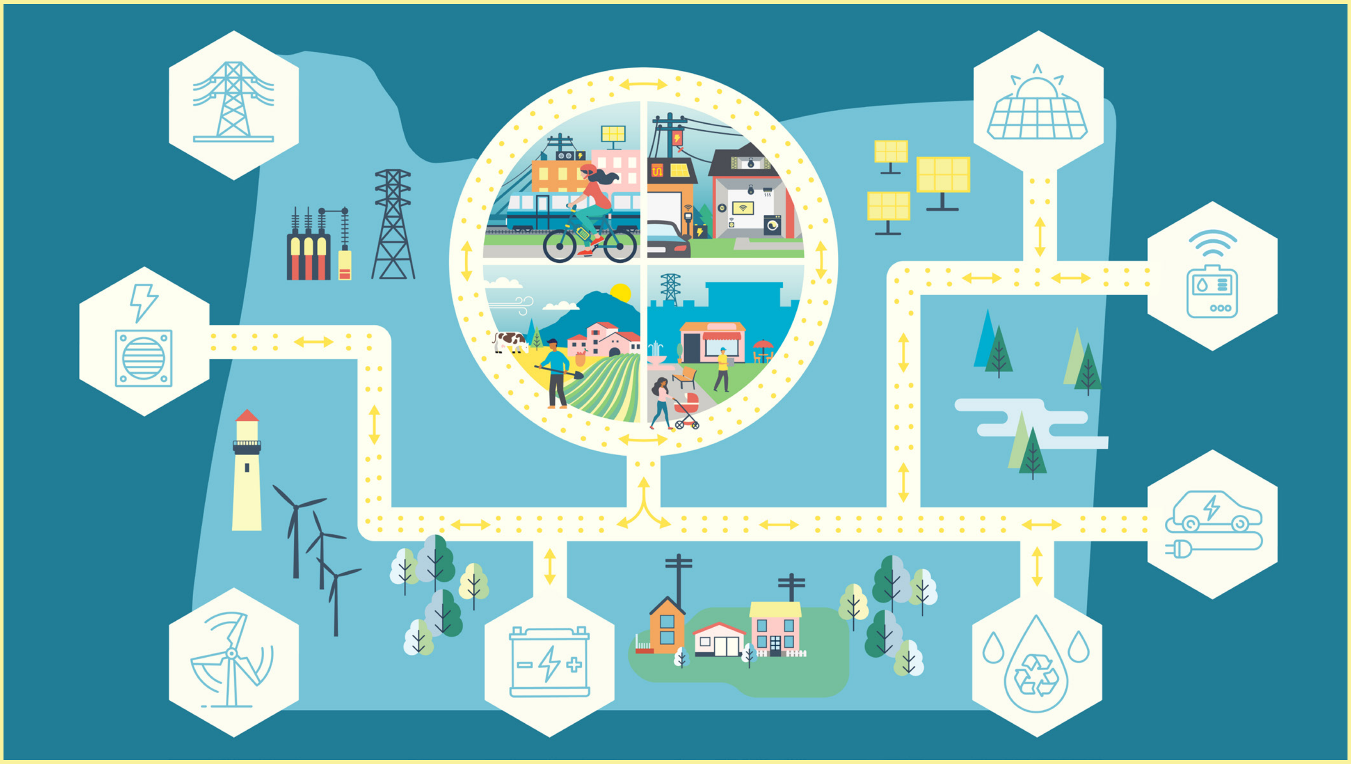
Chapter 3

Load and DER forecasting



Chapter 3. Load and DER forecasting

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

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

3.1 Readers guide

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

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

WHAT WE WILL COVER IN THIS CHAPTER

Corporate load forecasting process and drivers

Current bottom-up load forecasting methods

DER forecasting methods

DER forecasting results at the granular substation level

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

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

Table 9. Distribution system overview: Guideline mapping

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

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

3.2 Introduction

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

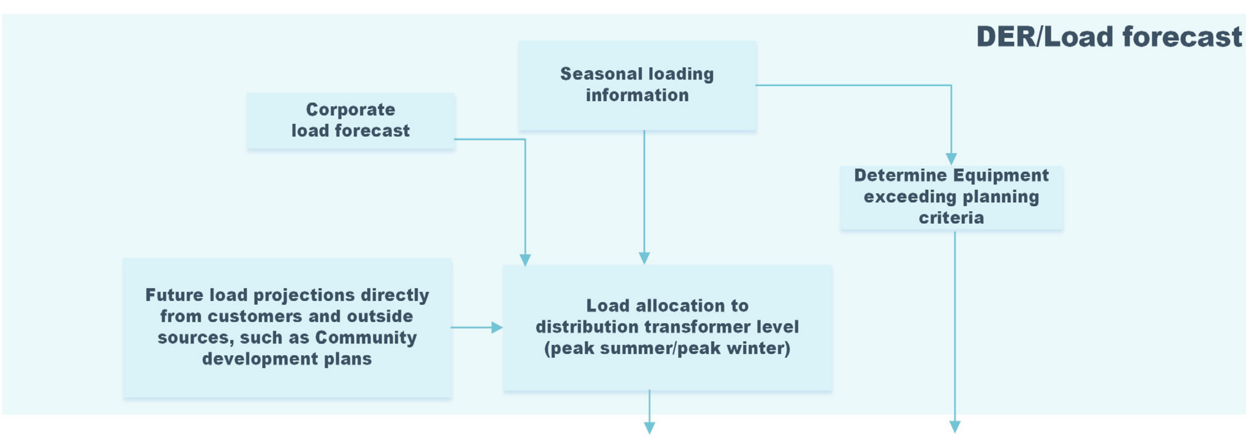
As PGE modernizes the grid, we are simultaneously increasing our ability to plan for distributed energy resources (DERs) and the variety of potential benefits and challenges they can pose for the distribution grid. We are focused on improving our DER forecasting tools to provide locational insights and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

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

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

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

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



3.3 Corporate load forecast

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

3.3.1 CORPORATE LOAD FORECAST APPROACH

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

From period to period, weather — specifically ambient temperature — is the largest factor affecting customer electricity demand. PGE uses several weather variables in its energy and peak models, including heating and cooling degree days and wind speed. For each variable, the forecast relies on an input assumption.

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

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

Type	Drivers used	Source
Historical load data	Monthly energy deliveries and customer count	PGE billing data
Historical load data	Monthly PGE system peak demand	PGE net system load data
Economic indicator	Oregon employment and personal income	Oregon Office of Economic Analysis
Economic indicator	Oregon population	PSU's Population Research Center
Historical weather[20]	Monthly heating and cooling degree days, wind speed, and rainfall (for average energy models) 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

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

3.3.2 CORPORATE LOAD FORECAST CUSTOMER SEGMENTATION

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

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

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

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

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

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

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

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

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

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

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

3.3.3 PEAK LOAD TRENDS

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

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

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

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

3.4 Bottom-up load additions

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

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

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

3.4.1 TYPES OF ELECTRIC LOAD AND IMPLICATIONS FOR POWER QUALITY

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

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

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

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

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

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

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

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

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

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

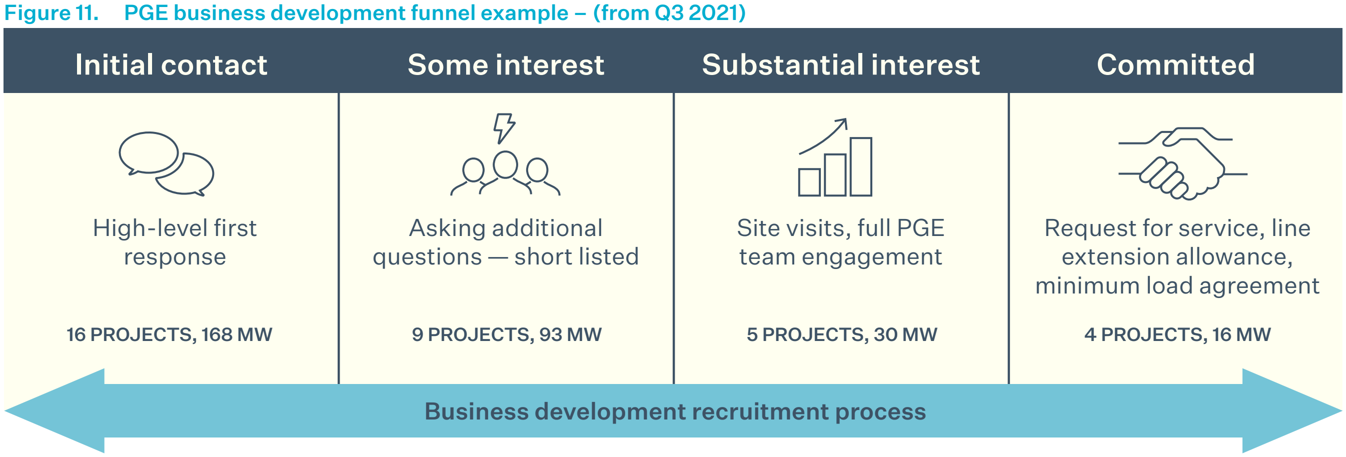
In examining each distribution feeder and substation transformer for peak loading, PGE uses specific knowledge of distribution equipment, local government plans, and customer loads to forecast future electrical loads. Our planning engineers consider many types of information for the best possible future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

3.4.2.1 Tracking customer load growth and regional growth-related factors

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

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

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



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

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

3.4.3 SYSTEM PEAK TREND ANALYSIS AND ANNUAL LOAD ALLOCATION PROCESS

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

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

3.4.3.1 Asset Management Database

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

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

3.4.3.2 Weak link report and load allocation tool

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

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

Inputs to this load allocation model include:

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

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

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

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

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

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

3.4.4 EVOLUTION OF DISTRIBUTION SYSTEM BOTTOM-UP LOAD FORECASTING

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

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

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

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

3.5 DER locational forecast

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

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

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

3.5.1 ADOPDER MODEL OVERVIEW

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

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

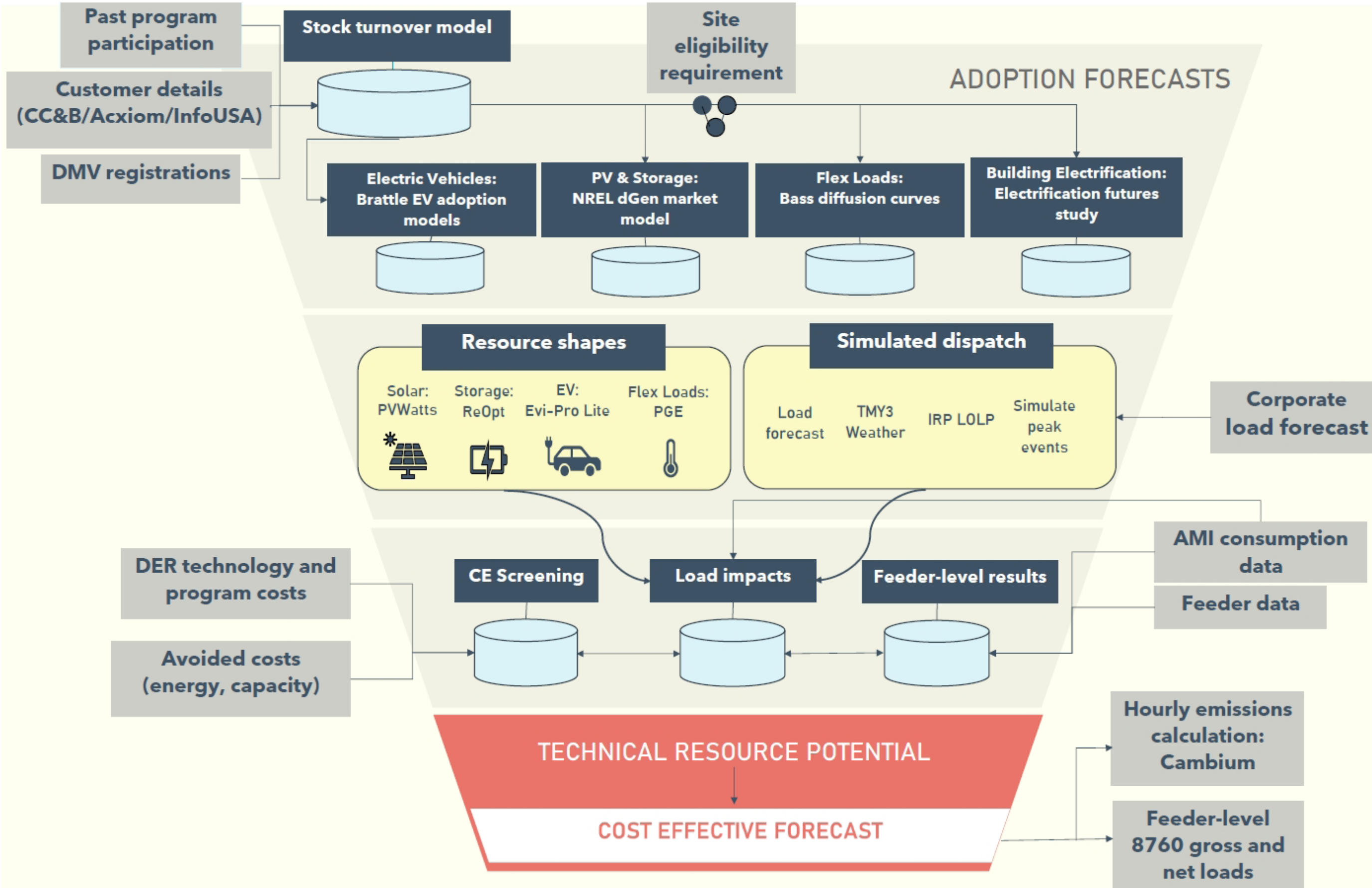
- Demand response/flexible loads
- Distributed rooftop photovoltaic (PV)
- Distributed battery storage
- EVs and charging infrastructure

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

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

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

Figure 12. AdopDER model conceptual overview



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

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

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

3.5.2 ADOPDER BOTTOM-UP LOAD FORECASTING METHODOLOGY

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

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

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

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

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

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

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

3.5.2.1 Transportation electrification bottom-up load additions

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

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

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

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

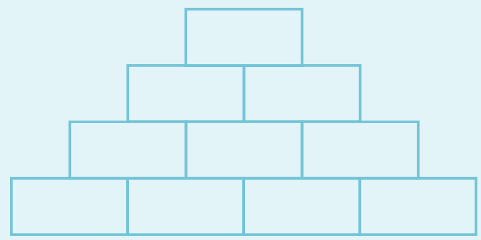
Fleet Partner plan

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

No cost; no commitment

Fleet Partner build

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



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

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

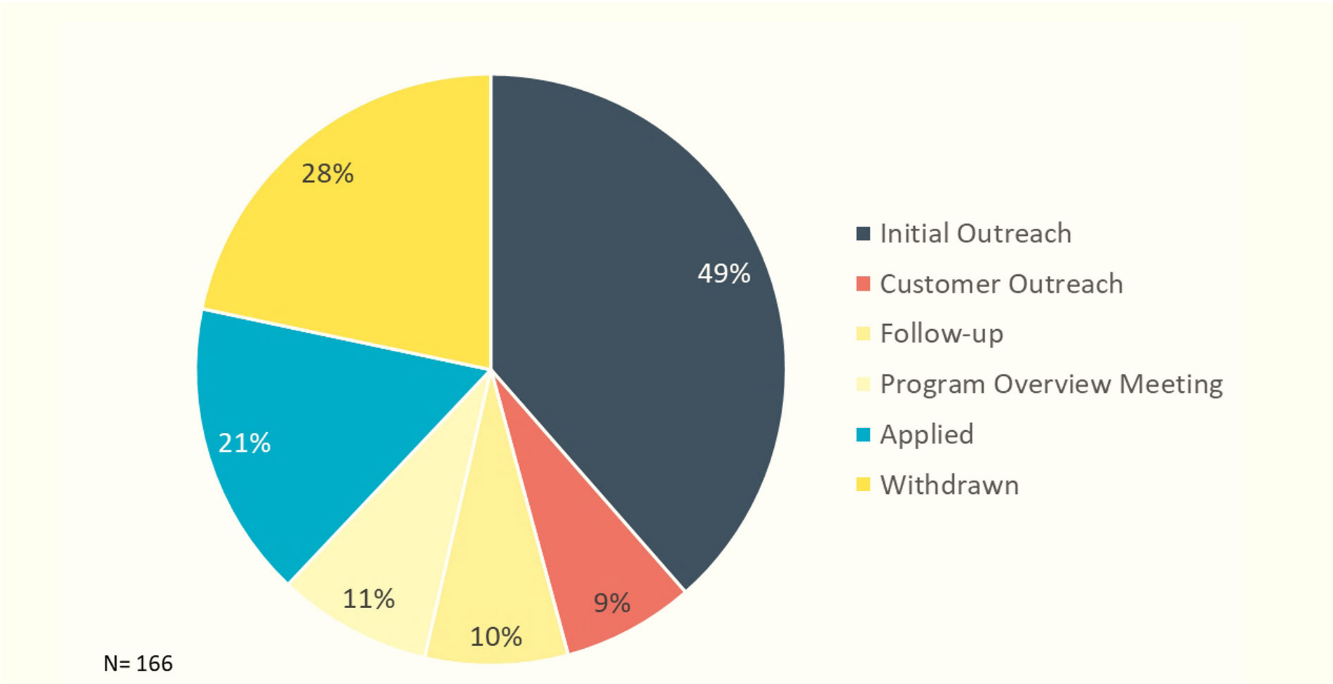
PGE has been tracking customer interest in TE in our customer management system and sales tracking database (Salesforce). As of May 2022, we have 7.7 MW (nameplate) of connected charging load requests at various stages in our Fleet Partner program application process. These requests are cumulative across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

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

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

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

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



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

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

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

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

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

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

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

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

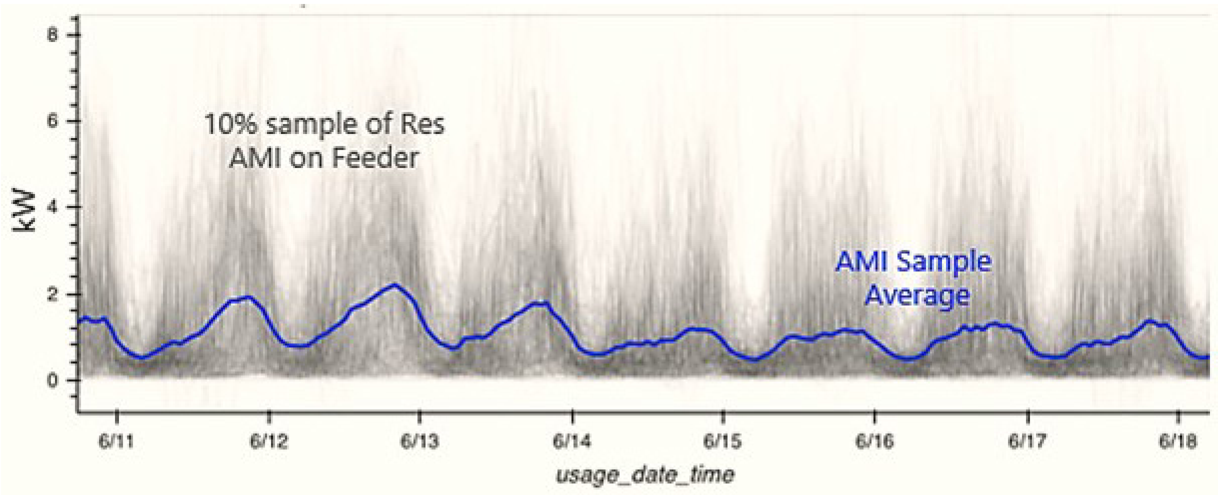
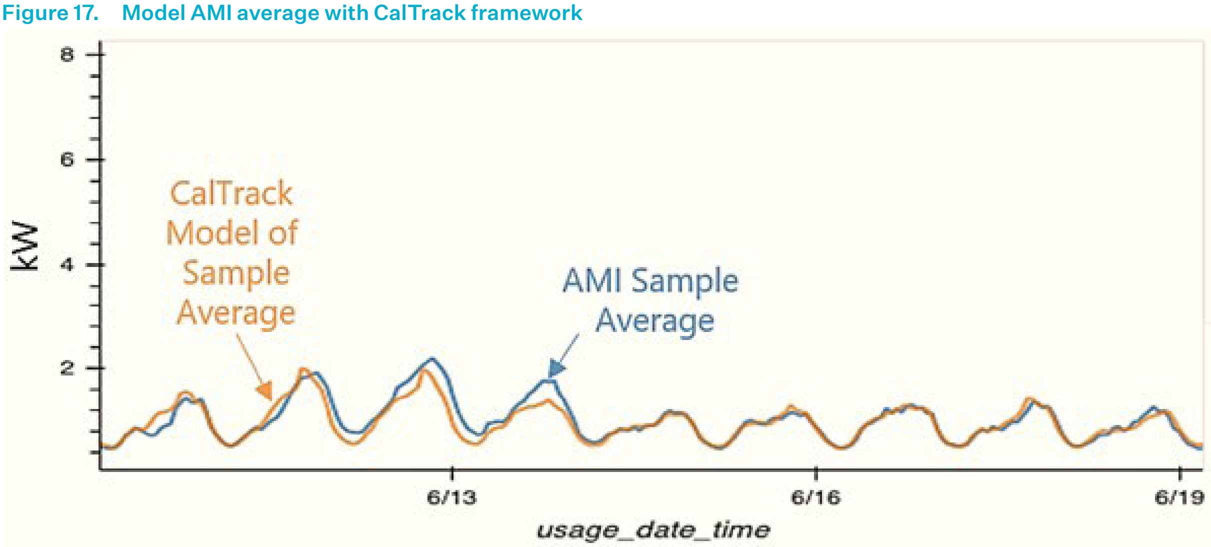


Figure 17. Model AMI average with CalTrack framework



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

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

3.5.3 ADOPDER LOCATIONAL DER ADOPTION METHODOLOGY

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

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

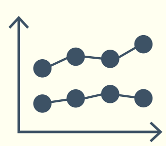
PGE considered two primary factors when deciding whether a DER was suitable for propensity scoring with statistical methods: 1) availability of sufficient data needed to train models, and 2) having well-established findings in the literature relating certain socioeconomic or other geographic factors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

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

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

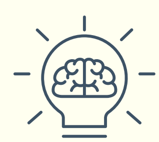
Statistical model

- EV charging
- BTM storage (res, non-res)
- Microgrid



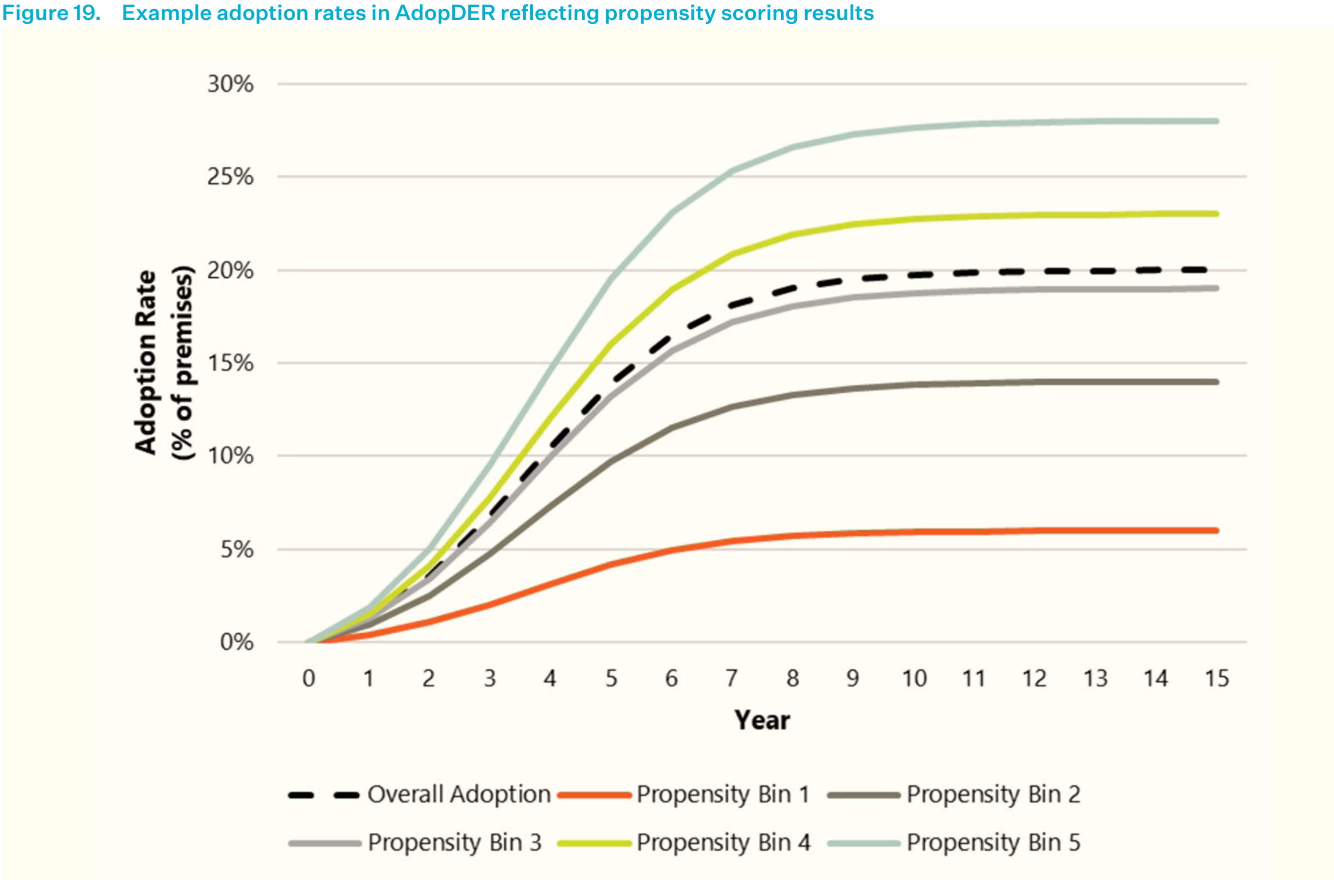
Heuristic model

- EV charging
- BTM storage (res, non-res)
- Microgrid



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

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



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

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

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

3.5.4 INTEGRATING EQUITY DATA INTO ADOPDER

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

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

The overall study objectives were to:

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

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

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

Figure 20. Process overview for incorporating equity data into AdopDER

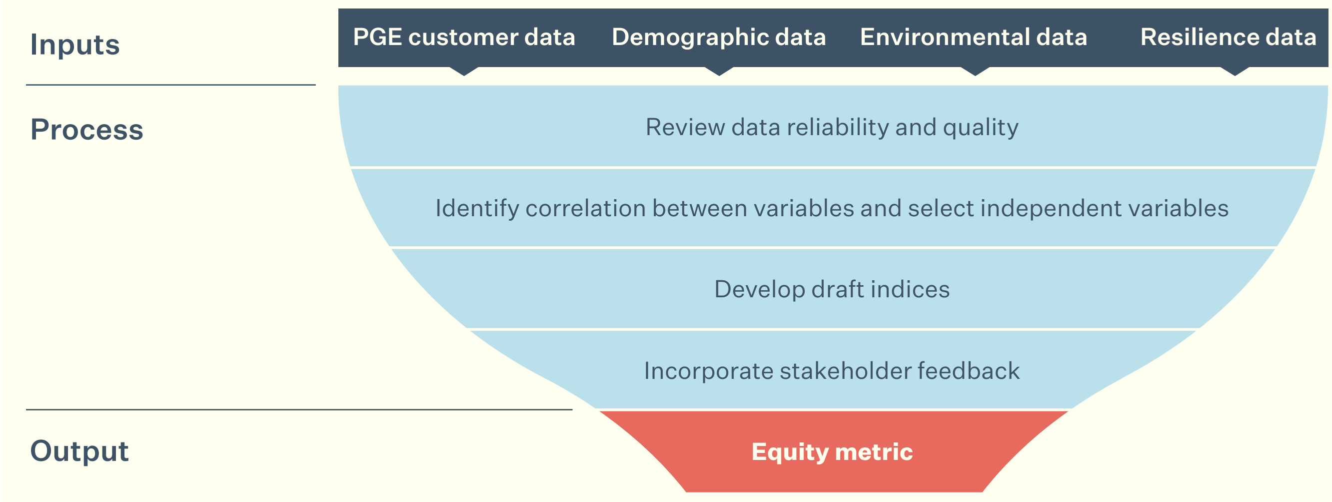


Table 13 describes the three primary data categories (DEI, environmental and resiliency data) and what purpose they play in the model. PGE also notes indicative data sources. See **Appendix C** for a full description of the variables and data sources, as well as a detailed description of the methodology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

Table 13. High-level equity data indicators for AdopDER

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

3.5.5 BOTTOM-UP LOAD AND DER FORECASTING LOCATIONAL RESULTS

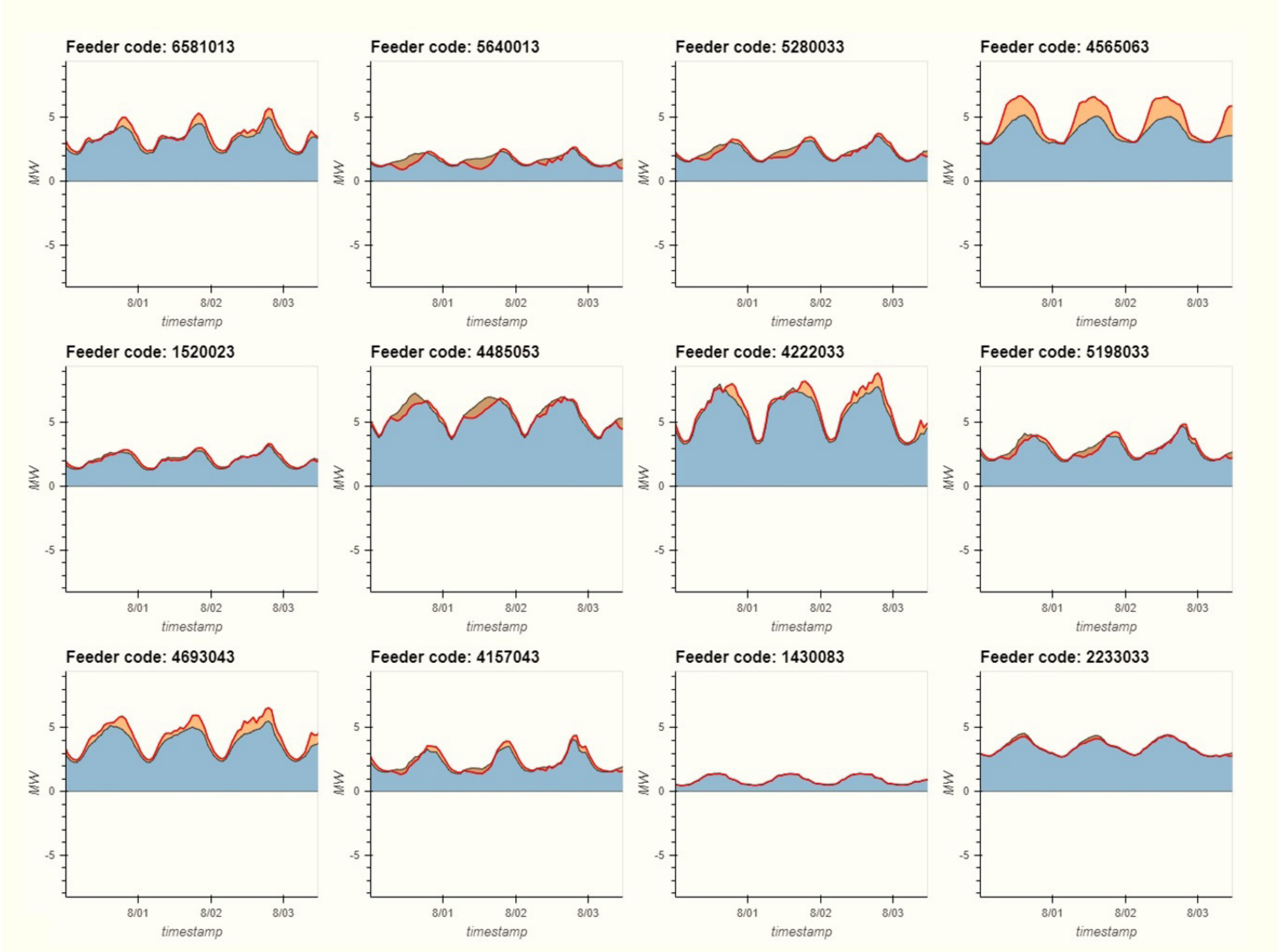
This section presents the results of PGE's bottom-up load forecast efforts and DER forecast disaggregation. We first present results of the load forecast portions of AdopDER and discuss the findings in context to their impact on ultimate DER adoption.

3.5.5.1 Bottom-up load forecast results

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

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

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



3.5.5.2 DER DISAGGREGATION RESULTS

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

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

Table 14. Summer demand response/flex load peak impacts

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

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

Table 15. Winter demand response/flex load peak impacts

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

Table 16. Solar potential forecasts

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

Table 17. Energy storage potential forecasts

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

Table 18. Transportation electrification potential forecasts

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

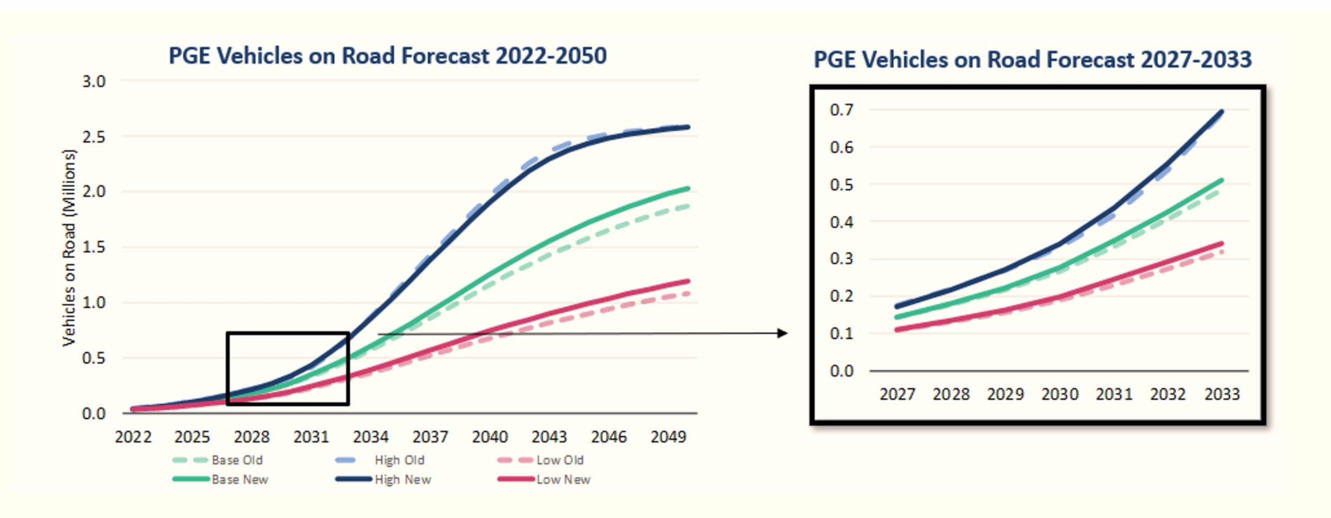
Table 19. Building electrification potential forecasts

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

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

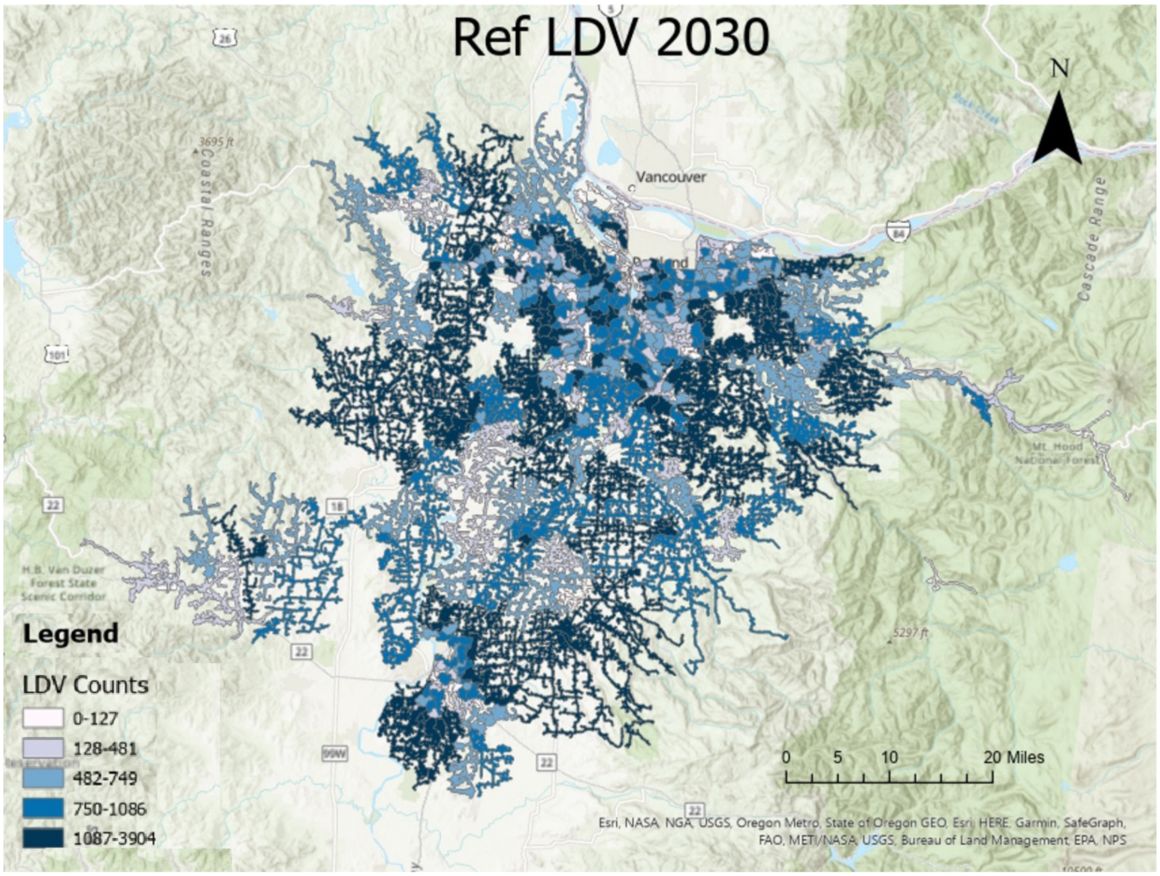
Figure 22 shows the comparison of the updated March forecast to the LDV forecast used in Phase I DER Forecast study. See **Appendix C** for additional details about the EV forecast modeling approach and March update.

Figure 22. Brattle LDV econometric forecast March 2022 update



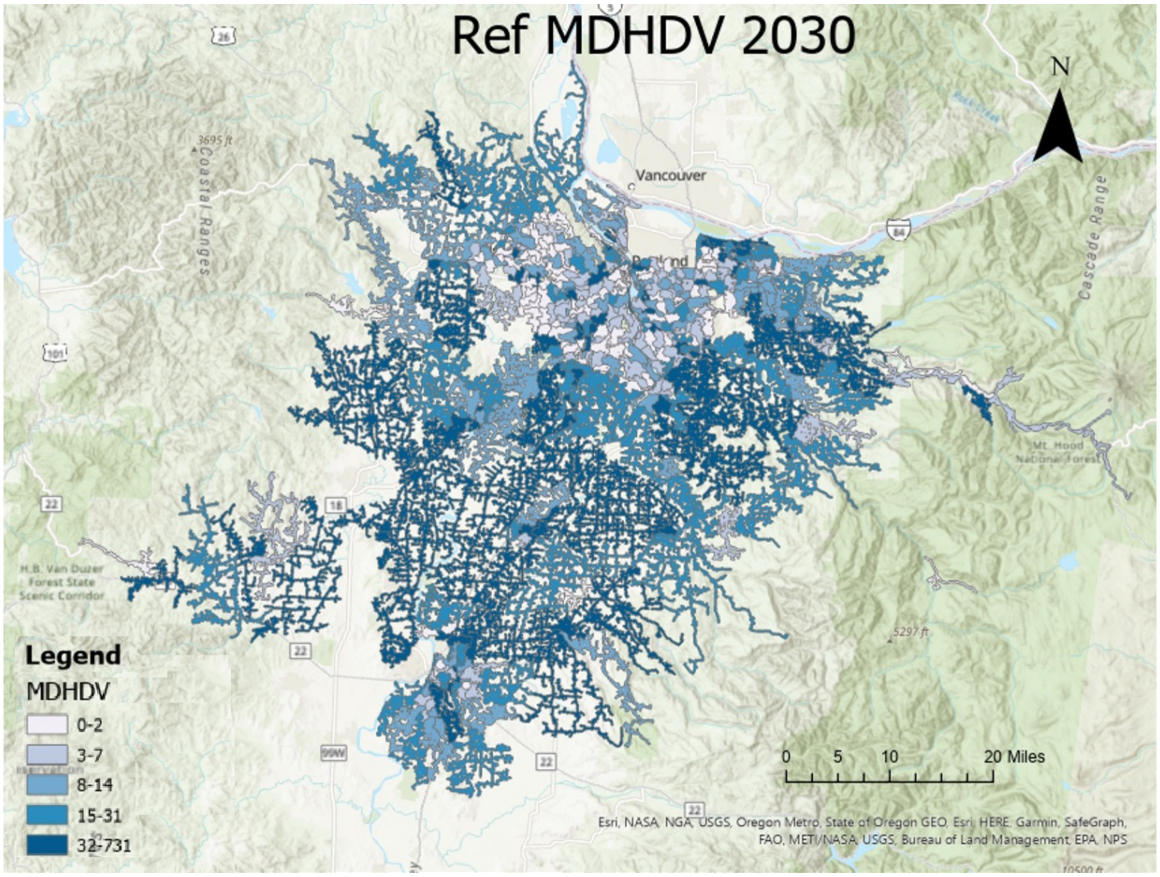
Looking at the concentration by geographic area, PGE sees the highest density of LDV adoption in urban metropolitan areas as shown in **Figure 23**, with a high case of LDV adoption in 2030 at the feeder level.

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



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

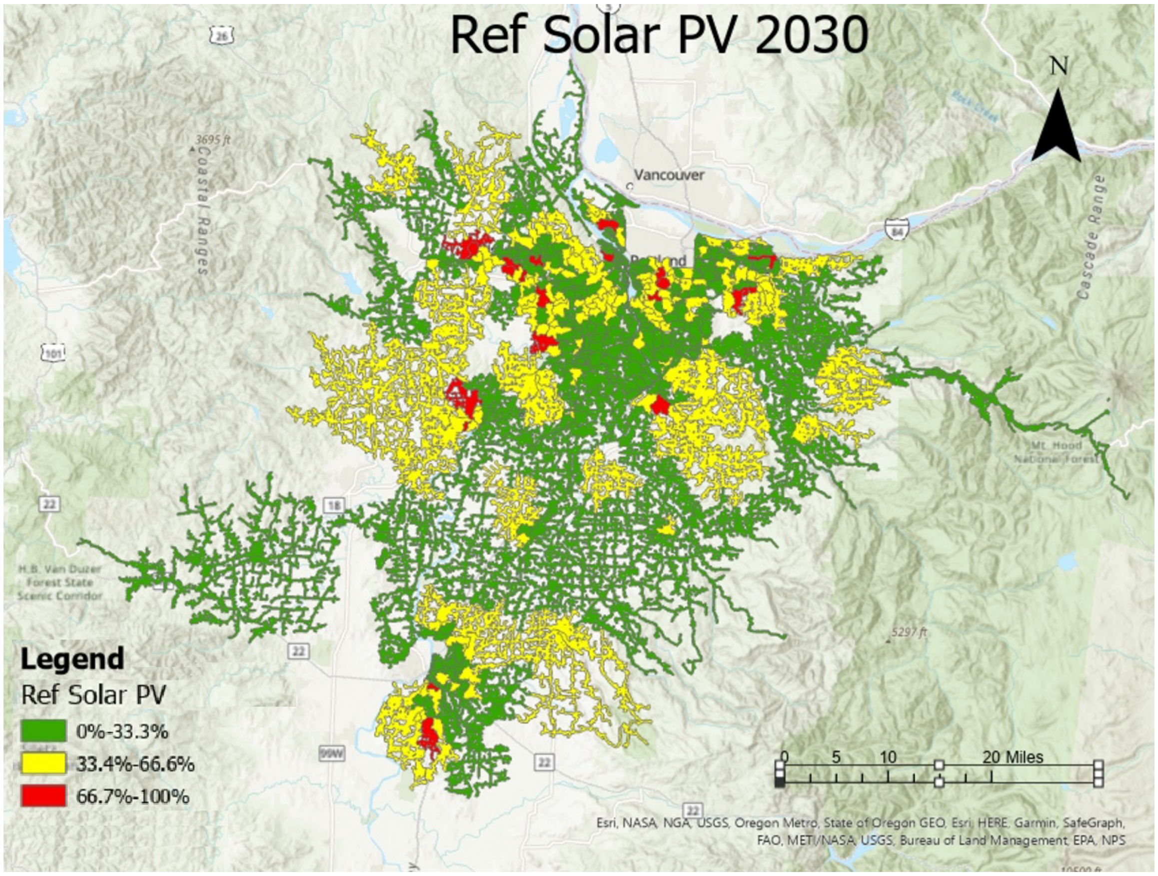
Figure 24. Reference case MDHDV adoption at the feeder level in 2030



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

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

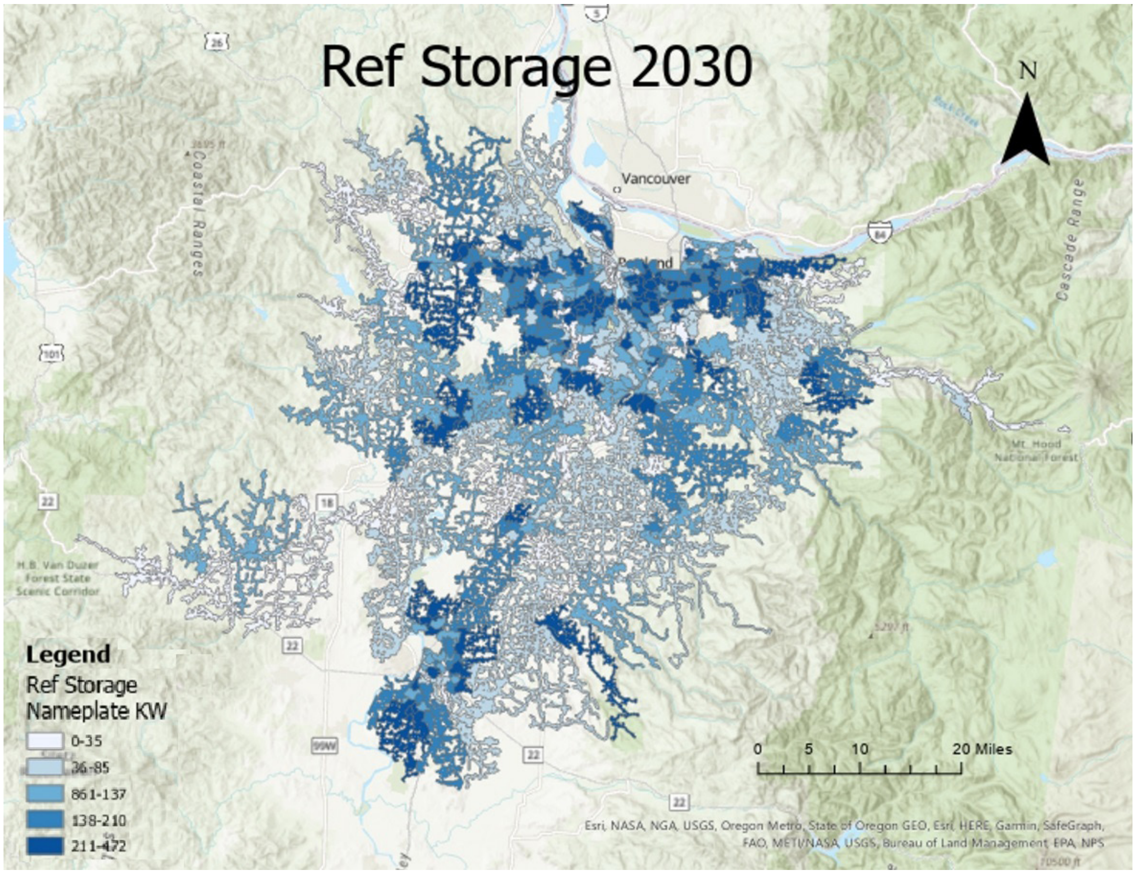
Figure 25. Reference case rooftop solar PV adoption at the feeder level in 2030



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

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

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



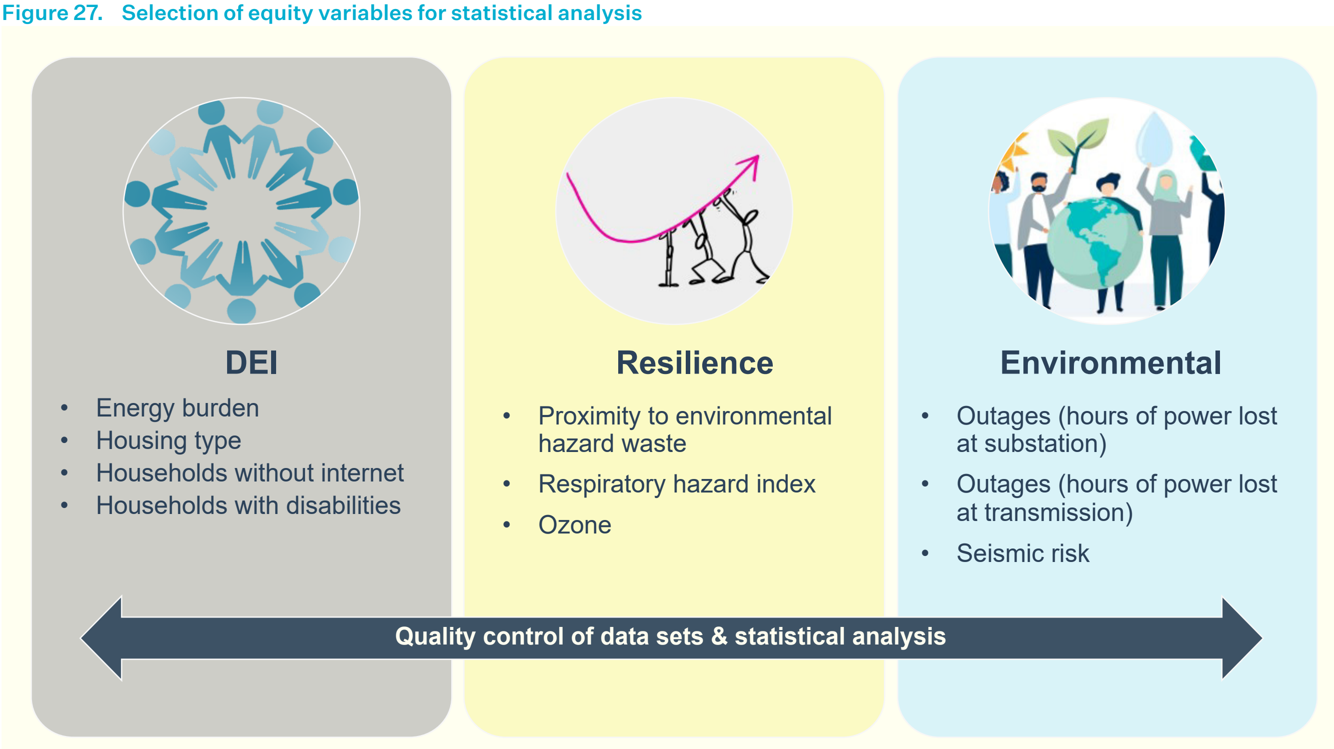
3.5.5.3 Using equity data research to inform future planning efforts

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

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

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

Figure 27. Selection of equity variables for statistical analysis

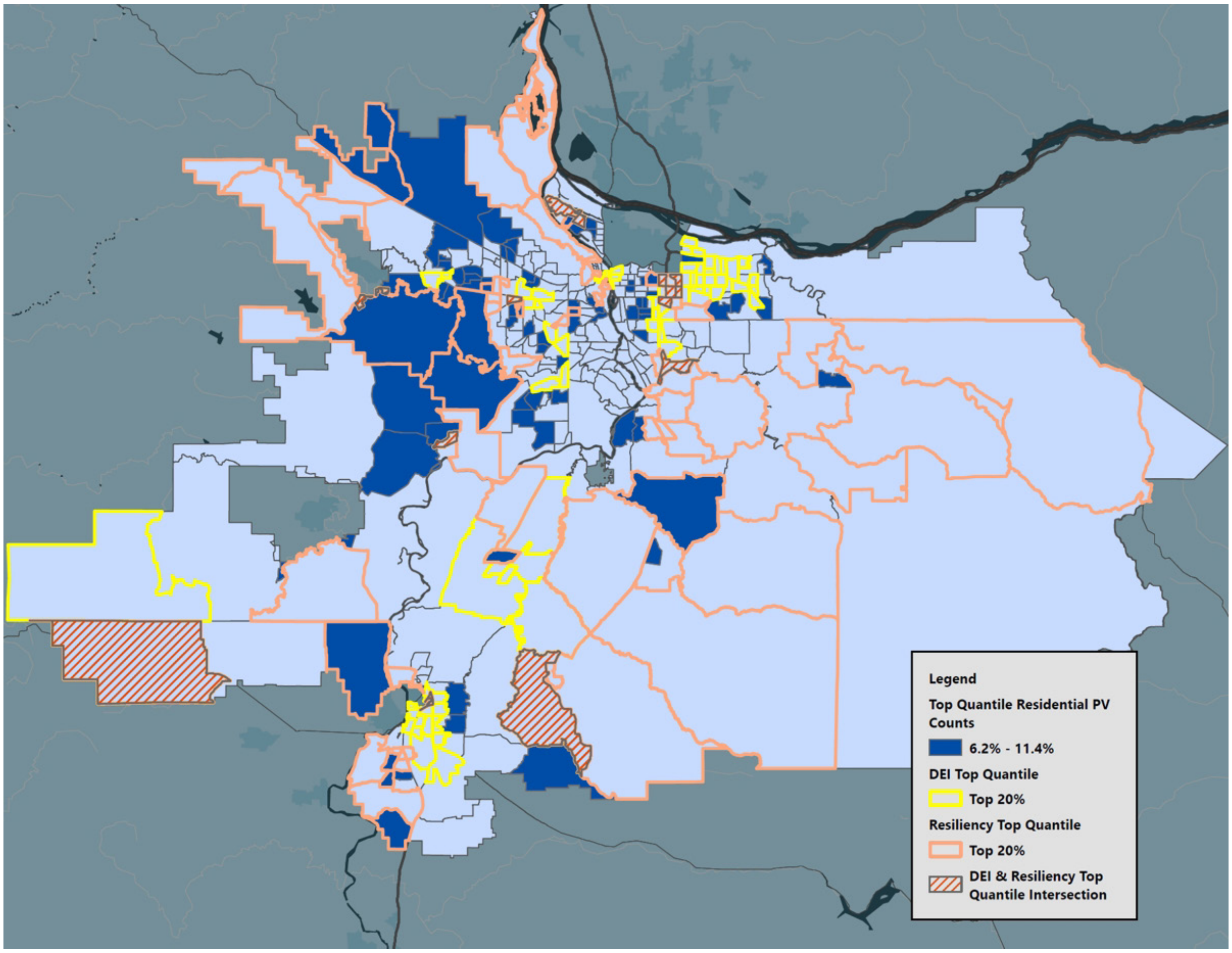


As described in **Chapter 2**, PGE is in the process of rolling out an Equity Index across use cases within the DSP. For the present analysis purposes, we applied this Equity Index to the locational DER adoption results in order to identify any patterns.

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

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

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



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

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

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

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

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

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

3.6 Evolution

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

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

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

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

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

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