**Portland General Electric Company**
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August 15, 2022

***Via Electronic Filing***

Public Utility Commission of Oregon
Attention: Filing Center
P.O. Box 1088
Salem, OR 97308-1088

Re: UM 2197 Distribution System Plan Part 2

Dear Filing Center:

Portland General Electric Company (PGE) submits this Distribution System Plan (DSP) Part 2 pursuant to Public Utility Commission of Oregon (OPUC or Commission) Order 20-485. Through Order No. 20-485, the OPUC required investor-owned utilities (IOUs) to develop an initial DSP using a two-part approach. This submittal meets Staff's proposed, and Commission's adopted DSP guidelines (found in Attachment 1 of Order No. 20-485) as summarized in Appendix A of this DSP.

Per the OPUC's order, contents of DSP Part 2 include detailed distributed energy resource (DER) and electric vehicle (EV) load and adoption forecasts, grid needs identification, solution identification and a near-term action plan. Building on our learnings and approach from DSP Part 1, PGE developed our plan using a human-centered process featuring robust outreach and engagement.

Our DSP Part 2 functions as a complementary Distribution System Plan which refreshes and integrates topics presented in Part 1 of our plan. The DSP continues to be our vision of the 21st century community-centered distribution system, integrating two-way resources into our grid in an equitable manner, while enabling reliable access to electricity. Our vision builds on the values of reliability, resiliency, safety and security, while considering fair and reasonable costs through a customer centered approach. This includes new plans to address key items including greenhouse gas emissions, community impacts and cybersecurity.

In our DSP Part 2, we provide a detailed update of our community engagement process used to develop our DSP. We then describe our load and DER forecasting analysis and analytical framework to identify grid needs. This work then informs our processes to identify solutions to address the grid needs and consider non-wires solutions projects, including conceptual proposals for two pilots. Implications are summarized in a near-term action plan which forecasts traditional transmission and distribution investments needed to meet customer, reliability, safety and compliance needs as well as expected grid modernization initiatives.

We conclude with a discussion of long-term actions which highlights necessary changes to evolve the regulatory framework needed to support the realization of a decarbonized, equitable and modern electric grid, including reforms to planning prudency standards, utility incentives and cost effectiveness methodologies. For reference, Appendix A provides a compliance checklist in which we identify where in the document we addressed each of the DSP Guidelines.

DSP Part 2 is a step towards a holistic, comprehensive, collaborative and streamlined planning process that begins to align our decarbonization plans across the DSP, Integrated Resource Plan and Clean Energy Plan. We are working with the OPUC, partners and interested parties to identify synergies between the three plans. A key focus will continue to be the improvement of opportunities for community engagement and accessibility, including coordination across planning efforts to reduce workload wherever possible. Looking ahead, we will be continuing to evolve our annual distribution planning process in the direction described in the DSP while working through the OPUC process outlined in Order No. 20-485 to iterate and evolve DSP guidelines for future cycles.

Our Distribution System Plan Part 2, along with our DSP Part 1, is posted on our DSP website (https://portlandgeneral.com/dsp) where additional DSP related information and updates can be found including past and upcoming meeting materials.

Please direct any questions regarding this filing to Sam Newman at 503-464-2112 or Angela Long at 503-464-7277. Please direct all formal correspondence and requests to the following e-mail address pge.opc.filings@pgn.com

Sincerely,

/s/ Jason R. Salmi Klotz

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# Distribution System Plan

## Part 2

**AUGUST 15, 2022**


# Contents

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# Figures

# Acronyms

| | |
|---|---|
| AAC | All Aluminum Conductor |
| ACS | US Census American Community Survey |
| ACSR | Aluminum Conductor Steel-reinforced |
| ACT | Advanced Clean Trucks |
| ADMS | Advanced Distribution Management System |
| AdopDER | Distributed Energy Resources Forecasting Tool |
| ADPS | Advanced Distribution Planning System |
| AMI | Automated Metering Infrastructure |
| AMP | Asset Management Planning |
| ANSI | American National Standards Institute |
| API | Application Program Interface |
| ASTM | American Society for Testing and Materials |
| AVERT | Avoided Emissions and Generation Tool |
| AWG | American Wire Gauge |
| AWOs | Accounting Work Orders |
| AWRR | Advanced Wildfire Risk Reduction |
| B/C | Benefit-Cost Analysis |
| BC | Business Continuity |
| BCA | Benefit-Cost Analysis |
| BCEM | Business Continuity and Emergency Management |
| BES | Bulk Electric System |
| BESS | Battery Energy Supply System |
| BOD | Board of Directors |
| BSG | Business Sponsor Group |
| BTM | Behind the Meter |
| C&I | Commercial and Industrial |
| CBIAG | Community Benefit and Impact Advisory Group |
| CBO | Community-Based Organization |
| CE | Cost-effectiveness |
| CELID | Customer Experiencing Long Interruption Durations |
| CEMI | Customers Experiencing Multiple Interruptions |
| CEP | Clean Energy Plan |
| CI | Customer Interrupted |
| CIMT | Corporate Incident Management Team |
| CMI | Customer Minutes Interrupted |
| CPS | Capital Project Sponsor |
| CRG | Capital Review Group |
| CRIP | Customer Reliability Improvement Program |
| CVR | Conservation Voltage Reduction |
| CYME | Power Flow Modeling Software |
| DA | Distribution Automation |
| DEI | Diversity, Equity, and Inclusion |
| DEQ | Department of Environmental Quality |
| DER | Distributed Energy Resource |
| DERMS | Distributed Energy Resource Management System |
| DG | Distributed Generation |
| DHP | Ductless Heat Pump |
| DNP 3.0 | Distributed Network Protocol 3.0 |
| DOE | Department of Energy |
| DPSST | Department of Public Safety Standards and Training |
| DR | Demand Response |
| DRMS | Demand Response Management System |
| DSG | Dispatchable Standby Generation |
| DSMS | Demand Side Management System |
| DSP | Distribution System Plan |
| DSPx | Next Generation Distribution System Platform |
| EAHUrisk | Expected Annual Relative Housing Unit Risk |
| EE | Energy Efficiency |
| EJ | Environmental Justice |
| EMS | Energy Management System |
| EO | Executive Order |
| EPA | Environmental Protection Agency |
| EPRI | Electric Power Resource Institute |
| ESG | Environmental, Social and Governance |
| ETO | Energy Trust of Oregon |
| EV | Electric Vehicle |
| EVSE | Electric Vehicle Supply Equipment |

# Acronyms (continued)

| | |
|---|---|
| FAN | Field Area Network |
| FCC | Federal Communications Commission |
| FEMA | Federal Emergency Management Agency |
| FERC | Federal Energy Regulatory Commission |
| FIRM | Flood Insurance Rate Map |
| FLISR | Fault Location, Isolation, and Service Restoration |
| FP | Funding Project |
| FPL | Federal Poverty Line |
| FTM | Front-of-the-meter |
| GARE | Government Alliance on Race and Equity |
| GEB | Grid-Interactive Efficient Building |
| GEM | Greenlink Equity Map |
| GHG | Greenhouse Gas |
| GIS | Geographic Information System |
| GMS | Grid Management Systems |
| G-T&D PMO | Generation, Transmission & Distribution Project Management Office |
| GTB | Grow the Business |
| HB | House Bill |
| HCA | Hosting Capacity Analysis |
| HEMS | Home Energy Management System |
| HRFZs | High-Rise Fire Zones |
| HVAC | Heating, Ventilation, and Air Conditioning |
| ICEA | Insulated Cable Engineers Association |
| IDP | Integrated Distribution Planning |
| IEC | International Electrotechnical Commission |
| IEEE | Institute of Electrical and Electronics Engineers |
| IMT | Incident Management Team |
| IOC | Integrated Operations Center |
| IOUs | Investor-Owned Utilities |
| IPT | Integrated Planning Tool |
| IREC | Interstate Renewable Energy Council |
| IRP | Integrated Resource Plan |
| ISO | Independent System Operators |

| | |
|---|---|
| IT | Information Technology |
| IVR | Interactive Voice Response |
| kW | Kilowatt |
| L2 | Level 2 EV Charging |
| LBNL | Lawrence Berkeley National Laboratory |
| LBNR | Loading Beyond Nameplate Ratings |
| LCOO | Lifecycle Cost of Ownership |
| LDV | Light-duty Vehicle |
| LEAD | Low-Income Energy Affordability Data |
| LTC | Load Tap Charging |
| MDHDV | Medium- and Heavy-duty Vehicles |
| MDM | Meter Data Management |
| MFH | Multifamily Housing |
| MLA | Minimum Load Agreement |
| MV90 | Meter Interval Data Acquisition System |
| MVA | Mega-Volt Amp |
| MVAR | Mega Volt-Amp Reactive |
| MW | Megawatt |
| MWh | Megawatt-hour |
| MYP | Multi-Year Plan |
| NAICS | North America Industrial Classification System |
| NAN | Neighborhood Area Network |
| NEBs | Non-Energy Benefits |
| NERC | North American Electric Reliability Corporation |
| NFHL | National Flood Hazard Layer |
| NPV | Net Present Value |
| NREL | National Renewable Energy Lab |
| NT | Near-Term |
| NTR | Near-Term Asset Risk |
| NWA | Non-Wire Alternatives |
| NWS | Non-Wire Solutions |
| O&M | Operation and Maintenance |
| ODEQ | Oregon Department of Environmental Quality |
| OMS | Outage Management System |
| Ops | Operations |
| OPUC | Oregon Public Utilities Commission |

# Acronyms (continued)

| | |
|---|---|
| PF | Power Factor |
| PI Data Historian | Software for tracking SCADA measurements |
| PMO | Project Management Organization |
| PPE | Personal Protective Equipment |
| PSPS | Public Safety Power Shutoff |
| PUC | Public Utilities Commission |
| PUMS | Public-Use Microdata Sample |
| PV | Photovoltaic |
| R&D | Research and Development |
| RBA | Results Based Accountability |
| RD Meter | Remote Disconnect Meter |
| RFP | Request for Proposal |
| RUCA | Rural-Urban Commuting Area |
| SAIDI | System Average Interruption Duration Index |
| SAIFI | System Average Interruption Frequency Index |
| SAM | Strategic Asset management |
| SB | Senate Bill |
| SCADA | Supervisory Control and Data Acquisition |
| sFCI | smart Faulted Circuit Indicator |
| SGIP | Self-Generation Incentive Program |
| SGTB | Smart Grid Test Bed |
| SME | Subject Matter Expert |
| SSPC | Salem Smart Power Center |
| STB | Sustain the Business |
| T&D | Transmission & Distribution |
| TE | Transportation Electrification |
| TEINA | Transportation Electrification Infrastructure Needs Assessment |
| TEP | Transportation Electrification Plan |
| TRC | Total Resource Cost Test |
| TSO | Transmission System Operator |
| TWG | Technical Working Group |
| UST | Underground Storage Tanks |
| V | Volts |
| V2G | Vehicle-to-Grid |
| VOS | Value of Service |
| VPP | Virtual Power Plant |
| VVO | Volt/VAR Optimization |
| WCCTC | West Coast Clean Transit Corridor |
| WTC | World Trade Center |
| WVRP | Willamette Valley Resiliency Project |
| ZEV | Zero-Emission Vehicle |

# Executive summary

We applaud the leadership of the Public Utility Commission of Oregon (Commission or OPUC) in creating expectations for a human-centered planning approach to distribution system planning (DSP). Through Order 20-485, the DSP guidelines intend to "foster a developing process that supports a human-centered approach to DSP."

Our Empowered Communities strategic initiative promotes equitable participation in the clean energy transition. It is foundational to our new, human-centered approach and reflects the ideas and opinions of those who have participated in our community-based workshops and technical partnership workshops. During a DSP community engagement effort, we learned as new interested parties enter the energy space, expectations of us are changing. This means we need to evolve our practices and skills so that we show up in a way that aligns with our values and desired outcomes – to engage and serve all of our customers and communities.

The OPUC's Order 20-245 required utilities to develop and file their initial DSP in two parts. On August 15, 2021, Portland General Electric Company (PGE) submitted our inaugural Distribution System Plan (DSP) Part 1 to the Public Utility Commission of Oregon (OPUC).

This submittal serves as PGE's second submittal (or DSP Part 2) and meets Staff's proposed, and Commission adopted DSP guidelines (found in Attachment 1 of Order No. 20-485).

This requires a learning mindset, which means we are curious and willing to listen and see things in different ways. It is not enough to simply gather the information; we must integrate new voices into our decision-making processes. This builds trust and enables meaningful collaboration. Engaging with our customers and communities in this way will help us move closer to our goal of an equitable energy future for all.

We held 10 public workshops, including two community-led workshops led by three community-based organizations (CBOs) in the development of our DSP Part 1 and held an additional nine public workshops and four community-focused workshops facilitated by a CBO for DSP Part 2. In total, we conducted 23 total workshops between DSP Part 1 and Part 2.

Our Modernized Grid strategic initiative is critical to our vision of a 21st century community-centered distribution system and enables an optimized grid platform for a safe, secure, reliable system through current and future grid capabilities. It is a key element of the transformation and enablement of large-scale DER integration. Specifically, modernization will enable solar photovoltaic (PV) systems, storage capabilities and electric vehicles (EVs) to be integrated through DER programs. Modernizing the grid works to improve grid flexibility and asset utilization as well as reduces the need for long-term supply-side resources.

However, grid modernization is a complex undertaking requiring large investments focused on augmenting and improving the electrical grid. PGE is wary of the impact of these investments on customer prices. We will continue to take a pragmatic approach, balancing differing objectives. In this way, PGE can focus on investments that provide customer value once in service.

Our Resilience strategic initiative is an acknowledgement that climate change and a movement toward electrification, highlight the importance of a resilient energy ecosystem, especially regarding investments closer to the customer. We are leveraging emerging technology and building new relationships with customers and municipalities. These investments not only enable a stronger, more resilient infrastructure, but also enable an accelerated, robust response to the challenges that we and our customers face.

The past few years have brought profound changes to our daily lives, our society and our world.  In Oregon we experienced historic heat and wildfires, ice and snowstorms, and increasing devastation from extreme weather. Changes to our climate are already resulting in widespread, rapid and intensifying observable impacts. Recent extreme weather events driven by changes to global systems affecting rainfall patterns and seasonal snow cover in the region have impacted our customers significantly, and the frequency and severity of these events is increasing. Throughout all this, customers deserve the peace of mind to know we are doing all we can to help keep the power on, especially during the hottest summer days and coldest winter nights.

Our Plug and Play strategic initiative is a key component of our connected electric system that gives customers a choice and a voice in the transformation of the grid. This interactive customer experience encompasses different aspects of the energy ecosystem – generation sources, electrical infrastructure, and customers – and connects them to each other through clean energy resources, technology, communications, data, services and products.

We are building a distribution system that provides more information to help manage energy bills and empowers everyone to make energy choices to support decarbonization. This includes providing seamless, equitable and affordable opportunities for rooftop solar, electric vehicle charging, home batteries, and home smart devices, along with building the people, process, and technology capabilities to meet growing demands, all while adapting to new challenges created by climate change. All of this is in service of creating a safer, more secure, reliable, resilient system and working environment.

### WILLAMETTE VALLEY RESILIENCY PROJECT

PGE’s sub-transmission (57 kV) and distribution system in the Willamette Valley is aging. Some of its unique equipment and assets have become non-standard or are nearing end-of-life; they weren't designed to withstand the ice storm of 2021. While PGE continues to maintain these assets to ensure reliability of the system, the increased demand from new load growth to severe weather events, has jeopardized an already fragile system. With these system improvements, we are supporting at least 50 MW of load growth for economic development in the valley, setting the foundation for adapting to future electrification of the I-5 corridor, reducing the impact of disruptive events, and providing for operational flexibility and compliance. The upgrades also will provide the infrastructure to bring more renewable generation resources onto the system, when needed.

Our Evolved Regulatory Framework strategic initiative aims to partner with the Commission and stakeholders to align our DSP with the current policy landscape and identify any downstream policy implications. The evolution of the DSP may require new rules and regulations to support its success. This evolution of rules and regulation is a key component to enable the goals of the DSP.

We are transforming the way we do business to support new policies, regulation, and community and customer demands. Our Evolved Regulatory Framework strategic initiative highlights the changes need to support investment in customer- and community- centered solutions. It seeks to identify and advance reforms to rules, regulations, and the regulated utility business model that streamline and enable the changes to distribution planning processes, investments and operations envisioned by the entire DSP effort.

# PGE's strategy and vision

Our company's overall strategy to decarbonize, electrify, and perform supports our DSP's vision of a 21st century community-centered distribution system. Our DSP begins our journey of human-centered planning that advances environmental justice, promotes distribution energy resource (DER) adoption, maximizes grid benefits, and furthers decarbonization through DER programs, non-wires solutions (NWS), virtual power plants (VPP), resiliency, and other mechanisms to strategically provide community benefits — for all customers, especially environmental justice communities — while improving metrics around safety, reliability, resiliency, and security. **Figure 1** highlights the goals of this vision and the strategic initiatives that will help realize this vision.

**Figure 1. PGE's corporate strategy, and vision, goals and strategic initiatives for the DSP**

| | | | | | |
|---|---|---|---|---|---|
| **Corporate strategy** | Decarbonize | | Electrify | | Perform |
| **DSP vision** | 21st century community-centered distribution system | | | | |
| **DSP goals** | Advance environmental justice goals | | Accelerate DER adoption | | Maximize grid benefits |
| **DSP strategic initiatives** | Empowered communities | Modernized grid | Resilience | Plug and play | Evolved regulatory framework |

# PGE's future holistic planning vision

While most agree that the energy transformation underway should address the threats of climate change, its alignment with social and environmental justice goals is still in its infancy. Oregon has been at the forefront of working to address historical wrongs and breaking down existing systems that discriminate or exacerbate inequities in society. In recent years, several policies have paved the way to support the move forward on our vision for a clean energy future such as UM 2005.[1] New emerging policy and regulation, such as Oregon's House Bill 2021 and Oregon Department of Environmental Quality's Climate Protection Program, address decarbonization of the electric sector and have also begun to investigate how energy policy can address equity. Throughout the UM 2005 proceeding, we noted intersections between the goals of the DSP and current policies, rules, standards and other regulations.[2] These policies provide a view of the regulatory drivers for change. In our DSP, we identify downstream regulation that can align with these policies to enable the vision of the DSP.

On August 7, 2022, the US Senate passed the Inflation Reduction Act.[3] The bill is focused on addressing climate change through federal funding and by extending and expanding clean energy tax incentives (such as wind, solar and storage), as well as incentives for energy efficiency and transportation electrification. The bill contains credits for EV charging infrastructure, for

1. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf
2. Oregon's 2021 HB 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021 and Oregon's Climate Protection Program can be found at: https://www.oregon.gov/deq/ghgp/cpp/Pages/default.aspx
3. Inflation Reduction Act one-page summary, available at: https://www.democrats.senate.gov/imo/media/doc/inflation_reduction_act_one_page_summary.pdf

purchasing new and used EVs, and energy efficiency investments for both residential and commercial buildings.

We embrace the challenge of leveraging the clean energy transformation to address environmental justice. We anticipate that the creation, filing, and acceptance of our initial plans will educate all parties and identify areas for continuing improvement for the DSP process. We expect the evolution of the DSP guidelines, alongside new policy, regulation, and federal funding, will advance distribution system planning and define how future investments are made and investment costs are recovered.

## COORDINATION OF DSP BETWEEN IRP AND CEP

The introduction of the Clean Energy Plan (CEP) has forced a near-term conversation about where DSP should fit into the broader planning framework. What was previously a question of how the Integrated Resource Plan (IRP) and the DSP would successfully align inputs, outputs, and high-level assumptions, is now a conversation about how the DSP and IRP will feed into the CEP to convey a utility's overall decarbonization strategy. That strategy will need to address the following:

- Balance supply side and demand side investments to achieve decarbonization,
- Enable adoption of DERs such as solar, storage, EVs,
- Continue to support robust economic development in PGE's service territory, and
- Address aging infrastructure in the downtown core and older parts of the system.

All while maintaining reliability at fair and reasonable costs.

In DSP Part 2, we begin to advance our vision for the DSP to create a holistic, comprehensive, collaborative, and streamlined planning process that reports our decarbonization plans across the DSP, IRP, and CEP. This planning process shares our journey toward decarbonization in a clear and concise way and connects the dots for our regulators, policymakers, stakeholders, partners, and communities. While our vision of a holistic planning process aims to integrate workstreams alongside our corporate strategy to decarbonize, electrify, and perform, there is still much more work to be done.

We are working with the OPUC, partners, and interested parties to identify synergies between the three plans. As a starting point, we have incorporated the outputs from the DSP into the IRP, which will drive the creation and selection of future planning portfolios for DERs and electrification. Our IRP will incorporate available DER forecasts needed to assess system needs and solutions. These inputs will inform the IRP's selection of capacity expansion need, and ultimately will drive the creation of a preferred resource strategy and an action plan.

> House Bill 2021, creates an ambitious clean energy framework that requires us to decarbonize our retail electricity sales by 2040 in a manner that provides direct benefits to local communities, maintains a focus on reliable service, and a commitment to affordability and equitable outcomes. HB 2021 sets forth a robust set of requirements including annual goals/actions that demonstrate progress towards the clean energy targets.

The CEP may present the new findings from analytical planning processes through the lens of Oregon's rapidly changing and decarbonized energy future, with a focus on reliable, affordable, and equitable outcomes. Through the CEP, we are working to further clarify the timing and intersections between the DSP, IRP and CEP. A key focus will continue to be the improvement of opportunities for community engagement and accessibility, including coordination across dockets to reduce workload wherever possible. The result of these proceedings must meaningfully reflect stakeholder and community input. **Figure 2** illustrates the initial relationship we see between these planning processes. This relationship will evolve over time with the finalization of DSP and CEP guidelines from the OPUC, which we anticipate will happen in 2023.

**Figure 2. Current relationship between planning documents**

| Clean Energy Plan (CEP) | Distribution System Plan (DSP) | Integrated Resource Plan (IRP) |
|---|---|---|
| **Purpose**: Reports emissions reduction progress; defines regular progress and compliance actions. Emerging requirements: resilience, community energy projects and benefits. | **Purpose**: Details vision, goals, and strategic initiatives for the distribution system, develops community engagement (CE) strategies, and DER forecasting and load. | **Purpose**: Identifies long-term resource needs; select best portfolio of resources to meet needs. |
| **Timeline**: March 2023 | **Timeline**: August 2022 | **Timeline**: March 2023 |
| **Differences**: Communicates PGE's vision through the lens of HB 2021 requirements. | **Differences**: Accelerates DER adoption; maximizes grid benefits. | **Differences**: Less flexible process and less nimble than other plans. |
| **Inputs**: IRP action plan; actual and forecasted emissions. | **Inputs**: Distribution load forecasting; DER and TE/BE scenario forecasting; cost-effectiveness assumptions; locational forecasting and action plan for T&D and DERs. | **Inputs**: Existing resource characteristics; new resource characteristics. |
| **Outputs**: Forecast emissions by year; action plan. | **Outputs**: System and feeder-level DER and load forecast; CE Plan; NWS action plan. | **Outputs**: Action plan of system resource needs. |

This new landscape requires thoughtful and ongoing discussion. At the time of this DSP filing, there are still many outstanding questions on how CEP requirements will impact existing DSP guidelines and which types of proactive investments should be made to the distribution system to accelerate the equitable implementation of a decarbonization future envisioned in HB 2021. The CEP will identify actions and investments not envisioned in our DSP or the OPUC's DSP initial guidelines. We look forward to working with the OPUC and partners to further develop and refine the DSP guidelines. Our intent is to present our DSP Part 2 at an OPUC Public Meeting between three to five months following this filing, and after a period of stakeholder feedback and OPUC staff review.

# PGE's Distribution System Plan (DSP) summary and highlights

PGE is proud to submit Part 2 of our inaugural DSP for consideration by our customers, partners and the Commission. This DSP reinforces our ongoing commitment to the clean energy future and takes the steps to integrate environmental justice goals. We detail, in this plan, our actions for the distribution system and the role of the DSP in achieving it. We are committed to transitioning to a human-centered planning approach and believe the engagement process that contributed so heavily to this submission is evidence of that commitment.

Our customers are at the center of everything we do. In addition to addressing the OPUC's UM 2005 requirements, the 23 workshops we conducted created a community of DSP partners, committed to building a better understanding of both our work and our partners' needs and expectations. Our goal for the workshops was to start conversations that contributed to our DSP while also creating a platform for collaboration. **We thank the participants for continuing with us on this journey and are grateful for their partnership and insights.**

As OPUC Staff pointed out in the acceptance of our DSP Part 1, we "expect a great amount of learning will result from the Part 2 filings," including the following high-level lessons:

- How and where utilities are forecasting load growth, DER and EV adoption.
- How and where utilities identify areas of the distribution system which need investment.
- How utilities consider and evaluate various investments to address grid needs.
- How utilities have evaluated non-wires solutions pilot concept proposals.
- How utilities' community engagement plans were implemented.
- And finally, what investments utilities are planning in the next several years.

We are eager to continue working with our DSP partners and learn together as we take on the challenges presented by a 21st century energy ecosystem.

This report provides substantial transparency into our company and distribution system planning functions. To highlight some of the key aspects of our plan, we summarize below the main points in each chapter.

## CHAPTER 1
## DISTRIBUTION SYSTEM PLANNING OVERVIEW

The Distribution system planning overview chapter represents PGE's process to determine the distribution grid's ability to serve existing and future power demand. Our process includes meeting customer needs, enhancing safety, increasing reliability and resiliency, meeting new standards and requirements, reducing risk, and optimizing the configuration of the distribution system. We analyze the grid under both normal operating conditions and abnormal conditions that could arise during situations such as equipment failure. Our distribution planning is a cyclical process that includes DER/TE load forecasting and adoption, grid needs analysis and solution identification steps.

We review the current state of our system and evaluate near- and long-term projections for system loading conditions based on established guidelines. Our current guidelines are centered on project priority, long-term system adequacy, operational flexibility and ability to serve customers during weather extremes.

### MAIN POINTS

- Discusses our existing and future distribution system adequacy analysis.
- Highlights our distribution grid analyzes during normal and abnormal conditions.
- Distribution system conditions in near- and long-term are evaluated based on established guidelines.

New technologies, including advanced system monitoring and control and lower-cost DERs, have allowed us to better understand what's happening inside the distribution system and has changed our approach to planning and operating the distribution grid. Our distribution system planning has historically been focused on the analysis of one-way power flow during current and future peak loading conditions. But with the rise in DERs, more complex and detailed power flow analysis will become increasingly necessary.

## CHAPTER 2
## EMPOWERED COMMUNITIES

The Empowered communities chapter represents PGE's efforts as an essential service provider to engage and understand where our customers live, work, learn, play as well as co-develop solutions that provide direct clean energy community benefits. To begin to understand all our customers and communities, we must leverage the work started in DSP Part 1 and integrate best practices into community outreach and engagement efforts across our organization. Doing so enables all of our teams to have a more complete understanding of our customers' and communities' needs; the community has a better understanding of our business; and we are all ready to develop solutions together.

The DSP has provided a platform for us to expand our community engagement efforts. Since its inception, there is increasing need for community outreach and engagement across our workstreams. Traditionally, We have conducted customer outreach, but legislation and regulation is calling for two-way communication and interaction. Community engagement requires the application of an equity lens and a commitment to iteration to so that we can be flexible and responsive to new learnings. We are in a continuous pattern of learning, iterating and engaging, while simultaneously working to operationalize equitable community engagement practices and strategies across our company. As we work to evolve our competency and capacity for this new work, we acknowledge that we need to learn and intend to be open and transparent in our engagement with community partners and other interested parties.

### MAIN POINTS

- In response to our evolving needs around community engagement, PGE is developing a portfolio-based program approach to how we conduct community outreach and community engagement across our organization.
- Community engagement requires a commitment to an iterative approach in how it is conducted and competency in who conducts it.
- We continue to learn from community partners on how to best show up for and engage EJ communities and those that serve and advocate for them.

For DSP Part 2, we honored our three focus areas from Part 1's Community Engagement Plan. These focus areas include competency in community engagement practices and operationalizing equity, activation of CBOs and making better use of demographic data. In each of these focus areas, we reflect on our goals and objectives previously identified and outline the actions that PGE has taken since DSP Part 1.

## CHAPTER 3
## LOAD AND DER FORECASTING

The Load and DER forecasting chapter represents PGE's current state of our distribution system needs assessments, which are informed by three key input streams: the corporate load forecast, bottom-up load additions and historic seasonal peak load trends at the locational level.

We forecast a significant increase in electrification from transportation and buildings, and with it, opportunities to offset localized capacity constraints with a growing mix of flexible loads and distributed renewable energy technologies like solar and battery storage. This load and the subsequent adoption will grow significantly beyond 2030 and areas of the grid will likely see significant growth even sooner. Because of this, we are evolving our tools and processes around bottom-up load and DER forecasting which can provide useful information to planning and system operations so we can prepare our grid for these new loads come.

For the first time in 2022, we completed a granular, feeder-level forecast for DER adoption through 2050. Our DER and transportation electrification (TE) forecasting and adoption model, AdopDER, is a new planning tool that combines detailed accounting of our customer base, technology performance features and costs, and public policy drivers in order to forecast DER and TE load and adoption at the customer site-level. By combining top-down and bottom-up forecasting methods, we can better understand the potential impacts to our distribution system from a growing adoption of clean energy resources.

While we are improving our distribution system forecasting capabilities, we are also incorporating equity metrics and data to inform program planning and grid investments. We've integrated demographic, environmental justice and resiliency data into our AdopDER model to assess whether current programs and offerings lead to equitable outcomes, and where we can make improvements to better serve our communities.

### MAIN POINTS

- Corporate load forecasting process and drivers
- Current bottom-up load forecasting methods
- DER forecasting methods
- DER forecasting results at the granular substation level

Increased adoption of DERs will, at some point, affect our system; we know we need to plan for these new loads and resources in order to be responsive to new customer requests, especially if they require significant system upgrades to accommodate our customers' climate and decarbonization goals such as fleet electrification. Our planning teams are now working with our TE team to provide greater insight into customer plans to electrify medium- and heavy-duty vehicles. We incorporated these insights into our workflow and have mapped likely hotspots of fleet electrification. We look forward to working with our partners as the regulatory framework continues to evolve to enable investments in the distribution grid to accelerate transportation electrification.

## CHAPTER 4
## GRID NEEDS ANALYSIS

The Grid needs analysis chapter represents PGE's analytical framework to plan and identify grid needs at the distribution system. This planning process is informed by key drivers such as load growth forecasts, economic development, new large single loads, grid modernization, regulatory requirements, safety, reliability performance of the system, urban growth boundary expansion, and zoning changes.

The DSP is tasked with identifying grid needs and prioritizing those grid needs for solution development. There are several metrics used to consider what these grid needs are and how to prioritize them.

We plan the distribution system to prevent equipment overloads when it is in normal configuration, as well as configurations during outage scenarios. During outage scenarios, we restore power using switching devices that move customer load to adjacent distribution equipment. We analyze equipment that is overloaded or is approaching overload levels in both a normal or an outage configuration.

Our forecasts for general load growth and new forecasts for DER adoption are two inputs we use to anticipate future load growth. In addition to forecasts, we analyze known large load additions coming from new or existing customers, which can also dictate the anticipated load growth on the distribution grid. These large load additions can come from our internal teams as well as external resources.

### MAIN POINTS

- Showcases the analytical framework for identification of Grid Needs.
- How we assess risk within the distribution system.
- How grid needs are ranked and prioritized according to the Distribution Planning Ranking Matrix.
- Identifies 12 prioritized grid needs.

We utilize existing loading conditions, anticipated load growth, and risk and reliability assessments, which all feed into a scoring matrix called the Distribution Planning Ranking Matrix. In addition to these three main categories, we assign points to each grid need for addressing safety concerns, adhering to transmission system compliance issues, meeting customer commitments, and being a precursor to other grid needs projects. Our Distribution Planning Ranking Matrix prioritizes the distribution grid needs that will be the focus of solution development.

## CHAPTER 5
## SOLUTION IDENTIFICATION

The Solution identification chapter presents PGE's process to identify potential solutions that address system deficiencies. Our solution identification process is directly fed from the output of the grid needs analysis process. In the solution development process, we perform a system study that supports identification of potential project options.

Our study includes a problem statement, study methodology, analysis, project benefits, cost estimates and a recommended option. We utilize distribution load flow software to analyze distribution system options by modeling scenarios and running load flow simulations, which assist in determining a preferred option for a project.

Once options are identified, we conduct a benefit-cost analysis (BCA) that will produce a range of outputs used to analyze risk and economic costs associated with specific assets that are included in the solution. We then include the risks and economic costs associated with each asset in the scope of a project, which are aggregated to provide a project level assessment of risk, benefits, and cost.

### MAIN POINTS

- System studies are performed to further understand and characterize the prioritized grid needs.
- A benefit-cost analysis is performed to evaluate proposed solutions.
- Recommended solutions are scored and ranked using the ranking matrix discussed in the grid needs analysis.
- Provides recommended solutions for the 12 grid needs identified in Grid needs analysis.

The distribution planning projects we develop in the Solution Identification process are prioritized using our Distribution Planning Ranking Matrix and inform our portfolio planning process. Our Generation, Transmission, & Distribution Portfolio is split along two axes: Sustain the Business (STB) and Grow the Business (GTB). STB focuses on projects that replace our existing assets for the purposes of operational improvement and risk reduction. GTB focuses on projects that increase grid capacity and/or flexibility needed to address load growth or increased demand, which may include a commitment to a customer, internal partner, municipality, or co-owner.

## CHAPTER 6
## NON-WIRES SOLUTIONS

The Non-wires solutions chapter represents PGE's commitment to empower our communities to engage in the clean energy transition by supporting efforts like NWS. Oregon is leading by engaging in complex and difficult concepts that push the envelope of traditional utility business practices, all while conducting extensive technical and community engagement with our partners. We are co-developing solutions that meet the needs of the communities we serve and help evolve the overall conversation of distribution system planning.

To assess non-wires solutions, we developed a process flow that lays out the framework to evaluate these new technologies against traditional distribution investments. We've considered several factors, including screening criteria, community engagement, technical performance characteristics, and reliability improvements. Following our process, we identified five candidates that passed our initial screening, of which two were selected as pilot projects for this DSP. Both pilot projects feature a range of DER-based solutions.

As a part of our NWS process, we created a policy and procedures document (**Appendix E**) that was shared with partners through our DSP Partner Workshops. We also shared NWS analysis with various stakeholders, partners and community-based organizations through our DSP Partnership Workshops and Community Workshops. The participants of these workshops assisted us in identifying strengths and weaknesses, as well as opportunities within our NWS approach and plan.

### MAIN POINTS

- Demonstrates our commitment to supporting our communities through innovative offerings like non-wires solutions and finding ways to maximize community benefits.
- We developed a process flow for our two pilot concepts that can act as a blueprint for future NWS engagements.
- We identified over 5 million annual kWh of energy efficiency, over 4 MW of distributed solar, and over 2 MW of flex load potential for an Southeast Portland community.

In this initial approach to develop a minimum of two NWS pilot concepts, we applied our process to the grid needs identified through the heavily loaded equipment report accounting for overlap with historically disenfranchised communities, current staffing availability, DSP time constraints, and size of the grid need, where possible. From this short list, we then engaged in an initial review of the customer demographics of each location. Based on this exercise, we saw two potential candidates rise to the top as preferable sites to develop the full NWS concept proposal (i.e., Eastport and Dayton).

## CHAPTER 7
## NEAR-TERM ACTION PLAN

The Near-term action plan chapter represents PGE's two- to four-year action plan, which focuses on maintaining grid performance and further enhancing capabilities that support Oregon's policy goals. Among these are maintaining adequate, reliable, and affordable electric service; integrating DERs and TE; supporting beneficial electrification; and augmenting resilience to mitigate the severe weather effects of climate change, as well as emerging cyber and physical threats.

The investments described here are based on an assessment of key grid and customer needs, new technology developments, and best practices. Much of the current distribution system was designed and deployed decades before the wide-scale adoption of DERs, the rise in transportation electrification, evolving customer expectations for digital interactions and emerging challenges caused by climate change and cyber threats. Operational challenges introduced by these new technologies and customer demands require process refinements to plan, engineer, and design the grid's capabilities in advance of its changing uses.

In creating our vision of a 21st century community-centered distribution system, we developed goals that not only focus on maintaining a safe and reliable grid, but also advance environmental justice, accelerate DER adoption, and maximize grid benefits. We utilized these goals alongside our five strategic initiatives to create an action plan that meets the DSP guidelines, aligns to our vision for the DSP, and represents our plans for modernizing the distribution system. These goals are focused on:

- **Empowered communities** — Enabling the equitable participation in the clean energy transition through human-centered planning, outreach and community engagement.
- **Modernized grid** — Optimizing a grid platform that is safe, secure and reliable though current and future grid capabilities.

### MAIN POINTS

- Specific investments in the distribution system that address the grid needs discussed in earlier sections.
- Investments in the distribution system that are being made to address other drivers.
- Investments and proposed investments to advance the 21st century distribution system.

- **Resilience** — Strengthening the grid's ability to anticipate, adapt to, withstand and quickly recover from disruptive events.
- **Plug and play** — Enabling DER adoption by improving access to grid edge investments that accelerate customers' clean energy transitions through activities such as hosting capacity analysis.
- **Evolved regulatory framework** — Establishing the regulatory framework needed to support utility investment in customer and community centered solutions.

The actions outlined in our plan are summarized in **Table 1**.

Table 1. Near-term action plan summary

| Action plan investments |
| --- |
| 276 capital investment projects through 2026 needed to address reliability, resiliency, safety, compliance, and customer loads |
| 12 prioritized grid needs investments in 2023 |
| DER Opportunities by 2026 |
| Investments into customer DER portal needed to develop a device management, enhance customer billing and settlements, streamline interconnections and customer communications |
| Design of a VPP with expansion capabilities needed to meet HB 2021 |
| Investments for planning and engineering capabilities needed to enhance PGE's AdopDER model, development of a Next Generation Planning Tool, DER data management systems, and updates to cost-benefit model and tools for NWS |
| Investments into grid management systems for ADMS for critical infrastructure and DA |
| Investments into sensing, measurement, and automation, telecommunication and cybersecurity |

**Table 2** shows the estimated costs for proposed investments, solutions, and actions within our DSP, which reflect our commitments to our DSP goals and vision. At the time of this DSP filing, there are still many outstanding questions on how CEP requirements will impact existing DSP guidelines and which types of investments should be made to the distribution system to accelerate the equitable implementation of a decarbonized future. These investments in our distribution system do not include investments, solutions, and/or actions related to our Clean Energy Plan (CEP).

Table 2. Near-term action plan estimated investment summary

| Investment Summary (estimated $M, incurred) | 2023 | 2024 | 2025 | 2026 | Total |
| --- | --- | --- | --- | --- | --- |
| **Traditional T&D Investments for Customers, Reliability, Safety and Compliance** | $285.0 | $285.0 | $285.0 | $285.0 | $1,140.0 |
| Prioritized Grid Needs (included in Traditional T&D Investments) | $55.3 | $56.3 | $87.1 | $28.7 | $227.4 |
| **Grid Modernization Investments** | $40.0 | $40.0 | $40.0 | $40.0 | $160.0 |
| **Total T&D and Grid Mod Investment** | $325.0 | $325.0 | $325.0 | $325.0 | $1,300.0 |

PGE's budgets are fixed each year and many factors could cause a reprioritization of the work that is identified in the plan, often on a year-to-year basis. The projects and investments represent the body of work that PGE has identified for the coming years. Changes in our local environment will dictate the timing and duration over which that work is completed and whether or not the identified projects are displaced by other projects of higher priority.

Chapter 1

# Distribution system planning overview

# Chapter 1. Distribution system planning overview

"The journey of a thousand miles begins with one step."

— **Lao Tzu**, ancient Chinese philosopher and writer

## 1.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[4] It's designed to improve safety and reliability, resilience and security and apply an equity lens when considering fair and reasonable costs.

This chapter provides an overview of PGE's distribution planning process. We describe the key factors we consider when analyzing the system and identifying the investments in the distribution system. We also discuss our advancements to innovate legacy distribution planning practices since our DSP Part 2 filing.

**WHAT WE WILL COVER IN THIS CHAPTER**

Existing and future distribution system analysis.

Distribution grid, analyzed during normal and abnormal conditions.

Distribution system conditions evaluated based on established near- and long-term guidelines.

4. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.

## 1.2 Introduction

Distribution system planning is the process of analyzing the electric distribution system to assess whether it is capable of serving existing and future power demand (sometimes called load) under normal conditions and when things go wrong (sometimes called contingencies), like equipment failure. This process allows us to provide reliable, safe and resilient energy to PGE's customers at a fair and reasonable cost.

Historically, PGE distribution system planners were primarily concerned about managing current and future power demand because power flowed in one direction; from the place it was created or generated to homes and businesses. This has changed as technologies, policies, and our capabilities continue to evolve. The grid has become more complex, which means PGE has to plan for more situations and predict new, possible scenarios for operating and maintaining the distribution system.

When conducting distribution system planning, PGE looks at how we will meet customer needs, improve safety, increase reliability and resiliency, meet new standards and requirements and reduce risk to the system and our customers. We also optimize the configuration of the distribution system to improve customer experiences and reliability. We are doing this work with detailed network models of the distribution grid using Eaton's power flow modeling software, CYME, that factors into most aspects of distribution system planning. CYME is used for the analysis of three-phase electric power networks and is equipped with powerful analytical options and alternative solution techniques. This model is our way of identifying and developing solutions for traditional grid needs on our system such as equipment overloads or voltage issues.

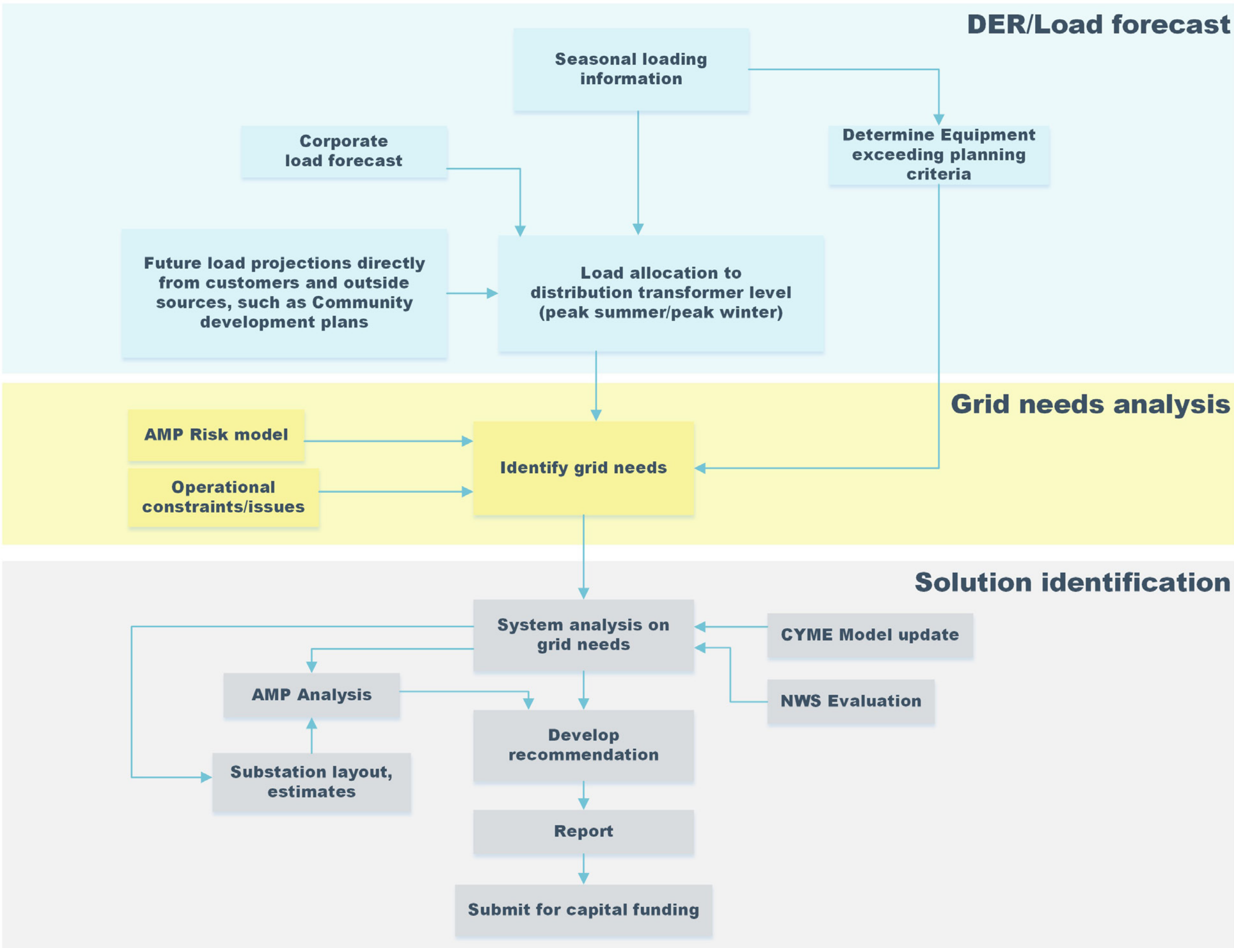
## 1.3 Current distribution planning process

A robust distribution planning process helps us make the best decisions to improve safety, increase reliability, meet customer needs, meet standards and requirements and reduce risk. PGE analyzes our distribution system on a continual basis, including analyses for scenarios such as new customer loads or changes in system conditions. Our distribution planning process has traditionally followed five major guiding principles:

- **Plan to peak** — PGE plans the distribution system to serve customers even during extreme temperatures, at the largest power demand at a given point during a year.
- **Plan for load capacity** — PGE's target loading is less than 67% for feeders and less than 80% for transformers. This gives us flexibility and spare capacity to move load around on the system, when needed, to meet the needs of our customers.
- **Target system flexibility** — All customers are served by switching load from one piece of equipment to another (at both the transformer and feeder level) during planned or unplanned outage events.
- **Prioritize customer load growth projects** — Large housing developments, manufacturing facilities and industrial parks that anticipate an increased need for power.
- **Planning at least 10 years out** — New infrastructure is built for the long-term load needs of an area, ensuring that the infrastructure provides adequate capacity and reliability for at least 10 years.

This planning process is a cyclical process that follows a series of steps shown in **Figure 3**. The planning process considers a wide array of variables, such as equipment loading and asset health, so that PGE continues to provide safe and reliable power to our customers.

Figure 3. Current distribution planning process




## 1.3.1 CAPITAL PLANNING PROCESS

In the spring of each year, PGE begins the capital planning process (described in **Appendix L**) in which we identify needs on the grid, develop projects (investments) to address those needs and request funding for projects that need to be prioritized to support reliability and safety.

PGE starts our capital planning process with the forecast of peak customer load and now the DER forecast (starting in 2022). We conclude our planning process with the design and construction of prioritized and funded projects. This process can be lengthy and sometimes takes years. As part of our annual distribution planning process for capital planning, we thoroughly review existing and historical conditions, as defined in **Table 3**.

**Table 3. Planning considerations**

| Consideration | Description |
|---|---|
| Safety concerns | When equipment is obsolete or at end of life and failure is imminent, or equipment can no longer safely protect the transmission or distribution system. |
| Customer commitments | Includes signed agreements such as minimum load agreements (MLAs) or customer-provided estimates of future load needs that we identify as highly likely. |
| Feeder and substation loading, reliability, and resiliency performance | Covers historical loading and future load projections, compared to planning guidelines and thermal limits of substation equipment (reliability and resiliency performance is determined using IEEE standards metrics). |
| Dependencies between substations and feeders | Ensure that system upgrades leave room for system reconfiguration during planned or unplanned outages, so we can move customer load to other facilities when we need to take equipment out of service. |
| Temporary equipment use and system configurations | Allow the removal of temporary equipment that has been installed as a result of an outage. |
| Asset health | The condition of an asset, such as a substation transformer, and how much longer it can be used before it is at risk of failing. |
| Known and projected load growth | Increased load for new residential developments or large commercial customers, and growth of existing commercial/industrial customers in specific locations. |
| Quantity and types of DERs | Review of current and projected types of DERs on the distribution system. |
| Total system load forecasts | The corporate load growth forecast applied across the entire service territory, as well as DER forecasts. |
| Previous planning studies | May require updates to information, such as projected loading and large customer load additions. |

Solutions identified as part of the distribution planning process may include, but are not limited to, a new feeder or substation, upsizing, or "reconductoring" distribution lines for more capacity, or upgrading substation transformers for more capacity. While PGE has relied on these traditional solutions in the past, we will evolve to explore non-wires solutions to resolve our grid needs. We develop cost estimates and perform cost-benefit analyses to determine the best options based on several factors, including operational requirements, technical feasibility and future needs.

Proposed projects are funded as part of an annual budgeting process. This is based on a portfolio-level ranking methodology that also funds other distribution investments and expenditures (including asset health, grid modernization, storm response and mandated projects to relocate utility infrastructure in public rights-of-way when required for public projects like road widening). This process is described in **Section 5.3**.

### 1.3.2 PLANNING CRITERIA

All distribution system equipment has thermal loading limits that must factor into PGE's planning processes. Exceeding these limits stresses the system, causes premature equipment failure and can result in customer outages.

The thermal loading limit is the maximum amount of load that can be served by a piece of equipment before risking equipment failure.

PGE's planning processes primarily focus on the substation distribution transformer and mainline feeder levels. We plan, measure and forecast distribution system load with the goal of ensuring we can serve all customer load under system normal (N-0) and single contingency (N-1) conditions (N-1 refers to conditions when '1' system component fails, for example, a feeder or transformer). Our goal is always to keep electricity flowing to as many customers on the feeder as possible. Designing our system for adequate N-1 capacity allows for restoring power to all customers by reconfiguring the system using electrical switching when there is an outage of any single element. Planning criteria for our distribution feeders require associated feeder getaways, mainlines and voltage regulators not to exceed 67% of their seasonal thermal limits or 12 MVA, whichever is lower, under system normal, or N-0, conditions. For most standard feeders, this equates to two-thirds normal capacity of a standard feeder mainline. Under N-1 conditions, distribution feeders can load up to their seasonal thermal limits. For both N-0 and N-1 conditions, the distribution system is planned such that voltage at the customer meter is maintained within 5% of the customer's nominal service voltage, which for residential customers is typically 120 volts.

Underground feeder circuits are installed in a group of plastic pipes called a duct bank that is strengthened with concrete when required. When multiple feeder circuits are installed close to each other in the duct banks they heat up more quickly than a single underground feeder circuit would. PGE planning engineers use software tools to determine maximum N-0 and N-1 feeder circuit cable capacities for circuits installed in duct banks. When underground feeders fill existing duct banks, and there is no more room for additional duct banks from a substation to the distribution load, we have to construct facilities from a different area to serve this load.

In addition to examining distribution feeder demands, PGE looks at the loading levels compared to the capacity limits for the substation distribution transformers. A transformer loading limit study was performed on our system in July 2009 to determine the summer and winter transformer loading beyond nameplate ratings (LBNR). This study evaluated the transformer winding limits based on top oil temperature, hot spot temperature, and loss of life with derating factor considerations for individual transformers based on bushings, LTC, and/or auxiliary components on a case-by-case basis. The transformer loading limit study calculations used the Institute of Electrical and Electronic Engineers (IEEE) standard for transformer loading.[5] The distribution power transformer ratings were classified based on transformer capacity (MVA), manufacturer and cooling type to provide the loading capabilities that planning engineers use for transformer loading analysis.

The IEEE standard criteria used to determine the summer and winter LBNR is:

- Top-oil temperature not to exceed 110˚C
- Hottest-spot temperature not to exceed 130˚C
- Insulation loss of life not to exceed 0.0133% (per day)
- Hottest-spot temperature range from 120˚C to 130˚C not to exceed four hours

Transformer design life is determined by the longevity of all the transformer components. At a basic level, most substation transformers have a high voltage coil of conductor and a low voltage coil electrically insulated from each other and submerged in a tank of oil. Transformer loading generates heat; the more load transformed from one voltage to the other, the more heat; too much heat damages the insulation and connections inside the transformer. Hottest-spot temperatures refer to the places inside the transformer that have the greatest heat, and top-oil temperature limits refer to the maximum design limits of the material and components inside the transformer. The LBNR rating is the transformer thermal loading limit that must be maintained to avoid loss of life. Loss of life refers to the shortening of the equipment design life that leads to premature transformer degradation and failure.

To maximize the service life and the ability to reliably serve customers, PGE's loading objective for transformers is 80% of the distribution power transformer's LBNR. A robust distribution system keeps substation transformer utilization rates below 80%, with multiple restoration options in the event of a substation transformer becoming unavailable because of an equipment failure or required maintenance and construction. During emergency situations, such as N-1 contingencies, distribution power transformers are permitted to be loaded up to 100% of their LBNR rating.

5. IEEE Guide for Loading Mineral-Oil-Immersed Transformers - Corrigendum 1," in IEEE Std C57.91-1995/Cor 1-2002, vol., no., pp.1-16, 12 June 2003, doi: 10.1109/IEEESTD.2003.94283

All supervisory control and data acquisition (SCADA)-enabled substation feeders and transformers are equipped with metering equipment that can measure various power quantities (MW, MVAR, MVA, voltage and current) and these meters are polled by grid management systems (EMS and ADMS) every 10 seconds. These 10-second sample values are archived in a historian (PI system) which allows us to refer to historical peak demands for system planning needs. For non-SCADA stations, the feeders are equipped with meters, and they are polled hourly for interval data and demand values are then archived in the historian (PI system). Transformer loading in non-SCADA stations can be obtained by aggregating corresponding feeder loads.

Each transformer's peak in a multi-transformer substation is typically non-coincident, which means the transformers can each individually experience peak load at different times, and potentially on different days. This is because each transformer serves multiple feeder circuits, and each circuit serves different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer, because typically the feeders also experience peak load at differing times. Using PGE's planning criteria, planning engineers evaluate the distribution system, assess transformer and feeder loading, and identify risks for normal and contingency operation of the system.

### 1.3.3 FEEDER AND SUBSTATION DESIGN

Distribution feeders for standard service to customers are designed as radial circuits (**Figure 4**). Therefore, the failure of any single critical element of the feeder causes a customer outage. PGE constructs ties between different feeders so that we can switch load from one feeder to another in the event of an outage. The distribution system is planned with enough capacity to minimize the number of switching operations that are required to restore power to customers after a single outage event. In the past few years, we have automated some of these feeder ties through distribution automation, which automatically moves the load from one feeder to another if there is an outage. This is an essential component of our grid modernization efforts and can reduce outage frequency and duration.

PGE plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. This is based on anticipated load but can occasionally be limited by factors such as geography and available land (as seen in **Figure 5**, where the changes in the fence line required us to make the substation a polygon instead of the typical rectangle shape). Many substations are planned for a maximum ultimate design capacity of three transformers at the same distribution voltage, however, geography and land constraints for substations can limit capacity to two transformers, like the substation in **Figure 5**. This maximum size balances substation and feeder costs with customer service, customer load density

Figure 4. Typical radial distribution system one-line schematic

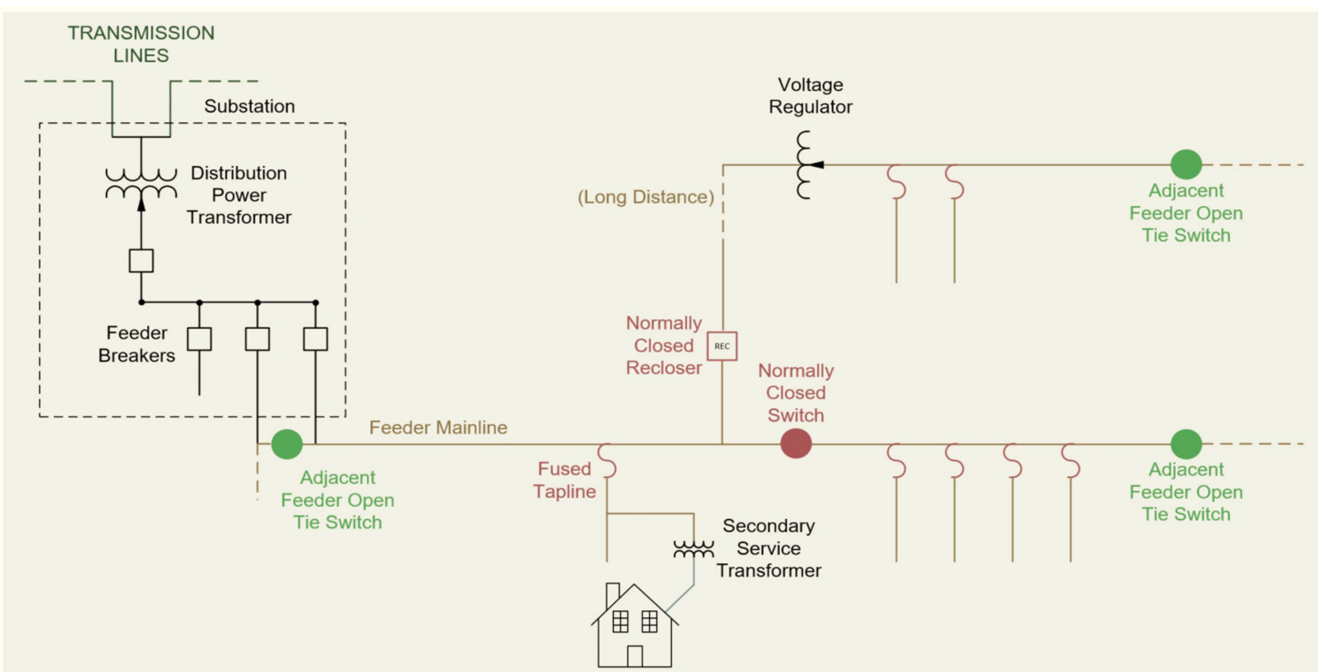


**Figure 5. Distribution substation**

and reliability considerations. Some substations serve very large industrial loads and require more than three transformers to provide enough power.

Planning includes cost, reliability and customer service considerations. Cost considerations include the transmission, sub-transmission, and distribution capital investment in the lines, land cost and space to accommodate growth. Customer service and reliability implications include line length and route, integration with the existing system, access and security. Over time, transformers and feeders are incrementally added within the established footprint until the substation is built to ultimate design capacity. Higher levels of DER will affect substation capacity, system protection and voltage regulation. Sometimes a large development will require the addition of a new substation because the area substations do not have enough capacity to serve the new development.

To best serve customers with reliable power, distribution feeders are sized to carry existing and planned customer load. PGE's distribution system is designed to serve existing customer loads with adequate reserved capacity to pick up load in the event of a failure. The maximum design ampacity on our standard feeders is 900 amps. Some distribution feeders are sized larger to serve large industrial load and minimize the amount of infrastructure in a constrained space.

A substation's size is limited not only by the physical space inside the fence, but also by the number of feeder circuits that can be physically routed to the surrounding area's loads. Overhead feeder construction is the most cost effective and standard overhead construction is one feeder circuit on a pole line. For more feeder density, two overhead feeder circuits per pole line can be constructed when conditions allow it. Underground feeder construction has a higher cost than overhead construction but is often mandated by the local jurisdiction, especially in urban areas. For this reason, underground feeder construction is becoming more common than overhead feeder construction for new feeders. Thermal limits of underground feeder cable require spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in **Table 4** and **Table 5**.

**Table 4. 13 kV Overhead feeder thermal limits**

| Conductor | Winter (MVA) | Summer (MVA) |
|---|---|---|
| 795 kcmil[1] ACSR[2] | 27.9 | 18.9 |
| 795 kcmil AAC[3] | 27.1 | 17.8 |
| 556 kcmil ACSR | 22.3 | 14.7 |
| 556 kcmil AAC | 21.6 | 14.3 |
| 336 kcmil ACSR | 16.3 | 10.7 |
| 336 kcmil AAC | 15.8 | 10.4 |
| 4/0 AWG[4] AAC | 11.7 | 7.8 |
| 4/0 AWG ACSR | 11.1 | 7.3 |

1. kcmil: measure of conductor size representing one thousand circular mils
2. ACSR (aluminum conductor steel-reinforced): galvanized steel conductor or conductors surrounded by one or more concentric layers of 1350-grade aluminum conductors
3. AAC (all aluminum conductor): high-purity, corrosion-resistant, concentric lay of 1350-grade aluminum conductors
4. AWG (American Wire Gauge): measure of conductor size as defined by American Society for Testing and Materials (ASTM) standards

**Table 5. 13 kV Underground feeder thermal limits**

| Cable | Winter (MVA) | Summer (MVA) |
|---|---|---|
| 750 kcmil Cu[1] - Dual run | 26.7 | 24.9 |
| 1,000 kcmil Al[2] - Dual run | 23.3 | 20.9 |
| 750 kcmil Al - Dual run | 20 | 18.4 |
| 750 kcmil Al - Single run | 12.2 | 11 |

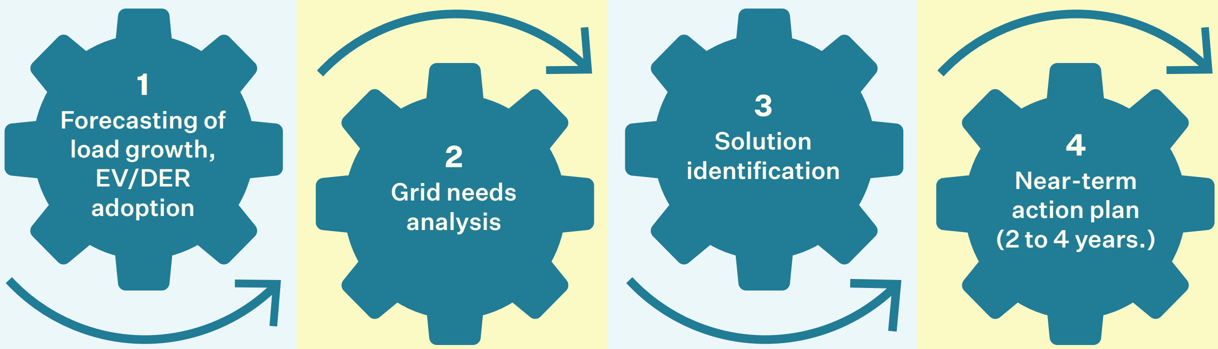
1. Cu: denotes copper conductor
2. Al: denotes aluminum conductor

## 1.4 Evolution

The following chapters provide a more detailed description of each phase of the Distribution Planning process. The chapters follow the order of the four groups of Part 2 requirements in the DSP guidelines, illustrated in **Figure 6**.

The description of forecasting, grid needs, and solution identification is delivered in two sections: current state and evolution. The current state description provides an explanation of current practices. The evolution section briefly discusses the plan to incorporate additional information and capabilities as described in the DSP Guideline's Stage 2 and Stage 3 requirements.

**Figure 6. DSP requirements summary**




- Describe current state for load forecast – process, tools, data
- DER/EV:
  - Forecast methodology and geographic allocation
  - Adoption by substation – high/medium/low scenarios
  - Forecast of load growth and adoption

- Document process to assess grid adequacy and identify grid needs
- Discuss criteria used to assess reliability and risk – methods and modeling tools used
- Present prioritized constraints publicly, including prioritization criteria and timeline to resolve constraints

- Document process for identifying the range of solutions to address grid needs
- For each need, describe the data used to support investment decisions
- For large projects, describe process for engaging communities and getting input
- Propose two NWS pilot projects

- Provide 2- to 4-year plan to address grid needs
- Disclose planned spending, timeline and recovery mechanism
- Discuss relationship between planned investments
- Discuss pilots being conducted to enhance the grid

Chapter 2

# Empowered communities: human-centered design and planning

# Chapter 2. Empowered communities: human-centered design and planning

"Those closest to the problems are closest to the solutions."

— **Glenn E. Martin** , social and criminal justice advocate

## 2.1 Readers guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice (EJ) communities.[6] The Distribution System is designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter provides an overview of PGE's community engagement process used to develop our DSP. We describe our engagement tactics and desire to meet where our customers live, work, learn and play, as well as co-develop solutions that provide direct clean energy community benefits. We also discuss the feedback we received on our DSP and how we incorporated that feedback; specifically, on how we:

- Gathered community interest,
- Identified community energy needs and desires, barriers,
- Defined energy burden within the community, and
- Leveraged tools to identify community demographics.

### WHAT WE WILL COVER IN THIS CHAPTER

In response to our evolving needs around community engagement, PGE is rethinking when and how to conduct community outreach and community engagement across our organization.

Community engagement requires a commitment to an iterative approach in how it is conducted and the expertise of those who perform it.

PGE continues to learn from community partners on how to best show up for and engage EJ communities and those that serve and advocate for them.

6. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.

**Table 6** illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[7]

**Table 6. Distribution system overview: Guideline mapping**

| DSP guidelines | Chapter section |
|---|---|
| 4.3.a.i-iii | **Section 2.3, 2.4** |
| 5.3.d.i | **Section 2.1, 2.3.1, 2.4, 2.5** |
| 5.3.d.ii | **Section 2.4, 2.5** |
| 5.3.d.iii | **Section 2.4** |
| 5.3.d.iv | **Section 2.6** |
| 5.3.d.v | **Section 2.6** |

## 2.2 Empowered communities

Community engagement is based on the belief those impacted by a decision, program, project, or service system need to be involved in the decision-making process. This belief underpins PGE's community engagement plan. "Nothing about me without me" is our guiding principle for conducting and evolving toward equitable community engagement practices. Additionally, we believe a clean energy future that is affordable and equitable requires a commitment to diversity, equity, and inclusion throughout our business.

Empowered communities represent PGE's efforts as an essential service provider to engage and understand where our customers live, work, learn and play, and co-develop solutions that provide direct, clean energy community benefits. As systemic inequities based on race continue to predict life outcomes among under-served communities, we are committed to pursuing the twin goals of racial equity and decarbonization. At the root of this process is the equitable inclusion of community voices in the planning and decision-making processes that impact their lives. There is "no one-size-fits-all" approach to community engagement. We will promote equitable and inclusive practices regarding how we collaborate, partner, work, share space, and co-create solutions with community partners.

To successfully include equity in PGE's planning, we will continue to leverage our learnings from DSP Part 1, engage diverse stakeholders and community partners, and take a particular interest in partners whose voices have not been centered in decision-making processes. We are also focusing on accountability and being coordinated across efforts. Through our Clean Energy Plan, we are developing a streamlined community outreach and engagement plan to inform when and how to conduct community outreach or engagement across our organization.

PGE seeks to build on our existing diversity, equity and inclusion (DEI) efforts by increasing our competency in equity principles and community engagement practices. Our community partners call on us to consider and integrate employment and economic opportunity, community resiliency, neighborhood connectivity, and cultural preservation in our planning and decision-making processes.

PGE's communities want to understand how we will create business opportunities that benefit everyone, including minority-owned, women-owned, and indigenous-owned small businesses. Specifically, community members and advocates call on us to explain who will benefit from the DSP's purchase of goods and services and what those mechanisms are. We are committed to implementing best practices to accomplish community-defined goals. We will track and monitor our progress to meet our DEI goals to hold ourselves accountable for what our customers and communities have asked and expect from us through our Environmental, Social and Governance (ESG) report.[8]

PGE will leverage our enterprise-wide **DEI goals**, which feature three business priorities:

- Increasing supplier diversity
- Promoting diversity and inclusion in the workplace
- Focusing on equitable community outreach and engagement to help meet the needs of communities

To deliver these goals, we will use various information-gathering tactics to understand how best to meet community goals and needs, which can be found in the

7. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.
8. PGE's ESG report, available at: https://investors.portlandgeneral.com/esg

following sections of this Chapter. This approach will allow PGE to set clear and common goals, outcomes, and strategies. Clear goals and outcomes will allow us to create qualitative and quantitative metrics promoting accountability throughout our DSP community engagement processes. Doing so will help move equity to the center of clean energy-related decisions and prioritize actions to address community desires.

PGE's DEI efforts through the DSP process have influenced other areas of our company, inspiring DEI engagement on other teams. We continue to learn from community partners and other interested parties on how to best show up for communities and are committed to being open to iterating our approaches and being responsive to evolving needs and factors.

The following sections outline the activities and efforts PGE has undertaken since the filing of DSP Part 1 and are organized by the three focus areas (competency, activate and data) that were identified in DSP Part 1's Community Engagement Plan.

## 2.3 Evolving our capabilities

In PGE's DSP Part 1 filing, we acknowledged we were only beginning to embark on our journey to integrate equity into our organization and as time has passed, we continue to have work to do. As we continue to work toward closing the gaps in our skills, capacity, and competency, this requires us to focus on our internal processes.

In 2022, PGE created two new positions that are dedicated to community engagement. These community engagement practitioners form our new Energy Equity Team and are focused on our long-term planning processes and partner with our Community Outreach and Engagement Team. Together, these teams build and maintain durable, long-lasting, and mutually beneficial relationships with community partners and EJ communities, while contributing to the operationalizing of equity across the organization.

PGE currently has a group of community outreach and engagement professionals that possess a wide range of skills in community outreach and engagement, DEI, organizational change management, data analysis, strategy development, conflict resolution, and coalition building. Our team's wide-ranging experience and skillsets help enhance our community engagement competencies and ability to integrate equity in decision-making processes. The addition of these roles has expanded our resources to undertake this new and evolving work in community engagement for the DSP and more broadly across the organization.

### 2.3.1 PGE'S COMMUNITY ENGAGEMENT PRACTICES

PGE believes transforming our energy future requires reckoning with and addressing historical and current disparities head-on. We believe that such a future is achievable through PGE-, customer- and community-informed solutions.[9] During DSP Part 1, we learned from experience that community outreach and community engagement is both an art and science. There are many factors at play that must be considered, including culture and history, which shape how individuals and groups view each other.[10]

PGE also learned that creating spaces to reach out to and engage diverse community partners not only requires pre-work, but also, culturally competent staff that understand the discipline and art of community outreach and community engagement. Even with additional staff dedicated to community outreach and engagement, we must continue to build DEI skills and competencies throughout the organization. We are fostering an understanding that community outreach and engagement is a discipline (science) and ensuring we have properly prepared staff to understand and incorporate nuanced considerations and approaches when involved in or facilitating dialogue in spaces where we are engaging with new and/or different interested parties (art).

PGE's community outreach and engagement efforts acknowledge and seek to understand the needs and wishes of communities. We seek to create equitable, inclusive, and welcoming spaces where EJ communities' voices are centered in our discussions, decisions, and meeting places. Additionally, we will continue to incorporate opportunities for all our partners to build capacity and knowledge of our business, and demonstrated our intentions, goals, and outcomes, both in the near- and long-term.

9. PGE's 2022 Strategic document, Getting to Zero, Transforming the Energy Future, available at: https://assets.ctfassets.net/416ywc1laqmd/2Jed2USz5UsTthlR3q3F6E/c829c5ccdfbd3dd7d65812d99ae77741/2022_Strategy_Paper.pdf
10. Principles of Community Engagement, (2011), Department of Human Health and Sciences, available at: https://www.atsdr.cdc.gov/communityengagement/pdf/PCE_Report_508_FINAL.pdf

PGE is pursuing community outreach and engagement as both a goal and an outcome. PGE is in the process of developing an enterprise-wide community engagement and outreach strategy which will include goals and outcomes, with metrics to measure outreach and engagement activities. Our goal is to perform community outreach and engagement activities that are equitable and to measure and track our progress and impact.

Historically, PGE has focused on outreach to customers; however, we are evolving our efforts to reach and engage EJ communities and seek to move from a traditional outreach approach to a community engagement approach. The former tends to be short-term and for the purpose of providing information. The latter is long-term and is predicated on trust-building and relationships, reflecting a diversity of community members, particularly those impacted by a program, project, or decision.

### 2.3.2 APPLYING AN EQUITY LENS

PGE's community engagement framework views equity as "a process and outcome." However, process equity and outcome equity cannot address harmful impacts without the application of an equity lens. An equity lens is a versatile tool and has been deployed to think through community engagement processes, geospatial planning, policy analysis, and the performance of programs and projects. Equity lens tools call for the use of data to surface how disparities are institutionalized into policies, cultures, and practices and how organizations are conditioned not to consider traditionally under-served groups.

Using an equity lens can serve as a tool by showing how a particular decision, policy, program, planning, and engagement initiative will benefit or impact people. PGE commits to applying an equity lens, because the lens provides us with a reflective framework that intentionally works to uncover potential or actual impacts of our actions. This lens will help us identify whether we are missing anything or anyone or creating unintentional barriers as we think through our planning and engagement activities.

The below bullets are the types of high-level analytical and planning questions our equity lenses process will typically ask.

- What decision is being made?
- Who is at the table?
- How are decisions being made?
- What assumptions are at the foundation of the issue?
- What data or information is available, and what is missing?
- How will resulting benefits and burdens be distributed?

If PGE is not intentional about how we make decisions and do our work, we are more susceptible to risk, as unintentional consequences of not applying an equity lens include producing and/or perpetuating burdens and impacts in EJ communities. Therefore, an equity lens can also be viewed as a risk-mitigation tool. Viewing equity-related impacts and burdens as risks, and equity as both a process and outcome will help us to shift from transactions and self-interested outreach efforts to collaborative and shared value engagement processes. We believe this will also help us expand our understanding of the relationship between community, infrastructure, and resiliency.

**Process equity** — Voices of traditionally excluded groups are centered, and their access prioritized to influence and participate in decision-making. Power is shared with historically under-served communities, and it is clear how their perspectives will shape programs, projects, and service systems objectives, design, implementation, and evaluation of success.

**Outcome equity** — Results from a successful process equity as demonstrated by the tangible community and economic benefits for historically under-served communities.

### 2.3.3 HUMAN-CENTERED PLANNING

As PGE transforms how we reach, engage, and interact with our community partners, we will continue to assess whether our community outreach and engagement practices are equitable, inclusive, welcoming, and build upon previous learnings. We will leverage human-centered principles of collective impact in engagement processes, including developing a common agenda, defining terms, and using operating agreements, creating shared goals, metrics, and ongoing feedback and support systems.

As described in PGE's DSP Part 1, environmental justice guides us toward a human-centered design and planning approach. "Energy justice" is a subset of environmental justice and refers more narrowly to the public policy, and economic and environmental impacts of our work on those we serve. Achievement of energy justice demands attention to:

- **Procedural justice** — Fairly and competently incorporate historically excluded perspectives by bringing community voices to the decision-making table.
- **Distributive justice** — Equitably distribute the benefits and burdens of energy infrastructure and systems.
- **Restorative justice** — Repair past and ongoing harms caused by energy systems and decisions.

To embrace a human-centered approach, PGE will remain focused on building skills and resources that help to address competency gaps in community engagement, operationalizing equity, and demonstrating transparency and accountability. The following sections demonstrate our ongoing efforts and commitments to this work.

### 2.3.4 DEI ALIGNMENT COUNCIL

PGE has long-standing relationships with many partners in the nonprofit, public and private sectors. However, partners from under-served communities are just beginning to participate in our decision-making processes and as a result we need to evolve our community outreach and engagement strategies; applying a human-centered approach as described above. As we work to address the needs and desires of our communities and legislation (such as HB 2021, HB 2475, and HB 3141) continues to drive accountability that calls for transparency and alignment, our Community Outreach and Engagement Team has created an internal alignment group called the DEI Alignment Council.[11]

This forum provides oversight to PGE's DEI and community engagement practitioners who require support for current initiatives, projects, and programs. This group's purpose is to provide oversight so we show up appropriately in our outreach and engagement efforts. The DEI Alignment Council's outcomes all nest into the following areas:

- **Competency** — We invest in PGE engagement practitioners that are well versed in DEI, know the difference between community outreach and engagement, are disciplined and able to evolve the practice of community engagement, focuses on the importance of understanding community values, provides historical context (such as systemic racism), and communicates nuanced approaches that are necessary when engaging with EJ communities.
- **Consistency** — Promotes consistency in PGE's outreach and engagement practices and approaches and in how we show up externally.
- **Coordination** — Drives internal PGE alignment and coordination of community outreach and engagement efforts and activities, as well as promotes knowledge sharing and opportunities to collaborate across all our workstreams to minimize burdens on interested parties that are engaging with us.

As mentioned, PGE's Community Outreach and Engagement Team is working on an enterprise engagement strategy to align and coordinate our community outreach and engagement practices and efforts. The DEI Alignment Council and other internal groups (such as the Energy Equity Team) will play a key role in implementation.

11. Oregon's HB 2475, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2475 and HB 3141, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB3141.

### 2.3.5 ESTABLISHING ACCOUNTABILITY

In response to community feedback, PGE intends to use a mixed-methods approach that will combine practices from Results Based Accountability (RBA) and Targeted Universalism, along with a commitment to iterate our approach to achieve co-developed intended outcomes. We are aware of how community is impacted from our decisions and will use the RBA method, championed by the Government Alliance for Race and Equity (GARE), to track and measure our engagement performance. We intend to work with partners to develop and refine our methods; with an emphasis on meaningful metrics that allow for qualitative experiences to be captured and included.

The RBA approach highlights the importance of beginning with a focus on the desired end condition or results and working backward to create a strategy to accomplish the goal. To measure the desired results, the RBA method encourages teams to answer three main questions:

- How much did PGE do?
- How well did PGE do it?
- Is anyone better off?

The above questions will allow PGE to determine, both quantitatively and qualitatively how our decisions impact and/or benefit those we seek to engage. These questions will allow us to develop and use metrics and/or indicators to measure the success of engagement processes. In addition to utilizing the RBA, we are committed to using the Targeted Universalism approach. This will enable us to:

- Acknowledge structural and systemic inequities
- Listen and communicate
- Use innovative and disaggregated data collection methods to understand inequalities, pursue procedural equity and promote transparency
- Be iterative and continuously learn by tracking both qualitative and quantitative data
- Budget for collaboration with community-based organizations (CBOs) so that they are compensated for their expertise and engagement processes center on the needs, strengths, and desires of impacted communities

**Targeted universalism** means setting universal goals pursued by targeted processes to achieve those goals. Within a targeted universalism framework, universal goals are established for all groups concerned.

The strategies developed to achieve those goals are targeted, based on how different groups are situated within structures, cultures, and geographies to obtain the universal goal. Targeted universalism is goal-oriented, and the processes are directed in service of the explicit, universal goal.

### 2.3.6 ENGAGEMENT STRATEGIES AND DESIRED OUTCOMES

PGE plans to engage communities early and often in our decision-making process and will identify which level of engagement makes sense based on the opportunity. This could range from information sharing to consultation to shared decision-making and referring opportunities to community where appropriate. In doing so we will:

- Operationalize PGE's community outreach program and enterprise-wide strategy, leveraging the community engagement framework identified in DSP Part 1 as an input and committing to operate transparently and accountably through the application of an equity lens.
- Leverage existing venues to work more effectively and efficiently. Some examples include reduce the burden of contributors' time and resources, minimize duplicative work and unnecessary meetings. We will continue to integrate related DSP activities into CEP-, IRP- and CBIAG-related work groups.
- Listen to community members' engagement priorities rather than proposing a specific agenda or initiative. We will continue to receive input and develop appropriate ways to engage and reflect on what we hear.
- Compensate partners for their time and expertise, in recognition that we respect and value their contribution to our planning work and overall business.

# 2.4 Activating CBO participation

In DSP Part 1, PGE identified goals to center meaningful participation of EJ communities and to foster a CBO ecosystem. The objectives associated with these goals included allocation of appropriate time, resources, and budget to promote quality engagement, as well as provide energy information that is accessible, relevant, and approachable. In response to these goals and objectives, we created a new venue, Community-focused Workshops, that was focused on unpacking the technical aspects of the DSP into more relevant and translatable topics and content.

### 2.4.1 PARTNERS AND COMMUNITY

During DSP Part 1, PGE learned the first step to achieving meaningful engagement is to level set with your partners, "people don't know what they don't know". With that in mind, each identified audience should have an engagement venue that meets them where they are. For these DSP there were three venues for participation: our Community-focused Workshops which serve a community audience or non-technical audience, the Technical Working Group (TWG) hosted by the OPUC which serves a technical audience, and our Monthly Partnership meetings which serve a mixed audience.

During DSP Part 2, PGE identified three audiences: highly technical, mixed (technical and non-technical), and non-technical stakeholders. The highly technical and mixed audiences are typically composed of traditional stakeholders with a history of interacting with us and the technical background, experience, and knowledge needed to actively participate in energy conversations (such as the Oregon Citizens' Utility Board, Energy Trust of Oregon, NW Energy Council, Oregon Public Utility Commission (OPUC), Oregon Solar + Storage Industries Association). And the non-technical audience are typically composed of community-based organizations (CBOs), community members, municipalities, and local government representatives.

### 2.4.2 UNPACKING THE DSP COMPONENTS

As previously mentioned, the three engagement venues worked together to design a format needed to level set and unpack the complexity of the DSP. This strategy promotes a human-centered approach because it was responsive to partner needs identified in the process and incorporates lessons learned along the way.

PGE made a roadmap of concepts and ideas to share with community partners to identify the appropriate audience. This information sharing process was piloted with technical and non-technical groups. What we discovered, is the need for an additional venue for CBOs/community partners and using a third-party facilitator to deliver this information. Also, to be intentional to not create silos, and share the lessons learned with each of the venues. As part of this effort, we also leaned into self-learning through consistent and active participation in all venues to hear and experience community needs and desires firsthand (human-centered approach).

### 2.4.3 COMMUNITY-FOCUSED WORKSHOPS

Comments received in PGE's DSP Part 1 requested we lean into CBOs' expertise and knowledge through the co-development of relevant materials to communicate to the community. The creation of the Community-focused Workshop was a collaboration between us, a CBO partner, Community Energy Project, and a neutral third-party facilitator, ICF. Community Energy Project is a well-established CBO that serves low-income populations and specializes in community education, home energy upgrades and repairs.

The goal of the Community-focused Workshops was to encourage the inclusion of non-technical interested parties in DSP conversations and to expand their knowledge and understanding of DSP-related topics. To achieve that goal, PGE worked with Community Energy Project to translate the technical DSP workspace into more consumable and relevant information, as well as explore and implement more effective methodologies to communicate with non-technical audiences. We will use the lessons learned through this work to identify how to replicate and scale up this mechanism for input and integrate it into DSP technical processes.

### 2.4.4 COMMUNITY-FOCUSED WORKSHOP TOPIC AREAS

The following topics were covered over the course of our four Community-focused Workshop series:

- Utility planning
- Distributed energy resources (DERs)
- Grid needs and solutions
- Wired solutions (traditional) and non-wires solutions (NWS) that include DERs
- Customer/community needs
- Equity indicators

### 2.4.5 WORKSHOP METHODOLOGY

Every workshop series informed the content creation of the next one. This iterative approach allowed PGE to be responsive to the needs of this audience, provide additional time for topics and content, and when needed, the opportunity to incorporate lessons learned throughout the series. The first two workshops were used to level set on terminology and concepts, and the last two focused on leveraging the foundational knowledge obtained to walk through an example of how, where and why NWS can be implemented. The following steps were identified through the process:

- **Step 1** — Identify a grid need that a NWS could solve in a specific location.
- **Step 2** — Identify the community energy needs of the location.
- **Step 3** — Conduct a DER stacking exercise to address the identified community energy needs and grid need.

### 2.4.6 TERMS IDENTIFIED THROUGH THE WORKSHOPS

These definitions were used as a baseline for the Community Workshops but have not been adopted as PGE's formal definitions of these terms.

**Equity** — Fair treatment concerning benefit vs. burden, infrastructure and wealth. Access in the sense of removing barriers, inclusion and finances. Opportunity to live in a healthy environment while being included. Advancement for all in a healthy environment, equal power and inclusion and harm remediation.

**Customer resilience** — This is the ability to adapt, maintain safety, be prepared for and recover from disaster (such as wildfires, smoke), planning for energy justice and equity.

### 2.4.7 THEMES IDENTIFIED IN RELATION TO COMMUNITY NEEDS

Participants brought forth ideas covering a valuable array of topics throughout the workshops. The following themes were identified after aggregating responses, finding commonalities, and determining what is of the highest importance to partners.

**Outcomes** — CBOs want to continue understanding how community feedback will translate into action by PGE. Clear communication of goals and how collaboration leads to actions and benefits for the community (such as planning with an equity lens to help support EJ community needs).

**Transparency** — CBOs want transparency on PGE's processes, responsibilities, budgets, activities, rates, and decisions. Clarity on the elements of a customer's electric bills (such as DER impacts), how customer/DER data will be used, and how privacy will be maintained.

**Trust** — A lack of trust is a key barrier to greater DER participation, given the historical relationship with PGE which has been viewed as not prioritizing all customers' interests. There is a clear connection between the proposed solutions to overcome the "lack of trust" and "lack of knowledge and awareness" barriers. Demonstrating that as knowledge grows, so does community trust and vice versa.

**Financial needs and incentives** — CBOs need funding sources to participate in workshops and utilities should offer new options to their constituents through incentives, rebates, and programs. Money is a primary barrier to participation in PGE programs, particularly in upfront costs, balancing other financial needs, and realizing program benefits to cover costs. Given that cost is the primary barrier to customer adoption of DER, monetary incentives, such as bill savings or rebates, were identified as a consistent benefit needed to promote customer participation.

**Education and awareness** — CBOs want to learn more about PGE's conservation programs (such as rebates, incentives, grants, tax credits), DSP processes, resilience, new technologies (such as how to use them), PGE program options, and how to work together.

**Community benefits** — Human well-being is fundamental to energy equity and must be reflected in solutions. In addition, CBOs want EJ communities to benefit from the energy transition with workforce and economic development, particularly in business opportunities. Human health, home health and overall comfort ranked high as non-energy benefits (NEBs).

**Community/customer involvement** — CBOs can be partners in projects, community education, sharing community needs and involving their constituents in beneficial programs. The ability of customers to understand their own energy needs and technology options (benefits vs. costs) can improve decision-making.

**Customer resilience** — CBOs defined customer resilience as the ability to withstand and prepare for climate-related disasters such as wildfires, blackouts and major storms.

**Renters' vs. owners' needs** — CBOs highlighted the distinction between building owners and renters, such as decision-making power and cost burden (cost pass-throughs).

**Topics in need of more education were** — CBOs identified a need for additional conversations on customer energy costs, better understanding the connection between energy drivers and utility bills (what goes into a bill), and environmental impacts (needed to understand the relationships between a customer's decisions and environmental impacts). When sharing this information, PGE should do it in a geographically targeted manner.

Recommended formats to share information are:

- Workshops
- Direct communications
- Touring places (such as galleries, neighborhood energy hubs)
- Materials (such as hard copies, flyers, infographics, social media, videos, surveys)

### 2.4.8 THEMES IDENTIFIED RELATED TO DERS

PGE spent significant time discussing DERs, their benefits, barriers to adoption and use, and ways to overcome these obstacles and increase their accessibility. DERs provide benefits at the utility system level, by helping reduce peak load (including solar panel programs paired with battery storage, allowing customers to share their unneeded, stored solar power with PGE when energy demand is high) and at the customer level, by lowering energy bills, earning peak-time rebates, increasing home value, and adding local jobs. Other DER benefits are related to customer comfort and safety, adding protection from grid outages, resilience to disasters, and environmental and air quality benefits.

Barriers to DER adoption and use include upfront costs, lack of trust in PGE's intentions and data privacy, lack of technology/program awareness and understanding, renter limitations, and the digital divide (internet access). Changes that could be implemented to increase DER accessibility are innovative program design to provide benefits to participants, data collection transparency, education on the "why" and the "how", renter solutions (low/no-cost, protections from pass-through costs). Additional ways to overcome these barriers include:

- **Structure cost differently** — Combined incentives (align DSP with other efforts), design incentive structures for easier access to those who most need it, remediate upfront costs (including increased bills), and implement low/no-cost options and financing programs.
- **Build trust** — Diversify the workforce, improve education and visibility of DER (such as solar) in communities, work with trusted organizations and community members, increase transparency in communications, and attend and create community events.

- **Increase knowledge and awareness** — Expand marketing and communications, educate the community (such as property owners, homeowners, tenants), work with trusted organizations and community members, and diversify the workforce.
- **Focus on renters** — Support rental housing standards, work with renter advocate organizations, support funding for repairs needed to adopt DERs, and expand benefits to renters, particularly those living in multifamily housing (MFH).
- **Increase access to technology** — Program enrollment beyond the website, solutions for Wi-Fi access (such as link to community Wi-Fi or broadband programs, unrestricted access for MFH to support smart tech), support home repairs to enable DER, and improve access to energy data.
- **Work with policymakers and regulators** — Expand benefit-cost framework to account for broader values, upgrade building codes and permitting, increase feeder capacity to install more solar PV, and develop community solar programs.
- **Specific strategies** — Increase community presence (such as farmer's markets), align with tech divide strategies (such as continue using paper forms), coordinate with existing structures, and leverage other funding sources for a specific community or DER technology.

An important topic that came up during workshops was the opportunity to partner with other organizations to expand the reach of DER implementation. Other organizations include:

- **Energy-related organizations** — Energy Trust of Oregon (ETO), Portland Clean Energy Fund, Community Energy Project, Verde, Oregon Solar + Storage Industries Association, Citizens Utility Board.
- **Non-energy-related organizations** — Native American Youth and Family Center, Hispanic Metropolitan Chamber, other culturally specific organizations (such as African American Alliance for Homeownership), REACH CDC Community Builders, Coalition of Communities of Color.
- **Higher education and workforce development** — Blueprint Foundation, Leaders Become Legends, OSU-Cascades, Oregon Tech, PSU (teaming/ leverage curriculum), union labor partners

## 2.4.9 COMMUNITY NEEDS

We also had rich discussions related to additional community needs for PGE to consider. Participants highlighted the need for reliability of electricity in times of need and seeking alignment with existing mandated planning processes (such as new homes with solar PV, counties' and cities' climate or climate-emergency plans, the Community Benefits & Impacts Advisory Group). Further discussions focused on prioritizing community needs and what criteria to use such as demographic data, data on historical disinvestment areas, and focus on health, safety and wealth-building, and affordability for customers.

PGE was interested in CBO's recommendations on the following questions:

**How to work with communities?**

Leverage existing community meetings, engage with the broader community, meet often across the community, and implement workshop feedback.

**How to prioritize community needs?**

Use demographic data, data on historical disinvestment areas, and focus on health, safety and wealth-building, and affordability for customers.

**How to communicate grid needs and identified solutions with community?**

Leverage existing community meetings, engage with the broader community, often meet across the community, and implement workshop feedback.

Practical formats to share information are workshops, direct communications, touring places (galleries, neighborhood energy hubs), and materials (hard copies, flyers, infographics, social media, videos, and surveys).

## 2.4.10 COMMUNITY-FOCUSED WORKSHOP TAKEAWAYS

PGE's objectives for the workshops focused on engaging community business organizations to both develop an effective approach to community engagement and get community input in the development of the NWS concept proposals required in DSP Part 2. What we found through the course of conducting the workshops was that we struggled to get participation from the communities most affected by the NWS being proposed. This finding is consistent with the themes previously discussed.

The participants that were able to attend the workshops were a subset of the organizations that attend the DSP Partner meetings. We learned first-hand the impact of not removing some of the barriers to participation, such as funding for the participants and conducting the meetings in local venues.

Although we were not able to co-develop NWS with the affected communities, we did build capacity within the organizations that did attend the workshops. PGE intends to leverage this capacity in the next iteration of NWS solution development and community engagement related to large projects.

PGE leveraged an existing opportunity to seek greater collaboration with our CBO partners by matching the grant funds offered through ETO's -Working Together Grant. We supported Community Energy Project in applying for the grant and ultimately matched the grant amount to ensure adequate participation for the organization to provide consultation and content creation for the Community Workshops.

In the next planning cycle, which begins in the fall of 2022, PGE is going to take the following steps:

- Conduct our normal system analysis process to identify NWS candidates and grid needs that might result in large projects that could be disruptive to the community;
- Recruit volunteers from our Community Workshop participants to form a small advisory group. This group will participate in the review of NWS and large project candidates with the intent of identifying the CBOs who represent the affected community members;
- PGE will then work with the advisory group to develop effective outreach plans in order to engage the right CBOs;
- PGE will then work with the right CBOs to develop effective engagement plans for their constituents; and
- To support this effort, PGE will identify a means to fund participation of the advisory group and CBOs.

This should set the stage for PGE to work with communities to co-develop solutions. If successful, this process also will further develop capacity for CBOs and our advising partners to participate in these discussions.

# 2.5 DSP Partner Workshops retrospective and partner feedback

PGE's DSP Part 2 required more direct engagement with community partners than Part 1. Our DSP Part 2 co-developed and co-assessed community needs as well as publicly reviewed data and decisions. **We appreciated the participation of the partners who attended the over 20 workshops and assisted in the development of our entire DSP process**. As stated previously throughout this chapter, we are still learning how to do this work and how to do a better job of communicating what we are doing with the feedback we have received from our partners.

The partners who participated in the DSP Part 2 workshops — DSP Partner Workshops, OPUC's Technical Working Group and Community-focused Workshops — directly influenced and contributed to the content of this plan. We hope partners can see their contributions in the content. That said, we also know there are still unmet requests and unanswered questions. We will continue to work to meet those needs.

To honor the time our partners spent in various workshops throughout this process and to repeat what we heard, we catalogued the conversations and exchanges that took place during the workshops and distilled that information into three main themes: Trust, Community, and Financial. The purpose of collecting and analyzing this data is to inform future community engagement processes, DSP filings and equitable best practices.

To assess the feedback we collected systematically, we first compiled a database of written and verbal comments provided from each workshop. Then we tagged each comment with a theme in order to identify areas of particular emphasis by our partners, as well as an applicable focus area (such as community engagement, baseline data). There were approximately 140 comments relating to community engagement needs. Within the comments collected, we identified approximately 160 unique mentions of the three main themes: 62% pertaining to trust and transparency, 25% pertaining to Community and 13% pertaining to Financial.[12]

The themes are further elaborated, and the cataloged feedback can be found in **Appendix B**.

### 2.5.1 TRUST AND TRANSPARENCY THEMES

Trust and transparency themes consisted of approximately 62% of all the comments collected (99 comments). It was the most popular theme from the partner workshops. Below we highlight the sub-themes related to trust and transparency.

- **Education** — CBOs want to learn more about energy conservation programs (rebates, incentives, grants, tax credits), DSP processes, resilience, new technologies, new ways to work together.
- **Outcomes** — Clear communication of goals, collaboration that leads to actions and benefits for the community. For example, planning with an equity lens to help support EJ community needs. Participants want to continue to understand how community feedback will translate into action by PGE.
- **Transparency** — CBOs want transparency on PGE's processes, responsibilities, budgets, activities, rates, and decisions. Clarity on the elements of a customer's electric bills (DER impacts), how customer and DER data will be used, and privacy maintained.
- **Trust** — A lack of trust is a key barrier to greater DER participation, given the historical relationship with PGE which has been viewed as not prioritizing all customers' interests.

12. Some comments had more than one theme.

### 2.5.2 COMMUNITY THEMES

Community themes consisted of approximately 25% of all the comments collected (40 comments). It was the second-most popular theme from the Partner workshops. Below we highlight the sub-themes related to community.

- **Community benefits** — Human well-being is fundamental to energy equity and must be reflected in solutions. In addition, CBOs want EJ communities to benefit from the energy transition with opportunities for workforce and economic development.
- **Customer empowerment** — The ability of customers to understand their own energy needs and technology options (benefits vs. costs) can improve decision-making.
- **Community involvement** — CBOs can be partners in projects, community education, sharing community needs; involve their constituents in beneficial programs.
- **Customer resilience** — The ability to withstand and prepare for climate related disasters such as wildfire, blackouts, and major storms was identified as a key consideration.
- **Health outcomes** — Human health, home health, and overall comfort ranked high as NEBs.

### 2.5.3 FINANCIAL THEMES

Financial themes consisted of approximately 13% of all the comments collected (20 comments). It was the third-most popular theme from the Partner workshops. Below we highlight the sub-themes related to financials.

- **Financial incentives** — Given that cost is the primary barrier for customer adoption of DERs, financial incentives, such as bill savings or rebates, were identified as a consistent benefit needed to promote customer participation.
- **Financial needs** — Money is a primary barrier to participation in PGE programs, particularly in the form of upfront costs, balancing other financial needs, and realizing program benefits to cover costs.
- **Funding** — CBOs need funding sources to participate in meetings as well as offer new options to their constituents through incentives, rebates, and programs.
- **Renters' vs owners' needs** — Participants highlighted the distinction between building owners and renters, such as decision-making power and cost burden (cost pass-throughs).

# 2.6 Unlocking demographic data

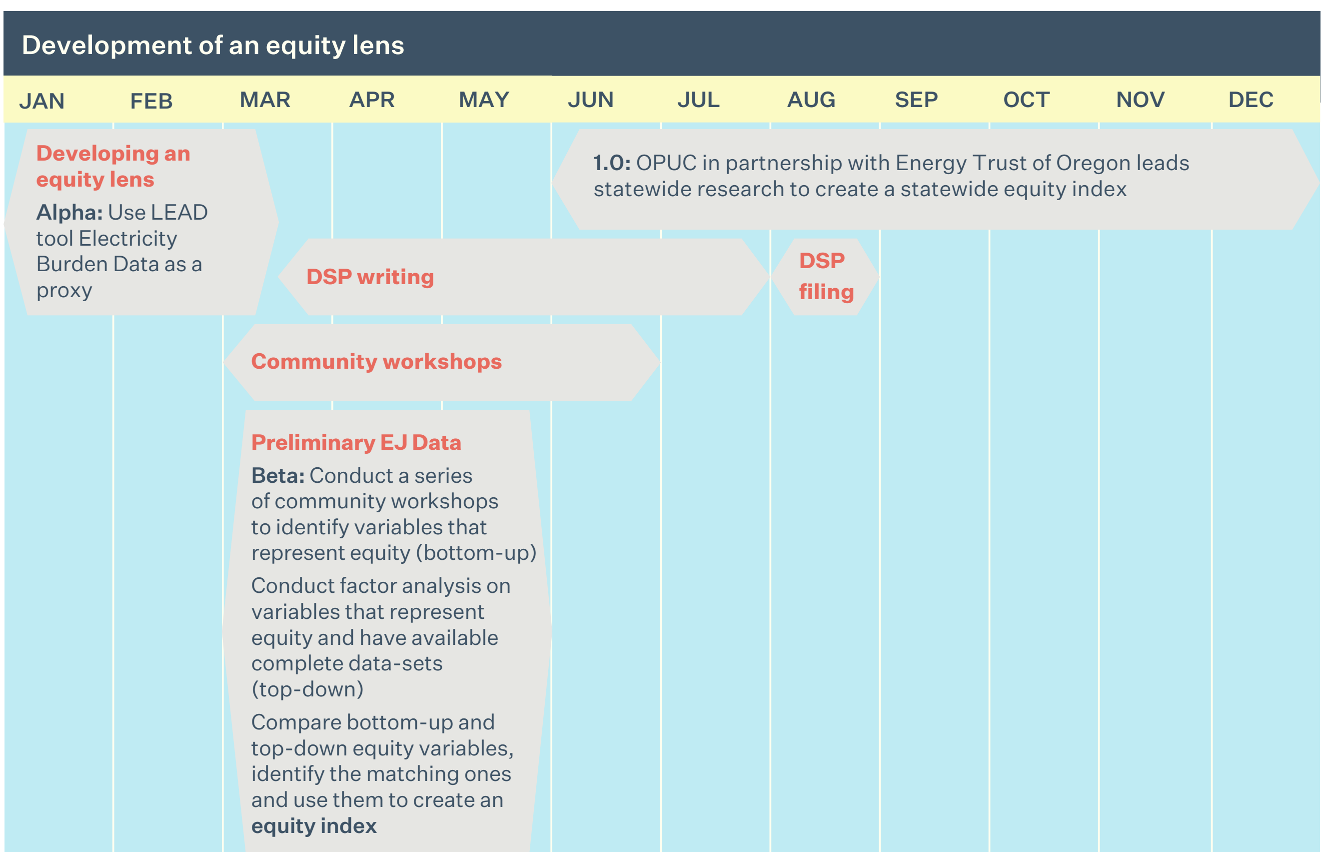
Distribution system planning is a process composed of several steps that include load forecasting, identification of grid needs, solution identification of those grid needs, and arriving at a set of recommended projects to be funded to solve the grid needs and modernize the grid. Oregon's UM 2005 opened an investigation on the current state of the distribution system and its related planning processes and recommended adding three new components to its future state analysis:[13]

- Community needs assessment
- The use of equity metrics to weigh in decision-making processes
- The consideration of NWS to solve grid needs, when appropriate

The data-related goal identified in DSP Part 1 relies on a diversity of data (GARE Racial Equity Tool, Step #2) and both quantitative and qualitative research. The main objective was that the engagement was informed by data and tailored to the needs and interests of affected communities. The outcome was to understand community energy needs, desires, barriers, and interest in clean energy planning and projects and where opportunities exist.

PGE approached the development of an equity metric in three phases (**Figure 7**). Phase 1 used electricity burden, an already used metric in the industry, as the Alpha version of the equity metric. Phase 2 involved developing an equity metric that reflected our service territory as the Beta version. And Phase 3 is currently being developed in a partnership between the OPUC and ETO to build version one of a statewide-vetted equity metric that can be used as the future standard by all parties.

Figure 7. Development phases of an equity matrix




13. These new components are being developed and tested and as a result haven't been added to PGE's DSP future state. PGE will work to integrate them over time.

In developing the Beta version and in response to partner feedback and recommendations, PGE used Greenlink's Equity Map (GEM) data, customer payment metrics, Acxiom third-party datasets, and public data sources such as the US Census American Community Survey (ACS), Public-Use Microdata Sample (PUMS), and US Department of Energy's (DOE) Low-Income Energy Affordability Data (LEAD) tool.[14]

To operationalize equity within our current decision-making framework, PGE is conceptualizing the following:

- Internal definitions of equity
- Identification of key variables that track equity in programming
- Quantifiable equity indices

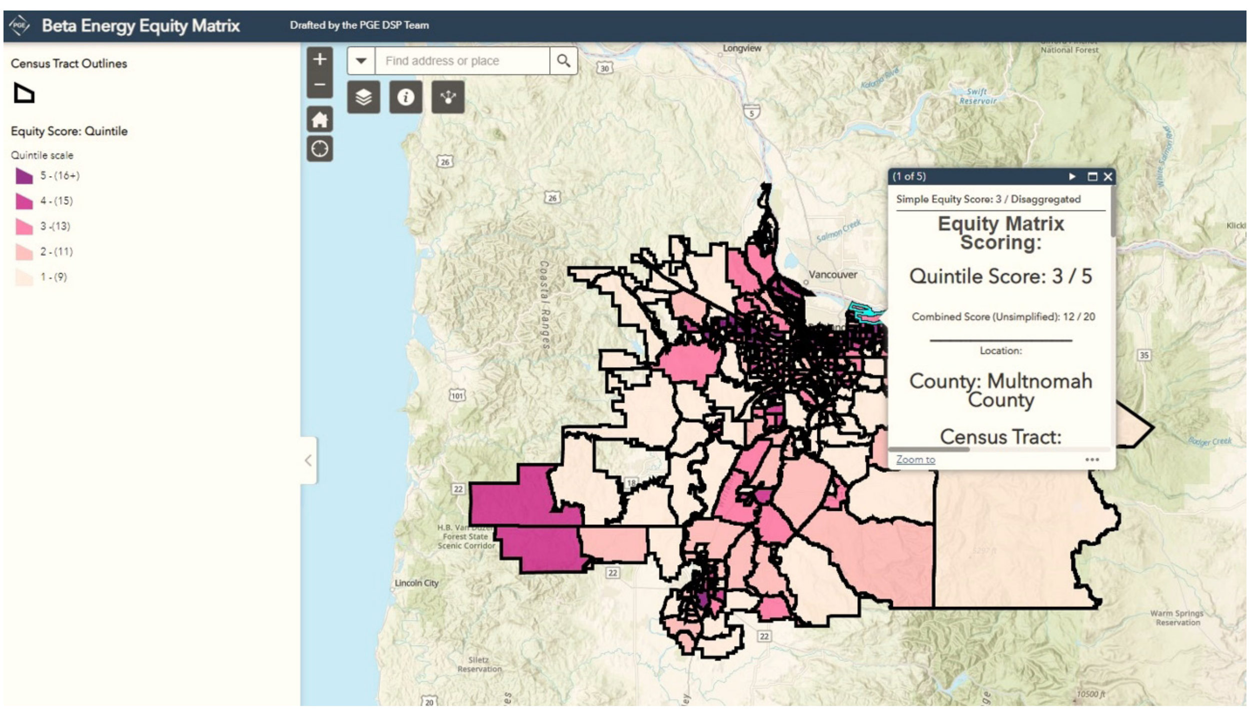
PGE then engaged within our Community-focused Workshops forum to co-develop key metrics that have the most meaning for the participants and the communities they represent. The following variables were specifically highlighted to indicate community needs related to energy equity, and then were used when drafting our Beta Energy Equity Index:

- Percentage average energy burden of income below 200% federal poverty line (FPL)
- Percentage of renters (housing status)
- Percentage of people of color (race)
- Percentage of multiple family and manufactured homes (housing type)

Each indicator holds equal weight within PGE's Beta version of the Energy Equity Index. We expect these variables may change over time as we gain more experience implementing them for various use cases, as well as the individual weighting applied to each variable.

**Figure 8** shows the Beta Energy Equity Index scores at the census tract level for PGE's service area.

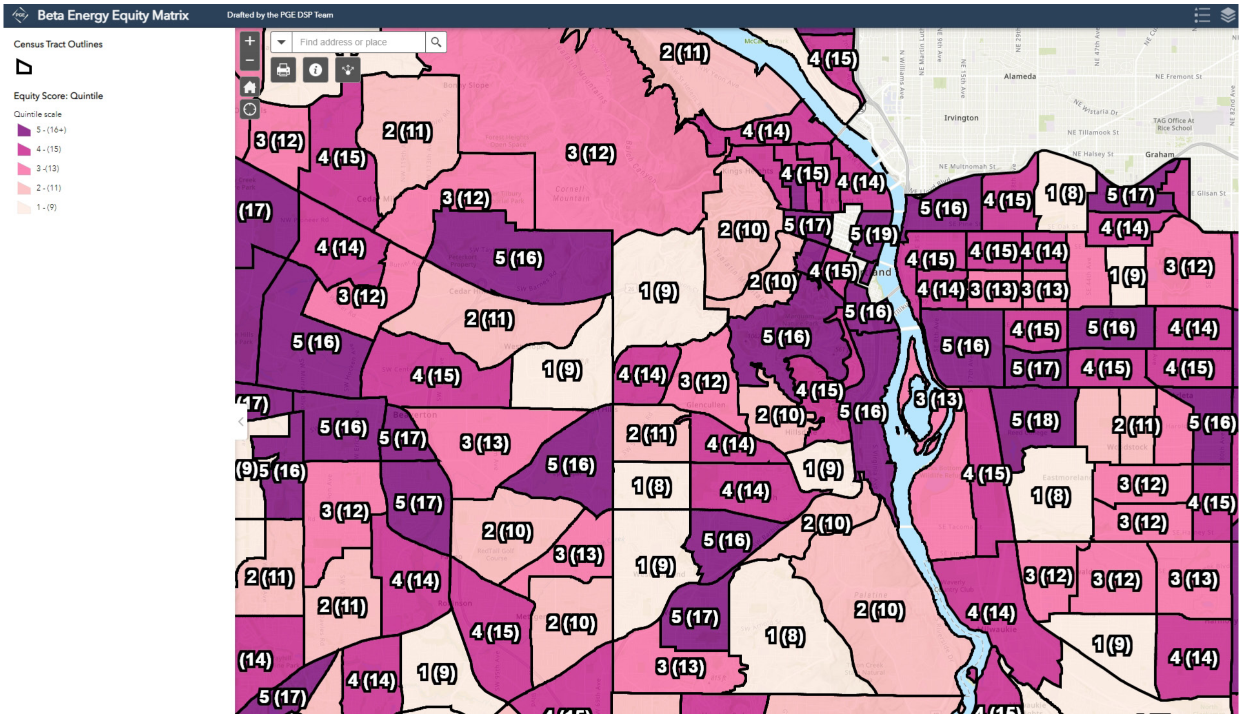
**Figure 8. Beta energy equity map view 1**




14. The GEM tool, available at: www.equitymap.org and DOE's LEAD tool, available at: https://www.energy.gov/eere/slsc/maps/lead-tool

**Figure 9** shows a subset of our service territory with greater visibility into the individual score differences between Census Tracts.

**Figure 9. Beta energy equity map view 2**




## 2.6.1 GEOGRAPHY

The current geographic level of the Beta Energy Equity Index is the census tract. Census tracts act as geographic areas within which PGE can characterize groups of individual households.

This geography level was chosen for the following reasons:

- **Compatibility** — It is consistent and inter-operable with two equity-focused tools that have been highlighted as important to community partners
- **Tools** — Determined utilizing DOE's LEAD and the GEM tools
- **Sustainability** — Data can be annually updated using updates from the ACS

## 2.6.2 METHODOLOGY

The methodology PGE used was to assign five scales (or bins) to each indicator with a quintile methodology, then we add up the scale points for each indicator to get combined bin scores (**Table 7**). Then the quintile methodology is used to differentiate the combined bin scores into five different groups. The following tables show the bin aggregation for each indicator and the final equity index scale from the quintile of combined value. The higher scale numbers indicate a higher concentration of our four variables in a given census tract area (percentage of energy burden, people of color, renters and multifamily and manufactured homes).

Table 7. Equity index variables and quintile scale

| Bin# | Percent of | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Renters | | People of Color | | Multiple Family | | Energy Burden | |
| | Start | End | Start | End | Start | End | Start | End |
| 1 | 0 | 17 | 0 | 9 | 0 | 13 | 0 | 5 |
| 2 | 18 | 28 | 10 | 13 | 14 | 24 | 5.1 | 6 |
| 3 | 29 | 39 | 14 | 19 | 25 | 35 | 6.1 | 7 |
| 4 | 40 | 53 | 20 | 27 | 36 | 52 | 7.1 | 8 |
| 5 | 54 | 100 | 28 | 52 | 53 | 100 | 8.1 | 26 |

Table 8. Combined quintile scale

| Combined Quintile Scale | | |
|---|---|---|
| Quintile | Value | Scale |
| 0.2 | 0-9 | 1 |
| 0.4 | 10-11 | 2 |
| 0.6 | 12-13 | 3 |
| 0.8 | 14-15 | 4 |
| 1 | >15 | 5 |

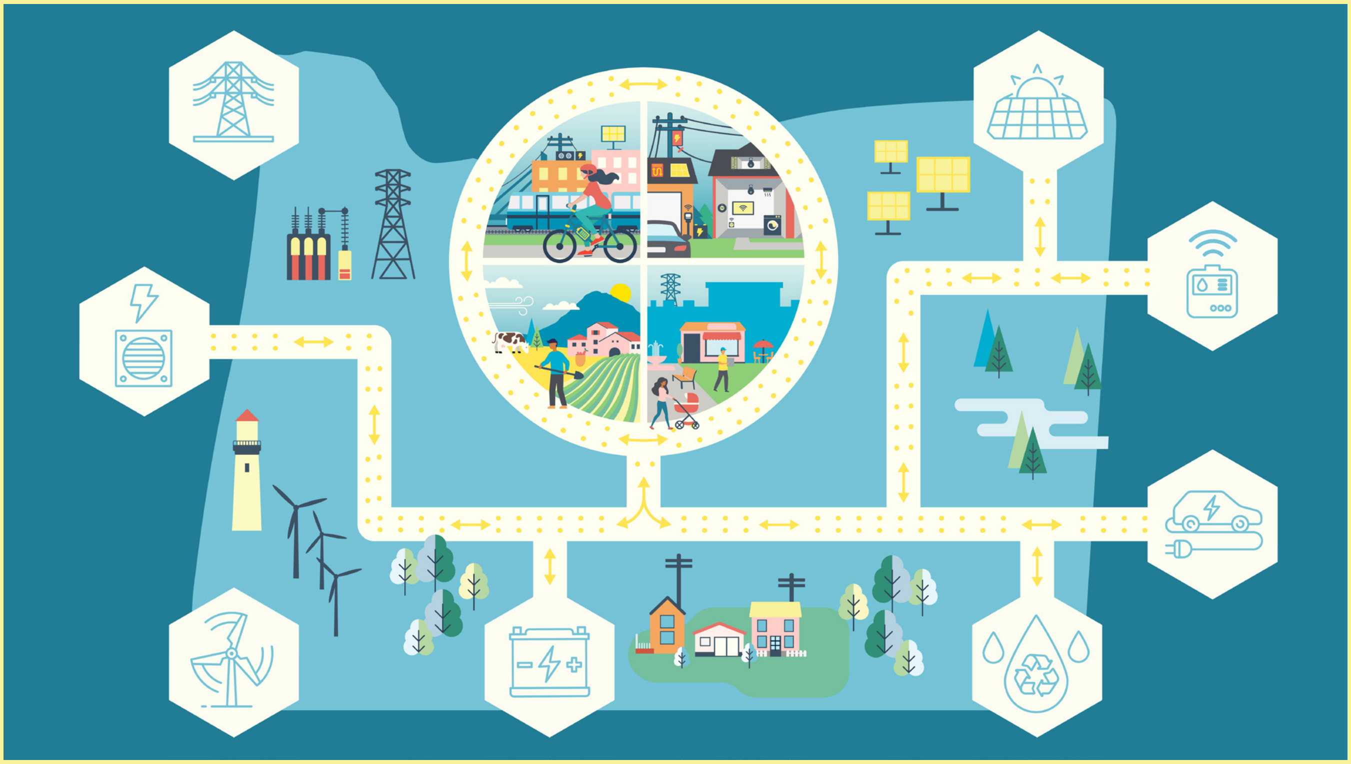
### 2.6.3 TENTATIVE NEXT STEPS FOR THE BETA ENERGY EQUITY INDEX

PGE has identified tentative next steps for the Beta version of the Energy Equity Index. Our planned rollout will be incremental and not across all programs at once. It will include continual testing, tweaking, outreach, and updating to improve the tool's use in incorporating equity within targeted DSP investments and decisions.

- **Internal review phase** — Testing, harmonizing across programs, cleaning visuals, and synthesizing the understanding and explanation for the how and why.
- **External review phase** — Community engagement, presenting map to community members/groups and collecting their feedback.
- **Second internal review phase** — Incorporating community feedback into our design process, legal review and engineering review.
- **Prospective soft launch** — Contingent on the successful completion of the earlier stages, this phase will be defined by incorporating the Beta Energy Equity Map into our decision-making processes (e.g., Solution identification including NWS).

Chapter 3

# Load and DER forecasting



# Chapter 3. Load and DER forecasting

"There are two kinds of forecasters: those who don't know, and those who don't know they don't know."

– **John Kenneth Galbraith,** economist, diplomat, public official, and intellectual

## 3.1 Readers guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[15] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter provides an overview of PGE's corporate load forecasting process (top down), our current approach to bottom-up load forecasting at the distribution system level, and methods used for forecasting DER adoption including EV load growth and distributed generation. We describe our current forecast processes, methodologies, and results of our forecasts. We also discuss advancements we have made in DER forecasting, including ability to forecast DER growth at the feeder- and substation- level, and how these improvements can influence distribution system planning and enable us to reliably meet future energy and capacity needs. We also discuss the advancements we have made in incorporating equity data into our DER forecasting tools and how these insights can be used in making informed program design choices.

**WHAT WE WILL COVER IN THIS CHAPTER**

Corporate load forecasting process and drivers

Current bottom-up load forecasting methods

DER forecasting methods

DER forecasting results at the granular substation level

15. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.

**Table 9** illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[16]

**Table 9. Distribution system overview: Guideline mapping**

| DSP guidelines | Chapter section |
|---|---|
| 5.1.a | **Section 3.1, 3.2, 3.3, 3.4** |
| 5.1.a.i | **Section 3.2, 3.3, 3.4** |
| 5.1.a.ii | **Section 3.3.1, 3.3.2, 3.4.3.2** |
| 5.1.a.iii | **Section 3.2, 3.3, 3.4.2, 3.4.3** |
| 5.1.a.iv | **Section 3.4.3** |
| 5.1.b | **Appendix M** |
| 5.1.b.i | **Appendix M** |
| 5.1.b.ii | **Section 3.5, Appendix C** |
| 5.1.c | **Section 3.5.5, Appendix M** |
| 5.1.c.i | **Section 4.5** |

16.OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

# 3.2 Introduction

PGE's assessment of distribution system needs is dependent on the forecasting of electric loads using a combination of top-down and bottom-up methods. Load forecasting for the distribution system is conducted with this hybrid approach due to the nature and timing of customer load additions, and because relying exclusively on one or the other method alone would be insufficient. The top-down approach does not provide specific details about where customers will add new loads, and yet a purely bottom-up approach that includes knowledge of local business activity and customer growth patterns is often incomplete.

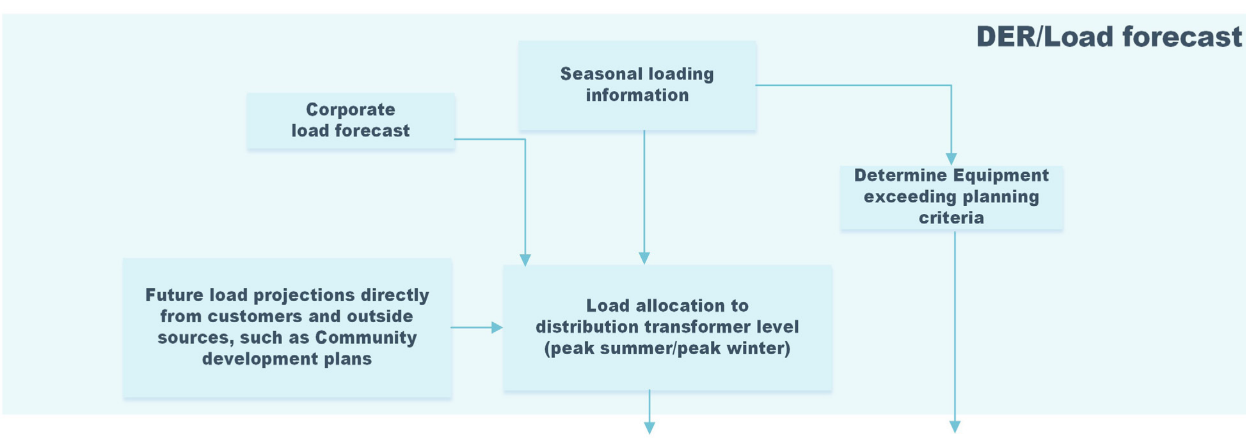
As PGE modernizes the grid, we are simultaneously increasing our ability to plan for distributed energy resources (DERs) and the variety of potential benefits and challenges they can pose for the distribution grid. We are focused on improving our DER forecasting tools to provide locational insights and integrating these practices and forecast results into our core distribution system planning functions.

The load and DER forecasts that drive PGE's distribution system needs assessment and solutions identification activities include:

- **Corporate load forecast** — PGE's top-down econometric forecast describes large-scale patterns in electricity use, particularly as related to weather and the economy, and is the basis of load forecasting in our Integrated Resource Plan (IRP). In this section we provide a high-level overview of the key assumptions and drivers, as well as highlight some areas that might be improved going forward to better serve the needs of forecasting growth on the distribution system.
- **Bottom-up load additions** — These bottom-up customer load additions come from a variety of sources. In this step, PGE runs a variety of scenarios that account for all the various drivers of load changes. This includes consideration of historical load growth, weather history, zoning and building permit activity, and more. Throughout the year, we collect detailed information across a range of potential areas of activity that will lead to locational impacts on the distribution grid. These include planned load additions, circuit reconfigurations, new sources of demand (such as increased use of central air-conditioning, electric vehicles), DER interconnection applications, local development policies and zoning changes, and any planned development or redevelopment activity spurring from local community or business development plans.
- **DER locational forecasting** — This section describes PGE's methodology for forecasting DER growth, using our AdopDER tool, including methodologies and results of the disaggregated forecast at the locational level. Our DER forecast takes account of detailed data about each customer class, DER technology and performance considerations, and Oregon-specific policy changes (such as adoption of the California Advanced Clean Trucks rule, state-level zero-emission vehicle (ZEV) mandates).

The high-level process to integrate the top-down and bottom-up forecast into our distribution planning activities is represented in **Figure 10**. These elements are combined to create the distribution-level load forecasts described in **Appendix C**.

**Figure 10. Current state process to integrate load forecast into distribution planning**



# 3.3 Corporate load forecast

PGE's top-down forecasting models estimate monthly energy deliveries by customer class and peak demand for our entire system. These models take an econometric approach by estimating the relationships between our service territory load growth and exogenous drivers, including macroeconomic indicators, weather, and seasonality.[17]

## 3.3.1 CORPORATE LOAD FORECAST APPROACH

PGE's corporate load forecast takes an econometric approach by using regression models to estimate the relationship between historical energy deliveries and customer count data series and outside variables. Indicator variables are also used to improve model fit, including binary monthly variables, indicator variables accounting for the impact of COVID-19 on energy deliveries, and steps and spikes.[18]

From period to period, weather — specifically ambient temperature — is the largest 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. For each variable, the forecast relies on an input assumption.

For economic variables, PGE relies on local forecasting entities for input assumptions. For weather variables, we focus on estimating a 'normal' weather year, rather than predicting what may occur in any specific given year. Traditionally, historical averages have been used to define the weather input. Most commonly, these were 30-year, 15-year or 10-year historical averages. As of 2019 (via the Oregon Public Utility Commission's Docket UE-335), we implemented use of a linear trend model to reflect gradual warming in our monthly heating and cooling degree day input variables.[19] A rolling 15-year average is used as an input for peaking event conditions, windspeed, and rainfall, additional analysis of how climate change impacts these events may be considered in the future. Key input data used in PGE's corporate load forecast is described in **Table 10**.

**Table 10. Key data sources used in PGE's corporate load forecast**

| Type | Drivers used | Source |
|---|---|---|
| **Historical load data** | Monthly energy deliveries and customer count | PGE billing data |
| **Historical load data** | Monthly PGE system peak demand | PGE net system load data |
| **Economic indicator** | Oregon employment and personal income | Oregon Office of Economic Analysis |
| **Economic indicator** | Oregon population | PSU's Population Research Center |
| **Historical weather[20]** | Monthly heating and cooling degree days, wind speed, and rainfall (for average energy models)<br><br>Daily heating and cooling degree days, wind speed (for peak demand model) | National Weather Service, NOAA |
| **Normal weather input, trended** | Monthly heating and cooling degree days | PGE estimated, based on linear trend |
| **Normal weather input, 15-year average** | Monthly wind speed and rainfall (for average energy models)<br><br>Daily heating and cooling degree days, wind speed (for peak demand model) | National Weather Service, NOAA |

17. This section provides a high-level summary of PGE's Corporate load forecast methodology relevant to understanding implications for distribution system. For more detail see Section 4 of PGE's 2019 IRP, available at: https://portlandgeneral.com/about/who-we-are/resource-planning
18. Step and spike variables account for issues in the historical data. These are often in alignment with billing corrections, or reclassifications.
19. The OPUC's Docket UE-355, available at: https://apps.puc.state.or.us/orders/2019ords/19-129.pdf
20. PGE's Corporate Load Forecast uses the Portland International Airport (KPDX) weather station as a proxy for PGE's service area

### 3.3.2 CORPORATE LOAD FORECAST CUSTOMER SEGMENTATION

PGE's corporate load forecast is estimated using two distinct forecast horizons. The primary difference between these models is the segmentation used for forecasting. For the near-term forecast, which captures trends within the next five years, the model is split into multiple segments based on residential dwelling type and heat type, for residential, and US Census' North American Industry Classification System (NAICS) industry classification, for commercial and industrial.[21] This allows the forecast model to capture business cycle trends at a disaggregated level by segment.

This model also accounts for approximately 25 large customer loads as individual customer forecasts. For example, in the near term, PGE can reflect the transition from brick-and-mortar retailers to distribution facilities driven by online retail, which is seen in the historical load data, in the forecast. We do this by modeling those segments individually.

**Table 11** lists the specific forecast sub-segments from the near-term (five-year) horizon load forecast.

Table 11. Customer segmentation used for PGE's near-term corporate load forecast

| Near-term model (years 1 to 5) | |
|---|---|
| **Customer classes** | **Forecast sub-segment** |
| **Residential** | Single family electric heat type, single family non-electric heat type, multi-family electric heat type, multi-family non-electric heat type, manufactured home electric heat type, manufactured home non-electric heat type, other |
| **Commercial** | Food stores, government and education, healthcare, lodging, miscellaneous commercial, merchandise stores, office - finance, real estate, insurance, other services, other trade, restaurants, transportation, utilities, communications, other |
| **Manufacturing** | Food, high-tech, lumber, metals, other, paper, transportation equipment, other |
| **Miscellaneous** | Irrigation, area lighting, street lighting, traffic signals |

After five years, the models are aggregated based on customer revenue class. This approach allows for long-term trends to be captured agnostic to the growth cycles of different industries and specific customers within the economy. In the long term, there is less certainty about what the landscape of different industries looks like, and aggregation allows PGE to take a higher-level approach to estimating growth in total electricity demand.

**Table 12** shows the high-level customer segments used for the long-term corporate load forecast.

Table 12. Customer segmentation used for PGE's long-term corporate load forecast

| Long-term model (year 5+) | |
|---|---|
| **Customer classes** | **Service Network** |
| **Residential** | **Secondary** |
| **Commercial** | **Secondary** |
| **Industrial** | **Primary** |
| **Industrial** | **Sub-transmission** |
| **Street Lighting and Traffic Signals** | **NA** |

21. The US Census' NAICS segmentation, available at: https://www.census.gov/naics/

Both sets of models capture the distinct responses of PGE's customer classes to weather. This is important because the system has different planning needs in the summer and winter seasons. Our residential and small commercial customers are most sensitive to changes in temperature due to the relatively large percentage of total usage designated to heating and cooling. Industrial loads have been growing most rapidly and while these customers often have limited heating needs, they do have cooling needs which adds to summer loading.

### 3.3.3 PEAK LOAD TRENDS

The Pacific Northwest has historically experienced annual peaking events in the winter based on characteristics of the regional climate, including a long heating season, generally mild temperatures, and appliance stock (including penetrations of electric heat and historically low penetration of air conditioning systems).

PGE's annual system peak demand occurred in the summer for the first time in 2002. Since then, it has occurred in the summer 12 of the last 20 years, and 8 of the last 10 years. Over this time, long-term trends in appliance stock (including increased adoption of air conditioning systems) and rapid growth of high-tech industrial loads (which require cooling to ensure temperature-controlled conditions) have driven a transition from a winter-peaking to a dual-peaking system. Our winter peak remains important to planning analysis as it has been approximately 94% of the summer peak over the last 10 years and winter events are still expected to drive system needs.

The seasonal trends in peak load and associated uncertainties around future climate change impacts make it more important than ever to plan in a holistic fashion so that we are able to continue providing customers with safe and reliable power. In the summer heat waves of 2021, PGE's net system load broke the prior system record for peak load on four different days, for a total of 28 hours. This further highlights the importance of developing new mechanisms to both assess changing customer loads and behaviors under a greater range of temperature conditions as well as system states. In addition, these trends raise important issues pertaining to how utilities are expected to weigh various risk and cost trade offs when it comes to planning the electricity system.

So far, the discussion has centered around top-down load forecasting for energy and peak demand. The next sections detail how PGE will calibrate the top-down corporate load forecast to our bottom-up load and DER forecasts.

## 3.4 Bottom-up load additions

PGE's corporate load forecast provides an important calibration point that drives decision-making at various levels across our company. However, to be useful for distribution planning, we need to match our expectations of overall customer growth across the entire service territory to the information we have available regarding where and when customer loads will likely materialize.

These bottom-up customer load additions come from a variety of sources. In this step, PGE runs a variety of scenarios that account for all the various drivers of load changes at the locational level. This includes consideration of historical load growth in a given geographical area, weather history, customer planned load additions, new sources of demand (such as penetration of central air-conditioning, electric vehicles), DER interconnection applications, and any planned development or redevelopment.

In this section, PGE first provides an overview of the types of electric loads we plan for on the distribution system and highlight some specific factors that need to be addressed to maintain power quality and reliability given the type of load addition. Then we provide an overview of how we collect and track bottom-up customer load additions, as well as the lens that distribution planning takes to assess the impacts of new customer load additions and naturally occurring load growth on the distribution system. This step has direct implications for how we use the load forecast to assess system constraints and plan new projects to address them. Finally, we discuss planned improvements to this process to better reflect anticipated changes based on the evolution outlined in the OPUC's UM 2005 Guidelines.

### 3.4.1 TYPES OF ELECTRIC LOAD AND IMPLICATIONS FOR POWER QUALITY

In alignment with the long-term corporate load forecast model groupings described in **Section 3.4.2**, PGE defines five distinct revenue classes that differ based on the service delivery voltage as well as other features that help distinguish the type of loads and related impacts they may have on the transmission and distribution (T&D) systems used to serve them. These five revenue classes are:

- **Residential** — Delivered via PGE's secondary service network that branches off of the primary distribution lines (usually 13 kV) through service transformers to the typical residential service voltage of 120/240 volts (V)
- **Commercial** — Delivered via PGE's secondary service network that branches off of the primary distribution lines (usually 13 kV) through service transformers to the typical commercial service voltages of 120/208V, 277/480V or 120/240V
- **Sub-transmission** — Larger (usually industrial) customers who supply their own substation and therefore take service directly from a PGE sub-transmission radial line
- **Primary voltage** — Larger (usually industrial) customers who take electrical service directly from the primary feeder lines (13 kV or 34.5 kV)
- **Street lighting** — Street lighting and traffic signals

In addition to differences in service voltage delivery and associated distribution equipment used to provide service to end-use customers, the type and nature of the electric load can have an important impact on the distribution grid and must be considered when planning the system. There are generally three types of loads, each requiring different strategies to mitigate possible negative effects on voltage or power quality. These are:

- **Inductive loads** — Examples are motor-based loads (such as fans, pumps), air conditioners, and various heavy equipment (such as cranes, mixers). Inductive loads draw power by "inducing" a magnetic field and consuming reactive power that can negatively impact the functioning of the distribution system. Corrections must be made to respond to those negative impacts.[22] Large inductive loads (usually large motors) are a typical example of new load that PGE planners must evaluate for potential power quality issues.
- **Resistive loads** — Examples are residential lighting, electric furnaces and consumer electronics. Resistive loads do not cause any disturbance to power factor (PF).
- **Capacitive loads** — Examples are capacitors used to correct imbalances in PF caused by inductive loads. PGE uses capacitor banks to correct PF imbalances on the distribution grid, though certain industrial customers also employ capacitors at their sites. This type of load is the least common of the three.

Traditionally, issues with reactive power and voltage fluctuations have been managed by installation of equipment either at the substation or somewhere on the primary feeder mainline (either capacitor banks or voltage regulators). However, with the advancement of DER technical capabilities and the ongoing decrease in technology costs, imperative to continue to evolve our planning practices to identify and evaluate the wide range of potential services from grid-connected consumer devices. For instance, DERs introduce both more dynamic load patterns on the grid (as in the case of TE) and potential for providing reactive power (in the case of inverter-based technology) and other ancillary services (from a broader suite of consumer appliances).[23]

Improving PGE's forecasting granularity to explicitly account for these factors will be an important step as we continue building a 21st century human-centered distribution system (see **Section 3.5** for advancements in DER forecasting).

22. For more detail on how different types of loads impact the functioning of the distribution system, and a good overview of the technical details of planning and operating the distribution system generally, see PNNL's 2016 report, "Electricity Distribution System Baseline Report" by Warwick et al., available at: https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf
23. For a good discussion of this see for example Holmberg and Omar (2018), "Characterization of Residential Distributed Energy Resource Potential to Provide Ancillary Services," available at: https://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.1900-601.pdf

### 3.4.2 OVERVIEW OF DISTRIBUTION PLANNING'S BOTTOM-UP LOAD FORECASTING PROCESS

The primary perspective that PGE's distribution planning has taken with respect to the load forecast has been to focus on demand (MW), and not energy (MWh), so that we can serve loads during system peaks.[24] Measured peak loads fluctuate from year-to-year due to variations in weather and subsequent impacts on energy usage patterns. For example, our summer peaks are generally affected by the duration and intensity of hot weather events and related spikes in customer air conditioning usage.

For planning purposes, we define "**peak load**" as the largest power demand at a given point during the course of one-year.

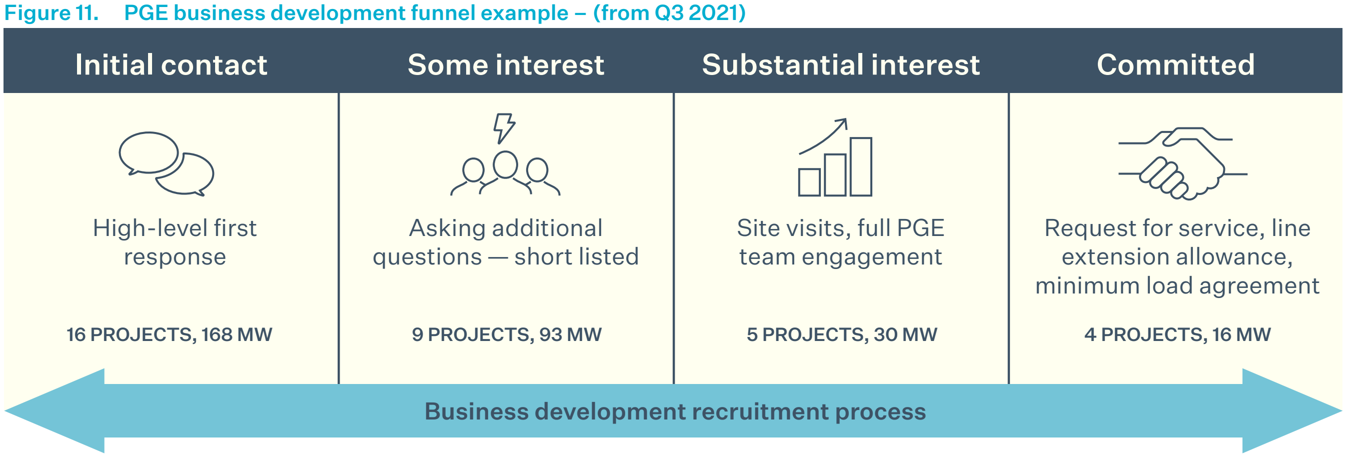
In examining each distribution feeder and substation transformer for peak loading, PGE uses specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Our planning engineers consider many types of information for the best possible future load forecasts, including historical load growth, customer planned load additions, circuit and other distribution equipment additions, circuit reconfigurations, and local government-sponsored development or redevelopment.[25]

#### 3.4.2.1 Tracking customer load growth and regional growth-related factors

A key element of PGE's distribution load forecast is tracking new potential discrete large load additions (also known as "spot load additions") that can occur anywhere throughout our service territory. We rely on our customer sales team and business development team to keep us apprised of different trends affecting Oregon's key economic sectors, as well as to generate information about potential expansions from existing business customers and potential new customers hoping to expand into Oregon. **Figure 11** highlights the different stages of establishing new customer agreements using an example customer growth pipeline report from 2021.[26]

The process for assessing lumped load additions is a fairly discrete and important activity undertaken to forecast future load growth on the distribution system. However, there are also cases where locational info on likely load additions can be assessed prior to PGE hearing about it directly from customers, as in the case of new developments and re-development activities resulting from local economic policies, plans, and zoning changes.

Figure 11. PGE business development funnel example – (from Q3 2021)




24. Though forecasting energy needs on the distribution system has not been a focus historically, with the increasing penetration of DERs on the distribution grid it will be important to consider energy along with peak demand. For example, energy-limited resources such as demand response and battery storage need to be studied in such a way that we evaluate whether there is enough flexibility in the system to charge these devices throughout the day so that they are available for peak discharge.
25. Distribution planning also communicates with transmission planning regularly throughout the year. Specifically, any time we become aware of larger loads or significant DER interconnections at any time of the year, we share that information with transmission planning.
26. Note that this is a simplified view of the business development process and that in practice customer load additions may be surfaced at any level on this spectrum and can have very different time horizons for bringing on new load.

For example, to quantify the load for a residential subdivision project in the Scholls Ferry area, PGE used a per-home demand (kW) estimate that was determined by evaluating existing demand for groups of typical home sizes in the North Bethany area. North Bethany was chosen as the model because the area has had many new homes built in the past several years. These new home demand estimates were segmented based on size of home and information from the zoning maps (such as single family/low density, single family/high density, multifamily) and multiplied by the expected total number of homes to predict an anticipated load for the development.[27]

### 3.4.3 SYSTEM PEAK TREND ANALYSIS AND ANNUAL LOAD ALLOCATION PROCESS

As described in **Section 3.3.3**, PGE is forecasting its system peak in the summer to outpace its winter peak. When we look at the distribution system, summer peak trends are even more accentuated because the seasonal standards of our distribution equipment were designed for a winter peak. As can be seen from **Table 4** in **Section 1.3.3**, the winter ratings for overhead 13 kV lines are roughly 50% higher than summer ratings, reflecting the fact that during summer the higher average temperatures reduce the amount of effective capacity to serve load. This phenomenon, coupled with the already discussed trend toward greater air conditioner usage among residential and commercial customers due to a warming climate, means that summer peak is generally the limiting factor when it comes to distribution system equipment.

Still, PGE monitors both summer and winter peak loads to maintain a holistic view of grid needs. We assess historic trends in seasonal peak load at the feeder and substation transformer level to inform our distribution planning studies. The following subsections describe the different databases and tools PGE uses to collect historical loading information, as well as the process for merging this data with both the bottom-up load additions and the corporate load forecast.

#### 3.4.3.1 Asset Management Database

PGE's Asset Management Database is used to store information about each feeder, substation distribution transformer, and substation within our service territory. The type of information stored includes equipment loadings, equipment ratings, telemetry type at a substation, location, manufacturer information, settings, and other electrical data that is necessary to properly model and operate the distribution system.

After each summer (June 1 through September 15) and winter (November 1 through March 1) season, PGE's Distribution Planning team populates the Asset Management Database with the seasonal peak load obtained from substation monitoring (SCADA/MV90) and metering sources for the substation distribution transformers and feeders.

#### 3.4.3.2 Weak link report and load allocation tool

PGE plans for reliability across the "weakest link" along the distribution pathway from the substation to the end customer, which is defined as the electrical component along the distribution pathway with the lowest current carrying capability. An updated Weak Link Report is generated after each summer and winter season from the Asset Management Database with loading information to represent how the system performed during the most recent seasonal peaks.

PGE then utilizes a load allocation model that combines the various top-down and bottom-up load forecasting inputs described above to aggregate them at the distribution substation transformer level. The load allocation model is updated annually and is also used for transmission planning studies.

Inputs to this load allocation model include:

- **Historical peak load information** (taken from the Asset Management Database for most recent five-year period) for each distribution power transformer.

27. This conversation is limited to more traditional load growth tracking considerations. A key sector requiring additional support to track potential new customer needs is transportation electrification (TE), given that the larger fleet conversions to electric medium- and heavy-duty vehicles are sources of potentially significant spot-load additions. See **Section 3.5.1** for a discussion of how planning for TE load is being incorporated into our DER forecasting processes.

- **Bottom-up load additions** Each distribution planning engineer populates these known load additions, as well as any planned load shifts (for example to reconfigure load to switch to a different part of the system) or load reductions (for example if equipment is being decommissioned or replaced) for each of the distribution transformers in their region for both the peak summer and peak winter seasons.
- **Compensated Power Factor (PF) for each distribution power transformer** during the designated peak period. Accounting for PF allows for the prediction of real (MW) and reactive (MVAR) power needs.
- **Corporate load forecast** peak summer and winter scenarios for 1-in-3 expected weather year.

A 20-year bottom-up forecast for each substation distribution transformer is then created.[28] This forecast starts with the previous year's seasonal peak value, and then creates a year-by-year cumulative forecast by adding the bottom-up load additions to the previous year's value. For example, if a transformer loaded to 20 MW the last summer, and a load addition of 1 MW is expected, the one-year forecast is 21 MW. If a load addition of another 1 MW is expected the following year, this is added to the 21 MW, resulting in 22 MW in year two. This repeated process produces a bottom-up 20-year forecast for each substation distribution transformer.

In order to calibrate the bottom-up distribution forecast to the top-down corporate load forecast, PGE summarizes all of the existing peak loads plus known load additions across more than 300 distribution substation transformers and compares them to the seasonal peak load forecast for the service territory. We calculate an adjustment factor based on the difference in each year and apply this factor to all non-fixed loads so that the total load value (non-fixed loads + fixed loads) equals the 1-in-3 corporate load forecast value. The output from this program produces a 20-year forecast for each distribution transformer for both summer and winter seasons.

The next subsection describes recent and planned advances regarding better integration between bottom-up distribution system load forecasting, DER forecasting and corporate load forecast.

### 3.4.4 EVOLUTION OF DISTRIBUTION SYSTEM BOTTOM-UP LOAD FORECASTING

The capital planning process is more than a year long. Grid needs identified in 2021, presented later in this report, are prioritized, studied, and developed into projects for PGE's 2023 capital planning process, which occurred in June of 2022.

PGE first produced a corporate load forecast that included the combined impact of demand response, TE and storage in March of 2022.[29] The combined DER forecast was then included as an input to our load allocation model in April of this year. The output of the 2022 load allocation model includes DERs (other than energy efficiency, which is done by ETO) for the first time and will be used by our Distribution Planning team for our next capital planning cycle for 2024 investment, which begins in 2022.

Existing DERs on the system are naturally incorporated into the planning process because the peak loading on substation distribution transformers and distribution feeders will include DERs if they are generating during the time of the peak.

28. The 20-year time horizon is necessary to meet regional transmission planning needs. However, most of the bottom-up load additions are characterized no more than 10-years out for distribution planning needs.
29. Previous versions of the Corporate Load Forecast used to inform distribution planning load forecasting included energy efficiency forecasts from Energy Trust of Oregon.

# 3.5 DER locational forecast

Under the OPUC's initial DSP guidelines, the requirements call for a bottom-up load forecast and disaggregation of the DER forecast to the substation level. This section introduces PGE's in-house DER adoption and forecasting model (AdopDER), presents the methodology we used to disaggregate our DER forecast, and presents results.

While **Section 3.4** provides an overview of the current state of our bottom-up load forecasting methods and tools for use in distribution planning, this section will provide an overview of improvements that PGE has made and will be included routinely going forward. The reason we are presenting the methodology and discussion separately in this initial filing is to avoid confusion about current- and future-state tools and methods related to the load and DER forecasting contributions in our distribution planning processes. Breaking the discussion out this way also highlights the changes we are making to existing processes, underscoring the fact that it will take time to fully integrate these new methods into our core business planning processes.

In this section PGE will provide a brief overview of the AdopDER model and highlight some key updates to the model since filing our DSP Part 1, discuss the capabilities for bottom-up load forecasting within AdopDER, present our methodology for disaggregating DER forecasts to the substation level (including energy efficiency), and finally provide results.

### 3.5.1 ADOPDER MODEL OVERVIEW

PGE worked with third-party consultants, Cadeo and Brattle, to develop our AdopDER model. The AdopDER model is a comprehensive modeling framework built in Python that is used to estimate the adoption of DERs (such as flexible loads) and electrification. AdopDER forecasts adoption dynamically, with stochastic influences where appropriate, under different programmatic and market conditions.[30]

At a high-level, the AdopDER model is intended to develop robust DER potential estimates and adoption forecasts across the following resource types:

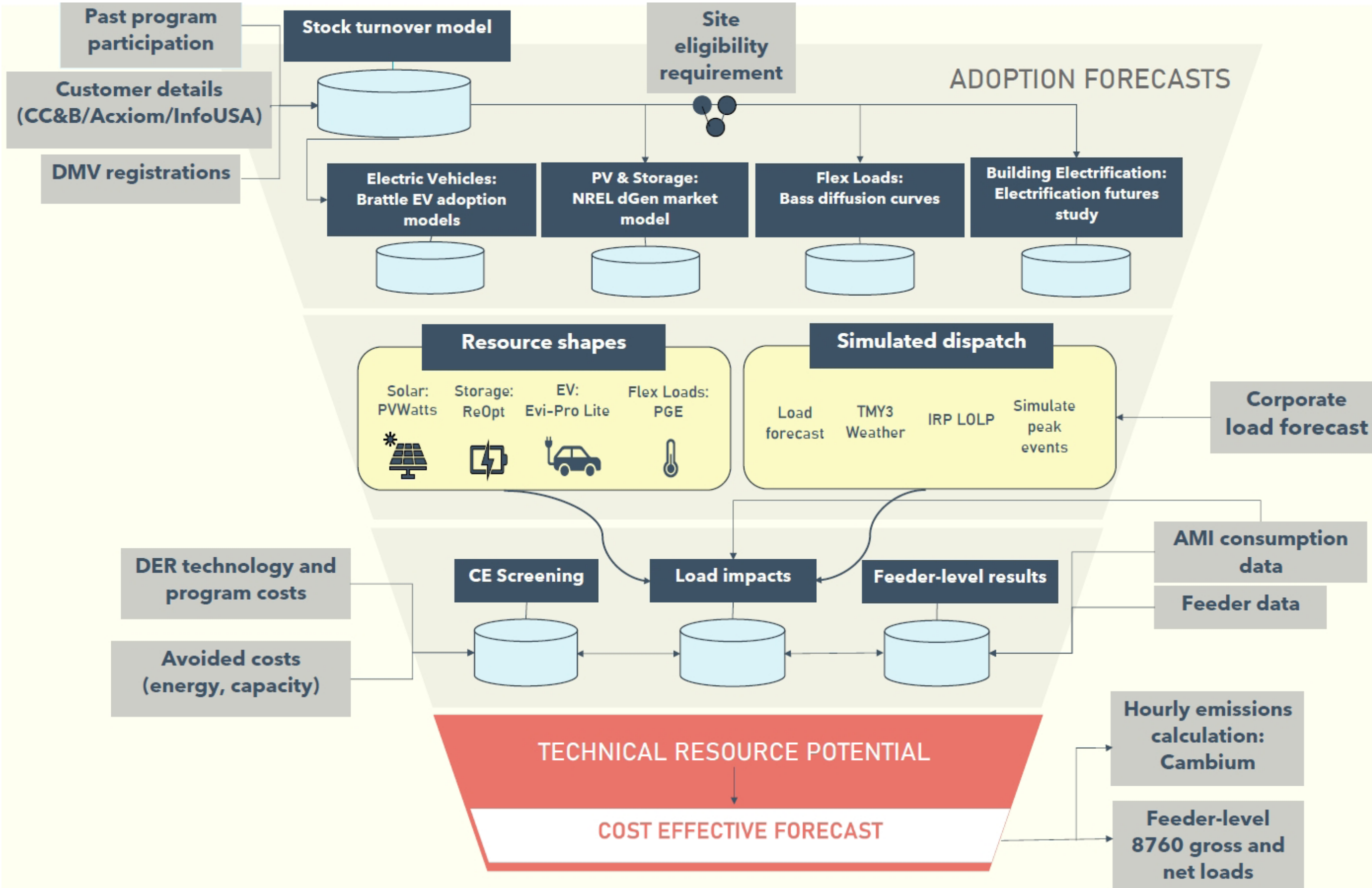
- Demand response/flexible loads
- Distributed rooftop photovoltaic (PV)
- Distributed battery storage
- EVs and charging infrastructure

In PGE's Phase I DER Potential study, we modeled DER adoption and impacts at a system-wide level. In order to meet the DSP Part 2 requirements and to inform ongoing distribution planning needs, we added features to the model to capture site-level customer characteristics and capabilities to report results at the granular feeder- and substation-level.

**Figure 12** shows the main modules within AdopDER in a simplified flowchart.[31]

30. See "PGE DER and Flexible Load Potential – Phase I" report for more detail, available online as Appendix G to the DSP Part 1 at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning
31. Note that this visual is meant to be more easily digestible than typical engineering flowcharts, and some of the relationships between model components may differ in the actual model.

Figure 12. AdopDER model conceptual overview




Updates to AdopDER for Phase II locational adoption and load impacts modeling were largely complete by February 2022. In order to align the results between IRP and DSP, PGE re-ran the results with updated corporate load forecast inputs in March 2022. During this March update, we also implemented a few changes to the methodology reflecting changes to the policy and market landscape, as well as a few model improvements identified after completing the Phase I study. These updates are:

- Updated vehicle battery pack cost data used in Brattle's LDV econometric model, as well as ran sensitivity scenarios to test the impact on EV adoption of recent gasoline price spikes
- Updated stock turnover model with 2021 actuals using solar adoption from PGE active generator report and new DMV registration data extract
- Worked with NREL to calibrate dGen inputs to more closely reflect PGE's service area, as opposed to relying on the statewide defaults used in Phase I
- Implemented logic for MDHDV adoption to account for Oregon DEQ adoption of Advanced Clean Trucks (ACT) rule

The remainder of this section details AdopDER's locational forecasting methodology and presents results of DER adoption by substation.

### 3.5.2 ADOPDER BOTTOM-UP LOAD FORECASTING METHODOLOGY

In Phase II, PGE introduced capability into the model that allows disaggregation of the corporate load growth forecast by geography as well as developing the type of hourly load shape and end use load breakdown needed for detailed DER planning.

Under PGE's current distribution planning process, we calibrate the corporate load forecast to the historic trends and past peak loads of each substation, adjusting for any known bottom-up customer additions (see **Section 3.3**). We are currently reviewing this process and aiming to make some improvements that increase our accuracy and ability to pair the localized expected load growth with a granular DER forecast.

Some key updates that we prioritized during Phase II of the AdopDER model:

- Improving the characterization of bottom-up known load additions to capture customer segment, and number of new customers (such as assigning hourly load shapes to new residential developments versus just peak MW at the feeder breaker)
- Calibrating expected customer growth from corporate load forecast based on specific customer additions on each feeder, as opposed to treating evenly across all feeders
- Adding weather normalization to the disaggregated load forecast to enhance ability to understand underlying consumption drivers at the localized level, and evaluate potential impact of DER adoption under different weather-based planning scenarios

PGE believes these are important elements to more accurately forecasting not just the changing nature of load, but also help to more accurately quantify the potential for DERs located on the distribution grid to provide a range of grid services. As we develop the capabilities to integrate DERs into a virtual power plant (VPP), providing grid operators with better information regarding how changing customer loads will interact with these devices under a wide range of conditions becomes increasingly important.

Integrating this new methodology will take time as PGE works across our planning functions to vet the new methodology and validate the model against experience. Building trust in this way within our Distribution Planning and Distribution Operations engineering teams is critical to find the best ways to incorporate these granular insights into our planning and forecasting efforts.

In PGE's current state, we look at peak MW of new customer loads being added to the distribution system and therefore do not capture the hourly shape of the new load additions. Our new process is moving towards an integrated approach between distribution-level load forecasting and DER forecasting. We now discuss an important facet of tracking customer loads from TE and then relate that to the overall process for integrating top-down and bottom-up load forecasts into AdopDER to derive a holistic picture of anticipated activity on the distribution system.

#### 3.5.2.1 Transportation electrification bottom-up load additions

A key sector requiring additional support to track potential new customer needs is transportation electrification (TE), given that the larger fleet conversions to electric medium- and heavy-duty vehicles are sources of potentially significant spot-load additions. In 2021, PGE created a TE team dedicated to developing customer relationships and understanding the evolving needs of these customers with respect to their utility provider. Through our technical education and outreach efforts, and more recently through our Fleet Partner program, we are working with our customers to plan for and install charging infrastructure to support their electrification plans.[32]

**Figure 13** details the different stages a customer goes through when entering PGE's Fleet Partner program.

32. More information about the Fleet Partner program, available at: https://portlandgeneral.com/energy-choices/electric-vehicles-charging/business-charging-fleets/fleet-charging

**Figure 13. PGE's Fleet Partner pilot program process overview**

### Fleet Partner plan

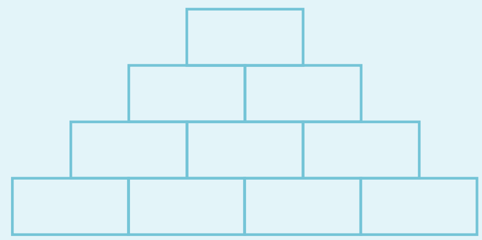
- Electric vehicle feasibility assessment
- Charging analysis
- Fuel cost and clean fuel credit analysis
- Site assessment
- Preliminary design and cost estimate
- Summary of incentives
- Presented in a Fleet Partner Study



**No cost; no commitment**

### Fleet Partner build

- Turnkey final design and construction of make-ready infrastructure
- Make-ready incentive based on forecasted energy use of the chargers
- PGE ownership of make-ready infrastructure



**Customer must purchase/install qualified Level 2 or DC fast chargers**

They begin by receiving a no-cost feasibility assessment and charging analysis. This step provides helpful information to inform our planning efforts about potential new loads if a customer moves forward to the "build" portion by applying to the program.

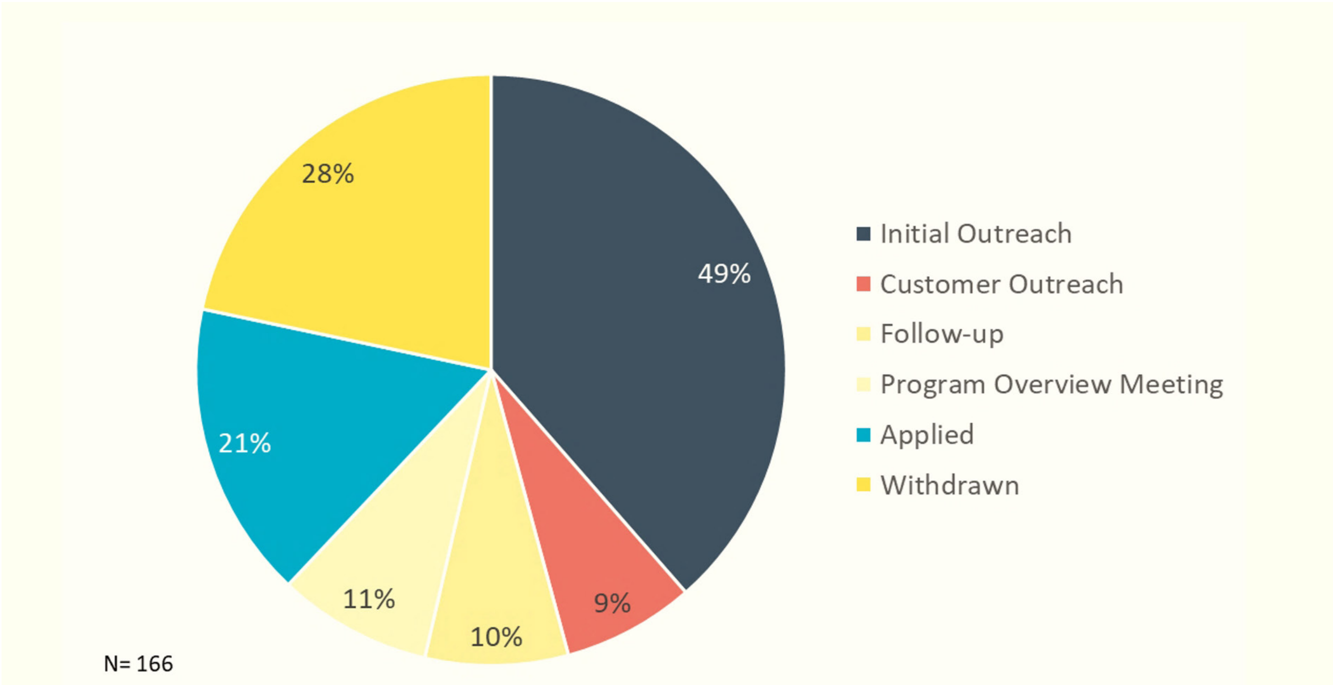
PGE has been tracking customer interest in TE in our customer management system and sales tracking database (Salesforce). As of May 2022, we have 7.7 MW (nameplate) of connected charging load requests at various stages in our Fleet Partner program application process. These requests are cumulative across the service territory and stem from 27 distinct customers aiming to add over 650 electric vehicles (EVs) over the next five years. The load additions are spread across 33 different feeders and average 311 kW per site.

In addition to the leads generated through PGE's Fleet Partner program, we also track customer plans that are not expected to participate in the program, but nevertheless desire to install EV charging infrastructure to meet their fuel needs.

**Figure 14** summarizes the combined interest in fleet electrification we have received whether or not they are expected to participate in the program.

These customer-specific leads for TE plans are incorporated into our Phase II modeling in AdopDER at the customer site level. The next section discusses how we calibrate all bottom-up load additions with the top-down corporate load forecast in AdopDER.

Figure 14. Potential fleet customers by status as of May 2022




### 3.5.2.2 Calibrating bottom-up and top-down load forecasts in AdopDER

In this first iteration leveraging the locational forecasting functionality within AdopDER, PGE has assigned new spot loads from our load allocation tool (see **Section 3.4.3.2**) and the TE bottom-up load additions (see **Section 3.5.2.1**) in AdopDER according to which feeder they land on and what sector the customer is in (e.g., food manufacturing, warehouse, etc.). Once we have accounted for these customer additions, we spread the remainder of the corporate load forecast equally across remaining feeders. **Figure 15** illustrates this process for the residential rate class for the year 2023.

Figure 15. Illustration of new customer growth addition by feeder in AdopDER

As shown in **Figure 15**, in 2023 the corporate load forecast included 7,800 new connects for residential customers. The total residential new developments captured in the distribution planning bottom-up load additions (part of the Load Allocation workflow), is 1,500 new residential units, leaving 6,300 new residential sites to be allocated across the remainder of the service area.

A similar process is followed for non-residential customer additions. Taken together, each new site from the corporate load forecast gets added to the model and associated with the given feeder. Each site is assigned a load profile generated from analysis of neighboring sites in comparable rate classes using load research conducted on 2019 AMI data. Residential and small commercial (schedule 32) load shapes are modeled using a 10% sample of meters on each feeder (minimum sample size of 300 meters) to calculate average hourly consumption, whereas larger customers are modeled individually (census approach).

**Figure 16** shows an example of the feeder-level average residential load profile.

PGE then used the CalTrack framework to develop a parametric model of hourly consumption for the average service point on each feeder. **Figure 17** shows a comparison of the sample average from AMI data and the CalTrack modeled consumption.

Figure 16. 10% sample of service points on example feeder

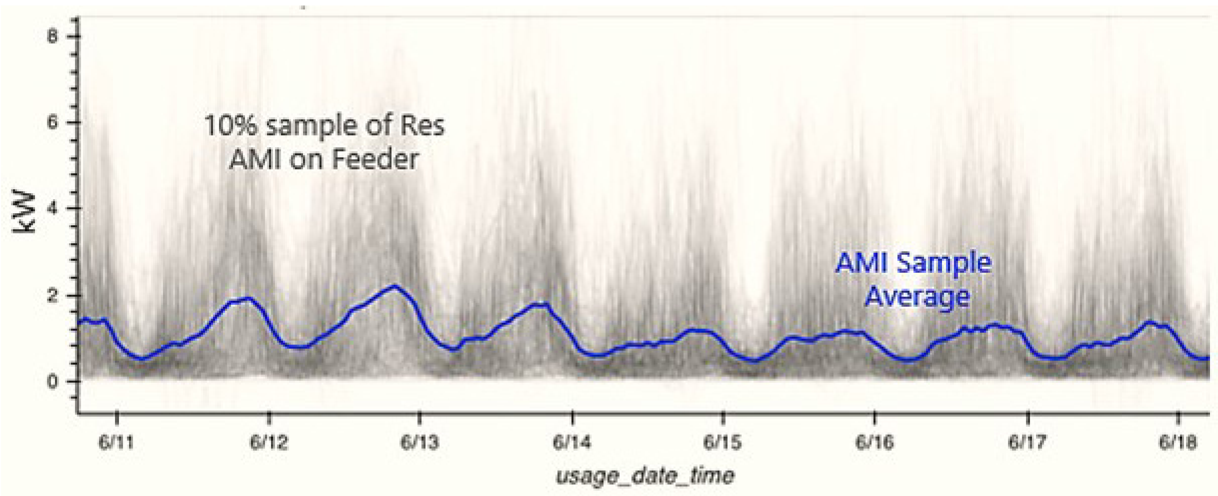
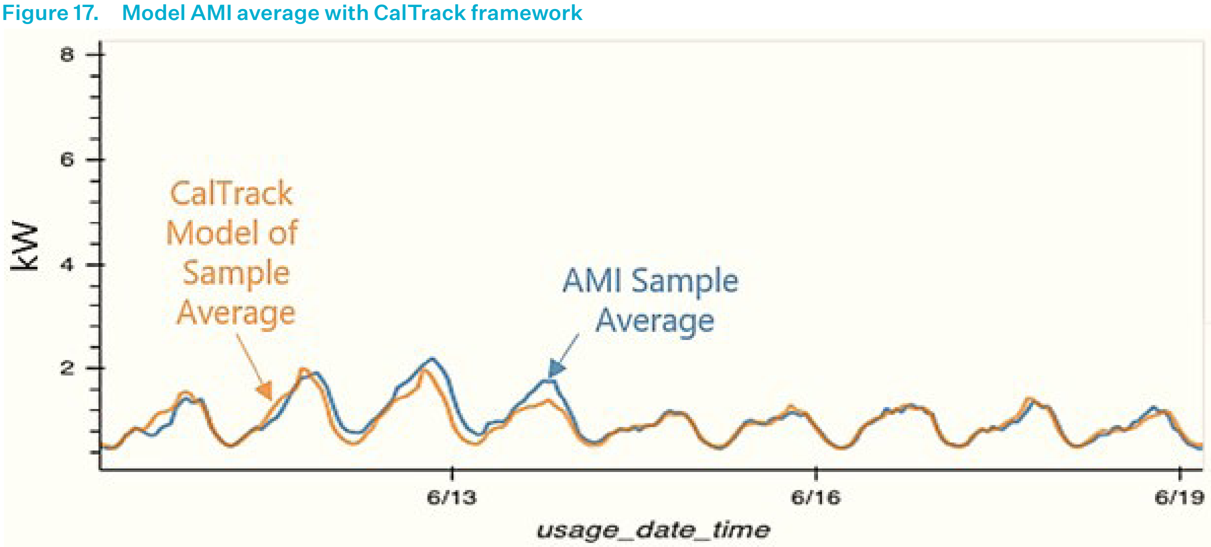



Figure 17. Model AMI average with CalTrack framework



After developing the model of the average service point with CalTrack, PGE multiplied this by the number of customers in the rate class to get the feeder-level net load shape. Net load is what is measured using SCADA measurements and represents the actual load that is impacting PGE-owned equipment — meaning, for instance, that behind the meter solar generation is not explicitly factored out, but rather the proportion of distributed generation reduces the overall electrical load on the system.

However, to understand more fundamental trends in customer usage, and consequently their impacts on future load patterns and DER potential, PGE developed forecasts for both gross and net load. We accomplished this by adding back estimated existing solar PV production (based on current interconnection report) using PVWatts and thereby reconstituted a gross load profile. Each DER shape is then calculated independently and applied to the gross load shape to arrive at a final net load shape accounting for future DER adoption. See **Appendix C** for more details on how we calculated DER shapes.

### 3.5.3 ADOPDER LOCATIONAL DER ADOPTION METHODOLOGY

AdopDER is inherently a hybrid top-down and bottom-up approach because PGE simulated market adoption trends using a blend of macro-level forecast and market demand models and then calibrated these to the granular site-level stock turnover model and customer class characteristics. Our Phase II modeling added a site-specific measure adoption probability that is used to account for geospatial differences between customer types.

PGE's approach to creating site-level propensity scoring depends on the level of available data used in training statistical models. Where such data exists, we developed **statistical models** to develop scores associated with each customer site across the service area. These scores are used to allocate the system-level adoption outputs in proportion to the relative differences between customers according to their individual model scores. If insufficient market data exists or there are tenuous relationships between a DER type and customer characteristics driving adoption, we developed **heuristic adoption models**.

PGE considered two primary factors when deciding whether a DER was suitable for propensity scoring with statistical methods: 1) availability of sufficient data needed to train models, and 2) having well-established findings in the literature relating certain socioeconomic or other geographic factors to actual DER adoption levels.

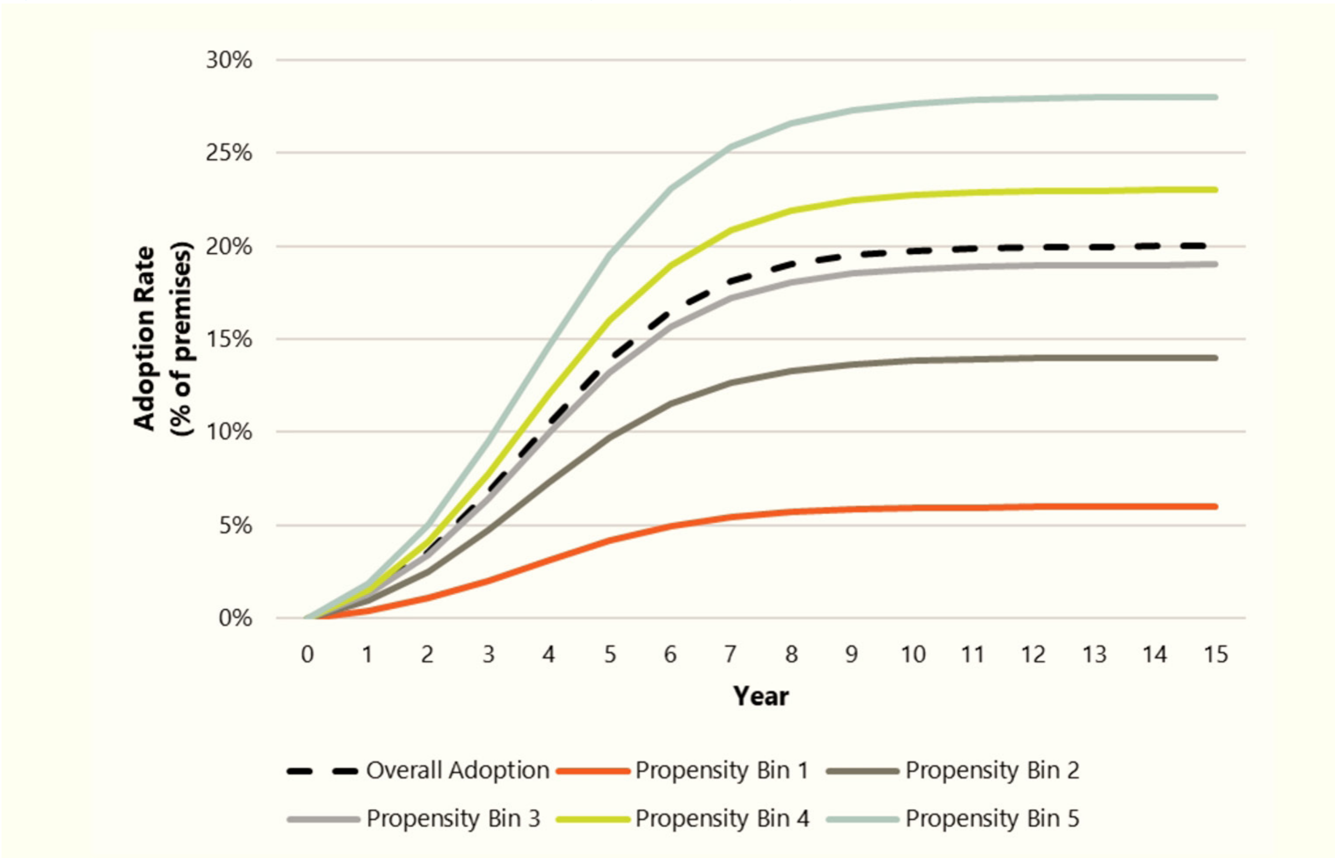
**Figure 18** shows which DER types were modeled with statistical and heuristic models. See **Appendix C** for details about the statistical and heuristic modeling approach.

**Figure 18. Types of DERs modeled with statistical and heuristic approach**

| Statistical model | Heuristic model |
|---|---|
| • EV charging<br>• BTM storage (res, non-res)<br>• Microgrid | • EV charging<br>• BTM storage (res, non-res)<br>• Microgrid |

After developing the final model specifications by resource type, PGE combined both variable types (statistical and heuristic) into AdopDER customer input files that leverage PGE and third-party customer-level datasets. For each year, premise, and measure, we use a function to calculate a single score and assign each score to an adoption bin that is ultimately used to adjust the adoption probability for that site. We divide the scores into five equal groups (i.e., quintiles) each with a corresponding increase or decrease from the system-level average adoption rate based on their relative characteristics. **Figure 19** shows the relative change in adoption rate by each quintile group compared to the overall adoption rate.

**Figure 19. Example adoption rates in AdopDER reflecting propensity scoring results**



At the end of this process, PGE effectively has a view of each feeder based on the specific customer makeup of that feeder that combines these propensity curves with the site-level eligibility criteria for DER adoption.[33] It is the interplay of these two factors that yields our locational adoption results.

Energy efficiency (EE) long-run forecasts are provided by ETO and have routinely been included in corporate load forecast and IRP modeling. This is the first-time EE will be reported at the granular geographic level. We held multiple discussions with ETO to understand what locational factors might be suitable to develop a substation-level disaggregation. We also reviewed experiences of utilities in other jurisdictions for example methodologies to disaggregate EE forecasts to the distribution system level.

After review of comparable methodologies and considering the available data from ETO, PGE decided to use the "Proportional Allocation Method" as recommended by the California working group on Distribution-level DER forecasting methods.[34] See **Appendix C** for more details about how we applied the proportional allocation method to disaggregate the ETO's long-term EE forecast.

### 3.5.4 INTEGRATING EQUITY DATA INTO ADOPDER

Based on feedback PGE heard during our DSP Partner workshops, we developed a methodology to incorporate equity data into our DER forecasting approach that can be used to inform cross-cutting future planning efforts such as solution identification, non-wires solutions, and general program planning. The methodology and results presented in this section concerning incorporation of equity data and indices into the DER forecast occurred in parallel to the development of community-informed equity metrics and the Energy Equity Index (see **Section 2.6** for discussion of how we are working with our partners to integrate equity data and community needs across our resource planning activities).[35]

PGE worked with Cadeo to develop an approach to help us identify priority communities within our planning tools that builds off of a range of prioritization needs identified broadly either by our partners, Oregon-specific policy direction, or national best practices. This specific discussion is limited to near-term activities to incorporate various equity indicators into resource modeling within AdopDER.[36]

The overall study objectives were to:

- Develop indices for diversity, equity and inclusion (DEI), environment, and resilience categories
- Define DEI criteria for community targeting and project prioritization/planning
- Develop ranking/prioritization for NWS consideration (including several example deployment strategies)

**Figure 20** shows the high-level process PGE followed to identify appropriate equity, resiliency, and environmental factors to include in our modeling, and how these can be developed in the right format for inclusion into AdopDER.

33. See **Section 4.3** of PGE's DSP Part 1, Phase I Flex Load Study for the detailed eligibility criteria for each DER type modeled within AdopDER. Examples include presence of a garage to install home L2 charging, and presence of ducted HVAC system to enroll in smart thermostat program, available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf
34. Itron's June 28, 2018 Distribution Forecasting Working Group Final Report, available at: https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M229/K731/229731972.PDF
35. We did this in order to be able to present results of overlaying the DER forecast with equity indicators in time for the Part II Plan submission. Given timelines on this inaugural plan and considering the feedback we have heard during Part I concerning time required to re-build trust with the community, we did not see a pathway to both establish equity metrics and data sources with full community buy-in and have time to incorporate into DER forecasting work which had more lead time associated with it. Nevertheless, we endeavored to incorporate those recommendations and lessons learned that we have heard throughout the DSP Partner meetings, as well as informed by other community engagement processes carried out in the utility planning sphere in Oregon (see for example UM2165 Staff Report, Page 6-8.) Moreover, we heard from participants that there is an expectation to utilize DEI data to inform decision making in the Solution Identification and NWS areas of the DSP Part II in particular.
36. We recognize that the metrics, data sources, and use cases of such data will continue to evolve with more engagement within the Clean Energy Plan and future DSP rounds. The functionality we have built into AdopDER to incorporate these variables is able to be updated based on evolving needs and definitions.

Figure 20. Process overview for incorporating equity data into AdopDER

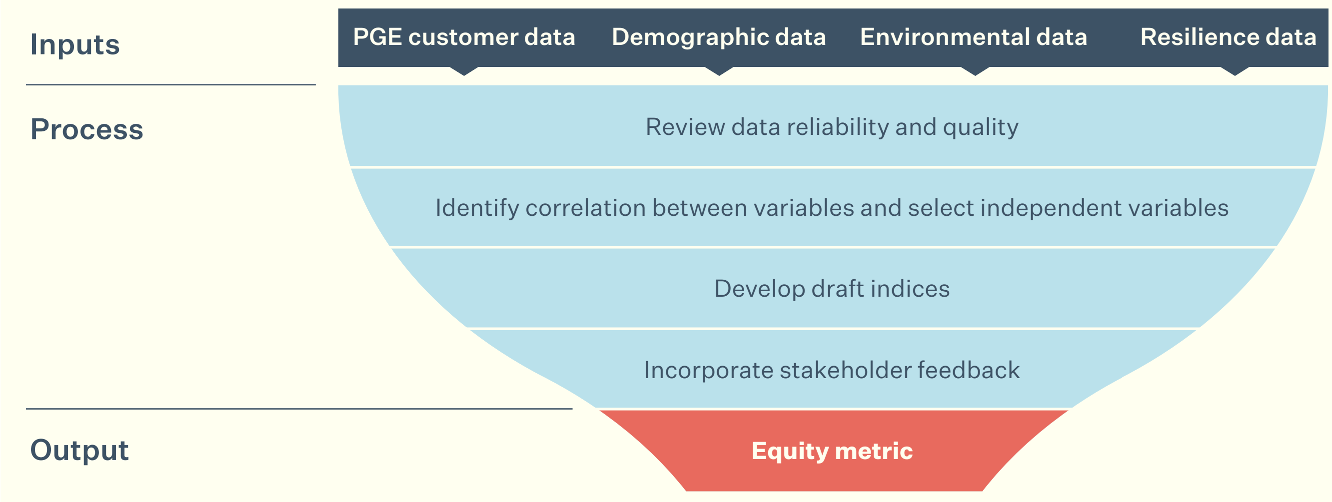



**Table 13** describes the three primary data categories (DEI, environmental and resiliency data) and what purpose they play in the model. PGE also notes indicative data sources. See **Appendix C** for a full description of the variables and data sources, as well as a detailed description of the methodology to assess their suitability for inclusion in AdopDER.

Table 13. High-level equity data indicators for AdopDER

| Targeting category | Purpose | Date sources |
|---|---|---|
| DEI | Characterize populations for prioritization based on equity criteria | PGE (Axiom, Greenlink, customer payment metrics); Public (ACS/ PUMS, DOE LEAD) |
| Environmental | Identify environmental effects, including air quality, proximity to hazards | Public (EPA EJ) |
| Resilience | Identify areas at risk for long outages due to natural disasters / extreme weather | PGE (from SAM: long duration outage locations; PSPS; Public (USDA, FEMA) |

## 3.5.5 BOTTOM-UP LOAD AND DER FORECASTING LOCATIONAL RESULTS

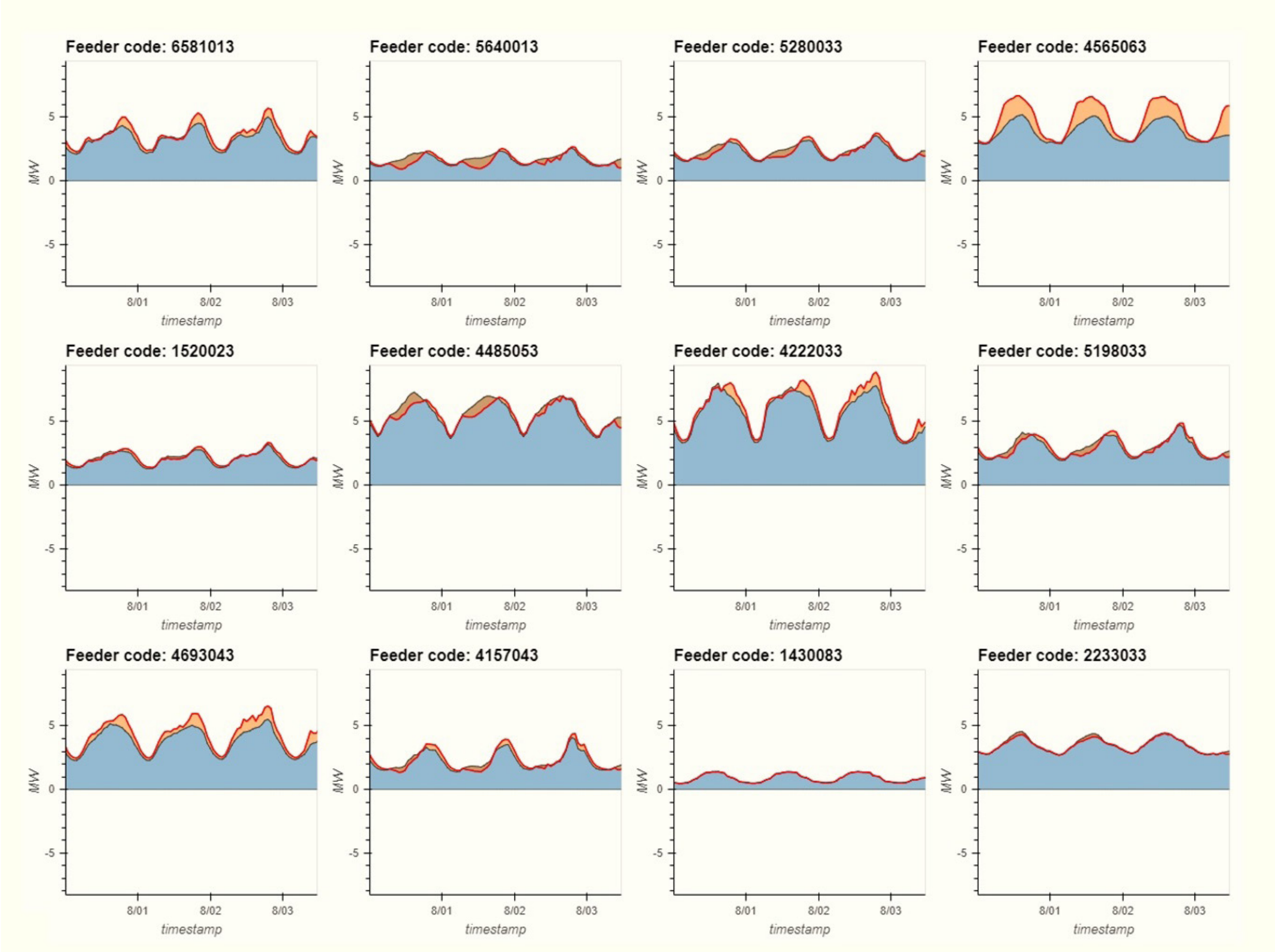
This section presents the results of PGE's bottom-up load forecast efforts and DER forecast disaggregation. We first present results of the load forecast portions of AdopDER and discuss the findings in context to their impact on ultimate DER adoption.

### 3.5.5.1 Bottom-up load forecast results

Following the method described in **Section 3.5.4**, PGE developed feeder-level forecasts of gross load, DER impacts, and net load for each feeder in PGE's service area with suitable data.[37] **Figure 21** shows results of our bottom-up load forecast for 12 example feeders.

37. Some feeders were removed from the calculation due to missing data, or because they were not energized at the time of pulling the data for this study. Out of 650 feeders, we were able to develop bottom-up load forecasts for 565, or 80% of active feeders. In future iterations, we will work to better integrate AdopDER and our core Distribution Planning databases.

Figure 21. Example of feeder-level gross and net load forecasts




## 3.5.5.2 DER DISAGGREGATION RESULTS

In order to contextualize the substation-level DER forecast results, PGE first presents overall results of the March 2022 update to AdopDER.

**Table 14** to **Table 19** show the system-level DER forecast for 2022-2030, broken out by resource type.

Table 14. Summer demand response/flex load peak impacts

| Summer MW Peak Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| All achievable potential | | | | | | | | | |
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 200 | 250 | 271 | 298 | 310 | 326 | 343 | 359 | 385 |
| Ref | 81 | 112 | 146 | 183 | 211 | 236 | 257 | 274 | 294 |
| Low | 70 | 82 | 98 | 118 | 137 | 155 | 173 | 187 | 201 |

| Cost-effective achievable potential (TRC >=1) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 195 | 239 | 256 | 273 | 278 | 282 | 287 | 287 | 294 |
| Ref | 78 | 105 | 133 | 162 | 183 | 199 | 211 | 218 | 228 |
| Low | 68 | 79 | 93 | 110 | 126 | 141 | 155 | 166 | 177 |

Table 15. Winter demand response/flex load peak impacts

| Winter MW Peak Impacts | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| All achievable potential | | | | | | | | | |
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 102 | 145 | 174 | 191 | 204 | 219 | 234 | 259 | 282 |
| Ref | 56 | 78 | 106 | 134 | 158 | 177 | 194 | 213 | 231 |
| Low | 48 | 57 | 68 | 83 | 99 | 113 | 127 | 141 | 152 |
| Cost-effective achievable (TRC >=1) | | | | | | | | | |
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 100 | 139 | 165 | 176 | 183 | 188 | 192 | 199 | 205 |
| Ref | 54 | 74 | 98 | 119 | 137 | 149 | 158 | 167 | 174 |
| Low | 47 | 55 | 66 | 79 | 92 | 104 | 115 | 126 | 134 |

Table 16. Solar potential forecasts

| Solar PV potential (Nameplate MW-dc) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 148 | 155 | 161 | 186 | 192 | 253 | 297 | 377 | 458 |
| Ref | 144 | 149 | 154 | 173 | 192 | 226 | 261 | 318 | 377 |
| Low | 144 | 147 | 150 | 154 | 157 | 160 | 164 | 167 | 172 |

Table 17. Energy storage potential forecasts

| Energy storage potential (nameplate MW-dc) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 5 | 6 | 7 | 13 | 21 | 35 | 49 | 77 | 105 |
| Ref | 4 | 5 | 5 | 9 | 13 | 22 | 31 | 46 | 61 |
| Low | 4 | 4 | 5 | 5 | 6 | 6 | 7 | 8 | 9 |

**Table 18. Transportation electrification potential forecasts**

| Transportation electrification potential (MWa) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 13 | 21 | 30 | 40 | 53 | 68 | 86 | 109 | 135 |
| Ref | 12 | 19 | 26 | 35 | 45 | 57 | 72 | 90 | 111 |
| Low | 12 | 17 | 22 | 29 | 36 | 45 | 55 | 67 | 82 |

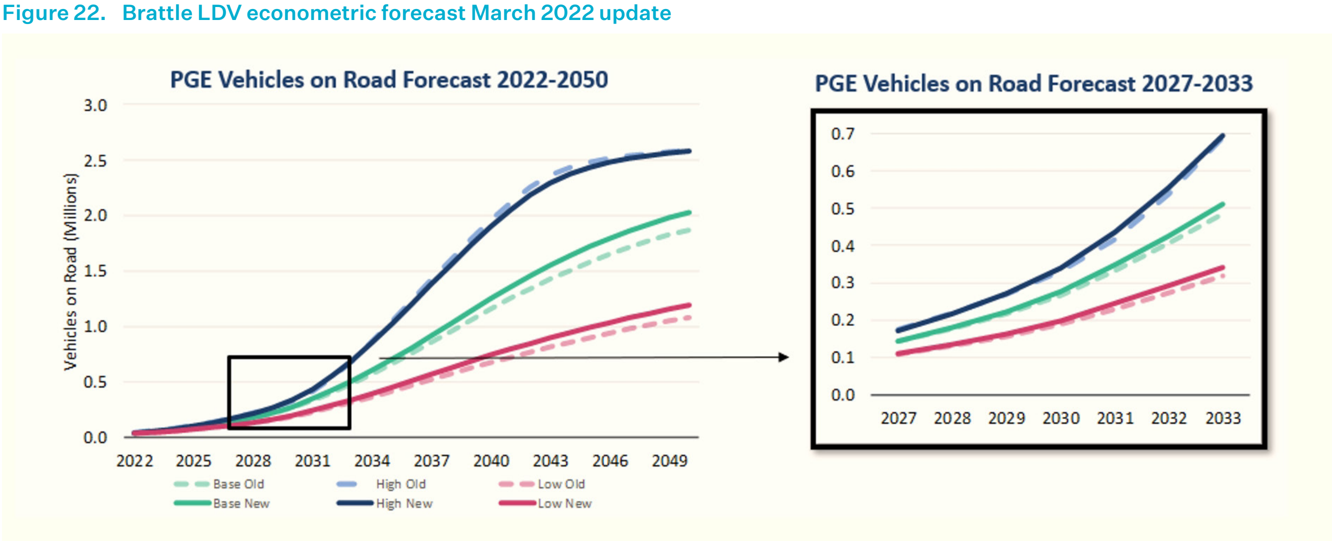
**Table 19. Building electrification potential forecasts**

| Building electrification potential forecasts (MWa) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| High | 3 | 7 | 10 | 16 | 21 | 27 | 33 | 39 | 45 |
| Ref | 3 | 7 | 10 | 14 | 18 | 22 | 27 | 31 | 36 |

Next, PGE presents these results by DER type at the disaggregated substation level. Light-duty electric vehicles are projected to exceed 2,000,000 by 2050 under our reference case scenario. In our March update to the forecast, we saw a slight change in the near-term and larger growth in the long-term.

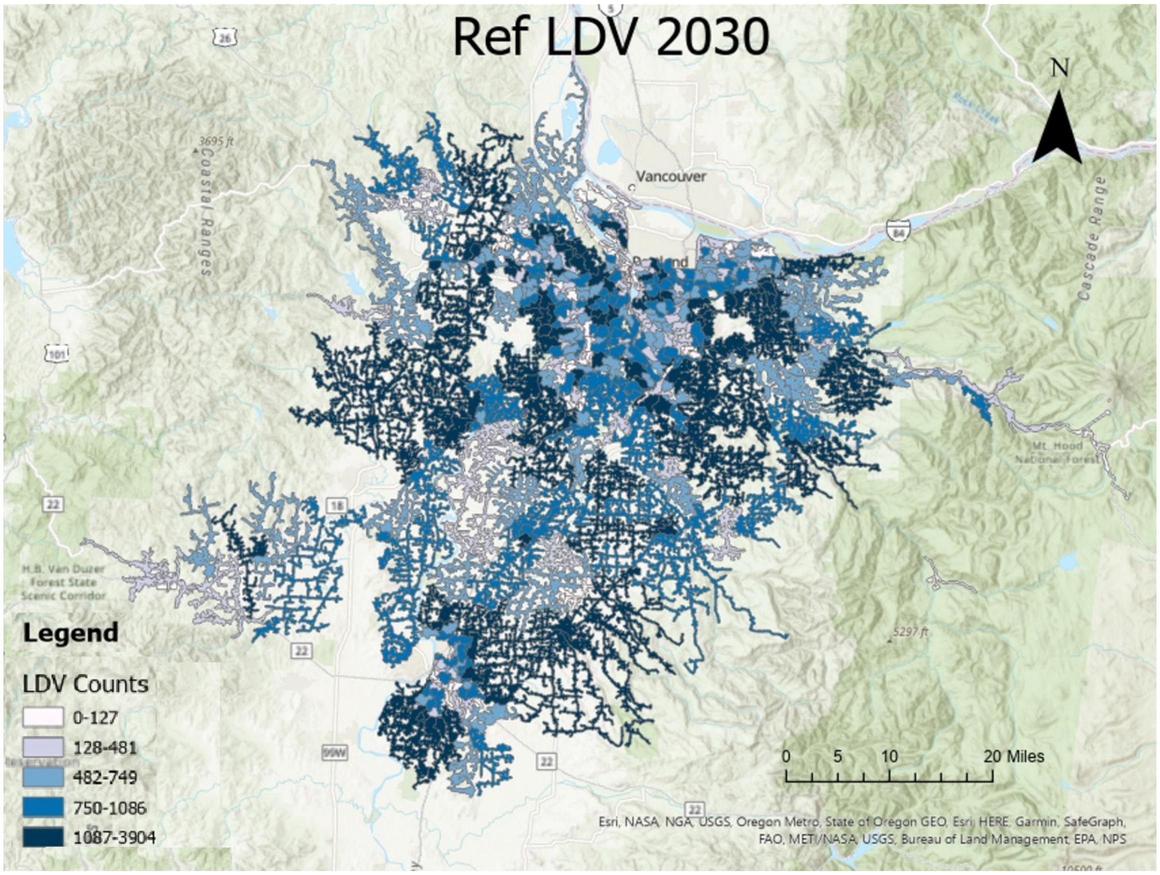
**Figure 22** shows the comparison of the updated March forecast to the LDV forecast used in Phase I DER Forecast study. See **Appendix C** for additional details about the EV forecast modeling approach and March update.

**Figure 22. Brattle LDV econometric forecast March 2022 update**



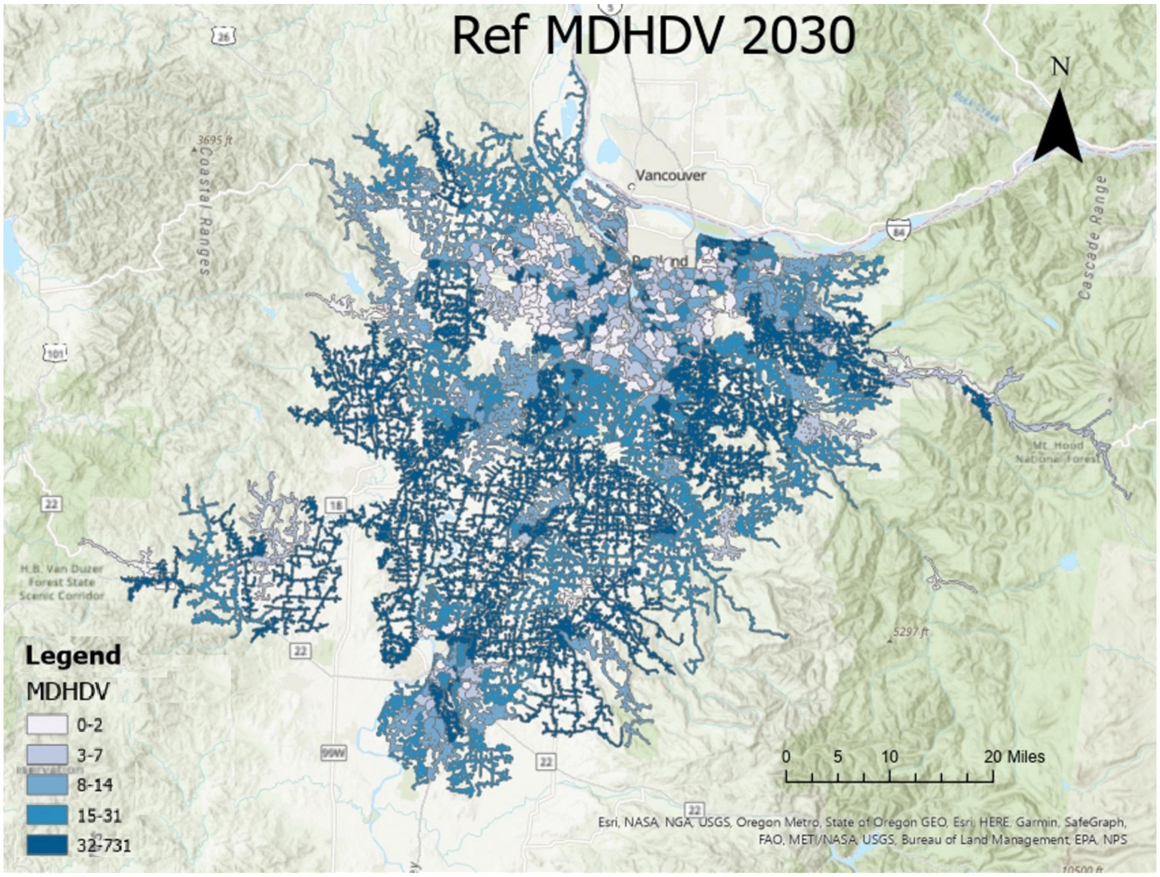
Looking at the concentration by geographic area, PGE sees the highest density of LDV adoption in urban metropolitan areas as shown in **Figure 23**, with a high case of LDV adoption in 2030 at the feeder level.

**Figure 23. Reference case LDV adoption at the feeder level in 2030**



When looking at potential grid impacts at the distribution feeder (primary) and substation transformer level, medium- and heavy-duty vehicle (MDHDV) fleet charging is most likely to have impacts that will drive the need for discrete capacity additions, as well as public corridor sites for interstate trucking. **Figure 24** shows the results of forecasted MDHDV adoption at the feeder level.

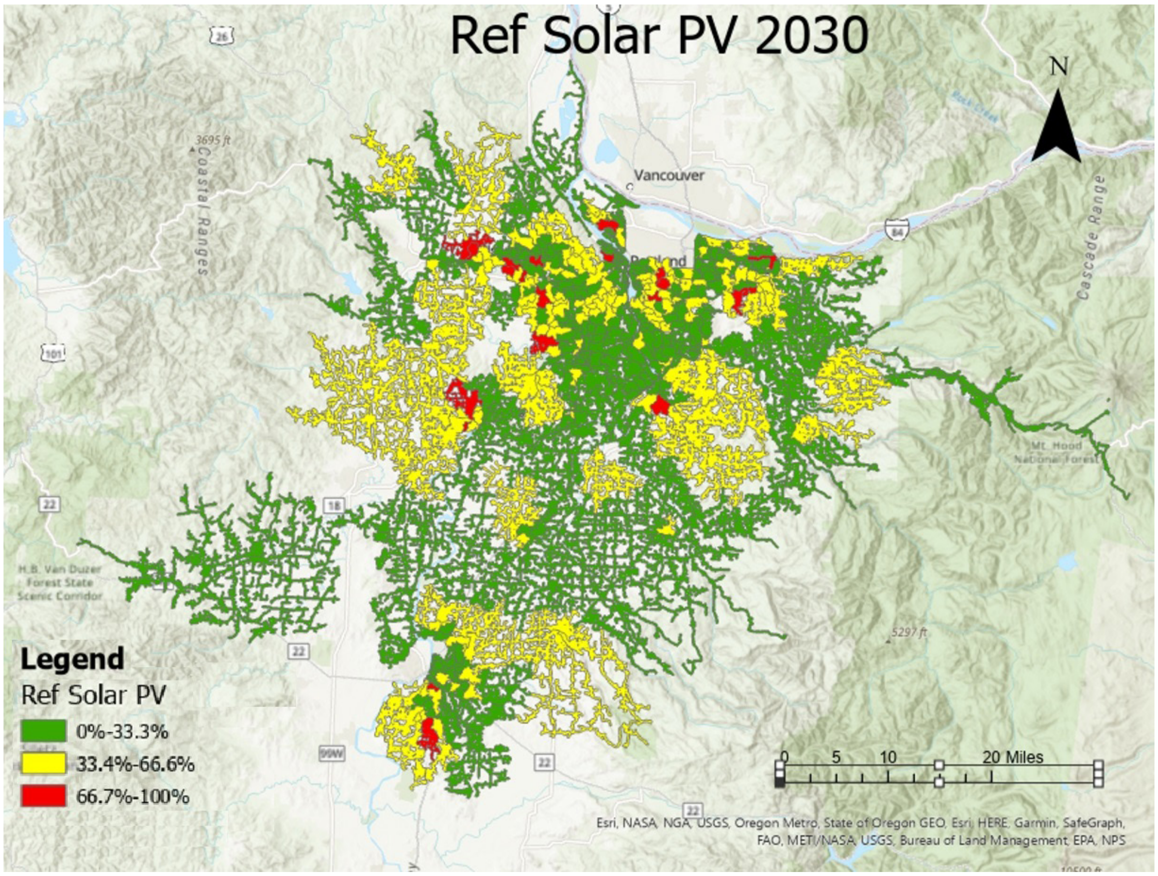
**Figure 24. Reference case MDHDV adoption at the feeder level in 2030**



Looking at rooftop solar PV adoption, PGE sees a fair amount of geographic dispersion with a few clusters of high likelihood of adoption.

**Figure 25** shows the reference case adoption at the feeder-level for residential and non-residential rooftop solar in 2030.

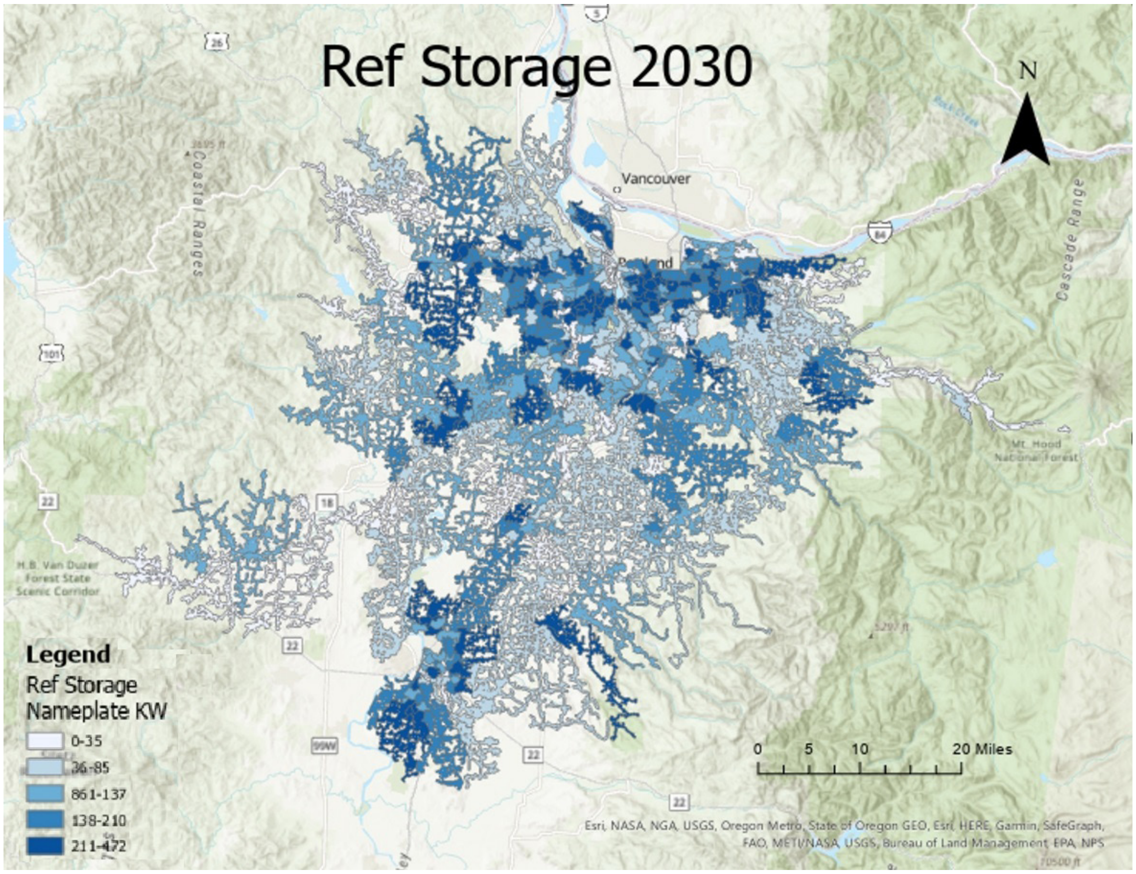
**Figure 25. Reference case rooftop solar PV adoption at the feeder level in 2030**



Finally, **Figure 26** shows the geographic breakdown of distributed behind-the-meter storage adoption from the reference case in 2030. Part of the adoption propensity logic reflects presence in a public safety power shutoff (PSPS) zone due to higher likelihood of facing extended outages.

For more detailed results in tabular form and aggregated to the substation-level, see **Appendix M**.

**Figure 26. Reference case behind-the-meter storage adoption at feeder level in 2030**



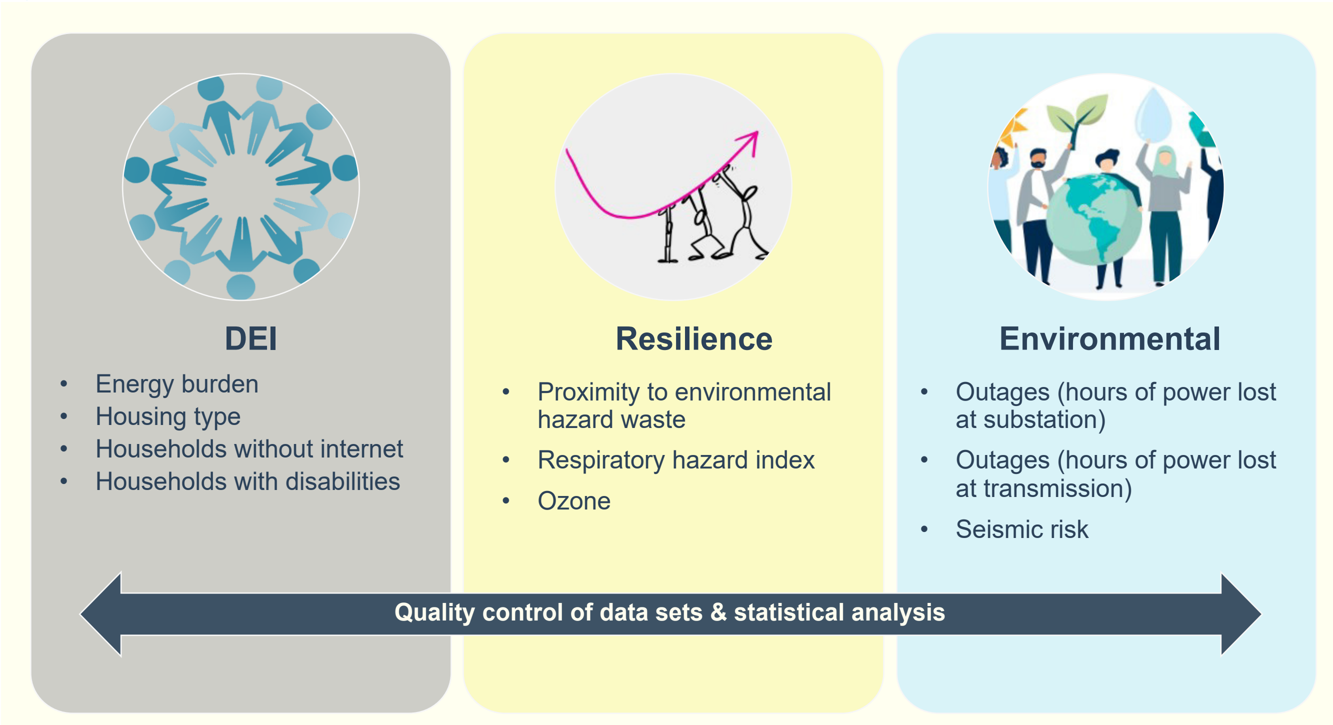

### 3.5.5.3 Using equity data research to inform future planning efforts

The equity research we undertook to develop DEI and environmental data layers for incorporation into AdopDER (see **Section 3.5.4**) can inform future planning and program design. It also helps to corroborate the energy equity metrics identified in **Chapter 2** through PGE's Community-focused Workshop series, as well as provide a statistical means of incorporating these metrics into the mathematical portions of DER forecasting.

For example, a key goal of the research was to identify correlation between variables (since many variables are intertwined, such as income and home size) and select unique indicator variables that can then be applied to the population (see **Table 13**). Overall, PGE reviewed greater than 50 candidate variables from diverse data sources (see **Appendix C** for details about the variable selection process).

**Figure 27** highlights the results of our selection process for each of the main equity categories identified.

Figure 27. Selection of equity variables for statistical analysis

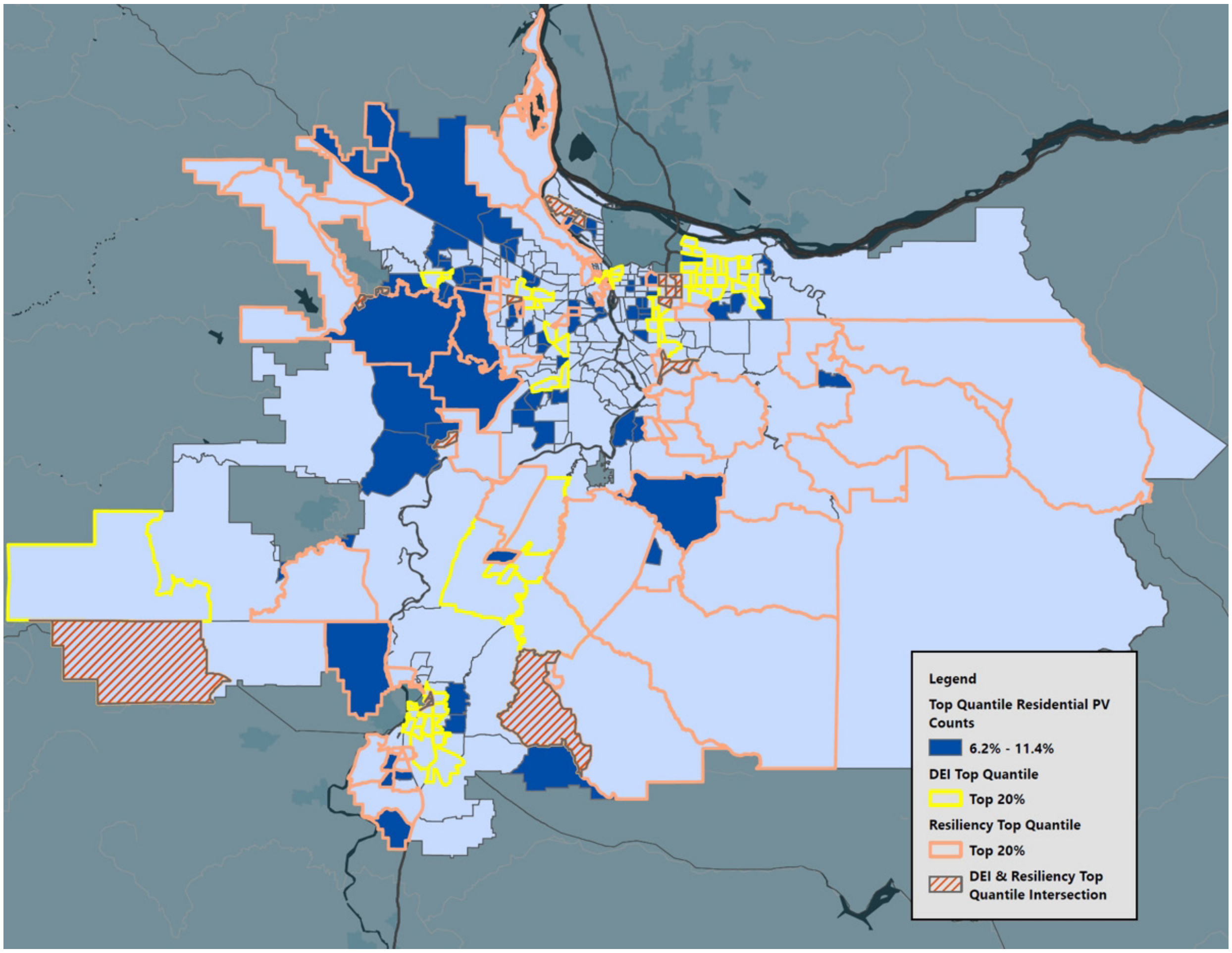



As described in **Chapter 2**, PGE is in the process of rolling out an Equity Index across use cases within the DSP. For the present analysis purposes, we applied this Equity Index to the locational DER adoption results in order to identify any patterns.

To illustrate how this type of data can inform more equitable program design, PGE provides an example of applying the Equity Index to Solar PV locational adoption shown from **Figure 25**. First, we overlaid the locational solar PV adoption with the DEI and Resiliency indices scores by census tract. **Figure 28** shows the residential PV counts by census tract and the boundary outlines of the census tracts scoring in the top 20% for both the DEI and Resiliency.[38]

38. Note that residential PV counts shown here reflect project counts, not size of the systems installed.

**Figure 28. Solar PV locational adoption with DEI and Resiliency Index overlay**




By 2030, the top 20% of census tracts for residential solar PV adoption generally fall outside of those census tracts within the top 20% based on DEI and Resiliency indices. This indicates that, given current program designs incorporated into AdopDER, forecasted PV installations would tend to be comparatively lower within environmental justice (EJ) communities compared to the rest of the service territory, all else equal.

The census tracts in the top 20% for solar PV adoption are characterized by:

- 85.5% of SF homes
- 12.7% of MF buildings
- 1.7% of manufactured houses
- 79.7% owned and 20.3% rented

By comparison, the top 20% DEI census tracts are characterized by:

- 72.3% of SF homes
- 25.4% of MF buildings
- 2.3% of manufactured houses
- 71.3% owned and 28.7% rented

PGE will continue to work with our partners to identify ways the DSP can continue to add value to program interventions aimed at achieving our shared vision of an equitable clean energy future.

# 3.6 Evolution

As the distribution system continues to evolve with more DERs on the system, planning models and analysis will need to change. With this growth in DER comes more uncertainty about when and how much power will be demanded, as well as the need to plan for increasing amounts of two-way power flow. Planning for this new reality necessitates evolving our tools to address these highly dynamic loads and generation resources, as well as more opportunities to shift loads through pricing and programs to address a range of grid needs.

In this chapter we have described our current processes and tools for conducting distribution-level load growth forecasts, as well as introduced an important component related to improving our capabilities regarding DER forecasting. AdopDER represents an investment in a foundational planning capability that will continue to add value over time. Planned improvements to the model include integration with core PGE systems like our GIS systems, customer and AMI databases, and CYME modeling software. By tying AdopDER to our core systems we will be able to bring down the computational time required to run scenarios, thus freeing up more resources to analyze different DER adoption scenarios and policy-related questions.

Based on our DER forecast results, transportation and building electrification could result in significant load additions to PGE's system, however, these could be partially managed with time-of-day pricing and other flexible load programs coupled with continued investments in energy efficiency. Understanding the locational clustering impacts of different DER combinations will be a consistent feature of all future planning efforts. As a result, time-series power flow analysis becomes critical, as well as capability to run scenarios across power flow simulations to better evaluate the distribution system impacts of different DERs under a range of contexts. PGE is investing in CYME tools and training to advance our capabilities in these areas, as well as more discretely modeling different end use loads like EV charging and solar plus batteries.

Another important improvement we have planned is better characterization of end use load modeling both in our AdopDER model and subsequently in our CYME modeling. Today, AdopDER simulates DER adoption at the granular site-level and evaluates net impacts to load for each DER type according to each DER's hourly shape. We plan to build on the foundational capabilities of AdopDER by adding greater end use load shape detail at the whole-building level and greater predictive capabilities about flexible load response during extreme weather events.

This step allows greater disaggregation of customer load profiles stemming from the combined influence of DERs coupled with coincident changes to end use efficiency resulting from energy efficiency programs and market transformation activities, including continued evolution in state and local building codes. Consolidating our load disaggregation capabilities under one integrative modeling framework is fundamental to continued improvements in bottom-up load forecasting that can provide actionable insights to grid operators, customer program teams, and our customers and communities.

PGE is partnering with the Lawrence Berkeley Lab Energy Technology Area for a project funded by the DOE Office of Electricity that seeks to use large-scale sensing and data fusion techniques to better forecast system load during extreme heat events and improve distribution system planning and operation during heat waves. Key components of the project are to develop better DR forecasts under extreme temperatures (especially for weather-sensitive loads like seasonal cooling) that assist in unlocking building demand flexibility to support grid operations, and testing and validating new equitable operational procedures to reduce the overheating risk of vulnerable communities. The project will start in October 2022 and has an expected duration of two years, and we will provide an update on progress during our DSP partner meetings.

Chapter 4

# Grid needs analysis

# Chapter 4. Grid needs analysis

"Prediction is very difficult, especially if it is about the future."

– **Niels Bohr**, Nobel prize winning physicist

## 4.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[39] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

**WHAT WE WILL COVER IN THIS CHAPTER**

The analytical framework for identification of grid needs

A discussion of assessing risk within the distribution system

How grid needs are ranked and prioritized according to the Distribution Planning Ranking Matrix

Identifies 12 prioritized grid needs

This chapter provides an overview of PGE's current capabilities, distribution system analysis, the demands on that system, and how we prioritize grid needs. We describe the technical requirements needed to provide a safe, reliable and resilient system that provides adequate power quality to the customers it serves. We also discuss the process for identifying needs and constraints in the distribution system and include a review of our risk assessment framework.

**Table 20** illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[40]

Table 20. Distribution system overview: Guideline mapping

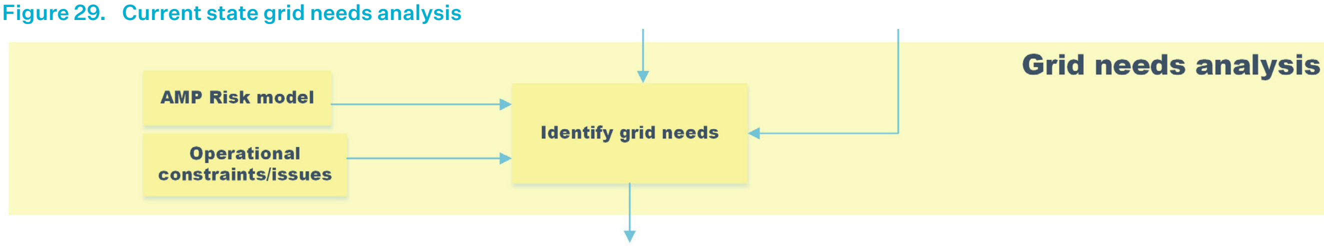
| DSP guidelines | Chapter section |
|---|---|
| 5.2.a | **Section 4.2, 4.3** |
| 5.2.b | **Section 4.4** |
| 5.2.c | **Section 4.5** |
| 5.2.d | **Section 4.5** |

39. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.
40. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

## 4.2 Introduction

Distribution planning is informed by key drivers such as load growth forecasts, economic development, new large single loads, grid modernization, regulatory requirements, safety, reliability performance of the system, urban growth boundary expansion, and zoning changes. At PGE, we see the distribution grid as an evolving system that is at different stages of modernization. By responding to changes in the communities we serve, we can advance and improve distribution operations and customer service. Grid needs analysis is the process (depicted in **Figure 29**) by which we identify the impacts of these drivers on the distribution system.

Figure 29. Current state grid needs analysis




## 4.3 Assessing grid adequacy and identifying needs

Grid adequacy is assessed by determining existing system conditions, creating projections for future system conditions, and then determining mitigation strategies for system deficiencies. It requires existing system loading and performance conditions that are obtained from substation SCADA and metering sources, customer metering data, load projections from PGE's Corporate Planning team, Key Customer team, and Business Development team as well as directly from municipalities and customers.

Near-term studies are performed in the one- to five-year horizon for project development, and long-term studies, in the five- to ten-year horizon, are used to inform strategic substation and distribution infrastructure placement and land acquisition for future use. An example is a large swath of undeveloped industrial land. Studies would be performed on the anticipated customer load levels on the site. The existing electrical infrastructure in the area would be analyzed to determine how much load could be accommodated and what additional infrastructure, such as substations, would be required to serve the projected load. This information would be used to inform decisions on proactively purchasing property for a future substation site.

Existing conditions and future system conditions are evaluated by PGE's Distribution Planning team utilizing our engineering analysis software, CYME, to determine system deficiencies based on established criteria explained in the following sections. Using CYME, input from Distribution Operations engineers, and Distribution Planning engineers' technical knowledge of long-range plans for the system, multiple options to mitigate system deficiencies are developed.

### 4.3.1 CONTINGENCY ANALYSIS

Grid adequacy assessments are performed on worst-case system conditions. For most of PGE's system, this is during the summer, when system loading conditions are the highest and equipment and line thermal limits are at the lowest due to high temperatures. Two scenarios are evaluated, the system normal condition, referred to as N-0, and the system during a single outage, or contingency, referred to as N-1. N-0 refers to the system when all substation transformers and distribution feeders are in service and in their normal configuration. When a single substation transformer or a single distribution feeder is out of service, this is an N-1 condition. System loading information is obtained from PI Historian as well as customer metering data. This information is entered into CYME distribution analysis software, which is used to determine where system operating conditions are outside acceptable ranges.

PGE's system is designed to serve customers with adequate reserved capacity needed to allow timely restoration of service after an outage of one distribution power transformer or one distribution feeder (N-1 conditions). This is accomplished by limiting the peak loading of distribution transformers to 80% of capacity and limiting distribution feeders to 67% of capacity.

### 4.3.2 LOAD LIMITS

Loading limits are determined by ambient temperatures and industry standards for obtaining expected length of service before failure. Institute of Electrical and Electronics Engineers (IEEE) Standard C57.91 is applied for transformer loading.[41] Insulated Cable Engineers Association (ICEA) and IEEE standards are applied for feeder loading.[42] The system is also designed to maintain an acceptable voltage range, as defined by American National Standards Institute (ANSI) C84.1.[43] The primary voltage of the system is required to stay within +/- 5% from nominal.

### 4.3.3 SYSTEM MODELING

Once existing system deficiencies, if present, are determined, system loading conditions are modified in the CYME model to account for projected load growth. Data is collected from PGE's Corporate Planning team, Key Customer Management team, Business Development team, Design Project Manager team, the Distribution Operations Engineering team, as well as local and state agencies. This data is used to predict the amount and location of load growth that will occur in the one- to ten-year planning horizon. Loading and voltage conditions are then analyzed a second time to determine possible deficiencies that will likely occur during any known load ramp timeframe and five years out with potential, but not committed, load growth.[44] We modify the CYME model for the system until all existing and possible future deficiencies are corrected. Increasing the size of conductors, adding substation transformers, or adding new distribution feeders are examples of modifications to correct distribution system deficiencies in the CYME model.

## 4.4 Assessing reliability and risk

System reliability is determined by PGE's Distribution Planning team through two primary sources — historical outage information and existing and future system contingency analysis. Outage information is collected from our Outage Management System (OMS) and industry-specified indices are calculated according to IEEE Standard 1366 and IEEE Standard 1782 for every feeder by Asset Management Planning (AMP) team.[45]

Feeders showing poor performance based on these indices are evaluated for traditional wired solutions as well as modern techniques like distribution automation. In the future, non-wires solutions (NWS) may also be deployed to address reliability performance concerns. The PGE system is evaluated in CYME for the ability to continue to serve all customers during the outage of one transformer or one feeder. The existing system as well as the projected future state of the system are evaluated.

In addition to using industry standards and CYME, PGE uses the outputs of the economic life cycle models developed by the AMP team to identify concentrations of system risk. These models and outputs are discussed in **Section 4.4.1** and **Appendix H**. Reduction in system risk is primarily determined through analysis of PGE's assets with the Integrated Planning Tool (IPT) by the AMP group.

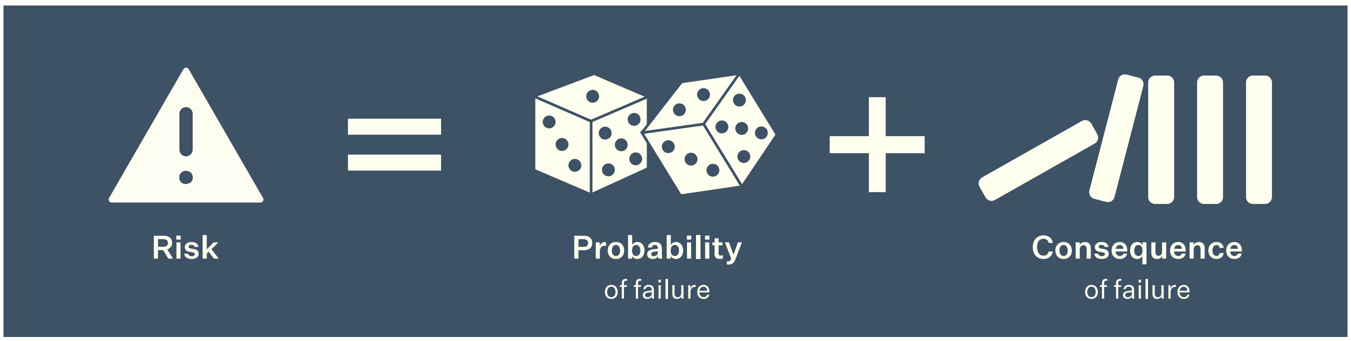
41. IEEE standards, available at: https://standards.ieee.org/.
42. ICEA standards, available at: https://www.icea.net/docs.
43. ANSI standards, available at: https://ansi.org/.
44. Historically, in most of PGE's system, the load growth has been relatively flat and any significant fluctuations in load have been due to weather, not actual new demand on the system. As a result, sometimes the forward-looking analysis has not been required.
45. IEEE Guide for Electric Power Distribution Reliability Indices," in IEEE Std 1366-2012 (Revision of IEEE Std 1366-2003), vol., no., pp.1-43, 31 May 2012, doi: 10.1109/IEEESTD.2012.6209381 and " in IEEE Std 1366-2012 (Revision of IEEE Std 1366-2003), vol., no., pp.1-43, 31 May 2012, doi: 10.1109/IEEESTD.2012.6209381.

## 4.4.1 RISK ASSESSMENT FRAMEWORK

PGE has an Asset Management program, which has a goal to cost effectively mitigate risk while achieving customer value. Our AMP team uses risk-based economic lifecycle models to prioritize long term capital investments. These models calculate the lowest cost of ownership. We determine the lowest cost of ownership as the optimal time to replacement of an asset which balances maintenance cost and the risk of owning and operating the existing asset compared to the cost of replacing the asset. Using the outputs of these models as a determinate for proactive asset replacement reduces risk of failure on the system, improves reliability, and improves the customer experience.

The approach PGE's AMP team takes to modeling assets is based on the fundamental concept of risk. Risk is defined as the product of annual probability of failure and consequence cost of failure (**Figure 30**). The cost includes reliability impacts to customers, load impacted from the failure, as well as environmental, safety and direct cost impacts to our company.

Figure 30. The risk equation




PGE's AMP team uses a suite of asset models combined with the IPT to assess projects on economic benefits and key risk and reliability metrics. The AMP team's asset models calculate annual probability of equipment failure and corresponding consequence costs of failure, resulting in annual risk cost streams. These risk cost streams are aggregated with annual maintenance and annualized capital costs to develop cost of ownership net present value (NPV) estimates for each asset.

The lifecycle cost values, combined with other key risk and reliability metrics, are used to evaluate projects. Risk, reliability, and lifecycle cost metrics are calculated for each asset using PGE's AMP team's asset risk models, which have been developed for multiple different transmission and distribution asset classes. Assets and their associated model outputs are combined to analyze potential projects using the IPT.

The annual failure probability is the likelihood an asset will have a repairable or non-repairable failure as a function of its age, condition and model.

Consequence cost of failure is the weighted average cost of repairable and non-repairable failure scenarios of the asset.

## 4.4.2 ASSET MODELS

PGE has developed 11 different transmission, sub-transmission, and distribution asset class models, identified in **Figure 31**. Within each model, PGE calculates risk using the definition from **Figure 30** for every individual asset on the system, which can then be aggregated to calculate the risk on the system at the asset class level.

Details of the calculation of both terms of the risk equation for these assets are discussed in **Appendix H**.

**Figure 31. Existing asset models**

**Economic life cycle models**

| Substation assets | Distribution assets |
| --- | --- |
| ✓ Transformer<br>✓ Circuit breaker<br>✓ Relay system<br>✓ SCADA system<br>✓ Switch | ✓ UG cable<br>✓ Line transformer<br>✓ Recloser<br>✓ Regulator<br>✓ Switch<br>✓ Structures |
| **Geographic risk** | **Business case tools** |
| ✓ Vegetation/ weather risk<br>✓ Wildfire risk<br>✓ Animal risk<br>✓ Public risk | ✓ Risk register<br>✓ Integrated planning tool |

# 4.5 Prioritized list of grid constraints

Currently, grid needs originating from PGE's Distribution Planning team are driven by loading on equipment. Substation transformers and distribution feeder lines that exceed planning criteria are identified as potential grid needs and prioritized using multiple factors into a same Distribution Planning Ranking Matrix. The ranking matrix is split into five different levels (**Figure 32**), with multipliers from five to one.

Each level of the Distribution Planning Ranking Matrix and the associated evaluation criteria is described in **Appendix I**.

**Figure 32. Distribution planning ranking matrix**

| | |
| --- | --- |
| **Level 5** | **Safety and customer commitment** |
| **Level 4** | **Impacts to other facilities** |
| **Level 3** | **Heavy loading, telemetry and substation risk** |
| **Level 2** | **Feeder risk, load growth, and redundancy** |
| **Level 1** | **System utilization and DG readiness** |

### 4.5.1 LIST OF GRID CONSTRAINTS

Utilizing the Distribution Planning Ranking Matrix, PGE prioritizes grid needs. The following distribution planning grid needs in **Table 21** were analyzed for solutions as part of the 2023 capital cycle, which began in 2021 and are based on 2020 loading information on equipment.

Table 21. List of prioritized grid needs

| | | | Level score | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Priority** | **PGE location** | **Grid need** | **5** | **4** | **3** | **2** | **1** | **Total** |
| 1 | Evergreen substation | Industrial load growth in North Hillsboro | 75 | 40 | 18 | 14 | 2 | **149** |
| 2 | St. Louis substation | Commercial load growth in Woodburn area and 57 kV system constraints | 0 | 80 | 9 | 12 | 1 | **102** |
| 3 | Silverton substation | Existing loading issues and industrial load growth in Silverton | 75 | 0 | 9 | 12 | 0 | **96** |
| 4 | Redland substation | Aging infrastructure, heavily loaded transformer and feeders, lack of telemetry east of Oregon City | 0 | 20 | 36 | 26 | 2 | **84** |
| 5 | Kaster substation | Substation with high arc flash concerns, commercial load growth in St Helens | 75 | 0 | 0 | 8 | 0 | **83** |
| 6 | Glisan substation | Industrial load growth in Gresham | 75 | 0 | 0 | 6 | 0 | **81** |
| 7 | Waconda substation | Commercial load growth south of Woodburn and 57 kV system constraints | 0 | 60 | 3 | 14 | 1 | **78** |
| 8 | Harrison substation | Capacity addition to implement other grid need mitigations, temporary equipment being used for support in inner SE Portland | 0 | 60 | 3 | 10 | 0 | **73** |
| 9 | Linneman substation | Residential load growth in the Happy Valley and Gresham areas, temporary equipment being used for support | 0 | 20 | 18 | 20 | 0 | **58** |
| 10 | Boring substation | Transformer failure resulting in capacity constraints, aging infrastructure in the Boring area | 0 | 20 | 18 | 16 | 1 | **55** |
| 11 | Glencullen substation | Capacity addition to implement other grid need mitigations in SW Portland, lack of SCADA telemetry, feeder reliability improvements | 0 | 40 | 9 | 4 | 1 | **54** |
| 12 | Scholls Ferry substation | Existing loading issues and residential development in the Murrayhill/Scholls areas resulting in capacity constraints | 0 | 0 | 18 | 20 | 0 | **38** |

### 4.5.2 GRID NEEDS THAT WILL BE CONSIDERED IN FUTURE PLANNING CYCLES

PGE's Distribution Planning Ranking Matrix is continuously evolving to account for the changing planning environment. Based on the current ranking criteria, the grid needs listed below will be re-evaluated in future planning cycles. Typically, each planner will take on one to three grid needs depending on complexity. The prioritization framework and matriculation of grid needs will be re-evaluated as equity is incorporated into the ranking matrix.

Multiple grid needs from prior planning cycles already have solutions proposed and projects defined, but the projects were deferred for various reasons (most notably COVID-19-related challenges). These projects have been delayed long enough that the grid needs must be re-evaluated and re-prioritized in the 2024 capital planning cycle. These grid needs are listed in **Table 22**.

Table 22. Grid needs that need to be re-evaluated

| PGE location | Need/constraint |
|---|---|
| Arleta substation | Heavily loaded transformer and feeders |
| Centennial substation | Heavily loaded transformer |
| Eastport substation | Heavily loaded feeder (currently under consideration for a non-wires solution) |
| Hogan South substation | Heavily loaded transformer and feeders |
| Mt Pleasant substation | Heavily loaded transformer and feeders |

The grid needs in **Table 23** have been identified and will be included in the grid needs prioritization using the Distribution Planning Ranking Matrix for the 2024 capital planning cycle.

Table 23. Grid needs that are ready to be ranked

| PGE location | Need/constraint |
|---|---|
| Bell substation | Heavily loaded feeder |
| Bethany substation | Heavily loaded transformer |
| Canby substation | Heavily loaded transformer and feeder |
| Carver substation | Heavily loaded transformer |
| Cedar Hills substation | Heavily loaded feeder |
| Clackamas substation | Heavily loaded feeder |
| Delaware substation | Heavily loaded feeder |
| Elma substation | Heavily loaded feeder |
| Fargo substation | Heavily loaded transformer |
| Glencoe substation | Heavily loaded feeder |
| Harmony substation | Heavily loaded transformer |
| Hillsboro substation | Heavily loaded feeders |
| Huber substation | Heavily loaded transformers and feeders |
| Indian substation | Heavily loaded transformer and feeders |
| Kelley Point substation | Heavily loaded feeder |
| Molalla substation | Heavily loaded feeders |
| Mt Angel substation | Heavily loaded feeder |
| North Plains substation | Heavily loaded feeder |
| Sandy substation | Heavily loaded transformer and feeders |
| Swan Island substation | TE growth |
| Sylvan substation | Heavily loaded transformer |
| Tabor substation | Heavily loaded transformer |
| Tualatin substation | TE growth |
| Twilight substation | Heavily loaded feeder |

### 4.5.3 RISKS TO TIMELINE AND ADDRESSING GRID CONSTRAINTS

Grid needs or constraints may take many years to be addressed, depending on the solution identified to mitigate the constraint. Supply chain constraints have become a significant roadblock in implementing projects to address grid constraints in the desired timeframe. Other factors that could delay implementation of a project to address grid constraints are permitting, easement and/or land acquisition, labor shortages and capital budget constraints.

## 4.6 Evolution

PGE's AMP team is evolving their model to incorporate resiliency. As a customer centric utility, we need to address both the reliability and resiliency needs on our grid. We have outlined below the key milestones that need to be addressed or adapted.

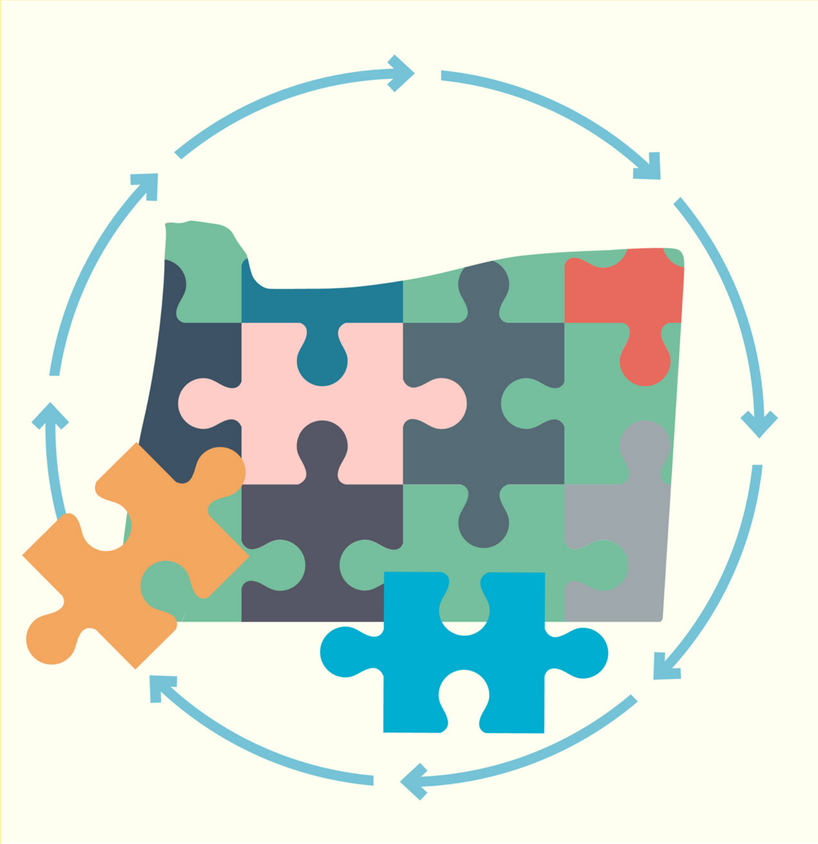
> Resiliency is defined as being able to anticipate, adapt to, withstand, and quickly recover from disruptive events.

- **Risk Framework** — The risk methodology PGE has developed and utilized for reliability can be adapted to calculate risk mitigation for resiliency. The overall methodology is the same calculation, where risk equals probability of failure multiplied by consequence of failure; however, instead of using a reliability-focused consequence impact, "blue sky" event, we will update the consequence impact to a "dark sky" event. "Blue sky" events are traditional outage events that are less than 24 hours in duration, such as, cable failure, vegetation or animal related outage, or minor storm. "Dark sky" events are extreme events that result in outage duration greater than 24 hours, such as a wildfire event or significant ice storm. To properly reflect the customer experience in these "dark sky" events, we need to acquire updated outage duration assumptions and resiliency-based value of service (VOS) measures.
- **VOS** — As part of the risk-based methodology, PGE uses reliability-based VOS measures from a CPUC-approved PG&E study, which was developed in 2012. This study is out of date and does not capture resiliency-related events (such as outages greater than 24 hours). We plan to survey our own customer base to acquire resiliency VOS measures along with updated reliability VOS measures. Our goal for a new study is to have more current data that reflects our customer-base and captures value of service for both reliability and resiliency events. Conducting a survey of our customer base will enable our teams to better understand how customers value both reliability and resiliency and what we should take into account when making decisions.
- **Resiliency Metrics** — PGE has identified changes to Customer Experiencing Long Interruption Durations (CELID) as the primary resiliency metric. Our teams are working through various ways to leverage this and other metrics to evaluate resiliency.

As stated earlier, PGE's corporate load forecast first incorporated a DER forecast in March of 2022. We refreshed our DER forecast in April of 2022. This forecast will be used in the 2024 capital planning cycle to factor into the grid needs identification. In addition, an equity metric will be incorporated into the Distribution Planning Ranking Matrix. As the regulatory landscape changes with regards to generation investments by utilities and the planning process in general evolves, the ranking matrix discussed in **Section 4.5** will be re-evaluated.

Chapter 5

# Solution identification



# Chapter 5. Solution identification

"We cannot ask others to do what we have not done ourselves."

– **Christiana Figueres**, diplomat and climate change leader

## 5.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[46] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

**WHAT WE WILL COVER IN THIS CHAPTER**

The system studies that are performed to further understand and characterize the prioritized grid needs

The benefit-cost analysis framework for evaluating proposed solutions

Scoring and ranking of recommended solutions

This chapter provides an overview of our solution identification for the prioritized grid needs. We describe how we develop solutions that respond to varying grid needs and how we rank these solutions. We also describe programs that are developed to address asset risks that are not addressed by other solutions.

**Table 24** illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[47]

Table 24. Distribution system overview: Guideline mapping

| DSP guidelines | Chapter section |
|---|---|
| 5.3.a | **Section 5.3, 5.3.2** |
| 5.3.b | **Section 5.3** |
| 5.3.c | **Section 5.4, Appendix J** |

46. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021
47. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf

# 5.2 Introduction

PGE's Solution identification chapter describes the process by which our planning engineers identify potential solutions that are needed to provide necessary additional capacity and address any identified system deficiencies. The solution identification process is directly fed from the output of our grid needs identification process. We perform a system study to develop and support potential project options. The study will include a problem statement, study methodology and analysis, project benefits, cost estimates and a recommended solution option. We utilize our distribution load flow software, CYME, to analyze distribution system options by modeling scenarios and running load flow simulations which will assist in determining a preferred solution option for a project.

# 5.3 Solution identification process

To accommodate load growth, such as the load growth identified in the grid needs analysis, PGE commonly implements new infrastructure, such as new transformers and/or distribution feeders. For substation transformers, our planners will determine the necessary transformer capacity based on standardized transformer sizes so we can accommodate the loading needs identified in the study. We have standardized transformers sizes (28 MVA and 50 MVA), however non-standard sizes may be required based on specific needs of a customer and/or a location. Our planners will then work to determine:

- If upgrading existing infrastructure will adequately alleviate loading concerns (such as upgrade an existing 28 MVA transformer to a 50 MVA transformer).
- If expanding an existing site will be enough (such as expanding an existing substation to have three transformers instead of two).
- If a new substation and associated equipment are necessary.

For distribution feeders, PGE's planners determine if reconductoring (upgrading existing conductor to a larger size) of an existing conductor will meet the loading needs and will develop a feeder reconductor project. Or, if there are reliability or jurisdictional requirements, our planners will develop an underground conversion or rebuild project. When existing feeders are heavily loaded, a new feeder may be necessary. The planner will determine the size of the new conductor and the best route.

Once PGE's planners have narrowed down options in a study, there will be discussions with internal stakeholders regarding feasibility, constructibility and any challenges. Some of the internal stakeholders our planners will work with are:

- **Substation Engineering team** — Help determine if an existing substation can accommodate upgrades to existing equipment or expansion of the site.
- **Property Services team** — Help identify and acquire real estate if a new substation site is required or if existing property expansion is possible.
- **Distribution Operations Engineering team** — Help determine if spacing will be an issue for new feeder getaways, if expanding an existing substation, and will provide feedback for new feeder routes and emergency switching sheets for transferring load off transformers and feeders.[48]

Next, PGE's planners work with our estimators to obtain substation and/or distribution system estimates for the proposed solutions options. Once estimates are acquired, the Asset Management Planning (AMP) group will perform an economic/cost-benefit analysis (see **Section 5.3.1**). The outputs of this analysis will include benefit-cost ratio, reduction in risk value, avoided customer interruptions, and reduction in customer minutes interrupted, among others.

The information PGE needs to identify solutions is provided by multiple internal teams and sources:

- **Historical loading** — Metered data points sourced from our PI Historian data (real-time data historian program).
- **Load forecast** — The corporate load forecast (**Section 3.3**).

48. Emergency switching sheets outline the necessary steps to transfer load from a feeder or transformer to neighboring feeders and transformers when we need to perform equipment maintenance or construction-related activities (such as rebuilding a substation), or when there is an outage.

- **Known block loads** — Information regarding projects coming online from our Economic Development, Key Customer Management, Distribution Operations Engineering, Design Project Management and Local Government Affairs teams.
- **New or upgraded substation** — Layout design from our Substation Engineering team.
- **New or expanded property** — Information from our Property Services team.
- **Distribution feeder layout and switching sheet feedback** — Information from our Distribution Operations Engineering.
- **Economic analysis** — Information from our AMP team.
- **Transmission analysis** — Information from our Transmission Planning team.
- **Estimates for substation, transmission, and distribution system work** — From our Estimators in the Project Management Organization (PMO) team.

PGE's distribution planning manager reviews our system studies to confirm that all important information has been included and will consider constructibility, cost and timelines. The study shows a recommended solution option, why it's being recommended and how much it will cost. Ideally, the recommended solution option would last for at least 10 years before requiring additional investment in new technologies and/or equipment. The study is used to formulate the design and construction scope of a project.

## 5.3.1 BENEFIT-COST ANALYSIS

A benefit-cost analysis (BCA) of options is performed by PGE's AMP team with the Integrated Planning Tool (IPT). Budgetary estimates for options are calculated by our Estimators in the PMO team and supplied to our Distribution Planning team.

The asset models described in **Section 4.4** give PGE information that we use to analyze risk and economic costs associated with specific assets. These asset-related risks and economic costs are aggregated to provide a project-level assessment of risk, benefits and costs. Some key metrics are:

- **Lifecycle cost of ownership (LCOO)** — The cost to own, operate and maintain asset(s) over time and is the net-present value (NPV) of an annual cost stream which includes maintenance, risk, and capital investment.
- **Near-term asset risk (NTR)** — The annual probability of failure multiplied by consequence of failure. This is simply the annual risk value for this year, as described in the asset models.
- **Near-term customers interrupted (CI) and customer minutes interrupted (CMI)** — Near-term customers interrupted is annual probability of failure multiplied by consequence of failure, but instead of consequence being measured in dollars, it is measured in customer interruptions. CMI is similar, but instead of interruptions, consequence is measured in total minutes interrupted.
- **Benefit cost ratio (BC ratio)** — Compares the reduction in lifecycle cost of ownership divided by capital investment required to determine whether risk and reliability benefits exceed investment.
- **Geographic risk (geo risk)** — The annual probability of an asset failing as a result of geographic conditions multiplied by the consequence of asset failure. Example sources of geo risk are vegetation, weather, lightning, animal and other risks, like a car hitting a pole.

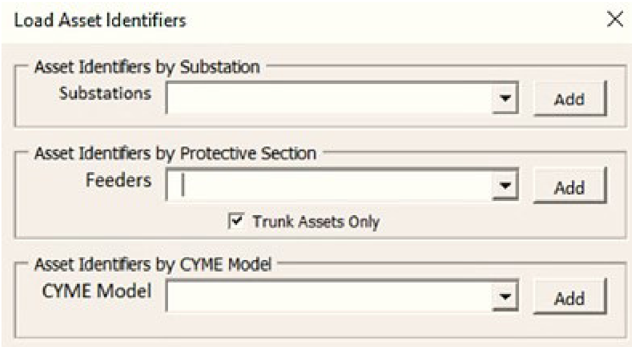
Each of these values is calculated at the individual asset level and rolled up to calculate total values across all the assets for each alternative considered for a project. **Section 5.3.1.1** discusses analyzing projects consisting of more than a single asset using the AMP team's IPT.

### 5.3.1.1 Integrated planning tool (IPT)

PGE utilizes an option analysis and cost benefit evaluation tool, IPT, to evaluate projects. The IPT evaluates projects consisting of many assets by combining the inputs and outputs of multiple asset models. PGE's AMP team uses the IPT to help analyze multiple project options, all measured against a current state or "base case."

When performing an analysis, PGE first creates a base case by pulling in all the assets related to the project in question. This can be done by substation, by feeder, by CYME Model (**Figure 33**), or one asset at a time.

Figure 33. IPT asset loading by substation, feeder, or CYME model




The tool loads the respective data for each asset from the individual models, such as asset age, failure likelihoods, load, consequence scenarios and replacement assumptions. At this step, these values can be adjusted from their modeled baseline values to account for any additional project-specific information.

Once assets and asset data are all loaded, the IPT calculates metrics for each asset, such as LCOO, NTR, near-term CI and CMI, BC ratio, geo risk, and years to replacement. The tool also performs a crucial function, aggregating these across all assets to provide project-level values for these metrics (**Figure 34** and **Table 25**).

Figure 34. Example of economic outputs from the IPT

| DEMOGRAPHICS | | ECONOMIC OUTPUTS | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| ASSET IDENTIFIER | ASSET CLASS | B/C RATIO | YTR | PROGRAM YTR | LIFECYCLE COST OF OWNERSH | NON-ASSET RISK, NPV | NEAR-TERM FAILURES | NEAR-TERM RISK | AGGREGATE RISK (5 |
| ASSET 1 | Substation Circuit Breaker | 0.17 | 34 | | $57,800 | $0 | 0.000 | $443 | |
| ASSET 2 | Substation Relay System | 0.14 | 45 | | $58,688 | $0 | 0.001 | $1,043 | |
| ASSET 3 | Substation Switch | 0.36 | 34 | | $10,089 | $0 | 0.001 | $122 | |
| ASSET 4 | Substation Circuit Breaker | 0.95 | 4 | | $104,419 | $1,261,461 | 0.006 | $3,874 | |
| ASSET 5 | Substation Switch | 0.44 | 28 | | $11,974 | $0 | 0.001 | $167 | |
| ASSET 6 | Substation Switch | 0.20 | 189 | | $2,043 | $0 | 0.000 | $80 | |
| ASSET 7 | Substation Switch | 0.00 | 189 | | $400 | $0 | 0.000 | $0 | |
| ASSET 8 | Substation Switch | 0.22 | 35 | | $5,347 | $0 | 0.000 | $32 | |
| ASSET 9 | Substation Switch | 0.00 | 189 | | $400 | $0 | 0.000 | $0 | |
| ASSET 10 | Substation Relay System | 0.06 | 145 | | $5,567 | $0 | 0.008 | $146 | |
| ASSET 11 | Substation Switch | 0.16 | 70 | | $4,576 | $0 | 0.001 | $41 | |
| ASSET 12 | Substation Relay System | 0.26 | 28 | | $41,831 | $0 | 0.001 | $791 | |
| ASSET 13 | Substation Circuit Breaker | 0.95 | 4 | | $104,006 | $1,508,553 | 0.006 | $3,833 | |
| ASSET 14 | Substation Relay System | 0.71 | 9 | | $58,147 | $0 | 0.003 | $955 | |
| ASSET 15 | Substation Circuit Breaker | 0.47 | 23 | | $78,436 | $0 | 0.002 | $1,283 | |
| ASSET 16 | Substation Circuit Breaker | 0.28 | 29 | | $64,547 | $0 | 0.001 | $743 | |
| ASSET 17 | Substation Relay System | 0.00 | 190 | | $11,281 | $0 | 0.001 | $491 | |
| ASSET 18 | Substation Switch | 0.22 | 35 | | $5,347 | $0 | 0.000 | $32 | |
| ASSET 19 | Substation Switch | 0.00 | 189 | | $400 | $0 | 0.000 | $0 | |
| ASSET 20 | Substation Relay System | 0.08 | 60 | | $69,629 | $0 | 0.001 | $2,309 | |
| ASSET 21 | Substation Transformer | 1.53 | 0 | | $837,369 | $0 | 0.029 | $53,364 | |
| ASSET 22 | Substation SCADA System | 0.29 | 18 | | $201,641 | $0 | 0.018 | $1,097 | |
| ASSET 23 | Substation Relay System | 0.14 | 45 | | $58,688 | $0 | 0.001 | $1,043 | |
| ASSET 24 | Substation Switch | 0.00 | 189 | | $400 | $0 | 0.000 | $0 | |
| ASSET 25 | Substation Switch | 0.20 | 36 | | $5,136 | $0 | 0.000 | $26 | |
| ASSET 26 | Substation Switch | 0.42 | 29 | | $11,598 | $0 | 0.001 | $159 | |
| ASSET 27 | Substation Switch | 0.30 | 42 | | $8,197 | $0 | 0.001 | $93 | |
| ASSET 28 | Substation Relay System | 0.24 | 30 | | $56,967 | $0 | 0.001 | $1,552 | |
| ASSET 29 | Substation Relay System | 0.71 | 9 | | $58,147 | $0 | 0.003 | $955 | |

**Table 25. Example economic outputs aggregated across assets in the IPT**

| Economic outputs | Option 1 |
|---|---|
| Lifecycle cost of ownership, assets ($) | $735,258 |
| Non-asset risk, NVP ($) | $10,224,462 |
| Total cost ($) | $11,885,030 |
| Benefit cost ratio (#) | 1.46 |
| Reduction in near-term total risk ($) | $554,948 |
| Reduction in customer interruptions (#) | 710.7 |
| Reduction in minutes interrupted (#) | 206,358 |

The same process is repeated for different proposed solution options for a project, with a key variation. When building out a proposed project solution option, all assets from the base case would typically be pulled into the tool, but now, certain input parameters can be adjusted. For example, PGE can mark equipment as "replaced" in the tool, which brings its age back to zero, resulting in adjusted risk calculations. Proposed project solutions may also reduce or eliminate geographic risk, and this can be accounted for as well.

The IPT allows for comparing multiple different solution options against a base case to see which option provides the greatest reduction in risk, or the greatest reduction in lifecycle cost of ownership. The tool does not compare completely different projects against one another. These types of comparisons are done at the transmission and distribution portfolio level and use several of the key outputs from the IPT.

### 5.3.2 PLANNING PROJECT PRIORITIZATION

The distribution planning projects shown in Table 25 are prioritized using the same Distribution Planning Ranking Matrix as the grid needs prioritization (**Figure 32**). This prioritized list is used to inform the portfolio planning stage. These projects were analyzed for solutions as part of the 2023 capital cycle, which began in 2021 and are based on equipment loading information from 2020. PGE will continue to work with communities and partners to identify improvements to our project prioritization process.

**Table 26. Planning project prioritization list**

| Priority | PGE Location | Grid need | Project | Ranking total |
|---|---|---|---|---|
| 1 | Evergreen substation | Industrial load growth in North Hillsboro | Evergreen | 149 |
| 2 | St. Louis substation | Commercial load growth in Woodburn area and 57 kV system constraints | St Louis | 102 |
| 3 | Silverton substation | Existing loading issues and industrial load growth in Silverton | Silverton | 96 |
| 4 | Redland substation | Aging infrastructure, heavily loaded transformer and feeders, lack of telemetry east of Oregon City | Redland | 84 |
| 5 | Kaster substation | Substation with high arc flash concerns, commercial load growth in St Helens | Kaster | 83 |
| 6 | Glisan substation | Industrial load growth in Gresham | Glisan | 81 |
| 7 | Waconda substation | Commercial load growth south of Woodburn and 57 kV system constraints | Waconda | 78 |
| 8 | Harrison substation | Capacity addition to implement other grid need mitigations, temporary equipment being used for support in inner SE Portland | Harrison | 73 |
| 9 | Linneman substation | Residential load growth in the Happy Valley and Gresham areas, temporary equipment being used for support | Linneman | 58 |
| 10 | Boring substation | Transformer failure resulting in capacity constraints, aging infrastructure in the Boring area | Boring | 55 |

| Priority | PGE Location | Grid need | Project | Ranking total |
|---|---|---|---|---|
| 11 | Glencullen substation | Capacity addition to implement other grid need mitigations in SW Portland, lack of SCADA telemetry, feeder reliability improvements | Glencullen | 54 |
| 12 | Scholls Ferry substation | Existing loading issues and residential development in the Murrayhill/Scholls areas resulting in capacity constraints | Scholls Ferry | 38 |

### 5.3.3 EMERGING PROGRAMS DRIVEN BY ASSET RISK

Risk driven asset investments are identified utilizing the economic life cycle models as described in **Section 4.4.1**. These models calculate the optimal time, based on cost and risk, to proactively replace an asset. Replacement is recommended when the risk of owning and operating the asset is greater than the annualized cost of replacing the asset.

The models have enabled PGE's AMP team to understand the various drivers, or combination of drivers, such as age, condition, poor make/model, reliability, safety, obsolete technology, among others, that accelerate assets to the end of their economic life. If the magnitude of the assets is due or coming due for replacement is greater than the forecasted rate of replacement from other existing projects or programs, then our AMP team undertakes steps to analyze the benefits of a proactive replacement program.

These proactive replacement programs are developed in collaboration with the subject matter experts to recommend a replacement cadence targeting the highest risk assets within a certain asset class or sub-class while also considering operational realities. To be part of the economic program, the asset needs to be identified as being economically due for replacement and will target assets that will not be addressed under other planned capital investments.

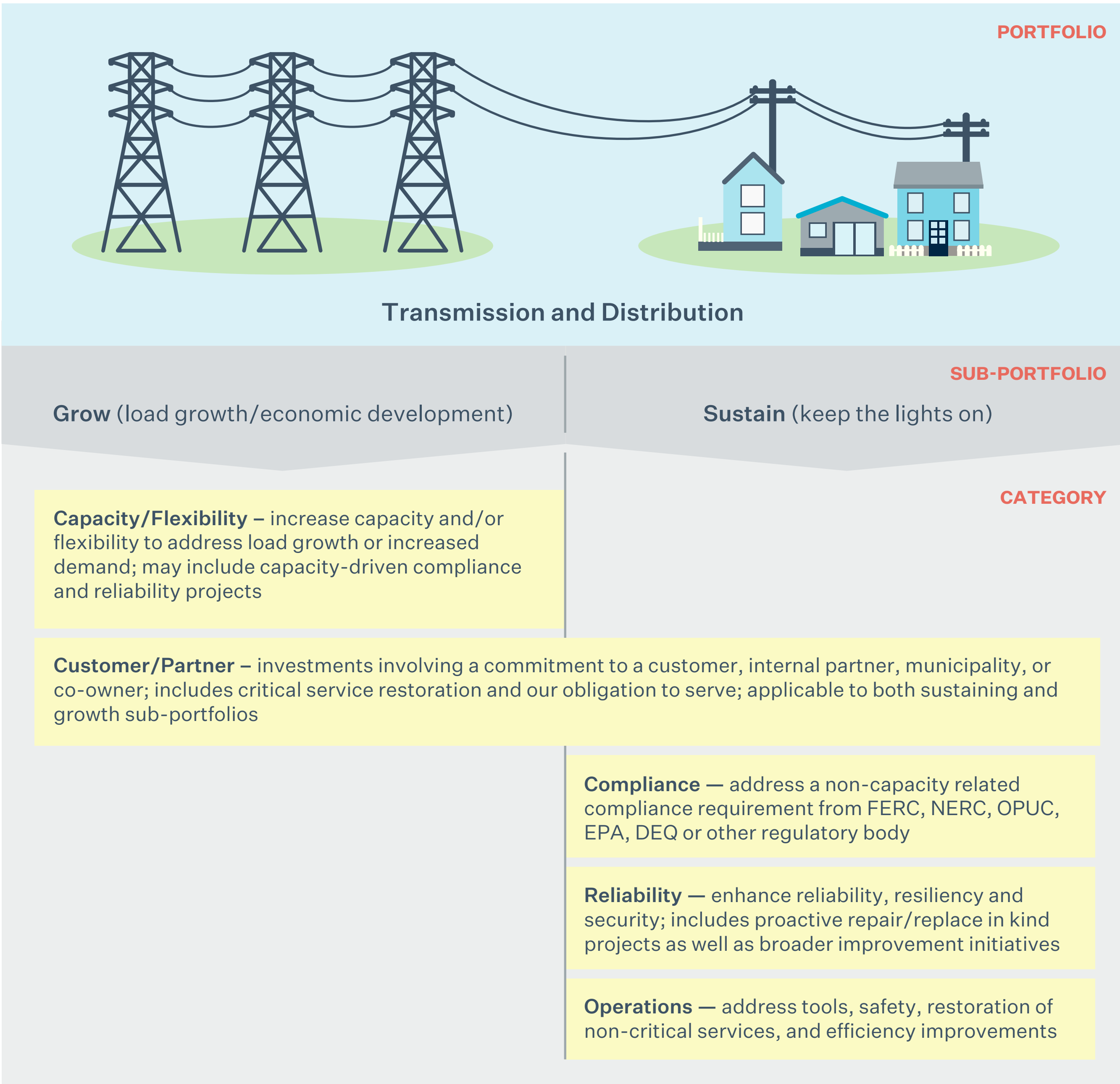
PGE is in the process of developing proactive replacement programs for each of the following asset classes. These emerging programs will propose projects for future planning cycles.

- **Substation transformers** — Developing a proactive replacement program to address the subset of the substation transformer fleet that are at a higher risk of failure due to age and condition.
- **SCADA** — Developing a proactive program to replace antiquated MV90 technology with current standard SCADA technology. MV90 collects and records meter data but does not support real-time data for operations. Upgrading to the current standard SCADA monitoring technology will enable real time operator visibility, support switching tasks, enable improved voltage monitoring and control, capacity, safety and further support integration of DERs into the grid.
- **Substation circuit breakers** — Developing a proactive replacement program to address the population of oil circuit breakers that are at high risk of failure due to age and condition coupled with environmental concerns. Replacing the assets with new gas breakers will address the above concerns, but also result in operational efficiencies.
- **Distribution switches** — Developing a proactive replacement program to address the population of live-front pad mount switches that present safety concerns and reliability risks due to their design. Replacing these assets with the dead-front switches, will address the above concerns, but also result in operational efficiencies.

## 5.3.4 PORTFOLIO PLANNING

PGE utilizes a portfolio planning process that is managed by our Generation, Transmission & Distribution (T&D) Portfolio team. This portfolio is split along two axes: Sustain the business and Grow the Business, and Discretionary and Non-discretionary. Along one axis, the portfolio is split between Sustain the Business (STB) and Grow the Business (GTB) (**Figure 35**). Projects in the GTB portfolio are non-discretionary due to their focus on serving new customer load growth. For that reason, those projects are not subject to the scoring and ranking process described below. The project ranking outlined here applies to the STB portfolio, which is concerned with

**Figure 35. Sustain the business (STB) and grow the business (GTB)**



discretionary projects that replace existing assets for the purposes of operational improvement and risk reduction.

Along the second axis, the STB portfolio is split into discretionary and non-discretionary buckets. Currently, decisions about non-discretionary projects in the STB portfolio are made outside of the process described here. The scope of the scoring and ranking framework described here will be expanded to include non-discretionary projects. Once the non-discretionary projects are funded, the discretionary projects must be scored and ranked to help prioritize them for funding.

Discretionary projects in the STB portfolio are scored across eight categories, with responsibility for the two categories of metrics distributed between the T&D Portfolio team and the AMP team.

The T&D Portfolio team provides input and scores for the following metrics which add up to 20% of the total score for a project.

- **Safety (4% weight)** — Projects that reduce incidents and risk exposure to both employees and the public while promoting a safe and healthy workplace.
- **Compliance (4% weight)** — Projects driven by compliance requirement from regulatory agencies such as Federal Energy Regulatory Compliance (FERC), North American Electric Reliability Corporation (NERC), Oregon Public Utility Commission (OPUC), Environmental Protection Agency (EPA), Oregon Department of Environmental Quality (DEQ).
- **Environmental (4% weight)** — Projects that exceeds today's environmental compliance standards or projects identified as an industry best practices that will reduce PGE's environmental impact.
- **Operational (4% weight)** — Projects that address new tools/materials, restoration of non-critical services and improves costs and performance efficiencies.
- **Customer (4% weight)** — Projects that increase capacity to address load growth, or increased demand.

The AMP team uses the asset modeling approach described above to calculate values for each of the following metrics which add up to 80% of the score for a project.

- **Reliability (27% weight)** — The reliability metric is equal to the expected reduction in near-term CMI due to the project.
- **Risk (27% weight)** — This metric is equal to the expected reduction in near-term asset and geographic risk resulting from the project.
- **Financial (27% weight)** — This metric comprises three sub-metrics, each of which are given an equal weight. These are:
  - **BC Ratio (9% weight)** — This is the BC Ratio associated with the project, as described above.
  - **NTR/Capex (9% weight)** — This metric shows the expected reduction in near-term asset and geographic risk for every dollar of capital spend due to project.
  - **Near-term CMI/Capex (9% weight)** — This gives expected reduction in near-term CMI per dollar of capital spend due to the project.

Once analysis is complete for a project and each of these metrics have been calculated, they are transformed from their actual values to a score of 1, 2, 3 or 4. This is done by collecting metric scores on all projects which have been analyzed and determining statistical quartile ranges for each. This allows for a value of one through four to be assigned to each metric accordingly as it falls into the 1st, 2nd, 3rd, or 4th quartile range of values for that metric across all projects.

These scored values of one through four are used with the weighting for each metric to calculate a weighted average value which is the final score of the project. A visual example of this calculation is shown in **Figure 36**.

**Figure 36. Sample calculation of a project score**

| | Score | Weighting | SAM score (avg) | |
|---|---|---|---|---|
| **Reliability** | 4 | 27% | 1.08 | |
| **Risk** | 4 | 27% | 1.08 | **3.2** |
| **Financial** | 4 | 27% | 1.08 | |
| | | | Portfolio score (avg) | |
| **Safety** | 0 | 4% | 0 | |
| **Compliance** | 0 | 4% | 0 | |
| **Environmental** | 0 | 4% | 0 | **0.2** |
| **Operational** | 1 | 4% | .04 | |
| **Customer** | 1 | 4% | .16 | |
| Final prioritization score; Optimizes on value | | | Total value **3.4** | |

Priority score

**4** – Extreme
**3** – Strong
**2** – Moderate
**1** – Low
**0** – None

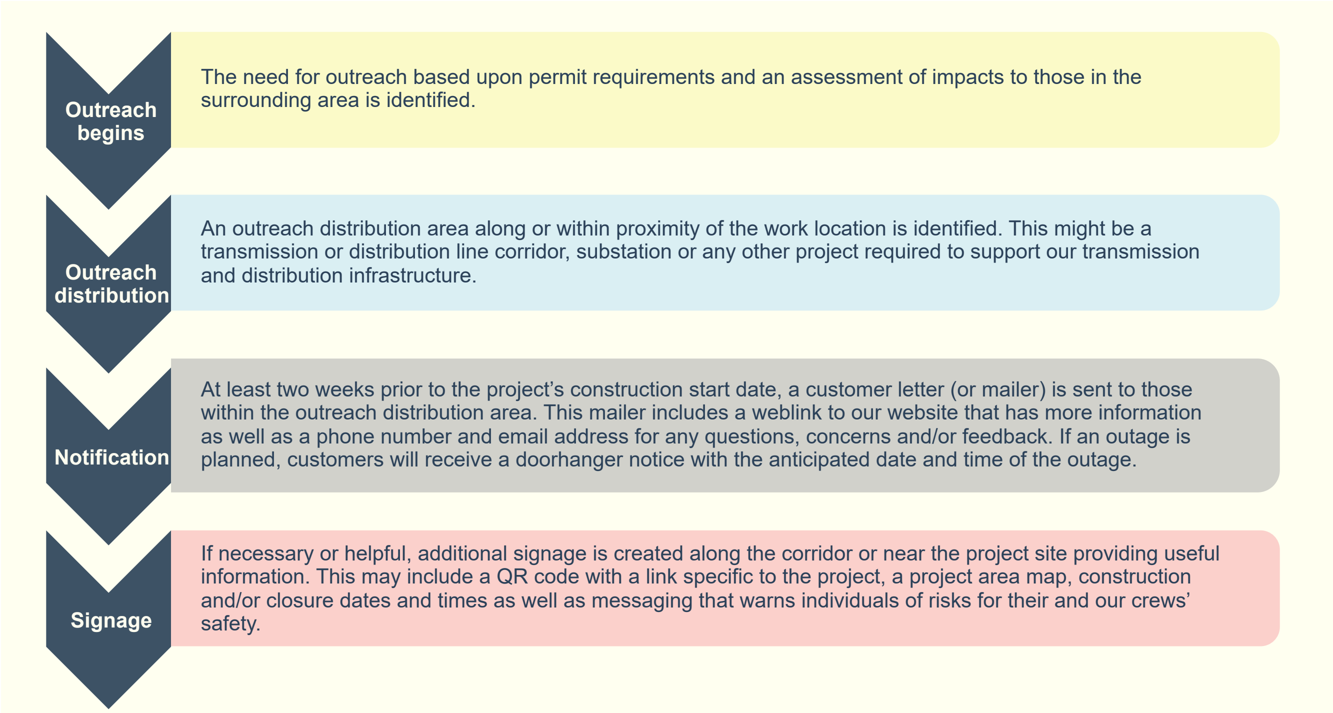
Following this process for each discretionary project in the STB portfolio allows for ranking based on the final value assigned to each project. PGE's AMP team uses this process to recommend a suite of prioritized projects that help achieve risk reduction and reliability goals for the STB portfolio to the T&D Portfolio team.

# 5.4 Process for community engagement on large projects

The ongoing transformation in the energy sector will drive the need for large investments in the public, private and utility sectors for years to come. These investments often fuel the economic growth that will pay for them over time. But a large project has consequences that go well beyond a specific substation, wind farm, or electric vehicle charging hub. PGE's DSP partners have emphasized the need to take a hard look at who benefits and who pays in the delivery of infrastructure projects. Getting this analysis right is good for everyone.

PGE's current process for community engagement on large projects is driven largely by the permitting and public notification requirements of the jurisdiction involved. As a result, our communication timelines and deliverables are as diverse and as complicated as our projects. Some projects require simple outreach that may be provided within one week of a project manager's request. Others require over a year of planning, coordination and execution with deliverables conceived and developed specific to the needs of that project. With that said, we do have a current standard project outreach process, which illustrated in **Figure 37**.

**Figure 37. Current standard project outreach process**




To supplement these communication activities, PGE creates and maintains a website for each large project. An example of a website is included in **Figure 38** and additional project websites can be accessed through the Neighborhood Projects page.[49]

49. Neighborhood projects page, available at: https://portlandgeneral.com/about/who-we-are/innovative-energy/neighborhood-projects

**Figure 38. Neighborhood projects web page**

## Neighborhood Projects

**Learn how we're building a brighter energy future for you**

Home > About > ··· > Neighborhood improvem...

### Keeping your energy safe, reliable and affordable

Wondering what the construction in your neighborhood is all about? As we work toward Oregon's clean energy future, we're strengthening the energy grid to make it smarter, more efficient and more reliable for you. This includes replacing aging equipment to increase resiliency, reduce outages, keep energy affordable for you and your neighbors, accommodate growth in our area and allow for better integration of renewable resources.

Learn more about Smart Grid benefits.

### System Upgrades

Our energy grid is the backbone structure that brings you safe, affordable energy. We regularly inspect and replace older power lines and equipment with new "smart grid" technology that allows for two-way energy communication. This helps us provide reliable power to you and your neighbors, but it also does so much more!

Got a rooftop solar panel? Now we can connect it to our grid and share energy. Another example is smart meters that let us start or stop service remotely.

### Underground Projects

Many of the power lines and equipment in the energy grid are underground. That means there's a lot going on that you can't see! We inspect, and when needed, replace those lines to keep the grid strong and resilient.

By making sure these underground lines are working their best, we can keep up with the growth of all the new homes and businesses in your neighborhood.

### Preventative Maintenance

Look up! You might see our crews in your neighborhood removing branches that could otherwise fall on power lines. Keeping you safe and with power is all in a day's work.

By trimming trees and removing other vegetation, we can prevent outages and help improve safety for our workers and you.

PGE intends to continue the current standard project outreach process and supplement it in two ways:

- Expand the number of projects for which we create informational websites, and
- Earlier engagement of affected communities.

With respect to earlier engagement, PGE plans to use our current DSP workshops to present grid needs and proposed solutions. We will work with the partners and the OPUC to identify the projects that are not included in the current process and/or require a level of engagement in excess of the process outlined above.

For those projects that are identified, we plan to use the outreach and engagement approach outlined in **Chapter 2** of this document as well as our Community Engagement Plan described in our DSP Part 1.[50]

50. DSP Part 1 Community Engagement Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/e5oN7SaTG7jQRTGcPzt/576380f14d90a976469968517b187f95/DSP_2021_Report_Chapter3.pdf#page=13

## 5.5 Evolution

Starting with PGE's 2024 capital planning cycle (which began in spring 2022), solutions for grid needs will consider both traditional wired solutions and non-wires solutions. The criteria for when grid needs will be considered for non-wires solutions is described in **Appendix E**. In addition, we will engage with the community when developing possible solutions to grid needs.

PGE plans to conduct load sensitivity analysis when evaluating grid needs. Currently, studies are conducted using load values we would expect to see once every three years. The summer of 2021 set a new load record for our system and far exceeded the expected loading on the system. Moving forward, after a solution is identified (wired or non-wires), loads will be scaled to the load values we would expect to see once every ten years, or the summer 2021 values, whichever is higher (accounting for new load additions and system changes). Any additional upgrades required because of these higher loads will be considered a sensitivity option that will be evaluated by our AMP team using their IPT tool to determine the benefit/cost ratio.

PGE also will begin to integrate resiliency metrics into the capital decision framework. The framework likely will have a new resiliency improvement category by which projects are evaluated in addition to existing risk reduction, reliability improvement and financial benefit categories.

## Chapter 6

# Non-wires solutions

# Chapter 6. Non-wires solutions

"I was taught that the way of progress was neither swift nor easy."

– **Marie Curie**, Nobel prize winning physicist and chemist

## 6.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[51] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter provides an overview of PGE's evaluation of non-wires solutions (NWS) pilot concepts. We describe the process and journey of each of the evaluated pilot concepts, describing the grid need, customers impacted, and the expected wires and non-wires solutions. We also discuss impacts to existing processes, systems and regulations, and lessons learned.

**WHAT WE WILL COVER IN THIS CHAPTER**

An overview of non-wires solutions (NWS)

PGE's proposed process to screen, model, and evaluate NWS

A case study approach to describing each of the evaluated pilot concepts

Expected evolution of NWS in the distribution planning process

**Table 27** illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485.[52]

Table 27. Distribution system overview: Guideline mapping

| DSP guidelines | Chapter section |
|---|---|
| 5.3.d | **Section 6.2, 6.3, 6.4** |
| 5.3.d.i | **Section 2.4**, **6.3.1** |
| 5.3.d.ii | **Section 2.4**, **6.4.1.4** |
| 5.3.d.iii | **Section 2.4** |
| 5.3.d.iv | **Section 2.6** |
| 5.3.d.v | **Section 2.6**, **3.5.5.3, 6.4.1.4, 6.4.2.4** |
| 5.3.d.vi | **Section 6.4.1.8**, **6.4.2.8** |

51. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.
52. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

# 6.2 Introduction

The landscape of utility planning is changing. This shift is created through state policy and regulation addressing climate change, the acceleration of customer adoption of distributed energy resources (DERs), customer preferences, and the declining costs of DERs; especially rooftop photovoltaic solar units, electric vehicles and energy storage.[53] As availability of and interest in DERs increase, this influences PGE's planning processes. Our planners now need to consider more granular data and additional analysis to account for bi-directional flows (such as energy produced by customer solar panels), variable and new demand profiles (such as electric vehicle charging), and growing amounts of digital technologies, including controls (devices that enable us to communicate with a customer's thermostat or water heater).

In addition to modifying the planning approach, DERs also present themselves as a possible solution to grid constraints. Using DERs to address grid constraints is commonly called non-wires solutions (NWS). The Oregon policy landscape takes this concept one step further, focusing on how NWS can potentially address distribution system constraints reliably, resiliently, and affordably while also supporting environmental and energy justice goals, particularly for historically underrepresented communities.

PGE is focused on developing a distribution system planning approach that considers all solutions from a societal perspective when making investment decisions. We also are working to balance current policies, customer desires, and a growing number of other investment priorities as we consider alternative solutions, including customer-sited DERs.

## 6.2.1 DISTRIBUTION SYSTEM PLANNING IN TRANSITION

PGE's distribution planning process is in transition. As noted in the OPUC's Order 20-485, this is a multistage transition which will likely go through intermediate phases before the desired future state can be fully integrated into our business planning cycles. This chapter focuses on one significant element of that transition — NWS, and the steps we are taking to accelerate the transition toward the end state.

In this DSP, PGE evaluated five NWS candidates, with the goal to identify two viable NWS candidates. To do this, we did the following:

- Utilized site level adoption forecasts of several DER technologies
- Evaluated hourly impacts
- Identified and calculated system benefits from both locational and bulk power system perspective of DERs included in a NWS portfolio
- Gathered community input regarding NWS goals and equity considerations though our DSP Partnership Workshops and Community-led Workshops
- Identified key barriers and highlight future discussion areas

However, PGE is still working on key processes that will help us develop NWS that are designed to meet the goals identified in the DSP. The key processes include:

- **Forecasting** — PGE's planning process is a multi-year effort where projects submitted to our 2023 Capital Plan are based on the forecast from 2020 and updated with forecast from 2021, where feasible.
- **Modeling practices** — Large sections of the distribution system have seen relatively flat load growth for several years. To improve operational efficiency during this time, PGE instituted practices to minimize modeling time by only modeling years with significant changes over the planning horizon. However, to accommodate the expected growth in transportation and building electrification, PGE has started transitioning away from this practice.
- **Modeling tools** — PGE is undertaking a multi-year effort to obtain the next generation of planning tools. These tools will enhance our ability to analyze and model NWS among other capabilities.

53. Per OPUC Docket UM 2005, Order 20-485 "distributed energy resource" includes distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid.

### 6.2.2 DEFINITION OF NON-WIRES SOLUTIONS

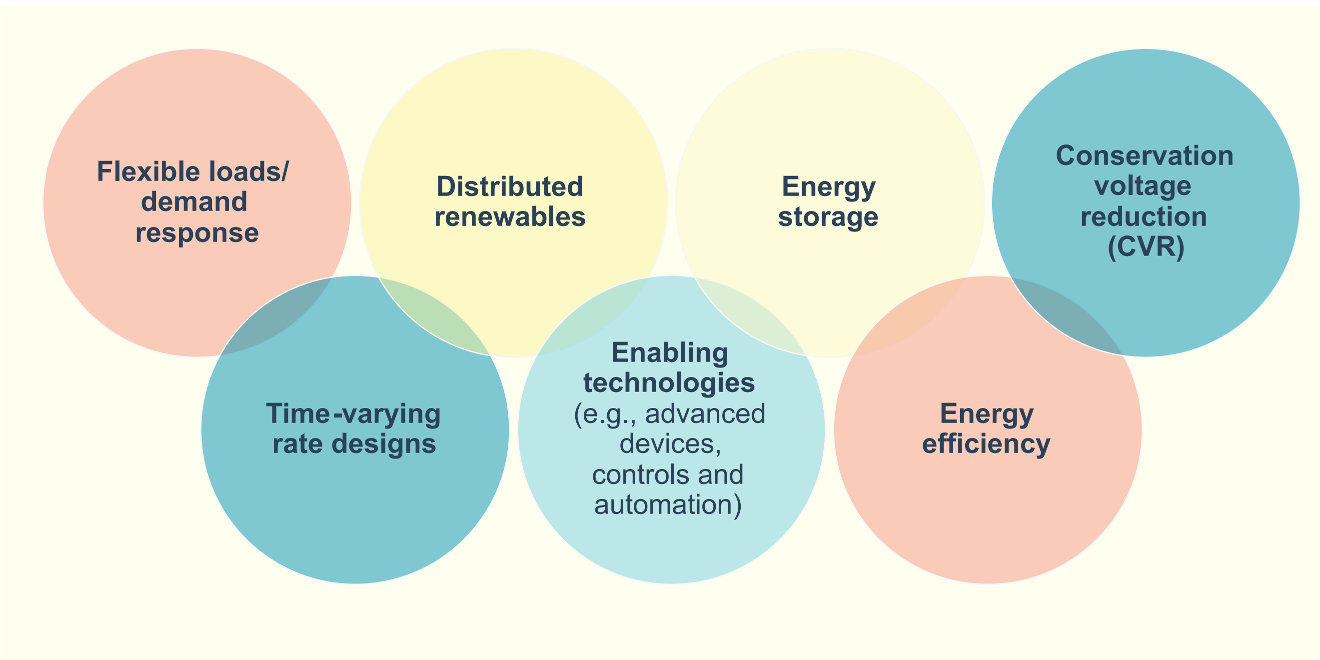
PGE defines a NWS as an investment, strategy, or action intended to defer, reduce or remove the need for a traditional utility solution (such as upgrading a substation or building a new line) in a specific geographical region to an identified distribution system need, such as managing load, generation, reliability, voltage regulation, and/or other wide-ranging distribution system needs. Most NWS are likely to include a combination of several different solution types and can range from pricing mechanisms such as time-of-use tariffs to technological solutions such as DERs or advanced controls. These solutions can be located either on the customer-side of the meter or the utility-side.

### 6.2.3 APPLICABLE TECHNOLOGIES CONSIDERED WITHIN NWS

NWS can include any action (such as energy conservation or behavioral actions), or technology (such as solar and battery storage) that meets the above definition. NWS action examples are included in **Figure 39**.

NWS projects can include these and other investments, individually or in combination, to meet the specified grid need in a cost-effective manner. In addition to the technical and cost considerations, it is also important to consider applicable state policy goals, ensure regulatory compliance, maintain safety standards, and identify any potential impacts on customer experience.

Figure 39. Example NWS actions



## 6.3 Process flow

PGE intends to complement existing solutions used to address specific types of grid needs with NWS. This requires traditional planning and regulatory processes to evolve and include NWS specific considerations (**Section 7.5**). This section details how we will evolve our planning processes to enable the evaluation of NWS. In the subsections that follow (**Figure 40**), we describe the process changes and new steps needed to integrate NWS as part of our annual planning cycle.

Figure 40. Distribution planning process — augmented with consideration of NWS

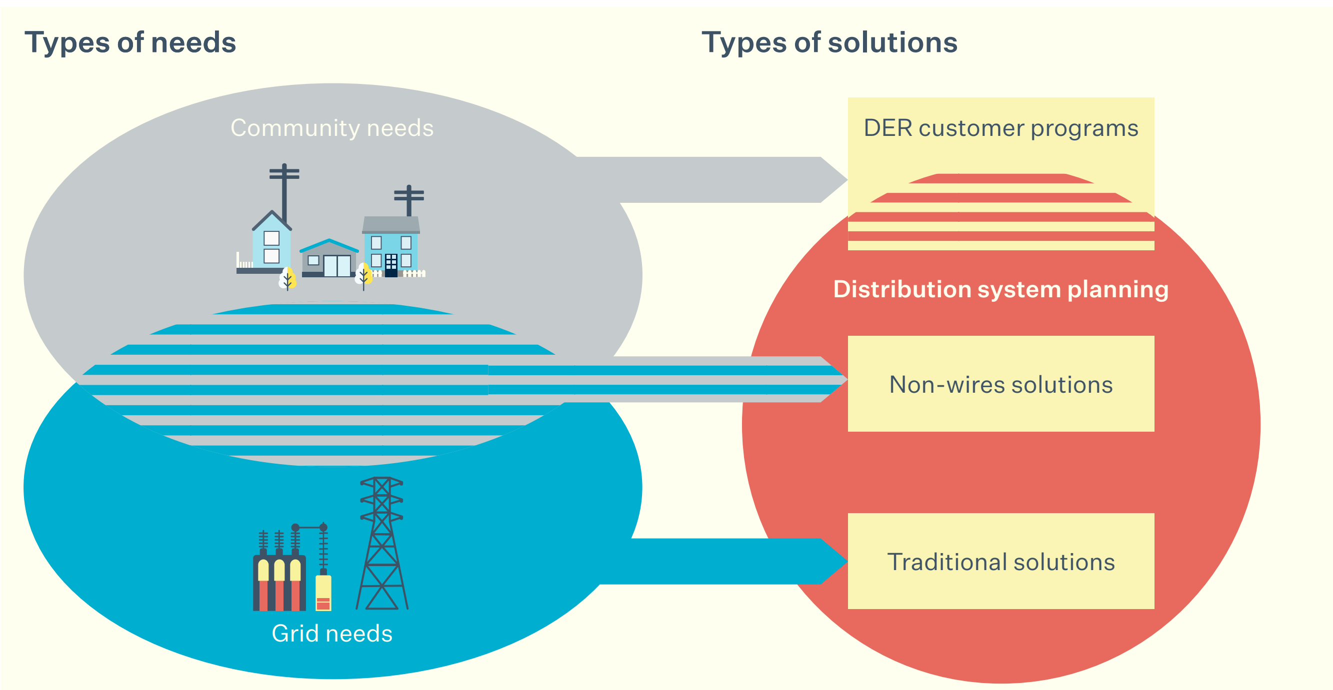
The NWS process depicted in **Figure 40** is described in further detail in **Appendix E**.

## 6.3.1 GRID NEEDS AND SOLUTIONS REVIEW

During the NWS evaluation process and based on Community input, there are two key periods where communities should be engaged within the DSP Process: Grid Needs Analysis and Solution Identification. PGE has facilitated a series of Community-led Workshops to develop capacity and share learnings with our community-based organization (CBO) partners on the technical components of our NWS process flow (see **Section 2.4**). Moving forward, we aim to use the existing monthly partner meetings as a venue to discuss our grid needs analysis and solution identification processes, while also providing additional avenues for engagement on specific projects.

As part of the review of grid needs, PGE will also review and discuss community needs. Community needs can be addressed through two channels depending on the type of need and the overlap with grid needs. Overlapping grid needs and community needs provide a unique opportunity to address multiple objectives with a single solution set. NWS, if applicable, are likely to comprehensively address these objectives. **Figure 41** shows the relationship between these needs and the types of solutions we can offer. **Section E.3.1** further describes our approach to combine community needs with NWS planning going forward.

**Figure 41. Evolution and relationship between needs and solutions**



# 6.4 Non-wires solution concept proposals

In PGE's initial approach to develop a minimum of two we followed the process flow outlined in **Figure 40** to the extent practicable, while accounting for overlap demographic and equity data, current staffing availability, DSP time constraints, and size of the grid need, where possible. For more information on our NWS screening process please see **Appendix E**. This process yielded five potential NWS candidates shown in **Table 28**.

**Table 28. NWS candidates identified and evaluated by PGE**

| PGE Substation | Target assets |
|---|---|
| Eastport | Eastport-Plaza and Eastport substation transformer (WR1) |
| Dayton | Dayton-East feeder and Dayton substation transformer (BR1) |
| Ruby | Ruby-Junction and Ruby-Carline feeders |
| Clackamas | Clackamas-Tolbert feeder |
| West Union | West Union-West Union 13, Oak Hills-Somerset, and West Union-Cornelius Pass feeders |

From these five projects, PGE then took our first step toward evaluating customer demographics at each location, as well as worked closely with our distribution engineers to better understand the grid needs and scope of a traditional solution for each project. Based on this exercise, we saw two potential candidates rise to the top as preferable sites to develop the full NWS concept proposal: Eastport and Dayton.

In the sections below, PGE has provided a detailed description of these two candidates, including results of the NWS solution development process.

### 6.4.1 EASTPORT CANDIDATE

PGE evaluated three options for the Eastport candidate: a traditional wired solution, and two non-wires solutions that feature different combinations of DERs to meet different resiliency and customer benefit objectives. This section presents the overview of the Eastport area concept proposal.

### 6.4.1.1 Summary of NWS portfolio for Eastport

PGE categorized information about the grid needs, traditional solutions, and non-wires solutions pertaining to the Eastport candidate. **Table 29** provides a high-level summary of project details for the Eastport candidate.

**Table 29. Summary of NWS candidate: Eastport-Plaza and Eastport-WR1**

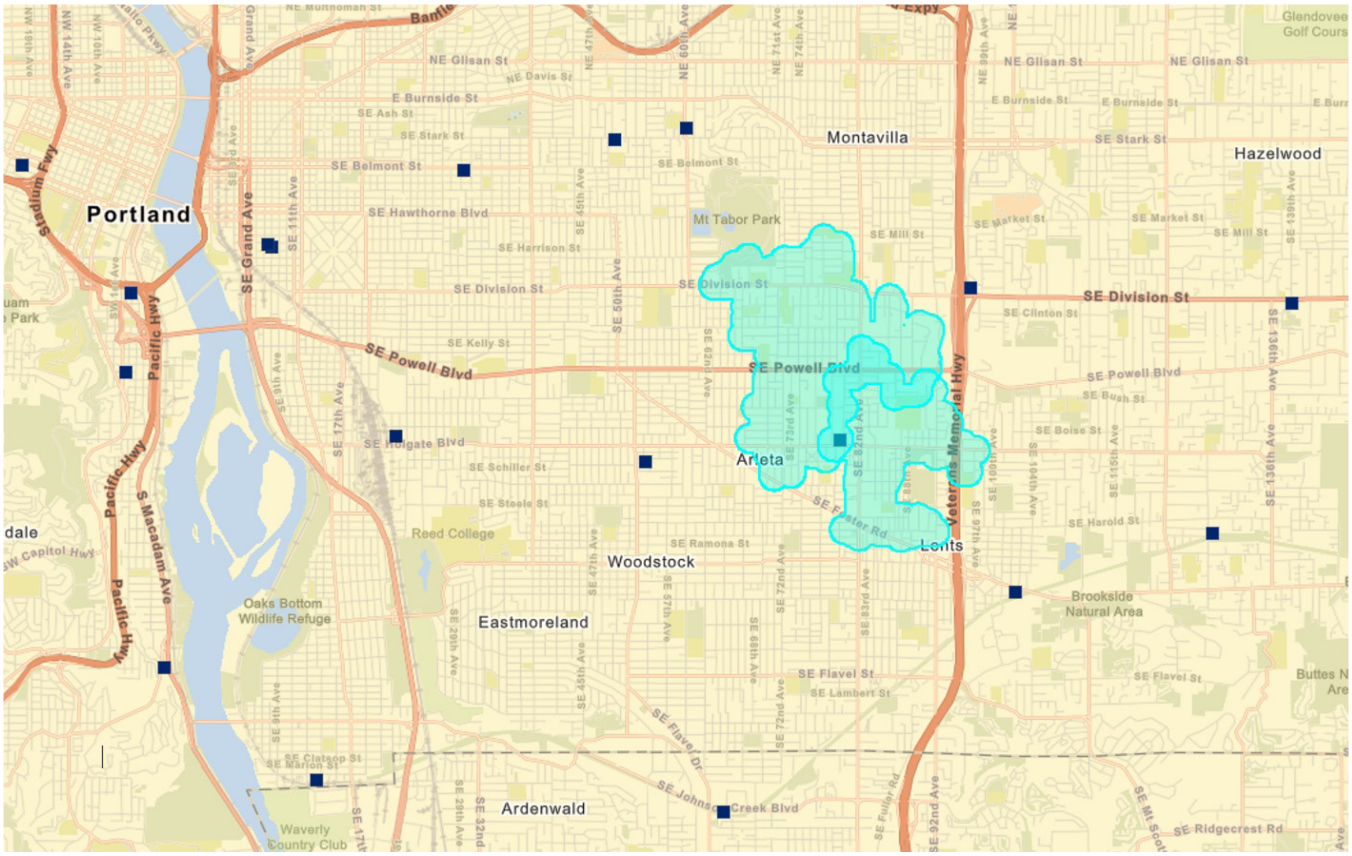
| **NWS candidate: Eastport-Plaza and Eastport WR1** | |
|---|---|
| **Scope of grid need** | Planning criteria violation on Eastport-Plaza and Eastport WR1 |
| | Violation seen on summer weekdays from 1pm-7pm |
| | Relief can be provided anywhere along the feeder and partially at the substation |
| **Traditional solution** | Substation transformer upgrade and feeder section reconductoring |
| **NWS** | Energy efficiency<br>• 5,500,000 kWh/yr annual savings by 2032 |
| | Demand response<br>• 2,166 kW of summer peak demand potential by 2032 |
| | Solar and storage<br>• 2,940 nameplate kW-dc of residential rooftop solar PV<br>• 743 nameplate kW-dc of non-residential rooftop solar PV<br>• 1,000 nameplate kW-dc of Community Solar installations |
| **Decision making metrics** | Relief can be provided anywhere along the feeder and partially at the substation |
| **Community engagement** | Performed outreach to CBOs through four Community Workshops (see **Section 2.4**) |
| | Conducted outreach to schools and government partners in the affected area to align plans with existing efforts and potential projects |
| | Going forward, will conduct detailed community needs assessment for the Eastport area by working directly with CBOs with connections and existing relationships in the area (see the community needs assessment section of **Appendix E**) |

### 6.4.1.2 Location and customer types

The Eastport substation is located within Southeast Portland and has two feeders, Eastport-76th and Eastport-Plaza, both of which are both fed from the Eastport WR1 transformer. The grid need originated at the Eastport-Plaza feeder and the transformer that feeds it, Eastport WR1. The affected equipment serves approximately 5,000 customers, of which three are critical customers and 40 are managed accounts.

Additionally, eight residential customers on the feeders have registered medical equipment. **Figure 42** highlights the customers served within the blue outline under normal conditions.[54]

Figure 42. Area served by the Eastport-Plaza Feeder




54. To see the area served by any feeder you can access PGE's Distribution Generation Evaluation map, available at: https://www.arcgis.com/apps/webappviewer/index.html?id=959db1ae628845d09b348fbf340eff03

### 6.4.1.3 Summary of grid need

The needs analyses on the Eastport substation are summarized as follows:

- The hourly load profile and the expected annual peak load growth on the Eastport-Plaza feeder and the Eastport WR1 transformer are shown in **Figure 43**.
- **Table 30** details the applicable areas for load relief to provide relief to the grid need.
- The minimum annual relief required to meet the grid need is shown in **Figure 44**.

Figure 43. Load profile and Load growth at Eastport-Plaza and Eastport WR1

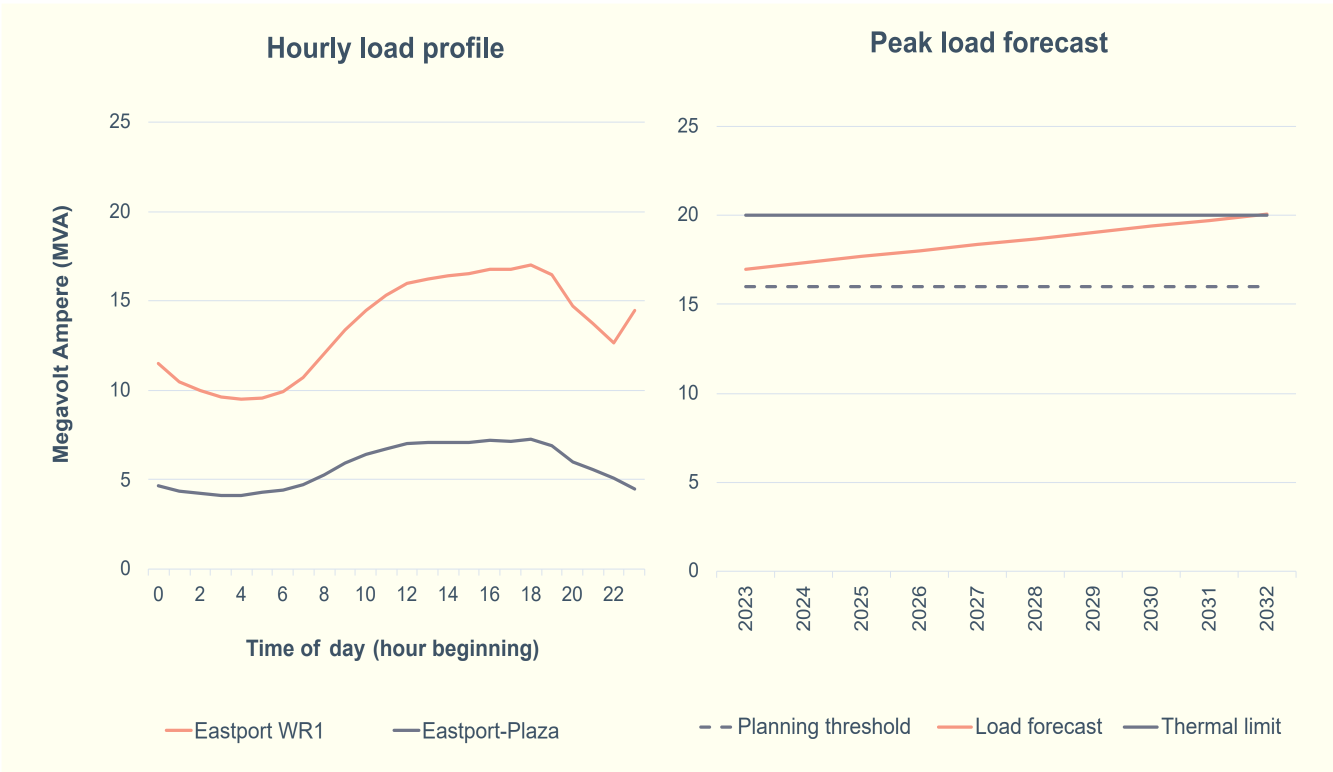
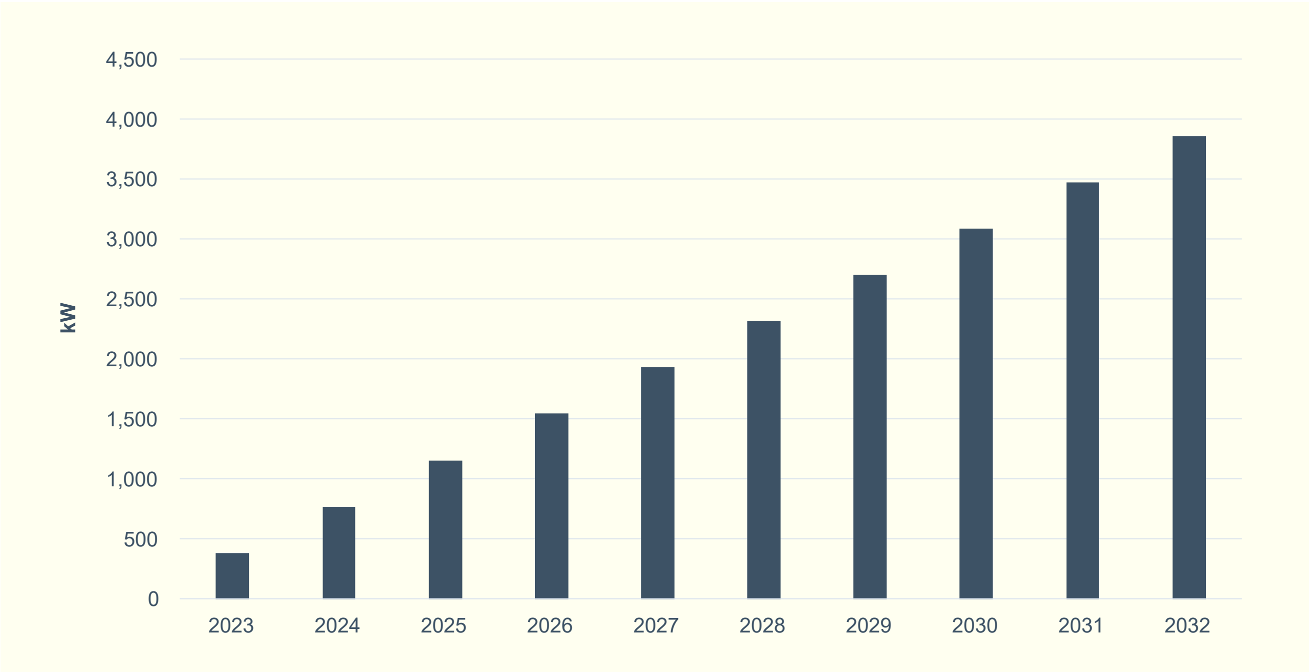



Table 30. Summary of grid need for Eastport-Plaza and Eastport WR1

| Parameter | Value under normal condition (N-0 condition) |
|---|---|
| **Violation type** | Planning criteria violation (thermal) for both the Eastport-Plaza feeder and Eastport WR1 transformer |
| **Applicable areas for load relief** | Entire scope of Eastport-Plaza and Eastport-76th feeders |
| **Violation time and duration** | 1-7 PM, Summer weekdays, non-holidays |

**Figure 44. Minimum annual relief required for N-0 scenario**




### 6.4.1.4 Customers and equity data

As PGE transitions to human centered planning, a key step is to understand the customers that are impacted by the grid need and consider how the customer mix can inform potential opportunities. Some key insights we learned about the customers affected by the grid need include:

- Residential customers make up 86% of all customers impacted with a split of 45% living in multifamily and 55% living in single family units. Small commercial customers represent 11% of the building stock and 2.4% is classified as large commercial.
- On an annual basis, residential customers account for 40% of total energy consumption. Small commercial accounts for 16%, large commercial accounts for 44%.
- There is a mix of building age, with just under 25% of today's building stock built in or before 1964, 10% built in 1980, and approximately 21% of the building stock built after 2000.
- Residential customers received approximately $69,000 in energy assistance payments; with renters receiving 86% of the assistance.
- Equity and demographic data of the customers on this feeder can be found on PGE's distributed generation evaluation map available on our DSP website.[55]

In addition to reviewing these datasets, PGE took additional steps to understand the customer landscape so that our solutions consider all relevant angles. We met with CBO leaders and local government representatives, engaged our Key Customer Management team and socialized concepts with select customers in the identified target areas, and leveraged our internal resources and knowledge base to better understand potential local needs and preferences. This engagement helped refine our data; including filling in data gaps such as current cooling penetration, providing insights into solution preferences such as clean energy needs and desires, and energy burden.

55. See PGE's DSP website, available at: Distribution System Planning | PGE (portlandgeneral.com)

### 6.4.1.5 Solutions

#### 6.4.1.5.1 Wired solution

PGE first evaluated and eliminated opportunities to address grid needs by permanently transferring load from the overloaded feeder/transformer to adjacent feeders/transformers. Subsequently, we developed a more detailed wired solution that included the following elements:

- The violation on the Eastport WR1 transformer can be eliminated by upgrading the substation transformer to accommodate current and future growth while improving system flexibility and resiliency.
- The violation on the Eastport-Plaza feeder can be addressed by reconductoring a 500-foot section of feeder on Southeast Holgate Boulevard.

#### 6.4.1.5.2 Non-wires solution

##### 6.4.1.5.2.1. Eastport substation locational value

To determine the locational value of the NWS, PGE employs the Present Worth Method as described in the Locational Value of Distributed Energy Resources report developed by the Lawrence Berkeley National Lab.[56] Key inputs to the locational value include the cost of the recommended wired solution, expected in-service date of the wired solution, and the deferral time.[57]

For the Eastport WR1 and Eastport-Plaza grid need, deferring the wired investment by 10 years (assuming the ramped annual relief shown **Figure 44**) yields an annualized locational value of $283.39/kW-year. This translates to an approximate twelve-fold increase in the distribution system avoided cost as compared to our current system-wide value used for energy efficiency cost-effectiveness ($24.39/kW-yr).[58]

##### 6.4.1.5.2.2. Eastport resource potential and application

PGE evaluated locational DER potential for each of the two NWS options (Option 1 – Reliability Portfolio and Option 2 – Customer Resiliency portfolio). Option 1 is a front-of-the-meter approach that relies on utility-scale battery storage with some customer adoption, while under Option 2 (Customer Resiliency) the need for a utility-scale battery is offset by more aggressive customer adoption.

We first present the annual DER adoption potential to reflect the growth in adoption over time commensurate with the identified relief needed in **Figure 44** and then discuss the hourly shape of the resources identified.[59]

56. The locational value of DERs work from LBNL, available at: https://emp.lbl.gov/publications/locational-value-distributed-energy
57. The deferral time can be determined by a combination of factors such as the asset's 'Time to Intervention' which represents the expected time until PGE must take to replace the asset, the planning horizon, and when the relief from DERs cannot overcome the peak load growth.
58. For an overview of the most recently approved T&D avoided costs used in energy efficiency resource planning, see Order No. 21-476 under Docket No. UM1893, available at: https://apps.puc.state.or.us/orders/2021ords/21-476.pdf
59. We only present the more aggressive Customer Resiliency DER buildup because the process undertook is essentially the same for each option within our NWS evaluation. The results of both are included in the summary presented in **Table 28**.

**Figure 45** shows the annual energy efficiency potential identified for Eastport substation.

**Figure 45. Energy efficiency resource potential for Eastport substation**

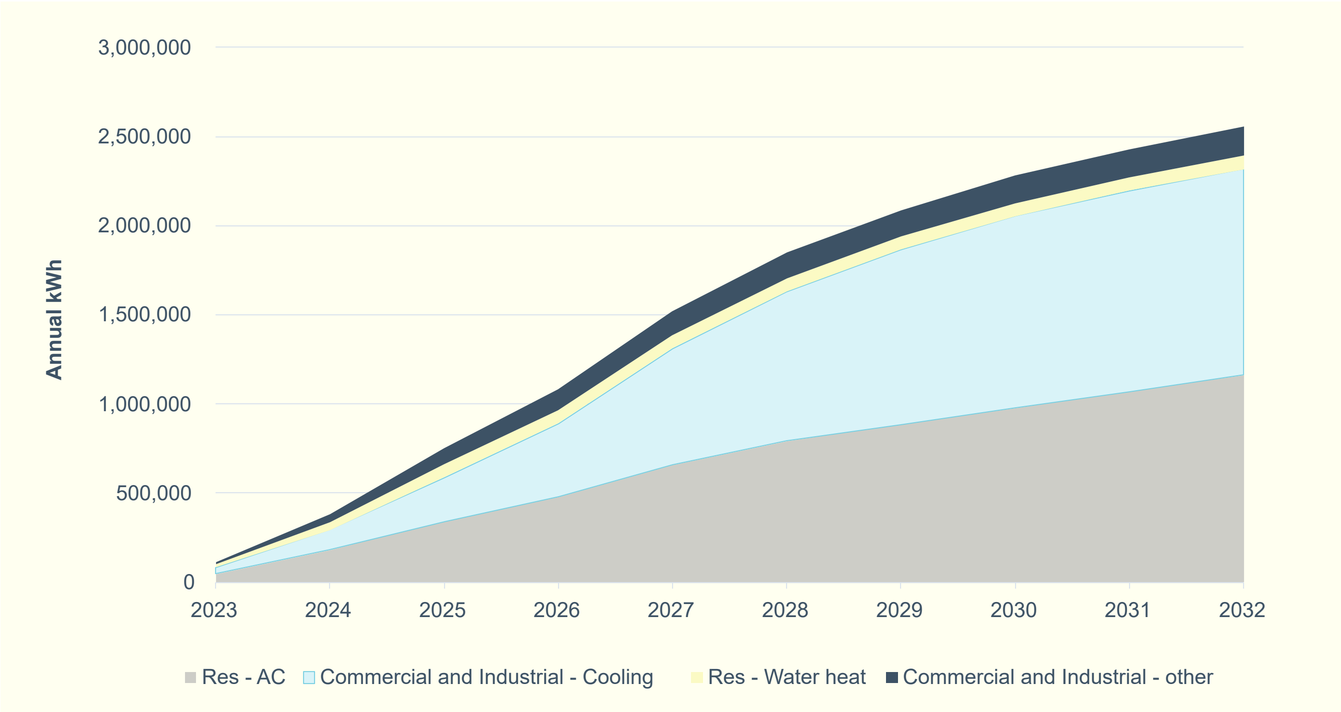
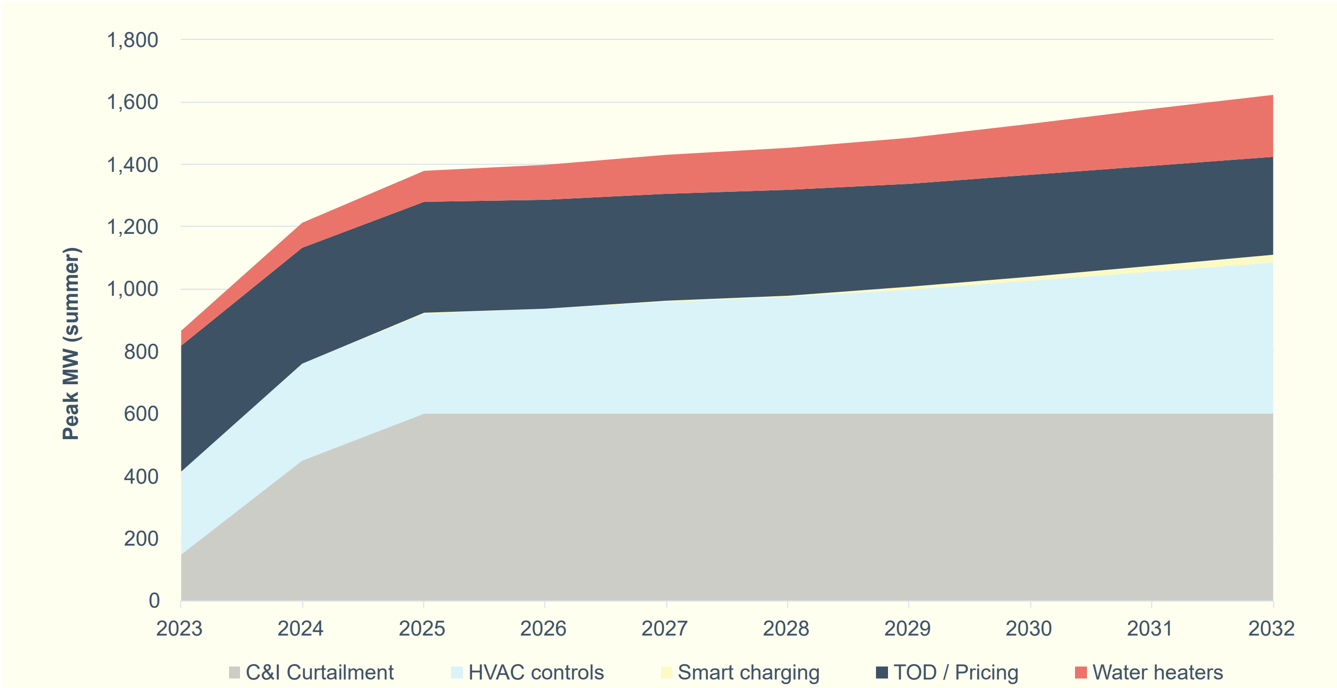


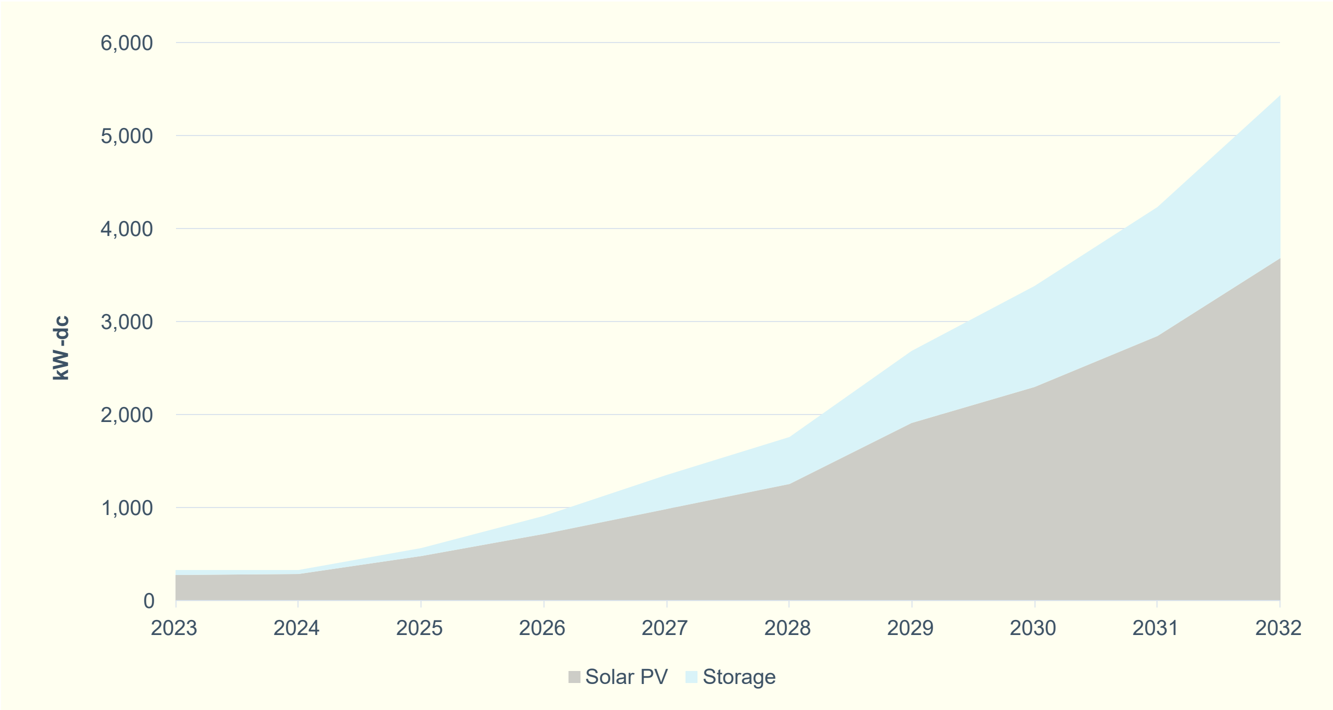

**Figure 46** shows the annual flexible load and demand response potential for Eastport substation.

**Figure 46. Flexible load and demand response potential for Eastport substation**



Finally, PGE estimated significant distributed solar photovoltaic (PV) and storage potential at the Eastport substation, as shown in **Figure 47**.

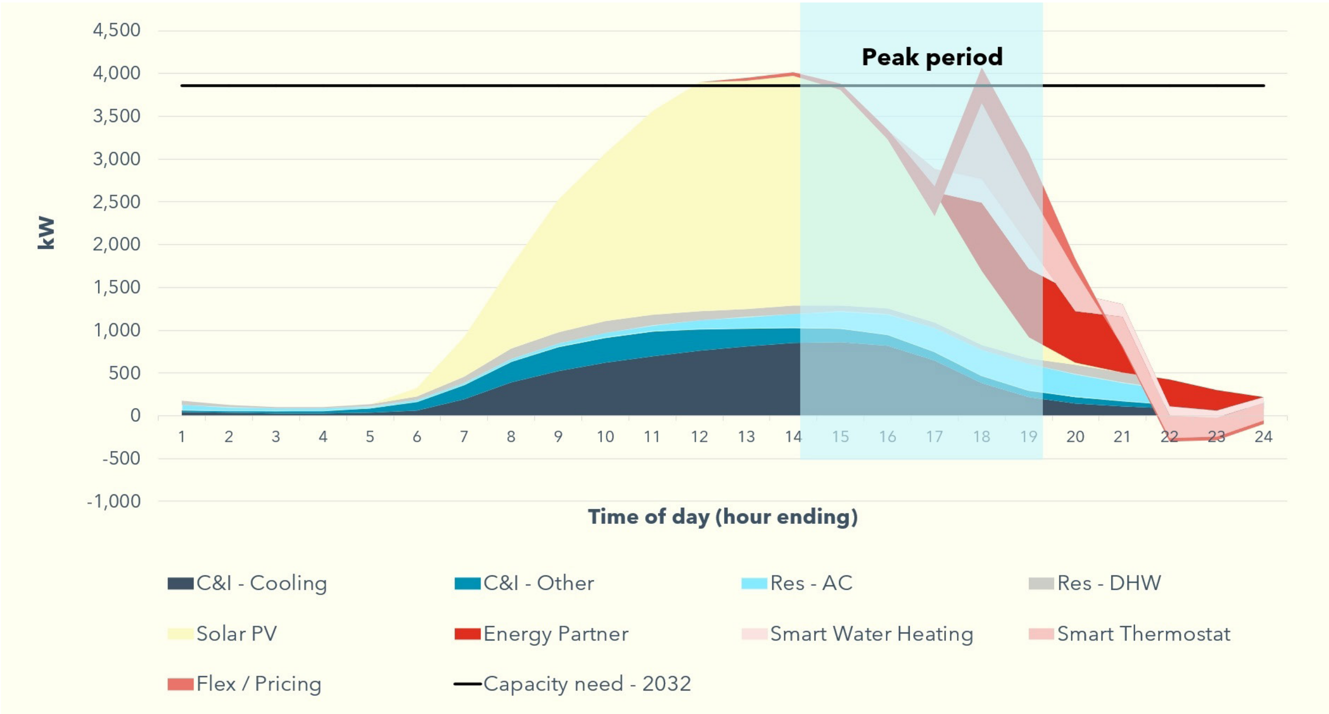
**Figure 47. Solar plus storage potential for Eastport substation (Nameplate kW-dc)**




After identifying the achievable DER potential for Eastport substation, we analyzed the hourly availability of each resource to assess ability to bring future forecasted load growth back within the planning guidelines. This is particularly important for resources like solar PV, that might only provide relief for a percentage of the identified hours (12pm-7pm).

**Figure 48** shows the hourly summer peak day shape of the combined reductions to load due to energy efficiency, solar PV, and PGE's demand response offerings, relative to the identified relief needed on the Eastport WR1 transformer in 2032. We see that the DERs work together to complement one another and provide relief during different hours of the day. In particular, as solar is reducing output in the late-afternoon and early evening, then the combined effect of our Flexible Load programs provide relief.

Figure 48. Combined efficiency, flex load, and solar PV peak day shape

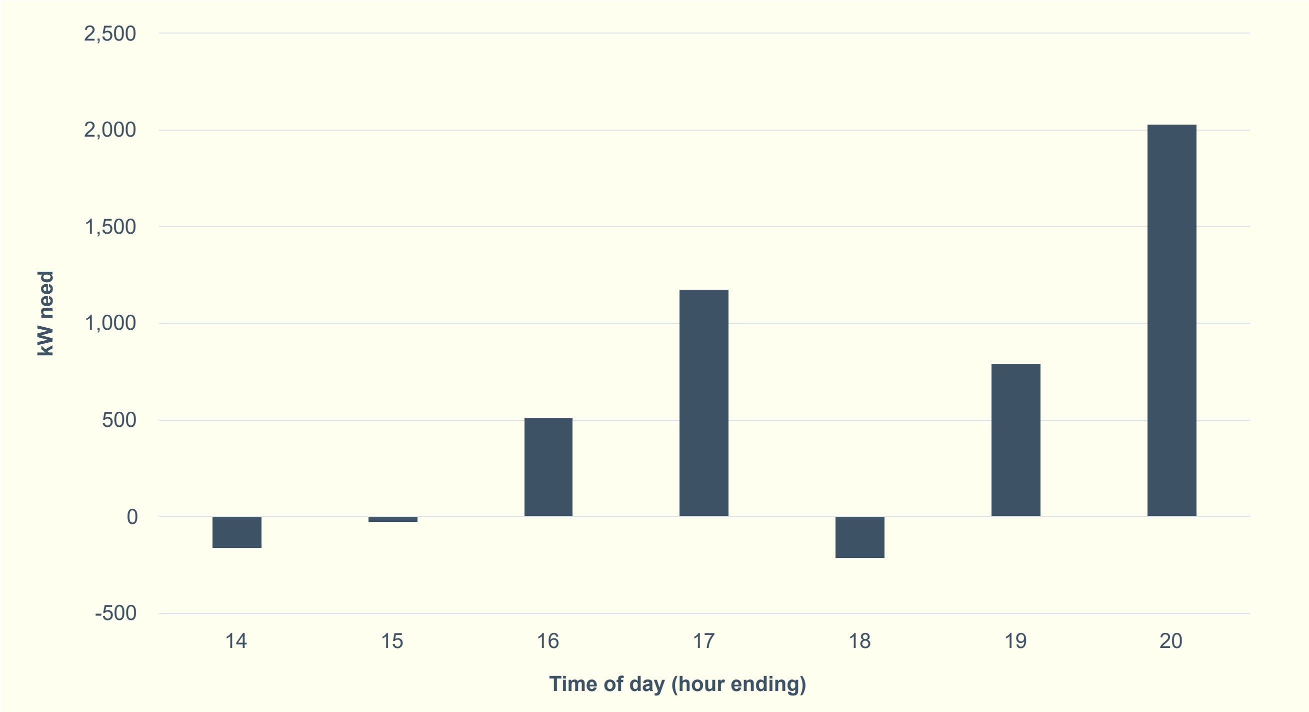



Battery storage was not shown in this chart because it is highly flexible and can be dispatched to meet almost any shape of need required. Therefore, the next step in the course of our portfolio development was to evaluate the impact of customer-sited battery storage to fill the remaining gaps (the area of the graph in shaded blue that lies above the resource stack and below the black solid line). This area reflects the remaining resource need.

The amount of remaining need by each hour during the identified window is shown in **Figure 49**. The maximum height of the need is in hour ending 20 (8pm) and is around 2 MW, and the sum of the positive bars gives PGE an energy need of 4.5 MWh. After we subtract from this our distributed storage potential (1.8 MW and 3.6 MWh from **Figure 47**) we are left with a need for a 250 kW / 1,000 kWh battery solution so that the NWS portfolio can reduce load below the planning threshold and remove all violations identified for this study area. We propose to either keep this remaining need for a front-of-the-meter solution, or consider a community resiliency microgrid.[60]

60. For example, PGE's pilot installation at Beaverton Public Safety Center is a 250 kW, 4-hr microgrid.

**Figure 49. Remaining relief needed by storage for Eastport NWS**




This approach minimizes cost while maximizing behind-the-meter resources that can reliably deliver both energy and capacity.

### 6.4.1.6 Eastport costs breakdown

In this section PGE provides a detailed accounting of the costs of each of the evaluated options and discusses our process for considering each in the formation of the final pilot configuration. The wired solution for resolving the identified constraint includes the following scope of work at the substation:

- Installation of temporary 115 kV/12.47 kV mobile transformer
- Removal of existing 22.4 MVA Eastport WR1 transformer
- Replacement of transformer foundation
- Installation of new 28 MVA transformer at Eastport WR1
- Removal of temporary transformer
- In addition, the wired solution includes the following scope of work at the feeder level:
- Removal and replacement of distribution poles
- Replacement of open delta banks with closed delta banks
- Upgrade of 336 KCM overhead conductors to 795 KCM

The conceptual estimate is approximately $2.8 million. This is a preliminary engineering estimate provided for the purpose of evaluating the NWS. Additional analysis will be performed and a final estimate prepared if we need to move forward with the wired solution. These costs are not included in the near-term action plan.

To assess the costs of the NWS options, PGE used a combination of EPRI's Energy Storage Cost Estimation Tool and internal bid data for potential future costs of the front-of-the-meter storage components.

**Table 31** shows the assumptions for operations and maintenance (O&M) costs required to maintain the front-of-the-meter (FTM) battery solution.

**Table 31. Operations and maintenance cost assumptions for FTM storage**

| Attribute | Value | Unit |
|---|---|---|
| Maintenance and warranty | 2.5% | per year |
| Capacity augmentation | $200 | per kWh |
| End of life decommissioning | $34 | per kWh |

**Table 32** shows the total capital costs and operations and maintenance (O&M) summary for the Eastport substation. The capital costs represent all costs necessary to make the storage system operational, including battery system hardware and software components, installation and contractor overhead, and site work. The O&M costs were factored in based on the size of the storage unit in each option given the inputs in **Table 31** and levelized over a 25-year period.

**Table 32. Eastport NWS costs for FTM storage component of each DER portfolio**

| Cost element | Option 1 - Reliability (1.5 MW / 6 MWh) | Option 2 – Customer resiliency (250 kW / 1 MWh) |
|---|---|---|
| Total turnkey EPC capital costs | $2,334,009 | $741,472 |
| Microgrid controller costs | $91,300 | $91,300 |
| O&M (annual $/yr) | $114,510 | $27,897 |

For all other DERs, PGE developed estimates for the following cost categories:

- **Admin costs** — We assumed 20% adder (applied to the total measure costs of each DER portfolio) to reflect enhanced project management needs, and any targeted marketing required to achieve greater locational adoption for NWS
- **Incentive costs** — We used past incentive data from Energy Trust of Oregon (ETO) and current incentive levels from PGE's Multi-year Plan for flexible loads
- **Participant costs** — We used past data from ETO for energy efficiency and participant cost assumptions from AdopDER for all other DERs.

PGE calculated both utility costs and participant costs in order to inform discussion around the cost impact of the NWS from various perspectives, as well as to highlight the relative amount of customer investment that can be leveraged with a more aggressive deployment of DERs.[61] **Table 33** summarizes these customer-sited DER costs for each NWS option.

61. PGE is using estimates of participant costs based on current and past data and does not reflect actual expected customer cost contributions of the NWS since that will be determined by the ultimate incentive levels set by the program delivery teams.

Table 33. DER and flex load cost summary - Option 1 Reliability Portfolio

| DER Type | Option 1 - Reliability portfolio | | |
|---|---|---|---|
| | Admin costs | Incentive costs | Participant costs |
| Energy efficiency | $177,585 | $782,312 | $5,069,632 |
| Demand response / flex load | $180,159 | $641,525 | $1,999,351 |
| Solar PV | $237,978 | $275,023 | $2,065,002 |
| Storage | $23,450 | $1,297,213 | $745,356 |

**Table 34** shows the same cost information for Option 2 – Customer Resiliency portfolio. Note, there is more aggressive deployment of DERs for Option 2.

Table 34. DER and flex load cost summary - Option 2 Customer Resiliency portfolio

| DER Type | Option 2 - Customer resiliency portfolio | | |
|---|---|---|---|
| | Admin costs | Incentive costs | Participant costs |
| Energy efficiency | $236,779 | $1,043,082 | $6,759,509 |
| Demand response / flex load | $240,211 | $855,367 | $2,665,801 |
| Solar PV | $416,179 | $437,752 | $3,594,516 |
| Storage | $35,000 | $1,936,139 | $1,061,702 |

With both the NWS options, it is important to highlight the role that both customer co-funding as well as matching local, state, and federal tax credits and other funding sources can contribute to such a robust customer-focused NWS application. Because the benefits of DERs encompass a wider range of value streams (both monetizable and non-monetizable), these costs appear higher but may be preferable depending on the decision-making lens applied. It will be important to further assess the incremental costs of deploying the pilot during the more detailed planning phase after final program and budget goals are set.

### 6.4.1.7 Eastport benefits breakdown

In this section, PGE provides a detailed accounting of the benefits of each of the evaluated options and discuss our process for considering each in the formation of the final pilot configuration. We evaluated two primary categories of benefits when comparing the wired solution with each non-wired solution option: 1) system reliability improvements, and 2) additional DER benefits stemming from complementary grid services.

In **Section 4.4**, PGE discussed our Asset Management Program's (AMP) process for evaluating asset risk and assigning outage consequences. To evaluate the reliability improvements and subsequent benefits of the wired solution and each of the NWS options, PGE utilized our traditional AMP methods of evaluating a distribution capital project for its impact on lifecycle cost of ownership, and various metrics of reliability improvements and risk reduction.

The summary of results is shown in **Table 35**.[62] The table shows reductions in key metrics like Near-Term Asset Risk (NTR) and Near-Term Customer Minutes Interrupted (CMI) expected to result from each option. It also shows a reduction in expected outage durations that would result from each outage. This is an important customer resilience metric, along with expected number of outages. Expected number of outages is excluded from this summary, as the options presented here had either negligible or zero impact. The near-term values are for the first year of the project being in-service.

**Table 35. Summary results of AMP risk reduction and lifecycle cost comparison**

| Option | LCOO | NTR | CMI |
|---|---|---|---|
| Wired solution | $2,182,255 | $323,259 | 250,917 |
| NWS Option 1 | $1,609,442 | $140,620 | 40,394 |
| NWS Option 2 | $2,963,357 | $190,989 | 49,277 |

PGE present these results for informational purposes only, since they show how DERs under a NWS would compare to a traditional wired solution all else being equal. However, we took the NTR as a proxy for resiliency value of DERs and used this value as an input into our evaluation of the full stacked value of DERs. This is necessary because DERs can provide system value in times other than during peak load conditions, and we must quantify the NPV of each of these value streams to round out our evaluation of potential benefits from a NWS. **Table 36** shows the system avoided costs that result from the energy efficiency and flexible load portion of the Eastport NWS portfolios.[63]

**Table 36. Overall system benefits from energy efficiency and flexible loads**

| DER Type | Option 1 - Reliability portfolio | Option 2 - Customer resiliency portfolio |
|---|---|---|
| Energy efficiency | $2,915,519 | $3,887,000 |
| Customer-sited storage | $888,457 | $1,265,761 |
| Demand response / flexible load | $2,629,454 | $3,505,939 |

NWS provide an opportunity to accelerate customer DER adoption and achieve significant benefits for customers and communities. The system benefits shown in Table 35 represent traditional evaluation of system avoided costs for both EE and DR. However, there are other potential benefits that have yet to be quantified that PGE highlights here, as it factored into the decision making when evaluating the various NWS options.

The customer- or community-sited DER portions of a NWS can provide multiple potential sources of community benefits, including:

- Local employment impacts, especially if installation work is carried out by local contractors
- Reduced air pollution and subsequent public health impacts
- Resiliency to outages and impacts on vulnerable customers and business processes
- Bill savings from reductions in energy use or rebates from program participation

62. See detailed discussion about the AMP results for Eastport presented in **Appendix E**.
63. We show here the avoided costs associated with energy efficiency and demand response programs because these have readily available and accepted methods for assessing system benefits of such programs. For solar and storage, we note that these have system benefits, but they have yet to be included due to the uncertain impact they can have on the distribution grid. We will explore this further in the more detailed planning phase of the pilot should it move forward.

PGE expects that methodologies to quantify these important benefits will be advanced through development of the CEP, with significant input from community groups via the Community Benefits and Impacts Advisory Group (CBIAG) and other ongoing engagement venues. In the meantime, we considered these qualitatively while considering the different NWS options.

### 6.4.1.8 Greenhouse gas reductions due to NWS

Both option 1 and option 2 NWS portfolios for Eastport contain significant amounts of energy efficiency, demand response, solar PV, and battery storage. Each of these DER types have different implications for quantifying greenhouse gas (GHG) reductions associated with implementing these projects as a potential NWS.[64]

PGE's approach to quantifying GHG associated with each DER type included in the NWS portfolios for Eastport is as follows:

- Energy efficiency potential is quantified as annual energy savings (MWh) and are translated to GHG reductions using PGE's reported emissions intensity per MWh of PGE's electricity delivered to Oregon retail customers for 2021. This has the benefit of being straightforward and in line with ETO's common reporting regarding the GHG impacts of past installations.
- Demand response / flexible loads primarily shift load, rather than reduce it outright. This load shifting may be associated with GHG reductions depending on the state of the grid. Disentangling marginal emissions rates and assessing how different dispatch considerations of flexible loads remains a large and complex undertaking and we do not attempt that here given the interdependencies with both emerging policy guidance and IRP and CEP modeling. In the interim, we have relied on GHG reduction estimates derived from the U.S. Environmental Protection Agency's Avoided Emissions and geneRation Tool (AVERT) to develop a more static estimate of GHG reductions from demand response and flexible loads.[65]
- Solar PV is a clean generation source measured in annual energy (kWh) that directly reduces the amount of electricity consumed from the grid, and therefore we use PGE's emissions intensity per MWh of PGE's electricity delivered to Oregon retail customers for 2021, as we do with energy efficiency.
- Storage resources provide valuable flexibility and non-emitting capacity to the system but incur an energy penalty due to their round-trip efficiency losses. However, storage acts similarly to demand response in that you can shift load and generation to yield incremental GHG reductions. This can be achieved by charging the battery either from a paired rooftop solar system or when the grid's relative carbon intensity is lower and discharging during peak periods which tend to be more GHG intensive.

The 2021 emissions intensity for PGE retail load as reported to Oregon Department of Environmental Quality (DEQ) was 0.32 MT $CO_2e$/MWh.[66]

Using this as a baseline, we calculated the cumulative MWh reductions associated with each of the NWS portfolio options based on the amount of energy efficiency and solar PV production in each over the 10-year pilot window (**Table 37**).[67]

64. An important consideration is how the relative change in DER procurement would change PGE's future emissions profiles. Carbon dioxide emissions associated with PGE's thermal generating resources are evaluated in the IRP, and the DER forecast presented in **Section 3.5** is an input to IRP modeling that ultimately impacts the dispatch decisions of the portfolio and subsequent GHG intensity across a variety of scenarios. The impact of DER adoption on emissions will be further elaborated in IRP and CEP analyses.
65. U.S. Environmental Protection Agency. Last updated October 6, 2021. "AVERT Web Edition" available at: https://www.epa.gov/avert/avert-web-edition
66. Emissions intensity is calculated based on the Oregon Department of Environmental Quality (ODEQ) Investor-Owned Utility GHG report. The ODEQ report shows greenhouse gas emissions associated with power provided to PGE customers and does not account for emissions associated with power delivered outside of PGE service territory.
67. We use historical emissions factors for this analysis primarily due to the complexity of forecasting reductions in GHG over time, given that the actual GHG intensity of a given dispatch mix will be altered by the successful completion of NWS projects. As such, we expect this topic to be a subject of interest as we continue to discuss HB2021 emissions requirements under the IRP and CEP efforts.

Table 37. Cumulative GHG reductions from NWS portfolios

| Metric | Option 1 - Reliability portfolio | Option 2 - Customer resiliency portfolio |
|---|---|---|
| MWh from EE and PV | 34,726 | 50,874 |
| MT $CO_2e$/MWh | 0.32 | 0.32 |
| MT $CO_2e$ reduced | 11,112 | 16,280 |

## 6.4.2 DAYTON CANDIDATE

PGE evaluated three options for the Dayton candidate: a traditional wired solution, and two non-wires solutions that feature different combinations of DERs to meet different resiliency and customer benefit objectives. This section presents the overview of the Dayton area concept proposal.

### 6.4.2.1 Summary of NWS portfolio for Dayton

PGE categorized information about the grid needs, traditional solutions, and non-wires solutions pertaining to the Dayton candidate. **Table 38** provides a high-level summary of project details for the Dayton candidate.

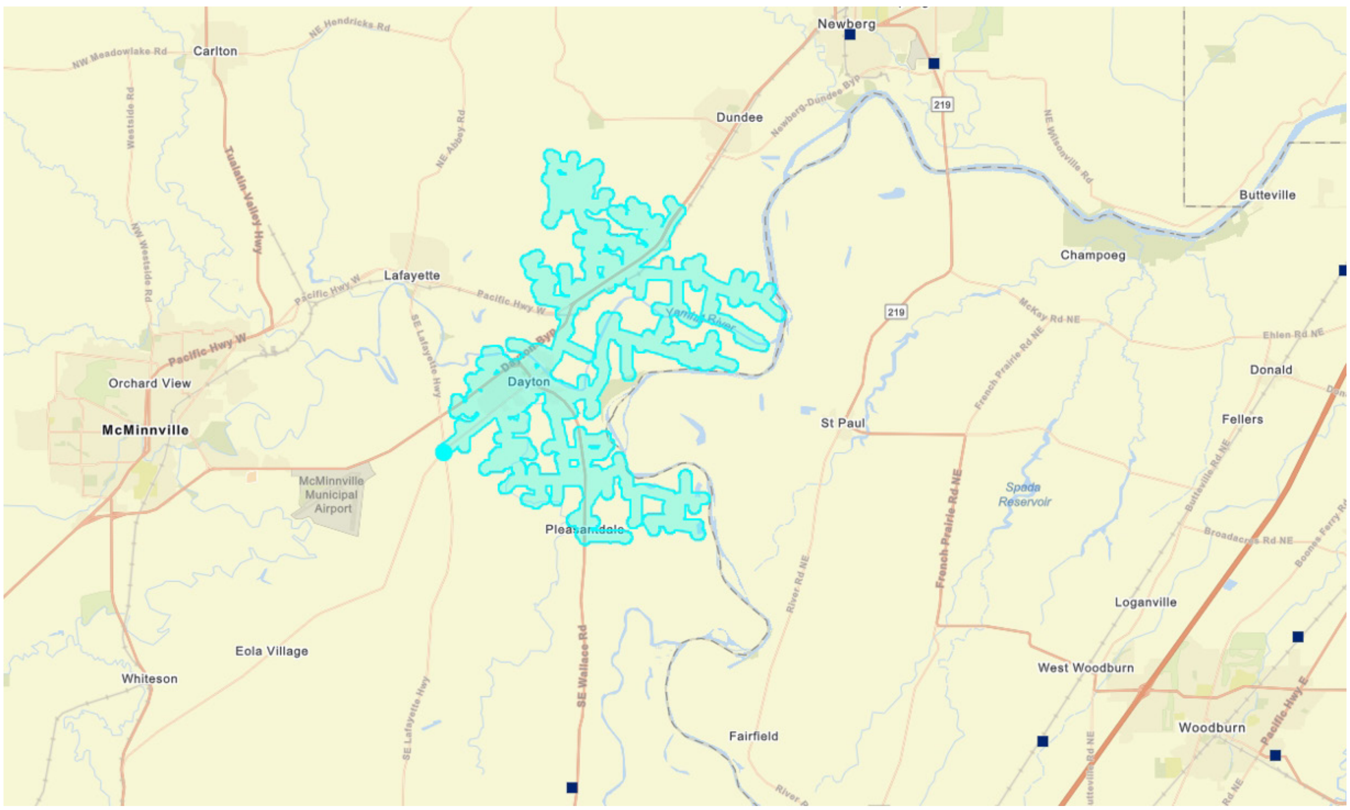
Table 38. NWS candidate: Dayton-East and Dayton BR1

| NWS candidate: Dayton-East and Dayton BR1 | |
|---|---|
| **Scope of grid need** | • Planning criteria violation on Dayton-East and Dayton BR1 |
| | • Violation seen on summer weekdays from 1pm-7pm |
| | • Relief can be provided anywhere along the feeder and partially at the substation |
| **Traditional solution** | • Substation transformer upgrade and feeder section reconductoring |
| **NWS** | • Energy efficiency: 1,700,000 kWh/yr annual savings by 2032 |
| | • Demand response: 1,500 kW of summer peak demand potential by 2032 |
| | • Solar and storage: 563 nameplate kW-dc of rooftop solar |
| **Decision making metrics** | • Relief for Dayton-East must be located downstream (to the northeast) of the 8th St. and Ferry St. intersection. |
| | • Relief for the Dayton BR1 transformer can be located anywhere throughout the footprint |
| **Community engagement** | • Insights regarding community needs were applied to the Dayton NWS primarily from the Community Workshops (see **Section 2.4**) in terms of general principles |
| | • Due to timing constraints, we did not engage customers and community partners to the same extent as we did for Eastport NWS |
| | • Going forward, we will leverage the same community outreach principles and processes for each individual NWS depending on the level of effort required. For this case, our decision was also informed by the desire to explore more front-of-the-meter solutions in Dayton, given the greater need for installing the NWS in a specific location to mitigate the Dayton-East constraint. |

### 6.4.2.2 Location and customer types

Dayton substation is located in Dayton, OR and has just one feeder: Dayton-East. The Dayton BR1 transformer serves only one feeder, Dayton-East. The feeder serves 1,600 customers and is considered a rural feeder, of which 75% are residential and 25% are non-residential. There are 13 managed accounts in the impacted area and 8 residential customers have registered medical equipment. **Figure 50** highlights the customers served within the blue outline under normal conditions.[68]

Figure 50. Area served by the Dayton BR1 transformer




68. To see the area served by any feeder you can access PGE's Distribution Generation Evaluation map, available at: https://www.arcgis.com/apps/webappviewer/index.html?id=959db1ae628845d09b348fbf340eff03

### 6.4.2.3 Summary of grid need

The needs analyses on the Dayton NWS candidate are summarized as follows:

- The hourly load profile and the expected annual peak load growth on the Dayton-East feeder and the Dayton BR1 transformer are shown in **Figure 51**.
- **Table 39** details the applicable location to provide relief to the grid need.

The minimum annual relief required to meet the grid need is shown in **Figure 52**.

Figure 51. Load profile and Load growth at Dayton-East and Dayton BR1

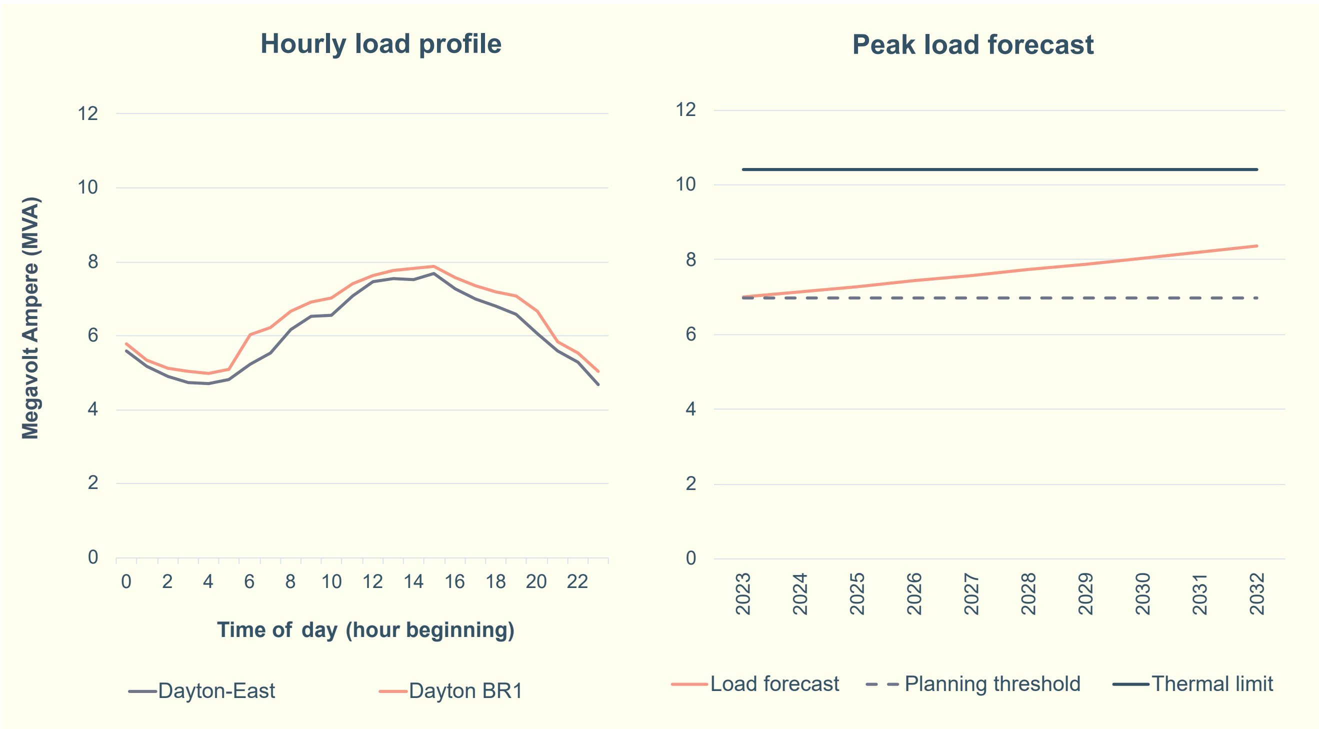
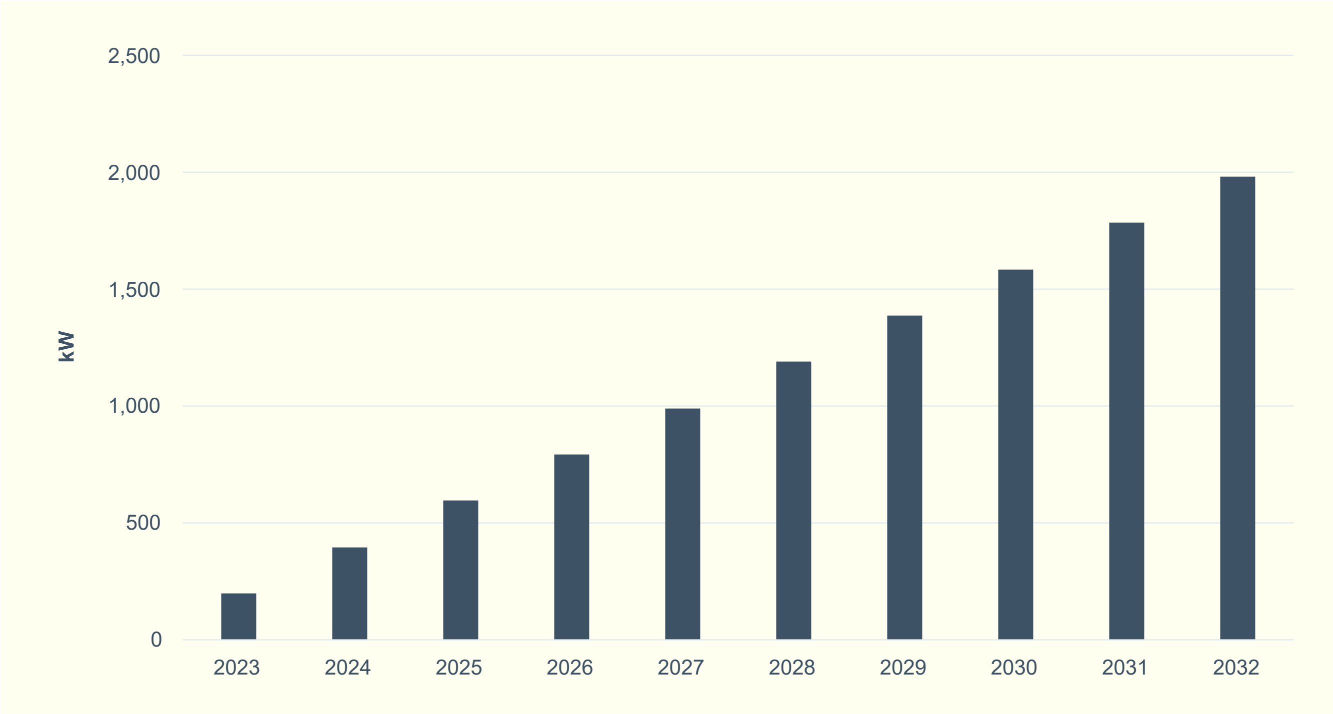



Table 39. Summary of grid needs for Dayton-East and Dayton BR1

| Parameter | Value under normal condition (N-0 condition) |
|---|---|
| **Violation type** | Planning criteria violation (thermal) for both the Dayton-East feeder and Dayton BR1 transformer |
| **Applicable areas for load relief** | • Relief for Dayton-East must be located downstream (to the northeast) of the 8th St. and Ferry St. intersection.<br>• Relief for the Dayton BR1 transformer can be located anywhere throughout the footprint |
| **Violation time and duration** | 12-6 PM, Summer weekdays, non-holidays |

**Figure 52. Dayton NWS - minimum annual relief required for N-0 scenario**




### 6.4.2.4 Customer and equity data

Dayton presents an opportunity to investigate potential benefits and challenges of delivering a NWS in a more rural part of the service area. Key highlights of the customers served by Dayton-East are as follows:

- Of the 1,200 residential customers on the feeder, 79% dwell in single family residences, 14% in manufactured homes, and 7% in multifamily buildings. The relatively high percentage of manufactured homes provides opportunity to leverage innovative delivery mechanisms such as Energy Trust's manufactured home replacement pilot.[69]
- 57% of residential customers own their homes, while 43% are renters.
- Of the 377 business customers, nearly 40% are categorized as agricultural and mining, indicating good potential for irrigation measures as part of the solution set.
- Customers received over $52,000 in energy assistance payments over the last 12 months, with renters receiving 73% of the assistance.

69. Energy Trust's blog, available at: https://blog.energytrust.org/energy-trust-scales-up-work-to-replace-inefficient-manufactured-homes/

### 6.4.2.5 Solutions

#### 6.4.2.5.1 Wired solution

The load on Dayton-East creates two grid needs: load growth-driven thermal capacity upgrade N-0 projects for the Dayton BR1 transformer and the Dayton-East feeder mainline conductor. The N-1 scenarios do not introduce any further needs. If a NWS project can reduce load northeast of the feeder constraint, it can potentially defer both thermal capacity constraints (Dayton BR1 and Dayton-East).

The traditional, wired solution to the constraints on Dayton BR1 and Dayton-East would be to replace the Dayton BR1 7.5 MVA transformer and its associated voltage regulator with a standard 28 MVA transformer, and to reconductor the approximately 6,000 feet of distribution feeder conductor along Southeast Amity Dayton highway from 336 KCM AAC to 795 KCM AAC conductor. Additional substation work would include replacement of the transformer relays and replacement of the transformer high-side fuse with a circuit switcher. The substation work would also require the use of a mobile substation.

#### 6.4.2.5.2 Non-wires solutions

For Dayton, PGE simplified the development of the NWS because of the nature of the grid need and available customer base within which to deploy DERs (Dayton has only one impacted feeder compared to two, larger feeders in Eastport). Similar to Eastport, we developed two options for the NWS to compare against the wired solution: Option 1 (Front-of-the-meter) contained only a single installation of a utility-scale battery storage option, while under Option 2 (Customer Resiliency) the need for a utility-scale battery is reduced by more aggressive customer adoption.

##### 6.4.2.5.2.1. Dayton substation locational value

PGE used the same present worth method developed by Lawrence Berkeley National Laboratory (LBNL) to evaluate the locational distribution-system avoided cost from deferring the identified grid need with a NWS. For the Dayton BR1 and Dayton-East grid needs, deferring the wired investment by 10 years yields an annualized value of $650.53/kW-yr.

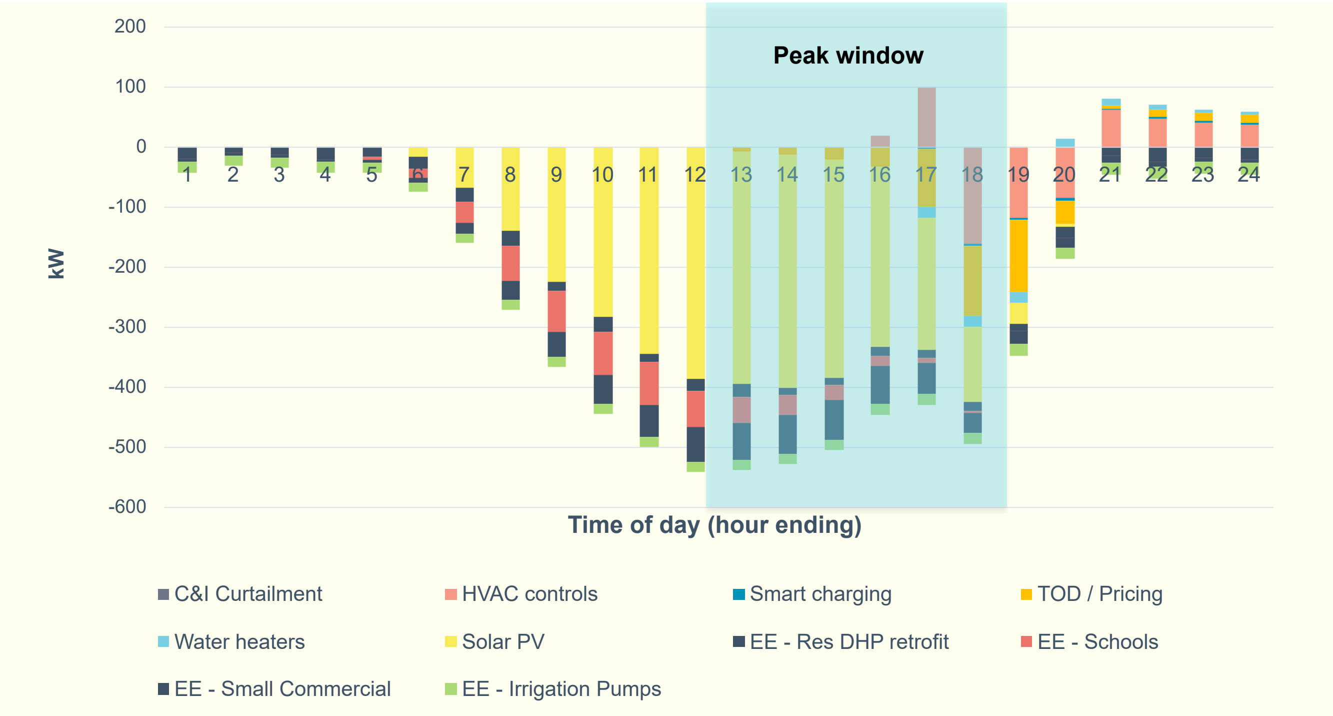
##### 6.4.2.5.2.2. Dayton resource potential and applicability

Given the higher focus on the Dayton NWS toward the utility-scale solution, PGE did not develop as detailed of annual forecasts of DER potential as done for Eastport. Instead, PGE focused on right-sizing the storage solution to mitigate the grid need. To estimate the size of the storage solution, we first compiled the hourly historical SCADA measurements of load on both the Dayton-East feeder and Dayton BR1 transformer during the summer 2021 June heat wave. Using this information, we calculated the max energy and capacity needs to bring the feeder load back under acceptable levels. This method allowed for consideration of potential constraints to charging the battery from the grid up to its max capacity during a multi-day heat wave as experienced in June 2021.

Once PGE sized the system for Option 1, we ran the cost estimates and AMP analysis on the utility-scale solution. For Option 2 – Community Resiliency option, we first layered in the hourly contributions of the distributed customer potential (energy efficiency, solar, storage, and demand response)[70] to reduce the loading described for Option 1. Then with the new, lower loading we sized the max energy and capacity of the front of meter storage requirement. **Figure 53** shows the total hourly profile from the DERs included in Option 2 that were used to adjust the expected future load downward.

70. For developing the DER potential for Dayton NWS - Option 2, we followed the same method described for Eastport.

Figure 53. Dayton NWS Option 2 - Customer resiliency




The addition of the DERs again greatly reduced the capacity and energy need from the utility-scale storage solution but did not eliminate it. **Table 40** shows the final composition of each of the two evaluated NWS options for Dayton.

Table 40. Dayton NWS options - DER portfolio contributions

| NWS element | Option 1 - Reliability focused | Option 2 - Customer resiliency focused |
|---|---|---|
| EE potential | N/A | 1,732,626 kWh/yr |
| DR / Flex potential | N/A | 1.5 MW |
| Solar potential | N/A | 563 kW nameplate |
| Distributed customer storage | N/A | 1.2 MW / 2.4 MWh (2-hr) |
| Utility-scale storage | 2 MW / 12 MWh (6-hr) | 1.5 MW / 6 MWh (4-hr) |

### 6.4.2.6 Dayton costs breakdown

In this section PGE provides a detailed accounting of the costs of each of the evaluated options and discuss our process for considering each in the formation of the final pilot configuration.

The wired solution for resolving the identified constraints involves the following scope of work:

- Installation of temporary 115 kV/12.47 kV mobile transformer
- Removal of existing 7.5 MVA Dayton BR1 transformer and its associated voltage regulator
- Replacement of transformer foundation
- Installation of a new standard 28 MVA transformer
- Replacement of the transformer relays and replacement of the transformer high-side fuse with a circuit switcher
- Removal of temporary mobile transformer
- In addition, the wired solution includes the following scope of work at the feeder level
- Upgrade approximately 6,000 ft. of transmission under-build mainline from 336KCM AAC to 795KCM AAC conductor

The conceptual estimate is approximately $3.3 million. This is a preliminary engineering estimate provided for the purpose of evaluating the NWS. Additional analysis will be performed and a final estimate prepared if we need to move forward with the wired solution. These costs are not included in the near-term action plan.

For the Dayton NWS, Option 1 – Reliability Focused only includes a front-of-the-meter battery. For simplicity, Table 41 shows the cost estimates for the front-of-the-meter storage component of both Option 1 and Option 2 using the same assumptions about capital costs and O&M as used for the Eastport NWS from **Table 32**.

**Table 41. Dayton NWS costs for FTM storage component of each DER portfolio**

| Cost element | NWS Option 1 (2 MW / 12 MWh) | NWS Option 2 (1.5 MW / 6 MWh) |
|---|---|---|
| Total turnkey EPC capital costs | $3,579,096 | $2,160,692 |
| Microgrid controller costs | $91,300 | $91,300 |
| O&M (annual $/yr) | $201,797 | $110,177 |

For all other DERs, PGE developed estimates for the following cost categories:

- **Admin costs** — We assumed 20% adder (applied to the total measure costs of each DER portfolio) to reflect enhanced project management needs, and any targeted marketing required to achieve greater locational adoption for NWS
- **Incentive costs** — We used past incentive data from Energy Trust of Oregon (ETO) and current incentive levels from PGE's Multi-year Plan for flexible loads
- **Participant costs** — We used past data from ETO for energy efficiency and participant cost assumptions from AdopDER for all other DERs.

To assess the DER costs for each portfolio option, PGE took the total expected contributions in Option 2 – Customer Resiliency Focused and used the same cost assumptions as when assessing the Eastport NWS concept.[71] **Table 42** shows the final cost breakdown of Option 2 – Customer Resiliency focused DER portfolio.

71. It should be noted however that there are more current matching funding opportunities in the Portland area due to the availability of the Portland Clean Energy Fund. However, we did not explicitly assume any matching funds for Eastport or Dayton but simply highlight the potential to influence the cost structure of the pilots.

**Table 42. Dayton cost summary - Option 2 - Customer resiliency focused**

| DER Type | Option 2 - Customer resiliency portfolio | | |
|---|---|---|---|
| | Admin costs | Incentive costs | Participant costs |
| Energy efficiency | $75,055 | $330,640 | $2,142,656 |
| Demand response / flexible load | $169,063 | $602,014 | $309,875 |
| Solar PV | $63,623 | $66,921 | $549,513 |
| Storage | $23,333 | $1,290,759 | $395,970 |

### 6.4.2.7 Dayton benefits breakdown

In this section PGE, provides a detailed accounting of the benefits of each of the evaluated options and discuss our process for considering each in the formation of the final pilot configuration. Similar to Eastport, PGE followed the AMP procedures for assessing the change to reliability and risk from each the wired solution and the two evaluated NWS options in Dayton.

The summary of the AMP analysis is shown in **Table 43**. The table shows reductions in key metrics like NTR and CMI expected to result from each option. It also shows a reduction in expected outage durations that would result from each outage. This is an important customer resilience metric, along with expected number of outages. Expected number of outages is excluded from this summary, as the options presented here had either negligible or zero impact. The near-term values are for the first year of the project being in-service.

**Table 43. AMP benefits summary of Dayton wired solution and NWS options**

| Scenario | LCOO | NTR | CMI |
|---|---|---|---|
| Wired solution | $2,035,395 | $472,350 | 139,551 |
| NWS Option 1 | -$8,030 | $70,184 | 19,767 |
| NWS Option 2 | $3,083,061 | $252,412 | 54,819 |

**Table 44** shows the system avoided costs that result from the energy efficiency and flexible load portion of the Dayton NWS portfolios.

**Table 44. Overall system benefits from energy efficiency and flexible loads**

| DER Type | Option 1 - Reliability portfolio | Option 2 - Customer resiliency portfolio |
|---|---|---|
| Energy efficiency | N/A | $1,684,564 |
| Customer-sited storage | N/A | $1,265,761 |
| Demand response / flexible load | N/A | $849,979 |

As discussed for Eastport, NWS provide an opportunity to accelerate customer DER adoption and achieve significant benefits for customers and communities. For Dayton, since we evaluated a slightly different combination of NWS options (with Option 1 comprised of solely a utility-scale battery) these community benefits mainly pertain to Option 2, though certain benefits may accrue as well under the utility-scale battery option.

The customer- or community-sited DER portions of a NWS can provide multiple potential sources of community benefits, including:

- Local employment impacts, especially if installation work is carried out by local contractors
- Reduced air pollution and subsequent public health impacts
- Resiliency to outages and impacts on vulnerable customers and business processes
- Bill savings from reductions in energy use or rebates from program participation

For Dayton there may be an additional potential to derive significant water savings as part of the energy efficiency components of the NWS portfolio (under Option 2) due to the high amount of agricultural activity on the impacted feeder. PGE expects that future collaboration through the CBIAG under the CEP will continue to evolve the quantification of these important benefits. In the meantime, we considered these qualitatively while considering the different NWS options.

### 6.4.2.8 Greenhouse gas reductions due to NWS

Applying the same methodology was used for Eastport, PGE estimates that the NWS – Option 2 portfolio for Dayton will result in retail electricity demand reductions of 15,476 MWh over the cumulative 10-year deferral period from EE and solar PV installations, resulting in emissions reductions of 4,952 MT CO2e.

## 6.4.3 OUTCOMES AND NEXT STEPS

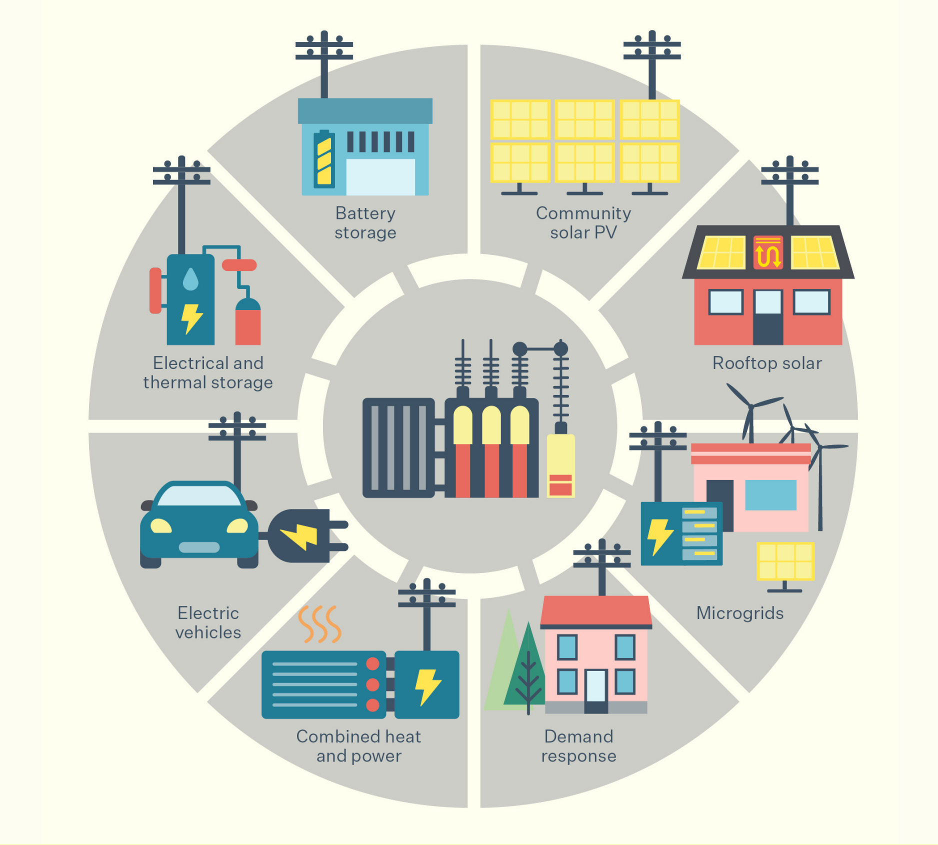
NWS are inherently a question of trade-offs between competing goals. In most cases, traditional wired solutions will provide greater reliability improvements at lower cost, given their ability to provide for longer-duration support and reach a greater number of customers given their scale. However, important considerations must be factored into decision making surrounding when to invest in a NWS such as the potential value of customer resiliency to withstand grid outages without experiencing interruption of service (which might be particularly beneficial for vulnerable customers and critical public facilities), the additive impact of operating DERs to capture diverse grid benefits (which is not typically possible with traditional wired solutions), and a variety of non-energy considerations such as local employment impacts, environmental and public health benefits, and policy objectives.

PGE demonstrated that as a concept these representative DERs can meet the identified requirements for providing capacity relief on the Eastport NWS location. We have also outlined the potential costs and benefits of implementing each NWS option and the traditional wired solution. Our recommendation is to move forward with Option 2 – Customer Bill relief for both Eastport and Dayton, based on both a quantitative and qualitative examination of the relative strengths of each. Part of our reasoning is that the NWS option with more aggressive DER deployment maximizes the type of customer and community engagement potential that is highlighted throughout our DSP and is also strongly indicated in the UM2005 Guidelines. Targeted deployment of existing customer programs will contribute strongly to NWS project implementation, but new dedicated investments will also be necessary for project success. These investments will need to be aligned with resource planning activities and the evolving regulatory framework.

As we move forward with implementing this pilot concept, a more detailed round of DER planning will need to take place, including more concrete considerations or risk, customer acceptance, and budget impacts. After this more detailed planning round, the final detailed pilot designs would need to be compared the DER portfolios assessed here and examined for any key variances. The planning approach should be validated by PGE program teams and Energy Trust through detailed program planning, as well as other partners contributing to delivery of the DER solutions. In addition, PGE distribution planning engineers will need to validate the final portfolio with a CYME power flow analysis to confirm that the solution addresses all thermal and voltage violations and no new issues arise, such as excess solar generation during the spring or fall due to changing daytime minimum load conditions.

## Chapter 7

# Near-term action plan



# Chapter 7. Near-term action plan

"The actions we are taking to enhance reliability and resiliency within a community-centered distribution system support two, equally important, goals of decarbonization and environmental justice."

**– Maria Pope**, President and CEO, PGE

## 7.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities.[72] It's designed to improve safety, reliability, resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter provides an overview of PGE's planned investments over the next two to four years. We describe two main categories of investments: traditional transmission and distribution solutions needed to meet UM 2005 requirements and grid modernization solutions that advance our long-term vision of the DSP. We also discuss additional actions needed to achieve a 21st century community-centered distribution system.

**WHAT WE WILL COVER IN THIS CHAPTER**

Specific investments in the distribution system that address the grid needs discussed in **Chapter 4**.

Investments in the distribution system that are being made to address other drivers, such as transportation electrification, resilience and DER adoption.

Existing investments and proposed investments to advance the 21st century distribution system, such as grid modernization.

**Table 45** illustrates how PGE has met OPUC's DSP guidelines under Docket UM 2005, Order 20-485. [73]

Table 45. Distribution system overview: Guideline mapping

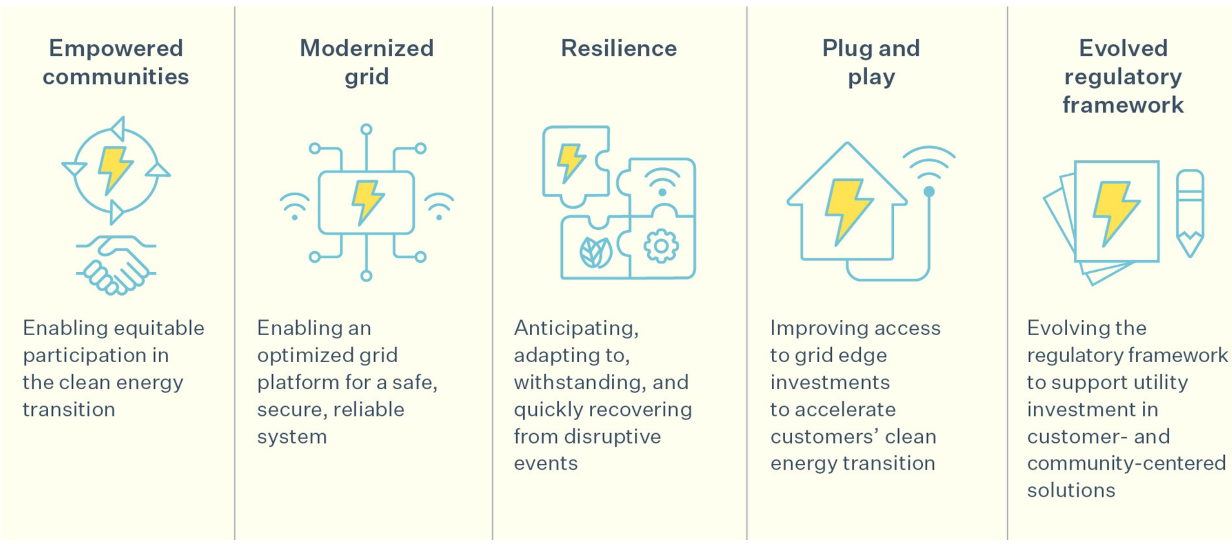
| DSP guidelines | Chapter section |
|---|---|
| 5.4.a | **Section 7.3** |
| 5.4.b | **Section 7.3** |
| 5.4.c, 5.4.d | **Section 7.3, Appendix K** |

72. PGE uses the definition of environmental communities under Oregon HB 2021, available at: https://olis.oregonlegislature.gov/liz/2021R1/Measures/Overview/HB2021.
73. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf.

# 7.2 Introduction

PGE's vision for the distribution system builds on traditional utility values of reliability, safety and affordability by incorporating values such as decarbonization, community impact, resiliency and security. In building our vision of a 21st century community-centered distribution system, we developed goals that focus on advancing environmental justice, accelerating DER adoption, and maximizing grid benefits through our DSP. **Figure 54** highlights our focus on these goals through our strategic initiatives.[74]

Figure 54. DSP strategic initiatives




As part of PGE's DSP action plan process, we conducted analysis and shared with various stakeholders, partners and community-based organization through our DSP Partnership Workshops and Community-focused Workshops. In total, we held 23 engagement meetings from January 2021 to August 2022: 17 DSP Partner Meetings and 6 Community Workshops. The workshop participants assisted us in identifying strengths and weaknesses, as well as opportunities within our DSP approach and plan.

Many factors influence the way the plan is executed, such as disruptive weather events, supply chain disruptions that lead to price swings and delays, jurisdictional permitting requirements, and significant economic development, such as data centers. Over time, we will continue to refine our strategies so that the way we plan aligns with the reality that we operate in a dynamic environment.

74. Community engagement was a driving theme in developing DSP Part 2 and was discussed in **Chapter 2**. The remaining sections within this Chapter discuss the specific planned and proposed actions for modernized grid, resilience, and plug and play.

# 7.3 High-level action plan

PGE's DSP action plan presents our proposed solutions to address grid needs, as well as other investments in the distribution system as required by UM 2005. The elements of our DSP describe how the planning process meets the DSP Guidelines under UM 2005. These DSP Guidelines specify the initial requirements for the DSP and identify baseline expectations for how these requirements may evolve over time.

PGE's near-term action plan aligns our vision for the DSP and outlines a plan that we believe advances environmental justice, accelerates DER adoption, and maximizes grid benefits. It represents our initial steps toward modernization of the distribution system to achieve the necessary levels of decarbonization and greenhouse gas emission reductions that can slow the advance of climate change.

We anticipate investments, outside this DSP, will be included in our CEP and IRP as a result of our DER forecast and adoption results. The CEP and IRP are expected to be filed in 2023. For example, we are currently conducting analysis through our Integrated Resource Plan (IRP) to understand how the contributions of DERs can assist in meeting system need.

As we advance to a 100% clean energy supply, we are often replacing base-loaded thermal resources with variable energy resources like wind and solar. As a result, we determined that in order to achieve this decarbonized future, we would need to find new sources of flexibility for the supply portfolio. Our grid modernization investments represent a key element to transforming the grid and enabling large-scale integration of DERs, especially solar PV, batteries and electric vehicles, in a manner that can improve grid flexibility and reduce the need for supply-side resources. **Table 46** describes our high-level approach to modernizing our grid. These investments support our modernized grid architecture, systems and capabilities. Details on PGE's roadmap and planned investments for modernizing the grid, increasing resilience and promoting DER adoption can be found in **Appendix K**.

Table 46. High-level grid modernization investments summary

| Grid modernization investments |
|---|
| Investments into customer DER portal needed to develop a customer DER device management platform, enhance customer billing and settlements, streamline interconnections and customer communications |
| Design of a Virtual Power Plant with expansion capabilities needed to meet HB 2021 |
| Investments for planning and engineering capabilities needed to enhance PGE's AdopDER model, development of a Next Generation Planning Tool, DER data management systems and updates to cost-benefit model and tools for NWS |
| Investments into grid management systems for ADMS for critical infrastructure and distribution automation (DA) |
| Investments into sensing, measurement, and automation, telecommunications and cybersecurity |

Our traditional T&D planning include investments needed to enable security, resiliency, and DER adoption. For these investments, we have identified a suite of projects to be prioritized in this planning cycle. These investments are needed to address the prioritized grid needs identified in **Section 4.5** that improve reliability, safety, resiliency and compliance with state and federal requirements and advance toward the 21st century human-centered distribution system. **Table 47** provides a summary of the number of projects in each category of T&D investment described in **Section Table 50**.

Table 47. Count of T&D investments by category

| Investment types (# of projects) | 2023 | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|---|
| Capacity/Flexibility | 9 | 10 | 13 | 7 | 39 |
| Customer/Partner | 24 | 19 | 17 | 13 | 73 |
| Compliance | 22 | 18 | 14 | 9 | 63 |
| Reliability | 21 | 21 | 24 | 19 | 85 |
| Operations | 4 | 4 | 4 | 4 | 16 |
| **Total** | **80** | **72** | **72** | **52** | **276** |

**Table 48** shows the estimated costs for proposed investments, solutions and actions within our DSP, which reflect commitments to our DSP goals and vision. These estimated costs were developed utilizing current known opportunities and challenges within our 2022 planning environment.

At the time of this DSP filing, there are still many outstanding questions on how CEP requirements will impact existing DSP guidelines and which types of investments should be made to the distribution system to accelerate the equitable implementation of a decarbonized future. **Table 48** represents investments into our distribution system utilizing current state analysis; thus, these costs do not include investments, solutions and/or actions related to our Clean Energy Plan (CEP). Our intent is to evaluate impacts on the distribution system related to meeting the CEP targets and identify actions and investments not envisioned in our DSP or the OPUC's DSP initial guidelines in our CEP filing, which is expected to be filed in March of 2023.

PGE's budgets are fixed each year, and many factors could cause a reprioritization of the work that is identified in the plan, often on a year-by-year basis. The projects and investments that are shown here represent the body of work that PGE has identified for the coming years. Changes in our local environment will dictate the timing and duration over which work is completed and whether or not the identified projects are displaced by other projects of competing priority.

Table 48. High-level action plan estimate

| Investment Summary (estimated $M, incurred) | 2023 | 2024 | 2025 | 2026 | Total |
|---|---|---|---|---|---|
| **Traditional T&D Investments for Customers, Reliability, Safety and Compliance** | **$285.0** | **$285.0** | **$285.0** | **$285.0** | **$1,140.0** |
| Prioritized Grid Needs (included in Traditional T&D Investments) | $55.3 | $56.3 | $87.1 | $28.7 | $227.4 |
| **Grid Modernization Investments** | **$40.0** | **$40.0** | **$40.0** | **$40.0** | **$160.0** |
| **Total T&D and Grid Mod Investment** | **$325.0** | **$325.0** | **$325.0** | **$325.0** | **$1,300.0** |

## 7.4 Long-term actions

Traditional regulatory rules require capital investments to be used to provide service to customers before they are eligible for inclusion in customer rates. The regulatory framework also includes interconnection rules that establish system upgrade cost responsibility for interconnecting customers and resource developers. However, this regulatory framework complicates PGE's ability to proactively build out new infrastructure to support DERs and electrification using the existing capital planning and regulated rate case process. In coordination with CEP and IRP processes, changes to the regulatory framework could accelerate projects that ready the grid for decarbonization.

### 7.4.1 DER-READINESS UPDATES FOR SYSTEM PROTECTION

PGE has performed and regularly refreshed analysis of distribution upgrades required to make the system DER ready. The Plug and Play section of **Appendix K** outlines investments that have been identified to upgrade breakers, switchgear, and transformers to address constraints to connect more distributed generation (DG). Projects needed to address safety issues are prioritized through the needs analysis and solution identification process and are included in our 2023 capital plan. However, updated cost recovery guidance would be needed to support proactive investment in the remaining projects via the capital planning process.

In coordination with ongoing investigations in UM 2099 and UM 2111, we are considering the following initiatives to evolve the regulatory framework to overcome these challenges:

- Operational solutions to expand hosting capacity: we support the concept of a "Net Metering Fast Track" pathway.[75] Under this approach, new projects with smart inverter (IEEE 1547-2018) capabilities enabled that fall under a predetermined screening threshold may avoid the need for system upgrades and the corresponding upgrade costs, therefore expediting the interconnection. Additionally, we are continuing to develop flex load resources and interconnection standards that can be used to support additional DG integration.

- Regulatory framework for incremental investments. As described above, our internal grid solution prioritization and design criteria rigorously focuses on the least cost least risk solutions to serve load. Accordingly, these criteria do not lead to prioritization of other project types or design solutions, such as a substation upgrade that would increase hosting capacity, or an oversized transfer switch that would increase project cost but minimize risk of replacement in the event of near-term local DER growth. These planning standards are not set in stone; they are based on the system of statutory and regulatory standards and precedent. With development of a supportive regulatory prudency standard and cost recovery pathway, we can integrate hosting capacity projects within our grid planning process.

- Consideration of full or partial cost recovery within interconnections. In accordance with the principle that interconnecting resource developers bear the cost of upgrades, we encourage further DSP and UM 2111 attention to evolutionary cost sharing options. Updated cost sharing methods could allow incremental costs of capacity investments to be tied to all interconnecting DERs benefiting from the upgrade.

### 7.4.2 ELECTRICVEHICLECHARGINGREADINESS

As noted in OPUC's Order 22-083 accepting PGE's DSP Part 1, DSP alignment with Transportation Electrification (TE) initiatives is a continuing area of focus. We aim to file the TE Plan (TEP) in fourth quarter of 2022. It will include proposals for TE programs and TE infrastructure that will support the vehicles projected in the DSP TE forecast and the overall state decarbonization trajectory.

The TEP will include budgets for programmatic and TE infrastructure activities directly related to TE projects; grid infrastructure projects will continue to be identified and prioritized through the grid planning process described in this document.

As described in the Plug and Play section in **Appendix K**, these investments could be significant but are largely excluded from the current need-based action plan. This is in large part due to the regulatory framework's expectation of usage as a condition for cost recovery. Unlike customer-driven load growth, which is frequently influenced years in advance by municipal and regional planning processes, TE charging growth within our territory may be very lumpy and unpredictable – large loads and peak demands have the potential to materialize at specific grid locations with very little advance notice. Large infrastructure projects that are essentially at risk of non-recovery do not align with the traditional regulated investment model. DSP data and processes should also inform early-stage conversations between PGE and TE-interested customers to encourage alignment of TE charging load with locations where existing distribution investments and capacity can support additional load.

75. See "PGE's status update on the Company's efforts to identify an alternative method or technology for cost-effectively interconnecting net metering customers on constrained feeders," filed to UM 2099 on June 24, 2022, available at: https://edocs.puc.state.or.us/efdocs/HAD/um2099had143957.pdf

PGE anticipates actively working with the OPUC, stakeholders, and partners in the DSP review and guidance update and the TEP review so that the distribution planning process balances investment prudency standards, supports our customers and system, and supports Oregon's TE objectives.

### 7.4.3 UTILITY INCENTIVES FOR OPERATOR ROLE

Throughout the UM 2005 process, there has been recognition that the utility business model under the traditional regulatory framework may need to evolve to align with the needs of a decentralized future.[76] While recognizing that changes to utility incentives need to be addressed thoughtfully, we seek to advance this conversation by including a pilot incentive mechanism in our NWS proposals.

PGE recognizes there has been varying and limited progress in normalizing non-wires solution projects by other jurisdictions. A review of utility efforts across the country shows that in spite of considerable work to develop new planning frameworks, establish applicable cost-effectiveness criteria, screen project opportunities and identify candidate resources, implemented NWS projects have been notably rare.[77]

An incentive mechanism for NWS and VPP operationalization can help to address challenges experienced in other jurisdictions. Under this approach, a new earnings element would be determined by the value provided by DER portfolios. The incentive would reward utility success in pursuing solutions that maximize customer and community benefits in a way that is agnostic to resource type and ownership structure.

As a starting point in developing a new incentive structure, we suggest a structure guided by the following principles (**Figure 55**):[78]

**Figure 55. Example incentive structure**

**Linked to policy objectives of community & customer value**

Utilities should be encouraged to deploy and use DERs in a manner that optimizes system and community value. Determination of value should be informed by cost-effectiveness evaluation and leverage available data.

**Complementary to established regulatory framework**

The utility regulatory framework serves many important functions. Exploration of alternative mechanisms should avoid duplication of existing regulatory processes and focus on specific areas appropriate to reform, including adoption and optimization of DERs.

**Scalable as the system decarbonizes**

PGE's vision anticipates the ability to plan and dispatch DERs as virtual power plants (VPPs) to enhance locational and system value. Incentives designed for NWS projects should also be designed to apply to VPP activities.

**Objective, timely and intuitive**

Financial incentives are most effective when utility managers and investors can understand and plan for them. Effective incentives should depend on factors withing the utility control, be measurable if tied to performance and be available without extended delay.

76. The possibility of business model reform was addressed in Order 20-485 which provided DSP guidance and included as a core element of PGE's DSP Part 1 (7.4.2). Order 22-083, in which the OPUC approved all three utilities' DSP Part 1 documents, states that "Revision of utility incentives and proactive grid investments are topics that will require deliberate discussion and consideration by Staff, stakeholders and the Commission."

77. For example, see Wood Mackenzie's 2020 research summary, "US utilities are leaving non-wires alternatives on the table", available at: https://www.woodmac.com/news/editorial/us-nwa-on-the-table/. Further discussion of this topic can be found in Table 48 and Section 7.4.5 of PGE's DSP Part 1.

78. PGE's suggested principles are informed by best practices publicized by groups such as LBNL and RMI and design guidelines proposed and adopted in stakeholder processes and PUC orders in performance-based regulation dockets in states including Hawaii, Minnesota, and Washington.

Using these principles, an approach could be to calculate earnings eligibility as a function of DER utilization and total benefits. In all cases, cost-benefit analysis would be used to evaluate whether net incremental costs of DER development and utilization would be less than net benefits. Since the incentive's value would be directly tied to quantity and quality of DERs used to provide customer and community value, it would help shift the utility's business motivation toward DER development, utilization and optimization in service of customer and community benefits.

PGE encourages development of a properly aligned regulatory mechanism, but we are not asking for the Commission to acknowledge or approve any mechanism through the DSP. We seek to work with the OPUC to advance the discussion of such a mechanism in our next rate case, drawing on nationally recognized recommendations and best practices. We readily acknowledge the numerous complexities associated with introduction of a new element of the regulatory framework; however, an incentive mechanism for the NWS projects could be treated as a pilot that can inform future investigations.

This incentive structure could fit within our current regulatory framework, if a NWS is planned for, designed and implemented just as traditional resources are under established capital planning processes in alignment with DER forecasts and resource planning processes (IRP and CEP). We look forward to the evolution of DSP guidance in UM 2005 to formalize procedural expectations that support NWS identification, selection, and implementation within the evolved regulatory framework.

### 7.4.4 DISTRIBUTED ENERGY RESOURCE COST-EFFECTIVENESS

PGE's ability to accurately and consistently account for costs and benefits is crucial to achieving the goals of grid modernization, decarbonization and customer satisfaction. Enhanced cost-effectiveness (CE) methodologies and tools will enable us to conduct broader, more detailed analysis, allowing enhanced cost-benefit analysis which will help us improve DER forecasts, program design and operational decisions. This strategy will result in capabilities for us to look broader at opportunities to modernize the grid and provide customer choice and help outcomes listed in **Table 49**.

**Table 49. Cost effectiveness desired outcomes**

| Outcome | Objective |
|---|---|
| **Consistency and alignment** | Create consistency and coordination between analysis and recommendations in DSP, IRP, CEP, MYP and TEP<br>Streamline regulatory and stakeholder review and rework<br>Increase transparency for prudency reviews and potential earning mechanisms |
| **Robust decision-making framework** | Enhance target setting across planning efforts leading to improved integration with CEP and IRP<br>Inform planning standards and guidance for cost allocation at the measure, program and portfolio level<br>Promote standard approaches to evaluation scope and cadence<br>Enable better decision-making process for company investments |
| **Operational efficiencies** | Use a company-wide CE model<br>Conduct CE with new value streams |
| **Program development and implementation** | Develop high value measures/programs/products<br>Accelerate DER adoption for higher value DERs<br>Create data discipline and consistency<br>Assist customers in reducing bills<br>Reduce energy burden and promote equity by incorporating social and environmental benefits |

PGE's development of robust and transparent valuation methodologies can promote streamlined regulatory approval of DER-related proposals, reducing uncertainty and rework. Our CE evaluation approach is evolving as we update valuation methodologies for generation capacity, T&D avoided costs, locational value, bulk ancillary services, resiliency, and incorporate equity metrics as discussed in Chapter 2. The CE project is underway and will continue into 2023. In addition to their use in NWS project assessment, we intend to continue refining these inputs as they are applied in upcoming MYP, TEP and CEP filings:

- **DSP** — The Grid Modernization Chapter of PGE's DSP Part 1 described progress made on CE in 2021 and outlined plans for a future CE model. These capabilities have implications throughout DSP Part 2, where updated CE values factor into numerous analytical workstreams, including DER forecasting, NWS project assessment, and regulatory evolution.
- **MYP (August 2022)** — PGE's 2022 MYP will address Staff and stakeholder feedback to the 2021 MYP by incorporating improvements to cost-effectiveness methodologies. We are working toward alignment of valuations by updating our tools and capabilities for assessing flexible loads.
- **TEP (Fourth quarter 2022)** — CE work will support advancement of electrification policy and program proposals based on cost-benefit analysis for transportation and building electrification. This work will provide strategic direction on evaluating costs and benefits as well as the integration of DERs on the distribution system.
- **CEP (March 2023)** — As PGE develops its first CEP, examinations of DER opportunities to reduce emissions and provide community benefits will incorporate CE tools developed in DSP.

# 7.5 Evolution of DSP guidelines

The 2023 DSP guideline update planned by OPUC offers the opportunity to streamline and clarify several topics, reducing administrative workloads on OPUC Staff, stakeholders, partners and utilities.

**Table 50** summarizes actions identified by PGE, stakeholders and partners from DSP Part 1, along with items we have identified in the DSP Part 2 work.

Table 50. Evolution of DSP guidelines recommendations

| Topic | Recommendation | Status |
|---|---|---|
| **DER cost-effectiveness / standardized valuation framework** | An updated cost-effectiveness model that includes social and environmental policy considerations supports design and evaluation of DER programs and assists in development and approval of non-wires solutions | Staff has recognized this need across multiple dockets. Staff notes its potential inclusion in DSP Guideline revisions in Order 22-083 |
| **Comparable treatment of NWS and traditional investments** | Regulatory approval process and utility revenue mechanisms should provide explicit incentives to pursue NWS projects that maximize community benefits relative to traditional T&D solutions | Staff notes its potential inclusion in DSP Guideline revisions in Order 22-083 |
| **Community engagement metrics** | Metric development should be informed by new Community Benefits & Impacts Advisory Group and consistent across engagement areas | Staff notes its potential inclusion in DSP Guideline revisions in Order 22-083. Similar metrics are also being considered in UM 2225 (HB 2021 Investigation into Clean Energy Plans) |
| **System-level and customer data policy** | Engage stakeholders in review of additional system attributes recommended by IREC in their DSP Part 1 comments [1] | Staff notes its potential inclusion in DSP Guideline revisions in Order 22-083 |
| **Docket integration** | Consolidation of several reports and plans into comprehensive DSP guidance can eliminate redundancies | Initially proposed in PGE DSP Part 1 and recognized as need in Order 22-083. Consolidation will require update to guidelines and in some cases may require rule updates |

1. IREC DSP Part 1 comments, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2197hac153720.pdf&DocketID=23043&numSequence=11

# Appendix

# Appendix A. DSP plan guidelines compliance checklist

| Forecasting of Load Growth, DER Adoption, and EV Adoption | DSP guideline | Chapter section |
|---|---|---|
| Discussion of current utility processes for distribution system load growth forecasting including: | 5.1.a | **3.1, 3.2, 3.3, 3.4** |
| Forecasting method and tools used to develop the forecast | 5.1.a.i | **3.2, 3.3, 3.4** |
| Forecasting time horizon(s) | 5.1.a.ii | **3.3.1, 3.3.2, 3.4.3.2** |
| Data sources used to inform the forecast | 5.1.a.iii | **3.2, 3.3, 3.4.2, 3.4.3** |
| Locational granularity of the load forecast | 5.1.a.iv | **3.4.2** |
| Forecast of DER adoption and EV adoption by substation | 5.1.b | **Appendix M** |
| The forecast should include high/medium/low scenarios for both DER adoption and EV adoption | 5.1.b.i | **Appendix M** |
| A utility should fully describe its methodologies for developing the DER forecast, EV forecast, high/medium/low scenarios, and geographical allocation in its plan (for example methods and tools, time horizons, data sources). | 5.1.b.ii | **3.5, Appendix C** |
| For the initial Plan, the methodology for geographical allocation (to the substation) is at the utility's discretion. The Commission may provide direction for subsequent Plans. | 5.1.b.iii | Not applicable |
| A utility may consider leveraging information such as: historical utility program trends, historical customer adoption trends, data from ETO, data from Transportation Electrification Plans and pilots, or studies on DER technical and economic potential used in other dockets. Utilities should use the most recent data available. | 5.1.b.iv | Not applicable |
| Results of forecasting load growth, DER adoption, and EV adoption | 5.1.c | **3.5.5, Appendix M** |
| Document existing and anticipated constraints on the distribution system | 5.1.c.i | **4.5** |

| Grid Needs Identification | DSP guideline | Chapter section |
|---|---|---|
| Document the process used to assess grid adequacy and identify needs. | 5.2.a | **4.2, 4.3** |
| Discuss criteria used to assess reliability and risk, and methods and modeling tools used to identify needs. | 5.2.b | **4.4** |
| Present a summary of prioritized grid constraints publicly, including criteria used for prioritization. | 5.2.c | **4.5** |
| Provide a timeline by which the grid need(s) must be resolved to avoid potential adverse impacts. | 5.2.d | **4.5** |

| Solution Identification | DSP guideline | Chapter section |
|---|---|---|
| Document the process to identify the range of possible solutions to address priority grid needs. | 5.3.a | **5.3**, **5.3.2** |
| For each identified Grid Need provide a summary and description of data used for distribution system investment decisions including: discussion of the proposed and various alternative solutions considered, a detailed accounting of the relative costs and benefits of the chosen and alternative solutions, feeder level details (such as customer types on the feeder; loading information), DER forecasts and EV adoption rates. | 5.3.b | **5.3**, **Appendix J** |
| For larger projects (this may exclude, for example, regular maintenance projects, or inspection projects), engage with impacted communities early in solution identification. Facilitate discussion of proposed investments that allow for mutual understanding of the value and risks associated with resource investment options. | 5.3.c | **5.4** |
| Evaluate at least two pilot concept proposals in which non-wire solutions would be used in the place of traditional utility infrastructure investment.<br><br>The purpose of these pilots is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, power quality improvements in under-served communities. These pilots will prepare utilities to achieve the goals listed in Stages 2 and 3 of **Figure 6**.<br><br>In its pilot concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The pilot concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective. In addition, evaluation of pilot concept proposals should utilize the community engagement process developed in **Section 4.3**. (a) (ii) and address: | 5.3.d | **6.2**, **6.3**, **6.4** |
| Community interest in clean energy planning and projects | 5.3.d.i | **2.4**, **6.3.1** |
| Community energy needs and desires | 5.3.d.ii | **2.4**, **6.4.1.4** |
| Community barriers to clean energy needs, desires, and opportunities | 5.3.d.iii | **2.4** |
| Energy burden within the community | 5.3.d.iv | **2.6** |
| Community demographics | 5.3.d.v | **3.5.5.3, 6.4.1.4, 6.4.2.4** |
| Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix | 5.3.d.vi | **6.4.1.8, 6.4.2.8** |

| Near-term Action Plan | DSP guideline | Chapter section |
|---|---|---|
| Action Plan: Provide a 2-4 year plan consisting of the utility's proposed solutions to address grid needs and other investments in the distribution system | 5.4.a | **7.3** |
| Projected spending: Disclose projected system spending to implement the action plan, timeline for improvement, and anticipated requests for a cost recovery mechanism | 5.4.b | **7.3** |
| Relation to other investments: As applicable, the Action Plan should identify areas of relation and interaction with other investments such as transmission projects and demand response programs | 5.4.c | **7.3** |
| Document current innovations and pilots being conducted to improve, modernize, and/or enhance the grid beyond its current capabilities | 5.4.d | **7.3**, **Appendix K** |

# Appendix B. Stakeholder comments and PGE answers

| Near-Term Action Plan | |
|---|---|
| **Comment** | **PGE Response** |
| **The guidelines don't prohibit PGE from making any needed improvements or upgrades tomorrow. Just because there is a structure, there is no prohibition to keeping the lights on.** | We agree that the guidelines are not a barrier to PGE's ability to continue operating the distribution system. |
| **I don't understand why PGE doesn't have - within your current plan, the solutions for current problems in Salem. I understand the need for considering future DER's and am glad that PGE is planning for incorporating DER's for the future, but what about the needs of current customers.** | Currently, the two-meter solution provides a workaround for net metering customers who want to interconnect on the generation-limited feeders. The evolved regulatory framework section of the DSP discusses the barrier to proactively invest in hosting capacity on those feeders. |
| **Why is PGE focused on potential future problems and not on the current problems, like the limited generation feeders?** | We discuss this in the regulatory evolution section of the DSP report. The discussion of cost allocation will take place in association with the UM 2111 docket. |
| **Will you address why your HCA was more costly than other states utilities?** | We recognize that the costs to implement HCA vary from jurisdiction to jurisdiction. Based on our analysis and conversations with other utilities, the estimated HCA costs are comparable. We expect there will be an opportunity to review our analysis at an upcoming OPUC-led workshop on HCA. |
| **Why are you not speaking in the filing that PGE is already doing HCA ad-hoc?** | The requested focus of the HCA within the DSP is on generation. PGE evaluates HCA when we perform system impact studies for interconnections. The DSP requires evaluation across the entire system, so that is where we focused our HCA discussion. |
| **Can you clarify if you will be using the DRIVE tool software?** | We plan to use DRIVE in the near term. We have evaluated a CYME module called ICA that we plan to use for future Hosting Capacity Analysis. The testing of this module showed greater accuracy but is much more computationally intensive, so it may require new or upgraded IT infrastructure to implement. |
| **Thank you for acknowledging these items. I think these are the biggest improvements to your upcoming filed plan. This is how we want to see HCA - a modular update base. We would ideally like to see something monthly because we have seen that the more frequent the more useful.** | Thank you. We expect to work with Staff and stakeholders to determine the best path forward for implementing system-wide HCA. |

| Non-Wires Solutions | |
|---|---|
| **Comment** | **PGE Response** |
| **If the NWS pilots go forward, will they be rate based?** | As noted in the DSP, PGE sees the need for regulatory evolution to address several elements impacting DERs including specific elements pertaining to the approval and recovery process of NWS investments. We look forward to continued discussion with our DSP partners through the docket process to address this question. |
| **The goal for phase II is to propose non-wires pilots in Aug 2022 and activity would take place in 2023. Do I have that right?** | In this DSP, PGE has proposed two pilot concepts. PGE will start the project design and construction phases based on Commission acceptance of the plan and proposed actions associated with NWS. |
| **What if a customer or group desires a NWS that imposes a cost on the system?** | PGE proposes solutions to address grid needs across the territory. As shown in this DSP, PGE is learning to include a new solution option in NWS. Addressing grid needs with any solution, NWS or wired, imposes cost on the system and our customers. As described in **Section 4.6**, PGE is transitioning its decision-making process by not only analyzing solution options that are least cost and least risk but also include new decision-making elements related to equity and resilience. |
| **Will CBO's be included in the community engagement efforts around cost-effectiveness?** | Yes, we will be engaging CBO's within our community sub-group and discuss cost-effectiveness. |
| **Does PGE consider resilience/community resilience benefits in the DSP?** | As noted in **Section 5.5**, PGE is transitioning and will include resilience metrics within its distribution system investment decision-making processes. |
| **How are folks in the equity space who aren't here being reached out to?** | We can separate our answer into the long term and short-term.<br><br>Long-term: Our intention is to create or leverage a compensation structure to get more players from the equity space represented within these meetings. Compensation for meeting attendance has been shared as one of the key incentives for gaining more partners – beyond organizations that are specifically funded for energy advocacy.<br><br>Short-term: We are going to email our existing NWS partners for updates with our community-focused meetings that are tailored for strategizing our work with CBO's and communities. |
| **I feel firmly the equity benefits should be rooted and started in the perspective of the communities themselves. Instead of starting something in PGE and bringing it to community-based organizations and invite them to make the first step** | Incorporating equity within our business practice is an iterative process, and we strive to continuously improve. We would like to balance integrating community values with meeting regulatory exceptions and deadlines, while moving toward a more inclusive and equitable outcome. |
| **Will advances in cost effectiveness methods replace the current risk-based cost-benefit analysis?** | No, the new cost effectiveness method is largely around resource economics, and it will be used in tandem with the risk-based cost benefit analysis. |
| **When addressing a grid need, does PGE prefer resources that are mitigating peak or resources that provide maximum value annually?** | Resources that address the grid need receive the highest value in the decision-making process. Thus, the resource preference is dependent on the grid need. In the case of these NWS pilot concepts, the needs are driven by peak load and thus resources that address peak loading issues would be most beneficial. |

| Non-Wires Solutions | |
|---|---|
| **Comment** | **PGE Response** |
| **How does PGE create hourly solar generation profiles at the feeder?** | PGE uses NREL's PV Watts to determine solar generation profiles at the site level. |
| **Does PGE consider pricing-based demand response programs within its NWS?** | Pricing based programs are become reliable across large populations of participation. Localized pricing programs can see significant variability making them less reliable from a solution perspective. PGE is using an incremental approach as noted within the DSP to include pricing programs but determine its reliability impact based on the results of the pilot concepts. |
| **What is PGE's planning horizon for distribution planning?** | PGE leverages a 10-year planning horizon for planning the distribution system. Given the dynamic nature of the distribution system longer horizons may misrepresent the future system. |

| DER/Load Forecast | |
|---|---|
| **Comment** | **PGE Response** |
| **Are you planning for increased two-way flow as increased DER implementation happens?** | Yes, we are accounting for it in our planning. We are investing in updating our distribution planning tools and capabilities to allow more efficient analysis of distributed generation. We are also installing appropriate protective devices to support distributed generation anytime we perform a major substation upgrade or build a new substation. |
| **Curious about an element of forecasting/analysis. You mentioned changes in zoning from rural to residential. But have you also looked at zoning density changes statewide (and in Portland)? For example, how our Residential Infill Project zoning change, where all properties can have multiple accessory dwelling units, might impact local load?** | We are looking at all relevant changes in zoning. |
| **Looking at the difference between population and customers. When PGE talks about 'customers' does that equal meters or billing accounts?** | Depending on the context, we may use the term 'customers' differently, but generally speaking we identify a customer as nearly as possible with the point of common identification (e.g., a physical site either a residential dwelling or a place of business). We typically do not use number of meters to refer to customers since there can be many meters per site for commercial customers. |
| **Is the effect of climate change (e.g., heat domes) taken into account for peak loads?** | Yes, we account for climate change in our load forecast by incorporating both historical and projected weather trends, as well as evaluating potential future loading conditions under a range of expected probabilities of extreme weather ranging from weather (and load) conditions expected once every 2 years to once every 20 years. We are also working with Oregon State University on climate risk modeling at a more spatially resolute level that can be incorporated into our standards for hyper-local needs like subdivision new construction guidelines. |
| **Are you considering how highly dynamic use-rates can be?** | We have not incorporated dynamic rates into our DER potential study at this time. We do model a mix of existing rates and tariffs, including time-of-day pricing, as well as rebate programs such as Peak Time Rebates. |

| DER/Load Forecast | |
|---|---|
| **Comment** | **PGE Response** |
| **Has the model been validated against real world adoption?** | Given that this is our first round of using AdopDER for purposes of forecasting DER adoption, we have not had the ability to validate the model's forecasts with actuals. We plan to do so going forward and this will help improve the model's accuracy over time. However, in building the model we did calibrate our statistical models to known adoption by withholding a sample of the historical data to 'train' the model. See **Appendix C** of the DSP Part II for more detail on this methodology. |
| **Now that HB 2021 is out and there is authorization for rate and market design, are you all looking at dynamic rate tariffs?** | We have not incorporated dynamic rates into our DER potential study at this time. We do model a mix existing rates and tariffs, including time-of-day pricing, as well as rebate programs such as Peak Time Rebates. We recognize the important role that pricing can have on helping reach decarbonization goals and are open to exploring this further. |
| **Are you taking low- and moderate-income variables into your model?** | AdopDER incorporates many different variables, including income, when disaggregating the forecast into the locational feeder-level. The relative influence that income plays in driving adoption will differ based on the established correlations between past adoption and other findings from our literature review. |
| **When considering data on people with low-to -moderate income, I suggest referencing the data from the ETO's 'Solar within Reach' program and the state Solar + Storage rebates program. Both programs serve low-income homes and service providers and should have helpful data.** | We will work with ETO to leverage their Solar-within-Reach data whenever possible in terms of understanding the long-run adoption potential of these customers. We have reached out to Oregon DOE to understand the geographic uptake of the statewide solar + storage rebate program and will likewise seek to model the influence of these additional incentives in future modeling runs. |
| **This [ODOE low-income solar + storage rebate program] data from the state has been around since 2020. It feels wrong in that it is flawed in representing/modeling recent adoption in other communities. Why can't we update this now?** | We leverage NREL's Gen Market Demand Model to develop service-area wide estimates of Solar market share, which we then apply to individual sites based on our algorithm which includes income-levels. We will look at updating the model to account for the low-income solar more explicitly + storage state-level rebate, but do not expect relative influence on overall levels of adoption will be much of a driver. We will work with Energy Trust to include the likely influence of this tax rebate in any future improvements to how we characterize low-and-moderate income solar + storage adoption in AdopDER. |
| **Was the input used from the existing solar systems on the feeder knowing their capacity, tilt, and orientation?** | In this case [identifying solar PV potential for incorporating into a NWS project] we are talking about the forecast, which includes any historical PV adoption on the feeder, plus expected future installations. Currently, our model does not incorporate tilt and orientation for the historical adoption – but it is one area we expect greater collaboration and data sharing with Energy Trust, which will be beneficial. For the forecast, AdopDER does make assumptions about tilt, orientation, and azimuth from PVWatts but is not specific to each individual rooftop. Doing so would be an interesting exercise but is also computationally intensive. We are open to exploring the benefits of including more granular data about solar potential where available and when it would add the most value to the planning process. |

| DER/Load Forecast | |
|---|---|
| **Comment** | **PGE Response** |
| **Is the current forecast based on the initial distribution system planning forecast that Cadeo worked on with you or is this the new NREL work you're doing right now?** | Yes, the current forecast is built using AdopDER, which Cadeo developed for PGE. The AdopDER model leverages NREL's dGen Market Demand Model for estimating adoption rates for rooftop solar PV in our service area and combines those with site-specific characteristics from other sources to assign adoption to the granular feeder-level. We are working on a project with EPRI and NREL to update dGen to more accurately reflect PGE's customers and what factors influence their decision making when looking at solar, storage, and EVs. We expect to be able to leverage new capabilities going forward given the significant work PGE is doing with NREL around the SALMON project and other areas. |
| **Can you breakdown the numbers for your solar forecast?** | The annual number of forecasted rooftop solar MW-dc and MWa are included in **Chapter 3** of the DSP Part II filing. |
| **Are all non-water heater flex load programs up and running or are they in the pilot phase?** | Currently, we are running a multifamily water heater flexible load pilot and are submitting plans to launch a single-family pilot offering in 2023. In terms of the resource potential modeled in AdopDER, we are modeling both current pilots and future pilots to better understand the total potential of these resources. |
| **What is solar PV?** | In the context of our DER forecast, solar PV refers to rooftop residential and commercial solar photovoltaics (PV). |
| **What was your plan for gross load at the substation level and what you are planning on doing with it?** | We evaluated how our construction of bottom-up feeder-level load profiles (re-constituted from aggregating individual AMI usage data for all customers on the feeder) matched the SCADA measurements from the feeder breaker. The intention for using the SCADA data was to identify more granular distribution system losses between the substation and the end customer. However, after analysis we determined that due to inability to match front-of-the meter generation for the sample data year (2019) we had to revert to relying on AMI load profiles. |
| **Are you incorporating line losses into the gross load aggregation?** | Yes, we included it in AdopDER as an estimate of line losses from previous distribution studies. We also attempted to quantify line losses specific to each feeder, but due to issues identified with matching the SCADA data to the AMI data (primarily, missing data and confounding influence of front-of-the-meter generation) we reverted to relying on existing distribution loss estimates for this round. |

| DER/Load Forecast | |
|---|---|
| **Comment** | **PGE Response** |
| **How are folks in the equity space who aren't here being reached out to?** | We can separate our answer into the long term and short-term.<br><br>Long-term: Our intention is to create or leverage a compensation structure to get more community from the equity space represented within DSP meetings. Compensation for meeting attendance has been shared as one of the key incentives for gaining more partners – beyond organizations that are specifically funded for energy advocacy.<br><br>Short-term: We are going to email our existing DSP partners for updates with our community-focused meetings that are tailored for strategizing our work with CBOs and communities. |
| **I feel firmly the equity benefits should be rooted and started in the perspective of the communities themselves. Instead of starting something in PGE and bringing it to community-based organizations and invite them to make the first step.** | Incorporating equity within our business practice is an iterative process, and we strive to continuously improve. We would like to balance integrating community values with meeting regulatory exceptions and deadlines, while moving toward a more inclusive and equitable outcome. |

| Grid Needs Analysis | |
|---|---|
| **Comment** | **PGE Response** |
| **Why does the icon above the poles look like a Wi-Fi connection?** | This is because the Distribution Automation Team at PGE is using LTE Verizon and our wireless field area network (FAN). |
| **Does automation encompass how BTM (behind the meter) assets are sync/sourcing with the feeder?** | Distribution automation (DA) currently splits our feeders into different switchable sectors that may or may not have behind the meter DERs.<br><br>The goal with the current DA program is to maximize the number of customers that are safely restored after a fault event in our system. |
| **Did you say earlier, because there are DERs that you have to think about minimum load more?** | Electricity used to flow one way; now it can flow back into our equipment (e.g., feeders, substations). This results in different analyses. We need to make sure that our equipment and customers are properly protected from this reverse power flow. |
| **Do you know if that network is for both the grid assets (reclosers, substation comms, etc.) and the MDM (meter data management)?** | Both AMI and SCADA use PGE's telecommunication network. AMI wireless network collects data from meters and uses PGE's communication infrastructure to backhaul data to MDM. Grid assets like reclosers and substations also use communication infrastructure. It could be wireless field area network (FAN), direct fiber, or third-party service (Verizon Cell modem connection) for connectivity. |

| Grid Needs Analysis | |
|---|---|
| **Comment** | **PGE Response** |
| **Why isn't there a stakeholder process or input for the grid needs? Specifically, why aren't you prioritizing generation-limited feeders?** | We will be implementing community engagement for our grid needs starting this year, for our 2024 capital cycle.<br><br>Currently, the two-meter solution provides a workaround for net metering customers who want to interconnect on the generation-limited feeders. **Section 7.4** discusses the barrier to proactively investing in hosting capacity on those feeders. |
| **Are the 67% and 80% thresholds company standards/ industry standards or a little bit of both?** | They are company standards to establish system flexibility for planned and unplanned outages. |
| **(1) Are you looking at the state building energy code changing over the next few years?**<br><br>**(2) What goes into the numbers you're putting together for energy modeling?**<br><br>**(3) What information goes into the sort of modeling and forecasting you're doing when you're considering a development?** | (1) Yes, absolutely. We are looking at state building energy codes.<br><br>(2) We look at other communities that were built and we try and find a community with a similar profile. We use load data from these other communities to develop a metric for how much load is expected for each building type (multi-use, single family, etc.).<br><br>(3) Some key information that would go into forecasting would be zoning type, heating/cooling equipment, and other factors such as the presence of solar panels. |
| **Is the forecast at an hourly level or granular?** | Historically and now, we are planning to peak, so we're looking at the maximum amount of load that we would be required to serve. In the future we will be moving towards a more granular analysis. |
| **With regard to electric vehicle loads, what sort of modeling and the numbers are you expecting in this kind of neighborhood (North Bethany)?** | The project that was presented in the workshop was completed a couple of years ago and planned even earlier, so we did not have any forecasting for transportation electrification at that time. Moving forward, our load forecast incorporates DERs, including TE. |
| **How representative is a new substation of typical projects and investments you know would this represent?** | Most new substations that PGE has constructed over the last 15 years have been driven by new large load editions. We strive to first add capacity at existing substations when possible. |
| **Concerning the nature of data centers, would high temperatures create a peak for them? I remember PGE staff saying they are not as weather dependent.** | Data centers are not as weather dependent as other sectors, but we see them peak when their chillers are online in the summer. However, data centers operate with a high load factor, meaning that their load is close to their peak consistently (unlike, for example, a residential home where load will drop off at night when people are sleeping). |
| **How are you considering the future guidelines of loading levels and N-1 conditions as you are thinking about penetration of customer assets?** | We are incorporating our DER forecast starting with the 2024 capital cycle. We will evolve to a more granular analysis (more than just peak analysis) which will help us better understand the impact of DERs, and customer assets, on our system. |
| **It would be helpful for a broader audience if there were multiple definitions of stress – as opposed to N-1, so people can easily understand what kind of stress(es) is impacting the system.** | We do now need to consider the impacts of reverse power flow on our system during minimum load conditions. We are also exploring the flexible feeder concept that we have seen deployed in Europe. |

| Grid Needs Analysis | |
|---|---|
| **Comment** | **PGE Response** |
| **Where can I find a deeper dive into the engineering and math behind the projects listed within the DSP?** | A summary of each solution/project is in **Appendix J**. This does not include a deep dive into the engineering math behind the projects as this would be overly detailed. However, we do discuss the reason for the solution/project and alternatives we considered. |

| Human-Centered Design & Planning | |
|---|---|
| **Comment** | **Response** |
| **It would be helpful to have a user-friendly catalog of NWS options that's digestible to the average community member.** | Yes, we agree that would be very helpful. For example, our products team is working on streamlining these options, providing bundles, and then building a website where customers may receive a more user-friendly experience for sorting through these options. |
| **Is engaging with CBOs the only avenue PGE is working through to suggest NWA projects or is there going to be means to propose NWA demos?** | No, we're going to work on engagement with each of our partners and we plan to refer to CBOs as local experts when referring to equity and community-based issues. |
| **There should be a catalog of both utility needs and wants and customer needs and wants. Both of those need to be organized for the DSP process and outcome.** | We have noted your response. We recognize this is important and will continue improving on transparency and inclusion for this process. |
| **Is there a straw proposal?** | Yes, we have some concepts in mind, but we want to hear from you to make sure we don't duplicate any efforts. |
| **Has PGE done any scoping on the initial solar concept?** | We are initially looking at single-family homeowners and multi-family property owners. |
| **Can we know some of the concepts and ideas you all have for solar before we begin the ideation process?** | We are considering financing options as well as looking at the multi-family space. |
| **How do we create more projects that move forward clean energy and proliferate community benefits across products?** | We do not have all the answers at this time, but a good first step is strategic collaboration.<br><br>We look forward to working together and supporting our partners – like Multnomah County, as we move forward with this work across our products. |
| **Could someone in the winter receive credits for the extra generation they'll have in the following summer?** | No, not at this time.<br><br>Currently, we envision this would be given at the time of the solar installation to reduce the upfront cost. It's sort of like an advanced credit. |
| **I don't really understand information from solar installation and potential bill credits from export generation. Would you mind walking me through this?** | By rewarding the customer for future export generation, the customer could receive credits in advance to help reduce the cost of the solar installation. |
| **With stakeholders particularly the focus on low-income communities, how much interest you've heard from community-based organizations and partners?** | We have heard interest from both community-based organizations and partner organizations for specifically including CBOs in equitable community benefits and low-income program offerings. We are currently working on a framework for effectively including CBOs across PGE plans, products, and programs. The Community Workshops within the DSP are an example of steps PGE is taking for proactive inclusion of CBOs. |
| **Where exactly does equity fit into the rubric category, does it get blended into another category and how it how should that be done?** | This is currently fluid because we are still figuring out the metrics behind equity and cost benefits. |

| Solution Identification | |
|---|---|
| **Comment** | **PGE Response** |
| **Does savings mean savings for PGE or savings for the customer?** | We consider the most cost-effective solution that mitigates the grid need to avoid impacting customer rates. When PGE is able to save money on a project, those savings are used for other capital investments, thus stretching PGE's capital to achieve more. This benefits customers. |

# Appendix C. Load and DER forecasting supplemental information

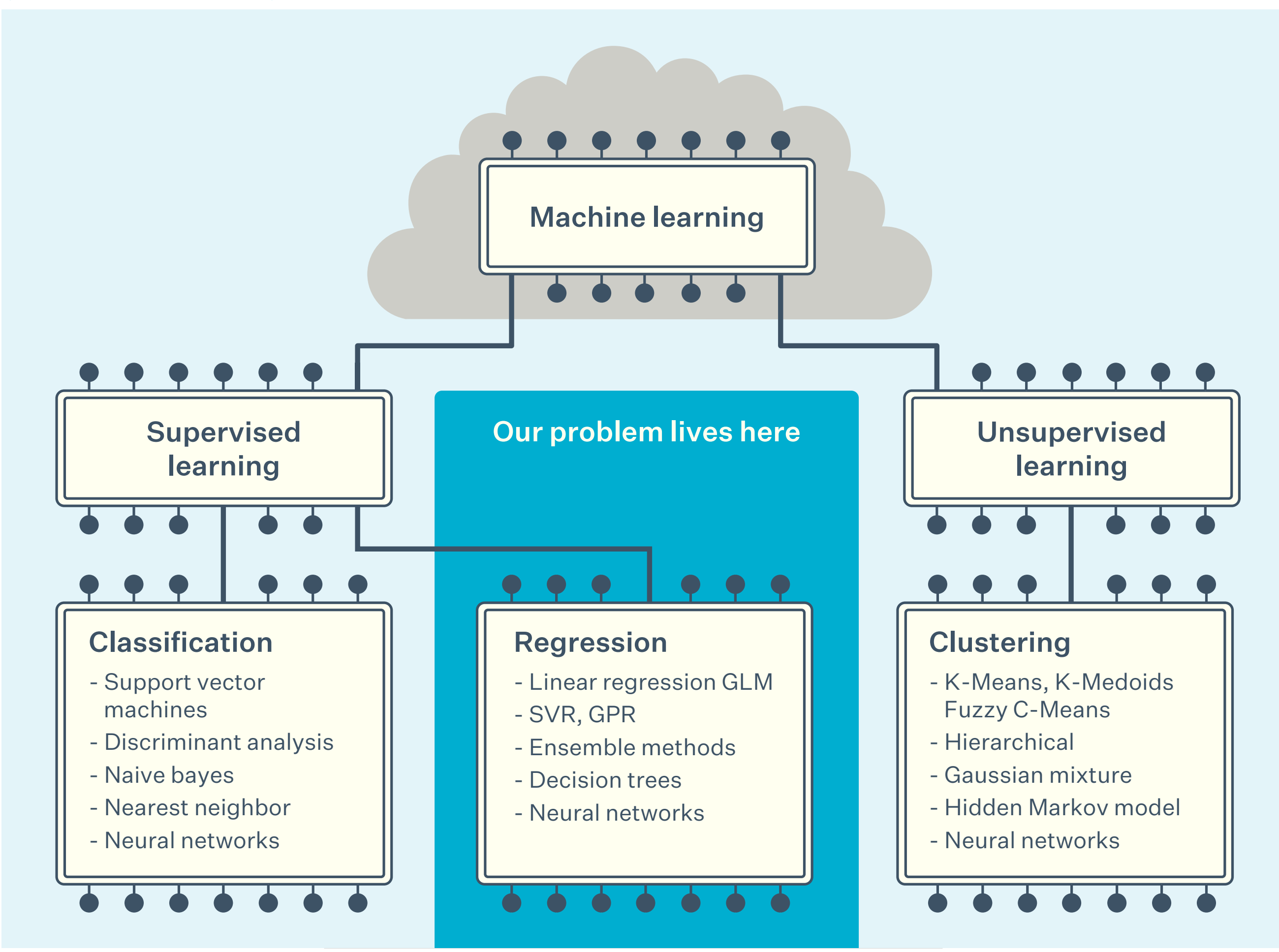
## C.1 Statistical model detailed methodology

The overarching goal of the statistical models is to rank-order adoption probability for selected DER measures, not to develop the most sophisticated model. We considered the following requirements when constructing the statistical models:

- Model must be scorable in AdopDER for every customer, measure, and year. This means that considerations of model run time place natural upper limits on the scoring algorithm's complexity.
- We need to be able to use the statistical model to adjust adoption probability for each customer and measure.
- Model must have locational and temporal awareness.

The selected methodology to develop these models was the scorecard model. A scorecard model is a type of regression model, as shown in **Figure 56**.

Figure 56. Machine learning taxonomy



Moreover, the scorecard model fits our selection criteria for model characteristics:

- Predicts a binary outcome (Adopt: yes/no)
- Uses binning for continuous variables
- Able to work around missing data
- Applies transformation to assign score points
- Provides a high degree of transparency, used in financial services
- "Easy" to implement in AdopDER

We used a structured modeling framework for statistical modeling. For all DER types modeled with a statistical modeling approach, we follow the steps in **Figure 56** to:

- Select variables
- Test the strength of the model, and
- Apply to the full population

**Figure 57** shows the workflow used for developing each separate model.

For the statistical models, we take all potential candidate variables identified in the literature review that may potentially help explain differences in adoption and then create a training model. We train the model on 70% of past adopters and test different combinations of variables for their ability to "predict" adoption for the remaining 30% of the sample that was withheld from the model training. This method is a commonly applied industry practice called "out of model validation".

Once we select the candidate variables and develop the final model specification, we conduct one last validation step (KS scoring) before deploying the model into AdopDER to disaggregate the DER adoption into locational granularity. At the end of this process, we have a process to feed into AdopDER and develop site-level adoption estimates for each year, and these are then aggregated up to the feeder or substation level for reporting purposes.

Figure 57. Structured modeling framework for statistical models

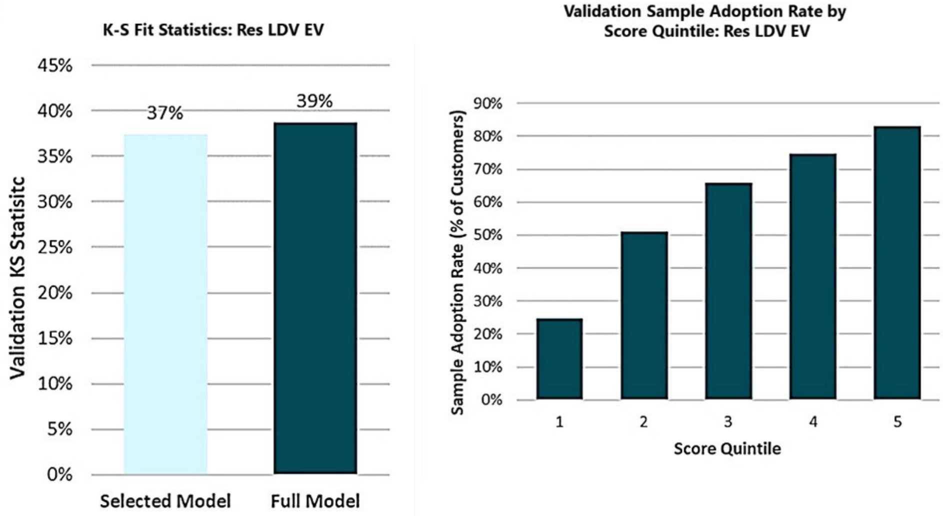
| Acquire data | Combine | Sample | Train | Validate | Deploy |
|---|---|---|---|---|---|
| • Identify candidate variables | • Join all candidate variables into single dataset | • Train model on 70% of premises<br>• Validate model on 30% of premises | • Variable selection<br>• Model specification | • Test rank order with validation KS | • Add scorecard to AdopDER<br>• Dynamic scoring in AdopDER |

The full variable list, specification results, and resulting EV LDV adoption propensity quintile rankings are shown in **Figure 58**. The selected model is shown as the model with blue-shaded variables in the univariate screening table, while the full model includes all variables that pass the univariate screen. Variables that were considered but had weak correlation (i.e., did not pass univariate screening) are shown in gray text.

**Figure 58. Residential LDV adoption — model creation process**

**Univariate Screening and Model Selection: Res LDV EV**

| Variable | Information Value |
|---|---|
| ch_num_vehicles | 0.591 |
| ct_med_hh_inc | 0.306 |
| ct_prop_park_area_tract | 0.294 |
| ct_est_vmiles | 0.290 |
| ct_tot_pop | 0.243 |
| ct_num_bev_adopt | 0.240 |
| AX_Score_GreenAffinity | 0.231 |
| consump_last_12_mos | 0.158 |
| ct_pv_kw_median | 0.141 |
| ct_avg_energy_burden_pct | 0.127 |
| xEstimatedIncomePremPlus | 0.109 |
| ch_solar_present | 0.108 |
| ct_num_solar_adopt | 0.108 |
| building_type | 0.087 |
| HomeOwnerRenterPremPlusAX | 0.058 |
| available_breakers | 0.054 |
| AgeCustName | 0.052 |
| ct_count_open_parks | 0.044 |
| vintage | 0.042 |
| te03_eligible_2020_no_vehicle_r | 0.041 |
| AX_Score_TechPropensity | 0.026 |
| ct_ev_level2_evse_num | 0.019 |
| ct_urban_rural | 0.017 |
| ct_ev_dc_fast_num | 0.012 |
| osps_zone | 0.012 |
| ct_ev_level1_evse_num | 0.005 |
| has_battery | 0.005 |
| ch_has_garage | 0.003 |
| ind_prim_road | 0.000 |
| ind_major_road | 0.000 |




The relative contribution that each of the final variables has on increasing or decreasing the adoption propensity away from the overall average is shown in the scorecard. **Table 51** shows how the selected model variables were binned and what their score was. Note that a score higher than zero means higher adoption probability compared to the baseline, whereas a score less than zero means lower adoption probability compared to the baseline adoption.

## Table 51. Residential LDV EV adoption scorecard

| Variable | Bin | Score Points |
|---|---|---|
| base points | NA | 552 |
| ch_num_vehicles | [-Inf,2) | -213 |
| ch_num_vehicles | [2,3) | -17 |
| ch_num_vehicles | [3,4) | 84 |
| ch_num_vehicles | [4, Inf) | 115 |
| ct_med_hh_inc | missing | 3 |
| ct_med_hh_inc | [-Inf,50000) | -4 |
| ct_med_hh_inc | [50000,75000) | -1 |
| ct_med_hh_inc | [75000,90000) | 1 |
| ct_med_hh_inc | [90000, Inf) | 5 |
| ct_est_vmiles | missing | -25 |
| ct_est_vmiles | [-Inf,30) | 19 |
| ct_est_vmiles | [30,37) | 7 |
| ct_est_vmiles | [37,49) | -7 |
| ct_est_vmiles | [49,52) | 24 |
| ct_est_vmiles | [52, Inf) | -17 |
| ct_num_bev_adopt | missing | 44 |
| ct_num_bev_adopt | [-Inf,40) | -84 |
| ct_num_bev_adopt | [40,90) | -23 |
| ct_num_bev_adopt | [90,130) | 10 |
| ct_num_bev_adopt | [130,310) | 39 |
| ct_num_bev_adopt | [310, Inf) | 103 |
| xEstimatedIncomePremPlus | missing | -5 |
| xEstimatedIncomePremPlus | $100,000 - $124,999 | 8 |
| xEstimatedIncomePremPlus | $15,000 - $19,999%,%$20,000 - | -13 |
| xEstimatedIncomePremPlus | $40,000 - $49,999%,%$50,000 - | -3 |
| xEstimatedIncomePremPlus | $75,000 - $99,999 | 5 |
| xEstimatedIncomePremPlus | Greater than $124,999 | 13 |
| xEstimatedIncomePremPlus | Less than $15,000%,%Unknown | -19 |
| AX_Score_GreenAffinity | missing | -16 |
| AX_Score_GreenAffinity | [-Inf,3) | -74 |
| AX_Score_GreenAffinity | [3,5) | -31 |
| AX_Score_GreenAffinity | [5,6) | 7 |
| AX_Score_GreenAffinity | [6, Inf) | 56 |

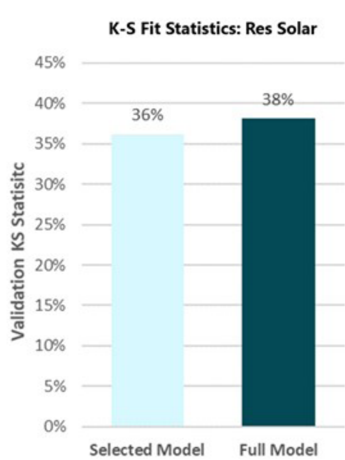
**Figure 59** and **Table 52** show the same model selection process and scorecard results for the residential Solar PV model.

## Figure 59. Residential solar PV — model creation process

**Univariate Screening and Model Selection: Res Solar**

| Variable | Information Value |
|---|---|
| building_type | 0.788 |
| ct_med_hh_inc | 0.637 |
| ct_num_solar_adopt | 0.554 |
| ct_tot_pop | 0.492 |
| HomeOwnerRenterPremPlusAX | 0.438 |
| ct_num_bev_adopt | 0.365 |
| xEstimatedIncomePremPlus | 0.327 |
| ch_num_vehicles | 0.302 |
| AgeCustName | 0.256 |
| AX_Score_GreenAffinity | 0.242 |
| consump_last_12_mos | 0.240 |
| ct_pv_kw_median | 0.231 |
| vintage | 0.176 |
| AX_Score_TechPropensity | 0.084 |
| has_battery | 0.058 |
| ct_avg_energy_burden_pct | 0.040 |
| ct_urban_rural | 0.014 |
| psps_zone | 0.011 |

Selected Variable
Fails Univariate Screen



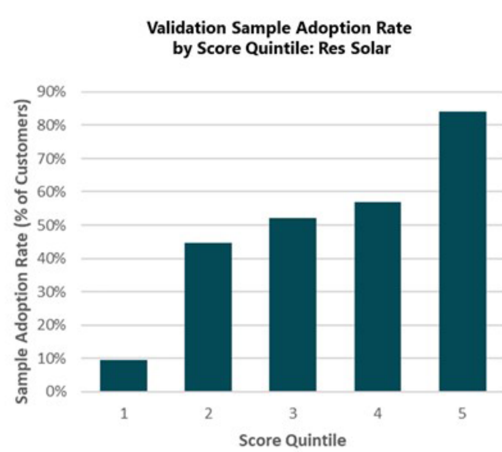



Table 52. Residential solar PV — adoption scorecard

| Variable | Bin | Score Points |
|---|---|---|
| basepoints | | 493 |
| building_type | MF | -325 |
| | MH%,%SF | 31 |
| ct_med_hh_inc | missing | -17 |
| | [-Inf,40000) | -26 |
| | [40000,50000) | -13 |
| | [50000,65000) | -2 |
| | [65000, Inf) | 7 |
| ct_num_solar_adopt | missing | -80 |
| | [-Inf,10) | -169 |
| | [10,20) | -64 |
| | [20,25) | -25 |
| | [25,75) | 22 |
| | [75, Inf) | 95 |
| HomeOwnerRenterPremPlusAX | missing | -97 |
| | O | 34 |
| | R | -112 |

# C.2 Heuristic model detailed methodology

For the heuristic models, variables and weighting assignments were developed based on a combination of literature review and subject area expert judgment by Cadeo and Brattle.

The single largest driver for residential storage adoption probability is whether or not a customer resides in a public safety power shutoff (PSPS) zone. Following that, there are high adoption probabilities for customers with solar, those residing in single-family dwellings, and/or those with high household incomes.

**Table 53** shows the variables considered and the relative "points" used to score their impact on raising or lowering adoption propensity.

Table 53. Residential behind-the-meter energy storage scorecard

| Variable | Value | Approx % of customers | Points |
|---|---|---|---|
| Baseline | | 100% | 500 |
| In PSPS Zone | Yes | 2% | 300 |
| | No | 98% | -30 |
| Presence of Solar | Yes | 2% | 200 |
| | No | 98% | -20 |
| Type of Building | SF | 73% | 50 |
| | MF or MH | 27% | -100 |
| Household Income | 0-40k | 18% | -50 |
| | 40k-100k | 40% | 0 |
| | 100k+ | 34% | 50 |
| | Unknown or Missing | 19% | -10 |

For non-residential storage, we sorted non-residential premises according to the type of business (using North American Industry Classification System or NAICS codes), their "green score," and their load factor based on analysis of customer load profiles. Similar to residential storage, being located in a PSPS zone drives the highest adoption probability. Otherwise, high probability tends to reflect customers with a high load factor, such as manufacturing and health care customers. The NAICS classification and ranking we used aligns with recent CA Self-Generation Incentive Program (SGIP) reported data. **Table 54**, **Table 55** and **Table 56** show the scorecard development process for non-residential storage, including the categorization and contribution of the principal components.

Table 54. Non-residential behind-the-meter energy storage scorecard

| Variable | Value | Approx % of customers | Points |
|---|---|---|---|
| Base | | 100% | 500 |
| In PSPS Zone | Yes | 2% | 300 |
| | No | 98% | -30 |
| Type of Business | Tier A | 10% | 250 |
| | Tier B | 20% | 100 |
| | Tier C | 15% | 0 |
| | Tier D | 55% | -100 |
| Green Score | 5 | 40% | 80 |
| | 3 or 4 | 45% | 0 |
| | 0 or 2 | 5% | -50 |
| | Unknown | 10% | -20 |
| Load Factor | LF > 0.25 | 20% | 0 |
| | 0 < LF <= 0.25 | 20% | 50 |
| | Missing | 60% | -50 |

Table 55. Non-residential behind-the-meter storage NAICS groupings

| Tier | NAICS2 | Count |
|---|---|---|
| A | Manufacturing | 5229 |
| A | Health Care | 5688 |
| B | Education | 2727 |
| B | Professional Services | 7097 |
| B | Public Admin | 4159 |
| B | Accommodation and Food | 6613 |
| B | Retail | 13160 |
| B | Transport and Warehouse | 2169 |
| B | Wholesale | 3915 |
| C | Admin and Waste Management | 2199 |
| C | Ag Forestry Fishing | 3017 |
| C | Arts Entertainment Recreation | 2540 |
| C | Corp Management | 470 |
| C | Financial | 2428 |
| C | Mining and Extraction | 53 |
| D | Construction | 5804 |
| D | Information | 1924 |
| D | Other Services | 8520 |
| D | Real Estate | 14730 |
| D | Unknown | 22085 |
| D | (blank) | 1092 |
| D | Utilities | 216 |

Table 56. Non-residential behind-the-meter energy storage profile by score quintile

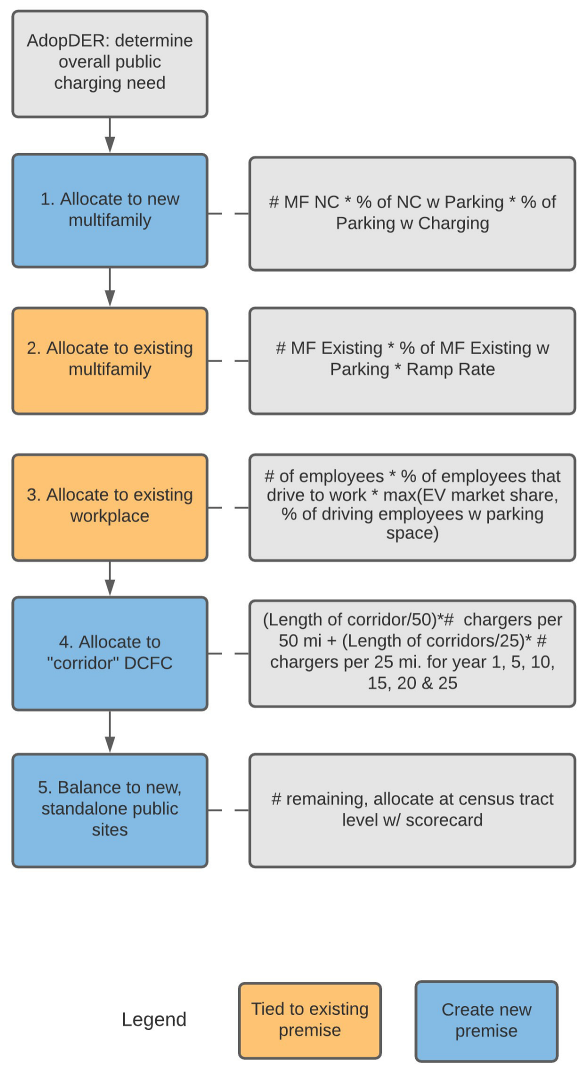
| Metric | Quintile 1 (Lowest Score) | Quintile 2 | Quintile 3 | Quintile 4 | Quintile 5 (Highest Score) |
|---|---|---|---|---|---|
| *Min Score* | *270* | *320* | *420* | *520* | *620* |
| *Max Score* | *320* | *420* | *520* | *620* | *1180* |
| | | | | | |
| % in PSPS Zone | 0% | 0% | 0% | 0% | 15% |
| % Tier A NAICS* | 0% | 0% | 0% | 1% | 47% |
| % Tier B NAICS* | 0% | 0% | 33% | 68% | 27% |
| % w/ Green Score = 5 | 0% | 54% | 47% | 48% | 35% |
| % w/ Green Score < 3 | 5% | 1% | 11% | 7% | 2% |
| % w/ Load Factor > 0.25 | 0% | 14% | 21% | 25% | 43% |
| % w/ Load Factor between 0 and 0.25 | 2% | 21% | 30% | 27% | 26% |
| % w/ missing Load Factor (i.e. no demand charge | 98% | 65% | 49% | 49% | 31% |

For public EV charging needs,[80] AdopDER determines public EVSE need based on EV adoption and on-site EVSE adoption. We allocate public EVSE based on premise and census-tract level data within AdopDER by considering the following factors:

- Presence of multifamily buildings
- Workplace charging requirements
- Corridor DCFC needs
- Equity considerations

**Figure 60** shows the heuristic allocation process by which we assign public charging needs in AdopDER. The overall public charging need is an output of the Phase I DER forecast and is accounts for the amount of unmet total charging energy across all vehicles and across segments.[81]. Both AdopDER and TEINA use NREL's EVI-Pro Lite tool in order to determine EV charging needs, but AdopDER is considering both private charging and public charging needs. Therefore, the TEINA study is a helpful benchmark, but is by itself insufficient for understanding the overall charging need of our customers.

Figure 60. Non-residential public charging process flow




80. "Public" = any EV charging not directly tied to the premise of a customer that has adopted an EV.
81. For a discussion of how AdopDER determines the overall public charging need, see chapter 4 of PGE DER and Flex Load Potential Study – Phase I Report, submitted as Appendix G to the DSP Part I filing and available at: https://portlandgeneral.com/about/who-we-are-planning/distribution-system-planning

The balance of new, standalone EV charging sites (Step 5 in **Figure 60**) are then allocated by census tract using criteria shown in **Table 57**. We differentiate between census tract median income levels to reflect the greater need of public charging infrastructure in areas where there may not be high accessibility for home charging, either because of higher multi-unit dwellings or no presence of garage/driveway for single-family sites. The greater need for public charging in these areas can help inform program design efforts aimed at improving equity of access to EV charging infrastructure.

Table 57. Non-residential standalone public charging scorecard

| Variable | Value | Points |
|---|---|---|
| Base | | 500 |
| Census tract Median Income | > 85,000 | -100 |
| | 45,000 to 85,000 | 0 |
| | < 45,000 | 100 |
| NAICS Tier 1 | > 100 premises in (Public Admin, Accom+Food, Arts+Ent, Retail) | 50 |
| | > 20 premises in (Public Admin, Accom+Food, Arts+Ent, Retail) | 0 |
| | Otherwise | -50 |
| Unmet charging | > 1000 vehicles | 25 |
| | 200 to 1000 | 0 |
| | < 200 vehicles | -25 |

# C.3 Detailed energy efficiency locational methodology

Given the nature of energy efficiency programs, the Proportional Allocation Method was recommended by the California Working Group on Distribution-level DER forecasting. This method consists of three steps:

1. Using the service territory EE forecast
2. Allocating to circuits based on allocation factors (calculated as ratio of sector-level energy or peak at the individual circuit-level to the overall sector energy or peak)
3. Making adjustments to this allocation to account for local information, such as large known projects

PGE hopes to continue working with Energy Trust to refine the method used in this initial DSP and better account for specific program and measure offerings included in the long-run Energy Trust forecast and how they align with geographic and customer characteristics, and past adoption of EE measures. PGE sees potential for greater planning integration along the following general areas:

- More refined modeling of new construction code impacts within Energy Trust's New Homes residential program. Currently, PGE provides a system-wide forecast of residential customer additions based on Population Estimates from PSU's Population Research Center that inform Energy Trust's long-run potential assessment for above-code energy savings. PGE sees potential to allocate these residential new construction savings forecasts into more granular elements by developing shared assumptions of location-specific population growth estimates, impact of local reach codes, and market knowledge of builder practices and customer demand preferences.
- Greater coordination on impact of low-to-moderate income programs on changes to measure adoption rates. Income is a key variable for our solar PV statistical model and is likely an important indicator of relative adoption for more expensive energy efficiency retrofits like shell upgrades (windows and insulation), HVAC and water heating equipment upgrades, and other higher cost measures. Although past Energy Trust studies have shown that more impactful measures do tend to be clustered among higher income groups, there is potential to improve the equitable adoption of these measures by continued refinement of LMI program offerings and combination with other potential funding sources (e.g., Portland Clean Energy Fund, low-income weatherization funds, and federal infrastructure bill dollars).
- Identify commercial and industrial EE potential by key market segments and drivers

Historically, the linkage between PGE's load forecast for business customers and Energy Trust's EE forecast for commercial and industrial programs has been difficult to align. The current method of allocating by proportion of annual kWh deliveries by revenue class and substation does not account for the relative measure mix included in Energy Trust's forecast as it applies to building- and equipment-level baselines. In future iterations, identifying how the EE potential differs by market sub-segment could potentially allow greater insights about locational impacts of EE on the distribution grid.

# Appendix D. Equity variables and sources

The following table shows the equity related variables and data sources we are considering and analyzing.

| Variable | Category | Details/ Description | Data Source | Data Source Geographic Scale | Notes |
|---|---|---|---|---|---|
| Racial Composition | DEI | % of the census block population is non-white | ACS | Census Block Group | Variable from Greenlink database |
| Homeownership | DEI | % of households in census block group that is renting | ACS | Census Block Group | Variable from Greenlink database |
| Households with Above Average, High, or Severe Energy Burden | DEI | Energy Burden is the percent of median yearly income that households pay for electricity and gas bills. Households nationally on average pay about 3% of their income on energy bills. A household that pays more than 6% of their income on energy bills is considered to have high energy burden, while a household that pays more than 10% is considered to be severe energy burden. These indicators show the number of households with energy burdens above the 3% national average, the 6% threshold for high energy burdened, or the 10% threshold for severe energy burden across different census tracts. | DOE LEAD | Census tract | Variable from Greenlink database |
| Education | DEI | % of households in census block group with no high school diploma | ACS | Census block group | |
| PGE Payment Issue | DEI | Household with one or more need criteria: payment assistance, disconnection due to lack of payment, late notices (1 or 0) | PGE | Household | |
| PGE Payment Issue Score | | Households with payment issues get a score of 1-3 with a point for each issue: payment assistance, disconnection due to lack of payment, late notices | | | |
| Poverty level | DEI | Households at or below 200% FPL OR at or below 60% AMI | ACS | Census block group | |

| Variable | Category | Details/ Description | Data Source | Data Source Geographic Scale | Notes |
|---|---|---|---|---|---|
| Tribal Communities | DEI | Oregon's nine recognized Native American tribes: Burns Paiute Tribe, Confederated Tribes of Coos, Lower Umpqua and Siuslaw Indians, Coquille Tribe, Cow Creek Band of Umpqua Tribe of Indians, Confederated Tribes of the Grand Ronde Community of Oregon, The Klamath Tribes, Confederated Tribes of Siletz, Confederated Tribes of the Umatilla Indian Reservation, and the Confederated Tribes of the Warm Springs Indian Reservation. | DOE LEAD | Census Tract | |
| Native American Populations | DEI | % of population in census block group that is Native American | ACS | Census Block Group | |
| Rural Communities | DEI | The rural-urban commuting area (RUCA) codes classify U.S. census tracts using measures of population density, urbanization, and daily commuting. A second dataset applies 2010 RUCA classifications to ZIP code areas by transferring RUCA values from the census tracts that comprise them. The most recent RUCA codes are based on data from the 2010 decennial census and the 2006-10 American Community Survey. The classification contains two levels. Whole numbers (1-10) delineate metropolitan, micropolitan, small town, and rural commuting areas based on the size and direction of the primary (largest) commuting flows | RUCA | Census Tract | https://www.ers.usda.gov/data-products/rural-urban-commuting-area-codes/documentation/ |
| Housing Type | DEI | Single or Multi (i.e., single family attached, single family detached, multifamily 2 units, multifamily 3-9 units, up to 50 units or more). | ACS | Census Block Group | Variable from Greenlink database |
| Lack of Internet Access | DEI | Median percentage of homes that do not have internet subscription. | ACS | Census Block Group | Variable from Greenlink database |
| Energy Burden | DEI | The percent of median yearly income that households pay for electricity/gas | DOE LEAD | Census Tract | Variable from Greenlink database |

| Variable | Category | Details/ Description | Data Source | Data Source Geographic Scale | Notes |
|---|---|---|---|---|---|
| English Proficiency | DEI | % of households in census block group with limited English | ACS | Census block group | |
| Householder's Age | DEI | Disclosure of ages of heads of household - those in charge of decisions about improvements | ACS | Census block group | |
| Eviction Rate | DEI | Median percent of evictions per 100 renting households | Princeton Eviction Lab | Census Block Group | Variable from Greenlink database |
| Electricity Burden | DEI | The percent of median yearly income that households pay for electricity bills. | ACS | Census Block Group | Variable from Greenlink database |
| Asthma | DEI | Median percentage of adults (populations age 18 or older) with asthma in census tract | CDC 500 Cities | Census Tract | Variable from Greenlink database |
| Air quality (PM2.5); | Environmental | Daily an Annual PM2.5 Concentrations for US in 1 km grids | EPA EJ Screen | Census block based on particular collection points (4 in Portland metro area) | Variable from EPA EJScreen |
| Air quality (O3); | Environmental | Daily and Annual O3 Concentrations for US in 1 km grids | EPA EJ Screen | Census Tract | |
| Air toxics cancer risk | Environmental | Lifetime cancer risk from inhalation of air toxics | NATA | Map layer created using EPA air quality facilities | Variable from EPA EJScreen |
| Respiratory hazard index | Environmental | Air toxics respiratory hazard index (ratio of exposure concentration to health-based reference concentration) | NATA | Map layer created using EPA air quality facilities | Variable from EPA EJScreen |
| Proximity to Traffic (Air quality) | Environmental | Traffic proximity and volume by Census Block Group, as a percentile compared to state or compared to US | EPA EJ Screen | Census Block Group | Variable from EPA EJScreen |
| Proximity to Environmental Hazards | Environmental | Data available for proximity to hazardous waste and superfund sites by census tract as a percentile compared to the state or the US. Count of hazardous waste facilities or proposed or listed superfund sites (TSDFs, LQGs and NPLs) within 5 km (or nearest beyond 5 km), each divided by distance in kilometers | EPA EJ Screen | Census Tract | Variable from EPA EJScreen |
| RMP Facility Proximity | Environmental | Count of RMP (potential chemical accident management plan) facilities within 5 km (or nearest one beyond 5 km), each divided by distance in kilometers | EPA EJ Screen | Census Tract | Variable from EPA EJScreen |

| Variable | Category | Details/ Description | Data Source | Data Source Geographic Scale | Notes |
|---|---|---|---|---|---|
| Underground Storage Tanks (UST) | Environmental | Count of LUSTs (multiplied by a factor of 7.7) and the number of USTs within a 1,500-foot buffered block group | EPA EJ Screen | Census Tract | Variable from EPA EJScreen |
| Wastewater Discharge | Environmental | Modeled toxic concentrations at stream segments within 500 meters, divided by distance in kilometers (km) | EPA EJ Screen | Census Tract | Variable from EPA EJScreen |
| Public Safety Power Shutoff Zone | Resiliency | Sites are marked as in a PSPS zone and are more likely to experience safety shutoffs due to natural disasters like fires. | PGE | Household | |
| Wildfire Risk - Expected Annual Relative Housing Unit Risk (EAHUrisk) | Resiliency | EAHUrisk is an index of the expected damage to, or loss of, housing units within a summary polygon due to wildfire in a year. This is a long-term annual average and not intended to represent the actual losses expected in any specific year. It is calculated as the product of HUexposed (housing units exposed) and MeanRPS (MeanRPS is the housing-unit weighted mean of the Risk to Potential Structures raster within a summary polygon). | US Forest Service | Raster | https://www.fs.usda.gov/rds/archive/Catalog/RDS-2020-0016 |
| Flood Risk | Resiliency | The National Flood Hazard Layer (NFHL) data incorporates all Flood Insurance Rate Map (FIRM) databases published by the Federal Emergency Management Agency (FEMA), and any Letters of Map Revision (LOMRs) that have been issued against those databases since their publication date. The primary risk classifications used are the 1-percent-annual-chance (or 100-year) flood event, the 0.2-percent-annual-chance (or 500-year) flood event, and areas of minimal flood risk. | RLIS-FEMA | Polygons | |
| CMI | Resiliency | Average annual customer minutes interrupted - total customer outage time for a sustained outage. | PGE SAM | Feeder level | Variable from PGE |
| CELID24 | Resiliency | Average percentage of customers exceeding 24 hours of outage duration including Major Event Days | PGE SAM | Feeder level | Variable from PGE |
| Loss of supply substation - count | Resiliency | Average annual number of loss of supply substation outages at feeder level. Major event days excluded | PGE SAM | Feeder level | Variable from PGE |

| Variable | Category | Details/ Description | Data Source | Data Source Geographic Scale | Notes |
|---|---|---|---|---|---|
| Loss of supply substation - hours | Resiliency | Average annual customer hours interrupted due to loss of supply substation outages. Major event days exclude | PGE SAM | Feeder level | Variable from PGE |
| Loss of supply transmission - count | Resiliency | Average number of loss of supply transmission outages. Major event days excluded | PGE SAM | Feeder level | Variable from PGE |
| Loss of supply transmission - hours | Resiliency | Average customer hours interrupted due to loss of supply transmission outages. Major event days excluded | PGE SAM | Feeder level | Variable from PGE |
| MED | Resiliency | Average number of major event days that occurred during the year (SAIDI exceeding a threshold value) | PGE SAM | Feeder level | Variable from PGE |
| SAIFI | Resiliency | SAIFI for the feeder (frequency of outages). Major event days excluded | PGE SAM | Feeder level | Variable from PGE |
| SAIDI | Resiliency | SAIDI for the feeder (duration of outages). Major event days excluded. | PGE SAM | Feeder level | Variable from PGE |
| Sustained outages | Resiliency | Average number of sustained outage events (classification based on exclusion criteria). Major event days excluded | PGE SAM | Feeder level | Variable from PGE |

# Appendix E. NWS details

This appendix provides more detail regarding the NWS process we applied while formulating the two pilot concept proposals. Much of the discussion is about overarching considerations and important factors that we have considered throughout the process. We expect that these considerations will lead to more discussion in the evolution of the DSP guidelines and do not represent an end state.

# E.1 NWS process overview

**Figure 61. Distribution planning process — augmented with consideration of NWS**

# E.2 NWS screening

This section describes the criteria PGE uses to identify if a NWS can solve the identified grid needs. Following Step 3a: Current state analysis, projects will be screened to determine if a NWS is applicable to the grid need, focusing on:

1. Type of grid need
2. Forecast certainty
3. Lead time
4. Minimum project cost

## E.2.1 TYPE OF GRID NEED

To meet this criterion, a grid need must align with **Table 58**, which lists the type of grid needs that are applicable for NWS along with examples of wired and non-wired solutions that could potentially resolve the problem.

Table 58. Types of projects that are suitable for non-wired solutions

| Type of grid need | Example of traditional solution | Example NWS product and/or service |
|---|---|---|
| **Thermal capacity upgrade projects or (N-0) capacity projects usually driven by growth in load on existing infrastructure** | Substation transformer capacity upgrade<br><br>Reconductoring of circuit (larger wire size)<br><br>Build new feeder | DERs that can reliably shape or be dispatched to alleviate existing or forecasted peak load on the distribution circuit or substation transformer. |
| **Reliability solutions driven by N-1 contingency requirements** | Substation transformer capacity upgrades<br><br>Reconductoring of circuit<br><br>Build new feeders<br><br>Distribution automation | DERs that can be reliably dispatched to provide contingency relief at a requested time, duration and/or frequency. |
| **Hosting capacity and volt-var improvements** | Capacitor banks<br><br>Change load tap changer settings<br><br>Line voltage regulators<br><br>Protection Upgrades (Hot Line Blocking, 3V0 Protection) | Smart inverters and batteries could be used to provide volt-var and Conservation Voltage Reduction (CVR) services. This would include supporting voltage quality, reducing losses, and net energy consumption on the feeder. |
| **Resiliency upgrades: new supply paths for increased resiliency** | New substation or feeders<br><br>New switching points or tie lines<br><br>Reconductors<br><br>Substation upgrades<br><br>Distribution automation | Microgrids for partial/full back-up power during grid and/or wildfire related emergencies. |
| **Customer Experience** | Case by case | Case by case |
| **Policy-mandated NWS** | Case by case | Case by case |

### E.2.2 FORECAST CERTAINTY

Modeling NWS, especially customer-sited solutions, is complex given the many different technologies and their interactive effects with each other and the grid under different weather scenarios, customer behavior, and device settings or preferences. The addition of forecast uncertainty exponentially increases the complexity and time required to analyze the different NWS options. To make prudent use of planning resources, the forecast variation within a study area must be reasonably certain for the project to be considered for a NWS. Presently, this is determined by the distribution planning engineer based on the available data and confidence. PGE expects learnings from the implementation of pilot projects will help establish a metric and threshold to determine forecast certainty and when (or if) a given level of uncertainty should prevent projects from proceeding through the screening process.

### E.2.3 LEAD TIME

Timeline suitability is recommended to make sure there is sufficient time to develop a NWS, engage with the community, and implement the chosen solution in time to address the identified grid need. Aligning with national best practices[82], PGE will adopt a typical minimum lead time required for NWS of 30 months, though we will not exclude shorter lead time projects if there is compelling reason to do so. We also expect this requirement to change as we learn more from the pilot projects. This lead time requirement can be attributed to the following processes:

- NWS Development Process. The iterative nature of developing a NWS and additional regulatory approvals increase overall lead times for NWS. This process may take between 6 to 12 months.
- Implementation Process. The implementation time for the chosen solution is also a function of the scale and complexity of the project. The time for NWS implementation is typically 20 to 40 months, which contributes to the "minimum of 30-month" requirement above.

### E.2.4 MINIMUM PROJECT COST

Smaller projects are often addressed by wired solutions that are relatively inexpensive and quick. Plus, the locational value of the avoided or deferred wired solution must be large enough to make a meaningful difference to DER adoption through different program mechanisms, such as marketing or incentives. For these reasons, and in alignment with national best practices, PGE maintains a minimum project cost threshold for NWS. This will allow us to focus on utility projects of sufficient scale that are more likely to be good candidates for NWS.

Following feedback from stakeholders and learnings from early efforts to develop the pilot concepts, PGE recommends $500,000 as a threshold for smaller grid needs (under 2 MW) and longer deferral periods (5 years or more). This is based on the expected impact to the benefit stack where an ideal/perfect resource could improve its benefits by approximately 20%. For all other projects a nominal figure of $1 million will be used to assess NWS suitability, but we will also consider the size of the project when determining suitability.

- Multi-Feeder/Substation. Typical lead time of more than two years to design and construct. Cost of project is typically higher (>$1 million). Geographic footprint is likely to cover a larger area, more customers, and thus, an increased opportunity for customer-sited DER solutions.
- Feeder/Circuit-specific. Typical lead time nine months to two years to design and construct. Cost of project is typically lower (<$1 million). Geographic footprint is also likely to cover a smaller area and present fewer load relief opportunities.

82. Screening of Non-Wires Alternatives in Distribution Planning: Guidance, Criteria, and Current Practices. EPRI, Palo Alto, CA: 2020. 3002018820.

# E.3 NWS development process

If a NWS is deemed suitable to address a specific grid need, PGE will conduct the following steps to develop the NWS concept proposal:

- Conduct community needs assessment
- Determine resource potential and applicability to grid need criteria
- Assess DER costs and benefits
- Compile NWS portfolio and evaluate performance risks
- Document implementation considerations and engagement roadmap

We first provide a detailed overview of each of these key steps, and results of this process for our two concept proposals presented in **Section 6.4**.

## E.3.1 CONDUCT COMMUNITY NEEDS ASSESSMENT

Following our best practices identified in **Section 2.2**, we aim to communicate early and often with our communities and break down technical barriers to robust participation in solution development. Therefore, our first step to developing a NWS project will be to conduct a community needs assessment. The precise scope and format of this needs assessment will evolve based on feedback received from participants. However, we expect this needs assessment to include a minimum of the following elements:

- **Community outreach and engagement findings:** Building off the series of Community Workshops we held to inform these initial concept proposals, we will continue to refine the presentation materials in ways that are meaningful to our community partners, as well as seek additional ways to connect and solicit meaningful participation and feedback.
- For instance, we will schedule and plan these engagement efforts with an increased emphasis on identifying CBO partners serving the affected areas where a NWS is being proposed, and providing opportunities for community leaders to be appropriately compensated for providing their localized expertise and knowledge of the communities they serve. This is a critical aspect to the work because many of our CBO partners are primarily engaged in delivering programs that are critical to the health and well-being of the community, but may lie outside of the traditional utility or energy services industry landscape and areas of expertise. Therefore, we need to pay for the type of services and know-how just like we do for other consulting engagements in the more technical realms of DER planning and implementation.
- All methods, outreach, and recommendations employed in a targeted NWS community engagement exercise will be compiled for later use in the decision-making and implementation phases of the process.
- **Localized survey of the building stock and customer base:** In order to make good on our promise of implementing human-centered planning, we will contract with local community partners and other technical service providers to develop detailed assessments of the local building stock in the NWS area. Doing so will ground the development of the NWS within the values of the community and identify DER solutions that will be both realistic and achievable.
- There is a large push to increase the capacity of CBOs to engage in the energy transition. For example, the Portland Clean Energy Fund recently awarded over $100M to fund 65 different projects in their second round of awards.[83] While this particular funding opportunity is unique to Portland, we see elements of this transition reflected in HB2021 and expect this dynamic of broadening participation in the energy system to continue growing across the state. We aim to continue developing the capacity of our CBO partners to enable them to directly benefit by procuring implementation and delivery contracts for initiatives like NWS projects. This is doubly important because not only can our community partners gain valuable experience scoping and delivering clean energy projects by participating in this manner, but they also maintain networks of trust with some of our most vulnerable customers, and therefore can greatly aid in the efficient delivery of these customer-sited solutions to the end users.

83. Portland Clean Energy Fund grant recipients, available at: https://www.portland.gov/bps/cleanenergy/2022-pcef-rfp-2-grant-recipients

While we are separately detailing these aspects of the Community Needs Assessment, they are in fact interdependent. At the outset, we will share existing information and datasets with our community partners (such as the results of our Equity Index scores for the targeted areas) in order to engage in discussions about what additional datasets our CBO partners may have regarding their community. For instance, the sheer scope and availability of Census data is helpful for conducting analyses across many geographic areas and scales of granularity, but there are serious limitations to relying solely on this data source for developing culturally responsive program interventions.[84]

We will attempt to augment our existing DEI data with localized knowledge to the extent possible for each targeted NWS project development. We expect feedback and insights gathered during the community outreach and engagement step to directly influence the nature and scope of localized survey activities we outlined. For example, by conducting initial community outreach, we might identify which CBOs have the relevant expertise and interest in bidding on a competitive grant or contract opportunity (likely through competitive RFP). The vehicle of these contract opportunities would then provide opportunity for direct economic development in the community, while generating actionable findings such as:

- Detailed energy needs of the community
- Identification of any additional datasets about local demographics and trends
- Insights regarding technical potential for DER solutions given the local building stock
- Recommendations regarding effective delivery channels to promote equitable distribution of DER solutions.

This is a high-level proposal of what we interpret as valuable aspects of a community needs assessment. However, we recognize that we are not the experts in this area and we welcome feedback on this proposed approach to help us realize the vision of empowered communities.

### E.3.2 DETERMINE RESOURCE POTENTIAL AND APPLICABILITY TO GRID NEED CRITERIA

As discussed in **Section 3.5**, PGE uses the AdopDER model to forecast DER growth, including distributed solar and storage, EVs, and demand response / flexible loads.

However, this forecast simply applies different disaggregation rules to our system-wide DER forecast to assess locational adoption under business-as-usual programmatic and market effects. To assess the potential of DERs to contribute to a NWS, we need to further define and prioritize DER potential based on the particular characteristics of each area. The main areas we will discuss in our evaluation of the pilot concepts are:

- **Shape of contribution:** Assess the contribution of each DER type toward reducing locational system needs
- **Availability of resource:** Determine the realistic amounts of DERs that can be installed on a timeline that will alleviate grid constraints commensurate with the deferred traditional solution, given existing and potential new programs and partnerships and the potential influence of higher avoided costs on making existing offerings more economically attractive to customers
- **Reliability:** Develop understanding of how the DERs can be expected to contribute to system relief during expected worst-case scenarios, including during N-1 contingency events and extreme weather conditions.

Taken together, these factors will improve our ability to weigh the benefits and costs against existing and established practices of evaluating distribution system improvements.

In this filing, we developed a representative mix of DER technologies that could comprise a NWS portfolio of adequate size to meet the identified grid needs. We did this in order to evaluate the relevant costs and benefits of each option compared to the traditional (wired) solution to meet the grid need, and to solicit dialogue about the various considerations of each approach within the context of existing rules and practices.[85]

84. This dynamic has been raised by DEI practitioners and community advocates for some time, and we accept their critique as valid in and of its own account. However, to see an overview of this issue from a national media source as it pertains to the 2020 Census undercount, see for example this NPR article, available at: https://www.npr.org/2022/03/10/1083732104/2020-census-accuracy-undercount-overcount-data-quality
85. We have done our best to ensure the DER portfolio developed, as well as associated costs and benefits, represent what would likely get installed under a future NWS pilot. We emphasize that due to timing constraints and the uncertainty associated with eventual Commission guidance on the relative merits of these proposals, what we present here and in **Section 6.4** are representative portfolios only and may not reflect actual mix of technologies (and therefore overall costs and benefits) that would get deployed if the NWS pilot concept is approved.

For each grid need, we developed two NWS options to compare against the traditional wired solution:

- **Reliability focused:** These portfolios assumed relatively low DER penetration and a higher reliance on front-of-the-meter storage to address the identified grid need. These tend to be higher cost but also have elements of higher reliability given the known timelines and performance characteristics of these type of resources.
- **Customer resiliency focused:** These portfolios sought to maximize the amount of realistic achievable customer-sited DER adoption, including distributed solar and storage, demand response / flex loads, and energy efficiency. While the size of the need still likely requires some level of firm resource procurement (such as front-of-the-meter storage), the size of this need is greatly reduced by the increase in customer-sited DERs.

To develop the amount of DERs contributing to each portfolio, we first leveraged the feeder-level DER adoption results from AdopDER for solar PV, storage, and flex loads / demand response. In order to reflect the higher locational value and potential for increased targeted marketing and incentives, we quantified the achievable potential as the difference between the reference case adoption and 120% of the high adoption scenario.

For energy efficiency, we reviewed Energy Trust's typical project types over the last few years and evaluated these for their ability to contribute savings during the time period (generally summer, 12pm to 7pm) of the grid needs particular to each NWS area. We then used our judgment to apply these average project sizes to the specific types of customers we see on the NWS feeders. After developing this forecast, we confirmed with Energy Trust that these targets are reasonable given the potential for enhanced incentives and the lead times needed to bring these resources online.[86]

## E.3.3 ASSESS DER COSTS AND BENEFITS

A benefit cost ratio is calculated based on the present value of the costs and benefits over the lifetime of the project. PGE has leveraged the National Standard Practice Manual, DOE's next generation of distribution planning, New York's BCA handbook, and California's DER ACC, which are vetted by experts across several jurisdictions and stakeholders to determine the range of costs and benefits applicable to NWS analysis. PGE screens each DER/program's benefit-cost ratio accounting for locational value, value stacking of bulk system benefits, and community values including reduction in energy burden, health and safety, and customer resilience, as applicable.

The resource economics may change based on available community partnership opportunities and various potential external funding arrangements. These will be reviewed on a case-by-case basis and may include efforts to pair NWS projects with local-, state-, or federal tax rebates or incentives, or any other means of supplemental funding that acts to reduce the total cost of delivering the NWS solution. In such cases, leveraging this cost share may tip the calculation in favor of projects that otherwise would not be cost-effective.

86. PGE appreciates the continued partnership from Energy Trust to identify additional ways to showcase the potential of energy efficiency investments to alleviate constraints on the distribution system and provide for additional GHG benefits to our communities. We believe that Energy Trust's experience with Targeted Load Management pilots for PacifiCorp and Northwest Natural will prove valuable if the pilot concepts are approved and move forward for further development. Due to staff and budget constraints for this filing expressed by Energy Trust, we opted to keep the energy efficiency potential assessment for the NWS at a high-level and therefore is subject to future refinements.

### E.3.4 COMPILE NWS PORTFOLIO AND EVALUATE PERFORMANCE RISKS

PGE's preference is to leverage NWS to accelerate DER adoption and provide enhanced opportunities for customers to benefit directly from our distribution system investments, particularly EJ communities. Therefore, once the applicable resources and their respective characteristics are identified, the customer-sited DERs are assessed to determine if they can, in aggregate, meet the identified grid need for the required years. Based on the remaining need, the portfolio is either reduced or augmented (based on considerations of risk and cost, among others) with utility-scale solutions like front-of-the-meter storage.

When analyzing the performance of the portfolio, we will also consider the interactive effects of resources and any unintended consequences they may pose to the distribution system. PGE integrates the impact of a NWS within CYME through modified load profiles. The study area is simulated in CYME to determine if the NWS solution addresses all applicable thermal and voltage violations under both N-0 (normal) and N-1 (contingency) grid conditions. PGE will analyze peak and day-time minimum loading impacts, as applicable. If the NWS successfully addresses the applicable violations, the project is moved to the next step of decision making.

PGE is undertaking a multi-year effort to obtain the next generation of planning capabilities. Time-Series Power Flow is a key capability needed to study the impact over the course of a day, or potentially multiple days, that the NWS portfolio has on reducing thermal and voltage violations. This is a reflection of the fact that resources must be available at the right time of day, and potentially across multiple days and/or seasons (depending on the need being addressed). As part of the solution development, PGE will also consider eliminating NWS that may result in unsafe conditions and/or negatively impact equity, create equipment or human safety concerns, or other case-by-case considerations.

Given that there are significant unknowns about the reliability of DERs to provide locational grid services, PGE is adopting a phased approach to the implementation of customer programs where the range of potential demand reductions are large, meaning that either savings are unpredictable during peak conditions, or where savings can be significantly influenced by customer behavior, especially in smaller geographical footprints.

For instance, although certain programs (e.g., Peak Time Rebates or Time of Day pricing) offer potential for quick scaling and low cost of enrollment, they also are more variable in the shape of the savings provided and therefore increase uncertainty risks. Therefore, PGE will balance the amount of more reliable resources like battery storage and water heater DR programs, with more behavioral-based programs like these. In addition, key learnings of the pilot will be to further quantify and determine the operational characteristics of these resources when aggregated at smaller geographic scales. This type of information is important for system operators to develop the trust needed to call on these during contingency events.

# E.4 Decision making

All wired and non-wired solutions are analyzed and compared via a comprehensive set of metrics and analysis. NWS can impact the following metrics:

- **Lifecycle cost of ownership.** Represents the delta between the current system and the proposed solution, where lifecycle cost of ownership is the cost to own and maintain asset(s) over time and is the NPV of cost stream, which includes maintenance, risk, and capital investment. Customer owned assets shift the cost to own and maintain asset(s) to the customers lowering the lifecycle cost of ownership and making the project more favorable.

- **Benefit cost (B/C) analysis.** For wired solutions, this metric compares the delta in lifecycle cost of ownership divided by capital investment required to determine whether risk and reliability benefits exceed investment. For NWS, it includes incremental costs and benefits that stem from the resource economics as detailed in the **NWS development process**. Thus, the benefit-cost analysis for NWS can include distribution system benefits such as the locational value, bulk system benefits such as capacity and energy, and applicable non-energy benefits, which can make it more favorable.

- **Near-term risk.** Annual probability of failure multiplied by consequence of failure. Consequence of failure is primarily focused on the customer's reliability experience, monetized by willingness-to-pay data. The analysis also includes, where applicable, calculated safety and environmental risks. The interaction of near-term risk with NWS portfolios is complex and may make the NWS more or less favorable for selection.

- **Equity metrics.** This is an emerging metric. NWS have the potential to positively impact equity metrics. We have outlined multiple pathways to develop an equity index in this report, including a comprehensive assessment of potential candidate variables across demographic, environmental, and resiliency categories, and will continue to work with DSP participants to appropriately integrate equity metrics into decision making for NWS projects.

- **Resilience metrics.** This is an emerging metric. Given the breadth of DER options evaluated, the impact on resiliency depends on both the definition given, and the operation of the DER type. Solar PV has the potential to provide backup generation during an outage if the inverter is set with appropriate settings. Similarly, battery storage can provide relief to the grid or can be reserved for providing maximum backup power to the customer in the event of an outage. Moreover, demand response and flexible loads provide value in an outage if they are configured as part of a microgrid, and therefore can help shed non-critical loads to maximize the availability of any on-site generation and storage. Given the inherent trade-offs concerning resilience impacts of NWS, further analysis is required to better understand these use cases.

Once each metric is calculated, PGE will leverage guidelines to score the different elements and determine the recommended solutions. Each metric has an associated weight that determines the effective impact of the metric to the final decision. These weights will be shared following the development of the equity metrics through the DSP public process.

# Appendix F. Modernized grid capability descriptions

The description of each capability identified in the DOE's DSPx framework along with the needs they address, and examples of the associated technologies and functions are included in the table below.

| Capability | Description of capability and needs statement |
|---|---|
| **Customer DER Portal** | **Description:** Provide customer access to relevant and timely usage, performance, and system data. Data-driven personalization of product and program recommendations to aid customers in meeting their energy goals.<br><br>**Needs statement:** Enable customer choice, customer awareness and decision making.<br><br>**Example technologies:** Customer analytic tools (e.g., calculators), green button (automated data transfer), smart meters/meter data management system, customer energy management tools.<br><br>**Example functions:** Remote meter data collection and verification, energy management and DER purchase/program performance analysis, advanced interactive voice response (IVR) systems, IT based customer interfaces, mobile-enabled digital dashboards, mobile alerts. |
| **Virtual power plant (VPP)** | **Description:** Aggregated flexible loads and DERs, that in coordination supply grid services visible to and dispatchable by PGE power operations, characteristic of a traditional power generation facility.<br><br>**Needs statement:** Distribution investment deferral, support for customer needs such as resilience and resource adequacy.<br><br>**Example technologies:** DERs, DER programs, dynamic tariffs, DERMS.<br><br>**Example functions:** Delivery of peak load electricity or load-following power generation on short notice, ancillary services including frequency regulation and providing operating reserve. |
| **Planning and engineering** | **Description:** Integrated tools to support distribution system planning and engineering functions.<br><br>**Needs statement:** Improved planning enables more efficient grid investments, incorporating DER integration, stakeholder information exchange, and non-wires solutions.<br><br>**Example technologies:** CYME (power flow analysis), cost-effectiveness tools, AdopDER (DER forecasting).<br><br>**Example functions:** Grid needs analysis, locational net benefit analysis, non-wires solutions analysis, hosting capacity analysis, DER forecasting and Interconnection studies. |

| Capability | Description of capability and needs statement |
|---|---|
| **Grid management systems** | **Description:** Operational technology-based tools used by operators of electric utility grids to monitor, control and manage the performance of the distribution system.<br><br>**Needs statement:** Shifting from management of one-way power flows to two-way power flows requiring coordination of large numbers of DERs presents engineering and operational challenges. As DER adoption grows, so grows the need for technology to enable efficient operation of the system to handle proliferation of possible control actions, reduction in time to implement control actions, and increases in frequency and magnitude of potential safety and reliability issues.<br><br>**Example technologies:** Advanced distribution management system (ADMS), DER management system (DERMS), outage management system (OMS), demand response management system (DRMS).<br><br>**Example functions:** Monitor grid operations, analyze the data collected, predict events and grid behavior through algorithms, schedule operations and switching, issue commands to grid devices based on the analyzed information (fault location, isolation, and service restoration/FLISR scheme and volt VAR optimization/conservation voltage reduction), Optimal Power Flow, Constraint management, and DER operational functions. |
| **Sensing, measurement and automation** | **Description:** Operating the distribution system requires continuous monitoring of the infrastructure that comprises the grid. Sensing, measurement and automation is accomplished through devices installed at various points on the distribution system — such as along feeders, at breakers, switching devices and distribution power transformers. The deployment of those devices determines the degree to which the grid can be controlled by the grid management system.<br><br>**Needs statement:** More granular sensing and measurement is needed to operate the distribution grid in a high DER scenario. Power flows along the feeder could vary from point to point based on the location of various DERs and how they are called to operate for various gird services.<br><br>**Example technologies:** Reclosers, Smart Communicating Faulted Circuit Indicators, real time metering of solar qualifying facilities, Bell-weather meters etc.<br><br>**Example functions:** Grid management system can use measurement from these devices to optimize the grid for voltage and power flow and enable reliability and safety for all DER use scenarios for DERs on the feeder. |
| **Telecommunications** | **Description:** The infrastructure that connects grid assets and the distribution system operators.<br><br>**Needs statement:** A reliable telecommunications network allows grid operators to monitor and control with grid assets and enable more grid services.<br><br>**Example technologies:** Communication spectrum licensed from the Federal Communications Commission (FCC), owned and leased fiber, cellular communication equipment, AMI mesh network.<br><br>**Example functions:** Communication networks at different levels of granularity — field area networks (FAN) to enable communication between field devices and the Integrated Operations Center, neighborhood area networks (NAN) to enable communication between devices in a microgrid. |

| Capability | Description of capability and needs statement |
|---|---|
| **Physical grid infrastructure** | **Description:** The poles, wires, transformers, substations, operations control center and other distribution system equipment (e.g., reclosers, capacitors, regulators) and intelligent monitors/controllers that comprise the distribution system.<br><br>**Needs statement:** Enable the safe, reliable, bi-directional flow of power.<br><br>**Example technologies:** Poles, wires, transformers, switchgear, line capacitor banks, microprocessor-based capacitor controls, line regulators, line regulator controls.<br><br>**Example functions:** Voltage transformation, reactive power compensation, voltage control, and switching. |
| **Cybersecurity** | **Description:** The protection of computer systems, operational technology equipment and networks from information disclosure, theft of or damage to their hardware, software or electronic data and the disruption or misdirection of the services they provide.<br><br>**Needs statement:** The power grid is a highly connected system as described by the capabilities above. The ongoing modernization of the grid will create more connections and introduce more vulnerability to cyberattacks, efforts by rogue actors to threaten the operation of the grid.<br><br>**Example technologies:** Cyber-physical barriers to restrict access to critical assets, advanced physical security systems (e.g., intelligent badging), firewalls, data encryption, spyware/malware detection.<br><br>**Example functions:** Ensuring access is restricted to authorized personnel, insulating critical infrastructure networks from external threats, obscuring critical communication between devices and operators. |

# Appendix G. Smart grid test bed phase II project descriptions

## G.1 Flexible feeder

As PGE's flexible load portfolio expands and its DERMS capabilities mature, there is a growing need to understand how DERs can be integrated into distribution operations and the value they provide. In this research area, projects will be developed to explore the values of DERs as an operational asset, by driving high levels of dispatchable load on a single feeder, using targeted incentives for new equipment, controls, storage, distributed solar and EE. This work will involve close collaboration between PGE and Energy Trust of Oregon, as the two organizations learn about co-deployment of DER solutions and the capabilities of a virtual power plant by investing in significant DER deployment in a traditionally under-served North Portland community historically subjected to redlining and gentrification.[87]

The purpose of the project is to create a concentration of resources dense enough to create or approach the capabilities of a virtual power plant.

This project area is closely linked to the DOE Connect Communities grant recently submitted by PGE with Energy Trust, NEEA, National Renewable Energy Laboratory and Community Energy Project. That proposal focuses its efforts on the Overlook/Arbor Lodge portion of the SGTB, a historically under-served community in North Portland. If funded, the team seeks to build a 1.4 MW flexible load resource in the community, consisting of efficiency measures, connected devices, distributed solar, energy storage, and smart charging. This community resources will then be integrated into PGE's ADMS/DERMS and optimized by NREL to demonstrate a series of bulk services, including energy, capacity, and frequency response, as well as distribution services including capacity relief, power quality, and Volt/Var optimization, including CVR. The results of this work will be shared regionally through the existing network of stakeholder groups, spurring a realignment of utility planning and operation.

The effort will target a mix of 750 single family, multifamily, and commercial customers.

## G.2 Managed charging/V2X

Electric vehicle adoption is expected to increase rapidly in the coming years, increasing electricity sales and improving the economic efficiency of grid investments. These efficiency gains, however, could be offset by the need for increased infrastructure investment if charging coincides with peak demand. Identifying effective pathways to manage EV load is essential to controlling system costs and meeting flexibility targets. A series of nimble, responsive demonstration efforts are necessary to keep pace with EV adoption and a rapidly changing marketplace.

Research in this project area will focus primarily on improving understanding of the technical paths for charge management, their costs, performance, and limitations. The work will evaluate customer acceptance of charge rate/time and location-based price signals and demonstrate vehicle-to-grid and managed charging use cases, including technical requirements, limitations, and operational considerations of various the electric vehicle OEMs and EVSE. These efforts will span multiple customer segments, including single family, multifamily, commercial and ROW charging, and fleets, overlapping with numerous other research areas. Research in this area will also explore advanced use cases, such as vehicle to grid and the associated rates structures.

The effort will target 300-500 vehicles.

87. Mapping inequality, available at: https://dsl.richmond.edu/panorama/redlining/#loc=12/45.564/-122.758&city=portland-or, 2018 Gentrification and displacement neighborhood typology assessment, available at: https://www.portland.gov/sites/default/files/202001/gentrification_displacement_typology_analysis_2018_10222018.pdf

# G.3 Distributed PV/smart inverters

Customer investment in distributed solar has been growing steadily in the PGE service territory. These distributed generation projects, combined with larger QF sites, have created operational challenges on certain segments of the distribution system. As the market has matured, so too has the technology embedded in the inverter. Integration and control of distributed PV through these "smart inverters" (those equipped with the IEEE 1547-2018 standard) can provide insights and support to system operation, distribution planning, and asset valuation.

Projects in this area will assess the value of inverter-based controls to deliver distribution operations value (e.g., Volt/VAR support); address hosting capacity issues, including as an alternative to PGE's two-meter solution; and support orchestration of DERs together with distributed solar and storage to minimize grid export. Work in this area may also include rate design (e.g., fixed price) and transactive energy strategies that incentivize self-consumption and/or distribution level load balancing. The effort will target participation from 200-400 customers.

# G.4 Commercial & industrial, municipal flexible load and resiliency

Commercial, industrial, and municipal customers have a keen focus on operational efficiency, engaging with utilities in EE and self-generation programs to reduce costs while taking advantage of incentives and other financial inducements. PGE has tapped into this model to a limited extent with its Energy Partner program, providing cash incentives for load flexibility. Now, with the continued decline in the cost of self-generation, the emergence of low-cost energy storage and a newfound focus on resiliency, there is a new opportunity for a combined offering that can bring together these business drivers to deliver customer value and grid benefit.

This project area seeks to identify pathways and strategies to achieve higher levels of commercial & industrial and municipal site participation in flexible load and resiliency programs. The team will explore enhancements to existing programs and the development of new programs with the goal of better understanding and capturing the value of participating in combined measures for EE, flexible load, and resiliency. This work will include an evaluation of engagement approaches and how to structure incentives and rates to maximize program and event participation, as well as customer value.

The effort targets five large C&I sites, five municipal sites, and a hundred small-medium business sites. The technologies to be evaluated may include:

- Building management systems
- Self-generation
- Energy storage
- EE and DR strategies and measure installation

# G.5 Multifamily bundle

Multifamily is a critical customer segment, making up 33% of PGE's residential meters, and a key source of flexible load potential. Multifamily units are generally heated with electricity via in-unit sources, and many buildings also use electricity for water heating. Multifamily is also important from an equity perspective, with disproportionate numbers of low income or other under-served customers occupying this building type. However, multifamily presents significant challenges, with high turnover rates that make customer enrollment and retention challenging and building designs that can impede device communications.

Projects in this area will assess how to scale PGE's existing multifamily water heater offering while exploring new products, bundles, and engagement strategies to increase adoption and participation across a broader range of flexible load technologies within the segment. The effort will also test whole building load management strategies and rate design options.

The effort will target three-to-five buildings, representing approximately 500 multifamily units.

# G.6 Single family new construction bundle

The new construction market presents unique challenges and opportunities for developing a flexible load resource. Project developers have the buying power and scale to drive down costs and the ability to incorporate the price premium associated with grid-enabled devices into the overall financing of a new home purchase. However, they also operate in a business with tight margins and will require a return on investments in grid-integrated appliances. PGE can reduce risk to the developer through upfront incentives to project developers based on future participation by the occupants of the new housing stock. Payment based on participation from future customers transfers the risk of having fronted the incentives to the developer and future occupant non-participation, to the utility.

This project area seeks to explore the potential value of connected homes in the new construction market to deliver cost effective load flexibility, and the associated program design that can adequately manage the risks associated for developers and PGE. The work will focus on partnering with residential developers to deploy an all-electric, flexible home bundle. In doing so, we hope to explore partnership strategies, pricing structures and incentive designs that support an increased flexible load offering within this market segment.

The Testbed team will develop and test the effectiveness of product bundles in driving increased demand among new home buyers, as well as test new pricing strategies, tools (e.g., the line extension allowance) and rate design options. The overall goal of this effort is to better understand how PGE can partner with the Energy Trust of Oregon, developers, and builders to incorporate flexible load technology into the design/build process, securing low-cost demand flexibility potential before the customer even occupies the home.

The effort targets up to three residential developer partners, and a goal of 200-300 participating homes. The technologies evaluated may include:

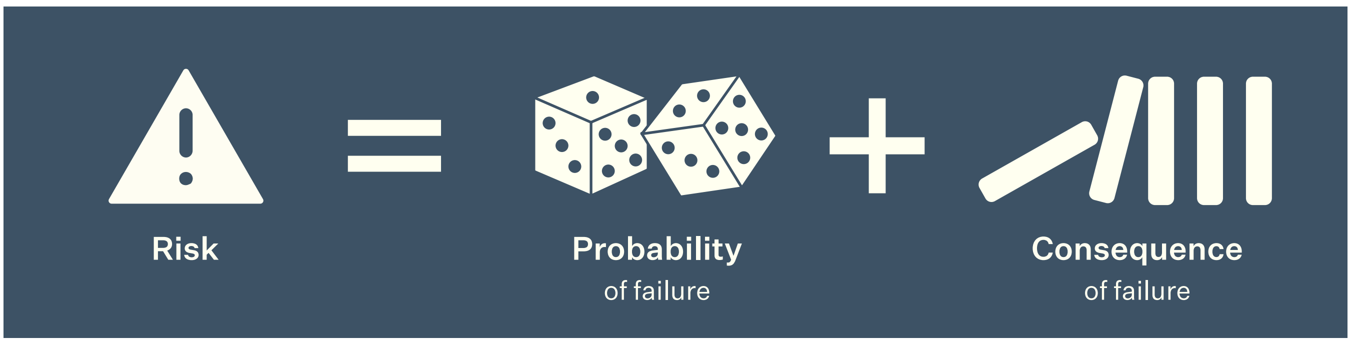
- Smart thermostat/DHP controls
- Heat pump water heater
- Solar PV with smart inverter
- Battery storage
- Home energy management system (HEMS)

# Appendix H. Calculating asset risk

The goal of PGE's Asset Management program is to cost effectively mitigate risk while achieving customer value. PGE's AMP team uses risk-based economic lifecycle models to prioritize long term capital investments. These models calculate the lowest cost of ownership, which is optimal time to replacement of an asset which balances maintenance cost and the risk of owning and operating the existing asset compared to the cost of replacing the asset. Using the outputs of these models to justify proactive asset replacement reduces risk of failure on the system, improves reliability, and improves the customer experience.

The approach the AMP team takes to modeling assets is based on the fundamental concept of risk. Risk is defined as the product of annual probability of failure and consequence cost of failure (**Figure 62**). The annual failure probability is the likelihood an asset will have a repairable or non-repairable failure as a function of its age, condition and model. Consequence cost of failure is the weighted average cost of repairable and non-repairable failure scenarios of the asset. The cost includes reliability impact to customers, load impacted from the failure, along with environmental, safety and direct cost impacts to the company. These concepts are further described below.

Figure 62. The risk equation




## H.1 Probability of failure

Modeling annual probability of equipment failure rests on three building blocks:

- The annual failure probability that corresponds to calendar age of the asset via the failure curve
- Identification of any asset degradation via the health index
- Adjustment for any known bad vintages/ manufacturers via a failure multiplier

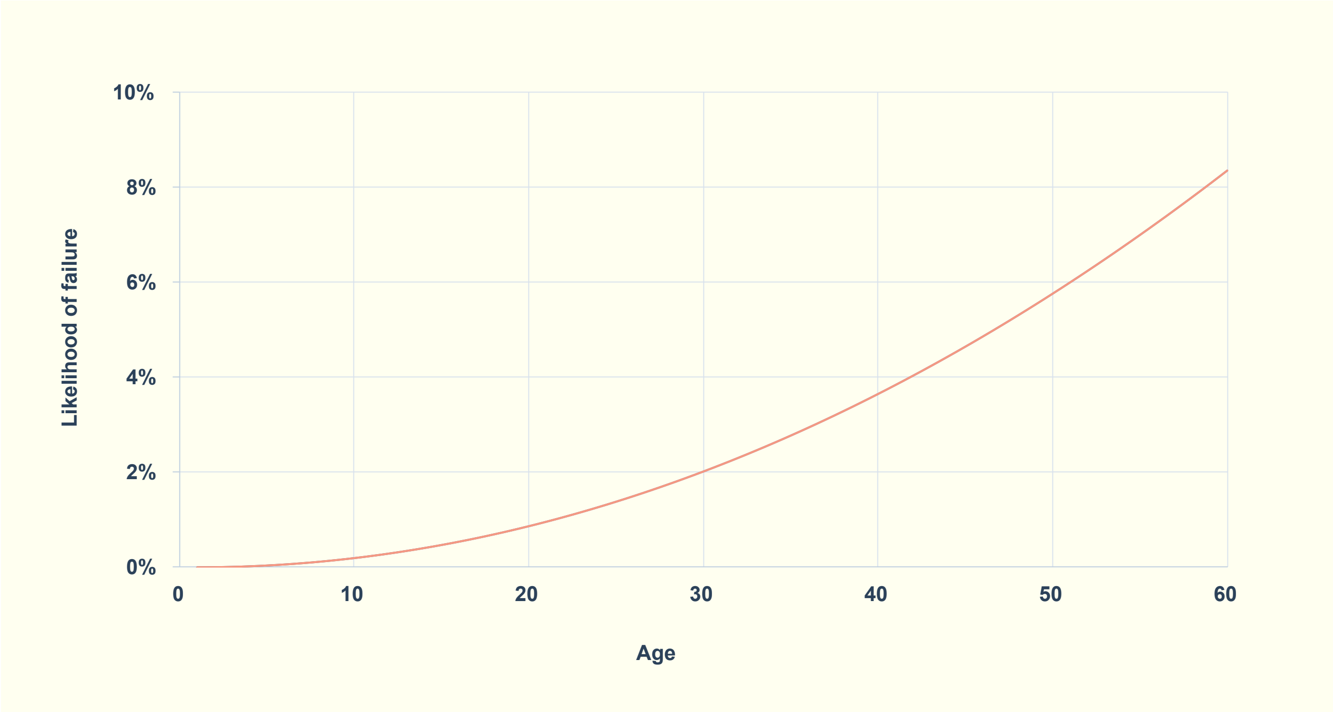
## H.2 Failure curves

AMP uses Weibull[88] distributions to statistically model the annual probability of equipment failure. These curves are developed for each asset class family and sub-asset class family, if warranted, to estimate the annual likelihood an asset will fail as a function of its age, assuming it has made it to that age. An example Weibull failure curve is shown in **Figure 63**.

In some cases, an asset family may have several different sub-types of assets with different characteristics and historical failure data. When this happens, different failure curves with different parameters are applied to the different sub-types.

88. Weibull is a continuous probability distribution used to analyze life data, model failure times and assess product reliability.

Figure 63. Example probability of failure (Weibull) curve




### H.2.1 HEALTH INDEX

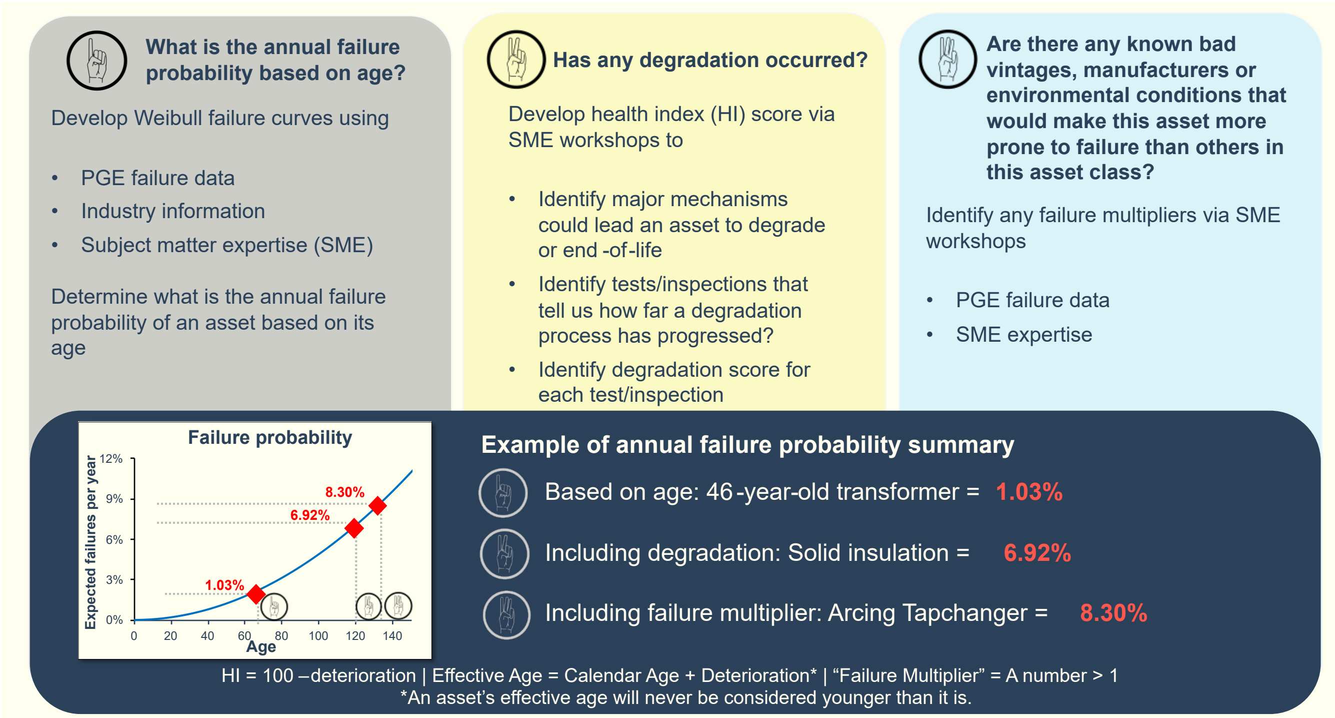
The health index is used to quantify an asset's condition relative to its end of life and calculate the asset's effective age. The health index assesses if the asset is acting older than its calendar age based on poor test or inspection results. If it is acting older than its calendar age, an adjustment to the calendar age occurs to reflect its "true age" via its effective age. This new effective age is then used as the input to the failure curve.

### H.2.2 FAILURE MULTIPLIERS

Failure multipliers are identified for "bad actor" types of assets. This may be a particular configuration, manufacturer or production date. PGE subject matter experts identify "bad actors" and assign failure multipliers based on their expertise. The failure multiplier is literally multiplied against the likelihood of failure to elevate the annual failure probability for the "bad actors."

These three components are combined to calculate annual probability of asset failure. **Figure 64** shows an example of how this calculation works.

Figure 64. Failure probability calculation example




# H.3 Consequence of failure

The other half of the risk equation is consequence of failure, which is the quantified impact to PGE and the customer when an asset fails. The customer impact represents about 75%-80% of the overall consequence cost of failure, which is calculated using values of service (VOS) lifted from a Pacific Gas & Electric study approved by the CPUC. In the future, PGE expects to be able to conduct its own customer survey to understand the value of reliability and resiliency for its customer base. The values from PGE's survey would replace Pacific Gas & Electric's VOS values.

To calculate the weighted average consequence cost, subject matter experts identify approximately 4 to 6 different failure scenarios, informed by historical data as available, that range from benign to catastrophic and assign their relative likelihoods.

## H.3.1 FAILURE SCENARIOS

Each failure scenario developed for an asset assesses the following and calculates a corresponding cost:

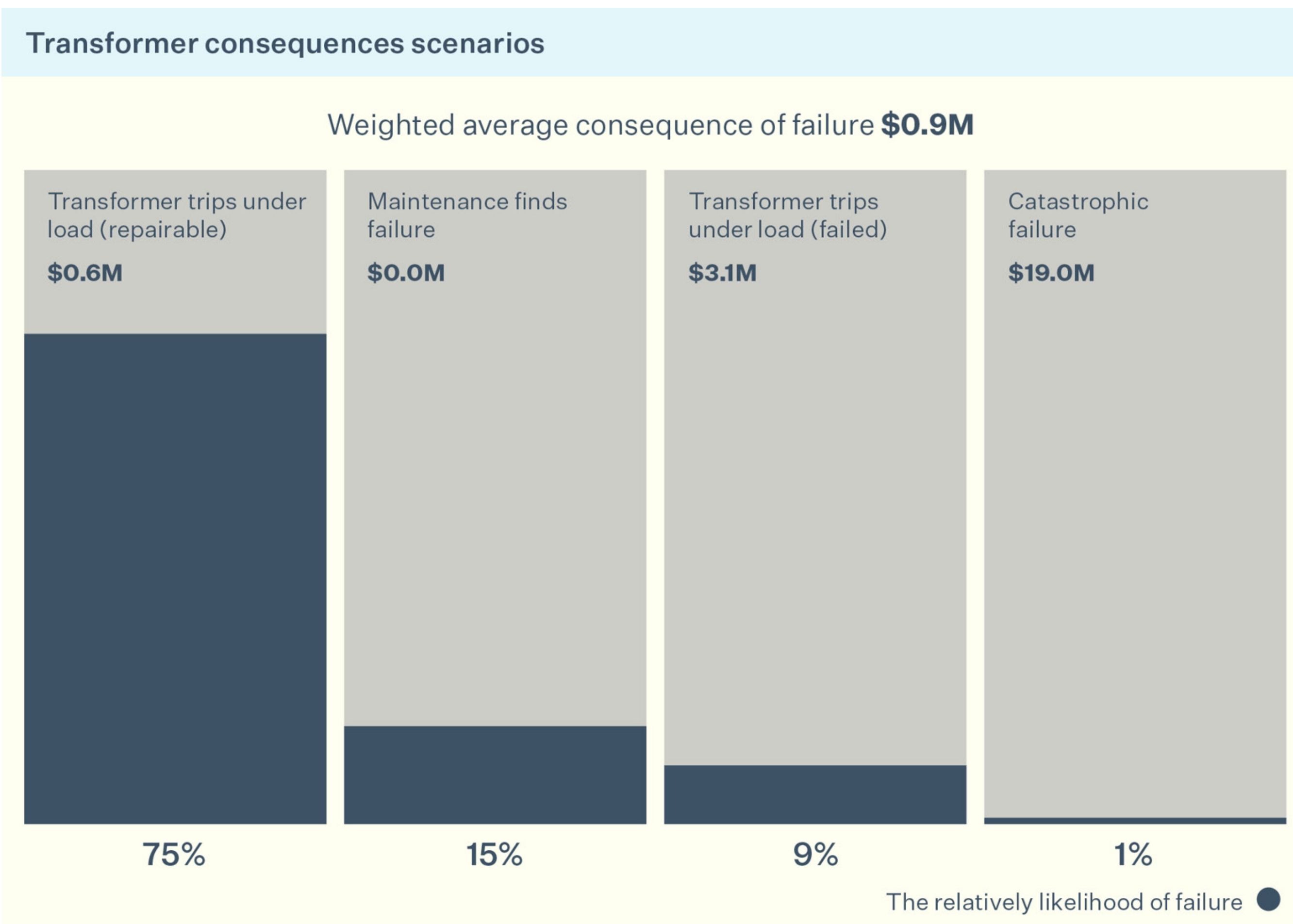
- **Associated damages** — Typically represents costs for adjacent equipment damage
- **Repair cost** — If failure is non-destructive, estimated cost to repair the asset that comes from either a percentage of asset replacement cost, or subject matter expert feedback
- **Additional costs** — Typically represents safety or environmental costs
- **Emergency premium** — Represents the cost to address the failure immediately
- **Outage impact** — Comprised of the following components:
- **Load by impacted customer class** — Asset models use average annual load (kWa) for each customer type (residential, commercial, and industrial) on a feeder or served at a substation
- **Customers impacted** — Total load and customer count impacted
- **Outage type** — Either a sustained outage, which is an outage greater than five minutes, or an extension, which is the extension of an existing outage not caused by the asset in question
- **Outage duration** — How long it takes to restore power to customer, not necessarily how long it may take to repair or replace the failed asset

- **Outage cost** — Quantified by the reliability impact from the event cost plus duration cost for the asset failure by applying customer interruption costs. Outage cost typically represents approximately 75% of the total weighted average consequence cost. These two costs are defined as follows:
  - **Event cost** — For each respective customer class (residential, commercial, industrial), this is the load impacted by failure multiplied by event VOS ($/kW)
  - **Event VOS** — The dollar value customers would be willing to pay per kW to avoid having an outage, irrespective of duration. There are different $/kW assumptions for outage event by customer class (residential, commercial, and industrial).
  - **Duration cost** — For each respective customer class (residential, commercial, industrial), this is the load multiplied by duration value of service (VOS) ($/kWh), multiplied by duration of outage.
  - **Duration VOS** — The dollar value customers would be willing to pay per kW per hour to avoid an outage. There are different $/kW *hour assumptions for outage by customer class (residential, commercial, and industrial).

Using the dollar value and relative likelihood of these failure scenarios, a weighted average is then calculated, which is the dollar-valued consequence associated with asset failure. A graphical representation is shown in **Figure 65**.

Combined with the annual probability of failure, this allows for calculating an annual risk value for each asset for its entire lifecycle. These risk cost streams are then combined with annual maintenance costs, annualized capital costs and discounted using PGE's cost of capital to calculate cost of ownership. This gives present year values which are then used to calculate key metrics for each asset. These metrics are defined in the solution identification section (**Section 5.3.3**).

Figure 65. Transformer failure scenarios and their relative likelihoods



# Appendix I. Grid needs ranking methodology

**Table 59** summarizes each level of the ranking matrix. Each level is further described in the following sections.

Table 59. Distribution planning ranking matrix

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| **Level 5** | Addresses Safety Concern?<br>Yes = 15, No = 0 | 15 | 5 | 75 | 21.8% |
| | Must Do for Customer Commitment?<br>Yes = 15, No = 0 | 15 | 5 | 75 | 21.8% |
| **Level 4** | Compliance Driver or Mitigates Transmission/ Sub-Transmission Constraint?<br>115 kV+ = 10, 57 kV = 5, No = 0 | 10 | 4 | 40 | 11.6% |
| | Precursor to mitigating other grid needs?<br>Two or More = 10, One = 5, No = 0 | 10 | 4 | 40 | 11.6% |
| | Frees up or mitigates mobile/ temporary equipment or configuration?<br>Yes = 5, No = 0 | 5 | 4 | 20 | 5.8% |
| **Level 3** | Feeder % Loading of Seasonal Limit (N-0)<br>>100% = 4, 90%-99% = 3,<br>80%-89% = 2,<br>67%-79% = 1, <67% = 0 | 4 | 3 | 12 | 3.5% |
| | Transformer % Loading of LBNR (N-0)<br>>100% = 4, 90%-99% = 3,<br>80%-89% = 2, <80% = 0 | 4 | 3 | 12 | 3.5% |
| | Existing Total Risk (Substation)<br>Top 10 = 4, Top 30 = 2,<br>Top 50 = 1, Other = 0 | 4 | 3 | 12 | 3.5% |
| | Existing CMI Impact (Substation)<br>Top 10 = 4, Top 30 = 2,<br>Top 50 = 1, Other = 0 | 4 | 3 | 12 | 3.5% |
| | Substation SCADA<br>Adds New = 3, Replace Obsolete = 1,<br>No or New Sub = 0 | 3 | 3 | 9 | 2.6% |

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| Level 2 | Existing Total Risk (Feeder)<br>Top 10 = 4, Top 30 = 2, Top 50 = 1, Other = 0 | 4 | 2 | 8 | 2.3% |
| | Existing CMI Impact (Feeder)<br>Top 10 = 4, Top 30 = 2, Top 50 = 1, Other = 0 | 4 | 2 | 8 | 2.3% |
| | Known Load Growth Impact to Equipment<br>Exceeds Limits in 1-5 Years = 4,<br>Exceeds Planning Criteria = 2,<br>Other or No Growth = 0 | 4 | 2 | 8 | 2.3% |
| | Multiple Feeders or Xfmrs Exceed Planning Criteria?<br>Three or More = 3, Two = 2, No = 0 | 3 | 2 | 6 | 1.7% |
| | Overload or Voltage Issue for a N-1 condition (Feeder)<br>Yes = 1, No = 0 | 1 | 2 | 2 | 0.6% |
| | Overload or Voltage Issue for a N-1 condition (Transformer)<br>Yes = 1, No = 0 | 1 | 2 | 2 | 0.6% |
| Level 1 | Distribution Xfmr Utilization Index<br>If Summer and Winter Xfmr Peaks are ≥ 80% = 1, Otherwise = 0 | 1 | 1 | 1 | 0.3% |
| | Distribution Feeder Utilization Index<br>If Summer and Winter Feeder Peaks are ≥ 67% = 1, Otherwise = 0 | 1 | 1 | 1 | 0.3% |
| | Makes Substation DG Ready?<br>Yes = 1, No = 0 | 1 | 1 | 1 | 0.3% |

# I.1 Prioritization criteria and data

Level 5 of the Distribution Planning Ranking Matrix is shown in **Table 60**. The two categories for Level 5, the highest category in the ranking matrix, are safety and customer commitment. Safety and customers are PGE's highest priority, so the maximum possible score is weighted such that these grid needs are prioritized against all other metrics.

Safety is a top priority for PGE; however, many grid needs and projects originating from Distribution Planning will not have this component. An example of a safety concern in a grid need that may originate from Distribution Planning is a substation with an arc flash level that requires additional personal protective equipment (PPE) to safely operate equipment. Another example is a substation in an abnormal configuration that requires an outage to the entire substation to safely perform maintenance or operate equipment.

Customer Commitments are considered must-dos for PGE. These are often large commercial or industrial customers with significant, constant power demands that requires physical infrastructure to serve.

**Table 60. Distribution planning ranking matrix — level 5**

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| **Level 5** | Addresses Safety Concern?<br>Yes = 15, No = 0 | 15 | 5 | 75 | 21.8% |
| | Must Do for Customer Commitment?<br>Yes = 15, No = 0 | 15 | 5 | 75 | 21.8% |

Level 4 of the Distribution Planning Ranking Matrix is shown in **Table 61**. Level 4 includes heavy weighting for grid needs that have a transmission or sub-transmission constraint mitigation component. Transmission projects (115 kV+) are often driven by North American Electric Reliability Corporation (NERC) compliance obligations for the Bulk Electric System (BES). While sub-transmission (57 kV or radial 115 kV+) is not subject to NERC compliance obligations, PGE strives to operate this system to the same level as the BES. The transmission and sub-transmission systems are the sources to PGE's distribution system. If there are thermal or voltage issues on the sources to the system, customers are at risk of having their power shut off to alleviate these issues. As a result, grid needs that contain a transmission or sub-transmission mitigation are weighed heavily, with more weight to the BES in order to comply with NERC standards.

Level 4 also includes grid needs that will unlock the ability to mitigate other grid needs. For example, capacity may need to be added to one substation in order to completely offload a different substation during construction. At times, there are a series of grid needs that are dependent upon each other, so if two or more grid needs are dependent on one grid need being mitigated, it is weighed heavier. This is important because there could be a new development served by a substation, but the system may not be able to accommodate it if that substation needed two other substations to be upgraded before capacity could be added for the new development. This extends timelines to serve customers.

There are times where equipment can fail catastrophically, and temporary measures are implemented until the situation is resolved. This can include a scenario where a substation transformer fails, and PGE must install a mobile or temporary transformer to serve the load that was served by the substation transformer. These mobile and temporary transformers are intended to perform maintenance and not be permanent replacements. In addition, there are situations where a piece of equipment can fail, and that equipment is not replaced immediately. In this situation, the power is diverted to other substations, which can stress the substation and distribution line elements in the area. These scenarios are intended to be temporary until a permanent solution is implemented. To avoid straining other parts of the distribution system, grid needs that mitigate these temporary measures are prioritized in Level 4.

Table 61. Distribution planning ranking matrix — level 4

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| **Level 4** | Compliance Driver or Mitigates Transmission/ Sub-Transmission Constraint?<br>115 kV+ = 10, 57 kV = 5, No = 0 | 10 | 4 | 40 | 11.6% |
| | Precursor to mitigating other grid needs?<br>Two or More = 10, One = 5, No = 0 | 10 | 4 | 40 | 11.6% |
| | Frees up or mitigates mobile/ temporary equipment or configuration?<br>Yes = 5, No = 0 | 5 | 4 | 20 | 5.8% |

Level 3 of the Distribution Planning Ranking Matrix is shown in **Table 62**. Level 3 evaluates the current loading of the system in its "normal" state, with all distribution feeders and transformers in service. If a grid need consists of multiple system loading issues, the worst-case loading issue is used to score these categories. While the planning criteria for feeders is 67% of its thermal rating and for transformers is 80% of its thermal rating, scoring is based on the limits of the equipment. However, if feeders or transformers do not exceed these planning criteria, they are assigned a score of zero in these categories.

Level 3 includes weighting for adding SCADA to a substation. SCADA is important for system operators to understand the real-time state of the transmission, sub-transmission and distribution systems. Some substations have obsolete SCADA systems that are also given a score in this category. New substations are always constructed with SCADA.

Level 3 also incorporates risk and reliability improvements into the prioritization, at the substation level. These values are calculated outputs of the economic lifecycle model developed by the AMP team. The existing total risk and existing customer minutes interrupted (CMI) impact for the grid need at the substation level is used to score this category. See **Section 4.4** for more about the PGE risk model.

Table 62. Distribution planning ranking matrix — level 3

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| **Level 3** | Feeder % Loading of Seasonal Limit (N-0)<br>>100% = 4, 90%-99% = 3,<br>80%-89% = 2,<br>67%-79% = 1, <67% = 0 | 4 | 3 | 12 | 3.5% |
| | Transformer % Loading of LBNR (N-0)<br>>100% = 4, 90%-99% = 3,<br>80%-89% = 2, <80% = 0 | 4 | 3 | 12 | 3.5% |
| | Existing Total Risk (Substation)<br>Top 10 = 4, Top 30 = 2,<br>Top 50 = 1, Other = 0 | 4 | 3 | 12 | 3.5% |
| | Existing CMI Impact (Substation)<br>Top 10 = 4, Top 30 = 2,<br>Top 50 = 1, Other = 0 | 4 | 3 | 12 | 3.5% |
| | Substation SCADA<br>Adds New = 3, Replace Obsolete = 1,<br>No or New Sub = 0 | 3 | 3 | 9 | 2.6% |

Level 2 of the Distribution Planning Ranking Matrix is shown in **Table 63**. Level 2 also incorporates asset risk, but at the feeder level, out on the distribution line. Like the substation risk, the existing total risk and existing CMI impact for the grid need is used to score this category.

Load growth is also included in Level 2. The metric is evaluated looking at the impact of the load growth on the equipment. If the load growth will result in equipment exceeding thermal or voltage limits within the next one to five years, it is weighted heavier. If the load growth causes equipment to exceed planning criteria, it also receives a score. If the load growth does not cause equipment to exceed thermal or voltage limits or planning criteria, then the system can reliably accommodate this load and no score is assigned. A five-year outlook is used because load growth impacts beyond five years do not need to be mitigated immediately, as most projects to mitigate grid needs can be implemented within five years.

Level 2 prioritizes grid needs that can be combined to have a single project mitigate multiple feeders or transformers exceeding planning criteria. The ranking increases if there are three or more feeders or transformers that exceed planning criteria.

Finally, Level 2 incorporates redundancy into the scoring. If the grid need involves a feeder or transformer that cannot be completely offloaded to other feeders and transformers, a point is given in these categories. This also speaks to the resiliency of the system; if an unplanned outage occurs during peak loading conditions, the goal is to be able to pick up all the load and leave no customers unserved.

**Table 63. Distribution planning ranking matrix — level 2**

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| Level 2 | Existing Total Risk (Feeder)<br>Top 10 = 4, Top 30 = 2, Top 50 = 1,<br>Other = 0 | 4 | 2 | 8 | 2.3% |
| | Existing CMI Impact (Feeder)<br>Top 10 = 4, Top 30 = 2, Top 50 = 1,<br>Other = 0 | 4 | 2 | 8 | 2.3% |
| | Known Load Growth Impact to Equipment<br>Exceeds Limits in 1-5 Years = 4,<br>Exceeds Planning Criteria = 2,<br>Other or No Growth = 0 | 4 | 2 | 8 | 2.3% |
| | Multiple Feeders or Xfmrs Exceed Planning Criteria?<br>Three or More = 3, Two = 2, No = 0 | 3 | 2 | 6 | 1.7% |
| | Overload or Voltage Issue for a N-1 condition (Feeder)<br>Yes = 1, No = 0 | 1 | 2 | 2 | 0.6% |
| | Overload or Voltage Issue for a N-1 condition (Transformer)<br>Yes = 1, No = 0 | 1 | 2 | 2 | 0.6% |

Level 1 of the Distribution Planning Ranking Matrix is shown in **Table 64**. Level 1 evaluates the utilization of the distribution system. If a grid need has a transformer or feeder that exceeds planning criteria for both summer and winter, it is scored in these categories. Level 1 also includes substation DG readiness. If the grid need mitigation makes a substation DG ready, a point is given in this category. As regulatory policy evolves regarding utilities mitigating interconnection issues, the placement of substation DG readiness in the ranking matrix will be re-evaluated.

**Table 64. Distribution planning ranking matrix — level 1**

| Level | Title | Max possible score | Multiplier | Max total | Peak importance |
|---|---|---|---|---|---|
| **Level 1** | Distribution Xfmr Utilization Index<br>If Summer and Winter Xfmr Peaks are ≥ 80% = 1, Otherwise = 0 | 1 | 1 | 1 | 0.3% |
| | Distribution Feeder Utilization Index<br>If Summer and Winter Feeder Peaks are ≥ 67% = 1, Otherwise = 0 | 1 | 1 | 1 | 0.3% |
| | Makes Substation DG Ready?<br>Yes = 1, No = 0 | 1 | 1 | 1 | 0.3% |

Sometimes grid needs can result in the same score when populating the Ranking Matrix. The combined score for Levels 5 and 4 is used as a tiebreaker in this instance.

# Appendix J. Description of solutions to address grid needs

Below, PGE has outlined estimated costs for prioritized projects as described in **Chapter 5**. The actual project costs will vary as a result of changes in construction costs. Dynamic factors such as the supply chain, labor market, permitting, regulatory requirements and customer growth projections also impact project costs and timelines. PGE reviews projects after design and engineering to validate estimates prior to proceeding with construction.

## J.1 Evergreen project

The Evergreen project addresses the grid need of industrial load growth in the North Hillsboro area. This project was originally conceptualized as a transmission-only project to meet NERC Compliance obligations. However, the rapid load growth in the North Hillsboro area dictates the need to add distribution infrastructure to the project. Two new 150 MVA substation transformers, two metal-clad switchgear, and new feeders will be installed to serve the load growth in the area. This project is considered a “must do” because the existing infrastructure is not capable of serving the new customers. As a result, there are no alternatives to this project.

This project started in 2018 and is planned for completion by the end of 2024.

## J.2 St. Louis project

The St Louis project is part of the larger Willamette Valley Resiliency Project (WVRP), which is discussed in detail in the Resilience section of **Appendix K**. The WVRP mitigates existing loading and voltage issues on the 57 kV sub-transmission system in the Willamette Valley by rebuilding six substations, converting four of these to 115 kV, and building two new 115 kV lines. The St. Louis project rebuilds the St. Louis substation to a 115 kV ring bus configuration and replaces the existing distribution transformers with two standard 28 MVA transformers. A new commercial customer must be served by a temporary transformer starting in 2022 until the St. Louis project is complete, because there is not enough capacity to serve this new load at the existing substation. This rebuild accommodates this new commercial load growth and the rebuild combined with the rest of the Willamette Valley Resiliency Project provides for at least 50 MVA of load growth in the area.

Currently, the Willamette Valley area 57 kV sub-transmission system is at risk of experiencing overloads and even voltage collapse, which could result in PGE equipment damage and significant customer outages. Multiple options to mitigate these issues were analyzed, including a battery energy supply system (BESS) connected to the 57 kV system. However, with the loading and voltage issues that can persist even in light loading conditions, charging this BESS could contribute to the problems. In addition, the aging substation assets in the area and the potential for significant load growth (including some commercial load growth served by the St Louis substation) dictated the need to improve the reliability and resiliency of the area.

The St. Louis project is beginning in 2022 and is projected for completion in 2025.

## J.3 Silverton project

A new feeder, Silverton-Oak, is required to serve a new large industrial customer in the Silverton area. The existing feeder serving the site, Silverton-North, is heavily loaded, exceeding planning criteria, and cannot accommodate the new 5.3 MW of load. Therefore, the new Oak feeder, which will split the North feeder, must be constructed.

The addition of the new 5.3 MW load causes the Silverton BR2 transformer to be heavily loaded during peak summer conditions, exceeding planning criteria. To mitigate this new loading concern, a second new feeder, the Silverton-Garden feeder will be constructed, splitting the Silverton-West feeder and moving 5.1 MW from the Silverton BR2 transformer to the Silverton BR1 transformer.

Both new feeders are low-cost options to serve the new load and mitigate loading issues. Splitting existing feeders to create new feeders is ideal, because you do not need to build new infrastructure for the entirety of the path to the customer. The option to install another feeder and shift load from one transformer to another is ideal to alleviate a heavily loaded transformer because the alternative would be to replace the transformer with a larger transformer, which by itself would exceed the combined cost of the two feeder projects.

The Silverton-Oak feeder is planning for construction in 2022 to meet the new customer timeline. The Silverton-Garden feeder is projected to be constructed before summer 2023 to mitigate the summer loading concern.

## J.4 Redland project

The Redland project addresses multiple grid needs west of Oregon City: aging infrastructure, heavily-loaded equipment, and lack of SCADA telemetry. The Leland substation, which is adjacent to the Redland substation, experiences heavy loading on both its substation transformer and two of its three distribution feeders during peak loading conditions, especially during the summer. The Leland substation feeders also are in the top 10 of the AMP Risk Register for both Existing Total Risk and Existing CMI Impact. The Leland substation, however, does have SCADA, and its substation transformer was manufactured in 2001.

The adjacent Redland substation, however, has a substation transformer that was manufactured in 1971 and is shown to be due for replacement per the AMP model. In addition, the Redland substation does not have SCADA telemetry. There are only two distribution feeders served by the Redland substation, and one is heavily loaded during peak summer conditions. Rebuilding the Redland substation addresses the aging infrastructure at Redland, provides telemetry to a rural area, and adds a second distribution transformer to offload heavily loaded equipment at both the Leland and Redland substations, reducing risk and CMI.

The alternative to rebuilding and adding capacity at the Redland substation is to add a second distribution transformer at the Leland substation. This option may mitigate the loading issues at the Leland substation, but the Redland substation will still have infrastructure past its end of life and will not have telemetry. As a result, the most prudent investment is to address all the grid needs in one project by rebuilding and adding capacity at the Redland substation.

The Redland project is beginning in 2023 and is projected for completion in 2025.

## J.5 Kaster project

PGE's service territory in the St Helens area is isolated from the rest of the service territory, which means that it cannot be served from adjacent substations in the event of an outage like most of PGE's system. The only PGE-owned substation in the area is the Cascade substation, which is antiquated, past its end of life, and has arc flash concerns. This substation serves only one industrial customer and cannot reliably accommodate new load growth.

A new commercial customer has requested 7.4 MW of load service in PGE's St. Helens service territory. PGE evaluated a few options. The first option was to build a new substation, Kaster, to replace the aging Cascade substation and serve the new load. The second option was to pay CRPUD to make upgrades to serve the load and then build a new smaller substation just to replace the Cascade substation. PGE chose the first option because the St. Helens service territory still has available land for future load growth, and the second option did not allow for future expansion. Rather than pay CRPUD for a one-time solution, we determined that the best option was to build a new substation that can accommodate the existing Cascade substation load, the new 7.4 MW load addition, and have space for future equipment to serve load growth. The new substation will have the room to serve up to 100 MVA with full N-1 redundancy if load continues to grow in the area.

The Kaster project is beginning in 2023 and is projected for completion in 2025.

## J.6 Glisan project

The Glisan project addresses the grid need of industrial load growth in the Gresham area. The Glisan substation is a service island to one customer, meaning that if one substation transformer is out of service, the other must be able to serve all the load at the facility. PGE has a contractual obligation to provide full N-1 redundancy to this customer at the Glisan substation.

The Glisan WR1 transformer is rated at 21 MVA nameplate, with a 23.1 MVA summer thermal rating. The Glisan WR2 transformer is rated at 28 MVA nameplate, with a 32.2 MVA summer thermal rating. The current total load served by the two transformers is 22.7 MVA. The customer will begin adding load to their facility in 2022, ultimately reaching 6 MVA of new load by Q2 or Q3 in 2023. This increases the total load served by the two transformers to 28.7 MVA. This load could be entirely served by the WR2 transformer, but not the WR1 transformer. As a result, the WR1 transformer needs to be replaced.

The Glisan WR1 transformer position used to have a 28 MVA transformer. Back in 2013, PGE swapped the Glisan WR1 28 MVA transformer with a 21 MVA transformer at the Ramapo substation to mitigate the heavy loading at the Ramapo substation. At the time, the 21 MVA transformer was sufficient to serve the total load for the customer at the Glisan substation, and PGE was able to perform a low-cost upgrade by swapping two existing transformers to increase capacity at the Ramapo substation. However, now that load is growing at the Glisan substation, the WR1 transformer must be upgraded.

The Glisan project is planned for implementation in 2023.

## J.7 Waconda project

The Waconda project is also part of the larger Willamette Valley Resiliency Project, which is discussed in detail in **Appendix K** and earlier in this section under the St Louis project. The Waconda project rebuilds the Waconda substation to a ring bus configuration and replaces the existing distribution transformers with two standard 28 MVA transformers. This rebuild provides capacity for new load growth, including potential Transportation Electrification growth as part of the West Coast Clean Transit Corridor (WCCTC) initiative.

The Waconda project also includes the construction of a third 115 kV transmission source to the substation which improves reliability and resiliency.

The Waconda project is beginning in 2023 and is projected for completion in 2026.

## J.8 Harrison project

The Stephens substation was decommissioned in 2020. To temporarily serve the non-standard 11 kV distribution feeders, a temporary transformer was installed at the Harrison substation. This is a service island in SE Portland, as the rest of the circuits in the area are at the standard 13 kV voltage. The Harrison project mitigates these grid needs by installing a standard 115/13 kV transformer at the Harrison substation and converts the non-standard 11 kV distribution feeders to 13 kV, served by the new transformer. This enables the removal of the temporary transformer, to be used for maintenance or other truly temporary needs as it was intended.

There are no cost-effective alternatives to this project, as the Harrison substation is the closest substation to the former Stephens substation.

The Harrison project is beginning in 2022 and is planned for completion in 2025.

## J.9 Linneman project

The Linneman project addresses the grid needs of residential load growth in the Happy Valley area and the use of temporary equipment to serve this load growth. Load has been steadily increasing in the Happy Valley and Gresham areas. In June 2021, a mobile substation had to be installed at the Pleasant Valley substation to serve load during the heat wave, because existing infrastructure was heavily-loaded and at risk of exceeding its thermal limits. This mobile substation remains at the Pleasant Valley substation because the area is constrained.

The Linneman substation site used to be a transmission-only substation and was decommissioned in 2020. PGE now wants to use this property to install distribution infrastructure to help serve load in the Happy Valley area and alleviate heavily-loaded equipment. This will enable the removal of the mobile transformer at the Pleasant Valley substation so it can be used for its intended purpose, maintenance and emergency situations. Using an existing PGE-owned property is the least-cost alternative because PGE does not need to purchase property for a new substation elsewhere.

The Linneman project will begin in 2023 and is projected for completion in 2025.

## J.10 Boring project

The Boring project addresses multiple grid needs in the area of the City of Boring, OR, specifically heavily loaded equipment and aging infrastructure. The Boring BR1 transformer was removed from service in 2019 due the threat of imminent failure. PGE's operations team detected increased gassing which could have caused a catastrophic failure of the transformer and damage to other equipment and a significant safety risk to personnel, if left in service. As a result, the load from that transformer was transferred to other facilities in the area. This has resulted in heavily loaded transformers at both Boring and Dunns Corner, as well as voltage problems because the distribution feeders serving the load that was served by Boring BR1 are now much longer.

In addition, the Boring BR2 transformer was manufactured in 1957 and is nearing the end of its economic life per the AMP models. Numerous other pieces of equipment at the Boring substation are also at their end of life, including the SCADA telemetry system. The complete rebuild of the substation is the recommended option to address aging infrastructure and add capacity with a second transformer.

One alternative is to rebuild the substation with only one 28 MVA substation transformer. However, this does not provide the full N-1 redundancy that two 28 MVA transformers provide. Loading and voltage issues could still occur if there was an outage to the one Boring substation transformer.

The Boring project is beginning in 2023 and is projected for completion in 2025.

## J.11 Glencullen project

The Glencullen project addresses multiple grid needs in SW Portland: heavily-loaded equipment at adjacent substations, lack of SCADA telemetry, and multiple tree-related outages on distribution feeders. The Sylvan substation is heavily loaded during peak summer conditions on both the substation transformer and one of the distribution feeders. When PGE rebuilds a substation and equipment is taken out of service for many months, the load served by that substation must be either transferred to a temporary transformer or to adjacent substations. Unfortunately, there is not enough room at the Sylvan substation to install a temporary transformer and have enough room to construct the new facilities. Some of the load at Sylvan can be transferred to the Cedar Hills substation, but this still leaves significant load unserved. Installing additional capacity with a second transformer at the Glencullen substation provides the capacity to pick up the load from the Sylvan substation for the rebuild. This second transformer enables full N-1 transformer redundancy for both the Sylvan substation and the Glencullen substation in the event of future maintenance or unplanned outages. The Glencullen substation also lacks SCADA telemetry, so the rebuild will include the installation of a SCADA system. In addition, the Glencullen distribution feeder's route goes through some heavily treed areas and has experienced multiple tree-related outages. This project will address these outages by installing tree wire.

The rebuild and capacity additions for both Glencullen and Sylvan substations provides capacity for a future rebuild of the Canyon substation, which carries the 4th-most risk of all of PGE's substations.

The Glencullen project is beginning in 2023 and is projected for completion in 2026.

# J.12 Scholls Ferry project

The Scholls Ferry project addresses the grid needs of existing heavily loaded equipment and significant residential load growth. The Murrayhill WR2 substation transformer and the Scholls Ferry WR1 substation transformer both exceed planning criteria during peak summer conditions. In addition, three of the five Murrayhill substation distribution feeders exceed Planning Criteria during peak summer conditions. The Murrayhill-Kinton feeder can exceed its summer thermal rating during peak summer loading conditions. As a result, load on this feeder must be shifted to adjacent distribution feeders, which constrains these distribution feeders.

There are multiple residential developments in various stages of construction around the Scholls Ferry substation. Approximately 16,700 new homes are planned and new infrastructure is required to serve these new developments, as the existing infrastructure is already constrained. The Scholls Ferry project installs a second transformer at the Scholls Ferry substation, a 50 MVA transformer, to both have enough capacity to serve the new load and provide redundancy on the system in the event of an outage. Five new distribution feeders will be installed to be served by this new transformer.

An alternative was analyzed with a 28 MVA transformer installed at Scholls Ferry substation instead of a 50 MVA transformer. This option does not have enough capacity to offload the heavily loaded Murrayhill substation while also serving the projected new load. As a result, an additional capacity addition to alleviate loading at the Murrayhill substation would need to be completed, which is not as cost effective as the recommendation to install a 50 MVA transformer at the Scholls Ferry substation.

The Scholls Ferry project is beginning in 2023 and is projected for completion in 2025.

# Appendix K. Modernized grid action plan

## K.1 Modernized grid action plan

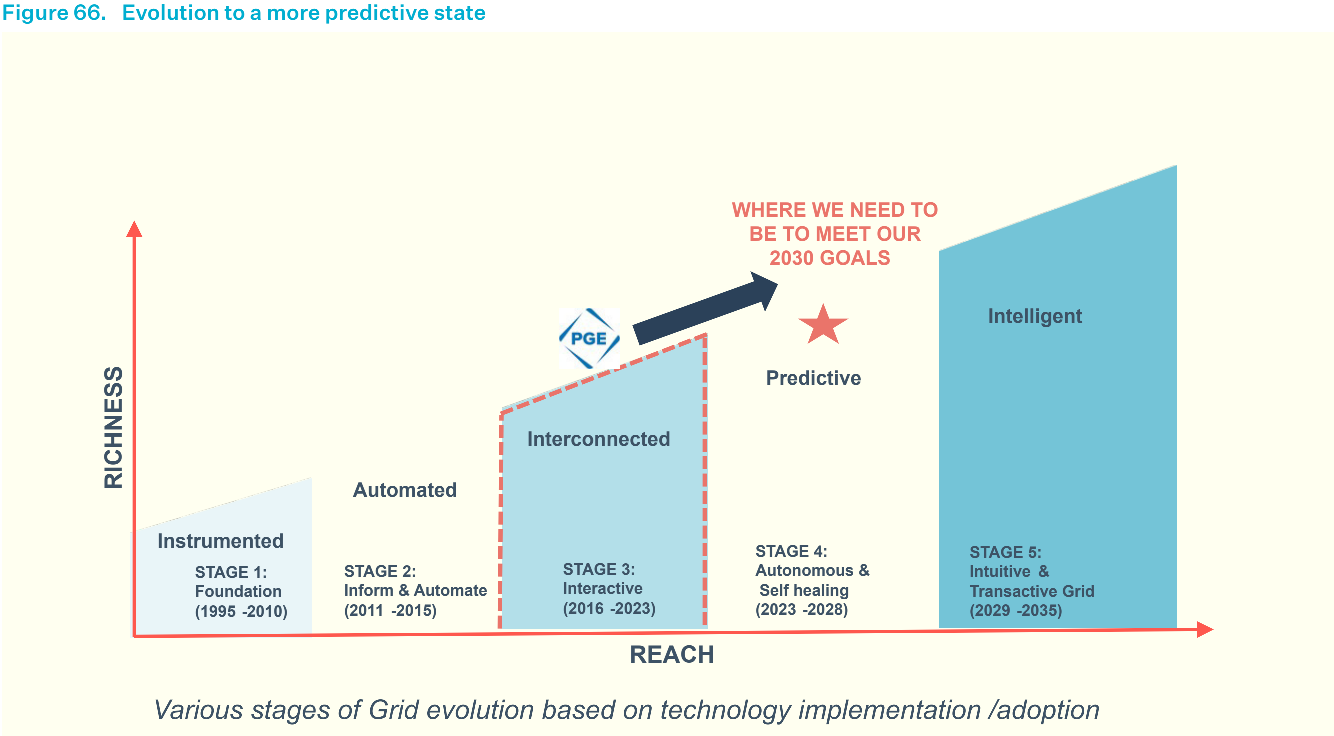
Our modernized grid initiative aims to enable an optimized grid platform that is safe, secure and reliable through current and future grid capabilities. The goal of a modernized grid is establishment of a system that can meet evolving customer needs while realizing the full value of DERs.

In order to meet the 2030 and 2045 goals, PGE's modernized grid needs to adopt a more predictive state and should evolve into an intelligent grid as shown in **Figure 66**.

PGE is currently working on realizing Stage 3 of the grid-evolution (Interconnected). Most IOU utilities in the US are at this stage of evolution. In order to meet Oregon's aggressive decarbonization requirements as set forth in HB 2021, it is imperative that PGE's grid should evolve to a state where systems predict the grid's next operational state and prepare customers and system operators to anticipate, rather than react.

PGE has been proactively modernizing the grid, integrating technologies such as smart meters and an advanced distribution management system (ADMS) to reduce outage response times and billing costs, among other benefits. Moving forward, this initiative will help align critical activities to enable and scale DER programs while addressing capability gaps in the company, such as performing locational net benefits analysis and optimized DER dispatch.

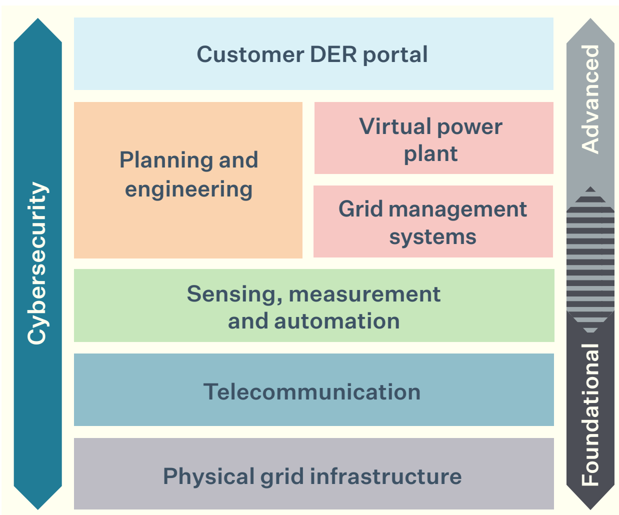
Figure 66. Evolution to a more predictive state



# K.2 Modernized grid framework

PGE's latest iteration of its modernized grid framework is outlined in **Figure 67**. This iteration builds on the integrated grid concept outlined in PGE's 2019 Smart Grid Report and leverages the grid architecture outlined in DOE's DSPx to align with industry best practices.[89]

**Figure 67. PGE's modernized grid framework**




PGE's modernized grid framework can be broken down into three categories:

- Foundational capabilities refer to the set of core platform investments to enable visibility and control of the distribution system. These investments follow a least-cost, best-fit approach, usually through a request for proposal (RFP) or similar process.
- Advanced capabilities refer to investments that build on or, in some cases, supplement foundational investments to develop advanced, intelligent control of the grid. These investments, depending on their function, either go through a benefit-cost analysis or use a least-cost, best-fit approach.
- Overarching capabilities impact both foundational and advanced capabilities and are key considerations when making the investments after the primary need is addressed. These capabilities include cybersecurity, workforce implications and other compliance needs. This overarching nature requires the investment justification to mirror the base investments.

# K.3 Currently planned capabilities investments

PGE has planned near-term investments with a direct impact on the outcomes of our vision for the distribution system. Each investment includes a forecasted timeline and costs over the short term. Where available, PGE also describes the expected long-term evolution of the specific investments.

## K.3.1 CUSTOMER DER PORTAL

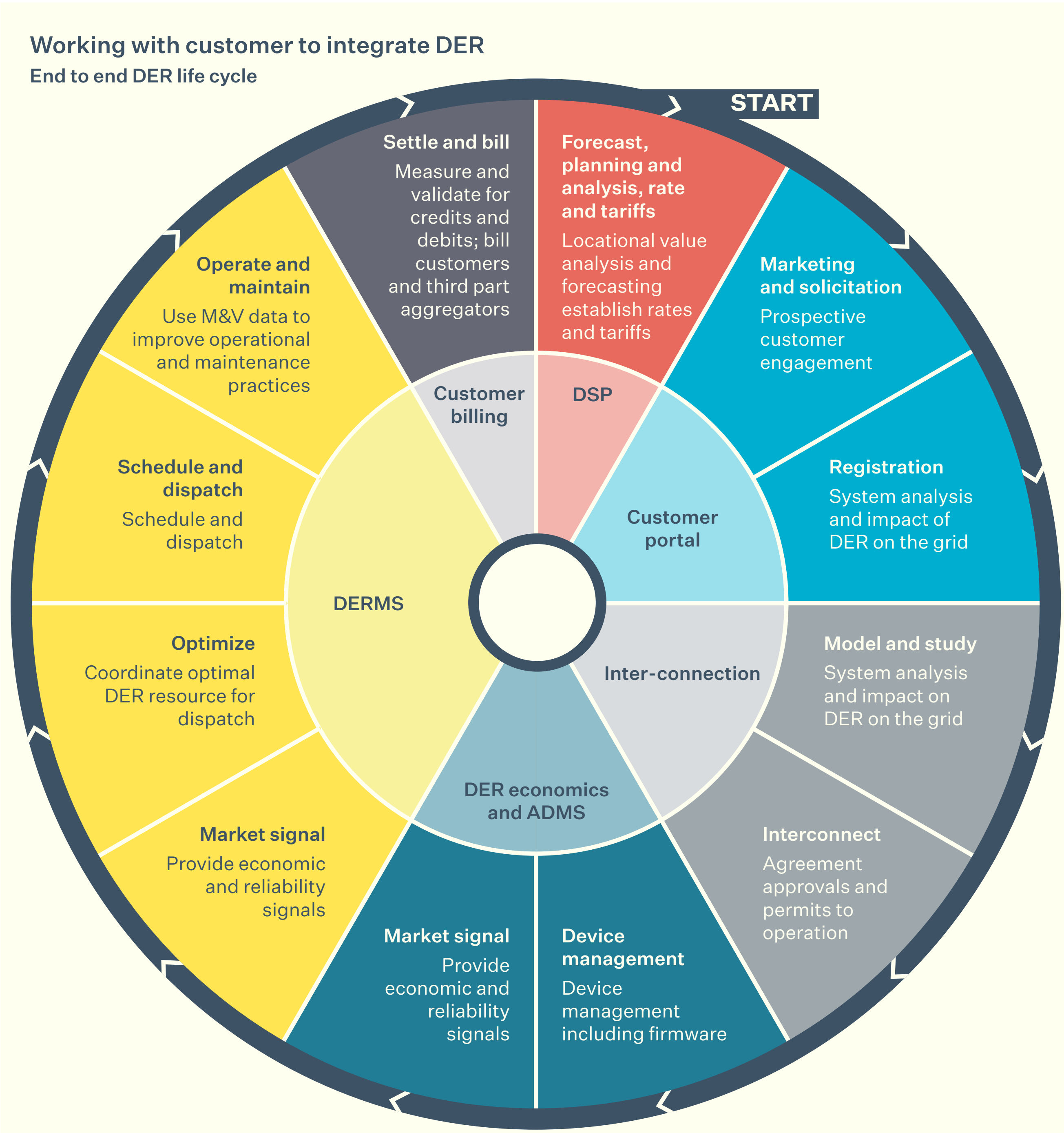
As part of the DER lifecycle, new functionalities and capabilities are being planned to improve customer interaction and experience. Customers need to be solicited and marketed with newer products and at the same time, they need to be recruited and registered to use the new product offerings from interconnection to various demand response and energy efficiency products. New products related to distributed energy resources are being devised and the customers' experiences of procuring and registering is critical. At the same time, PGE will have a responsibility to maintain the grid connectivity to those devices and manage the behavior of those devices including device management and cyber security.

The accuracy of the interconnected devices will allow the grid operations to have a detailed view through the distribution management system, as these devices will form the basis of the Virtual Power Plant which is described below.

89. US Department of Energy's Modern Distribution Grid Project is available at https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx More details can be found in DOE's DSPx guidance in Volume III, available at https://gridarchitecture.pnnl.gov/media/Modern-Distribution-Grid-Volume-III.pdf

Customers are expected to be marketed, solicited, and sold various products through which measurement and verification along with billing/settlements can be performed. The complex life cycle of the DER is being studied and evaluated at PGE. PGE plans to slowly invest and improve the customer portal. Some of the major customer portal functions that PGE is thinking about and leading the way are Customer DER Device Management, Customer Billing and Settlements, Customer DER Interconnections and Customer Interconnection Communications. Some future functions are DER Marketplace portal, Transactive Energy Portal, Transportation Energy related functionalities, Building Electrification related functionalities that provide a low carbon future by prioritizing cost effective, clean energy upgrades. PGE is also planning to develop various modeling tools and data science-based insights to deliver customized customer energy insights.

**Figure 68. DER lifecycle diagram**



### K.3.2 Virtual power plants

PGE is designing a new virtual power plant (VPP) business function enabled by a next-generation technology platform. The VPP function will operate at the nexus of Grid Operations, Customer Products and Programs, and Planning and Engineering.

For grid operators, the VPP function will act as a central hub for dispatching DERs and flexible load in large quantities. The VPP function will present operators with bundled DER portfolios that mimic the operational characteristics of traditional power plants, allowing operators to call on VPPs to provide various grid services without concern for the varying requirements of underlying customer programs.

For product developers, the VPP function will define standard business requirements for supplying various grid services. This will enable product developers to focus their attention on designing for customer value and customer experience within established constraints.

The VPP function will assume ownership of program dispatch from program operators. Centralizing operational dispatch will reduce workload at the level of individual programs, enabling program managers to focus on marketing, recruitment and program improvement. Centralizing dispatch will also position the VPP function to standardize operations and drive automation across programs.

The DER Forecast team will work with the VPP function to establish DER forecasts and planning assumptions. The VPP function will then be able to reserve and manage resources for non-wires solutions when deferring upgrades is the highest value usage of specific DERs.

The VPP function's scope will include any DERs and flexible loads on the distribution grid, including front-of-meter and behind-meter resources, PGE-owned resource, and resources owned and operated by customers. Depending on the size and nature of the individual resources they may be managed individually or aggregated at the program level — either by PGE or by a third-party aggregator.

The primary mission of the VPP function is to drive DERs and flexible loads to scale by maximizing the value of grid services delivered. To accomplish this, PGE will segment grid services into groups according to their scaling potential. Grid services that PGE is capable of scaling immediately will take priority, and the VPP function will actively pursue resource acquisition while eliminating obstacles to growth. For grid services where existing conditions do not enable scaling, the VPP function will work proactively with other functions to build enabling capabilities.

Bulk generation capacity, contingency reserves, frequency response, and hourly economic dispatch are expected to be the priority grid services for scaling as the VPP begins operating. Focus areas for capability building will likely include distribution locational benefits, volt/var control, and sub-hourly economic dispatch.

An ongoing VPP operating model project will produce business requirements, a five-year road map, and a detailed action plan for implementation by the end of Q3 2022. Development of the VPP technology platform will then occur in parallel with business implementation.

### K.3.3 PLANNING AND ENGINEERING

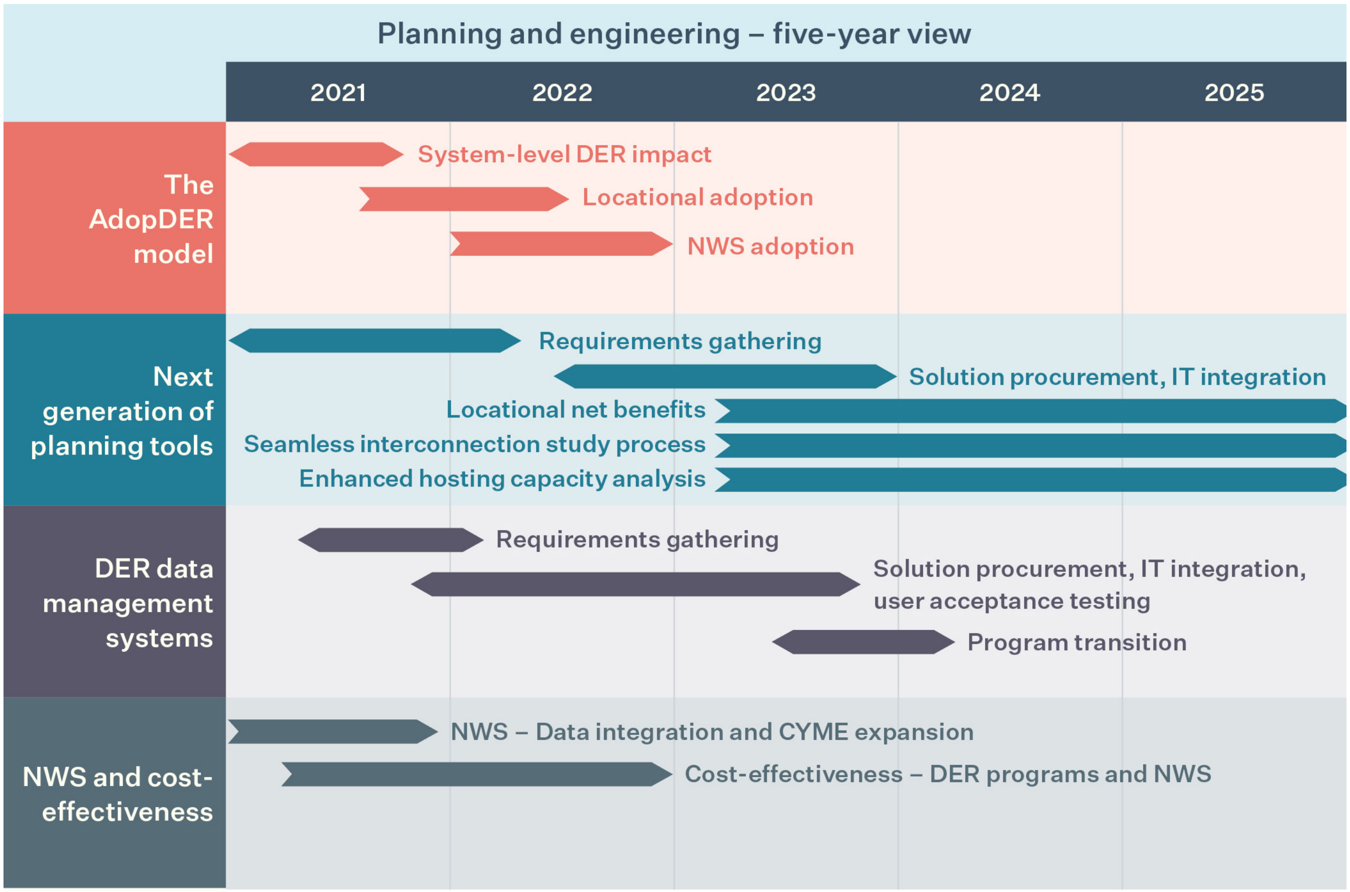
The planning and engineering capability refers to a suite of integrated, next-generation tools needed to perform distribution system planning functions. PGE's current approach to this capability builds on the functionalities outlined in the DOE's DSPx, as noted in **Figure 69**. This approach follows best practices and links investments directly to the goals outlined in our vision for the distribution system.

**Figure 69. Planning functions as defined by DOE's DSPx**

<table>
<tr><th colspan="3">Distribution planning</th></tr>
<tr><th>Functionality</th><th colspan="2">Technologies</th></tr>
<tr><td>Short and long-term demand and DER forecasting</td><td colspan="2">Demand forecast models<br>Load profile models<br>DER forecasting (customer DER adoption models, customer-EV adoption models)<br>Scenario analysis tools</td></tr>
<tr><td rowspan="3">Short-term distribution planning<br>Long-term distribution planning<br>Hosting capacity<br>EV readiness</td><td>Power flow analysis</td><td>Peak capacity analysis<br>Voltage drop analysis<br>Ampacity analysis<br>Contingency and restoration analysis<br>Balanced and unbalanced power<br>Flow analysis<br>Time series power flow analysis<br>Load profile analysis<br>Volt-var analysis</td></tr>
<tr><td>Fault analysis</td><td>Fault current analysis<br>Arc flash hazard analysis<br>Protection coordination analysis<br>Fault probability analysis</td></tr>
<tr><td>Power quality analysis</td><td>Voltage sag/swell analysis<br>Harmonics analysis</td></tr>
<tr><td>Planning analytics</td><td colspan="2">DER impact evaluation tool<br>Stochastic analysis tools</td></tr>
<tr><td>Reliability and resilience planning</td><td colspan="2">Realiability study tool<br>Value of lost load (VoLL) models<br>Resilience study models<br>Resilience benefit-cost models</td></tr>
<tr><td>Interconnection process</td><td colspan="2">Process management software and portals</td></tr>
<tr><td>Locational value analysis</td><td colspan="2">Cost estimating tools</td></tr>
<tr><td>Integrated resource, transmission and distribution planning</td><td colspan="2">Planning integration and analysis platform</td></tr>
<tr><td>Planning information sharing</td><td colspan="2">Web portals<br>Geospatial maps</td></tr>
</table>

PGE has planned the following key investments to enable the functions from **Figure 69**. These investments are considered foundational and aligned with DOE's DSPx. They are evaluated based on least-cost, best-fit and reasonableness. **Figure 70** provides a five-year overview of PGE's investments in planning and engineering.

Figure 70. PGE's planned investments in planning and engineering over next five years




Note: Includes future initiatives

### K.3.3.1 Bottom-up DER forecasting and potential assessment – The AdopDER model

To meet the evolving needs of customers, we developed an in-house model, AdopDER, to conduct bottom-up DER forecasting and assess DER potential at the system- and locational-level. This model leverages an open modeling framework that integrates true bottom-up modeling of the building and vehicle stock with market-level adoption forecasts, creating a rich, integrated view of how different DER and electrification technologies complement and compete under different conditions. The AdopDER model represents a paradigm shift in how potentials are modeled and lays the foundation for continued evolution in planning processes across the energy system.

This project is being developed in two phases over a two-to three-year period. In Phase I, PGE estimated system-wide DER potential to inform the company's Integrated Resource Plan (IRP). In Phase II, PGE estimated locational adoption of DER resources and fine-tuned adoption models to account for different demographics, energy use patterns, built infrastructure and cluster effects that are known to impact the distribution of DERs on the system. Phase II results are discussed further in **Section 3.5**.

PGE expects to incorporate lessons learned and feedback to build on the existing functionality, enabling new features such as locational adoption for non-wire solutions (NWS), improved data and information technology (IT) integration and data quality.

### K.3.3.2 Next-generation planning tools project

PGE is currently conducting an investigation to understand the current and required future planning capabilities needed to realize PGE's vision. This effort will also provide the required tools, data and IT infrastructure to perform planning analysis at the appropriate frequency, as well as the workforce changes to update our approach to distribution system planning and engineering.

We refer to this project as "next-generation planning tools." Through this investment, we expect to enable integrated distribution planning (IDP), acquiring additional technical analysis capabilities that will allow us to meet the future planning needs of the distribution system. The integrated distribution planning framework allows us to identify appropriate investments in the distribution system that deliver safety, reliability and security, while accommodating load and DER growth, as well as modernization of the grid through technology and aging asset replacements. Enabling IDP will also help us to enhance interconnection study processes to support rapid growth of DERs and improved processes for engaging community in addressing grid needs.

Some of the advanced technical analysis capabilities being considered include:

- Ability to perform time series analysis (8,760 hour analysis)
- Ability to consume profile-based forecast (8,760 hour forecast profiles)
- Ability to incorporate granular data in the analysis of the distribution system
- Enhancements and efficiencies to performing hosting capacity/integration capacity analysis
- Ability to perform integration of non-wires solutions (NWS) into the distribution grid
- Enhance and efficiencies in performing interconnection technical screenings and studies
- Distribution system optimization — Volt/Var, DER placement and dispatch, device placement (capacitor, regulator, DER)

Our next generation planning tools project will be a foundational investment designed to enhance PGE's current planning capabilities and enable improvements in various facets of distribution system planning.

As the initial phase of the next generation planning tools project, PGE evaluated the state and maturity of various planning tools and processes. An investigation into available planning engineering tools in the industry was also conducted to decide which vendor/tool provides the best flexibility and capability to meet the future needs.

An assessment of various commercially available planning tools was conducted to evaluate which vendor/tool could provide most of the capabilities that PGE is desiring to gain. Based on the assessment, a decision was made that CYME, through various analysis modules they offer, meets most of the capabilities that PGE needs.

CYME is currently engaged to work with PGE in developing a detailed road map for implementing an Advanced Distribution Planning System (ADPS) which would be foundational for enabling Integrated Distribution Planning capabilities.

Through this engagement, CYME and PGE will:

- Identify the current usage of CYME tools and modules at PGE
- Identify PGE pain points in the current planning engineering process
- Identify additional data and integration needs
- Identify specific analysis tools and capability maturity needs
- Explore various use cases of CYME tools and modules in planning engineering as well as operations planning
- Identify and document existing IT system and integration used by CYME
- Create a system architecture diagram to develop detailed IT system and integration design

Based on the discovery process, CYME and PGE will develop a high-level design for the ADPS. The design will include data integration needs with other systems and tools (e.g., GIS, AMI, SCADA, and Forecasting). The design will include automation of various processes needed in planning engineering such as — system model updates, power flow with profiles, integration capacity analysis, forecast profile creation, and grid needs summary output.

This high-level design will act as the foundation for the next steps to undertake a detailed design, develop and implement expanded and automated CYME capabilities (Advanced Distribution Planning System) that enables an Integrated Distribution Planning process. This will be a multi-year process that involves new IT equipment and integration as well as process changes in the planning engineering team.

### K.3.3.3 DER cost-effectiveness update project

PGE has a strategy to develop a benefit-cost framework aligned with state policy and goals. This framework will be designed to account for the new and emerging value of DERs. The new comprehensive investment strategy presents many opportunities which come with challenges. DER investment strategy, with the growth forecasted, needs to be supported by an enhanced methodology to adequately value resources added to our grid. An improved cost-effectiveness analysis capability will help us look at broader impacts of DERs and open opportunities for expanding existing programs or creating new pilots. In return, it will help PGE reach our clean energy goals, while offering broader options for our customers to interact with the grid and contribute to greener future.

As part of this new methodology, PGE is developing a new cost-effectiveness tool, called Ben-Cost. It builds on PGE's previous work on the resource value of solar, flexible load and transportation electrification valuations. The new tool will enable DERs to be valued through multiple perspectives, accounting for energy system, host customer and societal impacts.

The Ben-Cost tool will enable PGE's product development teams to experiment with more nuanced program designs, especially as they pertain to impact on environmental justice communities.

In 2022, PGE will build on the Ben-Cost tool to enable economic analysis for NWS and perform studies to calculate other societal benefits. We expect to focus on refining the functions of the tool, performing IT integration of the model with AdopDER and the proposed Demand Side Management System (DSMS).

### K.3.3.4 Systems of Record for DER Data

As DERs proliferate and become an increasing part of the physical infrastructure with which PGE interacts, PGE must maintain and organize new types of data related to generation, storage, and flexible load resources on the distribution grid. The availability of accurate and relevant data will determine how much value can be captured for the grid and for individual customers.

Examples of new or newly significant data include:

- **Nameplate characteristics, electrical and geographic location, configuration settings, and control functions of interconnected DERS:** Systems exist for storing relevant information about traditional, utility-owned resources, but these systems are not designed to manage all required information about new resource types, nor are they designed to manage information about resources owned by customers.
- **Characteristics of buildings and building loads that affect suitability and performance in flexible load programs:** Traditional utility systems have limited ability to represent and store information about what lies "behind the meter." Such data has typically been managed as a list of characteristics related to the service point. But emerging applications require richer multi-dimensional data.
- **Information necessary to gain insights from the operation of DERs and customer programs:** Site-level performance data — such as device telemetry — in association with customer insights and external variables like weather and market conditions enables more accurate forecasts and can generate ideas for innovation and improvement. And the benefits of applied data science compound over time as improved program performance drives lower rates and higher incentives for customer participation.

Identifying the source of data and which stakeholder team at PGE is responsible makes it easier to leverage data. Making effective use of DER data will enable key functions:

- **Planning and evaluation:** Support more accurate studies through awareness of each DER's capabilities and operational characteristics.
- **Operations:** Support real-time decisions through awareness of DER location, characteristics, and expected impact.
- **Products and programs:** Streamline program management, reporting, incentive processing, and cost-effectiveness calculations, and help improve program design.
- **Customer support:** Provide customers with improved information about the programs they participate in and the benefits available to them.
- **Field crews:** Ensure accurate information for maintenance assessment and crew safety.
- **Participation in organized markets:** Enable DERs to participate in the energy imbalance market and provide bulk system services.

In 2022 PGE has contracted with the Electric Power Research Institute (EPRI) as part of a collaborative R&D effort to help PGE remain abreast of emerging industry practices for managing DER data. Knowledge gained will be applied through various initiatives that implement or change PGE information systems. Primary near- and medium-term implementation efforts include:

- Efforts to further operational integration by automating the dispatch of flexible load resources and/or integrating dispatch into the processes and systems used to dispatch other resources.
- Efforts to rationalize and standardize technology implementation across programs through competitive procurement and improvement of the interfaces between systems.
- Efforts, such as the Customer 360 Project, that directly address the breadth, quality, and availability of data for analysis.

### K.3.3.5 Demand Side Management System (DSMS)

PGE is in the early stages of developing an enterprise-wide central source of DER data and attributes. This project, also known as a DER measure database in energy efficiency, is a foundational requirement to record and house important DER details, such as:

- DER attribute data, telemetry data, locational data and customer information
- DER program performance data
- DER cost-effectiveness and evaluation results
- Energy efficiency and renewable energy integration with the ETO
- DER reporting and regulatory compliance

An analytical platform that works with this data will streamline core business functions, including interconnection and program application processes, incentive payments, demand response (DR) event performance reporting, standard reports for regulatory filings and data requests, integration with planning tools, improved visibility for operators, integration interconnection data, EV impacts and program opportunity analysis.

PGE is also in the process of contracting with Electric Power Research Institute (EPRI) as part of a new research and development (R&D) effort in which PGE will leverage EPRI's expertise and ensure best practices are implemented in the design of the DSMS.

The project is expected to affect the following business functions:

- **Planning and evaluation:** Accurate studies through awareness of each DER's capabilities and operational characteristics
- **Operations:** Real-time decisions supported by awareness of DER location, characteristics and expected impact
- **Product teams:** Streamlined program management, reporting, incentive processing, cost-effectiveness calculations and program design

- **DER customer support:** Utility staff and websites to provide DER customers with information
- **Field crews:** Accurate information for DER maintenance and assessment
- **Coordination with independent/transmission system operators (ISOs)/TSOs:** Support of requirements for DERs providing bulk system services

PGE has created a cross-functional team to develop requirements for procurement of a DSMS. We expect the project to take one to three years for completion.

## K.3.4 GRID MANAGEMENT SYSTEMS

Grid management systems (GMS) are a collection of operational technology tools used by operators of electric utility grids to monitor, predict, analyze, control and optimize the performance of the distribution system.

The GMS communicates with field devices that sense, measure, protect and control the grid, via a telecommunications network. Investments across the GMS, field devices and telecommunication systems are interlinked and considered together to maximize customer benefit.

The following details describe key ongoing and planned investment activities within both the GMS and supporting infrastructure. Where available, PGE has provided long-term evolutions of these investments. The current set of planned investments in the following sections are foundational prerequisites for the modernized grid. PGE leverages the least-cost, best-fit approach to justify these investments. PGE has noted investments where future evolution will require investment justification through benefit-cost analysis.

PGE has developed a comprehensive grid modernization strategy that will facilitate cultural shifts, shorter development cycles and cohesive strategic alignment across PGE. These capabilities are needed to provide safe, secure, reliable and resilient power on the electric grid subject to high DER penetration. **Figure 71** illustrates the functions necessary from a comprehensive GMS.

**Figure 72** illustrates PGE's five-year roadmap for GMS.

Figure 71. Grid management system functions

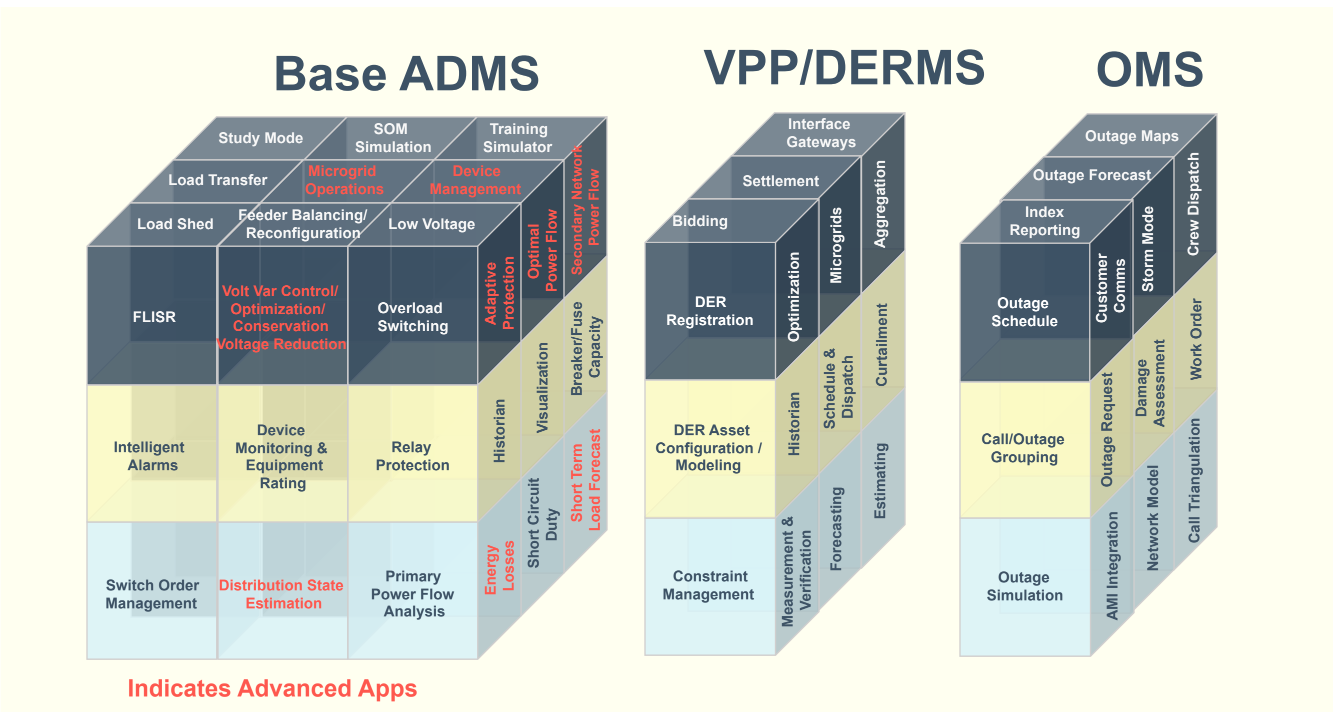
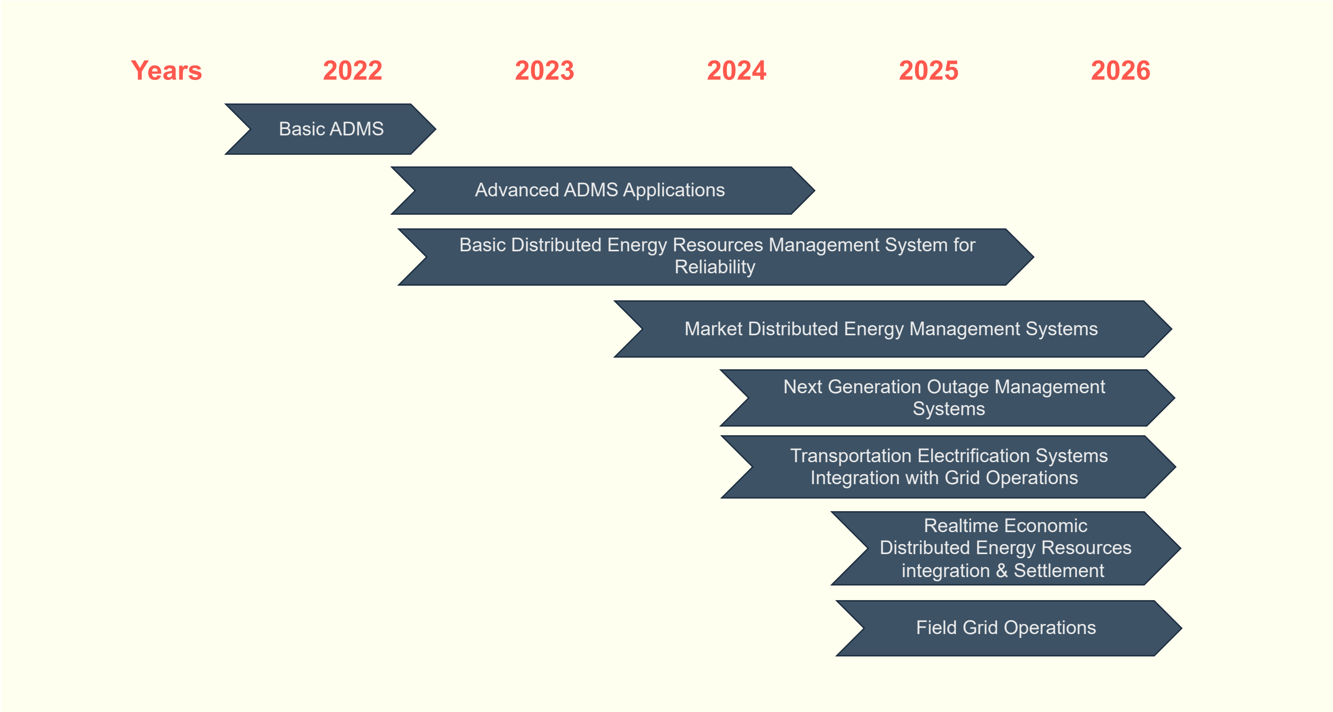


**Figure 72. PGE's expected five-year roadmap for grid management systems**




In 2022, completion of our Basic ADMS deployment included implementation of a distribution management system (DMS) with functions focused on monitoring, predicting and operating distribution devices on the distribution system. Additionally, PGE implemented fault location, isolation, and service restoration (FLISR) on several feeders to leverage the monitoring and operational capabilities of the DMS for direct reliability benefits. Finally, PGE's Basic ADMS implementation included management of electronic switching sheets, clearances, monitoring of integrated grid systems, and operation of equipment on the distribution system.

ADMS will collect real-time information from distribution substations and feeder and customer devices and integrate existing and future distribution automation schemes, which are defined in the following section.

While DER and DSG resources may not be classified as critical infrastructure protection assets, protective measures similar to the energy management system (EMS) are in place.

### K.3.5 SENSING, MEASUREMENT AND AUTOMATION

Substations serve as the hub of energy transmission and delivery. State-of-the-art substations enable reliable and resilient operation of the grid. Substations need to be equipped with modern protection and automation (e.g., SCADA with device and data integration) to realize many of the capabilities needed to operate the modern grid.

### K.3.5.1 Distribution automation (DA)

DA is the umbrella term for smart grid solutions that solve power system issues by integrating various equipment, devices and data into a centralized system (the ADMS). These solutions include FLISR, Volt-VAR optimization (VVO) and smart faulted circuit indicator (sFCI) integration. Each DA solution requires a unique set of integrated devices and systems to fully realize the benefits. Types of DA solutions are described below:

- **FLISR:** Normally open and normally closed supervisory control and data acquisition (SCADA)-integrated switching devices are strategically placed throughout the feeder to maximize the implementation's expected benefits. The preferred communications medium is PGE's FAN. When paired with a centralized controller (e.g., ADMS), the system will identify the location of sustained faults using sensor data, then will isolate the faulted section and restore service to customers outside of the isolation zone via automated, remote switching. The result is reduced frequency and duration of sustained outages for customers.
    - 2021 through 2024: For each year, install approximately 83 SCADA-integrated switching devices across approximately 20 feeders; perform upgrades at approximately 15 substations to enable ADMS integration.
    - 2025 and beyond: During the first four years of implementation, evaluate realized and forecasted FLISR cost-effectiveness to determine future implementations plans.
- **VVO:** Equipment that can manage voltage and optimize VAR flow and controlled via SCADA within ADMS, reducing system losses and contributing to peak reductions, is installed inside substations and along distribution feeders. Capacitor banks provide the principal source of VARs (a unit of reactive power) with smaller amounts of reactive power potentially being contributed by secondary VAR controllers or customer owned DERs. Similarly, load tap changers (LTC) and line voltage regulators provide direct voltage control for distribution feeders with supplemental voltage support provided by capacitor banks and some amount of local voltage support provided by inverter based DERs. Once integrated with an ADMS, this equipment is controlled to meet a variety of objectives, including implementing active or real-time conservation voltage reduction (CVR), minimizing power system losses, maintaining acceptable voltage for all customers and regulating the power factor (PF) for feeders and substation transformers.
    - Plan for initial active VVO implementation through PGE's across three LTCs and associated feeders
    - Pilot active VVO implementation.
    - Evaluate effectiveness of active pilot VVO implementation.
    - Scale VVO program commensurate with cost effectiveness.
- **Smart fault circuit indicator (sFCI):** Installation and integration of communicating line monitors, strategically placed throughout the distribution system, will help inform real-time operational decisions. Specifically, these monitors provide data that allows improved accuracy for FLISR as well as improved situational awareness, and reduced truck rolls and line patrols.
    - 2021: Select sFCI vendors for select feeders that are designated as having heightened wildfire risk.
    - 2022: Evaluate effectiveness of sFCI deployments and plan for future deployments throughout all identified wildfire feeders (if applicable).
    - 2023: Finalize an sFCI placement model to help strategically place sFCIs in areas that are forecasted to receive the greatest benefits. Consider other use cases for implementation (e.g., feeders without SCADA telemetry).
    - 2024 and beyond: Scale FCI program commensurate with cost effectiveness.

Execution of DA initiatives is paramount to transforming PGE's distribution system into a smarter, more integrated grid.

### K.3.5.2 Substation automation and SCADA systems

- **Achieve efficient monitoring and operations:** 83% of PGE's substations have SCADA capability. This means the remaining 17% of substations do not have the same remote monitoring and control capabilities. Information about emerging equipment problems and loading issues at these substations is not readily known to grid operators and could lead to unintended events, affecting the reliability of the grid and customer experience. For emergency response operations at substations without SCADA, a person must be physically dispatched to the substation to validate the issue and take action. This reduces response efficiency and reliability and diminishes the customer experience.

- **Optimize the grid:** Optimizing the grid requires continuous measurement and control capabilities. Optimization can be achieved through VVO capabilities. This will help with reducing system losses, demand reduction and reduced energy consumption through CVR. An updated substation automation system with relay, metering and transformer load tap changer (LTC) control device integration through distributed network protocol 3.0 (DNP 3.0) and the ability to integrate with systems like ADMS is needed to achieve this.

- **Improve asset management and utilization:** With a modern substation automation and associated SCADA system, intelligent devices such as relays, controllers, meters and asset monitoring devices can be integrated and information can be bought back to the office (e.g., Reliability and Performance Monitoring Center) for additional analysis. This data allows for better management of substations and major assets, enables efficient operations, increases asset utilization, lowers maintenance costs, predicts failures and assists with fine-tuning of the grid for more reliable operations.

- **Secure the grid:** All connected devices should be configured, connected and managed in a secure manner.

- **Simplify design and construction:** Continue to explore newer methods of protection and automation construction (e.g., IEC61850).[90]

### K.3.5.3 Modernize cost-effective communication-aided protection systems

- **Improve system reliability:** A protection system is fundamental to operating the grid. Modern digital relays are required to meet new operational objectives by providing multiple settings groups, supporting remote modification of settings and locally adaptive protection when enabled. They also provide more detailed data via connection to a substation automation gateway and centralized SCADA platforms.

- Many of PGE's distribution substations and feeders do not have protective devices that easily support integration of distributed generation (i.e., many require setting changes be made at the relay within the substation). Improved protection capabilities will support remote modification of protection settings to accommodate increasing levels of distributed generation.

PGE's approach to substation automation is to balance grid needs, budget priority, and budget availability. We expect this project to be an ongoing activity with investments made on an as-needed basis and usually coupled with other investments such as substation rebuilds and feeder upgrades.

PGE has standardized the integration of cybersecurity monitoring and management for protection/automation systems as part of constructing new substations or rebuilding older substations. PGE also establishes data integration between all substation automation systems/devices and the Reliability and Performance Monitoring Center in PGE's IOC.

PGE estimates consistent multi-year investments for automation and protection.

#### K.3.5.3.1 Substation automation

- PGE will add SCADA automation to remaining non-SCADA substations (i.e.,100% SCADA coverage for substations) based on need, priority, and budget.

- PGE will replace legacy SCADA with modern SCADA and substation automation platforms (e.g., DNP 3.0) based on need, priority, and budget.

90. IEC 61850 is an international standard defining communication protocols for intelligent electronic devices at electrical substations. It is a part of the International Electrotechnical Commission's (IEC) Technical Committee 57 reference architecture for electric power systems.

#### K.3.5.3.2 Substation protection

- 2021 through 2025: Prioritize replacement of all electro-mechanical relays in wildfire zone substations.
- Post 2025: PGE expects to put microprocessor-based relays on an 18-year replacement cycle. This will enable new functionality through new technology, which reduces failures within the protection system.

### K.3.5.4 Field area network (FAN)

One of the communication options as part of the strategy is the Field Area Network. The FAN is a PGE-owned and operated wireless network that will cover PGE's service territory, enabling quick and reliable grid communications using the 1MHz of PGE owned spectrum. It is worth noting that the FAN provides speeds in the Kbps range. FAN's primary use case is providing the communications necessary to operate DA reclosers but can be extended to other devices with similar connection profiles.

The alternative to the FAN is cellular service and, though ubiquitous, it has disadvantages for certain critical systems:

- **Reliability:** We are at the mercy of wireless operators for outage resolution (and even throttling during major events). Past experience shows troubleshooting can get bogged down between companies.
- **Longevity:** Wireless operator's technology can be decommissioned and their spectrum is continuously being repurposed. Hence there is a potential that our field equipment could be made obsolete.
- **Security:** The FAN is part of the PGE network, so our data does not go out of the PGE network.
- **Cost:** Cellular service is an operational expense

The FAN project involves the design, procurement and installation of PGE-owned and operated base stations, currently at 90 sites to covers our service area, with the goal to have all sites constructed and online by the end of 2024. Today we have constructed 28 of the 90 sites and we are in the process of connecting our first end device. We are on track to complete this project by 2024.

### K.3.5.5 Automated metering infrastructure (AMI) improvements

AMI is the technology that allows the bi-directional communication and control of utility meter assets at residential, commercial, industrial and generation service points. It includes meters that are embedded with a combination of network radios and network towers (collectors) that gather the transmissions from the meters and, ultimately, the software that stores, visualizes and integrates that data to various downstream systems and processes.

PGE was among the first utilities fully implementing AMI and has a fully operational system with 99.9% AMI penetration for more than 10 years. The technology has become more advanced over time and continues to evolve very quickly as AMI use cases broaden beyond the traditional "meter reading" to focus more on grid sensor and controller functions. The AMI system at PGE collects data from 920,000 meters, aggregating 50 million daily messages that contain usage, generation, reactive power, voltage and temperature. This system also has alarms indicating the relative health of the measurements and of the electrical service itself. The system is capable of bulk (over the air) transactions that monitor outage status and power quality, as well as keeping the meter and network software, programming and configuration up to date with the latest standards. On any given day, there are up to 2 million of these two-way transactions.

The original AMI design included only remote disconnect (RD) meters installed on non-owner-occupied single-phase homes. As of 2019, PGE's strategy has been to install RD meters for all new single-phase services and replace non-functioning single-phase meters with RD meters. In addition, the company started proactively replacing approximately 25,000 meters per year with RD meters. From a DER perspective, RD meters are a necessary backstop to prevent reliability issues if DER solutions do not perform as planned.

The core business case for AMI has generally been tied to the ability to remotely, quickly and accurately gather billing reads once a month, rather than sending a meter reader into the field. AMI has allowed for remote disconnection and reconnection of power, rather than sending a disconnect representative to the home. From there, AMI has been used to present hourly usage (interval data) to some customers to allow for greater insight into usage patterns, as well as enable variable rate structures such as Time of Use/Time of Day without the necessity of field visits in all cases.

In thinking about the future of AMI over the next five- to 10-year timeframe, PGE has completed an initial "AMI 2.0" assessment that built a list of requirements for a forward-looking AMI strategy. These requirements build on the initial capabilities for billing, collections and simple outage management, as well as what will be required to facilitate the dynamic, bi-directional smart grid of tomorrow.

## K.3.6 TELECOMMUNICATION STRATEGY

PGE is planning to deploy various distribution automation devices and sensors to support the increased adoption of DERs. To operate a reliable and resilient grid, PGE needs to be able to monitor and react to the behavior of these DERs. In order to monitor their behavior, PGE needs to have a comprehensive telecommunication network to support the increased level of communication between devices and operators. The successful operation of the telecommunication network depends on the following major characteristics:

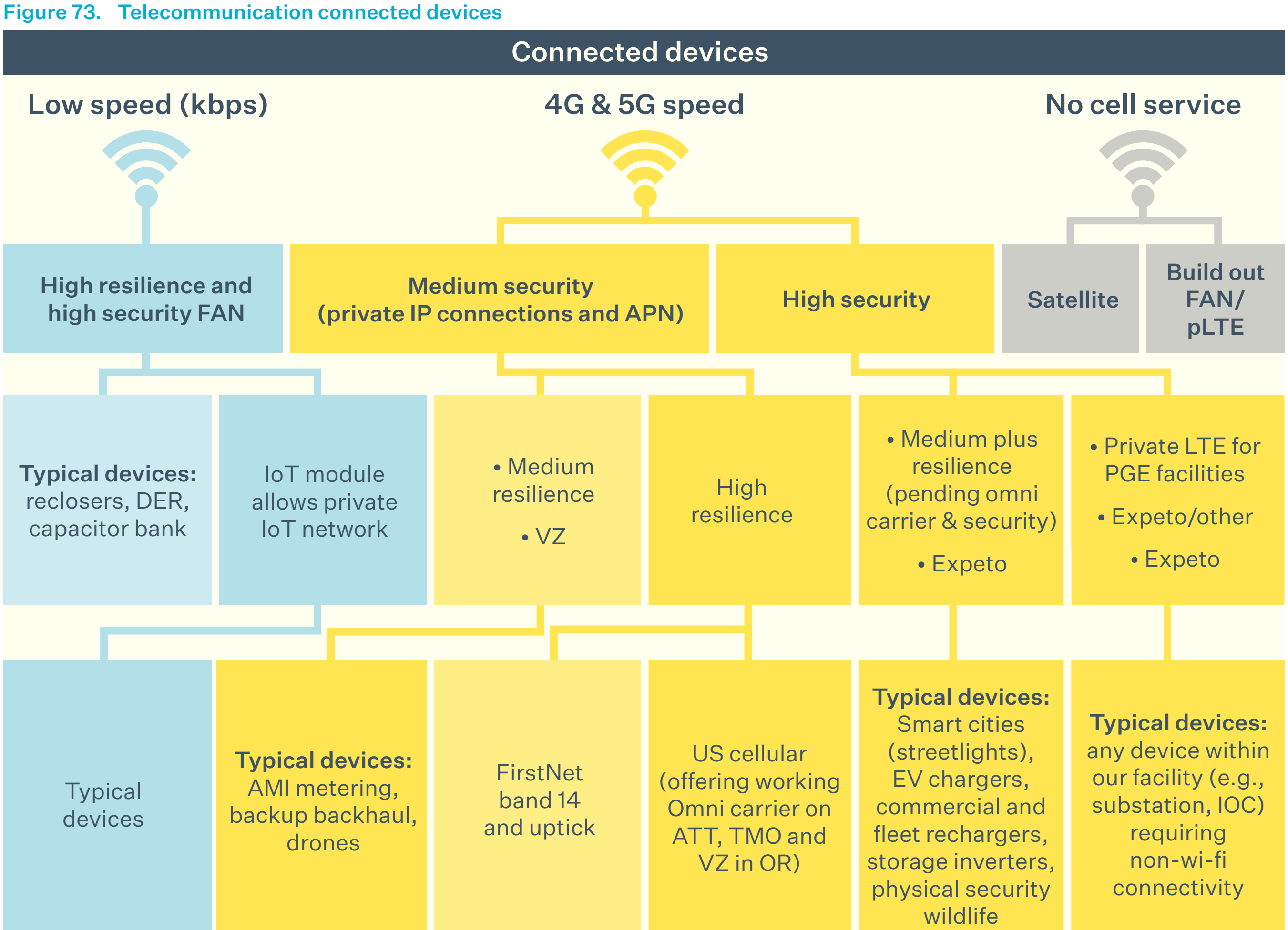
- Speed
- Bandwidth
- Latency (<40ms or >1s)
- Minimal service levels
- Security
- Availability
- Cost

The goal of the strategy is that the answers to the above points would drive the device to the network that best fulfills its needs.

**Figure 73** shows the initial thoughts on how the different requirements translate into the connectivity options. At present, only the options highlighted in green are available for connectivity:

- Verizon data SIM
- PGE field area network (FAN)

Figure 73. Telecommunication connected devices



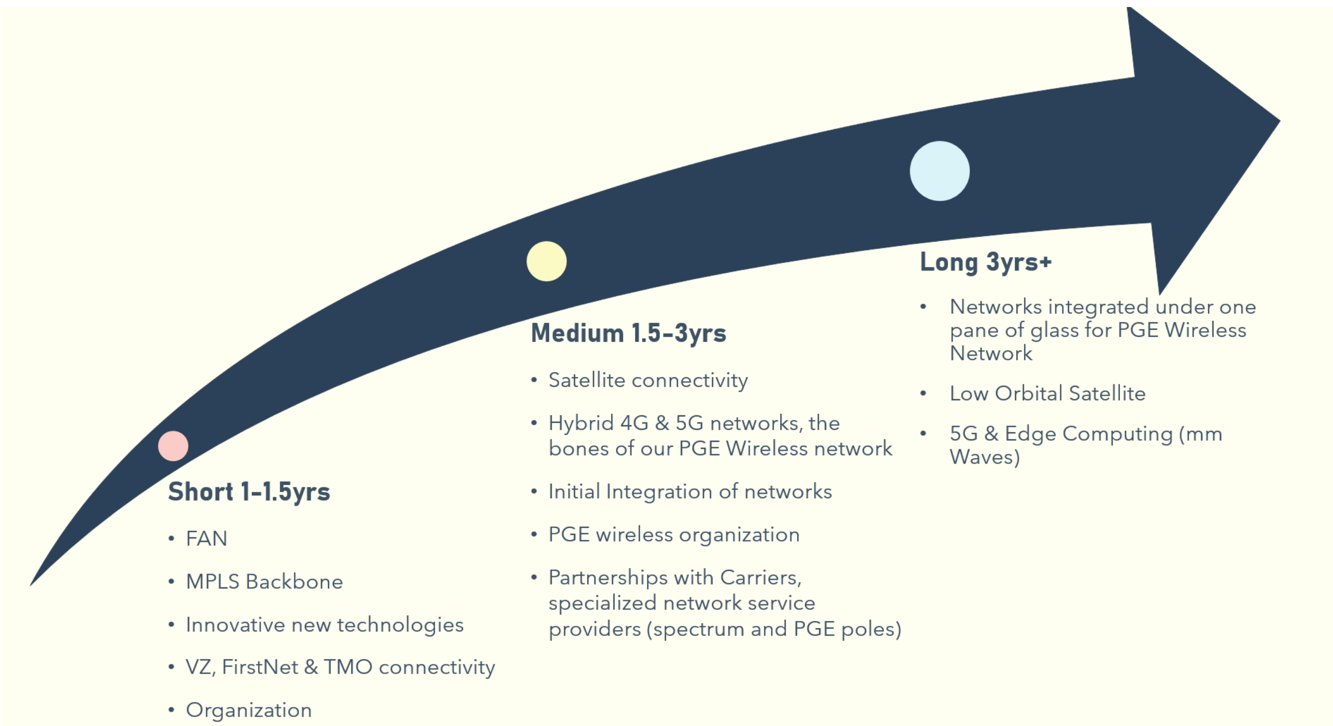
The other cellular options are in the process of being evaluated to see if they can meet our needs and to define their shortcomings. Some of the options being considered include:

- The concept of Omni carrier (the SIM will go on the "best" wireless provider), which both eXpeto, and now US Cellular, are proposing
- New FAN hardware, which would provide Internet-of-Things connectivity
- The security analysis for these different communication options

One of the challenges is how to get connectivity when there is no cell service from any operator (this is coming up more often when deploying sensors for wildfire mitigation)

**Figure 74** depicts a high-level roadmap for advancing the telecommunication capability.

**Figure 74. Telecommunication capability roadmap**



### K.3.6.5.1 Short term

There are a handful of short-term tasks that we can do to be in a better position for grid modernization:

- Integrate all operators — we currently have only one cellular wireless solution, Verizon. As such we are not able to leverage competitive prices from both T-Mobile and AT&T. To get the other operators added, we would need to set up the necessary connectivity between their networks and ours. We are researching the monthly costs to set this up.
- Organization — at present, we do not have a clear process to troubleshoot cellular network performance/outage issues. Our recent experience with Verizon and the AMI outages highlighted gaps in the process, such as:
  - Missing a troubleshooting step to confirm that the issues are not PGE's
  - The inability to track issues and open internal and external service requests with the wireless provider

There is an important area of focus regarding the organization required to manage all the different connection options and which team should be responsible.

### K.3.6.5.2 Medium term

The noteworthy milestones are the deployment of a PGE wireless network and getting an initial platform in place to support that network. We anticipate narrowing down the technologies we want under the PGE wireless network and designing the organization that will be responsible for managing the network.

### K.3.6.5.3 Long term

The PGE Wireless network will consist of different connection methods, such as:

- Hybrid 5G data network (Expeto)
- Satellite network
- Private LTE (5G)/edge computing for very low latency connectivity
- Private IoT network/mesh networks
- Commercial cellular (traditional voice)
- FAN

The challenge is integrating diverse technologies into one platform while being able to switch between the technologies at the end device to ensure we have diversity.

We expect to see the deployment of target, private LTE (5G) deployments together with edge computing to provide the necessary low latency that today's wireless signals struggle to achieve.

# K.4 Resilience action plan

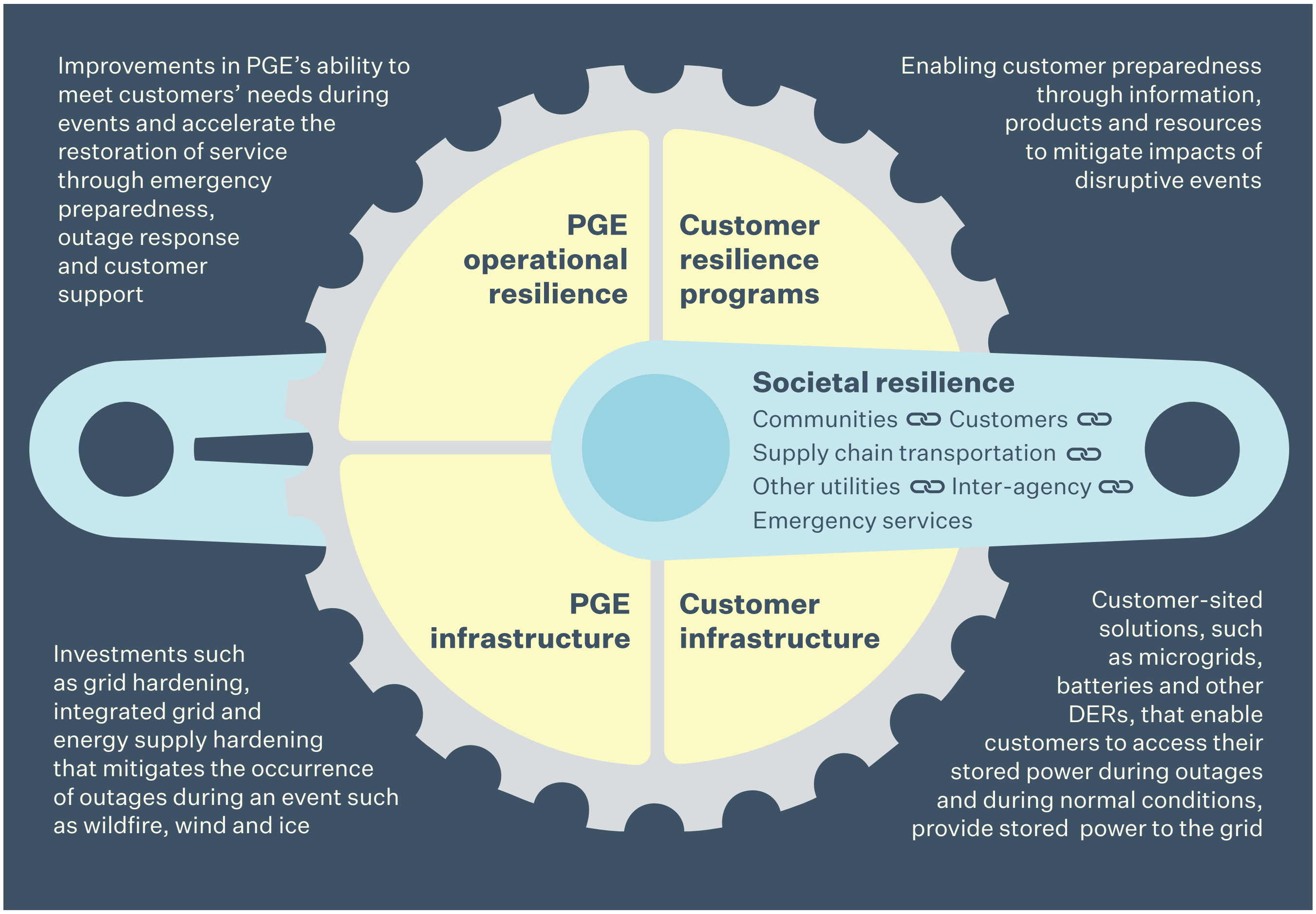
Resilience is defined as our ability to anticipate, adapt to, withstand, and quickly recover from disruptive events. Some customers are feeling the urgency to take action to prepare for the unexpected, and PGE does recognize this urgency. Our approach to resilience brings together leaders and teams from across the company to improve our ability to meet customer and community expectations for resilient power delivery. We align the efforts, investments, and plans across multiple functions and business lines to reduce the impacts of climate change, other natural disasters and human threats on our ability to serve customers.

PGE's approach focuses on four outcome-based capabilities:

- **Robustness:** the ability to absorb shocks and continue operating
- **Resourcefulness:** the ability to skillfully manage a crisis as it unfolds
- **Recovery:** the ability to get services back as quickly as possible
- **Adaptability:** the ability to incorporate new information and lessons learned from past events

PGE's resilience is highly dependent upon our broader societal resilience, including transportation, supply chain, and other agencies. Because energy system resilience is a critical component of societal resilience, PGE must take a community-centric approach to planning resilience investments. PGE's energy system resilience spans generation, transmission, distribution, and information technology operations with four areas of focus as shown in **Figure 75**.[91]

Figure 75. Resilience focus areas




91. Reliability – the availability of electric service
Hardening – a tool to create stronger infrastructure to protect customers from weather or other environmental impacts

Complementing the focus areas are PGE's resilience guiding principles:

**Ahead of the game:** PGE is monitoring changes in our environment and our community. We are proactively adjusting our plans to address your needs.

**When we know, you know:** PGE will communicate with you about the performance of your electric service. We will be transparent with our investment plans and resiliency challenges.

**Meet you where you are:** PGE delivers resilient electric service and programs to serve the diverse needs of all customers and communities.

**Pushing the envelope:** PGE is constantly exploring new solutions, customer programs, processes, and technologies to reinvent outage prevention and deliver value for you.

**We'll help you prepare:** PGE will partner with you and your community leaders to prepare for the future.

**Affordable service:** PGE is making prudent investments to improve the resilience of your electric service. We are considering both traditional and non-traditional solutions to new challenges.

### K.4.1 RESILIENCY AS AN IMPERATIVE

Climate change brings increased risk of storms, power outages. In a survey conducted in 2016 among residential customers about battery energy storage, 63% of PGE residential customers indicate never experiencing a power outage is extremely important.[92] Working from home was cited as the main reason why consistent power was of utmost importance, and one can imagine that with record numbers of Oregonians working out of the home due to COVID-19 that importance has only increased.

Sixty-two percent of business customers say that an outage of five minutes or longer would have a moderate or significant impact on their business operations, with almost 40% saying the impact would be significant. The same survey showed that customers feel that reliable electric service without outages is the most important issue as a business customer of PGE, scoring one point higher than even "keep prices predictable and affordable."[93]

PGE must make the investments and help prepare our customers for both proactive, in the case of a public safety power shutoff (PSPS), and unplanned interruptions of power so that customers can withstand periods of utility power interruption and can have faith in our product. PGE customers are increasingly reliant upon electric service to power electric vehicles, medical equipment, internet access, appliances and more.

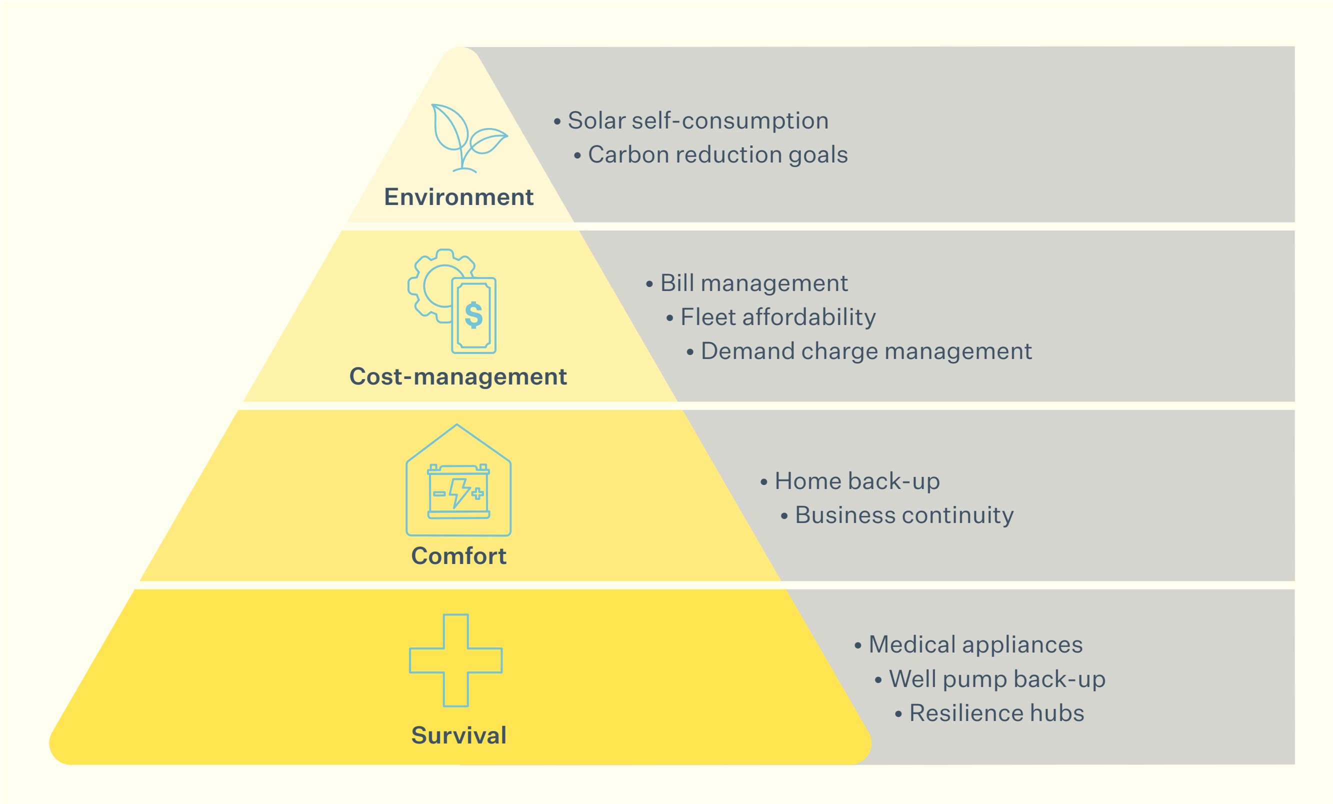
The following sections provide examples of the activities PGE is planning or undertaking to mitigate the effects of disruptive events.

### K.4.2 CUSTOMER PREPAREDNESS AND CUSTOMER INFRASTRUCTURE

When considering customer resilience needs across all segments, we can categorize these needs into a few areas: survival, comfort, cost-management and environment. These customer needs can be arranged as a hierarchy, whereby a customer will focus on foundational needs such as survival before other use cases, such as carbon reduction. **Figure 76** illustrates this hierarchy with some examples of customer needs.

92. Residential Battery Storage Demand Assessment Research: Importance and Interest, January 2016
93. PGE Business Customer Segmentation Report, April 2019

**Figure 76. Resilience use case hierarchy**




This hierarchy for resilience is important because PGE may not have as many grid services that may be co-optimized with customers closer to the bottom of the hierarchy. For example, a battery that provides back-up power to a medical appliance would not be a technical or practical solution for participating in demand response or other grid services. PGE seeks to understand the resilience needs of all customers and understands that in order to support the most vulnerable needing resiliency for survival, customer programs may look different than traditional flexible load initiatives. Solutions may also involve societal solutions that are outside of PGE's control.

Our goal for how customers experience PGE's services is captured in the following vision statement:

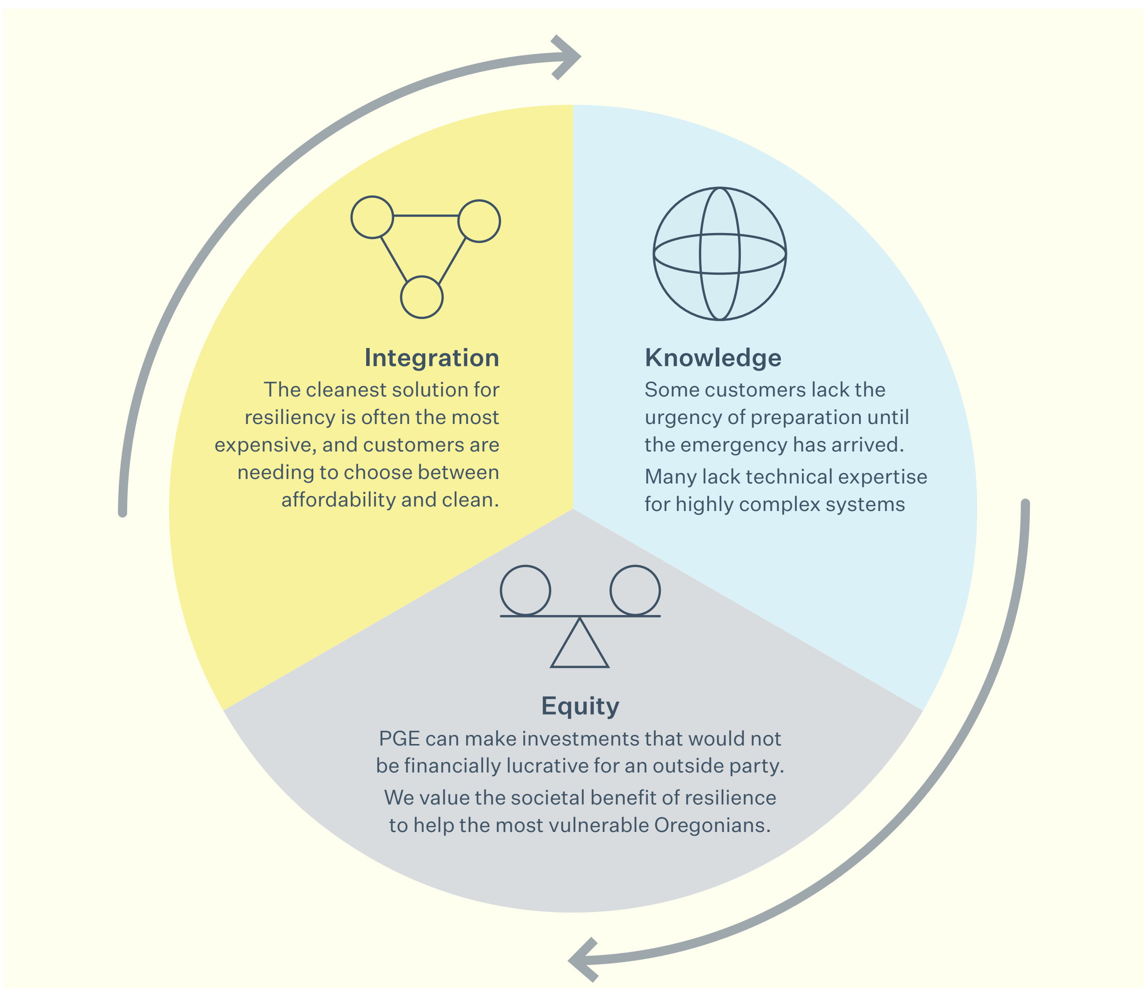
*PGE provides my community with service that I can rely on. PGE understands our needs and is planning for the future, adapting and leading the way. I trust that my electric service will be safe, reliable and resilient.*

*I believe in PGE.*

PGE's approach to customer resilience programs is:

1. Make **integrating** customers' resiliency assets with PGE as easy as possible
    - Full valuation of grid services, resilience, and locational benefits
    - Streamlined and cohesive programs
    - Give customers options to allow them to participate how they prefer
2. Serve as a **knowledge** partner so that customers know how to achieve their goals
    - Comprehensive consulting services
    - Vetted and specific recommendations for customers on how to prepare for the unexpected
3. **Equitable** access across all customer segments
    - Prioritize solutions for customers unlikely to be served via the competitive market
    - Overcome split incentives, economic obstacles
    - Partner with community, government, and non-profit agencies

**Figure 77. Customer resilience programs ethos**



## K.4.3 EXISTING CUSTOMER RESILIENCE PROGRAMS

### K.4.3.1 Smart Battery Pilot

PGE launched its 5-year Smart Battery pilot in 2020 that seeks to install and connect 525 residential energy storage batteries that will contribute up to four megawatts of energy to PGE's grid. Once installed, these distributed assets will create a virtual power plant that is made up of small units 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.

PGE continues to learn from this pilot and is considering whether a tariff update is warranted to iterate and improve the pilot based on what has been learned thus far. For example, the current structure provides a single incentive level per customer, per month. Based on customer feedback, there is a desire to have more control and customization options for participation. PGE also has observed that the up-front rebates intended to encourage adoption on specific areas of the grid do not appear to be high enough.

Another consideration for energy storage is whether a new participation model is needed to allow customers to dispatch the battery themselves rather than by PGE direct dispatch. This will provide an option to engage with customers who are unwilling to allow PGE to have any control of their devices. Additionally, PGE has received numerous inquiries from customers that have an energy storage device that is not one of the five qualified products within the pilot. Limited product availability of approved brands means that PGE customers would benefit from a change in the pilot program that would allow for any battery brand to participate.

Historical information on this pilot can be found within the UM 1856 Energy Storage Docket. Should PGE file any revisions to Schedule 14 it will be within that docket as well, using the existing deferral.

### K.4.3.2 Energy Partner

Energy Partner's Schedule 26 is a demand response (DR) program providing incentives to large nonresidential customers during seasonal peak time events for reducing their load. 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, as well as support customers' resiliency and clean energy goals by incorporating battery energy storage as a dispatchable resource.

### K.4.3.3 Dispatchable Standby Generation

In 1999, the MacLaren Youth Correctional Facility became the first PGE customer to enroll their standby generator in the DSG program, a partnership with customers that interconnects 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 MW. While not fuel restrictive, the bulk of this capacity has historically consisted of internal combustion diesel generators, and PGE has undertaken a concerted effort to modernize and decarbonize the program.

With the increased commercialization of battery energy storage, as well as PGE's successful integration of customer-sited batteries for grid services as demonstrated by the Beaverton Public Safety Center and Anderson Readiness Center, PGE proposed to build upon those capabilities to expand the DSG program to include battery energy storage greater than 250 kW, receiving approval to do so in June 2022. In addition to contingency reserve and frequency response, customers with battery energy storage may opt to also participate in DR activities, a flexible load service not currently possible with fossil-fueled resources.

This program can now provide the same advanced resilience support to enrolled customers as the legacy DSG program, while also supporting customers', PGE's, and Oregon's decarbonization goals.

## K.4.4 COMMUNITY MICROGRID DEMONSTRATIONS

PGE hopes to develop a programmatic approach to microgrid development that uses new front-of-the-meter renewable plus storage microgrids to access multiple value streams. Key benefits include generation capacity and energy, ancillary services, customer and societal resiliency value, local distribution grid benefits where applicable and local community benefits. Like the existing customer programs described above, development of these microgrid resources would support and benefit economically from the critical need for flexible capacity across the west, which is similarly motivating near-term storage development in California.

At scale, some microgrid projects may be deemed to be cost-effective for inclusion in general rates, especially if their upfront costs can be bought down through usage of external funding sources and incorporation of customer-owned generation and flex load resources. Other projects may depend on cost-sharing from benefiting local customers to pencil out economically through introduction of to-be-developed resiliency subscription rate option.

As a step toward this larger program, PGE has several planned and active initiatives that serve to create or enable more resilient customer infrastructure with a focus on critical community facilities. The following descriptions provide examples of the activities PGE is planning or undertaking to enable customers to mitigate the effects of disruptive events and get access to the services they need. We intend to use an evaluation of learnings and opportunities from these pilot activities to inform potential future expansion of distribution microgrid investments.

### K.4.4.1 Salem Smart Power Center

At PGE's Salem Smart Power Center (SSPC), a 5 MW / 1.25 MWh battery is nearing the end of its 10-year life. Commissioned in May 2013, it has been showing signs of degradation and only maintains about 60 percent of its original capacity. Over the years, battery technology has advanced, and now most of the center's equipment is not supported; spare parts are unavailable. However, the SSPC remains critical in providing capacity to meet PGE's frequency response obligation.

With substation upgrades, the connection could support up to 15 MW of active power export. A repowered SSPC would provide support for fast frequency response, generating capacity, demand response, contingency reserve, and electric vehicle (EV) support.

At a nearby site, plans are underway for the future City of Salem Public Works Operations Center — a critical hub for responding to emergencies such as natural disasters or extended power outages. When the city reached out to PGE to inquire about a highly resilient power supply for the site, a utility-scale battery was proposed to support the customer's loads during events that disrupt infrastructure and public services. A repowered SSPC battery would be a possible solution.

PGE's recommendation is to isolate and automate the power grid in the vicinity of the new building, creating a distribution system microgrid — the first "community microgrid" of its kind in the Northwest. Our engineers helped the city design the innovative community microgrid infrastructure, including increased incremental power storage at the nearby SSPC.

To help fund the new operations center and microgrid, the City of Salem (partnering with Pacific Northwest National Labs) in June applied for an Oregon Department of Energy grant, established through HB 2021. It provides up to $1 million for planning and constructing community renewable energy and energy resilience projects. If awarded to the City of Salem, this grant would help meet its strategies for increased energy resilience in the new operations building constructed with renewable energy features, including solar panels and EV charging stations. Funds also could be used to support the new microgrid infrastructure and increased power storage at the SSPC.

During a power outage, the installed microgrid technologies and additional power storage would allow PGE to maintain power to the operations building. In turn, excess power from the city's solar panels would help to recharge the SSPC and extend the longevity of the microgrid. The microgrid also would serve an area of residences, including single family homes and an apartment complex, in a qualified low income and under-served community.

If the application is successful, ODOE will award the grant this year, and the city will contract with PGE for the proposed work.

By partnering with the City of Salem to create this microgrid, everyone will share the benefits from greater resiliency to the system. The SSPC will be repowered, and the City of Salem Public Works Operations Center will have a continuous power supply during emergencies.

### K.4.4.2 Department of public safety standards and training (DPSST) Microgrid

PGE has been actively exploring the potential of custom-engineered microgrids at commercial and industrial customers' locations that can provide resilience to the customer, as well as flexible load for the power grid. This concept of creating a microgrid "island," disconnected from the main electrical grid and able to sustain itself for an extended period of time, has been implemented for single facilities in PGE's service area. However, creating a microgrid that serves a campus with multiple buildings is unique to the microgrid PGE is proposing for the Oregon Department of Public Safety Standards Training (DPSST) campus in Salem. As the State's key operational hub for emergency management, a microgrid at this site could be the solution for a reliable source of electricity during extended power outages.

The DPSST microgrid would use solar and battery storage to partially offset the need for fueled generation on the PGE distribution system. The solar resource will be generating and providing clean energy even when there is no grid outage. We will propose a generator hookup option in case the battery and solar output isn't sufficient for a more extended outage, especially in the winter. In that case, because of the generator, the microgrid will provide greater resiliency to the entire campus.

Although PGE began developing plans for the DPSST project several years ago, the effort was put on hold in 2020 when COVID-19 impacted Oregon state government activities. We have designed the structure and set of distribution upgrades needed to complete the campus microgrid, which could be operational by 2025 if funds are available.

PGE and the State would share the costs and benefits of this project. Our share of the project would include installing the battery and portable generator hookup. The State would install the solar resource and may be able to apply for grant funds to help support some of these expenses. Once funding details are agreed upon, the project will move forward.

# K.5 PGE infrastructure resilience

PGE has several planned and active initiatives to strengthen infrastructure by mitigating the occurrence of outages during disruptive events such as wildfires and wind or ice storms. The following descriptions provide examples of the activities PGE is planning or undertaking to harden the grid against outage events.

## K.5.1 WILLAMETTE VALLEY RESILIENCY PROJECT (WVRP)

PGE's sub-transmission (57 kV) and distribution system in the Willamette Valley is aging. Some of its unique equipment and assets have become non-standard or are nearing end-of-life; they weren't designed to withstand the ice storm of 2021. While PGE continues to maintain these assets to ensure reliability of the system, the increased demand, from new load growth to severe weather events, has jeopardized an already fragile system.

While the 57 kV system is not part of the Bulk Electric System, we strive to operate to the same criteria as required by the North American Electric Reliability Corporation (NERC) and the Reliability Coordinator (RC West), which states that there be no overload or voltage issue on our system for the next credible worst-case contingency. This means that if an outage is scheduled on the 57 kV system, we must be able to survive the next outage without any issues. The system in this area cannot reliably serve the distribution load if two lines are out of service during the summer or winter, meaning that the ability to perform maintenance is severely restricted.

To resolve deficiencies in the system, the WVRP will "future proof" the system to be resilient and reliable to withstand these events, minimizing restoration time and damage. A portfolio of projects is proposed for the 99E and I-5 corridor, from Oregon City to Salem. These projects; including transmission, sub-transmission, and distribution; will add capacity and resiliency to the system.

We will convert much of the Willamette Valley's 57 kV sub-transmission system to 115 kV. The project includes rebuilds of five substations and a significant portion of a sixth substation in the Willamette Valley with updated substation configurations for greater reliability. The transmission lines associated with these substations will be rebuilt and two new transmission lines will be constructed to improve reliability, resiliency, and capacity in the area. The distribution infrastructure at these substations will be upgraded for additional capacity and redundancy.

With these system improvements, we are supporting at least 50 MW of load growth for economic development in the valley, setting the foundation for adapting to future electrification of the I-5 corridor, reducing the impact of unpredictable outages and events, and providing for operational flexibility and compliance. The upgrades also will provide the infrastructure to bring more renewable generation resources onto the system, when needed.

Currently, we are engineering, scoping, and planning for these projects necessary to support the Willamette Valley system. These are the projects that comprise the WVRP:

- Monitor project
- St Louis project (included in 2023 Plan)
- Waconda project (included in 2023 Plan)
- North Marion project
- Woodburn project
- Bethel project
- WVRP Transmission project

By investing in these projects today, before an event occurs, PGE is avoiding the high costs of storm recovery and manual intervention in the future. For our customers, today and tomorrow, we are providing peace of mind with reliable and resilient energy services.

### K.5.2 TELECOMMUNICATION SINGLE POINTS OF FAILURE PROGRAM

PGE designs and maintains a vast telecommunication transport network critical to the operation of our power system. We send critical information to substations, power plants and facilities over a network of microwave radios and fiber optics. The network also supports PGE phones, the internet, Customer Service, and other customer-facing technology. The better we can communicate, internally and externally, the more efficient we are.

Most importantly, when there is a failure on the telecommunication system, our power system is at risk. Information sent and received protects our critical infrastructure by supporting the relay systems in detecting faults on the lines. Real-time data from substations provide information about circuit breakers opening and closing and tell us why. By adding redundancy to the network, we increase its reliability and improve resiliency across multiple communication channels within one system.

When successful, the impact of this work has low visibility. If a communication path is lost, the redundant one allows us to operate the network from a different direction. Redundancy in the communication network provides resilience through un-interrupted service during disruptive events such as ice storms and fires in the service area. This ensures that there is minimal or no disruption to company voice, IT and control systems during such events.

PGE's goal is to strengthen our infrastructure by identifying vulnerabilities to the telecommunication network, including risks and consequences. Single points of failure, without redundancy, are given a high priority in that process. If we lose communication visibility at these points, an event could impact multiple lines and substations, requiring Dispatch to send line crews to investigate the issue. That can cause longer restoration time and dissatisfied customers.

We have identified numerous projects to add redundancy to our telecommunication network, as well as upgrades to new technology. In addition, as new generation resources come online, such as solar and battery storage, and new substations are built, the telecommunication network will expand to support system growth.

Over the next four years, the top ten Telecommunications vulnerability mitigation projects have been prioritized for completion to help harden the system.

- Bethel-Round Butte fiber; single fiber connection leased from Century Link.
- World Trade Center (WTC); lack of fiber route diversity
- Marquam Substation; lack of redundant, diversely-routed communications
- Corporate Network WAN; connections from WTC to outlying locations
- Integrated Operating Center (IOC), south fiber route
- Salem area; relies on single fiber route leased from CenturyLink to reach PGE Control Centers
- Corporate Readiness Center, lack of point-to-point wireless connection
- WTC to Healy Heights collapsed SONET ring section
- Monitor Substation; communications upgrade
- SONET Ring 9, collapsed section near Mt. Scott

Nearly half of these single point of failure projects include building diversity in the communication network.

### K.5.3 CUSTOMER RELIABILITY IMPROVEMENT PROGRAM (CRIP)

The goal of the customer reliability improvement program (CRIP) is to improve the customer experience. Specifically, for customers that have experienced multiple, sustained interruptions year over year. The program uses a customer focused metric called CEMI (customers experiencing multiple interruptions) to identify areas of poor performance. The interruption causes for these areas are evaluated and solutions to mitigate reoccurring interruptions are recommended. Solutions typically leveraged for this program include, but are not limited to, additional protection/isolation devices and covered conductor.

The CRIP program is being launched in 2022 with the intent to learn how to best analyze and quickly deploy solutions that will reduce the re-occurrence of outages for customers. The initial focus of the program is on customers experiencing six or more interruptions per year from 2019 - 2021. Funding will be increased for this program in coming years as the mechanics of the program, and resulting benefit to customers, are better understood.

# K.6 Operational resilience

PGE has several planned and active initiatives to accelerate and improve the response to outages during disruptive events such as wildfires and wind or ice storms. The following descriptions provide examples of the activities we are planning or undertaking to enhance outage response.

### K.6.1 MOBILE COMMAND VEHICLES

Mobile Command is used and deployed to enhance or re-establish communication and coordination during emergency incidents and special security events. Mobile Command Units will allow PGE to enhance our capability to coordinate between utility management, crews, and first responders in the field, so they can restore power as quickly and safely as possible. Users of Mobile Command units include the Corporate Incident Management Team, Transmission & Distribution Operations Team, Corporate & Social Responsibility, and Customer Solutions.

Delivery of the first unit is scheduled for Q2 of 2023 and a second unit will begin build-out in late 2023 or early 2024.

### K.6.2 IMT (INCIDENT MANAGEMENT TEAM) REFRESHER AND TRAINING

Business continuity and emergency management (BCEM) is planning and coordinating an exercise that will provide training and refresher to current and new IMT members. The exercise will work in conjunction with Grid Operations to have a real-world scenario for the IMT to facilitate restoration of power to customer. BCEM and Grid Ops are working to develop multiple scenarios that could challenge the IMT in complexity and develop muscle memory for the IMT members.

Objectives of IMT refresher and training include training new IMT members, providing refresher training for current team members, practice “right sizing” IMT to meet the outage complexity, establish communications lines, and build team through practice.

Qualified BCEM team members will schedule annually a minimum of one FEMA ICS300 and ICS400 courses for IMT members and other individuals interested in pursuing IMT roles.

### K.6.3 BC (BUSINESS CONTINUITY) PARTNER ENGAGEMENT LIFECYCLE

BC will engage with Partners to develop/update plans for response to and recovery from disruptive events. The team will ensure plans are reviewed, tested, and exercised for accuracy by key stakeholders. Then they will finalize updates and approval by the business area director. This plan is distributed to all stakeholders, with each receiving training to instill an understanding of their role and required actions at the time of plan activation.

Plans will be housed in a location that BCEM, CIMT, and all key stakeholders can easily access before, during, and after an incident. Partners are empowered to initiate updates with BCEM if there are change conditions that require the plan to be revised to remain relevant.

# K.7 Targeted interventions to reduce wildfire risk[94]

### K.7.1 PUBLIC SAFETY POWER SHUTOFFS (PSPS)

Before and during fire season, PGE reviews regional National Weather Service forecasts, fire activity briefings, fire potential forecasts, and readings from PGE weather stations strategically located throughout the service territory daily. In 2022, PGE is deploying additional weather stations to increase situational and conditional awareness and provide visibility within the newly identify high-risk fire zones (HRFZs) on the west side of its service territory. PGE consulted with external meteorologists to identify locations that will provide the best overlap for wildfire risk coverage. PGE uses meteorological and outage data predictive analytics to better inform decisions regarding PSPS events, as well as outage/curtailment decisions related to transmission.

In 2022, PGE is developing the model architecture and sourcing the required data to implement a risk-based predictive analytical approach to meteorological modeling. The purpose of this project is to provide more granular and sophisticated inputs to PGE's PSPS decision analysis, as well as its system alarming.

### K.7.2 VEGETATION MANAGEMENT

Primarily focused on inspection and maintenance activities in the high fire risk portions of PGE's service territory, as identified through PGE's HRFZ assessment process, PGE's Vegetation Management strategy includes both cyclical, routine inspections and maintenance of the entire PGE transmission system and Advanced Wildfire Risk Reduction (AWRR) activities driven by PGE's wildfire risk analytics. Specific, year-to-year vegetation management activities are guided by PGE's Risk Assessment Program, data from PGE's Remote Sensing Pilot Project (which uses LiDAR and hyperspectral imagery to precisely monitor vegetation density and proximity to PGE assets), and annual vegetation surveys. AWRR crews follow program trim specifications, which include increased removal rates and enhanced vegetation control techniques.

### K.7.3 SYSTEM HARDENING FOR WILDFIRE

PGE continues to leverage its Strategic Asset Management (SAM) utility wildfire risk methodology and Wildfire Construction Standards to harden the transmission and distribution (T&D) system within its HRFZs. PGE's system hardening activities are designed to accomplish three goals:

- Reduce the risk of potential wildfire ignition caused by PGE facilities
- Reduce the impacts of a wildfire on PGE's assets by installing system hardening technologies (fire mesh, ductile iron poles, fiberglass crossarms)
- Protect utility infrastructure during potentially disruptive natural and human-caused disasters, supporting PGE's ability to maintain and restore reliable electrical service to support disaster relief and public safety.

In working towards these goals, PGE will deploy additional reliability improvements within the HRFZs. PGE is guided by its Wildfire Construction Standards in conducting equipment replacement in HRFZs. As outlined in PGE's Wildfire Construction Standards, the company will evaluate the following assets, with input from PGE subject matter experts, for replacement or implementation when warranted:

- Undersized/aging conductors in HRFZs
- Tree wire, an insulated overhead conductor designed to reduce service interruptions, which also reduces the potential for the conductor to become an ignition source
- Fuse replacement with non-expulsion fuses to eliminate a potential ignition source
- Viper reclosers and switching devices to increase operational flexibility and minimize customer impacts through the application of wildfire operational settings.

94. See PGE's Wildfire Mitigation Plan for a complete discussion of PGE's wildfire mitigation actions and investments, available at: https://assets.ctfassets.net/416ywc1laqmd/4w4NtrZtZZUpDeWoNC5vXn/e035ceb24ce56518afab817b0c0ffe6/2022_Wildfire_Mitigation_Plan_Final_Version_1.0_FINAL.pdf

## K.7.4 Investment decisions

PGE is also revising its capital investment strategy to align with its ongoing analysis of risk velocity over time. The goal of this effort is to create a multi-year investment framework to implement these separate but interrelated mitigation strategies, based on a risk profile that incorporates all wildfire risk drivers (such as vegetation contact). This multi-year investment strategy will help PGE balance system hardening mitigation measures with speed of execution.

**Figure 78** below shows the multiple system hardening and situational awareness investment programs currently included in PGE's multi-year wildfire risk mitigation investment strategy, through 2025.

PGE's multi-year investment strategy articulates a gradual increase in capital spending, distributed among multiple asset types. **Table 65** describes PGE's planned capital project investment types, together with estimated quantities. PGE will begin scoping these capital project investments in 2022. In addition to these asset replacements, PGE will begin scoping potential undergrounding areas. These investments (including undergrounding) will be prioritized in alignment with PGE's wildfire investment strategy, which ranks system hardening and situational awareness projects identified as the highest value risk mitigation projects per dollar of investment.

Figure 78. Planned wildfire system hardening and situational awareness investments

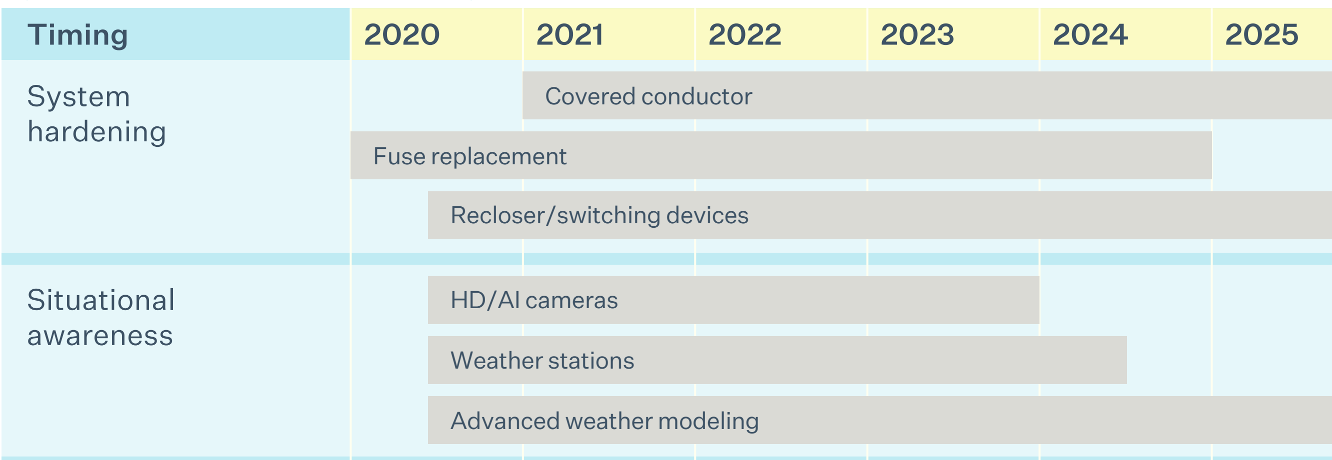



Table 65. Planned wildfire-related capital investments for 2022

| Asset Category | Quantity |
|---|---|
| Wildfire cameras | 10 |
| Intelligent reclosers | 40 |
| Weather stations | 23 |
| Non-expulsion fuses | 480 |
| Aluminum-conductor steel reinforced cable (ACSR)/Tree wire | 8 miles |

The wildfire mitigation efforts will continue for multiple years. As such PGE is developing a multi-year mitigation investment effort which is based on risk reduction and providing enhanced value to our customers. The investment plan will be reflected in PGE's annual Wildfire Mitigation Plan which is filed with the OPUC.

# K.8 Plug and play action plan

Our plug and play initiative addresses how we can improve access to grid edge investments needed to accelerate customers' clean energy transitions through such activities as hosting capacity analysis and developing the capability to connect dynamic devices (e.g., batteries).

With the ability to seamlessly interconnect a bi-directional flow, a modernized grid is a key enabler to improved access to DERs. Additionally, DERs have different effects on the grid under different conditions, including time, location, demand magnitude and system contingency. Today's grid is not designed to receive energy from customers at scale. Thus, some DERs today, specifically inverter-based systems and some types of EVs, such as mass transport electrification, may require complex studies.

The following project descriptions highlight the work PGE is doing to remove barriers to DER adoption.

## K.8.1 SYSTEM PROTECTION FOR DISTRIBUTED ENERGY RESOURCE (DER) READINESS

PGE performed a full review of the distribution system to identify the upgrades required to make the system DER ready. DER Readiness in this context is defined in terms of system protection to accommodate distributed generation (i.e., the appropriate equipment is in place to enable the system to support bi-directional power flow).

The full cost of these upgrades is dependent on the specific project conditions associated with the upgrade and include considerations such as:

- Need for a mobile substation to provide continuity of service while the substation is taken offline
- Permitting requirements for the jurisdiction involved
- Telecommunication requirements
- Labor costs
- Additional upgrades that are required to support a specific DER implementation, such as upgrades to provide additional hosting capacity for load or generation

Performing these upgrades would address constraints such as PGE's generation-limited feeders. Some of these upgrades will occur in conjunction with projects that address grid needs. PGE currently does not have a cost recovery mechanism that enables proactive investment to perform these upgrades. This is discussed further in **Section 7.4**.

## K.8.2 DISTRIBUTED GENERATION EVALUATION MAP UPDATES

PGE's response to the DSP guidelines for DSP Part 1 included augmentation of the Limited Generation Feeder map to show more distribution data and included demographic data sourced from the US Census. With the help of our DSP stakeholders the new map was named the Distributed Generation (DG) Evaluation map and serves as PGE's "phase 1" version of a hosting capacity analysis (HCA) map.[95]

Going forward, docket UM 2111: Staff Investigation into Interconnection Process and Policies is the forum for discussing utilities' plans for implementing HCA.[96] However, it was clear from stakeholder comments on DSP Part 1 that, regardless of whether we advance our HCA capability, there is value in providing more and different types of data to support stakeholders' decision-making processes.

95. EPRI's "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State" study, available at: https://www.epri.com/research/products/000000003002008848, page 15, Table 1 and PGE's DG Evaluation Map, available at: https://pge.maps.arcgis.com/apps/webappviewer/index.html?id=959db1ae628845d09b348fbf340eff03
96. The OPUC's Docket UM2111, available at: https://apps.puc.state.or.us/edockets/docket.asp?DocketID=22475

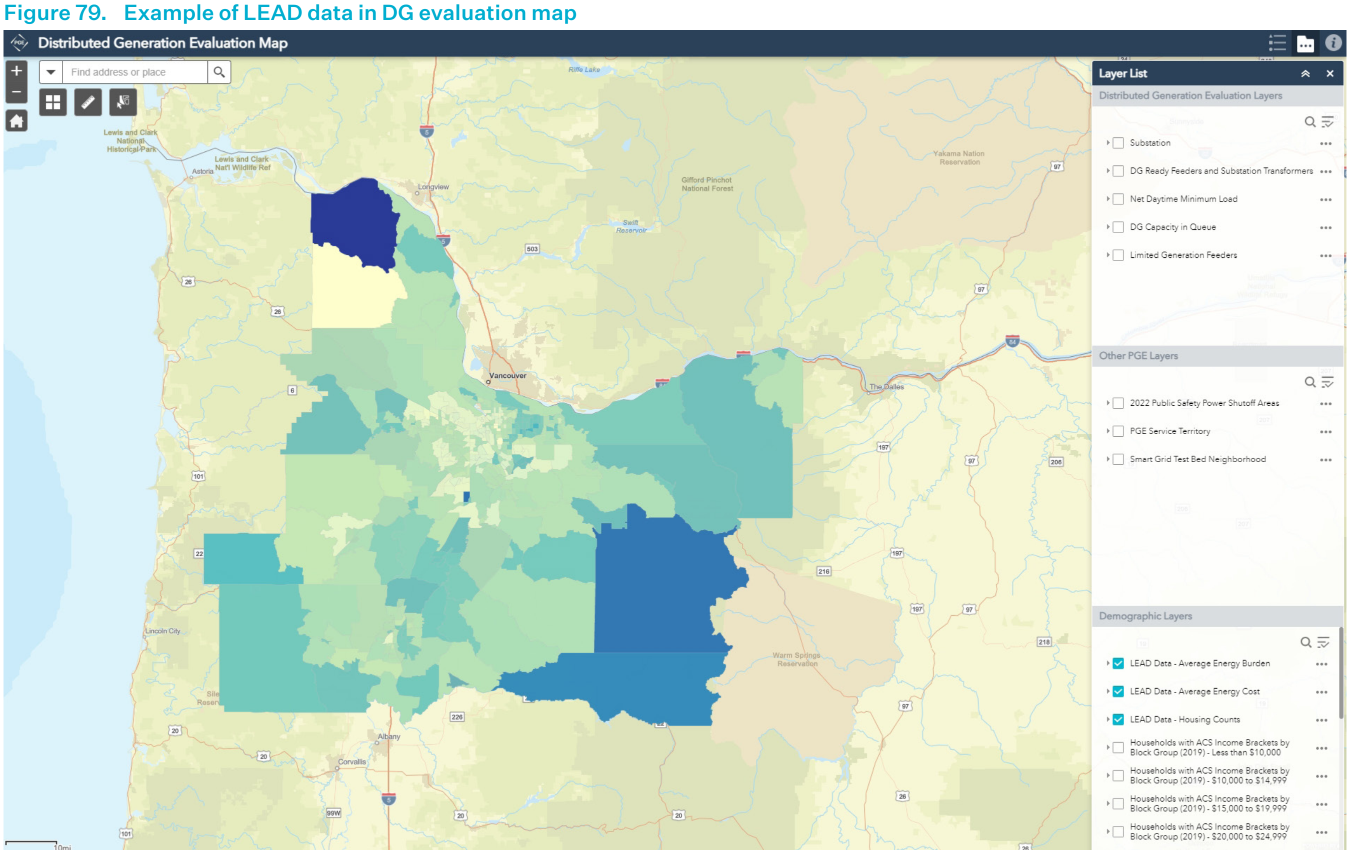
The DG Evaluation map is PGE's platform for sharing distribution system indicators and other datasets that enable developers, installers and customers to identify favorable locations for connecting distributed generation to the grid. A few key themes emerged from stakeholder's feedback on the map:

- Current viewer map needs to be refined to incorporate equity indicators;
- More distribution system data needs to be included; and
- The data needs to be downloadable, preferably in a mapping file format.

We understand that the provision of these data is the best approach to improving the value of our current DG Evaluation map. Based on the feedback and OPUC's guidance we received, we reviewed a number of different data sources and determined that data from the LEAD Tool, shown in **Figure 79**, as well as peak load data could readily be added to the map as a next step.

The Low-income Energy Affordability Data (LEAD) Tool is an online, interactive platform that allows users to build their own national, state, county, city, or census tract profiles. LEAD provides estimated low-income household energy data based on income, energy expenditures, fuel type, and housing type. Data from the LEAD tool is free to the public, and by incorporating it into our DG Evaluation map, will enable PGE and stakeholders to make data-driven decisions on energy goals and program planning by improving the understanding of low-income and moderate-income household energy characteristics. LEAD Tool data comes primarily from the U.S. Census Bureau's American Community Survey 2016 Public Use Microdata Samples (5-Year Average, 2012-2016) and are calibrated to the U.S. Energy Information Administration's electric utility (Survey Form-861) and natural gas utility (Survey Form-176) data.[97]

**Figure 79. Example of LEAD data in DG evaluation map**




97. LEAD tool, available at: https://www.energy.gov/eere/slsc/low-income-energy-affordability-data-lead-tool

PGE will continue to evaluate equity related indicators, such as those from the Greenlink Equity Map (GEM), for inclusion in the DG Evaluation map.[98] We have three goals as we consider which data should be incorporated into the DG Evaluation map:

- Publishing additional distribution system data – add more granular and more descriptive data, such as the data identified in IREC's comments on DSP Part 1, as well as enabling downloads in shapefile format or potentially through an Application Program Interface (API).[99]
- Collaboration on best-practices for maps – evaluate possibilities to add interconnection related data to help interconnection screening process; add reliability info including historic outage data – minutes of duration, outage frequency and customers affected; integration of DER forecasting and adoption results into map.
- Inclusion of equity metrics – consider adding more equity metrics such as health related indicators from Greenlink platform and others.

**Figure 80** shows the equity related variables and data sources we are considering and analyzing.

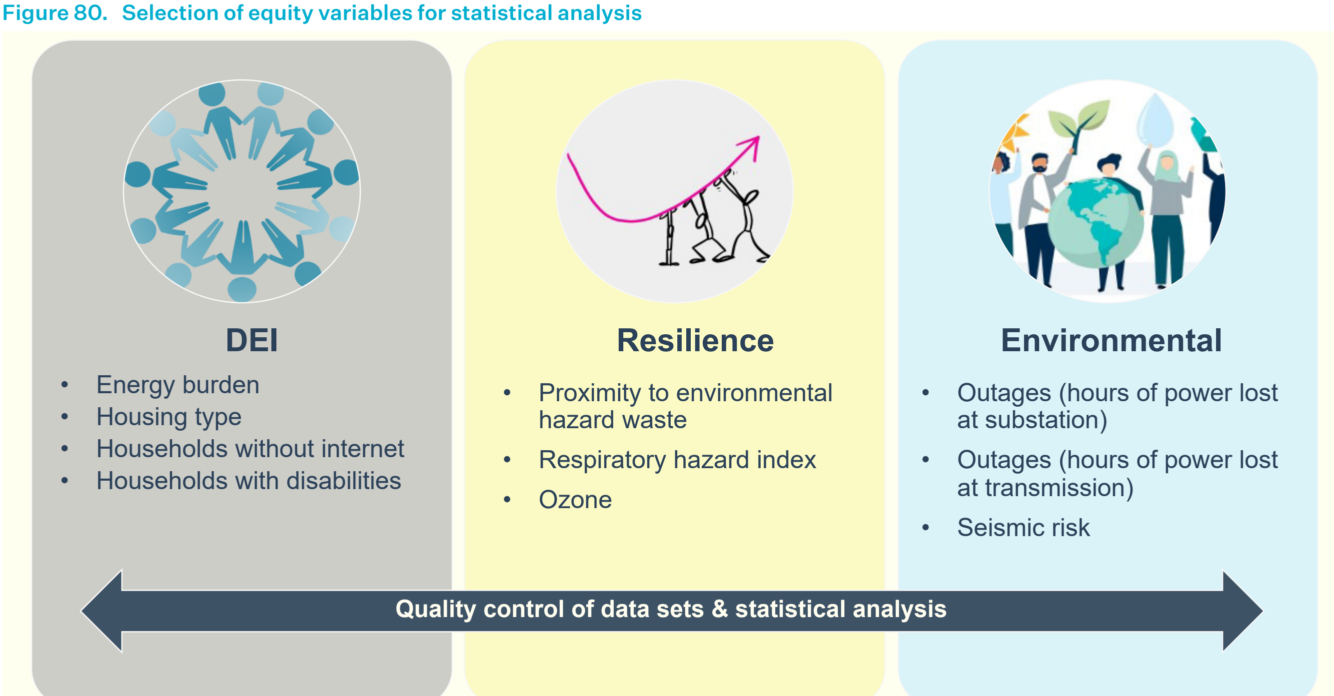
As described in **Chapter 2**, PGE is in the process of rolling out an Equity Index across use cases within the DSP. For the present analysis purposes, we applied this Equity Index to the location DER adoption results to identify any patterns.

Most data are free and from public sources such as the US census bureau, American Communities survey at census tract and census block level. We also are reviewing PGE customer information to determine whether this data would assist in needs identification or program planning.

### K.8.3 SMART GRID TEST BED (SGTB) PHASE II INITIATIVES

For Phase II of the SGTB, PGE proposed a five year, roughly $11 million program that builds on successes achieved in Phase I.[100] This proposal will leverage the high levels of customer awareness and engagement achieved over the last two years to develop a portfolio of technology and market demonstration projects. These projects spread across several research areas and will help expand and enhance PGE's flexible load product portfolio while exploring the additional use cases and value streams of DERs.

**Figure 80. Selection of equity variables for statistical analysis**




98. Greenlink Equity Map GEM, available at: https://www.equitymap.org/equity-map
99. IREC Comments on DSP Part 1, available at: https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAC&FileName=um2197hac153720.pdf&DocketID=23043&numSequence=11
100. PGE Phase II Proposal and Phase 1 Report, available at: https://edocs.puc.state.or.us/efdocs/HAD/um1976had145212.pdf Adoption of Staff Recommendation: https://apps.puc.state.or.us/orders/2021ords/21-444.pdf

The goals of Phase II are threefold:

- Carry forward, and apply “at scale,” the customer-centric strategies learned in Phase I
- Demonstrate enhanced value of flexible load/DER technologies as a grid resource, including planning and operations
- Support the development of the product portfolio through testing of new technologies and program design, including pricing strategies, gamification and direct control of DERs to address a grid need

PGE is not proposing a firm budget for Phase II, but rather providing a budget estimate and funding cap, with project level expenditures to be authorized during the review process agreed upon with stakeholders and the Commission. PGE estimates that the five-year effort will cost approximately $11 million and launch in January 2022. A brief description of the initiatives included in the Phase II scope is provided in Appendix G.

## K.8.4 ADOPTION OF IEEE 1547-2018 (SMART INVERTER STANDARDS)

The modernization of the standard used for inverters, IEEE-1547, is set to occur in the first phase of current Commission docket UM 2111. In the first phase of UM 2111, several issues will be addressed. The current proposal is that a stand-alone workgroup will be established that will focus specifically on the implementation of the newest version of IEEE-1547. The workgroup will consist of Staff, utility representatives, and other stakeholders. It is intended that the workgroup will meet at least on a monthly basis and make decisions based on group consensus. Further discussion and documentation of IEEE 1547 will occur in the UM2111 proceedings.

## K.8.5 TRANSPORTATION ELECTRIFICATION (TE) CONSIDERATIONS

PGE’s investments in customer energy efficiency over the past several decades will enable us to make initial investments in transportation electrification without significant impacts on our distribution system. TE will, however, have a growing overall impact on energy and capacity needs. PGE must continue to make investments into our system to ensure that our service-level transformers, feeders, substation transformers, and substations will have enough capacity to provide EV drivers access to charging service throughout our service area.

This section introduces the expected distribution system impacts arising from TE for which PGE will need to plan. This section is not intended to present a thorough distribution planning exercise for EVs. Instead, we provide indicative examples of how various types of EVs can impact the distribution system, and strategies to efficiently manage the grid in light of these impacts.

For example, PGE did not conduct power flow analyses to determine EV hosting capacity or estimate locational value. Such analyses will be done in concert with other new loads coming to the system through the course of routine distribution planning.

The TE forecast is shown in **Table 66**. The forecast clearly indicates levels of load growth that require upgrades to the distribution system much in the same way a new residential development or manufacturing facility would require upgrades to serve new load. As we know from the grid needs analysis described in **Section 4.5**, the primary considerations for planning those upgrades are the size of load growth, timing and location.

**Table 66. Transportation electrification forecast**

| Transportation Electrification Potential Forecasts (MWa) | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Scenario** | **2022** | **2023** | **2024** | **2025** | **2026** | **2027** | **2028** | **2029** | **2030** |
| **High** | 13 | 21 | 30 | 40 | 53 | 68 | 86 | 109 | 135 |
| **Ref** | 12 | 19 | 26 | 35 | 45 | 57 | 72 | 90 | 111 |
| **Low** | 12 | 17 | 22 | 29 | 36 | 45 | 55 | 67 | 82 |

To accommodate EV adoption, we must make planful investments so that infrastructure is right-sized, future-proofed, and optimally located to minimize integration costs. Adoption of light duty EVs is less likely to trigger distribution system upgrades beyond service-level transformers that are typically paid for by customers. Large, spot-load additions, such as fleet electrification or development of charging hubs, are the types of TE-driven load growth that require system impact analyses from the distribution planning team.

When EV adoption starts to reflect the forecast, the associated load will show up as a need in PGE's grid needs analysis and, if prioritized at that time, we will develop solutions to meet those needs. Two examples of emerging needs, needs that might require a distribution infrastructure investment, are described in the following sections.

### K.8.5.1 West Coast Clean Transit Corridor

The transportation sector is one of the largest contributors to greenhouse gas (GHG) emissions in the U.S. according to the EPA — 29 percent of the total GHG reported in 2019. Within that sector, medium- and heavy-duty trucks represent 24 percent of GHG emissions impacting our environment. The manufacturing industry relies upon this transportation to move more than 50 million tons of goods worth about $50 billion every day. On the West Coast, electric utilities are working together to find a solution for this growing problem.

By the year 2026, commercial freight and fleet electric vehicles will be able to transport their loads from southern California to the Canadian border — all within a corridor of charging sites along the Interstate-5 (I-5) highway system. That's the vision of the West Coast Clean Transit Corridor project, which can only be accomplished with the support of all electric utility companies on the route, including PGE.

There would be a phased approach for electrifying the I-5 corridor. Charging sites would be built about 50 miles apart, within a mile from I-5, to serve medium- and heavy-duty trucks. The next phase would be to upgrade every site to accommodate faster heavy-duty charging using the new Mega-Watt (MCS) standard. Additional sites may be built on arterial highways, as well.

Today, PGE does not have the charging infrastructure necessary for a customer to switch over to electric vehicles for long-haul trucking applications. A survey of fleet operators found that improved access to public charging would accelerate deployment of EVs if their trucks could use public charging sites. This project will help support our customers in that effort, as well as help reduce greenhouse gas emissions from freight transportation and eliminate health-harming diesel emissions from trucks in our service area.

PGE will be responsible for building two charging sites in the corridor — one near Salem and the other near Troutdale. Currently, we are conducting feasibility assessments of existing truck stops in each of the areas to determine the interest of the site host and what upgrades would be needed at the location, substation, and distribution system. With the costs of the chargers, customer construction, grid enhancements and added storage to the charging hub, the investment could be in excess of the cost of a new substation.

Both PGE charging sites could be built to support the initial scope of 3.5MW and operational by 2026, along with other utility partners' sites in the region — all with the ultimate goal to help complete the West Coast Clean Transit Corridor. For local EV commercial trucks transporting within our service area, just the completion of our two charging sites will help support their regional deliveries.

Electrifying commercial transportation on the I-5 corridor is one more step we can take to meet our long-term imperatives to decarbonize and electrify for a clean energy future.

### K.8.5.2 Newberg School Bus Program – V2G Demonstration

As customer demand for electric vehicles (EVs) continues to grow, and electric vehicle equipment with its supporting infrastructure technology advances, many EVs will have the ability to power your home, as well as send electricity to the power grid as a dispatchable resource when it's needed. This vehicle-to-grid (V2G) technology also has potential with commercial vehicles. That's why, in 2020, PGE began a small-scale V2G demonstration project funded through our Electric School Bus grant program, awarded to the Newberg School District, contracting with their transportation provider, First Student, Inc.

In 2021, PGE began work at the school district bus yard, installing the V2G electrical infrastructure and switchgear. The utility infrastructure was completed in December 2021, and the electrical charger installed and energized in March 2022. By April, students and the school district were enjoying the benefits of the newly commissioned electric school bus — no carbon emissions, lower maintenance and fuel costs, and a quieter ride. The total cost of the project, including the bus, charger and infrastructure, was $395,155 .

The bus now is ready to support the new V2G technology as we enter the project's next phase.

Given the changing relationship with the school district, First Student is now in the process of moving the charger to another location within PGE's service territory. We will provide technical assistance as First Student selects a site and constructs the necessary infrastructure. It is anticipated that the V2G bus could begin operations at a new school district by fall 2023, where it will be among the first dispatchable V2G sources in Oregon.

Although the technology may not be fully commercialized at this time, we are preparing to modernize the grid beyond its current capabilities to support our customers who will be purchasing vehicles with V2G capability. As a "proof of concept" project, the school bus demonstration allows us to evaluate the technology and identify lessons learned so we may design scalable ways for our customers to use V2G in the future. We look forward to deploying this new V2G technology at additional electric bus sites and passenger vehicle sites, and to partnering with our customers to help them provide clean flexible resources for a flexible and reliable power grid.

# Appendix L. Capital planning process

## L.1 Introduction

This Capital Process description provides an overview of the T&D (Transmission & Distribution) processes, roles, and responsibilities for T&D Project governance from budget-setting to project ideation to funding authorization. The Capital Portfolio team governs this process, monitors project statuses throughout the project lifecycle, and acts as custodian on behalf of the Business Sponsor Group (BSG) and the Capital Review Group (CRG) of a prioritized five-year roadmap.

### L.1.1 ROLE DEFINITIONS

- **Board of Directors (BOD)** – The Board of Directors reviews and approves the annual capital budget. In addition, the BOD approves large strategic projects and future-year obligations for long-lead-time equipment purchases.

- **Capital Review Group (CRG)** – The Capital Review Group is a standing committee with governance over capital projects and allocates capital resources based on business value and alignment with PGE's strategy.

- **Business Sponsor Group (BSG)** – The Business Sponsor Group is a standing committee, empowered by the CRG to approve capital projects and manage the assigned portfolio to deliver the most value at the least cost. The BSG reviews and approves a proposed annual budget based on a five-year project road map that prioritizes projects based on PGE's initiatives and project readiness.

- **Generation, Transmission & Distribution Project Management Office (G-T&D PMO)** – The G-T&D PMO is an organization that manages a standardized process for the governance and execution of assigned capital projects for Generation and T&D.

  - Project Manager
  - Project Controller
  - Estimator
  - Construction Manager

- **Capital Portfolio Management** – The Portfolio Management team optimizes the project portfolio, acts as the primary interface with the BSG and CRG, and oversees the steps related to the planning and execution gates. The Portfolio Management team also monitors Portfolio health and execution risks throughout the year, escalating issues to the executive team and the CRG as needed. The Capital Portfolio team has several functions and specialties within the group. They are:

  - **Portfolio Manager** – Manages day-to-day portfolio activities, including but not limited to balancing portfolio, evaluating project trade-offs, recommending projects, and delivering portfolio at maximum value.
  - **Financial Analyst** – Perform portfolio financial modeling, track portfolio health, and maintain portfolio reporting.
  - **Capital Project Sponsor (CPS)** – Evaluate and recommend projects based on benefits and alignment to corporate strategy. Ensures scope, budget, and schedule are complete before authorization.

- **Asset Management Planning** – The Asset Management Planning (AMP) team creates risk-based economic models to prioritize capital investments based on the asset failure risk and asset replacement cost.

- **T&D Planning** – The T&D Planning team provides transmission and distribution planning analysis to recommend necessary capacity and customer-driven T&D projects over a five-year planning horizon.

- **Distribution Operations Engineering** – The Distribution Operations Engineering (DOE) team manages the day-to-day operations and health of the distribution grid, including but not limited to maintenance, improvement, and optimal use.

- **Substation Maintenance** – The Substation Maintenance team manages the health of substation assets. Their responsibilities include executing a comprehensive maintenance program and addressing real-time performance issues.

## L.2 Capital budget setting

PGE employs a simultaneous bottom-up and top-down approach to cost management, with multiple layers of controls. PGE's annual capital budgeting process is governed primarily by three groups:

- PGE's Board of Directors (BOD),
- the Capital Review Group (CRG), and
- Business Sponsor Groups (BSG).

This is a layered process which is explained in more detail below. From the "bottom-up," based on rigorous review of a project's need, scope, budget, and forecast, the BSG approves a portfolio of projects for funding. This is shared with the CRG which adjusts funding priorities across PGE. The aggregate annual budget is presented to the BOD for review and approval. The rigorous review is continuous, and the BOD budget review is performed once annually with incremental changes and revisions submitted and reviewed as needed. From the "top-down," the BOD is the ultimate decision-maker for determining the amount of capital available across PGE. The CRG then allocates this to BSGs based on funding allocation priorities, and then each BSG manages its allocation by reprioritizing and balancing its portfolio of projects.

The BOD is responsible for reviewing and approving the annual capital budget. In addition, the BOD approves large strategic projects and future-year obligations for long-lead-time equipment purchases. To the extent additional capital funds are needed after the annual budget is approved, the BOD must approve any additional spending. Finally, the BOD also determines the CEO's extended approval authority, which provides the CEO with limited authority to approve budgets over the BOD-approved amount.  The annual capital budget is recommended to the BOD by the CRG. The CRG develops the proposed annual budget based on the rigorous portfolio development and management of each BSG and evaluates the use of funds throughout the year on a monthly basis. Each BSG develops a proposed annual budget based on its three- to five-year project road map that prioritizes projects based on PGE's strategic initiatives to benefit customers and project readiness.

PGE incorporates a multi-year outlook in our capital planning and management in several ways. The BSG develops three- and five-year roadmaps which estimate projects over a longer-term duration. This provides the BSG with a broader view of the portfolio and enables the portfolio manager to balance project priority and cost management. The roadmaps enable portfolio managers to maintain funding stability over time and allow PGE executives to monitor the overall trend of the capital programs. PGE also employs analytical tools like asset risk models, system planning models, customer forecasts, and community development plans to help drive long term plans. With this multi-year perspective, PGE leaders can carefully balance customer price impacts with the need to invest in a reliable and safe system.

Portfolio Management refers to the management of the entire portfolio within a particular area, such as T&D. The two primary leadership roles in Portfolio Management are performed by the BSG leadership and a Portfolio Manager. Portfolio Management decides when projects are ready to move from the roadmap to active work, allocates funds to projects based on performance, approves projects at stage-gate milestones, monitors portfolio execution and delivery of benefits, manages portfolio exceptions, and escalates issues to the CRG as needed.  The Portfolio Manager verifies that projects benefit customers by aligning with and delivering on PGE's strategy, allocates budgeted dollars to projects based on performance, approve stage gate milestones for projects, monitors portfolio execution and benefits delivery, manages project expectations, maximizes value in the portfolio, actively balances the portfolio, and identifies and escalates

Figure 81. Capital governance structure


issues, as needed. Project Management refers to the management of an individual project through the process by a Project Managers. The Project Manager manages a project's progression through the planning and execution stage-gates and helps keep the project on schedule and within the budget, as discussed in more depth below.

The T&D Capital Project Process is structured into the following sections:

- Project/Program Development
- Project Qualification
- Project Prioritization
- Project Authorization

# L.3 Project/program development

New program and project ideas come from various sources within PGE. These sources are described below as inputs. PGE employs analytical tools like asset risk models, system planning models, customer forecasts, and community development plans to help drive long-term capital project priorities. These inputs and outputs are represented in **Figure 82**.

### L.3.1 AMP RISK ANALYSIS

For business cases, AMP utilizes an evaluation tool known as the Integrated Planning Tool (IPT) for each analysis. The team identifies and loads in the assets from the project using respective life cycle models. The tool enables a comparison of the current state to various project options to calculate the reduction in life cycle cost of ownership, risk, and other reliability metrics to determine the optimal economic solution.

### L.3.2 OPERATIONS REQUESTS

Operations requests originate from maintenance activities by departments such as Substation Maintenance, Transmission Engineering, and Distribution Operations Engineering.

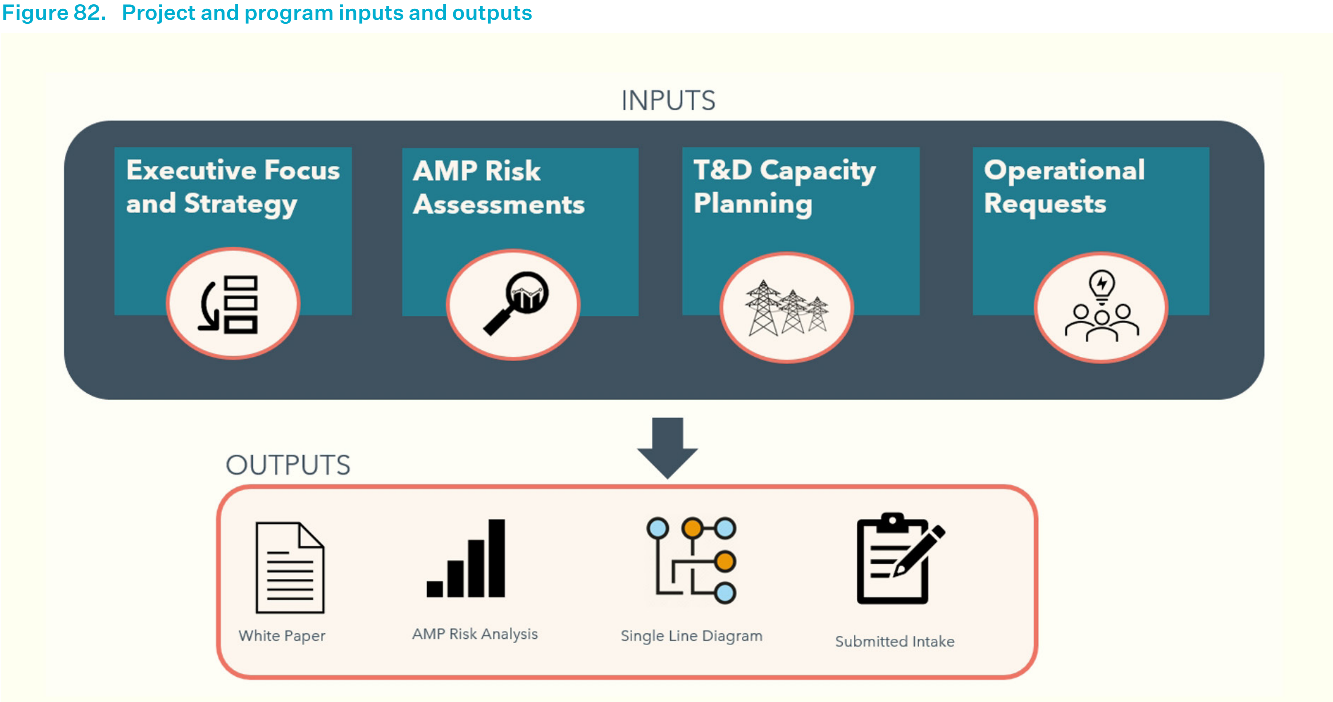
### L.3.3 EXECUTIVE FOCUS

PGE's executive focus is on emerging high-profile initiatives such as Wildfire Mitigation and Resiliency, core infrastructure, and resiliency.

Outputs may include, but are not limited to:

- Study reports
- One-line diagrams
- AMP Risk Analysis
- Submitted Project Intake Form

Figure 82. Project and program inputs and outputs



# L.4 Project qualification

The project qualification process, also known as the T&D Capital Intake process, begins with identifying a project or program need. The Capital Project Sponsor administers this process by reviewing the project demand submittal and coordinating between subject matter experts (SMEs). This results in an initial project concept with a vetted scope, benefits, cost, and schedule. The process concludes with a project demand recommendation (via the T&D Project Intake Tool).

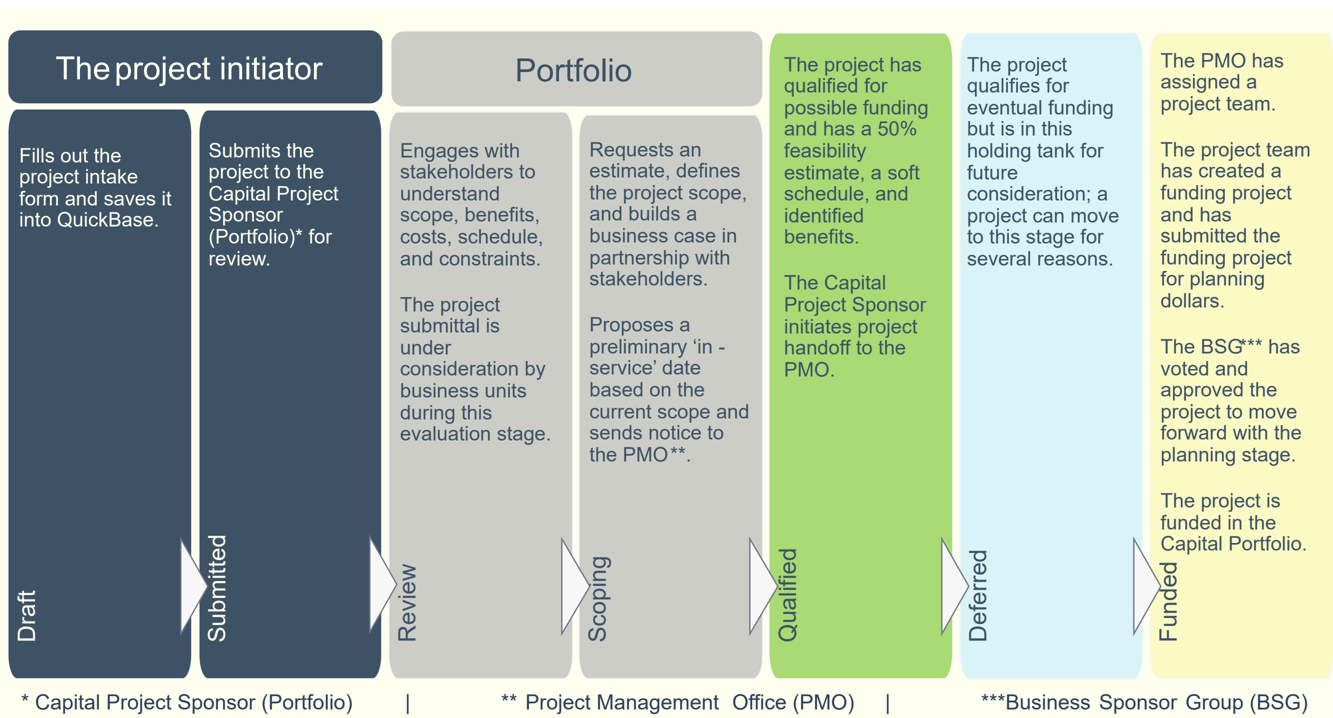
The Capital Portfolio team uses the T&D Project Intake Tool to collect project demands. This tool facilitates project evaluation on multiple criteria. The Intake Tool has been developed on the QuickBase platform and can be accessed via a web browser.

All employees within T&D have basic access to the T&D Project Intake Tool. Additional transmission-level access is provided to staff with proper FERC (Federal Energy Regulatory Commission) level access to transmission data. When requesting evaluation of a project demand, the requester must enter a minimum amount of information, including project scope, alternatives considered, schedule, and budget information.

# L.5 T&D project intake process

Each project demand follows a prescribed lifecycle, which tells requester(s) the status of their request. **Figure 83** describes the Project Intake Lifecycle graphically.

**Figure 83. Project demand intake lifecycle and status detail**



Once an Intake is submitted, an automated email notifies the Capital Sponsorship team. Then a Capital Project Sponsor will schedule a review meeting with the requester(s) to determine any additional information needs.

The Intake will enter the Scoping status while anything missing or unclear from the qualification inputs is addressed. Depending on the degree of the incomplete information, the Capital Project Sponsor may schedule an additional review meeting(s).

Upon completing the details and a recommendation from the Capital Project Sponsor, the project demand awaits review and qualification determination by the Portfolio Manager. During the qualification determination, the Portfolio team may consider additional factors, including strategic alignment, project dependencies and overlap with other projects.

# L.6 Project prioritization

The Portfolio team develops an annual five-year Capital Project Roadmap. The T&D BSG reviews and approves the roadmap and issues it every June to help establish the priority for the years ahead. Many groups provide input to the roadmap's development, including System Planning, Asset Management, Operations, Project Management, and Supply Chain. It is a living document that the Portfolio team manages monthly. The project prioritization process results in project inclusion on the roadmap.

Prioritization inputs include:

- Qualified Project Demand from Capital Project Sponsor
- Resource Availability
- Material Availability
- Cash Flow
- AMP Risk Register

Prioritization outputs include:

- Updated T&D Capital Roadmap
- Resource Plan
- Long Lead Equipment authorization
- Project authorization

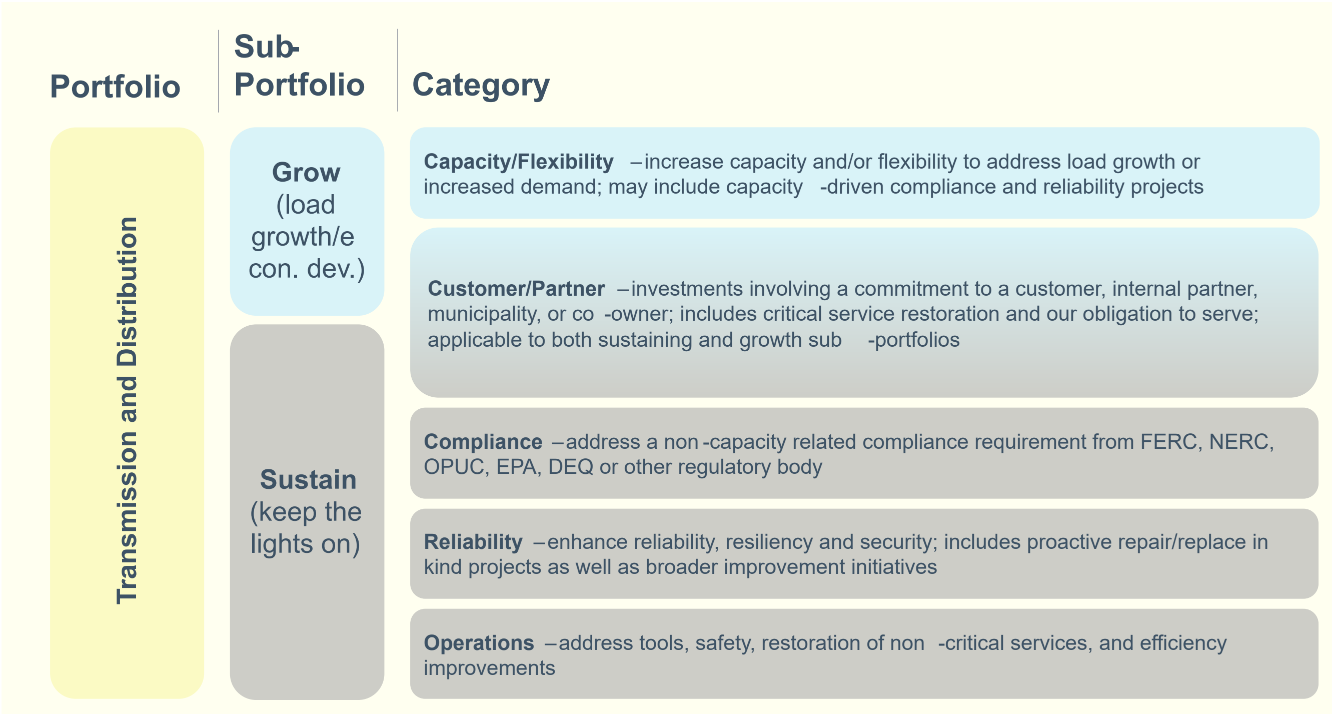
## L.6.1 PORTFOLIO DEFINITION

PGE invests in capital projects for many reasons. Some projects are discretionary, and some are non-discretionary. It is important to capture the drivers for the project in a manner that is quick and easy to understand. For the Base Portfolio, the T&D BSG established two sub-portfolios: Grow the Business (GTB) and Sustain the Business (STB).

At a high level, this sub-portfolio classification helps PGE understand if our company is balancing growth with core business investments. Examples of STB investments are aging asset replacements and work to keep the lights on. GTB investments are mainly new customer load requests or capacity-driven projects due to load demands.

In addition to the sub-portfolio classification, each sub-portfolio has a set of categories to help provide more details on the nature of the investments (**Figure 84**).

Figure 84. T&D capital investment categories




Before funding authorization, every project entering the Portfolio is assigned a sub-portfolio and category. The main driver of the project is used to determine the sub-portfolio and category assignments. There can be only one sub-portfolio and one category assignment per project, even though there may be multiple reasons for the investment. System Planning and/or the AMP team help provide a sub-portfolio and category assignment, depending on where the project originated.

Using the sub-portfolio and categories together, the T&D BSG can quickly see what projects are discretionary versus non-discretionary. For example, non-discretionary projects are GTB-compliance/customer or STB-compliance/customer since there are firm customer or compliance commitments. Discretionary projects fall in the remaining categories, such as operations, reliability, and capacity. Examples of discretionary projects are proactive asset replacements and asset health and reliability mitigation.

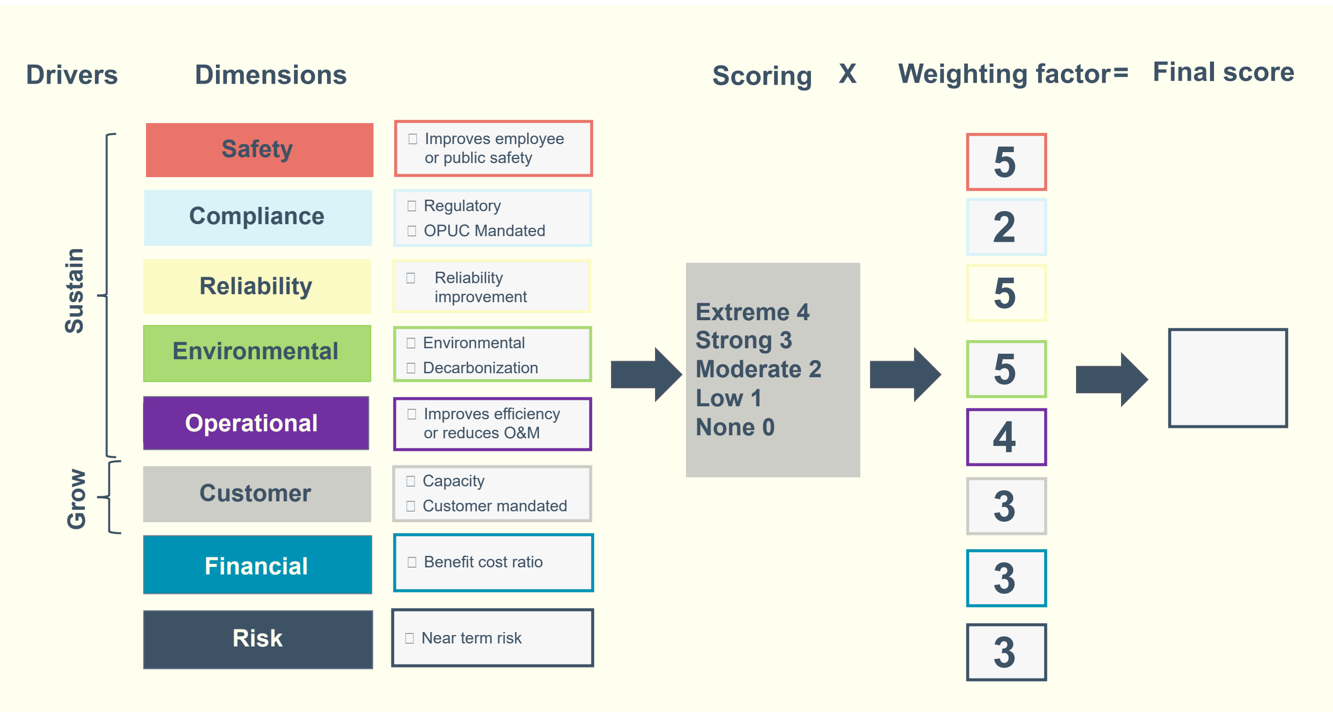
# L.7 T&D capital roadmap

The T&D Capital Roadmap provides a five-year forecast of all the current and future projects in the portfolio at the Funding Project (FP) level. The planned forecast dollars are split across all the phases of a project or program.

In addition to portfolio definition and Roadmap, the Portfolio is establishing a value framework where every project gets a score based on various dimensions. The value framework encompasses eight dimensions that help our capital investments align with our corporate commitments. The framework is illustrated in **Figure 85**.

To promote fair and diverse assessments of projects, the Portfolio team enlists the help of other departments such as System T&D, Operations Engineering and Asset Management to collectively and objectively score the work. Realizing that work can originate from different groups, this approach helps provide balanced scoring and transparency.

Figure 85. T&D portfolio scoring framework



## L.8 Authorization

Once a project demand is developed, qualified and prioritized, it goes through a final process for authorization. This is the last step required to fund the project/program and hand it off for execution. It is important to note that not all project demands go through authorization immediately. Only project demands that are prioritized in the current calendar year go through authorization. Some project demands may be developed, qualified but prioritized in future years. These projects will remain in the backlog of qualified demands.

Once authorized, a demand obtains the 'Qualified' status, and the Capital Project Sponsor transfers ownership of project execution to the PMO. At this stage, the project has a vetted and defined scope, a concept estimate for the planning gate, an initial Project Scoping Document, an initial project benefits list, an initial project risk list, and a high-level schedule, if applicable.

## L.9 Create a funding project

Once the project handoff meeting is complete, the PMO will create a funding project within PGE's system of record, PowerPlan. The Project Controller will enter a project justification, create the necessary accounting work orders (AWOs) to segregate the work into funding streams for the project, enter a project cashflow forecast into PowerPlan and enter a project in-service date.

The funding project is a record of all budget requests, authorizations, and stage gating checklists associated with the project.

## L.10 On-going portfolio management

All active projects roll up into the overall T&D Portfolio. The Capital Portfolio team will perform recurring activities such as reviewing project forecasts, monitoring project cash flow and variances and evaluating overall health of the Portfolio.

# Appendix M. DER forecast results by substation

In **Section 3.5.5.2** we presented the DER adoption forecast across different scenarios (reference case and low and high case sensitivities) at the aggregate system level, as well as depicted select DER adoption results in a map. This appendix contains detailed substation level DER adoption for the year 2030 for each DER type.

**Table 67**. 2030 solar PV adoption by substation (nameplate kW-dc)

**Table 68**. 2030 storage adoption by substation (nameplate kW-dc)

**Table 69**. 2030 LDV EV adoption by substation

**Table 70**. 2030 MDHDV EV adoption by substation

**Table 71**. 2030 demand response peak demand impacts by substation (MW)

**Table 72**. Energy efficiency savings forecast at substation (Base case, aMW at generation)

Table 67. 2030 Solar PV adoption by substation (nameplate kW-dc)

| Substation Name | Low | Reference | High |
|---|---|---|---|
| ABERNETHY | 980 | 1,908 | 3,169 |
| ALDER | 1,356 | 3,916 | 5,052 |
| AMITY | 506 | 919 | 1,219 |
| ARLETA | 1,958 | 8,078 | 9,711 |
| BANKS | 772 | 1,178 | 1,674 |
| BARNES | 1,671 | 4,566 | 5,772 |
| BEAVERTON | 936 | 1,958 | 2,475 |
| BELL | 1,783 | 5,370 | 6,556 |
| BETHANY | 3,379 | 5,436 | 5,856 |
| BETHEL | 1,187 | 3,157 | 3,922 |
| BLUE LAKE | 879 | 1,235 | 1,287 |
| BOONES FERRY | 699 | 2,325 | 2,887 |
| BORING | 911 | 2,027 | 2,451 |
| BRIGHTWOOD | 190 | 477 | 978 |
| BROOKWOOD | 964 | 2,073 | 2,765 |
| CANBY | 2,143 | 2,672 | 3,139 |
| CANYON | 770 | 1,688 | 2,268 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| CARVER | 1,502 | 3,300 | 3,756 |
| CEDAR HILLS | 1,235 | 3,238 | 3,658 |
| CENTENNIAL | 1,011 | 3,789 | 5,091 |
| CLACKAMAS | 870 | 1,680 | 2,291 |
| CLAXTAR | 697 | 1,725 | 2,057 |
| COFFEE CREEK | 158 | 205 | 439 |
| COLTON | 216 | 607 | 634 |
| CORNELIUS | 1,170 | 2,933 | 3,291 |
| CORNELL | 1,149 | 2,417 | 2,804 |
| CULVER | 7 | 7 | 7 |
| CURTIS | 184 | 1,016 | 929 |
| DAYTON | 2,274 | 3,168 | 3,716 |
| DELAWARE | 930 | 4,130 | 5,450 |
| DENNY | 1,339 | 3,803 | 4,768 |
| DILLEY | 196 | 321 | 329 |
| DUNNS CORNER | 231 | 533 | 908 |
| DURHAM | 1,025 | 2,162 | 2,855 |
| E | 4,490 | 5,250 | 6,700 |
| EAGLE CREEK | 376 | 765 | 949 |
| EASTPORT | 436 | 1,942 | 2,602 |
| ELMA | 1,981 | 3,071 | 3,745 |
| ESTACADA | 1,085 | 2,519 | 2,812 |
| FAIRMOUNT | 953 | 2,621 | 2,749 |
| FAIRVIEW | 1,655 | 2,909 | 3,642 |
| FARGO | 278 | 612 | 867 |
| GALES CREEK | 227 | 381 | 568 |
| GARDEN HOME | 727 | 2,328 | 2,528 |
| GLENCOE | 1,144 | 2,631 | 3,086 |
| GLENCULLEN | 727 | 2,563 | 2,809 |
| GLENDOVEER | 1,023 | 4,170 | 5,035 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| GRAND RONDE | 187 | 356 | 396 |
| HARBORTON | 287 | 628 | 911 |
| HARMONY | 2,628 | 4,447 | 5,553 |
| HARRISON | 677 | 1,270 | 1,819 |
| HAYDEN ISLAND | 441 | 563 | 953 |
| HEMLOCK | 1,722 | 2,577 | 2,774 |
| HILLCREST | 116 | 242 | 237 |
| HILLSBORO | 3,871 | 6,413 | 7,571 |
| HOGAN NORTH | 1,722 | 4,466 | 5,428 |
| HOGAN SOUTH | 2,019 | 5,950 | 6,966 |
| HOLGATE | 2,123 | 4,826 | 5,375 |
| HUBER | 2,827 | 7,325 | 8,934 |
| INDIAN | 1,695 | 5,149 | 6,080 |
| ISLAND | 1,097 | 2,701 | 3,675 |
| JENNINGS LODGE | 1,393 | 3,486 | 3,939 |
| KELLEY POINT | 41 | 41 | 80 |
| KELLY BUTTE | 1,338 | 4,631 | 5,236 |
| KING CITY | 1,398 | 3,196 | 3,792 |
| LELAND | 1,866 | 3,582 | 4,556 |
| LENTS | 709 | 2,520 | 3,349 |
| LIBERAL | 305 | 528 | 568 |
| LIBERTY | 2,077 | 6,658 | 7,769 |
| MAIN | 1,802 | 5,112 | 5,979 |
| MARKET | 449 | 2,032 | 3,214 |
| MARQUAM | 200 | 257 | 349 |
| MCCLAIN | 506 | 1,317 | 1,705 |
| MCGILL | 301 | 1,359 | 1,825 |
| MERIDIAN | 1,710 | 3,165 | 4,335 |
| MIDDLE GROVE | 2,566 | 5,041 | 6,000 |
| MIDWAY | 852 | 3,605 | 4,318 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| MILL CREEK | 838 | 991 | 1,292 |
| MOLALLA | 1,526 | 3,246 | 4,393 |
| MT ANGEL | 755 | 973 | 1,055 |
| MT PLEASANT | 2,332 | 5,076 | 5,623 |
| MULINO | 289 | 719 | 924 |
| MULTNOMAH | 1,265 | 5,247 | 6,436 |
| MURRAYHILL | 2,287 | 4,930 | 5,683 |
| NEWBERG | 2,874 | 6,128 | 6,914 |
| NORTH MARION | 1,051 | 2,675 | 3,713 |
| NORTH PLAINS | 1,306 | 2,211 | 2,662 |
| NORTHERN | 578 | 1,921 | 2,459 |
| OAK HILLS | 2,772 | 4,142 | 4,718 |
| ORENCO | 2,375 | 5,322 | 6,222 |
| ORIENT | 1,221 | 1,688 | 2,073 |
| OSWEGO | 642 | 1,525 | 2,053 |
| OXFORD | 2,768 | 4,200 | 5,129 |
| PENINSULA PARK | 283 | 1,014 | 1,256 |
| PLEASANT VALLEY | 2,408 | 4,228 | 5,022 |
| PORTSMOUTH | 606 | 2,869 | 3,402 |
| PROGRESS | 572 | 1,670 | 2,218 |
| RALEIGH HILLS | 544 | 1,538 | 1,857 |
| RAMAPO | 945 | 3,134 | 3,829 |
| REDLAND | 1,120 | 2,009 | 2,539 |
| REEDVILLE | 2,294 | 4,810 | 5,826 |
| RIVERGATE SOUTH | 120 | 491 | 775 |
| RIVERVIEW | 786 | 2,439 | 2,943 |
| ROCK CREEK | 2,135 | 3,272 | 3,733 |
| ROCKWOOD | 838 | 2,001 | 2,436 |
| ROSEMONT | 619 | 1,260 | 1,502 |
| ROSEWAY | 2,824 | 5,760 | 6,602 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| RUBY | 848 | 2,158 | 2,523 |
| SALEM | 690 | 771 | 947 |
| SANDY | 1,437 | 4,047 | 4,700 |
| SCHOLLS FERRY | 2,253 | 3,470 | 3,733 |
| SCOGGINS | 277 | 655 | 930 |
| SCOTTS MILLS | 387 | 863 | 1,059 |
| SELLWOOD | 1,140 | 3,231 | 4,114 |
| SHERIDAN | 331 | 1,039 | 1,324 |
| SILVERTON | 2,611 | 4,633 | 5,098 |
| SIX CORNERS | 2,511 | 4,902 | 6,014 |
| SPRINGBROOK | 2,355 | 3,625 | 4,284 |
| ST LOUIS | 1,548 | 2,428 | 2,442 |
| ST MARYS EAST | 443 | 1,166 | 1,738 |
| SULLIVAN | 1,483 | 3,370 | 4,283 |
| SUMMIT | 3 | 62 | 91 |
| SUNSET | 1,377 | 1,377 | 1,786 |
| SWAN ISLAND | 707 | 707 | 954 |
| SYLVAN | 1,215 | 2,232 | 2,656 |
| TABOR | 1,789 | 3,888 | 4,709 |
| TEKTRONIX | 1,481 | 4,075 | 5,106 |
| TEMP B | 42 | 42 | 42 |
| TEMP H | 396 | 410 | 638 |
| TIGARD | 1,183 | 2,712 | 3,331 |
| TOWN CENTER | 472 | 1,190 | 1,744 |
| TUALATIN | 1,620 | 2,963 | 3,161 |
| TURNER | 849 | 1,298 | 1,391 |
| TWILIGHT | 615 | 843 | 945 |
| UNIONVALE | 379 | 502 | 872 |
| UNIVERSITY | 228 | 1,104 | 1,215 |
| URBAN | 585 | 1,164 | 1,505 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| WACONDA | 1,114 | 1,512 | 1,813 |
| WALLACE | 516 | 1,110 | 1,254 |
| WELCHES | 85 | 502 | 934 |
| WEST PORTLAND | 1,568 | 3,249 | 3,771 |
| WEST UNION | 592 | 1,826 | 2,107 |
| WILLAMINA | 249 | 688 | 783 |
| WILLBRIDGE | 73 | 94 | 168 |
| WILSONVILLE | 2,184 | 4,713 | 5,664 |
| WOODBURN | 2,223 | 3,390 | 4,205 |
| YAMHILL | 1,708 | 2,425 | 2,955 |

Table 68. 2030 Storage adoption by substation (nameplate kW-dc)

| Substation Name | Low | Reference | High |
|---|---|---|---|
| ABERNETHY | 36 | 281 | 671 |
| ALDER | 184 | 784 | 1,221 |
| AMITY | 0 | 90 | 255 |
| ARLETA | 142 | 1,762 | 3,054 |
| BANKS | 10 | 110 | 224 |
| BARNES | 45 | 815 | 1,451 |
| BEAVERTON | 75 | 320 | 555 |
| BELL | 73 | 968 | 1,853 |
| BETHANY | 113 | 523 | 796 |
| BETHEL | 45 | 585 | 1,032 |
| BLUE LAKE | 30 | 120 | 185 |
| BOONES FERRY | 87 | 462 | 783 |
| BORING | 35 | 295 | 557 |
| BRIGHTWOOD | 0 | 50 | 255 |
| BROOKWOOD | 95 | 340 | 643 |
| CANBY | 20 | 105 | 295 |
| CANYON | 95 | 325 | 486 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| CARVER | 107 | 512 | 842 |
| CEDAR HILLS | 52 | 522 | 856 |
| CENTENNIAL | 40 | 720 | 1,580 |
| CLACKAMAS | 108 | 273 | 515 |
| CLAXTAR | 55 | 318 | 598 |
| COFFEE CREEK | 59 | 59 | 74 |
| COLTON | 5 | 100 | 170 |
| CORNELIUS | 35 | 455 | 813 |
| CORNELL | 37 | 372 | 572 |
| CURTIS | 25 | 235 | 305 |
| DAYTON | 50 | 300 | 505 |
| DELAWARE | 98 | 883 | 1,639 |
| DENNY | 50 | 690 | 1,254 |
| DILLEY | 0 | 20 | 38 |
| DUNNS CORNER | 9 | 84 | 179 |
| DURHAM | 97 | 382 | 645 |
| E | 99 | 254 | 623 |
| EAGLE CREEK | 20 | 130 | 170 |
| EASTPORT | 80 | 500 | 851 |
| ELMA | 176 | 476 | 766 |
| ESTACADA | 47 | 377 | 618 |
| FAIRMOUNT | 36 | 426 | 604 |
| FAIRVIEW | 65 | 335 | 770 |
| FARGO | 5 | 100 | 185 |
| GALES CREEK | 13 | 28 | 98 |
| GARDEN HOME | 39 | 484 | 684 |
| GLENCOE | 35 | 415 | 735 |
| GLENCULLEN | 55 | 470 | 750 |
| GLENDOVEER | 45 | 835 | 1,448 |
| GRAND RONDE | 0 | 45 | 90 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| HARBORTON | 10 | 95 | 220 |
| HARMONY | 149 | 634 | 1,168 |
| HARRISON | 15 | 145 | 463 |
| HAYDEN ISLAND | 0 | 30 | 186 |
| HEMLOCK | 115 | 305 | 435 |
| HILLCREST | 55 | 80 | 160 |
| HILLSBORO | 266 | 931 | 1,455 |
| HOGAN NORTH | 105 | 808 | 1,203 |
| HOGAN SOUTH | 143 | 1,093 | 1,713 |
| HOLGATE | 126 | 776 | 1,248 |
| HUBER | 110 | 1,155 | 2,107 |
| INDIAN | 90 | 1,001 | 1,516 |
| ISLAND | 65 | 485 | 801 |
| JENNINGS LODGE | 48 | 560 | 943 |
| KELLEY POINT | 0 | 0 | 10 |
| KELLY BUTTE | 82 | 927 | 1,525 |
| KING CITY | 43 | 578 | 883 |
| LELAND | 106 | 541 | 903 |
| LENTS | 54 | 829 | 1,189 |
| LIBERAL | 13 | 63 | 73 |
| LIBERTY | 130 | 1,295 | 2,119 |
| MAIN | 65 | 876 | 1,543 |
| MARKET | 20 | 420 | 1,029 |
| MARQUAM | 65 | 80 | 85 |
| MCCLAIN | 10 | 205 | 460 |
| MCGILL | 25 | 375 | 619 |
| MERIDIAN | 282 | 627 | 981 |
| MIDDLE GROVE | 140 | 922 | 1,583 |
| MIDWAY | 80 | 825 | 1,354 |
| MILL CREEK | 70 | 115 | 291 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| MOLALLA | 50 | 425 | 910 |
| MT ANGEL | 18 | 78 | 118 |
| MT PLEASANT | 120 | 719 | 1,169 |
| MULINO | 60 | 160 | 215 |
| MULTNOMAH | 82 | 1,142 | 1,766 |
| MURRAYHILL | 100 | 625 | 1,120 |
| NEWBERG | 115 | 891 | 1,407 |
| NORTH MARION | 15 | 400 | 926 |
| NORTH PLAINS | 65 | 305 | 430 |
| NORTHERN | 65 | 380 | 760 |
| OAK HILLS | 80 | 460 | 750 |
| ORENCO | 115 | 770 | 1,135 |
| ORIENT | 20 | 130 | 283 |
| OSWEGO | 72 | 297 | 567 |
| OXFORD | 85 | 530 | 840 |
| PENINSULA PARK | 25 | 220 | 455 |
| PLEASANT VALLEY | 163 | 608 | 1,004 |
| PORTSMOUTH | 40 | 720 | 950 |
| PROGRESS | 110 | 365 | 725 |
| RALEIGH HILLS | 62 | 352 | 553 |
| RAMAPO | 68 | 628 | 1,072 |
| REDLAND | 57 | 277 | 450 |
| REEDVILLE | 63 | 733 | 1,289 |
| RIVERGATE SOUTH | 13 | 133 | 228 |
| RIVERVIEW | 40 | 430 | 860 |
| ROCK CREEK | 50 | 295 | 485 |
| ROCKWOOD | 30 | 320 | 603 |
| ROSEMONT | 39 | 149 | 389 |
| ROSEWAY | 78 | 713 | 1,284 |
| RUBY | 30 | 380 | 619 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| SALEM | 291 | 296 | 431 |
| SANDY | 71 | 661 | 1,046 |
| SCHOLLS FERRY | 139 | 409 | 539 |
| SCOGGINS | 16 | 121 | 161 |
| SCOTTS MILLS | 17 | 137 | 212 |
| SELLWOOD | 78 | 568 | 988 |
| SHERIDAN | 35 | 245 | 325 |
| SILVERTON | 42 | 537 | 707 |
| SIX CORNERS | 105 | 725 | 1,360 |
| SPRINGBROOK | 65 | 375 | 710 |
| ST LOUIS | 55 | 320 | 489 |
| ST MARYS EAST | 75 | 290 | 580 |
| SULLIVAN | 61 | 506 | 942 |
| SUMMIT | 0 | 5 | 5 |
| SUNSET | 10 | 15 | 218 |
| SWAN ISLAND | 60 | 60 | 210 |
| SYLVAN | 193 | 448 | 558 |
| TABOR | 43 | 588 | 998 |
| TEKTRONIX | 46 | 686 | 1,406 |
| TEMP B | 0 | 0 | 5 |
| TEMP H | 5 | 5 | 25 |
| TIGARD | 119 | 509 | 854 |
| TOWN CENTER | 30 | 180 | 387 |
| TUALATIN | 160 | 465 | 515 |
| TURNER | 100 | 225 | 308 |
| TWILIGHT | 30 | 85 | 145 |
| UNIONVALE | 18 | 58 | 118 |
| UNIVERSITY | 115 | 385 | 499 |
| URBAN | 49 | 189 | 322 |
| WACONDA | 65 | 175 | 395 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| WALLACE | 18 | 168 | 213 |
| WELCHES | 20 | 90 | 313 |
| WEST PORTLAND | 75 | 545 | 862 |
| WEST UNION | 15 | 330 | 445 |
| WILLAMINA | 18 | 118 | 218 |
| WILLBRIDGE | 0 | 5 | 10 |
| WILSONVILLE | 58 | 553 | 953 |
| WOODBURN | 39 | 413 | 769 |
| YAMHILL | 40 | 195 | 436 |

Table 69. 2030 LDV EV adoption by substation

| Substation Name | Low | Reference | High |
|---|---|---|---|
| ABERNETHY | 1,702 | 2,282 | 2,646 |
| ALDER | 2,304 | 3,038 | 3,523 |
| AMITY | 1,124 | 1,535 | 1,894 |
| ARLETA | 3,594 | 4,754 | 5,557 |
| BANKS | 949 | 1,288 | 1,496 |
| BARNES | 3,664 | 4,828 | 5,567 |
| BEAVERTON | 1,088 | 1,460 | 1,754 |
| BELL | 2,627 | 3,392 | 4,061 |
| BETHANY | 4,960 | 6,217 | 7,207 |
| BETHEL | 2,579 | 3,498 | 4,211 |
| BLUE LAKE | 605 | 811 | 1,001 |
| BOONES FERRY | 3,392 | 4,322 | 4,970 |
| BORING | 1,970 | 2,635 | 3,064 |
| BRIGHTWOOD | 658 | 898 | 1,038 |
| BROOKWOOD | 1,031 | 1,327 | 1,556 |
| CANBY | 1,718 | 2,256 | 2,720 |
| CANYON | 1,651 | 2,066 | 2,342 |
| CARVER | 3,556 | 4,670 | 5,431 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| CEDAR HILLS | 2,728 | 3,449 | 4,054 |
| CENTENNIAL | 2,146 | 2,914 | 3,679 |
| CLACKAMAS | 1,087 | 1,442 | 1,650 |
| CLAXTAR | 1,290 | 1,682 | 2,004 |
| COFFEE CREEK | 188 | 245 | 282 |
| COLTON | 878 | 1,181 | 1,428 |
| CORNELIUS | 1,998 | 2,642 | 3,192 |
| CORNELL | 2,070 | 2,581 | 2,834 |
| CULVER | 52 | 72 | 77 |
| CURTIS | 438 | 584 | 650 |
| DAYTON | 1,950 | 2,587 | 2,975 |
| DELAWARE | 2,112 | 2,713 | 3,336 |
| DENNY | 2,015 | 2,651 | 3,230 |
| DILLEY | 396 | 535 | 644 |
| DUNNS CORNER | 894 | 1,157 | 1,416 |
| DURHAM | 1,116 | 1,442 | 1,746 |
| E | 1,823 | 2,311 | 2,734 |
| EAGLE CREEK | 893 | 1,202 | 1,472 |
| EASTPORT | 1,079 | 1,388 | 1,649 |
| ELMA | 1,873 | 2,521 | 2,936 |
| ESTACADA | 2,156 | 2,855 | 3,437 |
| FAIRMOUNT | 1,813 | 2,384 | 2,818 |
| FAIRVIEW | 1,321 | 1,760 | 2,082 |
| FARGO | 977 | 1,270 | 1,487 |
| GALES CREEK | 445 | 595 | 661 |
| GARDEN HOME | 1,716 | 2,224 | 2,696 |
| GLENCOE | 1,602 | 2,057 | 2,413 |
| GLENCULLEN | 1,723 | 2,186 | 2,506 |
| GLENDOVEER | 2,312 | 3,114 | 3,815 |
| GRAND RONDE | 404 | 542 | 677 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| HARBORTON | 566 | 756 | 992 |
| HARMONY | 2,090 | 2,803 | 3,414 |
| HARRISON | 617 | 808 | 968 |
| HAYDEN ISLAND | 274 | 378 | 421 |
| HEMLOCK | 716 | 968 | 1,129 |
| HILLCREST | 66 | 83 | 119 |
| HILLSBORO | 3,670 | 4,790 | 5,734 |
| HOGAN NORTH | 3,287 | 4,301 | 5,089 |
| HOGAN SOUTH | 3,319 | 4,532 | 5,374 |
| HOLGATE | 2,491 | 3,173 | 3,700 |
| HUBER | 4,499 | 5,824 | 6,924 |
| INDIAN | 4,354 | 5,801 | 6,923 |
| ISLAND | 1,692 | 2,230 | 2,728 |
| JENNINGS LODGE | 2,513 | 3,359 | 3,994 |
| KELLEY POINT | 12 | 16 | 19 |
| KELLY BUTTE | 2,369 | 3,076 | 3,792 |
| KING CITY | 1,957 | 2,600 | 3,239 |
| LELAND | 3,125 | 4,145 | 4,956 |
| LENTS | 1,495 | 1,976 | 2,412 |
| LIBERAL | 619 | 842 | 997 |
| LIBERTY | 4,656 | 6,269 | 7,412 |
| MAIN | 2,821 | 3,762 | 4,475 |
| MARKET | 1,681 | 2,335 | 2,932 |
| MARQUAM | 146 | 185 | 215 |
| MCCLAIN | 857 | 1,129 | 1,303 |
| MCGILL | 912 | 1,232 | 1,499 |
| MERIDIAN | 2,684 | 3,587 | 4,115 |
| MIDDLE GROVE | 4,144 | 5,564 | 6,456 |
| MIDWAY | 2,057 | 2,770 | 3,374 |
| MILL CREEK | 758 | 1,019 | 1,086 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| MOLALLA | 3,290 | 4,384 | 5,152 |
| MT ANGEL | 574 | 761 | 961 |
| MT PLEASANT | 3,113 | 4,099 | 4,896 |
| MULINO | 606 | 802 | 923 |
| MULTNOMAH | 3,175 | 4,118 | 4,813 |
| MURRAYHILL | 3,587 | 4,640 | 5,411 |
| NEWBERG | 4,324 | 5,674 | 6,814 |
| NORTH MARION | 2,371 | 3,209 | 3,827 |
| NORTH PLAINS | 1,442 | 1,883 | 2,264 |
| NORTHERN | 820 | 1,081 | 1,256 |
| OAK GROVE | 10 | 10 | 10 |
| OAK HILLS | 1,996 | 2,609 | 3,056 |
| ORENCO | 2,633 | 3,473 | 4,193 |
| ORIENT | 1,408 | 1,886 | 2,256 |
| OSWEGO | 2,212 | 2,782 | 3,325 |
| OXFORD | 1,504 | 2,026 | 2,412 |
| PENINSULA PARK | 503 | 652 | 822 |
| PLEASANT VALLEY | 4,459 | 5,767 | 6,914 |
| PORTSMOUTH | 1,196 | 1,582 | 1,956 |
| PROGRESS | 840 | 1,102 | 1,242 |
| RALEIGH HILLS | 1,475 | 1,903 | 2,208 |
| RAMAPO | 2,173 | 2,890 | 3,520 |
| REDLAND | 2,420 | 3,190 | 3,787 |
| REEDVILLE | 2,195 | 2,932 | 3,480 |
| RIVERGATE SOUTH | 260 | 330 | 431 |
| RIVERVIEW | 1,366 | 1,722 | 1,968 |
| ROCK CREEK | 2,299 | 2,905 | 3,371 |
| ROCKWOOD | 996 | 1,375 | 1,603 |
| ROSEMONT | 2,286 | 2,881 | 3,247 |
| ROSEWAY | 3,042 | 4,009 | 4,709 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| RUBY | 1,318 | 1,740 | 2,086 |
| SALEM | 112 | 151 | 168 |
| SANDY | 2,842 | 3,797 | 4,579 |
| SCAPPOOSE | 2 | 4 | 1 |
| SCHOLLS FERRY | 3,146 | 4,022 | 4,450 |
| SCOGGINS | 678 | 904 | 1,028 |
| SCOTTS MILLS | 994 | 1,321 | 1,586 |
| SELLWOOD | 1,535 | 1,998 | 2,377 |
| SHERIDAN | 1,350 | 1,861 | 2,299 |
| SILVERTON | 3,332 | 4,458 | 5,238 |
| SIX CORNERS | 4,075 | 5,292 | 6,163 |
| SPRINGBROOK | 2,136 | 2,832 | 3,481 |
| ST LOUIS | 1,367 | 1,824 | 2,177 |
| ST MARYS EAST | 942 | 1,278 | 1,506 |
| STEPHENS | | | 1 |
| SULLIVAN | 3,478 | 4,466 | 5,186 |
| SUMMIT | 61 | 76 | 100 |
| SUNSET | 124 | 160 | 170 |
| SWAN ISLAND | 161 | 216 | 247 |
| SYLVAN | 2,153 | 2,609 | 3,010 |
| TABOR | 1,670 | 2,138 | 2,488 |
| TEKTRONIX | 2,026 | 2,669 | 3,079 |
| TEMP B | 5 | 5 | 5 |
| TEMP H | 96 | 132 | 156 |
| TIGARD | 2,210 | 2,912 | 3,486 |
| TOWN CENTER | 648 | 854 | 1,066 |
| TUALATIN | 3,858 | 5,113 | 6,035 |
| TURNER | 1,058 | 1,393 | 1,618 |
| TWILIGHT | 653 | 886 | 1,009 |
| UNIONVALE | 661 | 888 | 1,070 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| UNIVERSITY | 662 | 899 | 1,074 |
| URBAN | 770 | 980 | 1,150 |
| WACONDA | 1,135 | 1,484 | 1,843 |
| WALLACE | 1,182 | 1,584 | 1,992 |
| WELCHES | 773 | 1,007 | 1,169 |
| WEST PORTLAND | 1,916 | 2,518 | 3,068 |
| WEST UNION | 1,055 | 1,441 | 1,769 |
| WILLAMINA | 748 | 989 | 1,156 |
| WILLBRIDGE | 29 | 47 | 58 |
| WILSONVILLE | 3,863 | 5,002 | 5,807 |
| WOODBURN | 2,496 | 3,422 | 4,198 |
| YAMHILL | 2,544 | 3,313 | 4,040 |

**Table 70. 2030 MDHDV EV adoption by substation**

| Substation Name | Low | Reference | High |
|---|---|---|---|
| ABERNETHY | 48 | 104 | 140 |
| ALDER | 58 | 98 | 121 |
| AMITY | 20 | 44 | 70 |
| ARLETA | 14 | 30 | 36 |
| BANKS | 17 | 32 | 42 |
| BARNES | 64 | 119 | 166 |
| BEAVERTON | 29 | 59 | 83 |
| BELL | 31 | 59 | 77 |
| BETHANY | 10 | 14 | 18 |
| BETHEL | 23 | 34 | 49 |
| BLUE LAKE | 54 | 121 | 170 |
| BOONES FERRY | 13 | 18 | 20 |
| BORING | 29 | 44 | 67 |
| BRIGHTWOOD | 8 | 10 | 13 |
| BROOKWOOD | 7 | 12 | 16 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| CANBY | 92 | 182 | 245 |
| CANYON | 35 | 61 | 80 |
| CARVER | 85 | 154 | 217 |
| CEDAR HILLS | 16 | 31 | 42 |
| CENTENNIAL | 30 | 44 | 60 |
| CLACKAMAS | 52 | 95 | 127 |
| CLAXTAR | 54 | 102 | 149 |
| COFFEE CREEK | 70 | 115 | 155 |
| COLTON | 11 | 23 | 35 |
| CORNELIUS | 38 | 79 | 102 |
| CORNELL | 11 | 14 | 19 |
| CULVER | 7 | 8 | 13 |
| CURTIS | 5 | 10 | 13 |
| DAYTON | 59 | 126 | 205 |
| DELAWARE | 16 | 23 | 32 |
| DENNY | 29 | 54 | 83 |
| DILLEY | 10 | 14 | 24 |
| DUNNS CORNER | 24 | 37 | 60 |
| DURHAM | 44 | 95 | 137 |
| E | 112 | 192 | 251 |
| EAGLE CREEK | 14 | 36 | 43 |
| EASTPORT | 11 | 16 | 20 |
| ELMA | 16 | 37 | 46 |
| ESTACADA | 30 | 65 | 86 |
| FAIRMOUNT | 17 | 32 | 49 |
| FAIRVIEW | 31 | 49 | 60 |
| FARGO | 43 | 76 | 106 |
| GALES CREEK | 8 | 13 | 20 |
| GARDEN HOME | 1 | 6 | 7 |
| GLENCOE | 5 | 7 | 10 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| GLENCULLEN | 2 | 4 | 5 |
| GLENDOVEER | 23 | 44 | 54 |
| GRAND RONDE | 19 | 35 | 46 |
| HARBORTON | 17 | 30 | 37 |
| HARMONY | 52 | 77 | 115 |
| HARRISON | 26 | 48 | 65 |
| HAYDEN ISLAND | 19 | 26 | 36 |
| HEMLOCK | 79 | 142 | 190 |
| HILLCREST | 7 | 17 | 25 |
| HILLSBORO | 86 | 152 | 211 |
| HOGAN NORTH | 89 | 119 | 138 |
| HOGAN SOUTH | 29 | 46 | 59 |
| HOLGATE | 77 | 142 | 196 |
| HUBER | 25 | 54 | 86 |
| INDIAN | 77 | 131 | 198 |
| ISLAND | 19 | 31 | 41 |
| JENNINGS LODGE | 19 | 37 | 50 |
| KELLEY POINT | 7 | 13 | 22 |
| KELLY BUTTE | 13 | 29 | 35 |
| KING CITY | 18 | 31 | 54 |
| LELAND | 46 | 95 | 131 |
| LENTS | 22 | 31 | 43 |
| LIBERAL | 23 | 41 | 54 |
| LIBERTY | 25 | 47 | 64 |
| MAIN | 7 | 19 | 38 |
| MARKET | 56 | 157 | 252 |
| MARQUAM | 6 | 10 | 13 |
| MCCLAIN | 16 | 26 | 34 |
| MCGILL | 5 | 10 | 12 |
| MERIDIAN | 38 | 70 | 103 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| MIDDLE GROVE | 152 | 270 | 392 |
| MIDWAY | 20 | 42 | 53 |
| MILL CREEK | 23 | 43 | 65 |
| MOLALLA | 79 | 151 | 226 |
| MT ANGEL | 11 | 23 | 32 |
| MT PLEASANT | 36 | 70 | 86 |
| MULINO | 8 | 25 | 32 |
| MULTNOMAH | 22 | 32 | 38 |
| MURRAYHILL | 4 | 7 | 13 |
| NEWBERG | 83 | 125 | 168 |
| NORTH MARION | 68 | 142 | 193 |
| NORTH PLAINS | 31 | 62 | 88 |
| NORTHERN | 10 | 12 | 13 |
| OAK HILLS | 10 | 16 | 19 |
| ORENCO | 32 | 59 | 74 |
| ORIENT | 26 | 53 | 90 |
| OSWEGO | 8 | 23 | 24 |
| OXFORD | 112 | 222 | 296 |
| PENINSULA PARK | 1 | 5 | 6 |
| PLEASANT VALLEY | 12 | 30 | 48 |
| PORTSMOUTH | 7 | 13 | 16 |
| PROGRESS | 14 | 22 | 25 |
| RALEIGH HILLS | 6 | 16 | 19 |
| RAMAPO | 4 | 16 | 19 |
| REDLAND | 47 | 72 | 101 |
| REEDVILLE | 49 | 90 | 119 |
| RIVERGATE SOUTH | 26 | 35 | 54 |
| RIVERVIEW | 44 | 54 | 65 |
| ROCK CREEK | 20 | 31 | 37 |
| ROCKWOOD | 37 | 72 | 108 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| ROSEMONT | 5 | 13 | 20 |
| ROSEWAY | 83 | 158 | 209 |
| RUBY | 44 | 84 | 116 |
| SALEM | 11 | 20 | 36 |
| SANDY | 64 | 112 | 133 |
| SCAPPOOSE | | 1 | 1 |
| SCHOLLS FERRY | 23 | 42 | 68 |
| SCOGGINS | 7 | 16 | 25 |
| SCOTTS MILLS | 20 | 32 | 40 |
| SELLWOOD | 32 | 62 | 80 |
| SHERIDAN | 32 | 65 | 100 |
| SILVERTON | 84 | 150 | 212 |
| SIX CORNERS | 68 | 116 | 157 |
| SPRINGBROOK | 36 | 53 | 76 |
| ST LOUIS | 60 | 108 | 146 |
| ST MARYS EAST | 17 | 24 | 31 |
| SULLIVAN | 25 | 34 | 40 |
| SUMMIT | 6 | 6 | 6 |
| SUNSET | 16 | 34 | 50 |
| SWAN ISLAND | 108 | 167 | 211 |
| SYLVAN | 36 | 41 | 49 |
| TABOR | 5 | 10 | 13 |
| TEKTRONIX | 24 | 36 | 49 |
| TEMP H | 19 | 32 | 44 |
| TIGARD | 89 | 136 | 210 |
| TOWN CENTER | 23 | 40 | 55 |
| TUALATIN | 544 | 943 | 1,297 |
| TURNER | 23 | 44 | 56 |
| TWILIGHT | 8 | 18 | 35 |
| UNIONVALE | 29 | 60 | 80 |

| Substation Name | Low | Reference | High |
|---|---|---|---|
| UNIVERSITY | 17 | 34 | 47 |
| URBAN | 6 | 10 | 11 |
| WACONDA | 67 | 144 | 200 |
| WALLACE | 34 | 59 | 74 |
| WELCHES | 18 | 38 | 50 |
| WEST PORTLAND | 72 | 126 | 179 |
| WEST UNION | 18 | 43 | 53 |
| WILLAMINA | 14 | 36 | 47 |
| WILLBRIDGE | 29 | 56 | 78 |
| WILSONVILLE | 118 | 217 | 310 |
| WOODBURN | 67 | 115 | 158 |
| YAMHILL | 79 | 142 | 209 |

**Table 71. 2030 demand response peak demand impacts by substation (MW)**

| Substation Name | Summer MW | Winter MW |
|---|---|---|
| ABERNETHY | -2.1 | -1.6 |
| ALDER | -3.4 | -2.7 |
| AMITY | -0.9 | -0.6 |
| ARLETA | -3.6 | -2.0 |
| BANKS | -0.7 | -0.5 |
| BARNES | -3.1 | -2.1 |
| BEAVERTON | -1.6 | -1.6 |
| BELL | -3.0 | -1.8 |
| BETHANY | -3.2 | -1.9 |
| BETHEL | -1.8 | -1.1 |
| BLUE LAKE | -1.6 | -1.3 |
| BOONES FERRY | -3.4 | -2.4 |
| BORING | -1.7 | -1.2 |
| BRIGHTWOOD | -0.6 | -0.3 |
| BROOKWOOD | -1.2 | -1.0 |

| Substation Name | Summer MW | Winter MW |
|---|---|---|
| CANBY | -1.1 | -0.8 |
| CANYON | -5.1 | -5.0 |
| CARVER | -4.2 | -3.0 |
| CEDAR HILLS | -2.8 | -2.3 |
| CENTENNIAL | -2.5 | -1.8 |
| CLACKAMAS | -1.9 | -1.5 |
| CLAXTAR | -1.6 | -1.4 |
| COFFEE CREEK | -0.7 | -0.7 |
| COLTON | -0.5 | -0.4 |
| CORNELIUS | -1.6 | -0.9 |
| CORNELL | -1.6 | -1.2 |
| CULVER | -0.1 | -0.1 |
| CURTIS | -0.4 | -0.2 |
| DAYTON | -1.7 | -1.3 |
| DELAWARE | -2.1 | -1.1 |
| DENNY | -2.2 | -1.5 |
| DILLEY | -0.3 | -0.2 |
| DUNNS CORNER | -0.5 | -0.4 |
| DURHAM | -2.7 | -2.0 |
| E | -4.4 | -4.6 |
| EAGLE CREEK | -0.7 | -0.5 |
| EASTPORT | -1.0 | -0.6 |
| ELMA | -1.7 | -1.1 |
| ESTACADA | -1.5 | -1.2 |
| FAIRMOUNT | -1.4 | -0.9 |
| FAIRVIEW | -1.6 | -1.3 |
| FARGO | -0.6 | -0.4 |
| GALES CREEK | -0.3 | -0.2 |
| GARDEN HOME | -1.7 | -1.1 |
| GLENCOE | -1.6 | -1.1 |

| Substation Name | Summer MW | Winter MW |
|---|---|---|
| GLENCULLEN | -1.5 | -1.0 |
| GLENDOVEER | -2.7 | -1.9 |
| GRAND RONDE | -0.4 | -0.3 |
| HARBORTON | -0.8 | -0.6 |
| HARMONY | -2.7 | -1.7 |
| HARRISON | -1.1 | -1.0 |
| HAYDEN ISLAND | -0.9 | -0.8 |
| HEMLOCK | -1.5 | -1.3 |
| HILLCREST | -0.7 | -0.5 |
| HILLSBORO | -3.0 | -1.8 |
| HOGAN NORTH | -3.4 | -2.6 |
| HOGAN SOUTH | -3.5 | -2.3 |
| HOLGATE | -2.8 | -2.2 |
| HUBER | -4.3 | -2.7 |
| INDIAN | -3.3 | -1.9 |
| ISLAND | -2.3 | -1.4 |
| JENNINGS LODGE | -2.5 | -1.7 |
| KELLEY POINT | -0.2 | -0.2 |
| KELLY BUTTE | -2.9 | -2.2 |
| KING CITY | -2.6 | -1.9 |
| LELAND | -2.2 | -1.7 |
| LENTS | -1.9 | -1.2 |
| LIBERAL | -0.5 | -0.3 |
| LIBERTY | -3.7 | -2.3 |
| MAIN | -2.7 | -1.6 |
| MARKET | -1.6 | -1.1 |
| MARQUAM | -0.9 | -0.9 |
| MCCLAIN | -1.0 | -0.7 |
| MCGILL | -1.0 | -0.5 |
| MERIDIAN | -3.0 | -2.0 |

| Substation Name | Summer MW | Winter MW |
|---|---|---|
| MIDDLE GROVE | -3.1 | -2.5 |
| MIDWAY | -2.2 | -1.7 |
| MILL CREEK | -0.9 | -0.7 |
| MOBILE 6 | -3.3 | -2.4 |
| MOLALLA | -2.2 | -1.5 |
| MT ANGEL | -0.6 | -0.4 |
| MT PLEASANT | -2.8 | -1.9 |
| MULINO | -0.5 | -0.3 |
| MULTNOMAH | -2.7 | -1.7 |
| MURRAYHILL | -3.1 | -2.4 |
| NEWBERG | -3.2 | -2.1 |
| NORTH MARION | -2.0 | -1.4 |
| NORTH PLAINS | -1.2 | -0.8 |
| NORTHERN | -1.0 | -0.8 |
| OAK GROVE | -0.1 | -0.1 |
| OAK HILLS | -1.9 | -1.5 |
| ORENCO | -4.2 | -3.8 |
| ORIENT | -1.1 | -0.8 |
| OSWEGO | -1.8 | -1.2 |
| OXFORD | -2.0 | -1.4 |
| PENINSULA PARK | -0.6 | -0.4 |
| PLEASANT VALLEY | -3.5 | -2.2 |
| PORTSMOUTH | -1.6 | -1.0 |
| PROGRESS | -1.5 | -1.1 |
| RALEIGH HILLS | -1.3 | -0.9 |
| RAMAPO | -2.0 | -1.5 |
| REDLAND | -1.4 | -1.1 |
| REEDVILLE | -3.4 | -2.1 |
| RIVERGATE SOUTH | -0.7 | -0.5 |
| RIVERVIEW | -1.5 | -1.1 |

| Substation Name | Summer MW | Winter MW |
|---|---|---|
| ROCK CREEK | -1.5 | -0.9 |
| ROCKWOOD | -1.4 | -1.1 |
| ROSEMONT | -1.5 | -0.9 |
| RUBY | -1.6 | -1.2 |
| SALEM | -1.4 | -1.1 |
| SANDY | -2.4 | -1.6 |
| SCAPPOOSE | -0.1 | -0.1 |
| SCHOLLS FERRY | -3.0 | -2.0 |
| SCOGGINS | -0.7 | -0.5 |
| SCOTTS MILLS | -0.6 | -0.5 |
| SELLWOOD | -1.2 | -0.9 |
| SHERIDAN | -0.9 | -0.7 |
| SILVERTON | -2.4 | -1.7 |
| SIX CORNERS | -3.5 | -2.2 |
| SPRINGBROOK | -1.9 | -1.3 |
| ST HELENS | -0.1 | 0.0 |
| ST LOUIS | -1.3 | -0.9 |
| ST MARYS EAST | -2.1 | -1.6 |
| STEPHENS | -0.5 | -0.4 |
| SULLIVAN | -2.2 | -1.2 |
| SUMMIT | -0.5 | -0.5 |
| SUNSET | -0.8 | -0.7 |
| SWAN ISLAND | -1.2 | -1.1 |
| SYLVAN | -1.7 | -1.1 |
| TABOR | -1.5 | -1.0 |
| TEKTRONIX | -3.6 | -2.7 |
| TEMP A | -0.1 | -0.1 |
| TEMP B | 0.0 | 0.0 |
| TEMP H | -0.3 | -0.3 |
| TIGARD | -2.5 | -1.9 |

| Substation Name | Summer MW | Winter MW |
|---|---|---|
| TOWN CENTER | -2.6 | -2.4 |
| TUALATIN | -2.9 | -2.3 |
| TURNER | -0.7 | -0.6 |
| TWILIGHT | -0.8 | -0.6 |
| UNIONVALE | -0.4 | -0.3 |
| UNIVERSITY | -1.0 | -0.5 |
| URBAN | -1.7 | -1.8 |
| WACONDA | -1.0 | -0.7 |
| WALLACE | -0.9 | -0.5 |
| WELCHES | -0.7 | -0.6 |
| WEST PORTLAND | -2.3 | -1.7 |
| WEST UNION | -1.2 | -0.9 |
| WILLAMINA | -1.5 | -0.9 |
| WILLBRIDGE | -1.0 | -0.7 |
| WILSONVILLE | -3.9 | -3.1 |
| WOODBURN | -1.2 | -0.7 |
| YAMHILL | -1.3 | -0.9 |

**Table 72. Energy efficiency savings forecast at substation (Base case, aMW at generation)**

| Substation Name | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| ABERNETHY | 0.17 | 0.18 | 0.13 | 0.12 | 0.14 | 0.15 | 0.17 | 0.18 | 0.20 |
| ALDER | 0.28 | 0.31 | 0.21 | 0.21 | 0.23 | 0.25 | 0.28 | 0.31 | 0.33 |
| AMITY | 0.07 | 0.07 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 | 0.07 | 0.08 |
| ARLETA | 0.25 | 0.27 | 0.18 | 0.18 | 0.20 | 0.22 | 0.24 | 0.27 | 0.29 |
| BANKS | 0.07 | 0.08 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 | 0.08 | 0.08 |
| BARNES | 0.23 | 0.25 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 | 0.27 |
| BEAVERTON | 0.18 | 0.19 | 0.13 | 0.13 | 0.14 | 0.16 | 0.17 | 0.19 | 0.20 |
| BELL | 0.33 | 0.36 | 0.24 | 0.24 | 0.27 | 0.30 | 0.33 | 0.36 | 0.38 |
| BETHANY | 0.20 | 0.22 | 0.15 | 0.15 | 0.16 | 0.18 | 0.20 | 0.22 | 0.23 |
| BETHEL | 0.12 | 0.13 | 0.09 | 0.09 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 |

| Substation Name | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| BLUE LAKE | 0.16 | 0.18 | 0.12 | 0.12 | 0.13 | 0.15 | 0.16 | 0.18 | 0.19 |
| BOONES FERRY | 0.24 | 0.26 | 0.18 | 0.17 | 0.19 | 0.21 | 0.23 | 0.26 | 0.27 |
| BORING | 0.14 | 0.16 | 0.11 | 0.10 | 0.12 | 0.13 | 0.14 | 0.16 | 0.17 |
| BRIGHTWOOD | 0.04 | 0.05 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 |
| BROOKWOOD | 0.19 | 0.20 | 0.14 | 0.14 | 0.16 | 0.17 | 0.19 | 0.21 | 0.22 |
| CANBY | 0.12 | 0.13 | 0.09 | 0.08 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 |
| CANYON | 0.45 | 0.49 | 0.34 | 0.33 | 0.38 | 0.41 | 0.45 | 0.49 | 0.53 |
| CARVER | 0.33 | 0.36 | 0.24 | 0.24 | 0.27 | 0.30 | 0.33 | 0.36 | 0.38 |
| CEDAR HILLS | 0.26 | 0.28 | 0.19 | 0.19 | 0.21 | 0.23 | 0.25 | 0.28 | 0.30 |
| CENTENNIAL | 0.21 | 0.23 | 0.16 | 0.15 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 |
| CLACKAMAS | 0.20 | 0.22 | 0.15 | 0.15 | 0.17 | 0.18 | 0.20 | 0.22 | 0.23 |
| CLAXTAR | 0.13 | 0.14 | 0.10 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 |
| COFFEE CREEK | 0.09 | 0.10 | 0.07 | 0.07 | 0.07 | 0.08 | 0.09 | 0.10 | 0.10 |
| COLTON | 0.05 | 0.05 | 0.03 | 0.03 | 0.04 | 0.04 | 0.05 | 0.05 | 0.05 |
| CORNELIUS | 0.14 | 0.16 | 0.11 | 0.10 | 0.12 | 0.13 | 0.14 | 0.16 | 0.17 |
| CORNELL | 0.15 | 0.16 | 0.11 | 0.11 | 0.12 | 0.14 | 0.15 | 0.16 | 0.17 |
| CULVER | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 | 0.01 |
| CURTIS | 0.03 | 0.04 | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 |
| DAYTON | 0.12 | 0.13 | 0.09 | 0.08 | 0.10 | 0.10 | 0.11 | 0.13 | 0.14 |
| DELAWARE | 0.16 | 0.18 | 0.12 | 0.12 | 0.13 | 0.15 | 0.16 | 0.18 | 0.19 |
| DENNY | 0.20 | 0.21 | 0.15 | 0.14 | 0.16 | 0.18 | 0.19 | 0.21 | 0.23 |
| DILLEY | 0.03 | 0.03 | 0.02 | 0.02 | 0.02 | 0.02 | 0.03 | 0.03 | 0.03 |
| DUNNS CORNER | 0.08 | 0.09 | 0.06 | 0.06 | 0.07 | 0.07 | 0.08 | 0.09 | 0.09 |
| DURHAM | 0.23 | 0.25 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 | 0.27 |
| E | 0.56 | 0.61 | 0.42 | 0.41 | 0.46 | 0.51 | 0.55 | 0.61 | 0.65 |
| EAGLE CREEK | 0.06 | 0.07 | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 | 0.07 |
| EASTPORT | 0.11 | 0.11 | 0.08 | 0.08 | 0.09 | 0.09 | 0.10 | 0.11 | 0.12 |
| ELMA | 0.21 | 0.23 | 0.16 | 0.15 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 |
| ESTACADA | 0.16 | 0.18 | 0.12 | 0.12 | 0.13 | 0.15 | 0.16 | 0.18 | 0.19 |
| FAIRMOUNT | 0.11 | 0.12 | 0.08 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.12 |

| Substation Name | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| FAIRVIEW | 0.19 | 0.21 | 0.14 | 0.14 | 0.16 | 0.18 | 0.19 | 0.21 | 0.23 |
| FARGO | 0.06 | 0.07 | 0.05 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 | 0.07 |
| GALES CREEK | 0.02 | 0.02 | 0.01 | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 |
| GARDEN HOME | 0.11 | 0.12 | 0.08 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.12 |
| GLENCOE | 0.11 | 0.12 | 0.08 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.12 |
| GLENCULLEN | 0.09 | 0.10 | 0.07 | 0.06 | 0.07 | 0.08 | 0.09 | 0.10 | 0.10 |
| GLENDOVEER | 0.21 | 0.22 | 0.15 | 0.15 | 0.17 | 0.19 | 0.20 | 0.22 | 0.24 |
| GRAND RONDE | 0.06 | 0.07 | 0.05 | 0.04 | 0.05 | 0.06 | 0.06 | 0.07 | 0.07 |
| HARBORTON | 0.06 | 0.06 | 0.04 | 0.04 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 |
| HARMONY | 0.29 | 0.32 | 0.22 | 0.21 | 0.24 | 0.27 | 0.29 | 0.32 | 0.34 |
| HARRISON | 0.22 | 0.23 | 0.16 | 0.16 | 0.18 | 0.19 | 0.21 | 0.23 | 0.25 |
| HAYDEN ISLAND | 0.12 | 0.13 | 0.09 | 0.09 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 |
| HEMLOCK | 0.18 | 0.19 | 0.13 | 0.13 | 0.15 | 0.16 | 0.18 | 0.19 | 0.21 |
| HILLCREST | 0.05 | 0.05 | 0.04 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 | 0.06 |
| HILLSBORO | 0.26 | 0.28 | 0.19 | 0.19 | 0.21 | 0.23 | 0.25 | 0.28 | 0.30 |
| HOGAN NORTH | 0.26 | 0.28 | 0.19 | 0.19 | 0.21 | 0.23 | 0.25 | 0.28 | 0.30 |
| HOGAN SOUTH | 0.28 | 0.31 | 0.21 | 0.21 | 0.23 | 0.26 | 0.28 | 0.31 | 0.33 |
| HOLGATE | 0.23 | 0.25 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 | 0.27 |
| HUBER | 0.30 | 0.33 | 0.22 | 0.22 | 0.25 | 0.27 | 0.30 | 0.33 | 0.35 |
| INDIAN | 0.27 | 0.30 | 0.20 | 0.20 | 0.23 | 0.25 | 0.27 | 0.30 | 0.32 |
| ISLAND | 0.22 | 0.24 | 0.16 | 0.16 | 0.18 | 0.20 | 0.22 | 0.24 | 0.26 |
| JENNINGS LODGE | 0.21 | 0.23 | 0.15 | 0.15 | 0.17 | 0.19 | 0.21 | 0.23 | 0.24 |
| KELLEY POINT | 0.10 | 0.11 | 0.08 | 0.07 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 |
| KELLY BUTTE | 0.26 | 0.28 | 0.19 | 0.19 | 0.21 | 0.23 | 0.26 | 0.28 | 0.30 |
| KING CITY | 0.20 | 0.22 | 0.15 | 0.15 | 0.17 | 0.18 | 0.20 | 0.22 | 0.23 |
| LELAND | 0.20 | 0.21 | 0.15 | 0.14 | 0.16 | 0.18 | 0.19 | 0.21 | 0.23 |
| LENTS | 0.15 | 0.17 | 0.11 | 0.11 | 0.13 | 0.14 | 0.15 | 0.17 | 0.18 |
| LIBERAL | 0.07 | 0.08 | 0.05 | 0.05 | 0.06 | 0.07 | 0.07 | 0.08 | 0.08 |
| LIBERTY | 0.26 | 0.28 | 0.19 | 0.19 | 0.22 | 0.24 | 0.26 | 0.28 | 0.30 |
| MAIN | 0.43 | 0.47 | 0.32 | 0.31 | 0.35 | 0.39 | 0.42 | 0.47 | 0.50 |

| Substation Name | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| MARKET | 0.16 | 0.17 | 0.12 | 0.12 | 0.13 | 0.14 | 0.16 | 0.17 | 0.18 |
| MARQUAM | 0.18 | 0.19 | 0.13 | 0.13 | 0.15 | 0.16 | 0.17 | 0.19 | 0.21 |
| MCCLAIN | 0.09 | 0.09 | 0.06 | 0.06 | 0.07 | 0.08 | 0.09 | 0.10 | 0.10 |
| MCGILL | 0.08 | 0.09 | 0.06 | 0.06 | 0.07 | 0.07 | 0.08 | 0.09 | 0.10 |
| MERIDIAN | 0.30 | 0.33 | 0.22 | 0.22 | 0.25 | 0.27 | 0.30 | 0.33 | 0.35 |
| MIDDLE GROVE | 0.28 | 0.30 | 0.21 | 0.20 | 0.23 | 0.25 | 0.27 | 0.30 | 0.32 |
| MIDWAY | 0.19 | 0.21 | 0.14 | 0.14 | 0.16 | 0.17 | 0.19 | 0.21 | 0.22 |
| MILL CREEK | 0.11 | 0.12 | 0.08 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.13 |
| MOLALLA | 0.24 | 0.26 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.26 | 0.27 |
| MT ANGEL | 0.07 | 0.08 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 | 0.08 | 0.08 |
| MT PLEASANT | 0.23 | 0.25 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 | 0.27 |
| MULINO | 0.04 | 0.05 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.05 | 0.05 |
| MULTNOMAH | 0.19 | 0.21 | 0.14 | 0.14 | 0.16 | 0.17 | 0.19 | 0.21 | 0.22 |
| MURRAYHILL | 0.24 | 0.26 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.26 | 0.27 |
| NEWBERG | 0.26 | 0.28 | 0.19 | 0.19 | 0.21 | 0.23 | 0.26 | 0.28 | 0.30 |
| NORTH MARION | 0.15 | 0.17 | 0.11 | 0.11 | 0.13 | 0.14 | 0.15 | 0.17 | 0.18 |
| NORTH PLAINS | 0.10 | 0.10 | 0.07 | 0.07 | 0.08 | 0.09 | 0.10 | 0.10 | 0.11 |
| NORTHERN | 0.08 | 0.08 | 0.06 | 0.06 | 0.06 | 0.07 | 0.08 | 0.08 | 0.09 |
| OAK GROVE | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| OAK HILLS | 0.24 | 0.26 | 0.18 | 0.17 | 0.20 | 0.22 | 0.24 | 0.26 | 0.28 |
| ORENCO | 0.41 | 0.44 | 0.30 | 0.30 | 0.34 | 0.37 | 0.40 | 0.44 | 0.47 |
| ORIENT | 0.09 | 0.10 | 0.07 | 0.07 | 0.07 | 0.08 | 0.09 | 0.10 | 0.11 |
| OSWEGO | 0.17 | 0.18 | 0.13 | 0.12 | 0.14 | 0.15 | 0.17 | 0.18 | 0.20 |
| OXFORD | 0.18 | 0.20 | 0.14 | 0.13 | 0.15 | 0.17 | 0.18 | 0.20 | 0.21 |
| PENINSULA PARK | 0.08 | 0.09 | 0.06 | 0.06 | 0.07 | 0.07 | 0.08 | 0.09 | 0.09 |
| PLEASANT VALLEY | 0.25 | 0.27 | 0.19 | 0.18 | 0.21 | 0.23 | 0.25 | 0.27 | 0.29 |
| PORTSMOUTH | 0.16 | 0.18 | 0.12 | 0.12 | 0.14 | 0.15 | 0.16 | 0.18 | 0.19 |
| PROGRESS | 0.23 | 0.25 | 0.17 | 0.16 | 0.19 | 0.20 | 0.22 | 0.25 | 0.26 |
| RALEIGH HILLS | 0.13 | 0.14 | 0.10 | 0.09 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 |
| RAMAPO | 0.15 | 0.17 | 0.11 | 0.11 | 0.13 | 0.14 | 0.15 | 0.17 | 0.18 |

| Substation Name | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| REDLAND | 0.12 | 0.13 | 0.09 | 0.08 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 |
| REEDVILLE | 0.46 | 0.50 | 0.34 | 0.33 | 0.38 | 0.41 | 0.45 | 0.50 | 0.53 |
| RIVERGATE SOUTH | 0.16 | 0.18 | 0.12 | 0.12 | 0.13 | 0.15 | 0.16 | 0.18 | 0.19 |
| RIVERVIEW | 0.14 | 0.15 | 0.10 | 0.10 | 0.12 | 0.13 | 0.14 | 0.15 | 0.16 |
| ROCK CREEK | 0.10 | 0.11 | 0.08 | 0.07 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 |
| ROCKWOOD | 0.35 | 0.38 | 0.26 | 0.26 | 0.29 | 0.32 | 0.35 | 0.38 | 0.41 |
| ROSEMONT | 0.10 | 0.11 | 0.08 | 0.07 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 |
| ROSEWAY | 0.13 | 0.14 | 0.10 | 0.09 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 |
| RUBY | 0.13 | 0.14 | 0.10 | 0.09 | 0.11 | 0.12 | 0.13 | 0.14 | 0.15 |
| SALEM | 0.10 | 0.11 | 0.08 | 0.08 | 0.09 | 0.09 | 0.10 | 0.11 | 0.12 |
| SANDY | 0.23 | 0.25 | 0.17 | 0.17 | 0.19 | 0.21 | 0.23 | 0.25 | 0.27 |
| SCAPPOOSE CRPUD | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| SCHOLLS FERRY | 0.11 | 0.12 | 0.08 | 0.08 | 0.09 | 0.10 | 0.11 | 0.12 | 0.13 |
| SCOGGINS | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 |
| SCOTTS MILLS | 0.04 | 0.05 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 | 0.05 |
| SELLWOOD | 0.17 | 0.18 | 0.13 | 0.12 | 0.14 | 0.15 | 0.17 | 0.18 | 0.20 |
| SHERIDAN | 0.09 | 0.10 | 0.07 | 0.06 | 0.07 | 0.08 | 0.09 | 0.10 | 0.10 |
| SILVERTON | 0.19 | 0.21 | 0.14 | 0.14 | 0.16 | 0.17 | 0.19 | 0.21 | 0.22 |
| SIX CORNERS | 0.27 | 0.30 | 0.20 | 0.20 | 0.22 | 0.25 | 0.27 | 0.30 | 0.32 |
| SPRINGBROOK | 0.21 | 0.22 | 0.15 | 0.15 | 0.17 | 0.19 | 0.20 | 0.22 | 0.24 |
| ST HELENS | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| ST LOUIS | 0.13 | 0.14 | 0.09 | 0.09 | 0.10 | 0.11 | 0.12 | 0.14 | 0.15 |
| ST MARYS EAST | 0.19 | 0.20 | 0.14 | 0.14 | 0.15 | 0.17 | 0.18 | 0.20 | 0.22 |
| STEPHENS | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| SULLIVAN | 0.34 | 0.37 | 0.25 | 0.25 | 0.28 | 0.31 | 0.34 | 0.37 | 0.40 |
| SUMMIT | 0.03 | 0.04 | 0.03 | 0.03 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 |
| SUNSET | 3.83 | 4.16 | 2.84 | 2.79 | 3.16 | 3.46 | 3.79 | 4.16 | 4.45 |
| SWAN ISLAND | 0.19 | 0.21 | 0.14 | 0.14 | 0.16 | 0.17 | 0.19 | 0.21 | 0.22 |
| SYLVAN | 0.14 | 0.15 | 0.10 | 0.10 | 0.12 | 0.13 | 0.14 | 0.15 | 0.16 |
| TABOR | 0.17 | 0.18 | 0.12 | 0.12 | 0.14 | 0.15 | 0.16 | 0.18 | 0.19 |

| Substation Name | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 |
|---|---|---|---|---|---|---|---|---|---|
| TEKTRONIX | 0.37 | 0.40 | 0.28 | 0.27 | 0.31 | 0.34 | 0.37 | 0.40 | 0.43 |
| TEMP B | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| TIGARD | 0.18 | 0.19 | 0.13 | 0.13 | 0.15 | 0.16 | 0.18 | 0.19 | 0.21 |
| TOWN CENTER | 0.29 | 0.31 | 0.21 | 0.21 | 0.24 | 0.26 | 0.28 | 0.31 | 0.33 |
| TUALATIN | 0.38 | 0.41 | 0.28 | 0.27 | 0.31 | 0.34 | 0.37 | 0.41 | 0.44 |
| TURNER | 0.06 | 0.06 | 0.04 | 0.04 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 |
| TWILIGHT | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 |
| UNIONVALE | 0.04 | 0.04 | 0.03 | 0.03 | 0.03 | 0.04 | 0.04 | 0.04 | 0.05 |
| UNIVERSITY | 0.12 | 0.13 | 0.09 | 0.08 | 0.10 | 0.10 | 0.11 | 0.13 | 0.13 |
| UNKNOWN | 0.02 | 0.02 | 0.01 | 0.01 | 0.02 | 0.02 | 0.02 | 0.02 | 0.02 |
| URBAN | 0.34 | 0.37 | 0.25 | 0.25 | 0.28 | 0.30 | 0.33 | 0.37 | 0.39 |
| WACONDA | 0.13 | 0.14 | 0.10 | 0.10 | 0.11 | 0.12 | 0.13 | 0.14 | 0.16 |
| WALLACE | 0.07 | 0.07 | 0.05 | 0.05 | 0.05 | 0.06 | 0.07 | 0.07 | 0.08 |
| WELCHES | 0.07 | 0.07 | 0.05 | 0.05 | 0.06 | 0.06 | 0.07 | 0.07 | 0.08 |
| WEST PORTLAND | 0.22 | 0.23 | 0.16 | 0.16 | 0.18 | 0.19 | 0.21 | 0.23 | 0.25 |
| WEST UNION | 0.23 | 0.25 | 0.17 | 0.16 | 0.19 | 0.20 | 0.22 | 0.25 | 0.26 |
| WILLAMINA | 0.10 | 0.10 | 0.07 | 0.07 | 0.08 | 0.09 | 0.09 | 0.10 | 0.11 |
| WILLBRIDGE | 0.06 | 0.07 | 0.05 | 0.04 | 0.05 | 0.06 | 0.06 | 0.07 | 0.07 |
| WILSONVILLE | 0.44 | 0.48 | 0.33 | 0.32 | 0.36 | 0.40 | 0.44 | 0.48 | 0.51 |
| WOODBURN | 0.20 | 0.22 | 0.15 | 0.15 | 0.17 | 0.18 | 0.20 | 0.22 | 0.23 |
| YAMHILL | 0.11 | 0.11 | 0.08 | 0.08 | 0.09 | 0.10 | 0.10 | 0.11 | 0.12 |

# Appendix N. Equity index and community targeting assessment

PGE contracted with Cadeo to perform analyses of potential data sources and equity variables that could be incorporated into AdopDER and used to promote more human-centered resource planning. We heard loud and clear from our DSP partners the importance of including a community lens on various stages of resource planning, and data is a fundamental building block to ensuring that projects and programs are reaching their intended goals.

Cadeo conducted a review of the data landscape regarding the key variables of interest we heard expressed through the DSP: DEI data, environmental indicators, and resilience factors. In order to reduce the total potential variables from among the more than 50 variables reviewed, a statistical technique called latent factor analysis was performed in order to identify correlations between the data and determine appropriate representative variables for inclusion into the index. Finally, the composite indices were added into AdopDER and a spatial analysis was performed on adoption results for solar PV and TE scenarios. We expect the results of this work to change and evolve as conversations continue through the DSP Technical Working Group. Available at: https://portlandgeneral.com/dsp-part2-appendix-n.