Distribution System Plan Part 1

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Acronyms

3WTC	3 World Trade Center
ADMS	Advanced Distribution Management System
AFDC	Alternative Fuels Data Center
AMI	Automated Metering Infrastructure
AMR	Automatic Meter Reading
ANSI	American National Standards Institute
BCA	Benefit-Cost Analysis
BESS	Battery Energy Storage Systems
BEV	Battery Electric Vehicle
BIPOC	Black, Indigenous and People of Color
C&I	Commercial and Industrial
CAIDI	Customer Average Interruption Duration Index
CAISO	California Independent System Operators
CBIAG	Community Benefit and Impact Advisory Group
CBO	Community-Based Organization
CCC	Coalition of Communities of Color
CE	Community Engagement
CEOP	Corporate Emergency Operations Plan
CEP	Community Energy Project
CIMT	Corporate Incident Management Team
CO2e	Carbon Dioxide Equivalent
ComEd	Commonwealth Edison
CTA	Consumer Technology Association
CTWS	Confederated Tribes of Warm Springs Reservation of Oregon
CUB	Oregon Citizen's Utility Board
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DAN	Data Action Node
DCQC	Direct Current Quick Charge
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
DML	Daily Minimum Load
DMS	Distribution Management System

DNP3.0	Distributed Network Protocol 3.0
DOE	Department of Energy
DPU	Distribution Protection Unit
DR	Demand Response
DRMS	Demand Response Management System
DRMS	Demand Resource Management System
DSMS	Demand-Side Management System
DSP	Distribution System Plan
DSPx	Next Generation Distribution System Platform
EA	Electric Avenues
EFD	Early Fault Detection
EIM	Energy Imbalance Market
EJ	Environmental Justice
ELCC	Effective Load Carrying Capability
EMS	Energy Management System
EPRI	Electric Power Resource Institute
ERWH	Electric Resistance Water Heater
ESS	Electric Service Suppliers
ETO	Energy Trust of Oregon
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FAN	Field Area Network
FCC	Federal Communications Commission
FERC	Federal Energy Regulatory Commission
FITNES	Facilities Inspection and Treatment to the National Electrical Safety Code
FLISR	Fault, Location, Isolation and Service Restoration
GARE	Government Alliance on Race and Equity
GHG	Greenhouse Gas
GMS	Grid Management Systems
GRC	General Rate Case
HCA	Hosting Capacity Analysis
HPWH	Heat Pump Water Heater
HVAC	Heating, Ventilation and Air Conditioning
IAP2	International Association for Public Participation
ICE	Internal Combustion Engine
IEDs	Intelligent Electronic Devices

Acronyms (continued)

IEEE	Institute of Electrical and Electronics Engineers
IOC	Integrated Operations Center
IOUs	Investor-Owned Utilities
IRP	Integrated Resource Plan
ISO	Independent System Operators
IT	Information Technology
IVR	Interactive Voice Response
kV	Kilovolt
kVA	Kilovolt-Ampere
kW	Kilowatt
L2	Level 2 EV Charging
LBNR	Loading Beyond Nameplate Ratings
LDV	Light-Duty Vehicle
LIDAR	Light Detection and Ranging
LTC	Load Tap Charging
MAIFI	Momentary Average Interruption Event Frequency Index
MDHDV	Medium- and Heavy-Duty Vehicles
MHz	Megahertz
MLAs	Minimum Load Agreements
MPLS	Multi-Protocol Label Switching
MVA	Megavolt Amp
MVAR	Megavolt Amp Reactive
MW	Megawatt
MWa	Average Megawatts
MWh	Megawatt-Hour
NAN	Neighborhood Area Network
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electric Reliability Corporation
NETL	National Energy Technology Laborataory
NREL	National Renewable Energy Lab
NWA	Non-Wires Alternatives
NWEC	Northwest Energy Coalition
NWS	Non-Wires Solutions
NYISO	New York Independent System Operator
O&M	Operation and Maintenance
OMS	Outage Management System
Ops	Operations
OPUC	Oregon Public Utilities Commission

OT	Operational Technology
Pepco	Potomac Electric Power Company
PSPS	Public Safety Power Shutoff
PHEV	Plugging Hybrid Electrical Vehicle
PF	Power Factor
PLM	Product Lifecycle Management
PSPS	Public Safety Power Shutoff
PTR	Peak Time Rebates
PUC	Public Utilities Commissions
PV	Photovoltaic
RD	Remote Disconnect
REaL-D	Race, Ethnicity, Language and Disability
Resilience ARC	Resilience Accelerated Response Coordination
RFP	Request for Proposal
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SFCI	Smart Faulted Circuit Indicator
SGTB	Smart Grid Test Bed
SOGI	Sexual Orientation and Gender Identity
T&D	Transmission and Distribution
TGBs	Transceiver Gateway Base Stations
TLTC	Transformer Load Tap Changer
TNCD	Transportation Network Company Drivers
TOU	Time of Use
Tstat	Thermostat
TWG	Technical Working Group
UniteOR	Unite Oregon
VAR	Volt-Amperes Reactive
VOLL	Value of Lost Load
VPP	Virtual Power Plant
VVO	Volt-VAR Optimization
WAN	Wide Area Network

Executive Summary

The last few years, through the ongoing pandemic and increased focus on social justice, have brought to the forefront the importance of having the customer at the center of all that we do. More than ever, customers expect their power to be affordable, reliable and there when they need it. At the same time, customers want clean power options customized to their specific preferences, services delivered with speed and ease.

Background

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 the DSP and to utilize this human-centered approach in "identifying grid needs, implemented in partnership with communities and community-based organizations" that "create value-adding investments for communities, and align the energy system with community priorities." Portland General Electric's (PGE's) DSP aims to accelerate a fair and equitable clean energy transition to a modernized grid platform that is customer-inspired and community-centric. We embrace this energy transformation and will empower customers with innovative products and services by designing and modernizing the electric grid for our customers.

The evolution of distribution system planning is a central process within this transformation, providing a proactive pathway to address key drivers such as customer preference, decarbonization, affordability, reliability and resilience. Historically, distribution system planning processes have primarily focused on affordably serving load growth while ensuring safe and reliable operation of the distribution grid. With advances in technology, we are transitioning the distribution system from being a safe and reliable energy delivery system to becoming a safe, reliable, flexible, resilient and human-centered energy exchange platform that integrates seamlessly with the wholesale market. Customers increasingly expect choices and control in the products and services they consume. Ubiquity of low-cost communications and the proliferation of devices and control options mean that customers have unprecedented ability to manage their lives and their consumption. This extends to energy, where there is a growing, critical two-way exchange between customers and the electric grid.

Real-time information and options for flexibility in usage and pricing, combined with digital enablement (mobile, web), will enable customers to use the electric grid as a pathway for meeting their goals, whether those be cost management, sustainable lifestyle, independence, resiliency or other. These options may extend from simple time of use and behavioral demand response solutions all the way to turnkey services that bundle significant energy uses with renewables options (e.g., an electric vehicle paired with rooftop solar and a battery). In all cases, personal or corporate choices for engaging in these programs create the potential for individual customers' needs to be met while also delivering system value and reliability back to all customers.

Solutions are available to enable new capabilities, such as non-wires solutions, automated fault detection and restoration, and photovoltaic (PV) and electric vehicle integration — at scale — without sacrificing safety and reliability. In the following chapters, PGE outlines the vision of how these solutions can be leveraged to accelerate decarbonization and electrification and provide direct benefits to communities — especially environmental justice communities — while improving metrics around safety, reliability, resiliency and security, all at fair and reasonable costs.

PGE's strategy

PGE exists to power the advancement of society. We energize lives, strengthen communities and drive advancements in energy that promote social, economic and environmental progress. We aim to lead the clean energy future and together — with customers, partners and communities — we will lead the energy transformation by decarbonizing, electrifying and performing.

DECARBONIZE

We know our customers and communities want to use clean electricity, which is why we are committed to reducing greenhouse gas (GHG) emissions from the power served to customers by at least 80% by 2030 and 100% by 2040. These ambitious GHG reduction targets are in line with a new Oregon state law (House Bill [HB] 2021) establishing an electric sector decarbonization framework.[1] PGE is excited to have been part of a broad coalition supporting the passage of this important bill during the 2021 legislative session. Our customers want affordable, reliable electricity — and they want their choices to be cleaner than ever before. Right now, more than 90% of our electricity supply is generated right here in the Pacific Northwest, and we will continue to add new clean and renewable resources to the system so all customers can enjoy a clean energy future.

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 identified that in order to achieve this decarbonized future, we would need to find new sources of flexibility for the supply portfolio. It is estimated that as much as 25% of flexibility could come from customers and distributed energy resources (DERs).[2] It is imperative we find ways to incentivize customers to bring their flexibility and clean resources to the grid to participate in the greater decarbonized energy system.

Doing so is a complex task. It requires that the products and services offered by PGE must be designed to solve real customer needs and must deliver great, end-to-end experiences. Failure to do so will lead customers to seek solutions elsewhere, and the value of a two-way integrated electric system will not be realized. That is why we are also working to help several of our municipal local governments and large customers who want to move faster to achieve their 100% clean energy goals. In addition, we are implementing ways to reduce emissions associated with our own operations, including vehicles and facilities.

ELECTRIFY

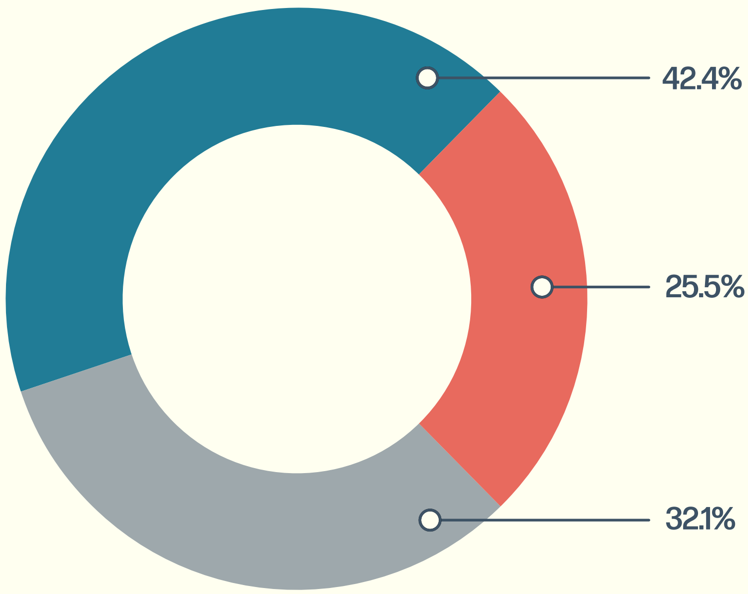
According to the Oregon Department of Energy's 2020 Biennial Energy Report, the majority of Oregon's energy use comes from electricity and the transportation sector, 42% and 32% respectively. Oregon relies on energy from a variety of resources (**Figure 1**) and imports energy like transportation fuels, natural gas, propane and other fuels.[3] Oregon also uses electricity from both in- and out-of-state sources — including coal, natural gas, nuclear, hydropower, wind and other renewable resources.

PGE sees a future in which we double our power served by electricity. We are helping our customers meet their goals of driving decarbonization, electrifying and alleviating energy burden. Our customers and communities are electrifying their vehicles, homes and workplaces and we are powering society in their clean energy journey. In doing so, we will capture the benefits of new technologies such as DERs, leading to an increasingly flexible and reliable grid.

1. House Bill 2021, available at: oregonlegislature.gov.
2. For the purposes of PGE's DSP, we utilize the OPUC's definition of DERs under Order 20-485, which includes distributed generation resources, distributed energy storage, demand response, energy efficiency and electric vehicles that are connected to the electric distribution power grid.
3. This percentage also accounts for source fuels that come from out of state, such as natural gas, but generate electricity in-state.

Figure 1. Oregon Department of Energy: Energy use by source[4]

Percentage of Oregon's 2018 energy consumption



Electricity
This is where most people begin when thinking about energy — the critical resource that powers our day-to-day lives. The electricity Oregonians use comes from facilities across the western United States and in Oregon. This percentage also accounts for source fuels that come from out of state, such as natural gas, but generate electricity in-state.

Direct use fuels
This category includes fuel oil and natural gas used to heat homes and commercial spaces, fuels used for other residential purposes, such as gas stoves, solar thermal heating, and fuels used directly in industrial processes.

Transportation fuels
This includes personal, passenger and commercial vehicles, both on and off the roads, plus airplanes, boats, barges, ships, and trains. Nearly all transportation-related sources of energy are imported from out of state for in-state use.

PERFORM

We know that the heart of our business is keeping the power on safely, reliably and affordably. We power communities, and our customers depend on us to deliver the power they need to live, work and play. Focusing on reliability allows us to bring more flexible and renewable electricity to customers. To keep things running smoothly, we continue to work on increasing efficiency and delivering exceptional customer experiences.

Over the last few years, as noted in our public commitments, such as our Integrated Resource Plan (IRP) filings and recent General Rate Case (GRC) filings, PGE has been shifting its corporate strategy to focus on leading the clean energy transformation by creating a path to zero GHG emissions associated with the power we serve customers.[5]

4. Data according to Oregon Department of Energy (ODOE) 2020 Biennial Energy Report, available at: www.oregon.gov
5. PGE About Us webpage, available at: portlandgeneral.com
PGE's 2019 Integrated Resource Plan, available at: PGE's 2019 Integrated Resource Plan
PGE's request for a General Rate Revision, 2021, available at: PGE's request for a General Rate Revision, 2021

PGE's distribution 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 the utility sector, Oregon is leading the way with policies such as HB 2021 and HB 2475 and regulatory directives such as UM 2005.[6] We embrace the challenge of leveraging the clean energy transformation to address environmental justice.

With the first filing of our Distribution System Plan (DSP), we are excited to share our vision of how the distribution system can help to achieve the shared goals of clean energy transformation and social and environmental justice for our communities.

Our vision is a **21st century community-centered distribution system** that can meet the following goals, detailed in **Chapter 2**.

a. **Advance environmental justice.** We envision the distribution system advancing environmental justice through the strategic deployment and use of grid assets (customer- or utility-owned) to yield more equitable outcomes, especially for those who are most vulnerable.

b. **Accelerate DER adoption.** We have a goal to accelerate DER adoption, which will require a distribution system that can easily enable DERs to not only connect to the grid, but also to deliver societal value through programs.

c. **Maximize grid benefits.** We will plan and operate the distribution system to maximize customer value.

To achieve this vision, we have five strategic initiatives:

- **Empowered communities**
- **Modernized grid**
- **Resilience**
- **Plug and play**
- **Evolved regulatory framework**

As illustrated in **Figure 2**, these strategic initiatives are connected to our vision and goals for the distribution system. These strategic initiatives are discussed in detail in subsequent chapters of the DSP.

Figure 2. PGE's vision, goals and execution approach

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

6. House Bill 2475, available at: oregonlegislature.gov

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

PGE is proud to submit 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 first step to integrate environmental justice goals. We detail in this report the vision, goals and strategic initiatives we plan for the distribution system and the role of the DSP in achieving it. We weave these goals into each section, showing a connection between our long-term vision, current actions and the evolution of the DSP. Additionally, we are committed to transitioning to a human-centered planning approach and have built the DSP on a foundation of engagement with the broader community (partners, customers and communities) and incorporation of their feedback.

Our customers are at the center of everything we do. In service to that commitment, we conducted eight partner and community workshops to share perspectives and gather input on key DSP subject areas. In addition to addressing the OPUC's UM 2005 requirements, these workshops created a community of DSP partners committed to building a better understanding of both our work and partners' needs and expectations. Our goal for the workshops was to initiate a dialogue that contributed to our DSP while also creating a platform for collaboration. **We thank the participants for joining us on this journey and are grateful for their partnership and insights**.

We believe this report is robust and meaningful and provides substantial transparency into our company and distribution system planning functions. To highlight some of the key aspects of our report, we summarize below the main points in each of the DSP's chapters.

CHAPTER 1
DISTRIBUTION SYSTEM OVERVIEW

The DSP is in its first stage and is an evolving, multi-stage process. We anticipate that the forming, filing and acceptance of the initial plans will educate all parties and identify areas for continuous improvement. This evolution will be informed by DSPs filed by all investor-owned utilities (IOUs) and help advance how the distribution system is defined, how investments can maximize customer value and even how investment costs are recovered.

In this chapter, PGE provides an overview of the distribution system in context to the overall electric grid. The grid is evolving from a paradigm of one-way power flow with centralized generation to customers, to a bi-directional grid with growing demands for DER interconnection. The distribution grid plays a critical role in enabling this future state, and it is important to understand the current state of system planning and asset replacement so that forward-looking investments can be contextualized and understood from the perspective of reliability, safety and affordability.

> The distribution system is defined as load-serving, PGE-owned equipment and lines at nominal voltage levels below 35 kV.[7] The distribution system starts at the circuit breaker and high-side disconnect of the substation distribution transformer.[8]

Our asset management practices ensure that we prioritize investments across a portfolio of distribution system assets in a manner that balances costs and maximizes improvements for reliability. Our distribution planning team maintains network models (in our power flow modeling software, CYME) of our distribution system and studies the impacts of changing loads to the projected needs of the distribution system in a near- and long-term planning horizon (five to 10 years). The key functions of PGE's distribution planning team are to:

- Perform system analysis and develop plans that ensure the distribution system will be operable and able to maintain functionality and flexibility in both the near and long term
- Provide support and guidance on distribution-related investment decisions
- Support grid modernization efforts and initiatives

The current adoption of DERs is critical to understand and informs what types of investments are needed to drive further adoption. We currently have 125 MW of net metered generation connected to our system, with another 35 MW in the queue. We continue to grow our flexible load resource, with 63 MW of enrolled summer demand response (DR) capacity as of 2020. We also have approximately 20,000 electric vehicles throughout our service area.

We invested an average of approximately $300 million per year on distribution system upgrades from 2016 to 2020, with the relative focus of investments changing each year to support new customer projects, upgrades for reliability and power quality, and capacity-related expansions. Increasing DER adoption will continue to change the nature and type of distribution-related investments required to maintain a safe, reliable system, while also ensuring the flexibility, resilience and security of the system.

MAIN POINTS

- The distribution system is a key part of the energy grid backbone.
- PGE's asset management practices maximize the impact of investments for reliability and resilience and to meet changing customer expectations.
- The changing nature of the grid, including more DER adoption, will require changes in future investments.

7. PGE functionally treats its 57 kVA lines as sub-transmission.
8. Substation circuit breakers are equipped with disconnects, which open a circuit quickly in the event of an overload. For more distribution system asset definitions, see Appendix B, section B.3.1.

CHAPTER 2
DISTRIBUTION SYSTEM VISION

PGE's corporate vision, its intersection with policy and how that informs the distribution system vision is a critical component to our vision for the distribution system. As we lead the clean energy future together — with customers, partners and communities — we will lead with action.

In this chapter we describe our vision of a **21st century community-centered distribution system**, which is needed to take advantage of DERs and accelerate decarbonization and electrification. The system must provide direct benefits to communities (especially environmental justice communities), while improving metrics around safety, reliability, resilience and security — all at fair and reasonable costs. To achieve this vision, we describe five key strategic initiatives: **Empowered communities, modernized grid, resilience, plug and play, and evolved regulatory framework**. These initiatives help realize the vision and goals by aligning critical activities and address gaps in capabilities within the company while addressing market barriers for DER adoption.

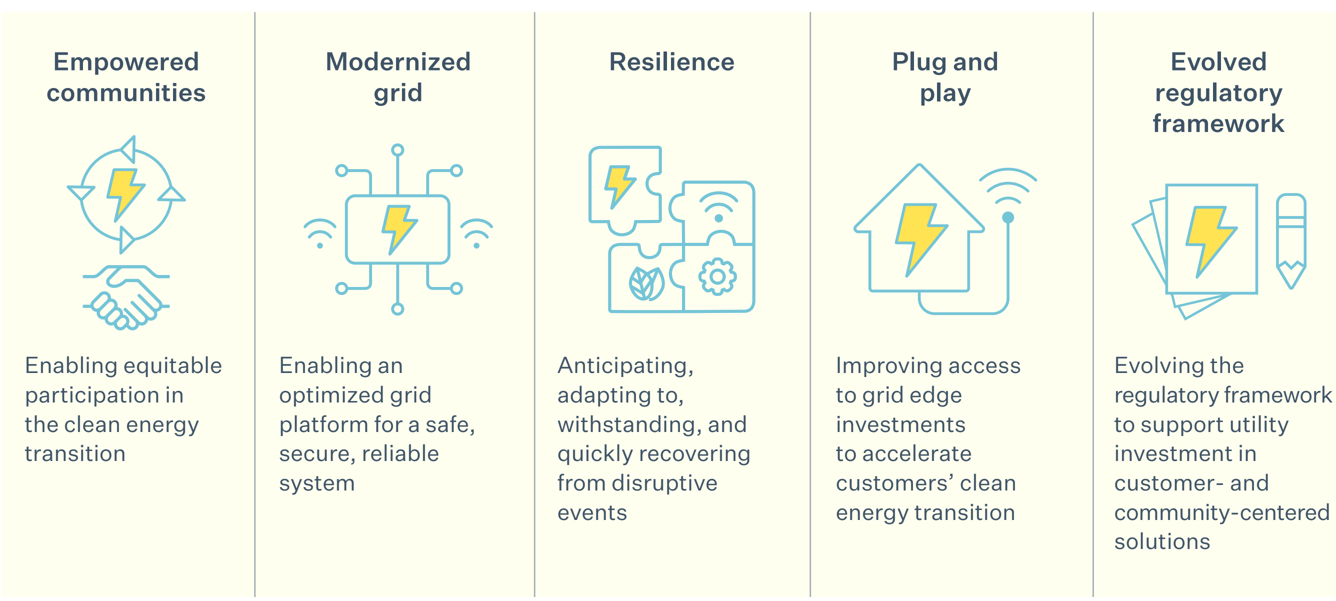
Our empowered communities initiative enables equitable participation in the clean energy transition through human-centered planning and community engagement. Our modernized grid initiative aims to enable an optimized grid platform that is safe, secure and reliable through current and future grid capabilities. The resilience initiative focuses on how we can strengthen the grid's ability to anticipate, adapt to, withstand and quickly recover from disruptive events. Our plug and play initiative discusses 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). Lastly, our evolved regulatory framework initiative speaks to the need to support utility investment in customer- and community-centered solutions.

Figure 3 illustrates these key strategic initiatives.

MAIN POINTS

- Federal and state clean energy policies are aligning the clean energy transition with social and environmental justice.
- PGE's vision for a 21st century community-centered distribution system is one that accelerates adoption of grid-integrated DERs while balancing grid, social and environmental justice goals.
- PGE has launched five strategic initiatives: Empowered communities, modernized grid, resilience, plug and play, and evolved regulatory framework.

Figure 3. PGE's five strategic initiatives



CHAPTER 3

EMPOWERED COMMUNITIES: EQUITABLE PARTICIPATION IN DISTRIBUTION DECISIONS

As an essential service provider, PGE must both engage and understand where and how customers live, work, learn and play. The work requires us to co-develop solutions with communities and develop solutions that deliver value to both them and the grid. We see it as imperative to pursue the twin goals of social justice, including racial equity, and decarbonization. These goals are needed to ensure that we address and redress disparities and impacts within the environmental justice communities PGE serves.

In this chapter, we outline the outreach and engagement done to date, including workshops for both traditional stakeholders as well the community workshops that were developed in partnership with, but delivered by, community-based organizations (CBOs). Additionally, the core tenets of environmental justice are introduced, as well as the Government Alliance on Race and Equity's (GARE's) racial equity toolkit that PGE is applying to this human-centered work.[9]

Finally, we have included our first Community Engagement Plan that is informed by recommendations and learnings that resulted from the community workshops and includes best practices provided by our CBO partners. This plan provides a framework for community engagement as well as planning strategies to inform the work we do in the second part of our DSP, as well as be a guide for how PGE intends to do community engagement more generally going forward.

There's much work to do, especially as new technologies — rooftop solar, battery storage, smart thermostats and electric vehicles — can amplify existing disparities in how we generate, access and conserve energy if not deployed strategically. The goal is not to just eliminate the disparities, but also to increase success for all groups.

Systems that are failing communities of color are failing all of us. Solving problems for everyone while paying special attention to communities suffering disproportionate burdens will increase our collective success. Societal inequities make it harder for some people to access energy-saving and clean energy programs, technologies and jobs. For everyone to benefit from a clean energy future, PGE must break through economic, cultural and linguistic barriers to give everyone a seat at the table when making decisions that define our path forward.

As we continue our work, we will focus on the equitable implementation of our DSP Action Plan that will be filed on August 15, 2022. The DSP will serve to support and complement the empowering communities pillar as well as other pillars, namely in improving community resilience and evolving the regulatory framework to provide flexibility in solutions that meet identified community needs.

MAIN POINTS

- We have learned that creating a collaborative environment requires building trust first.
- Designing programs and solutions with affected communities (instead of for them) produces better outcomes.
- We should collaborate and defer to our communities, where and whenever possible.
- PGE's Community Engagement Plan is informed by best practices, learnings and the recommendations of **Unite Oregon, Community Energy Project** and the **Coalition of Communities of Color** based on their engagement in the first phase of the DSP.

9. GARE's racial equity toolkit is available at: racialequityalliance.org

CHAPTER 4
MODERNIZED GRID: BUILDING A PLATFORM FOR PARTICIPATION

The modernized grid represents 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 to address the grid goals outlined in PGE's vision. However, modernizing the grid is a complex undertaking with large investments focused on augmenting and improving the electrical grid. PGE is aware of the impact of these investments on customer prices, especially on our must vulnerable communities, and takes a pragmatic, needs-based approach to balance the different goals and maximize customer and/or societal value of investments once in service.

In this chapter, we focus on informing PGE's modernized grid framework, the capabilities that underpin that framework, and PGE's roadmap at the capability level using the US Department of Energy's modernized distribution grid (DSPx) framework.[10] The chapter also details PGE's key planned investments and their expected evolution in the one- through five-year timeframe for each of the following capabilities.

- Virtual power plant
- Planning and engineering
- Grid management systems
- Sensing, measurement and control
- Telecommunications
- Physical grid

Grid modernization refers to the evolution of the grid through the integration of different technologies and computing solutions. This transformation has been underway for several years, with its scope evolving with time. Today, as we think about grid modernization on the operations side, we think both about operator awareness and also operator control, specifically focused on the interaction between DERs and the grid. On the planning side, planning needs have also evolved to focus on improving the ability to holistically interconnect DERs to deliver the maximum grid and community benefit. As more technologies and computation solutions mature, it is likely that the scope of grid modernization will continue to evolve as well.

We have adopted a platform-based architecture with modular elements as our approach to modernizing the grid. Certain capabilities of the platform remain relatively stable throughout the platform's evolution over time — these are known as core platform capabilities or foundational capabilities. Other capabilities and layers are complementary to these core capabilities and work in an integrated manner to deliver customer value. In other words, a modernized grid is equivalent to a platform with layers of digital capabilities upon layers of physical assets that work together in various combinations to improve and enable system capabilities. Over time, as different technologies mature, capabilities and layers can be added or replaced as needed.

MAIN POINTS

- A modernized grid is a platform that layers digital capabilities on a network of physical assets, all working together in various combinations to improve system capabilities.
- PGE has adopted the U.S. Department of Energy's modernized distribution grid (DSPx) framework.
- The evolving grid holds implications for workforce planning and cybersecurity.

10. DOE's DPSx is available at: gridarchitecture.pnnl.gov

CHAPTER 5
RESILIENCE: MANAGING DISRUPTIVE EVENTS

Resilience is top of mind for PGE as climate change and extreme weather present new challenges. In 2021, a once-in-40-years ice storm caused unprecedented power outages for approximately 740,000 customers, and the Bootleg wildfire interrupted Oregon's transmission of power to and from California. Our customers are feeling urgency to take action to prepare for the unexpected, as does PGE.

This chapter details the work of our Resilience Accelerated Response Coordination (Resilience ARC) initiative that focuses on improving our ability to meet customer and community expectations for resilient power delivery. Below are the three areas of focus for this initiative.

- **Customer infrastructure resilience** — Investigation into customer-sited solutions, such as microgrids, batteries and other DERs, that enable customers to ride through events and, during normal conditions, provide services to the grid.
- **PGE infrastructure resilience** — Investment in infrastructure, such as grid hardening, integrated grid and energy supply hardening, that mitigates the occurrence of outages during an event such as a wildfire or wind or ice storm.
- **Operational resilience** — Improvements in PGE's ability to meet customers' needs during events and accelerate the restoration of service through emergency preparedness, outage response and customer support.

Due to increasing levels of variable energy resources (e.g., solar and wind), we also are looking to develop solutions that offset those sources of energy.

Safety, reliability and resilience always have been core to our mission. Shifts in the climate as well as a shift toward electrification put a spotlight on the importance of resilience and resilience measures that are closer to the customer. We are using new technology and building new relationships with customers and municipalities. These investments not only enable a stronger, more resilient infrastructure, but also ties to our communities by enabling an accelerated, robust response to the challenges we face together.

MAIN POINTS

- Increasing fire and storm risk, coupled with increasing electrification, requires enhanced resilience measures.
- Our Resilience Accelerated Response Coordination (Resilience ARC) initiative will bring focus to resilience efforts.
- Investing in resilience measures that are closer to communities and customers is essential.

CHAPTER 6
PLUG AND PLAY: ENABLING DER ADOPTION

Growth in the adoption of DERs implies ease of access to and integration of those DERs into the distribution system. Our plug and play initiative focuses on enabling that access and integration — removing barriers and streamlining the interconnection process. Hosting capacity analysis (HCA) is a fundamental capability in a high-DER adoption, plug and play future.

PGE uses Electric Power Research Institute's (EPRI's) definition of hosting capacity.[11] According to EPRI:

Hosting capacity in a distribution system is the amount of DERs that can be accommodated without significant upgrades or adversely impacting power quality or reliability under existing feeder design and control configurations.

In this iteration of the DSP, our plan is focused on HCA as it relates to distributed generation (DG) and does not include consideration of DERs such as electric vehicles, as described in EPRI's definition. Flexible loads such as electric vehicles, hot-water heaters and behind-the-meter storage will be considered in future DSP submittals.

PGE's approach to HCA has been shaped by conversations with partners and communities and best practices gleaned from other utilities that have implemented HCA tools and methodologies. We conducted a series of feedback sessions with partners and communities and interviews with peer utilities to gain insight into lessons learned and the most effective approach to delivering value to partners.

In this chapter, we will discuss the common use cases for HCA, which include:

- Preliminary screening for DG proposals
- Guidance in the early phases of the interconnection process
- Enhancing distribution system visibility when determining locations for future DG

HCA may be utilized to identify the potential need for preliminary system upgrades in the early stages (e.g., scoping call, feasibility study) of the interconnection process. Although valuable in informing customer decisions, we do not support using HCA to replace any part of the interconnection process. Additional local studies will need to be performed to determine the viability of adding DG.

While our system modeling and remote sensing capabilities are maturing, we will use distribution system indicators to provide information to identify areas where DG can be accommodated. Moving beyond this level of HCA requires advancements in forecasting, system monitoring and system modeling. We will begin to see these advancements with the implementation of our advanced distribution management system (ADMS) in 2022.

Beginning in 2022, we plan to conduct HCA twice annually at the distribution feeder level. We anticipate that an ideal future state for HCA is:

- Accurate at the time and place of use
- Cost-effective
- User-friendly for both external and internal audiences

We anticipate that, as HCA matures and more datasets become available (e.g., energy burden, socioeconomic indicators, DER adoption), combining these data will enable us and our customers to identify and unlock the value of DERs. As we move toward a 21st century community-centered distribution system through our modernized grid framework and implement our Community Engagement Plan, integration of DERs should be seamless. The ability to seamlessly interconnect to the modernized grid is a key enabler to improved access to DERs, achieving a plug and play future.

MAIN POINTS

- PGE has enhanced its Net Metering map to include Distributed Generation Readiness information and demographic data from the US Census.
- Starting in late 2022, PGE will begin performing HCA twice annually.
- HCA updates should be performed at the line segment level on an as-needed basis rather than monthly or hourly.

11. Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State," EPRI, June 2016, is available at: epri.com

CHAPTER 7

EVOLVED REGULATORY FRAMEWORK: INCENTIVES THAT MOTIVATE EQUITABLE DER ENABLEMENT AND ADOPTION

With communities, partners, Staff and other utilities, we plan to identify regulatory and rulemaking opportunities needed for the safety and reliability of the system, as well as equitably supporting utility investment in customer- and community-centered solutions while keeping pace with the clean energy transition. This evolution aims to ensure the sustained success of this transition while minimizing the impact to those who are marginalized.

The Pacific Northwest's conception of the "smart grid" dates back to the 1990s when the Bonneville Power Administration issued a paper about the "energy web." In 2005, the OPUC began contemplating the benefits of a smart grid.[12] In response to the Energy Policy Act of 2005, PGE proposed in its 2006 Rate Case (UE 189) to make AMI investments. Several years later, that Commission, in Docket UM 1460, issued smart grid guidelines to inform subsequent Commission guidance on smart grid investment. The pace of investment is now accelerating, as is policy. We must match the pace of policy and technical evolution with targeted reform, guidance and new policy. The DSP identifies items to be raised for discussion and possible reform to advance the vision outlined by PGE, the policies and direction of the Commission, the governor and the legislature.

Throughout the UM 2005 proceeding, we noted intersections between the goals of the DSP and current policies, rules, standards and other regulations. In this chapter, we provide a detailed summary touching on policies at the federal level through FERC and the federal government to state policies through the legislature and the Commission. These policies provide a view of the regulatory drivers for change. We then complement this information by identifying downstream regulation that can align with these policies to enable the vision of the DSP. Below are the categories of regulation we focused on in this DSP.

- New regulation that can accelerate DER adoption and our ability to leverage their value
- Current regulation that is inconsistent with policy drivers and thus can act as barriers for us to leverage DERs and their value
- Ongoing updates to policies, rules, standards and other regulations and their relationship with the DSP.

While these regulations impact the DSP, we do not believe the DSP is the appropriate avenue to discuss all of them. While some can be discussed in the DSP, other regulatory recommendations are more suited to their respective dockets, General Rate Cases or other plans.

MAIN POINTS

- PGE has identified an initial set of regulations that can help accelerate DER adoption and PGE's ability to leverage DER value.
- PGE has categorized regulation that can accelerate DER into:
  - New regulation
  - Current regulations
  - Ongoing updates to regulation

12. OPUC Docket UM 1020, Order 05-878 where the Commission considered the advantages of dynamic rates made possible through smart grid technologies such as Advanced Metering Infrastructure

CHAPTER 8
PLAN FOR PART 2 DEVELOPMENT

In the DSP guidelines, the Commission requires PGE to provide a high-level summary of our preparation for Part 2 of the DSP, focusing on planning evolution and interaction with our Integrated Resource Plan (IRP).

In this chapter, we focus on planning practice updates related to DER forecasting and potential non-wires solutions (NWS) and efforts to synchronize IRP activities with requirements of Part 2 of the DSP. Continuously working on advancing DER modeling tools, we recently built a DER forecasting and potential assessment modeling tool, AdopDER. This will increase transparency of the modeling approach (inputs, outputs, algorithms), capture broad resource parameters and key assumptions, advance understanding of flexible load potential needed to achieve a range of grid services, and integrate DERs into the IRP.

As we explore how NWS can replace, defer or be combined with traditional transmission and distribution solutions, this will present an opportunity for us to test new processes, analysis and tools from a planning perspective. Improving our planning capabilities is a critical step in enabling and leveraging DERs for different use cases such as NWS, improved asset utilization and providing community benefits.

MAIN POINTS

- PGE is planning the next steps for DER forecasting and non-wires solutions.
- PGE presents considerations for alignment of the DSP with the IRP.

Chapter 1.

Distribution system overview

Chapter 1. Distribution system overview

> "A transition to clean energy is about making an investment in our future."
>
> — **Gloria Reuben**, environmental activist and a special advisor to The Alliance for Climate Protection

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 (EJ) communities communities.[13] It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter describes our current system assessment and planning processes and provides baseline data for distribution system assets, historical investments and DER penetration. It also provides context about the distribution system's function in relation to the overall grid. **Table 1** illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP guidelines under Docket UM 2005, Order 20-485.[14]

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A: DSP plan guidelines compliance checklist**.

WHAT WE WILL COVER IN THIS CHAPTER

The key components of the electric grid and distribution system

How the grid is changing and why distribution system planning matters

An overview of PGE's distribution system, assets and planning approach

How PGE makes capital investments in our distribution system

The types of distributed energy resources (DERs) joining the grid and the value they offer

13. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at: oregonlegislature.gov
14. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, and is available at: puc.state.or.us

Table 1. Distribution system overview: Guideline mapping

DSP guidelines	Chapter section
4.1.a	Section 1.2, 1.3
4.1.b	Section 1.3
4.1.c.i	Section 1.3
4.1.c.ii	Section 1.3
4.1.e	Section 1.4
4.1.f	Section 1.5.1
4.1.g	Section 1.5.3
4.1.i	Section 1.5.4
4.1.j	Section 1.5.4
4.1.l	Section 1.5.2
4.4.b.i.3	Section 1.5
4.4.b.i.4	Section 1.5

1.2 Introduction

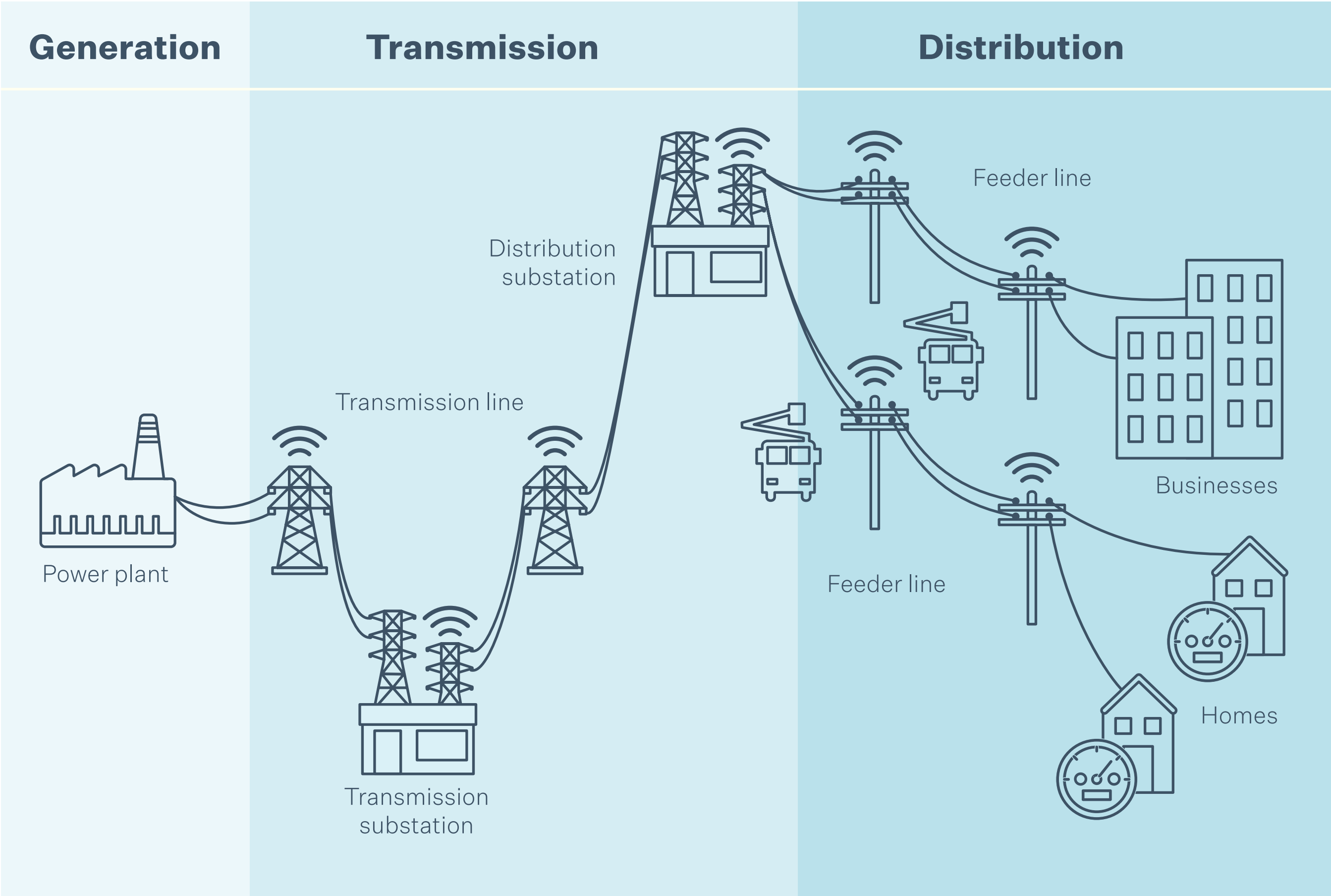
Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to foster transparency and to include an overview of baseline assessments of their distribution system as part of their DSP. This includes an asset inventory, management and monitoring practices, recent investments and DER penetration at the time of filing.

Our inaugural DSP is the first effort in an evolving, multi-stage process. PGE anticipates that the forming, filing and accepting of the initial plans will educate all parties and identify areas for continuous improvement. We expect the evolution from the Order 20-485 guidelines to more advanced stages may change how the distribution system is defined, how investments are made and even how investment costs are recovered.

1.2.1 WHAT IS THE ELECTRIC GRID?

The electric grid's primary purpose is to deliver power to end users. **Figure 4** illustrates a simplified grid network comprised of three main components: generation, transmission and distribution.

Figure 4. The electric grid



System operators must balance the competing demands of the grid using available resources while ensuring the reliable delivery of power within a specified range of voltage and frequency. The functions of the three main grid components are:

- **Generation**: Power plants generate energy from various sources, like hydro or wind. Our energy generation is located both on our system and outside our service territory.
- **Transmission**: Electricity is transported at a high voltage from the large generation resources, which are often centrally located, to the distribution system. Generation is connected to generation step-up transformers. Transmission lines and substations are then used for the transmission of power to distribution substations, where energy voltage is stepped down for safety reasons.
- **Distribution**: Distribution delivers power from transmission to the customer. Transmission lines are connected at a distribution substation, where voltage is stepped down to safer levels for transfer to homes and businesses. Our two most common voltages directly serving customers are 35 kV and 13 kV, which serve industrial, residential and commercial customers across our service territory.

1.2.2 WHAT IS A DISTRIBUTION SYSTEM?

For the purposes of meeting the intent of the DSP guidelines, namely providing understanding and transparency into how PGE plans for and operates its distribution system, PGE defines the distribution system as follows:

1.2.2.1 Engineering definition

The distribution system is defined as load-serving, PGE-owned equipment and lines at nominal voltage levels below 35 kV.[15] The distribution system starts at the circuit breaker and high-side disconnect of the substation distribution transformer.[16]

Throughout this filing, we use the engineering definition of the distribution system as beginning at the high-side disconnect of the substation distribution transformer, and comprising any load-serving, PGE-owned equipment and lines at nominal voltage levels at or below 35 kV, unless otherwise noted.[17]

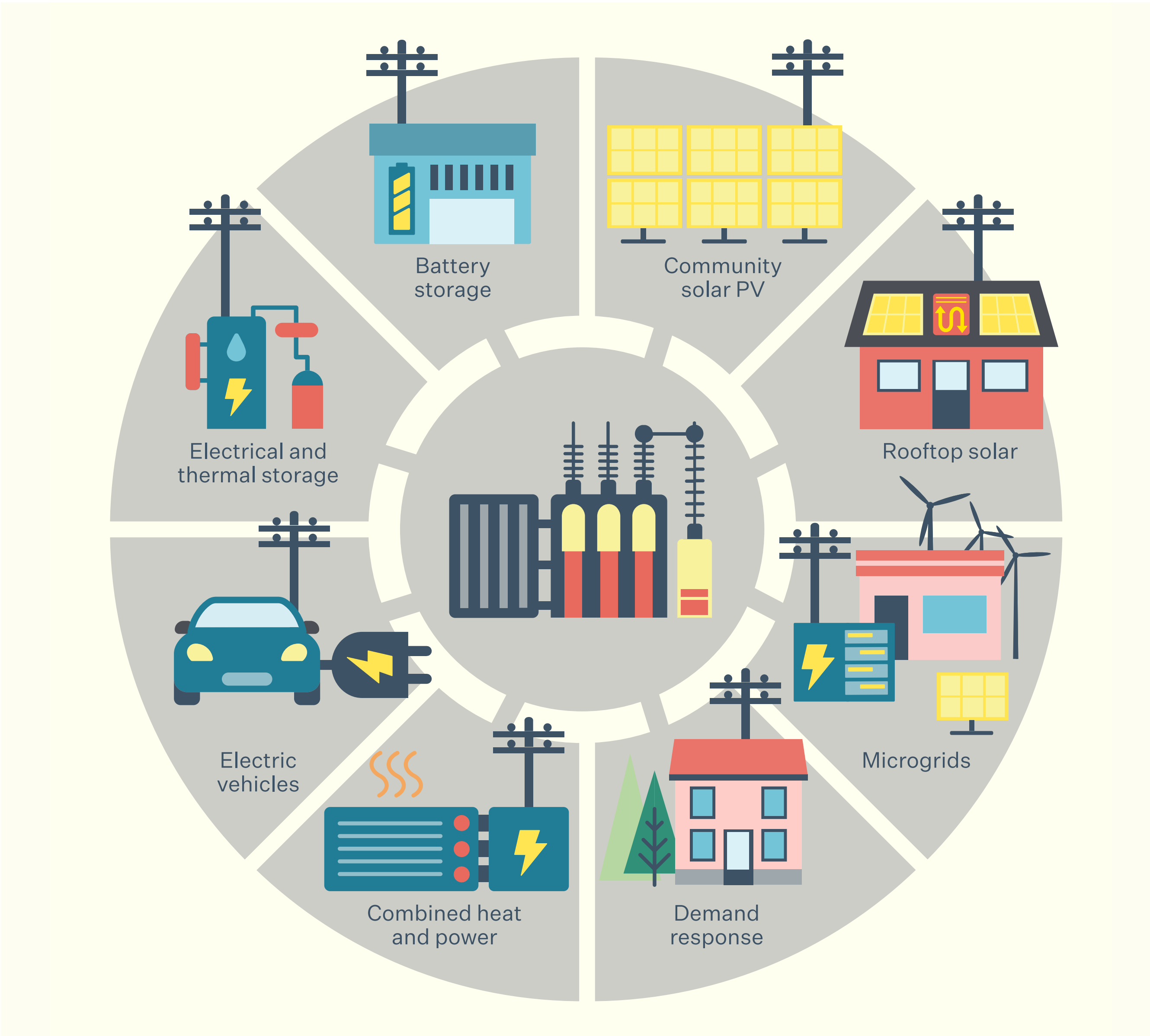
1.2.3 WHAT IS DISTRIBUTION SYSTEM PLANNING?

Distribution system planning is the process of analyzing the distribution grid to ensure it is capable of serving existing and future load (power demand) under normal operating conditions and in the face of contingencies, such as failure of a component. This process is vital, allowing us to ensure reliable, safe and affordable power for our customers. Historically, the primary planning concerns have been around managing current and future peak loads under one-way power flow, as shown in **Figure 4**.

These objectives are changing as technologies, policies and our capabilities continue to evolve. The grid has become more nuanced and requires more considerations in planning. **Figure 5** shows the dynamic, two-way nature of the modern distribution grid.

15. PGE functionally treats its 57 kVA lines as sub-transmission.
16. Substation circuit breakers are equipped with disconnects, which open a circuit quickly in the event of an overload. For more distribution system asset definitions, see Appendix B, section B.3.1.
17. Alternative categorizations of discrete transmission and distribution (T&D) system elements may be applicable depending on the stated purpose. The above definition was deemed most suitable for the DSP filing based on the stated policy goals of UM 2005 and associated guidelines. For more information on alternative T&D classifications, see OPUC Order 19-400, available at: puc.state.or.us

Figure 5. Examples of distributed energy resources connected to the distribution grid



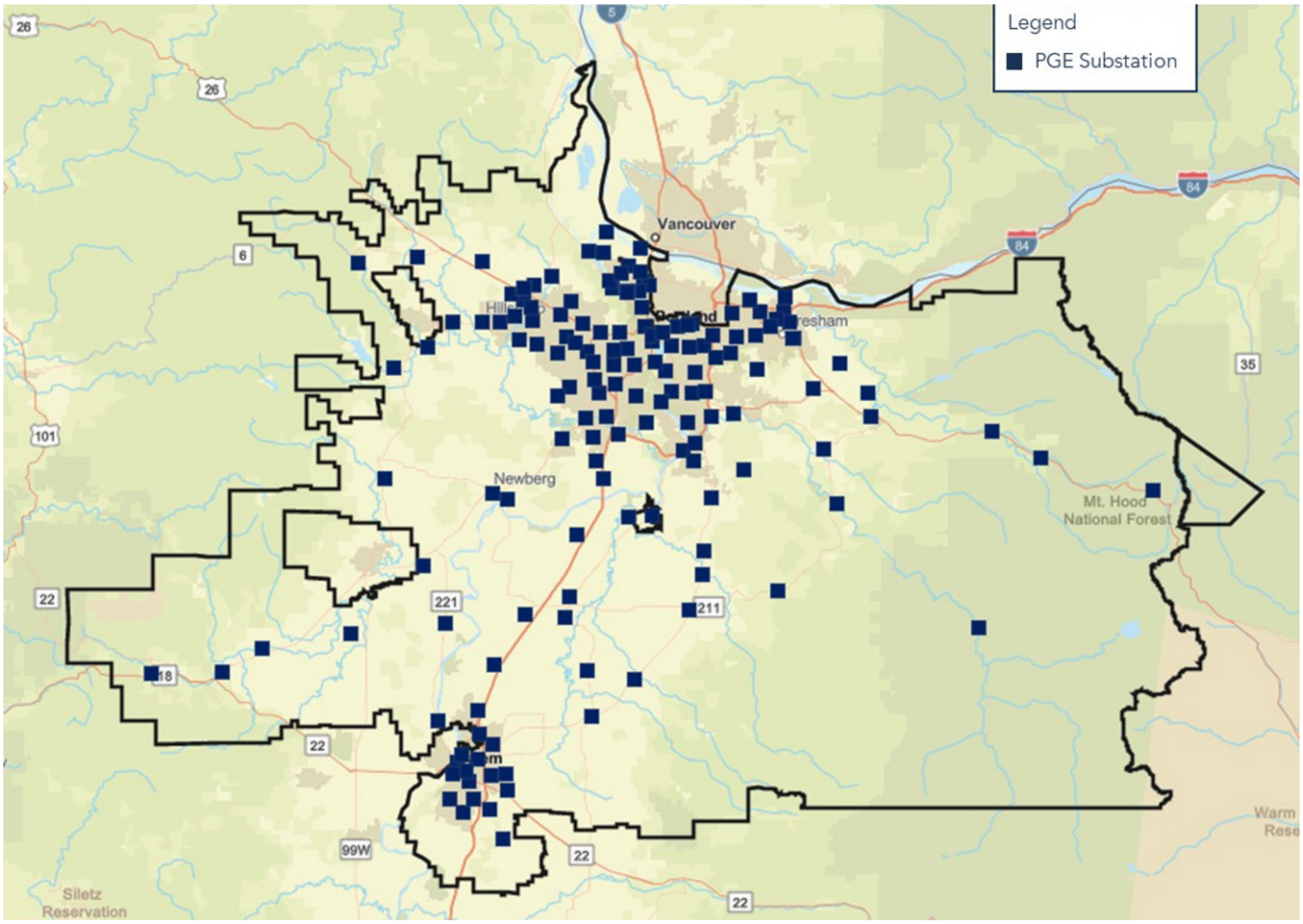
This brief timeline shows how technology has impacted distribution system planning:

- Historically, the distribution system has been optimized for one-way flow with a relatively low granularity and visibility of the system's real-time state.
- Over the last 10-15 years, more advanced and lower-cost sensor and control technologies have increased the level of detail received about the distribution system. This has enabled new functionalities that lead to improvements such as reduced outage response times. System planners can also improve the accuracy of forward-looking studies, facilitating better decision-making.
- In the last 5-10 years, technology improvements and lower-cost DERs have expanded the amount of clean energy resources on the grid. Utilities have taken several steps to accommodate this growth, including improving protection at substations.
- Today, with new digital capabilities that can optimize DERs, we are entering a new age in which planning can help the distribution system accelerate decarbonization, provide community benefits and more. The future state of the distribution system is discussed further in **Chapter 2** and **Chapter 4**.

1.3 System baseline and assessment practices at PGE

PGE serves a population of 1.9 million people, representing about 900,000 customers over 4,000 square miles. Our distribution system is composed of 153 distribution substations, 270 distribution power transformers and 695 distribution feeders (**Figure 6**).

Figure 6. PGE's service area



The safe operation of the distribution grid requires continuous tracking, assessment and maintenance of all the various pieces of electrical equipment dispersed across the network. We implement strategic asset management to ensure we are adequately addressing cost and risk considerations across our portfolio when making investment decisions. This requires maintaining a risk assessment model that combines asset-specific information (such as equipment age, nameplate and emergency ratings and average load) with expected consequences (e.g., customer costs) resulting from service interruptions.

Poles are physically inspected through PGE's Facilities Inspection and Treatment to National Electrical Safety code (FITNES). Oregon Admin Rule 860-024-0011 requires a detailed visual inspection as well as wood utility pole testing and treating.[18] It works on a 10-year cycle and covers 10% of PGE's system per year. The rule recommends a pole be replaced if the inspection finds that insufficient pole strength or pole height exists (Note: Pole age varies depending on wood product quality).

18. Oregon Admin Rule 860-024-001, available at: oregon.public.law

We classify our distribution assets into 13 categories. **Table 2** shows the average age and average service life of each asset category. Definitions of each category and further details about asset age ranges can be found in **Appendix B, Section B.3.1**.

Table 2. Summary of distribution assets as of Q1 2021

Asset classes	Number of assets	Average age of assets[1]	Average service life[2]
Substation structures	N/A	N/A	65
Substation transformers	407	38	55
Circuit breakers	1,617	21	55
Other substation equipment	9,967	30	65
Distribution poles	203,615	41	48
Overhead transformers	108,500	29	50
Reclosers and sectionalizers	422	8	50
Voltage regulators	55	9	50
Capacitor banks	689	27	50
Other open hole (OH) conductor devices	175,492	21	48
Underground (UG) transformers	71,153	28	55
UG conduit	243,273	12	80
Other UG conductor devices	3,411	19	55

1. Average age is the actual average age of all in-service assets within each group as of Q1 2021.
2. Average service life is derived from a five-year depreciation study and used for cost-recovery purposes.

In addition to monitoring asset health and conditions, we maintain detailed network models of the distribution grid in CYME (our power flow modeling software) that factor into nearly all aspects of system planning. Our distribution planning engineering team uses these models to support the following key functions:

- To perform system analysis and develop plans that ensure the distribution system will be operable and maintain functionality and flexibility in both the near and long term (5-10 years)
- To provide support and guidance on distribution-related investment decisions
- To support grid modernization plans

When conducting distribution system planning, we look at how we will meet customer needs, enhance safety, increase reliability, meet new standards and requirements and reduce risk. We also optimize the configuration of the distribution system to improve customer experiences and reliability.

1.3.1 DISTRIBUTION SYSTEM PLANNING DRIVERS

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. DERs are newer drivers, and different DERs have different impacts. For example, electric vehicle charging is an intermittent load addition, photovoltaic installations provide distributed generation and flexible loads offer opportunities for capacity relief by shifting energy use to more optimal times of day.

At PGE, we see the distribution grid as an evolving system at different stages of modernization. By proactively responding to the changes in the communities we serve, we can advance and improve distribution operations and customer service. For example, we work hand in hand with our business development team by providing them with up-to-date information on our current system capacity to serve potential new customers. When a potential customer becomes an actual customer by signing a service agreement, we anticipate their future energy growth needs by incorporating their home or business into our load growth forecast and exploring whether upgrades to the system are needed.

1.3.2 PGE DISTRIBUTION LOAD GROWTH FORECASTING METHODOLOGY

For load forecasting purposes, PGE's distribution system is evaluated for a 1-in-3 peak load condition during the summer and winter seasons for near-term (years 1 through 5) and longer-term (years 6 through 10) studies. The 1-in-3 peak system load is calculated based on weather conditions that PGE can anticipate experiencing once every three years. The summer (June 1 through October 31) and winter (November 1 through March 31) load seasons are considered the most critical study seasons due to heavier peak loads and high-power transfers over PGE's transmission and distribution system to its customers.

PGE calculates the seasonal peak load forecasts for each distribution power transformer via an in-house program using a "top-down" approach for predicting loads for each of our 270 distribution power transformers. Inputs to this forecasting tool include:

- Our corporate forecast for 1-in-3 peak summer and winter loading
- Historical loading information (most recent five-year period) for each distribution power transformer
- Compensated power factor (PF) for each distribution power transformer during the designated peak period

This program factors in historical load growth and "bottom-up" known load additions to scale forecasted, individual, distribution power transformer loading to the aggregate load level provided by our corporate forecast. It also factors in internal and external losses and uses scaling factors to approximate non-coincidental loading that is provided in historical loading information. Outputs from the program include:

- Peak annual seasonal megawatt (MW) and megavolt-amp reactive (MVAR) output for each distribution power transformer for each year of the forecast horizon
- Peak annual seasonal megavolt amp (MVA) and PF for each distribution power transformer for each year of the forecast horizon

When a feeder or substation power transformer is forecasted to increase beyond its planning design criteria, we continue to monitor the loads and may conduct a detailed planning study to inform investments on needed system upgrades. See **Appendix B** for details on the planning design criteria for specific distribution assets, as well as an overview of our modeling approach using CYME. We now turn to a summary of recent capital investments made on the distribution system.

1.4 Distribution system historical capital investments

Our electric grid is the mechanism by which we bring our customers safe, reliable, affordable energy, and the distribution system is a significant part of it. In one form or another, the investments described in this section allow us to maintain a reliable distribution infrastructure and keep outages low. For details about system reliability key performance metrics and outages, see **Appendix B**.

Budgeting and investing are done for our distribution system on a yearly basis. **Table 3** shows our historical spend on the distribution system for the last five years for the categories outlined in the guidelines (defined below), as well as average budgeted amount in the same period.

- **New customer projects** are new connects, minimum load agreements (MLAs) tied to specific customer base and interconnections. These cover any customer coming online with a contract agreement.
- **Age-related replacements and asset renewals** are like-for-like replacements due to age or reactive failure.
- **System expansion or upgrades for reliability and power quality** are proactive upgrades to improve reliability and reduce risk. Examples include our distribution protection unit (DPU) relay replacement program, tree wire program (installs insulation on overhead wires to reduce outages), underground cable replacements and substation upgrades. These projects aim to reduce outages and improve the customer experience.
- **System expansion or upgrades for capacity** are driven by load growth per our Distribution Planning Department's load forecast.
- **Metering** involves meter installs and purchases to enhance metering capabilities for our customers.
- **Preventative maintenance** is operation and maintenance (O&M) spending to ensure grid components are up to standards and operating efficiently.
- **Grid modernization projects** involve new technologies such as energy storage, distribution automation, communications via field area network (FAN) or multi-protocol label switching (MPLS), and software, such as advanced distribution management system (ADMS) platforms, to modernize the grid.

Table 3. Distribution of yearly spending by expenditure category[19]

Spending category	Yearly spending (million USD) 2016	2017	2018	2019	2020	Budget average 2016-2020
New customer projects	$49	$84	$86	$87	$86	$78
Age-related replacements and asset renewal	$50	$52	$60	$86	$175	$85
System expansion or upgrades for reliability and power quality	$39	$51	$76	$122	$84	$74
System expansion or upgrades for capacity	$32	$67	$82	$37	$30	$50
Metering	$9	$7	$7	$12	$9	$9
Preventive maintenance	$0.4	$4	$8	$5	$2	$4
Grid modernization projects	$0.01	$2	$3	$4	$5	$3
Total	**$180**	**$268**	**$322**	**$352**	**$390**	**$302**

As discussed throughout this chapter, the distribution system is facing tremendous change as a result of evolving customer demands and advancing DER technologies. In the next section, we provide a summary of current DER adoption as laid out in the baseline requirements section of the guidelines. In **Chapter 2**, we discuss how forecasted growth in DERs is driving the need for continued investments in the distribution grid.

19. Totals may not add up due to rounding.
The investment figures presented in Table 3 reflect the stipulation reached by parties and reflected in Order 19-400, available at: apps.puc.state.or.us
PGE may revisit this definition in future DSP filings.
A. Radial lines both to distribution and to customers tend to be classified as distribution.
B. Radial generation tie facilities tend to be classified as transmission for accounting purposes, but should be classified as production for ratemaking purposes.
C. Non-radial line segments of 100 kV or higher voltage tend to be classified as transmission.
D. Transformers with a secondary voltage under 100 kV tend to be classified as distribution.
E. Substation assets (e.g., circuit breakers) that are part of the path that connects the transmission line segments, or equipment associated with transformers with a secondary voltage higher than 100 kV, are classified as transmission.

1.5 DERs currently integrated in PGE's distribution system

Understanding how many DERs are connected to our system is foundational to understanding the associated challenges and opportunities. For the purposes of the UM 2005 guidelines, "distributed energy resource" includes the following resources that are connected to the distribution power grid:

- Distributed generation resources, either net metering (NM) or qualifying facilities (QFs) connected to distribution[20]
- Distributed energy storage
- Demand response
- Energy efficiency programs
- Electric vehicles

The following sections provide a brief introduction to each DER type and a summary of how many DERs are currently connected to our distribution system.

1.5.1 NET METERING AND DISTRIBUTED GENERATION

For customers who install their own renewable generation sources, net metering rules allow for the flow of electricity both to and from the customer — typically through a single, bi-directional meter. When a customer's on-site generation exceeds their individual use, electricity flows back to the grid, generating bill credits that can be used to offset electricity consumed by the customer at a different time during the same 12-month period. In effect, the customer uses excess generation to offset electricity that they otherwise would have to purchase from the utility.[21]

QFs can encompass both large-scale, transmission-connected generators and smaller facilities connected to the distribution system. Based on the final DSP guidelines, the following information for QFs pertains only to those connected to the distribution system.

1.5.1.1 In-service facilities

In-service facilities are integrated with the grid and producing energy. **Table 4** shows that net metering facilities in our territory as of September 2021 have the capacity to produce close to 126 MW, and that approximately 96% of that capacity comes from rooftop solar facilities.

Table 4. In-service net metering facilities by generator type, number and capacity

In-service net metering facilities				
	Generator		Capacity	
Generator type	Number	Percent of total	kW	Percent of total[22]
Solar	13,454	99.59%	121,170	96.28%
Methane gas	4	0.03%	3,801	3.02%
Wind	40	0.30%	650	0.52%
Hydro	6	0.04%	185	0.15%
Solar + wind	2	0.01%	22	0.02%
Fuel cell	3	0.02%	21	0.02%
Total	**13,509**	**100%**	**125,848**	**100%**

20. Qualified facilities (QFs) fall into two categories: qualifying small power production facilities and qualifying cogeneration facilities. QFs are reported on annual bases in the Annual Small Generator report found in Appendix D.
21. Oregon's net metering rules can be found in OAR 860-039-0010 through 860-039-0080, available at: secure.sos.state.or.us
22. Totals may not add up due to rounding.

We currently have 54 in-service QFs with an estimated nameplate capacity of 118 MW (**Table 5**).

Table 5. In-service qualifying facilities by generator type, number and capacity

In-service qualifying facilities				
Generator type	**Generator**		**Capacity**	
	Number	**Percent of total**	**kW**	**Percent of total**[23]
Solar	51	94%	117,921	99.85%
Diesel	2	4%	175	0.15%
Storage only	1	2%	1.20	0.001%
Total	**54**	**100%**	**118,097**	**100%**

1.5.1.2 In-queue facilities

In-queue facilities have applied to be permitted to integrate with the grid and are not producing power yet. **Table 6** and **Table 7** show the number of in-queue net-metering and QF applications as of September 2021.

We have created an electronic map showing all in-service and in-queue distributed generation summarized by feeder, available on our DSP website.[24]

Table 6. In-queue net metering facilities by generator type, number and capacity (September 2021)

In-service net metering facilities				
Generator type	**Generator**		**Capacity**	
	Number	**Percent of total**	**kW**	**Percent of total**[25]
Solar	1,698	99.71%	33,911	94.82%
Methane gas	2	0.12%	1,833	5.13%
Storage	3	0.18%	21	0.06%
Total	**1,703**	**100%**	**35,765**	**100%**

Table 7. In-queue qualifying facilities by generator type, number and capacity (September 2021)

In-queue qualifying facilities				
Generator type	**Generator**		**Capacity**	
	Number	**Percent of total**	**kW**	**Percent of total**[26]
Solar	37	97%	82,965	98%
Storage only	1	3%	1830	2%
Total	**38**	**100%**	**84,795**	**100%**

23. Totals may not add up due to rounding.
24. PGE map is available at: arcgis.com
25. Totals may not add up due to rounding.
26. Totals may not add up due to rounding.

1.5.2 DEMAND RESPONSE

In June 2021, the Commission accepted PGE's Flexible Load Plan, which laid out a holistic vision for how we plan to accelerate flexible load development through streamlined budget planning and improvements to cost-effectiveness and greater integration with our system operations.[27] As we continue to build on the transparency provided in our Flexible Load Plan, we will work with participants to ensure the appropriate level of information is being shared between Flexible Load Plan activity and DSP filings.

In 2020, we had successfully enrolled 63 MW of available summer demand response (DR) capacity and 39 MW of available winter DR capacity. **Table 8** and **Table 9** provide historic achievements of our DR pilots by customer segment, as of the end of 2020. More detail about each product offering, as well as future plans, are available in the Flexible Load Plan.[28]

Table 8. Number of customers participating in demand response (2016-2020)

	2016	2017	2018	2019	2020
Residential	16,409	16,370	26,552	107,876	116,835
Business	42	18	43	95	509
Total	**16,467**	**16,388**	**26,595**	**107,971**	**117,344**

Table 9. Demand response capacity by season (2016-2020)

2016		2016	2017	2018	2019	2020
Maximum available capacity of DR (MW)	Residential	1.4	0.5	5.3	17.1	17.9
	Business	14.9	3.0	15.2	18.6	21
	Total	**16.3**	**3.5**	**20.5**	**35.7**	**38.6**
PGE's Season Peak (MW)		3,716	3,727	3,399	3,422	3,330
Available capacity of DR (percent of season system peak)		0.44%	0.10%	0.60%	1.04%	1.16%
Winter						
Maximum available capacity of DR (MW)	Residential	5.8	4.5	13.0	32.3	39.0
	Business	12.9	3.0	15.2	20.6	23.7
	Total	**18.7**	**7.5**	**28.2**	**52.9**	**62.7**
PGE's Season Peak (MW)		3,726	3,976	3,816	3,764	3,771
Available capacity of DR (percent of season system peak)		0.50%	0.19%	0.74%	1.41%	1.66%
Summer						

27. Order No. 21-158 is available at: apps.puc.state.or.us
28. PGE Flexible Load Plan is available at: edocs.puc.state.or.us

1.5.3 ELECTRIC VEHICLES (EVS)

EV growth is accelerating around the country, and Oregon is a leader in the space. State policies and supporting legislation are driving this adoption, and with increasing EV model availability, this trend is projected to continue accelerating as more diverse segments of the vehicle consumer market have viable EV options from which to choose.

At the same time, EV range has increased dramatically with improvements in battery technologies and overall EV efficiency. The median range of an EV in 2011 was 68 miles, while for model year 2020 EVs, the median range was 259 miles with the top models surpassing 400 miles of maximum range.[29]

The Oregon Department of Energy has launched an EV dashboard that provides an easy way to track electric vehicle adoption by powertrain (battery electric vehicle or plug-in hybrid) and can easily be filtered by county or utility provider.

At the time of this filing, the number of EVs in our service area as reported by the Oregon Electric Vehicle Dashboard was 19,545.[30] **Table 10** shows the number of EVs added to our service area over the last five years.

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Table 10. Electric vehicle (EV) growth in PGE service area by powertrain (additional EVs by year)

EV powertrain	2016	2017	2018	2019	2020[31]
Battery electric vehicle (BEV)	900	1,189	2,307	3,634	3,729
Plug-in hybrid electrical vehicle (PHEV)	636	873	1,379	1,344	1,230
Total EVs	**1,536**	**2,062**	**3,686**	**4,978**	**4,959**

We performed additional analysis on the existing vehicle stock, both EVs and internal combustion engine (ICE) vehicles, to inform the DER and Flexible Load Study for our upcoming Integrated Resource Planning. **Table 11** shows all vehicles by weight class and fuel type in our service area as of the fourth quarter of 2020.

Table 11. Existing vehicle summary in PGE service area by vehicle class and powertrain

Vehicle class	Total vehicles	Percent of total
Light-duty vehicles	1,552,891	87%
Medium-duty vehicles	215,743	12%
Heavy-duty vehicles	13,102	1%
Total	**1,781,736**	**100%**

We used the fuel type, vehicle weight class and vehicle model year information from our analysis to inform our stock turnover model, which captures the changing nature of vehicle ownership over time as older models are retired and more EVs are introduced into the service area. We will present the results of this work and a description of how the EV stock is forecasted to change over time in Part 2 of our DSP filing (**Appendix G**).

29. Source: US Department of Energy. energy.gov
30. Source: oregon.gov
31. In 2020 there was a pandemic-related slowdown.

1.5.4 CHARGING STATIONS

In our 2019 Transportation Electrification Plan, we highlighted the role that public charging infrastructure plays in accelerating transportation electrification.[32] While currently many EV drivers prefer to charge at home, as more and more drivers adopt EVs there will be a growing need to provide quick and convenient access to public charging. This is especially true of EV drivers who may face hurdles to home charging, such as renters or those without a garage or driveway.

We have since updated our tracking of charging infrastructure installed in our service area. We have also gained new insights into charging station usage patterns and information about newly launched PGE initiatives.

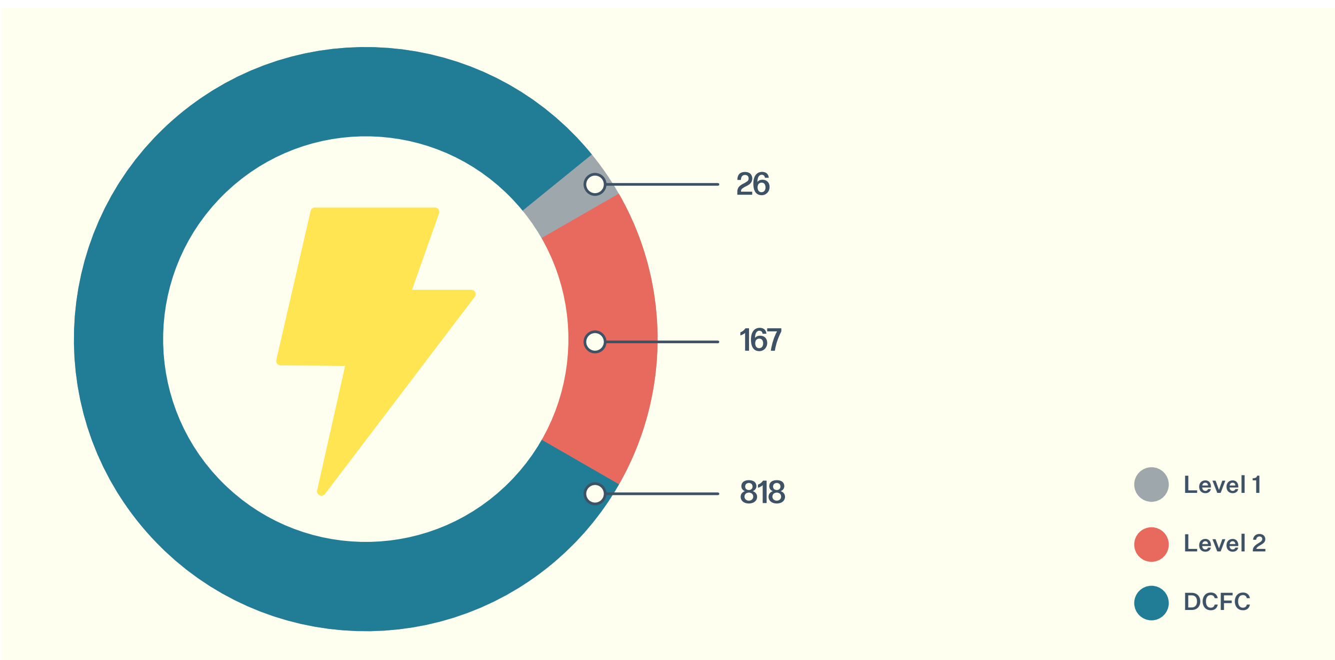
1.5.4.1 Charging stations in our territory

Nationwide, there are several efforts to collect and disseminate data on the availability of charging stations to support EV drivers (e.g., PlugShare, Electrify America and the U.S. Department of Energy [DOE] Alternative Fuels Data Center). As useful as these sources are, each are bound to be incomplete as a standalone source because of the decentralized nature of infrastructure development in both public and private locations across the grid.

For this reason, we decided to rely on the U.S. DOE Alternative Fuels Data Center (AFDC) as a single, trusted external source that we supplement with existing information about our network of EV chargers.[33] We will continue to evaluate the landscape of EV charging databases available in the industry and may modify this decision if more resources become available.

Figure 7 and **Figure 8** summarize the existing charging stations in our service area by charging speed, network type and accessibility. **Figure 9** summarizes the charging stations added to PGE service area by year and type.[34]

Figure 7. Electric vehicle supply equipment (EVSE) counts in PGE service area



Direct Current Fast Charge (DCFC)

32. PGE Transportation Electrification Plan, September 2019, is available at: edocs.puc.state.or.us
33. U.S. DOE AFDC is available at: afdc.energy.gov
34. The U.S. DOE AFDC dataset has many gaps in the installation year, making it difficult to compare the historical trend of EVSE installation by type with the present snapshot presented in Figure 9.

Figure 8. Charging stations by ownership and type

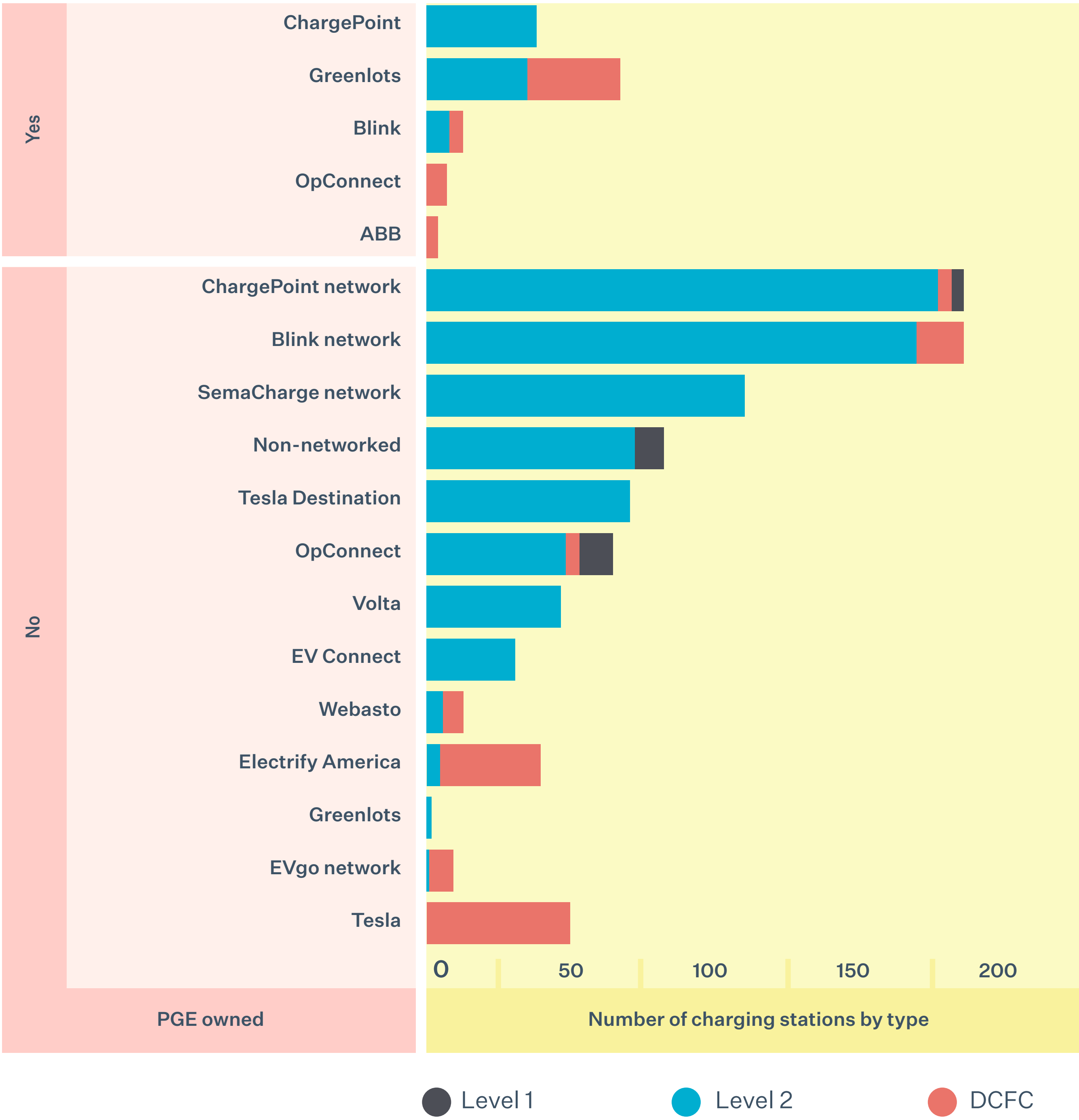
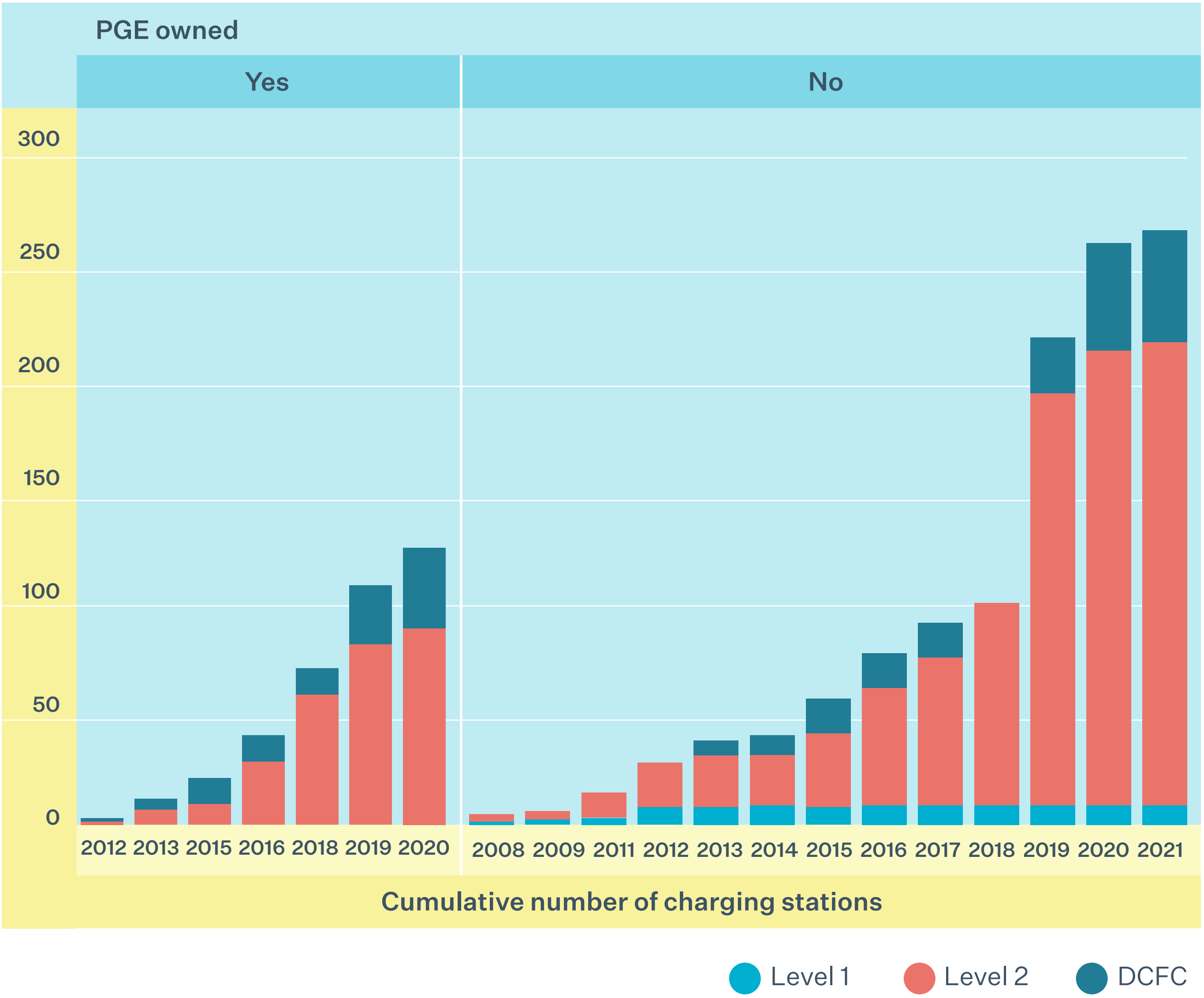


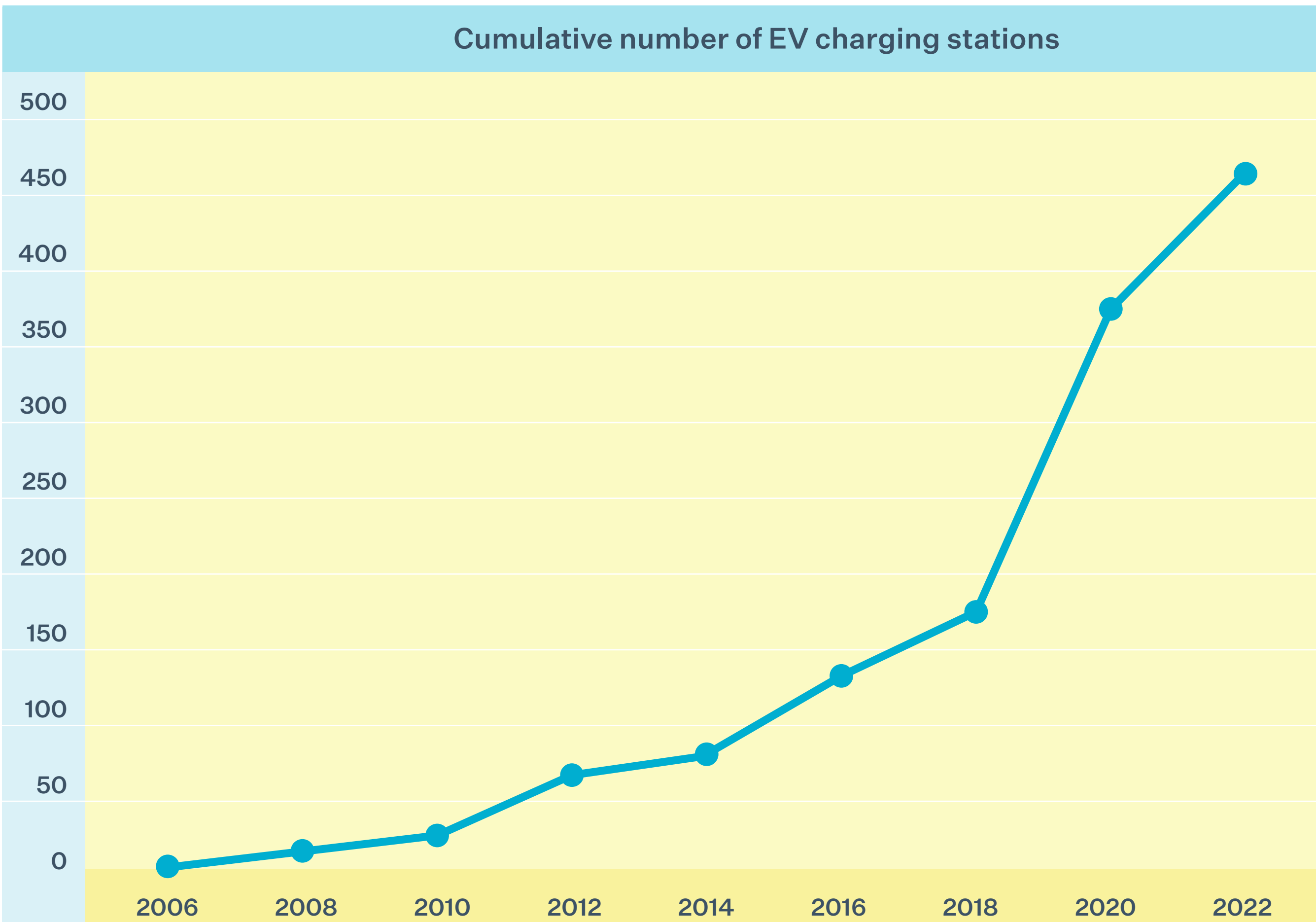
Figure 9. Cumulative number of charging stations by ownership and type



We gathered data on the year charging stations went into service ("in-service year") from the AFDC database and combined this with data on PGE-owned sites. **Figure 10** shows the number of charging stations added by year.[35] One caveat is that many of the entries in the AFDC are missing an in-service year and are therefore not pictured in the chart. We are investigating other data sources to supplement this figure and will update as more information is available.

For additional details on our transportation electrification activities, including usage patterns of charging stations, see **Appendix B**.

Figure 10. Historical growth of EV charging stations in our territory



35. Source: AFDC dataset and PGE internal analysis. AFDC data regarding installation is incomplete and those sites are not reflected in this chart.

1.5.5 RESILIENCE ENERGY STORAGE/ MICROGRIDS

We are developing five energy storage projects totaling 30 MW/102 MWh, including two microgrids at critical facilities, across multiple end-use applications.[36] These projects are providing early insights for how to successfully develop and execute on these technically challenging projects. The following sections provide more detail about residential and commercial mass market products and how they might be used for increased resiliency of the distribution system.

1.5.5.1 Residential storage

Our Residential and Energy Storage Product Management team is responsible for our residential Smart Battery Pilot.[37] Since its launch, the pilot has been helping customers afford whole-home back-up power through on-bill rewards, plus up-front incentives for select customers. In turn, PGE may dispatch the batteries for grid services. This not only increases the resilience of PGE's customers, but also lays the groundwork for expanding PGE's energy storage capabilities across the service territory.

As the pilot matures, we will continue to watch the evolution of energy storage technology and consider how we can continue to innovate and partner with our customers to meet their resilience and clean energy needs. This might mean developing innovative ways to help customers afford home energy storage, like financing options for interconnected devices, or enhanced resilience options on the utility side that can pair energy storage as a grid resource, such as a neighborhood-level microgrid. The pilot will also explore whether letting customers control their own dispatch of the battery during a peak event, as with our Peak Time Rebates program, will yield comparable savings to PGE-dispatched energy.

We are enrolling 525 residential customers into a bring-your-own-battery program that will compensate customers for allowing us to manage the charging and discharging of batteries for a variety of uses. We have also been watching the emerging market of vehicle-to-grid and vehicle-to-home, wherein electric vehicles that have the capability to provide two-way flow could potentially be used in the event of an outage or to export to the grid. Further study is needed to test the safety and reliability of this new technology, as well as customer acceptance and willingness to use vehicle batteries for this purpose. Nevertheless, were this technology to scale, this could be a large change to the resilient home backup market.

1.5.5.2 Commercial and industrial storage

We have been conducting research among customers who have medical equipment powered by electricity or who are otherwise more vulnerable from a health and safety standpoint during a power outage. We want to understand the diversity of this population and consider what products or services may be offered to protect against negative health outcomes in the event of an outage.

Recent power outages have hit our non-residential customers hard during an already challenging economic climate. Customers are asking how we can provide them with solutions to prevent the loss of inventory, keep patients safe and allow businesses and institutions to remain open when they are needed most.

We are exploring a range of solutions, such as custom-engineered microgrids at customer locations that can provide resilience to the customer and flexible load to the utility. With this approach, we would share the costs and benefits with our customers, with PGE paying for the cost-effective portion of the grid resource and the customer paying for their share of the resiliency backup power benefit over time. This structure could potentially be applied to other transformational energy solutions, such as grid-connected heavy-duty fleet charging, pairing energy storage with vehicle charging and multi-family dwellings.

36. Docket UM 1856 and the state law directing Investor-Owned Utilities to invest a minimum of 5 MWh storage
37. Tariff schedule 14

Chapter 2.

Distribution system vision

Chapter 2. Distribution system vision

"The only way forward, if we are going to improve the quality of the environment, is to get everybody involved."

— **Richard Rogers**, architect and author, A Place for All People: Life, Architecture and the Fair Society

2.1 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 (EJ) communities.[38] It's designed to improve safety and reliability, ensure resilience and security and apply an equity lens when considering fair and reasonable costs.

This chapter describes PGE's vision to transform the distribution system of today to a 21st century community centered distribution system. We share our goals and our strategic initiatives to realize this vision: empowered communities, modernized grid, resilience, plug and play, and evolved regulatory framework. **Table 12** illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP guidelines under Docket UM 2005, Order 20-485.[39]

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A: DSP plan guidelines compliance checklist**.

Table 12. Distribution system vision: Guideline mapping

DSP guidelines	Chapter section
4.4.a	Section 2.3, 2.4, 2.5
4.4.b.iv	Section 2.3.2, 2.4
4.4.b.iv	Section 2.5
4.4.f	Section 2.5
4.4.g	Section 2.6

WHAT WE WILL COVER IN THIS CHAPTER

PGE's vision for a 21st century community-centered distribution system

How the distribution system can advance societal and environmental justice

How the distribution system can accelerate DER adoption

How the distribution system can maximize customer value

PGE's five strategic initiatives for the distribution system

How policy and planning will intersect to enable a transformed distribution system

How PGE's vision will be monitored and adapted over time

38. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at: oregonlegislature.gov
39. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at: apps.puc.state.or.us

2.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to provide a clear long-term vision for their distribution system that advances policy goals and customer values.[40] This order also requires IOUs to share the goals of their vision and associated strategies — which impact safety, reliability, resilience, security, affordability and decarbonization — through direct investments in technologies and by accelerating the adoption and integration of DERs.

In 1995, a piece in the literary journal "Massachusetts Review" ascribed a saying to Arthur C. Clarke, in which he noted that society tends to overestimate what it can do in the near future and grossly underestimate what can be done in the distant future. This is because the human imagination extrapolates in a straight line, while real world events develop exponentially — like compound interest.

We envision a 21st century community centered distribution system that accelerates decarbonization through DER programs, non-wires solutions (NWS), virtual power plants and other mechanisms to strategically provide community benefits — especially to EJ communities — while improving metrics around safety, reliability, resiliency and security.

Our vision for the distribution system aims to steadily build on traditional utility values of reliability, safety and affordability by including new considerations such as decarbonization, community impact and cybersecurity. The sections below highlight the goals of this vision and the strategic initiatives that will enable us to realize this vision.

Our vision informs our long-term plan for the DSP and represents our initial steps toward evolving the distribution system. This initial DSP affords us the opportunity to explain how we plan to evolve the grid in a more inclusive way. We recognize that distribution system planning is an ongoing and iterative process. We look forward to gaining insights and feedback from partners and the Commission that will inform our next DSP submission.

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** Enabling equitable participation in the clean energy transition through human-centered planning and community engagement	**Modernized grid** Optimizing a grid platform that is safe, secure and reliable through current and future grid capabilities	**Resilience** Strengthening the grid's ability to anticipate, adapt to, withstand and quickly recover from disruptive events	**Plug and play** Improving access to DER investments needed to accelerate customers' clean energy transitions through such activities as hosting capacity analysis	**Evolved regulatory framework** Evolving the regulatory framework needed to support utility investment in customer- and community-centered solutions

40. OPUC Docket UM 2005 and Order 20-485, available at: apps.puc.state.or.us

2.3 Goals for the DSP

This section of our DSP consists of our long-term distribution system vision that is informed by broader goals related to maximizing reliability, customer benefits and efficient operation of the distribution system.

2.3.1 ADVANCE ENVIRONMENTAL JUSTICE

PGE envisions the distribution system advancing EJ through strategic deployment and use of grid assets (customer or utility owned) and tariffs to yield more equitable outcomes, especially for those who are most vulnerable.

Definitions of EJ have evolved over time, expanding from a narrower focus on distributive equity to include procedural and restorative practices. Historical inequities have led to frontline and EJ communities experiencing larger impacts. With this context, we acknowledge the need for an exploration of these multiple layers of burden faced by frontline and EJ communities and we are committed to alleviating and reducing the trauma experienced from policies and procedures that do not fight against inequities.[41]

In advancing EJ, it is important to lead with racial equity. There are many underserved populations in our service territory. Leading with race is not to ignore those factors. When all else is equal, race is the factor that points to inequities across all indicators of success. When we address these deep and pervasive inequities, we will also help to address other areas of marginalization in our EJ communities. Engaging with these communities will "bring the genius of a much broader group of constituencies to the task of developing…roadmaps and policies [and] the active support of those broader constituencies can help secure new policies and resources necessary to implement the strategies identified in roadmaps."[42]

The cost-of-service model, under which PGE is regulated, has assumed fairness for decades. However, recent legislation dictates that our collective understanding of rate design and cost-of-service principles demands reconsideration. Many communities are at risk of being left behind in the clean energy revolution if the company and regulations do not evolve.

The significant overlap between grid transformation and social transformation focuses our attention on the following goals in the transition to the 21st century community-centered distribution system:

- **Assist EJ communities:** As defined in HB 2021, EJ communities include communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities that have been traditionally underrepresented in public processes and adversely harmed by environmental and health hazards. These include seniors, youth and people with disabilities. PGE has begun the process to better understand the concerns and needs of EJ communities through engagement as outlined in **Section 3.4.** As the DSP evolves, we will continue to learn from these experiences and seek more ways to address specific concerns through outreach, planning and investments.

- **Provide direct benefits to communities:** Historically, loads were seen as homogenous, and utilities had little need to understand individual customer behavior. As distribution infrastructure and data resolution improve and DER penetration increases, PGE envisions new opportunities to provide customer and community value through new products and services. These include community microgrids, NWS and continued flexible load development. These new investments are a key feature of the 21st century community-centered distribution system and can be strategically used to reduce energy burden and create significant local economic impacts through workforce development. PGE will continue to work with participants to understand knowledge gaps in accurately identifying and valuing community benefits stemming from distribution-related investments. In Part 2 of the DSP, PGE will propose NWS projects focusing on community benefits as defined by our engagement with the local community (in accordance with our Community Engagement Plan outlined in **Chapter 3**).

41. Energy Justice Workbook, developed by Initiative for Energy Justice, available at: iejusa.org
42. Zero Cities Project, Equity Assessment Tool, Urban Sustainability Directors Network (USDN), 2019, pg. 5, available at www.usdn.org

2.3.2 ACCELERATING DER ADOPTION

Customer needs are evolving, especially as they relate to preferences for DERs driven by cost decreases, lifestyle factors and other considerations. PGE has noted this in the 2019 Integrated Resource Plan (IRP), and we continue to see an increasing importance placed by customers on power reliability and enabling a smart grid to further climate change abatement.[43] Additionally, the studies demonstrate the continued importance of a clean energy future, generating electricity from clean sources and keeping prices affordable.

DERs, however, introduce new challenges for traditional utility planning and operations because of their versatile operational capabilities and how they change customers' interaction with the grid. Without proper visibility into the impacts DERs will have in terms of changes to net load shapes and voltage profiles, as well as having adequate system protection devices in place, growth will be challenged by higher costs and greater uncertainty. However, if harnessed appropriately, these DERs can become assets for society by helping to enable decarbonization, system cost reduction and customer bill reduction. PGE has taken several steps to improve DER integration, but we are still learning and developing its capabilities. PGE envisions that the 21st century community-centered distribution system will accelerate DER adoption and leverage those DERs to deliver additional value to customers. In the following section, we talk about the strategic initiatives, each with one or more activities focused on the goal of accelerating DER adoption.

At a system level, PGE plans for DER impacts to the grid within the IRP, ensuring we have adequate resources to meet the energy and capacity needs of these emerging technologies. However, the locational nature of DER adoption has potential cost implications that must be explored through the DSP. The interplay of these analytical exercises between the DSP and IRP is a topic we explore further in **Section 2.5** on policy and planning intersections.

The rate of DER adoption directly impacts PGE's needs to invest in DER-ready infrastructure, such as EV charging infrastructure and substation protection devices for increased photovoltaic (PV) adoption. DER adoption may be driven by larger market forces (as in the case of solar PV and EVs) or more programmatic in nature (such as flexible loads). PGE is actively monitoring market trends for DERs as well as exploring opportunities to increase the adoption of flexible loads to balance the impacts of new loads through continued product and program development. **Figures 11a-d** show PGE's latest forecast of DER adoption through 2030. **Appendix G** provides detail of PGE's AdopDER model underlying these estimates. The figures below represent current forecasts, which were developed as part of our DSP. During the development of the DSP, Oregon has passed key legislative policies needed to help decarbonize the state's electricity supply, such as House Bill 2021. PGE will update the DER forecast for future DSP filings in order to account for policy evolution, new market trends, customer approaches, and emerging technology identified through PGE's Product Development initiatives and Smart Grid Testbeds. In support of Oregon's commitments to decarbonization and electrification, we have aspirational goals to aggressively grow our flexible load portfolio to upwards of 250 to 500 MW, the equivalent of serving more than 200,000 households. Additionally, we have aspirational goals to accelerate the state's Senate Bill 1044's goal of 25% of all registered vehicles and 50% of new vehicle sales across the state, growing Oregon's total number of electric vehicles on the road to over a million by 2030.[44]

Achieving these aspirational goals will require all of us to participate in this transition in new innovative ways, create new customer approaches, and new tools for engagement that assist in first cost hurdles and peace of mind. Through our future DSPs we will help pave the way for this transition. For example, we continue to evolve our AdopDER model, which will allow us to perform more iterative DER cost-effectiveness and locational adoption scenario analysis. This model will help us understand adoption patterns based on feeder-level customer demographics, new policies or intervention strategies. Developing new benefit accounting methods (e.g., locational net benefits analysis) will help quicken DER adoption. In addition, a more established mechanism to scale non-wires solutions wherein community benefits can be fully accounted for will help to promote DER adoption in the market.

43. 2021 Q2 PGE Escalant Residential Tracking study, available upon request.
44. Based on the Oregon Department of Transportation's (ODOT's) Transportation Electrification Infrastructure Needs Analysis (TEINA) report available at www.oregon.gov

Figure 11.a. PGE's transportation electrification load forecast, reference case

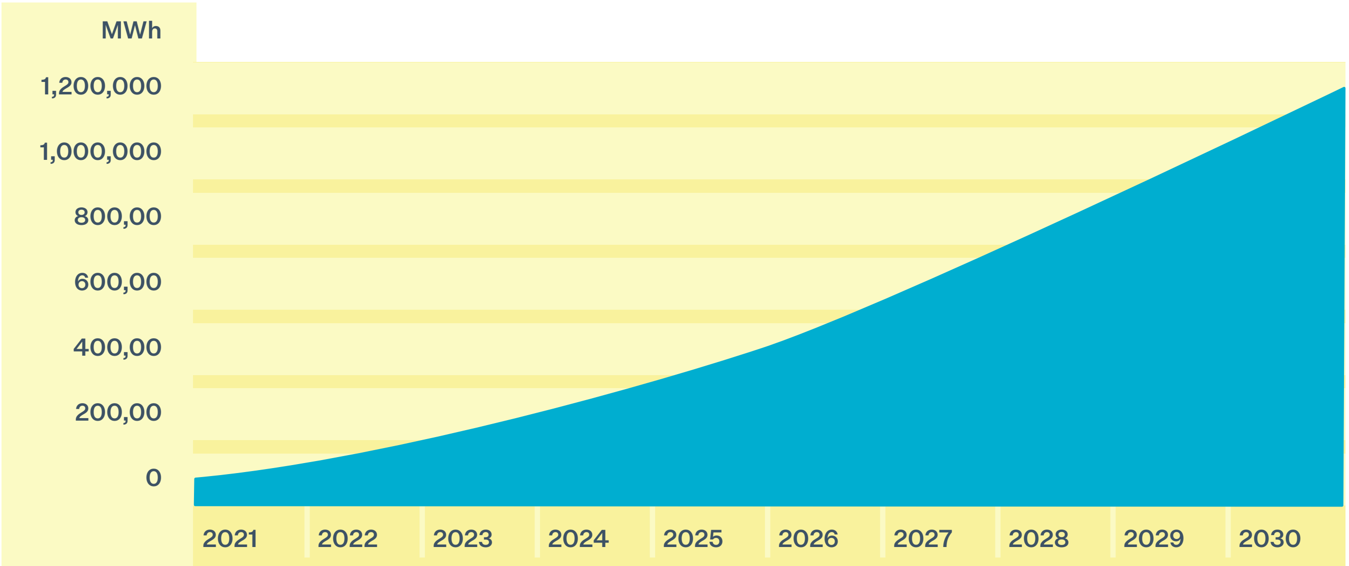


Figure 11.b. PGE's DR/flex load forecast, reference case

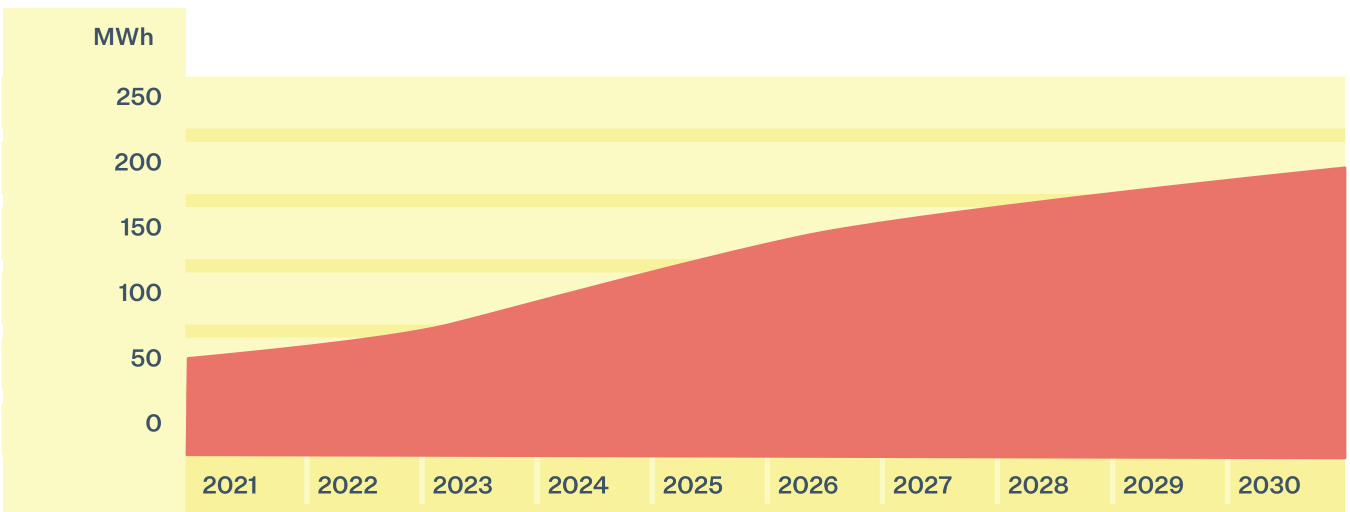


Figure 11.c. PGE's solar PV forecast, reference case

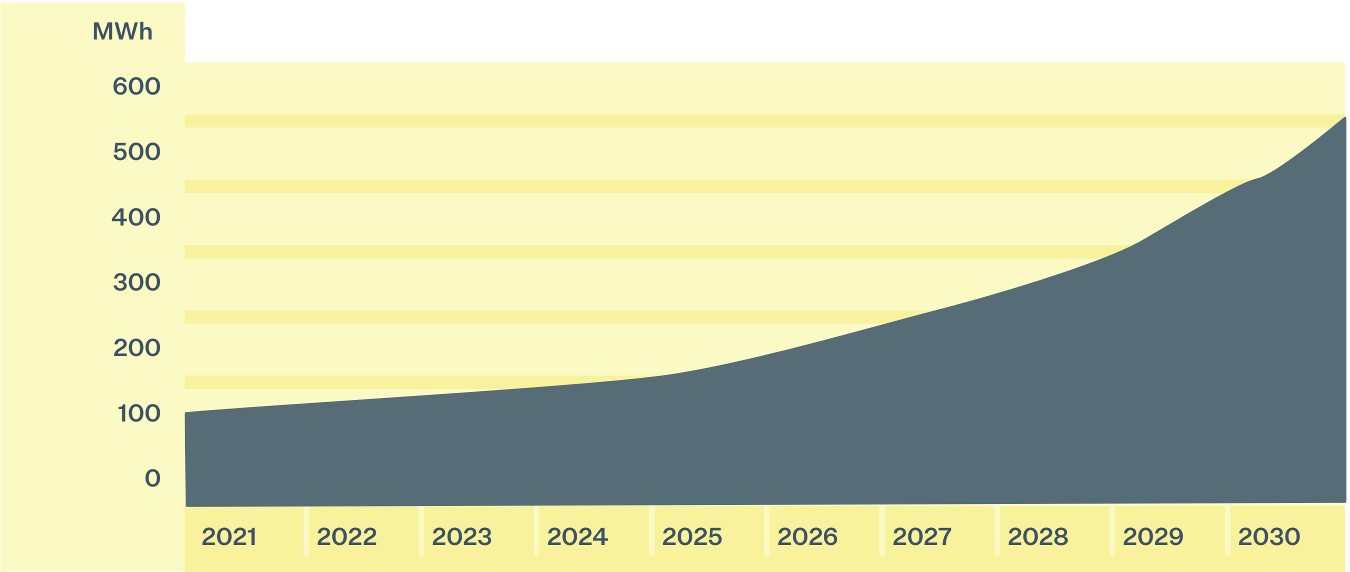
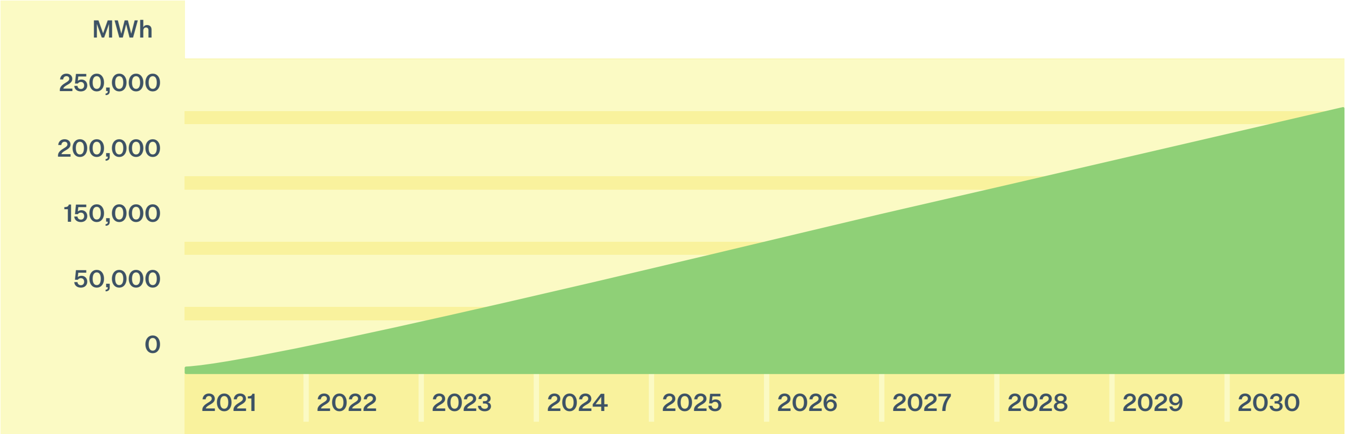


Figure 11.d. PGE's building electrification load forecast, reference case



The graphs in **Figure 11** are described below by DER:

- The transportation electrification and building electrification graphs represent the total energy impacts of these DERs.
- The solar PV graph represents the estimated nameplate capacity (in MW-dc) of rooftop solar that will be added to the system.
- DR/flex loads represent the expected MW contribution of PGE's flex load portfolio to summer peak.

2.3.3 MAXIMIZE GRID BENEFITS

Grid benefits, in this context, refer to customer value that results from the planning and optimal operation of the system. Their impact can be measured through quantitative metrics that are established either nationally or at the state level. These metrics represent elements of both traditional planning and relatively newer initiatives such as decarbonization, cybersecurity and resilience. PGE identifies the following as primary grid benefits addressed by the transition to the 21st century community-centered distribution system.

- **Decarbonization:** In line with HB 2021, PGE is committed to reducing greenhouse gas (GHG) emissions from the power served to customers by at least 80% by 2030 and 100% by 2040. Measured in metric tons of carbon dioxide equivalent, we will address this goal primarily through the IRP process. However, through improved management of DERs, we expect the distribution system to have an increasing role in reaching these reduction targets. Part 2 of the DSP will include an analysis of how DERs can factor into solution identification for identified grid constraints.

- **Safety:** Safety has, for more than 130 years, been a central focus for PGE. PGE is committed to the safety of communities and employees and will ensure safety improvement is a key consideration as PGE transitions to the 21st century community-centered distribution system.

- **Reliability:** PGE continues to improve reliability through the integration of technology, better planning practices and improved operator control. We use industry-standard reliability metrics, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), which are detailed further in **Appendix B**. As PGE transitions to the 21st century community-centered distribution system, the need for reliability is further emphasized as more and more end uses come to rely on electricity as their primary energy source. For example, a customer adopting EVs should not experience an overall reduction in reliability compared with a gasoline vehicle.

- **Resilience:** The frequency and intensity of disasters such as wildfires, storms, heatwaves and droughts have been increasing. This has propelled the conversation around resilience to the very top of PGE and society's focus. Resilience is defined as the robustness and recovery characteristics of utility infrastructure and operations, which avoid or minimize interruptions of service during an extraordinary and hazardous event.[45] Through this transition, PGE will focus on resilience by incorporating new strategies and analytical techniques that improve decision-making across the company. For example, strategies may include leveraging locational benefits to promote resilience-based DERs such as microgrids and risk-based assessment of pole materials.

- **Security:** The protection of the cyber-physical grid has received increased attention from the discussions driven by UM 2005. In March 2021, the U.S. Government Accountability Office (GAO) reported on cybersecurity vulnerabilities, especially on the distribution grid and need for immediate action.[46] Information technology (IT) and operational technology (OT) play a key role in enabling the 21st century community-centered distribution system. However, IT/OT also increase the number of access points for cybersecurity attacks and require an integrated and proactive approach to security development. PGE has taken several steps to improve physical and cybersecurity as outlined in PGE's 2021 General Rate Revision Request.[47]

- **Fair and reasonable costs:** The transition to a clean energy future will require additional investment in the grid. Historically, PGE has ensured the affordability of the distribution system through a combination of lowest-cost and -risk investments that provide safe, reliable power for customers. We believe the regulatory paradigm must evolve to capture the intent of policy direction (HB 2021), which requires the elimination of GHG emissions in a manner that provides direct benefits to communities. This shift requires all parties to rethink the evolution of fair and reasonable costs to include an equity-lens.

Equitable implementation of our future DSP Action Plan is a critical next step and will serve to support and complement the empowered communities pillar, as well as other pillars. Notably, equitable implementation will improve community resilience and assist in evolving the utility regulatory framework, which is needed to provide flexibility in co-developed solutions that meet identified community needs.

45. Definition of resilience per the National Association of Regulatory Utility Commissioners (NARUC), available at: pubs.naruc.org
46. Government Office of Accountability Report: GAO-21-8, available at: gao.gov
47. PGE's UE 394 filing on July 9th, 2021, available at: edocs.puc.state.or.us

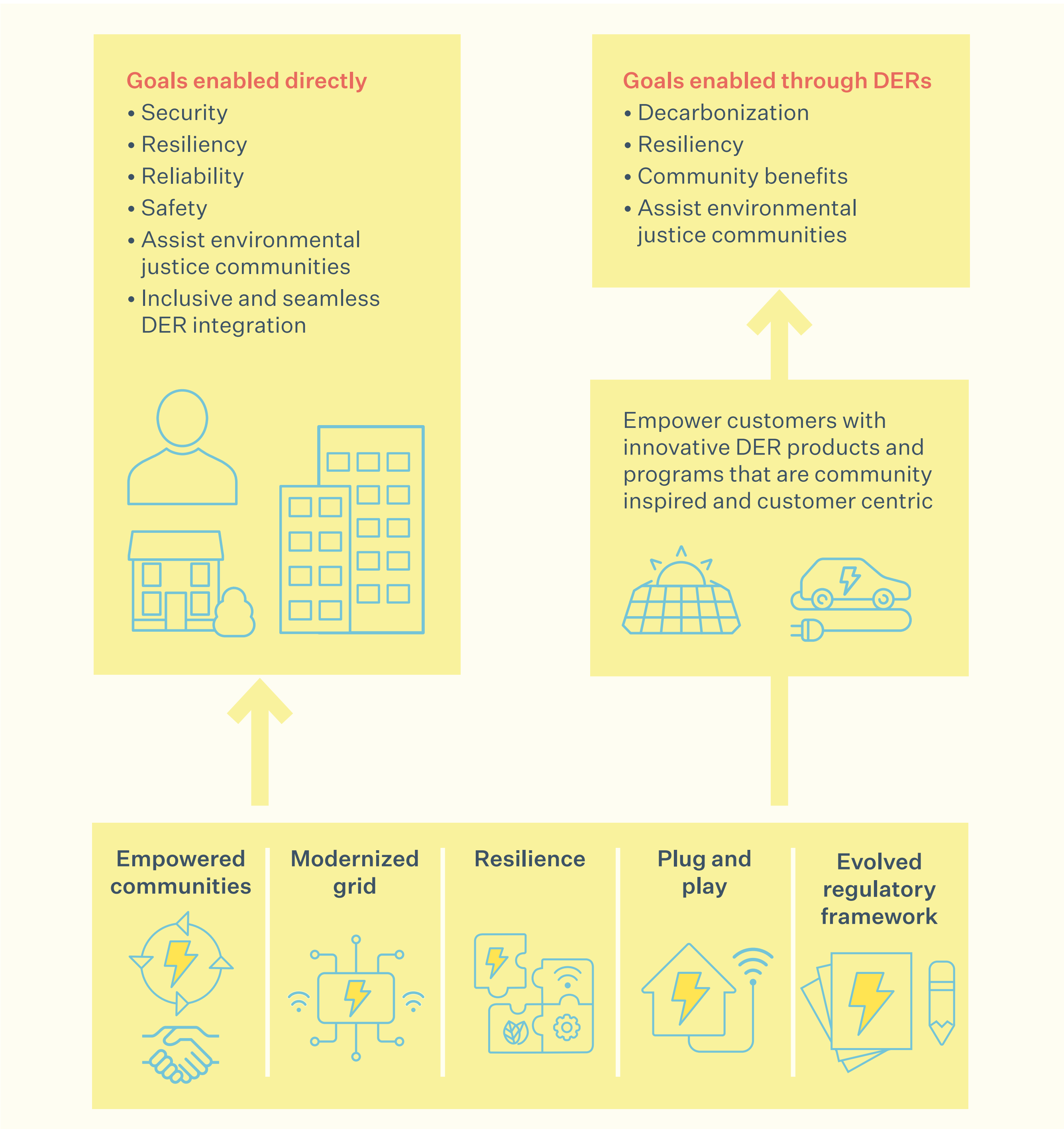
2.4 Strategic initiatives for the DSP

To execute on our vision and goals for the distribution system, PGE has developed and is working on five strategic initiatives:

- Empowered communities
- Modernized grid
- Resilience
- Plug and play
- Evolved regulatory framework

Figure 12 illustrates how these strategic execution initiatives enable DERs and help achieve the goals of a 21st century community-centered distribution system.

Figure 12. PGE's initiatives address the goals of the 21st century community-centered distribution system



The strategic initiatives are briefly described here, with more details in subsequent chapters.

2.4.1 EMPOWERED COMMUNITIES

The empowered communities initiative focuses on evolving PGE's culture to better integrate EJ goals as outlined in **Section 2.3.1** in the distribution system. Activities under this initiative will be the primary way to create the right space and relationships needed to foster equitable participation in the clean energy transition. In the action plan in Part 2 of this DSP, PGE will outline the company's tactical approach. With this, we take the first step in creating a more integrated and community-centered distribution system planning approach. PGE expects this initiative to help the company develop new DER products and programs that meet the precise needs of PGE customers, especially EJ communities, while improving their participation to enable these DERs to scale and provide broader societal benefits. **Chapter 3** provides the current activities PGE is undertaking within this initiative as related to the DSP.

2.4.2 MODERNIZED GRID

PGE's vision of a grid expands on the integrated grid approach as reported in the company's 2019 Smart Grid Report.[48] The goal of a modernized grid is to ensure the system can meet evolving customer needs while realizing the full value of DERs. 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. The capabilities that collectively form the modernized grid and current investments in those capabilities are expanded in **Chapter 4**.

2.4.3 RESILIENCE

Resilience is top of mind for PGE as climate change and extreme weather present new challenges. A 1-in-40 year ice storm caused unprecedented power outages just in the past year, and the largest wildfire in the nation at the time temporarily severed Oregon's transmission of power to California. Customers are feeling the urgency to take action to prepare for the unexpected, as does PGE. This initiative brings together leaders and teams from across the company to improve our ability to meet customer and community expectations for resilient power delivery through solutions both old and new, such as grid hardenings and resilience-focused DERs. Details on this initiative are provided in **Chapter 5**.

2.4.4 PLUG AND PLAY

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. This increases lead times and impacts the customer experience. Furthermore, studies are difficult to scale with PGE's current capabilities. To improve access to DERs, we envision that information exchange of key studies, such as hosting capacity and locational net benefits, will allow us — and the market — to determine the best DER locations to maximize customer and societal benefits. As the company progresses, these studies will become standard processes that can be regularly updated with new data. By modernizing the company's planning capabilities, we strive to create a seamless, scalable interconnection process that addresses barriers to DER adoption. This DSP notes investments in planning tools, detailed in **Section 4.7.3**, to improve interconnection capabilities. Hosting capacity analysis will be a focus of plug and play in **Chapter 6**.

48. PGE's 2019 Smart Grid Report, available at: apps.puc.state.or.us

2.4.5 EVOLVED REGULATORY FRAMEWORK

Working with communities, partners, OPUC Staff and other utilities, PGE plans to identify regulatory and rulemaking opportunities for equitable, resilient energy delivery that keeps pace with the clean energy transition. We will work toward the sustained success of this transition while minimizing the impact to those who are most marginalized. PGE expects that as DER proliferation increases, more regulatory alignment and evolution is needed. The rate of this evolution must be correlated with the expected adoption of DERs, thus helping the company through clear regulation. PGE identifies an initial set of regulatory elements that can accelerate PGE's vision in **Chapter 7**.

2.5 Policy and planning intersections

Our vision for the distribution system over the next 5 to 10 years includes our DSP strategic initiatives and goals, and their alignment with state law and OPUC policies. These goals, as stated in the DSP requirements, include increased reliability, effective integration of DERs and broader GHG emissions reduction. There are many aspects of the DSP that intersect with other key policies and regulatory requirements, as well as utility planning and investments. Below, we discuss the interactions of the DSP with other planning activities, investments and tools that will advance the DSP vision.

2.5.1 PLANNING INTERSECTION

The impact of DERs will have an increasing influence on both IRP and transmission and distribution (T&D) planning. This influence can vary depending on how specific DERs are used for different needs, such as distribution relief, system level capacity contribution or other ancillary grid needs.

Moving forward, PGE will continue to build on and integrate the tools to further improve and align IRP and DSP methodologies around resource contribution of DERs.

2.5.1.1 DSP interactions with IRP

PGE has developed the in-house capability to produce DER forecasts in a transparent, consistent and repeatable manner based on a site-level adoption model. This marks the first step in integrating DSP and IRP tools to provide holistic system needs and impacts of DERs. By coupling the bottom-up and top-down approaches to DER forecasting in a single tool, PGE will be able to evaluate future scenarios of DER adoption with a consistent set of inputs and outputs, ensuring greater alignment of decision making.

At the time of this DSP filing, the IRP receives the following inputs related to DERs:

- Market adoption of DERs such as EVs and solar PV: This is the expected adoption of DERs free of programmatic influence on the market.
- Economic potential of current and expected future DER products and programs: This refers to the expected programmatic adoption of cost-effective DERs given their grid and societal impacts.
- Integration of non-cost-effective DER supply curves: The IRP will receive estimated supply curves of non-cost-effective DERs that will be introduced with other supply-side resources to better understand the portfolio dynamics of integrating DERs.

Currently, the peak MW contributions of DERs in PGE's DER forecast are determined based on an assumed dispatch taken from the IRP's loss of load probability (LOLP) heat map. In future evolutions, PGE plans to include more refined dispatch and control assumptions capturing a wider array of potential grid services of DERs and any commensurate change in value streams that impact cost effectiveness.

Appendix G provides additional detail of PGE's AdopDER model and includes responses to key stakeholder questions as they pertain to the interaction between the IRP and the DSP.

2.5.1.2 DSP interactions with T&D planning

DER adoption impacts T&D planning in the following ways:

- AdopDER's cost-effective DERs and locational adoption capabilities will help us understand adoption patterns based on feeder-level customer demographics. This feature will allow for additional modeling granularity by accessing gross and net load shapes for each feeder based on a range of plausible DER adoption scenarios. This will be a significant evolution compared to today's distribution load forecasting approach described in **Section 1.3.2**.
- PGE will plan for NWS by identifying grid locations with different maximum potential for DER adoption based on feasibility factors (e.g., building stock characteristics) as well as how changes in localized incentives might spur additional adoption. PGE is investing in evolving its capabilities to perform other NWS analyses ahead of the Part 2 DSP filing as noted in **Section 8.3.2**.
- PGE is exploring how DER behavior may affect T&D systems at higher levels of penetration. Because AdopDER explicitly models DER shapes (both passive and dispatchable) and aggregates up to feeder-level impacts on net system load, T&D planners can explore the impacts of different DERs, such as solar PV and EVs. In addition, AdopDER includes impacts of weather and solar resource availability, allowing system planners to understand expected DER behavior under extreme weather conditions.

Our near-term focus has been alignment between DER modeling and distribution planning functions. PGE is currently performing a gap analysis to determine if DERs require additional transmission planning capabilities as noted in **Section 4.7.3.2**.

2.5.2 IMPACTS ON T&D CONSTRUCTION BUDGET

The DSP has wide-ranging and significant effects on PGE's construction budget. The following are key investments driven by the DSP:

- **Grid modernization investments to advance PGE's vision:** PGE has developed a new capital allocation group called the Grid Modernization Business Service Group (Grid Mod. BSG) to help the company balance and prioritize grid modernization projects and ensure funding is allocated for projects based on appropriate justification. The Grid Mod. BSG also includes a significant IT overlay to ensure IT/OT and cybersecurity integration.
- **T&D investments driven by locational adoption of transportation and building electrification:** EV adoption, especially medium- and heavy-duty vehicles, is likely to have distribution system impacts in the long term. These impacts may be mitigated, but not necessarily eliminated, by DER programs such as managed charging. Through the DSP, the net impact and location of EVs will be supplied as inputs to the T&D planning process. This interaction between the planning teams will increase as building electrification ramps up, which will likely drive relatively more T&D projects than in the past. PGE will consider NWS for T&D projects that can be deferred or eliminated.
- **T&D investments, such as protection, driven by the impact of inverter-based systems' impact on hosting capacity:** High DER penetration may lead to excess generation, driving protection equipment needs that ensure safe and reliable operation under excess generation conditions. PGE has updated its engineering standards to ensure new substations have the necessary equipment to allow for generation backfeed. However, for existing substations, this problem may require a solution such as a battery and/or protection system upgrades. As DER programs and tariffed offerings improve, we will better optimize energy use across these different DERs, further minimizing the number of T&D investments relative to the increasing penetration of energy-generating DERs.

- **Investments in NWS and hybrid solutions (wired and non-wired) to replace some traditional T&D projects:** As PGE's planning capabilities mature, NWS will become a more prominent part of the solution mix for T&D projects. Traditional T&D solutions aim to address specific constraints with reliable solutions that have long asset lives. NWS are different in that they require more complex probabilistic planning models to ensure they address specific T&D constraints at the same reliability levels. Unlike traditional infrastructure investments, they can potentially satisfy local grid needs while also providing system-level benefits, such as resource adequacy, frequency response and optimized wholesale energy purchases. In addition, DERs may contribute societal and environmental benefits, such as decarbonization and resilience. For these reasons, NWS have a more complex relationship with planning and budgeting compared to traditional T&D projects.

2.6 Monitoring and adapting PGE's DSP vision

PGE's plan is to monitor progress using a combination of traditional and newer metrics. For metrics around reliability, resilience and outages, we measure the overall performance of the distribution system in three ways:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Momentary Average Interruption Event Frequency Index (MAIFe — calculations are limited to feeders with remote monitoring)

These are further detailed in **Appendix B. Baseline data and system assessment details**, along with PGE data over multiple years.

- For the metrics around decarbonization, community impact and EJ impact, PGE will draw from the metrics outlined in HB 2021, including the topics to be covered in the biennial report developed by the Community Benefits and Impact Advisory Group. These include:
  - Million metric tons of carbon dioxide equivalent (CO_2e) per year
  - Energy burden change
  - Disconnections within EJ communities

Through the development of Part 2 of the DSP, PGE will deliver locational forecasts that provide the analytics to calculate the change in these metrics resulting from DER investments. Additionally, PGE will work with partners and OPUC Staff to convene relevant advisory groups, such as the Community Benefits and Impact Advisory Group outlined in HB 2021, to set targets, track progress and adapt the DSP, IRP and Clean Energy Plan over time.

Chapter 3.

Empowered communities: equitable participation in distribution decisions

Chapter 3. Empowered communities: equitable participation in distribution decisions

"Injustice anywhere is a threat to justice everywhere. We are caught in an inescapable network of mutuality, tied in a single garment of destiny."

— Dr. Martin Luther King, Jr

3.1 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.[49] It's designed to improve safety and reliability, ensure resilience and security and apply an equity lens when considering fair and reasonable costs.

This chapter describes the activities planned or in progress to create a human-centered distribution system that provides safe, secure, reliable and resilient power, at fair and reasonable rates. It includes PGE's evolving understanding of energy justice, where the company is on its Diversity, Equity and Inclusion (DEI) journey, and the approach taken to meet and exceed the Public Utility Commission of Oregon's (Commission or OPUC) requirements for this docket. It also puts forth a framework for community engagement best practices. **Table 13** illustrates how PGE has met the Commission's DSP guidelines under Docket UM 2005, Order 20-485.[50]

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A: DSP plan guidelines compliance checklist**.

WHAT WE WILL COVER IN THIS CHAPTER

Why community engagement and empowerment is critical to achieving a distribution system that benefits everyone

An overview of human-centered design and planning

The key characteristics of PGE's Community Engagement Plan

What PGE has learned from community engagement

Table 13. Empowered communities: guideline mapping

DSP guidelines	Chapter section
4.3.a.i	Section 3.2
4.3.a.ii	Section 3.2, 3.4, 3.5
4.3.a.iii	Section 3.2, 3.3
4.4.b.v	Section 3.3, 3.4, 3.5
4.5 a-c	Section 3.5
5.3.d	Section 3.3
5.3.d.i-vi	Section 3.4

49. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at: oregonlegislature.gov.
50. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, and is available at: apps.puc.state.or.us.

3.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to ensure community engagement that fostered a "developing process that supports a human-centered approach to DSP." To help foster and support a human-centered approach, the OPUC requires IOUs to develop a plan describing how they will engage community representatives in the development of non-wires solutions (NWS) pilots. It also requires IOUs to host at least four pre-filing community workshops in their DSP.[51] The guidelines help IOUs create a DSP that:

- Empowers all customers with authentic choices, including access to diverse providers
- Creates inclusive, nondiscriminatory, equitable access to opportunities across customer types, with particular attention to opportunities that reduce energy burden
- Engages customers in an approachable, fully accessible manner
- Creates procedural inclusion for new stakeholders who are traditionally not represented
- Promotes collaboration between utilities and community-based organizations (CBOs) to broaden perspectives and representation in planning processes and outcomes

The goal is not to just eliminate the disparities, but also to increase success for all groups. Systems that are failing communities of color, for example, are failing everyone. Providing solutions for all while paying special attention to communities suffering disproportionate burdens will increase collective success.

Environmental justice

As a pillar of PGE's DSP, empowered communities represents the company's efforts as an essential service provider to both engage customers and understand where they live, work, learn and play. It also represents PGE's efforts to co-develop solutions with customers that provide direct community benefits and access to clean energy. It is incumbent upon us to pursue the twin goals of racial equity and decarbonization and ensure that our company addresses and acknowledges disparities and impacts within all the communities PGE serves. Not all communities PGE serves have been represented in the work done to date. PGE's Community Engagement Plan has a strong focus on those who comprise environmental justice communities, which was defined recently in Oregon's 2021 House Bill (HB) 2021.[52]

> "Environmental justice communities" includes communities of color, communities experiencing lower incomes, tribal communities, rural communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including but not limited to seniors, youth and persons with disabilities.

51. This requirement is split into two parts to follow the initial plan filing: two stakeholder workshops preceding Part 1 of the initial DSP filing, and two additional workshops preceding Part 2.
52. Oregon House Bill 2021 is available at: oregonlegislature.gov

In response to HB 2021, OPUC staff guidance and partner and community feedback, and to ensure the intended equity outcomes are achieved, PGE has adopted an integrated approach that embraces both internal and external considerations. Identified equity outcomes include, but are not limited to:

- Acknowledgement of structural and systemic inequities
- Integration of an explicit consideration of racial equity in decisions
- Pursuit of procedural equity by ensuring communities have a seat at the table
- Promotion of transparency and candor

Equitable implementation of PGE's DSP Action Plan is a critical next step and will serve to support and complement the empowered communities pillar, as well as other pillars. Notably, equitable implementation will improve community resilience and assist in evolving the utility regulatory framework, which is needed to provide flexibility in co-developed solutions that meet identified community needs.

Partners and community

PGE supports OPUC staff goals and principles and greatly appreciates comments provided in Docket UM 2005 and PGE's DSP partnership and community workshops to date. A summary of partner and community feedback relative to PGE's community engagement efforts, actions and responses is provided in **Section 3.4.3.1**.

The partners and communities PGE engages within the DSP vary in terms of utility-related technical and procedural background, access and influence.

PGE established two distinct approaches to its DSP workshops. The first approach was a monthly workshop that was more technical in nature and focused on aspects of the DSP guidelines and PGE's efforts to meet them. The second was to partner with CBOs to host two community-led workshops. PGE's approaches to both partner and community workshops were to ensure diversity of voice and to provide context and translation where needed to elicit meaningful and timely feedback.

3.2.1 PARTNERSHIP WORKSHOPS

During the development of PGE's DSP Part 1, PGE hosted eight monthly DSP partnership workshops from January 2021 to October 2021, focused on providing transparency into and information about PGE's DSP processes. **Figure 13** illustrates the topics shared during the monthly meetings.

A plan to share the work on PGE's DSP was developed and shared during the DSP partnership workshop on January 10, 2021. From there, future DSP partnership workshops gathered feedback and ideas on how PGE should shape its approach to the DSP Community Engagement Plan. PGE invited partners and communities to participate and influence this approach. Feedback led PGE to develop a website and email to provide people with the means to provide input and support PGE in developing the plan. Presentations and datasets shared during these meeting can be found at portlandgeneral.com/dsp.

Figure 13. DSP partnership workshops

2021	Baseline data and system assessment	Hosting capacity analysis	Community Engagement Plan	Long-term planning
January – April	Data collection, organization, QA/QC and visualization	System evaluation map and hosting capacity option analysis; iteration with OPUC's Technical Working Group (TWG)	Development of the Community Engagement Plan; hosted community input workshops	Development of long-term plan
May	**Presentation to partners and request of feedback on datasets**			
June	Data visualizations and demographics	**Presentation to all partners and receipt of feedback from OPUC's TWG**		
July	Sharing of final draft with partners	Enhancements to map as necessary		**Presentation to partners for feedback**
October	PGE DSP summary presentation	PGE DSP summary presentation	PGE DSP summary presentation	PGE DSP summary presentation
	October 15 filing	October 15 filing	October 15 filing	October 15 filing

3.2.2 COMMUNITY-LED WORKSHOPS

Workshops with traditionally underserved and underrepresented communities require that trust be established at the beginning of the workshop. This is achieved in part by providing space for connection, establishing agreements that enable a safe, inclusive space for discourse, and acknowledging past harm, cultural histories of trauma and structural inequities.

A community-led approach is people-centered. Difficult conversations are perceived as part of the work, failure is expected and treated as a learning experience and participants feel valued and empowered when they are asked for their opinion. This is considered long-term work based on the understanding that change is incremental and building trust takes time.

For these reasons, PGE partnered with Coalition of Communities of Color (CCC), Community Energy Project (CEP) and Unite Oregon (UniteOR) to assist in paving the direction of PGE's Community Engagement Plan. PGE deferred to these three CBOs to recruit and convene two community workshops in May 2021, months ahead of the expected filing date, to ensure feedback could inform the development of PGE's plan. The workshops provided context for the UM 2005 stated objectives and DSP Community Engagement Plan requirements. Based on feedback from CBO partners, PGE provided additional context to ensure transparency and build the trust needed to elicit candid feedback regarding needs, challenges and opportunities. The additional content focused on answering:

- Why is this relevant to me?
- What general problem are we trying to solve?
- What new information do you need to solve it?
- How will this feedback and information being gathered be used?

PGE compensated each CBO for its part in the delivery of these community workshops and compensated participants for their time. The scope of work included recruiting and convening, development of non-technical and multi-lingual educational materials and qualitative and quantitative research. The goal of those workshops, apart from serving to demonstrate a new partnership model, is to incorporate community insight and CBO recommendations into PGE's Community Engagement Plan.

The new partnership model included establishing a technical advisory group. This group was comprised of NW Energy Coalition (NWEC), Energy Trust of Oregon (ETO) and PGE. It served to provide CBOs context and translation of technical information in a manner intended to be objective and without bias. This served to create a collaborative environment among traditional and non-traditional stakeholders.

In partnership with CBOs and the technical advisory group, PGE sponsored the development of non-technical and publicly accessible educational materials. Two presentations were developed: (1) Energy/DSP 101, and (2) Community Resiliency/DERs, which can be found in **Appendix H** and **Appendix I**. The former provides an orientation to the grid and its components and described the role DSP will play in evolving the grid. The latter provides a deeper dive into why and how the DSP will foster climate resiliency for communities through distributed energy resources (DERs).

Through this process, PGE has made significant efforts to become a more accessible, transparent and inclusive utility partner. PGE engaged communities, partners, stakeholders and OPUC staff in the preparation and implementation of the DSP and the Community Engagement Plan. PGE sees the DSP as a critical planning mechanism in which ideas and innovation are created for PGE's customers and communities.

PGE's Community Engagement Plan seeks to detail the company's community engagement strategies within the DSP in support of achieving the following overarching goal for Oregon's long-term DSP process: "Be customer-focused and promote inclusion of underserved populations, including frontline, environmental justice communities."

It identifies the objectives and desired outcomes for achieving the goals of the DSP. This plan is informed by partner and community workshop comments and feedback. We intend to include in that plan a description of actions taken in fulfillment of the activities described in the following section.

Community Engagement Plan development process

As an essential service provider, PGE has both an opportunity and obligation to serve all customers and communities. We could be more inclusive, broadening our perspective of community to establish trusted relationship with marginalized communities and communities of color and the organizations that represent them. As a result, we have chosen to pursue partnerships with CBOs to guide this work. This process included the following:

- Research into services provided by community-based and community-led organizations representing various environmental justice communities
- Identification and engagement of specific organizations (e.g., UniteOR, CEP and CCC) to understand their missions, scope of services (e.g., facilitation, research and education) and their constituent representation
- Co-development of scopes of work that leverage those services and community relationships to lead an equity-centered approach to meeting and exceeding requirements of the docket
- Formation of a technical advisory committee (including ETO and NWEC) to inform and validate energy industry workshop context without bias
- Planning meetings to refine content ahead of a two-day workshop
  - The first three-hour workshop focused on the utility industry (Energy 101) and oriented participants to the DSP docket
  - The second three-hour workshop focused on DER in the context of climate resiliency
  - Workshop recruitment and facilitation was led by UniteOR, content created by CEP and research conducted by CCC
- Insights gleaned from workshop participant feedback collection tools to inform recommendations for the Community Engagement Plan

PGE established workshops for both partner and community stakeholders to ensure diversity of voice and provide context and translation where needed to elicit meaningful and timely feedback from community members.

We were intentional in fostering a diversity of voices. This effort is significant; there is still a substantial amount of work that needs to be accomplished to reach all communities. Specifically, this includes Native American tribal; lesbian, gay, bisexual, transgender and queer or questioning (LGBTQ); and Black, Indigenous and People of Color (BIPOC) communities, as well as seniors and people with disabilities. These communities have not historically been engaged or represented in utility planning like the DSP.

In addition, in support of community engagement, PGE developed a website dedicated to DSP efforts as well as a DSP email account that allows interested parties to contact PGE. Through this effort, we will maintain momentum and provide an opportunity for input, inquires and feedback.

To build trust, PGE must be transparent about what feedback the company may and may not act on. This requires communication about grid constraints and obligations to provide safe and reliable service to all customers. If comments are provided but not implemented, it is our intent to transparently describe why and elicit feedback from partners and communities and OPUC staff regarding how PGE may collectively address and overcome perceived constraints. Implementation of the Community Engagement Plan in Part 2 of the DSP will pose community-centered questions to inform pilot proposals, in the same manner as PGE has posed equity-centered questions internally, to ensure solutions are co-developed.

3.2.3 HIGH-LEVEL ROADMAP

Stage 1 activities, as provided in **Figure 14**, are well underway, and the status of these activities is provided here. OPUC staff has stated that there are plans to further build community needs assessment and co-created community solutions into this DSP roadmap, and so PGE's efforts serve that anticipated future state.[53]

PGE expects to implement the Community Engagement Plan as part of the transition to work on Part 2 of the DSP, following the completion of the grid needs assessment.[54] Coordination with community should precede implementation as PGE intends to engage early and often. We will, per OPUC staff and partner and community guidance, synchronize with the IRP, as the carbon planning workshop is expected to inform carbon impact for non-wires alternatives (NWA) screening.

Figure 14. Community engagement

	2021-2022	2023 and beyond
Stage 1	Utilities hold four public pre-filing workshops with partners on plan development.	
	Utilities create a collaborative environment among all interested partners and stakeholders. Utilities document community feedback and utility's responses.	
	OPUC prepares accessible educational materials on DSP with consultation from CBOs and utilities.	
	Utilities prepare a draft Community Engagement Plan as part of plan.	
	Utilities conduct focused community engagement for planned distribution projects.	
	OPUC to host quarterly public workshop and technical forums after plan filings.	
Stage 2		Reflecting UM 2005 outreach requirements, utility holds ongoing community stakeholder meetings during grid needs assessment, solution identification and action planning.
		Utilities and OPUC agree on community goals, project tracking and coordination activities.
		Utilities conduct baseline study to increase detailed knowledge of service territory communities. Utilities engage CBO experts to inform co-created community pilot(s).
		Utilities consult with communities to understand identified needs and opportunities, then seek to co-develop solution options, documenting longer-term needs.
Stage 3		Utilities collaborate with CBOs and environmental justice communities so that community needs inform DSP project identification and implementation. "Community needs" could address energy burden, customer choice and resiliency.
Community engagement		

53. OPUC UM 2005 DSP Introduction to DSP Plan Guidelines (October 2020) (pg.15), Figure 5: Grid Needs Identification, Stage 2, available at: edocs.puc.state.or.us.
54. Under UM 2005 Order 20-485, PGE is required to submit Part 2 of its initial DSP by August 15, 2022.

3.3 Human-centered design and planning

When PGE envisions the future of the industry and its place in society, we are inspired by the clean energy transformation emerging today, along with the environmental benefits, economic advantages and job opportunities that come with it. We see a flexible, resilient and reliable two-way power grid that lets customers choose when and how to use energy. This will allow our customers to partner with us to balance demand with emissions-free generating, storage and flexible load resources in a better, smarter and more climate-friendly energy system. As an essential service provider, PGE plays a critical role in delivering Oregon's clean energy transition equitably to all. Electricity powers how customers live, work, learn and play: PGE must continue to transform the energy system in an inclusive manner that addresses historic — and current — disparities head on. We embrace this imperative and the long-term commitment it requires. It's important that PGE's empowered communities initiative is inclusive of engagement with all stakeholders, partners and communities, and we will make that distinction throughout the DSP. Our goal for the DSP is to create a Community Engagement Plan that fosters a process that supports a human-centered approach to DSP. To ensure the DSP establishes a transparent and fluid public process that engages community members, particularly those from underserved communities, in a more robust way, we started our community engagement process early in the development of the DSP. This enabled PGE, in partnership with communities, partners, the OPUC and other IOUs, to have discussions about the structure, frequency and scope of our workshops.

There are three core energy or environmental justice tenets: procedural, distributive and restorative. Environmental justice is a broader concept that extends beyond PGE's sphere of activity as an energy company and electric utility. "Energy justice" is a subset of environmental justice and refers more narrowly to the public policy, economic and environmental impacts of PGE's work on those it serves. It also covers PGE's role in the communities where it does business. To achieve energy justice, it's critical to:

- Fairly and competently incorporate marginalized perspectives and communities in decision-making processes (procedural)
- Equitably distribute the benefits and burdens of energy infrastructure and systems (distributive)
- Repair past and ongoing harms caused by energy systems and decisions (restorative)

3.3.1 PROCEDURAL JUSTICE

Today, PGE brings community voices to the decision-making table in a variety of ways. For example, at semi-annual roundtable forums, PGE works through operational issues and other concerns with the low-income agency service providers and community action agencies that deliver energy assistance to PGE's customers. Also, as PGE embarks on a new multi-year planning process for its flexible load resources, it has an opportunity to foster procedural inclusion and partner with the communities it serves to develop and deliver equitable and local DER solutions. We strive to hear voices from community leaders while developing the leaders of tomorrow. Through conservation programs for schools, PGE teaches students about energy-related issues and career paths, encouraging their future participation in a clean energy future.

Most of PGE's service territory and generation sites are part of Tribes' ceded and usual and accustomed lands. PGE is working to develop a tribal partnership, which will be guided by PGE's draft Strategic Tribal Engagement Plan (STEP). STEP will provide a framework to understand the unique aspects of tribal worldviews, sovereignty and policies.

PGE and the Confederated Tribes of the Warm Springs Reservation of Oregon (CTWS) have co-owned and co-managed the Pelton Round Butte (PRB) project for more than a decade. The project provides enough emissions-free hydropower to power more than 150,000 homes and funds projects to improve water quality and enhance habitat for fish throughout the entire Deschutes River Basin. Very recently, CTWS and PGE renewed a power purchase agreement through 2040 in which PGE would purchase 100% of emissions-free electricity from the PRB project. More significantly, the Tribe announced its intention to increase its ownership share in PRB from 33% to 49%.

To "fairly and competently incorporate marginalized perspectives and communities in decision-making processes,"[55] we must now engage communities in new ways. Communities require not only access to proceedings, but also the context and compensation to engage meaningfully.

55. The Emerging Potential of Microgrids in the Transition to 100% Renewable Energy Systems. Wallsgrove, R.; Woo, J.; Lee, J.-H.; Akiba, L., Energies 2021, 14, 1687. Available at: researchgate.net

To address the barriers to participation, PGE worked in a coalition with utilities, environmental justice groups and local governments to secure passage of Oregon's 2021 House Bill (HB) 2475, which provides the OPUC with the authority to consider differential energy burden in rates or programs. The bill also provides access to funding for organizations representing the people most impacted by high energy burden, so they can participate in regulatory processes in the same manner as other broad customer advocate groups such as the Oregon Citizens' Utility Board (CUB). Oregon and Washington now have intervenor funding specifically targeted to BIPOC communities and CBOs, which will ensure these voices are centered in dockets and utility processes going forward.

Additional work is needed to address challenges inherent in utility and regulatory administrative processes, which can frequently be a barrier to participating; they can be convoluted, complicated and lengthy. This work will continue in earnest in partnership with communities and the OPUC.

3.3.2 DISTRIBUTIVE JUSTICE

As an essential service provider, PGE has an opportunity to "equitably distribute the benefits and burdens of energy infrastructure and systems" through its programs and rate design. Key to achieving this objective is understanding community needs and wants such that the design invites greater participation and, ultimately, value to the customer.

PGE's Smart Grid Test Bed (SGTB) team has incorporated principles of equity learned in the Oregon 2017 Senate Bill (SB) 978 process and will continue to address equity considerations and concerns from partners — especially those from community-based, community-led and environmental justice organizations — to ensure their voices are represented throughout the administration of the project.[56]

PGE's SGTB is designed to increase program participation, regardless of socioeconomic class, ability to pay or language spoken.[57] The project explores how new technologies and two-way power flow can help PGE manage energy demand more successfully. Customers can choose to use smart thermostats, smart appliances and energy storage devices, as well as shift their energy use to non-peak times to lower their overall energy bill. The portfolio of demand response (DR) within the SGTB includes Peak Time Rebates (PTR).[58] The strategy of using opt-out PTR is an equitable, non-punitive approach to establishing participation in the test bed; it holds the customer harmless for not participating, but otherwise rewards the customer's response to an event notice. This default approach, applied to all residential customers under Schedule 7, is inclusive and informed by an environmental justice principle of preventing harm to non-participating customers.

Distributive justice has also been pursued as part of PGE's response to the COVID-19 pandemic. The pandemic further emphasized and reinforced the utility's role as an essential service provider. In 2020, Oregon IOUs took voluntary actions to suspend disconnections of residential and non-residential accounts, stop sending late and final notices, stop assessing late fees and offer more and flexible payment arrangements to assist customers impacted by COVID-19 through March 30, 2021. At the request of the OPUC, the energy utilities extended these actions through July 31, 2021.[59]

56. Oregon's 2017 SB 978 available at: oregonlegislature.gov.
57. More information on PGE's Smart Grid Test Bed available at: portlandgeneral.com
58. More information on PGE's Peak Time Rebates program available at: portlandgeneral.com.
59. OPUC Docket UM2114 is available at: oregon.gov

PGE works with various stakeholders to support legislation that will provide support for low-income and vulnerable communities. This work requires ongoing collaboration with other energy providers, municipal and public partners and those PGE serves. In the 2021 Oregon legislative session, new laws were passed to help reduce barriers and increase access for environmental justice communities.

- HB 2475 (2021):[60] Enables the OPUC to consider differential energy burdens and other economic, social equity or environmental justice factors that affect affordability when approving proposals for rate design or bill credits.
- HB 2739 (2021):[61] Temporarily increases low-income bill assistance funding by an additional $10 million per year through 2023.
- HB 2842 (2021):[62] Establishes a grant program within the Oregon Health Authority to provide financial assistance to repair and rehabilitate low-income homes.
- HB 3141 (2021):[63] Increases funding for low-income weatherization and directs the OPUC to set equity metrics for all funds invested by Energy Trust of Oregon (ETO) and requires investment of 25% of funds to serve low- and moderate-income customers.

In coalition with others, PGE advocated for additional federal energy assistance funding, resulting in more than $78 million allocated to Oregon in 2020 and 2021 alone. PGE also helped secure authority for community action agencies to use express enrollment when qualifying customers for state bill assistance funding, reducing the need for duplicative application processes.

3.3.3 RESTORATIVE JUSTICE

Effective community engagement requires an acknowledgement that to build trust and advance partnerships with CBOs, PGE must seek to "repair past and ongoing harms caused by energy systems and decisions."[64] This is trauma-informed work for which PGE staff must develop a competency and literacy to navigate respectfully. Adopting restorative practices will allow us to build the necessary social capital to evolve our business to better serve all communities.

The safety of our customers and community is always our first priority. If extreme weather conditions threaten our ability to safely operate the electrical grid, we will turn off power in certain high-risk areas to help protect public safety. This is called a Public Safety Power Shutoff, or PSPS. Each substation and distribution line not only supports a community, but also serves several types of sub-communities. PGE's obligation to both serve and acknowledge disproportionate impact is realized in our application of an equity lens to wildfire mitigation efforts. Effective and inclusive communication with vulnerable populations requires an approach that honors different modes, languages and partnerships. As PGE is still learning where these customers and non-customers live, work and play, the company defers to those with expertise and tenured relationships to serve as a conduit for PSPS awareness and preparation. PGE asked for help from recipients of PGE and PGE Foundation funding, with whom the company has long-standing direct relationships, to identify partner organizations for PSPS communication. School districts and food banks in PGE's service area were added to this list. PGE then developed PSPS toolkits and communications in various modes (website, email, bill insert, and social posts) and multiple languages (English, Arabic, Chinese [simplified], Chinese [traditional], Farsi, Japanese, Korean, Rohingya, Russian, Somali, Spanish, Swahili and Vietnamese) to inform these populations how to plan for an extended outage. PSPS partners were proactively contacted in mid-July and offered the toolkit in both digital and print formats. Many of our PSPS partners are resource constrained and need to be compensated, accommodated or otherwise supported to ensure they may act as a conduit in these events. PGE plans to identify and address partner accommodations in future years. In the interim, the vulnerable populations engagement plan specifies the primary and contingent PGE staffer directed to engage each PSPS partner 48-72 hours before a PSPS event. The responsibilities of each staffer include both providing communication collateral and capturing that notification was attempted.

60. Available at: oregonlegislature.gov
61. Available at: oregonlegislature.gov
62. Available at: oregonlegislature.gov
63. Available at: oregonlegislature.gov
64. The Emerging Potential of Microgrids in the Transition to 100% Renewable Energy Systems. Wallsgrove, R.; Woo, J.; Lee, J.-H.; Akiba, L., Energies 2021, 14, 1687. Retrieved from: researchgate.net

Many distributional inequities may stem from a lack of social or political recognition. In the context of resilience planning, PGE takes inspiration from scholars in this area and seeks to: "(1) acknowledge community members' different intersecting identities (e.g., race, gender, class and age); (2) recognize that these identities are shaped by historical injustices and can shape individual vulnerability to shocks and stresses, ability to access resources and capacity to participate in decision-making; and (3) foster respect for different groups."[65] Investments in resilient infrastructure have a local, tangible and visible impact. Infrastructure planning can and should address and acknowledge historical harm (including but not limited to energy burden, insecurity, poverty and democracy) and ensure the safe and reliable delivery of energy.

3.3.4 APPLYING AN EQUITY LENS

An equity lens provides PGE with a reflective framework that intentionally works to uncover potential or real impacts of the company's actions. It is a tool we can use to ensure we are not missing anything or creating unintentional barriers as we think through our planning. An equity lens acknowledges that the ways in which disparities have been institutionalized into PGE's policies, practices and culture have conditioned PGE to not consider traditionally underserved groups.

The process of applying an equity lens allows us to identify and work toward mitigating these disparities, so we can better serve the unique needs of our customers. This lens serves to identify who will benefit or be burdened by a given decision, examine potential unintended consequences of a decision, develop strategies to advance equity and mitigate unintended negative consequences, and develop mechanisms for successful implementation and evaluation of impact.

The Government Alliance on Race and Equity (GARE) Toolkit poses several questions that PGE has posed internally. That line of inquiry centers PGE's work around the "who" and includes the following steps:[66]

3.3.4.1 GARE racial equity tool

STEP #1

Proposal: What is the proposal and the desired results and outcomes? PGE should also be vigilant in its focus on impact.

STEP #2

Data: What is the data? What does the data tell PGE?

STEP #3

Community engagement: How have communities been engaged? Are there opportunities to expand engagement?

STEP #4

Analysis and strategies: Who benefits from or will be burdened by the proposal? What are the strategies for advancing racial equity or mitigating unintended consequences?

STEP #5

Implementation: What is the plan for implementation?

STEP #6

Accountability and communication: How will PGE ensure accountability, communicate and evaluate results?

65. Sara Meerow, Pani Pajouhesh & Thaddeus R. Miller (2019): Social equity in urban resilience planning, Local Environment, DOI: 10.1080/13549839.2019.1645103. Available at: doi.org
66. Racial Equity Toolkit: An Opportunity to Operationalize Equity; Government Alliance on Race and Equity (GARE) (September 2015). Available at: racialequityalliance.org

3.4 Community Engagement Plan

3.4.1 ACKNOWLEDGEMENT

PGE is at the beginning of its journey to fully integrate equity. While the company has initiatives in varying levels of maturity, at present and as an organization, PGE operates in the programmatic stage (Level 2 in **Figure 15**, inspired by the Deloitte maturity model) as it relates to diversity, equity and inclusion (DEI) and has work to do to transition to the levels where DEI is integrated into all aspects of PGE's work.[67]

Figure 15. DEI maturity model

DEI maturity model

Mandate | Transition point | Movement

	Level 1	Level 2	Level 3	Level 4
	Compliance	**Programmatic**	**Leader-led**	**Integrated**
Focus	Compliance with equal opportunity/ affirmative action goals	Increasing the representation of specific demographic groups (e.g., women)	Leveling the playing field for all employees by addressing systemic cultural barriers	Leveraging difference to create business value
Center of gravity	**Legal/HR/D&I team** • Diversity seen as a problem to be managed • Actions are largely reactive	**HR/D&I team** • Diversity seen in terms of demographics, numbers and targets • Ad-hoc standalone initiatives	**Business leaders** • DEI linked to business strategy for culture change • Leaders/managers are committed and accountable	**Whole organization** • Shared sense of purpose • Integrated into all aspects of the organization

67. The diversity and inclusion revolution: Eight powerful truths, by Juliet Bourke and Bernadette Dillon, Deloitte Review (January 2018) (pg.93).

PGE partnered with UniteOR, CEP and CCC to develop, facilitate and synthesize findings from two pilot workshops designed to engage BIPOC, immigrant and refugee and low-income communities in Oregon. The information that follows is based on and inspired by their work. The DSP Community Engagement Best Practices and Recommendations report created by these organizations is cited throughout this plan.[68]

CBOs have long-standing relationships and trust in the communities PGE serves and are in the best position to garner candid feedback from customers. PGE contracted with these organizations to inform the activities required to engage communities effectively and meaningfully, and to assist with integrating findings and recommendations from their outreach on PGE's behalf into the DSP Community Engagement Plan.

3.4.2 PURPOSE

Community engagement helps build bridges that enable decision-makers to actively work with those impacted by projects, design more effective and inclusive solutions, and get better results. Community Engagement Plans are iterative and intentionally not prescriptive, as PGE understands that community engagement practices need to be flexible and responsive. Therefore, PGE envisions this plan to be a living document that evolves as needed along with the energy landscape and industry.

This plan is intended to serve as a framework for community engagement in the DSP and be a standalone document that could also be leveraged in future planning and engagement work at PGE.

As illustrated in **Table 14**, the Community Engagement Plan begins with the identification of its goals, objectives and desired outcomes for achieving the goals of the DSP. The plan then highlights the best practices and recommendations provided by CBOs involved in the community-lead workshops during the development of Part 1 of our DSP. These are foundational to the PGE community engagement framework and subsequent planning strategies sections. The last section of this plan details the results and suggestions from PGE's community-led workshops, as well as how PGE will incorporate them into its DSP Part 2 community engagement planning process.

Table 14. Goals, objectives and outcomes

Focus area	Goals	Objectives	Desired outcomes
Competency	• Build skills and resources that help PGE address its gap in competency in community engagement and operationalizing equity. • Ensure transparency and accountability. • Value community engagement as a partnership.	• Adopt a long-term orientation to this work by ensuring resources to maintain ongoing relationships with the community. • Budget for collaboration with community-based partners to ensure that community engagement processes center on the needs, strengths and desires of communities. • In NWA, Part 2, ensure frequent communication, feedback loops, follow-through, early and often engagement and transparent reports.	• Build durable, long-lasting and mutually beneficial relationships with community partners. After relationships are cultivated, work toward partnership with CBOs representing environmental justice communities.

68. Research Justice Institute, Coalition of Communities of Color. 2021. Distribution Systems Planning (DSP) Community Engagement Best Practices and Recommendations — Available at: portlandgeneral.com

Table 14. Goals, objectives and outcomes (continued)

Focus area	Goals	Objectives	Desired outcomes
Activate	• Center meaningful participation of environmental justice communities. • Foster CBO ecosystem.	• Allocate the appropriate amounts of time, resources and budget to ensure quality engagement processes. • Provide energy information that is accessible, relevant and approachable ahead of asking for input. • In NWA, Part 2, advocate for representation on HB 2021 Community Benefit and Impact Advisory Group (CBIAG), build CBO capacity/resources via financial assistance and pursue direct community engagement as a complement to CBO partnership.	• Foster procedural equity. • Enable members of environmental justice communities to contribute and be involved in a meaningful way.
Data	• Implement community-centered engagement best practices. • Rely upon a diversity of data (GARE Tool, Step #2) and diversity of research (including both quantitative and qualitative).	• Uphold best practices and recommendations provided by CBOs. • Ensure engagement is informed by data and tailored to the needs and interests of affected communities.	• Understand community energy needs, desires, barriers and interest in clean energy planning and projects and where opportunities exist. • Achieve “intentional representativeness.”

3.4.3 BEST PRACTICES

3.4.3.1 Recommendations from Community Energy Project

Popular education is an active learning process that raises social awareness, stimulates critical and creative thinking, and leads to action for social change. It’s based on the idea that people are the experts in their own lives and everyone, including the facilitator, can learn from one another on any given topic. Educators and organizers who use popular education should always start with what people already know and build on it.[69]

In partnership with UniteOR, CEP introduced many popular education elements to the DSP community workshops. Workshops were held for six hours across two days, allowing for a significant amount of time for storytelling, interactive activities and deeper understanding, which leads to deeper conversations. CEP provided the baseline knowledge and relevancy, while UniteOR led people into deeper thinking about each topic.

CEP takes a specific approach to community education with the Interpretive Method, which focuses on being accessible, relevant and approachable.

69. More information on popular education is available at: multco.us

3.4.3.1.1 Accessible

- Translation into both lay terms and the preferred languages of participants and accessibility for deaf and hearing-impaired participants (captioning and/or American Sign Language interpretation)
- Multi-sensory approach to serve multiple languages, literacy levels and learning styles (e.g., images, tactile opportunities, written and spoken)
- Digital and physical space accessibility (see **Section 3.4.3.1.4** on COVID-19 considerations)
- Scheduling based on times that work best for participants, not what's most convenient for presenters
- Easy registration, reminders and follow-up
- Content broken into themes and sub-themes for easy learning
- Third-grade reading level content for the most efficient understanding
- Cultural competence to ensure events are not scheduled during holidays and celebrations and food is not offered during fasts; recognition that some languages (e.g., Somali) are more spoken than written

3.4.3.1.2 Relevant

- Starting points at which participants understand concepts and expanding through examples and analogies, rather than starting from scratch
- Topics that are important to participants and information they want to know and value
- Ways to take immediate action
- Storytelling that allows participants to connect more with the content to better understand it and with one another to share wisdom, insight and advice

3.4.3.1.3 Approachable

- Respectful treatment of participants as intelligent people who are ready to learn about a new topic, with the understanding that some may know less than others
  - While it is recommended to aim for a third- to eighth-grade reading level, do not treat participants as if they are elementary school students, since people at all education levels understand new concepts when presented this way.
- Awareness that teaching adults is not the same as teaching children
- Acknowledgement that participants are the experts of their own lived experiences
- Space for participants to share their own tips, tricks and ideas with PGE and other participants
- Encouraging questions and inviting participants to answer (prizes in person are a great motivator)
- Dynamic, engaging presentations that show PGE values being in this space
- The ability for participants to leave whenever they want; they need to want to be present and participatory
- Well-trained presenters who can command the audience
- Well-prepared and practiced presenters to show the value on participants' time
- Flexible and welcoming environment that never shames people for being late, jumping ahead, asking simple questions or not understanding content

3.4.3.1.4 COVID-19 considerations

The pandemic altered the way CEP normally would have conducted workshops. There are elements to digital and physical workshops to be considered. CEP serves far more people through its workshops when they're able to meet in person, showing that the digital divide can be enormous for those who have low incomes or far less experience with digital formats, such as seniors.

3.4.3.1.5 Digital workshops

- Access to technology; laptops with data plans were provided to participants who did not have them
- Experience with technology; online formats mean technical troubleshooting and time spent explaining how to use the tools
- Session recording that was easy to do and made content available for later review
- Closed captions that, while flawed, can be easily provided to accommodate hearing impairment and learning styles

- Interpretation divided into rooms
  - **Pros:**
    - Interpretation is provided, making workshops more accessible overall
    - Simultaneous translation is possible, rather than back-and-forth, which doubles the time of content delivery, is chaotic and can reduce engagement overall
    - Content, messages and Q&A can all be in the participant's native language
  - **Cons:**
    - Pacing/timing can be difficult for the primary presenter, who may feel the need to rush or skip important information to keep up
    - The audience is separated into two or more groups, which silos them by language and makes it harder to take notes, track questions and manage messages
    - Workshops provided fully in one language are almost always preferred by presenters and audience members
- Recognition that digital workshops lack opportunity for tactile learning experiences
- Acknowledgement that digital workshops may be too difficult for some groups, and those groups will miss out

3.4.3.1.6 Physical (in-person) workshops

- Safe and familiar locations — consider spaces they're used to, such as schools if working with parents or a community space if working with people in a multi-family housing building
- Spaces easily accessible via public transit
- Spaces that meet ADA requirements
- Spaces that are welcoming and inclusive (be thoughtful when scheduling at places of worship, locations with political affiliations or in or near government agencies)
- Food and beverages provided
- Child-friendly spaces or childcare options/stipends provided
- Ability for people to eat together during breaks and lunches for more informal and fun bonding and storytelling

3.4.3.1.7 Budget considerations

In-person meetings require the budget for additional items, compared to digital or virtual formats.

3.4.3.1.8 Digital workshop considerations

- Mailing information and stipends
- Devices/data plans for accessibility
- Upgraded Zoom accounts to accommodate multiple rooms for different languages and settings that allow for closed captioning
- Possible IT support

3.4.3.1.9 Physical (in-person) workshop considerations

- Mileage and transportation/transit stipends
- Food, props and prizes
- Additional time for commuting, set-up, take-down and other location prep
- Possible rental fees for spaces

3.4.4 DSP COMMUNITY ENGAGEMENT BEST PRACTICES AND RECOMMENDATIONS REPORT (APPENDIX H)

PGE's work with UniteOR, CEP and CCC led to reflections and recommendations that informed our community engagement framework and planning. In addition, learnings from the DSP community workshops that were convened on PGE's behalf as well as their recommendations based on their expertise and experience with vulnerable communities were synthesized into a report that is referenced in the following sections.

3.4.4.1 Community engagement recommendations

Include the following items in the budget for community engagement:

- At least four to six months of planning in partnership with CBOs for outreach, recruiting, event planning (if in-person) and coordination with interpreters, facilitators and back-end support, such as transportation, food and childcare
- Stipends for all participants

- Funds for possible future re-engagement (e.g., sharing outcomes and vetting feedback with partners and community members/participants)
- Preparation and practice with interpreters (based on UniteOR's model)
- Community-based feedback loops
- Community engagement findings to share with community members and explanation of how those findings are influencing future decision-making
- Pre-workshop survey/evaluation to gauge expectations versus experience
- Terms/glossary to make technical information more accessible

Collect disaggregated demographic data using the REaL-D format (race, ethnicity, language and disability) and SOGI format (sexual orientation and gender identity; SOGI forms are still being drafted and vetted). The REaL-D format is lengthy, so depending on the data collection context, consider at least including the race and ethnicity questions and categories on participant evaluation tools/surveys to better capture the demographic diversity of participants.[70]

3.4.4.1.1 Workshop approach

- Ensure technical information is accessible and interpreters are available. Provide technical/digital support and incorporate interactive and discussion-based content.
- Present information that is relevant to community members' lived experiences.
- Foster trust- and relationship-building with historically marginalized communities.
- Enable and invest in community-led organizations and processes.

3.4.4.1.2 Workshop reflections

- Set aside time before the workshop for technology tutorials and plan for technology troubleshooting.
- Begin the workshop with stories, which allow for people to connect early in the session.
- Center the focus through a lens of environmental justice (EJ); for example, how can PGE's goals be balanced with EJ goals?
- Use a popular education model (which encourages a high degree of participation from everybody) by using trivia, polls or a Jeopardy-style format in which participants are given answers first and must guess the questions.
- Include various pauses and prompts to give participants time to process and relate.
- Discuss goals, actions and advocacy efforts around climate resiliency, EJ and energy issues at different levels, including personal, community and institutional/governmental.
- Include action items early on and provide information about CBOs with resources.
- Integrate energy-related resources throughout the workshops and allow time to discuss.
- Set aside time to discuss strategies for reducing the energy burden and energy consumption and how communities can access renewable energy sources at lower rates.
- Learn from the community by asking, "What tips and tricks do you have?"
- Include more community-based examples of climate resiliency (such as the California microgrid).
- Invite and involve more CBOs in the workshops.
- Provide more clarity about why these conversations are needed now. What laws and regulations are important to know about?

3.4.4.2 Importance of demographic data

There are many technical reasons to have demographic data; for example, to understand language and accessibility needs. However, gathering detailed demographics is also vital in the practice of data justice because it makes those who are marginalized visible, thus making institutions more accountable. Institutional research has a long history of being either exploitative or neglectful of marginalized communities.[71] In a time of increased awareness of the power of data, researchers need to ensure that their data is serving communities rather than extracting from them and potentially using data in ways that harm marginalized communities. This means collecting information on race/ethnicity, sexual orientation and gender identity, as well as disability, immigration, refugee status and socio-economic status. All these factors not only influence how participants may interact and react to the workshops, but also assist PGE and partners in understanding which communities need more intentional outreach.

70. More information about REaL-D is available at: oregon.gov
71. Taylor, Linnet. 2017. "What is data justice? The case for connecting digital rights and freedoms globally," Big Data & Society, July-December 2017:1-14.

3.4.5 PGE COMMUNITY ENGAGEMENT FRAMEWORK

Based on lessons learned, PGE's approach to community engagement in the DSP and future planning and investment efforts prioritize quality engagement by taking the following actions:

- Listen and communicate.
- Use data.
- Ensure budget.
- Ensure relevancy.
- Ensure time.

Throughout the life of a project, continuous application of an equity lens must be applied both to the internal and external work. PGE has a responsibility to identify disproportionate adverse effects that a project may have on any community, but particularly for EJ communities. As a guide to this work, PGE will use the GARE racial equity tool to integrate equity into operations and decision-making. This tool offers critical questions in each of its six steps, intended to integrate explicit considerations of racial equity into projects, programs, policies and budgets.

3.4.5.1 GARE racial equity tool

STEP#1

Proposal:
What is the policy, program, practice or budget decision under consideration? What are the desired results and outcomes? (Focus on impact.)

STEP# 2

Data:
What's the data? What data is missing? What are the limits associated with the data that is missing? What story does the data tell?

STEP# 3

Community engagement:
How have communities been engaged? Are there opportunities to expand engagement?

STEP#4

Analysis and strategies:
Who will benefit from or be burdened by the proposal? What are the strategies for advancing racial equity or mitigating unintended consequences?

STEP# 5

Implementation:
What is the plan for implementation?

STEP# 6

Accountability and communication:
How will you ensure accountability, communicate and evaluate results?

As part of this process, PGE must identify ways in which the communities' needs and desires inform planning, investment and implementation. In planning community engagement activities (e.g., listening sessions, workshops), it is important to center the needs, strengths and desires of communities throughout the process. Designing programs and solutions with affected communities (instead of for them) produces better outcomes.

The Movement Strategy Center's Spectrum of Community Engagement to Ownership provides further guidance. Communities will be engaged at various levels of the spectrum pre-, mid- and post-implementation. PGE intends to defer to communities wherever and whenever possible. This builds trust with our communities and fosters participatory planning and advances community-driven solutions.

Engagement will come only after PGE has identified communities geographically and their impacts. PGE must also determine the level of engagement needed and develop an understanding of the communities (data can inform this understanding, but alone is not enough). Partnering with community-based and culturally-specific organizations is crucial to building trusted relationships, learning from communities and understanding their needs, strengths and desires.

Quality engagement is ongoing and needs adequate investment. This includes budget, time and people. In addition to proper time allocation, it is necessary to invest in the resourcing of people to support the engagement work (internal community outreach and engagement staff). Compensation for all engagement participants is mandatory. Community time, input and expertise must be provided through stipends, supply of childcare and translation.

Meaningful participation is key to engagement success. Success for participants is defined by their experience and perceived value of the time they invested. Community wisdom must be valued in the engagement process, and PGE must seek to integrate these diverse perspectives in project decision-making. Transparency and accountability (describing how input is used or not used, ensuring results are communicated back, and explaining who is making these decisions) in the engagement process is necessary. Throughout the life of a project, continuous application of a racial equity lens must be applied both to the internal and external work. PGE has a responsibility to identify disproportionate adverse effects that a project may have on any community, but particularly for EJ communities.

3.4.5.2 Planning strategies

The following strategies are intended to guide the implementation of the PGE community engagement framework.

3.4.5.2.1 Listen and communicate

PGE must ensure transparency, clarity and accountability through effective and ongoing communication.

- Create a safe and inclusive space for all participants by establishing community agreements and ensuring there are protocols and processes in place if agreements are broken.
- Inform communities who the decision-makers are and what their input and involvement can influence.
- Build multiple feedback loops into the engagement plan, as well as the project's communication plan, to ensure results are reported back to the community in a transparent, relevant and accessible manner.

3.4.5.2.2 Use data

Data is essential to informing projects and programs and allows for assessment of the desired outcomes. PGE must ensure that data is leveraged to inform strategies and results. The company must use data to develop performance measures that allow program monitoring and improve the understanding of communities, trends and needs.

- Inventory data to assess whether the needed data is available and at the appropriate level; identify gaps and how to address them.
  - This inventory should include learnings from previous community engagement efforts. What has PGE already learned from community members? How is PGE incorporating and tracking community-informed changes within the organization?
  - PGE should research the history, culture, past plans and other needs of impacted communities and review these findings with community members (and/or organizations) who have the institutional and historical knowledge.
- Use demographic data to identify which groups have been engaged and who is missing.
  - PGE should collect disaggregated demographic data using the REaL-D format (race, ethnicity, language and disability) and SOGI format (sexual orientation and gender identity; SOGI forms are still being drafted and vetted). The REaL-D format is lengthy, so depending on the data collection context, consider at least including the race and ethnicity questions and categories on participant evaluation tools/surveys to better capture the demographic diversity of participants.
- Develop mechanisms of evaluation that are focused on impact and answer the following questions:
  - Quantity: How much did PGE do?
  - Quality: How well did PGE do it?
  - Is anyone better off?
- Use performance measures to monitor of the success of actions that have a reasonable chance of influencing indicators and contributing to success.
- Evaluate each community engagement process from both a PGE and community perspective and use feedback and lessons learned to inform future efforts.

3.4.5.2.3 Ensure budget

PGE must ensure the appropriate allocation of time, people and budget for community engagement in planning and pre-development of projects.

- Budget and prioritize resources to engage with EJ communities and ensure people have the competencies, understanding and experience to engage with historically excluded, underserved and underrepresented communities.
- Budget for collaboration with community-based partners to ensure that community engagement processes center the needs, strengths and desires of communities. Community-based partners and organizations have a deep understanding of the current engagement context, including the challenges and opportunities in various types of engagement (e.g., remote/online and culturally appropriate processes). CBOs also understand the amount of time and money it takes to genuinely engage communities. CBOs have invested resources into building long-standing relationships and trust with communities; however, engagement is an ongoing process, rather than a one-off, and conducting outreach for any new project requires significant resources.
- Allocate at least four to six months of planning in partnership with CBOs for outreach, recruiting, event planning (if in-person) and coordination with interpreters, facilitators and back-end support, such as transportation, food and childcare.
- Build in additional time buffers to adjust plans as needed, address newly identified concerns and account for changes to political and/or regulatory context.
- Budget for stipends that compensate all participants for their time, expertise and input, including language interpretation and translation services, food and childcare (if in-person).
- Reserve budget for possible re-engagement with community (e.g., sharing outcomes and vetting feedback).

3.4.5.2.4 Ensure relevancy

PGE must ensure engagement activities are informed by community-centered best practices and are tailored to the needs of each community.

- Ensure participants have clarity around why they are being asked to engage, what the benefit to their engagement is and why it matters to PGE and the topic or concept.
- Offer information in an accessible, relevant and approachable way that provides participants with the context needed to fully participate.
  - Ensure translation needs are met and language is non-technical.
  - Allow for multiple language translations, literacy levels and learning styles.
  - Make the engagement process as easy as possible (e.g., removing barriers and sending reminders).
  - Provide examples that participants can build on and relate to.
  - Focus on topics that are important and valued by participants.
  - Incorporate calls to take action where appropriate and provide supporting resources.
  - Use a popular education model (which encourages a high degree of participation from everybody) by using trivia, polls or a Jeopardy-style format in which participants are given answers first and must guess the questions.

3.4.5.2.5 Ensure time

PGE must challenge the all-too-familiar sense of urgency by ensuring that there is adequate time to enable engagements and activities that achieve their intended outcomes.

- Set aside time during activities to discuss related issues that are relevant to participants and provide context for how they connect with energy (e.g., energy burden or climate-related recent events).
- Incorporate storytelling and allow participants the space to share their experiences and offer wisdom (e.g., tips and tricks for staying cool or warm).
- Offer energy-related resources throughout the engagement activity and ensure time to discuss.
- Design activities with intentional pauses and prompts to allow time for participants to process and relate to the content being shared.
- Treat participants with respect by being flexible and welcoming; never shame participants for being late, entering discussions at a different place of understanding or leaving early.

3.4.6 RESULTS AND LEARNINGS FROM PART 1 DSP PILOT COMMUNITY WORKSHOPS

3.4.6.1 Part 1 community engagement

PGE partnered with UniteOR, CEP and CCC to develop, facilitate and synthesize findings from two pilot workshops designed to engage BIPOC, immigrant and refugee and low-income communities in Oregon. The workshops are part of community engagement activities that utility agencies are required to perform by the OPUC's DSP guidelines. These workshops were held on Saturday, May 22, and Sunday, May 23, and each lasted for three hours (9 a.m. to noon). Participants were provided with a $250 stipend for attending both workshops.

The feedback and recommendations collected from participants and partner teams (CCC, UniteOR and CEP) were synthesized and shared with PGE via the DSP Community Engagement Best Practices and Recommendations report, prepared by the Research Justice Institute at the CCC. The following results and suggestions are excerpts from this report.

3.4.6.2 Part 1 community workshop results

Sample size: The outreach sample size (composed of the community members who completed the registration survey) was 46. The total number of participants who engaged with either the first or second workshop was 35. The workshop on day one had 32 attendees, day two had 21 and a total of 18 participants attended both.

Data collected: Demographic data was collected from participants at registration and on the day one workshop post-survey. Participation from people who identify as LGBTQ+, people of color, those with disabilities, older adults and those within the Arab, Middle Eastern and Muslim communities was lacking in the workshops.

Data sources and analysis: Participants completed three surveys; the analysis includes quantitative and qualitative data from each survey.

Highly rated topics among participants: After each day of the community workshops, participants were asked what topics were most useful. Many indicated that all topics were useful, but some topics were highlighted more than others. On day one, information about reducing and saving energy (including peak hours), where energy comes from (including the modern grid system), and the consequences of fossil fuels and benefits of renewable energy were valued by participants. On day two, valuable topics included microgrids and examples of energy-resilient communities and the connection with institutional or structural conditions, how to reduce energy use, strategies for saving energy and other environmental resources. Many participants indicated that they were previously not aware of the topics discussed in the workshops. This highlights the importance of accessible introductory workshops for community members.

Community effects and needs regarding energy systems: Participants were asked about how the topics affected them and their communities. Participants indicated many ways in which climate change, energy costs and other factors influenced their communities. Some of the most repeated examples include communities still reeling from recent natural disasters such as wildfires, communities surviving disasters through mutual aid, but not having the resources to prepare for or prevent future disasters, and energy efficiency not being accessible for all renters.

Participants spoke about a range of needs. These include more community-centered education and resources on energy savings, communities' need to be alleviated from cost barriers to resources in renewable energy, weatherization and smart technology, support in utility payments (for communities still reeling from COVID-19), and more government and corporate agencies addressing climate change and its effects on vulnerable communities.

In addition, vulnerable communities (such as low-income, rural and BIPOC communities, renters and those who work outside) need more support in energy saving and protection from climate change. A workshop participant was quoted as saying, "I do think it is important not to just put the [climate change] burden on communities, but also hold governments and corporations accountable. It is more like a top-down approach."

Participant suggestions for future workshops: Co-creating a brave space with community members of different backgrounds, languages and abilities is a difficult feat that requires time to practice, reflect and reconfigure.[72] Many participants gave positive feedback, which reflects the efforts of UniteOR and their partners. However, even among experts in community organizing, there is always room for improvement, which was reflected by the participants as well. Some suggestions were addressed in the day two workshop. For example, many participants on the day one workshop mentioned having difficulties understanding the presentation due to language barriers. This was addressed in the day two workshop by adding a slide better explaining how to use the interpretation features on Zoom. Additionally, participants also requested having more interactive learning and engagement tools during the presentation. This was addressed by adding more online learning tools, such as JamBoard, during the day two workshop.

Participants wanted more information about energy in different systems, such as community and institution, and about efforts to address energy and climate burden among vulnerable communities across the nation. Participants also requested more resources on energy-saving techniques, examples of energy-resilient communities and educational opportunities, so they can be more informed and make better energy decisions. What is most apparent from these comments is that community members need more engagement through CBOs, more information about energy and climate change in their communities and more investment from companies like PGE. Workshops like these are rare for marginalized communities, and due to this they are often left out of important decisions. However, this exclusion does not have to continue, and through these workshops, PGE has been able to provide recommendations to change that practice.

72. Brave Space: A brave space is a space where participants feel comfortable learning, sharing and growing. A brave space is inclusive to all races, sexes, genders, abilities, immigration status and lived experiences. More information available at: rooseveltufsd.org

3.4.6.3 Planning for Part 2 DSP pilot community engagement

In addition to leveraging the PGE community engagement framework and ensuring best practices are applied, PGE will also incorporate the results and suggestions of Part 1 community workshop participants. The following outlines how those results and suggestions will be addressed in the Part 2 pilot community engagement process.

- Although PGE sought to be intentional in fostering the diversity of voices and recognizes this effort as significant, there is still a substantial amount of work that needs to be accomplished to reach all communities. Specifically, this includes Native American tribal communities, LGBTQ+ communities, people of color, seniors and people with disabilities who have not been engaged (or properly represented) in the UM 2005 process thus far. It is the intention of PGE to prioritize reaching the communities that have not been engaged thus far by identifying community partners that have existing relationships with these communities and seeking consultation on how to best reach and engage them.
- As PGE plans for the next phase of DSP, the company will think more expansively about the topics for community engagement as well as the resources PGE can provide. This includes additional community-centered education and resources on energy savings and addressing the cost barriers in renewable energy, weatherization and smart technology, the impacts of COVID-19 on communities, and climate change protection for vulnerable communities and individuals. PGE will seek to incorporate a broader array of relevant and timely topics and resources into future workshops and engagement activities.
- Finally, PGE seeks further partnership with previously involved and additional CBOs to help continue to reach and meaningfully engage marginalized communities, identify their needs and include their perspectives and input in future planning.

3.5 Community engagement learnings to date

Table 15. Community engagement lessons

Requirement area	Learnings
Baseline data	• To better understand the needs and wants of the communities PGE serves, it must first understand where environmental justice communities live, work and play. • PGE may begin to identify these communities by examining demographics or attributes that include income, race/ethnicity, age, disability, language spoken and heat type. • A map and its dimensions enable PGE, partners and communities to apply a human-centered approach to grid topology and planning.
Hosting capacity analysis (HCA)	• The HCA is a tool upon which a community needs analysis may be based in a subsequent phase, so it is important to carefully consider the screens applied to this data. • Staff guidance states that pilot concept proposals should be reasonable and meet the guidelines, even if the individual proposal may not be cost-effective, likely because screens like cost-effectiveness may have the unintended consequence of disqualifying certain locations and perpetuating structural inequities.

3.5.1 ENGAGING ALONG THE SPECTRUM

Effective planners know that designing programs and solutions with affected communities (instead of for them) produces better outcomes. In the Connectivity Means Community presentation "Distribution System Planning for Humans," presenters noted five approaches to engagement: inform, consult, involve, collaborate and defer to. Staff subsequently requested that each of these approaches be incorporated into a robust Community Engagement Plan and ongoing process.

As referenced in the "Centering on Communities" presentation by Verde and the Community Energy Project, the Movement Strategy Center's Spectrum of Community Engagement to Ownership guidance with respect to these recommended approaches is provided in **Figure 16**.[73] As stated, PGE intends to defer to communities wherever and whenever possible. Doing so empowers communities, fosters participatory planning and advances community-driven solutions.

73. The Spectrum of Community Engagement to Ownership; Movement Strategy Center. Retrieved from: movementstrategy.org

Figure 16. The Spectrum of Community Engagement to Ownership

Stance toward community	0 Ignore	1 Inform	2 Consult	3 Involve	4 Collaborate	5 Defer to
Impact	**Marginalization**	**Placation**	**Tokenization**	**Voice**	**Delegated power**	**Community ownership**
Community engagement goals	Deny access to decision-making processes	Provide the community with relevant information	Gather input from the community	Ensure community needs and assets are integrated into process and inform planning	Ensure community capacity to play a leadership role in implementation of decisions	Foster democratic participation and equity through community-driven decision-making; bridge divide between community and governance
Message to community	Your voice, needs and interests do not matter	We will keep you informed	We care what you think	You are making us think (and therefore act) differently about the issue	Your leadership and expertise are critical to how we address the issue	It's time to unlock collective power and capacity for transformative solutions

PGE looks forward to transparent discussions with partners and community members that are grounded in the OPUC staff's approaches to engagement. Given the reality of both in-flight and planned projects, we envision different stages of engagement that are on a spectrum, occurring in parallel and informed throughout a given planning horizon. For example, engagement on long-term solution identification would be further to the right of the spectrum ("involve and collaborate") relative to in-flight projects that were planned prior to this proceeding ("inform and consult"). PGE supports engaging with communities early in the solution identification stage and will co-develop further criteria about the type and size of distribution investments that are shared through a tailored Community Engagement Plan process. We will also work with partners and stakeholders with location-based knowledge to identify who should be engaged, which types of projects they are interested in and what is most valuable to them. Additionally, PGE recognizes that "community" is not a monolith. Therefore, PGE requests that partners and stakeholders with location-based knowledge help in identifying with whom PGE should engage.

Building relationships with community partners and seeking out opportunities to establish strategic partnerships that evolve from an inform to a defer to approach is key to PGE's long-term success. To do so effectively, we must consider the following value drivers in how it engages the following:

3.5.1.1 Authenticity

PGE seeks to build durable, long-lasting and mutually beneficial relationships with community partners. We will take the time to get to know these partners, including their mission and current and past efforts, as well as their relationships with environmental justice communities and other community organizations, their capacity and their resources. It's important to engage in transparent discussions, including specific goals around engagement, and clearly communicate intentions, while also being mindful of the capacity constraints of partners and communities and within PGE. Once a relationship is established, we seek to move toward building a partnership with CBOs and organizations representing environmental justice community members.

3.5.1.2 Responsiveness

PGE is committed to ensuring product and service development is driven by community needs. We will create internal processes that ensure incorporation of community feedback, to identify, elevate and advocate for response to communicated needs, and commit to seeking new ways of thinking and developing solutions.

3.5.1.3 Sustainability

PGE is intentional in its efforts to build long-lasting, meaningful and authentic partnerships with priority communities. We will maintain ongoing communication with partner and community members and align internally to coordinate. Given this is relationship-based, trust-building work, PGE adopts a long-term orientation and seeks opportunities to leverage partners' cultural expertise to engage community members and customers in meaningful ways. As such, we are committed to pursuing various mechanisms for contracting with partners to elicit input from EJ communities with whom we may not yet have a relationship.

3.5.1.4 Summary of lessons learned

PGE is learning from partners how best to show up for communities. The chief lesson learned is that creating a collaborative environment requires first building trust. As a guide, we use the trust equation, whose founding is attributed to Charles H. Green and provided in **Figure 17**. Trust is gained by demonstrating credibility, reliability and empathy and by de-emphasizing one's self-orientation. This is complex and time-consuming work that requires a consideration of the biases and values that one brings to a potential collaboration. Trust-building behaviors establish credibility by being sincere, humble, transparent and DEI competent. They are evidenced in showing up reliably by consistently delivering on what was promised and through empathy by demonstrating care, concern and high degrees of emotional intelligence. Trust is further amplified by adopting a people-centered approach, shifting the focus toward the customer experience and de-emphasizing a utility-centric orientation to elicit meaningful insight.

Figure 17. Formula to build trust

$$\text{Trust} = f\left(\frac{\overset{\text{Words/ outputs}}{\text{credibility}} + \overset{\text{Actions}}{\text{reliability}} + \overset{\text{Emotions}}{\text{empathy}}}{\text{self-orientation}}\right)$$

3.5.2 DEVELOPMENT FOR PART 2

PGE supports the OPUC staff's multipronged engagement approach with two proposed pilot projects in the grids needs assessment and solution identification sections of the DSP plan guidelines. However, PGE does suggest that more time and flexibility be given to co-developing the scope of these pilots with partners and community members. This will allow planners to explore different engagement mechanisms that utilities can leverage to pursue these pilot projects, such as through contracting with a CBO and developing an advisory committee channel.

With respect to guidance for reasonable levels of spending to meet requirements for community engagement and planning, PGE supports the OPUC's efforts to break down barriers to inclusive participation in energy public processes, including a lack of funding to support historically excluded partners and communities. We encourage the OPUC to reach out to these groups as part of its community engagement activities.

The expected evolution of community engagement will include alignment with legislative policy and parallel regulatory dockets, as well as increased effort paid toward partnership and alignment with other energy conservation agencies like Energy Trust of Oregon (ETO), Northwest Energy Efficiency Alliance (NEEA) and EJ community coalitions.

Chapter 4.

Modernized grid: building a platform for participation

Chapter 4. Modernized grid: building a platform for participation

> "The virtue of the intelligent grid is that your connection to it can choose, opportunistically and economically, what the cheapest way is to provide energy when you need it. Your connection might think, 'Oh, there's wind that blows during the evening hours in this county, let's tap that energy right now.' 'Okay, it's a bright sunny day, let's go to the solar panels and bring that energy in.'"
>
> — Neil deGrasse Tyson, astrophysicist[74]

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 EJ communities.[75] It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter details PGE's capability roadmap over the next 10 years, along with planned investments. It discusses how the evolving grid has implications for workforce planning and cybersecurity. This chapter also provides research and development (R&D) activities undertaken by PGE.

Chapter 4, unlike other chapters, will address multiple requirements from Order 20-485[76] in each section. For this reason, we recommend revisions to the final DSP guidelines a s they pertain to the long-term plan investments, borrowing from national best practices outlined in the U.S. Department of Energy's (DOE) next-generation distribution system platform (DSPx) and DSP requirements from other jurisdictions.[77] Clearly addressing these requirements is essential to developing a DSP that communicates PGE's long-term direction and intent. We will work with partners and Oregon Public Utility Commission (OPUC) staff to more clearly frame and address these requirements in future DSPs.

74. "Astrophysicist Neil deGrasse Tyson tackles renewable energy's future," available at: renewableenergymagazine.com
75. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at: oregonlegislature.gov
76. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, and is available at: apps.puc.state.or.us
77. Department of Energy's Office of Electricity Delivery and Energy Reliability — Next-generation distribution system platform, available at: gridarchitecture.pnnl.gov

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

Table 16. Modernized grid: guideline mapping

DSP guidelines	Chapter section
4.1.c.iv	Section 4.7
4.1.d	Section 4.7
4.4.b.i	Section 4.6.3, 4.8
4.4.b.ii	Section 4.6.1, 4.6.2
4.4.b.iii	Section 4.6.3
4.4.b.vi	Section 4.7
4.4.b.vii	Section 4.6.1, 4.6.2, 4.6.3
4.4.c	Section 4.6, 4.7
4.4.d	Section 4.3, 4.4, 4.5
4.4.e	Section 4.8
4.4.b.vii	Section 4.6.1, 4.6.2, 4.6.3
4.4.c	Section 4.6, 4.7
4.4.d	Section 4.3, 4.4, 4.5
4.4.e	Section 4.8

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A: DSP plan guidelines compliance checklist**.

WHAT WE WILL COVER IN THIS CHAPTER

The benefits of a modernized grid

An overview of modernized grid architecture, systems and capabilities

PGE's roadmap and planned investments for modernizing the grid

4.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to:

- Capture planned investments
- Invest in smart grid opportunities in the next five to ten years
- Report key opportunities for distribution system benefits
- Provide a five- to ten-year roadmap of distribution system investments that advance their vision
- Provide relative costs and benefits for each category of investment
- Provide assumptions and barriers to adoption needed to achieve their vision of the DSP
- Provide current R&D activity
- Detail other opportunistic investments that can benefit the distribution system's ability to deliver customer value

In PGE's 2019 Smart Grid Report, PGE shared its integrated grid conceptualization for the modernized distribution system.[78] In this chapter, PGE builds on the integrated grid concept, provides details on its capabilities and describes how these capabilities address the goals outlined in the vision in **Section 2.3.** PGE's approach to this chapter is to provide the required details at the capability level. For each capability, PGE:

- Highlights the description and need for the capability
- Provides a gap analysis for each capability, identifying desired future functionalities
- Discusses the relative costs, benefits, assumptions, maturity and timeline at the capability level

PGE's planned investments focus on capabilities that will directly advance PGE's vision as described in **Section 2.3** by accelerating DER adoption and scaling of DER programs. PGE will build on this topic in its DSP Part 2 Action Plan.[79]

Modernizing the grid is a key element of the transformation and enablement of large-scale DER integration. Specifically, modernization will ensure solar photovoltaic (PV) systems, storage capabilities and electric vehicles (EVs) can be integrated through DER programs. Modernizing the grid works to improve grid flexibility and asset utilization as well as reduce the need for long-term supply-side resources. This approach addresses the grid goals outlined in PGE's vision as described in **Section 2.3.** DERs and their associated programs can provide community benefits, accelerating environmental justice goals as outlined in **Section 2.3.** 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 ensure investments provide significant customer value once in service.

78. PGE's 2019 Smart Grid Report is available at: apps.puc.state.or.us
79. Under UM 2005 Order 20-485, PGE is required to submit Part 2 of its initial DSP by August 15, 2022.

4.3 Modernized grid desired outcomes

Grid modernization refers to the evolution of the grid through the integration of new technologies and enhanced computing solutions. This transformation has been underway for several years, with its scope evolving over time. Early grid modernization efforts focused on improving the operator's awareness of the state of the distribution system, especially as it related to outages. This was soon followed by the need for improved planning and forecasting capabilities to ensure least-risk, least-cost planning. Today, grid modernization on the operations side involves not only operator awareness, but also operator control, specifically the interaction between DERs and the grid. On the planning side, needs have evolved to focus on the ability to holistically interconnect DERs to deliver maximum grid and community benefit. As technologies and computing solutions mature, it is likely that the scope of grid modernization will continue to evolve as well.

In line with this evolution, PGE continues to modernize the grid as reported in previous smart grid reports and the most recent General Rate Case.[80] While PGE's historical efforts have focused on improving operator awareness and distribution system resolution, current and future efforts will build on this work to enable seamless integration and control of DERs to deliver a vibrant, two-way grid that is safer, more secure, more reliable and more resilient, at fair and reasonable costs.

PGE shares examples of how the grid modernization capabilities broadly advance the vision described in **Section 2.3**.

- **Decarbonization:** By managing DERs connected to the grid, operators can co-optimize across available resources to ensure least cost and carbon intensity in resource dispatch.
- **Reliability:** Investments in sensors and communication devices to increase the amount of information received about the performance of the distribution grid can help operators better predict distribution system needs and take necessary steps to prevent system reliability issues.
- **Resilience:** Through investments in smart algorithms and sensing devices, feeder sections can be isolated to create microgrids that provide resilience during disruptive events.
- **Security:** While grid modernization investments increase the attack surface or number of access points for cybersecurity threats, PGE is taking proactive steps through investments in cybersecurity solutions and the integration of cyber-physical security in planned investments. This is highlighted in **Section 4.5**.
- **Assistance for EJ communities:** Through investments in analytics platforms that use smart meters, PGE can develop improved rate designs and DER programs to assist with energy burden relief in EJ communities. PGE has already started developing load-shaping solutions through its Time of Use programs.[81]

80. PGE's July 9, 2021, UE 394 filing is available at: ue394htb155528.pdf (state.or.us). Transmission and distribution expenditures are summarized in Exhibit 801.
81. More information on PGE's pricing programs is available at: portlandgeneral.com

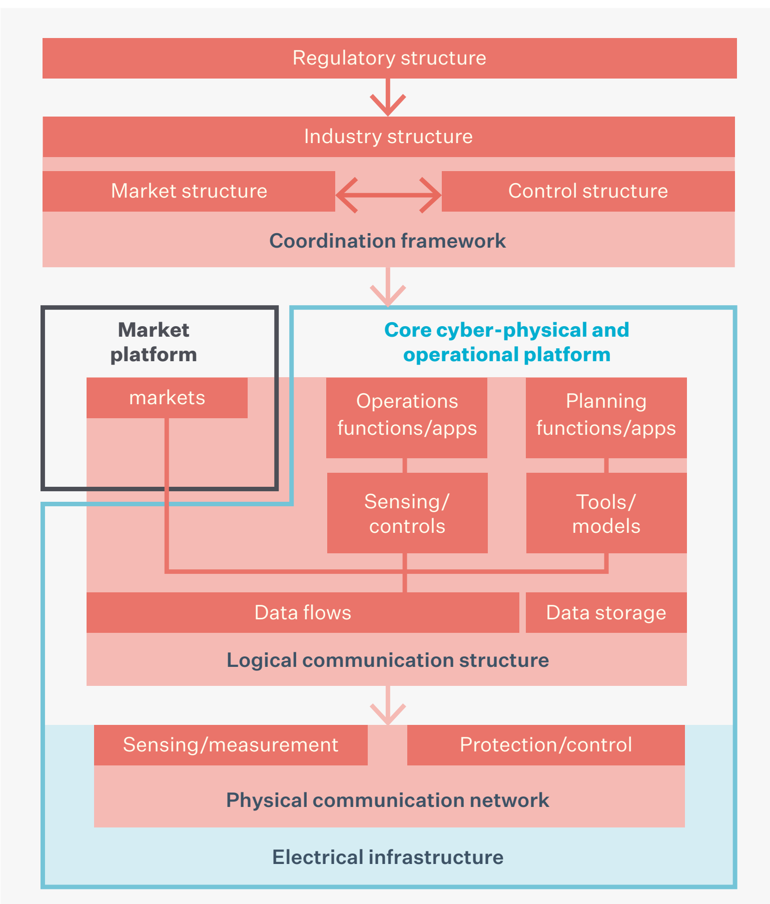
4.4 Modernized grid approach and architecture

The scope of grid modernization is likely to evolve with the maturity of different technologies. To ensure new technologies and capabilities can be integrated easily, a platform-based architecture with modular elements is the most promising approach. Certain central capabilities remain relatively stable throughout the platform's evolution over time. These are known as core platform capabilities, or foundational capabilities. Examples include planning for peak and daytime minimum load and transferring loads or isolating faults for system reliability. Other capabilities and layers are complementary to these core capabilities and work in an integrated manner to deliver customer value, such as a customer's digital experience through PGE's application on their smart phone.

PGE, just as most, if not all, utilities, has adopted a platform-based architecture. Additionally, there is consensus among most experts, including the U.S. DOE, on modernizing the grid using a platform architecture. In other words, a modernized grid is equivalent to a platform with layers of digital capabilities upon layers of physical assets that work together in various combinations to improve and enable system capabilities. Over time, as different technologies mature, capabilities and layers can be added or replaced as needed. A common example of this is in meter technology, where previous generations of automatic meter reading (AMR) have given way to advanced metering infrastructure (AMI) and smart meters, which can perform more computationally advanced functions.

In PGE's system, physical assets include grid infrastructure (such as poles and wires, smart sensors, meters and switches) and telecommunication assets (such as fiber optic cables and field area networks, or FANs). These components work together to send signals and receive actions from digital capabilities such as an advanced distribution management system (ADMS) or DER management system (DERMS). These digital capabilities use data from physical assets to feed algorithms that optimize system performance, delivering a more efficient and flexible electric system. The same data combined with ADMS and DERMS outputs is also used for planning purposes as part of a feedback loop. This interaction across the different layers of a modernized grid is shown in **Figure 18**.

Figure 18. Layers within a distribution system platform as described by DOE's DSPx



4.4.1 ALIGNMENT WITH DOE'S DSPX[82]

PGE's grid architecture is grounded in the DOE's DSPx approach. This architecture builds on PGE's work as described in prior smart grid reports and uses the same layered approach as the DOE's DSPx to build a cyber-physical grid platform.

We will continue to align as closely as possible, where reasonable and feasible, with the DOE's DSPx recommended method to justify grid modernization investments. This is operationalized through project assessment processes in PGE's Grid Modernization Business Service Group as described in **Section 2.5.2. Table 17** illustrates DOE guidance for grid modernization investments.[83]

Table 17. Grid modernization cost-effectiveness framework from DOE's DSPx Volume III

Expenditure need	Methodology	Examples
Grid expenditures to replace aging infrastructure, new customer service connections, relocation of infrastructures for roadwork or the like and storm damage repairs	Least-cost, best-fit or other traditional method recognizing the opportunity to avoid replacing like-for-like and instead incorporate new technology	Planning tools and models, physical infrastructure, sensing devices and telecommunication devices
Grid expenditures required to maintain reliable operations in a grid with much higher levels of distributed resources connected behind and in front of the customer meter that may be socialized across all customers	Least-cost, best-fit for core platform, or Traditional utility cost-customer benefit based on improvement derived from technology	Smart meters, volt-VAR management and optimization analytics
Grid expenditures proposed to enable public policy and/or incremental system and societal benefits to be paid by all customers	Integrated power system and societal benefit-cost (e.g., EPRI and NY REV BCA)	Non-wires solution analysis (NWS)
Grid expenditures that will be paid for directly by customers participating in DER programs via a self-supporting, margin-neutral opt-in DER tariff, or as part of project-specific incremental interconnection costs	These are "opt-in" or self-supporting costs, or costs that only benefit a customer's project and do not require regulatory benefit-cost justification	Customer portion of DER costs

4.5 Modernized grid framework

PGE's latest iteration of its modernized grid framework is outlined in **Figure 19**. 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 best practices. Because of the complexity of the DSPx graphic and the DSP's focus to appeal to both partners and communities (traditional and non-traditional stakeholders), we performed multiple iterations to create a consistent, capability-based, PGE-specific modernized grid framework.

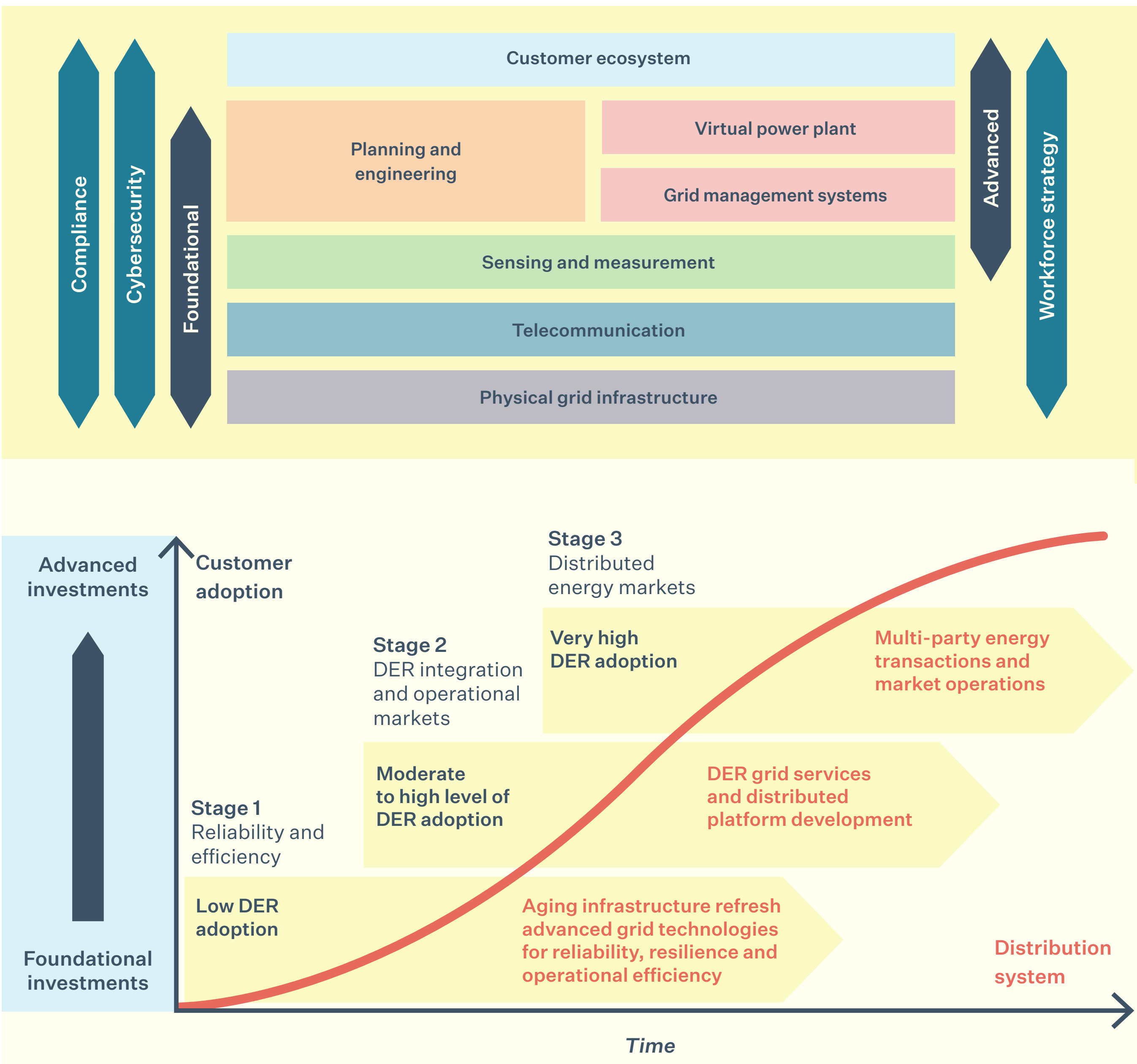
PGE's modernized grid framework can be broken down into three categories:

- **Foundational capabilities** refer to the set of core platform investments needed to improve monitoring and basic control of the distribution system. Based on **Table 17**, these investments follow a least-cost, best-fit approach, usually through a request for proposal (RFP) or similar process.

82. U.S. Department of Energy's Modern Distribution Grid Project is available at: gridarchitecture.pnnl.gov
83. More details can be found in DOE's DSPx guidance in Volume III, available at: gridarchitecture.pnnl.gov

- **Advanced capabilities** refer to investments that build on or, in some cases, supplement foundational investments to develop advanced controls 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 investments. They are key considerations when making the investments after the primary need is addressed. They include cybersecurity, workforce implications and other compliance needs. This overarching nature requires the investment justification to mirror the base investments (cybersecurity investments needed as part of foundational capabilities would be based on least-cost, best-fit, whereas cybersecurity investments as part of some advanced capabilities, such as a conservation voltage reduction program, would likely require a benefit-cost analysis).

Figure 19. PGE's modernized grid framework



We believe that compliance and workforce strategy are not capabilities by themselves but are key considerations in the development of each capability. Foundational and advanced capabilities will impact most areas of the company, so workforce gaps will need to be assessed and solutions prioritized at the functional level as well as at the organizational and enterprise level.

To be successful, PGE must develop a workforce plan that can help adapt to and evolve with changing conditions and the maturity of different technologies. Our workforce plan must be built on the foundation of recruiting, developing, retraining and retaining the talent required to help enable the grid's transformation. Hiring staff with skills relevant to new technologies while diversifying recruiting practices to broaden the range of skills and abilities will be important. However, as the market gets more constrained, workforce strategies must include more solutions than just recruiting.

New technologies with the requisite skillsets often outpace what the current workforce can provide. The ability to address key skill shortages will enable PGE to keep up with new technologies and progress through our capability maturity model. As such, reskilling, upskilling and implementing talent initiatives designed to redeploy staff to other parts of the business are essential components to PGE's workforce plan. Diversifying PGE's staffing strategies should include new ways of deploying talent to manage the transactional elements of its operations and the strategic and specialized elements of the grid. Augmenting the workforce with outside resources for various durations of time will allow us to more quickly move and pivot. Smart grid technologies and processes will require different levels of education and training, which has implications for how we invest in our training programs. There may be workforce segments where we hire more early-career professionals and train them to proficiency across a variety of technologies.

While it's important to build a flexible and dynamic workforce, we should ensure we are focusing on retention strategies that improve productivity and employee engagement. Keeping valuable employees will help PGE win in a competitive marketplace. All these elements are further strengthened by the right organizational structures that encourage alignment and cross-functional coordination to achieve modernized grid objectives.

Table 18 provides brief descriptions of each capability, including the needs they address and examples of the technologies and functions.

Table 18. Capabilities and their descriptions

Capability	Description of capability and needs statement
Customer ecosystem	Description: Providing customers access to relevant and timely usage, system infrastructure and operational data Needs statement: Enable customer choice and decision making. Example technologies: Customer analytic tools (e.g., calculators), green button (automated data transfer), smart meters/meter data management system Example functions: Remote meter data collection and verification, energy management and DER purchase/program performance analysis, advanced interactive voice response (IVR) systems
Virtual power plant (VPP)	Description: Multiple flexible loads and DERs, which in aggregate, supply grid services visible to and dispatchable by PGE power operations, characteristic of a traditional power plant facility. Needs statement: Distribution investment deferral, support for customer needs such as resiliency and resource adequacy Example technologies: DERs, DER programs, dynamic tariffs Example functions: Delivery of peak load electricity or load-following power generation on short notice, ancillary services including frequency regulation and providing operating reserve

Table 18. Capabilities and their descriptions (continued)

Capability	Description of capability and needs statement
Planning and engineering	Description: A suite of integrated tools to perform distribution system planning and engineering functions Needs statement: Improved planning enables optimal grid investments, including DER integration through information exchange and non-wires solutions. Example technologies: CYME/Synergi (power flow analysis), Envelio, cost-effectiveness tools, AdopDER (DER forecasting), OpusOne Example functions: Grid needs analysis, locational net benefit analysis, non-wires analysis, hosting capacity analysis, DER forecasting
Grid management systems	Description: A set of computer-aided tools used by operators of electric utility grids to monitor, control and optimize the performance of the distribution system Needs statement: Shifting from central management of one-way power flows supplied by relatively few bulk generators to coordinating large numbers of DERs, creating two-way power flows, may cause grid stability issues. As DER adoption grows, the number of possible control actions will increase and the time to execute those control actions will decrease beyond the capability of human grid operators to react to events. Safety and reliability issues will increase in both frequency and magnitude unless advanced technologies are used to stabilize the grid. Example technologies: Advanced distribution management system (ADMS), DER management system (DERMS), outage management system (OMS), demand response management system (DRMS) Example functions: Monitor grid operations, analyze the data collected, predict events and grid behavior through algorithms, issue commands to grid devices based on the analyzed information (fault location, isolation and service restoration/FLISR scheme and conservation voltage reduction/CVR control)
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 and algorithms that are installed at various points on the distribution system — such as at feeders, breakers and distribution power transformers. The sophistication of those devices determines the degree to which devices on the grid can be controlled by the grid management system. Needs statement: More advanced sensing, measurement and automation enables accurate information flow for rapid outage response and reduced outage durations; outage avoidance through real-time mitigation; enablement of DER integration and optimization. Example technologies: Supervisory control and data acquisition (SCADA), microprocessor relays, digital meters and power system monitoring devices Example functions: Detect emerging equipment and power system issues, automated circuit switching (e.g., Fault, location, isolation and service restoration (FLISR)), volt-VAR optimization (e.g., conservation voltage reduction (CVR))

Table 18. Capabilities and their descriptions (continued)

Capability	Description of capability and needs statement
Telecommunications	Description: The infrastructure that connects grid assets and the distribution system operators Needs statement: A reliable telecommunications network allows grid operators to communicate with grid assets and enable more grid services. Example technologies: Communication spectrum licensed from the Federal Communications Commission (FCC), owned and leased fiber, cellular communication equipment, AMI mesh network Example functions: Communication networks at different levels of granularity — field area networks (FANs) to enable communication between field devices and the Integrated Operations Center, neighborhood area networks (NANs) to enable communication between devices in a microgrid
Physical grid infrastructure	Description: The poles, wires, transformers, substations, operations control center and other distribution system equipment (e.g., reclosers, capacitors, regulators) that comprise the distribution system Needs statement: Enable the safe, reliable, bi-directional flow of power. Example technologies: See description Example functions: See needs statement
Cybersecurity	Description: The protection of computer systems 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 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 Example technologies: Cyber-physical barriers to restrict access to critical assets, advanced physical security systems (e.g., intelligent badging), firewalls, data encryption and spyware/malware detection Example functions: Ensuring access is restricted to authorized personnel, insulating critical infrastructure networks from external threats and obscuring critical communication between devices and operators

4.6 Future capability roadmap with costs and benefits

4.6.1 ASSESSING COSTS AND BENEFITS

According to a recent study by U.S. DOE's Grid Modernization Laboratory Consortium, several public utility commissions have required electric utilities to prepare grid modernization plans demonstrating that grid modernization investments provide benefits to customers.[84] These plans typically include a benefit-cost analysis (BCA) to determine whether grid modernization investments' benefits will exceed costs. However, DOE's study found several challenges when determining the benefits of these investments. The challenges include:

- Multiple grid modernization components with interactive effects are difficult to analyze or justify separately.
- Many benefits are hard to monetize, making it difficult to compare them with costs using a single metric.
- Equity issues may arise when all customers pay for grid modernization projects, but benefits of a particular project may accrue more to some customers than others.
- Utilities seek some form of approval for grid modernization projects before making investments.

An earlier study conducted by the DOE's National Energy Technology Laboratory (NETL) estimated that grid modernization investments' benefits exceed the cost of those investments by a benefit-to-cost ratio of four-to-one.[85] The same study estimated that grid modernization investments deliver 20% savings per year relative to the cost (a $100 investment delivers $20 of savings each year).

The investments outlined in **Table 19** are in different stages of implementation, therefore the range of costs and benefits have not been fully developed. During the development of our DSP, we researched potential costs for modernizing the grid. Expected costs for grid modernization investments ranged widely depending on the type of investment and the goals of the project ($2.1 million to $275 million).[86] As we work to modernize the grid, we will balance customer costs with the need to modernize the grid, accelerate DER adoption and meet our customers' decarbonization goals.

4.6.2 ROADMAP

Table 19 provides a breakdown of each capability in the modernized grid framework and summarizes the relative costs and benefits of each over a 10-year planning horizon. Investments going through future action plans of the DSP will include the appropriate analysis to justify the investment. We expect to continue to use rate cases to provide detailed analysis and justification for specific grid modernization investments.

Investments, both within and across capabilities, are not mutually exclusive, so investments in one capability can affect future investments in other capabilities. Examples include:

- Investments in smart meters may impact telecommunication investments and virtual power plant needs under certain conditions and vice versa.
- Investments made in sensing, measurement and automation may offset field device and installation costs associated with developing hosting capacity analysis as noted in **Section 6.5** or operating a virtual power plant and vice versa.

84. U.S. DOE's Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations report is available at: eta-publications.lbl.gov
85. U.S. DOE's Modern Grid Benefits report is available at: netl.doe.gov
86. Sources for cost ranges are from GreenTech Media available at: greentechmedia.com

Table 19. Future relative potential costs and benefits by capability

Capability	Potential costs (0-10 years)	Potential benefits (0-10 years)
Customer ecosystem	Acquisition and provision of data Additional customer service IT infrastructure	Customer engagement Self-service analysis and decision-making 24/7 availability
Virtual power plant (VPP)	Development of rate structure to compensate participants Software to enable VPP Physical infrastructure to enable VPP (e.g., comms, controllers)	Distribution system efficiencies Optimized distribution system investments (NWS) Support for customer resilience and community benefits Support for decarbonization
Planning and engineering	Robust distribution planning tools Experienced planning engineers IT integrations	Distribution planning and engineering is how PGE accomplishes its goals for the distribution system and its customers, including safety, reliability, resilience, customer choice, decarbonization and electrification
Grid management systems	Grid management system hardware, software and infrastructure Cybersecurity infrastructure and protocols	Customer empowerment and decarbonization through DER enablement Improved workforce safety and productivity Improved grid efficiency and reliability Improved grid resilience
Sensing, measurement and automation	Cybersecurity infrastructure and protocols Shorter equipment lifecycles for digital vs. analog equipment Workforce requirements of a more digital grid	Improved situational awareness for line operations and distribution system operators Increased operational efficiency New and improved data for distribution planning and distribution operations Increased safety for line operations
Telecommunications	Cybersecurity infrastructure and protocols Shorter equipment lifecycles for digital vs. analog equipment Workforce requirements of a more digital grid	Enablement of benefits gained through grid management systems and sensing, measurement and automation
Physical grid	Undergrounding equipment Hardening equipment Replacement of old/failed assets Assets to support new growth	Safe, reliable and resilient delivery of power to customers
Cybersecurity	Included in grid management systems estimate	Operational technology (OT) visibility Ability to monitor and detect anomalous activity in operational systems Protection against threats to the safe, reliable operation of the grid Protection of customer information and, potentially, equipment

Table 21 provides additional detail on the state of PGE's current and planned capabilities based on Carnegie Mellon University's Smart Grid Maturity Model (**Table 20**).[87] This model is well suited to assist utilities in understanding the current and future state of their capabilities. PGE will utilize Carnegie Mellon University's Smart Grid Maturity Model to monitor and adapt our long-term roadmap over time. In addition to using this maturity model, we will also incorporate feedback we have received from our partners through our Community Engagement Plan.

Table 21 reveals a higher maturity level in grid management systems and the physical grid. This stems from investments in ADMS and PGE's Integrated Operations Center (IOC), which are some of the key drivers of PGE's 2021 General Rate Case.

Table 20. Carnegie Mellon University's Smart Grid Maturity Model

Maturity scale	Maturity type	Maturity description
5	Pioneering	Organization is breaking new ground and advancing the state of practice within a domain
4	Optimizing	Organization's smart grid implementation within a given domain is being tuned and used to further improve organizational performance
3	Integrating	Organization's smart grid deployment within a given domain is being integrated across the organization
2	Enabling	Organization is implementing features within a domain that will enable and sustain grid modernization
1	Initiating	Organization is taking the first implementation steps within a domain
0	Default	Default level of the maturity model

87. Available at: Carnegie Mellon University, Smart Grid Maturity Model Version 1.2

Table 21. PGE's capability gap analysis, assumptions and barriers

Capability	Current maturity	Desired maturity	Assumptions	Barriers
Customer ecosystem	2	4-5	Customer information can be protected. System vulnerabilities are not exposed.	Availability of data in sharable format Identification of valuable information to share
Virtual power plant (VPP)	1	4-5	ADMS is fully implemented. DER adoption continues/ accelerates. Economic value is identified.	Technology not yet mature across all DERs Regulatory alignment of VPP
Planning and engineering	2	4-5	Sensing and measurement in place to collect better data. Advanced tools acquired.	Advanced planning capabilities not supported by current market VPP.
Grid management systems	3	4-5	Adoption curve of DER is similar to planned/ forecasted. OPUC policies are consistent. Stakeholder demands and community demands are similar. Investments are made in parallel with sensing, measurement and automation and telecommunication capabilities.	Balancing spending with rate impacts Complex information and operational technology (IT/ OT) integration
Sensing, measurement and automation	1-2	4	Adequate planning, engineering, design and construction resources. ADMS is fully implemented.	Balancing spending with rate impacts
Telecommunications	2	4	Adequate planning, engineering, design and construction resources. Adequate bandwidth and speeds are available at low costs.	Balancing spending with rate impacts
Physical grid	3	4	Adequate planning, engineering, design and construction resources.	Balancing spending with rate impacts
Cybersecurity	2	4-5	Current strategy and tools maintain effectiveness; no emergence of new types of threats or vulnerabilities.	Balancing spending with rate impacts

A modernized grid will help our customers and communities better manage and reduce their energy consumption and costs, while giving them greater access to their own energy data. Customers also benefit from a modernized grid with improved security, reduced peak load costs, increased integration of renewables and lower operational costs. As utilities upgrade grid infrastructure that is being pushed to do more than it was originally designed to do, investment analysis is critical. Modernizing the grid to make it smarter and more resilient through the use of cutting-edge technologies, equipment and communications controls that work together to deliver cleaner electricity more reliably and efficiently can greatly reduce the frequency and duration of power outages, reduce storm impacts and restore service faster when outages occur.

4.6.3 RECOMMENDATION FOR COST-BENEFIT ANALYSIS

We recommend a discussion with OPUC staff on potential cost-benefit analysis options using the U.S. DOE's "Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations" report as a starting point for discussion. **Table 22** illustrates DOE's options for addressing key BCA challenges.

Table 22. U.S. DOE's options for addressing key BCA challenges

Challenge	Potential approaches
Identifying objectives	Use long-term strategic planning to define objectives up front. Identify the amount and type of cost-effective DERs.
Documenting the purpose of each grid modernization component	Specify a standard taxonomy for grid modernization. Define purpose and driver of each grid modernization component.
Determining when to apply least-cost, best-fit approach	Consider grid modernization objectives. Consider purpose and driver of the component. Consider whether component is core or application.
Choosing BCA framework	Articulate the BCA framework up front. Focus on two tests: utility cost test and regulatory test.
Choosing discount rate(s)	Choose a discount rate that reflects state regulatory goals. Conduct sensitivities using different discount rates.
Accounting for interactive effects	Use the least-cost, best-fit approach, where warranted. Use scenario analysis with different combinations of components. Conduct BCA for grid modernization components in isolation.
Accounting for benefits that are hard to quantify or monetize	Use the least-cost, best-fit approach, where warranted. Establish metrics to assess the extent of benefits. Apply methodologies to make unmonetized benefits transparent.
Addressing uncertainty	Use approaches that include contingency costs, scenario and sensitivity analyses, and probabilistic and expected value modeling.
Putting BCA results in context	Estimate long-term bill impacts.
Prioritizing grid modernization investments	Identify least-regrets investments that balance cost, risk, functionality and value.
Encouraging follow-through	Encouraging follow-through.

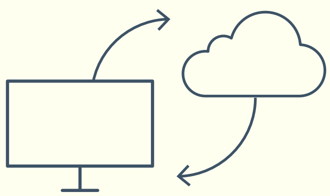
4.7 Currently planned capabilities investments

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. Investment justification is based on guidance provided in **Table 16**. Where available, PGE also describes the expected long-term evolution of the specific investments.

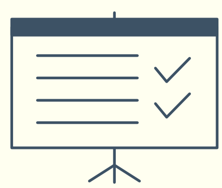
While investments are primarily driven by the needs within each capability, there are several considerations unique to each investment. **Figure 20** provides example considerations related to IT needs and impacts, business process changes and workforce implications.

Figure 20. Example considerations for investments in a modernized grid

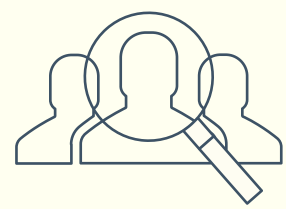
IT needs and impacts
- Data availability and analytics
- System integration
- Cybersecurity



Business process changes
- Work management
- Operational protocols
- Design standards
- Engineering procurement and construction



Workforce impacts
- New and evolving roles and responsibilities
- Skill gaps and training for reskilling and upskilling current employees
- Labor market competition for digital skills



4.7.1 VPP

There is no current industry consensus on the definition of a VPP and how it differs from certain DER programs. For the purposes of this DSP, PGE defines a VPP as follows:

> The VPP is a combination of DERs that work together to provide an array of grid services such as capacity, regulation, load following, contingency reserves and frequency response. Controlled through a central platform which integrates with DERMS, DRMS and ADMS, these bundles of DERs mimic the operational abilities of a traditional power plant.

PGE expects this definition to evolve both as the company learns and as the industry standardizes around the concept and application of VPPs. Over time, as PGE integrates foundational investments such as ADMS and DERMS, we will further the discussion around VPPs. PGE will continue to leverage the DSP to communicate its progress toward VPP integration.

Today, PGE has a variety of aggregation platforms (DRMS), each with a set of distinct energy services they can offer. Within the next five years, we intend to integrate these platforms into our real-time operations teams for a more streamlined dispatch, servicing the needs of PGE's energy portfolio using a DERMS software. We will be integrating these same DERMS platforms into our ADMS for enhanced distribution operational value.

Investments in VPP require that ADMS and DERMS projects are complete and functional across all use cases (see **Section 4.7.3** for details on ADMS and DERMS) and assume that PGE sees the forecasted penetration of customer-sited DERs that enable VPPs. The technology platforms available today do not offer critical support to PGE's energy needs or distribution reliability needs because our operations teams are not accustomed to managing behind-the-meter DERs and flexible loads. Customer impact is not yet fully understood for PGE's plan to migrate these resources to a full-fledged VPP.

Within the next five years, we intend to consolidate aggregation platforms and put in place the structure, people, processes, tools and training needed to support a full-fledged VPP operation. We will rely on the VPP to provide the flexibility needed in our energy portfolio to sustain reliable energy delivery at reasonable costs. This supports PGE's goal of operating a more carbon-free energy portfolio and assist Oregon in meeting its clean energy goals as specified in Oregon's House Bill 2021. VPP is an advanced capability where each portfolio of aggregated DERs is evaluated through a BCA that includes customer and societal values as detailed in **Section 4.7.1**.

4.7.2 PLANNING AND ENGINEERING

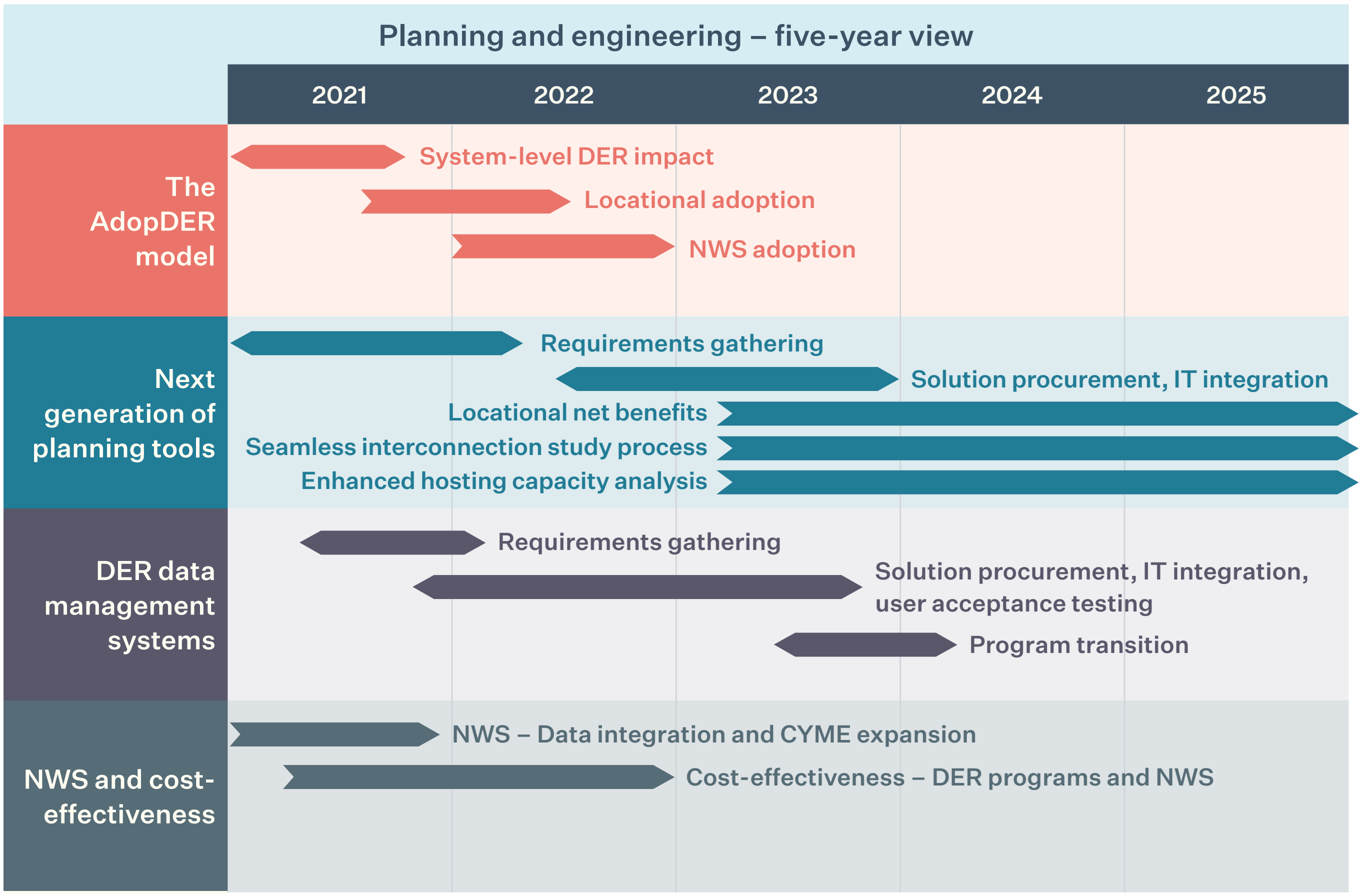
The planning and engineering capability refers to a suite of integrated, next-generation tools needed to perform distribution system planning functions. PGE's current approach to this capability builds on the functionalities outlined in the DOE's DSPx, as noted in **Table 23**. This approach ensures we are following best practices and can link investments directly to the goals outlined in our vision for the distribution system.

Table 23. 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
Load profile models
DER forecasting (customer DER adoption models, customer-EV adoption models)
Scenario analysis tools</td></tr>
<tr><td rowspan="3">Short-term distribution planning
Long-term distribution planning
Hosting capacity
EV readiness</td><td>Power flow analysis</td><td>Peak capacity analysis
Voltage drop analysis
Ampacity analysis
Contingency and restoration analysis
Balanced and unbalanced power
Flow analysis
Time series power flow analysis
Load profile analysis
Volt-var analysis</td></tr>
<tr><td>Fault analysis</td><td>Fault current analysis
Arc flash hazard analysis
Protection coordination analysis
Fault probability analysis</td></tr>
<tr><td>Power quality analysis</td><td>Voltage sag/swell analysis
Harmonics analysis</td></tr>
<tr><td>Planning analytics</td><td colspan="2">DER impact evaluation tool
Stochastic analysis tools</td></tr>
<tr><td>Reliability and resilience planning</td><td colspan="2">Realiability study tool
Value of lost load (VoLL) models
Resilience study models
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
Geospatial maps</td></tr>
</table>

PGE has planned the following key investments to enable the functionalities from **Table 23**. These investments are considered foundational and aligned with DOE's DSPx. They are evaluated based on least-cost, best-fit and reasonableness as described in **Section 4.4.1**. **Figure 21** provides a five-year overview of PGE's planned investments in planning and engineering.

Figure 21. PGE's planned investments in planning and engineering over next five years



Note: Includes future initiatives

4.7.2.1 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.

4.7.2.1.1 Project details

- PGE, through a competitive-bidding process, selected three third-party consultants, Cadeo Group, The Brattle Group and Lighthouse Energy Consulting, to develop an open-source framework for DER forecasting and potential analysis.

- 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 will estimate locational adoption of DER resources and fine-tune 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 will inform PGE's DSP Part 2, as well as future DER program and distribution system planning efforts.

- PGE is expecting to invest approximately $500k over the two phases of the project (2020-2021).
- PGE expects model improvements in the next year (2022) to build on the existing functionality, enabling new features such as locational adoption for NWS, improved data and IT integration and data quality. PGE expects this cost to be approximately $400k.

4.7.2.2 Next-generation planning tools project

PGE is conducting an internal investigation to understand the current and required future planning capabilities needed to realize PGE's vision. This effort will also provide the required 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 see outcomes such as integrating NWS at scale instead of on a case-by-case basis, reducing operational uncertainty through probabilistic planning, streamlining interconnection study processes and ensuring safety and reliability in a dynamic grid. Our next-generation planning tools project will be a foundational investment designed to enhance PGE's current planning capabilities and enable improvements (**Figure 22**) in various facets of distribution system planning.

Figure 22. PGE's current distribution planning capabilities

- Enhanced power flow analysis
- Enhanced power quality analysis
- Resiliency analysis
- Hosting capacity analysis
- Streamlining interconnection studies
- Probabilistic planning
- Advanced fault analysis
- Dynamic analysis
- Safety analysis
- System optimization
- Locational value analysis
- Risk assessment

Each of these facets of planning have one or more elements, each with their own needs. **Table 24** gives an example of PGE's assessment for enhanced power flow analysis.

Table 24. Example of PGE's assessment for enhanced power flow analysis

Component	Study name	Current state	Future state	Current tool
Enhanced power flow analysis	**Full-sequence power flow analysis:** The ability to determine the flow of electric power in an interconnected system. A full-sequence power flow analysis comprises the analysis of positive, negative and zero sequence flows, which allows the capture of system unbalance conditions in three-phase circuits.	2	4	CYME
	Power flow on secondary circuits: The ability to determine the capacity and model the important components of any secondary network. A secondary system model includes model representations of all the components (e.g., lines, cables, switches) between the customer connection and the distribution transformer at the intersection of the secondary system and primary system, including a representation of the distribution transformer.	1	4	CYME
	Voltage analysis: The ability to determine the voltage profile along the feeder as a function of (1) distance from the substation and (2) time of day. Line and transformer impedances cause a voltage drop between the generation source and the point of consumption.	2	4	CYME

4.7.2.2.1 Project details

- PGE is evaluating the current state of its planning tools and analysis, as well as its desired future state. PGE will subsequently develop requirements needed to procure market solutions through a request for proposal (RFP) that can work in an integrated manner to achieve the functionalities outlined above.

- PGE will design the underlying IT architecture needed to improve computation speeds, reduce labor costs and ensure PGE can perform scalable calculations for an increasing number of interconnection applications, NWS and other distribution system analyses.

- Based on the IT infrastructure, PGE will determine any workforce implications. It is anticipated that PGE may see a need for engineers to perform analysis, such as hosting capacity and interconnection.

- PGE expects the project to span a one- to three-year timeline with an expected RFP in early 2022.

- PGE estimates the upfront project costs in 2022 of approximately $2 million with additional multi-year ongoing costs based on available market products, IT capabilities and workforce needs.

4.7.2.3 NWS data integration and CYME expansion

PGE will actively invest to improve data integration in current planning capabilities and expand capabilities by procuring new CYME modules, such as:

- Load relief DER optimization: This allows engineers to evaluate load relief projects using battery energy storage systems (BESS) as well as dispatchable and non-dispatchable generation. The module bundles two distinct algorithms, one for the optimization of BESS and dispatchable generation and one for the sizing of non-dispatchable generation.
- Microgrid modeling and analysis: This module enables modeling and simulation of grid-tied microgrids operating in either islanded or grid-connected mode, as well as isolated microgrids, such as those of remote communities far from any transmission and distribution infrastructure.
- Long-term dynamic load flow analysis: This module performs time series long-term dynamics load flow analysis (in the seconds to minutes range) of the variable phenomena introduced by DERs. Device controls are included in the analysis, including load tap changers, shunt capacitors and switchable shunt banks. This module also enables the time-domain simulation of smart inverters and battery energy storage systems.

By procuring these types of modules, PGE will have the ability to repeatably perform specific elements of an NWS analysis. We expect this project and next-generation planning tools to work together, with this project focusing on needs within the next year (2022) and next-generation planning tools focusing on needs post 2022, including IT and workforce implications.

4.7.2.3.1 Project details

- PGE is working with CYME to determine the necessary modules to perform NWS. We expect there will be incremental license costs of approximately $100k to obtain these modules.
- PGE is also working internally with the relevant IT teams to improve AMI integration, CYME gateway updates and other data integration to improve planning accuracy and resolution.
- We expect both elements of the project to be complete by mid-2022, with a focus on performing the analysis to identify NWS opportunities for our DSP Part 2.

4.7.2.4 DER cost-effectiveness update project

In alignment with direction from OPUC staff's comments to PGE's Flexible Load Plan, we are working to update DER cost-effectiveness.[88] We've started developing a new cost-effectiveness tool to perform robust analysis that is aligned with the National Standard Practice Manual and regional best practices. To ensure PGE takes advantage of best-in-class approaches from other leading national sources and jurisdictions, we are working with third-party consultants, Applied Energy Group and The Cadmus Group.

This cost-effectiveness tool, called Ben-Cost, builds on PGE's previous work on the resource value of solar, flexible load and transportation electrification valuations. The new tool will ensure DERs can be valued through multiple perspectives, accounting for energy system, host customer and societal impacts. Through this project, PGE will:

- Review current cost-effectiveness methodology and inputs.
- Perform gap analysis and valuation research.
- Refine and develop cost-effectiveness methodology and inputs that may include, but are not limited to:
  - Updating the proxy resource for the value of capacity to a non-emitting resource if available through an updated IRP analysis
  - Integrating system-level transmission and distribution impacts of DERs
  - Non-energy benefits and low-income benefits development with future iterations improving on these values
  - Improving EV benefit calculations, such as avoided gasoline car operations and maintenance, avoided gasoline and emission reduction

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.

88. PGE's Flexible Load Plan available at: apps.puc.state.or.us

4.7.2.4.1 Project details

- In 2021, PGE began review of existing cost-effectiveness methods to identify gaps compared to national best practices. This work is expected to be completed in early 2022. .
- In 2021, PGE is estimating a spend of approximately $100k to develop a new cost-effectiveness tool that includes development of low-income customer benefits.
- 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). Estimated costs for this project vary between $100k to $250k for 2022.

4.7.2.5 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 connection
- DER program performance data
- DER cost-effectiveness and evaluation results
- Energy efficiency and renewable energy integration with Energy Trust of Oregon (ETO)
- DER reporting and regulatory compliance

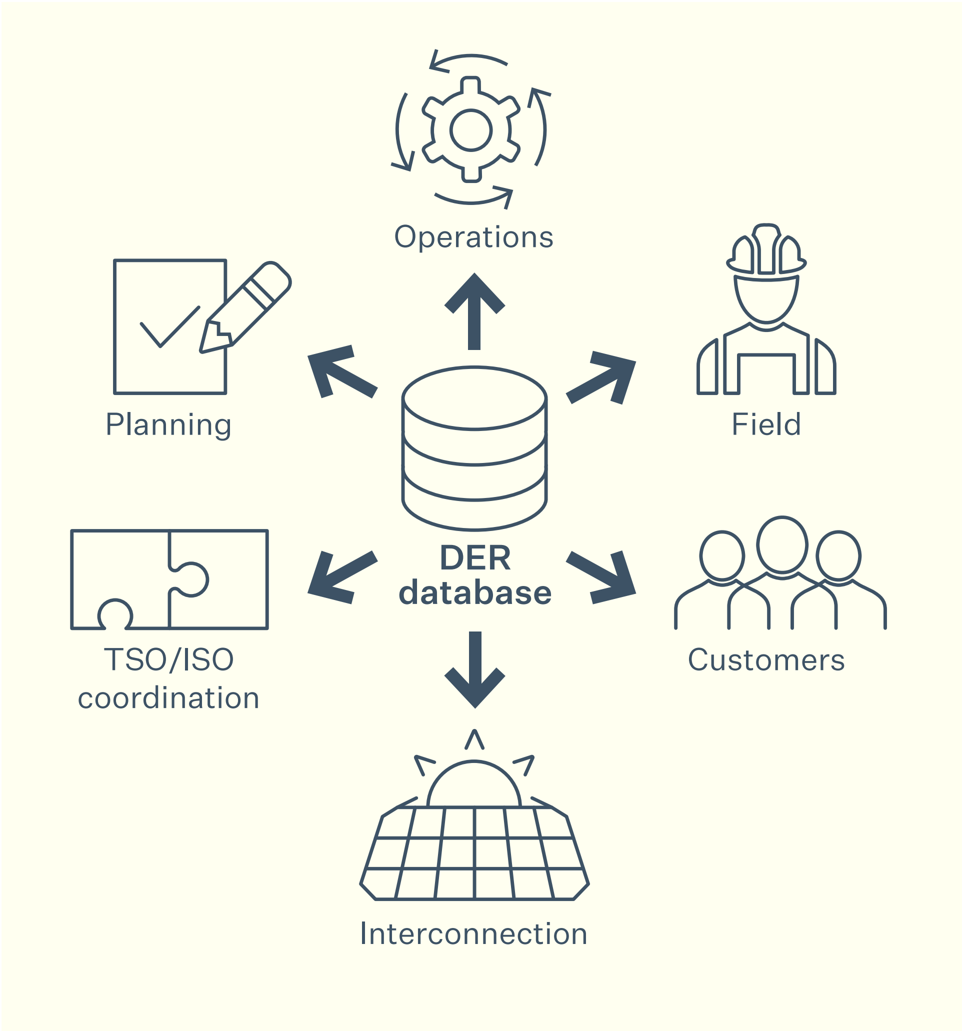
An analytical platform that works with this data will streamline core business functions, including interconnection and program application processes, incentive payments, demand response (DR) event performance reporting, standard reports for regulatory filings and data requests, integration with planning 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 R&D effort in which PGE will leverage EPRI's expertise and ensure best practices are implemented in the design of the DSMS. **Figure 23** represents the breadth and importance of an enterprise-wide single source of truth for DER data.

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

Figure 23. EPRI's illustration of a DER data management system



4.7.2.5.1 Project details

- 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.
- PGE estimates initial costs of approximately $1 million to include project scoping and customized software, with future costs contingent on the chosen solution.

4.7.3 GRID MANAGEMENT SYSTEMS

Grid management systems (GMS) are a collection of computer-aided tools used by operators of electric utility grids to monitor, predict, analyze, control and optimize the performance of the distribution system.

The GMS operates with a complex infrastructure of field devices that sense, measure, protect and control the grid, enabled by 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 highlighted below are foundational in nature and a requirement 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.

4.7.3.1 Grid management systems

We have developed a comprehensive grid modernization strategy that will facilitate cultural shifts, shorter development cycles and cohesive strategic alignment across PGE. These are needed to provide safe, secure, reliable and resilient power on the electric grid that will be dominated by DERs. We have determined that a comprehensive GMS that can perform the functions described in **Figure 24** is required. **Figure 25** illustrates PGE's five-year roadmap for GMS.

Figure 24. Grid management system functions

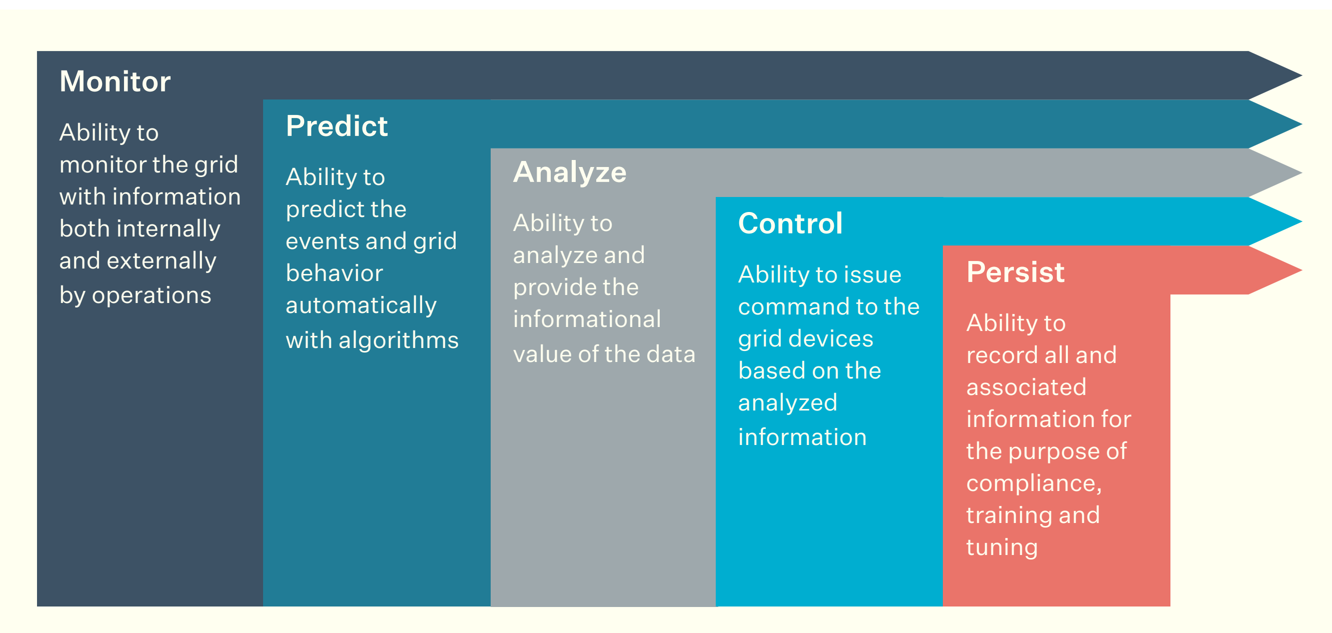
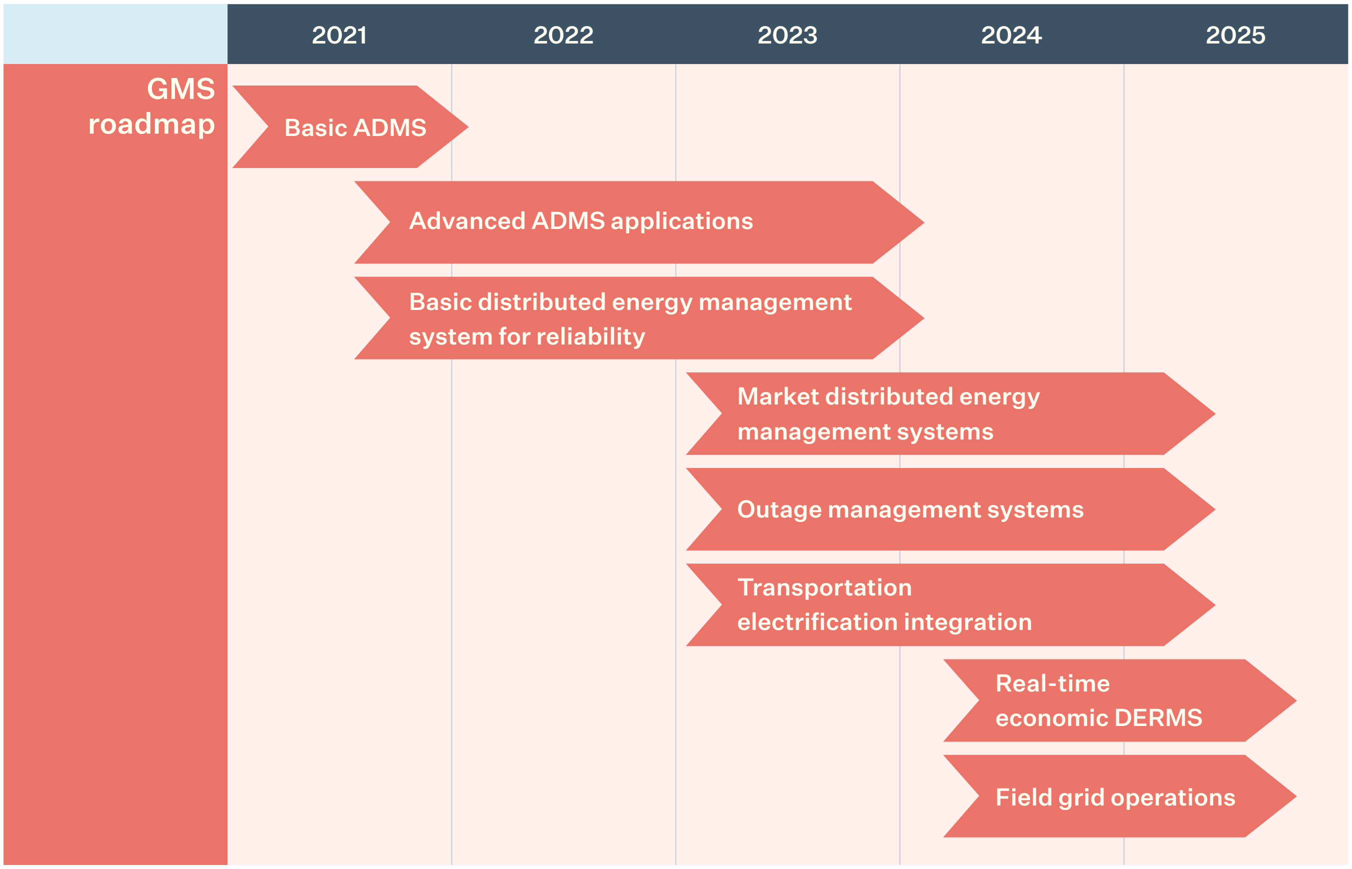


Figure 25. PGE's expected five-year roadmap for GMS



4.7.3.1.1 Project details

- In Phase I (basic ADMS), PGE plans to implement a distribution management system (DMS) with fault location, isolation and service restoration (FLISR) on a minimum of three circuits. The primary function of the DMS will focus on monitoring, predicting and operating distribution devices on the distribution system. PGE will then update the outage management system (OMS), manage electronic switching sheets, issue clearances, monitor integrated grid systems and operate equipment on load-serving distribution systems.
  - 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, they will require protective measures like the energy management system (EMS).
- PGE estimates $40 million in grid management systems investments for 2022.

4.7.3.2 Distribution automation (DA)

DA is the umbrella of smart grid solutions aimed at solving 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. Feeders targeted for DA implementation are those with a high exposure to non-asset failure risk. The addition of DA reclosers and substation upgrades will reduce the risk of mainline non-asset failure on these feeders, reduce the total number of customer outage minutes for a sustained mainline fault and minimize the consequence of sustained mainline faults. The following describes the types of DA solutions:

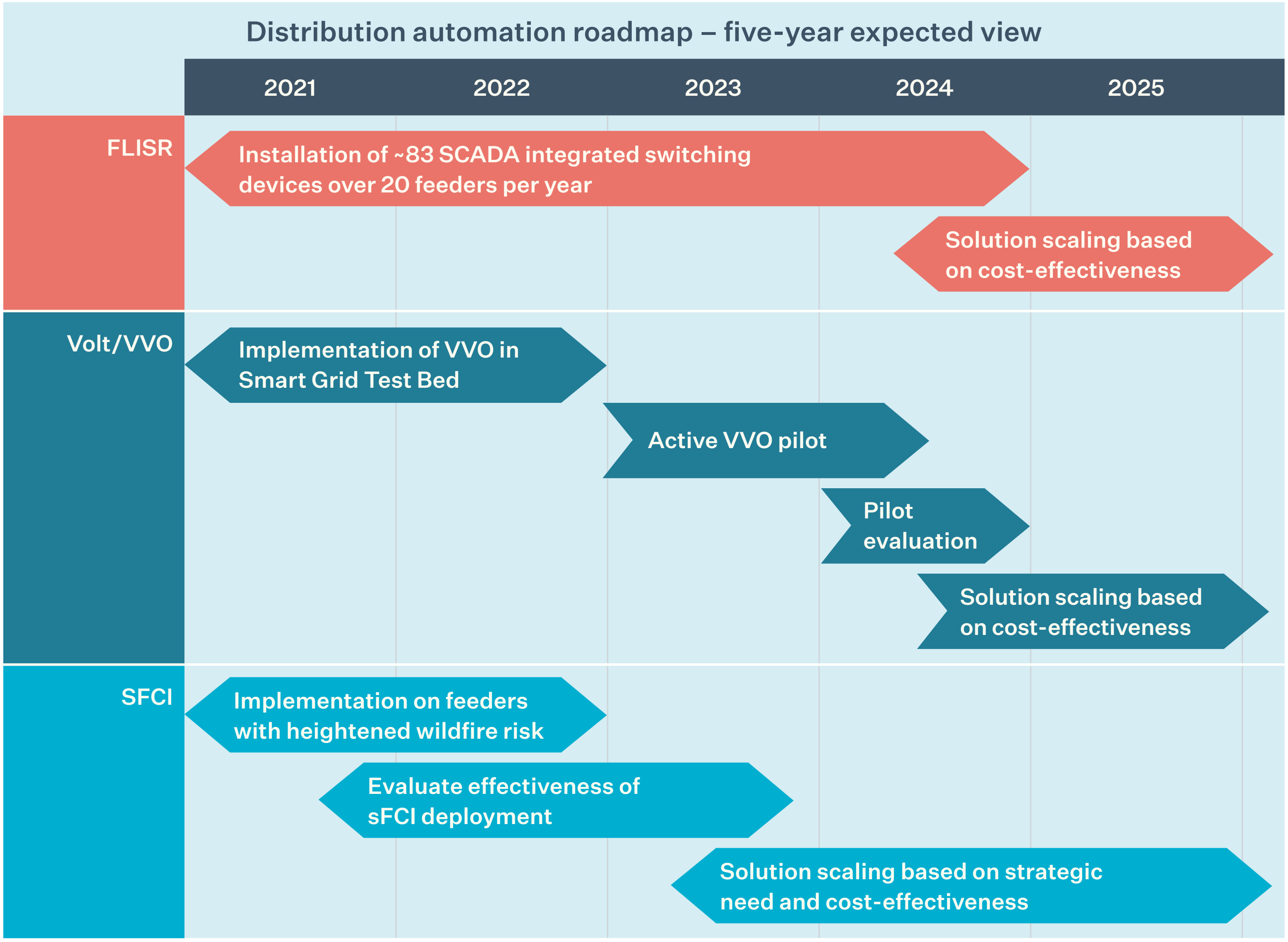
- **FLISR:** Normally open and normally closed supervisory control and data acquisition (SCADA)-integrated switching devices are strategically placed throughout the feeder to maximize the implementation's expected benefits. The preferred communications medium is PGE's FAN. When paired with a centralized 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.
- **VVO:** Equipment that can manage voltage and optimize VAR flow, which reduces system losses and improves efficiency in power distribution, is installed inside of substations and throughout the distribution feeder. VAR, a unit of reactive power, can be produced by inverter-based DERs. Other equipment to optimize voltage and VARs includes load tap changers (LTC), switched capacitor banks and line regulators. As with other smart grid solutions, harnessing the full benefits of this technology deployment requires integration into a control system (e.g., ADMS). Once fully integrated, 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 distribution power transformer's power factor.
- **sFCI:** Installation and integration of communicating line monitors, strategically placed throughout the distribution system, will help inform real-time operational decisions. Situational awareness is improved, and truck rolls and patrols are reduced. This results in reduced duration of sustained outages.

Execution of DA initiatives is paramount to transforming PGE's distribution system into a smarter, more integrated grid.

4.7.3.2.1 Project details

- PGE estimates $8 million of DA investments in 2022 with additional, annual investments through 2024.
- **Figure 26** shows PGE's expected roadmap for DA solutions.

Figure 26. PGE's expected five-year roadmap for distribution automation



Note: Includes future initiatives

FLISR

- 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

- 2021 through 2022: Plan for first active VVO implementation through PGE's Smart Grid Test Bed.
- 2023: Pilot active VVO implementation.
- 2024: Evaluate effectiveness of active pilot VVO implementation.
- 2025 and beyond: Scale VVO program commensurate with cost effectiveness.

sFCI

- 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 sFCI program commensurate with cost effectiveness.

4.7.3.3 Substation protection 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.

4.7.3.3.1 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 (TLTC) 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 SCADA system, intelligent devices such as relays, meters and asset monitoring devices can be integrated and information can be brought 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 and 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).[89]

4.7.3.3.2 Modernize cost-effective communication-aided protection systems

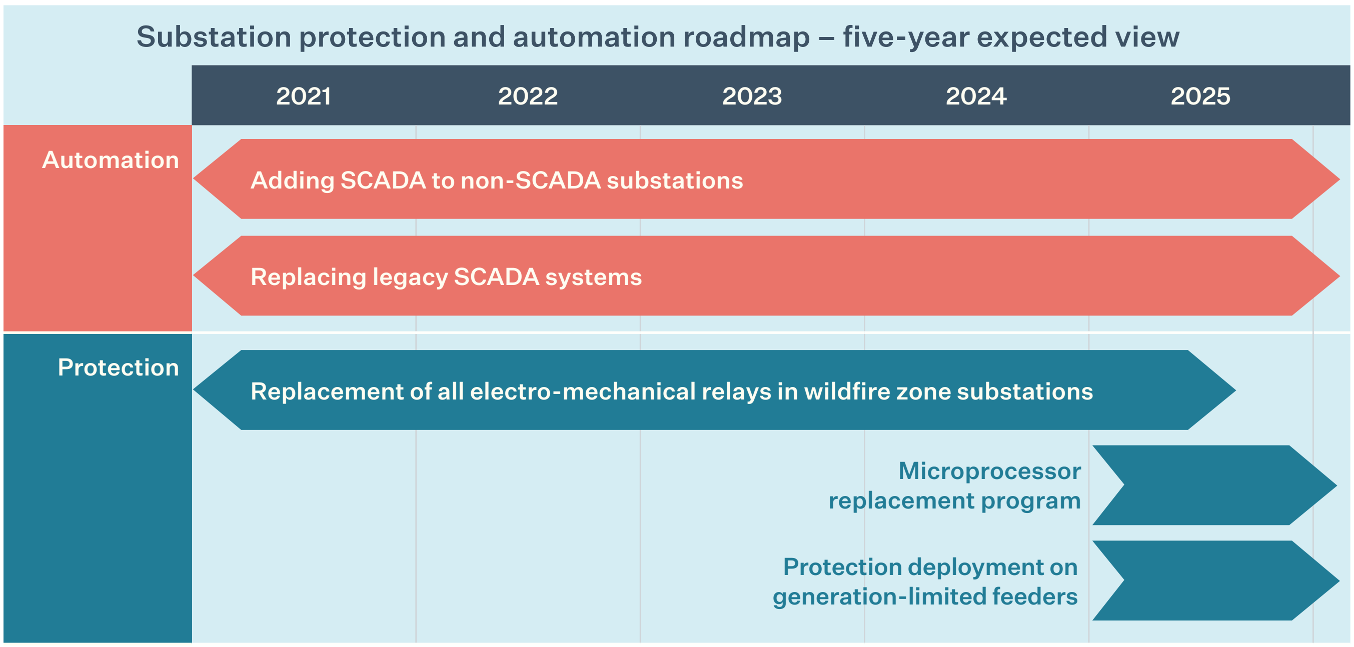
- **Improve system reliability**: A protection system is fundamental to operating the grid. Many of the distribution substations are still operated with 40- to 50-year-old electromechanical relays, providing bare minimum, inflexible protection. This often leads to mis-operations, failures that could cause major outages and equipment damage or even seriously affect the personal safety of employees working on the grid. Modern relays are required to meet new operational objectives. Modern relays also provide much more detailed information through integration with a substation automation system to analyze events, make settings modifications and fine-tune the grid to operate in a more stable, reliable fashion.
- **Enable the integration of DERs**: Many of PGE's distribution substations and feeders do not have sufficient protective devices to allow for easy integration of DERs. By building protection capabilities, PGE will better integrate inverter-based DERs (e.g., rooftop solar and batteries).

89. 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.

4.7.3.3.3 Project details

- 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 opportunistic investments such as substation rebuilds, feeder upgrades and the like.
- PGE has standardized the integration of cybersecurity monitoring and management for protection/automation systems as part of new substations or older substation rebuilds.
- PGE also ensures 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.
- **Figure 27** provides PGE's expected five-year roadmap for substation automation and protection investments.

Figure 27. PGE's expected five-year roadmap for substation automation and protection



Note: Includes future initiatives

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.

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 also ensures reduced failure of the protection system.
  - Update protection on generation-limited feeders or feeders nearing the load/generation threshold (e.g., modern relays with protection capabilities, hot line blocking capabilities, substation 3V0 protection).

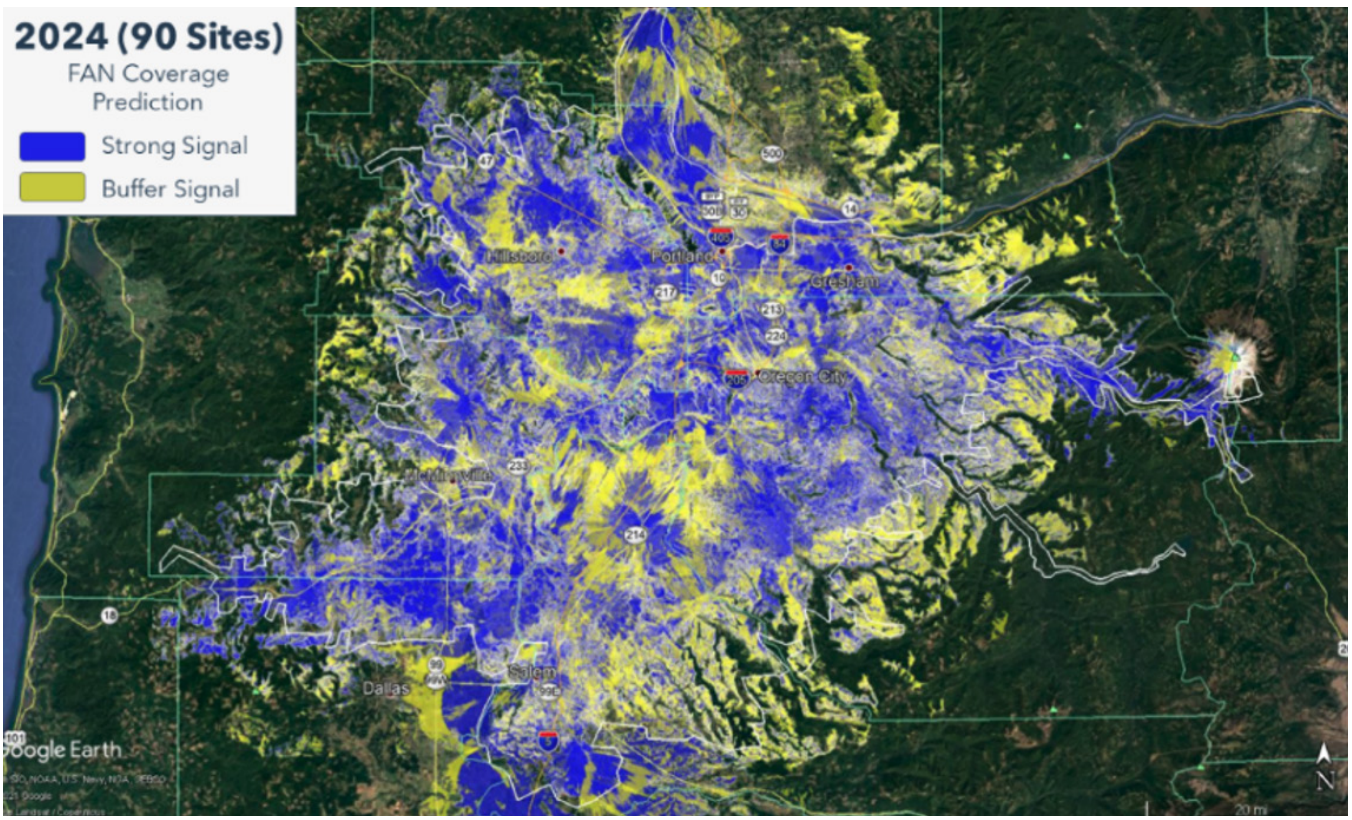
4.7.3.4 Field area network (FAN)

The FAN is a PGE-owned and operated wireless network that will cover PGE's service territory, enabling quick and reliable grid communications. FAN's primary use case is providing the communications necessary to operate DA reclosers. For this use case, the current alternative solution is Verizon cell modems, which have monthly operation and maintenance (O&M) costs in perpetuity, are less secure and do not guarantee reliability of service in a natural disaster scenario.

As PGE launches ADMS, the company is deploying more reclosers, meaning that the issues experienced with the current modems will exponentially increase. FAN mitigates this by building PGE's own private, secure and resilient network, which is scalable to accommodate future needs. It reduces the O&M costs of renting a network, provides control over reliability, security, latency and quality of service, and allows PGE to scale. As our grid becomes more sophisticated, we will have additional visibility into customer demand, empowering us to improve response.

The project scope is the design, procurement and installation of PGE-owned and operated base stations (estimated at 90 physical locations, with three sectors each for a total of 270 tier 1 base stations); coverage area shown in **Figure 28**.

Figure 28. PGE's estimated FAN coverage by 2024



These base stations will aggregate field traffic and transport it to the IOC. That transportation will occur over the multi-protocol label switching (MPLS) network and use fiberoptic cables, microwave or another radio path to connect to the final destinations. The FAN will use 700 MHz transceivers deployed on PGE's poles, towers and substation assets. These radios will utilize PGE-owned and licensed spectrum, providing coverage certainty, deployment flexibility, application prioritization, increased security and lowest possible latency.

4.7.3.4.1 Project details

- FAN is a new technology for PGE, requiring additional training to operate and maintain and collaboration between departments to ensure its continued viability. There is a component of customer education to promote awareness of the benefits and limitations of the network so that it can incorporate additional use cases. We will monitor this project to ensure all operational risks are mitigated.
- PGE considered and rejected the following alternatives to FAN:
  - An AMI network, which is a lower-quality, high-latency connection with limited bandwidth
  - Cellular networks, which also have a lower-quality, high-latency connection, are shared and are not PGE exclusive
  - Leased circuits to endpoints, which are more expensive and limited in bandwidth
- PGE expects multi-year investments to deploy FAN. PGE estimates $3 million in FAN investments in 2022.
- FAN investments are expected to continue through 2024, when the FAN tower build-up is expected to be complete.

4.7.3.5 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 wave of utilities fully implementing AMI and had 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.

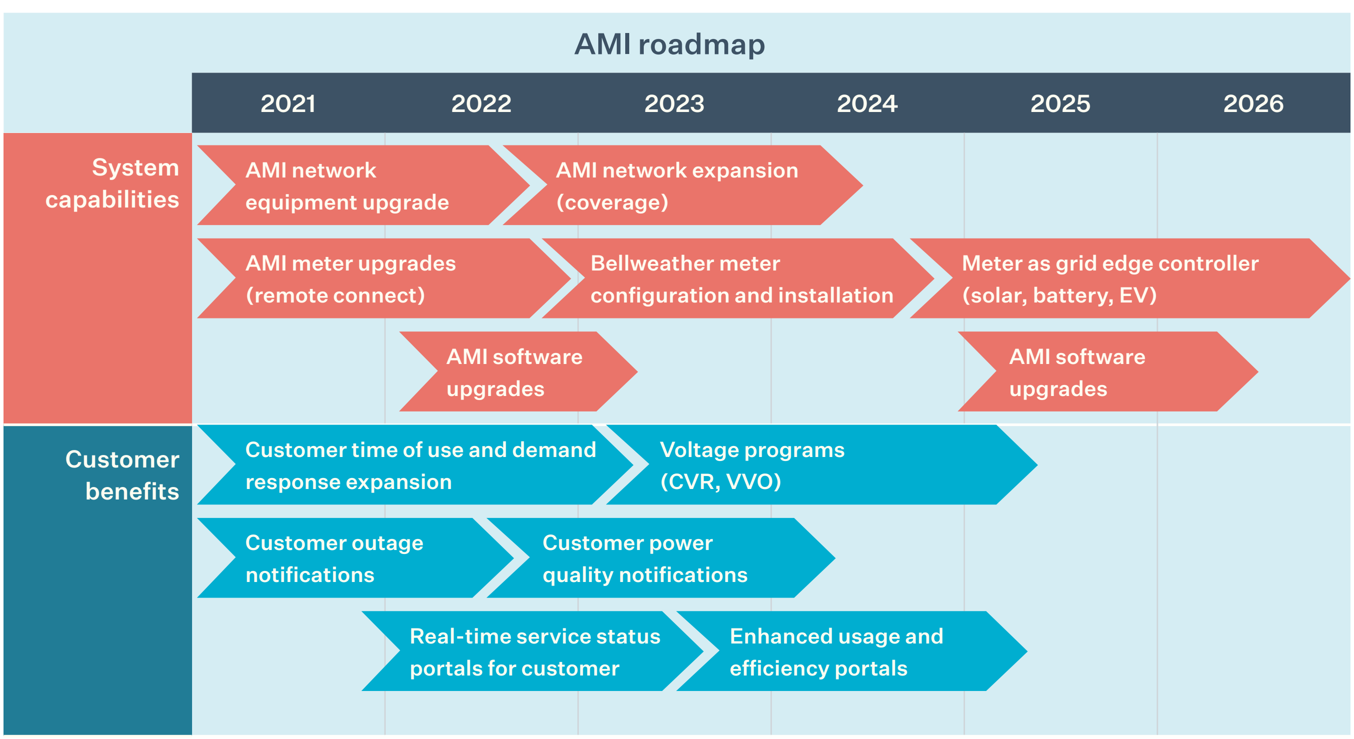
AMI is also used for operational outage processes focused on detection and restoration, as well as customer-facing use cases like notifications. In 2021, PGE started using the AMI system for more than just an outage restoration tool, but also to send proactive customer notifications (proactive outage text alerts). PGE is investing $2.7 million in AMI by the end of 2021, with the objective of improving reliability of two-way coverage. This will include meter replacement, modernizing backhaul at transceiver gateway base stations (TGBs), installing/sectorizing new TGBs and emergency generation make-ready work. TGBs are computational processing units that collect and process data, usually at the substation. Emergency generation make-ready refers to getting sites ready to be plugged in and powered by a generator, mostly during storms, when site service is down. This will allow PGE to have higher-quality data directly from the customer meter. It will also reduce the operational risks of additional truck rolls to replace failing batteries at a base station site and unnecessary dispatches when the repair has already been made.

Following this project completion, PGE will see the following outcomes:

- **Availability:** 99.9% of towers have the power, capacity and bandwidth to receive messages, even in a storm.
- **Resilience:** 98% of meters can talk to at least two towers.
- **Reliability:** 99% of meters respond when a ping is sent.
- **Completeness:** 92% of outage alarms reach their destination.

In thinking about the future of AMI over the next five- to ten-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. **Figure 29** visualizes PGE's expected roadmap for AMI functionalities.

Figure 29. PGE's expected five-year roadmap for AMI



4.7.4 PHYSICAL GRID

4.7.4.1 IOC

An IOC is a facility that centralizes all mission-critical operations that maintain the flow of power to customers. These operations include primary support functions, including the System Control Center (SCC), cybersecurity, physical security and network security. The IOC will be a critical part of PGE's strategy to deliver the reliable, resilient, affordable clean energy future customers need and expect. It will provide immediate and enduring value to customers through:

- Resource and system integration: weaving together clean energy resources and smart technologies into a seamless, reliable whole — renewable power, flexible load (demand response), distributed energy resources and storage, and regional resources (e.g., Energy Imbalance Market)
- Improved reliability: daily grid management of load/generation, transmission and distribution with advanced visibility and control for improved reliability and outage response (for both routine and extreme weather events and catastrophic events, such as wildfires)
- Increased resilience and security: strong physical and cybersecurity to meet critical infrastructure standards, seismic and other natural disaster readiness and extended off-grid operational capacity to facilitate recovery operations

By integrating the relevant people, functions and systems into a single facility, PGE will be able to maximize the effectiveness of this modernized grid initiative and provide a more reliable and resilient system for customers. In addition, an IOC will allow for the direct analytics and security support that is needed to effectively operate the future electrical grid, which cannot be achieved by simply rebuilding or replacing the control center. The IOC is critical to the successful transition to a more complex, smarter, more flexible power grid that can reliably integrate a diverse portfolio of renewable and distributed generating resources and load management systems.

The delivery of power to our customers during and after a disaster is critical for the safety of the communities PGE serves. A seismic evaluation performed on the current location of PGE's SCC and other grid-related functions at 3 World Trade Center (3WTC) determined that, although the 3WTC building is fit for general purpose activities, it has deficiencies for mission-critical activities that could result in localized hazards or partial or total collapse of the structure in a major seismic event. The nature of the 3WTC facility and its urban location have required additional security resources to address the trend of increasing encounters with protesters and individuals engaged in civil unrest. In addition to reliability and resilience risk mitigation, PGE's IOC will better allow the company to bring together grid control and cyber, physical and network security into one center. The needed space is not available at WTC, and simply providing the needed seismic upgrades for 3WTC was estimated to cost $350 million.

The IOC includes the implementation of an ADMS, enterprise data analytics and expansion of the Reliability Performance Monitoring Center. The IOC will provide value to customers through enhanced day-to-day functioning of a more efficient, cleaner and more flexible power grid. It will also provide improved resilience in the face of routine and extreme natural and human threats to physical, cybersecurity and network operations.

4.8 Research and development

PGE provides annual reports on R&D updates and spending pursuant to Order 15-356 under UE-294.[90] The latest annual report, a retrospective on 2020 R&D activity as reported in PGE's 2020 annual report, is available at portlandgeneral.com/DSP and will be available at apps.puc.state.or.us.

90. Order 15-356 within UE 294, available at: apps.puc.state.or.us

Chapter 5.

Resilience: managing disruptive events

Chapter 5. Resilience: managing disruptive events

"If we can come up with innovations and train young people to take on new jobs, and if we can switch to clean energy, I think we have the capacity to build this world not dependent on fossil fuel. I think it will happen, and it won't destroy the economy."

— Kofi Annan, former Secretary-General of the United Nations

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 (EJ) communities.[91] It's designed to improve safety and reliability, ensure resilience and security and apply an equity lens when considering fair and reasonable costs.

This chapter describes the activities, planned or in-flight, and how PGE's human-centered vision of the distribution system can provide safe, secure, reliable and resilient power, at fair and reasonable costs. It also describes PGE's resilience efforts and the investments needed to anticipate, adapt to, withstand and quickly recover from disruptive events. Shifts in the climate, as well as a shift toward electrification, put a spotlight on the importance of resilience, especially measures that are closer to the customer. PGE is leveraging new technology and building new relationships with customers and municipalities. These investments not only enable a stronger, more resilient infrastructure, but ties to communities also enable an accelerated, robust response to the challenges PGE and customers face together. **Table 25** illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP guidelines under Docket UM 2005, Order 20-485.[92]

WHAT WE WILL COVER IN THIS CHAPTER

Why it's important to maintain a resilient grid and the current challenges in doing so

New approaches to building resilience, both on the customer side and the utility side

How PGE is strengthening resilience throughout the distribution system

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A. DSP plan guidelines compliance checklist**.

91. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at oregonlegislature.gov
92. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, available at apps.puc.state.or.us

Table 25. Resilience: guideline mapping

DSP guidelines	Chapter section
4.4.b.i	Section 5.3, 5.4, 5.5
4.4.b.ii	Section 5.3, 5.4, 5.5
4.4.b.vi	Sections 5.3, 5.4, 5.5
4.4.d	Sections 5.3, 5.4, 5.5
5.2	Sections 5.3, 5.4, 5.5
5.3	Sections 5.3, 5.4, 5.5

5.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to provide a list of planned investments that advance the vision of the company. PGE is also required to identify key opportunities for distribution system investments that provide benefits to customers.

Resilience is top of mind for PGE as climate change and extreme weather present new challenges. The largest ice storm in 40 years caused unprecedented power outages just in the past year, and the Bootleg wildfire partially severed Oregon's transmission of power to and from California.

If Oregon is going to achieve its decarbonization and vehicle electrification goals, Oregonians must be able to depend on the electrical infrastructure when it is most needed. Because of this, PGE has established the Resilience Accelerated Response Coordination (Resilience ARC) initiative, which brings together leaders and teams from across the company to improve PGE's ability to meet customer and community expectations for resilient power delivery. This initiative has three areas of focus:

- **Customer infrastructure resilience:** investigation into customer-sited solutions, such as microgrids, batteries and other DERs, that enable customers to mitigate the effects of outage events and, during normal conditions, provide services to the grid
- **PGE infrastructure resilience**: investment in infrastructure, such as grid hardening, integrated grid technologies and energy supply hardening, that mitigate the occurrence of outages during disruptive events such as wildfires and wind or ice storms
- **Operational resilience:** improvements in PGE's ability to meet customers' needs during disruptive events and accelerate the restoration of service through emergency preparedness, outage response and customer support

5.3 Customer infrastructure resilience

PGE has several planned and active initiatives that serve to create or enable more resilient customer infrastructure. 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.

5.3.1 COMMUNITY RESOURCE CENTERS

As Oregon grapples with wildfires, extreme and erratic weather and the potential of a large-scale earthquake, communities and municipalities must ensure that clean water is available, emergency services are able to function and citizens have a safe place to cool off or warm up, reach loved ones and power critical equipment. PGE will investigate the best way to partner with municipalities on resilience solutions for critical infrastructure, as well as the optimal solution for public community resilience centers. These centers could be used for PGE's areas at risk of a Public Safety Power Shutoff (PSPS) or, in the case of seismically sound structures, could act as a gathering site in the event of a large-scale earthquake.

5.3.2 BATTERY ENERGY STORAGE

Battery energy storage plays an important role in PGE's clean energy future, as well as in helping customers meet their resilience goals.[93] Because of this intersection in use cases, a Resilience and Energy Storage Products team was created in early 2021 to consolidate work being done across the company on customer solutions.

PGE's residential storage pilot — the PGE Smart Battery Pilot — helps customers afford whole-home back-up power through on-bill rewards and includes upfront incentives for select customers. In turn, PGE may dispatch the batteries for grid services. This not only increases the resilience of our customers, but also lays the groundwork for expanding our energy storage capabilities across the service territory.

We will continue to watch the evolution of energy storage technology and continue to innovate and partner with customers to meet their resilience and clean energy goals. This might mean developing innovative ways to help customers afford home energy storage, such as financing options for interconnected devices, or enhanced resilience options on the distribution side that can pair energy storage as a grid resource, such as a neighborhood-level microgrid.

5.3.3 MICROGRIDS

Power outages from the recent ice storm hit PGE's non-residential customers hard during an already challenging economic climate. Commercial and industrial customers are asking how PGE can provide them with solutions to prevent the loss of inventory, keep patients safe and allow them to remain open when their customers may most need them — during a power outage.

Some solutions we are exploring include siting custom-engineered microgrids at customer locations that can provide resilience to the customer and flexible load to the utility.[94] In this concept, PGE and the customer would share the costs and benefits, with PGE paying for the cost-effective portion of the resource and the customer paying for their share over time.

93. For more information about PGE's work with batteries, docket UM1856, available at apps.puc.state.or.us
94. Learn more about PGE's work with Beaverton to establish the Beaverton Public Safety Center, available at microgridknowledge.com

5.3.4 ENERGY PARTNER PILOT

The Energy Partner Pilot is investigating revisions to allow commercial and industrial customers to be appropriately compensated for integrating their energy storage resources with PGE.[95] With the advent of advanced energy technologies, customer-owned equipment can now provide a variety of grid services, such as contingency reserve, frequency response and renewable power integration, all of which contribute to a more resilient grid while addressing customer needs.

5.3.5 TRANSPORTATION ELECTRIFICATION

PGE has been watching the emerging market of electric vehicles that have the capability to provide backup power to a home or facility in the event of an outage. Transformational solutions like grid-connected heavy-duty fleet charging (which pairs energy storage with vehicle charging) are able to provide back-up power to facilities. We are investigating the ability for fleet vehicle owners to be credited for energy put back onto the grid when they do not qualify for traditional net metering. School bus fleet operators in particular are hoping to find additional revenue streams to help pay for the more expensive electric busses through Time of Use bill management.

5.4 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.

5.4.1 WILDFIRE RISK ASSESSMENT AND MODELING

PGE has developed a model based on its asset management methodology to assess wildfire risk due to PGE equipment and proximity to vegetation. Additional improvements in 2021 will allow us to assess risk closer to real-time with current meteorological conditions to assist in making PSPS decisions.

5.4.2 SITUATIONAL AWARENESS

There are multiple projects underway to enhance situational awareness on the transmission and distribution grid and in PGE's service territory.

- Permanent weather stations: Construction of an additional 23 weather stations, in addition to the two active stations on Mt. Hood, is commencing in 2021. These stations will enhance PGE's awareness of weather conditions during extreme weather events in high-risk wildfire areas.
- Early fault detection system (EFD): An EFD system will be constructed and deployed on all feeders in the Mt. Hood PSPS area in 2021. This system will monitor distribution lines and alert PGE of possible failure modes, which then can be addressed before a fault event occurs. The system will be in the pilot stage in 2021.
- Smart faulted circuit indicators (sFCIs): Deployment of sFCIs on feeders in high-risk wildfire areas will enhance PGE's ability to quickly locate a failure on the distribution system to isolate and restore customers' power faster. This is especially important in high-risk wildfire areas during the wildfire season.

95. For more information on PGE's Energy Partner activities, docket UM1514, available at apps.puc.state.or.us

- Intelligent reclosers: Additional smart reclosers will be deployed in the high-risk wildfire areas and on other feeders in the service territory. These reclosers provide for automatic switching schemes to quickly segment and restore power. In addition, they will improve our ability to deploy better system protection routines and feed system status to distribution system operations teams through supervisory control and data acquisition (SCADA) connections.

5.4.3 DESIGN AND CONSTRUCTION STANDARDS

Robust design and construction standards are an essential part of ensuring the resilient operations of the electric grid now and into the future. Given recent extreme events, several efforts are underway to provide the confirmation and confidence that the standards PGE has today will position the company to meet its long-term goals. Specifically, design criteria are being reviewed to ensure the weather events we design for today align with forward-looking climate models. That effort will drive a review and future updates to construction standards, ensuring that the construction materials specified meet performance criteria. By ensuring PGE understands the changing weather patterns, we can ensure that facilities are built to withstand future disruptive events.

5.4.4 INSPECTION AND MAINTENANCE PLANS

PGE maintains a Facilities Inspection and Treatment to the National Electrical Safety Code (FITNES) program that is designed to satisfy Oregon's Chapter 860, Division 024 Safety Standards. The program involves a detailed inspection of approximately 10% of PGE's overhead facilities per year, with an overall objective of inspecting 100% of the facilities every 10 years. The program includes a detailed visual inspection of structure and support systems (e.g., poles, crossarms, insulators, guys and anchors), grounding and conductor clearances. The detailed inspection also includes testing to assess the condition of wood poles and the application of wood preservatives. Poles that are found to have inadequate height or remaining strength are replaced. The FITNES program operates year-round.

5.4.5 MT. HOOD IMPROVEMENTS

The goals of this project are to increase reliability and reduce outages for PGE customers in the Mt. Hood corridor to keep life-critical services available to the general population.

Mt. Hood is an area where PGE customers face many outages from storms, wildfires and PSPS. This project will work to move transmission and distribution lines from overhead to underground and increase redundancy in PGE's system to prevent many of these outages. This project also will increase reliability in the distribution system for critical customers in the vicinity, such as medical centers, water treatment facilities, fire departments, ranger stations and grocery stores.

5.4.6 TELECOMM RISK AND SINGLE POINTS OF FAILURE

The goal of this effort is to develop a quantitative framework for capturing known vulnerabilities to the telecom transport network and using subject matter expertise to validate the risks and consequences. This information will be translated into business cases that support the articulation and prioritization of investments in PGE's telecom network.

5.4.7 ADVANCED METERING INFRASTRUCTURE (AMI) RESILIENCE IMPROVEMENTS

Initially intended to support automated meter reading, AMI can now provide resilience for customers and communities as an additional, critical function. The improvements planned by this initiative will ensure the infrastructure supporting AMI data's resilience is upgraded to mission-critical versus the current state.

5.5 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.

5.5.1 END-TO-END ASSESSMENT PROCESS

This effort aims to ensure accurate descriptions of the extent of impacts from an incident early enough and consistently throughout an event to allow customers and communities to make key decisions.

Personnel will perform damage assessment activities and will merge assessment outputs into the overall outage response command, control and information systems of the incident management structure. This consolidated, holistic assessment allows us to better understand the material, personnel and equipment needed early in the storm, which in turn accelerates outage modeling and speeds up the development of estimated restoration times for customers.

5.5.2 OUTAGE MANAGEMENT PLANNING AND PREPARATION

Recent ice storm and wildfire events have required PGE to exercise its full complement of outage management and response capabilities. Lessons learned during these events have provided improvement opportunities. A few examples of include:

- Aligning outage management plans that are maintained within each organization
- Clarifying roles, responsibilities and terminology among those plans
- Ensuring that all PGE staff are familiar with these planning materials

This will promote collaborative planning and training and exercise participation within the operational levels of the organization.

5.5.3 STAGING SITE OPERATIONAL PLAN

The size and scope of these events exposed the challenges of not having a mobile command post and associated resilient communication capabilities in the field, as some locations were affected by communication outages. Based on review of the existing staging site operational plans, PGE is creating a prioritized list of enhancements that will increase logistical and operational support capabilities for wildfires, large storms and earthquakes. For example, company-owned sites such as the Rodeo Grounds will be improved to handle restoration activities of up to 100 mutual assistance crews.

5.5.4 COMMUNITY ENGAGEMENT AND PUBLIC INFORMATION TOOLS

This effort focuses on the development of a set of essential elements of information and intelligence products (such as dashboards and online maps) that meet customer needs for actionable information and ensure the corporate incident management team (CIMT) is aware of expectations. PGE is working with local governments and organizations to identify communication needs and develop a means to engage impacted customers directly. This includes direct notifications across multiple channels, including SMS, phone and email.

5.5.5 WIRE-DOWN, WIRE-WATCHER AND DAMAGE ASSESSMENT PROGRAM

The goal of this project is to enhance the wire-down/wire-watcher program in coordination with damage assessment program improvements, expanding capacity and capabilities and providing a broader group of PGE employees the ability to participate. This will ensure that the wire-down program relies on non-line department resources to staff the program, rather than resources that could otherwise perform assessment and restoration work.

5.5.6 PARTNERSHIPS

Significant outage events present the need to engage resources external to PGE, such as local governments and third-party restoration crews. This effort will promote collaborative planning and training and exercise participation within the operational levels of these disparate organizations. PGE will formalize agreements, establish interoperable information-sharing mechanisms among emergency management agencies, and establish public/private sector operating agreements. These agreements will define clear expectations between what PGE does and what the emergency management community does to inform customers and alleviate impacts during an outage.

5.5.7 CRITICAL MATERIALS AND SERVICE PROVIDER REQUIREMENTS

Large outage events often result in the rapid depletion of materials on hand. This effort focuses on ensuring PGE's materials and supply chain are equipped to handle a surge in demand. It includes activities such as defining storm response and business continuity requirements for all critical material and service contracts, documenting contingency tactics to set up service providers for extended or expanded services, and having vendors stock up facility supplies beyond normal levels ahead of a storm.

Chapter 6.

Plug and play: enabling DER adoption

Chapter 6. Plug and play: enabling DER adoption

"Replacing traditional sources of energy completely with renewable energy is going to be a challenging task. However, by adding renewable energy to the grid and gradually increasing its contribution, we can realistically expect a future that is powered completely by green energy"

— Tulsi Tanti, world-renowned clean energy expert

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.[96] It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.

This chapter provides a description of the activities, planned or in flight, and how our human-centered vision of the distribution system can provide safe, secure, reliable and resilient power, at fair and reasonable costs. It supports PGE's plug and play strategic initiative, describing our efforts to enhance our net metering map to include distributed generation readiness and demographics information, as well as how we'll perform hosting capacity analysis (HCA) twice annually beginning in 2022.[97] It also provides details on PGE's recommendation for HCA updates at the line segment level on an as-needed basis, rather than monthly or hourly. **Table 26** illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP guidelines under Docket UM 2005, Order 20-485.[98]

WHAT WE WILL COVER IN THIS CHAPTER

- An overview of hosting capacity analysis (HCA) and its role in the modernized grid
- How HCA matures over time
- How PGE identifies areas where distributed generation can be added
- An overview of the options for analyzing hosting capacity
- PGE's HCA plans moving forward

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A. DSP plan guidelines compliance checklist**.

96. PGE uses the definition of environmental justice communities under Oregon House Bill 2021, available at oregonlegislature.gov
97. PGE's net metering map, available at portlandgeneral.com
98. OPUC UM 2005, Oregon 20-485 was issued on December 23, 2020, available at apps.puc.state.or.us

Table 26. Plug and play: guideline mapping

DSP guidelines	Chapter section
4.2.a	Section 6.4
4.2.b	Section 6.5

6.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities to conduct a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades and present the results through an unredacted map that is continuously available on the utility's website. PGE also is required to analyze three options to meet future HCA needs. This section provides an overview of HCA, what it is and how it can be used to support decisions. Also included is a description of PGE's partner and community feedback process, which helped shape PGE's approach.

PGE will use Electric Power Research Institute's (EPRI's) definition of hosting capacity.[99] According to EPRI:

> Hosting capacity in a distribution system is the amount of DERs that can be accommodated without significant upgrades or adversely impacting power quality or reliability under existing feeder design and control configurations.

Our plan is focused on HCA as it relates to distributed generation (DG) and does not include consideration of DERs such as electric vehicles (EVs), as described in EPRI's definition. Flexible loads such as EVs, hot-water heaters and behind-the-meter storage will be considered in future DSP submittals.

PGE is supportive of OPUC staff's goal of transparency and visibility into PGE's system. HCA will allow prospective interconnection customers to make more informed business decisions prior to committing resources to an interconnection application.

As PGE heard in OPUC staff's webinar series, and as witnessed from other states' experiences, use cases for HCA include:

- Preliminary screening for DG proposals
- Guidance in the early phases of the interconnection process
- Enhancing distribution system visibility when determining locations for future DG

PGE's approach to HCA has been shaped by conversations with partners, communities and other utilities that have implemented HCA tools and methodologies. We conducted a series of feedback sessions with partners and communities and interviews with peer utilities to gain insight into lessons learned and the most effective approach to delivering value.

We also hosted a total of six community workshops from March 2021 to September 2021. One of the primary objectives was to gather feedback for the HCA options analysis and clarify the use cases for the DG evaluation map.

PGE gathered feedback from the OPUC's Technical Working Group (TWG) via three sprint sessions over 10 weeks.[100] Each sprint session was composed of a feedback period, analysis of the feedback and updates to the map. The periods for each sprint session are outlined in **Figure 30**.

99. "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State," EPRI, June 2016, available at epri.com
100. A description of the OPUC's TWG, available at edocs.puc.state.or.us

Figure 30. 2021 feedback sprints

Sprint 1, 5/3-5/21
5/3 – 5/7: Stakeholders provide feedback
5/10 – 5/21: PGE team incorporates feedback
Sprint 2, 5/24-6/11
5/24 – 5/28: Stakeholders provide feedback
5/31 – 6/11: PGE team incorporates feedback
Sprint 3, 6/14-7/2
6/14 – 6/18: Stakeholders provide feedback
6/14 – 7/2: PGE team incorporates feedback

During this process, PGE received 124 comments from partners and communities. The complete set of feedback with PGE's responses can be accessed on PGE's DSP website.[101]

The feedback process proved valuable for PGE as an opportunity to calibrate on terms, definitions and value levers. As noted earlier, the results of a complete HCA will not be available until late 2022. In the interim, it is important to identify the means by which PGE can support customers' DG decision-making processes.

A few examples of important takeaways from the feedback process are:

- **Naming the map:** Initially, the map's name was "DER Readiness Viewer." It became clear that the name needed to change to reflect the fact that only DG is addressed in the DSP Part 1 HCA requirements and represented on the map, not other DERs such as electric vehicles.
- **Recognizing complexity:** For the purpose of making the map and data usable, PGE provided some definitions and descriptions that were oversimplified. They do not apply in all situations. As a result, PGE is revisiting its definitions and how the data is presented.
- **Missing data:** Although the data PGE provided has been publicly available for more than a year, this feedback process revealed missing and inaccurate data that PGE will have an opportunity to correct in future publications.
- **Overall:** This activity generated productive conversations. Viewing data through the perspectives of different customers, partners and communities generated valuable insights, and PGE looks forward to continuing this dialogue as DG readiness and HCA analyses evolve.

101. PGE's DSP website, available at assets.ctfassets.net

6.3 Hosting capacity maturity model

PGE appreciates the OPUC's recognition of PGE's constrained feeder map as a starting point for communicating to partners and communities. We will continue to produce this level of hosting capacity and, with input from partners and communities, improve its usefulness. This level of data transparency is identified as Phase 1 in EPRI's hosting capacity maturity model, illustrated in **Table 27**.[102]

Table 27. Hosting capacity maturity model

Phase	Consideration	Data requirements	Outcome	Possible outputs
1. Indicator assessment (PGE current state)	Possible indicators such as: – Estimated minimum load levels – Voltage class – Substations over a MW threshold typically indicative of backfeed	– Currently available data – Understanding the interconnection queue	– Provides an indication where certain substations/ feeders may have high costs associated with interconnecting DER	– Maps indicating where interconnection costs may be higher
2. Hosting capacity evaluations – Radial systems	– All feeders modeled in service territory with periodic updates for existing DER and queued DER mapped into planning models	– All feeders modeled in service territory with periodic updates for existing DER and queued DER mapped into planning models	– Feeder-level hosting capacity determinations	– Maps indicating feeder-level hosting capacity
3. Advanced hosting capacity evaluations	– Substation and transmission assessments and mapping of distribution-level impacts to substation and transmission – Normal and reconfigured system models	– Substation and transmission assessments and mapping of distribution-level impacts to substation and transmission – Normal and reconfigured system models	– Refined hosting capacity evaluations that take into account additional criteria	– Maps indicating node/section-level hosting capacity
4. Fully integrated DER value assessments	– Increased level of detail regarding distribution constraints, asset performance and DER performance metrics – Models of emerging technologies, such as energy storage	– Increased level of detail regarding distribution constraints, asset performance and DER performance metrics – Models of emerging technologies, such as energy storage	– Comprehensive hosting capacity and DER value assessments considering both distribution and transmission – Ability to increase hosting capacity	– Maps indicating hosting capacity along with areas where DER can bring additional value to the grid

102. "Defining a Roadmap for Successful Implementation of a Hosting Capacity Method for New York State," accessed October 26, 2020, available at nyssmartgrid.com

While PGE's system modeling and remote sensing capabilities are maturing, PGE will use distribution system indicators to provide information to identify areas where DG can be accommodated. Possible indicators include daily minimum load (DML), installed/planned distributed generation and current system configuration. These indicators will allow developers to consider the type of constraints that may exist in different areas they are considering for installations.

Moving beyond Phase 1 in this maturity model requires advancements in forecasting, system monitoring and system modeling. PGE will begin to see these advancements with the implementation of its advanced distribution management system (ADMS) in 2022.

6.4 Distributed generation (DG) constrained areas

Recognizing that a true HCA requires complete and current distribution feeder models for the entire system, PGE is using distribution system indicators to identify areas where DG can be accommodated. Distribution system indicators include DML (the estimated level at which substation backfeed may occur), installed DG and planned DG.

PGE's current net metering map uses these indicators to help provide visibility into locations where there may be a significant cost to interconnect. These indicators can help developers identify the type of constraints that may exist in different areas where they are considering installations.

PGE's approach for conducting a system-wide HCA at the feeder level is presented in **Section 6.6**. The remainder of this section provides a discussion of distribution system indicators and how they can support DG siting and sizing decisions.

6.4.1 PGE GENERATION LIMITED FEEDER MAP

Most PGE feeders can support new net metering projects; however, a few areas have limited capacity to connect new generation projects without significant changes to the feeder or the substation. Small residential and business projects can usually still be accommodated but may require design changes to maintain grid safety and reliability.

For the purposes of our Generation Limited Feeder Map, PGE is using the following definition:

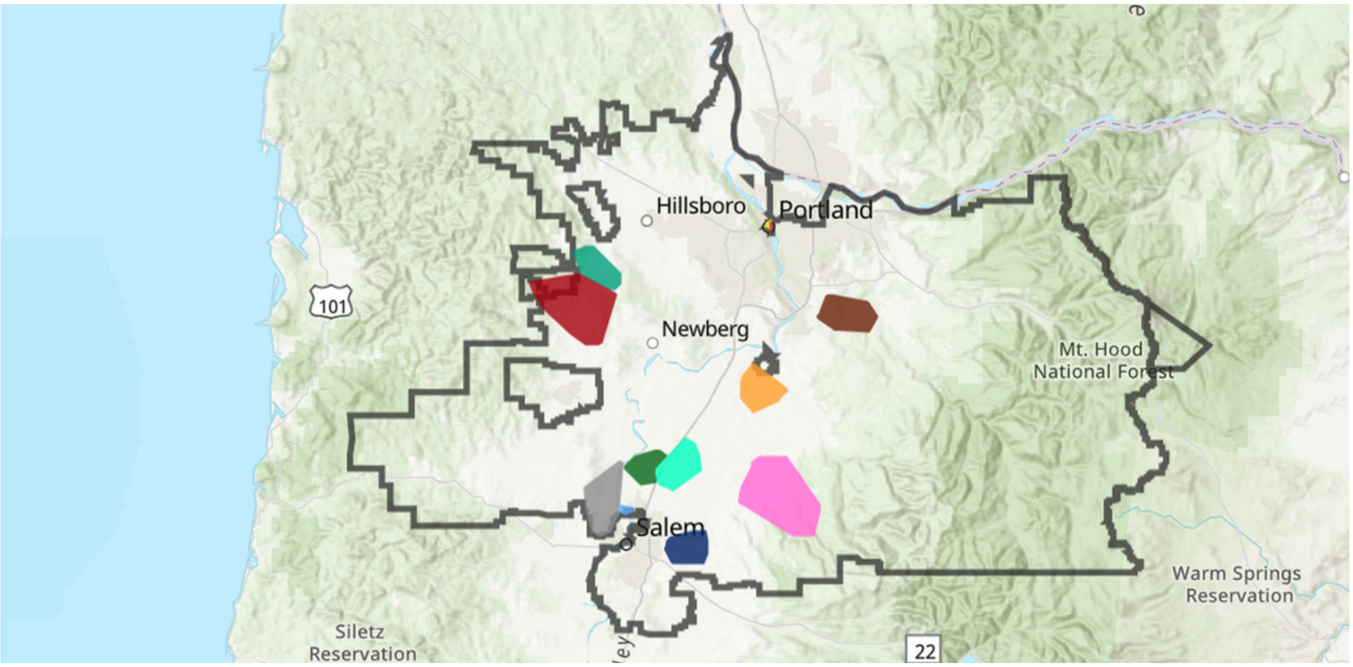
> A generation-limited feeder is a feeder that has installed and queued generation that exceeds 90% of the DML.

This use of DML data is an example of using distribution system indicators to support or inform the siting of DG.

PGE's generation limited feeder map, shown in **Figure 31**, allows a customer to enter their street address to find out if their location is served by a generation-limited feeder.[103]

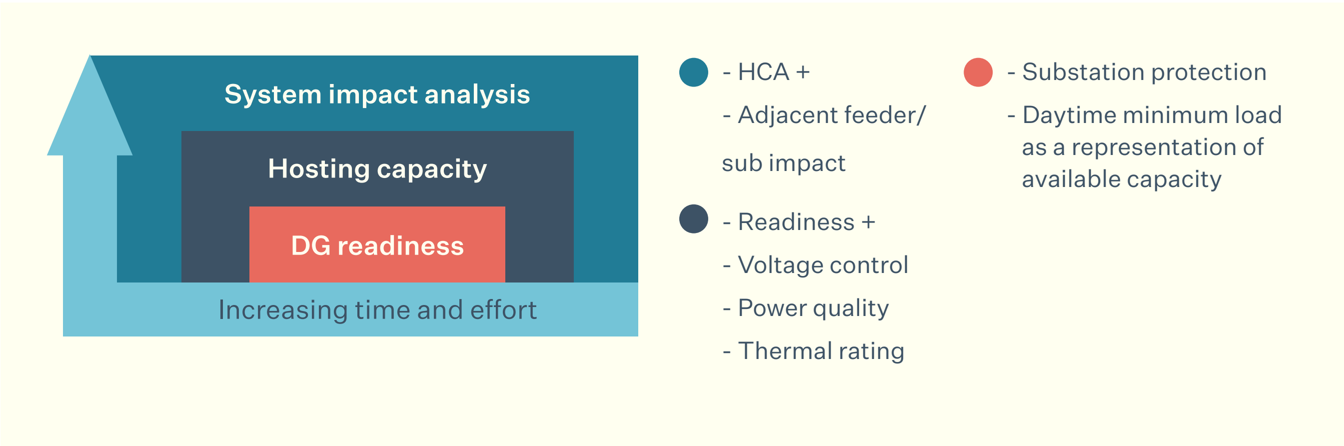
103. The data that supports production of PGE's Generation Limited Feeder map is publicly available and located on the portal for interconnection information, available at oasis.oati.com

Figure 31. PGE generation limited feeder map



The purpose of providing the net metering map is to enable customers to perform some preliminary screening activities before submitting an application for interconnection. The expectation is that empowering customers to take these steps will reduce the time and work necessary to process interconnection applications, enhance the customer experience and reduce the number of withdrawn applications. **Figure 32** depicts some of the interconnection screening activities.

Figure 32. Interconnection screening activities

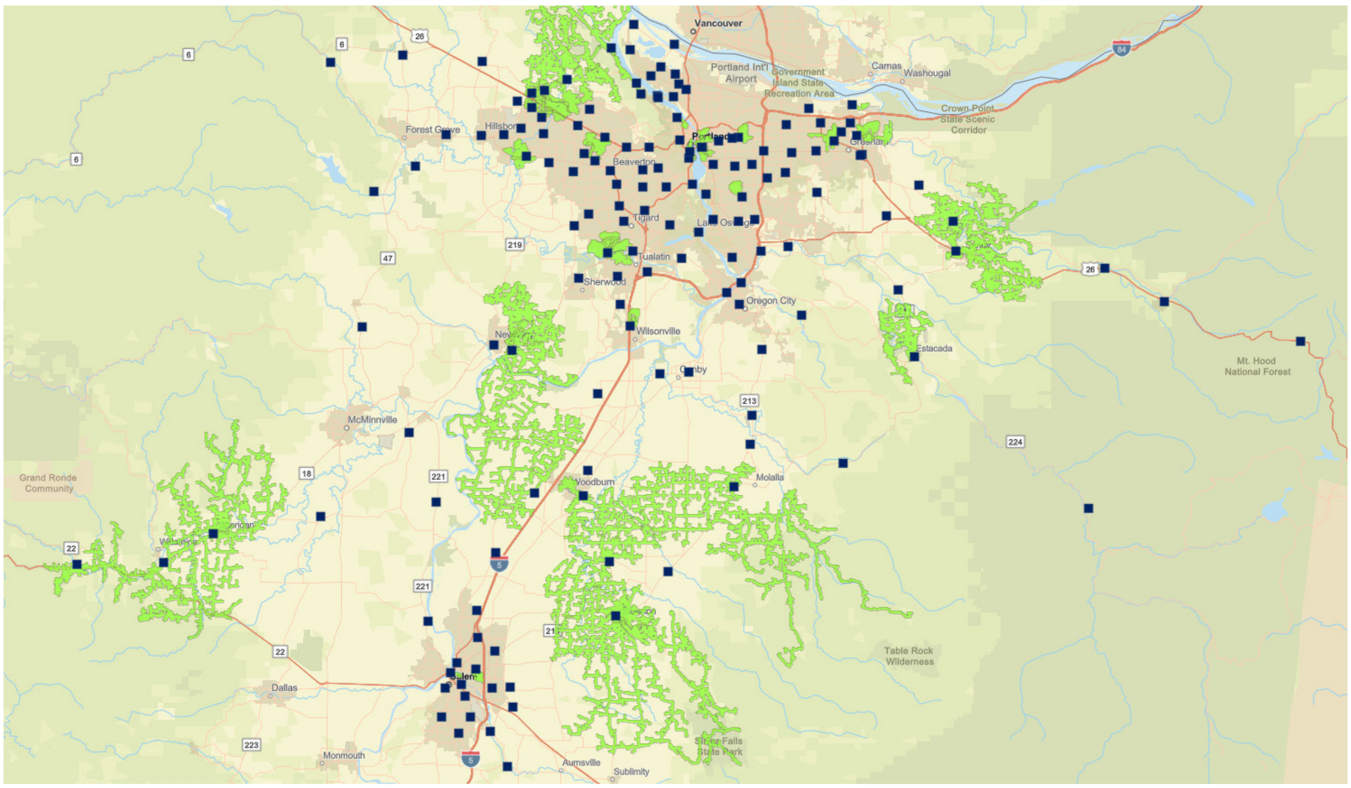


6.4.2 DISTRIBUTED GENERATION EVALUATION MAP

In an effort to expand the availability and usability of the data posted on OASIS, PGE worked with the OPUC's TWG to identify information that would be valuable to add to the generation limited feeders map (a sample of this data is available in **Appendix K. OASIS** dataset. The initial version of the distributed generation evaluation map is shown in **Figure 32**. The map provides access to several categories of PGE system data and demographic data from the U.S. Census Bureau.

The distributed generation evaluation map is a high-level display of the PGE distribution system's ability to accommodate DG. This map is one tool designated to help assess the grid's ability to support DG, such as rooftop solar or a larger solar installation.[104]

Figure 33. Distributed generation evaluation map



104. A complete description of the map's features can be found in the user guide posted on PGE's DSP website, available at assets.ctfassets.net

The information in the map can be used to support DG siting and sizing decisions in many ways:

- **DG-ready feeders and substation transformers:** This information is provided in contrast to the limited-generation feeders represented in the net metering map. The "DG-ready" designation indicates that these feeders and substation transformers have the protection equipment required to prevent damage during a backfeed event. The availability of protection equipment and implementation of protection schemes are cost drivers for DG installations. Knowledge of where protection is in place can help customers, installers and developers identify more cost-effective locations for DG installations.
- **Substation location:** This is an informational-only item. Distance from a substation to the point of interconnection, such as a solar installation, can be an interconnection cost driver. For example, if communication infrastructure (e.g., fiber) needs to be provided to a location, longer distances typically result in additional costs to prepare the utility poles for communication attachments.
- **Daytime minimum load (DML):** If a feeder is not identified as DG-ready, then the DML provides an indication of how much generation might be accommodated by a feeder. This information can be used in several ways:
  - DML helps identify how much DG could potentially be accommodated on a feeder.
  - DML indicates how to size a DG so that the DG does not exceed the DML.
  - If DG capacity in queue is greater than DML, then it is possible that the DG in queue may have to pay for upgrades to the feeder, substation or both, thus indicating that future installations may not have the same upgrade expenses.
  - DML is a proxy for hosting capacity, but it is not hosting capacity. Hosting capacity includes other considerations, such as the thermal rating of a feeder and voltage regulation. Therefore, DML can help with screening, but additional analyses are required to evaluate the impact of DG at a location.
- **DG capacity in queue:** This represents the amount of generation that was in the interconnection queue as of the date reflected in the "Date DG status updated" field. The number of projects in the queue, as well as the amount of proposed generation, provides a level of uncertainty to the future state of the associated feeder and transformer. With the possibility of projects removing themselves from the queue (the dropout rate has been as high as 60%), the study process becomes more complex with the added risk of re-studies.

PGE anticipates that the value of the Demand Generation Evaluation Map will evolve as partners, communities and customers use the map to support DG decisions.

6.5 Hosting capacity options analysis

The three options outlined in the OPUC's UM 2005 DSP requirements represent increasing degrees of granularity in both time and data resolution. The evaluation of each option is based on the best available information today. PGE recognizes that HCA is a rapidly evolving capability with new tools and techniques being introduced every year. We have used our current understanding of DG-specific HCA as a starting point and scaled that model to represent the three options, with additional assumptions incorporated to capture option-specific costs/benefits. For example, Option 1 outlines annual HCA at the feeder level; Option 2 outlines monthly HCA. The cost of Option 2, therefore, is approximately 12 times the cost of Option 1. As with any process, efficiencies will be gained, and annual costs are expected to decrease in iterations past the initial implementation timelines.

The outcome of this analysis may not be precise with respect to the actual cost of executing the different options, but we expect that it is representative of the relative complexity, effort and costs between the three options.

6.5.1 METHODOLOGIES

There are four main methods to analyze hosting capacity in the industry today: Stochastic, streamlined, iterative and hybrid. Electric Power Resource Institute (EPRI) has conducted several evaluations on the different hosting capacity methods, which all reached parallel conclusions. This means regardless of the hosting capacity method used, they all can provide similar, accurate results. The minor variations in input assumptions and factors have greater impact on results than one method versus another. EPRI recognized that hosting capacity methods are continuously evolving and improving as new technologies become available. A hybrid method, such as DRIVE, is the most likely and successful path going forward.

Table 28 summarizes the advantages and disadvantages of the four main hosting capacity methods.[105]

Table 28. Four main methods to analyze hosting capacity

Method	Approach	Advantages	Disadvantages	Computation time	Recommended use case
Stochastic	– Increase DER randomly – Run power flow for each solution	– Similar in concept to traditional interconnection studies – Becoming available in planning tools	– Computationally intensive – Limited scenarios	Hours/feeder	– DER planning
Iterative (Integration capacity analysis)	– Increase DER at specific location – Run power flow for each solution	– Similar in concept to traditional interconnection studies – Becoming available in planning tools	– Computationally intensive – Limited scenarios – Vendor-specific implementations can vary – Does not determine small, distributed rooftop Photovoltaic (PV)	Hours/feeder	– Inform screening process – Inform developers

105. Source: Methods and application considerations for hosting capacity (hawaiianelectric.com), available at hawaiianelectric.com

Table 28. Four main methods to analyze hosting capacity (continued)

Method	Approach	Advantages	Disadvantages	Computation time	Recommended use case
Streamlined	– Limited number of power flows – Utilizes combination of power flow and algorithms	– Computationally efficient – Not vendor tool-specific	– Novel approach to hosting capacity – Method not well understood – Limited scenarios – Not available in current planning tools	Minutes/feeder	– Inform screening process – Inform developers
Hybrid (DRIVE)	– Limited number of power flows – Utilizes combination of power flow and algorithms	– Computationally efficient – Many DER scenarios considered – Not vendor tool-specific – Broad utility industry adoption and input – Becoming available in planning tools	– Novel approach to hosting capacity – Method not well understood – Lag between modifications/ upgrades and associated documentation	Minutes/feeder	– DER planning – Inform screening process – Inform developers

Table 29 shows the recommended use cases for each method. Exelon Corporation companies, such as Potomac Electric Power Company (Pepco) and Commonwealth Edison (ComEd), have used the stochastic method, while California utilities have used both the iterative and streamlined methods. More than 27 utilities have used the hybrid method via the DRIVE tool.

Table 29. Recommended use cases to analyze hosting capacity[106]

Method	Industry adoption	Recommended use case
Stochastic	Pepco, ComEd	– Enabling planning – Informing the public
Iterative	Southern California Edison (SCE), San Diego Gas & Electric (SDG&E)	– Assisting with interconnection – Informing the public
Streamlined	Pacific Gas & Electric (PG&E)	– Enabling planning – Informing the public
Hybrid-DRIVE	27+ utilities worldwide (including XCEL)	– Enabling planning – Assisting with interconnection – Informing the public

106. "Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity." January 31, 2018, pages xixii, 5-2, available at epri.com

Based on the positive experiences in other jurisdictions and PGE's own experience with the tool, we believe DRIVE is the correct tool at this time to perform our HCA and help inform where the system has availability to interconnect DG. As a hybrid method, DRIVE has several benefits, including computational efficiency, accuracy of results and multiple use case scenarios. Another advantage is PGE's use of CYME as the distribution planning tool, which integrates well with DRIVE. Additionally, DRIVE's continued growth in popularity has enhanced consistency across the industry in analyzing hosting capacity.

6.5.2 OPTIONS ANALYSIS

Table 30 shows the three options outlined in the OPUC UM 2005 DSP requirements. The second and third characteristics are particularly important, as they represent the granularity of analysis. The DRIVE tool supports analysis at the granularity requested in all three options. The challenge is in providing the inputs to the DRIVE tool to enable analysis at increasing levels of granularity.

A summary of the options analysis results is presented in **Table 31**. A more detailed description of each option appears in the following sections.

Table 30. Three HCA options included in the options analysis

HCA characteristic	Option 1	Option 2	Option 3
Methodology	Stochastic modeling/ EPRI DRIVE modeling	Same as option 1	Iterative modeling
Geographic granularity	Circuit	Feeder	Line segment
Temporal granularity	Annual minimum daily load	Monthly minimum daily load	Hourly assessment
Data presentation	Web-based map for the public and available tabular	Same as option 1	Same as option 1
Data update frequency	Annual refresh	Monthly refresh	Monthly refresh
Other info	Queued generation	Same as option 1	Same as option 1

Table 31. HCA options analysis summary[107]

Evaluation parameter	Option 1	Option 2	Option 3
Timeline	12 months	24 months	24-36 months
Cost	$141k	$2.61M	$58.38M
Data security risk	Low	Low	Medium
Result validation	Low	High	High
Implementation concerns	Low	Medium	High
Interconnection use case implications	Medium	High	High
Planning use case implications	Low	Medium	Medium
Locational value and benefits	Medium	Medium-high	Medium-high
Interaction with grid needs identification	Medium	Medium-high	Medium-high

107. Costs and hourly estimates are provided for the purpose of comparing the options. They are subject to change.

In the analysis of each option, PGE considered these questions from the DSP guidelines:

- What are the costs and timeline?
- What are the implementation barriers?
- How frequently should the data and map be updated?
- How helpful will this be for grid needs identification?
- How helpful will this be for interconnection studies?

The DSP questions were translated into the evaluation parameters shown in **Table 31**.

The definition of each evaluation parameter and its rating scale follow:

- **Timeline:** the duration required to develop the capability to execute HCA at the specified level of granularity
- **Cost:** the monetary value of the people, processes and tools required to execute HCA at the specified level of granularity

Table 32. Criteria that utilize a low/medium/high rating scale

Evaluation criterion	Low	Medium	High
Data security risk: the degree of risk related to system or customer data	Individual customer data or system vulnerability is not exposed	PGE must take additional steps to obscure the data so that individual customer data or a system vulnerability is not exposed.	Information about an individual customer can be derived from the information provided or a system vulnerability can be identified.
Result validation: the effort needed for input and output data quality assurance (QA) to validate the results	All the data is the most recent for the effort; some data clean-up and validation work is necessary.	Detailed QA will be done by engineers to validate assumptions, models and results.	Automated QA will be done by engineers to validate results and models.
Implementation concerns: challenges and roadblocks for data availability, staff and computational resources	No immediate or severe concerns	Anticipate data availability, system process and computationally intensive issues with moderate possibilities for delays	Anticipate data availability, system process and computationally intensive issues with severe possibilities for delays
Interconnection use case implications: the ability of HCA results to support the interconnection process (e.g., DG siting and sizing decisions)	The HCA results do not support DG siting/sizing decisions; only generation-constrained areas will be identified.	The HCA results support DG siting/sizing decisions, but may not be reliable. Feeder, substation and system-level data will be shared for all connected DG as well as DG in queue. Overview of constraints evaluated will be provided. Maps will be refreshed annually.	The HCA results provide a high degree of confidence in DG siting/sizing decisions. Feeder, substation and system-level data will be shared for all connected DG as well as DG in queue. Overview of constraints evaluated will be provided. Maps will be refreshed more frequently.

Table 32. Criteria that utilize a low/medium/high rating scale

Evaluation criterion	Low	Medium	High
Planning use case implications: the ability of HCA results to serve as a tool for distribution system planning	Distribution Planning is made aware of the location and size of the DERs being interconnected, but cannot control or direct the location of DERs; DER-related distribution upgrades are made in a reactive manner.	Hosting capacity is evaluated to understand the impacts of DERs on the feeders at different loading levels, locations and type of DER, among other factors. Time-varying impacts of DERs on the distribution system are studied. High DER penetration effects are studied, along with their mitigation options. Provides a basis for cost benefit and deferral framework.	Hosting capacity captures both transmission and distribution impacts. The analysis informs and captures much more detailed and granular results. The analysis informs non-wires solutions' (NWS) cost/ benefit and deferral framework. Improved system and scenario planning with enhanced load and DER forecasts. Improvements to update cost allocation for the services provided by DERs. Benefits and impacts of smart inverters and energy storage are evaluated. Grid impacts are studied when feeders are reconfigured.
Locational value and benefits: the ability of HCA results to support the evaluation of locational value and benefits	Cannot help the evaluation of locational value and benefits	Evaluation of some, but not all, locational value and benefits are supported by the HCA results.	Evaluation of locational value and benefits is supported by the HCA results.
Interaction with grid needs identification: HCA results can be used to assess grid needs	HCA results do not support grid needs analysis.	HCA results partially support grid needs analysis.	HCA results support grid needs analysis.

The following sections provide an analysis of each option. The criteria described previously are applied to each option.

6.5.3 OPTION 1: ANNUAL REFRESH AT CIRCUIT LEVEL

Option 1 as defined in the DSP requirements represents the base case for performing HCA and reflects the starting point for most utilities that have begun performing HCA. The description of Option 1 as provided in the DSP requirements is included in **Table 33**.

Table 34 includes a summary of the results of PGE's analysis of Option 1. A brief description of the evaluation of each parameter follows.

Table 33. HCA Option 1 requirements

HCA characteristic	Option 1 requirement
Methodology	Stochastic modeling/EPRI DRIVE modeling
Geographic granularity	Circuit
Temporal granularity	Annual minimum daily load
Data presentation	Web-based map for the public and tabular format
Data update frequency	Annual refresh
Other info	Queued generation details

Table 34. Analysis summary for option 1

Evaluation parameter	Option 1	Evaluation rating description
Timeline	12 months	No lead time is required to prepare for this level of HCA execution. PGE owns the tools and has the capability to perform Option 1. The resources to perform this analysis need to be made available and that resource commitment is outlined in **Table 35**.
Cost	$141k	Cost details are included in **Table 35**.
Data security	Low	Due to the granularity of data being presented, there is little to no risk to data security.
Result validation	Low	Provision of data on an annual basis makes the QA process easy to execute; no automation or expedited processing are required.
Implementation concerns	Low	Annual processing of HCA leverages data that PGE already produces and tools that PGE currently uses.
Interconnection use case implications	Medium	The basic information to support siting and sizing is available, but the frequency may render it inaccurate.
Planning use case and implications	Low	DER upgrades are made in a reactive manner.
Locational value and benefits	Medium	The evaluation of benefits is limited based on the spatial and temporal granularity of data. Not all benefits can be identified or maximized.
Interaction with grid needs identification	Medium	The evaluation of grid needs is limited based on the spatial and temporal granularity of data.

The detailed breakdown of costs is included in **Table 35**.

Table 35. Option 1 estimated cost detail

Activity	Hours	Cost
Setup	1,120	$67,200
GIS	120	$7,200
Reporting	120	$7,200
Modeling	700	$42,000
Analysis	163	$9,750
License renewals		$7,200
Total	**2,223**	**$140,550**

Note that the activities and costs summarized in **Table 35** are explained further in **Section 6.6**.

6.5.4 OPTION 2: MONTHLY REFRESH AT FEEDER LEVEL

Moving beyond annual to monthly HCA updates would stretch the manual processes beyond their limits, therefore performing the analysis will require automation of various components of the process, as well as completing the field verification and underlying data updates. This automation will not only allow for more frequent updates, but it will also improve the accuracy of the information. The description of Option 2 as provided in the DSP requirements is included in **Table 36**.

Table 36. HCA Option 2 requirements

HCA characteristic	Option 2
Methodology	Same as Option 1
Geographic granularity	Feeder
Temporal granularity	Monthly minimum daily load
Data presentation	Same as Option 1
Data update frequency	Monthly refresh
Other info	Same as Option 1

Table 37 includes a summary of the results of PGE's analysis of Option 2. A brief description of the evaluation of each parameter follows.

The detailed breakdown of costs is included in **Table 38**.

Table 37. Analysis summary for Option 2

Evaluation parameter	Option 2	Evaluation rating description
Timeline	24 months	In order to execute HCA on a monthly basis, additional field data collection will need to occur, as well as automation of data management and analyses. The estimated time to put those tools and processes in place is approximately two years.
Cost	$2.61 million	Cost details are included in **Table 38**.
Data security	Low	Due to the granularity of data being presented, there is little to no risk to data security.
Result validation	High	Execution of HCA on a monthly basis requires automation or another means of expedited processing.
Implementation concerns	Medium	Monthly execution will put pressure on the resources involved, both computational and personnel.
Interconnection use case and implications	High	The interconnection queue is updated on a monthly basis. Monthly execution of HCA will provide the most up-to-date DG information relative to the information in the queue.
Planning use case and implications	Medium	Execution on a monthly basis provides more of an opportunity to factor DG requests into DG investment planning processes.
Locational value and benefits	Medium-high	The evaluation of benefits is limited based on the spatial and temporal granularity of data — not all benefits can be identified or maximized. Note that the ability to maximize locational net benefits is more of an operational capability. The ability to control DG installations is necessary to achieve more value/benefits.
Interaction with grid needs identification	Medium-high	The evaluation of grid needs is limited based on the spatial and temporal granularity of data. Note that the ability to maximize DG's contribution to grid need is more of an operational capability. The ability to control DG installations is necessary to achieve more value/benefits.

Table 38. Option 2 estimated cost detail

Activity	Hours	Cost
Setup	13,440	$806,400
GIS	1,440	$86,400
Reporting	1,440	$86,400
Modeling	8,400	$504,000
Analysis	1,950	$117,000
DRIVE software, data management and computing		$1,007,200
Total	**26,670**	**$2,607,400**

Note that the activities and costs summarized here are explained further in **Section 6.6**.

6.5.5 OPTION 3: HOURLY REFRESH AT THE LINE SEGMENT

Performing HCA on an hourly basis at the line segment level creates an exponential increase in the data collection needed. It requires an increase in our monitoring/sensing and data polling processes to an hour or sub-hour frequency. In some cases, current equipment does not support that frequency or granularity. New equipment will need to be deployed and existing equipment will need to be reconfigured.

Much of this monitoring/sensing currently takes place at the substation transformer. Extending a similar level of sensing/monitoring and data polling to the line segment level will require deployment of additional equipment.

The exponential increase in data collection requires expanded storage and processing capabilities and, potentially, communication bandwidth to transport data from remote monitoring equipment.

Based on these factors, a significant increase in cost and timeline to develop the capability is to be expected for Option 3. The costs and timeline outlined below are in line with the costs estimated by peer utilities as shown in their HCA plans (e.g., SCE and MN Xcel). We have noted in the following outlined costs where we believe the investment is already being made. For example, PGE's distribution automation program will deploy remote sensing capabilities on line segments, thereby reducing the cost to implement this level of HCA.

The requirements for Option 3 are depicted in **Table 39**.

Table 40 includes a summary of the results of PGE's analysis of Option 3. A brief description of the evaluation of each parameter follows.

Table 39. HCA Option 3 requirements

HCA characteristic	Option 3
Methodology	Iterative modeling
Geographic granularity	Line segment
Temporal granularity	Hourly assessment
Data presentation	Same as Option 1
Data update frequency	Monthly refresh
Other info	Same as Option 1

Table 40. Analysis summary for Option 3

Evaluation parameter	Option 3	Evaluation rating description
Timeline	24-36 months	In order to execute HCA on an hourly basis, additional field data collection will need to occur, as well as automation of data management and analyses. The estimated time to put those tools and processes in place is 2-3 years.
Cost	$58.38M	Cost details are included in **Table 41**.
Data security	Medium	Data will be published at the line segment level, and that will expose some customer information. PGE will need to perform some aggregation, such as applying the 15/15 rule, to protect customer data.[108]
Result validation	High	Execution of HCA on an hourly basis requires automation or another means of expedited processing.
Implementation concerns	High	Hourly execution will require a new execution paradigm.

108. The 15/15 rule is an approach to maintaining customer privacy. More information is available at elevatenp.org

Table 40. Analysis summary for Option 3 (continued)

Evaluation parameter	Option 3	Evaluation rating description
Interconnection use case and implications	High	The interconnection queue is updated monthly. Hourly execution of HCA will provide the most up-to-date DG information relative to the information in the queue.
Planning use case and implications	Medium	Execution on an hourly basis does not provide more information for planning purposes than monthly execution.
Locational value and benefits	Medium-high	The evaluation of benefits is limited based on the spatial and temporal granularity of data — not all benefits can be identified or maximized. Note that the ability to maximize locational net benefits is more of an operational capability. The ability to control DG installations is necessary to achieve additional value/benefits.
Interaction with grid needs identification	Medium-high	The evaluation of grid needs is limited based on the spatial and temporal granularity of data. Note that the ability to maximize DG's contribution to grid need is more of an operational capability. The ability to control DG installations is necessary to achieve more value/benefits.

PGE expects that one-half to two-thirds of the costs cited above could be attributed to modernized grid efforts already underway.

The detailed breakdown of costs is included in **Table 41**.

Table 41. Option 3 estimated cost detail

Activity	Hours	Cost
Setup	645,120	$38,707,200
GIS	6,240	$374,400
Reporting	1,440	$86,400
Modeling	36,400	$2,184,000
Analysis	117,000	$7,020,000
DRIVE software, data management and computing		$10,007,200
Total	**806,200**	**$58,379,200**

Note that the activities and costs summarized here are explained further in **Section 6.6**.

6.6 Plan to conduct initial hosting capacity analysis (HCA)

PGE plans to conduct HCA twice annually and at the feeder level. This places PGE's initial HCA between Option 1 and Option 2, described above. There are a few factors that contribute to taking this approach:

1. PGE currently is required to update its DML analysis and limited generation feeder list twice annually.[109] DML is the primary input into conducting HCA and represents a significant amount of the time and effort required to perform HCA.

2. PGE is required to update its peak load data twice annually. In addition to performing HCA during minimum load scenarios, the EPRI DRIVE tool will also run its iterative process for heavy loading scenarios.

3. PGE does not use "circuit" in its infrastructure analysis and planning. Feeders are the unit of infrastructure that PGE is most familiar with. Furthermore, EPRI's DRIVE tool, by default, provides results at the line segment level. It is possible that PGE's initial HCA will provide results at this level. We will investigate the possibility of providing results at this level while committing to providing results at the feeder level.

Table 42 reflects how PGE's approach maps to the three options presented in the OPUC's DSP requirements.

Table 42. PGE's HCA approach mapped to the options

HCA characteristic	Option 1	Option 2
Methodology	Stochastic modeling/ EPRI DRIVE modeling	Same as Option 1
Geographic granularity	Circuit	Feeder
Temporal granularity	Annual minimum daily load	Monthly minimum daily load
Data presentation	Web-based map for the public and available tabular	Same as Option 1
Data update frequency	Annual refresh (**PGE's analysis is semi-annual**)	Monthly refresh
Other info	Queued generation	Same as Option 1

It is important to note that the costs of conducting HCA twice annually is approximately two times the cost as described in the Option 1 analysis. However, because PGE already is incurring much of this cost to meet other obligations, the proposed approach adds minimal incremental cost. Section 6.6.1 describes the methodology employed to execute HCA, operating assumptions, DRIVE settings, the execution plan and examples of the HCA results.

109 Order 20-402 requires that PGE's list of generation-limited feeders is updated twice per year, which requires updates to DML and peak load information. More information is available at apps.puc.state.or.us

6.6.1 METHODOLOGY OVERVIEW

PGE currently has its distribution system modeled in the CYME software. In total, PGE serves 653 feeders in its service territory. Broadly, the inputs to CYME include PGE's Geospatial Information System (GIS), supervisory control and data acquisition (SCADA) and aggregate consumption data from advanced metering infrastructure (AMI) records. This information is used to build the feeder models through the CYME gateway and Python scripting. Data quality checks are performed both via the CYME gateway process and after the feeder models are created. Some data checks include accurate representation of feeder voltage, specifying accurate voltages, and definitions for overhead and underground conductors, transformers, capacitors, reclosers, fuses and regulators, among other power system equipment. Other errors are corrected by engineers as and when they are noted.

Once the CYME models are created, loads on individual feeders are usually allocated based on historical loading data. Load forecast data is used where necessary. Base case power flow analysis is performed typically for peak and daytime minimum loading conditions. Feeder performance is studied and validated using available measurements. Errors may sometimes be identified in this data, in which case appropriate corrections are made. Once these models are created, the appropriate input files are created for the HCA in DRIVE, where the DRIVE hybrid method is used to conduct the analysis.

6.6.2 ASSUMPTIONS

The following assumptions are used when assembling the inputs for and conducting the HCA:

- Power flow models: As mentioned earlier, CYME power flow models are checked for data accuracy at multiple levels. PGE considers data quality to be a continuous process and will continue to improve its QA process.
- Low-voltage secondary systems: PGE's GIS system currently models the primary side of the distribution system in detail. The load is aggregated to the service transformer on the secondary side. Secondary conductors are not modelled.
- Load: Peak and daytime minimum load was calculated for each feeder. This is true of both SCADA and MV90 substations.
- Conductor spacing: Conductor spacing is used to model the electrical impedance characteristics of the distribution lines. PGE uses this information where available to calculate conductor impedance. For a substantial portion of the distribution grid, PGE uses conductor nameplate information to calculate impedances.
- Capacitors: Capacitors are modelled in accordance with their nameplate and operational details as available in the GIS system. For the most part, PGE employs fixed capacitor banks on its feeders. Where PGE employs capacitor controls, the appropriate state of the capacitor in the peak and daytime minimum load condition is reflected in the DRIVE analysis.
- Feeder topology: PGE regularly reconfigures feeders as a normal course of business. For the purposes of this analysis, however, we assumed the configuration of the system is correct and static. Therefore, this analysis is a point-in-time snapshot of hosting capacity as of the date of our analysis, which is a reality of any analysis of the distribution system.
- Substation voltage set point: PGE maintains records of the substation load-tap-charging (LTC)/voltage regulator voltage set points. These set points are allocated in CYME per substation. These set points affect the feeder hosting capacity.
- DG output: PGE assumes 100% of the allowed DG output was flowing on the associated distribution feeders during the boundary conditions of peak load and daytime minimum loading.

6.6.3 HOSTING CAPACITY EXECUTION PLAN

PGE has already embarked on a proof of concept to visualize available generation capacity at an entire feeder or circuit-level granularity on a feeder-by-feeder basis. This method uses available data and does not incorporate use of the EPRI DRIVE tool that is specified in the options analysis requirements described earlier.

PGE currently possesses the tools to perform HCA using EPRI DRIVE system wide. The process to do so adds a slightly more labor than the current method of calculating and publishing the daytime minimum load twice annually. **Table 43** draws a comparison between a single iteration of the current method and a single iteration of a method that produces a more granular output via usage of the EPRI DRIVE tool.

Table 43. Comparison of current practice vs. proposed approach

Current practice (per iteration)			DRIVE model incorporation (per iteration)		
Activity	**Hours**	**Cost**	**Activity**	**Hours**	**Cost**
Setup	1,200	$67,200	Setup	2,240	$134,400
GIS	80	$4,800	GIS	240	$14,400
Reporting	120	$7,200	Reporting	240	$14,400
			Modeling	1,400	$84,000
			Analysis	325	$19,500
			DRIVE license renewals		$7,200
Total	**1,400**	**$79,200**	**Total**	**4,445**	**$273,900**

The transition from publishing DML twice annually to producing an HCA twice annually will cost an additional $195k (from **Table 40**, the DRIVE model incorporation cost minus the current practice cost). PGE's Distribution Planning Team will be expected to execute the bulk of the analytical work. Initially, this will add a workload equivalent to one full-time distribution planner. When staffing levels are appropriate to execute the additional workload, the fist iteration/output is expected to be published within 12 months.

The GIS team will use the data outputs from the EPRI DRIVE tool to publish comprehensive system maps. The Interconnection team will assist in report verification and posting information on OASIS (**Table 44**).

Table 44. HCA tasks, resources and effort

HCA activity	Resources	Level of effort (hours)	Notes
Create base case models, distribution (CYME) model validation; functionality testing	Planning engineers CYME software	1,400	Approximately 1 hour per feeder
Calculate peak and DML	Feeder voltage at any location not to go below specified voltage magnitude	2,240	Includes peak winter, peak summer, minimum and daytime minimum load
Load data into DRIVE and execute HCA		325	Approximately 15 minutes per feeder

Table 44. HCA tasks, resources and effort (continued)

HCA activity	Resources	Level of effort (hours)	Notes
Result validation		40	Estimated effort to identify, analyze and correct issues for 653 feeders
Reporting	Planning engineers Interconnections team Excel	200	Includes publishing system data content that resides in OASIS
Result publication	EPRI DRIVE ARC GIS	240	Transfer of data from DRIVE to ARC GIS and Excel; visualization and testing of data

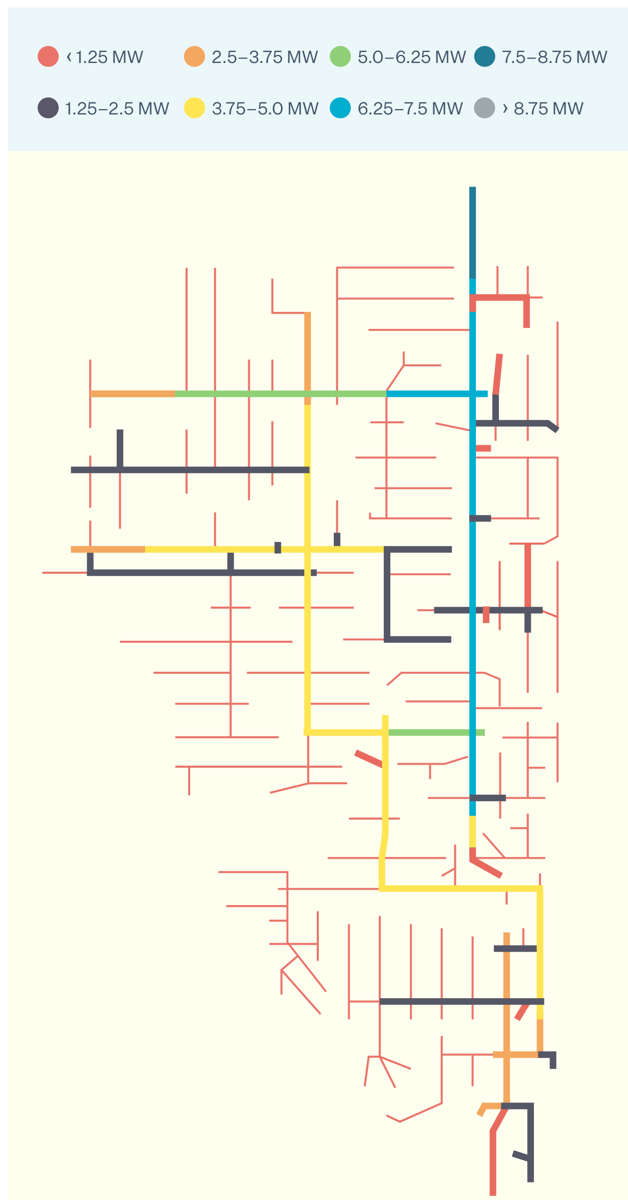
Engineers will first spend time creating and validating base case models through the CYME gateway. PGE uses automated scripts and works directly with CYME to rectify errors that can be corrected in the gateway. Additional detail about the QA process is provided in **Section 6.6.5**.

Once these models are created, work will be done to create peak and daytime minimum loading conditions from historical SCADA loading data. CYME models are then created with the peak loading and daytime minimum loading conditions. These CYME model outputs are validated once again.

Next, data is prepared for input to DRIVE. DRIVE runs automated scripts that select the necessary feeder and system data from CYME. Analysis is performed in DRIVE one feeder at a time. Batch runs often present unidentifiable problems, and one problematic feeder can ruin an entire batch process. Results are validated, then heat maps are consolidated and excel files are prepared for publication.

A sample screenshot of a hosting capacity output map is shown in **Figure 34**. All outputs will be consolidated and transitioned to a public-facing GIS platform.

Figure 34. Sample screenshot of the hosting capacity heat map[110]



110. The data shown is for illustration purposes only.

6.6.4 LIMITING CRITERIA AND VIOLATION THRESHOLDS

Broadly, DRIVE v2.1 evaluates hosting capacity violations under voltage, congestion, protection and power quality and reliability thresholds.

Table 45 describes the limiting criteria and violation thresholds that are established in DRIVE in more detail. Final analysis may result in changes to the criteria shown below.

Table 45. Limiting criteria and violation thresholds

Criteria	Description	Threshold	Basis
Primary over voltage	Feeder voltage at any location not to go above specified voltage magnitude	5%	ANSI C84.1 Range A — maintain quality of service to customers
Primary under voltage	Feeder voltage at any location not to go below specified voltage magnitude	5%	ANSI C84.1 Range A — maintain quality of service to customers
Primary voltage deviation	Feeder voltage at any location not to change by more than specified percent	3%	Maintain power quality for customers
Regulator voltage deviation	Feeder voltage observed at any regulating device not to change by more than a specified amount of the regulating device bandwidth	50%	Prevent reliability and power quality issues by avoiding excessive regulator operations
Primary voltage unbalance	Feeder voltage unbalance at any location not to exceed a specified percent	1-3%	Phase imbalance requirements
Thermal for load	Power flow through any element in the direction away from feeder head not to exceed a percentage of the element's normal rating	100%	Continue reliable customer service by staying within the normal ratings of existing elements
Thermal for gen	Power flow through any element in the direction toward the feeder head not to exceed a percentage of the element's normal rating	100%	Continue reliable customer service by staying within the normal ratings of existing elements
Additional element fault current	Feeder fault current not to increase by more than a percentage of fault current prior to generation	10%	Based on worst-case scenarios from internal studies — maintain customer reliability
Breaker relay reduction of reach	Breaker fault current not to decrease by more than a percentage of fault current prior to generation	10%	Based on worst-case scenarios from internal studies — maintain customer reliability
Reverse power flow	Power flow through specified elements not to flow in the direction toward feeder head	100%	Potential protection and thermal issues can occur with reverse power flow into the substation

Table 45. Limiting criteria and violation thresholds (continued)

Criteria	Description	Threshold	Basis
Unintentional islanding	Power flow through specified elements not to be reduced by more than a percentage of minimum power flow	100%	Power flow through the selected elements is allowed to zero, but reverse power flow is prohibited
Ground fault overvoltage (3v0)	Power flow through substation not to be reduced by more than a percentage of minimum load power flow	100%	Substations equipped with 3v0 sensing at the substation
Sympathetic breaker tripping	Breaker zero sequence fault current not to exceed specified amount in amps	300 amps	Related to breaker protection flags

6.6.5 QUALITY ASSURANCE AND ACCURACY ASSESSMENT

PGE performs a series of quality assurance protocols throughout its analysis process to ensure the inputs and results are as accurate as possible. This includes the following steps:

- Running model clean-up checks in CYME after extracting asset data from PGE's GIS. This ensures consistency in feeder modeling for both subsequent modeling and from one feeder to the next.
- Checking for exceptions within CYME to verify no issues exist. After a power flow analysis is run, some "out of bounds" exceptions may exist. This could include high or low voltages, overloads and model connection issues. These exceptions are flagged for engineer investigation and correction.
- Responding to any flags generated by DRIVE. After the CYME model is finalized, it its converted by DRIVE to enable processing in DRIVE. During this conversion, further flags can occur that alert us to any abnormal conditions. These conditions are then followed up on by an engineer.
- Comparison of DRIVE results with previous analysis to check for any large deviations in values or thresholds violated. If we find deviations larger than 500 kW or see a change in the number of times a certain threshold is violated, an engineer determines if the change in results was appropriate. For example, if additional DERs were added to a feeder, we would expect the hosting capacity to decrease and would see this in the analysis. If we see any unexpected changes in the results, we will investigate them further and make corrections if needed.

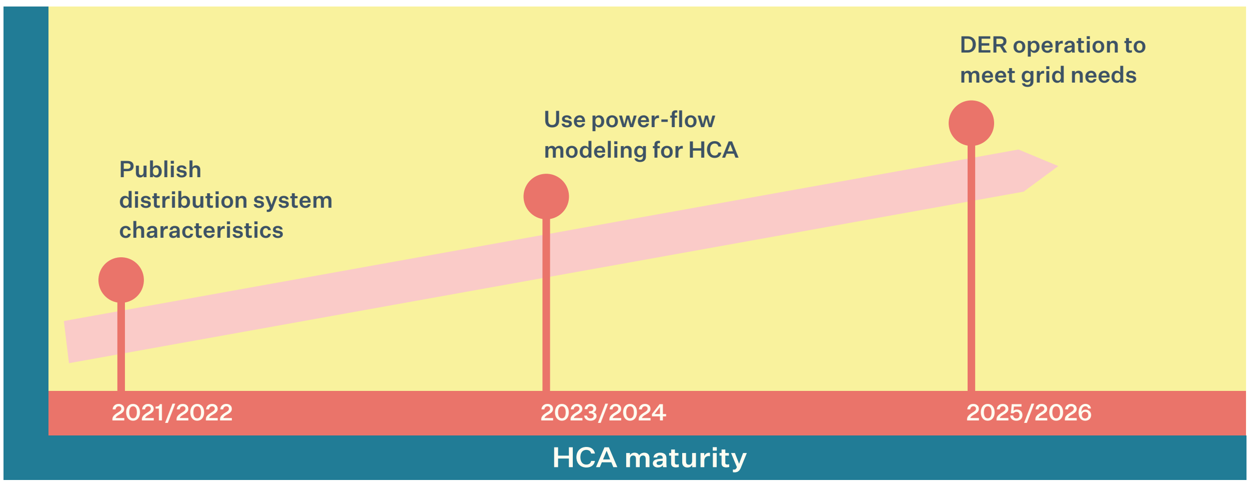
The initial HCA outlined here puts PGE on a path to move from Phase 1 to Phase 2 of maturity as described by EPRI in **Table 27**. This plan also enables us to take advantage of data, processes and tools that are already established, lowering the barriers to executing the initial HCA. We look forward to completing this analysis and initiating additional rounds of partner and community feedback to advance understanding of what is most valuable and refocus efforts in future iterations of HCA. The following section reflects PGE's thoughts on the evolution of HCA.

6.7 Evolution and near-term action

A mature HCA capability is essential to PGE's vision of a plug and play DER future. The ability to seamlessly interconnect a modernized grid with a multi-directional flow is a key enabler to improved access to DERs. HCA provides the necessary visibility into system conditions to support seamless, on-demand integration of DERs. By modernizing PGE's planning capabilities, such as system modeling, reliability analysis, DER analysis and contingency analysis, we can use the outputs to generate a comprehensive HCA. This will facilitate a streamlined interconnection process that provides customers an experience that enables DER adoption.

Figure 35 illustrates PGE's hosting capacity roadmap, which outlines the progression through increasing degrees of granularity in both time and system data. The roadmap focuses on meeting the Stage 3 objectives outlined in the OPUC's UM2005 DSP Guidelines.[111] The progression through the roadmap stages will be punctuated by periods of partners and community feedback. The measure of success at each stage will be the value delivered to partners and communities, as well as to PGE.

Figure 35. Hosting capacity analysis roadmap



Hosting capacity analysis (HCA)	• Publish info about equipment, performance and queue to inform siting, reduce failed applications • Expand data displayed on net metering map • Identify how ADMS can support HCA	• Use ADMS to support powerflow modeling • Use HCA in distribution studies and investment planning, e.g., add capacity for DER penetration	• Increase granularity, data sharing, frequency • Leverage ADMS/ Distributed Energy Resource Management System (DERMS) to match DERs with load
Interconnection	• HCA as screening tool for developers/customers • Technical outreach and education regarding data	• More granular visualization of hosting capacity in GIS	• Recruit DERs to meet grid needs • Evolve distribution market functions
Target use cases	Identify favorable DER locations communicate DER readiness accelerate screening process	Support investment decision-making to increase DER readiness	Promote DER investment to address grid needs, facilitate distribution market operations

111. OPUC's UM 2005 DSP Initial Guidelines, available at apps.puc.state.or.us

PGE anticipates that an ideal future state for HCA is an analysis that is:

- Accurate at the time and place of use
- Cost-effective
- User-friendly for both external and internal audiences

This future state echoes the DSP requirement's Stage 3 benchmark of "Update and publish hosting capacity maps and datasets sufficiently accurate and frequent to streamline interconnection." This does not inherently call for "real-time" hosting capacity.

We view the term "real-time" as being reflective of system operating conditions — within a time frame of seconds or less. That level of temporal granularity is required for distribution grid operations, while distribution grid planning requires data at the granularity of a year or greater. We are assuming that the term "real-time" as discussed in the DSP workshops is intended to apply to the planning process generally and the HCA specifically. If so, the available hosting capacity on sections of distribution feeders would need to be updated and made available publicly on a virtually continuous basis (temporally in a matter of seconds, minutes or hours) because the values will change continuously based upon changing system conditions. There would be significant cost associated with the additional resources required (e.g., software, staffing, training and data sharing) to achieve and maintain this capability for planning, rather than operational, schemes.

In PGE's view, HCA is clearly a planning tool and should be subject to the temporal standard of a planning analysis. The interconnection process is based on forward-looking analysis using set values that allow months for review and approval of interconnection applications, construction, inspection and, ultimately, energization. As the term "real-time" is applied in the interconnection context, it must refer to how frequently the hosting capacity values used in the analysis of new interconnection applications are updated.

PGE's long-term plan for HCA includes establishing criteria aimed at targeting feeders in need of updated HCA and ensuring that analysis takes place on a regular basis, with the results uploaded to a publicly accessible location directly following the updated analysis.

To streamline the process of updating the hosting capacity of feeders and avoid having to run the HCA on all distribution feeders on a continuous basis, PGE will develop a method to identify which feeders have had, or are forecasted to have, changes that would appreciably affect the hosting capacity value. This will target planners' efforts toward the feeders where the hosting capacity value would have reason to change. This could be as few as 20% of PGE's 653 feeders.

PGE will develop a process in which a review would take place on a time- or event-basis to detect which feeders require an updated HCA. Sample criteria for triggering this determination could include:

- Voltage conversion: Has a voltage conversion of the feeder or on part of the feeder taken place?
- Load variation: Does the load forecast for the feeder show a significant increase or decrease?
- Reconfiguration: Has the feeder been reconfigured?
- Reconductoring/phasing: Has any section of the feeder been reconductored (or phases added)?
- Voltage controlling/regulating devices: Has a device that either directly controls or affects voltage, such as a line voltage regulator and/or capacitor, been installed or removed from the feeder?
- Customer class composition: Has the composition of any of the customer classes on the feeder changed?
- DER capacity additions: Does the total DER capacity of recent interconnection applications on a feeder exceed a load or generation capacity threshold?
- Protective devices/settings: Has a protective device been installed/removed (e.g., line recloser) or settings been changed?

This targeting of feeders would eliminate the need to continually update hosting capacity on feeders where no change in the value should be expected and represents an efficient, cost-effective method given the amount of new DER capacity applications PGE receives on any given distribution feeder. As adoption and penetration of DERs increase, it will become even more important to forecast how much, when and where different types of DERs will reside.

The objectives of HCA are to provide increased transparency as to where each utility has hosting capacity, provide developers/customers visibility into better or worse locations for DERs, and understand where and how DERs impact the entire distribution system. Over time, combining this analysis with existing DER penetration and long-term DER forecasts can help inform where infrastructure upgrades may be considered.

We anticipate that, as HCA matures and more datasets become available, combining these data will enable us and our customers to identify and unlock the value of DERs. As we move through our modernized grid roadmap and Community Engagement Plan toward a 21st century community-centered distribution system, integration of DERs should be seamless. The ability to seamlessly interconnect with a modernized grid is a key enabler to improved access to DERs, achieving a plug and play future.

Chapter 7.

Evolved regulatory framework: incentives that motivate equitable DER enablement and adoption

Chapter 7. Evolved regulatory framework: incentives that motivate equitable DER enablement and adoption

"We must now agree on a binding review mechanism under international law so that this century can credibly be called a century of decarbonization"

— Angela Merkel, Chancellor of Germany

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. It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.[112]

As noted in earlier chapters, the electric sector is undergoing a profound transformation. Many elements of this transformation intersect with regulation and policy. Over the last few years, several policies have paved the way to support PGE to move forward on our vision for a clean energy future. In this chapter, we highlight key policies that enable this change and discuss potential future work that could continue to support a 21st century community-centered distribution system. PGE notes these regulations are an initial set of opportunities that can enable us to streamline and accelerate elements highlighted throughout this DSP and other related filings.

PGE expects the other regulations to surface as the DSP and related filings evolve. **Table 46** illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP Guidelines under Docket UM 2005, Order 20-485.[113]

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A**. DSP plan guidelines compliance checklist.

WHAT WE WILL COVER IN THIS CHAPTER

An overview of the regulatory framework that impacts the distribution system

How regulation affects current activities, opportunities and barriers

112. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at olis.oregonlegislature.gov.
113. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, and is available at apps.puc.state.or.us

Table 46. Evolved regulatory framework: Guideline mapping

DSP guidelines	Chapter section
4.4.a	Section 7.3
4.4.b.vii	Section 7.4
4.4.d	Section 7.4

7.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to provide alignment with current Oregon law and policies. The Commission also required PGE to highlight opportunities and possible benefits for distribution system investments, and barriers or constraints to advancing our vision.

Driven by climate change, social and environmental justice, evolving customer and community expectations, and the proliferation of DERs, the energy sector is undergoing a paradigm shift. These shifts require us to adapt to and address risks to ensure development of a modern grid capable of serving all customers and able to recover quickly from extreme weather events, physical security attacks or cybersecurity attacks. Yet, there are other factors we must consider such as changes in customer energy usage, new system stresses, and new perspectives on local community investment and engagement. These items make a clear case that the traditional regulated utility role must evolve to keep pace with the needs of customers.

Our commitment to transforming and innovating to meet our customer needs is not new. Since 2018, PGE has shifted how we plan for resource investments to address climate change, which was robustly displayed in our *2018 Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory*, our pursuit to accelerate flexible load resource development and transportation electrification.[114, 115] PGE is evolving our Integrated Resource Planning process to meet the goals of HB 2021 and our DSP work is evolving through UM 2005.

Through the authorship and filing of the Transportation Electrification Plan and the Flexible Load Plan, PGE has communicated our commitment to DERs to Oregon, our customers and communities, the Commission and stakeholders.

Through the OPUC's Docket UM 2005 and PGE's own investments, we are developing a new approach to distribution resource planning and system planning that will further commit the company to resource investments that are closer to and behind the customer meter. A major component of PGE's vision is to empower customers and communities on their entire energy journey so they can proactively address their energy needs. Addressing changing energy usage and the climate crisis while maintaining safety, security, reliability and resilience at fair and reasonable prices will require a shift in how we approach and understand the role of the utility. We are evolving from simple provider and deliverer of energy, to a new type of utility that is prepared and capable of delivering a holistic set of energy solutions that meet the needs of our customers and communities.

To achieve this, there is a need for regulatory change. Throughout the UM 2005 proceeding, we see intersections between the goals of the DSP and current policies, rules, standards and other regulations. Under Docket UM 2005, Order 20-485, the OPUC also recognized, "the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches." These include:

- New policies that can accelerate DER adoption and leverage their value for the grid and customers
- Current policies that inhibit DER adoption and the realization of their value to the grid and customers
- Ongoing regulation discussion and its relationship with the DSP

PGE also highlights the current policy landscape that has downstream policy implications. The evolution of the DSP will need new rules and regulations to support its success. This evolution of rules and regulation are a key component to enable the goals of the DSP.

114. This study among other insights pointed to a future where distribution sited resources could provide as much as 900 MW of energy services by 2035, available at assets.ctfassets.net.

115. UM 2141, available at edocs.puc.state.or.us.

7.3 Policy landscape

7.3.1 FEDERAL POLICY PERSPECTIVE

At the federal level, the passage of major infrastructure and budget reconciliation legislation has the potential to significantly drive efforts in the clean energy space for some time. President Biden has drawn a strong link between climate change mitigation and environmental and social justice through policies that enable human-centered planning. His administration also took bold action at the agency level in support of addressing climate change — rejoining the Paris Accord, advancing aggressive tailpipe and vehicle mileage standards, setting a higher social cost of carbon than prior administrations, and utilizing the federal government's purchasing power. These policies have several downstream implications from DER cost-effectiveness to technology cost curves. PGE believes the OPUC must align appropriate downstream regulation to maximize customer value creation through these federal policies.

Additionally, the Federal Energy Regulatory Commission (FERC) has issued a series of orders to enable aggregated DERs to participate in regional wholesale electricity markets. Traditionally, these markets have been judged to be "whole" when all supply side generation resources are either sold, bid or scheduled into these markets. But recently this paradigm has been changing by including new types of generation, demand-side resources such as energy efficiency and demand response, energy storage and other distributed energy resources. **Table 47** highlights how PGE believes these orders can unlock new possible value streams for our customers and will be a part of the broader considerations of PGE's participation in a future market.

Table 47. Summary of FERC orders enabling DERs to provide new value

FERC Order	Primary implication
FERC Order 719[116]	First of the major FERC Orders requiring market operation changes to include a new form of energy resource (e.g., demand response)[117]
FERC Order 745[118]	The FERC found that demand response can be a cost-effective resource and included a cost-effectiveness test within the Order for determining when to accept demand response bids.
FERC Order 755[119]	Outlined how energy storage should be compensated for its dispatch response and performance accuracy
FERC Order 841[120]	Advanced rules for electric storage participation in wholesale markets
FERC Order 2222[121]	Establishes and allows for the participation of aggregated DERs in markets operated by Regional Transmission Organizations (RTO) and Independent System Operators (ISOs)

7.3.2 STATE POLICY PERSPECTIVE

On the state level, Oregon has been among those at the forefront of the energy transformation with innovative policy and statewide goals. Since 1984, the legislature has passed several energy-related bills promoting the development of local renewable resources.

Figure 36 illustrates some of the energy policies that have been established in Oregon. It is important to highlight that clean energy policies are not unique to Oregon. As recently as 2019, 11 states and territories and approximately 200 local jurisdictions have made commitments to 100% clean energy policies in the United States.[122]

116. FERC Order 719, available at www.ferc.gov.
117. 125 FERC P 61,071, Docket Nos. RM07-19-000 and AD07-7-000, Wholesale Competition in Regions with Organized Electric Markets (Issued October 17, 2008).
118. FERC Order 745, available at www.ferc.gov.
119. 137 FERC P 61,063, Docket Nos. RM11-7-000 and AD10-11-000, Frequency Regulation Compensation in the Organized Wholesale Power Markets, (Issued October 20, 2011)
120. 162 FERC P 61,127, Docket Nos. RM16-23-000 and AD16-20-000, Electric Storage Participation in Market Operated by Regional Transmission Organizations and Independent System Operators, (Issued February 15, 2018).
121. FERC Order Fact Sheet, available at www.ferc.gov.
122. State goals and mandates, available at www.cesa.org and local jurisdiction commitments and goals, available at www.sierraclub.org.

Figure 36. State policy timeline

1980 – 1999

In **1984** through a ballot measure, voters in Oregon created the Oregon Citizen's Utility Board (CUB) to advocate on behalf of residential customers of investor-owned utilities in Oregon.

In **1989** Oregon became the first state to institute long-term resource planning now called the Integrated Resource Plan (IRP).

- Commission Order 89-5

In **1999**, Senate Bill 1149 established a nonprofit to manage energy efficiency in Oregon.

In **1999**, HB 3219 required utilities to allow customer-generators through Net Metering

2000 – 2020

In **2018** the Oregon Public Utility Commission (OPUC), in response to SB 978, established a report to the legislature on utility model, challenges, opportunities and recommendations

In **2007**, Oregon adopted the original 25% requirement for the renewable portfolio standard that the 2016 bill, SB 1547, increased to 50% by 2030.

In **2002** Oregon was the second state to create an independent energy efficiency agency, now known as the Energy Trust of Oregon (ETO).

Today

House Bill 2021 A was passed requiring that electricity supplied to retail electricity consumers:

- Reduces annual greenhouse gas emissions by 100% below baseline emissions level by 2040
- Is generated in a manner that provides additional direct benefits to communities in OR

Utilities are required to submit a Clean Energy Plan to the OPUC and the Department of Environmental Quality (DEQ). The plan should include annual goals for meeting clean energy targets and demonstrate continual progress towards meeting the clean energy targets.

As the state has adopted policies to address decarbonization of the electric sector, it also has begun to ensure that energy policy also addresses equity. We see this in the bills that have recently passed the Oregon legislature and in such rulemakings as the OPUC's 2019 Order 20-485 under Docket UM 2005.[123] Key legislation and administrative actions that will inform PGE's DSP and/or DER planning are outlined below.

SENATE BILL (SB) 1044 (2019): ZERO-EMISSION VEHICLES (ZEV)[124]

SB 1044: established metrics for evaluating statewide ZEV adoption and supporting infrastructure to meet the state's climate goals; provided flexibility to schools to use their Public Purpose Charge allocations to invest in electric buses, fleet vehicles and charging infrastructure; and codified the state's policy on alternative fuel vehicles to ensure the state was leading by example in purchasing and leasing ZEVs.

EXECUTIVE ORDER (EO) 20-04: GOVERNOR BROWN'S CLIMATE ACTION[125]

On March 10, 2020, Governor Brown issued EO 20-04, directing state agencies to take actions to reduce and regulate greenhouse gas emissions. EO 20-04 establishes new science-based emissions reduction goals for Oregon. The EO directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. It also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

123. State of Oregon: Public Utility Commission of Oregon, available at apps.puc.state.or.us
124. SB 1044, available at olis.oregonlegislature.gov.
125. EO 20-04, available at www.oregon.gov.

7.3.2.1 HOUSE BILL (HB) 2021 (2021): 100% CLEAN ELECTRICITY FOR ALL[126]

HB 2021, passed by the legislature in June 2021 and signed by the Governor in July 2021, sets a framework for PGE and other electricity suppliers in Oregon to reach a 100% reduction in greenhouse gas emissions by 2040. The bill also sets interim targets on the path to 2040 including an 80% reduction in greenhouse gas emissions by 2030 and a 90% reduction in greenhouse gas emissions by 2035. These targets in HB 2021 align with our climate goals announced in November 2020. Utilities must develop a Clean Energy Plan concurrent with the development of each future Integrated Resource Plan that shows continual progress towards reaching these greenhouse gas reduction targets.

HB 2021 also establishes a grant program for community renewable energy projects from a Community Renewables Investment Fund. It also creates a Community Benefits and Impacts Advisory Group that is tasked to prepare a biennial report, which will report on:

- Energy burden and disconnections for residential customers and disconnections for small commercial customers
- Opportunities to increase contracting with businesses owned by women, veterans or members of the BIPOC community
- Actions within environmental justice communities within the electric company's service territory intended to improve resilience during adverse conditions or facilitate investments in the distribution system, including investments in facilities that generate non-emitting electricity
- Distribution of infrastructure or grid investments and upgrades in environmental justice communities in the electric company's service territory
- Social, economic or environmental justice co-benefits that result from the electric company's investments, contracts or internal practices
- Customer experience, including a review of annual customer satisfaction surveys
- Actions to encourage customer engagement

HB 2021 is an innovative policy that is not only paving the way to clean electricity, but also fosters a planning process supported through a community-centered approach. We embrace the state's policies to decarbonize the electric sector and see it as an imperative for PGE as we power the advancement of society fairly and equitably.

7.3.2.2 HB 2062 (2021): APPLIANCE ENERGY EFFICIENCY STANDARDS[127]

HB 2062 codified Oregon Department of Energy rulemaking that established energy efficiency standards for certain appliances sold in Oregon. Included in the bill was the requirement that electric water heaters manufactured on or after January 1, 2022, have a modular demand response communications port compliant with CTA-2045 or equivalent, enabling their participation in utility demand response programs.

7.3.2.3 HB 3141 (2021): PUBLIC PURPOSE CHARGE MODERNIZATION[128]

HB 3141 modernized the Public Purpose Charge (PPC) and extended it through 2035. Important provisions of the bill include increased funding for low-income weatherization, equity metrics for all funds invested by the Energy Trust of Oregon, and a required investment of 25% of renewable energy program funds to serve low- and moderate-income customers.

7.3.2.4 HB 2475 (2021): DIFFERENTIAL ENERGY BURDEN[129]

HB 2475 granted the OPUC the authority to consider differential energy burden in utility rates or programs and allows ratepayer-funded intervenor funding for environmental justice organizations.

126. HB 2021, available at olis.oregonlegislature.gov.
127. HB 2062, available at olis.oregonlegislature.gov.
128. HB 3141, available at olis.oregonlegislature.gov.
129. HB 2475, available at olis.oregonlegislature.gov.

7.3.2.5 HB 2165 (2021): TRANSPORTATION ELECTRIFICATION[130]

HB 2165 extends and improves Oregon's electric vehicle (EV) rebate to better serve low-income families, rural communities and communities of color. The bill also requires PGE and Pacific Power to collect a charge set to 0.25% of the total utility revenues to support transportation electrification, with at least half that amount spent supporting underserved communities.

The bill also recognizes that utility investments in transportation electrification infrastructure are a utility service and a benefit to ratepayers if certain conditions are met. It codifies that utility investments to support transportation electrification can include behind-the-meter infrastructure.

Together, these policies show a clear direction in accelerating DERs to decarbonize Oregon's energy mix while addressing issues such as energy burden.

7.4 Regulatory focused activities, opportunities and barriers

These key downstream regulatory elements will help PGE achieve the desired outcomes of these new policies. **For each element, we have provided a description and its interaction with the DSP**.

7.4.1 DISTRIBUTED ENERGY RESOURCE COST-EFFECTIVENESS

DERs can become grid assets under the right conditions. One of these conditions is economics, comparing DER costs and benefits relative to the alternative. PGE has taken steps to ensure that programs and products we offer are evaluated for cost-effectiveness, but we are still growing our analytical capabilities. We believe that DER cost-benefit analysis should not only accommodate utility needs but also include social and environmental policy considerations.

PGE has, in alignment with direction from OPUC Staff's ("Staff") comments in the Flexible Load Plan, undertaken an effort to update its DER cost-effectiveness method.[131] We have begun the work needed to develop a new cost-effectiveness tool to perform robust analysis that is aligned with the National Standard Practice Manual.[132] To ensure we leverage best-in-class approaches from other leading national sources and jurisdictions, we have contracted with two third-party consultants to develop the "Ben-cost" tool. These consultants will, at a minimum, help PGE by:

- Enriching PGE's decision-making on distributed energy resource (DER) investments by providing adjustments to PGE's current cost-benefit methodology (e.g., provide expert advice on cost-effectiveness best practices, cited/published literature and industry standards).
- Assisting PGE with building future capabilities on DER cost-effectiveness by evolving PGE's cost-effectiveness model framework.
- Developing a cost-effectiveness tool/model that will allow PGE to quantify cost and benefit impacts by measures, program and portfolio. The model will be built to accommodate the incorporation of other local and societal qualitative costs and benefits, as identified by PGE at a later date, such that it can address PGE's long-term needs.
- Reviewing overall methodology needed to identify where and when DERs can be compensated for benefits and be provided in ways that are efficient, accurate and fair.
- Examining, within reason, differential and equitable impacts on customers and communities (e.g., if a specific DER or electric vehicles would make a significant impact on air quality and health in an underserved part of PGE's service territory).
- Incorporating the outcomes of the Transportation Electrification Infrastructure Framework discussion currently ongoing in accordance with Executive Order 20-04.[133]
- Incorporating outcomes of UM 2011 – General Capacity Investigation focused on the avoided cost of capacity.[134]

PGE expects an updated cost-effectiveness model to not only help us better design and evaluate DER programs, but also assist our valuation of non-wires solutions moving into Part 2 of the DSP.

130. HB 2165, available at olis.oregonlegislature.gov.
131. PGE's Flexible Load Plan, available at apps.puc.state.or.us
132. The National Standard Practice Manual, available at www.nationalenergyscreeningproject.org
133. OPUC workplan on EO 20-04, available at www.oregon.gov
134. Docket UM 2011, available at apps.puc.state.or.us

7.4.2 ALIGNING UTILITY INCENTIVES TO SCALE DER PROGRAMS

With decision-making authority over utilities serving roughly 72% of US electricity customers, state public utilities commissions (PUCs) are uniquely positioned to orchestrate the transition to a decarbonized grid. State legislatures created PUCs in the early 20th century in response to the rise of the modern utility. To safeguard against the natural monopoly conditions utilities enjoy and to emulate competition in the absence of competitive markets, states empowered PUCs to oversee a "regulatory compact" in which utilities are obligated to provide nondiscriminatory access to reliable and safe electricity service at just and reasonable rates to customers. In exchange, utilities can recover the costs of providing service from customers and have the opportunity to earn a PUC-authorized rate of return. As a result, commission statutory authorities have traditionally focused on objectives like safety, reliability and affordability. Today, PUCs must increasingly address a broader range of outcomes than they have in the past. They remain accountable to traditional regulatory objectives but must also ensure resilience, energy justice, climate and other factors in their deliberations. Some of these objectives can be at odds under certain conditions, such as situations where the 'fair' solution is not the most 'equitable' solution.

Under Docket UM 2005, Order 20-485, the OPUC address the changes that utilities may make in implementing the DSP process, the OPUC stated it may, "explore new regulatory mechanisms that may better align with utilities' efforts to plan and invest in DSP over the long-term." **Table 48** is intended to assist the OPUC with exploring possible regulatory structures. Below are states where some sort of regulatory alignment has taken place in the form of a performance incentive mechanism for DER development and investment.

Table 48. Example states with regulatory alignment incentivizing DERs

State	Key design features	Maximum available incentive*	Performance period
Hawaii	Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement.	Lesser of 5% of aggregate annual contract value or $500,000	One year
Michigan	Up to 15% of demand response costs on a sliding scale based on demand response capacity, achieved growth rate, and non-wires alternatives assessment costs	15% of demand response spending	One-year cycle (approved for 2019 only)
Texas	1% of net benefits for every 2% of demand reduction goal exceeded	10% of net benefits	One-year cycle
Vermont	Percentage of total approved budget based on performance on several outcomes, including winter/summer peak demand reduction	2.5% of total approved budget	Three-year cycle
Rhode Island	Cash reward based on achievement of peak demand reduction, structured as a shared savings mechanism exempt from utility return-on-investment cap	45% of net benefits	Three-year cycle
New York	Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion	A portion of 100 basis points for SDR performance (currently approved at 65–70 total basis points)	Three-year cycle
Massachusetts	Portfolio-wide incentive based on performance from 75–125% of the PIM goals	5.4% of cumulative budget for program costs	Three-year cycle

7.4.3 REGULATIONS IMPACTING INTERCONNECTION OF DERS

PGE currently offers distribution system interconnection under PGE's Net Metering and Small Generator Interconnection processes. Under these interconnection programs, PGE has seen robust participation from both retail customers and independent power producers. Currently, PGE has approximately 12,000 net metering installations and 50 qualifying facilities (QFs) representing just under 220 MW of installed capacity.[135] Additionally, PGE has approximately 1,383 accounts enrolled in the Solar Payment Option, a now-closed pilot program based on the volumetric incentive rate pilot program derived from HB 3039 in 2007 and HB 3690 in 2010. The Solar Payment Option allocated PGE with 14.9 MW of the 25 MW statewide among the IOUs.[136] This 14.9 MW represents the upper limit to participation in the program for PGE customers.

Looking toward the future, PGE is excited to partner and engage with Staff and stakeholders as current efforts to reform the distribution system interconnection process in Oregon progress. Through UM 2099 and the Two-Meter Solution (TMS), PGE worked with stakeholders to find an alternative to costly substation upgrades when new small net metering installations interconnected to generation constrained distribution feeders. The TMS is a solution where the second meter is attached to the DER, triggering the violation with the capability to sever the link between the DER and grid to prevent reliability issues. PGE is an active participant in UM 2032 and UM 2111, which PGE believes will facilitate the modernization of the state-jurisdictional interconnection processes. Concepts that PGE recommends will be addressed under UM 2111 include, but are not limited to:

- Adoption of IEEE-1547, 2018 standard
- Implementation of rules that will allow for wide-scale adoption of smart inverter technology
- Reforms and concepts that could enable future implementation of FERC Order No. 2222
- Understanding of national approaches to cost allocation and cost-sharing for interconnection
- Analysis of the merits between cluster and serial study processes
- Development of interconnection reforms and business paradigms that can be used to enable adoption of distributed behind-the-meter storage and vehicle-to-grid discharging
- Exploration of policies and processes that will enable optimization of interconnections, possibly including utility directed operational schemes and/or control of DERs. Allowing for utility control can help alleviate the need for costly upgrades and possibly enable additional locational value for interconnected DERs.
- Simplification in the number of disparate interconnection rules and the extension of rules where none currently exist (e.g., between 10 and 20 MW). All interconnections happen to the same interconnected electrical system and the existence, and in some cases absence, of multiple sets of rules introduces unnecessary complications. With the adoption of IEEE-1547 2018 and its broad applicability, a holistic interconnection rule set could be developed.

7.4.4 ALIGNING EV REGULATION ACROSS LIGHT-, MEDIUM- AND HEAVY-DUTY VEHICLES

In recent years, PGE has highlighted the need for a revised cost-allocation methodology for grid investment that is predominantly driven by electric vehicle adoption. Through the work done in Adv 300, UM 1811 and others, PGE has collaborated with Staff and stakeholders to ensure fleet customers are not burdened by additional cost for switching to medium- and heavy-duty electric vehicles, which is one of the crucial elements in Oregon's push for economy-wide decarbonization.

However, similar regulation is currently not applicable for light-duty vehicles. PGE's understanding of HB 2165 focusing on infrastructure measures highlights the desire at the policy level to address this barrier for light-duty vehicles. PGE notes that EV adoption, especially light-duty vehicles, has a large "contagious" or "imitation" factor. In other words, customers are more likely to purchase EVs when they see their neighbors, friends or extended family have purchased one as well.

135. Additional information regarding qualifying facilities, available at www.oregon.gov.
136. Additional information can be found Order 10-200 in AR 538, which developed the rules for the program, available at apps.puc.state.or.us and Order 10-198, which set forth the shares amount the utilities, available at apps.puc.state.or.us.

Translating this to grid impact, it is likely neighborhoods will see spikes in adoption rather than a gradual change over time. The current cost allocation framework can deter this phenomenon, thus decreasing adoption of light-duty EVs.

We will work with the stakeholders and Staff to align relevant downstream regulations with HB 2165, addressing this barrier comprehensively for any electrification measures that provide a decarbonization benefit.

7.4.5 COMPARABLE TREATMENT OF NON-WIRES SOLUTIONS COMPARED TO TRADITIONAL TRANSMISSION AND DISTRIBUTION (T&D) SOLUTIONS

PGE defines a non-wires solution (NWS) as an investment intended to defer, reduce or remove the need for a specific wired solution in a specific geographical region to an identified grid need such as managing load, generation, reliability, voltage regulation and/or other wide-ranging grid needs. NWS can range from policy mechanisms such as tariffs, to technology solutions such as utility- or customer-owned DERs, to control solutions such as automated switching. Based on this definition, we consider NWS as another tool that distribution engineers can leverage to address grid needs. As these projects are implemented and confidence in the solutions grows, NWS are likely to become a larger part of the solution mix.

While PGE goes through the process of implementing and learning from NWS, a parallel discussion is needed on the regulatory elements of NWS, including the regulatory approval process and the appropriate utility incentives to maximize community impact relative to traditional T&D solutions. A review of other jurisdictions such as New York show how utilities and regulators worked with stakeholders and the community to develop a performance incentive mechanism that aligned with community interest in local investment, grid planning's desire to address a local load pocket and the ability of the utility to attract investment.[137] As part of this larger effort to normalize the application of NWS, regulators paved a path to streamline NWS approval to ensure NWS can also be leveraged for solutions with shorter lead times.

This approach and incentive mechanism was successfully leveraged by New York, but this may not necessarily be adaptable for Oregon, especially considering Oregon's focus on equity. As noted in Chapter 2, NWSs have a more complex relationship with the utility cost allocation than traditional T&D solutions:

- **NWS solutions cannot be evaluated the same way as traditional T&D solutions**. They require a broader consideration of costs and benefits. Costs may include RFP costs for solution procurement, added marketing and outreach, community education, socioeconomic and demographic analysis, and increased incentive costs. Benefits include distribution system benefits, bulk system benefits and societal and environmental benefits. Thus, to compare NWS to traditional T&D solutions, a more broad-based approach to costs and benefits must be considered. This, inherently, evolves the cost-benefit analysis or least-cost, least-risk approach. Part 2 of the DSP filing will include two utility pilot proposals for NWS projects where more detail will be provided. However, in the interim, PGE recommends that Staff and participants continue discussions on potential implications for NWS projects that may show higher costs and, thus, higher rate impacts than traditional solutions but provide long-term societal benefits.
- **NWS may produce higher distribution system (locational) benefits relative to system wide DER programs** because NWS are addressing specific distribution system constraints. When identifying NWS, consider that while these additional benefits can be used to increase incentives, there is an equity element that should affect how the increased benefits should be utilized. Based on the "Fair and reasonable costs" goal defined in **Section 2.3.3**, PGE's stance is that these benefits may translate, when feasible, to higher localized incentives to generate local community benefits and encourage local jobs, especially when environmental justice communities are impacted. Conversely, if environmental justice communities are not directly impacted by the local distribution system constraint, it would be equitable to ensure that these increased benefits are socialized, when feasible, similar to the treatment of costs for such a project. This ensures environmental justice communities are not bearing potentially larger upfront costs of NWS in affluent neighborhoods without receiving any local benefits, which would exacerbate the inequities. To account for this equity impact, PGE will work with Community-Based Organizations (CBO), stakeholders, and Staff to create a consistent methodology that can be applied to determine the equity impact of an NWS solution relative to a traditional T&D solution.

137. New York's Brooklyn Queens Demand Management program's information sheet, developed by Advanced Energy Economy (AEE), available at www.greentechmedia.com

7.4.6 REGULATORY GUIDANCE ON ENABLING INVERTER-BASED DER GENERATION

Today, the utility has a clear obligation to serve load and invest in the distribution system to ensure future load is served safely, reliably and affordably. However, similar guidance is not available to the Company to serve forecasted generation, specifically, how forecasts of inverter based DERs such as solar PV and battery storage can be used to justify distribution system investment. Currently, inverter-based system impacts on the distribution system are evaluated reactively through interconnection studies. These studies represent one of the primary means of determining distribution system investments in protection equipment necessary to enable generation for customers on existing substations.

As noted in **Section 2.5**, PGE is developing a bottom-up DER adoption model that identifies the expected solar and storage adoption at the feeder level. PGE can leverage the outputs of this model to determine net load and hosting capacity impacts at the feeder level as part of distribution planning studies to make the necessary investments to serve customer load and generation. In other words, with this new forecast, PGE can proactively make investments on the distribution system based on expected adoption of inverter-based systems, thereby removing barriers for DER adoption. PGE seeks to start a discussion with stakeholders and the Commission to finalize guidance on enabling this proactive approach to addressing adoption barriers to inverter-based DERs.

7.4.7 INTEGRATION OF DIFFERENT DOCKETS TO DRIVE OPERATIONAL EFFICIENCY

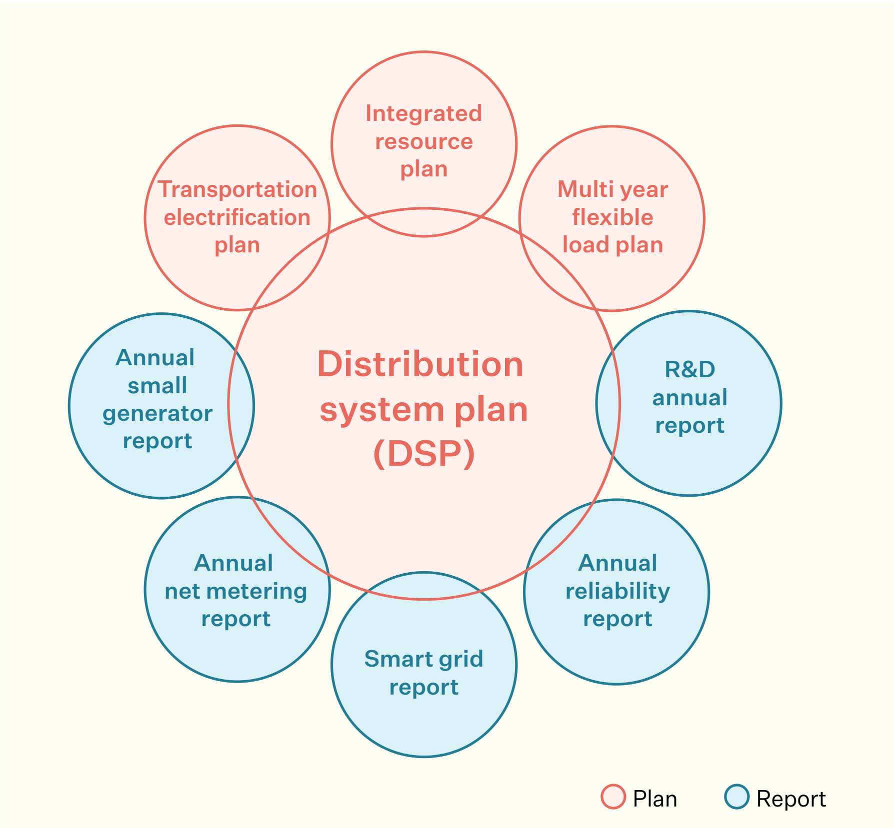
In the UM 2005 proceeding, Staff noted the overlap of the DSP with several other reports and plans. Overlap, in this context, refers to the same information that is presented across multiple filings. PGE believes that regulatory consolidation of these elements will reduce the overall burden for all parties involved. PGE advocates for Staff to leverage the UM 2005 proceeding to determine the optimal method to communicate this information.

Our initial set of recommendations is intended to streamline communication of relevant data (**Figure 37**):

- Establish the final guidelines of the DSP in a manner that eliminates the Smart Grid Report.
- Eliminate the duplication of the research and development (R&D) reports being made independently and in the DSP.
- Integrate distribution system specific R&D reports into the DSP and eliminate R&D annual reporting requirement required through Order 15-356 within UE 294.[138]
- Leverage dashboards to obtain and drill down on baseline and system assessment data requirements.
- Integrate Annual Reliability, Annual Small Generator and Annual Net Metering reporting with DSP requirements including associated data.

138. More information on UE 294, Order 15-356, available at apps.puc.state.or.us.

Figure 37. DSP overlap with annual/biennial reports and plans provided to the Commission



Chapter 8.

Plan for Part 2 development

Chapter 8.
Plan for Part 2 development

"We want to ensure that those communities that were locked out of the last century's pollution-based economy will be locked into the new, clean and green economy."

— Van Jones, author of The Green Collar Economy

8.1 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.[139] It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.

As we plan for Part 2, PGE shares information on DER load forecasting improvements that will increase transparency and broaden resource parameters, leveraging open-source tools and best practices with locational results of DER adoption. As we prepare for development of Part 2, we are exploring how non-wires solutions (NWS) can compete with traditional solutions and what tools and resources are needed to meet this goal. Better forecasting capabilities introduced to PGE in 2021 present the opportunity to share more detailed DER data with Integrated Resource Plan (IRP) and integrate these reports with modeling tools used by IRP.

Table 49 illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP Guidelines under Docket UM 2005, Order 20-485.[140]

WHAT WE WILL COVER IN THIS CHAPTER

PGE's activities for distributed energy resource and load forecasting

How PGE is planning for non-wires solutions

How PGE will synchronize the Integrated Resource Plan with Part 2 of the DSP

Table 49. Plan for Part 2 development: guideline mapping

DSP guidelines	Chapter section
4.5	Section 8.2, 8.3, 8.4
4.4.f	Section 8.4

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A.** DSP plan guidelines compliance checklist.

139. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at oregonlegislature.gov
140. OPUC UM 2005, Oregon 20-485 was issued on December 23, 2020, and is available at apps.puc.state.or.us

8.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to provide a high-level summary of their preparation for Part 2 of their DSP, focusing on planning evolution and interaction with the IRP.

In this chapter, PGE provides details in compliance with these requirements, focusing on planning practice updates around distributed energy resource (DER) forecasting/potential and NWS. These speak directly to requirements for Part 2 (4.1 Forecasting of Load Growth, DER Adoption and EV Adoption and 4.3 Solution Identification). PGE also provides details on the IRP interaction with the DSP, focusing on the upcoming IRP. This builds on the details provided in **Section 2.5**.

DERs, due to their operational versatility, create a dynamic operational environment in which greater levels of data, analysis and optimization are needed for PGE to continue to maximize value for customers. Improving PGE's planning capabilities is a critical step in enabling and leveraging DERs for different use cases, such as NWS, improved asset utilization and other projects that provide community benefits.

8.3 DSP Part 2 activities in flight

PGE has been proactively improving our planning capabilities prior to the approved guidelines issued in December 2020. As part of our evolving planning capability, we have identified data requirements, necessary tools and workforce needs. **Section 4.7** includes additional details on expected investments in planning and engineering. In preparation for Part 2 of the DSP, PGE is focusing its planning efforts on load forecasting and NWS.

8.3.1 DER AND LOAD FORECASTING

As noted in **Section 1.3** and further discussed in **Appendix B**, PGE continues to advance our DER modeling tools by contracting with consultants to build an in-house, bottom-up adoption model applied to behind-the-meter DERs and electrification called AdopDER. The AdopDER model improves on prior forecasting techniques because it increases transparency of the modeling approach (inputs, outputs, algorithms), captures broad resource parameters and key assumptions, advances understanding of the potential of flex loads to achieve a range of grid services, and develops supply curves with levelized costs to better integrate with the IRP analysis.

FORECASTING OF LOAD GROWTH, DER ADOPTION AND ELECTRIC VEHICLE (EV) ADOPTION

- Improve forecasting to account for DER impacts on load, as well as the ability of these resources to productively modify load
- Improve the accuracy and granularity of existing and anticipated constraints on the distribution system
- Input into grid needs identification

The model ties to the ETO forecast where possible and leverages open-source tools and best practices, including:

- CalTRACK for standardized baseline and net load profile calculations
- NREL data sets and forecasts
- PVWatts
- Re-Opt Lite
- EVI-Pro Lite
- NEEA CBSA/RBSA stock studies
- End-use load research studies

AdopDER calculates the technical and economic potential of DER programs and the market adoption of electric vehicles (EVs), photovoltaic (PV), building electrification measures and storage at the site level. PGE has broken the development of the AdopDER model into two phases. Phase 1 focuses on providing the system-level impacts of DER adoption for integration with PGE's upcoming IRP. Phase 1 development of AdopDER was completed in Q2 2021, with final draft results shared in the DSP partner meetings and the final system-level results shared in the IRP monthly roundtable in August 2021.

Phase 2 of the AdopDER model provides the locational results of DER adoption, which can be translated into localized impacts of DERs. PGE expects the development to be completed by Q4 2021. Phase 2 represents a key step in both providing critical data to accelerate DER adoption and enabling key studies to understand the transmission and distribution (T&D) impact of DER adoption on both load and hosting capacity. PGE also expects the underlying adoption modeling of Phase 2 to help us better estimate adoption probabilities of DERs for NWS.

8.3.2 NON-WIRES SOLUTIONS (NWS)

PGE is exploring how NWS can replace, defer or be combined with traditional T&D solutions. We support partner and regulator interests in understanding how NWS can complement environmental justice policies and foster procedural equity for historically underrepresented communities, creating a more equitable system.

As part of the requirement to propose a minimum of two NWS pilots in Part 2, we are developing internal processes for NWS and acquiring a tool that will be capable of running more comprehensive analyses. PGE's new process document for NWS is developed with input from relevant departments that are involved in or affected by distribution planning processes and community engagement. By leveraging work from leaders such as New York and California and speaking with experts and applying industry best practices developed by Electric Power Resource Institute (EPRI), PGE will balance between reliability, cost, local economic development and community benefits. In addition to developing this process, PGE is currently working with the CYME team at Eaton Corporation to integrate new modules that enable the analyses needed for NWS. We are also integrating advanced metering infrastructure (AMI) and advanced distribution management system (ADMS) data where possible to improve planning analytics.

PGE previously worked with two vendors to develop this functionality. Unfortunately, both tools required significant workforce investments and had unexpected issues delaying PGE's ability to implement NWS for behind-the-meter DERs. We are confident that the new modules from CYME will provide the platform to enable NWS. Working on two or more NWS pilots during Part 2 of the DSP presents an opportunity for PGE to test the new process and tool from a planning perspective.

8.4 Efforts to synchronize IRP activities with requirements of Part 2

As noted in **Section 2.6**, PGE is developing the AdopDER tool, a bottom-up model to forecast DER adoption for technical potential, market adoption and economic potential analyses. Phase 1 of the AdopDER model provides system-level DER potentials based on PGE's current cost-effectiveness methodology. Through this model, PGE has synchronized the following activities with the IRP:

- The AdopDER tool estimates PV and EV adoption, both naturally occurring adoption and programmatic adoption stemming from programs that provide fleet solutions, rebates or incentives. These results are then translated to load impacts for EV and solar PV, which are then integrated into the IRP process to determine resource needs.
- Using the current cost-effectiveness method, the AdopDER model determines the economic potential of flexible loads, including tariff offerings such as Time of Use and Peak Time Rebates. This portfolio of cost-effective flexible loads is integrated within the IRP's analysis as resources that can be used to reduce load.
- PGE has also ensured the AdopDER model can provide levelized cost curves of non-cost-effective DERs to the IRP process to better understand the portfolio selection mechanics around DERs.

PGE expects the interaction between the IRP and the DSP to improve even further through incorporation of locational impacts, improved portfolio optimization and aligned cost-benefit approaches.

Distribution system planning evolution framework

Stage 3		Achieving the long-term vision for distribution system planning capabilities and outcomes
Stage 2		Advancing requirements incrementally to better match growing utility capabilities and evolving grid, customer and community needs
Stage 1	Beginning with Initial Requirements of Utility DSP Filings, providing a foundation for future stages	
	2021 – 2022	**2023 – beyond**

Appendix

Appendix A. DSP plan guidelines compliance checklist

Baseline Data and System Assessment	DSP guidelines	Chapter section
A description of any currently used internal baseline and system assessment practices (such as system reliability baseline, system asset health baseline, etc.) that includes:	4.1.a	1.2, 1.3
Method and tools used to develop the baseline and assessment:	4.1.a.i	1.3, 1.3.1, 1.3.2
Forecasting time horizon(s)	4.1.a.ii	1.3.2
Key performance metrics	4.1.a.iii	Appendix B B.1,B.2
A summary of the utility's distribution system assets including:	4.1.b	1.3, Appendix B B.3.1
Asset classes	4.1.b.i	1.3, Appendix B B.3.1
Average age of assets in each class	4.1.b.ii	1.3
Age range of assets in each class	4.1.b.iii	1.3, Appendix B B.3.1
Industry life expectancy of assets in each class	4.1.b.iv	1.3
Number of assets in each class	4.1.b.v	1.3, Appendix B B.3.1
A discussion of distribution system monitoring and control capabilities including:	4.1.c	Appendix B B.4
Number of feeders	4.1.c.i	1.3, Appendix B B.4.1.1
Number of substations	4.1.c.ii	1.3, Appendix B B.4.1.1
Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology	4.1.c.iii	Appendix B B.4.1.1, B.4.1.2
A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)	4.1.c.iv	4.7, Appendix B B.4
A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). Include a description of system visibility and capabilities, the percentage of system reached with each capability, the percentage of customers reached with each capability, and any utility programs utilizing each capability.	4.1.d	4.7, Appendix B B.5
Historical distribution system spending for the past five years, in each category:	4.1.e	1.4
Age-related replacements and asset renewal	4.1.e.i	1.4

Baseline Data and System Assessment	**DSP guidelines**	**Chapter section**
System expansion or upgrades for capacity	4.1.e.ii	1.4
System expansion or upgrades for reliability and power quality	4.1.e.iii	1.4
New customer projects	4.1.e.iv	1.4
Grid modernization projects	4.1.e.v	1.4
Metering	4.1.e.vi	1.4
Preventative maintenance	4.1.e.vii	1.4
Net Metering and Small Generator information:	4.1.f	1.5.1
Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder.	4.1.f.i	1.5.1
The total number of net metering facilities by resource type	4.1.f.i.1	1.5.1
The total estimated rated generating capacity of net metering facilities by resource type	4.1.f.i.2	1.5.1
The total number of small generator facilities by resource type	4.1.f.i.3	1.5.1
The total nameplate capacity of small generator facilities by resource type	4.1.f.i.4	1.5.1
The total number and nameplate capacity of queued net metering facilities and small generator facilities at time of filing, by feeder, broken down by resource type	4.1.f.ii	1.5.1
A map, in electronic format, identifying locations of net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing.	4.1.f.iii	1.5.1
Total number of electric vehicles (EVs) of various sizes served by the utility's system at time of filing	4.1.g	1.5.3
Number of EVs added to the utility's system in each of the last five years	4.1.h	1.5.3
Total number of charging stations on the utility's system, broken down by type, ownership, and feeder	4.1.i	1.5.4
Total number of charging stations added to the utility's system in each of the last five years, broken down by type	4.1.j	1.5.4
Data on the availability and usage patterns of charging stations	4.1.j.i	Appendix B B.6.2
Summary data of other transportation electrification infrastructure, if applicable	4.1.k	Appendix B B.6
A high-level summary of demand response (DR) pilot and/or program performance metrics for the past five years including:	4.1.l	1.5.2
Number of customers participating by residential and business customer class, and combined total	4.1.l.i	1.5.2
Maximum available capacity of DR by residential and business customer class, and combined total	4.1.l.ii.1	1.5.2
Season system peak	4.1.l.ii.2	1.5.2
Available capacity of DR, expressed as a percentage of the season system peak	4.1.l.ii.3	1.5.2
Plans should include the utility's most recently filed **Annual Net Metering Report** and the most recently filed **Annual Small Generator Report**, each as an appendix to the Plan.	4.1.m	Appendix C, Appendix D
Plans should include the utility's most recently filed **Annual Reliability Report** as an appendix to the Plan. Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report.	4.1.n	Appendix E

Hosting Capacity Analysis (HCA)	**DSP guidelines**	**Chapter section**
Upon Commission adoption of these Guidelines each utility should begin conducting a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that is continuously available on the utility's website.	4.2.a	6.4
A utility should adopt the methodology underlying PGE's Net Metering Map, as presented in UM 2099, for calculating and identifying areas where it is difficult to interconnect DERs without system upgrades.	4.2.a.i	6.4
If this methodology is not feasible, a utility should present an alternative methodology with documentation of why it is necessary, and an explanation of any ways in which it may be different from the methodology utilized by PGE.	4.2.a.i.1	6.4
The resulting system-evaluation map should:	4.2a.ii	6.4
At minimum, meet the level of functionality of PGE's Net Metering Map.	4.2.a.ii.1	6.4
Label feeders serving Public Safety Power Shutoff areas.	4.2.a.ii.2	6.4
Each utility should analyze three options to meet future HCA needs consistent with Figure 2. At minimum, a utility shall develop cost and timeline estimates for each of the following three options. A utility should identify any data security, cost, result validation, or implementation concerns and/or barriers for each of the three options. Each utility should recommend a preferred timeline and development path for achieving the vision set forth in Figure 2, accounting for the relative strengths of Options 1, 2 and 3 below.	4.2.b	6.5
Option 1: The primary use of HCA is to inform Grid Needs Identification (see Section 5.2) and includes the following parameters: • Methodology: stochastic modeling / EPRI DRIVE modeling • Geographic granularity: circuit • Temporal granularity: annual minimum daily load • Data presentation: web-based map for the public and available tabular data • Annual refresh • Planned/queued generation details such as number and size of projects, description and costs of upgrades assigned to planned generation	4.2.b.i	6.5
Option 2: The two main uses are to inform Grid Needs Identification and to share regularly updated results publicly to inform stakeholders of potential interconnection challenges. Option 2 includes the following parameters: • Methodology: same as Option 1 • Geographic granularity: feeder • Temporal granularity: monthly minimum daily load • Data presentation: same as Option 1 • Monthly refresh • Planned/queued generation details: same as Option 1	4.2.b.ii	6.5
iii) Option 3: The two main uses are to inform Grid Needs Identification and to replace portions of the interconnection studies. Option 3 includes the following parameters: • Methodology: iterative modeling • Geographic granularity: line segment • Temporal granularity: hourly assessment • Data presentation: same as Option 1 • Monthly refresh • Planned/queued generation details: same as Option 1	4.2.b.iii	6.5

Community Engagement Plan	DSP guidelines	Chapter section
During Plan Development	4.3.a	3.1, 3.2, 3.3, 3.4, 3.5
A utility should host at least two stakeholder workshops prior to filing each Part of the utility's Plan, for a minimum total of four workshops. These workshops should be held at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to the Community Engagement Plan, described in (b). During stakeholder workshops, a utility must invite community members to share their relevant needs, challenges, and opportunities.	4.3.a.i	3.2
A utility should develop a Community Engagement Plan. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs during development of the pilot concept proposals required in Solutions Identification requirements (Part 2, Section 5.3. (d)). The Community Engagement Plan should include the activities described below (1-4). A utility should implement these activities as part of the development of pilot proposals prior to filing Part 2 of its DSP Plan:	4.3.a.ii	3.2, 3.3, 3.4, 3.5
Proactively engage stakeholders regarding proposed pilots in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; and solicitation of public comment, particularly to understand community needs and opportunities.	4.3.a.ii.1	3.2, 3.3
Document stakeholder comments and utility response, including comments that were heard but not implemented.	4.3.a.ii.2	3.3, 3.5
Collaboratively develop and share datasets and metrics to guide community-centered planning.	4.3.a.ii.3	3.3, 3.4
Refer to Section 5.3. (d, i-vi) of Appendix A of Order 20-485 for the community-centered questions that should be addressed through the process above, and during development of pilot proposals described in Part 2, Solutions Identification.	4.3.a.ii.4	3.3
Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders. To support collaboration between all interested parties, Staff plans to host public workshops and a technical working forum. These are in addition to the utility workshops required during Plan and pilot development.	4.3.a.iii	3.2, 3.3
With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.	4.3.a.iv	3.2

Long-term Distribution System Plan (LTP)	DSP guidelines	Chapter section
The utility's vision for the distribution system over the next 5-10 years, including any strategies, goals or objectives, and their alignment with State law and OPUC policies. These goals may include increased reliability, effective integration of DERs, broader greenhouse gas emissions reduction, or others.	4.4.a	2.2, 2.3, 2.4, 2.5
Roadmap of the utility's planned investments, tools and activities to advance the long-term DSP vision, using a 5-10-year planning horizon.	4.4.b	4.6.3, 5.3, 5.4, 5.5
Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:	4.4.b.i	4.6.3, 4.8, 5.3, 5.4, 5.5
Substation and distribution network and operations enhancements	4.4.b.i.1	4.5, 4.6, 4.7
Plans for conservation voltage reduction	4.4.b.i.1.a	4.5, 4.6, 4.7
Distributed resource and renewable resource enhancements	4.4.b.i.2	4.5, 4.6, 4.7
Penetration and activation/utilization of smart inverters	4.4.b.i.2.a	4.5, 4.6, 4.7
Transportation Electrification enhancements	4.4.b.i.3	1.5, 4.8, 5.3, Appendix B B.6
Customer information and demand-side management enhancements	4.4.b.i.4	1.5, 5.3
Plans to continue to expand customer benefits resulting from investments in advanced metering infrastructure	4.4.b.i.4.a	4.7
General business enhancements	4.4.b.i.5	4.5, 4.6, 4.7
Communications and supporting systems	4.4.b.i.5.a	4.5, 4.6, 4.7
Interoperability of systems and equipment	4.4.b.i.5.b	4.5, 4.6, 4.7
Work-management systems	4.4.b.i.5.c	4.5, 4.6, 4.7
Other enhancements	4.4.b.i.5.d	4.5, 4.6, 4.7
As applicable, any transmission network and operations enhancements	4.4.b.i.6	4.5, 4.6, 4.7
Explanation of how the investments reduce customer costs, improve customer service, improve reliability, facilitate adoption of demand-side and renewable resources, and convey other system benefits	4.4.b.ii	4.5, 4.6, 4.7, 5.3, 5.4, 5.5
Long-term assumptions, and impacts of Action Plan investments, etc.	4.4.b.iii	4.5, 4.6, 4.7
Forecasting future technical and market potential of DERs	4.4.b.iv	2.3.2, 2.4, Appendix F, Appendix G
Plans to further build community needs assessment and co-created community solutions into DSP roadmap	4.4.b.v	3.3, 3.4, 3.5
Transitional planning and operational activities underway in the organization to build capabilities in DSP-related functions	4.4.b.vi	2.5, 4.7, 5.3, 5.4, 5.5
Key barriers or constraints the utility faces to advancing investment (whether financial, technical, organizational) and mitigation plans	4.4.b.vii	4.6.1, 4.6.2, 4.6.3, 7.4
Smart Grid investment opportunities	4.4.c	4.5, 4.6
List and describe smart-grid opportunities that the utility is considering for investment over the next 5-10 years and any constraints that affect the utility's investment considerations	4.4.c.i	4.5, 4.6
Describe evaluations and assessments of any smart-grid technologies, applications, pilots, or programs that the company is monitoring or plans to undertake	4.4.c.ii	4.5, 4.6

Long-term Distribution System Plan (LTP)	DSP guidelines	Chapter section
Key opportunities and possible benefits for distribution system investment	4.4.d	4.3, 4.4, 4.5, 4.6, 5.3, 5.4, 5.5
Research and development the utility is undertaking or monitoring	4.4.e	4.8
Future policy and planning intersections:	4.4.f	2.5, 8.4
Discussion of how planned investments fit with the utility's IRP	4.4.f.i	2.5
Discussion of how planned investments fit with the utility's annual construction budget for major distribution and transmission investments	4.4.f.ii	2.5
Discussion of how distribution system planning may be coordinated in the future with other major policy and planning efforts discussed in these Guidelines. At a minimum, address the IRP and transmission planning, including how the Distribution System Plan filing is coordinated with each policy or planning effort, related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates	4.4.f.iii	2.5
Plans to monitor and adapt the long-term Distribution System Plan	4.4.g	2.6

Plan for the development of Part 2 of the DSP	DSP guidelines	Chapter section
As Part of its Part 1 filing each utility should prepare for the upcoming transition period and include a high-level summary to discuss:	4.5	8.2, 8.3, 8.4
How legacy distribution planning practices will be transitioned to the requirements of Part 2	4.5.a	8.3
Whether all legacy distribution planning practices will be transitioned in time for filing Part 2, and if not, the expected timeframe for that eventual transition	4.5.b	8.3
Efforts to synchronize IRP activities with requirements of Part 2	4.5.c	8.4

Appendix B. Baseline data and system assessment details

This section provides additional technical details regarding certain aspects of PGE's system assessment practices and baseline data.

B.1 Distribution engineering planning study process

To better understand the distribution engineering study process, PGE has defined three key terms:

- **Load:** The load on an electrical grid (used interchangeably with demand) is the total electrical energy being consumed by end users at a given time in order to convert into productive uses such as light, heat, or to drive machine processes.
- **Net system load:** Total retail load served by PGE, including losses.
- **Peak load:** The maximum coincidental system load experienced by the system, historical or forecasted. PGE calculates peak coincident load at the feeder- and substation-transformer level on an annual basis and differentiates between winter and summer peak load due to the differences in seasonal performance ratings of distribution system equipment.
- **Minimum load:** The lowest single measurement of net system load throughout a planning period. This is an important metric because when net loads are low, excess generation from distributed photovoltaic (PV) resources have a higher probability of backfeeding to impact the substation. Without proper protections, this can damage equipment and lead to reliability issues.

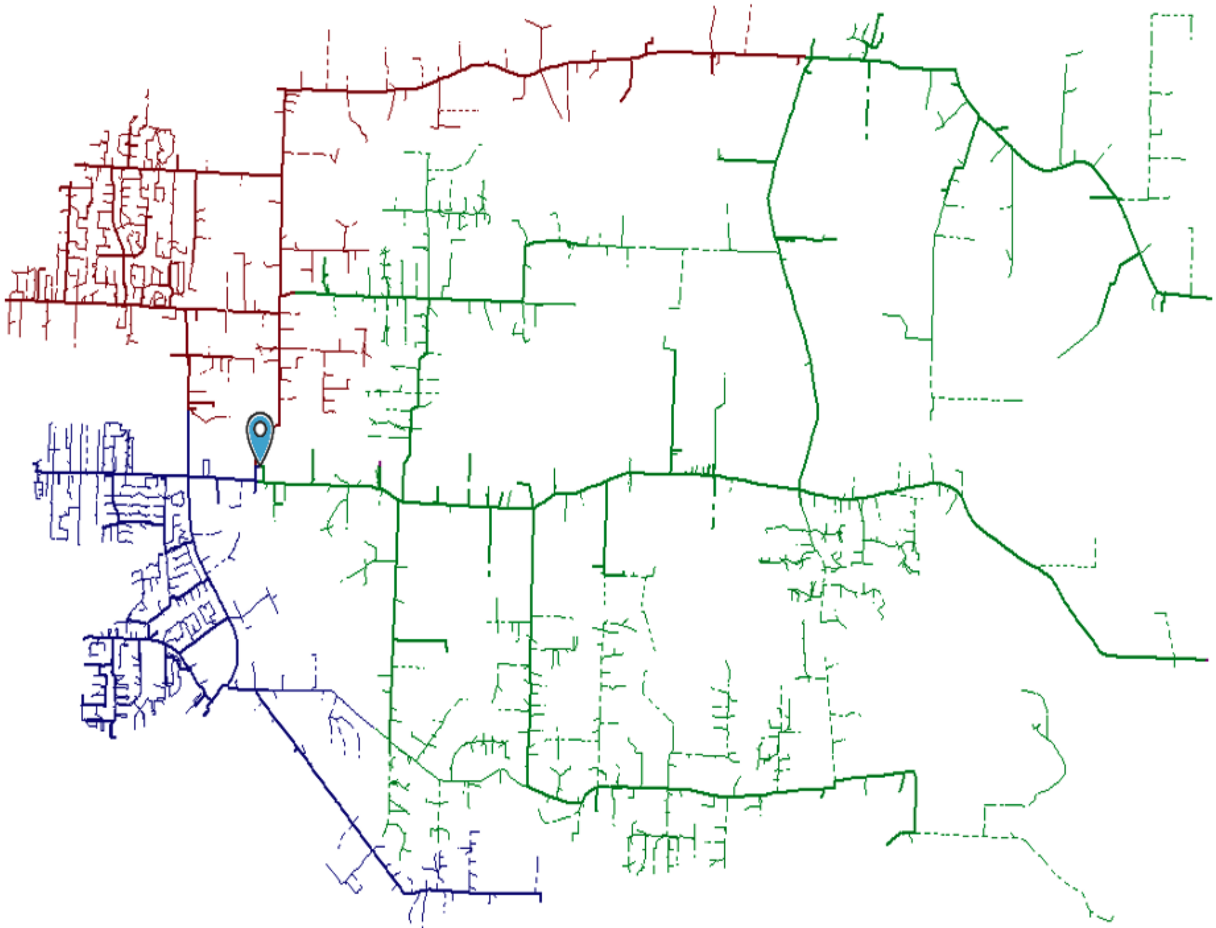
B.1.1 DISTRIBUTION PLANNING STUDY PROCESS

The process provides the criteria and methods for performing distribution planning studies. These studies form the basis for distribution project justification and development.

PGE uses CYME, a recognized industry software solution, to perform distribution system modeling. CYME has a broad range of capabilities including power flow analyses, fault analyses, hosting capacity analysis, and reliability analysis.

For each study, PGE focuses on a specific geographic area determined by the drivers and load forecast data discussed in **Section 1.3.1**. **Figure 38** shows an example study area of three feeders connected to a single distribution substation.

Figure 38. Example study area



B.1.1.1 Base case validation

The distribution grid and its assets are visualized through a combination of network models, equipment databases and historical system data. These together create the base case of the study area, modeling the current system performance under normal conditions (where all equipment is working as designed, called the N-0 condition) and contingency condition (where a substation transformer experiences failure or is undergoing a planned outage and cannot serve the intended load, called the N-1 condition). In contingency cases, neighboring transformers from either the same or adjacent substations must pick up the load to avoid a customer outage.

At PGE, distribution planning engineers are responsible for updating line and equipment configurations in the modeling environment to match existing field equipment, as well as addressing CYME-generated errors in their assigned regions. The planning engineers ensure model designations, set point voltage and other technical information is accurately captured. Updates are then compiled into a single database to be used for designated studies.

B.1.1.2 Base case analysis

Once the model is prepared and confirmed as error-free in CYME, a report can be generated to identify base case loading and voltage violations. A loading violation will occur if a certain piece of equipment (e.g., a substation power transformer) is loaded beyond its rated nameplate capacity. The CYME user interface can be used to physically locate this base case loading and voltage violations. These two types of violations (loading and voltage) are documented and have the highest priority for developing mitigation plans that may require additional investments in the distribution system to ensure reliability.

B.1.1.3 Design criteria

PGE's system is designed to serve existing customer loads with adequate reserved capacity to pick up that load via other nearby equipment in the event of a failure or planned outage. In the near-term distribution planning studies, PGE limits the failures to be studied to the loss of a distribution power transformer or a distribution feeder.

Planning design criteria for PGE's distribution power transformers provide guidance that transformers are not to exceed 80% of their seasonal loading beyond nameplate ratings (LBNR) under normal operation (N-0) during a peak-load period. Limiting components can vary and can include the transformer windings, load tap changers, bushings, leads and voltage regulators. In the event of a transformer-related failure or outage (N-1), nearby transformers from either the same or adjacent distribution substations can pick up the load.

Planning design criteria for PGE's distribution feeders provides the guidance that associated feeder getaways, mainlines, and voltage regulators are not to exceed 67% of their normal seasonal thermal ratings. For most general-use feeders, this equates to either two-thirds normal capacity of a standard feeder mainline, or 12 MVA.

B.1.1.4 Design criteria exceptions

There are some exceptions to the planning design criteria for distribution power transformers and for distribution feeders, which allow for equipment to load to levels beyond the recommended design criteria under normal (N-0) operation.

- **Dedicated transformers:** For distribution power transformers dedicated to a single customer, loading can reach 100% of seasonal LBNR under normal (N-0) configuration. For dedicated transformers, in the event of an outage there is a contingency or a load-shedding scheme that will prevent PGE transformers from loading beyond their LBNR.
- **Dedicated feeders:** Dedicated feeders may be loaded up to 100% of their normal seasonal thermal ratings under normal (N-0) configuration. For these feeders, a contingency or load-shedding scheme will prevent the feeders from exceeding these limits.
- **Alternate service:** Alternate service agreements affect the operation of general-use distribution power transformers and distribution feeders. An alternate service customer is generally served by a single feeder. In the event of an outage to the customer's preferred feeder, the customer will automatically transfer to an alternate feeder. PGE is contractually bound to reserve adequate capacity for alternate service customers. A transformer or feeder that is designated as an alternate source shall always have reserved capacity to pick up the agreed-upon load as stated in the corresponding alternate service agreement. For a transformer designated as a source for alternate service, the sum of the transformer's peak load and the reserved capacity must be equal to or less than the transformer's LBNR. For a feeder designated as a source for alternate service, the sum of the feeder's peak load and the reserved capacity must be equal to or less than the feeder's normal thermal limit.
- **Secondary network feeders:** Secondary networks are designed to allow customers to be served by a group or "system" of dedicated feeders. Secondary conductors are interconnected to serve pockets of load in common areas. Feeders in these network systems are allowed to be taken out of service one, and in some cases, two, at a time for planned or unplanned outage scenarios. With this redundancy in place, secondary network feeders and corresponding transformers are individually lightly loaded so that they have the capacity to pick up load from a transformer or feeder serving the same network load. Due to their complex nature, secondary network feeders are currently modeled in PowerWorld, which is PGE's planning tool used in transmission planning studies.

B.1.1.5 Study criteria

Two categories of studies are analyzed: N-0 base case and N-1 contingency. An N-0 base case corresponds to a normal operating condition; all feeders and distribution power transformers are in service. An N-1 contingency corresponds to an abnormal condition; a single component is out of service (e.g., distribution power transformer, distribution feeder). Contingencies will be limited to the distribution power transformer and to the distribution feeder.

Initial near-term studies will incorporate peak summer conditions. PGE's distribution system is modeled using projected 1-in-3 system loading conditions over a five-year horizon.[141] For a base case scenario, the distribution system is configured in an operational state with the addition of any approved capital funding projects included in the system model. This is important as new projects will change the equipment and assets on the network during the planning horizon and must be reflected in CYME. Distribution loading is allocated at the distribution power transformer level per substation.

B.1.1.5.1 Feeder switching

For N-1 contingency, all field devices used for restoration must be load-break, three-phase, gang-operated switches or three-phase reclosers. If required, devices used for restoration in distribution substations must be three-phase circuit breakers or circuit switchers. Other means that may be used for switching in the field (such as closing single-phase jumpers, closing cable disconnects or operating non-load-breaking devices) will not be included when performing studies. Field devices allowed to be modeled for switching purposes are overhead devices rated at either 600 or 900 amps, submersible devices rated at 600 amps and pad-mounted devices rated at either 600, 900 or 1200 amps.

Distribution feeders are split into switchable sections, or zones. Ideally, with feeders limited to 12 MVA, or 67% of their normal thermal ratings, a switchable section shall not exceed 6 MVA. This will allow an entire feeder under contingency (N-1) to be picked up by two adjacent feeders during a peak period. A section located on the load side of a fuse or a recloser without a bypass switch is not considered a switchable section.

Ideally, an urban feeder shall require one level of switching to adjacent feeders, due to denser loadings and shorter lengths relative to rural or remote feeders. This means that during a peak period, service restoration feeders adjacent to the feeder taken out of service shall not be offloaded to pick up unserved load. If further action is required, unserved load will be reported. Rural and remote feeders are allowed two levels of switching to adjacent feeders. To pick up unserved load, a feeder can be offloaded to an adjacent feeder.

141. 1-in-3 refers to modeling of weather-sensitive load changes based on expected 1-in-3 years weather conditions. For more detail on PGE's load forecasting methodology, see PGE's 2019 IRP Appendix D, available at: portlandgeneral.com

B.1.1.5.2 VOLTAGE CRITERIA

Distribution voltage requirements allow feeders to vary at a nominal voltage +/- 5%. In CYME, for most feeders, the base nominal delivery voltage is 120 volts. When performing contingency studies for distribution feeders and distribution power transformers, no feeder branch shall be outside of the allowable voltage range.

B.1.1.5.2.1 RESULTS

Study results will determine which areas of the system need improvements. Initially, small projects are considered to achieve the required reserve capacity on the feeder or substation power transformer. These may include feeder balancing, permanent load shifts that can be achieved without upgrades and small reconductor jobs.

The results are analyzed to determine if there are areas of the system, consisting of multiple feeders and/or transformers, that do not have N-1 redundancy. These areas are studied together to determine a project to mitigate multiple redundancy constraints.

Detailed studies are performed for feeders and/or transformers that may not meet loading or voltage criteria. These studies are prompted by the following:

- Base case loading and voltage violations
- Transmission and distribution (T&D) design criteria violations
- Existing load density
- Potential future load additions (reference community plans where possible)
- System performance (e.g., outage history, SAIDI/SAIFI indices)

Detailed studies will identify multiple options for each substation. The recommended option should defer additional capital projects at the substation for a minimum of 10 years, where possible. High-level cost estimates are developed for these options. Options analyses are performed to determine reduced risk and overall system benefits. White papers, and ultimately capital funding projects, are developed as a result of the detailed studies.

B.1.1.5.2.2 REPORTING

For the N-0 study, voltages outside of bandwidth, transformers loaded at 80% of LBNR or higher, and feeders loaded at 67% of normal thermal limit or higher will be listed and reported, some of which going on to receive more detailed studies as described above. More immediate corrective actions will be required for equipment projected to exceed 100% of their respective seasonal LBNR or seasonal thermal limits.

For N-1 scenarios, voltages outside of bandwidth, transformers loaded at 95% of LBNR or higher and feeders loaded at 95% of normal thermal limits or higher will be listed and reported. Corrective actions will be required for equipment that exceeds 100% of its respective seasonal LBNR or seasonal thermal limits. If possible, corrective actions will solve loading and voltage problems for a general area.

After studies are completed, options are analyzed, corrective actions are identified and a tentative timeline for these corrective actions is developed. The study process, analyses, results and recommendations are then captured in a formal report.

B.2 Distribution system reliability and outages

In this section, PGE describes performance metrics and analysis conducted to determine reliability and outage-related information. Each indicator reflects either outage duration or frequency, such that a score of zero is perfect (i.e., no outages).

B.2.1 ANNUAL RELIABILITY

Reliability is the ability to power the grid to deliver electricity to all points of consumption, in the quantity and quality the consumer demands. Reliability at the utility level is measured by outage indices defined by one international standard called IEEE 1366.[142] These outage indices are calculated by the duration of each interruption and the frequency of the interruption and are explained in detail as follows.

PGE collects outage data to calculate three distinct performance metrics to measure the reliability of its distribution system from various perspectives: 1) at the system- and region- level (east, south, west); 2) by outage causes; and 3) by feeder (urban, rural, and remote). PGE calculates three annualized reliability indices at the system, region and feeder level and groups the outage causes in 10 categories.

These three performance assessments are summarized every year in PGE's Annual Reliability Report, which is submitted to the OPUC for compliance.[143] This report provides distribution system performance information based on service interruptions to PGE customers. The report is used to understand the overall reliability of the distribution system and to identify areas of improvement and excellence.

System level reliability: The overall performance of PGE's distribution system is represented by the following three indices:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Momentary Average Interruption Event Frequency Index ($MAIFI_E$)[144]

PGE's distribution system performance calculations are based on the IEEE 1366 methodology. The data utilized for the calculations is captured from PGE's outage management system (OMS) and confirmed via a multi-step evaluation process. The results of the calculations are evaluated daily and confirmed via a standardized review process.

Planned outage events were excluded from the 2020 distribution system performance indices based on PGE's understanding of best practices performed by peer utilities and analysis methods utilized in IEEE 1782.[145] [146] While planned outage events were not captured in PGE's 2020 indices, these events are reported in Appendix E. Annual reliability report to comply with Oregon Administrative Rule (OAR) 860-023-0151.

B.2.1.1 System average interruption duration index (SAIDI)

This is the sustained interruption duration time (in minutes) that an average customer experiences during the year. It is determined by dividing the annual sum of all customer sustained interruption durations by the total number of customers served.

SAIDI = Sum of customer sustained interruption durations/Total number of PGE customers served

B.2.1.2 System average sustained interruption frequency index (SAIFI)

This index is the number of times that an average customer experiences a sustained interruption during a year. It is determined by dividing the total annual number of customer sustained interruptions by the total number of customers served.

SAIFI = Total number of customer sustained interruptions/Total number of PGE customers served

142. IEEE is the Institution of Electrical & Electronics Engineers, the biggest professional body of Electrical & Electronics Engineers. IEEE has its head office in the USA & has presence in most countries.
143. PGE 2020 Annual Reliability Report. OAR 860-023-0151, available at: edocs.puc.state.or.us
144. $MAIFI_E$ calculations are limited to feeders with remote monitoring equipment.
145. Per IEEE 1366, a planned outage event is defined as "the intentional disabling of a component's capability to deliver power, done at a preselected time, usually for the purposes of construction, preventative maintenance, or repair." IEEE 1782, states "the planned outage event category includes, but is not limited to: road construction, maintenance and repairs, load swaps, replacing equipment, and house moves. Typically, planned interruptions are those interruptions that can be delayed by the utility personnel and performed only after the appropriate or required customer notification."
146. PGE began excluding planned outages from distribution system performance indices in 2016. Planned outage events were not excluded in previous years.

B.2.1.3 Momentary average interruption frequency index ($MAIFI_E$)

This index is the number of times that an average customer experiences momentary interruption events during a year. It is determined by dividing the total annual number of customer momentary interruption events by the total number of customers served. Note that this index does not include the events immediately preceding a sustained interruption.

$MAIFI_E$ = Total number of customer momentary interruption events/Total number of PGE customers served on feeders with MV90 or SCADA

B.2.1.4 Customer average interruption duration index (CAIDI)

Once an outage occurs, this index is the average time to restore service to the customer. It is determined by dividing the annual sum of all customer sustained interruption durations by the total annual number of customer sustained interruptions.

CAIDI = Annual sum of all customer sustained interruption durations/Total annual number of customer sustained interruptions

B.2.1.5 Major event day (MED)

An MED is a day in which the daily system SAIDI exceeds a threshold value (TMED). The SAIDI index is used as the basis of this definition, since it leads to consistent results regardless of utility size and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine MEDs, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins. The TMED value is calculated at the end of each reporting period (typically one year) for use the next reporting period, as follows:

- Collect values of daily SAIDI for five sequential years, ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
- Only those days that have a SAIDI/day value will be used to calculate TMED (do not include days that did not have any interruptions).
- Take the natural logarithm (ln) of each daily SAIDI value in the dataset.
- Find **α** (alpha), the average of the logarithms (also known as the log-average) of the data set.
- Find ***ß*** (beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the dataset.
- Compute the MED threshold, TMED, using: TMED = $e^{(\alpha + 2.5\beta)}$
- Any day with daily SAIDI greater than the threshold value TMED that occurs during the subsequent reporting period is classified as an MED.

Activities that occur on days classified as MEDs should be separately analyzed and reported.

Table 50 illustrates five-years of outage metrics including and excluding major events. These metrics at the system level are used to benchmark PGE’s reliability performance against other utilities and identify areas of the company that need capital investment and opportunities for operational improvements.

Table 50. Five-year annual outage metrics summary

	Including MEDs[147] Average annual outages			Excluding MEDs Average annual			
	Reported outages	SAIFI per customer (occurrences)	SAIDI[148] duration per customer (min.)	Reported outages	SAIFI outage per customer (occurrences)	SAIDI outage duration per customer (min.)	MAIFI$_E$[149] momentary interruptions per customer (occurrences)
2016	9,340	0.79	169	7,496	0.59	97	1.1
2017	12,897	1.04	350	8,704	0.62	113	1.4
2018	6,884	0.52	89	6,884	0.52	89	1.3
2019	8,244	0.71	128	7,663	0.61	98	1.3
2020	10,506	0.81	312	7,973	0.60	100	1.4

B.2.2 OUTAGE CAUSES ANALYSIS

PGE conducts outage analysis by grouping outages causes by events, including and excluding major events, and comparing them by events and by total number of outage hours. PGE classifies outages in 10 cause-categories by order of magnitude: equipment, vegetation, wildfire, public, unknown, other, lightning, loss of supply — substation, loss of supply — transmission. **Table 51** shows that the two largest categories by number of events are equipment and vegetation. Thus, both are subdivided (**Table 52**) to express more granularity on the outage causes, showing that limbs on lines and trees uprooted represent approximately 90% of the vegetation-caused outages.

Table 51. 2020 Outages by cause excluding major events

Outage cause type	Number of outages	Percent of total outages	Number of hours	Percent of total hours
Equipment	3,345	42%	295,603	20%
Vegetation	2198	28%	642,488	43%
Wildfire	826	10%	56,481	4%
Public	628	8%	181,698	12%
Weather	439	6%	66,758	4%
Unknown	204	3%	51,635	3%
Other	188	2%	18,291	1%
Lightning	80	1%	20,465	1%
Loss of supply — substation	47	1%	108,099	7%
Loss of supply — transmission	18	0%	55,072	4%
Total	7,973	100%	1,496,590	100%

147. A Major Event Day (MED) is a day in which the reasonable design and or operational limits of the electric power system were exceeded. MEDs are determined via the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366.
148. SAIDI values are rounded to the nearest whole number.
149. MAIFI$_E$ events for MEDs are not excluded.

Table 52. 2020 Outages by top two causes excluding major events

Outage cause type	Number of outages	Percent of total outages	Number of hours	Percent of total hours
Equipment				
Cutout, fuse, arrestor	790	24%	32,171	11%
Underground (UG) conductor	786	23%	83,713	28%
Overhead (OH) hardware	704	21%	55,863	19%
Transformer	428	13%	25,032	8%
Overhead (OH) conductor	380	11%	53,817	18%
Underground (UG) accessory	173	5%	15,742	5%
Meter	45	1%	462	0%
Pole/structure	21	1%	3,443	1%
Primary device	18	1%	25,359	9%
Total	3,345	100%	295,602	100%
Vegetation				
Limb on line	1,168	53%	299,047	47%
Tree uprooted	853	39%	289,386	45%
Tree/limb burning	177	8%	54,054	8%
Total	2,198	100%	642,487	100%

B.2.3 FEEDERS PERFORMANCE SUMMARY BY REGION

PGE also conducts a feeder performance summary. First feeders are classified into three categories: urban, rural and remote (**Table 53**).

Definition of feeder classifications:

- A feeder is designated urban if 50% or more of the load is inside the urban growth boundary (UGB)
- A feeder is designated rural if one or more of the following apply:
  - The load on a feeder is greater than 0.5 MVA per square mile
  - A feeder has more than 100 customers per mile
  - A feeder is serving load inside an incorporated city
  - A feeder is directly adjacent to the UGB with feeder ties into the UGB
- A feeder is remote if all conditions above do not apply

Table 53. Individual feeder performance thresholds based on classification

Feeder classification	SAIDI	SAIFI	$MAIFI_E$
Urban	2 hours (120 minutes)	2.0 occurrences	5 occurrences
Rural	5 hours (300 minutes)	2.6 occurrences	10 occurrences
Remote	7 hours (420 minutes)	2.6 occurrences	15 occurrences

These performance indices are calculated at the feeder level which helps narrow down the area where the outage occurred. Once the outage area is identified, outage analysis is performed by categorizing the causes of the outage.

B.3 Distribution system assets

B.3.1 ASSET CLASSES

PGE classifies its assets into 13 categories:

- **Substation structures:** Access roads, landscaping, irrigation/drains, crushed rock surfacing, fences, security systems, yard area lighting and the steel structures that support electrical conductors within a substation.
- **Substation transformers:** These assets change the relationship between the incoming voltage and current and the outgoing voltage and current. They are rated on their primary and secondary voltage relationship and their power-carrying capacity. They consist of a core and coils immersed in oil in a steel tank.
- **Circuit breakers:** Each one of these assets is the combination of a thermostat and a switch. It has a bimetal strip that heats and bends during a circuit overload. When the strip bends, it trips the breaker and opens the switch, thus breaking the circuit.
- **Other substation equipment:** Disconnect switches, control panels, batteries, metal-clad switchgear, conduit and control house.
- **Distribution poles:** One of a set of upright poles to support electric cables, typically made of wood.
- **Overhead (OH) transformers:** One of a set of one to three pole-mounted distribution transformers. Overhead transformers step down the distribution voltage to levels that customers can use.
- **Sectionalizers and reclosers:** Sectionalizers and reclosers are protective devices on the distribution system. The sectionalizer automatically isolates a faulted section on the line, while a recloser interrupts the current on the faulted section.
- **Voltage regulators:** These are devices that create and maintain a defined output voltage, regardless of changes to the input voltage or load conditions. Voltage regulators keep the voltage from a power supply within a range that is compatible with the other electrical components.
- **Capacitor banks:** A capacitor bank is a group of capacitors of the same rating connected in series or parallel with each other to store electrical energy. The pack is used to correct or counteract a power factor lag or phase shift in an alternating current (AC) supply. It can also be used in direct current (DC) power supply to increase the ripple current capacity of the power supply to increase the overall amount of stored energy.
- **Other overhead (OH) conductor devices:** Per the Federal Energy Regulatory Commission (FERC) definition, these are devices, other than those previously defined, used on an overhead electrical distribution system. Common devices can be insulators, cutouts, disconnect switches, fuses and lightning arresters.
- **Underground (UG) transformers:** Underground transformers — also called “pad-mounted” transformers — are electrically the same as pole-mounted units, but packed in a box-like, oil-filled metal enclosure and installed on a ground-level concrete foundation, or “pad.” These transformers step down the distribution voltage to levels that customers can use.
- **Underground (UG) conduit:** Underground conduit are ducts installed beneath the streets, sidewalks or paved surfaces to house underground distribution cables.
- **Other UG conductor devices:** Per the FERC definition, these are devices, other than those previously defined, used on an underground electrical distribution system. Common devices can be switches, faulted circuit indicators, terminations and primary junctions.

Table 54 shows the 13 asset classes by age composition. The “unknown” entries are assets that are not tracked in PGE’s Maximo database (e.g., brackets).

Table 54. Asset classes by age range

Asset classes	Assets by age range (years)											
	0-9	10-19	20-29	30-39	40-49	50-59	60-69	70-79	80-89	90-99	100+	Unknown
Substation structures	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Substation transformers	31	47	79	28	78	44	44	15	10	1	0	30
Circuit breakers	497	280	335	32	106	72	75	6	0	0	0	214
Other substation equipment	1,075	1,107	1,490	192	891	924	211	48	1	0	111	3,917
Distribution poles	20,346	18,717	23,809	26,026	34,514	32,696	31,619	13,636	1,385	315	33	519
Overhead transformers	29,962	16,906	12,573	7,335	15,098	13,421	10,259	2,330	198	15	4	399
Reclosers and sectionalizers	256	160	2	1	0	1	0	0	0	0	0	2
Voltage regulators	29	18	4	0	0	0	0	0	0	0	0	4
Capacitor banks	69	103	229	239	46	0	0	0	0	0	2	1
Other overhead conductor devices	48	13	3,964	1	0	0	0	0	0	0	0	171,466
Underground transformers	2,405	17,943	21,228	11,722	13,988	3,569	135	15	0	1	4	143
Underground conduit	88,824	109,031	36,544	630	449	202	4	1	0	0	0	7,588
Other underground conductor devices	149	624	1,937	22	12	0	0	0	0	0	0	667

B.4 Distribution system monitoring and control capabilities

Distribution system and monitoring and control capabilities include supervisory control and data acquisition (SCADA) and advanced metering infrastructure (AMI) technologies.

B.4.1 SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

SCADA is control system architecture that uses networked computerized data communications systems to interface with and control PGE T&D infrastructure and systems. Deployment of SCADA to substations increases visibility of the grid to T&D operations and reduces the likelihood and duration of outages. Currently, 81% of PGE substations are controlled and monitored by SCADA. PGE is also strategically adding SCADA to reclosers and other intelligent electronic devices (IEDs) that will increase the visibility of the grid to T&D operators.

SCADA deployment to the remaining distribution substations will be planned in conjunction with the distribution management system (DMS) implementation. Prioritization of the SCADA deployment plan will be based primarily on reliability issues, wildfire risk mitigation, and DER interconnection requests. PGE is developing a plan for deploying SCADA to the remaining electronic reclosers and updating the standard recloser installation process to ensure all new devices are installed with SCADA.

B.4.1.1 Description of SCADA technology

SCADA systems provide critical information and remote-control capability to system dispatchers and the balancing authority. Initially, SCADA was deployed at transmission substations to ensure reliability and stability of the bulk electric system while balancing the utility's load with generation, negating the need for manned stations. Over time, the value of SCADA expanded to include safety and distribution reliability, increasing situational awareness and decreasing outage response times. Traditionally, SCADA transmitted limited information, like circuit breaker status and transformer loading. The number of SCADA points per station has expanded to include equipment alarms, enabling proactive response to emerging issues. SCADA is now a critical component of an integrated grid, enabling safe, reliable two-way power flow and optimization of grid assets.

B.4.1.2 ASSETS WITH SCADA DEPLOYMENT

Table 55 shows that of the 153 distribution substations, 81%, have SCADA deployment, and of 695 distribution feeders, 88% have SCADA deployment.

Some examples of other equipment that uses SCADA to control and monitor are voltage regulators, reclosers, protection relays, feeder meters, substation transformer monitoring and capacitors.

Table 55. SCADA assets deployment

	SCADA-deployed units		Unit counts	SCADA-deployed in percent	
	With	Without		With	Without
Distribution substations	124	29	153	81%	19%
Distribution feeders	611	84	695	88%	12%

Table 56 explains the time interval of data collection for SCADA. Distributed Network Protocol, Version 3 (DNP3) is PGE's SCADA protocol standard; TeleGyr (L&G8979) is PGE's legacy SCADA protocol standard that will be eventually converted to DNP3 when equipment replacement is triggered. PGE's SCADA equipment and software can retrieve data in a binary (i.e., open/close), analog (as a spot check of a continuous value — e.g., temperature or power), and accumulator (as an incremental value count, i.e., energy) fashion.

Table 56. Time intervals, interval type and protocols on SCADA data collection

Intervals	Type of interval	Protocols	
		DNP3	TeleGyr (L&G 8979)
2 sec.	**Status exception polling**	X	
10 sec.	**Analog full scan**	X	
30 sec.	**Status full/integrity scan**	X	
1 hr.	**Accumulator read**	X	
2 sec.	**Status full scan**		X
10 sec.	**Analog full scan**		X
1 hr.	**Accumulator scan**		X

B.4.2 ADVANCED METERING INFRASTRUCTURE (AMI)

AMI comprises meters located outside of customer homes and businesses. AMI records how much power is consumed during the day and tracks voltage levels of delivered power. Meters can record granular power and voltage reads, as well as other services described as follows.

B.4.2.1 Assets with AMI deployment

PGE uses AMI technology to remote connect and disconnect alongside usage and generation measurements for billing, load research, electric service suppliers (ESS) and energy imbalance market (EIM) settlements and unbilled revenue. In addition, AMI can provide:

Hot socket alarms: PGE rolls trucks to "hot socket" alarms, which occur when the meter gets above 85 degrees Celsius. In many cases, these are due to a meter base issue (in need of customer repair) or increased load at the site (such as marijuana grow operations).

Tamper alarms: PGE rolls trucks to unexpected tamper alarms, in which case there are no existing work orders driving a field visit from PGE. Many times, these are false alarms created by electricians, but there are cases of theft or illegal tampering.

Grid monitoring: Recently, PGE began using meters as grid monitoring sensors for large generation sites, such as qualified facilities (QFs) and community solar installations. PGE sends a feed of AMI data to the PI data historian (the monitoring tool used to house PGE's SCADA data) to create visibility for grid operators to large-scale generation occurring on the grid.

Voltage pinging: PGE developed a systematic voltage pinging program, which goes feeder by feeder and pings groups of meters every 15 minutes. This is currently being leveraged to establish data corrections in PGE's geographic information system (GIS) databases mapping meters to other system assets. PGE also relied on this service to aid in remotely confirming for customers whether power was restored to their meter during the 2021 winter storm outages. Potential future use cases are conservation voltage reduction (CVR) programs and theft detection analytics.

Service transformer loading: PGE built a transformer loading analytics tool using the company's in-house Smart Meter Toolbox program application. This tool allows more than 100 site service design professionals and engineers to enter a service transformer ID and see the aggregate load of all customers being served by that transformer. This is useful for overloading analysis, as well as capacity planning for new service requests and DER interconnection.

B.4.2.1.1 Residential

- Proactive power quality notification for half-outs, flickering lights and similar events
- More meter status visibility for customer service agents to help with outage calls, program enrollment eligibility and other tasks
- Enhanced customer web portal (Energy Tracker 2.0) to show more than just usage details, potentially to include generation, outage/alarm history and meter status (on/off)
- Prepaid metering for customers with remote disconnect meters, offering benefits to customer and utility with a pay-as-you-go approach (like filling a gas tank), rather than the typical, deposit, use, bill, pay monthly approach

B.4.2.1.2 Commercial

- Demand/rate migration alerts
- Proactive power quality notifications, single phase-outs, phase imbalance
- Power quality monitoring
  - Some larger customers are purchasing iGrid to monitor their power quality, which is costly to them and PGE
  - PGE could offer "iGrid lite" with current meters and some web development, or a more robust solution with a new meter coupled with data science and engineering support
- Controllable campus lighting, leveraging smart streetlights and AMI
- Water meter network
  - PGE can offer cities its AMI network to read their water meters, so they do not have to read them manually
  - PGE has capacity and has successfully demonstrated this capability with the City of Wilsonville
- Conservation voltage reduction
  - PGE has the opportunity to use meter data to reduce substation voltage, especially during peak-load, high-cost times of day, effectively reducing customer bills and utility power costs
- Theft detection using voltage signatures
- GIS and AMI integration for field crews, allowing for near real-time visibility to customers' on/off state during outage restoration efforts

Table 57 and **Table 58** shows the number of meters by type, the majority being residential customer meters, which account for 87% of total AMI deployments. Overall, PGE has near-universal adoption of AMI. PGE has 916,450 meters installed; all are AMI-enabled except for approximately 140 "opt-out" customers. **Table 57** shows the breakdown of interval length among the approximately 920,000 meters currently installed.

Table 57. PGE meters outfitted with AMI

Meter type	Count	Percent
Residential	794,000	87%
Commercial	103,000	11%
Industrial (>1 MW)	300	0.03%
Irrigation	4,150	0.45%
Vacant	15,000	2%
Total	916,450	100%

Table 58. Operational intervals on AMI Meters

AMI meter interval	Count	Percent
5 minutes	266	- Mix of qualified facilities - Community solar - Demand response
15 minutes	292,893	- Commercial - Newer residential meters
60 minutes	626,969	Exclusively residential

B.5 Distribution system advanced control and communication capabilities

B.5.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

ADMS is a PGE business imperative that will enable real-time management of the distribution system at a more granular level than what is capable today by leveraging use of automated technologies for system management, coordination and optimization. The result will be better reliability, improved power quality, increased operational efficiency and enhanced system safety and security. These benefits will become more evident with migration to a dynamic distribution system integrating DERs.

System functions enhanced by ADMS include heightened situational awareness through SCADA, real-time network connectivity analysis and faster and more accurate information on distribution network operating state and radial mode. ADMS will also facilitate power flow and state estimation, which provides insight into system voltages and power flows in areas that are not metered. This enables advanced applications and tools that can predict faults and allow proactive detection and mitigation of threats to system interruptions, failures and outages.

B.5.1.1 Description of ADMS technology

ADMS is a centralized, advanced operations technology platform for system operators to monitor, control, optimize and safely operate PGE's distribution system. It is comprised of a suite of core functions, such as dedicated distribution SCADA (DSCADA), an "as-operated" model of the distribution system and links to other applications, such as GIS, OMS and energy management system (EMS). ADMS uses the same types of analysis tools used for the transmission system to view and analyze the distribution system model (state estimation and power flow). This increased complexity associated with operating a distribution system in the presence of emerging technologies like DERs, EVs, and DRs will result in uncertainty regarding system state. This complexity is beyond the capability of the current EMS which is primarily designed to manage transmission and generation.

ADMS provides SCADA controls for distribution circuits, automated self-healing circuit functionality fault location, isolation, and service restoration (FLISR); assisted/automated switching for planned and unplanned outages; grid optimization; real-time power system studies and reporting capabilities. Advanced functions include conservation voltage reduction, volt-VAR optimization, protection analysis and adaptive protection. Mobile grid operations is an advanced ADMS capability that provides field personnel access to grid data and the ability to update the grid information.

Table 59 includes ADMS capabilities that PGE has tested, currently uses, or is planning on using over the next couple of years.

Table 59. Advanced control distribution management systems capabilities

ADMS capabilities	Percentage of customers reached with each capability
Control and operations[150]	Approximately 690 feeders; 100% of feeders
FLISR	3 feeders using YFA; approximately 3,000 customers

150. Examples of control and operations: Load transfer, microgrid ops, device management, load shed, feeder reconfiguration, low voltage analysis, FLISR/VVC, overload switching, intelligent alarms, relay protection, adaptive protection, optimal power flow, feeder balancing/rebalancing, breaker/fuse capacity analysis, Switch Order Management, State Estimation, Secondary Power Flow, Short Term Load Forecast, Energy Losses, Short Circuit Duty Analytics

B.5.2 CONSERVATION VOLTAGE REDUCTION (CVR)

CVR is the strategic reduction of feeder voltage, deployed with phase balancing and distributed voltage-regulating devices to ensure end-customer voltage is within the low range of American National Standards Institute (ANSI) acceptable voltages (114V–120V). PGE completed feasibility studies and two CVR pilot projects in 2014 at Hogan South substation in Gresham and Denny substations in Beaverton. By reducing voltage 1.5-2.5% in the pilot project, PGE was able to reduce customer demand (MW) and energy consumption (MWh) by 1.4-2.5%. The pilots yielded customer energy savings of 768 MWh in 2014. A preliminary evaluation has identified 94 transformers as potential CVR candidates with a customer energy savings potential of 142,934 MWh/year, or 16 average megawatts (MWa).

B.5.3 OUTAGE MANAGEMENT SYSTEM (OMS)

OMS is an asset/work management system that provides PGE grid operations the ability to monitor and manage customer outages while returning power. OMS assists with the following capabilities:

- Predicting the location of the transformer, fuse, recloser or breaker that opened upon failure.
- Prioritizing restoration efforts and managing resources based on criteria such as the location of emergency facilities, the size of outages and the duration of outages.
- Providing information on the extent of outages and number of customers impacted to management, media and regulators.
- Calculating the estimation of restoration times.
- Managing crews assisting in restoration and calculating the crews required for restoration.

PGE's distribution system is fully outfitted with OMS on all of its feeders, monitoring all customers.

B.5.4 DER MANAGEMENT SYSTEM (DERMS)

DERMS is a module of ADMS that optimally manages and dispatches DERs to provide grid services, facilitates non-wire alternatives, enables DERs to participate in markets, manages smart inverters, and cost-effectively manages distribution deferral resources. DERMS enables enhanced situational awareness under increasing DER penetration by providing DER modeling, aggregation and grouping. The DERMS also enhances the utilization of DER by providing DER forecasting, communication, and dispatch.

PGE will be piloting DERMS functionality in 2022.

B.5.5 DEMAND RESPONSE MANAGEMENT SYSTEM (DRMS)

DRMS follows ADMS in Phase 2 of the ADMS rollout **Section 4.9**. DRMS is essential for balancing energy supply with consumption and stabilizing load on the grid during peak hours. An automated demand response is enabled through AMI, which builds an integrated network between the customers participating in the DR program and the utility for exchanging signals and communicating in real-time.

In the future, PGE plans to use several DRMS capabilities, including: Solicitation, registration, interconnection, DER portfolio optimization, constraint management, aggregation functions, microgrid management, islanding, OPF, dispatch and schedule. **Table 60** shows all the PGE programs that apply to DRMS.

Table 60. PGE programs using DRMS

Utility programs	Number of units
Residential battery	200 of 500
Residential EV	110
Residential T-stat	25,842
Ductless heat pump	50-100
Single family water heater (SFWH)	70-150
Peak time rebate	90,993
Multi-family water heater (MFWH)	9,975
Energy partner Sch 26	65
Energy partner Sch 25	1,407
Beaverton microgrid	NA
Anderson microgrid	NA
E-Fleet platform	NA

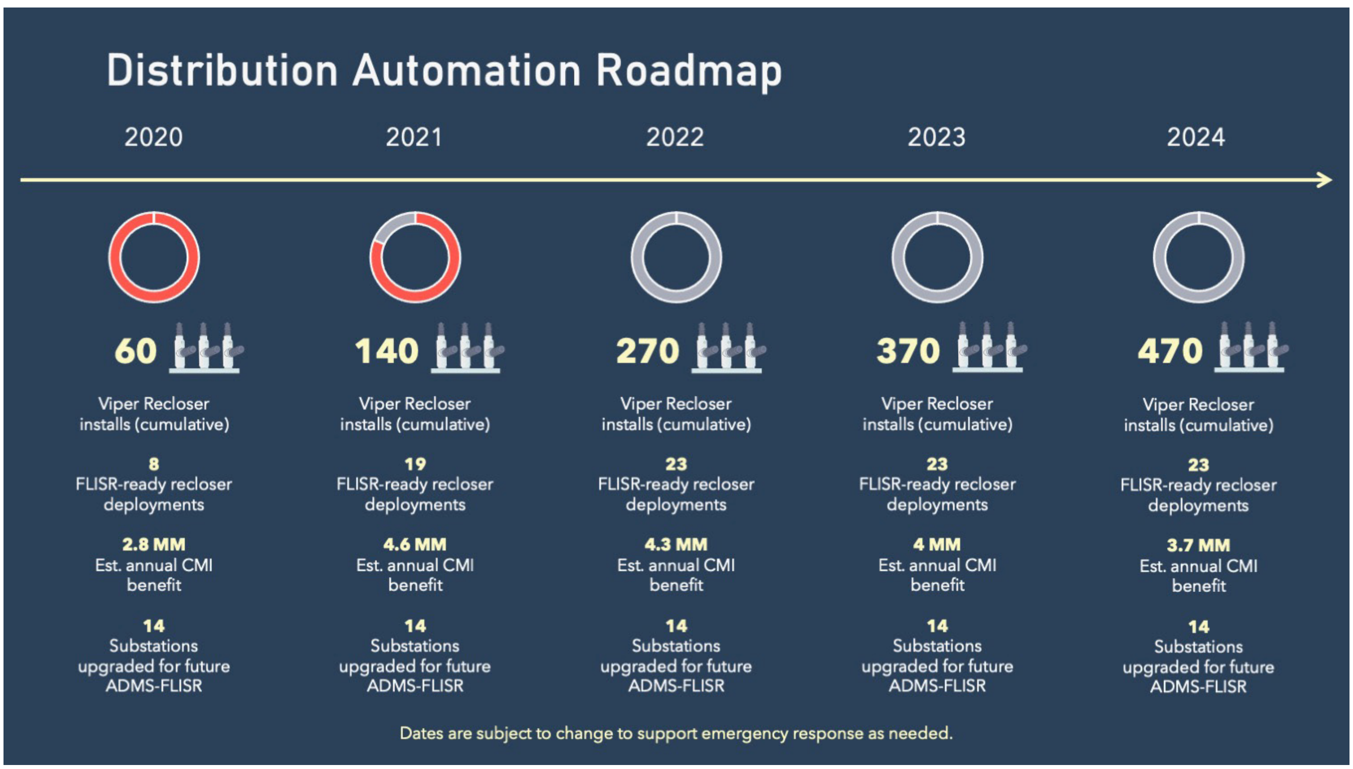
B.5.6 DISTRIBUTION AUTOMATION (DA)

Distribution automation (DA) improves reliability by utilizing switching devices to automatically isolate faulted areas and restore power to the remaining areas. It offers enhanced visibility with communicating reclosers providing additional monitoring on the distribution system. In addition, DA contributes to the migration to field area networks (FAN).

DA uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring and outage, voltage and reactive power management. Automation can improve the speed, cost and accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers.

PGE is implementing DA with the use of SCADA-integrated field devices (such as reclosers) across PGE's service territory to improve reliability for customers, increase safety for line crews and improve situational awareness for distribution system operators. DA reclosers and ADMS enable the operation of fully automated FLISR — a key grid modernization capability. Viper and Sentient MM3+ are two examples of equipment being installed to help implement ADMS FLISR capabilities (**Figure 39**).

Figure 39. Distribution automation roadmap



B.5.7 FIELD AREA NETWORK (FAN)

The FAN is a new two-way data communication network that uses PGE's privately-owned 700-megahertz (MHz) spectrum. PGE purchased the 700 MHz spectrum to support ADMS data collection once the tower buildup is concluded in 2024. The FAN is a private, PGE-owned and operated wirelessly with high reliability and low latency. This new, two-way data communication network allows quick and inexpensive data connections to various devices that PGE uses to operate and manage the power grid. It provides fast, secure and reliable wireless coverage across PGE's distribution service territory (**Figure 40**). A subset of the FAN will allow lower-reliability, higher-latency connections to customer-owned and operated devices like thermostats, EV chargers and behind-the-meter battery storage. The FAN will also allow PGE to respond to Smart City applications as they emerge. DA reclosers will be the first devices to communicate with PGE's grid management systems over the FAN.

PGE expects FAN will provide secure, ubiquitous communications to existing Distribution Automation (DA) assets as well as all emerging Distributed Energy Resources (DERs). PGE believes that this new FAN will deliver capabilities necessary for the safe, reliable and affordable operation of the electric grid. PGE plans to install FAN in 90 sites (**Table 61** & **Figure 40**).

Table 61. Field Area Network coverage implementation plan

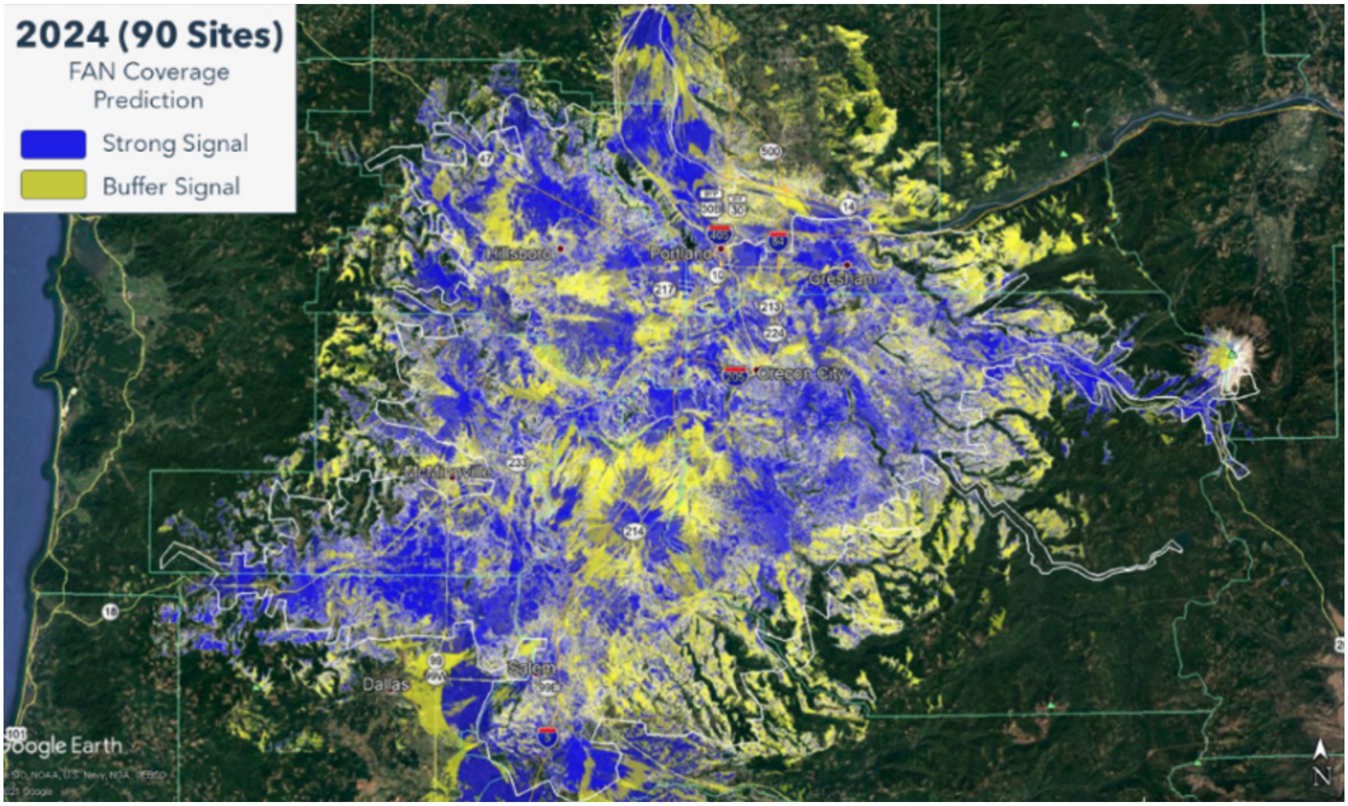
Year	Number of FAN sites	Percent of total coverage
2020	12	13%
2021	18	33%
2022	22	57%
2023	23	83%
2024	15	100%

One of several key pieces of PGE's Integrated Grid Portfolio, the FAN enables wireless communication between distribution assets in the field and the Integrated Operations Center.

The FAN offers substantial benefits compared to alternative communication networks:

- Improved reliability, speed, and restoration because we will not be dependent on third-party network providers
- Increased command-and-control capabilities over field sensors and control devices
- Better protection through increased security and encryption
- Greater ability to scale
- Data analytics, including greater visibility into customer demand for electricity

Figure 40. FAN coverage prediction, 2024



B.5.7.1 How the FAN supports PGE's integrated grid strategy

A FAN is designed to efficiently connect technologies, such as:

- Distribution automation (DA) such as reclosers for swift fault response and distribution reconfiguration
- Supervisory control and data acquisition (SCADA)
- Demand response management system (DRMS). PGE currently employs Enbala as its DRMS for visualization and control of all our demand response assets
- Energy Storage integration
- Microgrid control
- Distributed energy resource (DER) management
- Solar integration
- Transportation electrification (TE) integration
- Advanced metering infrastructure (AMI)
- Street lighting control system backhaul
- Field data communication

B.5.7.2 How the FAN will support integrated grid moving forward

The integrated grid relies on connectivity, sensing and automation/control. PGE's distribution network system currently has limited visibility and communication capability through its SCADA system to existing distribution automation controls. This limited visibility prevents the distribution system from being used to enable the efficient deployment of technologies to achieve greater energy efficiency, energy network management and system reliability that customers are demanding.

The FAN will provide the fundamental backbone to allow for the communication and visibility within the power grid network architecture.

B.6 Transportation electrification infrastructure and charging analysis

B.6.1 MASS TRANSIT ELECTRIFICATION — ELECTRIC MASS TRANSIT 2.0

PGE owns two bus depot charging stations (150 kW each) and one on-route charging station (450 kW), while TriMet acquired five electric buses with 200 kWh batteries. The pilot will gather bus charging data from the stations to assess the energy and cost impacts of electrifying an entire bus route over time as well as operations impacts to TriMet.

Transit is a critical component of the transportation sector and therefore we must continue to work with our transit agencies to ensure those customers relying on transit can realize the benefits of emissions-free transportation services. Throughout 2018, PGE worked closely with TriMet to design, install, commission and operate the proposed electric bus charging infrastructure. PGE provided guidance on the most flexible and cost-effective methods to connect the charging infrastructure at Sunset Transit Center and Merlo Garage to PGE's distribution grid, provided insight into site layout and construction, and held regular meetings with TriMet and other construction contractors. The first all-electric bus line launched in 2019.

B.6.1.1 Constructability and future-proofing assistance

PGE assisted TriMet in the design and layout of the charging infrastructure installations at Merlo Garage and Sunset Transit Center. At Merlo Garage, PGE proposed the installation of an additional underground vault, oversized transformer pad, and extra runs of secondary-side conduit to accommodate the addition of subsequent charging infrastructure more easily. TriMet chose to install oversized switchgear and additional underground electrical infrastructure to allow for the installation of up to six additional 150 kW-capable charging ports. PGE also collaborated with TriMet's contractors on the design and layout of the overhead fast charger installed at Sunset Transit Center. As at the Merlo project, PGE installed an oversized transformer pad and extra secondary side conduit runs to allow for the installation of a second overhead fast charger and TriMet installed oversized switchgear and additional underground electrical infrastructure.

B.6.1.2 Operations and maintenance plan development

PGE created an Electric Bus Charging Infrastructure operations and maintenance program in collaboration with TriMet and the infrastructure supplier. PGE worked with suppliers to identify the correct spare parts to stock at PGE facilities and train local electricians and PGE staff on equipment diagnostics and repair. TriMet and PGE also established a communications and response plan that provided a clear process for bus drivers to quickly identify issues for diagnosis and repair by PGE and the charger supplier. As TriMet began placing buses in revenue service, PGE activated remote monitoring and emergency repair programs. PGE has been available 24 hours per day / seven days per week to respond to charging infrastructure issues.

B.6.2 ELECTRIC AVENUES (EA)

PGE owns and operates seven public fast charging locations (Electric Avenues or EA), each with four Direct Current Fast Chargers (DCFC) charging ports (50 kW each) and two level 2 ports (7 kW each) for quick re-fueling. Under our EA Pilot,[151] we installed six EA charging sites[152] at geographically dispersed locations throughout our service area. The pilot will test pricing signals to encourage off-peak charging and charging when excess renewable energy is available. The pilot will also examine the impact of community charging on increasing adoption of EVs by PGE customers (including multifamily residents) and Transportation network company (TNC) drivers.

Figure 41 below presents an overall summary of energy delivered to the six different sites.

151. See Docket No. UM 1938 for more details on the Electric Avenue pilot
152. Six EA sites were installed under UM 1938, plus an additional existing site at World Trade Center, for a total of seven EA public charging sites total.

Figure 41. Monthly charging load at EA sites

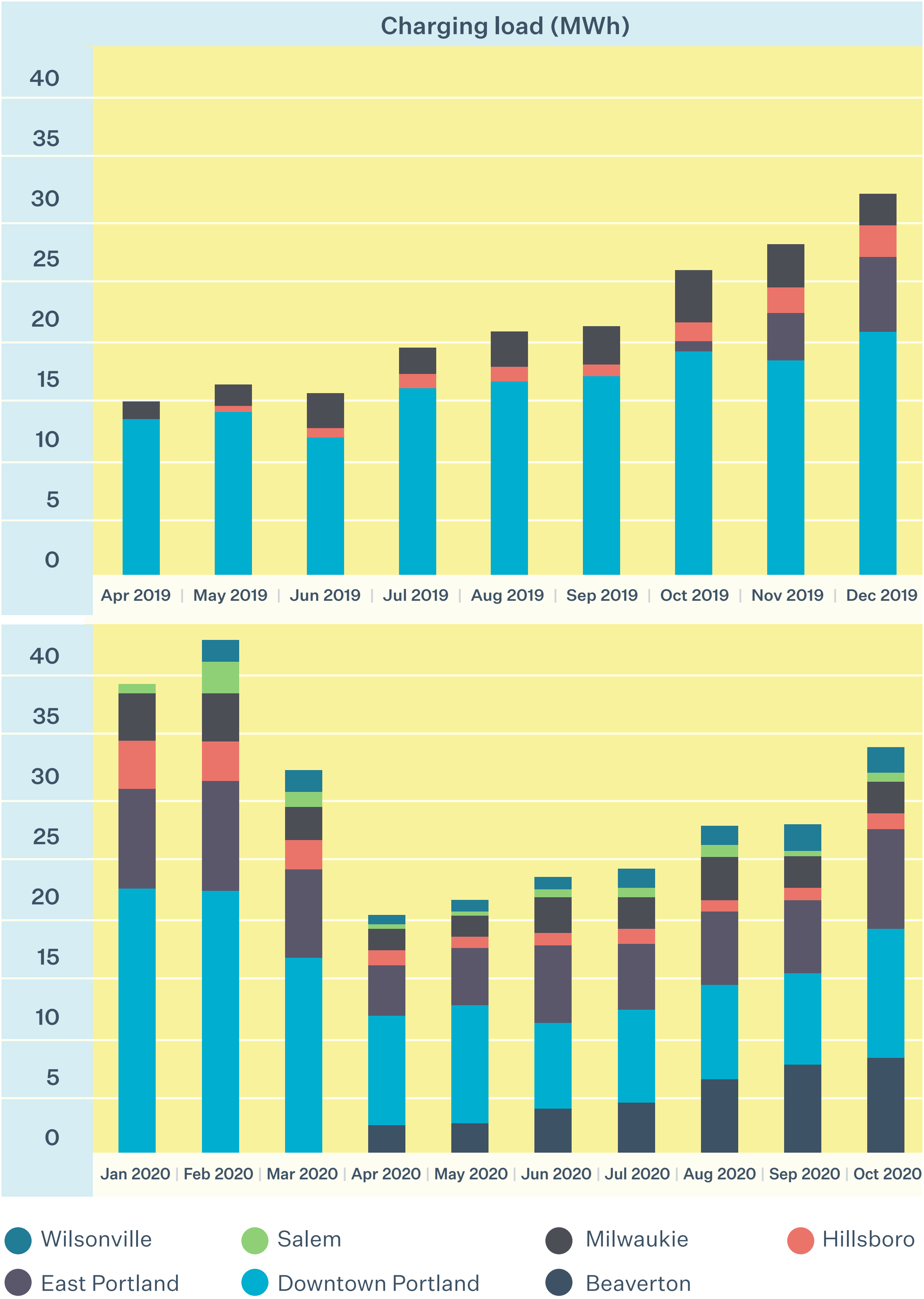
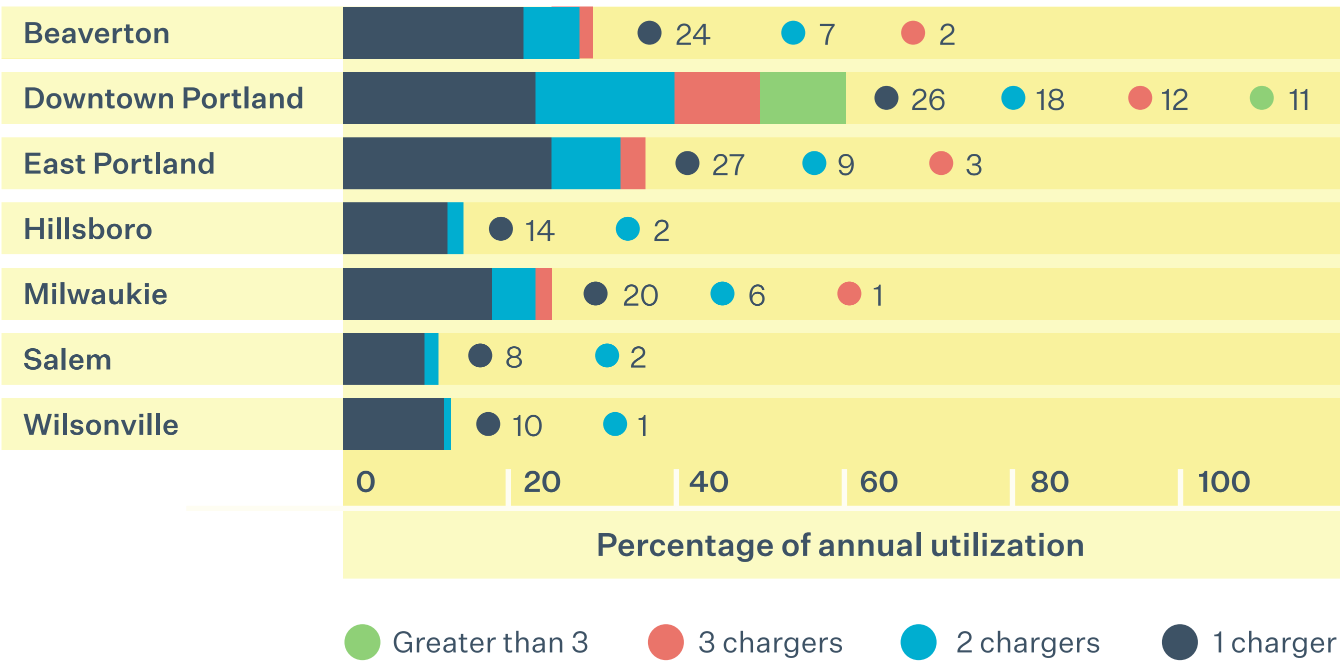


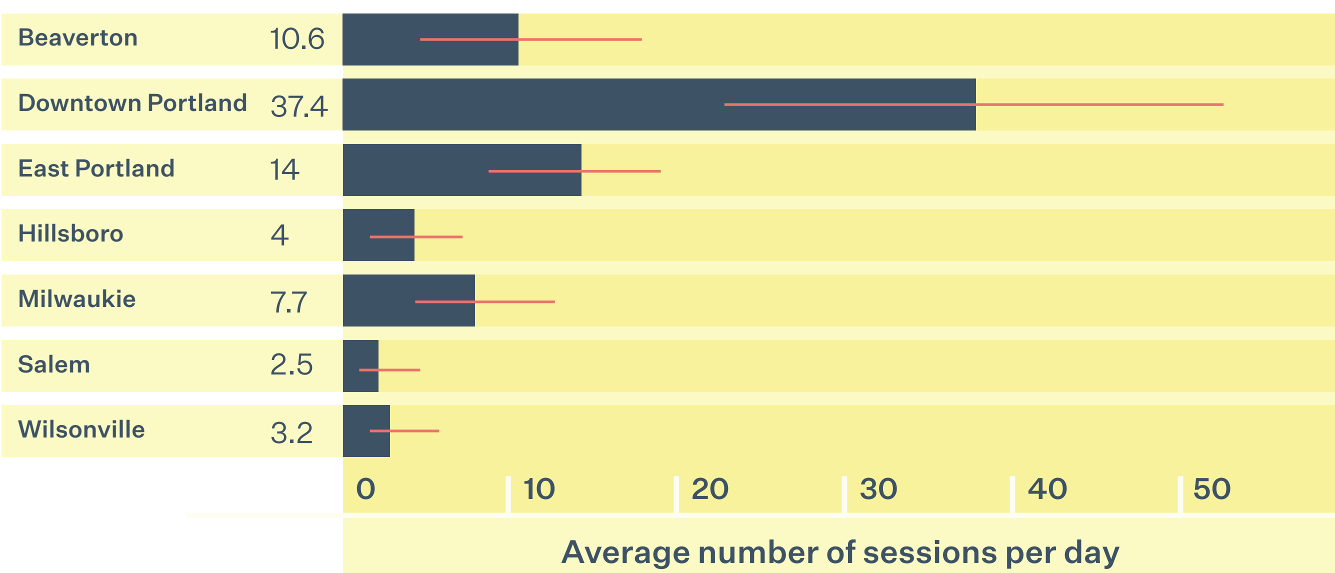
Figure 42 below shows how often each EA site experiences simultaneous charging (more than 1 port active at the same time). The downtown Portland site has the greatest amount of time with more than one port actively charging, followed by East Portland and then Beaverton sites.

Figure 42. Annual charger utilization at EA sites



We also looked at average number of charge sessions per day at each of the EA sites, presented in **Figure 43** below.

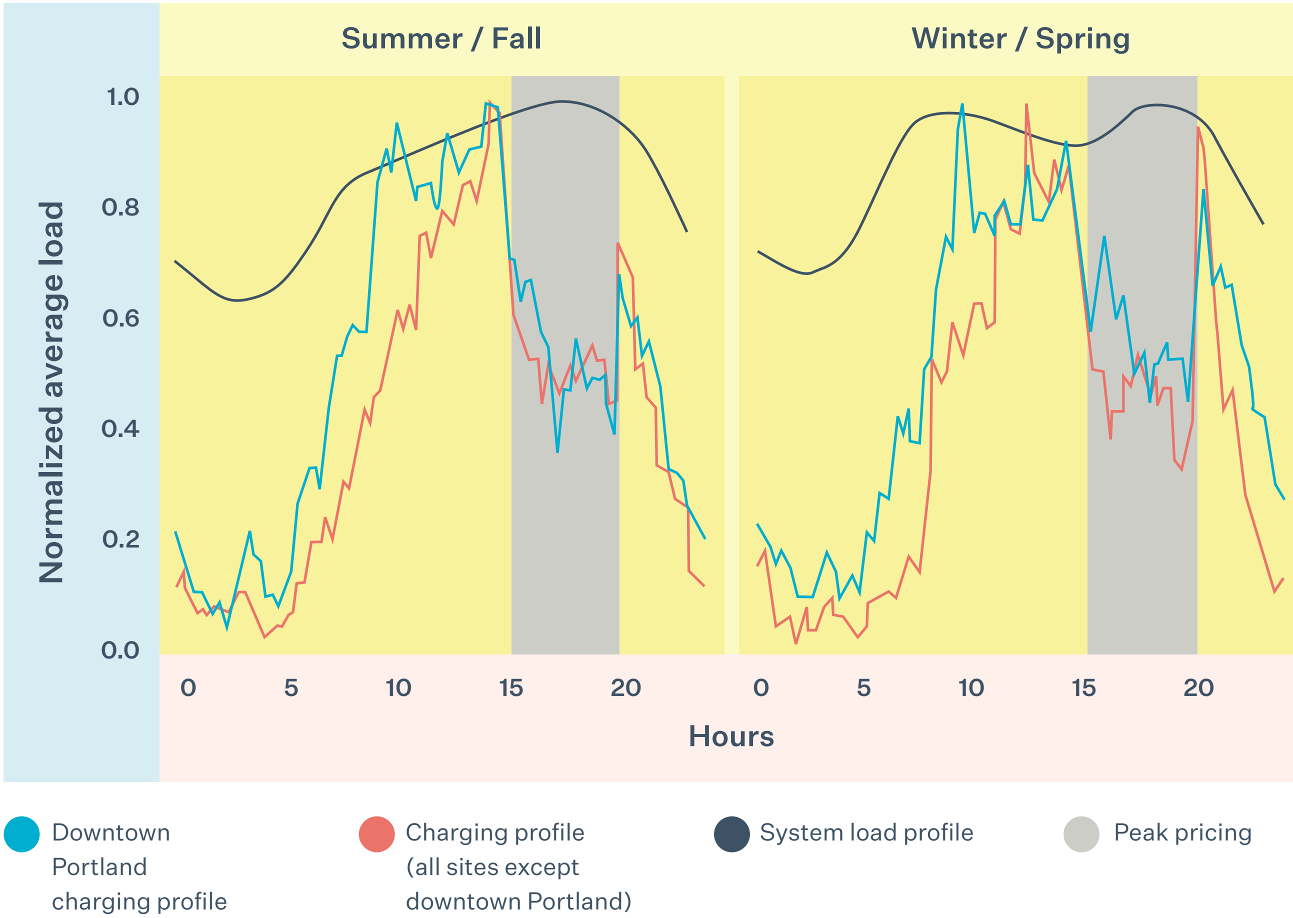
Figure 43. Average charging sessions by site



Note: The average number of charging sessions in the blue bars along with the standard deviation of the number of charging sessions in the red lines.

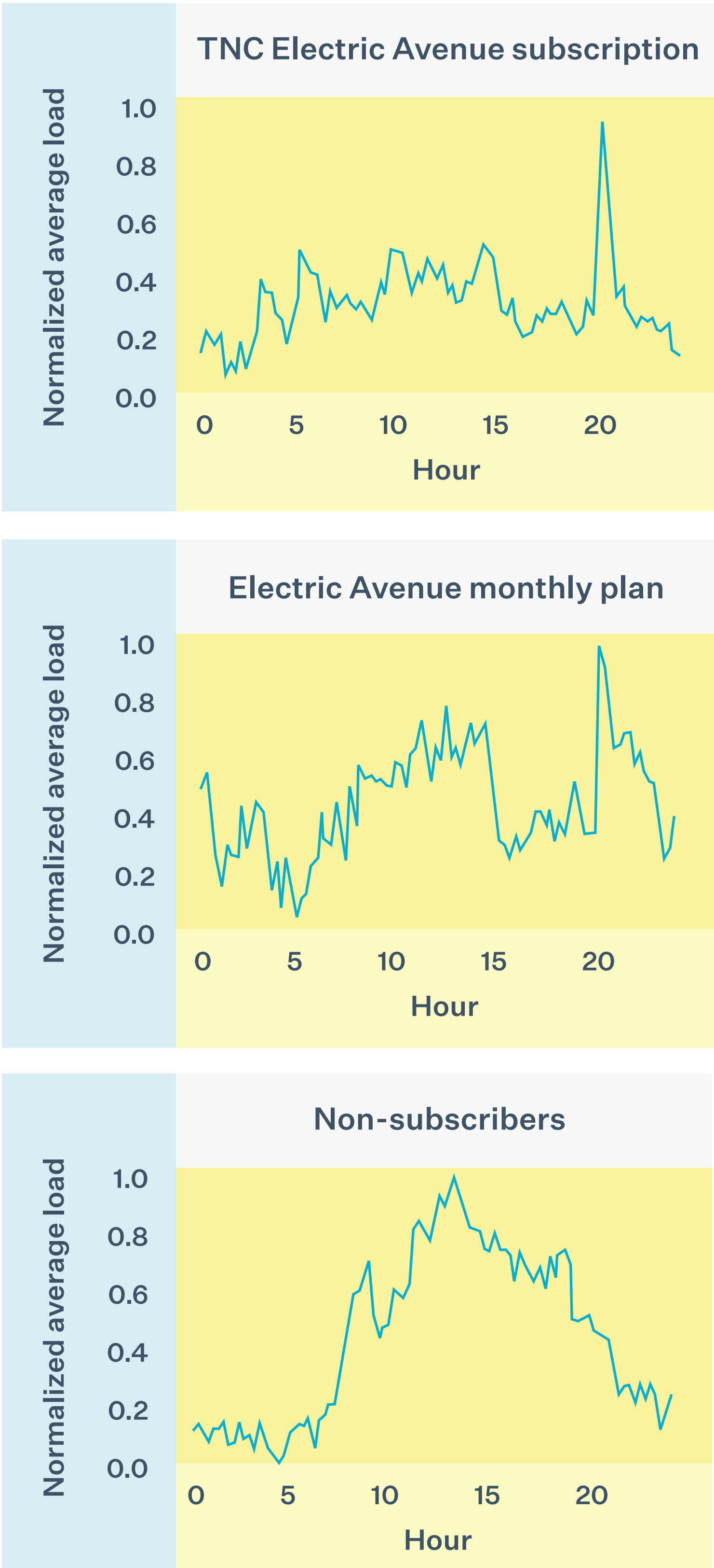
We also investigated the impact of peak pricing on charging demand, as well as the influence of subscription monthly rates and how that might impact charging behavior. The grey highlighted windows on **Figure 44** clearly demonstrate the effectiveness of the pricing signal to curb demand during system peaks.

Figure 44. Normalized system load shape verses the normalized charging profile



When looking across the type of users at the EA sites, there are clear differences in charging behavior depending on whether someone has a monthly subscription rate or simply uses a credit card at the point of sale. **Figure 45** below demonstrates that a pricing plan (whether that is the EA monthly subscription or the TNC subscription rate) generally reduces the proportion of charging during peak hours. Both EA and TNC user groups have a peak at around 8:00 p.m., whereas the unsubscribed users show a peak at around noon, and a much higher proportion of usage during system peak hours (about 70% of the normalized average daily load falls between hours 18 and 20 on the graph, or 5:00 a.m. and 8:00 p.m., respectively.)

Figure 45. Normalized average daily load profiles for EA user groups



To understand potential impacts of EA sites to the distribution system, we mapped EA load to the respective feeders where these sites are located. Overall, the operation of the current EA sites does not present a problem for the peak load of the host-feeders, all of which are well below the planning threshold of 67% peak load of seasonally adjusted nameplate ratings. If all chargers are in simultaneous use, then EA sites under current configuration could add between 1-2% of load. **Table 62** below shows this breakout for each EA host-feeder, and **Table 61** shows the type of charging stations by feeders.

Table 62. Loading on feeders serving EA sites

EA site	Feeder % loading with historical EA charging load		Feeder load charging % increase if all chargers are in use	
	Winter	Summer	Winter	Summer
Milwaukie	31%	48%	1.4%	2.1%
East Portland	36%	55%	1.4%	2.1%
Wilsonville	54%	56%	1.1%	1.2%
Beaverton	32%	40%	1.1%	1.2%
Salem	29%	39%	0.8%	0.9%

Table 63. Types of charging stations by feeders

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Abernethy-Clackamas Heights			1
Abernethy-Washington		4	
Alder-Ankeny		4	
Alder-Lincoln		2	
Amity-Amity 13		2	
Amity-Bellevue		1	
Banks-Cedar Canyon		1	1
Barnes-Battle Creek		2	
Barnes-Boone		1	
Barnes-Commercial		2	
Beaver-Kb Pipeline	0	4	0
Beaverton-Jamieson		9	3
Beaverton-Northwest		2	
Beaverton-West Slope	0	8	5
Bell-Battin		2	
Blue Lake-Sundial		4	1
Boones Ferry-Kruse		14	
Boones Ferry-Lake Grove		3	
Brookwood-Brookwood 13		4	
Canyon-13115 Network #1	0	9	14
Canyon-13120		3	
Canyon-13133 Network #3		4	
Canyon-13134 Network #3		3	2
Canyon-13136 Network #3		2	
Canyon-21st		4	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Canyon-23rd		2	
Canyon-Burnside		4	
Carver-North	0	2	2
Cedar Hills-Leahy		2	
Cedar Hills-Shopping Center	0	0	1
Cedar Hills-Skyline		4	
Cedar Hills-St Vincent		4	
Centennial-Braecroft		2	
Clackamas-Jennifer		2	
Clackamas-Tolbert		2	
Coffee Creek-Freeman		2	
Coffee Creek-Holiday		2	1
Cornelius-Cornelius 13		6	3
Cornelius-Verboort	0	5	0
Cornell-Bluffs		2	
Cornell-Westlawn		2	
Dayton-East		9	
Denny-North	1	2	
Durham-Bonita		10	
Durham-Bridgeport	12	12	
Durham-Durham 13	0	0	2
Durham-South		2	
E-11040		4	
E-11047	0	4	0
E-13140		2	
E-13141		9	
E-13142		1	
E-13144		6	
E-13145			1
E-13149		2	
E-13150		18	
Eastport-Plaza	0	0	5
Elma-Hudson		4	
Elma-State		1	
Estacada-Estacada 13		4	
Estacada-Faraday		4	
Fairmount-Candalaria	0	0	2
Fairview-Clear Creek		4	
Fairview-Fairview 13		1	
Fairview-Kennel Club		3	
Gales Creek-Gales Creek 13		2	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Glencoe-Glisan		2	
Glencoe-Sunnyside		1	
Glendoveer-13597		3	
Glendoveer-Northeast		2	
Grand Ronde-Forthill		1	1
Harrison-Davis		4	
Harrison-Harrison 13		2	
Hayden Island-North Shore		2	
Hemlock-Mason			2
Hillcrest-South		1	
Hillsboro-Dairy Creek		4	
Hillsboro-Jackson		10	
Hillsboro-Laurel		2	
Hillsboro-Scholls		34	2
Hogan North-Brigadoon		2	
Hogan North-Salquist	0	4	0
Hogan South-Cleveland		2	
Hogan South-Paropa		2	
Holgate-Bybee		1	1
Holgate-Gideon	0	4	0
Holgate-Holgate 13	0	5	0
Holgate-Kenilworth		1	
Huber-Farmington		2	
Indian-Keizer	0	0	2
Indian-Labish	0	4	0
Indian-Station		7	
Island-13180		4	
Island-13188		7	
Island-Island 13	0	16	0
Jennings Lodge-Jennings 13		2	
Jennings Lodge-Meldrum		3	
Kelly Butte-Binnsmead		9	
Leland-Kelm		4	
Lents-13101		1	
Liberty-Rosedale		2	
Main-Express		2	
Main-River		2	
Market-Hawthorne		3	12
Marquam-Mccall #11 Network		4	
Marquam-Mccall #12 Network		6	
Marquam-Spirit #1 Network		3	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Marquam-Spirit #2 Network		2	
Mcgill-Horsetail		4	
Meridian-65th		2	
Meridian-Borland		3	
Meridian-Childs		3	1
Meridian-Nyberg		1	2
Meridian-Pilkington		8	
Meridian-Sagert	0	14	0
Middle Grove-Brown		1	2
Middle Grove-Swegle			4
Midway-Division		1	
Midway-Powellhurst		1	
Molalla-Buckaroo		1	
Mt Pleasant-Clairmont	1	15	0
Mt Pleasant-Mt View		3	
Multnomah-13176	1	1	
Multnomah-13177		2	
Murrayhill-Kinton		2	
Newberg-Dundee		7	
North Marion-Crosby		2	12
North Marion-Front	0	4	0
North Plains-Mason Hill		2	
Northern-11071		4	
Oak Hills-Five Oaks		5	12
Oak Hills-Walker		2	
Orenco-Baseline		3	
Orenco-Orenco 13		21	
Orenco-Wilkins		10	
Oswego-Iron Mountain		2	4
Oswego-Marylhurst		18	
Oxford-Rural		21	2
Peninsula Park-Peninsula Park		3	
Progress-Greenburg			1
Progress-Sawyer		2	
Progress-Washington Sq #2			14
Riverview-Fulton		1	3
Riverview-Terwilliger		2	
Roseway-Roseway 13		1	
Ruby-Junction		2	
Salem-13260		2	
Salem-13261		3	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Salem-13262	0	0	3
Salem-13263		2	
Salem-13264		2	
Sandy-362nd		1	10
Scholls Ferry-Roy Rogers		2	
Sellwood-Sellwood 13		1	
Sheridan-East		1	
Silverton-North	0	2	0
Silverton-West		2	
Six Corners-13359	1	1	
Six Corners-Borchers		1	
Six Corners-Chapman		4	
Six Corners-Six Corners 13	2	5	3
Springbrook-Fernwood		6	1
Springbrook-Villa		1	
St Louis-East		7	1
St Marys East-Bethany		1	
St Marys East-Elmonica	0	0	2
St Marys East-Millikan		4	
St Marys East-St Marys 13	0	4	0
Summit-Summit 13		1	1
Sunset-Mccall	0	2	0
Sunset-Pauling		1	2
Sunset-Spalding		4	
Sunset-Whitman		12	
Swan Island-Dolphin		6	
Tabor-Hospital		17	
Tektronix-Hocken		2	
Tektronix-North		8	
Tektronix-South		4	
Tektronix-Tektronix 13		6	
Tektronix-West		2	
Temp H-Neptune	4	7	
Tigard-13337		5	
Tigard-13361	0	0	2
Tigard-Tigard 13		1	
Town Center-North	0	15	0
Town Center-Sunnybrook	2	2	
Town Center-Valley View		2	3
Tualatin-Avery	0	6	0
Unionvale-Unionvale 13		1	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
University-Mill		4	
University-Trade	0	12	0
Urban-Campus		6	
Urban-Gibbs		2	
Urban-Landing	2	2	
Waconda-River		2	
Wallace-Wallace 13		5	
Welches-Welches 13		1	
Welches-Zig Zag		1	1
West Portland-72nd		3	10
West Portland-Pacific		5	
West Portland-West Portland 13		1	
West Union-Cornelius Pass		2	
West Union-Jacobson		6	
Wilsonville-City	0	5	7
Wilsonville-Parkway		4	
Wilsonville-Villebois	0	2	0
Wilsonville-West		3	
Yamhill-Carlton		6	
Yamhill-Yamhill 13		3	
Grand Total	26	818	167

B.6.3 ELECTRIC ISLAND DEMONSTRATION

PGE and Daimler Trucks North America launched the nation's first public, purpose-built heavy-duty truck charging demonstration site, designed to serve up to 5 MW of load and up to 12 DC fast charging ports accessible by Class 8 vehicles with 53' trailers.

Daimler Trucks North America (DTNA) and PGE opened the site in April 2021, calling it "Electric Island" for reference to the new heavy-duty charging hub's location on Portland's Swan Island, home to many logistics and freight companies in the area. Electric Island will help accelerate the development, testing and deployment of zero emissions (tank to wheel) commercial vehicles, like the ones manufactured by DTNA.

Electric Island opened in Portland with eight vehicle charging stations (a majority of which are available for public use) for the charging of electric cars, buses, box vans and semi-trucks. The site is built to immediately provide charging for EVs of all shapes and sizes, and will serve as an innovation center, allowing both PGE and DTNA to study energy management, charger use and performance, and, in the case of DTNA, its own vehicles' charging performance.

Electric Island is designed to benefit both DTNA's work in commercial electric vehicle development and PGE's work in meeting customer charging needs. The site will inform each company's efforts by studying the future of heavy-duty charging, including:

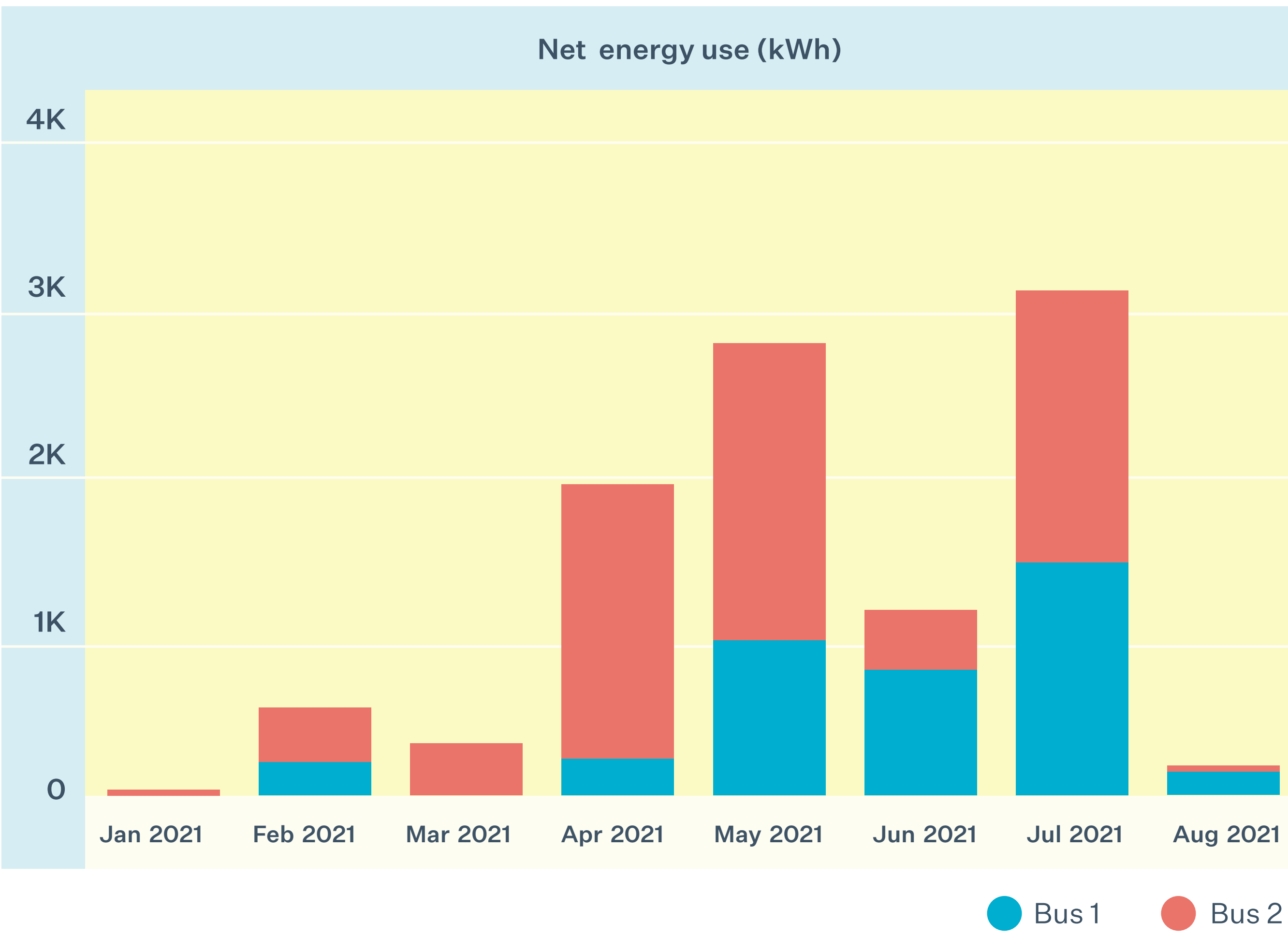
- Use of vehicle chargers featuring power delivery capable of over one megawatt charge speed (over 4 times faster than today's fastest light-duty vehicle chargers), enabling PGE and DTNA to develop best practices for cost-effective future deployments;
- Integration of heavy-duty charging technology into PGE's Smart Grid, such as vehicle-to-grid technologies, second-life use of Daimler's battery packs for stationary-grid applications, and onsite energy generation; and
- Testing information technology opportunities like fleet and energy management by captive solutions and services.

B.6.4 ELECTRIC SCHOOL BUS FUND

Through funding via the Oregon Clean Fuels Program (CFP), PGE provides grant funding to school districts to cover the incremental cost of the electric school buses (the difference in cost between a standard diesel bus and an electric bus) and the total installation of charging infrastructure. PGE also provides technical assistance to school districts throughout the process, including site assessments, cost-benefit analysis, vehicle and charger selection support, and driver and mechanic support. In return, participating school districts work with PGE to share their insights and learnings with other school districts interested in electrifying their bus fleets.

As the electric school buses come online and become operational, we are collecting load data to analyze how this charging use case compares to other EV types. At the time of filing, only one district had buses operational. **Figure 46** below summarizes usage at the Beaverton School District's two electric school buses.

Figure 46. Electric school bus energy delivery at Beaverton school district pilot site



We are interested in the ability of school buses to act as a flexible DER asset for the grid, particularly given that school buses may be docked more often during summer months, making them good candidates for future vehicle-to-grid applications.

In 2020, the school bus fund funded a total of six electric school buses for the Beaverton, Newberg, Portland, Reynolds and Salem/Keizer school districts.

B.6.5 FLEET CARMA PILOT STUDY

PGE launched an electric vehicle charging study to better understand vehicle usage and charging behavior in the service territory and how charging can be shaped through time of use incentives. Improving our understanding of vehicle use and behavior-based strategies to reshape load are critical to the successful integration of the widespread EV adoption expected in coming years. The study includes roughly 200 participants, comprised of a 100-customer control group and a 100-customer treatment group randomly assigned to one of three time of use incentive structures. Enrollment in the project closed in December of 2020 and data will be collected through the end of 2022. Vehicle charging data is being used to inform various load research efforts within PGE and to understand current EV driver preferences between home and public charging.

B.6.6 POLE CHARGING PILOT

In order to study opportunities to make EV charging more accessible and convenient, PGE has introduced a Utility Pole Mounted EV charging pilot in collaboration with City of Portland. Installing chargers on utility poles could offer a cost-effective way to increase access to chargers in traditionally underserved areas or in areas with limited access to off-street parking. As more Oregonians adopt EVs, innovative charging options like these are needed to support those without access to home charging.

During the first phase of the pilot, we installed two chargers in the SE Clinton neighborhood of Portland. Customers have shown high satisfaction with the chargers, giving them a 10 out of 10 rating on PlugShare.[153] PGE also received comments such as, "Absolutely love the idea of these stations. I would gladly pay to have more around," and "I wish these were located all over the city." Currently the chargers are free to use, with plans to switch to pay-for-use under Schedule 50. Preliminary data collected during the pilot can be found below in **Table 64**.

Table 64. Pole charging pilot key performance indicators

Key performance indicator	SE 29th Ave.	SE 35th Pl.
kWh used	16,826	18,479
Number of unique users	296	256
Number of sessions	1,076	1,044
Number of sessions per day	2.07	2.01
Average duration of stay	4 hours, 3 minutes and 8 seconds	4 hours, 37 minutes and 6 seconds
Average charging time	2 hours, 53 minutes and 45 seconds	3 hours, 2 minutes and 45 seconds

153. Available at: plugshare.com

Appendix C. Annual net metering report

RE: PGE's Division 39 Net Metering Annual Report

Pursuant to OAR 860-039-0070(2), on April 1, 2021, PGE submitted the Company's annual report on: a) the total number of net metering facilities by resource type, and b) the total estimated rated generating capacity of net metering facilities by resource type. This report is based on end of year 2020 information available to the Company.

PGE's cumulative installed net metering capacity year end of 2020 surpassed the 'soft cap' level described in ORS 757.300(6). One-half of one percent of PGE's historic system peak of 4,073 MW equates to 20.4 MW of net metering capacity. PGE currently exceeds the cap more than five times over with about 107.8 MW of net metered capacity.[154]

PGE reiterates our concern that as the MW total of net metered generation continues to grow, these customers may avoid fair contributions to the fixed costs of PGE's distribution, transmission, and generation facilities that, despite the production of the customer-generator, provide the same benefits to the net metered customer compared to a non-participating customer. As a result, non-participating customers subsidize net metering customers. With the Commission's approval of PGE's Resource Value of Solar (RVOS) rate, in Order No. 19-023, the subsidy to net metering customers becomes more explicit. The net metering subsidy is the difference between the retail net metering rate and the RVOS, more than half the retail net metering rate, meaning compensation to net metering customers is about two times the value the net metering system provides.

154. PGE 2021 Annual Net Metering Report. OAR 860-039-0070(2), available at: edocs.puc.state.or.us

Appendix D. Annual small generator report

RE: Division 82 Small Generator Interconnection Report

Pursuant to OAR 860-082-0065(3), on May 27, 2021, PGE submitted the Company's annual report on interconnection activities based on end of year 2020, including:[155]

- The number of complete small generator interconnection applications received;
- The number of small generator facility interconnections completed;
- The types of small generator facilities applying for interconnection and the
- nameplate capacity of the facilities;
- The location of completed and proposed small generator facilities by zip code;
- For each Tier 3 and Tier 4 small generator interconnection approval, the basic
- telemetry configuration, if applicable; and
- For each Tier 4 small generator interconnection approval:

  (A) The interconnection facilities required to accommodate the interconnection of a small generator facility and the estimated costs of those facilities; and

  (B) The system upgrades required to accommodate the interconnection of a small generator facility and the estimated costs of those upgrades.

155. PGE 2021 Small Generator Report. 860-082-0065(3), available at: apps.puc.state.or.us

Appendix E. Annual reliability report

RE: PGE 2020 Annual Reliability Report

Pursuant to OAR 860-023-0151, on April 29, 2021, PGE submitted the Company's 2020 Annual Reliability Report.[156]

Attachment A of the 2020 Annual Reliability report provides Section III, Feeder Performance Summary.

156. PGE 2020 Annual Reliability Report. OAR 860-023-0151, available at: edocs.puc.state.or.us

Appendix F. DSP and IRP interactions

This appendix provides answers to common participant questions around DSP and IRP interactions with respect to DER modeling.

1. How does PGE ensure the IRP process accurately accounts for the contribution of DERs to minimize supply side investment?

   - To understand the system- level and locational impacts of the DERs, PGE has created a new bottom-up forecasting model, named AdopDER. AdopDER calculates the technical and economic potential of DER programs, and the market adoption of electric vehicles (EVs), photovoltaics (PVs), building electrification measures, and storage at the site level. AdopDER is a true bottom-up forecasting model that simulates decision making at the site level accounting for economics and site constraints such as panel capacity, availability of a garage, and other building characteristics to determine the probability of DER adoption.

   - The AdopDER model leverages state of the art tools from the National Labs such as the National Renewable Energy Laboratory (NREL). PGE believes these state-of-the-art tools combined with the open-source nature of the AdopDER model provides the most flexibility in modeling different DER characteristics comprehensively in a collaborative manner with stakeholders and third-party experts. Additionally, PGE expects the tools to evolve to better support the IRP process by leveraging the in-built stochasticity to perform complex probabilistic simulations to determine the adoption probabilities under different scenarios providing new insights on the range of contributions from DERs under each scenario.

   - With this new model, we have improved our in-house capabilities enabling repeatability, scalability, and frequency of understanding DER adoption at the site level. In Part 2 of the DSP, expected to be filed in August 2022, PGE will elaborate on these results by highlighting the more granular impacts such as locational proliferation by each DER.

   - PGE notes that front-of-meter investments from DER developers cannot be captured within AdopDER and will likely be reflected through interconnection request data that is integrated into the planning processes.

   - A combination of the AdopDER's mathematical approach, and its open framework, ensuring a robust peer review process, enables PGE to accurately address the impacts of DERs in the IRP.

2. In modeling the DER programs, how is PGE ensuring DERs are valued accurately relative to supply side option?

   - As noted in **Section 8.2**, PGE is evolving its cost-effectiveness methodology, aligning it with the National Standard Practice Manual and regional approaches. With this update, PGE will create a transparent method of valuing DERs and accounting for their societal benefits. This methodology will be integrated with AdopDER enabling stakeholders to see a clear relationship between DER valuation and its adoption.

     Additionally, the AdopDER model also develops supply curves for non-cost-effective DERs that will be fed into the IRP's ROSE-E resource optimization engine. PGE believes this approach, addressing cost-effective and non-cost effective DERs, provide a platform that comprehensively accounts for DER value.

3. How does PGE ensure DERs are evaluated through robust scenarios accounting for variations in weather and cost curves?

   - PGE's approach to the AdopDER model was to align the load scenarios with the IRP process. Additionally, the model also runs three adoption scenarios based on different cost curves and policy futures. Combined, these provide nine outputs based on different load and adoption scenarios. Additionally, AdopDER has significant stochasticity impacting the analytics at the site and system level. Combined, we feel this provides a robust platform to ensure PGE is accounting for different futures. Over time, as we establish clear feedback loops of data, the model outputs will become more robust.

4. How does PGE account for the interactive effects of DERs within the IRP?

   - Determining the net impact of DERs at a site is a complex analytical process considering the interactive effects, which are accounted within AdopDER. PGE models programmatic measures with their expected interactive effects at the site level. Additionally, during the IRP process, DERs are considered part of the portfolio mix to determine the Effective Load Carrying Capability (ELCC) using the last-in method to determine the interactive effects of DERs with other supply-side resources accounting for portfolio interactive effects as well.

5. How does PGE holistically account for the impacts of transportation electrification on the grid, specifically focusing on impacts on the distribution and transmission system and resource adequacy?

   - The AdopDER tool provides a locational forecast of the market and programmatic adoption of EVs. These include customers that would opt for managed charging and other DER programs. This forecast is then integrated with the distribution planning process to determine the distribution system impact. Within the distribution planning process, transmission impacts are communicated to the transmission planning team ensuring transmission impacts of EVs are accounted for.

   - From an IRP perspective, the AdopDER tool provides market adoption and programmatic adoption of EVs, each with their respective load profile. The aggregated impact at the system level is calculated to determine peak impact and is integrated within the load forecast. The load forecast is the first step in determining resource adequacy needs. In cases where sites with EVs include other DERs, each DERs impact is individually calculated at the system level and provided to the IRP team.

Appendix G. PGE DER and flexible-load potential – phase 1

PGE has conducted an assessment to understand the potential adoption and impacts of distributed energy resources, and electrification in support of its Integrated Resource Plan and ongoing Distribution System Planning as outlined in UM 2005. This work was undertaken by Cadeo in close collaboration with Ethan Goldman (independent), the Brattle Group, and Lighthouse Consulting (hereafter, the "Cadeo team"). To meet the evolving needs of PGE and its stakeholders, the Cadeo team worked closely with PGE to develop an open modeling framework. The framework integrates true bottom-up modeling of the building and vehicle stock with market-level adoption forecasts to create a rich, integrated view of how different DER and electrification technologies complement and compete under different conditions. The AdopDER model that we developed with PGE represents a paradigmatic shift in how potentials are modeled and lays the foundation for continued evolution in planning processes across the energy system.

Phase I is the first of a two-phase process to estimate potentials. In this phase, we estimated system-wide potential to inform the IRP. In Phase II, we will estimate locational adoption of these resources, fine-tune 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 will be used to inform PGE's forthcoming Distribution System Plan (Part II) and ongoing customer program planning efforts.[157]

157. PGE DER and Flexible Load Potential – Phase 1, available at: Distribution System Planning | PGE

Appendix H. Community engagement report

PGE has partnered with the Coalition of Communities of Color (CCC), Unite Oregon, and Community Energy Project (CEP) to develop, facilitate, and synthesize findings from two pilot workshops designed to engage Black, Indigenous, and people of color (BIPOC), immigrant and refugee, and low-income communities in Oregon. The two pilot workshops are part of community engagement activities that utility agencies are required to perform by the Oregon Public Utility Commission's (OPUC) Distribution Systems Planning (DSP) Guidelines. The pilot workshops were held on Saturday, May 22 and Sunday, May 23 and each lasted for three hours (9am-noon). Participants were provided with a $250 stipend for attending both workshops.

The purpose of this report is to share back with PGE the results of feedback from participants and partner teams (Unite, CEP, CCC). The report concludes with recommendations for PGE's Community Engagement Plan.[158]

158. Distribution Systems Planning (DSP) Community Engagement Best Practices and Recommendations, available at: [Distribution System Planning | PGE]

Appendix I. Community engagement CBO slides

Distributed Systems Planning Pilot Workshops: Summary & Evaluation of Community Feedback.[159]

Distribution systems planning pilot workshops:
Summary and evaluation of community feedback

Coalition of Communities of Color

unite oregon

COMMUNITY ENERGY PROJECT

Empowering People – One Home at a Time

PGE

159. Distributed Systems Planning Pilot Workshops: Summary & Evaluation of Community Feedback, available at: Distribution System Planning | PGE

Appendix J. Portland General Electric: Use and applications of EPA's EJSCREEN

The term environmental justice (EJ) describes a variety of regulatory initiatives aimed at addressing adverse environmental impacts that historically have disproportionally impacted disadvantaged communities. A number of these initiatives, at both the federal and state level, could potentially or even directly affect PGE's operations. State-level legislation requires utilities to communicate effectively with a wide variety of customer groups and federal policies encourage agencies to foster effective engagement during permitting actions and enhanced compliance enforcement efforts in EJ communities. It will be increasingly important for PGE to recognize demographic differences, not only in the communities we serve, but also those surrounding our current and future generation, transmission and distribution assets. Failure to do so has the potential to undermine our standing in the community and to interrupt permitting activities, resulting in project delays and increased costs.

EPA's EJSCREEN paper is intended to introduce the reader to EJ issues, providing historical and regulatory context, as well as to highlight aspects of PGE's operations that may be affected. In addition, we provide detailed information on EJSCREEN, an important web-based tool developed by the Environmental Protection Agency (EPA), that can be used to identify geographic areas with potential EJ vulnerabilities.[160]

160. Portland General Electric: Use and Applications of EPA's EJSCREEN, available at: Distribution System Planning | PGE

Appendix K. OASIS dataset

In June 2019, the Oregon Public Utility Commission issued Order 19-217 which stipulated that utilities provide the following data and publish it on OASIS docket UM 2001.

In a subsequent interconnection docket, UM 2099, the OPUC issued Order 20-402 that stipulated this data be published twice annually docket UM 2099.[161]

PGE Oregon Small Generator Interconnection Queue (under OAR 860-082)

As of 10/01/2021

DISCLAIMER: The Queue is a dynamic database that can change from day to day as projects submit or withdraw interconnection requests or commence operation. Please keep in mind that not all proposed interconnection projects are built. Additionally, this queue only addresses small generator facilities (nameplate capacity of 10MW or less) and does not include FERC jurisdictional projects. It is the sole responsibility of users of this website and this information to independently verify the process to interconnect a small generator facility, as well as the status of any changes, pending changes, or updates to said process. PGE shall not be held liable under any circumstances for any errors, omissions, inaccurate, and/or out-of-date content or information provided herein. PGE MAKES NO WARRANTY OF MERCHANTIBILITY OR FITNESS FOR ANY PARTICULAR PURPOSE AND DISCLAIMS ANY AND ALL LIABLITY WITH RESPECT TO THE ACCURACY OF THE INFORMATION PROVIDED HEREIN OR THE FITNESS OR APPROPRIATENESS OF THE INFORMATION FOR ANY PARTICULAR USE OR THAT THIS INFORMATION IS CURRENT OR UP-TO-DATE. THIS INFORMATION IS SUPPLIED WITH ALL FAULTS.

Queue#	Application Date	Tier	QF Status	MW	Energy Source	Point of Interconnection	Substation	County	Customer Requested Commercial Operation Date	Status
SPQ0001	4/20/15	Tier 4	QF	0.5	Solar	Willamina-Buell	Willamina	Polk		Withdrawn
SPQ0002	6/5/15	Tier 4	QF	2.2	Solar	Grand Ronde-Fort Hill	Grand Ronde	Polk		Completed
SPQ0003	7/21/15	Tier 4	QF	2.2	Solar	Waconda 13	Waconda	Marion		Completed
SPQ0004	7/23/15	Tier 4	QF	2.2	Solar	Sheridan-Kadell	Sheridan	Polk		Completed
SPQ0005	8/29/15	Tier 4	QF	2.2	Solar	Silverton-North	Silverton	Marion		Completed
SPQ0006	9/2/16	Tier 4	QF	2.2	Solar	Turner-Cascade	Turner	Marion		Completed
SPQ0007	1/25/16	Tier 4	QF	2.2	Solar	Silverton-West	Silverton	Marion	4/1/19	Completed
SPQ0008	3/12/16	Tier 4	QF	2.2	Solar	Silverton-West	Silverton	Marion	5/14/20	Completed
SPQ0009	4/7/16	Tier 4	QF	2.2	Solar	Banks-13	Banks	Yamhill		Withdrawn
SPQ0010	4/20/16	Tier 4	QF	3	Solar	Dunns Corner-13	Dunns Corner	Clackamas	12/31/18	Completed
SPQ0011	4/20/16	Tier 4	QF	2.2	Solar	Sheridan-East	Sheridan	Polk	6/1/19	Completed
SPQ0012	4/28/16	Tier 4	QF	10	Solar	Sheridan-Kadell	Sheridan	Yamhill	5/24/19	Completed
SPQ0013	5/4/16	Tier 4	QF	10	Solar	Sandy-13	Sandy	Clackamas	11/30/19	Completed
SPQ0014	4/29/16	Tier 4	QF	10	Solar	Estacada-13	Estacada	Clackamas	11/24/19	Completed
SPQ0015	4/29/16	Tier 4	QF	2.19	Solar	Springbrook-Zimri	Springbrook	Yamhill	9/26/19	Withdrawn
SPQ0016	4/29/16	Tier 4	QF	6	Solar	Amity-13	Amity	Yamhill	1/31/20	Withdrawn
SPQ0017	4/30/16	Tier 4	QF	2.2	Solar	Scoggins-Laurelwood	Scoggins	Washington	1/26/19	Completed
SPQ0018	4/30/16	Tier 4	QF	2.2	Solar	St Louis-West	St Louis	Marion	10/31/19	Completed
SPQ0019	7/23/15	Tier 4	QF	2.2	Solar	Dayton-S&W	Dayton	Yamhill		Completed
SPQ0020	4/30/16	Tier 4	QF	2.2	Solar	Barnes-Battle Creek	Barnes	Marion	2/26/19	Completed
SPQ0021	6/17/16	Tier 4	QF	2.2	Solar	Indian-North	Indian	Marion	10/31/18	Completed
SPQ0022	6/17/16	Tier 4	QF	2.2	Solar	Willamina-Buell	Willamina	Yamhill	2/26/19	Withdrawn
SPQ0022A	6/17/16	Tier 4	QF	2.2	Solar	St Louis-North	St Louis	Marion	2/26/19	Completed
SPQ0023	7/23/15	Tier 4	QF	2.2	Solar	Colton-Dhoogie	Colton	Marion		Completed
SPQ0024	7/23/15	Tier 4	QF	2.2	Solar	Wallace-13	Wallace	Marion		Completed
SPQ0025	4/30/16	Tier 4	QF	2.2	Solar	Dayton-S&W	Dayton	Yamhill	5/24/19	Completed
SPQ0026	7/23/15	Tier 4	QF	2.2	Solar	Eagle Creek-River Mill	Eagle Creek	Clackamas	6/8/18	Withdrawn
SPQ0027	8/17/16	Tier 4	QF	2.2	Solar	Estacada-North Fork	Estacada	Clackamas	9/7/18	Completed

161. OASIS data (Generation Interconnection > Oregon Small Generator Interconnection), available at: OATI OASIS

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As of 10/01/2021

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Queue#	Application Date	Tier	QF Status	MW	Energy Source	Point of Interconnection	Substation	County	Customer Requested Commercial Operation Date	Status
SPQ0030	9/7/16	Tier 4	QF	1.85	Solar	Sandy-Wildcat	Sandy	Clackamas	12/1/18	Completed
SPQ0031	9/23/16	Tier 4	QF	2.2	Solar	Colton-Greys Hill	Colton	Clackamas	9/4/20	Withdrawn
SPQ0032	9/23/16	Tier 4	QF	2.2	Solar	Mt Angel-West	Mt Angel	Marion	1/17/20	Completed
SPQ0033	9/23/16	Tier 4	QF	2.2	Solar	St Louis-West	St Louis	Marion	12/16/19	Withdrawn
SPQ0034	9/23/16	Tier 4	QF	2.2	Solar	Amity-13	Amity	Yamhill	12/16/19	Withdrawn
SPQ0035	9/23/16	Tier 4	QF	2.2	Solar	Liberal-13	Liberal	Clackamas	4/20/20	Completed
SPQ0036	9/23/16	Tier 4	QF	2.2	Solar	Middle Grove-Cordon	Middle Grove	Marion	7/5/19	Completed
SPQ0037	9/23/16	Tier 4	QF	2.2	Solar	Scotts Mills 13	Scotts Mills	Marion		Withdrawn
SPQ0038	11/9/16	Tier 4	QF	2.2	Solar	Molalla-Marquam	Molalla	Clackamas	5/14/20	Completed
SPQ0039	11/9/16	Tier 4	QF	2.2	Solar	Dayton-S&W	Dayton	Yamhill	11/29/19	Withdrawn
SPQ0040	11/29/16	Tier 4	QF	2.5	Solar	Turner-13	Turner	Marion		Withdrawn
SPQ0041	11/29/16	Tier 4	QF	2.5	Solar	Turner-13	Turner	Marion		Withdrawn
SPQ0042	12/22/16	Tier 4	QF	2.29	Solar	Dilley-13	Dilley	Yamhill	9/26/19	Withdrawn
SPQ0043	12/20/16	Tier 4	QF	10	Solar	Brightwood-Rhododendron	Brightwood	Clackamas	9/30/19	Withdrawn
SPQ0044	1/27/17	Tier 4	QF	2.2	Solar	Yamhill-Yamhill 13	Yamhill	Yamhill	12/1/18	Withdrawn
SPQ0045	1/27/17	Tier 4	QF	0.75	Solar	Indian-North	Indian	Marion	5/14/20	Completed
SPQ0046	1/30/17	Tier 4	QF	2.5	Solar	Scotts Mills 13	Scotts Mills	Marion	2/3/20	Withdrawn
SPQ0047	1/30/17	Tier 4	QF	2.5	Solar	Colton-Greys Hill	Colton	Clackamas	4/13/20	Withdrawn
SPQ0048	1/30/17	Tier 4	QF	2.5	Solar	Waconda 13	Waconda	Marion	2/18/21	Withdrawn
SPQ0049	3/31/17	Tier 4	QF	4	Solar	Boring-City	Boring	Clackamas	3/31/20	Completed
SPQ0050	3/31/17	Tier 4	QF	2	Solar	Boring-City	Boring	Clackamas		Withdrawn
SPQ0051	10/20/17	Tier 4	QF	2	Solar	Dunns Corner-13	Dunns Corner	Clackamas		Withdrawn
SPQ0052	3/31/17	Tier 4	QF	2	Solar	Liberal-13	Liberal	Clackamas		Withdrawn
SPQ0053	3/31/17	Tier 2	QF	2	Solar	Liberal-13	Liberal	Clackamas		Withdrawn
SPQ0054	3/31/17	Tier 2	QF	2	Solar	Scotts Mills 13	Scotts Mills	Marion		Withdrawn
SPQ0055	3/31/17	Tier 4	QF	4	Solar	Mt Angel-West	Mt Angel	Marion		Withdrawn
SPQ0056	3/31/17	Tier 2	QF	2	Solar	St Louis-East	St Louis	Marion	12/17/18	Completed
SPQ0057	3/31/17	Tier 2	QF	2	Solar	St Louis-East	St Louis	Marion	12/17/18	Withdrawn
SPQ0058	4/3/17	Tier 4	QF	2.2	Solar	Sheridan-Kadell	Sheridan	Yamhill	11/16/19	Under Construction
SPQ0059	4/6/17	Tier 4	QF	8	Solar	Bethel-Mt Angel	Bethel	Marion		Withdrawn
SPQ0060	4/6/17	Tier 4	QF	6	Solar	Dunns Corner-13	Dunns Corner	Clackamas		Withdrawn
SPQ0061	4/13/17	Tier 2	QF	2	Solar	Banks-13	Banks	Washington		Withdrawn
SPQ0062	4/13/17	Tier 4	QF	4	Solar	Banks-13	Banks	Washington		Withdrawn
SPQ0063	4/13/17	Tier 2	QF	2	Solar	North Marion-Hubbard	North Marion	Marion		Withdrawn
SPQ0064	4/13/17	Tier 4	QF	5	Solar	North Marion-Sullivan	North Marion	Marion		Withdrawn
SPQ0065	4/13/17	Tier 2	QF	2	Solar	Fargo-13	Fargo	Marion	12/17/18	Completed
SPQ0066	4/13/17	Tier 4	QF	2	Solar	Middle Grove-Cordon	Middle Grove	Marion	2/17/20	Completed
SPQ0067	4/19/17	Tier 4	QF	2.552148	Solar	Dunns Corner-Kelso	Dunns Corner	Clackamas	1/8/20	Under Construction
SPQ0068	4/19/17	Tier 4	QF	2.5	Solar	Dayton-Lafayette	Dayton	Yamhill	5/1/20	Withdrawn
SPQ0069	5/9/17	Tier 4	QF	2	Solar	Molalla-Marquam	Molalla	Clackamas	11/15/19	Completed
SPQ0070	6/1/17	Tier 4	QF	2.2	Solar	Dunns Corner-13	Dunns Corner	Clackamas	2/17/20	Completed

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SPQ0071	6/1/17	Tier 4	QF	1.85	Solar	Dunns Corner-13	Dunns Corner	Clackamas	12/2/19	Under Construction
SPQ0072	6/12/17	Tier 4	QF	2.97	Solar	Molalla-Marquam	Molalla	Clackamas		Withdrawn
SPQ0073	6/12/17	Tier 4	QF	2.97	Solar	Scotts Mills 13	Scotts Mills	Marion		Withdrawn
SPQ0074	6/12/17	Tier 4	QF	2.97	Solar	Scotts Mills 13	Scotts Mills	Marion		Withdrawn
SPQ0075	5/9/17	Tier 4	QF	2	Solar	Woodburn-East	Woodburn	Marion	2/7/20	Completed
SPQ0076	6/15/17	Tier 2	QF	2	Solar	Molalla-Marquam	Molalla	Clackamas		Withdrawn
SPQ0077	6/15/17	Tier 2	QF	2	Solar	Sandy-362ND	Sandy	Clackamas		Withdrawn
SPQ0078	6/15/17	Tier 2	QF	2	Solar	Sandy-362ND	Sandy	Clackamas		Withdrawn
SPQ0079	6/15/17	Tier 4	QF	2	Solar	Canby-Butteville	Canby	Clackamas		Withdrawn
SPQ0080	10/20/17	Tier 4	QF	4	Solar	Yamhill-Carlton	Yamhill	Yamhill		Withdrawn
SPQ0081	6/15/17	Tier 2	QF	2	Solar	Yamhill-Carlton	Yamhill	Yamhill		Withdrawn
SPQ0082	6/21/17	Tier 4	QF	2.97	Solar	Molalla-Marquam	Molalla	Clackamas		Withdrawn
SPQ0083	6/21/17	Tier 4	QF	3	Solar	Canby-Zimmerman	Canby	Clackamas		Withdrawn
SPQ0084	7/19/17	Tier 3	Other	3	Diesel	Shute	Shute	Washington	2/19/19	Completed
SPQ0085	7/11/17	Tier 4	QF	2.97	Solar	Molalla-Forest	Molalla	Clackamas		Withdrawn
SPQ0085a	7/14/17	Tier 4	QF	10	Solar	Liberal-13	Liberal	Clackamas		Withdrawn
SPQ0085b	7/14/17	Tier 4	QF	5	Solar	Eagle Creek-River Mill	Eagle Creek	Clackamas		Withdrawn
SPQ0085c	7/14/17	Tier 4	QF	2.5	Solar	Turner-Cascade	Turner	Marion		Withdrawn
SPQ0086	7/17/17	Tier 4	QF	2	Solar	Liberal-13	Liberal	Clackamas	11/15/19	Completed
SPQ0087	7/17/17	Tier 4	QF	2	Solar	Mt Angel-West	Mt Angel	Marion		Withdrawn
SPQ0088	7/21/17	Tier 4	QF	1.26	Solar	Unionvale-13	Unionvale	Yamhill	4/16/19	Withdrawn
SPQ0089	7/21/17	Tier 4	QF	3	Solar	Unionvale-13	Unionvale	Yamhill		Withdrawn
SPQ0090	7/21/17	Tier 4	QF	2.79	Solar	Redland-13	Redland	Clackamas	4/26/19	Completed
SPQ0091	7/21/17	Tier 4	QF	2.97	Solar	Leland-Beavercreek	Leland	Clackamas		Withdrawn
SPQ0092	7/24/17	Tier 4	QF	2	Solar	Leland-Carus	Leland	Clackamas		Withdrawn
SPQ0093	7/24/17	Tier 4	QF	2	Solar	Scotts Mills 13	Scotts Mills	Clackamas	2/18/20	Interconnection Agreement
SPQ0094	7/24/17	Tier 4	QF	2	Solar	Molalla-Marquam	Molalla	Clackamas	11/18/19	Under Construction
SPQ0095	8/10/17	Tier 4	QF	2.97	Solar	Silverton-West	Silverton	Marion	8/15/19	Completed
SPQ0096	8/10/17	Tier 4	QF	2.97	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0097	8/10/17	Tier 4	QF	2.97	Solar	Sandy-13	Sandy	Clackamas		Withdrawn
SPQ0098	8/10/17	Tier 4	QF	2.16	Solar	Wilsonville-Charbonneau	Wilsonville	Marion	9/30/20	Completed
SPQ0099	8/10/17	Tier 4	QF	4	Solar	Amity-Bellevue	Amity	Yamhill		Withdrawn
SPQ0100	8/10/17	Tier 4	QF	2.97	Solar	Eagle Creek-River Mill	Eagle Creek	Clackamas		Withdrawn
SPQ0101	8/10/17	Tier 4	QF	2.97	Solar	Willamina-Bridge	Willamina	Polk	3/12/19	Completed
SPQ0102	8/21/17	Tier 4	QF	2.565	Solar	Dunns Corner-13	Dunns Corner	Clackamas	11/29/19	Completed
SPQ0103	8/21/17	Tier 4	QF	2.97	Solar	Indian-North	Indian	Marion		Withdrawn
SPQ0104	8/21/17	Tier 4	QF	2.97	Solar	Carver-13	Carver	Clackamas		Withdrawn
SPQ0105	8/21/17	Tier 4	QF	2.97	Solar	Cornelius-Verboort	Cornelius	Washington		Withdrawn
SPQ0106	8/21/17	Tier 4	QF	3	Solar	Sheridan-East	Sheridan	Yamhill	2/18/20	Completed
SPQ0107	9/5/17	Tier 4	QF	2.97	Solar	Six Corners-Borchers	Six Corners	Washington		Withdrawn

PGE Oregon Small Generator Interconnection Queue (under OAR 860-082)

As of 10/01/2021

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Queue#	Application Date	Tier	QF Status	MW	Energy Source	Point of Interconnection	Substation	County	Customer Requested Commercial Operation Date	Status
SPQ0108	9/5/17	Tier 4	QF	2.97	Solar	Molalla-Yoder	Molalla	Clackamas	4/28/19	Completed
SPQ0109	9/5/17	Tier 4	QF	2.97	Solar	Sandy-Wildcat	Sandy	Clackamas		Withdrawn
SPQ0110	9/1/17	Tier 4	QF	1.85	Solar	Silverton-West	Silverton	Marion		Withdrawn
SPQ0111	7/14/17	Tier 4	QF	2.2	Solar	Molalla-Marquam	Molalla	Clackamas		Withdrawn
SPQ0112	11/6/17	Tier 4	QF	4	Solar	Turner-13	Turner	Marion		Withdrawn
SPQ0113	12/7/17	Tier 4	QF	3	Solar	Silverton-West	Silverton	Marion		Withdrawn
SPQ0114	12/7/17	Tier 4	QF	2.97	Solar	Molalla-Forest	Molalla	Clackamas		Withdrawn
SPQ0115	12/7/17	Tier 4	QF	2.97	Solar	Willamina-Bridge	Willamina	Polk		Withdrawn
SPQ0116	12/7/17	Tier 4	QF	2.97	Solar	Willamina-Bridge	Willamina	Polk		Withdrawn
SPQ0117	12/7/17	Tier 4	QF	2.97	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0118	12/1/17	Tier 4	QF	2.2	Solar	Molalla-Forest	Molalla	Clackamas		Withdrawn
SPQ0119	12/7/17	Tier 4	QF	3	Solar	Amity-13	Amity	Yamhill		Withdrawn
SPQ0120	12/7/17	Tier 4	QF	3	Solar	Turner-13	Turner	Marion		Withdrawn
SPQ0121	12/7/17	Tier 4	QF	2.16	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0122	12/13/17	Tier 4	QF	2	Solar	Wallace-13	Wallace	Polk	3/30/20	Withdrawn
SPQ0123	12/13/17	Tier 4	QF	2.5	Solar	Leland-Beavercreek	Leland	Clackamas	12/31/19	Withdrawn
SPQ0124	12/13/17	Tier 4	QF	2.5	Solar	Molalla-Marquam	Molalla	Clackamas	5/8/20	Completed
SPQ0125	12/13/17	Tier 4	QF	2.349551	Solar	Woodburn-East	Woodburn	Marion	9/23/21	Completed
SPQ0126	12/13/17	Tier 4	QF	2.5	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0127	12/14/17	Tier 4	QF	2.5	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0128	12/14/17	Tier 4	QF	2	Solar	Willamina-Bridge	Willamina	Polk		Withdrawn
SPQ0129	12/14/17	Tier 4	QF	2.5	Solar	Wallace-13	Wallace	Yamhill		Withdrawn
SPQ0130	12/18/17	Tier 4	QF	2.5	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0131	12/18/17	Tier 4	QF	2.5	Solar	Molalla-Marquam	Molalla	Clackamas	5/6/20	Withdrawn
SPQ0132	1/2/18	Tier 4	QF	2.97	Solar	Cornelius-Verboort	Cornelius	Washington	2/28/20	Completed
SPQ0133	1/2/18	Tier 4	QF	2.97	Solar	Sheridan-East	Sheridan	Yamhill		Withdrawn
SPQ0134	1/2/18	Tier 4	QF	2.16	Solar	Silverton-North	Silverton	Marion		Withdrawn
SPQ0135	1/2/18	Tier 4	QF	2.97	Solar	Boring-City	Boring	Clackamas		Withdrawn
SPQ0136	1/2/18	Tier 4	QF	2.97	Solar	Bethel-Geer	Bethel	Marion		Withdrawn
SPQ0137	1/2/18	Tier 4	QF	2.97	Solar	North Plains-13	North Plains	Washington		Withdrawn
SPQ0138	1/2/18	Tier 4	QF	2	Solar	Grand Ronde-Agency	Grand Ronde	Polk		Withdrawn
SPQ0139	1/2/18	Tier 4	QF	2.97	Solar	Woodburn-Tomlin	Woodburn	Marion	9/10/19	Withdrawn
SPQ0140	1/2/18	Tier 4	QF	3	Solar	Wallace-13	Wallace	Marion	1/24/20	Withdrawn
SPQ0141	1/2/18	Tier 4	QF	3	Solar	Turner-13	Turner	Marion		Withdrawn
SPQ0142	1/2/18	Tier 4	QF	3	Solar	Waconda-River	Waconda	Marion		Withdrawn
SPQ0143	1/2/18	Tier 4	QF	2.97	Solar	Canby-Zimmerman	Canby	Clackamas	8/10/20	Withdrawn
SPQ0144	1/2/18	Tier 4	QF	2.97	Solar	Turner-Cascade	Turner	Marion		Withdrawn
SPQ0145	1/2/18	Tier 4	QF	2.97	Solar	Turner-13	Turner	Marion		Withdrawn
SPQ0146	1/2/18	Tier 4	QF	3	Solar	Silverton-West	Silverton	Marion		Withdrawn
SPQ0147	1/2/18	Tier 4	QF	1.26	Solar	Unionvale-13	Unionvale	Marion		Withdrawn
SPQ0148	1/21/18	Tier 4	QF	2.97	Solar	Estacada-13	Estacada	Clackamas		Withdrawn

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SPQ0149	1/21/18	Tier 4	QF	2.97	Solar	Sheridan-Kadell	Sheridan	Yamhill	8/16/20	Withdrawn
SPQ0150	1/18/18	Tier 4	QF	0.99	Solar	North Plains-Mason Hill	North Plains	Washington		Withdrawn
SPQ0151	1/18/18	Tier 4	QF	1.26	Solar	Mill Creek-Eastland	Mill Creek	Marion	6/28/19	Completed
SPQ0152	1/2/18	Tier 4	QF	2.5	Solar	Willamina-Buell	Willamina	Polk	4/1/20	Under Construction
SPQ0153	1/15/18	Tier 4	QF	2.97	Solar	North Plains-13	North Plains	Washington		Withdrawn
SPQ0154	1/15/18	Tier 4	QF	2.97	Solar	Silverton-West	Silverton	Marion		Withdrawn
SPQ0155	1/15/18	Tier 4	QF	2.97	Solar	Grand Ronde-Fort Hill	Grand Ronde	Polk		Withdrawn
SPQ0156	1/22/18	Tier 4	QF	2.5	Solar	Scotts Mills 13	Scotts Mills	Clackamas		Withdrawn
SPQ0157	1/29/18	Tier 4	QF	2.5	Solar	Newberg-Dundee	Newberg	Yamhill	12/1/19	Under Construction
SPQ0158	1/29/18	Tier 4	QF	2.5	Solar	Waconda 13	Waconda	Marion	1/25/21	Under Construction
SPQ0159	1/31/18	Tier 4	QF	2.5	Solar	Wallace-13	Wallace	Marion		Withdrawn
SPQ0160	1/31/18	Tier 4	QF	2.5	Solar	Sheridan-Kadell	Sheridan	Yamhill		Withdrawn
SPQ0161	1/31/18	Tier 4	QF	2.5	Solar	Redland-Henrici	Redland	Clackamas		Withdrawn
SPQ0162	1/31/18	Tier 4	QF	2.5	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0163	2/8/18	Tier 4	QF	2.5	Solar	Wallace-13	Wallace	Marion		Under Construction
SPQ0164	2/9/18	Tier 4	QF	1.75	Solar	Bethel-Geer	Bethel	Marion		Under Construction
SPQ0165	2/14/18	Tier 4	QF	2.5	Solar	Wallace-13	Wallace	Marion		Withdrawn
SPQ0166	2/14/18	Tier 4	QF	2.5	Solar	Woodburn-East	Woodburn	Marion	4/27/20	Completed
SPQ0167	3/8/18	Tier 4	QF	2	Solar	Yamhill-Carlton	Yamhill	Yamhill		Withdrawn
SPQ0168	3/8/18	Tier 4	QF	1.75	Solar	Grand Ronde-Fort Hill	Grand Ronde	Polk		Withdrawn
SPQ0169	3/1/18	Tier 4	QF	2.97	Solar	North Plains-13	North Plains	Washington		Withdrawn
SPQ0170	3/1/18	Tier 4	QF	2.97	Solar	Silverton-West	Silverton	Marion		Withdrawn
SPQ0171	3/1/18	Tier 4	QF	3	Solar	Molalla-Marquam	Molalla	Clackamas		Withdrawn
SPQ0172	3/23/18	Tier 4	QF	2.25	Solar	Waconda 13	Waconda	Marion		System Impact Study
SPQ0173	4/23/18	Tier 4	QF	2.97	Solar	Cornelius-Verboort	Cornelius	Washington		Withdrawn
SPQ0174	4/30/18	Tier 4	Other	0.175	Diesel	Brookwood-13	Brookwood	Washington	1/1/19	Completed
SPQ0175	5/23/18	Tier 4	QF	2.97	Solar	Canby-13644	Canby	Clackamas		Withdrawn
SPQ0176	6/4/18	Tier 4	QF	2.56	Solar	Sandy-13	Sandy	Clackamas		Withdrawn
SPQ0177	6/4/18	Tier 4	QF	3	Solar	Woodburn-Tomlin	Woodburn	Marion		Withdrawn
SPQ0178	6/4/18	Tier 4	QF	2.2	Solar	Leland-Beavercreek	Leland	Clackamas		Withdrawn
SPQ0179	1/15/18	Tier 4	QF	2.565	Solar	Grand Ronde-Fort Hill	Grand Ronde	Polk		Under Construction
SPQ0180	7/3/18	Tier 4	QF	2.565	Solar	Estacada-13	Estacada	Clackamas		Under Construction
SPQ0181	7/16/18	Tier 4	QF	2.5	Solar	Yamhill-Yamhill 13	Yamhill	Yamhill		Under Construction
SPQ0182	7/27/18	Tier 4	QF	2.22019	Solar	Dayton-East	Dayton	Yamhill	12/31/19	Under Construction
SPQ0183	9/18/18	Tier 2	QF	1.5	Solar	Liberal-13	Liberal	Clackamas		Withdrawn
SPQ0184	7/31/18	Tier 4	QF	3	Solar	Yamhill-Carlton	Yamhill	Yamhill		Withdrawn
SPQ0185	8/9/18	Tier 4	QF	2.16	Solar	Yamhill-Carlton	Yamhill	Yamhill		Withdrawn
SPQ0186	8/9/18	Tier 4	QF	2.97	Solar	Mt Angel-West	Mt Angel	Marion		Under Construction
SPQ0187	8/9/18	Tier 4	QF	2.97	Solar	Scoggins-Laurelwood	Scoggins	Yamhill		Withdrawn

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SPQ0188	8/9/18	Tier 4	QF	1.98	Solar	Liberal-13	Liberal	Clackamas		Withdrawn
SPQ0189	8/14/18	Tier 4	QF	2.5	Solar	Carver-13	Carver	Clackamas		Withdrawn
SPQ0190	8/16/18	Tier 4	QF	1.8	Solar	North Plains-13	North Plains	Washington		Withdrawn
SPQ0191	8/21/18	Tier 4	QF	2.5	Solar	Leland-Carus	Leland	Clackamas		Under Construction
SPQ0192	9/17/18	Tier 4	QF	1.5	Solar	Liberal-13	Liberal	Clackamas		Withdrawn
SPQ0193	10/11/18	Tier 4	QF	1.98	Solar	Canby-Zimmerman	Canby	Clackamas		Under Construction
SPQ0194	10/11/18	Tier 4	QF	2.16	Solar	Waconda-River	Waconda	Marion		Withdrawn
SPQ0195	10/11/18	Tier 4	QF	2.56	Solar	Silverton-West	Silverton	Marion		Withdrawn
SPQ0196	10/11/18	Tier 4	QF	1.26	Solar	Molalla-Forest	Molalla	Clackamas		Withdrawn
SPQ0197	10/17/18	Tier 4	QF	1.8	Solar	Amity-13	Amity	Yamhill		Withdrawn
SPQ0198	10/17/18	Tier 4	QF	1.8	Solar	Redland-Henrici	Redland	Clackamas		Withdrawn
SPQ0199	10/17/18	Tier 4	QF	1.8	Solar	Wallace-13	Wallace	Marion		Withdrawn
SPQ0200	10/17/18	Tier 4	QF	2.97	Solar	Molalla-Marquam	Molalla	Clackamas		Withdrawn
SPQ0201	10/17/18	Tier 4	QF	2.97	Solar	Leland-Carus	Leland	Clackamas		Withdrawn
SPQ0202	10/17/18	Tier 4	QF	2.565	Solar	Sandy-13	Sandy	Clackamas		Withdrawn
SPQ0203	11/5/18	Tier 4	QF	20	Solar	Grand-Ronde-Sheridan	Grand Ronde	Washington		Withdrawn
SPQ0204	11/7/18	Tier 4	QF	20	Solar	Chemawa BPA-Dayton	Dayton	Marion		Withdrawn
SPQ0205	11/13/18	Tier 4	QF	20	Solar	Banks-Orenco	Banks	Yamhill		Withdrawn
SPQ0206	11/13/18	Tier 4	QF	20	Solar	Leland-Molalla	Leland	Clackamas		Withdrawn
SPQ0207	11/30/18	Tier 4	QF	19.99	Solar	Chemawa BPA-Dayton	Dayton	Marion		Withdrawn
SPQ0208	11/30/18	Tier 4	QF	19.99	Solar	Grand-Ronde-Sheridan	Grand Ronde	Yamhill		Withdrawn
SPQ0209	11/30/18	Tier 4	QF	19.99	Solar	Leland-Molalla	Leland	Clackamas		Withdrawn
SPQ0210	11/30/18	Tier 4	QF	19.99	Solar	Banks-Orenco	Banks	Washington		Withdrawn
SPQ0211	12/7/18	Tier 4	QF	2.99	Solar	Woodburn-Tomlin	Woodburn	Marion		Withdrawn
SPQ0212	1/9/19	Tier 1	Other	0.0012	Other	Harrison-13	Harrison	Multnomah		Completed
SPQ0213	1/11/19	Tier 4	QF	2.2	Solar	Leland-Beavercreek	Leland	Clackamas		Withdrawn
SPQ0214	1/11/19	Tier 4	QF	2.2	Solar	Willamina-Buell	Willamina	Yamhill		Withdrawn
SPQ0215	1/11/19	Tier 4	QF	3.435489	Solar	Banks-13	Banks	Washington	4/15/20	Withdrawn
SPQ0216	2/4/19	Tier 4	QF	2.2	Solar	Molalla-Forest	Molalla	Clackamas		Withdrawn
SPQ0218	3/19/19	Tier 2	QF	0.042491	Solar	Arleta-Harold	Arleta	Multnomah	12/3/19	Withdrawn
SPQ0217	3/7/19	Tier 4	QF	2.988437	Solar	Woodburn-Tomlin	Woodburn	Marion	12/31/19	Completed
SPQ0219	3/13/19	Tier 4	QF	2.42184	Solar	Amity-13	Amity	Yamhill	12/1/20	Withdrawn
SPQ0221	3/14/19	Tier 4	QF	0.000218	Solar	Sunset WR1,2,3,4	Sunset WR1,2,3,4	Washington	3/31/20	Withdrawn
SPQ0220	4/12/19	Tier 4	QF	1.255993	Solar	Molalla-Forest	Molalla	Clackamas	10/15/20	Under Construction
SPQ0248	3/9/20	Tier 2	Other	0.234479	Solar	Tektronix-Ducks	Tektronix	Washington	11/1/19	Completed
SPQ0222	7/1/19	Tier 4	QF	2.970297	Solar	Turner-13	Turner	Marion	12/1/20	Withdrawn
SPQ0223	7/1/19	Tier 4	QF	1.980092	Solar	Waconda-River	Waconda	Marion	12/2/20	Withdrawn
SPQ0224	7/16/19	Tier 4	QF	1.265508	Solar	Boring-City	Boring	Clackamas	11/30/20	Withdrawn
SPQ0225	7/24/19	Tier 4	QF	2.159928	Solar	Turner-13	Turner	Marion	12/1/20	Withdrawn
SPQ0226	8/12/19	Tier 4	QF	2.970297	Solar	Boring-City	Boring	Clackamas	10/10/20	Withdrawn
SPQ0227	8/22/19	Tier 4	QF	1.530659	Solar	Wallace-13	Wallace	Polk	12/25/20	Withdrawn

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SPQ0230	9/10/19	Tier 4	QF	1.530659	Solar	Grand Ronde-Fort Hill	Grand Ronde	Polk	11/28/20	Withdrawn
SPQ0231	9/10/19	Tier 4	QF	2.970144	Solar	Woodburn-Tomlin	Woodburn	Marion	12/25/20	Withdrawn
SPQ0232	9/10/19	Tier 4	QF	1.800257	Solar	Silverton-West	Silverton	Marion	11/28/20	Withdrawn
SPQ0228	8/22/19	Tier 4	QF	2.970931	Solar	Molalla-Marquam	Molalla	Clackamas	12/25/20	Withdrawn
SPQ0229	8/30/19	Tier 4	QF	1.260434	Solar	Boring-City	Boring	Clackamas	10/10/20	Withdrawn
SPQ0233	10/16/19	Tier 4	QF	2.564782	Solar	Grand Ronde-Fort Hill	Grand Ronde	Polk	6/9/21	Interconnection Agreement
SPQ0234	10/16/19	Tier 4	QF	1.79994	Solar	Mulino-South	Mulino	Clackamas	7/7/21	Withdrawn
SPQ0235	10/16/19	Tier 4	QF	0.990205	Solar	Molalla-Forest	Molalla	Clackamas	12/25/20	Withdrawn
SPQ0236	10/16/19	Tier 4	QF	2.565271	Solar	Sandy-Sandy 13	Sandy	Clackamas	6/16/21	Under Construction
SPQ0237	10/16/19	Tier 4	QF	2.160245	Solar	Redland-13	Redland	Clackamas	12/25/20	Withdrawn
SPQ0238	11/14/19	Tier 4	QF	1.980092	Solar	Sandy-Sandy 13	Sandy	Clackamas	6/16/21	Interconnection Agreement
SPQ0241	1/17/20	Tier 3	Other	0.287191	Solar	Tektronix-Ducks	Tektronix	Washington	2/10/20	Completed
SPQ0239	11/15/19	Tier 4	QF	2.999826	Solar	Sheridan-Kadell	Sheridan	Yamhill	12/1/20	Withdrawn
SPQ0240	12/13/19	Tier 4	QF	2.970297	Solar	Wallace-13	Wallace	Polk	3/17/21	Under Construction
SPQ0242	1/15/20	Tier 4	QF	2.565271	Solar	Silverton-West	Silverton	Marion	6/6/21	Withdrawn
SPQ0243	1/30/20	Tier 4	QF	2.970297	Solar	Sandy-Wildcat	Sandy	Clackamas	6/6/21	Withdrawn
SPQ0244	1/30/20	Tier 4	QF	1.530345	Solar	Redland-13	Redland	Clackamas	6/6/21	Withdrawn
SPQ0245	2/5/20	Tier 4	QF	1.800257	Solar	Scotts Mills 13	Scotts Mills	Marion	1/6/21	Withdrawn
SPQ0246	2/14/20	Tier 4	QF	2.970931	Solar	Molalla-Marquam	Molalla	Clackamas	12/25/21	Under Construction
SPQ0247	3/2/20	Tier 4	QF	1.530345	Solar	Scotts Mills 13	Scotts Mills	Marion	1/6/21	Interconnection Agreement
SPQ0248	3/9/20	Tier 2	Other	0.235	Solar	Tektronix-Ducks	Tektronix	Washington	3/31/21	Completed
SPQ0250	5/1/20	Tier 4	QF	2.970931	Solar	Boring-City	Boring	Clackamas	10/14/21	Under Construction
SPQ0251	5/25/20	Tier 4	QF	2.567174	Solar	Rosemont-Hidden Springs	Rosemont	Clackamas	12/12/21	Withdrawn
SPQ0252	7/22/20	Tier 4	Other	1.150502	Solar	Sunset WR1,2,3,4	Sunset WR1,2,3,4	Washington	6/25/21	Interconnection Agreement
SPQ0253	12/4/20	Tier 4	QF	1.260301	Solar	Redland-13	Redland	Clackamas	4/7/22	Interconnection Agreement
SPQ0254	1/13/21	Tier 4	QF	2.995557	Solar	Grand Ronde-Agency	Grand Ronde	Yamhill	10/30/22	Withdrawn
SPQ0255	12/4/20	Tier 3	QF	3.194033	Solar	Mulino-South	Mulino	Clackamas	4/1/21	Withdrawn
SPQ0256	8/19/21	Tier 2	Other	1.83	Other	Wilsonville-Mentortek	Wilsonville	Clackamas	12/31/21	Feasibility Study