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December 18, 2024

Via Electronic Filing

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

Re: Docket No. UM 2197, PGE Distribution System Plan

Filing Center:

Portland General Electric (PGE or the Company) is pleased to submit its 2024 Distribution System Plan (DSP) to the Public Utility Commission of Oregon (OPUC or Commission) for acceptance in compliance with Commission Order No. 24-421.

The DSP describes PGE's comprehensive strategy for building a modern, bi-directional, clean energy grid that is cost-effective and supports customer affordability, electrification and decarbonization. The plan provides the context and vision driving carefully prioritized investments over the next two to four years to address grid modernization, virtual power plant (VPP) platform development and distributed energy resource (DER) integration in addition to traditional infrastructure needs. Taken together, these strategic investments will continue progress begun with PGE's inaugural DSP (Part 1 and Part 2) to establish a reliable system where customers and the utility can exchange resources and benefits to manage costs while meeting the region's growing need for electricity.

In reviewing the plan, we encourage the Commission, Staff and stakeholders to keep in mind:

- While Order No. 24-421 sets a deadline of April 1, 2025 for PGE's next DSP, the Company is filing now to align the DSP planning cycle with PGE's capital planning cycle. This will ensure the Commission has the most current information available regarding proposed investments. Because PGE's IRP/CEP update is due in April as well, filing the DSP now will also offset our DSP and IRP/CEP cycles, allowing each planning process to inform the other and helping to mitigate workload impacts for the Commission and stakeholders.
- The investments and specific projects described in the DSP and appendices are not a request for approval of new incremental spending. The DSP is not a cost-recovery or rate review proceeding. The investments identified in this filing can be expected to shift and change as the action plan is implemented and system needs and priorities are refined. Project cost estimates will also be updated as the Company makes final investment decisions, and requests for cost recovery will occur incrementally through the Commission's standard rate review process as projects are completed over the life of the plan and beyond.
- The benefit cost analysis (BCA) of the activities outlined in PGE's 2024 DSP makes clear that the strategy and investments in the plan bring about greater benefits to customers than costs over the long-term planning horizon. The evolution of the power grid to a bi-directional system

centered on a flexible VPP requires sustained investment on the part of the utility and its customers. The DSP provides insight into the kinds of investment needed to accomplish this transformation and contains PGE's best estimates of costs as they are known today. PGE looks forward to maturing the DSP BCA with input from Commission Staff and stakeholders in this and future planning cycles.

- The DSP discusses PGE's use of non-wires solutions (NWS) to address grid needs, including the need to develop appropriate standards for the application and reliable operation of NWS across the system, which will be facilitated in part by development of the VPP platform. It is also important to recognize, however, that the action plan is focused on descriptions of specific distribution projects, and our distribution engineers routinely look for alternative solutions before projects ever make it to the stage where they would appear in this plan. The plan does not describe projects and investments that were avoided, for instance, by load rebalancing or other practices our engineers and planners consider before recommending a significant infrastructure addition or upgrade. The projects described here are, by definition, the ones that system and engineering analysis have shown to be necessary and for which no lower-cost, alternative solutions, including NWS, are currently practical.

Finally, we note that this DSP was under development as Commission Staff worked with utilities and stakeholders to revise the Commission's DSP guidance in UM 2005. We structured the 2024 DSP to comply with the revised guidance adopted with Order No. 24-421 and respectfully ask for Commission acceptance of the plan. As the first DSP filed under the new guidance, we also look forward to a robust review with Staff and stakeholders. We appreciate the opportunity to share our vision for a transformed distribution system and flexible energy grid that will allow proactive DER management in partnership between PGE and our customers while contributing to clean energy targets and enhancing the well-being of the communities we serve.

Appendix E of the DSP provides the detailed project summaries requested in DSP Guideline 8(b). Because these materials include highly confidential information, we will provide Appendix E as a separate document with the appropriate protections.

Please contact Steven Corson at 503-550-0857 if you have questions or require further information. Please direct all formal correspondence and requests to pge.opuc.filings@pgn.com.

Thank you,

/s/ Riley Peck

Riley Peck
Senior Manager, Regulatory Strategy and Engagement

ATTACHMENT

Cc: UM 2197 Service List
Nick Sayen
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DECEMBER 18, 2024

Distribution System Plan

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Acronyms

Acronym	Agency/Entity/Term
AAC	All Aluminum Conductor
ACPD	Air Contaminant Discharge Permit
ACSR	Aluminum Conductor Steel-reinforced
ACT	Advanced Clean Trucks
ADMS	Advanced Distribution Management System
AdopDER	Distributed Energy Resources Forecasting Tool
ADPS	Advanced Distribution Planning System
AFDC	Alternative Fuel Data Center
AI	Artificial Intelligence
AAR	Ambient-Adjusted Ratings
AMI	Automated Metering Infrastructure
AMP	Asset Management Planning
ANSI	American National Standards Institute
AWG	American Wire Gauge
AWS	Amazon Web Services
AWRR	Advanced Wildfire Risk Reduction
BCA	Benefit-Cost Analysis
BE	Building Electrification
BEA	Bureau of Economic Analysis
BEV	Battery Electric Vehicle
BIL	Bipartisan Infrastructure Bill
BYOT	Bring your Own Thermostat
BOD	Board of Directors
BSG	Business Sponsor Group
BTM	Behind the Meter
C&I	Commercial and Industrial
CAISO	California Independent System Operator
CAIDI	Customer Average Interruption Duration Index
CBI	Community Benefit Indicator

Acronym	Agency/Entity/Term
CBIAG	Community Benefit and Impact Advisory Group
CBO	Community-Based Organization
COC	Community Outreach Consultant
CBRE	Community-Based Renewable Energy
CBSA	Commercial Building Stock Assessment
CEO	Chief Executive Officer
CEP	Clean Energy Plan
CSAs	Customer Service Agents
CI	Customer Interruptions
CEJST	Climate and Economic Justice Screening Tool
CMI	Customer Minutes Interrupted
CLF	Corporate Load Forecast
CPS	Capital Project Sponsor
CPUC	California Public Utility Commission
CRC	Community Resource Center
CRG	Capital Review Group
CSP	Community Solar Program
Cu	Denotes Copper Conductor
CVR	Conservation Voltage Reduction
CVP	Customer Value Proposition
CYME	Power Flow Modeling Software
DA	Distribution Automation
DACs	Disadvantaged Communities
DAN	Data Acquisition Node
DEQ	Department of Environmental Quality
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System

Acronym	Agency/Entity/Term
DMS	Distribution Management System
DMV	Department of Motor Vehicles
DOE	Department of Energy
DLR	Dynamic Line Ratings
DOJ	Oregon Office of Justice
DPF	Diesel Particulate Filter
DCFC	Direct Current Fast Charger
DR	Demand Response
DRMS	Demand Response Management System
DRRC	Demand Response Review Committee
DSE	Distribution State Estimation
DSG	Dispatchable Standby Generation
DSMS	Demand Side Management System
DSP	Distribution System Plan
DSPx	Next Generation Distribution System Platform
EA	Electric Avenue
EDERMS	Enterprise Demand Response Management System
EIM	Energy Imbalance Market
EE	Energy Efficiency
ESS	Electric Service Supplier
ELCC	Effective Load-Carrying Capacity
EMS	Energy Management System
EPA	Environmental Protection Agency
EPRI	Electric Power Resource Institute
ETO	Energy Trust of Oregon
EUFL	End Use Load Flex
FAN	Field Area Network
FPA	Fault Protection Analysis
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration

Acronym	Agency/Entity/Term
FTE	Full-time Employee
FTM	Front-of-the-meter
GLASS	Grid Logging and System Standardization
GEC	Grid Edge Computing
GETs	Grid Enhancing Technologies
GGRF	Greenhouse Gas Reduction Fund
GHG	Greenhouse Gas
GIS	Geographic Information System
GMS	Grid Management Systems
GRC	General Rate Case
G-T&D PMO	Generation, Transmission & Distribution Project Management Office
GTB	Grow the Business
GW	Gigawatt
HB	House Bill
HES	Head of System
HDV	Heavy Duty Vehicle
HEAR	Home Electrification Appliance Rebate
HRFZs	High-Risk Fire Zones
HVAC	Heating, Ventilation, and Air Conditioning
ICE	Internal Combustion Engine
IDP	Integrated Distribution Planning
IEEE	Institute of Electrical and Electronics Engineers
EIM	Energy Imbalance Market
IIJA	Infrastructure Investment and Jobs Act
IOC	Integrated Operations Center
IEDs	Intelligent Electronic Devices
IOUs	Investor-Owned Utilities
IPT	Integrated Planning Tool
IQBD	Income Qualified Bill Discount Program
ITC	Investment Tax Credit

Acronym	Agency/Entity/Term
IRA	Inflation Reduction Act
IRP	Integrated Resource Plan
ISO	International Organization for Standardization
IT	Information Technology
LBNL	Lawerence Berkeley National Laboratory
LBNR	Loading Beyond Nameplate Ratings
LDV	Light-duty Vehicle
LTC	Load Tap Changer
MAIFIe	Momentary Average Interruption Event Frequency Index
MDHDV	Medium- and Heavy-duty Vehicles
MDAR	Meter Data Analytics Response
MFWH	Muli-family Water Heater
MLA	Minimum Load Agreement
MPLS	Multiprotocol Label Switching
MVA	Mega-Volt Amp
MVAR	Mega Volt-Amp Reactive
MW	Megawatt
MYP	Multi-Year Plan
NEEA	Northwest Energy Efficiency Alliance
NERC	North American Electric Reliability Corporation
NPV	Net Present Value
NREL	National Renewable Energy Lab
NSPM	National Standards Practice Manual
NEM	Net Energy Metering
NOC	Network Operations Center
NWS	Non-Wire Solutions
OATI	Open Access Technology International
O&M	Operation and Maintenance
ODEQ	Oregon Department of Environmental Quality
ODF	Oregon Department of Forestry
ODOE	Oregon Department of Energy
ODOT	Oregon Department of Transportation
ORS	Oregon Revised Statute
OEM	Original Equipment Manufacturer
OMS	Outage Management System
OT	Operations Technology
OH	Overhead
OPUC	Oregon Public Utilities Commission
OTA	Over the Air
PCEF	Portland Clean Energy Community Benefits Fund
PDP	Program Delivery Pilot
PPC	Public Purpose Charge
PHEV	Plug-in Hybrid Electric Vehicle
PI Data Historian	Software for tracking SCADA measurements
PMO	Project Management Organization
PPA	Power Purchase Agreement
PQ	Power Quality
PSPS	Public Safety Power Shutoff
PTR	Peak Time Rebate
PUC	Public Utilities Commissions
PV	Photovoltaic
QF	Qualifying Facility
QPL	Qualified Products List
RC	Reliability Coordination
RAPC	Resource Adequacy Participants Committee
RBSA	Residential Building Stock Assessment
RFP	Request for Proposal
RL	Relative Likelihood
RSE	Risk Spend Efficiency
RTF	Regional Technical Forum
RES	Residential

Acronym	Agency/Entity/Term
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
sFCI	smart Faulted Circuit Indicator
SGTB	Smart Grid Test Bed
SME	Subject Matter Expert
SMI	System Management Interface
SPIDs	Service Point Identifications
SOR	System of Record
STB	Sustain the Business
T&D	Transmission & Distribution
TBD	To Be Determined
TE	Transportation Electrification
TEP	Transportation Electrification Plan
TNC	Transportation Network Company
TOD	Time of Day

Acronym	Agency/Entity/Term
TTC	Total Transfer Capability
TLM	Targeted Load Management
TRC	Total Resource Cost Test
TSO	Transmission System Operator
USFS	US Forest Service
UG	Underground
VIN	Vehicle Identification Number
VOS	Value of Service
VPP	Virtual Power Plant
VSE	Value Spend Efficiency
VVO	Volt/VAR Optimization
WCCTC	West Coast Clean Transit Corridor
WMP	Wildfire Mitigation Plan
WRAP	Western Resource Adequacy Program
YFA	Yukon Feeder Automation
WRMA	Wildfire Risk Mitigation Assessment
USAP	Utility-Specific Action Plan

Executive summary

Preface

Recent PGE investments in Distributed Energy Resources (DERs) and Demand Response are delivering value to customers by lowering peak demand, cutting power costs, preventing potential outages, and reducing exposure to volatile energy market conditions.

One important way that PGE is working together with customers is by integrating power that customers produce or store, through solar panels, back-up generators, home or car batteries, or other sources, into the grid to provide capacity and resilience. These new forms of two-way partnerships form a "Virtual Power Plant (VPP") that provides multiple benefits. These benefits include, lower bills for customers, lower system costs, decarbonization, community empowerment, resilience and deferred utility capital investment. The VPP helps match the supply of electricity with customers' needs at any given moment. Every kilowatt saved or shifted with a VPP means one less kilowatt that needs to be generated from more expensive and more environmentally impactful resources.

PGE customer actions resulted in the largest electricity demand-shift in company history during multi-day heat wave. For example, using these resources once during a time of transmission constraints in 2023 avoided a potential power outage that could have cost PGE and its customers over $165 million. This was achieved by activating our current virtual power plant (VPP) capabilities. The 2024 Distribution System Plan (DSP) outlines PGE's continued work to integrate technologies and programs that increase the value of the VPP to customers.

Reliable, affordable, clean energy is essential to our sustainable energy future, and renewable, non-emitting resources fundamentally change how the grid operates. Modernizing the grid to accommodate renewable energy and increased electrification, in part through creation of a VPP, presents a unique generational opportunity to maximize benefits for both customers and the system by efficiently using all clean energy resources wherever found on the grid. Collaborating with customers, communities, stakeholders, and the Oregon Public Utility Commission, we can leverage the capabilities of the virtual power plant to address key challenges and equitably distribute benefits.

By collaborating with customers to capture savings, even as small as half a kilowatt, through investments in insulation, smart thermostats, electric vehicle smart charging, rooftop solar, and batteries, the VPP enhances efficiency, rewards participating customers, and creates valuable partnerships between PGE and our customers and communities. Such an approach leads to lower bills, reduced need for costly infrastructure, and improved customer comfort and resilience. PGE's VPP strategy also means further collaboration with the Energy Trust of Oregon to procure two resources, energy efficiency and flexible load, with the same investment dollars.

Introductory statement

Portland General Electric's 2024 Distribution System Plan (DSP) documents a comprehensive strategy for building a modern, clean energy grid that is cost-effective and contributes to the goals of customer affordability, electrification and decarbonizing. PGE continues to navigate the challenges of improving resilience in the face of extreme weather events and a volatile energy market as we take on the new challenge of load growth attributed to data centers.[1] The increasing use of distributed energy resources (DERs) across our system presents a key opportunity to meet these challenges while containing customer energy costs, enhancing their experience through greater control over energy use and spending, and bringing utility investments closer to the community. PGE will continue refining its strategy, adapting to changing circumstances and actively engaging with stakeholders to drive successful implementation. This includes ongoing collaboration with customers, regulators, technology providers, and community stakeholders.

Plan highlights

In addition to PGE's vision and strategy for achieving a reliable, safe and clean energy grid, the DSP includes the Company's action plan, detailing the prioritized investments in traditional infrastructure, grid modernization, virtual power plant (VPP) platform development and DER resource integration that will be necessary to continue progress implementing the strategy over the next 2-4 years.

The full Action Plan is detailed in **Chapter 8**, with project descriptions in **Appendix E**. Full context and explanation of the VPP is offered in **Chapter 5**. The plan demonstrates PGE's commitment to modernizing the grid while maintaining reliability and enabling large-scale integration of distributed energy resources to improve flexibility and reduce supply-side resource needs.

Expected outcomes include enhanced customer affordability and satisfaction, reduced operating costs, improved grid reliability and resilience and accelerated decarbonization. The benefit-cost analysis (see **Section 5.2**) indicates a significant return on investment, a benefit cost analysis ration of over one for the VPP, demonstrating the economic viability of the strategy. By reducing overall energy costs and promoting equitable benefit-sharing, this approach offers significant opportunities to lower customer bills while ensuring fairness and affordability.

Please note that while the DSP naturally focuses on planned investments and actions, the analysis of solutions that underlies the plan is also grounded in the *avoidance* of investments through the use of strategies such as load rebalancing. The projects included in the plan are deemed necessary because we have explored the alternatives and do not believe a less costly option would be feasible or effective in meeting system needs and serving customers. An example of an area where we avoided investments is the Glencoe-Glisan feeder project on **Appendix E**; we discuss how upgrading a small section of the feeder achieves the same

[1] Resilience is the ability to anticipate, adapt to, withstand, and quickly recover from disruptive events.

reliability benefits as installing a new feeder while reducing the cost of new asset investments and reduces the implementation time. The process of project identification, evaluation of alternatives, and implementation is continually evolving. The DSP is in many ways a living document and preferred solutions as well as priorities can be expected to change as we implement the plan.

Further context and drivers

Advances in technology are allowing the transition from a conventional energy delivery system to a flexible, resilient, customer-centered and bi-directional energy exchange platform that operates at a lower cost and helps enable a more affordable and reliable clean energy transition.

We intend to mitigate the upfront costs of this transition by optimizing the growth of distributed energy resources on our system and facilitating integration of renewable resources, while providing our customers with the programs and tools they need to better manage their energy use and costs. PGE also is leveraging $50 M in matching funds from the U.S. DOE to demonstrate how near real-time information from edge computing devices can improve visibility of the electrical system, provide operational insights and improve outage response, and ultimately help to anticipate and mitigate the impacts of extreme weather on grid resiliency (see **8.6F.5.5** Grid edge computing and next gen AMI).

PGE's 2024 DSP introduces an evolved service paradigm based on new technologies that facilitate communication, automation, and customer participation. This will allow us to effectively capture and distribute the benefits of the new bi-directional energy system with a smarter, customer-centered grid that delivers greater value to customers and the system at-large.

Opportunity and strategic framework

Energy efficiency (EE) has served as the dominant distributed energy resource on PGE’s system for decades. As we transition to a system increasingly dominated by non-emitting, variable resources, energy efficiency must be joined by demand response and flexibility in how we operate the grid to meet our energy and capacity needs and manage peaks in energy demand. PGE is working closely with the Energy Trust of Oregon to coordinate program and investment activity to further develop the co-benefits of energy efficient technologies that also have the capability to shift load. This collaboration and coordination mean deploying two resources with the same investment dollar. Our collaboration with the Energy Trust of Oregon can be found within our Multi-Year Plan (MYP) filing (Chapter 3.4) in UM 2141 and within the 2024 DSP in **Chapter 2** and **Chapter 5**.[2] For convenience, we have provided the MYP content in **Appendix K**. Further, we have been working with the Energy Trust of Oregon on multi-year planning cycles which offer better opportunity for

[2] 2024 Multi-Year Plan. Available at: https://assets.ctfassets.net/416ywc1laqmd/6plT6yeMe8t2aWdDlbLqfb/676e555dbc58eea8858803b6629cf879/Flex_Load_MYP_2024_-_Full_Document.pdf

coordination of activity and funding. Co-deployment with the Energy Trust of Oregon encompasses a shared strategy, with common marketing, outreach and messaging. We will start with targeting priority high energy burdened customers with services that lead to meaningful bill reduction.

At the same time, we project significant growth in customer electrification of homes, businesses and vehicles, as well as increased adoption of customer-sited renewables and storage technologies. To realize the value of these growing resources on our system we must revise the engagement paradigm between utilities and customers. A **bi-directional infrastructure** is needed and through that system an exchange of benefits between customers, the system and the utility. Our DSP vision and strategy of **accelerated DER deployment** will provide new solutions to customers to address affordability and system needs.

Proactively managed DER development is an opportunity to share benefits, bring utility investment dollars to customers, manage and lower customers' overall energy costs, contribute to clean energy targets and enhance customer well-being.

PGE imagines neighborhoods where solar powered homes combine with other homes that can store energy through a battery, an electric vehicle, home insulation or a water heater. The aggregation and optimization of these assets is what PGE refers to as the **virtual power plant or VPP.** Through new tariffs and rates, customers would be compensated for their homes' contributions. PGE envisions the VPP can shift up to 25 percent of our peak demand by 2030 to meet customer needs. The detailed plan explains how we propose to realize the potential of these new technologies and strategies to benefit our customers and the communities we serve.

Reader’s guide – Important terms

Throughout the 2024 DSP we will be using terms of the industry that are perhaps not familiar to the reader or for which context or an example may benefit the reader. We define them here:

"**Poles and wires**" refers to the traditional infrastructure that moves electricity from where it's generated to where it is used – essentially the backbone of our electric system. This includes the wooden poles you see along streets, the transformers on those poles, and the wires that connect them. **For example**, just as highways move cars from city to city, our poles and wires move electricity from generators to substations to your home.

Distributed Energy Resources (DERs) are smaller energy devices located where electricity is used, rather than at large central power plants. Think of them as local energy resources – like rooftop solar panels, home batteries, electric vehicle chargers, or smart water heaters. **For example**, while a traditional power plant might be miles away, your neighbor's solar panels are a DER producing energy right in your community.

A **Virtual Power Plant** (VPP) is like an orchestra conductor for distributed energy resources. Instead of building a traditional power plant, we coordinate many smaller energy resources – like home batteries, electric vehicle chargers, and smart thermostats – to work together as if they were one large power plant. **For example**, during a hot summer afternoon, we might coordinate thousands of smart thermostats to slightly adjust their settings, creating the same effect as turning on a power plant.

Grid Enhancing Technologies (GETs) are advanced tools that help us get more capacity and efficiency from existing grid infrastructure – like upgrading from a two-lane road to a smart highway with variable speed limits. **For example**, sensors and controls that help us safely push more power through existing lines during periods of high demand.

Advanced Distribution Management System (ADMS) is like a smart traffic control system for the electric grid. It monitors and controls the flow of electricity, helping operators make quick decisions about routing power and responding to outages. **For example**, when a tree branch falls on a power line, ADMS can automatically reroute power around the problem area, similar to how GPS navigation reroutes you around traffic.

Distributed Energy Resource Management System (DERMS) is the technology platform that enables grid operators to monitor and control distributed energy resources. While the VPP operators determine how to use these resources as a power plant, DERMS provides the actual communication links and control signals to make it happen. **For example**, if the VPP operators decide to use stored energy from neighborhood batteries, DERMS sends the specific signals telling each battery when to release its power.

Distribution Automation (DA) is like adding smart traffic lights to the power grid. It allows the grid to automatically respond to changes without human intervention. **For example**, when a power line is damaged, automated switches can reroute power around the problem area in seconds, similar to how traffic lights can automatically adjust to traffic patterns.

Fault Location, Isolation, and Service Restoration (FLISR) is an advanced application within ADMS that quickly finds and fixes power outage problems. Think of it as having an emergency response team that can instantly locate an accident, block off the affected area, and create detours. **For example**, when a car hits a pole, FLISR can automatically isolate the damaged section and restore power to surrounding unaffected areas within minutes.

Advanced Powerflow Control helps us direct electricity more precisely through our grid – like having adjustable lanes on a highway that can change direction based on traffic needs. **For example**, when solar panels in one area are producing lots of power, these controls help us route that electricity to where it's needed most.

Volt-VAR Optimization (VVO) is like having a precise pressure control system for electricity. It ensures that the voltage (electrical pressure) stays at the right level throughout the grid. **For example**, when many solar panels are producing power in a neighborhood, VVO adjusts equipment to maintain stable voltage levels, similar to how water pressure regulators keep your shower pressure consistent.

Demand Response (DR) and **Flex Load** are programs where customers voluntarily adjust their electricity use to help balance grid needs, usually in exchange for financial incentives. It's like having a crowd of people work together to solve a problem. **For example**, during peak energy times, participants might allow their water heaters to briefly pause or their thermostats to adjust by a half degree, helping reduce strain on the grid.

Transportation Electrification (TE) refers to the shift from gasoline-powered vehicles to electric vehicles and the infrastructure needed to support them. This includes everything from personal electric cars to electric buses and charging stations. **For example**, when a city transitions its bus fleet from diesel to electric buses, that's transportation electrification in action.

Non-wires solutions (NWS) represent alternatives to traditional grid infrastructure when addressing certain grid needs. A grid need occurs when we identify that part of our system requires additional capacity, improved reliability, or enhanced performance to maintain quality service. While traditional solutions might involve new equipment or upgrades, NWS use a combination of distributed energy resources, energy efficiency, and smart technologies to address these needs. However, not every grid need can be met with NWS. **For example**, if a growing neighborhood needs 2 megawatts of additional capacity, we might be able to meet this through a combination of batteries, smart thermostats, and solar panels working together. But if the need is 20 megawatts, or if there are specific reliability requirements that require proven technology, traditional infrastructure might be the most prudent solution. As a regulated utility responsible for providing safe, reliable, and affordable energy, we must carefully evaluate both the cost and reliability implications of NWS compared to traditional solutions before implementation. While NWS offer innovative approaches, they may sometimes be more expensive or have less proven reliability than traditional solutions.

Chapter 1. Distribution system vision

Key Concepts

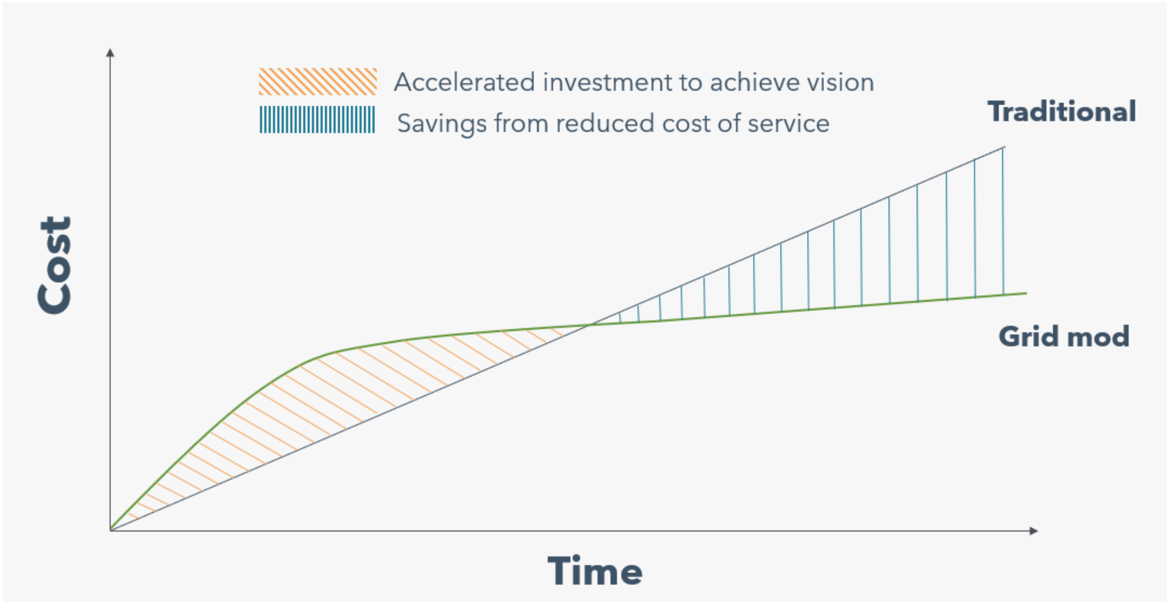
- PGE strives to create a modern, community-centered distribution system
- Goal: 25 percent of peak demand met by DERs by 2030
- Pursuing alternatives to traditional infrastructure investment
- Focus on customer benefits and long-term affordability

In Distribution System Plan (DSP) Parts 1 and 2, we introduced our vision of developing a 21st century community-centered distribution system.[3] That system uses distributed energy resources (DERs) to provide direct benefits to customers and accelerate decarbonization and electrification, all at fair and reasonable costs. Our most recent Clean Energy Plan/Integrated Resource Plan (CEP/IRP) reinforced that direction, demonstrating the important role of distributed energy resources, energy efficiency and demand response in meeting energy and capacity needs and decarbonization targets. It also set a goal – up to 25 percent of peak demand can be with power coming from customers and DERs by 2030. In this iteration of the DSP, that vision and the actions necessary to achieve it come into sharper focus.

The ability to optimize these resources is directly related to our collective ability to share benefits from customer to community from within a modern distributed bi-directional electric system. A strong partnership between the utility and customers, facilitated through co-investment in DERs and strategic investments in grid modernization, is essential for mitigating long-term costs and enhancing grid reliability as we decarbonize. This collaborative approach can unlock advantages that our traditional poles-and-wires model cannot. **Figure 1** illustrates this concept, highlighting that solely investing in conventional infrastructure misses the opportunity to harness benefits and manage costs in an evolving, more variable clean energy landscape.

[3] DSP Part 1 and 2. Available at: https://portlandgeneral.com/about/who-we-are/resource-planning/distribution-system-planning/dsp-resources-materials

Figure 1. Conceptual cost of service reduction with grid modernization



Pairing DERs with grid modernization investments to increase visibility, reliability, resilience, and control of the distribution system, transforms DERs into a system resource, similar to a power plant. When those DERs are optimized through a virtual power plant, we maximize their value, potentially offsetting the need for future investment in "traditional" generating assets or grid upgrades while maintaining or even enhancing service to customers. The ability to provide energy and capacity services to the grid while also deferring the need to invest in grid upgrades is unique to distributed energy resources and thus creates the foundational business case for investments to acquire, integrate and optimize them.

This concept underpins stakeholder and Commission interest in Non-Wires Solutions (NWS) found in the DSP guidelines. The investments outlined in this DSP to optimize DERs are the same capabilities PGE will need to invest in to develop NWS. The difference within the DSP vision is that a system investment in grid modernization creates the opportunity for NWS benefits to develop throughout the system, not just in target areas dictated by arising local system constraints. Through these investments the benefits which make up the concept of NWS is more easily captured to address operational and infrastructure challenges in the distribution system.

Customers who participate in DER programs may receive multiple benefits from their engagement. Direct financial rewards include payments for program participation, incentives for equipment installation, and reduced energy bills through more efficient usage patterns. Participants gain greater control over their energy consumption through real-time monitoring and automated management tools, allowing them to optimize their usage for maximum savings and shared benefits. A direct and shared benefit of DER adoption is a more resilient and efficient energy system that can lead to lower system costs for all customers. Whether through smart thermostats, solar panels, or energy storage systems, participating customers become active partners in modernizing the grid while receiving tangible benefits for their engagement. This evolution calls for strategic investments in networking, security, data systems, operational insights, and grid automation to coordinate the growing ecosystem of grid-connected sensors, protection devices, control systems, and DERs. A robust grid infrastructure unlocks the full potential and value of increased DER adoption while protecting the host customer and the grid.

Accelerating DER deployment and utilization has begun at PGE through many of the customer facing activities listed below. PGE recognizes that to meet our DER goals, empower our customers to share benefits and manage costs, we must continue and enhance but not be limited to the following activities:

Rate adjustment:

- **Income Qualified Bill Discount (IQBD) Program**[4]: Provides discounted rates for income-qualified customers while helping enable their participation in DER programs like energy efficiency and demand response. By combining bill discounts with opportunities to reduce or shift energy usage, the program helps make DER adoption more accessible to income-qualified customers.

Payments/Incentives:

- **Time of Day**[5]: Encourages off-peak energy usage through pricing incentives.
- **Peak Time Rebate**[6]: Engages customers in managing electricity demand during peak times for grid stability.
- **Smart Thermostat Program**[7]: Empowers customers with smart energy management tools for optimized consumption.
- **EV Smart Charging Program**[8]: Facilitates the integration of electric vehicles (EVs) by offering incentives for smart EV charging.

Specialized support:

- **Medical Certificate Program**[9]: Flags customers with medical needs through a specialized program.

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[4] Income-Qualified Bill Discount Program. Available at: https://portlandgeneral.com/income-qualified-bill-discount
[5] Time of Day. Available at: https://portlandgeneral.com/about/info/pricing-plans/time-of-day
[6] PGE Rebates, Peak Time Rebates & Peak Use Shifting. Available at: https://portlandgeneral.com/save-money/save-money-home/peak-time-rebates
[7] Smart Thermostat Program & Rebates. Available at: https://portlandgeneral.com/save-money/save-money-home/smart-thermostat-program
[8] Charging Your EV at Home - EV Smart Charging Program. Available at: https://portlandgeneral.com/energy-choices/electric-vehicles-charging/charging-your-ev/charging-your-ev-at-home
[9] Powering Medical Equipment – Outages. Available at: https://portlandgeneral.com/outages-safety/be-prepared/powering-medical-equipment

- **Multi-family Charging Program**[10]: Enables access to EV charging infrastructure in multi-family units.
- **Battery Program in PSPS Zones**[11]: Deploys portable battery storage systems in areas prone to Public Safety Power Shutoffs (PSPS) for improved reliability.
- **PGE +**: Offers personalized assistance and resources to help customers navigate their energy needs[12].

PGE envisions a customer experience where individuals can visit the PGE website to explore PGE+ services. This platform will help customers understand the shared costs and benefits, as well as their personal costs and advantages of installing new distributed energy resources (DERs) like thermostats, water heaters, batteries, or solar systems. These installations may be co-deployed with the Energy Trust of Oregon to combine incentives for energy efficiency and flexible load, ultimately reducing the retail upfront costs that have previously hindered adoption.

With the support of partners like the Energy Trust of Oregon, Northwest Energy Efficiency Alliance (NEEA), and trade allies, PGE aims to assist participating customers in smoothly installing devices that can automatically integrate with PGE's modern grid. Customers can set control parameters to indicate the device's availability and specify rules and requirements for how they function. This shared optimization will operate seamlessly in the background. The energy services purchased by the Virtual Power Plant (VPP) from the customer's device may be reflected on their bill, further reducing the cost of the device or offsetting the monthly financed cost, with the potential to mitigate the overall cost to serve all customers.

This envisioned customer journey, along with the program offerings mentioned, solutions for customers facing high energy burdens, and new approaches to customer service fostered by a shared modernized grid, forms the foundational vision that drives our submission of the 2024 Distribution System Plan (DSP).

[10] Commercial and Multi-Family Make Ready. Available at: https://portlandgeneral.com/commercial-and-multi-family-make-ready
[11] PGE Medical Battery Support. Available at: https://portlandgeneral.com/medical-battery-support
[12] PGE+. Available at: https://portlandgeneral.com/save-money/pge-plus

1.1 Progress toward the vision of a bi-directional distribution system

1.1.1 History and trajectory of the vision shared

PGE's 2024 DSP vision is not a radical departure but rather, it is part of an evolution informed by market and technology readiness and availability. Our planning for investments in grid modernization, the VPP and DER acceleration is informed by lessons learned from the industry and activities undertaken by PGE to understand the operational challenges and solutions brought about by smart grid technologies.

Further, PGE's commitment to decarbonization and the emissions targets established by HB 2021[13] sets up an imperative requiring a more dynamic system operations paradigm whereby a bi-directional system utilizes all available resources. PGE's 2023 Integrated Resource Plan and Clean Energy Plan identified a critical role for distributed energy resources in meeting clean energy and capacity needs. **Figure 2** provides a high-level history of our efforts to move to a bi-directional grid.

[13] House Bill 2021 is a climate policy aimed at decarbonizing the state's electricity sector. Oregon HB 2021 - Key Requirements for Electric Utilities:
Emissions Reduction Targets (from baseline):

- 80% by 2030
- 90% by 2035
- 100% by 2040

Required Actions:

- Submit Clean Energy Plans (CEPs) with annual targets
- Form Community Benefits Advisory Groups
- Enable community-supported renewable projects
- Follow labor standards for energy projects

The bill guides Oregon utilities' transition to clean energy while considering economic and community impacts. Available at: https://www.oregon.gov/puc/utilities/Pages/HB2021-Implementation-Activities.aspx#:~:text=Oregon%20House%20Bill%202021%20%28HB%202021%29%20is%20a,2040%20with%20consideration%20for%20benefits%20to%20local%20communities.

Figure 2. Journey towards a bi-directional grid

2010

- Joint utility, Lab, US DOE endeavor to explore "transactive control" at Salem Smart Power center.
- One of the country's first substation batteries.

2016

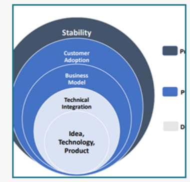
- PGE launches Smart T-Stats, Peak Time Rebates, and Energy Partner.
- The resource portfolio has since grown from 11MW to 109MW.

2018

- PGE launches the nation's first Smart Grid Test Bed providing insight into customer engagement.
- PGE now has one of the nation's highest levels of customer program participation at 22%.
- PGE also submits the Flexible Load Plan outlining new practices and standards for demand response development.

2019

- PGE submits the 2019 Smart Grid Report which reported on all of PGE smart grid activity across the company.
- The Smart Grid Report got consolidated into the DSP through DSP Guidelines and Commission Order.



2020

- PGE files the Multi-Year Plan – The first utility DR Plan outlining cost-effective portfolio development of demand response and flex load resources.
- The MYP set detailed resource development standards, assessments, targets, and budget.

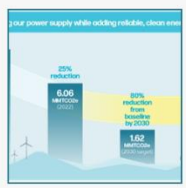
2021

Smart Grid Test Bed Phase II is launched, attracting $6.6M in US DOE funding.

The SALMON and Flexible Feeder Project are developing learnings on DER utilization, customer engagement, and resource development.

2021-2022

PGE submits the first Distribution System Plan, which addressed grid needs, people-based planning, non-wires solutions, and grid modernization plans.

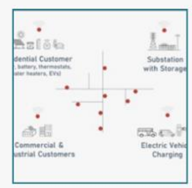


2023

PGE submits its 2023 CEP/IRP which aspires to be able to meet as much as 25 percent of the energy needed on the hottest and coldest days with power coming from customers and DERs.

2023

PGE submits its 2023 Transportation Electrification Plan, which leveraged Clean Fuels Funds and Monthly Meter Charge dollars to plan, serve, and manage the electrification of the transportation sector.

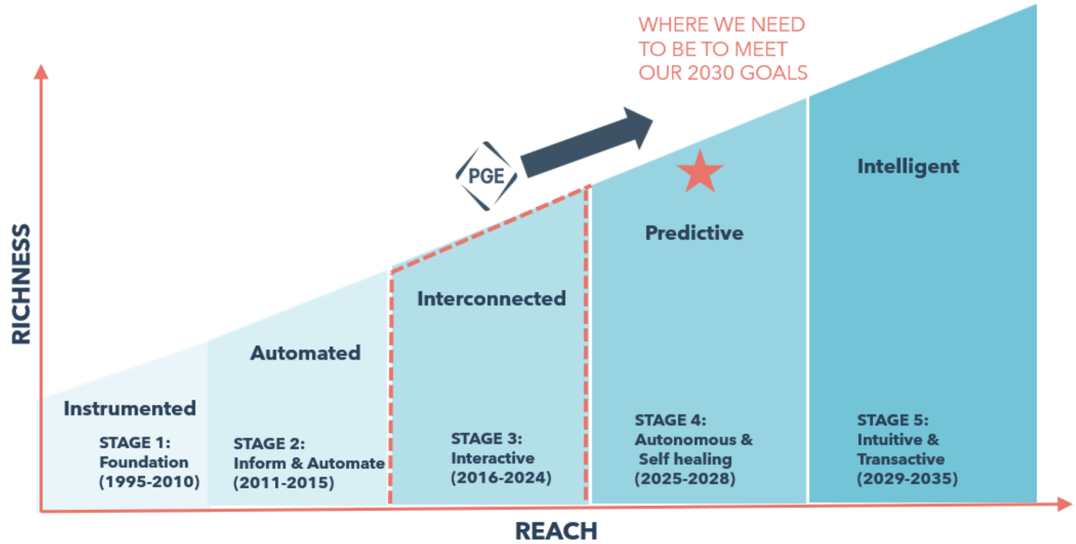


2023

Grid Edge Computing Project, US DOE funded $50M for the acceleration and deploying grid edge grant effective Oct 2024.

The activities outlined above have shown PGE that there is an incremental but necessary 'operational capabilities trajectory' to our vision and pathway to a bi-directional grid which utilizes all available resources to meet our goals. In order to meet the 2030 and 2040 decarbonization targets, PGE's modernized grid needs to adopt a more predictive state and should evolve into an intelligent grid as shown in **Figure 3.**

Figure 3. Evolution to a more predictive state



Stages of Grid evolution based on technology implementation /adoption

PGE is currently working on realizing Stage 3 of the grid-evolution (Interconnected). PGE has been 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.

Smart Grid Highlights

On March 18, 2024, a fault caused an outage for 1,017 customers. PGE's ADMS detected the fault and automatically restored power to 671 customers within three minutes. Crews were dispatched to restore power for the remaining 346 customers within three hours. The automated restoration performed by the ADMS system saved over 80k customer outage minutes.

Most investor-owned utilities (IOUs) in the US are at this stage of evolution. To meet Oregon's aggressive decarbonization requirements as set forth in HB 2021, PGE's grid must evolve to a state where systems predict the grid's next operational state and prepare system operators to anticipate, rather than react. The deployment of DERs is important to reaching our vision and our decarbonization targets. The DERs deployed and interconnected to the system must be able to meet communication and operational standards in-line with the operational stages outlined above. DER operational and communication standards must be informed by or compatible with PGE's communication and operational grid modernization infrastructure. Moving forward, this initiative will help align critical activities to enable and scale DER programs and resources while addressing capability needs, such as performing locational net benefits analysis and optimized DER dispatch.

Our long-term plan for the DSP represents our intent to modernize the distribution system. This DSP affords us the opportunity to explain how we plan to approach modernizing 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 the evolution of our long-term plan.

Chapter 2. Distribution system strategy

Our Distribution System Plan strategy aims to transform how we deliver and manage energy across our service territory while prioritizing customer affordability. We are adapting to a rapidly evolving customer landscape driven by increased electrification, technological adoption, and surging industrial demand from manufacturing reshoring and AI advancement. Our long-standing commitment to decarbonization, demonstrated through our transition away from coal and leadership in renewable resource integration, guides and necessitates the development of a reliable, modern, customer-centered grid that delivers affordable energy for all customers.

This chapter outlines our three-prong strategy for distribution system planning

Strategy Components

- Grid modernization
- Accelerated DER deployment
- Virtual Power Plant (VPP) development

These strategic elements work together to deliver value to customers and reduce long-term operating costs.

Figure 4 shows our distribution system strategy is built on three interconnected pillars, each contributing distinct but complementary actions. The first pillar, Grid Modernization, provides the foundation through advanced grid technologies that enhance system reliability and flexibility, including digital technologies like ADMS/DERMS that orchestrate bi-directional power flow. The second pillar focuses on accelerating the adoption of distributed technologies like solar panels, batteries, and smart devices, leveraging partnerships with Energy Trust of Oregon (ETO) and Northwest Energy Efficiency Alliance (NEEA) to maximize deployment and deliver value through customer programs. The third pillar encompasses our Virtual Power Plant platform, which integrates and optimizes these customer-owned resources to provide essential grid services while reducing operational costs for the benefits of all customers.

These strategic pillars, driven by a long-term commitment to least-cost planning, represent our comprehensive approach to delivering energy solutions that reduce customers' energy cost burden while creating a more resilient clean energy future. As outlined in **Chapter 1 Distribution system vision,** this strategy unifies our efforts through collaborations that align with community goals, promote sustainability, and deliver essential benefits to all customers.

Figure 4. Strategic pillars and actions[14]

2.1 Pillar One - Grid modernization investments

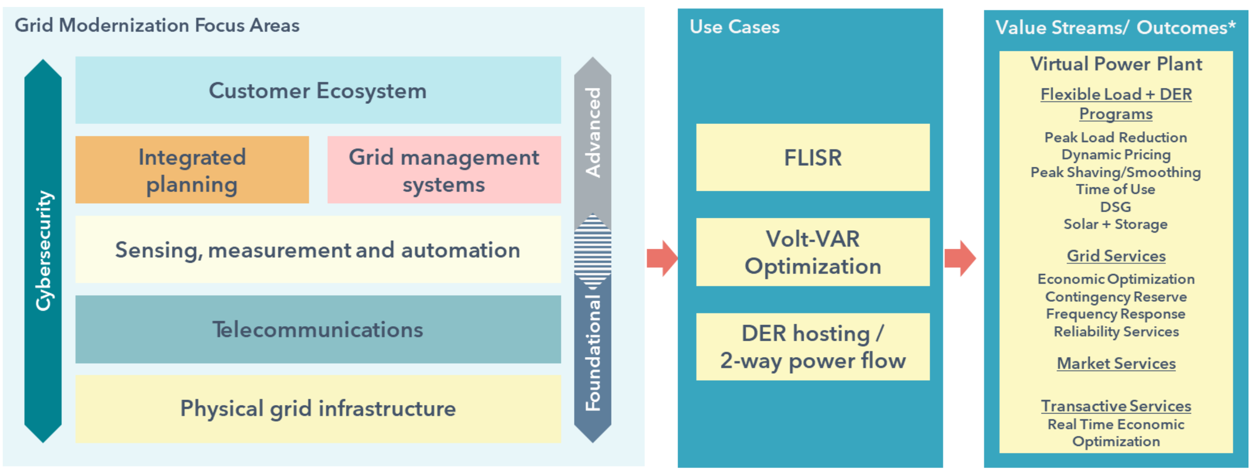
Grid modernization represents our foundational strategy pillar, focused on transforming our traditional infrastructure into an intelligent, flexible system capable of managing two-way power flows and integrating customer resources. This comprehensive approach integrates advanced technologies with traditional upgrades in support of VPP operations that deliver grid resilience and maximize the use of existing infrastructure (see **Chapter 5 Virtual Power Plant (VPP)**).

As our system is able to deliver higher and higher percentages of clean energy and DER adoption increases, grid operations become more complex. Grid modernization is necessary to achieve reliability, safety and security. As these investments are co-optimized with incremental grid modernization investments that enhance our ability to incorporate and optimize more DERs, benefits increase. PGE's 2023 CEP/IRP has set a goal by 2030 of being able to meet as much as 25 percent of peak demand with power coming from customers and DERs.[15] Visibility and operational optimization of those DERs is necessary to maintain a reliable, clean, affordable, safe system at least cost.

[14] Icons appearing throughout this document align with the strategic pillars shown in **Figure 4** to visually connect key activities with their corresponding strategic elements.
[15] See Section 1.4.2 of PGE's 2023 CEP/IRP. Available at https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf

To deliver maximum customer benefits, PGE proposes a comprehensive grid modernization strategy built on multiple integrated focus areas, from foundational physical infrastructure to advanced customer-facing systems (see **Figure 5**). More detail about these investments is found in **Chapter 4** (Technology foundations for a bi-directional grid) and **Appendix F** (Grid modernization long-term plan and workstreams). This approach optimizes traditional distribution infrastructure upgrades, such as substation or distribution line work, with modern digital systems and DER management capabilities.

Figure 5. Grid modernization focus areas



*Note: Value Streams/Outcomes list is not exhaustive

At the core of these modernization efforts are advanced grid management systems, ADMS and DERMS, that enable intelligent control and optimization of grid operations. These systems create tangible benefits for customers. One use case addresses the response to outages. For example, when power flow is interrupted, ADMS uses automatic fault location, isolation and service restoration (FLISR) capabilities to communicate with line reclosers via communication networks to isolate faults and restore service quickly. Currently 35 of our 695 feeders in the PGE service area have been retrofitted to respond to reliability events, reducing outage durations for about two-thirds of customers on those 35 feeders. This improvement is due to localized enhancements in PGE's system, enabling faster response and restoration for affected areas.

Another use case addresses voltage irregularities. Volt-VAR optimization (VVO) technology fine-tunes voltage and reactive power on the grid, leveraging customer-owned DERs like batteries to maintain optimal power quality.

When ADMS is coupled with DERMS, costs to operate the distribution system to industry standard for reliability and safety are reduced over traditional distribution infrastructure projects.[16]

Together, these investments, coordinated through a VPP, aim to create a flexible and intelligent grid that optimizes existing assets while integrating new technologies and customer resources. These systems work in harmony to enhance reliability, resilience (e.g., shorten outage durations), and improve overall grid efficiency. Further details about these technologies and implementation plans can be found in **Chapter 4** (Technology foundations for a bi-directional grid) and **Appendix F** (Grid modernization long-term plan and workstreams).

2.2 Pillar Two - Accelerating DER deployment

Accelerating distributed energy resource (DER) deployment encompasses a comprehensive strategy to increase customer adoption of technologies like solar panels, batteries, and smart devices through targeted programs, partnerships, and education. This strategic pillar creates pathways for customers to participate in the clean energy transition while ensuring system reliability and equitable access.

2.2.1 Customer engagement and partnership strategy

Our acceleration strategy operates through multiple channels to maximize impact. We partner with established organizations like ETO for co-deployment initiatives and the NEAA for market transformation of demand response programs. These strategic collaborations create a foundation for standardized interconnection requirements and customer support platforms.

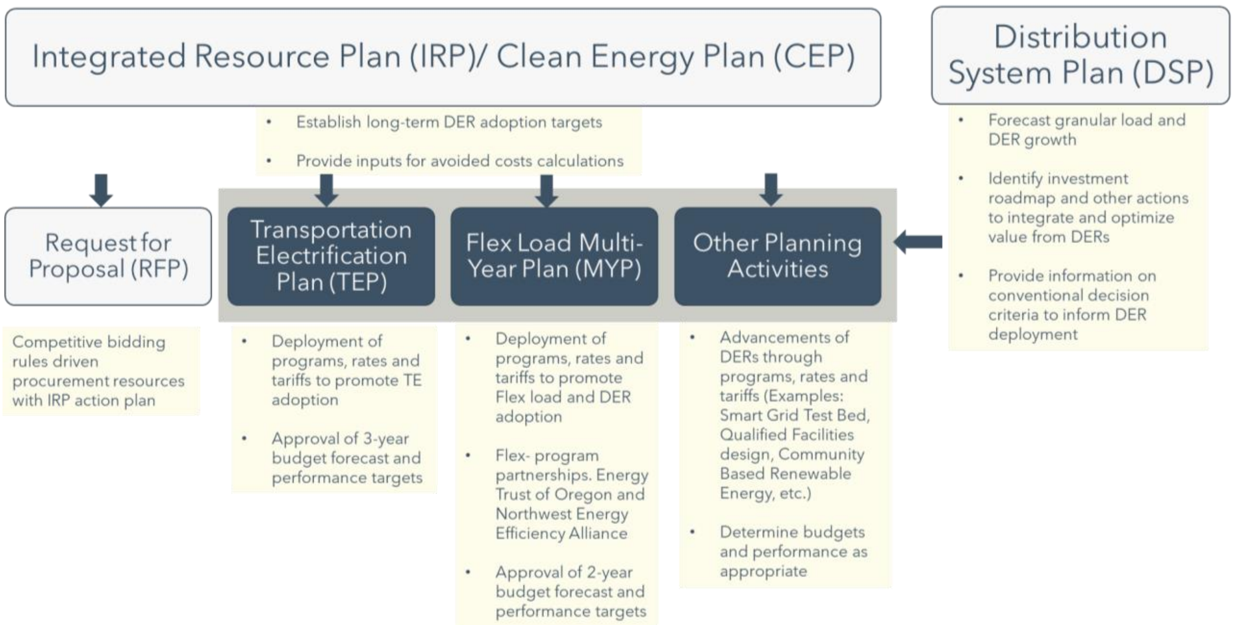
To streamline customer participation, we have developed engagement platforms like Marketplace and PGE+ that provide education, technical support, and streamlined access to DER technologies. Our Smart Grid Test Bed (SGTB) serves as a proving ground for testing and refining these approaches before broader deployment.

2.2.2 Planning framework integration

Our DER acceleration efforts are coordinated through three key planning processes, these relationships are depicted in (**Figure 6**).

[16] This study is referenced in the DOE's commercial liftoff report for Innovative Grid Deployment. Available at: https://liftoff.energy.gov/wp-content/uploads/2024/04/Liftoff_Innovative-Grid-Deployment_Final_4.12.pdf, *citing* Kazempour,F., Hu, K. November 2023. *Utility investment in grid modernization: H2 2023*. Wood Mackenzie.

Figure 6. Overview of planning environment relationships



2.2.2.1 Clean Energy Plan/IRP Integration

The CEP/IRP integration process aligns our DER forecasts with system-wide resource planning. Through our AdopDER model, we develop detailed projections that inform both distribution-level planning and broader system needs, creating a comprehensive view of how distributed resources can best serve our evolving grid.

- Leveraging our AdopDER model to inform system-wide planning
- Ensuring alignment between distribution and resource planning
- Identifying opportunities for distributed resources to meet system needs

2.2.2.2 Multi-Year Plan (MYP) Coordination

The MYP creates a bridge between long-term planning and near-term implementation. By coordinating infrastructure investments with resource development in two-year cycles, we can efficiently deploy flex load programs while maintaining alignment with our broader distribution system goals.

- Aligning infrastructure investment with resource development
- Implementing flex load programs in two-year increments
- Working toward consolidation of DSP and MYP for comprehensive planning

2.2.2.3 Transportation Electrification Integration

Our transportation electrification strategy takes a comprehensive approach through planning, serving, and managing TE load growth. With significant investment focused on underserved communities, we're developing targeted rates and load management solutions to promote equitable access while maintaining grid reliability.

- Executing our Plan, Serve, and Manage strategy for TE load

- PGE's 2023 Transportation Electrification Plan directs nearly $96 million investment. 58 percent of the Monthly Meter Charge dollars supports underserved communities[17]
- Developing TE-specific rates and load management approaches

2.2.3 Advanced forecasting and implementation

Our implementation success relies on sophisticated granular forecasting capabilities that inform both near-term actions and long-term planning. Through integration with our T&D capital planning processes, we develop detailed projections at the feeder and substation levels, allowing us to anticipate and prepare for localized grid impacts. This granular approach is enhanced by our partnership with EPRI on the Wide-Area Distribution Assessment study, which helps us identify electrification opportunities and prioritize grid investments across our service territory.

Building on these capabilities, we conduct comprehensive load modeling across various scenarios, particularly focusing on heavy-duty vehicle charging profiles and their grid impacts. This modeling includes both reference and high adoption scenarios for electric vehicles, helping us understand potential system impacts and investment needs. Through regular assessment of demand patterns and proactive infrastructure planning, we can better anticipate and address emerging grid needs while ensuring efficient use of existing assets. This data-driven approach enables us to make targeted investments that support accelerated DER adoption while maintaining system reliability and cost-effectiveness.

Our implementation success is informed by sophisticated forecasting and planning activities:

- Granular load growth projections at feeder and substation levels
- Integration with T&D capital planning processes
- Regular assessment of demand patterns
- Partnership with Electric Power Resource Institute (EPRI) for Wide-Area Distribution Assessment[18]
- **Key outcomes include:**
    - Assessment of electrification opportunities
    - Identification of high-priority feeders
    - Proactive infrastructure investment planning
    - Comprehensive load modeling scenarios

Through this coordinated approach, we are building a foundation for accelerated DER adoption while ensuring system reliability and equitable access. This pillar integrates with

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[17] PGE's 2023 Transportation Electrification Plan is available at: https://assets.ctfassets.net/416ywc1laqmd/2xv3CdVdbyaZuYVy3UFWkR/65122d294f36a14ee6514cab2cf6fb74/TEP_2023-08-25_Full_Report.pdf

[18] Wide Area Assessment is related more closely to reliability but produces data that may be used by the planning team. EPRI's product description for these assessments. Available at: https://www.epri.com/research/products/000000003002031146

our broader planning framework, bringing together elements of infrastructure investment, customer programs, and resource acquisition. While the infrastructure components are detailed in this DSP, specific program elements are further developed in the Multi-year Plan and Transportation Electrification Plan. Additional technical details can be found in **Chapter 4** (Technology foundations for a bi-directional grid) and **Appendix F** (Grid modernization long-term plan and workstreams).

PGE's distribution system plan strategy brings together elements of infrastructure investment, customer programs and resource acquisition. The infrastructure required to follow through on this strategy is discussed in this DSP. Elements of resource acquisition and customer programs are discussed in the Multi-year Plan and Transportation Electrification Plan.

2.3 Pillar Three - Virtual Power Plant

A Virtual Power Plant (VPP) is a sophisticated system that coordinates distributed energy resources - such as rooftop solar, batteries, electric vehicles, and flexible loads - to function like a traditional power plant. By integrating and orchestrating these resources through advanced technology platforms, a VPP provides essential grid services while optimizing costs and reliability. This approach transforms individual customer resources into a collective asset that benefits the entire energy system.

PGE's Virtual Power Plant (VPP) strategy creates a framework for customers to actively participate in a clean, reliable, and affordable energy system. Through the VPP, we will harness the power of distributed energy resources to optimize grid operations, reduce reliance on traditional power plants, and accelerate the transition to a non-emitting energy future.

This approach aligns with broader industry direction, as the United States Department of Energy (US DOE) has documented the importance of these objectives through several white papers and reports on the topics of grid modernization, virtual power plants (VPPs) and related concepts.[19] The federal government has identified VPPs as necessary to provide safe, reliable clean power at least cost, and has provided funding and support for VPP initiatives and DER integration.[20]

[19] See generally, The "Pathways to Commercial Liftoff" reports, available at: https://liftoff.energy.gov/ .

[20] Some of the key pieces of legislation include:

1. **Inflation Reduction Act (IRA)**: Passed in 2022, this act includes various provisions for clean energy technologies, tax credits for renewable energy development, and incentives that can support the integration of VPPs by promoting energy efficiency, renewable generation, and storage solutions.
2. **Infrastructure Investment and Jobs Act (IIJA)**: Enacted in late 2021, this legislation allocates funding for infrastructure improvements that can enhance grid reliability and

To execute this strategy effectively, we must create a platform that brings together resources distributed across the system to optimize their operation.

Our approach builds on established success. PGE ranks among the top utilities in the country for energy efficiency spending per customer and program offerings.[21] Building on this foundation, PGE's 2024 DSP focuses on how an accelerated deployment of DERs operating within a bi-directional system orchestrated through a VPP provides direct benefit to customers, communities and the system.

According to high-level projections from PGE's Integrated Resource Plan (IRP), long-term forecasts indicate a potential for over 2,000 MW of DERs and flexible loads to come online within PGE's service territory by 2030. This significant growth potential requires sophisticated management, which is why our VPP integrates various distributed energy resources such as solar panels, wind turbines, battery storage systems, and flexible demand-side resources into a unified and manageable network.

Moving forward, VPP operations will expand from our current, event-based responses (like heat waves or cold snaps) to thousands and eventually millions of automated operations for real-time energy management. Through this development, the VPP will harmonize customer participation and system operations to support growth in customer electrification without compromising reliability and keeping costs as low as possible throughout the clean energy transformation.

The integration of distributed energy resources (DERs) and flexible loads through technology systems to deliver grid services and operational benefits. Further detail can be found within **Chapter 5 Virtual Power Plant (VPP)**.

2.3.1 DER platform optimization

Updating the distribution system is necessary to create a platform that brings together resources distributed across the system to optimize their operation in a manner that provides the greatest number of megawatts at the highest system value. The development

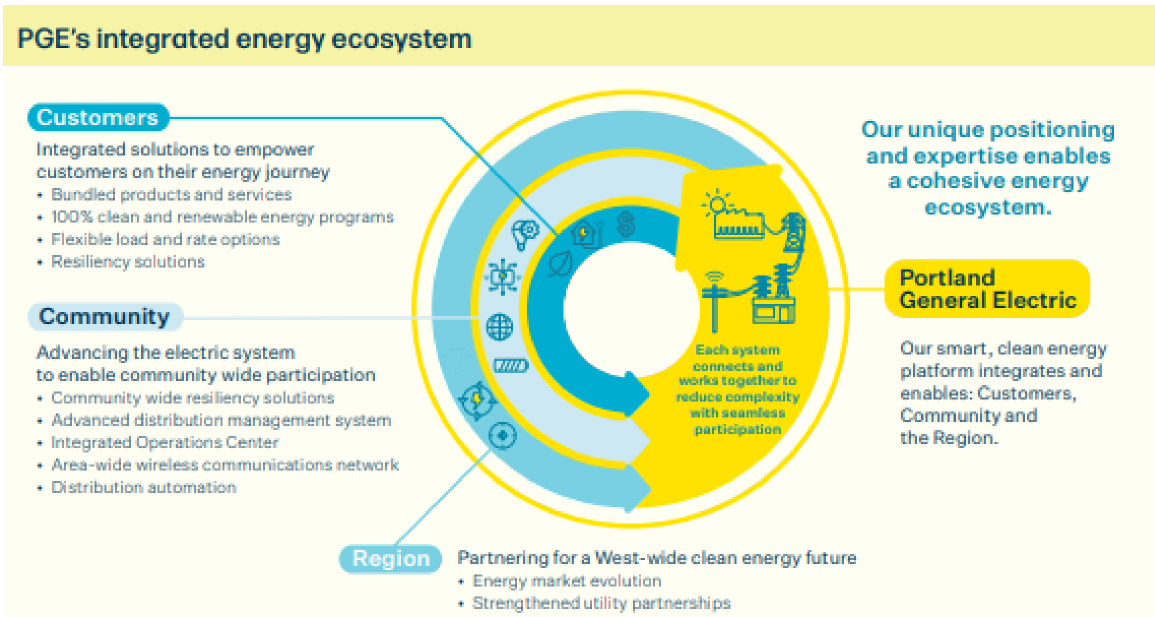
support the deployment of smart grid technologies. It includes provisions for funding research and development initiatives that can benefit VPPs and related technologies.

3. **Energy Policy Act**: This act includes various provisions that promote energy efficiency, renewable energy, and electricity reliability, which indirectly support the development of VPPs by funding programs that encourage the integration of DERs and modern grid technologies.
4. **Grid Modernization Grants**: The DOE administers various grant programs and funding opportunities for states and utilities to modernize the electrical grid. These programs often encourage projects that incorporate technologies like VPPs.
5. **State-Level Initiatives**: Besides federal legislation, various states have also instituted their own programs and funding mechanisms to encourage VPPs and DERs, sometimes in partnership with federal initiatives.

[21] ACEEE 2023 Utility Energy Efficiency Score Card. Available at https://www.aceee.org/research-report/u2304

of the resources can be done in myriad ways, but PGE holds that it has a significant role in building, operating and optimizing DERs that are least cost, transparent in its customer relations, transparent in cost and benefits and equitable in service and participation (see **Figure 7**).

Figure 7. PGE's integrated energy ecosystem

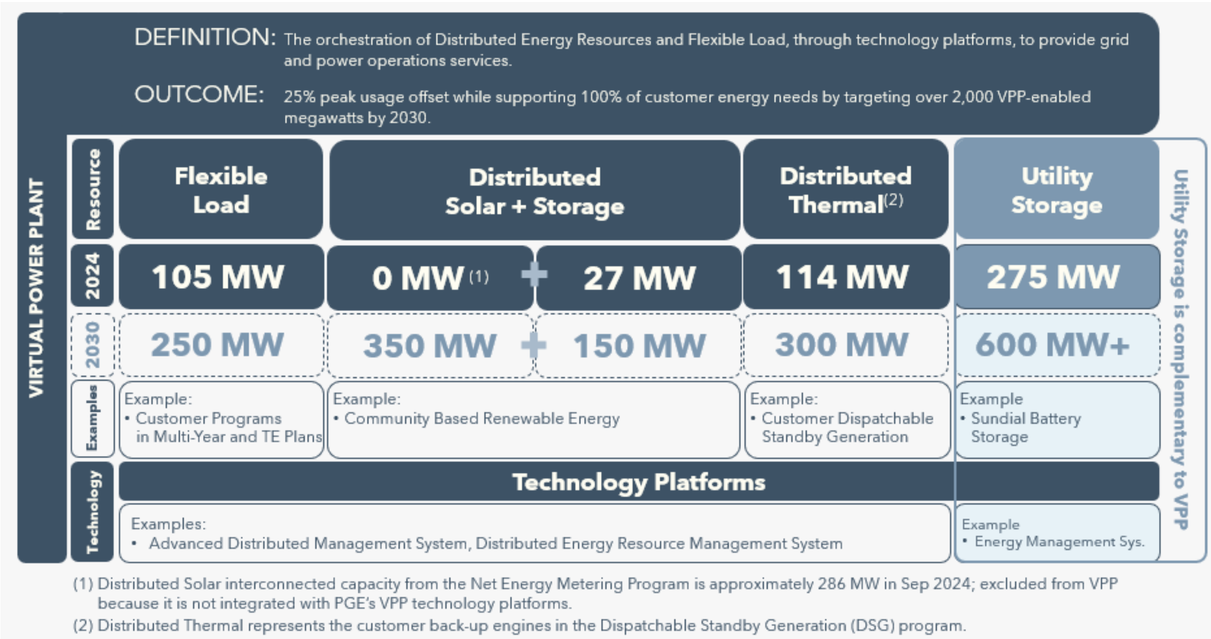


2.3.2 Distributed energy resources (DERs) integration

PGE's Virtual Power Plant (VPP), illustrated in **Figure 8**, integrates distributed energy resources (DERs) and flexible loads through advanced technology platforms, optimizing them to provide essential grid and power operation services (see **Section 5.1 Virtual Power Plant**). The continuous evolution of VPP capabilities is crucial for identifying and harmonizing these resources, benefiting our customers and community partners with equitable, local, clean, affordable, and resilient energy.

PGE VPP Operations, enabled with real-time visibility, will dispatch DERs and flexible loads within our distribution network to harmonize customer participation and system operations and support growth in customer electrification without compromising reliability. This will help keep costs as low as possible throughout the clean energy transformation, guiding customer participation and realizing value through market integration.

Figure 8. Components of PGE's VPP



The VPP integrates various distributed energy resources (DERs) such as solar panels, battery storage systems, and flexible demand-side resources into a unified and manageable network. Key capabilities and features of the VPP are discussed in **Appendix F** (**Grid modernization long-term** plan and workstreams**, Distributed energy management system (DERMS)** and **Technology foundations for a bi-directional grid**. The VPP represents a significant advancement in the way PGE manages and utilizes distributed energy resources.

Chapter 3. DER forecasting

Key Concepts

- Focus on DER integration and forecasting capabilities
- Evolution from basic tracking to advanced prediction models

Growth Projections

- Solar PV adoption trends
- Building electrification forecasts
- Transportation electrification growth
- Seasonal DR/Flex Load potential
- Behind vs. front-of-meter resources

The three components of PGE's strategy rely on the effective orchestration of DERs. The load and DER forecast provides the insights necessary to identify the types and pace of investment to achieve our strategy. For example, our grid modernization investments are informed by the types of DERs that need to be integrated into the system and the characteristics of those DERs that we need to understand in order to operate them. The acceleration of DER deployment can only be achieved if we understand what the potential is for customer adoption of DERs. The forecast of DER adoption enables effective design of customer programs. And, finally, the amount of DERs available can inform the types of services that the VPP can deliver and helps our planning teams understand what energy purchases or infrastructure investments might be deferred or avoided.

3.1 DER forecasting model

PGE worked with third-party consultants, Cadeo, Brattle, and Resilient Edge to develop AdopDER which is our DER forecasting model. The AdopDER model is a comprehensive site-level simulation model that allows for a hybrid top-down and bottom-up modeling approach to estimate locational, hourly annual load impacts from the co-adoption of 50+ DERs and electrification. AdopDER is built in Python and forecasts DER adoption dynamically, with stochastic influences where appropriate, under different conditions. We have considered both programmatic adoption (which simulates measure adoption through PGE programs), and market adoption (which simulates naturally occurring measure adoption without program intervention).

Within AdopDER adoption for the following technology groups has been modeled:

- **Transportation electrification (TE):** market and programmatic adoption of electric vehicles (EVs) and accompanying charging infrastructure across all sectors (residential and commercial) and vehicles classes.
- **Building electrification (BE):** market adoption of heat pumps, electric water heaters, induction cooking technologies etc. across sectors to increase electric efficiency or replace direct use of fossil fuels.
- **Solar and storage:** market and programmatic adoption of distributed behind-the-meter solar and battery energy storage in all sectors.

- **Demand response (DR) / flexible loads:** adoption of opt-in direct load control and pricing measures like peak time rebates, smart water heater controls, smart thermostats, and curtailable tariffs.

PGE uses AdopDER for enterprise-wide DER adoption modeling, including forecasting 8760 hourly load impacts at a feeder level, and 8760 hourly baseline (i.e., not associated with DER) loads at a feeder level across its distribution system. The detailed description of AdopDER's methodology is provided in Distribution System Plan Part 2.[22] This forecast is then integrated with the distribution planning process to determine the distribution system impact and evaluate grid needs.

PGE simulated market adoption trends using a blend of macro-level forecast and market demand models, and then calibrated these to the granular site-level stock turnover model using available knowledge of customer characteristics. Planning generates bottom-up customer DER additions based on detailed information across a range of potential areas of activities which include new sources of demand (such as increased use of central air-conditioning, electric vehicles), DER interconnection applications, local development policies, and any planned development or redevelopment activity spurring from local community or business development plans. This enables greater granularity of forecast both temporally and locationally which is immensely beneficial in distribution system planning since the impacts can be determined on individual feeders and rolled up to substation transformers. This is critical for more accurately quantifying the potential for DERs located on the distribution grid to provide a range of grid services especially as we develop the capabilities to integrate DERs into a VPP.

3.2 AdopDER enhancements

We have made advancements in our DER forecasting capabilities which allow us to estimate future DER forecasts at the feeder- and substation-level and therefore enable us to make informed program design choices. We have also made strides in incorporating equity data into our models to inform more equitable program design and community prioritization. Our corporate load forecasting process has evolved to predict electric loads and DER adoption more accurately. As we progress, our focus remains on further improving DER forecasting granularity and integrating these practices into core distribution system planning functions to reliably meet future energy and capacity needs. **Appendix G Forecast results and AdopDER** provides an overview of these recent advancements demonstrating our commitment to evolving our distribution system planning to meet the challenges and opportunities of a modern, equitable energy landscape.

3.3 Latest DER forecasts

- In this section we have provided the annual DER forecasts for the next 20 years (2025-2044) for three scenarios – reference, low and high adoption based on our

[22] PGE, "Distribution System Plan Part 2", August 2022. Available at: Distribution System Planning | PGE (portlandgeneral.com). See chapter 3.

latest AdopDER simulation in August 2024. During this update, we implemented a few enhancements to the methodology and updated several inputs reflecting changes to the policy and market landscape. Our DER forecast takes account of detailed data about each customer class, DER technology and performance considerations, and Oregon-specific policy changes. **Table 1** provides list of high-level inputs that are needed by AdopDER model for forecasting.

Table 1. List of inputs into AdopDER model

Input name	Brief description
AMI data	AMI data utilized to create baseline load profiles for Service Point Identifications (SPIDs), meters.
Customer database	Relevant customer information like location on feeder, rate schedule, heating source (if available)
Active generator list	List of existing solar PV installations within the PGE service area and relevant information
EV charging station list	List of EV charging stations within PGE service area along with information about location, ownership and type as available from Alternative Fuel Data Center (AFDC)[23]
Loss of load probability	Loss of load probability distribution throughout the year based on simulations
Corporate load forecast	Updated corporate load forecasts produced at the meter and grossed up for losses by rate schedules/ revenue classes
Load research study data	8760 hourly profiles for the baseline year created through load research
Cold thermal ice storage data	List of existing premises known to have cold thermal ice storage facilities
Rate schedule and revenue class information	Mapping of SPIDs to rate schedules and revenue classes
EVs within PGE service area	Recent Department of Motor Vehicles (DMV) registration data extract gone through address matching (using customer database) and Vehicle Identification Number (VIN) decoding (to determine fuel type of vehicle) in order to map existing EVs within service area
Spot load additions	List of known load additions by type at different feeders as obtained from distribution planning team

[23]Alternative Fuels Data Center: Alternative Fueling Station Locator. Available at: https://afdc.energy.gov/stations#/find/nearest

Input name	Brief description
Fleet vehicle and electrification	List of existing fleet vehicles known to be within service area and any available information about potential electrification plans
Community solar segment sizes	Identified community solar potential along with sizes
Demand Response (DR) data	List of SPIDs currently enrolled in different DR programs
Feeders with zip codes	List of all feeders within service area mapped to the postal zip codes
Residential appliance saturation survey	Data about equipment type, say for heating, cooling etc.
Residential building stock assessment data	Building characteristic and energy usage data on residential buildings in the Northwest
Measure parameters	Includes the different adoption curves for various segments of TE, solar PV, BE etc.
Measure sizes	Descriptions and characteristics of measure sizes

Within measure parameters some of the major updates to the adoption curves have been as follows:

- Updated forecasts of PV solar market shares for PGE's service area from NREL;
- Updated market shares of EV based on EPRI and Brattle's projections, and implemented logic for Medium- and Heavy-duty Vehicle (MHDV) adoption to account for Oregon Department of Environmental Quality (DEQ) adoption of Advanced Clean Trucks (ACT) rule;

Below, **Table 2** provides an understanding regarding the growth in TE and BE load as well as increase in distributed rooftop solar PV adoption by PGE's customers in both residential and non-residential sector combined. While TE and BE would lead to increase in gross load on the system, solar can help reduce the net load to some extent during hours when the rooftop solar PV systems generate energy.

Table 2. Forecast of DER adoption in aMW (AdopDER Aug. 2024 vintage data)

	2025	2030	2035	2040
TE	13	95	288	526
BE	2	55	179	285
Distributed Solar	49	97	100	202

In order to flexibly and reliably integrate renewable energy, enhance reliability by providing backup power or shift energy use for increasing grid stability or economic benefits (to customers and utility), it will be important to add energy storage assets in the system. **Table 3** presents data indicating the trend in the adoption of behind-the-meter batteries based on our forecast.

Table 3. Forecast of storage by nameplate capacity in MW (AdopDER Aug. 2024 vintage data)

	2025	2030	2035	2040
Distributed behind-the-meter storage	15	46	51	55

The data is used to determine the baseline loadshape without any DER impacts. Superposing the forecasted DER impacts the shapes of the net loads that would be observed at the different feeders can then be computed. These can be rolled up to the substation. The information will be important to forecast any potential grid constraints in the future. **Figure 9** provides example loadshapes (baseline load and net load forecast) observed at four of PGE's feeders (feeder numbers 4157013, 4157023, 4157033 and 4157043) during specific days in 2035.

Figure 9. Example loadshapes (which includes baseline and net load shapes) at four different feeders

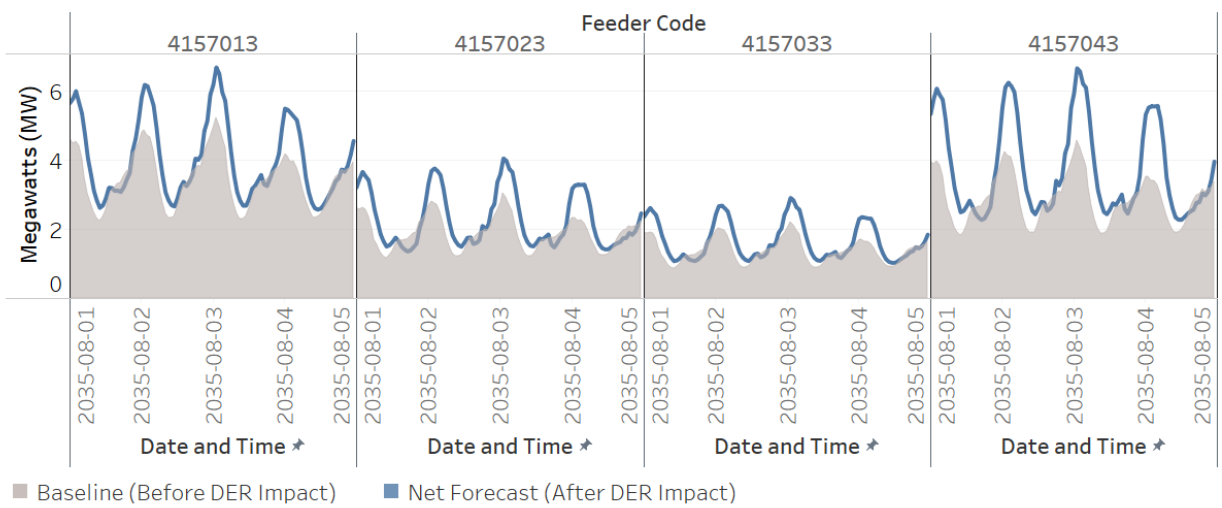


Figure 10, **Figure 11**, and **Figure 12** present plots of the growth potential in distributed solar PV, building electrification and transportation electrification adoption respectively over the next 20 years based on AdopDER's forecasting model. **Figure 13** and **Figure 14** provide growth potential of DR/flex load in the summer and winter seasons respectively, and it includes those DR/flex load measures that are assessed to be cost-effective by AdopDER. All of the above plots are based on results obtained from AdopDER's Aug. 2024 vintage data.

Figure 10. Forecast of solar PV adoption (AdopDER Aug. 2024 vintage)

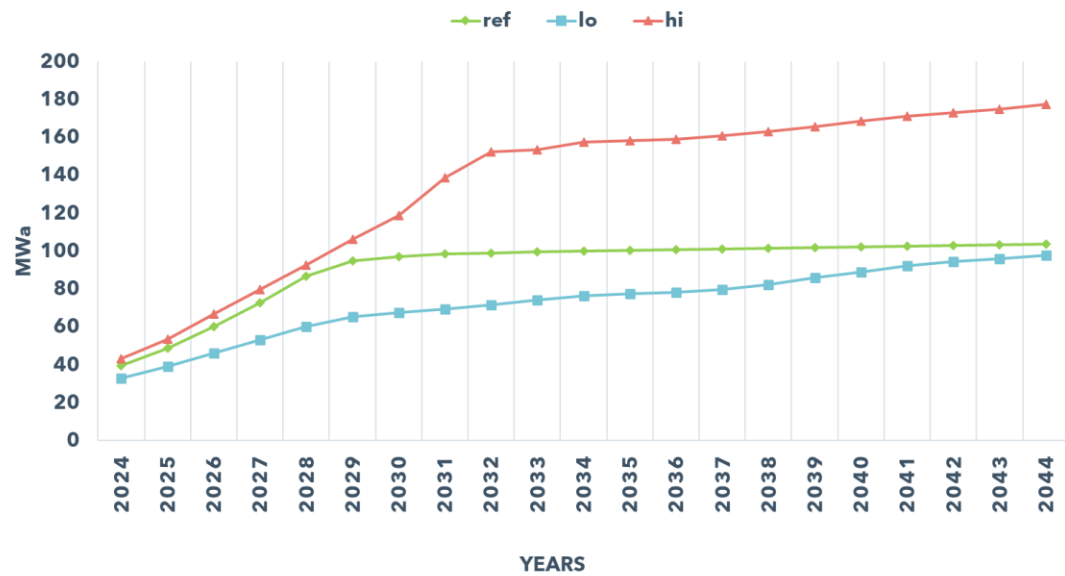


Figure 11. Forecast of BE (AdopDER Aug. 2024 vintage)

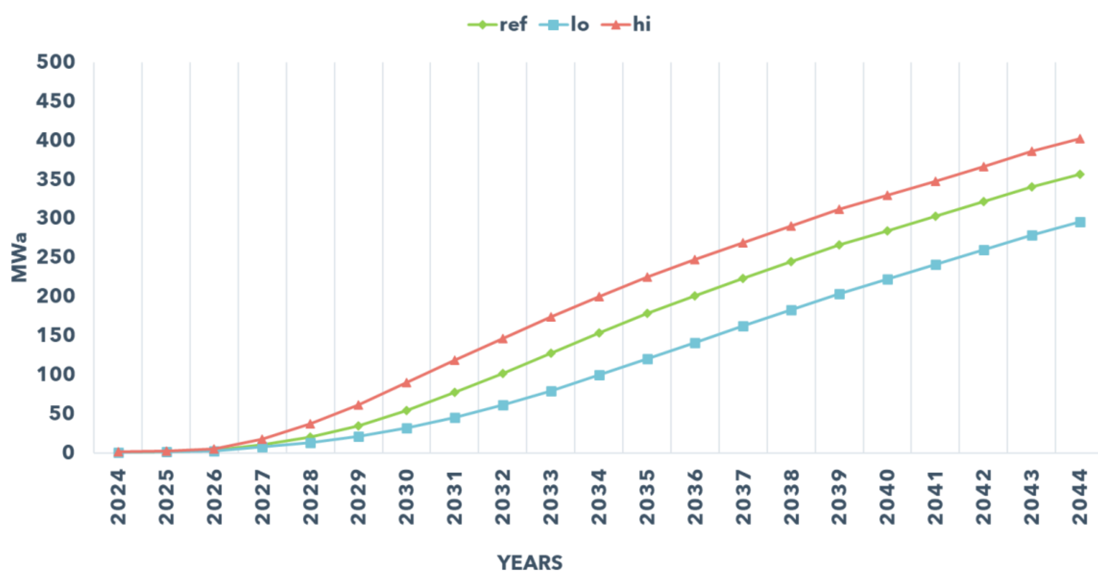


Figure 12. Forecast of TE (AdopDER Aug. 2024 vintage)

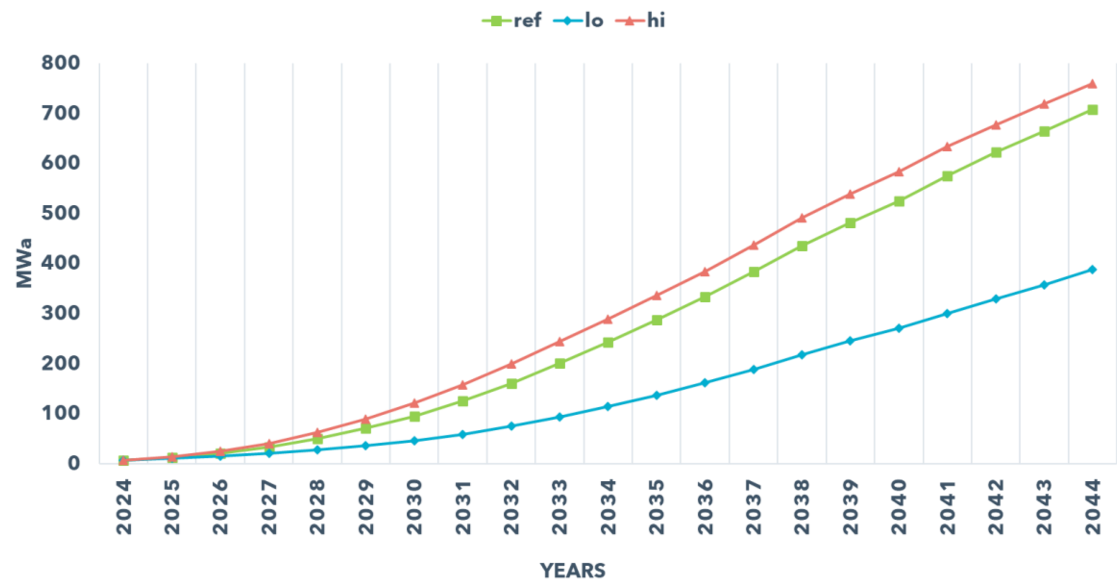


Figure 13. Forecast of DR/Flex Load Cost-Effective Summer MW (AdopDER Aug. 2024 vintage)

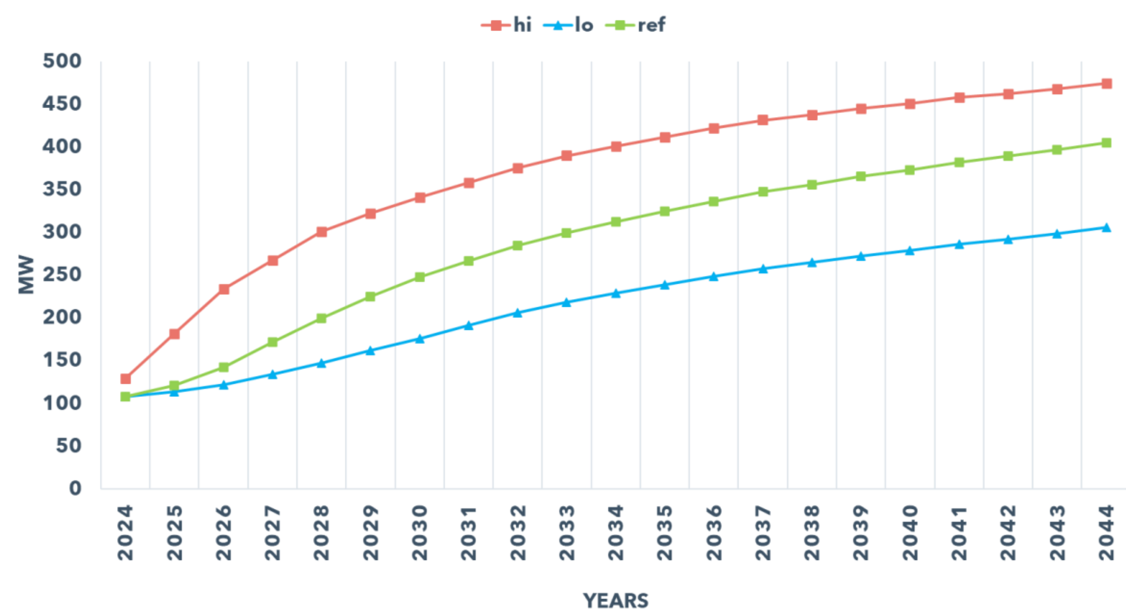
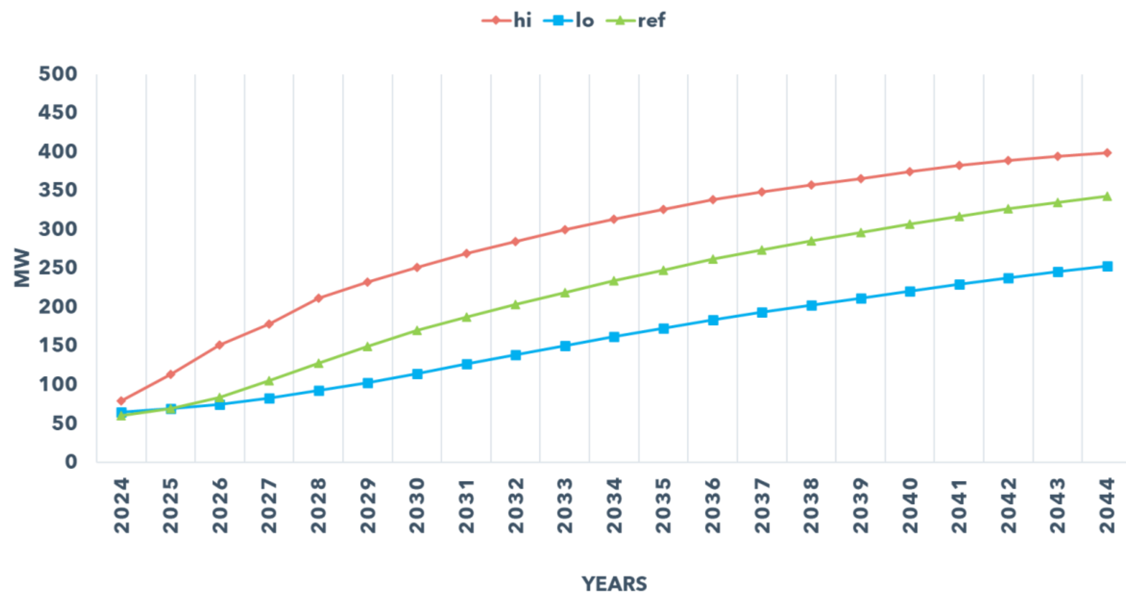


Figure 14. Forecast of DR/Flex Load Cost-Effective Winter MW (AdopDER Aug. 2024 vintage)



PGE continues to build on the AdopDER tool and incorporate improvements and new capabilities. Recent improvements include integration with CYME software for streamlined planning workflows, enhanced spot load addition handling, alignment with the Corporate Load Forecast, and the capability to incorporate multiple weather scenarios.[24] The model now provides forecasts at the service point ID, feeder, and substation levels, enabling more granular and accurate distribution system planning. While increased locational resolution offers benefits for detailed planning, it also presents challenges in forecast accuracy at individual sites. PGE is working to balance these trade-offs and further improve locational disaggregation methods to enhance overall forecast accuracy and support reliable energy and capacity planning in the face of increasing DER adoption.

[24] CYME is a power engineering software suite developed by CYME International that provides tools for distribution system analysis and planning. It's used by utilities for:

- Power flow analysis
- Short circuit analysis
- Equipment rating and sizing
- Network reliability studies
- Distribution system modeling and planning
- Distributed generation impact studies
- Volt/VAR optimization studies

Chapter 4. Technology foundations for a bi-directional grid

This chapter outlines PGE's grid modernization strategy and infrastructure needs, focusing on three main elements:

Current challenges & needs

- Projected 750 MW demand increase by 2030
- Requirements for DER integration
- Grid operator challenges with bidirectional power flow
- Location and firmness factors for DER effectiveness

Grid Modernization components

- Customer ecosystem
- Integrated planning
- Grid management systems
- Sensing and automation
- Telecommunications
- Physical infrastructure
- Cybersecurity

Solution implementation

- Structured framework for identifying and testing solutions
- Three-phase DERMS rollout plan
- Specific modernization initiatives for each pillar
- Integration of advanced technologies (VVO, FLISR, ADMS)
- Focus on cybersecurity and resilience

The chapter establishes how these components work together to create a modern, flexible grid capable of handling increased DER adoption while maintaining reliability and security.

PGE's assessment of the grid's needs through 2030 is informed by the objectives for decarbonization by 2040. Load growth, beneficial electrification, and DER adoption results in a projected 750 MW increase in net electric demand by 2030, raising the total peak demand served by PGE from 4.5 GW to 5.25.[25]

[25] Forecast is from PGE's May 2024 forecast update. This vintage of forecast also is used in the CEP/IRP update.

To meet this demand increase, the long-term plan suggests that we would need to construct or upgrade 5-15 substations. Each new substation or substation upgrade would also require extensive distribution line upgrades or new distribution lines to relieve load on existing distribution feeders. Development of a distribution system platform that maximizes the use of existing assets and optimizes power flow through the orchestration of DERs can avoid or defer the need for a portion of that investment.

4.1 Needs analysis for DER integration and operation

The need to address the load growth and further support DER integration while ensuring the just transition to a cleaner energy future is a challenge. The envisioned DSP distribution infrastructure deployment will provide the foundational customer reliability and grid flexibility required to deliver the benefits of clean energy to all customers.

While infrastructure investments are important, integrating DERs as grid assets is crucial for optimizing the distribution grid and achieving cost-effective clean energy deployment. Neighborhoods with solar panels or battery storage can provide surplus energy or stabilize the grid, reducing the need for expensive upgrades. By utilizing both capacity upgrades and DERs, we are using all available tools to meet our clean energy targets.

Grid operators face increasing challenges managing the complex electric distribution system, which is becoming more automated and bidirectional. Weather patterns and automated schemes can create abnormal conditions, like overloaded circuits, when restoring power after outages. Grid services solutions offer a new approach for grid operators to manage local constraints and improve system efficiency and reliability by utilizing customer owned DERs.

The potential of DERs to avoid or defer traditional infrastructure depends on two factors – location and firmness.[26] Whether DER facilities are connected to portions of the grid where they can address system needs identified in long-term planning or real time operations will drive their grid services potential. Historically, larger front of the meter (FTM) DERs have tended to be sited in areas where land is more readily available and not where capacity need is the greatest. With respect to firmness, the potential of DERs to add value by providing grid services is based on the degree to which they can be counted on when and where they are needed. Traditional utility infrastructure is monitored and maintained by PGE so that it is completely available when needed. The alternative must adhere to the same

[26] There are several types of DER some of these DER are dispatchable and some are not. Dispatchable DERs are more valuable to the system because of their operational availability and firmness of performance. These and other factor such as dispatch timing, length of dispatch and historical performance individually and in aggregate will affect the ability of DERs to replace traditional distribution system infrastructure investment. The concept of a replacing traditional distribution infrastructure with a or aggregation of DER is called a non-wires solution. There are several proofing activities and tool development that needs to be undertaken before PGE can rely on DERs to replace traditional distribution system technologies where the use cases directly align to distribution operation.

standard to support safe and reliable service to customers. A third party owned battery connected to the supervisory control and data acquisition (SCADA) system for monitoring and control by system operators is more reliable than a pay-for-performance Wi-Fi thermostat demand response program that allows for customer override[27].

With respect to using DERs to solve local issues, it needs to be clearly understood that load and charge management, if not orchestrated with the utility, can have the opposite effect. Distributed resources (electric vehicles, solar, storage) that are aggregated and dispatched towards bulk energy markets without proper integration can have severe impacts on the system. Introducing an external trigger event, such as a market price signal, would significantly increase the coincident factor of the aggregated resources.

PGE will need to address the following operational needs. These needs are applicable for all types of DER dispatch, including use of DER assets to address distribution system constraints.

- Must have sufficient information regarding dispatch schedules to conduct operational load forecasts used to inform switching operations, maintenance, or respond to anticipated critical events such as heat waves.
- Decisions must be informed by an awareness of anticipated system constraints, planned outages, and other events that might limit access to resources before final plans are established. Absent this awareness there may be a need for curtailment of DERs based on real time system conditions.
- Absent coordinated dispatch for wholesale and distribution use cases, PGE will have no avenue for providing additional incentives for resource dispatch to address real time congested systems, potentially requiring incremental system investments.
- During critical system events such as N-1 conditions (e.g., outages, faults, storm events), real time communication between aggregators and utilities is essential as system conditions change rapidly, requiring an adjustment of dispatch[28].

Although there are many factors related to policies, technology, markets, and customer preferences that will shape the future of DER participation as grid assets, the demand for maximizing the value of DER for multiple use cases will grow considerably over the next four years. Additional capabilities are required to enable this value-added orchestration of DERs.

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[27] Supervisory control and data acquisition (SCADA) is an industrial control system that enables utilities to:

- Monitor equipment and processes in real-time
- Collect and analyze data from across the grid
- Control grid equipment remotely
- Detect and respond to system issues
- Manage power flow and distribution

[28] N-1 conditions refer to situations where one major component of the power system (such as a transmission line, transformer, or generator) is out of service, either due to failure or planned maintenance. The grid must be designed to maintain reliable service even during these scenarios, which is a fundamental principle of power system planning and operations.

Upgrading and better utilizing the existing system—including by leveraging demand-side resources—can defer and/or avoid some of the cost of rebuilding or adding new transmission and distribution infrastructure. A Wood Mackenzie analysis of fifty major investor own utilities (IOU) rate cases found that the average project cost of DER management (e.g., DERMS) was 100 times cheaper than average physical infrastructure project costs.[29] While physical infrastructure will still be needed to enhance the grid, alternate solutions that can be more cost-effective should be considered.

4.1.1 Modernized grid

PGE Grid modernization is a critical transformation of our electricity infrastructure to meet the challenges and opportunities of the 21st century. It involves upgrading and integrating new technologies to create a more efficient, reliable, resilient, and sustainable power grid.

4.1.2 Why is grid modernization necessary?

The traditional power grid was designed with a singular purpose: to deliver electricity in a one-way flow from large, centralized power plants to consumers. But as our world evolves, so too must the infrastructure that powers it. The energy landscape has undergone a profound transformation:

4.1.2.1 Customer growth in energy use

As our population grows and we electrify transportation and the devices that shape our daily lives, the demand for electricity increases. This is not just about meeting the demand; it's about empowering people to live fuller, more connected lives.

4.1.2.2 Customer energy management

Customers are taking a more active role in how they use electricity by generating their own power, often through rooftop solar panels, and storing energy with battery systems. This shift allows them to use self-produced power. As a result, the relationship between customers and the grid is evolving. Instead of just receiving power from utilities, many customers now contribute electricity back to the grid, making them both consumers and producers of energy.

Additionally, through local energy generated by community-based solar and storage, communities can produce reliable and sustainable power, giving communities more control over how they use and produce energy.

4.1.2.3 Decarbonization through electrification

Solar and wind power, once on the periphery, are now central to our energy future with the integration of renewable energy. Yet, their intermittent nature requires a grid that is flexible,

[29] This study is referenced in the DOE's commercial liftoff report for Innovative Grid Deployment. Available at: https://liftoff.energy.gov/wp-content/uploads/2024/04/Liftoff_Innovative-Grid-Deployment_Final_4.12.pdf. This is a cite to the original publication: Kazempour,F., Hu, K. November 2023. *Utility investment in grid modernization: H2 2023*. Wood Mackenzie.

adaptable, and ready to harness the full potential of these clean energy sources regardless of where they are found on the grid.

4.1.2.4 Increase resilience

Our aging grid, with power lines and equipment approaching the end of their lifespan, presents not just a need for replacement but an opportunity to create a more adaptable, resilient, and future-ready system. With climate change, extreme weather events are becoming more frequent and severe, challenging the reliability of our grid. But this challenge is also a call to action—to build resilience, to protect our communities, and to keep power flowing, no matter what.

There has been an increase in overall cyber threats targeting energy infrastructure across the U.S., with Oregon's grid being no exception. Increased reliance on digital systems and vulnerabilities in aging grid infrastructure create openings for cyber-attacks. National experts continue to highlight the needs for greater cyber resilience in the energy sector.[30] Protecting this critical infrastructure is not just about security; it's about safeguarding our way of life, our economy, and our future.

4.1.2.5 Increase price competitiveness

When we provide customers with more control over energy usage (generating with DERs, and/or participating in demand response programs), we empower them to make to make their own choices, leading to better energy management, which can reduce energy costs.

To meet these challenges, the grid must do more than just keep up—it must transform. It must have the capacity and flexibility to harness the full potential of, to optimize, distributed energy resources (DERs) and adapt to the electrification that is reshaping our world. This is not just about technology; it's about resilience—building a grid that can meet our customers where they are, withstand the forces of nature, and adapt to changing needs over time.

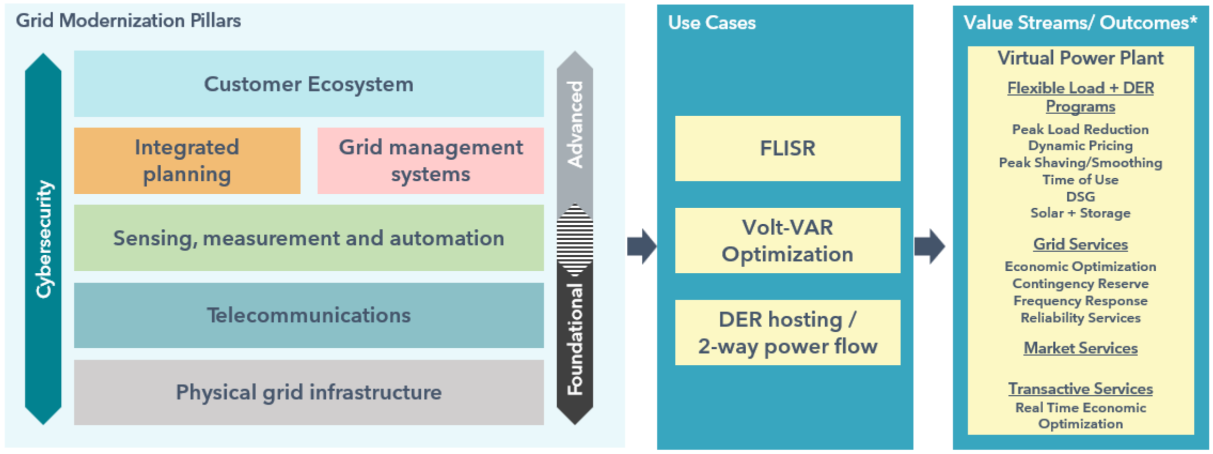
By hardening the grid today and designing systems that accommodate flexibility and enhanced monitoring, we reduce the risks posed by climate change and other threats. But more importantly, we reaffirm our commitment to a future where energy is not only reliable but also sustainable, secure, and equitable.

4.1.3 Key components of grid modernization

Grid Modernization comprises a group of functionalities that work together in a specific use case to deliver value stream outcomes outlined in **Figure 15** below.

[30] Greater resilience in the energy sector. Available at: https://www.opb.org/article/2023/01/19/surge-in-oregon-washington-substation-attacks-as-fbi-warns-neo-nazi-plots/.

Figure 15. PGE's modernized grid framework



*Note: Value Streams/Outcomes list is not exhaustive

As an example, today, when power flow is interrupted, ADMS (Grid management system), uses automatic FLISR (Fault, Location, Isolation, and Service Restoration) to communicate to line reclosers via a leased cellular network to isolate the fault on our distribution mainlines, reconfigure feeders to source power, and restore service to customers outside of the faulted section. Crews are then sent to repair the faulted section to restore power for affected customers. This results in fewer customer outages, reducing customer minutes interrupted (CMI) (reliability services). In the future, PGE would like to move from communicating via cellular network to utilizing a PGE-owned wireless network. Prior to the implementation of automatic ADMS FLISR, PGE relied on manual processes to locate faults, isolate the affected sections, and restore power. This involved sending field crews to patrol the circuits surrounding the outage to locate the fault and make repairs to restore service. This led to longer outage durations and slower restoration times.

Similarly, Volt-VAR Optimization (VVO) is a technology to fine-tune the voltage and reactive power on the grid, helping to improve energy efficiency and power quality (reliability services). Here's an example of how it will work when customer owned DERs like batteries are involved.

Imagine a PGE neighborhood where several homes have solar panels and batteries installed. These homes can generate their own electricity and store it in their batteries for later use. Normally, the electricity from PGE is sent through power lines to all the homes in the neighborhood, and the voltage (the "pressure" pushing the electricity) needs to stay within a specific range for everything to work correctly, such as keeping customers' appliances running smoothly.

Without VVO, PGE manages this voltage in several ways including phase balancing on the distribution feeders, adjusting equipment at the substation, or by adjusting transformers on power lines so that everyone in the neighborhood gets the right amount of voltage, but it's not always perfect. Sometimes, homes farthest from the power source might get lower voltage, while those closer might get higher voltage.

With VVO, the system will constantly monitor voltage. If it detects a drop in one area, VVO will tap into the energy store in home batteries. This will balance the voltage across the neighborhood without requiring additional power from the main grid.

By using customer owned DERs like batteries, PGE will not just rely on its own equipment to manage power quality. It will also leverage energy resources that are already in the community, meaning fewer upgrades to big infrastructure, better power stability, and a more adaptable grid. Beyond potential payments and on-bill credits, customers benefit from enhanced energy reliability, improved efficiency, and possible cost savings from better grid performance.

The VVO system will use meters at homes, voltage sensors along the grid, and advanced metering infrastructure (AMI) (sensing, measurement and automation) to gather real-time data on voltage and power flow. This data will be transmitted via telemetry (telecommunications) to PGE's ADMS (Grid management system) where it will be analyzed. If deviations from optimal voltage levels are detected, VVO will adjust grid devices like transformer load tap changers and voltage regulators (physical grid infrastructure). When needed, it will also tap into customer owned DERs, coordinated through a DERMS (Grid management system), to provide additional reactive power and balance voltage. The result will be a more stable and efficient grid with better power quality for customers (reliability service).

PGE is planning to accommodate distributed energy resources (DERs) like solar panels and batteries—by assessing the current state of the grid, predicting future energy needs, and integrating technical, operational, and financial considerations.

PGE also could make operational adjustments to manage 2-way power flow more effectively. PGE may shift or reduce electricity demand during peak times through flexible load programs such as peak shaving, peak load reduction, and time-of-use pricing, which encourages customers to use energy when the grid has more capacity, (e.g., mid-day when solar generation is high). These help the grid accommodate more DERs and 2-way power flow. The capabilities needed to enable these operations are described in **Table 4**.

Table 4. Descriptions and needs by components for PGE's modernized grid are summarized

Component	Description of grid modernization components and needs statement
Customer ecosystem	**Description:** Portals to provide customers access to relevant and timely usage, performance, and system data. Data-driven personalization of product and program recommendations to aid customers in meeting their energy targets. **Needs statement:** Enable customer choice, customer awareness and decision-making.
Integrated Planning	**Description:** A suite of integrated tools to perform distribution system planning and engineering functions such as hosting capacity, forecast, pricing will be included as part of the integrated plan

Component	Description of grid modernization components and needs statement
	Needs statement: Improve planning to enable optimal grid investments, including DER integration through information exchange and non-wires solutions.
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 a large number of DERs, creating two-way power flows, which 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.
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 (e.g., line sensor or electric meters) 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 is required to enable accurate information flow for rapid outage response and reduced outage durations; outage avoidance through real-time mitigation; and enablement of DER integration and optimization. Enable customers to participate more and use assets wisely.
Telecommunications	**Description:** The infrastructure that connects grid assets and the distribution system operators. **Needs statement:** A reliable, secure, cost-effective telecommunications network for grid operators to communicate with grid assets that will enable more grid services, including deployment of latest IT/OT sensors and devices.
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 and allows grid operators to monitor, control and predict the behavior of the electrical grid.
Cybersecurity	**Description:** The protection of computer systems and networks from information disclosure, theft of or damage to their hardware, software or

Component	Description of grid modernization components and needs statement
	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. Therefore, it will be necessary to continue to enable the protection from any rogue actors by continually improving cybersecurity efforts.

4.1.4 Benefits of grid modernization

A modernized grid offers numerous advantages:

- **Improved reliability:** Reduced power outages and faster restoration times
- **Increased efficiency:** Lower energy losses and cost savings
- **Enhanced sustainability:** Greater integration of renewable energy sources
- **Economic growth:** Creation of new jobs and industries
- **Improved grid resilience:** Better ability to withstand extreme weather events and cyberattacks.

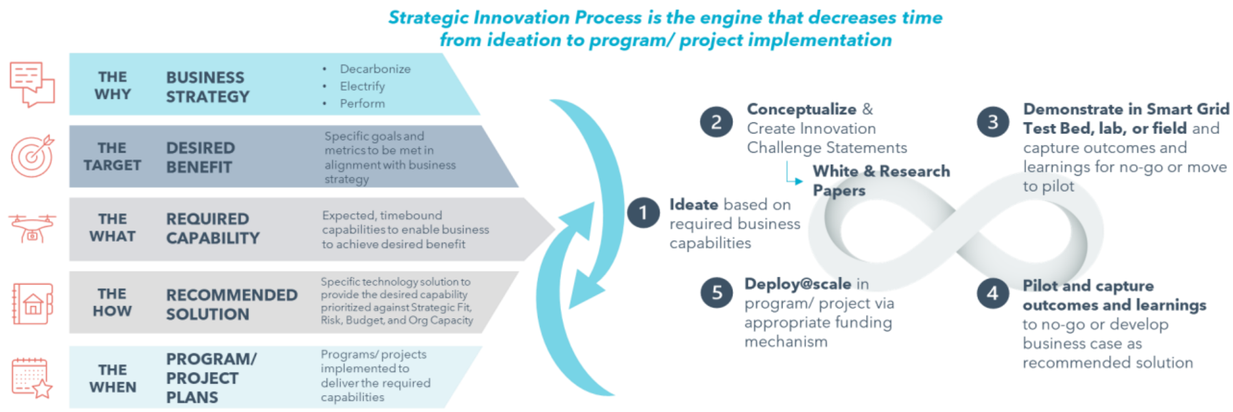
4.2 Grid modernization solution identification

PGE is focused on modernizing its grid infrastructure to support the growing adoption of Distributed energy resources (DERs) and enhance overall grid reliability and efficiency.

4.2.1 How do we identify solutions?

PGE is utilizing a new grid modernization solution framework, a structured process to identify, test, and scale innovative solutions that will enable the grid of the future meeting customer expectations and PGE's business strategy (depicted in **Figure 16**). While PGE already completes many of these steps today, what's new is using this structured process from end-to-end consistently.

Figure 16. Grid modernization solution framework



In *Step 1* of **Figure 16**, PGE teams ideate and research potential options to address required business capabilities that are aligned to PGE's long-term corporate strategy and to our short-term (one to-three year) goals.

In *Step 2*, teams further conceptualize their ideas. They conduct research, develop use cases, and create innovation challenge statements regarding what they might want to test or learn to determine if the solution will prove to be viable and valuable. Some may write research papers or whitepapers outlining their research findings and plans.

Then teams move to *Step 3* to demonstrate or test their use cases using their prototype solution in a PGE lab, out in the field, or in the Smart Grid Test Bed. The purpose is for teams to capture learnings and outcomes to assess quickly if the solution is worth investing in a pilot and moving to *Step 4*, or if it's a no-go.

Teams that move viable solutions to pilot in *Step 4* use the solution on a small-scale. Similarly, based on outcomes and learnings in the pilot, a solution may be ready for deployment at scale. The team develops a business case leveraging the outcomes and learnings gained through Steps 1-4 of the strategic innovation process. Once the business case is approved by a PGE Business Sponsor Group, a governance and funding approval committee, the recommended solution is moved to *Step 5* to deploy at scale. The recommended solution is still prioritized against other approved recommended solutions. Prioritization includes looking strategic fit, including value to the customer, risk, compliance, organizational capacity, and budget. At that point, the final list of recommended solutions become programs or projects to deliver the required business capabilities for the year, or in some cases multi-year efforts.

PGE's Grid Modernization team explores various grid technologies and systems that support business strategy, advance grid readiness for DER growth, and improve reliability and resiliency for customers. The team works with planning and operations teams to develop various use cases and frame innovation challenges to support required grid modernization capabilities, and pair it with the right selection of technologies to solve it.

Before at-scale deployment, the Smart Grid Test Bed team will explore these technologies on the distribution system through targeted deployment and explore cost, technical feasibility, and validate effectiveness, etc. Customer resources development requires product/program development to meet grid needs and customer preferences, exploring market potential, branding and marketing efforts, and the value proposition for customers.

Once proven in the Smart Grid Test Bed and/or the pilot stage, the DERMS platform will be used to integrate resources and services from DERs at scale. The DERMS platform will also enable security constrained dispatch of DER resources at scale, allow for wholesale market participation of DERs, and optimize resources across multiple service offerings, which can simultaneously improve reliability, resilience, and capacity. The DERMS platform will also optimize services based on DER capabilities and availability which unlocks the best value for customer resources in the market.

4.2.2 What solutions are needed?

PGE Grid Modernization Solutions can be classified into seven categories, aligning with our grid modernization focus areas:

- Foundational Infrastructure Investments - > Physical Grid Infrastructure
- Network Investments (Wired and Wireless) -> Telecommunications
- Integrated Planning Systems
- Sensors/Grid Edge Technologies & Next Gen AMI -> Sensing, measurement, and automation
- Grid Management Systems (GMS)
- Advanced Analytics, which supports all focus areas

PGE is making strategic foundational infrastructure investments to enhance the safety, flexibility, and intelligence of the grid. One such investment is in protection digital relays, which can detect faults in either direction, ensuring that protection settings respond dynamically to changing grid conditions. This technology prevents the potential miscoordination of protection devices, which is critical in handling the complexities introduced by DERs and the two-way power flow they create.

In addition to these protection measures, PGE is also focusing on upgrading substation automation and Supervisory Control and Data Acquisition (SCADA) systems. These systems form the backbone of the grid's monitoring and control capabilities, ensuring real-time responsiveness and operational efficiency as the grid becomes more complex.

A key part of this modernization is PGE's telecommunications strategy, which includes the deployment of a Field Area Network (FAN). This network, operating on a dedicated 1 MHz spectrum owned by PGE, provides secure and reliable communications for critical grid operations, particularly for distribution automation devices. By combining this telecommunications infrastructure with ongoing investments in SCADA and substation automation, PGE will improve the ability to monitor, control, and optimize the grid, making it more resilient and efficient.

Telecommunication investments are essential to support the monitoring and control of DERs. PGE is exploring a range of telecommunication technologies to provide the necessary connectivity, reliability, and security to meet our future needs. The key differences from today are the sheer volume of devices on the horizon, the distributed location of these devices within our footprint, and the wide array of connection and reliability requirements with the corresponding data costs. To that end, we are implementing solutions such as:

- Hybrid wireless solutions (e.g., Expeto platform) a different way to get the best aspects of private wireless and commercial cellular services to provide a secure wireless integrated network, quickly
- Private LTE /5G to reduce data costs in the long-term
- Private satellite to securely reach deep into Public Safety Power Shut-off (PSPS) zones and other rural areas.

To complement these advancements, PGE is upgrading its Advanced Metering Infrastructure (AMI) to enable bi-directional metering and enhanced management of utility meters. A new meter head-end system has been implemented as part of this upgrade, which has achieved 99.9 percent penetration. The AMI system collects critical system data from meters, providing valuable insights for better management of energy usage and overall grid performance.

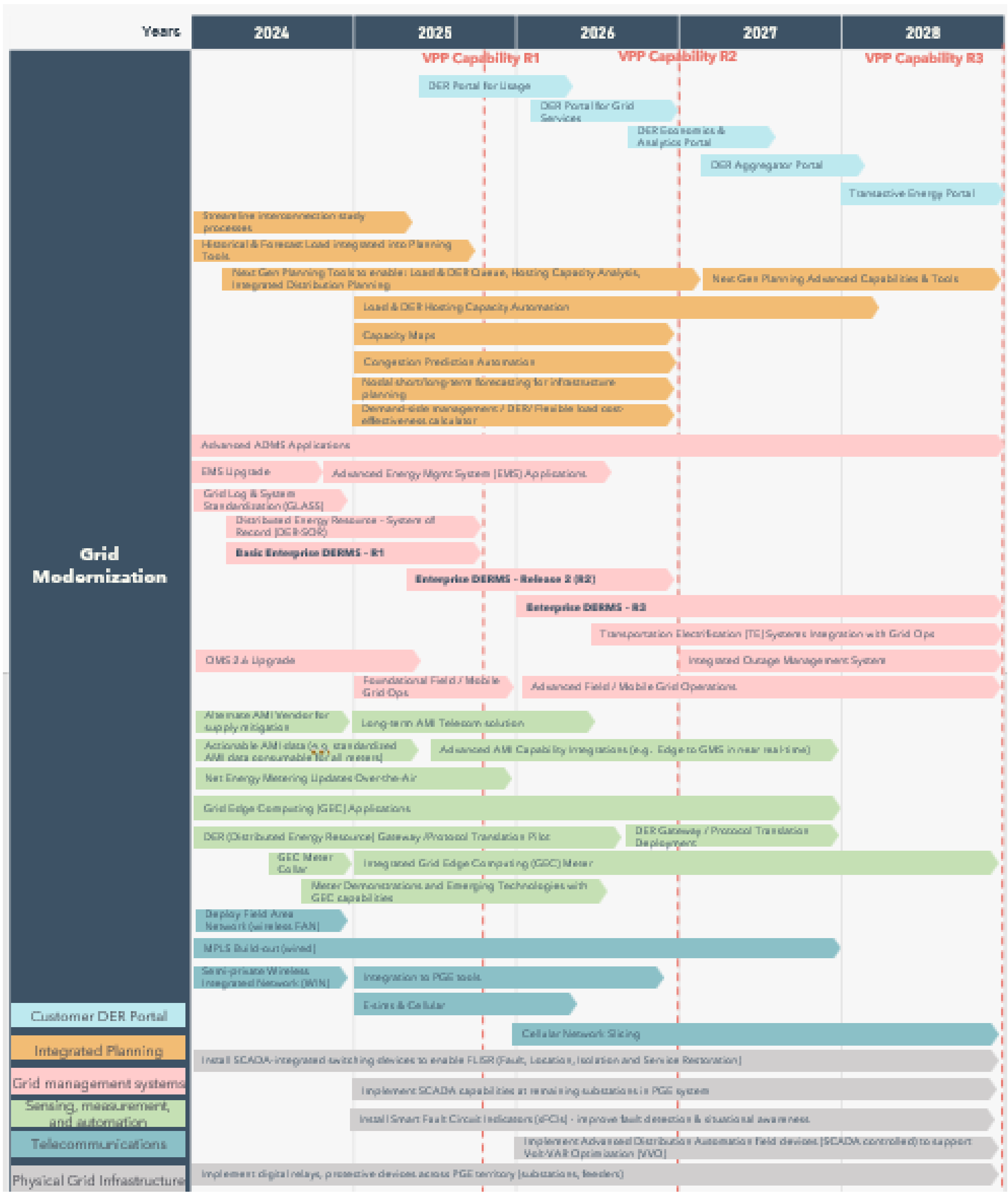
These efforts are part of PGE's broader grid modernization strategy, designed to integrate customer-owned equipment, such as distributed energy resources (DERs), advanced devices, and grid edge computing technologies. This integration will enhance asset management, enabling PGE to deliver reliable, secure, and cost-effective energy services while positioning the utility for a safe, smarter, more dynamic grid future.

Advanced systems like Advanced Distribution Management System (ADMS) and Distributed Energy Resource Management System (DERMS) orchestrated by Virtual Power Plant (VPP) operations will tie all these elements together, providing critical grid services and delivering tangible value to customers. These systems will manage the flow of energy and resources, optimize grid performance, and promote a seamless transition into a modern, flexible energy system.

PGE has mapped out near-term investments that will have a direct and measurable impact on achieving its vision for the future of the distribution system. Each investment is accompanied by a forecasted timeline for implementation, with an eye toward both short-term outcomes and the long-term evolution of the grid, ensuring PGE is prepared for the next generation of energy challenges.

In **Figure 17** below is a summary of grid modernization solutions organized by pillar. A summarized table of investments is in **Section 8.3 Grid modernization investments**.

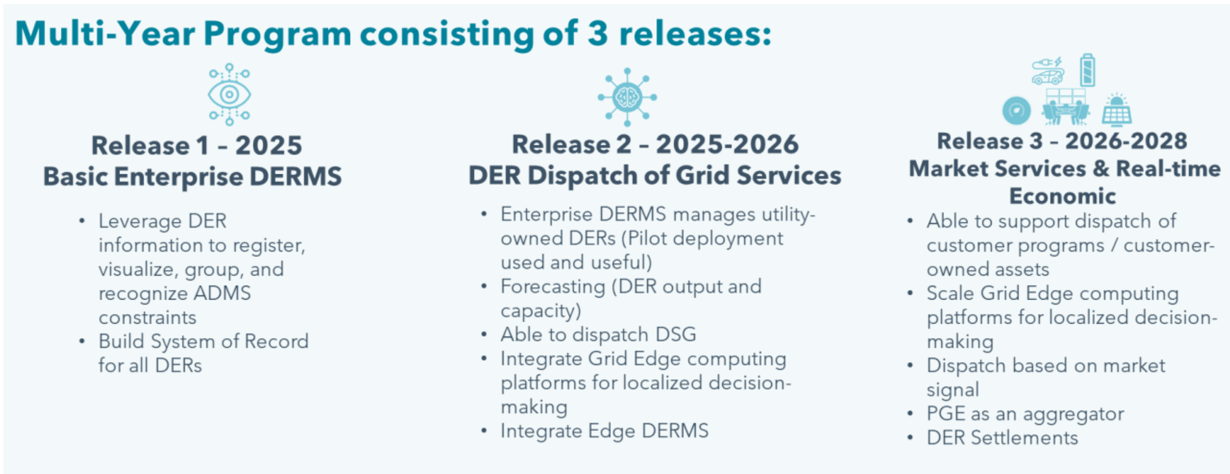
Figure 17. Summary grid modernization roadmap



Each swim lane is explained briefly below and elaborated in **Figure 16**. It is important to note that as part of our grid management system solutions, PGE has begun implementing an DERMS, a software platform used to visualize, group, manage, and dispatch DERs to provide grid services, such as energy capacity with PGE's distribution network in real-time.

Enterprise DERMS will be rolled out over three releases, each delivering additional capability and value as we move towards scaling PGE's Virtual Power Plant. These releases are summarized in **Figure 18.**

Figure 18. Enterprise DERMS rollout timeline



4.2.2.1 Customer ecosystem

The Customer Ecosystem aims to enhance customer interaction and experience with new DER functionalities. PGE plans to inform customers about energy products, encourage partnerships for self-generation and energy efficiency solutions, and deliver grid connectivity and device management. This system will form the basis of a Virtual Power Plant, providing detailed grid operations data.

PGE is improving its customer portal for device management, billing, settlements, interconnections, and communications. Future developments include a DER marketplace, transactive energy portal, transportation energy functionalities, and building electrification tools. Many of these capabilities will be enabled by Enterprise DERMS implementations.

4.2.2.2 Integrated planning capability

PGE is enhancing its integrated planning capabilities with next-generation tools for distribution system planning, aligning with DOE's DSPx guidelines.[31] This approach directly supports PGE's distribution system vision, with key investments planned over the next five years to enable foundational functions.

The company has developed an in-house model for bottom-up DER forecasting and potential assessment at both system and locational levels (see **Chapter 3** for more information on AdopDER). This model integrates building and vehicle stock modeling with market-level adoption forecasts, offering a comprehensive view of DER and electrification

[31] DOE's DSPx documentation. Available at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

technologies. PGE is also investigating next generation planning tools to enable Integrated Distribution Planning (IDP) by enhancing technical analysis capabilities.

4.2.2.3 Grid management systems

Grid management systems use operational technology tools to monitor, predict, analyze, control, and optimize the distribution system performance. These systems communicate with field devices via a telecommunications network, with investments in Grid Management System (GMS), field devices, and telecom systems interlinked for maximum customer benefit.

PGE's grid modernization strategy includes foundational investments for a modernized grid, ensuring safety, security, reliability, and resilience where there is high DER penetration. The company has completed its Basic ADMS deployment and is now focusing on improving its implementation by expanding and adding advanced functions such as FLISR, Distribution State Estimation, and Fault Protection Analysis.

4.2.2.4 Physical grid infrastructure

Modernizing substations with SCADA, advanced protection, and updating physical grid infrastructure with technologies like FLISR, VVO, and smart fault circuit indicators offers clear benefits to customers. These include fewer and shorter power outages, preventive maintenance, reduced downtime, and a more reliable power supply.

PGE's physical grid infrastructure depends on the continued deployment of distribution automation solutions such as FLISR, VVO, and Smart Fault Circuit Indicators (sFCI). The company is also enhancing monitoring and operations by increasing SCADA capabilities at substations and modernizing protection systems with digital relays that support remote setting modifications and detailed data integration with SCADA platforms.

4.2.2.5 Sensing, measurement & automation

PGE is moving towards a more predictive grid by adding advanced computing capabilities at key locations, enabling real-time management of the grid. This approach provides better visibility into Distributed Energy Resources (DERs) and supports broader and more equitable access to clean energy.

The company is implementing Grid Edge Computing (GEC) and Next Gen Automated Metering Infrastructure (AMI) to enable real-time edge decision-making, DER visibility and optimization, and plug-and-play DER capabilities. PGE has been selected for a $50 million matching funds grant to deploy GEC at approximately 90,000 locations, which will improve visibility of the electrical system, provide operational insights, and help anticipate and mitigate the impacts of extreme weather on grid resiliency.

4.2.2.6 Telecommunications

PGE plans to deploy distribution automation devices and sensors to support DER adoption, requiring a robust telecommunication network for reliable grid monitoring and response. The company's strategy aims to move away from the current ad hoc telecommunications choice to a handful of reliable, secure, and cost-effective telecommunication networks to support grid modernization efforts.

Key components of this strategy include the Field Area Network (FAN), Multiprotocol Label Switching (MPLS), and a wireless integrated network (i.e., Expeto). These systems will provide enhanced service reliability, greater integration of renewable energy, and improved network performance and resilience.

4.2.2.7 Cybersecurity

In response to the increasing number of cyberattacks on U.S. utilities, PGE is exploring advanced cybersecurity capabilities to maintain grid resilience in an environment of evolving threats. These capabilities apply to IT/OT cybersecurity, physical security/access control, network security, data loss prevention, threat detection, and information risk management.

Key areas of focus include implementing zero trust architecture, AI/Machine learning for threat detection, real-time anomaly detection for OT networks, converged IT/OT network security with integrated threat intelligence, and ongoing employee training and awareness through simulated cyberattacks. These measures aim to protect PGE's infrastructure and support the reliability and security of the power grid.

Chapter 5. Virtual Power Plant (VPP)

This chapter details PGE's Virtual Power Plant (VPP) strategy and benefit-cost analysis, focusing on three main elements:

VPP Components & Strategy

- Definition and purpose of VPP
- Core resources: Flexible load, distributed supply (solar + storage), distributed thermal
- Technology platforms and integration
- Grid services and capability stages
- Strategic alignment with customer needs

Resource Development

- Flexible load programs targeting 211MW summer/158MW winter by 2028
- Distributed solar and storage forecasts and implementation
- Dispatchable Standby Generation (DSG) program expansion
- Technology platform integration requirements

Benefit-Cost Analysis

- Overall benefit-to-cost ratio of over one
- Detailed analysis of costs and benefits across VPP components
- Quantitative and qualitative impact assessment
- Conservative preliminary analysis showing positive economic returns

The chapter establishes how these elements work together to create a comprehensive VPP strategy while demonstrating its economic viability and customer benefits.

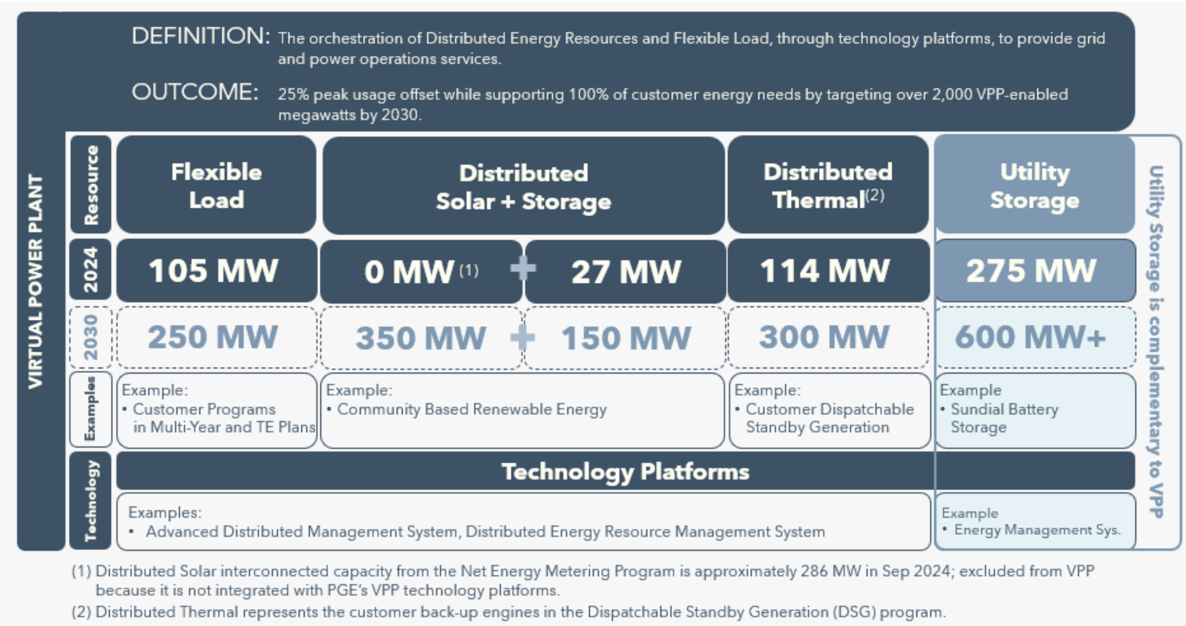
5.1 Virtual Power Plant

5.1.1 What is the VPP

The term "VPP" is used across the industry with disparate and potentially conflicting definitions. PGE's VPP is a combination of resources, technologies, infrastructure, and operations. To clearly articulate these discrete components and describe how they are integrated to scale the size and capabilities of the VPP, PGE defines its VPP as "the orchestration of Distributed Energy Resources (DERs) and Flexible Load, through technology platforms, to provide grid and operations services." The VPP is *how* PGE integrates and operates the distribution system with increasingly distributed resources, flexible loads, and technology in an optimized manner to deliver value to customers.

A visual representation of this definition is provided below. Further description of the resources, quantities targeted, technology platforms, and the how they are orchestrated is provided in **Figure 19** and the sections that follow.

Figure 19. Visualization of virtual power plant definition

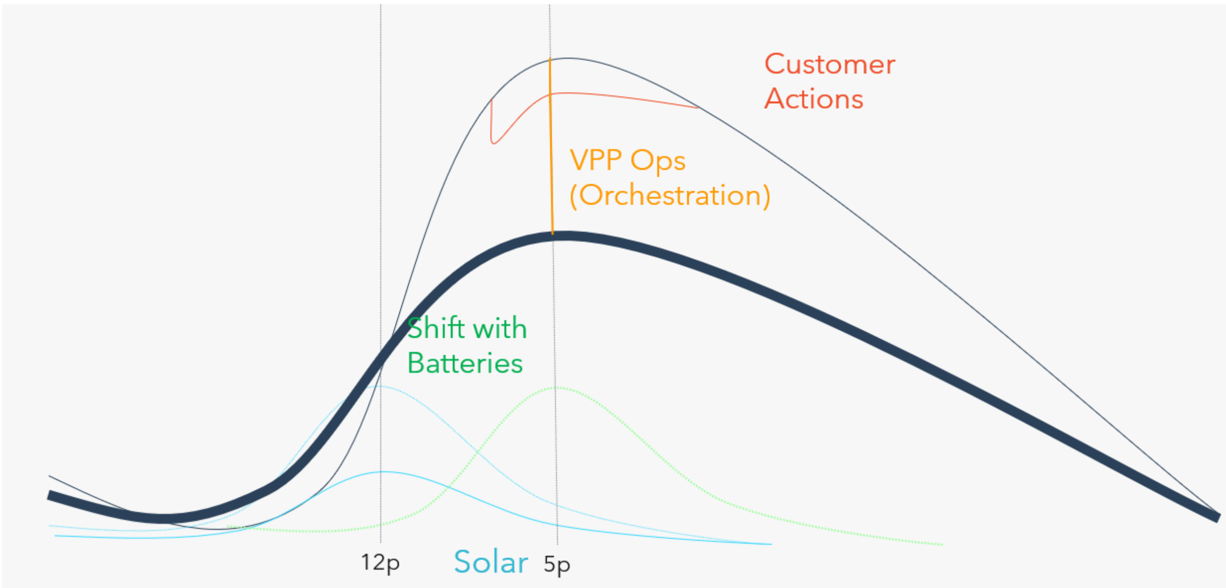


5.1.2 Why develop a Virtual Power Plant

There are several reasons to develop a virtual power plant (VPP), each integrally contributing to a more reliable and resilient grid that scales electrification to serve customer energy needs and enables efficient decarbonization as affordably as possible.

As a sophisticated aggregation, integration, and optimization platform through orchestration of DERs and flexible loads to deliver grid and operations services, PGE's VPP enables active customer participation in controlling their energy usage and costs. The VPP provides agility to meet the needs of customers through a reliable distribution grid, delivering a range of services by reshaping demand curves (**Figure 20**), accelerating decarbonization, helping customer affordability, and to bridge the time for new transmission and clean energy capacity to come online.

Figure 20. Illustration of shifting energy generation and usage via VPP Orchestration



5.1.2.1 Customer growth in energy use

PGE's strategy continues to reflect the needs of our customers and meets their growth with clean, reliable, and affordable energy. Customers share a common need for energy but their drivers for when, how, and how much energy they use vary.

The residential growth forecast is driven by electrification and adoption of customer products like electric vehicles, heat pumps, and smart devices. Customers expect seamless interoperability of their devices and a digital interface to see and manage their energy use.[32] PGE's VPP strategy integrates programs through customers' preferred channels while ensuring affordability options for all residential customer segments (**Section 8.5.1 MYP programs**).

The largest acceleration in customer growth is occurring in the industrial segment. Driven by national policy to strengthen U.S. economic competitiveness and enhance national security through domestic manufacturing (particularly semiconductors)[33] along with the growing computational demands of emerging technologies like generative artificial intelligence (AI), we are experiencing a global increase in demand for energy that has not been seen since post-World War II industrialization.[34] PGE's service territory is a key location for these customers. The geographic location of the international fiber terminus, high-tech workforce

[32] Reference Section 5.2.7 Sensing, Measurement, & Automation and Section 5.2.8 Telecommunications.
[33] CHIPS and Science Act. Available at: https://www.congress.gov/bill/117th-congress/house-bill/4346
[34] A New Surge in Power Use Is Threatening U.S. Climate Goals. Available at: https://www.nytimes.com/interactive/2024/03/13/climate/electric-power-climate-change.html

capabilities, reliable and affordable power, and a clean energy ethos all converge here and are stimulating industrial growth.[35,36] This creates opportunity to engage with these customers to integrate VPP capabilities and bring innovative solutions to meeting their growing needs while benefiting all customers and the community.

Commercial growth of small and medium businesses and the municipalities within which they operate is also incorporated in PGE's load forecast. Subsegments such as builders, developers and fleet managers are incorporating sustainability more directly into their operations. In some cases, subdivisions are now being designed with fully electric homes and electric vehicle charging in every garage, and trucking and logistics companies are building charging depots with the capability to charge electric vehicle fleets quickly. Key to enabling growth in this segment are the municipalities where these businesses operate as they are focused on growing the economy and making more goods and services available to their residents. For example, in Portland the Electric Vehicle (EV) Ready Code Project amends the Portland Zoning Code (Title 33) to require all new multi-dwelling and mixed-use development with five or more units – that include onsite parking – to provide EV-ready charging infrastructure at higher rates than required by State rules.[37]

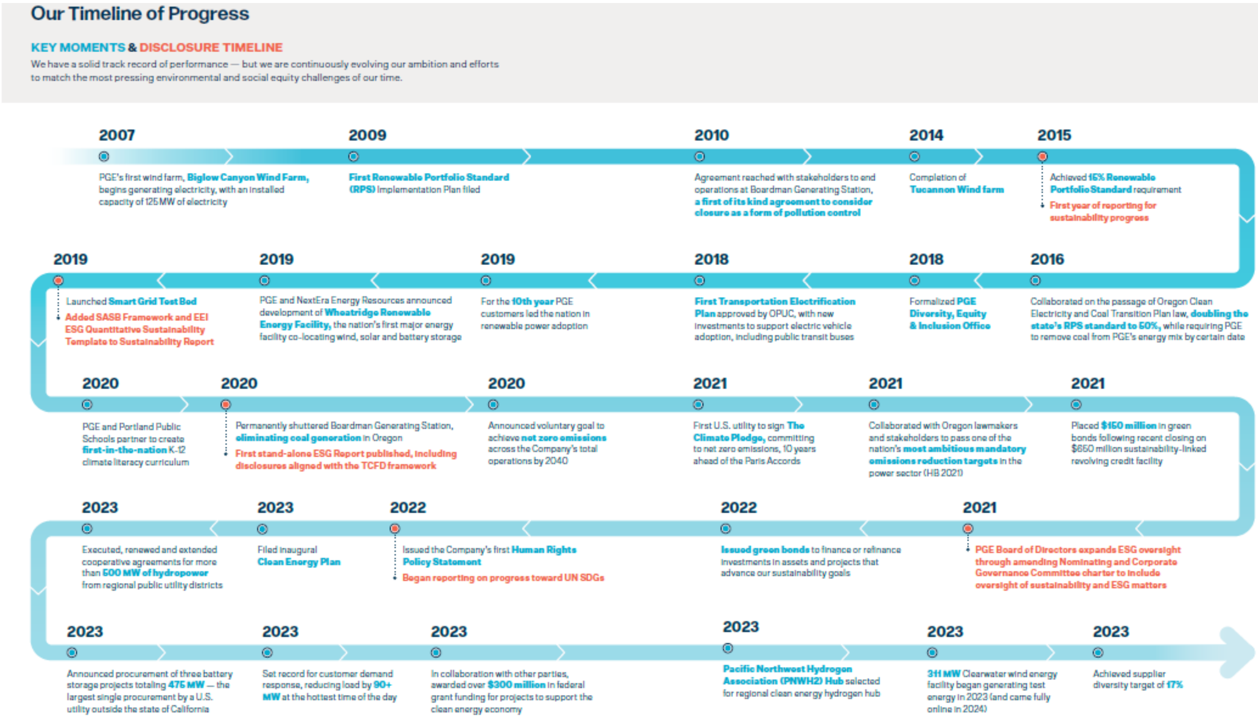
5.1.2.2 Decarbonization through electrification

PGE began the transition to clean energy many years ago. Milestones along that journey are shown in in **Figure 21** below. We have long been advocates for energy efficiency, and have been integrating wind and solar generation since the early 2000's. We closed Oregon's only coal fired plant at Boardman. We are exploring different ways to operate our existing thermal fleet, which includes some of the highest efficiency natural gas plants in the nation. We are also exploring novel cleaner fuels, such as hydrogen, to replace natural gas combustion in existing plants. In the future, other non-emitting technologies like long-duration storage, off-shore wind, advanced geothermal, and nuclear may prove cost-effective for serving customers in our region, but today they have long development timeframes.

With the increased dependence on weather-driven resources, like wind, solar, and hydro, a reliable clean energy grid requires distributed energy resources and flexible loads, orchestrated through technology platforms, to provide grid and operations services. It requires the VPP.

[35] Daimler Truck North America Expands Portland, Oregon, Operations. Available at: https://www.opb.org/article/2024/03/20/intel-investment-oregon-federal-funding/
[36] Intel announces $36B Hillsboro investment following federal funding commitments. Available at: https://www.areadevelopment.com/newsitems/5-16-2024/daimler-truck-north-america-swan-island-oregon.shtml#:~:text=Daimler%20Truck%20North%20America%2C%20an,expected%20to%20create%20150%20jobs .
[37] Portland Zoning Code (Title 33). Available at: https://efiles.portlandoregon.gov/record/16627527

Figure 21. Timeline of progress toward clean energy transformation[38]



5.1.2.3 Customer energy management

The rapid customer adoption of distributed energy resources (DERs) and technology that enable flexible load provides both tremendous opportunities to utilize resources already on the system, as well as necessitates an evolution in how PGE operates its distribution system. Technology and resources must be integrated with the grid to unlock the value of energy supply and load flexibility. [39]

Through our smart grid connected appliance programs for water heaters and thermostats customers can automatically adjust their energy use. Our customer offerings aim to benefit both participating and nonparticipating customers, support grid reliability and increase portfolio flexibility and resource diversity. We continue to partner with customers, in collaboration with ETO, on energy efficiency programs (e.g., rooftop solar, battery storage and electric vehicle chargers).

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[38] PGE 2023 ESG report, pages 8-9. Available at: https://downloads.ctfassets.net/416ywc1laqmd/FMJv3RPASD70GLZFvHx3g/6fe4b31c4eba6669557f5c97ac8c3584/Printer-friendly_ESG_Report_2023.pdf

[39] PGE CEP & IRP portfolio analysis refresh addendum. Available at: https://assets.ctfassets.net/416ywc1laqmd/E074bPlYZi0LF129vutf7/a6766ab7ba78c9cf28a51a2a0441a7c9/2023_CEP-IRP_Portfolio_Analysis_Refresh_Addendum.pdf

5.1.2.4 Increase resilience and bridge infrastructure development

To serve our communities with reliable energy, we continue to actively plan and invest in transmission, distribution, and generation to support the growth of existing and new load from our customers.

The long development timeframes noted above to bring new transmission and off-system clean energy to our customers necessitate orchestrating two-way energy flows on the distribution grid. This provides capability to utilize DERs and Flexible Load to improve distribution utilization and serve as a bridge until new central resources and transmission capacity are available.

We continue to innovate with the local community on smart grid technology learning programs, including the Smart Grid Test Bed (SGTB) and Smart Grid Advanced Load Management & Optimized Neighborhoods (SALMON) projects. We are using wireless smart sensors and centrally controlled automated switches to help isolate disruptions and more quickly reroute power, preventing or shortening disruptions. During outages, these technologies help us to share timely, accurate information with customers – notifying them when their power goes out and providing updates through digital and mobile channels.

We have been working with municipalities to pair energy storage batteries with rooftop solar and advance equitable electric vehicle charging needs through a municipal charging program, placing Level 2 chargers on utility poles or in the right-of-way. We are also working with transit providers and school districts on bus charging on-route and at the depot.

5.1.3 Examples of the services that will be provided by the VPP

Today, the VPP provides essential grid services when they are most needed such as load reduction during peak load events and contingency and frequency reserves for grid disruptions. Further capabilities to provide locational value, voltage regulation, microgrid support, and other grid services are unlocked with the implementation and integration of technology platforms, such as the Enterprise DERMS, for resource dispatch.

5.1.3.1 Grid services

Grid Services (**Table 5**) describe the list of grid and operations services that can be individually or jointly provided by a Resource or combination of Resources via the VPP. The PGE Balancing Authority schedules services for reliable and compliant operations. Grid Services include:

Table 5. Example grid services that a VPP can provide[40]

Service Category	Grid Service [X]	Duration [Y]	Response Time [Z]
Energy Schedule	Capacity	3 hours	Scheduled
	Energy	1 hour	< 5 minutes
Reserve	Contingency	1 hour	< 10 minutes

[40] NOTE: Program and Resource Capabilities vary by Grid Service. Support for each Grid Services varies based on Program and Resource parameters for operation.

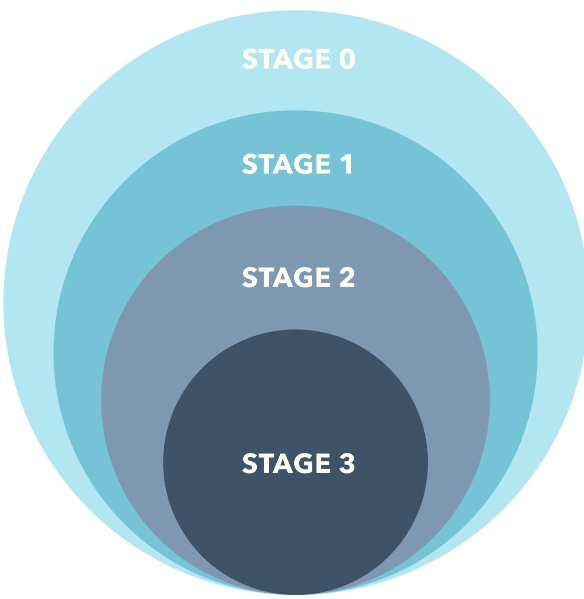
Service Category	Grid Service [X]	Duration [Y]	Response Time [Z]
	Frequency	1 hour	< 2 seconds (20-52 seconds for compliance)
Regulation	Regulation	1 hour	< 4 seconds
Voltage	Voltage	Seconds to minutes	< 10 minutes
	Volt-VAR Control	Seconds to minutes	60 cycles < Z < 90 seconds

Other Grid Services are not considered to be provided by the VPP at this time. For example, Black-start Service is not a service currently provided by the VPP.

5.1.3.2 Capability stages

Capability Stages (**Figure 22**) encourage cross-functional coordination and create the visibility necessary to inform the sequence of execution that optimizes development of the VPP. Capability Stages include:

Figure 22. Capability stage definitions[41]



STAGE 0

Physically connected within PGE service territory and has potential to provide a Grid Service.

STAGE 1

Capable of delivering a Grid Service for any 60-minute window in a 24-hour period.

STAGE 2

Dispatched via telemetry integrated with PGE to deliver a Grid Service for a specified duration within the required response time to improve reliability.

STAGE 3

Dispatched to lower cost based on a market signal when a Grid Service is most valuable.

5.1.3.2.1 CAPABILITY STAGE 0

Capability Stage 0 is the foundational qualification for VPP. At this Stage, the intent is to identify the devices and resources connected within PGE's service territory which have the potential to provide Grid Services in the future.

[41] NOTE: Program and Resource Capabilities vary by Grid Service

A resource/program at this stage is not required to provide the specified Grid Service [X] for a minimum Duration [Y], within a specified Response Time [Z], or for a quantifiable value at this stage.

For Programs, the requirement to qualify at Stage 0 is that the device exists in PGE's Service Territory, but the device doesn't need to be participating. For example, a customer may have a smart thermostat, but may not be participating in PGE's Peak Time Rebate Program.

For Resources, the requirement to qualify at Stage 0 is that the resource has an approved or waived interconnection agreement to PGE's system. For example, a customer may be building a rooftop solar panel system, but it may not be operational, may not have a smart invertor, nor be connected to a battery. As long as that system is approved in the interconnection queue it qualifies for Stage 0. The purpose of including an interconnection waiver is to reflect the process by which resources connected through the Dispatchable Standby Generation (DSG) Program (Schedule 200) are connected.

In contrast, an interconnection that has been requested but is not approved/waived, does not qualify for Stage 0. This is to reduce the risk of overestimating the potential to provide Grid Services from resources that don't get approved or projects that are cancelled.

5.1.3.2.2 CAPABILITY STAGE 1

Capability Stage 1 requires a program or device to have the ability to provide a Grid Service during any hour within a 24-hour period. At this stage, the intent is to require the devices and resources to have the ability to be scheduled to provide a Grid Service when needed.

A resource/program is not required to provide the specified Grid Service [X] repeatedly in the same 24-hour period, nor is activation required within a specified Response Time [Z] at this stage.

This provides additional value over Stage 0 due to the ability to shift when energy is used or store energy for later use. For example, a customer with a solar panel system coupled with a battery will have the ability to charge the battery when the sun is shining and use that energy in the middle of the night. In contrast, a stand-alone solar panel system may have to be curtailed when it could otherwise be generating, thereby foregoing the utilization of that clean energy.

For Programs, the requirement to qualify at Stage 1 is that the device is registered to participate in a PGE Program, but the customer doesn't need to respond when called. For example, a customer participating in PGE's Peak Time Rebate Program may elect to opt out during an event.

For Resources, the requirement to qualify at Stage 1 is that the resource be coupled with a source that enables its energy to be utilized in any hour as described in the examples above.

5.1.3.2.3 CAPABILITY STAGE 2

Capability Stage 2 requires a program or device to have the ability to provide the specified Grid Service [X] for a minimum Duration [Y], within a specified Response Time [Z]. At this stage, the intent is to require the devices and resources to have the ability to dispatch in concert with the conditions of the grid to maintain or improve reliability.

A resource/program is not required to have a direct compensation mechanism at this stage.

This provides additional value over Stage 1 due to the ability to respond to dynamic grid conditions with confidence that system reliability will be maintained. For example, if there is a forced outage of a generation facility which impacts grid frequency, a device or resource at Capability Stage 2 specified for Frequency Reserve Service can be activated within 2 seconds to help mitigate the event. As another example, if a feeder is experiencing high load conditions, the device or resource can be scheduled within 5 minutes to reduce the load along the line by activating customers to reduce usage or utilize their distributed energy resources to reduce loading on the line.

For Programs and Resources, the requirement to qualify at Stage 2 is to be monitored and dispatched via telemetry integrated with PGE's Enterprise DERMS system. Until operational go-live of Enterprise DERMS, resources connected to GenOnSys will qualify for Stage 2. After operational go-live of the Enterprise DERMS, GenOnSys will become an Edge DERMS and resource dispatch will be required via the Enterprise DERMS to qualify for Stage 2.

5.1.3.2.4 CAPABILITY STAGE 3

Capability Stage 3 requires a program or device to have the ability to be dispatched to lower system cost, based on a market signal. At this stage, the intent is to require the devices and resources to have the ability to dispatch when they are most valuable.

This requires the existence of valuation and allocation mechanisms.

This provides additional value over Stage 2 due to the ability to dispatch programs and resources based on the dynamic grid conditions with confidence that the lowest cost portfolio is being utilized. For example, if there is congestion on a feeder, the options to ask customers to reduce their load or to utilize (charge or discharge) their distributed energy resources will be dispatched based on the highest value option.

5.1.3.3 Capability stage qualification thresholds

Qualification Thresholds (**Table 6**) provide the requirements for each program or resource type to qualify for each Capability Stage. The Qualification Thresholds are:

Table 6. Qualification thresholds for each VPP capability stage[42]

Capability Stage	Threshold Qualification	Customer Programs	Distributed Solar	Distributed Thermal	Distributed Storage	Utility Storage
Stage 0 - connection	Base qualification					
Connected to PGE's system and has potential to	Physically connected within PGE service territory	Device connected within PGE Service Territory	Interconnection to PGE's system approved	Interconnection to PGE's system approved/accepted	Interconnection to PGE's system	Interconnection to PGE's system approved

[42] NOTE: Program and Resource Capabilities vary by Grid Service

Capability Stage	Threshold Qualification	Customer Programs	Distributed Solar	Distributed Thermal	Distributed Storage	Utility Storage
provide Grid Service [X]					approved/accepted	
Stage 1 - delivery	Stage 0 plus					
Customer/ Resource delivers Grid Service [X] for Duration [Y]	Capable of delivering in any 60-minute window in a 24 hour period	Customer enrolled in a PGE Program	Solar coupled with battery storage	Thermal fuel source available	Storage coupled with a charging source	Storage coupled with a charging source
Stage 2 - utilization	Stage 1 plus					
Customer/ Resource responds in Timeframe [Z] to committed Grid Service [X] for Duration [Y]	Monitored and dispatched via telemetry integrated with PGE	Connected to PGE Enterprise DERMS	Connected to PGE Enterprise DERMS	Connected to PGE Enterprise DERMS (GenOnSys for 2024)	Connected to PGE Enterprise DERMS (GenOnSys for 2024)	Connected to PGE EMS
Stage 3 - price	Stage 2 plus					
Customer/ Resource deployed when Grid Service [X] is most valuable	Dispatched to lower cost based on a market signal	Signal via PGE DERMS	Signal via PGE DERMS	Signal via PGE DERMS	Signal via PGE DERMS	Signal via PGE EMS

5.1.4 VPP resources: Flexible load programs

The Flex Load activities described herein are in service to the acquisition goals of 211 MW Summer and 158 MW winter demand response by 2028. These goals were laid out in PGE's 2019 & 2023 CEP & IRP, and associated Addenda.

Since 2021, existing pilot and program capacity has grown +20 percent, adding 22.8 summer MW and 13.6 winter MW, forecasted to end 2024 with an additional 10.8 summer MW and 4.3 winter MW. PGE seeks to continue to grow existing pilot and program capacity with an additional 22.7 summer MW and 8.5 winter MW by the end of 2026. This performance represents both growth and retention of the portfolio.

Flex Load customers served are summarized in **Table 7**, below, with detail for the underlying offerings in the subsections thereunder.

Table 7. Flex Load portfolio: Customers enrolled

Customers Served	2023 (actual)	2024 (forecast)	2025 (forecast)	2026 (forecast)
Residential Offerings	188,187	204,629	229,847	253,430
Commercial Offerings	13,162	15,602	17,512	19,578

PGE is working to increase the value and utilization of Flexible Load locally and regionally.

Requirements of state and regional entities regarding demand response participation in markets and resource adequacy programs such as the California Independent System Operator Energy Imbalance Market and Extended Day-Ahead Market (CAISO EIM and EDAM) and the Western Resource Adequacy Program (WRAP) need to be aligned to maximize the value of Flexible Load.

PGE has advocated for demand response to receive credit for its capacity contribution through WRAP's resource adequacy participants committee (RAPC) process. This resource adequacy credit is another source of valuation or benefit that can be ascribed to PGE's demand response and Flex Load investments. Within WRAP, demand response programs can receive credit in one of two ways: submitted as a 'Qualifying Resource' or as a load shaving capability in the forward showing demonstration.

To date, PGE has submitted demand response as load shaving capability. In doing so, PGE's peak load demonstration + Planning Reserve Margin is lowered by the amount claimed in the forward showing. This delivers real benefits to customers, because filling PGE's Planning Reserve Margin with supply-side resources creates opportunity costs that are borne by customers.

Additionally, PGE is pursuing opportunities for co-deployment with Energy Trust, with the goal to leverage synergies between offerings and capabilities of both organizations to more effectively and economically deploy products to customers. PGE is also funding NEEA market transformation along with other regional utilities.

Table 8. Prospective co-deployment measures PGE is pursuing

Measure	Objective	ETO-Exception	ETO-Pilot	RTF-Flex[43]	Public Sector Braiding[44]
All Insulation/ Weatherization	Affordability, DERs Activation	Expires March 2028		2025-2029	IRA HEAR, 25C
Low-Income Insulation/ Weatherization	Affordability	Expires March 2028		2025-2029	IRA HEAR, 25C
Ducted Heat Pumps	Affordability, DERs Activation	Expires Dec 2026 (Fixed Promotion)	No-Cost Program Delivery Pilot (PDP)	2025-2029 upgrades/ conversions	IRA HEAR, 25C
Ductless Heat Pumps	Affordability, DERs Activation	Expires March 2025	No-Cost Program Delivery Pilot (PDP)	2025-2029 + Small Commercial	IRA HEAR, 25C
Extended Capacity Heat Pump	DERs Activation	Expires Jan 2026			IRA HEAR, 25C
Manufactured Home Replacement	Affordability	Expires March 2025			
New Buildings	DERs Activation	Expires March 2024			
Heat Pump Water Heater	Affordability, DERs Activation		No-Cost Program Delivery Pilot (PDP)	2025-2029 + Commercial	IRA HEAR, 25C
Connected Thermostat	DERs Activation	Equity Metrics < $500		2025-2029 + Commercial	
Line Voltage Thermostat	DERs Activation			2025-2029	

[43] The Regional Technical Forum (RTF) is a technical advisory committee to the Northwest Power and Conservation Council established in 1999 to develop standards to verify and evaluate energy efficiency savings. In the 2025-2029 Funding Levels the RTF has included in its business plan priority energy efficiency and demand response technologies.
[44] The Inflation Reduction Act (IRA) includes the Home Electrification Appliance Rebate (HEAR) program which provides funding for incentives to flow state energy offices. In addition, there exists IRS sections 25C and 25D for energy-efficient home improvements and residential clean energy credits.

Measure	Objective	ETO-Exception	ETO-Pilot	RTF-Flex[43]	Public Sector Braiding[44]
Level 2 Electric Vehicle Service Equipment	DERs Activation			2025-2029	25D
Irrigation Pump Controls	DERs Activation			2025-2029	
Battery	DERs Activation				ODOE, 25D
Inverter	DERs Activation				ODOE, 25D

5.1.4.1 Capabilities and customer benefit

PGE's comprehensive Flexible Load portfolio includes the following key pilots and programs:

- Energy Partner on Demand Schedule 26: This program targets large commercial and industrial customers, providing incentives for custom load curtailment strategies and event-based energy shifts. The offering is technology agonistic and flexible, with a mix of behavioral/manual participants and other customers who opt for direct load control.
- Residential Smart Thermostat: A direct load control offering aimed at residential HVAC systems, utilizing smart thermostats to manage and optimize energy usage.
- Peak Time Rebates (PTR): A behavioral/manual DR offering which incentivizes residential customers to reduce energy consumption during peak times without the need for up-front equipment investment.
- Time of Day (TOD): A residential time-varying rate offering designed to encourage customers to shift their energy use to off-peak times, reducing overall demand during peak periods.
- Energy Partner Commercial Thermostats Schedule 25: A direct load control offering which targets small and medium-sized businesses, using smart thermostats to manage HVAC loads.
- Multi-family Water Heater (MFWH): An offering targeting multi-family residences to control water heater loads, providing significant demand response potential in an underserved market segment.

5.1.4.2 Flexible load program MW forecast and funding

Table 9. Schedule for increasing summer capacity (MW)

Large-scale Pilots and Programs	2025	2026	2027	2028	2029
Energy Partner Sch 26	41.3	43.8	45.8	47.8	49.6
Energy Partner Thermostats	2.1	2.8	6.3	7.6	8.8

Large-scale Pilots and Programs	2025	2026	2027	2028	2029
MFWH	2	2.3	2.7	3.0	3.4
Peak Time Rebates	16.1	16.6	17.1	17.6	18.1
Res EV Smart Charging	2.6	3.3	4.1	4.8	5.6
Res Smart Thermostat	48.1	52.5	57.2	61.8	66.7
Time of Day	4.1	5.6	7.1	8.7	10.2
Grand Total	**116.3**	**126.9**	**140.3**	**151.3**	**162.3**

Table 10. Schedule for increasing winter capacity (MW)

Large-scale Pilots and Programs	2025	2026	2027	2028	2029
Energy Partner Sch 26	33.5	35.5	37.3	38.8	40.3
Energy Partner Thermostats	0.6	0.7	0.4	0.5	0.6
MFWH	2.5	2.8	3.2	3.7	4.1
Peak Time Rebates	12.0	12.4	12.8	13.1	13.5
Res EV Smart Charging	2.7	3.5	4.3	5.0	5.8
Res Smart Thermostat	9.9	10.8	11.9	12.9	13.9
Grand Total	**61.2**	**65.7**	**69.8**	**74.0**	**78.2**

Table 11. Summary of Flex Load funding

Activity	2025 (proposed)	2026 (proposed)	2025-2026 (proposed)
Residential Smart Thermostats	$3,756,000	$4,044,000	$7,800,000
Peak Time Rebates	$2,913,610	$2,967,105	$5,880,715
Time of Day	$666,500	$535,150	$1,201,650
Energy Partner on Demand	$6,087,977	$6,055,727	$12,143,704
Multi-family Water Heating	$1,170,250	$2,771,080	$3,941,330
Energy Partner Smart Thermostat	$1,422,000	$1,573,460	$2,995,460
NEEA Market Transformation[45]	$ 357,500	TBD	$ 357,500
Funding	**$16,373,837**	**$17,946,522**	**$34,320,359**
Smart Grid Test Bed[46]	*$ 2,030,214*	*$ 1,254,288*	*$ 3,284,502*
Residential EV Charging[47]	*$ 2,130,409*	*TBD*	*$ 2,130,409*
Holistic Flex Load Spending[48]	*$20,534,460*	*$19,200,810*	*$39,735,270*

5.1.5 VPP resources: Distributed supply (solar + storage)

The integration and optimization of distributed supply-side resources (likely primarily comprised of solar and storage) is a central goal of PGE's VPP.

PGE's intent is to continue progressing toward HB 2021's decarbonization targets and small-scale resource targets, while doing so in a way that prioritizes reliable energy supply and keeping prices as low as possible for customers. Currently, PGE's system has >460 MW of rooftop and distributed solar installed[49] that is being sub-optimized due to lack of

[45] While PGE expects NEEA's Market Transformation activity to continue past 2025, the scope and cost of that work remains to be determined. PGE will reengage with the Commission once PGE and other utilities have aligned on the scope and costs of that additional work and cost.
[46] Smart Grid Test Bed figures are subject to change; those funding proposals and related filings can be found in UM 1976. Available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21662.
[47] Residential Smart Charging pilot is funded separately under UM 2033 and has yet to propose funding for 2026. The 2025 funding for this pilot reflects the most recent available: that filed with PGE's 2023 Final Transportation Electrification Plan under UM 2033. Available at: https://edocs.puc.state.or.us/efdocs/HAH/um2033hah15818.pdf.
[48] As noted in the prior footnotes, Smart Grid Test Bed and Residential EV Charging activities are funded via separate dockets (UM 1976 and UM 2033, respectively) and are included for informational purposes only.
[49] Largely as a result of longstanding programs such as feed-in tariff, net energy metering, qualifying facilities and Oregon Community Solar Program

aggregation and widespread pairing with battery storage. While these resources add energy to the grid, they provide little flexibility to the grid as defined in the Capability Stages above and point to the need for continued action by PGE and customers.

As PGE seeks to grow the number of renewables connected to our grid, the company is also seeking new builds by partnering with customers and communities to bring forward new projects via Community Based Renewable Energy (CBRE) and other opportunities to add small-scale resources in a way that provides best value for customers. The availability of subsidies, including those from the Energy Trust of Oregon (ETO) via solar and battery incentives, the EPA's Solar 4 All Funding, potential partnership with the Portland Clean Energy Community Benefits Fund (PCEF), and the Federal Investment Tax Credit (ITC), provide a unique opportunity to increase grid stability and flexibility as energy infrastructure (transmission) is built and technology advances in preparation for Oregon's 2040 target of zero carbon.

5.1.5.1 Key outcomes

Combining distributed solar with distributed storage and the technology platforms included in the VPP is advantageous for several reasons. First and foremost is that it provides customers energy independence and resilience. Doing so puts control into customers' hands to drive cost savings and help mitigate the increase in outages caused by extreme weather events. Second, pairing solar and storage increases grid stability while reducing reliance on emitting resources. PGE proposes to act swiftly while there are considerable subsidies available now that will help buy down the cost of this investment on behalf of customers.

Included in **Table 12** below is a summary of the targets PGE has established for both distributed solar and storage and incorporate time required to navigate global supply chain constraints, need for updated/amended permits, and construction timelines. Critical to success is active participation from customers with standalone rooftop solar, counterparties (QF, CSP), and communities (CBRE) as PGE looks to partner in delivering the clean, reliable, affordable grid of the future.

5.1.5.1.1 SCHEDULE AND IMPLEMENTATION

Each program contributing to the distributed solar and storage planned outcomes requires planning, design, regulatory engagement, and ultimately deployment. Some programs are more mature than others today and require less planning and design, while others are new or in their infancy.

5.1.5.1.2 NEW STANDALONE DISTRIBUTED STORAGE

As PGE adds new VPP resources and as demand growth is realized, PGE anticipates that adding new standalone distributed storage on the grid can help alleviate distribution, transmission, or power flow constraints. The deployment of standalone grid-sited storage may allow for investments in new infrastructure to be deferred and/or to help mitigate the operational risk of transmission constraints.

The combination of PGE's Integrated Resource Plan (IRP)/Clean Energy Plan (CEP) and Distribution System Plan (DSP) processes will help identify forecasted opportunities for the deployment of storage. PGE is actively working on identifying potential sites for battery storage projects within our distribution system. Our team is currently analyzing grid needs across all distribution substation transformers, focusing on both summer and winter peak loading values. This assessment is based on our established substation transformer planning guidelines.

The ongoing analysis aims to determine the peak demand reduction required at various locations to optimize transformer loading. Additionally, we are evaluating the maximum energy requirements over a 24-hour period for each site. It's important to note that this initial assessment primarily considers loading conditions and serves as a starting point for further investigation.

As we progress, we will conduct more comprehensive evaluations that take into account site suitability and other relevant factors to determine the viability of battery storage systems at specific substation transformers. This thorough approach will help us make informed decisions about potential battery storage implementations across our distribution network.

5.1.5.1.3 CUSTOMER-SITED ROOFTOP SOLAR

PGE is forecasting 299,545 kW (i.e. almost 300 MW but not greater) of nameplate capacity of solar by the end of 2024 and growing to at least 672 MW of nameplate capacity of solar by the end of 2030. The battery storage market is nascent and has been piloted through PGE's Smart Battery pilot for residential, and Energy Partner On-Demand and DSG for non-residential efforts. However, because uptake is low in the early stages of this market, the majority of Customer-sited rooftop solar remains at Capability Stage 0.

For customers who are interested in adding battery storage to their solar, PGE will continue to support the Smart Battery pilot, including the evolution to Phase 2 as outlined in the Multi-Year Plan. The Company will evaluate customer needs and methods to accelerate market adoption to increase the attachment rate of solar with storage and transition existing solar from Stage 0 to a more VPP-ready state. PGE will continue collaboration with the Energy Trust of Oregon (ETO) to deploy available subsidies to customers.

PGE intends to target 150 MW of distributed storage to add to the grid in a way that leverages the output of distributed solar by the end of 2027. If successful, these resources, that are capability stage 2 or 3, can defer the need to acquire additional resources to otherwise maintain a reliable system. As these resources achieve a more mature grid value status, PGE believes such resources should qualify for satisfying the Small-Scale Renewable mandate.

5.1.5.1.4 QUALIFYING FACILITY (QF)/COMMUNITY SOLAR PROGRAM (CSP)

PGE has existing contracts for greater than 300 MW of distribution system connected solar projects with QF and CSP developers sold to PGE pursuant to standard Power Purchase Agreements (PPA). Pairing such resources with distributed storage, either through actual co-location or through the addition of batteries to the grid that roughly approximates the amount of renewable generation, can meaningfully improve the contribution to grid reliability and flexibility.

Adding distributed storage to QF and CSP projects requires collaboration between PGE and project owners to identify which projects are best positioned to add distributed storage and provide the greatest benefit to the grid, including addressing transmission and distribution system constraints. Most QF/CSP projects are sized between 2 and 3 MW and depending on land configuration could be ideal candidates to add up to 1 MW of distributed storage for every MW of distributed solar.

Based on the total volume of installed QF and CSP projects in PGE's service area, combined with PGE's sense of battery energy storage supply chains via engagement as part of the Smart Battery pilot, PGE currently forecasts that adding more than 100 MW of storage to take renewable resources from capability stage 0 to capability stage 2 or 3 is possible.

PGE issued its inaugural CBRE acquisition process to the market in November 2024 and will be accepting bids through October of 2025. This inaugural process, working in collaboration with various communities, will seek to acquire at least 65 MW of distributed solar paired with distributed storage, or just distributed storage, and will be followed in the future with additional CBRE RFP windows to procure an additional 90 MW bringing the total forecast to 155 MW by 2030 as demonstrated in the 2023 IRP.[50] Should CBRE RFP windows result in a greater number of mature resources, PGE will evaluate the cost effectiveness of such resources and may procure additional MWs.

Bids submitted in each review window (multiple windows are anticipated each year) will be reviewed for project maturity with a focus on key development activities (e.g., site control, interconnection, permitting). To the extent projects lack maturity, PGE will work with bidders/communities to identify plans to mature the projects to achieve readiness in a future review window.

The CBRE RFP includes technical specifications designed consistent with PGE's VPP capability stages. Therefore, all resources acquired would provide meaningful grid value to customers and operate at capability stage 2 or 3.

Table 12. Distributed solar and storage forecast

	YE 2025	YE 2026	YE 2027	YE 2028	YE 2029
Current Storage	28	0	0	0	0
CBRE Solar	0	0	36	6	8
CBRE Hybrid (Solar and Storage)[1]	0	0	71	14	15
QF Solar	0	0	100	0	0
QF Storage[2]	0	0	50	0	0

[50] PGE's 2023 CEP/IRP. Available at: https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf

	YE 2025	YE 2026	YE 2027	YE 2028	YE 2029
NEM Solar	0	0	150	30	30
NEM Storage[3]	0	0	15	3	3
Total VPP Resources	**28**	**28**	**450**	**503**	**559**

1 Assumes CBRE resources are required to pair solar resources with battery storage
2 Assumes 50 percent of QF solar resources will be paired with battery storage
3 Assumes 10 percent of NEM solar resources will be paired with battery storage

5.1.5.2 Strategic alignment

5.1.5.2.1 CUSTOMER GROWTH IN ENERGY USE

Availability of economic incentives, such as tax credits, rebates, grants, and subsidies can make it economically viable for customers to expand their energy use while adopting distributed solar and storage. Customers can be credited for excess energy sent back to the grid and distributed solar and storage assets can then be orchestrated by PGE through participation in energy markets further optimizing portfolio benefits for all customers.

Distributed solar and storage similarly support community climate action plans by providing a shared resource that benefits multiple customers, including low-income customers, that may not otherwise have opportunities to participate in the clean energy transition. Additionally, by reducing peak demand on the local grid, solar paired with storage can help prevent grid overloads as energy consumption grows from extreme weather conditions, electrification, semiconductors, or data centers, supporting broader community and regional growth enhancing Oregon's economic development objectives and bringing value to customers.

5.1.5.3 Capabilities and customer benefit

Distributed solar and storage in the VPP play a crucial role in enhancing the efficiency, sustainability, and resilience of the power grid. Here are the intended benefits:

Table 13. Benefits of solar and storage

	Existing Rooftop	CBRE	New batteries	Battery-paired QF/CSP	Existing standalone batteries
Energy production	+++	++	N/A	++	N/A
Integration	N/A	++	+++	++	+++
Grid flexibility	+	+++	+++	++	+++
Peak needs	+	++	+++	++	+++
Scalability	+++	+	+	+	+

+ = relative measure of benefits

5.1.5.4 Roles and responsibilities

As the orchestrator of the VPP, PGE's role within the distributed solar and storage program is to collaborate with customers, counterparties, and stakeholders to convert approximately 460 MW of distributed solar providing minimal grid value into 460+ MW of distributed solar and storage contributing to grid value with the VPP platform and operating at capability stage 1, 2, or 3 by 2030.

PGE will work collaboratively with existing and future rooftop solar customers to deploy battery storage systems to move participating MWs from Stage 0 to Stage 1 (or further) while simultaneously furthering PGE's advancement of its Small-Scale Renewable target. The cost effectiveness of adding storage to existing distributed solar customer assets benefits greatly from ETO and PCEF (where applicable) subsidies to drive down up-front cost for customers. Where applicable, PGE will look to connect customers with third-party financing to further reduce the barrier of up-front costs to customers, as outlined in PGE Schedule 342.

QF and Community Solar developers are uniquely situated to coordinate with PGE by adding distributed storage. These currently operational resources have already completed the difficult development activities including obtaining land/site control and permits. Today, land within PGE's service territory is increasingly sparse as economic development from the semiconductor and technology industries look to grow in Oregon. By working collaboratively with the owners of the QF and CSP projects and regulatory stakeholders including the OPUC, identifying a structure to add distributed storage at an appropriate avoided cost price can be achieved and convert a significant number of distributed solar MWs into MWs not contributing to Stage 2 or 3 withing PGE's grid value capability framework.

Lastly, PGE's Community Based Renewable Energy (CBRE) RFP process has initiated and is seeking new distributed solar/storage resources providing value to various communities within PGE's service territory, all of which will be designed to contribute to the VPP portfolio operating at Stage 2 or 3 of the capability gates. PGE is planning for the CBRE RFP framework to be repeated through at least the end of the current decade, creating multiple opportunities for customers and communities to participate in the clean energy journey and contribute to building a more flexible and resilient grid.

5.1.5.5 PGE cross functional coordination

Integrating distributed solar and storage into the VPP requires extensive cross-functional coordination among various internal PGE teams and stakeholders to achieve technical viability, regulatory compliance, financial optimization, and customer satisfaction.

5.1.5.5.1 TECHNICAL/ENGINEERING

PGE and third-party engineers will be required to work on the design, installation, and optimization of distributed solar and storage systems to ensure proper connection capable of feeding into the VPP. To monitor, control, and dispatch the assets through the Enterprise DERMS, software and hardware infrastructure design and management will be necessary to integrate into the VPP.

Integration of distributed solar and storage with the grid will also be necessary to ensure that power generated is compatible with grid requirements and that any grid stability issues are addressed. This function in essence delivers on the grid value associated with each capability stage. These teams must coordinate with IT and cybersecurity teams to maintain secure and reliable communication between distributed solar and the VPP platform while also handling data management, storage, and cybersecurity protocols.

5.1.5.5.2 OPERATIONS AND MAINTENANCE

Asset management functions, whether PGE or customer owned, are essential to monitor the performance of the distributed solar and storage assets to achieve optimal operation within the VPP. This team will coordinate with the technical teams to manage maintenance schedules and address any performance issues that may arise. Field technicians will be responsible for the on-ground maintenance and repair of installations and must work closely with the remote monitoring team to respond to alerts and faults.

5.1.5.5.3 POWER OPERATIONS

Analyzing market trends and forecasts of energy prices to optimize the dispatch of distributed solar and storage assets within the VPP combined with managing the sale of excess solar generation or ancillary services in energy markets enable the VPP's solar contributions to maximize economic and financial benefits for customers.

5.1.5.5.4 REGULATORY/COMPLIANCE

Design and integration of distributed solar and storage into the VPP must comply with local, regional, and national regulations. This includes interconnection standards and any incentives for renewable energy. Similarly, PGE and our customers must understand how the VPP satisfies environmental standards and sustainability goals including Oregon's HB 2021 emission reduction targets and the Small-Scale Renewable requirements.

PGE must also coordinate with the OPUC and stakeholders to navigate establishing the VPP from inception/strategy through development and ultimately operations to deliver on the value proposition for customers.

5.1.5.5.5 PROGRAM OPERATIONS

Achieving participation in the VPP requires engagement with potential customers to enroll their assets into the appropriate flexible load program. The program teams continue to support customer questions and needs as they look to invest in distributed solar and storage, but also provides ongoing support to customers whose assets are integrated into the VPP, ensuring they understand how their systems are being used and compensated.

5.1.5.5.6 COMMUNITIES

Working and coordinating with local communities to address any concerns or questions regarding the integration of distributed solar and storage into the VPP, including how their respective community can participate, will be critical to drive adoption but more importantly providing the opportunity for all customers to actively participate in the clean energy transition.

Communities will be key partners to PGE in identifying land or buildings, accelerating permitting, and helping define success measures within their respective goals and climate action plans.

5.1.6 VPP resources: Distributed thermal

PGE began the Dispatchable Standby Generation (DSG) program as a pilot program in 2000. The program has grown, 2024 enrollment is 130 MW of capacity provided from 79 generators at 45 different sites with 38 customers.

The DSG program partners PGE with commercial and industrial customers who have emergency, standby generation or batteries greater than 250 kW. Reciprocating diesel engines normally power these standby generators. The program helps to fulfill PGE's NERC requirement for reserves to respond to local region reliability impacts. Through deployment of communications and our dispatch via Genonsys an Edge DERMs control technology, PGE can remotely start the generators to supply capacity to the grid when the region has a reliability need.

Under the DSG program, PGE is responsible for communication, metering, control equipment, generator maintenance, and fuel costs. The typical DSG agreement is for a term of 10 years, and PGE uses the DSG capacity to help meet its reserve requirements, NERC BAL-002 for meeting Contingency Reserve Obligation (CRO) and NERC BAL-003 for Fast Frequency Response (FFR). This is beneficial as the generators are located throughout the service territory. DSG benefits the customer through financial and technical support described by Schedule 200.

5.1.6.1 Capabilities and customer benefit

The DSG program offers a low-cost distributed generation resource, which PGE uses to help satisfy required reserves.

Customers that have a DSG generator system partner with PGE to obtain a more reliable and versatile generator system. PGE's program covers some of the O&M costs of the generator system for the customer. Because each customer system is an integral part of PGE's DSG program, the Company also provides customers enhanced monitoring and metering. PGE monitors the system on a 24/7 basis, before the implementation of DSG (Distribution System Generators), some customers lacked this capability, while for others, it provided enhanced monitoring of their electrical systems.

PGE manages maintenance for the generators participating in the program. The company has also developed a high level of expertise in troubleshooting, analyzing problems, and finding solutions to issues with the generator systems. In addition, the DSG control system has data logging and reporting capabilities that are often lacking in less sophisticated generator systems – thus, PGE can easily understand and quickly resolve problems for customers within the program.

Finally, DSG customers can transition from generator to the grid without load interruption, enabling smooth and efficient outage recovery for customers. This is attributable to the inherent nature of a paralleling generator system, which allows the generator output connected to the utility grid to perform “closed transitions” into and out of the parallel mode.

The DSG program currently helps fulfill some of PGE’s reserve requirements and PGE uses the generators when the local region has experienced a critical reliability event such as generation tripping offline, local transmission constraint, or Frequency deviation events associated with overall system and generation constraints. These requirements vary based upon the amount of generation that PGE is operating, system load, and how much reserves are available. PGE estimates that the DSG program could grow to meet the majority of the Company’s required reserve capacity need.

In summary, the customer benefits are significant and largely quantifiable, lasting throughout the life of the partnership. Ongoing maintenance and monitoring add extra value for existing DSG customers, who report lower labor requirements and peace of mind from entrusting these functions to PGE. Customers with smaller facility teams can focus on other critical items due to participation in the program.

5.1.6.2 Schedule and implementation

The DSG customer engagement and operational cycle ranges between 16 and 30 months, depending on customer and site complexity. A customer with existing qualified backup power will present shorter timelines for program activation. Customers leveraging the DSG incentives to invest in backup power will have a longer sales cycle due to acquisition times for new generation, which can vary widely by capacity. PGE is compressing our project schedule of customer education, site engineering assessments and planning, local grid enhancements, and environmental permitting requirements to acquire program capacity. **Table 14** represents PGE’s estimated project growth over the next five years.

Table 14. Distributed thermal forecast

	2024	2025	2026	2027	2028	2029
Yearly Incremental DSG Online		26	40	40	40	40
Cumulative DSG Online	114	140	180	220	260	300

Increasing total program capacity to 300 MW within the next five years will require strategic investment, process improvement, and modernization of the Schedule 200 incentives to enroll more customers in the program. Customer outreach and program marketing can support the program at existing staffing levels with prioritization adjustments. Additional full-time employee (FTE) will be required on the program team to meet the increased requirements for sales support, project management, customer site assessments and engineering, and program oversight.

The DSG project plan and project schedule has been rebuilt in 2024 to match the current landscape, as the last kW enrolled occurred in 2018 before an idle period. This updated process will serve as a guide for customers and the allocation of internal resources. Regular updates and continuous improvement to our processes will be necessary as customers enroll and become operational.

DSG growth will require regular engagement from PGE's environmental compliance, partially due to diesel emissions criteria at the Oregon Department of Environmental Quality (ODEQ). Per ODEQ, customers with a General Permit for Electric Power Generation (GP-18) must install a Diesel Particulate Filter (DPF) on any Tier 2 diesel generators prior to program participation. Customers using Tier 4 generators do not need a DPF. A Tier 2 diesel generator is the near universal choice for customers seeking cost effective backup power. Customers with larger sets of generators may require an individual Air Contaminant Discharge Permit (ACDP) and may be required to conduct environmental modeling to determine if they meet federal and state requirements. For each individual engagement, PGE may need to assist customers with the program capacity and run hour specification needed for the air modeling processes.

Finally, the economics of standby generation are evolving as PGE navigates a changing environment around capacity, congestion, and decarbonization. Over this 5-year period of aggressive program growth, the shifting economics may influence the structure of the DSG program and require changes to our tariff. Under the shared value model of the virtual power plant, any increase in financial support for customer-sited backup generation will directly benefit local organizations and communities.

5.1.7 Technology platform

PGE's VPP leverages the components of the modernized grid platform by integrating and optimizing a diverse array of distributed energy resources (DERs) and flexible loads through advanced technology platforms. By orchestrating distributed resources, the VPP enables PGE to operate a dynamic two-way system, unlocking additional grid services and increasing overall system flexibility and reliability. This approach not only reduces the need for new infrastructure but also aligns with PGE's 2023 Clean Energy Plan and Integrated Resource Plan, with potential to scale to 2,000 MW by 2030.[51]

5.2 Benefit cost analysis

The preceding sections have outlined the key benefits of a VPP:

- Increased Resilience: VPPs can enhance grid reliability by integrating backup power and eliminating single points of failure.
- Decarbonization: They support the integration of renewable energy, reduce reliance on fossil fuels, and lower greenhouse gas emissions.
- Cost Savings: VPPs can defer grid capital expenditures, avoid fuel costs, and offer compensation to consumers and businesses.
- Enhanced Efficiency: By smoothing demand peaks and alleviating congestion, VPPs improve the overall efficiency of the transmission and distribution (T&D) infrastructure.

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[51] 2023 Annual Report. Available at: https://investors.portlandgeneral.com/static-files/2457aa2d-263c-4933-a33b-8fc6b53ca9bb

- Community Empowerment: VPPs enable consumers to optimize their energy usage and costs, fostering greater engagement and creating local jobs.
- Versatility: The adaptable nature of VPPs allows them to meet evolving grid needs.

PGE intends to be more concrete in its understanding and demonstration of the types and extent of benefits of the Modernized Grid platform in combination with the VPP resources. This understanding can only be gained by quantifying the costs incurred towards the development and operation of the VPP, identifying the various streams of benefits that can be obtained through its utilization, and performing an initial computation of those benefits. Such an assessment would be the first essential step towards demonstrating the net benefits of VPP and justifying the VPP-related investments to our different stakeholders. Although this analysis is preliminary in nature, this exercise would provide important insights towards determining which VPP resources are economically more effective, and what benefit streams should be harnessed in a targeted manner to achieve maximization of net benefits.

Benefit-costs analysis (BCA) is a systematic approach for assessing the cost-effectiveness of investments by quantifying the benefits and the costs. The analysis entails precise identification of the possible streams of financial impacts (benefits and costs), computation of those benefits and costs in monetary terms, and then determining whether overall the benefits exceed the costs over the considered lifetime of the program or not. In this Section, we have described the assumptions, high-level methodology and results of a preliminary BCA for the VPP effort.

It is important to note that all the use cases and operational characteristics of the different resources and enabling technologies considered as part of this VPP are not known. In this BCA, reasonable assumptions have been made based on their technical specifications of relevance, and their direct benefits that are PGE's priorities. Over time as VPP is operationalized, we would obtain more accurate data regarding the costs and benefits which would be utilized to update this analysis.

This analysis is prepared consistent with the National Standards Practice Manual (NSPM) BCA Principles as follows[52]:

1. The VPP resources under consideration should be compared to other energy resources including other DERs using a consistent approach to avoid any kind of bias.
2. Benefits and costs should be treated symmetrically.
3. The analyses should be forward-looking, long-term and incremental to what would have happened in the absence of the VPP components being assessed.
4. All impacts should be clearly defined to avoid double counting.
5. Assessment should be based on transparent assumptions and methodologies.
6. In this section we have kept BCA separate from rate impact analysis and focused on only the BCA portion.

[52] NSPM-DERs. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

The net benefits analysis model is an Excel-based tool developed to calculate quantitative benefits associated with the proposed portfolio of VPP investments and compare these benefits to the costs of investments. This section explains the analysis context, approach, findings, and detailed methodology in support of the pre-filed testimony for net benefits.

5.2.1 Scope of analysis

Safely managing and integrating additions of electric loads (e.g., electric vehicles), other distributed energy resources (e.g., energy storage, rooftop solar), industrial load (e.g., manufacturing, data centers), and renewable generation at the bulk scale requires a larger grid with greater capacity and more flexibility. VPP resources and the integrated grid platform with supportive grid solutions can provide that added capacity and flexibility utilizing the DERs that are existing or are planned to be added in the distribution system.

VPP components considered individually or as a whole can help strategically relieve to a great extent the generation, transmission and distribution constraints in the distribution system, thereby deferring or avoiding the need for infrastructure upgrades in the short or long term. Therefore, within the portfolio of VPP considered here, we have included those projects which provide resources or supporting capabilities of dispatching distributed resources or coordinating edge devices. **Figure 23** includes the list of projects/resources that have been included within the scope of this first iteration of the BCA.

Figure 23. Items included in benefit cost analysis

Strategic storage	•Front of meter (Coffee Creek, Salem Smart Power Center, Dispatchable Standby Generation) •Behind the meter (Beaverton Public Safety Center, ARC, Integrated Operating Center, Daimler Electric Island)
Generic storage	•Feeder storage •Substation storage
Demand response / flex load	•PTR, TOD, MFWH, smart thermostat, Energy Partners - Schedule 25, Energy Partner - Schedule 26
Distribution automation	•FLISR
Transportation electrification	•Biz EV charging, biz make ready - multifamily, clean fuels program, fleet partners, HDV pilot, muni charging, residential EV charging
VPP grid integration	•Platform •Desk

5.2.1.1 Strategic storage projects

The strategic storage projects include those specific energy storage projects that are developed/operated at specific locations on the distribution system of PGE. Batteries can provide capacity and reliability benefits that reduce risk on key substation or feeder assets, extending economic life and deferring capital investments needed for replacement.

- **Front-of-meter storage projects**: There are some front of meter storage projects where PGE is the owner and operator. Therefore, there are no separate customer costs in this category of projects. PGE may be able to control these resources more readily and more often. To minimize costs of purchasing costly bulk generation, arbitrage would be a good future strategy. Arbitrage may be performed to charge those batteries during off-peak times and discharge them during on-peak times.
- **Behind-the-meter storage projects**: There are behind-the-meter storage projects where PGE is not the owner or operator. PGE did not have extensive information about additional costs that customers may have incurred for these projects. We included all the available information on costs.

Table 15 lists the various strategic storage projects that PGE has considered in its VPP portfolio along with the high-level specifications for the associated battery resources.

Table 15. High level specifications of strategic storage projects included in the analysis

	Coffee Creek	Beaverton Public Safety Center (BPSC)	Anderson Readiness Center (ARC)	Integrated Operating Center (IOC)	Daimler Electric Island	Salem Smart Power
Type of resource	Lithium-Ion Battery Energy Storage System	Lithium-Ion Battery Energy Storage System				
Capacity	17 MW	250 kW	500 kW	2 MW	750 kW	3.9 MW
Energy	34 MWh	1,000 kWh	1,000 kWh	4 MWh	1,000 kWh	7.8 MWh

5.2.1.2 Generic storage projects

Feeder and substation storage are generic storage projects which consist of front of meter storage resources that are located at the utility's feeders in order to serve the loads downstream in a strategic manner. Such storage could be used to supply stored energy during times of higher-than-normal level of load or when bulk generation cost is high, when there are constraints in the transmission and distribution system, or provide critical power when recovering from faults.

5.2.1.2.1 FEEDER STORAGE

The battery size assumed for feeder storage is 5.5 MW/11 MWh which is typically sufficient to supply entire feeder load so that it can either reduce or eliminate customer outages, depending on duration. A conservative effective load-carrying capabilities (ELCC) with average annual values of 38 percent (average of summer and winter seasons) has been assumed for these 2-hour batteries; for more details on ELCC calculation method please refer to 2023 CEP/IRP. [53] In the absence of any operational feeder storage projects, we have utilized data from the Dayton Non-Wires Solution pilot project as proxy for the relevant costs (like reconductor costs) and benefits. For feeder-sited storage, the outage risk reduction analyzed the benefit of avoiding an outage for customers on the feeder due to either asset failures or failure caused from vegetation/weather. Assets like distribution switches, transformers, and underground cable are considered in the analysis. The benefit timeline of each of these projects is assumed to be 10 years to align with the battery depreciation schedule.

5.2.1.2.2 SUBSTATION STORAGE

The battery size assumed for substation storage is 14.5 MW/5.8 MWh which allows for supplying energy to the load downstream on the substation transformer after accounting for a conservative ELCC with annual average value of 57 percent[53]. In the absence of any operational substation storage projects, we have developed a proxy project using real-world data from the Eastport Substation project. For substation storage, the transformer is used to measure benefits, since it is the primary beneficiary of a low side bus-connected battery. Outage mitigation benefits include avoidance of a 4-hour outage. The benefit timeline of each of these projects is assumed to be 10 years to align with the battery depreciation schedule.

5.2.1.3 Demand Response / Flex Load

Demand response programs are considered part of VPP since they play an important role by enabling coordination of the edge devices and therefore managing the net load. Leveraging demand-side resources can defer and/or avoid some of the cost of rebuilding or adding new transmission and distribution infrastructure. PGE's mature pilots and programs for DR are some of the first DERs to be enrolled in our Virtual Power Plant (VPP) and used for delivering grid services.

5.2.1.4 VPP platform and desk

The integrated VPP platform, which allows the monitoring and orchestration of the various DER and VPP resources, consists of an Enterprise DERMS (EDERMS) platform built on the same code-base as ADMS and EMS. EDERMS is integrated seamlessly with ADMS and eMAP, the topological view of PGE's system. This integration allows PGE to dynamically aggregate and disaggregate DERs and flexible loads, through edge DERMS, to provide essential grid services. ADMS includes applications like FLISR and switch order management

[53] PGE, Clean Energy Plan and Integrated Resource Plan 2023, Chapter 10 – Resource Economics, June 2023, Available at: [2023_CEP-IRP_Ch_10.pdf (ctfassets.net)]

which may benefit VPP with more efficient fault handling, optimized switching operations, and improved overall reliability. The cost estimates of the VPP Platform beyond 2025 would be refined as the system requirements and use cases are finalized; in this initial BCA they are rough estimates based on reasonable assumptions and information available thus far.

Within VPP, a plan for establishing a VPP desk is also considered, and costs for staffing the desk with personnel of appropriate skills has been included in the BCA.

5.2.1.5 Transportation electrification

VPP includes TE activities that require participating customers to partner with PGE to manage load. Investments in the Integrated Operations Center and Advanced Distribution Management System will pair with managed load programs to use TE load as a resource thereby enhancing our capability to reliably serve at least cost. VPP resources can be expanded by integrating and managing TE load using for example DR-capable chargers, vehicle telematics, vehicle-to-building, or through rates specific to TE load types.

5.2.1.6 Distribution Automation (DA)

In the future, DA would play an important role in enhancing VPP operations. DA includes umbrella of smart grid solutions like SCADA-enabled/automatic switch management, FLISR etc. These are aimed at solving power system issues by integrating various equipment, devices and data into a centralized system (e.g. ADMS). These would therefore add essential pre-emptive actions to enable the provision of various grid services from DERs while mitigating potential issues. Feeders targeted for DA implementation are those with a high exposure to vegetation/weather risk (see **Appendix F** for a discussion of ADMS and Distribution Automation capabilities).

Half of the feeders in the system are currently planned to be FLISR enabled in the system by 2035 which will lead to deployment of remote/SCADA enabled switch management capabilities in those feeders. This advanced switch management capability which would be crucial for optimal routing of energy from the VPP resources in the system. Since VPP relies on high number of customer-owned resources it is important to reduce the frequency and duration of outages for customers. By rerouting of power around faults using FLISR, energy from DERs (or VPP resources) would be utilized more efficiently thereby maximizing benefits from DERs.

In this BCA, DA benefits have focused on the probabilistic reactive outage mitigation benefits for faster fault isolation and service restoration utilizing FLISR. The benefits of using SCADA-enabled or automatic switch management for optimal VPP dispatch by reconfiguring feeders have not been quantified and therefore not included.

Approximately 300 feeders could be FLISR-enabled, which is about 50 percent of feeders on the system. Thirty-five feeders have already been enabled in 2024. We have identified the next batch of 57 feeders, which is a good average representation for the remaining 300 feeders. To quantify the benefits, we took the average profile of those identified 57 feeders.

- For outages originating at cable section or breaker, the assumption is that an outage affecting the entire feeder (all three sections) will immediately be isolated down to one section. The reliability benefit of the DA system is that only 1/3 the customers will be impacted by a sustained outage. This is modeled as each outage having 1/3 the duration as normal to all customers impacted.

- For outages originating at recloser, the assumption is that an outage affecting the customers downstream of a recloser will impact at least 2 of the switchable sections (the first switchable section from breaker to recloser is unaffected). The reliability benefit of the DA system is that only 1/2 the customers will be impacted by a sustained outage.

After a few years of the schemes being in-service, the actual benefits vs. modeled benefits of the FLISR schemes would be compared to refine the estimates. Actual benefits may be higher or lower depending on if/where the feeders experienced an outage.

The timeline we used for realizing benefits is 18 years. This aligns with the other DSP benefit streams ending in 2041. Given the fact that benefits are curtailed in 2041, only 35 feeders are getting 18 years of benefits due to feeders being added incrementally each year. All other feeders are getting less than 18 years of benefits but reflecting the full cost. As such this is a conservative benefit estimation. The total benefits received over the lifetime of the DA capability is not included but the entirety of the estimated costs are included.

5.2.2 Benefit-costs tests

The Total Resource Cost (TRC) test has been employed which includes the benefits and costs experienced by the utility system, plus benefits and costs to host customers. The TRC has been typically adopted for cost-effectiveness testing by PGE and various other utilities, and it is acceptable to OPUC. Here utility system benefits typically include all the utility system costs that would be avoided or deferred by implementing VPP. These avoided costs are one of the more important and sometimes challenging inputs to any BCA and can significantly affect the results of the analyses. Therefore, it is important that the assumptions are clearly articulated, methodology is informed and aligned with other internal stakeholders, and ultimately the analysis is shared with regulators. Costs typically include a portion of the VPP resources paid by the utility, other financial or technical support provided to host customers, and interconnection costs and distribution upgrades not paid by customers who may own certain VPP resources. The costs also generally include administration, marketing, measurement and evaluation.

Engineers, analysts and economists worked collaboratively to consider how PGE intends to use the technology and systems it will put in place as part of the VPP. The specific functions of the VPP components determine the impacts that arise, which in turn determine the benefits. For example, FLISR automatically restores (with reduction of manual intervention) power to as many customers as possible, as quickly as possible, in the event of a sustained fault. Therefore, it will help to direct truck rolls to fault locations which is a significant positive impact. One of the quantified economic benefits related to this impact is the cost savings due to more efficient truck rolls. Next step was to ascertain which impacts could be reasonably quantified for their economic impacts using methodologies known to be accepted by the stakeholder community. However, the benefits which could not be quantified in this version of the analysis have been qualitatively described in the later part of this section. Where possible, PGE utilized data regarding actual costs incurred and benefits realized through projects as direct inputs into the model and to refine forward-looking assumptions.

This BCA presents two perspectives:

- Primary conservative analysis without DA/FLISR benefits
- Prospective analysis which looks into 10-15 years in the future and includes FLISR benefits anticipated and needed for SCADA-enabled switch management to achieve reactive outage mitigation benefits. The second perspective illustrates how the planned DA capabilities in the later years will enhance benefits during the lifetime of the projects included in the BCA.

It is axiomatic that PGE will actively manage the topology of the distribution system to orchestrate and optimize DERs in the long-term. If this assumption was used in the development of the BCA the score would be higher. However, we took a conservative approach and thus only accounted for the reliability benefits of reactive switching presently employed by FLISR.

5.2.3 Costs

Costs include capital for internal and external labor, equipment, software, hardware, and vendor-provided services. Costs also include the Operation and Maintenance (O&M) expenses to sustain the investments. Recent historical and actual cost data have been collected and leveraged to develop the cost inputs, if available and as applicable.

5.2.4 Quantitative impacts

The National Standard Practice Manual provides a comprehensive list of the potential benefits and costs of DERs that should be considered when computing TRC. Since DERs are the building blocks of VPP, therefore this list is applicable for performing BCA of VPP portfolio. Below in **Table 16** is a subset of those quantifiable impact streams from NSPM that are directly applicable in our analysis.

Table 16. National standard practice manual impact categories

Type	Utility system impact	Summary
Generation	Energy generation (includes energy arbitrage)	The production or procurement of energy (kWh) from generation resources on behalf of customers
	Capacity	The generation capacity (kW) required to meet the forecasted system peak load
	Ancillary Services	Services required for providing flexibility to the grid
	Risk reduction	Benefit due to decrease in the likelihood of negative impacts on a system, such as reduced risk of power outages due to increased grid resilience or decreased exposure to volatile fuel prices

Type	Utility system impact	Summary
Transmission	Transmission capacity	Maintaining the availability of the transmission system to transport electricity safely and reliably; Congestion relief and upgrade deferral
Distribution	Distribution capacity	Maintaining the availability of the distribution system to transport electricity safely and reliably; Congestion relief and upgrade deferral
	Distribution capital cost Deferral	Distribution capital cost deferral
Other	Program administration	Utility outreach to trade allies, technical training, marketing, and administration and management of DERs
	Reliability, or outage risk reduction benefit	Maintaining generation, transmission and distribution system to withstand instability, uncontrolled events, cascading failures, or unanticipated loss of system components; ability to prevent or reduce the duration of customer outages
	Host portion of costs (DER/ transaction/ interconnection)	Cost incurred to install and operate DERs Other costs incurred to install and operate DERs Costs paid by host customer to interconnect DERs to the electricity grid
	Tax incentives	Federal, state, and local tax incentives provided to host customers to defray the costs of some DERs

A number of these impact streams have been included in plans of other utilities as well like AES Ohio and Eversource.[54, 55]

5.2.5 Qualitative impacts

The CBA encompasses the identification and enumeration of benefits that are quantitative and economic in nature as well as benefits that are strictly qualitative in nature, or that would be difficult to quantify. Qualitative benefits are important estimates of impacts and outcomes arising from VPP, and incremental to the quantitative benefits included in the principal CBA model result. To account for those benefits, PGE's community benefit indicator (CBI) study is in the process of cataloguing and valuing indicators that reflect broader societal and community benefits, such as increased access to clean energy, economic development, and

[54] The Dayton Power and Light Company D/B/A AE Ohio, Case no. 24-10112-EL-GRD. Available at: dis.puc.state.oh.us/DocumentRecord.aspx?DocID=e9f48179-b76b-4d01-bf1b-d30e067a9256
[55] Petition of NSTAR Electric Company d/b/a Eversource Energy, pursuant to G.L. c. 164, § 92B, for approval by the Department of Public Utilities of its Electric Sector Modernization Plan. Available at: 18550448 (comacloud.net)

improved public health outcomes. This work supports a more holistic approach to resource planning, moving beyond traditional cost measures to include impacts on underserved communities and other non-monetized benefits. The draft list of CBIs and approach to the study were presented to stakeholders for discussion and feedback.[56] In August and September of 2023, Cadeo presented to OPUC staff, PGE's IRP Roundtable group, and led a facilitated discussion with community-based organizations participating as part of the Community Benefits and Impacts Advisory Group (CBIAG).

Below is a list of some the key examples of other benefits which have not been quantified in this round are as follows:

- **Safety:** Increased worker safety via proposed investments in DA will reduce trips to resolve outages, particularly during dangerous conditions (i.e., storm response).
- **Minimization or Mitigation of Impacts on Ratepayers:** Reduce future utility spend through reduced storm costs and optimized grid planning; create opportunities for customers to reduce their bill by deploying distributed resources. The VPP investments aim to minimize or mitigate impacts to ratepayers in the long-term by reducing utility costs (and thereby reducing passthrough to customers) through expansion of access to DG, optimized grid planning, deployment, and operations – all of which reduce the need for infrastructure upgrades and break/fix.
- **Reduced emissions of Greenhouse Gas (GHG) and air pollutants:** Carbon dioxide emission reductions quantified are assumed to be related to one of two impacts: 1) reduced electricity generation; and/or 2) reduced internal combustion engine vehicle usage. The VPP components that reduce the consumption of electricity, result in reduced electricity generation and resulting greenhouse gas emissions. For example, transportation electrification enables reduction in gas usage which leads to reduction in CO2 emissions. The plan includes targeted projects to reduce environmental burdens in underserved communities. Development of VPP will enable the interconnection of DERs (like solar, EV) while optimizing system demand at all times of the year, and therefore improve air quality and reduce pollution-related health issues. In the next version of this analysis, we intend to include quantified estimates of benefits from reduction of GHG and air pollutants. Limiting pollutants such as nitrous oxide (NOx) and particulate matter (PM2.5) result in improved health outcomes for all communities.
- **Economic and workforce development:** Over a 20-year period, consistent with the considered timeframe of analysis, the Bureau of Economic Analysis (BEA) 13 RIMS II Model suggests that direct and indirect yearly jobs will be created. Direct jobs are expected to be higher-paying, technology-oriented positions that will support

[56] September 4, 2024 CEP/IRP Roundtable, CBI Study presentation, Available at: https://assets.ctfassets.net/416ywc1laqmd/2KYZToHzDEUncfQrvJfCNS/f6c4eeef494dcfc85975515f53d1ea5a/IRP_Roundtable_September_24-5.pdf.

economic growth and stability, while providing rewarding and developmental opportunities to a growing workforce. Additionally, there will be creation of indirect jobs, such those associated with restaurants, hotels, and construction support activity. The development of projects related to VPP will stimulate the regional economy.

- **DER proliferation:** For example, should FERC Order 2222 become applicable to PGE, investment in a VPP platform enables the Company to comply and to see, forecast, and respond to DER generation on their grid, thus making it easier for customers to adopt DERs.
- **Customer satisfaction:** Detect problems before they impact a customer, thereby improving the overall customer experience,
- **Commercial investments:** For example, the Company has heard from manufacturing and commercial customers that reliable electric service is important to their selection of Portland and the surrounding area for additional investment, thus demonstrating how the reliability of the local grid can directly contribute to regional economic growth.
- **Facilitation of the electrification of buildings and transportation:** Increased feeder and substation capacity to support growing EV and electric heating adoption.
- **Avoided Land Use Impacts:** Reduce requirement for build or expansion of traditional generation infrastructure.

The significant qualitative benefits further support the reasonableness of VPP.

5.2.6 Assumptions

Evaluation of costs and benefits is a complex undertaking which needs to consider many factors, some of which may be easier to quantify than others. It is important to understand the base financial and framework assumptions that go into the assessment, including forecasting to estimate the future benefits and costs, and cumulative impacts of changes to systems over time. Below are some of the key assumptions that have shaped the analysis.

Benefits are captured from an investment's in-service dates to either 2041 or to the end of their asset lives, whichever comes first. This analysis only recognizes benefits for assets that go in service after 2021. In order to quantify the different benefit streams, it is necessary to assume certain avoided cost elements and they are shown in **Table 17**. The widely accepted or approved sources from which their values have been obtained are also mentioned. The annual ELCC values for 2-hour and 4-hour batteries are assumed to be 38 percent and 57 percent respectively, by averaging over the time the numbers reported for summer and winter in Table 50 of 2023 IRP[57]. **Table 18** provides the financial parameter values that have been utilized for the computation of the costs and the benefits. **Table 19** presents the

[57] PGE, Clean Energy Plan and Integrated Resource Plan 2023, Chapter 10 – Resource Economics, June 2023. Available at: 2023_CEP-IRP_Ch_10.pdf (ctfassets.net)

annualized energy and flexibility benefits for 4-hour battery resources in $/kW-yr that have been leveraged.

Table 17. Avoided cost elements utilized in the BCA and their values

Avoided cost element	Units	Value	Source
Transmission Loss Factor (Summer)	Percent	2.09%	BPA Open Access Transmission Tariff, Effective Date: October 1, 2023
Transmission Loss Factor (Winter)	Percent	2.04%	BPA Open Access Transmission Tariff, Effective Date: October 1, 2023
Risk Reduction Value	$/MWh	$3.00	2019 IRP (not updated in 2023 IRP)
Transmission Deferral Credit	$/kW-yr	$87.34	2024 General Rate Case (GRC UE 416) Transmission Marginal Cost Study
Distribution Deferral Credit	$/kW-yr	$17. 21	2024 GRC
Generation Capacity Credit	$/kW-yr	$175	2023 IRP Update - New Resource Economics

Table 18. Financial parameters from - June 2024

Parameters	Assumed Values
Inflation Rate	2.04%
Pre-Tax Cost of Capital	7.64%
After-Tax Nominal Cost of Capital	6.85%
After-Tax Real Cost of Capital	4.71%

Table 19. Annualized benefits for 4-hour battery resources in $/kW-yr[58]

Years	Energy value	Flexibility value
2026	9	10
2027	9	12
2028	9	14

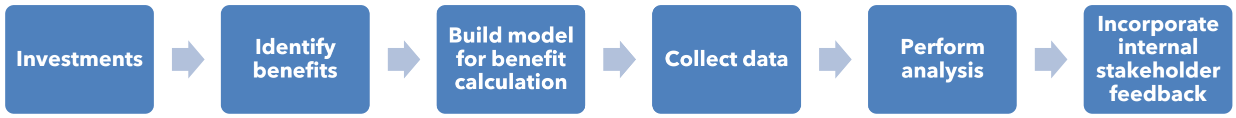
5.2.7 Approach

Benefits and costs for projects, programs and portfolios depend on the assets/technologies developed; each with specific benefits delivered and costs associated to do so. Careful consideration of the project, program and portfolio must be given to properly parse out these details, on both the benefit and cost side, to allow determination of inputs without co-inflating, overlapping or discounting benefits or costs in error. Quantifying the impacts of a technology within the project, program or portfolio is an important initial step; assignment of valuation and monetizing the benefits, as well as identification of the associated costs follows the initial quantification.

The net benefits analysis relies on industry best practices, nationally recognized methodologies used to evaluate similar types of electric utility investments, and assumptions that may have been previously considered. The widely accepted principles outlined in National Standard Practice Manual ("NSPM")[59] and the United State Department of Energy's ("DOE") Modern Distribution Grid documents have been adopted; these state that net benefits should account for state regulatory and policy goals as well as all relevant costs and benefits and assess investments as bundles and portfolios instead of separate measures. Once the key impacts that need to be assessed were identified, the framework was developed for each resource category complete with the specific method of cost and benefit quantification implemented in an excel tool. Source data needed for the CBA model was identified and gathered from stakeholders including actual data where available and appropriate. This source input data was then applied within the CBA model to compute the outputs. A simplified process flowchart has been provided in **Figure 24**.

[58] IRP/CEP 2023. Available at: https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf
[59] NSPM-DERs. nationalenergyscreeningproject.org. Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf

Figure 24. Benefit cost analysis steps



Finally, iterative review and adjustments were performed to firstly validate that model inputs are correctly stated and applied, secondly confirm calculation accuracy under the applied methodologies, thirdly maintain consistency in net benefits approach across the EDCs, and lastly confirm comprehensive benefits included. These efforts have resulted in a set of reasonable cost and benefit estimates as part of this initial BCA.

5.2.7.1 Generation energy

In general, VPP resources will create energy generation benefits when they reduce the amount of electricity utilities need to produce or procure in order to meet load and will create costs if they require higher levels of energy generation[60]. For energy generation we calculated the amount of energy (i.e. in kWh) produced by the DERs and the corresponding reduction in energy that needs to be purchased from the grid. A conservative estimate of benefits related to 100 days of arbitrage each year has been included.

5.2.7.2 Generation capacity

The amount of generation (i.e. in kW) required to meet the forecasted peak load. With load growth if over time the utility does not have sufficient generation capacity then it may either need to build generation capacity or procure it (through bilateral contracts or wholesale market). DERs spread geographically over the system can provide additional capacity which can help. For example, curtailment through demand response, injections from storage and solar PVs during the system peak can result in a net decrease in load, and therefore PGE can derive a benefit in the form of lower capacity needs.

The generation capacity benefit provided by VPP resources can be calculated by determining the avoided costs of building new generation capacity or upgrading existing infrastructure. This includes capital costs, operation and maintenance costs, and any other costs associated with new capacity. Since the VPP resources are essentially DERs, therefore for measuring their contribution to meeting peak demand we have considered the Effective Load Carrying Capability (ELCC) values which are highly conservative in values. A monetary value to the capacity benefits is provided by comparing the costs of VPP resources to the costs of traditional capacity solutions.

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[60] Available at: https://www.nationalenergyscreeningproject.org/wp-content/uploads/2020/08/NSPM-DERs_08-24-2020.pdf.

5.2.7.3 Ancillary services

Ancillary Services are those services that are required to maintain grid stability and enhance flexibility. The extent of ancillary service benefits from any resource depends on how the DER operates and what are expected to be the system conditions during its time of operation. VPP resources like storage, especially if they are front of the meter, may be actively dispatched to increase grid flexibility. We have calculated how much each VPP resource contributes to the ancillary services which involves measuring the capacity of DERs to provide these services and their performance during grid events.

5.2.7.4 Transmission capacity

Transmission capacity refers to the availability of transmission infrastructure to transfer bulk energy from generation to the loads in a reliable manner. Since DERs like solar PV can generate electricity in the distribution system, storage can shift load by charging during off-peaks and discharging during peak load times, and demand response can reduce the system load, so these resources can essentially defer the need for new transmission infrastructure. We calculated the potential capacity constraints that the VPP resources can alleviate and calculated the costs that are avoided by deferring transmission upgrades. This includes capital costs, operation and maintenance costs, and any other costs associated with new transmission capacity.

5.2.7.5 Distribution capacity

Distribution capacity refers to the substation and distribution line infrastructure necessary to meet customer electric demand. By reducing net load during peak period, DERs can help defer distribution capacity upgrade needs either actively or passively, and therefore eliminate deferral costs. We calculated the costs that are avoided by potentially deferring distribution upgrades through the development of the considered VPP resources.

5.2.7.6 Distribution capital cost deferral

Utilities face ongoing O&M and capital expenses to achieve safe and reliable operation of distribution facilities. VPP resources, particularly batteries, can help defer both capacity-driven investments and reliability-driven asset replacements, especially for aging infrastructure. We evaluated various investment types that VPP-related initiatives could potentially avoid or postpone, including equipment, distribution infrastructure, and other assets. The implementation of VPP resources is expected to lead to a reduction in future capital expenses within the considered timeframe, which would likely continue into the future without VPP adoption.

VPP resources offer two primary reliability benefits to customers: reducing the impact of outages and potentially deferring aging infrastructure investments. Both of these benefits effectively mitigate risk while delivering customer value. To calculate these reliability benefit streams, risk-based economic lifecycle models are employed. These models determine the optimal time to replace an asset by balancing maintenance costs and the risk associated with owning and operating the existing asset against the cost of replacement. Utilizing the outputs of these models to justify proactive asset replacement reduces the risk of system failures and customer outages, efficiently allocates capital to improve reliability, and enhances the overall customer experience.

This asset modeling approach is founded on the fundamental concept of risk, defined as the product of annual failure probability and the consequence cost of failure. The annual failure probability represents the likelihood of an asset experiencing a repairable or non-repairable failure, based on its age, condition, and/or vintage. The consequence cost of failure is the weighted average cost of various failure scenarios for the asset. To calculate this weighted average, subject matter experts identify different failure scenarios, ranging from minor to catastrophic, and assign their relative likelihoods, informed by historical data when available. The failure scenario costs encompass the reliability impact on customers, the load affected by the failure, and direct cost impacts to the company. This risk modeling approach effectively enables the quantification of both outage risk reduction for customers and the deferral of aging infrastructure investments.

5.2.7.7 Reliability, or outage risk reduction benefit

This benefit focuses on calculating the reliability improvement estimates based on the proposed scope of work. The analysis provides estimates avoidance of customers interrupted ("CI") and customer minutes of interruption ("CMI") and the number of customers directly impacted by the failure. Since the analysis focused on VPP components in the system, the actual number and type of customers that would see a direct benefit was identified. We then leveraged PG&E's 2012 Value of Service (VOS) study that was approved by the California Public Utility Commission to calculate the economic impact of avoiding an outage, referred to as Customer Outage Impact. Annual Outage Risk Reduction ($) is the reduction in outage risk for customers from asset and geographic factors by having each of the VPP components versus in their absence. For example, in case of DA, reduction in outage risk for customers by having a 2/3 or half of customers on respective feeder no longer experiencing outage due to automated switching. Benefits are comparing manual switching to automated switching resulting from the installation of distribution automation.

5.2.8 Discussion of results

The model computes costs and quantified economic benefits of these two perspectives (with and without FLISR-based reliability benefits) based on a utility cash flow cost basis over the 20-year CBA timeframe. For each of these results, a net present value calculation is performed. We assigned the appropriate benefits to the appropriate VPP resources and based on that we derived the calculation.

Table 20. Benefit cost analysis results

Types	Categories	Benefits ('000s)	Costs ('000s)	B/C Ratio
Storage	Front of meter storage	$974,429	$734,129	1.33
	Behind the meter storage	$57,387	$20,655	2.78
	TOTAL (Storage)	$1,031,815	$754,784	1.37
Demand response / flex load (excluding storage)	EP Schedule 26	$44,093	$10,775	4.09
	Tstat	$73,294	$16,456	4.45
	EP Schedule 25	$2,795	$4,350	0.64
	PTR	$14,266	$7,652	1.86
	TOD	$11,035	$3,858	2.86
	MFWH	$4,394	$7,609	0.58
	DR-portfolio level reliability benefits	$90,000		
	TOTAL (DR/Flex Load)	$239,877	$50,701	4.73
VPP Desk & Platform			$64,566	
TE		$40,942	$20,881	1.96
FLISR		$635,252	$90,184	7.04
VPP (Perspective 1 – without DA/FLISR)		1,276,374	880,810	1.45
VPP (Perspective 2 – with FLISR)		1,911,626	970,995	1.97

The NPV method has been used to compare the present value of benefits to the present value of costs over the time horizon considered in this analysis. This involves discounting future benefits and costs to their present value using an appropriate discount rate. The accompanying workbook shows the quantified economic benefits, costs, net present value ("NPV"), and benefit-to-cost ratio result.

This is a conservative preliminary BCA which has considered only the quantifiable direct customer benefits, although there are several indirect customer benefits which are accrued over time. While direct customer benefits represent the economic value that is expected to accrue directly to the company and its customers, indirect benefits represent those which are more difficult to quantify due to lack of standardized computation methodology. However, some of these indirect benefits hold major significance since they enable PGE to advance towards Oregon state's clean energy targets. For example, part of the rationale for investing in clean energy focused resources is to meet state energy goals, which can be difficult to quantify in the absence of carbon tax in the state, and therefore not included in the direct benefits that have been calculated for VPP. In spite of quantifying a subset of the benefits the overall quantified economic benefits for the portfolio exceeds the costs giving a benefit-to-cost ratio that is over one then it provides solid justification for pursuing the investment and going ahead with the effort.

All the use cases and operational characteristics of the different resources are not yet known. In this analysis, assumptions have been made based on technical specifications of these resources and their direct benefits that are PGE's priorities. As the resources will be developed, interconnected, energized and operated, we would obtain more accurate data regarding the costs and benefits over time. The analysis performed here helps determine the benefits of the planned investments; what use cases for each type of resource would be beneficial to the utility and/or customers, and what type of resources may be relatively more cost-effective. This analysis serves to provide direction to the utility internally and is a first step towards demonstrating the benefits of VPP to the external stakeholders.

It is important to note that this BCA is only applicable to the scope of the projects that have been mentioned and only as part of the Distribution System Plan. Because this analysis is preliminary and not complete it is not applicable elsewhere and should not be used by stakeholders in any other context.

Chapter 6. Traditional infrastructure needs and solutions

This chapter outlines PGE's approach to distribution system needs and solutions, focusing on three main elements:

Distribution Planning Process

- Evolution from one-way power flow to modern grid requirements
- Updated grid needs ranking methodology
- Integration of equity considerations
- Prioritized list of grid needs across service territory

Traditional Solutions

- Standardized process for identifying infrastructure solutions
- Eight priority projects identified for 2025 capital cycle
- Detailed solution identification workflow
- Cross-functional collaboration requirements

Non-Wires Solutions (NWS)

- Shift toward alternative infrastructure investments
- Current capabilities and challenges
- SALMON project as pilot implementation
- Required capabilities for NWS implementation:
    - Grid modeling and analysis
    - DER control and dispatch
    - Product design and marketing
    - Integration with existing systems

The chapter demonstrates how PGE is balancing traditional infrastructure needs with innovative solutions while maintaining reliability and incorporating equity considerations.

Alternative solutions to traditional infrastructure investment can mitigate some needs within the distribution system. However, the need for new or upgraded distribution infrastructure will always be present. This chapter discusses the needs within the distribution system that pose a risk to reliability and the solutions that are being developed to address those needs.

6.1 Traditional grid needs analysis

6.1.1 Distribution planning process

Distribution system planning is the process of analyzing the distribution grid to assess whether 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, helping us to deliver 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.

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

The power grid has evolved significantly from its traditional one-way distribution system, with modern sensor technologies and control systems now enabling greater visibility, faster response times, and seamless integration of distributed energy resources. 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.

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.

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 (EV) charging is an intermittent load addition, photovoltaic (PV) installations provide distributed generation and flexible loads offer opportunities for capacity relief by shifting energy use to more optimal times of day.

The distribution planning process was described in DSP Part 2, Section 1.3 Current distribution planning process.[61] For convenience, that content has been included here as **Appendix B. Distribution planning process**.

6.1.2 Prioritized list of grid needs

The evolution of PGE's Grid Needs ranking matrix represents a significant methodological overhaul driven by stakeholder feedback, which highlighted opportunities for improvement in the original scoring system. Previously, the ranking matrix utilized a 1-5 level system, where a Level 5 criterion could garner a disproportionately high score due to a multiplier effect, potentially reaching a score of 75, while a Level 1 criterion might only score a 1. This disparity created an imbalance, making the scoring lopsided and not reflective of the nuanced needs and priorities.

In response to this feedback, PGE revamped the ranking matrix, removing the 1-5 level system entirely. The reformed methodology maintains most of the original criteria but has recalibrated the scoring to reinforce the criticality of certain factors, such as safety and

[61] DSP Part 2. Available at: https://assets.ctfassets.net/416ywc1laqmd/i9dxBweWPkS2CtZQ2lSVg/b9472bf8bdab44cc95bbb39938200859/DSP_2021_Report_Full.pdf.

customer-driven needs. One of the significant updates in the new methodology is the inclusion and elevation of equity criteria. Equity, which now holds a pivotal role, is integrated into the matrix with a score range of 1 to 5 and included as part of the new tiebreaker criteria.

This revamped approach ensures that no single criterion can dominate the overall score unduly, with the maximum possible score for any criterion capped at 20. This change effectively narrows the scoring range and addresses the concerns about previous disparities. The new tiebreaker criteria encompass all former Level 5 and Level 4 criteria, ensuring that critical factors continue to receive due emphasis. Additionally, the equity index has been incorporated, reflecting PGE's commitment to addressing and integrating social equity into their planning processes.

6.1.2.1 Detailed breakdown of the updated methodology

6.1.2.1.1 SAFETY AND CUSTOMER COMMITMENT

These remain paramount, each with a maximum possible score of 20, accounting for 15.50 percent of the overall weighting. This underscores PGE's commitment to maintaining high safety standards and fulfilling customer commitments.

6.1.2.1.2 COMPLIANCE AND GRID CONSTRAINTS

Criteria related to compliance with transmission and sub-transmission constraints have been refined. For example, compliance drivers or constraints at the 115 kV level or above can score up to 15, with a weighting of 11.60 percent.

6.1.2.1.3 PRECURSOR TO MITIGATING OTHER GRID NEEDS

This criterion, which scores up to 15 (11.60 percent), acknowledges projects that enable subsequent grid improvements, emphasizing the importance of sequencing in infrastructure projects.

6.1.2.1.4 TEMPORARY EQUIPMENT MITIGATION

Freeing up or mitigating mobile/temporary equipment or configurations is valued similarly, highlighting the need to maintain operational flexibility and readiness.

6.1.2.1.5 EQUITY INDEX

The equity index, scoring up to 5 (3.90 percent), includes metrics such as energy burden, housing type, race, internet access, and disabilities. This index systematically integrates equity considerations into grid planning.

6.1.2.1.6 LOADING AND RISK FACTORS

Detailed criteria address loading percentages, asset and geographical risks, and customer minutes interrupted (CMI), each with specific scoring mechanisms to reflect their importance accurately.

Table 21. Ranking criteria and updated weighting scores

Prioritizing criteria	Max possible score	Weighting
Addresses safety concern	20	15.5%
Must do for customer commitment	20	15.5%
Compliance-driver or mitigates transmission constraint	15	11.6%
Precursor to mitigating other grid needs	15	11.6%
Frees up or mitigates mobile/temporary equipment	15	11.6%
Equity index metric	5	3.9%
Feeder % loading of seasonal limit (N-0)	4	3.1%
Transformer % loading of load beyond nameplate ratings LBNR (N-0)	4	3.1%
Existing total asset and geo risk (substation)	4	3.1%
Existing CMI impact (substation)	4	3.1%
Existing total asset and geo risk (feeder)	4	3.1%
Existing CMI impact (feeder)	4	3.1%
Known load growth impact to equipment	4	3.1%
Substation SCADA	3	2.3%
Multiple feeders or transformers exceed criteria	3	2.3%
Overload or voltage issue for N-1 condition (feeder)	1	0.8%
Overload or voltage issue for N-1 condition (transformer)	1	0.8%
Distribution transformer utilization index	1	0.8%
Distribution feeder utilization Index	1	0.8%

Prioritizing criteria	Max possible score	Weighting
Makes substation DG ready	1	0.8%

Utilizing the Distribution Planning Ranking Criteria and Scores, PGE prioritizes grid needs. The following distribution planning grid needs in **Table 22** were analyzed for solutions as part of the 2025 capital cycle, which began in 2023 and are based on 2022 loading information on equipment.

Table 22. List of prioritized grid needs

Priority	PGE location	Grid need	Project	Total
1	Evergreen substation	Add distribution infrastructure	Evergreen	**4.9**
2	Swan Island substation	Substation Rebuild	Swan Island	**4.8**
3	Glisan substation	Industrial load growth in Gresham	Glisan	**4.5**
4	New Station E	New Load/Capacity need, rebuild substation	Sub E	**4.4**
5	Glencoe-Glisan	Capacity addition to implement other grid need mitigations	Glencoe-Glisan	**2.7**
6	Holgate substation	Capacity addition to implement other grid need mitigations in SE Portland, lack of SCADA telemetry, feeder reliability improvements, aging assets	Holgate	**2.5**

Descriptions of these proposed solutions are provided in **Appendix E Description of solutions to address grid needs.**

6.1.3 Distribution planning process evolution

PGE is continuously evolving its planning practices to adjust to a rapidly changing distribution system landscape. This evolution is particularly critical to the load growth in the PGE service territory.

To address these challenges, we have outlined below several focus areas where the team are pursuing changes.

- Forecast new electrification load (TE/BE) and resources (DER) and right size the distribution grid investments to safely and reliably serve the growing demand for electricity and proliferation of DERs.

- Modernize grid assets and systems to enable bi-directional power flow and real-time information exchange to maximize efficiency and reliability and adoption of clean energy resources.
- Improved information exchange for efficient analytics and management of behind-the-meter resources for grid level optimization of load and resources.
- Focus on reliability and resiliency as extreme weather scenarios become more common. (Hardening, and redundancy of service)

6.2 Traditional solution identification

6.2.1 Traditional solution identification process

This section provides an overview of our solution identification process for the prioritized grid needs. We describe the process by which our planning engineers identify potential solutions that are needed to provide necessary additional capacity and address any identified system deficiencies. Prior to recommending a capital investment, planners will thoroughly evaluate existing infrastructure to identify opportunities for increased capacity utilization, potentially avoiding the need for new capacity projects. Potential solutions to address capacity issues that involve minimal or no incremental cost may include rebalancing distribution loads, phase balancing, and small-scale reconductoring projects to facilitate incremental distribution capacity.

The solution identification process is directly fed from the output of our grid needs identification process. We perform a system study to develop and support potential project options. The study will include a problem statement, study methodology and analysis, project benefits, cost estimates and a recommended solution option. We utilize our distribution load flow software, CYME, to analyze distribution system options by modeling scenarios and running load flow simulations which will assist in determining a preferred solution option for a project.

To accommodate load growth, such as the load growth identified in the grid needs analysis, PGE commonly implements new infrastructure, such as new transformers and/or distribution feeders. For substation transformers, our planners will determine the necessary transformer capacity based on standardized transformer sizes so we can accommodate the loading needs identified in the study. We have standardized transformers sizes (28 MVA[62] and 50 MVA), however non-standard sizes may be required based on specific needs of a customer and/or a location. Our planners will then work to determine:

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

[62] The nameplate rating is 28 MVA, with Load Beyond Nameplate Ratings (LBNR) providing capacity equivalent to approximately 30 MVA.

- If a new substation and associated equipment are necessary.

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

Once PGE's planners have narrowed down options in a study, PGE will analyze feasibility, constructability and any potential issues. Internal experts are included in this process, including the following:

1. **Transmission Planning team -** Help evaluate impacts of distribution changes on the transmission system, including DER integration effects on power flows and system stability. Provide input on transmission constraints that could affect substation capacity additions and ensure coordinated planning between transmission and distribution systems. Support analysis of how proposed distribution projects align with broader transmission system capabilities and future needs.
2. **Substation Engineering team** – Help determine if an existing substation can accommodate upgrades to existing equipment or expansion of the site.
3. **Property Services team** – Help identify and acquire real estate if a new substation site is required or if existing property expansion is possible.
4. **Distribution Operations Engineering team** – Help determine if spacing will be an issue for new feeder getaways, if expanding an existing substation, and will provide feedback for new feeder routes and emergency switching sheets for transferring load off transformers and feeders.[63]

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

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

- **Historical loading** – Metered data points sourced from our PI Historian data (real-time data historian program).
- **Load forecast** – The corporate load forecast (**Chapter 3 DER forecasting**).

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

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

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

6.3 Non-wires solution identification and development

Stakeholders, OPUC staff, and PGE all recognize the need to more thoroughly consider alternative resources. As Distributed Energy Resource (DER) penetration increases and associated costs decrease, interest in implementing Non-Wires Solutions (NWS) has grown as a way to defer or replace conventional distribution infrastructure investments. These innovative solutions are anticipated to address localized needs while generating cost savings for customers.

However, significant learning and testing are required to identify the most effective and efficient NWS options. Given that NWS serve as substitutes for traditional infrastructure, reliability and affordability remain paramount considerations. The interest from the Commission, stakeholders, and staff in developing NWS that leverage DERs, energy efficiency, and flexible load underscores the perceived value of PGE's ongoing investments in these resources.

Transitioning from our current state of DER development and VPP maturity to an operational capacity where these resources can effectively collaborate with PGE operations and enhance customer engagement is a complex journey. While PGE's Smart Grid Test Bed is actively conducting research and demonstrations to address operational, development, deployment, and customer value challenges, the complexity of implementing NWS represents a significant evolutionary step.

Currently, PGE operates primarily within Stage 1 of the VPP Capability Stages framework. Challenges in orchestrating a locational aggregation of DERs to provide consistent, location-specific grid services include but are not limited to:

- Customer adoption of DER technologies
- Customers' willingness to allow strict management of their smart grid investments to maintain reliability
- The need for differentiated service tariffs for customers participating in NWS, tailored to local grid constraints
- Clearly defined compensation structures to avoid confusion among customers enrolled in PGE programs, whether they are part of NWS or not
- The operational capability to dispatch DERs to meet identified grid needs
- Addressing changes in customer demographics over the lifespan of the NWS

As PGE's VPP capabilities advance and customer adoption of DERs grows, grid planning will increasingly identify opportunities where these resources can collaboratively meet local grid demands.

PGE's investments in VPP and grid modernization position the development of NWS as a more organic and cost-effective approach to addressing grid challenges through DERs. By leveraging customer-owned resources, as outlined in the Distribution System Plan (DSP) guidelines, NWS has the potential to provide valuable grid services while delivering direct benefits to customers. Initiatives like virtual power plants exemplify non-wires alternatives that incorporate community-generated renewable energy, reducing the need for costly energy purchases, fuel expenditures, and infrastructure investments—all while enhancing grid reliability and customer resilience.

Many utilities, including PGE, are determining best practices and standard approaches in real-time. Through our work on the NWS concept proposals developed for DSP Part 2, we identified key capabilities that need to be in place in order to address a grid need (**Table 23**).

Table 23. Capabilities required to support implementation of non-wires solutions

Capability	Description
Grid modeling and analysis	Digital twin/network model development, including analysis of SCADA and field sensor data, typology models and control settings, and DER performance data.
DER control and dispatch	Design and implement DER controls, including DERMS alignment, lab simulation, hardware-interoperability and testing, OEM communication and coordination.
Product design and marketing	Analyze customer composition of chosen locations, assess customer preferences/needs, customize product offerings to maximize participation/adoption, incorporate considerations for disadvantaged populations, design and implement measurement and evaluation framework.
Contractor training and management	Identify installers who are willing to add NWS requirements to the install process, work with installers to design efficient installation processes, prepare installers to configure DERs to integrate with PGE systems/controls.

Capability	Description
ADMS/DERMS controls integration	Configure ADMS/DERMS to recognize and operate NWS DERs, develop operations procedures to cover NWS use cases.
Equity lens	Apply environmental justice principles in the deployment of DER-based solutions

Through our concept proposal, we demonstrated that DERs could meet the identified requirements for providing capacity relief on the Eastport location. We have been working to elaborate on that concept by focusing our work in the SGTB to develop the capabilities identified in **Table 23**.

6.3.1 Flexible Feeder Project (SALMON: SmartGrid Advanced Load Management & Optimized Neighborhood)

As PGE's flexible load portfolio expands and its DERMS capabilities mature, there is a growing need to understand how DERs can be integrated into distribution operations and the value they provide. In this research area, projects to explore the values of DERs as an operational asset, by driving high levels of dispatchable load on a single feeder, using targeted incentives for new equipment, controls, storage, distributed solar and EE. This work involves close collaboration between PGE and Energy Trust of Oregon to learn about co-deployment of DER solutions in a traditionally underserved North Portland community historically subjected to redlining and gentrification.

Non-wires solutions (NWS) offer alternatives to some traditional grid infrastructure upgrades, while Virtual Power Plants (VPP) aggregate and manage distributed energy resources to provide grid services similar to conventional power plants. While distinct in purpose, both NWS and VPP leverage similar DER capabilities to benefit the grid. The purpose of the project is to create a concentration of resources dense enough to create or approach the capabilities of a virtual power plant or non-wires solution. This project area is closely linked to the DOE Connected Communities grant (SALMON) awarded to PGE and its partners in this work – Energy Trust, NEEA, National Renewable Energy Laboratory and Community Energy Project.

That proposal focuses its efforts on the Overlook/Arbor Lodge portion of the SGTB, a historically under-served community in North Portland. The team is aiming to build up to a 1.4 MW flexible load resource in the community, consisting of:

- Efficiency measures,
- Connected devices,
- Distributed solar,
- Energy storage, and
- Smart charging.

These community resources will then be integrated into PGE's ADMS/DERMS and optimized by National Renewable Energy Lab (NREL) to demonstrate a series of bulk services, including energy, capacity, and frequency response, as well as distribution services including capacity relief, power quality, and Volt/Var optimization, including conservation voltage reduction (CVR). The results of this work will be shared regionally through the existing network of stakeholder groups, spurring a realignment of utility planning and operation.

Chapter 7. Empowered communities

This chapter outlines PGE's approach to community engagement and equity initiatives, focusing on three main elements:

Strategic Framework

- Equity lens integration in DSP planning
- Focus on affordability and partnerships
- People-centered planning approach
- Goals for community empowerment and participation

Customer Support Programs

- Income-qualified bill discount programs
- Energy efficiency initiatives
- EV charging infrastructure
- Battery storage in PSPS zones
- PGE+ personalized assistance

Engagement Initiatives

- IRP Roundtable (monthly)
- Distribution System Workshop (bi-monthly) – (2024 – 5 workshops)
- Community Learning Labs (in-person)
- Community Benefits and Impacts Advisory Group (CBIAG)

The chapter demonstrates PGE's commitment to creating an equitable, sustainable energy future through meaningful community engagement and targeted support programs while maintaining transparency in decision-making processes.

Portland General Electric (PGE) recognizes the role of the distribution system in fostering equitable and sustainable resources. Operating within a modern grid that facilitates two-way bi-directional flow, PGE is dedicated to developing innovative and creative resources that will benefit customers and communities. Through developing and establishing comprehensive approaches which includes programs, projects, and initiatives, we will continue to provide safe, reliable, affordable service with the capacity to provide resilient and equitable energy to our customers and communities.

As we continue on this transformational journey, we acknowledge the challenges and benefits, while striving to achieve decarbonization targets. PGE acknowledges these efforts will require a combination of people-centered planning and technological inclusivity.

Over the past few years PGE has made concerted efforts to practice better community and stakeholder engagement recognizing the importance of these engagements as we continue to serve our many different customers, differently situated with different needs in balance with our transition to a clean energy future. We acknowledge this clean energy future will affect our communities and customers in different ways and we are taking a more thoughtful and proactive approach when it comes to our people centered planning.

The DSP is unique when it comes to serving our customers and communities as it has pushed the utilities to think differently in how we deliver power. Some of the ways we want to empower our customers is to participate in our energy ecosystem. This could be rooftop solar, solar plus storage, energy efficiency, demand response and batteries. These options provide alterative solutions to support our growing demand.

Through the DSP, our goal is to implement and optimize a Virtual Power Plant (VPP) in conjunction with Distributed Energy Resources (DERs) to enhance community needs and provide maximum benefits to customers. We plan to accomplish this goal, in part, by increasing participation in PGE programs and products, partnerships and implementing and executing strategic objectives listed below:

- Applying an equity lens framework in DSP strategy and planning.
- Collaborate with community leaders/partners, EJ communities, CBIAG members and interested stakeholders.
- Share updates and provide learning opportunities in DSP technical workshops, community Learning Labs and other appropriate venues.
- Establish continuous improvement and feedback loop process.

These objectives will help us achieve our desired outcomes, such as increase bill savings for customers, reduce energy burden in communities, improve community well-being and create more resilient communities and more clean and sustainable energy resources (reduction in GHG emissions).

By meeting goals, objectives and desired outcomes will assist in PGE having a greater impact in providing a more safe, reliable, affordable, resilient and equitable clean energy to communities and customers.

To support our customers equitably, especially those who experience high energy burden, we are currently creating an affordability strategy to address the needs of our customers.

Our affordability strategy is grounded in two key themes: affordability and collaboration. Our mission is to create a sustainable and equitable energy future by providing comprehensive support to our customers and meaningful long-term collaborations with our partners.

We recognize the importance of making energy affordable for all our customers, particularly those who face economic challenges. Our affordability strategy encompasses a holistic approach to bill assistance, discounts, and energy efficiency. This commitment to equity is reflected in our various programs designed to alleviate financial burdens and provide support where it’s needed most.

Key initiatives include:

- **Bill Assistance Programs**: Providing financial aid to customers struggling with their energy bills.

- **Discount Programs**: Offering reduced rates for income-qualified customers to promote equitable access to energy.
- **Energy Efficiency Programs**: Helping customers lower their energy consumption and costs through education and resources in partnership with the Energy Trust of Oregon.

Also, our affordability strategy highlights the history and future of partnership as we work alongside various stakeholders to drive innovation and sustainability. By leveraging our partnerships, it helped implement several pilot projects and initiatives aimed at enhancing energy efficiency and flexibility.

Notable collaborations include:

- **Smart Grid Test Bed (SGTB) Phases**: Working with stakeholders on the Smart Grid Test Bed (SGTB) to improve grid reliability and efficiency.
- **SALMON and Flex Feeder Initiatives**: Collaborating on projects focused on sustainable and renewable energy solutions.
- **Smart Inverter and Battery Pilots with ETO**: Partnering with Energy Trust of Oregon (ETO) to test and deploy advanced technologies that enhance energy resilience.
- **Northwest Energy Efficiency Alliance (NEEA) End Use Load Flexibility Project**: NEEA to explore new ways to optimize energy use and increase flexibility in the grid.

Our approach to affordability and partnership is strategically integrated through our Distribution System Planning (DSP) and Multi-Year Planning (MYP) processes. The DSP identifies the locations and communities that would benefit most from targeted interventions. MYP, on the other hand, outlines details of the specific actions and initiatives we will undertake to achieve our affordability and sustainability goals.

As previously mentioned in our benefits chapter, PGE offers several programs that help address some our customers' needs. This includes:

- **Income Qualified Bill Discount (IQBD) Program**[64]: Provides discounted rates for income-qualified customers.
- **Medical Certificate Program**[65]: Flags customers with medical needs through a specialized program.
- **Peak Time Rebate**[66]: Engages customers in managing electricity demand during peak times for grid stability.
- **Time of Day**[67]: Encourages off-peak energy usage through pricing incentives.

[64] Income-Qualified Bill Discount Program. Available at: https://portlandgeneral.com/income-qualified-bill-discount
[65] Powering Medical Equipment – Outages. Available at: https://portlandgeneral.com/outages-safety/be-prepared/powering-medical-equipment
[66] PGE Rebates, Peak Time Rebates & Peak Use Shifting. Available at: https://portlandgeneral.com/save-money/save-money-home/peak-time-rebates
[67] Time of Day. Available at: https://portlandgeneral.com/about/info/pricing-plans/time-of-day

- **Smart Thermostat Program**[68]: Empowers customers with smart energy management tools for optimized consumption.
- **EV Smart Charging Program**[69]: Facilitates the integration of electric vehicles (EVs) by offering incentives for smart EV charging.
- **Multi-family Charging Program**[70]: Enables access to EV charging infrastructure in multi-family units.
- **Battery Program in PSPS Zones**[71]: Deploys battery storage systems in areas prone to Public Safety Power Shutoffs (PSPS) for improved reliability.
- **PGE +**: Conveniently offers personalized assistance and resources to help customers navigate their energy needs[72].

Together these programs not only help address immediate needs but pave the way for a more resilient and sustainable distribution system.

In our commitment to advancing community and stakeholder engagement, we draw learnings from other venues such as the CEP/IRP Roundtable [73]and Community Benefits and Impacts Advisory Group (CBIAG)[74]. By leveraging these insights, we strive to evolve our external engagement efforts to enable a people-centered approach to Distribution System Planning, including with our community engagement and impact team to strategically align outreach and engagement efforts to the communities we serve.

We recently reformatted and refocused the Learning Labs to be more community centered. PGE is committed to enhancing communication and collaboration with communities we serve and with interested stakeholders. We have made the following changes to our external engagement forums:

1. **IRP Roundtable** - We will continue hosting our Integrated Resource Plan (IRP) and Clean Energy Plan (CEP) Roundtables sessions for stakeholders who want to discuss, understand, and provide input on in-depth technical issues and decisions relating to our IRP and CEP.

   Details: Every month, virtual 3-hour meetings via Zoom.

[68] Smart Thermostat Program & Rebates. Available at: https://portlandgeneral.com/save-money/save-money-home/smart-thermostat-program
[69] Charging your EV at Home - EV Smart Charging Program. Available at: https://portlandgeneral.com/energy-choices/electric-vehicles-charging/charging-your-ev/charging-your-ev-at-home
[70] Commercial and Multi-Family Make Ready. Available at: https://portlandgeneral.com/commercial-and-multi-family-make-ready
[71] PGE Medical Battery Support. Available at: https://portlandgeneral.com/medical-battery-support
[72] PGE+. Available at: https://portlandgeneral.com/save-money/pge-plus
[73] Resource Planning Meeting Materials. Available at: https://portlandgeneral.com/about/who-we-are/resource-planning/resource-planning-engagement/resource-planning-meeting-materials
[74] Community Benefits & Impacts Advisory Group (CBIAG). Available at: https://portlandgeneral.com/about/who-we-are/community/community-benefits-and-impacts-advisory-group

2. **Distribution Workshop** - We will host distribution public workshops for community members and stakeholders who want to discuss, understand, and provide input on in-depth technical issues and decisions relating to our Distribution System Plan, Flex-load Multi-year Plan, Transportation Electrification Plan, and other demand-side programs and resources.

   Details: Every 6-8 weeks, virtual 2–3-hour meetings via Zoom.

3. **Community Learning Lab** – The Learning Labs will be reformatted and refocused to be in person. These sessions will emphasize engagement with groups and individuals to build intentional relationships with communities. We will provide content on request and information on energy topics, PGE initiatives and activities, and opportunities for community involvement and collaboration on projects such as Non-Wires Solutions (NWS), Demand Response/Flexible Load, and Community-Based Renewable Energy (CBRE) installations.

   Details: To be scheduled upon request, in person, outside work hours, and at community venues.

From February 2024 to December 2024, PGE hosted six public distribution system workshops. This included attendees, from the Oregon Public Utility Commission (OPUC), government entities, community-based organizations, community advocates and leaders, individuals, peer utilities and developers.

The first workshop highlighted PGE's development of the Distribution System Plan (DSP) and focused on advanced grid technologies, non-wire solutions, distributed energy resources (DERs), and community-based renewable energy (CBRE). PGE emphasized partnerships, funding, and timelines for these initiatives.

Also, we introduced PGE Plus, a program designed to address barriers to clean energy adoption through rebates, financing options, and installer connections. The discussion addressed the complexities of on-bill financing and implementing consumer protections such as fair administrative charges and product warranties. PGE aimed to support diverse customer groups, including low- and moderate-income households, through small loan programs, with plans to expand offerings to HVAC systems.

In a subsequent workshop, PGE introduced the Distributed Energy Resources (DER) Forecast, detailing improvements made to forecasting practices and tools since the 2022 DSP filing. This helped explain how DER forecasting aids distribution system planning.

The grid needs assessment presentation outlined PGE's focus on safety, reliability, and capacity management. It explained how grid needs are prioritized for capital investments and how analysis of these needs supports DER integration and operation.

Additionally, in our workshops we shared solutions for grid needs, evaluating their cost-effectiveness and reliability. During the workshop the capital planning process was highlighted as key to long-term grid reliability, addressing customer demand and budget constraints. Overall, PGE emphasized the challenges and opportunities of integrating DERs, demonstrating how this integration would enhance grid flexibility and reliability through effective planning and orchestration. Similarly, we focused on how DER integration supports the evolving needs of the grid, emphasizing the importance of maintaining grid reliability and flexibility.

Another presentation on the Flex Load and Multi-Year Plan Update provided a comprehensive overview of PGE's ongoing and future efforts to manage flexible loads. The discussion centered on various programs and pilots designed to optimize demand response and other customer-based energy management initiatives, demonstrating progress made in these areas and outlining PGE's future direction in multi-year planning.

In our final workshop series, we addressed the consideration of transmission issues in distribution system planning, particularly concerning the increasing penetration of DERs. The presentation aimed to explain the integration of transmission and distribution planning, ensuring alignment with overall grid modernization efforts. **Table 24** shows the workshop attendees by major categories.

Table 24. Distribution System Workshop attendees by major category

Row Labels	DSW # 1 - 2/24	DSW # 2 - 5/24	DSW # 3 - 6/24	DSW # 4 - 7/24	DSW # 5 - 9/24	DSW # 6 - 12/24
Gov	**7**	**4**	**11**	**6**	**5**	**5**
Regulator	**3**	**4**	**9**	**6**	**5**	**5**
OPUC	3	4	9	6	5	5
Gov			**1**			
ODOE			1			
Legal	**1**		**1**			
OPUC	1		1			
City	**1**					
Muni	**2**					
CUB	**1**	**1**	**1**			
Advocate	**8**	**5**	**3**	**1**	**1**	**4**
Advocate	**2**	**4**	**1**	**1**	**1**	**3**
CBO	**4**		**2**			
Solar	**2**	**1**				**1**
EE	**9**	**2**	**2**	**4**	**1**	**1**
Research	**1**					
NEEA	1					
Trust	**8**	**2**	**2**	**4**	**1**	**1**
ETO	8	2	2	4	1	1
Consulting	**2**	**2**	**1**	**2**	**1**	**1**
Developer			**1**	**2**	**1**	
Individual	**3**		**5**	**1**	**1**	**2**
IOU	**6**	**1**	**7**		**2**	**3**
Electric	**3**	**1**	**5**		**2**	**2**
Gas	**3**		**2**			

Row Labels	DSW # 1 - 2/24	DSW # 2 - 5/24	DSW # 3 - 6/24	DSW # 4 - 7/24	DSW # 5 - 9/24	DSW # 6 - 12/24
Natural Gas						1
Research	2	1		1	1	1
Service Provider	1		1			
Tribes	1					
Total	40	16	32	17	13	17

In conclusion, the workshops on PGE's Distribution System Plan (DSP) highlighted the utility's proactive approach to integrating Distributed Energy Resources (DERs) and advancing grid modernization. In line with the Commission's recent order in the 2023 Clean Energy Plan and Integrated Resource Plan in LC 80, we have been working closely with staff, stakeholders, peer utilities, and the Community Benefits and Impacts Advisory Groups (CBIAGs) within a dedicated working group.

As we move forward, PGE remains steadfast in its mission to provide safe, reliable and affordable power to all our customers as we transition to clean energy. We understand the power of community and collaboration, and with these initiatives, we are building a more sustainable future—together.

Chapter 8. Action Plan (2-4 yrs)

This chapter provides an overview of PGE's planned investments over the next 2 to 4 years.

PGE's planned investments and strategies for grid modernization and infrastructure upgrades, focusing on three main elements:

- Traditional Infrastructure Investments
- Grid Modernization Investments
- Virtual Power Plant (VPP) Resource Investments

The chapter demonstrates PGE's commitment to modernizing the grid while maintaining reliability and enabling large-scale integration of distributed energy resources to improve flexibility and reduce supply-side resource needs.

We describe the three categories of investments that are covered in the Needs analysis and Solution identification sections: traditional infrastructure needs, grid modernization solutions that advance our long-term vision and VPP resource investments. Additionally, we provide some insight into distribution system investments driven by other factors, such as wildfire mitigation and transportation electrification.

8.1 Introduction

Our vision for the distribution system aims to build on traditional utility values of reliability, safety and affordability by including values such as decarbonization, community impact and cybersecurity. Our Near-term action plan aligns to this vision for the DSP and represents our initial steps toward modernization of the distribution system.

We operate in an evolving planning environment. Many factors influence the way the plan is executed:

- Disruptive weather events
- Supply chain disruptions that lead to price swings and delays
- Jurisdictional permitting requirements, or
- Emergence of significant industrial or commercial development

PGE's budgets are fixed each year and any of these factors could cause a reprioritization of the work that is identified in the plan. The projects and investments that are described below represent the body of work that PGE has prioritized for the coming years. The forces at play in our local environment will dictate the timing and duration over which that work is completed and whether the identified projects are displaced by other projects of higher priority.

8.2 Traditional infrastructure investments

Our traditional T&D investments include investments needed to enable security, resiliency, and DER adoption. For these investments, we have identified a suite of projects to be prioritized in this planning cycle. These investments are needed to address the prioritized grid needs identified in **Section 6.1.2 Prioritized list of grid needs** that maintain reliability, safety, resiliency and compliance with state and federal requirements.

The proposed solutions identified by the Distribution Planning team and described in **Section 6.2 Traditional solution identification** are submitted to the Transmission and Distribution (T&D) Portfolio Team for consideration as part of the next year's Capital Plan (e.g., submitted in 2024 for initiation in 2025). Based on these submissions and submissions from other teams within PGE, the Portfolio team develops a five-year Capital Project Roadmap. The T&D Business Sponsor Group reviews and approves the roadmap and issues it every June to help establish the priority for the years ahead. Many groups provide input to the roadmap's development, including System Planning, Asset Management, Operations, Project Management, and Supply Chain. It is a living document that the Portfolio team manages monthly. Prioritization inputs include:

- Resource Availability
- Material Availability
- Cash Flow
- AMP Risk Register
- Strategic Alignment
- Compliance
- Customer commitments

The project prioritization process results in project inclusion on the roadmap.

In the Solution identification section (**Section 6.2**) we described the project scoring and prioritization process for projects that originate in the Distribution Planning department. **Table 25** summarizes the projects that were prioritized for execution in the next four years along with the estimated costs. The projects are presented in PGE's transmission and distribution investment categories (described in **Appendix I.5 Historical distribution system capital investments, Figure 60**).

Table 25. Summary of distribution system investments (as of July 2024)

Project category ($M)	2024	2025	2026	2027	2028
Compliance	$148.32	$187.38	$141.53	$91.10	$72.07
Customer/Partner	$153.44	$140.55	$131.80	$135.58	$140.49
Capacity/Flexibility	$38.76	$94.64	$158.01	$132.78	$162.75
Reliability	$41.37	$70.27	$47.90	$38.62	$31.85
Operations	$1.25	$1.10	$2.26	$2.47	$2.56
Totals	**$383.15**	**$493.95**	**$481.50**	**$400.54**	**$409.72**

All of these projects go through PGE's annual capital planning and budgeting process. Plans and forecasts are refined over the life of the project. Plans and forecasts for projects in future years (2026-2028) are subject to change. The future year forecast also reflects the projects that were identified as of July 2024. We expect that new projects will be identified in future years and the forecasts for those years will increase.

Our local economy, environment, and technologies are evolving. As such, the grid needs and our investment priorities may change in response to those conditions.

8.3 Grid modernization investments

While it is essential to address the prioritized grid needs, that is a largely reactive response to conditions in our service territory. In order to execute on our vision and goals, we need to build capabilities, create partnerships and establish the technology platform that will enable that level of execution.

Our grid modernization investments represent a key element to transforming the grid and enabling large-scale integration of DERs, especially solar PV, batteries and electric vehicles, in a manner that can improve grid flexibility and reduce the need for supply-side resources.

Table 26. Summary of grid modernization investments (as of July 2024)

Project category ($ million)	2024	2025	2026	2027	2028
Grid management systems	$48.29	$37.16	$16.10	$5.50	$4.00
Integrated planning	$1.50	$0.70	$1.40	$-	$-
Sensing, measurement, and automation	$2.50	$4.05	$13.60	$35.60	$4.20
Telecommunications	$12.80	$14.16	$13.65	$9.85	$3.55
Physical grid infrastructure	$5.00	$4.84	$8.50	$8.80	$9.00
Totals	**$70.09**	**$60.91**	**$53.25**	**$59.75**	**$20.75**

All of these projects go through PGE's annual capital planning and budgeting process. Plans and forecasts are refined over the life of the project. Plans and forecasts for projects in future years (2026-2028) are subject to change. The future year forecast also reflects the projects that were identified as of July 2024. We expect that new projects will be identified in future years and the forecasts for those years will increase.

Our local economy, environment, and technologies are evolving. As such, the grid needs and our investment priorities may change in response to those conditions.

8.4 VPP resource targets

As we advance to a 100 percent 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.

Chapter 5 Virtual Power Plant (VPP) details the portfolio of resources that PGE is targeting for enrollment in its VPP.[75] A summary of the portfolio is provided in **Table 27**.

Table 27. VPP resources and target MW

VPP Resources (MW)	2025	2026	2027	2028	2029
Flexible Load (Summer/Winter)	116.3/61.2	126.9/65.7	140.3/69.8	151.3/74.0	162.3/78.2
VPP Solar+Storage	28	28	450	503	559
Distributed Thermal	140	180	220	260	300
Grand Total (Summer/Winter)	**284.3/229.2**	**334.9/273.7**	**810.3/739.8**	**914.3/837**	**1,021.3/937.2**

Note that the VPP Solar figures reflect the resources that are available to the VPP for VPP operations. There are additional solar resources installed throughout the system (see NEM and QF installed in **Appendix I.6 Net metering and distributed generation**) and forecast in the coming years.

	2025	2026	2027	2028	2029
Distributed Solar Forecast (nameplate MW)	376	453	549	643	658

We are working to develop opportunities for customers to make those NEM resources available for VPP operations.

[75] Note that the information in **Table 27** does not reflect the total MW of DERs that are interconnected in PGE's service area, only those MW that are targeted for enrollment in the VPP.

8.5 Other significant or emerging drivers for distribution system investment

8.5.1 MYP programs

8.5.1.1 Existing activity

PGE's 2023 Integrated Resource Plan (IRP) highlights the need to develop distributed energy resources (DERs) to meet load demands and achieve decarbonization targets cost-effectively. The IRP projects that approximately 25 percent of PGE's energy and capacity will come from DERs, driven by factors such as resource availability, valuation, and system delivery constraints. Policy initiatives like Community Based Renewable Energy (CBRE), Community Benefit Indicators (CBI), and small renewable mandates further emphasize the importance of investing in DERs. The Multi-Year Plan is central to PGE's DER development and is a key component of our forthcoming Distribution Plan's Near-Term Action Plan.

The Flex Load activities described herein are in service to the acquisition goals of 211 MW Summer and 158 MW winter demand response by 2028. These goals were laid out most recently in PGE's 2023 Integrated Resource Plan (IRP), and associated Addendum.

PGE's comprehensive Flexible Load portfolio includes the following key pilots and programs:

Table 28. Summary of flex load capacity (forecasted for 2025-2026)

	Summer capacity			Winter capacity		
Activity	2024	2025	2026	2024	2025	2026
Residential Smart Thermostats	43.7	48.1	52.5	9.0	9.9	10.8
Peak Time Rebates	15.4	16.1	16.6	11.5	12	12.4
Time of Day	2.5	4.1	5.6	–	–	–
Energy Partner on Demand	38.8	41.3	43.8	31.5	33.5	35.5
Multi-family Water Heating	2.0	2.0	2.3	2.5	2.5	2.8
Energy Partner Smart Thermostat	2.2	2.1	2.8	0.5	0.6	0.70
Residential EV Charging[76]	1.8	2.6	3.3	1.9	2.7	3.5
Flex load capacity (MW)[77]	**106.5**	**116.3**	**126.9**	**56.9**	**61.2**	**65.7**

[76] PGE includes Residential EV Charging capacity in Flex Load portfolio capacity totals as, despite the fact that it is funded through the Transportation Electrification Plan, it does contribute Flex Load capacity.
[77] Neither NEEA Market Transformation nor Smart Grid Test Bed projects are included in Flex Load capacity figures as they only contribute indirectly thereto.

Related activities include:

- Smart Grid Test Bed which, with guidance from the Demand Response Review Committee (DRRC), PGE uses to perform research demonstrations and small-scale pilots to assess new technology and inform future Flex Load development.
- Residential EV Charging, which contributes Flex Load capacity, as illustrated in **Table 28**, but is funded under Transportation Electrification activities.

Table 28 reflects the Company's forecast of Flex Load Capacity through the current MYP planning cycle.

Since 2021, existing pilot and program capacity has grown +20 percent, forecasted to end 2024 with an additional 10.8 summer MW and 3.9 winter MW. PGE seeks to continue to grow existing pilot and program capacity with an additional 20.4 summer MW and 8.8 winter MW by the end of 2026. This performance represents both growth and retention of the portfolio.

Flex Load customers served are summarized in **Table 29**:

Table 29. Flex Load portfolio: Customers served

Customers served	2023 (actual)	2024 (forecast)	2025 (forecast)	2026 (forecast)
Residential offerings	188,187	204,629	229,847	253,430
Commercial offerings	13,162	15,602	17,512	19,578

Table 29 reflects the Company's forecast of residential and commercial enrollments in Flex Load pilots and programs through the current MYP planning cycle.

Cost effectiveness of Flex Load activities is assessed via a Total Resource Cost test (TRC) at the portfolio level. Measuring at the portfolio level allows mature activities to provide support for the development of pilots to validate prospective market solutions. PGE also reports TRC results at the underlying pilot and program level to provide insight into the performance of each individual activity.

Table 30. Summary of flex load cost effectiveness (2023-2026)

Activity	TRC (2023)	TRC (2024)	TRC (2025-2026)
Residential Smart Thermostats	1.97	1.86	3.90
Peak Time Rebates	0.68	0.60	1.13
Time of Day	1.50	1.37	2.52
Energy Partner on Demand	1.29	1.48	2.59
Multi-family Water Heating	0.16	0.28	0.29
Energy Partner Smart Thermostat	0.22	0.12	0.64
Flex Load Portfolio[78]	**0.97**	**1.00**	**2.07**

Table 30 presents cost effectiveness tests from both the last two MYP filings (2023 and 2024) as well as that as of the current MYP planning cycle (2025-26).

8.5.1.2 New activity

New Flex Load development currently focuses on electric vehicle (EV) load management, the emerging battery market, and collaboration with the Northwest Energy Efficiency Alliance's (NEEA) End Use Load Flex (EULF). We expect to continue to bring new activities over the next two years.

[78] Smart Grid Test Bed and Residential EV Charging are not included in Flex Load cost effectiveness calculations as they are funded via separate dockets (UM 1976 and UM 2033, respectively). NEEA Market Transformation project is not included as it does not provide direct benefits to the portfolio.

8.5.1.3 Budget high level

Table 31. Summary of flex load funding

Activity	2025 (proposed)	2026 (proposed)	2025-2026 (proposed)
Residential Smart Thermostats	$3,756,000	$4,044,000	$7,800,000
Peak Time Rebates	$2,913,610	$2,967,105	$5,880,715
Time of Day	$666,500	$535,150	$1,201,650
Energy Partner on Demand	$6,087,977	$6,055,727	$12,143,704
Multi-family Water Heating	$1,170,250	$2,771,080	$3,941,330
Energy Partner Smart Thermostat	$1,422,000	$1,573,460	$2,995,460
NEEA Market Transformation[79]	$ 357,500	TBD	$ 357,500
Funding	**$16,373,837**	**$17,946,522**	**$34,320,359**
Smart Grid Test Bed[80]	*$ 2,030,214*	*$ 1,254,288*	*$ 3,284,502*
Residential EV Charging[81]	*$ 2,130,409*	*TBD*	*$ 2,130,409*
Holistic Flex Load Spending[82]	*$20,534,460*	*$19,200,810*	*$39,735,270*

Table 31 reflects the Company's proposed funding, as found in the current MYP filing, for the portfolio of Flex Load pilots and programs for the 2025-2026 planning cycle.

[79] While PGE expects NEEA's Market Transformation activity to continue past 2025, the scope and cost of that work remains to be determined. PGE will reengage with the Commission once PGE and other utilities have aligned on the scope and costs of that additional work and cost.

[80] Smart Grid Test Bed figures are subject to change; those funding proposals and related filings can be found in UM 1976. Available at: https://apps.puc.state.or.us/edockets/DocketNoLayout.asp?DocketID=21662.

[81] Residential Smart Charging pilot is funded separately under UM 2033 and has yet to propose funding for 2026. The 2025 funding for this pilot reflects the most recent available: that filed with PGE's 2023 Final Transportation Electrification Plan under UM 2033. Available at: https://edocs.puc.state.or.us/efdocs/HAH/um2033hah15818.pdf.

[82] As noted in the prior footnotes, Smart Grid Test Bed and Residential EV Charging activities are funded via separate dockets (UM 1976 and UM 2033, respectively) and are included for informational purposes only.

8.5.2 Transportation electrification

8.5.2.1 Transportation electrification strategy

The 2023 TE Plan's strategy details PGE's role in planning for, serving and managing TE load.[83] Below is a synopsis of the 2023 TE Plan strategy elements: Plan for TE Load, Serve TE Load and Manage TE Load.

8.5.2.1.1 PLAN FOR TE LOAD

PGE will **lead through planning and siting**. This work includes but is not limited to extending forecasting capabilities to provide insight into load, location and impact by feeder, EV class, and customer type. Additionally, PGE will influence siting of larger loads (e.g., medium-to-heavy duty and fleets) at feeders and substations with available capacity. The collection of this data will inform next steps in planning and program development, as well through which tools PGE serves the load.

PGE will focus on **coordinated corporate planning** by consolidating Distributed Energy Resource (DER) and TE forecasting, as well as consolidating planning of CEP, IRP, and TE Plans to foster coordination across all efforts.

PGE will update TE forecasts to inform **distribution upgrades and planning**. This new practice will inform **capital planning** activities in a strategic manner.

PGE's **state, local, and regional planning** will include parties involved in federal and corridor planning, including regional utilities, Oregon Department of Transportation (ODOT), Oregon Department of Environmental Quality (Oregon DEQ or DEQ), and Oregon Department of Energy (ODOE).

8.5.2.1.2 SERVE TE LOAD

PGE will **build distribution and grid infrastructure to serve customers**, aligning those investments to support and serve ongoing TE customer load. PGE's advanced planning tools now incorporate IRA and IIJA data as well as meter data. As a result, our AdopDER model perspective is both broad enough to encompass market shifts and also granular enough to identify new usage and load pockets unique to TE load. These capabilities allow PGE to plan for TE load in a targeted manner, forecasting local TE-driven load growth and distribution system needs assessments ahead of load materializing.

Our planning tools also inform our need for new power generation balanced against trends in customer DER adoption, which PGE is seeing driven by federal tax credits and state incentives. This adoption of self-generation and energy storage is expected to help manage the need for new supply-side generation and TE-related distribution system upgrades. PGE is implementing site generation and storage similarly at our Electric Island facility. Investments such as these will be operationalized through our prior investments in our Integrated Operations Center and our Advanced Distribution Management System. These

[83] 2023 TE Plan. Available at: https://assets.ctfassets.net/416ywc1laqmd/2xv3CdVdbyaZuYVy3UFWkR/65122d294f36a14ee6514cab2cf6fb74/TEP_2023-08-25_Full_Report.pdf

advanced capabilities enable PGE to harvest the grid benefits of TE load and the new smart grid capabilities of EV batteries and managed TE load, thereby enhancing how we will serve all TE load reliably, safely, and at "least cost". In addition, PGE will conduct work to inform how to better serve TE customers and how to incorporate both TE load and TE customer needs into current business practices and tools. PGE will pursue learnings from distinct, business, multi-family, municipal, and heavy-duty activities. PGE will look for opportunities to acquire TE load management through traditional tools like rate design and tariffs such as line extension allowances.

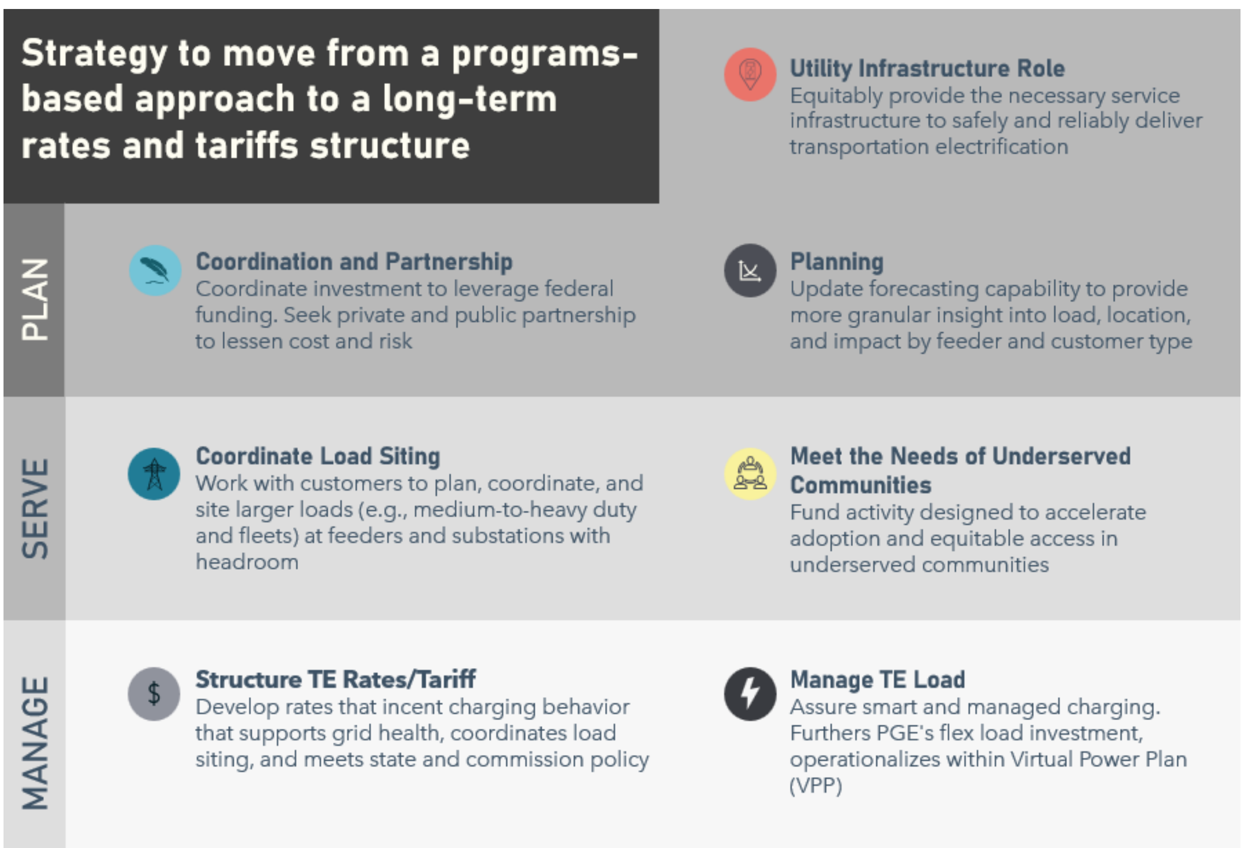
8.5.2.1.3 MANAGE TE LOAD

PGE seeks to **effectively manage TE load**, enabling and scaling managed charging with vehicle telematics and delivering flexible load and Virtual Power Plant (VPP) MWs.

PGE will **structure TE rates and tariffs to incent "grid-friendly" behaviors**, developing rates that motivate charging behavior, support grid health, load siting investment (e.g., make-ready), and meet policy requirements.

The following icons (**Figure 25**) represent the central elements of PGE 2023 TE Plan Strategy. PGE created these icons to visually connect activity to the 2023 TE Plan Strategy.

Figure 25. Central elements of TE strategy



Each of the following intersecting components are part of each of the activities outlined within PGE's 2023 TE Plan. The consistence of these cross-cutting activities is a further reflection of the strategy outlined above. These activities include but are not limited to:

- **Collect data -** Particularly load profile data, which informs how to manage TE loads and develop long-term, sustainable, traditional utility structures to incorporate how we serve TE loads into our rates and tariffs.
- **Continue to collect market experience** - To meet the needs of this evolving market PGE must be a market participant, whether as a provider of electricity or other TE specific services. Though adoption is accelerating, additional use cases and needs may yet be identified.
- **Cultivate partnerships** - PGE will continue to cultivate partnerships with private market entities, municipalities, non-profits, community-based organizations, and state, regional and federal entities to solve challenges, address barriers, provide solutions and meet customer needs.
- **Meet current demands to inform how to evolve service** - PGE's 2023 TE Plan attempts to meet current demand in the program areas while carefully managing spending and market presence. The focus of these activities is to collect information to shape a sustainable long- term approach to TE load.
- **Inform planning activities -** Data is a foundational element in planning but market presence and market activity will also inform our planning activities. Our market presence, customer engagement and site development work will inform PGE's planning activities.
- **Learn how best to meet the needs of underserved communities** -Underserved community TE needs may be unique and may outline a different role for PGE. Therefore, the TE Plan activities are structured to both serve the current need while informing how to meet evolving or emerging needs.

8.5.2.2 Transportation electrification forecast

PGE's investments in customer energy efficiency over the past several decades will enable us to make initial investments in transportation electrification without significant impacts on our distribution system. TE will, however, have a growing overall impact on energy and capacity needs. PGE must continue to make investments into our system so that our service-level transformers, feeders, substation transformers, and substations will have enough capacity to provide EV drivers access to charging service throughout our service area.

This section introduces the expected distribution system impacts arising from TE for which PGE will need to plan. This section is not intended to present a thorough distribution planning exercise for EVs. Instead, we provide indicative examples of how various types of EVs can impact the distribution system, and strategies to efficiently manage the grid in light of these impacts.

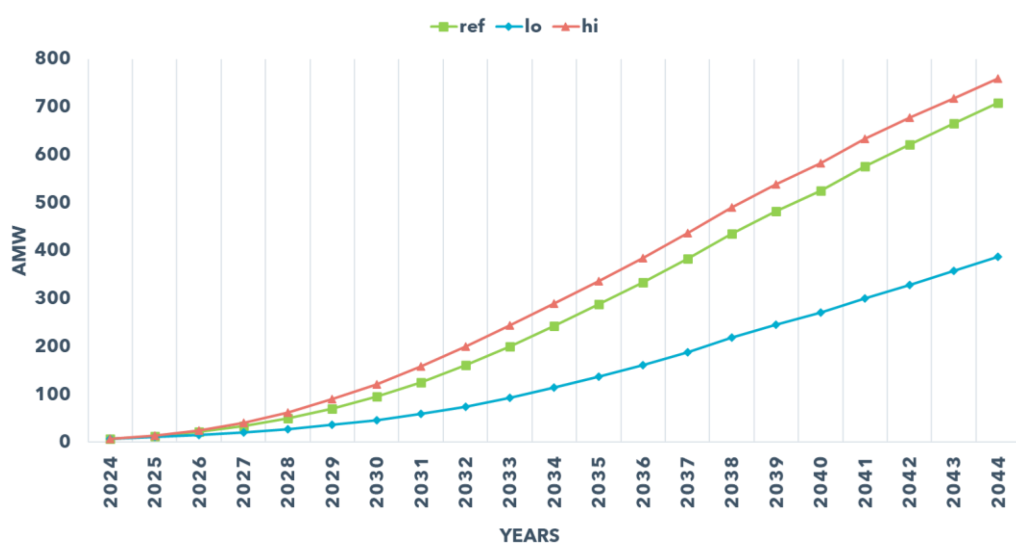
For example, PGE did not conduct power flow analyses to determine EV hosting capacity or estimate locational value. Such analyses will be done in concert with other new loads coming to the system through the course of routine distribution planning.

The TE forecast is shown in **Table 32** and **Figure 26**. The forecast clearly indicates levels of load growth that require upgrades to the distribution system much in the same way a new residential development or manufacturing facility would require upgrades to serve new load. As we know from the grid needs analysis described in **Section 6.1**, the primary considerations for planning those upgrades are the size of load growth, timing and location.

Table 32. Transportation electrification forecast

Scenario	2023	2024	2025	2026	2027	2028	2029	2030
High	19	36	57	87	119	158	203	252
Ref	17	29	43	63	83	110	141	177
Low	15	23	31	43	55	70	87	106

Figure 26. TE load growth forecast



There are several drivers behind the changes between the May and August TE forecasts:

1. In May 2024, market shares for TE fleet electrification and TE heavy-duty vehicle (HDV) city bus (ref, lo and hi) were kept very high. However, we have seen a temporary slowdown in the adoption of medium and heavy duty EVs, and we have reduced the market share inputs based on the actual observed trends. The reduction in these market shares and since HDVs contribute significantly to energy impacts so we see an associated reduction in the energy impacts.
2. We have improved the vehicle fuel type categorization process that helps us determine the number of BEVs, plug-in hybrid electric vehicle (PHEVs) vs internal combustion engine (ICE) vehicles. This has resulted in the identification of a number of vehicles that were previously categorized as EV to actually be ICE vehicles. This re-classification would have lowered to some extent our current TE load forecasts.

3. We have been working with Cadeo (vendor for AdopDER) to improve the TE forecast module. After the May 2024 forecast, we were able to review the results and propose improvements in the vehicle allocation and their mapping to load shapes. This too has led to reduction of battery electric vehicle (BEV) MDV/HDVs load impacts.

We have been giving increased focus on AdopDER's TE forecast and making improvements. We are achieving better vehicle count forecasts progressively. There were manual adjustments that were previously needed which we are able to eliminate by making improvements to the AdopDER code and data processing steps. We are in the process of making further improvements in the mapping of vehicles to load shapes and also improving the load shapes themselves, so we expect to see some more changes next time.

To accommodate EV adoption, we must make planful investments so that infrastructure is right-sized, future-proofed, and optimally located to minimize integration costs. Adoption of light duty EVs is less likely to trigger distribution system upgrades beyond service-level transformers that are typically paid for by customers. Large, spot-load additions, such as fleet electrification or development of charging hubs, are the types of TE-driven load growth that require system impact analyses from the distribution planning team.

When EV adoption starts to reflect the forecast, the associated load will show up as a need in PGE's grid needs analysis and, if prioritized at that time, we will develop solutions to meet those needs. An example of an emerging need, a need that might require a distribution infrastructure investment, is described in the following section.

8.5.2.3 Existing activity

Table 33. 2023 - 2025 TE portfolio overview

Programs	Overview	Target audience and goals
Business and Multi-Family Make-Ready Solutions	Make-ready and rebate support for business, workplace, public and multi-family customers PGE provides technical support, and also installs/owns make-ready infrastructure Leverage learnings from this pilot to identify new approaches to meet the needs of underserved and multi-family sectors Rebate to support customer charger ownership, with the final payment provided at year five if rate follows Schedule 50 pricing	Public charging at businesses and multi-family locations Charging cost parity with schedule 7 customers in the multi-family sector 100 Level 2 (L2) ports by end of year 2025
Business EV Charging Rebates	Rebate to support customer charger ownership, with higher rebate amount provided to multi-family sites	Workplace, multi-family, fleet, semi-public and public charging locations

Programs	Overview	Target audience and goals
		~500 L2 port rebates, 250 L2 installation rebates, and 20 DCFC ports
Clean Fuels Program	Portfolio of programs funded through DEQ's Clean Fuels Program credits based on residential EV ownership, managed by PGE Programs include grants and infrastructure (Drive Change Fund and Electric School Bus grants), education and outreach activities, and emerging technology PGE and stakeholders created this portfolio approach in 2021	Programs and grants must electrify transportation in Oregon and support residential customers, with a focus on underserved communities
Fleet Partner Pilot	Pair fleet advisory services with turnkey design and construction of make-ready for L2 and DCFC 10-year usage commitment Provides insight and visibility into fleet charging plans and locations Research managed charging strategies for fleet customers beyond current time of day pricing	Larger fleet customers 533 L2 and 110 DCFC make-ready ports by end of year 2025 13.2 MW of load capacity by 2028
Heavy Duty Charging Pilot	Install heavy-duty charging paired with solar and battery deployment to learn grid management with all technologies combined Coordinated site development Co-siting of storage and local generation where feasible Distribution upgrade insights West Coast Clean Transit Corridor (WCCTC) coordination	Medium- to heavy-duty charging users Two sites of medium- to heavy-duty charging Where feasible, sites must have solar and battery installed to manage the charging load
Portfolio Support	Funding to support TE-related program activities at the portfolio level Grant-writing partnerships to utilize federal and state grant dollars to minimize rate payer impact Funding to expand load forecasting capabilities, data options, and modeling	All TE programs and customer classes

Programs	Overview	Target audience and goals
	2022 funding for statewide campaign support	
Public Charging - Electric Ave	Public charging pilot supporting six Electric Avenue sites across PGE's service area Support equitable transition to electric vehicles through utilizing schedule 50 rate, which is comparable to residential home charging costs Explore on-peak price signals to manage public charging load and minimize grid impact	Underserved residential customers Improve uptime to 90%+ for six Electric Avenue charging locations
Public Charging - Municipal Charging Collaboration	Pole charging and curbside charging installations to support equitable charging transition for underserved communities Build upon the success of the pole charging demonstration to support equitable neighborhood charging Utilize schedule 50, which is comparable to residential home charging costs Underserved community partnership	Underserved residential customers 180 pole chargers + 160 make-ready curbside by end of year 2025
Residential Smart Charging Pilot	A charger or telematics rebate to support residential customers' transition to electric vehicles, whilst minimizing impact to the electric grid Create equitable path for installation of chargers if panel upgrades are required Extend pilot enrollment through 2025 to incorporate learnings from Smart Grid Test Bed demonstrations into future program design	Residential single-family EV owners Scale enrollments from ~2,200 as of EOY 2022 to +7,000 by EOY 2025 2.6 MW managed charging by EOY 2025

8.5.2.4 New activity

The following activities were newly approved with the 2023-2025 TEP and are described in **Table 33**:

- Public Charging – Municipal Charging Collaboration
- Business and Multi-family Make-ready Solutions

8.5.2.5 Budget high level

Table 34. Program operating and capital expenditures, 2023-2025

PROGRAMS	2023	2024	2025	2023-2025 TOTAL
Business and Multi-family Make-ready Solutions	$210,100	$1,085,452	$1,251,578	$2,547,130
Business EV Charging Rebates	$460,000	$2,328,728	-	$2,788,728
Clean Fuels Program	$11,758,817	$13,714,381	$17,856,449	$43,329,647
EV Ready Affordable Housing Grants	$1,000,000	-	-	$1,000,000
Fleet Partner Pilot	$5,258,760	$6,415,740	$6,442,773	$18,117,273
Heavy Duty Charging Pilot	$1,997,290	$1,186,441	$436,723	$3,620,453
Portfolio Support	$1,811,500	$387,500	$287,500	$2,486,500
Public Charging - Municipal Charging Collaboration and Electric Ave	$4,927,903	$2,941,812	$7,779,689	$15,649,404
Residential Smart EV Charging Pilot	$2,417,000	$1,945,313	$2,130,409	$6,492,722
GRAND TOTAL	**$29,841,370**	**$30,005,365**	**$36,185,121**	**$96,031,856**

8.5.3 Wildfire mitigation

8.5.3.1 Overview

PGE designed the Wildfire Mitigation Plan (WMP) to provide strategic direction for the programs and activities that seek to mitigate the potential for PGE equipment, facilities, or activities to become wildfire ignition sources.[84] The WMP incorporates 'lessons learned' from the 2023 fire season and describes PGE's wildfire preparedness and response activities for 2024.

The success of the Program relies on the active participation of a broad spectrum of internal and external stakeholders with the coordination of PGE's Wildfire Mitigation organization. The Program is informed by PGE's wildfire risk mitigation assessment (WRMA) and Value Spend Efficiency (VSE) calculations. PGE uses these calculations to develop and guide Program activities and wildfire mitigation investments.

[84] 2024 Wildfire Mitigation Plan. Available at: https://assets.ctfassets.net/416ywc1laqmd/5Fg5ArDStzdqKNleC5e6lV/6fbe9201a693e4bea42721ddc9d665a5/WMP_final-2024.pdf

PGE reviews its fire season operations and wildfire mitigation preparedness and response actions annually and updates the WMP as needed. The issues PGE seeks to address with the WMP are dynamic, and the increasing risks of wildfire have been and will continue to be hard to predict. Oregon has been subject to unprecedentedly fierce heat and ice storms, increases in dead fuels, population growth (with accompanied extension of electric service) into the wildland urban interface, and hard to predict local weather conditions that can accelerate the speed and spread of fire, and amplify the destruction of property and critical services.

Global climate change continues to alter the Pacific Northwest's climate in ways that are difficult to model and predict. This reality will drive continuous evaluation and modification of PGE's WMP for the foreseeable future.

PGE's primary wildfire risk mitigation objective is to reduce the risk of ignition from PGE assets while limiting the impacts of specific mitigation activities, such as PSPS events, to customers. The Program can be broken down into four risk mitigation approaches and associated objectives:

- PSPS: Temporarily turn off power during extreme weather conditions to reduce wildfire risk.
- Operational Practices: Implement operational system settings, including protection systems (e.g., reclosers), line and vegetation maintenance, and use a risk-informed protection strategy to reduce the risk of ignitions.
- Situational Awareness: Improve PGE's wildfire-related risk management and situational awareness capabilities.
- System Hardening: Implement a systematic, risk-informed approach to identify and prioritize system hardening and resiliency measures to reduce the likelihood of ignitions caused by utility assets and protect PGE assets from damage.

PGE has delivered and continues to find cost-effective ways to maximize wildfire risk reduction by applying risk assessment modeling to guide mitigation strategies. This work aims to deliver the highest risk reduction per dollar spent on mitigation.

PGE WRMA methodologies include multiple statistical models that use a variety of data sources to identify the areas of highest wildfire risk within PGE's service area to:

- Identify and refine the boundaries of the high-rise fire zones (HFRZ) within the PGE service area.
- Quantify the likelihood that individual PGE assets could contribute to the ignition of large wildfires (>100 hectares for fires in timber; >400 hectares for grass or rangeland) and map their location.
- Apply a consequences model to determine where a potential wildfire ignition would be most significant.

These methods enable PGE to identify the highest-risk areas within its service area and prioritize wildfire mitigation actions. In addition, PGE evaluates wildfire risk across PGE transmission and generation assets outside our service area. Assessment results allow PGE to evaluate susceptibility to the natural and human factors that could contribute to electric asset-caused wildfire ignitions and provide data-driven guidance for PGE's Program.

8.5.3.2 Wildfire risk informed decision-making

Climate change will continue to increase wildfire threats, requiring continual adaptation of asset management and other routine business practices. This challenging reality and PGE's responsibility to maintain reliable electric service require a careful balance between often-competing interests and system requirements. As the complexity of this analysis increases with each passing year, the industry's best practice of risk-informed decision-making (selecting mitigation projects based on estimated risk reduction value) continues to guide PGE.

In advancing the risk-informed decision-making process, PGE has developed and is evaluating a new method to measure risk. Value Spend Efficiency (VSE) builds off the Risk Spend Efficiency (RSE) concept shared in the 2023 WMP, in which pre-and post-mitigation risk is measured in a quantifiable way and adjusted for qualitative impacts not easily measured in dollars. An example of this is the impact of wildfires on watersheds/drinking water—a critical consequence to understand and factor into decision-making, but not accounted for in the classical RSE equation.

PGE considers risk, lifecycle costs, and performance in a single process to guide understanding and estimate the effectiveness of mitigation measures. PGE works to continuously apply RSE/VSE concepts in assessing mitigation alternatives across various PGE programs, including PSPS, vegetation management, system hardening, capital investment, and operations. PGE continually improves its RSE/VSE assessment approach for long-term and real-time planning and analysis. PGE recognizes that RSE and VSE only directionally inform the selection of wildfire mitigation options for inclusion in the mitigation strategies within the HFRZ. PGE aims to achieve the highest estimated risk reduction value per dollar invested.

This VSE assessment approach is flexible enough to allow PGE to adjust the analytical variables to account for factors such as climate change and to incorporate findings from its ODF, USFS, and local fire agency partnerships, as well as other critical concepts in mitigation, including the speed of execution.

8.5.3.3 Expected program costs

PGE develops an annual implementation and administrative cost budget and an administrative cost and forecasted capital budgets for the Program.

Table 35. PGE 2024–2027 Wildfire mitigation forecasted capital costs

Cost Area ($M)	2024	2025	2026	2027
Wildfire Mitigation	$39.5-$44.4	$52.6-$73.7	$57.9-$73.7	$61.1-$78.9
Wildfire-Related Utility Asset Management	$3.5-$4.8	$4.0-$4.6	$4.2-$4.7	$4.4-$5.7

Cost Area ($M)	2024	2025	2026	2027
WMP Total Range	$43.0-$49.2	$56.6-$78.3	$62.1-$78.4	$65.5-$84.6

Table 36. 2024 WMP activity and descriptions

Activity	Description
Wildfire Mitigation Program and Compliance	Develop, monitor, and track compliance to PGE's WMP. Includes Industry Engagement and Research & Development.
Risk Mapping & Simulation	Activities included in PGE's WRMA, HFRZ development, and valuation of capital projects and O&M programs.
Grid Operations and Protocols	Develop, implement, and monitor changes to PGE's Operations during fire season. Includes fire season training to select employees.
PSPS Program	Continue maturing PGE's de-energization protocols for public safety. Includes CRC and Customer Programs associated with supporting customers during a PSPS.
WMP Engagement, Public Awareness & Education, and Public Safety Partner Coordination	Engage customers, communities, and public safety partners to educate and gather feedback on PGE's WMP.
Asset Management & Inspections	Ignition Prevention Inspections and corrections performed under PGE's Inspect-Correct methodology in HFRZ.
Vegetation Management & Inspections (AWRR)	AWRR annual inspections, trimming, and tree removals within HFRZ.
Investment O&M	O&M associated with prior investments in system hardening and situational awareness to reduce wildfire risk in HFRZ.
Capital	
Wildfire Mitigation	System hardening and situational awareness investments that are focused on risk reduction in HFRZ.
HFRZ Utility Asset Management	Capital additions and/or replacements in HFRZ based on inspection results or specific programs.

PGE will continue to refine its WRMA program in 2024 and beyond and will continue to forecast its wildfire mitigation capital spending needs based on the results of that analysis. State or Federal grant funds may augment PGE's planned programs if PGE receives an award. PGE is pursuing further grant funding for wildfire risk reduction and resiliency improvement. These programs include Federal Emergency Management Agency's Building Resilient Infrastructure and Communities grants and the Department of Energy's (DOE) Bipartisan Infrastructure Bill (BIL) with grant funding opportunities through the Grid

Resilience and Innovation Partnerships section. PGE also explores additional opportunities through the State of Oregon's formula grants under the BIL.

8.6 Monitoring and adapting PGE's DSP

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 (MAIFIe)

For the metrics around decarbonization, community impact and environmental justice 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 environmental justice communities

Additionally, PGE will work with stakeholders and 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.

Appendix A. Compliance crosswalk

A.1 Community engagement

DSP gdln	Community Engagement Plan	Chapter section
3.a	During Plan development a utility should host at least four stakeholder workshops prior to filing the utility's Plan. These workshops should be held during Plan development, at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include in-person meetings located in a community, and may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to community engagement. During stakeholder workshops, a utility must invite community members to share their perspectives, relevant needs, challenges, and opportunities or novel solutions for the grid.	**Chapter 7 Empowered communities** discusses our approach to public workshops and briefly describes the six workshops conducted for this DSP filing.
3.b	To engage stakeholders and community on distribution system planning, a utility should leverage best practices, and lessons learned from engagement efforts from prior Plans, and other planning processes. A utility should also leverage ongoing community and stakeholder engagement processes, while maintaining accessible engagement forums, and integrate distribution system planning engagement to the full extent it is beneficial to do so. Ongoing processes may include but are not limited to Clean Energy Planning, and regional or local-area planning exercises.	**Chapter 7 Empowered communities** discusses our approach to public workshops and briefly describes the six workshops conducted for this DSP filing.
3.c	During preparation and implementation of a DSP, a utility should document community and stakeholder comments and feedback and utility response, including comments and feedback that were heard but not implemented. This documentation should be included in the utility's Plan when filed.	**Appendix C Stakeholder feedback** provides a record of the questions/comments received during the development of this DSP along with PGE's responses.
3.d	A utility should maintain a Community Engagement Plan, as developed in the Company's prior DSP. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs if it needs to develop and implement non-wire solutions to address grid needs, or if it needs to engage communities around implementing larger projects that may have a reasonable expectation of impacting surrounding	PGE's Community Engagement Plan is included in DSP Part 1 and informs our current engagement activities. DSP Part 1: https://assets.ctfassets.net/416ywc1laqmd/Ade5oN7SaTG7jQRTGcPzt/576380f14d90a97

DSP gdln	Community Engagement Plan	Chapter section
	communities. Larger projects may exclude, for example, regular maintenance projects, or inspection projects. The Community Engagement Plan should include the activities described below.	6469968517b187f95/DSP_2021_Report_Chapter3.pdf
3.d.i	Proactively engage stakeholders regarding possible non-wire solutions or larger projects in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; discussion of proposed utility projects and the value and risks associated with options; and solicitation of public comment, particularly to understand community needs and opportunities.	The SGTB (see **Section 6.3**) is a stakeholder-driven project which in part is working to develop a tool set that would inform the development of non-wires solutions and the outreach/engagement activities that accompany their implementation.
3.d.ii	Collaboratively develop and share information, for example datasets and metrics to guide community-centered planning of the possible non-wire solutions or larger projects.	See 3.d.i
3.d.iii	Consider engagement of local governments and Tribal nations for input on possible non-wire solutions, larger projects, as well as on other policies intersecting distribution system planning. Examples of such policies may include micro-grids and other resiliency planning, or local environmental and climate plans such as fleet-electrification and building-electrification efforts.	See 3.d.i
3.e	Utilities should aim to create a collaborative and accessible environment among all interested CBO partners, local governments, Tribal nations, and stakeholders.	PGE's DSP workshops are the primary activity focused on creating a collaborative and accessible environment for all parties. In addition, PGE conducted "office hours" after each workshop and provided all workshop materials through our DSP website.

A.2 Baseline data

DSP gdln	Current System Data Assessment	Chapter section
4.a	A summary description and table of the utility's distribution system assets including:	**Appendix I Baseline data**
4.a.i	Asset classes	**Appendix I Baseline data, Table 59**
4.a.ii	Number of assets in each class	**Appendix I Baseline data, Table 59**
4.a.iii	Average age of assets in each class	**Appendix I Baseline data, Table 59**
4.a.iv	Age range of assets in each class	**Appendix I Baseline data, Table 60**
4.a.v	Life expectancy of assets in each class	**Appendix I Baseline data, Table 59**
4.a.vi	Percentage of assets in each class at or beyond the end of expected life	**Appendix I Baseline data, Table 59**
4.b	A discussion of distribution system monitoring and control capabilities including:	**Appendix I Baseline data**
4.b.i	Number of feeders	**Appendix I Baseline data**
4.b.ii	Number of substations	**Appendix I Baseline data**
4.b.iii	Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology.	**Appendix I Baseline data, Distribution system monitoring and control capabilities**
4.b.iv	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)	**Appendix I Baseline data, Distribution system monitoring and control capabilities**
4.c	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.). The discussion should include:	**Appendix I Baseline data, Distribution system advanced control and communication capabilities**
4.c.i	A description of system visibility and capabilities	**Appendix I Baseline data, Distribution system**

DSP gdln	Current System Data Assessment	Chapter section
		advanced control and communication capabilities
4.c.ii	The percentage of system reached with each capability, the percentage of customers reached with each capability	**Appendix I Baseline data, Distribution system advanced control and communication capabilities**
4.c.iii	Any utility programs utilizing each capability	**Appendix I Baseline data, Distribution system advanced control and communication capabilities**
4.d	Historical distribution system spending for the past five years, in categories that reflect Company project management and financial management practices and have been shared with Staff prior to filing.	**Appendix I Baseline data, Historical distribution system capital investments, Table 68**
4.e	Net Metering and Small Generator information:	**Appendix I Baseline data, Net metering and distributed generation**
4.e.i	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.	**Appendix I Baseline data, Net metering and distributed generation**
4.e.i.1	The total number of net metering facilities by resource type.	**Appendix I Baseline data, Net metering and distributed generation**
4.e.i.2	The total estimated rated generating capacity of net metering facilities by resource type.	**Appendix I Baseline data, Net metering and distributed generation**
4.e.i.3	The total number of small generator facilities by resource type.	**Appendix I Baseline data, Net metering and distributed generation**
4.e.i.4	The total nameplate capacity of small generator facilities by resource type.	**Appendix I Baseline data, Net metering and distributed generation**
4.e.ii	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.	**Appendix I Baseline data, Net metering and distributed generation**
4.f	Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan. Any descriptions of reliability challenges and	**Appendix H Annual reliability report**

DSP gdln	Current System Data Assessment	Chapter section
	opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report, or other properly cited, publicly available data source.	
4.g	Plans should include high-level summary data on electric vehicles (EV) and EV charging, or link to such data if it is provided through other utility planning practices or publicly available sources. If not provided through other utility planning practices or publicly available sources, the data should include:	**Appendix I Baseline data, Electric vehicle (EV) data** and **EV charging data**
4.g.i	Total number of EVs of various sizes served by the utility's system at time of filing	**Appendix I Baseline data, Electric vehicle (EV) data**
4.g.ii	Number of EVs added to the utility's system in each of the last five years	**Appendix I Baseline data, Electric vehicle (EV) data**
4.g.iii	Total number of charging stations on the utility's system, broken down by type, ownership, and feeder	**Appendix I Baseline data, EV charging data**
4.g.iv	Total number of charging stations added to the utility's system in each of the last five years, broken down by type	**Appendix I Baseline data, EV charging data**
4.g.v	Data on the availability and usage patterns of charging stations	**Appendix I Baseline data, EV charging data**
4.g.vi	Summary data of other transportation electrification infrastructure, if applicable	**Appendix I Baseline data, Other TE infrastructure**
4.h	Plans should include high-level summary data on demand response/flexible load pilot and/or program performance metrics for the past five years, or link to such data if it is provided through other utility planning practices. If not provided through other utility planning practices, the data should include:	**Appendix I Baseline data, Demand response**
4.h.i	Number of customers participating by residential and business customer class, and combined total	**Appendix I Baseline data, Demand response, Table 76**
4.h.ii	By winter and summer demand response season:	**Appendix I Baseline data, Demand response, Table 77** and **Table 78**
4.ii.1	Maximum available capacity of DR by residential and business customer class, and combined total	**Appendix I Baseline data, Demand response, Table 77** and **Table 78**

DSP gdln	Current System Data Assessment	Chapter section
4.ii.2	Season system peak	**Appendix I Baseline data, Demand response, Table 77** and **Table 78**
4.ii.3	Available capacity of DR, expressed as a percentage of the season system peak	**Appendix I Baseline data, Demand response, Table 77** and **Table 78**
4.i	Data and information assembled for the Current System Data and Assessment requirement should be submitted to the Commission in electronic format and without protective order. Utilities may take necessary action to protect confidential or sensitive information that is sought in this electronic submission, such as anonymizing customer data or critical infrastructure.	The baseline data is available on PGE's website at: https://content-pre-p1-dot-gcp-csweb-dev-d78c.appspot.com/dsp-baseline-data

A.3 Forecast

DSP gdln	Forecasting of Load Growth, DER Adoption, and EV Adoption	Chapter section
5.a	Forecast of load growth to a granularity of, at a minimum, the substation level, including discussion of:	**Appendix G. Forecast results and AdopDER**
5.a.i	Forecasting method and tools used to develop the forecast	**Appendix G. Forecast results and AdopDER**
5.a.ii	Forecasting time horizon(s)	**Appendix G. Forecast results and AdopDER**
5.a.iii	Data sources used to inform the forecast (sources and vintage should be clearly identified in DSP filings)	**Appendix G. Forecast results and AdopDER,** and **Table 52**
5.a.iv	The load forecast should include data, inputs, and assumptions from the Company's most recent IRP/CEP, or from the most current and accurate sources at the time. Sources should be consistent with those used in other Company planning practices at the time. Examples include but are not limited to:	**Appendix G. Forecast results and AdopDER,** and **Table 52**
5.a.iv.1	System modeled scenarios decomposed to the distribution system	**Appendix G. Forecast results and AdopDER**
5.a.iv.2	Discussion of how IRP/CEP forecasting is decomposed to, and reconciled with, geographic areas of the distribution system, and identification of	The IRP/CEP forecast is not decomposed to the distribution system. Rather,

DSP gdln	Forecasting of Load Growth, DER Adoption, and EV Adoption	Chapter section
	those specific geographic areas. Examples of such areas may include transitional planning areas.	forecasting is performed at the Bus-bar level and aggregated up to the substation and system level.
5.b	Forecast of DER adoption and EV adoption to a granularity of, at a minimum, the substation level, including discussion of:	**Appendix G. Forecast results and AdopDER, Table 53, Table 54, Table 55, Table 56,** and **Table 57**
5.b.i	Forecasting method and tools used to develop the forecast	**Section 3.1 DER forecasting model**
5.b.ii	Forecasting time horizon(s)	**Section 3.1 DER forecasting model**
5.b.iii	Data sources used to inform the forecast (sources and vintage should be clearly identified in DSP filings)	**Appendix G. Overview of AdopDER and Integration within Planning Processes**
5.b.iv	The forecast should include high/medium/low scenarios for both DER adoption and EV adoption	**Appendix G. Forecast results and AdopDER, Table 53, Table 54, Table 55, Table 56,** and **Table 57**

A.4 Grid needs identification

DSP gdln	Grid Needs Identification	Chapter section
6.a	Describe any currently used system assessment processes and practices (such as system reliability assessments, system asset health assessments, etc.) that are utilized in assessing grid adequacy and identifying grid needs and evaluating possible solutions, which may include:	**Section 4.1 Needs analysis for DER integration and operation, Section 6.1 Traditional grid needs analysis** and **Appendix B Distribution planning process** describe PGE's approach to assessing the system's needs.
6.a.i	Criteria, methods, and tools used to develop the assessment	**Appendix B Distribution planning process** describes PGE's criteria, methods and tools for assessing the system's needs.
6.a.ii	Forecasting time horizon(s)	**Appendix B Distribution planning process** describes

DSP gdln	Grid Needs Identification	Chapter section
		PGE's forecast horizon for assessing the system's needs.
6.a.iii	Key performance metrics	**Appendix B Distribution planning process** describe PGE's performance metrics.
6.b	Discuss and identify anticipated grid needs, to the extent such identification does not violate customer privacy or NERC/CIP protections, including the following:	**Section 6.1.2 Prioritized list of grid needs** provides a list of grid needs identified through the grid needs analysis. Additional grid needs are captured in the Annual Reliability Report provided in **Appendix H Annual reliability report**
6.b.i	Replacement needs based on asset condition	**Section 6.1.2 Prioritized list of grid needs** provides a list of grid needs identified through the grid needs analysis. Additional grid needs are captured in the Annual Reliability Report provided in **Appendix H Annual reliability report**
6.b.ii	Grid needs to address forecasted load growth, DER adoption, EV adoption	**Section 6.1.2 Prioritized list of grid needs** provides a list of grid needs identified through the grid needs analysis. Additional grid needs are captured in the Annual Reliability Report provided in **Appendix H Annual reliability report**
6.b.iii	Grid needs to address customer needs such as new service, additional service, or service quality	**Section 6.1.2 Prioritized list of grid needs** provides a list of grid needs identified through the grid needs analysis. Additional grid needs are captured in the Annual Reliability Report provided in **Appendix H Annual reliability report**

DSP gdln	Grid Needs Identification	Chapter section
6.b.iv	Grid needs identified through other utility planning processes including, as relevant:	With the exception of Wildfire Mitigation planning, the planning processes identified in items 1-6 are represented in the Load and DER forecasts and are prioritized by the Distribution Planning process per the Ranking Matrix presented in **Table 21.**
6.b.iv.1	IRP/CEP	See 6.b.iv
6.b.iv.2	Wildfire Mitigation Plan, including but not limited to identified Increased risk, either in geographically targeted areas, or at a system-level	Many wildfire-related investments are driven by risk, rather than load or DER growth. The wildfire risk assessment process is described in PGE's 2024 Wildfire Mitigation Plan, available at: https://assets.ctfassets.net/416ywc1laqmd/5Fg5ArDStzdqKNleC5e6IV/6fbe9201a693e4bea42721ddc9d665a5/WMP_final-2024.pdf
6.b.iv.3	Transportation Electrification Plan	See 6.b.iv
6.b.iv.4	Geographically targeted efforts of any demand side programs/DER programs	See 6.b.iv
6.b.iv.5	Annual reliability reporting, and any related performance issues	See 6.b.iv
6.b.iv.6	Transmission planning	See 6.b.iv
6.b.v	Timing of grid needs	Timing of grid needs is driven by their priority. The grid needs for which solutions are developed are considered the highest priority to address.
6.c	Provide a summary table of each identified grid need, and specify the timing of each need.	**Section 6.1.2 Prioritized list of grid needs** provides a list of grid needs identified through the grid needs analysis. Additional grid needs are captured in the Annual Reliability Report provided in **Appendix H Annual reliability report**

A.5 Solution identification

DSP gdln	Solution Identification	Chapter section
7.a	Document the process to identify the range of possible solutions to address grid needs.	**Section 4.2.1 How do we identify solutions?** and **Section 6.2 Traditional solution identification** describe PGE's approach to identifying solutions to address grid needs.
7.b	Identify at a project- or program-level processes or approaches to employing no or low-incremental cost options to resolve a grid need without capital projects (examples may include rebalancing distribution loading through switching and phase balancing, or other actions).	**Chapter 1 Distribution system vision** discusses PGE's focus on reducing the cost to operate the system through orchestration of DERs. PGE's development of traditional solutions follow a least cost approach.
7.c	Assess each identified grid need for possible traditional solutions, alternative solutions, and for low-cost solutions.	PGE's grid modernization solutions (**Section 4.2**) are focused on developing the capabilities to pursue alternative solutions. PGE's development of traditional solutions (**Section 6.2**) follow a least cost approach. PGE's progress toward non-wires solutions is discussed in **Section 6.3 Non-wires solution identification and development.**
7.c.i	Document possible solutions in Near-term Action Plan investment/expenditure summaries (Guideline 8bv)	Investment summaries are provided in **Appendix E Description of solutions to address grid needs.**
7.d	If a utility has grid needs that could reasonably be considered candidates for non- wires solutions, develop at least two non-wires solutions pilot concept proposals (concept proposals). If no candidates are identified, a utility should describe the investments needed to enable non-wires solutions in its service area.	PGE's progress toward non-wires solutions (NWS) is discussed in **Section 6.3 Non-wires solution identification and development. Section 6.3.1 Flexible Feeder Project (SALMON: SmartGrid Advanced Load Management & Optimized**

DSP gdln	Solution Identification	Chapter section
		Neighborhood) provides insight into how we are gaining experience with NWS.
7.d.i	In these concept proposals non-wire solutions would be used in the place of traditional infrastructure. The purpose of these concept proposals is to gain experience and insight into the evaluation of non-wire solutions to address priority issues such as the need for new capacity to serve local load growth, or power quality improvements in underserved communities.	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.ii	In its concept proposals, a utility should discuss the grid need(s) addressed, various alternative solutions considered, and provide detailed accounting of the relative costs and benefits of the chosen and alternative solutions. The concept proposals should be reasonable and meet the Guidelines, even if the individual proposal may not be cost-effective. Should a utility elect to pursue implementation of a concept proposal the utility may propose regulatory investment and cost recovery treatment of implementation costs.	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iii	Concept proposals should utilize the utility's Community Engagement Plan and address:	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iii.1	Community interest in clean energy planning and projects	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iii.2	Community energy needs and desires	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iii.3	Community barriers to clean energy needs, desires, and opportunities	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.

DSP gdln	Solution Identification	Chapter section
7.d.iii.4	Energy burden within the community	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iii.5	Community demographics	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iii.6	Any carbon reductions resulting from implementing a non-wires solution rather than providing electricity from the grid's incumbent generation mix.	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.
7.d.iv	The concept proposal should include a process in which the utility works with stakeholders to set equity goals, as appropriate for the need.	PGE's next concept proposal will follow from the lessons learned and capabilities developed through the SALMON project.

A.6 Near-term action plan

DSP gdln	Near-term Action Plan	Chapter section
8.a	Prioritized list of the utility's proposed solutions (investments/expenditures) over the next five years to address identified grid needs.	**Appendix E Description of solutions to address grid needs,** provides the prioritized list (the capital portfolio) of T&D and Grid Modernization projects.
8.b	A summary of each planned investment/expenditure estimated to cost more than $2 million. Each summary should be roughly one page in length and should include the content listed below. A utility should use best efforts to include the content listed below and if omitting content, provide an explanation of why it was not included.	**Appendix E Description of solutions to address grid needs** provides the project summaries for T&D and Grid Modernization investments > $2 M.
8.b.i	Project narrative including benefits of the project, the asset classes and unit counts of proposed solution, and as available, foundational assumptions and key	**Appendix E Description of solutions to address grid needs** provides the project

DSP gdln	Near-term Action Plan	Chapter section
	barriers or constraints (for example financial, technical, organizational) and mitigation plans. The narrative should identify the grid need(s) addressed by the project, and if the project was prompted by a standard, company policy, or other requirement.	summaries for T&D and Grid Modernization investments > $2 M.
8.b.ii	Estimated timeframe	**Appendix E Description of solutions to address grid needs** provides the project summaries for T&D and Grid Modernization investments > $2 M.
8.b.iii	Estimated project cost/expenditure amount, and as applicable, estimated ongoing or maintenance costs beyond normal inspection (for example lease line costs or software maintenance costs)	**Appendix E Description of solutions to address grid needs** provides the project summaries for T&D and Grid Modernization investments > $2 M.
8.b.iv	Description of the criteria and methods the utility used to prioritize the investment/expenditure in Guideline 8a, including consideration of if, and how the investment/expenditure advances State policies and goals and PUC objectives, including but not limited to: - Reliability - Safety and security - Customer benefits and promoting inclusion of underserved populations - Optimized operation of the system - Efficient integration of DERs When possible, the description should include quantification of the improvement in the goal and should demonstrate improvement by using cited, publicly available data, for example a utility's Annual Reliability Report. Should a planned investment/expenditure advance a goal not included above, a utility should explain the rationale for the investment/expenditure, and when possible, include quantitative outcomes.	**Sections 4.2** and **6.2** describe the process for identifying and prioritizing Grid Modernization and T&D investments respectively. **Appendix E** identifies the primary driver/category for the project and those drivers/categories are described in **Figure 60**.
8.b.v	Description of alternative solutions considered (for example, traditional utility solutions, low-cost solutions, and if applicable any non-wires solutions the utility may have considered) including, where available, the proposed asset classes and unit counts,	**Appendix E Description of solutions to address grid needs** provides the project summaries for T&D and Grid Modernization investments > $2 M.

DSP gdln	Near-term Action Plan	Chapter section
	and estimated project cost/expenditure amount for each alternative.	
8.b.vi	Description of if, and how the investment/expenditure is coordinated with the utility's other planning processes (such as the most recent IRP/CEP, Wildfire Mitigation Plan, Transportation Electrification (TE) Plan, and DR/Flexible Load Plan)	See **Appendix J Capital planning process** for a discussion of how PGE coordinates investments across planning activities.
8.b.vii	Description of if, and how the proposed investment/expenditure interacts with non-distribution asset strategies (for example, transmission strategies), whether alternatives to distribution investment were considered, and if made, what impact does the proposed investment/expenditure have on other network assets.	**Appendix E Description of solutions to address grid needs** provides the project summaries for T&D and Grid Modernization investments > $2 M.
8.c	Projected spending: Provide a table of the projected cost to implement the Action Plan. The table should present costs on an annual basis for each year of the Action Plan and break costs into the same spending categories used for historical distribution system spending (Guideline 4d). Provide a description of anticipated requests for cost recovery.	**Chapter 8 Action Plan (2-4 yrs)** provides a summary of the Action Plan. **Table 25** and **Table 26** summarize the T&D and Grid Modernization investments respectively.

A.7 Long-term plan

DSP gdln	Long-term Distribution System Plan (LTP)	Chapter section
9.a	The utility's vision for the distribution system for the next 10 years, and a discussion of if, and how, it aligns with State policies and goals and PUC objectives, including but not limited to: - Reliability - Safety and security - Customer benefits and promoting inclusion of underserved populations - Optimized operation of the system - Efficient integration of DERs	**Chapter 1 Distribution system vision** and **Chapter 2** Distribution system strategy outline PGE's vision for the distribution system.
9.b	Prioritized list of investments/expenditures the utility expects to make in years 6 through 10 in order to advance the 10-year vision.	**Appendix F Grid modernization long-term plan and workstreams** provides a description of the types of investments that will

DSP gdln	Long-term Distribution System Plan (LTP)	Chapter section
		be needed to achieve our vision.
9.c	A summary of each planned investment/expenditure which should be no more than one page in length, and include the following, as available:	**Appendix F Grid modernization long-term plan and workstreams** provides a description of the types of investments that will be needed to achieve our vision.
9.c.i	Project narrative including benefits of the project, and as available, foundational assumptions and key barriers or constraints (for example financial, technical, organizational, and mitigation plans).	**Appendix F Grid modernization long-term plan and workstreams** provides a description of the types of investments that will be needed to achieve our vision.
9.c.ii	Estimated timeframe	**Appendix F Grid modernization long-term plan and workstreams** provides a description of the types of investments, accompanied by high-level roadmaps, that will be needed to achieve our vision.
9.c.iii	Estimated project cost/expenditure amount	PGE has made best efforts to describe the long-term plan. Development of this detail in the long-term plan currently is not a PGE practice.
9.c.iv	Description of any rationale, criteria, or methods the utility used to prioritize the investment/expenditure in Guideline 9b, including consideration of if, and how the investment/expenditure advances policies/goals/objectives identified in Guideline 9a, and consideration of any connections to, and impacts on, Near- term Action Plan projects.	PGE has made best efforts to describe the long-term plan. Development of this detail in the long-term plan currently is not a PGE practice.
9.c.v	Description of if, and how the investment/expenditure fits with the utility's other planning processes (such as the most recent IRP/CEP, Transmission, Wildfire Mitigation Plan, TE Plan, and DR/Flexible Load Plan).	PGE has made best efforts to describe the long-term plan. Development of this detail in the long-term plan currently is not a PGE practice.

Appendix B. Distribution planning process

B.1 Introduction

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

Historically, PGE distribution system planners were primarily concerned about managing current and future power demand because power flowed in one direction; from the place it was created or generated to homes and businesses.[85] This has changed as technologies, policies, and our capabilities continue to evolve. The grid has become more complex, which means PGE has to plan for more situations and predict new, possible scenarios for operating and maintaining the distribution system.

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

B.2 Current distribution planning process

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

- **Plan to peak** – PGE plans the distribution system to serve customers even during extreme temperatures, at the largest power demand at a given point during a year.

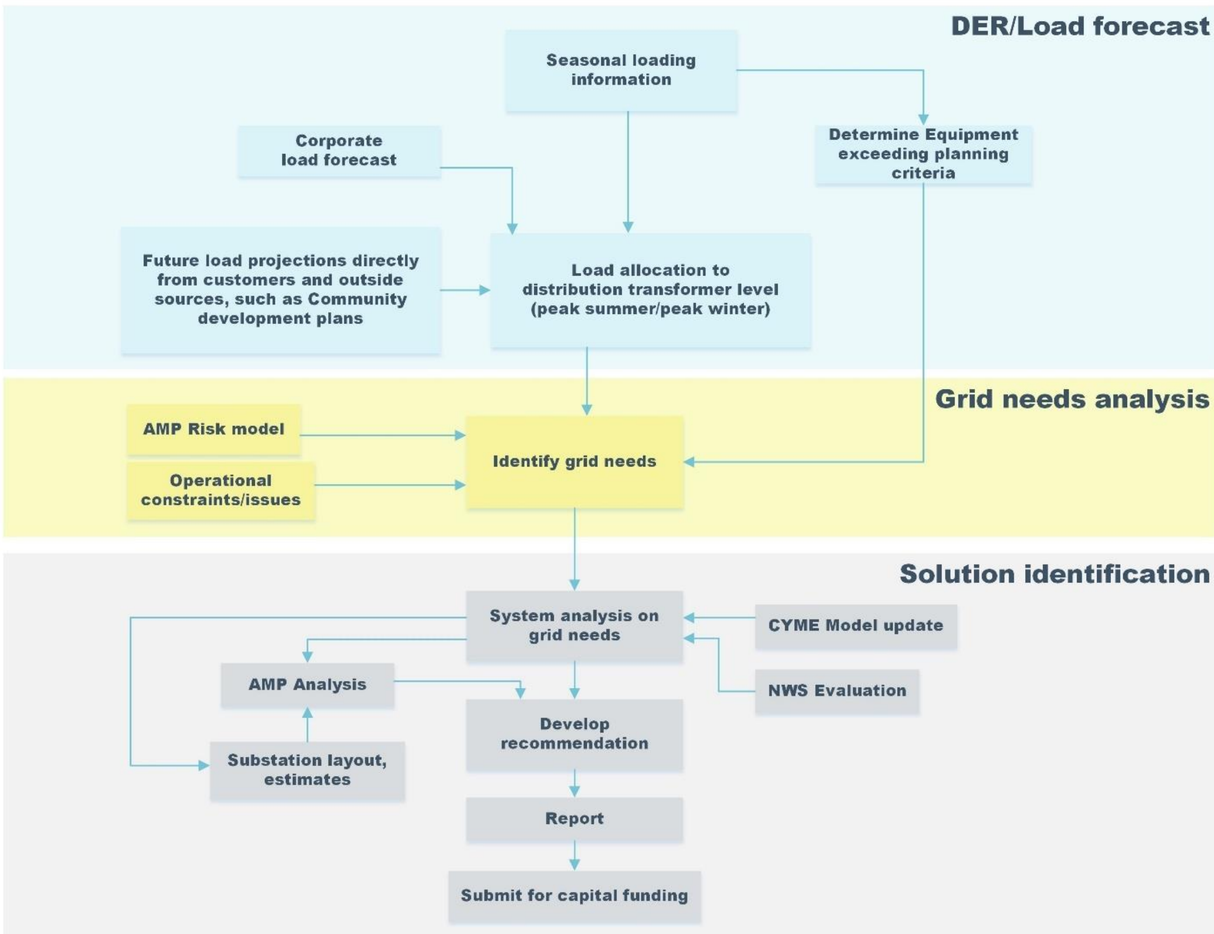
[85] PGE's DSP Part 1, Figure 4. The electric grid illustrates the one-way flow of power discussed in this section.

- **Plan for load capacity** – PGE's target loading is less than 67 percent for feeders and less than 80 percent for transformers.[86] This gives us flexibility and spare capacity to move load around on the system, when needed, to meet the needs of our customers.
- **Target system flexibility** – All customers are served by switching load from one piece of equipment to another (at both the transformer and feeder level) during planned or unplanned outage events.
- **Prioritize customer load growth projects** – Large housing developments, manufacturing facilities and industrial parks that anticipate an increased need for power.
- **Planning at least 10 years out** – New infrastructure is built for the long-term load needs of an area, ensuring that the infrastructure provides adequate capacity and reliability for at least 10 years.

This planning process is a cyclical process that follows a series of steps shown in **Figure 27**. The planning process considers a wide array of variables, such as equipment loading and asset health, so that PGE continues to provide safe and reliable power to our customers.

[86] DSP Part 2. Current distribution planning process. Plan for load capacity. Available at: https://downloads.ctfassets.net/416ywc1laqmd/2Fr2nVc4FKONetiVZ8aLWM/b209013acfedf1125ceb7ba2940bac71/DSP_Part_2_-_Full_report.pdf#page=26

Figure 27. Current distribution planning process



B.2.1 Capital planning process

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

PGE starts our capital planning process with the forecast of peak customer load and now the DER forecast (started in 2022). We conclude our planning process with the design and construction of prioritized and funded projects. This process can be lengthy and sometimes takes years. As part of our annual distribution planning process for capital planning, we thoroughly review existing and historical conditions, as defined in **Table 37**.

Table 37. Planning considerations

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

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

Proposed projects are funded as part of an annual budgeting process. This is based on a portfolio-level ranking methodology that also funds other distribution investments and expenditures (including asset health, grid modernization, storm response and mandated projects to relocate utility infrastructure in public rights-of-way when required for public projects like road widening). This process is described in **Section 6.2.1.**

B.2.2 Planning criteria

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

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

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

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

In addition to examining distribution feeder demands, PGE looks at the loading levels compared to the capacity limits for the substation distribution transformers. A transformer loading limit study was performed on our system in July 2009 to determine the summer and winter transformer loading beyond nameplate ratings (LBNR). This study evaluated the transformer winding limits based on top oil temperature, hot spot temperature, and loss of life with derating factor considerations for individual transformers based on bushings, LTC, and/or auxiliary components on a case-by-case basis. The transformer loading limit study calculations used the IEEE standard for transformer loading.[87] The distribution power transformer ratings were classified based on transformer capacity (MVA), manufacturer and cooling type to provide the loading capabilities that planning engineers use for transformer loading analysis. The IEEE standard criteria used to determine the summer and winter LBNR is:

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

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

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

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

Each transformer's peak in a multi-transformer substation is typically non-coincident, which means the transformers can each individually experience peak load at different times, and potentially on different days. This is because each transformer serves multiple feeder

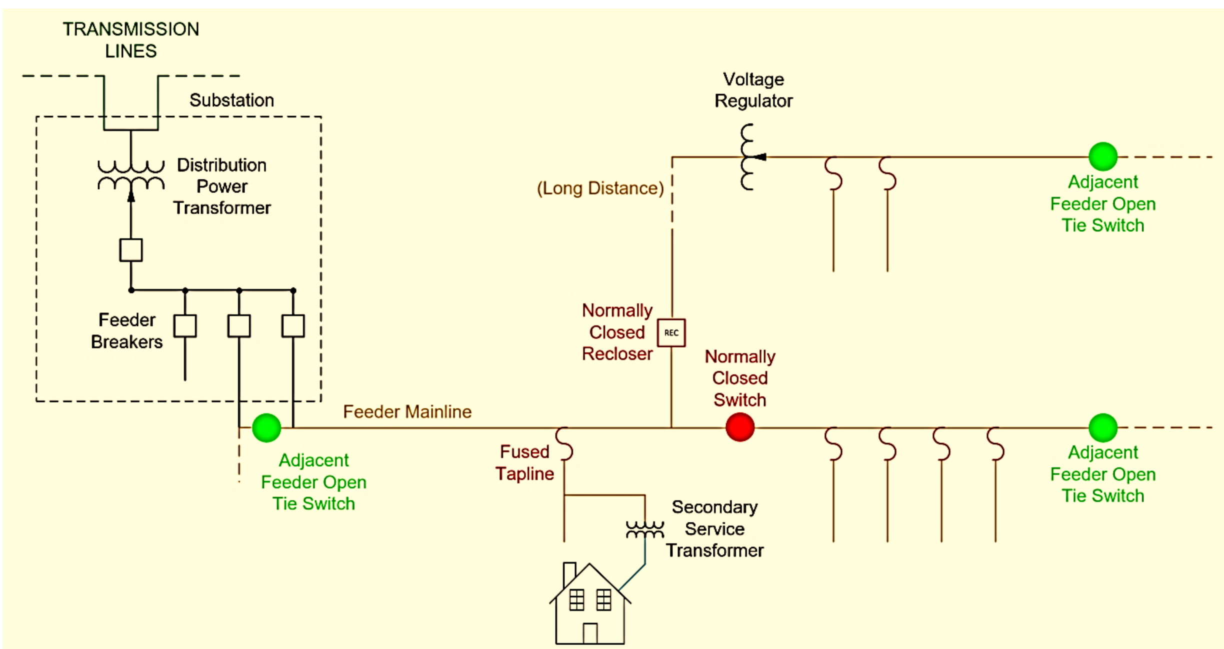
[87] IEEE Guide for Loading Mineral-Oil-Immersed Transformers - Corrigendum 1," in IEEE Std C57.91-1995/Cor 1-2002, vol., no., pp.1-16, 12 June 2003, doi: 10.1109/IEEESTD.2003.94283

circuits, and each circuit serves different loads. Substation transformer peak load is proportional to, but usually less than, the sum of the feeder circuit peak loads served from that substation transformer, because typically the feeders also experience peak load at differing times. Using PGE's planning criteria, planning engineers evaluate the distribution system, assess transformer and feeder loading, and identify risks for normal and contingency operation of the system.

B.2.3 Feeder and substation design

Distribution feeders for standard service to customers are designed as radial circuits (**Figure 28**). Therefore, the failure of any single critical element of the feeder causes a customer outage. PGE constructs ties between different feeders so that we can switch load from one feeder to another in the event of an outage. The distribution system is planned with enough capacity to minimize the number of switching operations that are required to restore power to customers after a single outage event. In the past few years, we have automated some of these feeder ties through distribution automation, which automatically moves the load from one feeder to another if there is an outage. This is an essential component of our grid modernization efforts and can reduce outage frequency and duration.

Figure 28. Typical radial distribution system one-line schematic



PGE plans and constructs distribution substations with a physical footprint sized for the ultimate substation design. This is based on anticipated load but can occasionally be limited by factors such as geography and available land (as seen in **Figure 29**, where the changes in the fence line required us to make the substation a polygon instead of the typical rectangle shape). Many substations are planned for a maximum ultimate design capacity of three transformers at the same distribution voltage, however, geography and land constraints for substations can limit capacity to two transformers, like the substation in **Figure 29**. This maximum size balances substation and feeder costs with customer service, customer load density and reliability considerations. Some substations serve very large industrial loads and require more than three transformers to provide enough power.

Figure 29. Distribution substation

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

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

A substation's size is limited not only by the physical space inside the fence, but also by the number of feeder circuits that can be physically routed to the surrounding area's loads. Overhead feeder construction is the most cost effective and standard overhead construction is one feeder circuit on a pole line. For more feeder density, two overhead feeder circuits per pole line can be constructed when conditions allow it. Underground feeder construction has a higher cost than overhead construction but is often mandated by the local jurisdiction, especially in urban areas. For this reason, underground feeder construction is becoming more common than overhead feeder construction for new feeders. Thermal limits of underground feeder cable require spacing between multiple feeder circuit main line cables. Thermal limits for primary distribution lines are defined in **Table 38** and **Table 39**.

Table 38. 13 kV Overhead feeder thermal limits

Conductor	Winter (MVA)	Summer (MVA)
795 kcmil[88] ACSR[89]	27.9	18.9
795 kcmil AAC[90]	27.1	17.8
556 kcmil ACSR	22.3	14.7
556 kcmil AAC	21.6	14.3
336 kcmil ACSR	16.3	10.7
336 kcmil AAC	15.8	10.4
4/0 AWG[91] AAC	11.7	7.8
4/0 AWG ACSR	11.1	7.3

Table 39. 13 kV Underground feeder thermal limits

Cable	Winter (MVA)	Summer (MVA)
750 kcmil Cu[92] - Dual run	26.7	24.9
1,000 kcmil Al[93] - Dual run	23.3	20.9
750 kcmil Al - Dual run	20	18.4
750 kcmil Al - Single run	12.2	11

[88] kcmil: measure of conductor size representing one thousand circular mils
[89] ACSR (aluminum conductor steel-reinforced): galvanized steel conductor or conductors surrounded by one or more concentric layers of 1350-grade aluminum conductors
[90] AAC (all aluminum conductor): high-purity, corrosion-resistant, concentric lay of 1350-grade aluminum conductors
[91] AWG (American Wire Gauge): measure of conductor size as defined by American Society for Testing and Materials (ASTM) standards
[92] Cu: denotes copper conductor
[93] Al: denotes aluminum conductor

B.3 Assessing grid adequacy and identifying needs

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

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

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

B.3.1 Contingency analysis

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

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

B.3.2 Load limits

Loading limits are determined by ambient temperatures and industry standards for obtaining expected length of service before failure. IEEE Standard C57.91 is applied for transformer loading.[94] Insulated Cable Engineers Association (ICEA) and IEEE standards are applied for feeder loading.[95] The system is also designed to maintain an acceptable voltage range, as defined by American National Standards Institute (ANSI) C84.1.[96] The primary voltage of the system is required to stay within +/- 5 percent from nominal.

B.3.3 System modeling

Once existing system deficiencies, if present, are determined, system loading conditions are modified in the CYME model to account for projected load growth. Data is collected from PGE's Corporate Planning team, Key Customer Management team, Business Development team, Design Project Manager team, the Distribution Operations Engineering team, as well as local and state agencies. This data is used to predict the amount and location of load growth that will occur in the one- to ten-year planning horizon. Loading and voltage conditions are then analyzed a second time to determine possible deficiencies that will likely occur during any known load ramp timeframe and five years out with potential, but not committed, load growth.[97] We modify the CYME model for the system until all existing and possible future deficiencies are corrected. Increasing the size of conductors, adding substation transformers, or adding new distribution feeders are examples of modifications to correct distribution system deficiencies in the CYME model.

B.3.4 Assessing reliability and risk

System reliability is determined by PGE's Distribution Planning team through two primary sources – historical outage information and existing and future system contingency analysis. Outage information is collected from our Outage Management System (OMS) and industry-specified indices are calculated according to IEEE Standard 1366 and IEEE Standard 1782 for every feeder by Asset Management Planning (AMP) team.[98]

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

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

during the outage of one transformer or one feeder. The existing system as well as the projected future state of the system are evaluated.

In addition to using industry standards and CYME, PGE uses the outputs of the economic life cycle models developed by the AMP team to identify concentrations of system risk. These models and outputs are discussed in (**Appendix G.3.1 Forecast results and AdopDER, CYME integration**). Reduction in system risk is primarily determined through analysis of PGE's assets with the Integrated Planning Tool (IPT) by the AMP group.

B.4 Risk assessment framework

PGE's approach to Asset Management is to maximize customer value by cost-effectively mitigating risk. Our Asset Management Planning (AMP) team employs risk-based economic lifecycle models to prioritize long-term capital investments and optimize maintenance strategies. These models assess both system reliability and wildfire risks, factoring in both asset-specific conditions as well as geographic influences like vegetation and weather. By aggregating annual risk projections with maintenance expenses and levelized capital costs, we calculate the cost of ownership for each asset on the grid in terms of net present value (NPV).

The lowest cost of ownership determines the optimal timing for proactively replacing an asset or intervening to mitigate risks in another manner. This value strikes a balance between maintenance costs, operational risks, and intervention expenditures. AMP utilizes these outputs to inform project development to reduce system failure risks, enhance reliability, and improve the overall customer experience. The key input for calculating risk-spend efficiency is the reduction in cost of ownership, which incorporates decreased expected reliability risk, wildfire risk, and maintenance costs across the asset's economic lifecycle, as well as those of future lifecycles.

The approach PGE's AMP team takes to modeling assets is based on the industry definition of risk and in line with the International Organization for Standardization (ISO) 55000 Standard.[99] Reliability Risk is defined as the product of annual probability of failure and consequence cost of failure (**Figure 30**). The consequence cost reflects the economic impact of an outage to customers and direct cost impacts to PGE to respond to the failure.

[99] International Organization for Standardization (ISO) 55000. Available at: https://www.iso.org/standard/83053.html

Figure 30. The risk equation

PGE's AMP team uses a suite of asset models combined with the Integrated Planning Tool (IPT) to evaluate proposed projects on economic benefits and key risk and reliability metrics.

B.4.1 Asset models

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

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

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

Figure 31. Existing asset models

Economic life cycle models

Reliability Risk and Wildfire Risk

Substation assets	Trans. and Dist. assets	Geographic risk
✓ Transformer	✓ UG Cable	✓ Vegetation/weather
✓ Circuit breaker	✓ Line transformer	✓ Animal
✓ Relay system	✓ Recloser	✓ Public
✓ SCADA system	✓ Regulator	
✓ Switch	✓ Switch	
	✓ Structures	

Business Case Tools
- ✓ Risk register
- ✓ Integrated planning tool

B.4.2 Calculating asset risk

The approach the AMP team takes to modeling assets is based on the industry definition of risk.

B.4.3 Probability of failure

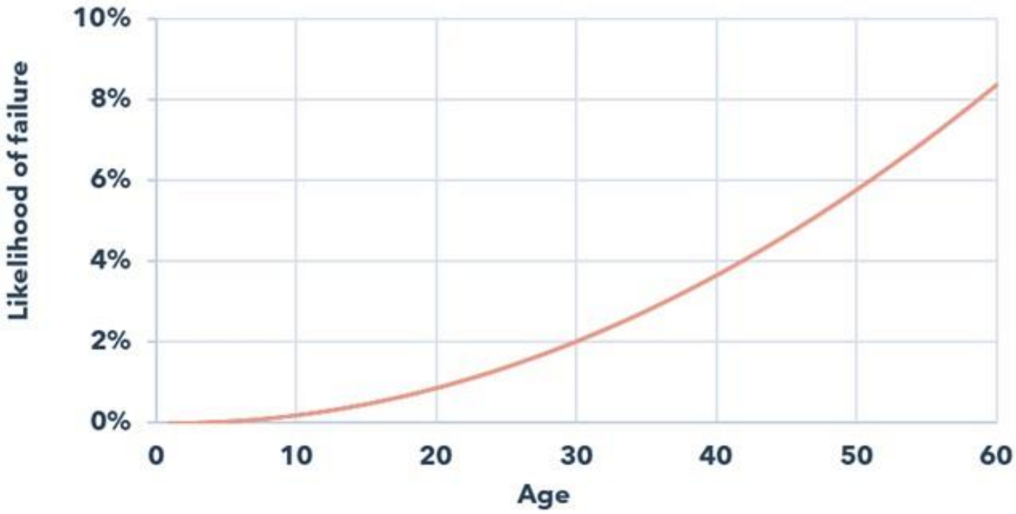
Modeling annual probability of equipment failure rests on three building blocks:

- The base annual failure probability that corresponds to calendar age of the asset via the Weibull distribution curve
- Identification of any asset degradation via the health index
- Adjustment for any known bad vintages/manufacturers via a failure multiplier

B.4.4 Base failure curves

AMP uses Weibull distributions to statistically model the annual probability of equipment failure. These curves are developed for each asset class family and sub-asset class family, if warranted, to estimate the annual likelihood an asset will fail as a function of its age, assuming it has made it to that age. An example Weibull failure curve is shown in **Figure 32.**

Figure 32. Example probability of failure (Weibull) curve



In some cases, an asset family may have several different sub-types of assets with different characteristics and historical failure data. When this happens, different failure curves with different parameters are applied to the different sub-types.

B.4.5 Health index

The health index is used to quantify an asset's condition relative to its end of life and calculate the asset's effective age. The health index assesses if the asset is acting older than its calendar age based on poor test or inspection results. If it is acting older than its calendar age, an adjustment to the calendar age occurs to reflect its "true age" via its effective age. This new effective age is then used as the input to the failure curve.

B.4.6 Failure multipliers

Failure multipliers are identified for "bad actor" types of assets. This may be a particular configuration, manufacturer or vintage. PGE subject matter experts often help identify "bad actors" and with respective failure data assign failure multipliers based on their expertise. The failure multiplier is applied against the likelihood of failure based on the effective age of the assets to elevate the annual failure probability.

These three components are combined to calculate annual asset failure probability calculation. **Figure 33** shows an example of how this calculation works with substation transformers.

Figure 33. Failure probability calculation example

B.4.7 Consequence of failure

The other half of the risk equation is consequence of failure, which is the quantified impact to PGE and the customer when an asset fails. The customer outage impact for substation assets typically represents about 75 percent-80 percent of the overall consequence cost of failure, which is calculated using values of service (VOS) lifted from a Pacific Gas & Electric 2012 study approved by the California Public Utility Commission (CPUC) and escalated to 2024 dollars.

PGE is engaged conversation with Lawerence Berkeley National LBNL's ICE Calculator 2.0 project will allow PGE to refine the VOS values used in customer outage impact modeling, improving the accuracy of calculated project benefits. The values identified from PGE's survey will also be used to update and improve the accuracy of LBNL's ICE 2.0 calculator, delivering broad value across the industry.

To calculate the weighted average consequence cost, leveraging both available failure data and subject matter experts, PGE determines approximately 4 to 6 different failure scenarios that range from benign to catastrophic and assign their relative likelihoods.

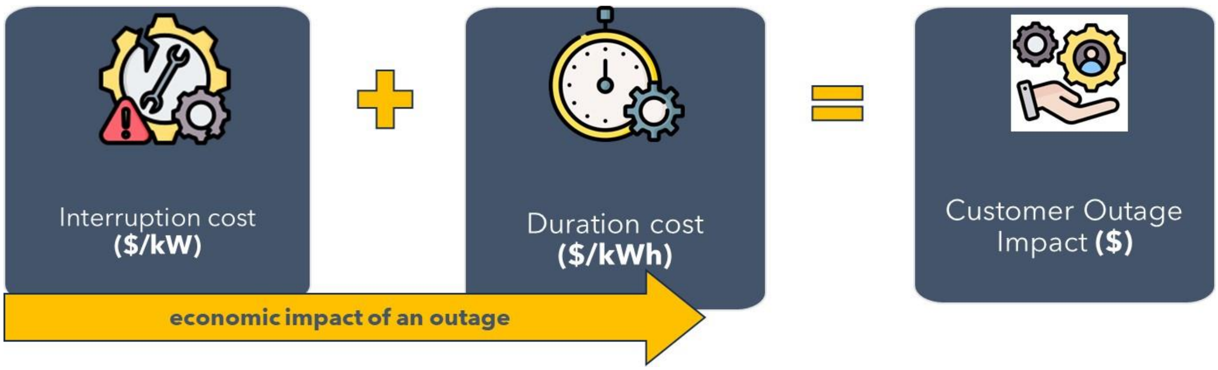
B.4.8 Failure scenarios

Each failure scenario developed for an asset assesses the following and calculates a corresponding cost:

- **Associated damages** – Typically represents costs for adjacent equipment damage
- **Repair cost** – If failure is non-destructive, estimated cost to repair the asset that comes from either a percentage of asset replacement cost, or subject matter expert feedback

- **Additional costs** – Environmental cleanup costs
- **Emergency premium** – Represents the increased cost to address the failure immediately
- **Customer Outage impact** – baseline economic impact of an outage by customer classes (residential, commercial, and industrial), depicted in **Figure 34.**

Figure 34. Calculation of customer outage impact



PGE uses a weighted average approach to quantify the impact of asset failure, leveraging subject matter expertise and failure data to build out failure scenarios from minor to catastrophic. Each scenario is assigned its own relative likelihood and corresponding cost of failure as shown in the equation below.

$$y = (RL * S_1) + (RL * S_2) + (RL * S_3) + (RL * S_4)$$

y = weighted outage consequence cost or CMI

RL = relative likelihood

$S_1 - S_4$ *: substation transformer failure consequence scenarios*

Figure 35 shows how this algorithm is applied to a specific substation transformer within PGE's service territory.

Figure 35. Consequence of failure scenarios

Appendix C. Stakeholder feedback

C.1 Distribution system workshop # 1 – Feb 8, 2024 | 9-11a

Type	Question/comment	Response
Question	Just curious about the repayment. Are you taking that out through payroll deduction or how are you doing that?	Yes. It will be payroll deduction
Question	Got it. And then my other question is around the service fees. I'm assuming that's not quite figured out yet?	Correct.
	When will the loan program be available?	We hope to have it available by the end of the quarter, but it depends on our negotiations with the lenders.
Question	How do we help the diverse customer base and the underserved rural low moderate income?	We're still working on it. This is why we're here, to see if there are any considerations we need to take into account.
Question	How do we cover all these costs for on-bill payment service?	We're still wrangling with that. Nothing is free. We're trying to figure out what is fair and whether the admin charge should be a percent or a flat fee.
Question	What happens if we don't collect enough money or if we collect too much?	We don't have answers to all of these yet. We're still working it out.
Question	How are you thinking you'll identify lending partners for this?	We did an request for proposals (RFP) for lenders, and we had several credit unions apply. We'll probably come back to you on that one.
Question	Is PGE going to play a role in how installers interact with the consumer if things go wrong?	Yes. Every single one of our installers will honor the manufacturer warranty. We've layered that into how we selected our network

Type	Question/comment	Response
Question	When did the smart grid test bed begin?	In 2016, as a response to our 2016 IRP, commission staff issued a white paper which was an appendix to the decision acknowledging the 2016 IRP. They requested PGE develop something called a smart grid test bed to explore the acceleration of demand response. At the time, the commission was concerned that PGE was not developing demand response as quickly or as necessary as outlined in the requirements from the 2016 IRP. So, in 2018, PGE submitted a proposal for the smart grid test bed. Phase one of the test bed was focused on the customer value proposition for demand response. The learnings from that were valuable, and today, PGE has nearly double the national average participation rate in our demand response programs, about 22% compared to the national average of 12%. We're now in phase two, which includes various technologies like vehicle-to-grid and water heaters, and flexible feeder approaches, with additional funding from the US Department of Energy.
Comment	Yeah, thanks. I thought it had begun before 2021, and I was confused. It sounded like it came after that. So okay, just thank you. That could confirm. It's been around for a while.	
Question	Will PGE be looking at other non-wire solutions in the test bed like flow enhancements?	We believe that understanding flow, both on the distribution feeders and the sections of distribution feeders, is important. We still have yet to identify all the things that we would be looking at with a non-wire solutions project, but through the distribution system plan, all of those activities that we intend or propose to demonstrate would be brought to forums like this so that we could receive input from our stakeholders. Does that help?

Type	Question/comment	Response
Question	Will the Smart Grid Test Bed discussion include learnings from programs contained in PGE's Flex Load Plan?	The Smart Grid Test Bed (SGTB) proposals to the commission for activity are separate filings. Each project that the SGTB intends to execute is also separately placed before the commission for approval. Before it goes to the commission, it goes to a group called the Demand Response Review Committee, which includes stakeholders like Citizens Utility Board, Northwest Power Council, Oregon Department of Energy, NEEA, Energy Trust of Oregon, and others. Additionally, in Docket 2141, we incorporate those activities so that readers of the multi-year plan or the flex load plan can see holistically the activities PGE is conducting around demand response, flex load, and DR development.
Question	What timeline are you looking at for unveiling or publishing this plan? Also, are you considering how to braid different sources, like federal funding, into the system to increase accessibility of DERs (distributed energy resources)?"	It is important to communicate timelines for the plan, including for acquisition, system upgrades, and integrating DERs. He also acknowledged the necessity of braiding in various funding sources, like grants from the U.S. Department of Energy and support from Energy Trust of Oregon, to help reduce the burden on ratepayers.
Question	Are you thinking of this Demand Response (DR) and non-wires solutions work as having overlap with the community-based renewable energy identified in your IRP?"	PGE is developing an RFP for community-based renewable energy (CBRE) resources and hopes to find overlap between these proposals and the identified locations for non-wires solutions. The goal is to integrate CBREs into these projects, creating a stronger connection to operations and realizing broader benefits for both the community and the energy system.
Question	I hear these high-level frameworks, but can you provide some examples of action items on the ground, such as how PGE would make investments to create resilient communities and reduce emissions?	Examples of non-wire solutions, such as community-based renewable energy projects, are part of the plan. She referenced past work on the SGTB pilot as an example, aiming to replicate aspects of that project in the future to enhance community engagement and system efficiency.

Type	Question/comment	Response
Question	I guess kind of like, then what? How are those insights being used now? Is this something that will be leveraged again in the Empowered Communities project?	PGE clarified that while they do not intend to replicate the SGTB exactly, the lessons learned from that pilot helped inform program design, particularly around demand response programs like the Smart Thermostat Program and the Water Heater Program. The success of these programs, especially in terms of customer participation, is a direct outcome of those lessons. These insights also inform future outreach and engagement strategies in projects like Empowered Communities.
Question	Did the rebate program apply to residential customers only?	Yes, the peak time rebate program applied only to residential customers. The program was tested in areas like Hillsboro, Milwaukie, and North Portland to represent the demographics of the overall service territory. This was to understand how different customer groups, especially those with low to moderate income, participated and responded to messaging and event calls.
Question	Is PGE looking at income demographics for the test beds? How are high-income customers, who may also be high energy users, being targeted to reduce load?	When developing the smart grid test bed, the focus was on having a representative sample of customers from various income levels. The outcomes and reports are filed with the commission and available for review. High-income customers tend to have more load flexibility, and while they may not be motivated as much by monetary incentives, they respond more to environmental and community benefits.
Question	What is PGE doing to ensure high-energy users, especially high-income customers, are reducing their energy use?	The Energy Trust of Oregon offers incentives to all customers, including high-income earners. Higher income customers often have more flexibility in reducing energy usage. While PGE may not increase incentives for them, it focuses on communicating other value propositions like environmental impact, which higher income customers respond to more strongly than bill reductions.

Type	Question/comment	Response
Question	While low-income customers are a focus, PGE should also ensure that higher-income households are participating in demand response (DR) programs. Are there are tools or programs in place to encourage their involvement without necessarily increasing incentives. What about the equitable distribution of DR benefits across income levels, particularly whether low-income customers experience different effects when participating in DR events due to factors like poor insulation in their homes?	PGE has been working to braid energy efficiency with demand response for low-income customers, in collaboration with the Energy Trust of Oregon. Improving the energy efficiency of a home enhances the benefits of demand response participation. PGE is also exploring ways to bring distributed energy resources (DERs) to low-income households, but regulatory reforms may be necessary to achieve this.
comment	In addition to submitting reports to the legislature, it would be helpful if PGE could make these documents more accessible in these spaces so that people could provide more meaningful feedback, tied to actual PGE actions, rather than broad goals	The reports are submitted to the commission, not the legislature, and that there is transparency through the Demand Response Review Committee, which guides the work within the smart grid test bed. He reiterated the importance of stakeholder involvement in these processes and offered to go over older reports if needed.
	Was there already sufficient transparency and whether PGE wanted the group to collaborate in real-time.	Bringing materials to this venue to engage stakeholders, not necessarily a reflection of overall transparency. They agreed to discuss internally how to incorporate the feedback and provide materials for discussion.
Question	Is there a specific timeline for short-term versus long-term benefits?	Short-term benefits are expected this year, while long-term benefits extend beyond that. The work on IQBD will support this evolution.
Question	What venue stickers and level of engagement along the spectrum does PGE plan for code deployment, co-development, inequity metrics, and program designs?	this venue is the primary one for eliciting feedback, and they will also engage in the 2211 docket and the CBIAG. PGE aims to take inspiration from the Energy Trust of Oregon’s equity metrics while adapting based on their specific context.
Comment	Attendee provides a caution about directly aligning with Energy Trust’s equity metrics, as those were developed under specific conditions.	PGE will take inspiration from those metrics and appreciates the guidance.

Type	Question/comment	Response
Question	How will PGE's compensation structure influences decisions against their build-outs.	This is not directly related to the current discussion.
Question	Can you clarify where the community interaction points are for this process?	PGE works with energy advocates and CBIAG members to engage communities. t PGE also collaborates with the Energy Trust.
Comment/ Question	I would also like to see these Learning labs be a little bit more bi-directional in terms of learning. was just curious because I've wondered if there were opportunities for this in other venues.	I receive that and thank you so much for your contribution to the conversation. I hear you, and we acknowledge the request to be transparent.
Comment	I would really encourage PGE to be very authentic about the dialogues that happen in venues outside of the CBIAG.	We acknowledge the request to be transparent about our engagement with the CBIAGs. The CBIAG was stood up to serve in this capacity.
Question	Is there an easy way for customers to access help from PGE if the website is confusing such as a phone number?	Our call center agents, called Customer Service Agents (CFAs), are trained to help navigate the website with customers. So, if a customer calls in using our normal service number, they will be connected to an agent who can assist them. The agents can help guide customers through various questions and website navigation. However, for more complex product-specific queries like PGE Plus, we provide additional resources for self-service.
Question	Can customers call someone if they get frustrated with the website?	Yes, if they get frustrated, they can call, and a customer service agent will help them navigate. These decisions customers make often involve multiple engagements such as researching outside of PGE, talking to friends, family, or a CSI, before taking action. We try to support customers across all types of engagement, not just through the website.
Question	Should an admin charge be a percent versus a flat fee?	We are still discussing this internally and trying to determine what is fair. It's a significant question because it affects how customers will experience it in their daily lives, but we have not settled on a clear answer yet. We are seeking feedback on

Type	Question/comment	Response
		what would be fair and considering different factors as we move forward.
Comment	So, I'm just thinking about what I as a customer and we fit into that low middle income as my household does, range. Like what I would be thinking about in terms of whether this is a good value for me or not if I'm going through this process. And I know one thing that I would think of is, if there's a comparison between the charge that I'm being charged through PGE versus what it might cost me to figure that out on my own, right? Like if I have to go and find a contractor to do all this work, how much time might that cost me and maybe, you know, there's a value on that, and if you could give a comparison.	Yeah, that's a fair statement. I think we have a lot left to go and watch because we just got launched, right? So, I think it's only 5 or 6 weeks in. In our first few applications, we estimate that absent a service like PGE plus, it's about 3 months from the time that you're interested in buying equipment, going through finding your own installers, and getting enrolled in the smart charging program and getting your incentives. That process takes about 3 months. Now, in our first install that was complete end to end and finished last week, the whole process took about 3 weeks. I'm not going to proclaim that to the public yet because that's just one sample, but it is exciting. As we get more data behind it, we'll be able to present how much time we can save customers.
Question	And the only other question I have again, this is probably just from a perspective as a customer, is because people may be going through this process several times. Like, they might put in an EV charger and the next year, they might be ready to upgrade to a heat pump or a furnace. So, what if they have to do this over multiple years? Would there be a cap on how much they would have to pay in total for these services from PGE?	Interesting, okay. Like if you do multiple products, we kind of cap so that you know you won't have to keep paying PGE over and over again for the same services. That's a fair point, and something we'd have to look into to see how we could implement that without creating a bigger burden, but it's worth considering.
Question	How are you thinking you'll identify lending partners for this? And do you know if you would be looking at one lender across the board or multiple lenders for different offers or customers?	We did an RFP for lenders for this initial launch. Several credit unions applied, and they went through a rigorous process where we cataloged and identified which lender would serve our customers best based on criteria. As for looking at more than one lender, potentially, but we wanted to start with one lender first to see if we could

Type	Question/comment	Response
		manage it well before taking on additional partnerships. Ideally, if done right, we could offer customers choice. Regarding the Environmental Protection Agency (EPA) Greenhouse Gas Reduction Fund (GGRF), we will follow up on that as we are not familiar with it yet.
Comment	It would be interesting to connect this to EPA GG RF capital that may become available later this year.	That's a great question. GGRF stands for Greenhouse Gas Reduction Fund. Thank you for calling that out. We'll likely follow up with you on that one.
Question	As a consumer, what happens if things break? Does PGE play a role in warranty length or how installers interact with customers in those scenarios?	That's a great question. When selecting criteria for our installer network, warranty management was included. Installers must honor manufacturer warranties, meaning if something breaks, the customer can contact the installer, and they will handle the issue with the manufacturer. There's also a labor warranty, which varies by product—EV charging has a one-year labor warranty, for example. We're still assessing the length of warranties for other products.

C.2 Distribution system workshop # 2 – May 8, 2024 | 9- 11a

Type	Question/comment	Response
Question	Can you elaborate on the forecasting use cases for both integrated resource planning (IRP) and distribution system planning (DSP)?	Sure, the forecasting use cases for IRP and DSP differ slightly. In IRP, we primarily focus on forecasting contributions of distributed energy resources (DERs) to the bulk power system, such as large generation and transmission systems. This includes assessing energy and capacity contributions, costs, and their impact on resource adequacy and capacity expansion. On the other hand, in DSP, we zoom in to the distribution system level, incorporating substation and feeder-level DER forecasting, including variables like electric vehicle (EV) adoption. These forecasts are crucial for

Type	Question/comment	Response
		grid planning workflows and capital portfolio planning efforts.
Question	How does PGE forecast distributed energy resource (DER) growth?	We utilize a tool called adopter, which is a site-level simulation tool capable of estimating locational hourly impacts of over 40 distributed energy resources. This includes assessing the adoption of various technologies at the site level, allowing us to understand aggregate load impacts at the feeder level while simulating individual site-level adoption patterns.
Question	Could you explain the workflow of the adopter model in forecasting distributed energy resource impacts?	Certainly. The Adopter model follows a simplified workflow, starting with market segmentation to analyze customers, both residential and commercial. This data feeds into the model, which then moves through various stages of input data processing, ultimately generating final outputs that provide insights into the impacts of distributed energy resource adoption on the grid at both aggregate and site-specific levels.
Question	Can you explain how different customer segments, such as single-family homes, multi-family buildings, and various commercial sectors, are considered in the DER adoption model?	Certainly. We break down customer segments based on factors like revenue class, rate schedules, and building types. This segmentation allows us to tailor the model to each customer type's characteristics and needs. For example, eligibility and feasibility screens are implemented based on criteria like the age of the home or building. Additionally, we incorporate vehicle registration data to assess electric vehicle adoption potential. This segmentation influences the types of DERs eligible for adoption by each customer type.

Type	Question/comment	Response
Question	Could you elaborate on the process of forecasting DER impacts using the Adopter model?	Of course. The Adopter model follows several steps to forecast DER impacts. First, we employ a stock turnover model, which uses probability failure curves to estimate the lifespan of equipment like water heaters or heating systems. Over time, homes or buildings are assigned new choices for adopting technology based on these probability curves. This data feeds into the potential model, which assesses the potential for different adoption scenarios and measures their impacts on the grid. Finally, economic screening and adoption probability curves are applied to evaluate the economic viability of technology adoption over time.
Question	Can you provide examples of the different types of measures considered in the DER adoption model?	Absolutely. The model considers over 50 measure combinations, categorized into solar and storage, electric vehicles, and flexible load-related measures. For electric vehicles, this includes light, medium, and heavy-duty vehicles, as well as different charging infrastructure options like residential level 1 and level 2 chargers, and public fast charging stations. On the flexible load side, measures such as water heating, heating and HVAC controls, and commercial-industrial demand response are considered. The model also includes emerging technologies like irrigation load control and cold thermal storage.
Question	Is there anything specific you'd like to ask or discuss about the presented information?	Feel free to ask any questions or share thoughts about the content presented. We'll delve into more detailed charts and discussions in the subsequent slides, but I'm here to address any immediate queries or points of interest.

Type	Question/comment	Response
Question	How do retail rates and changing retail rate structures impact DER adoption rates and incentives?	Retail rates and their changes are considered differently depending on the type of DER. For flexible loads, which are assessed based on total resource costs, the impact of changing retail rates is indirectly factored in through the programmatic decisions and incentives. However, for solar and electric vehicles, market-based adoption is a significant factor. Solar adoption is modeled using industry formulas like the mass diffusion curve, which considers future electricity prices and equipment cost declines. Similarly, electric vehicle adoption is influenced by econometric screening, including factors like the price ratio between gasoline and electricity for charging EVs.
Question	Could you clarify the assumption regarding PGE retail rates and their escalation for solar and EV adoption?	Yes, the baseline assumption for DER adoption modeling involves using PGE retail rates from 2023. For solar and EV adoption, these rates are escalated using industry models or trends to reflect anticipated changes in the future. However, for flexible loads, the total resource cost (TRC) methodology is used, which complicates the consideration of changing costs and benefits associated with evolving retail rates.
Question	What are the primary data sources used for inputting adoption trends and usage trends in the modeling process?	We utilize a combination of internal utility customer information and external data sources for inputting adoption and usage trends. Previous customer adoption data for ongoing programs or pilots at PGE is crucial for calibrating adoption curves. This data is benchmarked against other jurisdictions or industry studies to determine maximum saturation points and ramping speeds for adoption curves. Additionally, external data sources like the DMV data are utilized to inform the modeling process.

Type	Question/comment	Response
Question	Can you please clarify the details of the question asked in the chat for viewers watching the video?	Certainly. Before answering the question asked in the chat, I'll finish my thought on customer data sources and how they inform the modeling process. Then, I'll address the question posed in the chat for the benefit of viewers watching the video.
Question	Can you explain how CBSA and RBSA data are utilized in the modeling process?	Commercial Building Stock Assessment (CBSA) and Residential Building Stock Assessment (RBSA) data are integrated into the modeling process as part of the base year inputs. These data sources provide information about the baseline heating and cooling equipment present in buildings. For example, if a utility program incentivizes the adoption of heat pumps, customers enrolled in that program are identified, and their equipment is recorded. The remaining data is filled in using statistical averages from CBSA and RBSA. Additionally, the model incorporates load growth estimates to account for new residential and commercial customers, each potentially adding various end-use equipment types.
Question	Could you explain how EV registration data informs EV management in your modeling?	EV registration data, encompassing both electric and internal combustion vehicles, is utilized to populate the base year of the model. Each customer's vehicle ownership is mapped to their site IDs. The model then simulates future scenarios, projecting when vehicles may require replacement or when customers may choose to adopt EVs. If a customer decides to switch to an EV in the model, they become eligible for EV management programs like smart charging or time-based rates. The number of EVs projected is influenced by both registrations and market adoption curves.

Type	Question/comment	Response
Question	Could you explain the implications of pushing out the IRA tax credit to 2023-2025?	Pushing out the Investment Tax Credit (IRA) tax credit to 2023-2025 means that the forecast presented does not incorporate the Solar for All incentives or more recent developments. While discussions with Energy Trust are ongoing to understand the utility-specific forecast impacts of these initiatives, the model is keeping track of various federal and state funding activities.
Question	How do you interpret the demand response and flex load charts, particularly regarding summer and winter potential?	The demand response and flex load charts illustrate contributions to summer and winter peaks. These are not total enrolled megawatts but rather average dispatch during event windows. The higher potential for summer demand response compared to winter is partly due to baseline gas heating. However, as building electrification grows, there's potential for more electric end-uses, which may increase winter flexibility. The charts depict cost-effective views, indicating contributions to the preferred resource portfolio in the Integrated Resource Plan (IRP).
Question	Is the forecasted doubling of dispatchable demand response by 2026 accurate?	The forecasted doubling of dispatchable demand response by 2026 is roughly accurate, although the data presented in the charts is about a year and a half old. The numbers are refreshed with each IRP cycle, considering various market dynamics, goals, and achievable targets set on a yearly basis. The program teams are more closely aligned with near-term market dynamics and adjust goals accordingly.
Question	Can you explain the feedback loop from inputs to outputs in the model and when the most current inputs are plugged in to get the most current outputs?	The feedback loop involves recalibrating the model for each cycle. This process includes gathering updated cost information, current enrollments, and other relevant data inputs. For example, solar adoption might be informed by the number of applications in the current queue in Power Clerk. There's also

Type	Question/comment	Response
		consideration for the lag between program managers setting annual budgets and the timing of IRP modeling. The aim is to solidify this process with more structured procedures over time.
Question	Why does the demand response chart start in 2022 while other components start in 2023?	The demand response chart starts in 2022 because it reflects data generated after the passage of the Investment Tax Credit (IRA), which occurred midway through the IRP modeling process. Solar, electric vehicles, and building electrification components started in 2023 because the demand response and flex load modeling inputs were generated approximately six months later. Additionally, there were minimal changes in the flex load landscape, so updating it wasn't deemed necessary.
Question	Do you use DB info to keep track of EVs on TLU rates, or do you just use DMV info for DSP?	We primarily use Department of Motor Vehicles (DMV) registration data for DSP, which provides a 95% match rate at the service point level. For analyzing customer participation in programs like time-of-use rates or voluntary solar programs, we cross-tabulate enrollment with DMV data and look for overlaps with EV adoption.
Comment	Sorry to catch you after the click. Just wanted to acknowledge this new effort and appreciate the transparency in evaluating past performance and planning future adjustments.	Thanks for acknowledging that. It's essential to assess how things went initially and openly discuss adjustments for improvement. We'll aim to present similar evaluations in the future for other aspects, like electric vehicles.
Question	Do you like this type of truck as a homeowner? Or do you prefer an electric vehicle of a similar type?	EPRI and NREL conduct surveys to gauge customer preferences regarding various technologies like solar PV, battery electric storage, and electric vehicles. They systematically analyze responses and compare them to actual adoption data to understand stated preferences versus revealed preferences. The data will be fed into NREL's model for further analysis.

Type	Question/comment	Response
	Can you provide more details on how EVs to scale initiative is progressing and how it integrates with your planning efforts?	The EVs to Scale initiative, led by EPRI, involves collaboration with various stakeholders to advance electrification, especially in fleet vehicles. They analyze locational energy demand and adoption patterns to complement and integrate with PGE's adopter workflow. The initiative includes strategies for fleet charging behaviors, based on real travel pattern data, and involves synthetic profiles of potential charging use cases.
Question	How does PGE utilize distribution system planning criteria, particularly for the proposed Tonquin project in Clackamas and Washington County?	For the Tonquin project, they assess if the current infrastructure can handle the additional load requested by the customer. They compare the customer's energy usage to their planning criteria, particularly looking at whether it exceeds 67% of the feeder's capacity. If it does, they evaluate if they can maintain flexibility to restore customers within a couple of hours in case of an outage. If they can't meet these criteria, they propose a project with multiple solutions to design the best investment for the company and ratepayers.
Question	How the long-term goals discussed in the presentation factor into PGE's analysis of distribution and transmission upgrades, specifically with a project like the Tonquin Project? Also, how does PGE balances DR goals with other potential solutions to capacity?	Once they gain confidence from the smart grid test bed and are sure about the demand response (DR) solutions, they'll incorporate them into their planning studies. Currently, they are investing in the test bed to gather lessons learned and confidence levels to include in future planning studies. Fatima envisions that with confidence in DERs, they'll be able to defer capital investments and shift peak energy use according to customer needs, especially during extreme weather conditions.

C.3 Distribution system workshop # 3 – Jun 27, 2024 | 9 - 11a

Type	Question/comment	Response
Question	What percentage of winter energy use is met by methane gas? May explain why summer peak is higher in part. What happens to your winter peak when gas declines in use to reduce greenhouse gases?	As fuel switching occurs, we'll probably see that winter peak creep up, you know, whether or not it overtakes the summer peak, it's hard to say.
Question	Are you drawing on an association between gas use and the summer peak?	Yes. Are you drawing on an association between gas use and the summer peak?
Question	How much of the heating is actually taken care of by natural gas rather than electricity?	I think really what you're asking is a building electrification question, and what is the assumption around building electrification?
Question	What is the expected timeline and rate of growth for building electrification?	Growth. And the pace of that growth, you know, when is it expected to happen, and at what rate does it happen?
Question	Which sector is most affected by building electrification, specifically the residential sector?	And within what sector does it happen? I think you're asking right now around the residential sector, so there are some building electrification assumptions built into our IRP.
Question	How is the switch from natural gas to electricity incorporated into your Integrated Resource Plan (IRP)?	Our load forecast within the IRP has some assumptions around building electrification, including the switch from natural gas to electricity.
Question	Within what sector is building electrification happening, especially in the residential sector?"	There are some building electrification assumptions built into our IRP. So our load forecast within the IRP has some assumptions around building electrification, including the switch from natural gas to electricity.
Question	How does your distribution system planning account for the new load as electrification speeds up?"	Our distribution system planning team, led by Rejo and Fatima, account for that in their planning processes around what is necessary on the distribution system to accommodate that new load as electrification or building electrification speeds up.

Type	Question/comment	Response
Question	What happens when electrification becomes a more significant planning item?	It becomes a direct planning item that we will have to address, largely through assumptions around whether we need new resources or if it's pushing the need for new resources, or can it be mitigated through additional investments in energy efficiency.
Question	Can investments in energy efficiency, demand response, or distributed energy resources (DERs) help manage increased load?	We can mitigate through some additional investments in energy efficiency, demand response, and the adoption of distributed energy resources, where they happen to be rooftop solar and batteries.
Question	How do you evaluate the implications of building electrification when looking at energy efficiency and DER adoption?	When we do our assessment for the DSP (Distribution System Planning), we will be looking at building electrification in context with how much energy efficiency we expect as building electrification comes on, and how much DER adoption we expect.
Question	How close to accurate will your load assessments be with the new factors in play?	We are aiming to get a true or as close to a true assessment of what the new load might look like.
Question	In the step one, I see there's work at two substations. In step two under option one, I see transformer in the singular. Would that 28 MVA transformer be part of the rebuild at Scholls Ferry or an addition at Murray Hill?	Option one will be adding the 28 MVA transformer, and by adding that, we'll be adding capacity to the Scholls Ferry substation. This may also allow shifting some load from Murray Hill to balance the area better.
Question	In your solution/option analysis, what role does cost efficiency play in making your choice of how much extra capacity is necessary?	We are still developing our options. Once we go into analyzing and comparing options and the benefits we get for the cost, we'll dig into the finance model to see what cost efficiency means for the option analysis
Question	Do you ever look at expected unserved energy or the probability that you're needing the full capacity of that particular substation at that time? How do you incorporate the coincidence of peak versus outage into the calculation?	We look at our previous peak and forecast load, adding DR and load additions like the 15,000 new customers. We sum this up to forecast the peak for the next 10 years and ensure our solutions work both for peak load and in case of an outage, to assess how our other assets would handle the added load.

Type	Question/comment	Response
Question	It sounds like the assessment is always at the peak, and there's not any kind of probabilistic approach. It's deterministic. How much of the time am I at peak, and how much unserved energy would there be if I were not at peak?	Yes, we're looking at the worst-case scenario, but we aim to move toward a more flexible time-series analysis. This will require a lot of computational work since every hour's allocation will need to be different for all customers.
Question	Does PGE do a sensitivity analysis of distribution demand if significant levels of accessible storage at load were to exist within the area? Cost-effectiveness of developing that storage versus upsizing the distribution equipment?	PGE does assess behind-the-meter energy storage and evaluates its cost-effectiveness within the load and DR assessments. They also take into account different sensitivity analyses related to storage and its impact on distribution systems.
Comment	If accessible storage could be built up during off-peak hours and used for on-peak management, it would arguably affect Fatima's calculations and help address the n-1 consequences.	The potential benefits of energy storage, emphasizing the need to balance customer and utility use cases, cost-sharing, and considerations of equity in battery investment.
Question	Are you looking at alternative cases or sensitivities in your analysis, like developing customer-side resources or virtual power plants (VPPs)? Partial customer investment could impact the outcomes.	Recognizing the potential of VPPs and customer-side resources to influence both transmission and distribution investment modeling, suggesting that as this technology evolves, it will have a growing impact on system planning.
Question	How do you provide incentives for both customers and the utility to invest in grid services like batteries, which are expensive, and at what cost?	The high cost of batteries and emphasizes the need for customers with sufficient capital to invest. They also highlight the importance of creating incentives that benefit both the customer and the utility, especially in the case of 15,000 new homes being constructed.
Question	There are cases where customers already have batteries (e.g., in their driveway) but are not fully integrated into the grid. How do we make use of this existing infrastructure?	The utility is exploring possibilities like integrating customers' existing batteries into the grid. They stress the need for a partnership between the customer and the utility, potentially cutting deals to maximize benefits from these resources.
Question	Should we add columns of benefits together (e.g., 28.4 and 3.4) to understand the benefits of option one? Similarly for 31.1 and 3.8?	These columns assess different types of benefits. One column refers to bringing dollars into the present, while the other focuses on risk reduction, so they shouldn't be added together.

Type	Question/comment	Response
Question	Is there a lot of complex math behind the final column (ratios), and is it a subject for a separate workshop?	The benefit-cost ratio is calculated through complex processes, and the higher the ratio, the better. They explain that Option 2 (the larger transformer) is slightly more cost-effective and would lower the risk of outages.
Question	Are the costs for these projects detailed in another section?	Project costs fluctuate depending on the timing and estimation of the project. They express caution about presenting specific dollar amounts, as they can change significantly due to factors like escalation.
Comment	Low-income customers can benefit from customer-side generation and storage resources but can also benefit if higher-income customers link their Tesla batteries into a grid. Create more peaking/emergency cushion and defer PGE rate-based investments in larger transformer substation equipment.	I agree that when we leverage, the benefits accrue to the entire system and those served by that system. However, I feel it's important to be more DER inclusive, as DERs are a way to reduce customers' energy burden. That's a big question—how to do so—and our team is very open to having that discussion and constructing programs, tariffs, rates, and policies so we can be more DER inclusive and help address energy burden through the adoption and utilization of smart appliances, rooftop solar, EVs, and batteries.
Question	What's driving the need to redeploy capital if there's a delay due to supply chain issues? Why not save that money	Once the funding is procured for capital projects, they bear the cost of that capital. If they don't spend the money, it costs more, so it's prudent to ensure the capital is spent within the planned timeframe.
Question	For projects like VPP with IT and grid modernization components, do they get owned by one BSG, or is there coordination across groups?	Grid modernization investments used to be split across different groups (customer, T&D, IT). Due to growing importance and the need for a coordinated approach, a Grid Mod business sponsor group (BSG) was created, with a dedicated spending cap. The respondent also mentioned that VPP is currently split across groups, and the company is considering whether it needs its own dedicated funding.
Question	Is it the case that a project with multiple components has shared responsibility across groups?	Larger projects often require multiple business sponsor groups to get funding, making it a complicated process.

Type	Question/comment	Response
Comment		Response to earlier question, while there is a cost to carrying capital, the process exists to prioritize projects, as there is not always enough capital to fund all projects in a given year.
Question	When is a large load edition, a real large load edition?	We are always communicating with potential customers, municipalities, and our customer service folks to assess the realness of things. Firm commitments matter. In an environment of limited resources, we can't distract the teams until there's execution readiness.
Question	Do you fund the entire project at once, or do you break it up?	We break the funding up. Initially, we fund the design portion of the project. Once the design is complete, we fund the execution. The conditions on the ground—cost of materials, availability of resources, permitting, and other factors—can change over time, affecting the final cost.
Question	Are there any questions about the scoring rubric for projects?	No questions at this time, but I will point out that while a higher score helps prioritize projects, it doesn't guarantee funding or execution due to factors like resource availability and timing.
Question	Can I ask about the wildfire mitigation plan (WMP) spending? Would WMP be considered part of compliance or reliability?	Yes, WMP is categorized under compliance. Ben Wen, our current portfolio manager for transmission and distribution, confirmed this.
Question	Do you reconcile spending patterns with historic categories outlined in the baseline spreadsheet from prior filings?	We have not done that for this set of investments. It's a topic for future discussion in the next iteration of DSP (Distribution System Planning) guidelines. Mapping current categories to the initial DSP guidelines would require manual effort, and we'll need to evaluate the value of doing so.
Question	What's to be done about trying to reconcile things in a sustainable way?	Stay tuned

Type	Question/comment	Response
Question	Have compliance costs been rising over time? And if so, why?	Yes, compliance costs have been rising, particularly due to wildfire mitigation and pole replacement efforts. Wildfire mitigation has become a growing investment area requiring new approaches. Pole replacement needs vary based on service area conditions (wet vs. dry areas), increasing compliance demands recently, though this might decrease in the future. While costs have gone up recently, it's uncertain whether this will be a long-term trend.
Question	Are you using some of the Distributed Standby Generation (DSG) resources to fast-track the development of capabilities for non-wires alternatives?	Yes, DSG investments have been valuable in developing these capabilities. However, most DSG units are diesel generators, so they are used minimally due to environmental concerns. The next step is to convert some of these diesel generators to battery power and scale the solution to include residential customers with solar rooftops and batteries. We are looking into the valuation of distributed energy resources, and it's tied to the services they can provide—what time they can provide them and how much they can provide at any given time.
		We are also as part of that valuation, active in the commission's discussions around energy efficiency avoided costs, particularly UE 1893. We see energy efficiency as a type of distributed energy resource, even though it may not be dispatchable. The work around community benefits indicators also provides a perspective on the value of these resources, directly tied to the customer and the community, though not necessarily to grid services or market value
Question	I was wondering whether from the presenters perspective, how this impacts the scenario modeling done through SIM? There's a locational aspect to it, hopefully reducing pressures on the distribution system investment as well as the resource piece described.	Yes, I would say absolutely, location is an important factor. However, we are at time and will continue this discussion in our next DSP workshop where we'll move these slides to the start so we can cover more of them

C.4 Distribution system workshop # 4 – Jul 25, 2024 | 9 - 11a

Type	Question/comment	Response
Question	When PGE thinks about solar standalone with a smart inverter, but not batteries, would that be something controlled? There are benefits from that arrangement, right? Or should I not think about standalone solar as part of this?	Standalone solar can provide some services, but solar introduces variability since the sun goes down or there are cloudy days. It's more useful when coupled with a battery to manage energy when the sun is not shining.
Question	When PGE thinks about a virtual power plant (VPP) or managed distributed energy resources (DERs), are you only considering direct load control, or does it also include market signals like time-of-use rates or peak-time rebates, where someone might move their solar power use to a different time of day?	Many options are available for managing load. Time-of-use rates can move load to more beneficial times for the grid, but they aren't dispatchable like direct load control, which is what we think of with a virtual power plant. Attendee's question is broader, asking about PGE's broader DER strategy and how rate design plays into that, along with the connection to a VPP.
Question	What is PGE's broader distributed energy (DE) strategy? How does rate design play into that? When you pair rate design with a virtual power plant (VPP), what are the capabilities you're seeking between those two, what are the benefits you can identify, and what costs are you containing through that coupling?	We recognize that time-of-use rates are an important part of a DE strategy. VPP is also part of that, as well as direct load dispatch and voluntary participation from customers. We are working on that and will try to articulate that strategy within our Distribution System Plan (DSP).
Question	Can you explain the difference between 'shift' and 'shed' one more time?	Sure! 'Shift' is when you take an activity and move it to a later time or outside of peak windows, either earlier or later. 'Shed' is the complete drop or reduction of energy usage during a specific time.
Question	How many customers participated?	95,000 customers participated in the program, with an additional group of customers contributing via the customer appeal. This event was the first portfolio-wide dispatch, involving various programs like thermostats, peak time rebates, water heaters, and large Commercial & Industrial (C&I) thermostats.

Type	Question/comment	Response
Question	What programs contributed to the dispatch? Do you have data on contributions from specific programs like smart thermostats, batteries, or EVs?	The data shared was portfolio-wide, but they do understand what each program contributed. Evaluations are done to assess program contributions, and there is a process in place, but results are shared only after evaluations are completed. A follow-up on specific program contributions can be addressed in future workshops after data is available, typically after three days for internal reporting.
Question	Do you have data from last summer? Why is not it shared publicly?	They do have data from last summer, but it is not shared publicly until evaluations are completed. A follow-up on data sharing can be addressed in future DSP workshops.
Question	We should consider capturing and packaging this information for easier public access.	The next presentation might reflect the first iteration of capturing and sharing this information. The need for better measurement and granular data collection to publish results more effectively in the future.
Question	How dependable are time-of-use rates? How much can you depend on a certain amount of resource?	The reliability is something we study. Time-of-use optimized equipment is very reliable as it's typically set and forget. The equipment shapes the load reliably.
Question	So, if you send out a text asking everyone to adjust their thermostats, how much can you predict will happen in terms of load reduction?	We forecast the response, and we have a resting capacity of 101 megawatts. Depending on the temperature and conditions, the response can vary. We provide this forecast to the balancing authority and California Independent System Operator (CAISO), and we work hard to achieve accuracy, often erring slightly on the conservative side.
Comment	It sounds like you don't want to share this information with the public?	It's not that we don't want to share it. We do want it to be considered a reliable resource. We're new to including this in forecasts, but as we grow, we'll be sharing it more frequently.

Type	Question/comment	Response
Comment	At least share it with the Utility Commission if not the public	Absolutely.
Question	What are these muscles we need to build?" (After describing the evolving grid and new practices, the respondent outlines various "muscles" such as digital twins, DER controls, and lab simulation.)	Necessary capabilities like grid modeling and analysis, controls for distributed energy resources, testing and lab simulations, and how these integrate into PGE's system for improved operations. We don't have a mountain of data yet, but we're building it to have these conversations in a more targeted way.
Question	How do we design DER controls, and how do they integrate with our system?	Designing DER controls involves understanding the capabilities of devices like thermostats, batteries, or EVs, and then calling on them when needed. This also includes using smart inverters and distributed energy resource management systems (DERMS)
Question	How do we coordinate with manufacturers to ensure their devices integrate seamlessly into our systems?	PGE needs to collaborate closely with manufacturers to ensure devices are ready to plug into their systems easily. We need to reach customers effectively and avoid customer fatigue.
Question	What about equity? How do we ensure everyone can benefit and participate in these programs?	An equity lens underpins all these initiatives, ensuring that as DER solutions expand, they remain inclusive and accessible to everyone.
Comment	I suspect y'all do a good job of this, but coordinating with Edison Institute, the National Labs... I don't think we have to invent a new wheel here in Oregon.	Yeah, our smart grid test bed is the marquee piece of us growing these capabilities... We're using the National Renewable Energy Lab to build a digital twin for evaluating virtual power plant operations or non-wire solutions.
Question	Would the DERMS be installed at a substation level, and how much reach do you have with advanced metering infrastructure in terms of percentage?	The DERMS we're referring to is an enterprise-level system housed in our integrated operating center... It would not be installed in a substation. Substations have monitoring devices like SCADA, but that's separate from the DERMS

Type	Question/comment	Response
Question	Are you going to be doing aggregation yourself, or would you leave that to aggregators	In our demand response program, we are doing aggregation ourselves, but we will depend on third-party aggregators as well.
Question	Regarding control and dispatch, how are you thinking about controlling residential batteries? Would it be full control or just when needed?	It depends on the program design. Some customers might allow 10% of their battery anytime, while others might allow full control. It will depend on agreements made with customers about how much of their battery is available to us.
Question	Who is the DERMS vendor?	"I believe it's OSI Aspen Tech, but Katie could speak more on the edge DERMS we use to manage multiple programs.
Question	Can you share who you use for your large CNI	Currently, we're using Clear Result for our large CNI program, but we have an open RFP out, so we may have something different in the future.
Question	What would you consider to be your current VPP capacity?	It's basically a combination of our available demand response portfolio and our dispatchable standby generation, which totals about 230-240 megawatts
Question	Is the standby generation used for non-spinning reserve?	Yes, but there are limits on how we can use those resources. For example, during the heat dome in 2021, we dispatched our standby generation to relieve a specific transformer.
Comment	I liked that PGE helped customers meet emissions compliance for backup generators.	That's continuing to evolve, and we've recently opened the program to include customer-owned batteries as well.
Question	Can you clarify the relationship between the MYP, DRP, DSP, and IRP?	The DRP, DSP, and IRP provide assessments of available resources and what to plan for, while the MYP gives specifics on what we'll acquire, including budget and megawatt capacity.

Type	Question/comment	Response
Question	Can you clarify the process for moving from demonstration to pilot to program?	We have a robust process that starts with technical demonstrations, moves to small-scale pilots, and ultimately, once they are well-established and self-sustaining, transitions to full programs. We seek approval for new activities within our multi-year plans and inform about new demonstrations with the potential to move to pilot status.
Question	What is the significance of the Smart Grid Test Bed in your portfolio?	The Smart Grid Test Bed is managed under a separate docket, but we present it within the multi-year plan for a holistic view of our portfolio. This includes details on activities and budget numbers, even if they are not formally approved in the multi-year plan.
Question	What are the key growth trends in your programs?	We see a growth trend since introducing new pilot programs in 2019. As of June 30, we have 101 megawatts across seven programs, with 22% of our residential customers enrolled in one or more programs, which is a significant number.
Question	Can you explain the reduction in opt-outs during the recent heatwaves?	Yes, we saw fewer opt-outs than expected during the three-hour events. Customers stayed in programs longer, indicating that they were more accepting of the conditions compared to previous events. We analyze this post-event to understand trends better.
Comment	It's good to see data broken down by program performance.	We strive to provide comprehensive data on program performance to inform forecasts and understand customer engagement better.
Question	What updates can we expect in the upcoming multi-year plan filing?	We plan to file in mid-September, featuring continued growth, updates to cost-effectiveness, and pathways for pilot programs transitioning to full program status.

Type	Question/comment	Response
Comment	The correlation between performance and enrollment is impressive.	Yes, there's a strong correlation between our performance metrics and the number of enrollments, especially during extreme temperature events.
Question	The discussion in Grid is grid-centric, and that VPPs are called in only for peak... How will the challenges evolve as DERs deliver more power?	This is an excellent question. We believe in the power of distributed energy resources (DERs) to provide services back to the grid. However, there are many complexities regarding market dynamics, communication standards for devices, and how to optimize these resources for grid services. Our distribution system plan will address how to incorporate and optimize DERs.
Question	What is the average value of DER capacity in kilowatt-month at PGE?	Currently, the avoided cost of capacity is $144 per kilowatt-year. We're also discussing T&D avoidance values, which are crucial for our cost-effectiveness assessment of DERs. The detailed assessment will be included in our multi-year plan.
Question	So, it should go up, right? If you're considering Transmission and Distribution (T&D) avoidance.	Yes, that's correct. The value will increase when considering T&D avoidance as part of the overall cost-effectiveness calculation.

C.5 Distribution system workshop # 5 – Sep 12, 2024 | 9 - 11a

Type	Question/comment	Response
Comment	I think I have a simple question. Recognize that a lot of the machinations in these steps are theoretical. These are extrapolations that are done. I'll use myself as an example. I have the plug-in hybrid that and the charger is part of PGE's EV charging program. Theoretically, if a person yourself knew and understood, could you put in my site ID and understand. Oh, it's a house of such and such, it's got a charger, and thus the adoption propensity at this house would be X, Y, or Z?	That's a great question. It looks very theoretical, but we use a lot of practical data. For example, we get DMV data. We can figure out which sites have EVs... whether they are plug-in hybrids or fully electric vehicles. We also know which sites have internal combustion engine vehicles. For your case, if the data is good, we would already be able to figure out you have a plug-in hybrid, and combining the customer data, we could also figure out how you are using it.

Type	Question/comment	Response
Question	I just had a question about the purchase price incentives that you're including. Is that just forecasting potential price incentives? Or is that taking into account like changes in manufacturing, to take use of the Inflation Reduction Act (IRA)? Like? How in depth are those. Consensus. And some of those inputs being analyzed and kind of look like, are those getting their own scenarios themselves? And then that influencing the actual forecast?	So there are 2 things, and both have been taken care of here. One is the price of vehicles. We may think that vehicle prices may decrease over time because certain attributes may become cheaper, or some other technology part may become cheaper, or they may not decrease that much. That influences the adoption rate, as well as what you mentioned, like federal incentives or state incentives. Those can really motivate or demotivate customers to buy these vehicles. Both of these factors are taken care of in the scenarios. For the high adoption scenario, we might assume more incentives and cheaper prices over time. For the lower adoption scenario, we might assume higher car prices and see the range of possibilities over time.
Question	I know that PGE has goals as far as decarbonization. Is there any relationship between these scenarios that you're showing? Like does the reference relate to the goals? Is the high one what the goals are? How do they relate?	Definitely, we put a high focus on the goals. We are always looking at them and assessing whether all of that information is incorporated into our modeling and estimates. For example, there is the advanced clean energy goal, and we do take that into account when we plug in the adoption curves over the years, with the goal of achieving those targets. So yes, we give a lot of importance to these goals. I think you may have been asking about PGE's overall goals regarding decarbonization. So those targets for 2030 and 2040 are set to be met regardless of the amount of load on our system or where that load comes from. There is not a decarbonization goal that's specific to transportation electrification. Our decarbonization targets are tied to the number of kilowatts served and how clean those kilowatts are over time.

Type	Question/comment	Response
Question	I'm curious about how the building forecast is trued up with field data. For example, does it incorporate data from the Energy Trust for heat pumps or PG&E's own marketing that resulted in leads to heat pump clients? Is some of that data in there to establish a baseline?	Yes, it is. We've taken various approaches to make the model as realistic as possible. We've utilized multiple surveys that provide information on what types of heating and cooling systems customers use. For the customers where we have this data, we incorporate it directly into the model. For those we don't have detailed information on, we use stochastic methods to assign heating and cooling systems—whether it's electric heat pumps or gas—based on the known customer data as a sample. In addition, we factor in cost incentives and other relevant data for billing electrification. For future trends, we've used sales information on different equipment types relevant to building electrification and combined it with market share data to get a clearer picture of current and future trends. These methods allow us to provide a more realistic estimate.
Question	With this, stakeholders' visibility and the ability to inform assumptions and data inputs that are built into the model, or only allow interactions with the output of the model?	That's a very good question, and I think that's a criterion that we're going to take back and write down. If that is an expectation, then that is an expectation we should strive to meet. We know that the adopter model still requires some upgrades to be even better or more granular, and so we will share that information with you. We can certainly share those updates as part of this process. Yes, you'll have the outputs through this interaction, and I believe we have seen other utilities, like we sat down with Avista a couple of weeks ago, where they share their input information. So I think it's possible to share input information through this process.

Type	Question/comment	Response
Question	I was curious if there's anything publicly available that's kind of a step in this direction, maybe not as complex and thoroughly thought through, but for example, Puget Sound Energy has posted priority electric lines for their DERs. I was wondering if you guys have taken any steps in that direction similar to that?"	We do have a DER map available on the DSP site. We do, through this process, identify where on our system we have needs and how we address those needs. We gave a presentation about that a couple of meetings ago, and there'll be some additional information in the DSP about that. I'm unfamiliar with what PSE is doing, so I can't commit to that until I see it, sorry.
Question	I know this was discussed. Your highest-level goals for this. But it probably would bear... Would be helpful for me to hear you describe again. Just kind of what your intended. I think you've talked about the problem around transparency and certainly reflecting some of the staff feedback. But just what your highest-level goals again are for the effort?	Yeah, I mean it is to share a forecasting tool with our stakeholders and the commission staff. Create a tool that's easy to use. Right now, the adopter model is not particularly easy to use. It requires an understanding of the Python code and data analysis. What we want to do is just create an ability for you and other stakeholders to be able to query, adopter and create scenarios to your interests.
Question	What would the relationship then be to a back-end side? In terms of governance, are there delineations between the data sets that the company will not disclose or how do you conceptualize it? How is this replicative of that? Or how does it interface with the structure of the tool, as today?	Yes, there's some things that will have to be reduced in some manner... We have a full distribution system map within adopter. It carries meter information, and it queries sensitive customer information around usage. That information cannot be shared... We will have to work on how that information is collected, reduced, anonymized, and shared into that model, so that it can be secure, but also still useful, relevant, and equitable.
Question	How much of what information will be shared? And how much of that do I have transparency to?	I think that needs to be part of the stakeholder conversation and the build requirements that we are all collectively developing around this interface.
Question	When is your launch for that? What is your proposed date for that launch?	I would like to start working on this this year, probably the last quarter of the year. We'll be working with Lisa Schwartz over at Lawrence Berkeley National Lab. I owe her a scope of work in the next couple of weeks around the

Type	Question/comment	Response
		expenditures... We intend to give that detail through the Multi Year Plan.
Comment	I'm excited about this particular project. I think there's a lot of opportunity here for us to set some best practices around data sharing and access. My hope is that we can successfully execute on this together and demonstrate to the rest of the country that this type of transparency and utilization of these models with stakeholders is a positive.	Thank you for your enthusiasm! We will submit additional information as part of an appendix within the Multi-Year Plan that we intend to file in mid-October. We'll be collaborating with the U.S. Department of Energy and Lawrence Berkeley at Astral Lab for this round of funding and subsequent rounds.
Question	Can you clarify the commitment from the U.S. Department of Energy regarding funding for this activity post-election?	Yes, I should be transparent that the commitment from the US DOE is to continue funding this activity, assuming the right administration is in place after the next election
Comment	I would appreciate if you could share the slide deck and video recording.	As mentioned in our previous presentation, we will have the slide deck and the video recording in your inboxes and uploaded to our website within a week for you to review.
Question	Will there be opportunities to discuss this topic further?	If you have further questions or want to discuss this specific topic more, you're welcome to join us during our office hours in two weeks, on September 26th.
Question	Can we hear more about the collaboration between transmission and distribution system planning teams?	Absolutely! Fatima, our distribution system planning manager, will be joining us to talk more about how these two teams work together to provide safe and reliable power to all of our customers.
Question	Can you provide a brief overview of how the transmission and distribution planning teams work together?	Sure! I will give a very brief overview of how the transmission and distribution planning teams coordinate to provide safe and reliable power. We build our system for peak demand and study the system to make sure it can handle increased electricity usage.

Type	Question/comment	Response
Question	Could you clarify what you mean by 'partially energized' customers?	Sure! A 'partially energized' customer is one that is connected and using energy but has not yet reached their full load potential. This means they may have plans for future expansion but have not completed that process yet
Question	How do you ensure that the customer timelines align with our project timelines?	We maintain constant communication with our customers, specifically through our key customer managers. This helps us understand their needs and timelines better, ensuring that we can accurately forecast our system needs.
Question	What happens if a customer decides not to proceed with their plans?	We still keep them on our list even if they are no longer committed. However, for planning purposes, we only share the list of committed customers with transmission, as those are the customers we will move forward with.
Question	Can you provide examples of how customer construction delays impact our planning?	Absolutely. If a customer has issues with construction, it may mean that we cannot energize our projects as early as initially planned. We need to verify their construction timelines to ensure that we can align our infrastructure development with their actual needs.
Question	What processes do you use to aggregate customer load additions?	We aggregate all confirmed customer load additions on a yearly basis, ensuring that we have accurate data on new requests. This data is then used for forecasting and planning in both distribution and transmission.

Appendix D. Multi-Year Plan 2024 – Program descriptions

D.1 Residential Smart Thermostats

Table 40. Regulatory reference: Sch 5 Residential Direct Load Control Pilot (deferral UM 2234)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 52.5 MW Winter 10.8 MW	$7,800,000 (Admin 41%, Incentives 59%)	TBD

The Direct Load Control Smart Thermostat pilot aims to enroll and operate connected residential thermostats to control electric heating and cooling load, providing PGE with firm capacity. To participate in the program, PGE customers must have a qualifying HVAC system (ducted heat pump, electric forced-air furnace, or central air conditioner).

Customers may enroll online in PGE's DR program by purchasing a new qualifying thermostat via the PGE Marketplace or another retailer or using an existing qualifying thermostat attached to a qualifying HVAC system. Customers receive up to $25 as an enrollment incentive and $25 for each DR season that they are able to participate in (defined as 50 percent of the DR hours called within a season). Customers are permitted to opt out of any or all events.

Customers who enrolled through the direct installation delivery channel (closed to new enrollment as of May 30, 2022) received a free or discounted and professionally installed smart thermostat but are not eligible for the up to $25 enrollment incentive or $25 seasonal incentive.

D.2 Peak Time Rebates

Table 41. Regulatoryr: Sch 7 Flex 2.0 (deferral UM 2234)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 16.6 MW Winter 12.4 MW	$5,880,715 (Admin 33%, Incentives 67%)	TBD

The Direct Load Control Pilot targets HVAC load curtailment using smart thermostats for commercial customers. Launched in 2017, Schedule 25 complements Schedule 26 by recruiting customers and installing qualified smart thermostats directly. This pilot allows small and medium-sized businesses to participate in demand response through a turnkey approach, benefiting those who cannot curtail load via Schedule 26.

Participants let PGE manage their thermostats during events, with the option to opt out. To qualify, customers need a qualifying rate schedule, a PGE network meter, an internet-connected thermostat, and a suitable heating or cooling system (ducted heat pump or electric forced air heating for winter; central air conditioning or ducted heat pump for summer).

Event Limits: Up to two events per day, not exceeding five hours per day.

Event Seasons: Events occur only during designated seasons, not on holidays, with a cap of 150 event hours per season.

Incentives: Participants receive a free thermostat upon signing up through direct installation. They can earn up to $60 per site per season (up to $120 per year). Payments are made via ACH, check, bill credit, or gift card. To qualify for payment, thermostats must participate in at least 50 percent of event hours per winter and/or summer season.

The Energy Partner Smart Thermostat program extends impact to commercial businesses, many of whom are residential customers. This program helps businesses reduce costs and earn incentives.

Customers can get a free smart thermostat with professional installation from PGE and explore ways to save money, time, and energy. In May 2024, PGE launched the “bring your own thermostat” (BYOT) channel, offering a $100 reward for businesses enrolling with a qualifying thermostat. Customers in the direct installation channel receive a free thermostat but are not eligible for the $100 BYOT incentive.

D.3 Time of Day

Table 42. Regulatory reference: Sch 7 Flex 2.0 (deferral UM 2234)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 5.6 MW	$1,201,650 (Admin 100%, Incentives 0%)	TBD

Residential customers want more choice, information, and control to help them manage their energy use and costs. The Time-of-Day (TOD) pricing plan gives customers more control over their electric bills and offers opportunities to save money by shifting energy use away from the peak hours when power costs more and renewable resources are less plentiful.

Time of Day also helps reduce system peak loads and reduce associated carbon footprint and greenhouse gas emissions. Aligning on-peak hours with capacity constraints encourages customers to shift usage during energy peaks, reduces need for construction of new power plants and supports a reliable grid. TOD is one way our customers can partner with PGE and play an active role in grid management to enable a cleaner, greener energy future for all.

Time of Day operates under Schedule 7 and all pricing plan details are provided in the tariff. Main pricing details are provided below:

On-Peak 5:00 p.m. to 9:00 p.m. Monday-Friday

Mid-Peak 7:00 a.m. to 5:00 p.m. Monday-Friday

Off-Peak 9:00 p.m. to 7:00 a.m. Monday-Friday; All day. Saturday, Sunday and holidays

Holidays: New Year's Day on January 1; Memorial Day, the last Monday in May; Independence Day on July 4; Labor Day, the first Monday in September; Thanksgiving Day, the fourth Thursday in November; and Christmas Day on December 25. If a holiday falls on a Saturday, the preceding Friday will be designated the holiday. If a holiday falls on a Sunday, the following Monday will be designated the holiday.

D.4 Energy Partner on Demand

Table 43. Regulatory reference: Sch 26 (deferral UM 2234)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 43.8 MW Winter 35.5 MW	$12,143,704 (Admin 46%, Incentives 54%)	TBD

Energy Partner Schedule 26 is focused on large customers via custom load curtailment plans with monthly incentive payments during Winter and Summer seasons, and event-based incentives for shifting their energy consumption during seasonal Peak Time Events. Energy Partner Schedule 26 provides firm capacity and will evolve to provide intra-hour grid services to support resiliency and renewables integration now that the Tariff update to Schedule 26 was approved by the Commission.

In its current form, Schedule 26 customers can elect to participate in up to 20, 40, or 80 hours of events per season and customize their participation schedule by selecting one or more event windows such as 7-11 am (winter), and 11 am to 4 pm, 4-8 pm, 8-10 pm (summer and winter). Customer compensation opportunities are also more favorable relative to the previous pilot: the same selections as the prior pilot now earn 22 percent more, and the maximum hour / maximum window option pays 76 percent more.

The program is operated with sales and engineering staff (provided by our third-party implementer) who work on-site with customers to identify opportunities for curtailment, enable manual and auto DR and support ongoing customer needs. Unlike residential DR efforts leveraging a "mass market" approach, business customers require individualized, ongoing focus to confirm that their operations are not disrupted by DR events (e.g., nominations may require adjustments, and questions may arise as to how to optimize participation during events).

D.5 Multi-family Water Heating

Table 44. Regulatory reference: Sch 4 Multi-family Residential Demand Response Water Heater pilot (deferral UM 1827)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 2.3 MW Winter 2.8 MW	$3,941,330 (Admin 84%, Incentives 16%)	TBD

The Multifamily Residential Demand Response Water Heater Pilot aims to retrofit existing water heaters in multifamily residences with demand response enabled technology. Launched in 2018, this pilot focuses on electric resistance water heaters with a communication interface supporting Direct Load Control Events or a retrofitted device with a control switch in the power supply.

The program provides capacity and intra-hour energy flexibility, supporting reliability and renewables integration in PGE's grid services. It allows multifamily residents, often unable to make significant energy investments, to participate in energy programs. Property managers receive annual incentives of $20 per installed device for five years.

Multifamily Property Owners can enroll their properties in this opt-out pilot, automatically enrolling residential customers unless they choose to withdraw. Notifications and instructions for opting out are provided at installation or when the resident moves in.

Since January 2023, the pilot has been in maintenance mode, with no new installations. Maintenance includes ongoing support for active participants, fleet maintenance, incentive processing, and coordination with PGE, vendors, and partners to enhance program performance. This mode also involves strategy development, tracking, reporting, invoicing, billing, and other program management functions.

D.6 Energy Partner Smart Thermostats (Schedule 25)

Table 45. Regulatory reference: Sch 25 nonresidential Direct Load Control pilot (Deferral UM 1514)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 2.8 MW Winter 0.7 MW	$2,995,460 (Admin 81%, Incentives 19%)	TBD

The Direct Load Control Pilot targets HVAC load curtailment using smart thermostats for commercial customers. Launched in 2017, Schedule 25 complements Schedule 26 by recruiting customers and installing qualified smart thermostats directly. This pilot allows small and medium-sized businesses to participate in demand response through a turnkey approach, benefiting those who cannot curtail load via Schedule 26.

Participants let PGE manage their thermostats during events, with the option to opt out. To qualify, customers need a qualifying rate schedule, a PGE network meter, an internet-connected thermostat, and a suitable heating or cooling system (ducted heat pump or electric forced air heating for winter; central air conditioning or ducted heat pump for summer).

Event Limits: Up to two events per day, not exceeding five hours per day.

Event Seasons: Events occur only during designated seasons, not on holidays, with a cap of 150 event hours per season.

Incentives: Participants receive a free thermostat upon signing up through direct installation. They can earn up to $60 per site per season (up to $120 per year). Payments are made via ACH, check, bill credit, or gift card. To qualify for payment, thermostats must participate in at least 50 percent of event hours per winter and/or summer season.

The Energy Partner Smart Thermostat program extends impact to commercial businesses, many of whom are residential customers. This program helps businesses reduce costs and earn incentives.

Customers can get a free smart thermostat with professional installation from PGE and explore ways to save money, time, and energy. In May 2024, PGE launched the "bring your own thermostat" (BYOT) channel, offering a $100 reward for businesses enrolling with a qualifying thermostat. Customers in the direct installation channel receive a free thermostat but are not eligible for the $100 BYOT incentive.

D.7 Residential EV charging

Table 46. Regulatory reference: See Transportation Electrification Plan

MW 2025-26 (forecast)	Costs 2025 only (forecast)[100]	Cost Effectiveness (TRC)
Summer 3.3 MW	$2,130,409 (Admin 53%, Incentives 47%)	TBD

[100] Funding for Residential EV Charging pilot is provided through the Transportation Electrification Plan. We include a brief overview of the pilot here in the interest of presenting a holistic picture of

MW 2025-26 (forecast)	Costs 2025 only (forecast)[100]	Cost Effectiveness (TRC)
Winter 3.5 MW		

PGE's residential EV Smart Charging pilot offers qualifying residents of single-family homes a $300 rebate towards the purchase and installation of qualified L2 at-home charger ($1,000 income-qualified rebate) or a $50 rebate for customers who enroll through a qualifying vehicle telematics provider. The pilot also offers a $25 seasonal incentive (six-month season; Oct-Mar, Apr-Sep) for allowing PGE to pause EV charging during peak loads. In addition to the above, PGE's Monthly Meter Charge funds panel upgrade rebates and trade ally network development.

Although funding for the pilot is provided through PGE's Transportation Electrification activities, we include it here as it contributes to PGE's flex load acquisition. Further detail on the pilot can be found in PGE's 2023 Transportation Electrification Plan.

D.8 Residential Smart Battery (Schedule 14)

Table 47. Residential Smart Battery (Schedule 14)

MW 2025-26 (forecast)	Costs 2025-26 (forecast)	Cost Effectiveness (TRC)
Summer 2.3 Winter 2.3	TBD	TBD

The Smart Battery Pilot was launched in 2020 under docket UM 1856. The pilot is paid for under UM 2078 and will continue to operate thereunder until its mandated June 31, 2025 expiration. At that point PGE plans to propose the pilot transition into the Flex Load portfolio as the technology and market continues to mature.

The pilot objective is to understand how best to incorporate residential energy storage into PGE's power operations, customer acceptance and experience, and programmatic operation.

The pilot has always been vendor agnostic. PGE is expanding the qualified products list (QPL), with requirements based on the following features: UL listed, commercially available in PGE's service territory, and dispatchable by PGE's Distributed Energy Resource

Flex Load activity, to which the pilot contributes. Note also that since the funding cycles of the MYP and TEP differ, we only include 2025 pilot funding (2026 pilot funding has not yet been proposed). Further detail on the pilot can be found in PGE's 2023 Transportation Electrification Plan (UM 2033).

Management System (DERMS). PGE has onboarded three additional brands, and the QPL now allows 97 percent of existing battery devices in PGE's service territory to participate.

PGE will continue to pursue enhancements as the pilot moves into its final year of operations under UM 1856, and later under the Flex Load portfolio.

The process evaluation of the Pilot's performance can be found as the appendix of the 2023 Annual Energy Storage Update filed with the OPUC[101]. PGE will file the second comprehensive process evaluation for close-out of the Pilot.

The UM 1856 pilot expires July 31, 2025, amidst the summer demand response season. So as to avoid interruption of the resource, PGE will seek to extend the date to September 30, 2025. This extension would allow the pilot to continue through the summer DR season uninterrupted and give the program team the fall shoulder season to transition customers to the next iteration of the Pilot.

After the conclusion of the UM 1856 pilot, PGE seeks to continue operating and growing the resource. PGE expects to file a proposal to fund this work under Schedule 135 via on off-cycle MYP update filing in mid-2025. For clarity this document will refer to the first Pilot associated with UM 1856 as "Phase 1" and the continuation as "Phase 2". Phase 1 is currently funded through the Schedule 138 Energy Storage Cost Recovery Mechanism.

While PGE has made significant progress in stabilizing and growing the pilot over the past four years, the market remains nascent and relatively small, with about 8 MW of total nameplate capacity among all residential customers. PGE seeks to continue to tailor the offering and pursue market transformation to grow the overall adoption as well as expanding participation.

Options under consideration for Phase 2 of the pilot include:

- Allowing small non-residential customers to participate with a qualifying dispatchable battery. Currently, businesses with residential-scale devices (e.g., a Tesla Powerwall installed at a small vineyard) are enrolled in Energy Partner On-Demand.
- Adjustments to the incentive structure based on what has been learned from Phase 1.
- How to further optimize the value of customer rooftop solar when paired with batteries.
- A rebate to income-qualified customers participating in the Oregon Solar for All[102] grant program to pair their solar project with an eligible battery.

The upcoming transition to Phase 2 will include a change to cost recovery, with expenses to be transferred from Schedule 138 deferral mechanism to the Schedule 135. The pilot will seek cost-effectiveness in its operations and will be evaluated bi-annually to measure performance and cost-effectiveness and identify areas for continued improvement.

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[101] Available at: https://edocs.puc.state.or.us/efdocs/HAD/um1856had151748.pdf
[102] Available at: https://www.oregon.gov/energy/Incentives/Pages/Solar-for-All.aspx

Appendix E. Description of solutions to address grid needs

Appendix E of the DSP provides the detailed project summaries requested in DSP Guideline 8(b). Because these materials include highly confidential information, we will provide Appendix E as a separate document with the appropriate protections.

Appendix F. Grid modernization long-term plan and workstreams

F.1 Customer ecosystem

As part of the Distributed Energy Resource (DER) lifecycle, PGE plans to enhance customer interaction and experience with new DERs functionalities and capabilities. Customers will be informed about energy products that meet their needs and encouraged to partner with PGE for self-generation, flexible load, or energy efficiency solutions. PGE will focus on grid connectivity and manage the devices, including cybersecurity. Accurate device data will enable detailed grid operations, forming the basis of the Virtual Power Plant.

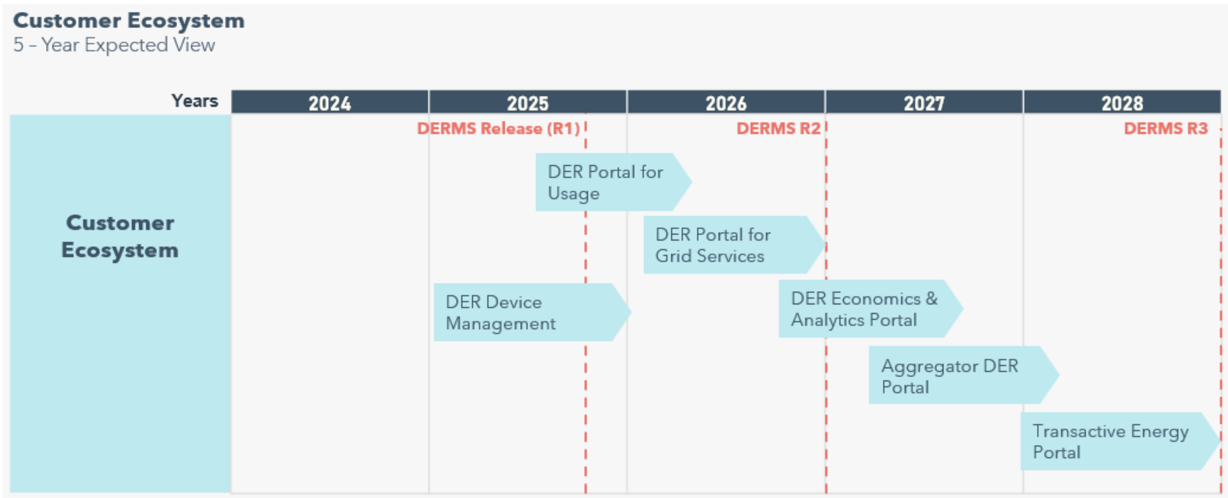
PGE aims to improve the customer portal for device management, billing, settlements, interconnections, and communications. Future developments include a DER marketplace, transactive energy portal, transportation energy functionalities, and building electrification for a low-carbon future, alongside modeling tools for customized energy insights.

Figure 36. DER lifecycle diagram

Many of these DER capabilities will be enabled by the Enterprise Distributed Energy Resource Management System (DERMS) implementations (Releases 1-3), as explained in **Figure 37**.

For example, DER device management and a customer DER portal to understand usage will be enabled with DERMS Release 2.

Figure 37. Customer ecosystem planned investments



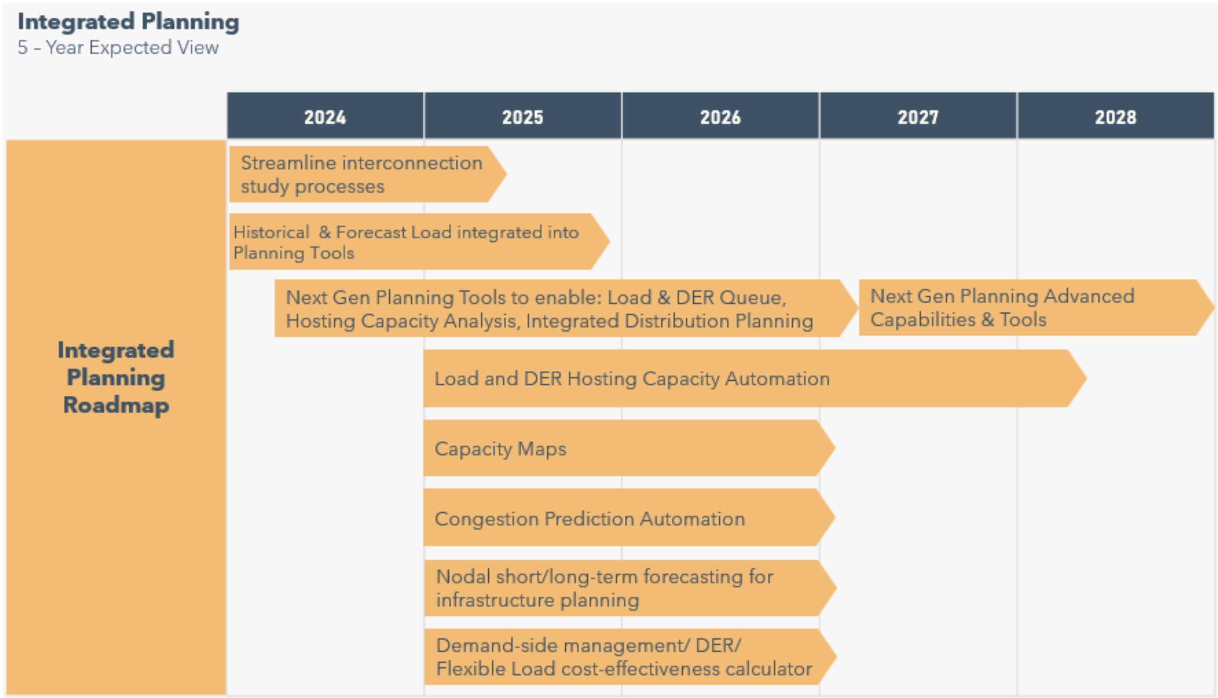
F.2 Integrated planning capability

PGE is enhancing its integrated planning capabilities with next-generation tools for distribution system planning. This approach aligns with Department of Energy Next Generation Distribution System Platform DOE's DSPx guidelines and best practices, directly supporting PGE's distribution system vision. Key investments, evaluated for cost-effectiveness and fit, are planned over the next five years to enable these foundational functions.

Figure 38. 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>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></td><td>Fault analysis</td><td>Fault current analysis
Arc flash hazard analysis
Protection coordination analysis
Fault probability analysis</td></tr>
<tr><td></td><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>

Figure 39. Integrated planning planned investments



F.2.1 Development of model for bottom-up DER forecasting

To meet evolving customer needs, PGE developed an in-house model for bottom-up DER forecasting and potential assessment at both system and locational levels. This model integrates building and vehicle stock modeling with market-level adoption forecasts, offering a comprehensive view of how different DER and electrification technologies interact. This DER forecasting modeling method represents a significant shift in potential modeling and enhances planning processes. The project spans two phases over two to three years. Phase I is focused on system-wide DER potential for the Integrated Resource Plan (IRP), while Phase II refines locational adoption models, considering demographics, energy use, and infrastructure. Future enhancements will include locational adoption for non-wire solutions, better IT integration, and improved data quality.

In 2024, PGE and Resilient Edge have coordinated on a US DOE project proposal to develop a public graphical user interface and other capabilities to extend bottom-up DER forecasting modeling. To provide this, PGE would provide a set level of access to the tool allowing stakeholders to develop planning scenarios for their advocated position or interests. This would lower the bar to entry for sophisticated modeling and demonstrate how shared access to such sophisticated tools better informs and effectively influences the utility planning and investment and regulatory decisions.

F.2.2 Next-Generation planning tools

PGE is investigating the current and future planning capabilities needed to realize its vision, focusing on tools, data, and IT infrastructure for effective distribution system planning. This "next generation planning tools" project aims to enable Integrated Distribution Planning

(IDP) by enhancing technical analysis capabilities. Key goals include improving safety, reliability, and security, accommodating load and DER growth, and modernizing the grid. The project will also streamline interconnection study processes and community engagement.

Advanced capabilities under consideration include time series analysis, profile-based forecasts, granular data analysis, hosting capacity analysis, and integration of non-wires solutions. PGE evaluated various planning tools and chose a flexible advanced distribution software solution with extensive planning, analysis, and modeling capabilities. PGE is developing a roadmap for an Advanced Distribution Planning System (ADPS), addressing current tool usage, pain points, data integration needs, and IT systems. This multi-year project will enhance PGE's planning processes with new IT equipment, integration, and process changes.

F.3 Grid management systems

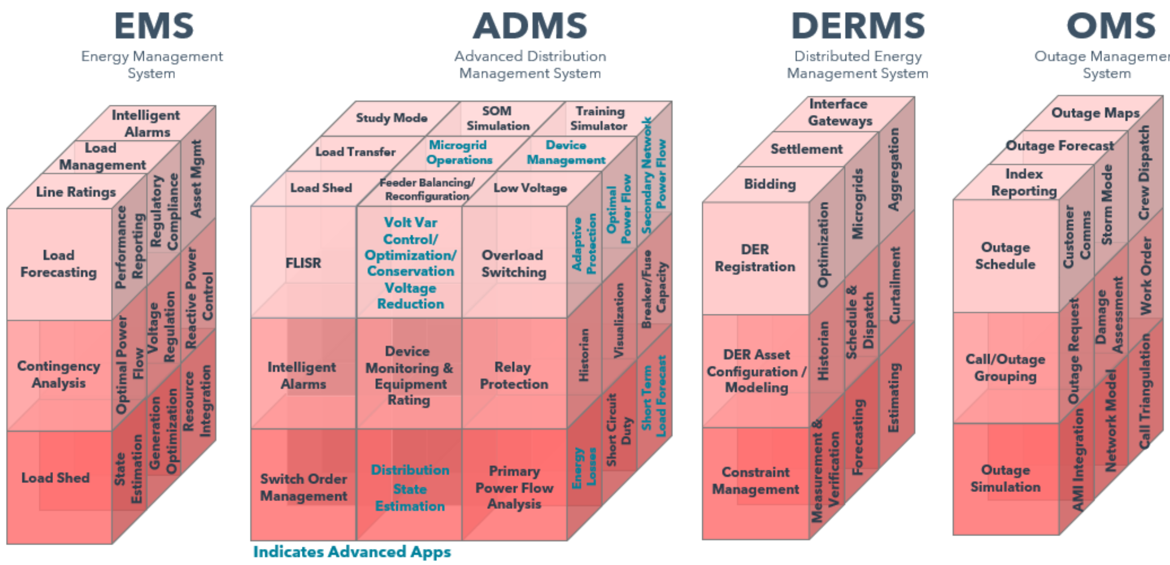
Grid management systems (GMS) use operational technology tools to monitor, predict, analyze, control, and optimize the performance of the distribution system. These systems communicate with field devices via a telecommunications network. Investments in GMS, field devices, and telecom systems are interlinked for maximum customer benefit. For example, when a storm causes a power outage, the integrated system quickly identifies the location of the outage using real-time data from smart meters and line sensors (AMI). The Outage Management System (OMS) prioritizes the repair and restoration efforts based on customer impact and criticality, while ADMS reconfigures the grid to minimize outage areas, restoring power to as many customers as possible.

At the same time, DERMS can optimize the use of battery storage to supply power to customers until full grid restoration is complete. Customers receive real-time notifications about outages and restoration progress. This integration leads to faster outage resolution, improved service reliability, and enhanced customer experience.

PGE's grid modernization strategy includes foundational investments for a modernized grid, ensuring safety, security, reliability, and resilience where there is high DER penetration.

Figure 40 illustrates Grid management systems core functions for the Energy Management System (EMS), Advanced Distribution Management System (ADMS), Distributed Energy Management System (DERMS), and Outage Management System (OMS). These have iteratively informed PGE’s business capabilities outlined within each respective section.

Figure 40. Grid management system core functions

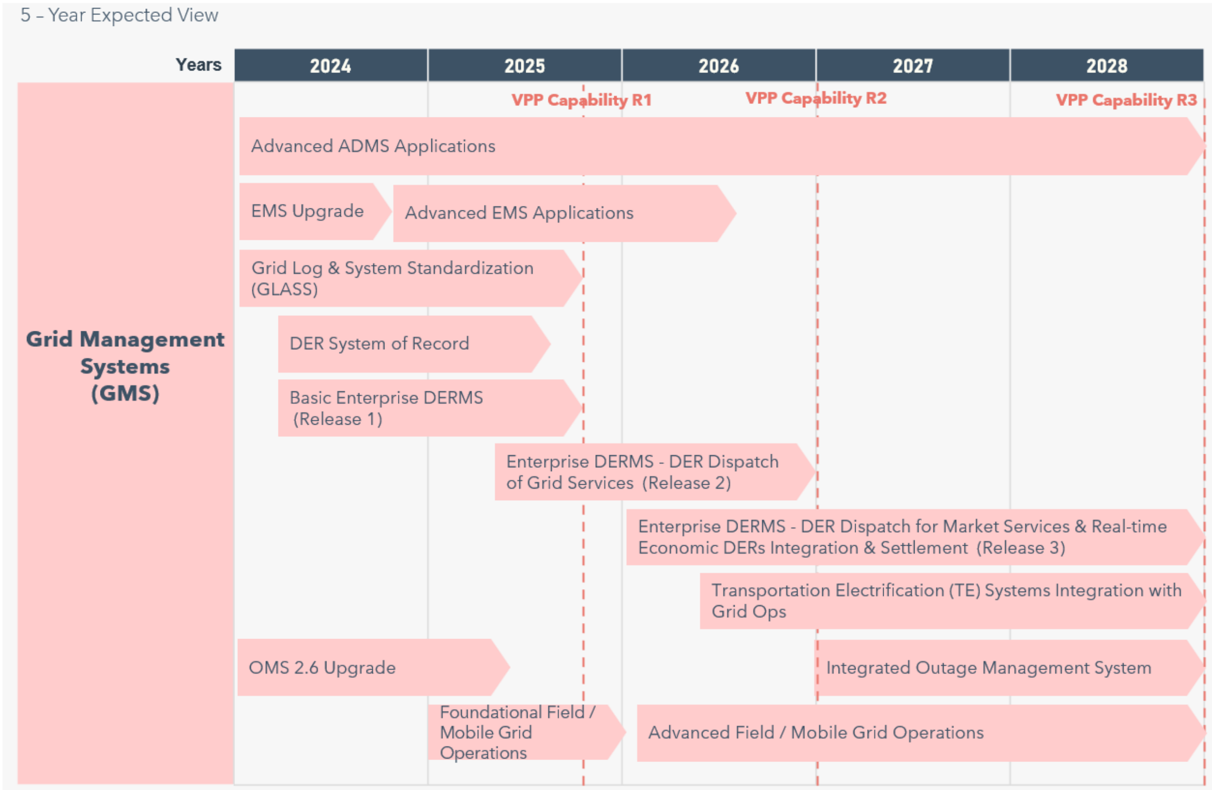


In 2022, PGE completed its Basic ADMS deployment, which includes a distribution management system (DMS) for monitoring and operating distribution devices. This deployment also implemented fault location, isolation, and service restoration (FLISR) on several feeders, enhancing reliability. ADMS collects real-time information from substations, feeders, and customer devices, integrating current and future distribution automation schemes. Protective measures similar to those for energy management systems (EMS) are in place for DER and DSG resources.

For example, operators can use Supervisory Control and Data Acquisition (SCADA) controls via EMS to remotely shut down DER and DSG resources in response to grid conditions or safety concerns. This remote capability is critical during grid faults, system overloads, or maintenance activities, ensuring that DERs do not continue to inject power into a compromised grid. Additionally, a transfer trip is a communication-based protective measure that can be used in the event of a grid fault, short circuit, or line failure. A transfer trip can be initiated through EMS to signal the DER to disconnect from the grid.

PGE's five-year roadmap (**Figure 41**) and future GMS investments follow a least-cost, best-fit approach to enable PGE's business capabilities informed by Grid Management System Core Functional capabilities. Each investment is discussed in the subsections following **Figure 41.**

Figure 41. Grid Management Systems planned investments



F.3.1 Advanced Distribution Management System (ADMS)

PGE has successfully implemented Advanced Distribution Management System to manage the distribution grid. PGE is improving its ADMS implementation, by expanding and adding advanced functions.

The **ADMS advanced capabilities** are:

- Expand **Fault, Location, Isolation, and Service Restoration (FLISR)**. FLISR includes the automatic sectionalizing, restoration, and reconfiguration of circuits. These applications accomplish distribution automation operations by coordinating operation of field devices, software, and dedicated communications networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all customers can avoid experiencing outages.
    - 35 FLISR Schemes have been deployed successfully across PGE's territory, reducing customer outages
- **Distribution State Estimation (DSE)** estimates the current operating conditions of a distribution network in real-time. This involves calculating the voltages, currents, and power flows across the network by using available real-time data, such as measurements from sensors and network models. DSE improves operational visibility and decision-making. For customers, DSE ensures more reliable, high-quality, and cost-effective power delivery while supporting the integration of DERs.
    - DSE will be fully implemented by the end of 2024.

- **Fault Protection Analysis (FPA)** performs analysis of protection device performance during faults. It focuses on ensuring that protective devices (like relays, circuit breakers, reclosers) operate correctly during faults, preventing equipment damage and ensuring grid safety and reliability. FPA prepares the grid to handle future faults, by preventing equipment damage and ensuring the proper fault response. Better protection leads to improved grid reliability.
    - Planned for 2026 deployment.
- **Secondary Network Power Flow** refers to capability to analyze and manage the flow of electricity in the secondary distribution network, which is part of the grid that delivers power from substations to customers (homes, businesses, etc.). This analysis typically includes monitoring and optimizing power flow in low-voltage networks, particularly in dense urban areas where secondary networks can be complex and interconnected. This will lead to improved reliability and better power quality. For example, in dense urban areas (like Portland) where secondary networks are often meshed, meaning they have multiple interconnected paths compared to simpler radial distribution system, power flow management helps prevent system overloads and failures. It also ensures that voltage levels and power quality are kept stable, which protects appliances and sensitive equipment from damage due to voltage fluctuations. By optimizing the flow of electricity, PGE can reduce power losses, improving efficiency. While customers may not see or interact directly with secondary network power flow management, the improvements it brings to grid stability and efficiency result in more reliable and resilient service for them.
    - Planned for 2025 Deployment

F.3.2 Energy Management System

PGE's last upgraded our Energy Management System (EMS) hardware and software in 2019. With the vendor is discontinuing some existing modules, new replacements are being installed following updated servers for better performance, efficiency, and support for new applications. This upgrade aims to prepare PGE for advanced functionalities such as Ambient-Adjust Ratings (AARs) and Dynamic Line Ratings (DLR), which will help meet FERC 881 regulatory standards, integrate renewable energy more efficiently, and improve overall system performance.

- **EMS & DAN Upgrade**
    - **Data Acquisition Node (DAN):** PGE has successfully installed a new Data Acquisition Node (DAN) to replace the data feed to EMS. Once the EMS upgrade is completed this year. DAN will serve as a common hub for collecting, processing, and sharing data from the field to both EMS and ADMS. This streamlined architecture means simpler management, better quality data, and greater reliability.
    - **EMS Upgrade:** Expected by the end of 2024, this upgrade replaces outdated modules, and includes new capabilities such as short-term load forecasting, transmission outage management, and net schedule interchange management. Net schedule interchange management is the ability to track, manage and adjust scheduled power exchanges between different control

areas, ensuring that planned exchanges align with actual grid conditions and area control areas.
Transmission outage planning will be enabled next year after the Grid Logging and System Standardization (GLASS) project is implemented. Part of the transmission outage management capability is dependent on an integration with the GLASS system.

- **Advanced EMS Applications**
  - **Ambient-Adjusted Ratings (AAR):** In 2025, PGE will implement real-time and forecasted Ambient Adjusted Ratings (AARs), to adjust the capacity of transmission lines based on ambient temperature, helping PGE meet FERC Order 881 by mid-July 2025. AARs optimize grid performance by accounting for cooler temperatures, which allow lines to carry more current safely.
  - **Dynamic Line Ratings (DLR):** Also in 2025, PGE will be begin deploying DLRs, which take multiple weather conditions into account – like wind speed and solar radiation – for more accurate and flexible line ratings. This technology will support anticipated load grown and better integration of DERs. In the Pacific Northwest, where weather varies significantly, DLRs can boost transmission line capacity during favorable weather conditions, easing congestion and increasing reliability.

PGE is upgrading its EMS with new hard and software to enhance performance and prepare for future needs. By implementing advanced capabilities like AARs and DLRs, PGE aims to meet regulatory requirements, improve renewable energy integration, and optimize the use of our existing infrastructure. These upgrades will set the stage for better efficiency and reliability in PGE's grid operations.

F.3.3 Grid logging and system standardization (GLASS)

In 2023, PGE implemented the first phase of an integrated suite of standard tools to enhance grid operations. This platform enables the following capabilities:

- **Electronic Logging:** standardized, automated grid operations event logging within one platform, serving as the event system of record
- **Event Analysis:** the ability to analyze and document transmission outage events and facilitate corrective actions
- **Switch Order Management:** automation of switching and tagging rules and processes for transmission operators
- **Reporting:** ad hoc data reporting and custom query generation to support quick and thorough analysis of grid operations and outage events
- **Auditing:** enhanced auditing capabilities, allowing PGE to review and learn from grid events
- **Interfaces:** integration with existing systems, such as the Energy Management System (EMS), transmission outage scheduling system, and data management visualization tools, to receive event information

As part of Phase 2, PGE is further enhancing GLASS with the following capabilities:

- **Transmission Switching enhancements:** a consolidated, single page of switching for operators, improving efficiency over the current practice of providing a separate page per job
- **Outage Coordination/ Scheduling:** the introduction of an improved and integrated outage coordination and scheduling system that will replace the current transmission outage scheduling system and support more efficient job scoping and planning
- **Additional interfaces**: New automated interfaces will send planned transmission outage information to EMS, OATI, and CAISO, in compliance with FERC 881 requirements due by July 2025. These enhancements include:
    - Posting any impacts to total transfer capability (TTC) on OASIS for the next 240 hours based on planned outage conditions
    - Providing OATI with TTC data related to ambient-adjust ratings (AAR) for the 240 hours

  These updates will also provide greater visibility into planned work schedules with the Reliability Coordinator (RC) West and CAISO,

In 2023, PGE deployed the first phase of an integrated system to standardize and automate event logging, outage analysis, transmission switch order management, and reporting in grid operations. The ongoing Phase 2 enhancements will streamline switch order management, improve transmission outage scheduling, and achieve compliance with FERC 881 by adding automated data-sharing interfaces with EMS, OATI, and CAISO. These enhancements will also grow coordination with key partners such as RC West and CAISO.

F.3.4 Distributed energy resources – system of record (DER-SOR)

As DERs expand, PGE must organize new data related to generation, storage, and flexible load resources. Accurate data is crucial for maximizing grid and customer value. Key data includes DER characteristics, building load data, and operational insights. Effective use of DER data supports planning, operations, program management, customer support, field crews, and market participation. PGE is working with EPRI to stay updated on industry practices and improve information systems. Current efforts focus on integrating flexible load dispatch, standardizing technology, and enhancing data availability through projects like Customer 360.

PGE is developing a DER System of Record (DER-SOR) as a central DER data source. This system will record DER attributes, performance, cost-effectiveness, and regulatory compliance data. The Demand Side Management System (DSMS) will streamline interconnection, program management, reporting, and demand response. PGE's partnership with EPRI promotes best practices in DSMS design. The project will impact planning, operations, product teams, customer support, field crews, and coordination with ISOs/TSOs. A cross-functional team is developing procurement requirements, with the project expected to take one to three years.

F.3.5 Distributed energy management system (DERMS)

What is Enterprise DERMS?

PGE recognizes a Distributed Energy Resource Management System (DERMS) can be classified by its positioning within the grid architecture and can consist of multiple systems, comprising a centralized DERMS platform and one or more distributed/localized fleet management and Edge DERMS systems. A centralized DERMS platform oversees PGE's complete DER portfolio and is integrated with Edge DERMS technologies, adjacent operational systems such as ADMS, OMS, and GIS, as well as other enterprise systems such as PGE's integrated Customer-to-Meter and Finance systems. PGE refers to this as the Enterprise DERMS.

Table 48. Enterprise DERMS Capabilities

Capabilities	Description of capabilities and needs statement
Constraint Management	Description: Constraint management in a Virtual Power Plant (VPP) involves optimizing the use of distributed energy resources (DERs) while considering various operational limitations and constraints. Needs Statement: Effective constraint management helps the VPP deliver reliable and efficient energy services while maintaining grid stability and meeting regulatory requirements.
Dynamic Power Flow	Description: Dynamic power flow management in a Virtual Power Plant (VPP) involves the real-time optimization and control of electricity distribution across the grid. Needs Statement: This process ensures efficient energy use, grid stability, and the seamless integration of distributed energy resources (DERs).
Switch Order Management Awareness	Description: Switch order management awareness in a Virtual Power Plant (VPP) involves coordinating and executing commands to switch operations for distributed energy resources (DERs) to ensure optimal performance, grid stability, and safety. Needs Statement: This process is crucial for maintaining the balance between supply and demand, managing grid constraints, and facilitating maintenance activities.
DER-SOR	Description: A Distributed Energy Resource (DER) System of Record (SOR) is a comprehensive database or platform that manages and stores data related to DERs within a Virtual Power Plant (VPP). Needs Statement: The SOR is crucial for effective DER management, integration, and optimization, providing a single source of truth for all DER-related information.
Grid Topology	Description: Grid topology refers to the way a power grid is structured or organized. It shows how different components like power plants, substations, and power lines are connected and interact to distribute electricity. Common grid topologies include radial (one main line serving multiple points), mesh (multiple interconnected paths), and ring (a looped system for redundancy).

Capabilities	Description of capabilities and needs statement
	Needs Statement: Understanding grid topology is essential for optimizing grid operations, managing distributed energy resources (DERs), and ensuring reliable and efficient power delivery.
DER Generation Forecasts	Description: DER generation forecasts are essential for integrating distributed energy resources (DERs) into the grid and ensuring their effective management. These forecasts predict the amount of electricity that will be generated by various DERs, such as solar panels, wind turbines, and other renewable sources, over different time horizons. Needs Statement: Accurate forecasting is crucial for optimizing grid operations, maintaining stability, and maximizing the use of renewable energy.
DER Control Functions	Description: DER control functions are essential for managing distributed energy resources (DERs) to ensure optimal performance, grid stability, and efficient energy use. Needs Statement: These control functions encompass various strategies and technologies designed to integrate, monitor, and regulate DERs in real-time.
DER Optimization	Description: Distributed Energy Resources (DER) Optimization is the process of managing and coordinating a variety of decentralized energy sources, such as solar panels, wind turbines, battery storage, electric vehicles (EVs), and demand response systems, to maximize their efficiency, economic value, and reliability within the energy grid. Needs Statement: The goal of DER optimization is to ensure that these diverse resources work together effectively to support grid stability, reduce energy costs, and meet environmental and policy objectives.

PGE refers to the grid edge systems and devices at the edge controlled by Enterprise DERMS as Edge DERMS.

Figure 42. Edge DERMS

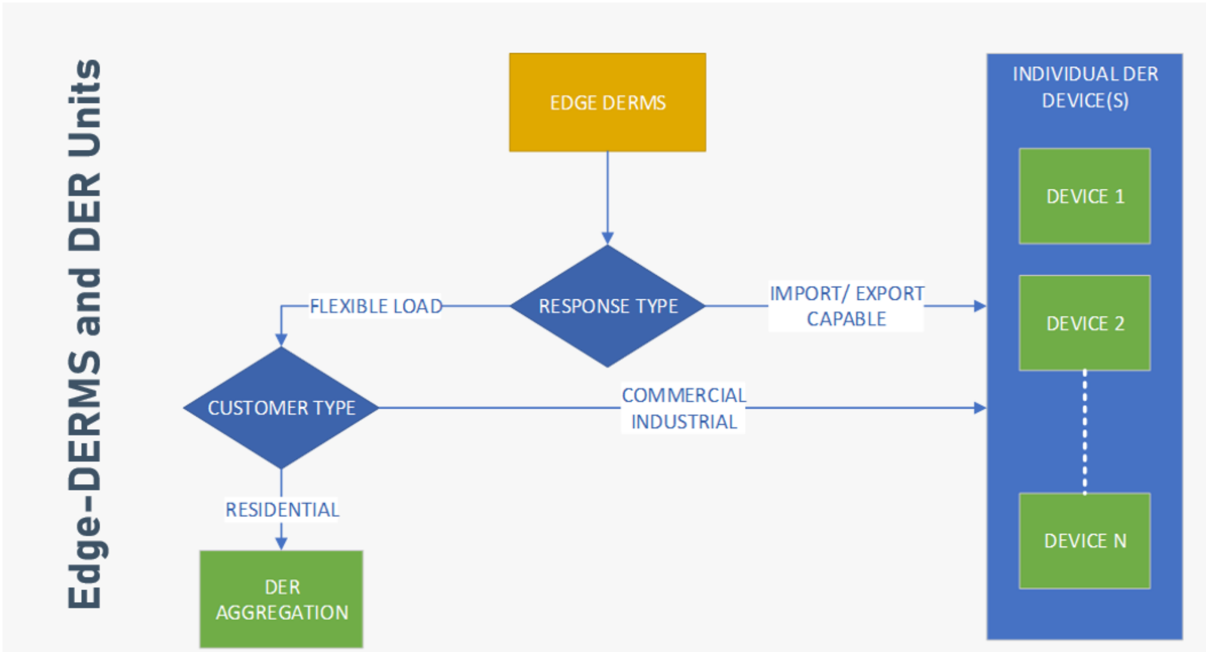


Figure 43. Edge DERMS vs. Enterprise DERMS

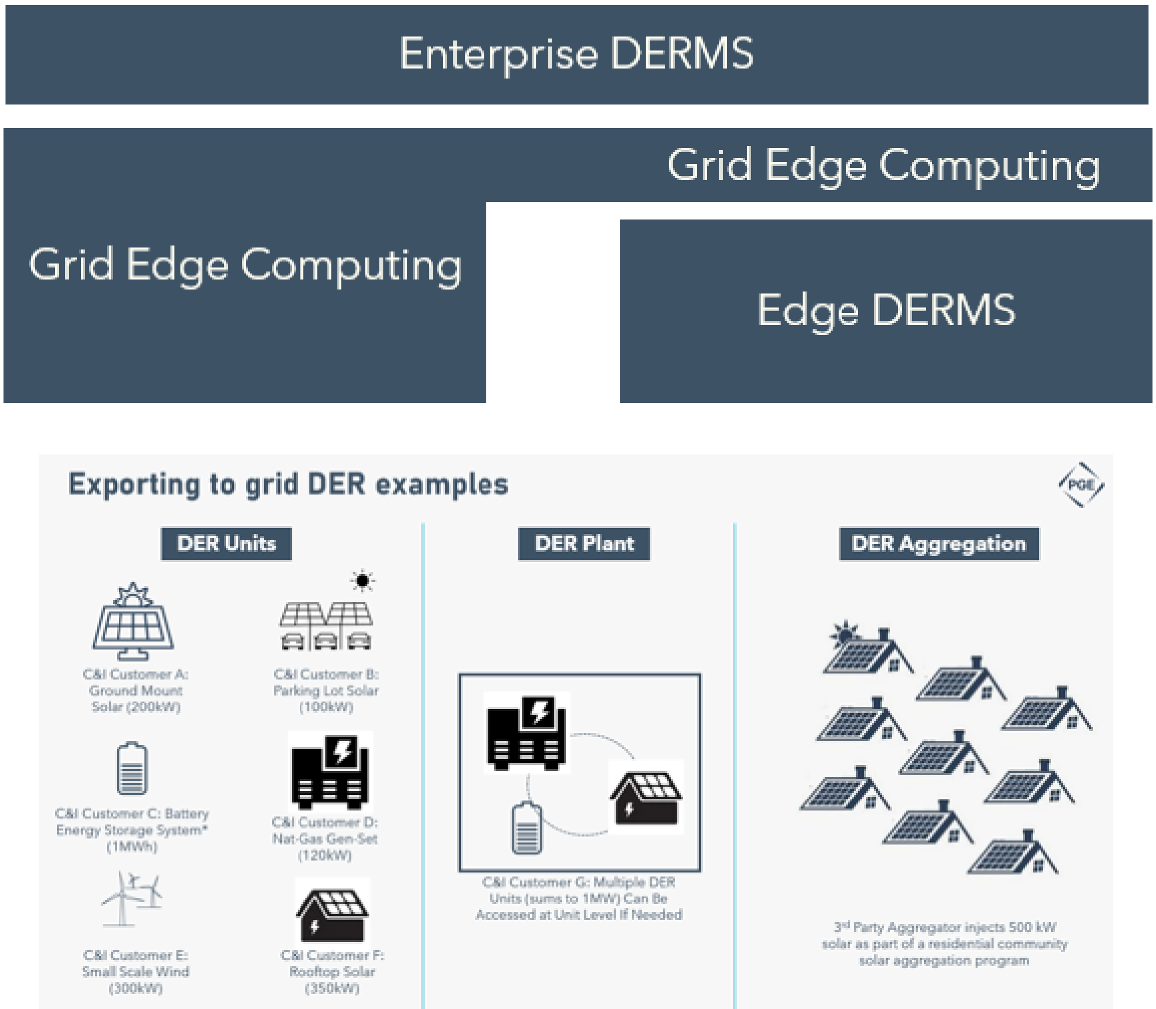


Figure 43 shows the relationship between aggregated, behind-the-meter resources (DER Aggregation) and direct integrated resources (DER Plant). Enterprise DERMS manages both aggregated DERs and direct integrated resources, overseeing coordination across the grid. Grid edge computing facilitates near-real time control and data processing closer to where DERs are located, supporting Edge DERMS in managing behind-the-meter resources and smaller-scale aggregation for local optimization. Edge DERMS focuses on managing and dispatching behind-the-meter resources and local aggregations.

The Enterprise DERMS can centralize program dispatch DERs, reducing workload for individual program managers, allowing them to focus on customer engagement, recruitment, and process improvement. This centralization would standardize operations and drive automation.

The planning team, who develops bottom-up DER forecasting, will collaborate with the VPP team to establish forecasts and planning assumptions in the Enterprise DERMS, enabling the system to manage resources for non-wires solutions when deferring grid upgrades is most valuable.

The Enterprise DERMS, through edge DERMS and Grid Edge Computing, will manage DERs and flexible loads on the distribution grid, including both front-of-meter and behind-meter resources, whether owned by PGE or customers. Resources may be managed individually or aggregated at the program level by PGE or third-party aggregators.

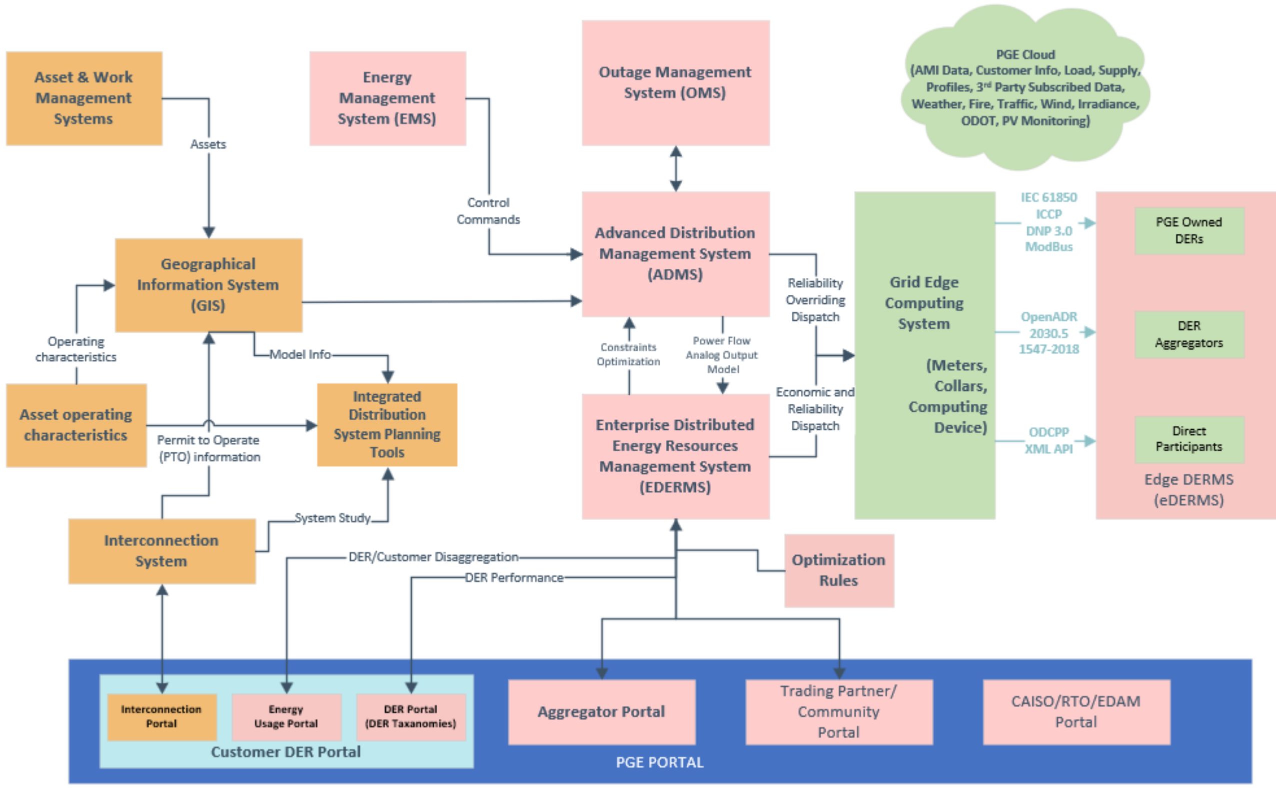
The VPP ongoing planning process identifies and integrates business requirements which inform a five-year roadmap, and near-term actions plan for implementation. The Enterprise DERMS (Release 1) and DER-SOR will be developed and implemented in parallel with business requirements. Future releases such as Release 2 (DER dispatch of grid services) and Release 3 (real-time economic and market services) will be based on business requirements and use cases that are being developed in parallel as part of the planning process.

PGE's DERMS technical platform is a combination of sophisticated systems, processes, people, and policy that integrate various distributed energy resources (DERs) such as solar panels, wind turbines, battery energy storage systems, and flexible demand-side resources into a unified and manageable network.

The proposed high level conceptual architecture for Grid Mod is shown in

Figure 44.

Figure 44. Overarching grid modernization landscape - future state



Here are some key capabilities of an Enterprise DERMS that will be delivered over the next five years and benefits it will provide to the Virtual Power Plant (VPP):

Aggregation and Optimization

Aggregation: Enterprise DERMS aggregates multiple DERs, which can include residential, commercial, and industrial assets. This aggregation allows for the collective management of these resources as a single entity.
Optimization: Advanced algorithms optimize the operation of these aggregated resources to maximize efficiency, reduce costs, and enhance reliability. This includes optimizing energy production, storage, and consumption.

Demand Response

Load Management: In response to grid conditions and market signals, the Enterprise DERMS can adjust and manage load. This helps balance supply and demand, especially during peak periods or when renewable generation is low.
Dynamic Pricing: Enterprise DERMS can respond to dynamic pricing signals from the grid, enabling participants to shift or reduce their energy usage during times of high prices.

Grid Services

Frequency Regulation: Enterprise DERMS provides frequency regulation services by quickly adjusting the output of DERs to maintain grid stability.
Voltage Support: By managing reactive power, Enterprise DERMS can help maintain voltage levels within the desired range, ensuring the efficient operation of the grid.
Reserve Capacity: Enterprise DERMS offers reserve capacity to the grid, acting as a backup during unexpected outages or demand spikes.

Integration of Renewable Energy

Enhanced Integration: Enterprise DERMS facilitates the integration of renewable energy sources by smoothing out their intermittent and variable nature through aggregation and storage solutions.
Curtailment Reduction: By effectively managing and dispatching renewable energy, Enterprise DERMS reduces the need for curtailment, ensuring more non-emitting energy is utilized.

Enhanced Reliability and Resilience

Backup Power: In the event of grid outages, Enterprise DERMS provides backup power to critical loads, enhancing the resilience of the energy supply.
Island Mode Operation: Enterprise DERMS can operate in island mode, allowing a segment of the grid to function independently during widespread outages or disturbances.

Scalability and Flexibility

Scalable Architecture: Enterprise DERMS can scale from small residential installations to large commercial and industrial setups, making them highly adaptable to different environments.
Flexible Operation: Enterprise DERMS quickly adapts to changing grid conditions and market demands, providing a flexible solution for modern grid challenges.

Advanced Monitoring and Control

Real-time Monitoring: Enterprise DERMS employs advanced monitoring systems to track the performance of aggregated DERs in real-time.
Predictive Analytics: Utilizing predictive analytics, Enterprise DERMS forecast energy production, demand, and market conditions to optimize operations.

PGE's DERMS delivers the following benefits to the VPP and customers:

Environmental Benefits

Emission Reduction: By enhancing the use of renewable energy and optimizing energy efficiency, the VPP, via the Enterprise DERMS, contributes to the reduction of greenhouse gas emissions.
Resource Efficiency: Through the Enterprise DERMS, the VPP improves resource efficiency by reducing wastage and maximizing the use of available energy resources.

Economic Benefits

Revenue Streams: Participants in a VPP, enabled by an Enterprise DERMS, can earn revenue by providing grid services, participating in energy markets, and through demand response programs.
Cost Savings: By optimizing energy use and participating in demand response, customers can reduce their electricity bills.

What is PGE is doing to implement DERMS

PGE is currently deploying a foundational Enterprise DERMS and DER System of Record (DER-SOR). This foundational Release 1 includes delivery of the following capabilities in 2025:

- leveraging DER information to register, visualize, group, and,
- adhere to ADMS constraints, which refer to limitations or restrictions on the distribution grid's capacity to accommodate or manage energy flows from DERs. These constraints can occur for various reasons including:
    - voltage regulation to ensure voltage stays within acceptable limits,
    - or congestion management to prevent feeding too much energy from multiple DERs feeding too much energy into the grid in the same area,
- intake DER information from customer programs for visibility,
- build system of record for all DERs

In summary, the VPP, represents a significant advancement in the way PGE manages and utilizes distributed energy resources, orchestrated through the Enterprise and edge DERMS. It offers a range of capabilities (Aggregation & Optimization, Demand Response, Grid Services, Monitoring and Control, Schedule, and Dispatch of DERs), that enhance grid reliability, integrate renewable energy, provide economic benefits, and contribute to environmental sustainability.

F.3.6 Outage Management System

PGE is upgrading its Outage Management system during the current year to bolster its ability to respond to storms and reduce outage events. It is also upgrading its software to reduce the risk of technology obsolescence.

Looking to the future, PGE is exploring an Integrated Outage Management System that would combine functionalities with existing operational systems such as ADMS. This provides a more unified approach to managing outages, offering improved operational efficiency, faster restoration times, and better decision-making capabilities.

Table 49 describes the key capabilities PGE is exploring as part of delivering an Integrated Outage Management System.

Table 49. Integrated outage management system capabilities

Capabilities	Description of capabilities and needs statement
Crew Dispatch	**Description:** Enables operator / dispatcher to dispatch crews comprising right set of skilled resources, monitor crews' workload and progress, and assign crews to jobs. **Needs Statement:** Integrated outage system and summary dashboards/ screens to view, manage, monitor, and dispatch crews for outages and restoration efforts.
Outage Forecast	**Description:** Use historical customer call data, external event information available from system data sources including SCADA, AMI, IVR, etc., and weather patterns, and grid conditions to predict potential outages and their impacts. **Needs Statement:** Require an outage forecast capability to anticipate outages enabling optimized resource deployment. This may lead to reduced downtime, enhancing customer service.
Unplanned Outage Management	**Description:** Enables the efficient logging, tracking, and analysis of customer-reported outages or issues, linking calls to real-time grid data for quicker diagnosis and response. Integrates with outage prediction to analyze and locate device failure or outage zone. **Needs Assessment:** Require an integrated outage capability to streamline customer issue reporting, enhance outage detection, and enable more efficient resolution.
Planned Outage Management	**Description:** Planning, communications, and performance of planned outages for construction, wildfire mitigation, and proactive grid management (e.g., replacing obsolete infrastructure). Management of power outage requests including advanced customer notifications, work permits, generation of switching plans from appropriate operational system (e.g., ADMS, OMS, etc.), field crew status updates, work order completion. **Needs Statement:** Integrated outage system to orchestrate planned outages to coordinate across PGE, minimize downtime, minimize customer impact, and facilitate an effective response/ restoration.
Outage Analytics & Reporting	**Description:** Provides detailed analysis and user-defined reporting on outage events, including causes, response times on outage events, device operations, call codes, etc. Automatic calculation and reporting of key performance indices including SAIDI, CAIDI, SAIFI, MAIFI, CMI, etc. enabling data-driven decision-making and performance improvement. **Needs Statement:** Integrated outage analytics and reporting capability across OMS, ADMS, Enterprise DERMS, etc. to better understand outage patterns, optimize restoration processes, and enhance regulatory compliance and customer transparency.

Capabilities	Description of capabilities and needs statement
Outage Simulation	**Description:** Enables modeling and simulation of various outage scenarios, enabling real-time analysis of potential grid disruptions, restoration strategies, and resource allocation. **Needs Statement:** PGE requires an outage simulation tool to proactively assess, plan, and train for outages, improving response times, resource coordination, and customer communication during actual grid disruptions.
Outage Map	**Description:** Provides a unified visual representation of outages across the grid, showing real-time information on grid performance, outage locations, affected DERs, and restoration progress. Enhances situational awareness and decision-making during grid events. **Needs Statement:** Need an integrated OMS outage map across ADMS, Enterprise DERMS, etc. to improve real-time monitoring of grid conditions, optimize outage response, and ensure coordinated management of DERs, improving service restoration and customer communication.
Call/ Outage Grouping	**Description:** Refers to the process of organizing and consolidating outage reports from customers into clusters or groups representing a potential outage event. This capability helps to efficiently manage and respond to outages by identifying patterns in customer-reported issues and associate them with outage locations on the grid. **Needs Statement:** Require a call/ outage grouping capability to streamline outage response by efficiently grouping and analyzing customer reports, reducing response and restoration times.
Storm Mode	**Description:** A specialize mode during severe weather events, optimizing outage detection, resource allocation, and restoration strategies by leveraging real-time data. **Needs Statement:** Need integrated OMS to enhance preparedness and response during major weather events, enabling more efficient resource deployment, improved communication with customers, and potentially faster restoration.
Damage Assessment	**Description:** Provides real-time analysis of grid infrastructure damage during outages incorporating information from sensors, DERS, crews, and grid management systems to prioritize repairs and restoration. **Needs Assessment:** Require an integrated outage damage assessment capability to assess infrastructure damage, prioritize repair efforts, and streamline restoration efforts, minimizing customer impact.

Crew Dispatch, Outage Forecast, Planned and Unplanned Outage Management, Outage Analytics & Reporting, Outage Simulation, Outage Map, Call/Outage Grouping, Storm Mode, and Damage Assessment are critical for providing enhanced data and tools for improved situational awareness and decision-making, optimizing resource allocation, ensuring effective coordination, minimizing customer downtime, and improving customer transparency.

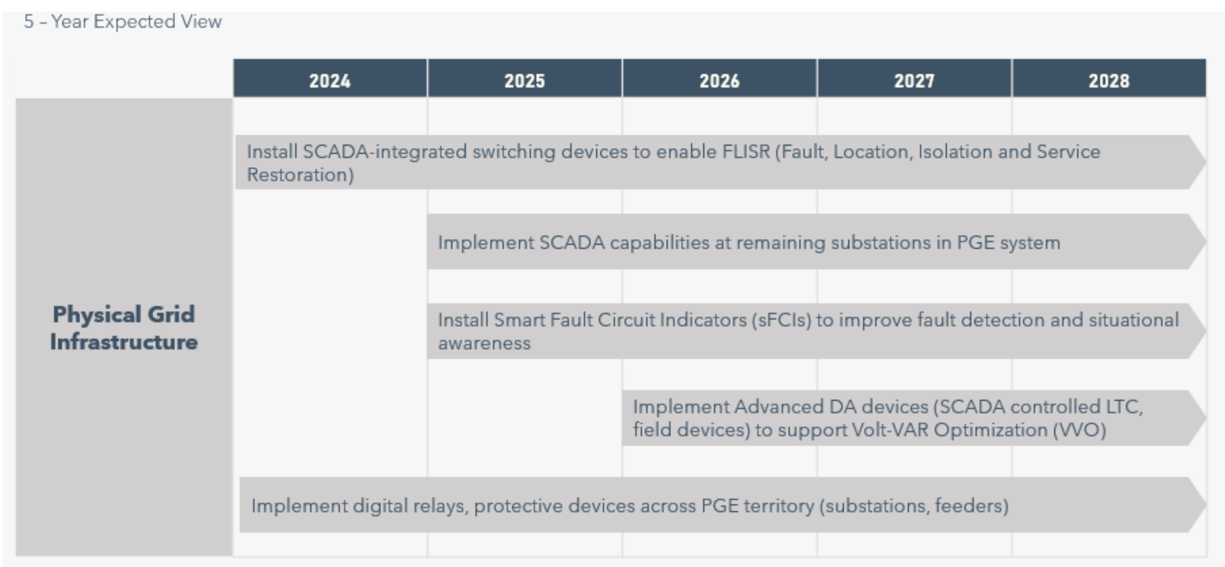
F.4 Physical grid infrastructure

Modernizing substations with SCADA, advanced protection, and updating physical grid infrastructure with technologies like Fault, Location, Isolation, and Service Restoration (FLISR), Volt-VAR Optimization (VVO), and smart fault circuit indicators (sFCIs) offers clear benefits to customers:

- **Fewer and shorter power outages**: FLISR, reclosers, and digital relays help quickly detect and isolate faults, automatically rerouting power. For example, if a power line is damaged during a storm, these technologies ensure that only the immediate area is impacted, restoring power to customers outside the impacted zone in minutes rather than hours.
- **Preventive maintenance and reduced downtime**: Upgraded systems provide real-time data, via SCADA, and condition-based monitoring with smart fault circuit indicators (sFCIs), enabling PGE to perform preventive maintenance on equipment before it fails. This leads to fewer unexpected outages and better overall reliability for customers.
- **More reliable power supply**: Digital relays and advanced protection devices continuously monitor grid conditions and protect critical equipment, reducing the likelihood of major outages or damage. They can respond instantly to abnormal grid conditions, preventing small issues from escalating into larger outages.

Our planned Physical Grid Infrastructure investments are illustrated in **Figure 45**.

Figure 45. Physical grid infrastructure planned investments



F.4.1 Key Distribution Automation (DA) solutions

Our physical grid infrastructure is dependent upon the continued deployment of our distribution automation solutions:

FLISR: Uses SCADA-integrated switching devices to detect and isolate faults, reducing outage duration. PGE plans to install ~83 devices annually from 2021-2024 and upgrade 15 substations each year for ADMS integration. Approximately 300 feeders could be FLISR-enabled, which is about 50 percent of feeders on the system. Future implementations will be based on cost-effectiveness evaluations.

VVO: Requires several key devices and systems to monitor and control voltage and reactive power on the grid. These devices work together to ensure efficient power delivery, reduce energy losses, and improve power quality. PGE is exploring a number of these advanced DA devices for implementation starting in 2026, coupled with the implementation of our advanced ADMS and AMI capabilities. These include voltage sensors to monitor grid conditions in real-time, SCADA-controlled Load Tap Changers (LTCs) to adjust voltage at transformers, capacitor banks to manage reactive power to control voltage, and Volt-VAR controllers to execute control commands. Following PGEs Grid Mod Solution Identification Framework (**Figure 16**), these solutions will be conceptualized, demonstrated in the Smart Grid Test Lab or field, piloted, and scaled based on learnings, outcomes, and budget.

sFCI: Communicating smart fault circuit indicators (sFCIs) enhance fault detection and situational awareness, reducing the need for manual inspections. In 2021, PGE conducted a field demonstration by installing smart fault circuit indicators (sFCIs) on feeders in high wildfire risk areas. These current-sensing devices trip when a programmable, predetermined amount of current threshold is exceeded. Equipped with Bluetooth, the sFCIs allow wireless notifications and updates. These sensors enable faster identification of fault locations, resulting in shorter outage durations and an improved customer experience. Pilots and full-scale deployments are planned through 2028, based on learnings, outcomes, and budget.

Distribution automation solutions lead to fewer and shorter power outages, improved power quality, and potentially, lower energy costs due to more efficient grid operations (e.g., reduction in need for manual inspections).

F.4.2 Substation automation and SCADA systems

PGE aims to enhance monitoring and operations by increasing SCADA capabilities at substations. Currently, about a fifth of our substations lack remote monitoring, leading to potential reliability issues and slower emergency responses, as personnel must be dispatched onsite. Grid optimization requires continuous measurement and control, achievable through VVO capabilities, which reduce system losses and energy consumption. Modern substation automation systems with integrated intelligent devices and protocols like DNP3 enable better asset management, efficient operations, and improved reliability.

Ensuring all connected devices are securely managed and exploring advanced protection methods like IEC61850[103] are also priorities for PGE.

F.4.3 Modernize cost-effective communication-aided protection systems

To improve system reliability, PGE is modernizing protection systems with digital relays that support remote setting modifications, locally adaptive protection, and detailed data integration with SCADA platforms. Many substations lack the protective devices needed for easy integration of distributed generation. Upgraded protection capabilities will support remote adjustments to accommodate these increasing levels.

PGE's substation automation approach balances grid needs and budget, making ongoing investments as needed, often alongside substation rebuilds and feeder upgrades. Cybersecurity is integrated into all new and rebuilt substations, with data linked to the Reliability and Performance Monitoring Center.

Planned investments include:

- Adding SCADA automation to all remaining substations to expand real-time control and monitoring, based on priority and budget
- Replacing legacy SCADA with modern, flexible platforms like DNP for better communication and integration with advanced systems, as needed
- Prioritizing the replacement of electro-mechanical relays with the latest generation of relays and reclosers, which are faster and more precise, in wildfire zones from 2021 to 2025
- Implementing an 18-year replacement cycle for microprocessor-based relays post-2025 to enhance functionality and reduce failures

Overall, these investments will help create a more resilient grid, better equipped for future demands.

F.5 Sensing, measurement & automation

As PGE moves towards a more predictive grid, PGE is adding advanced computing capabilities at key locations, enabling real-time management of the grid. By doing so, PGE can make decisions at the edge of the grid—closer to where power is used and generated—leading to more reliable and resilient power delivery.

One of the key benefits of this technology is that it gives PGE better visibility into Distributed Energy Resources (DERs), such as solar panels or battery energy storage systems. This visibility allows PGE to optimize how these resources are used, ensuring they contribute

[103] 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.

effectively to the grid. Moreover, PGE is making it easier for customers to connect their DER equipment, supporting broader and more equitable access to clean energy.

Edge computing plays a crucial role in this transformation. As the grid becomes more complex due to factors like severe weather, climate change, customer adoption of smart technology such as smart metering capabilities, home energy management systems, the increased use of DERS, with many customers beginning to generate their own power, the more advanced technology is needed to maintain grid stability. Customer energy patterns are changing. With smart meters and time-of-use programs, customers are shifting more of their energy consumption to off-peak times when electricity is less expensive, reducing strain on the grid during peak demand periods. Customers with distributed energy resources (DERS), such as solar panels, are no longer just energy consumers, but also producers. They can now generate electricity, altering their role in the energy ecosystem.

Edge computing enables near-real-time operations, going beyond traditional metering capabilities so that the grid remains resilient and reliable. This is especially important as PGE strives to meet our 2030 and 2040 decarbonization targets.

With edge-enabled smart devices, customers have more control over their energy use and can monitor and manage their energy consumption in real-time, leading to cost savings. With localized edge computing that doesn't send data back to a central system control center for every operational decision, customers will benefit from increased efficiency and faster response time.

Figure 46. PGE's vision of the grid

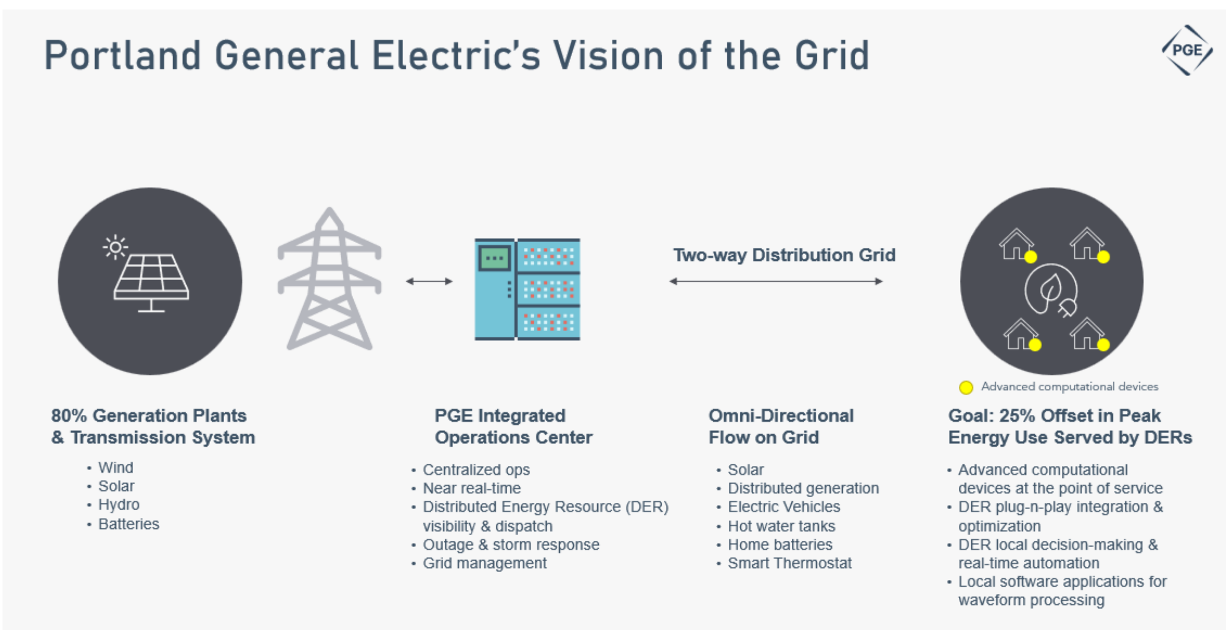
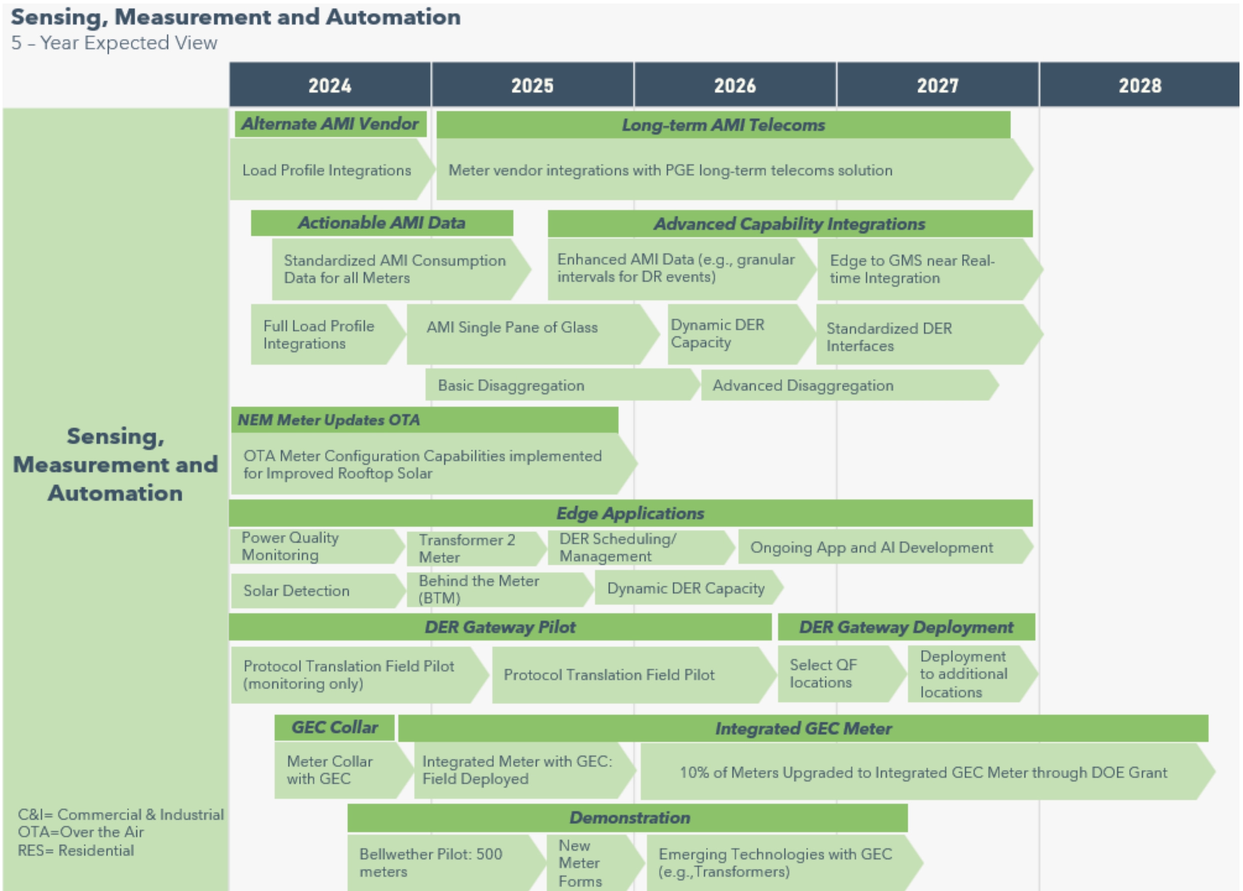


Figure 47. Sensing, measurement and automation planned investments



F.5.1 Automated metering infrastructure (AMI) improvements

PGE's AMI technology enables bi-directional communication and control of utility meters at customer service points. PGE's AMI system, operational for over 15 years, collects data from over 950,000 meters, generating 47 million daily messages on usage, generation, reactive power, voltage, and temperature. In 2023, to maintain resiliency in the meter supply chain, PGE contracted with a second vendor adding a supply of meters, providing added flexibility for the future.

Today's AMI benefits include remote billing reads, power disconnection/reconnection, and hourly/sub-hourly usage data for customers.

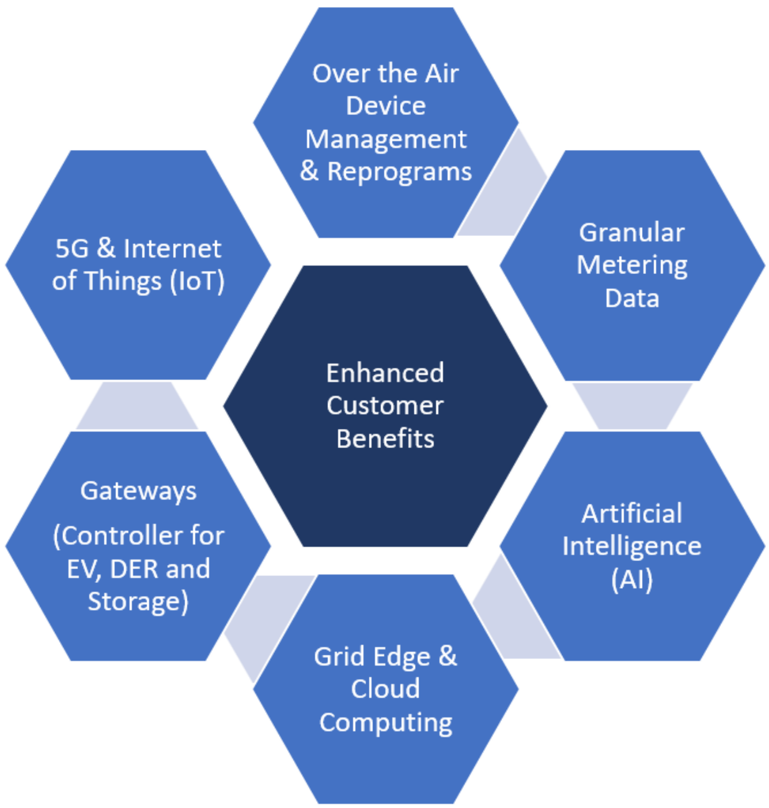
PGE's "Next Gen" strategy will enhance these capabilities and look to build new capabilities to support a dynamic, bi-directional smart grid (**Figure 48**).

F.5.2 AMI Next Gen

Vision: Enhance PGE's customer experience and increase operational savings through real-time data and advanced metering hardware-software systems.

Mission: Strategically update PGE's AMI system to enable new customer benefits, deliver operational efficiencies, and enhance grid readiness for DERs and a clean, resilient electric grid.

Figure 48. AMI Next Gen technologies



F.5.3 AMI Next Gen: Why It Is Important

Essential System: Advanced Metering Infrastructure (AMI) is the foundational system PGE uses today to efficiently collect customer usage data, administer customer billing, determine outages, and understand demand on the distribution system. Over 47 million intervals are collected by PGE's Sensus AMI system every day, or 17+ billion per year.

Aging Meters: With 75 percent of PGE's existing AMI meters projected to be 15+ years old and 65 percent to be 20+ years old by 2030, most meters are nearing their projected end of life requiring replacement. AMI Next Gen brings technology changes in all three major AMI components: the meters, IT head end system (HES), and telecommunications network.

New Capabilities: As a strategic initiative and through innovative technologies, AMI Next Gen will:

1. Enable new benefits for customers through more granular data and grid edge software apps,

2. Deliver operational efficiencies through near-real-time data and automated systems, and

3. Prepare PGE's advanced grid of the future through DER recognition and local decision making.

Strategic Planning & Funding: It is essential for PGE to begin transitioning to AMI Next Gen to adequately prepare for programmatic meter replacements, accelerate delivery of new benefits through new technology deployments to meet customer needs, and to best utilize $50 million in Federal Infrastructure Investment and Jobs Act (IIJA) grant funding PGE received from the Department of Energy (DOE) for grid edge computing and distributed energy resource (DER) integration from 2024-2029.

The next generation of AMI meters (AMI Next Gen) will supply real-time data and edge computing capabilities that are essential to meet PGE's core mission of safe, clean, reliable, affordable, and secure energy delivery.

F.5.4 AMI Next Gen: Strategic priorities

Five key priorities are identified as an AMI Next Gen Strategy:

1. Clean Energy and Decarbonization: Support PGE's decarbonization requirements of HB 2021, including 80 percent reduction of baseline emissions by 2030 and 100 percent reduction by 2040.

2. Accurate and Timely Granular Data: Deliver near-real-time data to support customer and operational decision making, moving PGE in line with and/or beyond peer technology service providers.

3. Mitigating Risks of Aging Infrastructure: Ensure PGE's aging AMI 1.0 meters, initially installed at PGE in 2008, are supported without issue through the upgrade to AMI Next Gen.

4. Customer Benefits: Deliver new customer benefits, supporting PGE's customer 360 initiative helping PGE understand all aspects of a customer and how to best deliver service.

5. Operational Benefits: Deliver new operational benefits to reduce O&M spend and improve reliability and resiliency of the grid.

Figure 49. Summary of AMI at PGE

Advanced Metering Infrastructure (AMI) at PGE

Importance

- PGE's AMI system collects customer usage data and is utilized to administer customer billing, determine outages, and understand demand on the distribution system.
- Over 47 million intervals are collected every day, 17+ billion per year.

Aging Meters

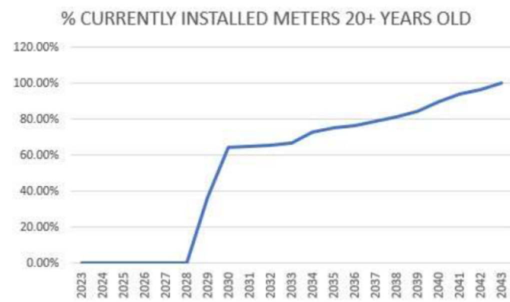
- 75% of meters projected to be 15+ years old by 2030
- 65% of meters projected to be 20+ years old by 2030

New Capabilities from New Tech

- More granular data and grid edge software apps
- Near-real-time data and automated systems
- Advancing grid readiness through DER recognition and local decision making

AMI Strategic Planning & Funding

- Adequately prepare for programmatic meter replacements
- Accelerate delivery of new benefits through new technology deployments
- Best utilize $50 million in DOE grant funding for grid edge computing



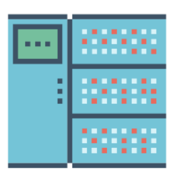
- ✓ 950,000 total meters
- ✓ 130 servers
- ✓ 80 RF base stations

Figure 50. PGE's vision for a 2-way flow

Vision for 2-Way Flow

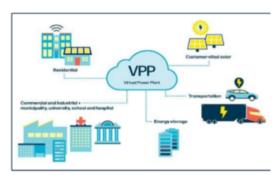
Connected

Near-real-time data connecting PGE with homes, businesses, & critical infrastructure.



Visible

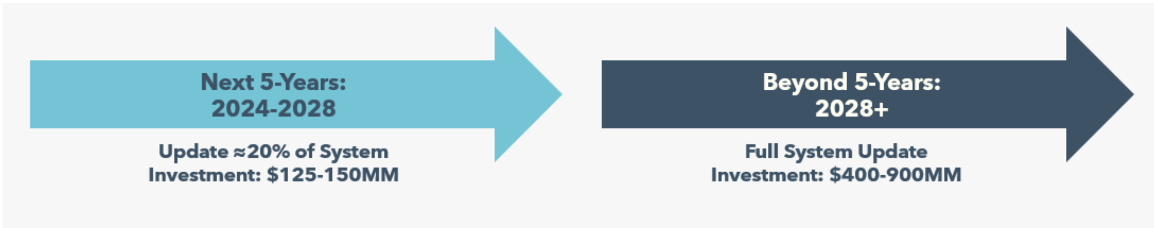
Granular visibility to improve customer power quality, proactive asset management, and grid reliability.



Actionable

Automation, AI, and machine learning optimize distributed energy resources and grid ops.

Figure 51. AMI Next Gen Investment



Key customer benefits

AMI Next Gen will enhance PGE's capabilities to be our customers' long-term, trusted energy advisor. There are many potential customer benefits with AMI Next Gen due to more advanced meter functionality and expected meter communication improvements. **Table 50** gives examples of some of these customer benefits.

Table 50. Potential customer benefits

Benefit Area	Current Capabilities	Anticipated Benefits
Customer Experience - Enhanced Outage Communications	On average, PGE receives 85% of power fail alarms and 95% of the power restore alarms.	Increased outage alarm receival rate and better communications resulting in PGE having a better understanding of outages / restorations.
Customer Experience - Enhanced Outage Accuracy	Voltage data is not used to determine the "Power Quality" status. Same outage alarm stats noted above.	Increased data for Realtime Service Status (AMI Gold Source) resulting in more accurate status and ability for customer to self-serve.
Customer Experience - Proactive Power Quality (PQ) Resolution	Currently AMI voltage data has low accuracy and granularity. Meter Data Analytics Response (MDAR) uses this voltage data to generate PQ leads.	Five-minute voltage data on all meters is more accurate and granular than we collect today. This will result in increased voltage issues being found by MDAR. Additional PQ data from AMI Next Gen meters can also be used to proactively capture and address PQ issues before a customer phone call.
Customer Experience - Easier Program Enrollments	Customers with a poor or non-communicating meter either cannot enroll in programs or require a field visit for a meter exchange.	Increased communication success rates with meters resulting in higher percentage of customers being able to enroll in programs without a field visit to exchange meter (e.g., PTR and TOD).
Customer Experience - New Program Offerings	Current meters do not support communications / control of beyond the meter devices.	With potential to manage beyond the meter devices, innovative programs could be developed. Examples:

Benefit Area	Current Capabilities	Anticipated Benefits
		Letting PGE control when EV is being charged to off-peak times, island customers with batteries as needed, etc.
Customer Experience – Self Service Granular Data	Most Commercial / Industrial customers have 15-minute consumption data and Residential have 60-minute.	Commercial / Industrial customers with 5-minute consumption data and Residential with 15-minute, allowing those customers that want to look at and track their usage at a more granular level.
Customer Experience – Self Service	Two-day lag in interval data being available in Energy Tracker due to data validation and system constraints.	Potential real-time, or near real-time, presentment of data to customers.
Customer Experience – Self Service Near-Real-Time Data	Voltage data is not available to customers.	5-minute voltage interval data could be beneficial for facility managers or engineers, particularly larger Commercial / Industrial customers like wafer or solar manufacturers.
Customer Experience – Self Service PQ Data	A meter exchange is required any time there is a need to change what the meter measures. This includes things like new solar (NEM) customers and adding kW or kVAR for Commercial / Industrial customers.	Between more meter capabilities, in addition to near term work like allowing meter programming over the air (OTA), there will be less need for field personnel to visit customer sites, as well as less need for meter exchanges and the temporary power outage (for single phase customers) for customers due to the exchange.
Customer Experience – Efficient Enrollments and Reduced Interruptions	Customers with a poor or non-communicating meter either cannot enroll in programs or require a field visit for a meter exchange.	Increased communication success rates with meters resulting in higher percentage of customers being able to enroll in programs without a field visit to exchange meter (e.g., PTR and TOD).

Key operational benefits

Table 51 gives examples of some of anticipated operational benefits.

Table 51. Potential operational benefits

Benefit Area	Current Capabilities	Anticipated Benefits
Outage Response – Enhanced Accuracy	On average, PGE receives 85% of power fail alarms and	Increased outage alarm receival rate and better communications resulting

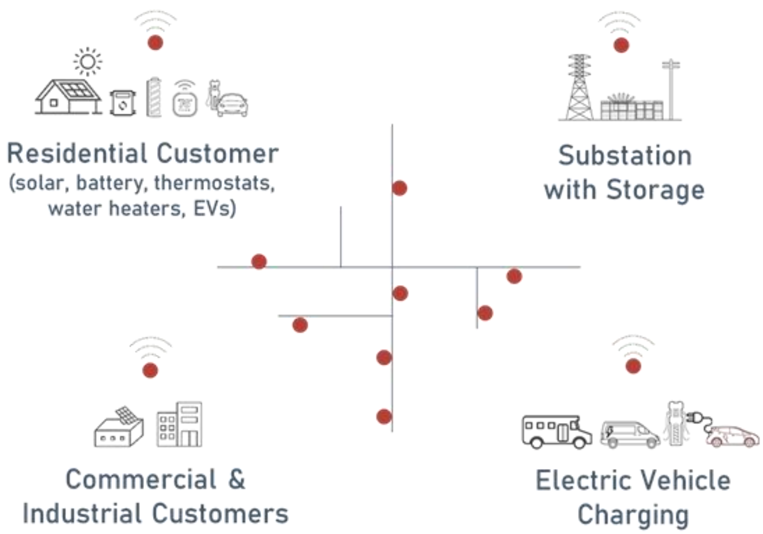
Benefit Area	Current Capabilities	Anticipated Benefits
	95% of the power restore alarms.	in PGE having a better understanding of outages / restorations. Could result in better outage roll ups as well as finding nested outages during restoration work.
Outage Response – Enhanced Real-Time Customer Service	Voltage data is not used to determine the "Power Quality" status. Same outage alarm statistics noted above.	Increased data for AMI Gold Source resulting in more accurate status and ability for Customer Service Agents (CSAs) to help customers.
Proactive Power Quality (PQ) Resolution	Currently AMI voltage data has low accuracy and granularity. Meter Data Analytics Response (MDAR) uses this voltage data to generate PQ leads.	5-minute voltage data on all meters is more accurate and granular than we collect today. This will result in increased voltage issues being found by MDAR. Additional PQ data from AMI Next Gen meters can also be used to proactively catch and address PQ issues.
Efficient Customer Program Enrollments	Customers with a poor or non-communicating meter either cannot enroll in programs or require a field visit for a meter exchange.	Increased communication success rates with meters resulting in higher percentage of customers being able to enroll in programs without a field visit to exchange meter (e.g., PTR and TOD).
Enhanced Distribution Network Modeling	Due to current limitations in accuracy and granularity of voltage data, we have to "ping" a meter for voltage data. Network bandwidth constraints limit to only pinging one feeder at a time.	Receiving 5-minute voltage data from all meters allows for better meter to transformer mapping, resulting in a better connectivity model and forecasting.
Grid Management – Beyond the Meter	Current meters do not support communications / control of beyond the meter devices.	With potential to manage beyond the meter devices, and integrations with ADMS / DERMS, innovative programs could be developed. Examples: Letting PGE control when EV is being charged to off-peak times, island customers with batteries as needed, etc.
Grid Management – Edge Automation	Current meters do not support any grid edge management.	Medium and High Processing Grid Edge meters have the potential for autonomous grid edge management through advanced software algorithms.

Benefit Area	Current Capabilities	Anticipated Benefits
Grid Management – DER Management	Current meters do not support disconnecting generation only. A two meter "solution" was evaluated and is the only way to supply power to the customer but disconnect their excess generation from coming back to PGE.	New form 43S meter and/or advanced software algorithm potentially allows for a single meter solution to PV constrained feeder situation. This would allow PGE to remotely disconnect the excess generation coming back to PGE, while not affecting power delivery from PGE to the customer.
Grid Visibility – Disaggregation	DSM team has created EV load disaggregation based on interval data brought back to PGE. This requires all data being brought back to PGE, then sent over to Snowflake, and process the data in the cloud.	Load disaggregation at the edge has the potential to be more accurate than if data was brought back to PGE and then disaggregated. Load disaggregation allows PGE to better support customer data needs, grid planning, and programs.
Reduced Truck Rolls - Commercial Severance Process	Current meters do not support remote disconnect on Commercial class meters.	Class 320 amp remote connect meters allow for Commercial Severance (credit) process improvements by potentially allowing for remote disconnect / reconnects and no longer needed to roll a truck.
Reduced Truck Rolls – OTA Programming	A meter exchange is required any time there is a need to change what the meter measures. This includes things like new solar (NEM) customers and adding kW or kVAR for Commercial / Industrial customers.	Between more meter capabilities, in addition to near term work like allowing meter programming over the air (OTA), there will be less need for field personnel to visit customer sites, as well as less need for meter exchanges.

F.5.5 Grid edge computing and next gen AMI

Grid Edge Computing (GEC) is a combination of advanced computing power and software applications deployed on devices at the grid edge, accelerating PGE's grid transformation. Edge computing is anticipated to enable real-time edge decision-making, DER visibility and optimization, and plug-and-play DER capabilities. Additionally, GEC solutions will complement PGE's Next Gen AMI and Enterprise DERMS platforms. Advanced computational devices with on-chip processing deployed at key locations will enable visibility, automation, and distributed energy resource (DER) optimization.

Figure 52. PGE's Vision of the Grid – Grid Edge computing deployed at key locations



Chip embedded in meters, collars, gateways, and other distribution grid devices. Provides advanced computational capabilities (on-chip processing) deployed at key locations and at the point of service.

The U.S. DOE selected Portland General Electric (PGE) for a $50 million matching funds grant to deploy GEC at approximately 90,000 locations. The project will use near real-time information from edge computing devices to improve visibility of the electrical system, provide operational insights and improve outage response, and ultimately help to anticipate and mitigate the impacts of extreme weather on grid resiliency.

Anticipated benefits include:

- Local decision-making – grid adjustments, like demand response, can potentially be made autonomously at the edge
- Better integration of DERs – seek to manage and optimize DERs such as EVs and storage at the grid edge
- Real-time monitoring and control – detect and respond to grid issues, such as dynamic DER capacity constraints or issues with power quality
- Improved reliability and resilience – Edge systems ensure critical functions are maintained even during network disruptions or cyberattacks. Customers benefit from fewer outages and more consistent energy delivery.

$50 million DOE Grant: Accelerating and Deploying Grid Edge Computing (GEC)

To support PGE's goal of sourcing 25% of its peak load from its distribution system and reducing greenhouse gas emissions by 80% by 2030, PGE will install a scalable, distributed artificial intelligence (AI) platform to accelerate grid edge computing capabilities and enhance distributed energy resource (DER) integration. PGE will deploy approximately 90,000 grid edge computing (GEC) devices by 2029, across approximately 10% of its customer base, as the first step towards deploying advanced grid edge computing throughout its territory. This deployment will allow PGE to target key locations within its service territory to demonstrate the value of edge computing prior to a full system deployment. The project will focus approximately 40% of the GECs in disadvantaged communities (DACs) to support greater resiliency and clean energy parity within DACs.

Through edge computing and advanced algorithms that collect and analyze high volumes of grid-edge data, and make decisions, this project will demonstrate how GEC can help accelerate the transformation of PGE's distribution system and help it meet clean energy targets. Advancements from this project that will accelerate grid transformation will be demonstrated through five technical use cases:

1. Real-time grid visibility
2. Dynamic (near-real-time) DER local capacity insights
3. DER integration and optimization
4. Validating DER performance
5. Enhanced Grid Resiliency

F.6 Telecommunications

PGE plans to deploy distribution automation devices and sensors to support DER adoption, requiring a robust telecommunication network for reliable grid monitoring and response. The network's success depends on speed, bandwidth, latency, service levels, security, availability, and cost. Currently, connectivity options include Verizon data SIMs and PGE's Field Area Network (FAN), with other cellular options under evaluation.

Short-Term Goals:

- Integrate multiple cellular operators to leverage competitive pricing and improve network performance troubleshooting.
- Establish processes to manage cellular network issues and service requests effectively.

Medium-Term Goals:

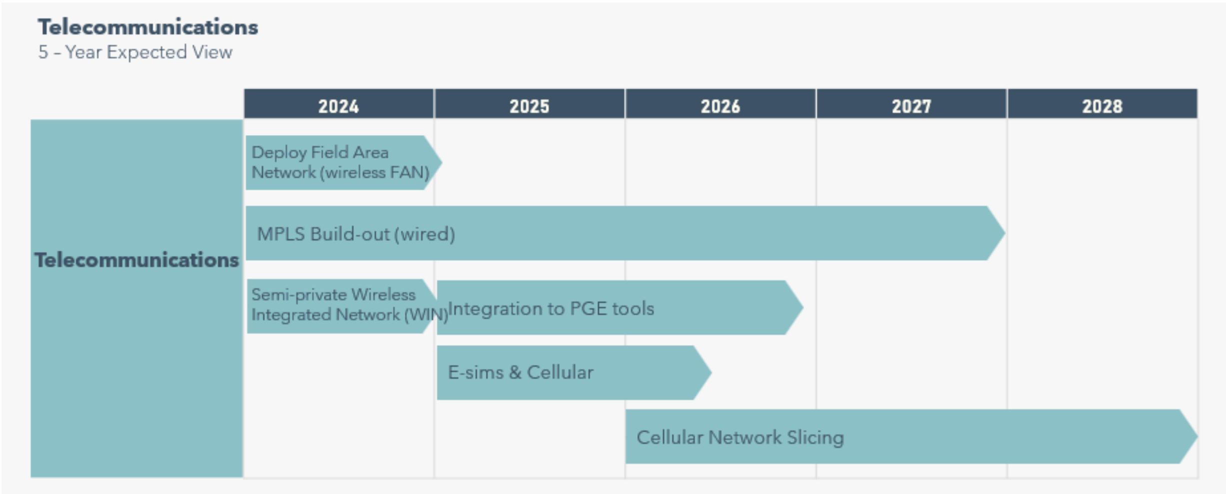
- Deploy a PGE wireless integrated network and establish a support platform.
- Define technologies and organizational structure for network management.

Long-Term Goals:

- Develop a PGE wireless network with hybrid 5G, satellite, private LTE, IoT, commercial cellular, and FAN connectivity.
- Integrate diverse technologies into a unified platform with seamless switching capabilities to deliver network resilience and low latency.

The strategy aims to move away from the current ad hoc telecommunications choice to a handful of reliable, secure, and cost-effective telecommunication networks to support PGE's grid modernization efforts supporting the vast number of devices on the horizon.

Figure 53. Telecommunication planned investments



F.6.1 Field area network (FAN)

PGE's Field Area Network (FAN) is a company-owned wireless network providing reliable grid communications across its service territory using 1MHz of PGE-owned spectrum at kilobits per seconds (kbps) speeds. FAN primarily supports DA reclosers but can extend to other devices, offering greater reliability, longevity, security, and lower costs compared to cellular service. Currently, 43 sites of an initial 91 site design are constructed. 36 of the 43 are on-air. Others are waiting for back-haul connecting from the MPLS.

A scheme of 14 automated FLISR reclosers will be connected to the FAN later this year. Next year 86 remaining devices need to be built and cutover to the FAN and a decision to be made on how much additional investment will be made into the FAN.

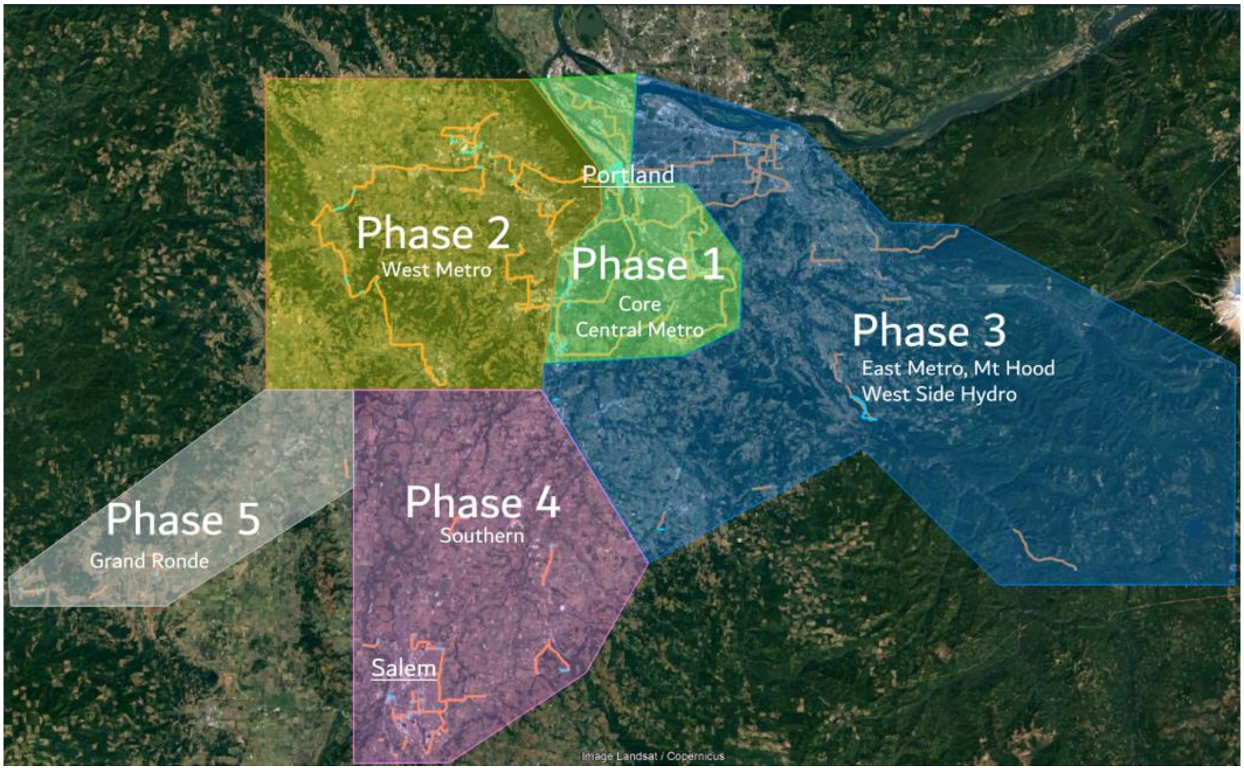
F.6.2 Multiprotocol Label Switching (MPLS)

MPLS is like a super-efficient GPS for the internet, helping data (like emails and streaming videos) find the best, fastest way to travel across a network. Instead of taking the slow route, it finds the quickest path.

Due to limited bandwidth and reduced reliability compared to modern systems with dynamic routing, PGE began modernizing its fiber and telecommunications network for over 200 sites several years ago. This work will continue through 2027.

The project has historically been described in Phases; however, PGE is updating the terminology to reflect the geographic areas of construction. Each phase has 1-4 rings composed of approximately 14 sites that are constructed and cutover together. Phase 5 addresses the southwest portion of our service territory as well as all our outlying generation sites.

Figure 54. MPLS phase map



MPLS Phase 1 has been fully constructed and Phase 2 construction is underway.

Benefits of MPLS

- Keeps systems separate and safe: MPLS enables PGE to keep important systems (e.g., EMS, ADMS) separate from other systems (e.g., email).
- Prioritizes important data: PGE can make sure important data, like signals to fix problems on the power grid, get through first. This is similar to letting first responders through a long line of cars in an emergency.

MPLS provides a robust, scalable, and secure solution for managing critical infrastructure, enhancing operational efficiency, and supporting grid modernization efforts. For customers, the primary benefits include enhanced service reliability and greater integration of renewable energy.

F.6.3 Semi-Private Wireless Integrated Network

After the successful performance in a development environment (sandbox), we are setting up this solution up in a more rigorous Production environment, technically speaking adding redundancy and automating and defining IT architecture which includes firewalls, rollbacks. On the non-technical front, as this is a complex system, it requires cross-functional expertise and processes for post go-live ongoing operational support (e.g., the vendor, field technician, comms engineers, IT AWS engineers, NOC etc.) the document the roles and responsibilities for smooth operations.

F.6.4 Integration to PGE tools

Going into 2024, we anticipate the bulk of the effort would be to have more integrations to PGE's tools and systems, specifically to automate alarms, service issues and billing.

F.6.5 E-Sims & Cellular

E-SIMs are a necessary feature in the future to allow us to switch between cellular operators with a field visit and or an equipment upgrade. Practically this means that we can move to the most competitive service with little effort. However, deployment of e-SIMs requires a platform and all the associated efforts in deployment.

F.6.6 Cellular Network SlicinG

This is a new feature that operators have approached us. They will guarantee an amount of their spectrum, within our service territory, that would be exclusively used for PGE devices and traffic. Immediately this means that during times of network "stress" (outages, storms) our traffic is on a different priority to the general population (our own personal FirstNet). It looks like some form of this service will be available for us to test in 2026.

In summary, PGE is strategically advancing its telecommunications infrastructure to support the growing adoption of DERs and grid modernization. By leveraging a combination of FAN, cellular integration, and MPLS modernization, PGE aims to enhance grid reliability, security, and efficiency. With plans to integrate connectivity options, including hybrid 5G and private LTE, PGE is building a resilient, scalable network capable of supporting the increasing demand from automated devices and sensors. Future initiatives such as e-SIM deployment and cellular network slicing will further strengthen our ability to respond to grid challenges, ensuring continued innovation and adaptability in the years to come.

F.7 Cybersecurity

U.S. utilities faced a near 70 percent jump in cyberattacks this year over the same period in 2023, from 1,162 on average through August compared to 689, according to data from Check Point Research.[104] Two of PGE's substations were physically attacked in 2022 as "part of a series of attacks on the Pacific Northwest power grid that prompted federal officials to warn that the U.S. power grid needs better security."[105]

In grid modernization, the most advanced cybersecurity capabilities push the boundaries of traditional defenses to maintain resilience against evolving threats. These capabilities apply

[104] Available at:

- https://www.reuters.com/technology/cybersecurity/cyberattacks-us-utilities-surged-70-this-year-says-check-point-2024-09-11/
- https://www.fastcompany.com/91189181/cyberattacks-utilities-surge-70-percent-check-point

[105] Available at: https://www.oregonlive.com/crime/2024/07/tacoma-man-accused-of-sabotaging-two-oregon-electrical-substations-and-stealing-24-guns-from-pawn-shop.html#:~:text=Rosenthal%20pleaded%20not%20guilty%20to,Subscribe%20today%20to%20OregonLive.com

to IT/OT cybersecurity, physical security/ access control, network security, data loss prevention, threat detection and information risk management.

Below are some of the Cyber, Human Risk, Intelligence, and Physical Security capabilities that are being explored over the next five years.

- Capabilities:
    - Zero trust architecture
    - AI/Machine learning for threat detection
    - Real-time anomaly detection for OT networks
    - Converged IT/OT network security with integrated threat intelligence
        - Threat Intelligence software – to automate the aggregation, analysis, and dissemination of threat data. These platforms allow for real-time enrichment of threat data and ensure that intelligence is actionable. As IT and OT systems are integrated, Threat Intelligence software can be used to provide situational awareness across both domains, ensuring the threat intelligence incorporates operational data from SCADA systems, substations, and other critical OT assets.
        - Threat Landscape Monitoring: Continuous monitoring of external and internal threats, including cyberattacks, natural disasters, and geopolitical risks.
    - AI-powered autonomous threat hunting
    - Deception technology
    - AI-Driven and behavior data loss prevention
    - Additional Physical Security protection, access control points at PGE facilities
    - Incident simulations, drills, Regular drills simulate OT-specific cyberattacks (e.g., on SCADA systems) to test the resilience and preparedness of personnel. These exercises help improve both detection and response times while identifying gaps in OT cybersecurity defenses
    - Information risk management
    - Ongoing employee training and awareness through simulated cyberattacks (e.g. phishing tests) to assess preparedness

Appendix G. Forecast results and AdopDER

G.1 Overview of load forecasting

PGE's top-down econometric forecast describes large-scale patterns in electricity use, and is the basis of load forecasting in our Integrated Resource Plan (IRP). The corporate load forecast takes an econometric approach by using regression models to estimate the relationship between historical energy deliveries and customer count data series and outside variables. Indicator variables are also used to improve model fit, including binary monthly variables, indicator variables accounting for the impact of unique factors (like COVID-19 pandemic on energy deliveries), and steps and spikes.[106]

From period to period, weather – specifically ambient temperature – is the largest factor affecting customer electricity demand. PGE uses several weather variables in its energy and peak models, including heating and cooling degree days and wind speed. For each variable, the forecast relies on an input assumption.

For economic variables, PGE relies on local forecasting entities for input assumptions. For weather variables, we focus on estimating a 'normal' weather year, rather than predicting what may occur in any specific given year. Traditionally, historical averages have been used to define the weather input. Most commonly, these were 30-year, 15-year or 10-year historical averages. Historically a linear trend model has been implemented to reflect gradual warming in monthly heating and cooling degree day input variables.[107] A rolling 15-year average is used as an input for peaking event conditions, windspeed, and rainfall, additional analysis of how climate change impacts these events may be considered in the future. Key input data used in PGE's corporate load forecast is described in **Table 52**.

Table 52. Key data sources used in PGE's corporate load forecast

Type	Drivers used	Source
Historical load data	Monthly energy deliveries and customer count	PGE billing data
Historical load data	Monthly PGE system peak demand	PGE net system load data
Economic indicator	Oregon employment and personal income	Oregon Office of Economic Analysis
Economic indicator	Oregon population	PSU's Population Research Center

[106] Step and spike variables account for issues in the historical data. These are often in alignment with billing corrections, or reclassifications.
[107] The OPUC's Docket UE-355. Available at: https://apps.puc.state.or.us/orders/2019ords/19-129.pdf

Type	Drivers used	Source
Historical weather[108]	Monthly heating and cooling degree days, wind speed, and rainfall (for average energy models) Daily heating and cooling degree days, wind speed (for peak demand model)	National Weather Service, NOAA
Normal weather input, trended	Monthly heating and cooling degree days	PGE estimated, based on linear trend
Normal weather input, 15-year average	Monthly wind speed and rainfall (for average energy models) Daily heating and cooling degree days, wind speed (for peak demand model)	National Weather Service, NOAA

Throughout the year, detailed information is collected across a range of potential areas of activity that will lead to locational impacts on the distribution grid. These include planned load additions, circuit reconfigurations, new sources of demand (such as increased use of central air-conditioning, electric vehicles), DER interconnection applications, local development policies and zoning changes, and any planned development or redevelopment activity spurring from local community or business development plans. PGE runs a variety of scenarios that account for all of the various drivers of load changes.

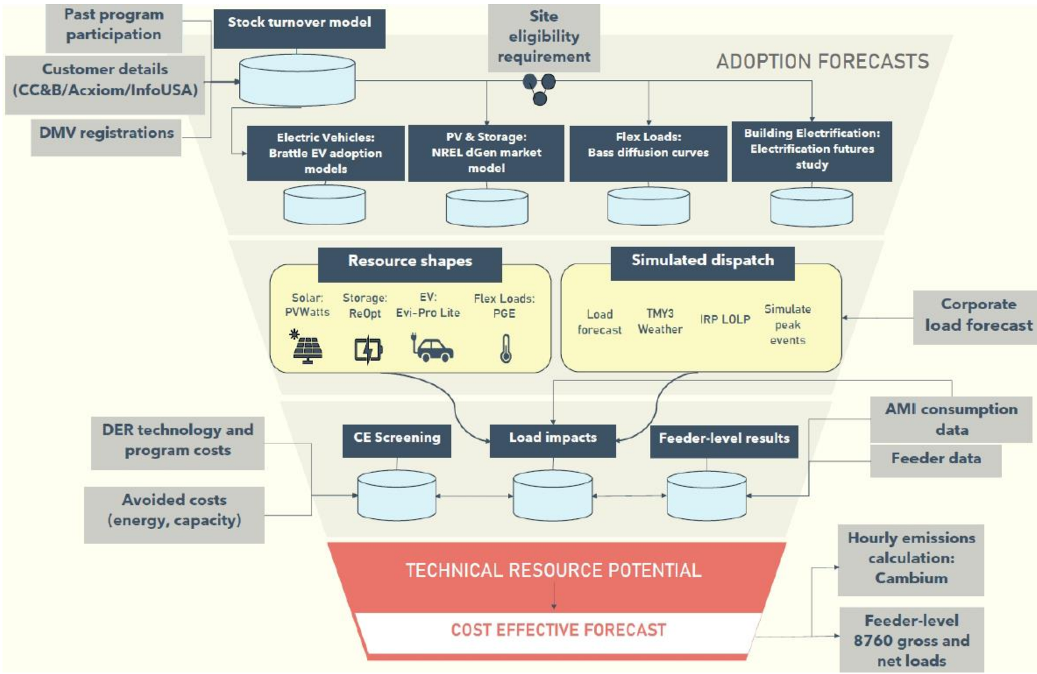
G.2 Overview of AdopDER and integration within planning processes

PGE worked with third-party consultants, Cadeo, Brattle, and Resilient Edge to develop our AdopDER model. The AdopDER model is a comprehensive site-level simulation model that estimates locational, hourly annual load impacts from the co-adoption of 50+ DERs and electrification. AdopDER is built in Python and forecasts DER adoption dynamically, with stochastic influences where appropriate, under different programmatic and market conditions. PGE uses AdopDER for enterprise-wide DER adoption modeling, including forecasting 8760 hourly load impacts at a feeder level, and 8760 hourly baseline (i.e., not associated with DER) loads at a feeder level across its distribution system. The detailed description of AdopDER's methodology is provided in Distribution System Plan Part 2.[109] This forecast is then integrated with the distribution planning process to determine the distribution system impact and evaluate grid needs.

[108] PGE's Corporate Load Forecast uses the Portland International Airport (KPDX) weather station as a proxy for PGE's service area

[109] PGE, "Distribution System Plan Part 2", August 2022. Available at: Distribution System Planning | PGE (portlandgeneral.com). See chapter 3.

Figure 55. High-level approach of AdopDER



AdopDER allows for a hybrid top-down and bottom-up modeling approach as shown in **Figure 55**. PGE simulated market adoption trends using a blend of macro-level forecast and market demand models, and then calibrated these to the granular site-level stock turnover model using available knowledge of customer characteristics. Planning generates bottom-up customer DER additions based on detailed information across a range of potential areas of activities which include new sources of demand (such as increased use of central air-conditioning, electric vehicles), DER interconnection applications, local development policies, and any planned development or redevelopment activity spurring from local community or business development plans. This enables greater granularity of forecast both temporally and locationally which is immensely beneficial in distribution system planning since the impacts can be determined on individual feeders and rolled up to substation transformers. This is critical for more accurately quantifying the potential for DERs located on the distribution grid to provide a range of grid services especially as we develop the capabilities to integrate DERs into a VPP.

G.3 Latest enhancements to AdopDER

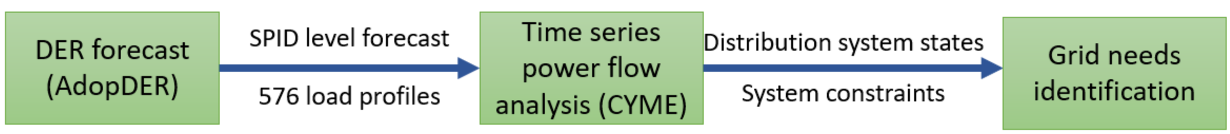
Since the publication of the DSP Part 2 in 2022, further advancements have been made in DER forecasting, including ability to forecast DER growth at the service point ID (SPID), feeder and substation- level. This will provide locational insights and integrating these forecast results into our core distribution system planning functions will enable us to better plan on how to reliably meet future energy and capacity needs.

G.3.1 CYME integration

One of the most important enhancements is tailoring of AdopDER outputs to meet the input requirements of the software used for distribution planning to create a streamlined workflow where DER forecasts can be readily integrated for planning studies as shown in **Figure 56**. PGE's distribution planning team uses CYME software in its system planning studies where it makes recommendations for infrastructure additions or reconfiguration. Planners must continually evaluate customer addition requests as they emerge throughout the year and respond to other operations-focused questions that could impact system reliability. But they also annually forecast for future known growth projects, any allocated top-down corporate load forecast, and the expected increased adoption of DERs. In the present state, PGE's modeling in CYME looks only at a static single-hour powerflow model (either peak or minimum daytime load, depending on the use case) but under our CYME enhancements discussed in our DSP Part II Action Plan, we are moving toward ability to analyze time-series powerflow which is important to better evaluate the distribution system impacts of different DERs under a range of dispatch contexts.

PGE is developing processes for AdopDER's software to export data in a format that can be consumed by PGE's CYME software suite for streamlined use in distribution planning. Figure 56 depicts some of the enhancements to support this integration.

Figure 56. AdopDER and CYME integration for improved planning workflow



AdopDER currently estimates feeder-level load profiles and DER load impacts in line the current CYME requirements for evaluating loads. However, as the CYME enhancement project unlocks ability to ingest site-level AMI data from historical usage, PGE is likewise making improvements to report on DER forecasts at the SPID level. Within the forecast horizon, AdopDER must calculate a SPID-level hourly load profile for each SPID in PGE service territory, and for each DER type modeled (e.g., Solar PV, batteries, EV charging). Ability to generate SPID level forecast will allow the planning team to look at the precise impacts on feeder line and substation transformer capacities. Understanding the locational clustering impacts of different DER combinations and how their intentional operation to provide grid services will be a consistent feature of future planning efforts.

AdopDER's functionality is being extended to be able to isolate the 24-hr profile from particular day-types that are important to distribution planning studies: the feeder's daytime minimum load, used in assessing solar PV hosting capacity, and maximum hourly load (i.e., peak load) within a selected date range, used in planning capacity expansion investments. Having this capability will facilitate studies of different scenarios and evaluate the impact of DER adoption and dispatch along each of these dimensions.

G.3.2 Enhanced spot load addition handling

The second major area for enhancements relate to the process for ingesting discrete load additions (known as "spot load additions") so that AdopDER can account for known, high-probability customer additions on PGE's distribution system in its hourly load and DER forecast. This is in line with one of our corporate goals to plan and enable DERs by further enhancing the forecasting process and tracking the forecast outcomes against the actuals; improved forecasts will enable to predict system capabilities and customer expectations over time. AdopDER currently takes in spot-load additions manually through incorporation of the Load Allocation model that Planning maintains, which consists of known, high-probability developments that PGE's distribution planning team is aware of. The team will enhance its AdopDER software to standardize input sources from PGE systems of record to feed AdopDER with all known large load and DER additions, including those solar projects that are in the PowerClerk application queue.

In order to allow planners to segment which future forecasts they wish to study, we are also changing our forecast tracking mechanism to allow the user to filter on known spot load additions, or the remainder of the load and DER forecast (the "known unknowns") which are more statistical in nature and therefore subject to greater uncertainty. Making these modifications to AdopDER to integrate known spot loads with the known unknowns of future load and DER growth in a way that is easily accessible to planning helps develop a holistic and consistent picture of future system impacts from which to plan needed investments.

G.3.3 Corporate Load Forecast (CLF) calibration

AdopDER's forecasting segmentation and weather inputs will be aligned with those used by PGE's CLF and load research teams. PGE's top-down econometric CLF describes large-scale patterns in electricity use, particularly as related to weather, seasonality and different macroeconomic indicators, and is the basis of load forecasting in our Integrated Resource Plan (IRP). Historically, distribution planning has calibrated top-down load growth to the feeder-level equally, regardless of feeder-level or customer-level nuances in growth trends, etc.

Moving forward, PGE is implementing a more refined calibration process that aligns the bottom-up load and DER forecasts reflective of discrete customer additions, with the annual energy needs encompassed in the CLF. This method will allow for preservation of localized peak load values (i.e., non-coincident peaks) that are more reflective of the distribution planning needs, while still harmonizing the top-down and bottom-up additions captured by AdopDER and the CLF. Having these forecasts in step with PGE's corporate load forecast allows PGE to make investment decisions using hourly load profiles and energy forecasting data that is consistent from a local all the way up to a global perspective.

G.3.4 Capability to introduce multiple future weather years

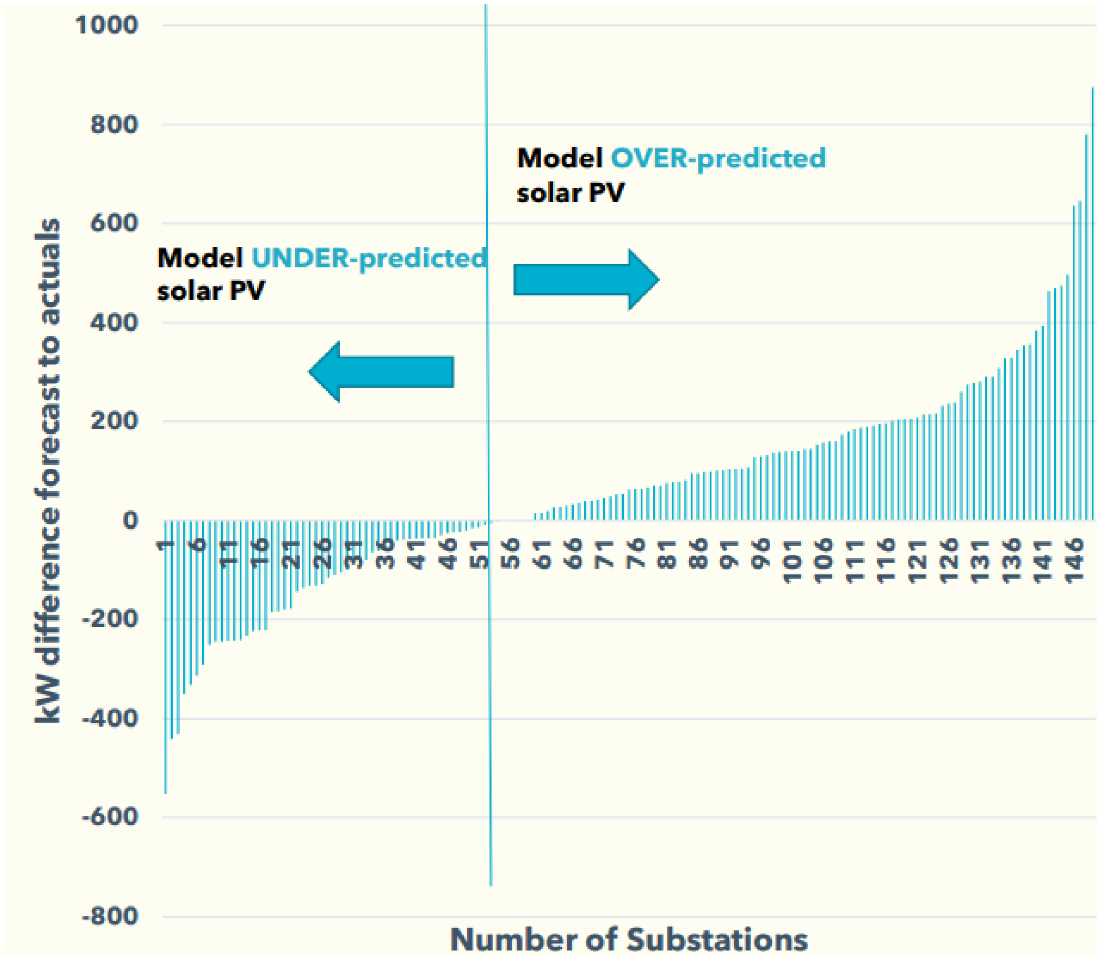
Weather is an important factor in predicting future loads and DER performance. AdopDER integrates weather in two ways currently: 1) as a way to normalize historical AMI meter consumption for purposes of forecasting, and 2) to inform solar resource potential for PV modeling. For historical weather normalization we use the CalTRACK open-source methodology to deconstruct historical observed consumption into heating, cooling, and baseload parameters, and then project modeled consumption patterns into the future using TMY3 weather years. Likewise, AdopDER leverages NREL's PVWatts module for assessing solar production potential and resource shape. PVWatts also makes use of TMY3, although, users have ability to configure different weather data sets into that tool to investigate outputs.

PGE is adding functionality to AdopDER that allows us to incorporate multiple weather forecasts that can reflect a range of uncertainty and potential climate-related impacts that are important to resilient infrastructure planning. For example, PGE is working with EPRI on its ClimateREADi initiative, and we can incorporate new datasets as those become available. Or, distribution planning will be able to run scenarios based on 1-in-5 or all 1-in-20 weather years to understand potential implications of extreme weather events.

G.4 Higher locational resolution and improving forecast accuracy

As the locational granularity of the forecast is increased from system-level to specific geographies (like substation or feeder level) it benefits the distribution planning team by giving more detailed view of the DER adoption and load impacts. It also allows the planning team to study the available capacity of individual lines and transformers within the system. However, this higher locational resolution of forecast comes with a tradeoff of expected accuracy of forecast for individual sites. This is observed for all the different forecasts that are performed by AdopDER. **Figure 57** shows this tradeoff by highlighting the difference in kW on a feeder-by-feeder basis from the forecasted 2023 incremental solar PV additions to actual installs for each substation (n=149).

Figure 57. Distribution of kW deviation between solar PV forecasts and actuals



Overall, 2023 incremental forecasted solar adoption at the system-level was 18 percent lower than actuals, which fell within the low case sensitivity range from our AdopDER outputs. At the locational level, the substation level forecast to actuals difference ranged from -550 kW to +875 kW, with an average of +64 kW over-forecasted per substation. Going forward, PGE is investigating opportunities to further improve the locational disaggregation methods to further increase locational accuracy.

As the locational granularity of the forecast is increased from system-level to specific geographies (like substation or feeder level) it benefits the distribution planning team by giving more detailed view of the DER adoption and load impacts. It also allows the planning team to study the available capacity of individual lines and transformers within the system. However, this higher locational resolution of forecast comes with a tradeoff of expected accuracy of forecast for individual sites. This is observed for all the different forecasts that are performed by AdopDER. **Figure 57** shows this tradeoff by highlighting the difference in kW on a feeder-by-feeder basis from the forecasted 2023 incremental solar PV additions to actual installs for each substation (n=149). This appendix contains detailed substation level DER adoption for the year 2030 for each DER type in the following tables below.

Table 53. 2030 Solar PV adoption by substation (nameplate kW-dc)
Table 54. 2030 Storage adoption by substation (nameplate kW-dc)
Table 55. 2030 LDV EV adoption (vehicle counts) by substation
Table 56. 2030 MDHDV EV adoption (vehicle counts) by substation
Table 57. 2030 demand response peak demand impacts by substation (MW)

Table 53. 2030 Solar PV adoption by substation (nameplate kW-dc)

Substation Name	Low	Reference	High
ABERNETHY	3,417	4,470	5,455
ALDER	6,496	8,691	11,656
AMITY	1,433	1,675	2,134
ARLETA	10,573	13,218	17,924
BANKS	1,764	1,988	2,260
BARNES	7,158	8,584	10,706
BEAVERTON	2,925	3,572	4,642
BELL	7,526	9,180	12,375
BETHANY	9,685	10,797	13,303
BETHEL	5,617	6,081	7,113
BLUE LAKE	1,298	1,487	1,516
BOONES FERRY	4,700	5,848	8,095
BORING	3,935	4,434	5,375
BRIGHTWOOD	764	1,012	1,276
BROOKWOOD	2,352	2,778	3,354
CANBY	3,456	3,876	4,382
CANYON	3,030	4,036	5,425
CARVER	6,172	7,275	9,277
CEDAR HILLS	4,499	5,652	7,406
CENTENNIAL	5,006	6,255	8,546
CLACKAMAS	3,053	3,733	4,379
CLAXTAR	2,128	2,530	3,242
COFFEE CREEK	502	549	825
COLTON	1,013	1,164	1,662

Substation Name	Low	Reference	High
CORNELIUS	3,940	4,459	5,123
CORNELL	3,213	3,892	5,185
CULVER	199	220	283
CURTIS	958	1,200	1,726
DAYTON	4,285	4,745	5,119
DELAWARE	6,173	7,891	10,952
DENNY	4,836	5,854	7,427
DILLEY	491	599	664
DUNNS CORNER	7,193	7,466	7,822
DURHAM	3,271	4,110	4,752
E	5,271	6,389	7,576
EAGLE CREEK	1,517	1,814	2,210
EASTPORT	2,842	3,941	5,115
ELMA	3,541	4,119	5,161
ESTACADA	4,564	5,344	6,490
FAIRMOUNT	3,606	4,317	5,566
FAIRVIEW	3,819	4,359	5,421
FARGO	867	1,017	1,225
GALES CREEK	604	689	847
GARDEN HOME	3,507	4,610	6,064
GLENCOE	3,756	4,685	6,140
GLENCULLEN	2,912	3,782	5,005
GLENDOVEER	5,202	6,412	8,891
GORMLEY	38	50	67
GRAND RONDE	594	636	943
HARBORTON	983	1,332	1,665
HARMONY	6,782	7,853	9,782
HARRISON	2,336	2,916	3,441
HAYDEN ISLAND	1,081	1,394	1,768
HEMLOCK	2,811	3,496	3,883

Substation Name	Low	Reference	High
HILLCREST	482	566	616
HILLSBORO	7,289	8,467	10,274
HOGAN NORTH	5,131	6,374	7,992
HOGAN SOUTH	7,054	8,477	10,915
HOLGATE	6,057	7,946	10,229
HUBER	11,294	13,755	17,868
INDIAN	6,765	7,995	10,045
ISLAND	4,820	5,961	7,253
JENNINGS LODGE	5,851	7,003	9,101
KELLEY POINT	88	129	129
KELLY BUTTE	6,568	8,499	11,028
KING CITY	5,950	6,945	9,044
LELAND	4,480	5,499	6,687
LENTS	3,927	5,037	6,673
LIBERAL	814	887	1,109
LIBERTY	9,185	11,320	15,157
MAIN	5,954	6,983	8,717
MARKET	3,563	4,502	5,759
MARQUAM	415	490	532
MCCLAIN	2,152	2,570	3,329
MCGILL	2,231	2,727	3,195
MERIDIAN	5,327	6,705	8,732
MIDDLE GROVE	6,669	7,951	10,139
MIDWAY	4,099	5,303	7,450
MILL CREEK	2,327	2,503	2,962
MOBILE 6	4,587	5,320	6,530
MOLALLA	9,105	10,034	11,248
MT ANGEL	1,548	1,870	2,157
MT PLEASANT	5,989	6,996	8,720
MULINO	968	1,055	1,455

Substation Name	Low	Reference	High
MULTNOMAH	6,315	8,087	11,326
MURRAYHILL	6,542	7,856	9,901
NEWBERG	8,019	9,325	11,675
NORTH MARION	3,644	4,359	5,236
NORTH PLAINS	3,431	4,077	4,771
NORTHERN	2,528	3,173	4,230
OAK GROVE	73	73	96
OAK HILLS	3,578	4,047	4,611
ORENCO	17	17	17
ORIENT	2,026	2,265	2,777
OSWEGO	3,293	4,179	5,524
OXFORD	3,493	4,320	5,599
PENINSULA PARK	1,679	2,197	2,921
PLEASANT VALLEY	10,291	11,865	14,549
PORTSMOUTH	3,092	3,948	5,092
PROGRESS	2,480	3,111	3,739
RALEIGH HILLS	2,515	3,090	4,298
RAMAPO	3,540	4,577	6,275
REDLAND	3,139	3,704	4,662
REEDVILLE	6,944	8,189	10,166
RIVERGATE SOUTH	646	750	1,046
RIVERVIEW	2,866	3,591	4,807
ROCK CREEK	4,078	4,641	5,641
ROCKWOOD	2,364	2,845	3,577
ROSEMONT	2,759	3,502	4,458
ROSEWAY	2,330	2,832	3,690
RUBY	2,579	3,115	4,097
SALEM	598	753	645
SANDY	5,020	6,016	7,553
SCHOLLS FERRY	8,670	10,817	14,160

Substation Name	Low	Reference	High
SCOGGINS	1,209	1,520	1,689
SCOTTS MILLS	1,650	1,918	2,147
SELLWOOD	4,473	5,437	7,098
SHERIDAN	4,029	4,295	5,006
SILVERTON	5,628	6,216	7,711
SIX CORNERS	6,468	7,405	8,932
SPRINGBROOK	5,164	5,716	6,707
ST HELENS	-	29	-
ST LOUIS	3,571	4,067	4,667
ST MARYS EAST	1,276	1,627	2,009
SULLIVAN	4,720	5,741	7,528
SUMMIT	134	249	261
SUNSET	3,411	3,502	3,624
SWAN ISLAND	1,145	1,170	1,229
SYLVAN	2,499	3,040	4,027
TABOR	4,936	5,876	7,821
TEKTRONIX	4,799	6,056	7,510
TEMP G	20	20	20
TIGARD	4,132	4,845	5,961
TOWN CENTER	2,666	3,589	4,831
TUALATIN	3,982	4,739	5,506
TURNER	2,104	2,323	2,714
TWILIGHT	1,282	1,363	1,674
UNIONVALE	839	1,016	1,115
UNIVERSITY	1,519	1,967	2,527
URBAN	1,773	2,405	3,453
WACONDA	4,546	4,908	5,098
WALLACE	2,057	2,668	3,134
WELCHES	573	821	1,146
WEST PORTLAND	4,573	5,446	7,256

Substation Name	Low	Reference	High
WEST UNION	2,097	2,572	3,132
WILLAMINA	3,980	4,282	4,634
WILSONVILLE	8,468	10,384	13,582
WOODBURN	8,583	9,354	10,120
YAMHILL	6,707	7,122	7,929

Table 54. 2030 Storage adoption by substation (nameplate kW-dc)

Substation Name	Low	Reference	High
ABERNETHY	126	211	426
ALDER	394	809	1419
AMITY	52	82	222
ARLETA	648	1148	2083
BANKS	120	165	280
BARNES	363	528	898
BEAVERTON	190	370	555
BELL	350	720	1320
BETHANY	530	690	1165
BETHEL	130	245	430
BLUE LAKE	65	85	195
BOONES FERRY	308	468	788
BORING	155	235	460
BRIGHTWOOD	30	55	125
BROOKWOOD	80	180	350
CANBY	160	260	395
CANYON	361	541	866
CARVER	318	573	1058
CEDAR HILLS	285	530	915
CENTENNIAL	240	390	915
CLACKAMAS	135	235	405
CLAXTAR	70	165	245

Substation Name	Low	Reference	High
COFFEE CREEK	20	15	105
COLTON	35	45	120
CORNELIUS	175	260	430
CORNELL	180	310	580
CULVER	5	55	55
CURTIS	30	60	150
DAYTON	80	135	230
DELAWARE	531	726	1281
DENNY	140	310	640
DILLEY	5	20	30
DUNNS CORNER	37	77	172
DURHAM	144	329	499
E	200	555	1080
EAGLE CREEK	45	75	240
EASTPORT	155	290	520
ELMA	254	319	494
ESTACADA	160	370	540
FAIRMOUNT	157	267	552
FAIRVIEW	152	257	412
FARGO	75	205	255
GALES CREEK	18	33	58
GARDEN HOME	230	360	605
GLENCOE	230	335	690
GLENCULLEN	242	372	577
GLENDOVEER	290	500	905
GORMLEY	5	10	15
GRAND RONDE	20	40	70
HARBORTON	38	68	143
HARMONY	270	440	760
HARRISON	165	215	350
HAYDEN ISLAND	130	180	220

Substation Name	Low	Reference	High
HEMLOCK	130	290	350
HILLCREST	15	20	45
HILLSBORO	270	420	745
HOGAN NORTH	319	414	719
HOGAN SOUTH	275	420	890
HOLGATE	346	756	1166
HUBER	498	793	1428
INDIAN	293	548	1068
ISLAND	318	468	733
JENNINGS LODGE	323	528	988
KELLEY POINT	5	5	10
KELLY BUTTE	257	412	947
KING CITY	277	437	892
LELAND	261	401	641
LENTS	172	312	557
LIBERAL	37	82	92
LIBERTY	526	821	1311
MAIN	222	362	622
MARKET	240	450	645
MARQUAM	60	120	145
MCCLAIN	109	174	369
MCGILL	78	173	243
MERIDIAN	415	595	960
MIDDLE GROVE	316	561	916
MIDWAY	168	303	723
MILL CREEK	80	160	260
MOBILE 6	162	232	457
MOLALLA	168	313	563
MT ANGEL	55	120	165
MT PLEASANT	245	350	635
MULINO	110	115	170

Substation Name	Low	Reference	High
MULTNOMAH	435	700	1180
MURRAYHILL	297	547	912
NEWBERG	372	587	1132
NORTH MARION	274	364	554
NORTH PLAINS	202	312	377
NORTHERN	170	400	685
OAK HILLS	92	252	422
ORENCO	0	0	5
ORIENT	50	135	340
OSWEGO	252	407	672
OXFORD	252	402	697
PENINSULA PARK	72	157	287
PLEASANT VALLEY	421	606	1076
PORTSMOUTH	112	207	442
PROGRESS	115	310	545
RALEIGH HILLS	245	335	460
RAMAPO	312	432	712
REDLAND	155	285	575
REEDVILLE	256	396	921
RIVERGATE SOUTH	51	101	161
RIVERVIEW	190	255	440
ROCK CREEK	228	323	458
ROCKWOOD	97	197	402
ROSEMONT	215	315	520
ROSEWAY	265	380	590
RUBY	110	270	480
SALEM	65	70	125
SANDY	327	542	817
SCHOLLS FERRY	703	958	1593
SCOGGINS	61	81	126
SCOTTS MILLS	132	177	247

Substation Name	Low	Reference	High
SELLWOOD	240	340	615
SHERIDAN	138	173	273
SHUTE	0	100	0
SILVERTON	210	360	640
SIX CORNERS	362	472	852
SPRINGBROOK	199	319	594
ST LOUIS	160	210	450
ST MARYS EAST	65	155	225
SULLIVAN	272	412	737
SUMMIT	10	20	35
SUNSET	0	0	205
SWAN ISLAND	55	105	105
SYLVAN	221	281	451
TABOR	304	409	779
TEKTRONIX	160	285	570
TIGARD	263	328	588
TOWN CENTER	205	420	635
TUALATIN	142	267	572
TURNER	65	105	145
TWILIGHT	70	80	190
UNIONVALE	40	50	135
UNIVERSITY	70	165	240
URBAN	103	168	393
WACONDA	25	165	325
WALLACE	104	199	339
WELCHES	82	152	207
WEST PORTLAND	325	485	860
WEST UNION	185	330	425
WILLAMINA	88	118	208
WILSONVILLE	352	602	1327
WOODBURN	119	274	469

Substation Name	Low	Reference	High
YAMHILL	185	325	465

Table 55. 2030 LDV EV adoption (vehicle counts) by substation

Substation Name	Low	Reference	High
ABERNETHY	896	2,224	2,864
ALDER	1,963	4,287	5,463
AMITY	391	1,042	1,348
ARLETA	2,630	5,882	7,521
BANKS	386	979	1,239
BARNES	1,922	4,683	6,010
BEAVERTON	776	1,845	2,388
BELL	1,735	4,139	5,339
BETHANY	4,284	7,550	9,078
BETHEL	1,134	3,028	3,947
BLUE LAKE	303	802	1,032
BOONES FERRY	2,247	4,547	5,641
BORING	715	1,929	2,441
BRIGHTWOOD	334	812	1,057
BROOKWOOD	729	1,719	2,139
CANBY	575	1,456	1,871
CANYON	1,450	2,836	3,535
CARVER	1,792	4,188	5,348
CEDAR HILLS	1,844	3,744	4,616
CENTENNIAL	1,192	3,206	4,177
CLACKAMAS	543	1,341	1,760
CLAXTAR	631	1,682	2,146
COFFEE CREEK	119	247	323
COLTON	277	785	1,017
CORNELIUS	1,013	2,542	3,303
CORNELL	1,483	2,965	3,657
CULVER	28	75	105

Substation Name	Low	Reference	High
CURTIS	291	644	812
DAYTON	696	1,879	2,426
DELAWARE	1,587	3,377	4,260
DENNY	1,253	2,937	3,769
DILLEY	105	235	313
DUNNS CORNER	258	703	895
DURHAM	726	1,626	2,038
E	1,716	3,521	4,426
EAGLE CREEK	339	836	1,068
EASTPORT	660	1,621	2,102
ELMA	1,256	2,809	3,628
ESTACADA	925	2,409	3,105
FAIRMOUNT	1,018	2,283	2,859
FAIRVIEW	786	2,018	2,626
FARGO	296	784	1,023
GALES CREEK	138	322	408
GARDEN HOME	1,224	2,530	3,211
GLENCOE	1,268	2,604	3,250
GLENCULLEN	1,265	2,389	2,970
GLENDOVEER	1,447	3,487	4,486
GORMLEY	13	22	29
GRAND RONDE	181	480	629
HARBORTON	264	563	699
HARMONY	1,142	2,809	3,671
HARRISON	580	1,163	1,479
HAYDEN ISLAND	193	458	571
HEMLOCK	412	1,058	1,379
HILLCREST	71	157	203
HILLSBORO	1,680	3,984	5,094
HOGAN NORTH	1,509	3,730	4,865
HOGAN SOUTH	1,915	4,763	6,160

Substation Name	Low	Reference	High
HOLGATE	1,698	3,675	4,579
HUBER	2,983	6,726	8,536
INDIAN	1,917	5,031	6,602
ISLAND	1,024	2,443	3,206
JENNINGS LODGE	1,347	3,246	4,231
KELLEY POINT	6	13	13
KELLY BUTTE	1,477	3,666	4,719
KING CITY	1,426	3,304	4,184
LELAND	1,181	2,918	3,809
LENTS	952	2,263	2,900
LIBERAL	193	482	625
LIBERTY	2,434	6,037	7,824
MAIN	1,500	3,899	5,011
MARKET	878	2,273	3,011
MARQUAM	157	331	412
MCCLAIN	431	1,201	1,586
MCGILL	511	1,284	1,660
MERIDIAN	1,616	3,571	4,556
MIDDLE GROVE	1,607	4,562	6,064
MIDWAY	1,193	3,100	4,029
MILL CREEK	442	1,117	1,445
MOBILE 6	1,109	2,416	3,080
MOLALLA	1,098	2,952	3,930
MT ANGEL	252	713	945
MT PLEASANT	1,610	3,950	5,080
MULINO	192	472	615
MULTNOMAH	2,344	4,791	6,001
MURRAYHILL	2,446	5,236	6,611
NEWBERG	1,918	4,776	6,266
NORTH MARION	844	2,327	3,039
NORTH PLAINS	644	1,532	1,954

Substation Name	Low	Reference	High
NORTHERN	629	1,410	1,770
OAK GROVE	4	7	7
OAK HILLS	1,376	2,992	3,786
ORENCO	2,304	4,979	6,305
ORIENT	432	1,030	1,311
OSWEGO	1,536	3,114	3,866
OXFORD	807	2,025	2,637
PENINSULA PARK	390	900	1,144
PLEASANT VALLEY	2,990	6,256	7,846
PORTSMOUTH	830	2,026	2,607
PROGRESS	637	1,421	1,821
RALEIGH HILLS	959	1,964	2,400
RAMAPO	1,281	3,036	3,851
REDLAND	882	2,049	2,601
REEDVILLE	1,461	3,478	4,461
RIVERGATE SOUTH	149	367	494
RIVERVIEW	1,028	2,070	2,578
ROCK CREEK	1,431	2,865	3,671
ROCKWOOD	583	1,528	2,011
ROSEMONT	1,273	2,430	3,073
ROSEWAY	943	1,921	2,335
RUBY	700	1,775	2,369
SALEM	132	290	375
SANDY	1,239	3,203	4,094
SCHOLLS FERRY	3,059	6,401	7,911
SCOGGINS	288	707	913
SCOTTS MILLS	341	856	1,127
SELLWOOD	1,192	2,581	3,248
SHERIDAN	425	1,124	1,525
SHUTE	2	4	5
SILVERTON	1,295	3,206	4,135

Substation Name	Low	Reference	High
SIX CORNERS	2,159	5,124	6,507
SPRINGBROOK	1,067	2,707	3,536
ST HELENS		3	3
ST LOUIS	514	1,426	1,901
ST MARYS EAST	731	1,771	2,274
SULLIVAN	1,929	4,117	5,159
SUMMIT	28	80	107
SUNSET	216	331	377
SWAN ISLAND	49	98	115
SYLVAN	1,336	2,451	3,003
TABOR	1,281	2,825	3,539
TEKTRONIX	1,369	3,090	3,955
TEMP A	5	22	35
TEMP B	6	11	12
TEMP G	1	10	15
TEMP H	80	172	215
TIGARD	1,157	2,749	3,521
TOWN CENTER	507	1,223	1,596
TUALATIN	1,900	4,960	6,373
TURNER	443	1,077	1,379
TWILIGHT	342	723	939
UNIONVALE	190	438	552
UNIVERSITY	363	950	1,225
URBAN	764	1,622	2,000
WACONDA	362	973	1,276
WALLACE	486	1,169	1,540
WELCHES	265	728	936
WEST PORTLAND	1,097	2,434	3,073
WEST UNION	610	1,425	1,820
WILLAMINA	280	736	961
WILSONVILLE	2,388	5,256	6,695

Substation Name	Low	Reference	High
WOODBURN	1,097	2,949	3,958
YAMHILL	740	1,851	2,418

Table 56. 2030 MDHDV EV adoption (vehicle counts) by substation

Substation Name	Low	Reference	High
ABERNETHY	310	717	929
ALDER	268	537	677
AMITY	211	574	761
ARLETA	298	754	993
BANKS	175	465	609
BARNES	503	1,354	1,766
BEAVERTON	131	358	465
BELL	375	919	1,176
BETHANY	683	1,347	1,699
BETHEL	408	1,208	1,576
BLUE LAKE	232	516	647
BOONES FERRY	507	1,035	1,306
BORING	278	814	1,081
BRIGHTWOOD	135	334	449
BROOKWOOD	134	344	442
CANBY	281	690	917
CANYON	245	433	540
CARVER	572	1,387	1,831
CEDAR HILLS	323	705	892
CENTENNIAL	320	849	1,096
CLACKAMAS	180	453	614
CLAXTAR	221	610	772
COFFEE CREEK	58	116	158
COLTON	150	421	565
CORNELIUS	344	943	1,208
CORNELL	261	589	729

Substation Name	Low	Reference	High
CULVER	14	27	38
CURTIS	51	127	168
DAYTON	304	792	1,052
DELAWARE	235	529	686
DENNY	240	595	796
DILLEY	44	106	161
DUNNS CORNER	131	344	465
DURHAM	174	380	491
E	356	577	697
EAGLE CREEK	148	365	496
EASTPORT	126	277	353
ELMA	469	1,003	1,278
ESTACADA	347	1,002	1,352
FAIRMOUNT	241	595	774
FAIRVIEW	225	583	745
FARGO	153	447	550
GALES CREEK	61	171	227
GARDEN HOME	182	443	576
GLENCOE	132	308	394
GLENCULLEN	193	412	520
GLENDOVEER	321	818	1,038
GORMLEY	6	15	23
GRAND RONDE	83	221	291
HARBORTON	123	281	362
HARMONY	302	797	1,046
HARRISON	96	181	222
HAYDEN ISLAND	254	641	700
HEMLOCK	156	346	445
HILLCREST	47	65	74
HILLSBORO	553	1,342	1,753
HOGAN NORTH	473	1,273	1,670

Substation Name	Low	Reference	High
HOGAN SOUTH	463	1,286	1,760
HOLGATE	236	515	676
HUBER	538	1,394	1,840
INDIAN	626	1,692	2,268
ISLAND	318	670	878
JENNINGS LODGE	336	885	1,185
KELLEY POINT	6	16	21
KELLY BUTTE	300	726	965
KING CITY	272	746	939
LELAND	474	1,290	1,679
LENTS	206	555	736
LIBERAL	112	293	380
LIBERTY	749	2,077	2,694
MAIN	399	1,111	1,504
MARKET	291	710	950
MARQUAM	17	38	50
MCCLAIN	121	334	442
MCGILL	131	378	518
MERIDIAN	541	1,291	1,597
MIDDLE GROVE	556	1,518	2,032
MIDWAY	264	689	908
MILL CREEK	233	528	670
MOBILE 6	220	585	770
MOLALLA	537	1,546	2,076
MT ANGEL	106	295	372
MT PLEASANT	479	1,302	1,749
MULINO	99	252	347
MULTNOMAH	310	711	922
MURRAYHILL	432	1,029	1,315
NEWBERG	661	1,765	2,324
NORTH MARION	347	936	1,267

Substation Name	Low	Reference	High
NORTH PLAINS	296	701	882
NORTHERN	76	190	264
OAK HILLS	229	575	738
ORENCO	299	727	933
ORIENT	197	492	667
OSWEGO	367	745	937
OXFORD	303	663	886
PENINSULA PARK	52	133	173
PLEASANT VALLEY	700	1,788	2,297
PORTSMOUTH	142	337	442
PROGRESS	118	287	362
RALEIGH HILLS	170	386	471
RAMAPO	257	656	841
REDLAND	358	923	1,208
REEDVILLE	378	987	1,271
RIVERGATE SOUTH	38	84	119
RIVERVIEW	171	317	394
ROCK CREEK	297	633	796
ROCKWOOD	168	432	588
ROSEMONT	311	717	903
ROSEWAY	163	449	584
RUBY	192	497	645
SALEM	37	52	63
SANDY	476	1,325	1,769
SCHOLLS FERRY	813	2,003	2,520
SCOGGINS	120	298	410
SCOTTS MILLS	232	570	723
SELLWOOD	213	448	579
SHERIDAN	177	499	628
SHUTE	1	1	3
SILVERTON	509	1,424	1,843

Substation Name	Low	Reference	High
SIX CORNERS	624	1,603	2,090
SPRINGBROOK	347	910	1,202
ST HELENS	15	38	45
ST LOUIS	252	689	877
ST MARYS EAST	114	322	434
SULLIVAN	516	1,177	1,520
SUMMIT	11	33	46
SUNSET	58	109	136
SWAN ISLAND	70	137	167
SYLVAN	272	513	653
TABOR	144	316	409
TEKTRONIX	265	643	818
TEMP A	25	46	55
TEMP B	1	1	1
TEMP G	1	3	3
TEMP H	29	57	71
TIGARD	364	904	1,164
TOWN CENTER	107	245	296
TUALATIN	826	1,426	1,772
TURNER	190	535	710
TWILIGHT	127	309	395
UNIONVALE	85	228	321
UNIVERSITY	94	213	267
URBAN	88	172	198
WACONDA	169	450	603
WALLACE	162	443	589
WELCHES	102	270	354
WEST PORTLAND	237	511	657
WEST UNION	205	489	615
WILLAMINA	132	369	482
WILSONVILLE	672	1,526	2,010

Substation Name	Low	Reference	High
WOODBURN	408	1,188	1,582
YAMHILL	340	942	1,243

Table 57. 2030 demand response peak demand impacts by substation (MW)

Substation Name	Summer MW	Winter MW
ABERNETHY	-3.0	-2.4
ALDER	-4.2	-3.7
AMITY	-0.8	-0.6
ARLETA	-4.1	-3.2
BANKS	-0.7	-0.5
BARNES	-3.0	-2.6
BEAVERTON	-1.9	-1.6
BELL	-3.4	-2.8
BETHANY	-3.7	-3.0
BETHEL	-1.7	-1.4
BLUE LAKE	-2.8	-2.4
BOONES FERRY	-3.7	-2.9
BORING	-1.3	-0.9
BRIGHTWOOD	-0.4	-0.3
BROOKWOOD	-1.5	-1.3
CANBY	-1.4	-1.1
CANYON	-4.0	-3.5
CARVER	-3.6	-2.8
CEDAR HILLS	-2.2	-1.7
CENTENNIAL	-2.4	-1.9
CLACKAMAS	-1.7	-1.4
CLAXTAR	-1.0	-0.9
COFFEE CREEK	-1.5	-1.2
COLTON	-0.4	-0.3
CORNELIUS	-1.7	-1.3
CORNELL	-2.0	-1.6

Substation Name	Summer MW	Winter MW
CULVER	-0.1	-0.1
CURTIS	-0.4	-0.4
DAYTON	-1.5	-1.2
DELAWARE	-2.7	-2.2
DENNY	-1.9	-1.5
DILLEY	-0.1	-0.1
DUNNS CORNER	-1.3	-1.0
DURHAM	-2.6	-2.1
E	-7.8	-7.5
EAGLE CREEK	-0.7	-0.6
EASTPORT	-1.4	-1.1
ELMA	-2.0	-1.6
ESTACADA	-1.7	-1.4
FAIRMOUNT	-1.3	-1.1
FAIRVIEW	-1.9	-1.5
FARGO	-0.5	-0.4
GALES CREEK	-0.2	-0.2
GARDEN HOME	-1.7	-1.4
GLENCOE	-1.5	-1.3
GLENCULLEN	-1.3	-1.0
GLENDOVEER	-2.7	-2.2
GLISAN	0.0	0.0
GORMLEY	0.0	0.0
GRAND RONDE	-0.3	-0.2
HARBORTON	-0.5	-0.3
HARMONY	-2.6	-2.2
HARRISON	-2.4	-2.0
HAYDEN ISLAND	-1.3	-1.1
HEMLOCK	-1.3	-1.1
HILLCREST	-0.6	-0.5
HILLSBORO	-2.9	-2.3

Substation Name	Summer MW	Winter MW
HOGAN NORTH	-2.8	-2.4
HOGAN SOUTH	-3.3	-2.7
HOLGATE	-2.9	-2.4
HUBER	-4.7	-3.8
INDIAN	-3.3	-2.6
ISLAND	-2.8	-2.3
JENNINGS LODGE	-2.6	-2.1
KELLEY POINT	-0.3	-0.2
KELLY BUTTE	-3.0	-2.5
KING CITY	-3.5	-2.9
LELAND	-2.2	-1.8
LENTS	-2.1	-1.7
LIBERAL	-0.4	-0.3
LIBERTY	-3.6	-2.9
MAIN	-2.3	-1.9
MARKET	-2.1	-1.7
MARQUAM	-0.9	-0.8
MCCLAIN	-1.2	-0.9
MCGILL	-0.8	-0.6
MERIDIAN	-2.7	-2.2
MIDDLE GROVE	-2.8	-2.3
MIDWAY	-1.4	-1.2
MILL CREEK	-2.1	-1.9
MOBILE 6	-1.6	-1.3
MOLALLA	-2.1	-1.7
MT ANGEL	-0.6	-0.4
MT PLEASANT	-2.5	-2.0
MULINO	-0.6	-0.5
MULTNOMAH	-3.0	-2.4
MURRAYHILL	-3.9	-3.2
NEWBERG	-3.4	-2.7

Substation Name	Summer MW	Winter MW
NORTH MARION	-2.7	-2.1
NORTH PLAINS	-1.7	-1.4
NORTHERN	-1.3	-1.1
OAK GROVE	-0.3	-0.3
OAK HILLS	-1.8	-1.5
ORENCO	-4.5	-4.1
ORIENT	-0.9	-0.7
OSWEGO	-1.9	-1.4
OXFORD	-2.4	-1.9
PENINSULA PARK	-0.7	-0.6
PLEASANT VALLEY	-3.7	-3.0
PORTSMOUTH	-1.4	-1.2
PROGRESS	-1.7	-1.3
RALEIGH HILLS	-1.3	-1.0
RAMAPO	-1.9	-1.5
REDLAND	-1.2	-0.9
REEDVILLE	-14.3	-9.5
RIVERGATE SOUTH	-2.7	-2.4
RIVERVIEW	-1.7	-1.4
ROCK CREEK	-1.6	-1.4
ROCKWOOD	-1.3	-1.0
ROSEMONT	-1.5	-1.1
ROSEWAY	-1.9	-2.1
RUBY	-1.8	-1.5
SALEM	-1.9	-1.3
SANDY	-2.3	-1.8
SCHOLLS FERRY	-5.9	-6.5
SCOGGINS	-0.4	-0.3
SCOTTS MILLS	-0.5	-0.3
SELLWOOD	-2.4	-2.2
SHERIDAN	-0.7	-0.5

Substation Name	Summer MW	Winter MW
SHUTE	-0.6	-0.4
SILVERTON	-2.3	-1.8
SIX CORNERS	-3.6	-3.1
SPRINGBROOK	-1.9	-1.4
ST HELENS	0.0	0.0
ST LOUIS	-1.2	-0.8
ST MARYS EAST	-1.2	-1.0
STEPHENS	0.0	0.0
SULLIVAN	-2.3	-1.7
SUMMIT	-0.2	-0.2
SUNSET	-2.7	-2.2
SWAN ISLAND	-1.7	-1.3
SYLVAN	-1.5	-1.2
TABOR	-1.7	-1.5
TEKTRONIX	-2.1	-1.8
TEMP A	-0.1	-0.1
TEMP B	0.0	0.0
TEMP G	0.0	0.0
TEMP H	-0.6	-0.5
TIGARD	-2.8	-2.4
TOWN CENTER	-2.0	-1.6
TUALATIN	-4.4	-3.6
TURNER	-1.0	-0.8
TWILIGHT	-0.4	-0.3
UNIONVALE	-0.2	-0.2
UNIVERSITY	-0.9	-0.7
URBAN	-2.5	-2.0
WACKER	0.0	0.0
WACONDA	-1.3	-1.1
WALLACE	-0.8	-0.6
WELCHES	-0.8	-0.7

Substation Name	Summer MW	Winter MW
WEST PORTLAND	-2.1	-1.7
WEST UNION	-2.1	-1.7
WILLAMINA	-0.7	-0.5
WILLBRIDGE	0.0	0.0
WILSONVILLE	-7.5	-6.2
WOODBURN	-2.0	-1.6
YAMHILL	-1.4	-1.1

Appendix H. Annual reliability report

Link to report:
https://apps.puc.state.or.us/edockets/edocs.asp?FileType=HAQ&FileName=re113haq328283024.pdf&DocketID=18326&numSequence=15

Appendix I. Baseline data

To foster transparency, the Distribution System Plan provides a snapshot of the current physical structures and sensing, measurement and control capabilities that make up the distribution system, recent investment in those systems, and the level of distributed energy resources (DERs) currently integrated into those systems.

Some categories of system data are dynamic, changing frequently, and some are more consistent over time. **Table 58** indicates whether the baseline data is sourced from the previous DSP or has been refreshed for this version of the DSP.

Table 58. Baseline data vintage guide

Baseline Data Guidelines	Vintage
A summary description and table of the utility's distribution system assets	DSP Part 1, filed 10/15/2021
A discussion of distribution system monitoring and control capabilities	DSP Part 1, filed 10/15/2021
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.).	DSP Part 1, filed 10/15/2021
Historical distribution system spending for the past five years	Updated for this version of DSP
Net Metering and Small Generator information	Updated for this version of DSP
Plans should include the utility's most recently filed Annual Reliability Report as an appendix to the Plan.	Annual Reliability Report filed in docket RE 113 and included as **Appendix H Annual reliability report**
Plans should include high-level summary data on electric vehicles (EV) and EV charging	Updated for this version of DSP
Plans should include high-level summary data on demand response/flexible load pilot and/or program performance metrics for the past five years	Updated for this version of DSP
Summary-level progress report on activities included in the last-filed DSP	Applies to the next filed DSP

Baseline Data Guidelines	Vintage
Data and information … should be submitted … in electronic format	Available on PGE's website[110]

I.1 Distribution system assets

PGE serves a population of 1.9 million people, representing over 900,000 customers in 51 cities. Our distribution system is composed of 153 (Q1 2021) distribution substations and 695 (Q1 2021) distribution feeders.

I.2 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.

[110] Baseline data. Available at: https://content-pre-p1-dot-gcp-csweb-dev-d78c.appspot.com/dsp-baseline-data

- **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 59 shows the average age and average service life of each asset category.

Table 59. Summary of distribution assets as of Q1 2021

Asset classes	No. of assets	Avg. age of assets[1]	Avg. service life[2]	% past avg. life
Substation structures	N/A	N/A	65	N/A
Substation transformers	407	38	55	23%
Circuit breakers	1,617	21	55	7%
Other substation equipment	9,967	30	65	3%
Distribution poles	203,615	41	48	39%
Overhead transformers	108,500	29	50	24%
Reclosers and sectionalizers	422	8	50	0.2%
Voltage regulators	55	9	50	0%
Capacitor banks	689	27	50	0.3%
Other overhead (OH) conductor devices	175,492	21	48	0%
Underground (UG) transformers	71,153	28	55	3%
UG conduit	243,273	12	80	0%

Asset classes	No. of assets	Avg. age of assets[1]	Avg. service life[2]	% past avg. life
Other UG conductor devices	3,411	19	55	0%

[1] Average age is the actual average age of all in-service assets within each group as of Q1 2021.
[2] Industry life expectancy is derived from a 5-year depreciation study and used for cost-recovery purposes.

Table 60 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 60. Asset classes by age range as of Q1 2021

Asset classes | Age range (yrs.)	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

Asset classes | Age range (yrs.)	0-9	10-19	20-29	30-39	40-49	50-59	60-69	70-79	80-89	90-99	100+	Unknown
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 (OH) conductor devices	48	13	3,964	1	0	0	0	0	0	0	0	171,466
Underground (UG) transformers	2,405	17,943	21,228	11,722	13,988	3,569	135	15	0	1	4	143
UG conduit	88,824	109,031	36,544	630	449	202	4	1	0	0	0	7,588
Other UG conductor devices	149	624	1,937	22	12	0	0	0	0	0	0	667

I.3 Distribution system monitoring and control capabilities

Distribution system monitoring and control capabilities include supervisory control and data acquisition (SCADA) and automated metering infrastructure (AMI) technologies.

I.3.1 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 percent 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.

I.3.2 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 promote 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.

I.3.3 Assets with SCADA deployment

Table 61 shows that of the 151 distribution substations, 81 percent, have SCADA deployment, and of 695 distribution feeders, 88 percent 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 61. SCADA assets deployment (as of Q1 2021)

	SCADA deployed units		Unit counts	SCADA deployed in %	
	With	Without		With	Without
Distribution substations	124	29	153	81%	19%
Distribution feeders	611	84	695	88%	12%

Table 62 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 62. Time intervals, interval type and protocols on SCADA data collection (as of Q1 2021)

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

I.3.4 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.

I.3.5 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.

I.3.6 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)

I.3.7 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 historically had capacity and has successfully demonstrated this capability with the City of Wilsonville
- Conversation 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 63 and **Table 64** shows the number of meters by type, the majority being residential customer meters, which account for 87 percent of total AMI deployments. Overall, PGE has near-universal adoption of AMI. PGE has more than 950,000 meters installed; all are AMI-enabled except for approximately 195 "opt-out" customers. **Table 63** shows the breakdown of interval length among the approximately 950,000 meters currently installed.

Table 63. PGE meters outfitted with AMI (as of Q3 2024)

Meter type	# of meters	Percent
Residential	835,239	87%
Commercial	106,125	11%
Industrial (>1 MW)	170	0.02%
Irrigation	4,116	0.43%
Vacant	13,367	1.4%
Total	959,017	100%

Table 64. Operational intervals on AMI Meters (as of Q3 2024)

AMI meter interval	# of meters	Usage
5 minutes	853	• Mix of qualifying facilities • Community solar • Demand response
15 minutes	465,002	• Commercial • Newer residential meters
30 minutes	224	• More complex large Commercial / Industrial meters • Non-SCADA substations
60 minutes	492,834	• Exclusively residential

I.4 Distribution system advanced control and communication capabilities

I.4.1 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.

I.4.2 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 65 includes ADMS capabilities that PGE has tested, currently uses, or is planning on using over the next couple of years.

Table 65. Advanced control distribution management systems capabilities (as of Q1 2021)

ADMS capabilities	Percentage of customers reached with each capability
Control and operations[111]	Approximately 690 Feeders; 100% of feeders
FLISR	3 feeders using YFA; approximately 3,000 customers

I.4.3 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

[111] 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

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 percent in the pilot project, PGE was able to reduce customer demand (MW) and energy consumption (MWh) by 1.4-2.5 percent. 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).

I.4.4 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.

I.4.5 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.

DERMS 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 DERMS capabilities, including: Solicitation, registration, interconnection, DER portfolio optimization, constraint management, aggregation functions, microgrid management, islanding, OPF, dispatch and schedule. **Table 66** shows all the PGE programs that apply to DRMS.

Table 66. PGE programs using DERMS (as of Q1 2021)

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

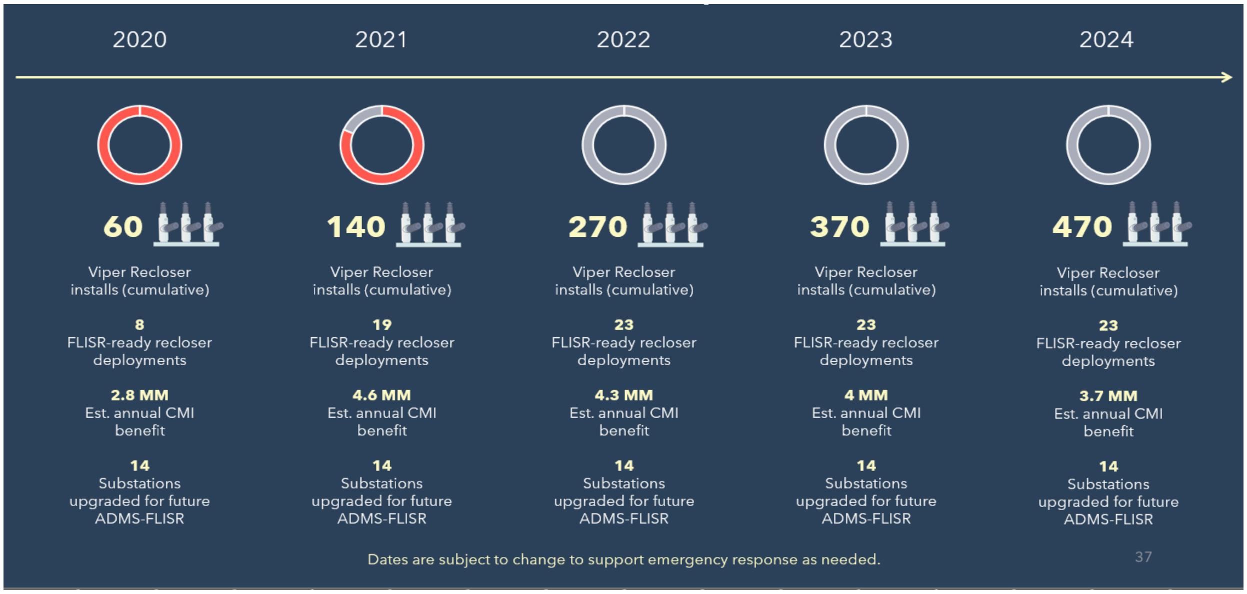
I.4.6 Distribution automation (DA)

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 58**).

Figure 58. Distribution automation roadmap (as of Q1 2021)



I.4.7 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 59**). 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 67 & Figure 59).**

Table 67. Field Area Network coverage implementation plan (as of Q1 2021)

Year	Number of FAN sites	Percent of total coverage
2020	12	13%
2021	18	33%
2022	22	57%
2023	23	83%

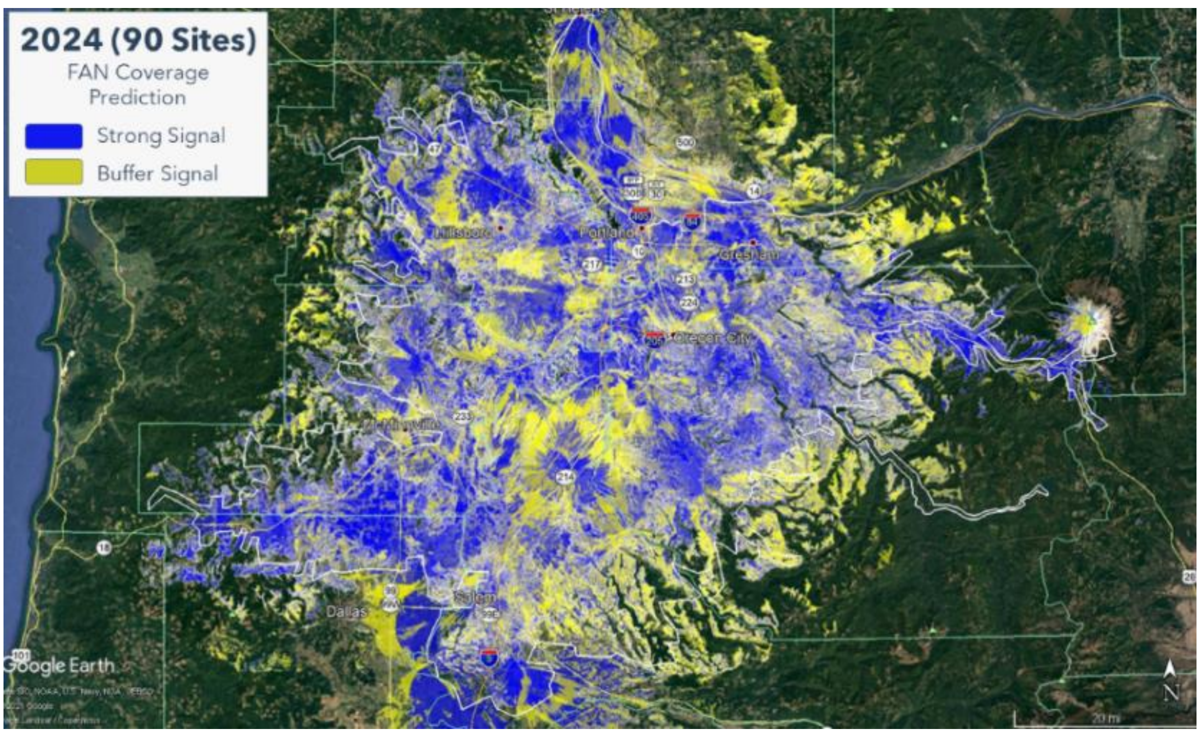
Year	Number of FAN sites	Percent of total coverage
2024	15	100%

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 59. FAN coverage prediction, 2024 (as of Q1 2021)



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
- Automated metering infrastructure (AMI)
- Street lighting control system backhaul
- Field data communication

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.

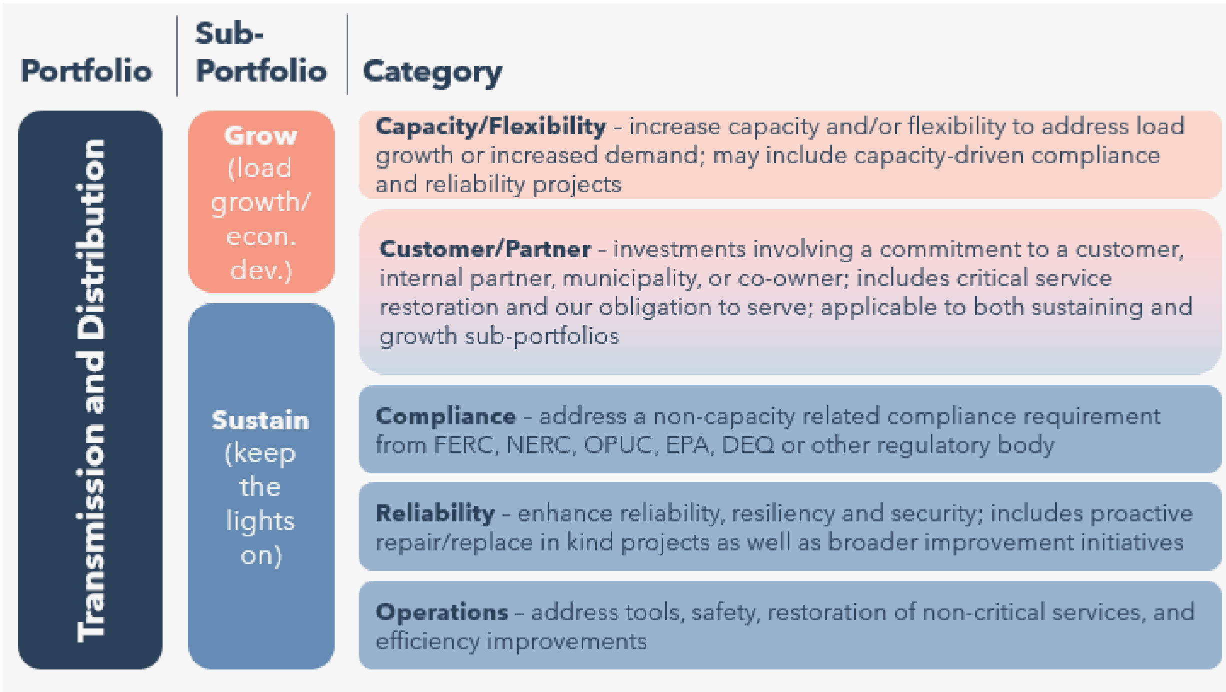
The FAN will provide the fundamental backbone to allow for the communication and visibility within the power grid network architecture.

I.5 Historical distribution system capital investments

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 H Annual reliability report**.

PGE invests in capital projects for many reasons. Some projects are discretionary, and some are non-discretionary. Each investment is categorized according to its primary driver or rationale. The transmission and distribution categories are described in **Figure 60**.

Figure 60. T&D investment categories



In addition to the T&D investment categories, projects that involve new technologies such as energy storage, distribution automation, communications and software, such as advanced distribution management system (ADMS) platforms, are categorized as Grid Modernization investments. Investments in these categories for the past five years are summarized in **Table 68**.

Table 68. T&D and Grid Mod investments for past five years

DSP Category	2019	2020	2021	2022	2023
Capacity/ Flexibility	$101,379,413	$26,752,373	$61,012,707	$73,092,207	$78,600,268
Compliance	$10,001,952	$2,972,728	$10,885,224	$122,415,746	$157,132,529
Customer/ Partner	$154,788,717	$56,981,883	$226,055,741	$200,209,710	$429,471,658
Operations	$19,138,049	$291,383	$473,512	$1,556,223	$11,582,550
Reliability	$80,543,190	$17,383,606	$102,235,867	$50,893,389	$57,734,219
Grid Modernization	$8,669,402	$67,158	$11,236,718	$24,651,670	$21,658,076
Grand Total	**$374,520,722**	**$104,449,132**	**$411,899,769**	**$472,818,945**	**$756,179,301**

I.6 Net metering and distributed generation

For customers who install their own renewable generation sources, net metering rules[112] 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.

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.

I.6.1 In-service facilities

In-service facilities are integrated with the grid and they are producing energy. **Table 69** shows the net metering facilities in our territory as of September 2024.

Table 69. In-service net metering facilities by generator type, number and capacity

In-service net metering facilities				
Generator type	Generator		Capacity	
	Number	Percent of total	kW	Percent of total
Solar	29,570	99.81%	286,020	98.39%
Methane Gas	4	0.01%	3,801	1.31%
Wind	40	0.14%	650	0.22%
Hydro	6	0.02%	185	0.06%
Solar+Wind	2	0.01%	22	0.01%
Fuel Cell	3	0.01%	21	0.01%
Total	**29,625**	**100%**	**290,699**	**100%**

We currently have 76 in-service QFs with an estimated nameplate capacity of 171,656 kW (**Table 70**).

[112] Oregon's net metering rules can be found in OAR 860-039-0010 through 860-039-0080. Available at: https://secure.sos.state.or.us/oard/displayDivisionRules.action?selectedDivision=4053.

Table 70. 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
Solar	68	89.47%	166,745	97.14%
Diesel	2	2.63%	3,175	1.85%
Storage Only	1	1.32%	750	0.44%
Hydro	5	6.58%	986	0.57%
Total	**76**	**100%**	**171,656**	**100%**

I.6.2 In-queue facilities

In-queue facilities have applied to be permitted to integrate with the grid and are not producing power yet. The application process can take from 6-24 months. Some applicants do not pursue their applications to project completion.

Table 71 and **Table 72** show the number of in-queue net-metering and QF applications as of September 2024.

Table 71. In-queue net metering facilities by generator type, number and capacity (Sep 2024)

In-queue net-metering facilities				
Generator type	Generator		Capacity	
	Number	Percent of total	kW	Percent of total
Solar	3,464	99.97%	48,401	99.98%
Bio Diesel	1	0.03%	9	0.02%
Total	**3,465**		**48,410**	

Table 72. In-queue qualifying facilities by generator type, number and capacity (Sep 2024)

In-queue qualifying facilities				
Generator type	Generator		Capacity	
	Number	Percent of total	kW	Percent of total
Solar	30	81.08%	65,166	89.03%
Storage Only	6	16.22%	7924	10.83%
Hydro	1	2.70%	107	0.15%
Total	**37**		**73,197**	

I.7 Electric vehicle (EV) data

At the time of this filing, the number of EVs in our service area as reported by the Oregon Electric Vehicle Dashboard was 65,352. **Table 73** shows the number of EVs in our service area. **Table 74** shows the number of EVs added to PGE's service area in each of the last five years.

Table 73. Total EVs by weight class (as of Sept 2024)

EV Weight Class	EV Powertrain	Vehicle Counts
Light-duty vehicle	Battery electric vehicle	53,597
	Plug-in hybrid electric vehicle	11,682
Medium-duty vehicle	Battery electric vehicle	9
Heavy-duty vehicle	Battery electric vehicle	64
Total		**65,352**

Table 74. EVs added in each of the last five years

Year	EVs Added
2023	14,686
2022	9,629
2021	6,648
2020	4,080
2019	3,473
Total	**38,516**

I.8 EV charging data

We rely on the U.S. DOE Alternative Fuels Data Center (AFDC) as a single, trusted external source of EV charging equipment that we supplement with existing information about our network of EV chargers. We will continue to evaluate the landscape of EV charging databases available in the industry.

Figure 61 summarizes the existing charging stations in our service area by owner, charging speed and network type. **Figure 62** summarizes the charging stations added to PGE service area by year and type.

Figure 61. Total charging stations by ownership and type

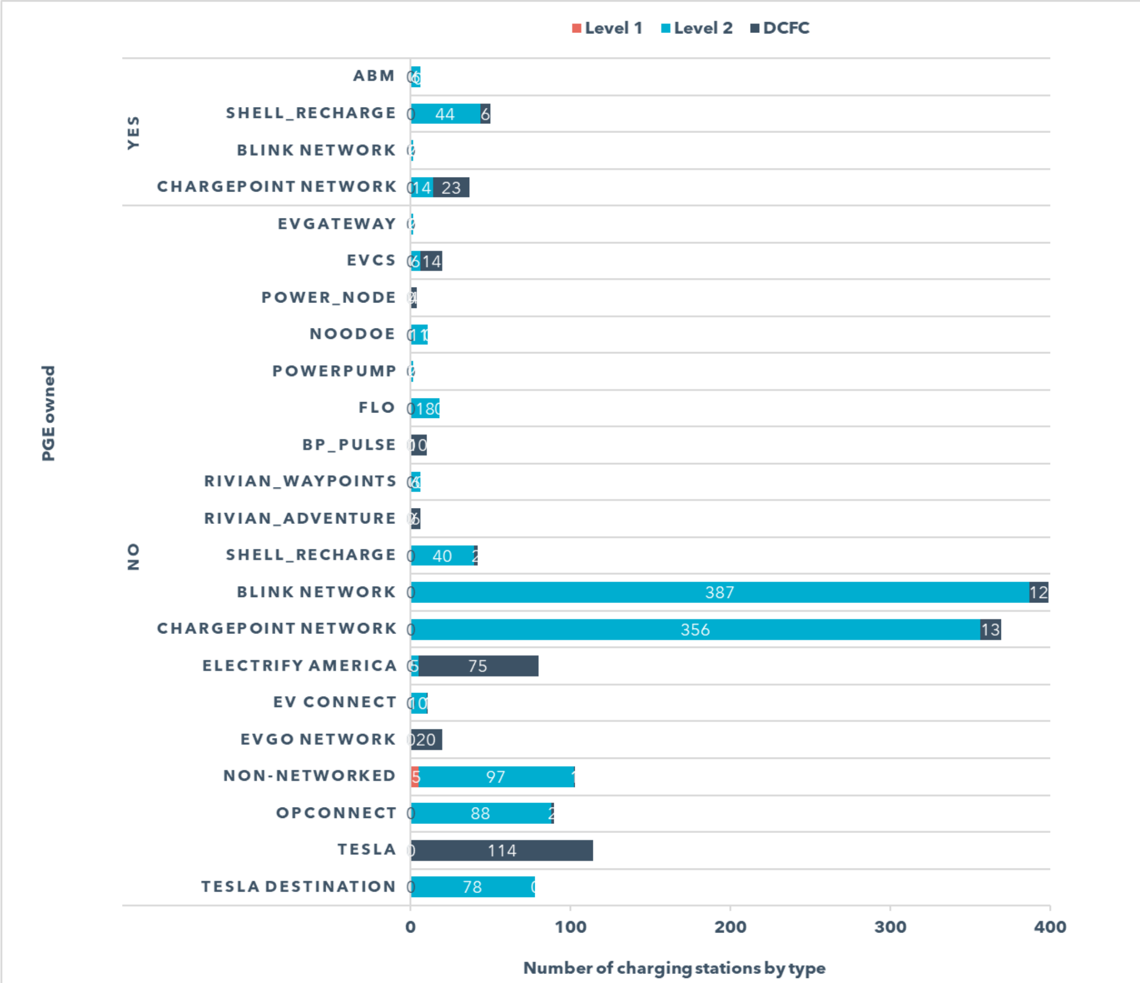


Figure 62. Total charging stations added to system in the last five years by type

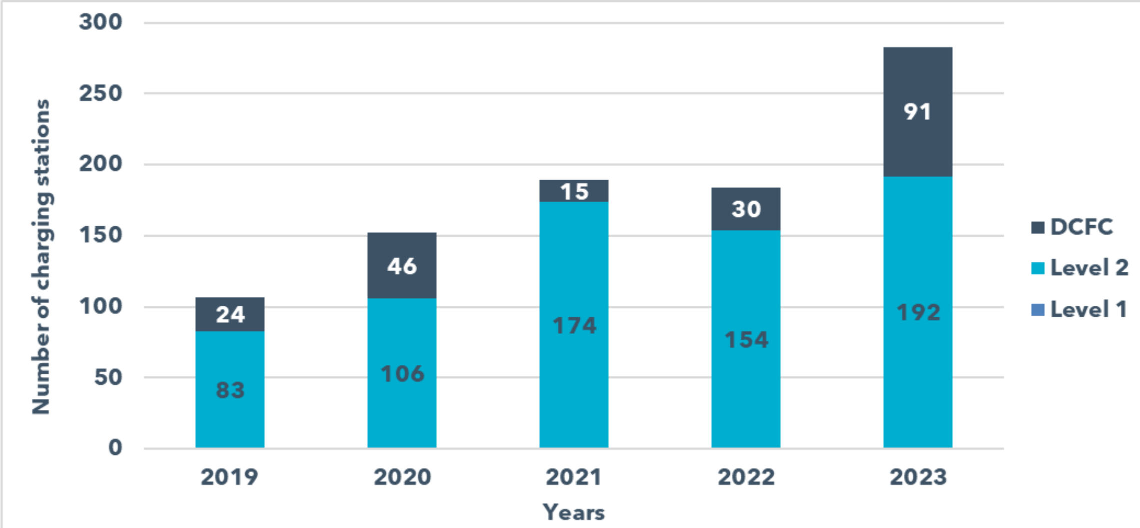
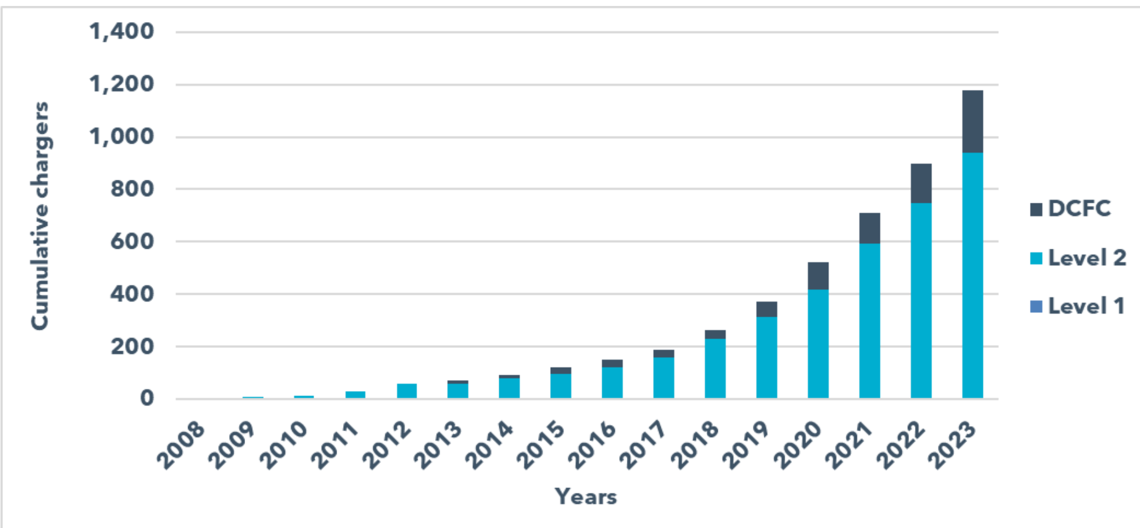


Figure 63. Cumulative growth of chargers by type



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 refueling. Under our EA Pilot, we installed six EA charging sites 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 also examined the impact of community charging on increasing adoption of EVs by PGE customers (including multifamily residents) and Transportation network company (TNC) drivers.

In 2024, six of the EA sites are being outfitted with new chargers to improve the uptime of the existing sites. The sites upgraded included Beaverton, Eastport, Hillsboro, Milwaukie, Salem, and Wilsonville. The updated chargers have increased DCFC charging speeds which are more in line with current DCFC charging standards (62.5 kW to 160 kW). No transformer upgrades were needed as the upgraded chargers were within the amount of capacity available at each site.

Updated pricing has also been recommended through UE 435 to transition to a per kwh pricing to better meet the needs of variable EV models, introducing an idle fee to encourage better utilization of the site, and updating the peak pricing timeframe to align with the updated on-peak timeframe for schedule 7's time of day pricing.

Figure 64 below presents an overall summary of energy delivered to the six different sites.

Figure 64. Monthly charging load at EA sites (2023)

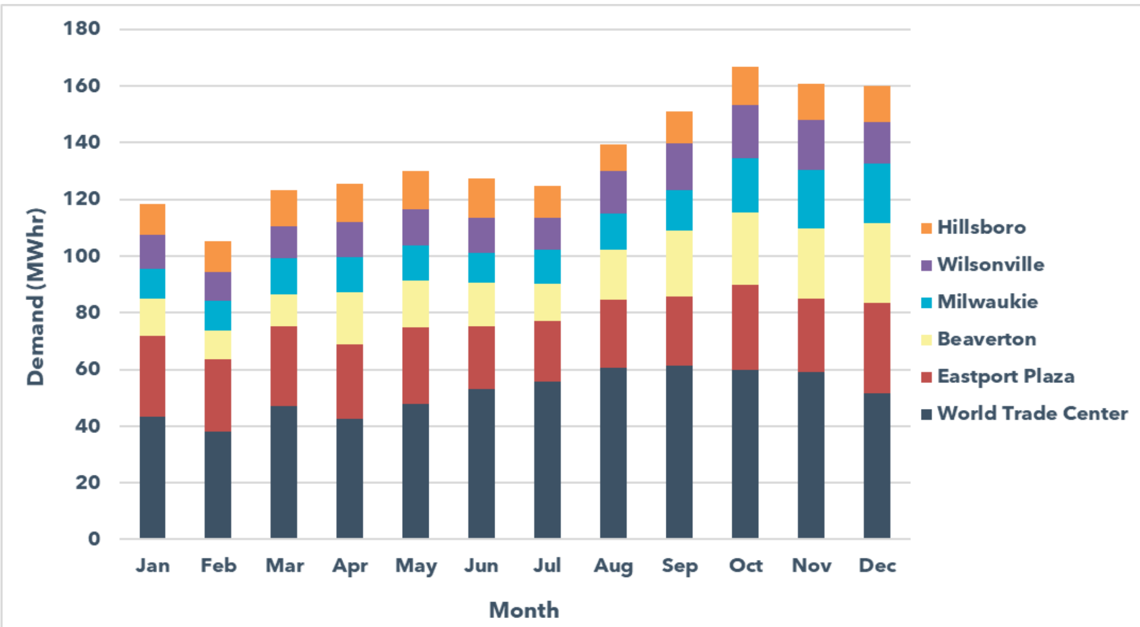
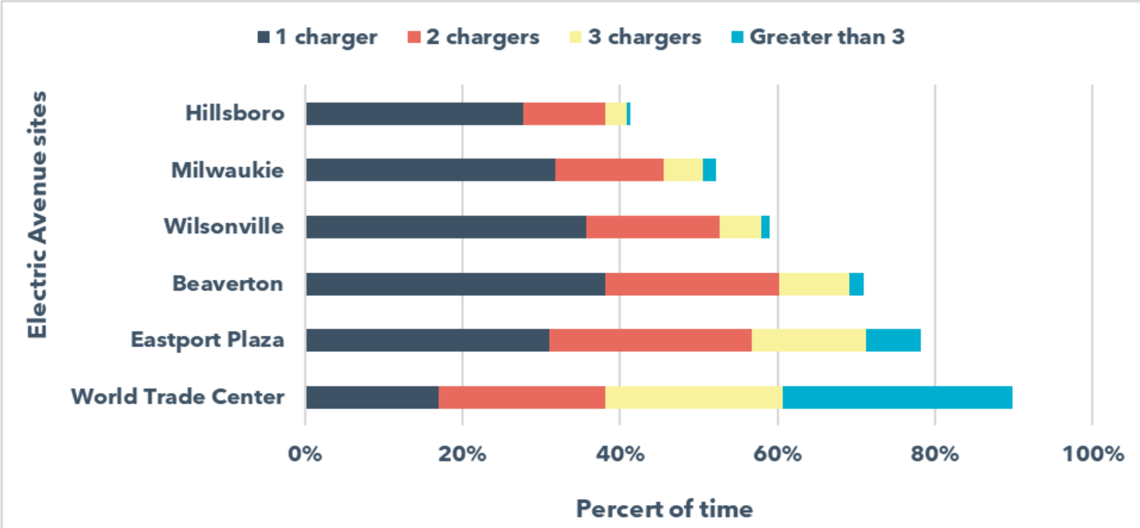


Figure 65 shows how often each EA site experiences simultaneous charging (more than one port active at the same time). The downtown Portland site has the greatest amount of time with more than one port actively charging, followed by East Portland and then Beaverton sites.

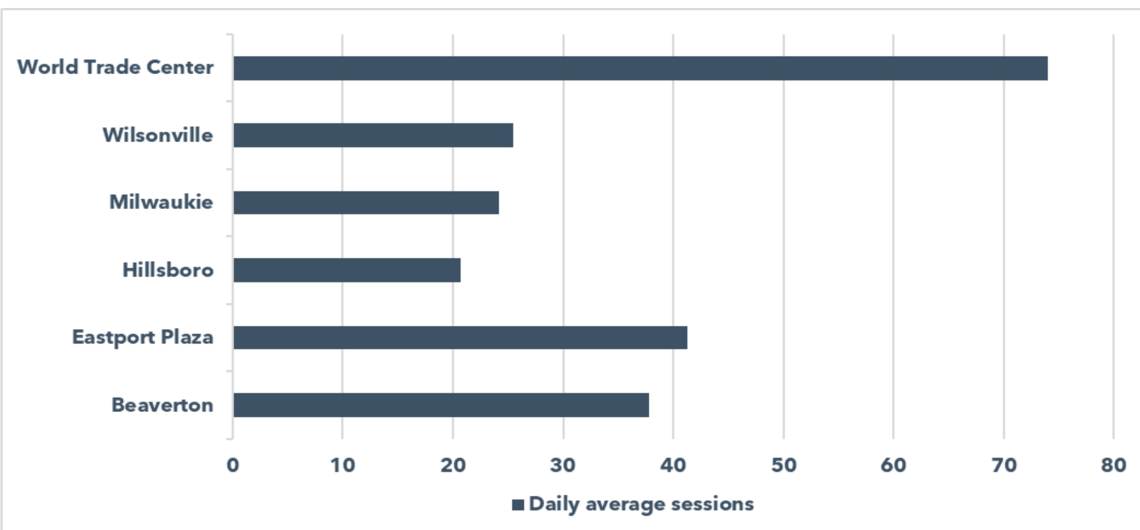
Figure 65. Percent of time with one or more chargers in use



We also looked at average number of charge sessions per day at each of the EA sites, presented in

Figure 66 below.

Figure 66. Average charging sessions per day



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 67** and **Figure 68** clearly demonstrate the effectiveness of the pricing signal to curb demand during system peaks.

Figure 67. Normalized system load shape verses the normalized charging profile - Winter/Spring

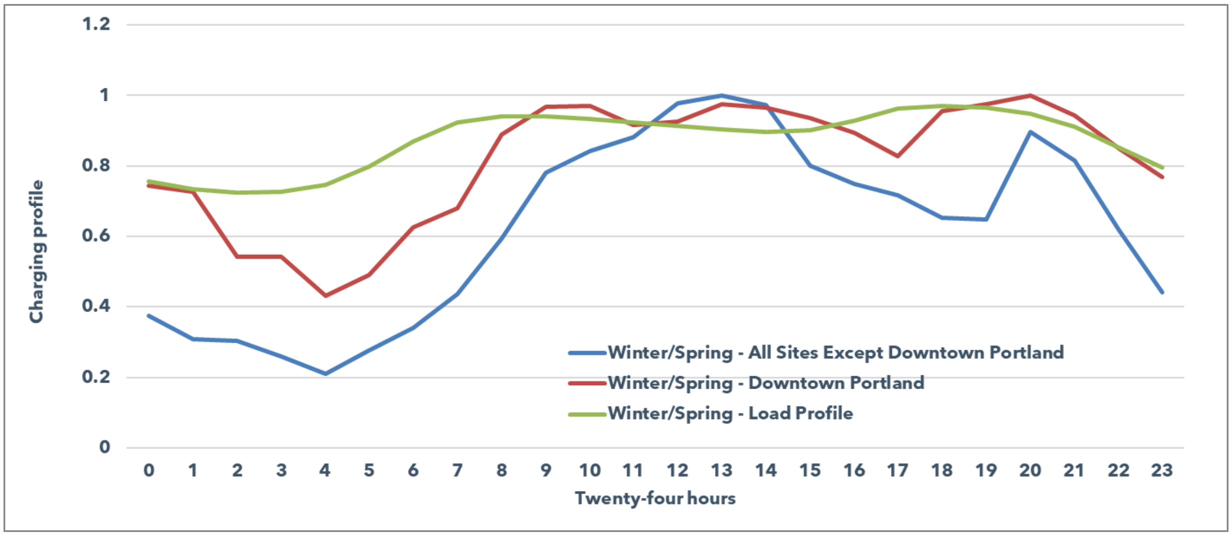


Figure 68. Normalized system load shape verses the normalized charging profile - Summer/Fall

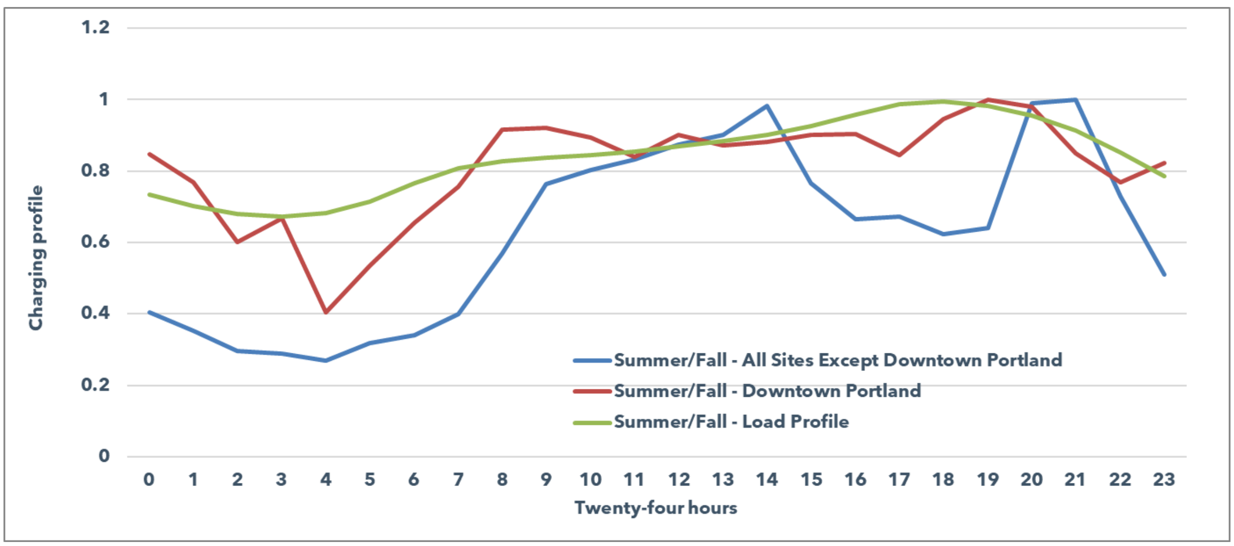


Table 75 shows the number of chargers available on each feeder.

Table 75. Chargers by feeder and type

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
E-13150		32		32
OXFORD-RURAL		20	12	32
HILLSBORO-SCHOLLS		30	1	31
TOWN CENTER-VALLEY VIEW		4	20	24
UNIVERSITY-TRADE		21	2	23

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
BOONES FERRY-KRUSE		20		20
MT PLEASANT-CLAIRMONT		19		19
OAK HILLS-FIVE OAKS		7	12	19
TEKTRONIX-DUCKS		19		19
ISLAND-ISLAND 13		14	4	18
NORTH MARION-CROSBY		2	16	18
TIGARD-13337		18		18
E-13141		17		17
SANDY-362ND		4	13	17
SUNSET-WHITMAN		17		17
ELMA-HUDSON		4	12	16
GRAND RONDE-FORTHILL		15	1	16
MARKET-FAIRGROUNDS		10	6	16
BLUE LAKE-SUNDIAL		3	11	14
WILSONVILLE-PARKWAY		6	8	14
HILLSBORO-JACKSON		13		13
ISLAND-13188		13		13
ST MARYS EAST-BETHANY		9	4	13
BEAVERTON-WEST SLOPE		8	4	12
DAYTON-EAST		12		12
EASTPORT-PLAZA		8	4	12
SUNSET-SPALDING		12		12
TEKTRONIX-SOUTH		11	1	12
TEKTRONIX-SHANNON			12	12
CORNELIUS-CORNELIUS 13		8	3	11
FAIRMOUNT-CANDALARIA		6	5	11
OSWEGO-IRON MOUNTAIN		7	4	11
ST LOUIS-EAST		7	4	11
BARNES-BATTLE CREEK		10		10
HOGAN NORTH-SALQUIST		7	3	10
MERIDIAN-PILKINGTON		10		10

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
SPRINGBROOK-FERNWOOD		9	1	10
NEWBERG-CHEHALEM		10		10
MARQUAM-MCCALL #10 NETWORK		10		10
OAK HILLS-GREENBRIER		10		10
SALEM-UNION		10		10
SCHOLLS FERRY-RAINBOW		10		10
PROGRESS-WASHINGTON SQ #1			10	10
BEAVERTON-JAMIESON		5	4	9
HOLGATE-HOLGATE 13		1	8	9
MCGILL-HORSETAIL		8	1	9
SWAN ISLAND-DOLPHIN		8	1	9
TEMP H-NEPTUNE	2	7		9
UNIVERSITY-MILL		9		9
WEST PORTLAND-72ND		1	8	9
OXFORD-LEE		5	4	9
DELAWARE-LOMBARD		9		9
CANYON-13115 NETWORK #1		8		8
DENNY-NORTH		8		8
ESTACADA-FARADAY		8		8
INDIAN-STATION		8		8
ISLAND-13180		8		8
MARQUAM-SPIRIT #2 NETWORK		4	4	8
MULTNOMAH-13177		8		8
RUBY-JUNCTION		8		8
SALEM-13264		8		8
SUMMIT-SUMMIT 13		7	1	8
TEKTRONIX-TEKTRONIX 13		8		8
TEKTRONIX-WEST		8		8
HOGAN SOUTH-WALLULA		8		8
RALEIGH HILLS-DOGWOOD		8		8
WEST UNION-WEST UNION 13		2	6	8

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
KELLY BUTTE-MALL 205		8		8
HAYDEN ISLAND-SOUTH SHORE			8	8
KELLY BUTTE-MCGREW		8		8
KING CITY-NORTH		4	4	8
GLENCOE-PROVIDENCE		8		8
REEDVILLE-TV		8		8
TOWN CENTER-MONTEREY		2	6	8
HEMLOCK-MASON		6	1	7
MIDWAY-DIVISION		7		7
NEWBERG-DUNDEE		7		7
WEST PORTLAND-WEST PORTLAND 13		5	2	7
MCCLAIN-COTTAGE		7		7
OXFORD-SHELTON		7		7
HARMONY-INTERNATIONAL		7		7
BELL-FLAVEL		7		7
ST MARYS EAST-JENKINS		7		7
AMITY-AMITY 13		6		6
CEDAR HILLS-LEAHY		6		6
COFFEE CREEK-FREEMAN		6		6
DURHAM-BRIDGEPORT		6		6
DURHAM-DURHAM 13		4	2	6
E-13144		6		6
GLENCOE-GLISAN		6		6
HARRISON-DAVIS		6		6
HILLSBORO-LAUREL		6		6
HOLGATE-BYBEE		6		6
KELLY BUTTE-BINNSMEAD		6		6
MAIN-RIVER		2	4	6
SALEM-13261		6		6
YAMHILL-YAMHILL 13		6		6
URBAN-GAINES		6		6

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
PENINSULA PARK-PENINSULA PARK 13			6	6
SUMMIT-MEADOWS		6		6
HARMONY-THIESSEN		6		6
MARQUAM-PORTER		6		6
CEDAR HILLS-SYLVAN		5	1	6
BOONES FERRY-LAKE GROVE		5		5
CANYON-13134 NETWORK #3		5		5
CENTENNIAL-BRAECROFT		5		5
HOLGATE-KENILWORTH		5		5
JENNINGS LODGE-MELDRUM		3	2	5
ORENCO-ORENCO 13		5		5
SIX CORNERS-BORCHERS		5		5
WALLACE-WALLACE 13		5		5
WELCHES-ZIG ZAG		1	4	5
WILSONVILLE-WEST		1	4	5
TOWN CENTER-SOUTH		2	3	5
ROCKWOOD-ROCKWOOD 13		5		5
SELLWOOD-KELLOGG PARK		5		5
BROOKWOOD-BORWICK		5		5
ROCK CREEK-185TH		5		5
RIVERVIEW-MACADAM		5		5
ABERNETHY-WASHINGTON		4		4
BANKS-CEDAR CANYON		1	3	4
CANYON-13120		4		4
CANYON-13136 NETWORK #3		4		4
CANYON-BURNSIDE		4		4
COFFEE CREEK-HOLIDAY		4		4
DURHAM-BONITA		4		4
HILLSBORO-DAIRY CREEK		4		4
LELAND-KELM		4		4
MAIN-EXPRESS		4		4

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
ORENCO-WILKINS		4		4
PROGRESS-GREENBURG		3	1	4
RIVERVIEW-FULTON		1	3	4
SALEM-13263		4		4
SCHOLLS FERRY-ROY ROGERS		4		4
SILVERTON-NORTH		2	2	4
SIX CORNERS-SIX CORNERS 13		1	3	4
ST MARYS EAST-MILLIKAN		4		4
TIGARD-13361		2	2	4
TOWN CENTER-NORTH		4		4
WEST UNION-JACOBSON		4		4
WILSONVILLE-VILLEBOIS		4		4
YAMHILL-CARLTON		4		4
SILVERTON-SOUTH		4		4
BARNES-SUNNYSIDE			4	4
CARVER-CARVER 13		4		4
LELAND-BEAVERCREEK		4		4
HILLSBORO-DENNIS		3	1	4
SWAN ISLAND-SHIPYARD		2	2	4
BROOKWOOD-SUNRISE		4		4
HEMLOCK-HEMLOCK 13		4		4
TABOR-82ND			4	4
ALDER-YAMHILL			4	4
NORTHERN-11009			4	4
ALDER-STARK		4		4
SWAN ISLAND-BASIN		4		4
E-13148		4		4
ROSEMONT-OVERLOOK			4	4
TEKTRONIX-MEADOW		4		4
SUNSET-MEEK		4		4
MIDDLE GROVE-WEST			4	4

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
AMITY-BELLEVUE		3		3
E-13149		3		3
MARQUAM-SPIRIT #1 NETWORK		3		3
MERIDIAN-CHILDS		2	1	3
MT PLEASANT-MT VIEW		3		3
CENTENNIAL-TREELAND		3		3
ALDER-IRVING		3		3
RUBY-CAR LINE		3		3
FAIRVIEW-TROUTDALE		3		3
TEMP H-SATURN		3		3
ORENCO-231ST		3		3
BROOKWOOD-BROOKWOOD 13		2		2
CANYON-21ST		2		2
CARVER-NORTH		2		2
CLACKAMAS-TOLBERT		2		2
CORNELL-WESTLAWN		2		2
FAIRVIEW-KENNEL CLUB		2		2
GALES CREEK-GALES CREEK 13		2		2
GLENDOVEER-13597		1	1	2
HOGAN NORTH-BRIGADOON		2		2
HOGAN SOUTH-CLEVELAND		2		2
INDIAN-KEIZER	2			2
LIBERTY-ROSEDALE		2		2
MARKET-HAWTHORNE		2		2
MERIDIAN-65TH		2		2
MERIDIAN-NYBERG		2		2
MULTNOMAH-13176	1	1		2
MURRAYHILL-KINTON		2		2
NORTH PLAINS-MASON HILL		2		2
PROGRESS-SAWYER		2		2
RIVERVIEW-TERWILLIGER		2		2

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
SILVERTON-WEST		2		2
SIX CORNERS-13359		2		2
TEKTRONIX-HOCKEN		2		2
TEKTRONIX-NORTH		2		2
TOWN CENTER-SUNNYBROOK		2		2
WACONDA-RIVER		2		2
WILSONVILLE-CITY		2		2
BANKS-BANKS 13		2		2
OXFORD-FAIRVIEW		2		2
HILLCREST-HILLCREST 13		2		2
SPRINGBROOK-ZIMRI		2		2
CLAXTAR-CLAXTAR 13		2		2
DAYTON-LAFAYETTE		2		2
MIDDLE GROVE-CHEMEKETA		2		2
HARMONY-LINWOOD		2		2
DURHAM-SATTLER		2		2
ROSEWAY-ALEXANDER		2		2
PLEASANT VALLEY-SUN		2		2
SULLIVAN-TANNER		2		2
BARNES-BOONE		1		1
E-11040		1		1
ELMA-STATE			1	1
LENTS-13101		1		1
OSWEGO-MARYLHURST		1		1
PROGRESS-WASHINGTON SQ #2			1	1
SHERIDAN-EAST		1		1
SIX CORNERS-CHAPMAN		1		1
TIGARD-TIGARD 13		1		1
UNIONVALE-UNIONVALE 13		1		1
WELCHES-WELCHES 13		1		1
MCCLAIN-HOLLYWOOD		1		1

Feeders/Charger Types	Level 1	Level 2	DCFC	Total
ROCKWOOD-REYNOLDS		1		1
MARKET-ENGLEWOOD		1		1
CENTENNIAL-CENTENNIAL 13		1		1
OXFORD-OXFORD 13		1		1
HOGAN SOUTH-LAWRENCE		1		1
OSWEGO-PALATINE		1		1
MARQUAM-MCCALL #9 NETWORK		1		1
WOODBURN-TOMLIN		1		1
BELL-WICHITA		1		1
BELL-KING		1		1
HARMONY-HARMONY 13		1		1
CANYON-13124 NETWORK #2		1		1
WILSONVILLE-CHARBONNEAU		1		1
CULVER-GAFFIN		1		1
CORNELL-SALTZMAN		1		1
UNKNOWN			1	1
MARQUAM-TILIKUM		1		1
WOODBURN-WEST		1		1
Grand Total	**5**	**1172**	**303**	**1480**

I.9 Other TE infrastructure

ORS 757.357 (HB 2165, 2021) allows PGE to extend utility ownership to behind-the-meter assets, like make-ready, for Transportation Electrification projects. By making PGE responsible for additional infrastructure, it allows the customer to focus on the parts of the project that most impact their business—the chargers and vehicles—while also allowing PGE to gather additional information and set additional requirements.

The utility fulfills the following roles for make-ready infrastructure:

Ensures sites are properly metered and ready for an EV rate:

- At present we believe a separate meter is needed to have clear data from which to learn and develop new approaches to TE Loads. However we are not sure that a separate meter is necessary for all types of TE load now or in the future. The activities funded through this Plan require a separate meter for sites where make-ready is necessary. For smaller EV loads, such as where an electrical contractor builds the circuit interconnecting the TE load to the system behind-the-meter, PGE is pursuing a load disaggregation approach or other usage data.

Site Development:

- Can help identify whether distribution system upgrades can be avoided by incorporating solutions into make-ready design (e.g., right-sizing charging, battery storage, load management).
- Where PGE dollars have been used to install make-ready, the utility can also impose terms and conditions. In the case of Business Make-Ready PGE can require public access to some portion of the chargers on site. This is how utility dollars can be leveraged to achieve equitable access to charging.

Standards, which ensure that chargers meet PGE's technical requirements and industry standards for safety, interoperability, and demand-response capability:

- In the future, these same technical requirements may also include more sophisticated forms of managed charging and V2G.

Data, which provides PGE with data for each individual charging port, including energy use, peak power, session duration, unique users, session cost:

- This continually informs PGE of how its rate structures are affecting how EV owners fuel their vehicles and whether a unique use case is emerging.

Education and Partnership, as having a role in make-ready means early engagement with our customers:

- This gives PGE more advance notice of future TE load and a load ramp over 5-10 years
- This allows PGE to help customers right-size their charger(s) and educate them on grid-friendly charging behavior.

Facilitate TE, as make-ready enables electrification:

- Early partnership with customers may create opportunity for more efficient/effective EV expansion at the site if it was made ready for additional chargers.
- If the benefits of TE load are valued and recognized within the structure of a TE line extensions, the system can provide make-ready cost-share so more businesses can make the financial case for EV charging

Seamless Customer Experience, making it easy for customers to choose electric "fuel":

- Reduces customer friction and provides peace of mind for customers that they don't have to manage design, construction, maintenance
- May improve project timelines because PGE is an expert in the plan/build process

As PGE contemplates the evolution of PGE-owned make-ready infrastructure and how it may be incorporated into the Line Extension process, a key component will be the process to estimate expected energy consumption associated with the new electric service.

For typical Line Extensions today, PGE receives an electrical load sheet in the customer's new service request. This identifies the connected load (kW) of all electrical devices on the new service. PGE uses this information to estimate demand load (kW) and to size transformers appropriately. PGE has also identified standard utilization factors (also called Combined Factors) based on the type of facility (e.g., 0.17x for hotels, 0.29x for hospitals). These Combined Factors were developed based on years of historical usage data and are used to estimate annual energy consumption based on the total demand load and the annual operating hours.

When PGE began to receive requests for new services with only EV charging (no building), PGE found it challenging to estimate annual energy consumption absent a clear Combined Factor. In 2021, PGE analyzed available historical data for existing EV charging stations and determined a standard Combined Factor to use for EV-only services. However, there was limited data available. The 2023 TE Plan requirements for meter data should provide learnings to assist this issue.

When PGE launched Fleet Partner in 2021, the program estimated energy consumption differently. Since the chargers were to be primarily used by fleet vehicles owned by the customer, PGE could estimate energy consumption based on the vehicle miles traveled, fuel efficiency (kWh/mi), and an estimated 10 percent in losses between the meter and the vehicle. PGE plans to validate this estimation method using actual data from Fleet Partner chargers but believes this method to be more accurate than the Combined Factor method. It should be noted that the accuracy is also improved because the customer legally agrees to using the estimated energy consumption in the Fleet Partner Participation Agreement.

Unfortunately, the vehicle-miles-traveled method for estimating energy consumption only works when there is a predictable schedule of vehicles using the chargers. For public charging, this method is less applicable, so PGE plans to use the Combined Factor method while gathering data through its various EV programs to improve the accuracy of the Combined Factor method (or create a different method for estimating energy consumption).

To aid in the development of future EV rates, PGE plans to use insights collected through make-ready programs. Every EV charging use case (fleet, multi-family, public L2, public DCFC, public heavy-duty) has its unique characteristics. These characteristics will be critical to identify during the rate design process. Each use case may vary by:

- Daily load profile hourly average and peak kW
- Charger-to-vehicle ratio
- Nameplate kW per charger by vehicle type
- Annual energy consumption per charger or vehicle
- Utilization factor/combined factor (energy usage based on demand load)
- Demand factor by charger quantity (demand load based on connected load)
- Off-peak versus on-peak usage
- Site load ramp (year-by-year)

Many of the products proposed in this Plan are built on the foundation that more data, insights, and customer engagement is needed for each of the EV charging use cases to effectively build full-scale programs and rates that address barriers and cost-effectively incorporate TE load onto the system.

I.10 Demand response

Table 76. DR customers by customer class

Customer Class	2019	2020	2021	2022	2023
Residential	107,876	116,835	168,011	175,945	192,716
Business	95	509	773	870	748
Total	**107,971**	**117,344**	**168,784**	**176,815**	**193,464**

Table 77. Winter DR capacity by year

Customer Class	2019	2020	2021	2022	2023
Residential	17.1	17.9	23.5	27.1	23.0
Business	18.6	21	30	35.7	32.0
Total	**35.7**	**38.6**	**54.1**	**62.8**	**55.0**
Season Peak	3422	3367	3629	4113	3661
DR as % of Peak	1.04%	1.15%	1.49%	1.53%	1.50%

Table 78. Summer DR capacity by year

Customer Class	2019	2020	2021	2022	2023
Residential	32.3	39	49.9	52.4	58.2
Business	20.6	23.7	32.1	40.3	38.6
Total	**52.9**	**62.7**	**81.9**	**92.7**	**96.8**
Season Peak	3765	3771	4453	4255.0	4498.0
DR as % of Peak	1.41%	1.66%	1.84%	2.18%	2.15%

Appendix J. Capital planning process

This Capital Process description provides an overview of the T&D (Transmission & Distribution) processes, roles, and responsibilities for T&D Project governance from budget-setting to project ideation to funding authorization. The Capital Portfolio team governs this process, monitors project statuses throughout the project lifecycle, and acts as custodian on behalf of the Business Sponsor Group (BSG) and the Capital Review Group (CRG) of a prioritized five-year roadmap.

Role Definitions

- Board of Directors (BOD) – The Board of Directors reviews and approves the annual capital budget. In addition, the BOD approves large strategic projects and future-year obligations for long-lead-time equipment purchases.
- Capital Review Group (CRG) – The Capital Review Group is a standing committee with governance over capital projects and allocates capital resources based on business value and alignment with PGE's strategy.
- Business Sponsor Group (BSG) – The Business Sponsor Group is a standing committee, empowered by the CRG to approve capital projects and manage the assigned portfolio to deliver the most value at the least cost. The BSG reviews and approves a proposed annual budget based on a five-year project road map that prioritizes projects based on PGE's initiatives and project readiness.
- Generation, Transmission & Distribution Project Management Office (G-T&D PMO) – The G-T&D PMO is an organization that manages a standardized process for the governance and execution of assigned capital projects for Generation and T&D.
    - Project Manager
    - Project Controller
    - Estimator
    - Construction Manager
- Capital Portfolio Management – The Portfolio Management team optimizes the project portfolio, acts as the primary interface with the BSG and CRG, and oversees the steps related to the planning and execution gates. The Portfolio Management team also monitors Portfolio health and execution risks throughout the year, escalating issues to the executive team and the CRG as needed. The Capital Portfolio team has several functions and specialties within the group. They are:
    - Portfolio Manager – Manages day-to-day portfolio activities, including but not limited to balancing portfolio, evaluating project trade-offs, recommending projects, and delivering portfolio at maximum value.
    - Financial Analyst – Perform portfolio financial modeling, track portfolio health, and maintain portfolio reporting.
    - Capital Project Sponsor (CPS) – Evaluate and recommend projects based on benefits and alignment to corporate strategy. Ensures scope, budget, and schedule are complete before authorization.

- Asset Management Planning – The Asset Management Planning (AMP) team creates risk-based economic models to prioritize capital investments based on the asset failure risk and asset replacement cost.
- T&D Planning – The T&D Planning team provides transmission and distribution planning analysis to recommend necessary capacity and customer-driven T&D projects over a five-year planning horizon.
- Distribution Operations Engineering – The Distribution Operations Engineering (DOE) team manages the day-to-day operations and health of the distribution grid, including but not limited to maintenance, improvement, and optimal use.
- Substation Maintenance – The Substation Maintenance team manages the health of substation assets. Their responsibilities include executing a comprehensive maintenance program and addressing real-time performance issues.

J.1 Capital budget setting

PGE employs a simultaneous bottom-up and top-down approach to cost management, with multiple layers of controls. PGE's annual capital budgeting process is governed primarily by three groups:

- PGE's Board of Directors (BOD),
- the Capital Review Group (CRG), and
- Business Sponsor Groups (BSG).

This is a layered process which is explained in more detail below. From the "bottom-up," based on rigorous review of a project's need, scope, budget, and forecast, the BSG approves a portfolio of projects for funding. This is shared with the CRG which adjusts funding priorities across PGE. The aggregate annual budget is presented to the BOD for review and approval. The rigorous review is continuous, and the BOD budget review is performed once annually with incremental changes and revisions submitted and reviewed as needed. From the "top-down," the BOD is the ultimate decision-maker for determining the amount of capital available across PGE. The CRG then allocates this to BSGs based on funding allocation priorities, and then each BSG manages its allocation by reprioritizing and balancing its portfolio of projects.

The BOD is responsible for reviewing and approving the annual capital budget. In addition, the BOD approves large strategic projects and future-year obligations for long-lead-time equipment purchases. To the extent additional capital funds are needed after the annual budget is approved, the BOD must approve any additional spending. Finally, the BOD also determines the CEO's extended approval authority, which provides the CEO with limited authority to approve budgets over the BOD-approved amount. The annual capital budget is recommended to the BOD by the CRG. The CRG develops the proposed annual budget based on the rigorous portfolio development and management of each BSG and evaluates the use of funds throughout the year on a monthly basis. Each BSG develops a proposed annual budget based on its three- to five-year project road map that prioritizes projects based on PGE's strategic initiatives to benefit customers and project readiness.

PGE incorporates a multi-year outlook in our capital planning and management in several ways. The BSG develops three- and five-year roadmaps which estimate projects over a longer-term duration. This provides the BSG with a broader view of the portfolio and enables the portfolio manager to balance project priority and cost management. The roadmaps enable portfolio managers to maintain funding stability over time and allow PGE executives to monitor the overall trend of the capital programs. PGE also employs analytical tools like asset risk models, system planning models, customer forecasts, and community development plans to help drive long term plans. With this multi-year perspective, PGE leaders can carefully balance customer price impacts with the need to invest in a reliable and safe system.

J.2 Portfolio management

Portfolio Management refers to the management of the entire portfolio within a particular area, such as T&D. The two primary leadership roles in Portfolio Management are performed by the BSG leadership and a Portfolio Manager. Portfolio Management decides when projects are ready to move from the roadmap to active work, allocates funds to projects based on performance, approves projects at stage-gate milestones, monitors portfolio execution and delivery of benefits, manages portfolio exceptions, and escalates issues to the CRG as needed.

The Portfolio Manager verifies that projects benefit customers by aligning with and delivering on PGE's strategy, allocates budgeted dollars to projects based on performance, approve stage gate milestones for projects, monitors portfolio execution and benefits delivery, manages project expectations, maximizes value in the portfolio, actively balances the portfolio, and identifies and escalates issues, as needed.

Project Management refers to the management of an individual project through the process by a Project Managers. The Project Manager manages a project's progression through the planning and execution stage-gates and helps keep the project on schedule and within the budget, as discussed in more depth below.

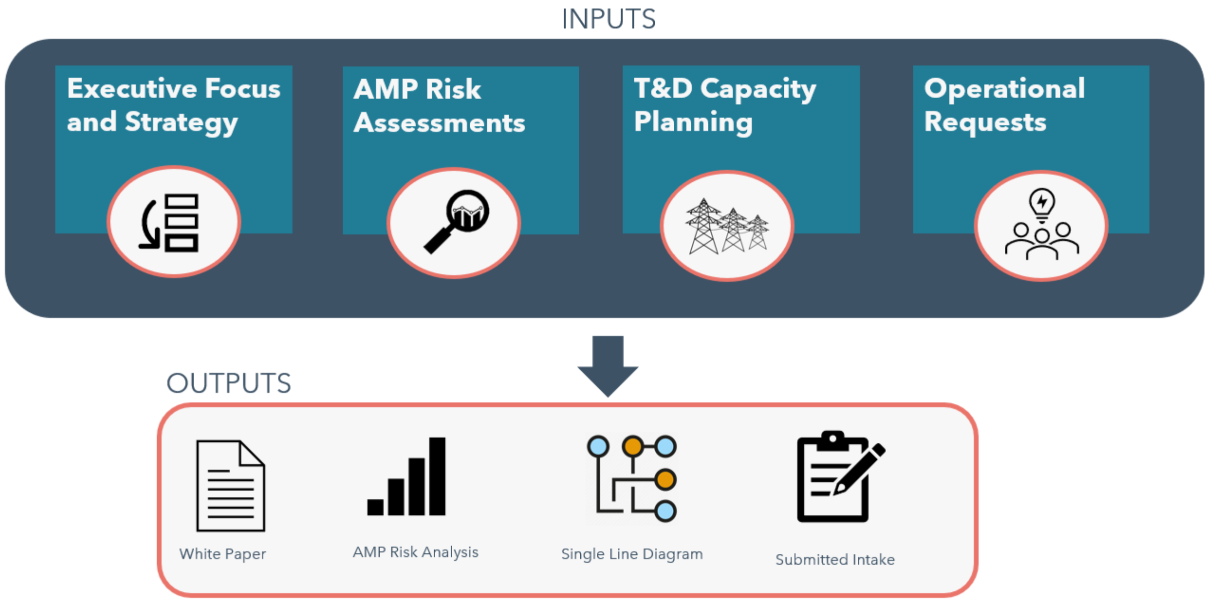
The T&D Capital Project Process is structured into the following sections:

- Project/Program Development
- Project Qualification
- Project Prioritization

J.3 Project/program development

New program and project ideas come from various sources within PGE. These sources are described below as inputs. PGE employs analytical tools like asset risk models, system planning models, customer forecasts, and community development plans to help drive long-term capital project priorities. These inputs and outputs are represented in **Figure 69**.

Figure 69. Project and program inputs and outputs



AMP Risk Analysis

For business cases, AMP utilizes an evaluation tool known as the Integrated Planning Tool (IPT) for each analysis. The team identifies and loads in the assets from the project using respective life cycle models. The tool enables a comparison of the current state to various project options to calculate the reduction in life cycle cost of ownership, risk, and other reliability metrics to determine the optimal economic solution.

Operations Requests

Operations requests originate from maintenance activities by departments such as Substation Maintenance, Transmission Engineering, and Distribution Operations Engineering

Executive Focus

PGE's executive focus is on emerging high-profile initiatives such as Wildfire Mitigation and Resiliency, core infrastructure, and resiliency.

Outputs may include, but are not limited to:

- Study reports
- One-line diagrams
- AMP Risk Analysis
- Submitted Project Intake Form

J.4 Project qualification

The project qualification process, also known as the T&D Capital Intake process, begins with identifying a project or program need. The Capital Project Sponsor administers this process by reviewing the project demand submittal and coordinating between subject matter experts (SMEs). This results in an initial project concept with a vetted scope, benefits, cost, and schedule. The process concludes with a project demand recommendation (via the T&D Project Intake Tool).

The Capital Portfolio team uses the T&D Project Intake Tool to collect project demands. This tool facilitates project evaluation on multiple criteria.

All employees within T&D have basic access to the T&D Project Intake Tool. Additional transmission-level access is provided to staff with proper Federal Energy Regulatory Commission (FERC) level access to transmission data. When requesting evaluation of a project demand, the requester must enter a minimum amount of information, including project scope, alternatives considered, schedule, and budget information.

J.4.1 T&D Project Intake Process

Each project demand follows a prescribed lifecycle, which tells requester(s) the status of their request. **Figure 70** describes the Project Intake Lifecycle graphically.

Figure 70. Project demand intake lifecycle and status detail

Draft	Submitted	Review	Scoping	Qualified	Deferred	Funded	Canceled
The project initiator fills out the project intake form and saves it into QuickBase.	The project initiator submits the project to the Capital Project Sponsor (Portfolio) for review.	The Capital Project Sponsor (Portfolio) engages with stakeholders to understand scope, benefits, costs, schedule, and constraints. The project submittal is under consideration by business units during this evaluation stage.	The Capital Project Sponsor (Portfolio) requests an estimate, defines the project scope, and builds a business case in partnership with stakeholders. The Capital Project Sponsor proposes a preliminary 'in-service' date based on the current scope and sends notice to the PMO.	The project has qualified for possible funding and has a 50% feasibility estimate, a soft schedule, and identified benefits. The Capital Project Sponsor initiates project handoff to the PMO.	The project qualifies for eventual funding but is in this holding tank for future consideration; a project can move to this stage for several reasons.	The PMO has assigned a project team. The project team has created a funding project and has submitted the funding project for planning dollars. The BSG has voted and approved the project to move forward with the planning stage. The project is funded in the Capital Portfolio.	The project may be canceled at any time during the process and for various reasons.

Once an Intake is submitted, an automated email notifies the Capital Sponsorship team. Then a Capital Project Sponsor will schedule a review meeting with the requester(s) to determine any additional information needs.

The Intake will enter the Scoping status while anything missing or unclear from the qualification inputs is addressed. Depending on the degree of the incomplete information, the Capital Project Sponsor may schedule an additional review meeting(s).

Upon completing the details and a recommendation from the Capital Project Sponsor, the project demand awaits review and qualification determination by the Portfolio Manager. During the qualification determination, the Portfolio team may consider additional factors, including strategic alignment, project dependencies and overlap with other projects.

J.5 Project prioritization

The Portfolio team develops an annual five-year Capital Project Roadmap. The T&D BSG reviews and approves the roadmap and issues it every June to help establish the priority for the years ahead. Many groups provide input to the roadmap's development, including System Planning, Asset Management, Operations, Project Management, and Supply Chain. It is a living document that the Portfolio team manages monthly. The project prioritization process results in project inclusion on the roadmap.

Prioritization inputs include:

- Qualified Project Demand from Capital Project Sponsor
- Resource Availability
- Material Availability
- Cash Flow
- AMP Risk Register

Prioritization outputs include:

- Updated T&D Capital Roadmap
- Resource Plan
- Long Lead Equipment authorization
- Project authorization

J.5.1 Portfolio definition

PGE invests in capital projects for many reasons. Some projects are discretionary, and some are non-discretionary. It is important to capture the drivers for the project in a manner that is quick and easy to understand. For the Base Portfolio, the T&D BSG established two sub-portfolios: Grow the Business (GTB) and Sustain the Business (STB).

At a high level, this sub-portfolio classification helps PGE understand if our company is balancing growth with core business investments. Examples of STB investments are aging asset replacements and work to keep the lights on. GTB investments are mainly new customer load requests or capacity-driven projects due to load demands.

In addition to the sub-portfolio classification, each sub-portfolio has a set of categories to help provide more details on the nature of the investments (see **Figure 60**).

Before funding authorization, every project entering the Portfolio is assigned a sub-portfolio and category. The main driver of the project is used to determine the sub-portfolio and category assignments. There can be only one sub-portfolio and one category assignment per project, even though there may be multiple reasons for the investment. System Planning and/or the AMP team help provide a sub-portfolio and category assignment, depending on where the project originated.

Using the sub-portfolio and categories together, the T&D BSG can quickly see what projects are discretionary versus non-discretionary. For example, non-discretionary projects are GTB-compliance/customer or STB-compliance/customer since there are firm customer or compliance commitments. Discretionary projects fall in the remaining categories, such as operations, reliability, and capacity. Examples of discretionary projects are proactive asset replacements and asset health and reliability mitigation.

Appendix K. Coordination on affordability

This section describes efforts which PGE, the Energy Trust of Oregon, and other regional entities are undertaking to coordinate planning and co-deployment of solutions to address affordability. This work reduces energy burden for affected customers, in part by supporting affected customers' ability to participate in PGE's Flex Load offerings and participate in the bi-directional grid.

K.1 Multi-year planning: Affordability pillars

Navigating the trilemma of affordability, reliability, and decarbonization is complex. Recent legislation has the potential to transform long held approaches to serving customer needs. House Bill (HB) 3141 (2021) revised public purpose charge (PPC) allocations, established equity metrics and evolved low-income electric bill payment assistance. HB 2475 (2021) allows the OPUC to consider customer characteristics that affect affordability when approving programs and energy rates charged by regulated utilities. Both bills invite reconsideration of the treatment of cost-effective energy efficiency and demand response resources as described in Oregon Revised Statute (ORS) 757.054.

PGE's ratepayer investment in energy efficiency is effectuated by Energy Trust of Oregon since 2002. The annual budget includes both cost-effective programs and non-cost-effective programs by way of measure exception. The latter is subject to criteria as provided in the docket progression: UM 551 (1994) Order No. 94-590, then UM 1622 – Gas and Electric Exceptions (2012) then, UM 1696 – Electric Exceptions (2014) Order No. 15-029. Generally, measure exceptions serve as a pathway to a cost-effective offering, however, they also serve to provide incentives for traditionally hard to reach customers. In addition to exceptions, PGE ratepayers fund the program delivery infrastructure to deliver these incentives to traditionally hard to reach customers via community partner organizations. This investment in both non-cost-effective measures and community partner capacity building represents a larger portion of the Energy Trust of Oregon budget since the passage of HB 3141 and HB 2475, and though necessary to increase participation, are a deviation from standard practice, a contributor to recent budget increases and therefore rate impacting for non-participants.

To manage the rate impact of energy efficiency investment and successfully garner the participation of customers who might otherwise experience barriers to participation, a more holistic approach is needed. This holistic approach must leverage and braid the federal, state, and local funds which have become available to reduce the costs to customers. PGE's approach includes work with the Energy Trust to cobrand and reach hard to serve customers to ensure our lowest income customers benefit.

PGE sees affordability as a mandate for all customers, however, of the approximately 800,000 residential customers that PGE currently serves, it is estimated that 20% are energy burdened – with bills that represent at least 6% of income. Numerous utility and state agency programs exist for the benefit of lower income customers and navigating these programs is challenging across multiple organizations and eligibility requirements.

To meet the needs of all residential customers, PGE proposes a holistic approach to affordability, built upon the following three pillars:

1. **Bill assistance** – Participation in Public Purpose Charge (Sch 108), low-income assistance (Sch 115), and other state agency programs that fund low-income housing, weatherization, and bill payment assistance.

   Between 2014 and 2023 PGE's public purpose charge disbursement and low-income assistance funding supported more than $235M in weatherization upgrades and electric bill assistance, including Energy Conservation Helping Oregonians and Oregon Energy Assistance Program funding, for income qualified households and delivered via Community Action Agencies.

2. **Bill discount** – PGE's Income Qualified Bill Discount (IQBD) (Sch 18) tiers of discounts afforded to income eligible PGE customers.

   On docket UM 2211 PGE conducted engagement on the IQBD proposal through the Fall and Winter of 2021, ultimately filing the Company's proposal on January 13, 2022. The proposed IQBD was the result of several evolutions informed by stakeholder feedback and met most Staff baseline evaluation criteria. The program is applicable to all PGE residential customers with a gross household income at or below 60 percent of Oregon state median income (SMI), adjusted for household size.

   Monthly bill discounts are calculated as a percentage of bill, and are offered at five tiers, based on the enrolled Customer's household income as a percentage of SMI. Total enrollment and expenditures in 2023 were approximately 70,000 and approximately $14.5M, respectively.

3. **Bill reduction** – Participation in energy efficiency (Sch 109/110) and/or Flexible Load programs to reduce consumption and the decrease in investment via braiding of federal, state and local public sector incentives.

   To ensure prudent investments PGE is required, per statute, to plan for and pursue all available energy efficiency resources that are cost effective, reliable, and feasible. The intent of this investment in energy efficiency is to promote lower energy bills, protect the public health and safety, and improve environmental benefits, and similarly, the intent of the utility investment in demand response resources is to reduce the need for procuring new power generating resources, which, in turn, reduces energy bills, protects the public health and safety, and improves environmental benefits.

   Distributed energy resources activation is a part of an all-resource solution to least cost service and an increasing contributor to meeting PGE's decarbonization goals as articulated in its recent Integrated Resource Plan. Also, per Section 7 of enrolled HB 2475, in addition to comprehensive classifications, tariff schedules, rates and bill credits, the Public Utility Commission may address the mitigation of energy burdens through bill reduction measures or programs that may include, but need not be limited to, demand response or weatherization.

An inventory of bill assistance, bill discount and bill reduction programming, and associated income eligibility as a percent of SMI, is provided in **Table 79** below.

Table 79. Income eligible program inventory

Program name	Customer outcome	Administrator	Funding source	Eligibility criteria	2023 Annual $
Low-Income Home Energy Assistance - Energy Conservation Helping Oregonians and Low-Income Housing program	Bill Assistance, Bill Reduction	Oregon Housing and Community Services	PGE schedule 108: PPC	< 60% SMI	~$36M in aggregate38F[113]
Oregon Energy Assistance Program	Bill Assistance	Oregon Housing and Community Services	PGE schedule 115: Low-Income Assistance	< 60% SMI	
Low-Income Home Energy Assistance - Weatherization Assistance Program	Bill Reduction	Oregon Housing and Community Services	PGE schedule 108: PPC	< 80% SMI	
Income Qualified Bill Discount	Bill Discount	PGE	PGE customer rates via non-participants	< 60% SMI	~$14.5M
PGE Flexible Load Management/ Demand	Bill Reduction	PGE	PGE customer rates	n/a	Subset of ~$15.6M

[113] Report to Legislative Assembly on Public Purpose Charge Receipts and Expenditures Report Prepared by Evergreen Economics Period: July 1, 2021 – June 30, 2023; As well as retrieved from remittance on PGE Schedules 108 and 115.

Program name	Customer outcome	Administrator	Funding source	Eligibility criteria	2023 Annual $
Response Programs					
Energy Efficiency Programs	Bill Reduction	Energy Trust	PGE schedule 109		Subset of ~$87M
Renewable Energy	Bill Reduction	Energy Trust	PGE schedule 108: PPC		Subset of ~$16M
Solar/ Savings Within Reach and on bill financing	Bill Reduction	Energy Trust	PGE customer rates and PPC	< 120% SMI	*Incl'd in Energy Efficiency & Renewable program spend*
Solar for All	Bill Reduction	ODOE, Energy Trust, Bonneville Env. Foundation	Public – Federal Braiding opportunity	tbd	$87M total beginning 2025/2026
Portland Clean Energy Community Benefits Fund (PCEF)	Bill Reduction	Grant recipients for single family, affordable multi-family and small business projects	Public – Local Braiding opportunity	tbd	tbd; MOU with Energy Trust re: deferred maintenance pending
Home Electrification (IRA Sec. 50122)	Bill Reduction	ODOE via Energy Trust	Public – Federal Braiding opportunity	< 80% SMI	$52M total beginning 2025
Home Efficiency (IRA Sec. 50121)	Bill Reduction	ODOE via Energy Trust	Public – Federal Braiding opportunity	< 80% SMI	$52M total beginning 2025

K.2 Action planning with the Energy Trust

As a result of legislative direction in HB 3141 (2021), codified as ORS 757.746(e), Energy Trust of Oregon was required to, "with public utilities, jointly develop public utility specific budgets, action plans and agreements that detail the entity's public utility-specific action plan (USAP), resources, including coordinated activities that require joint investment and deployment." Also, per the legislation, "Each action plan must reflect stakeholder feedback gathered through a public process managed by the entity and the relevant public utility as overseen by the commission." This statutory direction required modification to Energy Trust's current budget development process, with more utility-specific coordination. In June of 2022, following a series of work sessions with OPUC, Energy Trust, utility funders and ratepayer advocates, a Budget Process Coordination and Action Plan Memorandum (the "HB 3141 Budget Coordination Memo") was formed. This memorandum represented a joint planning framework that articulated stepwise activities to support annual budget and utility-specific action planning.

Building on this plan development process the Energy Trust and PGE propose evolving from a two-year cycle to a multi-year (2026-2030) time horizon and from an activity-based plan to an outcomes-based co-deployment framework. Doing so affords the two organizations the opportunity to better maximize value for our shared customers, accelerate procurement as determined in the PGE Integrated Resource Plan in compliance with HB 2021, as well as align based on organizational and program readiness.

K.3 Co-deployment with the Energy Trust

Co-deployment with the Energy Trust encompasses a shared strategy, with common marketing, outreach, and messaging, to efficiently deliver complementary energy services to shared customers. Through co-deployment of complementary services, customers benefit from behind-the-scenes coordination with streamlined participation and total delivery cost reduction for all ratepayers. To start, co-deployment will include targeting priority high energy burdened customers with services that lead to meaningful bill reduction and advance the shared objective of reducing energy burden. The timing of this effort is aligned with implementation of HB 2475 through the OPUC Docket No UM 2211, with the goal of reducing energy burden and the anticipated availability of public sector funding. Co-deployed services will initially consist of existing, feasible offerings provided by each organization today. Over time, additional services and deployment forms or pathways will be added to the framework as each organization is ready to bring in more services to market. The framework will evolve to focus on different configurations of candidate screening and more targeted delivery.

- Co-deployment may take a variety of forms and pathways:
- Community outreach: Shared program marketing collateral and tabling events together
- Co-funding: A methodological approach in which PGE provides complementary funding for flex value (e.g., residential thermostats)
- Bill reduction: Referral of IQBD customers to increase EE program participation (also provides flex potential for future co-funding opportunities)
- Solar+ storage: Aligning PGE smart battery roadmap with the U.S. Environmental Protection Agency Greenhouse Gas Reduction Fund Solar for All grant funding timing
- Pilot to program: Ensuring that tested collaboration yields a hand-off to product and measure development

Potential services and timing for co-deployment based on understood organizational and program readiness as laid out in **Table 80**.

Table 80. Potential services and timing for co-deployment with Energy Trust

	2025	2026-2027	2027-2028
Energy Trust	For single family residences: insulation, no cost heat pumps, heat pump water heaters, ductless heat pumps, targeted to replace electric resistance heating; For multifamily residences: strategic energy management	Solar plus storage (solar for all and PCEF combination); Develop and/or deploy co-funded measures for efficiency and flex value, learning from SGTB and flex feeder experiences; Co-evaluation of framework, recommendations for improvements For multifamily residences: line voltage thermostats	Evaluation of framework and impacts; Expand to other customers and/or geographical areas
PGE	Energy Burden Needs Assessment recommendations regarding UM 2211 New Discount Program	Alignment on solar+storage and midstream heating ventilation and air conditioning via PGE+, continue residential and non-residential thermostat co-funding, support new building demand response design and technical assistance	Co-fund or otherwise co-deploy "on-line" voltage thermostats and midstream HPWH

K.4 Governance with the Energy Trust

This section describes a new approach to coordination with the Trust. This governance structure clarifies and formalizes the roles of each partner and lays out a process to articulate priorities through utility-specific action planning.

A joint commitment by each organization is key to success, and an agreed upon process for decision-making, role definition and annual updates to the multi-year framework provide the guidance for stakeholders to understand the intent and accountability associated with co-deployment.

Though short, intermediate, and long-term outcomes are provided in the logical model, the processes that support those outcomes or impacts represent the key elements. Each of these elements needs to be clearly defined at both the organizational and project levels to support consistent management processes and achieve the intended outcomes.

Table 81. Energy Trust of Oregon coordination

Key element (what)	Decision (why)	Delivery partners (who)	Energy Trust inputs	PGE inputs	Activities (how)	Outputs (where)
Co deployment plan design	Objectives/ priorities	Contribute and/or Co-Create	Co-Lead	Co-Lead	Development of multi-year outcomes and governance	Frame-work
Determining market and/or resource potential	Planning/ policies	Contribute	Co-lead (EE/RE)	Co-lead (Flex Load/DR)	Define resource requirements	USAP
Budget Development/ Forecasting	Planning/ policies	Contribute	Co-lead	Contribute	Identify research objectives and co-deployment opportunities and locations	USAP
Budget Monitoring and Tracking	Administration / delivery	Contribute	Lead	Awareness / contribute	Discuss pipeline management and variance	USAP
Budget Reporting and Narrative	Administration / delivery	Contribute	Lead	Contribute	Discuss pipeline management and variance	USAP
Program management	Administration / Delivery	Lead and/or contribute	Lead	Contribute	Identify delivery channels and operational efficiencies	USAP
Delivery partner engagement	Planning/ policies	N/A	Lead	Contribute	Identify relevant partners based on opportunities and locations	USAP
Marketing plan development	Planning/ policies	Contribute and/or co-create	Co-Lead	Co-Lead	Identify delivery channels and operational efficiencies	USAP

Key element (what)	Decision (why)	Delivery partners (who)	Energy Trust inputs	PGE inputs	Activities (how)	Outputs (where)
Marketing implementation	Planning/ policies	Contribute	Co-lead	Co-lead	Identify relevant partners based on opportunities and locations	USAP
Customer outreach	Planning/ policies	Co-lead	Co-lead	Co-lead	Identify referral and tabling opportunities	USAP
Customer enrollment	Administration / delivery	N/A		N/A	Identify relevant partners based on opportunities and locations	USAP
Managing contractors & trade allies	Administration / delivery	Contribute and/or co-lead (depending on partner)	Lead	Contribute	Define resource requirements and operational efficiencies	USAP
Project installation	Administration / delivery	Lead/co-lead	Lead/co-lead		Identify delivery channels and operational efficiencies	USAP
Reporting, tracking outcomes	Administration / delivery	Contribute	Co-lead	Co-lead	Share metrics on outcomes	USAP
Manage 3rd party evaluation	Administration / delivery		Lead	Contribute	Identify operational efficiencies	USAP

K.5 History of regional partnership

PGE sees the value of a holistic approach which includes co-deployment of bill reduction programs with the Energy Trust of Oregon, in concert with bill assistance and bill discount programs, and observes the sizeable amount of public sector funding expected to deploy in Oregon in 2025 and beyond. Higher public sector incentives are expected for the same income eligible customers on PGE's IQBD, many of which benefit from Energy Trust measure exception, so an opportunity exists to braid and amplify. As Energy Trust is the Oregon Department of Energy (ODOE)-designated implementer of Inflation Reduction Act funds, and co-implementer of EPA Solar for All funds, it is in a unique position to braid and deploy to the customers for whom the incentives are intended.

Higher incentives for energy efficiency and renewable energy offered in specific geographic areas is not a new approach. There is a legacy of partnership in co-deploying at the neighborhood level with Energy Trust of Oregon, Northwest Energy Efficiency Alliance, national labs, Community Energy Project, and other members of the Demand Response Review Committee in the Smart Grid Testbed since 2019. Additionally, Energy Trust has pursued targeted load management (TLM) projects independent of PGE since 2018. An inventory of these projects is provided in Table 82. Lessons learned from these demonstration projects may be brought to bear on new locational co-deployment approaches.

Table 82. Demonstration Project Summary[114]

Project	Dates	Location	Evaluator	Measures
NW Natural – Energy Trust geographically targeted energy efficiency (GeoTEE)	2019 - 2022	Cottage Grove, Creswell	Apex Analytics, LLC	Furnaces, HVAC, insulation, windows, fireplaces
PGE Smart Grid Testbed Project	2019 - 2021	Portland, Hillsboro, Milwaukie	Cadmus Group	Peak Time Rebates (PTR), Thermostats, EV charging
Pacific Power – Energy Trust TLM Pilot	2018 - 2021	Medford area	Pivot Advising, LLC	Solar, weatherization, thermostats, central air conditioning, energy saver kits, lighting, food service equipment, HVAC systems controls and O&M (e.g., heat pumps)
Pacific Power – Energy Trust TLM Pilot	2016 - 2018	North Santiam Canyon	Navigant Consulting	HVAC, water heating, lighting, cooking, refrigeration

[114] PGE (March 2022). *SGTB Phase I – Final Evaluation Report*. Available at: [SGTB Phase I - PGE SGTB Final Evaluation Report - FINAL VERSION - 31MAR2022 - CLEAN.pdf - All Documents (sharepoint.com)]

Table 83, below, provides an analysis and synthesis of process and impact evaluations conducted by third party evaluators of demonstration projects in Oregon. Review of these reports was conducted to highlight lessons learned and identify themes across the various projects. The intent in cataloging findings from these multi-phase demonstration projects is to both promote awareness of the increase in participation the result of targeted geographic deployment, and the resulting organizational capabilities built that may be leveraged because of this local partnership work.

Table 83. Demonstration project evaluation themes

Category	Evaluation Theme
Research Objectives	An effort focused solely on maximizing peak reductions might take a different approach than an effort that also prioritizes reaching underserved customers In contrast to TLM and GeoTEE projects the SGTB objectives went beyond strictly load reduction and included an assessment of customer participation in, motivations for, and comfort levels with demand response as well as the best methods to engage.
Customer Value/ Participation	Spurred by increased incentives based on local avoided costs, in pilot areas identified by the utility, the TLM and GeoTEE pilots all realized an increase in residential participation over baseline For SGTB, it was observed that default opt-in enrollment in PTR also increased participation in firmer kinds of demand response (e.g., self- enrolled thermostats) Also, auto-enabling customers in PTR lifted enrollment rates for environmental justice community (EJC) groups and reduced disparities in program delivery for those who may have faced barriers to self- enrolling.
Equity	Unequal customer treatment was identified in concerns both arising from making offerings available to customers in the pilot area but not to those outside the boundary, and the extent to which offerings reach communities that have historically been underserved It was noted that less intuitive boundaries, those not defined by zip code but instead by the electric distribution infrastructure, invite issues from those outside the boundary

Apex Analytics LLC (June 2023). *Northwest Natural – Energy Trust Geographically Targeted Energy Efficiency (GeoTEE).* Available at:https://www.energytrust.org/wp-content/uploads/2023/07/GeoTEE-Phase-3-Evaluation-Report_REVISED_2023.06.05_Final.pdf
Pivot Advising (September 2021). *Pacific Power - Energy Trust Targeted Load Management Medford Pilot Process Evaluation*. Available at:https://www.energytrust.org/wp-content/uploads/2023/03/Final_PAC-TLM-Evaluation-Report_2021.pdf
Navigant Consulting (March 2020). *Pacific Power - Energy Trust Targeted Load Management Pilot North Santiam Canyon Summary Report*. Available at:https://www.energytrust.org/wp-content/uploads/2023/04/PAC_N.Santiam_TLM_SummaryReport_Final.pdf

Category	Evaluation Theme
	In the SGTB PGE Community Outreach Consultants (COC) worked with ETO and Community Energy Project to deliver weatherization and cooling workshops to low-income renters and homeowners.
Planning and Alignment	Given energy efficiency program delivery requires a distinct set of considerations it was recommended that ETO and its utility partners factor in the amount of demonstration project scopes the work needed to build relationships and understand community needs Providing quantitative savings targets specific to each program to help program implementers gauge their success An up-front local market analysis to inform marketing, outreach, and design SGTB targeted marketing of the Smart Thermostat program based on customer HVAC data increased the effectiveness of PGE's marketing
Marketing and Outreach	Efforts like email outreach played a larger role in building awareness of ETO than in directly motivating upgrade projects SGTB pursued five customer value proposition (CVP) marketing campaigns over the course of the pilot which explored engagement from a variety of perspectives - awareness, incentives, donating PTR earnings to a select non-profit, avoided carbon emissions, and renewables messaging Important to bring marketing into the conversation during the initial program design so that the approach is fully integrated
Org. Capabilities	ETO was able to develop systems and processes to coordinate special offerings and track the resulting uptake within targeted geographic areas It was suggested that the pilot's project manager be provided more authority to communicate directly with implementers rather than routing communications through staff from each program. Interviewees shared that key stakeholders should be consulted about their preference for the type and frequency of reporting that would be most useful to them

The DOE also awarded PGE a grant to accelerate and deploy grid edge computing, which will be effective October 1, 2024.40F The first edge computing meter installs thereunder are targeted for 2025, with 90K units expected by end of 2028. This work includes establishing a new DER gateway capability, DER disaggregation software, and options for customer facing applications/data. As noted on PGE's website, these investments "will help PGE maintain resilient grid operations during severe weather events and achieve progress toward our decarbonization targets. Grid edge technologies improve resilience, enable the integration of distributed energy resources, and maximize customer investments in home energy solutions." 41F

It bears acknowledging that there are active demonstration projects from which additional lessons will be learned (see **Table 84**). Those projects include the PGE Smart Grid Testbed

Collaboration (SALMON) and associated Flex Feeder, Smart Solar and Smart Battery pilots, pursued in partnership with Energy Trust, NEEA, NREL, and Community Energy Project, as well as the NEEA End Use Load Flexibility project for which PGE is one of several regional utility funders.

Table 84. Scope of regional partnership

Scope	Goals	Partners	Budget	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29
End Use Load Flexibility	Accelerate the adoption of grid-enabled end-use technologies through market transformation	*NEEA and another nine utilities across the region*	$0.7M (6-yr)											
SGTB Phase II DOE Connected Communities Project SALMON aka SGTB Collaboration	Build a 1.4 MW Flex Load resource within the project area and integrate the Flex Load devices into PGEs' ADMS and DERMS.	*Energy Trust, Community Energy Project, NREL*	$6.7M (5-yr)											
SGTB Phase II Flex Feeder Measure Development Incentive Delivery	Understand how best to integrate efficiency with other DERs in the planning, forecasting, & design of DSM programs, help PGE manage loads during periods of high demand.	*NREL, Energy Trust. NEEA serves as stakeholder*	$4.3M (5-yr)											
SGTB Phase II Smart Solar	Study how solar smart inverters can provide additional grid benefits via applying customized smart inverter settings	*NREL, Energy Trust*	$1.0M (2-yr)											
PGE Smart Battery	Explore the ability of distributed assets to provide grid services	*Energy Trust*	$1.1M (5-yr)											
SGTB Phase I	To accelerate the development of DR and to acquire it "at scale."	*PNNL, NWPC, NEEA, CUB,*	$5.8M (2.5 yr)											

Scope	Goals	Partners	Budget	'19	'20	'21	'22	'23	'24	'25	'26	'27	'28	'29
		ODOE, Energy Trust, cities, and CBOs												

Legend
Pilot period
Impact evaluation to determine savings realized

Defining time-based outcomes provides the end state necessary to understand the inputs, activities and outputs required to meet those targets. PGE collaborated with Energy Trust to identify Co-Deployment Logic Model outcomes and then presented them to PGE's Community Benefits and Impact Advisory Group (CBIAG) to inform the inputs, activities, and outputs. This approach ensured both that organizations were at a state of readiness to pursue stated outcomes and that those outcomes aligned with the CBIAG's understanding of our shared customers' needs. It is anticipated that PGE and Energy Trust will replicate this approach annually, in support of the utility specific action plan process, for intermediate and long-term outcomes.

Through a series of work sessions PGE and Energy Trust staff agreed that affordability represented the most urgent customer need and therefore it was appropriate to identify this as the short-term outcome. Co-deployment serves not only to address the affordability outcome but also serves as the first step toward locational deployment to address grid constraints and locational distribution value. That is, research objectives related to customer engagement in the short-term are therefore intended to inform the grid assessment criteria in the long-term. Put differently, a locational program-only approach in the short-term serves to address planning needs in the long-term.

Through a July 2024 workshop PGE and Energy Trust co-presented this logic model framework and proposed short- term outcomes to the CBIAG. Given PGE had completed and socialized an Energy Burden Needs Assessment with the group the request was to understand what program delivery approaches will be necessary to realize higher participation in customer segments that have historically been hard to reach.

It is anticipated that EPA Solar for All funding and IRA will begin to flow in 2025 and 2026, respectively.[115] Given 40% of those dollars are earmarked for environmental justice communities, including income-eligible customers there is an opportunity to amplify ratepayer funded energy efficiency and renewable energy incentives as well as increase participation in PGE's IQBD in communities for whom these programs are intended. An

[115] Wozniacka, G. (2024, October 7). *Oregonians won't see $113M in promised clean energy rebates until late 2025 or 2026*. OregonLive. Available at: https://www.oregonlive.com/environment/2024/10/oregonians-wont-see-113m-in-promised-clean-energy-rebates-until-late-2025-or-2026.html.

inventory of measures that meet both identified customer need and carry multiple funding opportunities are provided in **Table 85**.

Table 85. Prioritized co-deployment measures

Measure	Objective	Energy Trust-Exception	Energy Trust-Pilot	RTF-Flex43F[116]	Public Sector Braiding44F[117]
All Insulation/ Weatherization	Affordability, DERs Activation	Expires March 2028		2025-2029	IRA HEAR, 25C
Low-Income Insulation/ Weatherization	Affordability	Expires March 2028		2025-2029	IRA HEAR, 25C
Ducted Heat Pumps	Affordability, DERs Activation	Expires Dec 2026 (Fixed Promotion)	No-Cost Program Delivery Pilot (PDP)	2025-2029 upgrades/ conversions	IRA HEAR, 25C
Ductless Heat Pumps	Affordability, DERs Activation	Expires March 2025	No-Cost Program Delivery Pilot (PDP)	2025-2029 + Small Commercial	IRA HEAR, 25C
Extended Capacity Heat Pump	DERs Activation	Expires Jan 2026			IRA HEAR, 25C
Manufactured Home Replacement	Affordability	Expires March 2025			
New Buildings	DERs Activation	Expires March 2024			
Heat Pump Water Heater	Affordability, DERs Activation		No-Cost Program Delivery Pilot (PDP)	2025-2029 + Commercial	IRA HEAR, 25C

[116] The Regional Technical Forum is a technical advisory committee to the Northwest Power and Conservation Council established in 1999 to develop standards to verify and evaluate energy efficiency savings. In the 2025-2029 Funding Levels the RTF has included in its business plan priority energy efficiency and demand response technologies.
[117] The IRA includes the Home Electrification Appliance Rebate (HEAR) program which provides funding for incentives to flow state energy offices. In addition, there exists IRS sections 25C and 25D for energy-efficient home improvements and residential clean energy credits.

Measure	Objective	Energy Trust-Exception	Energy Trust-Pilot	RTF-Flex43F[116]	Public Sector Braiding44F[117]
Connected Thermostat	DERs Activation	Equity Metrics < $500		2025-2029 + Commercial	
Line Voltage Thermostat	DERs Activation			2025-2029	
Level 2 Electric Vehicle Service Equipment	DERs Activation			2025-2029	25D
Irrigation Pump Controls	DERs Activation			2025-2029	
Battery	DERs Activation				ODOE, 25D
Inverter	DERs Activation				ODOE, 25D

Public sector dollars may be braided with PGE customer dollars, bill discounts and programs, combined with Energy Trust measure exceptions (e.g., insulation, ductless heat pumps) and Energy Trust Savings and Solar Within Reach programs to increase participation in identified census block groups, and, if applicable, PCEF-funded deferred maintenance[118]. Numerous energy burden maps exist including: DEQ Disadvantaged Communities (DACs), HB 2165 electric vehicle charging for priority populations, and the Biden Administration's Climate and Economic Justice Screening Tool (CEJST) apart of the Justice40 initiative and the basis for deployment of IRA funds. A co-deployment on an identified census block group provides an opportunity to maximize value for the customers for whom these dollars are intended in a manner that draws inspiration from previous demonstration project successes and furthers PGE and Energy Trust's affordability objectives.

Therefore, in support of short-term affordability outcomes—and given limited inputs (or resources)—locations and implementation plans are provided in the UM 2211 Energy Burden Needs Assessment recommendations, informed by that rich dataset and the feedback elicited from the CBIAG.

[118] Up to 30-50% of PCEF project funding can be used for health, safety, accessibility, or enabling repairs and serve to complement other funding sources for equipment and components.