Appendix B. Baseline data and system assessment details

This section provides additional technical details regarding certain aspects of PGE's system assessment practices and baseline data.

B.1 Distribution engineering planning study process

To better understand the distribution engineering study process, PGE has defined three key terms:

- **Load:** The load on an electrical grid (used interchangeably with demand) is the total electrical energy being consumed by end users at a given time in order to convert into productive uses such as light, heat, or to drive machine processes.
- **Net system load:** Total retail load served by PGE, including losses.
- **Peak load:** The maximum coincidental system load experienced by the system, historical or forecasted. PGE calculates peak coincident load at the feeder- and substation-transformer level on an annual basis and differentiates between winter and summer peak load due to the differences in seasonal performance ratings of distribution system equipment.
- **Minimum load:** The lowest single measurement of net system load throughout a planning period. This is an important metric because when net loads are low, excess generation from distributed photovoltaic (PV) resources have a higher probability of backfeeding to impact the substation. Without proper protections, this can damage equipment and lead to reliability issues.

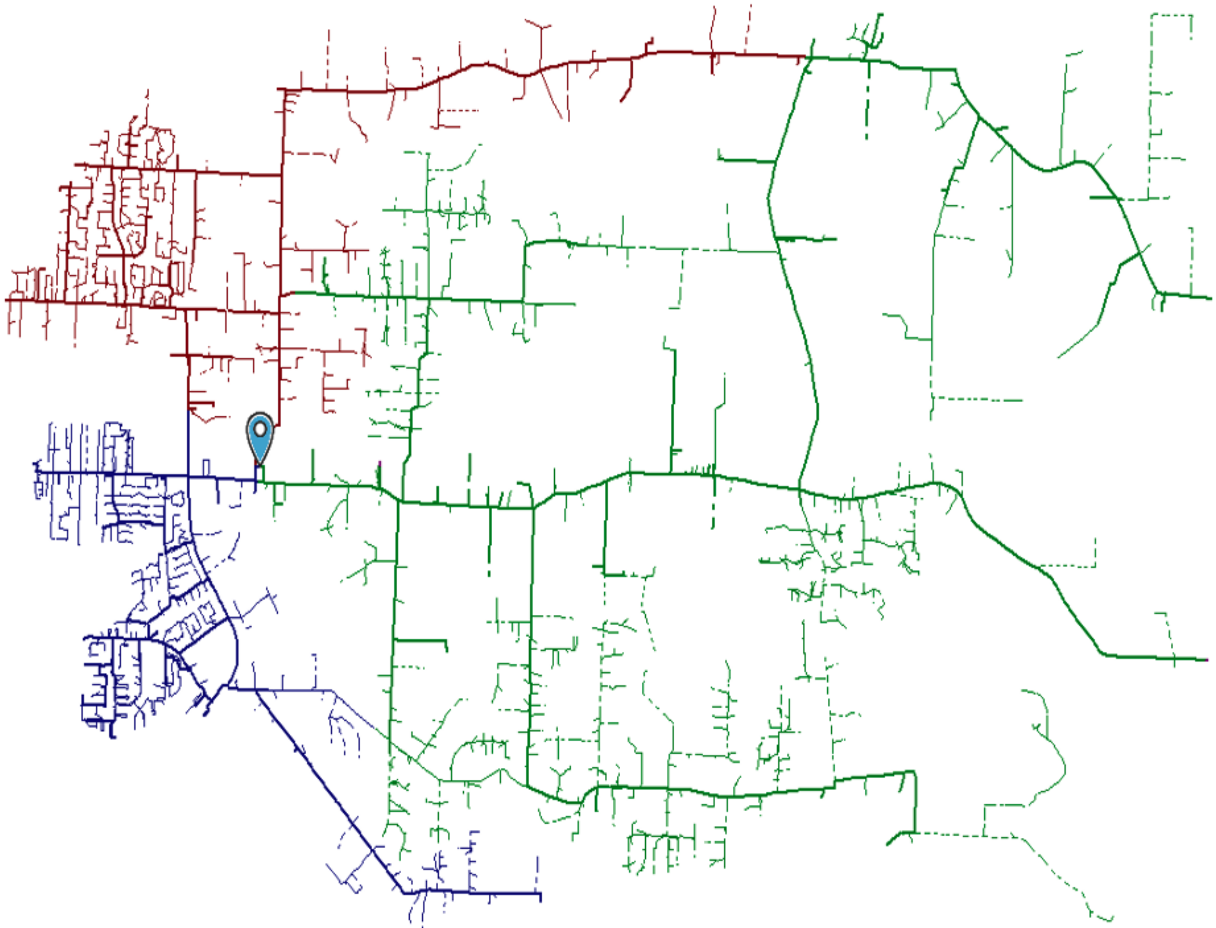
B.1.1 DISTRIBUTION PLANNING STUDY PROCESS

The process provides the criteria and methods for performing distribution planning studies. These studies form the basis for distribution project justification and development.

PGE uses CYME, a recognized industry software solution, to perform distribution system modeling. CYME has a broad range of capabilities including power flow analyses, fault analyses, hosting capacity analysis, and reliability analysis.

For each study, PGE focuses on a specific geographic area determined by the drivers and load forecast data discussed in **Section 1.3.1**. **Figure 38** shows an example study area of three feeders connected to a single distribution substation.

Figure 38. Example study area



B.1.1.1 Base case validation

The distribution grid and its assets are visualized through a combination of network models, equipment databases and historical system data. These together create the base case of the study area, modeling the current system performance under normal conditions (where all equipment is working as designed, called the N-0 condition) and contingency condition (where a substation transformer experiences failure or is undergoing a planned outage and cannot serve the intended load, called the N-1 condition). In contingency cases, neighboring transformers from either the same or adjacent substations must pick up the load to avoid a customer outage.

At PGE, distribution planning engineers are responsible for updating line and equipment configurations in the modeling environment to match existing field equipment, as well as addressing CYME-generated errors in their assigned regions. The planning engineers ensure model designations, set point voltage and other technical information is accurately captured. Updates are then compiled into a single database to be used for designated studies.

B.1.1.2 Base case analysis

Once the model is prepared and confirmed as error-free in CYME, a report can be generated to identify base case loading and voltage violations. A loading violation will occur if a certain piece of equipment (e.g., a substation power transformer) is loaded beyond its rated nameplate capacity. The CYME user interface can be used to physically locate this base case loading and voltage violations. These two types of violations (loading and voltage) are documented and have the highest priority for developing mitigation plans that may require additional investments in the distribution system to ensure reliability.

B.1.1.3 Design criteria

PGE's system is designed to serve existing customer loads with adequate reserved capacity to pick up that load via other nearby equipment in the event of a failure or planned outage. In the near-term distribution planning studies, PGE limits the failures to be studied to the loss of a distribution power transformer or a distribution feeder.

Planning design criteria for PGE's distribution power transformers provide guidance that transformers are not to exceed 80% of their seasonal loading beyond nameplate ratings (LBNR) under normal operation (N-0) during a peak-load period. Limiting components can vary and can include the transformer windings, load tap changers, bushings, leads and voltage regulators. In the event of a transformer-related failure or outage (N-1), nearby transformers from either the same or adjacent distribution substations can pick up the load.

Planning design criteria for PGE's distribution feeders provides the guidance that associated feeder getaways, mainlines, and voltage regulators are not to exceed 67% of their normal seasonal thermal ratings. For most general-use feeders, this equates to either two-thirds normal capacity of a standard feeder mainline, or 12 MVA.

B.1.1.4 Design criteria exceptions

There are some exceptions to the planning design criteria for distribution power transformers and for distribution feeders, which allow for equipment to load to levels beyond the recommended design criteria under normal (N-0) operation.

- **Dedicated transformers:** For distribution power transformers dedicated to a single customer, loading can reach 100% of seasonal LBNR under normal (N-0) configuration. For dedicated transformers, in the event of an outage there is a contingency or a load-shedding scheme that will prevent PGE transformers from loading beyond their LBNR.

- **Dedicated feeders:** Dedicated feeders may be loaded up to 100% of their normal seasonal thermal ratings under normal (N-0) configuration. For these feeders, a contingency or load-shedding scheme will prevent the feeders from exceeding these limits.

- **Alternate service:** Alternate service agreements affect the operation of general-use distribution power transformers and distribution feeders. An alternate service customer is generally served by a single feeder. In the event of an outage to the customer's preferred feeder, the customer will automatically transfer to an alternate feeder. PGE is contractually bound to reserve adequate capacity for alternate service customers. A transformer or feeder that is designated as an alternate source shall always have reserved capacity to pick up the agreed-upon load as stated in the corresponding alternate service agreement. For a transformer designated as a source for alternate service, the sum of the transformer's peak load and the reserved capacity must be equal to or less than the transformer's LBNR. For a feeder designated as a source for alternate service, the sum of the feeder's peak load and the reserved capacity must be equal to or less than the feeder's normal thermal limit.

- **Secondary network feeders:** Secondary networks are designed to allow customers to be served by a group or "system" of dedicated feeders. Secondary conductors are interconnected to serve pockets of load in common areas. Feeders in these network systems are allowed to be taken out of service one, and in some cases, two, at a time for planned or unplanned outage scenarios. With this redundancy in place, secondary network feeders and corresponding transformers are individually lightly loaded so that they have the capacity to pick up load from a transformer or feeder serving the same network load. Due to their complex nature, secondary network feeders are currently modeled in PowerWorld, which is PGE's planning tool used in transmission planning studies.

B.1.1.5 Study criteria

Two categories of studies are analyzed: N-0 base case and N-1 contingency. An N-0 base case corresponds to a normal operating condition; all feeders and distribution power transformers are in service. An N-1 contingency corresponds to an abnormal condition; a single component is out of service (e.g., distribution power transformer, distribution feeder). Contingencies will be limited to the distribution power transformer and to the distribution feeder.

Initial near-term studies will incorporate peak summer conditions. PGE's distribution system is modeled using projected 1-in-3 system loading conditions over a five-year horizon.[141] For a base case scenario, the distribution system is configured in an operational state with the addition of any approved capital funding projects included in the system model. This is important as new projects will change the equipment and assets on the network during the planning horizon and must be reflected in CYME. Distribution loading is allocated at the distribution power transformer level per substation.

B.1.1.5.1 Feeder switching

For N-1 contingency, all field devices used for restoration must be load-break, three-phase, gang-operated switches or three-phase reclosers. If required, devices used for restoration in distribution substations must be three-phase circuit breakers or circuit switchers. Other means that may be used for switching in the field (such as closing single-phase jumpers, closing cable disconnects or operating non-load-breaking devices) will not be included when performing studies. Field devices allowed to be modeled for switching purposes are overhead devices rated at either 600 or 900 amps, submersible devices rated at 600 amps and pad-mounted devices rated at either 600, 900 or 1200 amps.

Distribution feeders are split into switchable sections, or zones. Ideally, with feeders limited to 12 MVA, or 67% of their normal thermal ratings, a switchable section shall not exceed 6 MVA. This will allow an entire feeder under contingency (N-1) to be picked up by two adjacent feeders during a peak period. A section located on the load side of a fuse or a recloser without a bypass switch is not considered a switchable section.

Ideally, an urban feeder shall require one level of switching to adjacent feeders, due to denser loadings and shorter lengths relative to rural or remote feeders. This means that during a peak period, service restoration feeders adjacent to the feeder taken out of service shall not be offloaded to pick up unserved load. If further action is required, unserved load will be reported. Rural and remote feeders are allowed two levels of switching to adjacent feeders. To pick up unserved load, a feeder can be offloaded to an adjacent feeder.

141. 1-in-3 refers to modeling of weather-sensitive load changes based on expected 1-in-3 years weather conditions. For more detail on PGE's load forecasting methodology, see PGE's 2019 IRP Appendix D, available at: portlandgeneral.com

B.1.1.5.2 VOLTAGE CRITERIA

Distribution voltage requirements allow feeders to vary at a nominal voltage +/- 5%. In CYME, for most feeders, the base nominal delivery voltage is 120 volts. When performing contingency studies for distribution feeders and distribution power transformers, no feeder branch shall be outside of the allowable voltage range.

B.1.1.5.2.1 RESULTS

Study results will determine which areas of the system need improvements. Initially, small projects are considered to achieve the required reserve capacity on the feeder or substation power transformer. These may include feeder balancing, permanent load shifts that can be achieved without upgrades and small reconductor jobs.

The results are analyzed to determine if there are areas of the system, consisting of multiple feeders and/or transformers, that do not have N-1 redundancy. These areas are studied together to determine a project to mitigate multiple redundancy constraints.

Detailed studies are performed for feeders and/or transformers that may not meet loading or voltage criteria. These studies are prompted by the following:

- Base case loading and voltage violations
- Transmission and distribution (T&D) design criteria violations
- Existing load density
- Potential future load additions (reference community plans where possible)
- System performance (e.g., outage history, SAIDI/SAIFI indices)

Detailed studies will identify multiple options for each substation. The recommended option should defer additional capital projects at the substation for a minimum of 10 years, where possible. High-level cost estimates are developed for these options. Options analyses are performed to determine reduced risk and overall system benefits. White papers, and ultimately capital funding projects, are developed as a result of the detailed studies.

B.1.1.5.2.2 REPORTING

For the N-0 study, voltages outside of bandwidth, transformers loaded at 80% of LBNR or higher, and feeders loaded at 67% of normal thermal limit or higher will be listed and reported, some of which going on to receive more detailed studies as described above. More immediate corrective actions will be required for equipment projected to exceed 100% of their respective seasonal LBNR or seasonal thermal limits.

For N-1 scenarios, voltages outside of bandwidth, transformers loaded at 95% of LBNR or higher and feeders loaded at 95% of normal thermal limits or higher will be listed and reported. Corrective actions will be required for equipment that exceeds 100% of its respective seasonal LBNR or seasonal thermal limits. If possible, corrective actions will solve loading and voltage problems for a general area.

After studies are completed, options are analyzed, corrective actions are identified and a tentative timeline for these corrective actions is developed. The study process, analyses, results and recommendations are then captured in a formal report.

B.2 Distribution system reliability and outages

In this section, PGE describes performance metrics and analysis conducted to determine reliability and outage-related information. Each indicator reflects either outage duration or frequency, such that a score of zero is perfect (i.e., no outages).

B.2.1 ANNUAL RELIABILITY

Reliability is the ability to power the grid to deliver electricity to all points of consumption, in the quantity and quality the consumer demands. Reliability at the utility level is measured by outage indices defined by one international standard called IEEE 1366.[142] These outage indices are calculated by the duration of each interruption and the frequency of the interruption and are explained in detail as follows.

PGE collects outage data to calculate three distinct performance metrics to measure the reliability of its distribution system from various perspectives: 1) at the system- and region- level (east, south, west); 2) by outage causes; and 3) by feeder (urban, rural, and remote). PGE calculates three annualized reliability indices at the system, region and feeder level and groups the outage causes in 10 categories.

These three performance assessments are summarized every year in PGE's Annual Reliability Report, which is submitted to the OPUC for compliance.[143] This report provides distribution system performance information based on service interruptions to PGE customers. The report is used to understand the overall reliability of the distribution system and to identify areas of improvement and excellence.

System level reliability: The overall performance of PGE's distribution system is represented by the following three indices:

- System Average Interruption Duration Index (SAIDI)
- System Average Interruption Frequency Index (SAIFI)
- Momentary Average Interruption Event Frequency Index ($MAIFI_E$)[144]

PGE's distribution system performance calculations are based on the IEEE 1366 methodology. The data utilized for the calculations is captured from PGE's outage management system (OMS) and confirmed via a multi-step evaluation process. The results of the calculations are evaluated daily and confirmed via a standardized review process.

Planned outage events were excluded from the 2020 distribution system performance indices based on PGE's understanding of best practices performed by peer utilities and analysis methods utilized in IEEE 1782.[145] [146] While planned outage events were not captured in PGE's 2020 indices, these events are reported in **Appendix E**. Annual reliability report to comply with Oregon Administrative Rule (OAR) 860-023-0151.

B.2.1.1 System average interruption duration index (SAIDI)

This is the sustained interruption duration time (in minutes) that an average customer experiences during the year. It is determined by dividing the annual sum of all customer sustained interruption durations by the total number of customers served.

SAIDI = Sum of customer sustained interruption durations/Total number of PGE customers served

B.2.1.2 System average sustained interruption frequency index (SAIFI)

This index is the number of times that an average customer experiences a sustained interruption during a year. It is determined by dividing the total annual number of customer sustained interruptions by the total number of customers served.

SAIFI = Total number of customer sustained interruptions/Total number of PGE customers served

142. IEEE is the Institution of Electrical & Electronics Engineers, the biggest professional body of Electrical & Electronics Engineers. IEEE has its head office in the USA & has presence in most countries.
143. PGE 2020 Annual Reliability Report. OAR 860-023-0151, available at: edocs.puc.state.or.us
144. $MAIFI_E$ calculations are limited to feeders with remote monitoring equipment.
145. Per IEEE 1366, a planned outage event is defined as "the intentional disabling of a component's capability to deliver power, done at a preselected time, usually for the purposes of construction, preventative maintenance, or repair." IEEE 1782, states "the planned outage event category includes, but is not limited to: road construction, maintenance and repairs, load swaps, replacing equipment, and house moves. Typically, planned interruptions are those interruptions that can be delayed by the utility personnel and performed only after the appropriate or required customer notification."
146. PGE began excluding planned outages from distribution system performance indices in 2016. Planned outage events were not excluded in previous years.

B.2.1.3 Momentary average interruption frequency index ($MAIFI_E$)

This index is the number of times that an average customer experiences momentary interruption events during a year. It is determined by dividing the total annual number of customer momentary interruption events by the total number of customers served. Note that this index does not include the events immediately preceding a sustained interruption.

> $MAIFI_E$ = Total number of customer momentary interruption events/Total number of PGE customers served on feeders with MV90 or SCADA

B.2.1.4 Customer average interruption duration index (CAIDI)

Once an outage occurs, this index is the average time to restore service to the customer. It is determined by dividing the annual sum of all customer sustained interruption durations by the total annual number of customer sustained interruptions.

> CAIDI = Annual sum of all customer sustained interruption durations/Total annual number of customer sustained interruptions

B.2.1.5 Major event day (MED)

An MED is a day in which the daily system SAIDI exceeds a threshold value (TMED). The SAIDI index is used as the basis of this definition, since it leads to consistent results regardless of utility size and because SAIDI is a good indicator of operational and design stress. Even though SAIDI is used to determine MEDs, all indices should be calculated based on removal of the identified days.

In calculating daily system SAIDI, any interruption that spans multiple days is accrued to the day on which the interruption begins. The TMED value is calculated at the end of each reporting period (typically one year) for use the next reporting period, as follows:

- Collect values of daily SAIDI for five sequential years, ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
- Only those days that have a SAIDI/day value will be used to calculate TMED (do not include days that did not have any interruptions).
- Take the natural logarithm (ln) of each daily SAIDI value in the dataset.
- Find **α** (alpha), the average of the logarithms (also known as the log-average) of the data set.
- Find ***β*** (beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the dataset.
- Compute the MED threshold, TMED, using: TMED = $e^{(\alpha + 2.5\beta)}$
- Any day with daily SAIDI greater than the threshold value TMED that occurs during the subsequent reporting period is classified as an MED.

Activities that occur on days classified as MEDs should be separately analyzed and reported.

Table 50 illustrates five-years of outage metrics including and excluding major events. These metrics at the system level are used to benchmark PGE's reliability performance against other utilities and identify areas of the company that need capital investment and opportunities for operational improvements.

Table 50. Five-year annual outage metrics summary

	Including MEDs[147] Average annual outages			Excluding MEDs Average annual			
	Reported outages	SAIFI per customer (occurrences)	SAIDI[148] duration per customer (min.)	Reported outages	SAIFI outage per customer (occurrences)	SAIDI outage duration per customer (min.)	MAIFI$_E$[149] momentary interruptions per customer (occurrences)
2016	9,340	0.79	169	7,496	0.59	97	1.1
2017	12,897	1.04	350	8,704	0.62	113	1.4
2018	6,884	0.52	89	6,884	0.52	89	1.3
2019	8,244	0.71	128	7,663	0.61	98	1.3
2020	10,506	0.81	312	7,973	0.60	100	1.4

B.2.2 OUTAGE CAUSES ANALYSIS

PGE conducts outage analysis by grouping outages causes by events, including and excluding major events, and comparing them by events and by total number of outage hours. PGE classifies outages in 10 cause-categories by order of magnitude: equipment, vegetation, wildfire, public, unknown, other, lightning, loss of supply — substation, loss of supply — transmission. **Table 51** shows that the two largest categories by number of events are equipment and vegetation. Thus, both are subdivided (**Table 52**) to express more granularity on the outage causes, showing that limbs on lines and trees uprooted represent approximately 90% of the vegetation-caused outages.

Table 51. 2020 Outages by cause excluding major events

Outage cause type	Number of outages	Percent of total outages	Number of hours	Percent of total hours
Equipment	3,345	42%	295,603	20%
Vegetation	2198	28%	642,488	43%
Wildfire	826	10%	56,481	4%
Public	628	8%	181,698	12%
Weather	439	6%	66,758	4%
Unknown	204	3%	51,635	3%
Other	188	2%	18,291	1%
Lightning	80	1%	20,465	1%
Loss of supply — substation	47	1%	108,099	7%
Loss of supply — transmission	18	0%	55,072	4%
Total	7,973	100%	1,496,590	100%

147. A Major Event Day (MED) is a day in which the reasonable design and or operational limits of the electric power system were exceeded. MEDs are determined via the Institute of Electrical and Electronics Engineers (IEEE) Standard 1366.
148. SAIDI values are rounded to the nearest whole number.
149. MAIFI$_E$ events for MEDs are not excluded.

Table 52. 2020 Outages by top two causes excluding major events

Outage cause type	Number of outages	Percent of total outages	Number of hours	Percent of total hours
Equipment				
Cutout, fuse, arrestor	790	24%	32,171	11%
Underground (UG) conductor	786	23%	83,713	28%
Overhead (OH) hardware	704	21%	55,863	19%
Transformer	428	13%	25,032	8%
Overhead (OH) conductor	380	11%	53,817	18%
Underground (UG) accessory	173	5%	15,742	5%
Meter	45	1%	462	0%
Pole/structure	21	1%	3,443	1%
Primary device	18	1%	25,359	9%
Total	3,345	100%	295,602	100%
Vegetation				
Limb on line	1,168	53%	299,047	47%
Tree uprooted	853	39%	289,386	45%
Tree/limb burning	177	8%	54,054	8%
Total	2,198	100%	642,487	100%

B.2.3 FEEDERS PERFORMANCE SUMMARY BY REGION

PGE also conducts a feeder performance summary. First feeders are classified into three categories: urban, rural and remote (**Table 53**).

Definition of feeder classifications:

- A feeder is designated urban if 50% or more of the load is inside the urban growth boundary (UGB)
- A feeder is designated rural if one or more of the following apply:
  - The load on a feeder is greater than 0.5 MVA per square mile
  - A feeder has more than 100 customers per mile
  - A feeder is serving load inside an incorporated city
  - A feeder is directly adjacent to the UGB with feeder ties into the UGB
- A feeder is remote if all conditions above do not apply

Table 53. Individual feeder performance thresholds based on classification

Feeder classification	SAIDI	SAIFI	$MAIFI_E$
Urban	2 hours (120 minutes)	2.0 occurrences	5 occurrences
Rural	5 hours (300 minutes)	2.6 occurrences	10 occurrences
Remote	7 hours (420 minutes)	2.6 occurrences	15 occurrences

These performance indices are calculated at the feeder level which helps narrow down the area where the outage occurred. Once the outage area is identified, outage analysis is performed by categorizing the causes of the outage.

B.3 Distribution system assets

B.3.1 ASSET CLASSES

PGE classifies its assets into 13 categories:

- **Substation structures:** Access roads, landscaping, irrigation/drains, crushed rock surfacing, fences, security systems, yard area lighting and the steel structures that support electrical conductors within a substation.
- **Substation transformers:** These assets change the relationship between the incoming voltage and current and the outgoing voltage and current. They are rated on their primary and secondary voltage relationship and their power-carrying capacity. They consist of a core and coils immersed in oil in a steel tank.
- **Circuit breakers:** Each one of these assets is the combination of a thermostat and a switch. It has a bimetal strip that heats and bends during a circuit overload. When the strip bends, it trips the breaker and opens the switch, thus breaking the circuit.
- **Other substation equipment:** Disconnect switches, control panels, batteries, metal-clad switchgear, conduit and control house.
- **Distribution poles:** One of a set of upright poles to support electric cables, typically made of wood.
- **Overhead (OH) transformers:** One of a set of one to three pole-mounted distribution transformers. Overhead transformers step down the distribution voltage to levels that customers can use.
- **Sectionalizers and reclosers:** Sectionalizers and reclosers are protective devices on the distribution system. The sectionalizer automatically isolates a faulted section on the line, while a recloser interrupts the current on the faulted section.
- **Voltage regulators:** These are devices that create and maintain a defined output voltage, regardless of changes to the input voltage or load conditions. Voltage regulators keep the voltage from a power supply within a range that is compatible with the other electrical components.
- **Capacitor banks:** A capacitor bank is a group of capacitors of the same rating connected in series or parallel with each other to store electrical energy. The pack is used to correct or counteract a power factor lag or phase shift in an alternating current (AC) supply. It can also be used in direct current (DC) power supply to increase the ripple current capacity of the power supply to increase the overall amount of stored energy.
- **Other overhead (OH) conductor devices:** Per the Federal Energy Regulatory Commission (FERC) definition, these are devices, other than those previously defined, used on an overhead electrical distribution system. Common devices can be insulators, cutouts, disconnect switches, fuses and lightning arresters.
- **Underground (UG) transformers:** Underground transformers — also called "pad-mounted" transformers — are electrically the same as pole-mounted units, but packed in a box-like, oil-filled metal enclosure and installed on a ground-level concrete foundation, or "pad." These transformers step down the distribution voltage to levels that customers can use.
- **Underground (UG) conduit:** Underground conduit are ducts installed beneath the streets, sidewalks or paved surfaces to house underground distribution cables.
- **Other UG conductor devices:** Per the FERC definition, these are devices, other than those previously defined, used on an underground electrical distribution system. Common devices can be switches, faulted circuit indicators, terminations and primary junctions.

Table 54 shows the 13 asset classes by age composition. The "unknown" entries are assets that are not tracked in PGE's Maximo database (e.g., brackets).

Table 54. Asset classes by age range

Asset classes	Assets by age range (years)											
	0-9	10-19	20-29	30-39	40-49	50-59	60-69	70-79	80-89	90-99	100+	Unknown
Substation structures	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Substation transformers	31	47	79	28	78	44	44	15	10	1	0	30
Circuit breakers	497	280	335	32	106	72	75	6	0	0	0	214
Other substation equipment	1,075	1,107	1,490	192	891	924	211	48	1	0	111	3,917
Distribution poles	20,346	18,717	23,809	26,026	34,514	32,696	31,619	13,636	1,385	315	33	519
Overhead transformers	29,962	16,906	12,573	7,335	15,098	13,421	10,259	2,330	198	15	4	399
Reclosers and sectionalizers	256	160	2	1	0	1	0	0	0	0	0	2
Voltage regulators	29	18	4	0	0	0	0	0	0	0	0	4
Capacitor banks	69	103	229	239	46	0	0	0	0	0	2	1
Other overhead conductor devices	48	13	3,964	1	0	0	0	0	0	0	0	171,466
Underground transformers	2,405	17,943	21,228	11,722	13,988	3,569	135	15	0	1	4	143
Underground conduit	88,824	109,031	36,544	630	449	202	4	1	0	0	0	7,588
Other underground conductor devices	149	624	1,937	22	12	0	0	0	0	0	0	667

B.4 Distribution system monitoring and control capabilities

Distribution system and monitoring and control capabilities include supervisory control and data acquisition (SCADA) and advanced metering infrastructure (AMI) technologies.

B.4.1 SUPERVISORY CONTROL AND DATA ACQUISITION (SCADA)

SCADA is control system architecture that uses networked computerized data communications systems to interface with and control PGE T&D infrastructure and systems. Deployment of SCADA to substations increases visibility of the grid to T&D operations and reduces the likelihood and duration of outages. Currently, 81% of PGE substations are controlled and monitored by SCADA. PGE is also strategically adding SCADA to reclosers and other intelligent electronic devices (IEDs) that will increase the visibility of the grid to T&D operators.

SCADA deployment to the remaining distribution substations will be planned in conjunction with the distribution management system (DMS) implementation. Prioritization of the SCADA deployment plan will be based primarily on reliability issues, wildfire risk mitigation, and DER interconnection requests. PGE is developing a plan for deploying SCADA to the remaining electronic reclosers and updating the standard recloser installation process to ensure all new devices are installed with SCADA.

B.4.1.1 Description of SCADA technology

SCADA systems provide critical information and remote-control capability to system dispatchers and the balancing authority. Initially, SCADA was deployed at transmission substations to ensure reliability and stability of the bulk electric system while balancing the utility's load with generation, negating the need for manned stations. Over time, the value of SCADA expanded to include safety and distribution reliability, increasing situational awareness and decreasing outage response times. Traditionally, SCADA transmitted limited information, like circuit breaker status and transformer loading. The number of SCADA points per station has expanded to include equipment alarms, enabling proactive response to emerging issues. SCADA is now a critical component of an integrated grid, enabling safe, reliable two-way power flow and optimization of grid assets.

B.4.1.2 ASSETS WITH SCADA DEPLOYMENT

Table 55 shows that of the 153 distribution substations, 81%, have SCADA deployment, and of 695 distribution feeders, 88% have SCADA deployment.

Some examples of other equipment that uses SCADA to control and monitor are voltage regulators, reclosers, protection relays, feeder meters, substation transformer monitoring and capacitors.

Table 55. SCADA assets deployment

	SCADA-deployed units		Unit counts	SCADA-deployed in percent	
	With	Without		With	Without
Distribution substations	124	29	153	81%	19%
Distribution feeders	611	84	695	88%	12%

Table 56 explains the time interval of data collection for SCADA. Distributed Network Protocol, Version 3 (DNP3) is PGE's SCADA protocol standard; TeleGyr (L&G8979) is PGE's legacy SCADA protocol standard that will be eventually converted to DNP3 when equipment replacement is triggered. PGE's SCADA equipment and software can retrieve data in a binary (i.e., open/close), analog (as a spot check of a continuous value — e.g., temperature or power), and accumulator (as an incremental value count, i.e., energy) fashion.

Table 56. Time intervals, interval type and protocols on SCADA data collection

Intervals	Type of interval	Protocols	
		DNP3	TeleGyr (L&G 8979)
2 sec.	Status exception polling	X	
10 sec.	Analog full scan	X	
30 sec.	Status full/integrity scan	X	
1 hr.	Accumulator read	X	
2 sec.	Status full scan		X
10 sec.	Analog full scan		X
1 hr.	Accumulator scan		X

B.4.2 ADVANCED METERING INFRASTRUCTURE (AMI)

AMI comprises meters located outside of customer homes and businesses. AMI records how much power is consumed during the day and tracks voltage levels of delivered power. Meters can record granular power and voltage reads, as well as other services described as follows.

B.4.2.1 Assets with AMI deployment

PGE uses AMI technology to remote connect and disconnect alongside usage and generation measurements for billing, load research, electric service suppliers (ESS) and energy imbalance market (EIM) settlements and unbilled revenue. In addition, AMI can provide:

Hot socket alarms: PGE rolls trucks to "hot socket" alarms, which occur when the meter gets above 85 degrees Celsius. In many cases, these are due to a meter base issue (in need of customer repair) or increased load at the site (such as marijuana grow operations).

Tamper alarms: PGE rolls trucks to unexpected tamper alarms, in which case there are no existing work orders driving a field visit from PGE. Many times, these are false alarms created by electricians, but there are cases of theft or illegal tampering.

Grid monitoring: Recently, PGE began using meters as grid monitoring sensors for large generation sites, such as qualified facilities (QFs) and community solar installations. PGE sends a feed of AMI data to the PI data historian (the monitoring tool used to house PGE's SCADA data) to create visibility for grid operators to large-scale generation occurring on the grid.

Voltage pinging: PGE developed a systematic voltage pinging program, which goes feeder by feeder and pings groups of meters every 15 minutes. This is currently being leveraged to establish data corrections in PGE's geographic information system (GIS) databases mapping meters to other system assets. PGE also relied on this service to aid in remotely confirming for customers whether power was restored to their meter during the 2021 winter storm outages. Potential future use cases are conservation voltage reduction (CVR) programs and theft detection analytics.

Service transformer loading: PGE built a transformer loading analytics tool using the company's in-house Smart Meter Toolbox program application. This tool allows more than 100 site service design professionals and engineers to enter a service transformer ID and see the aggregate load of all customers being served by that transformer. This is useful for overloading analysis, as well as capacity planning for new service requests and DER interconnection.

B.4.2.1.1 Residential

- Proactive power quality notification for half-outs, flickering lights and similar events
- More meter status visibility for customer service agents to help with outage calls, program enrollment eligibility and other tasks
- Enhanced customer web portal (Energy Tracker 2.0) to show more than just usage details, potentially to include generation, outage/alarm history and meter status (on/off)
- Prepaid metering for customers with remote disconnect meters, offering benefits to customer and utility with a pay-as-you-go approach (like filling a gas tank), rather than the typical, deposit, use, bill, pay monthly approach

B.4.2.1.2 Commercial

- Demand/rate migration alerts
- Proactive power quality notifications, single phase-outs, phase imbalance
- Power quality monitoring
  - Some larger customers are purchasing iGrid to monitor their power quality, which is costly to them and PGE
  - PGE could offer "iGrid lite" with current meters and some web development, or a more robust solution with a new meter coupled with data science and engineering support
- Controllable campus lighting, leveraging smart streetlights and AMI
- Water meter network
  - PGE can offer cities its AMI network to read their water meters, so they do not have to read them manually
  - PGE has capacity and has successfully demonstrated this capability with the City of Wilsonville
- Conservation voltage reduction
  - PGE has the opportunity to use meter data to reduce substation voltage, especially during peak-load, high-cost times of day, effectively reducing customer bills and utility power costs
- Theft detection using voltage signatures
- GIS and AMI integration for field crews, allowing for near real-time visibility to customers' on/off state during outage restoration efforts

Table 57 and **Table 58** shows the number of meters by type, the majority being residential customer meters, which account for 87% of total AMI deployments. Overall, PGE has near-universal adoption of AMI. PGE has 916,450 meters installed; all are AMI-enabled except for approximately 140 "opt-out" customers. **Table 57** shows the breakdown of interval length among the approximately 920,000 meters currently installed.

Table 57. PGE meters outfitted with AMI

Meter type	Count	Percent
Residential	794,000	87%
Commercial	103,000	11%
Industrial (>1 MW)	300	0.03%
Irrigation	4,150	0.45%
Vacant	15,000	2%
Total	916,450	100%

Table 58. Operational intervals on AMI Meters

AMI meter interval	Count	Percent
5 minutes	266	- Mix of qualified facilities - Community solar - Demand response
15 minutes	292,893	- Commercial - Newer residential meters
60 minutes	626,969	Exclusively residential

B.5 Distribution system advanced control and communication capabilities

B.5.1 ADVANCED DISTRIBUTION MANAGEMENT SYSTEM (ADMS)

ADMS is a PGE business imperative that will enable real-time management of the distribution system at a more granular level than what is capable today by leveraging use of automated technologies for system management, coordination and optimization. The result will be better reliability, improved power quality, increased operational efficiency and enhanced system safety and security. These benefits will become more evident with migration to a dynamic distribution system integrating DERs.

System functions enhanced by ADMS include heightened situational awareness through SCADA, real-time network connectivity analysis and faster and more accurate information on distribution network operating state and radial mode. ADMS will also facilitate power flow and state estimation, which provides insight into system voltages and power flows in areas that are not metered. This enables advanced applications and tools that can predict faults and allow proactive detection and mitigation of threats to system interruptions, failures and outages.

B.5.1.1 Description of ADMS technology

ADMS is a centralized, advanced operations technology platform for system operators to monitor, control, optimize and safely operate PGE's distribution system. It is comprised of a suite of core functions, such as dedicated distribution SCADA (DSCADA), an "as-operated" model of the distribution system and links to other applications, such as GIS, OMS and energy management system (EMS). ADMS uses the same types of analysis tools used for the transmission system to view and analyze the distribution system model (state estimation and power flow). This increased complexity associated with operating a distribution system in the presence of emerging technologies like DERs, EVs, and DRs will result in uncertainty regarding system state. This complexity is beyond the capability of the current EMS which is primarily designed to manage transmission and generation.

ADMS provides SCADA controls for distribution circuits, automated self-healing circuit functionality fault location, isolation, and service restoration (FLISR); assisted/automated switching for planned and unplanned outages; grid optimization; real-time power system studies and reporting capabilities. Advanced functions include conservation voltage reduction, volt-VAR optimization, protection analysis and adaptive protection. Mobile grid operations is an advanced ADMS capability that provides field personnel access to grid data and the ability to update the grid information.

Table 59 includes ADMS capabilities that PGE has tested, currently uses, or is planning on using over the next couple of years.

Table 59. Advanced control distribution management systems capabilities

ADMS capabilities	Percentage of customers reached with each capability
Control and operations[150]	Approximately 690 feeders; 100% of feeders
FLISR	3 feeders using YFA; approximately 3,000 customers

150. Examples of control and operations: Load transfer, microgrid ops, device management, load shed, feeder reconfiguration, low voltage analysis, FLISR/VVC, overload switching, intelligent alarms, relay protection, adaptive protection, optimal power flow, feeder balancing/rebalancing, breaker/fuse capacity analysis, Switch Order Management, State Estimation, Secondary Power Flow, Short Term Load Forecast, Energy Losses, Short Circuit Duty Analytics

B.5.2 CONSERVATION VOLTAGE REDUCTION (CVR)

CVR is the strategic reduction of feeder voltage, deployed with phase balancing and distributed voltage-regulating devices to ensure end-customer voltage is within the low range of American National Standards Institute (ANSI) acceptable voltages (114V–120V). PGE completed feasibility studies and two CVR pilot projects in 2014 at Hogan South substation in Gresham and Denny substations in Beaverton. By reducing voltage 1.5-2.5% in the pilot project, PGE was able to reduce customer demand (MW) and energy consumption (MWh) by 1.4-2.5%. The pilots yielded customer energy savings of 768 MWh in 2014. A preliminary evaluation has identified 94 transformers as potential CVR candidates with a customer energy savings potential of 142,934 MWh/year, or 16 average megawatts (MWa).

B.5.3 OUTAGE MANAGEMENT SYSTEM (OMS)

OMS is an asset/work management system that provides PGE grid operations the ability to monitor and manage customer outages while returning power. OMS assists with the following capabilities:

- Predicting the location of the transformer, fuse, recloser or breaker that opened upon failure.
- Prioritizing restoration efforts and managing resources based on criteria such as the location of emergency facilities, the size of outages and the duration of outages.
- Providing information on the extent of outages and number of customers impacted to management, media and regulators.
- Calculating the estimation of restoration times.
- Managing crews assisting in restoration and calculating the crews required for restoration.

PGE's distribution system is fully outfitted with OMS on all of its feeders, monitoring all customers.

B.5.4 DER MANAGEMENT SYSTEM (DERMS)

DERMS is a module of ADMS that optimally manages and dispatches DERs to provide grid services, facilitates non-wire alternatives, enables DERs to participate in markets, manages smart inverters, and cost-effectively manages distribution deferral resources. DERMS enables enhanced situational awareness under increasing DER penetration by providing DER modeling, aggregation and grouping. The DERMS also enhances the utilization of DER by providing DER forecasting, communication, and dispatch.

PGE will be piloting DERMS functionality in 2022.

B.5.5 DEMAND RESPONSE MANAGEMENT SYSTEM (DRMS)

DRMS follows ADMS in Phase 2 of the ADMS rollout. DRMS is essential for balancing energy supply with consumption and stabilizing load on the grid during peak hours. An automated demand response is enabled through AMI, which builds an integrated network between the customers participating in the DR program and the utility for exchanging signals and communicating in real-time.

In the future, PGE plans to use several DRMS capabilities, including: Solicitation, registration, interconnection, DER portfolio optimization, constraint management, aggregation functions, microgrid management, islanding, OPF, dispatch and schedule. **Table 60** shows all the PGE programs that apply to DRMS.

Table 60. PGE programs using DRMS

Utility programs	Number of units
Residential battery	200 of 500
Residential EV	110
Residential T-stat	25,842
Ductless heat pump	50-100
Single family water heater (SFWH)	70-150
Peak time rebate	90,993
Multi-family water heater (MFWH)	9,975
Energy partner Sch 26	65
Energy partner Sch 25	1,407
Beaverton microgrid	NA
Anderson microgrid	NA
E-Fleet platform	NA

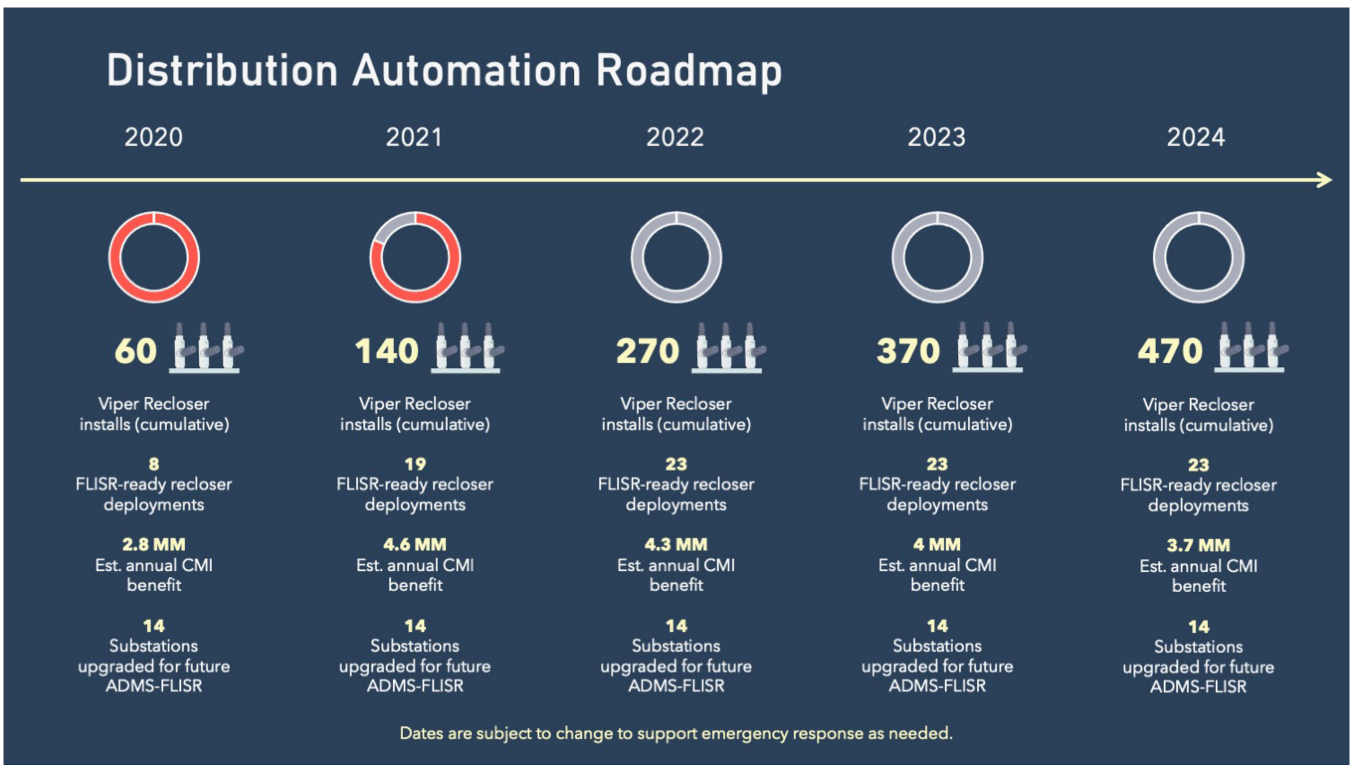
B.5.6 DISTRIBUTION AUTOMATION (DA)

Distribution automation (DA) improves reliability by utilizing switching devices to automatically isolate faulted areas and restore power to the remaining areas. It offers enhanced visibility with communicating reclosers providing additional monitoring on the distribution system. In addition, DA contributes to the migration to field area networks (FAN).

DA uses digital sensors and switches with advanced control and communication technologies to automate feeder switching, voltage and equipment health monitoring and outage, voltage and reactive power management. Automation can improve the speed, cost and accuracy of these key distribution functions to deliver reliability improvements and cost savings to customers.

PGE is implementing DA with the use of SCADA-integrated field devices (such as reclosers) across PGE's service territory to improve reliability for customers, increase safety for line crews and improve situational awareness for distribution system operators. DA reclosers and ADMS enable the operation of fully automated FLISR — a key grid modernization capability. Viper and Sentient MM3+ are two examples of equipment being installed to help implement ADMS FLISR capabilities (**Figure 39**).

Figure 39. Distribution automation roadmap



B.5.7 FIELD AREA NETWORK (FAN)

The FAN is a new two-way data communication network that uses PGE's privately-owned 700-megahertz (MHz) spectrum. PGE purchased the 700 MHz spectrum to support ADMS data collection once the tower buildup is concluded in 2024. The FAN is a private, PGE-owned and operated wirelessly with high reliability and low latency. This new, two-way data communication network allows quick and inexpensive data connections to various devices that PGE uses to operate and manage the power grid. It provides fast, secure and reliable wireless coverage across PGE's distribution service territory (**Figure 40**). A subset of the FAN will allow lower-reliability, higher-latency connections to customer-owned and operated devices like thermostats, EV chargers and behind-the-meter battery storage. The FAN will also allow PGE to respond to Smart City applications as they emerge. DA reclosers will be the first devices to communicate with PGE's grid management systems over the FAN.

PGE expects FAN will provide secure, ubiquitous communications to existing Distribution Automation (DA) assets as well as all emerging Distributed Energy Resources (DERs). PGE believes that this new FAN will deliver capabilities necessary for the safe, reliable and affordable operation of the electric grid. PGE plans to install FAN in 90 sites (**Table 61** & **Figure 40**).

Table 61. Field Area Network coverage implementation plan

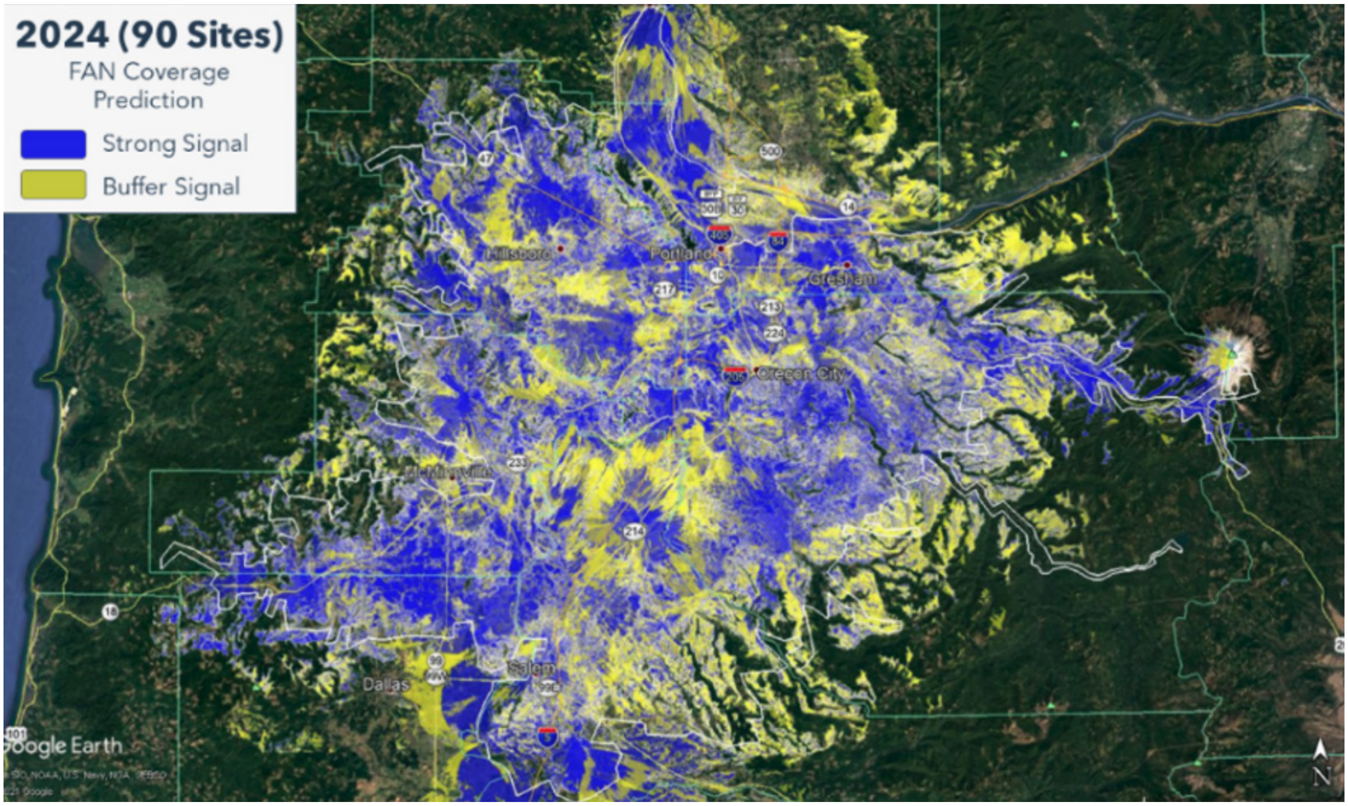
Year	Number of FAN sites	Percent of total coverage
2020	12	13%
2021	18	33%
2022	22	57%
2023	23	83%
2024	15	100%

One of several key pieces of PGE's Integrated Grid Portfolio, the FAN enables wireless communication between distribution assets in the field and the Integrated Operations Center.

The FAN offers substantial benefits compared to alternative communication networks:

- Improved reliability, speed, and restoration because we will not be dependent on third-party network providers
- Increased command-and-control capabilities over field sensors and control devices
- Better protection through increased security and encryption
- Greater ability to scale
- Data analytics, including greater visibility into customer demand for electricity

Figure 40. FAN coverage prediction, 2024



B.5.7.1 How the FAN supports PGE's integrated grid strategy

A FAN is designed to efficiently connect technologies, such as:

- Distribution automation (DA) such as reclosers for swift fault response and distribution reconfiguration
- Supervisory control and data acquisition (SCADA)
- Demand response management system (DRMS). PGE currently employs Enbala as its DRMS for visualization and control of all our demand response assets
- Energy Storage integration
- Microgrid control
- Distributed energy resource (DER) management
- Solar integration
- Transportation electrification (TE) integration
- Advanced metering infrastructure (AMI)
- Street lighting control system backhaul
- Field data communication

B.5.7.2 How the FAN will support integrated grid moving forward

The integrated grid relies on connectivity, sensing and automation/control. PGE's distribution network system currently has limited visibility and communication capability through its SCADA system to existing distribution automation controls. This limited visibility prevents the distribution system from being used to enable the efficient deployment of technologies to achieve greater energy efficiency, energy network management and system reliability that customers are demanding.

The FAN will provide the fundamental backbone to allow for the communication and visibility within the power grid network architecture.

B.6 Transportation electrification infrastructure and charging analysis

B.6.1 MASS TRANSIT ELECTRIFICATION — ELECTRIC MASS TRANSIT 2.0

PGE owns two bus depot charging stations (150 kW each) and one on-route charging station (450 kW), while TriMet acquired five electric buses with 200 kWh batteries. The pilot will gather bus charging data from the stations to assess the energy and cost impacts of electrifying an entire bus route over time as well as operations impacts to TriMet.

Transit is a critical component of the transportation sector and therefore we must continue to work with our transit agencies to ensure those customers relying on transit can realize the benefits of emissions-free transportation services. Throughout 2018, PGE worked closely with TriMet to design, install, commission and operate the proposed electric bus charging infrastructure. PGE provided guidance on the most flexible and cost-effective methods to connect the charging infrastructure at Sunset Transit Center and Merlo Garage to PGE's distribution grid, provided insight into site layout and construction, and held regular meetings with TriMet and other construction contractors. The first all-electric bus line launched in 2019.

B.6.1.1 Constructability and future-proofing assistance

PGE assisted TriMet in the design and layout of the charging infrastructure installations at Merlo Garage and Sunset Transit Center. At Merlo Garage, PGE proposed the installation of an additional underground vault, oversized transformer pad, and extra runs of secondary-side conduit to accommodate the addition of subsequent charging infrastructure more easily. TriMet chose to install oversized switchgear and additional underground electrical infrastructure to allow for the installation of up to six additional 150 kW-capable charging ports. PGE also collaborated with TriMet's contractors on the design and layout of the overhead fast charger installed at Sunset Transit Center. As at the Merlo project, PGE installed an oversized transformer pad and extra secondary side conduit runs to allow for the installation of a second overhead fast charger and TriMet installed oversized switchgear and additional underground electrical infrastructure.

B.6.1.2 Operations and maintenance plan development

PGE created an Electric Bus Charging Infrastructure operations and maintenance program in collaboration with TriMet and the infrastructure supplier. PGE worked with suppliers to identify the correct spare parts to stock at PGE facilities and train local electricians and PGE staff on equipment diagnostics and repair. TriMet and PGE also established a communications and response plan that provided a clear process for bus drivers to quickly identify issues for diagnosis and repair by PGE and the charger supplier. As TriMet began placing buses in revenue service, PGE activated remote monitoring and emergency repair programs. PGE has been available 24 hours per day / seven days per week to respond to charging infrastructure issues.

B.6.2 ELECTRIC AVENUES (EA)

PGE owns and operates seven public fast charging locations (Electric Avenues or EA), each with four Direct Current Fast Chargers (DCFC) charging ports (50 kW each) and two level 2 ports (7 kW each) for quick re-fueling. Under our EA Pilot,[151] we installed six EA charging sites[152] at geographically dispersed locations throughout our service area. The pilot will test pricing signals to encourage off-peak charging and charging when excess renewable energy is available. The pilot will also examine the impact of community charging on increasing adoption of EVs by PGE customers (including multifamily residents) and Transportation network company (TNC) drivers.

Figure 41 below presents an overall summary of energy delivered to the six different sites.

151. See Docket No. UM 1938 for more details on the Electric Avenue pilot
152. Six EA sites were installed under UM 1938, plus an additional existing site at World Trade Center, for a total of seven EA public charging sites total.

Figure 41. Monthly charging load at EA sites

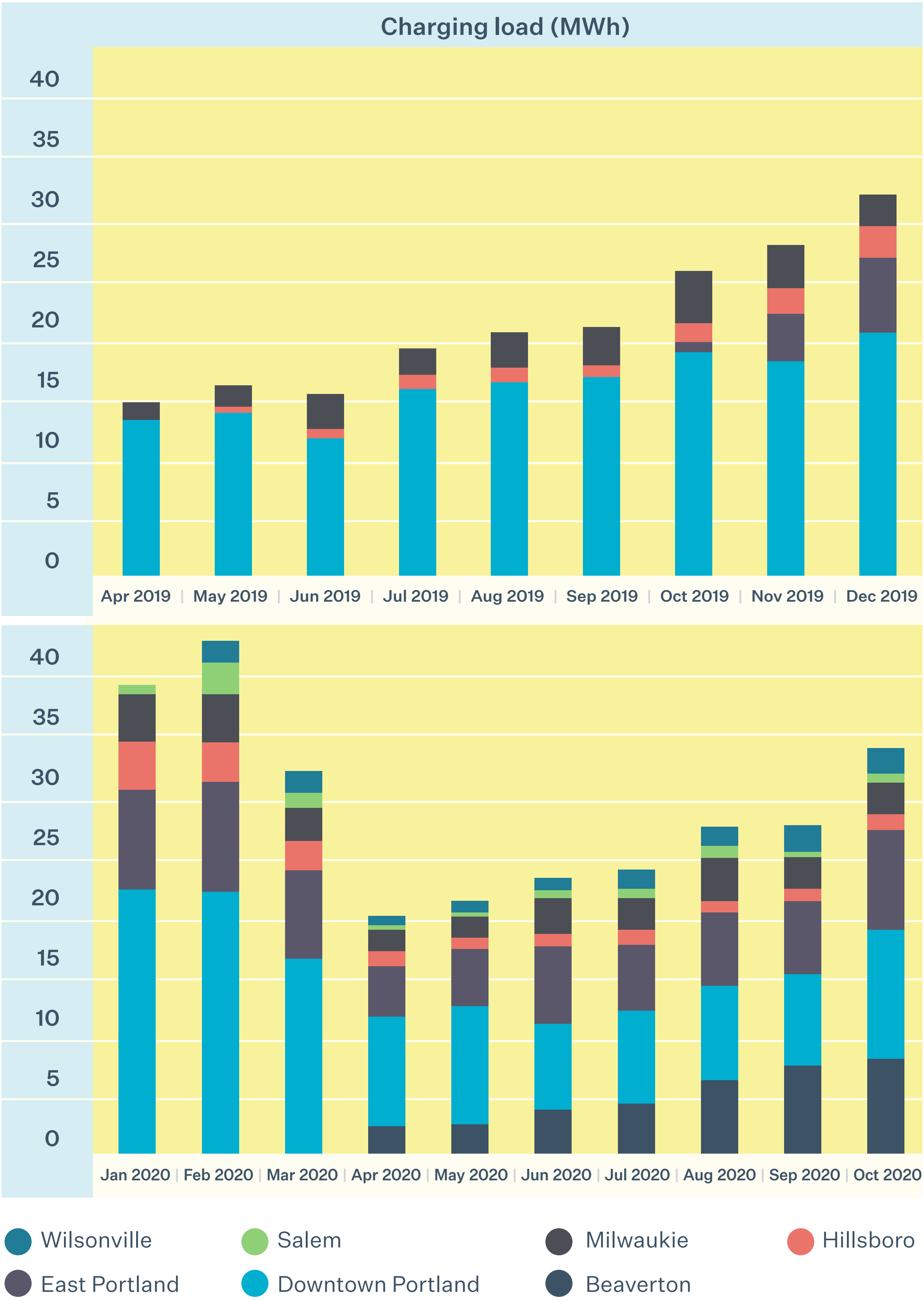
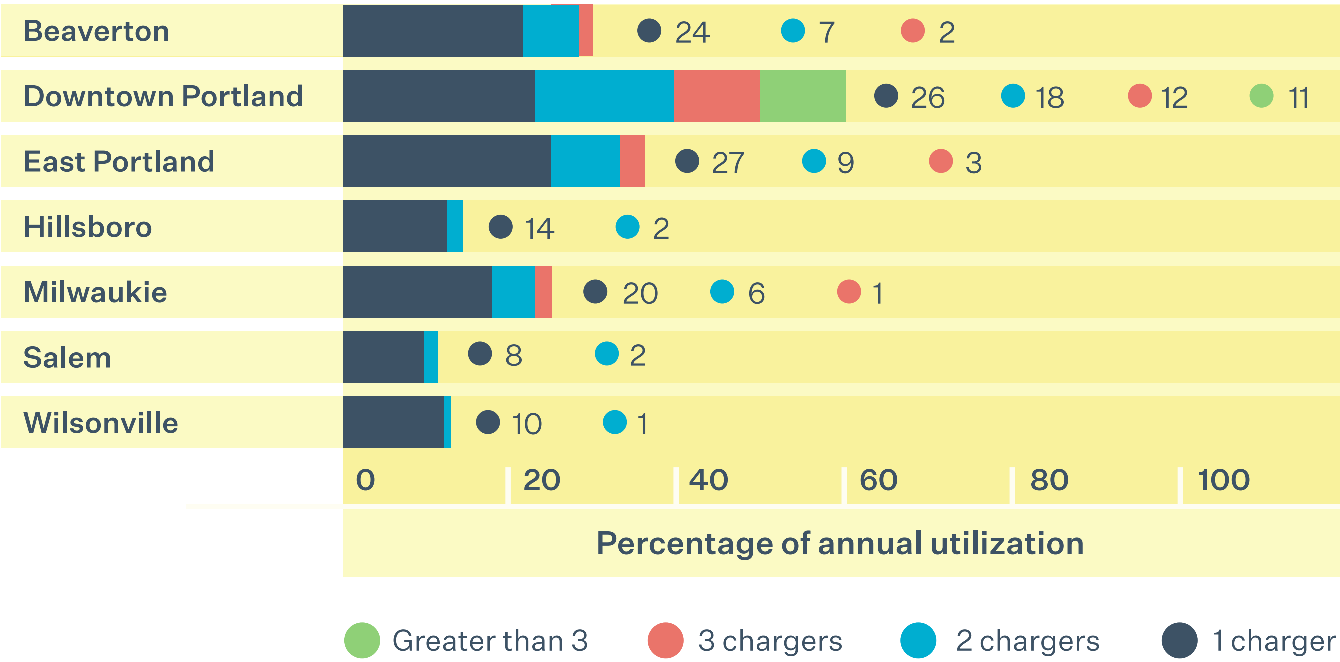


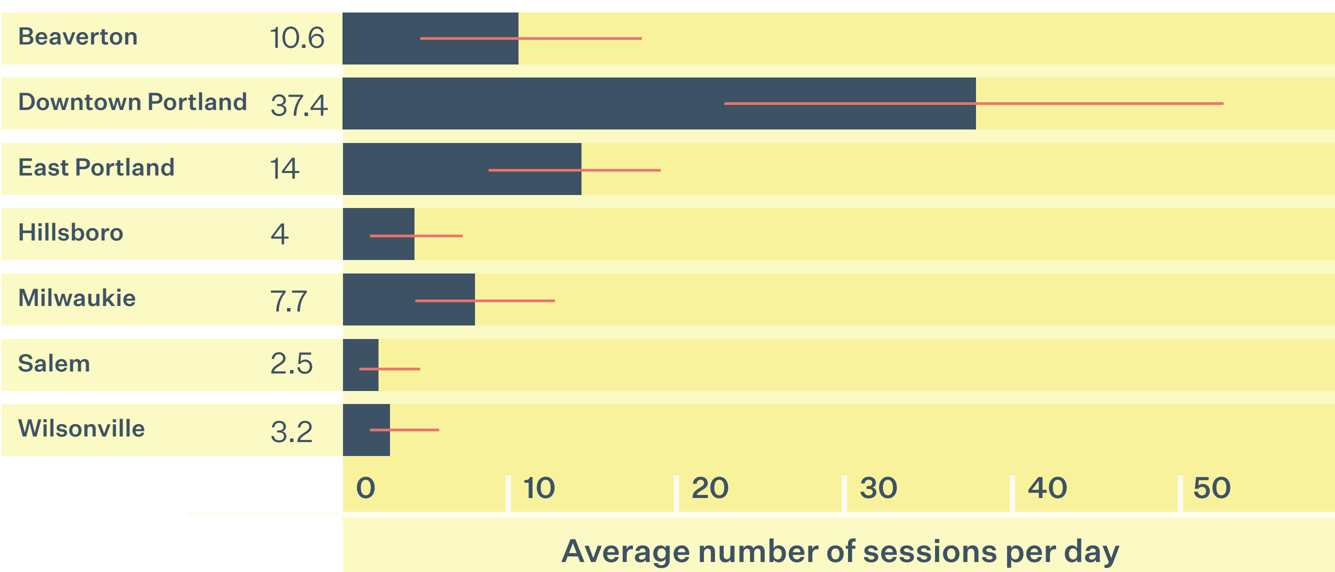
Figure 42 below shows how often each EA site experiences simultaneous charging (more than 1 port active at the same time). The downtown Portland site has the greatest amount of time with more than one port actively charging, followed by East Portland and then Beaverton sites.

Figure 42. Annual charger utilization at EA sites



We also looked at average number of charge sessions per day at each of the EA sites, presented in **Figure 43** below.

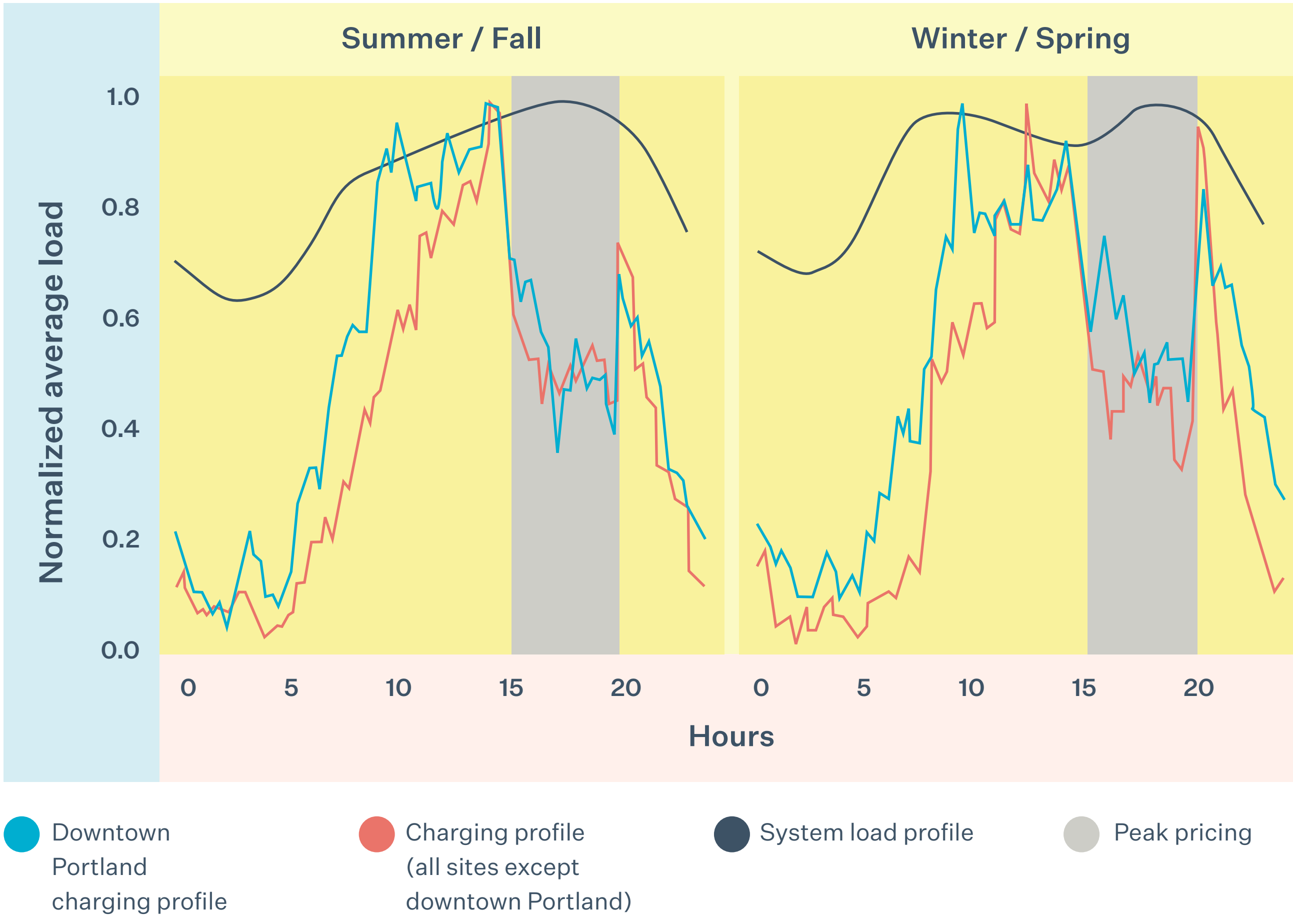
Figure 43. Average charging sessions by site



Note: The average number of charging sessions in the blue bars along with the standard deviation of the number of charging sessions in the red lines.

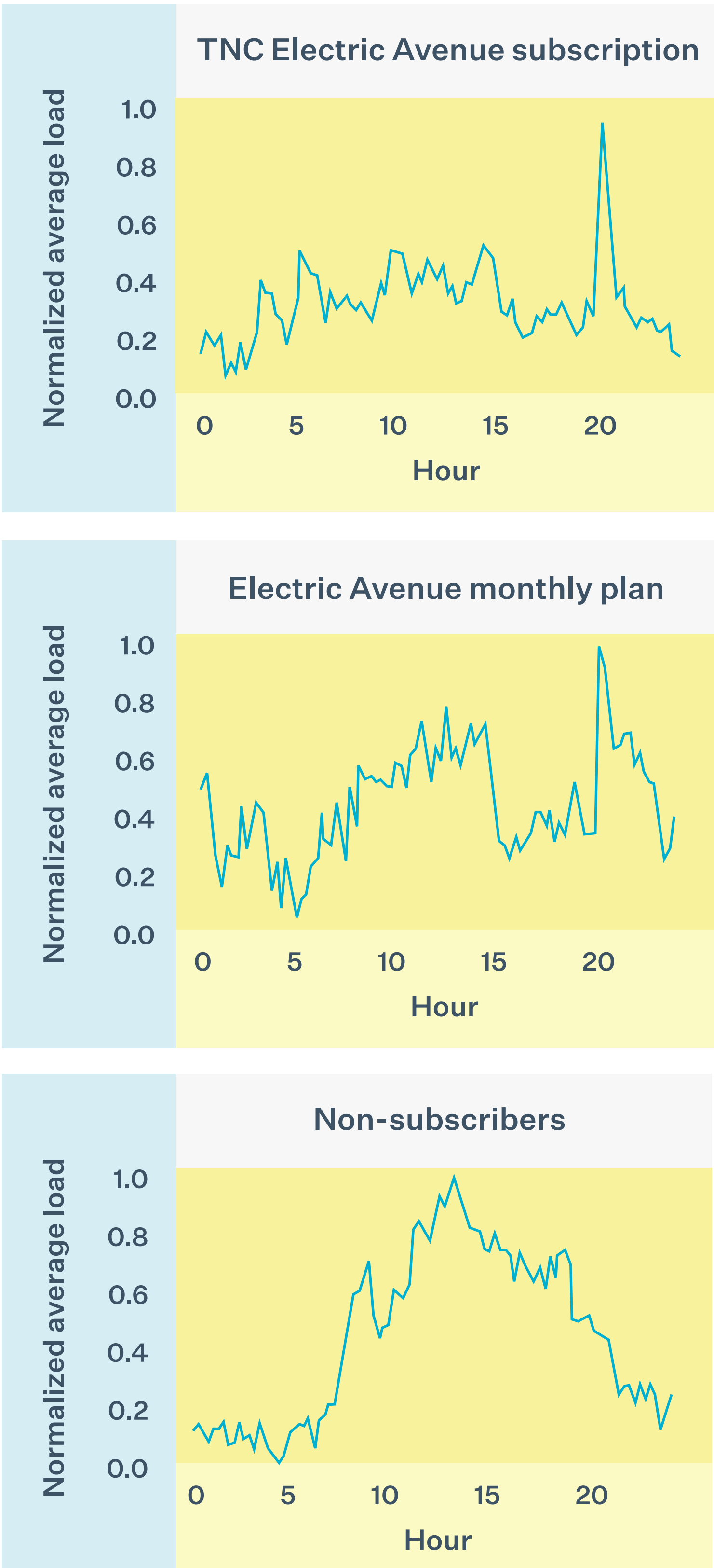
We also investigated the impact of peak pricing on charging demand, as well as the influence of subscription monthly rates and how that might impact charging behavior. The grey highlighted windows on **Figure 44** clearly demonstrate the effectiveness of the pricing signal to curb demand during system peaks.

Figure 44. Normalized system load shape verses the normalized charging profile



When looking across the type of users at the EA sites, there are clear differences in charging behavior depending on whether someone has a monthly subscription rate or simply uses a credit card at the point of sale. **Figure 45** below demonstrates that a pricing plan (whether that is the EA monthly subscription or the TNC subscription rate) generally reduces the proportion of charging during peak hours. Both EA and TNC user groups have a peak at around 8:00 p.m., whereas the unsubscribed users show a peak at around noon, and a much higher proportion of usage during system peak hours (about 70% of the normalized average daily load falls between hours 18 and 20 on the graph, or 5:00 a.m. and 8:00 p.m., respectively.)

Figure 45. Normalized average daily load profiles for EA user groups



To understand potential impacts of EA sites to the distribution system, we mapped EA load to the respective feeders where these sites are located. Overall, the operation of the current EA sites does not present a problem for the peak load of the host-feeders, all of which are well below the planning threshold of 67% peak load of seasonally adjusted nameplate ratings. If all chargers are in simultaneous use, then EA sites under current configuration could add between 1-2% of load. **Table 62** below shows this breakout for each EA host-feeder, and **Table 63** shows the type of charging stations by feeders.

Table 62. Loading on feeders serving EA sites

EA site	Feeder % loading with historical EA charging load		Feeder load charging % increase if all chargers are in use	
	Winter	Summer	Winter	Summer
Milwaukie	31%	48%	1.4%	2.1%
East Portland	36%	55%	1.4%	2.1%
Wilsonville	54%	56%	1.1%	1.2%
Beaverton	32%	40%	1.1%	1.2%
Salem	29%	39%	0.8%	0.9%

Table 63. Types of charging stations by feeders

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Abernethy-Clackamas Heights			1
Abernethy-Washington		4	
Alder-Ankeny		4	
Alder-Lincoln		2	
Amity-Amity 13		2	
Amity-Bellevue		1	
Banks-Cedar Canyon		1	1
Barnes-Battle Creek		2	
Barnes-Boone		1	
Barnes-Commercial		2	
Beaver-Kb Pipeline	0	4	0
Beaverton-Jamieson		9	3
Beaverton-Northwest		2	
Beaverton-West Slope	0	8	5
Bell-Battin		2	
Blue Lake-Sundial		4	1
Boones Ferry-Kruse		14	
Boones Ferry-Lake Grove		3	
Brookwood-Brookwood 13		4	
Canyon-13115 Network #1	0	9	14
Canyon-13120		3	
Canyon-13133 Network #3		4	
Canyon-13134 Network #3		3	2
Canyon-13136 Network #3		2	
Canyon-21st		4	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Canyon-23rd		2	
Canyon-Burnside		4	
Carver-North	0	2	2
Cedar Hills-Leahy		2	
Cedar Hills-Shopping Center	0	0	1
Cedar Hills-Skyline		4	
Cedar Hills-St Vincent		4	
Centennial-Braecroft		2	
Clackamas-Jennifer		2	
Clackamas-Tolbert		2	
Coffee Creek-Freeman		2	
Coffee Creek-Holiday		2	1
Cornelius-Cornelius 13		6	3
Cornelius-Verboort	0	5	0
Cornell-Bluffs		2	
Cornell-Westlawn		2	
Dayton-East		9	
Denny-North	1	2	
Durham-Bonita		10	
Durham-Bridgeport	12	12	
Durham-Durham 13	0	0	2
Durham-South		2	
E-11040		4	
E-11047	0	4	0
E-13140		2	
E-13141		9	
E-13142		1	
E-13144		6	
E-13145			1
E-13149		2	
E-13150		18	
Eastport-Plaza	0	0	5
Elma-Hudson		4	
Elma-State		1	
Estacada-Estacada 13		4	
Estacada-Faraday		4	
Fairmount-Candalaria	0	0	2
Fairview-Clear Creek		4	
Fairview-Fairview 13		1	
Fairview-Kennel Club		3	
Gales Creek-Gales Creek 13		2	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Glencoe-Glisan		2	
Glencoe-Sunnyside		1	
Glendoveer-13597		3	
Glendoveer-Northeast		2	
Grand Ronde-Forthill		1	1
Harrison-Davis		4	
Harrison-Harrison 13		2	
Hayden Island-North Shore		2	
Hemlock-Mason			2
Hillcrest-South		1	
Hillsboro-Dairy Creek		4	
Hillsboro-Jackson		10	
Hillsboro-Laurel		2	
Hillsboro-Scholls		34	2
Hogan North-Brigadoon		2	
Hogan North-Salquist	0	4	0
Hogan South-Cleveland		2	
Hogan South-Paropa		2	
Holgate-Bybee		1	1
Holgate-Gideon	0	4	0
Holgate-Holgate 13	0	5	0
Holgate-Kenilworth		1	
Huber-Farmington		2	
Indian-Keizer	0	0	2
Indian-Labish	0	4	0
Indian-Station		7	
Island-13180		4	
Island-13188		7	
Island-Island 13	0	16	0
Jennings Lodge-Jennings 13		2	
Jennings Lodge-Meldrum		3	
Kelly Butte-Binnsmead		9	
Leland-Kelm		4	
Lents-13101		1	
Liberty-Rosedale		2	
Main-Express		2	
Main-River		2	
Market-Hawthorne		3	12
Marquam-Mccall #11 Network		4	
Marquam-Mccall #12 Network		6	
Marquam-Spirit #1 Network		3	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Marquam-Spirit #2 Network		2	
Mcgill-Horsetail		4	
Meridian-65th		2	
Meridian-Borland		3	
Meridian-Childs		3	1
Meridian-Nyberg		1	2
Meridian-Pilkington		8	
Meridian-Sagert	0	14	0
Middle Grove-Brown		1	2
Middle Grove-Swegle			4
Midway-Division		1	
Midway-Powellhurst		1	
Molalla-Buckaroo		1	
Mt Pleasant-Clairmont	1	15	0
Mt Pleasant-Mt View		3	
Multnomah-13176	1	1	
Multnomah-13177		2	
Murrayhill-Kinton		2	
Newberg-Dundee		7	
North Marion-Crosby		2	12
North Marion-Front	0	4	0
North Plains-Mason Hill		2	
Northern-11071		4	
Oak Hills-Five Oaks		5	12
Oak Hills-Walker		2	
Orenco-Baseline		3	
Orenco-Orenco 13		21	
Orenco-Wilkins		10	
Oswego-Iron Mountain		2	4
Oswego-Marylhurst		18	
Oxford-Rural		21	2
Peninsula Park-Peninsula Park		3	
Progress-Greenburg			1
Progress-Sawyer		2	
Progress-Washington Sq #2			14
Riverview-Fulton		1	3
Riverview-Terwilliger		2	
Roseway-Roseway 13		1	
Ruby-Junction		2	
Salem-13260		2	
Salem-13261		3	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
Salem-13262	0	0	3
Salem-13263		2	
Salem-13264		2	
Sandy-362nd		1	10
Scholls Ferry-Roy Rogers		2	
Sellwood-Sellwood 13		1	
Sheridan-East		1	
Silverton-North	0	2	0
Silverton-West		2	
Six Corners-13359	1	1	
Six Corners-Borchers		1	
Six Corners-Chapman		4	
Six Corners-Six Corners 13	2	5	3
Springbrook-Fernwood		6	1
Springbrook-Villa		1	
St Louis-East		7	1
St Marys East-Bethany		1	
St Marys East-Elmonica	0	0	2
St Marys East-Millikan		4	
St Marys East-St Marys 13	0	4	0
Summit-Summit 13		1	1
Sunset-Mccall	0	2	0
Sunset-Pauling		1	2
Sunset-Spalding		4	
Sunset-Whitman		12	
Swan Island-Dolphin		6	
Tabor-Hospital		17	
Tektronix-Hocken		2	
Tektronix-North		8	
Tektronix-South		4	
Tektronix-Tektronix 13		6	
Tektronix-West		2	
Temp H-Neptune	4	7	
Tigard-13337		5	
Tigard-13361	0	0	2
Tigard-Tigard 13		1	
Town Center-North	0	15	0
Town Center-Sunnybrook	2	2	
Town Center-Valley View		2	3
Tualatin-Avery	0	6	0
Unionvale-Unionvale 13		1	

Table 63. Types of charging stations by feeders (continued)

Feeder Name	Charger Type		
	Level 1	Level 2	DCFC
University-Mill		4	
University-Trade	0	12	0
Urban-Campus		6	
Urban-Gibbs		2	
Urban-Landing	2	2	
Waconda-River		2	
Wallace-Wallace 13		5	
Welches-Welches 13		1	
Welches-Zig Zag		1	1
West Portland-72nd		3	10
West Portland-Pacific		5	
West Portland-West Portland 13		1	
West Union-Cornelius Pass		2	
West Union-Jacobson		6	
Wilsonville-City	0	5	7
Wilsonville-Parkway		4	
Wilsonville-Villebois	0	2	0
Wilsonville-West		3	
Yamhill-Carlton		6	
Yamhill-Yamhill 13		3	
Grand Total	26	818	167

B.6.3 ELECTRIC ISLAND DEMONSTRATION

PGE and Daimler Trucks North America launched the nation's first public, purpose-built heavy-duty truck charging demonstration site, designed to serve up to 5 MW of load and up to 12 DC fast charging ports accessible by Class 8 vehicles with 53' trailers.

Daimler Trucks North America (DTNA) and PGE opened the site in April 2021, calling it "Electric Island" for reference to the new heavy-duty charging hub's location on Portland's Swan Island, home to many logistics and freight companies in the area. Electric Island will help accelerate the development, testing and deployment of zero emissions (tank to wheel) commercial vehicles, like the ones manufactured by DTNA.

Electric Island opened in Portland with eight vehicle charging stations (a majority of which are available for public use) for the charging of electric cars, buses, box vans and semi-trucks. The site is built to immediately provide charging for EVs of all shapes and sizes, and will serve as an innovation center, allowing both PGE and DTNA to study energy management, charger use and performance, and, in the case of DTNA, its own vehicles' charging performance.

Electric Island is designed to benefit both DTNA's work in commercial electric vehicle development and PGE's work in meeting customer charging needs. The site will inform each company's efforts by studying the future of heavy-duty charging, including:

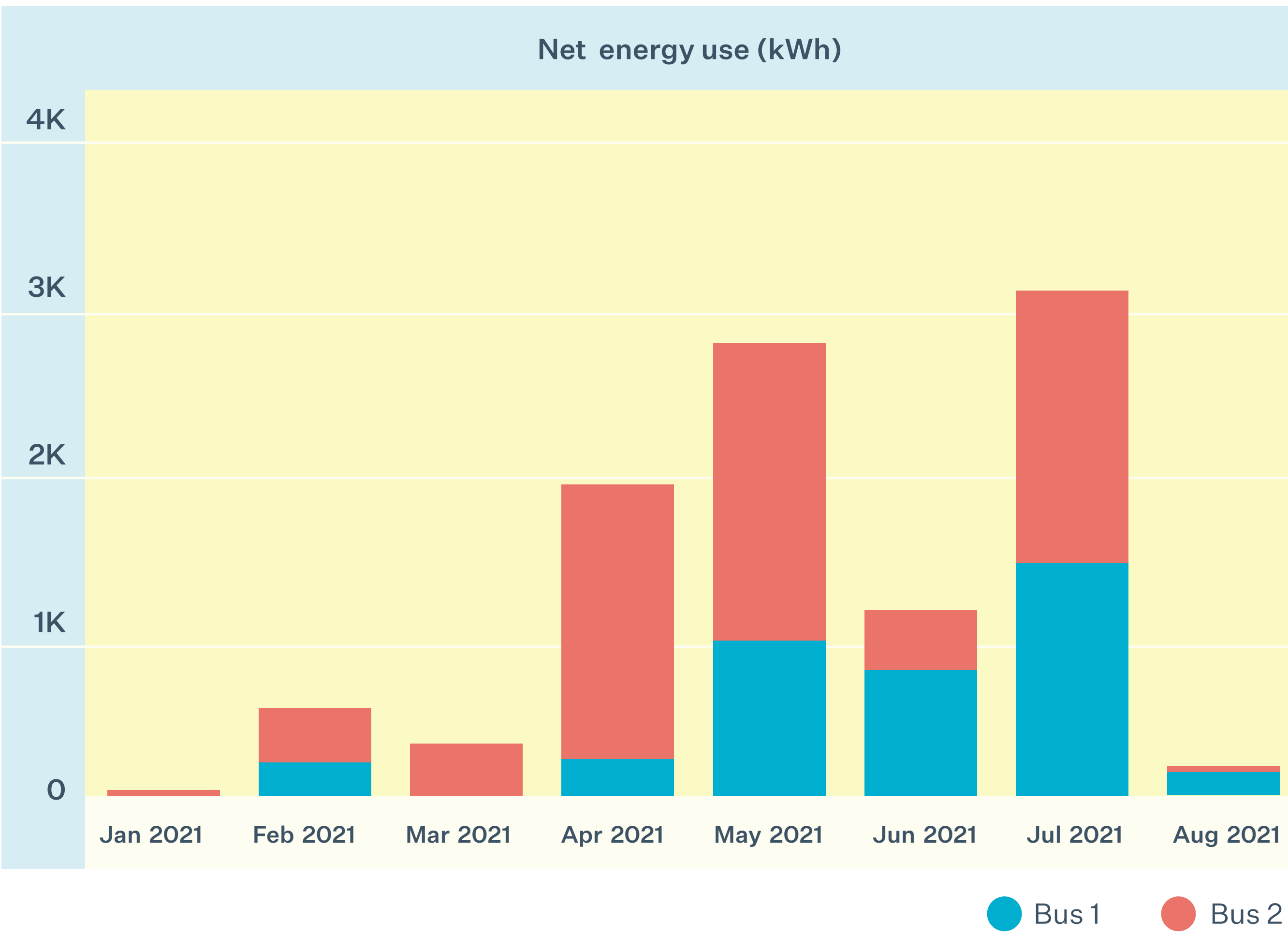
- Use of vehicle chargers featuring power delivery capable of over one megawatt charge speed (over 4 times faster than today's fastest light-duty vehicle chargers), enabling PGE and DTNA to develop best practices for cost-effective future deployments;
- Integration of heavy-duty charging technology into PGE's Smart Grid, such as vehicle-to-grid technologies, second-life use of Daimler's battery packs for stationary-grid applications, and onsite energy generation; and
- Testing information technology opportunities like fleet and energy management by captive solutions and services.

B.6.4 ELECTRIC SCHOOL BUS FUND

Through funding via the Oregon Clean Fuels Program (CFP), PGE provides grant funding to school districts to cover the incremental cost of the electric school buses (the difference in cost between a standard diesel bus and an electric bus) and the total installation of charging infrastructure. PGE also provides technical assistance to school districts throughout the process, including site assessments, cost-benefit analysis, vehicle and charger selection support, and driver and mechanic support. In return, participating school districts work with PGE to share their insights and learnings with other school districts interested in electrifying their bus fleets.

As the electric school buses come online and become operational, we are collecting load data to analyze how this charging use case compares to other EV types. At the time of filing, only one district had buses operational. **Figure 46** below summarizes usage at the Beaverton School District's two electric school buses.

Figure 46. Electric school bus energy delivery at Beaverton school district pilot site



We are interested in the ability of school buses to act as a flexible DER asset for the grid, particularly given that school buses may be docked more often during summer months, making them good candidates for future vehicle-to-grid applications.

In 2020, the school bus fund funded a total of six electric school buses for the Beaverton, Newberg, Portland, Reynolds and Salem/Keizer school districts.

B.6.5 FLEET CARMA PILOT STUDY

PGE launched an electric vehicle charging study to better understand vehicle usage and charging behavior in the service territory and how charging can be shaped through time of use incentives. Improving our understanding of vehicle use and behavior-based strategies to reshape load are critical to the successful integration of the widespread EV adoption expected in coming years. The study includes roughly 200 participants, comprised of a 100-customer control group and a 100-customer treatment group randomly assigned to one of three time of use incentive structures. Enrollment in the project closed in December of 2020 and data will be collected through the end of 2022. Vehicle charging data is being used to inform various load research efforts within PGE and to understand current EV driver preferences between home and public charging.

B.6.6 POLE CHARGING PILOT

In order to study opportunities to make EV charging more accessible and convenient, PGE has introduced a Utility Pole Mounted EV charging pilot in collaboration with City of Portland. Installing chargers on utility poles could offer a cost-effective way to increase access to chargers in traditionally underserved areas or in areas with limited access to off-street parking. As more Oregonians adopt EVs, innovative charging options like these are needed to support those without access to home charging.

During the first phase of the pilot, we installed two chargers in the SE Clinton neighborhood of Portland. Customers have shown high satisfaction with the chargers, giving them a 10 out of 10 rating on PlugShare.[153] PGE also received comments such as, "Absolutely love the idea of these stations. I would gladly pay to have more around," and "I wish these were located all over the city." Currently the chargers are free to use, with plans to switch to pay-for-use under Schedule 50. Preliminary data collected during the pilot can be found below in **Table 64**.

Table 64. Pole charging pilot key performance indicators

Key performance indicator	SE 29th Ave.	SE 35th Pl.
kWh used	16,826	18,479
Number of unique users	296	256
Number of sessions	1,076	1,044
Number of sessions per day	2.07	2.01
Average duration of stay	4 hours, 3 minutes and 8 seconds	4 hours, 37 minutes and 6 seconds
Average charging time	2 hours, 53 minutes and 45 seconds	3 hours, 2 minutes and 45 seconds

153. Available at: plugshare.com