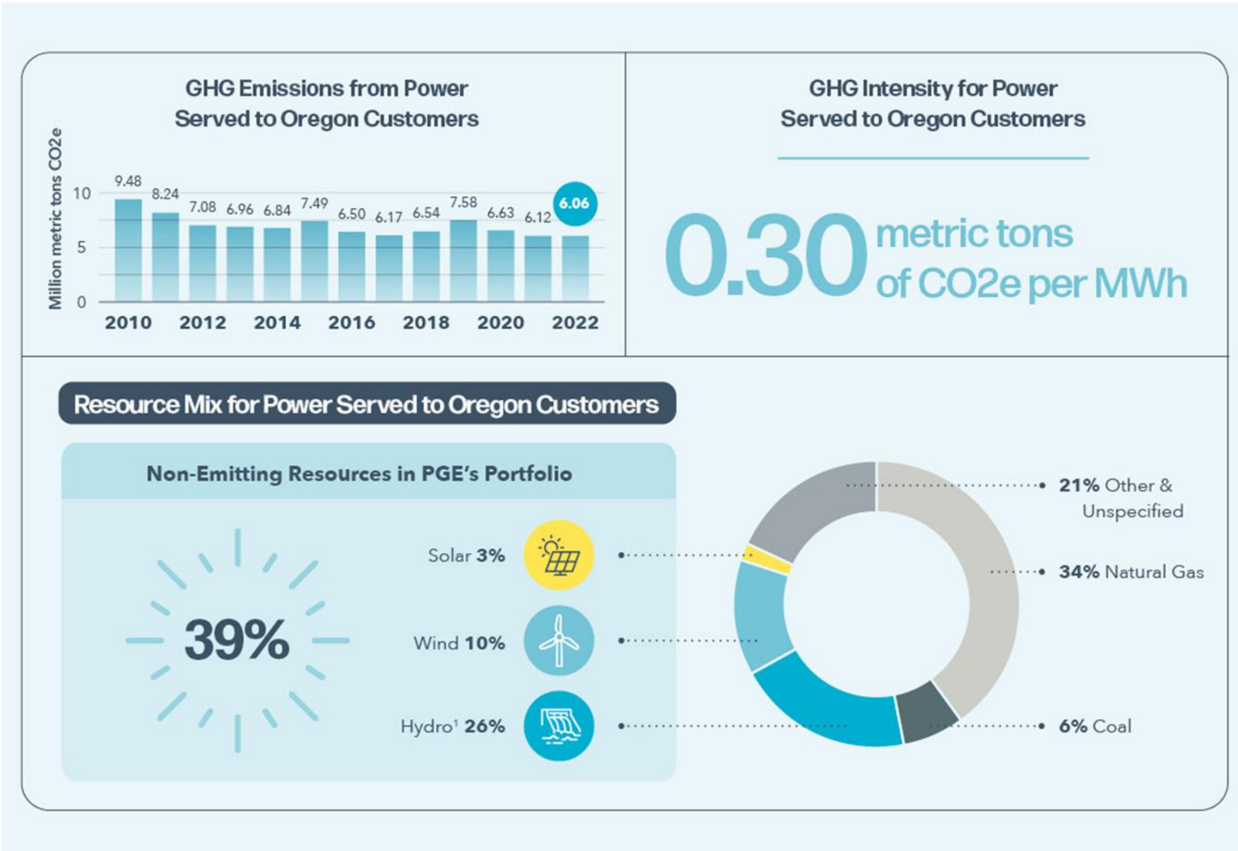
PGE's system includes more than 3,300 megawatts (MW) of generation capacity (**Figure 3**), including hydro, wind, solar, natural gas and coal. The remaining coal in our system stems from our ownership share of units 3 and 4 of the Colstrip plant in Montana. PGE also owns and operates five thermal generating units: Beaver, Power Westward Units 1 & 2, Coyote Springs and Carty, and its Westside hydro complex, including the Faraday, North Fork, Oak Grove and River Mill dams on the Clackamas, and the T.W. Sullivan dam on the Willamette. PGE also co-owns and operates the Pelton-Round Butte hydro complex in Madras with the Confederate Tribes of the Warm Springs. PGE's wind facilities include Biglow, Tucannon River and Wheatridge.

In addition to generation, PGE also purchases power to serve customers. Those purchases take a variety of forms and may include bilateral contracts (both short- and long-term) and market purchases. The GHG content associated with these market purchases is either specified (from a known source per contract) or unspecified (generation type not specified in a contract). PGE also sells surplus power to the market or to other energy suppliers in the region. Power sales can help offset power costs for customers.

PGE reports emissions from power generation and power purchased to Oregon Department of Environmental Quality (ODEQ) annually as required by OAR 340-215-0120.[9] **Chapter 5, GHG emissions forecasting**, provides a thorough overview of our emissions reporting requirements, especially as it pertains to HB 2021 compliance. In this section, **Figure 4** provides a snapshot of PGE's retail GHG emissions trends and resource mix.

[9] OAR 340-215-0120, available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=269300.

Figure 4. PGE emissions at a glance[10]



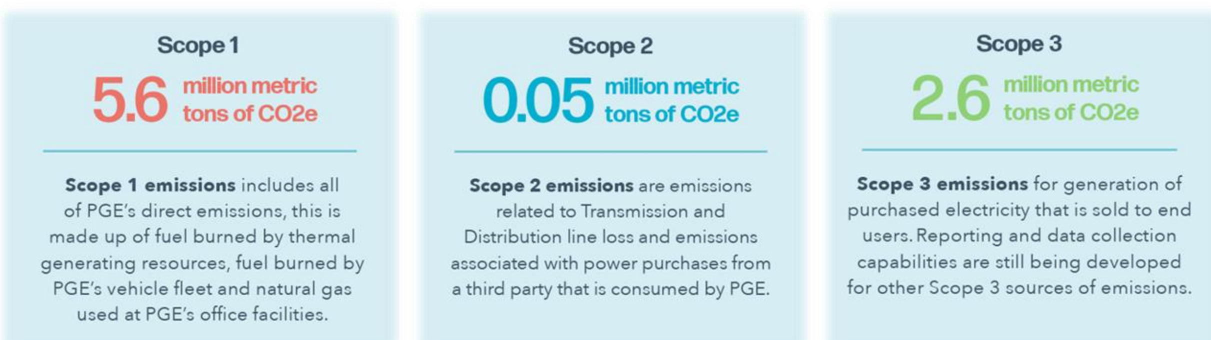
PGE is reporting 6.06 million metric tons of emissions from power generation and purchased power to service Oregon retail load in 2022. This reporting continues a downward trend in reported emissions since 2010. There will always be year-to-year variations in emissions reported due to changes in economic factors that affect load or changes in weather that affect hydro conditions, renewable capacity and peak energy needs, that are increasingly hard to forecast. It is also instructive to look at PGE's GHG emissions intensity, measured in emissions of carbon dioxide equivalent (CO2e) per megawatt hour (MWh), to show how PGE is meeting load growth in its service territory with lower emitting resources. PGE's GHG intensity has also been consistently declining in recent years, from 0.41 MT/MWh in 2019 to 0.30 MT/MWh in 2022. By 2040, PGE's GHG intensity for power associated with Oregon retail customers effectively will need to fall to zero to meet HB 2021 requirements.

[10] Figures in the graphic above are preliminary and based on energy served to retail customers within the State of Oregon, as required by the Oregon Department of Environmental Quality (ODEQ). Some or all of the renewable energy attributes associated with PGE's Basic Service Mix may be sold, claimed or not acquired. The 26% Hydro amount includes power purchased from Bonneville Power Administration. The 21% Other & Unspecified contains purchased power for which a specific generating resource is not defined and could be any of the generation types (e.g., wind, hydro, gas).

PGE lowers its reported emissions and emissions intensity by changing the portfolio of generated and purchased resources to meet Oregon retail load. In 2022, 39 percent of the power generated and purchased for Oregon retail customers came from specified non-emitting resources, primarily hydro, wind and solar. The percentage of power that was unspecified was 21 percent in 2022 and stems primarily from short-term market purchases. It is reasonable to conclude that a portion of those unspecified market purchases also came from non-emitting resources, given the surplus of solar exported from California during key intervals of the day. But because the underlying generating source is unknown for many short-term market purchases, including those occurring through the Energy Imbalance Market (EIM), ODEQ rules require PGE to assign a positive emission factor to unspecified resources, as compared to non-emitting resources which have an emissions factor of zero. PGE is committed to working with regional organizations to improve emissions tracking and accounting across Western markets to provide better visibility into the GHG content of market power.

PGE also discloses GHG emissions as part of its annual ESG reporting. In our ESG report, we disclose emissions associated with Oregon retail load, based on ODEQ methodology. We also disclose a different view on PGE's emissions using the categories of Scope 1, 2 and 3 emissions from the GHG Corporate Protocol, displayed in **Figure 5**.[11] That approach provides a wider lens on PGE's emissions than just those associated with power associated with retail customers and includes emissions associated with other areas of our operations, including wholesale operations, fleets and our buildings and facilities.

Figure 5. Scope 1, 2 & 3 emissions



The emissions regulated by HB 2021 do not directly correlate with the company's Scope 1, 2 or 3 emissions. HB 2021 applies to emissions associated with megawatts of generation and purchases for Oregon retail load. Scope 1 includes emissions from all fuels burned by thermal generating resources, whether for retail or wholesale customers, as well as fuels burned by our fleets and buildings. Power purchases for retail load are included in Scope 3.

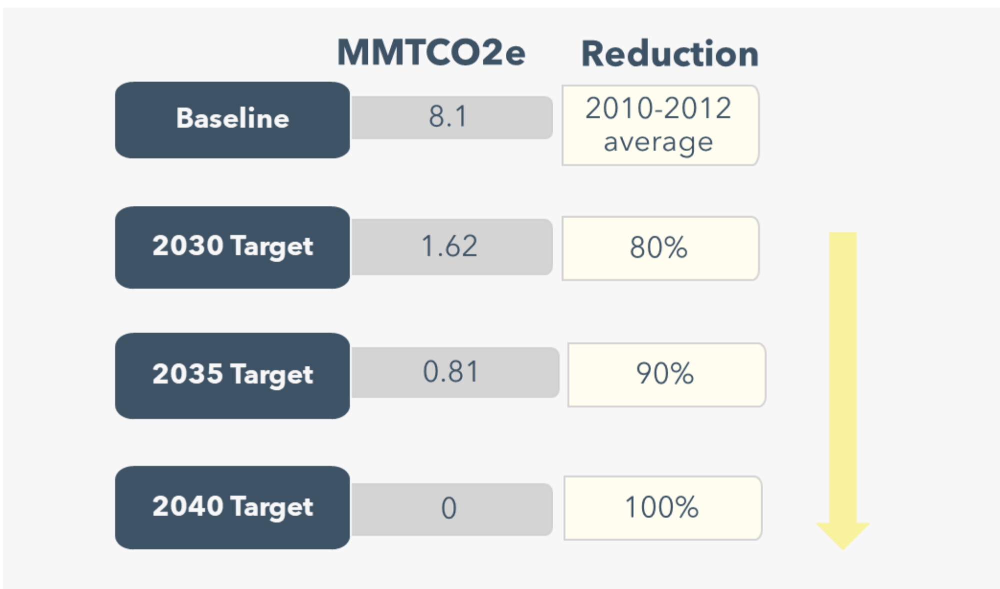
[11] Additional information about the GHG Corporate Protocol is available at: https://ghgprotocol.org/corporate-standard.

HB 2021 only applies to a segment of our Scope 1 and 3 emissions; however, emissions associated with power generation and purchases comprise the largest portion of the company's reported emissions, accounting for 99 percent of reported Scope 1, 2 and 3 emissions. We include data on Scope 1, 2 and 3 emissions in this CEP to provide greater transparency into PGE's corporate emissions footprint.

1.2.1 HB 2021 requirements

House Bill 2021 requires PGE to reduce emissions associated with electricity sold to Oregon retail customers, with specific targets PGE must achieve on a path to 100 percent non-emitting energy by 2040. HB 2021 is a technology-neutral requirement and compliance is determined by reporting absolute emissions to ODEQ at or below target levels by 2030, 2035 and 2040.[12] Targets are determined as percentage reductions from a 2010-2012 average baseline, as specified by ODEQ. A summary of PGE's HB 2021 targets is included in **Figure 6**.

Figure 6. HB 2021 emission targets for PGE



1.3 Recent milestones in efforts to decarbonize

PGE has already taken significant steps to decarbonize its system in recent years. PGE's emissions in 2022 are already 25 percent below HB 2021's 2010-2012 average baseline level

[12] ORS 469A.410

of emissions. While additional steps, as described in this chapter, are necessary to achieve the emissions targets in 2030 and beyond, we summarize some recent milestones in our efforts to build a non-emitting resource portfolio.

All-Source RFP: In 2021, we issued an All-Source RFP for non-emitting energy and capacity resources to meet customers' energy needs. Projects that included various combinations of wind, solar, battery storage, as well as pumped storage, were evaluated throughout 2022. PGE is seeking generation resources to provide up to 250-megawatt average (MWa) of non-emitting energy and 388 MW of non-emitting capacity in this RFP. The ultimate outcome is anticipated to result in the selection of multiple projects for both renewable and capacity resources.

Clearwater Wind Project: As part of the 2021 RFP, PGE and NextEra Energy Resources, LLC., have entered into agreements to construct a 311 MW wind energy facility, which will be part of the larger Clearwater Wind development in Eastern Montana. PGE will own 208 MW of generation, with another 103 MW of output purchased through power purchase agreements. The project has an estimated commercial operation date of December 31, 2023. Located approximately 65 miles northeast of the Colstrip Generating Station, the wind farm will span Rosebud, Garfield and Custer counties in Montana.

Wheatridge Renewable Energy Facility: The Wheatridge Renewable Energy Facility is the first development of its scale in North America to co-locate wind and solar generation with battery storage. Wheatridge includes a 300-megawatt wind farm, a 50-megawatt solar facility and a 30-megawatt battery storage system, which came fully online spring of 2022. PGE partnered with NextEra Energy Resources to develop the facility. Wheatridge is in Morrow County, Oregon, the same county where PGE recently decommissioned Oregon's only coal plant in Boardman.

Boardman Closure and Decommissioning: In 2020, PGE ceased operations at Oregon's last coal-fired plant. We are now in the process of sustainably decommissioning the facility. This includes seeding 100 acres of former coal yard and other previously developed areas with native plants; salvaging and/or repurposing all parts of the plant where feasible—including rail cars, vehicles, equipment and scrap metal —to avoid waste; and turning concrete from the plant buildings into gravel or fill material at the site.

Faraday Powerhouse: PGE recently completed the rebuild of the 100-year-old Faraday dam. This is an important asset in our non-emitting portfolio that is now back in service to customers. Investment in the upkeep and maintenance of our existing portfolio is essential to meeting our decarbonization targets reliably and affordably.

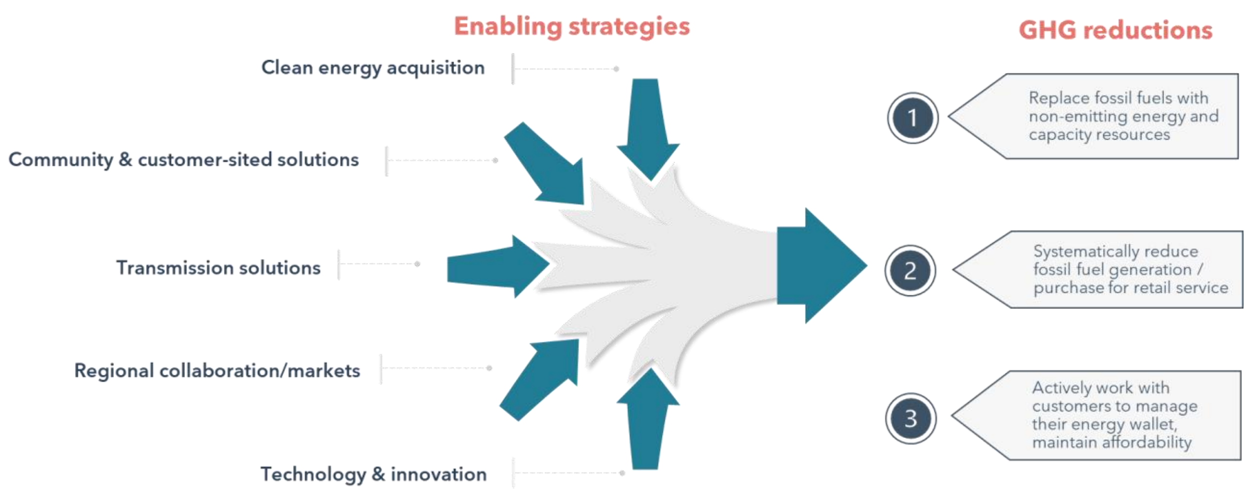
1.4 Strategies to decarbonize

Our decarbonization planning centers on customers' needs as we plan for investments in new resources and the grid that meet our emissions targets in 2030, 2035 and 2040. At the highest level, our approach to reducing emissions involves:

1. Replacing fossil fuel generation and purchases with non-emitting energy and capacity resources.
2. Systematically reducing the generation and purchase of fossil fuels for Oregon retail customers.
3. Actively working with customers to help them manage their energy use and total energy expenditures.

We bolster this approach with key enabling strategies to be able to deliver a reliable, affordable, clean energy supply, displayed in **Figure 7**.

Figure 7. Decarbonization strategies



1.4.1 Clean energy supply

Achieving our GHG targets requires gradually reducing fossil fuel generation and purchases and substituting non-emitting energy and capacity resources. Fossil fuel electric generators can provide much needed dispatchable capacity and reliability to the grid that is harder to replace with renewable energy resources alone. The sun is not always shining, and the wind is not constantly blowing. Batteries can offer energy storage on a finite basis, but prolonged weather events that inhibit wind and solar generation, as exhibited in recent years, can also deplete battery capacity. A reliable grid must be resource adequate, with enough capacity and reserves to maintain balanced energy supply and demand to meet peak energy needs at any time and under all weather conditions. For these reasons, as PGE looks to replace fossil fuel generation and purchases with renewables and storage, it will need geographic and resource diversity.

Identifying the Preferred Portfolio of non-emitting energy resources for PGE's system is the fundamental responsibility of the IRP, developed in later chapters of this filing. The IRP provides critical foundations for our CEP. The IRP estimates our system resource need by forecasting long-term demand growth and comparing it to projected generation from existing and contracted assets. The IRP then models the pathway to fill those resource needs, by evaluating resource options and determining the optimal size and timing of resource additions in different portfolios. The analysis results in a Preferred Portfolio of resources and a detailed Action Plan for the company to follow over the next 2-4 years. That Preferred Portfolio and Action Plan become the basis and rationale for the Company's clean energy procurement, including potential contract renewals and RFPs. This year's IRP optimizes the resource portfolio subject to the GHG emissions constraints introduced by HB 2021 and includes other important modeling innovations related to transmission, resilience and community benefits to reflect the Commission's feedback on our 2019 IRP, new Commission guidelines stemming from Docket UM 2225 and stakeholder and community feedback.[13]

To inform the resource path to 2030 emissions targets, the current IRP examined the following list of resource options that are currently known and at commercial scale in our region:

- On-shore wind: OR Gorge, SE Washington, Montana, Wyoming
- Solar: Central OR, OR Gorge, Willamette Valley, Desert SW
- Battery Storage: Lithium Ion, multiple durations
- Hybrid: Solar + Battery Storage
- Pumped Storage Hydropower
- Distributed energy resources
- Energy Efficiency (EE)
- CBRE (community scale solar, solar + storage microgrids, in-conduit hydro)

Beyond 2030, other non-emitting technologies like hydrogen, nuclear, carbon capture or long duration storage may prove cost-effective for serving customers in our region. These technology options are explored in greater detail in **Chapter 8, Resource options**.

[13] See *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Orders available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23160.

The IRP in **Chapter 6, Resource needs** describes the estimated capacity need in 2030 to be 1136 MW in summer and 1004 MW in winter. It forecasts an energy need of 905 MWa by 2030, which is roughly equivalent to 2,500 MW of non-emitting energy resources, depending on the capacity factors of those resources. This projected resource and capacity need is in addition to the 1,000 MW of non-emitting resources currently being pursued through the 2021 All-Source RFP. This means that by 2030, PGE may need to procure and integrate between 3,000-4,000 MW of non-emitting resources and capacity to meet customers' energy demands and our 2030 emissions target. Policy and market changes could change this estimated need by 2030, but the work in the near term is the same: we need to procure clean energy resources and capacity at an accelerated pace through one or more RFPs to achieve our first emissions target in 2030. To put the challenge in perspective, PGE currently operates 3,300 MW of owned and contracted assets (shown in **Figure 3**). As discussed further in **Chapter 3, Planning environment** and **Chapter 4, Futures and uncertainties**, the procurement of this quantity of non-emitting resources will be complicated by persistent supply chain and labor market challenges, as well as general competition for non-emitting resources against the backstop of a rapidly decarbonizing Western Interconnect (see **Section 4.1, The changing Western Interconnection**).

As clean energy resources and capacity come online between now and 2030, PGE can systematically replace the use of fossil fuel generation and purchases for Oregon retail customers. PGE began this transition from fossil fuels years ago. We closed Oregon's only coal fired plant, Boardman, in 2020, a first of its kind agreement to consider closure as a form of pollution control. We continue to evaluate the timing and conditions of exiting ownership of Colstrip Units 3 and 4 as part of meeting our regulatory and legislative requirements. As we look to the future, we expect to evolve operations of our thermal fleet, which includes some of the highest efficiency natural gas plants in the nation, to provide for reliability during periods of grid stress when clean energy resources are scarce relative to demand and to meet resource adequacy requirements. We will continue to maintain the efficiency and safety of these facilities, making upgrades as necessary for efficiency, safety and air quality.[14] We may also explore the potential to transition thermal generation to cleaner fuels, such as hydrogen, to replace natural gas combustion in those units.

1.4.2 Community and customer-sited solutions

As IRP portfolio analysis demonstrates, achieving targeted emissions levels reliably and affordably will require a diversity of resource options, not only utility-scale wind, solar and

[14] PGE entered into agreement with ODEQ in August 2021, agreeing to reduce permitted emission levels of nitrogen oxides, sulfur dioxide and particulate matter at the Beaver/Port Westward 1 plant. The combined total of permitted emission levels for these three pollutants will be reduced by 85 percent from 2021-2025.

battery resources. DERs, CBREs and a virtual power plant (VPP) to better support the utilization of DERs and CBREs, are important components of our decarbonization strategy, and they will enable customers and communities to play an important and growing role in the transition to a clean energy grid. As our award-winning track record of customer participation in our voluntary renewable energy programs attests, many customers are already choosing clean energy now. We are also proud to serve many municipal, commercial and industrial customers who have publicly established very ambitious sustainability and climate goals. Decarbonizing our power supply facilitates attainment of their clean energy goals. DERs and CBREs, however, are not only resources and programs that many customers want. They are also resources that can help us meet our energy and capacity needs as we decarbonize, especially given transmission limitations for new bulk system resources as described in **Chapter 9, Transmission**.

The grid of the future will be increasingly smart and adaptive, allowing for improved two-way energy transfers, which means customers can save money as we continue to work with them on energy efficiency programs, rooftop solar, battery storage and electric vehicle charging. For example, through our smart grid connected appliance programs, customers can automatically adjust their energy use. Our customer offerings aim to benefit both participating and non-participating customers, support grid reliability and help manage overall power costs.

Programs that help customers reduce their energy usage or incentivize customers to match their energy usage to times when clean resources are most abundant on the grid not only save customers money, but they can also hasten the transition to cleaner energy resources by replacing the need for fossil fuel standby generation. On extreme temperature days, or when unanticipated weather or other events pull generation assets offline, PGE can harness the flexibility of demand response programs and DERs to meet peak energy demand. By 2030, PGE aspires to be able to meet as much as 25 percent of the energy needed on the hottest and coldest days with power coming from customers and DERs.

We anticipate growing our flexible load portfolio, and we are already experiencing significant growth in EVs on our system. There are currently approximately 61,000 electric vehicles registered in Oregon, and the state has aggressive goals of adding 250,000 registered zero emissions vehicles statewide by 2025 and even larger goals by 2030. We continue to collaborate with the Energy Trust of Oregon (ETO) on local, community-driven smart grid technology learning programs, including the Smart Grid Test Bed (SGTB) and Smart Grid Advanced Load Management & Optimized Neighborhoods (SALMON) projects, funded through the Department of Energy. The SGTB collaboration is expected to continue through 2026 and will include a solarize campaign, as well as flexible feeder, smart inverter and battery pilots. The SALMON initiative is expected to continue through mid-2027 and includes the retrofit of approximately 580 buildings in North Portland with technologies such smart thermostats, smart water heaters, solar with smart inverters, storage and managed electric vehicle charging, with a focus on bringing benefits to low-income and environmental justice (EJ) communities within the SGTB.

We offer and continue to build our residential smart battery storage pilot which contributes up to 2.4 MWh of energy to support various grid services. We have been working with municipalities to pair energy storage batteries with rooftop solar and municipal electric vehicle charging. We are also working with transit providers and school systems on bus charging on-route and at the depot. In partnership with Daimler Truck North America, we continue to invest in large truck charging including pairing MW size chargers with co-sited batteries at the Electric Island facility. In 2022, we launched a fleet charging pilot and will look to continue this engagement in 2023.

Weather events, and delays in procurement timelines, including supply chain disruptions, could result in the region experiencing challenges meeting peak customer electricity demand in the next several years, particularly in the summer months. During this transition and when periods of emergency arise, utilities need the flexibility to access all available resources to meet increasingly uncertain peak load demands. Last year, the Commission approved a revision to our tariff to allow the addition of batteries into our Dispatchable Standby Generation (DSG) program. We are working with customers who are installing battery storage to be able to draw upon those batteries at peak times as we have historically done with existing customer-owned emergency generators. While the program is still only a few months old, we already have seven interested customers making up 14 MW of potential power. This is why our DSG program continues to be an essential resource even as we transition to clean electricity and add more non-diesel reserves. Our DSG program consists of 130 MW (as of this filing) of dispatchable contingency reserve in the form of diesel emergency backup generators. We have been experimenting with a new type of renewable diesel sourced from plant waste byproducts called R99 (99 percent renewable diesel) and have already rolled it out to our largest customer with hopes for additional customer adoption in the future.

Energy efficiency is an important component of PGE's decarbonization strategy, as a mechanism to reduce load while helping customers save on their energy bills. As detailed in **Chapter 12, Action Plan**, PGE plans to acquire all cost-effective energy efficiency, which is currently forecast by ETO to be 150 MWa on a cumulative basis through 2028. The Action Plan also calls for PGE to enroll 211 MW summer and 158 MW of winter customer demand response by 2028.[15]

In addition, as per UM 2225 guidelines, the IRP also evaluated CBREs. CBREs, as modeled in the IRP, are smaller scale, less than 20 MW, distribution-connected resources that can provide a wider range of community benefits including resiliency and bill savings for customers.

[15] Demand response values include existing programs.

CBREs as described in **Section 7.2, Community-based renewable energy (CBRE)**, could include standalone community-scale solar photovoltaic resources, solar paired with storage microgrids for resilience, and small low-impact hydro opportunities. We have established a target for CBRE acquisition of 155 MW by 2030. The Action Plan calls for 66 MW of CBREs by 2026.

DERs and CBREs, especially when combined as microgrids, can provide timely system capacity support, resiliency for the community and avoid disruptions to customer service. To ensure that these resources can contribute both the energy and capacity we need, we are investing in improved DER utilization through our development of a VPP with capabilities to support our clean energy transition, discussed in greater detail in **Section 8.4, Virtual Power Plant (VPP)**. A VPP is effectively a power plant consisting of DERs and flexible loads, orchestrated through a technology platform to provide grid and power operations services. We anticipate that changes in DER and energy efficiency program design and rate structures will also be necessary to support expansion of these resources in ways that provide grid benefits for all customers and distribute costs fairly.

We are actively planning for and investing in ways to equitably modernize our distribution system, while improving safety, reliability and reducing emissions. Building an equitable clean energy future will require intentional placement of resources like batteries, electric vehicle (EV) chargers and solar panels throughout Oregon communities. To plan for the smart grid and make its benefits available to all PGE customers, we collaborated with community-based organizations and stakeholders on Part I and II of our DSP, filed at the OPUC.[16] Our DSP is an integral step toward creating a 21st-century community-centric distribution system that can support decarbonization.

1.4.3 Technology and innovation

As we look to the future and our target to reduce emissions by 100 percent by 2040, we are embracing innovation and preparing to adopt and scale cost-effective clean energy technologies to benefit customers. A 100 percent emissions-free grid will require infrastructure upgrades and new resources, storage and grid technologies to maintain resource adequacy and affordability for customers. As discussed in **Chapter 2, Accessing support for energy transition**, passage of the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA), as well as ongoing efforts at the federal and state levels to streamline the siting of new energy resources, can accelerate the expansion of non-emitting resources across the West, including longer duration batteries, pumped storage, floating offshore wind, nuclear and hydrogen technologies. We are working with Federal and State

[16] PGE's DSP available at: Distribution System Planning | PGE (portlandgeneral.com).

governments, Tribes, peer investor-owned utilities and other technology experts to drive innovation and leverage available incentives (IRA and IIJA) to accelerate the development and ultimately reduce the cost of these new technologies, as well as micro-grids, advanced artificial intelligence (AI), grid edge autonomous operations, communications systems, and infrastructure upgrades and system hardening including transmission, distribution and hydro generation.

Our Integrated Operations Center (IOC), which finished its first full year of operations in 2022, is fulfilling its role as the nerve center for an increasingly complex and intelligent energy network. It integrates grid-connected assets and devices, whether consumer, utility or third-party owned — while coordinating and optimizing the flow of energy and information across the system.

As previously discussed, we are expanding our VPP capabilities to support our clean energy resource and capacity needs by leveraging customers' participation in demand response, solar, battery storage, electric vehicles and distributed energy generation programs. We discuss the VPP in greater detail in **Section 8.4, Virtual Power Plant (VPP)**. The new capabilities of our IOC and other smart grid investments provide the data, system visibility and insights to optimize resources under constantly changing conditions. More importantly, these advancements help accelerate customers' clean energy transformation by leveraging the scale and diversity of West-wide generation and transmission.

1.4.4 Regional solutions to resource adequacy: markets, partnerships and transmission

To achieve GHG targets, PGE will need access to a wider geographic area to source and site resources and a broader technological diversity of resources. That is why PGE is collaborating in innovative new ways across the Western Interconnection. From participation in the expansion of regional markets to coordination on resource adequacy to transmission planning, PGE, like other utilities across the West, is working across the energy system in the West to deliver better value and enhanced reliability as we and the region decarbonize.

This regional expansion is occurring against the backdrop of a rapidly evolving power system landscape across the Western Interconnection, as discussed in **Chapter 4, Futures and uncertainties**. In 2018, no Western states had policies mandating 100 percent clean or a non-emitting power system. Today, Oregon, Washington, California, Nevada, Arizona, New Mexico, Colorado and Idaho have state regulations and/or utility-specific goals requiring 100 percent clean or non-emitting power (shown in **Figure 17**). These policies will likely accelerate the transition from coal and natural gas fired generation to wind, solar, storage and other non-emitting resources. This rapid decarbonization will increase pressure on suitable locations for siting new resources, as well as on the transmission infrastructure required to deliver that power to load. These policies also highlight the need for regional coordination of planning to mitigate situations of utilities becoming energy-long or risking curtailment due to economics or lack of transmission.

Renewable penetration and retirement of fossil fuel plants require higher volumes of dispatchable power and capacity requirements. As a result, resource adequacy challenges have occurred in recent years in the Western Interconnection. In California, the California Independent System Operator (CAISO) system was forced to implement rotating power outages in August 2020 and issued a Stage 3 emergency alert in September 2022 due to an unprecedented extended heat wave. Prior to 2020, CAISO had not issued a Stage 3 alert since the 2001 energy crisis. Due to reliability concerns, California has created an electric reliability reserve fund and extended the life of the Diablo Canyon nuclear power plant for grid reliability purposes.

Climate change has ushered in new climatic patterns such that historical data cannot inform future summer and winter energy peaks as reliably. Weather events with 1-in-100-year frequency are occurring more regularly. Customer energy usage is also evolving in response. For example, the June 2021 heat dome event in Oregon led to a significant uptick in the number of air conditioners in residences. But recent data also suggest that not only do more customers have access to air conditioning, but they may be using air conditioners differently, running it more consistently over multiple days. At the same time, public policy across the West is encouraging and/or mandating building and vehicle electrification as discussed in **Chapter 3, Planning environment**, bringing new loads to the Western Interconnection. Our region is also experiencing significant load growth from data centers, crypto operations and the expansion of other energy-intensive industries like semiconductor manufacturing.

When resource adequacy challenges occur, they have implications across the Western Interconnect. For example, during the September 2022 heat event in California, generation assets across the Western Interconnect were operating at capacity to avoid power outages. PGE's generating assets play an important role in supplementing regional resource adequacy. At the same time, generating assets across the Western Interconnect contribute to the reliability and resource adequacy of our system. For this reason, in December 2022, we announced our intent to participate in the Western Resource Adequacy Program (WRAP) through the Western Power Pool (WPP), a proactive step to protect the reliability of the power supply for customers while we actively transition to non-emitting resources, as discussed further in **Chapter 3, Planning environment**. This is a critical step in our strategy to decarbonize.

So too is PGE's continued participation in the Western EIM, a west-wide real-time energy trading market in partnership with the California System Operator (CAISO) that has lowered power costs significantly for customers over five years. PGE is actively engaged with regional market expansion activities that would extend the benefits of the EIM to the Energy Day-

Ahead Market (EDAM). Regional energy markets like EIM and EDAM effectively expand our resource footprint, allowing PGE access to a wider diversity of resources as we and other regional utilities decarbonize. Markets deliver cost-savings and reliability benefits by economically dispatching participating utilities' generation assets to balance supply and demand over a wider geographic region. This enables greater renewable penetration and integration across the West while reducing the need for stand-by fossil fuel generation. Markets, therefore, facilitate decarbonization efforts and can lower the overall GHG intensity of power traded across the Western Interconnect.

Market design, however, will need to be carefully considered to account for disparate GHG policies and accounting requirements across Western states. The real-time nature of the market means that energy is dispatched where it is most economically valued at a point in time. When PGE participates in the EIM, or in other short-term market transactions, the power it imports is typically considered "unspecified" according to ODEQ's GHG reporting requirements in OAR 340-215-0020. Since the underlying generating resource is unknown, ODEQ's rules assign a positive emissions rate to those unspecified megawatts to reflect emissions from fossil fuel generating assets operating across the Western Interconnect. This means that PGE's participation in the EIM, and potential future participation in EDAM, will result in reporting GHG emissions from unspecified market purchases to ODEQ. CAISO has begun conversations with participating utilities through workshops and other venues to develop better market rules for tracking and attributing carbon to enhance regional decarbonization efforts and facilitate utility-specific compliance with different state GHG policies and requirements.

Beyond markets, PGE is also pursuing other beneficial regional collaboration opportunities. Our contract with Douglas Public Utility District provided 150 MW of non-emitting hydro capacity, while supporting our partners with our systems operation technology. Finally, our portfolio analysis demonstrates that additional transmission options are needed to access the diversity of non-emitting resources required to reliably meet our emissions targets, given the known constraints to Bonneville Power Administration's (BPA's) transmission system. As discussed in **Chapter 9, Transmission**, and outlined in **Chapter 12, Action Plan**, PGE will continue assessing potential transmission options that provide the best customer value. These policies also highlight the need for regional coordination of planning to mitigate situations of utilities becoming energy-long or risking curtailment due to economics or lack of transmission.

1.5 Pathway to HB 2021 emissions targets

Section 1.2, Historical emissions trends and resource mix, describes PGE's historic and current emissions, resource mix, GHG intensity and our HB 2021 emission targets. In **Section 1.3, Recent milestones in efforts to decarbonize**, we describe some of the significant actions that PGE has already taken to decarbonize. At the close of 2022, PGE had already reduced emissions by 25 percent from the HB 2021 established baseline.

In **Section 1.4, Strategies to decarbonize**, we describe our high-level approach to decarbonize, which involves gradually reducing fossil fuel generation and purchases for Oregon retail customers and replacing it with non-emitting energy resources and capacity, as well as key enabling strategies to facilitate a reliable and affordable transition. We also discussed the important and interrelated role of the CEP and IRP. The IRP estimates PGE's energy and capacity needs subject to HB 2021 emissions constraints. It creates a Preferred Portfolio of resources to meet those needs and details an Action Plan to guide the company's procurement and related resource actions over the next 2-4 years.

One of the CEP's primary objectives is to detail PGE's path to compliance with the HB 2021 targets. It should show that the Preferred Portfolio and Action Plan that PGE has developed in its IRP are consistent with "no-regrets" steps the company should take in the near-term to be able to meet emissions targets in 2030, 2035 and 2040, according to the best methods available at the time. Moreover, it should describe how the company will demonstrate continual progress toward those targets. In this section, we describe how our strategies described in **Section 1.4, Strategies to decarbonize** and the Preferred Portfolio and Action Plan developed in the IRP in subsequent chapters, inform a path to the required emissions targets that balance affordability and reliability for customers. More details on modeling specifics can be found in those chapters and the appendix to this document.

1.5.1 Portfolio analysis and Action Plan

The IRP estimates an energy need of 905 MWa by 2030 and a 2028 capacity need of 624 MW in the summer and 614 MW in the winter. To achieve our emissions target by 2030, all the resources acquired to meet these energy and capacity needs will have to be non-emitting. Integration of these resources onto our system will enable a systematic reduction in fossil fuels serving Oregon retail load and subsequent GHG reductions. As described in **Chapter 11, Portfolio analysis**, IRP portfolio analysis determines the best set of resource types and quantities to meet energy and capacity needs under different scenarios. This informs the creation of the Preferred Portfolio, the company's Action Plan and the path to HB 2021 emissions targets described in this section.

PGE addressed six key questions consistent with HB 2021 compliance in our portfolio analysis. The answer to these questions provides key insights for balancing cost, risk, community benefits and the rate of GHG reduction to achieve HB 2021 targets. Those questions include:

- At what pace should PGE reduce emissions?
- Which resource actions maximize community benefits?

- Will CBREs lower system costs?
- Should PGE pursue energy efficiency and demand response beyond what is planned and cost-effective?
- Is there sufficient transmission available to meet HB 2021 targets?
- Do transmission expansion options allow PGE to meet system needs at the lowest cost?

To answer these and related questions, PGE evaluated 39 different portfolios across seven categories of portfolio options (see **Table 1**). All portfolios meet HB 2021 emissions targets.

Table 1. List of portfolio categories and their purpose

Portfolio categories	Purpose
Transmission	Study the need for transmission, the timing of this need, and the corresponding magnitude needed over time to reliably decarbonize.
CBRE	Explore the relationship between costs, risk and community benefits.
Additional EE and DR	Determine if and how the role of these resources could change with the changing planning environment.
Optimized	Explore the relationship between minimizing costs in the short-term and the entire planning horizon and the cost of constraining the model.
Targeted policy	Inform stakeholder discussions on specific policy questions.
Emerging technology	Understand the potential impacts of emerging technologies.

The insights gleaned from the construction and comparison of these 39 different portfolios informed the creation of PGE's Preferred Portfolio and our balanced path to HB 2021 emissions targets. Specifically, we found that:

- Amongst the five decarbonization glidepath scenarios evaluated, a linear emissions glidepath best balances costs, risks and the rate of GHG reduction. Cumulative emissions reduction would be higher under scenarios that either front-loaded reductions in the early years, or accelerate GHG targets forward in time, but at additional risk and cost to customers. Alternatively, delaying emissions reduction until 2030 lowers estimated costs but incurs risks that PGE will not meet its targets because of procurement delays or supply chain constraints, increased uncertainties in available transmission inventory, and operational risks associated with adding large quantities of resources in a short period.

- Transmission is a very significant factor impacting the economics and timing of resource additions to PGE's system. The need for new on- and off-system transmission options is significant and will be required for PGE to achieve the HB 2021 targets reliably. The reality of these transmission constraints makes additional customer-sited solutions like energy efficiency, demand response and CBREs more competitive in portfolio analysis.
- Given these transmission constraints, selecting 100 percent of the CBRE technical potential (155 MW by 2030) lowers customer costs and risks while maximizing community benefits.
- Pursuing 100 percent of the cost-effective energy efficiency and demand response available minimizes costs and risks for customers. While additional increments of energy efficiency and demand response may lower long-term costs compared to alternative resource options, there are near-term price impacts and additional risk associated with procuring this additional energy efficiency and demand response in the current policy and market environment.

These findings, summarized in **Figure 8**, comprise the rationale for PGE's Preferred Portfolio.

Figure 8. Key findings for the Preferred Portfolio

Key Findings

1. A linear glidepath to meet the 80% reduction in emissions by 2030 best balances cost, risk, and pace of emissions reduction.
2. Adding 100% of the CBRE potential would best balance cost, risk, and community benefits.
3. The magnitude and timing of additional transmission capacity is the largest factor that influences resource additions and the cost and risk metrics of portfolios.
4. It is infeasible for PGE to meet the 2030 HB 2021 targets without any transmission upgrades and the magnitude of transmission need increases throughout the planning horizon.
5. Transmission upgrades to connect to off-system resources can be delayed by investing in resources such as energy efficiency, demand response, and distribution connected CBREs. However, given the magnitude of transmission capacity needed, these resources can only marginally delay the need in early years and cannot offset transmission need in the long-term.
6. Upgrades to PGE transmission that unlock additional access to proxy resources is sufficient to address system needs.
7. Increasing access to new transmission expansion options can help reduce costs, variability risk, and resource needs, which reduce potential risks associated with procurement, stemming from supply chain issues.
8. Emerging non-GHG-emitting technologies that could have a high capacity and/or energy contribution such as nuclear, hydrogen, long-duration storage, and advanced geothermal can mitigate this significant dependence on transmission over the long-term.

PGE built its 2023 Action Plan based on these findings from portfolio analysis and the Preferred Portfolio. The Action Plan, shown in **Figure 9**, is the best set of near-term "no-regret" resource options the company intends to take to reliably build towards HB 2021's emissions targets while minimizing costs.

Figure 9. Action Plan

1. Customer actions

- Acquire all cost-effective energy efficiency (150 MWa cumulative 2024 - 2028)
- Incorporate customer demand response (211 MW summer & 158 MW winter by 2028)

2. Community-Based Renewable Energy (CBRE)

- CBREs are resources that are typically <20 MW that promote climate resilience, community benefits through a community benefits agreement or ownership
- Issue RFP for 66 MW of CBREs by 2026
- Conduct any additional RFPs necessary to achieve target of 155 MW by 2030
- Pursue federal/state incentives

3. Energy actions

- Conduct one or more RFPs for an additional 181 MWa (~520 MW nameplate) of non-emitting resources each year through 2028 (totaling 543 MWa)
- These resources are in addition to the ~1000 MW projected from the 2021 All-source RFP
- Additional renewables needed if energy efficiency, demand response don't materialize
- Successful acquisition of CBREs and/or the renewal of existing contracts can reduce energy need

4. Capacity actions

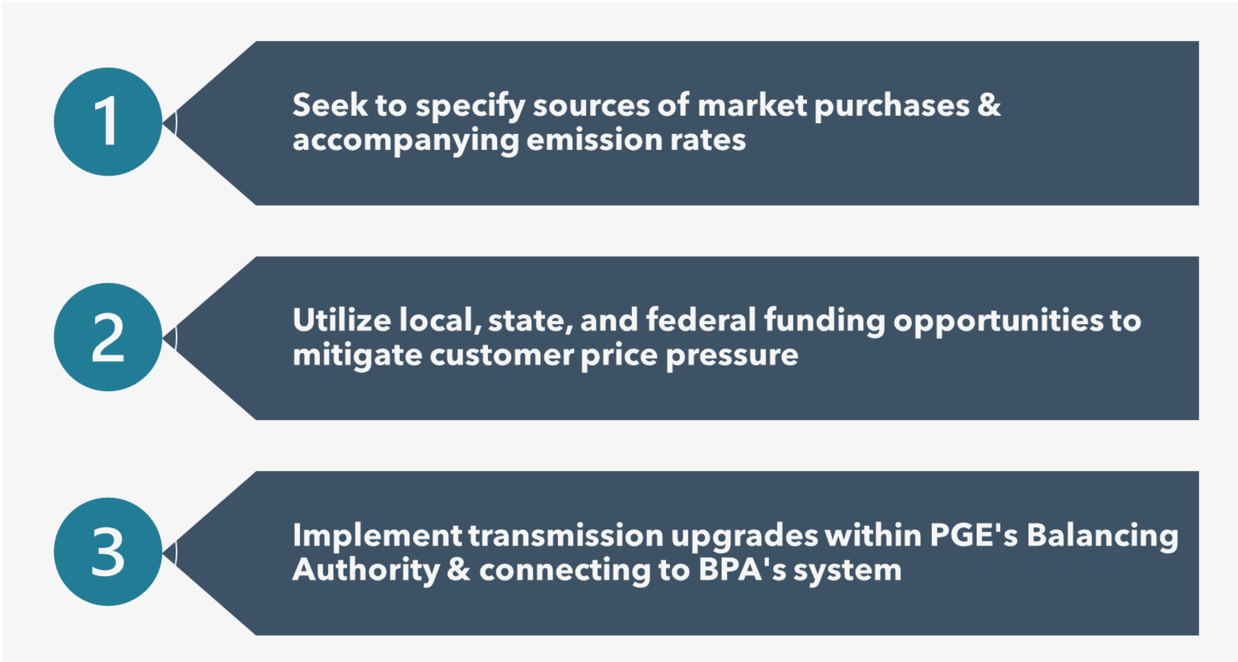
- Significant 2028 capacity need: 624 MW summer, 614 MW winter
- This need is estimated assuming the 400 MW of capacity resources acquired from the 2021 All-source RFP
- Will pursue staged approach: 1. acquire cost-competitive options in the bilateral market; 2. acquire CBREs, EE, and DR; 3. conduct one or more RFPs for remaining need
- Successful acquisition of CBREs and/or the renewal of existing contracts can reduce capacity need

5. Transmission

- Pursue options to alleviate congestion on the South of Alston (SoA) flowgate
- Explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)

In addition to the resources being pursued in the Action Plan, PGE is taking steps to meet resource adequacy and emissions targets at the least possible cost and risk. These additional actions are shown below in **Figure 10**.

Figure 10. Additional steps



1.5.2 Pathway to emissions targets

PGE's Preferred Portfolio represents the best set of incremental resource additions that balance cost and risk for customers while achieving HB 2021 emissions targets. Now we translate that analysis into emissions reductions planned for our system between now and 2030, and from 2030 to 2040.

If PGE is successful in acquiring these resources and taking related resource actions, it will be able to replace fossil fuel generation and purchases with non-emitting alternatives at a pace and scale sufficient to reduce emissions below HB 2021 targeted requirements. For planning purposes, our modeling assumes a linear decline in emissions associated with retail sales between 2026, when incremental IRP resources first become available, and 2030. It then plans a linear decline in emissions from 2030 to the zero emissions target in 2040. Between 2022-2026, emissions on PGE's system are expected to decline due to planned resource actions, including incremental resource additions stemming from the 2021 All-Source RFP.

Though PGE uses a linear glidepath for emissions reduction for planning purposes, PGE will measure annual progress in megawatts of non-emitting resources added to our system rather than in tons of emissions reductions for two reasons. First, emissions reductions are predicated on adding non-emitting resources and capacity to reduce thermal generation and purchases for meeting load and resource adequacy requirements. Second, actual emissions reported to ODEQ between now and 2030 will exhibit year-to year variation, due to factors like weather that impact hydro conditions, renewable capacity and peak loads or other events that the utility could not reasonably forecast or control.

PGE is planning for accelerated procurement through one or more RFPs between now and 2030. We expect annual acquisition and integration of non-emitting resources and have planned for a resulting annual decline in reported emissions, holding weather and other variables constant. However, the realities of market procurement, transmission and system integration may instead lead to step-changes in resources becoming available to PGE customers and resulting emissions reduction between now and 2030. From a planning perspective this is still consistent with our 2030 target. Our work to further develop the VPP to enhance utilization of DERs and CBREs will continue in parallel over this time frame.

Figure 11 details the incremental resource actions by year and annual decline in emissions planned between now and 2030. The incremental resource additions in the Preferred Portfolio are shown in **Table 2**.

Figure 11. Preferred Portfolio resource pathway through 2030

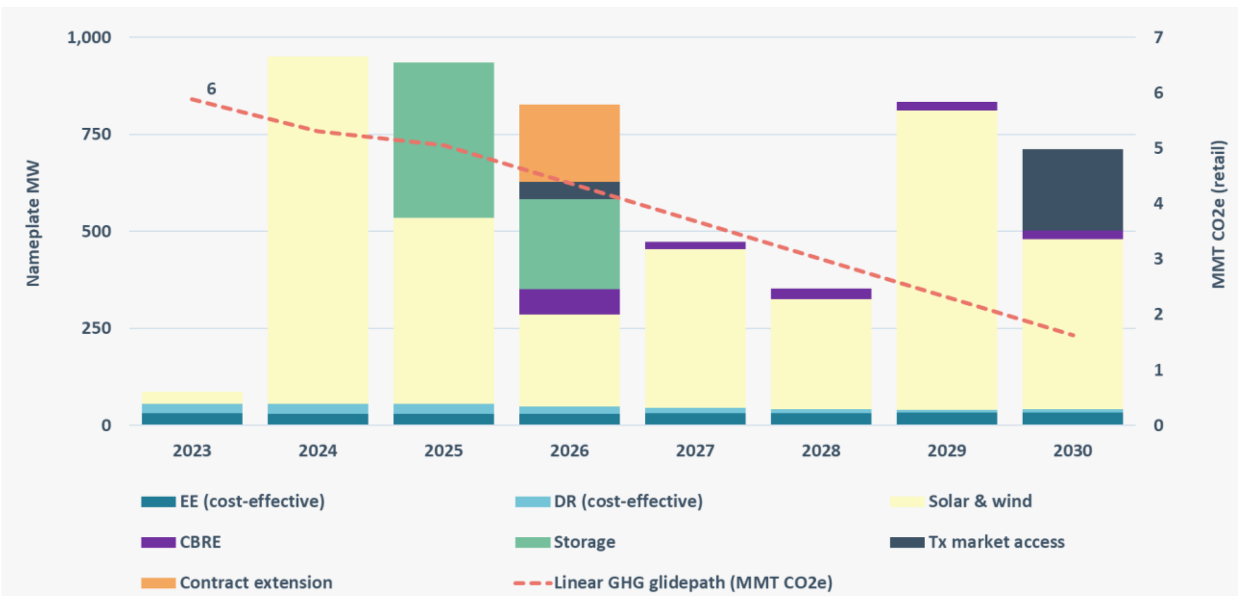


Table 2. Preferred Portfolio resource pathway through 2030[17]

Values in nameplate MW	2023	2024	2025	2026	2027	2028	2029	2030
DR (cost-effective)	24	26	25	19	14	11	8	9
EE (cost-effective)	31	30	30	30	30	31	33	33
Storage	0	0	400	232	0	0	0	0
Solar & wind	31	894	479	237	410	284	770	438
CBRE	0	0	0	66	19	26	23	22
Transmission (Tx) market access	0	0	0	44	0	0	0	211
Contract extension	0	0	0	200	0	0	0	0
GHG glidepath (MMTCO2e)	5.9	5.3	5.0	4.4	3.7	3.0	2.3	1.6

As the table and graph indicate, PGE anticipates being able to meet its 2030 target using resources that are currently known and commercially available. Between now and 2030, PGE's thermal fleet is continuing to economically dispatch, as it does presently, to meet resource adequacy and cost-minimization for PGE's customers and the region. As PGE adds non-emitting energy and capacity resources, it anticipates systematically reducing the amount of thermal output from natural gas and coal for Oregon retail load to meet emissions targets (see **Figure 12**). The market for thermal generation is increasingly constrained across the West, as discussed earlier, with clean energy or GHG requirements in place in almost every state in the Western Interconnect. Thermal generation sold into the Western Interconnect is therefore likely subject to the GHG or clean energy requirements of other states. For example, fossil fuel energy exported to California and Washington incurs direct carbon pricing obligations. Public policies like this, and the massive buildout of non-emitting resources anticipated across the region, lowers economically dispatched thermal output in our forward modeling.

[17] Cost-effective estimates of DR and EE in this table reflect incremental additions in each year

Figure 12. GHG emitting resources for retail load 2023-2030

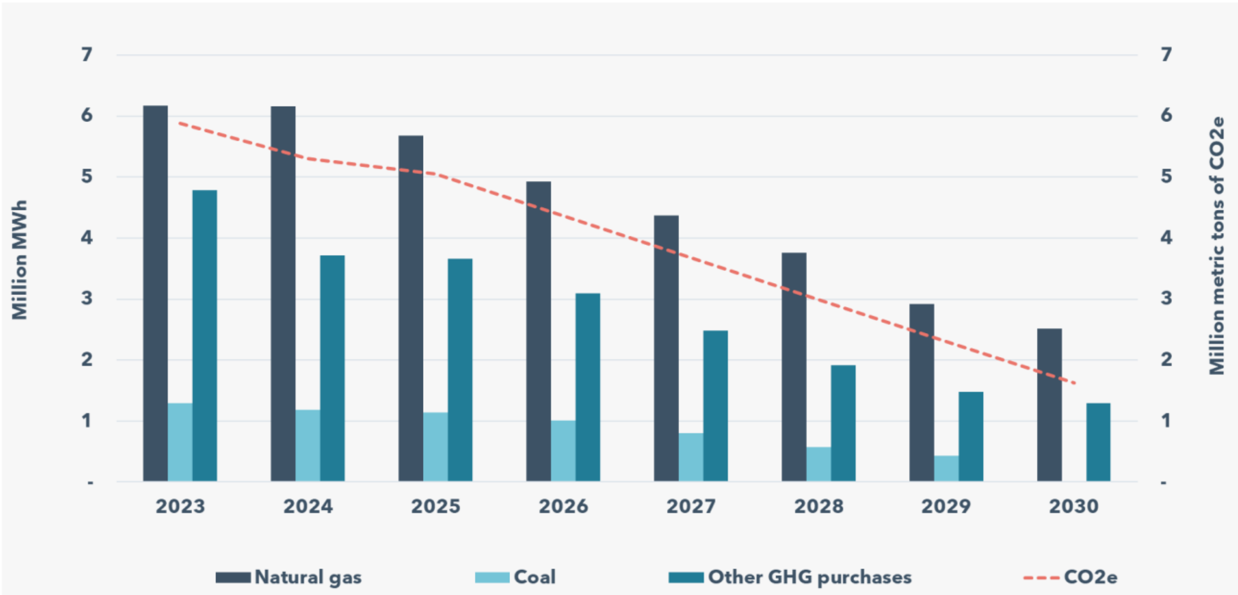


Table 3 and **Figure 13** display the longer-term resource additions in the Preferred Portfolio. As we look beyond 2030 to the 90 percent emissions reduction requirement in 2035 and the zero-emission requirement by 2040, two things become apparent. First, there is a need for additional dispatchable effective non-emitting capacity resources to be developed and available to us in our region to meet resource adequacy needs. The model effectively holds a place for a new non-emitting capacity resource by using two generic resources that provide the necessary capacity and energy for the model to meet reliability needs once transmission-constrained proxy resources have been exhausted, the need for which becomes larger the closer we come to 2040. That resource may be a new resource, currently commercially unavailable, like hydrogen, advanced nuclear or advanced geothermal, or an existing resource that becomes more cost-competitive over time, like longer-duration batteries or pumped storage. Second, part of the effective capacity need leading into 2040 could potentially be offset by existing thermal plants if they are able to transition to non-emitting fuels by 2040. It is possible that if supplies become commercially available sooner, PGE's thermal fleet could combust hydrogen or an alternative low-carbon fuel sooner. Almost all of PGE's existing thermal fleet is capable of combusting a blend of hydrogen or renewable natural gas at present.

Figure 13. Preferred Portfolio resource pathway 2031-2043

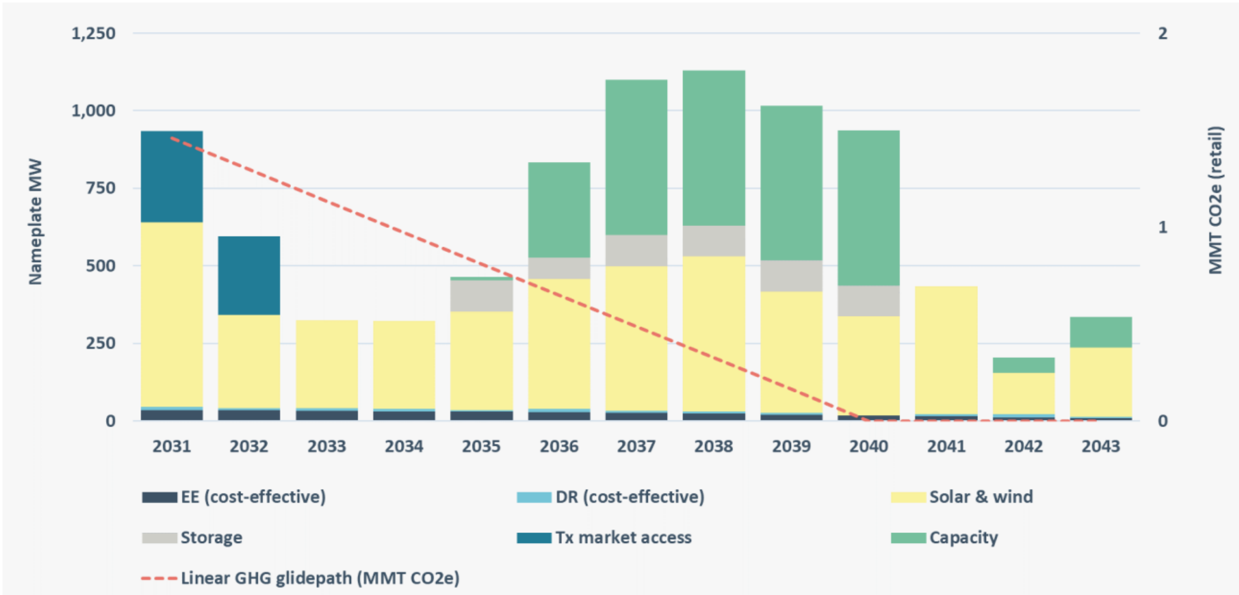


Table 3. Preferred Portfolio resource pathway 2031-2043 (detail)

Values in nameplate MW	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
DR (cost effective)	11	8	9	8	5	11	7	7	7	1	6	11	3
EE (cost effective)	34	34	32	31	29	28	25	23	19	16	15	11	9
Storage	0	0	0	0	100	68	100	100	100	100	0	0	0
Solar & wind	596	301	282	284	319	419	467	500	391	320	414	132	224
Tx market access	293	252	0	0	0	0	0	0	0	0	0	0	0
Capacity	0	0	0	0	13	309	500	500	500	500	0	50	99
GHG glidepath (MMTCO2e)	1.5	1.3	1.1	1.0	0.8	0.6	0.5	0.3	0.2	0.0	0.0	0.0	0.0

1.6 High-level opportunities, potential barriers, critical dependencies

In this section we discuss our compliance path in terms of the opportunities, challenges, critical dependencies and barriers we may confront. Our ability to decarbonize highly depends on acquisition and integration of non-emitting energy and capacity resources. PGE cannot reduce fossil fuel generation and purchases without the energy and capacity to replace it. As we discussed previously, PGE is pursuing different strategies to increase the likelihood that we can replace fossil fuel generation and purchases from emitting and unspecified sources on the timeline we need to meet our emissions targets. We will pursue large, non-emitting supply-side resources and the transmission options necessary to support them; we will continue our work to develop a VPP and deploy energy efficiency and demand response to reduce and actively shape load; we will work with communities to develop CBREs; and we will leverage technology, regional partnerships and markets to access a wider diversity of resources to balance reliability and costs for customers. Changes in the macroeconomy, markets, technology, the regional energy economy, federal and state policy incentives, and customer demands can either facilitate or delay the strategies we have identified. These risks and uncertainties are discussed further in **Chapter 2, Accessing support for energy transition, Chapter 3, Planning environment**, and **Chapter 4, Futures and uncertainties**.

Between now and 2030, there are clear, "low regrets" near-term actions that will be integral contributors to our future decarbonization portfolio regardless of future uncertainties. These are largely the actions articulated in our Action Plan. There is no path to an 80 percent emissions reduction on PGE's system that does not involve a significant buildout of non-emitting energy storage and renewables. This includes DERs, including distribution system connected CBREs, which have the advantage of not requiring additional transmission and provide grid and community benefits, and our efforts to improve utilization of flexible loads, through the VPP. As we look to acquire these resources, we will seek federal support and all of the benefits of federal policy such as the Inflation Reduction Act (IRA) or the Investment Infrastructure and Jobs Act (IIJA) for customers, as discussed in **Chapter 2, Accessing support for energy transition**.

In terms of transmission, we also consider the South of Alston (SoA) line congestion relief and upgrades to the Bethel-Round Butte line as "no-regrets." There is very little time between now and 2030 to acquire and integrate the scale of non-emitting resources necessary to offset fossil fuels, so a strategy that prioritizes moving forward with technologies that are commercially available today is the only plausible pathway to our targets. We will be moving forward on all these strategies simultaneously in an accelerated procurement cycle to support our success. We also anticipate negotiating contract renewals to maintain contracted non-emitting resources in our portfolio. We plan to pursue 100 percent of the demand response and energy efficiency identified as cost-effective and technically available for our system.

In the near-term, the risks of large, negative, long-term consequences for our compliance path relate to anything that delays or prevents our ability to execute on the Action Plan. The risks are real, given supply-chain and labor market challenges that, while improving, still exist as discussed in **Section 3.3, Market, labor and supplier dynamics**. Procurement delays, supply chain constraints, increased uncertainties in available transmission inventory, siting challenges and operational risks associated with adding large quantities of resources in a short period of time can delay our timeline. Any significant change in statutes, rules or guidelines that would require PGE to alter its strategy or restrict optionality in our pursuit of non-emitting resources, could also delay emissions reduction, or threaten reliability and affordability for customers. While demand response, energy efficiency and community-based renewable resources can offset some of the need for new resources, they cannot offset the need for most or avoid the need for new transmission options. These resources are an essential element of a successful outcome, but achieving their technical potential also depends on customer and community interest and participation. In the case of energy efficiency, under the current regulatory paradigm, it currently falls primarily to the ETO to deliver all the cost-effective energy efficiency potential in our service territory. Finally, our success also hinges on our ability to continue strengthening relationships and trust with stakeholders and communities. We will continue to look to stakeholders and communities for feedback on our efforts and be ready to adapt our strategies accordingly.

There will be critical junctures on our path to 2030, 2035 and 2040 emissions targets that may require material changes in our decarbonization pathways. Between now and 2030, PGE will be tracking closely the pace of acquisition of non-emitting energy and capacity. If we cannot maintain reliability or the pace of constant yearly acquisition of resources and capacity, we will need to adjust our approach to overcome delays or adjust timelines accordingly, if the variables causing the delay are beyond our control. At the same time, if new transmission options on- and off-system do not materialize, we will likely not be able to access the diverse resources our system needs to decarbonize and maintain reliability. Transmission is a challenge to both PGE and the region. Successful transmission solutions depend on regional coordination and cooperation, as well as on federal, state or local support for siting transmission resources.

To execute on our long-term plan beyond 2030, we need to see the quantities of non-emitting resources available on the market, and at the lower price points we forecasted for them. New transmission is needed to gain access to off-system resources or we risk the reliability of the system. As we near the 2040 target and an absolute zero emissions requirement, new technologies that can replicate thermal generation dispatchable capacity, such as advanced nuclear, hydrogen or carbon capture and storage will be needed across the region to support decarbonization and resource adequacy.

The critical barriers that need to be addressed to implement PGE's long-term plan are likely similar to those of other utilities across the West who are rapidly decarbonizing. The major barriers are transmission and the need to rapidly develop and scale new non-emitting technologies. Solutions will depend on regional cooperation, coordination and federal policy and financial support; PGE's actions to expand partnerships regionally and continuously innovate new technologies are key near-term strategies toward successful, long-term pathways. To the extent that the Commission can support PGE's participation in these efforts, for example, in our pursuit of federal grant dollars or our participation in expanded regional markets like EDAM, the Commission can play an important role in mitigating barriers.

Over the next 5-10 years, our success will also depend on the Commission, as well as the Federal Energy Regulatory Commission (FERC) and other federal, state, and local regulatory bodies, adapting regulatory processes and mechanisms to meet new needs associated with the rapid transition and new operational reality of a renewables-dominated system. We will need the Commission's support to pursue transmission solutions and alleviate interconnection challenges. We will seek the Commission's support for our expanded deployment of dispatchable resources through our VPP efforts, as well as the development of new customer programs to grow our flexible loads and help customers manage costs. We may ask the Commission to consider changes to current regulatory constructs, such as PCAM (discussed in **Section 3.1.8, Regulatory policy: Power cost adjustment mechanism (PCAM)**) to reflect the reality of operating a system that is soon to be dominated by variable resources or competitive bidding rules. Customer programs and pricing structures designed when clean energy was the exception, rather than the norm, will need to be adjusted to equitably distribute costs and enable us to integrate more of these resources as a core component of our decarbonization strategy.

Chapter 2. Accessing support for energy transition

Portland General Electric's (PGE's) resource and decarbonization planning is occurring against the backdrop of a global transformation from fossil fuels to non-emitting energy resources and storage in the power sector. Technological advancement and public policy are key drivers of this energy transition, with implications for the cost and pace of increased penetration of non-emitting energy resources in the energy supply mix and the rapid onset of electrification and energy storage. To manage costs and enhance reliability for customers during this highly dynamic period of evolution in the energy sector, PGE is actively seeking federal and state incentives and other opportunities. We are also working with organizations across the energy sector to access the latest research and coordinating with state agencies, community-based organizations, utilities, businesses and other actors in Oregon to deliver federal support for Oregon's energy transition. This chapter describes those efforts and the implications for PGE's resource and decarbonization planning.

Chapter highlights

- Federal and state policies are helping to drive rapid decarbonization in ways that impact PGE's resource planning.
- Federal legislation such as the Inflation Reduction Act (IRA) and Infrastructure Investment and Jobs Act (IIJA) that expanded and extended tax credits will facilitate PGE's acquisition of new resources and help manage customer rate impacts.
- We are working across the energy sector to stay abreast of rapid technological and market changes so that customers benefit from the rapid changes occurring across the energy ecosystem.

2.1 Federal support for energy transition

The 117th Congress delivered a comprehensive federal policy response to climate change and an investment package to support broad clean energy, climate and infrastructure investments. This includes enacting programs and funding that would support renewable energy development, clean transportation, energy efficiency, the resiliency of power infrastructure and clean energy research. The passage of the IRA and the IIJA has significant potential impacts on PGE's resource and decarbonization planning with potential benefits for customers.

In **Section 8.1.6, Treatment of tax credits**, we discuss how our Integrated Resource Plan (IRP) analysis incorporates incentives from the IRA and IIJA. At the time of writing this Clean Energy Plan (CEP) and IRP, not every potential channel or program for accessing this transition package is known; billions of dollars in funding from the IRA and IIJA are still making their way to state and local governments, and funding opportunities are still being announced. As these dollars can potentially reduce the costs of the energy transition for customers and render the communities we serve more equitable and resilient, PGE will actively pursue these and other state or local opportunities, often in collaboration with other organizations. PGE has already been successful winning federal Connected Communities funding for our Smart Grid Test Bed.

The implications of new funding opportunities and incentives for our resource and decarbonization strategies are potentially significant and likely include the following:

- Lower costs and accelerated buildout of renewables and stand-alone energy storage due to production and investment tax credits.
- Additional deployment of energy efficiency and demand response.
- Expansion of micro-grid and other resiliency investments.
- Accelerated electrification because of consumer incentives for electric vehicles, heat pumps and building retrofits.
- Faster development of emerging non-emitting, dispatchable technologies that could bring them into planning horizons earlier than currently anticipated.

2.1.1 Inflation Reduction Act

With the passage of the Federal IRA of 2022, Congress enacted extensions, expansions, modifications of clean energy tax provisions and provided funding and incentives to support decarbonization, energy efficiency and electrification.[18] This significant legislation has substantial implications for PGE, customers and climate and clean energy policy implementation.

Clean energy tax credits most directly affect PGE's decarbonization and resource strategy. Traditional Investment Credits and Production Tax Credits (ITCs and PTCs) for specific resources, such as wind and solar, were extended to apply to projects that begin construction from January 1, 2022 (retroactively) to December 31, 2024. A new credit for standalone energy storage began on January 1, 2023. On January 1, 2025, the credits transition to technology-neutral tax credits tied to emission reductions provided by the qualifying resource as determined by future Treasury Department guidance. Credit availability would phase out when the later of these two conditions is met: 1) when the US power sector emits 75 percent less carbon than 2022 levels or 2) December 31, 2032.

The ITCs and PTCs available for clean energy projects have been restored to full rates, eliminating previously planned phase-outs.[19] However, eligibility for the full credit applies only if prevailing wage and apprenticeship requirements are met. Specifically, facilities must pay prevailing wages during construction and the first 10 years of operation. Using apprentices as a percentage of labor hours increases over time (10-15 percent of total labor). Exceptions to the apprenticeship requirement are possible for good faith efforts to hire apprentices. Additional adders are provided for meeting other criteria. These include a 10 percent increased credit for meeting domestic content requirements, a 10 percent increased credit for projects placed on or near a coal plant, referred to as Energy Community, that was retired after December 31, 2009; a 10 percent increased energy credit for solar and wind facilities with a net output of less than 5 megawatts (MW) placed in service in low-income communities or on tribal land; and a 20 percent increased credit for property that is part of a qualifying low-income residential building project or low-income economic benefit project. The 50 percent credit rate reduction for qualified hydroelectric production for property placed in service after December 31, 2022, is also eliminated.

The ITC and PTCs, after being restored to the full rates and taking advantage of the additional adders, can significantly reduce the costs of generating renewable energy. The estimated cost reductions for select sources of generation are seen in **Figure 14**. The IRP modeling assumes incremental resources are eligible for the 100 percent level of applicable tax credits.

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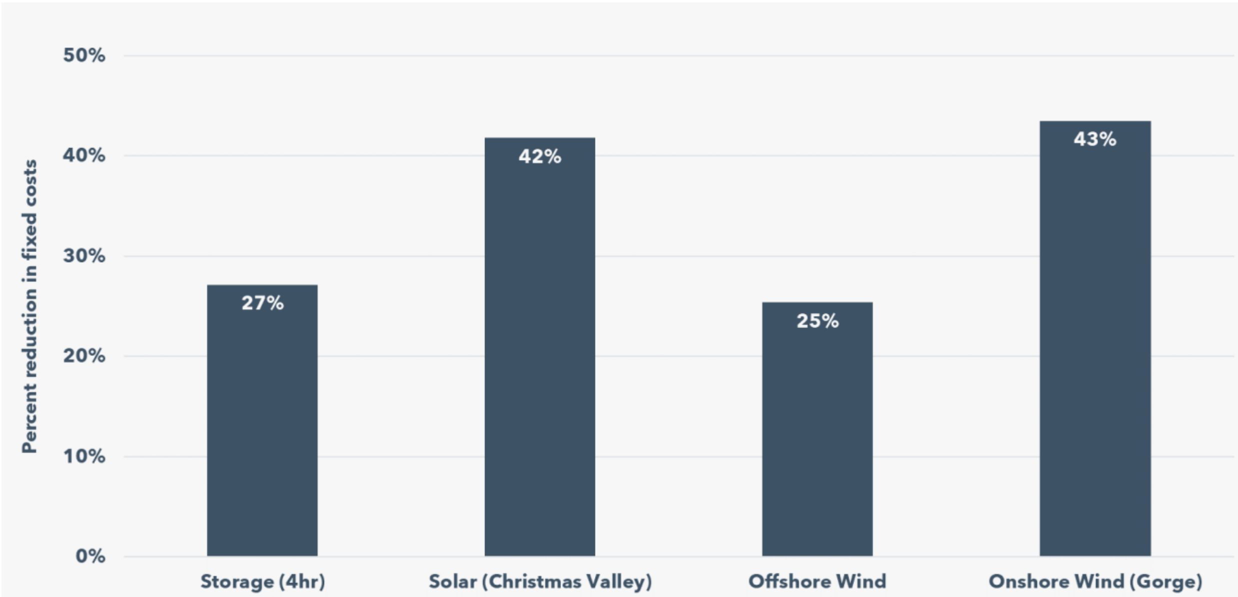
[18] Inflation Reduction Act of 2022, Pub. L. 117-169, Aug. 16, 2022, 136 Stat.1818.
[19] Modeling in this IRP assumes all requirements met by incremental resources to maximize tax potential. For additional information on the requirements associated with tax credits, please see the Inflation Reduction Act of 2022, available at: https://www.congress.gov/bill/117th-congress/house-bill/5376

Figure 14. Estimated cost reduction from IRA for select generation sources



The IRA attempted to resolve an important clean energy tax disadvantage that impacts resource costs for utility customers. The ITC is subject to tax normalization rules, which require public utilities to recognize the benefits from the ITC over the life of the resource, while non-utilities can recognize the benefits of the ITC in year one. The IRA provides alternatives to the ITC by providing a solar PTC and an opt-out from normalization rules for the new standalone storage ITC. However, the IRA was written, whether intentionally or not, so that the clean energy tax credit adders are not applied equally to the ITCs and PTCs. For example, the ITC, with one adder, goes from 30 percent to 40 percent of capital costs, which is a 33 percent increase in the credits value, while the PTC rate for generation only increases by 10 percent. This disproportionate increase will make the ITC with adders more valuable than a similar PTC with adders. Therefore, the normalization issue will likely persist only for solar projects, given its lower annual output compared to wind. PGE will continue exploring different options to work around the normalization issue, such as a wholly owned regulated affiliate, to promote greater competition in future resource solicitations to deliver the least cost resources for customers.

Overall, the clean energy provisions of this new legislation are expected to affect PGE's acquisition of new resources by helping keep customer rates lower through expanded and extended credits. Additionally, the IRA creates the concept of credit transferability. This allows for the sale of PTCs and ITCs generated by either new or existing facilities after December 31, 2022. PGE currently has a surplus of tax credits, resulting in a carryforward balance included in the rate base. However, with transferability, PGE will be able to monetize the value of the credits much more efficiently and eliminate the carryforward balance more quickly. This ultimately leads to lower costs for customers.

Other provisions in the law will support the expansion of transmission, help advance permitting, provide grants to support projects and support energy efficiency and transportation electrification. For example, the Building A Better Grid Initiative (BABGI)[20] incentivizes the development of new and upgraded transmission infrastructure. Key BABGI elements include:

- $2.5 billion Transmission Facilitation Program intended to support the development of nationally significant transmission lines, increase inter-regional connectivity and create access to renewables.
- $2.3 billion in Grid Innovation grants to states, territories and tribes to strengthen and modernize the country's grid. (PGE is working with the Confederated Tribes of Warm Springs in an effort to develop a qualifying project).
- $10.5 billion Grid Resilience and Innovation Partnership Program, which includes funding for projects that improve the grid's resilience, enhance grid flexibility and support the development of transmission and distribution (T&D) infrastructure.
- $760 million dollar Transmission Siting and Economic Development Grants program.

Also included are clean vehicle provisions, energy efficient credits and residential clean energy credits.

The IRA eliminates the previous 200,000-vehicle manufacturer cap on the clean vehicle tax credit, which means Tesla, GM and Toyota EVs will be eligible again. The Electric Vehicle (EV) credit will now be available for both new (credit up to $7,500) and used (credit is the lessor of $4,000 or 30 percent of sales price) vehicles. The credit does require vehicles to undergo final assembly in North America, which has limited the vehicles that currently qualify for credits. In addition, credits after December 31, 2023, and December 31, 2024, are increasingly tied to where minerals and batteries, respectively, are sourced, favoring materials from free trade partners. The electric vehicle (EV) and alternative fuel charging

[20] More information on the 'Building a better grid' initiative, available at: https://www.energy.gov/gdo/building-better-grid-initiative

credits are extended through 2032. Despite new limitations to some provisions, it is expected that these tax credits, along with others supporting transportation electrification, such as US Environmental Protection Agency (EPA) grants and commercial and manufacturing credits, will drive additional adoption of EVs and support transportation electrification. PGE's long-term load forecast will increase as a result. In this IRP, we consider a broad range of load growth scenarios to account for the potential impacts of factors that may accelerate electrification. This is further described in **Section 4.2, Need Futures**. Furthermore, PGE has also assessed how energy and capacity needs would change if the load grew faster than the high case. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

The Residential Energy Efficient Home Improvement credit is restored through 2032 and promotes energy efficiency investments in homes. Residential clean energy credits of 30 percent are extended in full through 2032, with a phase-out through 2034. Residential customers will be able to apply this credit to solar installations and standalone energy storage systems.

One additional goal of the IRA is to strengthen domestic manufacturing. This aim is reflected in the varying domestic content requirements for credits, as previously noted, for example, in the clean energy and clean vehicle tax credits. The domestic supply chain ecosystem will take time to develop, and the expectation is that there will continue to be supply chain issues in the short-term planning horizon.

2.1.2 Infrastructure Investment and Jobs Act

The IIJA was signed into law on November 15, 2021. The IIJA directs $1.2 trillion of spending to infrastructure, defined very broadly. This includes traditional infrastructure funding focused on roads and bridges, public transit systems, passenger rail, ports and airports, as well as investments in the electric grid, broadband infrastructure, water systems, cybersecurity, transportation electrification and climate resilience. It will spur a historic investment in energy. Most notably among its many programs, the bill funds $23 billion to enhance the resiliency of the power infrastructure and investment in renewable energy, $21.5 billion to develop clean energy demonstrations and research hubs, $9 billion to enhance manufacturing facilities and projects, and $5 billion to boost energy efficiency and clean energy creation. It also has over $18 billion in support of EV charging deployment, clean transit and school buses, and other transportation electrification funding.

PGE is pursuing – and plans to pursue – grant opportunities for infrastructure projects that can benefit customers and lower customer rate impacts. Currently, PGE is currently following the grant submission process for over $500M of potential award, on just over $900M of total project cost. The overall status of grants that PGE is pursuing through IIJA is shown in **Figure 15**, which is current as of March 2023:

Figure 15. IIJA grant submission and funding progress

Grant Potential	$12M	$0M	$400M+	$79.4M	$6M	Grant total potential: $497M+
Project Cost	$26M +	$0M	$800M+	$145M	$12M	Project total potential: $982M+

The funding opportunities sought by PGE align with the need for decarbonized energy supply, reliable service and more flexible processes and systems to meet customer needs. PGE's funding opportunities seek to meet those objectives as follows:

Grid resiliency improvement projects: These projects will accelerate the modernization of our T&D grid with the implementation of a variety of technologies. These technologies include distribution automation and early fault detection, along with hardening techniques such as undergrounding of high voltage lines and the installation of covered conductors where appropriate within PGE's High Fire Risk Zones (HFRZs).[21] We will also seek funding to upgrade existing lines to allow for the import of additional carbon-free generation to meet PGE's clean energy targets.

Middle mile fiber: The focus area will prioritize broadband communications and grid resiliency by providing broadband services to underserved communities along existing transmission paths. Fiber optic communications cables also will provide increased resiliency and communication options for PGE and customers.

Grid services demonstration: This demonstration will highlight the ways in which technologies at an existing PGE renewable energy facility can provide different types of active and reactive power controls to transform a renewable resource from a simple intermittent energy source to a resource capable of providing a wide range of grid services.

Hydropower initiatives: Hydropower facility grants will allow for upgrades and improvements that target resiliency, dam safety and environmental projects at multiple facilities that meet the requirements of the funding opportunity announcement. PGE continues to invest in hydropower as a carbon-free source of dispatchable capacity.

[21] HFRZs are areas within PGE's service territory where vegetation, terrain, meteorological patterns and wildland-urban interface considerations increase the risks associated with wildfire. PGE implements specific inspection and maintenance, vegetation management and operational actions within these HFRZs during and in preparation for PGE's declared Fire Season for improved ignition prevention and safety.

Table 4. Active PGE project applications

Grant Vehicle	Focus area	Projects	Grant Funding
IIJA Grid Resilience and Innovation Partnerships (GRIP)	Topic area 1 / Grid resilience	1	$100M
	Topic area 2 /Grid flexibility	2	$50+M
	Topic area 3 / Transmission innovative partnerships	1	$250M
National Telecommunication and Information Administration (NTIA)/IIJA	Middle Mile	1	$29M
IIJA	Grid services demonstration	1	$6M
IIJA	HydroWIRES technical assistance	1	TBD
IIJA	Hydropower incentives	4	$13M

2.2 State support for energy transition

Federal funding for the clean energy transition will be made available through different programs and channels, including those available to state agencies, utilities, businesses, community-based organizations, Tribes and local governments. PGE is committed to working with entities across Oregon to help deliver federal funding for the energy transition. While not all the previously-referenced federal funding for transition will flow through state agencies, the Oregon Department of Energy (ODOE) and Oregon Department of Transportation (ODOT) will be important conduits for customers to access these new opportunities.

With the new federal funding available, DOE has received and is seeking additional funding for the State Energy Program to support energy efficiency, resilience and sustainable transportation.[22] In addition, DOE is seeking funding for grid resilience, building codes and electrification, and energy efficiency programs, including an energy efficiency revolving loan fund. DOE is also supporting the energy transition under the direction of House Bill (HB) 2021. DOE was required to convene stakeholders to conduct a Small-Scale Renewable Energy Projects study.[23] HB 2021 also created a $50 million fund to provide grants for planning and developing community renewable energy and energy resiliency projects. While the grant program is not open to investor-owned utilities like PGE, it is available for Tribes and local governments in our service territory.

ODOT will receive $52 million in federal funds through the IIJA's National Electric Vehicle Formula Program over five years.[24] That program provides funding to states to build electric vehicle (EV) charging infrastructure and facilitate EV charging data collection, access and reliability. ODOT plans to work with a broad range of stakeholders and partners, including PGE, to apply funding toward building out passenger vehicle corridors, future-proofing corridors for future heavy-duty freight charging, and filling public EV charging gaps for medium- and heavy-duty vehicles, BIPOC and rural communities. Combined with other state policies helping to accelerate vehicle electrification, this additional funding can help accelerate the growth of new flexible loads in our service territory.

2.3 Technology and market research

Decarbonizing reliably and affordably for customers means staying abreast of the latest clean energy technology and market research across the globe. The energy landscape is rapidly evolving. To deploy customer dollars prudently in proven technologies, PGE works with other organizations to gain access to cutting edge data and information and to pool research dollars and best practices. For example, we are actively working with the Energy Power Research Institute (EPRI) on issues ranging from climate adaptation, wildfire protection, safety and transmission planning to new non-emitting technologies of the future, like carbon capture and storage, hydrogen and others. We participate in consortiums with utilities and energy companies that invest in early-stage new technologies to mitigate risks while learning first-hand how those technologies are evolving. Our CEO, Maria Pope, serves on the Secretary of Energy Advisory Board, and as part of the smart grid working group, PGE has

[22] Information about the State Energy Program is available at: https://www.energy.gov/scep/about-state-energy-program
[23] Information about the Small-Scale Renewable Energy Projects Study is available at: https://www.oregon.gov/energy/Data-and-Reports/Pages/SSREP-Study.aspx
[24] Information about the National Electric Vehicle Formula Program is available at: https://www.transportation.gov/bipartisan-infrastructure-law/regulations/2022-12704

prepared whitepapers for the ODOE on the virtual power plant (VPP) and transmission planning for distributed energy resources (DERs).

These relationships and others help us deliver the benefits of rapid technological change across the global energy ecosystem to customers in Oregon. They have helped us to lower our operating costs, minimize disruptions and transform how we integrate wind, solar and battery technologies. For example, our Wheatridge facility was the first of its scale to combine all three technologies to better utilize existing significant and scarce transmission resources and to serve customers with non-emitting power. As we look to the future and lowering emissions to meet our targets, these relationships and access to federal and state support for energy transition will help us manage costs for customers and provide exceptional products and services.

Chapter 3. Planning environment

Long-term planning occurs in the context of evolving law and policy, technological advances, economic conditions, advancing scientific understanding of the effects of climate change, and general environmental concerns. Each of these factors impact resource economics, customer prices, community benefits and the resource decisions Portland General Electric (PGE) makes in the best interests of its customers. This chapter explores the broader planning context influencing our overall resource strategy to reliably and affordably meet customers' energy needs while achieving emissions reduction and other regulatory requirements.

Chapter highlights

- Federal and state policy impacts the planning environment for PGE's Integrated Resource Plan (IRP) and Clean Energy Plan (CEP).
- Regulatory policy may need to adapt to changing dynamics created by state and regional decarbonization objectives.
- Thermal resource retirement in Oregon and the West creates challenges for resource adequacy as the region decarbonizes.
- Continued uncertainty related to labor markets, supply chains and the macroeconomy presents challenges to decarbonization efforts.

3.1 Federal and state law and regulatory policy

Since PGE's last IRP was acknowledged with conditions and directives on March 16, 2020, federal and state policies related to clean energy and greenhouse gas emissions have evolved significantly. As discussed in **Chapter 2, Accessing support for energy transition**, the federal government recently advanced transformative comprehensive climate policy with the passage of the Inflation Reduction Act (IRA) and the Infrastructure Investment and Jobs Act (IIJA). It also passed the CHIPS and Science Act, which has direct implications for our service territory. At the state level, new executive orders, state agency rules and legislation related to electric sector greenhouse gas emissions, energy efficiency, transportation electrification and building decarbonization impact the planning environment for this IRP.[25]

[25] 2021: HB 2021, HB 2475, HB 2482, HB 2027, HB 2165 and HB 3141;
2022: HB 5202, SB 1536 and SB 1518.

3.1.1 CHIPS and Science Act

Congress recently passed the CHIPS and Science Act of 2022 (H.R. 4346).[26] This legislation is designed to boost US competitiveness and innovation. It is expected to support future scientific research and development funding that could help clean energy advancement through future appropriations the Act authorizes. It also provides funding to support domestic semiconductor chip manufacturing, which may help address supply chain issues as chips are so prevalent throughout goods, and their shortage has impacted supply chains. The CHIPS Act directs $280 billion in spending over the next 10 years. The spending is allocated to scientific research and development (R&D) and commercialization ($200 billion authorization), semiconductor manufacturing, R&D, and workforce development ($53 billion), tax credits for chip production ($24 billion), and programs aimed at leading-edge technology and wireless supply chains ($3 billion). As a result of the CHIPS Act, Oregon Business Council and ECONorthwest research estimate Oregon could see upwards of $40 billion of investment over the next 10 years, with tens of thousands of jobs and $2-3 billion in local tax revenue. Service territory semiconductor investments will directly impact PGE's load growth.

In this IRP, we consider a broad range of load growth scenarios to account for potential impacts. This is further described in **Section 4.2, Need Futures**. Furthermore, PGE has also assessed how energy and capacity needs would change if the load grew faster than the high case. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

3.1.2 Oregon House Bill 2021

In the 2021 Legislative Session, the Oregon Legislature enacted House Bill (HB) 2021.[27] This bill requires PGE to reduce the greenhouse gas emissions associated with electricity sold to retail electricity consumers in Oregon. Specifically, the bill requires utilities to reduce those emissions by at least 80 percent below a 2010-2012 average baseline level of emissions by 2030, by at least 90 percent below baseline emissions levels by 2035; and to 100 percent below baseline emission levels by 2040.[28] Program implementation is shared between the Public Utility Commission of Oregon (OPUC or the Commission) and the Oregon Department of Environmental Quality (ODEQ). ODEQ's primary responsibility is collecting greenhouse gas emissions data, determining baseline emissions, calculating the reductions necessary to meet the targets and verifying projected emissions reductions. ODEQ's determination and

[26] The Creating Helpful Incentives to Produce Semiconductors and Science Act of 2022 (CHIPS Act) was signed into law on August 9, 2022.
[27] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[28] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 3, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

verification is based on emissions data reports submitted by the electricity providers under OAR-340-215-0120 to Oregon's Greenhouse Gas Reporting Program.[29] The Commission must ensure that utilities demonstrate continual progress toward the greenhouse gas targets.[30] Utilities must develop a CEP to meet the targets concurrent with each IRP development and convene a Community Benefits and Impacts Advisory Group (CBIAG) to solicit feedback from environmental justice (EJ) communities and low-income customers. This combined filing of PGE's CEP and IRP complies with HB 2021's requirements and related guidelines adopted by OPUC.[31]

PGE will continue to submit annual reports to ODEQ as it does now. As of 2021, ODEQ has required third-party verification of PGE's annual emissions reporting. PGE received a positive verification statement by the deadline of September 30, 2022, for the 2021 annual ODEQ Investor-Owned Utility emissions reporting. In the compliance years 2030, 2035, 2040 and every year thereafter, the OPUC will use the greenhouse gas emissions data reported to ODEQ for that compliance year to determine whether the emissions targets are met. This program is based on the actual emissions associated with the power served to retail customers and does not use renewable energy certificates (RECs) to track compliance.[32] The bill contains a reliability pause and a cost cap to ensure the targets are reached affordably and reliably.[33,34]

HB 2021 also includes a range of clean energy provisions not directly related to the Greenhouse Gases (GHG) targets at the heart of the bill. These include:

- **Allows community-wide clean energy tariff:** Sets forth the process for developing and approving a community-wide green energy tariff. PGE is actively engaged with the cities we serve to develop such a program.[35]
- **Bars new emitting facility site certificates:** Prohibits the Energy Facility Siting Council (EFSC) from issuing a site certificate for a new generating facility that produces electric power from fossil fuels unless the new generating facility will generate only non-GHG-

[29] Information about Oregon's Greenhouse Gas Reporting Program is available at: https://www.oregon.gov/deq/ghgp/Pages/GHG.aspx
[30] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 4(6), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[31] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, the OPUC adopted CEP expectations in Order Nos. 22-206 (Jun 3, 2022), 22-390 (Oct 25, 2022) and 22-446 (Nov 14, 2022).
[32] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Sections 1-3, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[33] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 9, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[34] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 10, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[35] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 20, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

emitting electricity. Further prohibits EFSC from approving a site certificate amendment for an energy facility powered by fossil fuels in a manner that would "significantly increase the gross carbon dioxide emissions that are reasonably likely to result from the operation of the energy facility."[36]

- **Small-scale Renewables Requirement:** Increases the existing small-scale renewable mandate in the Oregon Renewable Portfolio Standard from an 8 percent capacity standard to a 10 percent capacity standard.[37]
- **Community Renewable Energy Grant Program:** Creates a $50 million fund at the ODOE to provide grants for planning and developing community renewable energy and energy resilience projects.[38]

3.1.3 Oregon Climate Protection Program (CPP)

Oregon Governor Kate Brown issued Executive Order 20-04 in March 2020, directing state agencies to adopt policies and programs as allowable under existing law to help the state meet statewide emissions targets. In response, the ODEQ established the CPP, a new regulatory program that began in 2022 aiming to dramatically reduce greenhouse gas emissions in Oregon over the next three decades. The CPP sets a declining limit, or cap, on greenhouse gas emissions from fossil fuels used throughout Oregon, including diesel, gasoline, natural gas and propane, used in transportation, residential, commercial and industrial settings. The program also regulates site-specific greenhouse gas emissions at manufacturing facilities, such as emissions from industrial processes, with a best available emissions reduction approach. The CPP does not apply to Oregon's electric utilities, energy service suppliers or electricity-generating facilities.

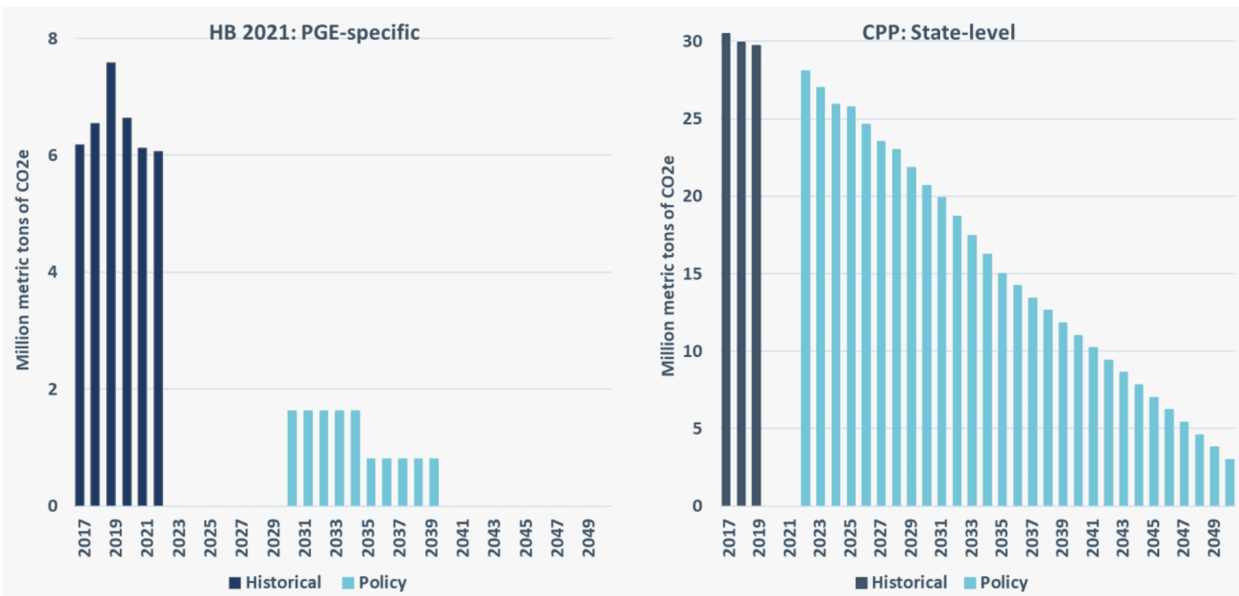
In 2022, PGE contracted with Evolved Energy Research (EER) to undertake an independent analysis exploring pathways to deep decarbonization across all energy sectors in its service area. ("Deep Decarb Study Update").[39] This study updated an earlier Deep Decarb Study in

[36] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 28, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[37] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 37, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[38] ORS 469A.400 469A.475, amended by OR Laws 2021, Chapter 508, Section 29, available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled
[39] Evolved Energy Research. (2022, August 15). Deep Decarb Study Update Technical Report. Portland General Electric Resource Planning. Retrieved February 14, 2023, available at: https://assets.ctfassets.net/416ywc1laqmd/3KDEMrOpMkbjduyiBeen3z/88464626dbcd98c97f669289cb0dbd7d/EER_PGE_Deep_Decarb_Study_Update_Memo_.pdf

2017 by EER to include Oregon's recent adoption of HB 2021 and ODEQ's CPP.[40] The study found that while the CPP does not directly regulate the electric sector, end-use electrification is likely to be a key CPP compliance strategy in transportation and building sectors. Electrification will increase PGE's total load (and corresponding resource requirements to meet HB 2021), but it will also create the opportunity to leverage flexibility from newly electrified loads like smart electric vehicle charging and water heating. As noted earlier, in **Section 4.2, Need Futures**, and **Section 6.10.2, Accelerated load growth sensitivity**, we consider a broad range of load growth scenarios to account for potential impacts of federal and state policy drivers of electrification.

A comparison of the emissions reduction goals of HB 2021 and the CPP is given in **Figure 16**.[41]

Figure 16. Emission reduction goals HB 2021 and CPP



[40] Evolved Energy Research. (2018, April 24). Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory. Portland General Electric Resource Planning. Retrieved February 14, 2023, available at: https://assets.ctfassets.net/416ywc1laqmd/7tc4cXtpYgEOTM8my6rxsP/987f9f746e1bae5072204693a34c1b68/exploring-pathways-to-deep-decarbonization-PGE-service-territory__1_.pdf

[41] PGE Deep Decarb Study available at: https://assets.ctfassets.net/416ywc1laqmd/7zH0gqWpupl16cMDeEGme5/46b024e14df63f3256a428c982f9708e/PGE_Deep_Decarb_Study.pdf

3.1.4 Transportation electrification

The 2021 Legislature enacted House Bill (HB) 2165 to extend and improve Oregon's electric vehicle (EV) rebate and support utility investment in electric vehicle infrastructure.[42] House Bill 2165 removes the 2024 sunset on Oregon's EV Rebate program and makes other targeted changes to support underserved communities better. House Bill 2165 also requires PGE and Pacific Power to collect a charge set to 0.25 percent of the total revenues collected by the utility, at least half of which is to be spent on TE in underserved communities. The bill updates ORS 757.357 to clarify OPUC authority to allow utility cost recovery for TE infrastructure measures and recognizes that utility investment to support TE includes behind-the-meter infrastructure.

Oregon's state agencies are also working to advance TE in response to Governor Brown's Executive Order 20-04. In March 2021, the Oregon Environmental Quality Commission (OEQC) adopted revised Clean Fuels Program rules to increase the amount of clean fuels credits generated from EV charging, and the EQC has extended the Clean Fuels Program another 10 years to 2035. The EQC also adopted California's Advance Clean Trucks rule that requires manufacturers of medium- and heavy-duty vehicles to sell a certain percentage of zero-emission vehicles and has adopted a similar standard for light-duty vehicles through the Advance Clean Cars II rule.

The Oregon Department of Transportation (ODOT) is working to implement the federal 2021 Infrastructure Investment and Jobs Act, which provides formula funds and flexible funds that ODOT plans to use to deploy EV charging across the state. The Department has announced more than $100 million in combined state and federal funding for transportation electrification over the next five years.

These state efforts to support, fund and accelerate TE are expected to complement PGE's utility- and Clean Fuels-funded programs. These policies are also expected to drive load growth from TE, as reflected in PGE's load forecast. As noted earlier, in this IRP, we consider a broad range of load growth scenarios to account for potential impacts of federal and state policy drivers of electrification in **Section 4.2, Need Futures**, and **Section 6.10.2, Accelerated load growth sensitivity**.

[42] HB 2165 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2165

3.1.5 Energy efficiency and building decarbonization

Energy efficiency is an important resource for PGE to meet its decarbonization targets and helps customers save money in the process. House Bill (HB) 3141 was enacted in the 2021 session to enable the continuity of energy efficiency programs for PGE customers by modernizing and extending the Public Purpose Charge beyond its scheduled expiration. [43,44] The bill extends the Public Purpose Charge to 2035 from its current expiration in 2025. It removes energy efficiency funding from the Public Purpose Charge, moves it into rates, increases funding for low-income weatherization and modifies the existing renewables provision to include storage and grid optimization investments that enhance resilience, reliability and renewable power integration.

At present, multiple bodies receive and disburse funding for energy efficiency investments in Oregon, including the Oregon Health Authority (OHA), Oregon Housing and Community Services (OHCS), ODOE and Energy Trust of Oregon (ETO). OHA administers the Healthy Homes Program established in the 2021 Legislative session via House Bill (HB) 2842.[45] The program provides funds to assist low-income households in repairing and rehabilitating their residences. The funds can be used to maximize energy efficiency and make improvements to make a home more fire-resistant or seismically resilient, among other health and safety measures. OHCS administers the Low-Income Home Energy Assistance Program (LIHEAP), Low Income Weatherization Assistance Program (WAP) and the Multifamily Energy Program, and Weatherization Training and Technical Assistance (WX T&TA). ODOE administers the Heat Pump Incentive Program established by Senate Bill (SB) 1536 (2022), Energy Efficient Wildfire Rebuilding Incentive established by House Bill (HB) 5006 and the Energy Efficient Schools Program and works to shape codes and standards for the built environment. [46,47]

In the 2022 Legislative Session, the Legislature enacted the Emergency Heat Relief Bill (SB 1536), including an allocation of $25 million to the ODOE to support the installation of heat pumps in the state through two distinct programs. The Heat Pump Deployment Program will support residential customers by providing grants directly to individuals to cover up to 100 percent of the cost of the purchase and installation of a heat pump. The grant funds can also be used to support related upgrades needed to support or enable the new heat pump,

[43] HB 3141 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB3141
[44] More information about the Public Purpose Charge, available at: https://www.oregonlegislature.gov/lpro/Publications/Public-Purpose-Charge-Background-Brief.pdf
[45] HB 2842 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2842/Enrolled
[46] SB 1536 (2022), available at: https://olis.oregonlegislature.gov/liz/2022R1/Downloads/MeasureDocument/SB1536/Enrolled
[47] HB 5006 (2021), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB5006/Enrolled

including new or upgraded electrical panels, weatherization and upgrades to improve the airflow of the home. The bill also establishes a residential heat pump program that will provide rebates to contractors for the "purchase and installation of air-source or ground-source heat pumps" for residential customers, not to exceed 60 percent of the purchase price. Since 2002, ETO has administered energy efficiency programs for industrial, commercial and residential sectors on behalf of, and in collaboration with, utility funders. PGE and ETO have realized conservation, on average, of greater than 30-megawatt average (MWa)/annually for the past 10 years and at a levelized cost of energy (LCOE) of less than $0.0375/kWh. In the 2021 Legislative Session, the Legislature enacted HB 3141 which maintained funding levels for OHCS low-income weatherization, low-income affordable housing and energy conservation in schools while tying energy efficiency funding to the cost-effective amount available as determined through planning.

House Bill 3141 required greater budgeting coordination between utilities and ETO. PGE and ETO are now identifying opportunities to leverage programmatic funding as well as other sources of funding to. Coordinated programmatic efforts between ETO and PGE can improve our collective efforts to manage deployment dollars and stack incentives and benefits of both energy efficiency and flex load to enhance grid reliability. In addition to enabling flexible resources that may be called upon to support decarbonization targets and address both equity and grid constraints via non-wires solutions, energy efficiency investments serve to enable beneficial electrification, which has the potential to foster beneficial load growth and stabilize rates.

Given that the 2022 Federal Inflation Reduction Act (IRA) will provide tax credits, incentives and loans for energy efficiency investment, we are also working closely with the ODOE as we collectively work to leverage activity to help those facing energy cost challenges to attract and deploy federal energy efficiency funding dollars.

3.1.6 Local climate action planning

Nine cities and counties served by PGE have already established climate-related goals through community processes and plans, and at least four more are in the process of developing plans. These plans typically cover a variety of goals and objectives, including those concerning greenhouse gases, energy use, transportation, waste, land use, health and safety, and economic development. **Table 5** captures a list of local governments with existing plans (or in some phase of developing one) and some key electricity and emissions goals.

Table 5. Local governments' climate action plans

Local government	Emissions Goals	Plan under development
Beaverton	Net zero emissions from electricity by 2035; 100% reduction of GHGs by 2050	
Clackamas County		X
Gresham		X
Hillsboro	General initiative to reduce carbon emissions	
Lake Oswego	Net zero emissions from electricity use in buildings by 2035; Carbon neutrality by 2050	
Milwaukie	Net zero emissions from electricity by 2030; Carbon neutrality by 2045	
Multnomah County	100% renewable electricity by 2035	
Portland	100% renewable electricity by 2030; 50% emissions reduction by 2030; carbon neutrality by 2050	
Salem	50% emissions reduction by 2035 and carbon neutrality by 2050	
Sandy	Carbon neutrality by 2050	
Silverton	100% carbon free electricity for City buildings	
Tigard		X
Tualatin		X
West Linn	50% reduction in buildings by 2040; 100% reduction in transportation by 2040	

Several cities and counties have timelines for their decarbonization goals that align with our HB 2021 targets. For those local governments that want to decarbonize on a faster timeline, PGE's Green Future Enterprise and Green Future Impact are being used to support clean energy goals. Many of our large commercial and industrial customers also use these and other programs to meet their decarbonization goals.

PGE has been working with local governments since 2020 to develop a community-supported renewable program to support those local governments that have adopted community-wide climate goals. During the 2021 legislative session, PGE worked in partnership with several of our local governments to pass language within HB 2021. The program will allow local governments to work with PGE to accelerate the procurement of non-emitting energy to meet their climate goals. Since the bill's passage, PGE staff have been meeting regularly with local governments to solicit feedback on the design so that the program will meet their goals and desired approach. As PGE continues to engage with local governments, collectively we will determine the right time to file the tariff to support the program.

3.1.7 Regulatory policy: Direct access

Oregon Electricity Service Suppliers (ESSs) have their own clean energy targets as part of House Bill (HB) 2021 Section 3(1) and are responsible for decarbonizing the electricity sold to direct access customers. IRP guideline 9 does not allow PGE's resource planning to include customers that have elected to receive their power through direct access from an ESS, even though PGE retains the responsibility of Provider of Last Resort. To be eligible for direct access, nonresidential customers must have a facility capacity of at least 250 kW and an aggregate load of 1 MWa. This direct access option was initiated in 1999 with the passage of Senate Bill (SB) 1149, "[r]elating to restructuring of electric power industry." The legislature's goals, articulated in the preamble, took into "consider[ation] national trends toward electric deregulation" at the time.[48]

Senate Bill (SB) 1149 included the provisions for direct access, which was defined as "[…] the ability of a retail electricity consumer to purchase electricity and certain ancillary services, as determined by the commission for an electric company […], directly from an entity other than the distribution utility."[49] These are the entities known as ESSs. Much has changed since the passage of this deregulation law, particularly Oregon's greenhouse gas reduction goals to address climate change.

The design of the various direct access offerings has largely been left to the discretion of the Commission. PGE began offering a one-year direct access/market price option effective March 1, 2002, consistent with legislative provisions.[50,51] In the 2003 service period, PGE added the option for eligible customers to opt out of cost-of-service energy supply for a minimum of five years (long-term direct access) with a pre-specified transition adjustment

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[48] Oregon Laws 1999, Chapter 865, available at: https://www.oregonlegislature.gov/bills_laws/lawsstatutes/1999orLaw0865.html
[49] *Id.*, at Section 1(6).
[50] *Id.*
[51] HB 3633 (2001), available at: https://www.oregonlegislature.gov/bills_laws/archivebills/2001_EHB3633.pdf

fee.[52] PGE's long-term direct access program has a cap of 300 MWa.[53] In 2020, PGE launched a new large load direct access option capped at 119 MWa, allowing customers with a "new load" (uncommitted to PGE and expected to grow to 10 MWa or more over three years) to avoid cost-of-service (PGE Schedule 689).[54] These direct access caps are essential to help mitigate the potential for cost shifting.

The Commission began an investigation into IRP requirements in 2002.[55] Five years later, the Commission adopted IRP Guideline 9 relating to the treatment of direct access loads: "[a]n electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier."[56] The Commission believed that long-term direct access customers are "[…] 'effectively committed to service' under direct access and should be excluded from the IRP load-resource balance over the planning horizon."[57] This has led to a situation where the Commission has limited insight into the extent that ESSs plan to serve their loads reliably, while electric utilities cannot plan for long-term direct access customers. As Commission Staff have observed, "IOUs don't plan for long-term opt-out customers, while ESSs generally have short-term contracts with the opt-out customers […] the mismatch between contract length, and resource lifecycles could lead to a situation where no entity is planning for the RA of long-term opt-out customers absent Commission intervention."[58] At the end of the September 2022 long-term direct access election window, approximately 11 percent of PGE's net system load had opted out of cost-of-service supply.

The Commission opened an investigation into long-term direct access in 2019, focusing on resource adequacy, the costs and benefits of direct access and lessons learned from other states.[59] At the beginning of 2021, a separate proceeding was opened to specifically investigate the topic of resource adequacy in Oregon (see **Chapter 4, Futures and**

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[52] Transmission Access Service Schedules: 485 Large Nonresidential Cost of Service Opt-Out (201-4,000 kW); 489 Large Nonresidential Cost of Service Opt-Out (>4,000 kW); 490 *Sch 490 must aggregate to >30MWa. This change became effective May 9, 2022, with UE 394*. Large Nonresidential Cost of Service Opt-Out (> 4,000 kW and Aggregate to >100 MWa). These all have a Minimum Five-Year Option and a Fixed Three-Year Option.

[53] In ADV 02-17 when we filed the first Sch 483. It had been discussed in a workshop for AR 441 and parties discussed the 300MWa in a workshop but decided it shouldn't be in the rules but should be included in the rate schedule.

[54] See PGE Schedule 689, New Large Load Cost of Service Opt-Out (>10MWa), available at: https://assets.ctfassets.net/416ywc1laqmd/1Cpia6NCTgU4OMLbqcru7J/52d5f28218bf70eb66366a9d677f682f/Sched_689.pdf

[55] *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning Requirements*, Docket No. UM 1056 (Jul 26, 2002), available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=10081

[56] Docket No. UM 1056, Order 07-002 at 19 (Jan 8, 2007), available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

[57] *Id.*

[58] *In the Matter of Public Utility Commission of Oregon, Investigation Into Resource Adequacy in Oregon*, Docket No. UM 2143, Staff Report at 9 (Mar 24, 2022), available at: https://edocs.puc.state.or.us/efdocs/HAU/um2143hau154059.pdf

[59] *In the Matter of Alliance of Western Energy Consumers, Petition for Investigation Into Long-Term Direct-Access Programs*, Docket No. UM 2024, ALJ Ruling issued February 21, 2020, adopting phasing proposal, Attachment A, available at: https://edocs.puc.state.or.us/efdocs/HDA/um2024hda12440.pdf

uncertainties).[60] In addition to this investigation, Oregon investor-owned utilities and some ESSs are committed to the binding phase in the Western Power Pool's Western Resource Adequacy Program (WPP WRAP), as discussed in **Section 3.2, Regional planning: resource adequacy**.

The Commission's investigation into long-term direct access led to an Informal Rulemaking in October 2021 aimed at narrowing the scope of issues under consideration.[61] Topics included the definition of non-bypassability (ensuring customers cannot avoid shared public policy costs by taking direct access), how to calculate a non-bypassable charge, the utility's role as the provider of last resort (PGE is required to serve direct access customers should an ESS fail) and rules for implementation of HB 2021 for ESSs. The Commission moved into Formal Rulemaking in October 2022, focusing initially on addressing provider of last resort risk. Stakeholders are currently exploring the option of preferentially curtailing (disconnecting) a direct access customer if they return to the utility at short notice and there is insufficient power to serve them.

3.1.8 Regulatory policy: Power cost adjustment mechanism (PCAM)

The PCAM framework is a central element of PGE's process to adjust customer rates to recover variance in power cost compared to the annual forecast. The PCAM allows for collection from, or refund to, customers of the power cost variance subject to power cost deadbands, sharing and earnings deadbands.

The current PCAM structure was adopted for PGE in 2007.[62] It originated from a Commission-established set of principles envisioned to ensure a well-designed PCAM and an appropriate balance of power cost forecast risk between PGE and customers. Sixteen years later, the circumstances to which PGE is exposed have changed significantly with respect to a changing resource mix, the impacts of climate change and changing wholesale market dynamics.

With the requirements of HB 2021, PGE's energy supply portfolio is shifting from predominantly high capacity, base load and dispatchable generation to a portfolio composed of increasing amounts of non-dispatchable and variable renewable energy resources. The renewable resource additions to PGE's and the region's supply portfolios

[60] Docket No. UM 2143, *Investigation into Resource Adequacy in the State*, available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=22698

[61] Docket No. AR 651, *In the Matter of Rulemaking Access Including HB 2021 Requirements*, Public Utility Commission of Oregon (Oct 1, 2021), available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=23063

[62] *See* OPUC Order No.07-015 (Jan 12, 2007), available at: https://apps.puc.state.or.us/orders/2007ords/07-015.pdf

have been primarily wind generation (and some solar), which presents unique challenges with respect to predictability and coincidence with critical peak load conditions.

PGE's service area has experienced the impacts of climate change with increased frequency and magnitude of extreme weather events. Increasingly frequent severe weather events in peak months have resulted in a shift to energy demand with system record-setting loads experienced in 2021 and 2022 for utilities across the Western Interconnection.

These load excursions, coupled with the resource intermittency and the somewhat negatively correlated nature of most variable energy resources in the regional energy stack to high demand conditions caused by extreme weather, have stressed regional resource adequacy and exacerbated volatility in the market. During these events, PGE must serve higher load requirements and replace previously expected wind energy generally unavailable during very cold or hot temperatures.

Collectively, these changes increase the degree of power cost variability and create conditions that become difficult to predict or forecast. The frequency, duration and magnitude of disruptive events have led (and will continue to lead) to higher variability and extreme levels of power cost outcomes around any baseline forecast established initially in rates. PGE expects these circumstances to continue and potentially intensify as climate change drives more frequent severe weather events and we transform the energy system to achieve the decarbonization targets of 2030 and beyond. Regulatory policy can (and should) adapt to changing dynamics. Changing capacity constraints, load profiles, decarbonization policy and scarcity pricing necessitate revisiting the original PCAM principles and structure.

3.2 Regional planning: resource adequacy

Resource adequacy refers to planning to have enough resource generation, efficiency measures and demand-side resources to serve loads across a wide range of conditions with a sufficient degree of reliability.[63] Planning to be resource adequate is especially important as the region decarbonizes, as increasing penetrations of variable energy resources and retiring coal plants occur against a backdrop of increasingly extreme and unpredictable weather events. As states across the Western Interconnection decarbonize in response to state or utility-specific mandates or targets, resource adequacy increasingly depends on regional coordination.

The Western Power Pool (WPP) began gathering information about the need for a regional resource adequacy program in 2019, finding "[t]he impending retirement of several thermal

[63] For example, NARUC Resource Adequacy Primer for State Regulators, July 2021, defines the resource adequacy long-term (years, months) planning focus as being "[a]ble to meet demand with sufficient supply side and demand-side resources", p.5., available at https://pubs.naruc.org/pub/752088A2-1866-DAAC-99FB-6EB5FEA73042.

generators within and outside the region (the Western US and Canada) mixed with increasing variable energy resources (VERs), has led to questions about whether the region will continue to have an adequate supply of electricity during critical hours." These efforts led to the formation of the Western Resource Adequacy Program (WRAP), which began implementing a voluntary, non-binding (no penalties) program in October 2021. The earliest binding (charges for failure) season is scheduled for Summer 2025 (with participants providing an advanced 'forward showing' of their resource adequacy positions for that season in October 2024). Twenty-six load-responsible entities across 10 states and one Canadian province currently participate in WRAP development.

The WPP WRAP includes a forward-showing planning mechanism to identify the collective capacity needed to meet a 1-day in 10-year loss of load expectation (LOLE) target. The forward showing requires participants to plan and submit a portfolio of resources seven months ahead of operational need and will not replace the multi-year IRP planning process. PGE's IRP and the WPP WRAP use different methodologies, footprints and timeframes to assess capacity adequacy, currently leading to differing resource effective load-carrying capabilities (ELCCs) and other capacity-critical hours. The OPUC's investigation into resource adequacy could lead to a state-level framework that bridges the WRAP and IRP.

The forward showing aims to provide reliability benefits through consistent metrics and methodologies while providing increased visibility and transparency. PGE will still be responsible for determining what resources to procure from other participants and suppliers. Participants will demonstrate compliance with forward-showing reliability metrics seven months before binding seasons (summer and winter). They will be given three months to cure any resource adequacy planning deficiencies. The program will calculate the required planning reserve margin (PRM) to meet the LOLE target for each month of the binding seasons. Participants will then be required to show they have adequate resources (specified generation and contracts backed by specified generation) and enough firm transmission to meet their P50 (median) load plus the PRM during the months of the binding seasons. The charge for noncompliance and failure to cure the inadequacy will be based on the cost of new entry for a gas peaking plant.

At the end of 2022, PGE, along with a majority of other participating load-responsible entities, committed to continued support for the WPP FERC Tariff (rules of program, governance), which was filed in August 2022 and approved February 2023.

At the state level, the OPUC opened an investigation into resource adequacy in January 2021.[64] Throughout 2021, a state-level resource adequacy framework straw proposal was developed to complement the regional efforts in the WPP WRAP. The state framework would

[64] See *Investigation into Resource Adequacy in the State*, Docket No. UM 2143, Order 21-014 (Jan 13, 2021), adopting Staff Report with Appendix A, available at: https://apps.puc.state.or.us/orders/2021ords/21-014.pdf

be mandatory for Oregon electric investor-owned utilities and ESSs, require forward showing of resource adequacy more than seven months ahead of a season (to enable time for physical resources to be built), and could be in place sooner than a binding WPP WRAP (set to go binding no earlier than 2025).[65] This would bring ESSs more into line with what utilities like PGE already undertake in IRPs, providing the Commission with visibility into how direct access loads are being planned for to ensure resource adequacy. OPUC Staff and stakeholders resumed consideration of this state framework in the fourth quarter of 2022. The current potential schedule could see rules in place by mid-2023.

3.2.1 Resource adequacy in the IRP compared to the WRAP

As discussed in the previous section, PGE is participating in the WPP WRAP. Binding participation (with penalties for failure) can occur no earlier than Summer 2025, with a forward showing of resource adequacy seven months ahead in October 2024. As PGE prepares for binding participation in the WRAP, it is necessary to consider how the IRP and WRAP may need further alignment to avoid future conflicts. Lawrence Berkeley National Laboratory (LBNL) identified four key IRP assumptions that will be impacted by participation in regional resource adequacy programs like the WRAP: reliability targets; resource capacity accreditation; transmission assumptions; and load forecasting.[66] Even with participation in the WRAP, it is important to note that the IRP still defines the resources that PGE can use to meet capacity needs, reliability and emissions targets.

The WRAP has adopted the resource adequacy standard of one event in 10 years LOLE, while PGE's IRP uses a one day in 10 years LOLE as a reliability metric. These reliability targets will need to come into closer alignment as utilities approach binding participation in a regional resource adequacy program. If PGE's IRP resource adequacy target led to a lower capacity need than the WRAP, there is a risk of being modeled as adequate at the balancing-authority level but not at the regional level. This could lead to the utility having to justify additional investments outside its acknowledged Action Plan. States and the WRAP will likely need to reach a consensus around reliability targets for use in state-level IRP planning.

The assignment of a capacity credit to a resource will also need to be more closely aligned between the IRP and the WRAP before participation in the regional resource adequacy program becomes binding. WRAP uses a variety of resource-specific methodologies to calculate the qualifying capacity contribution of a participant's generation resources during

[65] Docket No. UM 2143, Staff's Process Proposal and RA Solution Straw Proposal, filed October 15, 2021, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2143hah145744.pdf

[66] Juan Pablo Carvallo, Nan Zhang, Benjamin D. Leibowicz, Thomas Carr, Maury Galbraith, Peter H. Larsen. *Implications Of A Regional Resource Adequacy Program On Utility Integrated Resource Planning,* Energy Analysis and Environmental Impact Division, Lawrence Berkeley National Laboratory. November, 2020, available at: https://eta-publications.lbl.gov/sites/default/files/ra_paper_1_-_final_version.pdf

the region's capacity critical hours. PGE's IRP calculates the capacity contribution of individual resources using a stochastic model that optimizes resource generation to achieve a reliability objective. If an IRP relies on a different resource capacity accreditation methodology than that used regionally, there is a risk of different outcomes between state and WRAP adequacy assessments. A potential solution is for states and the WRAP to agree on capacity contribution values and incorporate them into IRPs.

The WRAP also considers the deliverability of power when determining a participant's resource adequacy. Any assumptions around transmission expansion should be consistent at both the IRP and the regional level, requiring increased coordination and information sharing between WRAP participants. There will also likely need to be increased standardizing on risk assumptions in load forecasts to avoid participants leaning on utilities that hedge more against forecast uncertainty.

PGE looks forward to working with WRAP participants and state regulators to ensure that state-level IRPs complement and work in harmony with regional resource adequacy programs.

3.3 Market, labor and supplier dynamics

The broader macroeconomic environment in the years following our 2019 IRP remains highly dynamic. While **Chapter 4, Futures and uncertainties** discusses a wide range of critical uncertainties addressed in IRP modeling directly, this section discusses additional trends contributing to market instability that impact PGE. Geopolitical unrest continues to contribute to volatile fuel markets and rising power costs for utility customers. Nationally and in Oregon, inflation remains high, labor markets are tight and the specter of economic recession looms. At the same time, PGE is experiencing highly localized growth in key areas of our service area. This imparts additional pressures on the transmission system, which is already highly constrained, as discussed in detail in **Chapter 9, Transmission**, and **Section 11.1.7, Transmission constraints**. Economic uncertainty, transmission constraints and labor and supply chain shortages may impact PGE's pace of acquisition and integration of non-emitting resources in the years ahead.

3.3.1 Localized load growth

Demand for data center capacity has grown exponentially across the globe and in the United States in the last 10 years, driven by factors such as the need for computing power, cloud and software-as-a-service offerings and entertainment. During that same time, certain areas of the PGE service area have become prime locations for data center siting. According to Cushman & Wakefield's 2023 Global Data Center Market Comparison, the Portland market jumped to a tie for first place in the overall global standing this year.[67] We are seeing a rapid expansion of hyperscale activity in the Washington County submarket from new entrants and existing customers due to access to the Transpacific cable landing, relatively favorable pricing, sustainability options, low environmental risk, access to power and available land. This contrasts with primary markets, such as Northern Virginia and Silicon Valley, seeing power and land constraints.

In addition to data center demand, Oregon is a global leader in semiconductor manufacturing and R&D. Fifteen percent of US semiconductor manufacturing takes place in PGE's service area, with Hillsboro supporting the largest concentration of integrated device manufacturers and semiconductor innovation in Oregon. With the Federal Government's 2022 passing of the CHIPS & Science Act, billions of dollars of federal incentives have been made available to help spur unprecedented domestic investment in semiconductor manufacturing and development. Oregon is vying to bring its share of that investment to the state for the benefit of local jobs and economic development. It is anticipated that much of that investment will focus on the region PGE serves, particularly the North Hillsboro semiconductor ecosystem. Specifically, the Oregon Semiconductor Competitiveness Task Force has recommended the addition of two 500-acre parcels of land in the N. Hillsboro and North Plains area to support the location of major new semiconductor manufacturing facilities.

With both trends described previously, PGE is projecting significant hyper-local growth and surging electricity demand in these geographic areas. PGE is proud to have supported enormous business growth in Washington County and the Hillsboro area for many years, helping to pave the way for new jobs, revenue streams and opportunity for the state. To meet this continued rapid demand growth, PGE is working diligently to increase infrastructure capacity by collaborating with industry, stakeholders and customers to benefit Oregon's economy. These efforts include:

- Advancing more than a dozen transmission projects with significant involvement of local governments and jurisdictions, including the Bonneville Power Administration (BPA);
- Actively engaging with BPA to increase transmission capacity by collaborating to accelerate upgrades and reinforce key substations and transmission lines along our 230 kilovolt (kV) and 500kV systems. We are also working with BPA to identify new options for incremental capacity;

[67] Information about the Global Data Center Market Comparison is available at: https://www.cushmanwakefield.com/en/insights/global-data-center-market-comparison

- Engaging residential and commercial customers to add value to the grid by participating in programs that compensate customers for lending their flexibility to the operation of the grid; and
- Deploying grid edge technologies such as remote sensors, dynamic line ratings and the use of advanced conductor materials.

At the time of the writing of this IRP, demand forecasts for North Hillsboro are being reviewed to ensure PGE is working from the most accurate load forecasts possible. We are working to understand customer timelines and flexibility, particularly around load delivery during peak usage times, to respond to new large load requests.

3.3.2 Workforce availability

Oregon's transition to the clean energy future will require investments in thousands of megawatts of new non-GHG-emitting resources and the people to build them. Oregonians are not unique in their desire for clean energy along the West Coast, which will lead to competition for the existing workforce to build those resources. Recognizing the need to be proactive, in mid-2022, PGE convened the Oregon Clean Energy Workforce Coalition (OCEWC). The OCEWC is a statewide coalition that includes utilities, renewable developers, unions, workforce investment boards, state agencies, pre-apprenticeship programs, local and regional governments, education providers and community-based organizations. The collective mission of the OCEWC is to build the clean energy workforce pipeline by intentionally engaging with historically underrepresented populations in the energy sector, including women and people of color. Ensuring the workforce pipeline will be able to meet the demand for clean energy will require all stakeholders to work together to support investments in pre-apprenticeship programs and educational awareness about the availability of jobs within the sector.

3.3.3 Supply chain

Like other electric companies nationwide, PGE continues experiencing delays in securing the material needed for development, maintenance and reliability.

These delays continue to be driven by material availability, labor constraints, shipping and transportation issues, increased construction demand and extreme weather, all exacerbating factors.

The situation is dynamic and is expected to continue. Therefore, we've taken these steps:

- We continue to take steps to alleviate the shortage impact on customers by delaying non-critical work, seeking new sources and adjusting material on order.

- We are working with industry organizations (like the Edison Electric Institute) and partners to advocate for measures to help address the shortage of critical materials.
- Partnering with distributors and manufacturers to increase forecasting and material ordering.

We will continue exploring options toward finding a solution to these issues.

3.3.4 Department of Commerce investigation into solar tariff circumvention

On January 23, 2018, then President Trump placed tariffs on imported solar cells and modules (PV panels) from China. The tariff level was set at 30 percent, with a 5 percent decline rate per year over the four-year term of the tariff. On February 4, 2022, President Biden extended the tariffs another four years but made an exemption for bifacial panels (two-sided panels used predominated in the utility-scale solar market segment).

On March 28, 2022, the US Department of Commerce (US DOC) announced a year-long investigation, which was prompted by a February 2022 petition from US company Auxin Solar, into whether imports of solar panels from Southeast Asia (specifically Cambodia, Malaysia, Thailand and Vietnam) are circumventing the tariffs in place against China. The investigation could result in retroactive tariffs of up to 240 percent. Despite President Biden's exemption for bifacial panels in the tariff extensions, the investigation would impact all developments that involve crystalline silicon photovoltaic (CSPV) cells. About 80 percent of panels installed in the US in 2021 came from the four countries under investigation.

The US DOC announced its preliminary determination in December 2022 that four of the eight companies being investigated were attempting to circumvent the existing tariffs through each of the four Southeast Asian countries. The US DOC is scheduled to release a final determination, including the assessed duties, on May 1, 2023. President Biden issued a proclamation on June 6, 2022, which suspended the solar tariffs for two years. Therefore, duties cannot be collected on any solar import until June 2024.

The PV panel supply chain is likely to continue to experience disruption. Given the large share of PV panels originating in the Southeast Asian market, US-based developers may not find adequate supplies of replacement panels from other countries of origin. The limited supply of North American manufacturing capacity is largely sold through 2023, limiting the potential for alternative domestic supply to backfill Southeast Asian equipment. Amidst this supply chain disruption, solar developers are faced with disrupting choices, including 1) importing Southeast Asian panels and facing exposure to retroactive penalties, 2) sourcing panels from more expensive countries of origin, including China, whose PV panels are subject to ongoing tariffs, 3) waiting for the US DOC investigation to resolve.

Chapter 4. Futures and uncertainties

To meet the evolving needs of the electricity grid and customers, it is critical to assess the wide range of uncertainties impacting different elements within the power system. Estimating the compounded effects of the different drivers and their impacts is foundational to ensuring the robustness of our resource actions by minimizing risk over time for customers across a wide range of potential futures.

The previous chapter discussed the broader policy and macroeconomic environment in which we are creating these plans. In this chapter we detail how we are incorporating this environment, including all the associated uncertainty, into our IRP. First, we discuss the different Need Futures, which describes the range of resource needs in terms of capacity and energy. This is followed by descriptions of the variation in technology costs of resources and wholesale electricity prices. This approach informs how resource actions taken by Portland General Electric (PGE) will account for future risks and uncertainties.

Chapter highlights

- Key drivers of uncertainty in this Integrated Resource Plan (IRP) include demand growth, economic trends and technological innovation, rate of electrification and customer adoption of new technologies, regional resource adequacy and buildout of new non-GHG-emitting resources.
- PGE's portfolio analysis accounts for uncertainty in future resource needs, technology costs, wholesale energy markets and hydro conditions.
- Portfolio analysis was conducted across 351 potential futures, defined by the range of resource needs, technology costs and wholesale electricity market prices

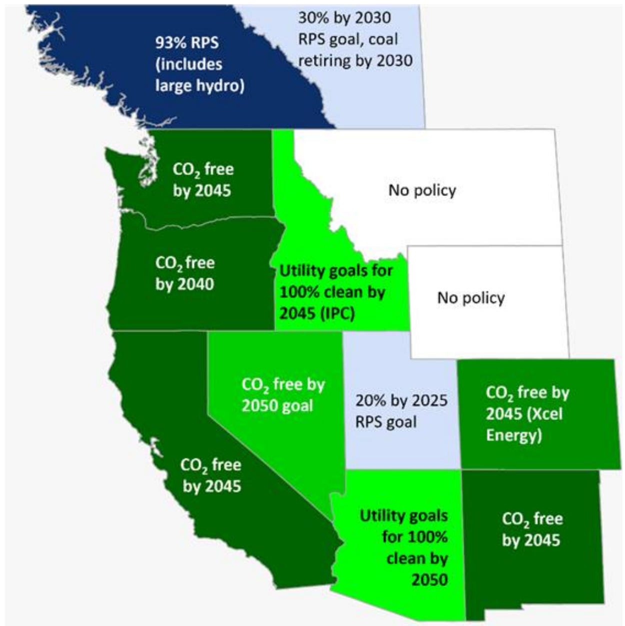
4.1 The changing Western Interconnection

The power system landscape across the Western Interconnection is changing rapidly.[68] At the start of 2018, there were no policies in the West that mandated a 100 percent clean/non-GHG-emitting power system. In September 2018, California signed Senate Bill (SB) 100 into law, which directed the state to reduce electric system GHG emissions to zero by 2045.[69] In

[68] Information about the Western Interconnection is available at: https://www.wecc.org/epubs/StateOfTheInterconnection/Pages/The-Western-Interconnection.aspx
[69] CA Senate Bill (SB) 100 (2018), available at: https://www.energy.ca.gov/sb100

the following years many states, including Oregon in 2021, passed similar bills targeting a non-emitting power system in the 2040s (**Figure 17**).[70] Additionally, several utilities in states without clean energy policies have made company-level decarbonization pledges.[71] **Figure 17** shows key state-level GHG reduction and renewable portfolio standard policies.[72] These policies will likely bring more wind, solar, storage and other non-emitting resources to the West and transition away from coal and gas-fired generation.

Figure 17. Western clean energy policies



Forecasting Western energy markets requires predicting how quickly non-GHG-emitting resources will arrive and how quickly GHG-emitting generation will decrease, considering market and transmission interoperability issues, and assessing if the transition creates adequacy challenges. Resource adequacy challenges have occurred in recent years in the Western Interconnection. In California, the California Independent System Operator (CAISO) system experienced blackouts in August 2020 and issued a Stage 3 emergency alert in September 2022.[73] Prior to 2020, CAISO had yet to issue a Stage 3 alert since the 2001 energy crisis. Due to reliability concerns, California passed AB 205 in the summer of 2022, which includes an electric reliability reserve fund, among other provisions. California also

[70] OR: HB 2021 (2021); WA: SB 5116 (2019); NM: SB 489 (2019); NV: SB 358 (2019); and CO SB 19-236 (2019).
[71] Available at: https://www.idahopower.com/news/idaho-power-long-range-plan-focuses-on-reliable-affordable-clean-energy/, and at https://www.aps.com/en/About/Our-Company/Newsroom/Articles/APS-sets-course-for-100-percent-clean-energy-future, January 22, 2020
[72] Policies listed on the map may not apply to smaller power providers; additional policies may exist.
[73] A Stage 3 alert indicates blackouts are imminent.

passed SB 846 in 2022, which attempts to extend the life of the Diablo Canyon nuclear power plant, mainly for grid reliability.[74]

Beyond the changing supply side landscape, there is uncertainty regarding Western electric demand. Many states and municipalities have passed laws encouraging and/or mandating building and vehicle electrification that could bring new loads to the Western Interconnection. For example, Oregon, Washington and California are banning the sale of gasoline passenger vehicles by 2035, accelerating the push toward electric vehicles.[75] In spring 2022, Washington amended its building codes to require electric heating in most large multifamily construction and commercial buildings.[76] These policies, which aim to reduce GHG emissions, may lead to increased demand for electricity. Beyond electrification, the Northwest has also seen increased demand for electricity in recent years from industrial customers, often in the form of data centers.

In late 2019, the Western Power Pool (then the Northwest Power Pool) reviewed reliability studies conducted by BPA, Energy and Environmental Economics, Inc. (E3), Pacific Northwest Utilities Conference Committee (PNUCC) and the Northwest Power and Conservation Council. The studies "identify an urgent and immediate challenge to the regional electricity system's ability to provide reliable electric service."[77] They also note that "studies have shown that it is possible to cost-effectively replace coal generation with… lower carbon resources and significantly reduce electricity sector carbon emissions."[78]

The Western Power Pool's findings helped spur the creation of the Western Resource Adequacy Program (WRAP). The WRAP is still under development. If it succeeds, it may change how the IRP examines power market availability, resource adequacy and resource capacity contributions (more information on the WRAP is in **Section 3.2, Regional planning: resource adequacy**).

As part of the Western Interconnection, PGE routinely buys and sells power with other Western power market participants. As noted earlier in this section, predicting how much power will be available to buy and sell in future years is challenging. However, the IRP considers short-term power markets as a resource adequacy tool. To accomplish this, the IRP includes an analysis that approximates how much power will be available in future years during peak hours. This analysis focuses more on power availability in Oregon, Washington,

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[74] Available at: https://www.utilitydive.com/news/california-sweeping-climate-package-carbon-neutrality-2045-clean-electricity-2035-diablo-canyon/631099/
[75] Available at: https://www.oregon.gov/deq/rulemaking/Pages/CleanCarsII.aspx
[76] Available at: https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/washington-state-to-require-electric-heating-in-building-code-update-69960737
[77] See "Exploring a Resource Adequacy Program for the Pacific Northwest", Northwest Powerpool, October 2019, at page 7, available at: https://www.westernpowerpool.org/private-media/documents/2019.11.12_NWPP_RA_Assessment_Review_Final_10-23.2019.pdf
[78] *Id.* at page 8.

Idaho and Western Montana and is used as an input into the resource adequacy model, Sequoia, that determines PGE's need for power. More information on the analysis is in **Appendix G, Market capacity study**.

For the Reference Case, the amount of market power available to the Sequoia model is in **Table 6.** Heavy load hours defined as 6:00 AM to 10:00 PM, Monday-Saturday, excluding holidays. Light load hours are all other hours. The light load hour range is dependent on load (lower load is associated with more market availability). The decrease in winter market availability starting in 2026 is largely due to coal unit retirements.[79]

Table 6. PGE 2023 IRP spot market power availability assumptions for resource adequacy

All values in MW	2025 and earlier		2026 and later	
	Winter	Summer	Winter	Summer
Heavy load hours	200	0	150	0
Light load hours	400-999	400-999	400-999	400-999

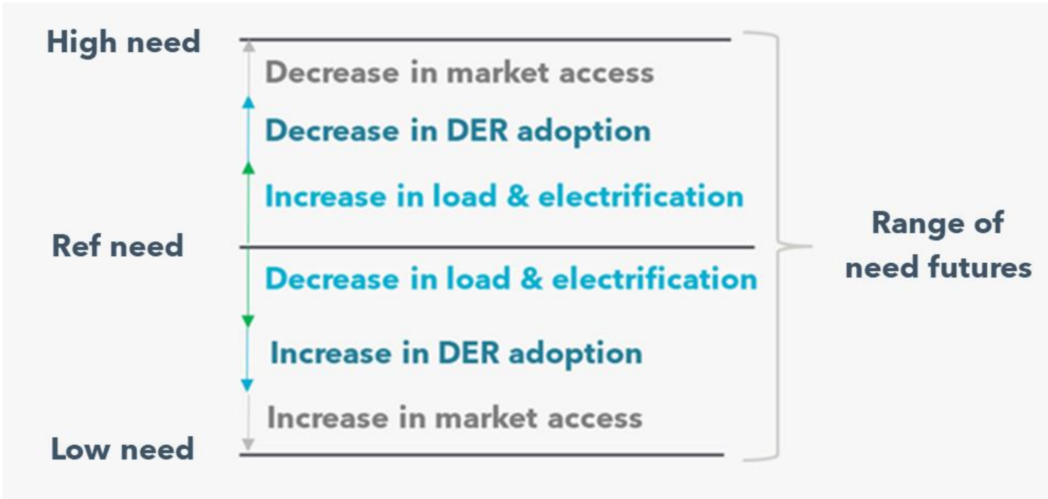
4.2 Need Futures

One of the two key objectives of the IRP process is to estimate system need under a variety of scenarios.[80] The IRP creates individual Need Futures that aggregate the impact of load growth, distributed energy resources (DERs) and market access assumptions. Different permutations of the load, DERs and market access assumption form the basis for the range of Need Futures in the IRP. The range of Need Futures is a vital input to determine the robustness of the proposed set of resource additions to a variety of conditions. The Need Futures not only capture the costs and risks associated with large and long-lived resource actions given the uncertainty in future resource needs but also highlight critical considerations for PGE's non-GHG-emitting resource procurement strategy.

PGE designed the Need Futures to capture a broad variation from the Reference Case by varying drivers that would impact the resource need.[81] **Figure 18** visually represents the driving variables that change the Reference Case to the High and Low Need Futures.

[79] The coal fired Centralia Unit 2 and Valmy Unit 2 are expected to retire at the end of 2025.
[80] The other key objective is to propose the optimal combination of resources, their size and timing, to address the identified system need. This culminates in **Chapter 11, Portfolio analysis**.
[81] The Reference Case refers to the collection of assumptions made across all applicable variables. These assumptions were made based on analysis and studies. Low and High Case assumptions are applied in relativity to the Reference Case.

Figure 18. Visualization of the range of Need Futures captured within the IRP



Articulated in this section is a comprehensive list of variables that result in the three Need Futures, which are summarized in **Table 7.**

- **Top-down Load Forecast.** This IRP considers three scenarios related to macroeconomic and policy trends and impacts on future loads. In addition to the reference load forecast, the low and high growth scenarios capture uncertainty in economic drivers and forecast model uncertainty. The top-down load forecast and associated high and low growth scenarios are detailed further in **Section 6.1, Load forecast,** and **Appendix D, Load forecast methodology**.
- **Energy Efficiency.** This IRP considers three scenarios related to energy efficiency adoption. In addition to the Reference Case, the Low Need Future assumes a higher acquisition of energy efficiency than the Energy Trust of Oregon's (ETO's) cost-effective forecast based on the ETO's high avoided cost scenario (which assumes a 25 percent increase in avoided costs as defined by UM 1893).[82] Similarly, the High Need Future is based on Energy Trust's low avoided cost scenario, which assumes a 25 percent decrease in avoided costs relative to the Reference Case. Energy efficiency that was deemed cost-effective by ETO is discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

[82] *In the Matter of Public Utility Commission of Oregon, Investigation Into the Methodology and Process for Developing Avoided Costs Used in Energy Efficiency Cost-Effectiveness Tests*, Docket No. UM 1893, available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=20999

- **Market Capacity.** This IRP considers three scenarios for the availability of capacity from the market across seasons, years and hours of the day. The High Need Future assumes reduced market capacity, indicating the minimal ability to serve load via market purchases during summer and winter high load hours. Conversely, the Low Need Future assumes higher market availability during the high load hours in summer and winter. These assumptions are based on the findings and recommendations in **Appendix G, Market capacity study**.

This IRP leverages the analytical work within PGE's Distribution System Plan Part 2 (DSP) to determine the range of impact of DER, using it as the primary source of data for the adoption of rooftop PV, building and transportation electrification loads and their integration with PGE through demand response programs.[83]

- **Distributed Photovoltaics (PV).** This IRP aligns with the three adoption cases developed within the DSP. High adoption of PV results in a lower resource need and is consequently included in the low Need Future. Similarly, low adoption of solar PV is included in a high Need Future, as shown in **Table 7**.
- **Transportation Electrification (TE) Load.** High TE adoption results in a higher resource need and is included in the high Need Future. Conversely, low adoption of TE load is included in the low Need Future.
- **TE-related Demand Response (DR) programs.** Unlike TE load, the low participation in TE-related DR programs is included in the High Need Future to ensure we capture the broadest range of potential futures. However, in the Low Need Future, we use a Reference Case of the adoption of TE-related DR programs because the low adoption of EVs would not have sufficient vehicles to be combined with a high adoption of TE-related DR programs.
- **Demand Response (DR).** Like energy efficiency and PV, this IRP models an inverse relationship between Need Futures and customer participation in DR programs.[84]
- **Building electrification (BE) Load.** This IRP introduces three BE load adoption scenarios to align with the DSP's adoption scenarios, so the high adoption scenario of BE load is included in the high Need Future.

[83] PGE's Distribution System Plan Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

[84] High adoption of demand response programs results in lower needs and low adoption of demand response programs results in higher needs. The customer adoption of batteries is included within the demand response variable of each Need Future.

- **BE-related Demand Response (DR) programs.** However, just as with TE-related DR load, low participation in BE-related DR programs is included in the High Need Future to ensure we are capturing the broadest range of potential futures, and in the Low Need Future, we use a Reference Case of the adoption of BE-related DR programs creating an appropriate lower bound to the Need Future.

Table 7. Need Future variables

	Low need	Reference need	High need
Top-down Load Forecast	Low growth	Reference	High growth
Energy Efficiency	High EE	Reference	Low EE
Distributed PV	High adoption	Reference	Low adoption
Transportation Electrification (TE) load	Low adoption	Reference	High adoption
TE-related DR programs	Reference	Reference	Low adoption
Demand Response programs	High adoption	Reference	Low adoption
Market capacity	High availability	Reference	Low availability
Building electrification load	Low adoption	Reference	High adoption
Building electrification-related DR programs	Reference	Reference	Low adoption

In addition to the three Need Futures, PGE examined sensitivities to provide insight into other uncertainties that may impact need. These are described in **Section 6.10, Need sensitivities**.

4.3 Energy technology capital cost scenarios

Throughout **Chapter 2, Accessing support for energy transition** and **Chapter 3, Planning environment**, PGE describes the developments since the 2019 IRP that impact the current and expected costs of resources:

- Tax credit changes (see **Section 2.1, Federal support for energy transition**)
- Clean Energy Policy (a reference to **Section 3.1, Federal and state law and regulatory policy**)

Capital cost estimates are uncertain. Evaluating this capital cost uncertainty in a period of rapid technological change, inflation and supply chain shortages is critical to creating a long-term plan robust to potential changes. In addition to the reference costs (see **Chapter 8, Resource options**, and **Appendix M, Supply-side options**), PGE uses low and high capital cost trajectories for supply-side resources. Reference Case trajectories are primarily informed by the Energy Information Administration (EIA) 2020 Annual Energy Outlook (AEO) and the National Renewable Energy Laboratory (NREL) 2021 Annual Technology Baseline (ATB) analyses.[85,86] The high- and low-cost sensitivities generally rely on the scenarios presented in the NREL ATB; however, resource-specific assumptions are discussed in **Appendix M, Supply-side options**. Capital costs are included in PGE's IRP resource modeling via the revenue requirements model (**Section 10.1, Fixed costs**).

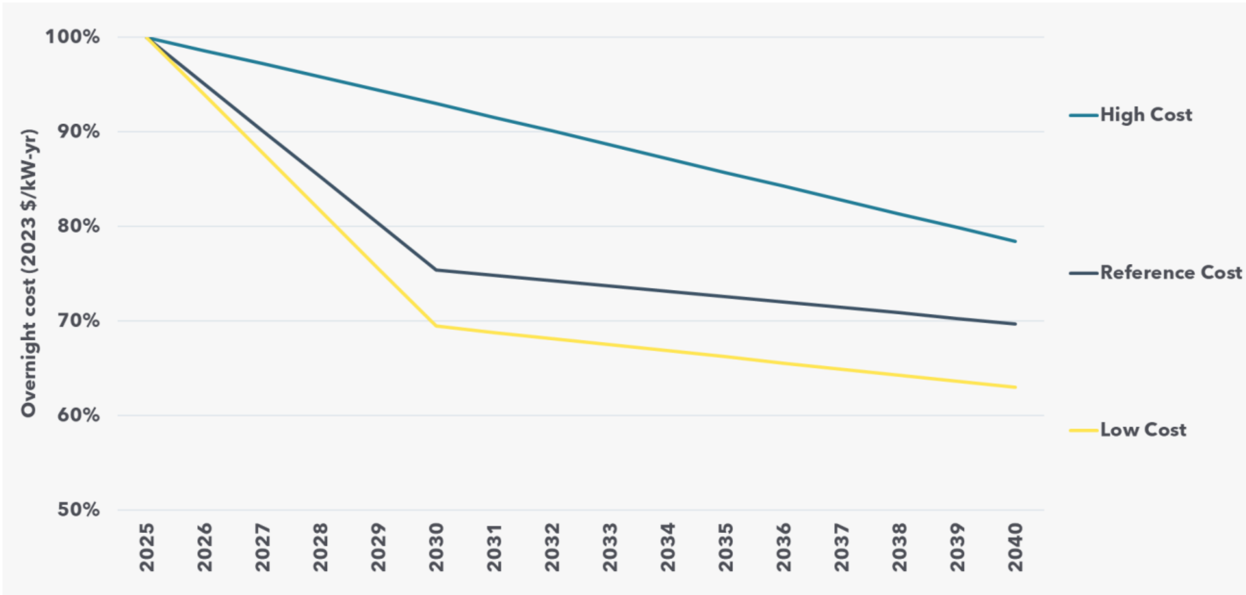
NREL summarizes the general technology innovation scenarios as follows:[87]

- Conservative scenario (high cost) In the NREL ATB Conservative scenario, historical investments come to market with continued industrial learning. The technology available is similar to the current day with a few technological innovations. Public and private investment in research and development (R&D) decreases.
- Moderate scenario (reference) NREL ATB describes this scenario as the expected level of technological innovation. The innovations observed in today's marketplace have become more widespread, and nearly market-ready innovations have come into the market. Public and private R&D investments continue at the current levels.
- Advanced scenario (low cost) Innovations far from market-ready today are successful and have become widespread in the NREL ATB Advanced scenario. Innovative technology architectures could look different from those observed today due to increased public and private R&D investment.

To illustrate the relationship between these three technology capital cost scenarios, fixed cost trajectories for the Christmas Valley Solar resource under each are presented in **Figure 19**.

85 EIA 2020 Annual Energy Outlook, available at: https://www.eia.gov/outlooks/archive/aeo20/
86 NREL 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/index
87 NREL 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/definitions

Figure 19. Christmas Valley solar resource overnight cost trajectory (2023$)



See also the discussion of technology costs with respect to the Scenarios discussed in **Chapter 11, Portfolio analysis**.

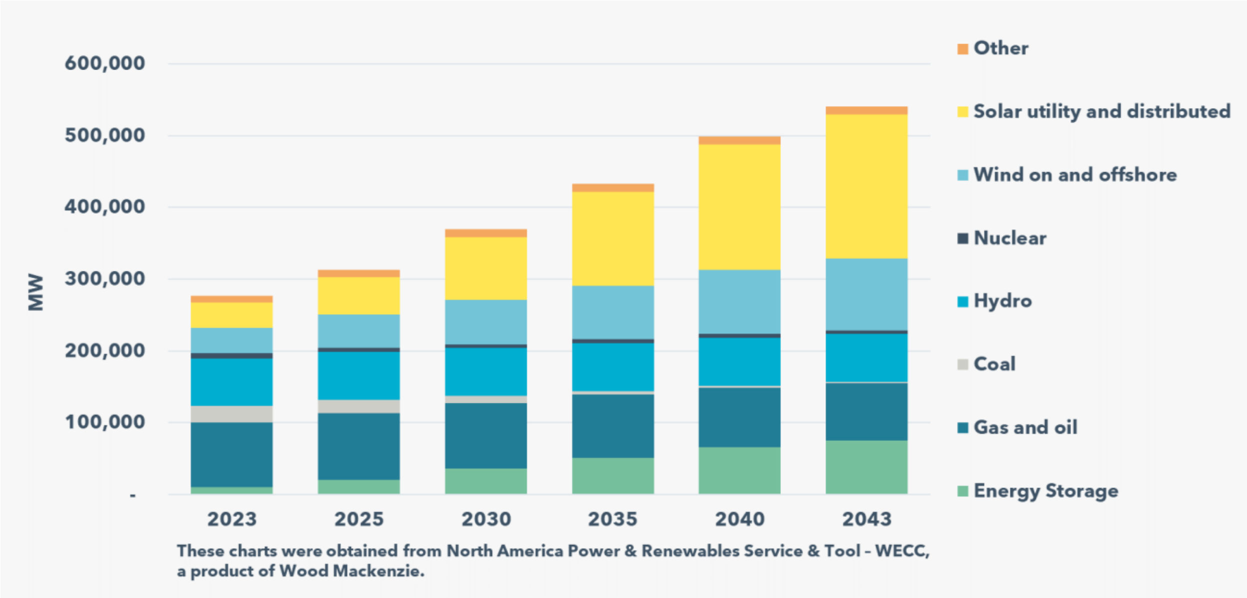
4.4 Long-term fundamental price forecast

The natural gas price forecast strongly influences the forecast of wholesale market prices for electricity.[88] PGE relies on the expertise of a power research consultancy, Wood Mackenzie (WM), to project the Western Electricity Coordinating Council (WECC) resource development and its impact on electricity prices in this IRP. Consequently, PGE incorporates WM's natural gas price forecasts into its long-term price forecasts, which reflects a declining reliance on the thermal fleet in the WECC as the region transitions to non-GHG-emitting resources. PGE also uses WM's WECC resource buildout outlook, shown in **Figure 20.**

The figure reflects the magnitude of the WECC effort to decarbonize, with resource additions being mainly renewables and storage. While the contribution share of gas and oil capacity is forecasted to decline over time as loads increase and non-GHG resources are brought on-line, the capacity of gas and oil capacity remains steady. The WECC capacity will nearly double the current level by 2043, with solar having the majority share and on and offshore wind being the next major contributor.

[88] Coal price forecasts have some influence on the wholesale electricity prices up until the end of 2029 as PGE's candidate resource portfolios include a coal-fired resource, Colstrip, that PGE is set to exit by January 1, 2030.

Figure 20. WECC capacity installed by year and generation source



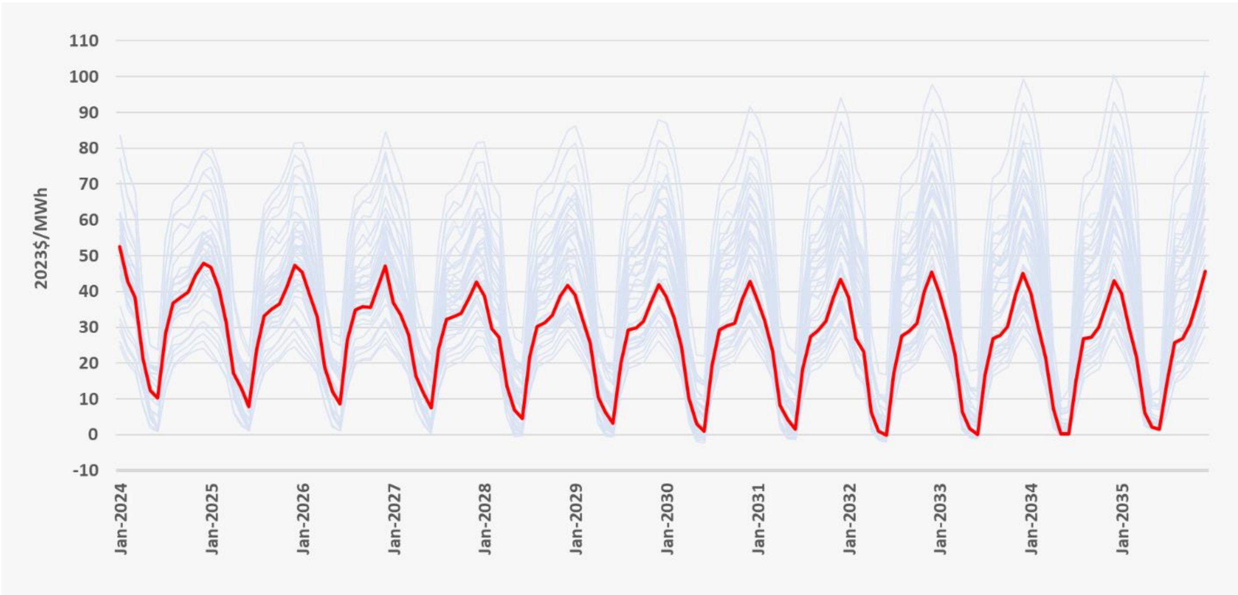
PGE benefitted from extensive discussions on our electricity price forecasts with stakeholders in several IRP Roundtables.[89] These identified the following risk drivers to be considered in the IRP forecasts:

1. Gas prices and hydro conditions
2. Cost of compliance with carbon policies
3. Uncertainty in net load
4. Scarcity of committed dispatchable resources

PGE used the planning software Aurora with the WM WECC assumptions to generate 39 electricity price futures from permutations of risk drivers and carbon policy. This analysis aimed to identify a reference electricity price and a range of reasonable electricity prices in the Pacific Northwest in the next 20 years.[90] **Figure 21** displays forecasted monthly average electricity prices for each future, with the red reflecting reference prices. Simulated electricity prices then become an input for dispatch of existing PGE resources and are used to create energy value for new candidate resources.

[89] See **Appendix C.1.3, 2022 Public meetings** and **Appendix C.1.4, 2023 Public meetings** for more detail
[90] To reflect plausible scenarios in the simulation model, PGE capped energy prices at $1000 per MWh to reflect the price level that would trigger the FERC to investigate the incremental price increase. For price futures where significant commitment errors are considered and may consequently observe frequent breaches to the price cap, PGE reduced the price cap to $250 per MWh to reflect the price experienced during the 2000 energy crisis.

Figure 21. Average annual PNW electricity price futures



Results suggest that the forecasted growth in renewable generation resources across the WECC will generally reduce annual average prices, but the variability associated with their generation profiles will have a significant impact throughout the planning horizon. Winters continue to be forecasted times of high average monthly prices. The months of May and June exhibit low average monthly prices given low demand and high generation supply. The large distribution of potential market outcomes of forecasted prices highlights the uncertainty in forecasts of economic conditions. An important consideration is that IRP price forecasts do not necessarily represent the operational prices that utilities might face in real time due to the operating conditions utilities face and the unpredictable forward procurement costs. Instead, the IRP's forecasted prices are the results of a balanced system and normal conditions, and they benefit from a good forecast of load and renewable production. The prices are representative of hour-of-dispatch cost once reserves are procured. The long-term assumption is that the system finds adequate supply to meet demand and reserves. In contrast, operational prices do not have any of the mentioned elements. Operational prices, instead, are strongly dependent on short-term market variables.[91]

[91] Short-term market variables are factors that influence the operational prices of natural gas because of shocks to the supply or demand side of the natural gas market. These shocks, for example, could be caused by weather events or political events that increase or decrease the level of supply or demand in energy markets.

Acknowledging that our model will likely not accurately predict actual prices, PGE forecasted hourly prices with a variety of market price drivers: the quantity of available renewable capacity across the WECC, carbon policies, natural gas prices and hydropower generation in the Pacific Northwest. **Section 4.5, Uncertainties in price forecasts,** describes these market price drivers in more detail.

4.5 Uncertainties in price forecasts

PGE uses a scenario approach to model economic and technological uncertainty. In this section, we describe the risks and uncertainties that are evaluated in price forecasting, along with the price futures summarized in **Section 4.4, Long-term fundamental price forecast**.

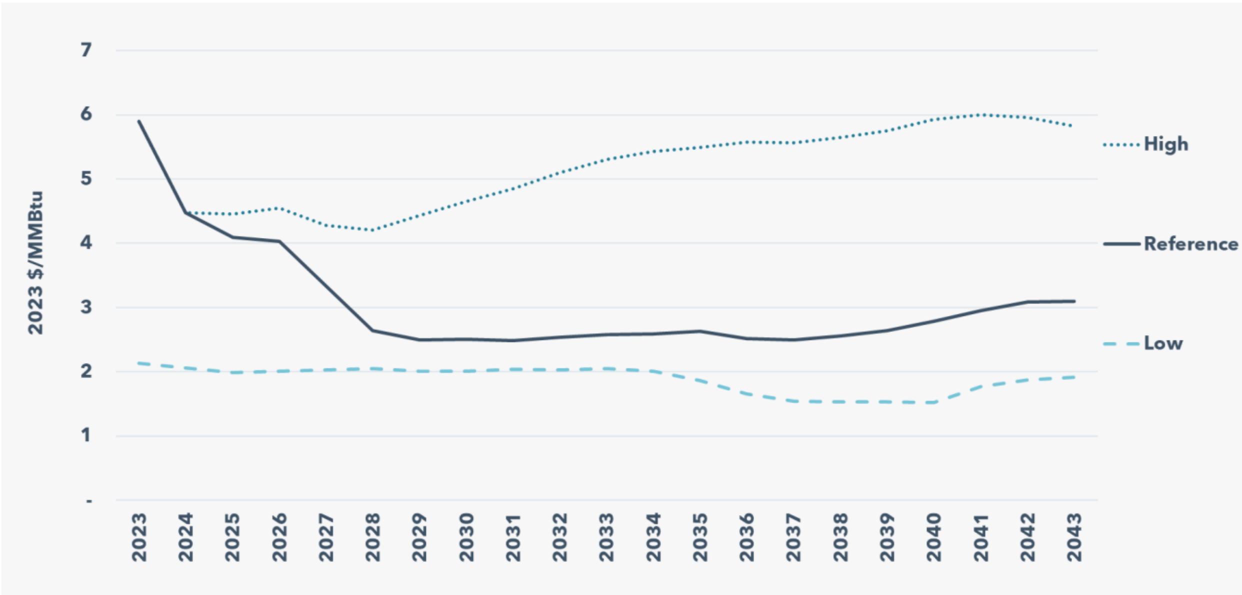
4.5.1 Commodity risk: natural gas prices

The price of natural gas has been and will continue to be a significant driver of wholesale electricity prices as natural gas-fueled power plants are used to meet loads, particularly during times of energy scarcity. The marginal units of power generated by natural gas-fueled power plants often set the market clearing price. While the contribution of gas-fueled power plants in the WECC declines in a high-renewable transition, the capacity of individual plants remains unchanged. With the significant increase of energy scarcity events, the forecasted price and availability of natural gas will continue to influence the electric power market while storage resources are not yet long-term multi-day capable.

PGE updated the gas price forecast input with Wood Mackenzie's long-term gas price forecast available in June 2022 to reflect the market sentiment prices following Russia's invasion of Ukraine in February 2022. The war triggered market volatility as the global sanctions against Russia's gas supply and increased export of liquefied natural gas (LNG) put a strain on the US oil and gas supply, causing historically high gas prices. WM's forecast also reflects the expectation of declining natural gas demand as states transition away from fuel-powered plants toward renewable generation.

Figure 22 shows the resulting Sumas hub gas price levels and trends. When simulating WECC prices, all gas hubs are input using the same input methodology previously described so that all WECC hubs are stressed simultaneously.

Figure 22. Natural gas price forecast Sumas Hub



4.5.2 Commodity and scarcity risk: hydropower generation

Hydropower generation (hydro) in the Pacific Northwest also strongly influences electricity prices. In addition to average hydro, PGE simulated a high and low hydro future. The average hydro is the Wood Mackenzie default and equal to the 2000-2011 average generation published by EIA. High hydro is 10 percent more than default and low hydro is 10 percent lower. See **Appendix H, 2023 IRP modeling details**, for more detail on this assumption. This hydro generation variability assumption is in line with the results observed in **Ext. Study-III, Climate adaptation**.

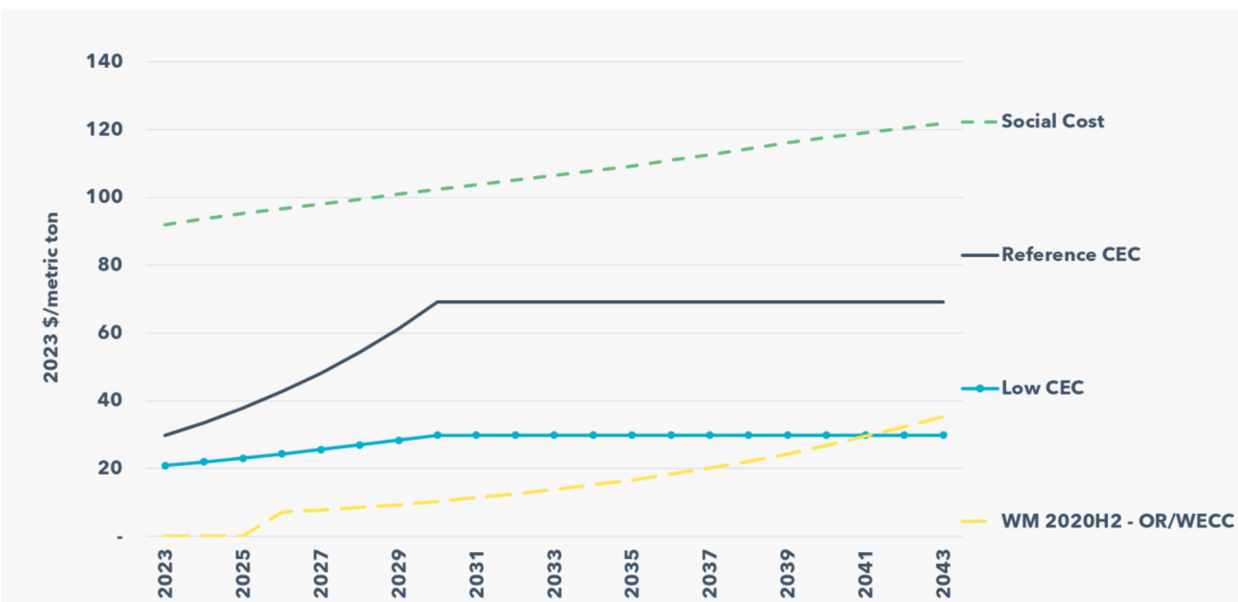
4.5.3 Carbon policies and emissions targets in WECC

This section explains how PGE modeled carbon price risk to market prices and unit dispatch simulations. PGE developed carbon adders to represent the cost of carbon policy compliance on power generation. These adders are added to dispatch cost based on individual resource fuel type and location.[92] The carbon adders are incorporated into three different carbon futures for the US portion of the WECC:

[92] A carbon adder is a modeling step in the PGE Zone Model (PZM) simulation where a cost is added to the dispatch cost of a carbon-emitting resource proportional to its emissions rate.

- Reference Case: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2019 Reference GHG Allowance Price Projections published by the California Energy Commission (CEC).[93]
- Low carbon: No carbon adders are applied to WECC except for California and Washington, where there is existing carbon pricing legislation. California and Washington carbon adders apply the 2019 Low GHG Allowance Price Projections published by the California Energy Commission (CEC).[94]
- High carbon: California, Washington and Oregon apply the social cost of carbon (SC-CO2) defined by the United States Environmental Protection Agency (US EPA) and other federal agencies.[95] PGE selected 2.5 percent as the discount rate in intergenerational discounting to represent the social cost of carbon. For the rest of WECC, PGE applied Wood Mackenzie's reference carbon adder forecast to proxy for the cost of compliance with new carbon regulation.[96]
- Across each future, British Columbia and Alberta have a carbon tax adder that reflects Canadian legislation. **Figure 23** shows the forecasted level of the carbon adders.

Figure 23. Carbon adders in WECC economic analysis



[93] CEC's Integrated Energy Policy Report (IEPR) 2019, available at: https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2019-integrated-energy-policy-report
[94] *Id.*
[95] See, The Social Cost of Carbon, US Environmental Protection Agency, available at: https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon_.html
[96] Wood Mackenzie 2020H2 WECC Carbon Adder Forecast, shown in **Figure 23**.

4.5.4 Uncertainty and scarcity risk

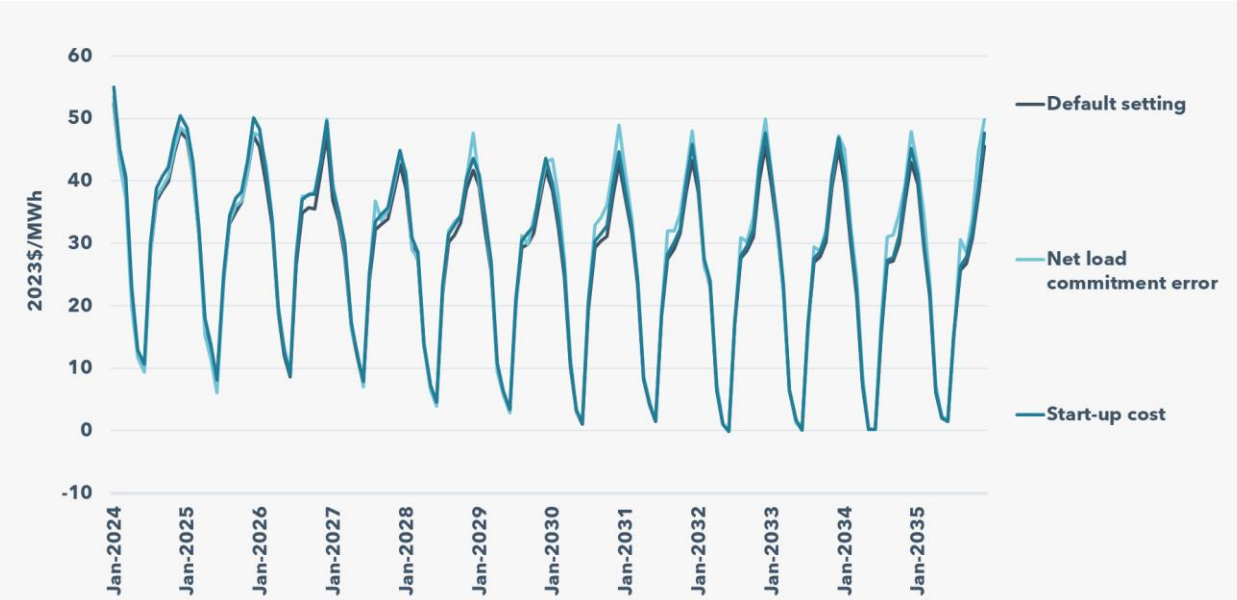
An important outcome of the public process leading to this IRP was the recognition of a disconnect between operational prices and fundamentals forecast, as mentioned in **Section 4.4, Long-term fundamental price forecast**. Traditionally, fundamental models do not embed operational difficulties experienced in actual operations as the model assumes that new dispatchable resources can be added to overcome operational obstacles. However, stakeholders and PGE agreed that the energy transition to non-dispatchable new additions would likely result in increasing difficulty in committing the resources at the right time. This volatility and scarcity price premiums have never been modeled in PGE's IRP. Hence, PGE created resource imbalance and scarcity premiums on prices by:

- **Introducing commitment error.** PGE purposely input a discrepancy between the wind forecast and the actual wind generation to represent the possibility of not having the right resources online and ready to generate when the net load is not what is expected. A 15 percent increase or decrease forecast error is randomly imposed on wind nameplate capacity hourly.
- **Adding start-up costs to simulated prices.** In our model, electricity prices are set by the marginal cost of the most expensive resource in the stack that is used to meet loads. When capacity is scarce, the marginal cost might underestimate prices, which demands a trade/bidding premium. We add the start-up cost to prices to reflect this premium.

This approach attempts to mimic the large generation and load swings with limited spare dispatchable resources. Additionally, we anticipate the magnitude of intermittent generation is and will increasingly be unprecedented, and climate change's impact on load, hydro and wind generation is largely unknown. The uncertainty and scarcity risk drivers were discussed in the April 22-3 roundtable, and more modeling detail is described in **Appendix H, 2023 IRP modeling details**.

Figure 24 illustrates the average electricity prices of the 39 price futures created in the WECC-wide Aurora simulation, organized into three categories: no modeling input, net load commitment error and start-up cost price futures. There is a pattern of more volatile electricity prices in the summer when net load commitment error, represented in light blue, is introduced. **Appendix H, 2023 IRP modeling details**, compares the intra-month hourly price range of reference and reference price future with start-up cost introduced.

Figure 24. Monthly average electricity prices across modeling specifications



By combining all the economic risk factors previously listed, we generated 39 price futures identified by a four-letter code for each risk model shown in **Table 8**.

Table 8. Simulated price futures

	Aurora Setup			Carbon Adder			Gas Price Forecast			Hydropower Generation		
	WM Model	Start-up cost	Net load commitment	Reference	Low	High	Reference	Low	High	Reference	Low	High
Number of price futures with risk factor	27	6	6	21	9	9	15	9	15	13	13	13

4.6 Addressing uncertainties

When the Capacity Need, Market Price and Technology Cost Futures are considered together, they explore a wide range of potential future conditions that influence the size and timing of resource additions. **Table 9** describes how these 39 price futures are combined with three Need Futures and three technology cost futures to consider 351 unique futures for each portfolio. Conducting portfolio analysis across these 351 alternative futures allows us to evaluate portfolios that meet system needs across a wide range of potential futures and score them based on cost and risk performance. While cost and risk metrics vary across all futures, resource builds do not vary by hydropower condition.

Table 9. Number of futures evaluated in portfolio analysis

	Market Price Futures		Capacity Need Futures		Technology Cost Futures		Total Futures Evaluated
Number of Futures	39	x	3	x	3	=	351

The WECC-wide simulation (conducted in Aurora) process is the first step to portfolio analysis and GHG emission forecasting. The simulated WECC electricity prices of the 39 price futures become the input for the PGE Zone Model simulation. Sequentially, the economic dispatch simulation results of new resources become inputs for the capacity expansion model, ROSE-E and the results of GHG-emitting resources become inputs for GHG emission forecasting. The following section discusses the GHG emission forecasting process in greater detail, and **Appendix H, 2023 IRP modeling details** explains the construct and relationships among models.

Chapter 5. GHG emissions forecasting

Under House Bill (HB) 2021, Portland General Electric (PGE) must reduce its greenhouse gas (GHG) emissions associated with electricity sold to Oregon retail customers. This chapter begins with a discussion of historical GHG emissions and the HB 2021 GHG targets. It then moves to describe the emissions reporting requirements of the Oregon Department of Environmental Quality (ODEQ). Finally, this chapter describes the emissions forecasting process that follows the ODEQ methodology and highlights five GHG reduction glidepaths PGE is studying as part of the 2023 Integrated Resource Plan (IRP).

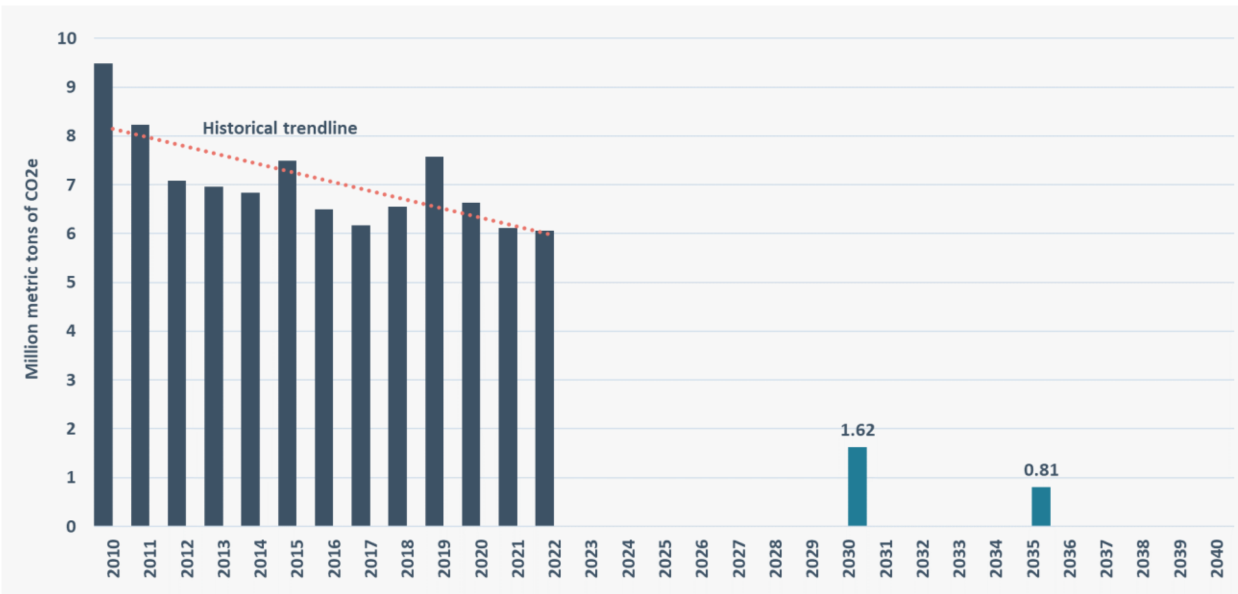
Chapter highlights

- HB 2021 sets 2030, 2035 and 2040 greenhouse gas (GHG) targets for energy associated with PGE retail load of 1.62, 0.81 and zero million metric tons of GHG emissions, respectively.
- PGE reports its GHG emissions associated with sales to Oregon retail customers to the ODEQ annually, and those reported emissions will be the basis for determining compliance with HB 2021.
- New for the 2023 IRP, PGE uses an Intermediary GHG model to account for differences in regulation of GHG emissions associated with serving Oregon retail customers and wholesale market sales.
- The IRP studies five different glidepaths for GHG reductions. Actual emissions may differ from those predicted here due to weather, resource procurement realities and other factors.

5.1 HB 2021 targets

House Bill (HB) 2021 sets Greenhouse Gas (GHG) emissions targets for PGE to meet. PGE must reduce GHG emissions associated with Oregon retail load as reported under ORS 468A.280 to 1.62 million metric tons CO2 equivalent (CO2e) by 2030, 0.81 million metric tons by 2035 and zero metric tons by 2040 and every year after. **Figure 25** shows PGE's historical GHG emissions under ORS 468A.280 and the HB 2021 targets.[97] As of the close of 2022, PGE's emissions have already fallen 25 percent from the baseline emissions level of 8.1 MMTCO2e.

Figure 25. Historical emissions for Oregon retail load service and HB 2021 targets



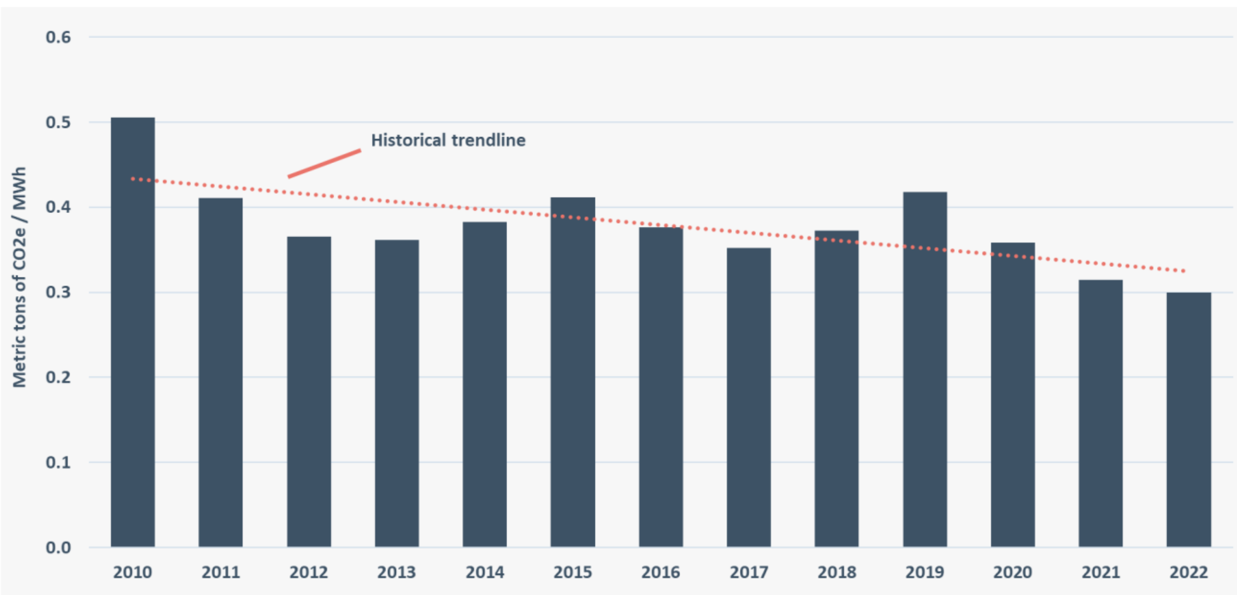
GHG emissions from generation and power purchases fluctuate year to year, often due to variations in economic conditions, temperature, wind/solar conditions, water conditions and other factors beyond the control of PGE. For example, higher-than-expected temperatures can increase the need for mechanical cooling (air conditioning), which increases load and the emissions associated with serving that load.[98] Water conditions can change hydroelectric power availability, with low water years increasing reliance on GHG emitting generation. An increase or decrease in macroeconomic activity can alter energy demand and the emissions associated with serving load. **Figure 25** demonstrates the non-linear pattern of year-to-year reported emissions, with a declining trend from 2010 through 2022. Due to these annual

[97] ORS 468A.280, available at: https://www.oregonlegislature.gov/bills_laws/ors/ors468a.html
[98] Since non-emitting resources dispatch first, an increase in load above the expected basis would likely be met by gas, coal or market purchases.

GHG variations, the Public Utility Commission of Oregon (OPUC or the Commission) has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…".[99] More discussion and analysis on how temperature and hydropower conditions impact GHG emissions is in **Appendix I, C-level analysis**.

Because of the correlation between load and emissions, GHG emissions intensity, defined as metric tons of CO2e per megawatt hour (MWh), is a useful decarbonization metric as it normalizes changes in load to better account for the resource mix that is serving that load. **Figure 26** shows PGE's Oregon retail GHG intensity from year 2010 through 2022. While GHG intensity provides useful information, HB 2021 requires an absolute reduction in utility GHG emissions, not a decrease in GHG intensity.

Figure 26. Historical GHG intensity for Oregon retail load service



HB 2021 does not explicitly set GHG limits for years prior to 2030. ORS 469A.415 (4)(e) states that electric utilities, like PGE, must demonstrate continual progress towards meeting clean energy targets in a Clean Energy Plan (see **Chapter 1, Clean energy plan**). HB 2021 did not define progress as actual annual emissions reductions. PGE believes that demonstrating continual progress includes planned annual actions to procure non-emitting resources to transition away from fossil fuel resources at a pace to reduce emissions to the targets in 2030, 2035 and 2040. The Clean Energy Plan (CEP) will detail actions sufficient to reduce emissions

[99] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 22-446 (Nov 14, 2022), Appendix A at 31, available at: https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

to at or below required thresholds under typical conditions. To examine the optimal progress toward 2030 GHG targets in portfolio analysis, PGE employs various GHG glidepaths to arrive at the HB 2021 targets. See **Section 11.4.1, Decarbonization glidepath portfolios,** for more detail.

The IRP assumes future load growth after cost-effective energy efficiency and distributed energy resources (DERs) are acquired and incorporated into PGE's system. Therefore, emissions reductions occur due to non-emitting resource procurement displacing coal or gas generation (as opposed to reductions from net demand reduction). In actual reporting, there will likely be a non-linear GHG decline due to various factors, including but not limited to:

- Weather variations: for example, the same power system will produce different emission levels in a mild temperature year vs. an extreme temperature year.[100] This is discussed by the OPUC in Order 22-446 and is further explored in **Appendix I, C-level analysis**.[101]
- Procurement timelines: GHG emissions decline when PGE acquires additional non-emitting energy. These acquisitions will occur in blocks and may lead to a staircase-like GHG reduction pathway. However, while each portion of resource procurement may lead to a 'blocky' reduction of GHG emissions, from a portfolio perspective, balancing regulatory, operational, financial and resource procurement risks point to the advantages of continual acquisition of non-emitting resources rather than delaying acquisition until just before the 2030 compliance window. Achieving a continual reduction pathway will necessitate procurement of non-emitting resources throughout the decade, which is likely to provide the best opportunity to add resources that offer an optimal combination of geographic location, resource characteristics, technological advancements and access to needed transmission rights.
- Unexpected economic conditions impacting loads: higher or lower than expected load may impact GHG emissions. Higher loads could arrive from faster-than-expected industrial growth (potentially from data centers) and/or faster-than-expected electrification.

5.2 Annual ODEQ reporting process

The HB 2021 GHG targets applicable to PGE include an 80 percent below baseline emissions level by 2030, a 90 percent below baseline emissions level by 2035 and 100 percent below baseline emissions level by 2040. ODEQ determines the baseline period for the investor-owned utilities as the average annual GHG emissions for 2010, 2011 and 2012 associated

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[100] See **Section 6.1, Load forecast**, for more discussion on extreme temperature events.

[101] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 22-446 (Nov 14, 2022), Appendix A at 13-14, available at: https://apps.puc.state.or.us/orders/2022ords/22-446.pdf

with the electricity sold to retail electricity consumers in Oregon as reported to the Oregon Department of Environmental Quality (ODEQ).

Regulated entities will continue to report annual GHG emissions to ODEQ, as they do today. In compliance years 2030, 2035 and 2040 and every year thereafter, the OPUC will use the data reported to ODEQ for that compliance year to determine whether the emissions targets are met.

Per the ODEQ's instructions for reporting greenhouse gas emissions, "Investor-owned utilities and electricity service suppliers must report their greenhouse gas emissions resulting from electricity served to end-users in Oregon to ODEQ, as prescribed by OAR 340-215-0120."[102]

As PGE's service area is only within the State of Oregon and PGE is not an "asset-controlling supplier" (as defined in the rule), PGE reports emissions following the non-multijurisdictional investor-owned utility methodology. This reporting must reflect emissions from the previous calendar year (Jan. 1 to Dec. 31) and be submitted to the ODEQ by June 1 of the following year. PGE is required to report the MWh of electricity generated or purchased to serve end users in Oregon for the previous emissions year for both unspecified and specified power sources.

From the total MWh of electricity generated or purchased to serve end users in Oregon, PGE then adjusts its reporting for sales to the wholesale markets, as prescribed by OAR 340-215-0120 (1)(d), "For electricity suppliers that are not multi-jurisdictional utilities, proportionally adjust all resources on an annual basis to account for the sale of power to the wholesale market that is not known to be just specified or unspecified."[103] PGE specifically adjusts certain resources for specified sales to the wholesale market for:

- Colstrip sales that are not wheeled into PGE's system and do not serve Oregon retail customers,
- Sales that are generated at a PGE-owned facility and delivered into the energy imbalance market (EIM), and
- Specified sales to California.

The remaining amount of wholesale sales is not known to be just specified or unspecified. As such, PGE proportionally adjusts all resources annually to account for the remaining sale of power to the wholesale market, as required by OAR 340-215-0120 (1)(d).

[102] ODEQ's instructions for reporting greenhouse gas emissions, available at: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf
[103] OAR 340-215-0120 (1)(d), available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=269300

5.2.1 Specified sources

A "Specified source of electricity" means a facility or unit allowed to be claimed as the source of electricity delivered.[104] PGE is required to report power as generated from a specified source when PGE is (1) a full or partial owner or operator of the generating facility or unit or (2) party to a power contract for a fixed percentage of generation from the facility or unit, or (3) party to a tolling agreement and rents a facility or unit from the owner, or is an exclusive power deliverer that is not a retail provider and that has prevailing rights to claim electricity from the specified source.[105] PGE is required to report power as purchased from a specified source when PGE can provide documentation that a power contract designated purchases from a specific generation power facility, unit or ODEQ-approved asset controlling supplier (ACS) at the time the transaction was executed.[106]

Per the ODEQ's instructions for reporting greenhouse gas emissions, reporting requirements for specified power include:

> *"If power is purchased or generated from specified sources, report the MWh of electricity disaggregated by facility or unit, and by fuel type or ACS, as measured at the busbar. Utilities must use a 2 percent transmission loss correction factor when reporting electricity not measured at the busbar of the generating facility.*
>
> *Annually, ODEQ will assign facility-specific or unit-specific emission factors for all registered specified sources by dividing the emissions (Metric tons of CO2 equivalent) by the net generation (MWh) from a specified facility or unit for the most recent year data is available.*
>
> *Emissions from specified sources are calculated by multiplying the MWh served to end users in Oregon by the ODEQ assigned facility or unit specific emission factor, and by transmission loss factor, where applicable."*[107]

[104] See Greenhouse Gas Reporting Protocols at: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf
[105] *Id.*
[106] *Id.*
[107] *Id.*

5.2.2 Unspecified sources

An "Unspecified source of electricity" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity. [108] Unspecified sources of electricity in PGE's system typically come from short-term market purchases, including the EIM. Currently, all unspecified market purchases receive the ODEQ-specified rate of 0.428 metric tons per MWh.[109] This rate is determined by ODEQ and is not updated at regular intervals. As a result, it may result in certain MWh receiving a higher CO2e intensity compared to the actual CO2e intensity of unspecified market purchases.

Per the ODEQ's instructions for reporting greenhouse gas emissions, reporting requirements for unspecified power include:

> *"Utilities must report the MWh provided to end users in Oregon from any unspecified power source.*
>
> *Electricity imported, sold, allocated or distributed to end users in this state through an EIM or other centralized market administered by a market operator is considered to be an unspecified source. Separately identify the MWh for power purchased from these markets from other unspecified sources.*
>
> *The default emission factor for calculating emissions from unspecified power is 0.428 MT CO2e/MWh.*
>
> *Emissions from unspecified sources are calculated by multiplying the MWh served to end users in Oregon by the default emission factor for unspecified power, and by the transmission loss factor, where applicable."*

5.2.3 Third-party verification of annual emissions

Beginning in 2021, ODEQ requires annual reporting of GHG emissions to be verified by a third party.[110] Third-party verifiers must be certified by ODEQ, and use of the same verifier for more than three consecutive years is prohibited. The annual deadline for verification is September 30th. PGE received a positive verification statement by the deadline of September 30, 2022, for the 2021 annual ODEQ Investor-Owned Utility emissions reporting.

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[108] *Id.*
[109] See OAR 340-215-0120, available at: https://secure.sos.state.or.us/oard/viewSingleRule.action?ruleVrsnRsn=269300
[110] See Greenhouse Gas Reporting Protocols, available at: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf

5.3 Components of IRP emissions reporting

Emissions flow through the IRP in three main steps. First, the PGE-Zone Model (PZM, conducted in Aurora) estimates the economic dispatch of all dispatchable resources, including the existing GHG-emitting resources. More information on economic dispatch and the PZM model is in **Appendix H, 2023 IRP modeling details**. Second, these data and historical GHG emitting market and contract purchases are input into the Intermediary GHG model. This model, described in the following section, estimates how much energy from GHG emitting sources is retained for serving retail load and how much is sold on the wholesale market. This information determines the yearly energy position used by the capacity expansion model (ROSE-E) that creates new resource portfolios. More information on the energy load resource balance is in **Section 6.5.1, Energy-load resource balance**, and **Appendix F, Load resource balance**.

5.3.1 Intermediary GHG model

The Intermediary GHG model inputs data from the PZM simulation, historical market transactions and GHG intensity values from the ODEQ to allocate GHG emitting generation between serving Oregon retail load and wholesale market sales. As discussed in **Chapter 4, Futures and uncertainties**, PGE creates 39 forecasts of electricity prices using a Western Interconnection simulation and then dispatches PGE owned/contracted generation against those prices.[111] This results in 39 forecasts of total power plant utilization. The 39 resource-level generation forecasts feed into the Intermediary GHG model.

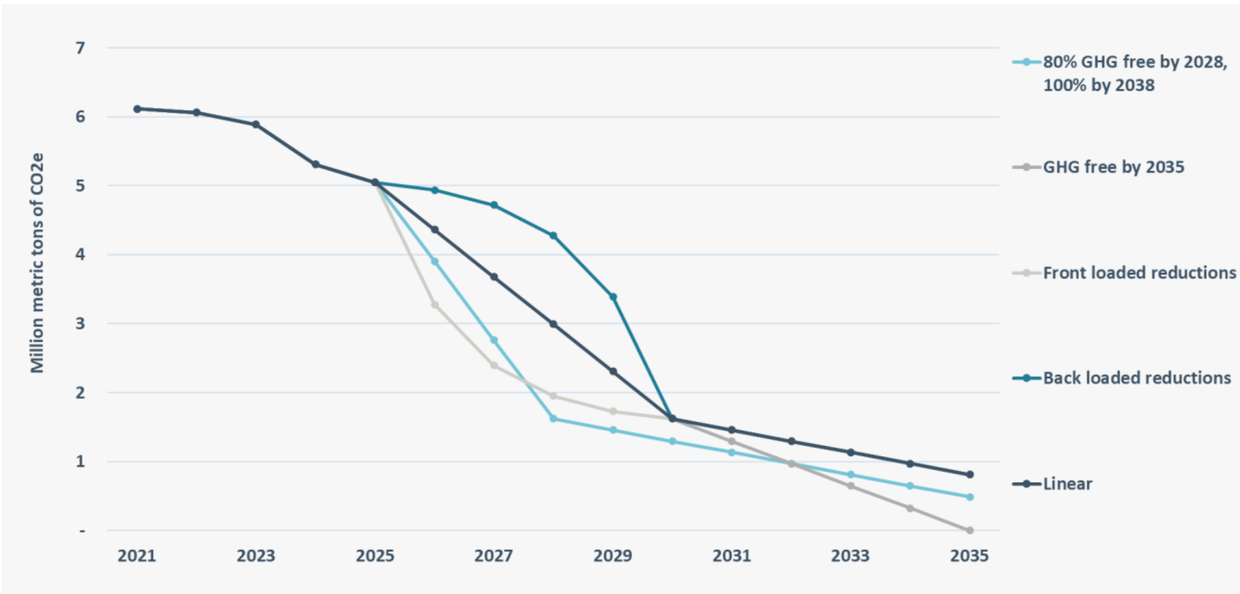
The PZM simulation forecasts total resource generation but does not distinguish between generation associated with retail load (regulated under HB 2021) and wholesale sales (not regulated under HB 2021). ROSE-E, the capacity expansion model, requires the amount of retail energy associated with GHG emissions as an input.[112] To bridge the gap between the PZM simulation and ROSE-E, the Intermediary GHG model performs two primary functions:

[111] The WECC-wide simulation simulates the power system through the end of the IRP planning horizon and takes Western carbon policies into consideration. These polices include carbon pricing, like in California and Washington, and decarbonization targets like Oregon's HB 2021. In aggregate, decarbonization policies add roughly 180,000 MW of solar, 70,000 MW of wind and 70,000 MW of storage to the Western Interconnection model from 2022 through 2045. PGE purchases the WECC-wide resource build database from Wood Mackenzie. More information on the resource buildout is in **Appendix H, 2023 IRP modeling details**.

[112] If instead the total existing thermal generation were used as an input by ROSE-E, the energy position would have an inappropriate amount of energy. This would lead to fewer non-emitting resources being built and the emissions targets would not be met on a planning basis.

1. Incorporates a GHG emission reduction glidepath to HB 2021 targets in 2030, 2035 and 2040: The GHG glidepaths for the 2023 IRP are in **Figure 27**. They are a linear reduction glidepath, a glidepath where emissions reductions until 2030 occur more rapidly (front loaded), another where reductions until 2030 occur less rapidly (back loaded) and two glidepaths with accelerated targets (non-emitting by 2035 and meeting HB 2021 targets two years faster).[113] Using these glidepaths, the Intermediary GHG model determines the amount of GHG emitting generation that PGE can retain to serve retail load.

Figure 27. GHG glidepaths associated with serving Oregon retail load in the 2023 IRP



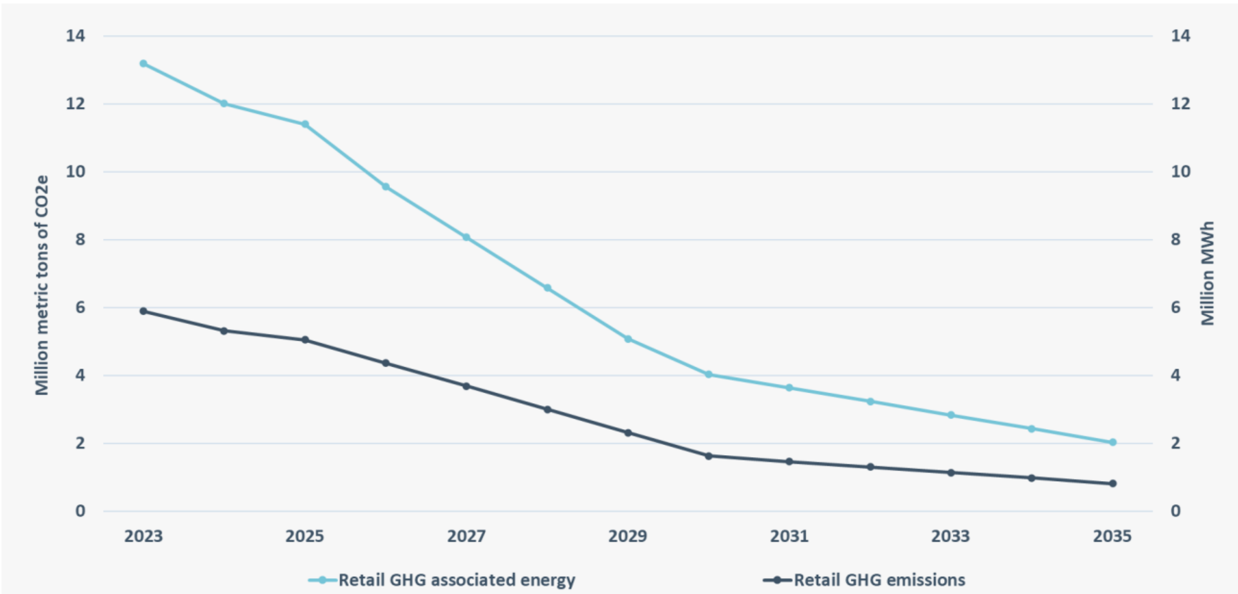
2. Incorporates an estimate of wholesale market transactions: PGE buys and sells power on the wholesale market for various reasons, including risk mitigation and net variable power cost reduction. The Intermediary GHG model estimates the size of market purchases based on historical data while considering the emissions associated with purchases. It also assumes that power not retained for retail load service sells into the wholesale market.

   The primary output of the GHG Intermediary model is an estimate of the energy from GHG emitting sources that PGE can use to meet retail load while meeting the GHG targets. This estimate flows into the energy load resource balance (**Section 6.5.1, Energy-load resource balance**) that is used as an input to the capacity expansion model (ROSE-E). An example of this output is in **Figure 28**, using the Reference Case price future and a linear GHG reduction glidepath. The lower line shows the GHG emissions

[113] With the front loaded-GHG pathway the amount of reduction from 2023 to 2030 half every year, in the back loaded-GHG pathway they double every year. All other pathways are linear to their respective targets.

associated with serving Oregon retail load, and the upper line is the corresponding GHG emitting energy retained for the retail load.

Figure 28. GHG emissions and energy associated with serving Oregon retail load (Reference Case)



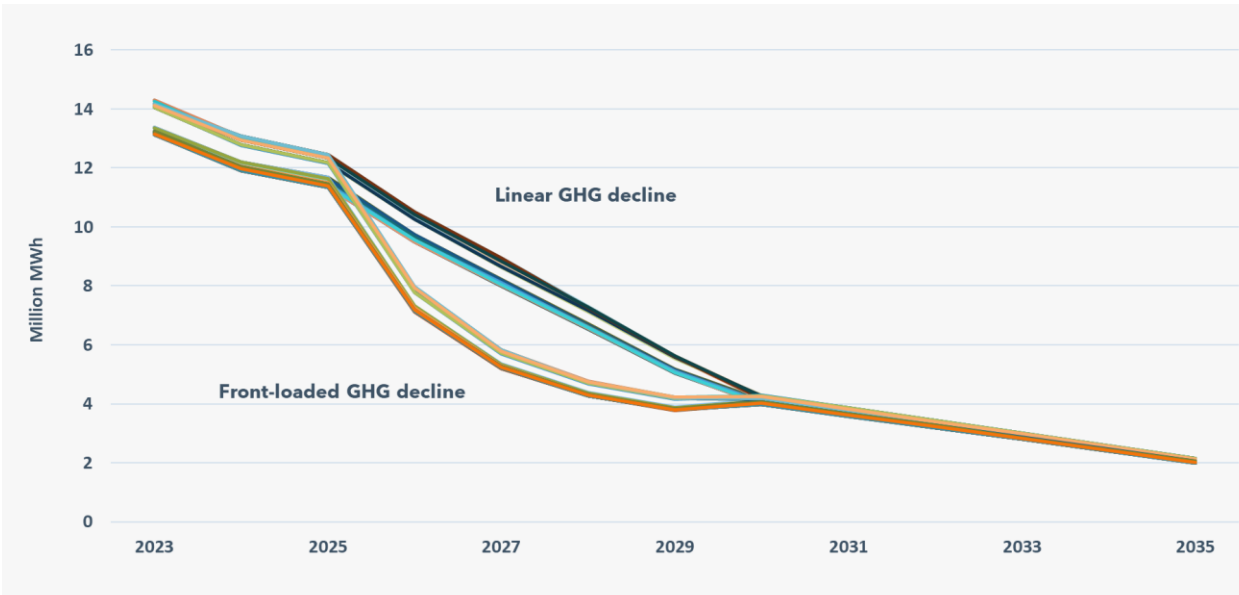
Other than Colstrip, most GHG-emitting energy in the PGE portfolio has a GHG intensity rate of around 0.37 to 0.43 MTCO2e/MWh (Colstrip is 1.00 MTCO2e/MWh).[114] Gas plants dispatch in order of economic efficiency, with the lowest emitting and most efficient plants usually operating at the highest capacity factors. As a result, unit dispatch generally plays a small role in determining how much energy from GHG emitting generation PGE can retain for retail load. For example, in 2030, retail GHG emissions must be 1.62 million metric tons or fewer. If PGE were to obtain all its GHG-related generation from unspecified market purchases with an intensity rate of 0.428 MTCO2e/MWh, it would result in 3.79 million MWh of generation. If PGE were to obtain all its GHG-related generation from Carty Power Plant with an intensity rate of 0.389 MTCO2e/MWh, it would result in 4.16 million MWh of generation, a relatively small difference of 0.37 million MWh (42-megawatt average (MWa)).

The difference in GHG emitting energy retained for Oregon retail load by price future (which impacts dispatch) is shown in **Figure 29**. It shows multiple price future outcomes under the linear glidepath and the front-loaded glidepath. While there are large energy differences

[114] Power Plants Beaver & Port Westward II, as well as some specified market purchases, have higher emissions rates in some years, but annual energy from these sources is typically low. BPA power has a much lower rate (0.013 MTCO2e/MWh as provided by DEQ for use in the CEP/IRP), but the variation of BPA power used for retail load is somewhat small across price futures.

between the two glidepaths, within the individual glidepaths, the energy differences are relatively small.

Figure 29. GHG emitting energy from serving Oregon retail load under different glidepaths and price futures



Beyond Oregon retail emissions, the GHG Intermediary model also calculates emissions and the associated energy from wholesale activities. The bulk of this estimate comes from the PZM simulation, which forecasts the generation levels of the major PGE thermal units and the GHG glidepath, a key input into how much energy is kept for Oregon retail load service.[115] In the PZM simulation thermal units economically dispatch against Western power prices. The prices are created taking carbon pricing and GHG reduction policies into consideration. For example, the PZM simulation includes carbon pricing in California and Washington and adds non-emitting resources to the West to meet emissions targets. Actual wholesale emissions will differ depending on the western resource buildout and future electric power policies.

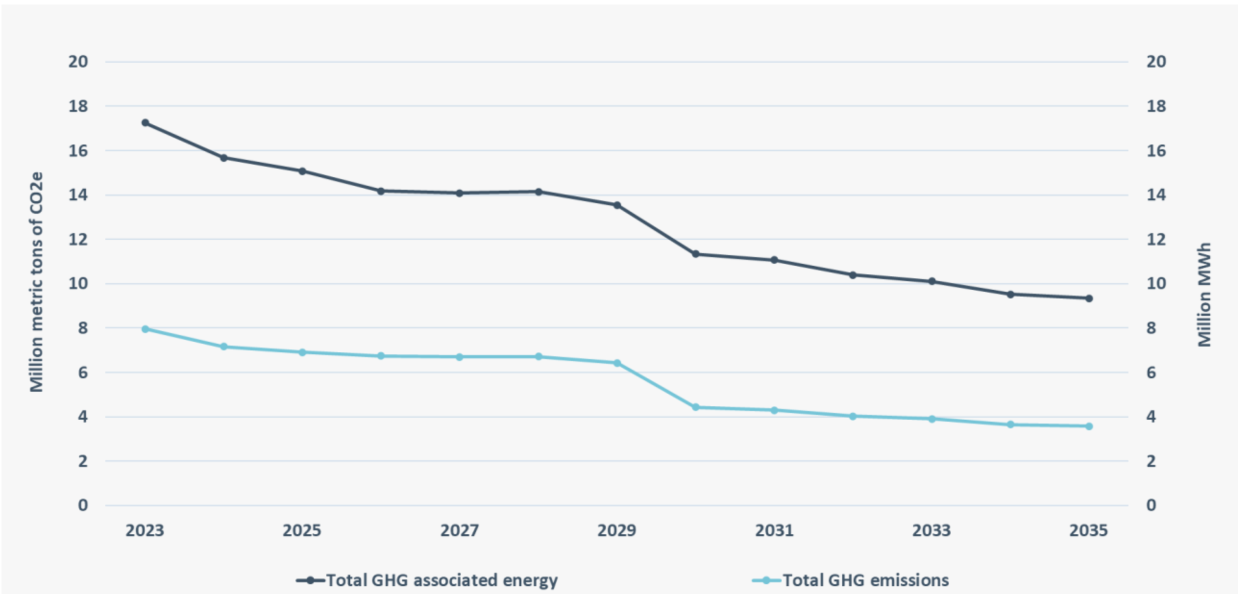
Economic dispatch also assumes an efficient dispatch order across the Western Interconnection. Operating gas plants less than economic dispatch may increase GHG emissions. For example, if the Carty power plant ran below economic dispatch, it would generate less energy. A less efficient gas plant elsewhere in the West would likely operate more to make up for this shortfall. The less efficient plant would emit more CO2e than Carty for each MWh of power produced, increasing GHG emissions across the West. This scenario would likely also increase PGE net-variable-power-costs if it reduced total wholesale

[115] These units are power plants Beaver, Carty, Colstrip (20 percent ownership), Coyote, Port Westward 1, & Port Westward 2.

transactions. Additional information on economic dispatch and the PZM simulation is in **Appendix H, 2023 IRP modeling details**.

Beyond PGE thermal units, the Intermediary GHG model adds additional energy and associated emissions with select contracts and wholesale market transactions. The total system (retail and wholesale) GHG emissions and associated energy from the Reference Case future is in **Figure 30**. More information on GHG-emitting resources (including requirements established in UM 2225) is in **Appendix O, Thermal Operations/ Output**.

Figure 30. Total GHG emissions and associated energy forecast



The Intermediary GHG model also passes to ROSE-E energy values from GHG-emitting resources. It does this using the retail and wholesale energy generation values in conjunction with annual forecasted power prices. The model is essentially a data pass-through from the PZM simulation to ROSE-E for this function.

5.3.2 ODEQ review of PGE forecasted emissions accounting

PGE will provide information to ODEQ to allow for a review of PGE's forecasted emissions accounting methodology as reported in this Clean Energy Plan. This will enable ODEQ to determine that emissions have been forecasted in alignment with ODEQ Greenhouse Gas Reporting protocols.

In forecasting emissions associated with portfolios, PGE will use ODEQ's emission factors for each existing GHG-emitting resource, and PGE will provide the associated forecast of the retail load generation of each plant, purchases and power sales by technology type for each year being forecasted.

Chapter 6. Resource needs

This chapter quantifies the drivers of system demand and their impact on energy, capacity and system flexibility need. Estimating these values is the first critical step in ensuring resource actions result in an adequate system that meets decarbonization and other policy objectives while minimizing long-term costs and risks.

Chapter highlights

- Load growth, expiring non-GHG emitting resource contracts and decreasing retail sales from existing thermal resources drive the need for more non-GHG emitting resources through the planning horizon.
- The load forecast has increased since the 2019 Integrated Resource Plan (IRP) Update due primarily to higher industrial load growth projections. In addition, the persistent impacts of COVID-19 have increased residential usage.
- Distributed energy resources (DERs), including transportation and building electrification, are having a more significant impact on total Portland General Electric (PGE) loads as compared to past IRPs.
- Capacity needs step upwards in 2026 and grow through the planning horizon due to expiring contracts, exiting resources and load growth. In the Reference Case, the 2028 capacity need is 624 megawatts (MW) in the summer and 614 MW in the winter.
- Flexibility needs in 2026 are estimated at 80 MW in the Reference Case, growing to 122 MW in 2030.
- Although capacity needs increase in both summer and winter throughout the planning horizon, climate change drives relatively more need in the summer and less need in the winter.

6.1 Load forecast

PGE's estimated demand for electricity is called its 'load forecast.'[116] Our load forecast has been influenced by rapidly evolving trends (such as those related to COVID-19 or extreme temperatures) and the slower-moving, longer-term trends in energy deliveries. Each is accounted for in different ways. The primary components of PGE's load forecast are:

- Top-down econometric load forecast: This model comprises two segments that capture business cycle impacts and long-term trends. **Section 6.1.1, Top-down econometric load forecasting**, describes the top-down econometric forecast mode and **Section 6.1.2, Load trends**, describes current load trends.[117]
- Incremental impacts associated with passive DERs: The impact of nascent and rapidly evolving end uses, including transportation electrification, rooftop solar and building electrification, is forecasted in PGE's Distribution System Planning process. The load impacts of DERs are accounted for in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

6.1.1 Top-down econometric load forecasting

PGE's top-down forecasting models take an econometric approach by estimating the relationships between PGE service area historical load and exogenous drivers. These exogenous drivers include seasonal and weather variables and macroeconomic indicators (population, employment and income) used to describe regional economic trends.

Weather, specifically ambient temperature, is the most significant factor affecting customer electricity demand. PGE uses several weather variables in its energy and peak models, including heating and cooling degree days and wind speed. Energy use is also correlated with economic activity. PGE's econometric models forecast monthly energy deliveries by customer class and peak demand for the total PGE system. The primary model inputs are weather, population, employment, income, customer counts and historical loads. **Appendix**

[116] The Corporate Load Forecast is described in Section 3.3 of PGE's DSP, available at: https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf

[117] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 21-129 (May 3, 2021), Appendix A at 5 states: "Staff concurs with CUB that the impact of large customers in the industrial load forecast should be closely monitored. Staff supports PGE's plan on page 8 of its Reply Comments to 'review… peer electric utility industrial load forecasts and… summarize findings in an IRP roundtable participant discussion during the next IRP.'" PGE presented results of its benchmarking of economic drivers used in peer regional electric utilities' industrial load forecasts and performance of a broad range of economic drivers in PGE's industrial load forecast model at the July 22, 2021, public roundtable meeting to meet this commitment. Available at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

H, 2023 IRP modeling details, provides additional details on the models that constitute this IRP top-down forecast and how those models were tested and selected.

Econometric models assume that certain structural relationships captured represent the future. In addition, PGE's Reference Case load forecast incorporates several key model input assumptions:

- **COVID Recovery:** An indicator variable is used in PGEs models to capture the impact of COVID-19 on energy deliveries. The input assumption for this variable implies how those impacts taper during the forecast period. While we expect this input to continue to evolve to reflect current expectations, this IRP forecast assumes the long-term equilibrium for residential customers was reached in mid-2022. This level is estimated to be approximately 30 percent of the impact seen in the early months of the COVID-19 lockdowns.
- **Weather:** PGE's load forecasts reflect normal or expected weather conditions throughout each year. For this IRP, the expected weather conditions are represented by a trended model for heating and cooling degree days to reflect the gradually warming regional climate. The forecasts do not attempt to predict, for example, an El Niño winter, a particularly hot summer or any weather event in any given year. A discussion of additional climate analysis is included in **Section 6.9, Climate adaptation**.
- **Direct access:** Customers with approximately 270-megawatt average (MWa) of combined commercial and industrial load in PGE's service area have opted out of PGE's cost-of-service (COS) supply rates and receive energy from electricity service suppliers (ESS).[118] In IRP Guideline 9, in Order No. 07-002, the Commission prohibits the inclusion of long-term direct access customer loads in long-term planning for both energy and capacity needs.[119] This IRP portfolio analysis excludes these customer loads. However, as discussed in **Section 3.1.6, Local climate action planning** nine counties and cities served by PGE have already established climate-related goals through community processes and plans, and at least four more are in the process of developing plans. These plans typically cover a variety of goals and objectives, including those concerning greenhouse gases, energy use, transportation, waste, land use, health and safety, and economic development. **Table 5** captures a list of local governments with existing plans (or in some phase of developing one) and some key electricity and emissions goals.

Several cities and counties have timelines for their decarbonization goals that align with our HB 2021 targets. For those local governments that want to decarbonize on a faster timeline, PGE's Green Future Enterprise and Green Future Impact are being used to support clean

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[118] This includes 1-year direct access (STDA), long-term direct access (LTDA) and new load direct access (NLDA) schedules.
[119] *In the Matter of Public Utility Commission of Oregon, Investigation Into Integrated Resource Planning*, Docket No. UM 1056, Order No. 07-002 (Jan 8, 2007) at 19, available at: https://apps.puc.state.or.us/orders/2007ords/07-002.pdf

energy goals. Many of our large commercial and industrial customers also use these and other programs to meet their decarbonization goals.

PGE has been working with local governments since 2020 to develop a community-supported renewable program to support those local governments that have adopted community-wide climate goals. During the 2021 legislative session, PGE worked in partnership with several of our local governments to pass language within HB 2021. The program will allow local governments to work with PGE to accelerate the procurement of non-emitting energy to meet their climate goals. Since the bill's passage, PGE staff have been meeting regularly with local governments to solicit feedback on the design so that the program will meet their goals and desired approach. As PGE continues to engage with local governments, collectively we will determine the right time to file the tariff to support the program.

- Regulatory policy: Direct access, this interpretation presents reliability and cost risks to cost-of-service supply customers. Consistent with prior IRPs, PGE includes one-year direct access customers in its IRP planning because they may return to PGE's COS rates with little notice.

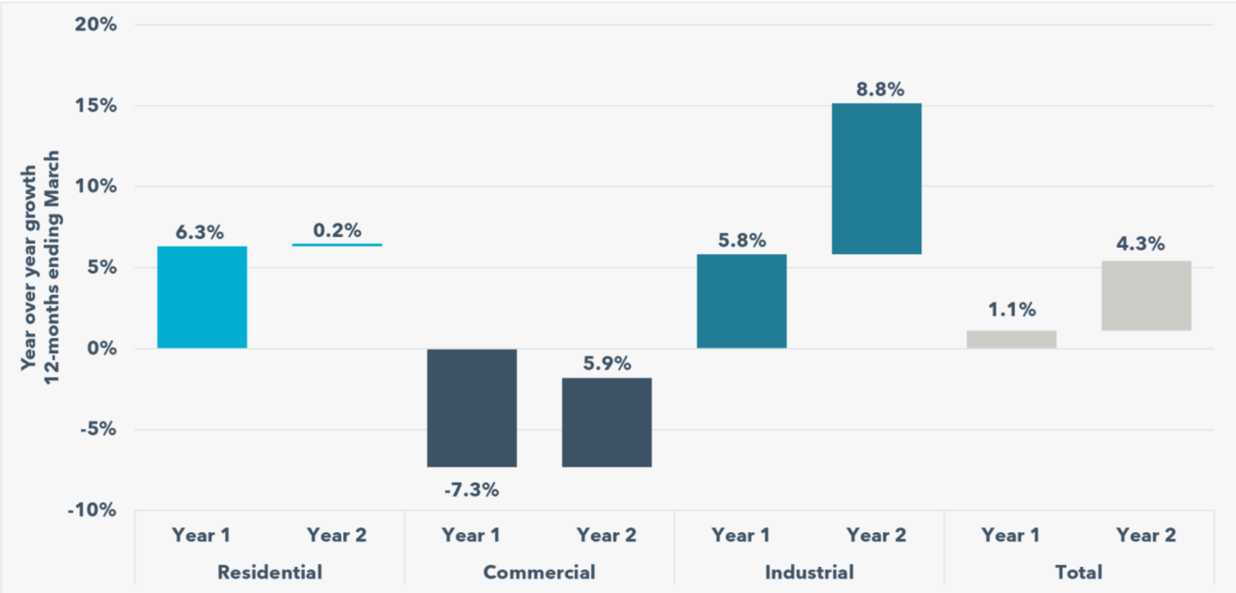
6.1.2 Load trends

6.1.2.1 Impact of COVID-19

Recent load trends (marked by the impact of COVID-19) have influenced how PGE's customers use electricity. The prevalence of work-from-home policies increased average residential usage, which remains high. As these changes to remote work will persist, we believe the impact of the last two years marks a longstanding change in average residential usage. In the commercial segment, initial shutdowns had a stark but short-lived impact on energy deliveries. We believe prior structural relationships, including long-term trends and relationships to macroeconomic indicators, hold true. PGE's industrial segment was impacted least by COVID-19 and has grown since the 2019 IRP.[120] **Figure 31** depicts changes in usage between customer classes since the March 2020 lockdowns.

[120] *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, filed July 19, 2019.

Figure 31. PGE's annual energy deliveries growth since the initial COVID-19 lockdown



Given the limited duration since the onset of COVID-19, PGE used out-of-model forecast adjustments to account for COVID-19 in its 2019 IRP Update load forecast.[121] Since the 2019 IRP Update load forecast was finalized, PGE developed a methodology to account for COVID-19 in its econometric models by using indicator variables to reflect various stages of closure and recovery. This method applies to most, but not all, of PGE's forecast segments and is discussed in further detail in **Appendix D, Load forecast methodology**. The evolution of the modeling approach was shared with stakeholders in IRP Roundtables, first on October 28, 2020, when out-of-model adjustments were used as a temporary approach, and then on July 22, 2021, where the indicator variable approach was presented.

6.1.2.2 Industrial growth

Energy deliveries to PGE's industrial segment have increased rapidly over the past few years. Industrial growth has been focused on the semiconductor manufacturing and data center segments. The construction of new customer facilities continues at a rapid pace as discussed in **Chapter 3, Planning environment**.

With respect to electric load, the number of projects and the average project size assessing sites in PGE's service area for new data center projects have increased. Additional projects may see investment opportunities associated with CHIPS and Science Act funding in coming years. The realization and timing of large projects present heightened uncertainty around

[121] Docket No. LC 73, PGE's Integrated Resource Plan Update, filed January 29, 2021.

PGE's load forecast. However, the rate at which the industrial sector incorporates energy efficiency also presents uncertainty in demand.[122]

6.1.2.3 Severe temperature

Since the 2019 IRP, PGE's service area experienced an unprecedented maximum temperature event, the "heat dome" of June 2021, and the warmest month on record in August 2022 based on average temperature.[123] Concurrent with these events came unprecedented hourly peak demands. PGE's net system peak on June 28, 2021, set a new system record at 4,453 MW. During the summer of 2022, PGE's net system exceeded 4,000 MW - a load level not seen in over 10 years prior to 2021 - on nine different days, including reaching 4,100 on five consecutive days in late July. These events, coupled with more time spent in the home due to work-from-home policies and national macroeconomic trends of strong consumer expenditures on home upgrades, will likely continue the long-term trend of increasing saturation of air conditioning in PGE's service area. Air conditioner saturation is included in PGE's peak demand forecast. Several sector-level energy delivery models have been modified to account for this additional cooling demand.

In addition to extreme heat events, winter weather continues to be a significant driver of PGE's peak loads. On December 22, 2022, PGE's service area set a record for its winter season net system peak at 4,113 MW. This event occurred during severe weather, with a daily average temperature of 23 degrees Fahrenheit at Portland International Airport and surpasses PGE's prior winter system peak set in 1998. This event highlights that while PGE has transitioned towards a summer peaking service area, the regional climate still faces the challenges of planning for a dual peaking system.[124]

6.1.3 Load uncertainty

All forecasts have inherent uncertainty. For example, uncertainty is associated with the model input data, the selection of the model itself and the relationships established within it, and factors external to the model. To reflect uncertainty in the model input data and the

[122] PGE and the ETO presented opportunities for energy efficiency at data centers at the February 2023 IRP roundtable; greater adoption by the industrial sector could mitigate demand growth.
[123] Mesh, Aaron. "August Was Portland's Hottest Month Ever: The key factor: warm nights." Willamette Week (Sept 2, 2022, 2:14 pm PDT), available at: https://www.wweek.com/news/environment/2022/09/02/august-was-portlands-hottest-month-ever/#:~:text=The%20key%20factor%3A%20warm%20nights.&text=This%20August%20was%20the%20hottest,record%3A%2074.1%20in%20July%201985. Accessed October 27, 2022.
[124] **Appendix I, C-level analysis**, provides discussion on how extreme temperature can impact system GHG emissions. These extreme weather trends were first discussed in the "Climate Change Projections in Portland General Electric Service Territory" that PGE commissioned Oregon State University's Oregon Climate Change Research Institute, Prepared by Meghan Dalton. The report is available in Docket No. LC 66, PGE's 2016 Integrated Resource Plan (filed Nov 15, 2016) at 391, available at: https://edocs.puc.state.or.us/efdocs/HAA/lc66haa144338.pdf

relationships estimated in the load forecast, PGE empirically develops high- and low-load growth scenarios. These scenarios focus on alternate futures for macroeconomic drivers and incorporate stochastic load risk analysis by adding or subtracting one standard deviation in model uncertainty. **Table 10** shows the inputs used to create the low, reference and high top-down load forecasts.

Table 10. Inputs to top-down econometric load forecast scenarios

Economic driver	Low load	Reference Case	High load
Population	0.0%	0.7%	1.5%
Employment	0.5%	1.3%	2.5%
Income	1.0%	2.1%	3.5%
Model uncertainty	-1 SD	None	+1 SD

Electrification is also a key area of load uncertainty. This is modeled outside PGE's top-down econometric forecast and discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

The resulting load scenarios are summarized in **Table 11**.

Table 11. Top-down econometric load forecast scenarios

	Low load	Reference Case	High load
Peak demand	0.4%	0.8%	1.1%
Total energy	0.5%	1.2%	1.7%
Residential	0.0%	0.5%	0.9%
Commercial	-0.4%	0.0%	0.3%
Industrial	2.3%	3.5%	4.3%

*Table reflects 20-year average annual growth rate for years 2023-2042, before the impacts of electrification, discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**.

6.2 Distributed Energy Resource (DER) impact on load

PGE's 2022 Distribution System Plan (DSP) Part 1 and 2 form the basis for DER actions within this IRP except for energy efficiency, which is sourced from Energy Trust of Oregon

(ETO).[125,126,127] The DSP leverages PGE's AdopDER model to perform bottom-up site-level adoption of over 60 DER technologies and technology combinations. The model accounts for key site-level factors such as access to garage parking, breaker space and equipment turnover to determine the technical, achievable and economic potential, as illustrated in **Figure 32**. The AdopDER model simulates the market adoption of passive DERs and the expected participation of customers in current and potential demand response programs. Within the DSP, we simulated the adoption across three scenarios with varying parameters such as cost and policy interpretation. Additional details on the DER forecast methodology, assumptions, and outputs can be found within the DSP filing. The Inflation Reduction Act (IRA) was signed into law after filing the DSP. Thus, its impact is not captured as it pertains to the market adoption of passive DERs such as rooftop solar, electric vehicles and building electrification. While this impact is not explicitly modeled, PGE has modeled both a high adoption case of these technologies and conducted a sensitivity to understanding how resource actions and system needs vary along the range of passive DER adoption. This is further described in **Section 4.2, Need** , and **Section 6.10.2, Accelerated load growth sensitivity**.

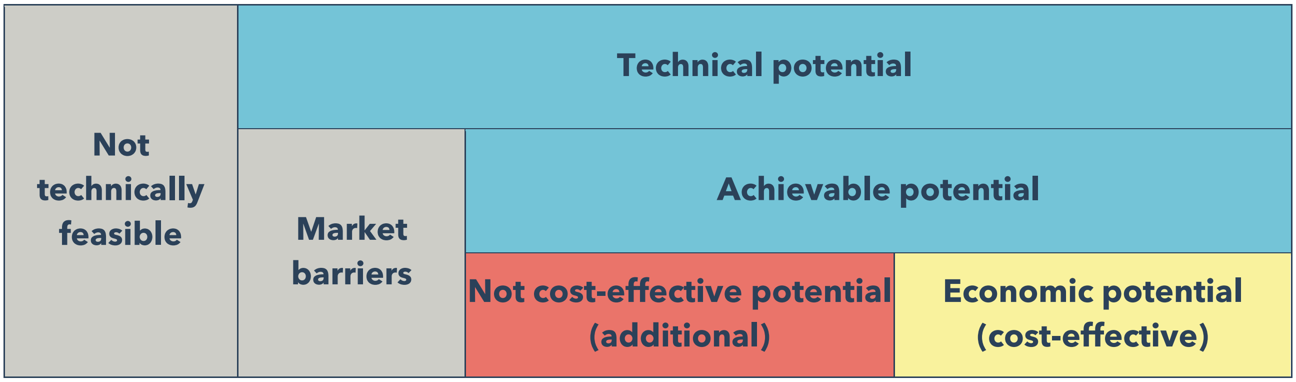
In this chapter, we first focus on the market adoption of passive DERs (rooftop solar, transportation electrification and building electrification). Then, we discuss the integration of cost-effective or economic potential of DR and EE through customer programs. The cost-effective potential is highlighted in yellow in **Figure 32**. The treatment of non-cost-effective or additional energy efficiency and demand response is described in **Section 8.2, Additional distributed energy resources**.

[125] PGE's DSP Part 1, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAA&FileName=um2197haa85326.pdf&DocketID=23043&numSequence=1

[126] PGE's DSP Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

[127] For the purposes of PGE's IRP, we utilize the OPUC's definition of DERs which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid. See *In the Matter of Public Utility Commission of Oregon, Investigation Into Distribution System Planning*, Docket No. UM 2005, Order No. 20-485 (Dec 23, 2020), Appendix A at 15, fn. 2.

Figure 32. The different potential assessments of DERs



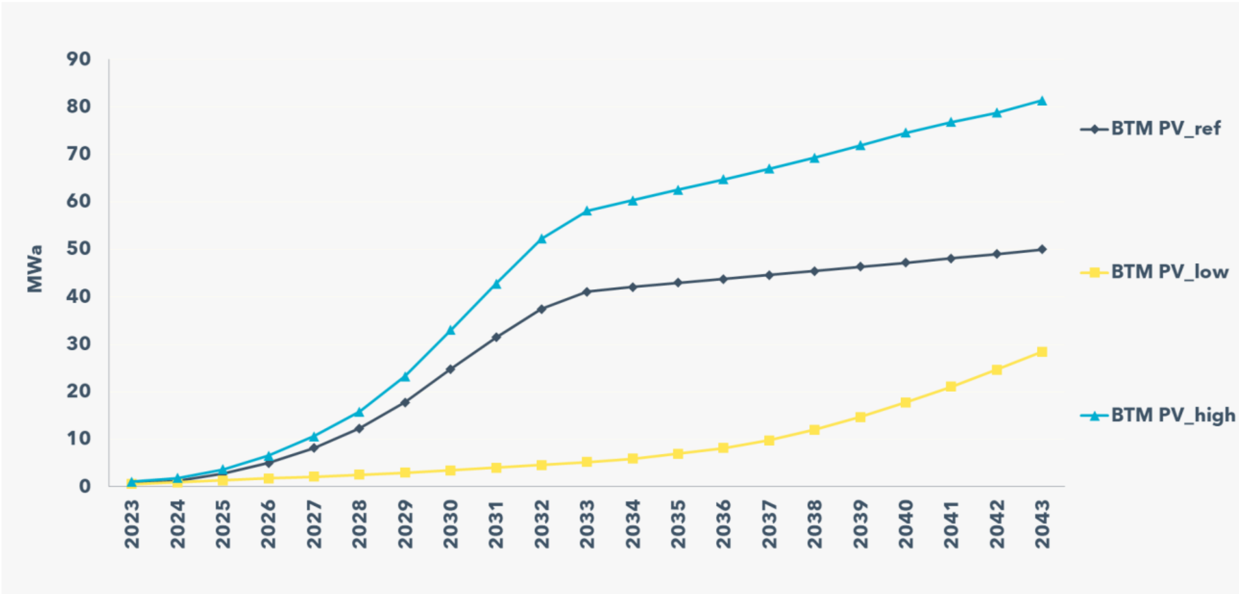
6.2.1 Passive DERs

Passive DERs are driven by direct customer adoption, such as distributed solar PV, electric vehicles and building electrification end uses. As identified in the DSP, distributed solar PV has a high technical potential of approximately seven gigawatts (GW) of nameplate capacity within the service area by 2050. Based on the adoption curves produced within the DSP, we expect annual customer adoption of solar to peak in the early 2030s because of declining solar PV costs, which will lead to favorable customer economics within the current policy environment. Thus, the incremental energy impact from 2023 of customer-adopted solar in the Reference Case is estimated at ~25MWa by 2030, as shown in **Figure 33**.[128] By the end of the planning horizon, this is expected to double. The incremental nature of **Figure 33** ensures that solar PV currently on the system is not double counted.[129] Residential customers drive the bulk of the solar adoption, given the economics between rates (Net Energy Metering (NEM) Incentives) and costs. However, NEM incentives do not require customers to comply with IEEE-1547, 2018 smart inverter standards. This prevents rooftop solar from being properly integrated and thus prevents PGE customers from realizing the full benefit of rooftop solar PV. Additionally, and especially with the IRA extending tax benefits on rooftop solar, the cost shift stemming from the current NEM policy will continue to increase inequities across customers and, consequently, energy burden, which was identified as a key measure by community partners in **Section 7.1.6, Informational community benefits indicators**.

[128] MWa and MW reporting of DERs may vary between the DSP and IRP, though the source data for the locational forecast is consistent between the DSP and IRP. The DSP outputs used for reporting purposes are simplified and do not account for intra-year ramping/adoption. IRP outputs shown here include intra-year ramping. This difference is larger in early years where intra-year ramping is significant and shrinks over time because each new year's incremental contribution decreases.

[129] In response to Docket LC 73, PGE 2019 Integrated Resource Plan, Order 20-152's requirement at 22, "In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019", PGE has provided this information within the DSP Part 1, Section 1.5 of Chapter 1, available at: https://assets.ctfassets.net/416ywc1laqmd/ELNdf17zyQvQiU9k71pIX/683cd2f7b3098517068c4594100a1025/DSP_2021_Report_Chapter1.pdf.

Figure 33. MWa generation impact of behind the meter (BTM) distributed solar PV over the planning horizon



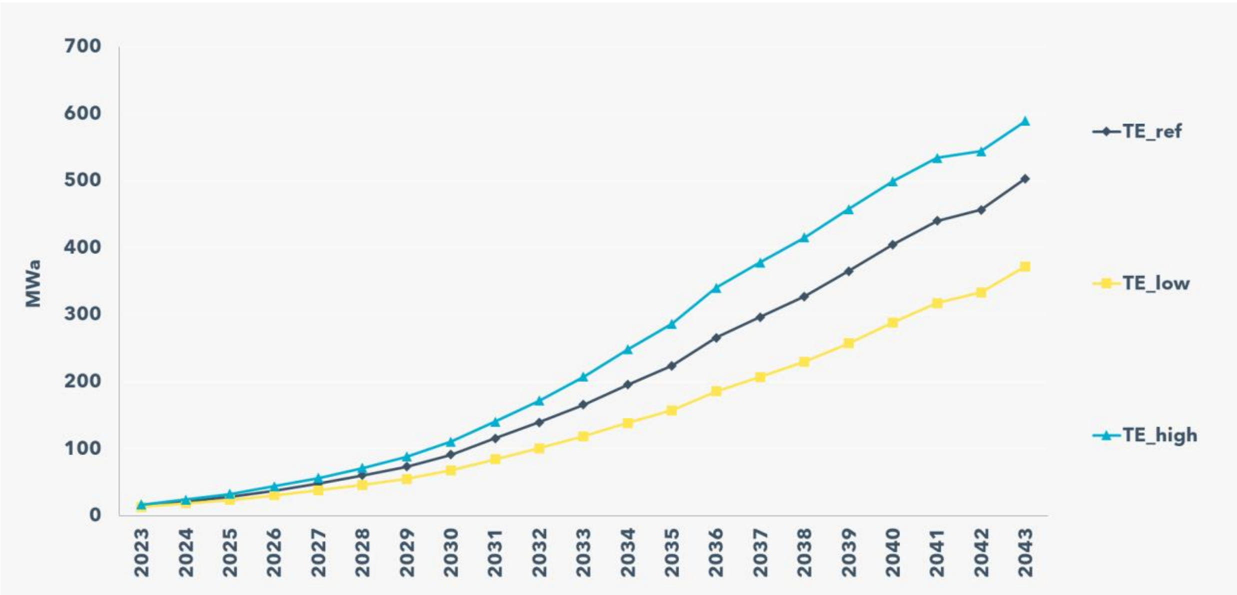
We forecast higher levels of adoption for electric vehicles than in the previous IRP, particularly in the light-duty segment. Based on the DSP, by 2030, we expect 341,280 light-duty electric vehicles on the road, with 298,244 vehicles in the residential sector and 9,817 medium and heavy-duty EVs in the Reference Case. Consequently, we expect the transportation electrification load to be ~91 MWa by 2030, with a fivefold increase by 2043 to ~503 MWa.

Policy assumptions in the DSP do not include the impact of the Advanced Clean Cars II rule passed on December 19, 2022, which requires auto manufacturers to deliver 100 percent new zero-emission battery electric and plug-in hybrid electric vehicles by 2035.[130] **Section 6.10.2, Accelerated load growth sensitivity**, details a demand growth sensitivity analysis that is more aggressive than the Advanced Clean Cars II rule.

Figure 34 represents the gross transportation electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These demand response programs are represented within the demand response potential in **Section 6.2.2, Demand response**.

[130] The Advanced Clean Cars II, Administrative Order No. DEQ-23-2022, effective 12/19/2022, available at: https://www.oregon.gov/deq/rulemaking/Documents/DEQ232022.pdf

Figure 34. MWa impact of transportation electrification (TE) over the planning horizon

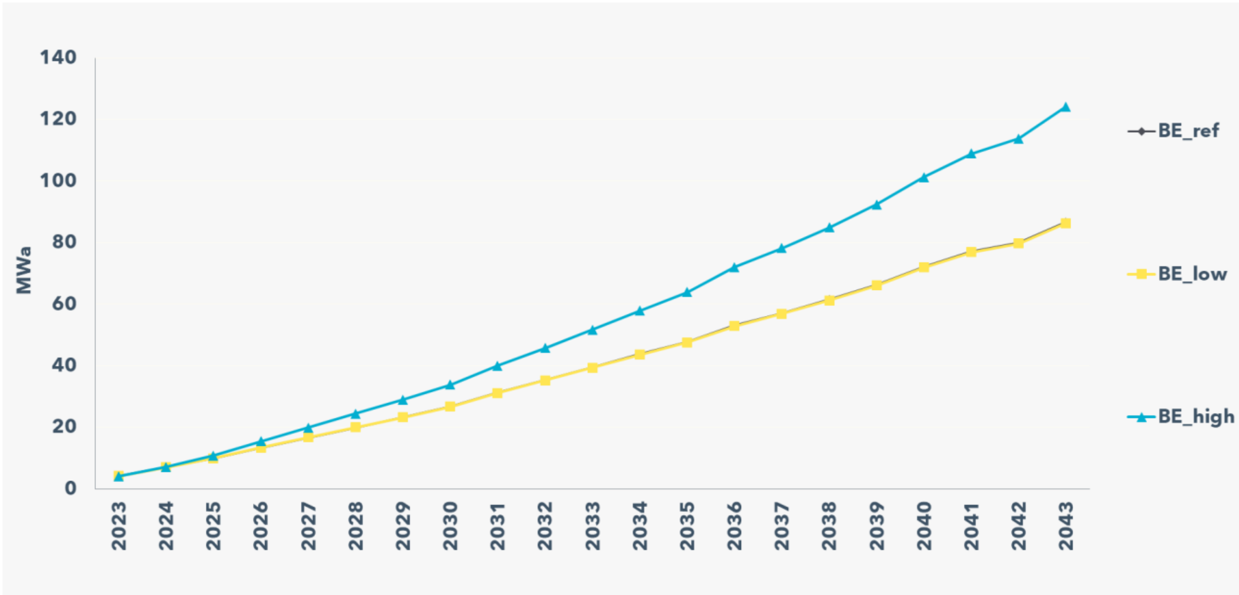


Building electrification has significant potential to decarbonize the economy further. The adoption of electric space heating, water heating and cooking technologies within the new construction sector and fuel switching within existing buildings drives the building electrification forecasts. For this IRP, we leveraged the DSP outputs and associated assumptions. By 2030, we expect a ~27MWa impact from building electrification. While this impact increases both summer and winter resource adequacy needs, the winter needs are impacted more prominently because of the space heating end use, which coincides with the winter peak.

Like transportation electrification, **Figure 35** represents the gross building electrification load across varying adoption scenarios, not accounting for the potential impact of associated demand response programs such as time-of-use or managed charging programs. These demand response programs are represented within the demand response potential in **Section 6.2.2, Demand response**.

In addition to the building electrification scenarios modeled in the DSP, we have also modeled an electrification sensitivity to understand the impact of electrification, assuming the Climate Protection Program's compliance is achieved only through increased electrification. This is further described in **Section 6.10.2, Accelerated load growth sensitivity**.

Figure 35. MWa impact of building electrification (BE) over the planning horizon



6.2.2 Demand response

As noted earlier in the section, the DSP informs DER[131] implications within the IRP, including demand response. PGE's DSP modeled current and potential demand response programs, including technologies (storage, smart thermostats, electric vehicles and water heaters) and strategies (peak time rebates and time of use pricing programs) across all customer classes. Three adoption cases, which are the inputs to the IRP, are produced based on industry trends, such as technology cost, heuristics of customer adoption from other utility territories, and policy. **Table 12** and **Table 13** detail the achievable potential by season through the Action Plan period, with the cost-effective potential broken out. The cost-effective potential is integrated within the Need Futures and the Action Plan as the procurement target. The difference between achievable and cost-effective potential is the non-cost-effective potential, included within the IRP as potential resource options and further described in **Section 8.2, Additional distributed energy resources**.

[131] For the purposes of PGE's IRP, we utilize the OPUC's definition of DERs which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid. See, UM 2005, Order No. 20-485, Appendix A at 15, fn. 2.

Table 12. Summer demand response/flex load peak impacts

Summer MW peak impacts, achievable potential							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	271	298	310	326	343	359	385
Ref	146	183	211	236	257	274	294
Low	98	118	137	155	173	187	201
Cost-effective, achievable potential (TRC >=1)[132]							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	256	273	278	282	287	287	294
Ref	133	162	183	199	211	218	228
Low	93	110	126	141	155	166	177

Table 13. Winter demand response/flex load peak impacts

Winter MW peak impacts, achievable potential							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	174	191	204	219	234	259	282
Ref	106	134	158	177	194	213	231
Low	68	83	99	113	127	141	152
Cost-effective achievable potential (TRC >=1)							
Scenario	2024	2025	2026	2027	2028	2029	2030
High	165	176	183	188	192	199	205
Ref	98	119	137	149	158	167	174
Low	66	79	92	104	115	126	134

As noted in the DSP Part 2, we expect approximately 228 MW of summer and 174 MW of winter economic achievable demand response (including behind-the-meter storage enrolled

[132] The Total Resource Cost (TRC) test compares the costs and benefits of a resource and determines if the benefits are equal to or outweigh the costs, *i.e.*, TRC >=1, or if the resource is not cost-effective, *i.e.*, the projected costs are not greater than the expected benefits. The TRC test is the primary determinant in the implementation of a demand response and energy efficiency program in Oregon.

in a program) by 2030.[133] The demand response portfolio will likely be dominated by Peak Time Rebates, Energy Partner and Thermostat programs in the near-term. In the latter years of the planning horizon, post 2030, the adoption of building and transportation electrification end-uses increase the demand response potential, especially for programs such as Time of Use when combined with technologies such as smart thermostats, batteries or EVs. Details on the procurement targets across these programs can be found in the DSP Part 1 and Part 2, the 2021 Flexible load Multi-year Plan (MYP) and the 2019 Transportation Electrification Plan (TEP).[134,135,136]

Figure 36 describes the Commission-filed resource plans that help PGE move from planning to procurement for demand response. This process will evolve as PGE's virtual power plant (VPP) capabilities mature. Presently, the DSP forms the basis for all DER forecasts. Demand response forecasts go through the IRP process, where they may be layered with additional demand response previously deemed not cost-effective. Thus, the IRP Action Plan sets a target that combines both the cost-effective and currently non-cost-effective resources. The MYP is where PGE details the programs and procurement strategies for those programs to meet this DR target. The MYP will also highlight any operational concerns that may prevent achievement of the target, which may result in increasing the current targets for the supply side Request for Proposals (RFP) or undertaking a new RFP.

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[133] PGE Distribution System Plan (DSP) Part 2 (August 15, 2022), available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[134] PGE Distribution System Plan (DSP) Part 1 (October 2021), available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf

[135] PGE Distribution System Plan (DSP) Part 2 (August 15, 2022), available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

[136] *In the Matter of Portland General Electric Company, Flexible Load Plan*, UM Docket No. 2141 (filed Nov 3, 2021), the 2021 Flexible Load Multi-Year Plan, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2141had16243.pdf&DocketID=22696&numSequence=19;

Figure 36. Planning to procurement Demand Response

6.2.3 Energy efficiency

This IRP incorporates the ETO's most recent long-term cost-effective EE savings forecast from May 2022. Additional details on ETO's forecast are provided in **Ext. Study-II, EE methodology**. ETO is working to understand how IRA tax credits might reduce costs. This work is in its infancy and is not captured directly in the IRP. However, the different Need Futures account for how cost changes impact the EE forecast, as described in **Section 4.2, Need Futures**.

From 2026 through 2030, ETO projects that cost-effective energy efficiency will provide ~156 MWa of energy savings averaging about ~31 MWa each year. **Table 14** provides the breakdown of the annual energy efficiency savings by sector and program from 2024 through 2030.

Table 14. Energy efficiency MWa savings breakdown by year, sector and program

Sector	Program	2024	2025	2026	2027	2028	2029	2030
Commercial	New buildings	3.5	3.8	3.8	3.9	3.6	3.5	3.4
Commercial	Existing buildings	9.4	9.2	9.0	9.0	9.1	9.2	9.1
Commercial	Multifamily	1.1	1.0	1.0	1.2	1.5	1.9	2.2
Commercial Total		14.0	14.0	13.8	14.1	14.1	14.6	14.8
Industrial Total		11.0	10.0	9.9	10.0	10.0	10.2	10.2
Residential	Existing homes	3.6	3.9	4.1	4.0	4.5	5.5	6.0
Residential	New homes	1.6	1.8	1.8	2.2	2.0	2.4	2.3
Residential Total		5.2	5.7	6.0	6.2	6.5	7.9	8.4
Yearly Total		30.2	29.7	29.6	30.2	30.6	32.7	33.3

Figure 37 highlights the annual EE forecast or cost-effective potential in MWa that is considered within the Need Futures, as noted in **Chapter 4, Futures and uncertainties**. **Figure 38** provides the same data in a cumulative approach to highlight the aggregate impact of the cost-effective EE. **Ext. Study-II, EE methodology,** also includes details on the annual energy efficiency trends. **Section 8.2.1, Additional energy efficiency**, provides more information on the additional energy efficiency evaluated within this IRP.

Figure 37. Annual EE forecast by adoption scenarios in MWa

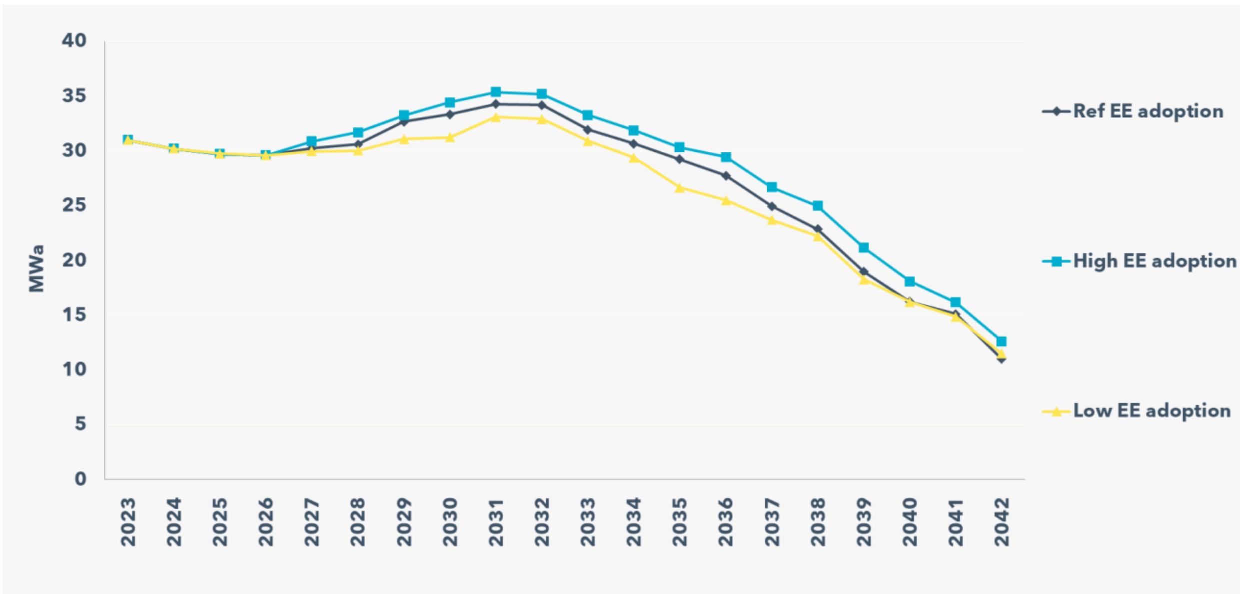
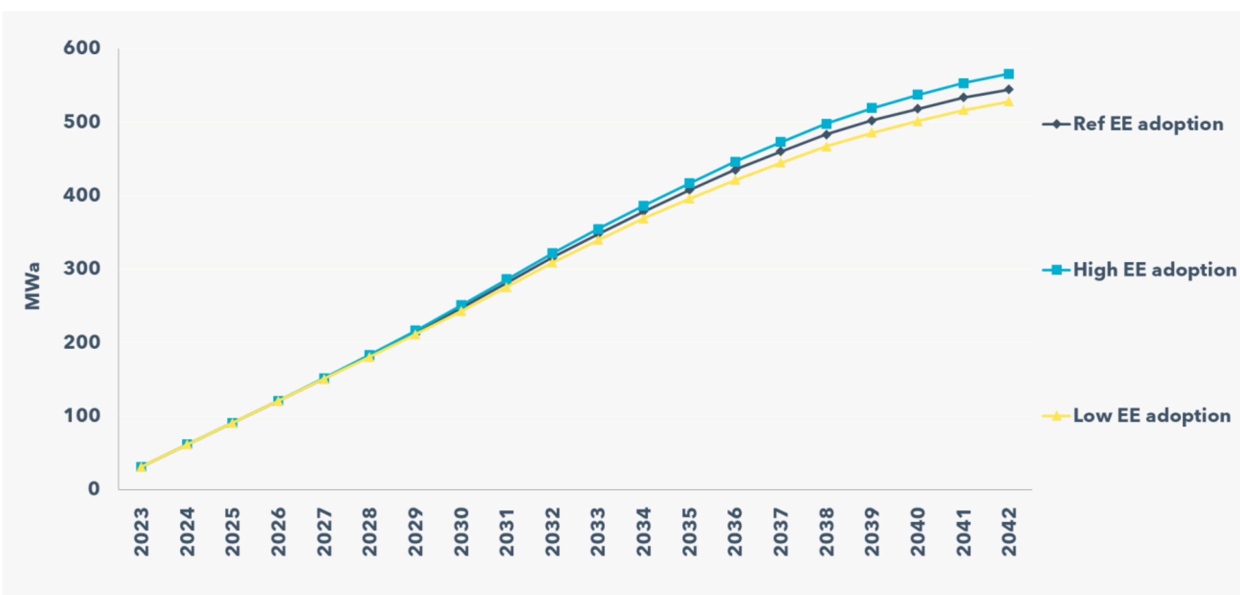


Figure 38. Cumulative EE impact over the planning horizon

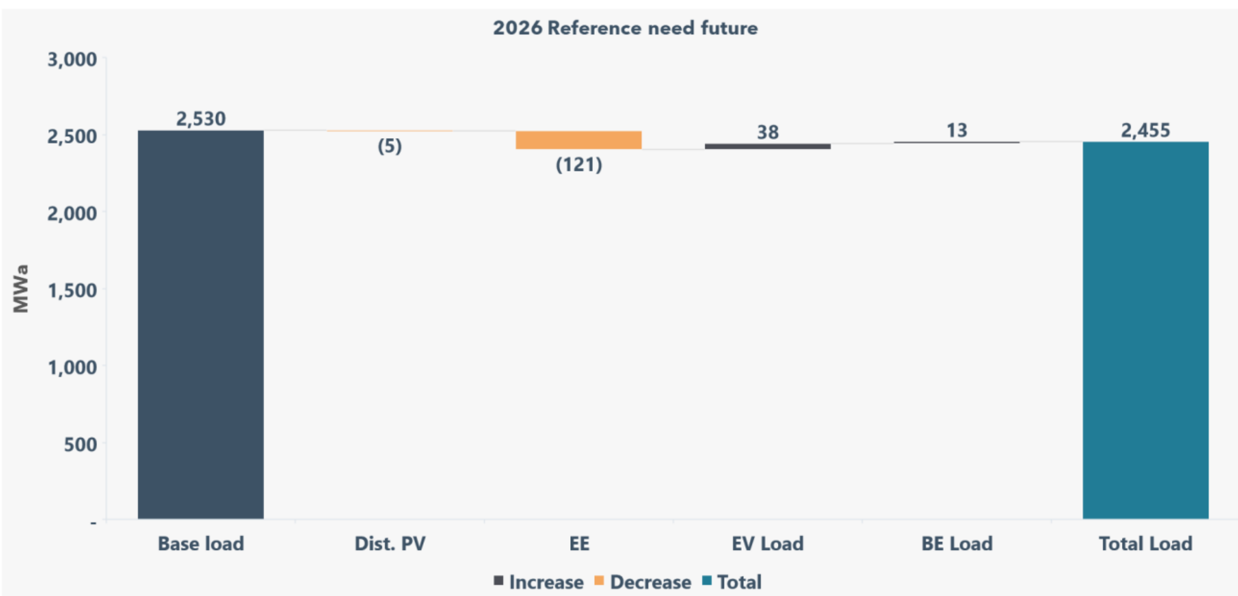


6.3 Load scenarios

The aggregate impact of energy efficiency, other passive DERs and the top-down economic forecast (or Base load forecast) yield the total load used within the IRP. In this section, we graphically present this information. **Figure 39** shows the energy impact of EE savings, distributed PV generation, building electrification and transportation electrification load in the Reference Case for 2026 and 2040. As mentioned earlier, key data considerations for **Figure 39** include the following:

- The base load forecast includes all DER impacts through 2022. The DER impacts highlighted here are the forecasted incremental impacts from 2023 to the year in question.
- The transportation and building electrification loads are gross loads, meaning they do not include the impact of associated demand response programs such as managed charging or time of use, which could increase or decrease loads based on the program design.

Figure 39. Aggregate impact of DERs on base load in 2026 and 2040



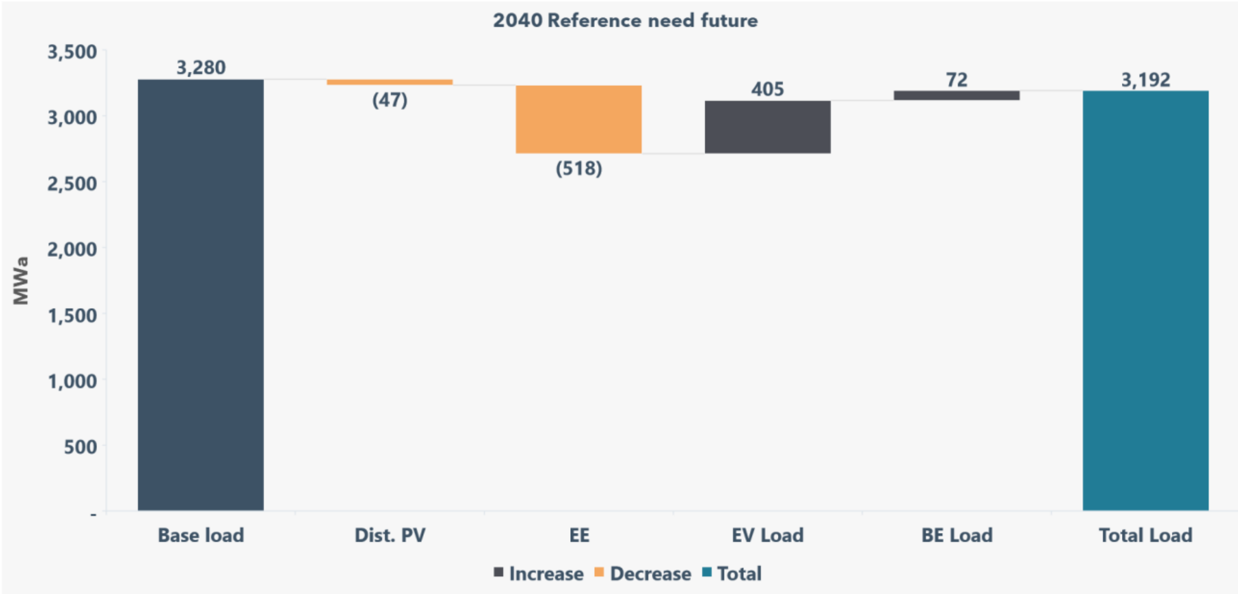
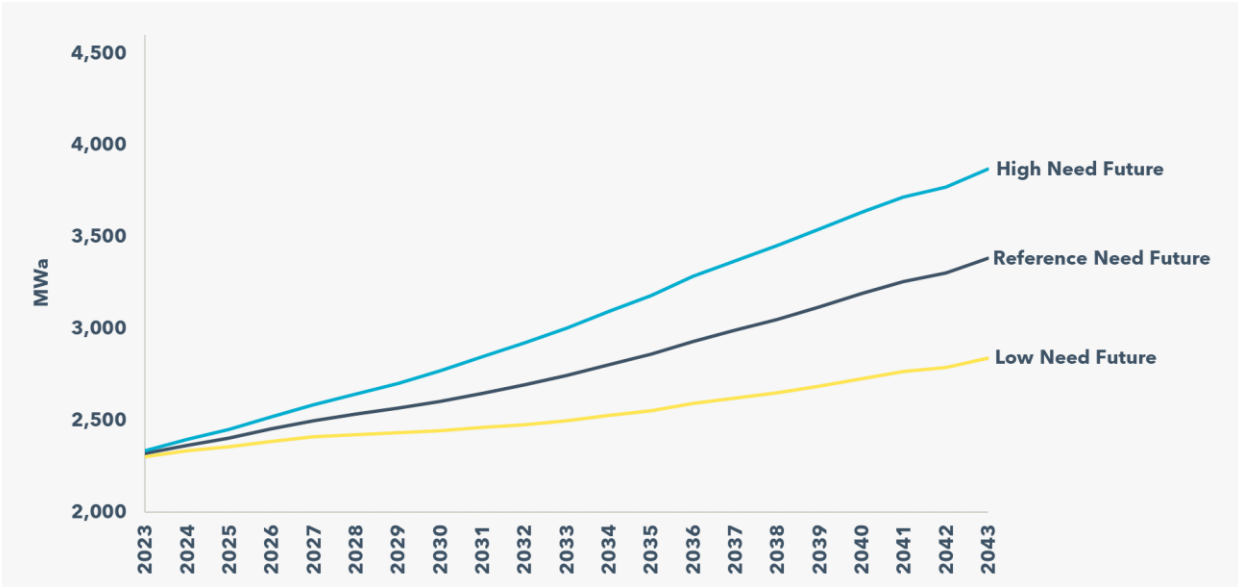


Figure 40 describes the expected total load of each Need Future over the planning horizon showing the divergence between the Need Future over time. By 2030, we expect the total load to be ~2604MWa, growing to just under ~3192MWa by 2040. This represents a 2.1 percent growth between 2030 and 2040. By 2040, the impact of building and transportation electrification is forecast to be ~13 percent of the total load of the system.

Figure 40. Total load for each Need Future over the planning horizon[137]



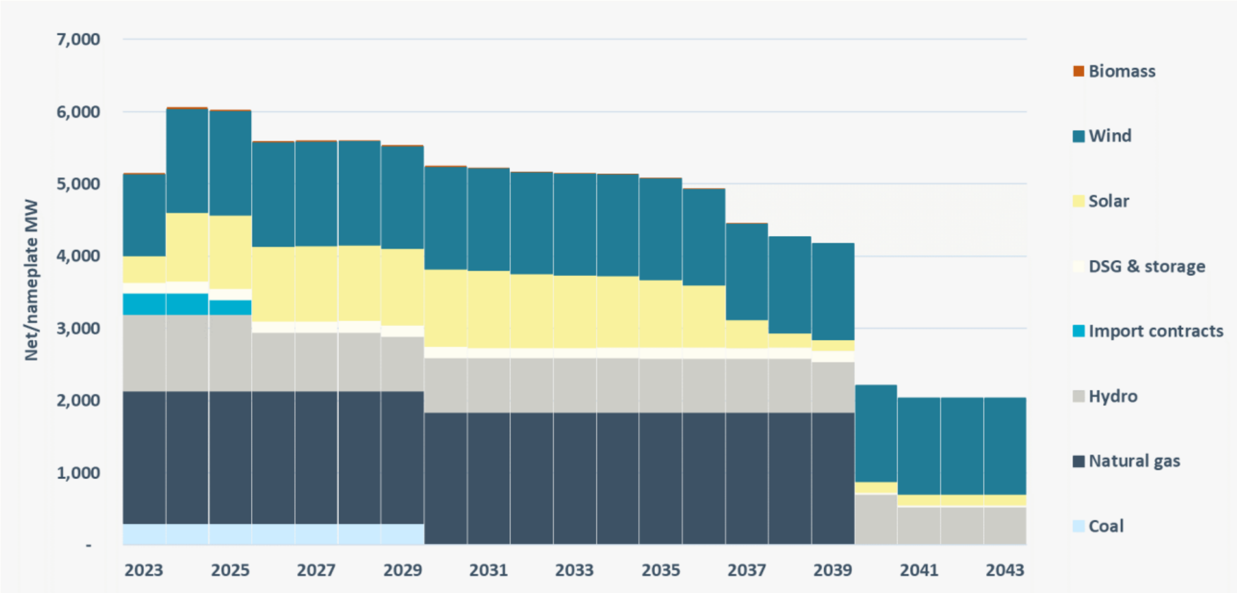
6.4 Existing and contracted resources

PGE owns and contracts a diverse set of resources to meet customer needs. Driven by state policy and company sustainability goals, PGE has been accelerating its transformation to a non-emitting power provider in recent years. This involves acquiring new non-emitting resources, like the Wheatridge Renewable Energy Facility, extending hydroelectric contracts like the Pelton and Round Butte projects, and moving away from coal resources, like the Boardman power plant, which was retired in 2020.

Figure 41 shows the net/nameplate MW of PGE-owned and contracted generating resources, including committed but not yet online resources (like the Clearwater wind project).[138] It does not show future resources from the IRP Preferred Portfolio and assumes no renewals of existing contracts. In 2023, 52 percent of capacity comes from PGE-owned resources, 31 percent from contracted resources and 17 percent from co-ownership and community resources. Net/nameplate MW indicates resource size but is not a good indicator of how much energy or capacity resources can contribute to the system. For a view of PGE's energy position, see **Section 6.5, Energy need**. For a view of PGE's capacity adequacy, see **Section 6.6, Capacity need**.

[137] The figure shows annual energy load forecasts, not peak load forecasts. Peak loads may grow at a different pace due to changing load shapes, demand response programs and other factors.
[138] The figure does not include demand-side resources other than distributed system generation. Net MW may differ from nameplate. Values are approximate.

Figure 41. PGE owned & contracted resources



The forecasted amount of solar on the system grows through 2025 due to bilateral contracts and qualifying facilities coming online.[139] In 2025 and 2026, there is a reduction in resources from the loss of the Avangrid capacity contract (100 MW), the BPA capacity contract (200 MW) and a contract with Douglas PUD. Later in the decade, additional hydro contracts expire, and Colstrip exits the portfolio at the end of 2029. In the mid/late 2030s, the quantity of solar resources on the PGE system declines due to contract expirations.

The IRP only assumes existing contracts will renew if there is a high degree of confidence that the specific contract (or something closely resembling it) will be executed. Contract uncertainty affects IRP resource adequacy and energy needs. PGE would, upon an extension of a contract or entering a new bilateral contract, update the resource need picture (and adjust RFP procurement levels if applicable). **Section 6.10.3, Contract extension sensitivity,** includes additional discussion on the impact of contracts on resource needs.

6.5 Energy need

After detailing forecasts of system demand (in **Sections 6.1-6.3**) and existing supply (**Section 6.4, Existing and contracted resources**), estimates of resource needs in terms of energy and capacity can be derived. This section describes PGE's resource needs through the lens of energy, which represents the amount of electricity demanded and supplied each year and is

[139] These solar projects are largely schedule 202 qualifying facilities and GFI resources.

discussed in terms of megawatt average (MWa) or megawatt hours (MWh).[140,141] **Section 6.6, Capacity need**, describes PGE's needs for capacity, which is discussed in terms of MW, referring to the ability to generate electricity when needed.

6.5.1 Energy-load resource balance

An energy-load resource balance estimates the difference between PGE's forecast customer load (demand) and the expected energy forecasted to be available to serve load (supply). The forecasted amount of energy available annually (in MWa) from owned and contracted non-dispatchable and non-emitting sources is calculated by multiplying the nameplate of each facility by the forecast capacity factor in each year.

The calculation of energy available annually from sources with associated GHG emissions requires a different methodology than was employed in the past due to the GHG emissions regulation created by House Bill (HB) 2021. Prior to the existence of GHG emissions targets, the availability of energy from thermal resources was calculated assuming the availability of the total capacity of PGE's thermal resources to serve load, with adjustments for expected maintenance and outages.

As described in **Section 5.3, Components of IRP emissions reporting**, the total generation levels from PGE's dispatchable thermal plants are determined through economic dispatch from the PZM simulation. To comply with HB 2021 emissions targets, only a portion of the total energy produced by those plants through economic dispatch can be retained to serve Oregon retail load. The amount of energy retained to serve Oregon retail load is determined using PGE's Intermediary GHG model. The amount of energy that can be retained from market purchases and contracts with associated GHG emissions intensity is also accounted for in the Intermediary GHG model.

When combined, the energy retained from GHG-emitting sources and the total energy from non-emitting sources determines the amount of energy allowed to serve Oregon retail load. The forecast of Oregon retail load and the amount of allowed energy that can be used to serve that load are shown in **Figure 42**. The quantity of allowed energy does not include new supply-side resources outside of those from the 2021 RFP and the continued acquisition of energy efficiency, demand response and other demand-side resources.[142] Before any additional incremental resource additions, the Oregon retail load is expected to surpass the

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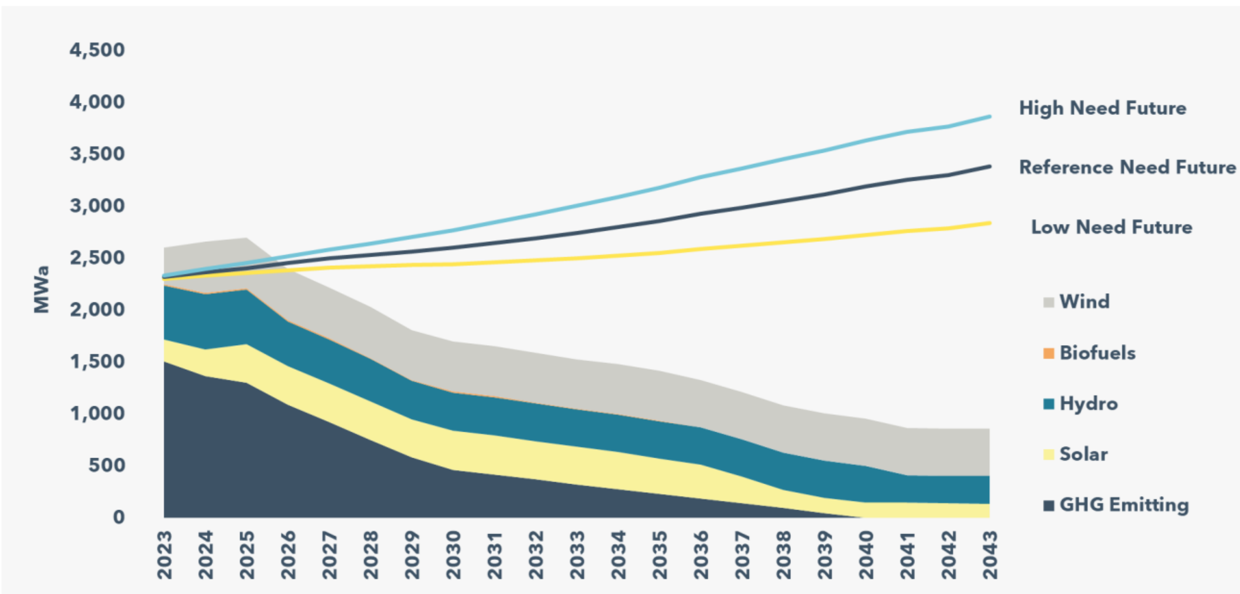
[140] One megawatt is 1 million watts. One megawatt delivered continuously 24 hours a day for a year (8,760 hours) is called an average megawatt.
[141] A megawatt hour (MWh) is equal to 1,000 kilowatts of electricity used continuously for one hour.
[142] As described in **Section 6.2, Distributed Energy Resource (DER) impact on load**, cost-effective EE and DERs are incorporated into PGE's load forecast as a reduction in future loads. Forecast of cost-effective EE and DERs used in this IRP are consistent with what was used in PGE's 2022 Distribution System Plan. Available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning

allowed energy on PGE's system starting in 2027, with the gap growing through the end of the 20-year planning horizon. The gap between Oregon retail load and allowed energy grows through time because of reductions in the amount of energy retained to serve retail load from GHG-emitting sources, expiration of certain contracts and growth in Oregon retail load through time. Because the entirety of PGE's GHG emissions budget is allocated through the dispatch of owned thermals and energy from contracts and purchases with associated GHG emissions, the future gap between load and allowed energy must be bridged with new non-emitting resources or specified-source non-emitting market purchases.[143]

Figure 42. Energy-load resource balance in linear GHG glidepath in Reference Case future



6.6 Capacity need

Capacity needs describe the effective capacity required to achieve a resource-adequate power system. For example, in 2026, the PGE system has a forecasted capacity need of 506 MW in the summer. This implies that the system needs additional resources that, in the aggregate, provide 506 MW of power during key summer hours.[144] These estimates come out of the PGE resource adequacy model, Sequoia.

[143] Assuming no change in the emissions rate used to account for GHG emissions associated with market purchases from unspecified sources.

[144] An effective load-carrying capability study (ELCC), described in **Chapter 10, Resource economics**, determines how much power different resources can effectively provide. In most cases, a resource's effective capacity is lower than the resource nameplate.

The IRP uses the Sequoia model to calculate the capacity needed to maintain resource adequacy in future years. Sequoia is an hourly model that simulates tens of thousands of weekly combinations of loads and resources to assess power system adequacy under a wide range of conditions.[145] Loads in the model represent all retail customers. Resources include owned and long-term contracted facilities (including Green Future Impact (GFI) resources), the recently signed Clearwater Wind project plus proxy resources that provide capacity and energy expected via the 2021 RFP, cost-effective levels of demand-side resources, and spot power market assumptions (see **Chapter 4, Futures and uncertainties**, for a discussion on the changing region and power market assumptions).[146] The capacity need assessment is performed before the portfolio model is run. As a result, the capacity need assessment does not include new resources identified by the IRP portfolio model. A list of major changes made to the Sequoia model between the 2019 IRP Update and the 2023 IRP is available in **Appendix H, 2023 IRP modeling details**.

GHG-emitting resources are available for use in Sequoia through the year 2039. There may be multiday periods with high GHG-emitting resource utilization to maintain resource adequacy (for example, a period of cold, non-windy weather in the winter). To support this assumption and meet HB 2021 GHG targets, the IRP must select sufficient non-emitting resources to offset GHG-emitting generation usage annually.[147]

For the IRP, a resource-adequate system must average 2.4 hours of lost load or fewer per season (2.4 LOLH), an interpretation of one outage every 10 years. This standard is for supply and demand-caused outages, not outages due to transmission and distribution system issues (like a downed power line). Additionally, the capacity needs assessment does not examine flexibility needs, like having quick-to-react resources to balance variable energy resources and mitigate forecast errors. See **Section 6.8, Flexibility adequacy**, of this chapter for a discussion on system flexibility needs.

The IRP examines power system capacity needs on a seasonal, summer and winter basis. **Figure 43** shows system capacity needs for summer and winter from 2024 through 2043 in the Reference Case in the solid lines.[148] The dashed lines show capacity needs with a 200 MW hydro-based contract renewing from 2026 through 2030.

[145] PGE developed Sequoia following the 2019 IRP. It was developed to better model energy limited resources and to incorporate process efficiency improvements. Sequoia was used in the 2019 IRP Update and in the PGE 2021 RFP. More information on Sequoia is in **Appendix H, 2023 IRP modeling details.**
[146] The GFI projects in Sequoia are Bakeoven Solar, Daybreak Solar and Pachwáywit Fields solar.
[147] The selection of sufficient non-emitting resources is done in ROSE-E, the capacity expansion model.
[148] Winter is defined as October through March; summer is defined as April through September.

Figure 43. Seasonal capacity need

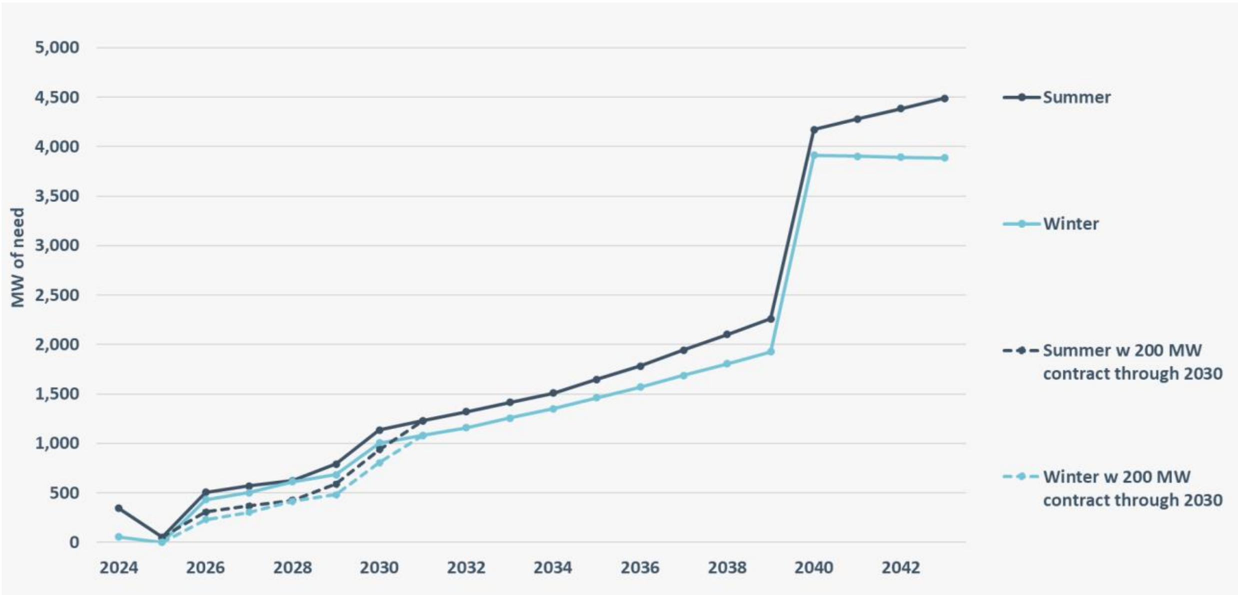
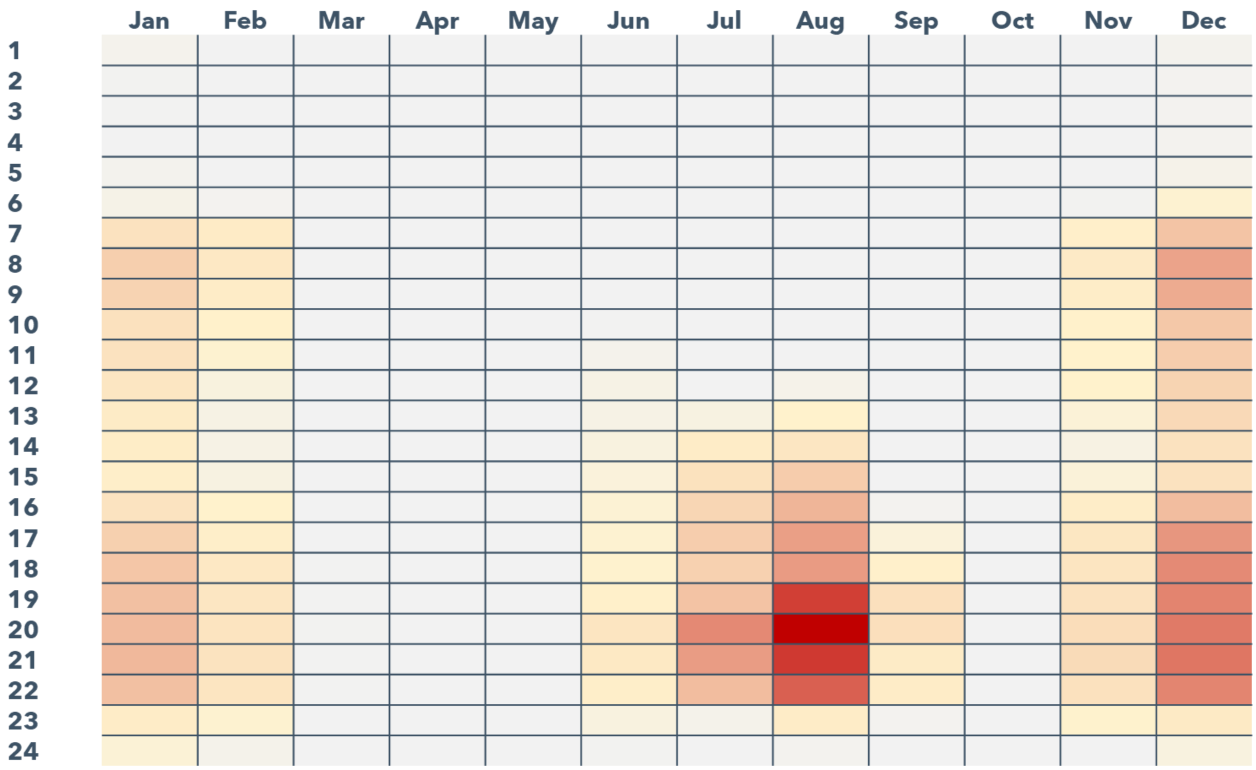


Figure 43 demonstrates larger capacity needs emerging in 2026 (lower levels of needs exist prior to 2026 as well). The increased 2026 need is due to various capacity contracts expiring in 2024 and 2025.[149] A second upward step in capacity need occurs in 2030 when Colstrip exits the portfolio. After 2030, the need for power will grow via two primary drivers. First, steady forecasted load growth for the core system and quickening electrified end-use growth projections push the need up. Second, resource reductions, like the loss of solar contracts in the mid/late 2030s, add to the need. In 2040, the need steps upward when existing GHG emitting resources, like natural gas power plants, can no longer serve retail load (the 2040 need increase could be reduced if existing gas plants are able to convert to a non-emitting fuel).

Figure 44 presents a 12x24 (monthly by hourly) look at 2026 capacity needs. The graph gradients from gray (zero/minimal outages) to red (higher levels of outages). PGE's system sees adequacy challenges in the winter and summer evening hours and the morning in the winter (hours in the heatmap are all Pacific standard time). In 2026, under the Reference Case assumptions, there is a need for 430 MW of effective capacity in the winter and 506 MW in the summer to achieve an adequate system (2.4 LOLH per season).

[149] Contracts may fail to renew for many reasons. These include actions by the seller, like keeping the power to serve local load and/or selling to another entity. The seller may also price the contract higher than other resource/contract options, causing PGE to pursue other options.

Figure 44. 2026 Reference Case capacity need heatmap

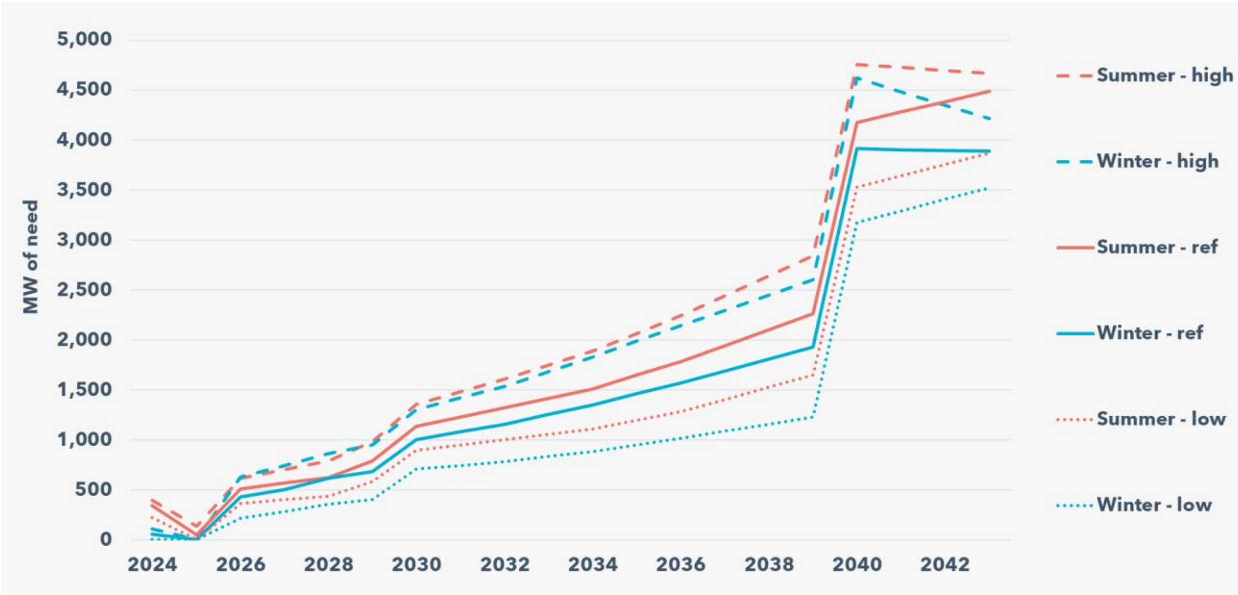


6.6.1 Capacity under different Need Futures

There is capacity need uncertainty in the next decade. The uncertainty is due to many factors, including:

- Load growth uncertainty, both from the core forecast and electrification
- Uncertainty regarding the level of demand-side resources PGE will acquire
- Existing contract renegotiation uncertainty
- This IRP examines low and High Need Futures to test uncertainty associated with loads and demand-side resources. See **Chapter 4, Futures and uncertainties**, for more information on Need Futures. **Figure 45** shows the capacity needs of the low and high-needs futures and the Reference Case. In 2026, summer need ranges from 364 MW in the low case to 617 MW in the high case. **Section 6.10, Need sensitivities**, examines how different qualifying facility forecasts, electrification projections, contracts and Colstrip impact capacity needs.

Figure 45. Capacity need under different futures



6.7 RPS need

The Renewable Portfolio Standard (RPS) was established as a law in Oregon in 2007. In 2016, Senate Bill (SB) 1547 escalated the RPS requirements for electric utilities to meet customer energy needs with 50 percent of electricity from renewable resources by 2040 (see **Table 15**).[150]

Table 15. RPS obligations per SB 1547

Year	RPS requirement (% of retail sales)	RPS requirement MWa (reference need)
2025	27%	491
2030	35%	691
2035	45%	975
2040	50%	1207

[150] SB 1547 (2016), available at: https://olis.oregonlegislature.gov/liz/2016R1/Downloads/MeasureDocument/SB1547/Enrolled

In conjunction with meeting HB 2021 requirements, PGE projects that without incremental renewable resource actions, RPS obligations will exceed the quantities of Renewable Energy Certificates (RECs) available from generation from existing RPS-eligible resources in the Low, Reference and High Cases beginning in 2030 when RPS requirements increase from 27 percent to 35 percent of the retail load. PGE's forecasted physical RPS shortage[151] in 2030 is illustrated in **Figure 46** and **Table 16**. For details regarding PGE's expected compliance with the RPS requirements, see **Section 11.5.2, Resulting RPS position**, which compares the RPS requirements with PGE's corresponding RPS position within its Preferred Portfolio.

Figure 46. PGE's physical RPS shortage across Need Futures

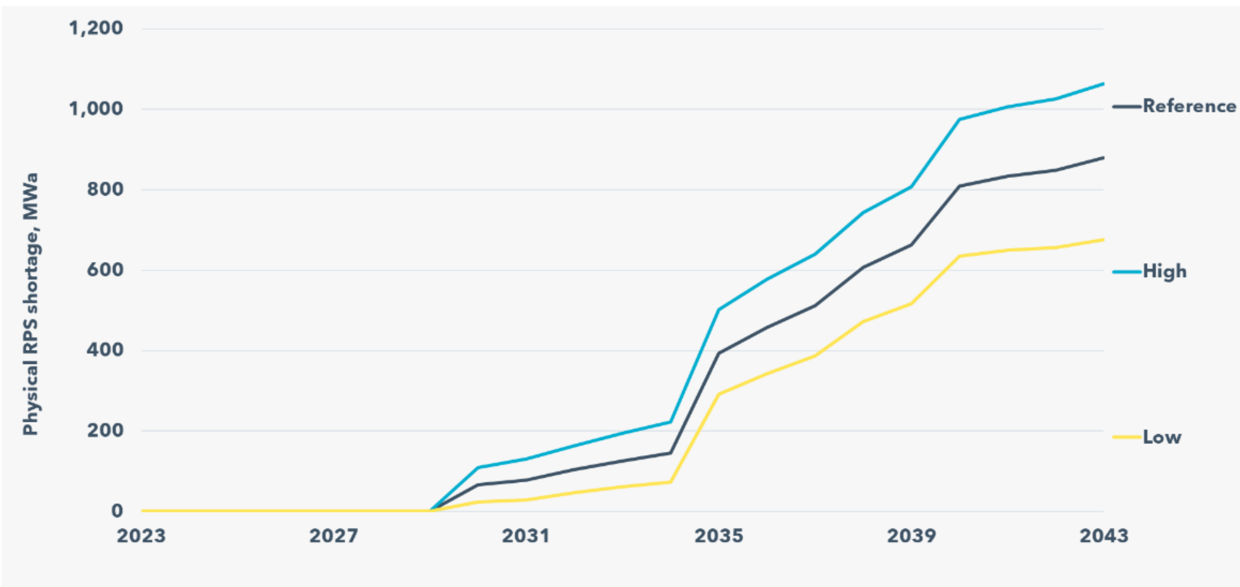


Table 16. Physical RPS shortage in 2030

Need future	2030 physical RPS shortage (MWa)
Reference Case	53
Low Need Future	11
High Need Future	97

[151] A physical RPS shortage is forecasted when RPS obligations exceed PGE's physical RPS position. Physical RPS position is the comparison of forecast-generated Renewable Energy Credit (REC) to the forecast RPS obligation over time. PGE includes information about physical RPS compliance as informational only and does not include any resource additions based on physical compliance. For more detail, see **Section 11.4.6, Targeted policy portfolios**.

6.8 Flexibility adequacy

Resource adequacy need is a vital part of the IRP process to ensure resource actions result in a reliable system. An element of this assessment is understanding operational challenges associated with the need for operating reserves, operational constraints of power plants and errors in supply forecasts and commitments. Unserved energy from these sources can be attributed to a deficit in the system's operational flexibility. Accordingly, flexibility adequacy is an element of resource adequacy that highlights the deficit in a system's operational capabilities hourly and is denoted by a MW flexible adequacy target.

In addition to the hourly flexibility adequacy, the importance of more granular flexibility analyses, from hourly to sub-hourly, is growing as more Variable Energy Resources (VERs) are integrated across the Western Interconnection. Sub-hourly resource integration impacts are a growing body of research across the industry. PGE is still in the learning phase on this topic, focusing on how it can be assessed, understanding its connection with other elements of resource adequacy and hourly flexibility adequacy, and its impact on resource selection.

As part of the flexibility assessment in this IRP, three key critical concepts are analyzed:

- **Flexibility adequacy.** A MW number that represents the magnitude of fast-acting dispatchable resources needed to meet the operational flexibility needs of the system and ensure system reliability. This metric is incorporated within our capacity expansion model, ROSE-E, to address this need by selecting an adequate amount of fast-acting dispatchable resources within the portfolio, such as batteries, pumped storage hydro and other dispatchable resources.
- **Flexibility value.** Represents a benefit value stream that fast-acting dispatchable resources such as batteries and certain DERs should receive for addressing flexibility adequacy. This benefit is integrated into resource economics and is described further in **Section 10.3, Flexibility value and integration cost**.
- **Integration cost.** Represents a cost value stream for VERs such as wind and solar that increase the need for flexibility adequacy due to their variability. This cost is integrated into resource economics and is described further in **Section 10.3, Flexibility value and integration cost**.

For this IRP, PGE worked with Blue Marble Analytics, a third-party consultant, to model all three elements. Blue Marble Analytics used its Grid Path Model to perform the analysis, calibrating the model to the 2019 IRP's flexible adequacy analysis. The findings of the Flexibility Adequacy Study are summarized in the following section, and the entire Blue Marble Analytics study is included in **Ext. Study-IV, Flexibility study**.

6.8.1 Study takeaways and implications

From **Ext. Study-IV, Flexibility study**, we gathered the following findings on flexibility adequacy (**Table 17**):

- **Flexibility challenges in the near- and mid-term are driven by forecast error**. In both the 2026 and 2030 test years, the system experiences inadequate flexibility driven by forecast error. This is where the system, after adjusting hydropower and gas generation, does not have sufficient capacity intra-day to address the magnitude of forecast error during the hours with the highest net load.
- **Flexibility adequacy grows in magnitude and frequency from near- to mid-term.** The study results indicate that in 2026, the system will require an additional 80 MW and 158 MWh of flexible resources to meet the needs of the system, which occur about 0.1 percent of the time. This inadequacy grows to 122 MW and 501 MWh by 2030, with the frequency increasing to 0.3 percent of the time.

Table 17. Flexibility adequacy in 2026 and 2030

	2026	2030
% Timepoints	0.1%	0.3%
Total MWh	158	501
Max MW	80	122

- **Flexibility adequacy challenges are experienced in both summer and winter seasons.** In 2026, the model sees that winter outages are most common in the evenings. In summer, outages are later in the evening, with most outages during hours with the highest net load, usually in the evenings from 6-10 PM. By 2030, as the magnitude and frequency of these outages increase, the outages also occur in the spring and fall seasons. However, the largest outages still occur during evening peaks in summer and winter.
- **System headroom is constrained during summer and winter.** Headroom is defined as how close the system is to experiencing a flexibility-related event. Blue Marble Analytics also assessed the system headroom and found that on a seasonal basis, the system is most constrained in the winter. System headroom is 300 MW or less 25 percent of the time in December and reaches zero in all three winter months as well as in November. Headroom is also frequently constrained in the summer and falls to zero in July, August and September.

- **Diverse resources can help mitigate the increasing flexibility adequacy issues of the system.** Blue Marble found that fast-responding battery storage is required to address flexibility adequacy issues caused by forecast errors. The magnitude of storage required can be reduced when the portfolio includes more diverse VERs. Thus, resource actions that maximize the diversity benefits of VERs that reduce the magnitude of storage needed to address flexibility adequacy issues is one of the more cost-effective methods to address the increasing flexibility challenges. However, given PGE's growing transmission constraints, the costs associated with new transmission for VERs may offset their diversity benefits for flexibility adequacy.

6.8.2 Future improvements/limitations of current data and analysis

As noted, performing a flexibility assessment at the hourly granularity is a critical step in ensuring the reliability of a VERs-dependent system. There is a growing need to understand flexibility needs at the sub-hourly level. Sub-hourly flexibility assessments ensure the system has adequate operational capabilities to balance real-time generation changes of VERs. Assessing the sub-hourly flexibility needs is not only an extremely data and computationally intensive exercise but also raises several questions such as:

- Is there sufficiently granular data of a future system to perform this analysis within resource planning?
- Is there an industry standard or accepted modeling practices to perform such an assessment?
- How do we apply annual reliability targets and standards to a sub-hourly analysis?
- How do we account for the interaction between the different adequacy analyses, ensuring that the needs are not under or over-represented?

PGE is committed to exploring these questions, among others, to ensure we are accurately assessing the system's needs and are developing resource plans to deliver clean energy to customers reliably.

6.9 Climate adaptation

As the climate warms, PGE is adapting its planning process to reflect future temperature and hydrologic conditions. Generally, continued warming in the Northwest will lead to higher temperatures and reduced snowpack (as more precipitation falls as rain rather than snow). Higher temperatures will increase summer electric demand (more AC) and decrease winter demand (less heating). Less snowpack but similar precipitation levels will result in more hydropower in the winter (more rain increases stream flows) but less hydropower in the summer (due to less snowpack and an earlier melt).[152] The impact of these changes will result in relatively higher capacity needs in the summer (due to more demand and less hydropower) and relatively lower capacity needs in the winter (due to less demand and more hydropower).

6.9.1 Climate change in the 2023 IRP Reference Case

PGE incorporates some elements of climate change into the IRP Reference Case scenario and is studying other aspects of climate change via sensitivities. PGE also engaged a consultancy, Creative Renewable Solutions, to review climate change incorporation in the IRP and to provide recommendations for future improvements. The consultancy's work is in the **Ext. Study-III, Climate adaptation**.

The IRP Reference Case incorporates climate change by:

- Including a warming assumption based on historical temperature trends in the load forecast. See **Section 6.1, Load forecast**, of this chapter for more information on the load forecast.
- Using a reduced number of historical years (30) for both temperature and hydropower sampling in the adequacy model to better reflect climate trends.
- Using climate change model data in the market capacity study.[153] This study dictates how much market power is available to the PGE resource adequacy model, Sequoia. Switching to climate change model data played a role in allowing market power access in the winter and restricting power market access in the summer.

Information on how historical temperature trends align with climate change model data are in **Appendix D, Load forecast methodology**. **Appendix G, Market capacity study**, discusses how climate change data impacted that analysis.

6.9.2 Temperature years in the 2023 IRP adequacy model

The IRP uses the Sequoia model to examine resource adequacy and determine capacity need in future years. The IRP uses the corporate load forecast and historical weather years to create the hourly load profile used in Sequoia and provide load variations based on weather. In past planning work, Sequoia used temperature data from 1980 through the most current year

[152] There is some ability to store/move water from month to month at select Northwest hydroelectric projects, but the overall trend is towards more water/hydro generation in the winter, and less in the summer.
[153] The market capacity study uses data from the Northwest Power & Conservation Council. Their switch to climate change data for the 2021 Power Plan led to the switch in the study.

available. For the 2023 IRP, the model uses the most recent 30 years (1992-2021). The rationale for the switch is that more recent temperature data should better reflect the changing climate.

To test the impact of switching to the 30-year record, Sequoia ran with two sets of temperature years:

- 1980-2021, a 42-year temperature record
- 1992-2021, a 30-year temperature record (created by shortening the 42-year record)

Table 18 shows how the seasonal capacity need in the year 2026 varies depending on the number of temperature years used in the model. In both summer and winter, the capacity need is higher in the 30-year record than in the 42-year record.

Table 18. Seasonal capacity needs in year 2026 under different weather years (MW)[154]

	42 load years	30 load years
Summer	452 MW	506 MW
Winter	417 MW	430 MW

6.9.3 Hydropower climate change data sensitivities

Resource adequacy needs can vary due to hydro conditions. Some years have relatively high levels of hydropower generation due to high levels of snow and rainfall. Due to the higher levels of hydropower generation, those years may have fewer adequacy issues than average. Other years have low levels of hydropower generation due to decreased rain/snow and may face more adequacy challenges than average.

Incorporating a wide and realistic array of hydro conditions in resource adequacy modeling is important to provide an accurate picture of system needs. In past planning work, Sequoia used a 79-year (1929-2007) hydro record. For the 2023 IRP, the model uses the most recent 30-year record (1989-2018). The rationale for the switch is that more recent hydrological records should better reflect the changing climate.

[154] These tests use the 30-year hydro record from the 2023 IRP.

The IRP tests how six different hydro generation records impact resource adequacy needs.[155] The first test uses the historical 1929-2007 record. The second test uses the 30-year historical hydro record (1989-2018). The third through sixth tests use climate change model forecasts for 2020-2048.[156]

Table 19 shows how summer and winter capacity needs in the year 2026 differ by the hydro record. Compared to the 79-year record, all other hydro records result in equal or increased summer capacity needs and decreased winter capacity needs. Going forward, PGE will continue to explore using climate change hydro data in planning work.

Table 19. Year 2026 capacity need (MW)

	79-year record	30-year record	CanESM2	MICRO5	HadGEM2	GFDL
Summer	506 MW	506 MW	514 MW	508 MW	507 MW	506 MW
Winter	432 MW	430 MW	423 MW	426 MW	423 MW	431 MW

6.10 Need sensitivities

For the 2023 IRP, PGE examined the capacity and energy need impacts of different qualifying facility success rates, accelerated load growth beyond the high Need Future, contract renewals, market emissions rates and Colstrip exiting the portfolio four years early.

6.10.1 Qualifying facility sensitivities

PGE ran two qualifying facility (QF) success rate sensitivities focusing on years 2026 and 2030. These sensitivities primarily impact the amount of solar energy on the PGE system. The Reference Case QF assumptions and the two sensitivities follow. In all cases, the IRP assumes that QF contracts do not renew after they end.

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[155] For all of the tests, the data which are changing are for the larger PGE owned/contracted projects which are Mid-C contracts associated with specific dams and the Pelton Round Butte projects. The impact of changing the hydro record for smaller hydro projects is not assessed in the IRP.
[156] The 30-year hydro record and climate change hydro data are from BPA/US Army Corps of Engineers and processed by the consultancy Creative Renewable Solutions. More information on the climate models is available in **Ext. Study-III, Climate adaptation**.

- Reference Case: All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 projects are included.[157]
- Low QF sensitivity: All QFs that are currently online plus 50 percent of executed Schedule 201 projects and 50 percent of executed Schedule 202 projects are included.
- High QF sensitivity: All QFs that are currently online plus 100 percent of executed Schedule 201 projects and 100 percent of executed Schedule 202 are included.

Table 20 shows capacity needs for winter and summer under the Reference Case and high/low QF case assumptions. With fewer QFs on the system, capacity needs increase; with more QFs on the system, capacity needs decrease or stay the same.

Table 20. Qualifying facility sensitivity Capacity need (MW)

Capacity impact	2026 summer	2026 winter	2030 summer	2030 winter
Low QF	537	431	1,156	1,008
Reference	506	430	1,136	1,004
High QF	505	430	1,136	1,004

On an energy basis, in 2026, the Low QF sensitivity results in a 36MWa decrease in energy, increasing PGE's energy shortage and requiring additional resources. The High QF sensitivity results in a 1MWa increase in energy, reducing the need for new resources.

This analysis shows that delays or terminations of executed QF projects have an impact on capacity and energy needs. To minimize these risks, PGE will continue to monitor the status of QF projects and provide updates within the docket if changes materially impact the Action Plan (**Chapter 12**)**.** PGE continues to advocate in OPUC policy and rulemaking dockets for changes in the power purchase agreements and the contracting process for QFs that would reduce speculative contracting and increase the success rate of QFs that sign power purchase agreements.

[157] Schedule 201 resources are 10 MW nameplate in size or fewer; Schedule 202 resources are greater than 10 MW, not to exceed 80 MW.

6.10.2 Accelerated load growth sensitivity

In addition to the High Need Future which includes the high building and transportation electrification adoption cases from the DSP, the IRP includes an electrification and load sensitivity to understand the combined impact of the following possibilities:

1. Increased building electrification from building-related Climate Protection Program compliance being achieved through electrification only (this results in higher building electrification than the high Need Future).[158]
2. Transportation electrification growth that is more aggressive than the Advanced Clean Cars II policy (this results in higher transportation electrification than the high Need Future).[159]
3. A base load forecast with higher load growth in part due to increased industrial growth.

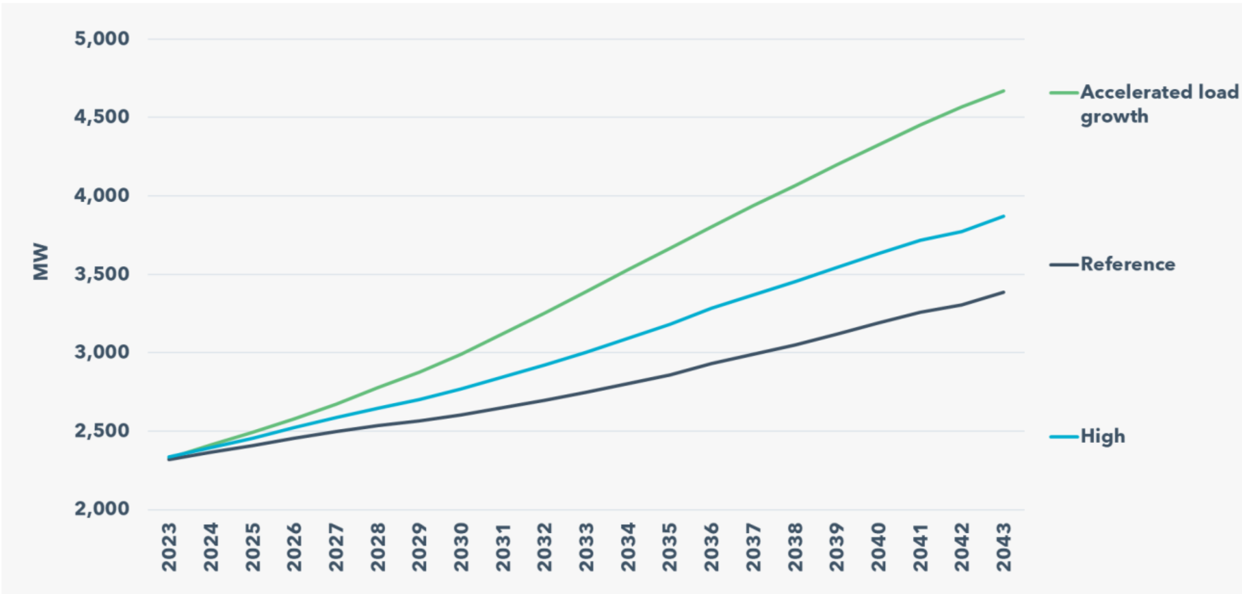
PGE created this sensitivity to test the capacity need and load impact of these possibilities in aggregate. **Table 21** compares the capacity need of this accelerated load growth sensitivity against the IRP's reference Need Future and high Need Future for years 2026 and 2030. **Figure 47** provides the same comparison on an annual energy load basis.

Table 21. Capacity need (MW), high electrification & load sensitivity

Case	2026 summer	2026 winter	2030 summer	2030 winter
Reference	506	430	1,136	1,004
Accelerated load growth	788	870	2,020	2,036
High Need Future	617	628	1,357	1,302

[158] The Climate Protection Program reduces GHG emissions from multiple sources, including space heating, available at: https://www.oregon.gov/deq/ghgp/cpp/pages/default.aspx
[159] Advanced Clean Cars II puts Oregon on a trajectory to 100 percent EV sales for passenger cars, SUVs and light-duty trucks by 2035, available at: https://www.oregon.gov/deq/rulemaking/Pages/CleanCarsII.aspx

Figure 47. Comparison of the accelerated load growth sensitivity with the IRP reference and high Need Future



6.10.3 Contract extension sensitivity

Table 22 estimates how the IRP's capacity and energy needs change based on existing contract renewal. The contracts included in the table are:

- A 100 MW capacity contract to Avangrid that expires in 2024
- A 200 MW capacity contract to BPA that expires in 2025
- Contracts with Douglas PUD that expire in 2025 and 2028

In the following table, all contracts extend through the year 2030. Contract extension reduces both energy and capacity need in all impacted years.

Table 22. Energy and capacity needs with and without select contract extensions

Year	Ref. case energy need (MWa)	Energy need with extensions (MWa)	Ref case summer capacity (MW)	Summer cap with extensions (MW)	Ref case winter capacity (MW)	Winter cap with extensions (MW)
2024	0	0	344	252	55	2
2025	0	0	51	-	-	-
2026	58	0	506	-	430	-
2027	277	167	568	48	502	-

Year	Ref. case energy need (MWa)	Energy need with extensions (MWa)	Ref case summer capacity (MW)	Summer cap with extensions (MW)	Ref case winter capacity (MW)	Winter cap with extensions (MW)
2028	504	388	624	104	614	28
2029	757	603	791	164	683	96
2030	905	756	1,136	540	1,004	458

6.10.4 Market emissions rate sensitivity

PGE buys unspecified power on the market. **Table 23** estimates how energy needs would change in 2030 if half of the recent quantity of unspecified market power purchased by PGE were instead specified as non-emitting. As existing thermal resources are considered always available for resource adequacy purposes, this change in purchases would have no effect on estimated capacity needs. However, such a change would significantly reduce PGE's yearly energy needs, which in turn would reduce the quantity of non-emitting generation and customer price increases. These results suggest that determining the appropriate emission factor of market purchases will be critical going forward to accurately determine resource needs.

Table 23. 2030 energy need with 50 percent of unspecified market purchases designated as non-emitting

2030 Energy Need	MWa
Low Need Future	746
Reference Need Future	905
High Need Future	1,071
Reference Need Future with 50% of unspecified market purchases designated as specified/non-emitting	686

6.10.5 Colstrip sensitivity

Table 24 estimates how capacity and energy needs change in years 2026 through 2029 if Colstrip no longer provides power to retail customers starting in 2026. This differs from the Reference Case assumption of Colstrip providing power to retail customers through the end of 2029. Capacity needs increase when Colstrip no longer provides retail power starting in 2026, but energy needs decrease. The decrease in energy needs is due to Colstrip having a higher GHG intensity than other resources in the portfolio. Its higher GHG intensity results in higher GHG emissions per MWh in the portfolio; thus, fewer MWhs from GHG-emitting sources are kept for retail load service. This accounting happens in the Intermediary GHG model (see **Chapter 5, GHG emissions forecasting**, for details on that model).

Table 24. Energy and capacity needs with and without Colstrip

Year	Ref. case energy need (MWa)	Energy need w/o Colstrip (MWa)	Ref case summer capacity (MW)	Summer cap w/o Colstrip (MW)	Ref case winter capacity (MW)	Winter cap w/o Colstrip (MW)
2024	0	0	344	344	55	55
2025	0	0	51	51	-	-
2026	58	0	506	799	430	726
2027	277	138	568	858	502	797
2028	504	406	624	917	614	902
2029	757	683	791	1,083	683	974
2030	905	905	1,136	1,136	1,004	1,004

Chapter 7. Community benefits indicators and community-based renewable energy

While our Integrated Resource Plan (IRP) has historically focused on least-cost, least-risk modeling as the foundation for providing safe, reliable and affordable power to customers, House Bill (HB) 2021 and OPUC guidelines for utilities' Clean Energy Plans expand the focus of resource planning to be more inclusive of the broader community benefits of resource options and the opportunities for Community-based Renewable Energy resources (CBREs). This chapter describes PGE's approach to the Community Lens topic as outlined in the OPUC's UM 2225, which provided guidance on the development of community benefits indicators (CBIs), the inclusion of a CBRE potential study and the identification of CBRE opportunities.

Chapter highlights

- Portland General Electric's (PGE's) Community Lens Potential study defines our approach to the CBRE forecast and identifies 155 megawatts (MW) of CBRE potential by 2030.
- PGE incorporates CBIs within our IRP using a 10 percent adder for our Resource CBI pathway and a scoring methodology for our Portfolio CBI pathway.
- PGE will continue to evolve our approach to CBIs and CBREs through our Community Learning Labs and by working with our communities to identify future CBRE opportunities through our community Request for Proposals (RFP) and development of non-wires solutions (NWS).

7.1 Community benefits indicators (CBIs)

7.1.1 Defining community benefits indicators

PGE defines a CBI as an equity tool that can be applied to modeling, analysis, scoring metrics, procurement, programs and reporting to inform decisions related to planning activities. CBIs aim to assist in pursuing equitable outcomes and beneficial long-term impacts to environmental justice (EJ) communities, tribes and the most vulnerable communities.

To begin our work, we reviewed OPUC guidance under Order 22-390 regarding CBIs and their application to CBRE analysis and IRP portfolio analysis. Based on the OPUC's guidance in Order 22-390, CBIs are divided into five categories:

- Resilience (customer and system)
- Economic
- Environmental
- Energy equity
- Health and community wellbeing

Additionally, PGE reviewed the OPUC's Attachment A from Order 22-390 (also referred to as "Attachment A"). [160] Attachment A was provided by a coalition of Energy Advocates detailing 15 distinct CBIs the Commission and utilities should consider. We reviewed the list of recommended CBIs from our communities within Attachment A and the broader literature around CBIs and the experiences of other utility jurisdictions (e.g., Washington's Clean Energy Transformation Act requirements). Utilizing this information, we worked with communities and stakeholders within our Community Learning Labs to identify additional CBIs and which CBIs are most important to our communities.

[160] See *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390 (Oct 25, 2022), Appendix A at 65 (Attachment A Stakeholder CBI Proposal), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

PGE will continue working with our communities and other stakeholders through the Community Learning Labs and other venues to develop more standardized information to guide implementation efforts and accountability around community benefits moving forward. This work includes:

- Developing metrics used to measure these benefits.
- Establishing a baseline of the current state of these benefits, where feasible.
- Determining thresholds/criteria for success.

7.1.2 Community benefits indicator pathways

PGE views CBIs as an important component of an inclusive process of the clean energy transition, helping us identify opportunities for communities to benefit from investments to achieve emissions targets. As discussed further in **Chapter 14, Community equity lens and engagement** PGE conducted community engagement within our Community Learning Labs to develop our initial approach to CBIs. Our goals were to identify CBIs of interest to our communities, identify baseline metrics where possible, and share objectives and goals for improving and updating those metrics in subsequent CEP and IRP filings.

PGE heard from our communities and stakeholders that CBIs are important within the planning process because they can influence how utilities make resource investment decisions. We also heard they are important to the implementation of Oregon's HB 2021. Based on this feedback, we developed and categorized CBIs into two groups: quantifiable and qualitative. Quantifiable CBIs refer to benefits that can be measured or expressed as a value. Qualitative CBIs refer to benefits that cannot be expressed as a value but can be described based on quality rather than quantity.

CBIs were then placed into one of three pathways: Resource, Portfolio and Informational, as per OPUC Order 22-390, which states that initial CEPs should include at least one interim CBIs for each pathway. Resource and Portfolio CBIs are considered quantifiable benefits for this CEP and Informational CBIs are qualitative. **Figure 48** illustrates the different pathways related to CBIs as defined by the OPUC's Order 22-390.

Figure 48. OPUC Order 22-390: CBI Pathways

Resource (rCBI)	Portfolio (pCBI)	Informational (iCBIs)
• Informs and tracks progress on specific outcomes achieved through CBRE actions • Should be reflected in the CBRE potential study and in IRP portfolio scoring	• Addresses the impacts of the utility's portfolio on communities • May or may not be tied to CBREs, and should be reflected in IRP portfolio scoring	• Provides transparency into topics of importance to communities • May or may not directly inform portfolio scoring in the IRP

Identifying, measuring and applying CBIs is new to PGE's energy resource planning and resource acquisition process. As described in **Section 7.2.1, Defining CBREs**, for the first step in the IRP portfolio analysis, PGE developed initial CBRE proxy values to reflect a variety of potential CBIs, which allow for distinguishing the energy system benefits of these resources from their relative contribution to community benefits. However, as we move to procure CBREs and initiate program planning and project development, it may be important to develop a set of CBIs that are both quantifiable and measurable.

As a starting point, we apply the Resource and Portfolio pathways to IRP modeling. We use the first pathway, Resource CBIs or rCBIs, to inform and track progress on actions related to CBREs. We use the second pathway, Portfolio CBIs or pCBIs, to address the impacts of the utility's portfolio on communities, which should be reflected in IRP portfolio scoring. For Informational CBIs or iCBIs, we include indicators that may provide transparency into important topics for communities.

7.1.3 Resource community benefits indicators

The OPUC provided guidance within their Community Lens Topics for UM 2225 for Resource CBIs (referred to as CBRE-focused CBIs) that rCBIs are used to "inform and track progress on CBRE actions and should be reflected in the CBRE potential study and in IRP portfolio scoring."[161] When developing rCBIs, PGE evaluated how to incorporate new benefits for the community within portfolio analysis, which is the IRP's process of resource selection. Portfolio analysis is used to understand future long-term resource needs, analyze the expected costs

[161] See *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390 (Oct 25, 2022) at 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

and associated risks of the alternatives to meet those needs, and determine the best set of resources to meet those needs for customers.

To integrate rCBIs into portfolio analysis, PGE used a process similar to the 1980 Northwest Power Act for energy efficiency, which allows the flexibility of choosing an adder from 10 percent to 50 percent.[162] Leveraging that approach, PGE created an rCBI adder that reduces the cost of a CBRE resource by 10 percent. We applied this 10 percent credit to the CBRE fixed cost for each of the three proxy CBRE resources evaluated, making them relatively more competitive compared to other supply-side options. A comparison of this credit relative to the other costs and benefits associated with the proxy CBRE resource value is displayed in **Section 10.9, Resource community benefits indicators**.

7.1.4 Portfolio community benefits indicators

The OPUC provided guidance within their Community Lens Topics for UM 2225 for Portfolio CBIs (pCBI) that pCBIs "address the impacts of the utility's portfolio on communities, may or may not be tied to CBREs and should be reflected in IRP portfolio scoring."[163]

PGE defines a portfolio as a fixed set of resource decisions in all scenarios. Our capacity expansion model, ROSE-E, selects the optimal set of incremental resource additions given the parameters in each scenario. As described in **Section 11.1.1, GHG emissions**, all resource buildouts are designed to meet or exceed the GHG emissions targets established in HB 2021. These resources are selected within the IRP process under consultation with our stakeholders to ensure that the best set of resources are selected. While cost and risk have traditionally been included in portfolio analysis, PGE includes pCBIs in this portfolio analysis to ensure that community benefits are maximized.

Portfolio CBIs are meant to adjust portfolio analysis scoring. PGE introduces pCBIs as a proxy for all supplemental community benefits that may come from the addition of CBREs. Portfolio benefits are 1 MW of CBRE equals 1 unit of community benefit. This metric reflects the unspecified portfolio benefits associated with the CBRE additions.

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[162] Northwest Power Act, 16 United States Code Chapter 12H (1994 & Supp. I 1995). Act of Dec. 5, 1980, 94 Stat. 2697. Public Law No. 96-501, S. 885, §839a(4)(D), available at: https://www.congress.gov/96/statute/STATUTE-94/STATUTE-94-Pg2697.pdf.

[163] *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390, pg. 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

7.1.5 DSP community targeting assessment

As part of PGE's DSP Part 2, we developed a Community Targeting Assessment that evaluated locational distributed energy resource (DER) potential with respect to various customer and community metrics.[164] We view this study as foundational to continued development of the CBRE framework for the CEP and IRP moving forward. During its initial development, we worked with our communities to review which variables and data sources were most relevant to developing a DEI lens to apply to distribution planning.[165] We then combined this information with environmental and resiliency variables to develop a final list, which informed a set of categories for ranking and scoring different investments (**Table 25**). PGE continues to evolve our resiliency analysis and variables; we expect the indicators shown in **Table 25** to progress beyond traditional utility reliability metrics to incorporate customer-centric metrics, resilience measures and grid constraints.

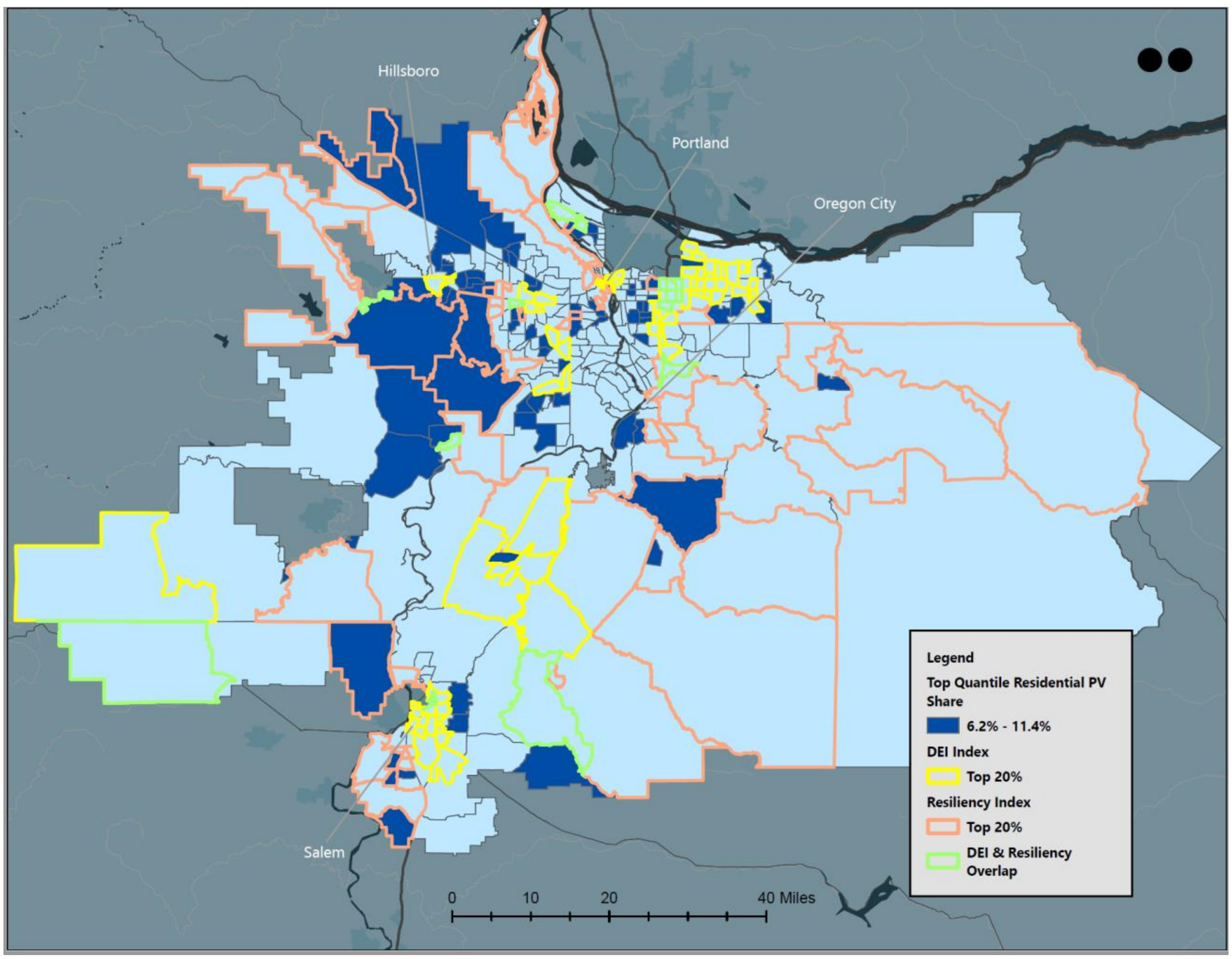
Table 25. DSP variable selection for index development

DEI category	Environmental category	Resilience category
Energy burden	Proximity to environmental hazard waste	Hour-loss power substation
Housing type	Respiratory hazard index	Hour-loss power transmission
Owner/renter	Ozone	System Average Interruption Duration Index (duration of outages)
Race		Seismic risk
Households without internet		
Households with disabilities		

[164] PGE's DSP Part II Appendix N, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning/dsp-resources-materials
[165] *Id*. at Chapter 2.

PGE leveraged this work to inform the combined CEP and IRP by assessing baseline metrics for new CBIs and applying these categories to CBREs. For example, **Figure 49** presents a PGE service area map with an overlay of the top quintile of census tracts with the highest scores for DEI and resilience and the top quintile of census tracts with the highest solar photovoltaic (PV) adoption (represented as a percentage of total residential households) by 2030. This work was conducted in 2022 as part of our DSP Part 2. It demonstrates where solar PV adoption may be lower than average and where additional CBREs could add resilience and DEI benefits. Together, these efforts will help to improve the future delivery of community benefits through targeted procurement or program development to identified communities.

Figure 49. PV example strategy Intersection of PV adoption with DEI and resilience by 2030



7.1.6 Informational community benefits indicators

The OPUC provided guidance within their Community Lens Topics for UM 2225 for Informational CBIs (iCBIs) that iCBIs "may or may not directly inform portfolio scoring in the IRP."[166]

PGE described our approach to developing interim rCBI and pCBIs for the purpose of the IRP. This section describes our approach to identifying Informational CBIs, or iCBIs. Informational CBIs will continue to shape our planning activities moving forward. As we continue to iterate with our communities through our Community Learning Labs and develop additional experience designing and implementing CBREs, we will leverage Attachment A and additional CBIs identified through our community engagement efforts. **Table 26** provides an overview of the interim CBIs that have resulted from our work thus far.

PGE intends to further refine and develop quantifiable and measurable CBI metrics where feasible. Our CBI strategy will continue to improve through robust conversations with stakeholders and continued community engagement throughout the CEP and DSP processes.

Table 26. Interim CBI metrics and roadmap for future development

CBI Category	CBI	Metric	Description
Energy Equity, Health & Community Wellbeing	CBI 1: Improve participation in clean energy programs by EJ communities	Metric 1A: DER program participation rates for EJ communities	Rate of improvement in customer participation in customer programs (demand response, solar, storage, energy efficiency) compared to baseline
		Metric 1B: Allocation of budget and/or savings goal within DER programs for EJ communities	Increase in share of budget and/or savings goal in customer programs (demand response, solar, storage, energy

[166] I *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390, pg. 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

CBI Category	CBI	Metric	Description
			efficiency) compared to baseline
Economic	CBI 2: Increase energy affordability for EJ communities	Metric 2A: Customers experiencing electricity bill burden	Reduction in electricity bill burden over time for low-income and EJ communities compared to baseline
		Metric 2B: Customer arrearages for customers in EJ communities	Reduction in the number of customers in arrearages in EJ communities compared to baseline
		Metric 2C: Number of customer disconnections for non-payment in EJ communities	Reduction in the number of customer disconnections for non-payment in EJ communities compared to baseline
Resiliency (Customer and System)	CBI 3: Improved grid resiliency	Metric 3A: % of customers experiencing frequent or long-duration outages	Increase in the percentage of customers in EJ communities with access to resilient power through grid infrastructure, customer infrastructure or emergency backup power.

CBI Category	CBI	Metric	Description
		Metric 3B: % of customers with access to emergency backup power in EJ communities.	
Economic	CBI 4: Increased access to jobs/economic impact	Metric 4A: Number of clean energy jobs related to CBRE goals and % held by members of EJ communities	Increase the number of clean energy jobs through future CBRE program and procurement activities
		Metric 4B: Support workforce training opportunities for EJ communities	Participate in diverse workforce development initiatives
Environmental	CBI 5: Environment	Metric 5A: Reduced GHG emissions	Reductions in annual GHG emissions for retail load

CBI Category	CBI	Metric	Description
Energy Equity, Health & Community Wellbeing	CBI 6: Improve efficiency and housing stock in the utility service area, including low-income housing	Metric 6A: Amount of residential energy efficiency achieved in target communities	Increase efficiency of housing stock in the residential sector, including low-income housing, through increased coordination with ETO and other local and state market actors
		Metric 6B: Work with OHCS, CAAs, ETO and other weatherization/energy efficiency implementors to encourage equitable distribution of benefits from energy efficiency programs in the PGE service area	Participate in working groups to support effective and equitable distribution of weatherization and energy efficiency benefits

7.2 Community-based renewable energy (CBRE)

Through Order 22-390, the OPUC set guidance that utilities' first CEPs should include "a potential study (or studies) that identifies opportunities for CBRE projects developed in coordination with communities that are served by the utility, including EJ communities, and with input from stakeholders and Staff". The potential study should:

- "Inform or directly identify annual acquisition targets (e.g., MW, megawatt hours (MWh)) for CBREs,
- Inform or identify the acquisition targets that appropriately balance cost, risk, the pace of greenhouse gas emissions reductions and community impacts and benefits, and

- Measure community impacts and benefits based on interim CBIs established by the utility."[167]

The OPUC also provided guidance that the first CEP should report on the "utility's plan to comply with the state's goal for CBRE projects provided in ORS 469A.210 and explain how the CBRE targets align with this strategy" as well as a "discussion of acquisition targets and actions that the utility will take in the Action Plan window to reach those targets".[168]

7.2.1 Defining CBREs

Oregon has a longstanding public policy interest in promoting small-scale and community-scale renewables.[169] A CBRE is differentiated from other renewable resources, including small-scale renewable energy resources, by the non-energy benefits that it brings to communities. A CBRE results from pairing a range of benefits with a non-emitting generating resource, a storage device, a flexible load program or a combination of investments. HB 2021 builds on that interest while specifically emphasizing resources that provide community benefits and are non-emitting. CBREs are further defined within Section 1(2) of HB 2021 which provides a legal definition for CBREs.[170,171]

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[167] *In the Matter of Portland General Electric Company, House Bill Investigation into Clean Energy Plans*, UM Docket No. 2225, Order No. 22-390 (Oct 25, 2022) at 38, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

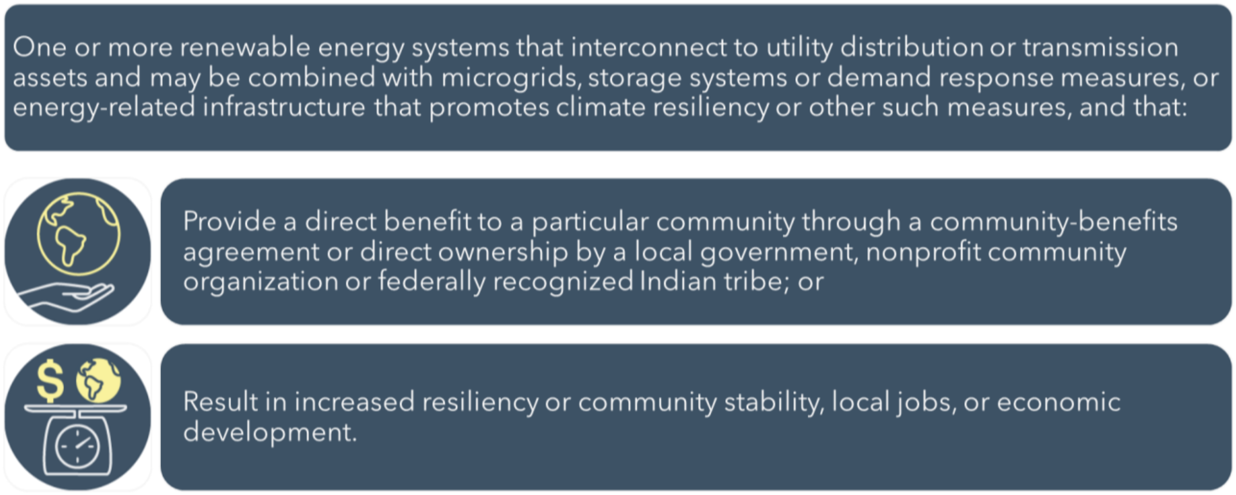
[168] *Id.* at 39, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

[169] The term "Community-based renewable energy" was initially added to Oregon statute by Senate Bill (SB) 838 in 2007, which put in place Oregon's Renewable Portfolio Standard. At that time, CBRE was not specifically defined and was indirectly associated with a policy goal of 8 percent for small-scale (20 MW or less) renewables by 2025. This goal was revised into a target by subsequent legislation (SB 1547 in 2016). Only with passage of HB 2021 were the community benefits of CBRE defined in statute and associated with direction for utilities to…"Examine the costs and opportunities of offsetting energy generated from fossil fuels with community-based renewable energy." *See* Section 4(4d) available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[170] *See* HB 2021 (2021), Section 2(2), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[171] *In the Matter of Small Scale Renewable Energy Projects Rulemaking*, Docket No. AR 622, Order No. 21-464 (Dec 15, 2021), at 6, the Commission stated: "Some participants in the rulemaking process recommended that we define 'community-based renewable energy projects' and limit eligible resources to those that both satisfy the explicit requirements in subsection (2) of the statute *and* meet some definition of 'community-based.' We decline to adopt this recommendation."

Figure 50. HB 2021 definition of CBRE



Additionally, HB 2021's CBRE definition describes resources on both the transmission and distribution system as well as energy-related infrastructure needed to support these investments. To evaluate CBRE potential for inclusion in resource planning, we used the HB 2021 definition as a starting point and sought input from community groups via our community engagement processes. The CBRE definition used in this initial CEP focuses on community-level resource types that offer the potential to align grid value, energy system benefits, community benefits and progress toward our 2030 small-scale renewables target.

For this CEP, we focus our CBRE analysis on small-scale non-emitting resources that also provide community benefits. In **Section 7.2.1.1, Community lens potential study**, we describe our approach to establishing the incremental CBRE technical potential which informed IRP analysis and target setting for CBREs. Our potential study identifies 155 MW of incremental technical potential by 2030. This aligns with CBRE goals found in community climate action plans such as City of Portland and Multnomah County. We then describe our approach to developing proxy CBRE resources that inform IRP portfolio analysis that meet the guidance provided by the OPUC through Order 22-390.

7.2.1.1 Community lens potential study

The transition to a clean energy future provides many opportunities to improve environmental and public health outcomes, spur local economic activity and job creation, and increase community resiliency in the face of growing threats posed by climate change. CBREs may provide some of these benefits while helping to meet our emissions targets.

Along with our communities and stakeholders, we seek to better understand the role these important resources play in ensuring an affordable, reliable, clean electric system.

Commission guidance on implementing initial CEPs outlined key questions and considerations for conducting a "Community Lens" potential study for CBREs.[172] The Community Lens was discussed throughout CEP regulatory proceedings and largely covered questions regarding incorporating community benefits and impacts, addressing resiliency opportunities and the potential role of CBREs in offsetting fossil fuels.

The Commission provided guidance on expectations for the Community Lens potential study, which states the study should either inform or directly identify annual megawatt (MW) or megawatt-hour (MWh) targets related to CBRE, report on the utility's plan to comply with the state's CBRE targets and explain how the CBRE targets align with the broader CBRE acquisition strategy.[173] In this section, PGE details our approach to the first Community Lens potential study, including methodology, community input and results.

7.2.1.2 Community lens potential study methodology

Community needs and interests in clean energy projects were recurring themes in conversations surrounding the development of both DSP and CEP guidelines.[174] Therefore, we began our consideration of CBRE potential by incorporating community and stakeholder feedback received during our DSP process into a revised DER forecast.[175]

Figure 51 depicts our overall process flow to establish CBRE targets, highlighting the places where community and stakeholder input help shape our direction.

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[172] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans*, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf
[173] *Id.*, Appendix A at 38.
[174] For example, see UM Docket No. 2005, Order No. 20-485, Appendix A at 31, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf
[175] For additional information regarding PGE's DER forecasting, see PGE's DSP Part 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf.

Figure 51. Overall CBRE potential methodology process flow

DSP Partner Meeting input and literature review

PGE first considered the feedback we received from our communities and stakeholders during the development of our DSP. Throughout the DSP process, we learned the importance of helping our communities understand and draw connections between utility regulatory processes when they may not have the bandwidth to engage in the many and varied proceedings related to distributed energy resources (DERs) and community benefits. PGE identified three topics from our DSP work as being most relevant for the CBRE discussion:

- Resiliency and reliability planning
- Non-wire solutions (NWS) pilot concept development
- Development of equity indicators

After reviewing DSP partner input, PGE conducted a literature review of relevant documents to supplement our understanding of the different themes identified throughout our planning activities, such as:

- Community comments related to CBRE and CBI were submitted under the DSP, Transportation Electrification Plan and CEP to identify key themes and viewpoints among various stakeholders and community members.
- OPUC Staff's straw proposal under UM 2225.[176]

[176] Docket No. UM 2225, Order No. 22-390, Appendix A, at 23-26, *see especially*, "Topic 1. Community Lens Acquisition Targets", and "Topic 2. Opportunities Considered within Community Lens Potential Studies", *id.* at 27, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

- "Attachment A Stakeholder CBI Proposal" detailing 15 distinct CBIs proposed by a coalition of Energy Advocates.[177]
- Academic journals and industry publications, including The Reliability and Resiliency sections of the Methods, Tools and Resources companion handbook to the National Standard Practice Manual for quantifying the costs and benefits of DERs.[178]
- A recent National Association of Regulatory Utility Commission (NARUC) and National Association of State Energy Officials (NASEO) report on valuing resiliency for microgrids.[179]
- Oregon Department of Energy's (DOE's) CBRE Working Group final report.[180]

Developing CBRE Potential

Based on PGE's review, we initially defined three proxy resources for inclusion in our IRP portfolio analysis, illustrated in **Figure 52**.[181]

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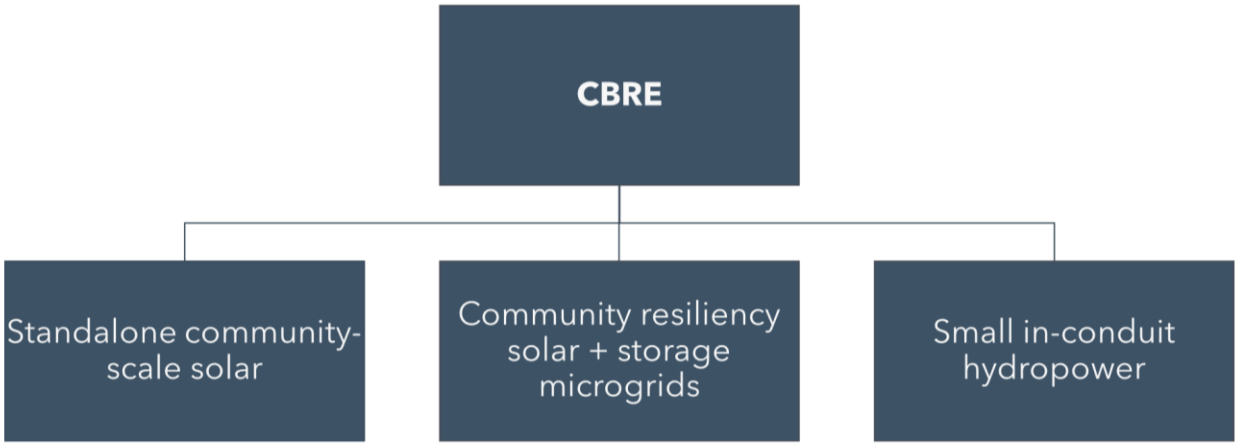
[177] *Id.*, Appendix A at 65, The Energy Advocates Attachment A.
[178] Tim Woolf, Courtney Lane, Danielle Goldberg, Erin Camp, Andrew Takasugi, Max Chang and Melissa Whited. "Methods, Tools and Resources: A Handbook for Quantifying Distributed Energy Resource Impacts for Benefit-Cost Analysis" NESP, March 2022, available at: https://www.nationalenergyscreeningproject.org/methods-tools-and-resources/ Also see chapter 8 "Reliability and Resilience", available here: https://www.nationalenergyscreeningproject.org/methods-tools-and-resources/reliability-and-resilience/.
[179] Wilson Rickerson, Kiera Zitelman, Kelsey Jones, "Valuing resilience for Microgrids: Challenges, Innovative Approaches, and State Needs," National Association of Regulatory Utility Commissioners and National Association of State Energy Officials, February 2022, available at: https://www.naseo.org/data/sites/1/documents/publications/NARUC_Resilience_for_Microgrids_INTERACTIVE_021122.pdf
[180] Stephanie Boles, John Cornwell, Rob Del Mar, Jessica Reichers, Adam Schultz, "Study on Small-scale and Community-based Renewable Energy Projects", Oregon Department of Energy, September 2022, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2022-Small-Scale-Community-Renewable-Projects-Study.pdf
[181] Due to its associated emissions, biogas was removed from the candidate list, leaving three proxy CBRE resources to be evaluated for potential within our IRP.

Figure 52. Initial CBRE proxy resources identified for IRP portfolio analysis



Many of HB 2021's broadly defined elements of CBREs are captured in IRP analysis via our DER forecast modeling (e.g., rooftop solar, behind-the-meter storage and customer-specific microgrids) and our supply-side proxy resources. Through our assessment, we identified a few characteristics that necessitated additional attention to delineate new proxy CBRE resource types for inclusion into the IRP.

Further informing our potential analysis was the consideration of 2030 targets for small-scale renewable energy projects.[182] As detailed below, our potential study identifies 155 MW of incremental technical CBRE potential by 2030. The IRP models this CBRE potential as additional to the customer-sited resource potential already accounted for within the corporate load forecast and traditional IRP modeling. This customer-sited technical potential, which comes from the DSP, is an additional 377 MW of solar and 61 MW of energy storage by 2030.[183] However, this customer-sited potential cannot be counted toward our small-scale renewable requirement because much of these customer-sited resources would likely be net-

[182] Changes to the small-scale renewables targets established by HB 2021 are codified in law through ORS 469A.210, available at: https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html. The target of 10 percent of "aggregate electrical capacity" may be met through small-scale (20 MW or less) renewable energy projects or certain biomass projects. Community benefits are not an explicit condition of the small-scale renewables definition, while resource size and RPS eligibility are not explicit conditions of the HB 2021 CBRE definition.
[183] For more information on PGE's customer-sited resources please refer to our DSP Part 2 at https://assets.ctfassets.net/416ywc1laqmd/46I2n65SyTv3TUMMdq1l55/a993aebb7b7a84ebd3209d798454a33a/DSP_Part_2_-_Chapter03.pdf#page=22.

energy metered. Net-energy metered resources cannot currently count toward our small-scale renewable requirement imposed by ORS 469A.210. [184]

Through the CBRE potential analysis, PGE considered the extent to which CBRE resources could contribute to the 10 percent small-scale renewables target. We found that in addition to providing benefits to communities, most resources that comprise the 155 MW incremental CBRE potential described in this IRP satisfy the conditions for the small-scale renewables target.

Our CBRE potential study focuses on resources that have the following characteristics:

- Medium- to large-size installations ~ 1-20 MW
- Distribution-connected
- Community-scale (as opposed to behind single customer meter)

To identify the potential for each CBRE included in PGE's IRP portfolio analysis, we relied on the following sources to estimate potential that could inform target setting.

- PGE's AdopDER model (our enterprise DER forecasting model) and community resiliency microgrid technical potential estimates
- Published municipal climate action targets with local resource goals and feedback gathered during product design work with our municipal customers
- ETO small renewable project lists and emerging community resiliency project pipeline
- Oregon Community Solar Program project data[185]
- US DOE National Lab potential studies such as the Oak Ridge National Lab in-conduit hydropower potential study

The following sub-sections provide greater detail about PGE's approach to estimating the potential for each CBRE proxy resource type within our IRP analysis.

[184] Through Order 21-464, the PUC adopted guidance and rules for utility compliance with the small-scale renewables requirement, including the finding that since "net-metered resources are generally viewed as customer-owned resources, reducing the utility's capacity needs, rather than a utility's resource for meeting load," their capacity does not contribute to the target. However, the Commission recognized that approaches toward customer-sited resources are evolving and expressed willingness to "revisit this determination upon a demonstration that this paradigm has changed in ways that make customer-owned resources part of a utility's supply portfolio." See https://apps.puc.state.or.us/orders/2021ords/21-464.pdf.
[185] See *In the Matter of Public Utility Commission of Oregon, Community Solar Program Implementation*, Docket No. UM 1930, Staff Report (September 15, 2021), available at: https://edocs.puc.state.or.us/efdocs/HAU/um1930hau175534.pdf

7.2.2 CBRE resources modeled[186]

Standalone community-scale solar

The definition of a CBRE under HB 2021 includes renewable energy systems that provide community benefits through a community benefits agreement or direct ownership.[187] This desire for local benefits is reflected in different ordinances and climate action plans by local governments and municipal entities. For example, the City of Portland and Multnomah County have both stated goals in their Climate Action Plans that call for 2 percent of their 2030 clean energy targets to be met with community-based renewables and related infrastructure.[188]

To inform PGE's potential estimate for community-scale solar,[189] we first translated those local commitments (i.e., 2 percent of load) into solar nameplate capacity requirements and then scaled these up to reflect what level of resource would be needed to meet a similar local resource goal applied to our entire service area. Finally, we compared this result to the solar components of our microgrid assessment (see **Community resiliency microgrid**) to cross-check this bottom-up method with our established potential estimate.

The community-scale solar proxy used in this IRP is a modified version of a standalone utility-scale solar resource. The modeled CBRE resource for this IRP is responsive to community feedback regarding appropriate size or placement within the community. By using the supply side solar resource as a proxy for a CBRE, modifying for community interest, IRP analysis was explicitly able to include CBRE.

[186] Additional details regarding the incorporation of CBREs into the IRP analysis can be found in **Section 7.2, Community-based renewable energy (CBRE), Section 7.1.3, Resource community benefits indicators,** and **Section 11.4.3, Community-based renewable energy (CBRE) portfolios.**
[187] ORS 469A.400(2)(a) available at: https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html.
[188] See Multnomah County Resolution No. 2017-046, dated June 1, 2017, available at: https://multco-web7-psh-files-usw2.s3-us-west-2.amazonaws.com/s3fs-public/2017-046.pdf and See City of Portland's 2022-2025 Climate Emergency Workplan, Exhibit A, pg. 4. Available at: https://www.portland.gov/bps/climate-action/documents/climate-emergency-workplan-2022-2025/download.
[189] PGE uses "community-scale solar" here and throughout this document to refer to the proxy CBRE resource type developed for inclusion in IRP analysis. Though similar in name, the resource characterization differs from Oregon's Community Solar Program, which under OAR 860-088-0070 requires projects to be three MW or less.

Community resiliency microgrid

The DOE CBRE working group report states that local resiliency is the primary benefit of CBRE and is also directly distinguishing it from other resource types.[190] This aligns with what PGE has heard during our community engagement process through our DSP Partner Workshops and Community Learning Labs. In addition, resiliency is identified by OPUC Staff in Order 22-390 as being among the highest priorities for the initial CEP.[191] PGE finds community resilience microgrids an intriguing opportunity as they provide significant potential to partner with the utility for funding to meet a variety of community, customer and grid benefits.

Given this focus on resiliency, PGE investigated the potential for community-resiliency microgrids, defined as solar and storage configurations with islanding controls capable of providing continuous power supply during a grid outage. A key distinguishing feature of a microgrid versus other hybrid solar + storage plants modeled in the IRP is the inclusion of advanced communications and controls to coordinate diverse DERs that operate behind the microgrid.[192]

To assess the potential for these resources, we used our AdopDER model, which provides locational DER forecasting.[193] AdopDER contains individual site-level characteristics of all customers and pertinent data about distribution-system factors like frequency and duration of past outages. AdopDER also includes DEI data based on a range of demographic and socioeconomic factors, environmental data including air quality and other EJ criteria and resilience data based on environmental risk factors, such as fire or flood vulnerability areas and grid/system needs, such as long-term outage locations.[194]

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[190] Stephanie Boles, John Cornwell, Rob Del Mar, Jessica Reichers, Adam Schultz, "Study on Small-scale and Community-based Renewable Energy Projects", Oregon Department of Energy, September 2022, at 19, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2022-Small-Scale-Community-Renewable-Projects-Study.pdf

[191] See *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022) at 12, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

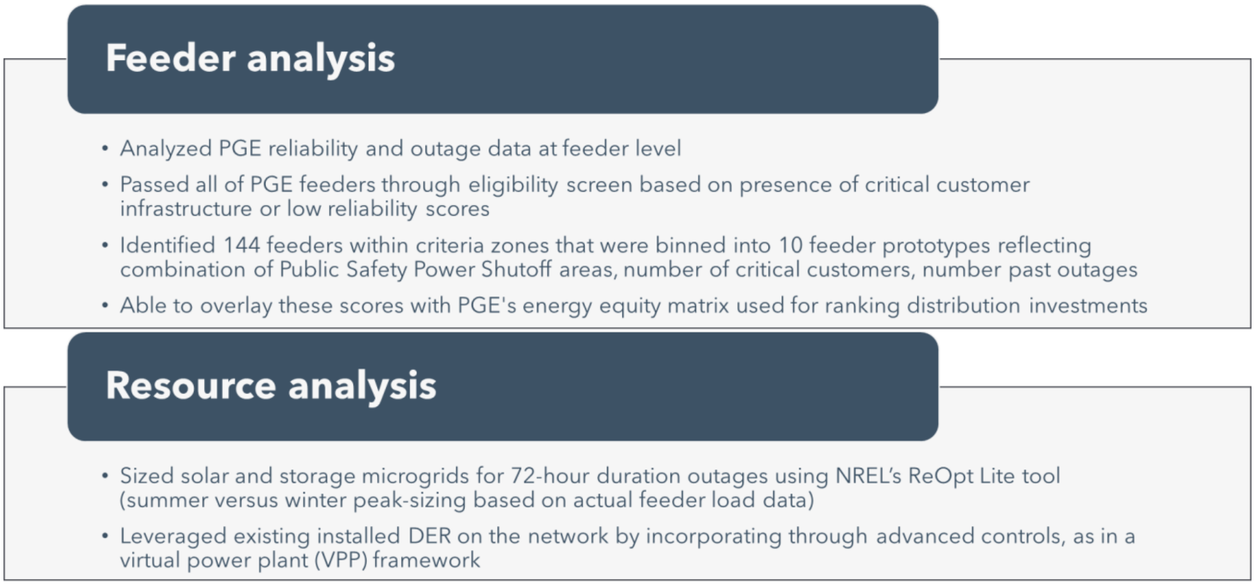
[192] While we distinguish the community-resiliency microgrid as serving multiple customers, it may also aggregate, and control loads behind a single customer meter. In this case, some of the solar PV and storage adoption from our AdopDER model is factored into the MW potential reflected here.

[193] PGE's methodology for locational forecasting can be found in its DSP Part 2, available at: https://assets.ctfassets.net/416ywc1laqmd/4CQCpp0ZlmbQMGDANJKUqN/d2088ce3be4ddc2bc3d0eeab99e7695e/DSP_Part_2_-_AppendixM.pdf.

[194] Additional information regarding PGE's evaluation of DEI, environmental and resiliency variables and data, available at: https://assets.ctfassets.net/416ywc1laqmd/2TbidNAlU4Z5ZsShRrhhb7/d5dcd1cd853d451eb91cdfbec4eeeefe/DSP_Part_2_-_AppendixD.pdf.

Figure 53 highlights the steps to identify community resiliency microgrid potential in the PGE service area using AdopDER.

Figure 53. Community resiliency microgrid potential modeling in AdopDER



The process outlined in the previous figure results in nameplate capacity and energy potential for each resource type within the community resiliency microgrid (i.e., solar nameplate, storage and backup generation). PGE ramped the technical potential based on the "low scenario" annual adoption rate for distributed solar as a proxy to reflect the achievable potential for community resiliency microgrids.

Small in-conduit hydropower

In-conduit hydropower is a low-impact hydropower that places a turbine inside a pressurized water supply or wastewater system. PGE discussed past example projects and potential future leads with ETO staff in assessing the potential for in-conduit hydropower. In addition, we analyzed technical potential data for Oregon taken from a recent Oak Ridge National Lab national potential study for in-conduit hydropower.[195]

Most of Oregon's in-conduit hydropower technical potential comes from irrigation modernization, of which PGE has relatively little in our service area. Therefore, we limited our

[195] Shih-Chieh Kao, Lindsay George, Carly Hansen, *et al.* "An Assessment of Hydropower Potential at National Conduits" Oak Ridge National Lab, ORNL.TM-2022/2431, October 2022, available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf

assessment to municipal water supply systems.[196] Overall, the Oak Ridge study found that Oregon has 77 MW of technical potential for in-conduit hydro, of which 12.4 MW is associated with municipal supply systems. We applied an allocation factor of 40 percent of the statewide total to reflect the available potential within our service area. Finally, we increased this potential slowly over time based partly on conversations with ETO staff familiar with past in-conduit projects, the complexities therein, and the relative timescale and cost to complete these projects. Our cost data for this study comes from a companion paper from the Oak Ridge team and the historical cost data provided by ETO.[197]

7.2.2.1 CBRE potential study results

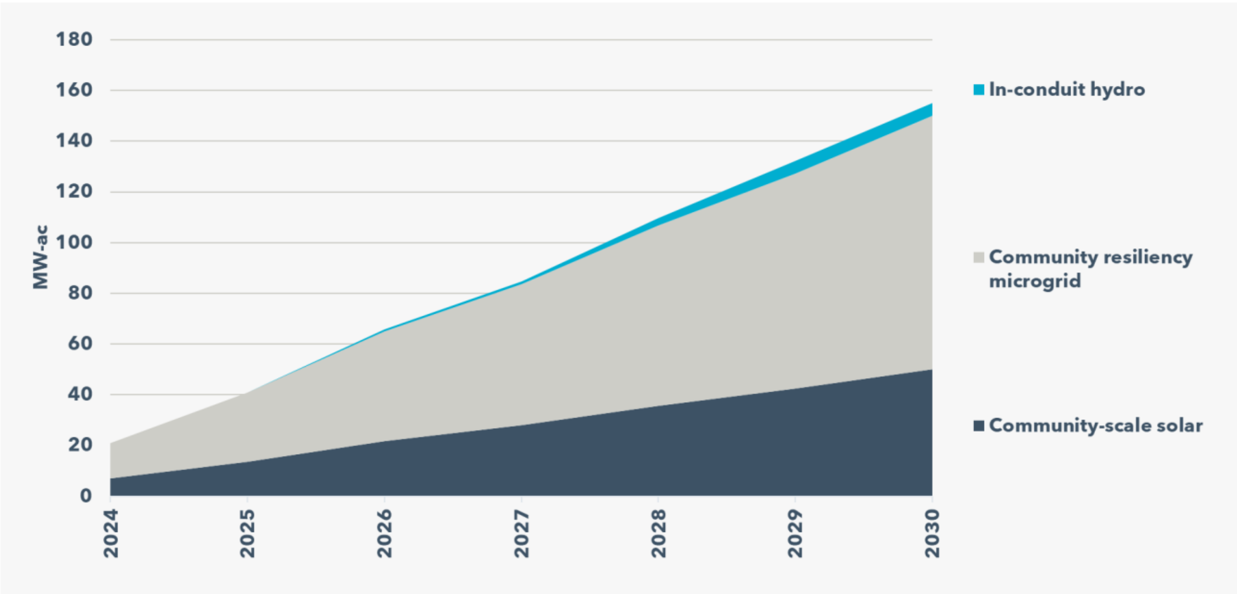
PGE identified 155 MW of nameplate CBRE resource potential by 2030 (**Figure 54**).[198] This potential is increased over time to reflect the time required to develop new delivery channels as may be necessary for these new resource types. We then applied the cost and proxy performance features (e.g., capacity factors) for the three identified proxy CBRE resources to IRP portfolio analysis, described in **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**.

[196] Note that the decision to limit to municipal water supply systems is a modeling choice and helps provide boundaries to the analysis in question. In practice, we expect that some CBRE proposed to meet our Action Plan will include small irrigation modernization projects. In fact, PGE has received interest from one small irrigation district as part of the outreach conducted for this study.

[197] Shih-Chieh Kao, Kurt Johnson, "An Assessment of Energy Potential at Public Drinking Water Systems: Initial Report on Methodology" Oak Ridge National Lab, ORNL/TM-2018/869, CRADA/NFE-17-06776, July 2018. Available at: https://www.ornl.gov/file/assessment-energy-potential-public-drinking-water-systems-initial-report-methodology/display

[198] These totals do not include rooftop solar, which is separately modeled in our 2023 IRP. We have included 377 MW-dc by 2030 in the IRP's reference-need future and 458 MW-dc in the low-need future (the low-need future corresponds to the high distributed solar PV adoption scenario). This delineation was done for the first analysis of CBRE potential within the IRP Portfolio Analysis to avoid double-counting, but in practice we expect rooftop solar to be included in certain program development efforts and procurement activities.

Figure 54. CBRE potential results (cumulative MW)



7.2.2.2 CBRE potential

This section presents the annual potential for CBRE based on PGE's AdopDER modeling and analysis of these proxy resources using the interim approach described previously. We identified the annual megawatt potential shown in **Table 27**.

Table 27. CBRE annual MW potential (cumulative installed nameplate MW-ac capacity)

Resource	2026	2027	2028	2029	2030
Community-scale solar	22	28	36	42	50
Community resiliency microgrid	43	56	71	85	100
In-conduit hydro	1	1	3	5	5
Total	66	85	110	132	155

While we present the detailed CBRE potential here, in alignment with the three CBRE proxy resources included in our initial Community Lens Analysis, this MW potential will be included in the Action Plan at an aggregate level (see **Chapter 12, Action Plan**). As we add CBREs to our system, we expect the actual CBRE resource mix may vary depending on cost, technology evolution and maturation, and market development.

Further discussion of how these targets for CBRE affect the Preferred Portfolio and our Action Plan is included in **Chapter 12, Action Plan**.[199]

7.2.3 Near-term approach within PGE's IRP

PGE incorporated the results of our CBRE potential study described in **Section 7.2.1.1, Community lens potential study,** into portfolio analysis to assess the contributions of these resources toward meeting the system requirements and providing community benefits. Incorporating CBIs and CBREs into PGE's overall portfolio planning process is described in **Chapter 11, Portfolio analysis**.

We include CBRE resource potential and associated CBIs in portfolio analysis to understand the implications that their relative costs, system benefits and CBIs have on various metrics considered within the planning framework and across various portfolio options. To better understand how the inclusion of CBIs in portfolio analysis impacts CBRE resource performance, we developed the following interim approach to applying CBIs in portfolio analysis:

- Include resource-CBI (rCBI) in portfolio optimization as a dollar per megawatt ($/MW) value assigned to each CBRE. The rCBI approach is described more fully in **Section 7.1.3, Resource community benefits indicators**.
- Include portfolio-CBI (pCBI) into portfolio scoring to reflect the increased value of portfolios with CBRE compared to those without. Including pCBIs enables portfolio analysis to evaluate any trade-offs between cost, risk and community benefits. A more detailed overview of how pCBIs influence CBRE selection across portfolios is presented in **Section 11.2, Portfolio scoring**.

Our approach to CBI development, including informational CBIs not included in IRP portfolio analysis, is described further in **Section 7.1, Community benefits indicators.**

[199] In particular, see **Chapter 12, Action Plan** for a summary of actions related to all DER types, including CBRE but also energy efficiency, demand response and rooftop solar. As the most consistently high-ranked CBIs from our communities and stakeholders are related to increasing efficiency in the building stock (through weatherization and targeted energy efficiency programs), we include a separate discussion in the Action Plan related to how our goals for procuring these other, stand-alone DERs may interact with those described in this section to help meet our CBRE goals and provide community benefits.

7.2.4 Refining the market characterization of CBRE

PGE may continue to refine CBRE resource categorization, such as adding different resource types, as we build on our experiences procuring CBREs through the steps outlined in our Action Plan (see **Chapter 12, Action Plan**). Responses to a community RFP, as well as continued developer outreach and engagement, will provide important feedback. We plan to include relevant information in future CBRE potential modeling, including more refined cost data, technology parameters, collaboration opportunities and opportunities for external funding sources.

Another important element of PGE's plan is to continue integrating new CBRE resource characterization into AdopDER. We expect to learn more about the most significant features of CBRE project types to better inform how we characterize CBRE potential in future study rounds. This will better align our CBRE potential methodology with the IRP's well-established demand-side resource forecasting practices. For instance, we will assess opportunities to leverage additional energy efficiency potential estimates from ETO into our CBRE modeling to allow greater assessment of the relative costs and benefits of different combined or hybrid CBRE project types.[200]

7.2.5 CBRE resource procurement activities

7.2.5.1 CBRE RFP

As shared in **Chapter 12, Action Plan**, the Action Plan calls for PGE to conduct an RFP for CBRE resources. The Community RFP will target 66 MW of CBREs to come online by 2026. This initial action will be in service of achieving the 155 MW technical potential of CBREs by 2030. Given the uncertainty described in the eventual composition of the CBRE resource mix that meets the targets outlined in the Action Plan, PGE anticipates a resource acquisition process that prioritizes flexibility and community engagement through an RFP and potential grant funding and program mechanisms.

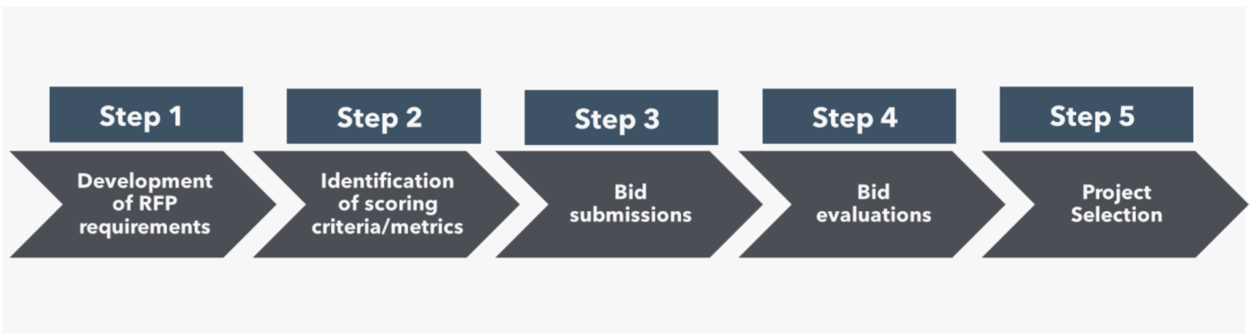
The RFP is intended to be a flexible procurement vehicle that leverages the market resources that align with community preferences. Our goal is to create a collaborative process that results in a co-developed RFP between PGE and the communities we serve. Under this approach, we will aim to design scoring metrics reflective of quantifiable and measurable CBIs through community feedback. The project evaluation and scoring will be guided by

[200] Our treatment of additional non-cost-effective energy efficiency opportunities are described in **Section 8.2.1, Additional energy efficiency**. What we mean here is that in future CEP rounds, we hope to be able to partner with ETO to develop energy efficiency inputs to our CBRE potential modeling from the outset.

community feedback received. The scoring process can also include analysis from the DSP to identify differences in the locational grid value of proposed CBRE projects.

PGE looks forward to future discussions with communities on the timing, technology, location and project selection criteria for CBREs. Additionally, PGE will explore opportunities for federal, state and local grants, as well as the development of future programs to add more CBREs to our system. **Figure 55** illustrates the steps PGE will take starting in 2023 to co-develop the Community RFP with communities and stakeholders.

Figure 55. Community RFP



7.2.5.2 Non-wire Solutions

Moving forward, PGE will engage communities, including EJ communities, to identify other CBRE resource types of interest that may provide meaningful community benefits. Our DSP community engagement opportunities present an excellent chance to continue to refine the definitions and shared understanding around CBREs and identify which CBIs are most meaningful to different communities. Non-wire solutions (NWS) are a particularly robust area of overlap, as a CBRE may end up providing both CBIs (e.g., by reducing bills for low-income customers on a given feeder through targeted program deployment) and achieving incremental locational grid value (e.g., by deferring traditional asset investment needs).

In 2023, we have committed to working with ETO to study NWS opportunities for targeting energy efficiency, customer-sited renewables and battery storage in areas with high grid needs and DEI scores.[201] Given the type of projects for CBRE development that are most meaningful to our communities (e.g., resiliency projects, community gathering places like schools or community centers, or energy efficiency and renewables for low-income multifamily buildings), we expect the NWS planning prioritization with ETO to be a fruitful

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[201] See discussion related to how PGE plans to use our DEI index for scoring and ranking grid needs and NWS opportunities in PGE's DSP Part II Chapter 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf.

venue to socialize further CBRE concepts, as well as gather more information about ideal project locations or potential partners for executing CBRE development.

7.2.5.3 Community resiliency hubs

Another customer-facing avenue is our expected continued work to investigate the creation of Community Resiliency Hubs. Community Resiliency Hubs are defined by the US DOE & Environment (DOEE) as "public-serving facilities that provide information and services to build resilient communities before, during and after emergency events."[202] US DOEE further states that Community Resilience Hubs should complement existing emergency response services and "serve communities year-round by promoting health, providing meeting spaces, educating the community about risks and emergency preparedness, and supporting workforce development."

As part of our continued engagement, we will continue to explore Community Resiliency Hubs within our Community Learning Labs that:

- Provide resilience to the community and critical facilities serving that community center's community voices in decisions regarding placement and use of CBREs.
- Create a high-value product that serves the public interest and serves many customers or targets to serve the most vulnerable customers.
- Design accessible and equitable solutions ensuring any solution considers a project's impacts on all customers.

Through PGE's next CBRE potential study, we have an opportunity to learn more from our communities about which projects and programs are most meaningful to them. In addition to the Community Learning Labs, PGE will leverage other stakeholder engagement channels (e.g., DSP and MYP) to socialize and refine our approach for the next CEP. We will work with our communities and community representatives to assess the need for more education and learning regarding CBRE and solicit ideas and input about a suggested direction for future study efforts.

[202] More information on US DOEE's Community Resilience Hubs, available at: https://doee.dc.gov/service/community-resilience-hubs.

7.2.6 CBREs and Oregon's 10 percent small-scale renewable requirement

PGE's support of CBREs is both established and evolving. We see significant potential to widen our CBRE near-term approach to include more community-scale and customer-sited generation paired with energy storage, flexible loads and energy-related infrastructure. As required by ORS 469A.210, PGE has a 10 percent small-scale renewable requirement. [203] We expect the CBRE potential PGE has identified to contribute to that requirement. That requirement uses only one metric (i.e., 20MW or less in size) and does not incorporate community benefits or non-emitting resources. In the past, wholesale projects typically contributed to the goal, which was then 8 percent. Moving forward, we expect the following activities will inform and contribute to the requirement:

- Continued engagement with communities
- Existing programs and procurement strategies such as:
    - Wholesale projects smaller than 20 MW, including PURPA, bilateral contracts and CBREs
    - Oregon Community Solar Program (projects are capped at 3 MW)
- New resources, programs and strategies such as:
    - Community Request for Proposals (RFP), described later in **Section 7.2.10, Further actions and considerations**
    - Virtual power plant (VPP)
    - Federal/local incentives

7.2.7 Continued engagement with communities

PGE's community engagement strategies will provide a forum to discuss CBRE acquisition strategies with communities, stakeholders and OPUC Staff. Key areas of engagement will include the timing, technology, location and project selection criteria for CBREs. We will co-develop the Community RFP with communities and stakeholders beginning in 2023.

[203] Oregon ORS 469A.210 can be found at https://www.oregonlegislature.gov/bills_laws/ors/ors469a.html.

7.2.8 Existing programs and procurement strategies

In recent years we have seen rapid expansion of customer-sited solar that both offsets load and delivers energy to the grid. We anticipate continued and significant expansion of customer-sited solar, especially given the new federal incentives described in **Chapter 2, Accessing support for energy transition**. Many of the existing resources and programs that fall within the CBRE definition also participate in PGE's evolving VPP. Current CBRE investments and programs on PGE's grid that are broadly understood to bring community benefits, include:

- Rooftop solar (residential, commercial, non-profit)
- PGE's residential battery pilot
- Flexible load programs: Energy Partner, Peak Time Rebates, Smart Thermostats, water heaters
- Oregon Community Solar Program
- Resiliency investments in critical facilities such as the Beaverton Public Safety Center

7.2.9 New resources, programs and strategies

PGE's efforts to scale and leverage CBREs underscores the importance of our efforts to expand our Virtual Power Plant (VPP). Enhancing our ability to utilize CBRE investments to support the larger grid's functioning, through incorporation into the VPP, is critical to our decarbonization goals, as described in **Section 8.4, Virtual Power Plant (VPP)**. This will be enabled via monitoring behind-the-meter generation (e.g., smart inverters). Once solar (and other) customer-sited resources are connected, visible and actionable to system operators, they can increasingly be considered supply-side resources for purposes such as resource adequacy, procurement, operations and the small-scale renewables goal.

Section 7.2.4, Refining the market characterization of CBRE describes our near-term acquisition approach. We have an initial target of 66 MW of incremental CBREs by 2026 that we will pursue through both a Community RFP and/or other programmatic approaches. However, even procurement of the entire CBRE potential will still require additional new small-scale renewables to meet the 10 percent small-scale renewables requirement of ORS 469A.210.

PGE will continue to explore opportunities for federal, state and local grants and incentives to improve and offer opportunities that create local jobs, save on energy bills and cost-effectively reduce greenhouse gas emissions and other harmful pollutants. Having access to additional financing opportunities will support and accelerate the development of future programs and provide unique financial advantages for customers and communities. Federal, state and local grants and incentives are a key ingredient of a socially inclusive, cost-effective energy transition.

7.2.10 Further actions and considerations

Our portfolio analysis finds that CBREs, as considered in the potential study, provide system benefits. Because of the transmission constraints PGE is facing, they compare favorably to larger scale renewable resources in portfolio analysis and comprise an important role in our Action Plan.

Broadly, our Action Plan and related acquisition actions seek to prioritize CBREs that provide community benefits, alongside grid services such as resilience. Today, large-scale CBREs (3 MW and above), can help us meet our CBRE target. These resources could provide benefits to nearby communities through community benefit agreements, as well as on-site renewables deployed at the individual customer-level.[204] However, as we improve on our ability to utilize smaller-scale CBREs at the individual neighborhood level (3 MW and below), CBREs will become an integral part of our VPP. As residential and small commercial renewables become an important part of our capacity planning, this will require changes to the regulatory framework. [205] These changes are needed to accelerate small-scale renewable projects that affordably support decarbonization of the grid. For example, this may require changes to the regulatory framework including net-energy metering and inclusion of net-energy metering as a resource needed to accelerate small scale renewable adoption. To the extent practicable, these resources and changes should provide additional direct benefits to Oregon communities in the forms of creating and sustaining meaningful living wage jobs, promoting workforce equity and increasing energy security and resiliency.

There are also uncertainties and potential risks of CBREs and CBIs to be explored further with our communities, OPUC Staff and other stakeholders. For example, there are many unknowns regarding resources that are not owned and operated by PGE such as how

[204] The US Office of Economic Impact and Diversity defines community benefit agreements as an "agreement signed by community benefit groups and a developer, identifying the community benefits a developer agrees to deliver, in return for community support of the project. Community benefit groups are coalitions comprised of neighborhood associations, faith-based organizations, unions, environmental groups and other stakeholders. Community Benefit Agreement (CBA) Toolkit | Department of Energy.

[205] PGE's DSP Part 1 and Part 2, discusses regulatory evolution and long-term actions within the regulatory framework could accelerate projects that ready the grid for decarbonization, which can be respectively found at: https://assets.ctfassets.net/416ywc1laqmd/7vUdTxBF2cEIhG276mH0UZ/2b5ad6bff08b334b101f566c7dfd957a/DSP_2021_Report_Chapter7.pdf and https://assets.ctfassets.net/416ywc1laqmd/5GRLxNj644P2Ty82WkLM5F/dfd5e8376a4eac9d1bf8bc65ec7dbf74/DSP_Part_2_-_Chapter07.pdf#page=5.

community ownership could work or whether third parties would be open to community benefit agreements. Additionally, there are issues regarding third party operations and maintenance standards to address. It will also be important to understand how third-party resources will be integrated into the grid in partnership with utilities and how to protect the security of these resources and facilities. These important topics will need to be considered so that CBREs can be developed to benefit the communities they are intended to serve and serve as grid assets that can benefit all PGE customers.

Chapter 8. Resource options

In this Integrated Resource Plan (IRP), we evaluate a broad set of resources to meet the needs identified in **Chapter 6, Resource needs**. To meet these system needs while reaching the emissions targets established in House Bill (HB) 2021, we focus on analyzing only commercially available technologies applicable through 2030. These resources include both distributed energy resources (DER) and supply-side options. This chapter begins with a discussion of technology trends and an exploration of candidate supply-side options tested in portfolio analysis, including energy storage and renewables. We then describe DER programs and technologies deemed non-cost-effective under prior estimates of cost-effectiveness. We conclude with discussions of how resources are expected to be integrated via Portland General Electric's (PGE's) virtual power plant (VPP), transmission, emerging technologies and the advantages and disadvantages of utility and third-party ownership of resources.

Chapter highlights

- PGE discusses utility-scale supply-side options available for meeting portfolio needs, including wind, solar photovoltaic (solar PV) and energy storage resources, among others.
- The costs and megawatt (MW) potential of additional energy efficiency and demand response are included as resource options in this IRP.
- An analysis showing the adequacy challenges of a decarbonized system based on current resource options, followed by potential long-term resource options and strategies that can help address the challenges.
- A discussion of the benefits and risks of different resource ownership structures for customers is included.

8.1 Utility-scale energy resources

8.1.1 Summary of technologies

The supply-side resources considered in this section represent technically and economically feasible options that are plausible options to meet PGE's needs through 2030. These resources are generally categorized as non-emitting renewable or storage resources. Additionally, natural gas-fueled resources are included for continuity with prior IRPs and in the event that data related to these resources are required for other regulatory proceedings. PGE relies on publicly available information to inform supply-side resource options' cost and performance parameters.[206]

8.1.2 Sources of information

8.1.2.1 Cost and performance parameters

Resource cost and performance parameters form the basis for the economic analysis of generic proxy resources in the IRP. In this IRP, PGE is generally using supply-side resource information from two sources:

- The National Renewable Energy Laboratory produces the Annual Technology Baseline (NREL ATB) to "develop and document transparent, normalized technology cost and performance assumptions" for typical generating resources in the United States.[207]
- The U.S. Energy Information Administration (EIA) commissioned Sargent & Lundy to "evaluate the overnight capital cost and performance characteristics for 25 electric generator types" to reflect these generators in the Annual Energy Outlook 2020 (EIA AEO).[208]
- Resource operating parameters are sourced from the ATB and AEO when possible. Where information needed for PGE's models is not provided in the ATB or AEO, PGE relies on information from other publicly available sources, including past IRPs. Overnight capital costs presented in this chapter are inclusive of interconnection costs. Historical inflation rates were applied to escalate from the EIA and NREL study values. Cost estimates do not explicitly account for supply chain-related disruptions experienced post-

[206] In PGE's recent IRPs, supply-side resource cost and operating parameter information was generally developed by third-party consultants.
[207] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/about.
[208] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy, available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/

2019.[209] These estimates do not reflect the impacts of the US Department of Commerce's investigation into the potential circumvention of tariffs on certain imported solar panels.

8.1.3 Renewable energy generation

The generation of wind and solar resources in PGE's models is based on input shapes simulated for each resource. PGE simulates hourly renewable generation using NREL's System Advisor Model (SAM). SAM is free software provided by NREL for modeling the performance and economics of renewable energy projects.[210]

8.1.4 Wind and solar weather data

Weather data for wind and solar resources are inputs to SAM (e.g., wind speed and solar irradiance). Onshore wind weather data are sourced from the NREL Wind Integration National Database (WIND) Toolkit for 2007–2014.[211] Offshore wind weather data rely on NREL's Offshore NW Pacific Dataset. The dataset comprises 20 years of weather data covering 2000–2019.[212] NREL's National Solar Radiation Database (NSRDB) is the source of weather data for solar PV simulations.[213] PGE uses NSRDB data for 1998–2020. PGE uses data available from these sources at the time of the analyses.

8.1.5 Methodology for average year Capacity Factor

As discussed in **Appendix H, 2023 IRP modeling details** PGE's energy valuation modeling (PZM simulation, conducted in Aurora) in this IRP uses a representative 8760 hourly shape of energy generation for each renewable resource.[214] These representative shapes are developed from the hourly simulations for each year of available data mentioned in this section, using the following steps:

1. Simulate 8760 hourly shapes for each year with available weather data (e.g., for 10 years of weather data, create 10 simulated 8760 hourly shapes).

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[209] This implicitly assumes that the supply chain issues are temporary.
[210] NREL SAM information, available at: https://sam.nrel.gov/.
[211] NREL WIND Toolkit information, available at: https://www.nrel.gov/grid/wind-toolkit.html and https://developer.nrel.gov/docs/wind/wind-toolkit/.
[212] NREL Offshore NW Pacific dataset information, available at: https://developer.nrel.gov/docs/wind/wind-toolkit/offshore-nw-pacific-download/.
[213] NREL's National Solar Radiation Database information, available at: https://nsrdb.nrel.gov/ and https://developer.nrel.gov/docs/solar/.
[214] In years past, the IRP utilized month-hour average energy shapes for wind and solar resources, specifically. In doing so, resource variability was potentially reduced.

2. Compute the monthly average capacity factors across the data from step #1 (average across 10 years each month).
3. For each month, choose the hourly data from the year that most closely matches the monthly average capacity factor computed in step #2 (if in January, for example, the year five capacity factor is nearest to the average from step #2, the representative shape will use the year five hourly data for January).
4. Use the hourly data from each month selected in step #3 to create the representative shape.

This process results in shapes that closely match the annual capacity factors averaged across the available weather data while maintaining the variability of the underlying hourly data. Using publicly available data from NREL is an attempt to enable transparent and comparable analysis across resources in the IRP. The resulting energy shapes and capacity factors from this analysis will differ from those experienced by resources constructed in the future. Resource developers participating in a competitive procurement process will perform detailed analyses of specific projects to optimize resource economics (cost and performance) with respect to geographic location and resource configuration, among other factors.

8.1.6 Treatment of tax credits

As discussed in **Section 2.1, Federal support for energy transition**, the Inflation Reduction Act (IRA) brought several changes to the tax credit landscape. These changes are expected to have material effects on the economic values of various generation and storage resources. When modeling resources in the IRP, the following assumptions are made:

- Tax credits will phase out over three years beginning in latter 2032, or the year in which the US electricity sector emits 75 percent less CO2 than in 2022. For modeling purposes, all tax credits are assumed to be extended through 2043 (the end of PGE's analysis time horizon). This assumption removes the possibility of tax credit expiration influencing the portfolio optimization process.
- Non-emitting generating resources qualify for 100 percent of the production- or investment-based tax credits.

- Standalone storage resources qualify for 100 percent of the investment-based tax credit without the need for normalization.[215]
- Carbon capture and hydrogen production resources qualify for specific credits outlined in the IRA.
- Tax credits are assumed to be fully monetized in the year they are generated.
- Numerous additional changes within the IRA and the IIJA are not currently built into modeling assumptions. Some of these are:
    - The EE forecast, as noted in **Section 6.2.3, Energy efficiency**, does not contemplate the IRA's tax credits, which include the Residential Energy Efficient Home Improvement Credit, that likely will increase the savings forecasted.
    - The DER forecast, as noted in **Section 6.2, Distributed Energy Resource (DER) impact on load**, also does not capture the impacts of the IRA tax credits, which include rooftop solar, electric vehicles and building electrification, that likely will result in faster adoption of these technologies.
    - The IIJA provides significant funding, which PGE is pursuing as appropriate, for the following areas of interest:
    - $23B to enhance the resiliency of the power infrastructure and investment in renewable energy.
    - $21.5B to develop clean energy demonstrations and research hubs.
    - $5B to boost energy efficiency and clean energy creation.
    - $18B to support electric vehicle (EV) charging deployment, clean transit and school buses, and other transportation electrification funding.

8.1.7 Renewable generation resources

8.1.7.1 Onshore wind

PGE analyzes proxy onshore wind resources at four locations in this IRP: Oregon Columbia River Gorge, Central Montana, Southeastern Washington and east of Casper, Wyoming. The

[215] To achieve 100 percent of the available credits, PGE's analysis assumes that prevailing wage and apprenticeship requirements are met, and that no additional tax credit adders apply, such as the those associated with domestic content, Energy Community or low-income community considerations. The adders, as noted in **Section 2.1.1, Inflation Reduction Act**, disproportionately benefit the ITC over the PTC. PGE will explore different options, including a wholly-owned affiliate, to work around the ITC normalization issue in order to promote a level playing field in future renewable solicitations, which will deliver least cost resources for customers.

Wyoming wind resource is available in PGE's analysis with an assumption of incremental transmission action.[216] For more detail on the costs and benefits associated with the incremental transmission, see **Section 9.4.1, Proxy transmission options identify transmission need**.

The resource configuration is common across the four locations, comprising 3.5 MW turbines with 136-meter rotor diameters and 105-meter hub heights. Standard resource configurations are used to focus the analysis on differences arising from locational characteristics rather than an optimized resource design. Resource cost information is based on EIA AEO data. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors. Characteristics for the four onshore wind resources are summarized in **Table 28**.

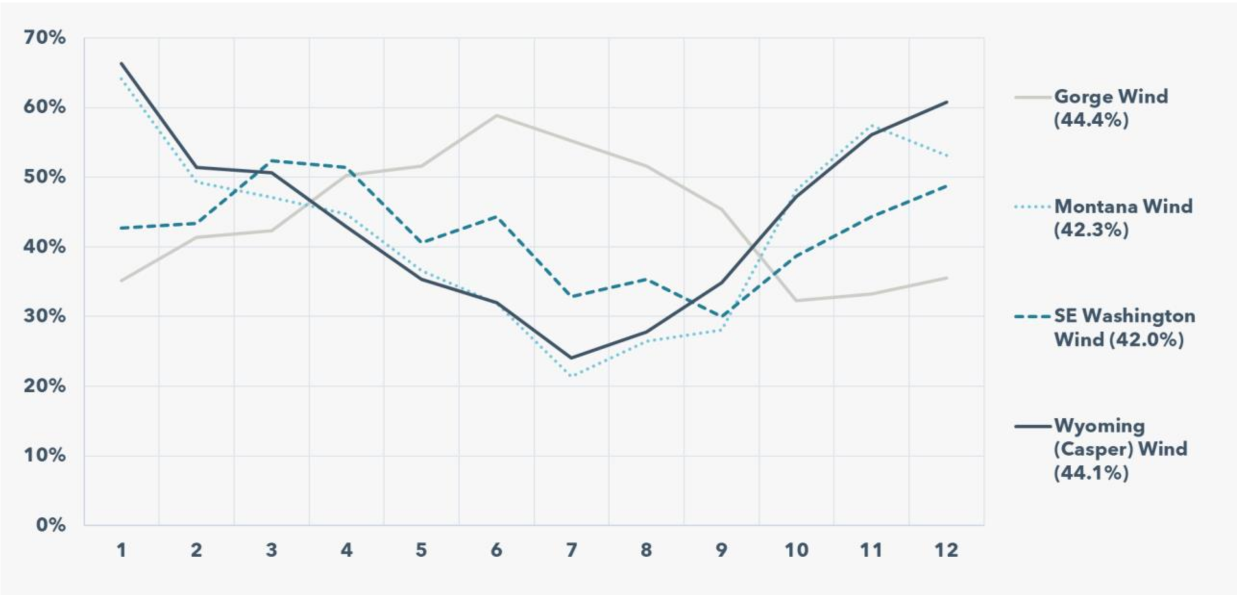
Table 28. 2026 COD onshore wind[217]

	Oregon Columbia Gorge	Central Montana	SE Washington	Casper, Wyoming
Location (Lat., Long.)	45.65, -120.63	46.35, -110.34	46.41, -117.84	43.04, -105.56
Capacity (MW)	300	300	300	300
Capacity Factor (%)	44.4%	42.3%	42.0%	44.1%
O/N Capital Cost ($/kW)	$1,503	$1,457	$1,491	$1,457

Figure 56 summarizes the shape of monthly capacity factors for the various wind resources used for energy valuation in this IRP.

[216] PGE's 2019 IRP included two Oregon-sited proxy wind resources; for purposes of streamlining the resources being analyzed, the Oregon wind site with the superior capacity factor is included in this IRP.
[217] Wind project capacity factor data are from NREL. They do not necessarily comport with historical generation values from these locations from existing projects.

Figure 56. Wind resources monthly capacity factor shapes



8.1.7.2 Solar photovoltaic (PV)

Three Oregon locations are used to represent solar photovoltaic (PV) resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville. A solar PV resource near Mead, Nevada, that will be accessed via incremental transmission action is also included in PGE's analysis. Each location is modeled using identical underlying parameter assumptions, so any difference in simulated energy production is attributable to the solar resource. Resource cost and parameter information is based on NREL ATB. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors. All solar PV resources use single-axis tracking. The inverter loading ratio (ILR) describes the ratio of solar array direct current (DC) capacity to inverter alternating current (AC) rating.[218] The 1.34 ILR modeled in the IRP is consistent with the NREL ATB. ILRs are also discussed further in the context of co-located, or hybrid, solar and battery energy storage resources. A selection of solar PV parameter assumptions is summarized in **Table 29**.

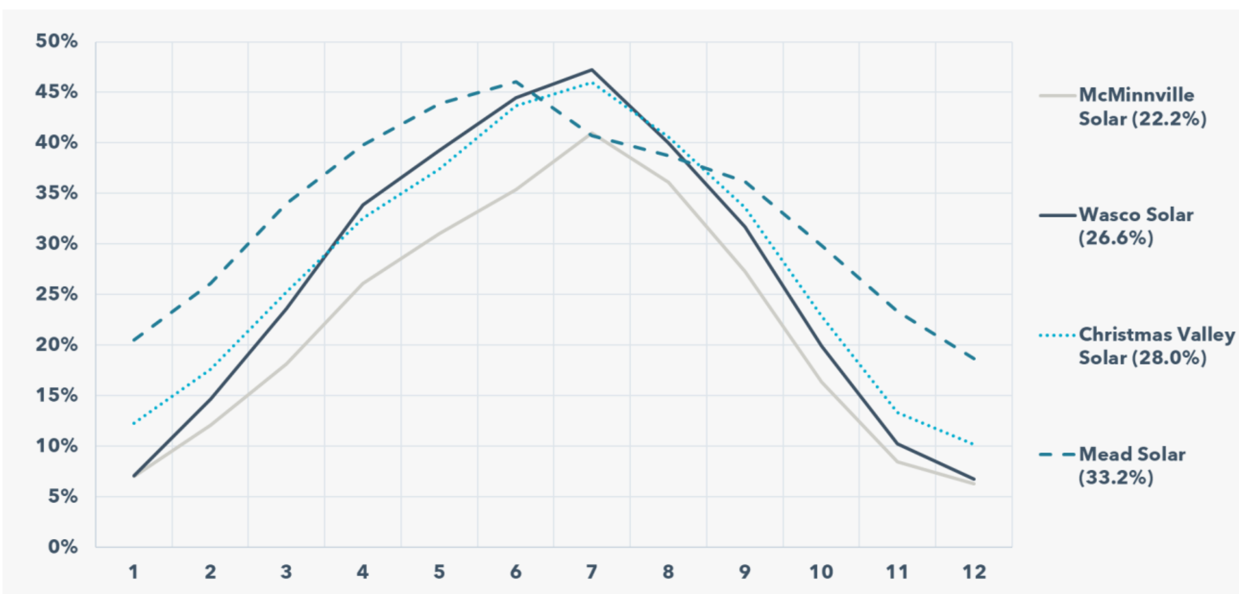
[218] An ILR greater than 1.0 means that the DC capacity of the solar array is greater than the AC capacity of the inverter. In such a configuration it is possible for the energy generation from the solar array to exceed the inverter rating resulting in the system output being limited to the inverter AC rating. This situation is referred to as "inverter clipping". The energy in excess of the inverter rating is lost and not delivered to load. All else being equal, as the ILR increases the quantity of clipped energy will increase.

Table 29. 2026 commercial operation date solar PV

	Christmas Valley, Oregon	Wasco, Oregon	McMinnville, Oregon	Mead, Nevada
Location (Lat., Long.)	43.25, -120.62	45.61, -120.7	45.21, -123.18	35.89, -114.98
Capacity (MWac)	75	75	75	75
Capacity Factor (%)	26.7%	25.3%	21.1%	31.6%
Inverter Loading Ratio	1.34	1.34	1.34	1.34
O/N Capital Cost ($/kW)	$1,297	$1,297	$1, 354	$1,297

Figure 57 summarizes the representative monthly average capacity factor for the three solar locations modeled:

Figure 57. Solar resources monthly capacity factor shapes



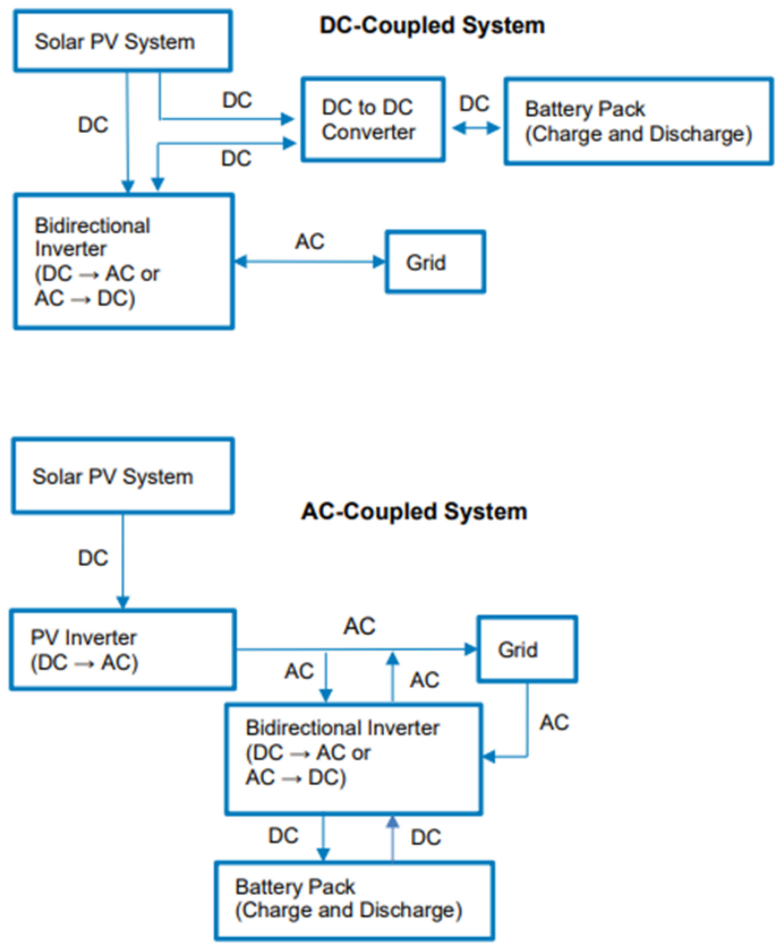
8.1.7.3 Hybrid: Solar + Storage

"Hybrid" resources pair renewable and storage resources behind a single interconnection. Hybrid resources could include solar PV with energy storage, wind with energy storage, and wind and solar PV with energy storage (such as PGE's Wheatridge Renewable Energy Facility), among others. In this 2023 IRP, PGE models solar PV with battery energy storage hybrid resources. Multiple elements are required when describing a solar + storage resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as previously described) and storage duration. Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each of these elements, the IRP simplifies the analysis to include two representative solar and battery energy storage system (BESS) hybrid resources. These two hybrid resources:

- Employ a DC-coupled configuration. The solar and storage components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC-coupled). When AC-coupled, the battery and solar resources use separate inverters. The IRP assumption of DC coupling is consistent with the NREL ATB. **Figure 58** illustrates the essential elements of these two configurations:[219]

[219] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai and Robert Margolis. 2021. US Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. Available at: https://www.nrel.gov/docs/fy21osti/77324.pdf.

Figure 58. Illustrative DC- and AC-coupled solar + storage



- Differ in the ratio of solar-to-storage capacity. Similar to using ILR to summarize the solar array and inverter relationship, the solar-to-storage capacity relationship is defined in the IRP as the ratio of the storage resource capacity to the inverter rating. The two representative hybrid resources tested in this IRP are differentiated by this ratio, with one resource featuring a storage power capacity equivalent to the inverter rating (1.0) and one with a storage power capacity equal to one-half of the inverter rating (0.5).
- Use the Christmas Valley and McMinnville solar locations as discussed; however, the solar resources differ regarding the inverter loading ratio. While the standalone solar resource is modeled with an ILR of 1.34, the hybrid solar resource has an ILR of 1.50. A potential benefit of DC-coupled hybrid solar PV and BESS, since both resources are on the DC side of the inverter, is the ability of the battery to capture energy from the solar PV resource that would otherwise be "clipped" by the inverter.
- Use storage resources with a four-hour storage duration, consistent with NREL modeling assumptions.

The optimal configuration of hybrid or co-located resources will likely depend on the cost and performance characteristics of the specific resource components. This includes both the generating (wind, solar, etc.) and storage resource technologies. Prior to the passage of the IRA, energy storage resources could qualify for the investment tax credit (ITC) only when paired with a solar generating resource (and sourcing at least a minimum amount of the charge energy from that resource). As mentioned, the IRA introduced an ITC for standalone energy storage resources, removing one of the primary benefits associated with this resource configuration. However, the prevalent regional transmission constraints suggest that important benefits of co-locating renewables and storage remain.

A summary of the NREL ATB-sourced costs and parameters for the hybrid solar PV and BESS resources modeled in the IRP is provided in **Table 30**. Capital cost estimates are adjusted by geographic location based on EIA's location-based adjustment factors.

Table 30. 2026 COD solar PV and battery energy storage

	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Location (Lat., Long.)	43.25, -120.62	43.25, -120.62	45.21, -123.18	45.21, -123.18
Duration (hours)	4	4	4	4
Solar ILR	1.50	1.50	1.50	1.50
Solar capacity (MWdc)	112.5	112.5	112.5	112.5
Solar capacity (MWac)	75	75	75	75
Storage capacity (MW)	37.5	75	37.5	75
Overnight (O/N) capital cost ($/kW)	$1,796	$2,297	$1,848	$2,348
O/N capital cost ($/kWh)	$449	$574	$462	$587

8.1.7.4 Offshore wind

NREL Oregon offshore wind studies are the basis for PGE's modeling of offshore wind in this IRP.[220] The NREL studies present five proxy resources distributed across the Oregon coast. For this IRP, PGE uses the southernmost of these proxy resource locations. This southern location provides the highest expected capacity factor from NREL's and PGE's modeling. This site also closely aligns with the Brookings wind energy Call Area identified for potential lease by the federal Bureau of Ocean Energy Management (BOEM).[221]

Consistent with NREL study assumptions for a 2032 commercial operation date, IRP modeling reflects 15 MW turbines with 248-meter rotor diameter and 150-meter hub height. Other modeled characteristics are summarized in **Table 31**.

Table 31. 2032 COD offshore wind

	Southern Oregon
Location (Lat., Long.)	42.69, -124.84
Capacity (MW)	960
Capacity Factor (%)	55.2%
O/N Capital Cost ($/kW)	$3,546

8.1.7.5 Geothermal

The representative geothermal resource in the IRP is modeled based on hydrothermal flash technology, as provided in the NREL ATB (Annual Technology Baseline). Given the site-specific nature of geothermal resources, the representative resource assumes a typical temperature and depth. NREL notes that costs heavily depend on these factors, requiring site-specific studies to improve accuracy.[222] These costs are summarized in **Table 32**.

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[220] Musial, Walter, Patrick Duffy, Donna Heimiller and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling, available at: nrel.gov/docs/fy22osti/80908.pdf.
[221] BOEM. Oregon Call Areas, available at: https://www.boem.gov/sites/default/files/images/or_callareas_april2022.jpg
[222] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal

While hydrothermal technology is relatively mature, future resource opportunities may include developing so-called enhanced geothermal systems (EGS). EGS resources differ from hydrothermal resources as they require engineering to promote the flow of underground fluids. See the additional discussion related to geothermal resources in **Section 8.5, Post-2030 resource options**.

Table 32. 2026 COD geothermal

Geothermal	
Capacity (MW)	40
O/N Capital Cost ($/kW)	$5,123

8.1.8 Energy storage resources

Two energy storage resources are included in the IRP and discussed in the following sections:

- Battery Energy Storage Systems
- Pumped-Hydro Storage

8.1.8.1 Battery Energy Storage System (NREL)

The representative battery energy storage systems (BESS) costs and performance characteristics are based on lithium-ion technology. These data are sourced from the NREL ATB for durations up to eight hours; IRP cost assumptions for longer durations apply the NREL ATB methodology of scaling the energy component costs and are derived from the same energy and power cost estimates.[223] By maintaining a representative technology assumption across durations, any analytical results between these resources are driven by the costs and benefits of the duration changes alone, not the details of their operating parameters. Costs and characteristics for the BESS resources are summarized in **Table 33**.

[223] NREL. Utility-Scale Battery Storage, available at: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage

Table 33. 2026 COD battery energy storage

	2 Hour Li-Ion	4 Hour Li-Ion	6 Hour Li-Ion	8 Hour Li-Ion	16 Hour Li-Ion	24 Hour Li-Ion
Capacity (MW)	50	50	50	50	50	50
Duration (hours)	2	4	6	8	16	24
Round-Trip Efficiency	86%	86%	86%	86%	86%	86%
O/N Capital Cost ($/kW)	$773	$1,189	$1,606	$2,022	$3,687	$5,353
O/N Capital Cost ($/kWh)	$386	$297	$268	$253	$230	$223

8.1.8.2 Pumped-Storage Hydro

The pumped-storage hydro resource is a 600 MW closed-loop system. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an average of proposed regional closed-loop projects gathered from information published by the Northwest Power and Conservation Council; a summary of that information is provided in **Table 34**.[224]

Table 34. 2026 COD pumped-storage hydro

	Pumped-storage hydro
Capacity (MW)	600
Duration (hours)	10
Round-trip efficiency	80%
O/N capital cost ($/kW)	$2,912
O/N capital cost ($/kWh)	$291

[224] NW Power and Conservation Council Generating Resource Reference Plants, available at: https://www.nwcouncil.org/2021powerplan_pumped-storage_generating-resource-reference-plants/

8.1.9 GHG emitting resources

Three natural gas-fired generators are included in this IRP:

- F Class simple-cycle combustion turbine unit
- H Class combined-cycle com combustion turbine unit
- H Class combined-cycle combustion turbine unit with CO2 capture and storage
- Closed-loop biomass

Each resource is modeled with fuel supplied at a price assumed for AECO-delivered natural gas.[225] See **Section 4.5, Uncertainties in price forecasts**.

8.1.9.1 Simple-cycle combustion turbine and combined-cycle combustion turbine

The simple-cycle combustion turbine (SCCT) and combined-cycle combustion turbine (CCCT) are based on EIA's cost and performance parameter estimates. The SCCT is representative of an F-class unit. The combined-cycle combustion turbine (CCCT) resource is based on EIA's representation of a 1 x 1 H-class unit. Lifetime net capacity and heat rate are summarized in **Table 35**.

Table 35. 2026 COD SCCT and CCCT

	Simple-cycle CT	Combined-cycle CT (1 x 1)
Capacity (MW)	227	407
Heat rate	10,042	6,564
O/N capital cost ($/kW)	$830	$1,325

[225] Wood Mackenzie. "North American Power & Renewables H1 2022 Long-Term Outlook."

8.1.9.2 Combined-cycle combustion turbine with CO2 capture system

The cost and parameters for CCCT with CO2 capture system (CCS) resources are based on those produced by EIA.[226] The H-class combined-cycle unit is similar in configuration and specification to the traditional resource described previously. In addition to the CCCT, the resource includes an amine-based CO2 capture system designed to remove 90 percent of the CO2 from exhaust gases. The costs of CO2 storage are not included in the EIA cost estimates; as such, these costs are derived from Hunter to represent an estimate of the total resource cost.[227]

The configuration and auxiliary power requirements for the CO2 capture system operation result in an approximately 40 MW decrease in the net capacity of this resource relative to the CCCT without the CO2 capture previously described. Similarly, the resource is less efficient, resulting in a higher heat rate than the CCCT without CO2 capture (**Table 36**).

Table 36. 2026 COD CCCT with CO2 capture

CCCT w/ CO2 capture system	
Capacity (MW)	367
Heat rate	7,271
O/N capital cost ($/kW)	$2,720

8.1.9.3 Biomass

The biomass-fueled resource uses bubbling fluidized bed boiler technology to drive a steam turbine. Emissions controls include overfire air in the combustion process, with selective catalytic reduction and a baghouse post-combustion. The EIA AEO is the basis for resource cost and operating parameter data. Wood chips serve as the fuel in this closed-loop system. Biomass fuel prices are based on Wood Mackenzie forecasts (**Table 37**).[228]

[226] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. 93–98.
[227] Hunter *et al.*, "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Available at: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769
[228] Wood Mackenzie. "North American Power & Renewables H2 2020 Long-Term Outlook."

Table 37. 2026 COD closed-loop biomass

Biomass	
Capacity (MW)	50
Heat rate	13,300
O/N capital cost ($/kW)	$7,186

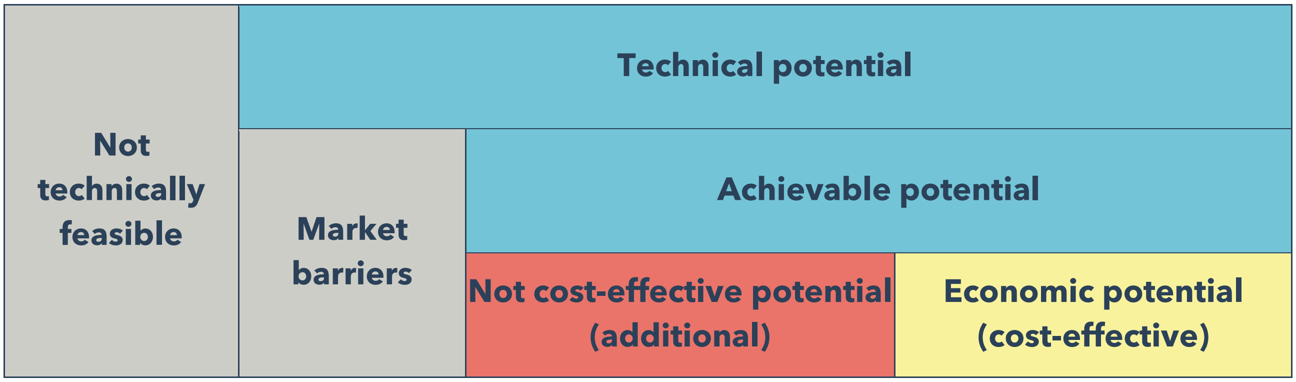
8.2 Additional distributed energy resources

In **Section 6.2, Distributed Energy Resource (DER) impact on load**, we focus on the market adoption of passive DERs (rooftop solar, transportation electrification and building electrification) and the cost-effective or economic potential, as highlighted in yellow in **Figure 59**. This IRP, like prior IRPs, includes the entire market adoption and cost-effective DERs forecast upfront when determining total load, as shown in **Section 6.3, Load scenarios**. While this process has been sufficient in the past to estimate DER impact in the IRP, the processing time between the IRP and developing the next DER potential could lead to suboptimal planning, especially in a rapidly evolving planning environment. The need to evaluate additional EE beyond cost-effective levels was also noted in Order 20-152.[229] PGE has taken steps to address this lag within resource planning by evaluating additional energy efficiency and demand response opportunities within the IRP, highlighted in red in **Figure 59**.

Additional DER or non-cost-effective DERs refer to energy efficiency and demand response technologies, measures or programs included in the Achievable Potential but were deemed non-cost-effective under the previous set of avoided costs developed for UM 1893 in 2021 and the DSP in 2022. Thus, additional DERs represent the difference between the Achievable potential and Economic potential for that DER. This is illustrated in **Figure 59**, which also highlights the relationship between the different DER potentials evaluated.

[229] *In the Matter of Portland General Electric, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 20-152 (May 6, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

Figure 59. The different potential assessments of DERs



In this IRP, we have developed a process to analyze these additional DERs previously deemed non-cost-effective through portfolio analysis. Traditionally, this is done outside of portfolio analysis using IRP inputs described in **Chapter 10, Resource economics Energy value, Capacity value, Cost of clean energy**, and **Section 10.8, Resource net cost**. Introducing the non-cost effective DERs within the portfolio has the following analytical differences:

- The IRP ELCC's method to determine capacity contribution ensures resource interactions between the DER and other resources are captured. Based on the resource's operational characteristics, this may lead to a higher or lower capacity contribution.
- The impact of transmission quality and availability significantly affects the capacity contribution and economics of supply-side options. Potential economic tradeoffs between higher fixed-cost resources, such as DERs, and avoiding additional transmission buildout, are captured within portfolio analysis.

If selected through portfolio analysis, it would provide early indications of the expected changes to upcoming avoided costs of demand response and energy efficiency, which are procured across different channels including the Energy Trust of Oregon (ETO) and PGE's demand response programs. The following sections describe the additional energy efficiency and demand response potential.

8.2.1 Additional energy efficiency

PGE worked with ETO to develop non-cost-effective or additional energy efficiency resources, leveraging the 2021 energy efficiency potential assessment to determine which list of measures did not pass the cost-effectiveness screen based on the 2021 values in UM 1893 and their associated characteristics, such as load shape, cost and expected life.

ETO provided 67 unique energy efficiency measures over the planning horizon. To optimize the modeling approach, PGE adopted a similar process as the Northwest Power and Conservation Council and aggregated energy efficiency measures into discrete bundles (or 'bins') based on the measures' levelized cost. The levelized costs are used to determine the bin size, which is the MW potential of the resources within that bin by year. Costs and design life for each bundle or bin is based on a weighted average of the measures within weighted by their megawatt average (MWa) potential. PGE also included benefits based on the UM 1893 filing,[230] by including a commensurate reduction in the fixed costs resulting from a distribution deferral credit, a regional Power Act credit of 10 percent and a risk reduction value.

Table 38 summarizes each bin for 2026, highlighting fixed costs, MWa potential and associated end uses. As the bins are developed based on levelized cost, the number and proportion of end use in each bin evolves with each year. End uses represent an aggregated set of unique measures referencing different market opportunities. For example, if we examine weatherization end uses in bins 3 and 4, we see that they contain different weatherization measures that apply to different types of buildings with different heating fuels:

- Weatherization in Bin 3 includes opportunities such as residential floor insulation, new construction manufactured housing space heating, retrofit opportunities for attic insulation and residential windows for homes heated with electricity.
- Weatherization in Bin 4 includes opportunities for residential wall insulation for homes heated with electric space heat and residential wall insulation and double pane windows in existing homes with gas heating and electric air distribution systems.

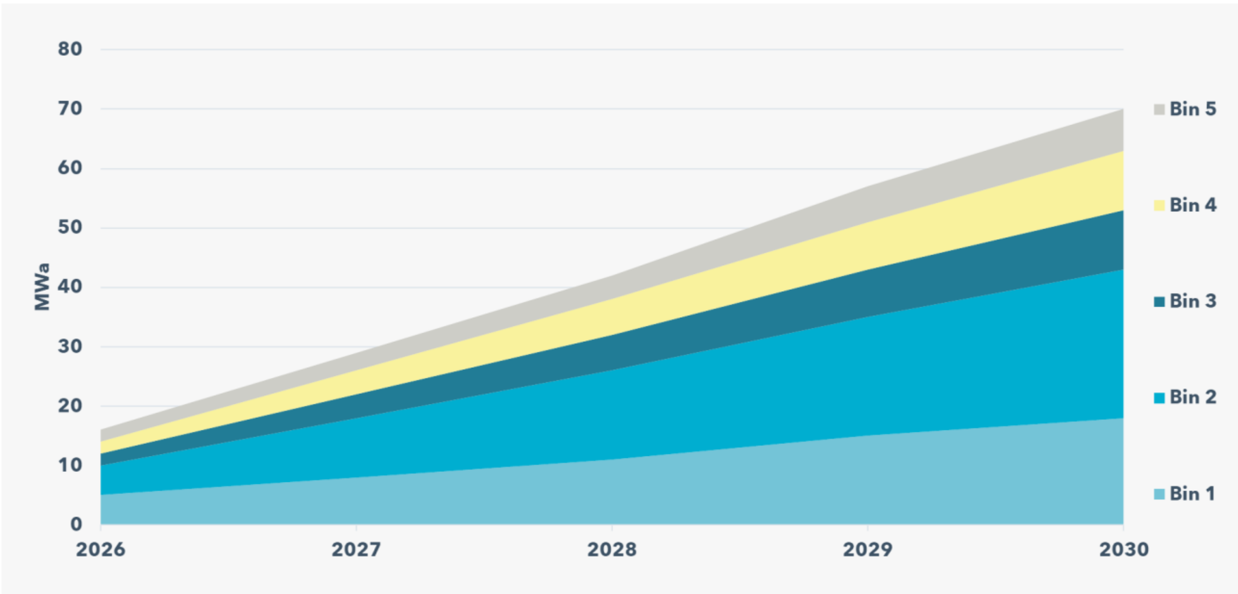
Table 38. The costs and additional potential of each EE bin in 2026

Bin	Fixed costs ($/kW-yr.)	MWa potential	End uses
1	687	5	Ventilation, lighting
2	1,486	5	Heating, weatherization, refrigeration
3	1,369	2	Lighting, weatherization
4	2,771	2	Cooling, weatherization
5	10,884	2	Weatherization

[230] PGE's updated UM 1893 avoided costs are available in ETO's presentation at the October 3, 2022 workshop, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAH&FileName=um1893hah161441.pdf&DocketID=20999&numSequence=45

Figure 60 describes the cumulative potential by bin from 2026 through 2030. While each bin has a combination of residential and commercial measures, commercial measures represent ~58 percent of the savings over the same period and residential represent the remaining ~42 percent.

Figure 60. Cumulative additional EE MWa potential through 2030



8.2.2 Additional demand response

Leveraging a similar approach for demand response as with energy efficiency, we have bundled the additional or non-cost-effective demand response programs identified by the DSP into four bundles or bins based on their dispatch characteristics and costs. **Table 39** summarizes each bin for 2026, followed by a brief description of the measures included in that bin for the year 2026.

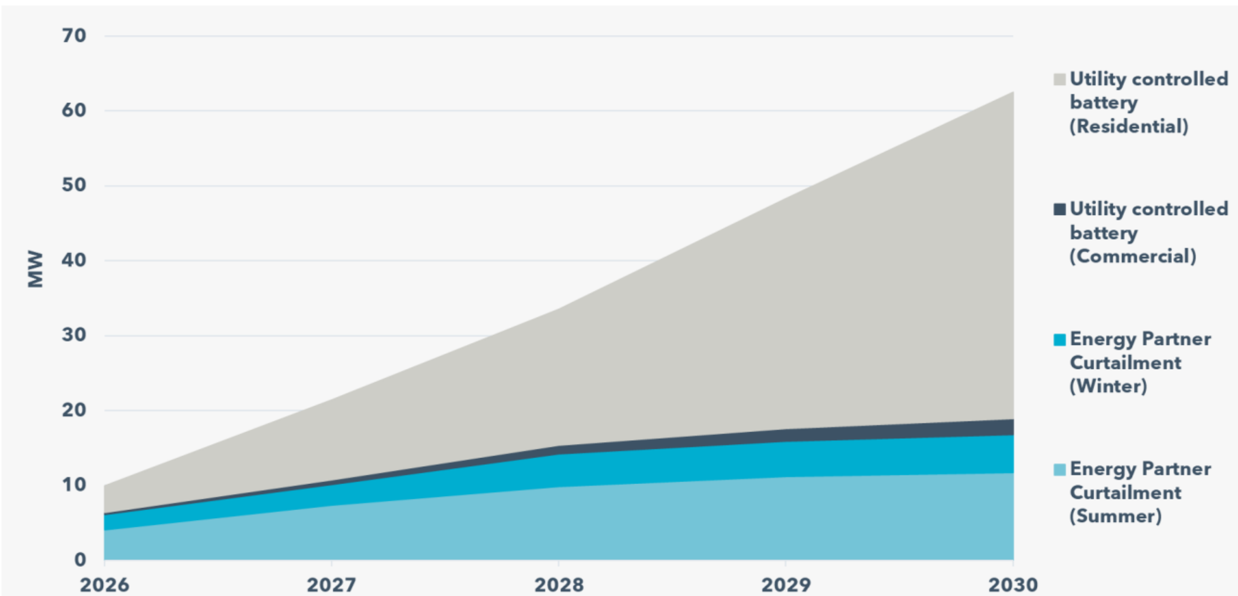
Table 39. Costs and potential of additional demand response opportunities in 2026

Measure	Fixed costs ($/kW-yr.)	MW
Energy Partner Curtailment (summer)	$499	4.1
Energy Partner Curtailment (winter)	$1,177	2.0
Utility controlled battery (commercial)	$453	0.3
Utility controlled battery (residential)	$660	3.6

- **Energy Partner Curtailment (summer and winter).** Represent the group of technologies that can deliver value within PGE's Energy Partner program, which dispatches seasonally during peak periods during weekdays and weekends.
- **Utility controlled batteries (commercial and residential).** Represents the batteries installed in partnership with customers and controlled by PGE for optimal dispatch. Optimal dispatch by PGE can offset variable power costs reducing costs for customers or can be used for reliability purposes, reducing potential market exposure risk during higher prices. PGE will conduct optimal dispatch through its VPP as described in **Section 8.4, Virtual Power Plant (VPP)**.

Figure 61 describes the cumulative potential through 2030. Residential batteries represent ~25 percent of the total MW potential.

Figure 61. Cumulative additional DR potential through 2030



8.3 Community-based renewable energy resources

Section 7.2, Community-based renewable energy (CBRE), describes the overall process PGE followed under the Community Lens Potential study. PGE identified three proxy resources for CBRE for inclusion in portfolio analysis:

- Community-scale standalone solar
- Community resiliency microgrid
- In-conduit hydropower

8.3.1 Community-scale standalone solar

PGE modeled the community-scale standalone solar proxy resource from a combination of sources. Cost assumptions were taken from the Oregon Community Solar program filing and include additional program administration and marketing costs typically associated with these resources.[231] PGE used the cost data for the "community-based carve out projects" to inform resource modeling, with an assumed efficiency factor of 20 percent cost savings from the historical baseline to account for expected economies of scale from a broader-based procurement effort.[232]

Performance features (such as capacity factor and resource shape) of the community-scale standalone solar proxy resource were modeled after a solar resource located in Boring, OR. A selection of solar PV parameter assumptions is summarized in **Table 40**.

Table 40. Performance and cost parameters of community-scale solar CBRE

Community-scale standalone solar	
Location (Lat., Long.)	45.45, -122.38
Capacity (MWac)	50
Capacity factor (%)	18.30%
Inverter loading ratio	1.2
O/N capital cost ($/kW)	$1,992

8.3.2 Community resiliency microgrid

The community resiliency microgrid CBRE proxy resource was modeled after the hybrid resources described in **Section 8.1.7.3, Hybrid: Solar + Storage**, with the solar resource component of the microgrid being the same as assumed for community-scale standalone solar described in **Section 8.3.1, Community-scale standalone solar.** Cost components, including advanced controls and islanding costs associated with the microgrid design, were used from PGE's Distribution System Plan (DSP).

The proxy microgrid resource was assumed to have a fixed ratio of solar and storage in a 2:1 ratio, such that 1 MW of storage resource was added for every 2 MW of solar PV. However, in

[231] See *In the Matter of Public Utility of Commission of Oregon, Community Solar Program Implementation*, Docket No. 1930, Staff Report for the September 21, 2021, Special Public Meeting, available here: https://edocs.puc.state.or.us/efdocs/HAU/um1930hau175534.pdf.

[232] *Id.*, Table 5 at 17, includes the upfront costs in $/kW for the carveout projects that PGE used as a starting point for analysis.

practice, the microgrid sizing and design will be location-specific and heavily dependent on the goals of the local community. For instance, system sizing decisions will differ depending on the amount and type of critical loads the microgrid supports, as well as the community preference for longer- or shorter-duration support during an outage.

PGE expects that certain projects that fall under this resource type will be eligible for federal funding opportunities under the IIJA, but because these are project-specific opportunities (as opposed to generic tax credits like the ITC), they are not reflected as a cost-reduction in IRP modeling.

8.3.3 In-conduit hydropower

The capacity factor for in-conduit hydropower resource in the IRP is modeled based on a study conducted by Oak Ridge National Lab.[233] PGE reviewed the capacity factor and other performance assumptions of the in-conduit hydropower resource and determined that it closely approximates the resource characteristics of the biomass resource described in **Section 8.1.9.3, Biomass.**

8.4 Virtual Power Plant (VPP)

Through both the DER adoption forecasts discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load** and the resource options listed in **Section 8.2, Additional distributed energy resources**, and **Section 8.3, Community-based renewable energy resources**, PGE is preparing for significant growth of distributed resources. In resource adequacy calculations and portfolio analysis (discussed in **Chapter 11, Portfolio analysis**), PGE assumes that all resource types can be integrated into PGE's system and orchestrated to deliver their full potential system value. However, extending this assumption to smaller and/or behind-the-meter resources requires advancement of PGE's ability to monitor, schedule and dispatch resources in an optimized manner. To ensure realization of the full value of these resources, PGE is coordinating resource deployment and operation through a VPP.

PGE's VPP comprises DERs and flexible loads managed through a technology platform to provide grid and power operations services. The VPP will incorporate and optimize the operation of DERs and flexible loads by connecting them through the VPP platform to provide services they would not be able to provide in isolation. The VPP will be an important

[233] Oak Ridge National Lab, "An Assessment of Hydropower Potential at National Conduits" October 2022. Available at: https://info.ornl.gov/sites/publications/Files/Pub176069.pdf. Capacity factor assumptions are on page 30.

tool for identifying and extending DER and flexible load benefits to customers and communities seeking local clean energy investments.

The progression of the VPP will allow us to activate the full value of DER capabilities assumed in IRP modeling. Over time, the number of VPP operations will grow from 139 events in 2022 to many thousands and eventually millions as we go from discrete event operation to real-time energy management. Resource orchestration will be managed by a VPP technology platform, which will provide real-time visibility and control of generation, flexible loads and batteries residing within the distribution network.

VPP implementation will provide analytics that can support improved accuracy of DER and flexible load modeling in IRP analysis, as well as program cost-effectiveness evaluation and DER acquisition actions.

8.5 Post-2030 resource options

In **Chapter 6, Resource needs**, the IRP discusses future resource adequacy needs. In 2040 there is a roughly 2,000 MW increase in need due to natural gas fueled power plants no longer being available to meet retail load.[234] As a result of this need, and earlier capacity and renewable needs, most portfolios require over 3,000 MW of transmission expansion and/or generic GHG free dispatchable resources.

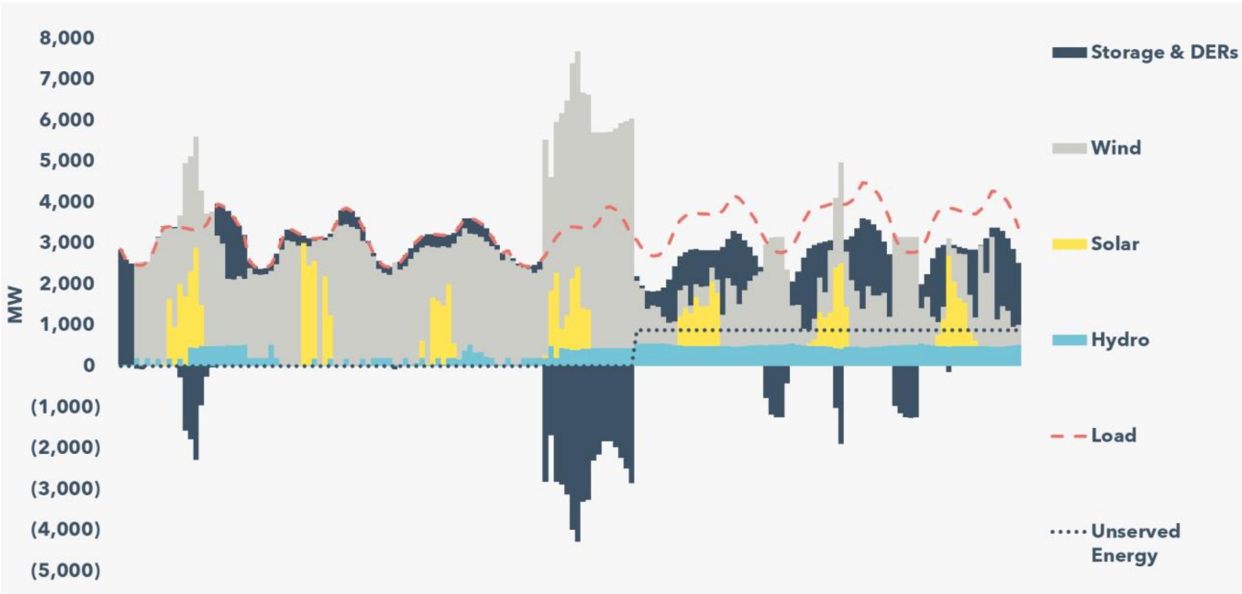
To test what happens if the assumed transmission expansion options and generic non-emitting resource are not available after 2030, PGE simulated an example power system in year 2040 with existing supply-side options available. In this example system, 6,000 MW nameplate of Northwest located wind, 6,000 MW of Northwest located solar and 6,000 MW of storage are added to the system in addition to existing resources (GHG emitting resources, like natural gas power plants, are not available in 2040 for meeting Oregon retail load). Despite adding 18,000 MW of new resource, the system still has adequacy challenges, particularly during winter days of low wind and solar generation.

A one-week example of these adequacy challenges is shown in **Figure 62**. [235] In this example, the model starts the week resource adequate, but in the last three days no longer has enough energy to meet load. Energy stored in the batteries is exhausted and there is not enough wind and solar generation available to recharge the storage and/or meet load (storage recharging is shown in the graph in negative values). The lack of energy is due to a multiday period in which both wind and solar locations in the Northwest are unproductive

[234] In 2040, per HB 2021, PGE must serve retail load with 100 percent non-emitting power. This 2040 increase in capacity needs could be reduced if the existing natural gas plants were converted to use an alternate GHG fuel source.
[235] This study was run with an earlier (spring 2022) version of Sequoia.

due to a lack of wind (reducing wind generation) and shorter winter daylight hours combined with cloud cover (reducing solar generation).

Figure 62. Example week in 2040 with only Northwest resources



As discussed earlier, the Northwest located resources provide insufficient diversity to always ensure power generation. This highlights the need for alternative resources and/or expanded transmission networks, from a geographic and/or technological perspective, to achieve longer-term GHG emission reductions while maintaining reliability. This section provides a summary of potential future resource options that PGE has considered in the 2023 IRP beyond transmission expansion to other regions.[236]

8.5.1 Hydrogen and ammonia

Hydrogen's high energy content makes it useful as an energy carrier and fuel source. On Earth, hydrogen exists naturally only in compound form with other elements, the most common being water (H_2O). Hydrogen and oxygen molecules in H_2O can be separated from one another using a process called electrolysis.[237] Hydrogen gas is combustible and it releases no CO2 when burned, which means it can provide an emissions-free fuel source.[238]

[236] While many of these resources are not included in IRP portfolio modeling, PGE may explore them in greater depth in future planning work. PGE may also explore other resource options not discussed in this section/IRP.
[237] Hydrogen production via electrolysis is done using equipment called an electrolyzer.
[238] When produced in an emissions-free manner.

One of the biggest challenges of achieving a fully decarbonized electricity system is the need for generating resources that are dispatchable, flexible and available for long durations. This is a role that is currently filled primarily with natural gas plants in today's system. Similar to natural gas, hydrogen can be used as fuel in combustion-based dispatchable electricity generating facilities, making it well-suited to providing these types of services in a decarbonized system. Hydrogen gas can be stored for long durations and used to generate power when needed, making it a complementary technology on a system with large buildouts of VERs. In such a system, electrolyzers could be powered by excess renewable energy in times of oversupply, producing hydrogen than can be stored for long durations and used to generate power when needed.

Hydrogen fuel can be used in power plants built specifically to run on hydrogen or in existing natural gas generating facilities with turbines that have been retrofitted with combustors designed to handle hydrogen fuel. Depending on the combustor technology used, appropriately equipped plants can use a fuel blend ranging from 0 percent to 100 percent hydrogen. PGE has over 1,800 MW of existing natural gas plants that could continue to provide dispatchable capacity in a fully decarbonized system if retrofitted to run on 100 percent hydrogen fuel. This represents substantial amounts of emission-free dispatchable capacity, with larger amounts possible through purpose-built facilities. Electricity generation in combustion-based power plants is far from a novel technology and while there are costs associated with retrofit, this part of the hydrogen electricity pathway is unlikely to present substantial development challenges or to be the main driver of development costs of this technology.

The largest costs and development challenges associated with this potential option for decarbonizing PGE's system are likely to be associated with development of hydrogen production, transportation and storage infrastructure. Transportation and storage infrastructure are likely to have large costs and long project lead-times, with hydrogen's low energy content by volume presenting storage and transportation challenges because of the large volumes required relative to natural gas. However, issues caused by hydrogen's low energy content by volume can be mitigated by conversion into ammonia, which has higher energy density and can be used as fuel in a similar manner as hydrogen. The production of hydrogen also has substantial capital costs associated with electrolyzers and variable costs of power used to drive the energy-intensive electrolysis process. Declines in these costs through technological innovation and economies of scale in manufacturing of electrolyzers and high penetration of VERs on the grid that lower power costs will be important developments needed to lower the barriers to hydrogen development.

Opportunities for government funding aimed at supporting the development of hydrogen production and transportation infrastructure could substantially lower the barriers to hydrogen playing a role in decarbonizing PGE's system. For example, in June of 2022, the US Department of Energy (US DOE) announced an $8 billion program associated with the

Bipartisan Infrastructure Law to fund the development of regional clean hydrogen hubs.[239] Additionally, the Inflation Reduction Act of 2022 (IRA) created clean energy tax credits, similar to those that have contributed to unprecedented development of wind and solar over the past decade, that apply to clean hydrogen production.[240]

8.5.2 Nuclear

Nuclear power is a mature technology, with the first commercial power generating reactors coming online in the 1950s, and hundreds of operating reactors around the world. Nuclear power provides both baseload capacity and non-emitting energy to the power system.

Although nuclear power has many positive characteristics, like non-emitting baseload generation, traditional large nuclear reactors also have hurdles to overcome. Nuclear power safety accidents, while rare, can be catastrophic and are often followed by public and political pushback on the technology. Recent large reactor nuclear builds in the US, like Vogtle units 3 & 4, have seen construction cost overruns and timeline delays (both units are currently in testing, with Unit 3 recently achieving criticality and expected in-service in Q2 2023).[241] Additionally, in Oregon, Measure 7 prohibits the construction of a new nuclear power plant in Oregon without a federal long-term nuclear waste repository and a statewide popular vote. Public dislike of nuclear power, largely due to safety concerns, led to multiple ballot measures in Oregon aimed at closing Trojan, a nuclear power plant operated by PGE that closed in 1992.[242] Oregon law does not prohibit PGE from purchasing nuclear power produced in a nearby state, subject to standard prudency review.

There is optimism that new generation nuclear plants will be competitive in the electric power landscape and reduce safety and political concerns of more traditional designs. UAMPS, a collective of smaller utilities in the US West, is planning to build a small modular reactor nuclear power plant. The project reactor design recently received US Nuclear Regulatory Commission certification (a first for Small Modular Reactor designs).[243] The reactor design has passive safety features, including being able to shut down and cool without operator action or power.[244] In their 2021 IRP, PacifiCorp identified a 500 MW sodium cooled fast reactor nuclear power plant with molten salt storage to come online in 2028.

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[239] Available at: https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across
[240] Available at: https://www.energy.gov/eere/fuelcells/financial-incentives-hydrogen-and-fuel-cell-projects
[241] Vogtle 3 & 4 were initially estimated to cost around 14 billion, more recent estimates are over 30 billion.
[242] The ballot measures failed; Trojan closed early in 1992 due to repair costs following a maintenance check.
[243] Available at: https://www.energy.gov/ne/articles/nrc-certifies-first-us-small-modular-reactor-design.
[244] Available at: https://www.nuscalepower.com/en/products/voygr-smr-plants.

Both the UAMPS and PacifiCorp nuclear projects have not begun construction. It remains to be seen if next generation nuclear technology can lower the cost, safety and political hurdles faced by traditional nuclear power. If it can, nuclear power could play a role in replacing existing dispatchable GHG emitting generation with non-emitting power that has similar characteristics.

8.5.3 Geothermal

Geothermal energy is the heat contained in the Earth's interior. Electricity generation from geothermal resources is generally achieved by the recovery of heat in the form of hot water or steam accessed via injection and production wells drilled into the Earth. Resources are broadly categorized as either hydrothermal or enhanced geothermal systems (EGS) depending on the characteristics of the groundwater and subsurface rock structure.[245] Geothermal resources are non-emitting and are expected to operate at an 80-90 percent capacity factor.

The US Geological Survey estimates nine gigawatts (GW) of electrical generation capacity are available from identified hydrothermal resources in the US.[246,247] Of this, approximately 3.5 GW have been developed, all in the WECC (except for the Puna plant in Hawaii).[248] An additional 30 GW may be present in favorable, yet undiscovered, hydrothermal resources. Over 95 percent of regional geothermal capacity is in California and Nevada. Roughly 30 percent of California's geothermal capacity is at Calpine's nearly 700 MW The Geysers project north of Santa Rosa.

The hydrothermal potential (discovered and undiscovered) in Oregon is estimated to be 2.4 GW. EGS development in Oregon could support electrical generation capacity of more than 60 GW. The only commercial geothermal project currently operating in Oregon is the Neal Hot Springs plant near Vale in eastern Oregon. The nearly 30 MW project, which began operation in 2012, is jointly owned by Ormat and Enbridge with Idaho Power as the off taker.[249]

[245] Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. EGS resources have sufficient heat but lack either the groundwater or rock structure to allow for efficient energy recovery, thus requiring the use of engineering techniques to introduce liquid or allow for the flow of liquid within the rock structure.
[246] USGS. "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States." Menlo Park, CA: US Geological Survey, 2008. Available at: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[247] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal.
[248] S&P Global Market Intelligence.
[249] S&P Global Market Intelligence.

An EGS demonstration project at Newberry Volcano (southeast of Bend, Oregon) is being developed.[250] The developer reports that commercial deployment of EGS technology at this site may be possible by 2030.[251] The approximately 3 MW Paisley Geothermal plant in Lake County, Oregon, is out of service per EIA reporting.

Factors that may restrict the development of geothermal resources include:[252]

- Difficulties in locating new resources (undiscovered);
- Technological challenges related to the development of and production from EGS resources over relatively long periods of time;
- Issues surrounding permitting, land access and environmental reviews may extend project development timelines;
- The general constraints to availability of transmission capacity discussed elsewhere in this IRP may apply to this resource site.

Future improvements in drilling technologies will result in reduced development time and costs. Developments in EGS stimulation technology and higher success rates will also reduce costs and development timelines.[253]

8.5.4 Renewable natural gas

Renewable natural gas (RNG) is a fuel derived from biogenic and other renewable sources that offers the potential of use within existing natural gas pipelines. Today RNG is commonly produced from waste streams found in landfills, wastewater treatment plants and animal manure. The American Gas Foundation estimates that under a high resource potential scenario the US could produce more than 4,500 trillion British thermal units (BTU) of renewable natural gas by 2040, which can serve 93 percent of current average residential gas usage nationally (the low resource potential study found roughly 60 percent less RNG available by 2040).[254] Oregon's DOE found nearly 50 billion cubic feet of potential renewable natural gas sources in Oregon, enough to replace around 20 percent of the state's current

[250] Available at: https://www.energy.gov/eere/geothermal/enhanced-geothermal-systems-demonstration-projects
[251] Available at: https://www.businesswire.com/news/home/20210923005253/en/AltaRock-Energy-Initiates-Development-of-First-SuperHot-Rock-Geothermal-Resource
[252] USGS. "Assessment of Moderate- and High-Temperature Geothermal Resources of the United States." Menlo Park, CA: US Geological Survey, 2008. Available at: https://pubs.usgs.gov/fs/2008/3082/pdf/fs2008-3082.pdf.
[253] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/geothermal
[254] American Gas Foundation, "Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment," 2019.

gas usage (this represents 10 billion cubic feet from biogenic sources and an additional 40 billion from thermal gasification, which currently faces technical obstacles).[255]

The integration of RNG into PGE's existing plants could potentially provide PGE a means to retain thermal generation at lower or zero GHG emissions. This would provide dispatchable capacity for periods of low renewable generation and/or elevated demand. However, there is uncertainty around if RNG will be considered GHG emissions free.[256] If GHG emissions are attributed to RNG usage it then becomes a bridge solution that could reduce emissions between 2023-2039.

RNG is not currently a scalable option for PGE due to its limited supply. While the ODOE has estimated that biogas could offset roughly 20 percent of the state's current natural gas use, there currently are only a few facilities that generate RNG. An economic push due to higher natural gas prices and the effect of directed state, local and federal policies could potentially increase both the number of RNG facilities and the quantities they produce.

8.5.5 Long-duration energy storage

Long-duration energy storage (LDES) is defined as any electricity storage with greater than six hours of duration. These storage options perform the same function as those described earlier in **Sections 9.1.8, Energy storage resources,** however their extended durations allow them to provide supply over longer times of need. This provides a better ability to maintain resource adequacy in larger times of system stress, and IRP modeling has demonstrated a more effective capacity per MW than shorter duration storage.[257] This section describes the wide variety of long duration storage technologies being developed.

Chemical energy storage resources convert electrical energy into an intermediate state and back using a chemical process. Currently lithium-ion batteries are the most common storage options on the market and are discussed in detail in **Chapter 11, Resource Economics**. Other chemical storage options include flow batteries. Longer duration batteries may soon be more widely available. For example, Great River Energy, a Minnesota Utility, is working to develop a multiday iron air battery.[258] Hydrogen storage is another long duration chemical storage option (discussed earlier in this section). Power can also be stored by converting electricity into potential energy with physical work, then reversing that process to discharge

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[255] Oregon Department of Energy, Biogas and Renewable Natural Gas Inventory SB 334 (2017) – 2018 Report to the Oregon Legislature, available at: https://www.oregon.gov/energy/Data-and-Reports/Documents/2018-RNG-Inventory-Report.pdf

[256] The California Air Resources Board (CARB) shows the Carbon Intensity Values of Certified Pathways of Bio-CNG (RNG) as being significantly less than LNG and CNG (geological natural gas). The Carbon Intensity Values of Certified Pathways table was last updated on December 30, 2022. LCFS Pathway Certified Carbon Intensities | California Air Resources Board.

[257] See **Appendix J, ELCC sensitivities** for more detail

[258] https://greatriverenergy.com/company-news/battery-project-includes-minnesota-flair/

back to the grid. This process of mechanical energy storage includes pumped storage hydro, compressed air storage and other storage technologies.

Thermal energy storage converts electricity into heat, stores the heat in a medium and then converts it back into electricity. For example, concentrating solar power often uses molten salt for energy storage.[259]

As more variable energy resources are expected to arrive on both the PGE system and the greater Western Interconnection, there may be increased opportunities to use storage to shift energy from oversupply hours to hours of greater need/value. Forecasted oversupply trends are discussed in IRP **Appendix N, Renewable curtailment**. PGE will continue to track trends in long duration storage and evaluate how new products can potentially bring value to the power system.

8.5.6 Carbon capture, utilization and storage

Carbon capture, utilization and storage (CCUS) is the process of capturing CO2 emissions produced by the combustion of fossil fuels so it can be stored or used in downstream processes. CO2 emissions can be captured through a process in which CO2 is separated from other gases by chemical absorption or physical separation during the power generation process. This is done using equipment that employs chemical "scrubbers" that bind to CO2 molecules, capturing them before they are released into the atmosphere. Such equipment can be installed on existing or new power plants. Once captured, the CO2 can be compressed and then stored or sequestered in underground geologic formations or utilized as a feedstock in downstream industrial applications.

CCUS could help PGE achieve a reliable decarbonized system by allowing existing or new natural gas plants to serve as non-emitting dispatchable resources. As noted previously with regards to hydrogen, PGE's over 1,800 MW of existing natural gas fired power plants represent a substantial amount of dispatchable capacity if retrofitted to become non-emitting resources.

The most substantial barriers to the use of CCUS as a tool for decarbonizing PGE's system are costs and technological maturity. CCUS costs are high relative to other technologies and globally there is currently only one operational commercial power plant equipped with CCUS (Boundary Dam coal plant, Canada)[260] after the other that existed was shut down due to persistent mechanical failures.[261] The ability of CCUS systems to convert fossil fuel plants to

[259] https://www.energy.gov/sites/default/files/2018/09/f55/Concentrating-Solar-Thermal-Power-FactSheet.pdf
[260] Boundary Dam Carbon Capture Project (saskpower.com)
[261] https://www.reuters.com/article/us-usa-energy-carbon-capture/problems-plagued-u-s-co2-capture-project-before-shutdown-document-idUSKCN2523K8

completely non-emitting is unproven and most CCUS projects today target 90 percent capture of emissions.[262] In order for CCUS to play a role on PGE's system beyond 2040, the technology would need to be able to capture 100 percent of emissions.

Substantial opportunities for government funding have the potential to both advance the technological development and reduce costs of CCUS. There is a federal tax credit for $50/MT of captured CO2 that is geologically stored and $35/MT if the CO2 is used as opposed to stored.[263] Additionally, the Bipartisan Infrastructure Bill appropriates significant funding for the development of CCUS, including: $3.5 billion for a Carbon Capture Technology program and CCUS large-scale projects over the next five years; $3.5 billion for four regional direct air capture (DAC) hubs. $2.5 billion for a ODOE carbon storage program; and establishment of a new Carbon Dioxide Transportation Infrastructure Finance and Innovation (CIFIA) program to provide $2.1 billion in low-interest loans to large CO2 pipeline projects (up to 80 percent of costs).[264]

8.5.7 Regional integration

A regional market administered through a Regional Transmission Organization (RTO), or an Independent System Operator (ISO) provides several key functions that can yield regional benefits. Key regional benefits that can help address the adequacy needs of 2040 include:

- **Common resource adequacy standards** across the region enable the opportunity to share capacity and capture regional diversity across a larger geographical footprint enabling reduction in planning reserve margins which reduce overall resource need.
- **Shared transmission planning** allows resource planning to inform transmission planning and vice versa. This broadens the set of capacity expansion alternatives that can reduce the overall size (nameplate MW) of the system needed to meet system needs. Additionally, shared transmission planning through an organized market yields governance benefits that can assist with cost and benefit allocation conflicts. This in turn increases the likelihood of successful construction and commissioning of a transmission project. Lastly, with shared transmission planning spanning a larger footprint of customers, the risk per customer is lowered.
- **A single market operator** can dispatch resources more efficiently and at lower production costs while optimizing use of transmission capacity, a key constraint within the region.

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[262] https://climate.mit.edu/ask-mit/how-efficient-carbon-capture-and-storage#:~:text=CCUS%20projects%20typically%20target%2090,will%20be%20captured%20and%20stored.
[263] The Tax Credit for Carbon Sequestration (Section 45Q) (fas.org)
[264] Bipartisan Infrastructure Bill Invests Billions in CCUS | Holland & Hart LLP - JDSupra

Today, PGE is part of or interested in multiple voluntary regional programs ranging from short-term capacity or resource adequacy programs such as the Western Resource Adequacy Program (WRAP) to real-time or energy imbalance programs such as the Western Energy Imbalance Market (EIM). These programs are focused on short-term market operations and are commonly designed to unlock key operational benefits such as price arbitrage, load diversity, improved visibility, reduced area control error etc. While these benefits are critical, they are usually unable to support long-term reliability planning needs. Consequently, these programs, given their current structure, are unable to address the 2040 needs highlighted earlier.

For this IRP, PGE described the Western Resource Adequacy Program (WRAP) in **Section 11.1.2, Resource adequacy**, including program details, benefits and its applicability in this and future IRPs. Additionally, PGE has also modeled a portfolio that explores the benefits of participating in an organized market by 2030. This is further detailed in **Section 11.4.7, Emerging technology portfolios.**

8.5.8 Coastal generation

There are several coastal energy technologies that could become commercially available inside the IRP planning horizon. In Oregon the PacWave South test bed is under development to evaluate different wave energy technologies and eyeing a 2025 online date.[265] The test bed will allow for various types of wave energy technologies to be evaluated. PGE will continue to follow the development of wave and other coastal technologies as they mature. Offshore wind, another coastal energy technology, is discussed in **Section 8.1, Utility-scale energy resources**.

8.6 Utility versus third-party ownership

The following section addresses the requirements outlined in IRP Guideline 13 of the Public Utility Commission of Oregon (OPUC or the Commission) Order No. 07-002 by providing a high-level discussion of the advantages and disadvantages of owning a resource instead of purchasing power from another party. This discussion, however, is not intended as specific recommendations for the IRP portfolio modeling or Action Plan process.

In this IRP, procurement action plans are designed to use technology-neutral procurement processes to allow PGE to pursue resources with the key attributes identified in the Preferred Portfolio. However, PGE does not procure the specific resource types in amounts set forth in the Preferred Portfolio. Instead, PGE preserves the flexibility to pursue various technologies

[265] https://today.oregonstate.edu/news/osu-led-wave-energy-testing-facility-reaches-key-construction-milestones

and resource locations that may deliver maximum value to customers. With dynamic technology development and pricing changes, we continue to be open to opportunities that would secure lower cost from projects bid into a Request for Proposals (RFP) that may diverge from the modeled technologies in the IRP Preferred Portfolio.

8.6.1 Benefits of utility resource ownership

Utility-owned resources provide multifaceted advantages to customers, including resource control, long-term access, fleet efficiency, physical and digital security integration, cost-of-service rate making benefits and reduced exposure to counterparty performance.

8.6.1.1 Operational autonomy

Customers benefit from utility-owned resources when utilities elect to change operations, determine maintenance practices, implement system upgrades or make any other decision that advances customers' best interests. When resources are under contract with a third-party, a utility's ability to make changes to third-party owned resources are generally restricted. Therefore, a utility is generally prevented from making any operational change at a third-party owned resource, regardless of the customer benefit associated with such a change.

8.6.1.2 Long-term access

Customers also benefit from reduced customer costs and risks when a utility decides to extend the operating life of a utility-owned asset. Direct ownership of a utility-owned resource provides long-term access to the asset and associated resource potential since the utility has prioritized rights to the site in addition to the holding of necessary permits, transmission rights and interconnection rights.

8.6.1.3 Alignment among owned resources

Operating utility-owned resources also provides utilities with the ability to design co-location resources to fit customer needs. Port Westward Unit 2 is an example of a co-location design decision where PGE was able to augment existing resource locations to cost save for customers while adding capacity to meet needs. Port Westward Unit 2 was put in the existing Port Westward site, where operations and maintenance are shared among resources. In doing so, the usable life of the site was extended, and fixed cost was reduced.

8.6.2 Risks of utility resource ownership

Utility resource ownership may come with the risk of production underperformance. Another risk of utility resource ownership is the significant increase in revenue requirement at the beginning of the resource's useful life and having this substantial cost increase impact customer prices.

Owning a resource also imposes on the utility the responsibility to deliver and integrate the resource to the power grid.

8.6.3 Benefits of third-party ownership

When a utility enters a contract with a power producing third-party, the project risk of the power plant is shared by both parties. In general, the terms of the agreement allocate some of the risks associated with construction of the project to the power producing third party. The reduced risk for the utility reduces the risk passed onto customers.

8.6.4 Risks of third-party ownership

There are contractual and operational risks associated with third party-owned resources. A utility is locked into specific contract arrangements for the duration of the contract, usually twenty to thirty years. Such long-duration commitments can introduce operational, market or regulatory compliance risks.

8.6.5 Resource ownership considerations

In general, PGE intends to engage in RFP processes that adhere to the competitive bidding rules to assess the resource ownership structure that will best serve customers from a delivery, cost and environmental standpoint. In the upcoming RFP, PGE is contemplating submitting a benchmark to encourage competitive bidding and solicitations from a wide range of resource technologies and structures that will provide the best value for customers. PGE is evolving the RFP process to objectively weigh the benefits and risks of the various ownership structures during the RFP process to make the best decisions about resource ownership for customers.

Note that in evaluating projects from an RFP process, each project is assessed using project-specific characteristics such as project development maturity, resource performance, resource pricing and counterparty capability. This level of detail is unique to the RFP selection process and does not apply to proxy resources included in the IRP evaluation. Proxy resources are designed to represent technology options rather than specific projects.

Chapter 9. Transmission

Portland General Electric (PGE) owns transmission assets and rights to ensure reliable delivery of electricity from generation resources to load. Many of the future resources PGE will acquire to decarbonize and maintain adequacy require additional transmission rights. However, there is a limited amount of existing transmission available for future resources to use. This chapter discusses today's transmission system, introduces the concept of transmission proxies to represent new transmission options in IRP modeling and identifies transmission projects that can be part of the IRP's Action Plan.

Chapter highlights

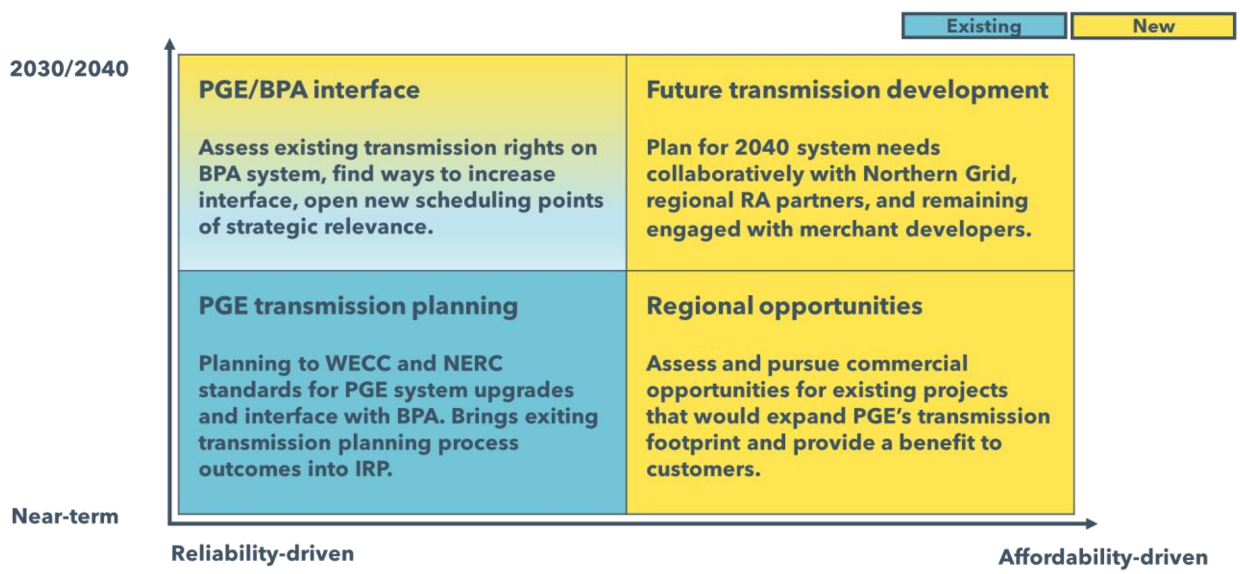
- PGE's unique footprint necessitates collaborative planning with Bonneville Power Administration (BPA) and regional peers to deliver resources to PGE's service area and to serve load within PGE's footprint. Transmission planning and development often takes longer than the Integrated Resource Plan (IRP) action window time horizon, necessitating early proactive efforts.
- As PGE plans to meet House Bill (HB) 2021's decarbonization targets, it is necessary to proactively mitigate transmission constraints to ensure reliable service of current and future load.
- Portfolio analysis in this IRP indicates additional transmission need on PGE's system, across BPA's system and in additional climate zones.
- PGE proposes addressing transmission need through a combination of rights and/or projects to alleviate congestion across the South of Allston flowgate, expanding transmission to reach additional climate zones that provide resource diversity, and increasing PGE's ability to import electricity through the study of upgrading the Bethel to Round Butte line from 230 to 500 kV.

9.1 Introduction to transmission environment and impact on resource strategy

PGE's transmission portfolio – comprised of PGE-owned assets and transmission rights held on other networks – is designed to ensure reliable delivery of electricity from a broad array of generation resources to load. As PGE works toward the decarbonization goals of HB 2021, PGE will likely need to explore adding Variable Energy Resources ("VERs") that are non-emitting electricity from new geographic areas within the backdrop of growing interconnectedness in the west. As PGE's system evolves to meet decarbonization goals reliably, we will need to evolve our transmission portfolio to expand our reach throughout the West and strengthen our ability to serve locally.

PGE's analysis in this IRP illustrates that the optimal portfolio balance of cost and risk includes holistic transmission investment over the next decade: through continued and expanded planning on PGE's system, through alleviating congestion on BPA's system, through regional opportunities to expand PGE's historic geographic transmission footprint and through robust planning for 2040 needs. This combination of transmission additions will provide reliable service as we add generating resources in Oregon and will supplement resources close to home by providing access to climate zones with higher and diversified wind and solar production. The transmission investment introduced in this chapter and recommended for acknowledgment through portfolio analysis balances cost, risk and a continual progress toward decarbonization targets (**Figure 63**).

Figure 63. PGE holistic transmission approach



The transmission system that serves PGE customers is highly integrated with other transmission systems in the West. It provides the critical infrastructure needed to serve customers in Oregon's largest metropolitan areas and enables economic development within the state.

PGE Transmission assets: As a vertically integrated investor-owned utility that is regulated by the Federal Energy Regulatory Commission (FERC), PGE is obligated by FERC to functionally separate its Transmission Function (PGET) from its Marketing function (PGEM). PGET is required to plan and operate PGE's transmission system in a non-discriminatory manner that provides open access to all transmission customers, including PGEM. Put plainly;

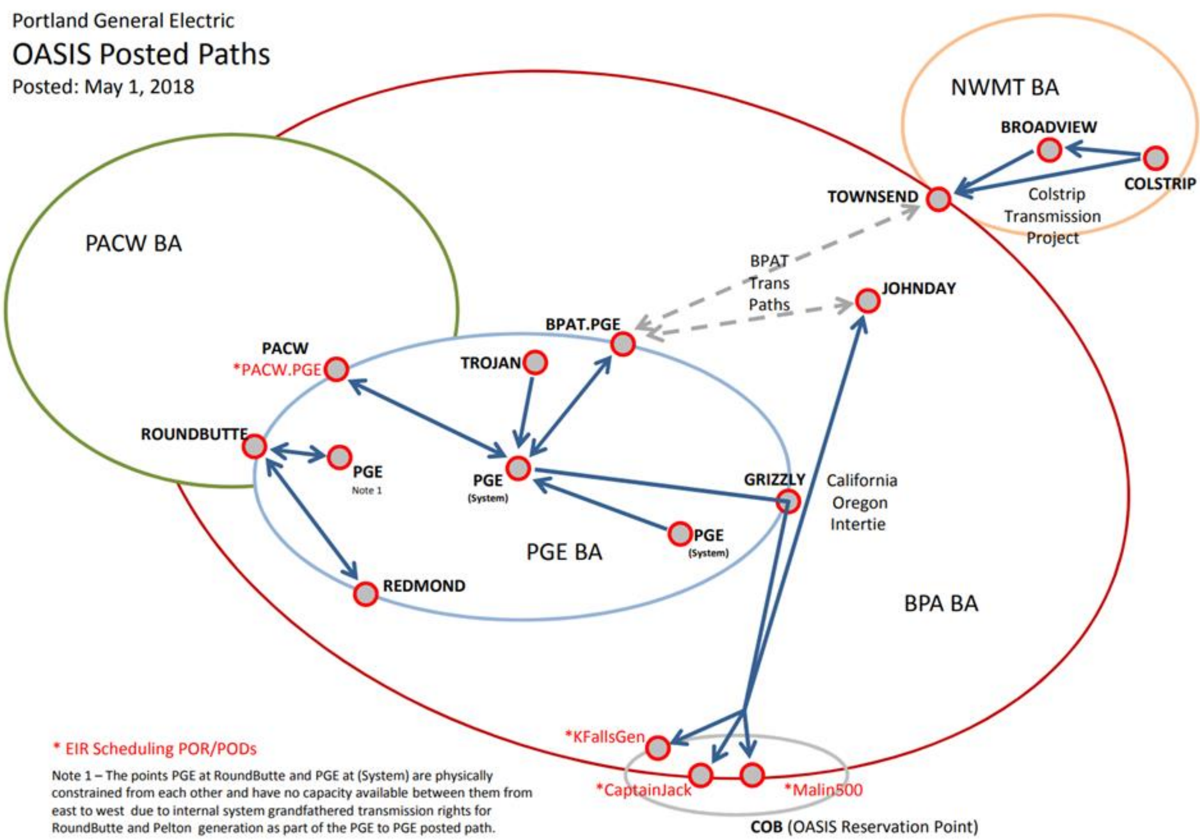
this means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGE serves. PGET's transmission customers include PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA and transmission customers who utilize PGE's transmission system to move power across the region.

PGE merchant portfolio: PGEM is responsible for purchasing transmission rights – on PGE's transmission facilities and those of other regional providers – to deliver power to PGE's service area to meet PGE's load obligations. PGEM holds extensive rights on the BPA transmission system, the largest in the Pacific Northwest. PGE is also interconnected to the western part of PacifiCorp's system, albeit with a much smaller transfer capability than PGE's interface with BPA. PGE's interface with PacifiCorp is primarily used to meet obligations within the Energy Imbalance Market (EIM). PGE is a co-owner of the Colstrip Transmission System, a 500 kV transmission line in Montana that runs between Colstrip and BPA's system in western Montana. Additionally, PGE co-owns one of the three 500 kV circuits in central Oregon that comprise the Northwest AC Intertie (NWACI) and connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp and it is operated by BPA.

Planning and regional opportunities: PGE is a member of NorthernGrid, the transmission planning organization that plans the transmission system used to serve the majority of the Pacific NW and Intermountain states of the western US.

PGE is uniquely situated, with load in the northern Willamette Valley served by PGE's physical transmission system (PGET) that exists largely surrounded by, and significantly dependent on, BPA's transmission system, as shown in **Figure 64**.

Figure 64. PGE transmission and interconnection to BPA, PACW and Northwestern



9.1.1 PGE transmission to serve load

The decarbonization requirements of Oregon HB 2021 direct load serving entities including PGE to reduce greenhouse gas emissions associated with serving Oregon retail electricity consumers, compared to baseline emissions levels by 80 percent by 2030, 90 percent by 2035 and 100 percent by 2040. PGE currently estimates that compliance with this decarbonization standard will require significant addition of resources to serve load in compliance with state law. As mentioned in **Section 6.5, Energy need,** and **Section 6.6, Capacity need**, this IRP has identified a need for 905 megawatt average (MWa) of GHG-free energy and 1136 megawatts (MW) of summer capacity to reach the 2030 target and maintain system adequacy. It is important to recognize that as economic development-driven load growth happens, there may be pockets that contain high concentrations of load within PGE's service area. To reliably serve this concentration of load, PGE will need to proactively develop unique transmission solution (see **Section 6.1.2.2, Industrial growth**).

PGE is considering investing in transmission solutions that would allow access to other climate zones to achieve additional resource diversity as its resources become more dependent on weather conditions to operate.

PGE is likely to meet transmission need through a combination of purchased transmission rights" or "transmission rights on other systems, investment in transmission assets currently in development regionally, and/or development and upgrade of PGE transmission assets to serve load.

As PGE selects the optimal portfolios of generating resources within this IRP to meet future load needs, PGE continues to plan for sufficient transmission to serve future load obligations reliably and comply with state law. The transmission options discussed in this chapter and recommended for acknowledgment in the Action Plan result directly from the future load-service needs associated with native load growth and HB 2021 requirements.

9.2 Regulatory environment

Consistent with the principles of FERC Order Nos. 890 and 1000, and requirements of PGE's FERC-approved Open Access Transmission Tariff (OATT), PGE is required to plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM and ESS customers.[266,267] Transmission customers typically utilize PGE's transmission system to serve load contained within PGET's system footprint or to transfer power through PGET's system to other transmission systems.

Customers who serve load located on PGE's transmission system generally use a transmission service called Network Integration Transmission Service (NITS). Transmission customers who move power through PGET's transmission system for delivery to a point on another transmission system typically use Point-to-Point (PTP) transmission service. For PGET to develop its transmission plans for most NITS customers, with the State of Oregon-defined Electric Service Supplier (ESS) customers being the exception, PGE uses the ten-year load-and-resource (L&R) forecasts supplied by NITS customers along with PTP transmission service commitments and requests. ESS customers are not obligated to designate generation resources to serve their loads.

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[266] *See* Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), FERC Stats. & Regs.¶ 31241 (2007), available at: https://www.federalregister.gov/documents/2007/03/15/E7-3636/preventing-undue-discrimination-and-preference-in-transmission-service

[267] *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49842 (Aug.11, 2011), FERC Stats. & Regs. ¶ 31323 (2011), available at: https://www.federalregister.gov/documents/2011/08/11/2011-19084/transmission-planning-and-cost-allocation-by-transmission-owning-and-operating-public-utilities

PGET uses the NITS customers' L&R forecasts and best available information, including transmission service, generation interconnection requests and information from neighboring transmission providers' transmission planning and construction activities, to determine the need and timing for investments in the transmission system. The bulk of PGET's NITS customer-driven needs comes from PGEM, which supplies energy and capacity for PGE's retail customers. Oregon's HB 2021 is expected to significantly impact the resource decisions of PGET's transmission customers, including PGEM, resulting in the need to develop new transmission system investment and deployment strategies. The 2022 L&R letter from PGEM to PGET documents the expectation that PGEM's future resource needs will change, given the need to comply with HB 2021. PGET must now work with its customers, including PGEM, to plan the PGET transmission system to maintain reliable service as its customers' resource mixes change over the next several years.

While PGE's transmission customers, except ESSs, are required to provide annual L&R forecasts looking 10 years into the future, transmission development in the West requires lengthy planning, rights-of-way (ROW) acquisition, permitting and construction timelines. As such, PGET cannot rely solely on the L&R forecasts to plan future transmission investments.

9.2.1 FERC transmission planning notice of public rulemaking

At the time of writing, FERC has an open rulemaking docket that seeks to explore potential improvements to the regional transmission planning requirements.[268] In the NOPR, FERC proposes to increase the transmission planning time horizon from 10 years to a minimum of twenty, identify whether transmission planning regions should contemplate standardized needs and benefits for cost allocation, determine whether transmission planning regions should be required to identify geographic resource zones, whether FERC should reinstate the right of first refusal for incumbent transmission providers when a proposed project would run through their territory, and/or require transmission planning regions to conduct sensitivity planning analysis contemplating a prescribed number and type of specific scenarios. PGE continues to follow and participate in this rulemaking process and will make any necessary updates to its OATT to reflect changes to the transmission planning process as they are approved by FERC and implemented over the next several years.

[268] FERC Docket No. RM21-17-000.

9.2.2 PGE transmission system reliability planning requirements

The PGE service area is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its transmission system and Balancing Authority Area (BAA) to deliver energy to PGE's retail customers while also providing transmission service to other wholesale transmission customers as required by FERC and in accordance with PGET's OATT. Most of PGE's existing, owned transmission assets are within the PGE service area. PGE also owns transmission assets in central and southern Oregon and Montana. PGE is obligated to plan, build and operate the transmission system in a manner that reliably delivers power to serve customer load and the needs of PGET's OATT transmission customers.

The PGE transmission and sub-transmission system has 1,663 miles of lines (213 miles of 500 kV, 408 miles of 230 kV, 566 miles of 115 kV and 476 miles of 57 kV sub-transmission) and includes 176 substations and switching stations.

As PGE plans for the transmission system that contemplates the increased resource need of the future, PGE's goals are:

- Reliable delivery of non-emitting energy to serve load;
- Ability to meet growing customer loads during a broad array of planned and unplanned system outage conditions;
- Adapting to the changing system conditions from economy-wide decarbonization and electrification;
- Ability to economically transfer power from other systems when needed and better prepare our system to ensure resource adequacy together with regional peers; and
- Ensure access to a diverse transmission portfolio to limit exposure to system and market disruptions that can constrain the transmission system.

PGE is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements.[269]

PGE's transmission system is also required to respond to directives issued by Reliability Coordinator (RC) West, the NERC-recognized Reliability Coordinator for PGE's portion of the Western Interconnection. PGE conducts annual transmission planning system assessments to

[269] See NERC TPL-001-4 standard, available at: https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf and the WECC planning criteria, available at: https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf, for additional details.

identify minimum levels of system performance during a wide range of operating scenarios, with all system elements in service to extreme seasonal conditions and scenarios where portions of the system are out of service. These assessments include load growth forecasts, operational history, seasonal performance, resource changes and transmission topology changes. Based on these analyses, PGE identifies potential system deficiencies and determines the necessary transmission system improvements to meet customer needs reliably.

NERC planning standards define the 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 consistently. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

Historically, PGE has focused on planning and development of reliable and load service-driven transmission given our unique geographic footprint within BPA's system. Until recently, this was primarily because BPA had ample Available Transfer Capability (ATC) on their transmission system that PGE has been able to leverage to transfer new remote generation resources to PGE's Willamette Valley load. With the recognition that ATC inventories on BPA's system have been fully allocated, PGE's transmission planning will need to evolve from an approach based primarily on reliability and load service to a more proactive approach that aligns with our future load service needs as we decarbonize. It is important to recognize the significant transmission planning and project development efforts already underway that are necessary for reliable load service with PGE's load service area.

Projects currently included in PGE's Local Transmission Plan (**Table 41**) span both projects that enhance regional transmission and expand interface capacity with BPA, as well as projects that are designed to meet high concentrations of new load and enhance reliability on specific parts of PGE's system:

Table 41. Projects included in PGE's local transmission plan

Summary of regional enhancement projects	
Title	**Purpose/scope**
Harborton Reliability	Reconfigure the system to reduce exposure and provide a stronger source to Northwest Portland 230 and 115 kV systems. Planned completion 2026.
Horizon-Keeler BPA #2 230kV	Accommodate load growth in Hillsboro by constructing a new bay at BPA's Keeler Substation. Expected completion 2024.
Willamette Valley Resiliency	Strengthen and increase the resiliency of PGE's system in the Central portion of PGE's territory, north of the Salem region. Expected completion 2028.
Pearl/Sherwood 230kV Reinforcement	Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the loss of the Pearl BPA-Sherwood 230 kV line. Expected completion 2026.
Hillsboro Reliability	Significant upgrades to prepare for load growth in the Hillsboro area. Expected completion 2027.
Horizon Keeler BPA #1 230 kV Reinforcement	Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth. Expected completion 2027.
Murrayhill-Sherwood #1 and 2 230 kV Reconductor	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.
Murrayhill-St. Mary's #2	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.

Additionally, PGE has identified projects that are included in the OATT Attachment K Local Transmission Plan and are designed to enhance local system reliability:

- Reedville Substation Rebuild
- Memorial Substation Project
- Tonquin Substation Project
- Kaster Substation Project
- Redland Substation Project
- Scholls Ferry Substation Project
- Groveland Substation Project
- Glencullen Rebuild & Cedar Hills Breaker Project
- SE Portland Conversion Project Holgate Substation Conversion
- Mt Pleasant Substation Project

9.2.3 Regional transmission planning in advance of 2040

PGE is a member of NorthernGrid, the transmission planning organization that serves the majority of the Pacific NW and Intermountain states of the western US. NorthernGrid has fourteen members, including seven FERC-jurisdictional investor-owned utilities (IOUs), six publicly owned utilities and BPA. NorthernGrid's planning process produces its transmission plan on a biennial basis following a FERC-accepted Attachment K planning process.[270]

In addition to the NorthernGrid transmission planning process, the Western Power Pool (WPP) is currently coordinating an effort to produce two additional regional transmission studies. The first study will evaluate the risk to the transmission system because of extreme weather events like a heat dome, wildfire or west-side arctic freeze event. The WPP is also conducting a 20-year transmission planning analysis that contemplates the implementation of Oregon HB 2021 and Washington's Clean Energy Transformation Act (CETA). The purpose of the studies is to start understanding as soon as possible the extent to which these new policies will require building out the region's transmission system. Because new significant transmission projects can take 15-20 years to develop, PGE and other transmission providers in the west recognized that studying these scenarios now is necessary if the region is to meet the collective future resource targets. These studies are both expected to be complete in mid-2023.

Further, PGE will deploy a portfolio of strategies to meet the future transmission needs covered in this chapter. PGE intends to explore expanding transmission access through the acquisition of rights on third-party systems, equity investment in regional projects as they are constructed, and PGE-developed projects, including upgrades of existing assets. These different avenues of transmission expansion will allow PGE to optimize for the least cost and least risk as we plan to meet future needs.

[270] Available at: https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_OATT_01012022-v2.pdf

9.3 PGE transmission rights and regional environment

9.3.1 The Pacific Northwest transmission system

Resource portfolios have grown and shifted in response to increasing loads, new large and highly concentrated loads and the significant growth of variable energy resources. However, the delivery capabilities of the Pacific Northwest's transmission system, generally, have not kept pace with these changing demands. As a result, the region is already constrained, with little or no ATC available across all time horizons.[271] This situation concerns PGE, as many future resource alternatives being explored will be located remote to PGE's retail service area and require delivery via the region's transmission system to reach PGE's service area.

PGE's system is largely surrounded by BPA's transmission system. PGE has long relied on BPA transmission to deliver energy throughout the west to serve the PGE load. PGE currently holds over 4,000 MW of long-term firm transmission under contract with BPA. As discussed by BPA and stakeholders throughout BPA's Transmission Study and Expansion Process 2022 (TSEP),[272] BPA's system is fully subscribed, and incremental transmission requests are unlikely to be granted until the late 2020s or early 2030s, pending significant upgrades. As such, PGE is viewing future transmission planning and procurement activity recommended throughout this chapter as a way to expand and diversify transmission options as we work to decarbonize our energy associated with serving load and we need to explore doing so in a way that does not rely on BPA transmission to the same extent PGE has historically relied on BPA. It is important to recognize that the identification and development of transmission solutions are long lead activities that often take longer than the Action Plan window time horizon of this IRP. Given this dynamic, it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window.

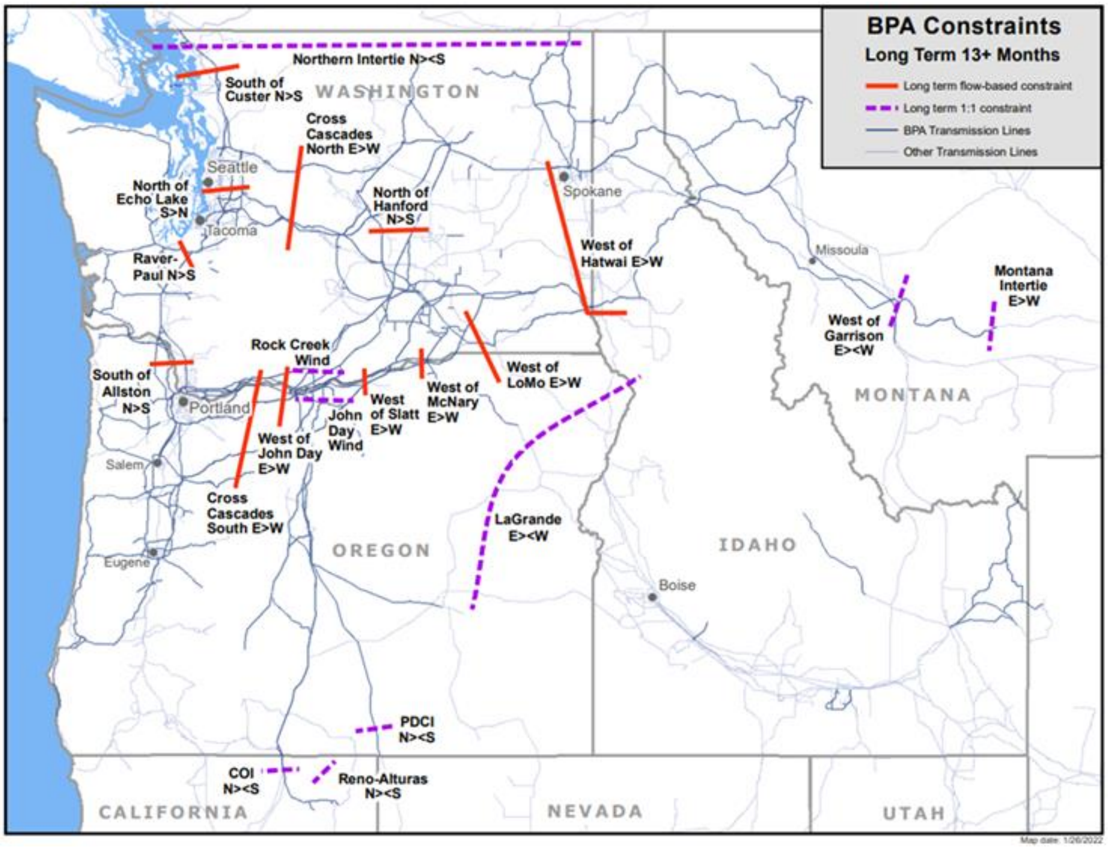
To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in **Figure 65.** The flowgates that currently have the most significant impact on PGEM's transmission rights portfolio are the South of Allston, Raver Paul, West of John Day and Cross Cascades South, all of which are constrained, with little or

[271] See BPA Presentation, TSEP Study Process Update, September 2022 p. 6: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/09-20-22-cluster-study-improvements-customer-update.pdf

[272] Available at: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep#:~:text=The%20TSR%20Study%20and%20Expansion,Network%20Open%20Season%20(NOS).

no ATC. Additionally, BPA has identified the need for two new flowgates that will directly impact PGE's ability to access new resources over the region's transmission system. One flowgate would be in the central Oregon area and the other would bisect PGE's service area in the Portland metropolitan area. PGE will continue to engage collaboratively with BPA as the paths are developed.

Figure 65. Northwest transmission lines and flowgates on BPA system



The following summarizes the most significant flowgates and paths affecting energy delivery from remote resources to PGE's service area.

- Some amount of energy from the majority of PGE's generating resources flow across the constrained South of Allston flowgate. This flowgate is most constrained during heavy summer and heavy winter loading periods.
- A portion of the energy flowing from PGE's remote resources flows across the West of Cross Cascades South (WOCS) flowgate and, as it travels to loads in the PGE area, it flows over the West of John Day and Raver-Paul flowgates. The WOCS flowgate is most constrained during heavy winter loading, while the West of John Day and Raver-Paul flowgates are typically most constrained during heavy spring and summer loading. PGE's

Bethel-Round Butte 230 kV transmission line is part of the WOCS path, although it is currently considered to have a de minimis impact on path flows.

- Energy from PGE's resources in Montana first flow over the West of Garrison flowgate before reaching several other flowgates on the way to PGE's load in the Willamette Valley.

9.3.2 Regional transmission resources are largely constrained

Some paths, like West of Garrison, are designed to operate close to their limits, while others are not; the latter group presents areas on the system where PGE sees particular importance in continuing to study, develop and possibly construct new transmission.

Figure 66 lists the Total Transmission Capability (TTC) and ATC on BPA flowgates that affect the delivery of off-system resources to PGE. This table highlights a constrained regional transmission system, especially on transmission paths impacting energy delivery outside the PGE service area.

Figure 66. Long-term firm available transfer capacity, less pending queued requests on the BPA system (as of January 27, 2023)

		LONG-TERM FIRM AVAILABLE TRANSFER CAPABILITY (ATC) LESS PENDING QUEUED REQUESTS								
Path Name	**TTC**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
South of Allston N>S	2115	(477)	(502)	(903)	(1038)	(1274)	(1422)	(1519)	(1696)	(1798)
Cross Cascades North E>W	10250	(4021)	(2807)	(3628)	(4307)	(4552)	(5182)	(5247)	(5388)	(5924)
West of Lomo E>W	4200	(13)	(108)	(153)	(416)	(412)	(408)	(404)	(527)	(523)
Cross Cascades South E>W	7500	(1502)	(2691)	(3609)	(415)	(4883)	(5858)	(5924)	(6120)	(6445)
North of Hanford N>S	4450	211	113	(356)	(450)	(588)	(668)	(616)	(577)	(539)
Raver-Paul N>S	1450	(140)	(270)	(568)	(707)	(777)	(875)	(983)	(1043)	(1122)
West of McNary E>W	5230	235	(335)	(1527)	(1698)	(1681)	(1657)	(1660)	(1607)	(1584)
West of Slatt E>W	4670	392	258	(395)	(526)	(573)	(609)	(663)	(657)	(695)
West of John Day E>W	4530	(495)	(1134)	(1679)	(2304)	(2756)	(3433)	(3545)	(3831)	(4133)
South of Custer N>S	900	(1169)	(1026)	(1056)	(1054)	(1052)	(1050)	(1048)	(1048)	(1046)
West of Hatwai E>W	3650	(444)	(412)	(939)	(910)	(880)	(850)	(820)	(1033)	(1004)
North of Echo Lake S>N	2800	(1129)	(213)	(385)	(659)	(659)	(659)	(659)	(659)	(659)
PATH NAME	**TTC MW**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
AC Intertie N>S	2725	(447)	(497)	(597)	(597)	(597)	(1197)	(1197)	(1197)	(1197)
AC Intertie S>N	795	795	795	495	14	(286)	(586)	(1736)	(1736)	(2486)
Northern Intertie N>S	2150	(200)	(200)	(200)	(200)	(200)	(200)	(200)	(200)	(200)
Northern Intertie S>N	1120	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)
DC Intertie N>S	3100	(609)	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)
DC Intertie S>N	1904	1704	1704	1704	1704	1704	1704	1704	1704	1704
LaGrande E>W	413	126	73	73	73	73	73	73	73	73
LaGrande W>E	350	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)
Montana Intertie E>W	1930	112	112	144	144	144	144	144	144	144
RATS N>S	300	(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)
RATS S>N	300	281	281	281	0	0	0	0	0	0
John Day Wind Gen	1255	149	149	99	99	99	99	99	99	99
Rock Creek Wind Gen	1200	176	176	174	174	177	177	177	177	264
West of Garrison E>W	1618	(985)	(1390)	(1490)	(1490)	(1490)	(1490)	(1490)	(1490)	(1490)
West of Garrison W>E	931	14	13	11	10	10	10	10	10	10

9.3.3 Regional transmission service request process

9.3.3.1 BPA TSR study and expansion process (TSEP)

BPA performs annual TSEP studies that combine various long-term Transmission Service Requests (TSRs) from transmission customers into a single study. The TSEP process is designed to obtain financial commitments from transmission customers before new facility construction. The cluster study process analyzes the impacts of the TSRs and new transmission facility requirements on an aggregated basis.

A TSR submitted to BPA could result in TSEP cluster study results with costly upgrades and completion dates of 10 years or longer. For example, the cost of the Montana-to-Washington upgrade project identified in the 2020 TSEP study was estimated at $1.4 billion and the earliest completion date was estimated to be 2030. It will enable an incremental 500 MW transmission service from East to West across the West of the Garrison path. PGE will likely see more high-cost and long lead-time proposals in the constrained areas of BPA's system, especially the South-of-Allston and Cross Cascades transmission areas.

9.3.3.2 2019 BPA TSEP study

In June 2019, BPA published the results of the 2019 TSEP Cluster Study. The Cluster Study comprised 105 TSRs with an associated demand of 3,993 MW. Seven BPA transmission customers submitted 59 TSRs that listed PGE as a Point of Delivery (POD) with a total transmission demand of 1,356 MW. Of the 59 TSRs submitted, 40 remain in active status. The results of those 40 active TSRs are listed in **Table 42**, including the TSR status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.3 2020 BPA TSEP study

In May 2020, BPA published the 2020 TSEP Cluster Study results. The cluster study comprised 62 TSRs with an associated demand of 3,871 MW. Five BPA transmission customers submitted 24 TSRs that listed PGE as a POD with a total transmission demand of 1,713 MW. Of the 24 TSRs submitted, seven remain in active status. The results of those seven active TSRs are listed in **Table 42**, including the TSR status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.4 2021 BPA TSEP study

In June 2021, BPA published the 2021 TSEP Cluster Study results. The cluster study comprised 116 TSRs with an associated demand of 5,832 MW. Eleven BPA transmission customers submitted 37 TSRs that listed PGE as a POD with a total demand of 1,851 MW. Of the 37 TSRs submitted, 26 remain in active status. The results of those 26 active TSRs are listed in **Table 42**, including the status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.5 2022 BPA TSEP study

In June 2022, BPA published the 2022 TSEP Cluster Study results. The cluster study comprised 144 TSRs with an associated demand of 11,118 MW. 49 TSRs submitted listed PGE as a POD, with 4,515 MW requested. Of the 49 TSRs submitted, 32 remain in active status. **Table 42** lists the results of those 44 active TSRs, including the status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

TSRs submitted to BPA, in the 2022 TSEP, for delivery to PGE's system resulted in cluster study results that identified costly upgrades and completion dates of 10 years or longer. **Table 42** summarizes BPA upgrades required to enable delivery of power to PGE's system from the five resource zones based on geographic relationship to generic resources modeled in this IRP.

Table 42. BPA identified upgrades by resource/generation zone

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
Christmas Valley Solar	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project	1. n/a 2. $109.2 3. $196.1 4. $233 5. $9.1 6. $382.21 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp)	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2033 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. n/a

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
	6. Subgrid Central Oregon South 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. Subgrid-Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls and Alvey) 9. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls and Alvey) 9. Impact to Third-Party Transmission System (PGE: North of Sherwood)	8. n/a 9. TBD	9. TBD
Gorge Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project	1. n/a 2. $109.2 3. $196.1 4. $233 5. $9.1 6. $35.39 7. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2028 7. TBD

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
	6. Raver-Paul 7. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. BPA Chehalis to Cowlitz tap 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: North of Sherwood		
SE WA Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler 6. Raver-Paul 7. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. BPA Chehalis to Cowlitz tap 230 kV Rebuild Project 7. Impact to Third-Party Transmission	1. n/a 2. $109.2 3. $196.1 4. $233 5. $9.1 6. $35.39 7. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2028 7. TBD

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost $M)	Estimated energization date
		System (Portland General Electric: North of Sherwood)		
Off-Shore Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid South Oregon Coast 6. Subgrid -Impact to Third-Party Transmission System (PGE: Santiam-Bethel & North of Sherwood)	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Santiam-Bethel & North of Sherwood)	1. n/a 2. $109.2 3. $196.1 4. $233 5. 903.66 6. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. 2033 6. TBD
Montana Renewables	1.West of Garrison E>W	1. M2W	1.$350M	1. 2030
Projects, cost and energization dates from BPA's 2022 TSEP				

Capacity limits from the generic resource zones were developed based upon PGE's experience with ATC, transmission that may be acquired by developers and the results of the 2022 TSEP.

9.3.3.6 Montana transmission

Wind resources in Montana are attractive because of their higher capacity factors and diverse seasonal output compared to the Washington and Gorge wind currently in PGE's resource portfolio. HB 2021 decarbonization requirements and coal restrictions provide an opportunity to evaluate Montana resources and the potential repurposing of PGE's existing Colstrip transmission rights to serve future PGE load from a renewable resource over the same transmission currently used to deliver Colstrip output to PGE's system.

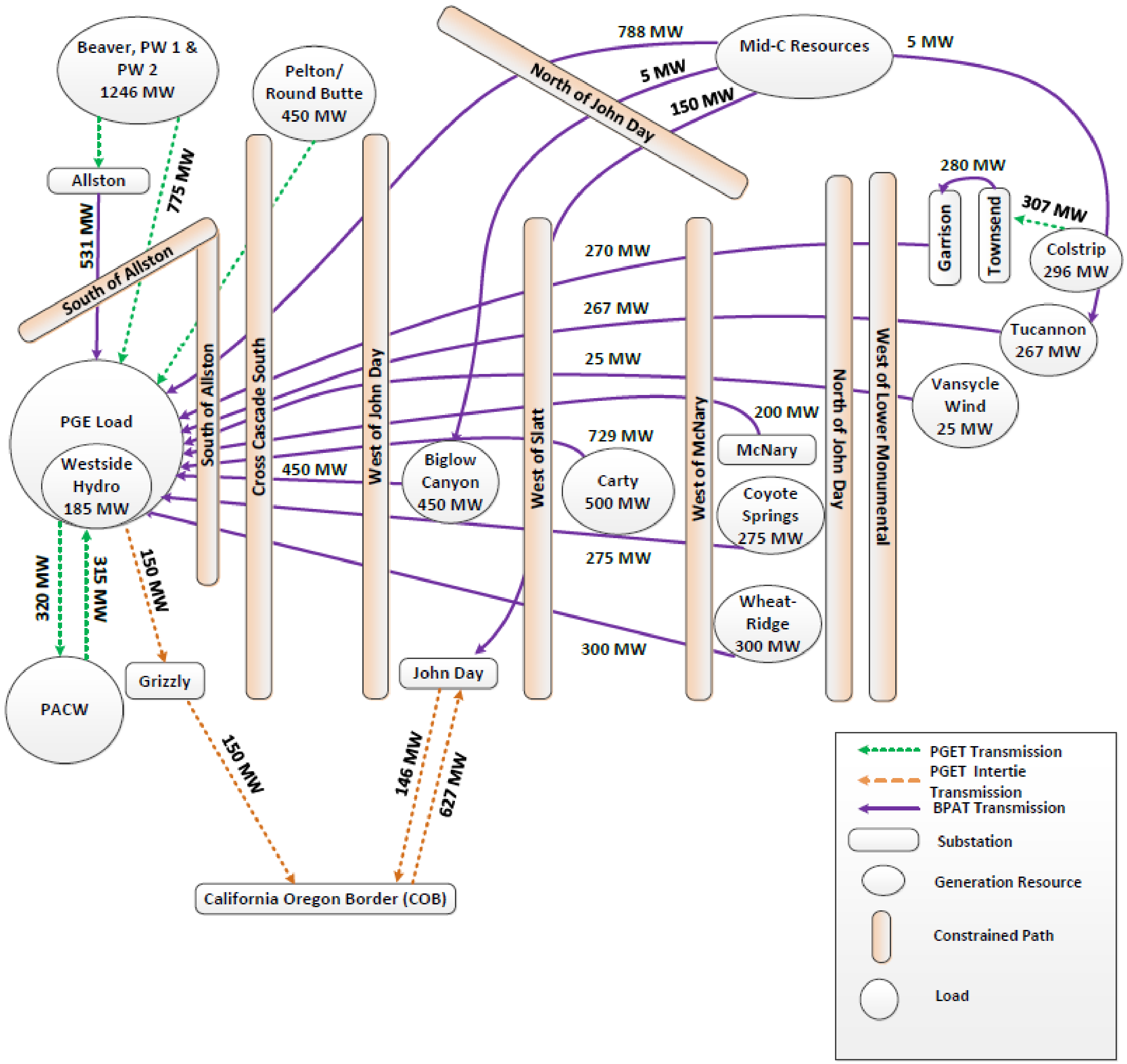
9.3.4 PGE merchant transmission portfolio

PGEM is responsible for obtaining the transmission service needed to serve PGE retail customer load and for scheduling the use of that transmission most efficiently and economically to meet demand. The transmission portfolio facilitates PGE's ability to:(1) deliver energy from generating resources to load during all seasons, (2) participate in regional energy markets and (3) optimize PGEM's energy portfolio.

PGEM's transmission portfolio consists primarily of capacity rights on the PGET and BPA systems, including the NWACI, the Colstrip Transmission System and Montana Intertie, enabling energy pathways through and into the Pacific Northwest. Due to the geographic location of PGE's service area compared to where most generation resources are or will be located, most of PGE's generation resources are outside of PGE's service area. Historically, PGEM has relied on BPA transmission rights to import power from remote generation resources and to deliver power purchases to serve PGE's load. PGEM also holds transmission rights to access the Pacific Northwest Mid-Columbia (Mid-C) wholesale power hub, which PGE relies on for balancing load, meeting peak demand and enabling economic transactions. See **Figure 67** for an overview of PGEM's transmission portfolio.

Figure 67 provides a snapshot of PGEM-contracted transmission scheduling rights to support the delivery of PGE-owned generation, power purchase agreements (PPAs) and market purchases. The tan bars in **Figure 67** represent BPA-managed flowgates. Due to the electron flow-based nature of the interconnected grid, constraints on these flowgates create limits on transfer capability to PGE's load centers, irrespective of where the source generation is located, whether on BPA's system or further away. Additionally, as described in this chapter, BPA is looking to establish new flowgates that will impact flows to and through PGE's service area.

Figure 67. Snapshot of PGE's market function transmission portfolio with generation resources and transmission



PGEM may also use its contracted transmission rights to access the Western EIM through transmission with Avista Corp, BPA, CAISO, Northwestern Montana, PacifiCorp, Puget Sound Energy, Seattle City Light and Tacoma Power. Access to the EIM enhances PGE's ability to efficiently integrate variable resources on an intra-hour energy basis and deliver the least-cost energy supply to customers. As additional wholesale market options develop in the West, like the CAISO's Extended Day Ahead Market or the Southwest Power Pool's Markets +, PGE may use its transmission portfolio to engage in these future opportunities.

9.4 Options to address transmission need

As discussed earlier in this chapter, there is a limited amount of long-term firm and conditional firm TSRs in study or confirmed status across BPA's system, deliverable to PGE without costly system upgrades. The total amount of each transmission product available is in the following table, roughly 1,800 MW combined (**Table 43**). At the same time, PGE expects to add approximately 3,000 to 4,000 MW of non-emitting resources to meet HB 2021 goals. In many scenarios, the resources needed to meet the adequacy and non-emitting energy goals require more transmission than is available.

Table 43. Transmission service requests on BPA pointed to PGE[273]

Conditional firm	Long-term firm
1,128 MW	690 MW

This need for additional generating resources to serve load in compliance with state law in contrast with a lack of available long-term transmission options creates a near-term need within PGE's resource plan and points to a long-term need that is outside of the IRP action window that, given the long development cycles necessary for transmission, warrant early engagement.

9.4.1 Proxy transmission options identify transmission need

To maintain system adequacy and achieve GHG reductions, PGE has analyzed transmission proxy options as part of the 2023 IRP. Like resource proxies, transmission proxies describe general characteristics that may be found on the market. If a portfolio selects a transmission proxy, that indicates that the model sees a need to expand PGE's transmission network for GHG reduction or resource adequacy purposes. PGE's portfolio modeling indicated that transmission need existed (and proxies were optimal) to meet BPA system need through the SoA proxy and to expand access to regional resources.

For the 2023 IRP, the capacity expansion model ROSE-E has two types of transmission proxies from which to choose. The choices in **Table 44** are 1) a Northwest transmission upgrade and 2) purchasing the rights on a transmission line to Wyoming or the Desert Southwest.

[273] Values represent all PGE resource zones and are based on the BPA TSEP.

Table 44. Proxy transmission options[274]

Proxy transmission option	Accompanying resource	Details
South of Allston upgrade (available as early as 2027 in most portfolios, $1.97/kilowatt (kW)-month)	IRP proxy resources	Increased transfer capacity on PGE's share of South of Allston via upgrade. Allows up to 400 MW of additional capacity for regional proxy resources.
Generic proxy transmission (Tx) **(Available as early as 2026 in select portfolios$20.46/kW-month to WY, $23.04/kW-month to SW)**	Wyoming wind	Model can select a Tx path to access Wyoming wind.
	Desert SW Solar	Model can select a Tx path to access Desert Southwest solar.

The South of Allston upgrade alleviates congestion on the BPA system and unlocks up to 400 MW of Northwest proxy resources, like Gorge Wind or Christmas Valley solar. It is available for selection as early as 2027 in most portfolios, indicating that this need could be alleviated by the acquisition of additional rights and, eventually, the exploration of new builds or upgrades.

Transmission to Wyoming or the Desert Southwest adds an equivalent amount of transmission capacity and a wind farm in Wyoming or a solar facility in southern Nevada (for example, 200 MW of Wyoming transmission includes 200 MW of Wyoming wind). The Nevada and Wyoming transmission proxies are available for portfolio selection as early as 2026 in select portfolios, again indicating that this identified need could be met through transmission rights, partnership in projects currently being developed, and/or additional development on a longer-term time horizon. These transmission projects have the same characteristics as the other IRP proxy resources, though their differing location changes their generation profiles. Additional information about these projects, including monthly capacity factors and other details, is in **Chapter 8, Resource options**.

Beyond providing access to renewables, the IRP assumes that transmission to Wyoming or the Desert Southwest also provides market capacity at a 1-to-1 ratio (every MW of

[274] Saadi, Fadl H, et al. "Relative Costs of Transporting Electrical Chemical Energy." *Energy & Environmental Science*, *Energy & Environmental Science*, no. 3, 29 Jan. 2018, pp. 469–475.

transmission acquired provides 1 MW of effective capacity). This is a simplifying assumption for modeling purposes only and capacity additions will be driven by access to additional climate zones through specific transmission projects and the resources within the climate zones. Additional planning for capacity will be informed by the concurrent development of the Western Resource Adequacy Program ("WRAP"), a regional day-ahead market (EDAM with CAISO or Market Plus with SPP), as well as the development of new program and storage technologies. The actual operational capacity needs will be revisited as regional conversations and study processes progress.

9.4.1.1 Transmission as a gateway to diversification

Transmission expansion in the IRP falls into two categories, Northwest expansion and expansion to other regions. The Northwest expansion increases access to resources located in the Northwest. Portfolio selection of regional proxy transmission allows access to additional climate zones and markets that could offer diversified resource options across the planning horizon.[275]

The concept of regional load diversity as a benefit is embedded in the design of the WRAP. The WRAP is planning to standardize peak capacity planning for utilities operating in the WECC region that are not within an RTO. This program will facilitate the daily exchange of resources and obligations from resources in regions that are in excess capacity to regions that find themselves in deficit. As a key component of this program's many benefits, participating utilities would be able to reduce their individual Planning Reserve Margin ("PRM") based on the regional load diversity. Each utility would have had to procure or build to a much higher capacity target had it not been for the transparency and standardization that the WRAP offers.

Underlying the WRAP is the ability of each of these diversified regions to transmit energy back and forth. More benefits would be associated with this program if there were more transmission capacity between the regions.

Further discussion of the WRAP can be found in **Section 3.2, Regional planning: resource adequacy**, including program details, benefits and applicability in this and future IRPs.

[275] This does not preclude PGE from exploring transmission options to other regions.

9.4.2 Other transmission options

The transmission options tested in the 2023 IRP are proxy resources. Other transmission options, either to Northwest resource locations or to other regions, may also be available. Non-wire solutions may also be available to assist with transmission congestion. Including proxy transmission resources does not preclude PGE from exploring other transmission and/or non-wire options in future planning and acquisition work.

9.4.3 Bethel to Round Butte upgrade for future load service

With the recognition that transmission system capacity inventories on the BPA system are or are expected to be fully allocated, PGE must look for other commercial transmission development opportunities that could enable the affordable delivery of these new non-emitting resources to PGE's service area. It is widely accepted that most new resources will be located east of PGE's service area, on the other side of the Cascade Mountain Range. PGE owns one transmission line that crosses the Cascades, the Bethel-Round Butte 230 kV line that runs from approximately the Salem area to Round Butte near Madras, OR.

The Bethel-Round Butte 230 kV line was conceived in the 1960s as part of the Pelton-Round Butte Hydro project to deliver the output of the Pelton-Round Butte hydro facility to PGE's load in the Willamette Valley. Most of the line is constructed on wooden H-frame structures and is prone to damage from significant weather events, including wind, snow/ice and wildfires. During the wildfire season in 2020, a portion of the Bethel-Round Butte line was damaged by fire and had to be repaired, taking the line out of service for several months while those repairs were made, resulting in an extended transmission outage.

The eastern terminus of the Bethel-Round Butte 230 kV line, at Round Butte Substation, is then connected to the NWACI via the Round Butte-Grizzly 500 kV line. The Grizzly substation, jointly owned by PGE and BPA, is a significant substation on the NWACI. The NWACI is a collection of 500 kV transmission facilities that run from the John Day substation near the Columbia River to two different substations near the California-Oregon border, commonly referred to as the "COB" scheduling interface with the California Independent System Operator (CAISO). The NWACI facilities are primarily owned by PGE, PacifiCorp and BPA and jointly operated as a single path by BPA. Idaho Power will also have a scheduling point presence on the NWACI according to the term sheet announced by BPA, PacifiCorp and Idaho Power when BPA withdrew from being a funding partner for the Boardman to Hemingway project.

The Bethel-Round Butte 230 kV line is an existing facility with an existing Right of Way (ROW) across the Cascade Mountains. The acquisition and permitting of greenfield transmission line ROWs is the single most challenging part of developing new transmission infrastructure in

Oregon. For example, Idaho Power and PacifiCorp's Boardman to Hemingway project has been in various stages of the permitting process for nearly two decades. While there may need to be some additional ROW changes made to the existing Bethel-Round Butte ROW, because PGE already owns the ROW, it is expected to be significantly less complex than a new greenfield ROW acquisition would be.

Increasing the transfer capability between PGE's system and the NWACI will provide PGE with significant incremental direct access to solar and wind resource-rich parts of Oregon and connections with neighboring transmission providers and western markets.

Rebuilding the Bethel-Round Butte line from 230 kV to 500 kV would require replacing all the wooden H-frame structures currently in place with significantly taller and more robust steel lattice towers that are less susceptible to wildfire impacts.

Chapter 10. Resource economics

As Portland General Electric (PGE) makes the energy transition to a decarbonized system, there are many elements to be considered. The economics of resources represent a crucial element of these dynamics within IRP analyses. In this chapter, we describe the relevant costs associated with each resource and summarize the associated benefits. We also visualize how resource comparisons can occur outside portfolio analysis by comparing resources on a net cost basis, which becomes the basis for the avoided cost approach.

Chapter highlights

- Resource costs are primarily a function of fixed costs in the current planning environment.
- With different resources providing disparate benefits, such as providing energy benefits and storage providing capacity benefits, resource competition is evolving within those two categories.
- The inclusion of non-cost-effective Distributed Energy Resources (DER) provides insight into how their role can be further magnified in a decarbonized future.
- The relative costs and benefits of different energy and capacity resources that will form the basis for resource selections in portfolio analysis are displayed.

10.1 Fixed costs

Fixed costs for new resource options in the 2023 IRP consist of fixed capital carrying costs and fixed operating costs. Fixed cost calculations are based on resource-specific data and PGE-specific assumptions, including the cost of capital, long-term inflation and taxes. To streamline resource modeling, costs that are technically variable in nature (as in, costs vary with a resource's energy generation) are included in the fixed cost calculation (**Table 45**). These costs generally have a fixed generation pattern in PGE's dispatch modeling **Appendix H, 2023 IRP modeling details**. As a result of this dispatch modeling treatment, the annual generation of variable wind and solar resources is known and can be assumed as a fixed quantity. A summary of the types of items included in PGE's fixed cost modeling is provided in the following table.

Table 45. Fixed cost calculation data and assumptions

Fixed capital carrying costs	Fixed operating costs	Variable operating costs treated as fixed
Book and tax depreciation	Fixed operation and maintenance costs	Production tax credits (benefit)
Required return	Fixed wheeling costs	Variable energy resource (VER) integration
Property tax and federal and state income tax	Fixed fuel transportation costs	Land lease

Fixed costs for new resources are incorporated into portfolio analysis by applying the annualized fixed cost (on a kW-year basis) for each year in which the resource is included in the portfolio. Annualization of fixed costs occurs over the entire economic life of each resource. Annualized fixed costs are specified by resource vintage (commercial operation date or "COD") to capture the effects of capital cost declines and other time-varying parameters.[276] For each technology, the 2023 IRP analysis examines three different capital cost scenarios (Low, Reference, High) that capture uncertainties in future cost declines (**Figure 68, Figure 69** and **Figure 70**). Resources for which Reference Case capital cost data were derived from the Energy Information Administration Annual Energy Outlook (EIA AEO) information use the EIA reference cost trajectory. All other data are sourced from the National Renewable Energy Laboratory (NREL) Annual Technology Baseline (ATB). These cost projection futures are based on the following possible paths for technological advancement:[277]

Low – NREL ATB Advanced Scenario – Innovations far from market-ready today are successful in the future and have become widespread in the marketplace. New technology architectures could look different from those observed today – public and private R&D investment increases.

Reference – NREL ATB Moderate Scenario – Innovations observed in today's marketplace become more widespread and nearly market-ready innovations come into the marketplace. Public and private research and development (R&D) investment continues at current levels. This scenario may be considered the expected level of technology innovation.

[276] Commercial operation date is defined as the date after which all testing and commissioning have been completed and is the date on which a facility starts to generate power to earn revenue.
[277] NREL. 2021 Electricity ATB, available at: https://atb.nrel.gov/electricity/2021/definitions

High – NREL ATB Conservative Scenario – Historical investments come to market with continued industrial learning. Technology is like that deployed in the marketplace today, with a few changes from technological innovation. Public and private R&D investment decreases.

Figure 68. Fixed cost scenarios for new lithium-ion battery storage resource options

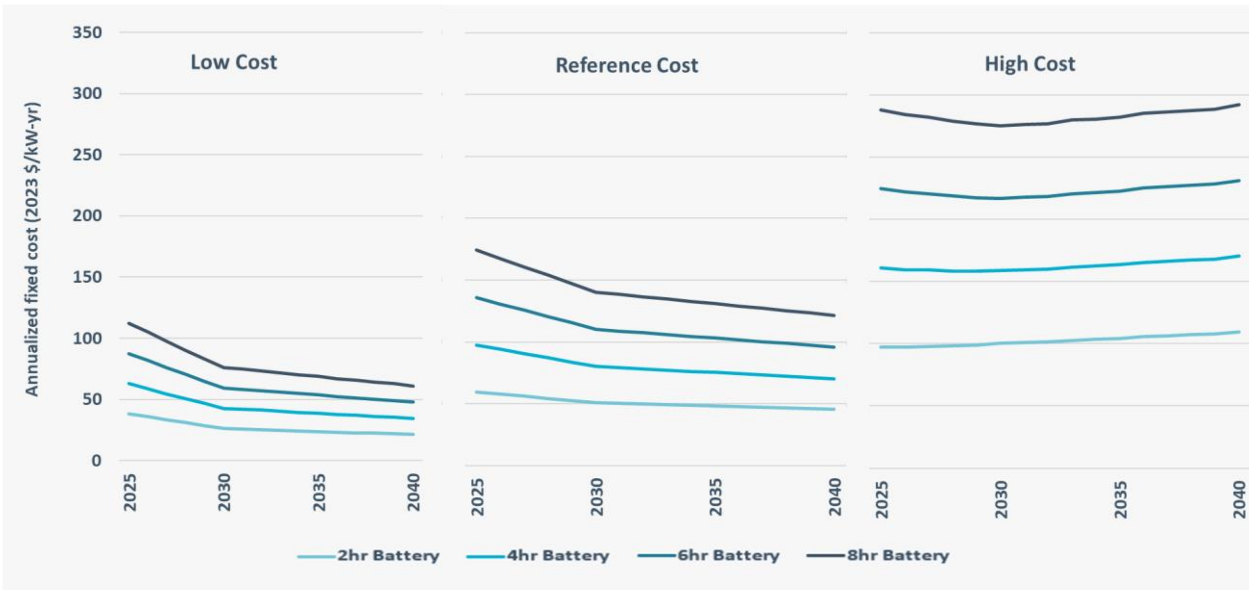


Figure 69. Fixed cost scenarios for new solar Photovoltaic (PV) resource options

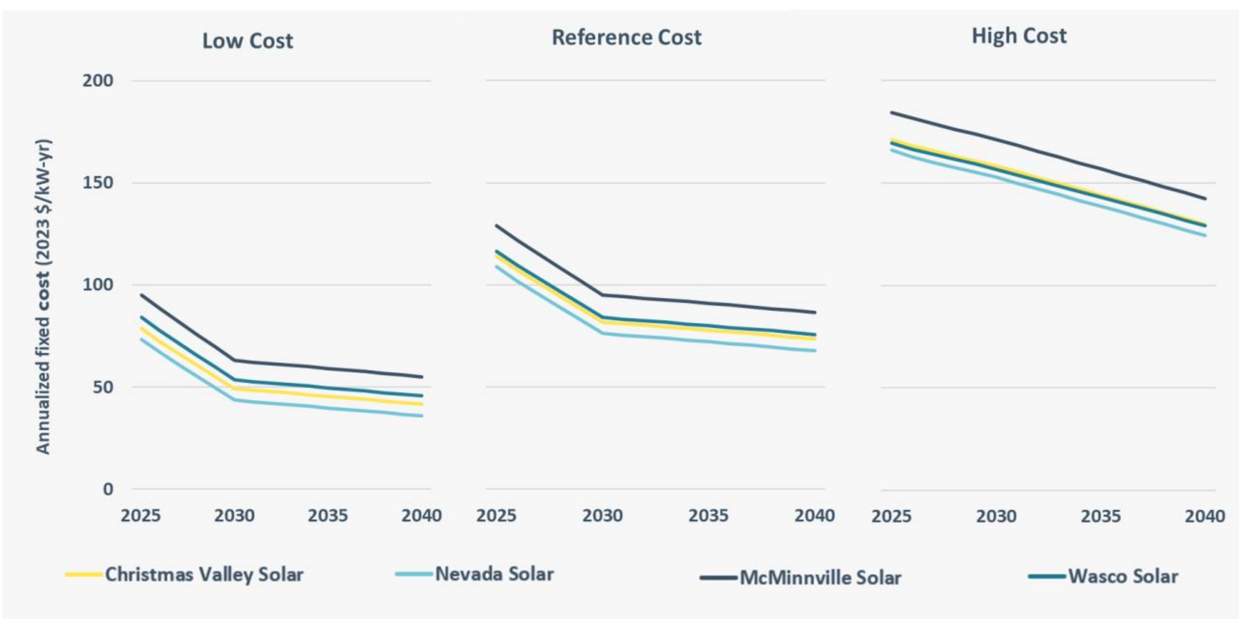
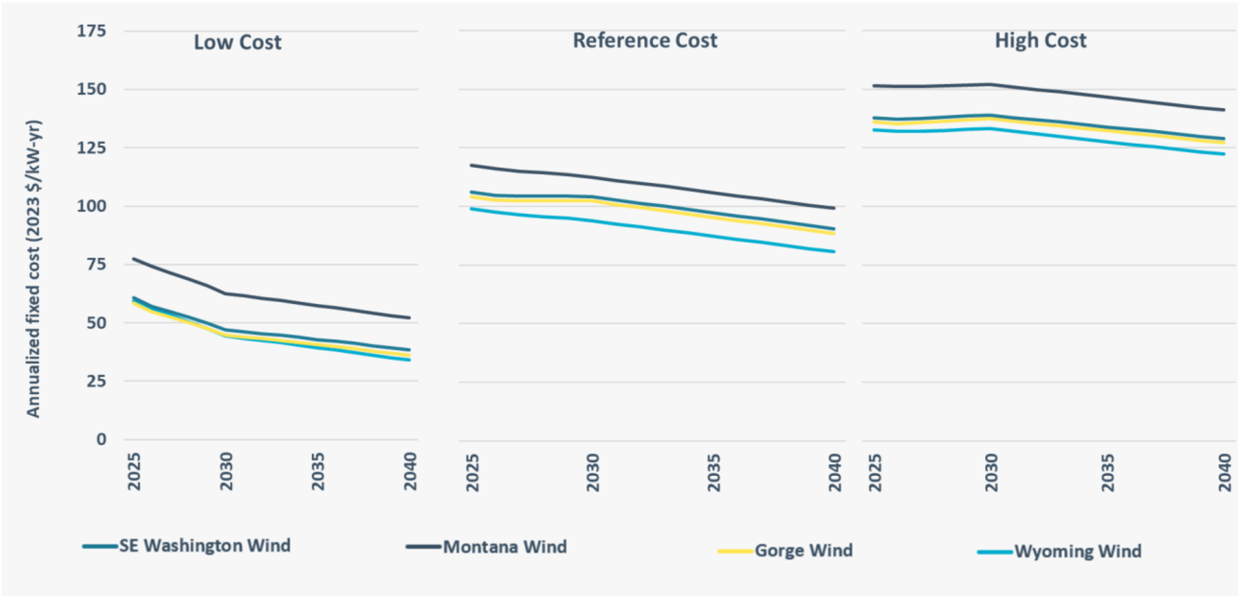


Figure 70. Technology maturity outlook for new onshore wind resource options



10.2 Variable costs

PGE assessed the total levelized variable cost of candidate new resources by performing hourly simulations from 2023 to 2043 of their dispatch across multiple price and input futures. The PZM simulation is used for this analysis as it can maximize resource value given resource availability, input prices and operational constraints. Total variable costs are composed of variable operation and maintenance costs, fuel and start-up costs and the costs associated with emissions, where applicable.[278] **Table 46** summarizes the levelized variable costs for each resource option under the Reference Case over the economic life of each resource option.

[278] All renewable resources are modeled as "must-run" with a fixed hourly shape that is varied by month as identified in **Appendix M, Supply-side options.** Daily operation might impose shutdowns for system balancing reason or because of transmission bottlenecks but such events cannot be foreseen and are therefore not embedded in resource evaluation. Although it is not possible to forecast the expected curtailment for any single resource, a simulation of regional potential curtailment of the total installed wind and solar resources for the Oregon and Washington macro area is presented in **Appendix N, Renewable curtailment**.

Table 46. Levelized variable cost (2023$/MWh) COD 2026[279]

	Levelized variable cost (2023$/MWh)	
	Reference Case	**Range**
Biomass	$51.44	$8.83 - $67.47
Combined-cycle combustion turbine (CCCT)	$20.50	$3.66 - $36.26
Combined-cycle combustion turbine carbon capture sequestration (CCCT_CCS)	$43.16	$5.53 - $149.5
Nuclear	$11.60	$2.61 - $12.11
(Simple-cycle combustion turbine (SCCT)	$28.39	$4.9 - $43.77
Small modular reactor (SMR)	$11.81	$2.52 - $12.91

10.3 Flexibility value and integration cost

Flexibility value and integration cost are critical components of variable and capacity resource economics. As defined in **Section 6.8, Flexibility adequacy**, flexibility adequacy needs encompass multiple operational value streams, including load following, regulation, spin, non-spin and renewable integration (ramping and forecast error mitigation). PGE defines flexibility value as the benefits provided by resources that help meet the system's flexibility adequacy target. Integration costs are the inverse of this benefit, generally attributed to VERs as their intermittent behavior increases the megawatts (MW) needed to meet flexibility adequacy targets.

PGE estimated the flexibility value and integration cost of new resources using Grid Path simulations of the PGE service area.[280] When additional resources are added to the system, some new resources can be used to serve load and avoid higher-cost market purchases, as well as enable the re-dispatch of existing resources, thereby affecting the flexibility needs of the system. At the same time, other resources may increase the flexibility needed. For new

[279] Renewable resources and battery storages do not incur fuel cost and do not emit CO2. Therefore, the associated variable costs are zero and not shown in the table. The range represents the semi-deviation of variable costs across all futures.

[280] Grid Path is an open-source modeling software developed by Blue Marble Analytics. This model is used to perform the flexibility assessment in the 2023 IRP. Additional details on Grid Path are available in **Ext. Study-IV, Flexibility study**

resource options, either a flexibility value or an integration cost is calculated by subtracting the market revenues associated with dispatching the resource from a change in the total system cost achieved by including the resource in the portfolio and dividing by the resource addition size.

PGE's estimates of flexibility values and integration costs for several new resources based on a 2026 and 2030 test year are summarized in **Table 47**. The difference in flexibility value between storage resources does not appear to be significantly impacted by duration, suggesting that most flexibility value is associated with flexibility constraints on short time scales (less than two hours).

Table 47. Flexibility value ($/kW-yr.) of new resources in 2026 and 2030

Resource	2026	2030
2-hour Battery	8.35	16.71
4-hour Battery	9.77	18.75
6-hour Battery	10.68	20.65
8-hour Battery	11.78	21.38
10-hour Pumped Storage	11.47	20.86

Table 48 displays the estimated costs of resource integration. As noted in the table, solar + storage resources increase integration costs in the short term but are expected to deliver system benefits (negative integration costs benefit the system) as the system evolves by 2030. This is not a function of any specific element but reflects the system's evolving nature between 2026 and 2030, driven by load growth, DERs and changes to supply.

Table 48. Integration costs ($/MWh) of new resources in 2026 and 2030

Resource	2026	2030
Gorge wind	2.57	3.90
WA wind	2.57	3.90
MT wind	0.95	1.46
Solar	2.84	3.30
Solar + Storage	0.33	-1.62

10.4 Energy value

PGE uses the PZM simulation to estimate the economic dispatch of existing generation resources, contracts and potential new resources using electricity prices and associated risk variable inputs from each price future. Economic dispatch leads dispatchable resources to generate when their dispatch costs are less than the market electricity price, subject to all modeled operational constraints.

Table 49 summarizes the Reference Case energy value and range of outcomes across the simulated price futures for each resource. These values are presented on a levelized basis, across each resource's economic life, for representative resources with 2026 commercial operation dates.

Table 49. Energy values for new resource options (2026 COD)[281]

	Levelized energy value (2023$/MWh)	
	Reference Case	**Range**
Solar PV Christmas Valley	$17.78	$2.83 - $30.08
Solar PV McMinnville	$16.85	$2.68 - $28.7
Solar PV Nevada	$19.51	$3.12 - $32.72
Solar PV Wasco	$16.50	$2.62 - $28.13
Wind Gorge	$21.97	$3.54 - $36.8
Wind MT	$26.39	$4.26 - $43.4
Wind SE Washington	$24.34	$3.92 - $40.28
Wind Wyoming	$27.18	$4.39 - $44.64
Wind Offshore	$23.55	$3.79 - $39.29
1:1 Hybrid Christmas Valley	$20.85	$3.12 - $35.05
2:1 Hybrid Christmas Valley	$18.63	$3.00 - $31.56
1:1 Hybrid McMinnville	$21.15	$3.18 - $35.69
2:1 Hybrid McMinnville	$18.29	$2.95 - $31.06
Geothermal	$24.46	$3.94 - $40.65
Biomass	$26.04	$4.09 - $64.44

[281] Ranges reflect upward and downward semi-deviations around the Reference Case across the market price futures.

	Levelized energy value (2023$/MWh)	
	Reference Case	Range
CCCT	$35.48	$6.61 - $54.19
CCCT w/ CCS	$49.81	$6.30 - $195.79
SCCT	$39.49	$6.63 - $59.41

10.5 Resource capacity contribution

In **Chapter 6, Resource needs**, the IRP describes future system capacity needs. These needs grow from a combination of expected load growth and resource loss. To fill these needs, the IRP adds new resources. To determine how much effective capacity new resources add to the system, PGE conducts an effective load-carrying capability (ELCC) study for each new resource.

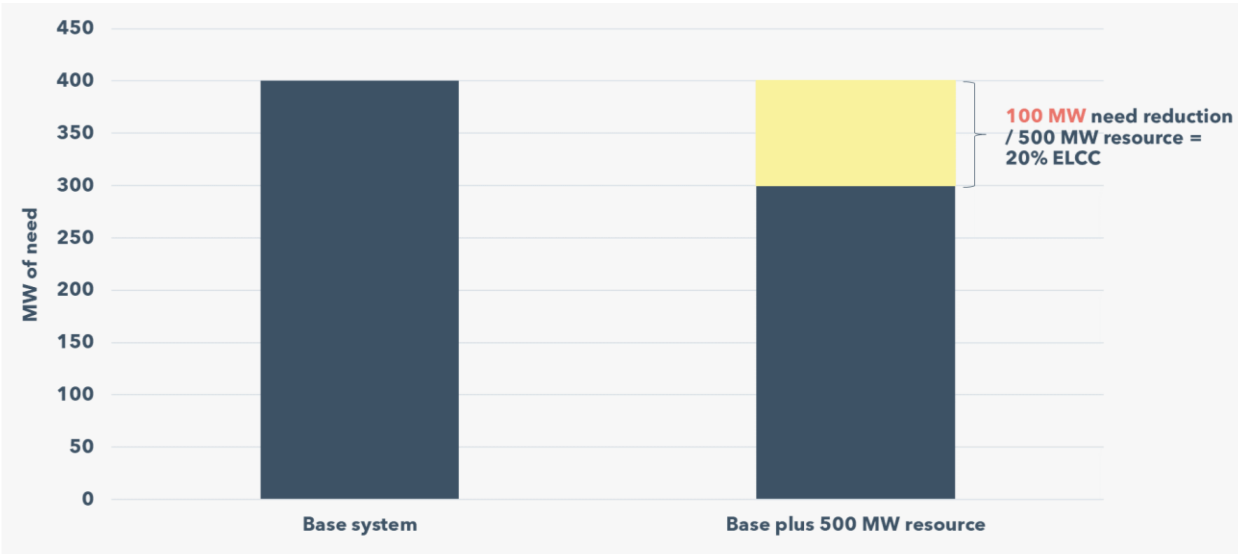
ELCC describes what percentage of a resource's nameplate capacity can be depended upon for resource adequacy needs. For example, the 100 MW nameplate capacity of a 4-hour battery may have an ELCC of 44 percent in the winter. This means that the 100 MW nameplate capacity of a 4-hour battery contributes 44 MW (100 * 0.44) towards reducing system capacity needs. If the starting system has a winter capacity need of 200 MW, after adding a 100 MW 4hr battery, the new capacity need is 156 MW (200 MW of need 44 MW of capacity).

PGE uses the Sequoia model to calculate ELCC values, following these steps:

- The model runs once to establish a baseline system capacity need
- The model runs again with a new resource added
- The difference in capacity need from the base system to the system with the resource added determines how much effective capacity the resource contributes
- The amount of effective capacity the resource contributes is divided into its nameplate to determine the ELCC value

For example, if the base system has a capacity need of 400 MW, and the same system plus a 500 MW nameplate resource has a capacity need of 300 MW. In that case, the resource provides 100 MW of effective capacity (400 minus 300). The effective capacity contribution,100 MW, is divided into the resource nameplate, 500 MW, to arrive at the ELCC value of 20 percent.[282] This example is graphically shown in **Figure 71.**

Figure 71. ELCC calculation example



The 2023 IRP tests resource ELCCs in the year 2026. The base 2026 power system has a resource deficit in both seasons. ELCCs can be calculated untuned, with a system deficit or tuned, where the base power system has had resources added until it is adequate or nearly adequate. For portfolio creation, PGE runs ELCC studies in an untuned system. PGE also runs a tuned ELCC study that includes the IRP Preferred Portfolio. Full ELCC values for portfolio creation are in **Appendix J, ELCC sensitivities**. Tuned ELCC values are in **Appendix K, Tuned system ELCCs**.

The 2023 IRP uses seasonal ELCC values rather than annual values. With many resources, ELCC values differ by season. For example, storage resources tend to have higher ELCCs in the summer than in winter. A seasonal approach helps ensure that the portfolio model (ROSE-E) can select an optimal and seasonally balanced portfolio.

Table 50 has untuned system ELCCs values for the first 100 MW of the IRP supply-side resources considered inside the Action Plan window. The resources use either firm or conditional firm 200hr transmission (CF200). For IRP modeling, CF200 transmission curtails the resource during the 100 highest load hours of the year, lowering ELCC values.[283] In IRP modeling, resources typically use CF200 transmission after firm transmission is exhausted.

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[282] This approach is similar to how the Northwest Power and Conservation Council determined resource capacity contributions in the 7th Power Plan (the Council calls this approach associated system capacity contribution).
[283] See **Appendix J, ELCC sensitivities** for more detail on how transmission products influence ELCC estimates.

Table 50. ELCC values for portfolio creation in year 2026[284]

Resource (100 MW nameplate)	Summer		Winter	
	Firm Tx	CF200	Firm Tx	CF200
Gorge Wind	47%	29%	39%	26%
SE WA Wind	15%	10%	35%	29%
MT Wind	28%	14%	61%	46%
McMinnville Solar	27%	9%	6%	6%
Wasco Solar	14%	6%	5%	4%
Christmas Valley Solar	23%	7%	8%	8%
McMinnville Solar Hybrid (1:1)	106%	55%	53%	43%
McMinnville Solar Hybrid (2:1)	72%	35%	30%	24%
Christmas Valley Hybrid (1:1)	102%	56%	55%	47%
Christmas Valley Hybrid (2:1)	63%	33%	33%	30%
2-hr battery	49%		27%	
4-hr battery	69%		44%	

ELCC values tend to decline due to resource saturation. For instance, the ELCC value of 100 MW of solar is higher than the ELCC value of 1,000 MW of solar. This occurs for various reasons, including:

- As more resource is added, the number of outages available to solve decreases. For example, if 500 MW of solar is added to a system, some outages during daylight hours may be solved. As a result, the next increment of solar added will have fewer outages available to solve and have a lower ELCC value.
- For storage resources, higher levels of resources may not be able to fully charge due to a lack of system energy. For example, there may be sufficient energy to charge 100 MW of a 4-hr battery reliably but not enough energy to charge 1,000 MW of a 4-hour battery. As a result, the 100 MW battery may have a higher ELCC value than the 1,000 MW battery.

[284] 2- and 4-hour batteries are modeled to be on-system. Accordingly, there are no transmission limitations included in ELCC calculations, equivalent to having firm transmission.

ELCC values reflect the percentage of the resource nameplate MW that can be relied upon for effective capacity. They do not reflect the total MW of effective capacity provided by the resource, which is equal to the ELCC value multiplied by the nameplate. Although 100 MW of a 4-hour battery in the winter has an ELCC of 44 percent, and 500 MW of a winter 4-hour battery has an ELCC of 32 percent, the 500 MW battery provides more effective MW of capacity (160 MW vs. 44 MW, in this example). More discussion on ELCCs is in **Appendix J, ELCC sensitivities**.

10.6 Capacity value

Portfolio analysis addresses system capacity needs through resource additions such that the resource contributions meet or exceed the model's seasonal capacity need constraints. More details on the modeling process are available in **Appendix H, 2023 IRP modeling details**.

Like in the 2019 IRP, the value of capacity outside of portfolio analysis is calculated by developing the net cost of capacity. The net cost of capacity is the cost required to get 1 kilowatt (kW) of capacity contribution from the next least cost capacity resource available to meet capacity needs, as shown in the following formula:[285]

$$Net\ cost\ of\ capacity\ for\ 1kW\ of\ capacity\ contribution\ =$$

$$(fixed\ costs + transmission\ costs\ + integration\ costs - tax\ credits - energy\ value - flexibility\ value)/_{ELCC}$$

Figure 68 (**Section 10.1, Fixed costs**) highlights the considerable uncertainty in the relative fixed cost trajectories of capacity resources such as batteries. **Table 47** in **Section 10.3, Flexibility value and integration cost**, quantifies the integration flexibility value of new capacity resources. ELCC of the first 100 MW of each resource is described in **Section 10.5, Resource capacity contribution**.

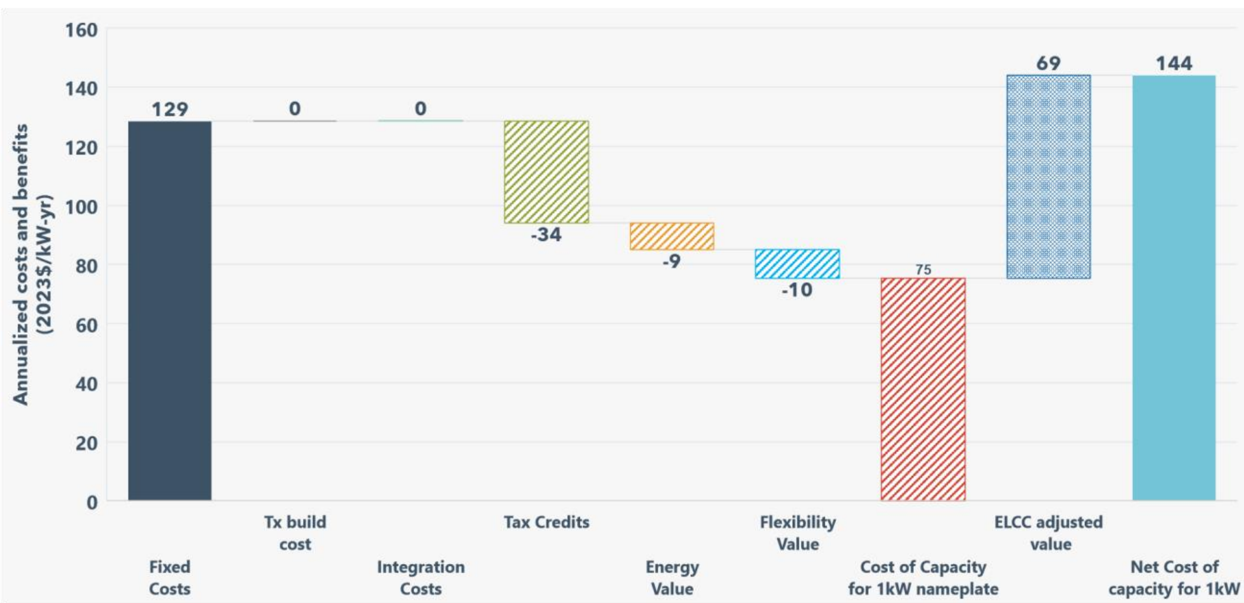
PGE has analyzed the Preferred Portfolio to determine the next least cost capacity resource available to meet capacity needs in 2026. The Preferred Portfolio is described in **Section 11.5, Preferred Portfolio**. From a capacity standpoint, the Preferred Portfolio adds 232 MW of 4-hr storage resource in 2026 to address the bulk of the capacity needs resulting from expiring contracts and load growth. Beyond this, through 2030, additional capacity is added through energy-dense resources such as wind, solar, community-based renewable energy (CBRE) and proxy transmission access to Nevada to add energy and capacity. Evaluating all

[285] This equation is also commonly referred to as the equation to determine the net cost of new entry (Net CONE) and is used to determine the cost of capacity when applied to the marginal resource that selected for capacity.

these resources based on the net cost of the capacity equation, we also determine that the next least cost capacity resource available to meet near-term capacity needs is a 4-hour battery.

The evaluation of the net cost of the capacity of a 4-hour battery is shown in **Figure 72**. The cost of the capacity of 1kW nameplate is calculated as the sum of all the applicable costs net of any benefits, including tax credits. This value, $75/kW-yr., represents the cost of capacity to procure a 1kW nameplate of batteries. PGE has calculated the cost of capacity to provide 1kW of capacity contribution, the metric that enables a fair comparison across resources. This is done by adjusting the capacity value of the 1kW nameplate by the ELCC of the battery at the marginal quantities of nameplate selected in the Preferred Portfolio. The ELCC of the 232MW nameplate of 4hr battery resource is 52 percent; by dividing $75/kW-yr. by 52 percent we determine that the net capacity cost is $144/kW-yr., which represents the avoided cost of capacity. The ELCC adjustment noted in **Figure 72** reflects the change in value after converting it from a 1kW nameplate to 1kW of capacity contribution, which is the metric that allows for a fair comparison across resources.

Figure 72. Deriving the cost of 1 kW of capacity contribution from a 4-hour battery



Using this new avoided cost of capacity of $144/kW-yr., the following equation can determine the capacity value of a resource at a nameplate value:

$$Capacity\ value\ of\ resource\ A\ =\ Capacity\ contribution\ of\ resource\ A\ *\ \$144/kW-yr$$

Table 51 shows the capacity value of the resources considered within the IRP. For capacity resources, the ELCC and corresponding capacity value (in $/kW-yr.) are shown to indicate the amount of capacity required of each resource to provide 100 MW of capacity contribution.[286] For energy resources, the ELCC and corresponding capacity value (in $/MWh) are shown corresponding to 100-megawatt average (MWa) addition sizes after accounting for the corresponding levelized capacity factors. These values reflect the effects of the declining marginal ELCC curves.

Table 51. ELCCs and associated capacity values[287, 288]

Resource	Annual ELCC for 100 MWa energy addition	Capacity value (2023$/MWh)
Gorge Wind	39%	15
Montana Wind	39%	15
SE Washington Wind	23%	9
Christmas Valley Solar	14%	9
McMinnville Solar	16%	12
Wasco Solar	14%	9
Energy efficiency bin 2	108%	156
Energy efficiency bin 1	118%	169
Christmas Valley 1:1 solar hybrid	78%	112
McMinnville 1:1 solar hybrid	78%	113
Nevada Solar + market access	100%	144
Wyoming Wind + market access	100%	144

[286] *E.g.*, if 500 MW of a capacity resource is required to achieve a 100-MW capacity contribution, the corresponding ELCC at 100-MW capacity contribution equals 20 percent.
[287] Energy efficiency bins represent the aggregate impact of several smaller energy efficiency technologies and strategies that are similar in their levelized costs. These are described in **Section 8.2.1, Additional energy efficiency.**
[288] The annual ELCCs shown in **Table 51** calculated with the average of the seasonal ELCC are for informational purposes and are meant to be directional indicators of capacity value. The actual value of capacity is estimated within portfolio analysis and is dependent on seasonal ELCCs.

10.7 Cost of clean energy

In previous IRPs, production cost and capacity expansion models used to develop portfolio analysis could rely on the market to meet energy needs based on available market prices. House Bill (HB) 2021 sets emissions targets, which are applied as emission constraints in the IRP. These constraints limit access to both specified and unspecified market purchases in the wholesale market that have embedded carbon content.[289] Thus, if the total energy needs of the system surpass the energy generated by both the existing non-emitting resources and the carbon-embedded energy, the model must rely on adding incremental generating resources to meet energy need. This represents a new cost associated with meeting energy needs through non-emitting resources. Conversely, this is a value to resources that avoid this new cost.

Within the IRP's portfolio analysis, these costs are accounted for; decisions about new resource additions fairly estimate all the costs and benefits associated with each potential supply-side option. However, the costs and benefits of many resources are currently estimated outside of the IRP. Current methods estimate energy value in one of two ways:

- The first relies on previous assumptions about market access.[290]
- The second involves determining the net cost of a new off-system VER. However, this option is only applied to resources assuming available transmission capacity.

If either of these methods is applied under the constraints the PGE faces today, they could significantly underestimate the energy value of potential new resources. Doing so would lead to a misidentification of resource economics, resulting in a higher cost system. The existing emissions and transmission constraints signal a need to reassess which values are used when comparing the costs of resources outside the IRP. Additional study is required to understand how estimating a new resource's energy value should be calculated outside the IRP.

10.8 Resource net cost

In **Section 10.6, Capacity value**, PGE applied the concept of the net cost of new entry to assess the capacity value. In this section, we apply the same concept to visualize the relative economics between resources and the dynamics seen within portfolio analysis. This approach was also used in the 2019 IRP and is common industry practice when evaluating resource economics. In this discussion, we define the net cost of new entry as the sum of all costs, such

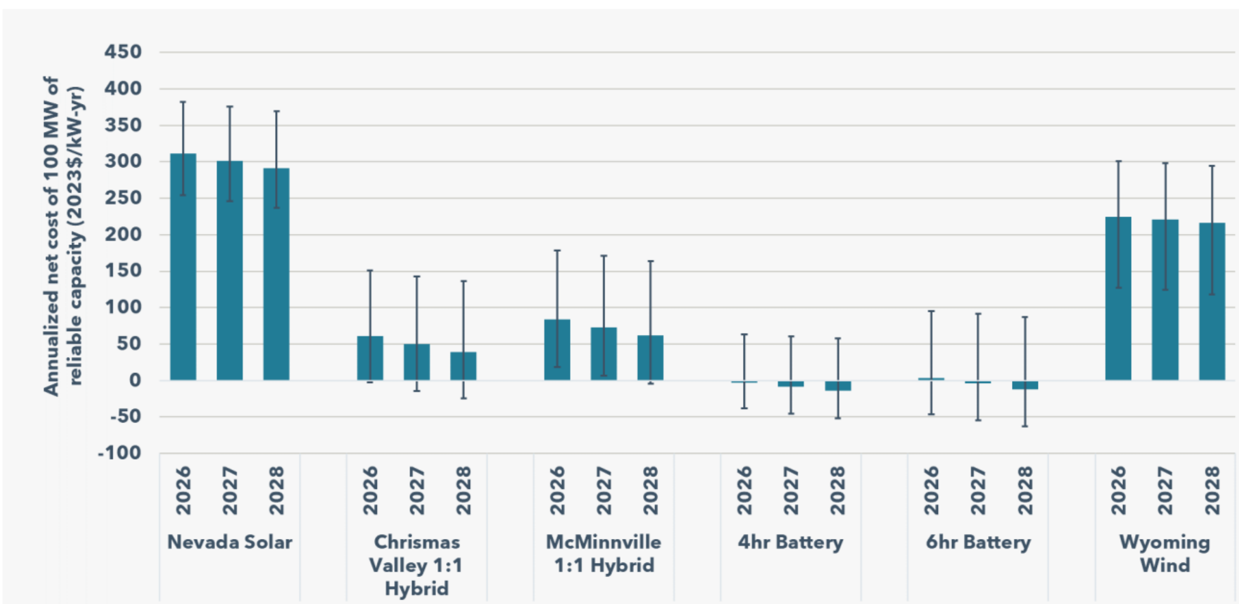
[289] Oregon Department of Environmental Quality (ODEQ) greenhouse gas (GHG) reporting rules (under ORS 468A.280) assign emissions to unspecified sources of energy that serve Oregon retail load.
[290] Generally involving summing the hourly product between generation and market prices.

as fixed, variable and integration costs, net of any benefits, such as tax incentives, and any value provided to the portfolio, including energy, flexibility, rCBI and capacity values. The following sections visualize the net cost of different capacity (in $/kW-yr.) and energy resources (in $/MWh).

10.8.1 Net cost of capacity resources

Figure 73 visualizes the net cost for the different capacity resources available in portfolio analysis. The 1:1 Christmas Valley solar+storage hybrid resource shows a net cost of $61/kW-yr. (2026 COD) while the net cost of a 4hr battery is -$3/kW-yr, highlighting the premium PGE customers would have to pay to procure that resource for capacity over a battery. The relative net costs also highlight the order of selection. For example, absent transmission constraints based only on the information in **Figure 73**, a model adding capacity while minimizing cost would select storage resources before any of the transmission expansion options.

Figure 73. Net cost for 100 MW of capacity contribution of capacity resources by COD[291]



[291] The "Error bars" of the column graph represent the aggregate uncertainty of the costs and benefits when estimating net costs. Uncertainty in costs stem from technology cost futures. Uncertainty in benefits stem from variation in energy value across price futures. The uncertainty in energy value is calculated as the upward and downward semi-deviation of the energy value relative to the Reference Case price future. Price futures are described in **Section 4.5, Uncertainties in price forecasts**.

10.8.2 Net cost of energy resources

The impact of transmission quality and availability is a significant element in the net cost of energy resources. To show this **Figure 74** illustrates the net costs of 100-megawatt average (MWa) of Gorge Wind (2026 COD) with the available transmission, with conditional firm transmission and with the South of Allston (SoA) upgrade cost, respectively. Changes to the transmission quality (from long-term firm to conditionality value firm) decrease the resource's capacity contribution and therefore capacity value. The difference of $6/MWh in the net cost between long-term firm and conditional firm transmission products represents the loss in value when selecting conditional firm transmission for the Gorge Wind resource. Additional costs of transmission upgrades are more intuitive as they increase the net costs of the resource.

Figure 74. Net cost for 100 MWa of Gorge Wind (2026 COD)

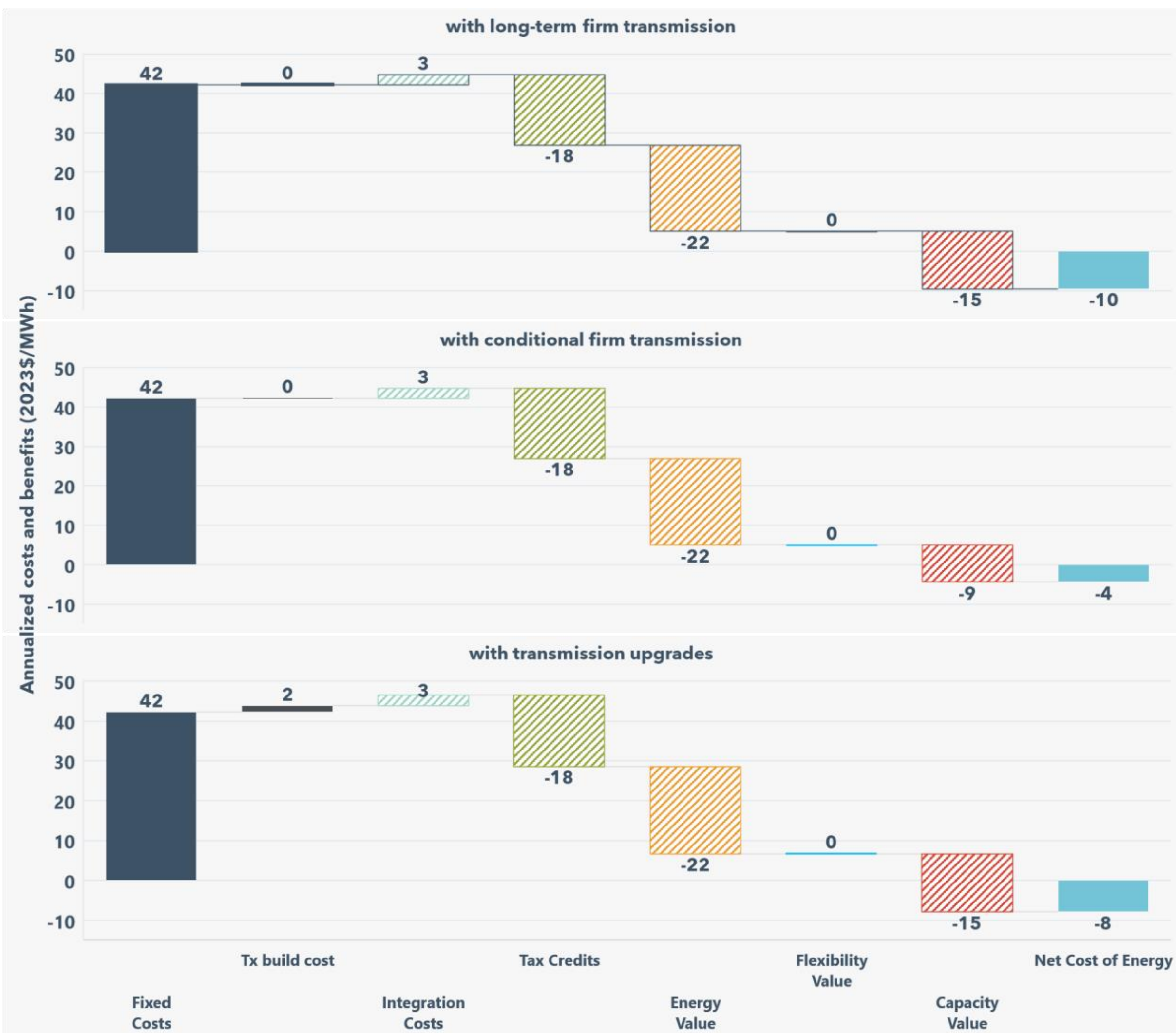


Figure 75 shows the net cost of 100 MWa of the new Wyoming transmission option to highlight the costs of new transmission and associated market access costs, showing the large incremental cost PGE customers will likely need to pay to address transmission constraints and access other regional markets. This premium also highlights why distribution-connected resources become increasingly cost-competitive, despite having higher fixed costs than their supply-side counterparts.

Figure 75. Net cost for 100 MWa of Wyoming Wind transmission (2026 COD)

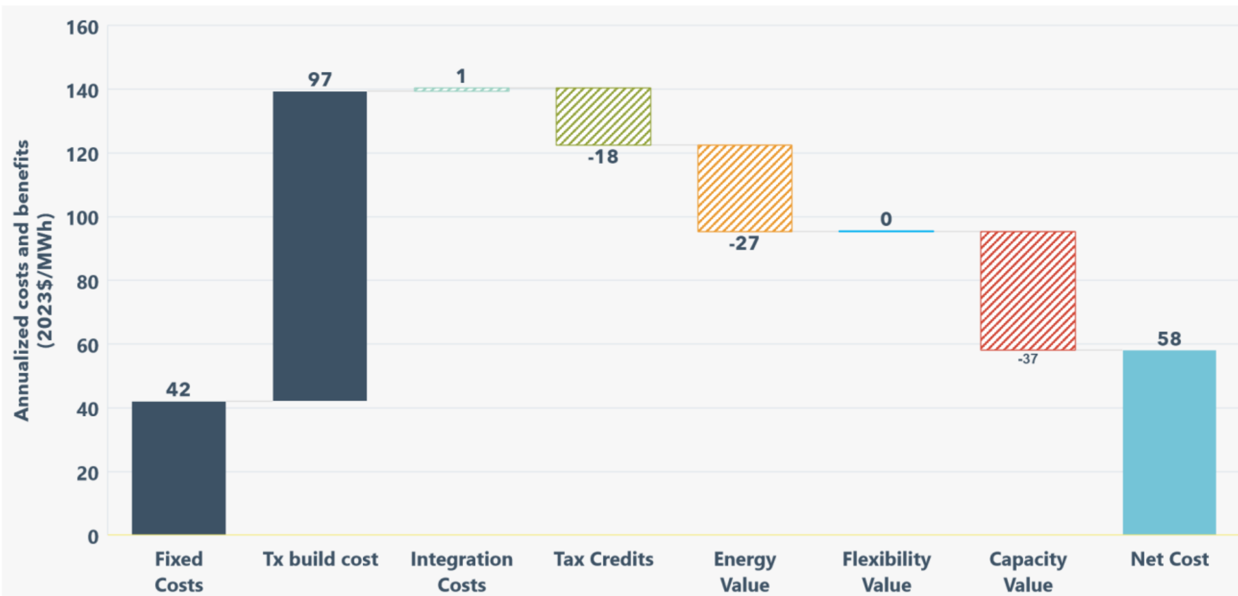
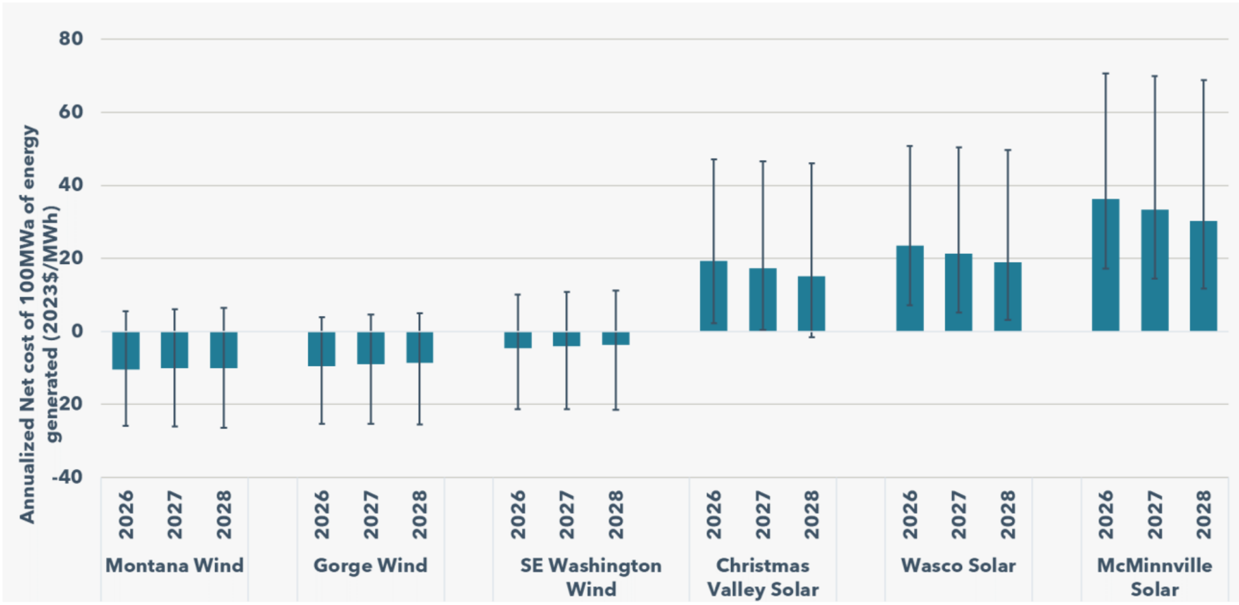


Figure 76, like **Figure 73**, shows the net cost of different resources. However, **Figure 76** focuses on energy resources such as solar and wind and represents the net cost for 100 MWa of a new solar and wind. While net costs of new resources described previously provide helpful insights for understanding the economic tradeoffs between specific resource actions, this simplistic view of resource economics neglects risks associated with future uncertainties and potential interactions between resources and constraints. These are investigated through portfolio analyses described in **Chapter 11, Portfolio analysis**.

Figure 76. Net cost for 100 MWa of solar and wind resources by COD

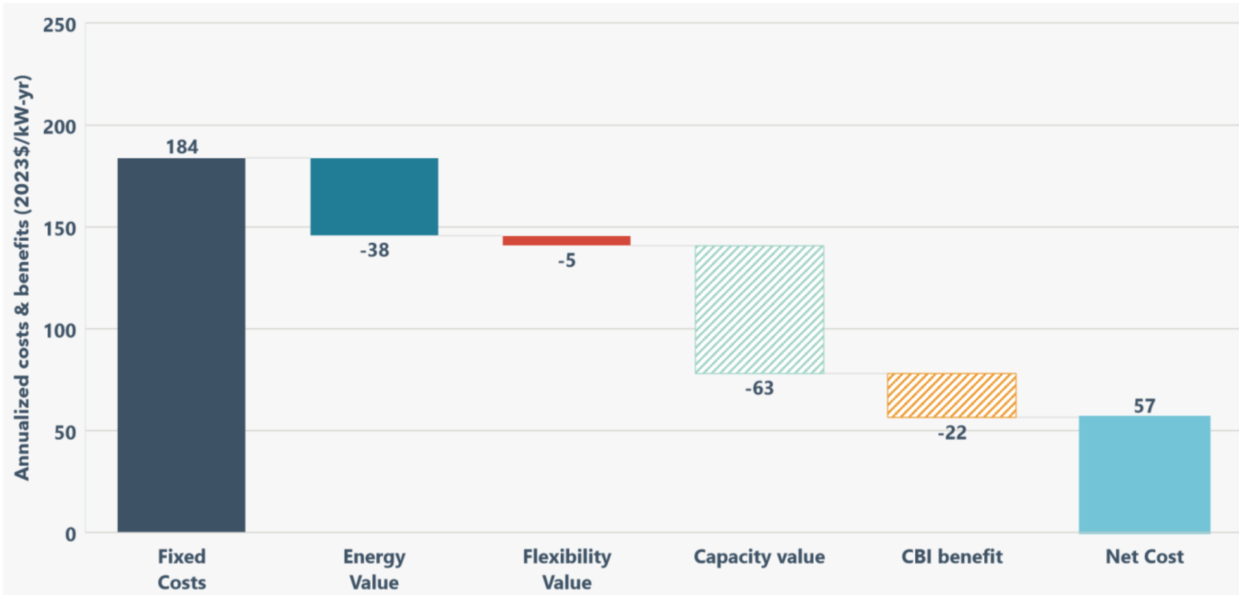


10.9 Resource community benefits indicators

Resource community benefits indicators (rCBI) aim to inform and provide a mechanism to track progress on specific outcomes achieved through CBRE actions. For this first Clean Energy Plan (CEP) filing, PGE developed a 'CBRE favored' approach, like the 1980 Northwest Power Act for energy efficiency.[292] These methods leverage the logic that in planning, we cannot necessarily know which benefits are applicable for each resource as they depend on many factors, such as the resource location and the nature of the resource. For rCBIs, PGE created a CBRE resource within the construct of its resource portfolio that reduces the fixed cost of the three proxy resources evaluated by 10 percent. When considering which resource to select to meet system needs, the capacity expansion model ROSE-E will evaluate the costs and benefits associated with all resources available; the rCBI benefit will lead to the selection of CBREs over an otherwise equivalent resource. **Figure 77** illustrates the impact of the rCBI benefit in the net cost calculation. See **Section 7.1.3, Resource community benefits indicators**, for more details on rCBI.

[292] Northwest Power Act, 16 United States Code Chapter 12H (1994 & Supp. I 1995). Act of Dec. 5, 1980, 94 Stat. 2697. Public Law No. 96-501, S. 885, §839a(4)(D), available at: https://www.congress.gov/96/statute/STATUTE-94/STATUTE-94-Pg2697.pdf

Figure 77. Net cost of a microgrid CBRE (2026 COD)



Chapter 11. Portfolio analysis

The 2023 Integrated Resource Plan (IRP) represents a significant evolution in Portland General Electric's (PGE's) portfolio analysis. PGE has conducted a comprehensive and robust portfolio analysis with stakeholder input to determine a Preferred Portfolio that best balances cost, risk, the pace of decarbonization and community benefits. Portfolio analysis considers needs such as capacity, energy, flexibility and policy as described in **Chapter 6, Resource needs**, and **Chapter 3, Planning environment**, along with resource options such as distributed energy resources (DERs), supply-side options and new transmission options as described in **Chapter 8, Resource options**, and **Chapter 9, Transmission**.

In this chapter, we first describe the portfolio design requirements that underpin portfolio analysis. On this foundation, we explore specific questions and dynamics within this IRP to inform how we can best balance cost, risk, the pace of decarbonization and community benefits. The insights of these investigations form the basis for the Preferred Portfolio, which is described in detail. Lastly, we conduct various sensitivities using the Preferred Portfolio to examine relevant questions in resource procurement.

Chapter highlights

- Portfolios are designed to meet emissions targets, adequacy needs, transmission and procurement constraints and are solved across all 351 permutations of price futures, Need Futures and technology cost futures.
- Portfolio analysis provides insight on the need for transmission, the cost and risk implications of different greenhouse gas (GHG) glidepaths, community-based renewable energy resources (CBREs) and the role for additional DERs in a decarbonized future.
- The insights from these analyses form the basis of the creation of the Preferred Portfolio.
- The Preferred Portfolio represents the combination and timing of resources that best balance costs, risk, emission reductions and community benefits for customers under the assumptions used in the IRP process.

11.1 Portfolio design requirements

PGE designed 39 distinct portfolios to test key questions concerning potential resource acquisition strategies. Each portfolio was analyzed across a wide range of scenarios varying combinations of potential future conditions for need, price and technology costs using the capacity expansion model ROSE-E.[293] For each portfolio, ROSE-E is given a fixed set of required resource acquisitions that meet a portion of needs. ROSE-E determines the optimal combination of resources to fill the remaining resource need while minimizing system costs for each of the 351 scenarios described in **Section 4.6, Addressing uncertainties**, subject to a variety of constraints.[294] Using this approach, 117 resource buildouts are produced for each portfolio, including one for the Reference Case scenario, which models Reference Case conditions for need, price and technology cost futures.[295]

ROSE-E has the ability to select new resources from a subset of the options described in **Chapter 8, Resource options**, and the transmission options described in **Section 9.4.1, Proxy transmission options identify transmission need**, and bases its decision on the economics presented in **Chapter 10, Resource economics**. To aid the reader, **Table 52** defines key terms within portfolio analysis.

Table 52. Defining key terms within Portfolio Analysis

Terms	Description
Portfolio	A fixed set of resource decisions set in all scenarios. The model (ROSE-E) creates resource buildouts around those choices in each scenario.
Scenario	Refer to elements that are varied within portfolio analysis resulting in multiple resource buildouts. Some of the predefined scenarios are need, technology cost, price, hydro.
Resource buildout	Least cost set of incremental resource additions given a set of specific input conditions such as a portfolio and scenario.
Portfolio sensitivities	Sensitivities test the robustness or provide additional information on the Preferred Portfolio by forcing changes in resource constraints or other inputs.

[293] ROSE-E was developed prior to the 2019 IRP and was used to conduct portfolio analysis in that filing. More information about the use of ROSE-E in the 2023 IRP can be found in **Appendix H, 2023 IRP modeling details**. Details on the use of ROSE-E in the 2019 IRP: *In the Matter of Portland General Electric Company, 2019 Integrated Resource Plan*, Docket No. LC 73, Order No. 20-152 (May 6, 2020), available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

[294] A small number of portfolios designed to test optimization assumptions differ from this protocol by either minimizing cost only with respect to the Reference Case future, or only for a subset of year of the analysis.

[295] System costs are evaluated across futures for price, hydro condition, technology cost and need (13 x 3 x 3 x 3 = 351), while resource buildouts vary across futures for price, and technology cost only (13 x 3 x 3 = 117).

Portfolios are subject to several constraints described in the following sections that ensure portfolios add sufficient resources to meet forecast capacity and energy needs and comply with all applicable regulatory requirements. All portfolios are designed to meet a uniform set of constraints and a default set of assumptions except where individual constraints and assumptions are altered on a portfolio-group-specific basis to test questions of interest. Using a consistent set of assumptions within groups of portfolios allows comparison of resource buildouts and portfolio scoring metrics while isolating the impacts of the specific assumptions being tested.

11.1.1 GHG emissions

Greenhouse gas (GHG) emissions limits are imposed on each portfolio consistent with House Bill (HB) 2021 requirements, limiting GHG emissions to a maximum of 1.62, 0.81 and 0 million metric tons in 2030, 2035 and 2040, as shown in **Figure 26** in **Section 5.1, HB 2021 targets**. HB 2021 does not explicitly set GHG limits for years prior to 2030 but does require continual progress toward meeting the clean energy targets of 2030.[296]

Determining the rate of GHG emissions reductions or GHG glidepath that best balances cost and risk is evaluated in portfolio modeling, which are described in **Section 11.4.1, Decarbonization glidepath portfolios.** Additional information about GHG emissions in the IRP is in **Chapter 5, GHG emissions forecasting**.

11.1.2 Resource adequacy

All portfolios are constrained to meet PGE's resource adequacy requirements in both summer and winter during all years. The calculation of capacity need is described in **Section 6.6, Capacity need**. Capacity needs in portfolio construction are met by adding new resources, which provide the capacity contribution described in **Section 10.5, Resource capacity contribution**.[297]

[296] HB 2021, Section 4 (4)(e), available at: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

[297] In addition to the new resource options described in **Section 8.5, Post-2030 resource options**, each portfolio is given 200 MW of capacity and 90MWa of energy in the years 2026 through 2030 to represent the expected extension of a portion of PGE's existing non-emitting capacity contracts.

11.1.3 Generic resources

Due to the presence of transmission constraints, the quantity of proxy resources available for selection in the model is insufficient to meet energy and capacity needs through 2043 in most portfolios. To allow the model access to the energy and capacity needed beyond the amount available through proxy resource options, all portfolios have access to two 'Generic' non-emitting on-system resources that are not subject to transmission constraints.

- 'Generic Cap' provides 100 percent effective load-carrying capacity (ELCC) and has no associated energy.
- 'Generic VER' provides both energy and capacity, with an ELCC curve and capacity factor defined by a weighted average of proxy variable energy resources (VER) in the Preferred Portfolio.

The generic resources have high costs so that they are available for the model to meet needs without competing economically with proxy resource options. Generic resources have fixed costs equal to 105 percent of the highest-cost proxy resource option (NV Tx). The model has access to 500 megawatts (MW) of each generic resource each year starting in 2026. All else equal, portfolios that require earlier or heavier reliance on generic resources will have increased costs relative to others.

11.1.4 Renewable portfolio standards

All portfolios presented in the IRP comply with Oregon's renewable portfolio standard (RPS) requirements described in **Section 6.7, RPS need**, through the entire planning horizon. ROSE-E simulates the generation, banking and retirement of Renewable Energy Certificates (RECs) from RPS-eligible resources and enforces the five-year lifetime limit on banked RECs consistent with Senate Bill (SB) 1547. For each portfolio to meet RPS requirements in each Future, the retired RECs in each year must meet or exceed the RPS obligation in that year. The resulting RPS position of the Preferred Portfolio is shown in **Section 11.5.2, Resulting RPS position**. With the introduction of HB 2021, the amount of non-emitting resources that need to be built to comply with emissions targets of HB 2021 is larger than the amount needed to comply with RPS requirements. Accordingly, RPS compliance is not forecasted to drive resource additions in this IRP.[298]

[298] It could be the case that PGE acquires non-emitting generation that helps move towards HB 2021 emissions targets but not RPS obligations. However, given the limited availability of non-emitting but non-RPS-qualifying generation the sizeable forecasted additions of RPS-qualifying generation (shown in **Section 11.5.2, Resulting RPS position**, and the size of PGE's REC bank it is a reasonable conclusion that RPS compliance will not drive future resource acquisition.

11.1.5 Energy position

To ensure that incremental resource additions do not put PGE's portfolio in a consistently long position (generating more energy than is needed to serve customers), the amount of energy added by new resources in portfolio modeling is constrained to not exceed PGE's forecasted net market position by more than 100-megawatt average (MWa) in any given year after 2026. The energy surplus constraint is relaxed between 2024-2026 to allow for a long energy position before adding new resources. In addition, the energy surplus constraint is relaxed in certain years for some portfolios to allow the testing of resource options that would otherwise violate the constraint or to avoid unintended confounding effects on resource buildouts that prevent the comparison of portfolios within a given portfolio category. In preventing the building of an overly long portfolio, the energy surplus constraint also helps ensure that the resource buildout contains an appropriate amount of dispatchable capacity resources and is not overly reliant on variable energy resources.

11.1.6 Procurement constraints

PGE has not imposed general limits on the total amount of resources that can be added each year, as PGE seeks to streamline the existing procurement process. To test the impact of procurement limitations, resource limitation constraints are imposed as part of sensitivity analysis, as described in **Section 11.7, Sensitivities**.

11.1.7 Transmission constraints

As renewable energy development grows around the West, the availability of transmission to move energy from the point of generation to load centers is becoming scarce (see **Chapter 9, Transmission**, for more detail). To account for this increasingly important consideration in the siting of resources, we incorporated contractual transmission constraints in portfolio analysis. A detailed description of the methodology, including derivation of transmission inventories, can be found in **Appendix H, 2023 IRP modeling details**.

11.2 Portfolio scoring

Portfolios were evaluated based on the scoring metrics described in **Table 53**. Comparing portfolios consistently based on these metrics allows PGE to quantify the impact of changes in key assumptions on portfolio outcomes. The direction and magnitude of change in these metrics generate beneficial insights that ensure the Preferred Portfolio and Action Plan are robust and represent the best combination of costs and risks.

Table 53. Portfolio scoring metrics

Metric	Description	Units
Cost	Net present value of revenue requirement (NPVRR), calculated for each of the 351 future scenarios and presented for the Reference Case for the analysis timeline (2024-2043).	Million 2023$
Variability	Semi-deviation of NPVRR across all futures, relative to the Reference Case. This metric captures the potential variation in cost outcomes across futures, considering only futures in which NPVRR exceeds the Reference Case. Portfolios with low variability scores tend to provide more cost certainty and lessen the customer's impacts of higher-than-expected cost conditions.	Million 2023$
Severity	The tail value at risk (TailVAR) at the 90th percentile of the NPVRR across futures. This metric measures the potential magnitude of very high-cost outcomes across all futures. Portfolios with low severity scores tend to have less costly worst-case scenarios for customer cost impacts.	Million 2023$
Community Benefits	This metric reflects the portfolio benefits associated with the CBRE additions that deliver community benefits. These benefits are further described in Section 14.2.3.2, CBI community engagement.	N/A

11.3 Yearly price impacts

In this IRP PGE has developed a new model to estimate the annual price impacts of a given portfolio.[299] The Annual Revenue-requirement Tool (ART) was created to provide an additional dimension in the analysis of forecasted system cost when comparing different portfolios. The ART was developed specifically for IRP purposes to evaluate yearly price impacts of planned proxy new resource additions. The model uses the existing and

[299] Developing this model satisfied the 2019 IRP Commission requirement "…PGE will need to continue to evaluate and balance the tradeoffs between more certain near-term rate impacts and less certain long-term projected cost savings.", Docket LC73, Order No. 20-152 at 19, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf, and ORS 469A.400 469.475, Section 4(4)(b) Clean Energy Plans; electric companies, from the CEP as detailed in Chapter 1, topic 3 of the UM 2225 Investigation into Clean Energy Plans Workplan Update and Straw Proposal, regarding annual metrics measuring the impacts of actions, at 7-8, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah11736.pdf.

incremental proxy resource costs described in **Chapter 9, Transmission** and Reference load presented in **Chapter 6, Resource needs**.

The model incorporates the impact of market sales on an annual basis and includes different combinations of ownership structures and tax incentives modeled for each portfolio.[300] Market purchases and thermal sales are calculated on an annual basis within the GHG Intermediary model and imported to ART. Further, ART only focuses on existing and new generating resources, including the associated transmission costs. Estimates do not include costs from the rest of PGE, such as those associated with administrative costs, grid modernization, other transmission and distribution maintenance and upgrades, wildfire mitigation or actual generation costs. Caution is warranted in interpreting these estimates, as these values reflect a change in forecasted annual costs of real and proxy generating assets that only represent a subset of PGE's total annual cost. Accordingly, these yearly price impacts do not represent actual customer price impacts (expressed either as total or a percent) as they only focus on planned generation cost changes and do not incorporate any other cost changes across PGE.

11.4 Portfolio analysis results

PGE has tailored the portfolio analysis in the 2023 IRP to answer key questions in resource planning and leverage insights from those answers in the creation of the Preferred Portfolio. These key questions are explored through different portfolio categories, comprised of multiple portfolios hand-designed to explore the impact of specific potential PGE actions or changes to the operational, economic, and/or policy landscape within which PGE operates. These categories are presented and described in **Table 54**. Some portfolios that PGE cannot effectuate have been intentionally developed to study specific questions. These portfolios are listed as informational in the relevant portfolio categories.

Table 54. List of portfolio categories and their purpose

Portfolio categories	Purpose
Decarbonization glidepath	Explore the relationship between the rate of emissions reduction to serve retail load, cost and risk
Transmission	Study the need for transmission, the timing of this need and the corresponding magnitude needed over time to reliably decarbonize

[300] Modeling assumption of the ownership structures do not impact or reflect future procurement approaches or prejudge outcomes of future procurement processes.

Portfolio categories	Purpose
Community-Based Renewable Energy (CBRE)	Explore the relationship between costs, risk and community benefits
Additional Energy Efficiency and Demand Response	Determine if and how the role of these resources could change with the changing planning environment
Optimized	Explore the relationship between minimizing costs in the short-term and the entire planning horizon and cost of constraining the model
Targeted policy	Inform stakeholder discussions on specific policy questions
Emerging technology	Understand the potential impacts of emerging technologies

All portfolios assume that a portion of PGE's existing long-term contracts for energy and capacity from non-emitting sources set to expire at the end of 2025 are renewed through the end of 2030, representing 90 MWa of energy and 200 MW of capacity contribution annually.

11.4.1 Decarbonization glidepath portfolios

PGE explored the relationship between the rate of emissions reduction to serve Oregon retail load, cost and risk with the Decarbonization Glidepath portfolios (**Table 55**). These portfolios are designed to meet or exceed HB 2021's GHG emissions targets using a variety of glidepaths or trajectories. Decarbonization Glidepath portfolios have identical assumptions and inputs aside from their differing GHG emissions reduction pathways to isolate insights on the impacts of the pace of decarbonization on portfolio costs and risks.[301]

The 'Linear decline, 'Front-loaded decline' and 'Back-loaded decline' portfolios meet HB 2021 emissions reductions targets using different rates of emissions reductions ("glidepaths") from 2026-2030 (as shown in **Table 55**) and converge on a single glidepath thereafter.

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[301] Because these portfolios have different energy position inputs, they are not subjected to the energy surplus constraint described in **Section 11.1.5, Energy position**. For the purposes of comparison across these portfolios, the imposition of an energy surplus constraint introduces confounding impacts on resource additions, preventing level comparison.

Portfolios '100 percent emissions reduction by 2035' and 'Two-yr forward shift in targets' rely on glidepaths that achieve emissions targets ahead of regulatory deadlines.

Table 55. List of decarbonization glidepath portfolios

Portfolios	Portfolio condition
Linear decline	Meeting 2030 targets by adopting a linear path in emissions reduction (each year must provide the same reduction in emissions as the previous year)
Front-loaded decline	Meeting 2030 targets by front-loading emission reduction (each year must provide half the reduction in emissions of the previous year)
Back-loaded decline	Meeting 2030 targets by rear-loading emission reduction (each year must provide twice the reduction in emissions of the previous year)
100% emissions reduction by 2035	Achieving 100% GHG emission reduction by 2035
Two-yr forward shift in targets	Achieving each carbon target two years ahead of schedule 80% by 2028, 90% by 2033 and 100% by 2038

Figure 78 visualizes the annual emissions of each of the decarbonization glidepath portfolios. Differences in the rate of decarbonization across the five portfolios can be seen starting in 2026.[302] When emissions targets are attained ahead of schedule, as in '100 percent emissions reduction by 2035' and 'Two-yr forward shift in targets', cumulative emissions from 2024-2043 are reduced relative to on-time attainment with a linear glidepath (**Figure 79**). Amongst the three portfolios that achieve targets on-time with different glidepaths to 2030 ('Linear decline', Front-loaded decline' and 'Back-loaded decline'), the front-loaded glidepath produces the lowest cumulative emissions throughout the portfolio modeling time-horizon and the back-loaded decline in produces the largest quantity of cumulative emissions (**Figure 80**). The linear emissions reduction glidepath falls in the middle, producing approximately 28.68 MMT CO2e throughout the planning horizon (**Figure 78**). **Appendix O, Thermal Operations/ Output** displays total emissions associated with serving retail load and market sales in each of these three decarbonization glidepaths.

[302] Forecasted emissions for 2023 through 2025 are based on the expected impact of the 2021 All-Source request for proposals (RFP), PGE's Green Future Impact (GFI) program, load growth and other factors. Forecasted emissions from 2026 onwards (when portfolios are able to add incremental resources) are from one of the five tested glidepaths.

Figure 78. Decarbonization glidepath portfolios

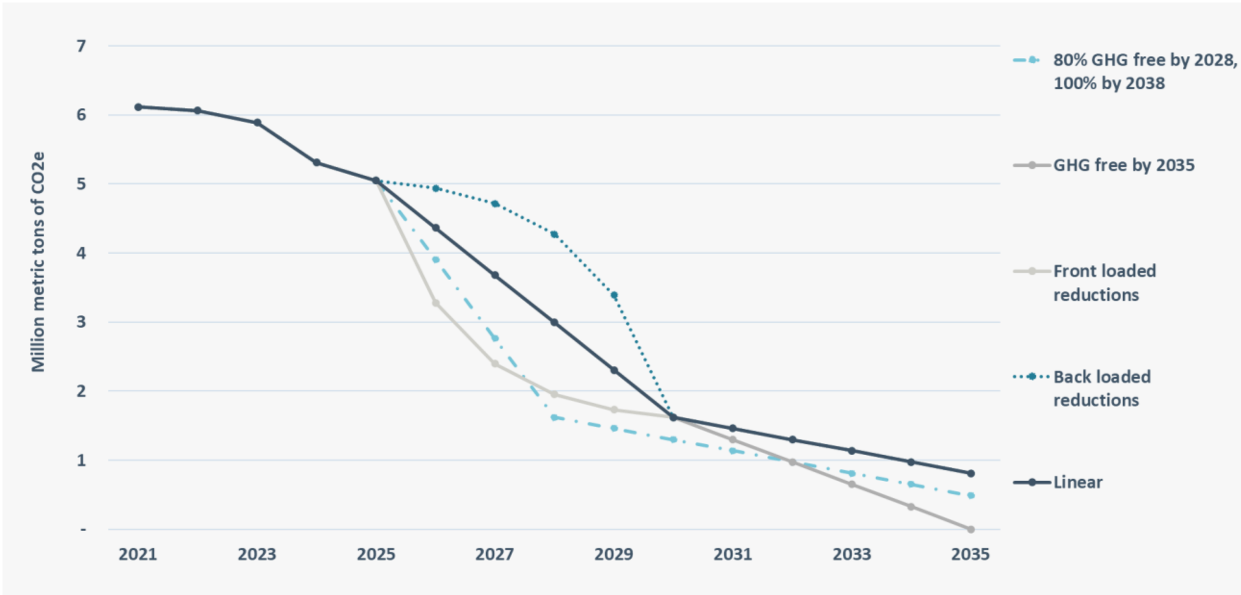


Figure 79. Cumulative emissions 2024-2043, accelerated decarbonization glidepath portfolios

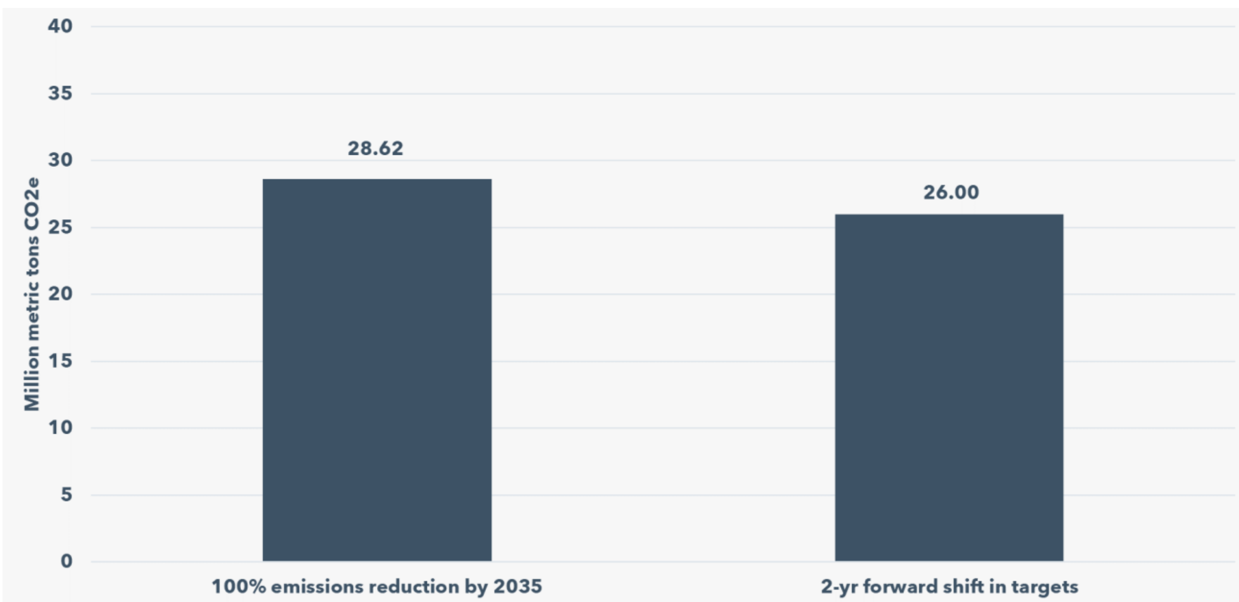
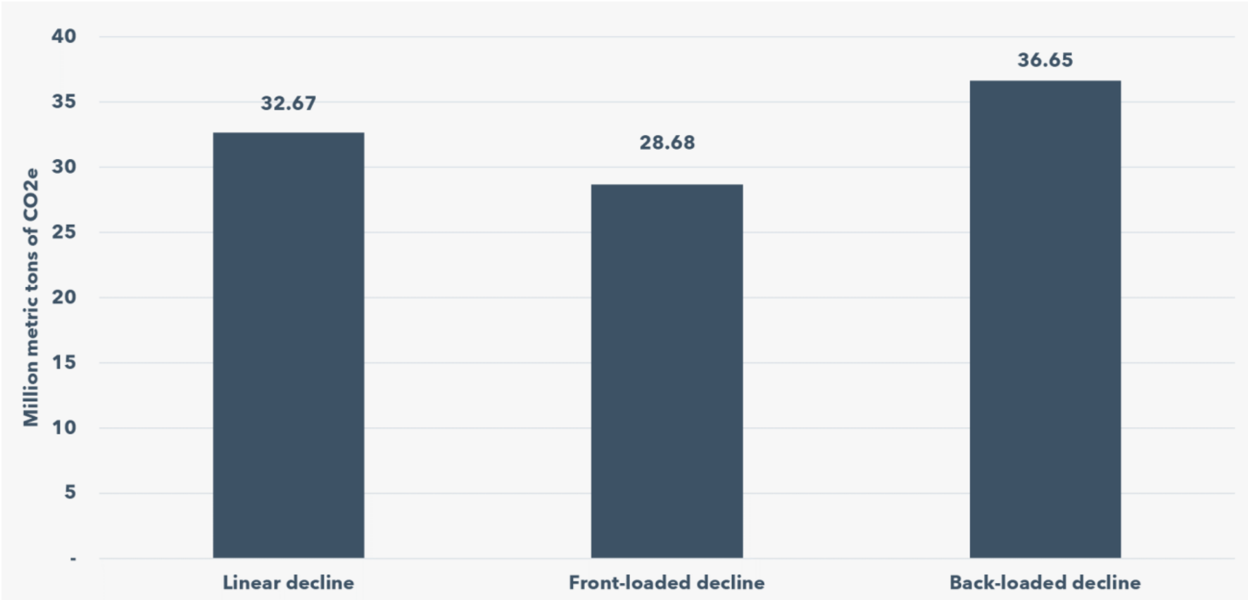


Figure 80. Cumulative emissions 2024-2043, decarbonization glidepath portfolios

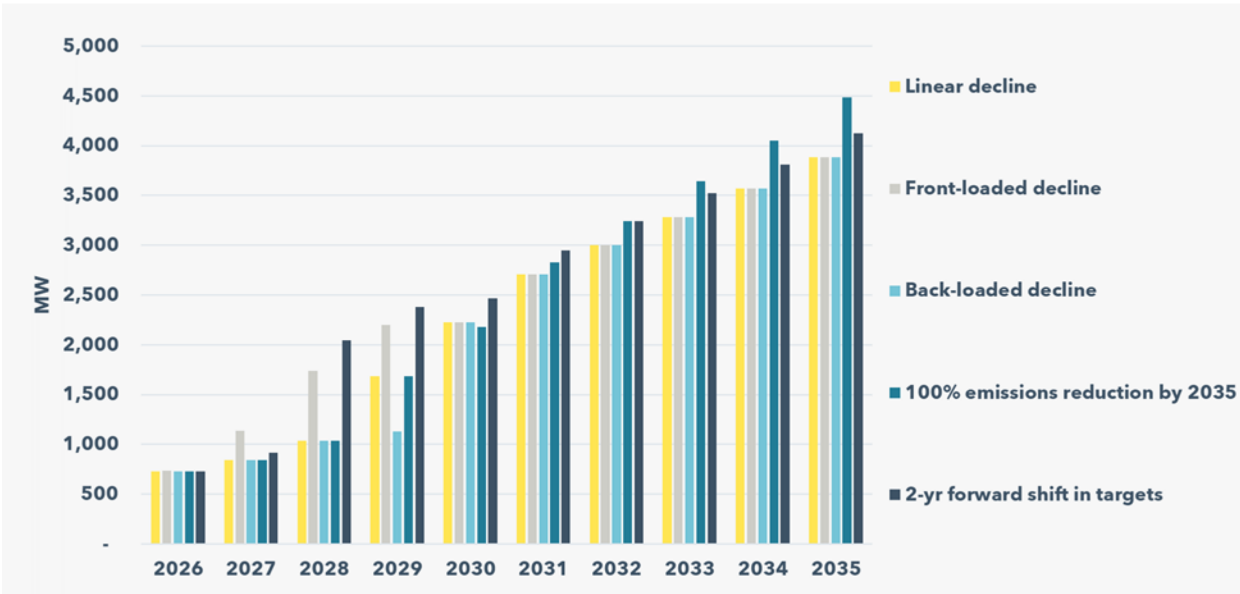


The lower cumulative emissions associated with accelerated rates of decarbonization come with tradeoffs in terms of portfolio cost and risks. Accelerated decarbonization increases the near-term Reference Case need for renewable resource additions (**Figure 81**). The difference between renewable additions in the 'Linear decline' portfolio and the 'Two-yr forward shift in targets' portfolio shows that accelerated decarbonization can increase the need for renewable procurement by over 1,000 MW by 2028 in the Reference Case. The front-loaded decline portfolio also increases procurement need through 2028, requiring 701 more MW than linear decline portfolio by 2028. The energy need in the '100 percent by 2035' glidepath begins to increase relative to the linear glidepath in 2031 and it requires larger energy procurement in 2031-2039 as a result, adding 605 MW more than the linear glidepath by 2035.

'Two-yr forward shift in targets' is unable to meet energy needs without access to the generic VER resource in 2029, showing that in a world with limitations on access to transmission, faster decreases in emissions in the near-term would further increase dependence on transmission and/or emerging technologies that might not be proven, which adds additional risk. While achieving early attainment of HB 2021 targets is possible without utilizing the generic resources in the pre-2030 timeframe in the '100 percent emissions reduction by 2035' portfolio, the need to add resources earlier in the planning-horizon results in increased costs compared to the three glidepaths that achieve compliance on-time.

On-time achievement of targets relying on a back-loaded glidepath to 2030 may also increase procurement risk relative to a linear glidepath, increasing the need to rely on large resource additions concentrated in fewer years approaching 2030. This includes uncertainties in available transmission inventories, procurement delays and other supply chain constraints, operational risks associated with adding large quantities of resources in a small amount of time.

Figure 81. Renewable resource buildout of decarbonization portfolios



Comparison of cost and risk metrics shows that the portfolios that meet HB 2021 targets early (100 percent emissions reduction by 2035 and Two-yr forward shift in targets) have increased system costs relative to meeting targets on schedule using the linear-decline glidepath (**Figure 82**). The increase in cost is driven by the earlier resource additions required for early attainment. This increases costs due to two factors; the discounting of values in the calculation of net present value revenue requirement (NPVRR), which weights the impact of near-term costs more heavily than costs accrued later in time, and the declining cost curves of new resource options (as described in **Chapter 8, Resource options**). The cost and risk tradeoff associated with faster emissions declines can also be seen in comparison between 'Back-loaded decline' and 'Front-loaded decline', with 'Front-loaded decline' being the most expensive and most variable as a result of earlier resource additions and 'Back-loaded decline' being the least expensive and least variable due to later resource additions (**Figure 83**). The linear glidepath in 'Linear decline' falls in the middle for both cumulative emissions and cost and risk metrics.

Figure 82. Cost and risk of accelerated decarbonization glidepath portfolios

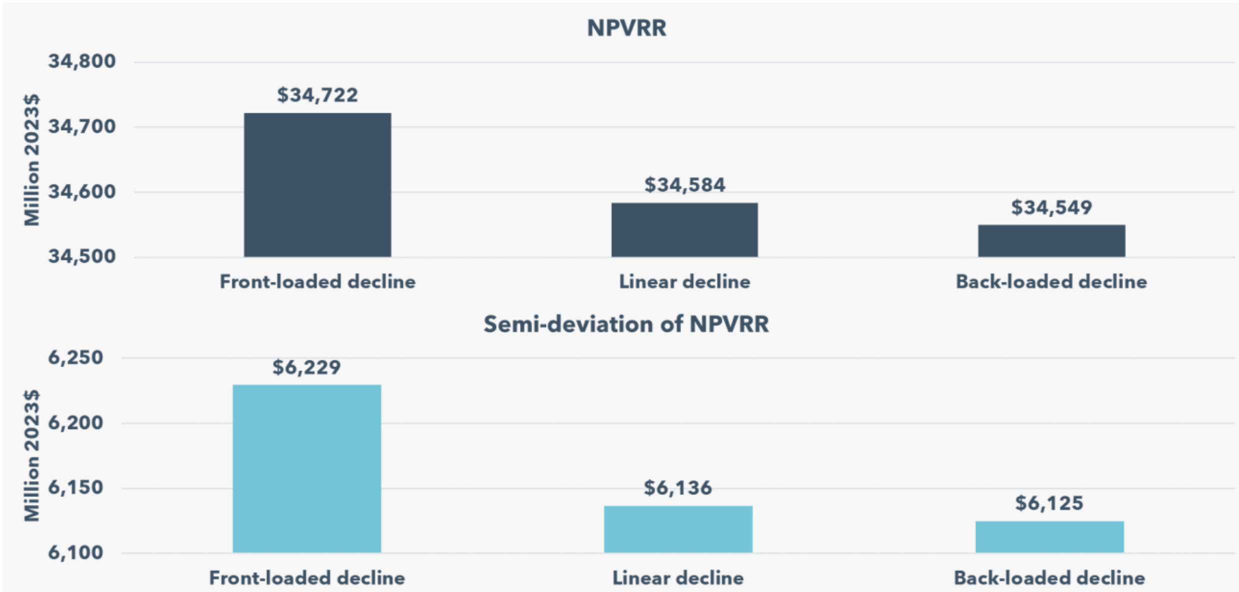
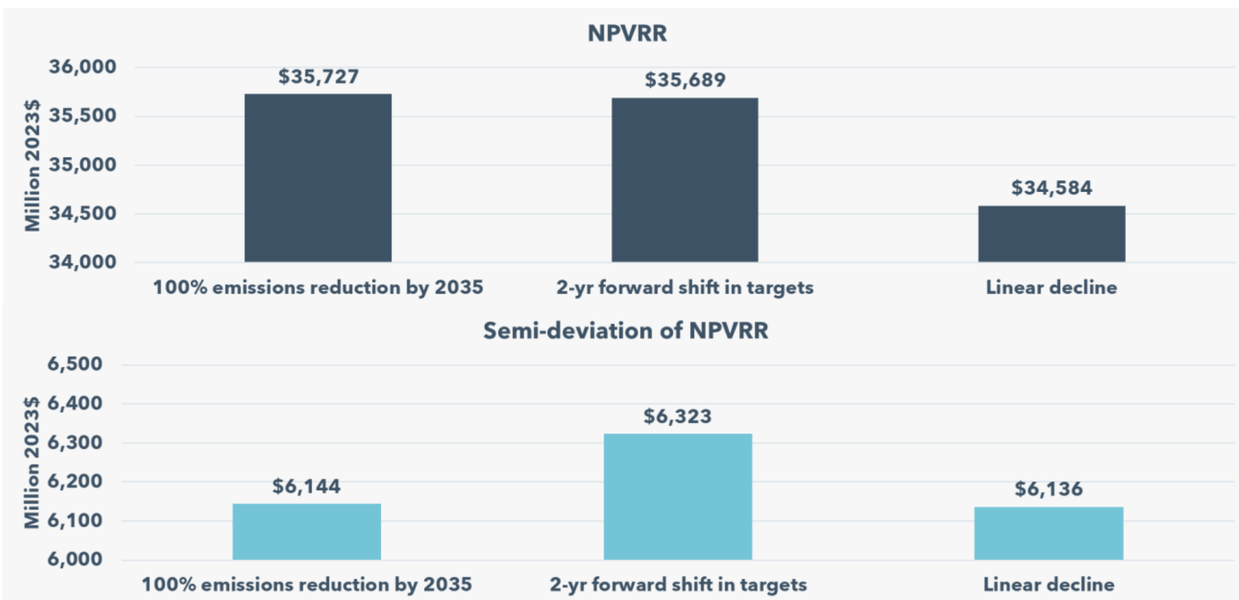


Figure 83. Cost and risk of decarbonization glidepath portfolios



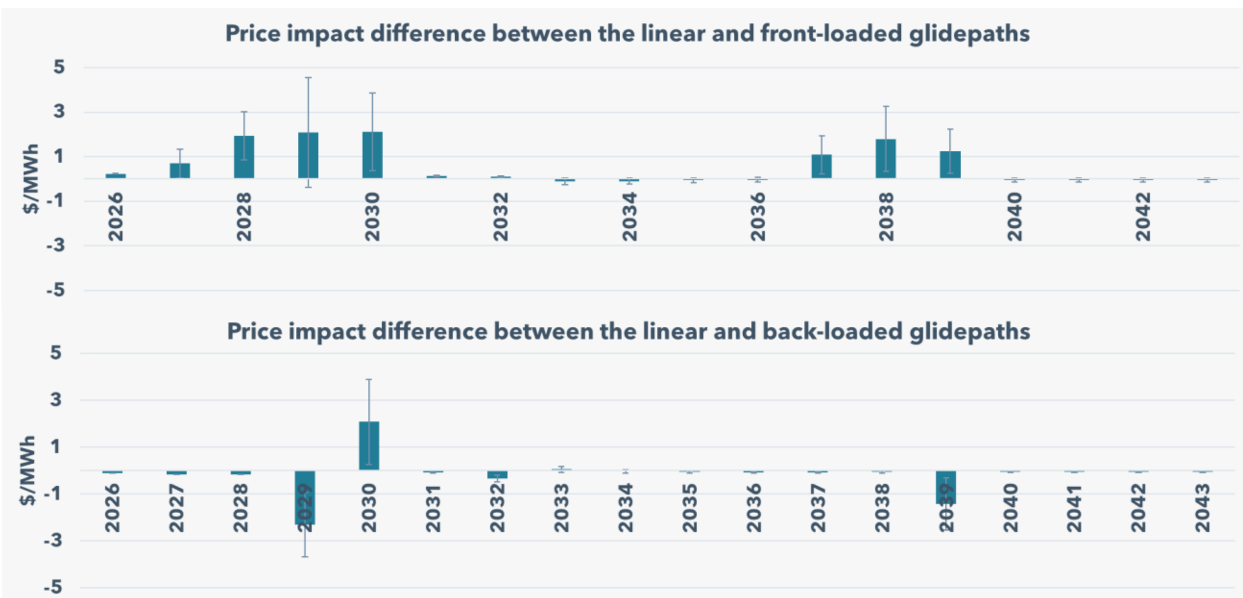
Given the tradeoffs between rate of emissions reduction and portfolio cost and risk, the findings of this analysis indicate that the 'Linear decline' best balances the costs and multiple sources of risk with the rate of emissions reductions to meet HB 2021 targets by 2030 and it is used as the default in all other portfolios, including the Preferred Portfolio.

11.4.1.1 Decarbonization glidepath annual price impacts

The forecasted difference in yearly cost impacts (associated with existing and incremental generation) per megawatt hour (MWh) of retail load between the linear decarbonization glidepath and the front and back loaded decarbonization glidepath can be seen in **Figure 84**.[303] Positive values represent higher costs relative to linear glidepath and negative values represent lower costs relative to linear glidepaths. The differences in portfolio costs are projected through the planning horizon starting in 2026, the first available year of incremental resource additions.

The higher costs of the front loaded decarbonization glidepath are primarily seen in the near-term with the additional costs through 2030. Additional costs in the 2037 through 2039 reflect the earlier expiration of production tax credits (PTC) in the front-loaded portfolio relative to the linear decline portfolio, which is a smaller determinant in decision making. The lower costs of the back-loaded decarbonization glidepath highlight a similar relationship, showing lower costs with a later buildout in the 2020's. These yearly cost forecasts support the finding described previously that GHG emission reductions lead to cost increases.

Figure 84. The annual ($/MWh) impact of Decarbonization Glidepath portfolios through 2035



[303] **Addendum: PGE CEP Data Template** contains the annual price impact in $'s and the annual price impact per unit retail sales ($/MWh) through the planning horizon for each portfolio

11.4.2 Transmission portfolios

PGE designed a set of transmission portfolios to understand the quantity and timing of need for transmission to reliably decarbonize the system and test the impact of assumptions about transmission on other resource choices (described in **Table 56**). To isolate the effect of differences in assumptions related to transmission resource buildout and cost and risk metrics, these portfolios contain otherwise consistent assumptions (i.e., availability of other resources such as CBREs and additional EE and DERs and a linear GHG reduction glidepath).

Table 56. List of transmission portfolios

Portfolios	Portfolio condition
No Transmission (Tx) constraints (informational)	No transmission constraints imposed
No upgrades (informational)	No transmission upgrades or build options available
Unconstrained SoA (informational)	Unlimited South of Alston (SoA) transmission access beginning in 2027
Unconstrained SoA Plus (informational)	Unlimited SoA transmission access beginning in 2027 New transmission options to WY and NV are available in 2026
SoA in 2027 plus	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2027 New transmission options 400 MW each to WY and NV are available in 2026
SoA in 2027	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2027
SoA in 2029	SoA upgrade unlocks 400 MW of IRP proxy resources in the PNW in 2029
WY in 2026	New transmission option 400 MW to Wyoming in 2026
NV in 2026	New transmission option 400 MW to Desert Southwest in 2026
WY in 2028	New transmission option 400 MW to Wyoming in 2028
NV in 2028	New transmission option 400 MW to Desert Southwest in 2028

11.4.2.1 Informational transmission portfolios

The informational portfolio 'No Tx Constraints' envisions a world where PGE operates free from contractual limitations in the transmission system. As shown in **Figure 85**, the cost of building a portfolio that meets PGE's resource needs appears to be relatively low cost when the contractual transmission landscape is not accounted for. The large amount of renewable additions that the model selects in the absence of transmission constraints (**Figure 86**) and the low portfolio cost of the 'No Tx Constraints' portfolio (**Figure 85**) suggests that in the absence of transmission constraints, renewables offer the lowest-cost method to decarbonize when paired with sufficient dispatchable capacity resources to meet reliability needs. When compared to other transmission portfolios, PGE finds that the inclusion of transmission constraints increases costs, an intuitive finding because the model has fewer resource options to choose from to meet capacity and energy needs.

In contrast, the 'No upgrades' portfolio evaluates a scenario where no transmission upgrades are actionable to PGE and where PGE must rely on the current estimated available contractual transmission capacity.[304] The resulting resource buildout reveals that without access to additional transmission, the model must rely relatively heavily on the generic resources by 2030 (**Figure 86**), an outcome that results in substantially increased estimated costs and risk (**Figure 85**). Given the uncertainties surrounding the cost and availability of the resources that would be added to fill this need, this also would require further study on their technical and economic feasibility. These results also demonstrate that the current forecasts of transmission capacity are insufficient to meet system needs over the planning horizon even after acquiring the entirety of the available potential for CBREs and cost-effective DERs.

[304] Information on the creation of these estimates can be found in **Appendix H.7, BPA transmission in ROSE-E.**

Figure 85. Cost and risk of informational transmission portfolios

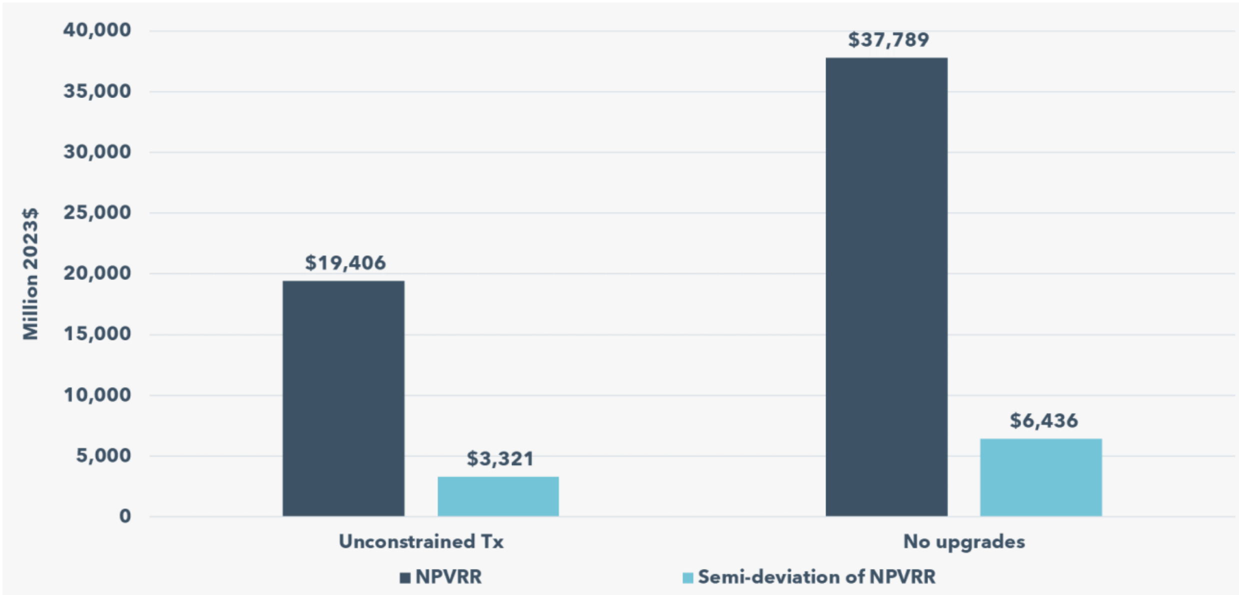
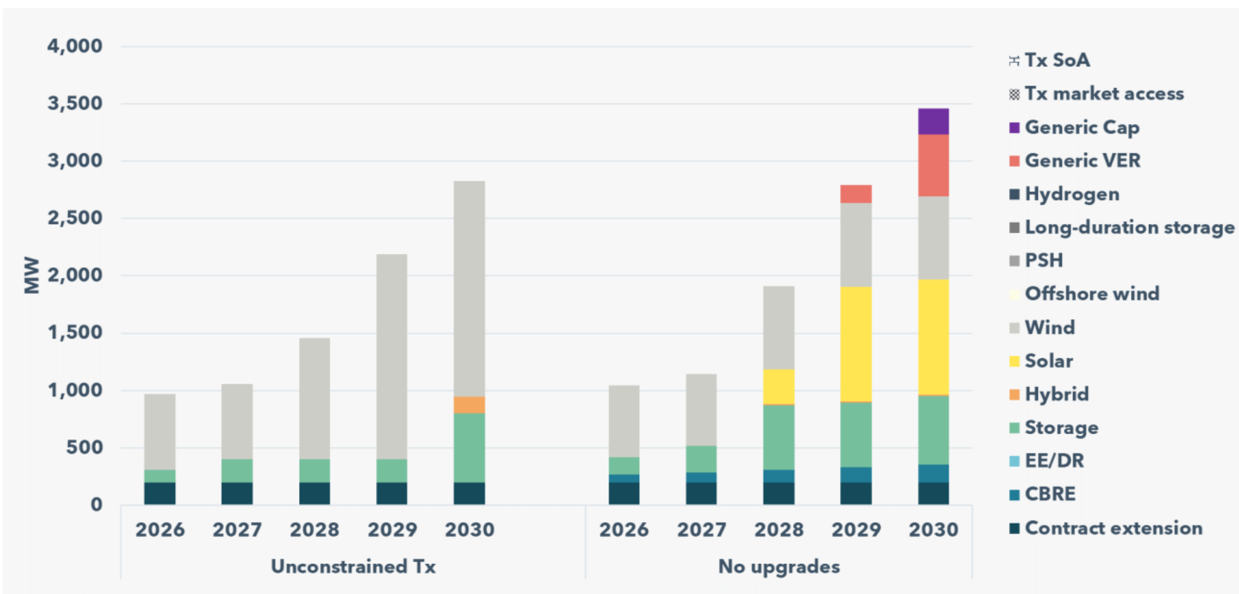


Figure 86. Resource buildout of informational transmission portfolios



With the inclusion of the generic on-system resources noted previously, the 'No Upgrades' portfolio can demonstrate the quantities of additional transmission capacity needed to reliably decarbonize. After accounting for the magnitude of the distribution connected resources that can minimize transmission need, the portfolio has identified the timing and magnitude of the most conservative perfect transmission required over the next 20 years

(**Table 57**).[305] Thus, this portfolio shows that in the absence of a technology breakthrough that yields a low-cost and scalable resource, there is a need to invest in incremental transmission to PGE. Additionally, it also shows that even after accounting for the impact of additional DERs beyond the Distribution System Plan (DSP), the transmission need is significant. This underscores that in the absence of investments in transmission, PGE would not be able to reliably decarbonize and meet the 2030 targets of HB 2021.

Table 57 shows the quantity of transmission that would be required corresponding to the quality of resources available. Resources that can provide significant energy and capacity benefits require the least amount of new transmission, while other resources may increase transmission needs. As these results emphasize, based on the type and quality of resources available, upwards of 800 MW of transmission may be needed as soon as 2030. The appropriate combination of transmission upgrades vs. new transmission required is explored in the following section.

Table 57. Estimated Reference Case transmission need

Year	Generic VER	Generic capacity	Potential transmission need (MW)
2026	-	-	-
2028	-	-	-
2029	159	-	159
2030	541	228	541-768
2035	2,199	807	2,199-3,005
2040	4,285	3,183	4,285-7,468

[305] Assuming that all remaining system needs are met through transmission. Other post-2030 resource options may fill some or all of this need, as discussed in **Section 8.5, Post-2030 resource options**.

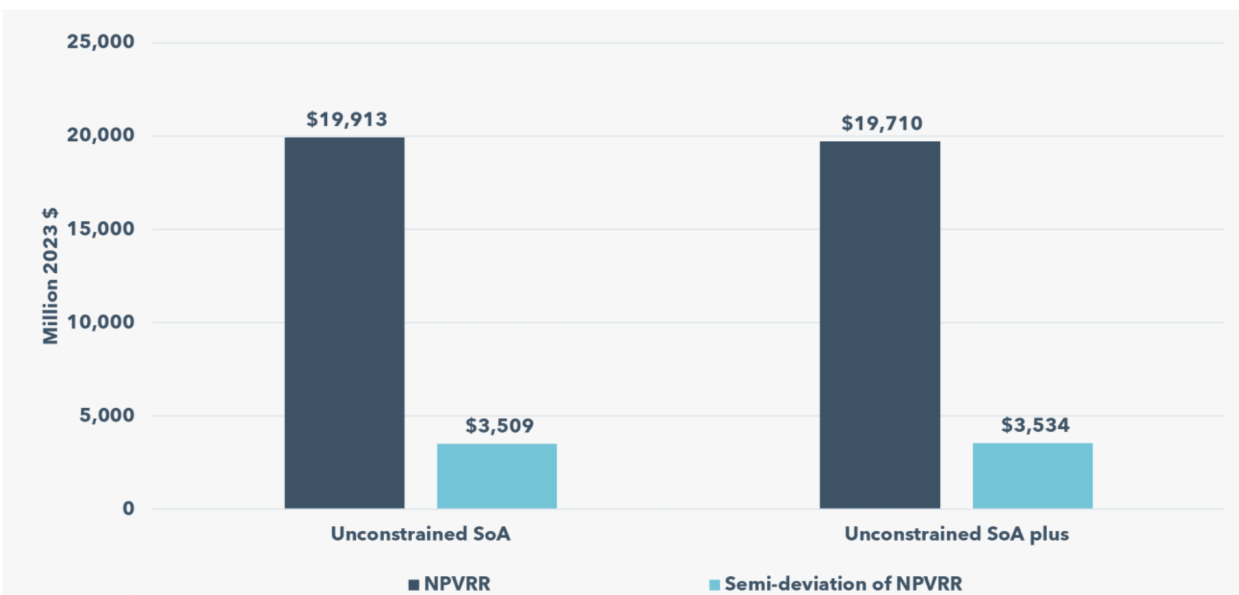
11.4.2.2 Transmission diversity portfolios

In the 'Unconstrained SoA' portfolio, the model has unlimited access to add transmission access to Oregon, Washington and Montana proxy renewable resources (Pacific Northwest [PNW] proxy resources) that are otherwise limited by the contractual transmission landscape, beginning in 2027. In the 'Unconstrained SoA Plus' portfolio, the model has the same access to reduce SoA congestion, plus access to 400 MW each of the WY and NV transmission expansion options beginning in 2026.

The resulting Reference Case resource buildout is very similar through 2030 for both portfolios, with the model choosing to rely on the SoA upgrade and not selecting WY or NV transmission expansion. However, later in the planning horizon, the model takes advantage of access to the WY and NV transmission expansion options in 'Unconstrained SoA Plus', adding 600 MW by 2040. As a result, 'Unconstrained SoA Plus' has a lower cost (**Figure 87**).

These resource buildout results demonstrate that significantly increasing access to PNW proxy resources helps delay the need for investments in more expensive transmission expansion options. Additional transmission options are forecasted to be an effective method to reduce both cost and risk, especially in higher-Need Futures.

Figure 87. Cost and risk of transmission diversity portfolios



11.4.2.3 Transmission timing portfolios

The transmission timing portfolios vary the timing of availability of transmission options to compare the transmission options against one another and to compare the impact of timing on the individual options. In 'SoA in 2027', 'SoA in 2029', 'WY in 2026', 'NV in 2026', 'WY in 2028' and 'NV in 2028', the model is required to add 400 MW of the corresponding transmission option in the noted year. In one additional portfolio ('SoA in 2027 plus'), the model is forced to add 400 MW of SoA in 2027 and has 400 MW each of WY and NV transmission options available for selection (but not required) beginning in 2026. The resource buildouts of the transmission timing portfolios are shown in **Figure 88**.

Comparing the cost and risk metrics of these actionable portfolios (**Figure 89**) shows that 'SoA in 2027' and 'SoA in 2029' have lower costs than the WY and NV portfolios. Because of declining resource cost curves and discounting of future costs, 'SoA in 2029' has lower costs than 'SoA in 2027'. However, it has higher risks, in terms of quantified risk metrics (**Figure 89**) and the unquantified risks associated with waiting to procure the necessary resources to comply with HB 2021's 2030 emissions targets.

The lowest costs and risks are found in the 'SoA in 2027 plus' portfolio, demonstrating the benefits of having more transmission options available (**Figure 88**). Comparing these actionable portfolios, PGE finds that investing to increase access to transmission earlier will provide the best balance of system costs and risks. This further reaffirms that PGE should first pursue all available opportunities to increase access to PNW proxy resources, such as the upgrade to the Bethel-Round Butte transmission line. Additionally, studying new transmission options can reduce potential dependence on emerging technologies and reduce costs, as shown in **Figure 89**.

Figure 88. Resource buildout in transmission timing portfolios

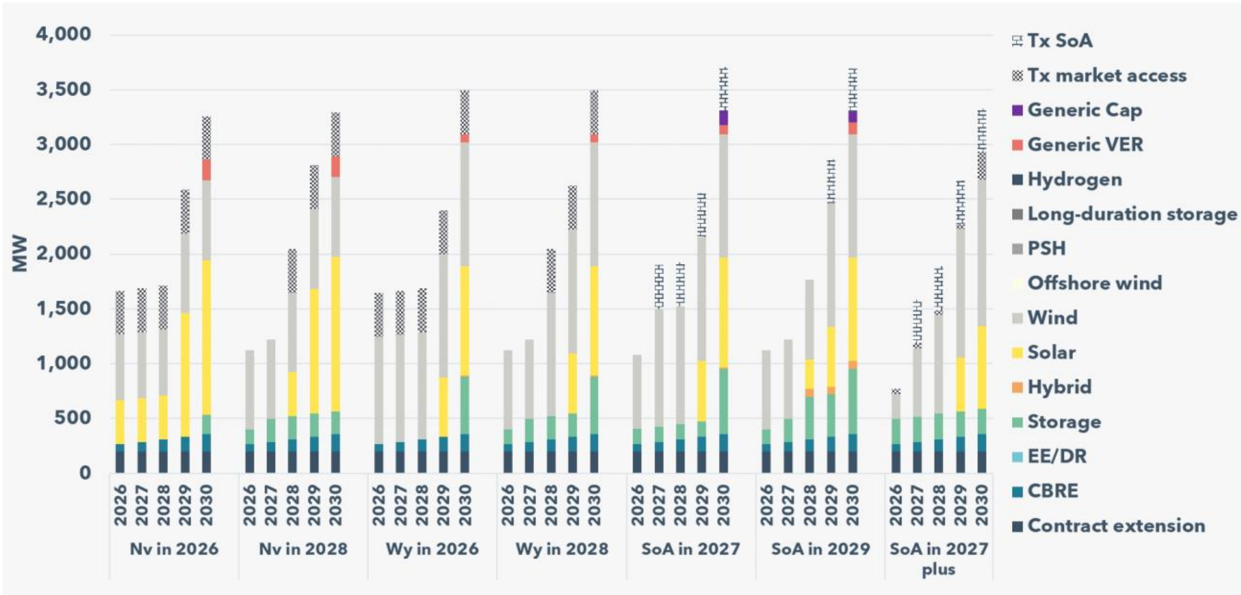
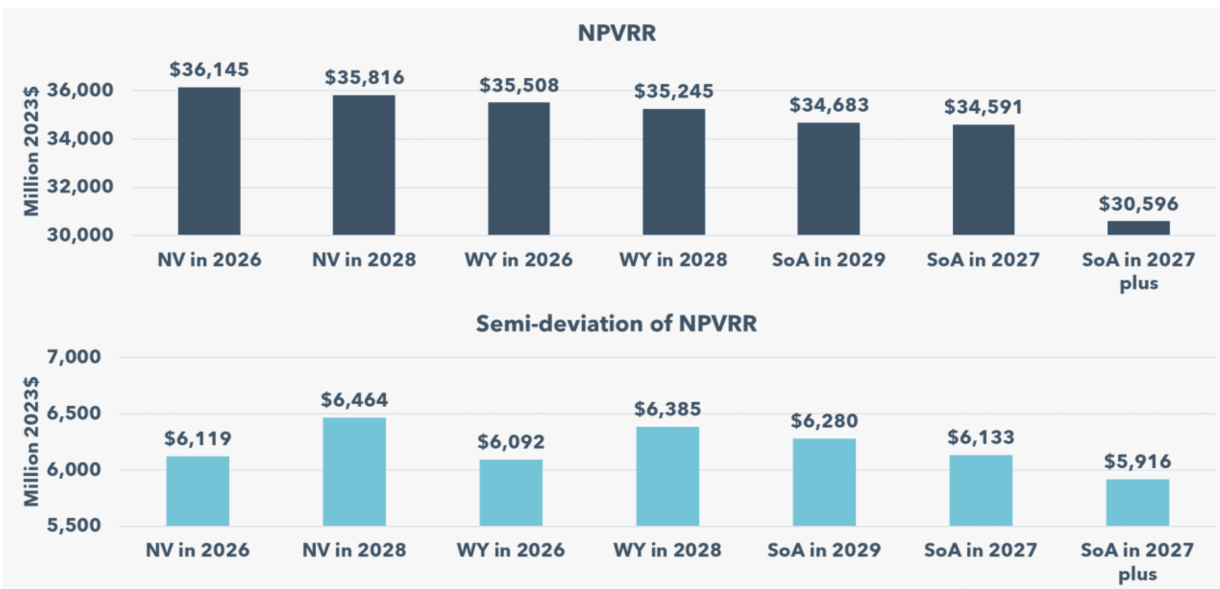


Figure 89. Cost and risk metrics of transmission timing portfolios



11.4.3 Community-based renewable energy (CBRE) portfolios

Studying the relationship between costs, risk and community benefits resulting from the deployment of CBRE resources has been a central discussion of this IRP.[306] PGE developed

[306] See **Sections 7.1 (CBRE), 7.1.3 (rCBI), 7.1.4 (pCBI)** and **7.1.6 (iCBI)**.

the portfolios listed in **Table 58** to explore this relationship. The CBRE portfolios vary the quantity of CBREs and whether they are forced-in or are available for optimized selection in the model. Aside from the variations in CBRE availability, portfolios in this section assume a consistent set of assumptions to ensure comparisons provide insight on the impact of CBRE resources on portfolio outcomes.

Table 58. List of CBRE portfolios

Portfolios	Portfolio Condition
Default CBRE	100% of CBRE achievable potential is selected
CBRE: 75%	75% of CBRE achievable potential is selected
CBRE: Unavailable (informational)	CBRE resources are unavailable
CBRE: Microgrids	Only Microgrid CBRE resources are available
CBRE Optimize	CBRE resources compete economically

11.4.3.1 Results and insights

Results from these portfolios indicate that increasing the amount of CBRE resources decreases portfolio costs and risk (**Figure 90**). Additionally, the 'CBRE Optimize' portfolio selects the full amount of available CBRE resources and, alongside 'Default CBRE', which forces in the full amount of CBRE resources, has the lowest cost and risk. Portfolios community benefits indicators (CBIs), which are a function of the nameplate capacity of CBREs added in each portfolio and represent the level of community benefits provided (described in **Section 7.1.4, Portfolio community benefits indicators**), are shown in (**Table 59**). These results show that in addition to having the lowest cost and risk, the 'CBRE Optimize' and 'Default CBRE' portfolios provide the greatest community benefits.

This finding suggests that in a transmission-constrained system, CBRE resources can decrease cost and increase community benefits. These results drive the conclusion that PGE should include all 155 MW of available CBRE in the Preferred Portfolio. Additionally, it supports the conclusion that community benefits and cost minimization are not mutually exclusive. However, given both the magnitude of long-term transmission needs and the total forecasted technical potential for incremental CBRE additions, CBRE resources cannot be seen as a panacea for the challenges PGE faces with transmission availability.

Figure 90. Cost and risk metrics of CBRE portfolios

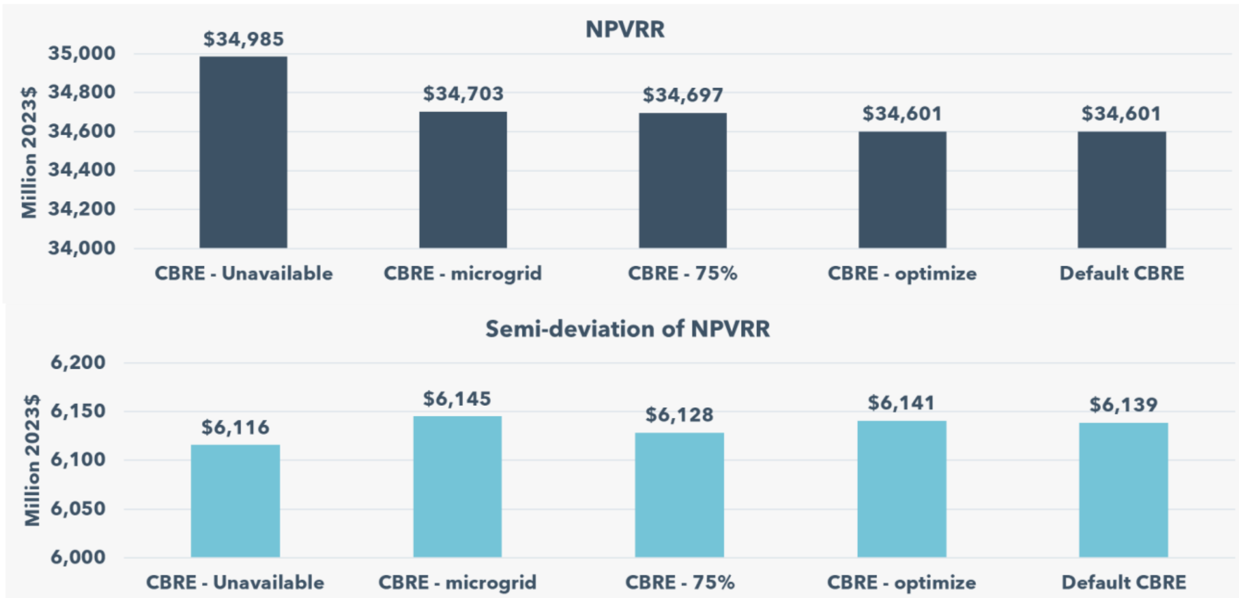


Table 59. Portfolio Community Benefit Indicator of each CBRE portfolio

Portfolios	Portfolio Community Benefit Indicator (pCBI)
Default CBRE	155
CBRE: 75%	116
CBRE: Unavailable	0
CBRE: Microgrids	100
CBRE Optimize	155

11.4.4 Energy efficiency and demand response portfolios

Through the DSP, PGE has committed to expanding the demand response (DR) portfolio to 211 MW of summer and 158 MW of winter demand response by 2028. Additionally, through the Energy Trust of Oregon (ETO) PGE estimates approximately 150 MWa of incremental cost-effective energy efficiency (EE) to be achieved by 2028. These resources are included as a reduction in resource needs, namely capacity and energy (for more detail, see **Section 6.2, Distributed Energy Resource (DER) impact on load**).[307]

In this IRP, we also have estimated the costs and benefits associated with additional quantities of EE and DR (these estimates are described in both **Chapter 8, Resource options**, and **Chapter 10, Resource economics**). **Table 60** lists the portfolios PGE developed to understand whether these additional quantities of EE and DR could provide system benefits at lower cost and risk relative to other supply-side options. All portfolios in this section assume a linear reduction in emissions and the full 155 MW buildout of CBRE resources to ensure comparisons focus on the role of EE and DR. Additional EE and DR resources are available for selection in the years 2026 through 2030.

Table 60. List of EE and DR portfolios

Portfolios	Portfolio condition through 2030
Optimized Non-Cost-Effective (NCE) DERs	Allow model to select from total potential of additional EE and DR
Zero NCE	No additional EE and DR available (ETO and PGE cannot increase savings beyond current commitments)
25 MWa NCE EE	25 MWa of additional EE (5 MWa annually)
50 MWa NCE EE	50 MWa of additional EE (10 MWa annually)
60 MWa NCE EE	60 MWa of additional EE (12 MWa annually)
70 MWa NCE EE	70 MWa of additional EE (14 MWa annually)

The quantity of additional EE and DR added in these portfolios is shown in **Figure 91**. In the 'Optimized Non-cost-effective (NCE) DERs' portfolio, the model selected 53 MWa of the 70 total MWa of EE available. Additional DR was not selected in any of the portfolios as it has higher costs than any other available resources when it is available for selection (2026-2030), highlighting the need for program redesigns that reduce costs. When comparing the scoring metrics in **Figure 92**, increasing the amount of additional EE available for selection decreases portfolio cost and reduces risk up to a point. This shows that there are energy efficiency options that are more expensive than transmission options and the generic resource. Portfolio NPVRR decreases as the model is allowed access to increasing amounts of EE, from the highest costs for the 'Zero NCE' portfolio to the lowest cost for the '50 MWa EE' portfolio. The implications of these results are further discussed in the following section.

[307] These estimates from the DSP and ETO are based on the avoided costs of the 2019 IRP Update and thus do not account for reflect the economic tradeoffs within this IRP.

Figure 91. Resource buildout in energy efficiency and demand response portfolios

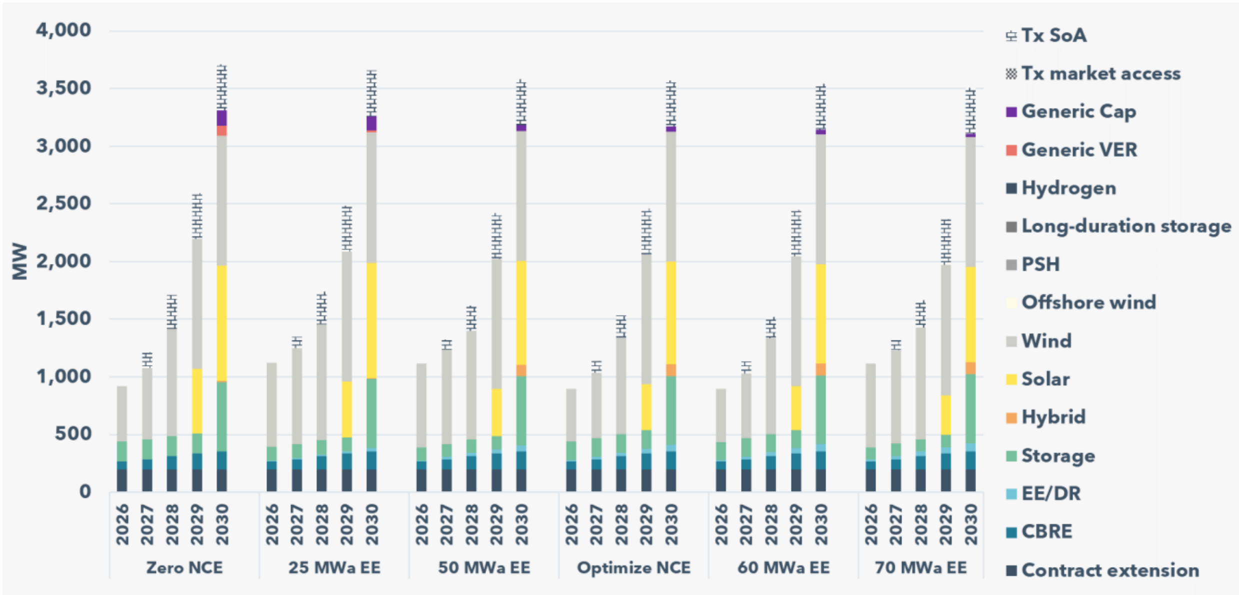
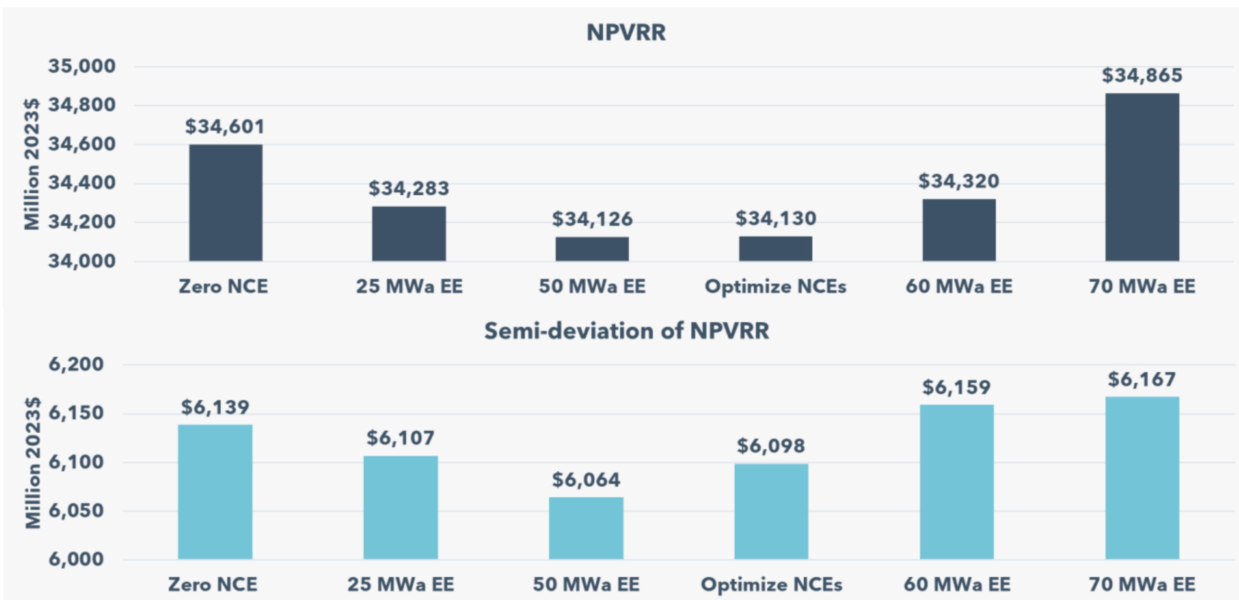


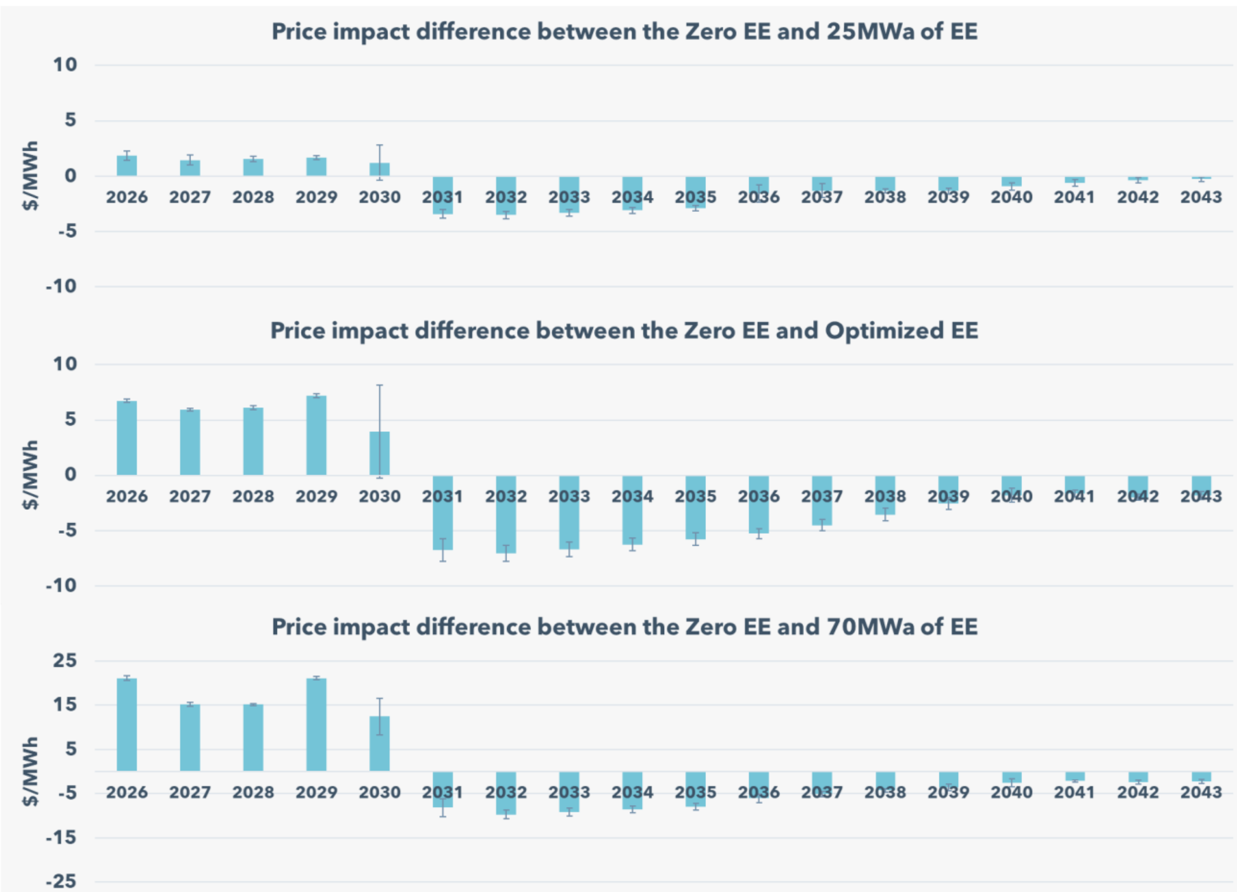
Figure 92. Cost and risk metrics of EE&DR portfolios



These results strongly identify the potential benefits of adding additional EE more than the quantities identified as 'cost-effective' using outputs from the 2019 IRP. This highlights a significant disconnect between resource planning using the current forecasts of costs and benefits in this IRP and resources that use previously calculated cost-effectiveness tests (such as energy efficiency and demand response). This disconnect is further described in **Section 10.7, Cost of clean energy**.

However, examination of the cost impacts of these portfolios identifies challenges related to the near-term cost impacts. **Figure 93** shows the difference in yearly price impact between the Zero EE portfolio and three portfolios with varying levels of additional EE (25MWa, Optimized and 70MWa). This figure underscores the relationship between acquiring increasing quantities of additional EE and the associated near-term price impacts. As additional EE is added the near-term price impact increases rapidly. Two unique policy factors drive these results. First, unlike other assets the additional EE is not financed or securitized, so the full cost is incurred before the generation starts. Second, EE decreases retail sales which leads to increased costs per unit of sales. Aggregated, these two effects lead to much higher near-term cost increases than the relevant comparators. Accordingly, EE under the current state policy creates large near-term price increases. When only considering long-term system cost this near-term effect is not apparent.

Figure 93. Yearly costs per MWh for additional EE portfolios through 2030



Despite ROSE-E suggesting the long-term benefits of adding additional quantities of EE, PGE has determined that the combination of near-term price impacts and the unquantified risk of pursuing the resource outweighs the associated benefit. Accordingly, the Preferred Portfolio described in **Section 11.5, Preferred Portfolio**, does not contain any additional EE.

While the updated avoided costs produced by IRPs (as highlighted in **Section 10.7, Cost of clean energy**) could lead to higher quantities of EE being realized, additional policy changes that could more assuredly lead to procurement and/or securitize the procurement of EE will likely be needed for PGE to achieve the full cost and risk savings articulated in these portfolios. As the modeling suggests, energy efficiency is an increasingly important resource to PGE and the region's decarbonization strategies.

11.4.5 Optimized portfolios

With the Optimized portfolios group, PGE explored the impact of optimization choices on resource buildout, portfolio cost and risk metrics by varying the constraints imposed and the objective functions used to minimize costs. **Table 61** lists the portfolios PGE developed to test different objective functions. All portfolios in this section are built upon a linear reduction in emissions.

The 'Min Avg LT cost' and 'Optimized' portfolios use the default objective function to minimize the average NPVRR across all combinations of price, need and technology cost futures for the full portfolio analysis time horizon (2024-2043). The 'Min Avg ST cost' and 'Min Ref ST cost' portfolios use different objective functions than the rest of the portfolios. 'Min Avg ST cost' minimizes the average of NPVRR outcomes across all combinations of need, price and technology cost futures through the year 2030. 'Min Ref ST cost' minimizes the NPVRR of the Reference Case only and only through the year 2030.

The 'Min Avg LT cost', 'Min Avg ST cost' and 'Min Ref ST cost' portfolios have the default settings used across most portfolios of adding all 155 MW of CBRE resources and access to 400 MW of SoA in 2027. The 'Optimized' portfolio allows the model access to the least-restricted set of resource actions PGE can take.[308] In the 'Optimized' portfolio, the model has access to 400 MW of SoA in 2027, 400 MW each of WY and NV transmission in 2026, the full 70 MWa of additional EE, and has the option of selecting up to 155 MW of CBRE resources.

[308] Some informational portfolios, like the 'No Tx constraints' portfolio' do contain fewer restrictions but are not actionable.

Table 61. List of optimized portfolios

Portfolios	Portfolio condition
Min Avg LT cost	Minimizing average long-term (LT) NPVRR
Min Avg ST cost (informational)	Minimizing average short-term (ST) NPVRR through 2030
Min Ref ST cost (informational)	Minimizing Reference Case short-term NPVRR through 2030
Optimized (informational)	Least constrained

The 'Optimized' portfolio uses the access to additional EE, selecting 53 MWa by 2030 and adding less storage and renewables compared to the 'Min Avg LT cost'. As a result of the additional resources available for selection, 'Optimized' achieves lower costs and risk than 'Min Avg LT cost' (**Figure 94**). Additionally, the portfolio selects the full quantity of available CBRE resources, supporting the robustness of the findings in **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**. And finally, the portfolio selects the SoA option, reinforcing the finding that the full quantity of resources available with existing transmission capacity (described in **Appendix H.7, BPA transmission in ROSE-E**) is insufficient to meet system needs at the lowest cost without also some expansion of transmission access.

Because they are optimized over a shorter timeframe of seven years compared to the standard 20 years for other portfolios, the cost and risk metrics of the 'Min Avg ST cost' and 'Min Ref ST cost' portfolios are not comparable to those of other portfolios for two reasons. First, only seven years of values are accounted for in their cost and risk metrics, so NPVRR outcomes are much smaller, and associated variability is lower. Second, beyond 2030, while the resource additions must still satisfy the constraints imposed on the model, they are not subject to the minimization of costs, and the model does not attempt to create an optimal resource buildout. The 'Min Avg ST cost' and 'Min Ref ST cost' portfolios produce nearly identical resource buildouts to one another and very similar resource buildouts (through 2030) to the 'Min Avg LT cost' portfolio (**Figure 94**).

Figure 94. Resource buildout in optimized portfolios

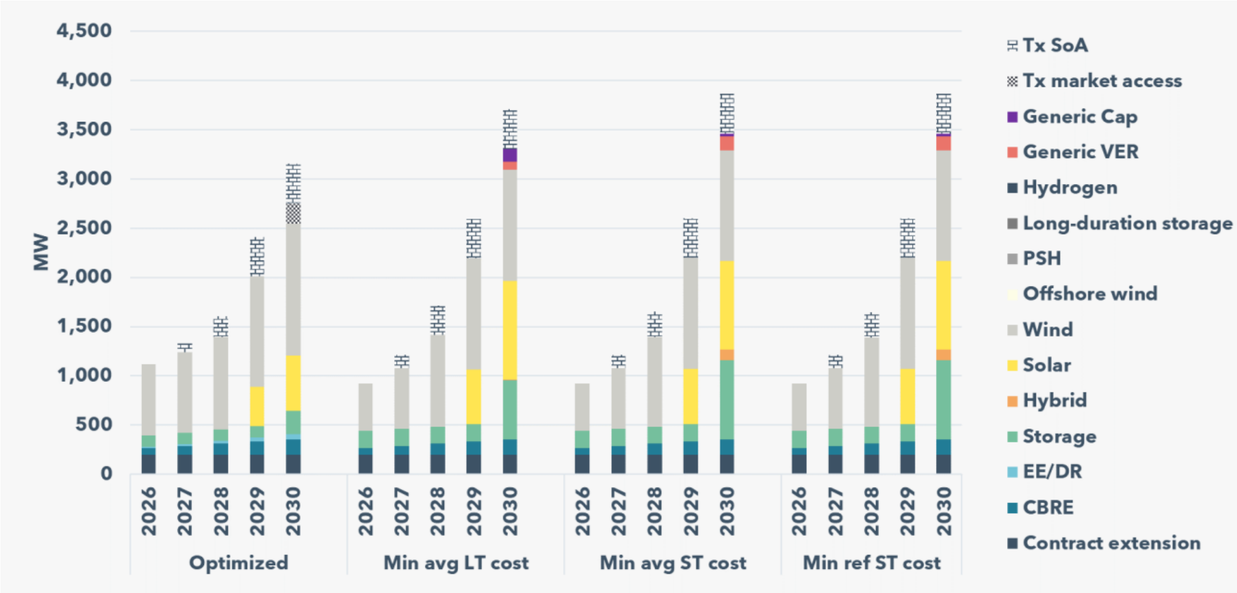
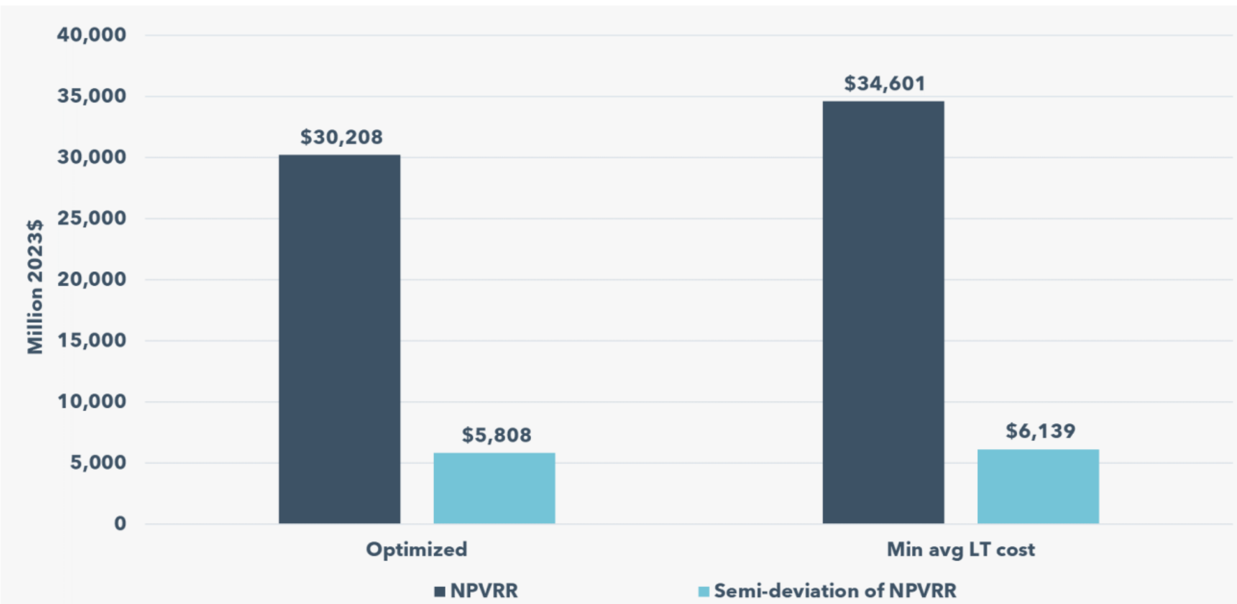


Figure 95. Cost and risk metrics of 'Optimized' and 'Min Avg LT cost' portfolios



11.4.6 Targeted policy portfolios

To inform stakeholder discussions, PGE developed targeted portfolios to study specific policy conditions, listed in **Table 62**. Both 'Targeted Policy' portfolios have a linear GHG-emissions reduction glidepath, have access to 400 MW of SoA upgrade in 2027, and must add all 155 MW of CBRE resources. Neither portfolio has access to WY or NV transmission expansion options.

Table 62. List of targeted policy portfolios

Portfolios	Portfolio condition
Physical RPS	Enforce physical renewable portfolio standard (RPS) compliance
Oregon-only Resources	Limit resource availability to Oregon-sited only

The 'Oregon-only resources' portfolio does not allow the model to select resources sited outside of Oregon (i.e., SE Washington, Wyoming, Montana Wind or NV Solar). Because the portfolio has less access to improved effective load carrying capacities (ELCC) of out-of-state resources and a lower total availability of non-generic resources, a larger quantity of resource additions and increased reliance on generic resources are required to meet energy and capacity needs compared to portfolios that have access to out-of-state resources. The impact on resource buildout is demonstrated in **Figure 96** through comparison with the 'SoA in 2027 plus' portfolio from the transmission timing portfolios, which allows the model to access all out-of-state resources. The increase in quantity of resource additions and reliance on generic resources creates higher portfolio costs and **Figure 97** shows that the NPVRR of the 'Oregon-only resources' portfolio is $4.213 billion higher than the 'SoA in 2027 plus' portfolio. These results suggest that limiting the geographic area available to develop generation resources could lead to increased cost and risk for PGE's customers.

The 'Physical RPS' portfolio requires a resource buildout that ensures physical RPS requirements, meaning REC generation from existing and new resources must meet or exceed RPS obligations in all years. Because the need to add renewable resources to meet the requirements of HB 2021 is greater than is required for RPS compliance, the physical RPS requirement does not impact resource buildout or portfolio cost.

Figure 96. Resource buildout in Oregon-only resources and SoA in 2027 plus portfolios

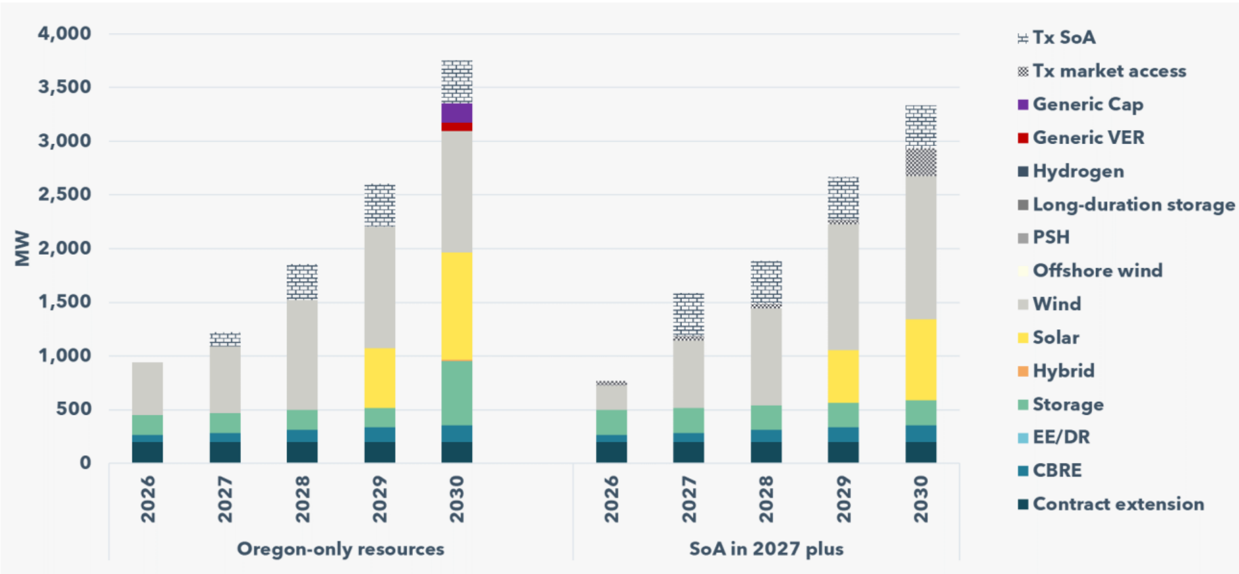
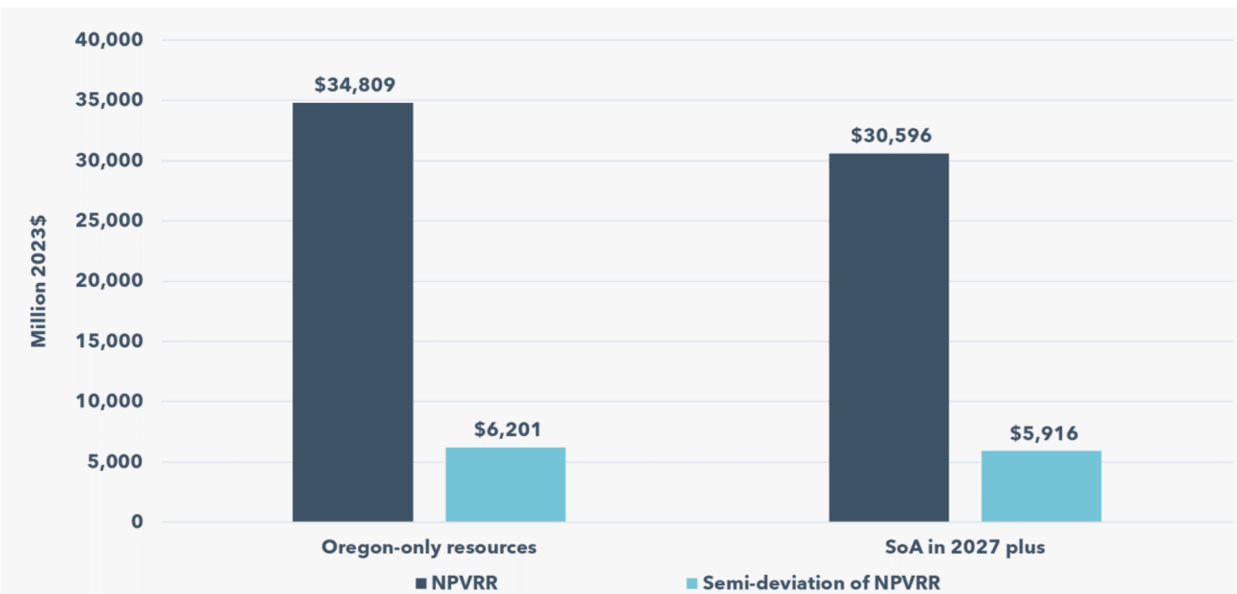


Figure 97. Cost and risk metrics of Oregon-only resources and SoA in 2027 plus portfolios



11.4.7 Emerging technology portfolios

Emerging technologies can potentially reduce portfolio costs and minimize the need for transmission expansion. To understand the potential impact of emerging technologies on transmission, cost and risk, PGE has explored portfolios listed in **Table 63**. The potential for emerging technologies to help PGE meet HB 2021 targets is explored in **Section 8.5, Post-**

2030 resource options, and the implications of the speed of development of and cost declines of emerging technologies are further explored here.

Table 63. List of emerging technology portfolios

Portfolios	Portfolio condition
Pumped hydro	333 MW of pumped storage hydro (PSH) in 2028
Hydrogen blending	Blending of hydrogen at existing natural gas (NG) plants
Hydrogen building	100 MW of hydrogen in 2029
Offshore wind (Informational)	500 MW of offshore wind in 2032
Long Duration Storage (Informational)	139 MW of 24 hr. battery in 2028
RTO (Informational)	200 MW Reduction in Capacity Need

In the 'Pumped hydro' portfolio, 333 MW of 10-hour pumped hydro storage (PSH) is added in 2028.[309] The 'Long Duration Storage (LDS)' portfolio includes 139 MW of 24-hour battery in 2028.[310] The 'Hydrogen blending' portfolio models the conversion of existing PGE-owned NG plants to run on a partial hydrogen fuel blend.[311] The hydrogen-derived non-emitting power provides energy but does not provide additional capacity because the hydrogen is blended into existing power plants. The 'Hydrogen building' portfolio adds 100 MW of new 100 percent hydrogen-fueled dispatchable capacity, providing both energy and capacity. The 'Offshore wind' portfolio adds 500 MW of offshore wind in 2032.[312,313] The 'Regional transmission organization (RTO)' portfolio considers the potential benefits that PGE might

309 This represents 1/6th of the 2000 MW of known potential projects in the region (Swan Lake 400 MW, Gordon Butte 400 MW and Goldendale 800 MW). A 1/6th portion of the total capacity is representative of the fact that PGE is one of six regional IOU's.
310 139 MW of 24-hr storage provides the same amount of energy storage as 333 MW of 10-hour storage.
311 Hydrogen is blended into PGE's CCCT natural gas plants starting in year 2029. For modeling purposes, the energy generated by hydrogen is additional to the energy generated by burning natural gas and fully serves retail load.
312 This represents 1/6th of the 3000 MW of potential capacity along the Oregon Coast identified by the Bureau of Ocean Energy Management (BOEM) available at: 2022-Floating-Offshore-Wind-Report.pdf (oregon.gov).
313 The 2032 expected COD for offshore wind is aligned with findings of the Northwest Power and Conversation Council, available at: https://www.nwcouncil.org/fs/17860/2022_08_p3.pdf.

realize from joining an RTO by reducing capacity need by 200 MW annually beginning in 2031.[314]

The addition of PSH, LDS and Hydrogen can be seen in the resource buildouts shown in **Figure 98**. Resource buildouts for the 'Offshore wind', 'Hydrogen blending' and 'RTO' portfolios are shown in **Figure 99**. The offshore wind addition can be seen in 2032, while for the 'RTO' and 'Hydrogen blending' portfolios, the impact on resource buildout takes the form of a reduced need for resource additions. The resource buildout of the 'Offshore wind' portfolio differs substantially from the other Emerging Technology portfolios beginning in 2032 when offshore wind is added. Because of the high-capacity factor of offshore wind and the resulting large amount of energy added to the portfolio, the model is able to add a large amount of storage to complement the offshore wind addition, reducing reliance on the generic VER resource relative to other Emerging Technology portfolios, which are more reliant on the energy provided by generic VER. As a result of the 'Offshore wind' portfolio's lower reliance on the expensive generic resource, it has the lowest cost outcomes in the group (**Figure 100**).

Some impacts of emerging technologies on the pre-2030 resource buildout can be seen. While all portfolios add the same amount of wind (1128 MW), the 'Hydrogen blending' portfolio adds less solar (668 MW) than the other portfolio (between 1000 MW and 1010 MW). This smaller addition of renewables in "Hydrogen blending' is because of the additional existing energy available associated with hydrogen blending starting in 2029. Additionally, the 'Pumped hydro' and 'Long Duration Storage' portfolios both reduce the addition of other storage options through 2030. The relatively minor impacts on resource builds across the Emerging Technology portfolios highlights that resource actions now are not likely to be majorly impacted by emerging technologies (a finding that is explored further in **Section 11.5.3, Resource buildout robustness analysis**).

However, emerging technologies have a larger impact on longer-term actions, decreasing dependence on transmission expansion and the expensive generic resources. Given the high cost of the generic resources, the larger the addition of an emerging resource, the more costs can be reduced (as shown in **Figure 100** by the relatively low costs of the 'Offshore wind' portfolio, which has the largest addition of emerging technology). Unquantified benefits of these emerging technologies could include reduced dependence on the timing of transmissions projects. Thus, continued investigation of emerging technologies is warranted and can be a strategy for reducing costs in the longer term.

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[314] A 200 MW reduction in capacity need represents 5 percent of PGE's peak load of approximately 4,000 MW. This was used to define the potential benefits of joining an RTO based on SPP's estimate that load diversity reduces their need for capacity by approximately 5 percent of their peak load, described here: [2021 spp mvs methodology.pdf.]()

Figure 98. Resource buildout in long duration storage, pumped hydro and hydrogen building portfolios

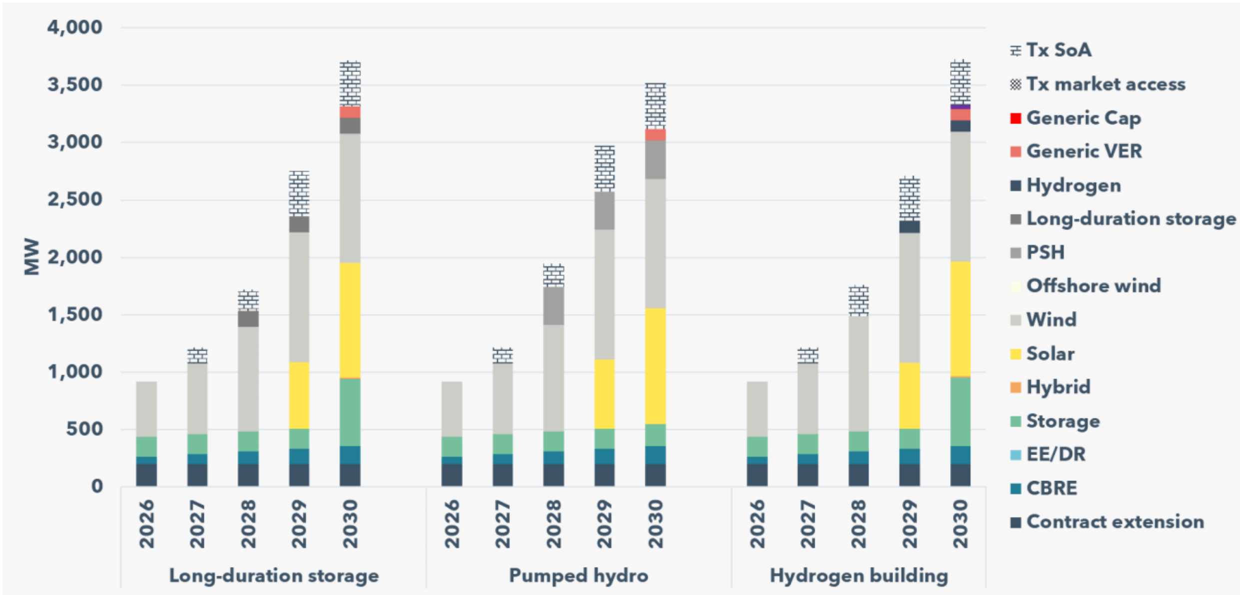


Figure 99. Resource buildout in RTO, hydrogen blending and offshore wind portfolios

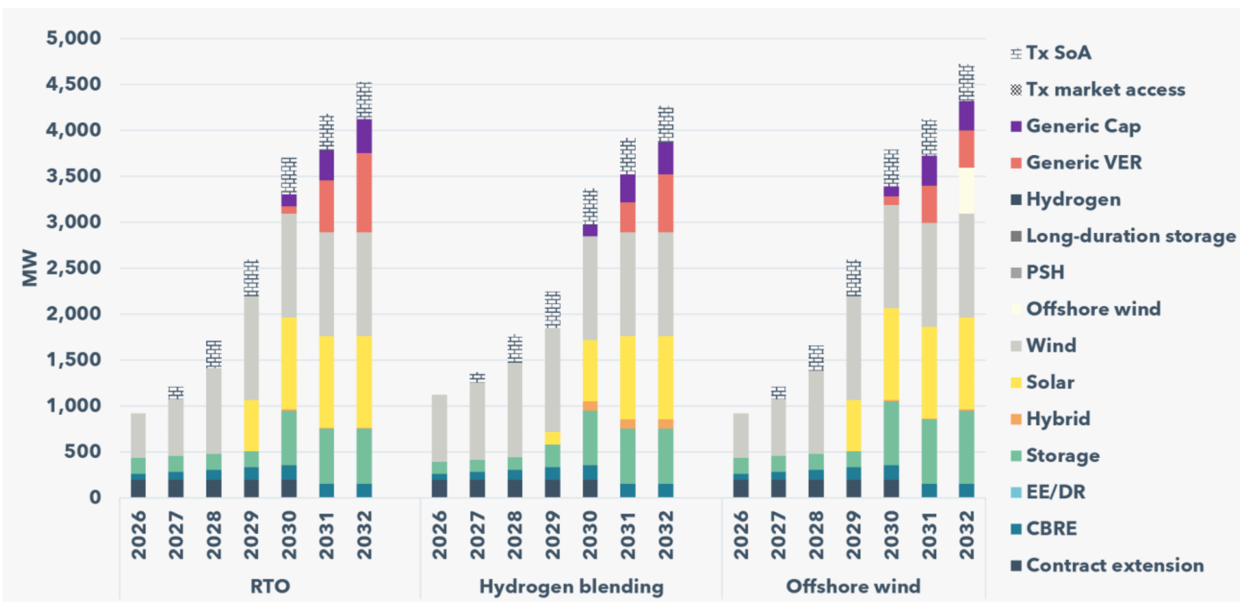
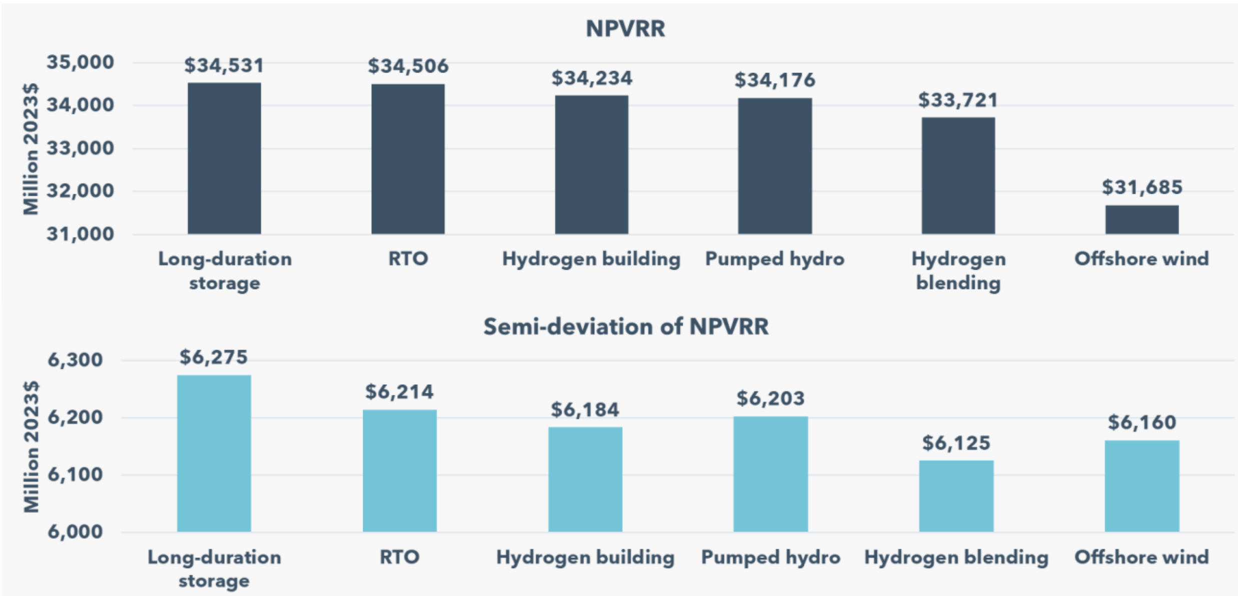


Figure 100. Cost and risk metrics of emerging technology portfolios



11.5 Preferred Portfolio

PGE evaluated 39 portfolios to answer key questions in PGE's current energy economic landscape. Based on these insights, PGE developed a Preferred Portfolio to meet system needs based on the answers to key questions and common themes. The Preferred Portfolio meets HB 2021 emissions reductions targets using the linear decarbonization glidepath and is forecast to emit 32.67 MMTCO2e over the entirety of the 2024-2043 portfolio analysis time-horizon (as shown for the 'Linear decline' portfolio in **Section 11.4.1, Decarbonization glidepath portfolios, Figure 78**). The Preferred Portfolio also complies with RPS obligations, as demonstrated in **Section 11.5.2, Resulting RPS position.** The key findings that emerged from portfolio analysis and were used to define the Preferred Portfolio are presented in **Figure 101**.

Figure 101. Key findings from portfolio analysis used to define the Preferred Portfolio

Key Findings

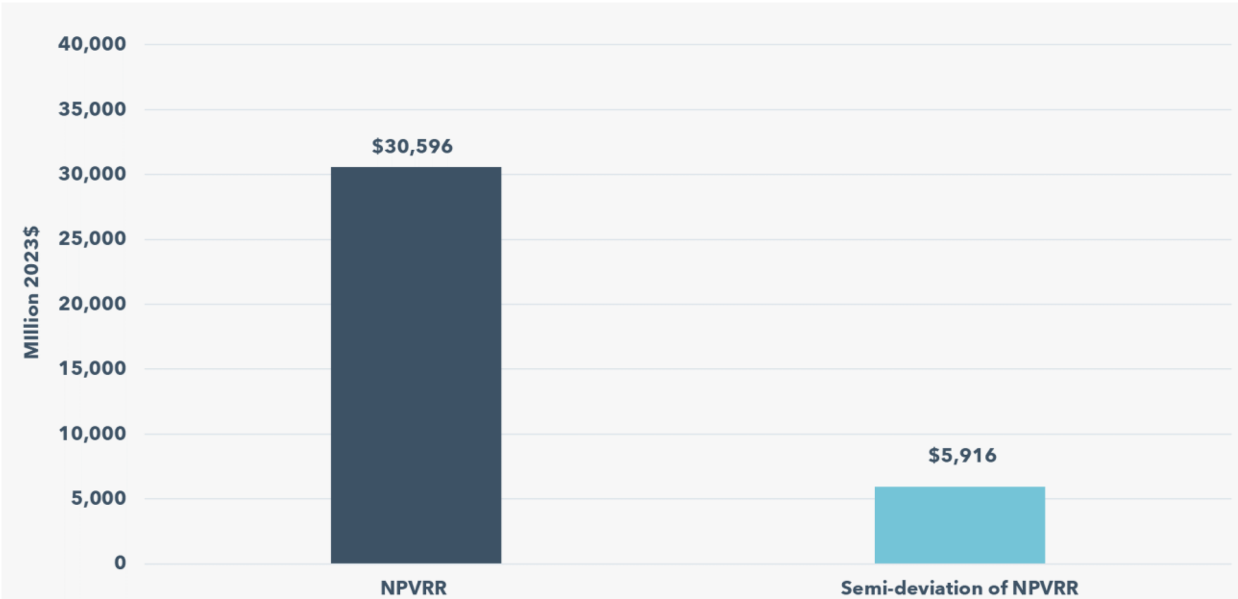
1. A linear glidepath to meet the 80% reduction in emissions by 2030 best balances cost, risk, and pace of emissions reduction.
2. Adding 100% of the CBRE potential would best balance cost, risk, and community benefits.
3. The magnitude and timing of additional transmission capacity is the largest factor that influences resource additions and the cost and risk metrics of portfolios.
4. It is infeasible for PGE to meet the 2030 HB 2021 targets without any transmission upgrades and the magnitude of transmission need increases throughout the planning horizon.
5. Transmission upgrades to connect to off-system resources can be delayed by investing in resources such as energy efficiency, demand response, and distribution connected CBREs. However, given the magnitude of transmission capacity needed, these resources can only marginally delay the need in early years and cannot offset transmission need in the long-term.
6. Upgrades to PGE transmission that unlock additional access to proxy resources is sufficient to address system needs.
7. Increasing access to new transmission expansion options can help reduce costs, variability risk, and resource needs, which reduce potential risks associated with procurement, stemming from supply chain issues.
8. Emerging non-GHG-emitting technologies that could have a high capacity and/or energy contribution such as nuclear, hydrogen, long-duration storage, and advanced geothermal can mitigate this significant dependence on transmission over the long-term.

Through 2030, the Preferred Portfolio selected optimized quantities of VERs totaling 2,090 MW, 232 MW of storage and 255 MW of transmission expansion proxy resources. The 255 MW of proxy transmission resources have an associated 206 MW of WY wind and 49 MW of NV solar, which are included in the total VER quantity. No hybrid resources were selected, with the model instead utilizing existing transmission capacity to select stand-alone VER resources with higher capacity factors paired with stand-alone storage options and capacity-dense Tx expansion proxies. Additionally, the resource buildout of the Preferred Portfolio includes 200 MW of non-GHG-emitting contract extension, 400 MW of SoA Tx upgrade added in 2027 and 155 cumulative MW of CBRE resources. The model was not allowed access to additional EE or DR in the Preferred Portfolio but does include a total of 156 MWa of cost-effective EE and 223 MW of cost-effective DRs, which are accounted for as a reduction in resource needs (see **Section 6.2, Distributed Energy Resource (DER) impact on load**). The Preferred Portfolio meets capacity and energy needs with the resource buildout, shown in **Table 64**, at a cost of $30,596 million (NPVRR in **Figure 102**).

Table 64. Cumulative resource buildout in Preferred Portfolio (MW)

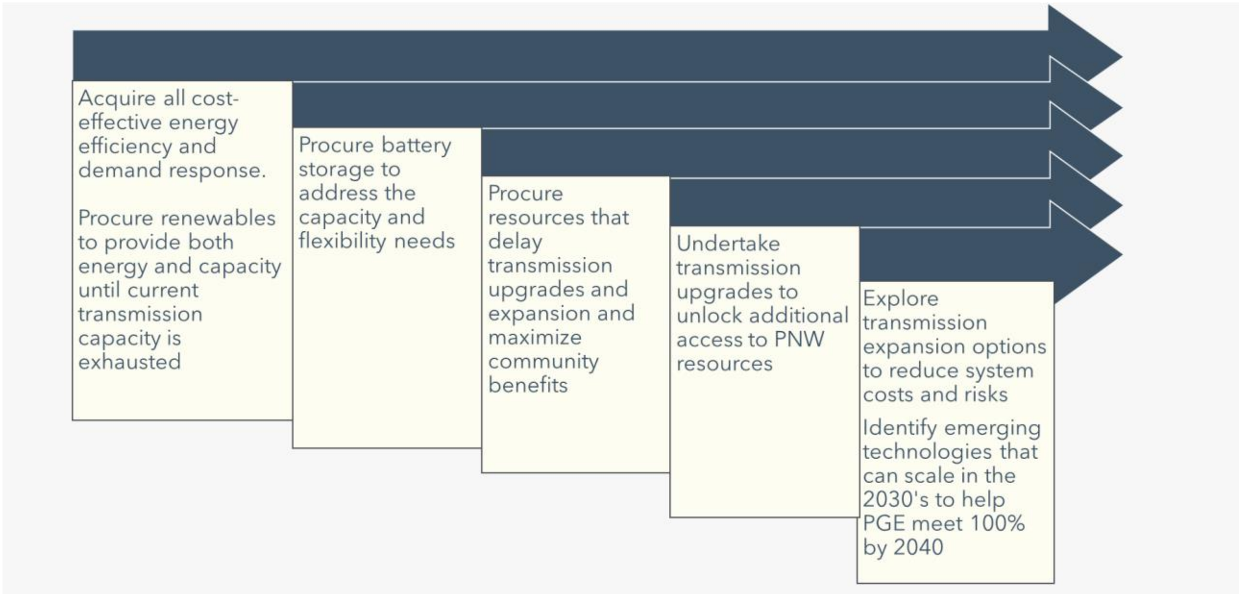
	2024	2025	2026	2027	2028	2029	2030
Wind	0	0	227	627	901	1172	1334
Solar	0	0	0	0	0	490	756
Hybrid	0	0	0	0	0	0	0
Storage	0	0	232	232	232	232	232
CBREs	0	0	65	84	110	133	155
WY Tx	0	0	44	44	44	44	206
NV Tx	0	0	0	0	0	0	49
SoA Tx	0	0	0	400	400	400	400
Additional EE & DERs	0	0	0	0	0	0	0
Non-GHG-Emitting Contract Extension	0	0	200	200	200	200	200
Cost-effective EE (MWa)	30	60	90	120	150	183	216
Cost-effective DR	133	162	183	199	211	218	228
Clearwater Wind	311	311	311	311	311	311	311
Wasco solar (RFP Proxy)	0	230	230	230	230	230	230
Christmas Valley solar (RFP Proxy)	0	180	180	180	180	180	180
4 hr battery (RFP Proxy)	0	400	400	400	400	400	400

Figure 102. Cost and risk metrics of the Preferred Portfolio



When considered in aggregate, these insights highlight how the binding nature of decarbonization and transmission constraints severely limit the options available to PGE and necessitate an approach to pursue all avenues of resource additions that are available and feasible. **Figure 103** visualizes the summary of these insights.

Figure 103. Visualizing the key themes of portfolio analysis that necessitate a 'pursue all' approach to best balance cost, risk, emission reduction and community benefits



11.5.1 Preferred Portfolio yearly price impacts[315]

Although the yearly price impacts do not represent actual customer price impacts, the near-term price impacts are an important concern when evaluating options to decarbonize reliably. Through an extensive analysis of resource additions amongst a variety of portfolios, we have found that while the incremental resource additions included in these estimates represent the least cost and risk manner to meet the emissions targets established in HB 2021, they are anticipated to raise the costs associated with generation resources relative to a 2023 baseline. These Reference Case price changes, normalized by load, are shown in **Figure 104**. In the very near-term, the price impact of the 2021 all-source RFP resources coming online in 2025 can be offset in part by expected increased wholesales sales based on economic dispatch and market prices. The compounded annual growth rates (CAGR) of those price impacts 2024-2030 are displayed in **Table 65**. After 2025, the Preferred Portfolio adds the resources listed in **Table 64**. With a 50 percent ownership assumption, the ITC benefits of storage resources added in 2026 partially offset the impact of cost increases from resources added in the 2021 all-source RFP. Incremental resource additions, including the expansion of the existing transmission system, continue to increase the costs of generation resources through 2030. While this analysis does not represent actual changes to customer prices, it is suggestive that, on a planning basis, system costs are likely to increase through

[315] **Addendum: PGE CEP Data Template** contains the annual price impact in $'s and the annual price impact per unit retail sales ($/MWh) through the planning horizon for each portfolio

2030: the Reference Case costs of generation resources, normalized by load growth, are forecast to increase by approximately 21 percent by the end of the decade.

Given the constraints in the planning environment associated with HB 2021 decarbonization goals and transmission availability, the need for resource procurement identified in this IRP is large and appears to result in substantial impacts on costs. PGE constructed a Preferred Portfolio that minimizes the costs and risk of these new resource acquisitions and maximizes the provision of community benefits by thoroughly investigating key decision points with the potential to impact costs. This includes selecting a linear GHG-emissions reduction pathway that complies with HB 2021 requirements while mitigating costs relative to more-aggressive pathways and reducing risks compared to less-aggressive pathways. Choices that minimize cost or risk were also made regarding additional DERs, the inclusion of CBRE resources and opportunities to expand transmission availability. Mitigating the impact of this increase in costs will be critical and PGE will continue to study all potential options that can help minimize costs, including continuing to explore the potential of emerging technologies as they develop and studying options to expand transmission access.

Figure 104. Yearly price impact (in $/MWh) of the Preferred Portfolio

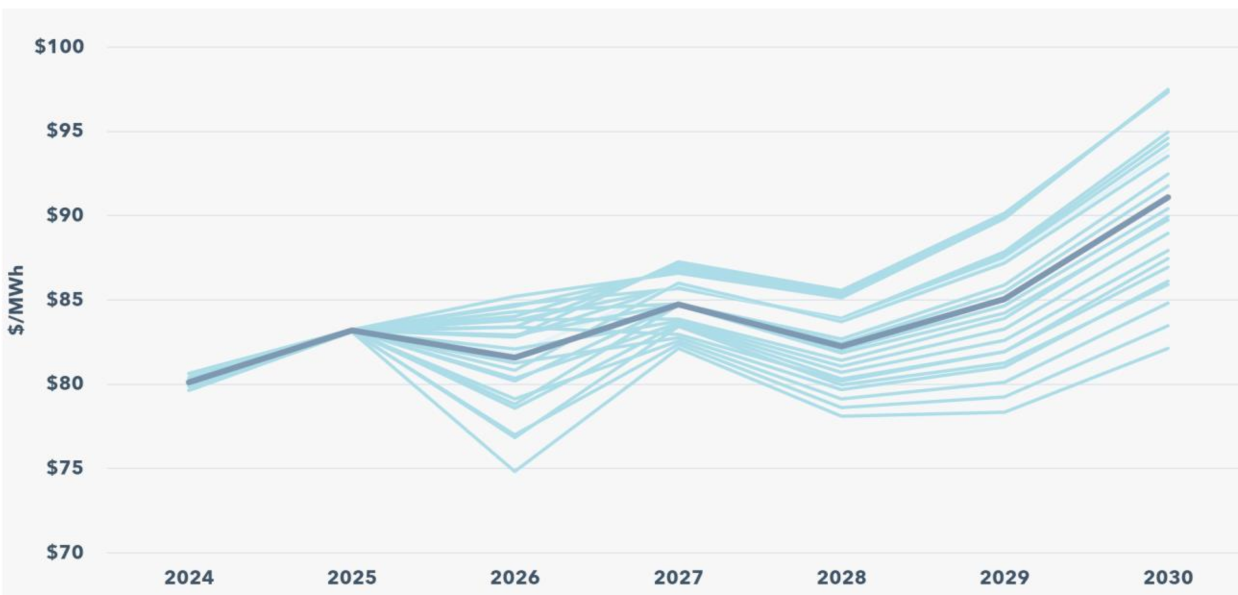


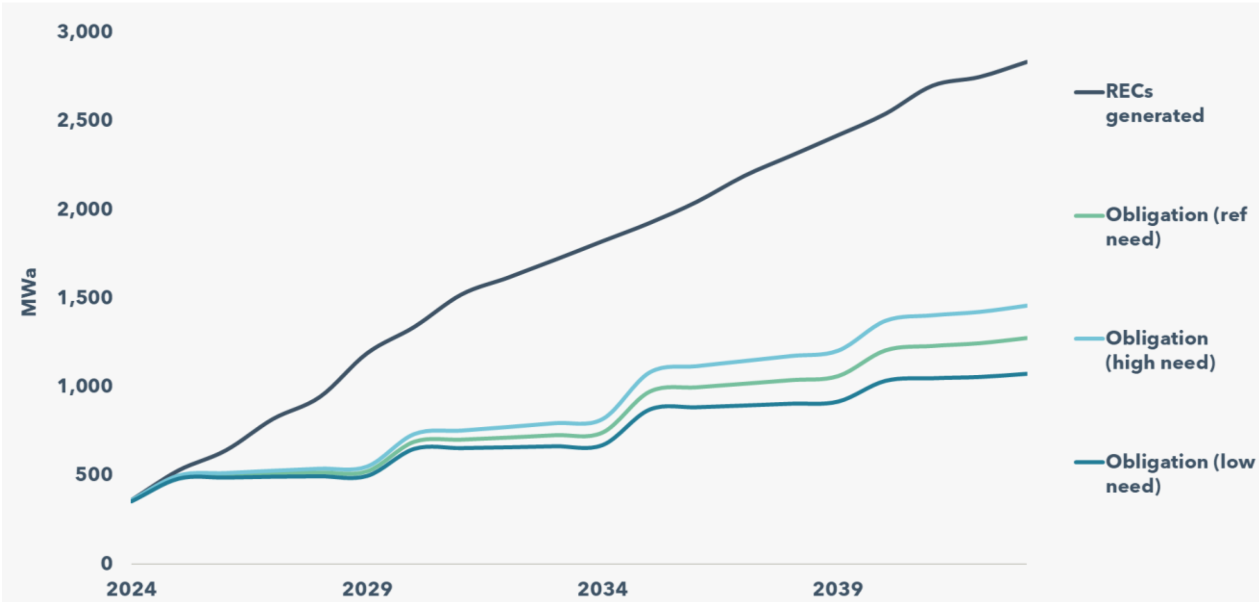
Table 65. Compounded annual growth rate of price impacts of the Preferred Portfolio 2024-2030

		PGE Ownership				
		0%	**25%**	**50%**	**75%**	**100%**
Tax Credit Levels	50%	3.9%	3.9%	3.8%	3.8%	3.8%
	75%	3.4%	3.3%	3.2%	3.2%	3.1%
	100%	2.9%	2.8%	2.6%	2.4%	2.3%
	125%	2.4%	2.2%	1.9%	1.7%	1.5%
	150%	1.9%	1.6%	1.3%	0.9%	0.6%

11.5.2 Resulting RPS position

PGE's RPS requirements are described in **Section 6.7, RPS need**. **Figure 105** shows the number of 5-yr RECs forecast to be generated by adding new resources in the Preferred Portfolio and REC obligations for the low, reference and high Need Futures. The generation of RECs from the existing and incremental RPS resources in the Preferred Portfolio is forecasted to enable PGE to comply with RPS requirements. While HB 2021 regulations are not REC-based, the need to add new non-emitting resources to comply with HB 2021 GHG reduction requirements is larger than is needed to comply with RPS requirements, resulting in the forecast number of RECs generated by PGE's portfolio greatly exceeding RPS requirements.

Figure 105. RPS compliance of Preferred Portfolio[316]



11.5.3 Resource buildout robustness analysis

Portfolio analysis in the 2023 IRP is heavily focused on resource acquisition needs primarily in the Action Plan window of 2026-2028, and secondarily on the crucial years for achieving compliance with HB 2021 emissions reductions targets of 2029 and 2030. Uncertainty surrounding key forecasts and assumptions used in portfolio analysis increases over the planning horizon, making findings for the latter years of the analysis less robust than those for the near-term.

In addition to the increased uncertainty in forecasts of variables like market prices and costs of commercially available technologies like VERs and storage, substantial uncertainty exists about the economic and technological development rate of emerging non-GHG-emitting technologies. It is likely that rapid development in the availability and cost of one or more of these emerging technologies will be needed for PGE to achieve the HB 2021 100 percent reduction in GHG-emissions target by 2040. The potential roles of a variety of emerging technologies in helping PGE fully decarbonize by 2040 are explored in **Section 8.5, Post-2030 resource options**.

Because of the substantial resource needs PGE faces in the near-term, it is infeasible to wait for emerging technologies to develop before taking resource procurement actions: near-term needs must be met using currently available technologies. However, resource

[316] This forecast of 5-year REC generation includes RECs that have been designated for retirement voluntary programs

acquisition decisions made by PGE now should attempt to minimize the risk of negative impacts on the ability to use the range of emerging technologies as they develop in the future.

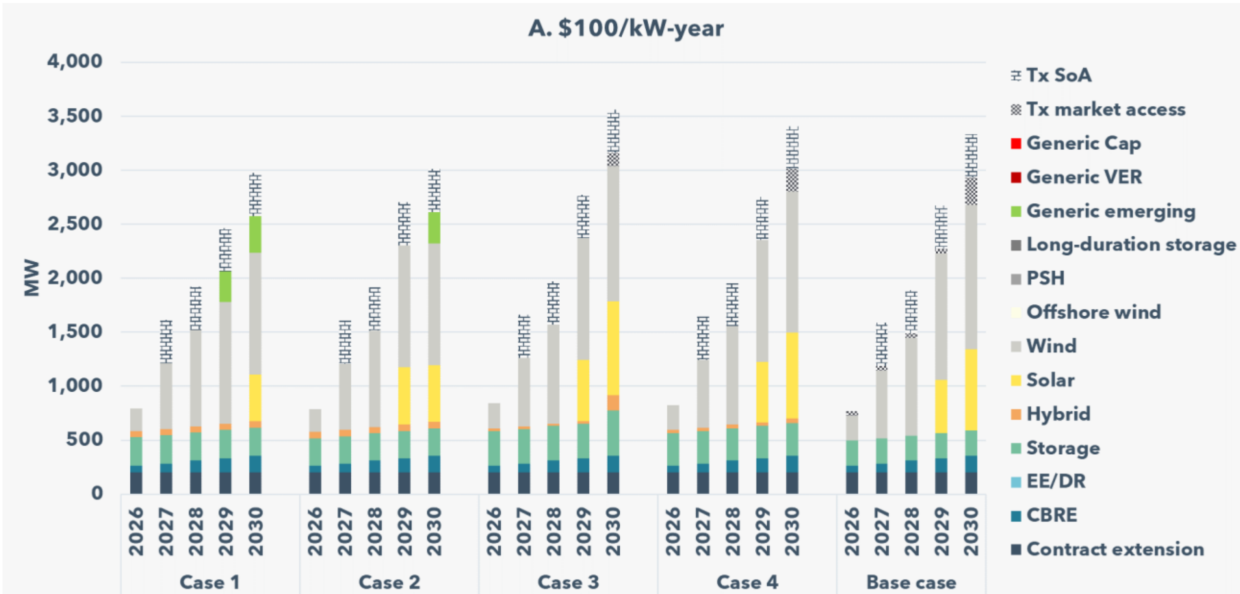
To test the robustness of the resource buildout in the near-term against these sources of uncertainty, PGE conducted an analysis varying the cost and timing of availability across multiple years and cost levels of an additional generic, non-emitting emerging resource with 100 percent ELCC and 50 percent capacity factor, representing a range of rates of development of emerging technologies. As shown in **Table 66**, 16 cases were analyzed with the first year of availability varying from the first-year post-Action Plan (2029) out to 2032 at a cost ranging from $100/kW-year to $1,000/kW-year. All cases have an otherwise consistent set of assumptions and are compared against a base case in which the generic emerging resource is defined in the default manner for portfolio analysis of being available for $1,000/kW-year after 2030.

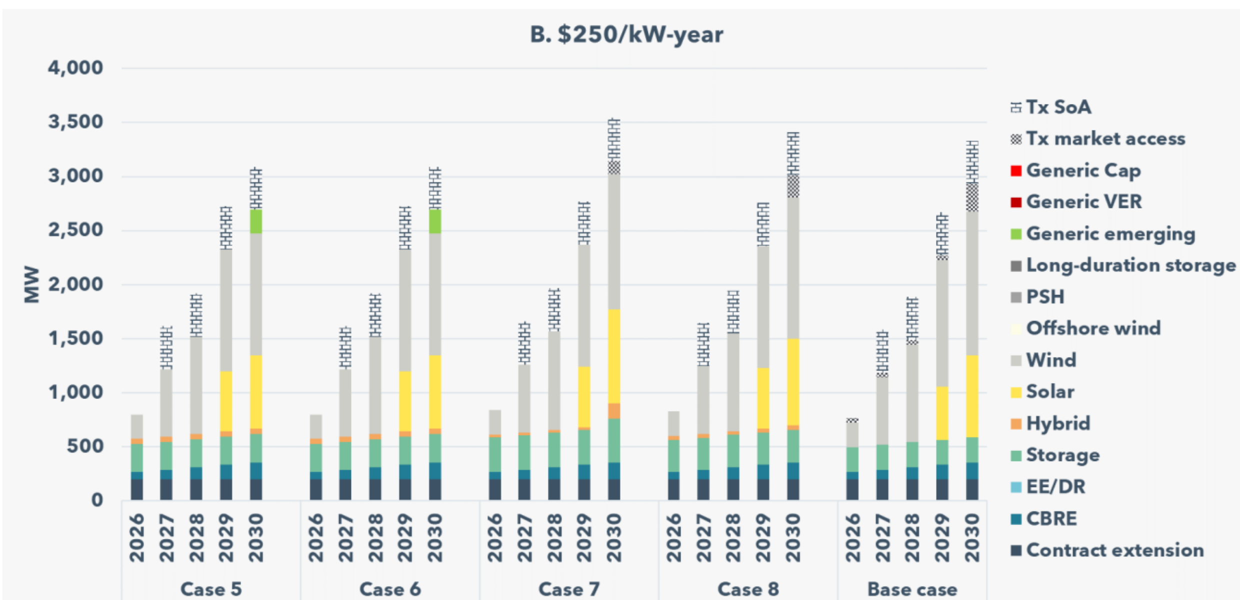
Table 66. Timing and cost of generic resource availability

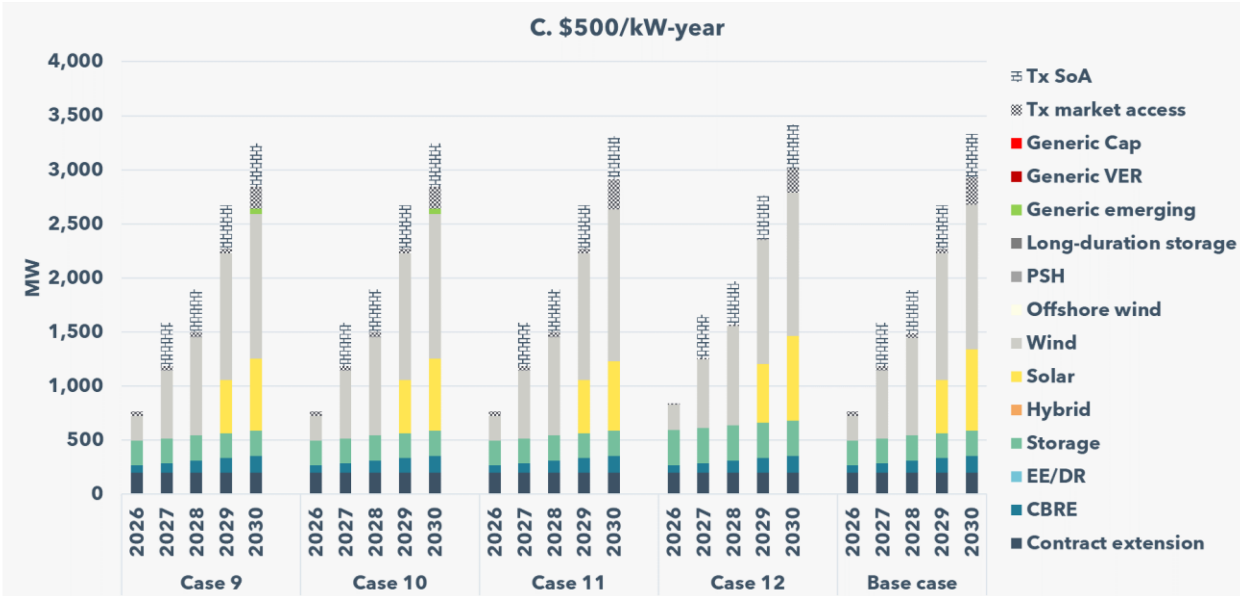
	Cost of generic resource			
Year	**$100/kW-year**	**$250/kW-year**	**$500/kW-year**	**$1000/kW-year**
2029	Case 1	Case 5	Case 9	Case 13
2030	Case 2	Case 6	Case 10	Case 14
2031	Case 3	Case 7	Case 11	Case 15
2032	Case 4	Case 8	Case 12	Case 16

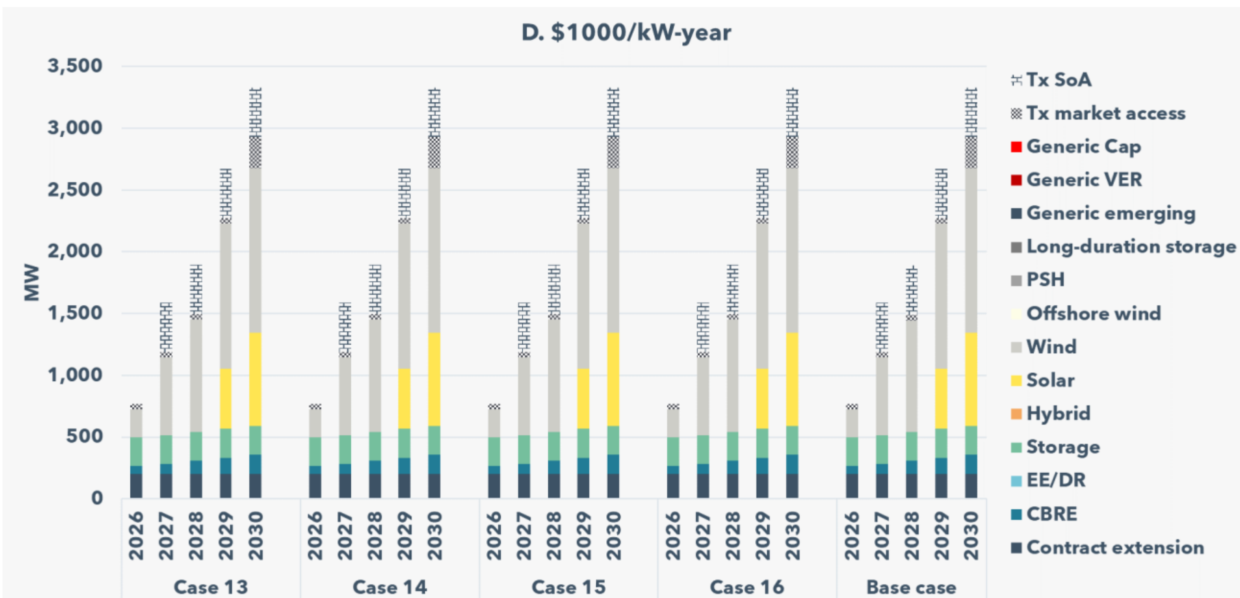
The resulting resource additions are shown in **Figure 106.** When the generic emerging resource is available for $1,000/kW-year, the resource buildout of the Preferred Portfolio is almost entirely unaffected, regardless of the year it becomes available. When the generic emerging resource is available for $500/kW-year, it is selected as early as 2030, and some minor changes in resource buildout are seen across all four cases. Additions of the generic emerging resource in 2030 offset solar and transmission additions. At a cost of $250/kW-year, the generic emerging resource is selected as early as 2030 and is added in larger amounts than at a cost of $500/kW-year. When the generic emerging resource is available for $100/kW-year, it is selected in the first year it becomes available (as early as 2029). In both cases, the most notable impact on the Preferred Portfolio resource buildout is on the selection of WY and NV transmission expansion. When the generic emerging resource becomes available in 2029 or 2030, the model shifts entirely away from transmission expansion, while in the cases in which it becomes available in 2031 or 2032, transmission expansion is selected in 2030, but in smaller amounts than in the Preferred Portfolio.

Figure 106. Resource buildout of resource build robustness analysis scenarios, grouped by generic resource cost









The results of the analysis show that at prices at or above $1,000, the resource buildout of the Preferred Portfolio is unaffected and at prices at or above $500/kW-year the impacts are very slight, regardless of when the generic resource becomes available. Between $250 and $500, there is an inflection point above which the resource buildout of the Preferred Portfolio is robust to the impacts of future technological developments of emerging non-GHG emitting resource options. Transmission expansions are the most expensive proxy resources available for selection (aside from non-cost-effective DR) and are, therefore, likely to be the first additions to be offset by development of emerging technologies. However, given the rapid cost declines and technological advances that would be required for emerging resource options to develop at costs below the inflection point before 2030, these results suggest that the near-term resource additions of the Preferred Portfolio (particularly within the Action Plan window) are robust and are low regret options despite the potential for emerging technologies to disrupt resource additions in the long-term.

11.6 Informational community benefits indicators

PGE reviewed the three CBI pathways with community members and environmental justice (EJ) communities. [317] We began development of Information Community benefits indicators (iCBIs) applying Attachment A from Order 22-390.[318] By providing an initial synthesis of potential focus areas from a diverse group of energy advocates, the attachment provided a starting point for CBI development which was supplemented and refined through our engagement process.

As we continue to engage with our communities through our Community Learning Labs, and as we develop experience designing and implementing CBRE resources, we will leverage Attachment A and additional CBIs identified through our community engagement efforts. **Table 26 (Interim CBI metrics and roadmap for future development)**, found in **Section 7.1, Community benefits indicators (CBIs)**, provides an overview of the interim CBIs for the three, identified pathways that have resulted from our work so far. As we heard from our engagement sessions, PGE will update and refine these metrics through our ongoing community engagement efforts. In addition to this work, we conducted research to address Reduction in High Energy Burden and Weatherization, discussed various methods to value these benefits and what PGE needs are to calculate these values (see **Section 7.1.6, Informational community benefits indicators**, for more details).

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[317] PGE defines Environmental Justice communities as communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities historically excluded in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.
[318] *See* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Attachment A at 65, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

11.7 Sensitivities

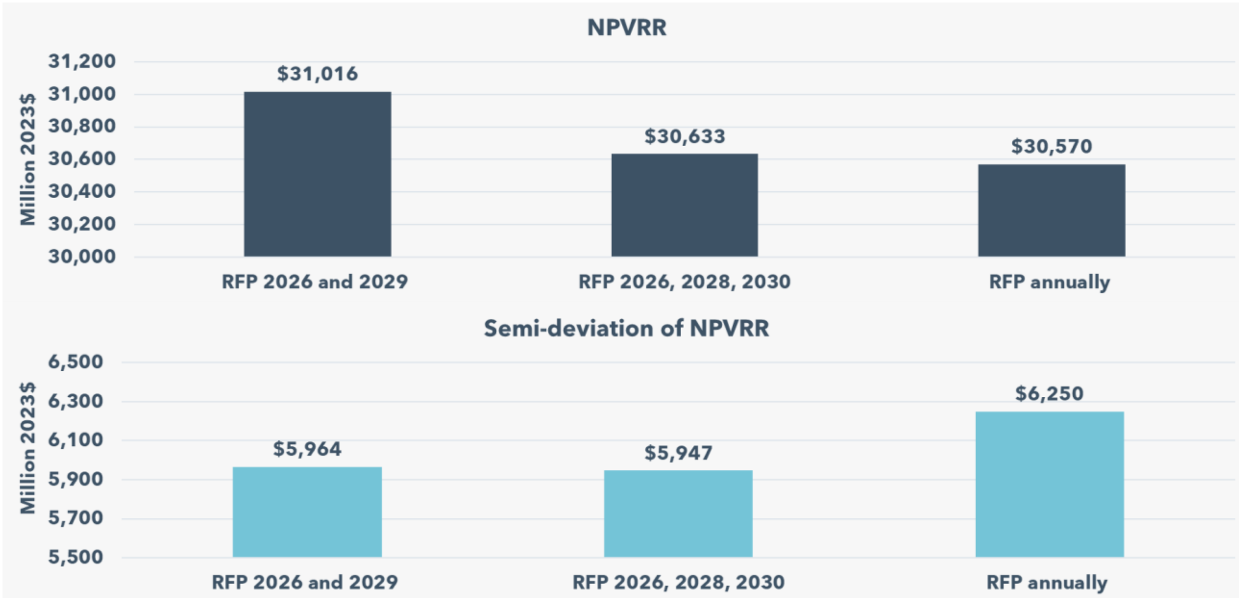
11.7.1 RFP size

Considering the unprecedented increase in the need for resource procurement to accomplish system decarbonization, further examination is needed to evaluate the timing of RFPs. To explore this topic, PGE conducted an analysis of the cost and risk impacts when the Preferred Portfolio is subjected to alternative RFP cadences and magnitude of procurement (**Figure 107**). Three scenarios were analyzed considering alternative procurement schedules by imposing constraints on annual procurement quantities through 2031 (**Table 67**). Aside from the procurement constraints, the portfolio's details match that of the Preferred Portfolio with the exception that all three RFP-size portfolios were not subjected to the energy surplus constraint to facilitate large resource additions where needed. Removal of the energy surplus constraint is necessary to allow the model to concentrate resource additions in 'RFP years', potentially adding more energy than is needed in that year to have sufficient energy in subsequent years when resource additions cannot be made.

Table 67. Procurement constraints through time in RFP size and timing scenarios

Year	Maximum annual resource addition					
	RFP 2026 and 2029		RFP Annually		RFP 2026, 2028, 2030	
	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)
2026	1,000	800	180	133	400	267
2027	0	0	180	133	0	0
2028	0	0	180	133	400	267
2029	1,000	800	180	133	0	0
2030	0	0	180	133	400	267
2031	0	0	180	133	0	0

Figure 107. Cost and risk of RFP size and timing scenarios



Results of the analysis show that the case in which resource additions are limited to occurring only two times before 2032 (RFP 2026 and 2029) produces the largest costs (**Figure 107**). This result is intuitive because this case constrains the model's ability to optimize the timing of resource additions the most, and results in resources being added before they are needed to meet capacity and energy needs. As previously mentioned, the earlier resources are added, the higher costs will be because of discounting in the calculation of NPVRR and the decline in resource costs through time. It is similarly intuitive that the case in which RFP's are conducted annually, 'RFP annually' is the least-cost because the model has the most freedom to match the timing of resource additions to capacity and energy needs. The 'RFP annually' scenario has higher variability than the scenarios in which RFPs are larger and occur less frequently because in some High Need Futures it has higher NPVRR. This is a result of having less ability to match the timing of larger needs with smaller and more frequent procurement. Additionally, adding resources early may increase costs but decreases procurement risk by obtaining resources when they are available, rather than waiting and risking not being able to procure resources when they are needed. As we approach a decarbonization target that is less than 7 years away, we continue to work with regulators and stakeholders to find ways to accelerate the acquisition timeline while retaining an emphasis on engagement and feedback throughout the process. PGE has proposed a streamlined framework for the 2023 RFP within docket UM 2274 and anticipates the need for frequent and nimble procurement throughout the remainder of the decade.[319] Procurement risk associated with supply chain constraints is explored further in **Section 11.7.2, Supply chain**.

11.7.2 Supply chain

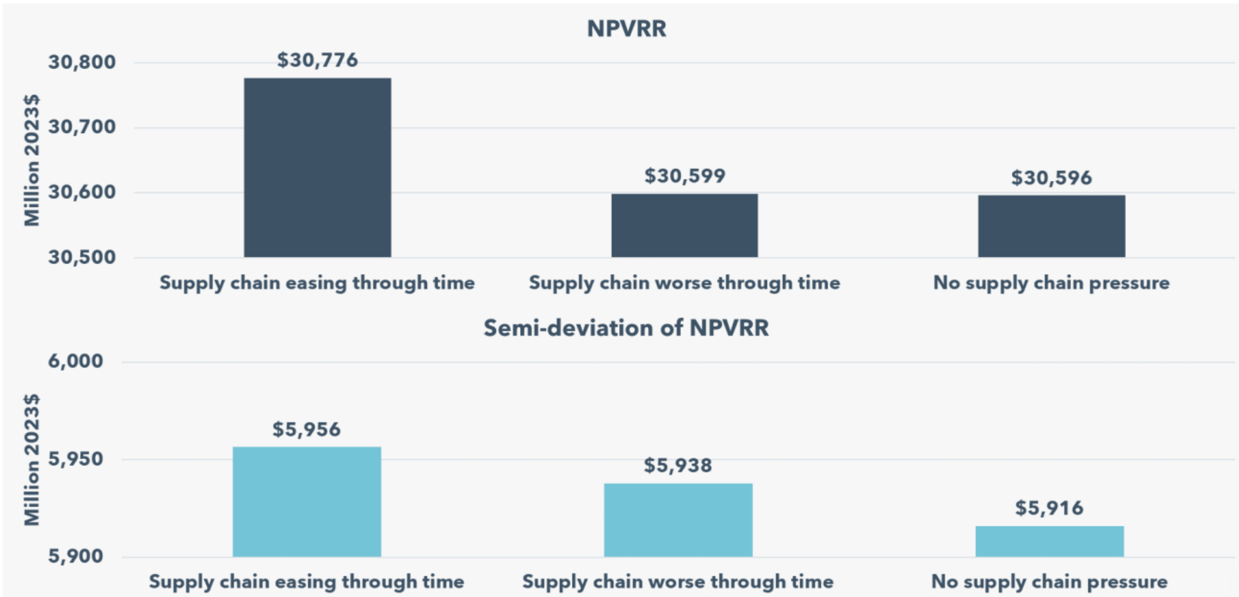
As described in **Section 3.3.3, Supply chain**, PGE's ability to procure new resources is subject to the ability of the complex global system of manufacturing, shipping and construction, known as supply chains, to produce, deliver and install the critical equipment (i.e., solar panels, wind turbines and batteries) used in energy generation facilities. PGE considered the potential impact of supply chain congestion on resource acquisition by imposing two different sets of procurement constraints. The first scenario (Supply chain pressure easing) simulates near-term supply congestions that eases through time, and the second simulates increasing congestion through time (Supply chain pressure increasing). Procurement constraints imposed for the two cases are shown in **Table 68**. The supply chain pressure cases are compared to a case with no procurement constraints, aside from the default set identified in **Section 11.1.6, Procurement constraints**.

Table 68. Procurement constraints of supply chain portfolios

Year	Maximum annual resource addition			
	Supply chain pressure easing		Supply chain pressure increasing	
	Renewables (MWa)	Storage (MW)	Renewables (MWa)	Storage (MW)
2026	150	38	400	228
2027	200	76	350	190
2028	250	114	300	152
2029	300	152	250	114
2030	350	190	200	76
2031	400	228	150	38

[319] *In the Matter of Portland General Electric Company, 2023 All-Source Request for Proposals, Request for Partial Waiver of Competitive Bidding Rules*, Docket No. UM 2274 (filed Jan 31, 2023), available at: https://edocs.puc.state.or.us/efdocs/HAA/um2274haa16364.pdf

Figure 108. Cost and risk of supply chain scenarios



Results of the analysis provide evidence suggesting that supply chain disruptions have the potential to increase the cost and risk associated with acquiring the resources needed for PGE to meet HB 2021 GHG emissions reduction requirements. As can be seen in the cost and risk metrics (**Figure 108**), both cases produce increased cost metrics compared to the unconstrained supply chain portfolio. Near-term supply chain disruptions have a larger impact on portfolio costs and risk than ones that occur further in the future. The larger magnitude of the impact on costs of near-term supply chain disruptions is due to the need to acquire resources earlier than would otherwise be necessary, when discounting has less of an effect and resources are more expensive. While the cost and risk metrics quantified in this analysis are lower if PGE waits to acquire resources, if resource acquisitions are delayed as much as possible, and supply chain disruptions occur closer to 2030, there are risks that the resources necessary to comply with HB 2021 GHG emissions reductions requirements will not be available. This suggests a tradeoff between cost-risk and compliance-risk that PGE must balance.

Chapter 12. Action Plan

Portland General Electric (PGE) developed the Action Plan for the 2023 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) based on the key findings of the Preferred Portfolio. The Action Plan represents the best combination of cost, risk, community benefits and emission reductions, and outlines the actions PGE proposes to undertake to maintain reliability and meet emissions targets on a planning basis.

Chapter highlights

- PGE's Action Plan proposes a set of resource actions that we intend to take over the next four years.
- The Action Plan is built on the results of the five key components of the Preferred Portfolio that meet long-term system needs and decarbonization targets while minimizing cost and risk and maximizing community benefits.
- Customer resource actions include acquiring forecasted quantities of 'cost-effective' energy efficiency and demand response.
- The pursuit of Community-Based Renewable Energy (CBRE) resources is a cost-effective way to maximize community benefits.
- The energy action conducts one or more Request for Proposals (RFP) for non-emitting energy resources targeting one fifth of the remaining energy need after the addition of EE and CBRE resources.
- A capacity action conducts one or more RFPs targeting the remaining resource adequacy needs in 2026 after contributions from CBRE and other energy resources as well as bilateral contracts.
- PGE will pursue all options to mitigate congestion on the South of Alston (SoA) flowgate
- The Bethel-Round Butte transmission provides the best alleviation of near-term transmission constraints.

12.1 Key components of the Preferred Portfolio

PGE's 2023 IRP shows near-term actions can be taken that position PGE to meet critical long-term reliability and decarbonization goals. This CEP and IRP present an estimation of system need, an identification of available supply-side options and the analysis of portfolios, all of which explore the challenges and uncertainties in long-term resource planning. The combined analysis resulted in a Preferred Portfolio, which contains a set of incremental resource options found to be the best combination of long-term costs, risks and community benefits. The Preferred Portfolio meets customer needs through five core components: customer resource additions, CBRE additions, energy additions, capacity additions and transmission expansion. These components in the Preferred Portfolio through the Action Plan window are detailed in the following sections.

12.1.1 Customer resource additions

The Preferred Portfolio includes the following customer resource additions:

- All cost-effective EE (forecasted by the Energy Trust of Oregon (ETO))
- All customer DR additions (forecasted by the Distribution System Plan (DSP) Part 2)

These forecasted quantities of EE and DR provide an important method to decarbonize. The energy and capacity these resources provide are especially critical given the market constraints PGE faces as we work toward the emissions targets in 2030 and beyond. While results from portfolio analysis suggest additional quantities of EE could be a cost-effective manner to meet system needs, the near-term cost pressure and risk of resource non-procurement led their maximum additions in the Preferred Portfolio to be limited to the cost-effective levels displayed in **Table 69**.

Table 69. Cumulative customer resource additions[320]

	Reference Case					Low need					High need				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
Energy Efficiency (MWa)	90	120	150	183	216	90	121	153	186	221	90	120	150	181	212
Summer Demand Response (MW)	183	199	211	218	228	278	282	287	287	294	126	141	155	166	177
Winter Demand Response (MW)	137	149	158	167	174	183	188	192	199	205	92	104	115	126	134

12.1.2 Community-based renewable energy additions

The portfolio analysis in this IRP included both CBRE resources and contractual transmission constraints. Combined, the economic conditions suggest that while proxy CBRE resources evaluated are generally higher cost than utility-scale proxy resources, their location on-system makes them an effective means in portfolio analysis to reduce cost and risk. **Table 70** summarizes the cumulative of CBRE resources in the Action Plan window.

Table 70. Cumulative CBRE resource additions[321]

	2026	2027	2028	2029	2030
CBRE Additions (MW)	66	85	110	132	155

[320] Demand response estimates are comprehensive of all existing and incremental PGE DR programs.
[321] CBRE additions are equal in each need future

12.1.3 Energy additions

To meet House Bill (HB) 2021's 2030 emissions target, PGE has estimated the Reference Case need to acquire 905 megawatt average (MWa) of incremental generation. The Preferred Portfolio has identified a set of proxy resources that can plausibly be added between now and 2030 given market economics and transmission constraints. This set of resources, displayed in **Table 71**, takes advantage of technological and geographic diversity to meet system needs at the lowest combination of cost and risk.

Table 71. Cumulative energy additions by type in Preferred Portfolio (MW)

	Reference					High					Low				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
Wind	227	627	901	1,172	1,334	403	803	1,136	1,228	1,440	29	429	660	1,128	1,128
Solar	0	0	0	490	756	58	58	58	929	1215	0	0	0	69	529
Hybrid	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
CBRE	66	85	110	132	155	66	85	110	132	155	66	85	110	132	155
Contract Extension	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200

12.1.4 Capacity additions

While the energy additions described previously do contribute capacity to the system, to maintain resource adequacy additional resources are needed. **Table 72** displays the total dispatchable capacity additions in the Preferred Portfolio depending on Need Future, while **Table 73** depicts the capacity contribution of each resource type.

Table 72. Cumulative incremental dispatchable capacity (MW) in Preferred Portfolio

	Reference					High					Low				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
4-hr Batteries	232	232	232	232	264	503	503	503	503	503	176	176	176	176	288

Table 73. Approximate capacity contributions by resource type (MW) in Preferred Portfolio[322]

	Reference				
	2026	**2027**	**2028**	**2029**	**2030**
Storage	157	157	157	157	157
Wind	95	162	268	293	498
Solar	0	0	0	77	127
Hybrid	0	0	0	0	0
CBRE	32	41	53	65	75
Tx Market Access	33	33	33	33	198
Contract Extension	200	200	200	200	200

12.1.5 Transmission expansion

Incorporating contractual transmission limitations into portfolio analysis highlights an insufficient capacity of the existing transmission system to meet PGE's system needs. Declining emission targets increase the need for non-GHG-emitting resources. Those resources are generally located in areas that currently lack sufficient transmission capability to move energy to PGE's load. To maintain reliability while meeting emissions targets, additional transmission options are needed. PGE evaluated two types of proxy resource additions: improvements that enable additional resources with PGE's historical geographic area of investigation (located in Oregon, Washington and Montana) and additions that provide access to resources farther away (Wyoming and Nevada). Portfolio analysis demonstrated that the alleviation of the SoA constraint on BPA's system is the most cost-effective manner to meet system needs. Further, the option of regional expansion offers an effective means to access non-emitting energy and capacity. **Table 74** displays the quantities of transmission expansion in the Preferred Portfolio.

[322] The capacity contribution of NV and WY Tx expansion each show up in two locations. Capacity contribution from the associated VERs are accounted for in solar and wind, respectively. Capacity contribution from market access is accounted for in Tx market access. When combined, the ELCC of each Tx expansion proxy is 100 percent.

Table 74. Cumulative transmission additions in Preferred Portfolio

	Reference					High					Low				
	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030	2026	2027	2028	2029	2030
SoA	0	400	400	400	400	0	400	400	400	400	0	400	400	400	400
Wyoming	44	44	44	44	206	100	100	100	100	312	0	0	0	0	0
Desert SW	0	0	0	0	49	58	58	58	58	205	0	0	0	0	0

12.2 Action Plan

PGE's 2023 CEP and IRP Action Plan builds on the key components from the Preferred Portfolio highlighted previously. The five actions detailed in the following sections encompass a set of low-risk, near-term actions that provide the best combination of cost, risk, and community impacts while meeting system need and positioning the company on a pathway to meet HB 2021 emissions targets in 2030 and beyond.

12.2.1 Customer resource action

Customer participation continues to be a critical piece in achieving long-term decarbonization at the lowest cost to customers. PGE will pursue the incorporation of the quantities contained in the cost-effective forecasts of both Energy efficiency (EE) and Distributed energy resources (DERs). These non-emitting resources will provide both energy and capacity to the system.

- Action 1A. Acquire all cost-effective EE

PGE plans to acquire all cost-effective energy efficiency, which is currently forecast to be a cumulative 150 MWa through 2028.

- Action 1B. Incorporate customer additions

We plan to enroll distributed flexibility resources that customers choose to provide. By 2028, this is currently forecast to be a total enrollment of:[323]

- 211 MW of summer demand response (Low: 173 MW, High: 343 MW)
- 158 MW of winter demand response (Low: 127 MW, High: 234 MW)

12.2.2 CBRE action

PGE plans to conduct an RFP for CBRE resources. While the proxy CBRE resources modeled in the IRP presents a higher cost resource than more traditional utility-scale resources, both the inclusion of an rCBI credit and the reflection of existing contractual transmission constraints generate results that suggest distribution-connected CBRE resources are part of the least-cost and -risk set of resource additions. The project evaluation and scoring in this CBRE RFP will be guided by the developing Community benefits indicators (CBI) performance metrics and community feedback received from the Community Learning Labs.

- Action 2: Initiate a CBRE-focused RFP

PGE will conduct a CBRE RFP targeting 66 MW of CBRE resources to come online by 2026 and additional RFP(s) as necessary to support a trajectory towards achieving PGE's goal of 155 MW of CBRE resources by 2030 155 MW in 2030. PGE should continue to pursue federal and state grant opportunities that may help to reduce the costs of CBRE projects and work with customers and communities to develop future potential CBRE programs.

12.2.3 Energy action

Under HB 2021's 2030 carbon emissions targets a significant amount of incremental non-emitting generation will be necessary. The energy action is focused on PGE procurement of sufficient resources to meet projected energy needs.

- Action 3: Conduct one or more energy RFPs

PGE will conduct one or more RFPs to add sufficient non-emitting resources to meet the emissions targets established in HB 2021. The current Reference Case 2030 energy need is 905 MWa; PGE will target acquiring one fifth of that need (181 MWa) each year in the Action Plan (2026-2028), for a total of 543 MWa through 2028. While the customer actions (EE and DR) are reflected in these forecasts, the CBRE resources targeted previously will contribute to these acquisition targets, reducing the total need up to a forecasted 29.6 MWa (to approximately 875 MWa, or approximately 175 MWa per year). PGE will update energy

[323] Demand response values include existing programs.

needs as new information about load growth, resource acquisitions and any applicable changes to policy become available throughout the CEP/IRP and RFP processes.

12.2.4 Capacity action

Maintaining resource adequacy will be critical as we make progress on decarbonization. This action seeks to provide sufficient capacity to the system to ensure reliability.

- Action 4a: Pursue capacity opportunities in the bilateral market
- Action 4b: Conduct one or more capacity RFPs

The 2023 CEP and IRP forecasts significant capacity needs in 2028: 624 MW and 614 MW are needed in the summer and winter, respectively. Elevated and reduced projections of load growth, electrification, DER adoption and market access suggest this need could grow to 786 MW and 864 MW or shrink to 435 MW and 359 MW in the summer and winter. Like the energy action, the cost-effective EE and DER targets in the customer action are already incorporated in this need. While the CBRE and other energy resources described previously could help meet this need, resource additions beyond the CBRE and energy actions are required to maintain resource adequacy. This action will focus on meeting those resource adequacy needs. PGE will pursue the procurement of these resources in a staged approach, first acquiring any beneficial opportunities in the bilateral market, and second by conducting one or more RFPs to meet any remaining capacity needs through the Action Plan window. Similar to the energy action, PGE will update capacity needs throughout the CEP/IRP and RFP processes as new information on both generation supply and demand becomes available.

12.2.5 Transmission expansion action

Assessing the projected growth in demand compared with the characterization of the existing transmission system emphasizes that PGE cannot wait take action to address the transmission concerns described above. Delay could significantly increase projected cost and risk to PGE customers and the energy system. PGE will undertake a multi-phase approach to explore all potential options and pursue those that allow us to reliably decarbonize at the lowest cost and risk.

- Action 5A: Pursue options to alleviate congestion on the SoA flowgate

As discussed in **Section 11.4.2, Transmission portfolios**, the alleviation of the transmission constraints imposed by the SoA flowgate would provide the most effective way to increase the existing transmission system's ability to meet PGE system needs. This action will help enable PGE to add the required off-system non-emitting capacity proposed in the previous actions.

- Action 5B: Explore options to upgrade the Bethel-Round Butte line (from 230 to 500 kV)

As outlined in **Section 9.4.3, Bethel to Round Butte upgrade for future load service**, upgrading the Bethel-Round Butte transmission infrastructure would alleviate transmission congestion and enable critical incremental direct access to solar and wind resource-rich parts of Oregon, and create connections with neighboring transmission providers and western markets.

12.3 Request for Proposals

PGE intends to issue an all-source RFP in 2023 to procure non-emitting energy and capacity resources that can achieve commercial operations by the end of December 2025 to support capacity needs and also acquire renewable resources to further progress towards meeting HB 2021 decarbonization goals. After filing the notice and waiver in January 2023, PGE anticipates the following key milestones:

- February-June 2023: Procedural schedule set, PGE files draft RFP, review and feedback on draft RFP from stakeholders, Commission consideration of approval of draft RFP
- July/August 2023: RFP issuance to market
- December 2023: Final shortlist acknowledgement
- Q1-Q2 2024: Execute definitive agreements with bids on the final shortlist

The timeline used for past resource acquisitions is insufficient to meet the anticipated 2026 capacity need and HB 2021's targets in a manner that achieves balance of minimizing cost and risk and maximizing benefit. Both the current planning process, which was estimated within UM 2225 to take 30 months (about 2 and a half years), and recent procurement processes, which have taken approximately 18 months (about 1 and a half years), are unwieldy when faced with a relatively short procurement window. The procurement timeline sought by PGE in UM 2274 is intended to streamline the resource procurement process while retaining robust opportunities for regulatory review and feedback.

In the last RFP, under the competitive bidding rules (UM 2166), PGE followed a "track one" approach in which the IRP was reviewed and acknowledged, the RFP scoring methodology was vetted in the IRP, and then the RFP was drafted, reviewed and approved.[324] Given the anticipated 2026 capacity need, a track one schedule where the scoring and modeling methodology is vetted in the IRP is not workable to acquire resources specified in the Action Plan in a timely enough manner.

[324] *In the Matter of Portland General Electric Company, 2021 All-Source Request for Proposals*, UM Docket No. 2166, Order No. 22-315 (Aug 31, 2022), available at: https://apps.puc.state.or.us/orders/2022ords/22-315.pdf

Instead, in UM 2274, PGE has proposed a "track two" approach in which the 2023 RFP would be reviewed in parallel with the Commission's acknowledgement process of PGE's 2023 CEP and IRP. PGE's 2023 CEP and IRP docket would run in parallel with the 2023 RFP, which would culminate in anticipated Commission decisions regarding acknowledgment of the 2023 CEP and IRP, and 2023 RFP final shortlist in December 2023. While the regulatory review of the 2023 CEP and IRP, and the 2023 RFP would run in parallel, PGE anticipates that the ultimate procurement volume will align with the 2023 CEP and IRP Action Plan once PGE's resource plans are acknowledged.

To work toward the resource volume necessary to meet the HB 2021 decarbonization targets, it is in the best interest of customers for PGE to take steps now through more nimble acquisition processes as opposed to a cadence that would lead to future procurements closer to the end of the decade when we approach compliance obligations. The preferred resource strategy in this IRP highlights that from a portfolio perspective, balancing regulatory, operational, financial and resource procurement risks point to the advantages of a linear decarbonization pathway rather than one that delays acquisition until just before the 2030 compliance window.[325] Meeting this linear reduction pathway will necessitate substantial procurement of non-emitting resources throughout the decade. Layering procurement throughout the decade and achieving linear carbon reduction is also likely to provide the best opportunity to add resources that offer an optimal combination of geographic location, resource characteristics, advancements in technology and access to needed transmission rights.

12.4 Conclusion

The 2023 Action Plan and RFP are designed to reflect PGE's values and our commitment to serving customers with low-cost and clean technologies while mitigating future risks. The Action Plan was developed by estimating system resource need using forecasts of long-term demand and projections of generation from existing and contracted assets. The difference between that estimated demand and existing supply forms the basis of our forecasted system need. To fill that need, we first evaluated all available options and their potential costs and benefits in our system. We then tailored portfolio analysis to answer the most critical questions PGE faces in long-term planning, comparing the relative performance of portfolios with various combinations of supply-side options. A Preferred Portfolio was created with the best set of incremental resource additions that met system needs while minimizing cost and risk, while maximizing community benefits. Finally, an Action Plan was created to act on the key near-term drivers of the Preferred Portfolio. Concurrently with these actions, PGE will

[325] See PGE's January 26, 2023 IRP roundtable discussion, slide 78, available at: https://assets.ctfassets.net/416ywc1laqmd/68igRlq3sE4VQ9CSEK4r5P/c6982aeef3768c5d645ba8f3716be18a/IRP_Roundtable_January_23-1.pdf

continue to work to specify sources of market purchases and accompanying emission rates, utilize funding opportunities to mitigate customer price pressure and implement transmission upgrades within PGE's Balancing Authority and connecting to BPA's system. These actions provide clarity on our priorities and become a tool for future conversation with customers, stakeholders and the Commission.

Chapter 13. Resilience

This chapter provides Portland General Electric's (PGE's) approach to resilience-related analysis as outlined in the Public Utility Commission of Oregon's (OPUC's) UM 2225 resiliency-specific guidelines, which requires the first Clean Energy Plan (CEP) to include a chapter or other narrative describing its resiliency-related analysis.[326] This includes detailing how PGE coordinated with communities and stakeholders, identifying resilience risks and opportunities, and describing the key resilience-related programs and opportunities PGE will prioritize to support community-based renewable energy (CBRE).

Chapter highlights

- PGE used existing risk assessment analysis regarding system and customer resilience, including energy equity work conducted through PGE's Distribution System Plan (DSP).
- PGE's current and potential resilience programs and opportunities are needed to anticipate, adapt to, withstand and quickly recover from disruptive events.

13.1 Resilience overview

PGE defines resilience as our ability to anticipate, adapt to, withstand and quickly recover from disruptive events. PGE plans for the resilience of our system by identifying critical risks related to generation, transmission, distribution, physical security and information technology operations. We align our resilience efforts and plans across multiple functions and business lines where feasible. PGE's goal is to develop strategies that contribute to community resilience across all of our planning environments. As contemplated by the OPUC's UM 2225 guidelines for the CEP, we considered and differentiated actions related to other plans, such as Distribution System Plan (DSP) and Wildfire Mitigation Plan (WMP) analysis.

[326] In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans, Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Appendix A at 40, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf

In this chapter, PGE describes how our planning efforts seek to advance resilience across three focus areas. Additional information related to these three areas can be found within our DSP Part 1.[327]

- **PGE infrastructure resilience:** investment in infrastructure, such as grid hardening, integrated grid and energy supply hardening that mitigates the occurrence of outages during a disruptive event such as a heatwave, wildfire, wind or ice.
- **Operational resilience:** improvements in PGE's ability to meet customers' needs during disruptive events and accelerate service restoration through emergency preparedness, outage response, cybersecurity and customer support.
- **Customer infrastructure resilience:** investigation into customer-sited solutions, such as microgrids, batteries and other distributed energy resources (DERs), that provide customers the ability to maintain electric service during disruptive events, during normal conditions and provide services to the grid.

13.2 Evaluating resilience risks

Recent seasonal trends in peak load and associated uncertainties around future climate change impacts make it more important than ever to consider multiple factors, such as our system constraints, community needs and climate change, in a holistic approach to providing customers with safe, reliable and resilient power. In the summer heat wave of 2021, PGE's net system load broke prior records on four days, making PGE a summer peaking utility. Winter loads continue to increase, with a new winter net system peak load set on December 22, 2022. PGE continues to see an increased frequency and impact of weather events on the system; we had 16 Major Event Days (MEDs) in 2021 and nine major event days in 2022.[328] In analyzing the data over the last 10 years, the largest contributors of weather-related outage events occurred from 2020 through 2022. In addition, these trends raise important issues pertaining to how utilities are expected to understand and incorporate the different community zone of tolerance levels (see **Section 13.3, Zone of tolerance**) when evaluating risk reduction and resilience investments.

As described below, PGE has taken multiple steps toward evaluating risks related to climate change and natural disasters. PGE also works to improve regional safety by reducing wildfire risk while limiting the impacts of Public Safety Power Shutoff (PSPS) events on customers and increasing the resiliency of PGE operations in the face of wildfires. We continue to build on

[327] PGE's DSP Part 1, Resiliency Chapter, available at: https://assets.ctfassets.net/416ywc1laqmd/4nOQVHQGlgbCRAAZWNpuEd/946827f45bb6859133a151a052578778/DSP_2021_Report_Chapter5.pdf.
[328] PGE utilizes the definition of Major Events, Major Event Days and reliability metrics from IEEE 1366-2022.

the work in our DSP and Wildfire Mitigation Plan (WMP) to evaluate resilience risks and strengthen our capacities and system resources to minimize risks, stresses and shocks to the system.[329]

13.2.1 Natural disaster risk assessment methodology

13.2.1.1 Transmission & distribution (T&D) seismic risk assessment

Substations are designed in accordance with the seismic requirements and recommendations of a number of standards, codes and guidelines. New foundations and structures are designed to meet the requirements of ANSI/ASCE 7 and the Oregon Structural Specialty Code. Substation equipment is specified to meet the high seismic requirements of IEEE 693. Substation physical designs follow industry best practices for seismic performance, such as flexible jumpers, equipment anchorage and seismic bracing.

In 2019, PGE developed a proof of concept to systematically assess seismic risk across our system to craft rational, economically prudent risk reduction investment plans. The study analyzed ground shaking caused by a magnitude 6.8 earthquake in Portland Hills, which would impact the Portland urban area of PGE's service area. We presented our proof-of-concept to the OPUC at a special public meeting on January 15, 2019.[330]

The goal was to assess the likelihood of asset failure, its impact on the grid and evaluate the feasibility of scaling the proof-of-concept model. The study determined that the likelihood of an electrical asset failing during a seismic event is largely determined by ground shaking and the asset's structural integrity. The results suggested that rather than model all critical assets, PGE should pursue an incremental approach focusing first on evaluating the seismic risk and resilience associated with oil circuit breakers (OCBs) and the relevant mitigations. OCBs were chosen because they are susceptible to failure with ground shaking and present a significant age-based reliability risk. To mitigate these risks, PGE is in the process of approving funding for a proactive OCB replacement program, which will remove these breakers from the system.

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[329] PGE's DSP and WMP, available at: Distribution System Planning | PGE (portlandgeneral.com) and Wildfire Safety | Wildfire Prevention Measures | PGE (portlandgeneral.com).
[330] PGE's presentation to the OPUC, available at: https://statics.teams.cdn.office.net/evergreen-assets/safelinks/1/atp-safelinks.html.

13.2.1.2 Generation seismic risk assessment

In 2014, PGE conducted a focused seismic risk and assessment of our hydroelectric facilities. Through established practices and regulatory requirements, the existing dam structures were known to be capable of withstanding a Maximum Credible Earthquake (MCE) produced ground shaking.[331] Powerhouse structures are not included in the evaluation of the dam. However, the powerhouse infrastructure is critical to the safe passage of river flows and is likely a critical generation asset following an earthquake event.

Powerhouse structures were screened based on construction type and features vulnerable to ground motions. Outdoor powerhouses such as Round Butte, Pelton and North Fork were expected to perform well and within their elastic range, with reinforced concrete operating floors and protective structures over the generating units. Oak Grove, Faraday, River Mill and Sullivan powerhouses have a building enclosure and overhead bridge cranes. These structures were found to have sufficient mass, which could lead to a progressive failure and limit the ability to operate and pass flows.

For River Mill, Oak Grove and Sullivan, PGE evaluated the building performance for these structures based on the American Society of Civil Engineers (ASCE) 41 Seismic Evaluation and Retrofit of Existing Buildings. Initial screening procedures highlighted deficiencies in the lateral load-resisting system. A deficiency-based upgrade could be designed to achieve an Immediate Occupancy (IO) level of performance. Faraday could not be upgraded based on construction type. Faraday powerhouse was unreinforced masonry (URM) which is not allowed based on the site-specific design parameters. Reconstruction was the only alternative.

13.2.1.3 Community assessment

In 2022, PGE studied how seismic risk can be addressed from a customer-centric point of view. As a portion of PGE's DSP, we developed a framework for applying resiliency indicators (including seismic risk) to our Equity Index. We overlayed the Equity Index to the forecasted DER adoption at the census tract level within PGE's service area to highlight how this data might be used to develop targeted customer resiliency programs and initiatives.[332]

The seismic risk component of the Equity Index was included along with other factors such as wildfire and flood risk. To develop an Equity Index metric for seismic risk to customers, we

[331] Information about Maximum Credible Earthquake available at: https://www.ussdams.org/glossary_definition/earthquake-maximum-credible-mce/
[332] PGE's DSP Part 2, Equity Index and Community Targeting Assessment, available at: https://assets.ctfassets.net/416ywc1laqmd/79djvul6i8euOIXwjj1ba5/ffb773d38fa86b08ad1c11f9c7058fff/DSP_Part_2_-_AppendixN.pdf.

required data available for the entire service area. Therefore, we based our initial scoring on publicly available spatial seismic data from the US Geological Survey. The data reflects the peak acceleration value, which estimates the worst amount of shaking in about a 500-year time frame. As we move forward, we will reassess the seismic risk indicators in our Equity Index for customer risk assessment by evaluating the inclusion of new variables, like the OCBs described in **Section 13.2.1.1, Transmission & distribution (T&D) seismic risk assessment**.

13.2.2 Climate change vulnerability assessment

Climate change is considered as a cross-cutting factor (not as a standalone risk), possibly increasing the frequency and intensity of extreme weather, and increasing weather-related natural disaster risks. For example, when evaluating current generation, transmission and distribution risks during the energy supply-demand imbalance risk assessment, climate change was considered as a potential risk driver, making it a cross-cutting factor that impacts multiple enterprise-level risks. The specific risk events identified in that assessment were an ambient temperature-related generation derate or outage during a heat event, transmission outage during a heat event and widespread distribution interruptions due to an ice storm. In two cases, climate change was seen as potentially increasing the frequency and intensity of the event itself. In the other, it was acknowledged that climate change might increase the event consequences.

As noted in the 2023 WMP, PGE continues to further build upon its understanding of climate change impacts on wildfire risk and has leveraged fuel ecology and wildfire studies for the Willamette Valley and Oregon to develop variables to reflect these future projections. Our 2023 WMP was filed with the OPUC in December of 2022 and is pending review by the OPUC.

13.2.2.1 Oregon State University projections of extreme weather study

Historically, we have designed our transmission and distribution (T&D) system according to weather cases identified in the National Electrical Safety Code or based on actual events that struck the service area. However, climate change is likely to contribute to changes in the frequency and intensity of high-impact extreme weather events and past extremes may not accurately indicate future extremes. To increase PGE's understanding of the impacts of climate change on the distribution and transmission system, we worked with the Oregon Climate Change Research Institute and Oregon State University (OSU) to conduct a study. The study was designed to project extreme heat, extreme wind, freezing rain and ice accumulation within our service area through 2070 or beyond. The climate study was based on two different Representation Concentration Pathway (RCP) emissions scenarios (RCP 4.5 & RCP 8.5). The two RCP scenarios provided insight into two different potential climate futures to better prepare for a variety of potential outcomes. The study results are being evaluated to determine if changes to the design and construction standards of PGE's T&D are warranted.

13.2.3 Reliability metrics

Traditionally, System Average Interruption Frequency Index (SAIFI), System Average Interruption Duration Index (SAIDI), Customer Average Interruption Duration Index (CAIDI) and Momentary Average Interruption Frequency Index (MAIFI) are utility-centric reliability metrics that focus on the average grid performance. Customer-focused metrics such as Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Duration (CELID) are used to identify customers experiencing more frequent or prolonged duration interruptions.

PGE has started to augment the more traditional system-wide metrics with customer-centered metrics in analyses to identify the need for system improvements. Metrics like CEMI and CELID provide a more accurate picture of the reliability experienced by our most impacted customers. Traditional reliability metrics exclude MEDs, allowing a utility to compare grid performance year over year, regardless of variation in weather patterns. As PGE identifies opportunities to improve resilience, CEMI and CELID are calculated, including MEDs, to provide a clear picture of customer experience during disruptive events.

13.2.3.1 Value of service

As part of PGE's customer-centered risk-informed methodology, we leverage Pacific Gas & Electric's (PG&E's) 2012 reliability-based Value of Service (VOS) study approved by the California Public Utilities Commission (CPUC).[333] PGE has since escalated the 2012 values to 2022 dollars using the US Bureau of Labor Statistics' (BLS') CPI Inflation Calculator.[334] These VOS values are intended to reflect the baseline economic impact the different customer classes (residential, commercial and industrial) experience from an outage.

The VOS values have two components:

- **Interruption cost** ($/kilowatt (kW) economic impact of an outage regardless of the duration), and
- **Duration cost** ($/kilowatt-hour (kWh) economic impact of an outage duration; up to 24 hours)

[333] PG&E's 2012 Value of Service Study, available at: http://www.caiso.mobi/Documents/AttachmentB_ISOResponsesCommentsDraft2012-2013TransmissionPlan.pdf.
[334] The US BLS' CPI Inflation Calculator, available at: https://www.bls.gov/data/inflation_calculator.htm.

As discussed in DSP Part 2, PGE has developed economic risk models as a tool to identify risk on the system. Risk is defined as the product of failure probability and consequence cost of failure. A consequence of failure includes:

- Type of customer (residential, commercial and industrial)
- Kilowatt load impacted
- Duration of impact
- VOS to customers
- Direct costs to PGE to respond to the outage.

These VOS measures will enable our teams to better understand how customers value both reliability and resiliency and what we should take into account when making decisions.

13.2.4 Community resilience index

As part of PGE's DSP Part 2, we conducted an assessment for considering diversity, equity and inclusion (DEI), environmental and resilience parameters as part of our distribution system planning process.[335] Resilience was based on environmental risk factors, such as wildfire or flood vulnerability areas, and grid/system needs, such as long-term outage locations. Through an assessment, we developed a set of indices needed to understand the geospatial distribution of these parameters within our service area and identify our most affected and vulnerable populations. We researched numerous factors that could explain the relative resilience of different portions of our distribution system. Through statistical and geospatial analyses, we summarized distributions of priority variables for resilience factors within our service area. These results were then statistically evaluated to develop quintile distribution frameworks. Within the study, we also presented a few application examples to show how we can integrate this toolkit into PGE's DER forecast model, AdopDER, and consider approaches for efficient targeting to influence program design, targeted deployment and benefit optimization based on locational factors.

The study aimed to achieve the following steps:

- Review available data sources and solicit stakeholder feedback to identify specific criteria and key variables used to characterize DEI, environmental and resilience parameters.

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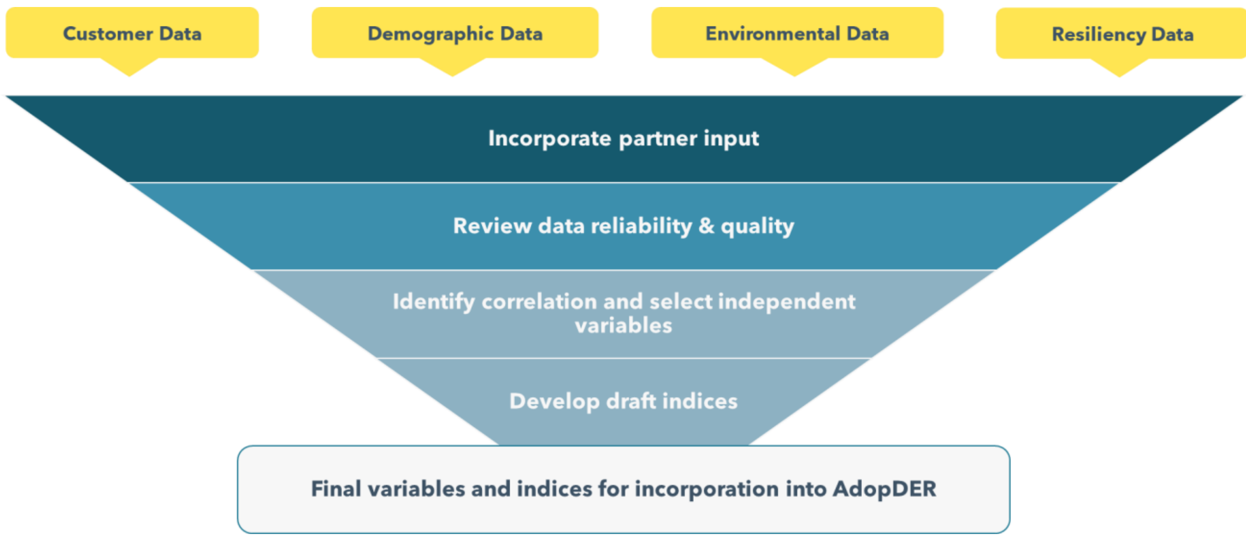
[335] PGE's DSP Part 2, Equity Index and Community Targeting Assessment, available at: https://assets.ctfassets.net/416ywc1laqmd/79djvul6i8euOIXwjj1ba5/ffb773d38fa86b08ad1c11f9c7058fff/DSP_Part_2_-_AppendixN.pdf.

- Develop a set of indices to account for the various underlying variables and locational elements across DEI, environmental and resilience prioritization areas.
- Summarize results of these indices to identify trends and consider future applications for resource planning, including siting locations for future non-wires solutions.
- Integrate with PGE's AdopDER model as a separate module for considering locational factors of DEI, environmental factors and resilience relative to feeder-level DER adoption forecasts.

Figure 109 provides an overview of these steps used in our approach.

Figure 109. Community targeting assessment approach



We are now proposing to leverage this analysis to target community resilience efforts in resource and program planning. **Table 75** shows the factors that were evaluated and those that were prioritized to develop the Index as part of our DSP Part 2.

Table 75. Data sources from DSP Part 2

Type	Source	Description
Geographic	PGE Shapefile Census Geographies	Define service area boundary and unit of geographic analysis
Income/demographics	ACS, PUMS PGE (CIS/Axiom); Greenlink; US DOE LEAD Tool	Characterize populations using DEI criteria

Type	Source	Description
Environmental	EPA EJScreen	Identify environmental indicators by location
Resilience	PGE (long duration outage locations, PSPS, major events); US Forest Service (wildfire risk); FEMA (flood risk); DOGAMI (seismic risk)	Identify areas at risk for long-term outages due to natural disasters/extreme weather
Customer arrearage	PGE (list of accounts with current and/or historical arrearages, assistance payments, disconnects/reconnects)	Characterize customers using DEI criteria

13.3 Zone of tolerance

The US GMLC's Considerations for Resilience Guidelines for CEPs report describes the "zone of tolerance" as a concept that "has been developed to account for different capabilities of households and communities to endure the adverse impacts of service disruptions."[336]

Through our work on our DSP Part 2, we aimed to develop better data that may enable us to widen the "resilient zone" so we are better able to assess and identify factors affecting risk disparity due to infrastructure service disruptions in wildfire, seismic and extreme weather events. PGE is considering new factors to assess the ability of a particular household or community to cope with service outages that can inform focused actions to increase customer and community resilience.

13.3.1 Energy equity index development

Within PGE's DSP Part 2, we reviewed a large number of factors that could represent the ability of our communities to withstand the effects of long-term outages. This data was then distilled to develop an Energy Equity index to approximate our customer's zone of tolerance. Currently, six energy equity indicators are used for distribution system planning on projects weighting and scoring Energy Burden, Dwelling Type, Owners/Renters, People of Color, households without internet and households with disability.

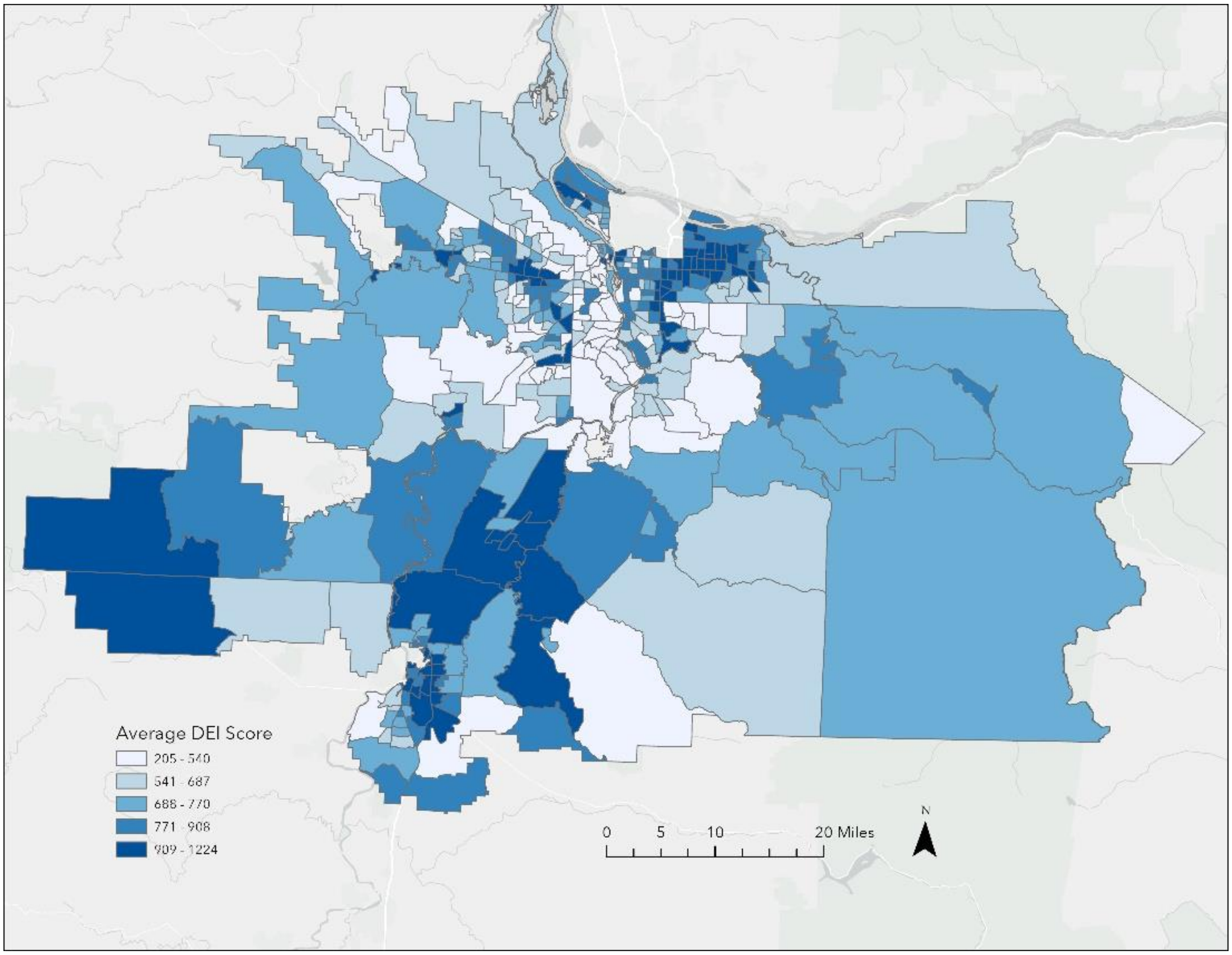
[336] The OPUC's Considerations for Resilience Guidelines for Clean Energy Plans report, available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah113046.pdf.

To illustrate an example of this weighting, energy burden received the highest weighting (and associated scoring) within the DEI category. The decision to prioritize this variable over others within the DEI category was a function of the following:

- Latent factor analysis results—energy burden received one of the highest explanatory capacities under the DEI category.
- The community-based organization DSP Community Workshops conducted by PGE in 2022, positioned this variable as highly relevant to determine disadvantaged communities.

Within the energy burden variable, points were allocated based on the geographic distribution of the variable (using quartiles). Thus, to reflect a higher prioritization of energy burden within the DEI index, we assigned the highest score (Q4 value = 300) to premise IDs in census tract areas within the highest quartile of average energy burden. The middle quartiles then received reduced scores (Q3/Q2 values = 150), with the lowest score assigned to the lowest quartiles (Q1 value = -50). Through this approach, customers with a higher energy burden would receive more points than those falling in the middle of the distribution, while customers showing the least amount of energy burden were given negative points. PGE followed a similar approach for other variables; however, those variables with lower prioritization within a category, such as households with internet access for the DEI category, would have a lower point distribution that would effectively result in a lower weight for the index development (i.e., Q4 = 60, Q3/Q2 = 20 and Q1 = -20). Finally, to build the index, we summed or subtracted points for each customer depending on where they sit on the distribution of each variable composing the index (**Figure 110**).

Figure 110. DEI index



13.3.2 Justice 40 initiative

In 2021, President Biden signed Executive Order (EO) 14008 into effect.[337] Section 223 of this EO creates a goal that 40 percent of the overall benefits of certain Federal investments flow to disadvantaged communities (DACs) that are marginalized, underserved and overburdened by pollution.

The US DOE currently has a working definition of disadvantage based on cumulative burden. Thirty-six (36) burden indicators reflect fossil dependence, energy burden, environmental and climate hazards and socio-economic vulnerabilities.[338] PGE is leveraging this data source

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[337] *See* Tackling the Climate Crisis at Home and Abroad, 86 FR 7619 (February 1, 2021), available at: https://www.federalregister.gov/documents/2021/02/01/2021-02177/tackling-the-climate-crisis-at-home-and-abroad, and https://www.regulations.gov/document/EPA-HQ-OPPT-2021-0202-0012.

[338] The US DOE's Justice40 Energy Justice Mapping Tool, available at: Energy Justice Dashboard (anl.gov).

as part of its energy equity mapping through its DSP to assist in our equity mapping to identify DAC within PGE's service area. This tool allows access and the opportunity to explore DAC using census tract data. US DOE's Justice40 data illustrates areas that may have greater need, outcomes and impacts. Applying equity indicators to our maps and data may inform decisions for future projects, plans and processes and how they could affect communities.

13.3.3 Medical Certificate Program

The PGE Medical Certificate Program provides awareness of where some customers, who are most vulnerable to a loss of electricity, are located throughout our service area.[339] This program allows a customer that provides us with an accepted medical certificate to set up more lenient payment arrangements or renegotiate payment arrangements when financial hardship can be demonstrated. This program continues the disconnection of service when payment arrangements are not kept and allows PGE to provide better outreach and support to our most vulnerable customers during a resilience event.

In evaluating resilience opportunities in our WMP, we proposed to pilot programs to specifically address the needs of these customers (within this plan, see **Section 13.5.9, Portable storage**). Beyond that direct activity, the location of these customers can provide valuable insight when prioritizing community resilience investments.

13.3.4 Heat vulnerability data

Climate change will continue to impact the frequency and intensity of extreme temperature events. During the summer of 2021, PGE experienced record-setting peak loads as the Portland metro region experienced a "heat dome" lasting several days which shattered historical temperature records. In addition to spikes in cooling-related peak loads, human health and safety risks also increase during extreme temperature events. In response to these extreme heat events, state and local governments responded by pursuing emergency cooling ordinances and response efforts; for example, the City of Portland developed and launched a Heat Response Program, and Oregon passed Emergency Heat Relief legislation to support vulnerable Oregonians.[340,341]

In the midst of this context, PGE initiated a research and development (R&D) project with researchers at Portland State University to study customer heat vulnerability across our

[339] More information on PGE's Medical Certification Program, available at: https://www.oregon.gov/puc/Documents/OregonMedicalCertificateProgram.docx.pdf.
[340] See Portland Clean Energy Fund's Heat Response Program, available at: https://www.portland.gov/bps/cleanenergy/heat-response-program
[341] See SB 1536 (2022), available at: https://olis.oregonlegislature.gov/liz/2022R1/Downloads/MeasureDocument/SB1536/Enrolled

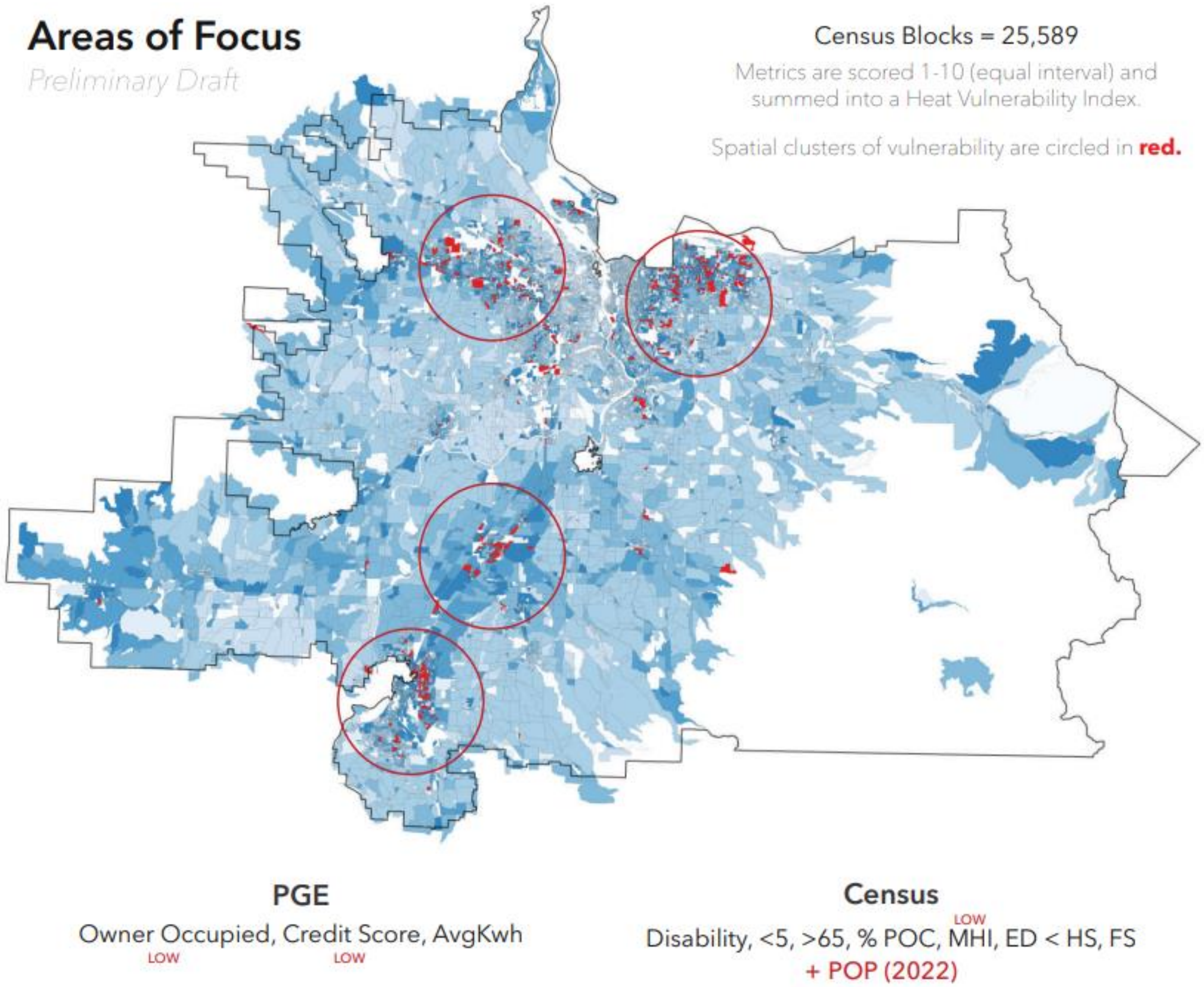
service area. The research builds on Portland State's extensive past efforts to model urban heat island dynamics to inform PGE's distribution grid planning efforts and related customer program development efforts.

The study uses data across environmental, social and built environment indices combined into a Heat Vulnerability Index. Examples of datasets used across these three areas that are known to influence heat vulnerability are:

- **Environmental data:** tree canopy cover, localized heat (temperature), percent of impervious pavement.
- **Social data:** socioeconomic factors (e.g., income, food security), demographics (e.g., race, age) and other factors such as disability data and overall population in a given area.
- **Built environment data:** building type, building age.

We applied the results of the Heat Vulnerability Index to our service area to identify areas of focus for near-term planning efforts. **Figure 111** shows a map of the PGE service area with four main zones of high heat vulnerability, indicating that cooling relief and resiliency initiatives geared at these population zones may significantly bolster customer resiliency during future extreme heat events.

Figure 111. Map of Heat Vulnerability Index scores in the PGE service area



PGE plans to continue socializing the results of our heat vulnerability assessment with municipal entities and communities through our Community Learning Labs and DSP community engagement meetings. In particular, we are interested in exploring the potential synergies between this level of data analysis and different customer DER programs that could alleviate these risks and also present opportunities for managing grid needs. For example, the cluster identified in East Portland in **Figure 111** is overlapping with the grid needs from our concept proposal presented in DSP Part 2 for the Eastport Plaza NWS, as well as the newer grid need identified for Arleta and Holgate substations, which are adjacent to Eastport and still score in high heat vulnerability areas.[342]

[342] PGE's DSP Part 2, Grid Needs Chapter, available at: DSP_Part_2_-_Chapter04.pdf (ctfassets.net).

13.4 Historical reliability data

PGE uses historical reliability performance data to evaluate the system's reliability and resiliency risk. The data informs the failure probability assumptions in the economic risk models for asset-caused and geographic-caused failures and is used to develop potential mitigation solutions. When evaluating risk, PGE considers the factors shown in **Table 76.**

Table 76. Factors considered when evaluating risk

Performance measures	Considered in risk evaluations	OPUC report
All outages (planned, major event or underlying)	Yes	Annual Report on Electric Reliability
Primary initiating event for each major event the utility analyzed	Yes	MED Exception Filing
Top causes for each day during which a major event occurred	Yes	MED Exception Filing
Number of customers out and the restoration performance for their supply	Yes	Annual Report on Electric Reliability & MED Exception Filing
Estimated costs to the utility to recover from the major event	Yes	NA
Estimated unserved energy during the period of a major event	PGE does not yet calculate this value	NA
Demographics of the community, including classification of energy equity or other social or EJ measures	Yes	NA
Estimated impacts to the customers	Yes	NA

Table 76 indicates which factors are also identified within our Annual Reliability Report, shared publicly in OPUC Docket RE 113 in May.[343] Our Annual Reliability Report provides distribution system performance information based on customer service interruptions. The

[343] PGE's Annual Report can be found: *In the Matter of Portland General Electric Company, Annual Reliability Report,* Docket No. RE 113, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=18326.

report is used to understand the overall reliability of the distribution system and to identify areas of improvement.

Within PGE's Annual Reliability Report, we include a definition for outage and outage data, including total outage hours, minutes, top outage causes and major initiating events such as equipment failure, lighting, vegetation, wildlife and weather. Additional detail on historical reliability performance can be found in our Annual Reliability Report. The results for 2022 will be included in our May 2023 filing.

Through Order 22-390, the OPUC provided resiliency-specific guidance that when evaluating resiliency risk, utilities should "rely on measurable historical reliability performance measures such as outage data and major events." PGE relies on historical reliability data already captured within our Annual Report. Moving forward, PGE suggests reliability reporting related to major outage events be included in the Annual Reliability Report rather than in the CEP. While pertinent to analyzing all resilience investments, it does not uniquely impact the resource procurement decisions being evaluated in the Integrated Resource Plan (IRP) and the CEP. Having a separate report to refine existing reported reliability data and the analysis can create confusion and possibly inconsistency between datasets. Additionally, PGE uses the VOS to estimate impacts on the customer. See **Section 13.2.3.1, Value of service**. We also identify and use socioeconomics and demographic data within our DSP Part 2. Specifically, we evaluated demographics as it relates to resiliency within our DSP Part 2, Appendix N, Equity index and community targeting assessment (see **Section 13.3.1, Energy equity index development**).[344]

13.5 Programs and opportunities

During PGE's community engagement process, we discussed potential resiliency analysis, approaches, programs and opportunities. For example, we received positive feedback in our Community Learning Labs that expanding metrics used in project scoring to have a CEMI reduction metric, in addition to the metrics identified in the DSP, may be useful in evaluating potential resilience projects. We will continue to explore these ideas with the community when evaluating resilience projects (such as T&D system projects) for the various benefit streams.

The following descriptions provide examples of the activities we are planning and/or undertaking to enable customers to mitigate the effects of disruptive events and access to the services they need.

[344] PGE's DSP Part 2, Appendix N, available at: https://assets.ctfassets.net/416ywc1laqmd/79djvul6i8euOIXwjj1ba5/ffb773d38fa86b08ad1c11f9c7058fff/DSP_Part_2_-_AppendixN.pdf.

13.5.1 Resilience in other plans

PGE has identified resilience as an important component of our DSP and WMP.[345] These plans have specific resilience programs and opportunities needed to address the modernization of the grid, acceleration of DER, energy equity and wildfire mitigation. PGE's DSP is filed in OPUC Docket UM 2197 and our WMP is filed in OPUC Docket UM 2208.[346]

13.5.2 CBRE potential study

The OPUC issued initial CEP guidance through Order 22-390. This guidance included conducting a CBRE potential study for the initial CEP. As described in **Chapter 7, Community benefits indicators and community-based renewable energy**, PGE conducted a CBRE potential study for this CEP and aims to build on this work to inform future CEPs. PGE intends to conduct a future CBRE potential study that will identify opportunities for CBRE actions, including distributed resources and their resilience benefits, and the study will be developed in coordination with communities, including EJ communities, stakeholders and Staff. PGE intends to coordinate this work, including coordination across other planning efforts, such as our DSP.

13.5.3 EPRI Climate READi: Power resilience and adaptation initiative

PGE understands the need to develop a common framework to understand the impacts of climate risks on the reliability and resilience of energy infrastructure. As such, PGE is participating in the EPRI Climate READi: Power Resilience and Adaptation Initiative. EPRI's initiative will convene global thought leaders and scientific researchers necessary to build an informed and consistent national approach. There are three primary targets for this initiative over the next three years.

- Develop a common approach for using climate data for specific power system assets and system vulnerability assessments, including how to treat the inherent uncertainty in climate variables.
- Identify and assess potential adaptation and mitigation strategies and their impact on risk.

[345] PGE's DSP and WMP, available at: Distribution System Planning | PGE (portlandgeneral.com) and Wildfire Safety | Wildfire Prevention Measures | PGE (portlandgeneral.com).

[346] *In the Matter of Portland General Electric Company, Distribution System Plan*, Docket No. UM 2197 (filed Oct 15, 2021), available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23043 and *In the Matter of Portland General Electric Company, Wildfire Protection Plan*, Docket No. UM 2208 (filed Dec 7, 2021), available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=23111.

- Offer guidelines for risk-based methods for prioritizing risk mitigation investments across generation, transmission, distribution and customer resources.

13.5.4 Smart battery pilot

PGE launched its five-year Smart Battery pilot in 2020.[347] Through this program, PGE works with residential customers with home battery energy storage devices. The program seeks to install and connect residential energy storage batteries that will contribute up to 9.5 megawatt hours of energy to our grid. Once installed, these distributed assets will contribute toward a virtual power plant (VPP) made up of DERs that can be operated individually or combined to serve the grid, adding flexibility that supports PGE's transition to a cleaner energy future. In addition, the energy storage batteries provide customers with a backup energy resource they can rely on in the event of a power outage.

In February of 2023, PGE received approval for a tariff update to the pilot based on learnings from the first two years of operation and to move the pilot closer toward a cost-effective and scalable structure. The update transitioned the ongoing customer payment structure from a flat monthly participation reward toward a pay-for-performance model, giving customers more customization on how we use their battery. The update also adjusts the up-front rebates to reflect the changed boundaries of the Smart Grid Testbed.

Historical information on this pilot can be found within the OPUC's Energy Storage Docket UM 1856.[348] If PGE files any revisions to our Schedule 14, it will also be within Docket UM 1856.[349]

13.5.5 Energy partner on-demand

Energy Partner On-Demand is a demand response (DR) program providing incentives to large nonresidential customers during seasonal peak time events for reducing their load.[350] The program develops highly customized load curtailment plans that can work with a variety of unique types of businesses. In June 2022, the program received regulatory approval to expand upon the grid services that Energy Partner may provide PGE and support customers' resilience and clean energy goals by incorporating battery energy storage as a dispatchable resource.

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[347] PGE Tariff Schedule 14, available at: Microsoft Word 014-21-10 Eff June 2.2021 (ctfassets.net).
[348] *In the Matter of Portland General Electric Company, Draft Storage Proposal,* Docket No. UM 1856, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=20913.
[349] PGE's Schedule 14, available at: https://assets.ctfassets.net/416ywc1laqmd/7rEQyshErHsASDCZZtIjL5/3e00bcdd66fc74c75e9f1a7af8c9efe4/PGE_Advice_No._22-43_Sch_7_and_14_Res_Energy_Storage_Update_OL_12.12.22.pdf.
[350] PGE tariff Schedule 26, available at: Microsoft Word 026 22-35 Eff Jan 1.2023 (ctfassets.net).

13.5.6 Energy partner resilience (dispatchable standby generation)

In 1999, the MacLaren Youth Correctional Facility became the first PGE customer to enroll their standby generator in our Dispatchable Standby Generation (DSG) program. This program is a collaboration with customers that interconnect generation resources, providing electricity to PGE's grid when there is a critical need for power in the local region. Since then, the DSG program has grown to 59 sites with a cumulative nameplate generation capacity of 130 megawatts (MW). While not fuel-restrictive, the bulk of this capacity has historically consisted of internal combustion diesel generators, and we have undertaken a concerted effort to modernize and decarbonize the program by adjusting the program tariff to target the integration of non-emitting energy storage.

PGE has successfully integrated customer-sited batteries for grid services, as demonstrated by the Beaverton Public Safety Center and Anderson Readiness Center. With the increased commercialization of battery energy storage, PGE proposed to build upon those capabilities to expand the DSG program to include battery energy storage systems greater than 250 kilowatts (kW). We received approval to do so in June of 2022.[351] In addition to contingency reserve and frequency response, customers with battery energy storage may opt to also participate in other demand response activities.[352] With the addition of batteries, we branded the program as "Energy Partner Resilience" for customer communications.

This program can now provide the same advanced resilience support to enrolled customers as our legacy DSG program while also supporting our customer's, PGE's and Oregon's decarbonization targets.

13.5.7 Multi-unit microgrid demonstration- Salem smart power center

In 2013, PGE commissioned the Salem Smart Power Center (SSPC), a 5 MW, 1.25 megawatt-hour (MWh) battery energy storage system that, at the time, was part of the largest regional smart grid demonstration project in the nation. As this battery energy storage system

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[351] See Docket ADV 1385, PGE Advice 22-05, *Schedule 200 Dispatchable Standby Generation Update* (June 1,2022), regarding the OPUC's approval of PGE's request to include battery storage in our DSG program, available at: https://edocs.puc.state.or.us/efdocs/UBF/adv1385ubf161150.pdf

[352] A flexible load service not currently possible with fossil-fueled resources. Additionally, Contingency Reserve is the portion of resource capacity that is capable of being synchronized and ramping to a specified load in 10 minutes (or that is capable of being interrupted in 10 minutes) and that is capable of running (or being interrupted) for at least 60 minutes from the time it reaches its award capacity. Frequency Response is similar; however, it has a response time at 22 seconds and duration typically less than 1 minute.

approaches its 10-year anniversary and is demonstrating end-of-life characteristics typical of a 10-year-old battery energy storage system, we are evaluating how to evolve the resource best to continue to provide value.[353]

In the Fall of 2022, the City of Salem, in partnership with PGE, received a one million dollar grant from the Oregon Department of Energy's (DOE's) Community Renewable Energy Grant Program. The project is described as follows:

> *A community energy resilience project, in partnership with PGE, to create a solar powered community microgrid with battery storage and electric vehicle charging. The system will connect to a solar array on and serve Salem's new Public Works Operations building and its electric vehicle charging stations, allowing it to function during grid outages. The microgrid will serve 96 apartments in six buildings, 34 homes, one local business, three other government buildings and a cellular communications tower, providing uninterrupted power during grid outages.*[354]

Leveraging the existing building and infrastructure of the SSPC and with a new and modern battery energy storage system, PGE seeks to build the first community microgrid of its kind in the Northwest. We are currently working with the City of Salem to begin construction in 2023 and anticipate the microgrid will be energized in 2024. When complete, the microgrid will provide grid services to support our decarbonization targets and resilience for our communities and critical facilities within the microgrid boundary.

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[353] PNNL conducted an assessment of battery performance and economic potential on PGE's Salem Smart Power Center, which can be found at. [The Salem Smart Power Center (pnnl.gov)](https://www.pnnl.gov).

[354] Oregon Department of Energy, Press Release, October 18, 2022, *Oregon Department of Energy Grant Program Supports Renewable Energy Projects from Ashland to Ontario*, available at: https://energyinfo.oregon.gov/blog/2022/10/18/oregon-department-of-energy-grant-program-supports-renewable-energy-projects-from-ashland-to-ontario

13.5.8 Community resilience hubs

As part of PGE's considered approaches to CBREs, we will leverage existing microgrid projects such as the Beaverton Public Safety Center (BPSC). At BPSC, we are also exploring the use of a portable battery energy storage unit to provide backup power to their electric vehicle fleet in the event of an outage while also having the flexibility to be used for urgent needs elsewhere. This work, along with community collaboration, will help inform potential community resiliency, such as CBREs for critical facilities (e.g., police, fire, EMS, wastewater treatment and water pumping facilities) and local resilience hubs.[355] Any potential programs will aim to work with community and local governments such as municipalities. This collaboration will help us identify microgrid solutions. For example, we are developing analytical approaches to identify CBRE locations. With this data-driven information, we can work with targeted communities to assess their resiliency needs and desired solutions.

With any resiliency solution, such as a microgrid, it is important that the solution be able to act as a locational grid asset during normal conditions and a resilience resource in the event of an outage. We will investigate the potential federal and state funding needed to support the cost of such an investment. Additionally, we aim to co-optimize any flexible resiliency load for the VPP, non-wires solutions and community benefits.

One consideration of any CBRE project is the need to provide direct community benefits. As starting points, some community benefits we may consider are:

- Reduction in recovery time of a local community in the aftermath of a natural or human-made disaster.
- Safety net resource for highly vulnerable households to reduce the negative effects of power outages and extreme conditions
- Increased renewable generation within and for our communities.
- Operational cost savings for host sites that can be passed to community members.

[355] We are defining local resilience hubs as a facility where members of the public may convene in the event of a power outage.

13.5.9 Portable storage pilot

Within PGE's 2023 WMP, we requested a pilot to provide portable energy storage to our most vulnerable customers affected by a PSPS. This program seeks to provide financial support for portable batteries to customers enrolled in our Medical Certificate Program who reside in a designated PSPS area. The objective is to increase resilience for customers dependent on electrically powered medical devices. A portable battery solution also allows renters, multi-unit housing dwellers and those who cannot afford a larger backup system to increase their resilience or those who struggle with other traditional methods (such as propane or diesel generators). Should the OPUC acknowledge this item within our WMP, we intend to request approval to implement the program.

We are exploring utilizing a portable battery unit at the Beaverton Public Safety Center. This portable battery will provide backup power to a panel of electric vehicle chargers. With this work, we will explore operations around the portable aspects of the battery.

13.5.10 Public safety partner engagement program

PGE is a provider of a core service for our communities. We cooperated with the communities in our service area to plan for and respond to emergency situations. Recognizing the importance of this cooperation, our Business Continuity and Emergency Management Team (BCEM) is formalizing a program to encourage and increase our ongoing engagement with the emergency management community, focusing on emergency preparedness and community resilience collaboration.

To achieve this, BCEM engages with public safety partners where we have distribution services and/or assets. Primarily this means interacting with the county emergency management agencies, which can provide a central coordination point for all the sub-jurisdictions, such as cities and special districts. The goals of this program are to:

- Enrich public/private sector emergency management partnerships.
- Enhance mutual readiness through coordinated preparedness activities.
- Strengthen connections between PGE and our communities.

PGE hopes to achieve these goals by increasing our interaction with the local community. We plan to host all-hazards summits to discuss preparedness activities and any specific concerns regarding upcoming seasonal hazards with local emergency managers. Additionally, through individual meetings with County Emergency Managers and participation in regional advisory bodies, we seek to engage with a broad cross-section of the community that is focused on community resilience.

For example, PGE is a member of the Regional Disaster Preparedness Organization (RDPO). The RDPO is a partnership of government agencies, non-governmental organizations and private-sector stakeholders in the Portland Metropolitan Region collaborating to increase the region's resilience to disasters. As resilience programs are developed, we will look to these groups and processes to refine our programs and ensure our communities leverage new resilience initiatives.

13.6 Looking ahead

The GMLC's report provides valuable insight into practices that can inform PGE's future analyses and links to practitioners we can turn to for additional knowledge and lessons learned.

During the ideation stage of our planning, we heard from the community that equity mapping within our investment decision framework is an area of interest. PGE's resiliency planning will continue to be refined as our understanding of our communities and climate change evolve. For example, we are exploring the idea of using maps with multiple layers such as equity metrics, outage information, risk assessment and PGE infrastructure information.

We understand CEPs will evolve PGE's planning practices over time and hope that initial guidance established through the current process accounts for the time needed to engage and collaborate with communities effectively. This includes engaging on such topics as CBIs, resiliency and community-based renewables while balancing the need to quickly procure clean energy resources to meet our decarbonization targets by 2030.

Chapter 14. Community equity lens and engagement

We recognize that climate change often disproportionately impacts our most vulnerable communities, including Black, Indigenous and People of Color (BIPOC) and low-income communities.[356] Prioritizing energy access, reliability and resiliency is more important now than ever, as we see the effects of climate change in real-time across our service area in the form of drought, extreme temperatures, wildfire, habitat loss and destructive storm events. This chapter provides Portland General Electric's (PGE's) approach to the Oregon Public Utility Commission's (OPUC's) Community Lens topic as outlined in the OPUC's UM 2225, which provided guidance on community engagement strategies for the Clean Energy Plan (CEP).[357]

Chapter highlights

- PGE's community engagement strategy and goals for PGE's long-term planning processes build on our experiences with the Distribution System Plan (DSP).
- As part of our planning process, PGE sought input from non-traditional stakeholders, including individuals and organizations representing environmental justice communities. Our engagement strategy aligned multiple channels such as our Community Learning Labs, IRP Roundtables, relationship building and surveys.
- PGE sought to deploy and iterate accessible opportunities to gather feedback, including Mural activities and surveys.
- We are tracking the input we received through Mural and using it to inform planning and resource acquisition activities related to the CEP and IRP process.

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[356] *See*, US Environmental Protection Agency Press Release, EPA Report Shows Disproportionate Impacts of Climate Change on Socially Vulnerable Populations in the United States, September 2, 2021, available at: https://www.epa.gov/newsreleases/epa-report-shows-disproportionate-impacts-climate-change-socially-vulnerable.
[357] See *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Order No. 22-390 (Oct 25, 2022), Appendix A at 36, available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.

14.1 Clean energy transition

14.1.1 Importance of equity and a human-centered approach

House Bill (HB) 2021 was the result of collaboration between utilities, environmental justice (EJ) groups, renewable energy and environmental advocates and other stakeholders. While much emphasis has been placed on the decarbonization objectives of the legislation, HB 2021 was also transformational for centering communities and equity in the clean energy transition. That equity lens is reflected in the work on Community-Based Renewable Energy (CBREs) and Community Benefits Indicators as described in **Chapter 7, Community benefits indicators and community-based renewable energy**. But it is also reflected in OPUC's provided guidance on community engagement strategies, as we discuss in this chapter.

PGE is committed to a future for Oregon in which all customers and communities can thrive. Investments in resources and grid modernization to meet our decarbonization targets can have a local, tangible and visible impact. As we plan for a clean energy transition, we are guided by our commitment to advancing social equity in the communities we serve. This begins with listening to and accounting for the diverse needs of all customers and communities and conducting our business in a way that promotes equitable access to clean energy solutions.

To support a human-centered approach to planning and prioritizing energy access, PGE works with communities and takes inspiration from best practices in community outreach and engagement. Our approach is intersectional, meaning issues such as gender, race, income and historical and geographic factors are considered when determining the disproportional impact that climate change, such as natural disasters, have on certain communities. Our approach also uses an equity lens, which allows for racial, gender and other inequities and how to address such disparities. This approach acknowledges how race, gender, people with disabilities, chronic health challenges and socioeconomic status will result in some members of our communities facing greater disparities.

Throughout this combined filing of PGE's CEP and IRP, we seek to present information in transparent, understandable and relatable ways.[358] We have worked, through our Community Learning Labs, to create content that can assist an introductory audience in understanding how PGE as a regulated utility engages in resource planning to meet energy needs reliably and affordably while complying with all regulatory requirements, including GHG emissions

[358] HB 2021 and subsequent OPUC Docket UM 2225 guidelines for utilities' Clean Energy Plans, emphasized the criticality of centering equity and community in planning for a clean energy transition.

targets. Further, Community Learning Labs provide additional context that customers and stakeholders need to understand, such as key terms, definitions and acronyms. This information enables our audiences to participate more fully in the public processes and dialogue surrounding our CEP and IRP. We also have created a website to provide transparency.[359]

14.2 Community engagement

Our vision is to lead the clean energy future together with our customers and communities. We are committed to cultivating and maintaining relationships with new and existing communities and community members, including those who have been historically excluded and underserved. In doing so, we work to consistently apply an equity and resiliency lens.[360] Community engagement is based on the belief that those impacted by a decision, program, project or service system need to be involved in the decision-making process.[361] This belief supports PGE's community outreach and engagement efforts of 'nothing about me without me.' This is PGE's guiding principle for conducting equitable community outreach and engagement practices. Additionally, we believe a clean energy future that is affordable and equitable requires a commitment to diversity, equity and inclusion (DEI) throughout our business.

Through our Distribution System Plan (DSP), PGE developed our human-centered approach as a starting point for our community outreach and engagement.[362] Our DSP Community Engagement Plan is informed by best practices, learnings and the recommendations of Unite Oregon, the Community Energy Project and the Coalition of Communities of Color based on their engagement in DSP Part 1.[363] We built on this work in our DSP Part 2 through

[359] Resource Planning website that provides access to CEP, IRP and DSP, available at: https://portlandgeneral.com/about/who-we-are/resource-planning.

[360] *In the Matter of Public Utility Commission of Oregon, House Bill 2021, Investigation into Clean Energy Plans*, Docket No. UM 2225, PGE's Updated Clean Energy Plan (CEP) Engagement Strategy (filed Aug 4, 2022), available at: https://edocs.puc.state.or.us/efdocs/HAH/um2225hah165755.pdf.

[361] A service system can be thought of as a portfolio of programs/services (*e.g.*, Income Qualified Bill Discount) and others provided to customers to meet a particular goal.

[362] PGE's Community Engagement Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/Ade5oN7SaTG7jQRTGcPzt/576380f14d90a976469968517b187f95/DSP_2021_Report_Chapter3.pdf.

[363] Distribution Systems Planning (DSP) Community Engagement Best Practices and Recommendations Report developed by Unite Oregon, Community Energy Project and the Coalition of Communities of Color Community (July 19, 2021), the Engagement Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/1wLNK2VjxZdnWiPSf5wvxf/f34e9939bd4cde85bb36d524b6a0177d/PGE_Community_Engagment_Report_7.20.21.pdf

Community-focused Workshops that concentrated on providing education on the technical aspects of the DSP into more relevant and translatable topics and content.

Our community outreach and engagement strategy for PGE's long-term planning processes builds on our experiences with the DSP Part 1 and Part 2 and is informed by three goals:

- Cultivate and maintain trusted and transparent relationships with community-based organizations (CBOs)/community-serving organizations (CSOs), EJ advocates and other community collaborators.
- Build awareness, inform and provide learning opportunities to communities.
- Encourage feedback that allows for continued transparency and the accessibility needed to improve collaboration and co-development of planning processes.

Additionally, PGE intends to use the three goals mentioned previously to achieve the following desired outcomes:

- Allow greater insights into the CEP and other planning processes needed to achieve decarbonization goals.
- Co-develop future community solutions and resiliency opportunities such as CBRE projects.
- Increase community participation, including Tribal and EJ communities.
- Demonstrate transparency and accountability.

We have engaged community groups through several channels in the development of this CEP. PGE hosted 30 Roundtable meetings and seven Community Learning Labs during the 2023 IRP development process. We made all meeting materials available on our CEP and IRP web pages and advertised public meeting dates there as well. We intend to continue our community engagement efforts beyond the filing of this plan, as our goals and desired outcomes are both near-term and long-term. For example, in this plan, we have a desired outcome for the co-development of community solutions and resiliency opportunities. This work will need to continue throughout 2023 and beyond as we have yet to begin procurement of these resources. We discuss those different engagement channels in the following sections.

14.2.1 Community Benefits Impact Advisory Committee

HB 2021 requires electric utilities that file a CEP to convene a Community Benefits and Impacts Advisory Group (CBIAG). PGE is establishing the CBIAG, a process that PGE embarked upon in 2022. The CBIAG will include representatives from EJ and low-income communities. Our CBIAG will be a forum in which HB 2021-mandated topics will be discussed.[364]

14.2.2 Tribal engagement

House Bill 2021 set forth a requirement for deeper and more meaningful engagement of Tribal and Indigenous communities. This bill included requirements for state agencies to consult with Tribes meaningfully, including consultation in the siting, permitting and construction of new energy facilities and new projects prior to actions that are likely to adversely impact designated archeological sites, or properties of traditional, cultural and religious importance.[365] HB 2021 also included a requirement that CBRE projects provide direct benefits to communities such as Tribes through direct ownership or a community benefits agreement or result in community benefits such as economic development. PGE continues to be committed to engaging with Tribes and Indigenous communities and demonstrates this commitment through our Strategic Tribal Engagement Plan (STEP). The STEP provides a framework for our teams to develop and maintain successful Tribal relationships by setting goals, identifying actions and implementing best practices to meet desired outcomes.

PGE acknowledges that the Tribal and Indigenous communities represent an important and multifaceted demographic and that their interests are intrinsically connected to our clean energy imperatives. Because of this, we partnered with Tribal entities on Federal grant applications to expand regional transmission capacity and open opportunities for renewable energy development on Tribal lands.

PGE and the Confederated Tribes of Warm Springs (CTWS) share ownership of Pelton Round Butte, a certified low-impact hydropower facility on the Deschutes River. This agreement is a shared testament to our close partnership and shared commitment to the Deschutes River Basin. In 2022, CTWS purchased an additional ownership interest in the Pelton Round Butte

[364] For information regarding HB 2021's CBIAG, see codified ORS 469A.425, available at: https://www.oregonlegislature.gov/bills_laws/ors/ors469A.html.
[365] ORS 469A.405(3).

hydroelectric project, increasing Tribes' share to 49.99 percent. PGE will continue to operate and purchase power generated from the Tribes' share of the project through 2040.

We also recognize the significance of collaboration with Tribes and Indigenous communities, which is why we have dedicated positions to support our Tribal relationships. Our Tribal Liaison is responsible for the overall program implementation and relationship management and serves as a company spokesperson at appropriate forums. Our Energy Equity Partner will work cross-functionally with our Tribal Liaison to engage Tribal and Indigenous communities.

14.2.3 Community learning labs

We designed our Community Learning Labs to foster an interactive experience for participants to learn about the CEP and other energy-related topics. This is in addition, and in contrast, to our monthly public IRP Roundtables, which describe the technical modeling and results of the IRP. Community Learning Labs are a public meeting space created for an introductory audience which includes, but is not limited to CBOs, CSOs, EJ advocates, other community collaborators and individuals. Community Learning Labs aim to build awareness, inform and collaborate with communities and stakeholders about specific CEP topics and seek feedback from participants. The Community Learning Labs provide opportunities to learn more about the CEP, and other relevant energy topics, including other PGE programs and planning processes like the IRP and DSP.

The Community Learning Lab process was originally used during DSP development to share related analysis and concepts with stakeholders with less experience participating in technical workshops. Through our DSP, we heard from our communities and stakeholders that creating an inclusive space for all our plans is their preference as it maximizes their time and helps connect the dots between planning efforts for them. We also heard from DSP attendees that they preferred shorter meetings, which resulted in scheduling Community Learning Labs for two hours versus three hours. Additionally, PowerPoint slides were used to present materials, recap previous meeting notes and introduce new topics.

To inform PGE's initial CEP and provide transparency and education to communities, we led seven Community Learning Labs from September 2022 through March 2023. In our first Community Learning Lab, we shared our approach, desired outcomes and process for community engagement. Throughout our CEP process, we explored several topics, such as CBREs, community benefits indicators (CBIs), non-wires solutions (NWS), resilience, our Preferred Portfolio and PGE's path to 2030 emissions targets.

We conduct all Community Learning Labs virtually via Zoom, as this was the preferred platform of attendees. To revisit materials asynchronously, we recorded all meetings per the request of our attendees and uploaded them to our CEP website.[366] Also, we used Mural to collect anonymous feedback on presented information. In addition, we sent email notifications to the CEP distribution mailing list shortly after meetings.

Community Learning Labs demonstrate the evolution of PGE's philosophy of human-centered planning. Centering on community voices acknowledges our intention to understand the energy needs, desires, barriers and interests in clean energy planning, projects and related processes. We continue to demonstrate our commitment to being inclusive and equitable and to promote accessibility by creating a space for communities to participate and openly share information and feedback. We worked with communities to thoughtfully curate Learning Lab content and provide relevant learning opportunities to the community throughout the CEP development process. We intend to continue through 2023 and beyond to address additional topics. Refer to **Appendix L, Clean Energy Plan: Learning Labs community feedback** for additional information regarding the questions and comments we received through our Community Learning Labs. See **Section 14.3, Continuing community engagement** for examples of how we intend to apply stakeholder feedback to our planning activities.

14.2.3.1 Community Mural board exercises

Community Learning Labs sessions present topics in segments. After each section, PGE employed Mural exercises to receive feedback from participants. After presenting a topic segment, PGE sought community feedback by leading Mural exercises to review the material we presented. Each Mural exercise provided participants with timed questions focused on the important subject matter. To allow more time to collect additional feedback, we left Mural exercises open for two weeks after each Community Learning Lab session. For a list of questions conducted during the exercise, see **Appendix L, Clean Energy Plan: Learning Labs community feedback**.

Our Mural board exercises covered many topics, including but not limited to non-wire solutions, CBREs, CBIs and resilience. For example, through our Mural exercises, we introduced CBIs in a series of Community Learning Labs and focus groups and had participants rank which CBIs should be prioritized as part of our future CBI analysis. As a starting point for the Mural board exercises, we utilized the OPUC's UM 2225 Community Lens topics provided by the Energy Advocates. The Energy Advocates are a group of community, local government, climate, energy and renewable advocates that jointly filed comments within the OPUC's Docket UM 2225. The Energy Advocates Community Lens

[366] PGE's recorded Community Learning Labs, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/clean-energy-planning.

topics comments are referenced in Attachment A of the Community Lens Straw Proposal in docket UM 2225).[367] The Energy Advocates' contributions helped start the conversation within our Community Learning Labs regarding how CBIs and Community Lens topics could be incorporated into our CEP.

14.2.3.2 CBI community engagement

PGE introduced CBIs in a series of Community Learning Labs and focus groups. In the Community Learning Labs and focus groups, we discussed our objectives for CBIs, our approach, our existing work on the DSP and its relationship to the CEP. PGE reviewed CBIs through a collaborative process with community members and EJ communities.[368] We conducted this process through our Community Learning Labs and other external engagement venues where we identified and prioritized CBIs with the community via the application, Mural. In our third Community Learning Lab, we asked participants to rank their top CBIs from the proposed list provided by the Energy Advocates. We had a total of fifteen participants and **Figure 112** illustrates the example results from the exercise.

[367] See OPUC Order No. 22-390, Appendix A at 65 (Attachment A Stakeholder CBI Proposal), available at: https://apps.puc.state.or.us/orders/2022ords/22-390.pdf.
Upcoming and past meeting materials, available at: https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings.

Figure 112. Community Mural board example exercise

Which additional indicators should be prioritized going forward.
Help us prioritize the Community Benefits Indicators.

Each participant has 6 stars to vote the next indicators to prioritize.

UM 2225 Stakeholder CBI Proposal (without associated measures)	**Add a star to the indicators you recommend prioritizing**
Tribal Benefits and Priorities	
Ecosystem/Non-Energy Benefits	
1. Protect fish and reduce the region's pressure on the Columbia River ecosystem	★★★★★★★ 7
2. Meaningful bilateral engagement between utilities and tribes on siting	★★★★★★★★★★★★ 12
Energy Benefits	
1. Increased availability of electricity storage in Tribal and non-Tribal communities	★★★★ 4
2. Improve energy efficiency of housing stock in Tribal communities	★★ 2
3. Increased number of clean energy generation that powers Tribal communities	★★★★ 4
Larger Community Benefits and Priorities	
Energy Benefits	
1. Improve efficiency of housing stock in utility service territory, including low-income housing	★★★★★★★★★★★ 11
2. Low income and vulnerable communities have access to an increasing number of renewable or non-emitting distributed generation resources	★★★★★★★★★★★★ 12
Non-Energy Benefits	
1. Community Employment opportunities	★★★★★★★ 7
2. Health and Community well-being	★★★★★★ 6
3. Improved Public Health outcomes	★★★★ 4
4. Reduction in number of customers suffering from high energy burden	★★★★★★★★★★★★★★★ 15
5. Reduced barriers for program participation	★★★★★★★★★ 9
Environment	
1. Reduction of GHG emissions	★★★★★★★★★★ 10
2. Reduced Pollution Burden and Pollution Exposure	★★★★★★★★ 8
3. Increase Neighborhood Safety	★★ 2
Energy Security	
1. Reduced Residential Disconnections	★★★★★★ 6
2. Improved access to reliable clean energy	★★★★★★★★ 8
Resilience	
1. Reduction in frequency and duration of blackouts or brownouts in target communities	★★★★★ 5
2. Reduction in energy and capacity need	★★★ 3
3. Reduction in recovery time and increase in survivability from outages	★★★★★★ 6

Although the Energy Advocates provided an extensive and thoughtful list of CBI recommendations, we reviewed CBIs with participants in our Community Learning Labs to identify additional CBIs and which CBIs are most important in the near-term. Through this work, we aim to begin defining and developing the CBIs in 2023. Based on the prioritization results from the community, we identified the top four CBIs to be prioritized as such:

- Reduction in the number of customers suffering from high energy burden
- Low-income and vulnerable communities have access to an increasing number of renewable or non-emitting distributed generation resources
- Meaningful bilateral engagement between utilities and tribes on siting
- Improve efficiency and housing stock in the utility service area, including lower-income housing in partnership with Energy Trust of Oregon (ETO)
- In **Section 7.1, Community benefits indicators**, we discuss the work we have done to begin prioritizing CBIs.

14.2.3.3 CBRE community engagement

PGE introduced CBREs in a series of Community Learning Labs and focus groups. In the Community Learning Labs and focus groups, we discussed our objectives for CBREs, our approach, our existing work on the DSP and its relationship to non-wire solutions. We also conducted Mural exercises on possible opportunities, approaches and the relationship between CBREs and CBIs.

Our goal with conducting community engagement on CBREs was to provide education on how we typically offer customer solutions. Today, CBRE resources within PGE's service area that bring community benefits are often supported by channels that tend to focus on individual technologies rather than stacking multiple technologies together to drive increased community benefits, which is allowed for under HB 2021’s definition of CBREs. For example, PGE has a Smart Battery program that provides residential customers with home battery energy storage devices, while ETO has a Solar within Reach program that offers increased cash incentives for income-qualified households.

PGE plans to conduct continued community and stakeholder outreach and program design efforts that may yield better insights into the available potential of certain project types and their relative accessibility and feasibility. For example, in December of 2022, we shared a draft Community Supported Renewables concept with local governments, OPUC Staff and customers to socialize the changes we made that reflect feedback from our community outreach efforts. We continue to meet with our communities and revise the Community

Supported Renewables tariff framework, with an expected filing date in the third quarter of 2023.

PGE will also leverage our Community Learning Labs and other community and stakeholder engagement channels (e.g., DSP and Flexible Load Multi-year Plan (MYP)) to socialize and refine our approach for future CBRE potential study efforts for the next CEP. We are committed to working with our communities and community representatives to assess the need for more education and learning regarding CBRE and solicit ideas and input to inform future study efforts. We expect the evolution of how CBIs should be categorized and incorporated into future Community Lens potential study efforts will be guided by input from the CBIAG and continued discussions with our communities, stakeholders and Staff.

Lastly, PGE plans to build on the engagement and outreach conducted for this initial plan filing by conducting more targeted and structured research with market participants and developers working on CBRE-style projects. In our future assessment rounds, we aim to capture information that can help to characterize better market barriers, achievable potential and the costs and benefits associated with different CBRE resource types.

14.2.4 Roundtables

PGE manages CEP and IRP development through a collaborative, interactive process with an active public stakeholder group. All IRP meetings are open to the public and are generally hosted once a month. These roundtable meetings are technical forums to communicate, educate and seek feedback regarding PGE's IRP methodology, analysis and results. The IRP content presented during roundtables is complex, often requiring experience and knowledge of the energy industry. Additionally, stakeholders represent diverse perspectives and expertise from various communities in the state.

Our team strives to present comprehensive information in an approachable structure to encourage feedback and requests for clarification. As topics and attendance change, and in response to stakeholder feedback, PGE has adjusted how and when we take feedback during roundtable meetings. To provide transparency to the public, we publish these direct questions and responses, as permission allows, monthly when we post our meeting materials and video recordings. This allows all stakeholders to benefit from questions that other groups bring to us. Also, it prioritizes presenting complete information during our scheduled monthly roundtables. In addition, PGE continues to engage community-based organizations via the Community Learning Lab venue, as described previously.[369]

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[369] CEP Community Learning Lab information available at: https://portlandgeneral.com/about/who-we-are/resource-planning/clean-energy-planning.

Before we started work on the 2023 IRP, we engaged stakeholders in a conversation about their organization's values and the IRP process.[370] Our stakeholders expressed what they value most: reliability and affordability in a decarbonized system, focusing on risk and uncertainty; clearly communicating what the IRP Action Plan means; and addressing and prioritizing the climate crisis in analysis.[371] We kept those values in mind throughout our process and built on the steps we took in the 2019 IRP to be responsive.

- We invited stakeholders to make specific portfolio requests during the 2023 IRP process and shared those requests at subsequent roundtable meetings.
- We shared draft information as the analysis unfolded.
- We invited stakeholders to submit informal comments throughout the process.
- We post video archives of each meeting and the meeting presentation on our website.
- We published comments received via the feedback form, starting in April 2022, and our responses each month to allow all participants to benefit from what others are asking about.
- We experimented with different approaches to facilitating the roundtables to encourage equitable participation among stakeholders.

The comments and suggestions shared with us are incorporated into our thinking and our final IRP, and the comments we received, plus our responses, are posted to our IRP webpage.[372]

14.2.5 Community surveys and feedback

To measure PGE's progress, we conducted six surveys after each Community Learning Lab, which were available on our CEP website. We left the survey open after each Community Learning Lab session to allow more time to collect additional feedback. The surveys allowed participants to provide feedback, evaluate Community Learning Labs and inform future content. We documented comments (via Mural, chat, and/or verbal) from Community Learning Labs and used them to uncover themes.

[370] Portland General Electric Integrated Resource Planning, Roundtable 21-2, March 21, 2021, roundtable available at: https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf.
[371] See Roundtable 21-2, March 21, 2021, slide 9, for more information about the values stakeholders expressed, available at: https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf.
[372] Information available at: https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning.

During this process, we engaged a diverse set of participants comprised of CBOs, CSOs, EJ communities, government entities and individuals. As previously mentioned, we used several modalities to collect input and receive information from our community collaborators. This included surveys, Mural, chats, emails, informal interviews, focus groups and meetings with EJ advocates. Community Learning Lab evaluation surveys were kept anonymous to ensure more authentic responses. Additionally, we created a section for community members and/or customers to share their feedback on our website. See **Appendix L, Clean Energy Plan: Learning Labs community feedback** for additional information on our surveys.

We realized early that surveys could be one of many ways to gather information, as our response rates were lower than we had hoped. Due to this, we met with a handful of community advocates who collaborated with us on our DSP. We conducted informal interviews to increase the effectiveness of our approach to community engagement and Community Learning Labs. From this experience, we discovered that we need different engagement modes. Surveys were an excellent tool for collecting data however getting participants to take a survey was challenging. Therefore, we met with attendees outside the Community Learning Labs to obtain qualitative data. This informal environment allowed for an organic experience for the person to share feedback and helped build relationships with participants.

Refer to **Appendix L, Clean Energy Plan: Learning Labs community feedback** for additional information regarding the questions and comments we received through our Community Learning Labs. See **Section 14.3, Continuing community engagement** for examples of how we intend to apply stakeholder feedback to our planning activities.

14.2.6 Relationship building & informal engagement

PGE conducted outreach to several organizations we have existing relationships through our DSP. These organizations represent climate, energy and community members. We worked to build new relationships for current and future plans, projects and programs and increase participation in our Community Learning Labs. Additionally, we used these forums to provide opportunities to roadshow specific topics covered in previous Community Learning Labs. Through this engagement channel, we heard from our communities and stakeholders how important it is for us to come to their locations/meetings to share information, as the capacity to participate in PGE public meetings is an ongoing challenge for most non-profits and community organizations.

We conducted follow-up, informal interviews with advocates and participants to capture more qualitative results and uncover gaps that need to be captured in surveys and Mural exercises. We interviewed several participants, who shared in-depth feedback on how they felt about the Community Learning Labs and our CEP generally. Some expressed how they appreciated our efforts and included the community in the conversation regarding the CEP process. However, some shared that we need to make the information more digestible and relevant to attendees. We also learned through conversations with the community that they want more regular updates on how their contributions will be incorporated into our planning and implementation.

Overall, most interviewees were satisfied with our efforts and believed PGE was on the right path in addressing the CEP. Lastly, many expressed willingness to support PGE throughout Oregon's clean energy journey. Over several informal interviews, PGE engagement practitioners met with Energy Advocates and other community members. What we uncovered from our conversations were some trending topics/recurring themes. This included, but is not limited to, in no particular order: CBIs, CBRE projects, equity, resilience, energy burden and procurement and contracting. The qualitative data we collected through conversations enabled us to incorporate some of these topics/themes into our Community Learning Labs. Also, we understood how important it was to leverage these topics/themes to address the community's needs as we continue to use and evolve our human-centered planning model. **Figure 113** lists some of the trending topics captured from these meetings.

Figure 113. Trending community topics /themes

- Community benefit indicators (CBIs)
- Community based renewable energy (CBREs) projects
- Equity
- Resilience
- Energy burden
- Procurement/contracting

14.2.7 OPUC public meeting and advocate feedback

Over the past several years, PGE has heard from many of our communities how important we are to their daily lives. As an essential service provider, we have both an opportunity and an obligation to serve customers and communities. We are working to be more inclusive, broadening our perspective of community to establish trusted relationships with marginalized communities and communities of color and the organizations that represent them.

On December 15, 2022, in an OPUC Special Public Meeting for a Resiliency Technical Conference, we heard heartfelt testimonies from the EJ advocates and individuals.[373] We listened to the lived experiences and stories of what happens when an outage occurs and how it affects families and individuals. Every family is affected differently, such as or the decreased air quality within a home due to using woodfire stoves to keep warm. The range of impacts is far-reaching, even beyond the electric sector; however, as an essential service provider, we know we have a role to play. These testimonies reinforced the resiliency focus we seek to incorporate with our CEP and across the planning landscape, where possible. We understand the importance and urgency of this topic and plan on continuing the conversation in future Community Learning Labs. For additional information on our resilience efforts, see **Section 13.5, Programs and opportunities**.

14.2.8 Transparency and accessibility

Through Order 22-477, the OPUC provides draft rules for the CEPs stating the CEPs "must be written in language that is as clear and simple as possible, so that it may be understood by non-expert members of the public."[374] Additionally, through Order 22-446, the OPUC provide guidelines that "Staff, utilities and all interested stakeholders should collaboratively develop by February 1, 2023, an agreed upon approach to capturing additional standardized information and data related to their CEP and how they will make it publicly available in a similar fashion on their websites."

PGE is committed to ensuring customer data is safe and secure while exploring ways to make data more consumable for the broader audience, such as creating a dashboard to display non-sensitive data and information. PGE used several strategies to ensure transparency and

[373] Docket UM 2225, December 15, 2022, OPUC Special Public Meeting, HB 2021 Clean Energy Plans Resiliency Technical Conference, video recording, available at: https://oregonpuc.granicus.com/player/clip/1063?view_id=2&redirect=true&h=c546c1727b98130d5a6f2cdcbc3fc327.

[374] *In the Matter of Public Utility Commission of Oregon, House Bill 2021 Investigation into Clean Energy Plans,* Docket No. UM 2225, Order No. 22-477 (Dec 14, 2022), Appendix A at 11 (Staff's proposed draft Division 27 rule revision 860-027-0400(5)).

accessibility of our CEP. For this CEP, we focus on two areas of transparency and accessibility. The first is information related to our Community Learning Labs, and the other is a streamlined and dedicated website for our planning documents (e.g., CEP, IRP and DSP).

Within our Community Learning Labs, we heard that utilizing Microsoft Teams to host meetings is challenging for attendees because not all participants use Microsoft applications. Because of this, we conducted our Community Learning Labs virtually via Zoom, as this was the preferred meeting platform of attendees. We offered our Community Learning Labs the following resources: live transcripts and/or closed captions during meetings, a dedicated CEP website with access to previous Community Learning Lab materials and archived public meeting recordings. PGE also provided multiple ways to engage during meetings, such as verbal, chat feature, Mural Board, dedicated time for questions and answers (Q&A) and providing attendees with real-time feedback from our subject matter experts. Additionally, a CEP-shared mailbox was established for inquiries from the community, where they could communicate directly with the CEP team via email.

PGE established a dedicated website for all our resource plans (e.g., IRP, CEP and DSP) and provided access to information in new ways.[375] We publish our IRP data on our IRP website, including all material presented at IRP Roundtable meetings, associated Q&A responses and video recordings. Our website also provides additional materials and other relevant information regarding the CEP. We updated our indexing system based on participant feedback to allow easier navigation to specific topics of interest within the many hours of meeting recordings and slides presented.

PGE will also continue to evolve our practices to support any future agreed-upon approaches to capturing and reporting standardized information and data associated with the CEP.

14.2.9 Effectiveness of community engagement

Through Order 22-390, the OPUC provided guidance to utilities on how to report on the effectiveness of community engagement. This included:

- Information regarding community engagement in developing the plan, and
- Surveying participants who provided input on their experiences participating in the utility's process and their perspectives on how their input influenced the plan.

PGE recognizes the importance of building trusted relationships with the community. We are making concerted efforts to build relationships with new and different community

[375] Portland General Electric's Resource Planning, information available at: https://portlandgeneral.com/about/who-we-are/resource-planning.

collaborators to help build more awareness and bring community perspectives to PGE's plans, projects, programs and processes.

PGE measured the effectiveness of its community engagement through the following activities: facilitated Community Learning Labs, led focus groups, conducted evaluation surveys, held informal interviews with individuals and targeted outreach to communities that may be interested in learning about the CEP. Also, we continue with our learnings from the DSP to maintain space for our non-technical audience and established Community Learning Labs to socialize concepts and seek feedback on our approach to the following topics:

- Resilience
- CBIs
- CBRE and Non-wire Solutions

14.3 Continuing community engagement

Though PGE has a long history of robust long-term resource planning and of supporting renewable energy development, social equity and sustainability goals, our planning for specific emissions targets and the inclusion of CBREs and CBIs in those planning efforts is still relatively new. We expect this work will evolve and change over time; especially, as we learn from our efforts and continue to engage with our stakeholders and communities. Moving forward, we plan to host continual Community Learning Labs across our different planning platforms to maintain the dialogue with communities around the clean energy transition and to facilitate the connections between our clean energy planning, long-term resource and transmission planning, distribution system planning and program planning for transportation electrification, flexible loads and other priority initiatives.

Appendix

Appendix A. 2019 IRP Action Plan in review

Portland General Electric Company's (PGE) 2019 Integrated Resource Plan (IRP) was developed in consultation with the Oregon Public Utility Commission (OPUC or the Commission), and public stakeholders. Through the March 16, 2020, Commission decision and subsequent order issued May 6, 2020, the Commission acknowledged, with conditions and additional directives, the 2019 IRP. The 2019 IRP focused on three categories of actions: customer resource actions, renewable actions, and capacity actions. This appendix reviews the 2019 IRP with a focus on those three categories.

A.1 Customer resource actions

Action 1A: Seek to acquire all cost-effective energy efficiency, which is currently forecasted by the Energy Trust of Oregon (ETO) to be 157 MWa on a cumulative basis by 2025.[376]

Action 1B: Seek to acquire all cost-effective and reasonable distributed flexibility

The Commission acknowledged these actions with additional conditions and directives:[377]

> *Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.*
>
> *Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios.*
>
> *Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and consider the adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.*
>
> *In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019.*

[376] This forecast was current at the time of the 2019 IRP filing, July 19, 2019.
[377] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, pg. 22, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

PGE has acquired 27.4 MWa in 2020 and 24.1 MWa in 2021 of cost-effective energy efficiency. These acquisitions compose 33 percent of the targeted 5-year goal of 157 MWa by 2025 as discussed during the 2019 IRP.

PGE has acquired distributed flexibility of 231.31 MW.

- 92.7 MW DR Summer / 62.8 MW DR Winter (Customer Programs)
- 8.5 MW Battery (Nameplate MW) (Grid-Edge)
- 130.1 MW DSG (Grid-Edge)

We have incorporated and discuss how PGE has worked with ETO in accordance with the Commission conditions regarding our work with ETO within this IRP, including their process for forecasting Energy Efficiency (EE) for PGE's IRP based on the analytical model, results from the recent IRP forecast for data center EE potential, examples of EE savings from past data center projects, technologies employed, costs, incentives, kWh and kW demand savings, and lessons learned from the evaluations (see **Chapter 6, Resource needs**). PGE and ETO held a technical discussion with Staff and public stakeholders on data center load and energy efficiency measures on March 8, 2023. Staff did not request a study related to energy efficiency capacity value modifiers for inclusion in the 2023 IRP.

PGE reports on trends in sales by customer class in **Section 6.1, Load forecast**. PGE has reported on trends of sales by customer class and Distributed Energy Resources (DER) installments for 2015 through 2019 in the DSP part 1, Section 1.5 of Chapter 1.[378]

A.2 Renewable actions

Action 2: As modified in PGE's final comments,[379] PGE conducted an RFP seeking up to approximately 150 MWa of new, renewable resources that contribute to meeting PGE's capacity needs by the end of 2024.

PGE received regulatory approval to issue the 2021 All-Source RFP[380] in December 2021, with the RFP structure reflecting the intent of the 2019 IRP Action Plan and the significant resource need to be driven by the passage of House Bill 2021 after the acknowledgment of the 2019 IRP. PGE's 2021 RFP saw robust participation, with 110 bid options received,

[378] Distribution System Planning Part 1 available at: https://assets.ctfassets.net/416ywc1laqmd/ELNdf17zyQvQiU9k71pIX/683cd2f7b3098517068c4594100a1025/DSP_2021_Report_Chapter1.pdf
[379] PGE's Response to Staff Report at 4.
[380] In the matter of Portland General Electric Company, Request for Proposal and Independent Evaluator, Docket UM 2166, Order No. 21-460

representing over 11,500 MW of potential resources. PGE's final shortlist proposed for Commission acknowledgment included 13 unique projects representing 599 MWa of energy and 497 MW of capacity contribution (ELCC - effective load carrying capacity).[381]

The OPUC acknowledged PGE's final shortlist with conditions on July 15, 2022 (later memorialized in Order No. 22-315). In the Order, the Commission encouraged the Company to consider procuring approximately 250 MWa of renewable resources should procurement conditions warrant.[382] On October 25, 2022, PGE announced the procurement of the Clearwater Energy Center, a 311 MW portion of a wind facility located in Eastern Montana that will be constructed and operated by NextEra Energy Resources LLC. PGE continues negotiations with final shortlist bidders and will announce further actions upon execution of agreements.

PGE entered into three long-term solar contracts to support PGE's Green Future Impact (GFI) program. The 162 MW Pachwaywit Fields (also known as Montague Solar Facility) was announced in February 2020 and is expected to reach commercial operations by Fall of 2023 to support the GFI PGE supplied option phase I. Long-term agreements were also executed for the Bakeoven Solar Project and the Daybreak Solar Project to support GFI Customer supplied option for both phase I and phase II. The Daybreak and Bakeoven Solar Projects are expected to reach commercial operations by 2024.

A.3 Capacity actions[383]

Action 3A: Pursue cost-competitive agreements for existing capacity in the region.

Action 3B: Update the Commission and stakeholders on the status of PGE's bilateral negotiations and any resulting impacts on capacity needs.

PGE and Douglas County Public Utility District No.1 signed a five-year power purchase agreement to supply PGE customers with up to 160 MW of additional capacity from the Wells Hydroelectric Project on the Columbia River north of Wenatchee, Washington. The five-year agreement began in January 2021. PGE successfully executed a long-term contract for the

[381] PGE's final shortlist request for acknowledgment, filed May 5, 2022, available here: https://edocs.puc.state.or.us/efdocs/HAH/um2166hah151340.pdf
[382] Order No 22-315 at Page 5
[383] In the final comments, PGE proposes size limits that would apply across all procured resources. For capacity, PGE proposes not to exceed PGE's identified 2025 Reference Case capacity need of 697 MW for the combined capacity contribution of all procured resources; PGE will refine that maximum following an updated needs assessment prior to any RFP. For energy, PGE proposes to constrain energy additions across the capacity action and the renewable action to approximately 150 MWa to align with the 250 MWa portfolio screen and the expectation that bilateral procurement will result in some energy additions. The Commission acknowledged these actions with the additional condition that PGE must optimize its procurement approach.

output of Pelton Round Butte Project share owned by the Confederated Tribes of Warm Springs (CTWS). The fifteen-year agreement begins in 2025 and secures long-term off-take for 249 MW

As discussed in the OPUC Special Public Meeting on April 20, 2021, PGE procured both capacity and energy through a single all-source RFP. The final shortlist, acknowledged with conditions on July 14, 2022, and memorialized in Order No. 22-315, included 497 MW capacity contribution (ELCC) through five projects.

Our 2021 IRP Update,[384] filed January 29, 2021, updated the Commission on our use of bilateral negotiations to procure needed capacity. Pursuant to Order No. 21-129, we kept the Commission and Staff informed on negotiations and ultimately executed contracts totaling 234 MW of nameplate capacity using the bilateral procurement process.

A.4 2019 Action Plan checklist order no. 20-152

Table 77. Requirements and compliance from Order 20-152

Requirement	PGE compliance
Order 20-152 at 2 **We ask PGE to continue working to build a common understanding of its modeling terms and processes.**	PGE communicates IRP analysis through a series of public meetings and informal communication. The process is open to the public and building understanding with participants is a key objective of these meetings. See **Appendix C, 2023 IRP public meeting agendas**.
At 7	PGE complies with this requirement as part of IRP analysis and development. GFI resources are included in 2023 IRP modeling. See **Chapter 6, Resource needs**.

[384] In the matter of Portland General Electric Company, Integrated Resource Planning, Docket No. LC 73, Order No. 21-129 https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

Requirement	PGE compliance
PGE does not exclude load associated with its voluntary green energy programs. PGE states that, because these programs have not yet started or are relatively new, the 2019 IRP considers potential customer participation in these programs in sensitivities. PGE states the sensitivities have little impact on PGE's needs. PGE states it will monitor participation in future IRPs and IRP Updates.	
At 8 **We also direct PGE to incorporate examination of customer program growth assumptions, including utility-offered programs and direct access, in its next IRP.**	PGE included the most up to date forecasts of customer programs, including both utility-offered programs and direct access; See **Section 3.1.7, Regulatory policy: Direct access** of **Chapter 3, Planning environment**.
At 8 **PGE stated it would continue to examine options related to Colstrip units 3 and 4 as additional information becomes available and will continue to prioritize cost impacts and risks to customers, reliability, and GHG emissions implications.**	PGE continues to perform this work as part of IRP analysis and development. See **Section 6.10, Need sensitivities** of **Chapter 6, Resource needs**.
At 9 **PGE communicated a sense of urgency to complete a Colstrip study and committed to complete the analysis by July 31, 2020. We consider this time frame reasonable, and because we expect that discussion of PGE's study will provide a framework for next steps, we do not establish a required schedule for updates at this time.**	Complete Colstrip enabling study.[385]

[385] The Colstrip enabling study is available at: https://assets.ctfassets.net/416ywc1laqmd/2AK9jf4GCmd1tyaLA8EODE/fb40144334f40fab7cc2e001676f1977/2020-colstrip-enabling-study.pdf

Requirement	PGE compliance
At 15 **We recognize Staff and stakeholders' growing frustration with PGE' s insistence on physical compliance modeling, and consider it important for PGE to proactively, consistently, and clearly show how portfolio results would change if PGE used an RPS compliance assumption that more closely matches its actual compliance strategy. This would involve maximizing use of unbundled RECs, which PGE has consistently done for RPS compliance, and should also involve using portfolio optimization tools to inform the least cost, least risk RPS compliance strategy.**	PGE discusses RPS requirements and our expectations of future REC generation in **Section 6.7, RPS need, Section 11.4.6, Targeted policy portfolios,** and **Section 11.5.2, Resulting RPS position**.
At 16 **We appreciate that PGE agreed to provide a climate adaptation strategy as an enabling analysis for the next IRP. This will be a helpful document to orient discussions around low water conditions, new flow patterns, and higher temperatures resulting from climate change.**	PGE worked with an external consultant to evaluate how climate adaptation should be incorporated into long-term utility modeling; see **Ext. Study-III, Climate adaptation.** PGE then took recommendations from this work and evaluated three climate adaption sensitivities; see **Section 6.9, Climate adaptation**.

Requirement	PGE compliance
At 16 **To advance a common understanding of whole portfolio decarbonization, we plan to hold a Commission workshop during the 2021 IRP development process to assess PGE's progress in developing and representing in its IRP a holistic decarbonization strategy, in the context of how other GHG policy drivers have developed. It is important that PGE consider its entire portfolio-including existing resource dispatch and transitions, new resource additions, and customer and demand-side resources-to deliver a full picture of how a least-cost, least-risk portfolio may also meet customer, company, community, and state decarbonization goals.**	Compliance with House Bill 2021 satisfies this request.
At 16-17 **We encourage PGE to consider portfolios that achieve PGE's proportionate share of the greenhouse gas emission reductions in Executive Order No. 20-04, as well as developing least-cost, least-risk strategies for assisting communities in its service territory that seek deeper, faster reductions.**	PGE included a robust discussion of the pace of decarbonization pathways going forward; See **Chapter 5, GHG emissions forecasting** and **Section 11.4.1, Decarbonization glidepath portfolios.**
At 17 **PGE explained the difficulties with transmission modeling, as transmission availability is constantly changing, and upgrade costs are not known until a specific project is studied. Nonetheless, PGE agreed to investigate how it can incorporate transmission availability of sub-regions to inform resource choices.**	PGE has incorporated transmission availability into portfolio modeling through data pulled from Bonneville Power Administration's (BPA) Transmission Study and Expansion Process (TSEP) and from an analysis of planned upgrades that may impact PGE's system. PGE describes transmission availability in **Chapter 9, Transmission** and its impact on portfolio selection in **Chapter 11, Portfolio analysis.**

Requirement	PGE compliance
At 19 **PGE's nontraditional screens were valuable here as a way to focus on key portfolio attributes, but in the future PGE should work closely with stakeholders to gain broad understanding of significant non-traditional screens before PGE uses a specific criterion as a constraint in modeling or as a screen in scoring.**	PGE complies with this requirement in **Chapter 11, Portfolio analysis,** and through discussion about scoring metrics and portfolio analysis assumptions at several IRP Roundtable meetings
At 19 **PGE should continue to work with Staff and stakeholders to explore how to model the cost and risk tradeoffs of energy additions in this environment.**	PGE complies with this requirement in **Chapter 11, Portfolio analysis** and through discussion about scoring metrics and portfolio analysis assumptions and results at several IRP Roundtable meetings
At 19 **...PGE also will need to consider future changes in energy markets, such as the potential transition to security-constrained, economic dispatch day-ahead markets, and how its resources will perform against market-wide clearing prices.**	PGE evaluates its resource portfolio against Western Power prices that are simulated in Aurora. This simulation approximates a Western economically dispatched day-ahead market. See **Appendix H, 2023 IRP modeling details** for more information on the Aurora model.
At 19 **...PGE will need to continue to evaluate and balance the tradeoffs between more certain near-term rate impacts and less certain long-term projected cost savings.**	**Chapter 11, Portfolio analysis** includes a substantial discussion about the trade-offs associated in resource planning between near- and -term costs.
At 19-20 **...PGE will also need to continue to support its proposal as it moves forward in changed circumstances, assessing whether the impacts of the COVID-19 pandemic are a material change to forecasts, needs, and its customers' tolerance for near-term rate pressure.**	PGE includes a substantial discussion of the effects of the pandemic as well as other developments in load forecasting in **Section 6.1, Load forecast** and **Appendix D, Load forecast methodology**.

Requirement	PGE compliance
At 21 **We agree that it is important to understand how PGE' s forecast would change with more aggressive energy efficiency measures, and also require PGE to explore the significant, cost-effective energy efficiency opportunities that may exist with data centers that are a significant component of industrial load growth.**	PGE evaluated the cost and risk trade-offs associated with the addition of more EE adoption in portfolio analysis; see **Section 8.2, Additional distributed energy resources** and **Chapter 11, Portfolio analysis** for more detail. With the Energy Trust of Oregon PGE presented on the topic of EE opportunities at data centers at the March 8th, 2023 round table.
At 22 **Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast.**	PGE evaluated the cost and risk trade-offs associated with the addition of more EE adoption in portfolio analysis; see **Section 8.2, Additional distributed energy resources** and **Chapter 11, Portfolio analysis** for more detail.
At 22 **Before the next IRP, PGE will work with Energy Trust to develop high and low energy efficiency forecasts that have internally consistent assumptions with the load scenarios.**	PGE included high and low EE forecasts developed by the ETO; see **Section 6.2, Distributed Energy Resource (DER) impact on load.** PGE then incorporated those forecasts into its Need Futures, described in **Section 6.6.1, Capacity under different Need Futures.**
At 22 **Before the next IRP, PGE and Energy Trust will conduct a workshop regarding data center load and energy efficiency measures and to consider adoption of the Northwest Power and Conservation Council energy efficiency capacity value modifiers. Staff may request a study if needed.**	This workshop was held **March 8, 2023**.

Requirement	PGE compliance
At 22 **In the next IRP, PGE is to report on trends of sales by customer class and DER installments for 2015 through 2019.**	PGE provided these data in the 2019 IRP Update Appendix B and Appendix C.[386]
At 23 **At the meeting, we also made special reference to the need for PGE to examine the implications of the COVID-19 public health crisis and corresponding economic disruption that were just emerging in Oregon as we made our acknowledgment decision in this case.**	PGE discussed these topics in **Chapter 6, Resource needs**.

[386] See pages 60-61: https://edocs.puc.state.or.us/efdocs/HAH/lc73hah13049.pdf

A.5 2021 IRP update order no. 21-129[387]

Requirement	PGE compliance
At 2 **Our deliberations involved two categories of interrelated issues, ELCC methodology and PGE's assumptions for new baseline solar resources. For methodology, PGE uses a single year of 2025, and we adopt Staff's recommendation for PGE to compute ELCC values by year and present the findings with its next IRP.**	We complied by estimating annual ELCCs by resource from the first main year of need through 2026, in line with the best practices provided by UM 2011. See **Appendix K, Tuned system ELCCs**.
At 4 **We find it is reasonable for PGE to complete its supply side resource study that is currently underway and update costs and operating characteristics of generation resources in the next IRP.**	PGE conducted its own evaluation of supply-side options; see **Appendix M, Supply-side options**.
At 1, 6 **Staff requests that PGE compute effective load carrying capability (ELCC) values by year and present the findings with its next IRP. Staff and stakeholders can use the findings to determine whether the impact of resource retirements and additions, and other changes in the load and resource balance, significantly change the ELCC values.**	Complete; see **Appendix K, Tuned system ELCCs**.

[387] In the matter of Portland General Electric Company, Integrated Resource Planning, Docket No. LC 73, Order No. 21-129, available at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf

Requirement	PGE compliance
At 1, 6 **Staff requests a workshop with PGE for the purpose of working with PGE before the 2021 IRP is filed to look at natural gas generation in the "high renewables buildout" price forecast and discuss whether gas resources would be likely to generate significantly less in that future, thus reducing market prices.**	PGE is not using a high-renewable buildout in this IRP.
At 4 **PGE should update its GEAR resources to include the recently approved customer-supplied option in Commission Order No. 21-053 in the base portfolio. The executed contract should not be treated as a sensitivity because it is now a reality.**	All GFI resources are included in the IRP planning models.

Appendix B. Compliance guidelines

The appendix catalogues, in tabular format, IRP requirements and lists where in the IRP the requirements are addressed.

B.1 Integrated Resource Plan guidelines

Table 78. Guideline 1: Substantive requirements

No.	Requirement	Compliance	Chapter
Guideline 1a	All resources must be evaluated on a consistent and comparable basis.	Resources are evaluated on a consistent and comparable basis as part of portfolio analysis work.	**Chapter 11, Portfolio analysis**
	All known resources for meeting the utility's load should be considered, including supply-side options which focus on the generation, purchase, and transmission of power – or gas purchases, transportation, and storage – and demand-side options which focus on conservation and demand response.	PGE's IRP includes known supply- and demand-side options that are expected to be available for meeting portfolio needs, including: wind, solar PV (photovoltaic), geothermal, biomass, standalone energy storage, solar PV with energy storage hybrid, energy efficiency, demand response, and incremental transmission resources. Supply-side resource options are tested with estimates of associated transmission wheeling costs.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**

No.	Requirement	Compliance	Chapter
	Utilities should compare different resource fuel types, technologies, lead times, in-service dates, durations, and locations in portfolio risk modeling.	PGE's portfolio analysis compares resources across each of these factors.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**
	Consistent assumptions and methods should be used for evaluation of all resources.	All resources are compared by using the same assumptions and methods.	**Chapter 11, Portfolio analysis**
	The after-tax marginal weighted-average cost of capital (WACC) should be used to discount all future resource costs.	Future costs are discounted at PGE's estimated long-term after-tax weighted-average cost of capital of 6.168% as a proxy for the long-term cost of capital.	**Appendix H, 2023 IRP modeling details**
Guideline 1b	Risk and uncertainty must be considered. At a minimum, utilities should address the following sources of risk and uncertainty:	PGE accounts for multiple sources of risk and uncertainty in the 2023 IRP.	**Chapter 11, Portfolio analysis**

No.	Requirement	Compliance	Chapter
	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.	Portfolio modeling is conducted over multiple future conditions for technology costs, energy prices, hydroelectric conditions, load conditions, combining for 1134 different potential future conditions. Uncertainty in costs associated with compliance with Green House Gas (GHG) emissions reductions is accounted for through analysis of alternative GHG reduction glidepaths. Plant forced outages and other sources of uncertainty in reliability planning is accounted for in resource adequacy modeling in Sequoia.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**
	2. Natural gas utilities: demand (peak, swing, and baseload), commodity supply and price, transportation availability and price, and costs to comply with any regulation of greenhouse gas emissions.	N/A for PGE	N/A for PGE

No.	Requirement	Compliance	Chapter
	Utilities should identify in their plans any additional sources of risk and uncertainty.	Refer to 1.b.1 for sources of uncertainty and risk considered by PGE in this IRP.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**
Guideline 1c[388]	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.	Portfolio modeling used optimization to create portfolios that minimize expected costs. Portfolios were evaluated using traditional scoring metrics quantifying cost and risk as well as Portfolio Community benefits indicators (pCBIs) to select a Preferred Portfolio that performed well across all metrics.	**Chapter 11, Portfolio analysis, Table 92. Roadmap Acknowledgement**
	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.	The planning horizon in portfolio analysis is 20 years (2024-2043). The costs and benefits associated with the resources considered extend over the entire expected lifetime. End effects are captured through levelized costs that account for the lifetime costs of resources procured within the planning horizon.	**Chapter 11, Portfolio analysis**

[388] In Order 23-060, OPUC waived Guideline 1c and directed utilities to follow revised planning guidance for the first IRP/CEP. PGE's approach to traditional cost and risk metrics is discussed below in **Appendix B.1**, with an additional description of our approach to new expectations described in the CEP RMA 1.5.a-h compliance section in **Appendix B.2**.

No.	Requirement	Compliance	Chapter
	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.	Each of these sources of costs are accounted for in portfolio analysis, which uses Net Present Value Revenue Requirement (NPVRR) as the main cost metric. For all existing resources in PGE's portfolio, including long-lived resources and short-term contracts, all costs the Company would expect to incur to access and operate the resource (i.e., fuel cost and transportation, transmission, fixed cost recovery, contract costs, etc.) are accounted for throughout the lifetime of the resource in revenue requirement modeling.	**Chapter 11, Portfolio analysis**
	To address risk, the plan should include, at a minimum:		

No.	Requirement	Compliance	Chapter
	1. Two measures of PVRR risk: one that measures the variability of costs and one that measures the severity of bad outcomes.	Both variability and severity are used as risk metrics in portfolio analysis. Variability is measured using the semi-deviation of NPVRR across all futures, relative to the Reference Case. Severity is measured using the tail value at risk (TailVAR) at the 90Th percentile of NPVRR across all futures.	**Chapter 11, Portfolio analysis**
	2. Discussion of the proposed use and impact on costs and risks of physical and financial hedging.	Costs and risks of the resource additions which could provide a physical hedge against future wholesale market volatility are part of the considerations made during PGE's portfolio analysis. PGE does not consider any other long-term financial or physical hedging activities beyond those considerations.	**Chapter 11, Portfolio analysis**

No.	Requirement	Compliance	Chapter
	The utility should explain in its plan how its resource choices appropriately balance cost and risk.	Groups of portfolios are designed to target key sources of uncertainty around transmission, Distributed Energy Resources (DERs), Community-based Renewable Energy (CBRE), etc. Comparison of costs and risk metrics amongst portfolios within each group provides insights on these key topics to inform the design of the Preferred Portfolio. The portfolio analysis chapter describes the logic of how cost and risk are balanced.	**Chapter 11, Portfolio analysis**
Guideline 1d	The plan must be consistent with the long-run public interest as expressed in Oregon and federal energy policies.	All known federal and state energy policies in Oregon are reflected in the 2023 IRP, including the requirements of HB 2021.	**Chapter 11, Portfolio analysis**

Table 79. Guideline 2: Procedural requirements

	Requirement	Compliance	Chapter
Guideline 2a	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 Commission for resolution.	PGE began providing an opportunity for public involvement in the 2023 IRP starting in January 2020. Thirty-six public meetings, including seven Learning Labs, have been held seeking stakeholder feedback. PGE provides email, meetings, and a public feedback form as venues to submit additional or written input to IRP content.	**Appendix C, 2023 IRP public meeting agendas**

	Requirement	Compliance	Chapter
Guideline 2b	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 the use of a protective order, through aggregation or shielding of data, or through any other mechanism approved by the Commission.	PGE provides non-confidential information used for portfolio evaluation and development of the Action Plan in the 2023 IRP.	All chapters and supporting appendices
Guideline 2c	The utility must provide a draft IRP for public review and comment prior to filing a final plan with the Commission.	PGE filed a motion on November 22, 2022, requesting this guideline be waived. Guideline waived via Order No. 23-010[389], adopting Staff's recommendation at the 1/24/23 Public Meeting.	N/A for this filing

[389] Order No. 23-010. Request for waiver of Integrated Resource Plan guideline 2(c), available online: https://apps.puc.state.or.us/orders/2023ords/23-010.pdf

Table 80. Guideline 3: Plan filing, review, and updates

	Requirement	Compliance	Chapter
Guideline 3a	A utility must file an IRP within two years of its previous IRP acknowledgment order. If the utility does not intend to take any significant resource action for at least two years after its next IRP is due, the utility may request an extension of its filing date from the Commission.	PGE filed its last IRP on July 16, 2019. Commission acknowledged with conditions on March 15, 2020. PGE requested a waiver to delay the IRP filing date from March 2022 to March 2023 on October 15, 2021. The Commission approved the motion on November 18, 2021.	N/A for this filing
Guideline 3b	The utility must present the results of its filed plan to the Commission at a public meeting prior to the deadline for written public comment.	PGE will comply with this Guideline as arranged in the procedural schedule.	N/A for this filing
Guideline 3c	Commission staff and parties should complete their comments and recommendations within six months of IRP filing.	N/A for PGE	N/A for PGE

	Requirement	Compliance	Chapter
Guideline 3d	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 plan before issuing an acknowledgment order.	N/A for PGE	N/A for PGE
Guideline 3e	The Commission may provide direction to a utility regarding any additional analyses or actions that the utility should undertake in its next IRP.	N/A for PGE	N/A for PGE

	Requirement	Compliance	Chapter
Guideline 3f	Each utility must submit an annual update on its most recently acknowledged plan. 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 Commission, unless the utility is within six months of filing its next IRP. The utility must summarize the update at a Commission public meeting. The utility may request acknowledgment of changes in proposed actions identified in an update.	N/A for this filing	N/A for this filing
Guideline 3g	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;	N/A for this filing	N/A for this filing

	Requirement	Compliance	Chapter
	Provides an assessment of what has changed since the acknowledgment order that affects the action plan, including changes in such factors as load, expiration of resource contracts, supply-side and demand-side resource acquisitions, resource costs, and transmission availability; and	N/A for this filing	N/A for this filing
	Justifies any deviations from the acknowledged action plan.	N/A for this filing	N/A for this filing

Table 81. Guideline 4: Plan components

	Requirement	Compliance	Chapter
		At a minimum, the plan must include the following elements:	
Guideline 4a	a. An explanation of how the utility met each of the substantive and procedural requirements;	The purpose of this table and **Appendix A** is to show compliance with this Guideline.	**Appendix A, 2019 IRP Action Plan in review** **Appendix B, Compliance guidelines**
Guideline 4b	b. Analysis of high and low load growth scenarios in addition to stochastic load risk analysis with an explanation of major assumptions;	PGE has included low, reference, and high Need Futures that capture variance in load growth, DER adoption, and market capacity. Stochastic load risk is integrated within our assessment of capacity needs.	**Chapter 4, Futures and uncertainties** **Chapter 6, Resource needs**

	Requirement	Compliance	Chapter
Guideline 4c	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;	The 2023 IRP includes a capacity adequacy assessment, a flexibility-adequacy study, and an energy load resource balance calculation. These studies are used to inform portfolio analysis. The portfolio analysis chapter describes which resources would be the best option to fill the gaps between supply and demand while incorporating resource adequacy needs and transmission constraints.	**Chapter 11, Portfolio analysis** **Appendix F, Load resource balance**
Guideline 4d	For natural gas utilities, a determination of the peaking, swing, and base-load gas supply and associated transportation and storage expected for each year of the plan, given existing resources; and identification of gas supplies (peak, swing, and baseload), transportation, and storage needed to bridge the gap between expected loads and resources;	N/A for PGE	N/A for PGE

	Requirement	Compliance	Chapter
Guideline 4e	Identification and estimated costs of all supply-side and demand-side resource options, considering anticipated advances in technology;	Costs of future resource options are estimated from publicly available documents, including those produced by National Renewable Energy Laboratory (NREL) and Energy Information Administration (EIA). These future costs include anticipated advances in technology and manufacturing. PGE includes multiple future resource cost paths.	**Chapter 8, Resource options** **Chapter 10, Resource economics**
Guideline 4f	Analysis of measures the utility intends to take to provide reliable service, including cost-risk tradeoffs;	PGE aims to have all portfolios meet a 2.4 LOLH (loss of load hours) target on a seasonal level. The portfolio model, ROSE-E, builds a least-cost system to this standard using available resources. We do sensitivities of how this buildout changes due to variations in demand or supply. We do not explore tradeoffs to system reliability at different levels (we do not study the cost/benefits of a less stringent adequacy standard).	**Chapter 6, Resource needs**

	Requirement	Compliance	Chapter
Guideline 4g	Identification of key assumptions about the future (e.g., fuel prices and environmental compliance costs) and alternative scenarios considered;	PGE has considered 351 potential futures across resource capacity needs, market electricity prices, and technology costs of new resources.	**Chapter 4, Futures and uncertainties** **Chapter 6, Resource needs**
Guideline 4h	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;	PGE has constructed 40 portfolios across six categories to test various conditions and their impact on costs, risk, community benefit, decarbonization rate, and balance of short-term and long-term costs and benefits allocation.	**Chapter 11, Portfolio analysis**
Guideline 4i	Evaluation of the performance of the candidate portfolios over the range of identified risks and uncertainties;	PGE conducted portfolio modeling over 1134 future scenarios, capturing a wide range of potential future conditions.	**Chapter 11, Portfolio analysis**

	Requirement	Compliance	Chapter
Guideline 4j	Results of testing and rank ordering of the portfolios by cost and risk metric, and interpretation of those results;	PGE scored portfolios across both traditional scoring metrics designed to evaluate cost and risk and pCBIs which capture a range of community benefits. A Preferred Portfolio was developed that not only provides the best combination of cost and risk, but which also maximizes community benefits as required by the Clean Energy Plan.	**Chapter 11, Portfolio analysis**
Guideline 4k	Analysis of the uncertainties associated with each portfolio evaluated;	Uncertainties are accounted for in the construction of each portfolio, with portfolios designed to test key sources of uncertainty. Uncertainty is quantified in portfolio scoring through the evaluation of cost and risk metrics based on many potential future scenarios.	**Chapter 11, Portfolio analysis**
Guideline 4l	Selection of a portfolio that represents the best combination of cost and risk for the utility and its customers;	PGE has developed a Preferred Portfolio that meets UM 2225 guidance of balancing costs, risks, and community benefits	**Chapter 11, Portfolio analysis**

	Requirement	Compliance	Chapter
Guideline 4m	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;	PGE creates portfolios which comport with all state and federal energy policies, to the best of PGE's knowledge. PGE does not allow for the construction of portfolios that violate said policies. For example, we would not allow a portfolio that emits 2 million megatons (MMT) of GHG in 2030 when our state policy requires 1.62 or fewer MMT of CO_2e emissions.	**Chapter 11, Portfolio analysis**
Guideline 4n	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.	PGE's Action Plan includes the resource actions PGE intends to take over the next two to four years, as reflected in the Preferred Portfolio. The Action Plan covers Customer Resource Actions, Renewable Actions, Capacity Actions, and Transmission Actions.	**Chapter 11, Portfolio analysis**

Table 82. Guideline 5: Transmission

	Requirement	Compliance	Chapter
Guideline 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, considering their value for making additional purchases and sales, accessing less costly resources in remote locations, acquiring alternative fuel supplies, and improving reliability.	PGE includes costs associated with fuel and electricity transmission, as appropriate, for new supply-side resources considered in portfolio analysis. See discussion in **Chapter 8, Resource options**, **Chapter 9**, **Transmission, Chapter 10, Resource economics**, and **Chapter 11, Portfolio analysis**.	**Chapter 8, Resource options** **Chapter 10, Resource economics**

Table 83. Guideline 6: Conservation

	Requirement	Compliance	Chapter
Guideline 6a	Each utility should ensure that a conservation potential study is conducted periodically for its entire service territory.	PGE has incorporated Energy Trust's most recent long-term conservation potential study from May 2022. PGE coordinated with the Energy Trust to support the development of the EE forecast. Specifically, PGE provided information to the Energy Trust, which included load growth assumptions, cost of capital, and avoided cost inputs. PGE incorporated cost-effective energy efficiency as a given, within the resource Need Futures. PGE also incorporated additional energy efficiency that was deemed non-cost effective as a supply side resource.	**Chapter 6, Resource needs**

	Requirement	Compliance	Chapter
Guideline 6b	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.	Since 2002, Energy Trust has been the independent, non-profit organization in charge of identifying the State's Energy Efficiency (EE) potential. PGE and other utilities fund such programs and work with the Energy Trust to implement EE measures. PGE maintains a long-term, productive relationship with the Energy Trust so that EE remains a top priority resource for PGE and the State.	N/A
Guideline 6c	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:		
	Determine the amount of conservation resources in the best cost/risk portfolio without regard to any limits on funding of conservation programs; and	The portfolios incorporate the results of the energy efficiency studies conducted by the Energy Trust which determine the amount of potential cost-effective energy efficiency without regard to any funding limits, except for the SB 838 funding constraints.	**Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**

	Requirement	Compliance	Chapter
		Portfolios also incorporated additional energy efficiency that was deemed non-cost effective as a supply side resource available during portfolio analysis.	
	Identify the preferred portfolio and action plan consistent with the outside party's projection of conservation acquisition.	PGE's Preferred Portfolio and Action Plan include the Energy Trust's EE savings projection. Additionally, PGE has also evaluated additional EE to understand if and how the role of EE will evolve with the changing planning environment. These insights are also incorporated into the Preferred Portfolio and Action Plan. PGE continues to work collaboratively with Energy Trust to achieve sufficient funding for acquisition of all cost-effective and reasonable EE.	**Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**

Table 84. Guideline 7: Demand response

	Requirement	Compliance	Chapter
Guideline 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).	PGE has incorporated the most recent long-term demand response potential study from the Distribution System Plan Part 2[390] from August 2022. PGE incorporated cost-effective demand response as a given, within the resource Need Futures. PGE also incorporated additional demand response that was deemed non-cost effective as a supply side resource.	**Chapter 6, Resource needs** **Chapter 8, Resource options**

[390] PGE's Distribution System Plan Part 2, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAD&FileName=um2197had151613.pdf&DocketID=23043&numSequence=21

Table 85. Guideline 8: Environmental costs (order 08-339)

	Requirement	Compliance	Chapter
Guideline 8a	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 also 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 allowance, credit trading, or a safety valve). The analysis should recognize significant and important upstream emissions that would likely	Portfolio analysis incorporates the requirements of House Bill 2021 and assumes full regulatory compliance for emissions for all resources. Specifically, we constructed a base-case scenario that includes carbon prices to dispatch for carbon emitting resources located in California, Washington, Alberta, and British Columbia to reflect the existing carbon emission legislation. In the base-case scenario, California and Washington carbon prices reference the California Energy Commission's (CEC) outlook of cap-and-trade legislation in California. The carbon prices for Alberta and British Columbia are equivalent to the locations' existing tax legislation. PGE also developed a high-carbon-case scenario in which the CEC's view of social cost is added as carbon prices for dispatchable carbon-emitting resources in California, Washington, and Oregon.	**Chapter 4, Futures and uncertainties**

	Requirement	Compliance	Chapter
	have a significant impact on its resource decisions. Each compliance scenario should maintain logical consistency, to the extent practicable, between the CO_2 regulatory requirements and other key inputs.	In this scenario, carbon emitting resources in the rest of the Western Electricity Coordinating Council (WECC) locations also have carbon prices forecasted by Wood Mackenzie's reference case. Finally, a low-case scenario is constructed with a low CEC carbon price outlook for California and Washington. The carbon prices for carbon emitting resources in British Columbia and Alberta are equivalent to their tax legislation. There are no carbon prices added to the rest of WECC carbon emitting resources in the low-case scenario.	
Guideline 8b	Testing alternative portfolios against the compliance scenarios: The utility should estimate, under each of the compliance scenarios, the present value of 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	PGE tested a wide variety of portfolios across a large range of potential future conditions, including several alternative GHG emissions reductions glidepaths for complying with HB 2021 GHG emissions targets. Cost and risk metrics based on NPVRR are calculated on a 20-year analysis	**Chapter 11, Portfolio analysis**

	Requirement	Compliance	Chapter
	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.	time-horizon and compared across portfolios.	

	Requirement	Compliance	Chapter
Guideline 8c	Trigger point analysis: The utility should identify at least one CO_2 compliance “turning point” scenario which, if anticipated now, would lead to, or “trigger” the selection of a portfolio of resources that is substantially different from the preferred portfolio. The utility should develop a substitute portfolio appropriate for this trigger-point scenario and compare the substitute portfolio’s expected cost and risk performance to that of the preferred portfolio – under the base case and each of the above CO_2 compliance scenarios. The utility should provide its assessment of whether a CO_2 regulatory future that is equally or more stringent than the identified trigger point will be mandated.	Since the Preferred Portfolio does not contain new resources that would emit GHG emissions, we do not anticipate more stringent CO_2 compliance requirements. We did, however, create three cases of carbon policy scenarios, described in Guideline 8a to anticipate a “trigger-point” scenario. For each of these carbon policy cases, base, high, and low case scenarios, they are paired with various permutation of WECC resource outlook, natural gas prices, and hydropower generation conditions. As a result, 27 price futures were created with base carbon policy case, 9 price futures were created with high carbon policy case, and 9 price futures were created with low carbon policy case. The inclusion of these price futures results in an increased variety of portfolio results. We also test the Preferred Portfolio under decarbonization scenarios, glidepaths, and other sensitivities.	N/A

	Requirement	Compliance	Chapter
Guideline 8d	Oregon compliance portfolio: If none of the above portfolios is consistent with Oregon energy policies (including the 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 of the preferred and alternative portfolios.	The portfolio analysis in the 2023 IRP is intended to be consistent with Oregon energy policies.	**Chapter 3, Planning environment**

Table 86. Guideline 9: Direct access loads

	Requirement	Compliance	Chapter
Guideline 9	An electric utility's load-resource balance should exclude customer loads that are effectively committed to service by an alternative electricity supplier.	Currently, PGE excludes estimated Direct Access load based on current customer elections and does not plan long-term resources to meet the potential demand from long-term opt-out customers. Nonetheless, PGE acts as the reliability provider for these customer loads.	**Chapter 4, Futures and uncertainties**

Table 87. Guideline 10: Multi-state utilities

	Requirement	Compliance	Chapter
Guideline 10	Multi-state utilities should plan their generation and transmission systems, or gas supply and delivery, on an integrated-system basis that achieves the best cost/risk portfolio for all their retail customers.	N/A for PGE	N/A for PGE

Table 88. Guideline 11: Reliability

	Requirement	Compliance	Chapter
Guideline 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.	The 2023 IRP uses a stochastic modeling approach to resource adequacy. The model assembles 50,000 synthetic test weeks to evaluate capacity need under a range of conditions. For example, it may pair an extreme weather event, like the June 2021 heatwave, with different hydroelectric conditions, wind conditions, solar conditions, and forced outage rates. This allows for an examination of worst-case scenarios in the IRP. The IRP does not create portfolios that fail to meet the 2.4 LOLH reliability target. It does create numerous other portfolios that examine the cost and risk trade-offs between different resources.	**Chapter 6, Resource needs**

Table 89. Guideline 12: Distributed Generation

	Requirement	Compliance	Chapter
Guideline 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.	PGE has incorporated the most recent long-term distributed solar and storage market adoption analysis from the Distribution System Plan Part 2[391] from August 2022.	**Chapter 8, Resource options** **Chapter 10, Resource economics** **Chapter 11, Portfolio analysis**

[391] PGE's Distribution System Plan Part 2, available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf

Table 90. Guideline 13: Resource Acquisition

	Requirement	Compliance	Chapter
Guideline 13a	An electric utility should, in its IRP:		
	Identify its proposed acquisition strategy for each resource in its action plan.	PGE describes the proposed Action Plan, which includes discussion of strategies to acquire customer resources, renewable resources, and capacity resources.	**Chapter 12, Action Plan**
	Assess the advantages and disadvantages of owning a resource instead of purchasing power from another party.	PGE discusses the benefits and risks of owning a resource and power purchase agreements.	**Chapter 8, Resource options**
	Identify any Benchmark Resources it plans to consider in competitive bidding.	PGE is considering whether to submit a benchmark for inclusion in the renewable and/or capacity resource RFP proposed in the Action Plan. PGE will provide updated information about benchmark resources prior to issuing an RFP to market.	**Chapter 9, Transmission**
Guideline 13b	Natural gas utilities should either describe in the IRP their bidding practices for gas supply and transportation or provide a description of those practices following IRP acknowledgment.	N/A for PGE	N/A for PGE

Table 91. Flexible capacity resources (order no. 12-013)

	Requirement	Compliance	Chapter
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;	PGE contracted with Blue Marble Analytics to conduct a flexibility assessment using the GridPath model to determine the flexibility needs such as balancing reserves among others, to assess the system responsiveness to short time-scale variability of load and renewables as well as forecast errors.	**Chapter 6, Resource needs** **Chapter 10, Resource economics** **Ext. Study-IV, Flexibility study**
2	Forecast the Supply of Flexible Capacity: The electric utilities shall forecast the balancing reserves available at different time intervals (e.g., ramping available within 5 minutes) from existing generating resources over the 20-year planning period; and	The Blue Marble flexibility study described in requirement 1 for Order No. 12-013 includes the balancing reserve capability of existing generating resources.	**Chapter 6, Resource needs** **Ext. Study-IV, Flexibility study**

	Requirement	Compliance	Chapter
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.	The Blue Marble Analytics study included a valuation of the integration costs, and flexibility value of new resource additions.	**Chapter 6, Resource needs**

B.2 Clean Energy Plan guidance

Table 92, **Table 93**, and **Table 94** provide PGE's compliance report for the expectations adopted by the Commission in Orders 22-390 and 22-446. "RMA", "CLA" and "AI" refer to Roadmap Acknowledgement, Community Lens, and Analytical Improvements expectation areas, respectively. These tables cross-reference to the numbering rubric provided by Staff on February 24th ("OPUC No." column).

Table 92. Roadmap Acknowledgement

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.1.a[392]	C.1, B.2	The first CEP should include analysis and annual goals over at least 20 years and CEP acknowledgment should focus on the annual goals in the first 2-4 years to align with the IRP analysis and acknowledgment horizons. Utilities may identify, and the Commission may use its discretion to acknowledge, resource actions outside of the Action Plan window.	The Clean Energy Plan (CEP) analysis covers the specified 20-year period and fully aligns with the IRP for the 2–4-year Action Plan. PGE has not proposed incremental actions specific to the CEP or outside of the Action Plan window.	**Chapter 1, Clean energy plan** **Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**

[392] PGE has assigned numbers to the CEP expectations adopted by the Commission in Orders 22-390 and 22-446. "RMA", "CLA" and "AI" refer to Roadmap Acknowledgement, Community Lens, and Analytical Improvements expectations, respectively.

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.2.a	C.2, C.2.a – C.2.i	For the first CEP, annual goals should be provided for all resource actions in each portfolio evaluated in the IRP. Resource actions include, at a minimum: clean energy resources, energy storage, energy efficiency, demand response, resource retirements, changes in system operations, transmission and other supporting infrastructure, and community-based renewable energy projects.	Annual goals for actions associated with all portfolios are provided for the full 20-year period.	**Chapter 11, Portfolio analysis** **Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.2.b	C.3	For the first CEP, annual goals for clean energy resources and storage should differentiate between system resources and resources that the utility expects to acquire through voluntary customer or community programs.	PGE's annual goals for clean energy and storage resources consider forecasts for voluntary program activity. Forecasts for voluntary supply-side programs (Green Future Initiative and Community Solar Program) are specifically differentiated from system clean energy resources in the 'Annual Goals for Actions' chart of PGE's supplemental data sheet. Forecasts for customer adoption of clean energy and storage are forecasted through AdopDER and are described in detail in PGE's Distribution System Plan.	**Chapter 11, Portfolio analysis** **Addendum: PGE CEP Data Template**
RMA1.3	C.4	The utility should report the following information on an annual basis in the first CEP for the Preferred Portfolio and a set of alternative IRP portfolios that test different paces of GHG reductions and different levels of community impacts:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.3.a	C.4.a	• Total greenhouse gas emissions associated with the portfolio based on the DEQ methodology, and broken out by individual fossil fuel resources, market purchases, and market sales.	PGE designed the Decarbonization Glidepath portfolios to compare outcomes associated with different paces of GHG reductions. Emissions data was provided for all portfolios, including several that tested the pace of GHG reductions through 2030.	**Section 11.4.1, Decarbonization glidepath portfolios** **Addendum: PGE CEP Data Template**
RMA1.3.b	N/A	• Normalized annual revenue requirement, calculated as the total revenue requirement for Oregon customers divided by the total retail sales in Oregon.	Expectation was removed by Order No. 22-390. See No. AI3.f-AI3.g.	--
RMA1.3.c	C.4.b	• A set of interim community impacts and benefits metrics that are developed in coordination with communities impacted by the plan, including environmental justice communities.	PGE designed the CBRE portfolios to compare outcomes associated with different levels of CBRE adoption, and associated community benefits. Informational CBIs developed in coordination with communities impacted by the plan, including environmental justice communities, were not used for portfolio evaluation consistent with definitions Order No. 22-390.	**Section 7.1, Community benefits indicators (CBIs)** **Section 11.4.3, Community-based renewable energy (CBRE) portfolios** **Addendum: PGE CEP Data Template**
RMA1.4.a	N/A	No near-term guidance.	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.5.a	Not listed	PacifiCorp and PGE are directed to consider Staff's planning guidance for the first IRP/CEP.[393]	PGE has selected the Preferred Portfolio in consideration of the factors described below.	**Section 11.5, Preferred Portfolio**
RMA1.5.b	B.1	• 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, the pace of greenhouse gas emissions reductions, and community impacts and benefits.	Metrics for costs, risks, emissions, and community benefits are evaluated in **Chapter 11, Portfolio analysis**. The answers to the most pressing questions in portfolio analysis helped inform the creation of the Preferred Portfolio, which best balances cost, risk, GHG reductions, and community impacts.	**Chapter 11, Portfolio analysis**
RMA1.5.c	Not listed	• The planning horizon…(see Guideline 1c, Order No. 07-002)	The planning horizon guidance was not modified by Order 23-060. Our compliance approach is described in **Appendix B.1**; see IRP Guideline 1c.	--
RMA1.5.d	Not listed	• Utilities should…(see Guideline 1c, Order No. 07-002)	Cost evaluation requirements was not modified by Order 23-060. Our compliance approach is described in **Appendix B.1**; See IRP Guideline 1c.	--
RMA1.5.e	Not listed	• To address risk…(see Guideline 1c, Order No. 07-002)	Risk evaluation requirements were not modified by Order 23-060. Our	--

[393] RMA 1.5a through 1.5h reflect revised language adopted via OPUC Order 23-060.

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			compliance approach is described in **Appendix B.1**; See IRP Guideline 1c.	
RMA1.5.f	Not listed	• The pace of greenhouse gas emissions reductions should be evaluated, at a minimum, in a manner consistent with the methodology approved by the Oregon Department of Environmental Quality. In testing different paces of GHG emissions reductions, all portfolios should, at minimum, demonstrate year-over-year emissions reductions on an expected basis.	For this IRP, PGE updated the modeling approach used to forecast greenhouse gas emissions in order to align with the Department of Environmental Quality (DEQ) reporting methodology. The decarbonization glidepath portfolios were designed to compare outcomes associated with different paces of GHG reductions and ensured that each portfolio demonstrated year-over-year emissions.	**Chapter 5, GHG emissions forecasting** **Chapter 11, Portfolio analysis** **Addendum: PGE CEP Data Template**
RMA1.5.g	Not listed	• Community impacts and benefits of different portfolios of actions should be evaluated using available interim CBIs developed by the utilities using reasonable best efforts for use in the first CEP.	PGE evaluated community impacts and benefits with community partners within our Community Learning Labs. This work included developing community benefits indicators (CBIs) to be utilized within our IRP resource and portfolio analysis. Additionally, PGE also utilized the Oregon Public Utility Commission's (OPUC) Attachment A from Order 22-390, submitted by	**Section 7.1, Community benefits indicators (CBIs)** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			community as a starting point to prioritize future CBIs.	
RMA1.5.h	Not listed	• The utility should explain in its plan how its resource choices appropriately balance cost, risk, and the pace of greenhouse gas emissions reductions, and community impacts and benefits.	PGE included narrative to describe how the plan balances cost, risk, emissions, and community benefits in **Chapter 1, Chapter 12, and Chapter 13**.	**Chapter 1, Clean energy plan** **Chapter 11, Portfolio analysis** **Chapter 12, Action Plan**
RMA1.6.a	Not listed	To inform the Commission's acknowledgment decision, utilities should address the following in the first CEP:	--	--
RMA1.6.b	Not listed	• Whether the plan achieves the clean energy targets set forth in HB 2021:	All portfolios are expected on a planning basis to meet the HB 2021 emissions targets.	**Chapter 1, Clean energy plan** **Chapter 2 - Chapter 12**
RMA1.6.c	D.1	• The CEP should demonstrate how the IRP Preferred Portfolio achieves the emissions reductions targets set forth in HB 2021, with DEQ verification.	All portfolios are expected on a planning basis to meet the HB 2021 emissions targets.	**Chapter 5, GHG emissions forecasting** **Chapter 11, Portfolio analysis**
RMA1.6.d	A.2	• Consistency with the IRP:	CEP maintains all IRP assumptions and analysis to ensure full consistency.	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.6.e	A.2	• The CEP should explain how it is consistent with the concurrently filed IRP in terms of assumptions, analysis, and planned actions.	All CEP and IRP analysis and Action Plan is interwoven, as described in **Chapter 1**. Analysis of emissions glidepaths to make continual progress toward 2030, 2035 and 2040 emissions targets for the CEP is an output of IRP modeling.	**Chapter 1, Clean energy plan**
RMA1.6.f	A.2	• To the extent that an analysis supporting the CEP was conducted in another docket (e.g., the IRP or DSP), the CEP should clearly reference that analysis. The utility should explain any updates or methodological changes to the referenced analysis and identify if the referenced analysis was or was not from a plan acknowledged by the Commission.	PGE has identified several sources of supporting analysis and information regarding the OPUC's CEP Community-Lens Topics such as equity analysis, resiliency, DER forecasting conducted within our DSP, tribal engagement, and reliability data within our Annual Report.	**Chapter 14, Community equity lens and engagement** **Chapter 13, Resilience**
RMA1.6.g	Not listed	• Effectiveness of community engagement:	As part of PGE's Community Learning Labs, we conducted surveys after each Learning Lab to gather feedback on the effectiveness of our community engagement.	**Section 14.2, Community engagement**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
RMA1.6.h	E.1, E.1.a – E.1.f	• The utility should report the following information regarding community engagement in developing the plan: what opportunities were provided for input and how was accessibility prioritized across those channels; which communities, including environmental justice communities and Tribal communities, did the utility consult with and how were those communities and their representatives identified; what input was received through each channel; how was input incorporated into the IRP/CEP; what input was not incorporated into the IRP/CEP and why was that input not incorporated; and what plans does the utility have for modifying the engagement strategy in future planning cycles.	PGE created multiple channels for community engagement. Our engagement strategies include virtual meetings for both technical and non-technical audiences, surveys, creating an accessible website and content, developing a CEP-specific email and individual one-on-one meetings with community. Community representation varied from individuals to community organizations. We collected feedback from community within our Community Learning Labs, which are iterative in nature. And, in the Looking Ahead section, we articulate how feedback will be incorporated into planning activities.	**Section 14.2, Community engagement** **Section 14.3, Continuing community engagement** **Appendix L, Clean Energy Plan: Learning Labs community feedback**
RMA1.6.i	E.2	• The utility should also survey participants who provided input on their experiences participating in the utility's process and their perspectives on how their input influenced the plan. Survey	As part of PGE's Community Learning Labs, we conducted surveys after each Learning Lab to gather feedback on the effectiveness of our community engagement.	**Appendix L, Clean Energy Plan: Learning Labs community feedback, Section L.2, Community input and feedback**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
		responses must be included with the plan.		**Chapter 14, Community equity lens and engagement, Section 14.1.1, Importance of equity and a human-centered approach**
RMA1.7.a	N/A	No near-term guidance at this time.	--	--
RMA1.8.a	L.2	The utility shall provide the following additional information in IRP Updates that follow CEP filings:	--	--
RMA1.8.b	L.2.a	• Progress to date relative to each annual goal for resource actions presented in the CEP. If resources have been secured, the utility should quantify the amount of each resource using the same units presented in the CEP.	N/A for this filing	N/A for this filing
RMA1.8.c	L.2.b, L.2.c	• Measured impacts across the same metrics that were presented in the CEP, including, at a minimum: greenhouse gas emissions intensity; total greenhouse gas emissions broken out by individual fossil fuel resources, market purchases, and market sales; average	N/A for this filing	N/A for this filing

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
		electric rates for Oregon customers; and the community impacts and benefits metrics.		
RMA1.8.d	L.2.d	• Any DEQ emissions reports filed since the CEP.	N/A for this filing	N/A for this filing

Table 93. Community lens analysis

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.1.a	G.1	The first CEP should include a potential study (or studies) that identifies opportunities for community-based renewable energy projects (CBREs) developed in coordination with communities that are served by the utility, including environmental justice communities, and with input from stakeholders and Staff.	PGE utilized its DER Potential and Flexible Load Study and its associated AdopDER model to develop forecast analysis needed to inform CBRE targets for the Initial CEP. There will be three forecasts considered: community-scale solar, solar+battery, and small in-conduit hydropower.	**Section 7.2, Community-based renewable energy (CBRE)** **Section 8.3, Community-based renewable energy resources**
CLA2.1.b	G.4	The potential study should inform or directly identify annual acquisition targets (e.g., MW, MWh) for CBREs.	PGE utilized its DER Potential and Flexible Load Study and its associated AdopDER model to develop forecast analysis needed to inform our CBRE targets for the CEP Action Plan.	**Section 7.2, Community-based renewable energy (CBRE)** **Section 8.3, Community-based renewable energy resources**
CLA2.1.c	G.4	The potential study should inform or identify the acquisition targets that appropriately balance cost, risk, the pace of greenhouse gas emissions reductions, and community impacts and benefits.	Portfolio analysis is used to determine the acquisition targets that are reflected in the Preferred Portfolio.	**Section 7.2, Community-based renewable energy (CBRE)** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.1.d	Not listed	The potential study should measure community impacts and benefits based on interim community benefits indicators (CBI) established by the utility.	As part of PGE's DSP Part 2, we conducted a Community Targeting Assessment that developed a set of indices that assisted PGE understand the geospatial distribution of these parameters in our service area and identify affected and most vulnerable populations. Additionally, PGE utilized our DER Potential and Flexible Load Study to develop CBRE forecasts that already account for these parameters.	**Section 14.2, Community engagement** **Section 7.2, Community-based renewable energy (CBRE)**
CLA2.1.e	G.6	The first CEP should include a discussion of acquisition targets and actions that the utility will take in the action plan window to reach those targets e.g., utility procurements, utility run programs (existing and/or new), utility partnerships with other entities' programs, and projections for other customer and community-driven actions.	As part of PGE's Action Plan, we propose a potential Community RFP that will help us meet our CBRE targets. As part of this work, PGE will work with community and regional partners to further develop the RFP parameters such as scoring metrics.	**Section 7.2.3, Near-term approach within PGE's IRP** **Section 13.5, Programs and opportunities** **Chapter 12, Action Plan**, see **Sections 12.1.2, 12.2.2, 12.3**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.1.f	G.7	If a specific project is proposed to meet some or all of the acquisition target, the utility should describe the timing, project status, status of any partnerships, and any other known critical path items involved.	PGE is not proposing a specific project needed to meet our CBRE targets. PGE has proposed conducting a potential Community RFP to meet our CBRE targets.	--
CLA2.1.g	G.8	The first CEP should include a narrative description of how the utility plans to further develop their CBRE potential study for the next CEP.	PGE intends to refine our CBRE approach through continued community engagement. We describe our plans in **Chapter 14, Community Equity Lens**.	**Section 7.2.9, New resources, programs and strategies** **Section 13.6, Looking ahead**
CLA2.1.h	G.9	The first CEP should report on the utility's plan to comply with the state's goal for community-based renewable energy projects provided in ORS 469A.210 and explain how the CBRE targets align with this strategy.	PGE's Action Plan includes steps PGE will take to acquire resources, including CBRE, that will advance our compliance toward the state's small-scale renewable target.	**Section 7.2, Community-based renewable energy**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.2.a	G.2.b	Opportunities for CBRE actions, including distributed resources and their resiliency benefits, should be developed in coordination with communities that are served by the utility, including environmental justice communities, and with input from stakeholders and Staff.	PGE provided education and outreach on CBREs through its IRP Roundtables and CEP Learning Labs. The DER forecast, which our CBRE forecast was based on, was developed in partnership with communities, Staff, and stakeholders over the last two years through our IRP Roundtables and DSP Partnership Workshops. Additionally, PGE is not proposing a specific action needed to meet our CBRE targets. Rather, we proposed conducting a potential Community Request for Proposal (RFP) to meet our CBRE targets as well as the development of a future resiliency potential study needed to advance CBREs.	**Chapter 14, Community equity lens and engagement**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.2.b	G.2.d	Plans for actions should reference DSP processes and engagement where appropriate.	PGE provided education and outreach on CBREs through its IRP Roundtables and CEP Learning Labs. The DER forecast, which our CBRE forecast was based on, was developed in partnership with communities, Staff, and stakeholders over the last two years through our IRP Roundtables and DSP Partnership Workshops.	**Section 14.2, Community engagement** **Section 13.5, Programs and opportunities**
CLA2.2.c	G.2.a	Opportunities that are considered for their community and/or resiliency benefits should also help facilitate greenhouse gas emissions reductions.	PGE evaluated four CBRE forecasts and as a result biogas was removed from our analysis due to the emitting nature of that resource. Our CBRE actions only will include opportunities that reduce GHG. PGE identified 155 MWs of CBRE potential by 2030.	**Sections 7.2, Community-based renewable energy (CBRE)** **Section 11.4.3, Community-based renewable energy (CBRE) portfolios**
CLA2.3.a	F.1	For the first CEP, the utility should develop interim community benefits indicators in coordination with communities served by the utility and with input from stakeholders and Staff.	PGE's CBI approach was based on suggestions provided by the Energy Advocates coalition. PGE worked with community advocates via our Learning Lab process to identify additional indicators and prioritize our approach.	**Chapter 14, Community equity lens and engagement** **Sections 7.1, Community benefits indicators (CBIs)**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
				Appendix L, Clean Energy Plan: Learning Labs community feedback
CLA2.3.b	F.2	At a minimum, the utilities should use quantifiable and measurable interim CBIs in development of the first CEP/IRP that together address the following CBI topic areas:	PGE's CBIs together address each topic area identified. The approach to CBIs within our IRP is to utilize a 10% adder for our Resource CBI pathway and a scoring methodology for our Portfolio CBI pathway.	**Section 7.1, Community benefits indicators (CBIs)**
CLA2.3.c	F.2.a	• Resilience (system and community)	PGE's iCBI-3 addresses improved grid resilience via two metrics that track customer outages and customer access to backup power in EJ communities.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.d	F.2.b	• Health and community well-being	PGE's Informational CBI-1 (iCBI) and iCBI-6 address health and community well-being via four metrics that track participation in clean energy programs and energy efficiency achievement in environmental justice (EJ) communities.	**Section 7.1.6, Informational community benefits indicators**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.3.e	F.2.c	• Environmental impacts	PGE's iCBI-5 addresses environmental impacts with a metric that tracks reduction in GHG emissions.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.f	F.2.d	• Energy Equity (distributional and intergenerational equity), and	PGE's iCBI-1 and iCBI-6 address energy equity via four metrics that track participation in clean energy programs and energy efficiency achievement in EJ communities.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.g	F.2.e	• Economic impacts	PGE's iCBI-2 and iCBI-4 address economic impacts via five metrics that track energy affordability and increased access to jobs by members of EJ communities.	**Section 7.1.6, Informational community benefits indicators**
CLA2.3.h	F.3	At a minimum, the interim CBIs should include at least one metric of each of the following categories:	PGE's CBI approach addresses each of the three CBI categories.	**Section 7.1, Community benefits indicators (CBIs)**
CLA2.3.i	F.3.a	• Informational CBIs, which may or may not directly inform portfolio scoring in the IRP;	PGE developed Informational CBIs or iCBIs, providing transparency into important topics for communities.	**Section 7.1.6, Informational community benefits indicators**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
				Section 11.6, Informational community benefits indicators
CLA2.3.j	F.3.b	• CBRE-focused CBIs, which are used to inform and track progress on CBRE actions and should be reflected in the CBRE potential study and in IRP portfolio scoring; and	PGE developed a Resource CBI (rCBI) to inform and track progress on CBRE actions. Our rCBI methodology applies a credit of 10% to the CBRE fixed cost for all three of the CBREs we evaluated, making them relatively more competitive compared to other supply side options. This methodology allows an approximation of the value of community benefits to be reflected in the CBRE potential study and in IRP portfolio scoring.	**Section 7.1.3, Resource community benefits indicators** **Section 10.9, Resource community benefits indicators**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.3.k	F.3.c	• Portfolio CBIs, which address the impacts of the utility's portfolio on communities, may or may not be tied to CBREs, and should be reflected in IRP portfolio scoring.	PGE developed a Portfolio CBI or pCBI to address the impacts of the utility's portfolio on communities. Portfolio CBIs are meant to adjust portfolio analysis scoring and are calculated for all portfolios evaluated. PGE introduces pCBI as a catch-all for all supplemental benefits that may come from the addition of CBREs. This metric (1 MW of CBRE =1 unit of Community Benefits) reflects the unquantifiable portfolio benefits associated with the CBRE additions.	**Section 7.1.4, Portfolio community benefits indicators** **Section 11.2, Portfolio scoring**
CLA2.3.l	F.4	The utility should explain how their interim CBIs address each of the five topic areas and note which of the three listed CBI categories each metric falls within. The utility should also explain their plans for further developing CBIs for the next CEP.	We developed three pathways for CBIs within our IRP. PGE will continue to work with community to identify CBIs that are of the highest priority for our communities. We will then work to identify which of those CBIs can be quantified and are measurable.	**Chapter 14, Community equity lens and engagement** **Section 7.1, Community benefits indicators (CBIs)** **Section 7.2.10, Further actions and considerations**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.4.a	G.5	For the first CEP, the utility should incorporate the CBRE acquisition targets into IRP portfolio modeling in a manner that accounts for their expected costs and their expected impacts on the IRP resource portfolio performance, including impacts to resource dispatch and fuel burn, portfolio emissions, resource adequacy needs, and resource additions.	Three CBRE proxy resources were developed for IRP portfolio modeling with specific cost and performance attributes. For portfolio modeling, a 10% cost reduction was applied via our rCBI methodology to account for unquantified community benefits. Portfolio analysis incorporated the costs and system benefits associated with the proxy CBRE resources.	**Chapter 11, Portfolio analysis**
CLA2.4.b	G.3	If system-wide benefits exist for a potential CBRE, the utility should quantify those benefits in a manner consistent with the IRP when evaluating the opportunity for inclusion in the first CEP. System-wide benefits are not limited to, but may include: resource adequacy contributions, energy value, avoided GHG emissions, and avoided transmission.	Since the three CBRE proxy resources were included in IRP portfolio modeling, treatment of all system-wide benefits are consistent with the IRP.	**Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.a	K.1	The first CEP must include narrative which describes its resiliency-related analysis, including at minimum:	PGE developed a resilience-specific chapter for this initial CEP. This chapter provides PGE's approach to resilience-related analysis as outlined by the OPUC's UM 2225 resiliency-specific guidelines. Additionally, it includes a discussion of how PGE coordinated with our partners, identifies resilience risks and opportunities, as well as key resilience-related programs and opportunities we will prioritize to support CBRE.	**Chapter 13, Resilience**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.b	K.1.a	How it was developed in coordination communities that are served by the utility, including environmental justice communities, and with input from stakeholders and Staff;	PGE created multiple channels for community engagement. Our engagement strategies included virtual meetings for both technical and non-technical audiences, surveys, creating an accessible website and content, developing a CEP-specific email and individual one-on-one meetings with community. Community representation varied from individuals to community organizations. We collected feedback from community within our Community Learning Labs, which are iterative in nature.	**Section 14.2, Community engagement,** **Chapter 13, Resilience**
CLA2.5.c	K.1.b	How resiliency risks were considered examined and weighted;	PGE has taken multiple steps toward evaluating risks related to climate change and natural disasters. We utilized existing risk assessment analysis regarding system and customer resilience; including energy equity work conducted through our Distribution System Plan (DSP) and Wildfire Mitigation Plan (WMP).	**Section 13.2, Evaluating resilience risks**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.d	K.1.c	How resiliency opportunities were identified, measured, and weighted; and	During PGE's community engagement process we discussed potential resilience analysis, approaches, programs, and opportunities. PGE provided education on several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience.	**Section 13.5, Programs and opportunities**
CLA2.5.e	K.1.d	The key resiliency-related actions the utility will prioritize in the action plan window to support its CBRE acquisition targets.	As part of PGE's Action Plan, we propose a potential Community RFP that will help us meet our CBRE targets including solar+storage microgrid projects that advance community resilience. Additionally, we will work with community to develop a future resiliency potential study needed to advance CBREs.	**Chapter 12, Action Plan** **Section 12.1.2, Community-based renewable energy additions** **Section 12.2.2, CBRE action**
CLA2.5.f	Not listed	When evaluating resiliency risks for the first CEP and associated IRP, the utility should at minimum:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.g	K.2	Account for system and community resilience.	We utilized existing risk assessment analysis regarding system and customer resilience; including an enterprise-wide risk assessment, transmission and distribution asset assessment, and a community assessment.	**Section 13.2, Evaluating resilience risks** **Section 13.3, Zone of tolerance**
CLA2.5.h	K.3	Identify risks that have been identified in other planning processes already as well as gaps in system and community resilience not filled by other planning activities, such as DSP and WPP.	We utilized existing risk assessment analysis regarding system and customer resilience; including an enterprise-wide risk assessment, transmission and distribution asset assessment, and a community assessment.	**Section 13.3, Zone of tolerance** **Section 13.4, Historical reliability data**
CLA2.5.i	K.4	Consider the zone of tolerance for communities/populations within the service area.	PGE discussed "zone of tolerance" within its **Resilience Chapter**. This section speaks to existing work such as our DSP, Biden's Justice40 Initiative, Medical Certification Programs and Critical Customer Program.	**Section 13.3, Zone of tolerance**
CLA2.5.j	K.5, K.5.a	Rely on measurable historical reliability performance measures that reflect: all outages (planned, major event, or underlying);		**Section 13.4, Historical reliability data**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.k	K.5.b	The primary initiating event for each major event the utility analyzed;	PGE utilizes historical reliability performance data as an input to evaluating reliability and resiliency risk on the system. The data informs the failure probability assumptions in the economic risk models for asset-caused and geographic-caused failures and is used to develop potential mitigation solutions.	
CLA2.5.l	K.5.c	The top causes for each day during which a major event occurred;		
CLA2.5.m	K.5.d	The numbers of customers out and the restoration performance for their supply;		
CLA2.5.n	K.5.e	The estimated costs to the utility to recover from the major event;		
CLA2.5.o	K.5.f	The estimated unserved energy during the period of a major event;		
CLA2.5.p	K.5.g	The estimated impacts to the customers;		
CLA2.5.q	k.5.h	The demographics of the community, including classification of energy equity or other social or environmental justice measures.	PGE utilized socioeconomics and demographic data within our DSP Part 2 as part of our CEP.	**Section 13.4, Historical reliability data**
CLA2.5.r	G.2	While evaluating opportunities and developing actions to achieve CBRE acquisition targets, the utilities should reflect a few minimum expectations:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.s	G.2.a	Focus on actions that help facilitate emissions reductions (e.g., generation, storage, demand-side actions). However:	PGE's Action Plan includes a potential Community RFP that will help us meet our CBRE targets, which will target resource actions that provide both emissions reductions and community benefits.	**Section 7.2, Community-based renewable energy (CBRE)** **Section 12.2.2, CBRE action**
CLA2.5.t	Not listed	The utility may include, for general understanding, if there are other actions, such as undergrounding lines connected to a microgrid that need to be included in the costs and benefits of a CBRE.	During PGE's community engagement process we discussed potential resiliency analysis, approaches, programs, and opportunities. PGE provided education on several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience. This work is included for general understanding only and is not directly included in the Action Plan.	**Section 13.5, Programs and opportunities**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.u	Not listed	The utility may include supplemental discussion of other actions the company is taking to further enhance the resiliency of its system and communities (such as situational awareness investments or helping customers access portable back up generation). This discussion would be for context only and if the actions are not facilitating emissions reductions, they should not be considered actions for the CEP.	During PGE's community engagement process we discussed potential resiliency analysis, approaches, programs, and opportunities. PGE provided education on several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience. This work is included for general understanding only and is not directly included in the Action Plan.	**Section 13.5, Programs and opportunities**
CLA2.5.v	G.2.c	Consider opportunities to work with local communities on local resiliency planning.	PGE has several planned and active initiatives that serve to create or enable a more resilient grid and to empower customer resilience. Additionally, we are exploring ideas to partner with local community and local resiliency planners such as Community Resiliency Hubs.	**Section 7.2.10, Further actions and considerations** **Section 13.5, Programs and opportunities**
CLA2.5.w	G.2.d	Consider and clearly differentiate actions that are related to other plans, such as DSP and WPP analysis, and those that are newly identified.	PGE provided an update on its resilience efforts within its Resilience chapter. This includes actions proposed within the DSP such as updating our Value of Service Study.	**Section 13.5, Programs and opportunities**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
CLA2.5.x	G.7	If proposing a specific action, describe the cost, timing for delivery and implementation into utility operations.	PGE is not proposing a specific action within our CEP; however, PGE will work with community on a future resilience-specific potential study needed to advance CBREs.	**Section 13.5, Resilience opportunities**

Table 94. Analytical Improvements

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.a	H.5	Staff recommends that PAC and PGE include narrative, supported by quantitative analysis where possible, answers to the following long-term decarbonization questions within the first CEP:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.b	H.5.a	1. What low regrets near term actions does the utility expect to perform relatively well, if implemented, regardless of future uncertainties in technology, demand, and regional developments?	PGE's Action Plan describes the low regrets actions which are appropriate to take in the next 2-4 years. All paths that achieve an 80% emissions reduction on PGE's system involve a significant buildout of non-emitting energy storage and renewables. In terms of transmission, we also consider South of Alston congestion relief and upgrades to the Bethel-Round Butte line as "no-regrets." We anticipate negotiating contract renewals to maintain contracted non-emitting resources in our portfolio. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies** **Chapter 12, Action Plan**
AI1.c	H.5.b	2. What near term actions that the utility considered might have large negative long-term consequences (in terms of cost, risk, GHG emissions, or community impacts or benefits) under one or more future technology, demand, or regional development scenarios?	In the near term, the risks of large negative long-term consequences for our compliance path relate to anything that delays or prevents our ability to execute on the Action Plan. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.d	H.5.c	3. What are the critical junctures at which the utility's plan would materially change and what indicators will the utility use to identify whether those junctures are approaching?	PGE will be tracking closely the pace of acquisition of non-emitting energy and capacity. If we cannot maintain reliability or the pace of constant yearly acquisition of resources and capacity, we will need to adjust our approach to overcome delays or adjust timelines accordingly, if the variables causing the delay are beyond our control. At the same time, if new transmission options on- and off-system do not materialize, we will likely not be able to access the resources our system needs to decarbonize and maintain reliability. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.e	H.5.d	4. What are the critical dependencies for the utility to successfully execute its long-term plan? What are the critical dependencies for the utility's plan to achieve the desired outcomes in terms of cost, risk, GHG emissions, and community impacts or benefits? What might be the implications of one or more of those critical dependencies failing?	Large quantities of non-emitting resources must be available on the market, and at the lower price points we forecasted for them. New transmission is needed to gain access to off-system resources, or we risk the reliability of the system. As we near the 2040 target and a zero emissions requirement, new technologies that can replicate thermal generation capacity, such as advanced nuclear, hydrogen, or carbon capture and storage will be needed across the region to support decarbonization and resource adequacy. Additional details are available in **Chapter 1, Clean energy plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.f	H.5.e	5. What critical barriers need to be addressed to implement the utility's long-term plan? Which of these barriers can be addressed by the utility or the Commission and which of these barriers are out of the utilities or the Commission's control? Which of these barriers would need to be addressed in the next 5-10 years? The utility should include a plan for addressing those barriers identified in the 5–10-year time frame, including direct actions that can be taken by the utility and opportunities to coordinate with other involved entities.	The critical barriers that need to be addressed to implement PGE's long-term plan are likely similar to those of other utilities across the West who are rapidly decarbonizing. The major barriers are transmission and the need to rapidly develop and scale new non-emitting technologies. Solutions will depend on regional cooperation, coordination, and federal policy and financial support; PGE's actions to expand partnerships regionally and continuously innovate new technologies are key near-term strategies toward successful, long-term pathways. Additional details are available in **Chapter 1, Clean Energy Plan**.	**Section 1.6, High-level opportunities, potential barriers, critical dependencies**
AI1.g	Not listed	To inform their responses to Staff's decarbonization planning questions, PGE and PAC should, within portfolio analysis:	--	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.h	H.1, H.1.a – H.1.c	Quantitatively evaluate opportunities and risks of emerging technologies, including, at a minimum: clean hydrogen, long duration storage, and offshore wind;	PGE developed and evaluated six emerging technology portfolios to specifically examine the implications of potential emerging technologies on portfolio costs and transmission needs. The emerging technology portfolio group included two hydrogen portfolios, an offshore wind portfolio, and a long duration storage portfolio.	**Chapter 11, Portfolio analysis**
AI1.i	H.2	Quantitatively evaluate potential impacts associated with building and transportation electrification, informed by current policy initiatives, and climate change and extreme weather;	PGE incorporated forecasts of building and transportation electrification from the DSP Part 2. PGE utilized a third-party study to inform how climate change was incorporated into the IRP via sensitivities.	**Chapter 6, Resource needs**
AI1.j	H.3	Quantitatively evaluate the impacts of transmission constraints and future transmission expansion; and	PGE developed three proxy transmission expansion options and evaluated 11 transmission portfolios to examine the implications of transmission opportunities and constraints on portfolio costs and resource actions.	**Chapter 9, Transmission** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.k	H.4	Evaluate the sensitivity of the plans to other opportunities for enhanced regional coordination, including RA programs and improvements in transmission utilization.	PGE developed a Regional Transmission Organization (RTO) portfolio to examine the potential benefits PGE could realize from joining an RTO.	**Chapter 11, Portfolio analysis**
AI1.l	Not listed	To ensure that utility plans align with the clean energy targets in HB 2021, PAC and PGE's IRPs should:	--	--
AI1.m	D.2	Achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions in those years. This should be demonstrated for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts; and	This methodology is applied to all portfolio analysis. All portfolios achieve the 2030 and 2035 emissions targets. Additional analysis on meeting resource adequacy needs under different weather and hydro conditions is also presented.	**Chapter 11, Portfolio analysis** **Appendix I, C-level analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI1.n	D.3	Achieve resource adequacy in 2040 with no associated greenhouse gas emissions across the tested system conditions. This should be demonstrated for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impact.	All portfolios achieve the 2040 emissions target.	**Chapter 11, Portfolio analysis**
AI2.a	Not listed	For the first CEP and associated IRP, if the Preferred Portfolio relies on fossil fuel resource retirements or conversions to reduce GHG emissions, the utility should:	--	--
AI2.b	I.1	• Provide a rationale for and describe the risks and benefits associated with the retirement or conversion; and	PGE did not evaluate early retirements of existing thermal resources. One hydrogen portfolio did evaluate the impact of blending hydrogen at existing facilities but given the uncertainty of cost and performance characteristics the option is not included in the Preferred Portfolio.	**Chapter 11, Portfolio analysis**
AI2.c	I.2	• Identify whether each planned retirement reflects plans to	See above	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
		decommission the plant or plans to exclude the plant from Oregon rates.		
AI2.d	I.3	For the first CEP and associated IRP, if the Preferred Portfolio relies on operational changes relative to expected economic dispatch to reduce GHG emissions, including, but not limited to, application of operating or emissions constraints, inclusion of a GHG emissions cost in dispatch decisions, or out-of-state sales of fossil fuel generation, the utility should:	--	--
AI2.e	I.3	Quantify the impacts of those operational changes relative to expected economic dispatch in terms of generation (curtailed, reduced, or sold) and GHG emissions (avoided); and	Based on input from OPUC Staff PGE retained the use of economic dispatch in determining the output of existing thermal plants.	**Chapter 5, GHG emissions forecasting** **Chapter 11, Portfolio analysis**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			From a modeling perspective, thermal generation (and the associated emissions) are allocated either to serve retail load or to market sales. The quantity of generation allocated to serve retail load contributes to the calculation of energy need, and the quantity for market sales affects system costs. Both inform portfolio analysis.	
AI2.f	I.4	Describe how the utility intends to implement those operational changes (e.g., through the development of operating or emissions limits, application of GHG emissions penalties, or execution of contracts with out-of-state entities), to the extent that they impact forecasted GHG emissions in the Action Plan window.	Actual operations depend on the actual weather, load, and market conditions, whereas the IRP forecasts depict simulated conditions based on averages conditions. Accordingly, IRP projections about the use of existing resources should not serve as constraints and/or direction to PGE's system operations. PGE operates its system to maintain reliability and minimize costs for PGE's customers.	--

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			HB 2021 introduces emissions targets for PGE that are anticipated to be achieved by adding a significant increase in non-emitting generation and capacity resources to our portfolio. The IRP/CEP calculates that energy and capacity need by assuming reduced operation of thermal generation to serve retail load. In actual operations between now and 2030, non-emitting resources are anticipated to be added to our system and offset the need for thermal output that will otherwise serve retail load. Thermal generation will still be available to meet capacity needs.	

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
			Rather than model changes to thermal dispatch as an optional action, operations results are embedded in IRP/CEP modeling as an assumption and hence not quantifiable as a direct comparison to status quo operations. As we advance toward 2030, we intend to prepare for and coordinate changes in both resource procurement and operations that will affect how we schedule resources and manage net variable power costs. As PGE anticipates incorporating operational changes to meet our Western Resource Adequacy Program (WRAP) obligations in 2025 and our 2030 GHG target, we plan to highlight necessary changes to regulatory policy adapt to the change dynamics.	

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.a	J.1	The first CEP, or a designated section of the IRP that contains all information required by HB 2021, should be written for an introductory audience and include definitions of all key terms and acronyms.	PGE has developed **Chapter 1** as an accessible and free-standing summary of all information required by HB 2021, including our approach to portfolio analysis and a description of our Action Plan and analysis of emissions reductions.	**Chapter 1, Clean energy plan** **Appendix P, Acronyms**
AI3.b	J.3	The first CEP, or a designated section of the IRP that contains all information required by HB 2021, should also include:	--	--
AI3.c	J.3.a, J.3.b	A table that lists the GHG emissions assumptions for each existing and proxy resource modeled in the IRP, developed in partnership with DEQ. A table that lists the cumulative forecasted GHG emissions from each existing and proxy resource in the Preferred Portfolio under the Reference Case over the entire analysis horizon (at least 20 years) and the location of each emitting resource.	PGE developed GHG emissions assumptions and methodologies in coordination with DEQ. Emissions have been modeled for all resources consistent with these methodologies for use in portfolio analysis.	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.d	J.3.c	The following graphs, which should include forecasted data under the Reference Case over the entire analysis horizon (at least 20 years) and at least three years of historical data:	--	--
AI3.e	J.3.c	Total annual portfolio GHG emissions, calculated in a manner consistent with the DEQ methodology, for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts.	Consistent with DEQ methodology, this analysis considers emissions for retail load service. PGE provides the resulting data each portfolio evaluated.	**Addendum: PGE CEP Data Template**
AI3.f	J.5.a	The total forecasted annual revenue requirement to serve Oregon customers for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts. This graph may exclude historical data if the forecasted revenue requirement does not approximate all costs borne by Oregon customers.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.g	J.5.b	The total forecasted annual revenue requirement to serve Oregon customers, divided by the total forecasted retail sales in Oregon, for the Preferred Portfolio and a set of alternative portfolios that test different paces of GHG reductions and different levels of community impacts. This graph may exclude historical data if the forecasted revenue requirement does not approximate all costs borne by Oregon customers.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**
AI3.h	J.4.a	Total annual GHG emissions by fuel type for resources in the Preferred Portfolio.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**
AI3.i	J.4.b	Annual GHG emissions to serve Oregon customers by fuel type for the Preferred Portfolio.	This data is provided for each portfolio.	**Addendum: PGE CEP Data Template**
AI3.j	J.4.c	Total annual generation by fuel type for resources in the Preferred Portfolio.	Consistent with the emissions reporting above, PGE has included emitting sources only in this graph. All non-emitting sources would have emissions of zero.	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.k	J.4.d	Annual generation serving Oregon customers by fuel type for the Preferred Portfolio.	Consistent with the emissions reporting above, PGE has included emitting sources only in this graph. All non-emitting sources would have emissions of zero.	**Addendum: PGE CEP Data Template**
AI3.l	J.4.e	Annual weighted average heat rate by fuel type for resources in the Preferred Portfolio.	PGE has included emitting sources only in this graph. Heat rate is not applicable to non-emitting sources.	**Addendum: PGE CEP Data Template**
AI3.m	J.6	In the 2023 IRP, PGE and PAC should provide a table that describes the utility's annual plans for the use of RECs associated with renewable energy generated by or contracted to the utility in the Preferred Portfolio under the Reference Case over the entire analysis horizon (at least 20 years). The table should clearly delineate between RECs that are expected to be:	--	--
AI3.n	J.6.a	Retired on behalf of Oregon customer load for RPS compliance in Oregon;	This data is provided for the Preferred Portfolio.	**Addendum: PGE CEP Data Template**
AI3.o	J.6.a	Retired on behalf of Oregon customer load for voluntary sales;	Included in CEP Data template	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.p	J.6.a	Retired on behalf of customer load in a different state where the utility serves customers (for either compliance or voluntary sales);	Not applicable to PGE	--
AI3.q	J.6.a	Banked for future Oregon compliance;	Included in CEP Data template	**Addendum: PGE CEP Data Template**
AI3.r	J.6.a	Banked for compliance in a different state where the utility serves customers;	Not applicable to PGE	--
AI3.s	J.6.b	Utilities must report the approximate number of MWhs not associated with RECs reported in the referenced table that are generated from renewable energy technologies.	Included in CEP Data template	**Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.t	Not listed	Staff, utilities, and all interested stakeholders should collaboratively develop by February 1, 2023, an agreed upon approach to capturing additional standardized information and data related to their CEP and how they will make it publicly available in a similar fashion on their websites.	PGE established a dedicated website for all our resource plans (e.g., IRP, CEP, and DSP) and provides access to information in new ways. We currently publish our IRP roundtable materials on our IRP website as well as associated Q&A responses and video recordings. Our website also provides additional materials and other relevant information regarding the CEP. Based on participant feedback, we updated our indexing system to allow easier navigation to specific topics of interest within the many hours of meeting recordings and slides presented. PGE has also provided all required quantitative data in the format of the template provided by Staff to PGE on February 24, 2023, which is publicly available as part of our CEP/IRP filing.	Web materials are available at https://portlandgeneral.com/about/who-we-are/resource-planning **Addendum: PGE CEP Data Template**

No.	OPUC No.	Guidance	Pathway to compliance	Chapter
AI3.u	J.2	Utilities should, moving forward, post any recordings made of IRP public input meetings on its website, and if a recording is not available, provide a general summary of comments received at the meeting.	All recordings are posted on our website, see https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings	**Section 14.2.8, Transparency and accessibility** **Appendix C, 2023 IRP public meeting agendas**

Appendix C. 2023 IRP public meeting agendas

PGE manages IRP development through a collaborative, interactive process with an active customer and public stakeholder group. All IRP meetings are open to the public and are generally hosted once a month. In addition, PGE continues to engage community-based organizations via the Learning Lab[394] venue, originally utilized during DSP development, to share IRP and CEP related analysis and concepts with stakeholders who have less experience participating in technical workshops.

PGE has hosted 30 public meetings and seven Learning Labs during the 2023 IRP development process, makes all meeting materials available on the IRP webpage, and advertises public meeting dates there as well. The comments and suggestions shared with us are incorporated into our thinking and our final IRP, and a summary of the comments we received are posted to our IRP webpage.

This summary of our meeting dates and topics, hosted in support of the 2023 IRP, is a collaboration between PGE and our dedicated stakeholder community who have put in the time to advocate for their communities. A summary of meeting topics is shown in **Table 95**, **Table 96**, **Table 97**, and **Table 98**. We have attempted to incorporate what we have heard and plan to continue to engage and evolve through this 2023 IRP and into future IRP development.

[394] https://portlandgeneral.com/about/who-we-are/resource-planning/clean-energy-planning

C.1.1 2020 Public meetings[395]

Table 95. 2020 public meeting summary

Roundtable	Agenda topics
Roundtable 20-1 March 19, 2020[396]	Agenda: IRP schedule and next steps, values refresh, capacity assessment, energy efficiency
Roundtable 20-2 April 14, 2020[397]	Agenda: Transmission, integration cost drivers enabling study, climate adaptation enabling study
Roundtable 20-3 May 20, 2020[398]	Agenda: Capacity Assessment – Preliminary Model Development Workshop, climate adaptation enabling study, Stakeholder input for design/scoping
Roundtable 20-4 July 29, 2020[399]	Agenda: Background on Integrated Resource Planning (IRP), values discussion
Roundtable 20-5 August 19, 2020[400]	Agenda: Price Futures, capacity assessment baseline, supply-side options

395 https://portlandgeneral.com/about/who-we-are/resource-planning/irp-public-meetings
396 March 19, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/VorVAYOPLXyi1R6uNinEL/d77876929095caf26665f35f90a9363c/2020-03-17-irp-roundtable-20-1.pdf
397 April 14, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/5KMI0Fqc36iRGIA4FvYHv8/1775a0f32fb5014a4a8cc17dd44ffc6f/2020-04-irp-roundtable-20-2.pdf
398 May 20, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/69E4wCSDi254PL7EwJMneu/1da2f516213a67a4f6d0a2458388a202/2020-05-20-irp-roundtable-20-3.pdf
399 July 29, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7rcLN02TYJg4soP2zvicTu/a188a0a68b2bb1a17e0333712d6ae575/2020-07-29-irp-roundtable-20-4.pdf
400 August 19, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/4QqSCUHVJkUMNTgW5BNiaZ/701668fd213498cc381f13b751eeb407/2020-08-19-irp-roundtable-20-5.pdf

Roundtable	Agenda topics
Roundtable 20-6 October 28, 2020[401]	Agenda: Load forecast for IRP update; capacity need, RPS position, energy position; market prices for IRP update
Roundtable 20-7 November 18, 2020[402]	Agenda: Change to Production Tax Credits for 2019 IRP update, interconnection costs (updated for 2019 IRP update), capacity contributions, LUCAS101, ROSE-E 101
Roundtable 20-8 December 10, 2020[403]	Agenda: 2019 IRP update – draft portfolio analysis, 2020 Distributed Energy Resources (DER) and Flex Load Potential Study.

C.1.2 2021 Public meetings

Table 96. 2021 public meeting summary

Meeting	Agenda topics
Roundtable 21-1 February 17, 2021[404]	Agenda: Price forecast part 1, supply side resource options
Roundtable 21-2 March, 21, 2021[405]	Agenda: Community values and the 2022 IRP, modeling overview and schedule, transmission update

[401] October 28, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2XkzCQDPsoEmae8kJn5ckD/6c2e1f9462d8cc16ce8ec7752e57d67a/irp-roundtable-20-6.pdf

[402] November 18, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2ffV7LUhMxgl3XwIjEXqqV/68f6668b8152d686ebe98a7025a7ff05/irp-roundtable- 20-7.pdf

[403] December 10, 2020 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/60OlDmUO5U9YWN6pcfNv0a/3620744cec9c57c6538ecd31fd10a817/irp-roundtable-20-8.pdf

[404] February 17, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/5fZx2C5US1n7iSasPRjU4x/b752f1a798fe5e39255129e760af70ee/irp-roundtable-21-1.pdf

[405] March 21, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/FYE0Gf8xbQgPZ4To88oZx/9f46ea7c1b93f55c1a0188160273880f/irp-roundtable-march-21-2.pdf

Meeting	Agenda topics
Roundtable 21-3 May 27, 2021[406]	Agenda: Price forecasts part 2, IRP uncertainty, capacity assessment
Roundtable 21-4 June 24, 2021[407]	Agenda: Technology costs, energy position
Roundtable 21-5 July 22, 2021[408]	Agenda: Load forecast
Roundtable 21-6 August 25, 2021[409]	Agenda: DER and flexible load phase 1 study
Roundtable 21-7 October 28, 2021[410]	Agenda: PGE's next IRP – update on timing,[411] Oregon House Bill 2021; Portfolio requests
Roundtable 21-8 November 18, 2021[412]	Agenda: Pricing methodology; Supply-side options; Portfolio requests

[406] May 27, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/CNMm5LJjd1EVRDUkfHauN/4f39030995783e132df0bbe94d7d5f30/IRP_Roundtable_May_21-3.pdf

[407] June 24, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/3cvd1UgpapBboirkYJLTEd/132bb6ab8ce967f92c33549560400ef5/IRP_Roundtable_June_21-4.pdf

[408] July 22, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2eI3mKz2HVK1uEPogSDofW/09fbb8476086009ffe7d181dfb95dc12/IRP_Roundtable_July_21-5.pdf

[409] August 25, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7nr8YY8Kpir36zOx9mNC9u/ab1da296963265fca522082f72d3a0d6/irp-roundtable-august-21-6.pdf

[410] October 28, meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/13yKrhtKw5KkMU0WfnmJSz/03626e36c13462e190454881e88396a2/irp-roundtable-oct-21-7.pdf

[411] Press release available at: https://portlandgeneral.com/news/2021-10-15-pge-plans-to-nearly-triple-clean-resources-by-2030

[412] November 18, 2021 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/1UeTCdvEqHlpH1MRPOGo85/45b03c61b37dfaba7e0a434c8a8cfb3d/IRP-Roundtable-November-21-8.pdf

C.1.3 2022 Public meetings

Table 97. 2022 public meeting summary

Meeting	Agenda topics
Roundtable 22-1 January 6, 2022[413]	Agenda: 2022 kickoff and schedule, clean energy plan, climate adaptation study, flexibility study, portfolio requests
Roundtable 22-2 March 14, 2022[414]	Agenda: Order 21-215: UM 1728 Settlement – Qualifying Facilities (QF) Sensitivities and Effective Load Carrying Capability (ELCC) Sensitivities
Roundtable 22-3 April 14, 2022[415]	Agenda: Solar Inverter Loading Ratios, GridPath Flexibility Analysis, Climate Adaptation Study, Final Load Forecast, RPS Modeling, and Price Update
Roundtable 22-4 May 17, 2022[416]	Agenda: Sequoia and ROSE-E Updates, Hybrid Resource Characteristics, Clean Energy Plan Update
Roundtable 22-5 June 30, 2022[417]	Agenda: House Bill 2021 and IRP Modeling, 2023 IRP Portfolio Analysis, Resource Adequacy Market Access

[413] January 6, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7cxcVacdmTWeIFsfP7G9cG/2a99ba1e764c753b02b899645d5b692e/IRP_Roundtable_January_22-1.pdf

[414] March 14, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/6hRQPptYmblk9Uvup4JDJU/f747f759ce667a80efcd041a12526c12/IRP_Roundtable_March_22-3.pdf

[415] April 14, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7b7HWYRGD36HHCHeWbBqYS/c17bd893aa9118ad2911293e680ed35f/IRP_Roundtable_April_22-4.pdf

[416] May 17, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/4YnCZf5PtwTE5ska7tclxS/a18aff0034e3fd9730f0a3f168619c87/IRP_Roundtable_May_22-5.pdf

[417] June 30, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/2e732S4plWpR59ID7ZDV8q/270c1816f005d6816e63ac88e9e61879/IRP_Roundtable_June_22-5.pdf

Meeting	Agenda topics
Roundtable 22-6 July 21, 2022[418]	Agenda: Need Futures, Yearly Capacity Needs, Distributed Energy Resources, and Updated Western Electricity Coordinating Council (WECC) Pricing
Roundtable 22-7 August 18, 2022[419]	Agenda: Transmission inventories, Hybrid resource locations, Draft supply side ELCC values, Draft energy load resource balance
Learning Lab #1[420]	PGE clean energy plan kickoff
Roundtable 22-8 September 15, 2022[421]	Agenda: Clean Energy Plan Workshop Informational, Inflation Reduction Act, Transmission
Roundtable 22-9 October 20, 2022[422]	Agenda: Transmission part II, climate study, flexibility study, resource adequacy, clean energy plan update
Learning Lab #2[423]	Agenda: DSP lessons learned, partner comments, PGE actions, update on Energy Trust of Oregon (ETO) collaboration, IRP 101, grid needs and non-wires solutions (NWS), DSP/CEP intersection: NWS, Community Benefit Indicator (CBI), Community-based Renewable Energy (CBRE).

[418] July 21, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/12mmGu2JZNE3tcjLkK6irQ/5220013d807848c057c27cbbed41a46e/IRP_Roundtable_July_22-6.pdf
[419] August 18, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/1ltEzsTwlgoFoOfVxtuGob/4bff485e57a30ad1549d061094a44347/IRP_Roundtable_August_22-7.pdf
[420] Meeting video archive available at https://www.youtube.com/watch?v=r-IPdBHsCjA
[421] September 15, 2022 meeting material available at https://assets.ctfassets.net/416ywc1laqmd/70ZtUZu614Muls6lKSpNm0/72d85334b7e9f4152a169c230393970e/IRP_Roundtable_September_22-8_92822.pdf
[422] October 20, 2022 meeting material available at https://assets.ctfassets.net/416ywc1laqmd/3Bv5b1kzoD9flvapvcpBrA/981ab90a5ef126db416dd0567a6b5bd5/IRP_Roundtable_October_22-9_V2.pdf
[423] Meeting video archive available at https://www.youtube.com/watch?v=ywCd4GjF0tw

Meeting	Agenda topics
Roundtable 22-10 November 16, 2022[424]	Agenda: Non-cost-effective distributed energy resources, emissions forecasting, CBRE and community benefits indicators overview, transmission part III, portfolios
Learning Lab #3[425]	Agenda: Recap, community-based resources and community benefits indicators, resilience, RFP 101, IRP roundtable recap
Roundtable 22-11 December 16, 2022[426]	Agenda: Emissions forecasting part II, community benefits indicators update, price futures update, transmission part iv, portfolio scoring metrics, draft portfolio results

[424] November 16, 2022 meeting material available at https://assets.ctfassets.net/416ywc1laqmd/3Ivg7tPLLkie7L8QiDS91t/45dd54a03de06c047106741ba77e0858/IRP_Roundtable_November_22-10-Final.pdf

[425] Meeting video archive available at https://www.youtube.com/watch?v=s4F6bG_tpGs

[426] December 16, 2022 meeting materials available at https://assets.ctfassets.net/416ywc1laqmd/7AUDtFKsutaZB5zUWTzbHo/db4f426352329e0fc05d30f50325b2f7/IRP_Roundtable_December_22-11.pdf

C.1.4 2023 Public meetings

Table 98. 2023 public meeting summary

Meeting	Agenda topics
Roundtable 23-1 January 26, 2023[427]	Agenda: Informational community benefits indicators, draft portfolio analysis results and scoring, waiver/IRP filing update, draft Action Plan
Learning Lab #4[428]	Agenda: Community engagement update, resilience update, potential CBRE acquisition paths update, community benefits indicators update, Community Benefits and Impacts Advisory Group (CBIAG) update, distribution system plan Distributed Generation (DG) map update, previous integrated resource plan (IRP) December roundtable recap.
Roundtable 23-2 March 8, 2023[429]	Agenda: Data center energy efficiency opportunities (with Energy Trust of Oregon), price futures, draft portfolio analysis results and Preferred Portfolio part II, draft Action Plan part II
Learning Lab #5	
Roundtable 23-3 March[430]	Agenda: 2023 IRP Action Plan, UM 1728

[427] Meeting materials available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings
[428] Meeting video archive available at https://www.youtube.com/watch?v=BvUdkenX4Is
[429] Meeting materials available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings
[430] Meeting materials available at https://portlandgeneral.com/about/who-we-are/resource-planning/integrated-resource-planning/irp-public-meetings

Appendix D. Load forecast methodology

This appendix provides detail about PGE's load forecast methodology and results for the 2023 IRP.

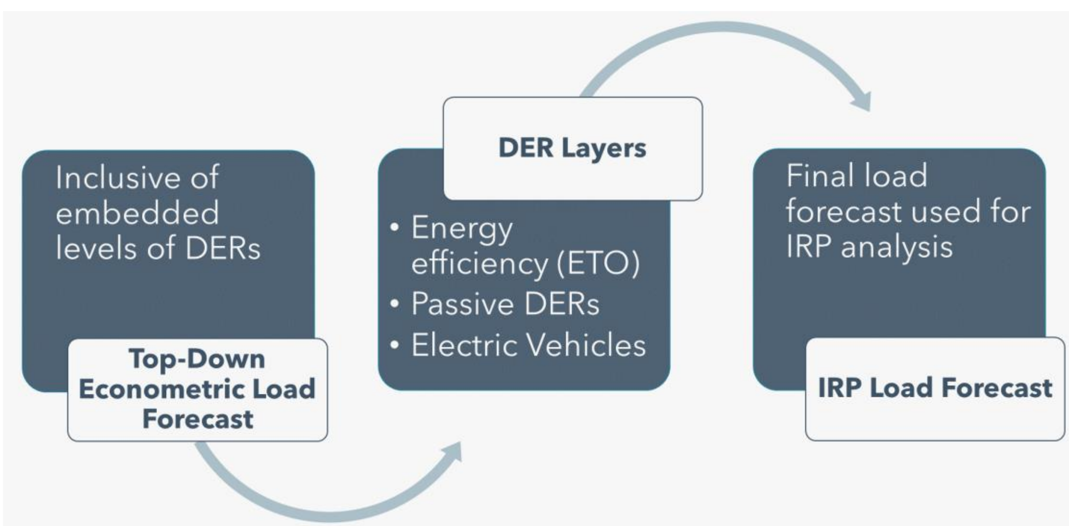
As discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**, the load forecast combines the top-down econometric forecast and the passive distributed energy resources (DER) forecast. This appendix focuses on the top-down econometric forecast models and provides annual summaries of forecast results.

Unless specified, the load values in this appendix reflect the cost-of-service supply load and do not include long-term direct access loads. The forecast vintage used is the March 2022 load forecast.

D.1 Load forecast methodology

PGE's load forecast is a compilation of several model outputs. The top-down econometric load forecast is the focus of this appendix. This is a set of models aiming to capture the relationships between PGE's energy deliveries and various structural trends and economic drivers. The impacts of DERs – primarily energy efficiency, rooftop solar, and transportation electrification – are modeled outside the top-down econometric framework and described in **Section 6.3, Load scenarios**. The incremental impacts of these loads are then 'layered' onto PGE's base forecast, as presented in **Figure 114**.

Figure 114. Load forecast methodology



PGE's top-down econometric load forecast consists of models focused on two distinct time horizons. **Table 99** describes some of the specific differences.

For the IRP process, PGE updates its long-term models to estimate growth rates for aggregated customer classes: residential, commercial, and industrial. However, the forecast result is dependent on the estimation of the near-term models as a starting point. The long-term growth rates described in this appendix are applied to the result of the near-term forecast model. The near-term model is focused on capturing near term business cycle impacts and individual forecasts for large projects. This model is submitted in PGE's general rate case (GRC) and annual update tariff (AUT) filings.

Table 99. Near term- vs. long-term model

Near Term (1-5 Years)	Long-Term (5+ Years)
25 regression-based monthly energy deliveries models Business cycle influences energy deliveries Individual customer forecast for ~25 large customers Historic data from 2010 to 2021 Explicitly removes incremental energy efficiency Updated as frequently as every quarter	Convergence to long-term growth rates, agnostic to the business cycle and specific customer growth. Three aggregated customer class growth rate models. Historic data from 2000 to 2021. Assumes energy efficiency is embedded in growth rates. Growth rates are appended to near-term model output. Updated annually to support IRP.

D.1.1 Refinements since last IRP

Development of PGE's econometric load forecast reported in this IRP began in 2020 with a review of critical models and an assessment of key issues raised by stakeholders during the 2019 IRP process.

In October 2020, at IRP Roundtable 20-6,[431] we discussed the impacts of COVID-19 on energy deliveries and out-of-model adjustments made in the near-term load forecast to account for those impacts. We also presented the testing of alternate economic drivers,

[431] Oct. 28, 2020, IRP Roundtable 20-6: https://assets.ctfassets.net/416ywc1laqmd/2XkzCQDPsoEmae8kJn5ckD/6c2e1f9462d8cc16ce8ec7752e57d67a/irp-roundtable-20-6.pdf

particularly focusing on the use of local drivers, for the industrial forecast model in response to feedback from CUB in LC-73.

In July of 2021, at IRP Roundtable 21-5,[432] we presented the preliminary long-term and peak demand models, recommended alternative industrial drivers - including benchmarking to utility peers – and requested feedback on driver selection and scenarios inputs.

In April of 2022, at IRP Roundtable 22-3,[433] we presented the final model results reflecting the March 2022 econometric load forecast and comparison to the 2019 IRP Update.[434]

Several refinements are reflected in the latest models.

- **COVID-19 Indicator**: For the 2019 IRP Update, PGE utilized out-of-model adjustments to account for the impact of COVID-19 in the near-term models. This method was purely pragmatic, an approach to manage the extreme effects quickly. Since that time, we have implemented a more robust approach to account for the impacts of COVID-19 in the econometric model via an indicator variable in the regression analysis. A further explanation of this process can be found in **COVID-19 Impact on short-term energy use.**
- **Industrial Driver**: PGE tested several local and national economic drivers for its industrial model. Variables tested included: US Gross Domestic Product (GDP), Total Oregon Income, Mean Oregon Income, Total Non-Farm Oregon Employment, Oregon GDP, and county-level GDP for PGE's service territory. Total Oregon Income was found to have the most robust relationship with PGE's industrial energy deliveries and was selected as the primary driver for the long-term industrial model.
- **Peak Demand Model Structure**: PGE separated the peak model into two seasonal models; separate cooling and heating models allow for individual seasonal-level model specifications. The peak model specification can be found in **Section D.1.5, Peak model**.

[432] July 22, 2021, IRP Roundtable 21-5: https://assets.ctfassets.net/416ywc1laqmd/2eI3mKz2HVK1uEPogSDofW/09fbb8476086009ffe7d181dfb95dc12/IRP_Roundtable_July_21-5.pdf

[433] Apr. 14, 2022, IRP Roundtable 22-3: https://assets.ctfassets.net/416ywc1laqmd/2e732S4plWpR59ID7ZDV8q/270c1816f005d6816e63ac88e9e61879/IRP_Roundtable_June_22-5.pdf

[434] PGE'S 2019 IRP Update: https://assets.ctfassets.net/416ywc1laqmd/7JkfpRUwMrqCwfKsxAPG3g/9703398aa3212f8532ffb5ced616af87/2019-irp-update-04-20-2021.pdf

D.1.2 Inputs

Normal weather assumption

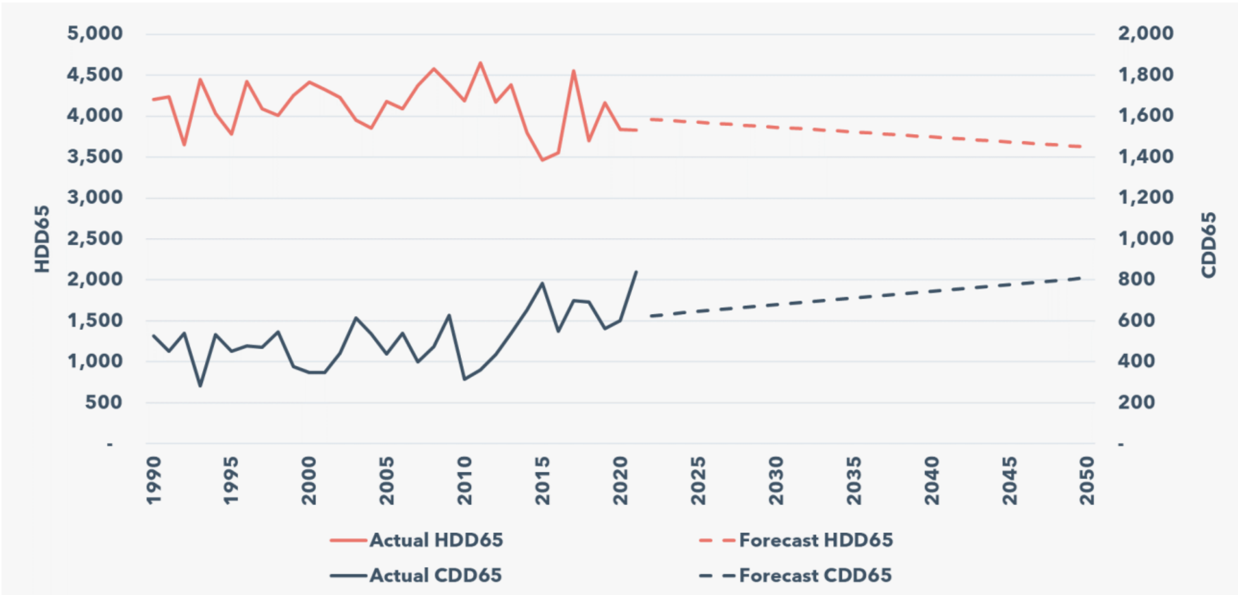
The COVID-19 pandemic has shifted energy usage in several ways. Residential usage experienced a significant increase, while in the commercial segment, initial shutdowns had a stark – but short-lived - impact on energy deliveries. PGE's industrial segment was impacted least by COVID-19 and has grown dramatically since the 2019 IRP. Recent trends impact the near-term forecast, which is the starting point for the long-term forecast.

PGE assumes normal weather year as an input to the load forecast rather than a weather forecast. Weather variability different from the normal weather assumption is expected. The intention is to use an unbiased weather assumption such that the actual weather is warmer or cooler than normal 50 percent of the time. PGE uses a trend to create the forward-looking normal weather assumption that reflects the gradually warming climate. The methodological approach continues the trend observed since 1975, using data since 1941 to "hinge" the initial point of that trend.[435] **Figure 115** shows historical actual and forward-looking normal for heating and cooling degree days (HDD and CDD)[436] using this methodology.

A review was performed in the 2023 IRP to compare this input assumption to specific Representation Concentration Pathway (RCP) Climate Change Scenarios. This review finds PGE's methodology to fit within the reasonable bounds of this scenario analysis. This is described further at the end of this appendix section.

[435] Livezey, Robert E., *et al.* "Estimation and extrapolation of climate normals and climatic trends." *Journal of Applied Meteorology and Climatology* 46.11 (2007): 1759-1776. https://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1
[436] Heating and cooling degree days (HDD and CDD) are the number of degrees that a day's temperature deviates from the temperature set point. For heating degree days, the measurement represents the extent to which a building would need to be heated to reach the temperature set point, and for cooling degree days, the measurement represents the extent to which a building would need to be cooled to reach the temperature set point. For these regressions with monthly data, HDD and CDD are summed for all days in the month. As an example, on a day with an average temperature of 75° F, HDD65 = 0 and CDD65 = 75 - 65 = 10.

Figure 115. Normal weather expectation in terms of heating degree days and cooling degree days



COVID-19 Impact on short-term energy use

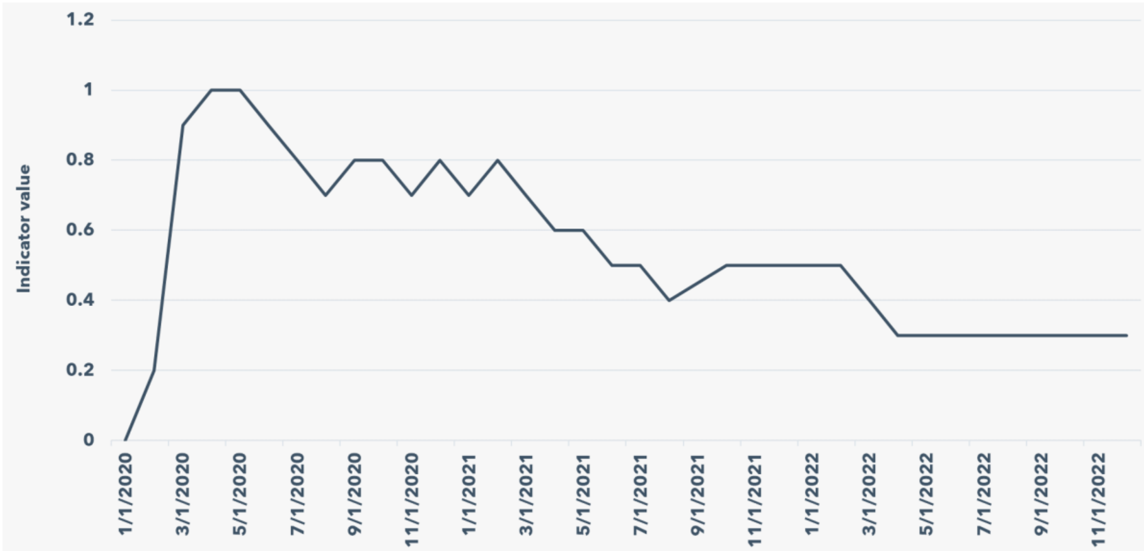
To account for changes in usage, PGE utilized a COVID-19 indicator variable based on the percent of work from home in Oregon produced by the Oregon Office of Economic Analysis.[437] The indicator variable is designed to range from 0 to 1, work from home peaked in May 2020, and that level was set to "1". The indicator was then scaled down based on monthly work from home compared to the May 2020 level. **Figure 116** presents the COVID-19 variable assumptions.

This variable was used in the residential model to account for the increase in usage and in the commercial model to account for the lower usage associated with the COVID-19 pandemic. Recent trends show that COVID-19 has permanently changed the way residential customers use energy. For the forecast, PGE assumed a slow decrease in work from home until April 2022, when long-term equilibrium will be reached at 0.3. This assumes that residential usage will remain elevate at 30 percent of the peak impact of COVID-19.

For the long-term models this variable is phased out in the long-term and does not impact the long-term growth rate beyond correcting the model fit in the short term.

[437] Lehner, Josh. "Just How Much is Working from Home on the Rise?" Available at: https://oregoneconomicanalysis.com/2021/12/16/just-how-much-is-working-from-home-on-the-rise/

Figure 116. COVID-19 indicator variable

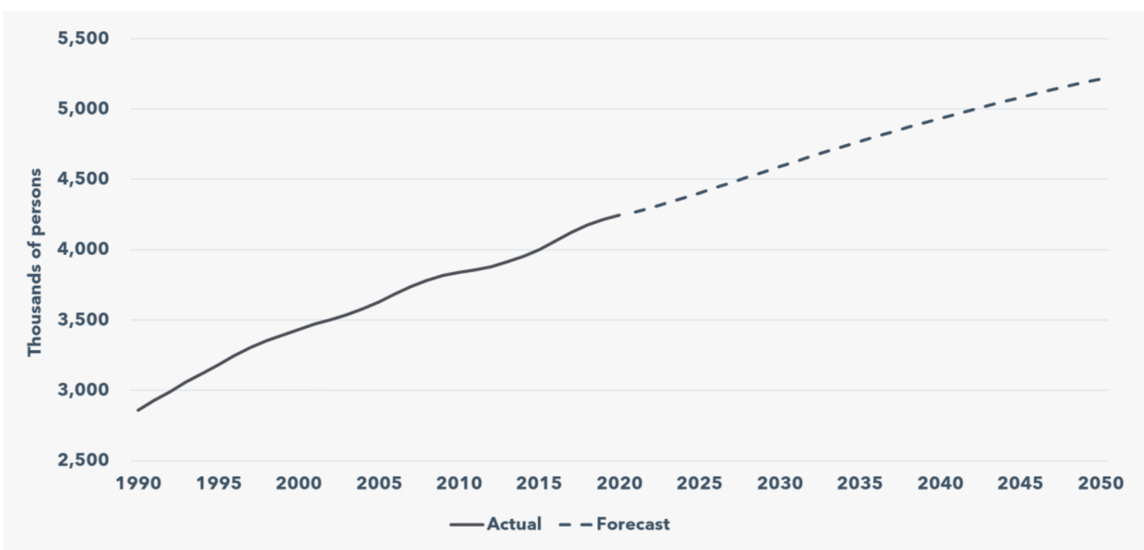


Long-term macroeconomic drivers

Oregon Population

Oregon's Population is closely related to the number of households in PGE's service area. It is used as a driver of residential customer count in PGE's residential energy deliveries model. PGE uses the Oregon Office of Economic Analysis's forecast of Oregon Population, extrapolated from 2030 to 2050. The projected average annual growth rate from 2022 to 2050 is 0.7 percent. **Figure 117** shows the historical actual and projected population levels.

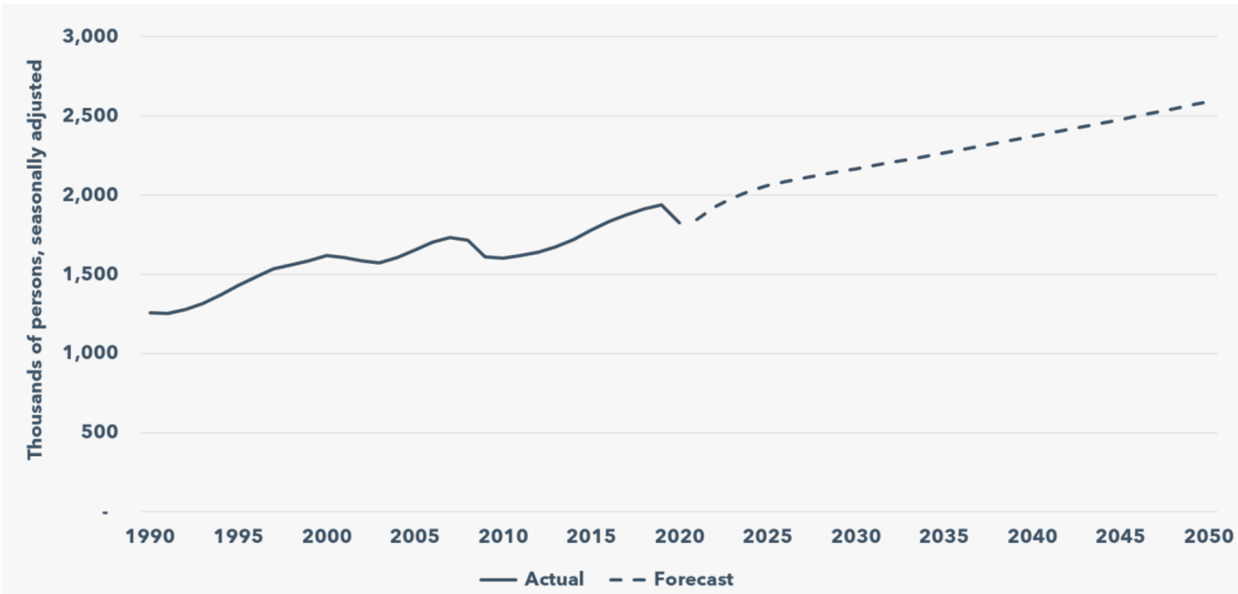
Figure 117. Oregon population



Oregon total non-farm employment

The level of employment in Oregon is the economic driver of PGE's commercial energy deliveries forecast. PGE uses the Oregon Office of Economic Analysis's forecast of employment, extended to 2050. The projected average annual growth rate from 2022 to 2050 is 0.9 percent. **Figure 118** shows the historical actual and forecasted levels of Total Non-Farm Employment.

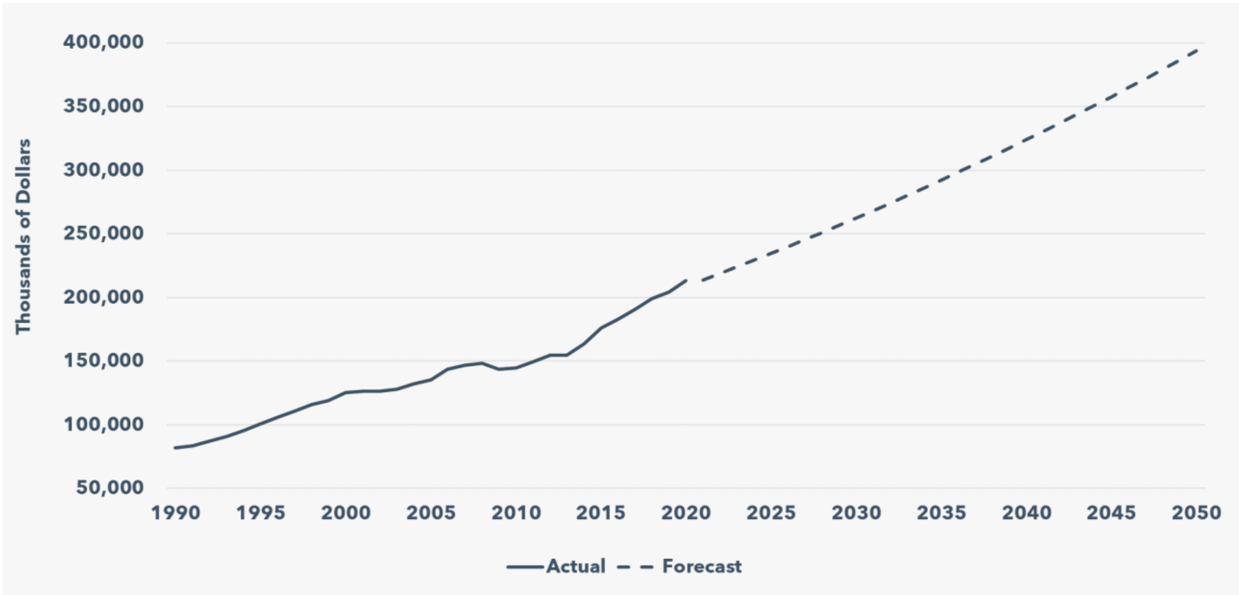
Figure 118. Oregon's total non-farm employment



Oregon Total Personal Income

Oregon's Total Personal Income is the economic driver of PGE's industrial energy deliveries forecast. Total Personal Income is income of individuals from wages, salaries, business ownership, interest and dividends, Social Security, and other government benefits. Measures of income are often used as an indication of financial health. PGE uses the vendor provided forecast released by Woods and Pool in 2021 for this input assumption. The projected average annual growth rate from 2021 to 2050 is 2.1 percent. **Figure 119** shows the historical actual and forecasted Total Personal Income.

Figure 119. Oregon total personal income



D.1.3 Model development and evaluation

In response to OPUC Staff feedback in PGE's 2016 Integrated Resource Plan and as part of continual methodology refinement, PGE worked to standardize and more formally document its model development process and evaluation criteria.[438]

A series of testing steps are used to develop long-term forecast models. This testing includes a univariate review of the underlying structure of the energy deliveries time series; an examination of the relationship between energy deliveries to drivers, including weather variables; and the testing of alternative model structures, including naïve, differenced, and "automatic" ARIMA. The model fit statistics, coefficients, and residuals are reviewed to compare and select alternate models.

- **Univariate analysis**. Univariate analysis of historical sector-level time series is conducted to identify trends, seasonality, cycles, breaks, and outliers. The first step is to inspect the data series visually. Then the autocorrelation of the series is reviewed, and statistical tests such as the Augmented Dickey Fuller (ADF) and Kwiatkowski, Phillips, Schmidt, and Shin (KPSS) tests are used to assess the underlying structure of the data. When tests imply non-stationarity in a variable, PGE explores data transformations, trend variables, and naïve forecasts.

[438] Staff Comments available at: https://edocs.puc.state.or.us/efdocs/HAC/lc66hac143454.pdf

- **Weather responsiveness**. Scatter plots and testing in the regression models are used to determine the appropriate HDD and CDD variables for inclusion in each model. **Figure 120** shows the weather responsiveness of the three long-term models with monthly energy deliveries plotted against average monthly temperature using data since 2000.

In **Figure 120**, the scatter follows a relatively tight "U" shape, indicating that residential energy usage increases as the average temperature falls under 60˚F and as the average temperature is higher than 65˚F. This implies using an HDD variable calculated from a 60˚F base and a CDD variable with a 65˚F base. In (b), commercial energy deliveries increase as the average temperature falls under 50˚F and when the average temperature is higher than 60˚F. In (c), the broad scatter implies that energy deliveries to the industrial class have no significant weather dependence.

- **Residual review**. PGE reviews the autocorrelation and normality of residuals in the models for any alternative model structures considered. Ideally, residuals are white noise, meaning they are uncorrelated, have a mean of 0, have constant variance, and are normally distributed. The extent to which residuals of a regression statistically differ from white noise indicates the potential to improve the model specification. Residuals that are meaningfully correlated might lead to the addition of autoregressive or moving average terms to the model or re-visiting the regression model specification.
- **Alternate forecasts and out-of-sample testing**. PGE reviews a variety of alternate model specifications for each of the forecast groups. Testing includes: 1) models using a variety of economic drivers, as well as those with no economic driver; 2) models with and without monthly indicator variables; and 3) models using a variety of data transformations. As part of the standardization of the model evaluation and to benchmark against the most simplistic models, PGE also tests naïve and seasonally naïve forecasts. Out-of-sample testing, which uses a training period to estimate the model and a testing period to evaluate model performance, was included as a part of PGE's testing process in the 2019 IRP Load Forecasting Appendix. While PGE intends to employ this method in the future, out-of-sample testing was not performed for the forecast vintage used in this IRP. PGE did not perform out-of-sample testing because the dramatic but short-lived period of impact for the COVID-19 indicator variable did not allow for a long enough period to reflect useful testing.

D.1.4 Long-term energy models

Residential model

The long-term residential energy deliveries model, shown in **Equation 1**, comprises of forecasts for both customer count, an annual model based on Oregon Population (**Equation 3**), and use-per-customer, a monthly model based on relationships to Oregon Total Non-Farm employment, COVID-19, and heating and cooling degree days (**Equation 2**). The resulting monthly use-per-customer forecast is combined with the annual customer count forecast for a monthly forecast of residential energy deliveries.

Equation 1. Residential energy deliveries

$$kWh_{res} = UPC_{res} * CC_{res}$$

Where:

- UPC = Use-per-customer
- CC = Customer count

Equation 2. Residential use-per-customer

$$UPC_{res,t} = \sum_{k=0}^{11} (\beta_k \, Month_k + \alpha_k Trend_k) + \beta_{12} HDD60 + \beta_{13} CDD65 + \beta_{14} COVID\ Indicator_t + \beta_{15} UPC_{res,t-1} + \varepsilon_t$$

Where:

- HDD60 = Heating degree day with 60° F set point
- CDD65 = Cooling degree day with 65° F set point
- Trend = Numerical variable that increases by 1 each year
- COVID Indicator = Indicator variable between 0 and 1
- ε_t = error term

Equation 3. Residential customer count

$$\Delta CC_{res,t} = \beta_0 + \beta_1 * \Delta POP_{or} + \beta_2 \sum_{n=1}^{12} \frac{CC_{res.n}}{\sum_{n=1}^{12} n + \varepsilon_t}$$

Where:

- $\Delta y = y_{t-} y_{t-1}$ representing a first-order difference
- POP_{OR} = Oregon Population
- ε_t = error term

Commercial model

The commercial energy deliveries model, shown in **Equation 4**, is a monthly model that establishes a relationship between commercial energy deliveries and Oregon's Total Non-Farm employment, COVID-19, and heating and cooling degree days.

Equation 4. Commercial energy deliveries

$$kWh_{com,t} = \sum_{k=0}^{11} \beta_k\, Month_k + \beta_{12} HDD50 + \beta_{13} CDD60 + \beta_{14} COVID\ Indicator_t + \beta_{15}\, OENTNA + \beta_{16}\, kWh_{com,t-1} + \varepsilon_t$$

Where:

- HDD50= Heating degree day with 50° F set point
- CDD60 = Cooling degree day with 60° F set point
- COVID Indicator = Indicator variable between 0 and 1
- OENTNA = Oregon's Total Non-Farm employment
- ε_t = error term

Industrial model

The annual industrial model includes Oregon's Total Personal Income as a driver of energy deliveries (**Equation 5**).

Equation 5. Industrial energy deliveries

$$\Delta kWh_{ind,t} = \beta_0 + \beta_1 X \Delta Personal\ Income + \beta_2 \sum_{n=1}^{12} \frac{kWh_{ind,n}}{\sum_{n=1}^{12} n + \varepsilon_t}$$

Where:

- $\Delta y = y_{t-} y_{t-1}$ representing a first-order difference
- Personal Income= Oregon's Total Personal Income
- ε_t= error term

D.1.5 Peak model

The peak models, shown in **Equation 6 and 7. Peak Demand**, are a monthly seasonal model that relates the single-hour peak demand of PGE's net system (in MW) to average monthly demand (in MWa) and weather variables. The models consider the impact of heating and cooling degree days (HDD and CDD), as well as the summer model, which accounts for the growing saturation of air conditioning in the home in PGE's service area. Both models include the previous day's temperature impacts by using cooling or heating degree days, and the winter model includes wind speed.

Equation 6 and 7. Peak Demand

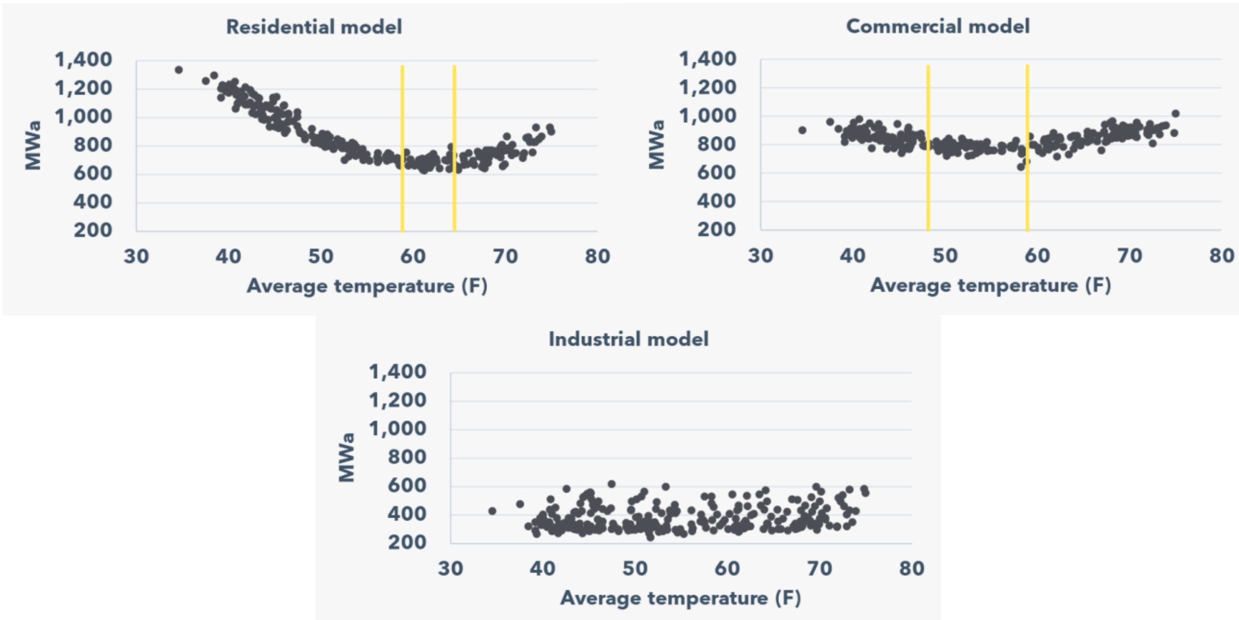
$$MW_{summer,t} = \beta_1 PKDAYCDD + \beta_2 PDCDD + \frac{\beta_3 ACSAT * NRC1_t}{1000} + \beta_4 CycleMA_t + \beta_5 CDD65 + \beta_6 May + \beta_7 Jun + \beta_8 Jul + \beta_9 Aug + \beta_{10} Sep + \beta_{11} Weekend + \varepsilon_t$$

$$MW_{winter,t} = \beta_1 PKDAYHDD + \beta_2 PDHDD + \beta_3 PKDAYWIND + \beta_4 CycleMA_t + \beta_5 HDD60 + \beta_6 Oct + \beta_7 Nov + \beta_8 Dec + \beta_9 Jan + \beta_{10} Feb + \beta_{11} Mar + \beta_{12} Weekend + \beta_{13} STEP0811 + \varepsilon_t$$

Where:

- MWa = Average monthly demand
- PKDAYCDD = CDD with 65° F set point on the day the peak occurred
- PDCDD = CDD with 65° F set point on the day before the day the peak occurred
- NRC1 = Count of residential customers
- ACSAT = Percentage of households with air conditioning
- CycleMA = Twelve months moving average of total monthly usage
- PKDAYHDD = HDD with 65° F set point on the day the peak occurred
- PDCDD = HDD with 65° F set point on the day before the day the peak occurred
- PKDAYWIND = Average daily wind speed on the day the peak occurred
- STEP0811 = An indicator variable beginning in November 2008
- ε_t = error term

Figure 120. Weather sensitivity of energy deliveries to (a) the residential class, (b) the commercial class, and (c) the industrial class



D.1.6 Probabilistic loads

All forecasts are subject to uncertainty, including uncertainties associated with forecasts of the input variables and the complexity of the estimated relationships with those variables. Some of these uncertainties can be characterized quantitatively using model parameters.

The single most important driver of load variability is the weather. Residential and small commercial loads are particularly sensitive to the weather due to heating and cooling loads. Weather is known to be highly variable from one year to the next. PGE addresses the stochastic risk in the load forecast associated with weather, analyzing 30 years of weather variability in its Resource Adequacy model, described in **Chapter 6, Resource needs.**

Two sources of uncertainty characterized using the output statistics of the regression models described previously are model uncertainty and coefficient uncertainty. Model uncertainty is the standard error of the regression or a reflection of how the model performs over the period of data used to inform the model. Coefficient uncertainty is the standard error associated with the estimated coefficient, which defines the relationship between the dependent and driver variables.

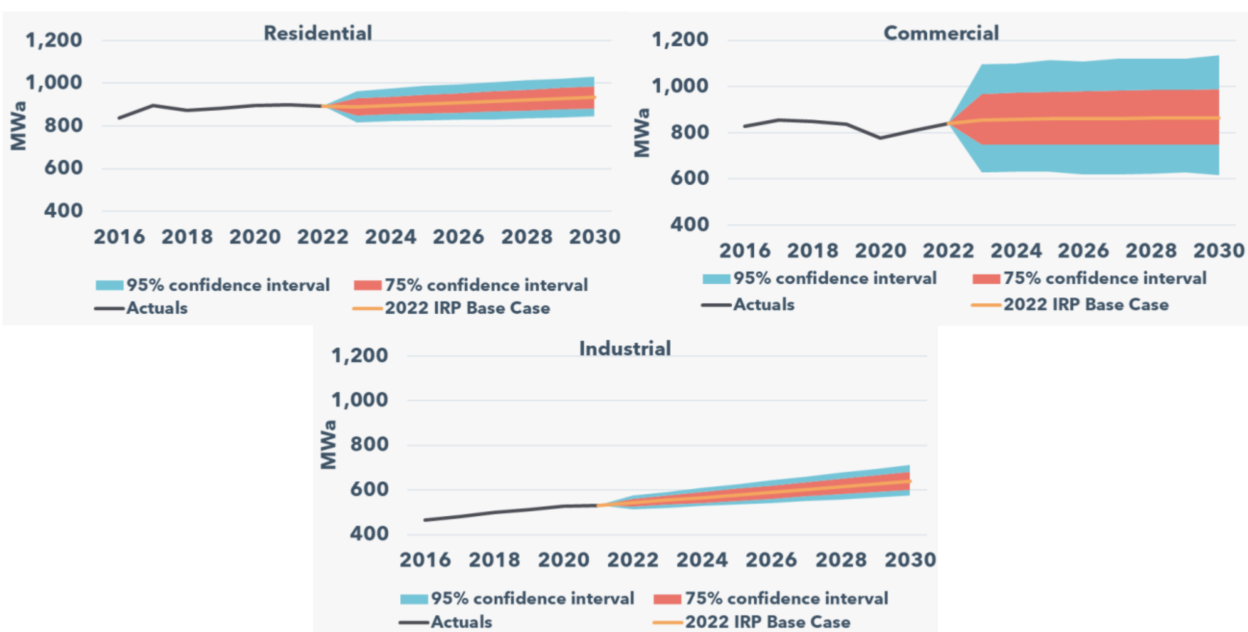
EViews, a statistical package used primarily for time-series oriented econometric analysis, and also the software package PGE uses to conduct its load forecast, was used to run stochastic simulations that combine model uncertainty and coefficient uncertainty to create confidence bands around the base case forecast. During simulation runs, coefficients are randomly varied along with residuals, and the errors are quantified and used to obtain confidence intervals. Over 10 thousand simulations were run for each of the long-term regression models.

Figure 121 shows the 75 and 95 percent confidence bounds on the three energy deliveries models.

Another category of uncertainty relates to the driver variables used in the regression models. Uncertainties in the forecast of the economic driver variables are considered by scenario analysis, described further in **Chapter 6, Resource needs**.

Other uncertainties not quantified by this approach yet worth mentioning relate to variables excluded from the models and the estimation periods of the models. For example, specific large load might cause shifts in load that cannot be precisely timed by a driver-based model. A model is, by design, a simplification of reality. The interdependencies of energy deliveries are complex and widespread across the macroeconomy. The benefits and uncertainties of different variable selection and estimation periods are weighed during the model development and evaluation process. Drivers which may impact loads outside of this modeling process may be considered in scenario analysis outside of the modeled uncertainties.

Figure 121. Confidence interval on the net system residential (left), commercial (right), and industrial (low) energy deliveries models



D.2 Results

Results of the top-down econometric models described previously are combined with explicit forecasts for EE, EV, and behind-the-meter solar and storage to arrive at the total load scenarios shown in the following tables. These load forecasts do not include long-term direct access loads, consistent with Guideline 9.[439] This section provides low, reference, and high forecasts for Net System Load by residential, commercial, and industrial customers. Net System Load includes both cost-of-service supply customers, long-term direct access customers and new load direct access customers.

D.2.1 Energy load forecasts

Table 100 summarizes the load forecast scenarios for energy deliveries (in MWa) at the bus bar.[440]

Table 101, **Table 102**, and **Table 103** provide the annual forecasts for the reference, low, and high scenarios. For these tables, note that passive DER only captures the forecasts for generation from distributed PVs.

Table 100. Load forecast scenarios in MWa[441]

	Low Need			Reference Case			High Need		
	2023	2043	AAGR	2023	2043	AAGR	2023	2043	AAGR
Top-down Load Forecast	2,351	3,644	2%	2,365	3,970	3%	2,378	4,276	3%
Base Load Forecast	2,320	3,054	1%	2,334	3,407	2%	2,347	3,731	0
Energy Efficiency	-31	-590	0	-31	-563	0	-31	-546	17%
Rooftop PV	-1	-81	28%	-1	-50	28%	-1	-28	22%
Building Electrification	4	86	17%	4	87	17%	4	124	20%

[439] Order No. 07-002 at 19, see Guideline 9, as amended by Order No. 07-047 at Appendix A, p.6
[440] As mentioned previously, the load forecasts in this section do not include long-term direct access loads.
[441] The base load forecast is the top-down load forecast adjusted to exclude the impacts of the cost-effective deployable EE savings and the assumptions for the embedded distributed PV generation and electric vehicle load. The EE savings are cumulative values adjusted for line losses and intra-year deployment beginning in 2022. Note that in this and the following tables the AAGR is not calculated because savings before 2020 are not reported in these values.

	Low Need			Reference Case			High Need		
	2023	**2043**	**AAGR**	**2023**	**2043**	**AAGR**	**2023**	**2043**	**AAGR**
Transportation Electrification	13	372	18%	15	504	20%	16	590	20%
Total Load Forecast	2,305	2,841	1%	2,321	3,385	2%	2,336	3,870	3%

Table 101. Reference case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,334	-31	15	-1	4	2,321
2024	2,402	-61	21	-1	7	2,367
2025	2,463	-91	28	-3	10	2,407
2026	2,530	-121	38	-5	13	2,455
2027	2,594	-151	48	-8	17	2,500
2028	2,649	-181	60	-12	20	2,535
2029	2,703	-214	73	-18	23	2,567
2030	2,759	-247	91	-25	27	2,605
2031	2,817	-282	115	-31	31	2,650
2032	2,875	-316	139	-37	35	2,696
2033	2,931	-348	166	-41	40	2,747
2034	2,986	-378	196	-42	44	2,804
2035	3,040	-408	224	-43	48	2,861
2036	3,093	-435	266	-44	53	2,932
2037	3,143	-460	296	-45	57	2,992
2038	3,192	-483	327	-45	61	3,052
2039	3,237	-502	365	-46	66	3,120
2040	3,280	-518	405	-47	72	3,192

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2041	3,323	-533	440	-48	77	3,258
2042	3,361	-545	457	-49	80	3,304
2043	3,407	-563	504	-50	87	3,385
Average annual growth rate	2%	N/A	20%	28%	17%	2%

Table 102. Low Case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,320	-31	13	-1	4	2,305
2024	2,373	-61	18	-2	7	2,336
2025	2,419	-91	24	-4	10	2,358
2026	2,471	-121	31	-7	13	2,388
2027	2,520	-152	38	-11	17	2,412
2028	2,558	-184	46	-16	20	2,425
2029	2,596	-217	55	-23	23	2,434
2030	2,637	-252	68	-33	27	2,446
2031	2,678	-288	84	-43	31	2,463
2032	2,719	-323	100	-52	35	2,479
2033	2,758	-357	118	-58	39	2,501
2034	2,796	-389	138	-60	44	2,529
2035	2,833	-420	157	-63	48	2,555
2036	2,869	-449	185	-65	53	2,593
2037	2,901	-476	207	-67	57	2,622
2038	2,932	-502	230	-69	61	2,652

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2039	2,959	-523	257	-72	66	2,688
2040	2,984	-542	288	-75	72	2,728
2041	3,007	-558	317	-77	77	2,767
2042	3,027	-570	333	-79	80	2,791
2043	3,054	-590	372	-81	86	2,841
Average annual growth rate	1%	N/A	18%	28%	17%	1%

Table 103. High Case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,347	-31	16	-1	4	2,336
2024	2,428	-61	24	-1	7	2,397
2025	2,503	-91	33	-1	11	2,454
2026	2,585	-121	44	-2	15	2,522
2027	2,664	-150	56	-2	20	2,587
2028	2,733	-180	71	-3	24	2,645
2029	2,802	-212	88	-3	29	2,704
2030	2,873	-243	110	-3	34	2,771
2031	2,946	-276	140	-4	40	2,846
2032	3,019	-309	172	-5	46	2,923
2033	3,091	-340	207	-5	52	3,005
2034	3,163	-369	248	-6	58	3,094
2035	3,233	-396	287	-7	64	3,181
2036	3,302	-421	340	-8	72	3,285

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2037	3,368	-445	378	-10	78	3,370
2038	3,433	-467	415	-12	85	3,454
2039	3,494	-485	457	-15	92	3,544
2040	3,553	-502	499	-18	101	3,635
2041	3,613	-517	534	-21	109	3,718
2042	3,668	-528	544	-25	114	3,774
2043	3,731	-546	590	-28	124	3,870
Average annual growth rate	2%	N/A	20%	22%	20%	3%

D.2.2 Peak load forecasts

Table 104 provides the seasonal peak loads for each year and Need Future.[442] These tables reflect total load values; the top-down econometric forecast combined with the forecasts for EVs and building electrification. This forecast includes costs effective energy efficiency but does not include the impacts of passive or active demand response programs. The values in this table are reflective of the loads used in the Sequoia model, which has 30-years (1992-2021) of weather variation included (median peak loads are shown).

Table 104. Peak load forecast by Need Future and season, MW

Year	Low Need		Reference Need		High Need	
	Summer	Winter	Summer	Winter	Summer	Winter
2023	3,712	3,510	3,726	3,525	3,740	3,541
2024	3,746	3,547	3,776	3,580	3,805	3,613
2025	3,781	3,583	3,828	3,635	3,874	3,689
2026	3,822	3,626	3,888	3,699	3,953	3,774

442 As mentioned previously, the load forecasts in the section do not include long-term direct access loads.

Year	Low Need		Reference Need		High Need	
	Summer	Winter	Summer	Winter	Summer	Winter
2027	3,861	3,668	3,948	3,766	4,032	3,864
2028	3,890	3,706	4,001	3,831	4,105	3,954
2029	3,924	3,734	4,061	3,885	4,188	4,036
2030	3,960	3,773	4,124	3,954	4,277	4,136
2031	4,002	3,814	4,195	4,030	4,376	4,244
2032	4,043	3,861	4,269	4,111	4,481	4,363
2033	4,095	3,908	4,355	4,198	4,602	4,492
2034	4,145	3,964	4,442	4,292	4,729	4,632
2035	4,200	4,020	4,535	4,389	4,860	4,773
2036	4,256	4,081	4,630	4,493	4,994	4,921
2037	4,319	4,139	4,732	4,592	5,130	5,058
2038	4,380	4,203	4,830	4,697	5,259	5,198
2039	4,442	4,267	4,930	4,801	5,383	5,329
2040	4,506	4,336	5,027	4,904	5,500	5,456
2041	4,576	4,402	5,128	5,002	5,616	5,573
2042	4,643	4,472	5,223	5,102	5,723	5,689
2043	4,709	4,540	5,316	5,197	5,824	5,797
Annual average growth rate	1.2%	1.3%	1.8%	2.0%	2.2%	2.5%

D.3 Net system load

Net System Load includes both cost-of-service supply customers and direct access customers. While Net System Load is not used in the IRP need assessments or portfolio analysis, the information in this section is provided for reference as it reflects the level of disaggregation at which the load forecast analysis occurs.

Table 105, **Table 106**, and **Table 107** provide the reference, low, and high econometric load forecasts for Net System Load in MWa at the bus bar by class. The commercial class includes street and highway lighting, and the industrial class consists of both transmission and primary-level customers. The high and low scenarios capture high and low growth conditions and +/- 1 standard deviation of uncertainty from the regression model parameters. These forecasts do not include the impacts of the explicit forecasts for Energy Vehicles (EVs), Distributed Energy Resources (DERs), or additional Energy Efficiency (EE) savings beyond Energy Trust's projections.

Table 105. Econometric Net System Load with reference growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	933	802	503	2,239
2023	922	815	566	2,303
2024	918	808	615	2,341
2025	914	801	657	2,372
2026	913	794	703	2,409
2027	915	786	743	2,444
2028	921	786	760	2,467
2029	928	788	772	2,489
2030	935	790	787	2,512
2031	942	791	802	2,535
2032	949	792	818	2,559
2033	956	793	834	2,583
2034	963	795	850	2,607
2035	970	796	866	2,632
2036	977	797	883	2,657
2037	984	798	900	2,683
2038	991	800	918	2,709
2039	999	801	936	2,735

Year	Residential	Commercial	Industrial	Total
2040	1,006	802	954	2,762
2041	1,013	803	972	2,789
2042	1,021	805	991	2,817
2043	1,028	806	1,010	2,845
2044	1,036	807	1,030	2,873
2045	1,043	809	1,050	2,902
2046	1,051	810	1,071	2,932
2047	1,059	811	1,091	2,961
2048	1,067	812	1,113	2,992
2049	1,075	814	1,134	3,022
2050	1,082	815	1,156	3,054
Average annual growth rate	0.5%	0.1%	3.0%	1.1%

Table 106. Econometric Net System Load with low growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	933	802	503	2,239
2023	918	812	559	2,289
2024	910	802	601	2,312
2025	902	792	634	2,329
2026	897	782	672	2,351
2027	895	771	703	2,369
2028	897	769	711	2,376
2029	901	768	713	2,382
2030	903	766	719	2,388
2031	906	764	724	2,395
2032	909	763	730	2,401

Year	Residential	Commercial	Industrial	Total
2033	912	761	736	2,408
2034	914	759	742	2,415
2035	917	758	748	2,423
2036	920	756	754	2,430
2037	923	754	760	2,438
2038	926	753	767	2,445
2039	929	751	773	2,453
2040	932	749	780	2,461
2041	935	748	787	2,470
2042	938	746	794	2,478
2043	941	744	802	2,487
2044	944	742	809	2,495
2045	947	741	817	2,504
2046	950	739	824	2,514
2047	953	737	832	2,523
2048	957	736	841	2,533
2049	960	734	849	2,543
2050	963	732	858	2,553
Average annual growth rate	0.1%	-0.3%	1.9%	0.5%

Table 107. Econometric Net System Load with high growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	926	813	628	2,367
2023	927	808	677	2,412
2024	931	803	731	2,464
2025	937	797	779	2,513

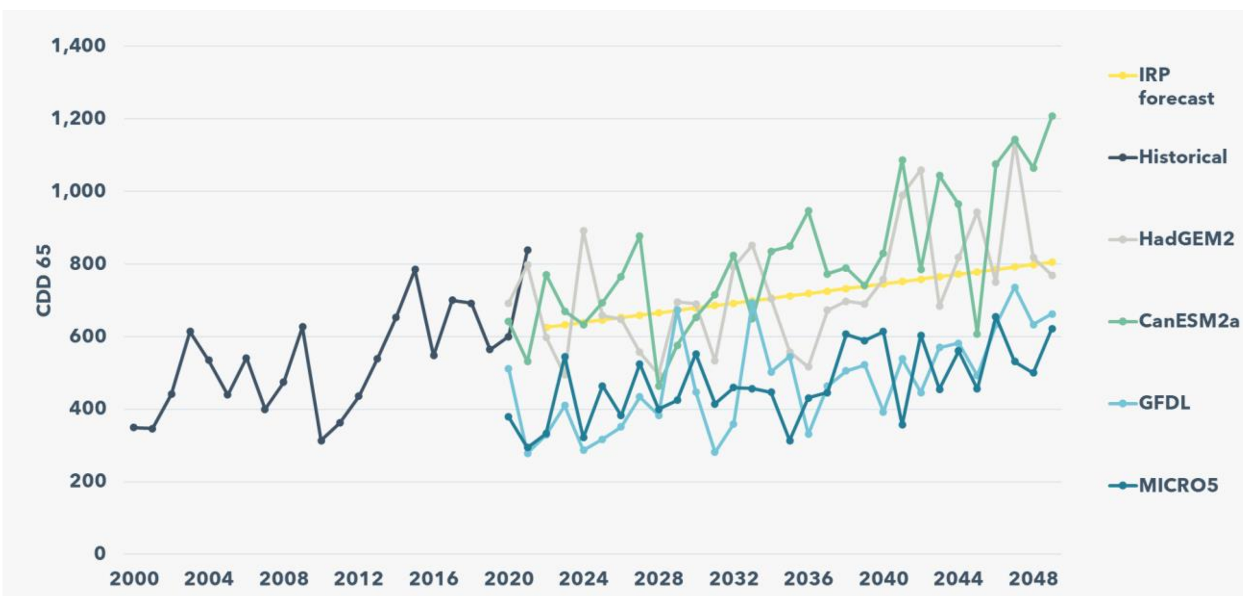
Year	Residential	Commercial	Industrial	Total
2026	947	800	804	2,552
2027	959	804	824	2,588
2028	971	808	848	2,626
2029	982	811	871	2,665
2030	994	815	895	2,703
2031	1,005	818	919	2,743
2032	1,017	822	944	2,782
2033	1,029	825	969	2,823
2034	1,040	829	994	2,863
2035	1,052	832	1,020	2,904
2036	1,064	836	1,046	2,946
2037	1,076	839	1,072	2,988
2038	1,089	843	1,099	3,031
2039	1,101	846	1,126	3,074
2040	1,113	850	1,154	3,117
2041	1,126	854	1,182	3,161
2042	1,138	857	1,210	3,205
2043	1,151	861	1,239	3,250
2044	1,164	864	1,268	3,296
2045	1,176	868	1,297	3,342
2046	1,189	871	1,327	3,388
2047	1,202	875	1,358	3,435
2048	1,216	879	1,388	3,482
2049	933	802	503	2,239
2050	926	817	572	2,316
Average annual growth rate	1.0%	0.3%	3.7%	1.6%

D.4 Climate change model data and the IRP load forecast

The temperature data used by the econometric load forecasting model have historical climate change trends built into them. In general, this increases cooling-degree days going forward and decreases heating-degree days.[443] The IRP compares these historical trends with climate model outputs to see how similar they are. The climate model data used in the comparison are from the River Management Joint Operating Committee (RMJOC) studies that use data from the Intergovernmental Panel on Climate Change (IPCC). The four models used in the comparison were selected by the RMJOC for streamflow analysis and were recommended for the IRP analysis by Creative Renewable Solutions.[444]

Figure 122 compares cooling degree days (CDD 65) annually between the historical data, the trend data used in the IRP econometric forecast, and the climate model outputs. Historical data and the econometric load forecast data are in gray. There is an upward trend in the econometric load forecast data. An upward trend in CDD 65 indicates warming temperatures in summer months and more demand for mechanical cooling (air conditioning). The figure data from the four climate models are in color and trend upwards, too.

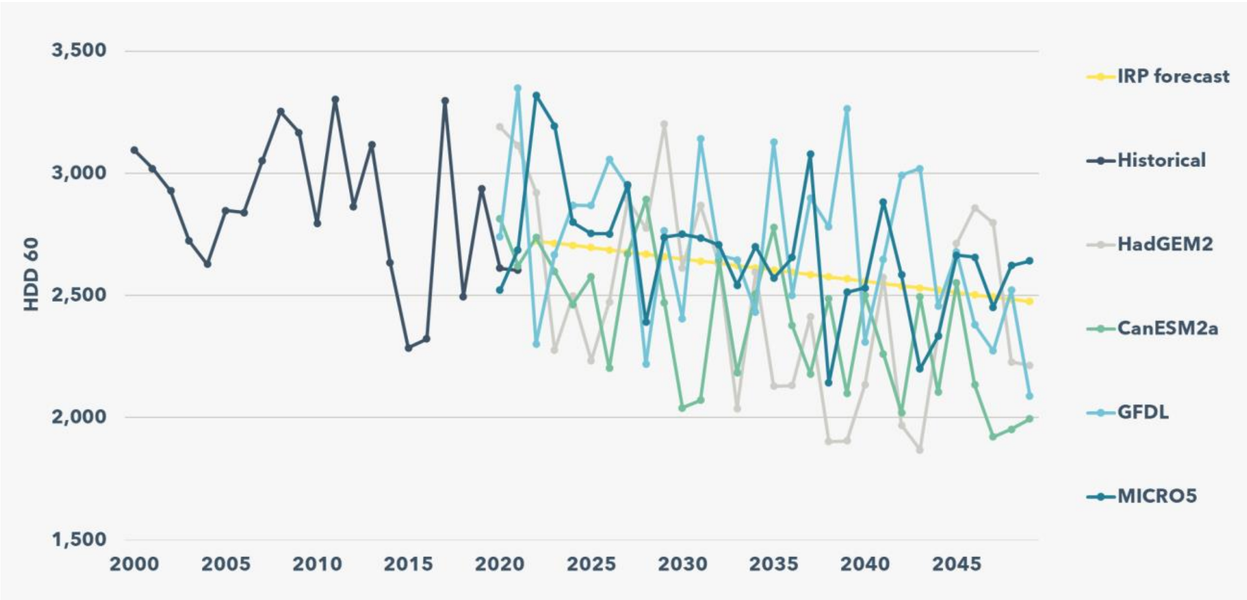
Figure 122. Annual cooling degree day forecasts



In **Figure 122**, the econometric load forecast CDD 65 inputs (in gray) trend inside the range of the climate change model data (in color). This indicates that the warming trend approach used by the econometric load forecasting model somewhat comports with the data from the climate change models.

Figure 123 compares heating degree days from historical data (in gray), the IRP econometric load forecast (in gray), and the climate change models (in color). All datasets show a decreasing trend in heating degree days on a yearly basis. This indicates warming temperatures in winter months, and a decreased need for heating.

Figure 123. Annual heating degree day forecasts



In **Figure 123**, the econometric load forecast HDD 65 inputs (in gray) trend inside the range of the climate change model data on an annual level. On a monthly level however, the econometric load forecast trend in December and February is flat, whereas the climate models have a declining trend (not shown).

Based on the observation that the annual HDD and CDD data used in the econometric load forecast are mostly in the range of the climate model data, PGE decided to stay with the warming trend approach for the 2023 IRP. In future planning work PGE will continue to update the trend approach while exploring using climate change model data.

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[443] Cooling degree days define days that average higher than a certain temperature, often 65 degrees F. An increase in cooling degree days indicates warming temperatures (and more need for air conditioning). Heating degree days define days that average less than a certain temperature, often 60 degrees F. A reduction in heating degree days indicates warming temperatures (and less need for heating).
[444] Additional climate change data are available at: https://www.bpa.gov/energy-and-services/power/climate-change-fcrps

Appendix E. Existing and contracted resources

PGE operates a diverse portfolio of resources to meet PGE's system energy and capacity needs. The appendix describes existing resources and resources with executed agreements that may not yet be in service.

E.1 Existing resources

E.1.1 Thermal resources

The technology and size characteristics for each plant are provided in the following sections. Note that these descriptions and capacity (in MW) represent the annual average net capacity of the power plant, which includes any duct-firing capabilities and excludes any de-rates for maintenance or forced outage rates. In contrast, energy (in MWa) represents the annual average availability after projected forced outages and maintenance. Also, note that the capacity of combined-cycle combustion turbines (CCCTs) varies across seasons as turbine operations are more sensitive to temperature changes. When the temperature is high during the summer, the turbines provide less capacity as operations are affected, while other steam technologies have more consistent capacity regardless of temperature change. In the following sections, each thermal resource is described in greater detail. The annual average energy availability, MWa, for each resource is for the period between 2023 to 2050, unless noted otherwise.

Carty

Carty is a CCCT resource built adjacent to PGE's Boardman coal plant in Boardman, Oregon. The plant became operational in 2016. It provides 391 MW of annual average capacity. The plant has a highly efficient Mitsubishi Heavy Industries (MHI) G-class combustion turbine. The annual average energy availability is 369 MWa. Finally, the plant has 47 MW of duct firing for capacity needs.

Coyote Springs

Coyote Springs is a gas fired CCCT facility in Boardman, Oregon, which became operational in 1995. Coyote Springs has an annual average capacity of 252 MW (including 2 MW of additional capacity when operating an auxiliary boiler to supply steam-to-steam customers) and an annual average energy availability of 228 MWa.

Port Westward 1

Port Westward 1 (PW1) reached commercial operation in June 2007. This CCCT plant is in Clatskanie, Oregon. The plant supplies approximately 411 MW of annual average capacity (including approximately 17 MW of duct firing) and has an annual average energy availability of 367 MWa.

Beaver

Beaver is a CCCT facility in Clatskanie, Oregon. PGE placed the plant into service in 1976. Beaver has an annual average capacity of 486 MW. The six combustion turbines (CTs) operate primarily on natural gas but can also be fueled with No. 2 diesel fuel oil via on-site tank storage. The CTs each have heat recovery steam generators that connect to a single steam turbine, allowing PGE to operate the plant either in simple-cycle mode or in combined–cycle mode. A separate simple cycle unit, Beaver 8, was added to the site in 2001 and has an annual average capacity of 23 MW.

Port Westward 2

Port Westward 2 (PW2) is in Clatskanie, OR, adjacent to PGE's PW1 plant. PW2 began commercial operations in December 2014. It comprises 12 natural gas-fired reciprocating engines with an annual average capacity of approximately 225 MW. In addition to providing peak capacity, the modular configuration offers a wide range of dispatch flexibility for wind, load following, and additional energy value.

Boardman

Boardman came into service in 1980 and went offline on October 15, 2020. It was decommissioned and demolished on September 15, 2022. Boardman was a coal plant in Boardman, Oregon, with an annual capacity of approximately 575 MW when it was operational.

Colstrip

Colstrip is a four-unit coal-fired plant located in Colstrip, Montana, with coal transported by conveyor belt directly from the on-site mine to the boiler. Colstrip units 1 and 2 became operational in 1975 and 1976, respectively. The units were owned by Talen Energy and Puget Sound Energy and were shut down in 2019.

PGE owns 20 percent of Colstrip units 3 and 4, representing approximately 296 MW (or 20 percent of the combined units 3 and 4) of annual average capacity. The average annual energy availability for PGE's share of Colstrip Units 3 and 4 is 262 MWa for the remaining operating period, 2023-2029. PGE has plans to discontinue usage of and exit its 20 percent ownership of the Colstrip plant by the end of 2029.

E.1.2 Hydropower plants

PGE owns and operates eight hydroelectric plants on the Deschutes, Clackamas, and Willamette River systems. Pelton and Round Butte plants have reservoir storage capability, while the remaining plants have limited ability to store water and shape energy. These plants are operated as run-of-river projects.

Pelton-Round Butte hydropower project

PGE operates the Pelton and Round Butte plants on the Deschutes River near Madras, Oregon. These plants provide peaking and load-following capabilities. A portion of PGE's hydropower capacity also contributes to meeting the required spinning and supplemental (non-spin) operating reserve requirements, which are necessary for responding to system contingencies.

In an average hydro condition, the plants have a combined annual average dependable capacity of approximately 447 MW and an expected annual energy production of 165 MWa. PGE owns 50.1 percent of each plant (approximately 224 MW, 82 MWa), with the remaining share owned by the Confederated Tribes of the Warm Springs Reservation (Tribes). The Tribes agreed to sell all their output to PGE through 2040. See **Section E.2.2, Pelton, Round Butte, and the Re-regulating dam**, for more details on the agreement.

Clackamas River hydropower projects

PGE owns and operates six plants on the Clackamas River system. Under average hydropower generation conditions, the plants have the following average annual capacities:

- Timothy Powerhouse, 1.2 MW (OR RPS compliant)[445]
- Harriet Powerhouse, 0.5MW
- Oak Grove, 27MW
- North Fork, 27 MW (OR RPS compliant)
- Faraday, 27 MW (OR RPS compliant)
- River Mill, 15 MW (OR RPS compliant)

Under average hydro conditions, the aggregated expected annual energy production from each of these projects is 84 MWa.

Willamette Falls hydropower project

PGE owns and operates the Sullivan plant on the Willamette River at Willamette Falls. Under average hydropower generation conditions, the plant's nameplate capacity is 14 MW, and the expected annual energy production is 14 MWa.

E.1.3 Wind and Solar plants

Biglow Canyon

The Biglow Canyon Wind Farm was completed in three phases in 2007, 2009, and 2010. The wind farm in the lower Columbia River Gorge near Wasco, Oregon, has a total nameplate generating capacity of 450 MW. Based on an expected capacity factor of approximately 26 percent, PGE estimates Biglow's annual average energy production at 118 MWa. Biglow's generation is RPS compliant as it is renewable energy that contributes towards the RPS requirement of being 50 percent renewable by 2040.

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[445] The Oregon Renewable Portfolio Standard (RPS) sets a requirement for how much of the electricity used in Oregon must come from renewable resources. The passage of Oregon Senate Bill 1547 increased Oregon's Renewable Portfolio Standard requirement to 50 percent renewables by 2040. RPS is discussed in **Section 6.7, RPS need**.

Clearwater wind

The Clearwater wind farm will span Rosebud, Garfield, and Custer counties in Montana. It is a 775 MW wind site in Montana being developed by NextEra Energy Resources, LLC. PGE will procure 311 MW of energy from the Clearwater Wind project, scheduled to be operational by December 31, 2023. PGE's power from Clearwater will be generated by 112 General Electric wind turbines. The Clearwater project is expected to deliver higher levels of production during the winter and summer. The power will be served to PGE customers through existing transmission on the Northwestern Energy and Bonneville Power Administration (BPA) systems.

Tucannon River wind farm

Located near Dayton, Washington, PGE's Tucannon River Wind Farm (Tucannon) consists of 116 2.3- MW Siemens wind turbine generators with a total nameplate capacity of 267 MW. The plant's 35 percent expected capacity factor results in an expected output of 94 MWa. The project was completed and became operational in December 2014. Generation from Tucannon is Renewable Portfolio Standard (RPS) compliant RPS compliant as it is a renewable energy that contributes towards the RPS requirement of being 50 percent renewable by 2040.

Wheatridge renewable energy facility

In 2019, PGE entered into agreements with NextEra for the Wheatridge Renewable Energy Facility in Morrow County, Oregon. The facility consists of 300 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility entered service at the end of 2021, and the solar and storage components began service in 2022. PGE owns 100 MW of the wind resources and entered into a long-term purchase agreement with NextEra for the remainder of the project.

E.1.4 Energy storage

HB 2193 Energy storage

In compliance with HB 2193, PGE submitted its fourth annual report on the progress of its energy storage proposal on September 2, 2022.[446] The report provides evaluation and progress updates of the energy storages: Baldock, Coffee Creek, Microgrid pilot, Port Westward 2 (PW2), Residential Storage pilot (called the "Smart Battery Pilot"), and the controls for the energy storage systems.

As of September 2, 2022, the energy storages have the following status:[447]

- Baldock, 2 MW, undetermined
- Coffee Creek, 17-20 MW, COD in 2024
- Microgrid pilot (Beaverton Public Safety Center), 0.25 MW, operating
- Microgrid pilot (ARC), 0.5 MW, COD in Q1 2023
- Port Westward 2, 5 MW, operating
- Smart Battery Pilot, active program

Salem smart power center (SSPC)

As part of the Pacific Northwest Smart Grid Demonstration, PGE invested approximately $6 million, which was matched by Department of Energy (DOE) and other partner's three-to-one investment, to deploy a 5-MW (1.25 MWh) Li-ion battery inverter system at the Salem Smart Power Center (SSPC). This advanced Li-ion battery system provides uninterrupted power, reactive power (value at risk (VAR) support), and ancillary services. It can also be configured for energy storage for small-scale ancillary services in firming and shaping variable resources, such as solar and wind generation. The SSPC fulfilled a regional and visionary transactive control demonstration project that was co-funded by the US DOE under the American Recovery and Reinvestment Act. The primary contractor was Battelle, with PGE serving as a subcontractor on the project.

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[446] H.B. 2193, 78TH Oregon Legislative Assembly, (2015) https://olis.oregonlegislature.gov/liz/2015R1/Downloads/MeasureDocument/HB2193

[447] A full evaluation of the energy storage updates can be found in PGE UM 1856 PGE Draft Storage Potential Evaluation 2022 Annual Energy Storage Update, September 2, 2022. Available at: https://edocs.puc.state.or.us/efdocs/HAD/um1856had133540.pdf

PGE formally launched the project in 2010 and became fully operative in May 2013. When the demonstration concluded in January 2015, PGE confirmed that project assets are responsive to transactive control. Since the battery inverter system continues to operate as part of PGE's transmission and distribution system. It currently provides a routine automatic under-frequency response in compliance with North American Electric Reliability Corporation (NERC) BAL-003-1.

E.2 Contracted resources

Contracts provide a diversity of energy and capacity to PGE's resource portfolio. This section summarizes the contracts included in this IRP. The hydropower capacity value in this section represents annual average dependable values, not plant capacities.

E.2.1 Mid-Columbia and Canadian entitlement allocation

PGE has a project share of some hydropower facilities on the mid-section of the Columbia River (Mid-C). This means that PGE has proportional rights to the project reservoirs, allowing for energy shaping across hours and days. PGE can utilize these resources to provide ancillary services, including regulation and spinning reserves.

Wells

The Wells Dam is located downstream of Chief Joseph and was completed in 1967. The 10-turbine facility is operated by the Douglas County PUD No. 1 (Douglas Public Utility District). Upon the contractual expiration on August 31, 2018, and per Oregon Public Utility Commission (OPUC) Order No. 14-415, PGE sought to renew all or a portion of the Wells contract if a cost-effective agreement could be reached. PGE reached a new agreement with Douglas PUD for projects through September 30, 2028.

Douglas Country PUD Contract

PGE and Douglas County Public Utility District No.1 signed a five-year power purchase agreement to supply PGE customers with up to 160 MW of additional capacity from the Wells Hydroelectric Project on the Columbia River north of Wenatchee, Washington. The five-year agreement began in January 2021.

Priest Rapids project

The Priest Rapids Project is located downstream of Rock Island and consists of the Wanapum Dam (10 units, completed in 1964) and the Priest Rapids Dam (10 units, completed in 1961). Both facilities are operated by the Grant County Public Utility District (PUD) No. 2 (Grant PUD). PGE has contractual rights to approximately 8.62 percent of each facility through the spring of 2052. The combined annual average dependable capacity of PGE's share is approximately 131 MW, and the expected annual average energy under average hydro conditions is 44 MWa. Both values are prior to PGE's associated Canadian Entitlement obligations as discussed in the following section.

Canadian entitlement allocation

An agreement was entered between the US and Canada in which the US shares a portion of the generation benefits from the Columbia River storage reservoirs in Canada.[448] This agreement for the entitlement benefits ended in 2003 but was extended to 2024. PGE's share of Mid-C projects (Wells, Wanapum, and Priest Rapids) are subject to the Canadian Entitlement Allocation Extension (CEAE) obligations. For the IRP, PGE reflects the Columbia River Treaty by assuming that the CEAE renews after 2024 (or that the net effect of any operating changes after the expiration is approximately the same as if the agreement is renewed). PGE models this as the delivery of on-peak power to Canada.

E.2.2 Pelton, Round Butte, and the Re-regulating dam

As discussed in **Section E.1.2, Hydropower plants**, the Confederated Tribes of the Warm Springs Reservation (Tribes) have a 33.33-percent ownership share of the Pelton and Round Butte plants which included contractual rights to increase their ownership to 49.99 percent at the end of 2021. The Tribes also own 100 percent of the associated Re-regulating Dam (Re-reg Dam, 10 MW, 10 MWa), which PGE operates. PGE and the Tribes entered into an agreement for PGE to purchase the Tribes' shares of Pelton, Round Butte, and the Re-reg Dam through 2040.

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[448] The Columbia River Treaty, ratified in 1964, required the U.S. to deliver one-half of three storage dams to Canada under the Canadian Entitlement Allocation Agreements (CEAA).
Canadian Entitlement Allocation Extension Agreements - April 29, 1997 (bpa.gov)

E.2.3 Wheatridge Energy Facility

PGE entered into agreements with Next Era for the Wheatridge Energy Facility, including long-term purchase agreements for 200 MW of wind, 50 MW of solar, and 30 MW of battery storage. The wind portion of the facility began service at the end of 2020, and the solar and storage components began service at the beginning of 2021.

E.2.4 Bilateral capacity agreements

Bilateral negotiations for capacity resulted in three agreements signed in early 2018.

Bonneville Power Administration (BPA)

PGE executed two agreements with BPA, each having 100 MW of annual capacity, with a five-year term beginning in 2021.

Avangrid renewables

PGE executed an agreement with Avangrid Renewables for 100 MW of seasonal peak capacity during summer and winter, with a five-year term beginning in July 2019.

E.2.5 Additional contracts

Table 108 summarizes additional contract resources in PGE's existing portfolio excluding qualifying facility (QF) agreements, which are covered in **Section E.2.6, Qualifying facility contracts**.

Table 108. Additional contracts by technology, MW[449]

	2023	2024	2025	2030	2035	2040	2043
Solar	311	397	404	453	453	93	93
Hydropower	875	875	875	36	-	-	-
Wind	99	99	99	75	75	-	-
Battery	-	-	-	-	-	-	-

[449] Solar includes green future initiatives, community solar PPA, and PPA. Hydropower includes hydro efficiency upgrades and hydro RPS.

	2023	2024	2025	2030	2035	2040	2043
Storage	4	4	4	4	-	-	-
Total	**1,289**	**1,376**	**1,382**	**568**	**528**	**93**	**93**

E.2.6 Qualifying facility contracts

PGE has contracted to purchase the output of numerous QF projects. The 2023 IRP includes QF contracts executed as of June 02, 2022, up to 601MW during 2023 to 2043. **Table 109** and **Table 110** summarize the QF contracts by technology and year-end capacity.

Table 109. Qualifying facility by technology, MWa

	2023	2024	2025	2030	2035	2040	2043
Solar	108	129	132	132	96	1	1
BioGas	9	9	9	4	4	-	-
Biomass	5	5	5	5	-	-	-
Hydropower	4	4	4	4	2	-	-
Wind	3	3	3	3	-	-	-
Total	**129**	**151**	**154**	**148**	**102**	**1**	**1**

Table 110. Qualifying facility by technology, MW (year-end)

	2023	2024	2025	2030	2035	2040	2043
Solar	471	553	564	564	455	6	4
BioGas	10	10	10	5	5	-	-
Biomass	10	10	10	10	-	-	-
Hydropower	7	7	7	7	3	-	-
Wind	9	9	9	9	-	-	-
Total	**508**	**590**	**601**	**594**	**463**	**6**	**4**

E.3 Customer side

E.3.1 Energy efficiency

PGE has a long history of working with the Energy Trust of Oregon (Energy Trust) to identify and acquire cost-effective energy efficiency measures to help customers reduce their energy use. Oregon is a national leader in capturing energy efficiency through the combined efforts of the Energy Trust, customers, and utilities. **Section 8.2, Additional distributed energy resources, Chapter 8, Resource options**, discusses the long-term energy efficiency savings forecast for the 2023 IRP, and **Ext. Study-II, EE methodology** contains a report from Energy Trust describing their forecasting methodology.

E.3.2 Demand response

In June 2021, the Commission accepted PGE's Flexible Load Plan, which laid out a holistic plan to accelerate flexible load development.[450] In 2022, PGE enrolled 93 MW of available summer demand response (DR) capacity and 63 MW of available winter DR capacity. **Section 6.2.2, Demand response, Chapter 6, Resource needs** describes PGE's current demand response programs.

E.3.3 Dispatchable standby generation

PGE's dispatchable standby generation (DSG) program provides PGE with additional generation capacity by contracting with large nonresidential customers for the right to operate their generation resources for the purpose of providing grid services and averting situations that could lead to power quality problems for the power supply in the local region.[451]

Effective June 1, 2022, Schedule 200 was updated to include battery energy storage resources in addition to the existing generator tariff. The new tariff update enrolls large battery resources for ancillary services in addition to demand response and peak shaving activities. This update is anticipated to add up to 8 MW of enrolled storage in 2023 to support PGE's decarbonization and flexible load objectives.

[450] Order No. 21-158.
[451] Schedule 200, Dispatchable Standby Generation, Issued April 7, 2022, Microsoft Word - 200 22-05 Eff June 1.2022 (ctfassets.net)

As of September 2022, PGE had agreements for approximately 127.8 MW of Dispatchable Standby Generation (DSG) capacity as a low-cost resource (approximately $42/kW-yr., including capital and fixed O&M, 2023$).

E.3.4 Distributed generation

Distributed generation is electrical generation and storage performed by a variety of small, grid-connected or distribution system-connected devices. It can be sited at a customer premise located behind the meter (e.g., rooftop solar or municipal biogas projects) or can be small power producing projects such as qualifying facilities. Distributed generation and storage provide a supply of energy from many sources and may lower environmental impacts and improve the security of supply.

As of February 2023, the In-Service Net Metering program produces approximately 183 MW, in which 53 percent of that capacity comes from rooftop solar facilities. Estimated nameplate capacity of 124 MW come from 47 in-service qualified facilities (QFs). There are 36 MW of nameplate capacity that are not yet producing power but have applied for integration with the grid. Owned resources are included in **Section E.1, Existing resources**, and contracted resources are included in **Section E.2, Contracted resources**.

The other distributed generators include low-impact hydropower, small-scale wind, fuel cells, biogas generators, and combined heat and power (CHP). Most of these are contracted for by PGE and are included in **Section E.2, Contracted resources**.

Appendix F. Load resource balance

This appendix includes information on projected capacity and energy needs in the 2023 IRP before new IRP resources are added (contracted resources that have not been constructed yet, like Clearwater, are included in some cases). In some instances, like the capacity load-resource balance, the data are not used in the IRP and are included for informational purposes only.

F.1 Projected capacity load – resource balance

For the 2023 IRP PGE uses a stochastic model (Sequoia) that targets a seasonal adequacy metric of 2.4 hour of lost load per season to determine resource adequacy need. PGE does not create a traditional load/resource balance capacity assessment as part of the IRP. **Table 111** and **Table 112** present an illustrative view of PGE's capacity need during the summer and winter. The resource values are approximations and should be interpreted directionally rather than as absolutes. This table and methodology are not used for power planning by PGE; for power planning the capacity need value directly from Sequoia is used.

Load and resource approximations are as follows:

- Thermal resources are derated 5 percent for outages and other contingencies (actual outage rates in Sequoia differ by unit and are calculated stochastically). Some thermal resources have different levels of peak generation between winter/summer due to temperatures.
- Wind, solar, DERs, other resources (representing biomass/biogas), and storage resources are estimated used proxy resource unturned ELCC values for year 2026 at the 100 MW increment (for wind and solar the average ELCC of the three proxy sites is used). Actual wind and solar performance will vary since the untuned ELCC values are based on new technology rather than existing resources. Hybrid resources are approximated in the disaggregate. Committed resources, like Clearwater Wind, and 2021 RFP proxy resources, are included in the table.
- Hydro values are approximate, include hydro contracts, and are a combination of nameplate/net values with a derate based on average hydro performance during an outage in the Sequoia model. Actual hydro performance will vary based on water conditions, the hours leading up to the peak event, and other factors.
- Contracts and market are at 100 percent nameplate value.
- Loads represent Reference Case 1-in-2 seasonal peak loads and include the impact of energy efficiency and vehicle and building electrification.

As noted earlier, these tables are an illustrative representation of capacity needs on the PGE system. The capacity need value used in IRP modeling is calculated using the Sequoia model which stochastically simulates millions of possible resource and load combinations and takes portfolio impacts, hourly generation and load profiles, temperature, water year, and other factors into consideration. For more information on Sequoia please see **Section H.3 of Appendix H, 2023 IRP modeling details**.

Lastly, the planning margin shown is back-calculated based on 1-in-2 peak load estimates, the resource estimates as defined above, and the capacity need out of Sequoia. Planning margins vary based on resource assumptions. For example, if we assume lower hydro generation (or lower generation from any resource) that would lead to a lower planning margin. The planning margins from these tables are not directly comparable to planning margins used in other reports and are not used in the 2023 IRP.

F.2 Estimated annual capacity need, MW[452]

Table 111. Estimated load resource balance, summer peak capacity need

All values apprx. MW	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Natural gas	1,698	1,698	1,698	1,698	1,698	1,698	1,698	1,698	-	-
Coal	281	281	281	281	281	281	-	-	-	-
Hydro	970	970	623	623	623	579	579	577	541	406
Solar and wind	658	773	775	777	780	775	777	744	532	531
DERs and DSG	180	197	214	226	240	251	268	337	257	281
Storage	35	311	311	311	311	311	311	297	297	297
Contracts and other	15	15	15	15	11	11	11	4	-	-
HLH Market	-	-	-	-	-	-	-	-	-	-
Total resource	3,838	4,246	3,918	3,933	3,944	3,906	3,645	3,656	1,626	1,515

452 This table is provided in compliance with IRP guideline 4c "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."

All values apprx. MW	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Median peak load	3,776	3,828	3,888	3,948	4,001	4,061	4,124	4,535	5,027	5,316
Sequoia capacity need	344	51	506	568	624	791	1,136	1,647	4,173	4,488
Implied margin	11%	12%	14%	14%	14%	16%	16%	17%	15%	13%

Table 112. Estimated load resource balance, winter peak capacity need

All values apprx. MW	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Natural gas	1,785	1,785	1,785	1,785	1,785	1,785	1,785	1,785	-	-
Coal	281	281	281	281	281	281	-	-	-	-
Hydro	1,063	1,063	683	683	683	634	634	633	593	445
Solar and wind	664	693	693	694	695	685	686	674	595	595
DERs and DSG	134	141	149	155	160	165	171	198	99	104
Storage	22	198	198	198	198	198	198	189	189	189
Contracts and other	117	17	17	17	12	12	12	4	-	-
HLH Market	200	200	150	150	150	150	150	150	150	150
Total resource	4,267	4,379	3,957	3,963	3,964	3,911	3,636	3,633	1,626	1,484
Median peak load	3,580	3,635	3,699	3,766	3,831	3,885	3,954	4,389	4,904	5,197
Sequoia capacity need	55	-	430	502	614	683	1,004	1,461	3,912	3,885
Implied margin	21%	20%	19%	19%	19%	18%	17%	16%	13%	3%

F.3 Seasonal capacity need by Need Future, MW[453]

Table 113. Summer capacity need by Need Future (MW)

	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Low	224	0	364	402	435	579	894	1197	3526	3869
Reference	344	51	506	568	624	791	1136	1647	4173	4488
High	395	136	617	704	786	982	1357	2065	4753	4670

Table 114. Winter capacity need by future (MW)

	2024	2025	2026	2027	2028	2029	2030	2035	2040	2043
Low	0	0	213	285	359	404	708	952	3173	3524
Reference	55	0	430	502	614	683	1004	1461	3912	3885
High	106	0	628	745	864	949	1302	1986	4618	4217

F.4 Projected annual average energy load-resource balance, MWa

Table 115 presents PGE's energy load-resource balance (LRB) given no incremental resource actions (except for energy efficiency) in a linear carbon reduction glidepath. As with the LRB presented in **Section 6.5, Energy need**, the availability of energy from GHG-emitting sources declines through time as a result of GHG constraints. The 'Other PPA + market purchases' category represents market purchases and PPAs with associated GHG emissions. Energy efficiency (EE) actions are included as a resource and reflect cumulative savings beginning in 2023 with adjustments for intra-year deployment and line losses. Forecasted load is the annual average load before incremental EE actions.

[453] This table is provided in compliance with IRP guideline 4c "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."

Table 115. Projected annual average energy load-resource balance, MWa

	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035
Gas	699	697	648	562	498	428	333	287	258	223	194	163	136
Coal	147	134	130	115	91	66	50	0	0	0	0	0	0
Hydropower	180	180	180	180	180	180	180	180	180	180	180	180	180
Hydropower Contracts	338	347	337	244	241	228	183	183	183	181	177	177	177
Wind	348	487	487	487	487	486	479	479	479	479	479	479	479
Solar	103	128	242	241	241	240	239	248	248	247	246	246	245
Other PPA + Market Purchases	659	535	524	413	331	254	197	173	157	145	128	114	95
Energy Efficiency	31	61	91	121	151	181	214	247	282	316	348	379	408
Qualified Facilities (online)	81	81	81	81	80	75	75	75	74	59	51	46	29
Qualified Facilities (not online)	49	70	73	73	73	73	73	73	73	73	73	73	73
Total Resources	2,636	2,722	2,792	2,517	2,373	2,212	2,024	1,947	1,933	1,903	1,877	1,857	1,823
Load	2,352	2,428	2,498	2,576	2,651	2,716	2,781	2,852	2,932	3,012	3,095	3,183	3,268
Energy Surplus/ (Deficit)	-284	-293	-295	59	278	504	757	905	999	1,109	1,218	1,326	1,446

Appendix G. Market capacity study

PGE's resource adequacy model, Sequoia, simulates PGE loads, owned resources, and long-term contracts. The PGE system is modeled as a power island, requiring sufficient owned or contracted resources to meet load every hour. In reality, the PGE system is part of the Western Interconnection. By being part of the Interconnection, PGE can buy and sell power with other entities, optimizing power costs, reducing risk, and potentially using purchased power for resource adequacy.

PGE may be able to buy power on short-term markets from others for resource adequacy needs. However, there may be seasons and hours when buying power is challenging due to competition from other utilities, transmission limitations, and other factors. The Western Interconnection is transforming into a cleaner power system. More wind and solar resources are arriving on the system and thermal dispatchable resources are being retired. New loads are forecasted to arrive from transportation and end use electrification along with high-tech industry (like data centers). As a result, predicting how much power PGE can rely on from the market for resource adequacy in future years is challenging.[454]

To approximate future short-term power market availability during heavy-load hours, the 2023 IRP uses a load-resource balance study for the Northwest region.[455] This study compares existing and committed resources in the Northwest against projected loads and exports to estimate if the Northwest is surplus or deficit in the winter and summer.[456]

G.1 Key input sources and changes

The key study inputs come from the following sources:

- The Power Council's 2021 Power Plan and GENESYS Classic model (as used in the Power Plan) provide the loads, resources, regional power market assumptions (imports from outside the Northwest), and power plant availability assumptions used in the workbook.
- The BPA White Book provides import/export assumptions for the Northwest, the largest being the Columbia River Treaty export.

Compared to the market capacity study in the 2019 IRP Update there have been impactful changes to the assumptions, most notably the usage of climate change model data for load

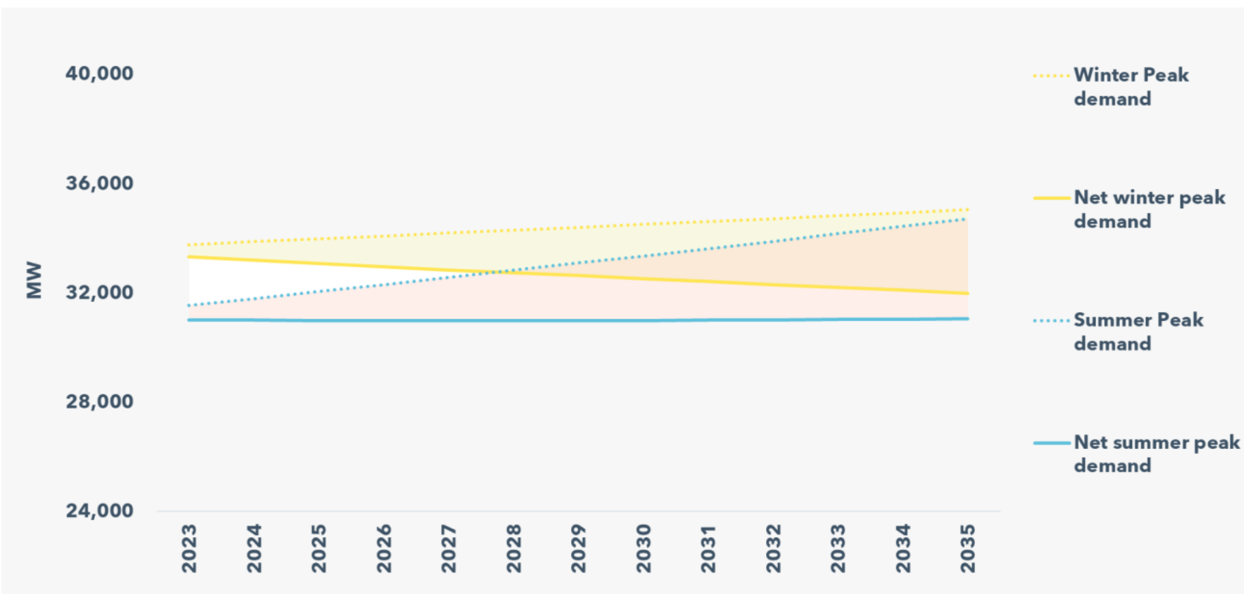
[454] More discussion on the changing west is in **Chapter 4, Futures and uncertainties**.
[455] Heavy-load hours are Monday through Saturday, hours ending 7 through hour ending 22, excluding NERC holidays. Light load hours are all other hours. The Northwest region is roughly ID, OR, WA, and Western MT.
[456] Winter is mid-November through mid-March, and summer is mid-June through September. The workbook used for the analysis originates from the 2019 IRP analysis performed by E3, a consultancy.

and hydropower inputs.[457] These changes lead to higher loads and lower hydropower generation in the summer, and lower loads and higher hydropower generation in the winter. This study indicates that surplus power is available in the winter but not in the summer. This conclusion differs from the 2019 IRP Update analysis that saw zero market power available in the winter Reference Case and limited power available in the summer. The change in findings is largely due to moving to climate change model data.[458]

G.2 Load and demand side resource assumptions

The load assumptions in the study are based on the 2025 load input file to the GENESYS Classic model and uses the average one-hour peak load for winter and summer. Using this starting point, the load scales up and down based on the 2021 Power Plan growth trends. Power Plan data are used to estimate the amount of energy efficiency and demand response in the analysis as well. **Figure 124** shows the load projections (dashed lines), demand side measure impacts (in shading), and net peak loads for this study (solid lines). The winter net load forecast experiences load decay, whereas the summer net load forecast is mostly flat.

Figure 124. Peak load forecasts



457 Load and hydro assumptions are from the Power Council, which switched to climate change data for their 2021 Power Plan.

458 The Power Council has additional discussion on how changing from historical data to climate change data impacted adequacy in their GENESYS classic modeling. Part of that discussion can be found here:https://nwcouncil.app.box.com/s/t40vm814w7qu86uzc00a5jckyofq72zh

G.3 Supply-side resource assumptions

The resources in this study come from the Power Council's resource database.[459] Only existing and firmly committed supply-side resources are in the analysis.[460] Resources are derated from nameplate values to their effective capacity values based on Power Council estimates.[461] One of the most significant adjustments occurs with hydropower, which is derated to its minimum 10-hr sustained peaking level in the climate change record.[462] The supply-side resource capacity contributions for summer and winter 2026 by fuel type are in **Table 116**.

Table 116. 2023 resource capacity contribution (MW)

	Summer	Winter
Hydropower (10-hr)	15,013	21,431
Natural gas	8,782	8,939
Coal	4,429	4,487
Nuclear	1,017	1,035
Wind	2,114	917
Solar	736	544
Other	694	694

One driver of Northwest resource adequacy challenges is coal unit retirements. **Table 117** explores how Northwest coal units are assumed to retire in the next decade. A change to the schedule would impact the study results. There are some changes in assumptions from the 2021 Power Plan in this study as shown in **Table 117**.

Table 117. Major coal power plants in the Northwest

Unit	Study Assumption	2021 Power Plan Assumption
Hardin	Retired	Retired
Colstrip 1	Retired	Retired

459 Additional information available at: https://www.nwcouncil.org/energy/energy-topics/power-supply/
460 Resources assumptions for this analysis were mostly frozen in spring 2022.
461 Additional information available at: https://nwcouncil.app.box.com/s/k12r8hry1ofogeqxgjw8spgnv2n55lvm
462 Ten-hour sustained peak derived from data in the GENESYS model. Compared to the 2019 IRP Update values, there is an extra ~3,600 MW of hydropower in the winter, and ~400 MW less in the summer.

Unit	Study Assumption	2021 Power Plan Assumption
Colstrip 2	Retired	Retired
Boardman	Retired	Retired
Centralia 1	Retired	Retired
N Valmy 1	Offline for NW in 2021	Offline for NW in 2021
N Valmy 2	Retiring end of 2025	Retiring end of 2025
Centralia 2	Retiring end of 2025	Retiring end of 2025
Colstrip 3	Offline for NW in 2030	Retiring end of 2035
Colstrip 4	Offline for NW in 2030	Retiring end of 2035
Bridger 1	Converting to gas	Retiring end of 2023
Bridger 2	Converting to gas	Retiring end of 2028
Bridger 3	Online	Online
Bridger 4	Online	Online

G.4 Import and export assumptions

Beyond loads and resources, the workbook takes key imports and exports into account. Export assumptions are from the BPA White Book. The Columbia River Treaty Canadian entitlement is the primary export in the workbook. Import assumptions come from the Power Council, with resource availability from outside the region (as included in the GENESYS Classic Model) being the primary import (winter only).[463] All Northwest located IPP resources are assumed to be fully available in the winter and are limited to 2,500 MW in the summer. **Table 118** shows import, export, and IPP assumptions in 2023 for winter and summer.

[463] This is often referred to as imports from the Southwest in Power Council analysis. Additional imports could potentially be available depending on the load/resource balance in other parts of the West and transmission expansion to other regions (for example, transmission expansion into Canada could potentially bring more power to the Northwest during certain hours).

Table 118. 2023 imports/exports/NW IPPs (MW)

	Summer	Winter
Imports	16	2,565
Exports	1,564	1,143
NW IPPs	2,500	2,716

G.5 Planning reserve margin assumptions

Planning reserve margins account for operating reserves, load deviations from extreme weather, forced outages (or higher than expected levels of forced outages), and other factors. This analysis uses three planning margins, 10 percent, 12.5 percent, and 15 percent. The three margins set the high (10 percent), reference (12.5 percent), and low (15 percent) market power assumption cases.

G.6 Results

Figure 125 and **Figure 126** show the load resource balance for the Reference Case summer and winter estimates. Note the step down in coal resources following 2025 and 2029.

Figure 125. Northwest summer peak load/resource balance

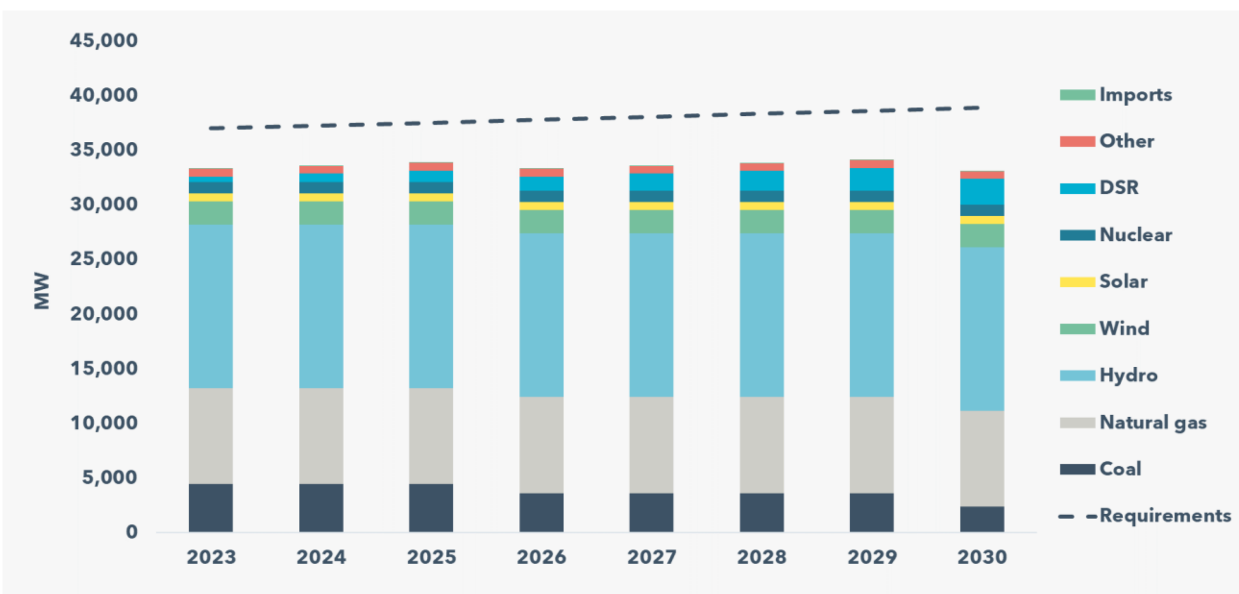
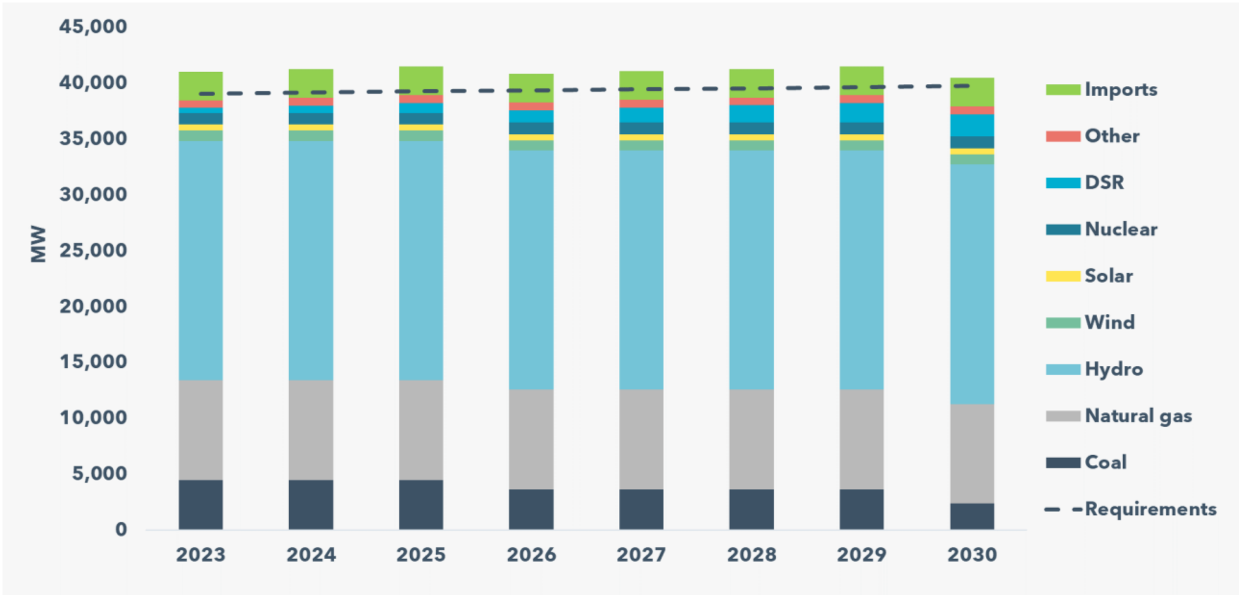


Figure 126. Northwest winter peak load/resource balance



In years with a power surplus PGE is assigned a share of the extra MWs. The share is based on the ratio of PGE's peak load to the Northwest region's peak load – roughly 10 percent. For example, if there is a 1,000 MW surplus, PGE's share is around 100 MW. For simplicity, and due to uncertainty regarding future loads and resources, the surplus values from 2023 through 2025 are averaged together, rounded to the nearest 50 MW, and used as the power market assumption in years 2023 through 2025. The average of the 2026 through 2035 surplus values are used as the power market assumption in year 2026 forward. The resulting heavy-load-hour market assumptions for the Reference Case are in **Table 119** and **Table 120**.

Table 119. Reference case 2023 IRP HLH market capacity

	2023	2024	2025	2026	2027	2028	2029	2030
Ref. Summer (HLH)	0	0	0	0	0	0	0	0
Ref. Winter (HLH)	200	200	200	150	150	150	150	150

The 2023 IRP has three market forecasts, low, reference, and high. They differ by planning reserve margin. The low case (lowest market availability) uses a 15 percent planning margin, the reference-case 12.5 percent, and the high case 10 percent. In all three cases, summer market power is zero. Winter market power availability varies by planning margin and year.

Table 120. High, reference, and low HLH market estimates

2023 IRP	2025 and earlier	2026 forward
High Summer (HLH)	0	0
High Winter (HLH)	300	250
Ref. Summer (HLH)	0	0
Ref. Winter (HLH)	200	150
Low Summer (HLH)	0	0
Low Winter (HLH)	150	50

G.7 Light load hour and shoulder season market assumptions

Unlike the heavy load hour (HLH) assumptions for winter and summer, the light load hour (LLH) and shoulder season assumptions are not based on a supply and demand balance study. For the spring and fall, 200 MW of HLH market power are assumed to be available in all years in the Reference Case. During light load hours in all months and years, a range of market power availability of 999 MW to 400 MW is used. The value declines as load increases (for example, during the highest load days there are 400 MW of LLH market available, during the lowest load days there are 999 MW available).

G.8 Limitations

The Power Council's Power Plans are produced every five years. Resultingly, the data and assumptions that underpin this market power assessment can fall behind the pace of public policy. Additionally, this assessment, a peak hour load/resource balance snapshot, is simplistic and does not take net load, flexibility challenges, transmission, and other factors into consideration. Going forward, PGE will seek more sources of data and more sophisticated approaches for assessing regional power market availability in IRPs and other planning work.

There may be a future opportunity to link IRP power market availability assumptions to work done by the Western Power Pool via the Western Resource Adequacy Program (WRAP). The WRAP was not sufficiently advanced to be used in this IRP cycle. PGE will consider using data from the WRAP to inform the market capacity study in future planning cycles.

Lastly, the estimates from this study are for long-range planning and are not at the detail needed for shorter-term operation applications.

Appendix H. 2023 IRP modeling details

The 2023 IRP relies on multiple models to create forecasts for power prices, emissions, capacity need, energy need, and more. This appendix provides additional detail on those models.

H.1 Aurora

Aurora is electric market forecasting and analysis software produced and maintained by Energy Exemplar. PGE uses Aurora to simulate wholesale electricity prices and resource dispatch. Within the use of Aurora, we use a separate model for each task: a regional WECC model, described in **Section H.1.1, Aurora – WECC model**, and a PGE-zone-only portfolio model (PZM), described in **Section H.1.2, Aurora PGE Zone Model**.

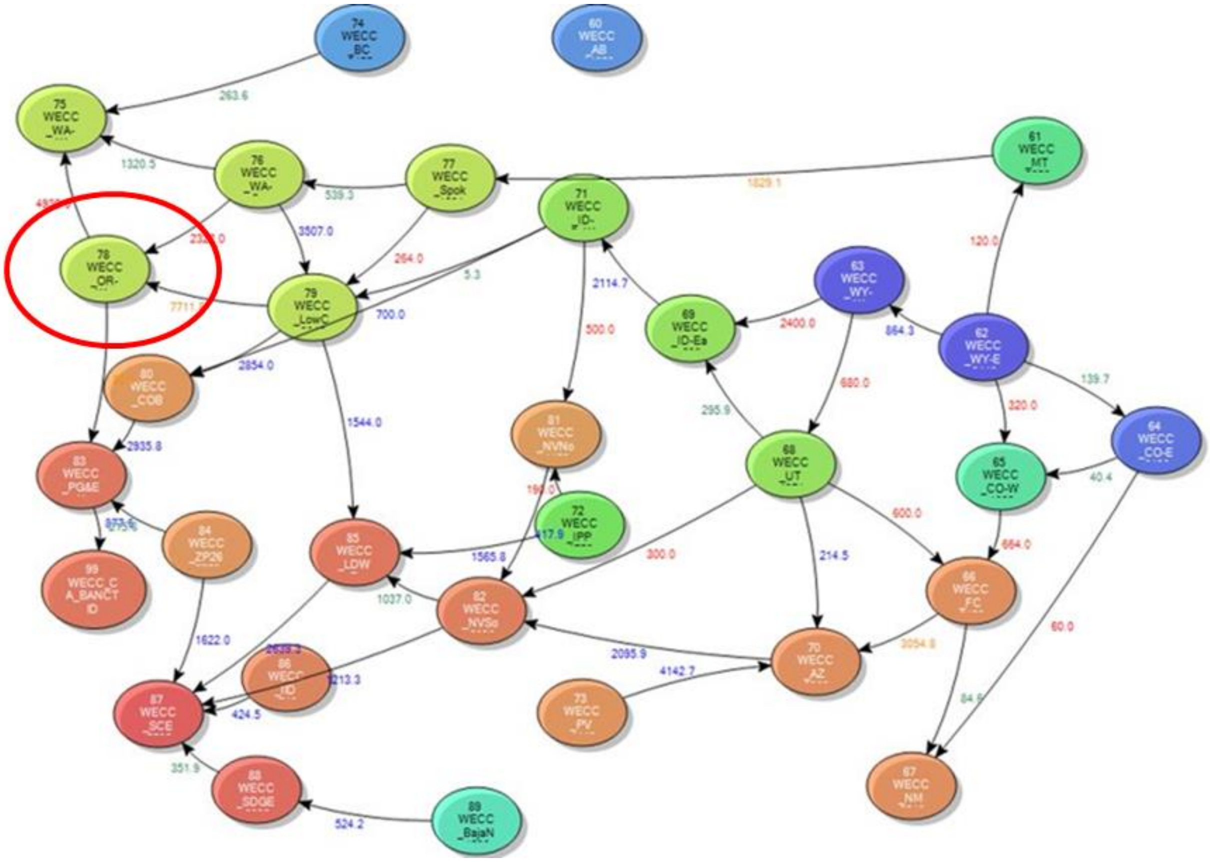
H.1.1 Aurora – WECC model

The Western Electricity Coordinating Council (WECC) model is a regional model provided by the global research consultancy, Wood Mackenzie. PGE input all the assumptions of the 2020H2 WECC model into Aurora as the base case environment for simulation and forecasting. Wood Mackenzie releases long-term forecasts twice a year. PGE updated the wholesale natural gas price forecast with 2022H1 gas price (which was published in June of 2022). In addition to commodity prices, Wood Mackenzie models the following information:

- Load and resources by geographical area. Resources are existing and new additions to meet the forecasted load through 2043.
- Transmission: capacity, constraints, wheeling costs, and carbon hurdle rates. Both existing and transmission lines planned and under construction are modeled.
- Macroeconomic data: environmental costs, inflation, etc.
- Calibration of resource behavior and optimization parameters.

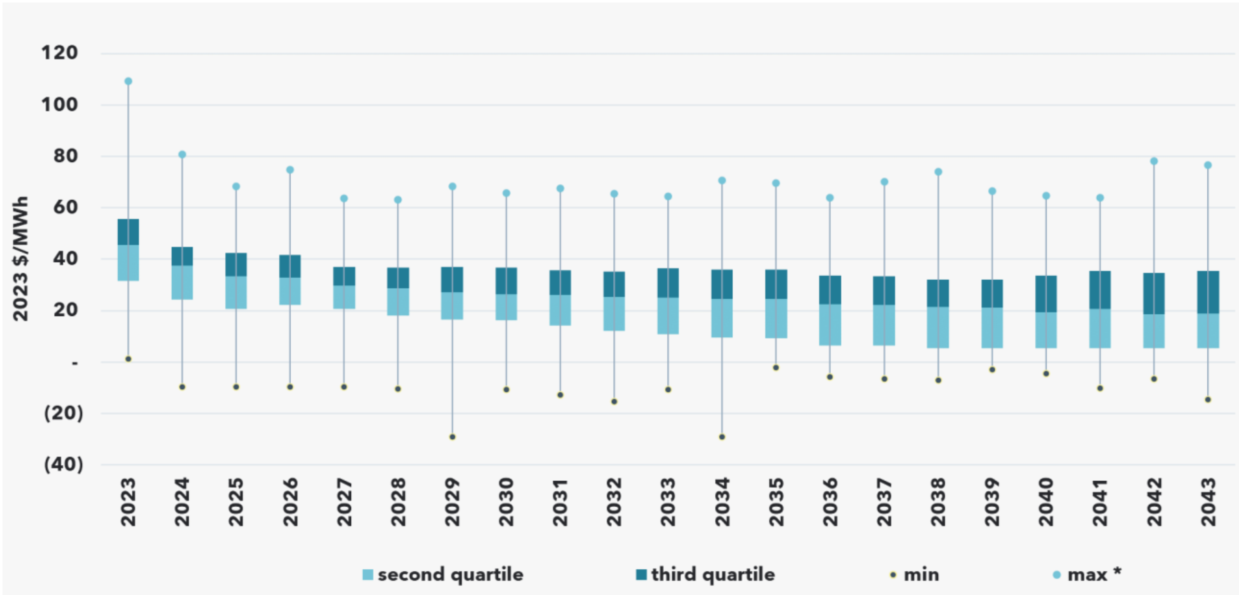
PGE uses the WECC model to forecast hourly electricity prices for the Pacific Northwest. This analysis is a regional simulation where PGE applies Wood Mackenzie's WECC assumptions, such as the growth and reduction of resource technology from 2023-2043, carbon policy, and resource capacity to maintain unbiased input of parameters and resource behavior. **Figure 127** shows the topology modeled in our WECC model: the colored bubbles represent geographical entities for which Aurora forecasts prices, and the lines represent transmission links for imports and exports. The model's objective is to minimize prices for WECC, given constraints on generation and import-exports across zones.

Figure 127. Illustrative snapshot of modeled WECC topology



For this analysis, PGE used Aurora version 14.0.1084 with the algorithmic performance optimizer, GUROBI. We simulated hourly prices from 2023 to 2043 for all areas and multiple futures, where we changed input assumptions. The Pacific Northwest is represented by 6 different areas of which Oregon West (highlighted in red in **Figure 127**), was chosen as best representative of the Pacific Northwest prices overall for PGE. Simulated Oregon West hourly prices for each future are then input in PZM and used to dispatch PGE resources. The Reference Case hourly electricity prices are summarized in **Figure 128**.

Figure 128. Reference case hourly electricity price range by year



To account for market uncertainty and volatility, PGE models three gas price futures (reference, high, and low) to capture a range of possible gas prices. The reference forecast is constructed using these components:

- 2023-2026 prices reflect PGE's 2022 Q2 forward gas trading price curve
- 2027 prices are a linear interpolation of 2026 prices and 2028 prices
- 2028-2043 prices are WM 2022 base long-term price forecast

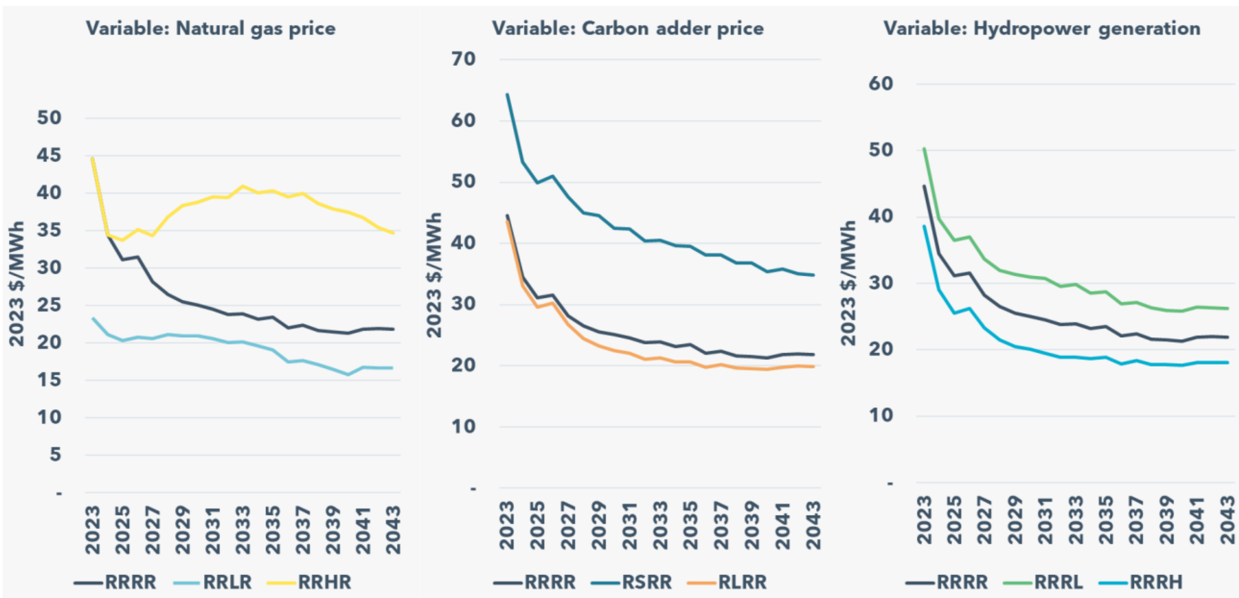
To model low gas price futures, PGE set a natural gas price floor of $2.30 per MMBtu for Henry Hub and applied a proportionate differential basis to other natural gas hubs. This price floor is based on Henry Hub's lowest gas price since 2016, which is approximately $2.30 per MMBtu. Putting a floor of $2.3 per MMBtu approximates a scenario where gas supply has no bottlenecks, and increased exports do not offset the shrinking domestic demand for electricity generation.

The High Gas Price Future applies the highest gas price scenario of the 2021 Annual Energy Outlook (AEO) forecast beginning in 2022. Among the scenarios published for the 2021 AEO, the Low Oil and Gas Supply case results in the highest long-term projection of gas prices. This is an approximation based on the U.S. Energy Information Agency (EIA) assessment of reduced ultimate recovery per well, limited stock of undiscovered resources, and a slow rate of cost-saving technological advancement.

PGE simulated 39 futures by varying four major risk drivers: natural gas prices, carbon price adders, PNW hydropower generation levels, and system commitment/scarcity. The construction of these price futures was discussed in **Chapter 4, Futures and uncertainties.**

The 2023 IRP Reference Case is modeled as a default Aurora setup, reference California Energy Commission (CEC)[464] carbon prices added to carbon-emitting resources in California and Washington and tax carbon prices to carbon-emitting resources in British Columbia and Alberta, reference natural gas price, and reference hydropower generation condition. **Figure 129** shows the impact on the reference prices of the risk drivers that capture commodity and carbon risk: natural gas prices, carbon adders, and hydropower generation. These risk drivers lead to a sustained different price level than the Reference Case and capture a wide range of possible price outcomes.

Figure 129. Wholesale electricity market price comparison between reference and individual variables



In this IRP, PGE added a few futures that proxy a system with increasing demand and supply balancing difficulty. This is because the Western Electricity Coordinating Council (WECC) electricity market transition to largely non-dispatchable resources combined with the still largely unquantifiable impact of climate change on load, wind, and hydro patterns. For these reasons, modeling cannot rely on history or widely adopted methodology. Consequently, PGE employs two Aurora features to incorporate forecast error into an otherwise perfectly balanced system and consider scarcity premiums on prices.

In Aurora, PGE applied the Dispatch Uncertainty table to the Pacific Northwest to mimic operational errors of wind generation forecast and dispatch commitment misalignment. The forecast errors are plus or minus 15 percent of wind nameplate capacity applied randomly to an hour each month. Such a percentage is based on the Wind Integration Study for hour-

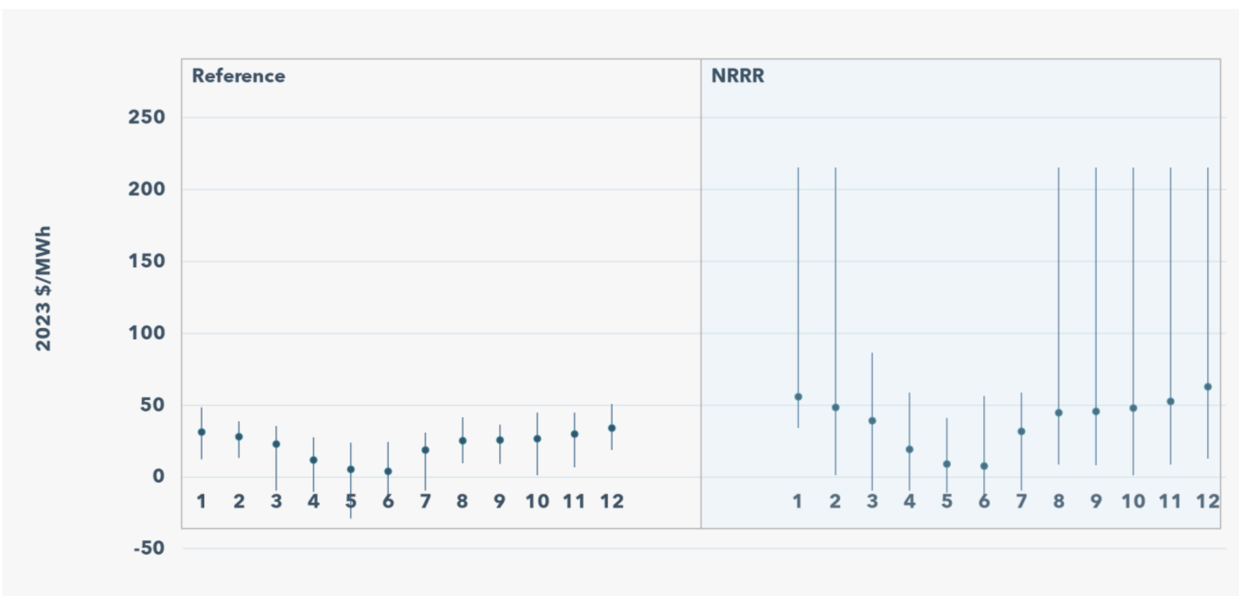
[464] PGE references the California Energy Commission (CEC)'s Integrated Energy Policy Report (IEPR) 2019 carbon price outlook for California. Available at: TN232922_20200506T151733_Adopted 2019 Integrated Energy Policy Report.pdf

ahead wind generation error. This error size is adequate to capture net load shocks. We simulated two futures with this characteristic: one in which all other risk inputs are set as Reference Cases and another future that has high gas prices and low hydro conditions. All other zones in WECC are kept with perfect foresight or no forecast error.

The default Wood Mackenzie database models a cycle of four different wind years, 2016-2019. The same error pattern is applied to the four wind years. The impact on annual average simulated wholesale electricity prices is generally moderate. Still, the volatility triggered by such an error is very different and much higher than the Reference Case, see **Figure 130**. The bar represents the range between minimum and maximum hourly prices for the month of 2031. The dot is the average monthly price.

For many hours, the model could not find resources to meet demand as the spare capacity was not committed and triggered the price cap of $1000 per MWh. The instances of $1000+ prices were so frequent that we reduced the price cap to $250 per MWh in these futures. Capping the price at $250 per MWh reflected the price experienced during the 2000 energy crisis, providing a likely scenario.

Figure 130. Intra-month hourly price volatility with dispatch uncertainty in 2030



Scarcity premium is a significant component of procurement economics. When resource capacity is scarce, the marginal cost of dispatch becomes higher since more expensive resources get dispatched to meet the load. These dispatched resources' associated maintenance and operational costs add to the scarcity premium. Typically, they are modeled in long-term models like Aurora because of their strong dependence on short-term zone-specific conditions. However, PGE agreed with stakeholders in the public process that occasional scarcity might be a characteristic of WECC given the uncertainty both on resource generation and load going forward. PGE proxied such premiums with the startup cost of thermal plants. In Aurora, PGE activated an Uplift Logic in which the startup cost of thermal plants is added to the dispatch cost. This cost is spread across the online hours of the thermal plants and consequently reflected in the electricity prices. We activated this logic for all hubs in the PNW and on-peak hours. This adder does not affect the annual average level of wholesale prices much. Volatility is shown in **Figure 131** for the year 2030, but price caps in this future are not triggered. The bar represents the range between minimum and maximum hourly prices for the month of 2030. The dot is the average monthly price.

Figure 131. Intra-month hourly price volatility with scarcity premiums: year 2030

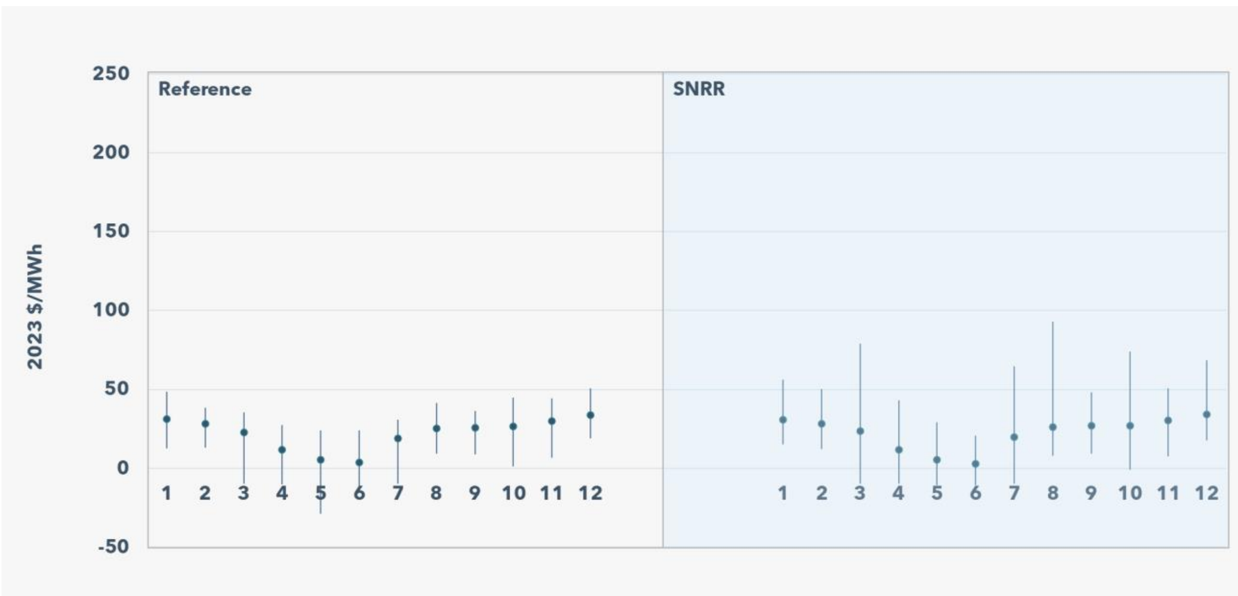


Table 121, **Table 122**, and **Table 123** show the annual average wholesale electricity prices simulated for all 39 futures.

Table 121. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	NRHH	NRHL	NRHR	NRRH	NRRL	NRRR	RLHH	RLHL	RLHR	RLLH	RLLL	RLLR	RLRH	RLRL	RLRR	RRHH
2023	39.2	51.3	45.3	39.1	51.1	45.3	37.7	49.0	43.6	18.5	25.3	22.3	37.7	49.0	43.5	38.7
2024	28.8	39.9	34.5	28.7	39.8	34.4	28.0	37.8	33.1	16.4	23.4	20.0	28.1	37.6	33.1	29.0
2025	27.5	39.1	33.2	25.3	36.6	30.9	26.7	36.8	31.9	15.4	22.4	18.9	24.7	34.1	29.6	27.7
2026	31.3	43.1	37.2	28.0	39.2	33.3	28.6	38.7	33.8	16.2	22.6	19.2	25.5	34.8	30.2	29.6
2027	29.6	41.8	35.6	24.2	35.0	29.5	27.6	37.5	32.7	15.7	22.3	18.9	22.3	30.8	26.7	28.6

Year	NRHH	NRHL	NRHR	NRRH	NRRL	NRRR	RLHH	RLHL	RLHR	RLLH	RLLL	RLLR	RLRH	RLRL	RLRR	RRHH
2028	31.1	44.5	37.5	22.0	33.2	27.7	29.5	39.5	34.7	15.8	22.6	19.2	20.5	28.4	24.5	30.8
2029	31.7	45.6	38.6	20.5	32.1	26.1	30.5	41.0	36.1	15.3	22.3	18.8	19.4	27.1	23.2	31.7
2030	35.3	50.5	42.3	22.5	35.3	28.3	30.8	41.1	35.8	15.1	21.8	18.4	18.8	26.1	22.4	32.5
2031	34.9	50.5	42.4	21.1	35.3	26.8	31.4	42.2	36.8	14.8	21.7	18.2	18.4	26.0	22.0	33.0
2032	33.9	48.9	41.2	20.0	32.3	25.3	31.5	41.8	36.3	14.1	20.7	17.3	17.6	24.9	21.1	33.3
2033	34.2	49.0	41.1	19.3	30.6	24.7	32.6	43.3	37.8	14.3	20.9	17.3	17.7	25.0	21.3	34.4
2034	37.4	51.6	43.8	21.0	32.7	26.2	32.3	42.2	37.1	14.1	20.2	17.0	17.3	24.1	20.6	34.3
2035	36.3	50.5	43.1	21.0	32.4	26.2	32.8	42.1	37.3	13.8	19.4	16.4	17.6	24.1	20.6	34.4
2036	35.0	48.5	41.2	19.1	29.5	23.8	32.4	41.7	36.8	12.9	18.1	15.3	16.9	23.0	19.8	33.7
2037	34.5	47.4	40.7	19.0	28.4	23.5	32.8	42.0	37.3	13.2	17.9	15.4	17.3	23.3	20.2	34.5
2038	36.3	49.9	43.0	20.6	31.1	25.5	31.6	40.6	36.2	12.7	17.6	15.0	16.8	22.7	19.7	33.2
2039	35.0	47.8	41.0	20.0	30.5	24.7	31.3	40.2	35.8	12.2	16.9	14.5	16.7	22.6	19.6	32.6
2040	33.0	45.4	38.8	18.8	28.0	23.2	30.4	39.5	35.2	11.7	16.5	13.9	16.6	22.6	19.4	31.7
2041	31.8	43.9	37.8	18.8	27.9	23.0	30.1	39.2	34.4	12.5	17.3	14.6	17.0	23.2	19.7	31.4
2042	34.2	47.5	40.8	21.6	32.3	26.4	28.7	38.0	33.2	12.6	17.6	14.9	17.0	23.5	19.9	30.2
2043	33.2	45.4	38.6	21.3	31.9	26.7	28.4	36.9	32.4	12.4	17.2	14.6	17.0	23.0	19.8	29.8

Table 122. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	RRHL	RRHR	RRLH	RRLL	RRLR	RRRH	RRRL	RRRR	RSHH	RSHL	RSHR	RSLH	RSLL	RSLR	RSRH	RSRL
2023	50.3	44.6	19.2	26.9	23.3	38.6	50.3	44.6	56.4	72.0	64.4	37.3	48.9	43.3	56.4	72.0
2024	39.7	34.4	17.1	25.2	21.1	29.0	39.7	34.5	46.0	60.5	53.4	34.1	46.1	40.5	45.7	60.4
2025	39.3	33.7	15.9	24.8	20.3	25.5	36.5	31.1	44.4	59.9	52.2	32.8	45.3	39.1	42.4	57.4
2026	41.0	35.1	16.9	24.9	20.8	26.2	37.0	31.5	46.5	61.6	54.5	34.2	46.0	40.3	43.7	57.7
2027	40.4	34.3	16.6	25.0	20.6	23.3	33.7	28.2	45.4	60.8	53.3	33.2	45.4	39.6	40.1	53.9

Year	RRHL	RRHR	RRLH	RRLL	RRLR	RRRH	RRRL	RRRR	RSHH	RSHL	RSHR	RSLH	RSLL	RSLR	RSRH	RSRL
2028	43.4	36.8	16.9	26.2	21.1	21.5	32.0	26.5	47.1	62.0	55.2	33.4	45.4	39.6	38.1	50.9
2029	45.2	38.4	16.3	26.6	20.9	20.5	31.3	25.5	47.9	63.8	56.4	32.9	45.2	39.1	37.2	50.0
2030	46.0	38.8	16.3	26.5	20.9	20.1	30.9	25.0	47.7	63.7	56.0	32.4	44.5	38.4	36.2	49.1
2031	47.1	39.5	15.9	26.5	20.6	19.5	30.8	24.5	49.0	64.8	57.1	32.3	44.4	38.5	35.9	48.5
2032	46.6	39.4	15.4	25.4	20.0	18.8	29.5	23.8	47.7	63.7	55.8	30.5	42.8	36.5	34.1	46.9
2033	48.2	41.0	15.4	25.7	20.1	18.9	29.8	23.9	49.1	65.1	57.2	30.7	42.6	36.5	34.3	46.8
2034	46.6	40.1	15.4	24.5	19.6	18.6	28.6	23.2	48.9	63.8	55.9	30.2	41.6	35.8	33.8	45.7
2035	46.8	40.4	14.9	23.9	19.0	18.9	28.7	23.5	48.9	63.7	56.0	29.7	40.8	35.0	33.9	45.6
2036	46.1	39.5	14.0	22.0	17.5	17.9	26.9	22.0	47.8	63.0	55.6	27.9	39.0	33.5	32.1	44.2
2037	46.0	40.0	14.3	21.7	17.6	18.4	27.2	22.4	47.8	62.4	55.2	27.5	38.3	33.0	32.1	43.8
2038	44.4	38.6	13.8	21.1	17.1	17.8	26.3	21.6	46.2	60.4	53.5	26.5	37.1	31.9	31.0	42.7
2039	43.8	37.9	13.3	20.3	16.5	17.7	26.0	21.4	45.8	59.9	53.0	25.9	36.3	31.2	31.0	42.3
2040	43.0	37.5	12.8	19.5	15.8	17.7	25.9	21.3	43.9	58.7	51.2	24.3	34.7	29.5	29.5	41.6
2041	42.6	36.8	13.5	20.7	16.7	18.1	26.5	21.9	43.3	57.8	50.7	25.0	35.2	30.1	30.0	41.5
2042	41.0	35.4	13.7	20.5	16.7	18.1	26.3	22.0	41.4	55.7	48.5	24.3	35.1	29.6	29.1	40.9
2043	40.1	34.7	13.5	20.3	16.7	18.1	26.2	21.8	41.0	54.5	47.6	24.5	34.3	29.3	29.4	40.5

Table 123. Average annual wholesale electricity prices for PNW by future (2023 $/MWh)

Year	RSRR	SRRH	SRRL	SRRR	SRHR	SRHL	SRHH
2023	64.3	40.7	52.9	47.1	47.2	52.8	40.8
2024	53.3	30.5	41.6	36.4	36.1	41.7	30.5
2025	49.9	26.8	38.4	32.7	35.5	41.3	29.1
2026	51.0	27.5	39.0	33.1	36.6	43.0	31.1
2027	47.7	24.3	35.3	29.6	36.2	42.5	30.1
2028	44.9	22.5	33.4	27.7	38.5	45.4	32.4
2029	43.6	21.4	32.8	26.8	40.3	47.5	33.3
2030	42.5	21.0	32.5	26.2	40.9	48.2	34.0
2031	42.4	20.3	32.1	25.4	41.2	49.1	34.2
2032	40.4	19.6	30.8	24.7	40.9	48.5	34.4
2033	40.5	19.8	31.2	24.9	42.8	50.2	35.6
2034	39.6	19.4	30.0	24.1	41.7	48.5	35.4
2035	39.5	19.6	30.3	24.3	42.1	48.8	35.5
2036	38.1	18.7	28.2	23.3	41.1	48.0	35.4
2037	38.1	19.3	28.2	23.5	41.6	47.7	36.1
2038	36.8	18.7	27.4	22.7	40.6	46.1	34.8
2039	36.8	18.5	27.0	22.4	39.9	45.5	34.3
2040	35.4	18.5	26.9	22.4	39.4	44.8	33.3
2041	35.8	19.0	27.5	22.9	38.4	44.4	33.0
2042	35.0	18.9	27.4	23.0	37.0	42.7	31.6
2043	34.8	19.0	27.2	22.8	36.2	41.8	31.1

H.1.2 Aurora PGE Zone Model

The Aurora PGE Zone Model (PZM) is used to simulate the economic dispatch of existing PGE and candidate new resources. Inputs to the model are:

- Variable costs and operating characteristics of PGE existing resources, power plants, and contracts, generally matching those of the 2022 annual update tariff (AUT) November 15 filing. An exception is planned maintenance and forced outages that represent our best estimate of plant's long-term performance instead of the snapshot of the test year of AUT.
- Fuel prices match those of the WECC model except for Colstrip, for which we have more detailed assumptions
- Carbon dispatch adders matching those of the WECC model
- Electricity hourly wholesale prices for the Pacific Northwest are simulated with the WECC model.

Aurora simulates PGE existing dispatchable generation resources, contracts, and new resources using economic dispatch based on electricity prices and associated risk variable inputs consistent with each price future. When economically dispatched, resources will generate when resource dispatch cost is lower than the electricity market price and will not generate when market purchases are cheaper.

The PZM outputs are sources of inputs to ROSE-E for all price futures across all years. ROSE-E inputs new resources' capacity factor and energy value, existing resources' variable costs and energy value, and existing portfolio's baseline resource costs and baseline net contract costs from PZM, the set of PZM outputs to ROSE-E includes total annual variable costs, annual net market purchases, resource dispatch, and energy value for new and non-carbon emitting resources. The dispatch results of the thermal units in various price futures from the PZM are provided to the Intermediary GHG model, described in greater detail in **Appendix H.2, Intermediary GHG model**.

H.2 Intermediary GHG model

PGE buys and sells power on the wholesale market for various reasons, including risk mitigation and net variable power cost reduction. Incorporating HB 2021 into planning requires differentiating between energy and associated emissions used to serve retail load, and energy and emissions used for wholesale market sales. To accomplish this, the 2023 IRP uses an Excel-based intermediary GHG model.

The intermediary GHG model focuses exclusively on GHG emitting generation. Its objective is to allocate GHG emitting power to retail load service and to wholesale sales. The model takes inputs from:

- Aurora for thermal units, based on economic dispatch and various price futures
- Historical data for market transaction patterns
- The Oregon DEQ for GHG intensity values from emitting sources (tons / MWh)

Using these inputs, the model creates estimates for how much power PGE can retain from each specific source to meet retail load under different GHG constraints. Total power plant dispatch ratios and historical sales patterns determine the amount of each resource retained for retail load service, keeping similar ratios across fuel types. For example, historically, PGE keeps a greater percentage of natural gas generation for retail load service than coal generation. Resultingly, in the model, natural gas generation is kept for retail load service at a higher rate than coal. Inside fuel classes (natural gas, coal, etc.) the ratio of power retained for retail load service is the same across resources. An example of this is in **Table 124**, using power plants Beaver and Carty and focusing on the year 2027. In this example, 77 percent of the plant output for both Beaver and Carty is kept for retail load.[465]

Table 124. Example retail/wholesale energy breakout in 2027

Resource	Total MWh	Retail MWh	Retail %
Carty	2,477,916	1,901,681	77%
Beaver	563,811	432,698	77%

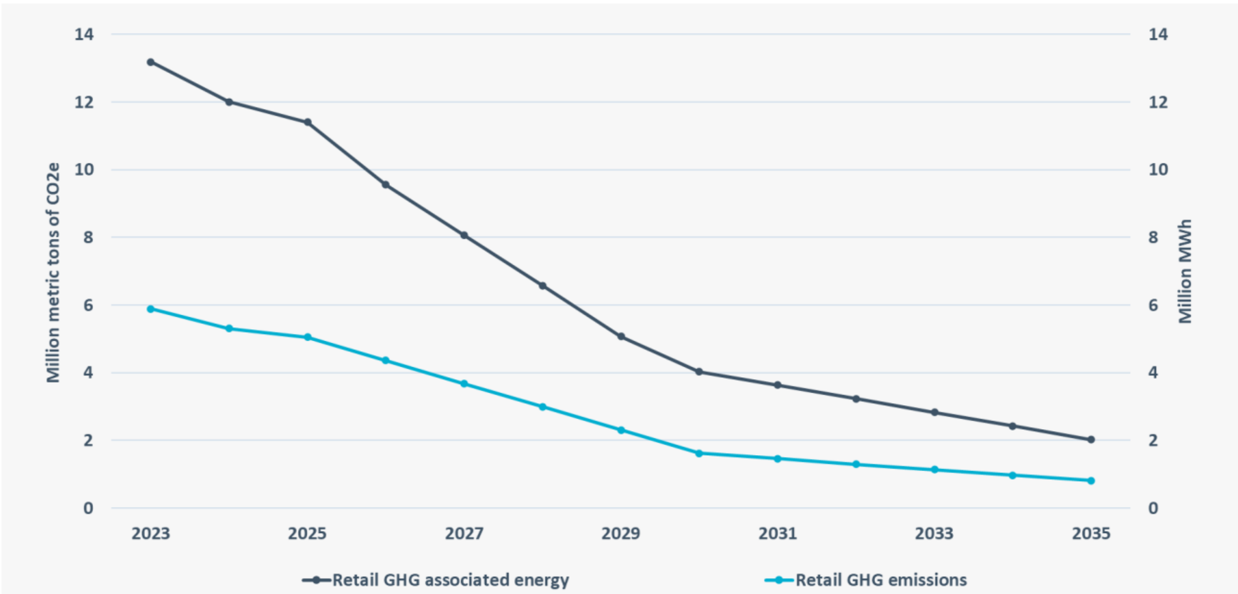
In the example shown in **Table 124**, the total MWh values are determined by the Aurora model, which provides the thermal plant inputs to the intermediary GHG model. The model then reduces the amount of generation retained for retail load (in this case down to 77 percent) while taking other resource emissions and GHG targets into consideration.[466] The generation not retained for retail load is assumed to be sold into the wholesale power market.

The primary output of the intermediary GHG model is the total amount of generation from GHG emitting resources retained for retail load.[467] This information helps set the energy

[465] Example data, actual values used in the IRP may differ.
[466] The 2023 IRP uses five different GHG glidepaths (targets). More information on the glidepaths is in **Chapter 5, GHG emissions forecasting**.
[467] Distributed system generation resources are not in the GHG model or IRP energy position. These resources typically dispatch under emergency conditions. Inclusion of DSG resources at 2022 dispatch levels was tested in the GHG model and resulted in a 2030 annual energy position change of under 0.1 MWa.

position for ROSE-E, the IRP capacity expansion model. An example of this is in **Figure 132** which shows GHG emitting resource energy and emissions retained for retail load service. More discussion on the model is in **Chapter 5, GHG emissions forecasting**.

Figure 132. Retail load GHG emissions and associated energy (Reference Case)



H.3 Sequoia

This section provides a brief overview of the Sequoia model and focuses on changes made to Sequoia since the 2019 IRP Update.[468] For more detailed information about the model, see Appendix K of the 2019 IRP Update.

H.3.1 Overview

Sequoia runs stochastic simulations to test the PGE system for resource adequacy, perform Effective Load Carrying Capability (ELCC) studies, and examine GHG emissions. It pairs different load and resource profiles to test the power system under a wide range of conditions. A typical test simulates 50,000 weeks per season (summer/winter) to provide a

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[468] 2019 IRP update with appendix K at p.75, available at: https://assets.ctfassets.net/416ywc1laqmd/1PO8IYJsHee3RCPYsjbuaL/b80c9d6277e678a845451eb89f4ade2e/2019-IRP-update.pdf

broad set of load and resource combinations. The model runs on an hourly timestep, with 50,000 weeks equating to 8.4 million hours.[469]

The Sequoia model runs each week independently. It starts with an initial draw of seven sequential historical days. From those days, it extracts three key inputs: the month, if the days are a weekday or a weekend, and the daily load bin (the load bin tells the model how high loads are). Using this information, Sequoia builds a synthetic week. The key pieces of the week are:

- Water year, which sets the weekly energy budget and hourly generation max/min for large hydropower projects. The model uses the same water year for the entire week. The water year data come from a historical 30-year record, with the data being specific by month.
- Load profile. The load profile changes daily and aligns with the initial draw data by month, weekday/weekend, and load bin. The load data use 30 historical temperature profiles to create variations.
- Wind/solar profile. The wind/solar profiles, which are independent by project, change daily and align to the initial draw data by month and load bin. Matching the load bin values to the wind/solar profile links temperature to wind/solar generation outputs.
- Thermal generation availability is set using stochastic forced outage rates and mean-time-to-repair inputs. Thermal generation can also vary by month, with higher generation available in colder months due to air density.
- Storage resources start the week 100 percent charged, this a change from the 2019 IRP update that started storage at a 50 percent charge level. Storage resources charge and discharge as needed, with perfect foresight, and are limited to one cycle per day.
- Power market inputs vary by month, time of day, and load bin. More information on power market inputs is in **Appendix G, Market capacity study**.
- Other inputs, like demand response programs and run-of-river hydropower, enter the model via month-hour shapes (which use hourly shapes that vary by month and weekday/weekend) or monthly blocks (the resource output varies by month).

Table 125 visually represents part of the process previously outlined for one week in Sequoia.

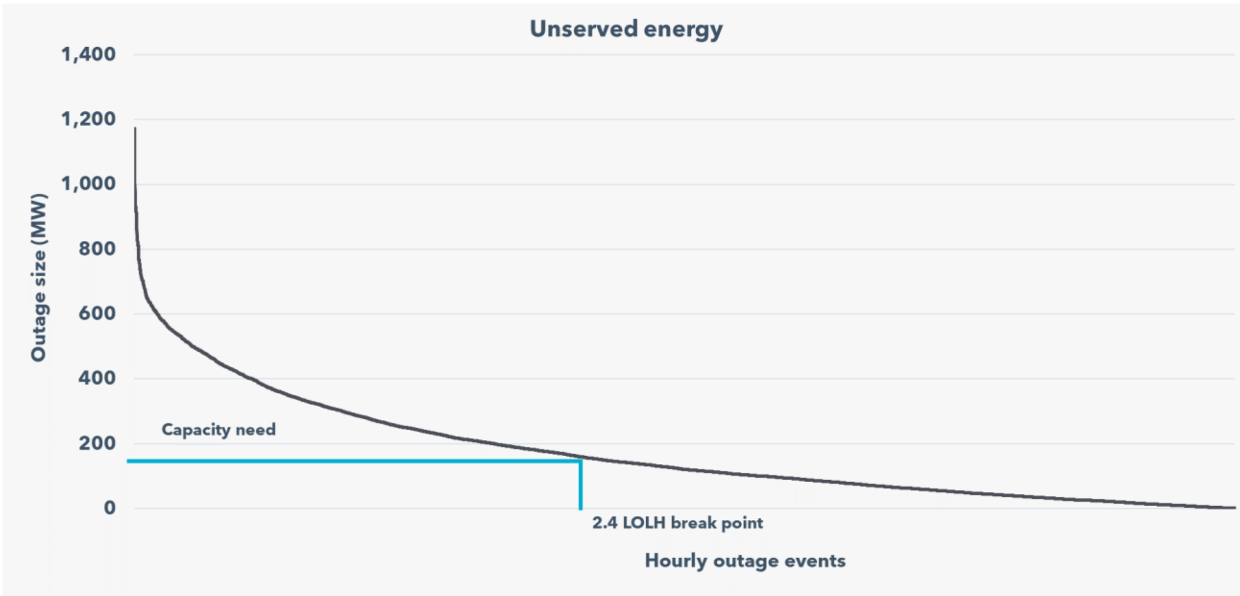
[469] 50,000 weeks are tested per year/season for capacity needs and to establish ELCC values. To reduce model runtime capacity needs in some years after 2030 are interpolated.

Table 125. Sequoia week creation example

Start date	Month	Load bin	Weekday	Water year	Biglow	Bakeoven	Load	Thermal resources
8/5/1997	8	5	1	2003	8/6/2005	8/11/2014	8/30/2007	Resource generation varies by month and by forced outage rate.
8/6/1997	8	5	1	2003	8/25/2016	8/3/2014	8/7/1981	
8/7/1997	8	5	1	2003	8/5/2010	8/10/2014	8/13/1992	
8/8/1997	8	3	1	2003	8/22/2005	8/24/2014	8/30/1991	
8/9/1997	8	4	0	2003	8/1/2005	8/9/2012	8/24/2019	
8/10/1997	8	5	0	2003	8/21/2011	8/26/2011	8/8/1987	
8/11/1997	8	5	1	2003	8/31/2004	8/19/2014	8/18/1981	

As the model runs, it tabulates when outages occur. Each outage enters a loss-of-load log, ranking outages from largest to smallest. The model then calculates the number of outage hours allowable to meet the 2.4 Loss of Load Hours (LOLH) target. It finds this value on the x-axis and outputs the corresponding capacity value on the y-axis. This value is the effective capacity needed to achieve an adequate system. If the system is already adequate, the value is zero. An example of this calculation is in **Figure 133** – in this case, the system needs around 200 MW of capacity.

Figure 133. Sequoia capacity need calculation example



PGE uses the Sequoia model to calculate resource ELCC values, using the following steps:

- The model runs once to establish a base system capacity need
- The model runs again with a new resource added and produces a new capacity need
- The difference in capacity need between the base system and the system with the new resource added determines how much effective capacity the resource contributes
- The effective capacity value is divided into the resource nameplate value to calculate the ELCC

This approach is similar to how the Northwest Power and Conservation Council determined resource capacity contributions in the 7th Power Plan (the Council calls this approach associated system capacity contribution or ASCC).

H.3.2 Sequoia input model changes since the 2019 IRP Update

Updates have been made to the Sequoia data inputs since the 2019 IRP Update. Select updates are in **Table 126**.

Table 126. Select input related Sequoia changes since 2019 IRP Update

Item	Update
Pelton/Round Butte	Hydropower contract renewed
Core load forecast	Updated spring 2022
Electrification loads	Updated summer 2022
Temperature years	Year 2021 included
Existing western solar profile	Updated with NREL data
Forced outage rates	Updated spring 2022
Qualifying facilities online	Updated spring 2022
DER inputs	Updated summer 2022
Power market availability	Updated market analysis
Run-of-river hydropower	Updated with BPA/Corps data
2021 Proxy RFP portfolio	Included

H.3.3 Other Sequoia model changes since the 2019 IRP Update

Since the 2019 IRP Update, Sequoia has undergone several non-input-related changes. They include:

- Running the model seasonally rather than annually. A seasonal ELCC provides more information for resource additions during portfolio analysis. With many resources, ELCC values differ by season. Using a seasonal approach can help ROSE-E, the capacity expansion model, better evaluate resource options and resource adequacy on a seasonal level. For example, Gorge wind tends to have higher ELCC values in the summer than winter. Resultingly, ROSE-E may see more value from Gorge wind if summer capacity needs are more prevalent than winter, and less value if winter needs are more prevalent than summer.

- Running the model to analyze GHG emission. Via an approach suggested by E3, a consultancy, Sequoia can provide insights into GHG emissions on the PGE system. **Appendix I, C-level analysis** discusses how the model runs for GHG emissions.
- Starting storage resources fully charged at the start of the week. More discussion regarding this change is in **Appendix J, ELCC sensitivities**.

H.4 ROSE-E

ROSE-E is a capacity expansion model that identifies resource additions across potential futures and years using information about PGE's capacity and energy need, operational and regulatory requirements, the current portfolio of resources, and technical and economic characteristics of new resource options. ROSE-E will select a portfolio of resources that satisfies the constraints imposed while minimizing the chosen objective. A full description of the model parameters and mathematical implementation can be found in Appendix I of the 2019 IRP.[470] This appendix focuses on changes and improvements made to ROSE-E since the 2019 IRP.

PGE has approached portfolio design in this IRP as a one-stage process where optimization and scoring have been combined into a single process that is focused on building a portfolio that allows PGE to comply with HB 2021. The previous IRP used a two-stage approach to create a variety of near-term portfolios based on alternative objective functions while minimizing Net Present Value Revenue Requirement (NPVRR) over the study period for any given near-term build.

H.4.1 Input data

Changes and improvements have been made since the 2019 IRP to methodology associated with some of the inputs that ROSE-E receives from other PGE models.

Existing resources

The source of information on PGE's existing resources has evolved since the 2019 IRP because of the new planning paradigm associated with HB 2021. To forecast PGE's future energy position, ROSE-E utilizes a load-resource balance (LRB) model (**Section 6.5, Energy need**). Energy from non-GHG emitting resources in the LRB is determined by estimated capacity factors. Energy from thermal plants and GHG-associated market purchases are

[470] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

estimated using the Intermediary GHG model. More information in **Section H.2, Intermediary GHG model**.

Baseline portfolio

Total variable costs and annual net market purchases for the Baseline Portfolio are generated by the Aurora PGE Zone simulation and factor into portfolio costs and energy-related constraints in ROSE-E. To follow the established DEQ emission methodology, market sales and market purchases are estimated using data from Aurora in conjunction with the Intermediary GHG model, which is used to determine the amount of GHG-associated energy that is retained to serve Oregon retail load, and how much is available for wholesale market sales.

Temporal granularity

The temporal granularity of certain inputs has been increased to add realism to model assumptions or provide additional modeling flexibility.

Resource adequacy

To foster reliable portfolios, ROSE-E utilizes data from Sequoia that defines the amount of accredited capacity needed to maintain a reliable system, which is defined as LOLE of 2.4 hours per year (see **Chapter 6, Resource needs**). In the 2019 IRP, capacity need data was defined at the annual level.[471] To capture the difference more accurately in system needs throughout the year, the capacity need is calculated seasonally (summer and winter) in Sequoia. ROSE-E must build sufficient resources to be adequate in both seasons. Effective Load Carrying Capability (ELCC) of new resource options is also calculated seasonally in Sequoia.

Flexibility value

Flexibility values have previously been static throughout the study period and can now vary across all years of the analysis. Flexibility value of storage resources was calculated for years 2026 and 2030. In ROSE-E the 2026 value is linearly interpolated for the years 2027 - 2029, and the 2030 value is linearly interpolated from 2031 – 2043. See **Ext. Study-IV, Flexibility study** for a detailed description of flexibility values.

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[471] In the matter of Portland General Electric Company, 2019 Integrated resource plan, Docket No. LC 73, Order No. 20-152, available at: https://apps.puc.state.or.us/orders/2020ords/20-152.pdf

New types of resource options

Portfolio analysis in the 2023 IRP includes three types of resource options that have not been included in previous IRPs. The following describes these new types of resource options.

Non-cost-effective EE and DR

As in the 2019 IRP, cost-effective Distributed Energy Resources (DERs) are accounted for as reductions in forecasted load, as described in **Appendix D, Load forecast methodology**. In this IRP, Energy Efficiency (EE) and Demand Resources (DR) that do not meet the cost-effectiveness criteria have been added as new resource options to be considered for selection by the model alongside supply-side options in portfolio analysis.

CBREs

Three types of community-based renewable energy (CBRE) resources are included as resource options in portfolio modeling. More information about CBREs is provided in **Section 7.2, Community-based renewable energy (CBRE)**.

Transmission expansion

Three options to expand transmission capacity are available for selection in the model. These options are described in detail in **Section 9.4.1, Proxy transmission options identify transmission need.**

Generic Resources

The model has access to two generic non-emitting resources (Generic Capacity and Generic VER). These resources give the model sufficient access to energy and capacity to meet system needs that would otherwise be infeasible in a transmission-constrained environment. The generic resources are priced slightly higher than the most expensive supply-side resource available to the model.

H.4.2 Constraints

In addition to the four constraints identified in the 2019 IRP, constraints have been added to accommodate new planning requirements or issues of increasing relevance.

Emissions

All ROSE-E portfolios are subject to an GHG emissions constraint that limits portfolio emissions to levels that comply with HB 2021 emissions targets. Except in the case of portfolios designed specifically to test the impact of alternative GHG reduction glidepaths, emissions targets are defined using the linear glidepath (**Section 5.3, Components of IRP emissions reporting**). The generation from existing PGE thermal plants made available in ROSE-E is limited to levels that produce emissions up to the levels associated with HB 2021 targets each year. The allocation between plants is determined by economic dispatch up to the emissions limit in each price future (**Section 5.3, Components of IRP emissions reporting**). Because the GHG budget is fully utilized up the GHG emissions reduction glidepath with the dispatch of PGE-owned thermals and GHG-emitting contracts/market purchases, gaps between energy needs to serve retail load and energy allowed to serve it must be made up through the building of new non-emitting resources, without the option to utilize market purchases beyond what is accounted for in the Intermediary GHG emissions model.

Transmission

A new constraint imposes limits on transmission availability to move energy from new off-system resources to PGE's system. Previous IRPs assumed all proxy resource builds would be able to deliver their energy to PGE's system. In the 2023 IRP, we incorporated the current contractual transmission landscape by assigning an inventory of transmission availability for each resource that limits the total quantity of each resource that can be built. Resource inventories are quantified in MWs of available transmission capacity (ATC) defined by zones, with cross-zonal impacts accounted for in the calculation of inventory quantity. Therefore, resource builds within a given zone do not impact the availability of transmission in other zones.[472] Resource transmission zones and the methodology used to determine available transmission inventories are described in **Section H.7, BPA transmission in ROSE-E**.

Each resource zone has an inventory of available firm transmission and an inventory of conditional firm transmission availability.[473] On-system resources do not have transmission limitations and do not impact the inventories of other resources.[474]

[472] For example, Gorge Wind and Wasco Solar are both in the Gorge transmission zone, which has 190 MW of LTF ATC. So, building 1 MW of either Gorge Wind and Wasco Solar reduces the LTF ATC of the Gorge zone to 189 MW, but does not impact the ATC of either a) the ATC of other transmission zones or, b) the CF ATC of the Gorge zone.
[473] Resources available with firm transmission generally have higher ELCC values than those with conditional firm transmission (as described in **Appendix K, Tuned system ELCCs**).
[474] Storage resources and CBREs are considered on-system.

H.5 LUCAS

H.5.1 LUCAS – Levelized fixed-cost revenue requirement tool

The Levelized Utility Cost Aggregator System (LUCAS) is a tool used to calculate revenue requirements for the fixed costs of new supply-side resources and PGE-owned resources. LUCAS is an Excel-based model. Significant inputs to LUCAS include:

- Financial assumptions. PGE's cost of capital required return, long-term inflation, tax rates (federal, state, and property), federal investment tax credits, and the Modified Accelerated Cost Recovery System (MACRS) schedule.
- PGE-owned resources. PGE's book and tax depreciation, economic life, deferred tax, fixed O&M, scheduled capital additions, and fixed gas transportation costs.
- Supply-side resources. Includes overnight capital costs, fixed operations & maintenance (O&M), project life, decommissioning costs, and plant operating parameters. As applicable, LUCAS captures fixed costs for gas transportation and wheeling.

For a given resource, LUCAS calculates the total fixed costs for each year, the net present value of those costs across the project's life, and the real-levelized cost. Outputs from LUCAS include real-levelized fixed costs for each resource option by commercial operation date (COD) and capital cost trajectory. These data are passed to ROSE-E for determination of the fixed component of portfolio costs and evaluation of resource economics.

H.5.2 Long-term financial assumptions

As required by Guideline 1a of Order No. 07-002, PGE's estimated after-tax marginal weighted average cost of capital of 6.25 percent serves as a proxy for the long-term cost of capital to discount future resource costs. PGE bases this estimate on information available as of Q1 2022. **Table 127** contains other relevant financial assumptions.

Table 127. 2023 IRP long-term financial assumptions

Component	Percent
Composite Income Tax Rate	27.5%
Incremental Cost of Long-Term Debt[475]	3.9%
Long-Term Debt Share of Capital Structure	50.0%

[475] The incremental cost of long-term debt is based on an average of three-year forward 30-year borrowing costs as of March 2022 (i.e., the cost of 30-year debt in 2022, 2023, and 2024).

Component	Percent
Common Equity Return	9.5%
Common Equity Share of Capital Structure	50.0%
Weighted Cost of Capital	6.7%
Weighted After-Tax Discount Rate	6.2%
Long-Term General Inflation	2.1%

H.6 Annual Revenue-requirement Tool (ART)

The Annual Revenue-requirement Tool (ART) is an Excel-based tool used to estimate the annual revenue requirement ($'s) and the normalized annual revenue requirement ($/MWh) impact for a set of portfolios. ART was developed in addition to ROSE-E and the differences between the two models are listed in **Table 128**.

Table 128. Differences between ROSE-E and ART

	ROSE-E	ART
Costs:	Existing and new resource related fixed, variable, and integration costs based on 100% PPA assumption	Existing and new resource related fixed, variable, and integration costs based on different ownership structures
Benefits:	Includes all resource benefits such as - energy value, flexibility value, RCBI	Only includes monetary benefits of wholesale market sales when generation is higher than load
Other:	All values are expressed in levelized terms which may not reflect actual yearly costs due to ownership structure and tax credit implications	All values are based on expected impact each year of the planning horizon, and are representative of the cost changes associated with existing and incremental generation

Figure 134 and **Figure 135** show a simplified version of the governing equation within ART to assess the annual revenue requirement or price impact.

Figure 134. Estimating the annual price impact ($)

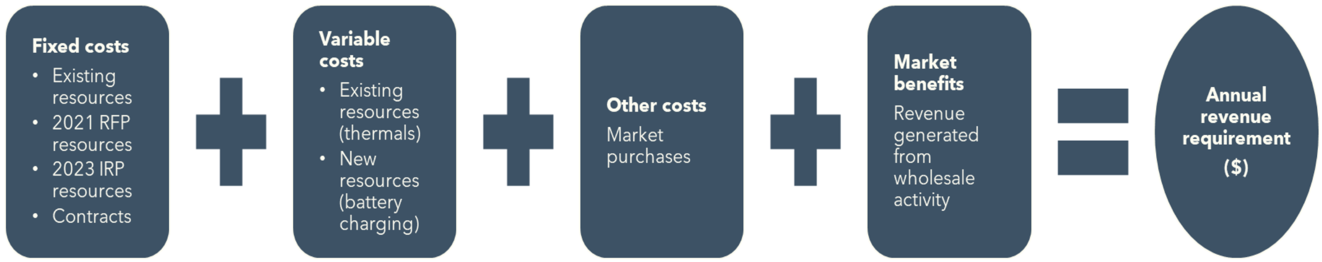
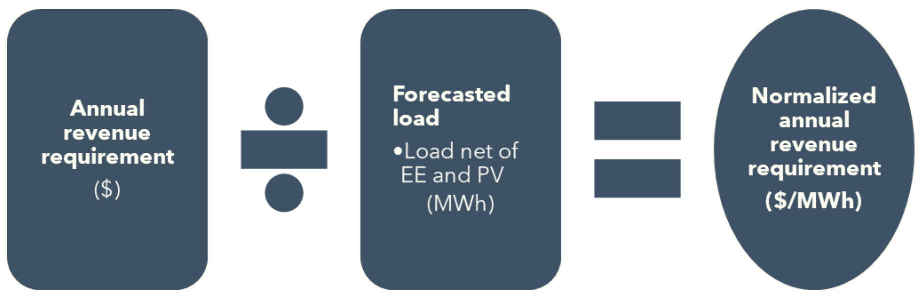


Figure 135. Estimating the annual normalized price impact ($/MWh)



Each component of **Figure 134** and **Figure 135** along with their corresponding source is detailed in the following:

- **Fixed costs** in ART represent the aggregate impact of fixed costs stemming from each of the following:
  - Existing resources – The fixed costs of existing resources include costs such as the capital carrying costs, depreciation, taxes, demand response program cost, and costs of Energy Trust programs. These are aggregated and sourced from the LUCAS model (**Section H.5, LUCAS**).
  - Contracts – Cost of Qualifying Facilities are calculated on a $/MWh basis within Aurora and included within ART. Additionally, costs of other contracts are aggregated and sourced from LUCAS.
  - 2021 RFP proxy resources – For the 2021 RFP, costs of PGE's Clearwater Wind project are included from 2024. Costs of the remainder of the 2021 RFP start in 2025 and are estimated through proxy solar and battery resources. PGE assumes 100 percent PPA for these resources.
  - 2023 IRP – The magnitude and timing of resources is sourced from ROSE-E (**Section H.4, ROSE-E**), while cost streams for both ownership and power purchase agreement (PPA) assumptions are sourced primarily from LUCAS.

- **Variable costs** in ART include the cost of running thermal units which primarily include fuel costs and the cost of charging batteries. Both of these costs come from the Aurora PGE zone model (PZM).
- **Other costs** include purchases PGE makes from the spot market for both specified and unspecified sources. These are calculated within the intermediary GHG model (**Section H.2, Intermediary GHG model**).
- **Market benefits** represent the benefits from wholesale sales which are calculated in part within the intermediary GHG model and through the load resource balance output from ROSE-E. These benefits are calculated yearly using yearly average prices.
- **Forecasted load** represents the load in MWh net of load reducing DERs including energy efficiency and rooftop solar.

The limitations of and assumptions used in ART are as follows:

- ART only include generation related costs and does not include costs from the rest of the company such as grid modernization, administration & general (A&G), wildfire mitigation, or PGE transmission & distribution costs. Additionally, generation costs include both actuals and proxy costs. Proxy costs and associated operating characteristics may not be reflective of costs or project capabilities seen in future RFPs. Thus, ART does not reflect actual or expected customer prices and applying percentages to these changes will not represent actual customer price changes over time. Instead, ART provides directional impact of resource actions and another dimension when comparing portfolios.
- All costs are noted in nominal terms
- Yearly prices are highly sensitive to assumptions of generic resources costs
- Results are specific for the Reference Case scenario (reference need, reference prices, reference cost future)
- Assumes Colstrip exit in 2029
- Assumes the following Reference Case conditions:
    - Ownership – 50 percent PPA and 50 percent PGE ownership of all new resources and 100 percent PPA for the remaining 2021 RFP proxy resources. This impact affects tax credit allocations and payment schedule.
    - Energy efficiency and demand response costs are not securitized or financed, and impact customer prices in year one.
    - All tax incentives are monetized.

H.7 BPA transmission in ROSE-E

Through engagement with stakeholders, it was determined that PGE would incorporate transmission-related assumptions and modeling in this 2023 IRP. Availability of capacity on BPA's transmission system was included as a resource build constraint in ROSE-E. The amount capacity available on BPA's system was quantified through a review of BPA's published TSR Study and Expansion Process reports (TSEPs) from 2016-2021.[476] BPA has stated that TSRs made starting in 2022 will only be granted service once upgrades are complete.[477] Transmission capacity on BPA's system that is subject to upgrades is not included in the calculated available inventories.

TSRs (Transmission Study Requests) made prior to the 2022 TSEP that point to PGE's system were used to quantity the availability of BPA transmission to access PGE's system, according to the following criteria:

- Requested transmission service associated with TSRs in 'study' status are categorized as available conditional firm (CF) transmission.
- Requested transmission service associated with TSRs in 'confirmed' status are categorized as available long-term firm (LTF) transmission.

This inventory is used in ROSE-E as a constraint on the quantity of resource that can be built in different resource zones, as described in **Section H.4.2, Constraints**. Available inventory by zone used in ROSE-E is shown in **Table 129**, and the resource zone of each proxy resource is shown in **Table 130**.

[476] Available at: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep

[477] With the exception of 80 MW of transmission capacity for offshore wind BPA identified in the 2022 TSEP as available without upgrades, which is included in ROSE-E transmission inventories (**Table 129**).

Table 129. Transmission ATC by Resource Zone

Resource Zone	LTF	CF	Total
Christmas Valley	490	510	1000
Gorge	190	388	578
McMinnville	10	0	10
Montana	0	0	0
Offshore	0	80	80
SE Washington	0	150	150
Total	690	1128	1818

Table 130. Transmission Zones of Proxy Resources

Transmission Zone	Proxy Resource
Christmas Valley	Solar_CV
Christmas Valley	CV_Hyb_1
Christmas Valley	CV_Hyb_2
Gorge	Wind_Gorge
Gorge	Solar_Wasc
McMinnville	Solar_Mcm
McMinnville	MCMN_Hyb_1
McMinnville	MCMN_Hyb_2
Montana	Wind_MT
Offshore	Wind_Off
SE Washington	Wind_SEWA

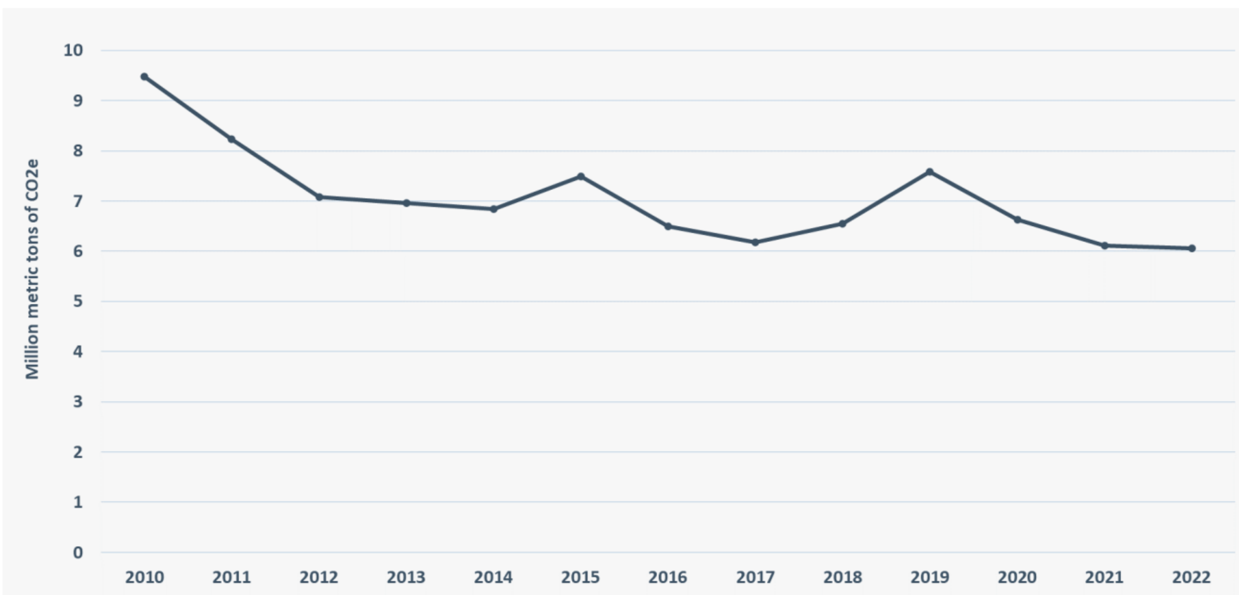
Appendix I. C-level analysis

This appendix discusses how GHG emission levels can vary on an annual basis due to weather, hydro conditions, and other factors. It starts by looking at historical variations, and then includes an analysis on potential variations in 2030 using the IRP Preferred Portfolio.

I.1 GHG variability in power systems

Figure 136 shows historical PGE system GHG emissions for retail load service from 2010 through 2022. In the historical data, there are annual variations in GHG outputs. These annual variations are often due to factors outside the control of PGE, like regional hydroelectric generation levels, and different weather patterns that impact temperature as well as wind/solar generation.

Figure 136. Historical PGE GHG emissions for retail load



Under HB 2021 PGE must emit 1.62 million metric tons of CO2e or fewer in 2030 for serving retail load, 0.81 MMT or fewer in 2035, and zero in 2040. A challenge in planning for the emissions targets is incorporating annual GHG emission variations. For example, in year 2030 PGE may have a power system that emits 1.62 MMT of CO2e under average conditions. But the same system may emit more GHGs under extreme temperature conditions. This is due to extreme temperatures typically requiring more electricity for heating and/or cooling needs, and the extra power likely coming from a GHG emitting resource. On the other hand, a year with mild weather may see lower GHG emissions due to decreased demand. Hydro conditions also play a role in GHG emission variations. In years with higher-than-average hydropower generation there may be a reduced need to operate GHG emitting resources, and in lower hydropower generation years the need for GHG emitting generation may increase.

The Oregon Public Utility Commission (OPUC) has stated that utilities should "achieve the 2030 and 2035 clean energy targets under typical or expected weather and hydro conditions…"[478] This implies that system emissions may be higher or lower than the GHG targets due to variability, but on a one-in-two basis meet the targets. To better understand the range of GHG emissions due to temperatures and hydro variations, PGE performed a GHG variability assessment as part of the IRP. This is called a carbon-level, or C-level, analysis in the IRP.

The GHG variability assessment focuses on the annual impact of hydro and temperature variations on GHG emissions. It does not account for variability outside of temperature and hydro conditions, nor does it account for temperature and hydro excursions outside of the historical range. While it provides insight into GHG variations, actual system variations may differ.

The assessment has four steps:

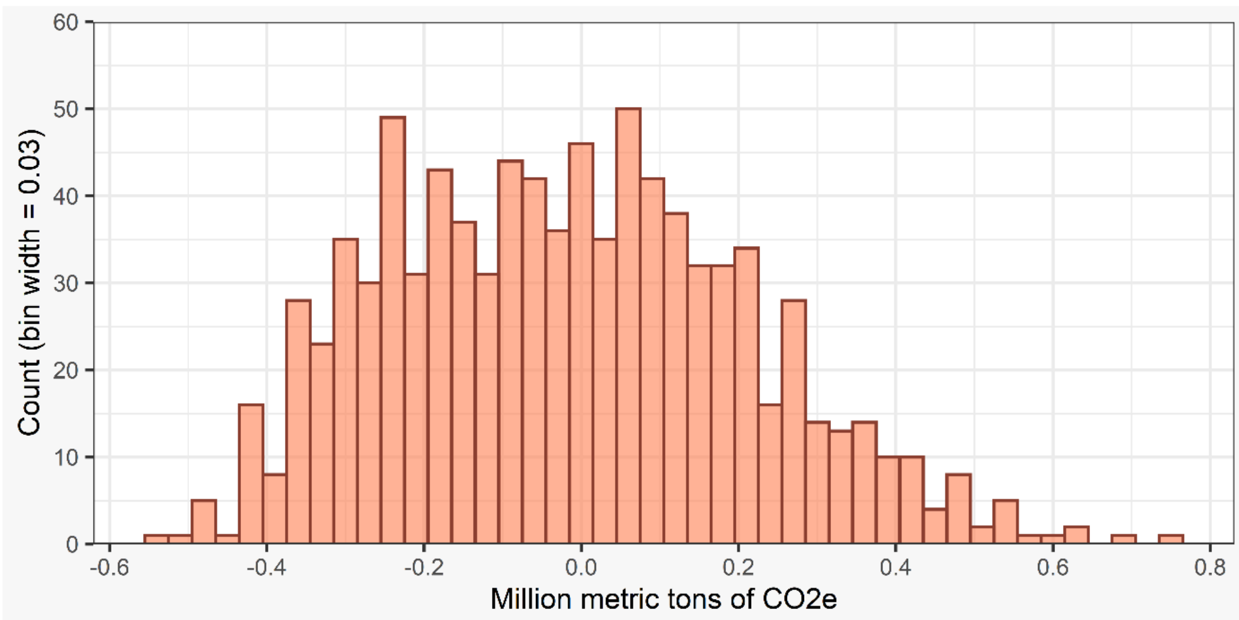
1. The Sequoia model estimates annual GHG variability from temperature utilizing its hourly dispatch logic and catalog of 30 temperature years. Based on a recommendation from consultant E3, Sequoia runs without thermal resources when performing this estimate to achieve GHG-free resource optimization. With thermal generation removed from the model, there are many hours in which load (demand) cannot be served by available generation (demand). These quantities of deficit are defined as unserved energy.
2. The MWhs of unserved energy in Sequoia are assumed to be met with GHG-emitting generation. The analysis assumes that this GHG-emitting generation has an intensity rate of 0.385 metric tons/MWh.[479] Annual GHG emissions are estimated by multiplying the MWhs of unserved energy in Sequoia by 0.385 tons/MWh. For example, if a year has 3 million MWhs of unserved energy, this is multiplied by 0.385 tons/MWh to arrive at an annual GHG emissions estimate of 1.155 million metric tons. The result is 30 different annual GHG estimates based on temperature variations.[480]
3. The impact of hydro variability on GHG emissions is estimated using a 30-year historical dataset. The annual median generation of the dataset is found, and the difference between each year and the median is calculated. Some years are higher than the median,

[478] Docket No. UM 2225, Order 22-446, at 31.
[479] 0.385 metric tons / MWh represents a mix of CCCT gas plants.
[480] For this analysis temperature years in Sequoia are created by grouping the initial draw data. The initial draw data sets the load bins, and Sequoia then pulls loads from the 30-year record within that bin. As a result, the synthetic load years will have similar, but not identical, temperature characteristics as the actual years.

others less than. For each year, a GHG value of 0.385 tons/MWh is assigned to each MWh of generation higher or less than the median. The result is 30 estimates of how hydro variations impact GHG emissions.

4. The hydro and temperature variations are paired together, creating 900 possible annual GHG variations, ranging from the mildest temperatures and highest hydro conditions (least GHGs) to the most extreme temperatures and lowest hydro conditions (highest GHGs). A histogram of the range is in **Figure 137**. The histogram shows the distribution of GHG emissions for retail load service above and below expected conditions in the Preferred Portfolio in year 2030. For example, the max value in the dataset is 0.74. This implies that there is a possibility of GHG emissions in 2030 being 0.74 million metric tons higher than the 1.62 million metric ton 2030 target (2.36 million metric tons).

Figure 137. GHG histogram from Preferred Portfolio



Using the data from **Figure 137**, PGE has created various GHG percentiles, known in the IRP as C-levels. The C-levels for year 2030 in the Preferred Portfolio are in **Table 131**. One way to use the data is to calculate how much extra GHG free energy PGE would need to acquire to shift the distribution and meet the 1.62 million metric tons of GHG target under a range of conditions. This is included in the right most column of the table, assuming each MWh of GHG free generation offsets 0.385 metric tons of GHG emissions.

Table 131. C-Level analysis

C-Level	MMT of CO2e (retail)	Million MWh of CO2e free energy needed to reach 1.62 MMT target
Max	2.36	1.93
90th percentile	1.90	0.73
75th percentile	1.76	0.36
Median	1.62	

The C-level analysis takes GHG variations from temperature and hydrological conditions into consideration. It does not include GHG variations from any other factors. As a result, the actual range of GHG variation is likely larger.

Appendix J. ELCC sensitivities

This appendix discusses effective load carrying capability (ELCC) values, portfolio interactions, and sensitivities. For general information on resource ELCCs in this IRP, see **Chapter 10, Resource economics**, and for information on the Sequoia model, see **Appendix H, 2023 IRP modeling details**.

The base assumptions in the Sequoia model changed over the course of 2023 IRP modeling due to resource changes, load changes, and stakeholder feedback. Some of these sensitivities ran earlier in the process with previous model versions. As a result, readers should focus on the directionality of the change in the sensitivities rather than the absolute values.

J.1 ELCC and resource portfolios

PGE uses the Sequoia model to calculate resource ELCC values, using the following steps:

- The model runs once to establish a base system capacity need.
- The model runs again with a new resource added and produces a new capacity need.
- The difference in capacity need between the base system and the system with the new resource added determines how much effective capacity the resource contributes.
- The effective capacity value is divided into the resource nameplate value to calculate the ELCC.

The 2023 IRP tests resource ELCCs in the year 2026. The base 2026 power system for ELCC testing has a resource deficit of 429 MW in the winter and 506 MW in the summer.[481] ELCCs can be calculated untuned, with a system deficit, or tuned, where the base power system has had resources added until it is resource adequate or nearly adequate. For portfolio creation PGE runs ELCC studies in an untuned system. Portfolio creation ELCC values for each resource are located at the end of this appendix. PGE also runs a tuned ELCC study that includes the IRP Preferred Portfolio. Tunned ELCC values are in **Appendix K, Tuned system ELCCs**.

Some resources, like batteries or pumped hydropower storage, may have lower ELCC values when tested in untuned systems. This is due to not having sufficient energy to charge. For

[481] Due to input changes the ELCC base system in the winter has a need 1 MW lower than the final 2026 need (which is 430 MW in the winter). PGE staff tested changes in ELCC values at 100 MW of resource added with the updated model and found an average change of less than 1 percentage point and a max change of 2 percentage points. Due to the small size of these changes untuned ELCC values were not rerun.

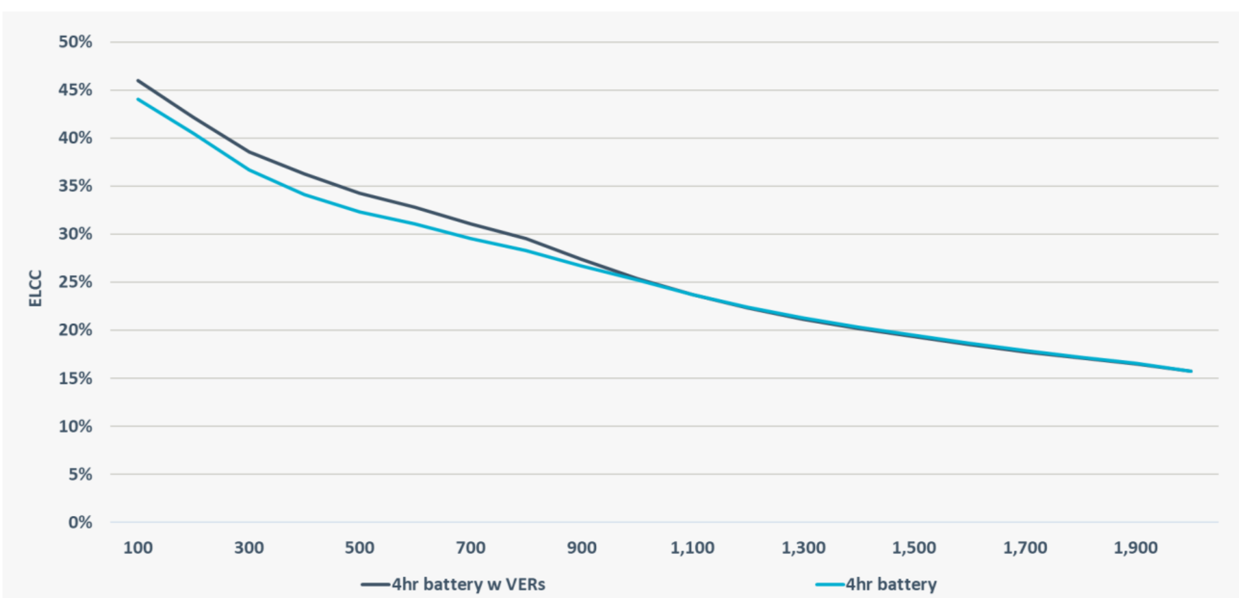
example, a battery might typically charge at night when tested in a relatively adequate, tuned system. But in an untuned deficit system, there may not be power available to charge at night, reducing the battery's ability to provide power the next day during key hours.

The 2023 IRP took two steps to provide more energy to batteries for charging when running untuned ELCC studies:

- Sequoia runs hourly in one-week increments. For the 2023 IRP, the starting charge state of storage at the beginning of the week is 100 percent rather than 50 percent used in the 2019 IRP Update. This adds additional energy into storage resources to help offset reduced charging ability in the untuned system.
- Increased the light-load hour market floor from 200 MW to 400 MW (initial modeling in the 2023 IRP used 200 MW as the light-load-hour floor). This gives storage more energy to charge from at night, to reflect a system/West with surplus energy during low-demand hours.

Beyond the two steps outlined previously, PGE also tested but did not include running untuned storage ELCCs with additional wind & solar added to the resource mix. In the test around 100 MWa of energy was added from a mix of wind and solar proxy resources. The model was then run to test winter 4-hr battery ELCCs. **Figure 138** shows an increase in 4-hr battery ELCC values with VERs as compared to 4hr battery in the Reference Case. The largest increase in the test is 2 percent, the average increase is 1 percent. PGE will continue investigating how to best model storage ELCC values in future planning work.

Figure 138. Winter 4hr battery with and without VERs



J.2 ELCC & transmission products

Transmission assumptions play a role in determining resource ELCC values. Many IRP resources require transmission over the BPA system. The IRP models two Bonneville Power Administration (BPA) transmission products, firm, and conditional firm with up to 200 hours of curtailment (CF200). Less than firm transmission products, like CF200, tend to produce lower ELCC values relative to firm transmission.

The Reference Case IRP approach to modeling CF200 transmission is to curtail the resource during the highest 100 hours of load per year. Since high-load hours are correlated with outages, the loss of resources in those hours reduces ELCC values. Other modeling approaches to CF200 transmission may yield different results.[482]

The IRP tests three CF200 transmission sensitivities. The sensitivities vary the hours curtailed by CF200 transmission from 100hr (Reference Case) to 200hrs, 50hrs, and 25hrs. The impact of these curtailment levels is tested on 300 MW of Gorge Wind and McMinnville Hybrid proxy resources. In all cases, increasing the number of hours curtailed reduces the resource ELCC value. The results, including the IRP reference values for firm transmission and 100hr of curtailment, are shown in **Figure 139** and **Figure 140**.[483]

[482]There is uncertainty on how to model CF200 transmission, for constancy the IRP takes the same approach as the 2021 PGE RFP, Docket No. UM 2166, Order No. 21-320, Appendix A page 24, available at: https://apps.puc.state.or.us/orders/2021ords/21-320.pdf

[483] These tests ran with an earlier version of the Sequoia model. The ELCC values may not align with the final values in the IRP. The directionality of the values should be the focus for the reader.

Figure 139. Conditional firm sensitivities, Gorge Wind, 300 MW

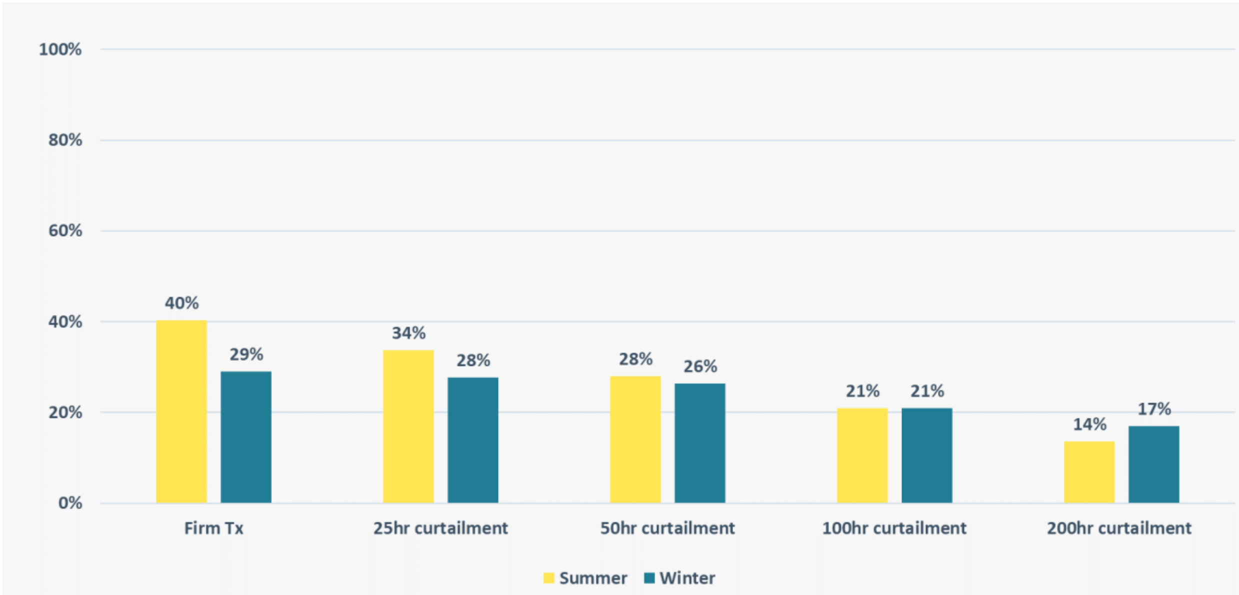
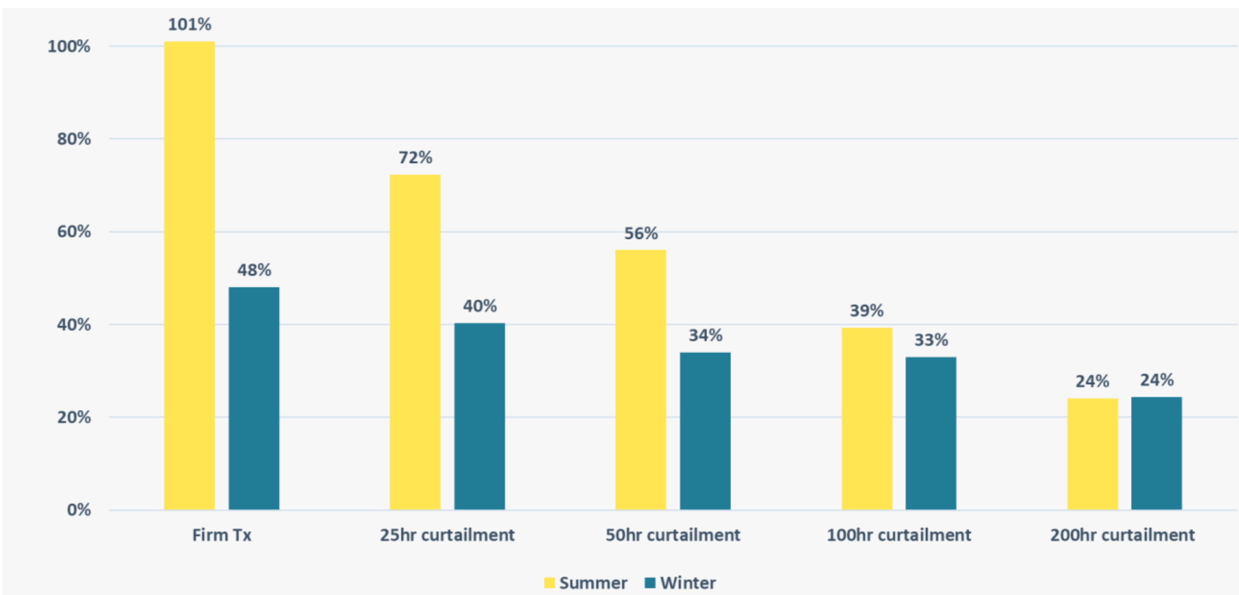


Figure 140. Conditional firm sensitivities, McMinnville Hybrid, 300 MW[484]



[484] ELCCs of over 100 percent can be achieved, typically due to the resource meeting need and providing energy for charging storage / saving hydropower.

PGE will continue to explore conditional firm transmission modeling options going forward. The CF200 modeling approach in the Reference Case, curtailing the top 100 load hours per year, is used due to uncertainty on modeling the product and a desire to maintain consistency with the 2021 RFP. Uncertainty on the CF200 transmission product arises since:

- Past curtailments are not a good indicator of future curtailments since sales of the CF200 product continue, leading to higher levels of transmission use
- BPA no longer posts conditional firm transmission available transmission capacity (ATC) inventories, making it challenging to assess future levels of system use
- BPA has not provided guidance on how to model the CF200 product

J.3 ELCC and resource characteristics

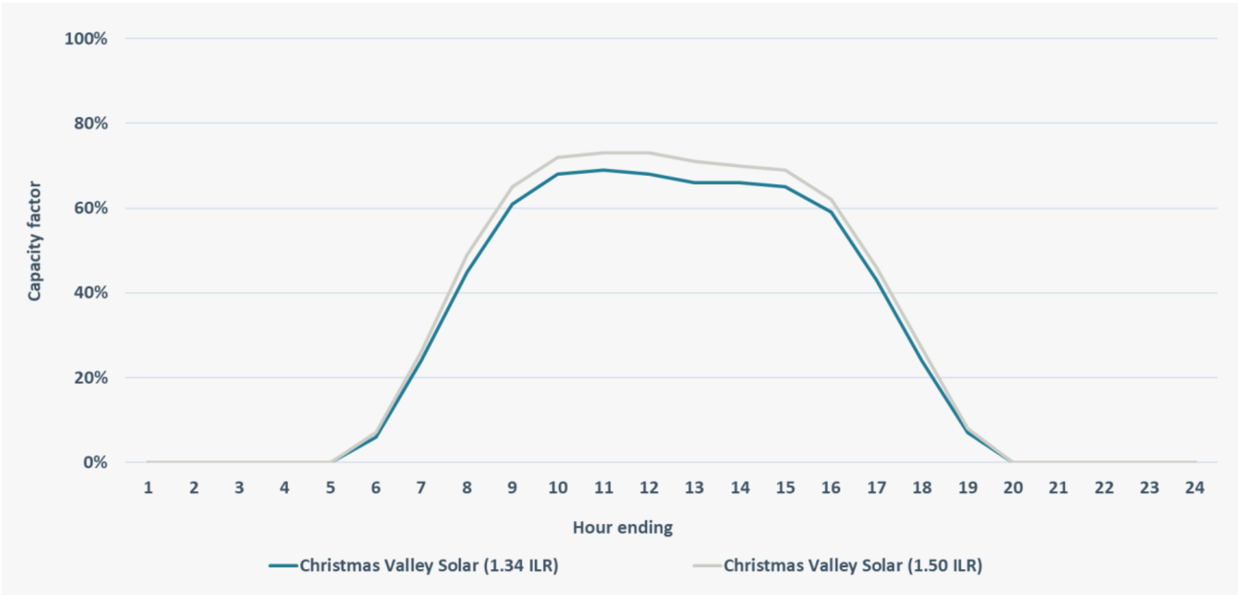
The 2023 IRP uses proxies to evaluate new resource options. These proxies are representative of new resources but do not represent the full range of options. To help study different solar facility specifications, the IRP tests the impact of solar inverter loading ratios (ILR) on ELCC values. A solar ILR describes the amount of DC solar panels in relation to the projects AC inverter. For example, a project with 134 MW of DC panel and a 100 MW AC inverter has an ILR of 1.34.[485]

Higher ILRs are beneficial for maximizing solar facility output. By collecting more solar irradiance, higher ILR facilities provide steadier/higher power output in cloudy conditions, during early morning and late evening hours, and higher output in the winter. During some hours, this higher output leads to clipping. Clipping occurs when the panels are capturing more solar power than the inverter size. Clipping generally increases when the ILR increases. The primary disadvantage to higher ILR for solar projects is higher costs due to the extra panels.

Figure 141 shows the annual hourly capacity factors of two solar facilities – one with the IRP default ILR of 1.34 and the other with a 1.50 ILR. Both sites use the Christmas Valley solar location. On an annual average basis, the 1.34 ILR project has a capacity factor of 28.0 percent, whereas the 1.50 ILR project is at 29.9 percent.

[485] 1.34 is the 2023 IRP default for utility scale stand-alone solar, utility scale hybrid projects in the IRP used a 1.50 ILR.

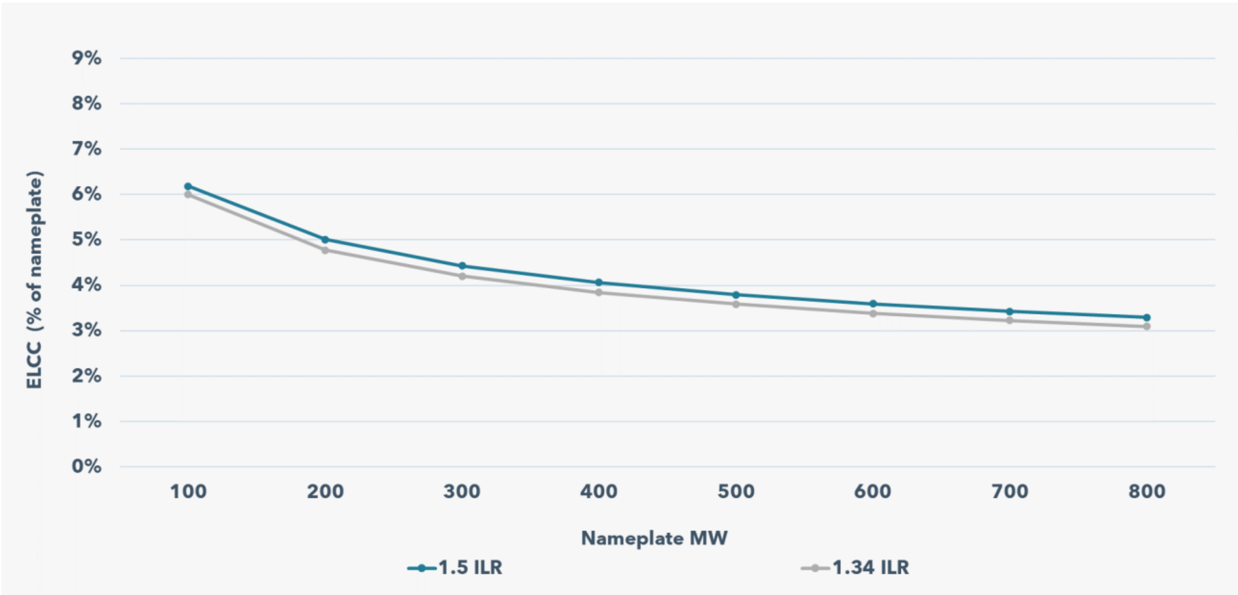
Figure 141. Annual hourly solar capacity factors by ILR



To test the impact of ILR on ELCC values, Sequoia analyzed both projects. The results are shown in **Figure 142** for 100 to 800 MW nameplate of resource added to the model. Over all eight resource tranches, the 1.50 ILR resource has higher ELCC values than the 1.34 ILR resource.[486]

[486] These tests ran with an earlier version of the Sequoia model. The ELCC values may not align with the final values in the IRP. The directionality of the values should be the focus for the reader. These results were shared in the April 2022 PGE Roundtable meeting.

Figure 142. Solar ILR ELCC test, Christmas Valley



For the 2023 IRP, PGE uses a stand-alone solar facility proxy with an ILR of 1.34 to comport with the NREL ATB data.[487] Additionally, the value of 1.34 is similar to values used by other Northwest utilities, as shown in **Table 132**. The table also includes the ILR value out of a more recent National Renewable Energy Laboratory (NREL) report, which moves the ILR down to 1.28. In part due to stakeholder requests, and in part due to DC coupling reducing the clipping issue, the utility scale solar-hybrid resource proxy has an ILR of 1.50.

Table 132. Inverter loading ratio in NREL and Northwest power planning documents

Source	Value	Notes
NREL 2020 ATB	1.34	Report released in 2021
NREL 2021 ATB	1.28	Report released in late 2021
PacifiCorp 2021 IRP[488]	1.30	Reduced from 1.46 in prior IRP based on industry trends - page 191

487 The PGE IRP solar assumptions point to 2020 NREL data (released in early 2021). The 2021 NREL data (released in late 2021) use a solar ILR of 1.28. Available at: https://www.nrel.gov/docs/fy22osti/80694.pdf
488 See page 191, available at: https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/Volume%20I%20-%209.15.2021%20Final.pdf

Source	Value	Notes
Puget Sound Energy 2021 IRP[489]	1.20	"All solar resources were modeled with a DC to AC ratio of 1.2" - page 55 appendix D
Idaho Power 2021 IRP	1.30	Discussed in February 2022 UM 2022 PUC Staff meeting
PGE 2023 IRP value	1.34	Proxy resource based on 2020 Q1 NREL study
NWPCC 2021 Power Plan[490]	1.40	Samples a range of IRPs/studies – only source higher than 1.3 is PAC from 2019 IRP (PAC has reduced value since)

J.4 IRP portfolio creation ELCC ladders

The following figures show the ELCC values of IRP proxy resources out to 2,000 MW nameplate run in an untuned 2026 system for IRP portfolio creation purposes. ELCC values calculated in a tuned system are available in **Appendix K, Tuned system ELCCs**. **Figure 143** and **Figure 144** shows the ELCC values of wind resources in the IRP.

[489] Available at: https://www.pse.com/-/media/PDFs/IRP/2021/appendix/Appendix_B-M_Complete.pdf?sc_lang=en&modified=20220307202833&hash=EFC80E908F117D14A97A30322D88AFAC
[490] Available at: https://nwcouncil.app.box.com/s/kp0c6w5ivhqvge20bg3j40rsm13hyy1h

Figure 143. Summer wind ELCCs

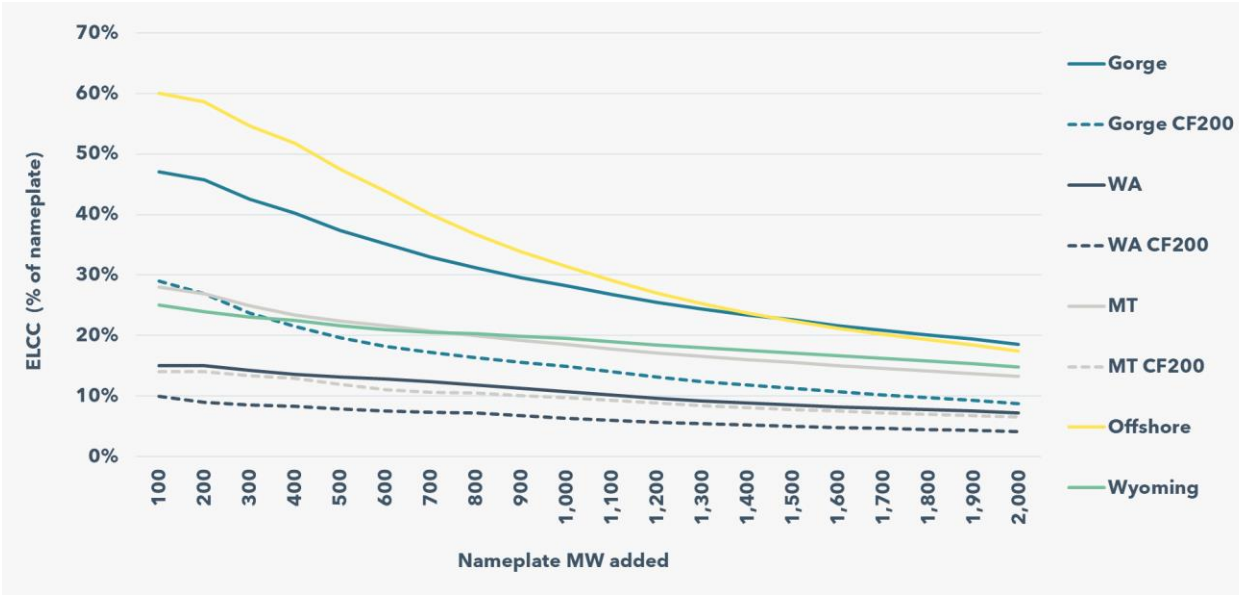


Figure 144. Winter wind ELCCs

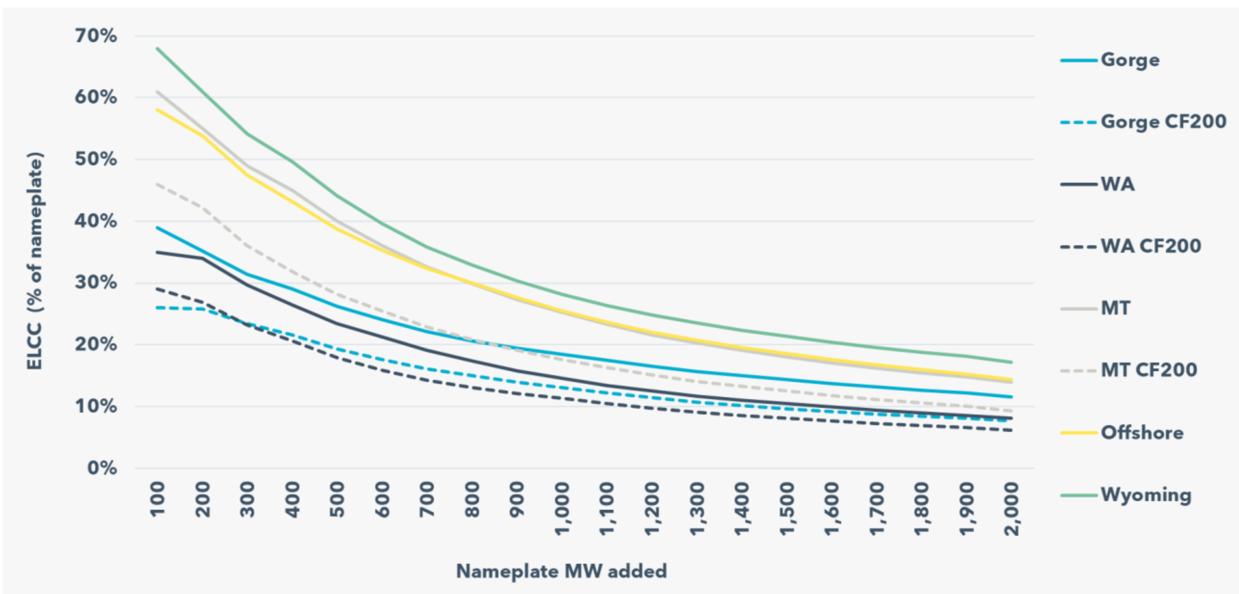


Figure 145 and **Figure 146** shows solar ELCC values in the 2023 IRP.

Figure 145. Summer solar ELCC

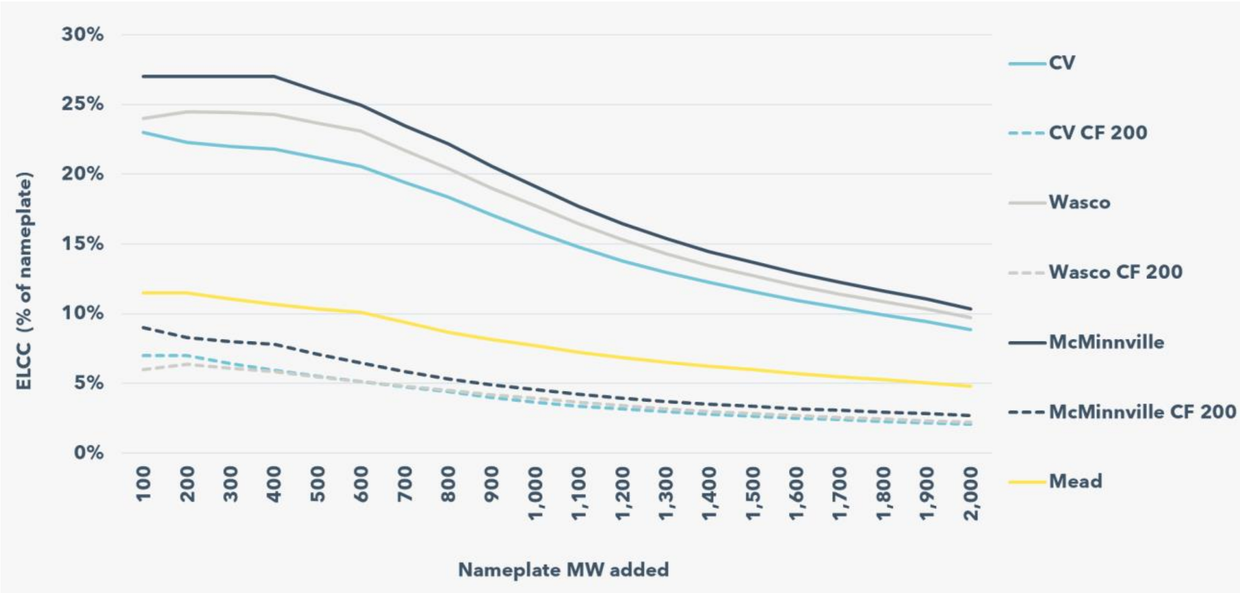


Figure 146. Winter solar ELCC

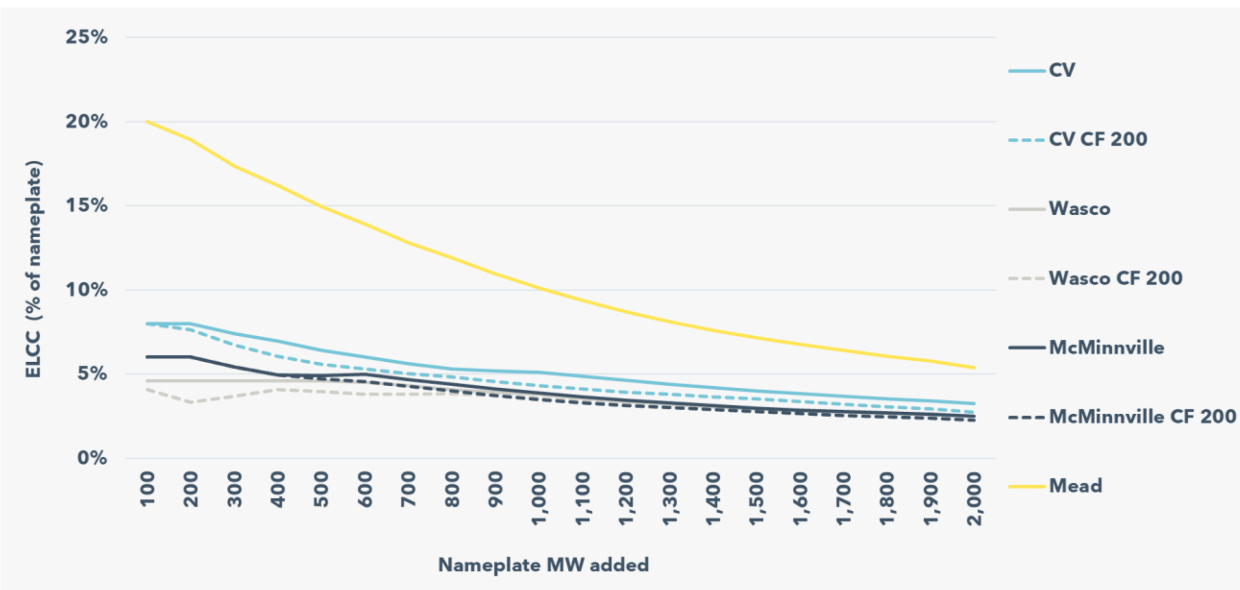


Figure 147 and **Figure 148** shows storage ELCC values.[491] Note that with pumped storage hydropower, the model entirely solves all adequacy issues before reaching the 2,000 MW

[491] Some resources, like pumped storage hydro, have ELCC values greater than 100 percent in the summer. This is generally due to the resource starting fully charged, bringing additional energy to the system.

nameplate of the resource. Once the model solves out, ELCC values are reduced by 1 percent for each subsequent 100 MW of resource.

Figure 147. Summer storage ELCC

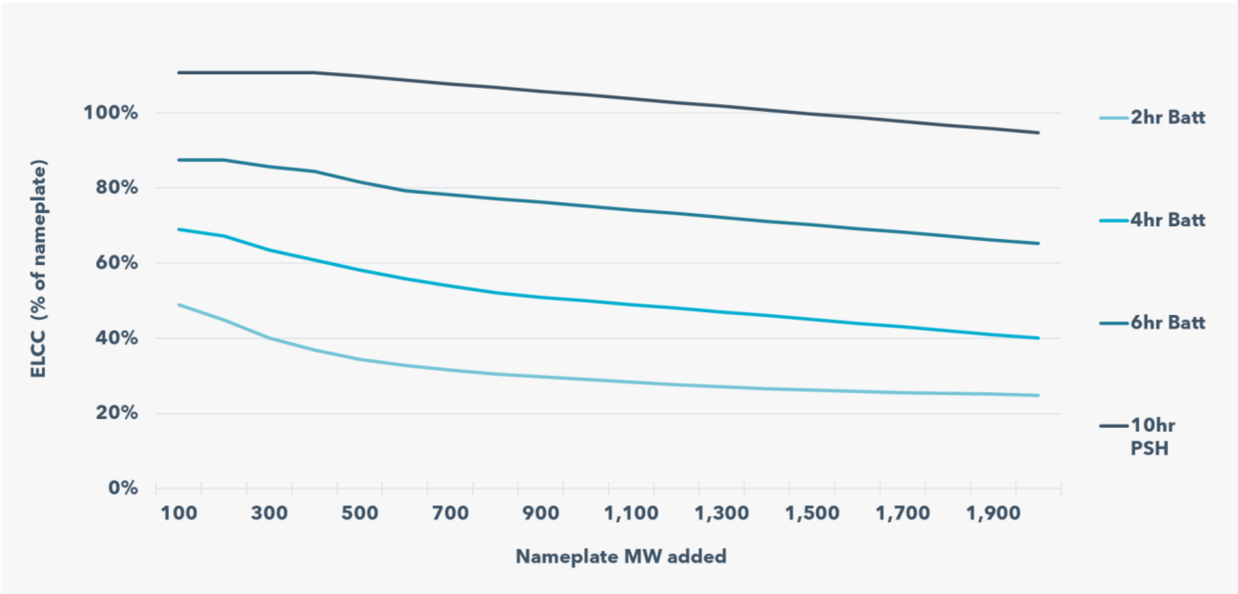


Figure 148. Winter storage ELCC

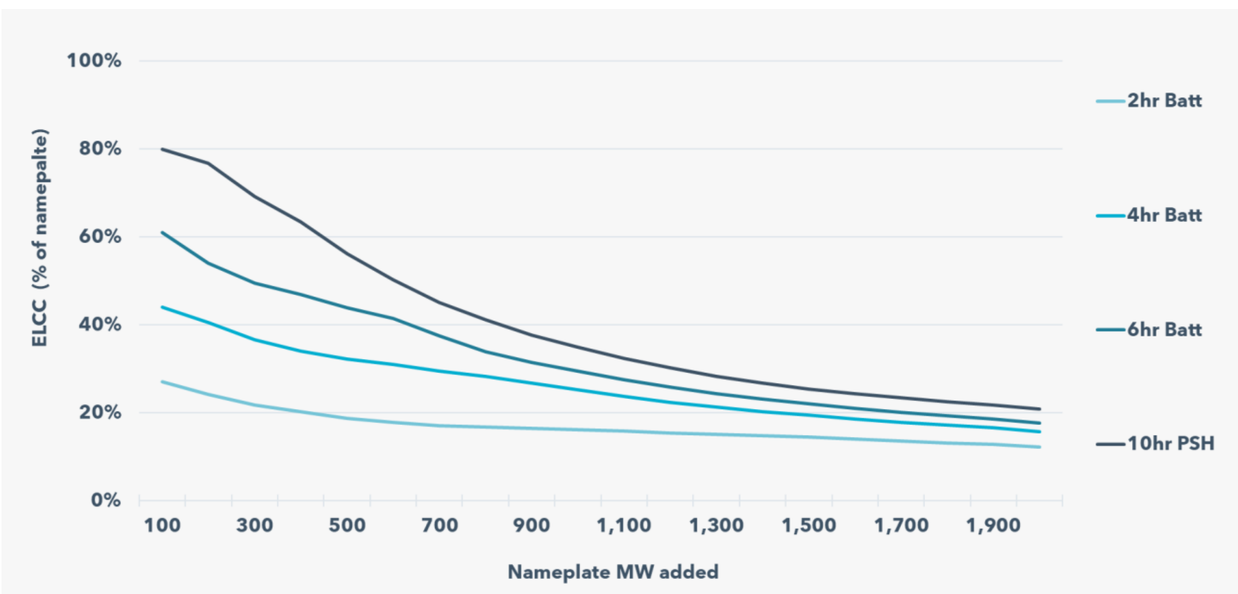


Figure 149 and **Figure 150** shows hybrid resource ELCC values. Some hybrid resources solve all adequacy issues before reaching the 2,000 MW nameplate of the resource. Once the model solves out, ELCC values are reduced by 1 percent for each subsequent 100 MW of resource.

Figure 149. Summer hybrid ELCC

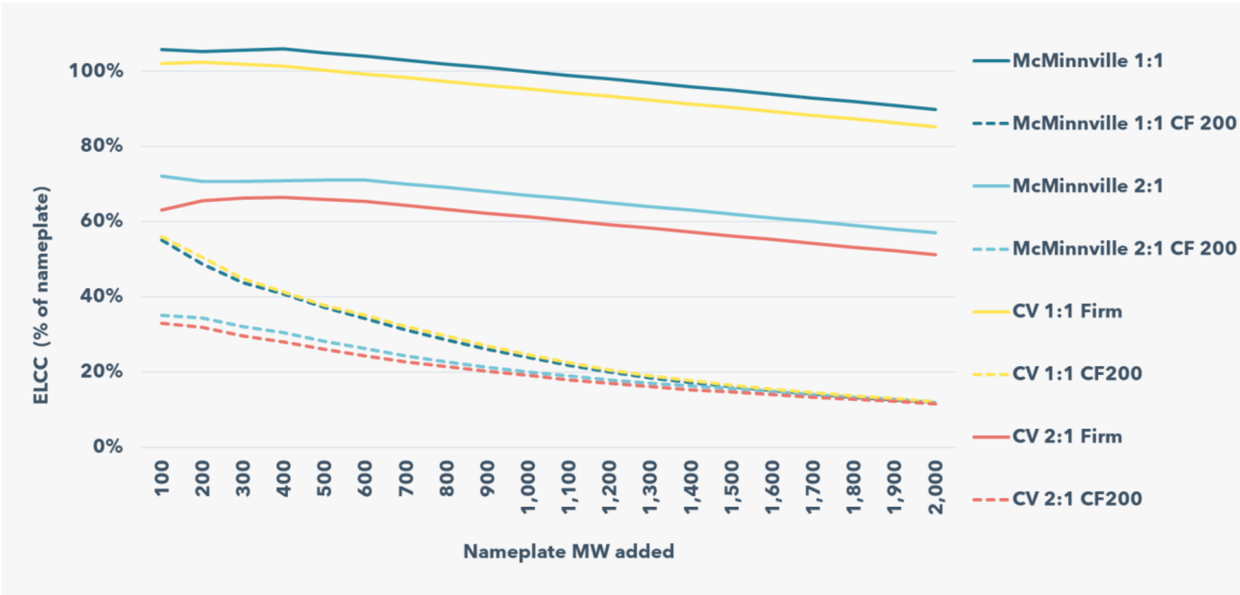
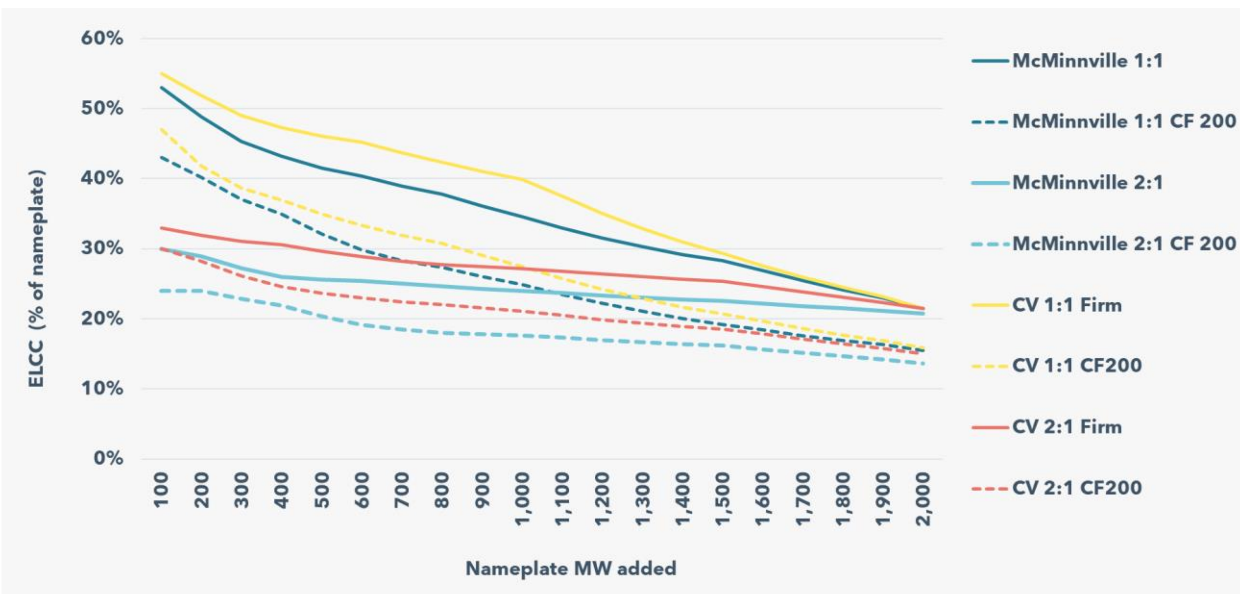


Figure 150. Winter hybrid ELCC



Appendix K. Tuned system ELCCs

This appendix provides tuned system ELCC values using the IRPs Preferred Portfolios. Tuned ELCC values are calculated in a model that is resource adequate or close to resource adequate. They provide an estimate of the resource's ELCC value when viewed as part of a complete system. Untuned values, which are used in this IRP for portfolio creation, are tested on a resource deficit system. Additional discussion on tuned vs. untuned ELCCs is available in the previous appendix.

K.1 Tuned system ELCCs

Annual tuned effective load carrying capability (ELCC) values are provided in line with the preferred practices recommended by the Oregon Public Utility Commission (OPUC) via the UM 2011 docket and to comply with LC 73 requirements.[492] The UM 2011best practices document applies "when calculating the capacity contribution of a supply or demand side resource, generally whenever a specific resource or resource type and not a portfolio of resources is being considered (incremental vs portfolio capacity analysis). This currently includes some aspects of regulatory purposes such as administrative pricing, cost effectiveness and customer program design, resource adequacy analysis, planning (IRP & DSP), and procurement (RFP)."[493]

The ELCC values in this section are calculated using a tuned system and at an annual level.[494] The tuned system includes IRP Preferred Portfolio resources and is adjusted by either adding or removing resources until the system deficit is around 70 to 100 MW.[495] The tunning is performed by adjusting up or down the level of perfect capacity resources in the portfolio (other resource types, like wind, solar, or battery, are not adjusted). After system tunning the ELCC studies run using the steps described in **Appendix J, ELCC sensitivities**. These values are not directly comparable to ELCC values used for portfolio creation in the IRP. The

[492] The LC 73 requirement is on page one of appendix A at: https://apps.puc.state.or.us/orders/2021ords/21-129.pdf
The UM 2011 practices are here: https://apps.puc.state.or.us/orders/2022ords/22-468.pdf
[493] *Id.*
[494] For general information on resource ELCCs in this IRP, see **Chapter 10, Resource economics, Appendix J**, **ELCC sensitivities**, and for information on the Sequoia model, see **Appendix H, 2023 IRP modeling details**.
[495] If deficits become too low some resources, like hybrids, may solve all the outage hours required to return the system to an adequate state and thus not receive an accurate ELCC estimate. If the deficit is too high this negates the advantage of testing in a tuned system, which is examining how the resource behaves in a plausible future portfolio. The 70 to 100 MW range provides headroom for testing ELCCs of 100 MW increments of resource while staying inside a relatively adequate system. More discussion on why a tuned portfolio is used can be found in the best practices report: https://apps.puc.state.or.us/orders/2022ords/22-468.pdf

portfolio creation values are calculated in an untuned system and on a seasonal (as opposed to annual) basis.

The results are for 100 MW of supply side resource available in the Action Plan period from 2026 through 2043. ELCC values are calculated in year 2026, 2031, 2036, and 2043, with the years between linearly interpolated.[496] For reference, the average ELCC value from 2026 to 2043 is also included.

[496] This method comes from UM 2011 recommended best practices. "At a minimum, the IRP index of proxy resources must include at least four ELCC modeling year resource capacity contribution values. Unless otherwise warranted, the first ELCC modeling year shall be the first year where a major resource need is identified, and the last ELCC modelling year shall be the last year of the study period. The other two modelling years shall be selected by the utility, after considering input from Staff and stakeholders. Years of the study period not directly modelled shall have the ELCC annual capacity contribution values derived through interpolation using a reasonable method given the findings if the ELCC modelling analysis."

Table 133. Tunned ELCC values by year

Resource	2026-2043 avg.	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Wind Gorge Firm	15%	22%	20%	18%	15%	13%	13%	13%	14%	14%	14%	14%	14%	14%	14%	13%	13%	13%	13%
Wind Gorge CF200	10%	17%	15%	13%	10%	8%	8%	8%	9%	9%	9%	9%	9%	9%	9%	8%	8%	8%	8%
Wind SE WA Firm	19%	20%	19%	18%	17%	16%	16%	16%	17%	17%	17%	17%	18%	19%	20%	21%	22%	23%	24%
Wind SE WA CF200	14%	13%	13%	13%	13%	13%	13%	13%	13%	12%	12%	12%	13%	14%	15%	16%	17%	18%	19%
Wind MT firm	31%	39%	37%	36%	34%	32%	31%	30%	29%	28%	27%	26%	27%	28%	29%	29%	30%	31%	32%
Wind MT CF200	22%	23%	23%	24%	24%	24%	23%	23%	22%	21%	21%	20%	20%	21%	21%	22%	22%	23%	23%
Solar CV Firm	7%	22%	18%	14%	9%	5%	5%	5%	5%	5%	5%	5%	5%	4%	4%	3%	3%	2%	2%
Solar CV CF200	3%	10%	8%	6%	4%	2%	2%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	1%	1%
Solar Wasco Firm	9%	22%	19%	16%	12%	9%	9%	8%	8%	7%	7%	6%	6%	6%	6%	6%	6%	6%	6%

Resource	2026-2043 avg.	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Solar Wasco F200	4%	9%	8%	6%	5%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	3%
Solar MCMN Firm	10%	21%	19%	16%	14%	11%	11%	10%	10%	9%	9%	8%	8%	7%	7%	7%	7%	6%	6%
Solar MCMN CF200	4%	8%	7%	6%	5%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	3%	2%	2%
MCMN hybrid 1 Firm	67%	65%	66%	66%	67%	67%	67%	68%	68%	68%	69%	69%	68%	68%	67%	66%	65%	65%	64%
MCMN hybrid 2 Firm	39%	44%	43%	42%	41%	39%	39%	39%	39%	38%	38%	38%	38%	37%	37%	37%	37%	36%	36%
MCMN hybrid 1 CF200	53%	47%	48%	49%	50%	51%	52%	52%	53%	54%	54%	55%	55%	55%	55%	55%	55%	55%	55%
MCMN hybrid 2 CF200	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	28%	29%	29%	29%	29%

Resource	2026-2043 avg.	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
CV hybrid 1 Firm	67%	64%	65%	66%	67%	68%	69%	69%	70%	70%	71%	71%	70%	69%	68%	66%	65%	64%	63%
CV hybrid 2 Firm	39%	46%	45%	44%	42%	41%	41%	40%	40%	39%	39%	38%	38%	37%	37%	36%	36%	35%	35%
CV hybrid 1 CF200	53%	46%	47%	49%	50%	51%	52%	53%	54%	55%	56%	57%	57%	56%	56%	56%	56%	55%	55%
CV hybrid 2 CF200	30%	28%	29%	30%	31%	32%	31%	31%	30%	29%	29%	28%	29%	29%	30%	30%	31%	31%	32%
Two hr. battery	31%	20%	23%	25%	28%	30%	31%	32%	34%	35%	36%	37%	36%	35%	34%	32%	31%	30%	29%
Four hr. battery	56%	39%	43%	47%	51%	55%	56%	58%	59%	60%	62%	63%	62%	61%	60%	60%	59%	58%	57%

Appendix L. Clean Energy Plan: Learning Labs community feedback

The Oregon Public Utility Commission's (OPUC) Order 22-390 established requirements for utilities to ensure the "effectiveness of community engagement" during the development of Clean Energy Plans (CEP). PGE built upon the community engagement approach, initiated through the Distribution System Planning (DSP) process, in response to these CEP requirements. We recognize that the traditional process for developing the Integrated Resource Plan (IRP) is complex. It requires communication of dense, technical details that support the recommendation of a Preferred Portfolio of resources and that communication occurs in a relatively compressed timeframe, i.e., it caters to a technical audience. We initiated a new series of meetings, Community Learning Labs, to create space for education on IRP topics and to explore new topics introduced through the CEP guidelines.

The CEP community learning lab is the non-technical venue PGE created to socialize CEP-related concepts. During the development of the OPUC's community lens requirements for UM 2225, we heard that community input should be a "principal factor in determining what is in the public interest" for the CEP as well as transparency, accessibility, and understandability. Additionally, the CEP should bring benefit to environmental justice and other energy burdened communities, with an emphasis on Tribal communities. For this CEP, we sought to align with our community. This alignment included what we can do for the initial CEP and what we would like to work on with community over time. **Figure 151**, describes the OPUC's community engagement requirements.

Figure 151. OPUC Order 22-390 community engagement requirements

Engagement strategies	Community input and feedback	Community surveys
a. What opportunities were provided for input and how was accessibility prioritized across those channels? b. Which communities, including environmental justice communities (EJ) and Tribal communities, did the utility consult with and how were those communities and their representatives identified?	a. What input was received through each channel? b. How was input incorporated into the IRP/CEP? c. What input was not incorporated into the IRPICEP and why was that input not incorporated? d. What plans does the utility have for modifying the engagement strategy in future planning cycles?	a. The utility should also survey participants who provided input on their experiences participating in the utility's process and their perspectives on how their input influenced the plan. b. Survey responses must be included with the plan.

L.1 Engagement strategies

PGE approached Learning Lab topics iteratively, building up concepts over multiple workshops. When possible, PGE used relatable examples to make these concepts more relevant to the audience. Once a concept was defined, PGE would use Mural[497] to request specific feedback to help inform PGE's approach to the topic. CEP Learning Lab's target a non-traditional audience such as community service organizations, community-based organizations, municipalities, cities, OPUC Staff, Energy Trust of Oregon, and interested public members. From September to March, PGE held seven monthly workshops. During Learning Labs, we requested feedback on our approach, and in subsequent workshops, we reported how feedback was used to inform the CEP planning process. PGE also requested feedback via surveys and used the answers to modify Learning Labs. Modifications include changes such as the preferred length of the meeting and the virtual meeting platform to use for workshops (two-hour long, via Zoom).

[497] Mural is an online platform that allows for multiple people to participate at the same time. An example of a Mural excessive, available at: https://app.mural.co/t/distributionsystemplanpart27687/m/distributionsystemplanpart27687/1673469662755/11f19693ee09b53ee85f3f7b07bc1410b06f206a?sender=u293527aa870441a19c743984

Table 134 shows the CEP Learning Labs were attended by seven types of organizations and individuals from the community from September 2022 to March 2023. **Table 135** shows the topics covered throughout the six Learning Labs and how often each was visited.

Table 134. CEP Learning Lab attendance

Participants by type of organization	Total number of participants						
	17 Sep	13 Oct	20 Nov	7 Dec	7 Jan	12 Feb	10 Mar
Cities and municipalities	3	3	3	1	1	3	4
Climate Advocates	3	2	5		1	2	1
Community Service Organizations	1	1	2	1	1	2	1
Associations			1				
Energy Trust of Oregon	2	2	1	1	1	2	
Oregon Utility Board	1	2	1	1			1
Regulator	6	2	2	1		2	1
Individuals	1	1	5	2	3	1	2

Table 135. Topics covered during CEP Learning Labs from Sep 2022-Mar-2023

Topics covered	09/27/22	10/27/22	11/17/22	12/14/22	01/19/23	02/16/23	03/16/23
Integrated Resource Planning (IRP) Overview & IRP Roundtable updates	X	X	X	X	X	X	X
Community Engagement Strategy	X				X	X	X
Community Benefits Impact Advisory Group (CBIAG)	X				X		
Community Benefits Indicators (CBIs)		X		X	X	X	X
Community-based Resources (CBREs)		X	X		X		X

Topics covered	09/27/22	10/27/22	11/17/22	12/14/22	01/19/23	02/16/23	03/16/23
Resilience			X		X		X
Request for Proposal (RFP) – Potential CBRE RFP			X		X	X	X

L.2 Community input and feedback

An important component to PGE's community engagement is receiving input and feedback on our planning processes. PGE requested community feedback by leading Mural exercises within our Learning Labs so that we could go deeper into a specific topic. The Mural exercises usually consisted of a few questions for participants to answer for a specific amount of time about a particular subject. To allow more time to collect feedback, Mural exercises were open for additional contributions two weeks after each Community Learning Lab session. This way, people who couldn't actively participate in our Community Learning Labs were able to provide their input later. The following discusses the topics we worked on with our participants during the Learning Labs.

L.3 Mural board exercises

- **Community Benefits Indicators (CBIs)**

  As described in **Chapter 14, Community equity lens and engagement**, the HB 2021 Energy Advocates conducted extensive research and outreach among their constituents to collate a list of 15 Community Benefits Indicators. This list was shared as Attachment A of OPUC Order 22-390 for utilities to consider when developing their CBI approaches. PGE requested community input on CBIs as part of its community engagement strategy. Community input came over three Learning Lab sessions. Using a Mural voting exercise, stakeholders recommended which CBIs to prioritize for further research, such as identifying metrics for each of the prioritized CBIs. Additionally, Community Advocates utilized PGE's Mural board in one of their regular meetings to prioritize CBIs with their constituents, community members within the state (14 participants). The Community Advocates are a cohort of 12 community members that have been meeting with Energy

Advocates and organizers. For these meetings, PGE translated our Mural board into Spanish.

Figure 152 shows the four CBIs prioritized by participants of the Learning Labs, Energy Advocates and Community Advocates.

Figure 152. Community Benefits Indicators prioritized by community

Community Benefits Indicators	
Non-energy	**Energy**
•Reduction in number of customers suffering from high energy burden •Meaningful bilateral engagement between utilities and tribes •Low income & vulnerable communities have access to an increasing number or renewable or non-emitting distributed generation resources	Improve efficiency of housing stock in utility service territory, including low-income housing

- **Resilience: Metrics to analyze resilience and "Zone of Tolerance"**

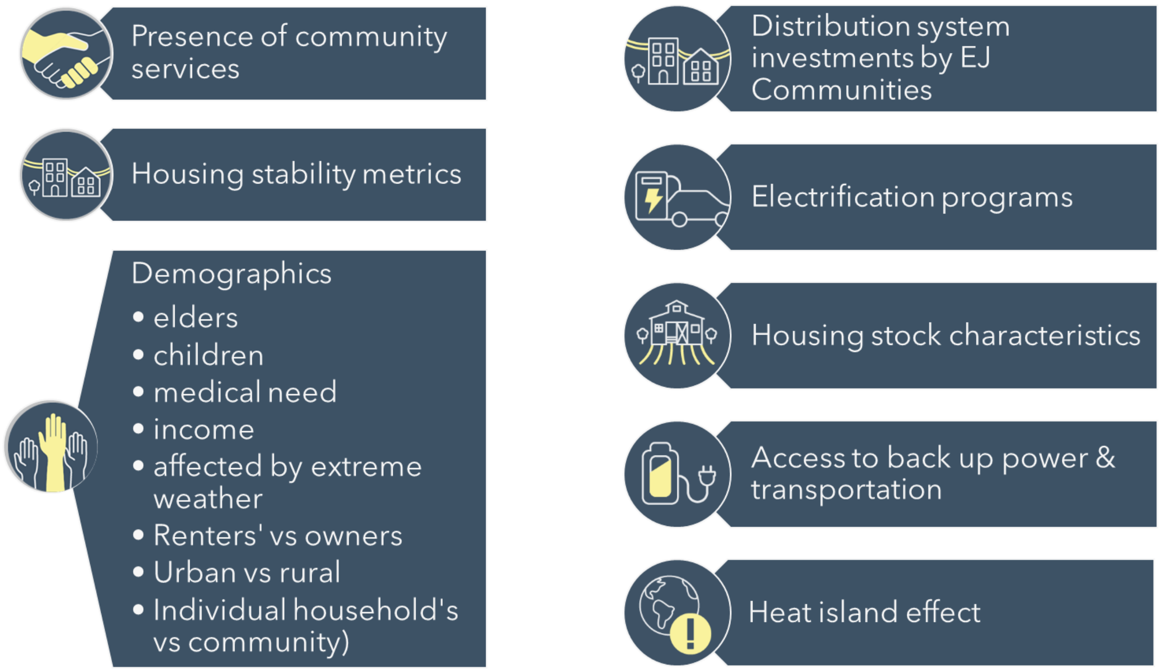
  PGE's approach to resilience started by exploring available utility data, such as localized outage data (CEMI16 and CELID), to analyze the electric system's resilience. PGE also leveraged the equity index map created for DSP Part 2 as the source of data to identify vulnerable communities in its service area. Overlaying both data sets, utility data and equity data, enables us to identify locations in our service area where vulnerable communities and system outages occur and therefore might benefit from resilience investments.

  Another resilience concept on which PGE requested input from community was metrics to understand and analyze "Zone of Tolerance." Zone of Tolerance definition: "Different capabilities of households and communities to endure the adverse impacts of service disruptions."

  PGE requested feedback via Mural on what other data sources PGE should explore to better understand and analyze resilience. Participants recommended that PGE explore eight data themes: community services, housing stability, demographics, distribution system investments, electrification, housing stock, access to back up power and transportation, and heat island effects (**Figure 153**).

  PGE will work on defining and locating vulnerable communities and assessing the Zone of Tolerance by exploring datasets in the eight themes community recommended. PGE will continue using the heat island study[498] from Dr. Vivek Shandas[499] as a guide to locate the affected areas.

Figure 153. Data themes recommended by Learning Lab participants for PGE to explore in analyzing resilience & "Zone of Tolerance"



- **Community-based Renewable Energy (CBRE)**

  Early in the CEP Learning Lab series, PGE requested community input via Mural on examples of CBREs. Community Learning Lab participants described CBREs as microgrids, resilience hubs, and generation assets on public buildings (i.e., solar panels on school roofs).

- **CBRE – Microgrids**

  PGE took stakeholder input (i.e., defining CBREs as community microgrids) and further explored CBRE microgrids as a topic in a subsequent Learning Lab. CEP resilience guideline requested utilities to explore potential strategies to implement resilience projects. PGE started exploring a potential strategy to implement community resilience hubs through product development. Developing products at PGE is done with customer input to design products that would best serve customers. In the case of a potential

[498] Urban Heat Island Mitigation, available at: https://www.pdx.edu/sustainability/urban-heat-island-mitigation
[499] Professor Vivek Shandas, Nohad A. Toulan School of Urban Studies and Planning, Portland State University.

community microgrid, PGE product development sought feedback from stakeholders during a Learning Lab regarding the uses/benefits of the microgrid product:

- What would it be used to power, and
- Where would be the best siting for such a product in a community?

After level-setting, PGE requested input via Mural on how a community microgrid would best serve the community. Members shared that community microgrids would help limit resource loss (i.e., food and medications), run medical equipment, increase energy reliability, provide access to power during a major event outage, and create jobs when building one. PGE then asked members what critical facilities they would prefer powering during a major outage. Members identified hospitals, elder care homes, emergency shelters and community resource and service providers (i.e., grocery stores). Last, PGE asked what the preferred siting criteria would be for these microgrids. Members expressed the need for these community microgrid hubs to be sited in accessible areas to vulnerable communities and to take into consideration what a "safe space" means to different communities (i.e., undocumented community members might feel uncomfortable going to a building that belongs to an institution they fear).

Figure 154. Community feedback on a potential resilience product

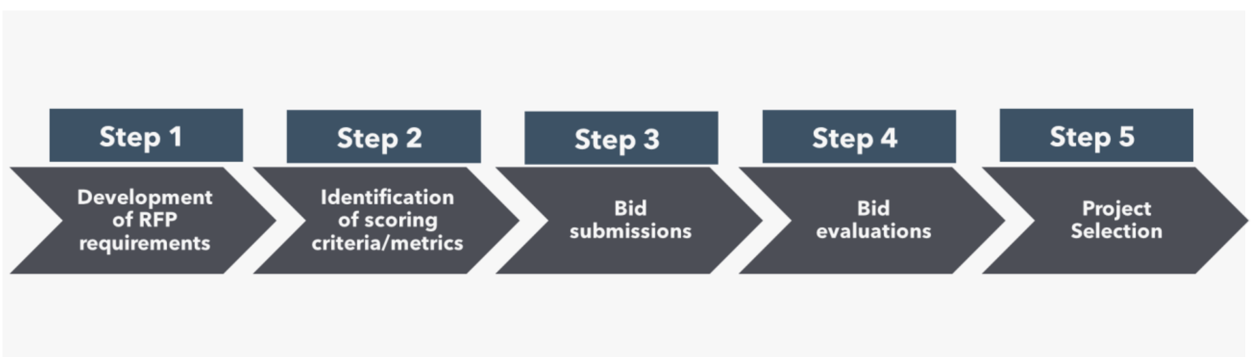
L.3.1 CBRE - Considerations

In a subsequent Learning Lab, PGE requested input on other considerations regarding CBREs. Participants expressed that, when designing or acquiring CBREs, PGE should give a higher priority to projects that solve for resilience and reduce GHG emissions. Participants also remarked that CBREs should not displace farm or forest land. Participants recommended that PGE explore stacking the value of resources when they support multiple objectives and policies and align with other agencies working on similar issues (i.e., Oregon Department of Energy (ODEO) Community Renewable Energy Grant program), understand which projects have been identified, and prioritize procurement of those projects. Two concerns participants raised were, 1) utilities will consider these CBREs too expensive, and will not consider the benefits these resources bring to community, and 2) utilities will favor companies with capital versus community focused enterprises.

L.3.2 CBRE - Acquisition paths

PGE used the participants' feedback on CBREs in designing an approach to acquire these energy resources. PGE is planning on working with Community Learning Lab participants to codevelop the scoring criteria (**Figure 155**) that are used to rank proposed CBRE projects and, ultimately, select the ones to move forward.

Figure 155. Community RFP evolution path



L.4 Community surveys

We used our community surveys to measure and track the effectiveness of our community engagement and our Learning Labs. From September 2022 through February 2023, we conducted six evaluation/feedback surveys to participants/attendees after each Learning Labs. This included hearing their perspectives on how their input should influence the plan.

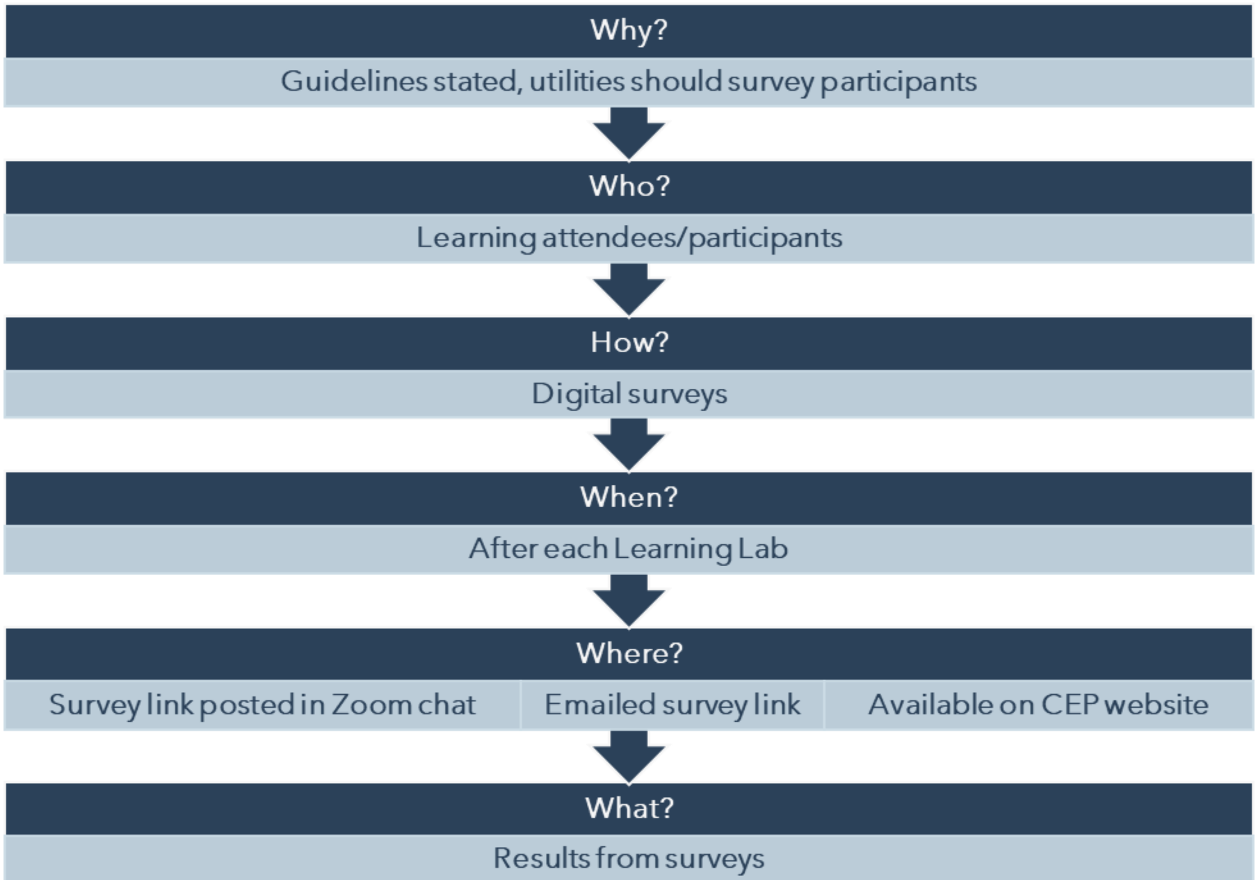
Surveys were left open several weeks after the Learning Lab so that participants had time to take the survey as their schedules allowed. Survey links were posted in the Learning Lab chat via Zoom, located on our CEP website, and sent via email notifications.

We designed digital surveys using a mix of quantitative and qualitative questions to assist in gathering information from participants. For consistency, and to easily quantify, we asked the repeated questions in our Learning Lab surveys 2-5 using a Likert-Scale (Strongly disagree, Disagree, Neutral, Agree and Strongly agree) to evaluate our presentations. Also, we asked open-ended qualitative questions where participants could provide written feedback, offer future Learning Lab content, and process improvement.

Survey respondents ranged from community-based organizations, and community service organizations to individual community members. Our survey results showed the highest response rate of 35 percent which was from our first Community Learning Lab – Kick-off Clean Energy Plan. As we administered more surveys, we saw a decline in respondents. Overall, we had a total of 10 respondents out of 64 attendees (16 percent) who took the survey. Although we didn't have high response rates, we still found the information collected to be meaningful and helpful.

We realized early that surveys could not be the only way to receive information as our response rates were lower than we hoped. Due to this, we met with a handful of attendees through informal interviews to receive input on suggestions for improvement and additional perspectives to our approach to community engagement strategy and the Learning Labs. From this experience we discovered we needed to have different modes of engagement. Surveys were a great tool to collect data, however getting participants to take a survey was challenging. Therefore, we decided to meet with attendees outside of the Learning Labs to obtain additional qualitative data. This informal setting allowed for a more relaxed environment for the person to share feedback and helped in building relationships with participants. **Figure 156** describes our process for conducting surveys.

Figure 156. Survey process map



PGE crafted 2 types of surveys to measure progress and incorporate feedback from participants. Our first survey was created to collect information on logistical preferences and potential future presentation topics. For logistical preferences we discovered was:

- 67 percent of respondents preferred to meet monthly versus quarterly.
- 83 percent of respondents it would be helpful to have meetings at the same day and time.
- 100 percent of attendees wanted Learning Labs to be recorded.

This feedback enabled us to set-up recurring meetings on the same day and time, so in January 2023 we scheduled our Learning Labs every third Thursday from 10:00am – 12:00pm.

Recommendations for potential future topics received from respondents were:

- "Different funding streams that can help build CBREs and other DSP projects."
- "How different dockets (IRP, DSP, CEP, WPP, TE) can be streamlined."
- "The follow-up to how CBIs could be part of large-scale resources RFP."
- "I was hoping the Learning Lab would be more like a tutorial to understand the IRP better. The IRP uses lots of acronyms and assumes many things that aren't made apparent even after listening for a year. I had hoped to be caught up on these matters. I would like to understand the unspoken pros and cons implied by graphs and discussions presented at IRP. For example, no one is explicit about the seriousness of the distribution/transmission problem. There isn't enough comparison of PGE demand and supply with the resources being considered in detail for me to get a sense of scale of the material. This could be improved at IRP (best) or addressed at the Learning Lab."
- "If leaving no one behind is one driving force for the work, it's going to be a huge task. Federal funds could do a lot but at some point, private funds will probably need to come into play. I like to get some idea of how much work can be accomplished in the short term and longer term to improve community resilience. How much funding is available through ETO and other sources? How much can we expect will get done in the next 5 years?"

From these recommendations from community, we incorporated topics for discussion, such as: CBREs, CBIs, DSP projects, conversations about other dockets, IRP Roundtable updates, created an acronym key to eliminate barriers to understanding materials, RFP process and spoke about large-scale resources.

Our approach to our second type of survey was used to measure and evaluate content presented in our Learning Labs. The method used was asking participants four questions (see

Table 136) using a Likert-Scale (1 strongly disagree, 2 disagree, 3 neutral, 4 agree and 5 strongly agree) and this process was repeated for Learning Labs 2-5 surveys to maintain consistency in measuring our progress. What we learned was on an average respondents 'Agreed', our meeting objectives of the presentation were clearly stated and met, the presentation was well-organized and easy to follow, the information presented was relevant and useful and the content presented increased my knowledge of topic(s). We were pleased with the results, and found it demonstrated we were delivering content in a way that was understandable. We do recognize we had a small sample size, but we believe our Learning Labs were in impactful and did good job incorporating attendees' feedback.

Table 136. Repeated survey questions to assess value delivered to attendees

Question	Agreed
The objectives of the presentation were clearly stated and met.	3.8
The presentation was well-organized and easy to follow.	4.3
The information presented was relevant and useful.	4.0
The content presented increased my knowledge of topic(s).	3.5

The qualitative data that was collected, via our survey, provided us greater insight into how the participant was feeling and gave them an opportunity to openly and anonymously express feedback on our Learning Labs (see **Table 138**). Highlights from what we learned from attendees when we asked for Additional comments/feedback you would like to share, including recommendations for improvement. The following are the responses from Learning Lab sessions 1-5:

- "I think it is important to have a sense of what these meetings are leading to. Process is really important, and iteration is important too, but when we are dedicating hours to a process it is crucial for us to see tangible outcomes. Having a sense of what those can be early on is helpful."
- "The presentation was good. The make-up of the room was low on the CBO space (I think at one point I counted 10 people who were not IOU or not PUC, and one CBO partner). Not sure how you can go about addressing that as I know you are trying to make this room accessible to people in the CBO space. Will keep thinking and offer any suggestions that I come up with."
- "It was a really good meeting. The content was good. All the presentations felt good to me. Will encourage folks to watch the video if they could not make it."

- "In general, it would have helped for audience members to have materials before the presentation so that they could review it and be ready to learn. The presenter had the most information dense slides in the deck and although he obviously knows his subject matter, he has to understand his audience doesn't have nearly as much insight as he does. Slowing down enough to allow listeners to visually bring their eyes to the information being highlighted would help. I saw the moving his cursor, but he did not linger over the info long enough to make sure listeners could catch up with him."

We read everyone's feedback and acknowledged the areas where could make improvements. One respondent called out there were a large number of investor-owned utilities (IOUs) in the meeting, so we internally addressed this and capped the number of PGE employees who could attend. Also, we heard from another respondent that they wanted to us to share "tangible outcomes", so at our fifth Learning Lab we provided a progress report and updates of where we were at in the CEP process. This meeting was well received by attendees, and it taught us to have progress reports and updates every few months. We recognized the importance and value of collecting qualitative data and used this inform our future Learning Lab content and process improvement.

In conclusion, the surveys provided helpful feedback and input from our Learning Lab participants. In addition to measuring and evaluating our progress throughout CEP process. Again, we recognize that surveys were an efficient tool to measure outcomes and collect data, however low response rates were a challenge and could be found as ineffective. Overall, we thought our level of engagement was good and will continue to develop and learn from this experience.

Table 137. Quantitative survey responses

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
9/21/2022	1	17	6			What cadence would you find useful (monthly, quarterly, semi-annually, annually, or other)?	
9/21/2022	1	17	6	4	67%		Monthly
9/21/2022	1	17	6	2	33%		Quarterly
9/21/2022	1	17	6	5	83%	Would it be helpful to have meetings the same day and time?	Yes
9/21/2022	1	17	6	1	17%		Other
9/21/2022	1	17	6	6	100%	Do you want meetings to be recorded?	Yes
9/21/2022	1	17				How many Learning Labs (0-6) would you mostly likely attend the before March 2023?	
9/21/2022	1	17	6	4	66%		6
9/21/2022	1	17	6	1	17%		5
9/21/2022	1	17	6	1	17%		4
TOTAL RESPONSE RATE	**1**	**17**	**6**		**35%**		
10/27/2022	2	13	1	1	100%	The objectives of the presentation were clearly stated and met.	Agree

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
10/27/2022	2	13	1	1	100%	The presentation was well-organized and easy to follow.	Strongly Agree
10/27/2022	2	13	1	1	100%	The information presented was relevant and useful.	Strongly Agree
10/27/2022	2	13	1	1	100%	The content presented increased my knowledge of: Grid Needs, Non-Wires Solutions, Community Benefits Indicators and Community-Based Renewable Energy.	Agree
TOTAL RESPONSE RATE	**2**	**13**	**1**		**8%**		

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
11/16/2022	3	20		1	50%	The objectives of the presentation were clearly stated and met.	Strongly Agree
11/16/2022	3	20		1	50%	The objectives of the presentation were clearly stated and met.	Neither agree nor disagree
11/16/2022	3	20		1	50%	The presentation was well-organized and easy to follow.	Strongly Agree
11/16/2022	3	20		1	50%	The presentation was well-organized and easy to follow.	Agree
11/16/2022	3	20		1	50%	The information presented was relevant and useful.	Strongly Agree
11/16/2022	3	20		1	50%	The information presented was relevant and useful.	Disagree
11/16/2022	3	20				The content presented increased my knowledge of the following:	
11/16/2022	3	20	2	1	50%	Resilience	Strongly Agree
11/16/2022	3	20	2	1	50%	Request For Proposal 101	Strongly Agree

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
11/16/2022	3	20	2	1	50%	Community Benefits Indicators	Strongly Agree
11/16/2022	3	20	2	1	50%	Community-Based Renewable Energy	Strongly Agree
11/16/2022	3	20	2	1	50%	Resilience	Neither agree nor disagree
11/16/2022	3	20	2	1	50%	Request For Proposal 101	Neither agree nor disagree
11/16/2022	3	20	2	1	50%	Community Benefits Indicators	Neither agree nor disagree
11/16/2022	3	20	2	1	50%	Community-Based Renewable Energy	Neither agree nor disagree
TOTAL RESPONSE RATE		**20**	**2**		**10%**		

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
12/14/2022	4	7	1	1	100%	The objectives of the presentation were clearly stated and met.	Neither agree nor disagree
12/14/2022	4	7	1	1	100%	The presentation was well-organized and easy to follow.	Neither agree nor disagree
12/14/2022	4	7	1	1	100%	The information presented was relevant and useful.	Agree
12/14/2022		7				The content presented increased my knowledge of:	
12/14/2022		7	1	1	100%	Community Benefits Indicators (iCBIs, rCBIs & pCBIs) in IRP modeling	Agree
12/14/2022	4	7	1	1	100%	Resilience Product Development	Agree
TOTAL RESPONSE RATE		**7**	**1**		**14%**		

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
1/19/2023	5	7	0	0	0%	The objectives of the presentation were clearly stated and met.	
1/19/2023	5	7	0	0	0%	The presentation was well-organized and easy to follow.	
1/19/2023	5	7	0	0	0%	The information presented was relevant and useful.	
1/19/2023	5	7	0	0	0%	I appreciated the updates and content presented about the following:	
1/19/2023	5	7	0	0	0%	Community Engagement	
1/19/2023	5	7	0	0	0%	Resilience Product	
1/19/2023	5	7	0	0	0%	Potential CBRE Acquisition Paths	
1/19/2023	5	7	0	0	0%	Community Benefits Indicators	
1/19/2023	5	7	0	0	0%	Community Benefits and Impacts Advisory Group	

Learning Lab Date	Lab #	# of attendees	Total # of responses	# of responses per question	Percent	Question	Response
1/19/2023	5	7	0	0	0%	IRP Roundtable	
1/19/2023	5	7	0	0	0%	Distribution System Plan Generation Evaluation Map	
TOTAL RESPONSE REATE		**7**	**0**		**0%**		

Table 138. Qualitative survey results

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	What topics do you want covered in our CEP learning labs?	CBIs, ways to streamline all three processes, how PGE will define resiliency.	Exploring in more detail how the three processes interact (IRP, DSP, CEP), community benefits indicators, exploring how justice issues can be addressed in IRPs (beyond CBREs), community resilience.	Multiple and varied community insights from the range of customers PGE serves, and reflection from PGE on how those insights are used or not.	Emissions reductions, upgrades to services in EJ communities, maximizing grid tech upgrades, reducing costs where possible	Understanding PGEs existing generation resources (purchases and facilities PGE owns) and which resources power residential customers electricity.	Utilities 101, what is OPUC, what is DSP, what does Energy Trust of Oregon do, benefits of heat pumps, funding opportunities.

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	Who is missing from this space (recommendations for whom we ought to invite)?			There were quite a few utility representatives and few community members.	I'm not sure the EJ representatives have enough presence from what I have observed in OPUC meetings.		

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	What are your recommendations for holding multiple meetings (i.e., IRP, DSP, and CEP)?	Recording them and sharing out recordings and slides so that people can watch when they have time. Sharing emails beforehand about the meeting topics so people can attend the pieces that they are most interested in (if they can't attend all of each meeting).		Meetings can be separate and held as needed; but each one should start as this one did - overview of the planning at PGE, where this particular meeting fits in there, where to go if you want to catch up on the whole or other pieces.	I think for me an integrated approach would be best.	Consolidate as much as possible.	

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	How can we make information more accessible?	Posting recordings and slides in an easy to access place or sharing out the recording and slides to the email group.		Broader distribution of meeting invitations; proactive outreach to get people to the table.	Because I'm not sure I know how to explore your existing information adequately, I would appreciate an overview.	Email resources and agenda prior to calls and make recordings available shortly after.	Materials translated in Spanish, also maybe a Spanish interpreter in meetings if needed
1	What recommendations can you provide for collaboration with our tribal communities?			Remain in a learning mode far longer than you are comfortable with; when you think it's time to move to the next stage, hold and go back into learning mode. Truly commit to a lasting relationship.	I have no expertise here.	Reach out to Tribes directly.	Start with one-on-one interviews - collaborate with Indigenous community-based organizations.

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
1	Any additional feedback you would like to share?		I think it is important to have a sense of what these meetings are leading to. Process is really important, and iteration is important too, but when we are dedicating hours to a process it is crucial for us to see tangible outcomes. Having a sense of what those can be early on is helpful.				Thanks for all the work you are doing, this is very important!

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
2	What topics would you like to be considered in future Learning Labs?	-Different funding streams that can help build CBREs and other DSP projects. -How different dockets (IRP, DSP, CEP, WPP, TE) can be streamlined.					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
3	What topics would you like to be considered in future Learning Labs?	The follow up to how CBIs could be part of large-scale resources RFP.	I was hoping the Learning Lab would be more like a tutorial to understand the IRP better. The IRP uses lots of acronyms and assumes many things that aren't made apparent even after listening for a year. I had hoped to be caught up on these matters. I would like to understand the unspoken pros and cons implied by graphs and discussions presented at	The presentation was good. The make-up of the room was low on the CBO space (I think at one point I counted 10 people who were not IOU or not PUC, and one CBO partner). Not sure how you can go about addressing that as I know you are trying to make this room accessible to people in the CBO space. Will keep thinking and offer any suggestions			

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
			IRP. For example, no one is explicit about the seriousness of the distribution/ transmission problem. There isn't enough comparison of PGE demand and supply with the resources being considered in detail for me to get a sense of scale of the material. This could be improved at IRP (best) or addressed at the Learning Lab.	that I come up with. It was a really good meeting. The content was good. All the presentations felt good to me. Will encourage folks to watch the video if they could not make it.			

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
3	Additional comments/feedback you would like to share, including recommendations for improvement.	The presentation was good. The make-up of the room was low on the CBO space (I think at one point I counted 10 people who were not IOU or not PUC, and one CBO partner). Not sure how you can go about addressing that as I know you are trying to make this room accessible to people in the CBO space. Will keep thinking and offer any suggestions					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
		that I come up with. It was a really good meeting. The content was good. All the presentations felt good to me. Will encourage folks to watch the video if they could not make it.					
4	What topics would you like to be considered in future Learning Labs?	If leaving no one behind is one driving force for the work, it's going to be a huge task. Federal funds could do a lot but at some point, private funds will probably					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
		need to come into play. I like to get some idea of how much work can be accomplished in the short term and longer term to improve community resilience. How much funding is available through ETO and other sources? How much can we expect will get done in the next 5 years?					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
4	Additional comments/feedback you would like to share, including recommendations for improvement.	In general, it would have helped for audience members to have materials before the presentation so that they could review it and be ready to learn. Mr. Shah had the most information dense slides in the deck and although he obviously knows his subject matter, he has to understand his audience doesn't have nearly as much insight as he					

Lab #	Question	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback	Participant Feedback
		does. Slowing down enough to allow listeners to visually bring their eyes to the information being highlighted would help. I saw Mr. Shah moving his cursor, but he did not linger over the info long enough to make sure listeners could catch up with him.					
5	No respondents						

Appendix M. Supply-side options

This appendix provides information summarizing the operational and cost attributes of various power generation and storage technologies. The technologies considered include onshore and offshore wind, solar photovoltaic, battery and pumped hydroelectric energy storage, hydrogen production and storage, geothermal, biomass, nuclear powered generation, and various natural gas-fueled resources including a combined-cycle combustion turbine with carbon sequestration.

M.1 Sources of information

M.1.1 Resource costs and operating parameters

The National Renewable Energy Laboratory produces the Annual Technology Baseline (NREL ATB) to "develop and document transparent, normalized technology cost and performance assumptions" for typical generating resources in the United States. The Energy Information Administration (EIA) commissioned Sargent & Lundy to "evaluate the overnight capital cost and performance characteristics for 25 electric generator types" to reflect these generators in the Annual Energy Outlook 2020 (EIA AEO).[500] Resource capital and operating expenditures, as well as operating parameters, are sourced from the ATB and AEO unless otherwise noted (**Table 139** and **Table 140**). Where information needed for PGE's models is not provided in the ATB or AEO, PGE relies on information from other publicly available sources, including supply-side options studies prepared in support of past IRPs. Historical inflation rates were applied to escalate from the EIA and NREL study values.

Note that in tables containing numerical values, the totals may not add due to rounding.

NREL defines capital expenditures as generally including costs in the following categories:[501]

[500] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf
[501] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/definitions

Table 139. Capital expenditure details

Capital expenditure components	Description
Balance of system/balance of plant	All other major plant components within the facility fence line are necessary to deliver electricity to the bulk power system.
Electrical infrastructure and interconnection (electrical interconnection, electronic, electrical infrastructure, electrical)	• Internal and control connections • Onsite electrical equipment (e.g., switchyard) • Power electronics • Transmission substation upgrades
Generation equipment and infrastructure (civil works, generation equipment, other equipment, support structure)	• Plant construction • Power plant equipment
Installation and indirect	• Distributable labor and materials • Engineering • Start-up and commissioning
Owners' costs	• Development costs • Environmental studies and permitting • Insurance • Legal fees • Preliminary feasibility and engineering studies • Property taxes during construction
Site costs	• Access roads • Buildings for operation and maintenance • Fencing • Land acquisition • Site preparation • Transformers • Underground utilities

NREL defines operational expenditures as generally including costs in the following categories:[502]

Table 140. Operational expenditure details

Operational expenditure components	Description
Fixed costs	• Administrative fees • Administrative labor • Insurance • Land lease payments • Legal fees • Operating labor • Other • Property taxes • Site security • Taxes
Fixed costs components	Project management
Maintenance costs	• General maintenance • Scheduled maintenance over technical life • Unscheduled maintenance over technical life
Variable cost components	• Consumables (e.g., water, chemicals, catalysts, etc.) • Waste disposal (e.g., ash, slag, process wastes, process byproducts that are not otherwise sold, etc.)
Maintenance components	Transformers
Replacement costs	Annualized present value of large component replacement over technical life

[502] *Id.*

M.2 Renewable resources

M.2.1 Onshore wind

Technology description

Wind turbine generators convert kinetic wind energy into electrical power. The horizontal-axis three-bladed design is the most ubiquitous type of wind turbine used for electric power generation. Lift is generated when wind flows around the turbine blades, resulting in rotation. The blades are connected to a central hub and drivetrain that turns a generator inside the nacelle, which is the housing positioned atop the wind turbine tower.

Commercial status

Installed wind capacity has grown by more than 50 percent in the United States since 2017. At the end of 2021, wind generating capacity in the country totaled nearly 136 GW.[503] Key aspects of wind turbine generator designs continue to grow as well. The average rated capacity of new turbines in 2021 was 3.0 MW, 9 percent more than the year prior. Likewise, the blade rotor diameter of new turbine installations grew 2 percent to 127.5 meters and hub heights rose to nearly 94 meters or 4 percent higher than the prior year's average.[504]

Operational characteristics

Three PNW sites, and one Wyoming location, are modeled with identical turbine specifications and layouts, shown in **Table 141**:

Table 141. Summary of Oregon onshore wind operational characteristics 2026 COD

Site	Lat.	Long.	IRP CF%
Oregon Gorge	45.65	-120.63	44.4%
Central Montana	46.35	-110.34	42.3%
Southeast Washington	46.41	-117.84	42.0%
Casper Wyoming	43.04	-105.56	44.1%

[503] Lawrence Berkeley National Laboratory. "Land-based Wind Market Report: 2022 Edition," available at: https://emp.lbl.gov/publications/land-based-wind-market-report-2022
[504] *Id.*

3.5 MW turbines are modeled in System Advisor Model (SAM) using eight years of weather data, as mentioned previously. The Hub height is 105 meters, and rotor diameter is 136 meters. These parameters are consistent with those specified for a NW wind resource in PGE's most recent IRP. Maintaining a consistent resource configuration at the three sites focuses any analysis on wind resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will use their expertise to design an optimal solar PV resource for any specific location. Each site employs 87 turbines to provide approximately 300 MW of generating capacity. The default layout in SAM arranges the turbines in three rows of 29 turbines with eight-rotor diameter spacing. The "Simple Wake Model" estimates the interactive effects on downwind turbines. According to NREL, this model "uses a thrust coefficient to calculate the wind speed deficit at each turbine due to wake effects of the upwind turbines."[505]

An hourly generation profile is simulated for each year of weather data for each site listed in the previous table. These hourly generation profiles are produced using SAM. The profiles are used as inputs to Sequoia. The hourly shape for the representative year is used as input to Aurora for energy modeling.

Operational expenditures

Operational expenditures for the representative onshore wind resource are derived from the EIA AEO 2020 study, shown in **Table 142**. The general categories of costs included in operational expenditures are listed earlier.

Table 142. Summary of Oregon onshore wind operational expenditures

Operational expenditures, onshore wind				
2019$	**Oregon Gorge**	**Southeast Washington**	**Central Montana**	**Casper Wyoming**
Fixed O&M ($/kW-year)	$26.34	$26.34	$26.34	$26.34
Less: Land Lease	$2.80	$2.80	$2.80	$2.80
Fixed O&M Ex-Land Lease	$23.54	$23.54	$23.54	$23.54

[505] SAM Version 2021.12.02 Help System. NREL. https://sam.nrel.gov/images/web_page_files/sam-help-2021-12-02.pdf

Operational expenditures, onshore wind				
Variable O&M ($/MWh)	$0	$0	$0	$0
Variable Land Lease ($/MWh)	$1.70	$1.70	$1.70	$1.70

Capital expenditures

Cost information is derived from the EIA AEO 2020 study. The general categories of costs included in capital expenditures are listed earlier. The EIA transmission line costs are removed, and PGE estimated values are used in the revenue requirements modeling process. A locational cost adjustment is applied based on the EIA study's resource location and the adjustment factors. The factors from the EIA study correspond to an average of Portland, Spokane, and Boise factors for the Oregon Gorge resource, an average of Spokane and Boise factors for the Southeast Washington resource, and Great Falls for the Montana resource (**Table 143**). Capital expenditures for the Casper, Wyoming, resource mirror the Central Montana location.

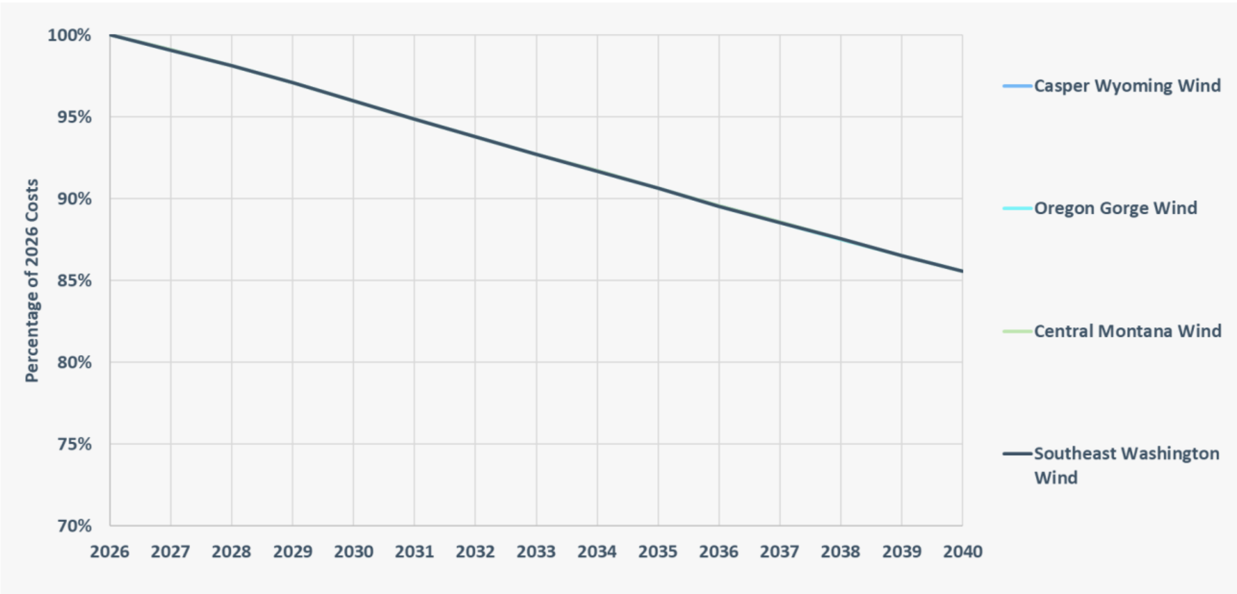
Table 143. Summary of Oregon onshore wind capital expenditures

Capital expenditures, onshore wind				
2019 $/kW	Oregon Gorge	Southeast Washington	Central Montana	Casper Wyoming
Overnight capital	$1,265	$1,265	$1,265	$1,265
Less: Transmission Line Cost	$6	$6	$6	$6
Overnight EPC Capital Cost -Ex Interconnect Cost	$1,259	$1,259	$1,259	$1,259
Location Adjustment	1.02	1.02	0.99	0.99
Location-adjusted Overnight Capital Cost	$1,288	$1,278	$1,246	$1,246

Forward capital cost curve

EIA onshore resources share a common forward capital cost trajectory across the various sites. The EIA AEO 2020 projection of future capital costs for the Reference Case scenario are presented in **Figure 157**.

Figure 157. Onshore wind capital cost trajectory



M.2.2 Offshore wind

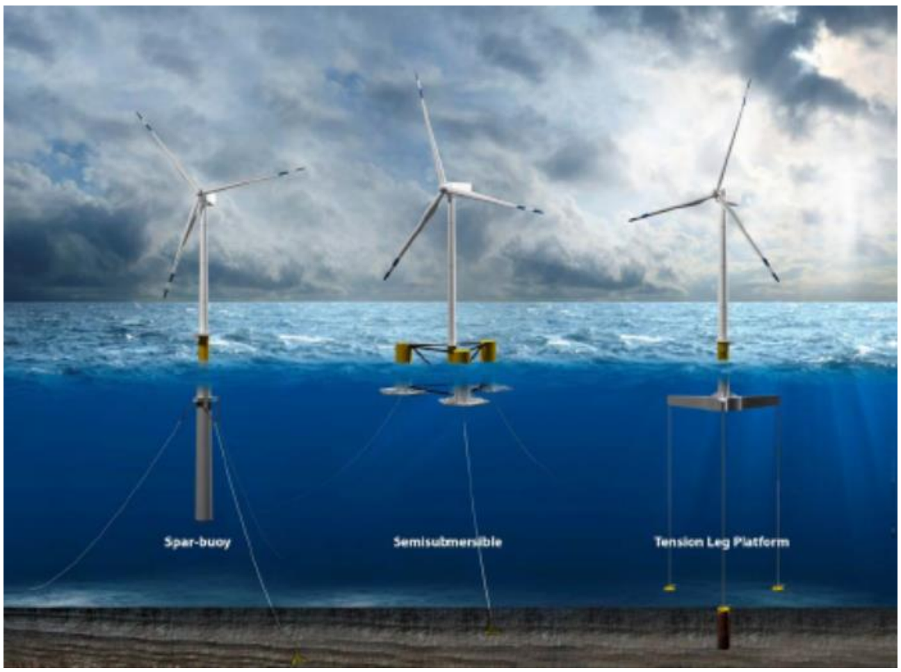
Technology description

Electricity generation from offshore wind is conceptually similar to that of onshore wind. The primary difference is that the wind plant is in offshore waters allowing access to a potentially diverse and more energetic wind resource. The offshore wind technology is generally described by the structure that suspends the turbine: "fixed-bottom" resources are those with a tower attached directly to the seabed; "floating" installations do not anchor the tower directly to the ground, but rather employ a structure that floats in the water and is anchored to the seabed (**Figure 158**). The application of fixed bottom vs. floating technology is generally dictated by the depth of the water, with water in excess of 60 meters typically requiring the use of a floating structure. According to NREL research, water depths are greater than 60 meters in 97 percent of the water on the Outer Continental Shelf (OCS – administered by the federal government) off the Oregon coast, dictating the use of a floating technology as opposed to fixed-bottom.

The structure further defines the technology: spar-buoy, semi-submersible, tension leg platform.

Each design offers certain advantages and disadvantages relative to the others. For example, the semi-submersible design has a shallower draft (the distance the structure occupies under the water surface) than the spar-buoy type, requiring less water depth for assembly. Companies are Innovating structure designs to optimize costs and performance. According to NREL, the semi-submersible structure is dominant in the conditions expected for Oregon offshore wind development and is the basis for cost estimates.

Figure 158. Floating offshore wind platforms



The assumption for a project online in 2032 makes use of semi-submersible platforms employing turbines rated at 15 MW with 248-meter rotor diameters at hub heights of 150 meters. These specifications are equivalent to those proposed by NREL for the 2032 reference technology. Turbine power curve data are also consistent with those used by NREL, as updated for 2021.[506]

[506] Musial, Walter, Patrick Duffy, Donna Heimiller, and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling. Available at: nrel.gov/docs/fy22osti/80908.pdf.

Commercial status

European deployments of offshore wind vastly outpace those of the United States. According to WindEurope, an industry advocacy group, total offshore wind capacity in Europe totaled more than 28 GW at 2021year-end. This capacity is expected to almost double in the period 2022–2026. More than 3 GW was added in 2021 alone.

The Biden Administration has stated a goal of 30 GW of offshore wind by 2030. The state of California has established a goal of 2-5 GW of offshore wind capacity by 2030 and 25 GW by 2045.[507] State and federal goals for offshore wind development In the United States, offshore wind development in federal waters is overseen by the Bureau of Ocean Energy Management (BOEM). The areas under BOEM's responsibility include the submerged lands on the OCS, which begins approximately three nautical miles offshore and extends to 200 nautical miles marking the exclusive economic zone boundary. BOEM controls the process for issuing leases and approving offshore wind projects on the OCS. The leasing process includes stakeholder engagement and numerous opportunities for review and approval. This process may extend many years from the lease initiation to the approval of a construction and operations plan preceding construction. BOEM plans to review 16 offshore wind projects, more than 22 GW, by 2025.

As of mid-2021, two offshore wind projects were operating in waters off the east coast of the US: Block Island Wind Farm (approximately 30 MW off the coast of Rhode Island) and the Coastal Virginia Offshore Wind pilot project (12 MW off the Virginia coast). Additionally, the 800 MW Vineyard Wind project off the Massachusetts coast is fully permitted and expected to be operational in 2024, while the 130 MW South Fork project off the coast of Rhode Island was approved in 2022 and may reach COD in 2023.

The 2022 New York Bright auction for offshore wind leases saw six developers win leases on six areas representing more than 488,000 acres. The winning bids totaled $4.37 billion, or an average of nearly $9,000 per acre.

Two BOEM wind energy areas are off the California coast (Morro Bay and Humboldt). The results of the lease sale for these sites were released December 7, 2022.[508] Five leases were sold through the auction. The sites comprise more than 370,000 acres with an average price of approximately $2,000 per acre. BOEM reports that development of these lease areas could potentially support 4.6 GW of generating capacity.

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[507] California Energy Commission. Offshore Wind Energy Development off the California Coast. August 2022. https://www.energy.ca.gov/filebrowser/download/4361#page=63&zoom=100,0,0

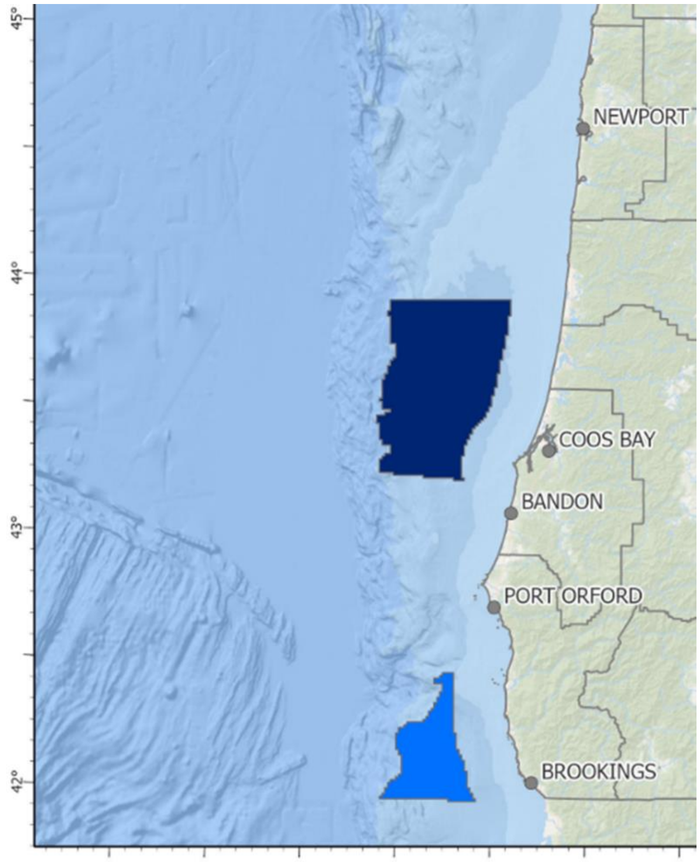
[508] US Department of the Interior. Biden-Harris Administration Announces Winners of California Offshore Wind Energy Auction. https://doi.gov/pressreleases/biden-harris-administration-announces-winners-california-offshore-wind-energy-auction

Oregon offshore developments

In HB 3375, Oregon's Legislative Assembly identifies several potential benefits and roles that offshore wind could bring to the utility/electricity sector and regional economy. The legislation requires the Oregon Department of Energy to explore the "benefits and challenges of integrating up to three gigawatts of floating offshore wind energy into Oregon's electric grid by 2030."

On April 27, 2022, the BOEM issued a Call for Information and Nominations regarding the potential for wind energy leases in federal waters off the south-central and southern Oregon coast (**Figure 159**). The two areas identified (Call Areas) comprise approximately 1,800 square miles. The Coos Bay Call Area represents over 1,300 square miles with water depths ranging from 400 to 700 feet. The southern Brookings Call Area is more than 400 square miles in depths of 400 to 1,100 feet.

Figure 159. Coos Bay and Brookings call areas[509]



The areas potentially leased for commercial development will be a subset of the Call Areas. The initial BOEM leases could result in up to 3 GW of offshore wind capacity, per published statements. The total potential offshore wind capacity in the Call Areas is roughly 14 GW according to BOEM's assessment (assumes 3 MW / square kilometer).

NREL analysis finds the potential for up to 2.6 GW of wind nameplate capacity, or nearly 2.2 GW, at the assumed points of interconnect (POIs) along the Oregon coast. The findings are summarized in **Table 144** (note that the difference between the "Max Capacity" and "Max Injected" values is explained by assumed losses between the plant and POI). These values arise from NREL's attempt to determine the "maximum possible penetration of offshore wind without trans-coastal transmission infrastructure upgrades." Per NREL, the analytical process is as follows:

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[509]Coos Bay and Brookings call areas, available at: https://www.boem.gov/sites/default/files/images/or_callareas_april2022.jpg

> *"We started by scaling the maximum power output of offshore wind at each of the five points of interconnection to match the summer trans-coastal line limit for the associated evacuation line. The summer limits were verified in consultation with BPA; however, there is uncertainty regarding the exact limits on these lines. Then, we ran the full-year model and checked for congestion of the trans-coastal lines. If a particular line did not exhibit congestion during the entire year, we increased the capacity of its associated offshore wind generation by the available capacity in its highest use hour (i.e., the maximum flow subtracted from the line limit). If a line exhibited congestion, we first checked that the congestion occurred simultaneously with the curtailment of its associated offshore wind generation. We then reduced the offshore generation capacity to eliminate the congestion. We repeated this process several times until the trans-coastal transmission was fully utilized with minimal congestion and with no study site experiencing more than 1 percent annual curtailment."*

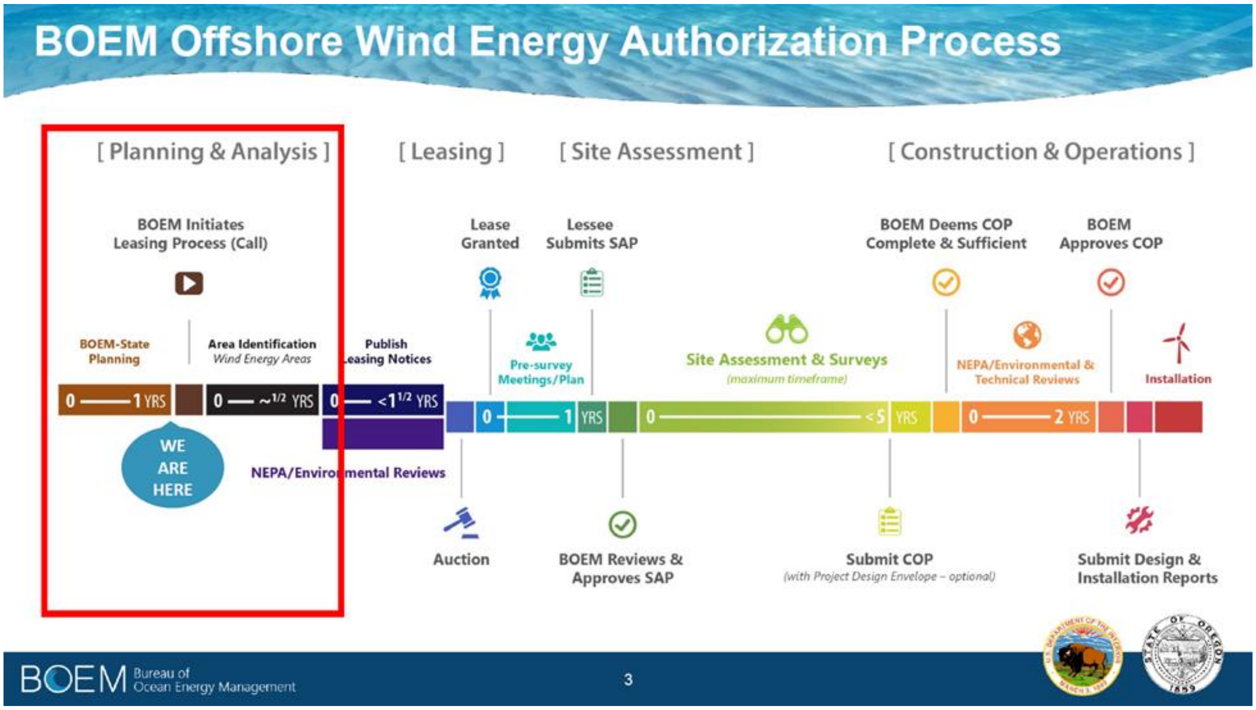
Table 144. NREL Oregon offshore wind interconnection potential

Offshore Wind Point of Interconnection	Max Capacity (MW)	Max Injected Power (MW)
1 – Clatsop	361	301
2 – Tillamook	553	461
3 -Toledo	156	130
4 - Wendson	613	512
5 - Fairview	941	7852
Total	2625	2189

The NREL authors note, "Detailed power flow analysis is needed to refine the distribution of offshore wind, the total offshore wind capacity, and identify small upgrades to the trans-coastal system to enable or increase the 2.6 GW finding."

Lengthy lead time gave the BOEM lease auction process and regulatory requirements (Site Assessment Plan – SAP, Construction and Operations Plan – COP) preceding the construction phase. The following timeline from BOEM's Oregon offshore wind process is still relatively near the beginning (**Figure 160**). Current expectations are a COD for the first Oregon offshore wind project in 2032.

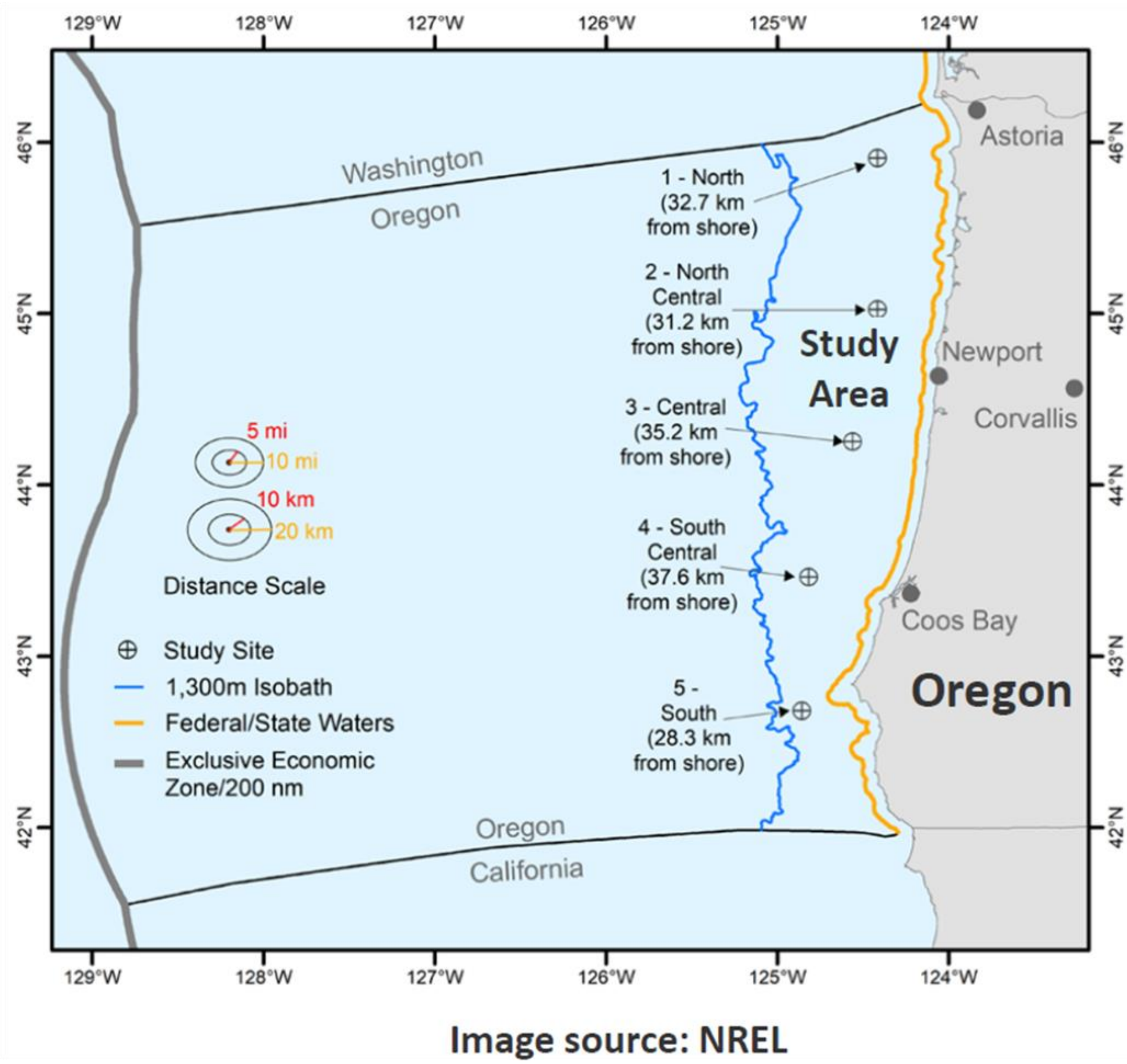
Figure 160. BOEM offshore wind development process



Operational characteristics

Figure 161 shows NREL research which presents five potential sites for Oregon offshore wind:

Figure 161. NREL Oregon offshore sites



Study Site "4 – South Central" in the NREL graphic is approximately equivalent to a location within the Coos Bay Call Area, while Study Site "5 – South" aligns with Brookings Call Area.

PGE focuses on the southernmost site to model an offshore wind resource. This site produces the highest capacity factors based on analysis of the historical weather data.

PGE's analysis of the wind resource utilizes an NREL dataset covering the 20 years 2000 through 2019 ("OR-WA20" dataset).

The generic offshore wind resource in the IRP is modeled as a semi-submersible platform 15 MW turbine with a 248-meter rotor diameter at a hub height of 150 meters (**Table 145**). These specifications are equivalent to those proposed by NREL for the 2032 reference technology. Sixty-four turbines are used to provide approximately 960 MW of generating capacity. The turbine arrangement is based on a seven-rotor diameter spacing per NREL. The default layout in SAM arranges the turbines in eight rows of eight turbines. As with the onshore wind analysis, the "Simple Wake Model" estimates the interactive effects on downwind turbines. PGE's energy modeling analysis uses the NREL published power curve for a 15 MW turbine, including revisions to the cut-out speed as detailed in the 2021 update.[510]

Table 145. Oregon offshore wind operational characteristics

Site	Lat.	Long.	Hub Height (m)	Rotor Diameter (m)	Turbine Rating (MW)	IRP CF (%)
Oregon South	42.69	-124.84	150	248	15	55.2%

Operational expenditures

Estimates for offshore wind operational expenditures use NREL's Oregon site-specific research to 2032 COD (**Table 146**). Beyond 2032, cost trajectories follow those provided in the NREL 2021 ATB.

Table 146. Summary of Oregon offshore wind operational expenditures

Operational Expenditures, offshore wind	
2019$	Oregon South
Fixed O&M ($/kW-year)	$97
Variable O&M ($/MWh)	$0

[510] Musial, Walter, Patrick Duffy, Donna Heimiller, and Philipp Beiter. 2021. Updated Oregon Floating Offshore Wind Cost Modeling, available at: nrel.gov/docs/fy22osti/80908.pdf.

Capital expenditures

NREL's Oregon site-specific research shows that capital expenditures are based on 2032 COD (2021 Update). Beyond 2032, cost trajectories follow NREL ATB. The NREL capital costs are adjusted to PGE's definition of overnight capital by removing the estimated decommissioning costs and financing costs during the construction period (AFUDC). Estimated decommissioning costs are included in the fixed lifetime cost of resource ownership as discussed in the details regarding PGE's fixed revenue requirements model, LUCAS (See **Appendix H, 2023 IRP modeling details**). The overnight capital cost for the earliest published year (2022) is detailed in **Table 147**.

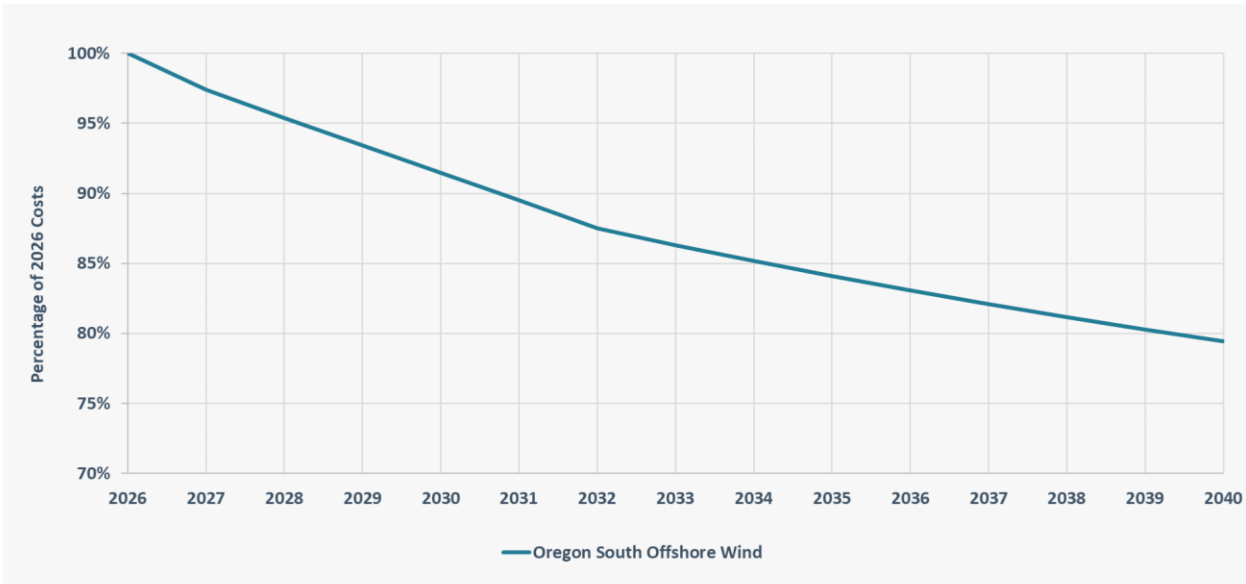
Table 147. Summary of Oregon offshore wind capital expenditures

Capital Expenditures, offshore wind	
2019 $/kW	Oregon South
Stated Capital Cost	$3,522
Less: Decommissioning	$34
Less: AFUDC	$142
Overnight Capital Cost	$3,346

Forward capital cost curve

Beginning with the earliest relevant year published by NREL, the overnight capital costs align with NREL's research to 2032 (**Figure 162**). Beyond 2032, cost curves developed by HDR for PGE's 2019 IRP are used.

Figure 162. Offshore wind capital cost trajectory



M.2.3 Solar photovoltaic

Technology description

Solar photovoltaic (solar PV) converts light from the sun into electrical energy. Cells generate direct current (DC) electrical energy. This conversion occurs within a cell; multiple cells are connected within a module. The total quantity of modules is the array. The power rating of the array is the DC capacity of the resource. The modules in the array can be either fixed at a given angle or tilted in one or two directions to track the sun. The orientation of the modules is typically defined with respect to azimuth (e.g., zero (0) if facing north, 180 if facing south).

Given that the array generates in DC, inverters are used to output AC electricity to the grid. The array's DC capacity related to the inverter's AC rating is referred to as the inverter load ratio (ILR). For example, an ILR of 2.0 means that the DC capacity of the array is twice the AC rating of the inverter. With this relationship, there will be periods when the array will have the potential to generate at levels higher than the inverter's rating. The inverter will limit the total output, and this excess energy from the array will be lost or "clipped."

Commercial status

Solar installations overall represented 45 percent of new generating capacity in 2021, up from 30 percent in 2017. The capacity installed in 2021 alone totaled approximately

18.9GWAC.[511] According to EIA data, approximately 60 GW of solar PV capacity was operational in the United States at the end of 2021.[512] Photovoltaic (PV) module efficiency has increased considerably over the past decade. An average standard monocrystalline module installed in 2021 was 20 percent efficient compared to approximately 14 percent in 2010.[513] National Renewable Energy Laboratory (NREL) reports recent increases in the share of bifacial modules installed, particularly in larger non-residential applications.[514] The median inverter loading ratio ("ILR" is the ratio of DC-to-AC capacity) for tracking solar PV projects installed in 2020 and 2021 was 1.34 and 1.33, respectively.[515] This value has been largely unchanged over the past five years. Solar PV installation with tracking continue to be preferred to fixed-tilt configurations. The trend towards tracking has grown significantly in the past eight years: in 2014, more solar PV capacity with fixed-tilt was installed than with tracking, by 2021, new tracking capacity additions represented nearly eight-times the capacity of fixed-tilt.[516]

Operational characteristics

Three Oregon locations are used to represent solar photovoltaic (PV) resources in the IRP: one central Oregon (east of Cascades) location near Christmas Valley, one location with a similar longitude (east of Cascades) but farther north near Wasco, and one location with a similar latitude as Wasco but in the Willamette Valley (west of the Cascades) near McMinnville (**Table 148**). A solar PV resource near Mead, Nevada, which will be accessed via incremental transmission action is included in PGE's analysis as well.

[511] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2022 Edition" available at: https://emp.lbl.gov/utility-scale-solar
[512] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only). https://www.eia.gov/electricity/data/eia860/
[513] National Renewable Energy Laboratory (NREL). Spring 2022 Solar Industry Update. April 23, 2022. available at: https://www.nrel.gov/docs/fy22osti/82854.pdf
[514] *Id.*
[515] Lawrence Berkeley National Laboratory. "Utility-Scale Solar, 2022 Edition" available at: https://emp.lbl.gov/utility-scale-solar
[516] *Id.*

Table 148. Summary of solar PV operational characteristics 2026 COD

Site	Lat.	Long.	IRP CF%
Central Oregon (Christmas Valley)	43.25	-120.62	26.7%
Oregon Gorge (Wasco)	45.61	-120.7	25.3%
Willamette Valley (McMinnville)	45.21	-123.18	21.1%
Nevada (Mead)	35.89	-114.98	31.6%

Solar PV resources utilize single-axis tracking. Energy estimates are created in SAM using crystalline silicon modules with 21 percent nominal efficiency and inverter efficiency of 98 percent.[517] The ILR is 1.34, consistent with the assumptions in the NREL ATB.

Similar to the rationale for onshore wind, resource configurations remain constant across the four Solar PV sites. This focuses any analysis on solar resource variations rather than attempting to optimize each site's design. It is expected that developers in the marketplace will employ their expertise to design an optimal solar PV resource for any specific location. An hourly generation profile is simulated for each year of weather data for each site listed in **Table 148**. These hourly generation profiles are produced using SAM. The profiles are used as inputs to Sequoia. The hourly shape for the representative year is used as input to Aurora for energy modeling. Consistent with the NREL ATB assumption, annual degradation of 0.5 percent is applied to arrive at the IRP capacity factor listed in **Table 148**.

Operational expenditures

Operational expenditures for the representative solar PV plant are sourced from the NREL 2021 ATB as well (**Table 149**). The general categories of costs included in operational expenditures are listed earlier.

[517] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf#page=66

Table 149. Summary of solar PV operational expenditures

Operational Expenditures, solar photovoltaic				
2019$	Central Oregon	Oregon Gorge	Willamette Valley	Mead, Nevada
Fixed O&M ($/kW-year)	$23	$23	$23	$23
Variable O&M ($/MWh)	$0	$0	$0	$0

Capital expenditures

Capital expenditures for the representative solar PV plant are sourced from the NREL 2021 ATB as well (**Table 150**). The general categories of costs included in capital expenditures are listed earlier.

Table 150. Summary of solar PV capital expenditures

Capital Expenditures, solar photovoltaic				
2019 $/kWac	**Central Oregon**	**Oregon Gorge**	**Willamette Valley**	**Mead, Nevada**
Overnight capital	$1,347	$1,347	$1,347	$1,347
Less: Transmission Line Cost	$71	$71	$71	$71
Overnight EPC Capital Cost -Ex Interconnect Cost	$1,277	$1,277	$1,277	$1,277

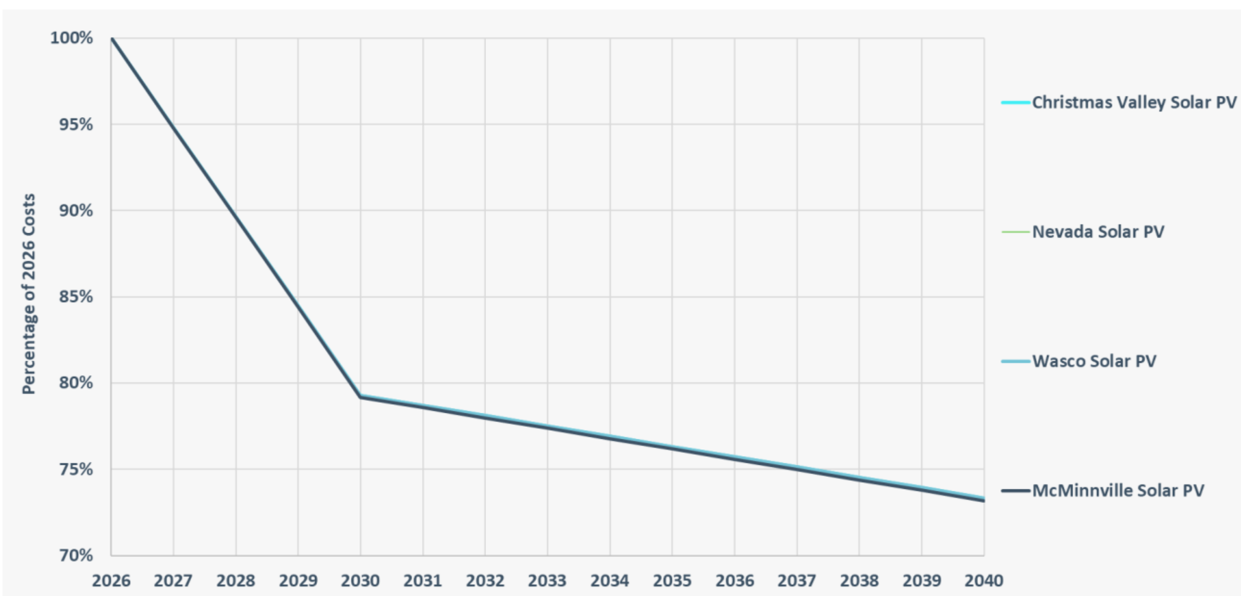
Capital Expenditures, solar photovoltaic				
Location Adjustment	1	1	1.05	1
Location-adjusted Overnight Capital Cost	$1,277	$1,277	$1,340	$1,277

Costs are presented in units of $/kWAC based on the aggregated inverter rating. The locational adjustments applied to Central Oregon and Oregon Gorge resources are based on an average of the EIA factors for Portland, Boise, and Spokane. The location adjustment factor for the Willamette Valley resource corresponds to the EIA factor for Portland. Note that NREL documentation includes land acquisition costs as a capital expenditure component.

Forward capital cost curve

The solar PV resources at different locations share a common forward capital cost trajectory. The NREL 2021 ATB projection of future capital costs for the Reference Case scenario are shown in **Figure 163**.

Figure 163. Solar PV capital cost trajectory



M.2.4 Geothermal

Technology description

Geothermal energy is the heat contained in the Earth's interior. This heat is typically accessed for electricity generation by the drilling of injection and production wells. Various technologies are used to harness the energy in a particular location depending on the nature of that specific resource, generally described by the temperature. Geothermal energy can also be employed for purposes aside from electricity generation; these so-called "direct use" cases include building and district heating, and recreation/therapeutic bathing.

Heat recovery generally generates electricity from geothermal resources in the form of hot water or steam via a well drilled into the earth. Resources are broadly categorized as either hydrothermal or enhanced geothermal systems (EGS) depending on the groundwater and subsurface rock structure characteristics.

Hydrothermal resources are those where the naturally occurring rock structure and groundwater flow are sufficient to support energy recovery. These may be referred to as "conventional" geothermal resources.

In contrast, EGS resources have sufficient heat but lack the groundwater or rock structure, allowing for efficient energy recovery. These resources require engineering techniques to introduce liquid or allow liquid flow within the rock structure.

EGS resources can be further classified based on their location with respect to existing conventional hydrothermal resources. When EGS techniques are applied within existing hydrothermal developments the resource is referred to as "in-field" EGS. This might happen to promote the recovery of energy from an otherwise non-productive well, for example. "Near-field" EGS occurs beyond the geological boundaries of a conventional resource where applying EGS engineering techniques can expand the development of cost-effective resources. "Deep" EGS refers to developing geothermal resources beyond those relying on hydrothermal fields. Areas of sufficient temperature would be identified and then accessed via drilled wells at depths of up to 7 km. The use of engineering techniques to introduce liquid and fracture the rock structure could allow for the recovery of vast amounts of energy.

In general, geothermal energy generates electricity by using the hot water or steam produced from within the Earth to turn a turbine and generator. The condensed liquid is then injected back into the ground. The technology to utilize that hot water or steam is generally dictated by the operating temperature of the specific resource.

Flash power plants are used at resources with relatively higher temperatures, generally exceeding 200 degrees Celsius. In this application, the heated fluid directly drives the turbine.

Binary power plants employ a heat exchanger to extract energy from the heated fluid and operate the turbine via a Rankine cycle (fluid movement through a system arising from temperature differences). This technology is generally used at resources with temperatures in the range of 100 – 200 degrees Celsius.

All else equal, it's expected that flash plants result in lower capital expenditures and higher operating efficiencies than binary plants.

Pairing resource descriptions and the technology options arising from the characteristics of a given resource results in the following six resource and technology categories:

(1) Hydrothermal Flash or (2) Hydrothermal Binary.

(3) Near-field EGS Flash or (3) Near-field EGS Binary.

(5) Deep EGS Flash or (6) Deep EGS Binary.

Commercial status

Nationally, according to EIA data, nearly 4 GW of geothermal generating capacity was operable at the end of 2021.[518] More than 3 GW are currently operating in the WECC. However, only one commercial project operates in Oregon, representing approximately 29 MW. The majority, over 95 percent, of regional geothermal capacity is in California and Nevada, representing 67 percent and 30 percent, respectively. Roughly 30 percent of California's geothermal capacity is at Calpine's nearly 700 MW The Geysers project is north of Santa Rosa.[519]

The only commercial geothermal project currently operating in Oregon is the Neal Hot Springs plant near Vale in eastern Oregon. The 28.5 MW project, which began operation in 2012, is jointly owned by Ormat and Enbridge; Idaho Power is the off-taker.

Operational characteristics

The representative geothermal plant in the RFP uses resource cost characteristics consistent with a hydrothermal flash resource from the NREL ATB.

[518] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)
[519] S&P Global Market Intelligence (work paper)

Operational expenditures

Fixed and variable operating expenditures are sourced from the NREL ATB. These costs represent the average annual expenditures for operations and maintenance over the resource's life (**Table 151**). These include the costs of plant and well-field components.

Table 151. Summary of geothermal flash operational expenditures

Operational Expenditures, geothermal flash	
2019$	**Oregon**
Fixed O&M ($/kW-year)	$137
Variable O&M ($/MWh)	$0

Capital expenditures

Capital expenditures for the representative geothermal plant are sourced from the NREL 2021 ATB as well (**Table 152**). In addition to the general cost categories listed earlier, geothermal-specific costs include: "exploration, confirmation drilling, well field development, reservoir stimulation (EGS), plant equipment" and "plant construction, power plant equipment, well-field equipment, and components for wells (including dry/noncommercial wells)."[520]

Table 152. Summary of geothermal flash capital expenditures

Capital Expenditures, geothermal flash	
2019 $/kW	**Oregon**
Overnight capital	$4,440
Less: Transmission Line Cost	$30
Overnight EPC Capital Cost -Ex Interconnect Cost	$4,410
Location Adjustment	1.04
Location-adjusted Overnight Capital Cost	$4,601

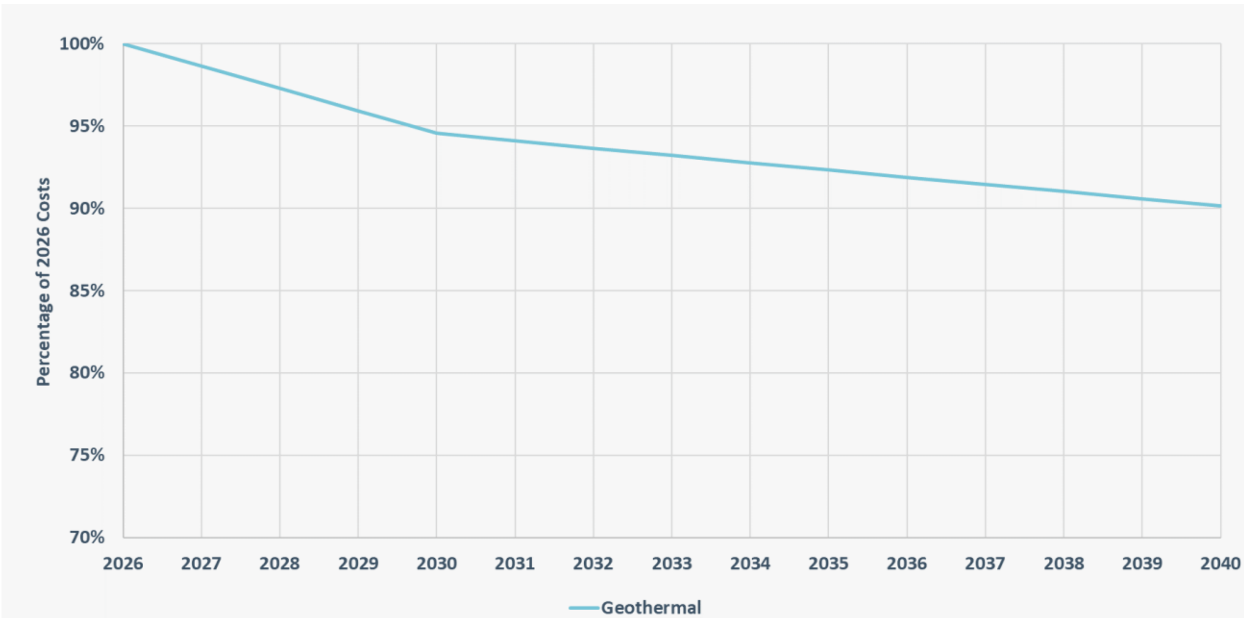
The locational adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

[520] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/geothermal

Forward capital cost curve

The NREL 2021 ATB projection of future capital costs for the Reference Case scenario are presented in **Figure 164**:

Figure 164. Geothermal capital cost trajectory



M.3 Energy storage resources

M.3.1 Battery energy storage

Technology description

PGE's IRP uses lithium-ion technology for analysis of battery energy storage systems (BESS) in this IRP. The cost and performance of storage durations ranging from 2-24 hours are evaluated.

Commercial status

According to EIA data, at the end of 2021, nearly 5 GW of battery energy storage capacity was operable in the United States. More than 3 GW of that total came online in 2021 alone.[521]

[521] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Operational characteristics

The representative battery energy storage systems (BESS) costs and performance characteristics are now based on lithium-ion technology. These data are sourced from the NREL ATB for durations up to eight hours; IRP cost assumptions for longer durations apply the NREL ATB methodology and are derived from the same energy and power cost estimates.

Operational expenditures

The NREL ATB derives fixed operational expenditures as a percentage (2.5 percent) of the overnight capital for BESS. As a result, these expenditures vary with by battery duration as summarized in **Table 153**. Fixed operational expenditures are inclusive of amounts required to compensate for degradation to enable the battery system to have a constant capacity throughout its life.[522]

Table 153. Summary of BESS operational expenditures

Operational Expenditures, battery energy storage system						
2019$	**2 Hour**	**4 Hour**	**6 Hour**	**8 Hour**	**16 Hour**	**24 Hour**
Fixed O&M ($/kW-year)	$20	$34	$48	$62	$117	$172
Variable O&M ($/MWh)	$0	$0	$0	$0	$0	$0

Capital expenditures

The capital expenditures for BESS are sourced from the NREL 2021 ATB (**Table 154**). The general categories of costs included in capital expenditures are listed earlier. The capital expenditures for BESS are a function of energy and power capacities:

Total system cost ($/kW) = Battery Energy Cost ($/kWh) * Storage Duration (hr.) + Battery Power Cost ($/kW)

[522] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/utility-scale_battery_storage

Table 154. Summary of BESS capital expenditures

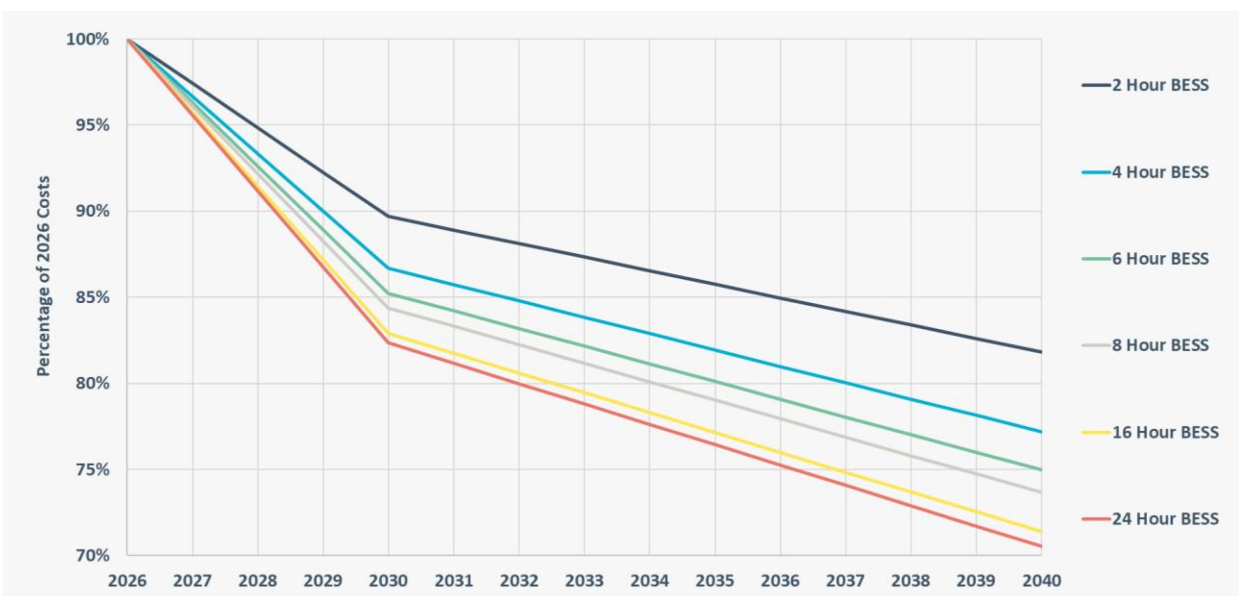
Capital Expenditures, battery energy storage system						
2019 $/kWac	**2 Hour**	**4 Hour**	**6 Hour**	**8 Hour**	**16 Hour**	**24 Hour**
Overnight capital	$792	$1,331	$1,870	$2,410	$4,567	$6,724
Location Adjustment	1.02	1.02	1.02	1.02	1.02	1.02
Location-adjusted Overnight Capital Cost	$810	$1,362	$1,914	$2,466	$4,674	$6,881

The location adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

Forward capital cost curve

Given that total capital costs are a function of the energy (weighted by duration) and power components, the trajectory of future capital costs for various durations depends on the developments assumed for these components. The NREL 2021 ATB future capital costs project a more rapid decline in energy component-related costs than power component-related costs. The result is that capital costs for longer-duration BESS decline more quickly than shorter duration. The Reference Case scenario is presented in **Figure 165.**

Figure 165. Battery energy storage system capital cost trajectory



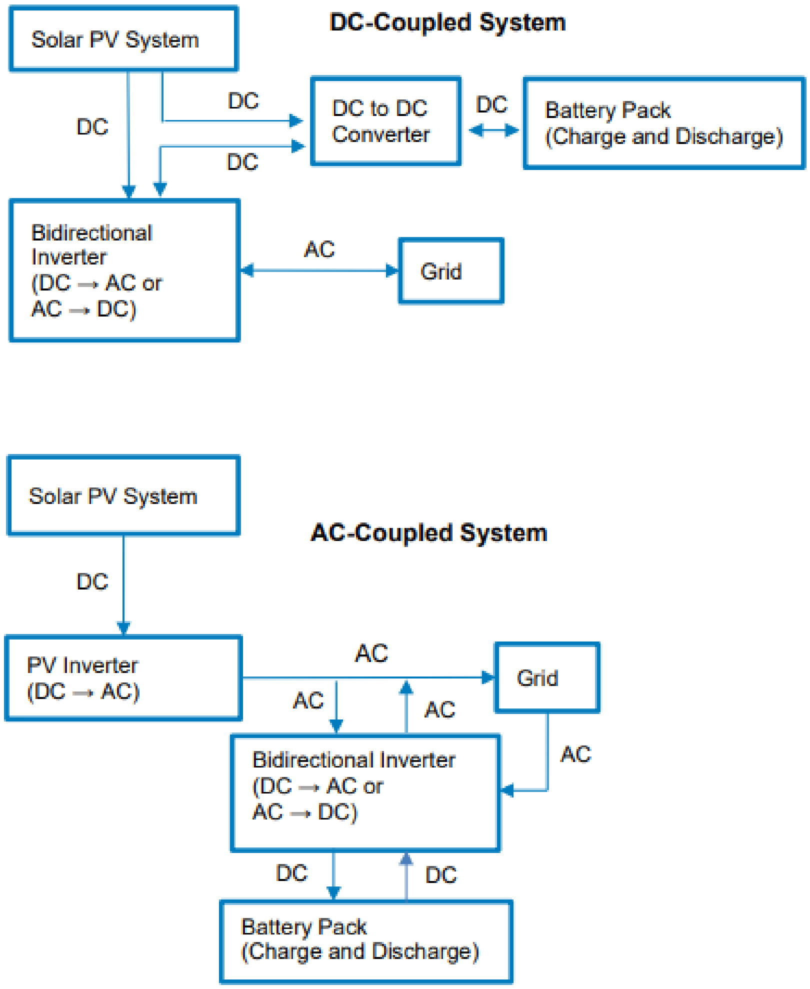
M.3.2 Hybrid solar photovoltaic + battery energy storage

Technology description

"Hybrid" resources pair renewable and storage resources behind a single interconnection. Hybrid resources could include solar PV with energy storage, wind with energy storage, and wind and solar PV with energy storage (such as PGE's Wheatridge Renewable Energy Facility), among others. In this 2023 IRP, PGE models solar PV with battery energy storage hybrid resources. Multiple elements are required when describing a solar + BESS resource, including resource coupling (AC- or DC-coupled), solar-to-storage ratio, solar-to-inverter ratio ("inverter loading ratio" as described previously), and storage duration. The solar and BESS components could be coupled on the AC side of the inverters (AC-coupled) or the DC side of the inverter (DC-coupled). When AC-coupled, the battery, and solar resources use separate inverters. The IRP assumption of DC coupling is consistent with the NREL ATB. **Figure 166** illustrates the basic elements of these two configurations.[523]

[523] Feldman, David, Vignesh Ramasamy, Ran Fu, Ashwin Ramdas, Jal Desai, and Robert Margolis. 2021. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2020. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-77324. https://www.nrel.gov/docs/fy21osti/77324.pdf.

Figure 166. Illustrative DC- and AC-coupled solar + BESS



Commercial status

Hybrid solar and storage were the dominant form of hybrid resources by the end of 2021. Solar and storage hybrids also saw a significant installed capacity increase; nearly 90 percent of all hybrid solar and storage resources came online in 2021 (when measured on a storage capacity basis, or ~77 percent when viewed on a generation capacity basis).[524]

[524] U.S. Department of Energy. "Land-based Wind Market Report: 2022 Edition." Available at: https://emp.lbl.gov/sites/default/files/2022_land_based_wind_market_report.pdf

Operational characteristics

Given the large number of hybrid resource permutations that would arise from investigating sensitivities around each design element, the IRP simplifies the analysis to include two representative solar and BESS hybrid resources at two locations (**Table 155**). At each location these two hybrid resources:

- Employ a DC-coupled configuration.
- Differ in the ratio of solar-to-storage capacity. The two representative hybrid resources tested in this IRP are differentiated by this ratio, with one resource featuring a storage power capacity equivalent to the inverter rating (1.0) and one resource with a storage power capacity equal to one-half of the inverter rating (0.5).
- Utilize the Christmas Valley and McMinnville solar locations discussed previously; however, the solar resources differ regarding the inverter loading ratio. While the standalone solar resource is modeled with an ILR of 1.34, the hybrid solar resource has an ILR of 1.50.
- Use BESS with a four-hour storage duration.

Table 155. Summary of hybrid solar PV + BESS operational characteristics

Hybrid PV + BESS				
Description	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Location (Lat., Long.)	43.25, -120.62	43.25, -120.62	43.25, -120.62	43.25, -120.62
Capacity (MWac)	75	75	75	75
Duration (hours)	4	4	4	4
Round-Trip Efficiency	86%	86%	86%	86%
Solar Capacity Factor[525]	28.6%	28.6%	23.0%	23.0%
Solar ILR	1.50	1.50	1.50	1.50

[525] Lifetime capacity factor inclusive of 0.5 percent annual degradation; does not account for battery storage of clipped energy.

Hybrid PV + BESS				
Solar Capacity (MWdc)	112.5	112.5	112.5	112.5
Storage Ratio	1:2	1:1	1:2	1:1
Storage Capacity (MW)	37.5	75	37.5	75

Operational expenditures

Solar PV and BESS values from the NREL 2021 ATB are the basis for the operational expenditures for the hybrid resources (**Table 156**).

Table 156. Summary of hybrid solar PV + BESS operational expenditures

Operational Expenditures			Hybrid PV + BESS	
2019$	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
Fixed O&M ($/kW-year)	$40	$53	$41	$54
Variable O&M ($/MWh)	$0	$0	$0	$0

Capital expenditures

The capital expenditures for the hybrid resources are sourced from the NREL 2021 ATB and cited NREL research (**Table 157**). The ILR of the solar resource in the hybrid configuration differs slightly from the standalone solar PV resource. The PV module and balance of system costs were scaled based on relationships from NREL research to approximate the difference in ILR.[526] Additionally, costs were scaled to estimate the two storage-to-inverter ratios mentioned previously. The general categories of costs included in capital expenditures are listed earlier.

Table 157. Summary of hybrid solar PV + BESS capital expenditures

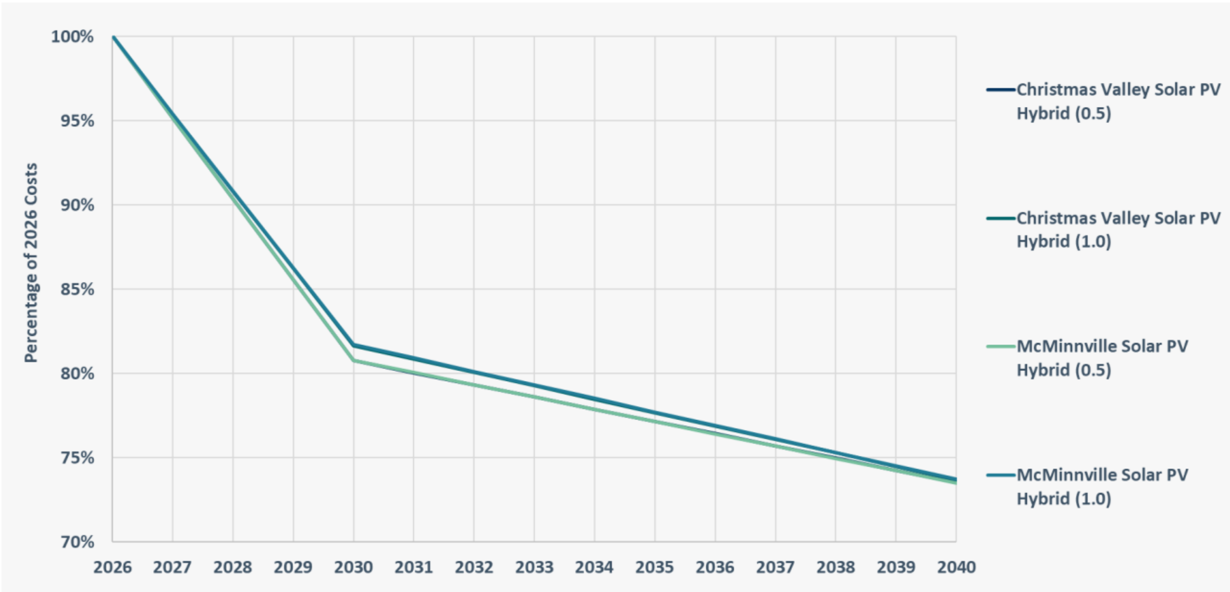
Capital Expenditures, hybrid PV + BESS				
2019 $/kWac	Christmas Valley Solar w/ 4 Hour Li-Ion (0.5)	Christmas Valley Solar w/ 4 Hour Li-Ion (1.0)	McMinnville Solar w/ 4 Hour Li-Ion (0.5)	McMinnville Solar w/ 4 Hour Li-Ion (1.0)
O/N Capital Cost ($/kW)	$1,931	$2,558	$1,995	$2,622
O/N Capital Cost ($/kWh)	$483	$640	$499	$655

Forward capital cost curve

The hybrid capital costs are a function of the solar PV and BESS components. As such, the trajectory of future capital costs for various durations depends on the developments assumed for those components. The NREL 2021 ATB future capital costs project a slightly faster decline in solar PV costs than BESS costs. The result is that capital costs for the hybrid pairings with relatively more solar than BESS (those with lower storage-to-inverter ratios) decline more quickly. The Reference Case scenario is presented in the following figure (**Figure 167**):

[526] NREL 2021 Electricity ATB. Available at: https://atb.nrel.gov/electricity/2021/utility-scale_pv-plus-battery#comparison_with_alternate_configurations

Figure 167. Reference case cost curve



M.3.3 Pumped hydroelectric energy storage

Technology description

Pumped hydropower energy storage resources generally employ two reservoirs at different locations. Water is pumped to the higher-elevation reservoir and stored, which converts electrical energy to operate the pumps into potential energy (charging). When the water is released from the reservoir it flows through a turbine, generating electricity (discharging).[527]

Commercial status

According to EIA data, approximately 22 GW of pumped hydropower capacity was operable in the United States at the end of 2021. However, no new capacity has come online in nearly a decade, with 370 MW of new capacity operable since 1995.[528]

[527] Portland General Electric. "THERMAL AND PUMPED STORAGE GENERATION OPTIONS." Prepared by HDR, Inc. as External Study D to 2019 Integrated Resource Plan. https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=556
[528] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Operational characteristics

The pumped-storage hydropower resource is a 600 MW closed-loop system (water is pumped between two reservoirs and is not connected to a water system) providing 10 hours of energy storage. The availability of this resource is geographically limited. Costs and performance attributes of this representative resource are based on an average of six proposed regional closed-loop projects gathered from information published by the Northwest Power and Conservation Council.

Operational expenditures

Operational expenditures for a representative pumped hydropower storage project in the pacific northwest are sourced from data published by the Northwest Power and Conservation Council in support of the 2021 Northwest Power Plan (**Table 158**).

Table 158. Summary of pumped hydropower storage operational expenditures

Operational Expenditures, pumped hydropower storage	
2019$	PNW
Fixed O&M ($/kW-year)	$17
Variable O&M ($/MWh)	$0

Capital expenditures

The capital cost for a representative pumped hydropower storage project in the pacific northwest is sourced from data published by the Northwest Power and Conservation Council in support of the 2021 Northwest Power Plan. The developer capital cost reported in **Table 159** is an average of the closed-loop system's data. To this cost, an allowance for the owner's expense is applied. The 20 percent owner's cost allowance compares with the 20 percent used by in other regional IRPs[529] on very similar data and approximately 25 percent used by PGE in the 2019 IRP based on data furnished by HDR, Inc. (**Table 159**).

[529] PacifiCorp. "2020 Renewable Resources Assessment." Revision 1, August 2020. https://www.pacificorp.com/content/dam/pcorp/documents/en/pacificorp/energy/integrated-resource-plan/2021-irp/2021-irp-support-and-studies/2020-10-01_PacifiCorp_2020_Renewable_Resource_Study_Report_FINAL.pdf#PAGE=44

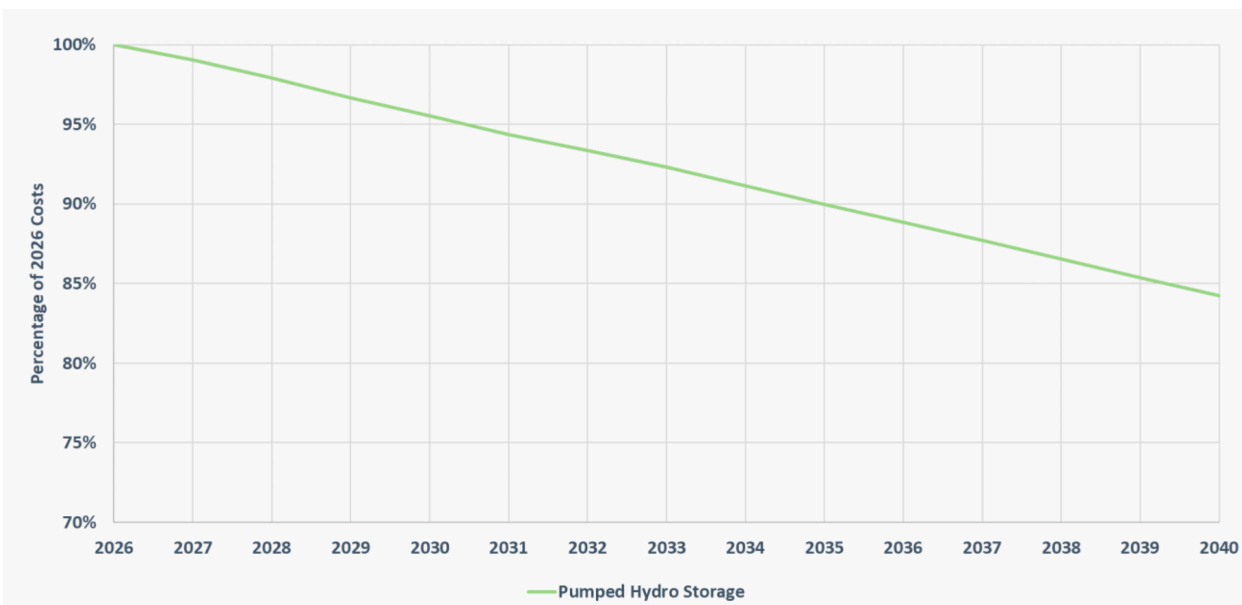
Table 159. Summary of pumped hydropower storage capital expenditures

Capital expenditures, pumped hydropower storage	
2019 $/kW	PNW
Developer Capital Cost	$2,135
Owner's Cost Allowance %	20%
Owner's Cost Allowance $/kW	$427
Overnight Capital Cost	$2,562

Forward capital cost curve

The HDR, Inc., projection of future capital costs for the Reference Case scenario are presented in **Figure 168**.[530]

Figure 168. Pumped hydropower storage capital cost trajectory:



[530] Portland General Electric. "THERMAL AND PUMPED STORAGE GENERATION OPTIONS." Prepared by HDR, Inc. as External Study D to 2019 Integrated Resource Plan. https://downloads.ctfassets.net/416ywc1laqmd/6KTPcOKFlLvXpf18xKNseh/271b9b966c913703a5126b2e7bbbc37a/2019-Integrated-Resource-Plan.pdf#page=522

M.3.4 Hydrogen-fueled CCCT with production and storage

Technology description

This resource is representative of a renewable ("green") hydrogen-fueled combined-cycle combustion turbine (CCCT) with hydrogen fuel production and storage. An electrolyzer uses electricity to produce hydrogen from water. The hydrogen (H2) is then compressed and stored in underground pipes; storage is sufficient to provide 24 hours of fuel supply. Where available, geologic formations (e.g., salt caverns) present an alternative means of fuel storage. The hydrogen fuel feeds the CCCT to generate electricity.

Commercial status

In June 2022, the U.S. Department of Energy (DOE) issued a loan guarantee in excess of $500 million to support the development of a hydrogen production and energy storage facility in Delta, Utah. 220 MW of electrolyzer capacity will produce hydrogen for storage in salt caverns. The hydrogen will then be available to fuel an 840 MW CCCT at the Intermountain Power Project.[531] The CCCT is expected to begin operation with blended hydrogen and natural gas fuel in 2025.[532] DOE states that the "scale of deployed electrolyzers as well as the use of salt caverns to store hydrogen are both significant innovations."[533]

Operational characteristics

For modeling purposes, the CCCT is consistent with the natural gas-fired resource described in **Section M.5 Natural gas-fueled resources**. Cost and performance parameters for this resource's hydrogen production and storage components are based on the research and analyses of Mongrid and Hunter.[534,535] The CCCT is paired with an equivalent electrolyzer capacity. As illustrated in the capital expenditure as shown in **Table 162**, the electrolyzer may be the primary capital expenditure on the H2 production side of the resource; reducing the electrolyzer capacity will lower costs but will result in longer H2 production (charging) times. The 1:1 pairing produces approximately seven metric tons of H2 per hour or approximately

[531] https://www.energy.gov/lpo/advanced-clean-energy-storage
[532] S&P Global Market Intelligence
[533] https://www.energy.gov/lpo/advanced-clean-energy-storage
[534] Mongrid et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[535] Hunter et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

38 percent of the fuel needed to operate the CCCT at full load for one hour. Consistent with the research, electrolyzer efficiency is assumed to be 72.5 percent. The CCCT is approximately 52 percent efficient (based on a perfect heat rate of 3,412 Btu/kWh and a CCCT lifetime heat rate of 6,561 Btu/kWh).

Table 160. Summary of CCCT w/ H2 operational characteristics

Operational Characteristics, combined-cycle CT (1 x 1) w/ H2 production/storage	
Capacity (MW average lifetime)	407
Heat Rate (Btu/kWh average lifetime)	6,561
Storage Duration (Hours)	24
Electrolyzer Efficiency (%)	72.50%
Planned outage rate	3.88%
Forced outage rate	2.19%

Operational expenditures

The H_2 production and storage operational costs are derived from Mongrid and Hunter and combined with the generation operational expenditures associated with the natural gas-fired CCCT (**Table 161**) discussed in **Appendix M.5.2, Combined-cycle combustion turbine**.[536,537]

Table 161. Summary of CCCT w/ H2 operational expenditures

Operational Expenditures, combined-cycle CT (1 x 1) w/ H2 production/storage	
2019$	
Fixed O&M ($/kW-year)	$27
Variable O&M ($/MWh)	$4

[536] Mongrid, et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf
[537] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

Capital expenditures

The H_2 production and storage component costs are derived from Mongrid and Hunter and summarized in **Table 162**.[538,539] Values are in 2019 dollars, and production costs are based on energy input to the system. These costs represent the components necessary to produce and store hydrogen for later combustion in an H-class CCCT.

Table 162. Summary of CCCT w/ H2 capital expenditures

Capital Expenditures, combined-cycle CT (1 x 1) w/ H2 production/storage	
2019 $kW	
PEM Electrolyzer (kW input)	$1,534
Rectifier (kW input)	$133
Compressor (kW input)	$40
Controls & Integration (kW input)	$20
Total Production (kW input)	$1,728
Pipe Storage (24 hours)	$710
Owner's Costs	$306
Total Production + Storage	$2,745

The owner's cost allowance of 12.5 percent (owner's cost in EIA research applicable to hydrogen fuel cell resource) is added to the production and storage values.[540]

Costs associated with the CCCT are based on the H-class CCCT detailed in **Appendix M.5.2, Combined-cycle combustion turbine**.

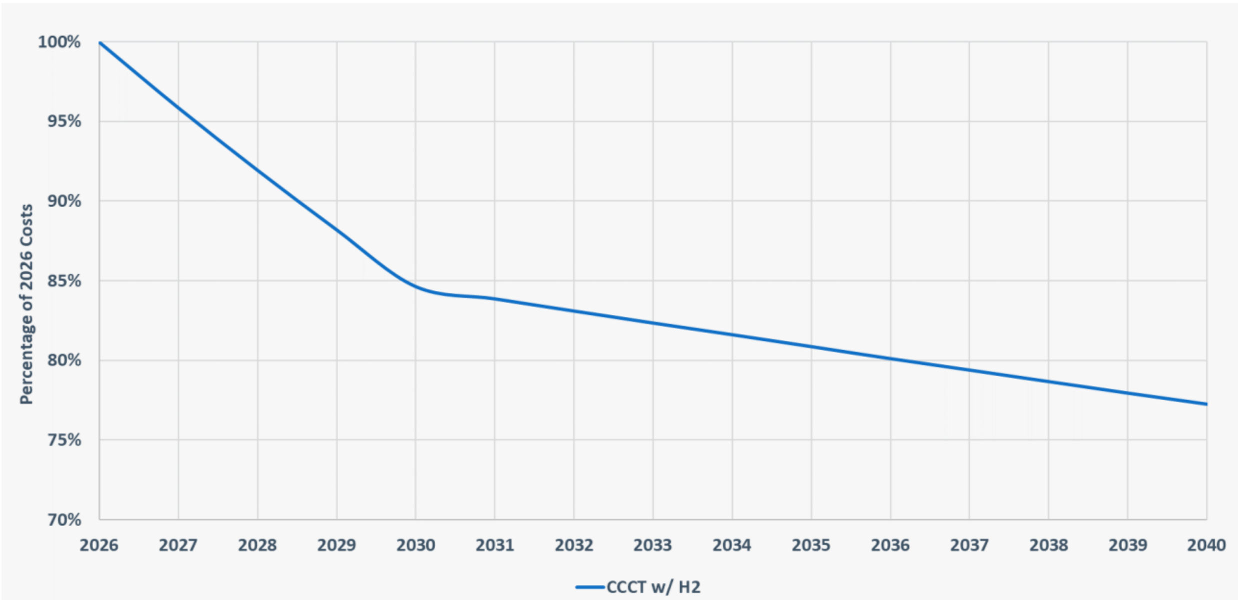
[538] Mongrid, et al., "2020 Grid Energy Storage Technology Cost and Performance Assessment." Pacific Northwest National Laboratory. December 2020. Retrieved from: https://www.pnnl.gov/sites/default/files/media/file/Final%20-%20ESGC%20Cost%20Performance%20Report%2012-11-2020.pdf

[539] Hunter, et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

[540] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy.

Forward capital cost curve

Figure 169. Hydrogen production/storage/CCCT capital cost trajectory



M.4 Dispatchable resources

M.4.1 Biomass

Technology description

Power production using biomass fuel is similar to other solid fuel power plants in that a boiler is used to combust fuel and generate steam to drive a turbine and produce electricity. The representative biomass-fueled resource uses a bubbling fluidized bed (BFB) design to combust wood chips. NOx emissions are controlled in-furnace using over-fire air (OFA), and with a high dust selective catalytic reduction (SCR) system, SO2 emissions from wood firing are inherently low and therefore are uncontrolled. Particulate matter is controlled using a pulse jet fabric filter baghouse.”[541]

[541] EIA AEO 2020. “Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies.” Prepared by Sargent & Lundy.

Commercial status

According to EIA data, at the end of 2021, wood and wood waste biomass capacity in the United States totaled more than 9 GW.[542]

Operational characteristics

Table 163. summary of biomass operational characteristics

Operational Characteristics, biomass	
2019$	BFB
Capacity (MW average lifetime)	50
Heat Rate (Btu/kWh average lifetime)	13,300
Planned outage rate	3.07%
Forced outage rate	6.03%

Operational expenditures

Table 164. Summary of biomass operational expenditures

Operational Expenditures, biomass	
2019$	BFB
Fixed O&M ($/kW-year)	$126
Variable O&M ($/MWh)	$5

[542] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Capital expenditures

Table 165. Summary of biomass capital expenditures

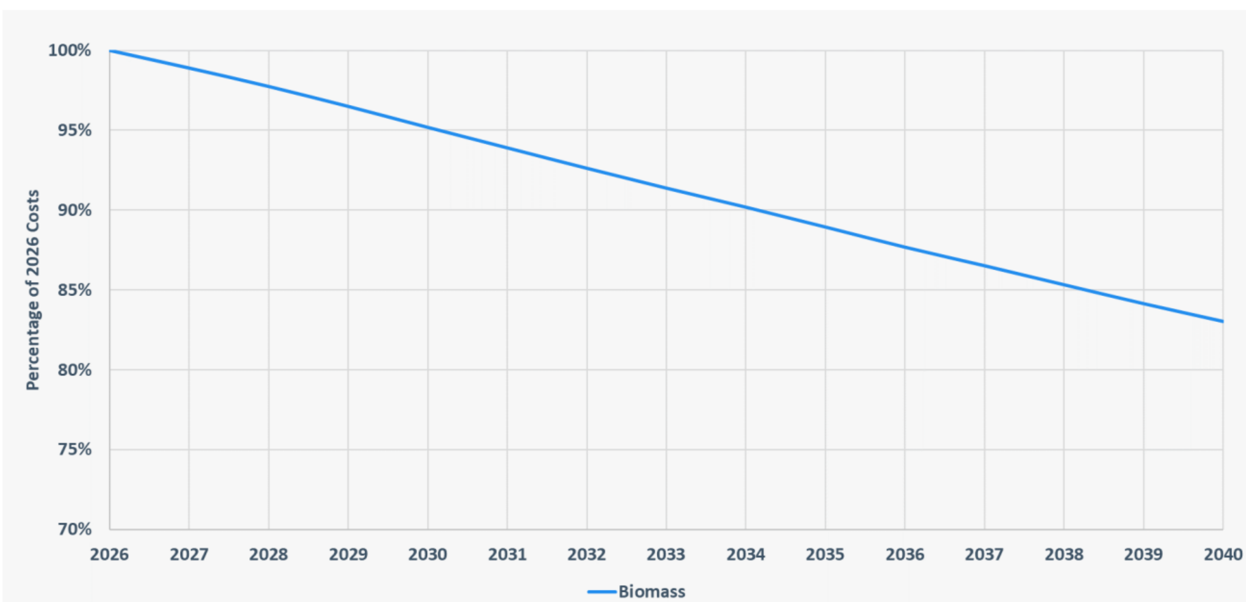
Capital Expenditures, biomass	
2019 $/kW	BFB
Overnight capital	$4,097
Transmission Line Cost	$24
Overnight EPC Capital Cost -Ex Interconnect Cost	$4,073
Location Adjustment	1.09
Location-adjusted Overnight Capital Cost	$4,453

The location adjustment is based on an average of the EIA factors provided by Portland, Boise, and Spokane.

Forward capital cost curve

The EIA 2020 AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 170**.

Figure 170. Biomass capital cost trajectory



M.4.2 Nuclear

Technology description

The AP1000 advanced passive design and a representative small modular reactor (SMR) design are considered two nuclear-fueled generating options. This description is excerpted from EIA:

"The AP1000 improves on previous nuclear designs by simplifying the design to decrease the number of components, including piping, wiring, and valves. The AP1000 design is standardized as much as possible to reduce engineering and procurement costs. The AP1000 component reductions from previous designs are approximately:

- 50 percent fewer valves
- 35 percent fewer pumps
- 80 percent less pipe
- 45 percent less seismic building volume
- 85 percent less cable

The AP1000 design uses an improved passive nuclear safety system that requires no operator intervention or external power to remove heat for up to 72 hours.

The AP1000 uses a traditional steam cycle similar to other generating facilities such as coal or CC units. The primary difference is that the AP1000 uses enriched uranium as fuel instead of coal or gas as the heat source to generate steam. The enriched uranium is contained inside the pressurized water reactor. The AP1000 uses a two-loop system in which the heat generated by the fuel is released into the surrounding pressurized reactor cooling water. The pressurization allows the cooling water to absorb the released heat without boiling. The cooling water then flows through a steam generator that provides steam to the turbine for electrical generation."[543]

The SMR resource is based on a representative design of 12 reactor modules, each representing 50 MW or 600 MW in total. "The mechanical systems of an SMR are much smaller than those of a traditional nuclear plant. The mechanical systems are similar to that of an advanced nuclear power plant. Each reactor module comprises a nuclear core and steam generator within a reactor vessel, enclosed within a containment vessel in a vertical

[543] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf

orientation. The nuclear core is located at the module's base, with the steam generator located in the upper half of the module. Feedwater enters, and steam exits through the top of the vessel towards the steam turbine. The entire containment vessel sits within a water-filled pool that provides cooling and passive protection in a loss of power event. All 12 reactor modules sit within the same water-filled pool housed within a typical reactor building.

Each SMR module uses a pressurized water reactor design to achieve a high level of safety and reduce the number of components required. To improve licensing and construction times, each reactor is prefabricated at the OEM's facility and shipped to the site for assembly. The compact integral design allows each reactor to be shipped by rail, truck, or barge.

Each module has a dedicated balance of plant (BOP) system for power generation. Steam from the reactor module is pumped through a steam turbine connected to a generator for electrical generation. Each BOP system is fully independent, containing a steam turbine and all necessary pumps, tanks, heat exchangers, electrical equipment, and controls for operation. This allows for the independent operation of each reactor module. Each reactor module's independent operation provides greater efficiencies at lower operating loads when dispatched capacity is reduced.

Additionally, the modular design of the reactors allows for refueling and maintenance of the individual reactors without requiring an outage of the entire facility. An extra reactor bay includes the pool housed with the reactor building. This extra bay allows for removing individual reactors for maintenance without impacting the remaining reactors."[544]

Commercial status

At the end of 2021, nearly 100 GW of nuclear capacity was operable in the United States, according to EIA data. Watts Bar Unit 2, which came online in 2016, is the most recent nuclear resource addition. Nearly 3 GW are currently proposed to come online between 2023 and year-end 2030, including six SMR units planned for Utah Associated Municipal Power Systems at the Department of Energy (DOE) Idaho National Laboratory.[545]

[544] *Id.*
[545] 2021 Form EIA-860 Data - Schedule 3, 'Generator Data' (Operable Units Only)

Operational characteristics

Table 166. Summary of nuclear-powered generating resource operational characteristics

Operational Characteristics	Nuclear	
	SMR	AP1000
Capacity (MW average lifetime)	600	2,156
Heat Rate (Btu/kWh average lifetime)	10,046	10,608
Planned outage rate	5.00%	5.00%
Forced outage rate	5.00%	5.00%

Operational expenditures

The EIA 2020 AEO provides the operational expenditures estimates for the nuclear-powered generation options in **Table 167**.

Table 167. Summary of nuclear-powered generating resource operating expenditures

Operational Expenditures, nuclear		
2019$	SMR	AP1000
Fixed O&M ($/kW-year)	$95	$122
Variable O&M ($/MWh)	$3	$2

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates in **Table 168**.

Table 168. Summary of nuclear-powered generating resource capital expenditures

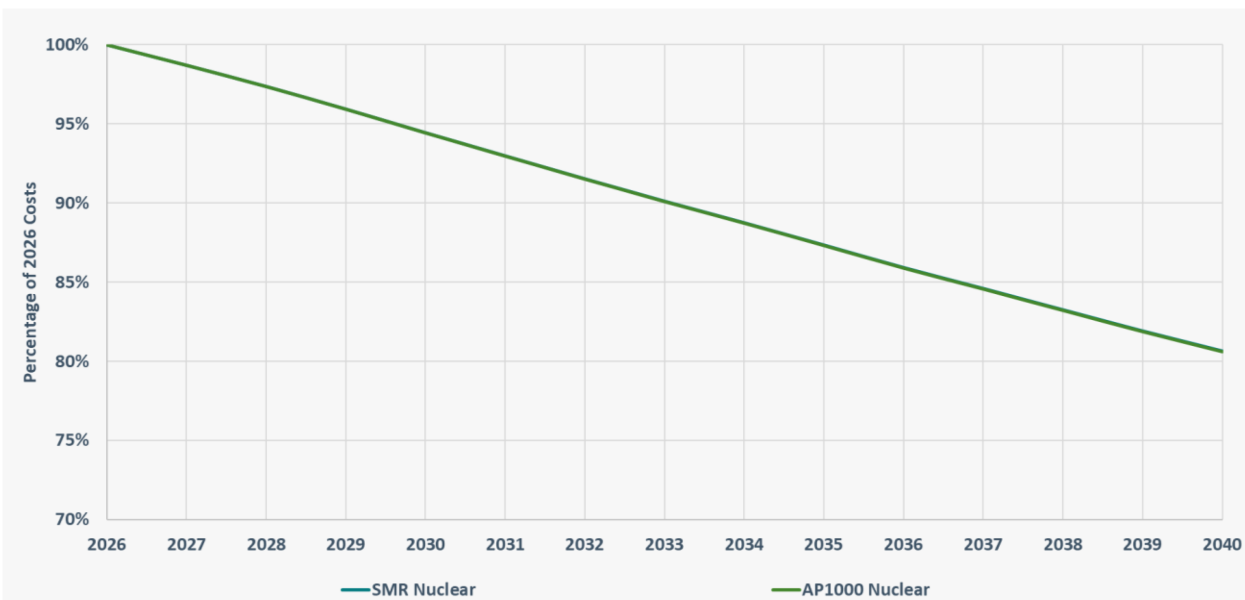
Capital Expenditures, nuclear		
2019 $/kW	SMR	AP1000
Overnight capital	$6,191	$6,041
Transmission Line Cost	$4	$1
Overnight EPC Capital Cost -Ex Interconnect Cost	$6,187	$6,040

Capital Expenditures, nuclear		
Location Adjustment	1.06	1.08
Location-adjusted Overnight Capital Cost	$6,579	$6,524

Forward capital cost curve

The EIA 2020 AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 171**.

Figure 171. Nuclear-powered generator capital cost trajectory



M.5 Natural gas-fueled resources

M.5.1 Simple-cycle combustion turbine

Technology description

The simple-cycle combustion turbine (SCCT) is based on "one industrial frame Model F dual fuel CT in simple-cycle configuration with a nominal output of 237.2 MW gross. After deducting internal auxiliary power demand, the net output of the plant is 232.6 MW. The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT output. The CT is also equipped with burners designed to reduce the CT's NOX emission."[546] Selective catalytic reduction (SCR) and CO catalysts are not included.

Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation."[547]

Operational characteristics

Table 169. Summary of SCCT operational characteristics

Operational characteristics	SCCT F-Class
Capacity (MW average lifetime)	227
Heat Rate (Btu/kWh average lifetime)	10,042
Planned outage rate	2.38%
Forced outage rate	1.73%

[546] EIA AEO 2020. "Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies." Prepared by Sargent & Lundy. Available at: https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2020.pdf
[547] *Id.*

Operational expenditures

Fixed O&M includes the fixed portion of a long-term service agreement.

"Variable O&M costs include consumable commodities, such as water, lubricants, and chemicals. Also included is the average annual cost of the planned maintenance events for the CT over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of equivalent starts the CT has accumulated. A significant overhaul is performed for this type of CT every 900 equivalent starts, and a major overhaul is performed every 2,400 equivalent starts. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of [equivalent operating hours] EOH)."[548]

The SCCT is assumed to use a starts-based schedule, and the effective cost per start is shown in **Table 170** and included in the dispatch modeling for this resource.

Table 170. Summary of SCCT operational expenditures

Operational expenditures, SCCT	
2019 $	F-Class
Fixed O&M ($/kW-year)	$7
Variable O&M ($/MWh)	$1

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates, shown in **Table 171**.

Table 171. Summary of SCCT capital expenditures

Capital Expenditures, SCCT	
2019 $/kW	F-Class
Overnight capital	$713
Less: Transmission Line Cost	$5
Less: Gas Interconnection Cost	$19
Overnight EPC Capital Cost -Ex Interconnect Cost	$688

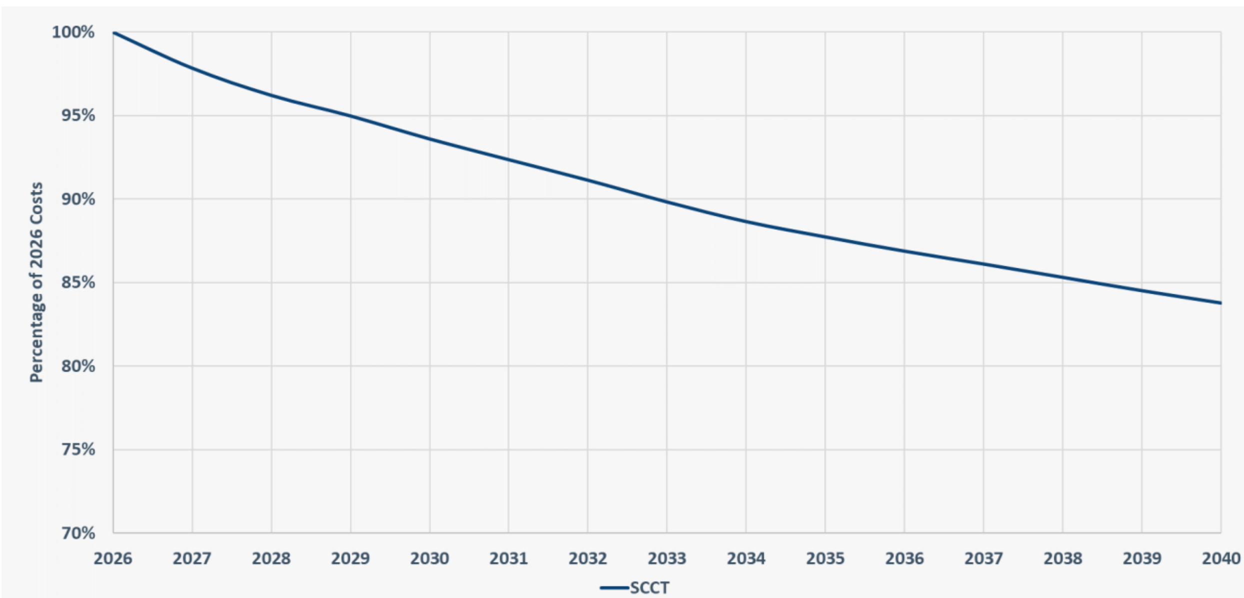
[548] *Id.*

Capital Expenditures, SCCT	
Location Adjustment	1.05
Location-adjusted Overnight Capital Cost	$721

Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 172**.

Figure 172. Simple-cycle combustion turbine capital cost trajectory



M.5.2 Combined-cycle combustion turbine

Technology description

The combined-cycle combustion turbine (CCCT) resource comprises one Model H "advanced technology" combustion turbine (CT), one steam turbine generator (STG), and one electric generator that is common to the CT and the STG.

Emissions controls include burners to reduce NOX emissions, an SCR to reduce NOX emissions, and a CO catalyst to reduce CO emissions. "The inlet air duct for the CT is equipped with an evaporative cooler to reduce the inlet air temperature in warmer seasons to increase the CT and plant output…"

The CT is categorized as Model H industrial frame type CT with an advanced technology design since it incorporates in the design the following features:

- High-firing temperatures (~2900°F)
- Advanced materials of construction
- Advanced thermal barrier coatings"[549]

Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation."

Operational characteristics

Table 172. Summary of CCCT operational characteristics

Operational characteristics	CCCT H-Class
Capacity (MW average lifetime)	407
Heat Rate (Btu/kWh average lifetime)	6,561
Planned outage rate	3.88%
Forced outage rate	2.19%

Operational expenditures

Fixed O&M includes the fixed portion of a long-term service agreement (**Table 173**).

"Variable O&M costs include consumable commodities such as water, lubricants, and chemicals and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOHs the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed

[549] *Id.*

every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH)."[550]

The CCCT is assumed to require an EOH-based maintenance schedule for the CT. The STG requires less frequent major outage maintenance.

Table 173. Summary of CCCT operational expenditures

Operational Expenditures	CCCT
2019$	H-Class
Fixed O&M ($/kW-year)	$14
Variable O&M ($/MWh)	$3

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates (**Table 174**).

Table 174. Summary of CCCT capital expenditures

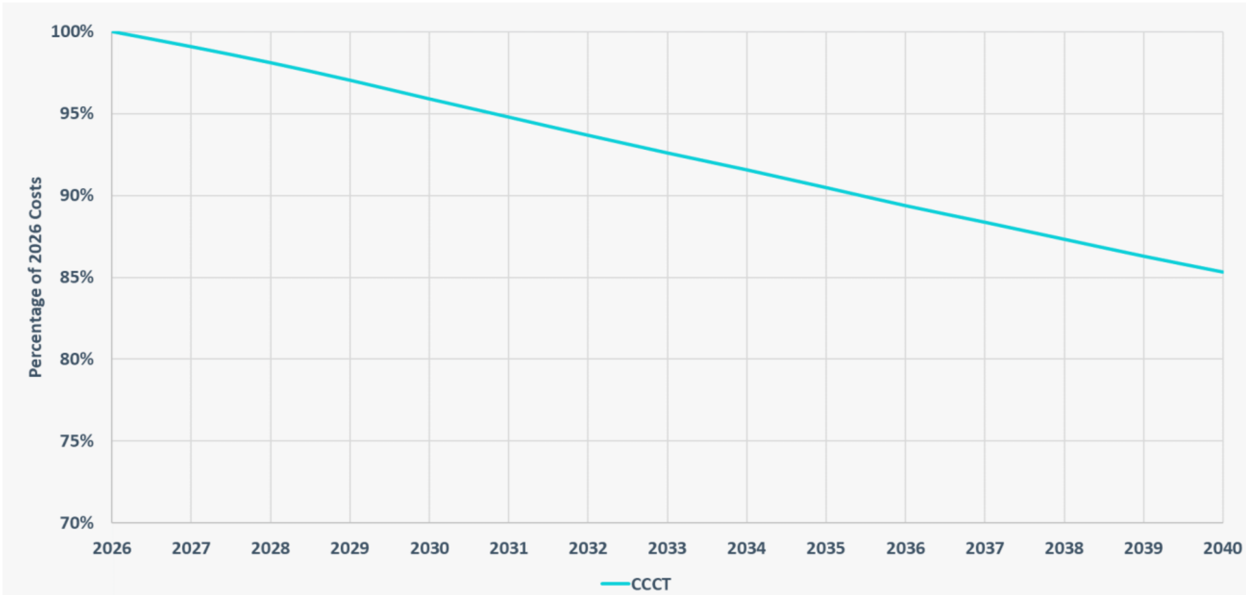
Capital expenditures	CCCT
2019 $/kW	H-Class
Overnight capital	$1,084
Transmission Line Cost	$4
Gas Interconnection Cost	$14
Overnight EPC Capital Cost -Ex Interconnect Cost	$1,066
Location Adjustment	1.08
Location-adjusted Overnight Capital Cost	$1,154

Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 173**.

[550] *Id.*

Figure 173. Combined-cycle combustion turbine capital cost trajectory



M.5.3 Combined-cycle combustion turbine with CO_2 capture system

Technology description

The H-class combined-cycle unit is similar in configuration and specification to the traditional resource previously described. In addition to the CCCT, the resource includes an amine-based CO_2 capture system designed to remove 90 percent of the CO_2 from exhaust gases. The resource configuration as described in the EIA research include:

"[T]o obtain 90 percent CO_2 removal from the flue gas generated from the CT, [t]he full flue gas path must be treated. The flue gas generated from natural gas-fired CT combustions results in a much lower CO_2 concentration in the flue gas than flue gas from a coal-fired facility. As such, the flue gas absorber and quencher would be much larger in scale on a per ton of CO_2 treated basis than with a coal facility. However, the stripper and compression system would scale directly with the mass rate of CO_2 captured.

In this scenario, it is not practical to increase the CT or STG size to account for the steam extraction and added auxiliary power required by the CO_2 capture system. The net power output in the CO_2 capture case is significantly less than in Case 8.

The flue gas path differs from the base case (Case 8) in that 100 percent of the gas is directed to the carbon capture system downstream of the preheater section of the HRSG. The SCR and CO catalysts would operate the same, and the flue gas mass flows would be the same. Rather than exiting a stack, the flue gases would be ducted to a set of booster fans that would feed the CO_2 absorber column. The total gross power generated from the CT is approximately the same as Case 8, with no carbon capture.

Steam for the CO_2 stripper is to be extracted from the intermediate-pressure turbine to the low-pressure turbine crossover line; however, the steam must be attemporated to meet the requirements of the carbon capture system. The total steam required for the carbon capture system is approximately 306,000 pounds per hour. As a result of the steam extraction, the gross STG generation outlet decreases from 133 MW to 112 MW."[551]

Commercial status

Research in PGE's recent IRPs indicates that resources employing natural gas-fired combustion turbine generators are "well-proven and commercially available technologies for power generation." Carbon capture and sequestration, however, has substantially fewer examples deployed in operation.

Operational characteristics

The CCCT described previously serves as the basis for this resource. The configuration and auxiliary power requirements for the operation of the CO_2 capture system, however, result in an approximately 40 MW decrease in the net capacity of this resource as described previously. Similarly, the resource is less efficient, resulting in a higher heat rate than the CCCT without CO_2 capture (**Table 175**).

Table 175. Summary of CCCT w/ CCS operational characteristics

Operational characteristics	CCCT w/ CCS
Capacity (MW average lifetime)	367
Heat Rate (Btu/kWh average lifetime)	7,271
Planned outage rate	3.88%
Forced outage rate	2.19%

[551] *Id.*

Operational expenditures

"Variable O&M costs include consumable commodities such as water, lubricants, chemicals, solvent makeup, and periodic costs to change out the SCR and CO catalysts. The variable O&M costs also include the average annual cost of the planned maintenance events for the CT and the STG over the long-term maintenance cycle. Planned maintenance costs for the CT in a given year are based on the number of EOHs the CT has run. A significant overhaul is typically performed for this type of CT every 25,000 EOH, and a major overhaul is performed every 50,000 EOH. (CTs generally have two criteria to schedule overhauls: number of equivalent starts and number of EOH)." The CCCT with CO_2 capture system is assumed to require an EOH-based maintenance schedule for the CT. The STG requires less frequent major outage maintenance.

"For the CO_2 capture system, variable costs include solvent makeup and disposal costs (usually offsite disposal; the spent solvent may be considered hazardous waste), additional wastewater treatment costs (predominantly CT blowdown treatment), and additional demineralized makeup water costs."[552]

The costs of CO_2 storage are not included in the EIA cost estimates; as such, these costs are derived from Hunter[553] to form a representative estimate of the total resource variable cost (**Table 176**).

Table 176. Summary of CCCT w/ CCS operational expenditures

Operational expenditures	CCCT w/ CCS
2019$	H-Class
Fixed O&M ($/kW-year)	$28
Variable O&M ($/MWh)	$6
Sequestration Cost ($/MWh)	$15
Total Variable O&M ($/MWh)	$21

[552] *Id.*

[553] Hunter et al., "Techno-economic analysis of long-duration energy storage and flexible power generation technologies to support high variable renewable energy grids." Retrieved from: https://papers.ssrn.com/sol3/papers.cfm?abstract_id=3720769

Capital expenditures

EIA 2020 AEO research provides the basis for capital expenditure estimates, shown in **Table 177**.

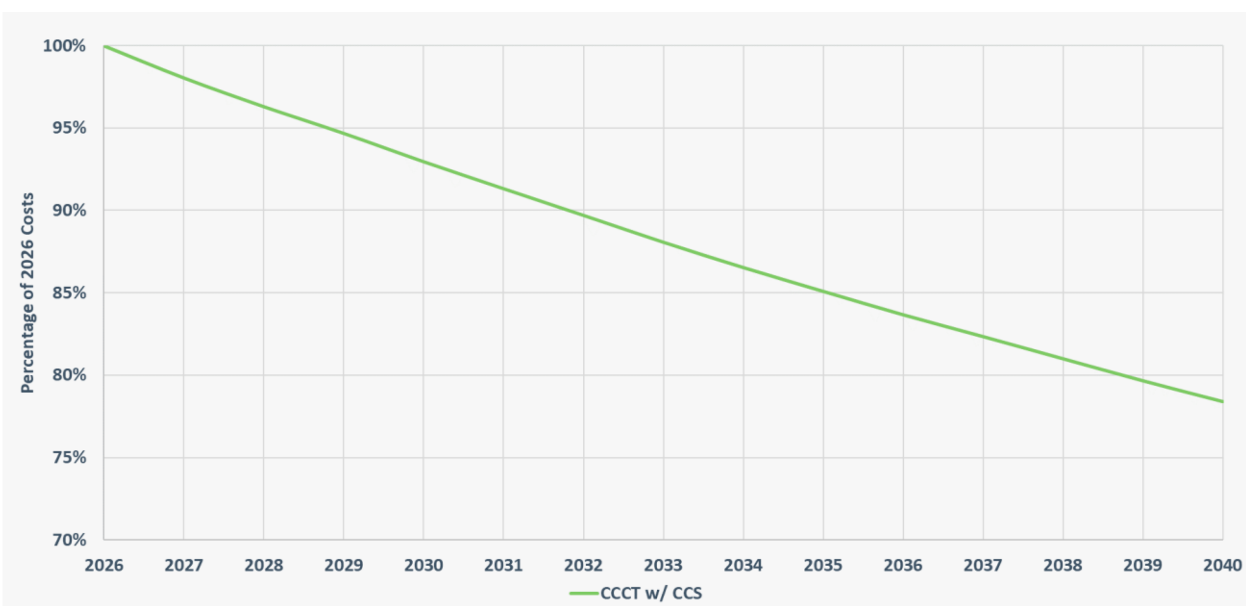
Table 177. Summary of CCCT w/ CCS capital expenditures

Capital expenditures	CCCT w/ CCS
2019 $/kW	H-Class
Overnight capital	$2,481
Transmission Line Cost	$5
Gas Interconnection Cost	$16
Overnight EPC Capital Cost -Ex Interconnect Cost	$2,461
Location Adjustment	1.08
Location-adjusted Overnight Capital Cost	$2,666

Forward capital cost curve

The EIA AEO projection of future capital costs for the Reference Case scenario are presented in **Figure 174**.

Figure 174. Combined-cycle combustion turbine w/ CCS capital cost trajectory



Appendix N. Renewable curtailment

As more variable energy resources are added to the system the amount of generation curtailed due to oversupply increases. This appendix discusses why oversupply happens and includes projections of future oversupply events.

N.1 Impact of resource curtailment

The addition of non-dispatchable intermittent resources in PGE's resource stack makes the balancing of demand and supply of energy increasingly complicated. These resources are primarily wind and solar, with hydropower uncertainty potentially adding to the complexity of committing the right resources at the right time leading. We define resource curtailment the result of regional surplus of wind and solar that cannot be balanced in other way than by shutting them down.

From PGE perspective, when wind is strong, hydropower is constrained to run at a given level, and solar generation is peaking, the combined output of such resources will be higher than PGE load. In this case, PGE will first attempt to:

- Sell surplus energy to the market
- Turn off thermal plants, if operationally possible, and/or fill storage, and/or minimize hydropower output if doable.

When both solutions are exhausted, the only option left is renewable curtailment, which is the partial or total shut down of the wind generation from one or more PGE wind and plants.

This section describes the impact of wind and solar curtailment on the value of such resources in the long-term. To estimate this effect, we used our WECC model, the same Aurora model used to forecast electricity prices in the PWN, as curtailment is triggered by regional imbalances. PGE estimated the monthly average generation curtailed for all wind and solar resources in Oregon and Washington under normal conditions and Reference Case prices. We did not identify which wind plant will be curtailed. We instead estimated how much is the expected overall curtailment for the whole wind and solar fleet in the entire PNW.

Using the WECC simulated resource output, we estimated curtailment as the difference between simulated generation and resource theoretical availability. We did this for all wind resources in Oregon and Washington, both existing and added by Wood Mackenzie to meet future load to 2043, both on-shore resources and off-shore. The result is that curtailment does and increasingly is projected to occur, especially in the Spring, when PNW wind, PNW hydropower, and WECC solar all maximize generation. **Table 178** shows the detail of simulated curtailment as percentage of maximum available monthly capacity for the future

RRRR, which represents normal condition, with reference gas prices and a California-like carbon cost. For each year and each month, the expected regional curtailment is color coded as follows: green, if there is no expected regional curtailment; yellow, when regional curtailment is expected; orange, when curtailment is significant; red, when regional curtailment is severe.

Table 178. Simulated wind curtailment in Oregon and Washington: RRRR future

Report Year/Month	1	2	3	4	5	6	7	8	9	10	11	12
2023	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%	0%
2026	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
2027	0%	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%
2028	0%	0%	0%	-1%	-2%	-1%	0%	0%	0%	0%	0%	0%
2029	0%	0%	0%	-1%	-1%	-1%	0%	0%	0%	0%	0%	0%
2030	0%	0%	0%	-4%	-4%	-4%	-1%	0%	0%	0%	0%	0%
2031	0%	0%	0%	-5%	-7%	-6%	0%	0%	0%	0%	0%	0%
2032	0%	0%	0%	-7%	-18%	-9%	0%	0%	0%	0%	0%	0%
2033	0%	0%	0%	-8%	-9%	-10%	0%	0%	0%	0%	0%	0%
2034	0%	0%	0%	-10%	-15%	-18%	-2%	0%	0%	0%	0%	0%
2035	0%	0%	0%	-13%	-18%	-19%	0%	0%	0%	0%	0%	0%
2036	0%	0%	-1%	-29%	-52%	-62%	-4%	0%	0%	0%	0%	0%
2037	0%	0%	-1%	-29%	-57%	-67%	-3%	-1%	-3%	0%	0%	0%
2038	0%	0%	-5%	-37%	-76%	-79%	-9%	-1%	0%	-1%	0%	0%
2039	0%	0%	-4%	-38%	-69%	-78%	-11%	-1%	-1%	-1%	0%	0%
2040	0%	-1%	-4%	-42%	-79%	-88%	-14%	-1%	-1%	-2%	0%	0%
2041	0%	0%	-2%	-44%	-74%	-84%	-17%	-5%	-4%	-3%	0%	0%
2042	0%	0%	-7%	-50%	-83%	-92%	-26%	-8%	-3%	-2%	-1%	0%
2043	0%	0%	-6%	-52%	-79%	-83%	-30%	-5%	-6%	-3%	0%	0%

Short-term simulated wind curtailment is not significant under normal conditions, while starting in the mid-2030s it becomes much more so as more and more wind is added to the system. We used the same methodology to estimate solar curtailment in Oregon and

Washington and reported results in **Table 179**. In our model, solar curtailment is not significantly impacting generation until the 2040s. This is the result of less capacity installed in the PNW and the Wood Mackenzie modeling choice of having wind curtail before solar. This means that solar plants are curtailed only after all wind is offline (a modeling simplification). Any actual curtailment will depend on operational constraints and financial considerations.

Table 179. Simulated solar curtailment in Oregon and Washington: RRRR future

Report Year/Month	1	2	3	4	5	6	7	8	9	10	11	12
2023	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2024	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2025	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2026	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2027	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2028	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2029	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2030	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2031	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2032	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2033	0%	0%	0%	0%	-1%	0%	0%	0%	0%	0%	0%	0%
2034	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2035	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2036	0%	0%	0%	0%	0%	-2%	-2%	0%	0%	0%	0%	0%
2037	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2038	0%	0%	0%	0%	0%	-4%	-6%	0%	0%	0%	0%	0%
2039	0%	0%	0%	0%	0%	-1%	-4%	0%	0%	0%	0%	0%
2040	0%	0%	0%	0%	0%	-5%	-5%	0%	0%	0%	0%	0%
2041	0%	0%	0%	0%	-1%	-4%	-4%	0%	0%	0%	0%	0%
2042	0%	0%	0%	0%	0%	-8%	-9%	0%	0%	0%	0%	0%
2043	0%	0%	0%	0%	-1%	-3%	-11%	0%	0%	0%	0%	0%

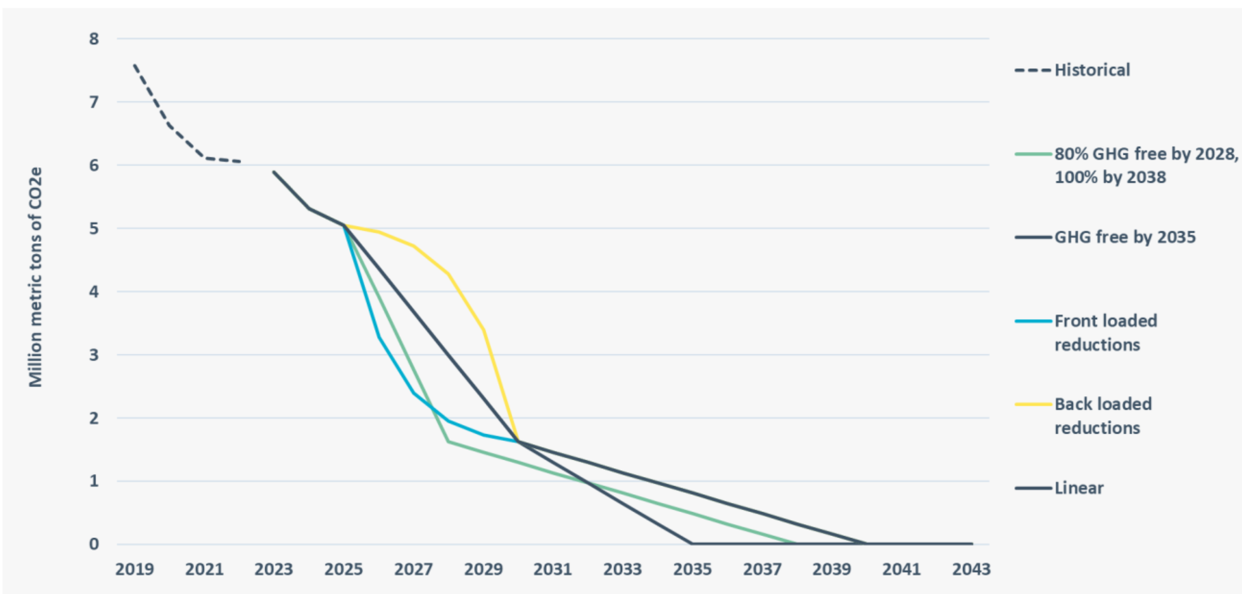
Appendix O. Thermal Operations/ Output

This appendix provides a graphical overview of PGE's projected retail GHG emissions, emissions and generation by fuel type, heat rate projections by fuel type, and a look at GHG emissions by unit under three different GHG glidepaths.

O.1 PGE GHG emitting resources

PGEs historical retail emissions from 2019 to 2021, as well as IRP forecasts for retail GHG emissions from 2023 to 2043, are shown below in **Figure 175.** The forecast includes five different GHG glidepaths, linear, front loaded (more GHG reductions early), back loaded (more GHG reductions later), GHG free by 2035, and achieving HB 2021 goals two years early.

Figure 175. Annual historical and projected GHG emissions for retail load service



The following graphs (**Figure 176** and **Figure 177**) show total annual GHG emissions and energy generated and purchased by fuel type for resources in the Preferred Portfolio.[554] Power plant Boardman, which retired in 2020, is in the historical values. Total generation and emissions represent both retail load service and wholesale sales.

[554] Waste represents a bilateral landfill contract.

Figure 176. Historical and projected total generation and purchases by fuel type from emitting sources

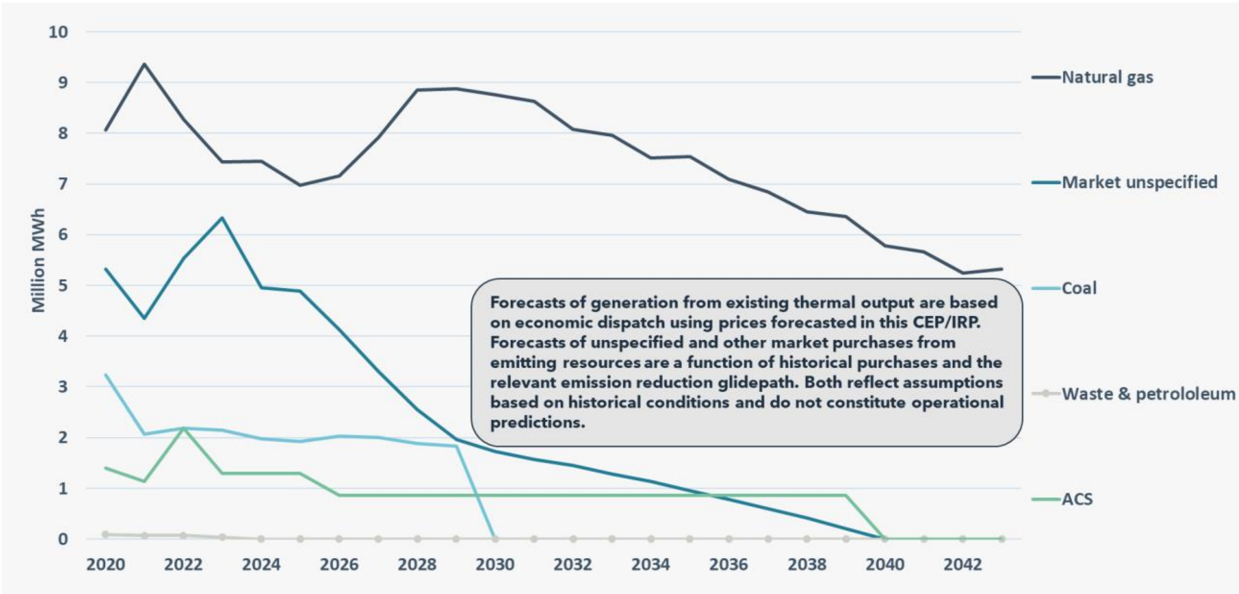
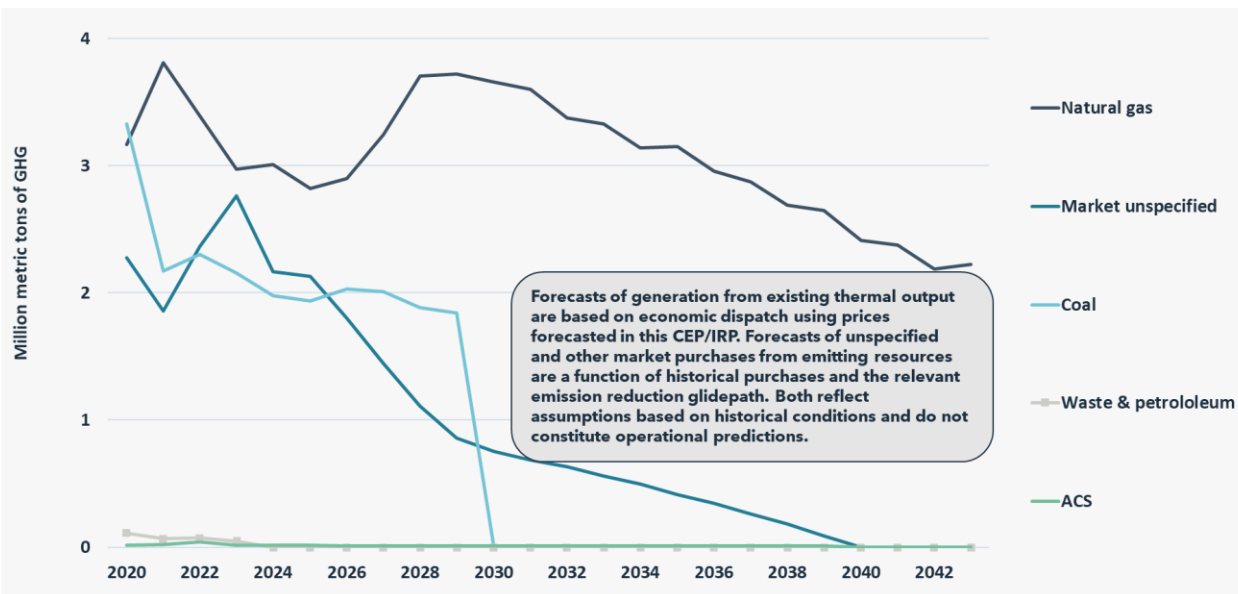


Figure 177. Historical and projected total GHG emissions by fuel type



The following graphs (**Figure 178** and **Figure 179**) show annual GHG emissions and energy generated and purchased by fuel type for resources in the Preferred Portfolio used to serve retail load (power plant Boardman, which retired in 2020, is in the historical values).

Figure 178. Historical and projected retail generation and purchases by fuel type from emitting sources

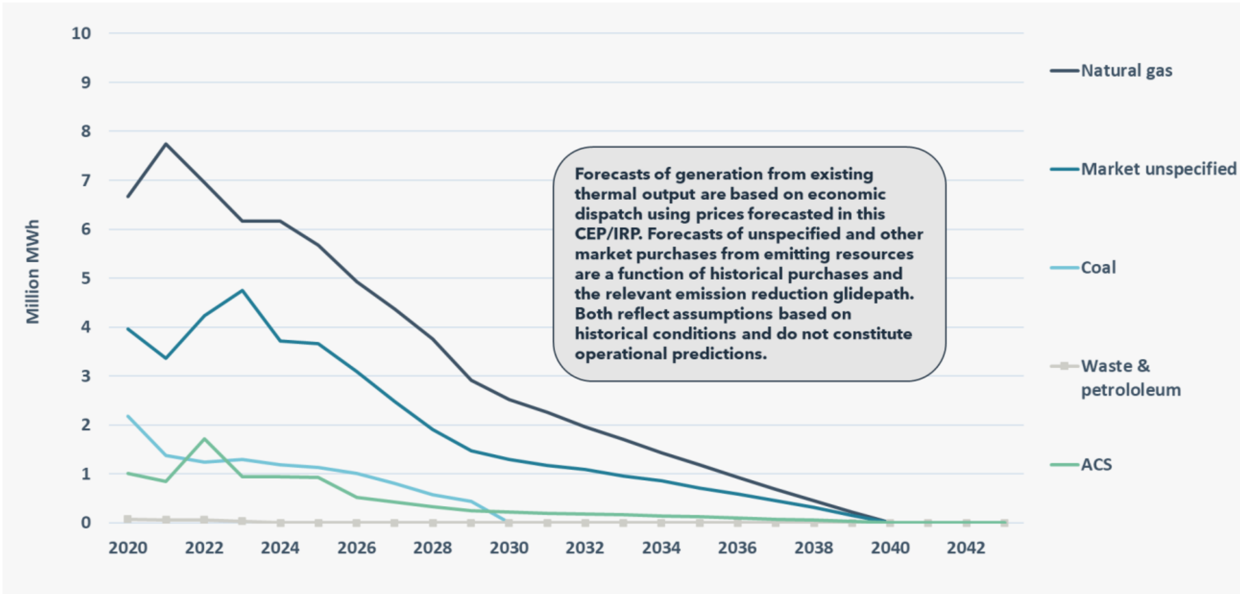
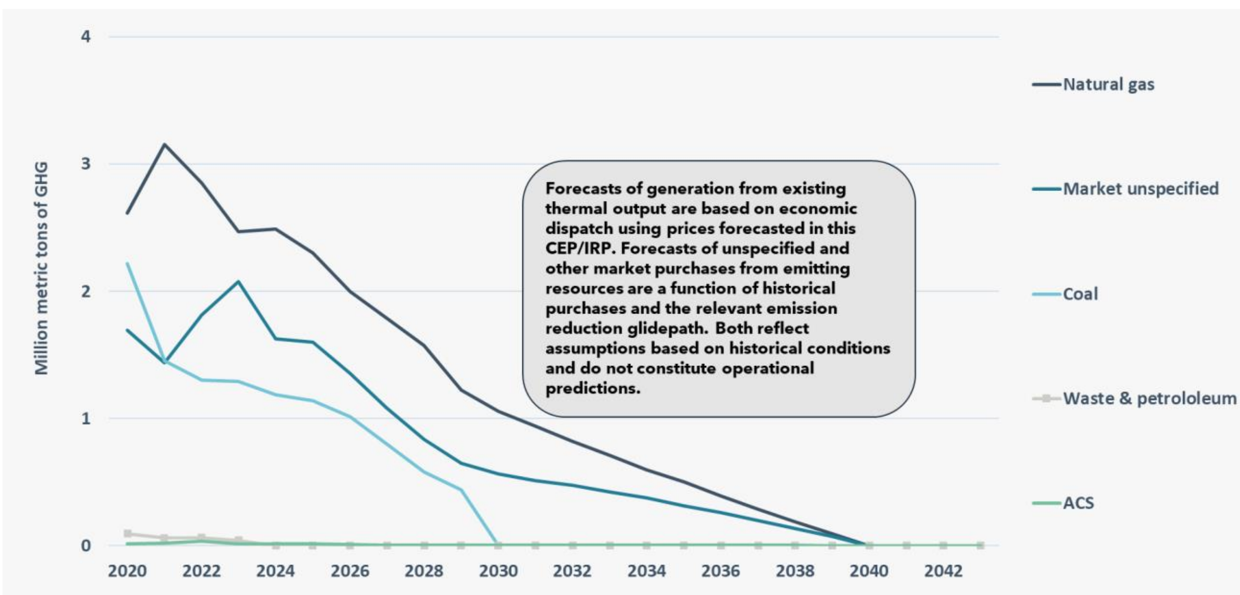


Figure 179. Historical and projected retail GHG emissions by fuel type



The following graph (**Figure 180**) shows the annual weighted average heat rate by fuel type for resources in the Preferred Portfolio. Individual plant heat rates in the forecasted data are static and based on Oregon Department of Environmental Quality (ODEQ) CO2e intensity values for future years. The future variations in weighted average heat rate are due to annual changes in forecasted economic dispatch. Due to a lack of knowledge of the underlying fuel source market purchase heat rates are not included.

Figure 180. Historical and projected annual weighted average heat rate by fuel

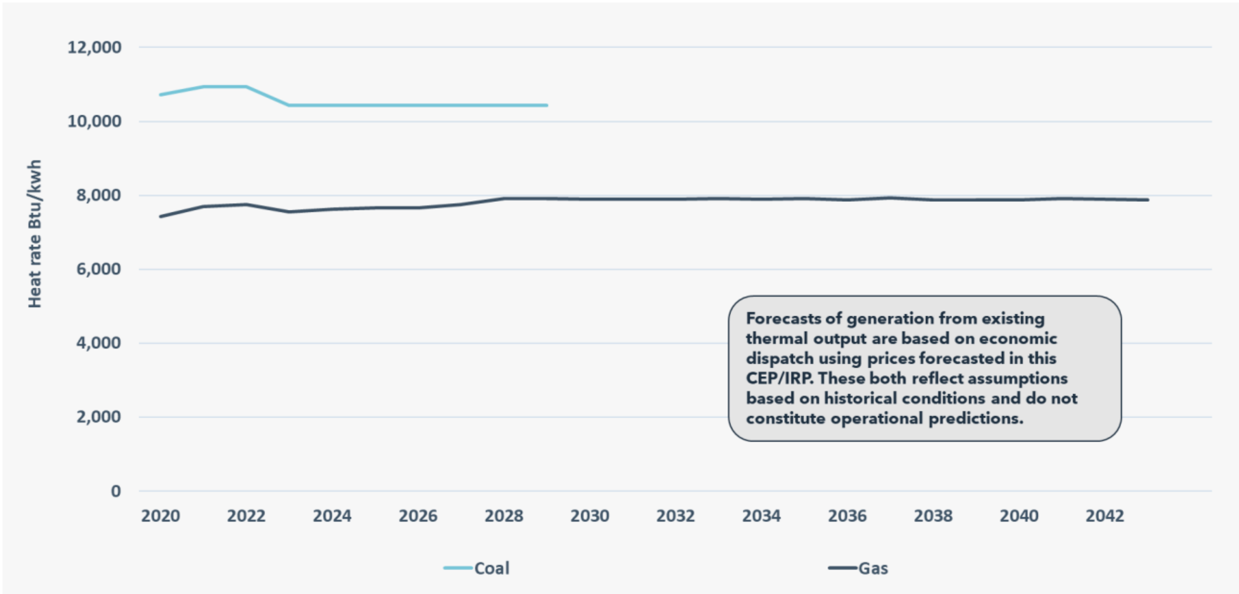


Figure 181-Figure 182 reflect GHG emissions from generation and purchases under three decarbonization glidepaths. The lines specific to individual resources show retail GHG emissions. The wholesale sales category captures GHG emissions from sales from all sources (these are additional to the retail GHG emissions).

Figure 181. Total (retail + wholesale) GHG emissions under a linear reduction glidepath (Reference Case)[555]

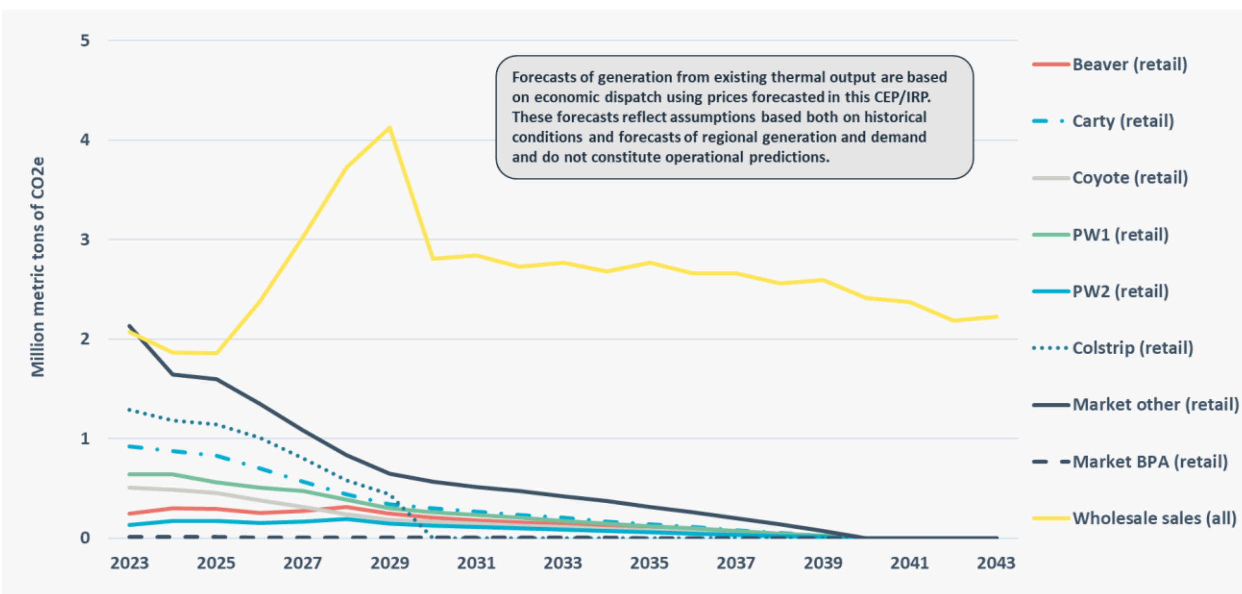


Figure 182. Total (retail + wholesale) GHG emissions under a front-loaded reduction glidepath (Reference Case)

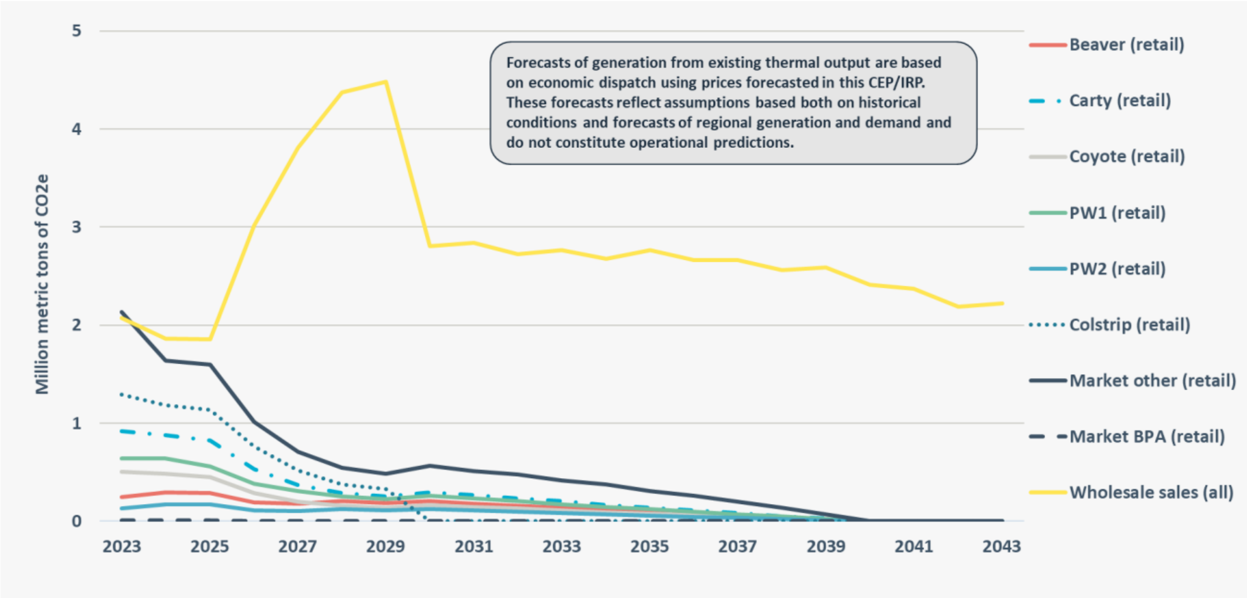
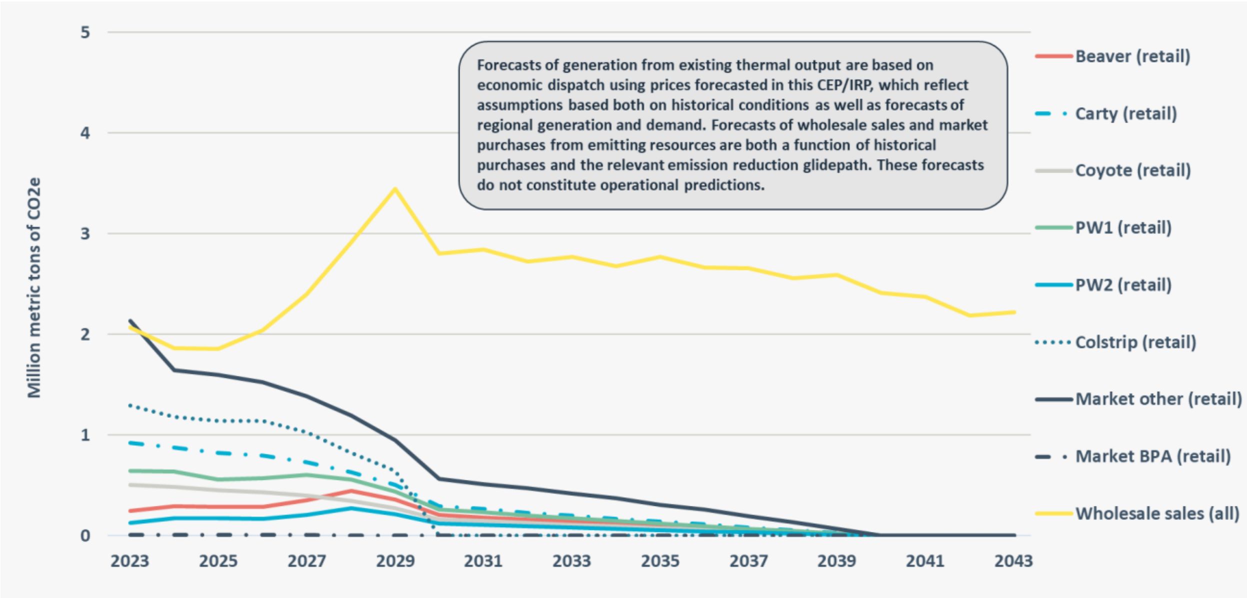


Figure 183. Total (retail + wholesale) GHG emissions under a back-loaded reduction glidepath (Reference Case)



Appendix P. Acronyms

Acronym	Agency/Entity/Term
AC	Alternating Current
ACS	Asset Controlling Supplier
ADF	Augmented Dickey Fuller tests
AEO	Annual Energy Outlook
AI	Artificial Intelligence
aMW	Average Megawatt
ANSI	American National Standards Institute
ARIMA	Autoregressive Integrated Moving Average
ART	Annual Revenue-requirement Tool
ASCC	Associated System Capacity Contribution
ASCE	American Society of Civil Engineers
ATB	Annual Technology Baseline
ATC	Available Transfer Capacity
AUT	Annual Update Tariff
B2H	Boardman to Hemingway
BAA	Balancing Authority Area
BABGI	Building A Better Grid Initiative
BCEM	Business Continuity and Emergency Management Team

Acronym	Agency/Entity/Term
BE	Building Electrification
BES	Bulk Electric System
BESS	Battery Energy Storage System
BFB	Bubbling Fluidized Bed
BIPOC	Black, Indigenous and People of Color
BLS	Bureau of Labor Statistics
BOEM	Bureau of Ocean Energy Management
BOP	Balance of Plant
BPA	Bonneville Power Administration
BPSC	Beaverton Public Safety Center
BTU	British Thermal Units
CA	California
CAA	Community Action Agencies
CAGR	Compounded Annual Growth Rates
CAISO	California Independent System Operator
CARB	California Air Resources Board
CBI	Community Benefit Indicator

Acronym	Agency/Entity/Term
CBIAG	Community Benefits and Impacts Advisory Group
CBO	Community-Based Organization
CBRE	Community-based Renewable Energy
CCCT	Combined-Cycle Combustion Turbine
CCS	Carbon Capture Sequestration
CCUS	Carbon Capture, Utilization and Storage
CDD	Cooling Degree Days
CEAE	Canadian Entitlement Allocation Extension
CEC	California Energy Commission
CELID	Customers Experiencing Long Interruption Duration
CEMI	Customers Experiencing Multiple Interruptions
CEP	Clean Energy Plan
CETA	Washington's Clean Energy Transformation Act
CF	Conditional Firm
CF200	Conditional Firm 200hr Transmission
CHIPS	Creating Helpful Incentives to Produce Semiconductors and Science Act
CHP	Combined Heat and Power

Acronym	Agency/Entity/Term
CIFIA	Carbon Dioxide Transportation Infrastructure Finance and Innovation Program
CO	Colorado
CO2	Carbon Dioxide
CO2e	Emissions of Carbon Dioxide Equivalent
COD	Commercial Operation Date
COP	Construction and Operations Plan
COS	Cost of Service
CPP	Climate Protection Program
CPUC	California Public Utilities Commission
CSO	Community-Serving Organization
CSPV	Crystalline Silicon Photovoltaic
CT	Combustion Turbine
CTWS	Confederated Tribes of Warm Springs
DAC	Direct Air Capture
DC	Direct Current
DEI	Diversity, Equity and Inclusion
DEQ	Department of Environmental Quality
DER	Distributed Energy Resources
DG	Distributed Generation

Acronym	Agency/Entity/Term
DOE	Department of Energy
DOGAMI	Department of Geology and Mineral Industries
DR	Demand Response
DSG	Dispatchable Standby Generation
DSP	Distribution System Plan
E3	Energy and Environmental Economics, Inc.
EDAM	Energy Day-Ahead Market
EE	Energy Efficiency
EFSC	Energy Facility Siting Council
EGS	Enhanced Geothermal Systems
EIA	Energy Information Administration
EIM	Energy Imbalance Market
EIR	Electric Industry Registry
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
EQC	Environmental Quality Commission
EO	Executive Order
EOH	Equivalent Operating Hours
EPRI	Electric Power Research Institute
ESG	Environmental, Social and Governance

Acronym	Agency/Entity/Term
ESSs	Electricity Service Suppliers
ETO	Energy Trust of Oregon
EV	Electric Vehicle
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
GDP	Gross Domestic Product
GFI	Green Future Impact
GHG	Greenhouse Gases
GMLC	Grid Modernization Laboratory Consortium
GRC	General Rate Case
GW	Gigawatt
H2	Hydrogen Gas
HB	House Bill
HDD	Heating Degree Days
HFRZs	High Fire Risk Zones
HLH	Heavy Load Hour
iCBI	Informational Community Benefits Indicator
IE	Independent Evaluator
IEEE	Institute of Electrical and Electronics Engineers
IEPR	Integrated Energy Policy Report
IIJA	Infrastructure, Investment, and Jobs Act
ILR	Inverter Load Ratio

Acronym	Agency/Entity/Term
IO	Immediate Occupancy
IOC	Integrated Operations Center
IOU	Investor-owned Utilities
IPC	Idaho Power Company
IPCC	Intergovernmental Panel on Climate Change
IQBD	Income Qualified Bill Discount
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	Independent System Operator
ITC	Investment Tax Credits
KPSS	Kwiatkowski, Phillips, Schmidt, and Shin tests
kV	Kilovolt
kW	Kilowatt
kWh	Kilowatt-hour
L&R	Load and Resource
LBNL	Laurence Berkeley National Laboratory
LC	Least Cost
LCOE	Levelized Cost of Wind Energy
LDS/LDES	Long-Duration Energy Storage
LGIP	Large Generator Interconnection Process

Acronym	Agency/Entity/Term
LIHEAP	Low-Income Home Energy Assistance Program
LLC	Limited Liability Company
LLH	Light Load Hour
LNG	Liquefied Natural Gas
LOLE	Loss of Load Expectation
LOLH	Loss of Load Hours
LRB	Load Resource Balance
LUCAS	Levelized Utility Cost Aggregator System
LTDA	Long-term Direct Access
LTF	Long-term Firm
MACRS	Modified Accelerated Cost Recovery System
MAIFI	Momentary Average Interruption Frequency Index
MCE	Maximum Credible Earthquake
MED	Major Event Days
MEP	Market Energy Position
Mid-C	Mid-Columbia
Min Avg LT Cost	Minimizing Average Long-term NPVRR
Min Avg ST cost	Minimizing Average Short-term NPVRR
Min Ref ST cost	Minimizing Reference Case Short-term NPVRR
MMBtu	1 Million British Thermal Units

Acronym	Agency/Entity/Term
MMT	Million Metric Tons
MT	Montana
MW	Megawatt
MWa	Megawatt Average
MWac	Megawatt of Alternating Current
MWh	Megawatt-hour
MYP	Multiyear Flexible Load Plan Aka Multi-year Plan
NARUC	National Association of Regulatory Utility Commissions
NASEO	National Association of State Energy Officials
NCE	Non-cost-effective
NEM	Net Energy Metering
NERC	North American Electric Reliability Corporation
NESP	National Energy Screening Project
Net CONE	Net Cost of New Entry
NG	Natural Gas
NITS	Network Integration Transmission Services
NLDA	New Load Direct Access
NM	New Mexico
NOPR	Notice of Open Rulemaking
NPVRR	Net Present Value Revenue Requirement

Acronym	Agency/Entity/Term
NREL	National Renewable Energy Laboratory
NSRDB	National Solar Radiation Database
NTIA	National Telecommunication and Information Administration
NV	Nevada
NWACI	Northwest AC Intertie
NWMT BA	NorthWestern Corporation Balancing Authority
NWS	Non-wires Solutions
O & M	Operations & Maintenance
OAR	Oregon Administrative Rules
OATT	Open Access Transmission Tariff
OCBs	Oil Circuit Breakers
ODOC	Oregon Department of Commerce
OCEWC	Oregon Clean Energy Workforce Coalition
OCS	Outer Continental Shelf
ODEQ	Oregon Department of Environmental Quality
ODOE	Oregon Department of Energy
ODOT	Oregon Department of Transportation
OEQC	Oregon Environmental Quality Commission

Acronym	Agency/Entity/Term
OFA	Over Fire Air
OHA	Oregon Health Authority
OHCS	Oregon Housing and Community Services
OPUC	Oregon Public Utility Commission
OR	Oregon
ORS	Oregon Revised Statutes
OSU	Oregon State University
PACW	PacifiCorp West
PCAM	Power Cost Adjustment Mechanism
pCBI	Portfolio Community Benefit Indicator
PG&E	Pacific Gas & Electric
PGE	Portland General Electric
PGEM	PGE Merchant
PGET	PGE Transmission System
PNUCC	Pacific Northwest Utilities Conference Committee
PNW	Pacific Northwest
POD	Point of Delivery
POI	Point of Interconnect
POR	Point of Receipt
PPA	Power Purchase Agreement
PRM	Planning Reserve Model
PSH	Pumped Storage Hydro
PSPS	Public Safety Power Shutoff
PTC	Production Tax Credit

Acronym	Agency/Entity/Term
PTP	Point-to-Point
PUC	Public Utility Commission
PUD	Public Utility District
PUMS	Public Use Microdata Sample
PV	Photovoltaic
PZM	PGE Zone Model
QF	Qualifying Facilities
rCBI	Resource Community Benefit Indicator
R&D	Research and Development
RC	Reliability Coordinator
RCP	Representation Concentration Pathway
RDPO	Regional Disaster Preparedness Organization
REC	Renewable Energy Certificates
RFP	Request for Proposals
RMJOC	River Management Joint Operating Committee
RNG	Renewable Natural Gas
ROSE-E	Resource Optimization Strategy Engine
ROW	Rights-of-Way
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization

Acronym	Agency/Entity/Term
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SALMON	Smart Grid Advanced Load Management & Optimized Neighborhoods
SAM	System Advisor Model
SAP	Site Assessment Plan
SB	Senate Bill
SC-CO2	Supercritical Carbon Dioxide
SCCT	Simple-Cycle Combustion Turbine
SCR	Selective Catalytic Reduction
SE	Southeast
SEC	Securities and Exchange Commission
SGTB	Smart Grid Test Bed
SMR	Small Modular Reactor
SoA	South of Allston
SPP	Southwest Power Pool
SSPC	Salem Smart Power Center
STDA	Standard-term Direct Access
STEP	Strategic Tribal Engagement Plan
STG	Steam Turbine Generator
T&D	Transmission and Distribution
TE	Transportation Electrification
TEP	Transportation Electrification Plan
TRC	Total Resource Cost
TSR	Transmission Service Request
TSEP	TSR Study and Expansion Process
TTC	Total Transfer Capability
Tx	Transmission
UAMPS	Utah Associated Municipal Power Systems
UGB	Urban Growth Boundary
UM	Utility Matter
URM	Unreinforced Masonry
US	United States
US DOC	United States Department of Commerce
US DOE	US Department of Energy
US DOEE	US DOE & Environment
US EPA	United States Environmental Protection Agency
VER	Variable Energy Resources
VAR	Value at Risk
VOS	Value of Service
VPP	Virtual Power Plant
WA	Washington
WAP	Low Income Weatherization Assistance Program

Acronym	Agency/Entity/Term
WECC	Western Electricity Coordinating Council
WIND	Wind Integration National Database
WM	Wood Mackenzie (consultancy)
WMP	Wildfire Mitigation Plan
WOCS	West of Cross Cascades South
WPP	Western Power Pool
WRAP	Western Resource Adequacy Program
WX T&TA	Weatherization Training and Technical Assistance
WY	Wyoming

External Studies

Ext. Study-I. Deep decarbonization

In 2021, Portland General Electric commissioned Evolved Energy Research (EER) to conduct an independent study exploring pathways to deep decarbonization for its service territory, called a Deep Decarb Study. This study was finished in 2022 and is an update to an earlier Deep Decarb Study that accompanied the 2019 IRP. The Deep Decarb Study explores potential pathways for economy-wide decarbonization across PGE's service territory given the enactment of House Bill 2021 and DEQ's Climate Protection Program emissions targets. The study does not replace existing tools or processes used by PGE to plan for resource and system needs in compliance with the law.

This analysis was completed prior to the passage of the Inflation Adjustment Act. To adjust for the impact of the IAA on PGE and our customers, an additional slide by PGE has been added to the study.

Information about the deep decarbonization study and study update can be found on our website at https://portlandgeneral.com/2022-deep-decarb-study.

Ext. Study-II. EE methodology

PGE relies on the Energy Trust to identify energy efficiency measures available in the IRP. Energy Trust is a nonprofit organization funded by Oregon and Southwest Washington utility customers. Using a resource assessment modeling tool they identify what energy efficiency measures are cost-effective for PGE. These cost-effective measures are built into the IRP load forecast and assumed to be acquired in most portfolios. Energy Trust also provide measures they deem to be non-cost effective to PGE. Non-cost-effective measures are screened for current cost-effectiveness a second time using IRP models.

Information about the deep decarbonization study and study update can be found on our website at https://portlandgeneral.com/2023-energy-efficiency-resource-assessment-model.

Ext. Study-III. Climate adaptation

PGE contracted with Creative Renewable Solutions to study the impact of climate change on PGE's loads and resources. The study was requested by stakeholders and PUC Staff as part of the 2019 IRP acknowledgement process. It cumulates in a list of recommendations PGE can incorporate to better address climate change in long term planning. Based on the recommendations and discussions with the consultancy, PGE reduced the number of hydro and temperature years used in long term planning adequacy models to better align with the changing climate. The study also provided data, via the RMJOC, on how hydropower generation may change due to climate change. Using these data, PGE ran multiple sensitivities assessing how different future hydro conditions impact resource adequacy. PGE will take Creative Renewable Solutions recommendations into consideration for future planning work.

Information about the climate adaptation study can be found on our website at https://portlandgeneral.com/pge-climate-change-resource-planning-study.

Video archive can be found at https://www.youtube.com/watch?v=SOT69jGpiv0&t=7618s

Presentation slides at https://assets.ctfassets.net/416ywc1laqmd/3Bv5b1kzoD9flvapvcpBrA/981ab90a5ef126db416dd0567a6b5bd5/IRP_Roundtable_October_22-9_V2.pdf#page=21

Ext. Study-IV. Flexibility study

PGE worked with Blue Marble Analytics to study system flexibility needs. This study builds off the 2019 IRP flexibility study also conducted by Blue Marble. It uses a production-cost model, GridPath, to examine the PGE system under various commitment stages (day-ahead, hour-ahead, real time). It focuses on three items: flexibility adequacy, flexibility integration cost of new resources, and new resource (like batteries) flexibility value.

Information about the deep decarbonization study and study update can be found on our website at https://portlandgeneral.com/flexibility-studies.