Chapter 1.

Distribution system overview

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"A transition to clean energy is about making an investment in our future."

— **Gloria Reuben**, environmental activist and a special advisor to The Alliance for Climate Protection

1.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice (EJ) communities communities.[13] It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.

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

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

WHAT WE WILL COVER IN THIS CHAPTER

The key components of the electric grid and distribution system

How the grid is changing and why distribution system planning matters

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

How PGE makes capital investments in our distribution system

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

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

Table 1. Distribution system overview: Guideline mapping

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

1.2 Introduction

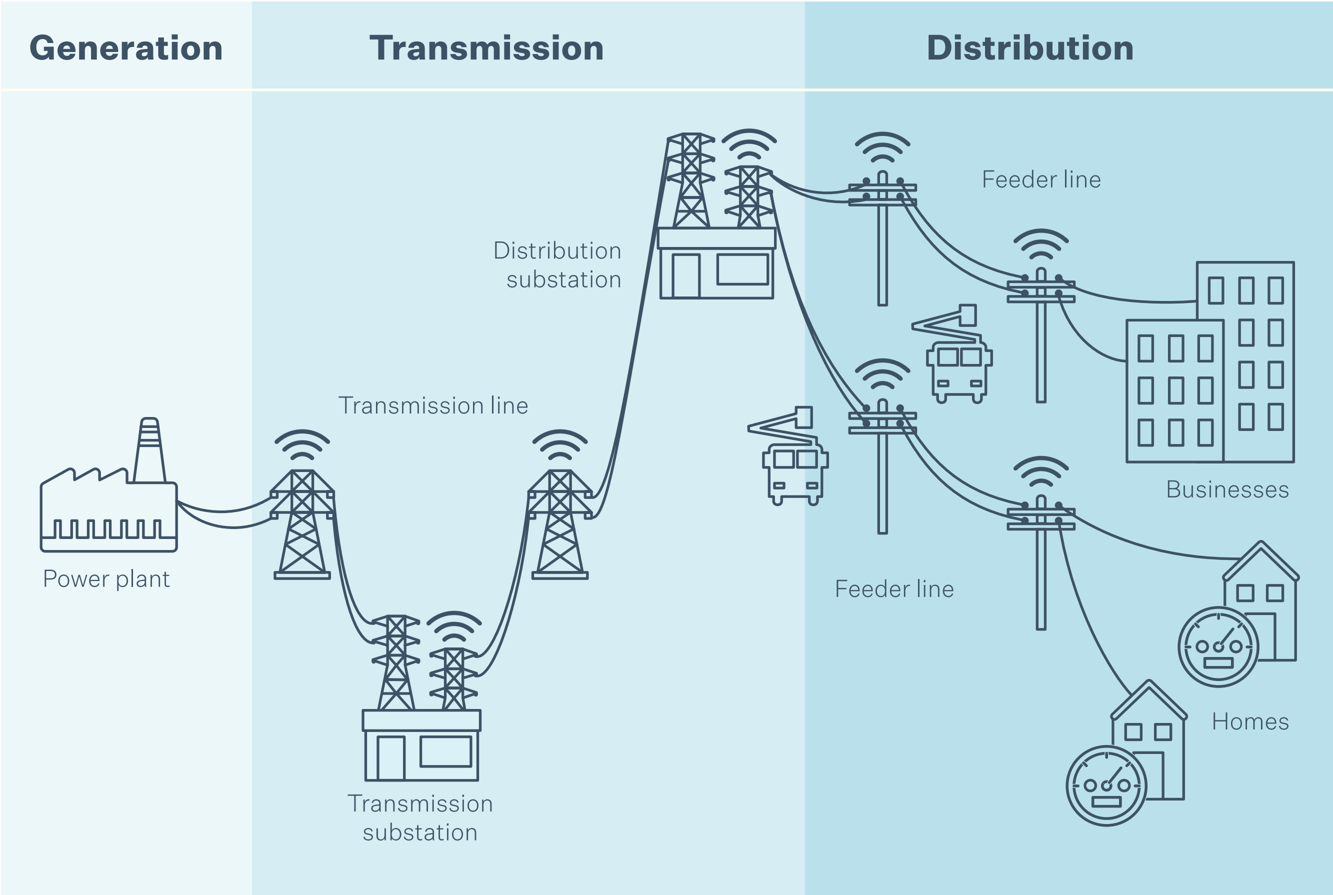
Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to foster transparency and to include an overview of baseline assessments of their distribution system as part of their DSP. This includes an asset inventory, management and monitoring practices, recent investments and DER penetration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

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

1.2.1 WHAT IS THE ELECTRIC GRID?

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

Figure 4. The electric grid



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

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

1.2.2 WHAT IS A DISTRIBUTION SYSTEM?

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

1.2.2.1 Engineering definition

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

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

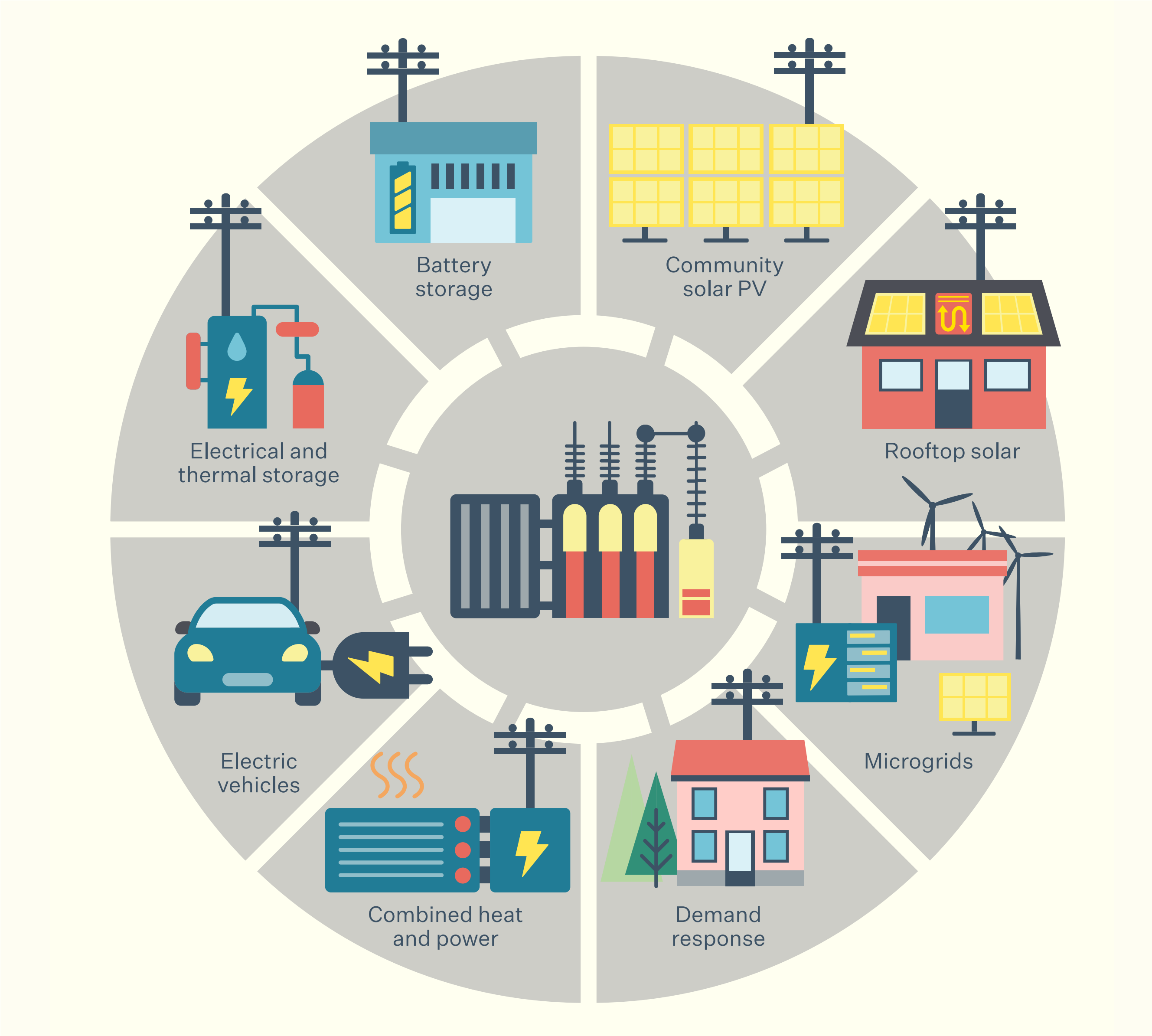
1.2.3 WHAT IS DISTRIBUTION SYSTEM PLANNING?

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

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

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

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



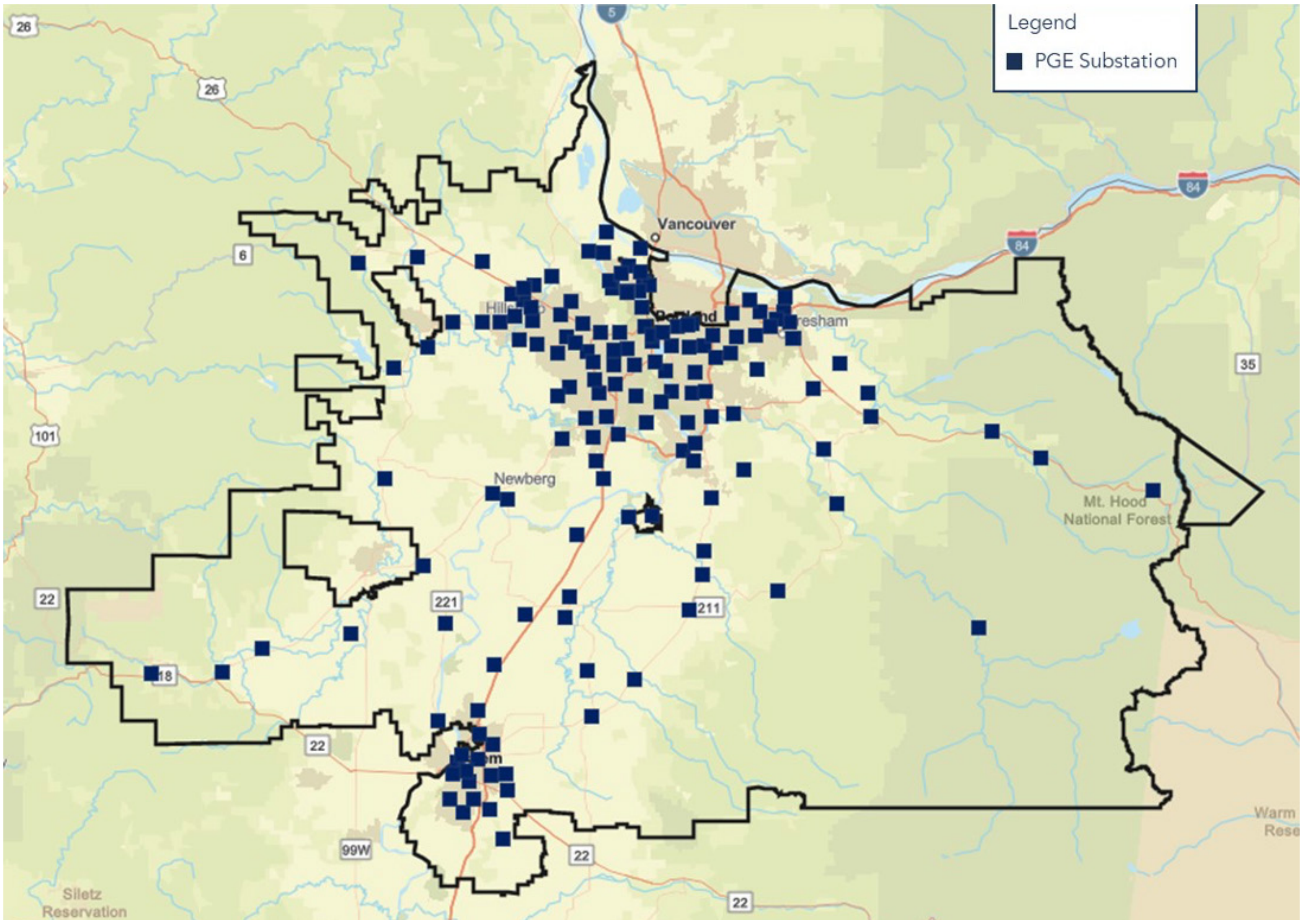
This brief timeline shows how technology has impacted distribution system planning:

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

1.3 System baseline and assessment practices at PGE

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

Figure 6. PGE's service area



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

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

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

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

Table 2. Summary of distribution assets as of Q1 2021

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

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

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

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

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

1.3.1 DISTRIBUTION SYSTEM PLANNING DRIVERS

Distribution planning is informed by key drivers such as load growth forecasts, economic development, new large single loads, grid modernization, regulatory requirements, safety, reliability performance of the system, urban growth boundary expansion and zoning changes. DERs are newer drivers, and different DERs have different impacts. For example, electric vehicle charging is an intermittent load addition, photovoltaic installations provide distributed generation and flexible loads offer opportunities for capacity relief by shifting energy use to more optimal times of day.

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

1.3.2 PGE DISTRIBUTION LOAD GROWTH FORECASTING METHODOLOGY

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

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

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

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

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

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

1.4 Distribution system historical capital investments

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

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

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

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

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

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

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

1.5 DERs currently integrated in PGE's distribution system

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

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

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

1.5.1 NET METERING AND DISTRIBUTED GENERATION

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

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

1.5.1.1 In-service facilities

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

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

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

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

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

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

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

1.5.1.2 In-queue facilities

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

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

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

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

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

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

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

1.5.2 DEMAND RESPONSE

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

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

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

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

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

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

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

1.5.3 ELECTRIC VEHICLES (EVS)

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

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

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

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

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

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

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

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

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

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

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

1.5.4 CHARGING STATIONS

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

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

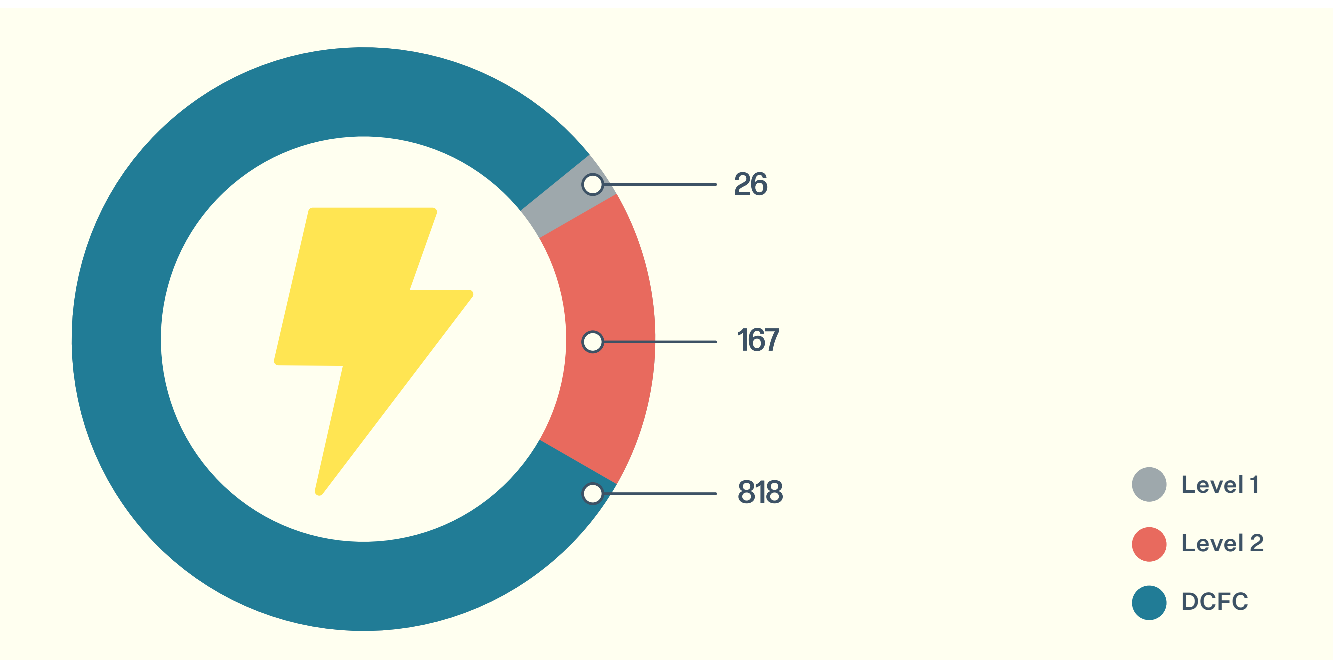
1.5.4.1 Charging stations in our territory

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

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

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

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



Direct Current Fast Charge (DCFC)

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

Figure 8. Charging stations by ownership and type

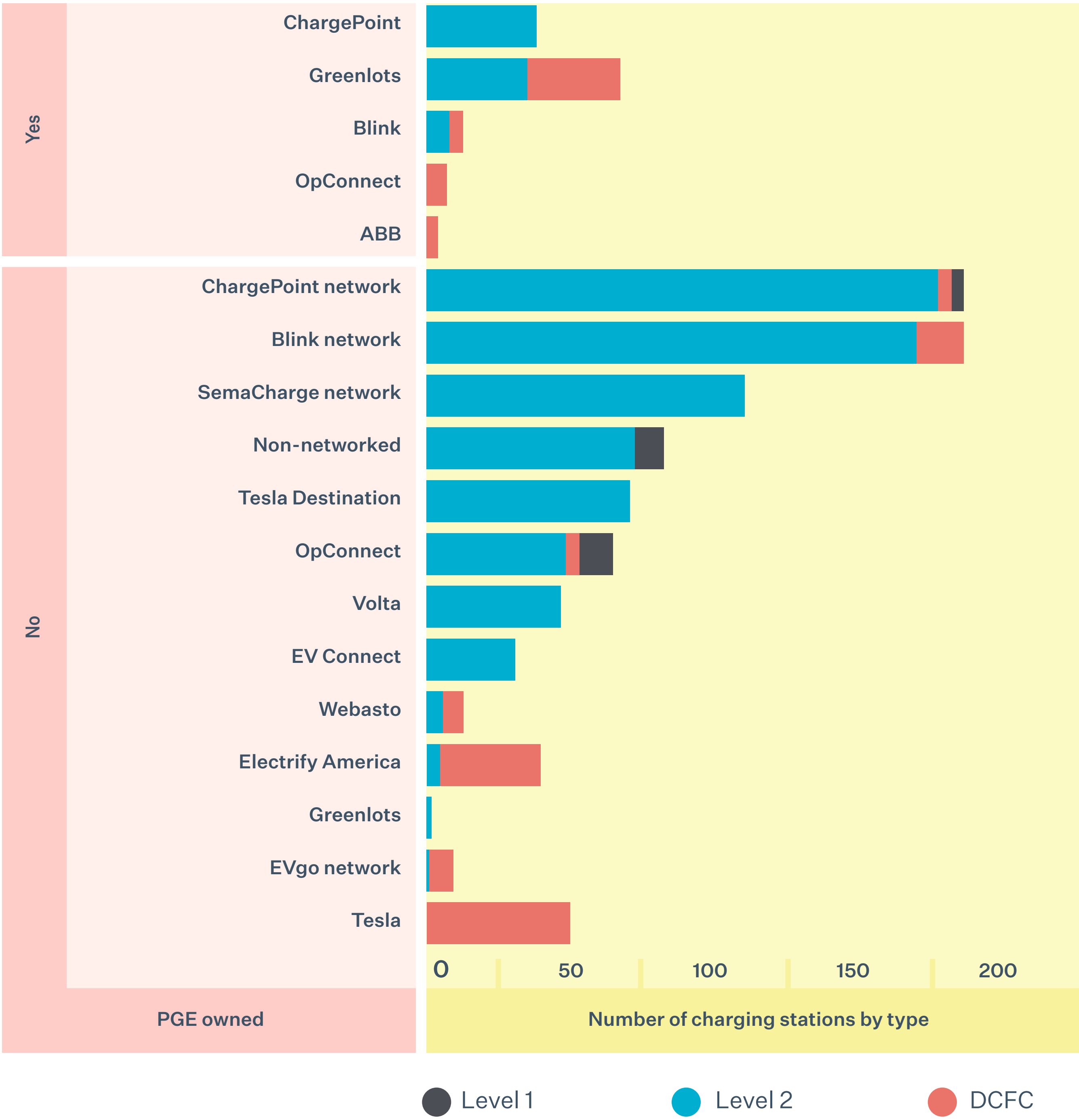
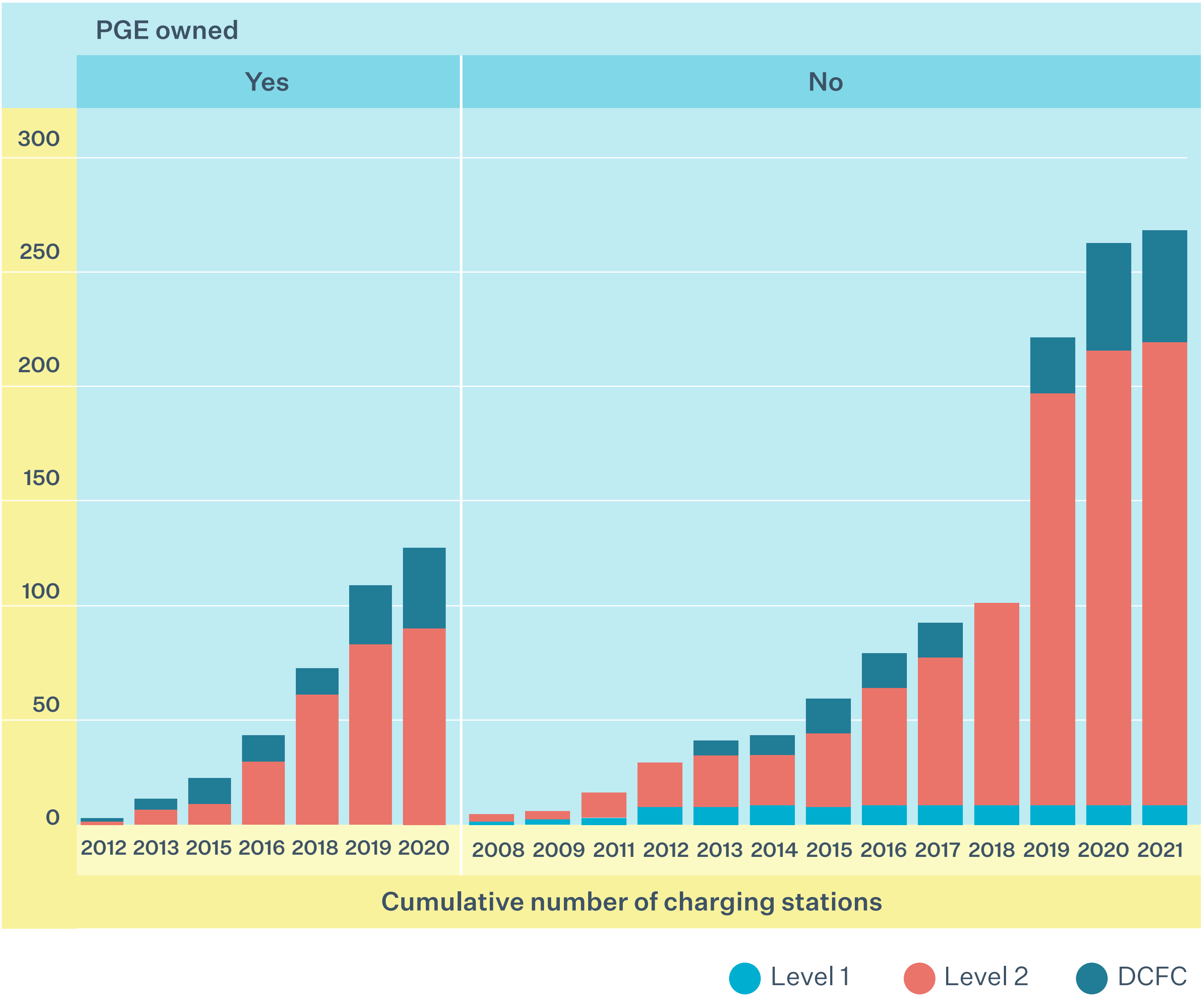


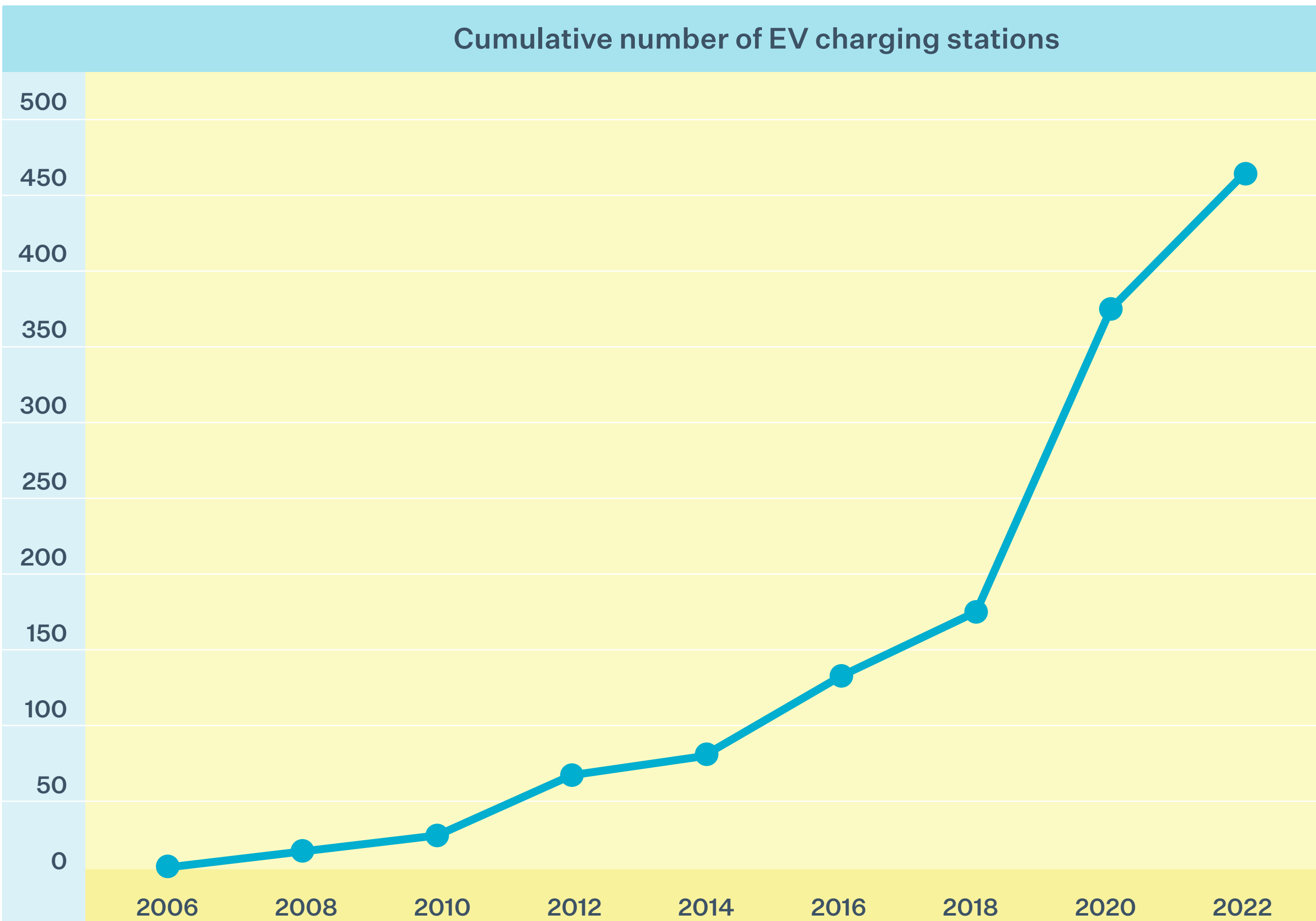
Figure 9. Cumulative number of charging stations by ownership and type



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

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

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



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

1.5.5 RESILIENCE ENERGY STORAGE/ MICROGRIDS

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

1.5.5.1 Residential storage

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

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

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

1.5.5.2 Commercial and industrial storage

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

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

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

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