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AUGUST • 2022

2022 DSP

OREGON DISTRIBUTION SYSTEM PLAN

A VIEW FROM ABOVE

SAFE HARBOR STATEMENT

This document may contain forward-looking statements, and it is important to note that the future results could differ materially from those discussed. A full discussion of the factors that could cause future results to differ materially can be found in Idaho Power's filings with the Securities and Exchange Commission.

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GLOSSARY OF ACRONYMS AND DEFINED TERMS

Acronyms

ANSI—American National Standards Institute

BESS—Battery Energy Storage System

CEMI—Customers Experiencing Multiple Interruptions

CPI—Circuit Performance Index

DER—Distributed Energy Resources

DGA—Dissolved Gas Analysis

DOE—Department of Energy

DSP—Distribution System Plan

EV—Electric Vehicle

HCA—Hosting Capacity Analysis

IEEE—Institute of Electrical and Electronic Engineers

IRP—Integrated Resource Plan

kV—Kilovolt

kW—Kilowatt

MAIFI—Momentary Average Interruption Frequency Index

MVA—Mega Volt Ampere

MW—Megawatt

NREL—National Renewable Energy Laboratory

NWS—Non-Wires Solution

OPUC—Public Utility Commission of Oregon

PV—Photovoltaic

SAIDI—System Average Interruption Duration Index

SAIFI—System Average Interruption Frequency Index

SGM—Smart Grid Monitor

T&D—Transmission and Distribution

V–Volt

Defined Terms

Bottom feeder—One of the distribution feeders with the lowest reliability rating

Distribution feeder—One of the circuits coming out of a substation, more commonly known as "Feeders"

Feeder trunk—A distribution feeder's main artery

Infrared inspection—Inspection designed to detect temperature variations in a property using thermal imaging technology

Planning limit—Equipment ratings designed to allow some operational and project scheduling flexibility

Regional electrical plans—Plans that help determine where to build new transmission lines, substations, and associated equipment to meet customers' future needs. These plans are created with the assistance of committees with representation from local governments and environmental agencies, business leaders, and community stakeholders.

Sentry grid monitoring devices—Idaho Power patented line sensors that monitor voltage and report when there is a loss of voltage, typically the result of a momentary or sustained outage. Some monitors also measure and report on wind speeds and ambient temperature.

DSP REPORT:

EXECUTIVE SUMMARY

EXECUTIVE SUMMARY

For more than 100 years, Idaho Power has delivered safe, reliable, and affordable electric service to its customers. Building off the company's many decades as a trusted provider of electricity, this Distribution System Plan (DSP) Report for Idaho Power's Oregon service area focuses on the critical role of the distribution system in continuing to develop a modern, clean, and responsive energy system of the future.

This DSP Report (Part II of II) presents a holistic view of Idaho Power's current distribution system practices, processes, and investments, and presents a vision for a more transparent and integrated planning process.

DSP Origin and Regulatory Background

While Idaho Power has always conducted distribution system planning, the DSP efforts detailed in this report were driven by the Public Utility Commission of Oregon's (OPUC) investigation into distribution system planning in docket UM 2005. The regulatory investigation began in March 2019, with the stated objective of directing electric utilities to "develop a transparent, robust, holistic regulatory planning process for electric utility distribution system operations and investments."[1]

Over nearly two years, OPUC staff, stakeholders, and utilities have engaged in workshops and seminars to discuss distribution system planning possibilities, best practices, and lessons learned from other jurisdictions. These efforts culminated in DSP guidelines from OPUC staff, which were subsequently adopted by the OPUC in Order No. 20-485 on December 23, 2020.

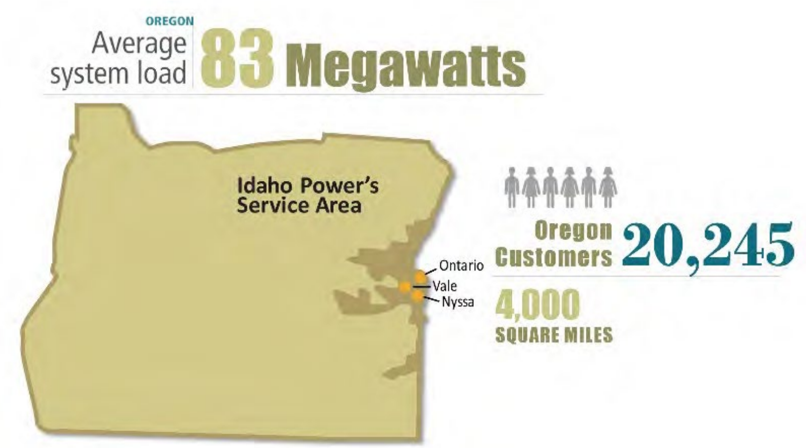
The adopted DSP guidelines identify specific efforts that utilities must conduct, analyze, and compile into reports filed every two years. For this inaugural DSP cycle, utilities will file two reports: Part I, focusing on current distribution practices, processes, and assets; and Part II (this document), focusing on the evolution of distribution system planning, distribution system pilot projects, and expanded public involvement in distribution system decision-making. Part I of the DSP Report was completed and filed with the OPUC in docket UM 2196 (Idaho Power's specific DSP docket) in October 2021. The Commission approved the company's DSP Part I in Order No. 20-083 on March 11, 2022.[2]

[1] *In the Public Utility Commission of Oregon, Investigation into Distribution system Planning*, UM 2005, Order No. 19-104, Appendix A at 1 (Mar. 22, 2019).

[2] *In the Matter of Idaho Power Company, Acceptance of Distribution System Plan—Part One*, UM 2196, Order No. 22-083 (Mar. 11, 2022).

Eastern Oregon Overview

The OPUC-led DSP process is a statewide effort. Compared to other utilities in Oregon, Idaho Power's service area is notably distinct, spanning some of the most remote landscape across eastern Oregon and encompassing 4,744 square miles which is largely comprised of rural communities. Additionally, a sizeable number of Idaho Power's Oregon customers live below or near the poverty line.



According to the United States Census Bureau,[3] the median household income (in 2018 dollars) for Ontario, Oregon, is $34,940,[4] compared to $65,740 for Portland, Oregon. Furthermore, in a report released in May 2015,[5] the Oregon Department of Human Services identified Malheur County—the primary county in Idaho Power's Oregon service area—as a "high poverty hotspot."

This context is critical to understand that, while Idaho Power will work toward a bold DSP future, its Oregon service area simply may not evolve at the pace of other Oregon utilities. And, importantly, all the company's planning efforts and future investments must consider the financial impact on its approximately 20,000 Oregon customers.

DSP Report Components

The OPUC's DSP guidelines identify specific sections for inclusion in Parts I and II of the DSP Report. Idaho Power's Part I report included baseline distribution system data; an assessment of the company's distribution system in Oregon; discussion of hosting capacity analysis and the company's method of developing that analysis; a community engagement plan; the long-term distribution system plan; and a plan for developing this the Part II report. The components for Part II are briefly described below and in more detail in the chapters that follow.

[3] census.gov/quickfacts/fact/table/ontariocityoregon,boisecitycityidaho,portlandcityoregon,US/PST045218

[4] Largest city in Idaho Power's Oregon service area.

[5] Oregon Department of Human Services Office of Forecasting, Research, & Analysis, "High Poverty Hotspots – Malheur County."

DSP Part I Review and Update

In this introductory section, the company refreshes the baseline data and system assessment from Part I and provides new analysis on the age of Idaho Power's distribution system assets in Oregon.

Forecasting Load Growth, DER Adoption, and EV Adoption

Forecasting load growth is a critical function of distribution system planning. This report offers insight into distribution system planning practices to forecast load growth, including some of the tools used to consider extreme temperature events. More specifically, Integrated Resource Plan (IRP)-forecasted electric vehicle (EV) and distributed energy resource (DER) adoption rates for the entire Idaho Power system are allocated to individual distribution substations and feeders. The EV and DER adoption forecasts are then applied to the load growth forecast to determine grid impacts.

Grid Needs Identification

To determine near-term grid needs, Idaho Power established the grid adequacy assessment process, including evaluation of specific planning studies; scheduled component inspections; and testing performed by a variety of trained equipment experts and engineers; and a review of system reliability data. This process is explained in more detail below in the section on Grid Needs Identification, along with a list of Idaho Power's identified specific grid needs in Oregon. A brief explanation of the need and required timing accompanies each identified grid need.

Solution Identification

In this section, Idaho Power provides a brief overview of the two major pathways to update the distribution system—that is, so-called traditional solutions (i.e., poles and wires) and non-wires solutions (NWS) that leverage technologies such as distributed solar and battery storage in lieu of traditional asset upgrades. The company explores the characteristics of projects that would be best suited for one type of solution over another, and then provides a summary of potential projects, as well as the need date and traditional solution cost estimate for each. Idaho Power also provides an extended list of grid needs that exist beyond the four-year window, along with discussion of the potential for those projects to be accomplished with NWS. Finally, the company profiles an NWS project, currently in progress, to provide a concrete example of the NWS evaluation process.

Near-Term Action Plan

Idaho Power identifies the total capital spend for its Oregon service area, including asset replacement, growth, and reliability projects. In addition to the near-term action plan, information is also included on the NWS project that is currently in progress.

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DSP REPORT:

PART 1 REVIEW AND UPDATE

DSP PART I REVIEW AND UPDATE

Part I of Idaho Power's DSP Report presented a holistic view of the company's distribution system practices, processes, and investments, and presented a vision to evolve distribution system planning in the future. A high-level summary of the Part I filing is provided below to ensure information in this Part II report is considered in context.

Baseline Data & System Assessment

The introductory section of Idaho Power's DSP Part I report provided, among other information, details on the physical status of the company's distribution assets, an overview of distribution-level investments, and an accounting of customer-facing grid technologies, such as rooftop solar. The section also included a list of asset classes and associated ages. Table 1.1 below presents the same information, but with updated numbers, as Part I was completed nearly a year ago.

Table 1.1 Idaho Power asset class data

Asset Classes	Average Age	Service Life	Total #
Substation Transformer	53	70	33
Circuit Breakers	17.4	50	68
Electromechanical Relays	51	45	41
Microprocessor Relays	11.5	20	83
Smart Grid Monitors	5	20	181
Overhead Transformers	18.6	30-40	10,096
Pad-mounted Transformers	21.1	40-50	924
Distribution Poles	29.2	40-50	38,545
Primary Overhead Line	35.3	40-50	1,990
Primary Underground Line	21.8	40-50	82
Meters	8.9	16-20	20,136
Fuses	17	20-30	1,592
Switches	15.6	20-30	330
Regulators	12.1	20	113
Capacitors	14.5	30-40	85
Reclosers	11.3	50	144
Sectionalizers	20.2	50	16

Idaho Power recognizes the advanced age of a few of its asset classes—specifically, substation transformers and electromechanical relays.[6] The company closely monitors the performance of its assets and will replace any assets that show performance issues or other problems that could negatively impact reliability or resiliency. In the case of the two noted asset classes, operation beyond the typical service life is acceptable, as the assets are not showing performance declines.

A review of the company's 2021 Electric Service Reliability Annual Report showed that less than 1% (0.7%) of the total sustained interruption events over a five-year period were due to substation facilities. None of these interruptions were due to substation transformer failure. Over the past 20 years, there have been no substation transformer failures in the Idaho Power Oregon service area. Idaho Power's 2021 Electric Service Reliability Annual Report is included in Appendix A of this report.

The advanced age of the transformer asset class can be attributed to the low amount of growth historically experienced in the eastern Oregon service area. To ensure highly reliable service to customers, substation transformers are maintained and inspected on a regular schedule. In high growth areas, transformers are changed out more often as capacity limits are reached. Transformers are also evaluated and prioritized for potential inclusion in an asset replacement program. For more information on maintenance, inspection, and asset replacement programs, please see the Transformer Maintenance and Inspection Procedure section of the Grid Needs Identification section of this Part II report.

Idaho Power has several planned transformer projects, which are listed in Table 1.2 below.

[6] In its recommendation for approval of Idaho Power's DSP Part I report, staff asked the company to assess whether the age of its distribution assets would change with the construction of the Boardman to Hemingway Transmission Line Project (B2H). As B2H will not involve any distribution system upgrades or build out, the average age of the company's eastern Oregon distribution system assets will not change.

Table 1.2 Transformer projects

Transformer Projects			
Substation	**Age (years)**	**Project Year**	**Project Description**
Durkee	83	2024	Convert to 138 kV
Lime	60	2024	Substation removal
Huntington	55	2024	Convert to 138 kV
Halfway	74	2025	Asset replacement
Hope	74	2026	Asset replacement
Juntura	83	2028	Growth project
Jamieson	81	2028	Growth project
Nyssa	51	2028	Growth project

The other asset class with advanced age—electromechanical relays—is being addressed via an in-progress replacement program. All feeder electromechanical relays in Idaho Power's Oregon service area are being replaced with microprocessor relays, with complete changeout anticipated by 2026. The budget for this replacement effort is shown in the Table 1.3 below.

Table 1.3 Relay replacement projects

Relay Replacement Projects			
Substation	**Feeders**	**Year Schedule to be Replaced**	**Project Description**
Harper	011, 012	2026	Install microprocessor relays
Unity	011	2026	Install microprocessor relays

Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) is used to identify how much load or generation can be added to segments of the distribution system before those segments become overloaded. In the Part I report, Idaho Power evaluated three options for expanding the scope and value of HCA. Further analysis was put on hold as OPUC staff and stakeholders analyzed whether HCA should instead be addressed in docket No. UM 2111 on interconnection procedures.
After consideration of both dockets, HCA was returned to UM 2005 and will be a topic of a future workshop.[7]

[7] OPUC staff has scheduled a workshop on HCA in UM 2005 on October 5, 2022. https://edocs.puc.state.or.us/efdocs/HAH/um2005hah17839.pdf

Community Engagement Plan

For over a decade Idaho Power has included public input as part of its electric plan process, using a community advisory committee to advise in the long-term plans for transmission and substation placement to meet community needs. Now, with this DSP, Idaho Power will expand its distribution system planning processes to include feedback from customers and communities.

The company hosted two public workshops associated with the Part I report. In compliance with the DSP guidelines, Idaho Power held two additional workshops associated with the Part II report on May 18, 2022, and June 6, 2022. Presentations from both meetings are available on the DSP-focused part of Idaho Power's website at www.idahopower.com/dsp. The public workshops served multiple purposes—they offered a chance to engage with the eastern Oregon community, provide education on the types of activities Idaho Power performs, raise awareness about electrical activities and plans, and seek feedback on DSP efforts and potential community impacts in Idaho Power's Oregon service area.

Long-Term Distribution System Plan

Recognizing that customers' energy needs will shift, and the distribution system will evolve, Idaho Power focused its long-term DSP efforts on the following:

- Forecasting long-term electrical demands for each service region, and
- Developing community advisory-based electrical plans.

The Part I report also discussed Idaho Power's evaluation of a single vendor platform to include the company's Advanced Distribution Management System (ADMS), Energy Management System (EMS), and Outage Management System (OMS). Idaho Power has selected OSI as the software vendor. Implementation will begin in 2022 and is anticipated to be completed by 2027.

This Part II report focuses on developing near-term local area plans that meet electrical demand and maintain a high level of reliability while also capturing community input and considering community impacts.

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DSP REPORT:

FORECASTING LOAD GROWTH, DER ADOPTION, AND EV ADOPTION

FORECASTING LOAD GROWTH, DER ADOPTION, AND EV ADOPTION

Current Load Forecasting

Accurately forecasting load growth is critical to a utility's ability to determine the correct time and place to invest in the distribution system. To facilitate this effort, Idaho Power developed a forecasting tool influenced by load forecasting research by Willis, Tram, and Rackliffe.[8] The tool produces a 10-year forecast of peak loading, adjusted for extreme temperature impacts. All substation and feeder peak loadings are reviewed after each summer and winter peak season. The substation and feeder peaks are then used to update the 10-year forecasts. An in-depth forecasting review is conducted once every three years—or more frequently in areas of high growth.

Load Growth Pattern Stages

A utility's distribution-level load growth typically follows an S-curve[9], as shown in Figure 2.1. In a newly developed area, population density initially increases slowly. As businesses expand, the surrounding community grows to accommodate the increased workforce resulting in a period of accelerated growth. Eventually, the environment reaches a transitional phase where growth slows and stabilizes as available land is utilized. Over decades, a community can experience multiple S-curves, driven by changes in the population, land use, available resources, and the broader economy.

[8] H. L. Willis, H. N. Tram, & G. B. Rackliffe, Short-Range Load Forecasting for Distribution System Planning—An Improved Method for Extrapolating Feeder Load Growth, Proceedings of the 1991 Institute of Electrical and Electronic Engineers (IEEE) Power Engineering Society Transmission and Distribution Conference, 22 September 1991.

[9] H.L. Willis, Power Distribution Planning Reference Book, CRC Press, 2004, Chapter 25 Transmission and Distribution (T&D) Load Forecasting Methods.

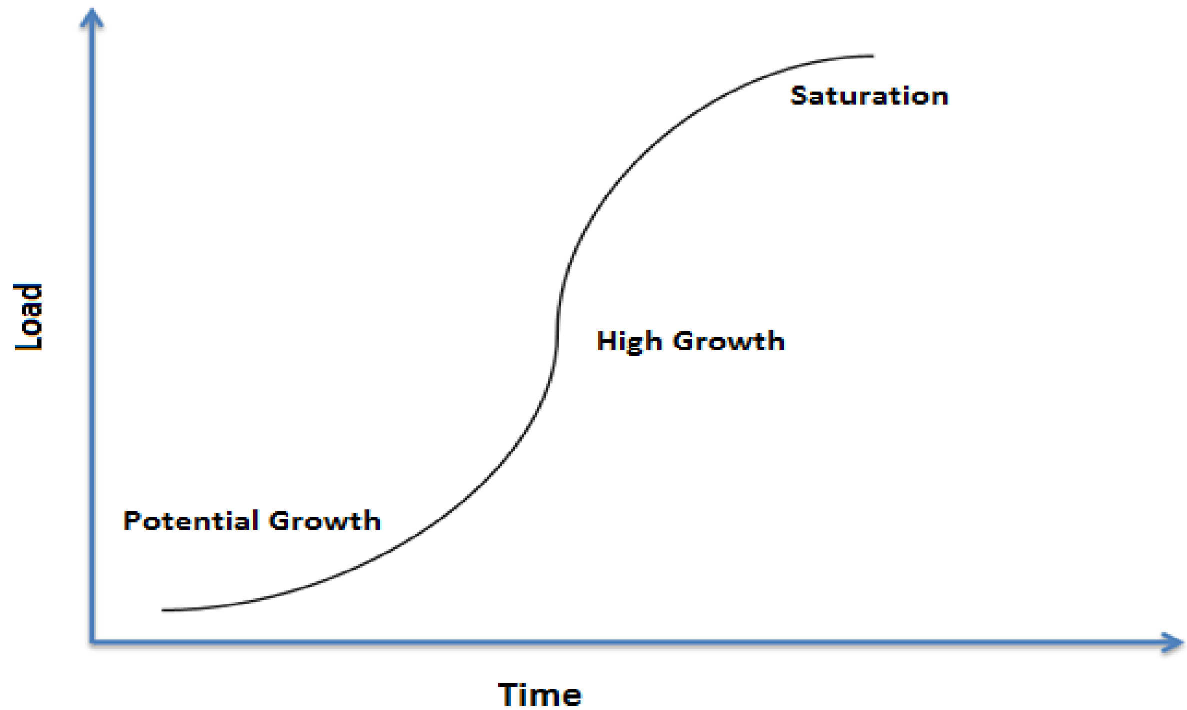


Figure 2.1 Population S-curve growth trends

The S-curve explanation and shape shown above provide a baseline for understanding how distribution-level load growth is generally understood. To forecast distribution load growth, Idaho Power uses a multi-stage process, as shown in Figure 2.2 and explained in detail below.

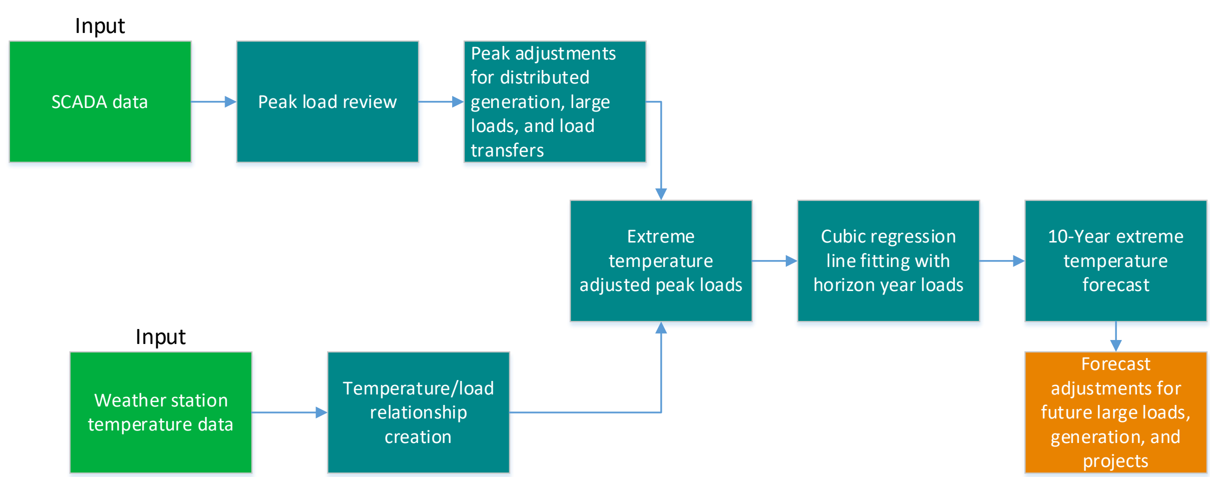


Figure 2.2 Load forecasting process flow diagram

Adjusted Actual Peak Load Data

At the end of the summer and winter seasons, an Idaho Power distribution planning engineer reviews and approves each feeder and transformer peak load. Seasonal peak loads are adjusted to account for large load additions or subtractions, load transfers between distribution feeders, and any data errors. For feeders that are connected to one or more large generation projects (> 100 kilowatts [kW]), the historical peak load is adjusted to account for the scenario in which the single largest generator is offline. This scenario exercise ensures that Idaho Power can continue to serve customers in the event that the largest single generator on a feeder becomes unavailable during peak loading.

Extreme Temperature Adjusted Peak Loads (1-in-20 Year)

Idaho Power divides its service area into weather zones that represent areas with similar weather patterns. For each weather zone, a weather station is identified to track the hottest summer and coldest winter daily average temperatures for the various weather zones. The most extreme daily average temperatures are recorded each year and compared to a 40-year rolling window, which allows the company to anticipate weather and temperature trends. For both summer and winter, the two years with the hottest temperatures and the two years with the coldest temperatures are identified as extreme temperature years. Figure 2.3 identifies the two years with the highest annual average temperatures since 1983. The extreme temperatures represent a 1-in-20 year (or 95th percentile temperature) event. Utilizing a 40-year rolling window captures current weather and temperature trends.

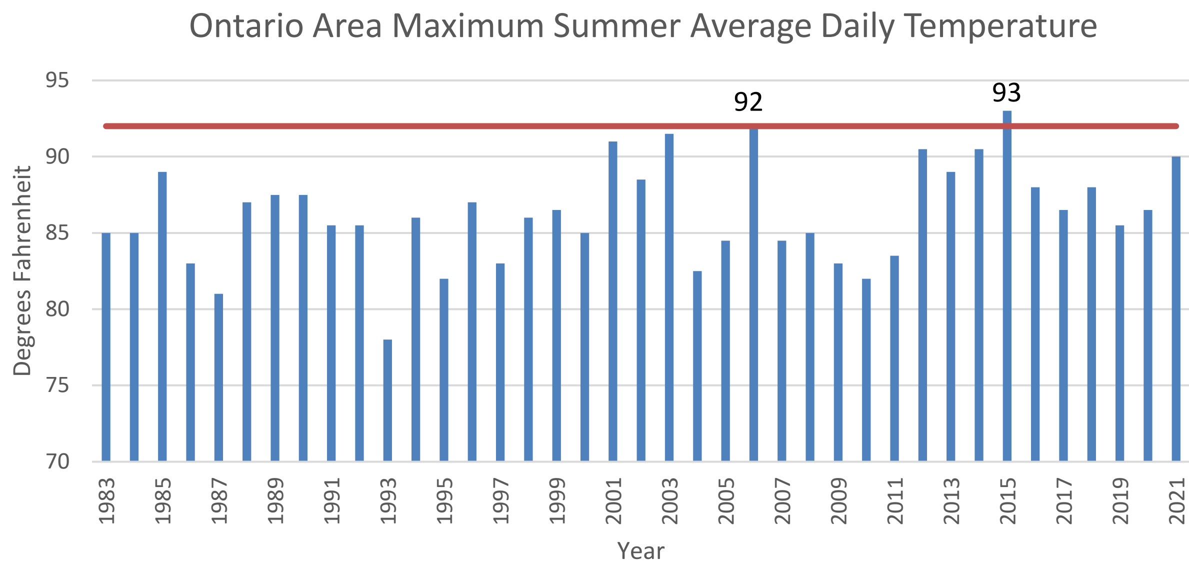


Figure 2.3 Ontario area maximum summer average daily temperature

The peak loads and the hottest/coldest daily average temperatures are used to establish temperature/load relationships for different types of customers. The temperature/load relationships are used to adjust the actual historical peak loads to what they would have been if the temperature had been extreme. These extreme temperature adjustments have different impacts on different types of customers. For example, industrial loads are not greatly impacted by temperature due to consistent operating procedures. By contrast, residential and commercial customers tend to use more energy for heating and cooling during extreme weather events. The company also adjusts the data for each feeder and transformer to show what the load would have been if it had been an extreme temperature year. Figure 2.4 shows an example of a feeder with adjusted actual peak load (yellow dots) and the extreme temperature load (blue dots).

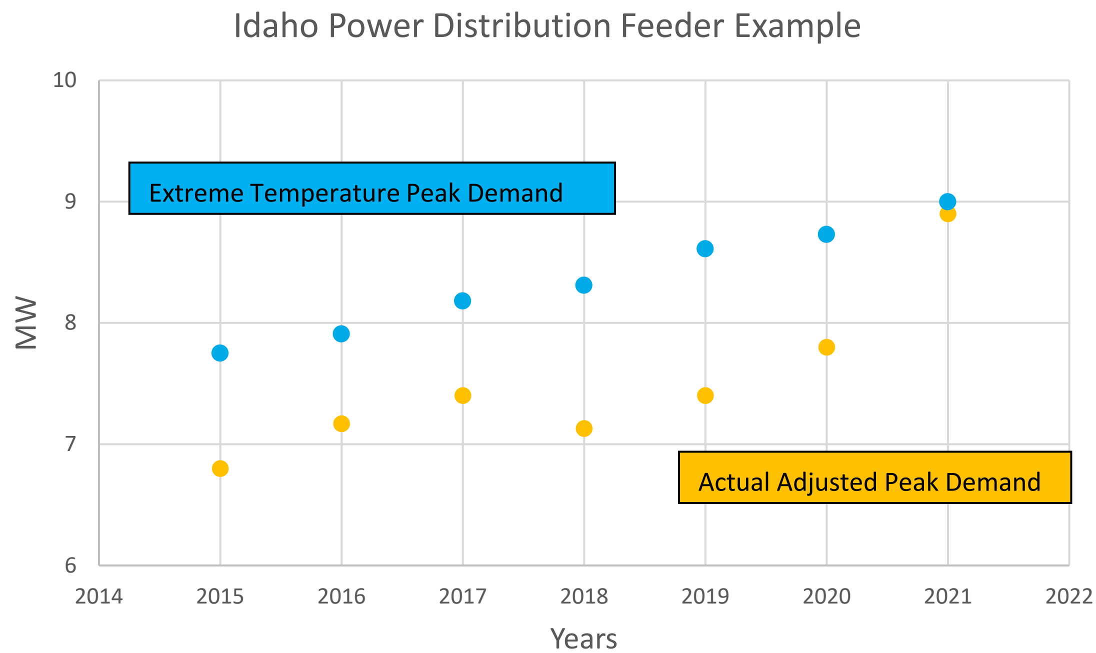


Figure 2.4 Temperature adjusted loads

Cubic Regression Formula

Idaho Power applies the cubic regression formula to determine the best fitting trend line for historical extreme temperature peak demand data. A typical cubic function increases rapidly toward infinity; however, datapoints are added to the function in future years to adjust the cubic function and more accurately predicts future load as shown in Figure 2.5. These future datapoints are known as horizon-year loads.

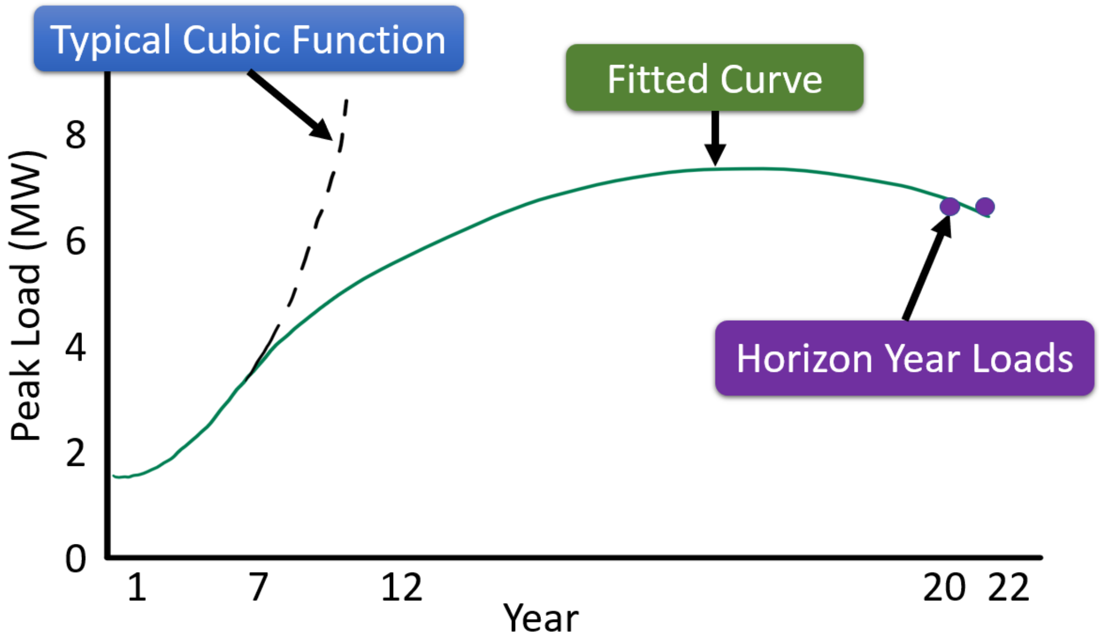


Figure 2.5 Cubic regression feeder S-curve fitted analysis

Figure 2.4 shows horizon-year loads are added to the forecast at 20 and 22 years from the current year. The horizon-year loads can be adjusted up or down to compensate for local knowledge which may include known infrastructure investments or customer growth that would not be captured in a trend based solely on historical peak loads.

Forecasted Load Growth

Forecasted extreme temperature peak loads are projected out 10 years based on the cubic regression of the extreme temperature peak loads and the horizon year loads. An example of forecasted values is shown in Figure 2.6, in which the graph identifies a forecasted peak load of 10 megawatts (MW) in the year 2028.

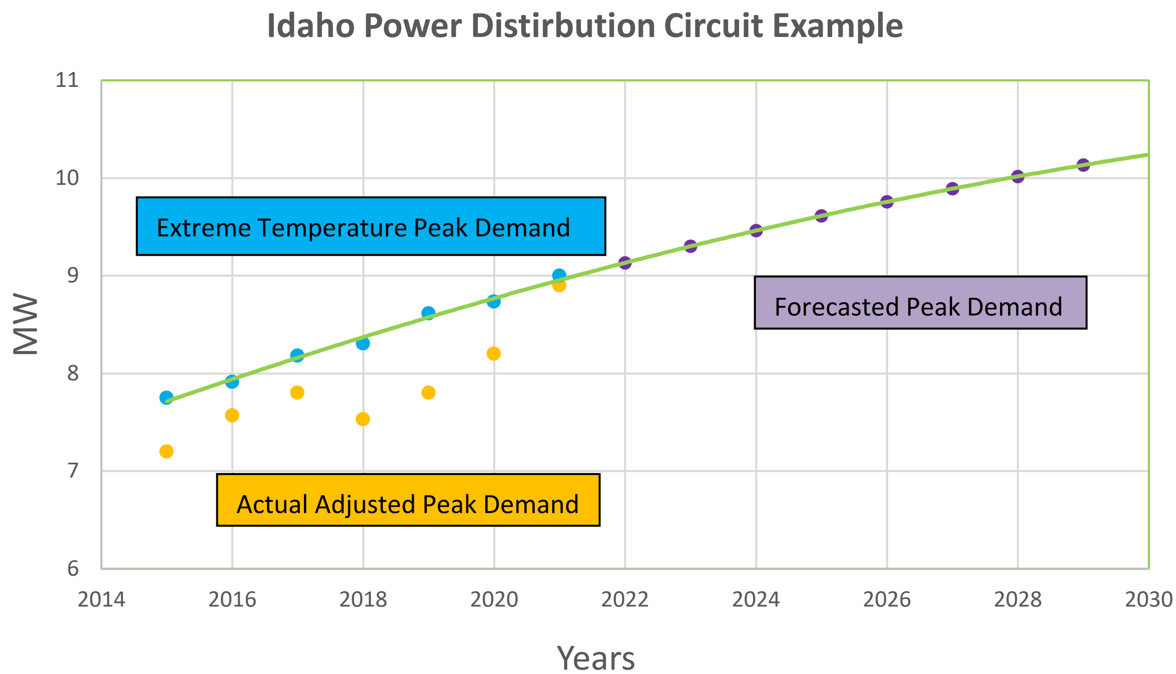


Figure 2.6 Forecasted growth curve

Forecast of DER Adoption

The term DER can include distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles. Idaho Power uses energy efficiency and demand response programs to assist with addressing systemwide capacity constraints. However, on a more granular nature, these programs are not currently a good fit for distribution-targeted deferral projects because of the lack of ability to monitor and control the energy demands affecting the project. As Idaho Power gains the ability to monitor and control these programs on a more granular level, a more targeted use of these programs will be analyzed as part of future DSPs. As a result, they are not currently considered in distribution forecasting and Idaho Power's DER forecast focuses on behind-the-meter customer generation such as rooftop or customer-owned solar.

Idaho Power's 2021 IRP included a systemwide (Idaho and Oregon) DER adoption forecast focused on behind-the-meter customer-owned generation. The IRP load forecast was used as the basis for this DSP DER adoption forecast. The Idaho Power billing system was then used to determine the portion of the total system forecast that was tied to Oregon customers.

At the end of 2021, there were a total of 80 DER installations in Idaho Power's Oregon service area. Low, Medium, and High forecast scenarios for new DER were created to reflect different conditions that might yield faster or slower customer adoption of DER. Factors influencing the slope of the adoption curve (that is, the speed of adoption) include the cost of solar systems, potential policy changes that might spur adoption, and consumer trends. The company considers the Medium scenario—representing a status quo growth path—the most probable outcome. The forecast scenarios are shown below in Figure 2.7.

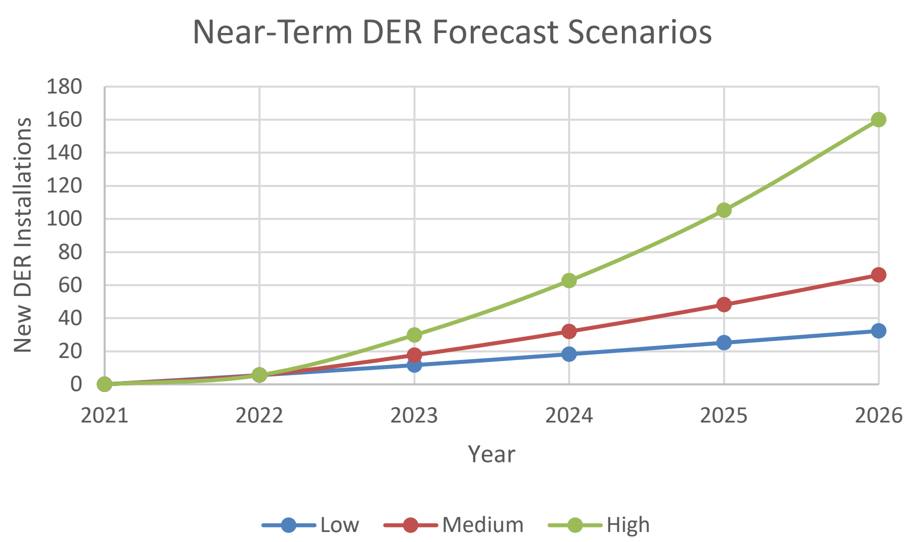


Figure 2.7 Idaho Power Oregon DER forecast scenarios

The sizes of customer-owned generation systems vary by customer type. Peak generation of solar generation does not coincide directly with peak loading times (i.e., peak generation at 2 p.m. MDT versus peak load at 7 p.m. MDT). Idaho Power used the System Advisor Model (SAM), a software tool developed by National Renewable Energy Laboratory (NREL), to estimate the amount of generation that occurs from customer-owned generation during peak times. From 2022 to 2026, the total rated capacity of new customer-owned generation for the High scenario is estimated at 960 kW with anticipated generation at peak loading times of 185 kW.

DER installations were geolocated to identify DER concentration on each feeder, and the levels and growth rates established in the 2021 IRP for the system forecast were applied to each feeder. The feeder-level DER forecast scenarios for 2026 are shown in Table 2.1 below.

Table 2.1 Idaho Power coincidental peak DER loading

2026 DER Forecast Scenarios				
Substation	Feeder	Low (kW)	Medium (kW)	High (kW)
Adrian	011	2.0	4.5	7.8
Adrian	012	4.2	9.4	16.3
Cairo	011	3.6	8.0	13.9
Cairo	013	0.8	1.7	3.0
Halfway	011	1.2	2.8	4.9
Halfway	012	1.2	2.8	4.9
Harper	012	0.6	1.4	2.4
Jamieson	011	1.2	2.8	4.9
Jamieson	012	3.7	7.5	12.2
Juntura	011	0.8	1.7	3.0
Nyssa	011	3.2	7.3	12.7
Nyssa	013	3.1	7.0	12.1
Ontario	018	0.6	1.4	2.4
Ontario	019	5.7	12.8	22.4
Ontario	020	4.8	10.6	18.6
Ontario	023	1.2	2.8	4.9
Ontario	024	1.8	4.2	7.3
Parma	042	1.2	2.8	4.9
Vale	011	2.8	6.1	10.8
Vale	012	0.6	1.4	2.4
Vale	013	2.6	5.9	10.2
Vale	015	1.0	2.1	3.6

Forecast of EV Adoption

Actual and forecasted EV adoption rates in Idaho Power's Oregon service area remain relatively low. Idaho Power continues to monitor battery technology advancement, EV prices, EV range, charging rates, and charging station availability—all of which influence EV adoption rates.

Idaho Power forecasted the adoption of EVs for its entire service area (Idaho and Oregon) in the 2021 IRP. This forecast was, in part, based on EV registration data from the Oregon Department of Transportation. The finest level of resolution in the data was city-level registration, which provided a basis for determining EV inventory in Idaho Power's Oregon service area. At year-end 2021, there were 19 registered EVs in eastern Oregon.

Similar to forecasting customer-owned solar, EV adoption was tied directly to the forecast included in the 2021 IRP. Based on current registrations, a proportionate share of the overall systemwide EV forecast was allocated to the Oregon service area. High, Medium, and Low EV growth scenarios were developed, with factors including the cost of EVs, consumer trends, and potential policy changes driving different adoption rates in the three scenarios. The near-term EV forecast scenarios are shown in Figure 2.8 below.

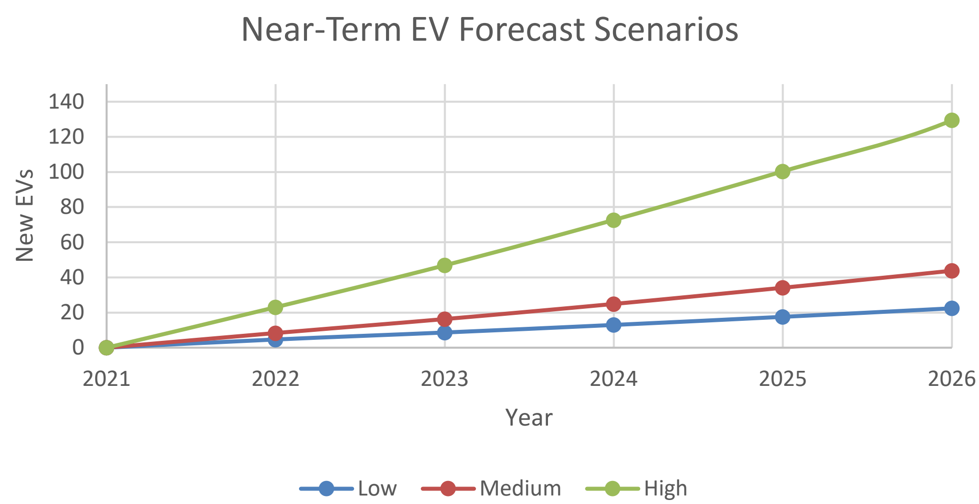


Figure 2.8 Idaho Power Oregon EV forecast scenarios

Idaho Power used the United States Department of Energy (DOE) Alternative Fuels Data Center tool[10]—the Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite—to estimate EV charging load per vehicle at the substation during peak load times. EVI-Pro Lite, allows the user to select specific urban areas to forecast the EV charging load profile based on location and several other adjustable assumptions, such as average daily miles traveled per vehicle.
Using EVI-Pro Lite, Idaho Power estimated the loading at peak time at 0.88 MW per 1,000 EVs (0.88 kW per EV) during the week and 0.65 MW per 1,000 EVs (0.65 kW per EV) during the weekend for residential Level 2 chargers. The weekday and weekend charging profiles per 1,000 EVs are shown in Figure 2.9 and Figure 2.10, respectively.

[10] DOE Alternative Fuels Data Center, Alternative Fuels Data Center: Electric Vehicle Infrastructure Projection Tool (EVI-Pro) Lite (energy.gov).

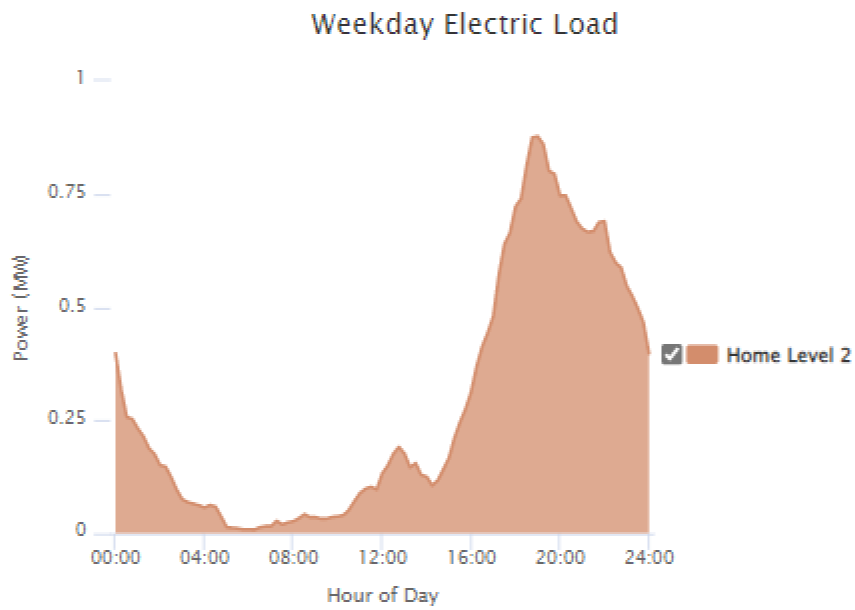


Figure 2.9 Estimated eastern Oregon weekday loading per 1,000 EVs

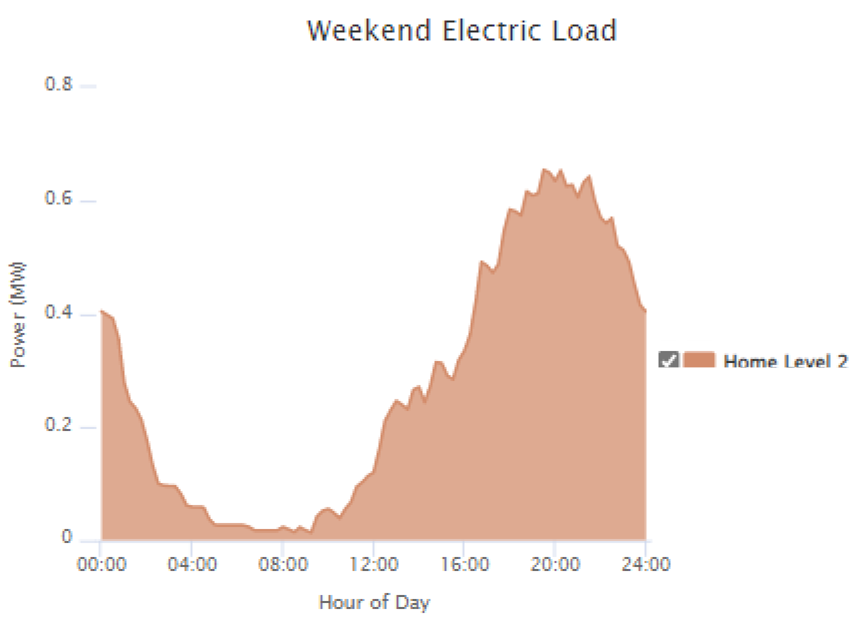


Figure 2.10 Estimated eastern Oregon weekend loading per 1,000 EVs

Notably, EVI-Pro Lite does not include a specific community to select for eastern Oregon. Nampa, Idaho, is located approximately 40 miles southeast of Ontario, Oregon. As a result, Nampa was used as the closest urban area in generating the loading estimates. The company also used the following set of baseline assumptions in EVI-Pro Lite to develop the EV load estimates:

- Number of Fleet EVs—1,000 (smallest quantity available)

- Average Daily Miles per Vehicle—25
- Average Ambient Temperature—104 degrees Fahrenheit (°F) (chosen to provide maximum loading at peak times)
- Plug-in Vehicles that are All-electric—75%
- Plug-in Vehicles that are Sedans—50%
- Mix of Workplace Charging—20% Level 1 and 80% Level 2
- Access to Home Charging—100% (50% Level 1 and 50% Level 2)
- Preference for Home Charging—100%
- Home Charging Strategy—Immediate (as fast as possible)
- Workplace Charging Strategy—Immediate (as fast as possible)

Using the EV estimates from the 2021 IRP and the weekday EVI-Pro Lite load estimates, Idaho Power developed a forecast of EV-based near-term total load increases in the company's Oregon service area. The EV load forecast scenarios are shown in Table 2.2.

Table 2.2 Low, medium, and high EV load forecast scenarios

Near-Term Additional EV Load Forecast			
Year	Low (kW)	Medium (kW)	High (kW)
2022	3.23	6.46	19.39
2023	6.73	13.46	40.37
2024	10.52	21.03	63.10
2025	14.57	29.15	87.45
2026	18.83	37.67	113.01

Given the lack of information on current EV locations, Idaho Power applied the total additional EV loading of 128 EVs to every feeder. However, for feeders with fewer than 266 customers, the EV loading forecast was based on a maximum of 50% EV adoption. Meaning, the maximum allowable EV loading on any feeder will not exceed a 50% customer adoption in this analysis.

Distribution Impacts of Forecasted DER and EV Adoption

As actual and forecasted DER and EV amounts are low, the company evaluated the combinations of EV and DER adoption and the impact those levels would have on the distribution system. In the company's estimation, a low DER and high EV situation is the severe scenario because low amounts of DER have little impact on system constraints, but high EV penetration does. The company applied this severe scenario to the year 2026 for summer and winter, as shown in Table 2.1 and Table 2.2, respectively.

Feeder and transformer extreme temperature forecasted values (with and without DER and EV impacts) in 2026 are shown in Table 2.3 and Table 2.4. As more geographically detailed EV adoption data becomes available, a more robust and location-specific analysis will be possible.

Table 2.3 Summer forecasted loading with and without DER and EV growth (2026)

Oregon Near-Term Summer 2026 DER and EV Loading Impact			
Substation[11]	Device	Year	
	Transformer/Feeder	Loading in 2026 (kW)	Loading in 2026 including DER and EV Growth (kW)
Adrian	T061	4.62	4.73
Adrian	011	2.58	2.69
Adrian	012	2.81	2.92
Cairo	T061	12.40	12.51
Cairo	011	5.15	5.26
Cairo	012	4.13	4.16
Cairo	013	3.88	3.94
Cow Valley	T061	2.29	2.33
Cow Valley	011	0.85	0.86
Cow Valley	012	1.65	1.68
Durkee	T061	0.62	0.67
Durkee	011	0.62	0.67
Duke	T061	0.57	0.58
Duke	011	0.27	0.28
Drewsey	T061	0.40	0.45
Drewsey	011	0.39	0.44
Easton	T061	0.04	0.04
Easton	011	0.04	0.04
Halfway	T061	3.89	4.00
Halfway	011	2.23	2.34
Halfway	012	1.75	1.86
Huntington	T061	1.52	1.59
Huntington	011	0.84	0.86
Huntington	012	0.89	0.94
Homedale	T062	17.03	17.07
Homedale	012	9.65	9.69
Holly	T061	7.41	7.52
Holly	011	2.61	2.68
Holly	012	4.03	4.06

[11] Note that the Homedale, Parma, and Weiser substations are physically located in Idaho but serve customers in both Idaho and Oregon.

Oregon Near-Term Summer 2026 DER and EV Loading Impact

Substation[11]	Device	Year	
Holly	013	1.35	1.41
Holly	014	0.13	0.13
Hope	T061	3.47	3.52
Hope	011	3.46	3.51
Harper	T061	2.54	2.63
Harper	011	0.48	0.52
Harper	012	1.67	1.72
Jamieson	T061	4.67	4.78
Jamieson	011	2.22	2.33
Jamieson	012	2.54	2.61
Juntura	011	0.23	0.24
Juntura	012	0.12	0.14
Jordan Valley	T061	2.21	2.29
Jordan Valley	031	2.21	2.29
Jordan Valley	T062	0.64	0.68
Jordan Valley	011	0.29	0.31
Jordan Valley	012	0.44	0.46
Lime	T061	0.13	0.16
Lime	011	0.13	0.16
Malheur Butte	T061	6.34	6.35
Malheur Butte	041	6.03	6.04
Malheur Butte	042	0.47	0.47
Nyssa	T061	10.53	10.64
Nyssa	011	4.07	4.16
Nyssa	012	5.89	5.97
Nyssa	T062	7.33	7.44
Nyssa	013	5.09	5.20
Nyssa	014	2.70	2.73
Ore-Ida	T061	22.13	22.23
Ore-Ida	011	7.71	7.81
Ontario	T134	25.83	25.94
Ontario	020	6.67	6.78
Ontario	023	6.26	6.27
Ontario	024	9.79	9.90
Ontario	025	4.08	4.12
Ontario	T135	18.67	18.78
Ontario	014	6.84	6.84
Ontario	018	2.70	2.77
Ontario	019	8.78	8.89

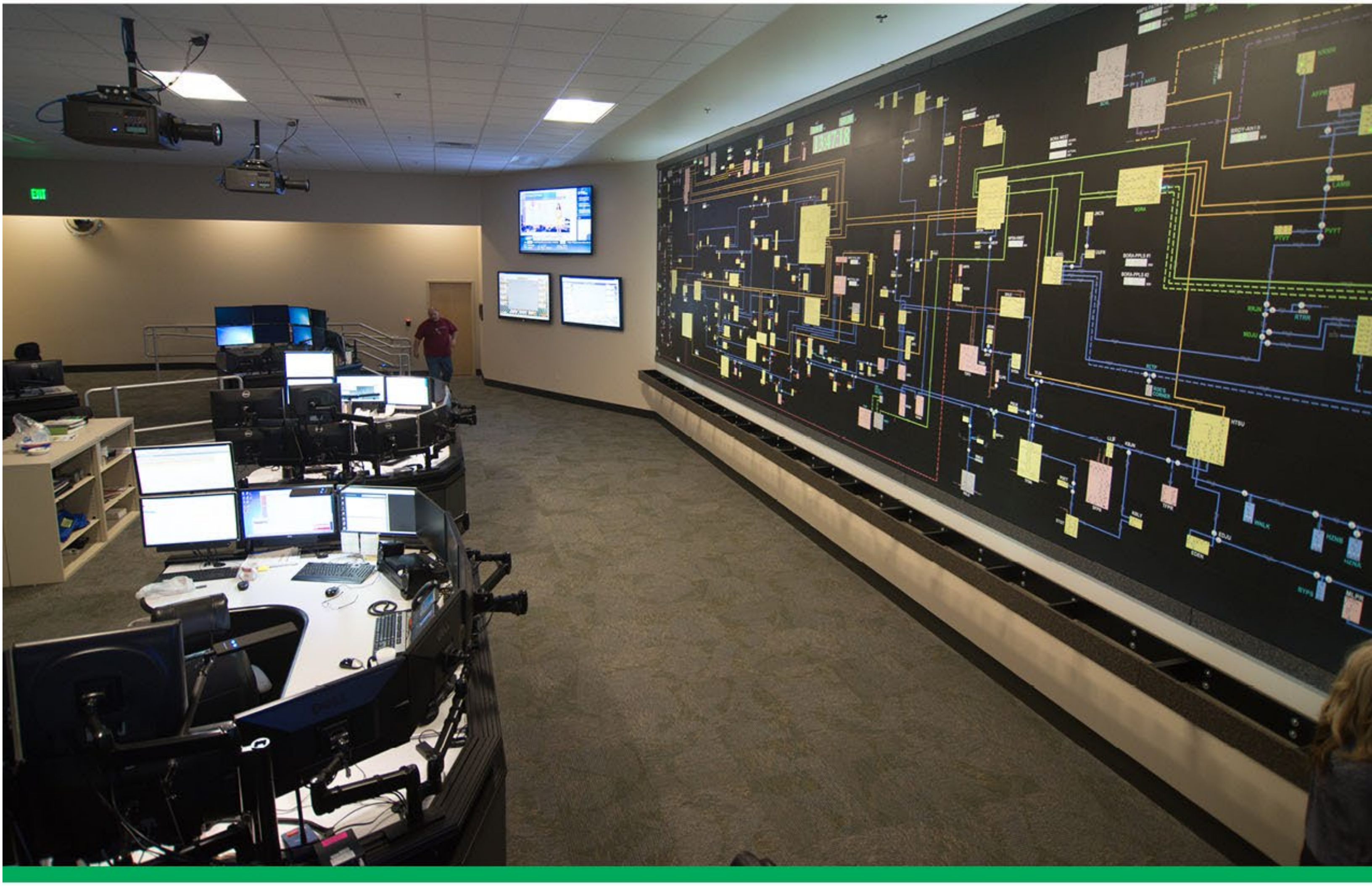
Oregon Near-Term Summer 2026 DER and EV Loading Impact			
Substation[11]	Device	Year	
Pine Creek	T061	0.37	0.39
Pine Creek	011	0.43	0.45
Parma	T061	7.77	7.77
Parma	012	2.98	2.98
Parma	T063	6.61	6.68
Parma	042	6.61	6.68
Unity	T061	1.85	1.96
Unity	011	0.34	0.37
Unity	012	1.57	1.64
Vale	T061	11.50	11.61
Vale	011	4.61	4.72
Vale	012	0.39	0.40
Vale	013	2.91	3.02
Vale	014	1.76	1.86
Vale	015	2.40	2.51
Weiser	T061	14.75	14.82
Weiser	013	0.06	0.12
Weiser	014	4.94	4.95

Table 2.4 Winter forecasted loading with and without DER and EV growth (2026)

Oregon Near-Term Winter 2026 DER and EV Loading Impact			
Substation	Device	Year	
	Transformer/Feeder	Loading in 2026 (kW)	Loading in 2026 including DER and EV Growth (kW)
Adrian	T061	6.92	7.03
Adrian	011	2.36	2.46
Adrian	012	4.44	4.55
Cairo	T061	15.00	15.11
Cairo	011	5.86	5.97
Cairo	012	6.03	6.14
Cairo	013	4.12	4.17
Cow Valley	T061	3.63	3.65
Cow Valley	011	1.11	1.11
Cow Valley	012	2.49	2.51
Durkee	T061	0.95	0.99
Durkee	011	0.85	0.89
Duke	T061	0.21	0.22
Duke	011	0.17	0.18
Drewsey	T061	0.68	0.73
Drewsey	011	0.72	0.77

Oregon Near-Term Winter 2026 DER and EV Loading Impact			
Substation	**Device**	**Year**	
Easton	T061	0.04	0.04
Easton	011	0.04	0.04
Halfway	T061	7.21	7.32
Halfway	011	4.79	4.90
Halfway	012	2.94	3.05
Huntington	T061	3.33	3.41
Huntington	011	1.48	1.49
Huntington	012	1.73	1.80
Homedale	T062	18.93	19.04
Homedale	012	9.80	9.91
Holly	T061	4.11	4.22
Holly	011	1.95	2.00
Holly	012	1.54	1.56
Holly	013	1.22	1.27
Holly	014	0.16	0.16
Hope	T061	3.40	3.43
Hope	011	3.52	3.55
Harper	T061	1.62	1.69
Harper	011	0.52	0.55
Harper	012	0.77	0.81
Jamieson	T061	2.35	2.46
Jamieson	011	1.96	2.04
Jamieson	012	1.03	1.06
Juntura	011	0.35	0.36
Juntura	012	0.28	0.30
Jordan Valley	T061	1.76	1.85
Jordan Valley	031	1.79	1.88
Jordan Valley	T062	1.33	1.40
Jordan Valley	011	0.53	0.55
Jordan Valley	012	0.77	0.81
Lime	T061	0.00	0.03
Lime	011	0.05	0.08
Malheur Butte	T061	2.65	2.65
Malheur Butte	041	2.51	2.51
Malheur Butte	042	0.09	0.09
Nyssa	T061	14.98	15.09
Nyssa	011	5.45	5.56
Nyssa	012	8.40	8.48
Nyssa	T062	10.51	10.62
Nyssa	013	6.03	6.14
Nyssa	014	4.54	4.61
Ore-Ida	T061	26.25	26.36
Ore-Ida	011	8.22	8.33
Ontario	T134	27.27	27.38
Ontario	020	6.87	6.98
Ontario	023	7.73	7.84

Oregon Near-Term Winter 2026 DER and EV Loading Impact			
Substation	**Device**	**Year**	
Ontario	024	9.81	9.92
Ontario	025	4.30	4.36
Ontario	T135	22.24	22.35
Ontario	014	8.84	8.95
Ontario	018	4.01	4.12
Ontario	019	9.53	9.64
Pine Creek	T061	0.93	0.95
Pine Creek	011	0.86	0.88
Parma	T061	10.87	10.98
Parma	012	3.71	3.82
Parma	T063	6.64	6.75
Parma	042	6.64	6.75
Unity	T061	1.75	1.85
Unity	011	0.71	0.74
Unity	012	0.78	0.84
Vale	T061	13.21	13.32
Vale	011	6.44	6.55
Vale	012	0.73	0.74
Vale	013	2.69	2.80
Vale	014	1.20	1.27
Vale	015	2.53	2.64
Weiser	T061	15.47	15.58
Weiser	013	0.07	0.13
Weiser	014	5.51	5.62



DSP REPORT:

GRID NEEDS IDENTIFICATION

GRID NEEDS IDENTIFICATION

Process to Assess Grid Adequacy and Identify Grid Needs

Idaho Power determines its grid needs using a multi-step process, as shown in Figure 3.1, that begins with a forecasting and needs assessment, then moves to a weather and peak evaluation, and the Small Area Study process before a project can be selected and constructed. The steps of this process are described in detail in this section.

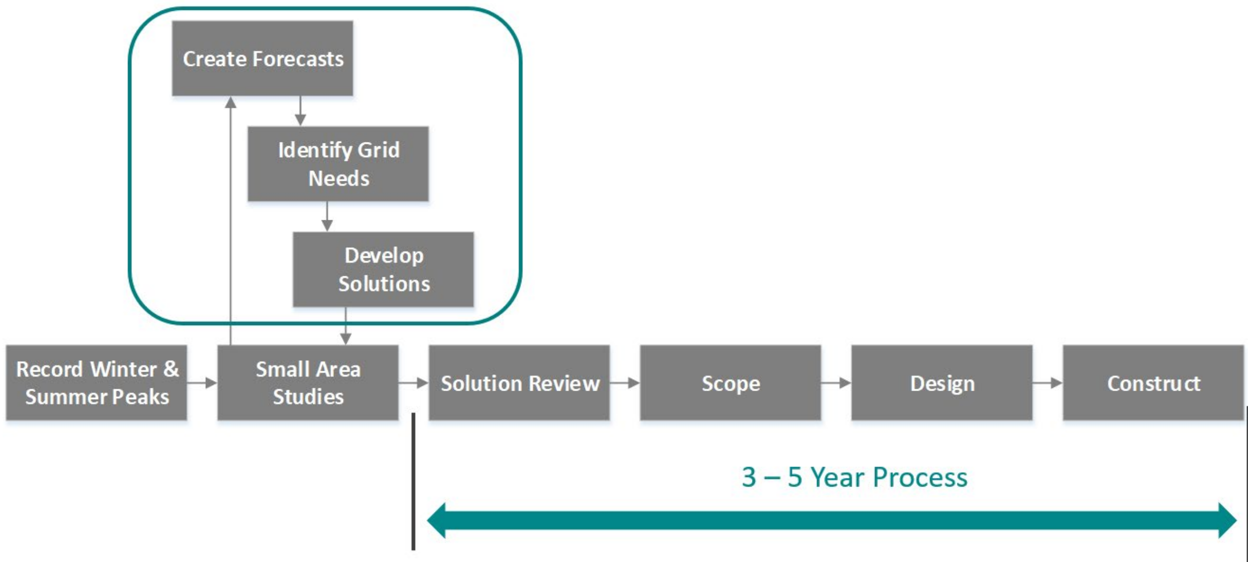


Figure 3.1 Distribution planning process flow chart

Small Area Studies

Idaho Power's substation transformers and distribution feeders are evaluated for capacity and voltage constraints through the Small Area Study process. The company completes these studies for each substation once every three years and more frequently in areas experiencing high growth.

The Small Area Study process includes extreme temperature forecasted load growth for the substation transformers and associated feeders. Distribution planning engineers use the load forecast information to model the substation transformer and distribution feeders using DNV's Synergi Electric software tool. In this tool, the transformer and feeder loadings are adjusted by growth factors to increase the system load over the next five to ten years to identify any capacity and voltage issues. The results are documented in the Small Area Study report.

Each Small Area Study report includes the following sections:

- An introduction that identifies the study scope which includes a five-year summary of anticipated solutions and projects for the substation transformers and feeders.
- Existing area configuration with general facts about the area, including the county in which the distribution system resides; nearby cities; adjacent substation boundaries; substation equipment information; customer count; area loading; large or notable loads served in the area; and sub-transmission information.
- Growth patterns and projections, including:
    - Range of the peak loads on the substation and the number of new customers added over the last five years
    - Load growth projections for the next ten years, based on the extreme temperature adjusted peak load forecast for each transformer and distribution feeder associated with the area study
    - Remaining capacity for each transformer and distribution feeder based on its limiting season whether it be summer or winter
- Concerns and mitigating solutions, including:
    - Issues due to capacity or voltage constraints on the distribution system
    - Solution(s) for capacity- or voltage-related issues in the next 10 years

Extreme Temperature Forecasts

Designing the distribution system to accommodate extreme temperature forecasted loads creates operational flexibility in the normal temperature years and less stress in the extreme temperature years. Planning limits are thresholds that are set below the distribution equipment thermal ratings to create increased operational margins. These planning limits are used to identify voltage and capacity grid needs. The increased operation margins allow for forecasting inaccuracies and the 3- to 5-year scope, design, and construct process.

Idaho Power developed an Extreme Temperature Forecasting Planning Limits guide that identifies the different planning limits based on substation transformer nameplate rating and feeder voltage levels. The full guide is available in Appendix C of this report. Examples of planning limits include:

- Substation transformer summer rating: 98% of the transformer's nameplate rating
- Substation transformer winter rating: 110% of the transformer's nameplate rating

- 12.5 kilovolt (kV) distribution feeders: 10 Mega Volt Amperes (MVA) for summer and winter planning limits
- 34.5 kV distribution feeders: 20 MVA for summer and winter planning limits

Distribution planning engineers assess the need for grid upgrades by evaluating forecasts against planning limits. The engineer will identify an intercept point—that is, the year when the forecasted load will exceed the planning limit. An example of an identified grid need is shown in Figure 3.2, in which the distribution feeder is forecasted to exceed the planning limit in 2028. Such a forecast would trigger the engineer to develop a solution to address the grid need.

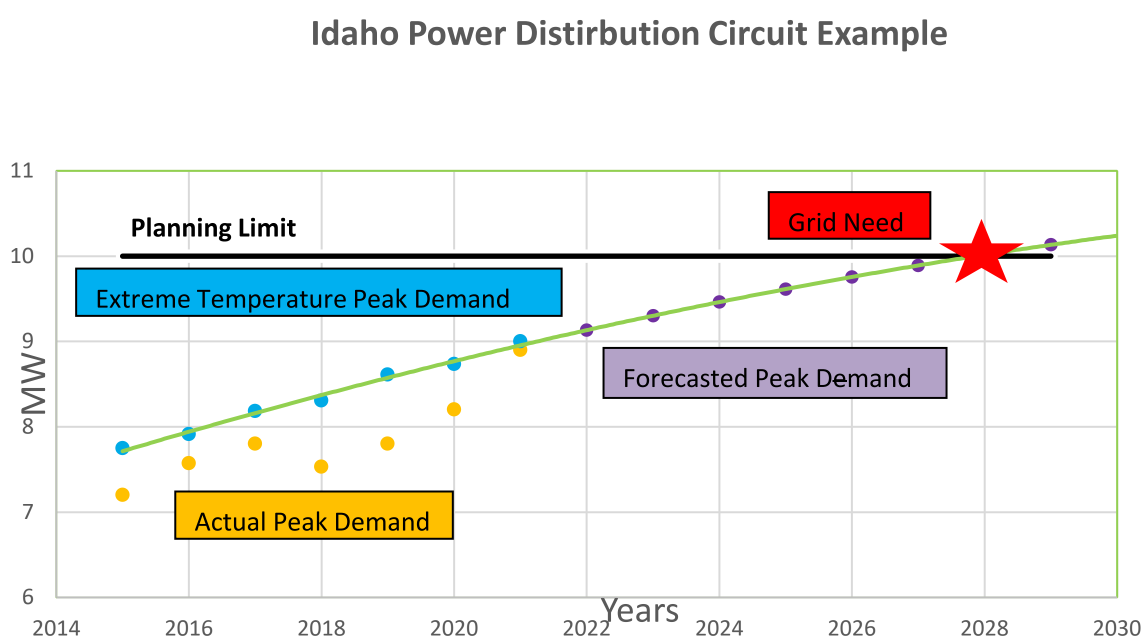


Figure 3.2 Projected grid need identified

Planning voltage limits are another trigger that drives the need for grid upgrades. During the Small Area Study modeling process, the ideal voltage on the primary system is between 117 and 126 volts (V). Maintaining a minimum voltage of 117 V on the primary system allows for voltage drop through the distribution service transformer and service conductor and ensures the customer is within the American National Standards Institute (ANSI) C84.1 Range A. Voltages that drop to 117 V on the primary system during the modeling process signify the need for solution and project development.

- Steady State Voltage ANSI C84.1 Range A 114–126 V
- Extreme Minimum or Maximum ANSI C84.1 Range B 110–127 V

Reliability Grid Needs Identification

Criteria to Assess Reliability and Risk

Idaho Power utilizes various programs to assess and rank grid needs relative to reliability and risk.

Bottom Feeder Program

The Bottom Feeder program has been one of Idaho Power's most effective reliability programs for reducing System Average Interruption Frequency Index (SAIFI). SAIFI tracks outages lasting longer than five minutes per customer per year. Feeders are prioritized using the following steps:

1. Evaluate the last five years of outage data
2. Calculate the Circuit Performance Index (CPI) for every feeder, using the following parameters:
    - Five years of outage data, weighted by recent years
    - CPI weighting: 50% SAIFI, 25% Customer Interruptions, 25% Customer Experience Multiple Index (CEMI)
    - Rank all feeders in prioritized list by CPI (high CPI = high priority)
3. Filter out feeders:
    - Feeders that were remediated through Bottom Feeder projects within the previous three years are removed from the high CPI list.
4. Screen the CPI list by reviewing the outage history for each feeder.
5. Field Engineers review the prioritized list, offer comments, and submit the scope of work for each identified project.

The scope of work for a Bottom Feeder project may include:

- Feeder trunk hardening—Distribution feeders main artery upgrades. This is usually a reliability issue that requires replacement of distribution wires, poles, and/or pole hardware.
- Installation of additional protective devices like fuses or reclosers
- Change existing protective device scheme/settings
- Avian protection—bird protection

Methods and Modeling Tools Used to Identify Reliability Needs

Idaho Power uses several different tools to measure the reliability of the distribution system and identify reliability-driven grid needs.

Sentry Grid Monitors

Distribution feeders are split up into line protection zones based on protective devices such as feeder breakers, reclosers, sectionalizers, and fuses. These zones are known as protective zones. The operation of a protective device results in the loss of electrical supply for all the customers in the device protective zone and all downline protective zones.

Line sections experiencing significant interruptions are identified using sentry grid monitoring devices. Idaho Power continuously monitors 85% of the distribution system (limited to areas with cellular service) with 1,493 sentry monitors across the Idaho Power service area, of which 182 are located in Oregon. The sentry grid monitors detect the loss of power and send alerts to Idaho Power's outage management system.

Microsoft Power BI Tool

Idaho Power engineers utilize Microsoft Power BI Tool to build reports and visualize reliability data across the distribution system, such as the example shown in Figure 3.3. The reliability reports give insight into which distribution feeders are under performing in areas such as: momentary events, feeder reliability metrics, and avian related outages.

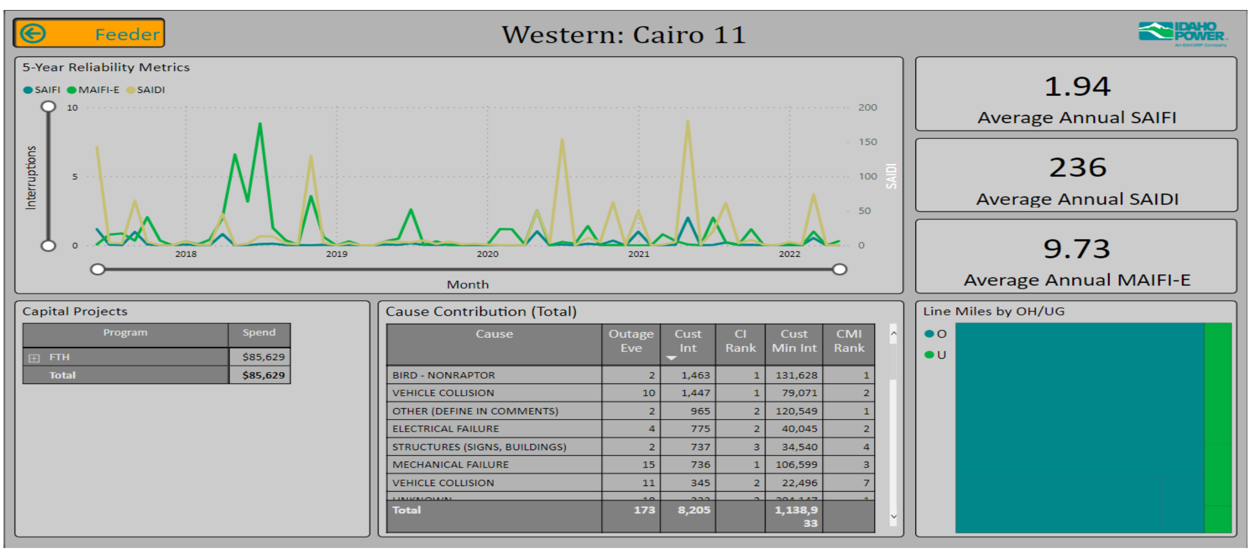


Figure 3.3 Cairo 11 reliability review

Maintenance and Inspection

The maintenance and inspection of our distribution apparatus devices—transformers and circuit breakers—are an integral part of our reliability and risk programs. Idaho Power follows NERC FAC 501 standards for maintenance and inspection plans, as described in the following sections. Inspections are recorded in the DNV Cascade software package for Idaho Power's maintenance management database.

Transformer Maintenance and Inspection Procedure

Figure 3.4 Substation transformer

A transformer, like the one shown in Figure 3.4, is a device that changes voltage levels. The transformer includes a tank that contains oil for cooling.

Summary of Transformer Maintenance Philosophy

Transformer maintenance consists of inspections, tests, and system operation evaluations. Trained inspectors and station technicians perform these inspections. All Idaho Power substation transformers fall within the same inspection and maintenance interval. The inspection and maintenance intervals are described in detail on the following pages. Identified concerns are recorded in Cascade. Device emergent issues are prioritized based on the severity of the issue.

Transformer Maintenance Program

Periodic inspection: Periodic inspections are performed within 90 days of the previous inspection. As part of Idaho Power's periodic substation inspection, each transformer is given a visual inspection which includes:

- Checking for oil leaks and assessing the overall condition of the transformer
- Checking the oil level of the bushings and tank
- Reading and recording the transformer gauge temperatures
- Checking that transformer cooling and oil preservation systems are operating in a normal mode for the operating conditions

Infrared inspection: An infrared inspection is a thermal test that identifies "hot spots" that may lead to material failure. Figure 3.5 shows an infrared image. The scale on the right side of the image represents the heat content within the image, with yellow indicating a higher heat content and, therefore, a higher probability of failure. The device circled on the left in green would be targeted for replacement.

Figure 3.5 Infrared image of substation disconnects

These inspections are completed within 18 months of the previous inspection. This includes:

- Inspecting all bushings and connections for hot spots
- Inspecting the tank for unusual heating

Oil dissolved gas analysis (DGA) test: DGA tests help to detect the presence of gas inside of a transformer's oil filled compartments. Increasing gas levels can indicate the breakdown of insulation internal to the transformer which can lead to transformer failure. This maintenance task is completed within nine months of the previous test. An oil sample is taken from the tank and sent to an outside laboratory for DGA and moisture analysis. The results are reviewed for indication of an abnormal condition or exception from normal operating conditions or trends.

Off-line testing: Some transformer tests require that the transformer be taken out of service before the tests occur which are called off-line tests. These tests are used to verify that the transformer internal and external components meet expected operational conditions and are conducted within seven years of the previous test. Typical off-line testing includes the following:

- Winding and bushing insulation power factor
- 10 kV exciting current
- Transformer turns-ratio
- Winding insulation resistance
- Arrester watts-loss

Transformer Asset Replacements

Asset replacement: The asset replacement process addresses end-of-life substation transformer issues and considers the following:

- Performance criteria—Is the transformer doing its job without significant corrective maintenance?
- Replacement parts availability
- Idaho Power-owned spare transformer availability
- Criticality—In the event of a transformer outage, can power be provided by adjacent transformer without overloading other system elements?
- Offline testing results that show the quality and quantity of insulation systems—How well is the transformer aging?

Any transformer not meeting performance criteria (including safety) is immediately replaced with a spare or mobile transformer. The other transformers that meet performance standards are prioritized for replacement and such prioritization is largely dependent on the dissolved gas analysis test and off-line testing.

Circuit Breaker Maintenance and Inspection Procedure

Summary of Circuit Breaker Maintenance Philosophy

Maintenance consists of inspections, tests, and system operation evaluations. Idaho Power employs vacuum circuit breakers for distribution feeder isolation. The inspection and maintenance intervals are described in detail on the following pages.

Vacuum Circuit Breakers

Vacuum Circuit Breakers, shown in Figure 3.6, are used to switch feeders and equipment in and out of the distribution system in a substation. They are most commonly used to isolate faulted distribution feeders.

Figure 3.6 Vacuum circuit breaker

Inspection and Test Procedures

Periodic inspection: Periodic inspections are completed within 90 days of the previous inspection. As part of Idaho Power's periodic substation inspections, each vacuum circuit breaker is given a visual inspection that includes:

- Searching for physical problems, such as damaged bushing, CT house/case, etc.
- Recording the number of breaker operations
- Recording any compressor/motor run times

Infrared inspection: As part of a station infrared inspection, each vacuum circuit breaker is given an infrared inspection which includes inspecting all bushings and connections for hot spots and inspecting the interrupter tanks for possible overheating. Infrared inspections are completed within 18 months of the previous inspection.

Six-year maintenance (off-line testing): The vacuum circuit breaker is removed from service and several standardized tests are performed including:

- Quality tests on bushing and interrupter insulation
- Testing the main contact grading device (where applicable)
- Testing the timing and speed of the main contacts (where applicable)
- Testing the resistance of the main current path
- Inspection of the operating mechanism

These maintenance tasks are completed within seven years of the previous test.

Distribution Maintenance and Inspection Procedure

Preventative maintenance performed on the Idaho Power distribution system improves the reliability of electric service to customers, maintains safe operation, and reduces expenses to restore service. The company has several existing preventative maintenance programs such as the distribution line inspection process, wood pole inspection and treatment program, and vegetation management program.

Distribution Line Inspection Process

The distribution line inspection process is designed to identify and correct maintenance needs that are not covered by other programs such as cross-arms, pins, insulators, potential clearance issues, and public safety concerns. The Delivery Reliability and Maintenance department is responsible for developing, providing training, and ensuring compliance with the distribution line inspection process. The department is also responsible for maintaining records of the maintenance activities.

The distribution line inspection process involves inspecting the electrical distribution line system as required by Division 24 of the Oregon Public Utility Commission's administrative rules. This process consists of a bi-annual public safety inspection and a Detailed Inspection. The bi-annual inspection is designed to identify obvious items in need of repair. The detailed inspection involves a thorough visual inspection at least once every 10 years. These inspections are conducted on a feeder-by-feeder basis and are completed to obtain information about the condition of the distribution line facilities to ensure the integrity of the system. The information collected from these inspections is used for planning and scheduling maintenance work.

The inspections are completed by personnel that have been trained in distribution line inspection procedures and have experience in distribution line construction. Idaho Power employees identify equipment in need of repair and indicate the level of priority for their repair based upon the following:

- **Emergency priority:** Conditions that require immediate attention that pose an immediate threat to the continued operation of the line or to life and safety. All emergency priority conditions are to be immediately reported and repaired as soon as possible, which may include immediate repair at the time of the patrol.
- **High priority:** Conditions that need correction but that are not an immediate threat. High priority conditions are scheduled during crews' normal work schedules. These items require correction within 12 months of their identification.
- **Low priority:** Conditions that need correction but can be budgeted and planned for correction within 36 months of their identification.

Overhead and underground equipment conditions needing repairs are reported to the Maintenance department and the work necessary to correct the condition is documented. The information is submitted to regional leadership for corrective action to be completed in the appropriate timeframe.

Wood Pole Testing and Treatment

All Idaho Power wood poles are inspected to detect decay, rot, or other concerns in the poles. Poles are internally and externally treated to prevent decay and extend the life of the poles. Poles are tested and treated on a 10- to 12-year cycle. All poles inspected fall into five categories as follows:

- Reported—Any pole inspected and found to be installed within 10 years of the inspection date, or any pole which is determined with reasonable opinion to be inaccessible such as on an island.
- Treated—Any pole inspected and found to be installed 10 years or more prior to the inspection date and, which upon further inspection, is found to be in good enough condition to warrant treatment.
- Rejected—Any pole, which upon inspection, is found to have less than 4" of shell, distance from the pole exterior to the internal pole decay, at 48" above groundline and/or less than 2" of shell at groundline, or is deteriorated below required strength.
    - Rejected poles fall into 2 categories:
        - Reinforceable with steel—All reinforceable poles are reinforced with stubs.
        - Non-reinforceable—All non-reinforceable poles are replaced.
- Visually rejected—Any pole, which has been burnt, split, broken, damaged, or decayed above groundline to such an extent as to warrant rejection.
- Sounded, bored, and treated—Any pole inspected and found to be installed in concrete, asphalt, or solid rock 10 years or more prior to the inspection date is internally treated, which involves fumigating the good wood and flooding the voids with fumigant.

Vegetation Management Program

Idaho Power's vegetation management program addresses public safety and electric reliability and helps ensure that Idaho Power's distribution and transmission lines are clear of vegetation that may cause customer outages, damage company facilities, or pose a wildfire risk. On a regular pruning cycle trees are pruned to maintain a clearance envelope between vegetation and overhead power lines. The pruning cycle also includes the removal of hazardous trees such as dead or dying trees leaning toward Idaho Power facilities. Trees are cleared using a pruning procedure called directional or natural pruning, a method recommended by the International Society of Arboriculture, and the ANSI A300 standards.

Wildfire Mitigation

In addition to regular cycle pruning activities, utility arborists conduct annual ground patrols to identify potential vegetation hazards of each distribution line identified in Idaho Power's Wildfire Mitigation Plan[12] two risk zones—Tier 2 (Yellow Risk Zones) and Tier 3 (Red Risk Zones). The company's Oregon service area does not contain any Tier 3 zones, as of the 2022 Wildfire Mitigation Plan.[13]

During these inspections, patrol personnel identify infrastructure defects and hazardous vegetation, within or adjacent to the right-of-way, that could fall in or onto the distribution lines or associated facilities. The patrol personnel then evaluate the hazardous vegetation as to the level of threat posed by categorizing the vegetation as a high priority, medium hazard, or low hazard. Any hazardous vegetation categorized as a high priority and that presents a risk to cause an outage at any moment shall also be reported without any intentional time delay to dispatch. The utility arborist will conduct a follow-up inspection if potential hazardous trees or grow-ins are identified. The utility arborist prioritizes and schedules any remedial action for all reported vegetation issues.

Prioritized Grid Constraints and Grid Constraint Timelines

For Idaho Power's Oregon service territory, a review of the loading and reliability performance identified five grid needs that have a required in-service date between 2022 and 2026. Idaho Power presented information on these grid needs at Idaho Power's Oregon Distribution System Planning public meeting on May 18, 2022. The presentation from the public meeting can be found on Idaho Power's website: https://www.idahopower.com/dsp. For each grid need presented, the criteria used to determine the grid need along with the need date was discussed.

After reviewing the scenarios for both the DER and EV impact, Idaho Power determined that the most severe scenario combination of low DER and high EV results in the highest anticipated loading for each feeder and transformer. The DER/EV combination mentioned did not impact

[12] Idaho Power Company Wildfire Mitigation Plan, https://www.idahopower.com/outages-safety/wildfire-safety/protecting-grid/.

[13] Idaho Power filed its 2022 Wildfire Mitigation Plan with the OPUC on December 30, 2021, in Docket No. UM 2209. To comply with the OPUC's conditions of approval, the company filed an updated Wildfire Mitigation Plan in the same docket on June 28, 2022.

the existing near-term forecast. Based on this forecasting, six identified grid needs are summarized in Table 3.1.

Table 3.1 Identified near-term grid need projects

Substation/Feeder	Project Type	Need Date	Grid Need
Adrian 011	Reliability	4/1/2023	Line protection equipment does not record information
Vale 013	Reliability	5/1/2023	Limit outage impact
Vale 015	Growth	5/1/2023	Low voltage on feeder
Weiser T061	Growth	5/1/2023	Substation Transformer Capacity
Halfway 012	Growth	10/1/2023	Regulator planning capacity at limit
Cow Valley 012	Growth	4/1/2024	Low voltage on feeder

Of the six grid needs, five were identified through distribution modeling and can be addressed with low-cost, traditional solutions. The Weiser T061 substation transformer grid need was identified through the forecasting process and requires a more complex and, therefore, expensive solution. Although the Weiser substation project is located in Idaho on the Idaho/Oregon border, it serves distribution feeders that serve Idaho Power's Oregon customers.

This transformer was identified in Idaho Power's 2021 Transmission and Distribution Substation Loading Analysis, filed in Docket No. UM 1911. This transformer is less than three years from its load reaching rated capacity, making it the company's only prioritized grid need constraint. At the beginning of 2021, a project was initiated to alleviate the forecasted overload on the transformer. Given the limited nature of near-term grid needs in Idaho Power's Oregon service area, the company looked beyond the next four years to identify additional grid needs. Based on the most recent Transmission and Distribution Substation Loading Analysis (posted on Idaho Power's OASIS and included in Appendix D), three transformers serving Oregon were medium loaded. A medium loaded transformer is estimated to reach its full capacity within three to ten years.

Idaho Power presented information on these long-term grid needs at the Oregon Distribution System Planning public meeting on May 18, 2022. For each grid need presented, the criteria used to determine the need, along with the need date, was discussed. A summary of these long-term projects is shown in Table 3.2.

Table 3.2 Long-term grid need projects

Substation/Feeder	Project Type	Need Date	Grid Need
Nyssa	Growth	5/1/2028	Transformer capacity limit
Juntura	Growth	5/1/2028	Transformer capacity limit
Jamieson	Growth	5/1/2028	Transformer capacity limit

DSP REPORT:

SOLUTION IDENTIFICATION

SOLUTION IDENTIFICATION

Process for Identifying Solution Options for Grid Needs

Traditional Solution Review

As discussed in the grid needs section, Idaho Power's distribution transformers and feeders are evaluated for capacity and voltage constraints through the Small Area Study process, which includes identification/forecasting of grid needs and the initial identification of solutions. Feeders are evaluated for reliability through the Bottom Feeder program and solutions are identified and developed by the company's reliability engineers.

Potential grid needs solutions are evaluated on cost, expected duration until a second grid need (or upgrade) is required, and alignment with other system plans such as the regional electrical plans. The solutions are also compared for their potential impact on reliability and maintenance projects.

Traditional solutions may be preferred if the grid need has any of the following characteristics or conditions:

- Load transfer to an adjacent feeder or substation;
- The addition or replacement of line equipment, such as line switches, capacitors, recloser, or voltage regulators;
- Upgrade of overhead or underground wires with higher capacity wires;
- Rebuild a feeder section to operate at a higher voltage;
- Replace the substation transformer with larger capacity transformer;
- Addition of a new feeder;
- Addition of a substation transformer; and/or
- Build a new substation.

NWS Review

Once an optimal traditional solution has been identified for a grid need, the company conducts an additional assessment to determine if NWS may be a more cost-effective option. For Idaho Power, NWS options include the following:

- Battery Energy Storage System (BESS);
- Photovoltaic (PV) solar;
- Or a combination of BESS/PV solar.

These NWS options are technically proven and commercially available. As more NWS-applicable technologies become viable and market-ready, they will be added to the list of NWS options for consideration.

Table 4.1 lists characteristics that are used as an initial screen to indicate when a specific grid need may be best met with NWS.

Table 4.1 Ideal grid need characteristics well-suited for NWS

Characteristics	Ideal NWS Candidate
Growth	Low
Traditional Solution Cost	High
NWS Cost	Low

The 2021 IRP identified battery storage to reduce the need for additional generation at peak loading times. This IRP requirement creates an additional value stream for battery installations that provides benefit during peak loading times. Additional value streams bring down the total cost of a BESS resulting in a lower net cost.

Grid Needs Summary

For Idaho Power's Oregon service area, a review of the loading and reliability performance resulted in six grid needs identified that have a need date between 2022 and 2026. These grid needs are identified as near-term. A summary of the six projects is listed in Table 4.2.

Table 4.2 Near-term grid need projects

Substation/Feeder	Project Type	Need Date	Traditional Solution
Adrian 011	Reliability	4/1/2023	New electronic recloser
Vale 013	Reliability	5/1/2023	Add fuses
Vale 015	Growth	5/1/2023	Add regulator
Weiser T061	Growth	5/1/2023	Convert to 138kV and upgrade transformer
Halfway 012	Growth	10/1/2023	Upgrade existing regulator
Cow Valley 12	Growth	4/1/2024	Add regulator

These six projects were considered for NWS. The grid need characteristics for each project were reviewed as shown in Table 4.3.

Table 4.3 Near-term grid need characteristics

Characteristic	Adrian 011	Vale 013	Vale 015	Weiser T061	Halfway 012	Cow Valley 012
Growth	Low	Low	Low	Low	Medium	Medium
Traditional Solution Cost	Low	Low	Low	High	Low	Low
NWS Cost	Medium	Medium	Medium	High	Medium	Medium

The Weiser substation transformer is the most promising candidate for NWS. None of the other five projects are good candidates for NWS due primarily to the low cost of the traditional solution to address the particular grid need. The cost for the traditional solutions can be found in Table 5.1: Idaho Power growth investments.

Looking beyond the next four years, additional grid needs were identified that could be candidates for NWS. Those projects are described in Table 2.3. As described in the prior section, the substation transformer upgrade grid needs were identified using the Extreme Temperature Forecasting Tool combined with planning limits to identify a capacity limit impacts.

Table 4.4 Potential long-term grid need projects

Area Impacted	Need Date	Traditional Solution
Nyssa	5/1/2028	Transformer upgrade
Juntura	5/1/2028	Transformer upgrade
Jamieson	5/1/2028	Transformer upgrade

These three projects were considered for NWS, beginning with an evaluation of each need against the characteristics of NWS, as shown in Table 4.5.

Table 4.5 Potential long-term grid need characteristics

Characteristic	Nyssa	Juntura	Jamieson
Growth	Medium	Low	Low
Traditional Solution Cost	High	Medium	Medium
NWS Cost	High	Low	Low

Based on this assessment, the Nyssa project is not a good candidate for NWS due to its medium growth rate, limited substation footprint, and high NWS cost. The other two projects may be better candidates for NWS, but a more thorough review will be conducted as the project moves through the normal solution review process.

Prioritized Grid Need Solutions Review—Weiser Substation Transformer

The Weiser Substation transformer (T061) capacity overload is the only near-term priority grid need in Idaho Power’s Oregon service area. As referenced earlier in this report, the project is already in progress and was underway before the grid needs assessment as part of this DSP. Below, the company provides more details about this project to demonstrate that NWS can be optimal for Idaho Power in certain circumstances.

Weiser Substation Transformer NWS Case Study

The Weiser T061 transformer has the following characteristics:

- Nameplate Rating = 14 MVA
- Planning Capacity Limit = 13.72 MVA
- Most recent actual peak, Summer 2021 = 12.25 MW
- Adjusted extreme temperature event peak, Summer 2021 = 12.48 MW
- Average growth trend in the area: 1.34% annually
- Multiple large load requests totaling 3.15 MW are factored into the transformer loading

A 1.13 MW load transfer from Weiser 013 to Holly 012 in 2022 is factored into the forecast customer counts by type for Weiser T061 are included in the table below.

Table 4.6 Weiser transformer customer details

Customer Type	Customer Count
Residential	1,549
Small Commercial	196
Large Commercial	103
Large Power	2
Irrigation	389

In an extreme temperature event, the forecasted peak load of 14.41 MW, Weiser T061 will exceed the planning capacity by 5.0% in the summer of 2023.

Traditional Solution and NWS Evaluation

New 138/12.5kV Transformer (Traditional Solution)

- **Project details:** The project will add a new 138 kV/12.5 kV, 44 MVA transformer at the Weiser substation. A circuit switcher will be installed for transformer protection. New open-air bus and four feeder bays and breakers will be installed on the low voltage side of the new transformer and will serve as new feeder bays for Weiser feeders 011, 012, 013, and 014. A mobile tie will be installed on the new 12.5 kV bus to allow for transformer maintenance. A normally open underground tie between the new 12.5 kV bus and the existing 12.5 kV bus of T062 will be established to allow offloading of Weiser feeders 015 and 016 during T062 maintenance.
- **Benefits:** This solution removes load from the 69 kV system. By removing this load, Idaho Power eliminates the need to upgrade the 138/69 kV tie bank at Weiser.

- **Drawbacks:** Solution is more expensive than a new transformer on the 69 kV system. Solution would also require significant substation rework in the form of an additional room in the Weiser control building, a yard expansion, and equipment removals.
- **Solution duration:** Approximately 20+ years
- **Approximate costs**: $2,200,000

69 kV Additional Transformer (Traditional Solution)

- **Project details:** The project would add a new 69/12.5 kV, 14 MVA transformer to the Weiser Substation. The 12.5 kV operating bus will need to be split between Weiser feeders 013 and 012 with a gang operated tie switch with load break capability. The new transformer will feed Weiser feeders 011 and 012. The existing Weiser T-061 will feed Weiser feeders 013 and 014.
- **Benefits:** This solution is the lowest-cost option. The addition of the transformer would not require significant substation work, as a fused protection scheme would prevent the need for additional control room space. Solution would also allow for a greater outage window for maintenance on Weiser T061, T062, or T063.
- **Drawbacks:** Adding a new 14 MVA transformer increases the station capacity but will overload the 138/69 kV tie bank transformer by 1.3% in 2028. Overloading the 138/69 kV tie bank transformer would drive the need for a new 138/69 kV tie bank transformer costing an additional $5,600,000.
- **Solution duration:** Approximately 6 years
- **Approximate costs:** $936,332

Weiser 012 to Payette 012 Load Transfer (Traditional Solution)

- **Project details:** Project would create a new feeder tie between Payette 012 and Weiser 012. New feeder tie would be constructed along Idaho Highway 95, requiring 8.5 miles of new distribution feeder.
- **Benefits:** The project would create a new tie between Weiser and Payette substations. This would allow for increased operational flexibility at either station, making maintenance on either Payette 012 or Weiser 012 easier to accomplish. Project would remove any permanently transferred load from Weiser 012 to Payette 012 from the 69kV transmission system and move it to the 138 kV system.
- **Drawbacks:** Project requires a significant amount of distribution construction. Payette 012 is a capacity constrained feeder, requiring a portion of the Payette 012 to first be offloaded to Holly 013 for a permanent load transfer from Weiser 012.

Project would require voltage mitigation to accommodate additional load on Payette 012.

- **Solution Duration:** Approximately six years
- **Approximate Costs:** $2,383,058 total
  - $1,500,000 to create tie
  - $883,058 for Payette 012 to Holly 013 offload.

Weiser 011 to Midvale 011 Load Transfer (Traditional)

- **Project Details:** Project would create a new feeder tie between Weiser 011 and Midvale 011. New feeder tie would be constructed along Idaho Highway 95, requiring 13 miles of new distribution feeder. To offload load from Weiser 011, The Midvale T061 transformer would need upgraded to a 7 MVA transformer or greater.
- **Benefits:** Project would create new ties between Midvale and Weiser substations, both of this have limited ties to surrounding substations. This would allow for increased operational flexibility at either station, making maintenance on either Midvale 011 or Weiser 011 easier to accomplish.
- **Drawbacks:** Project is incredibly expensive. The tie offloads a limited amount of load from Weiser substation and decreases reliability for any customers transferred from Midvale and Weiser. The purchase of a new transformer at Midvale substation to accommodate the additional loading makes this solution less effective than a new transformer at Weiser substation. Project would require significant voltage mitigation to accommodate load on Midvale 011.
- **Solution Duration:** Approximately 2 years
- **Approximate Costs**: $3,150,000

BESS (NWS)

- **Project details:** The project will add a 3 MW, four-hour battery (total of 12 MWh). The BESS will connect to an extended open-air distribution feeder bus.
- **Benefit/consequences:** The BESS would allow increased utilization of existing equipment, experience in BESS installations and operations. In addition to substation transformer peak shaving the BESS would contribute to Idaho Power System peak shaving, carbon reductions, and is part of the 2021 Integrated Resource Plan preferred portfolio which identified the need to add BESS to the system.
- **Solution duration:** Approximately nine years

- **Approximate cost**: $4,865,00 ($365,000 net cost including the IRP value for system peak shaving)

A review of the benefits, drawbacks, and approximate costs resulted in the preferred traditional solution being the new 138/12.5 kV transformer solution. After comparing the NWS (BESS) and considering additional IRP value streams, it was determined that the BESS with a nine-year deferral of the traditional solution makes the BESS the preferred solution.

Pilot Project Evaluation

Weiser BESS Project

The projects identified earlier in the grids need section of this report were evaluated in more detail to determine if these projects would be viable NWS pilot project candidates. The Weiser substation transformer was the only priority grid need project for which NWS was determined to be an optimal solution. As a result, this NWS project is currently in progress and is considered our pilot project. This will be Idaho Power's first distributed BESS.

When looking at the long-term grid needs (more than four years away) there were projects that also appeared promising for an NWS. The projects were evaluated to determine if the NWS had the capability to meet the grid need and accommodate five years of forecasted load growth. This evaluation considered the peak day load profile to determine the energy required to be supplied by the NWS and the specific daily times that energy would be required. For battery systems, the evaluation also looked at the time required to recharge the battery for it to be ready for use the following day.

Of the three projects identified above (Nyssa, Juntura, and Jamieson), Nyssa’s initial grid need characteristics excluded further evaluation. Juntura and Jamieson exhibited good grid need characteristics for potential NWS. However, Jamieson’s hosting capacity would benefit from a traditional transformer upgrade solution.

Juntura NWS Evaluation

Juntura is a remote, rural community that includes a small, centralized town and agricultural terrain. Approximately five years ago, Idaho Power executed a load transfer that deferred the substation upgrade.

Grid Need

The substation is comprised of two single phase feeders with independent transformers.
The town substation transformer has forecasted capacity constraints in 2028.

Traditional Solution and NWS Evaluation

Substation Solution (Traditional)

- **Project Details**: The exiting transformers adequately served the area but, due to transformer capacity constraints and lack of other load transfer options, the substation transformer upgrade became the reasonable traditional solution.
- **Benefits**: A new transformer would serve the area for an indefinite amount of time and provide feeder off load capability for maintenance and emergency operations.
- **Approximate Cost**: $294,000

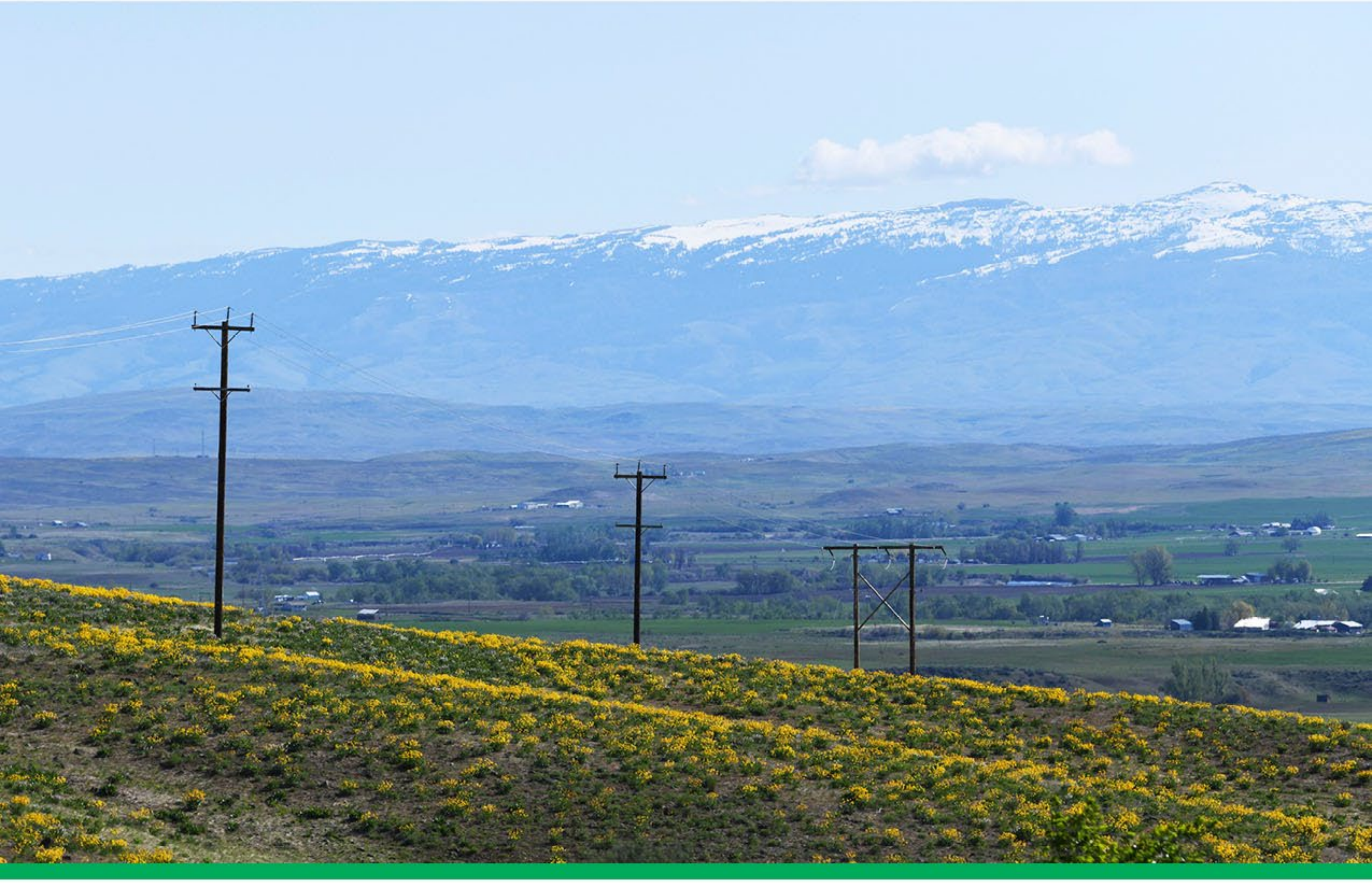
BESS Solution (NWS)

- **Project Details**: Initial evaluation reviewed a five-year substation transformer upgrade deferral. The required BESS is a 30 kW/4-hour BESS.
- **Benefits**: The BESS would allow increased utilization of existing equipment and provide experience in BESS installations and operations.
- **Approximate Cost**: $40,000

BESS/Solar Microgrid (NWS)

- **Project Details**: A five-year microgrid solution requires at least a 600 kW/4-hour BESS with 120–140 kW solar installation.
- **Benefits**: The microgrid would provide backup power support for four to eight hours, depending on loading. It would also provide valuable microgrid installation and operation experience for Idaho Power. This would provide a significant increase in substation reliability because the Juntura Substation is on a radial 69 kV sub transmission system. It would also provide an indefinite peak shaving for the existing substation feeder transformer.
- **Approximate Cost**: $900,000

The BESS at Juntura could provide valuable project deferral and microgrid opportunities, but due to the age of the transformer and communications costs the project will require further evaluation. This analysis will occur during the normal solution evaluation process.



DSP REPORT:

NEAR-TERM ACTION PLAN

NEAR-TERM ACTION PLAN

Idaho Power's near-term DSP action plan consists of moving forward with capital investment projects in the company's Oregon service area. Capital projects include those necessitated by growth, enhanced reliability, and asset replacement. The total projected near-term capital spend in the company's Oregon service area is estimated at $13.7 million for the 2023–2026, as shown in Figure 5.1.

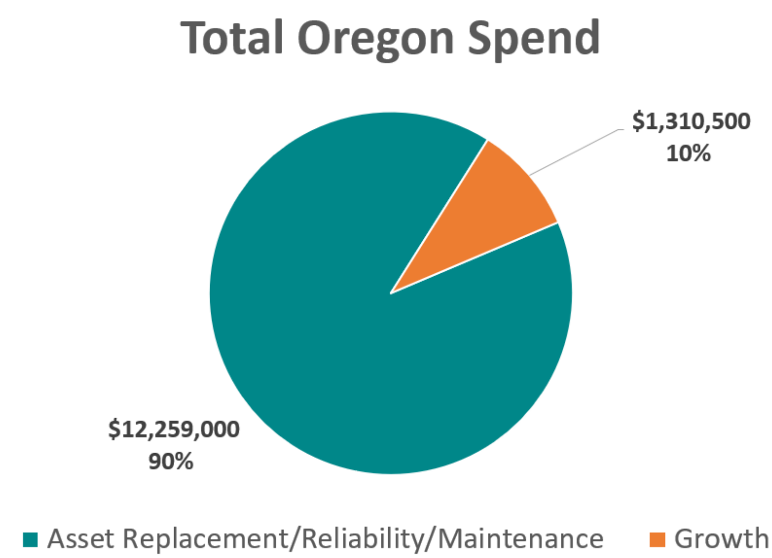


Figure 5.1 Idaho Power planned Oregon service area spend

In Figure 5.1, asset replacement projects, reliability projects, and maintenance projects were combined due to the frequent overlapping of drivers. For example, the Huntington/Durkee project and the Jordan Valley 031 project listed in Table 5.2: Idaho Power asset replacement/reliability/maintenance are projects that address both reliability and replacement due to the age/functionality of the assets. The capital investment projects are discussed in more detail in the following sections.

Growth Investments

The two-to-four-year growth action plan in eastern Oregon is identified in Table 5.1. These include projects that have need dates beyond 2026 but have investments in the 2023–2026 timeframe. The fourth project in Table 5.1 is the pilot BESS 3MW/4-hour project housed in the Weiser Substation; although located in Idaho, it serves Oregon customers with two of the four distribution feeders.

Table 5.1 Idaho Power growth investments

Substation/Feeder	Need Date	Grid Need–Solution	2023–2026 Investments	Total Project Cost
Vale 015	5/1/2023	Low voltage on feeder—Add regulator	$48,000	$48,000
Halfway 012	10/1/2023	Regulator planning capacity at limit—Upgrade regulator capacity	$51,500	$51,500
Cow Valley 012	4/1/2024	Low voltage on feeder—Add regulator	$58,000	$58,000
Weiser T061	5/1/2023	BESS 3MW/4-hour (Pilot Project)	$940,000	$4,865,000
Jamieson T061	5/1/2028	Increase station capacity by 2–3 MW.	$116,000	$837,600
Juntura T061	5/1/2028	Increase Station Capacity	$9,000	$294,000
Nyssa T061	5/1/2028	Nyssa T061 Transformer Upgrade	$88,000	$1,716,000

The Weiser pilot project will defer the forecasted substation upgrades for nine years. It will also support Idaho Power's system capacity peak resource requirements identified in its 2021 IRP. This aligns with the company's Preferred Portfolio in the 2021 IRP, which calls for the addition of battery energy storage systems. This plan also aligns with Idaho Power's goal to provide 100% clean energy by 2045.

Asset Replacement/Reliability/Maintenance Investments

The total projected capital investment related to asset replacement/reliability/maintenance investment is $12.2 million for 2023–2026. Asset replacement projects that are scheduled in the near-term include upgrades to substation transformers, feeder relays, cable replacement, air break switches, and substation bus. Reliability projects are intended to reduce outage impacts, improve outage response times, and improve the System Average Interruption Duration Index (SAIDI), SAIFI, and Momentary Average Interruption Frequency Index (MAIFI). The asset replacement projects, reliability projects, and maintenance investment projects have unique drivers, but have overlapping benefits. The same project will benefit all three aspects in varying degrees.

Several of the major Idaho Power asset replacement projects are listed in Table 5.2.

Table 5.2 Idaho Power asset replacement/reliability/maintenance

Substation/Feeder	Need Date	Project Solution	2023–2026 Investments	Total Project Cost
Huntington/Durkee	2023	Convert Stations (69 kV to 138 kV)	$1,764,700	$1,875,000
Adrian 011	2023	Line protection equipment does not record information–replace with modern smart recloser	$21,000	$21,000
Vale 013	2023	Limit outage impact–Add fuses	$38,000	$38,000
Jordan Valley 031	2024	Rebuild Jordan Valley 031 Trunk Line	$2,784,000	$2,911,000
Halfway T061	2025	Install new 14 MVA Transformer	$1,711,000	$1,818,000
Hope T061	2026	Install new Transformer	$864,000	$865,000

As examples, the Jordan Valley Trunk Line Project and the Huntington and Durkee Substations upgrades which are part of the Weiser to Baker City 69 kV to 138 kV conversion project are described below.

The Jordan Valley 031 project rebuilds approximately ten miles of line over three sections of the trunk line to larger conductor for voltage correction. Newer wire, poles, and modern design practices will also help reduce outages in this remote area, as well as improve power availability and reliability for local customers. Portions of the line are planned to be relocated for better access for routine maintenance.

The Huntington Station is currently served from an existing 69 kV line that has some structures dating from its original construction in 1927. The 69 kV line spans about 60 miles from Weiser, Idaho, to Baker City, Oregon. A three-mile section of the line that spans over rough terrain needs to be rebuilt to resolve maintenance/reliability issues. Because there was a 138 kV line parallel to the 69 kV line, a study was done to evaluate the 69 kV line removal and transfer the 69 kV loads to the 138 kV line. The review indicated that the cost savings from the 69 kV rebuild would fund 138kV Huntington and Durkee substations. It also will fund the Lime Substation and Steck Park Substation loads to be fed from Huntington distribution feeders increasing their reliability. This significantly improves transmission and distribution reliability not just for the three-mile section of the line in question but also for the customer being served by the Huntington, Durkee, Lime, and Steck Park substations.

The Jordan Valley trunk line project resolves distribution voltage issues and the Weiser to Baker City 69 kV to 138 kV conversion project will resolve a maintenance issue. In addition, both projects will improve their local system reliability.

Looking Ahead

This Part II report concludes the first cycle of Idaho Power's distribution system planning process, as established by the OPUC. This DSP effort has challenged the company to apply a holistic framework to the design and management of its distribution system. More specifically, this process has enhanced the ways in which the company assesses distribution-based capital investments, engages with the eastern Oregon community, and ultimately makes decisions about the future of its Oregon service area.

Idaho Power looks forward to the continued evolution of the DSP process, which will include the evaluation and consideration of new technologies, approaches, and practices for optimal distribution system planning, as well as more alignment with the IRP process. Idaho Power's Oregon service area may be small and change slowly, but future DSP reports will provide meaningful opportunities to evolve the distribution system in a way that ensures and enhances the provision of safe, reliable, and affordable power to its customers.

APPENDICES

Appendix A: Idaho Power Company 2021 Electric Service Reliability Annual Report

Idaho Power Company 2021 Electric Service Reliability Annual Report

April 2022

CONTENTS

FIGURES

TABLES

EXECUTIVE SUMMARY

The information in this document presents Idaho Power's 2021 Electric Service Reliability Annual Report in accordance with OAR 860-023-0151. The report discusses the performance of Idaho Power's Oregon electric service through a narrative summary and includes several tables and figures.

At year-end 2021, Idaho Power served 19,538 customers from 64 distribution circuits served by 30 substations in the far central-eastern portion of Oregon. The composite performance of the circuits in 2021 included the following:

- 779 sustained (greater than five minutes) interruption events
- 28,965 customer interruptions
- 72,018 customer hours out
- System Average Interruption Frequency Index (SAIFI) of 1.48
- System Average Interruption Duration Index (SAIDI) of 3.69 hours
- Momentary Average Interruption Event Frequency Index ($MAIFI_E$) of 1.80

Idaho Power used the calculation of a threshold for major event days (MEDs) as defined in the Institute of Electrical and Electronic Engineers (IEEE) Standard 1366 and monitored its Oregon service area for MED occurrences. All the indices at the circuit and system levels in this report are shown with and without MED events for years 2017-2021. Idaho Power's 2021 threshold in Oregon for a major event day (T_{MED}) per the IEEE 1366 definition was a daily SAIDI of 10.19 minutes per customer. With the additional criterion of a daily customer average interruption duration index (CAIDI) of 5 hours (300 minutes) per OAR 860-023-0161, Idaho Power experienced 0 major event day in its Oregon service area in 2021. Idaho Power's calculated T_{MED} for 2022 in Oregon is 10.66 minutes per customer. The calculation of the T_{MED} and identification of major event days is done while considering all of Idaho Power's Oregon customers.

Compared to 2020, Idaho Power's Oregon service area SAIFI increased by 0.52 interruptions per customer from 0.97 in 2020 to 1.48 in 2021. Excluding major events, SAIFI increased by 0.54 from 0.94 in 2020 to 1.48 in 2021. The average duration of sustained outages also increased compared to last year; SAIDI increased by 0.60 hours per customer from 3.09 in 2020 to 3.69 in 2021. The increase also occurred when excluding major events, as 2021 saw an increase of 0.81 hours per customer over 2020 (2.87 to 3.69). Finally, $MAIFI_E$ decreased in 2021 compared to 2020 by 0.27 momentary interruption events per customer from 2.07 in 2020 to 1.80 in 2021.

The attached charts and tables show Idaho Power's Oregon system performance over the previous five years for SAIFI, SAIDI and $MAIFI_E$ at the system and circuit level in accordance with OAR 860-023-0151 (2)(a). In addition to the reliability indices, a summary of sustained interruption causes is shown at the system level in accordance with OAR 860-023-0151 (2)(b). A table translating Idaho Power's cause categories to the cause categories listed in OAR 860-023-151 (2)(b) can be found in the Appendix. The Appendix also includes supplemental information such as substation, voltage, operating area and customers connected for each distribution circuit in accordance with OAR 860-023-0151 (2)(h). A map is also provided which shows the distribution circuits in Idaho Power's service area with Oregon customers in accordance with OAR 860-023-0151 (2)(g).

Idaho Power continues to collect detailed outage information for all sustained outage events through its Outage Management System (OMS). Historical data from the OMS is stored and circuit performance is analyzed for the prioritization of capital projects to improve reliability. Idaho Power also continues to utilize data from its Smart Grid Monitoring system to calculate $MAIFI_E$ as it has in past years.

Idaho Power continues to implement programs and projects to improve customer service and electric service reliability. Company programs related to electric service reliability include the annual Oregon safety inspection/reliability patrols, the line clearing and vegetation management program, the pole inspection and treatment program, and annual maintenance and capital projects that replace aging assets and improve reliability.

Idaho Power completed its Oregon AMI Expansion Project in 2021 where the Company replaced 1487 meters as outlined in the table below. AMI meters provide numerous benefits to customers and the Company with one of the major benefits being improved reliability. As a result of the project, 98.9 percent of Idaho Power's Oregon customers are now using AMI meters.

Year	# of AMI Meters Installed
2020	575
2021	912
Total	**1487**

DEFINITIONS

CAIDI – Customer Average Interruption Duration Index; the average duration that a customer experienced per sustained outage (greater than 5 minutes).

CHO – Customer Hours Out; CMI divided by 60.

CI – Customer Interruptions; the total number of customer interruptions from sustained outages (greater than 5 minutes).

CMI – Customer Minutes of Interruption; the total number of customer minutes of interruption from sustained outages (greater than 5 minutes). This is calculated as the product of customer interruptions and outage duration in minutes.

IEEE – The Institute of Electrical and Electronic Engineers.

IEEE 1366 – The Institute of Electrical and Electronic Engineers (IEEE) Standard 1366 entitled *IEEE Guide for Electric Power Distribution Reliability Indices* (the 2012 edition), approved on May 14, 2012 by IEEE-SA Standards Board.

$MAIFI_E$ – Momentary Average Interruption Event Frequency Index; the average number of momentary interruption events per customer (less than or equal to 5 minutes).

Major Event – An event that exceeds the reasonable design and/or operational limits of the electric power system. A major event includes at least one major event day (MED).

MED – Major Event Day; a day when the daily SAIDI exceeds a predefined threshold value.

MedEx – Major Event Day Excluded; this suffix is used after a reliability index to indicate major event days are excluded. For example, SAIFI MedEx is SAIFI excluding major event days.

OMS – Outage Management System; refers to Idaho Power's system for distribution system mobile workforce, switching and outage event tracking.

Operating Area – Idaho Power's customers in Oregon are split into two operating areas: 1) the Jordan Valley region of the reporting area served by the Canyon Operations Center in Caldwell, ID and 2) the rest of the reporting area served by the Western Operations Center in Payette, ID. Approximately 97% of Idaho Power's customers in Oregon are within the Western operating area, while the remaining 3% of Idaho Power's customers in Oregon are within the Canyon operating area.

Reporting Area – Idaho Power's entire service area in Oregon.

SAIDI – System Average Interruption Duration Index; the average duration from all sustained outages that a customer experienced per year (greater than 5 minutes).

SAIFI – System Average Interruption Frequency Index; the average frequency of sustained outages that a customer experienced per year (greater than 5 minutes).

SGM – Smart Grid Monitor; refers to Idaho Power's system for monitoring momentary interruption events on its distribution network.

T_{MED} – A major event day threshold value.

System SAIDI, SAIFI and MAIFI$_E$

System SAIDI

Year	2017	2018	2019	2020	2021
SAIDI	3.66	2.47	2.01	3.09	3.69
SAIDI MedEx	3.34	2.47	1.70	2.87	3.69

Table 1 Five Years of System SAIDI

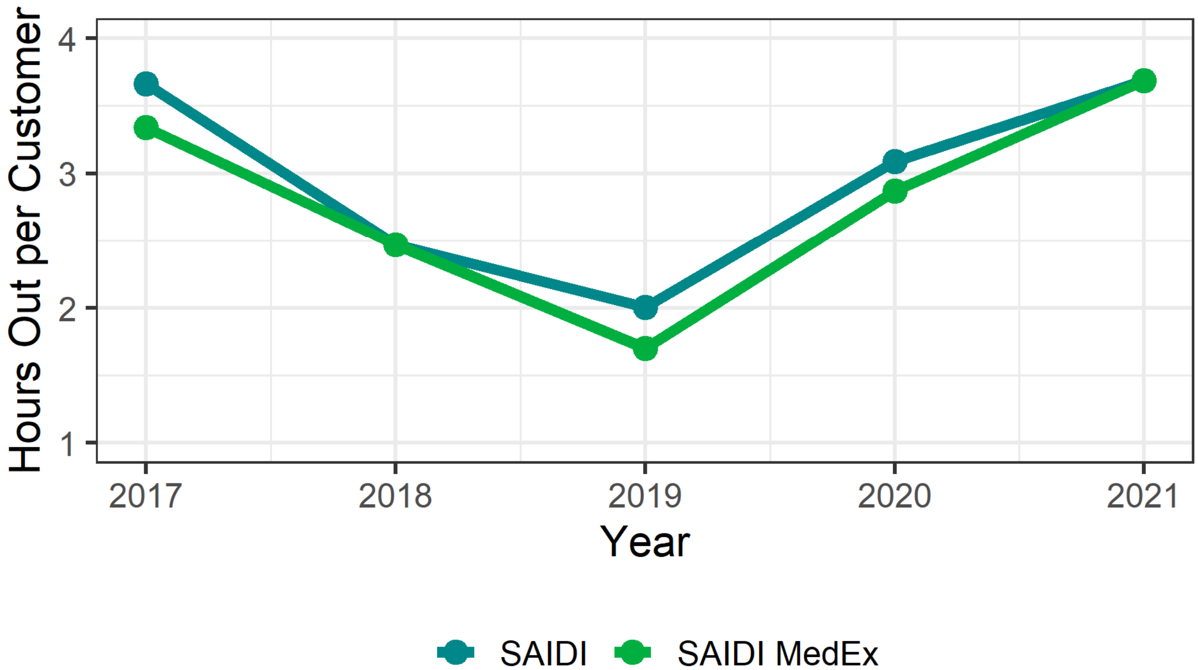


Figure 1 Five Years of System SAIDI

System SAIFI

Year	2017	2018	2019	2020	2021
SAIFI	1.22	0.95	0.63	0.97	1.48
SAIFI MedEx	1.16	0.95	0.63	0.94	1.48

Table 2 Five Years of System SAIFI

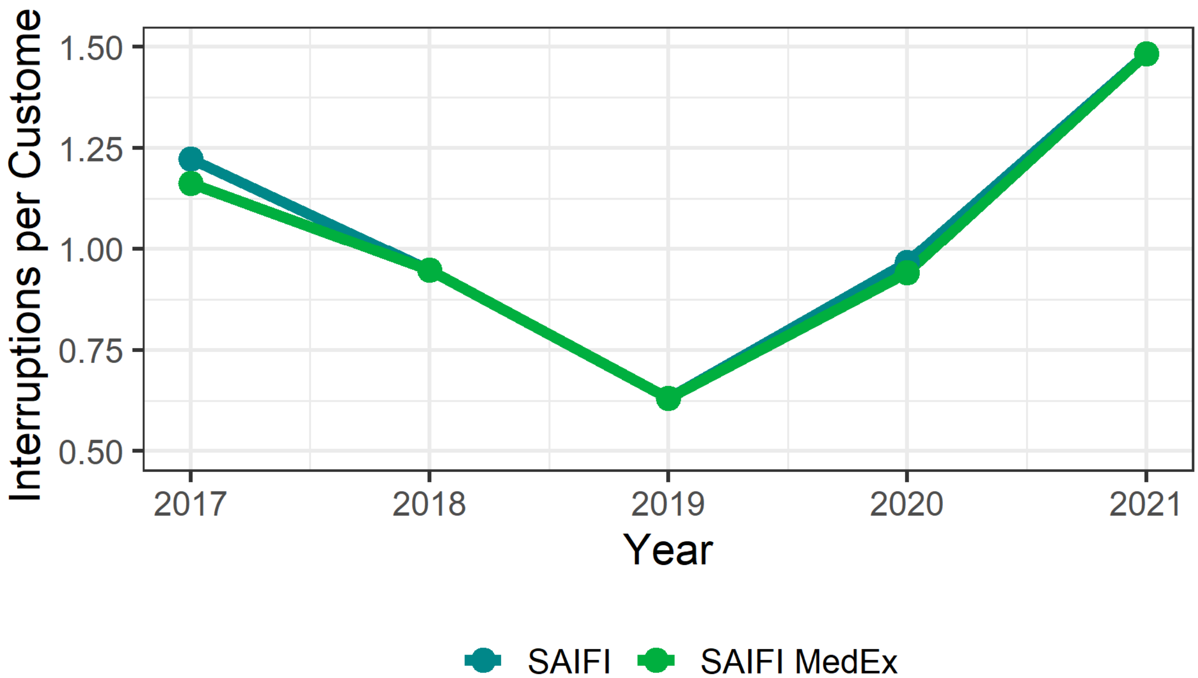


Figure 2 Five Years of System SAIFI

System $MAIFI_E$

Year	2017	2018	2019	2020	2021
$MAIFI_E$	2.44	3.16	2.28	2.07	1.80
$MAIFI_E$ MedEx	2.44	3.16	2.28	2.07	1.80

Table 3 Five Years of System $MAIFI_E$

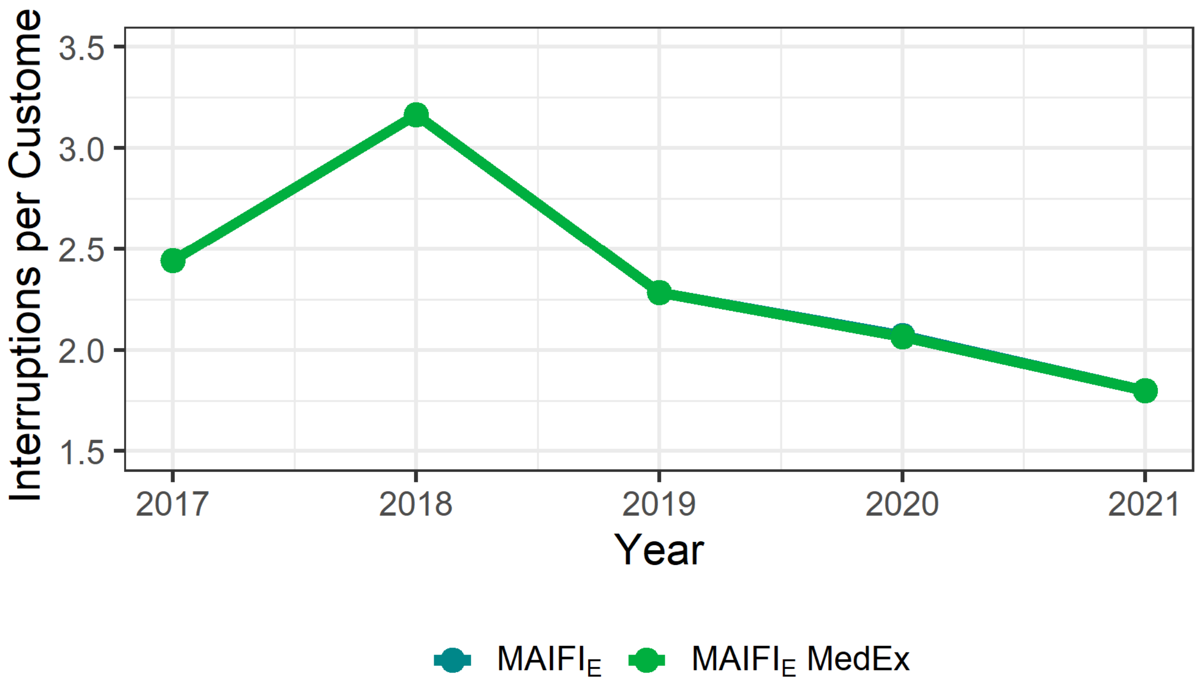


Figure 3 Five Years of System $MAIFI_E$

Sustained Interruption Event Causes

	Number of Sustained Interruption Events					Percent of Total Sustained Interruption Events				
Cause	**2017**	**2018**	**2019**	**2020**	**2021**	**2017**	**2018**	**2019**	**2020**	**2021**
Distribution – Equipment	277	159	172	150	197	27.5%	24.4%	25.2%	21.5%	25.3%
Distribution – Lightning	17	10	23	8	16	1.7%	1.5%	3.4%	1.1%	2.1%
Distribution – Other	63	46	46	41	27	6.3%	7.1%	6.7%	5.9%	3.5%
Distribution – Planned	114	91	119	133	125	11.3%	14.0%	17.4%	19.0%	16.0%
Distribution – Public	77	59	54	54	69	7.6%	9.1%	7.9%	7.7%	8.9%
Distribution – Unknown	97	72	62	99	108	9.6%	11.1%	9.1%	14.2%	13.9%
Distribution – Vegetation	118	79	91	120	128	11.7%	12.1%	13.3%	17.2%	16.4%
Distribution – Weather (Non-Lightning)	70	16	25	17	7	7.0%	2.5%	3.7%	2.4%	0.9%
Distribution – Wildlife	127	93	82	55	73	12.6%	14.3%	12.0%	7.9%	9.4%
Loss of Supply – Substation	11	7	3	2	5	1.1%	1.1%	0.4%	0.3%	0.6%
Loss of Supply – Transmission	36	19	6	20	24	3.6%	2.9%	0.9%	2.9%	3.1%
Total	**1,007**	**651**	**683**	**699**	**779**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Table 4 Five Years of Sustained Interruption Event Causes

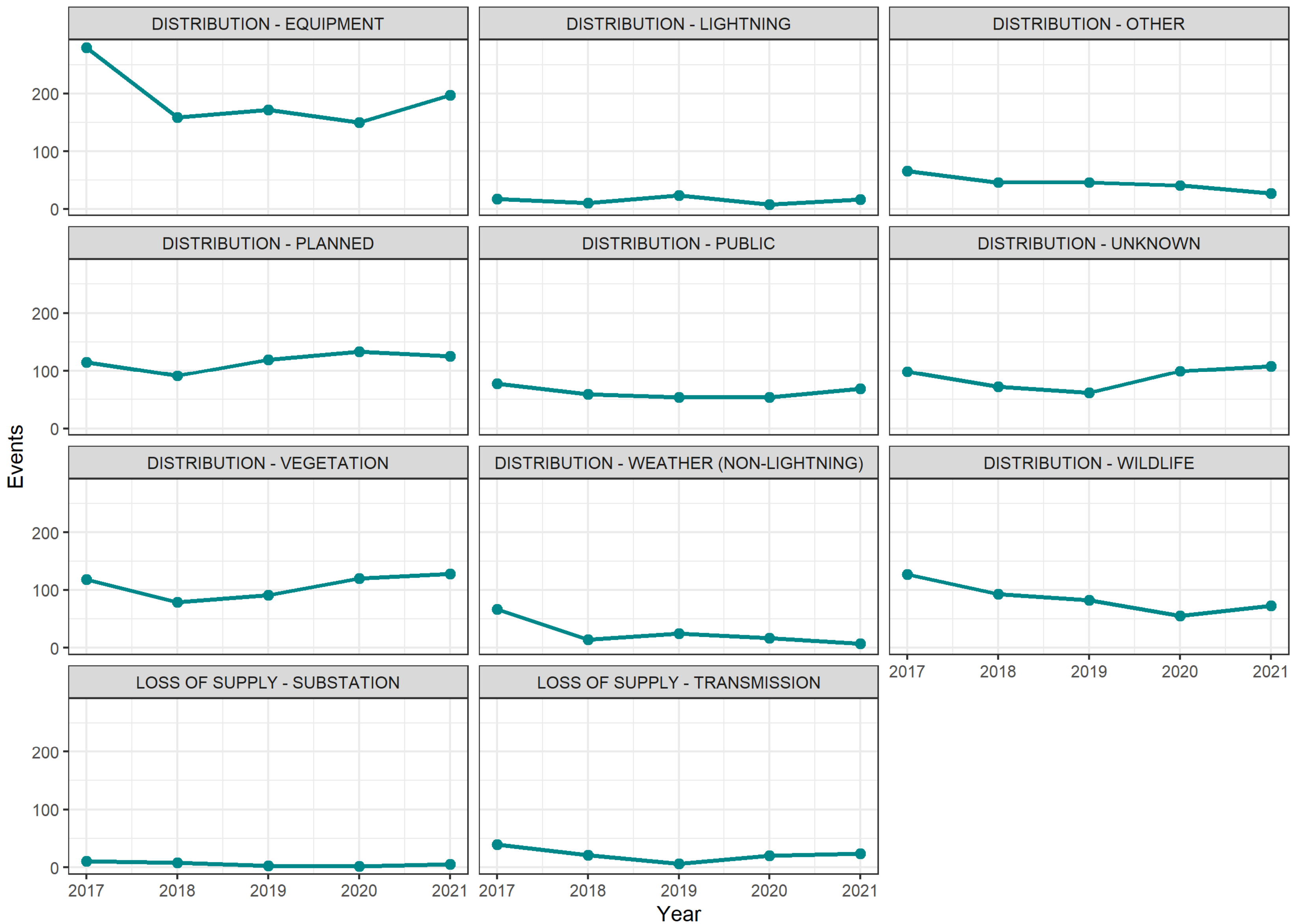


Figure 4 Five Years of Sustained Interruption Events by Cause

Cause	Events	Hours Out	Event Ranking	Hours Out Ranking
Distribution – Equipment	197	678	1	2
Distribution – Lightning	16	79	9	8
Distribution – Other	27	71	7	9
Distribution – Planned	125	3,029	3	1
Distribution – Public	69	246	6	5
Distribution – Unknown	108	445	4	4
Distribution – Vegetation	128	506	2	3
Distribution – Weather (non-Lightning)	7	21	10	10
Distribution – Wildlife	73	172	5	6
Loss of Supply – Substation	5	20	11	11
Loss of Supply – Transmission	24	85	8	7
Total	**779**	**5,361**		

Table 5 2021 Sustained Interruption Event Cause Ranking

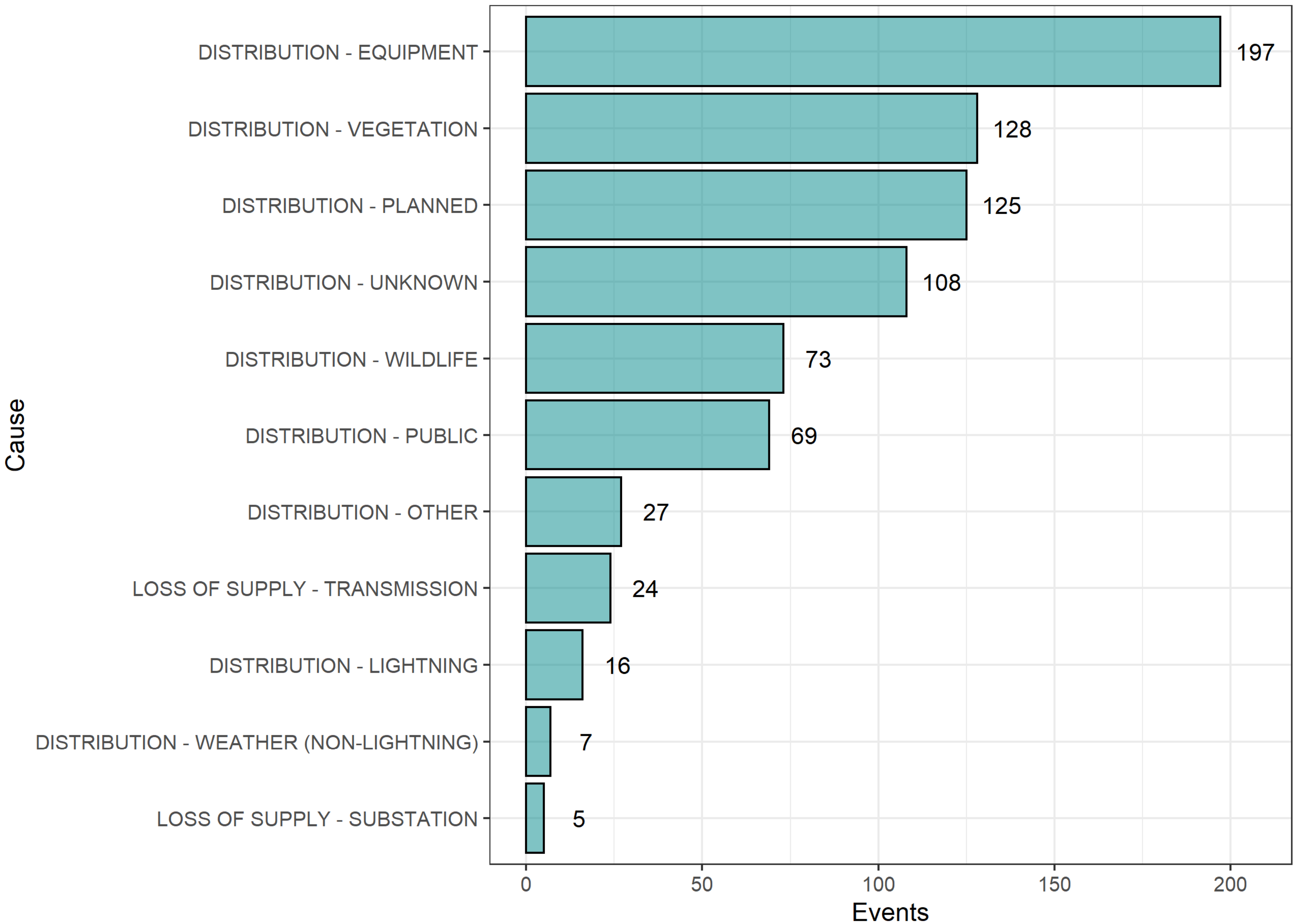


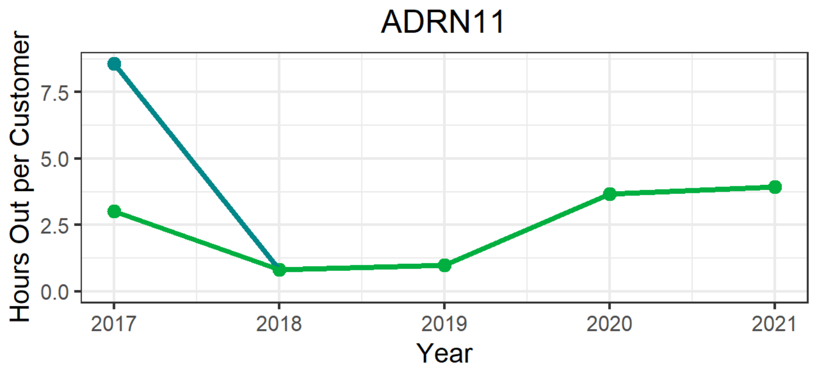
Figure 5 2021 Ranking of Sustained Interruption Event Causes

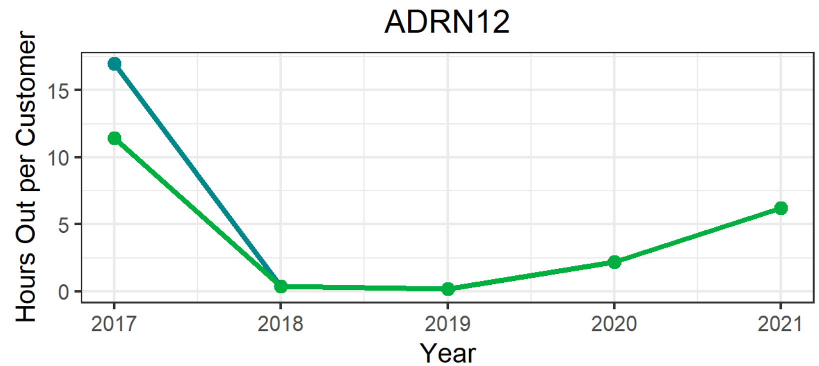
CIRCUIT SAIDI, SAIFI AND MAIFI$_E$

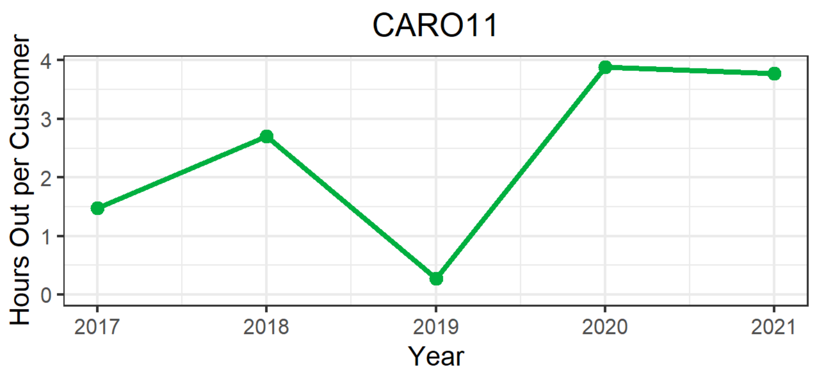
Five Years of Circuit SAIDI

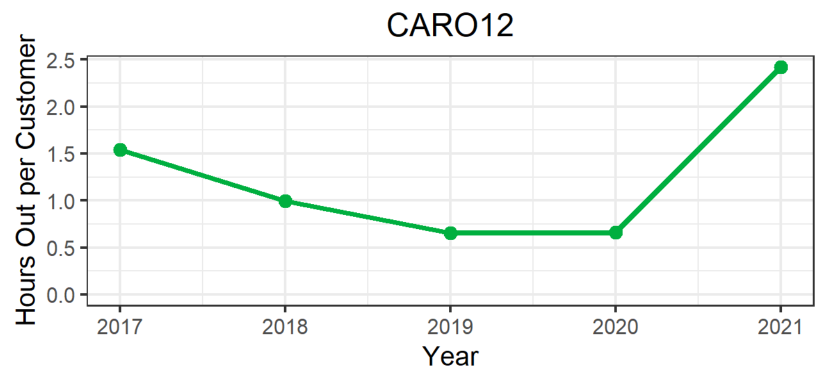
Circuit	2017	2018	2019	2020	2021	2021 MedEx
ADRN11	8.60	0.83	0.99	3.68	3.93	3.93
ADRN12	17.14	0.41	0.19	2.19	6.21	6.21
CARO11	1.49	2.70	0.28	3.89	3.78	3.78
CARO12	1.56	0.99	0.65	0.66	2.42	2.42
CARO13	0.17	0.13	0.16	0.86	4.71	4.71
CWVY11	0.74	16.00	5.93	11.00	1.96	1.96
CWVY12	7.78	10.77	59.83	10.99	8.55	8.55
DRKE11	8.44	0.48	3.70	2.93	2.35	2.35
DUKE11	1.34	1.90	0.11	0.00	8.18	8.18
DWSY11	15.18	15.68	1.94	13.44	20.21	20.21
ESTN11	13.21	15.40	1.27	11.40	36.14	36.14
HCSU11	0.00	0.00	0.00	0.00	0.00	0.00
HFWY11	2.94	2.60	6.70	7.36	2.58	2.58
HFWY12	4.50	7.87	6.20	7.84	0.86	0.86
HGTN11	0.21	0.01	6.00	3.88	1.06	1.06
HGTN12	0.47	0.03	0.13	3.06	0.52	0.52
HMDL12	2.32	1.67	12.11	1.43	5.10	5.10
HOLY11	1.23	0.09	0.43	0.86	0.85	0.85
HOLY12	7.60	0.41	1.72	0.92	0.64	0.64
HOLY13	0.19	1.35	3.69	1.08	1.35	1.35
HOLY14	NA	NA	1.33	0.00	0.00	0.00
HOPE11	1.87	3.32	1.36	6.11	6.46	6.46
HRPR11	8.10	2.03	3.66	14.32	15.33	15.33
HRPR12	21.23	6.02	4.54	9.70	25.32	25.32
JMSN11	0.60	2.24	6.41	3.50	2.09	2.09
JMSN12	2.07	1.10	1.18	2.15	4.34	4.34
JNTA11	6.65	3.93	1.31	10.89	20.88	20.88
JNTA12	7.56	4.73	1.33	12.08	34.56	34.56
JNVY11	11.30	2.59	0.17	17.02	0.09	0.09
JNVY12	10.75	1.70	0.10	16.29	2.64	2.64
JNVY31	14.50	3.37	6.40	19.07	13.73	13.73
LIME11	27.62	5.65	1.47	6.87	2.92	2.92
MRBT41	11.96	2.78	2.61	4.15	5.28	5.28
MRBT42	1.54	2.65	1.78	0.00	6.29	6.29
NYSA11	0.37	0.21	3.23	0.10	1.42	1.42
NYSA12	6.95	1.87	1.12	0.20	3.49	3.49
NYSA13	0.27	0.22	0.77	1.71	0.72	0.72
NYSA14	0.12	0.22	1.21	0.31	2.14	2.14
NYSA15	0.00	0.00	0.00	0.00	329.78	329.78
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OIDA11	1.12	0.78	1.73	2.77	3.05	3.05
OIDA12	2.80	0.00	5.58	0.00	0.00	0.00
ONTO14	0.54	0.00	0.04	0.00	0.00	0.00
ONTO18	0.12	1.48	0.55	0.03	0.32	0.32
ONTO19	0.69	2.05	0.59	0.55	2.52	2.52
ONTO20	0.64	0.51	0.63	0.98	0.54	0.54
ONTO23	4.07	0.28	0.00	0.00	1.23	1.23
ONTO24	5.23	11.00	2.13	0.48	1.94	1.94
ONTO25	0.37	0.12	1.50	0.03	0.11	0.11
OYDM11	3.48	0.28	2.97	0.00	3.87	3.87
PNCK11	0.26	0.69	1.38	27.39	0.00	0.00
PNCK12	3.17	0.00	0.00	4.48	12.97	12.97
PRMA12	7.22	5.04	0.23	0.00	6.61	6.61
PRMA42	12.84	7.15	0.89	5.95	12.50	12.50
RKVL11	4.61	1.29	0.30	17.07	0.05	0.05
UNTY11	27.58	12.35	0.30	5.99	2.37	2.37
UNTY12	17.21	11.57	0.81	6.85	7.66	7.66
VALE11	1.09	0.92	0.33	0.10	4.10	4.10
VALE12	1.07	0.15	0.00	0.00	0.70	0.70
VALE13	3.68	0.69	0.34	3.42	3.15	3.15
VALE14	2.93	6.49	0.31	3.14	1.68	1.68
VALE15	1.82	2.72	0.26	0.48	1.18	1.18
WESR13	3.21	1.89	1.37	1.04	5.26	5.26
WESR14	12.55	6.98	1.62	1.71	8.70	8.70

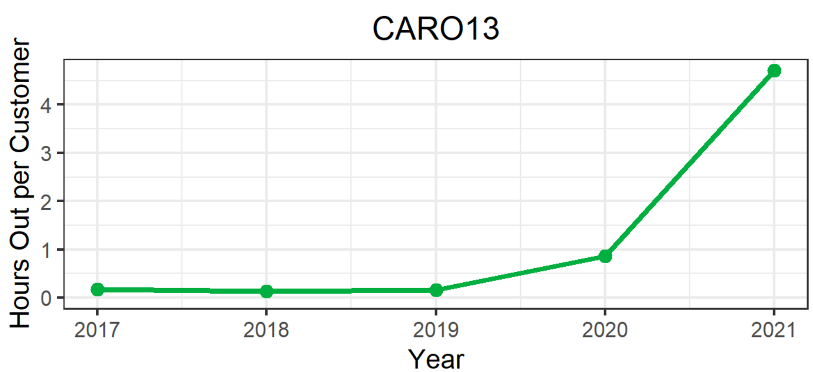
Table 6 Five Years of Circuit SAIDI

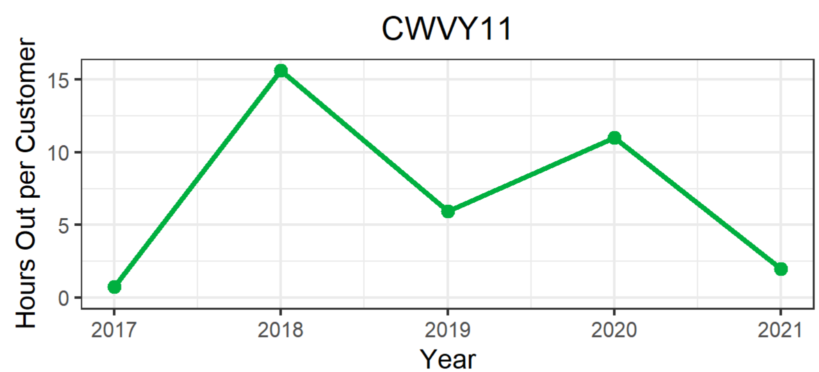

ADRN11
Hours Out per Customer
0.0
2.5
5.0
7.5
2017
2018
2019
2020
2021
Year

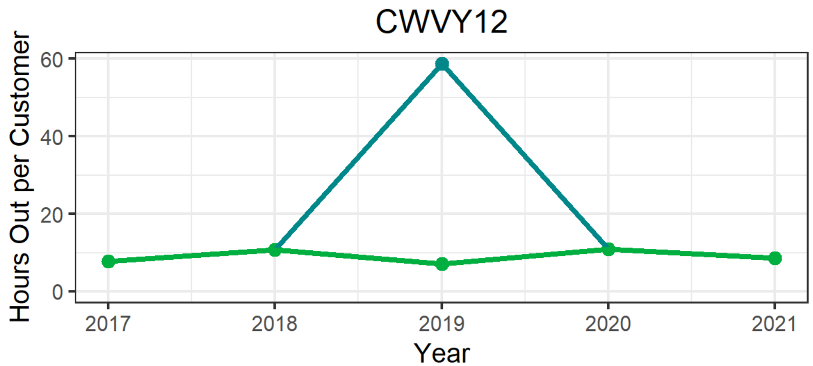

ADRN12
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

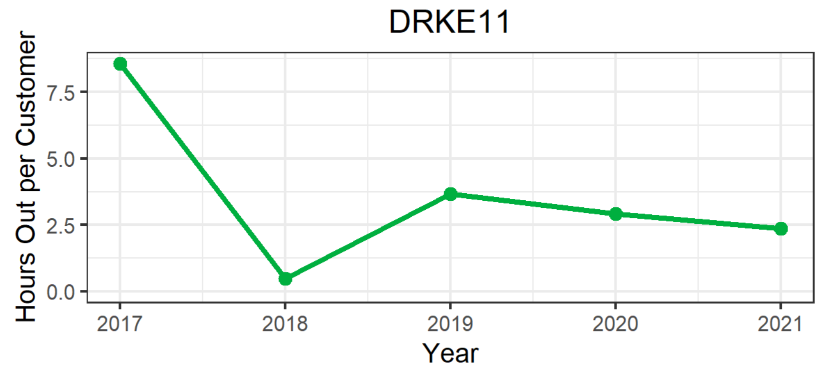

CARO11
Hours Out per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

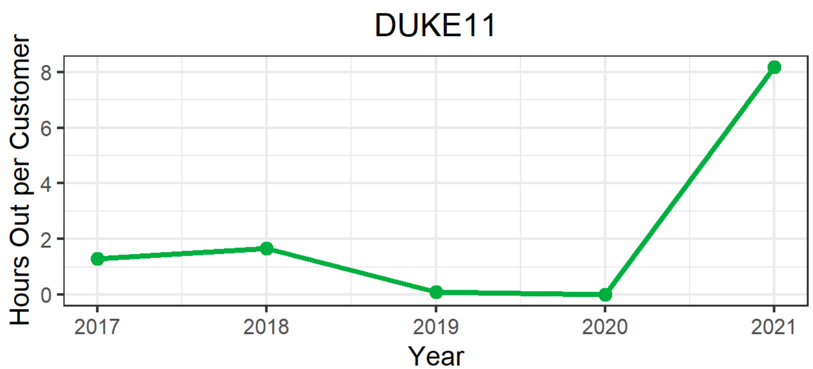

CARO12
Hours Out per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2017
2018
2019
2020
2021
Year

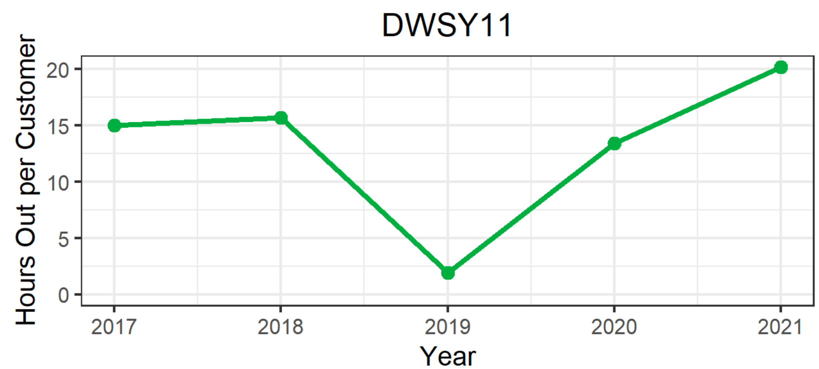

CARO13
Hours Out per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

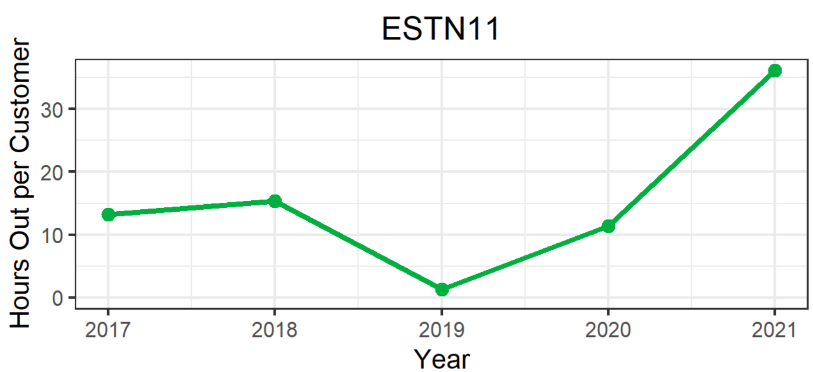

CWVY11
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

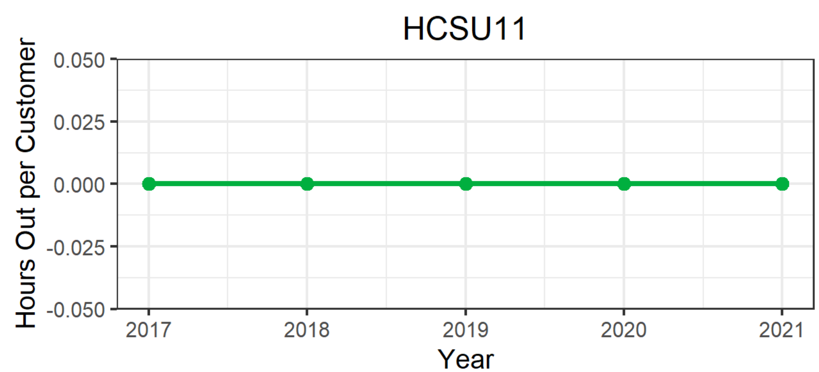

CWVY12
Hours Out per Customer
60
40
20
0
2017
2018
2019
2020
2021
Year

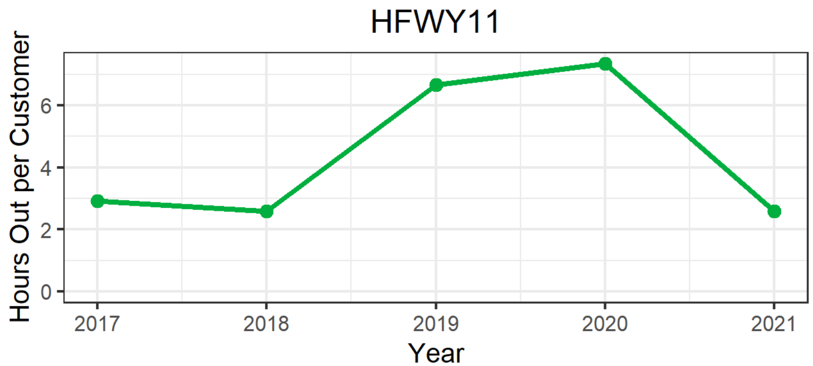

DRKE11
Hours Out per Customer
7.5
5.0
2.5
0.0
2017
2018
2019
2020
2021
Year

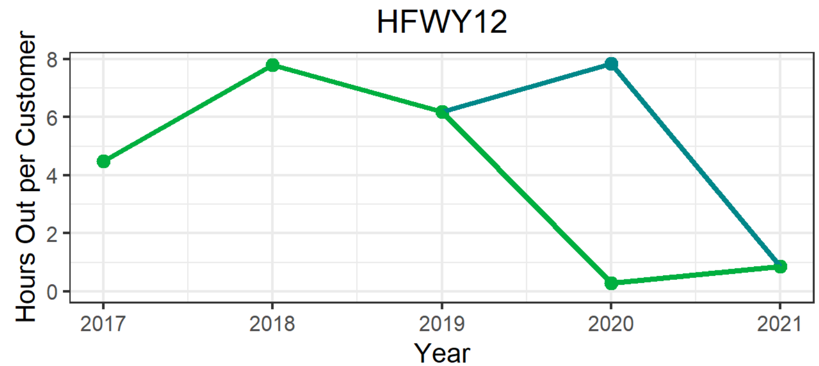

DUKE11
Hours Out per Customer
8
6
4
2
0
2017
2018
2019
2020
2021
Year

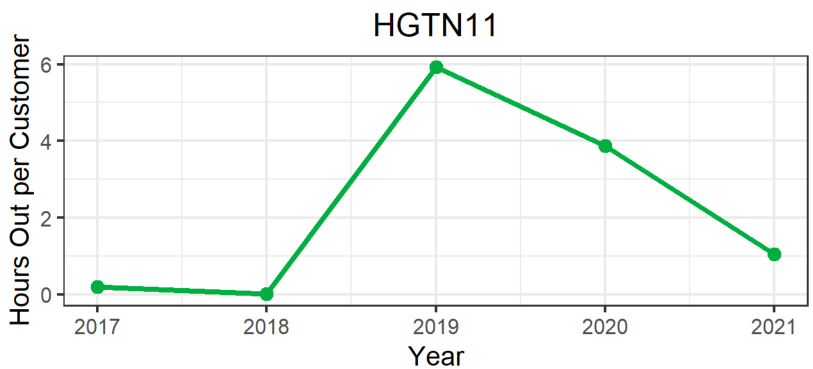

DWSY11
Hours Out per Customer
20
15
10
5
0
2017
2018
2019
2020
2021
Year

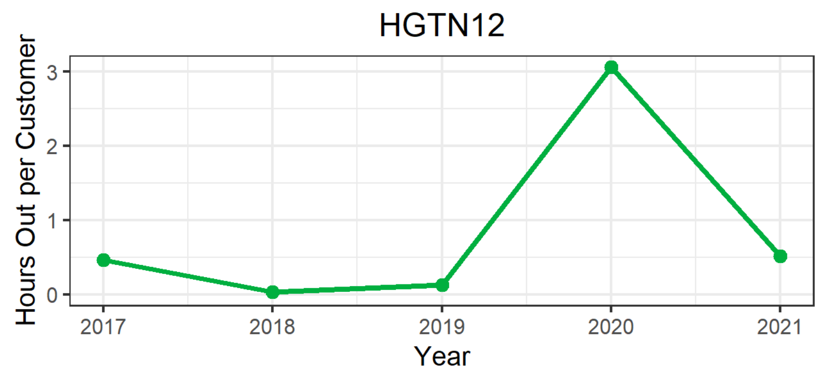

ESTN11
Hours Out per Customer
30
20
10
0
2017
2018
2019
2020
2021
Year

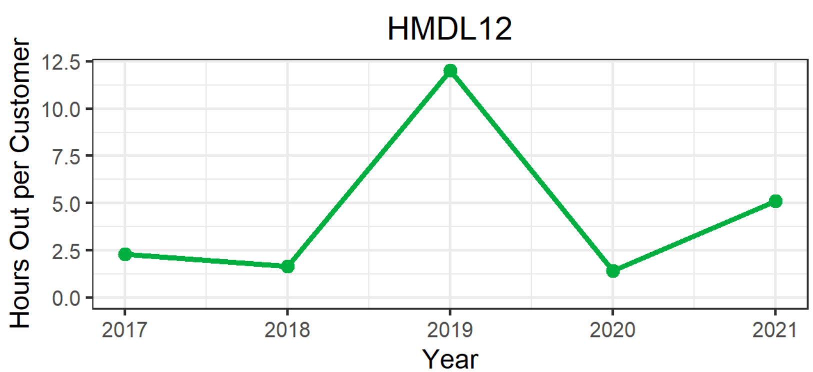

HCSU11
Hours Out per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

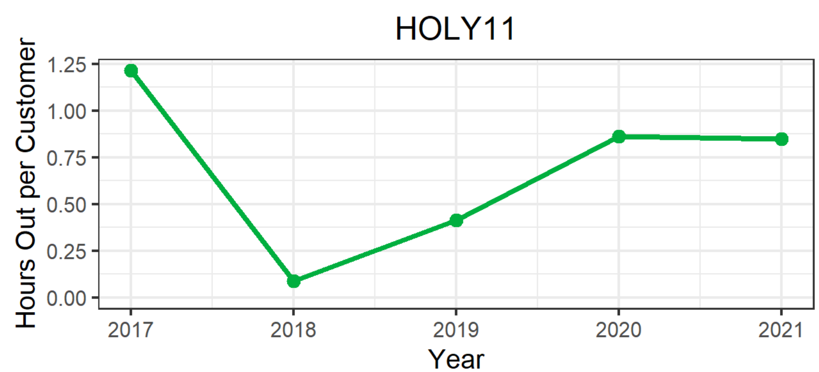

HFWY11
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

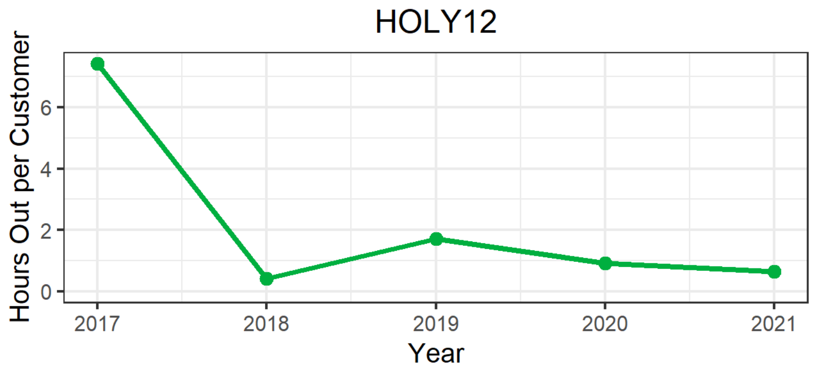

HFWY12
Hours Out per Customer
0
2
4
6
8
2017
2018
2019
2020
2021
Year

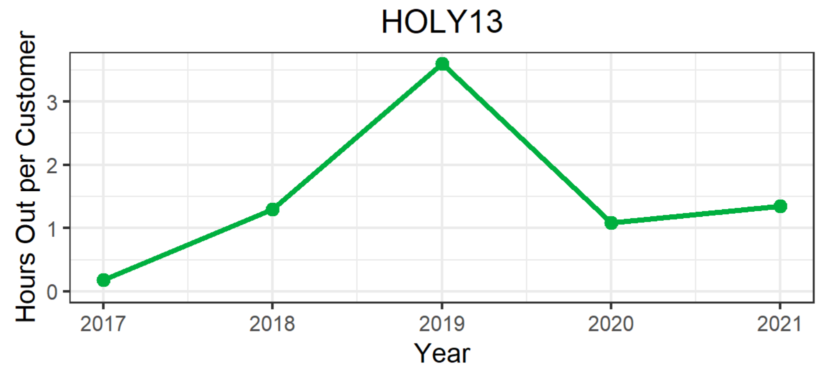

HGTN11
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

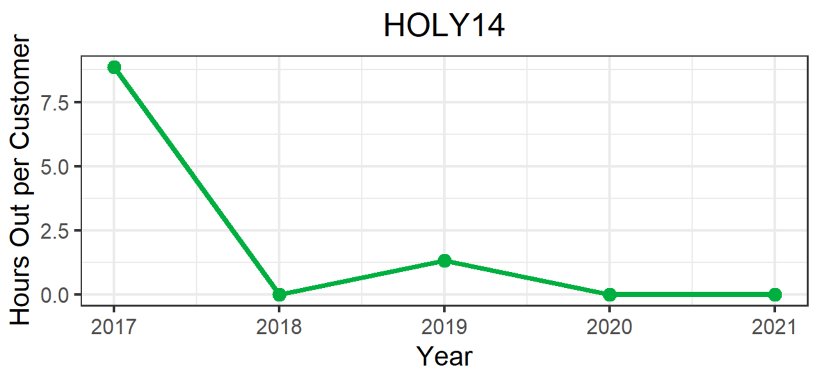

HGTN12
Hours Out per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

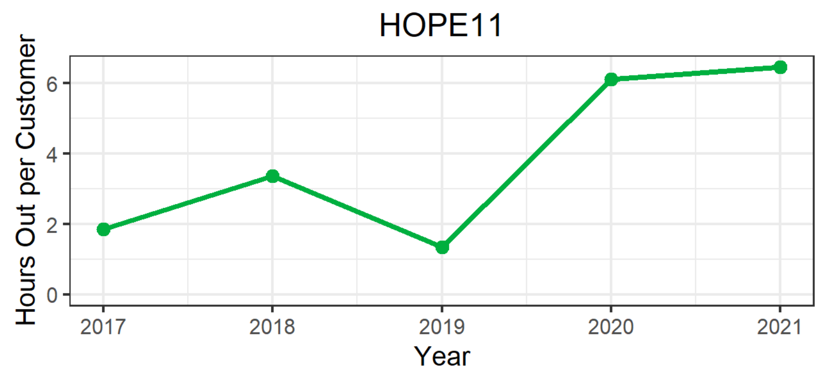

HMDL12
Hours Out per Customer
0.0
2.5
5.0
7.5
10.0
12.5
2017
2018
2019
2020
2021
Year

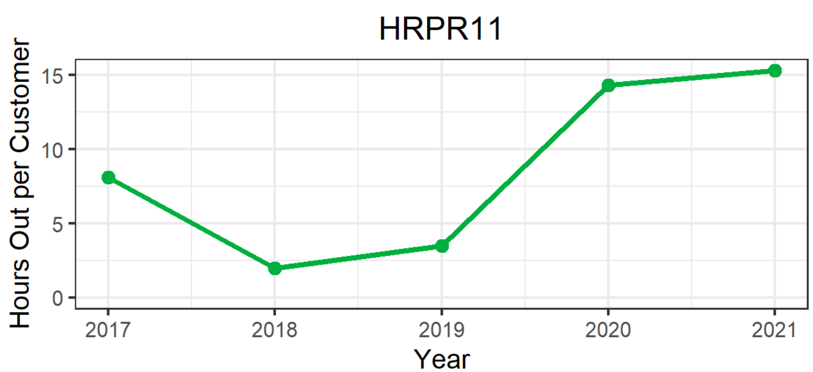

HOLY11
Hours Out per Customer
0.00
0.25
0.50
0.75
1.00
1.25
2017
2018
2019
2020
2021
Year

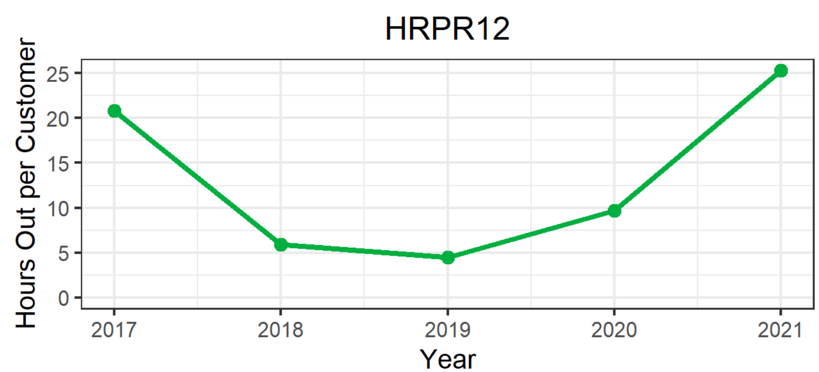

HOLY12
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

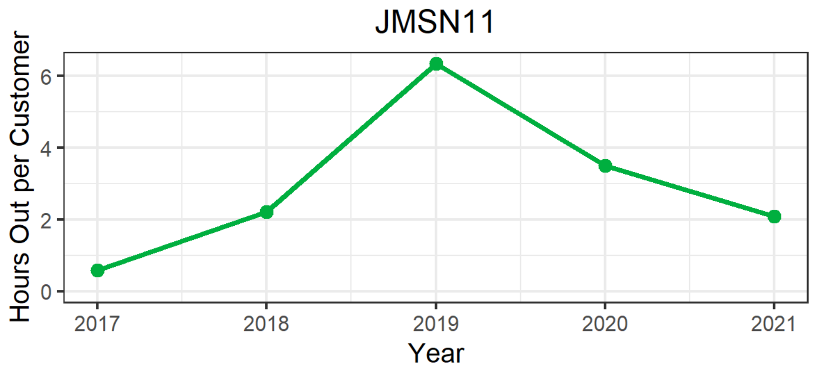

HOLY13
Hours Out per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

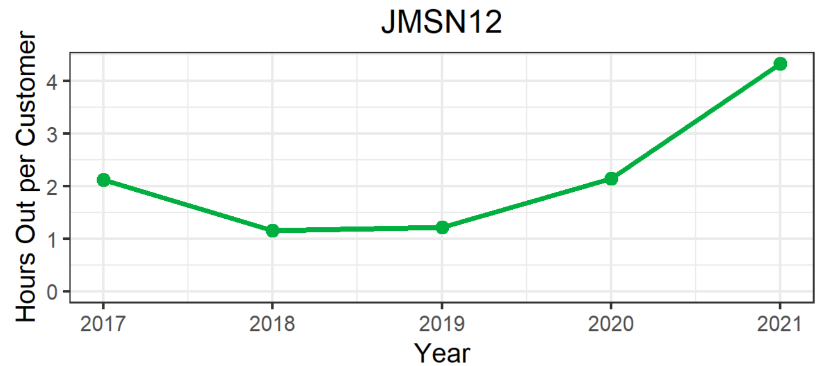

HOLY14
Hours Out per Customer
0.0
2.5
5.0
7.5
2017
2018
2019
2020
2021
Year

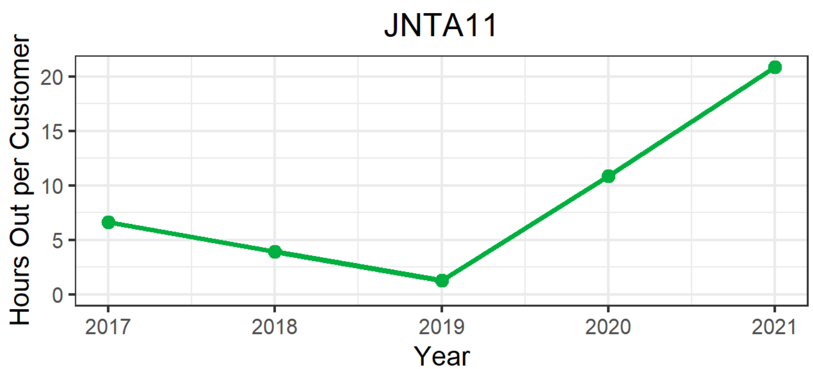

HOPE11
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

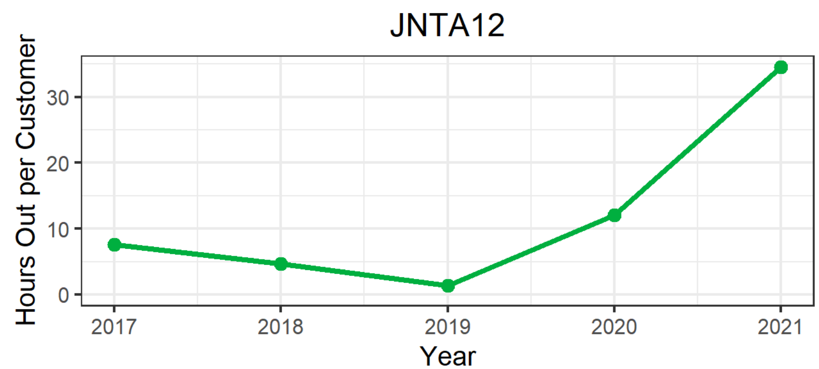

HRPR11
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

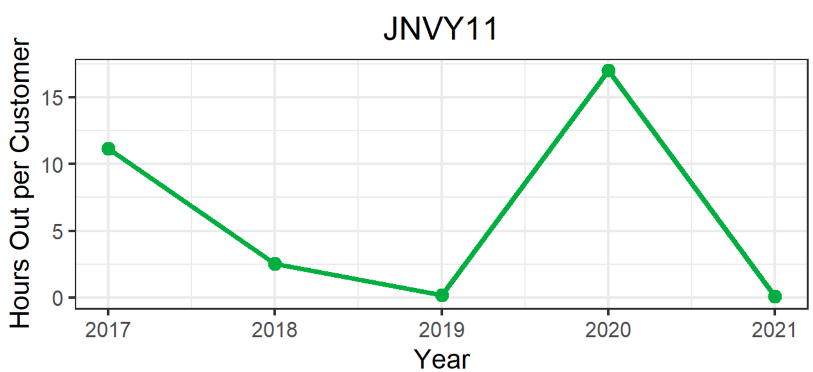

HRPR12
Hours Out per Customer
0
5
10
15
20
25
2017
2018
2019
2020
2021
Year

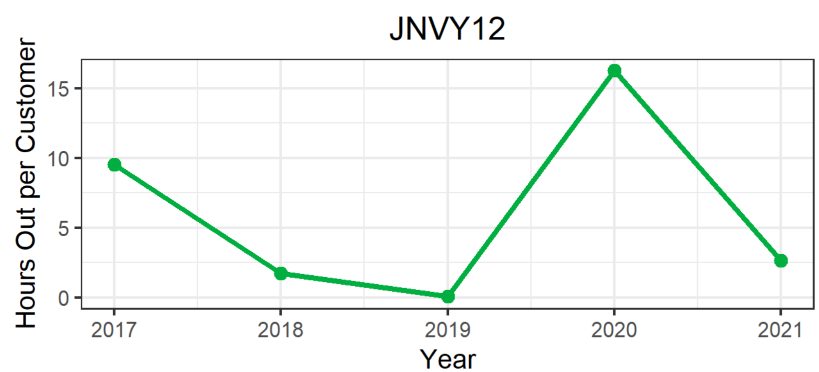

JMSN11
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

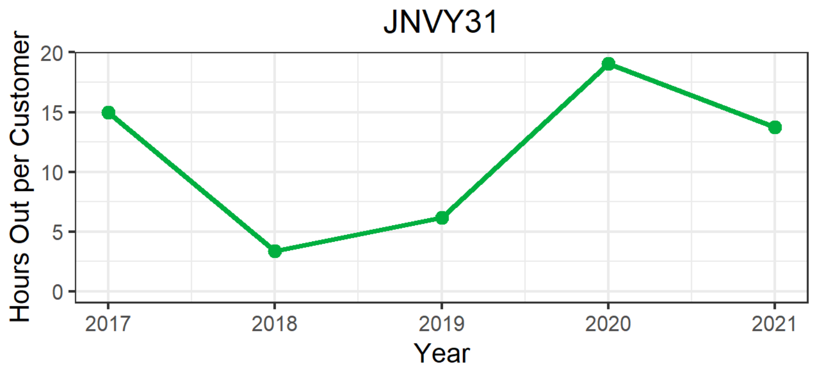

JMSN12
Hours Out per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

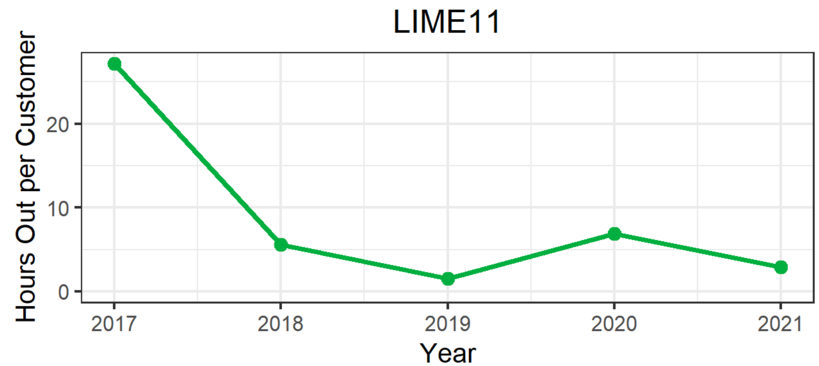

JNTA11
Hours Out per Customer
0
5
10
15
20
2017
2018
2019
2020
2021
Year

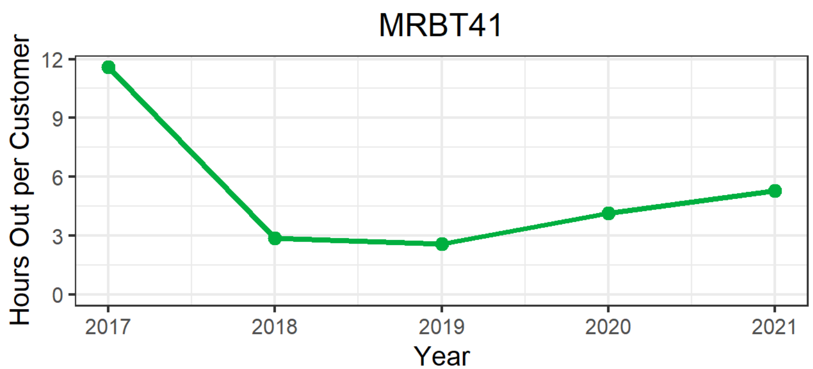

JNTA12
Hours Out per Customer
0
10
20
30
2017
2018
2019
2020
2021
Year

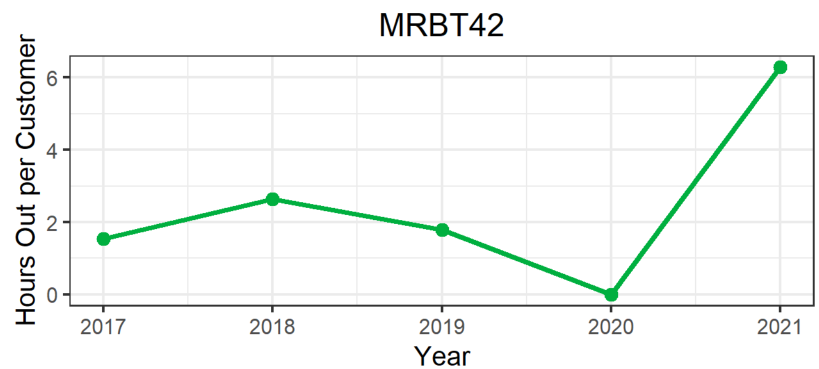

JNVY11
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

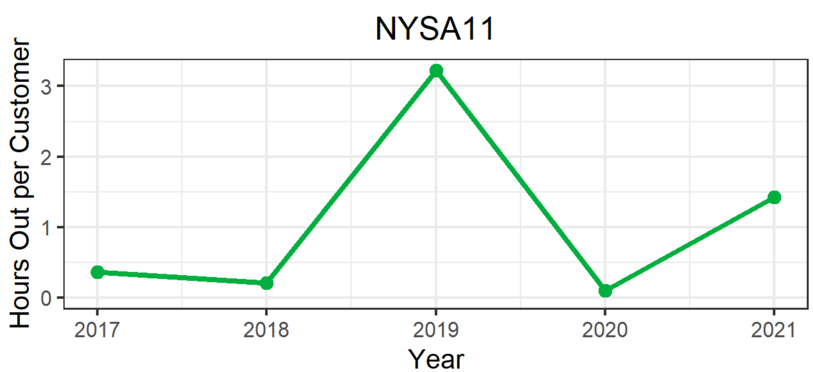

JNVY12
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

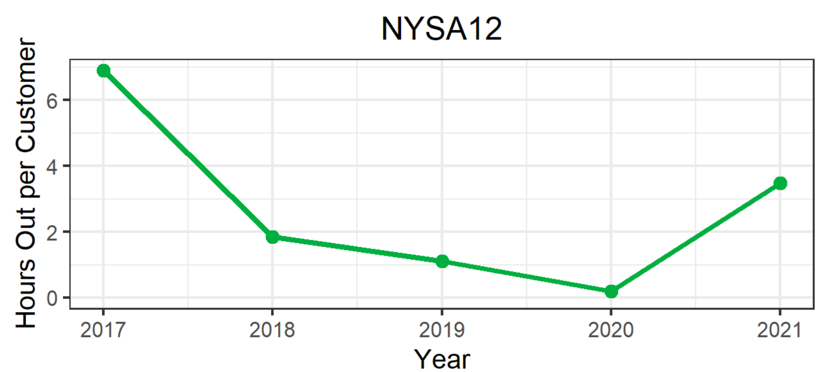

JNVY31
Hours Out per Customer
0
5
10
15
20
2017
2018
2019
2020
2021
Year

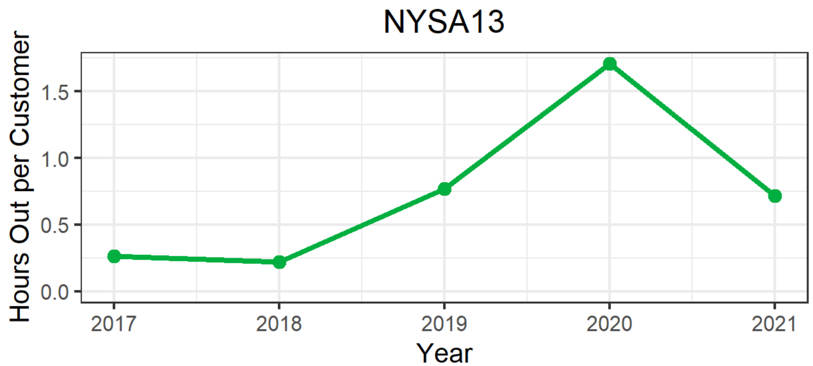

LIME11
Hours Out per Customer
0
10
20
2017
2018
2019
2020
2021
Year

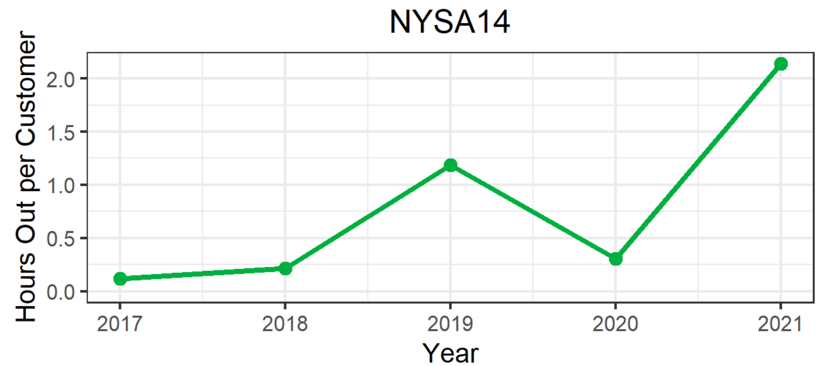

MRBT41
Hours Out per Customer
0
3
6
9
12
2017
2018
2019
2020
2021
Year

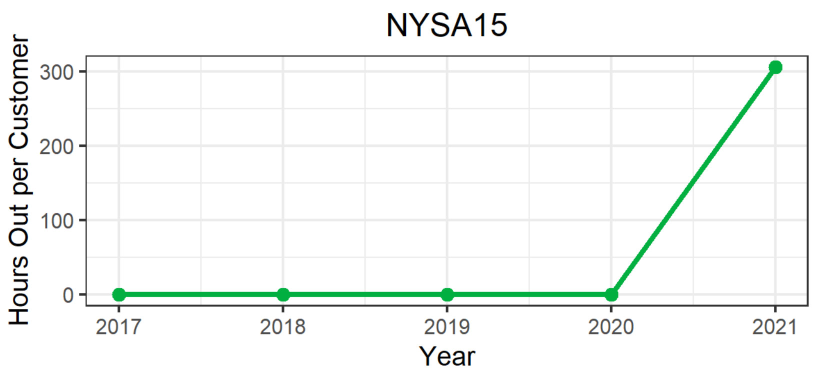

MRBT42
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

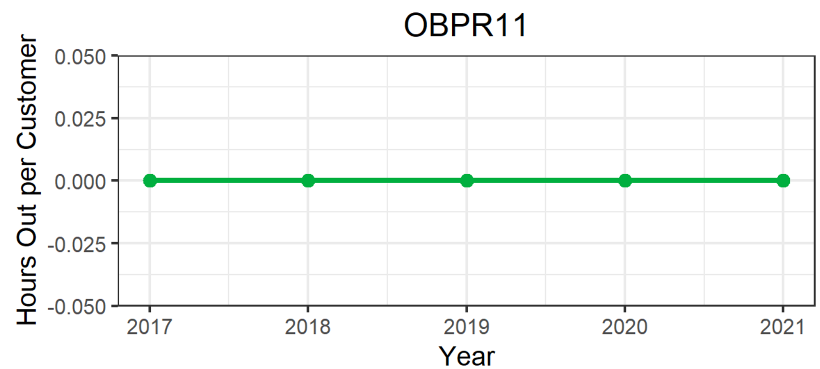

NYSA11
Hours Out per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

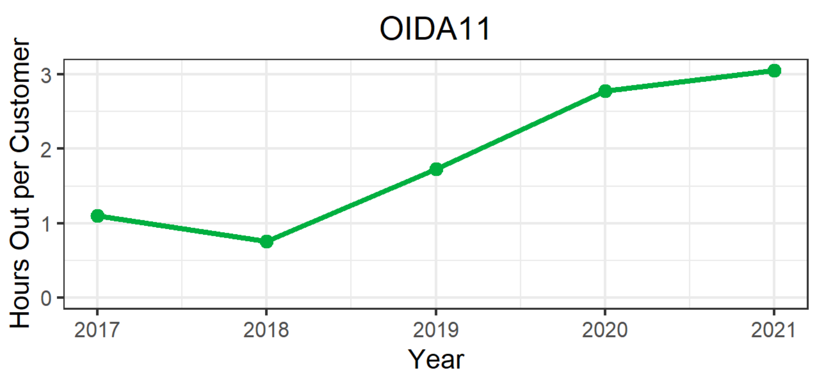

NYSA12
Hours Out per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

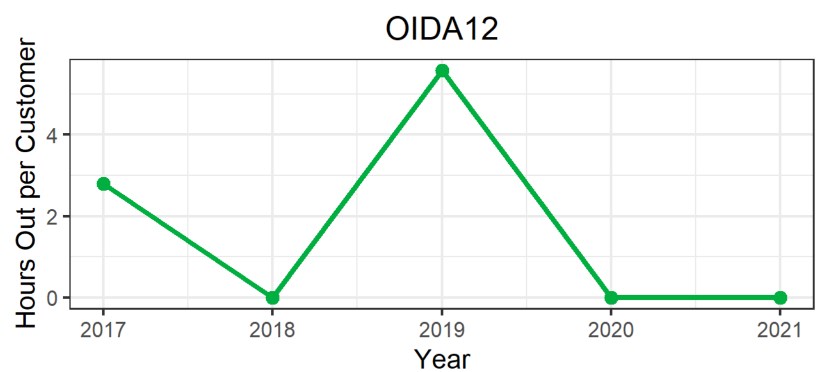

NYSA13
Hours Out per Customer
0.0
0.5
1.0
1.5
2017
2018
2019
2020
2021
Year

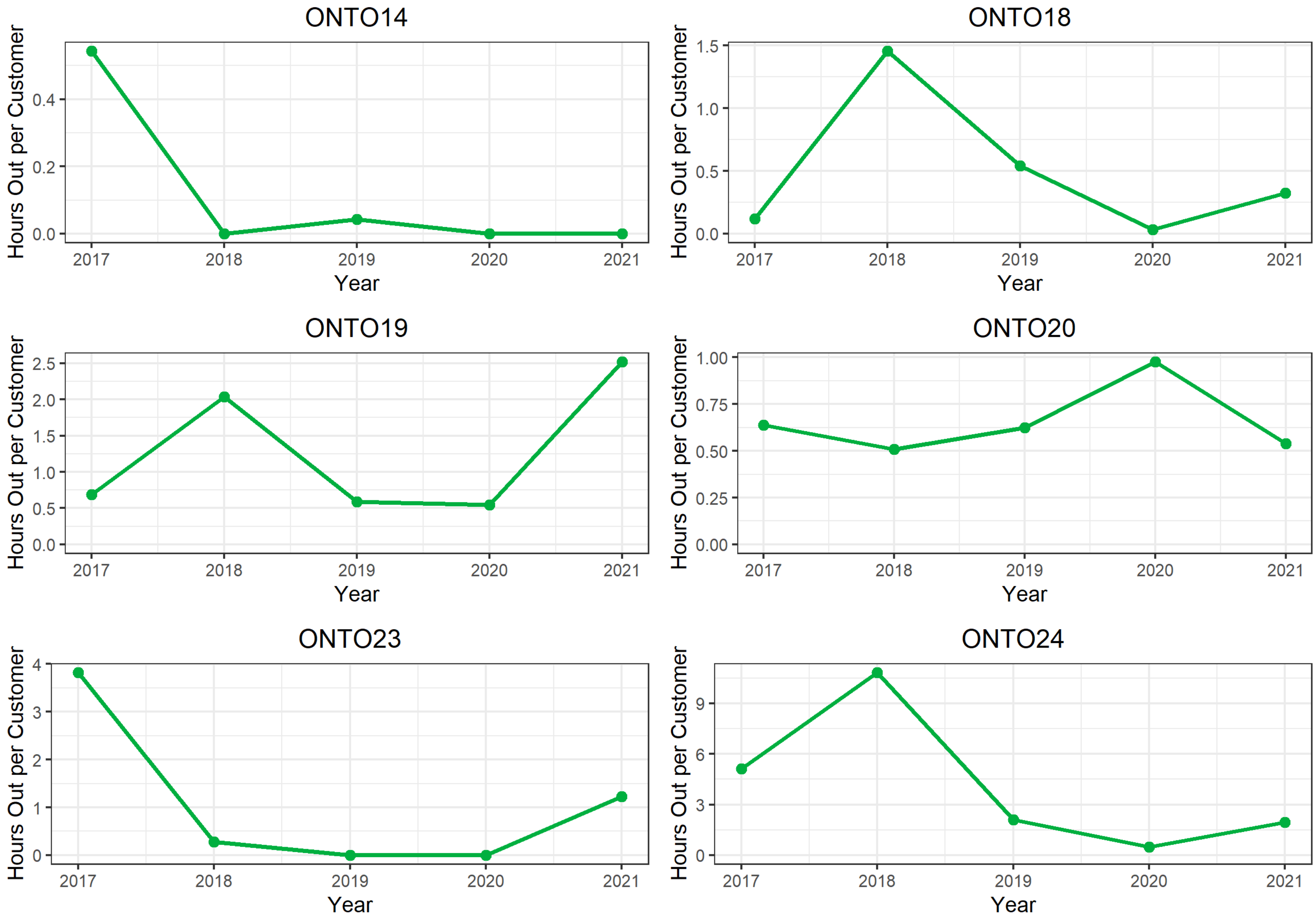

NYSA14
Hours Out per Customer
0.0
0.5
1.0
1.5
2.0
2017
2018
2019
2020
2021
Year

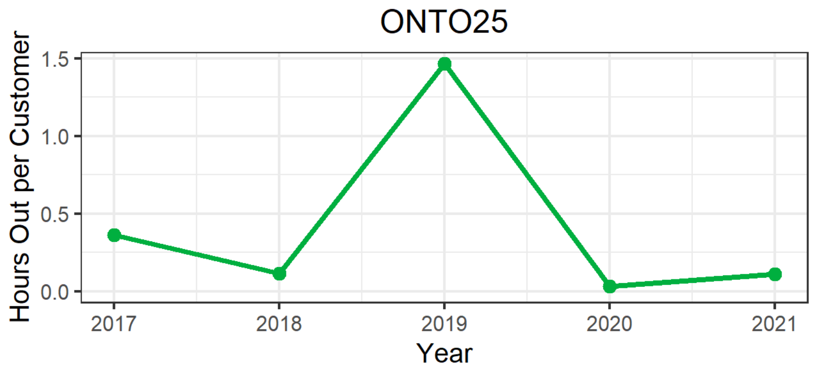

NYSA15
Hours Out per Customer
0
100
200
300
2017
2018
2019
2020
2021
Year

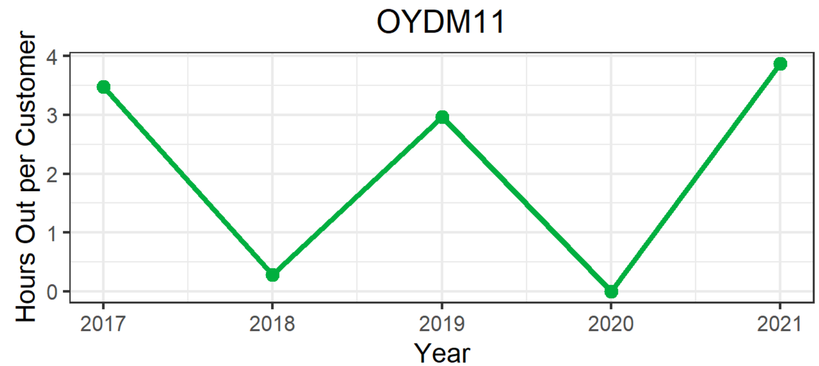

OBPR11
Hours Out per Customer
-0.050
-0.025
0.000
0.025
0.050
2017
2018
2019
2020
2021
Year

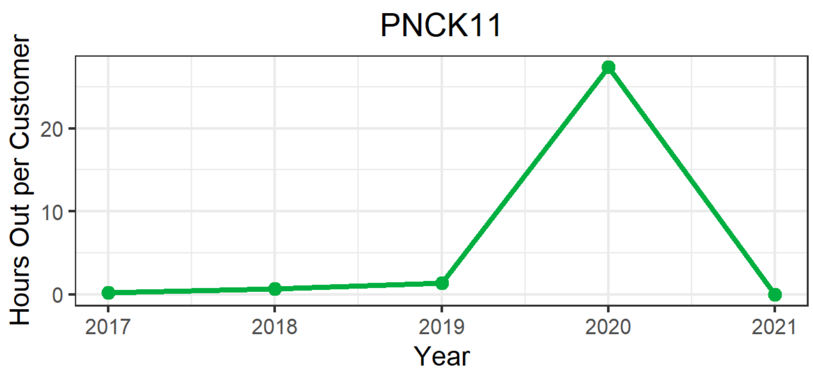

OIDA11
Hours Out per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

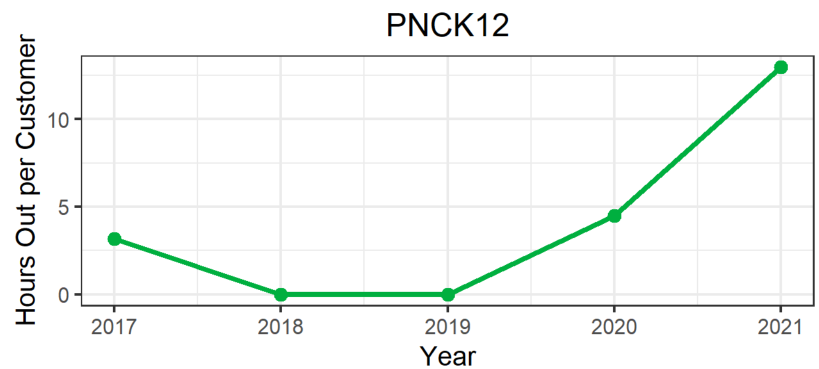

OIDA12
Hours Out per Customer
0
2
4
2017
2018
2019
2020
2021
Year

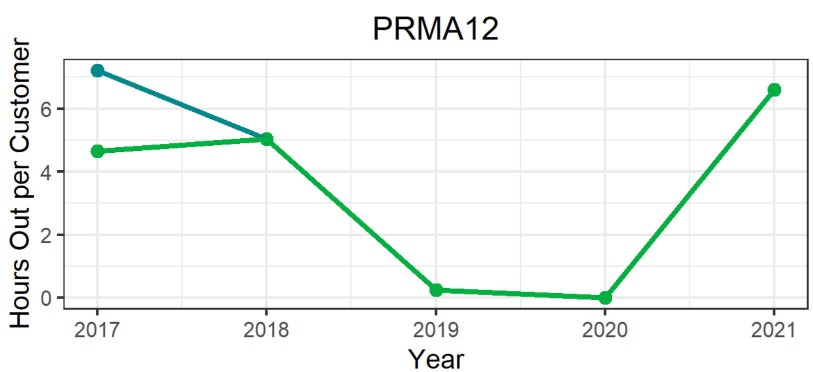

ONTO14
Hours Out per Customer
0.0
0.2
0.4
2017
2018
2019
2020
2021
Year
ONTO18
Hours Out per Customer
0.0
0.5
1.0
1.5
2017
2018
2019
2020
2021
Year
ONTO19
Hours Out per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2017
2018
2019
2020
2021
Year
ONTO20
Hours Out per Customer
0.00
0.25
0.50
0.75
1.00
2017
2018
2019
2020
2021
Year
ONTO23
Hours Out per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year
ONTO24
Hours Out per Customer
0
3
6
9
2017
2018
2019
2020
2021
Year

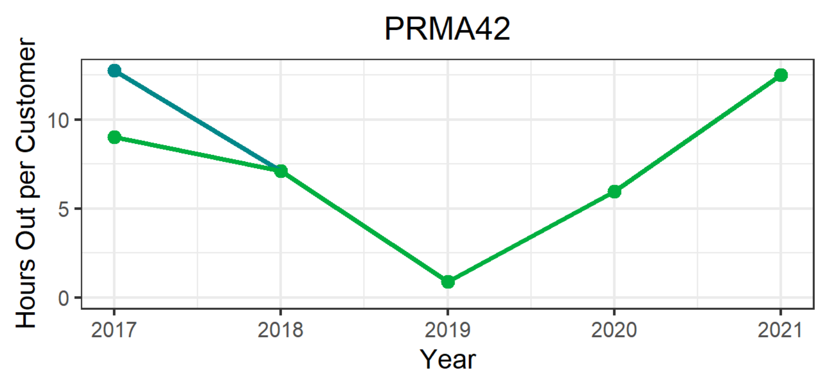

ONTO25
Hours Out per Customer
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

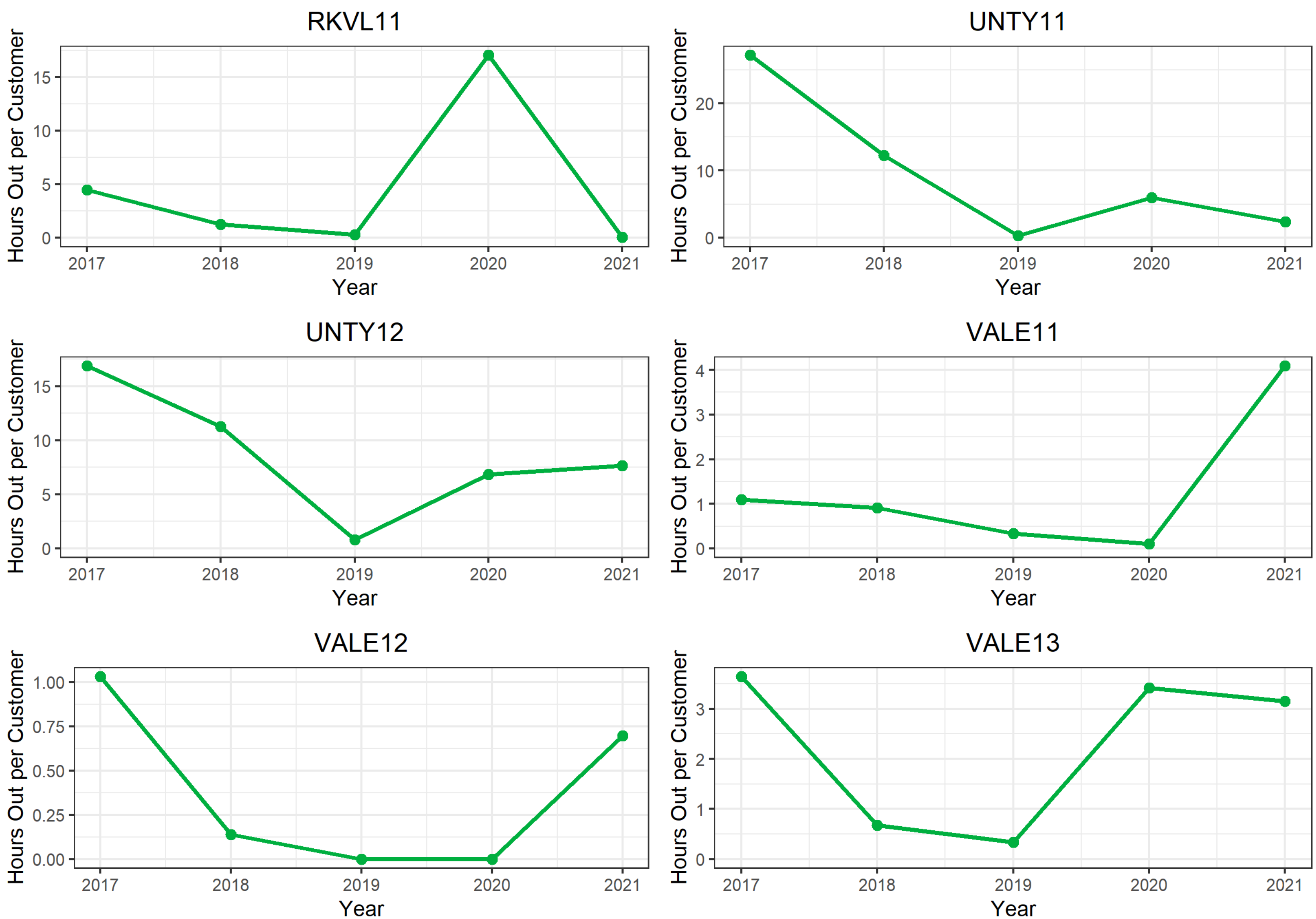

OYDM11
Hours Out per Customer
4
3
2
1
0
2017
2018
2019
2020
2021
Year


PNCK11
Hours Out per Customer
20
10
0
2017
2018
2019
2020
2021
Year


PNCK12
Hours Out per Customer
10
5
0
2017
2018
2019
2020
2021
Year


PRMA12
Hours Out per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year


PRMA42
Hours Out per Customer
10
5
0
2017
2018
2019
2020
2021
Year


RKVL11
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year
UNTY11
Hours Out per Customer
0
10
20
2017
2018
2019
2020
2021
Year
UNTY12
Hours Out per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year
VALE11
Hours Out per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year
VALE12
Hours Out per Customer
0.00
0.25
0.50
0.75
1.00
2017
2018
2019
2020
2021
Year
VALE13
Hours Out per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

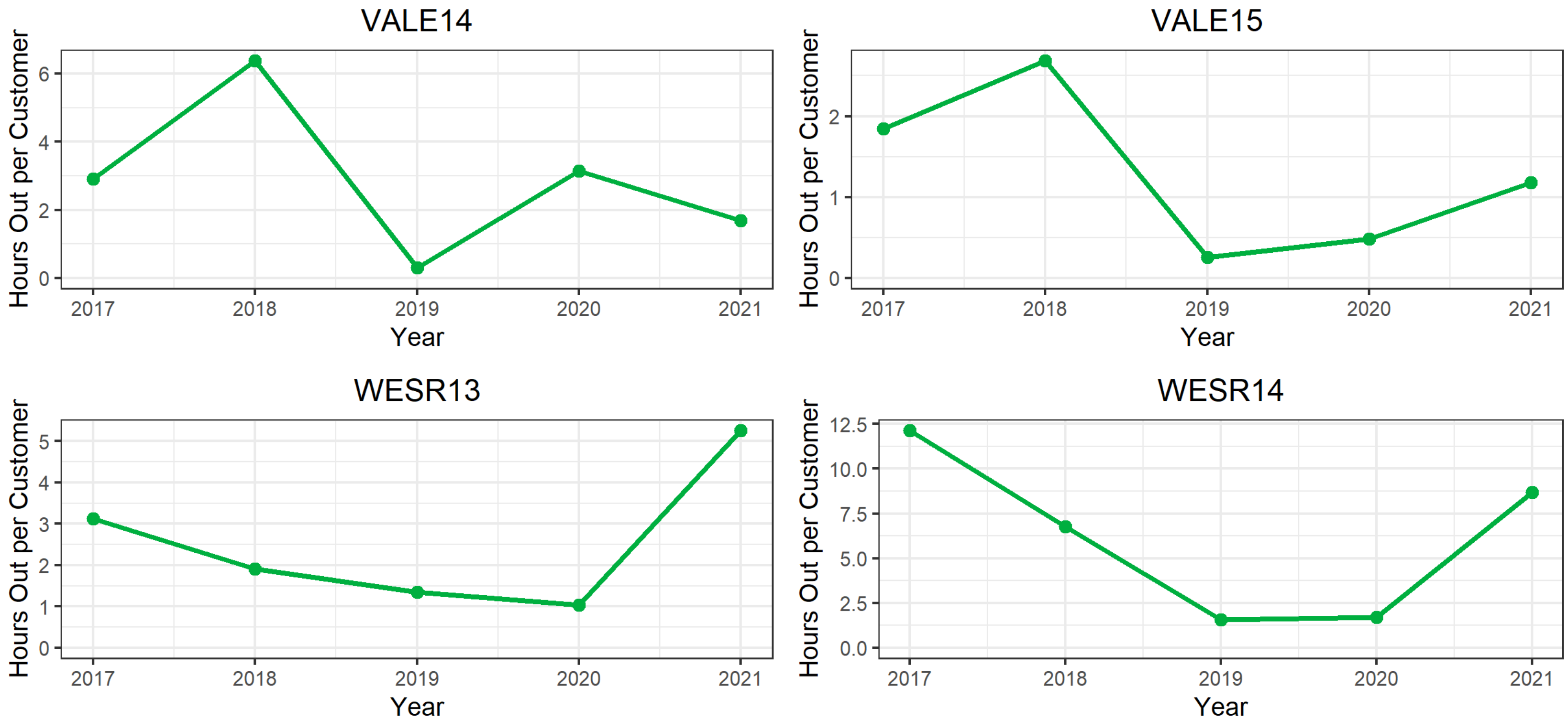
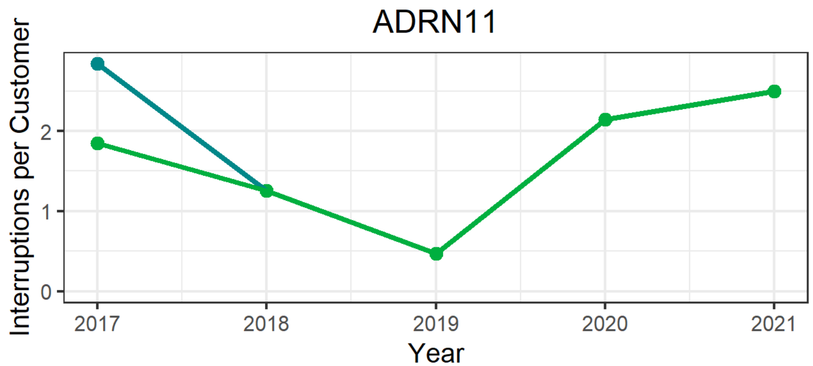


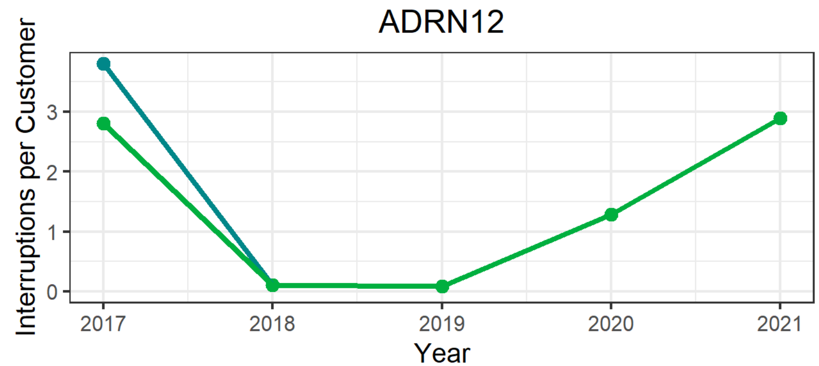
Figure 6 Five Years of Circuit SAIDI

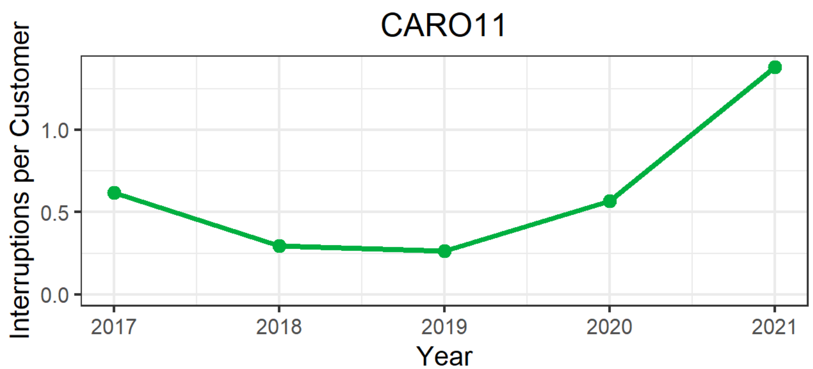
Five Years of Circuit SAIFI

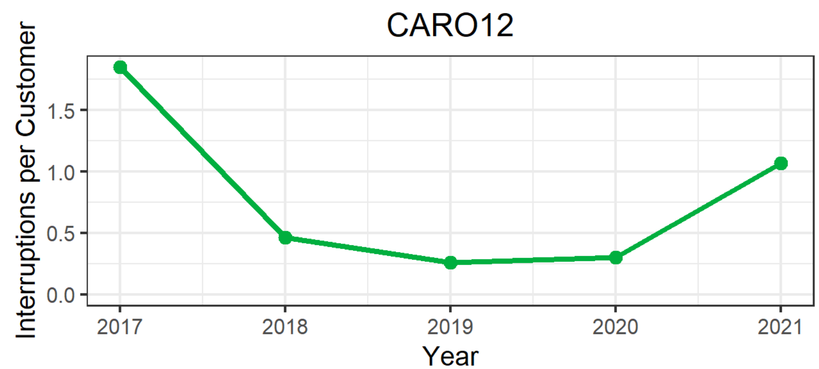
Circuit	2017	2018	2019	2020	2021	2021 MedEx
ADRN11	2.85	1.29	0.48	2.14	2.49	2.49
ADRN12	3.84	0.11	0.08	1.29	2.90	2.90
CARO11	0.62	0.30	0.27	0.57	1.38	1.38
CARO12	1.87	0.46	0.26	0.30	1.07	1.07
CARO13	0.11	0.06	0.10	1.04	3.14	3.14
CWVY11	1.20	2.14	1.02	2.17	2.05	2.05
CWVY12	1.27	1.13	1.74	2.15	3.73	3.73
DRKE11	2.46	0.18	1.27	1.25	0.52	0.52
DUKE11	1.48	1.04	0.04	0.00	3.00	3.00
DWSY11	2.87	4.63	1.16	4.06	3.14	3.14
ESTN11	4.67	5.00	1.00	4.00	7.00	7.00
HCSU11	0.00	0.00	0.00	0.00	0.00	0.00
HFWY11	1.71	1.23	1.46	1.39	0.52	0.52
HFWY12	2.36	2.32	1.46	1.13	0.85	0.85
HGTN11	0.34	0.01	1.65	1.06	0.40	0.40
HGTN12	0.24	0.01	0.08	1.06	0.15	0.15
HMDL12	1.64	1.13	4.89	1.17	2.12	2.12
HOLY11	0.26	0.08	0.17	0.47	0.39	0.39
HOLY12	1.43	0.24	1.10	0.38	0.15	0.15
HOLY13	0.11	1.37	0.30	0.61	0.59	0.59
HOLY14	NA	NA	1.20	0.00	0.00	0.00
HOPE11	1.28	1.57	1.05	1.32	3.75	3.75
HRPR11	1.49	1.10	1.47	4.42	5.18	5.18
HRPR12	3.21	1.04	1.91	3.68	5.86	5.86
JMSN11	0.37	1.23	0.34	1.88	2.24	2.24
JMSN12	1.16	1.07	0.33	1.12	2.29	2.29
JNTA11	1.00	2.03	1.02	3.16	3.05	3.05
JNTA12	1.23	2.24	1.02	3.19	4.09	4.09
JNVY11	2.26	1.11	0.20	4.14	0.02	0.02
JNVY12	2.26	1.16	0.05	3.86	1.00	1.00
JNVY31	3.66	3.01	0.86	4.57	1.38	1.38
LIME11	2.44	1.46	0.53	2.33	1.05	1.05
MRBT41	1.22	2.15	1.59	2.03	1.09	1.09
MRBT42	1.00	3.00	1.55	0.00	1.27	1.27
NYSA11	0.19	0.18	1.44	0.05	0.76	0.76
NYSA12	3.21	1.33	1.24	1.02	2.39	2.39
NYSA13	0.16	0.15	0.34	0.78	0.30	0.30
NYSA14	0.05	0.14	1.29	0.23	1.38	1.38
NYSA15	0.00	0.00	0.00	0.00	1.85	1.85
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OIDA11	0.74	0.29	1.15	1.63	2.08	2.08
OIDA12	2.00	0.00	2.00	0.00	0.00	0.00
ONTO14	1.09	0.00	0.06	0.00	0.00	0.00
ONTO18	0.06	1.12	0.30	0.02	0.18	0.18
ONTO19	0.29	1.22	0.31	0.19	0.70	0.70
ONTO20	0.17	0.32	0.35	0.49	0.24	0.24
ONTO23	2.17	0.21	0.00	0.00	0.46	0.46
ONTO24	1.69	2.85	1.39	0.38	1.21	1.21
ONTO25	0.13	0.17	1.08	0.04	0.05	0.05
OYDM11	0.93	0.13	0.93	0.00	1.00	1.00
PNCK11	0.96	0.25	0.35	4.82	0.00	0.00
PNCK12	1.00	0.00	0.00	1.00	2.00	2.00
PRMA12	3.00	2.33	1.00	0.00	4.67	4.67
PRMA42	4.60	2.64	0.30	2.15	6.51	6.51
RKVL11	2.25	1.00	0.03	5.22	0.03	0.03
UNTY11	6.21	2.15	0.16	2.10	2.12	2.12
UNTY12	6.81	2.06	0.21	1.65	2.92	2.92
VALE11	1.59	0.74	0.14	0.03	2.94	2.94
VALE12	0.50	0.14	0.00	0.00	1.02	1.02
VALE13	1.18	0.33	0.18	0.54	1.67	1.67
VALE14	0.91	1.59	0.12	1.67	1.66	1.66
VALE15	1.37	1.69	0.12	0.20	1.32	1.32
WESR13	2.34	1.08	0.78	0.61	2.62	2.62
WESR14	3.23	3.73	1.23	1.29	3.89	3.89

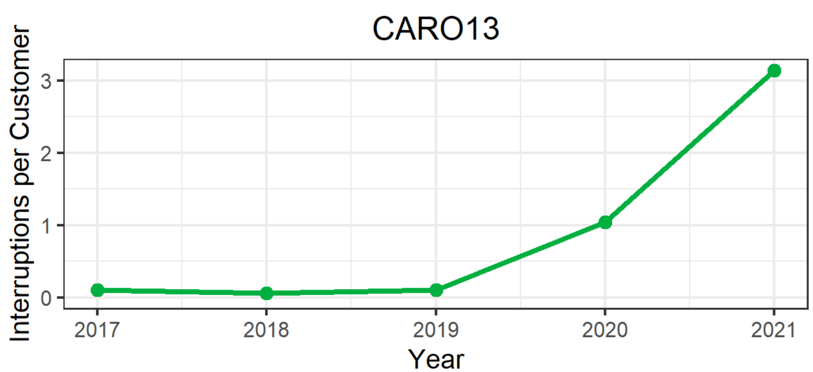
Table 7 Five Years of Circuit SAIFI

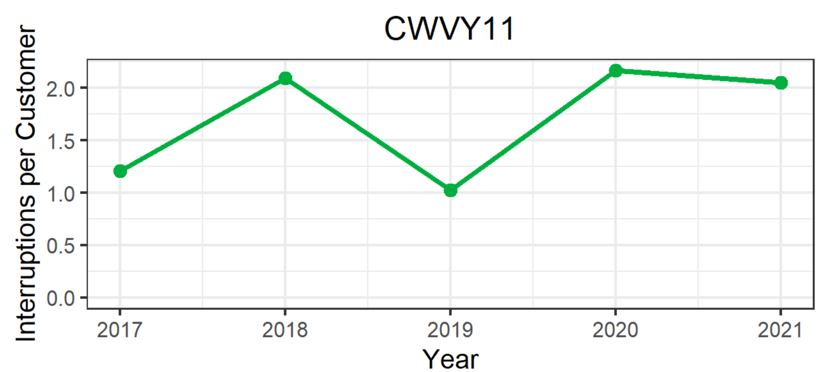

ADRN11
Interruptions per Customer
0
1
2
2017
2018
2019
2020
2021
Year

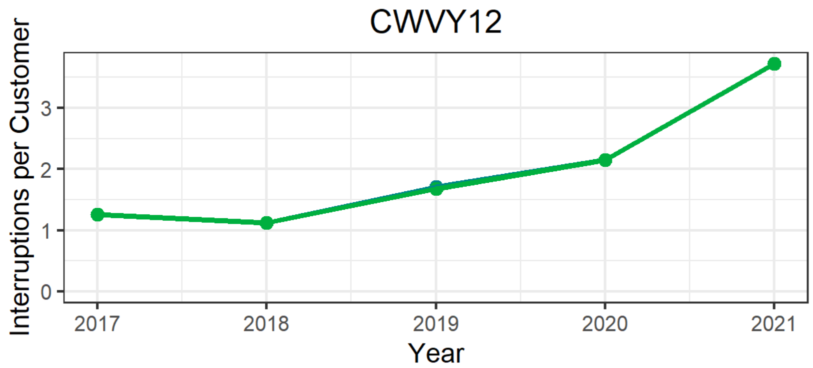

ADRN12
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

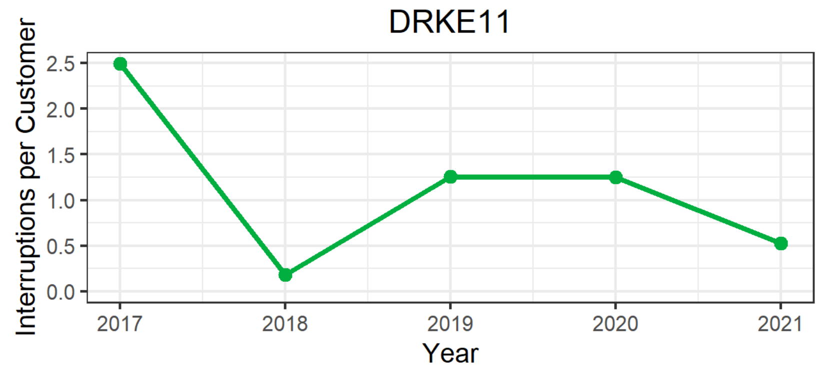

CARO11
Interruptions per Customer
0.0
0.5
1.0
2017
2018
2019
2020
2021
Year

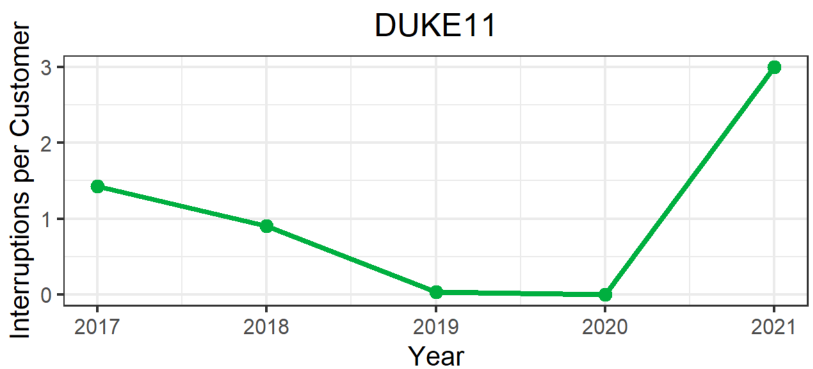

CARO12
Interruptions per Customer
0.0
0.5
1.0
1.5
2017
2018
2019
2020
2021
Year

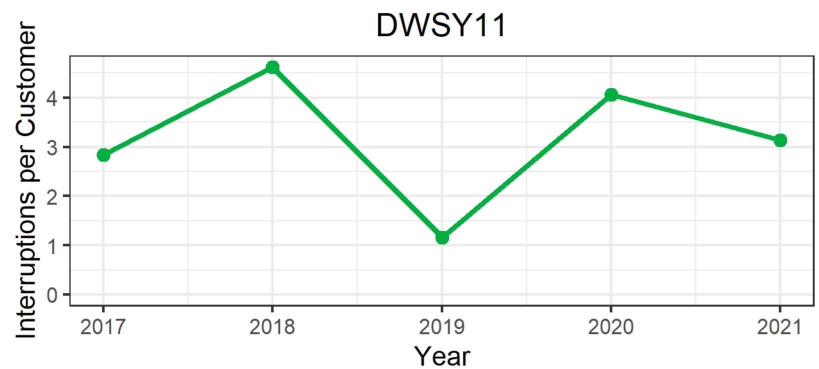

CARO13
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

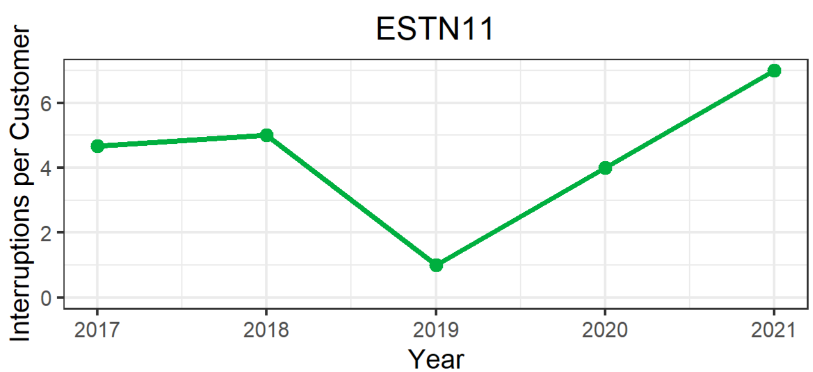

CWVY11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2017
2018
2019
2020
2021
Year

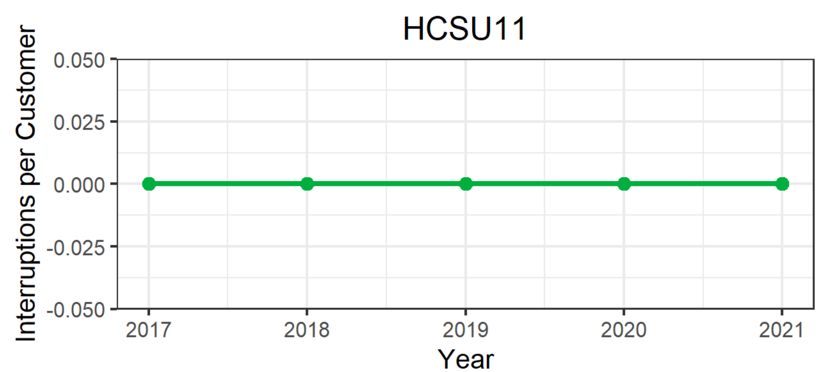

CWVY12
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

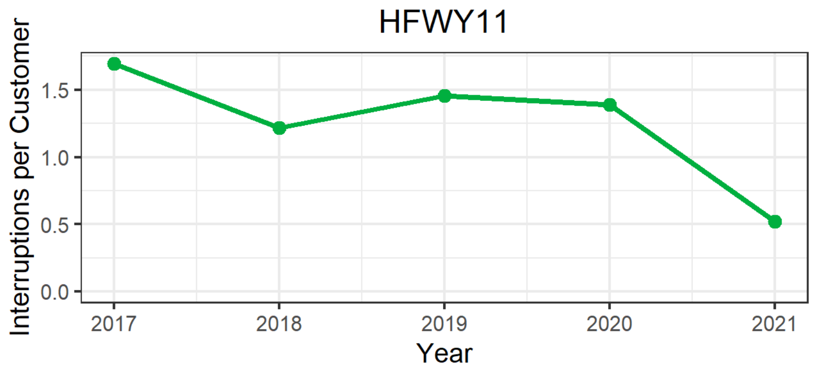

DRKE11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2017
2018
2019
2020
2021
Year

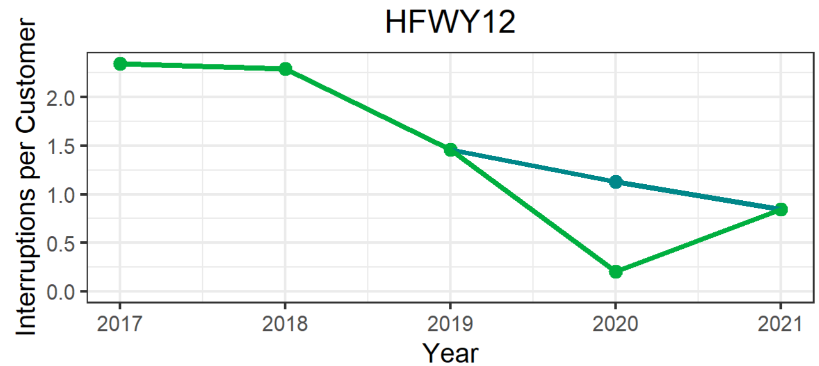

DUKE11
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

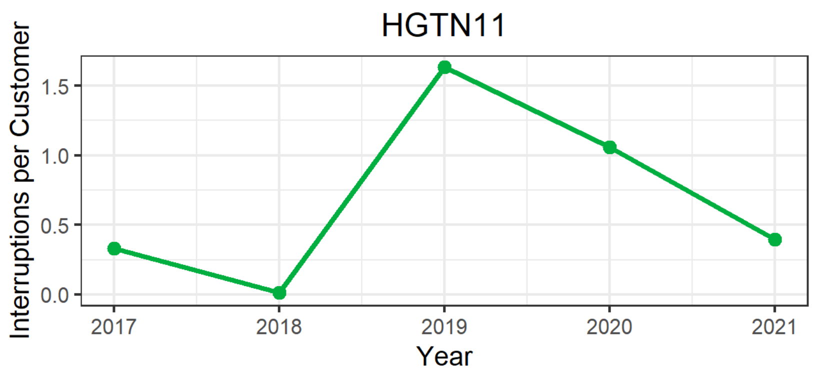

DWSY11
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

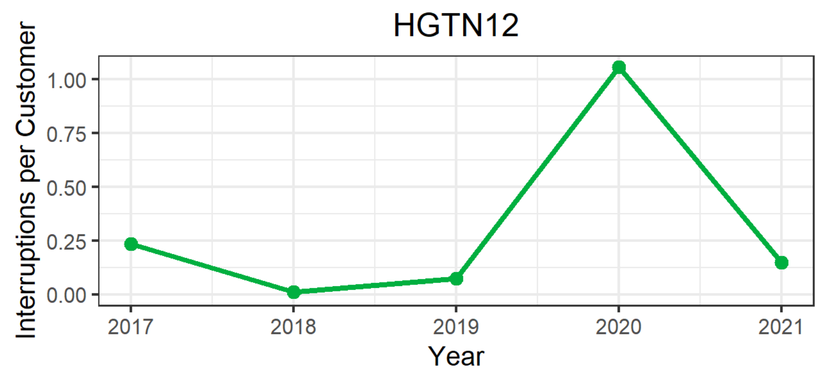

ESTN11
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

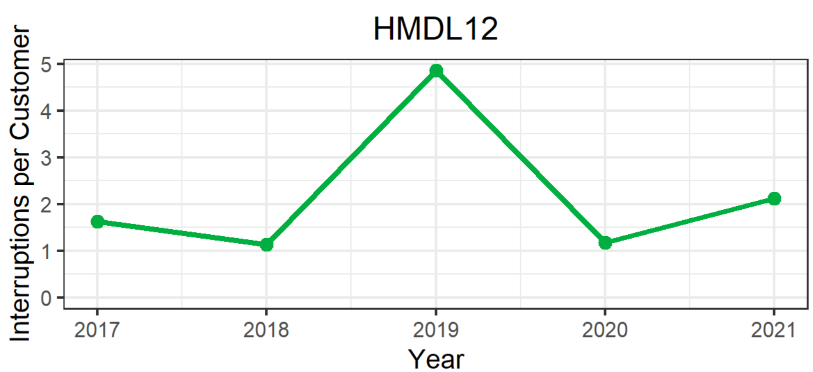

HCSU11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

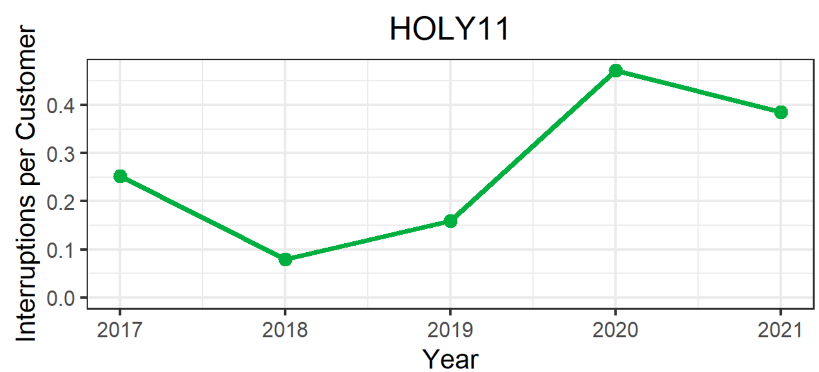

HFWY11
Interruptions per Customer
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

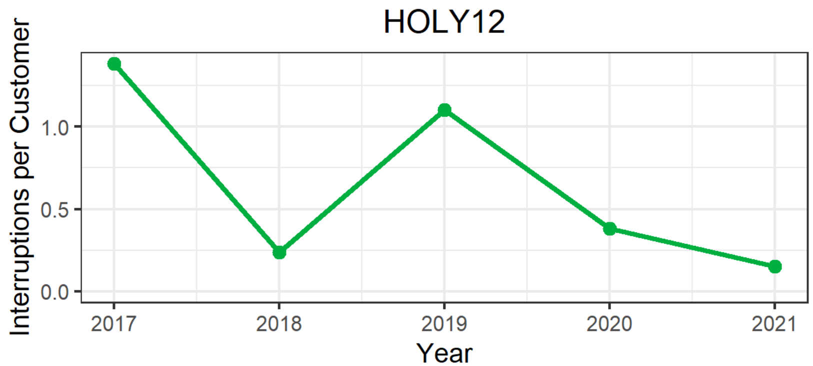

HFWY12
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

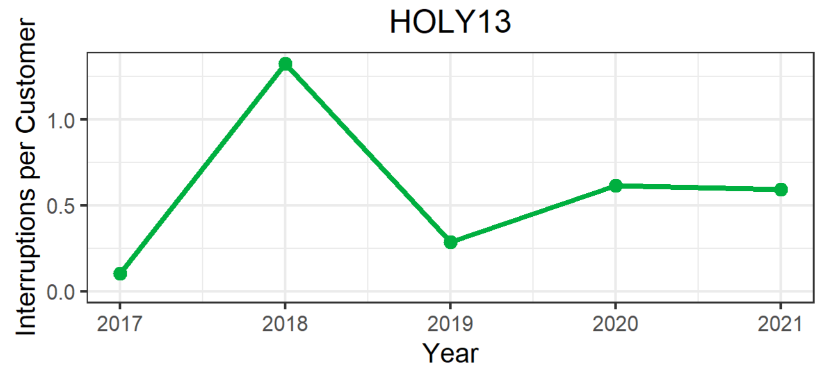

HGTN11
Interruptions per Customer
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

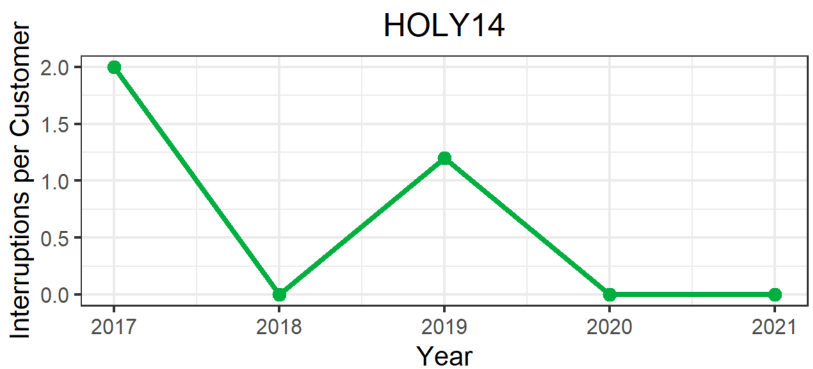

HGTN12
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2017
2018
2019
2020
2021
Year

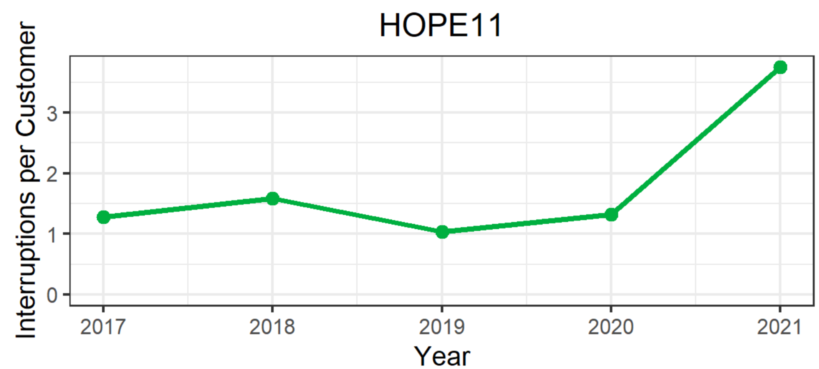

HMDL12
Interruptions per Customer
5
4
3
2
1
0
2017
2018
2019
2020
2021
Year

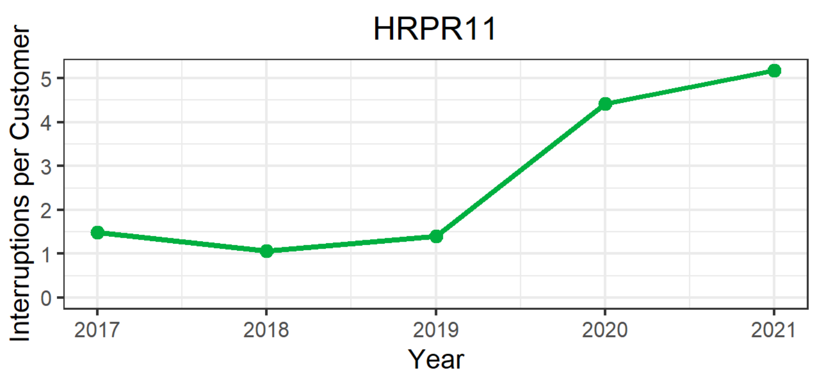

HOLY11
Interruptions per Customer
0.4
0.3
0.2
0.1
0.0
2017
2018
2019
2020
2021
Year

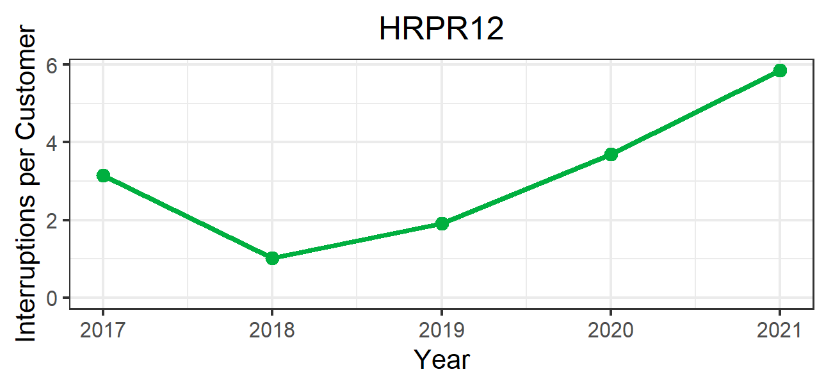

HOLY12
Interruptions per Customer
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

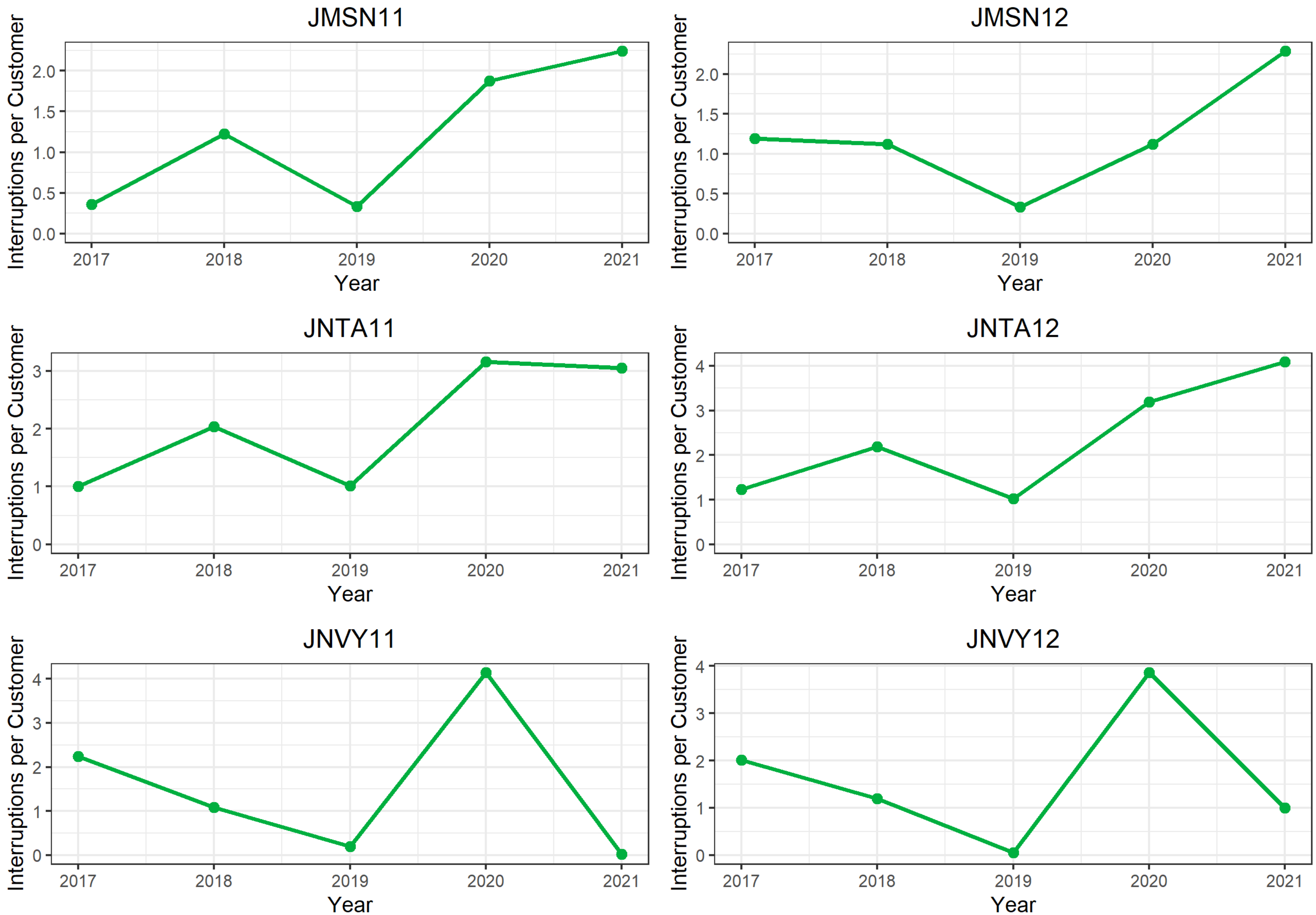

HOLY13
Interruptions per Customer
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

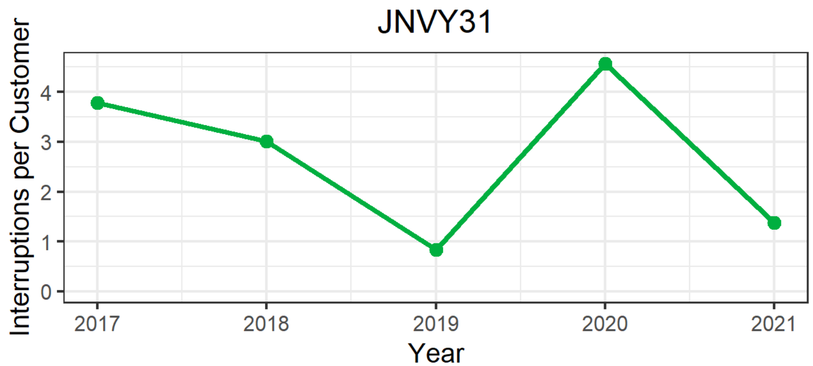

HOLY14
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

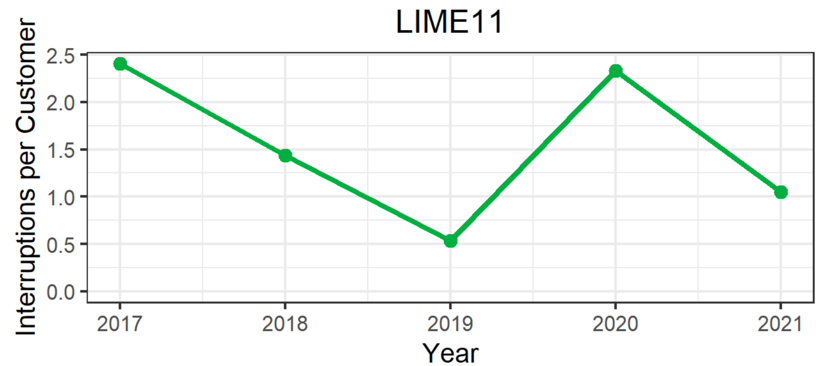

HOPE11
Interruptions per Customer
3
2
1
0
2017
2018
2019
2020
2021
Year

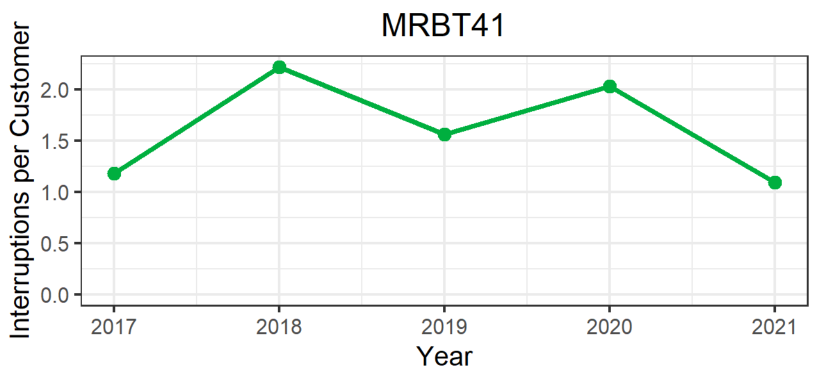

HRPR11
Interruptions per Customer
5
4
3
2
1
0
2017
2018
2019
2020
2021
Year

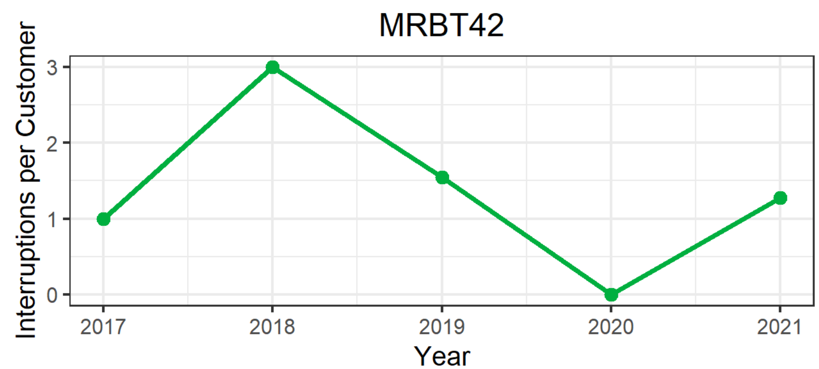

HRPR12
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year

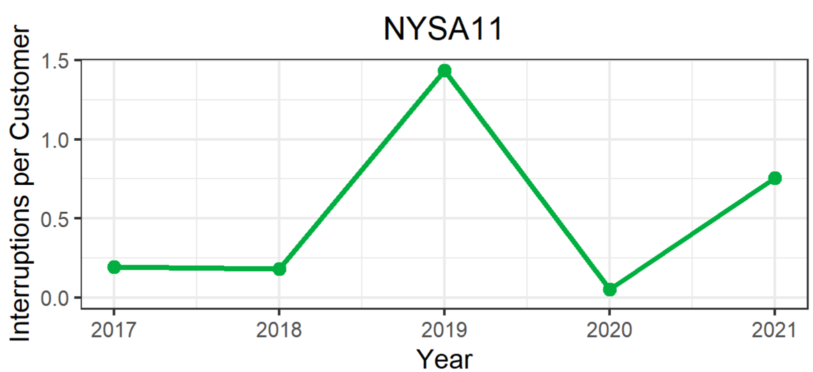

JMSN11
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year
JMSN12
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year
JNTA11
Interruptions per Customer
3
2
1
0
2017
2018
2019
2020
2021
Year
JNTA12
Interruptions per Customer
4
3
2
1
0
2017
2018
2019
2020
2021
Year
JNVY11
Interruptions per Customer
4
3
2
1
0
2017
2018
2019
2020
2021
Year
JNVY12
Interruptions per Customer
4
3
2
1
0
2017
2018
2019
2020
2021
Year

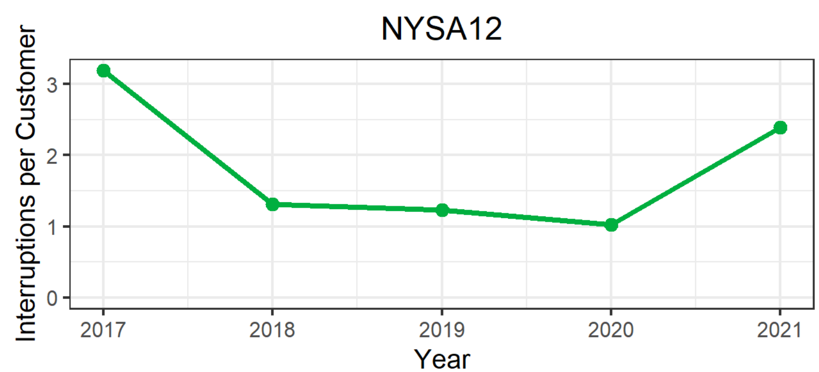

JNVY31
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

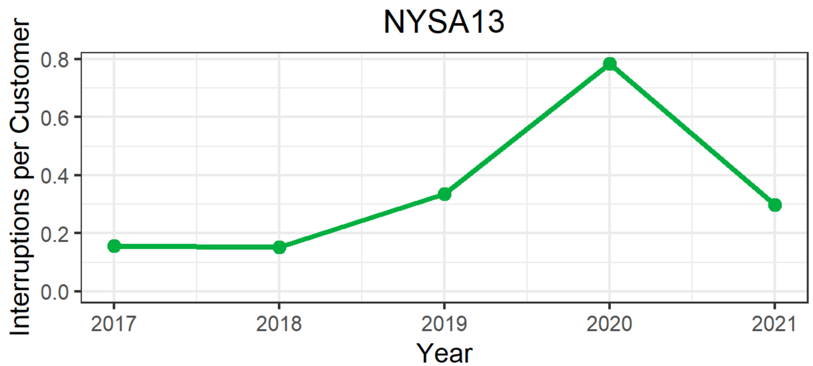

LIME11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2017
2018
2019
2020
2021
Year

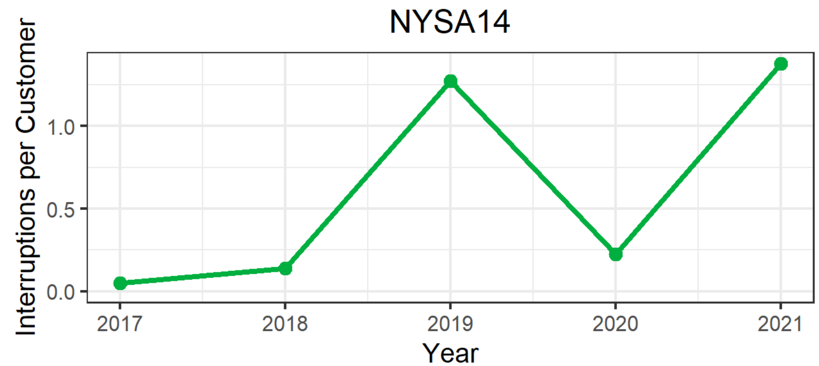

MRBT41
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2017
2018
2019
2020
2021
Year

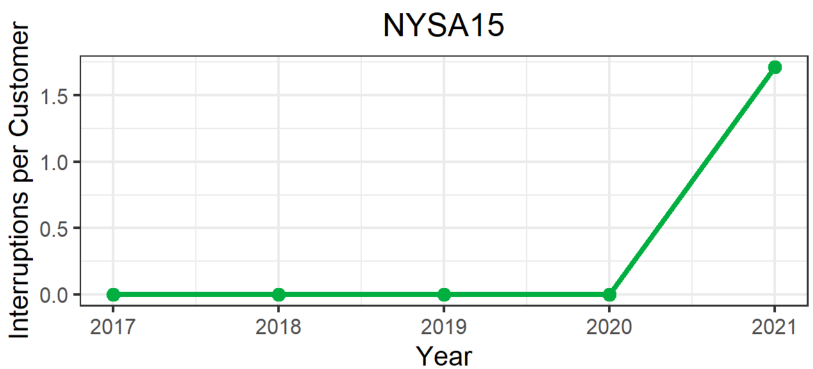

MRBT42
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

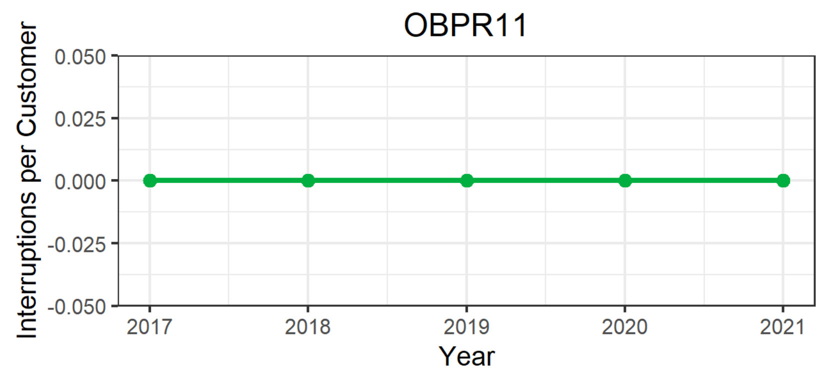

NYSA11
Interruptions per Customer
0.0
0.5
1.0
1.5
2017
2018
2019
2020
2021
Year

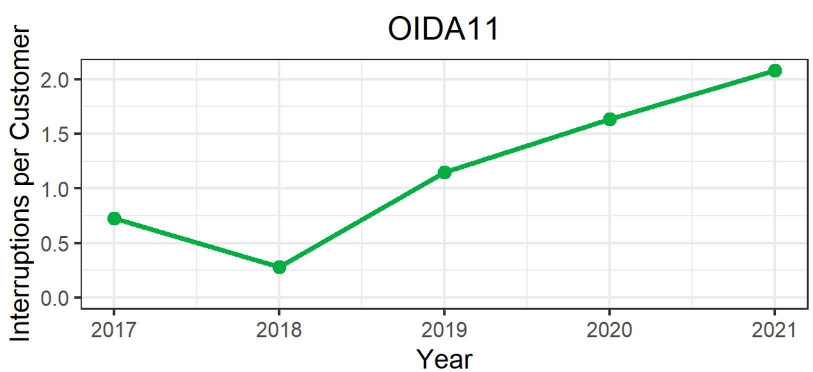

NYSA12
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

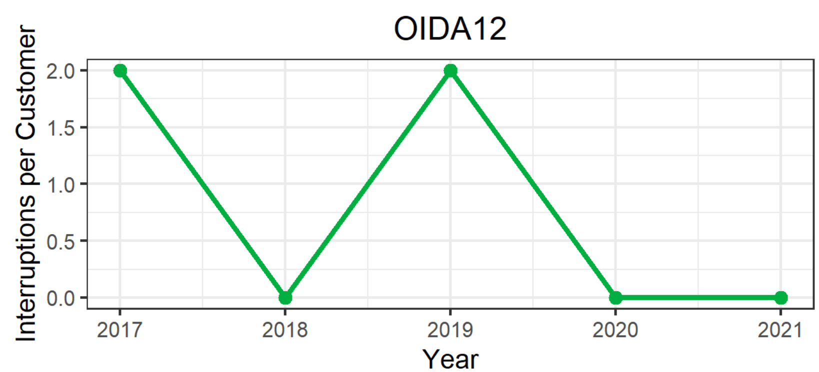

NYSA13
Interruptions per Customer
0.8
0.6
0.4
0.2
0.0
2017
2018
2019
2020
2021
Year

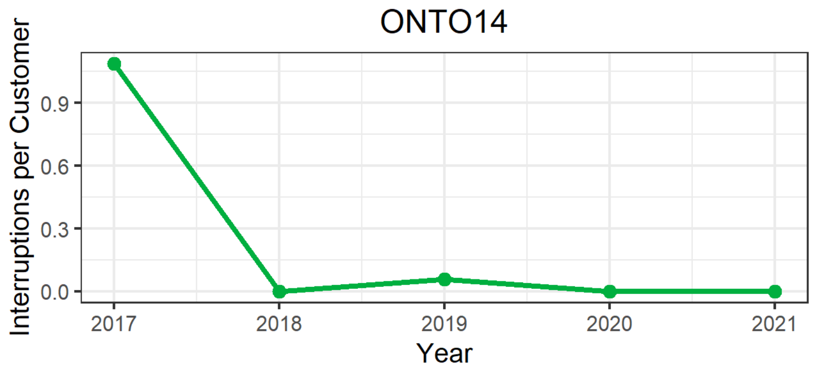

NYSA14
Interruptions per Customer
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

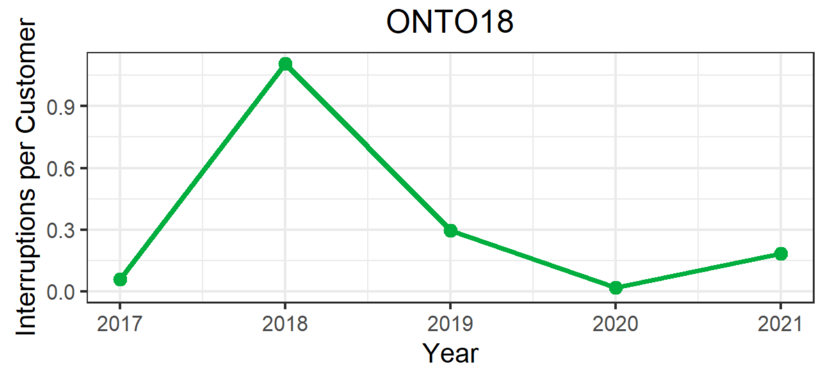

NYSA15
Interruptions per Customer
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

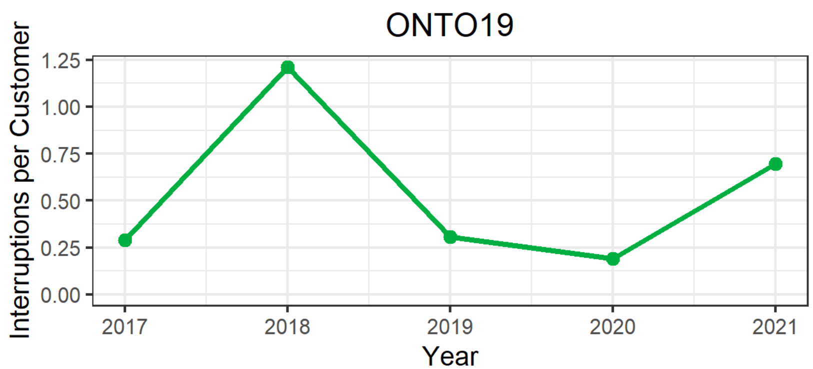

OBPR11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

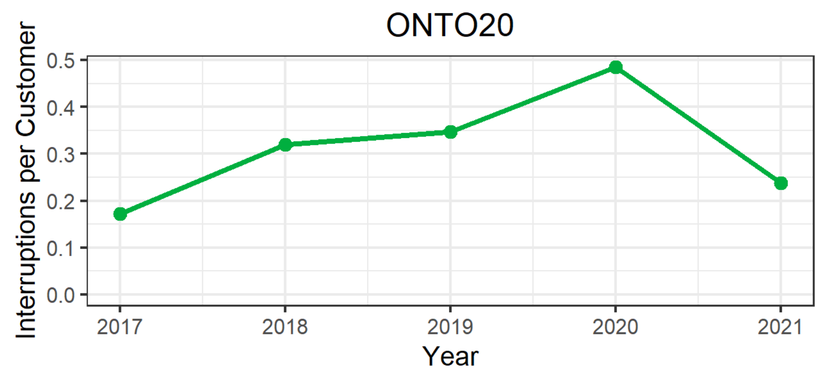

OIDA11
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

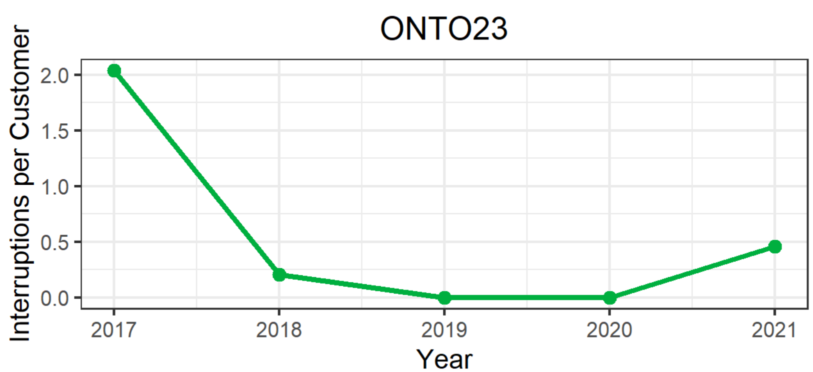

OIDA12
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

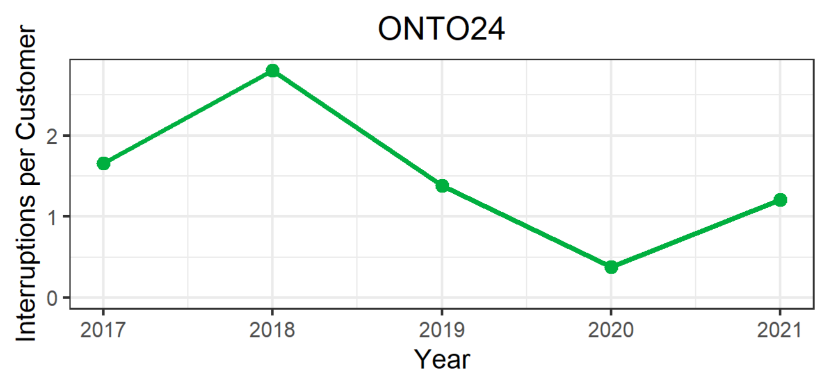

ONTO14
Interruptions per Customer
0.0
0.3
0.6
0.9
2017
2018
2019
2020
2021
Year

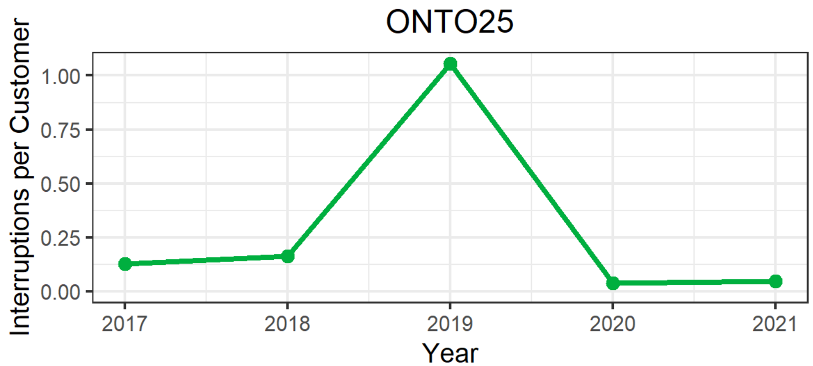

ONTO18
Interruptions per Customer
0.0
0.3
0.6
0.9
2017
2018
2019
2020
2021
Year

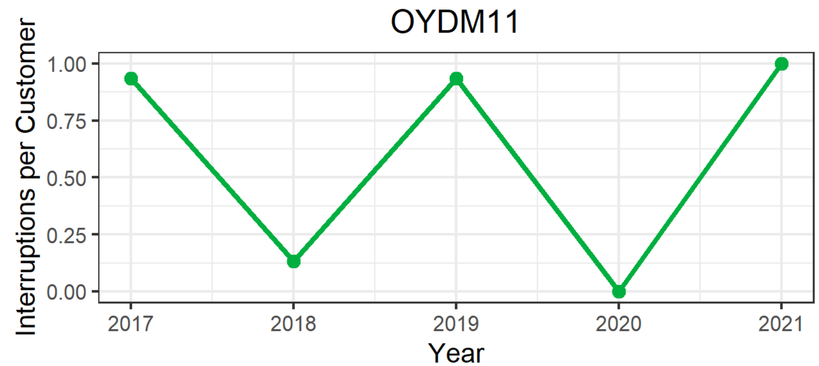

ONTO19
Interruptions per Customer
0.00
0.25
0.50
0.75
1.00
1.25
2017
2018
2019
2020
2021
Year

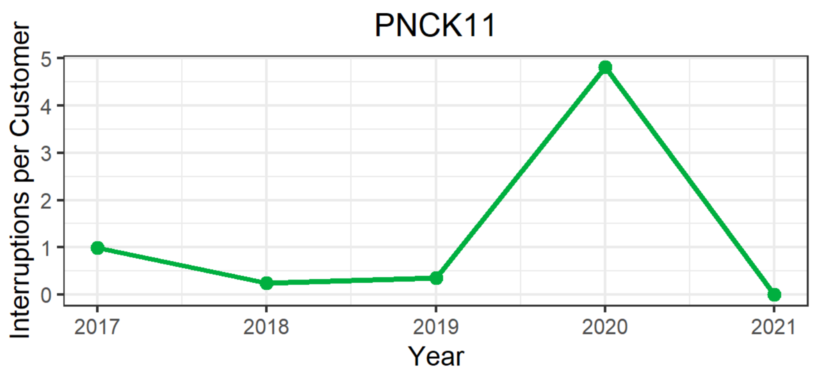

ONTO20
Interruptions per Customer
0.0
0.1
0.2
0.3
0.4
0.5
2017
2018
2019
2020
2021
Year

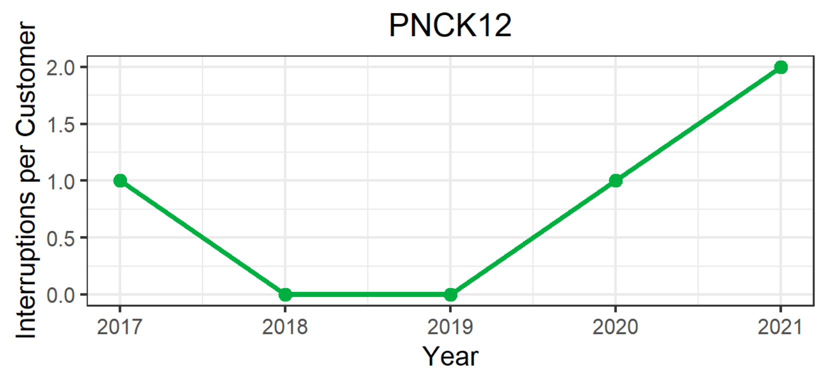

ONTO23
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2017
2018
2019
2020
2021
Year

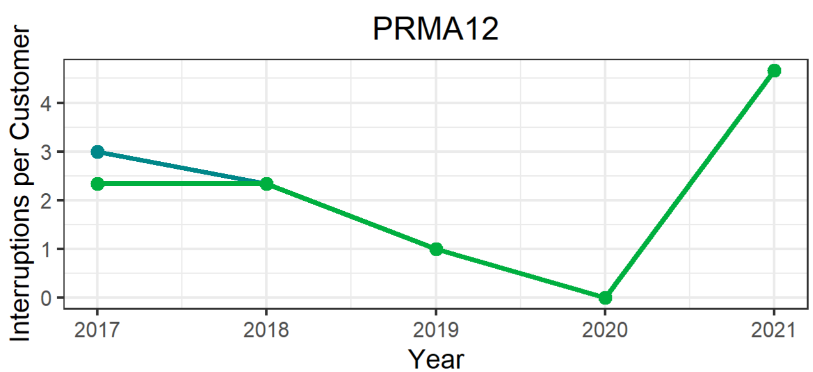

ONTO24
Interruptions per Customer
0
1
2
2017
2018
2019
2020
2021
Year

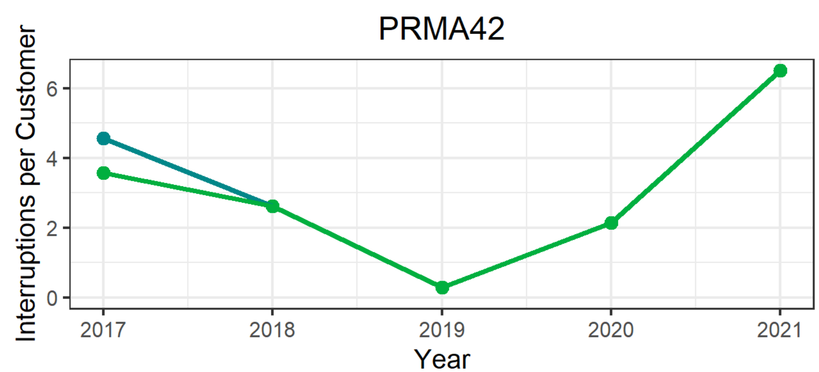

ONTO25
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2017
2018
2019
2020
2021
Year

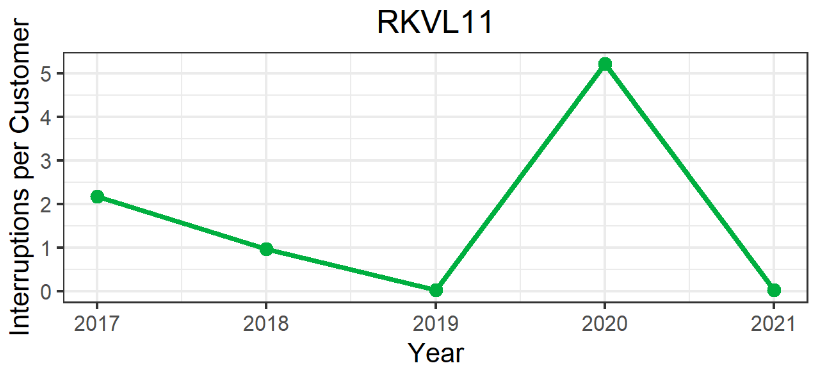

OYDM11
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2017
2018
2019
2020
2021
Year


PNCK11
Interruptions per Customer
5
4
3
2
1
0
2017
2018
2019
2020
2021
Year

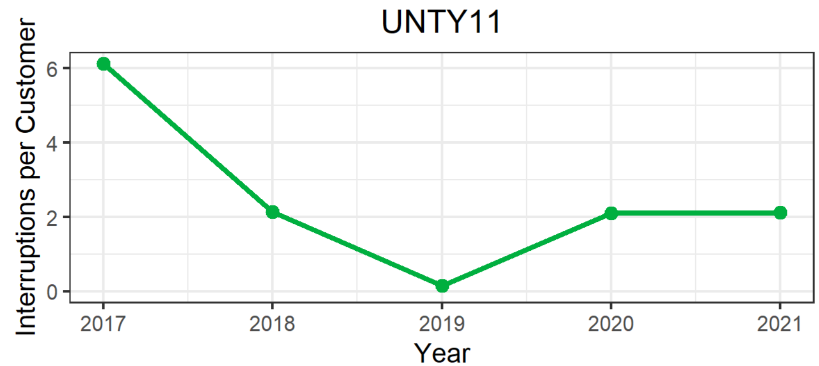

PNCK12
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year


PRMA12
Interruptions per Customer
4
3
2
1
0
2017
2018
2019
2020
2021
Year

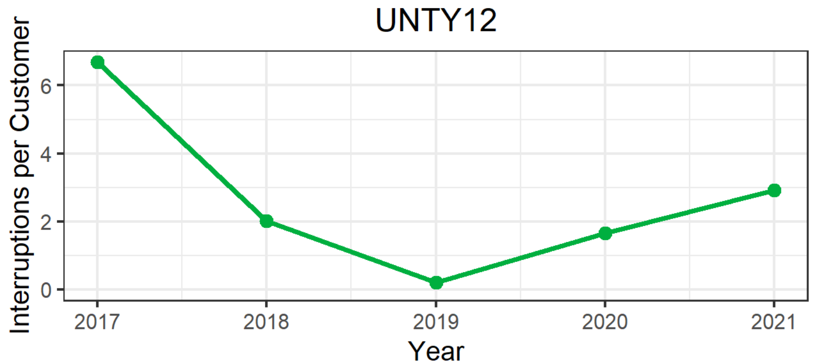

PRMA42
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year



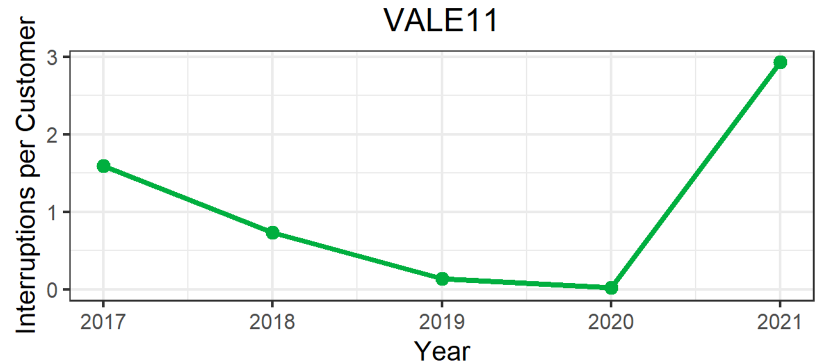
RKVL11
Interruptions per Customer
5
4
3
2
1
0
2017
2018
2019
2020
2021
Year



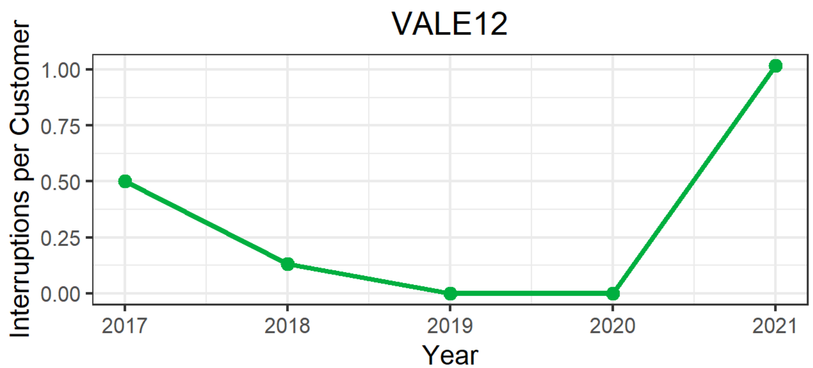
UNTY11
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year



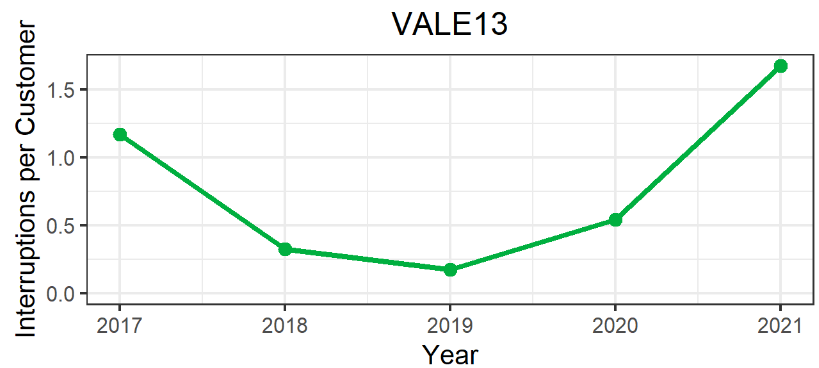
UNTY12
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year



VALE11
Interruptions per Customer
3
2
1
0
2017
2018
2019
2020
2021
Year



VALE12
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2017
2018
2019
2020
2021
Year



VALE13
Interruptions per Customer
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

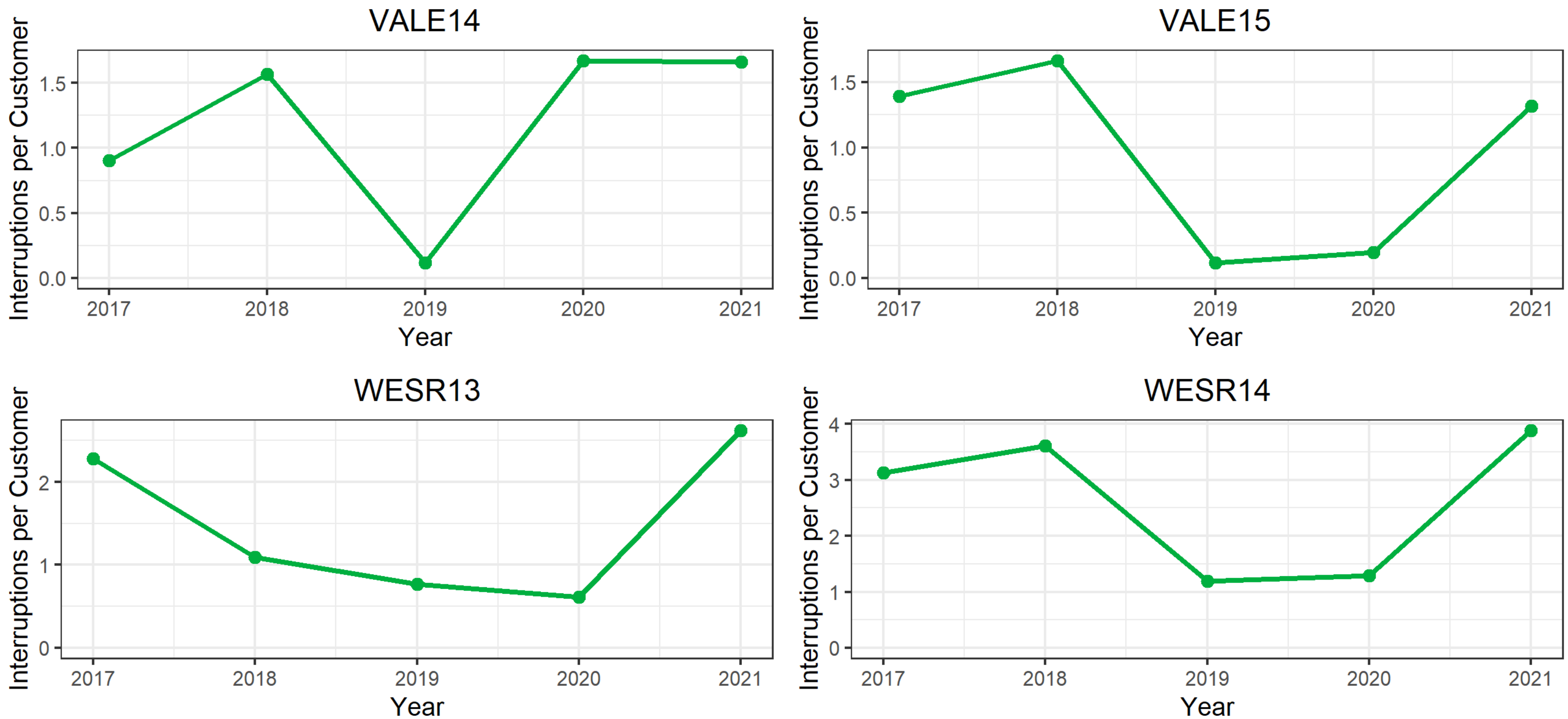
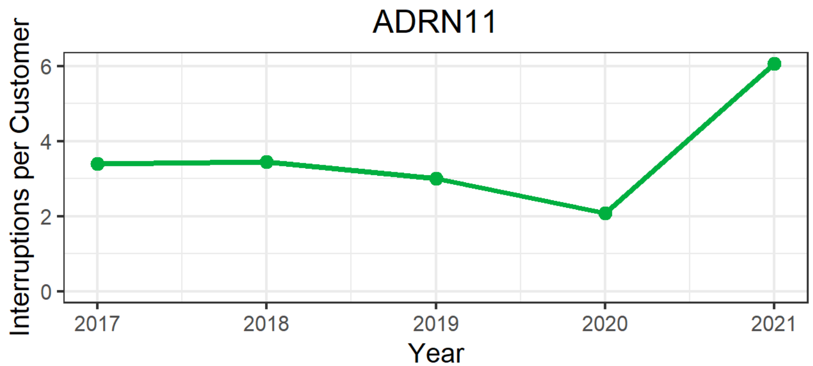


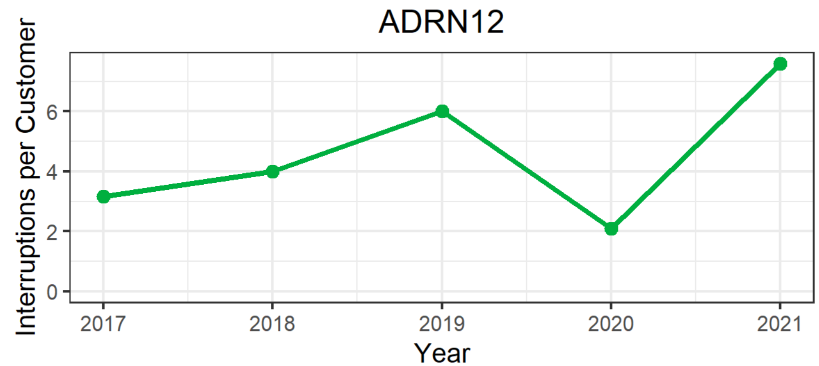
Figure 7 Five Years of Circuit SAIFI

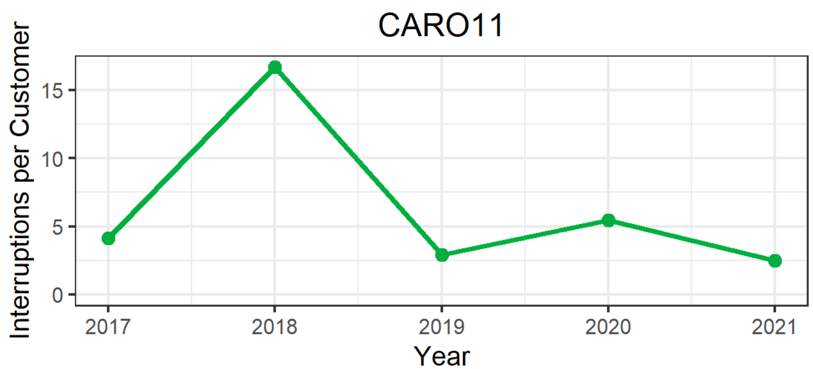
Five Years of Circuit $MAIFI_E$

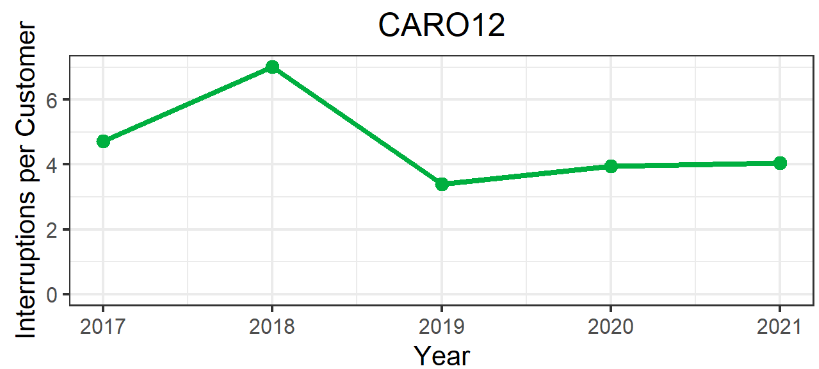
Circuit	2017	2018	2019	2020	2021	2021 MedEx
ADRN11	3.84	3.50	3.00	2.09	6.07	6.07
ADRN12	6.55	13.20	6.00	2.09	7.59	7.59
CARO11	4.42	11.18	3.10	5.43	2.48	2.48
CARO12	4.66	7.04	3.38	3.95	4.05	4.05
CARO13	0.00	5.00	0.00	0.00	0.00	0.00
CWVY11	8.00	5.00	0.00	0.00	0.00	0.00
CWVY12	6.65	3.00	6.00	0.00	2.00	2.00
DRKE11	18.00	4.00	5.00	3.00	1.00	1.00
DUKE11	2.00	2.00	0.00	0.00	0.00	0.00
DWSY11	7.47	9.00	7.85	4.48	9.85	9.85
ESTN11	0.00	0.00	0.00	0.00	0.00	0.00
HCSU11	0.00	0.00	0.00	0.00	0.00	0.00
HFWY11	15.57	1.79	6.29	1.73	0.70	0.70
HFWY12	9.15	6.00	5.17	17.00	0.00	0.00
HGTN11	1.00	2.00	4.00	4.00	0.00	0.00
HGTN12	2.00	0.00	2.00	4.00	0.00	0.00
HMDL12	8.23	6.92	6.52	2.04	4.71	4.71
HOLY11	0.00	0.00	0.00	0.00	0.00	0.00
HOLY12	4.00	6.00	2.00	5.00	5.00	5.00
HOLY13	3.72	2.00	4.00	0.00	1.31	1.31
HOLY14	NA	NA	0.00	0.00	0.00	0.00
HOPE11	5.00	2.00	0.00	2.39	0.91	0.91
HRPR11	3.00	2.00	3.00	4.63	1.00	1.00
HRPR12	5.42	3.27	5.03	3.45	1.57	1.57
JMSN11	1.11	0.70	0.94	0.87	0.98	0.98
JMSN12	9.67	7.00	7.00	4.00	4.00	4.00
JNTA11	12.00	9.00	9.00	3.00	1.00	1.00
JNTA12	14.13	9.63	10.00	8.00	14.00	14.00
JNVY11	6.32	6.00	7.00	0.00	2.51	2.51
JNVY12	5.00	2.00	3.00	1.00	4.00	4.00
JNVY31	10.12	7.24	5.00	4.46	12.13	12.13
LIME11	2.19	2.00	2.00	0.60	0.13	0.13
MRBT41	1.00	1.00	1.00	3.00	5.00	5.00
MRBT42	0.00	1.00	1.00	2.00	6.00	6.00
NYSA11	0.00	2.00	1.00	2.00	0.00	0.00
NYSA12	7.15	1.95	0.00	0.00	3.00	3.00
NYSA13	1.26	1.09	1.00	0.52	3.47	3.47
NYSA14	1.35	0.00	1.00	0.00	3.51	3.51
NYSA15	0.00	0.00	0.00	0.00	0.00	0.00
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OIDA11	2.00	0.00	0.00	3.00	0.00	0.00
OIDA12	0.00	0.00	0.00	0.00	0.00	0.00
ONTO14	1.00	1.00	1.00	0.00	0.00	0.00
ONTO18	2.00	3.00	4.00	3.00	1.00	1.00
ONTO19	0.00	1.72	1.72	1.34	1.28	1.28
ONTO20	0.00	0.00	2.00	1.00	0.00	0.00
ONTO23	7.00	0.00	0.00	0.00	1.00	1.00
ONTO24	3.28	0.00	0.00	0.68	0.00	0.00
ONTO25	3.00	0.00	0.00	0.00	1.00	1.00
OYDM11	0.00	0.00	0.00	0.00	0.00	0.00
PNCK11	4.00	4.00	4.00	5.00	0.00	0.00
PNCK12	0.00	0.00	0.00	0.00	0.00	0.00
PRMA12	5.00	1.00	0.00	0.00	0.00	0.00
PRMA42	12.23	9.74	6.24	3.15	4.47	4.47
RKVL11	6.00	5.00	6.00	3.00	4.00	4.00
UNTY11	15.00	8.00	7.00	8.05	4.00	4.00
UNTY12	14.85	0.00	0.00	0.00	0.00	0.00
VALE11	4.55	2.86	1.00	1.00	0.39	0.39
VALE12	0.00	0.00	0.00	0.00	0.00	0.00
VALE13	3.73	0.00	0.91	2.89	3.35	3.35
VALE14	2.61	2.00	0.00	0.12	2.00	2.00
VALE15	2.76	2.25	0.00	5.00	0.46	0.46
WESR13	0.27	0.74	4.26	1.26	3.00	3.00
WESR14	2.90	6.00	3.00	2.00	0.86	0.86

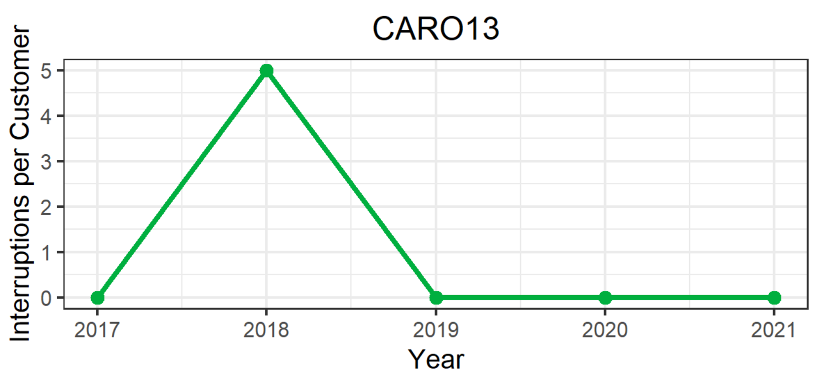
Table 8 Five Years of Circuit $MAIFI_E$

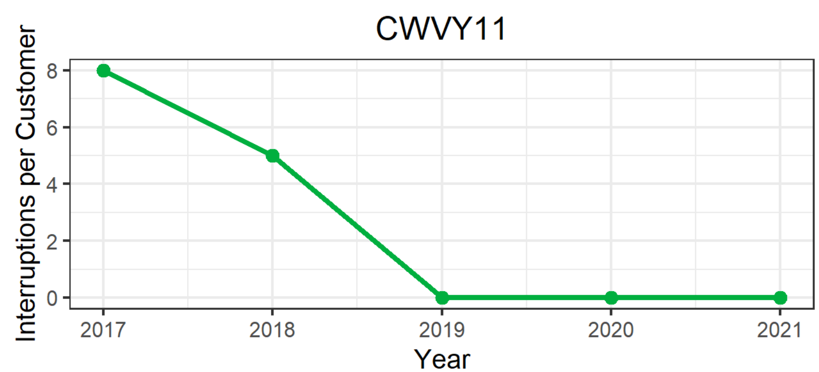

ADRN11
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

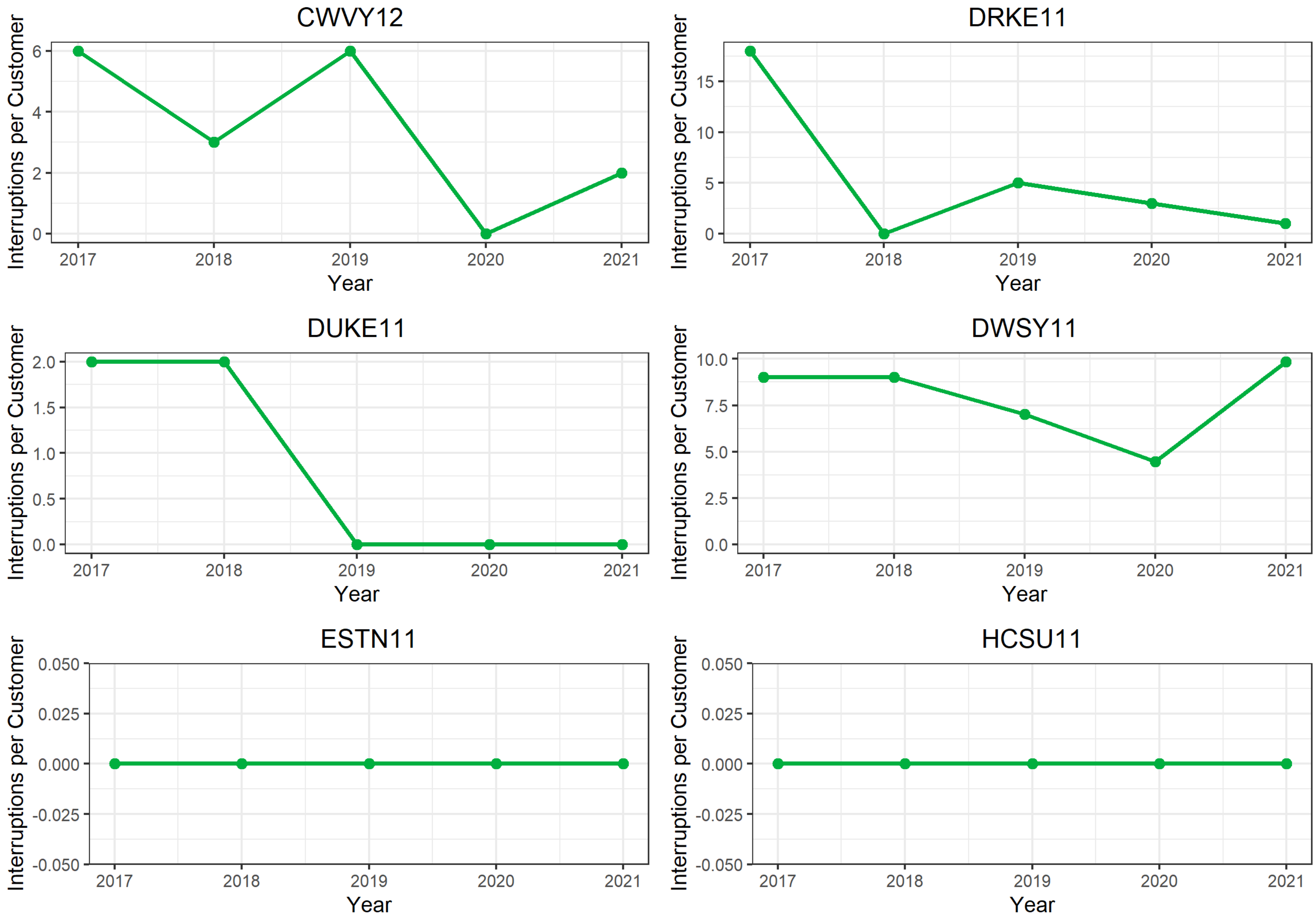

ADRN12
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

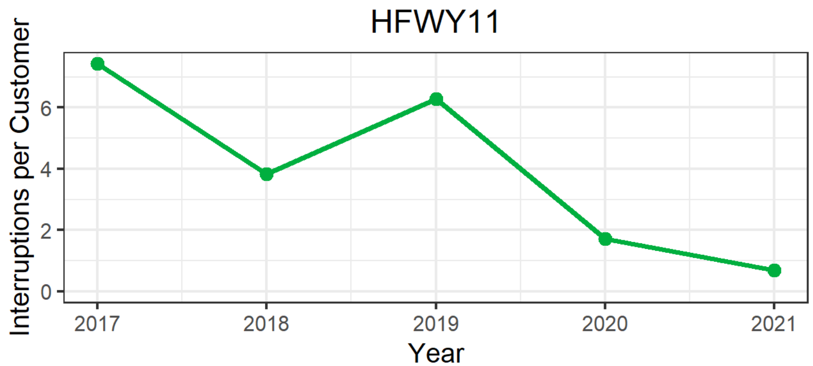

CARO11
Interruptions per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

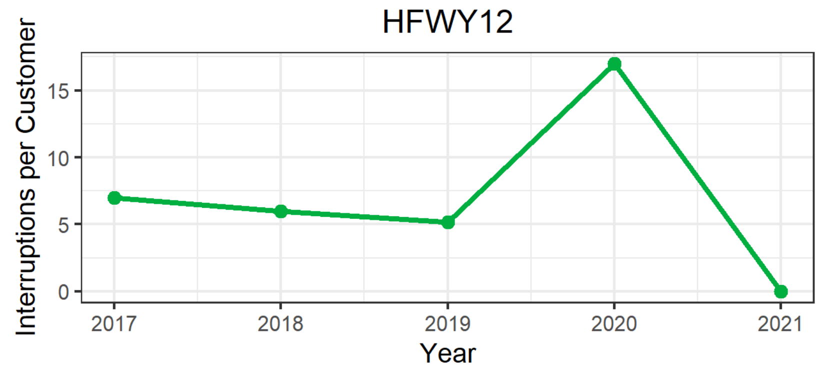

CARO12
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

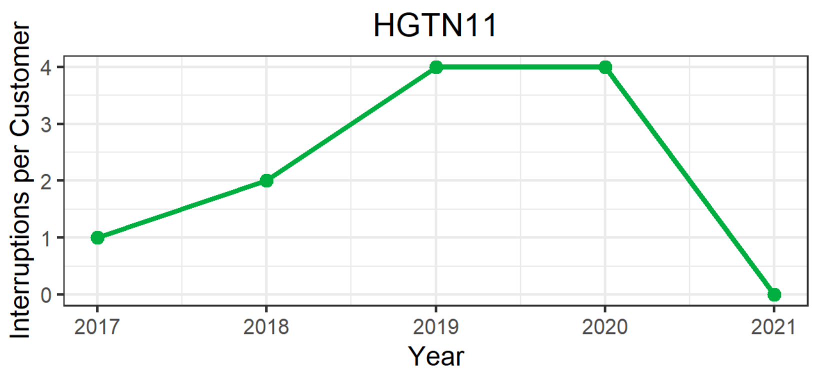

CARO13
Interruptions per Customer
0
1
2
3
4
5
2017
2018
2019
2020
2021
Year

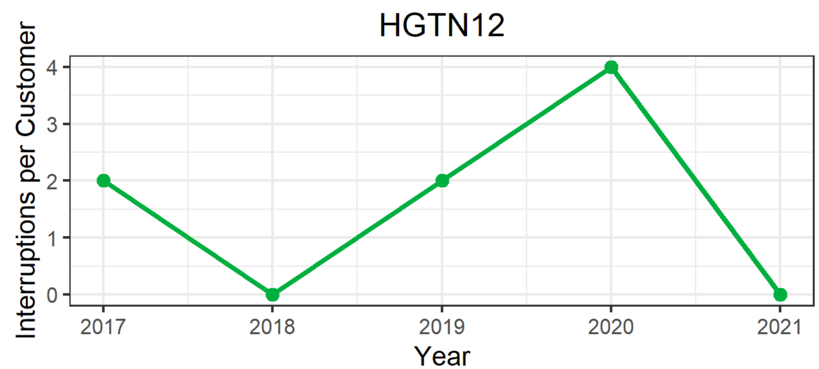

CWVY11
Interruptions per Customer
0
2
4
6
8
2017
2018
2019
2020
2021
Year

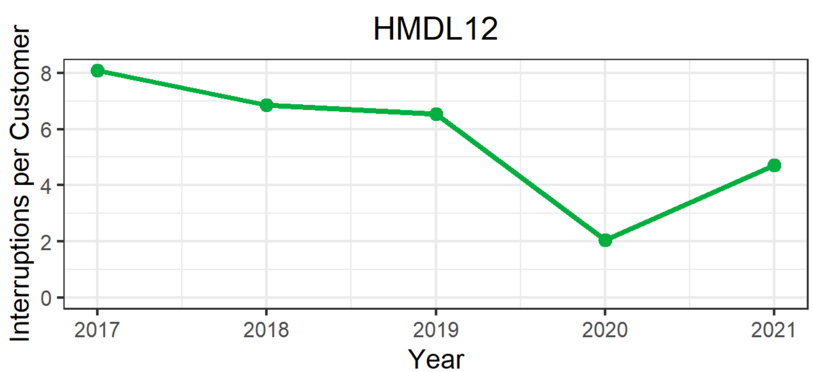

CWVY12
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year
DRKE11
Interruptions per Customer
15
10
5
0
2017
2018
2019
2020
2021
Year
DUKE11
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year
DWSY11
Interruptions per Customer
10.0
7.5
5.0
2.5
0.0
2017
2018
2019
2020
2021
Year
ESTN11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year
HCSU11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

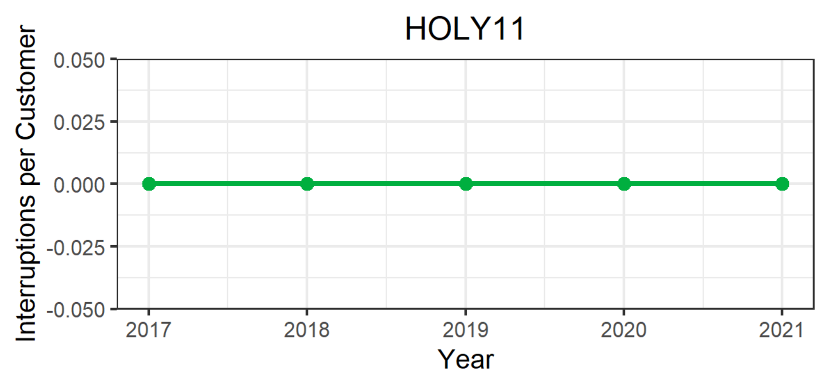

HFWY11
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

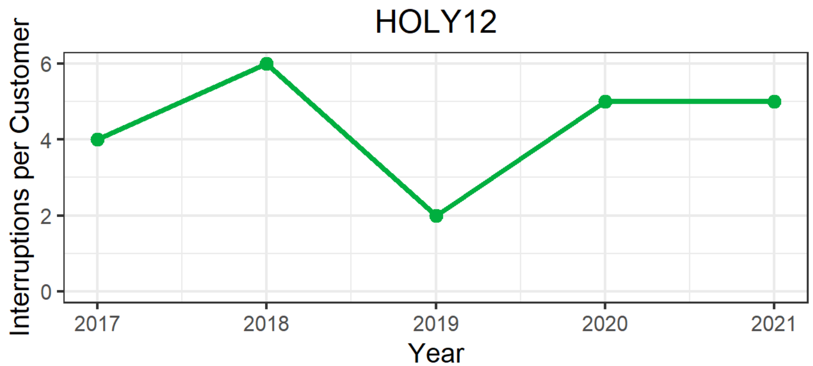

HFWY12
Interruptions per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year

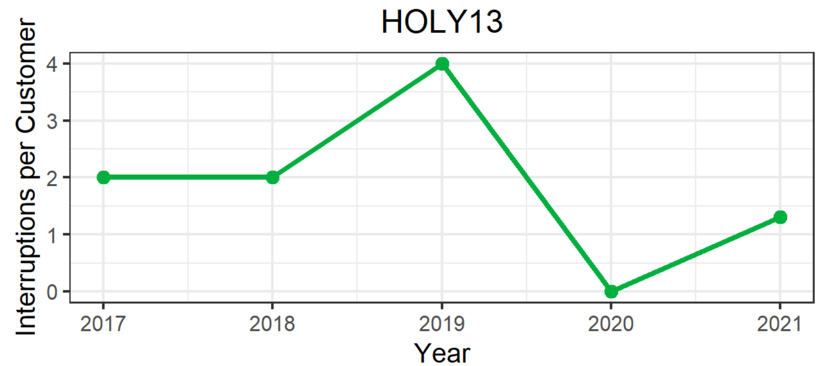

HGTN11
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

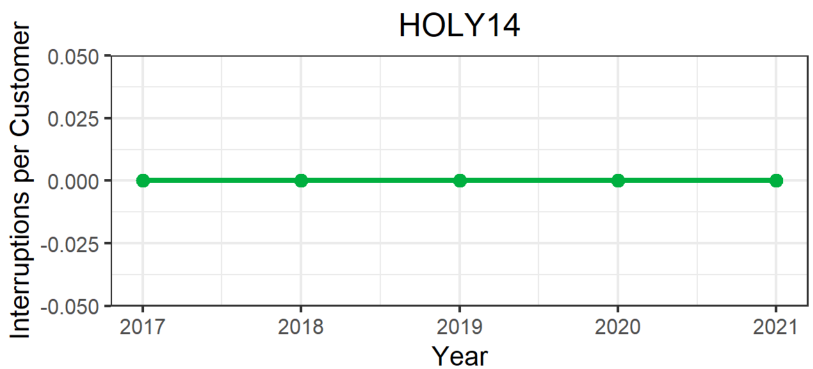

HGTN12
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

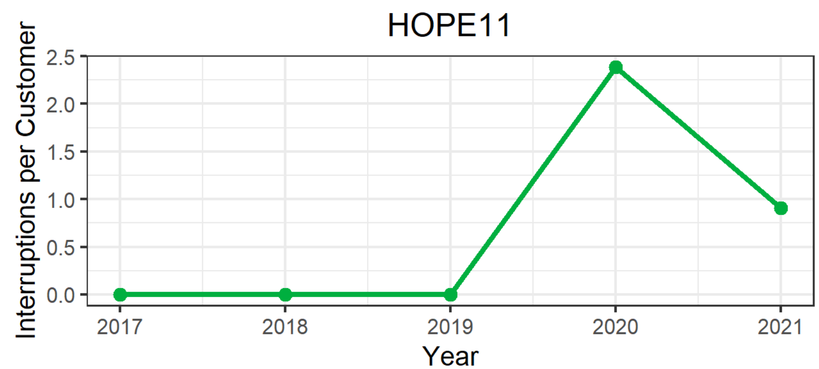

HMDL12
Interruptions per Customer
0
2
4
6
8
2017
2018
2019
2020
2021
Year

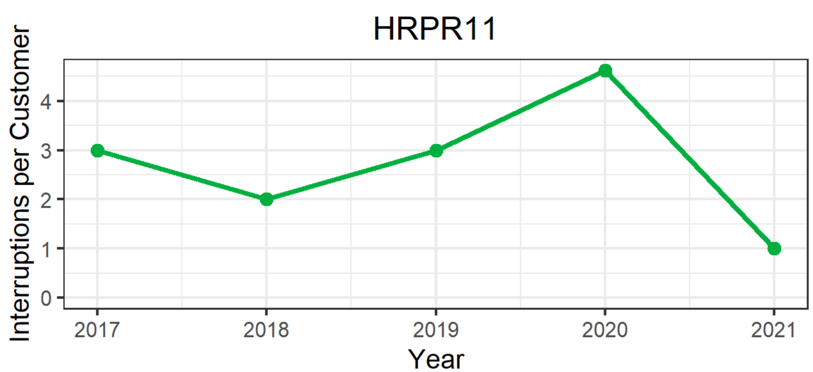

HOLY11
Interruptions per Customer
-0.050
-0.025
0.000
0.025
0.050
2017
2018
2019
2020
2021
Year

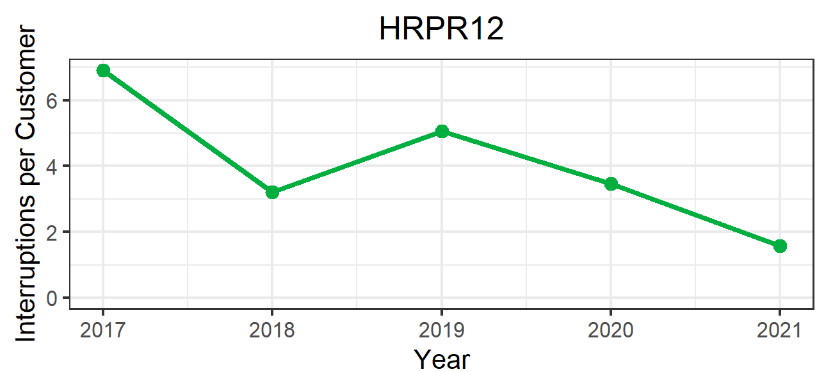

HOLY12
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

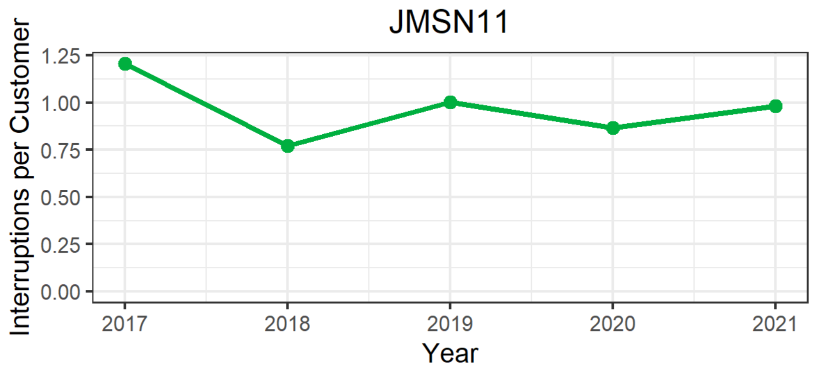

HOLY13
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

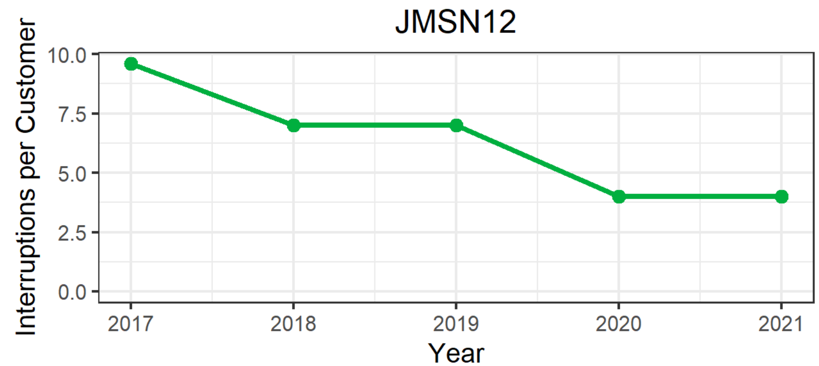

HOLY14
Interruptions per Customer
-0.050
-0.025
0.000
0.025
0.050
2017
2018
2019
2020
2021
Year

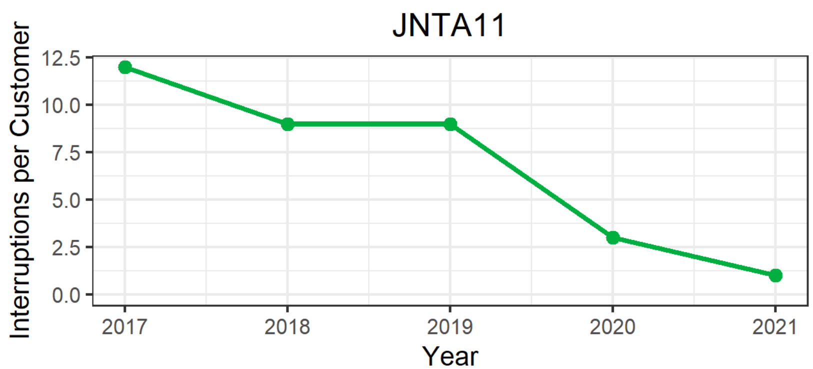

HOPE11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2017
2018
2019
2020
2021
Year

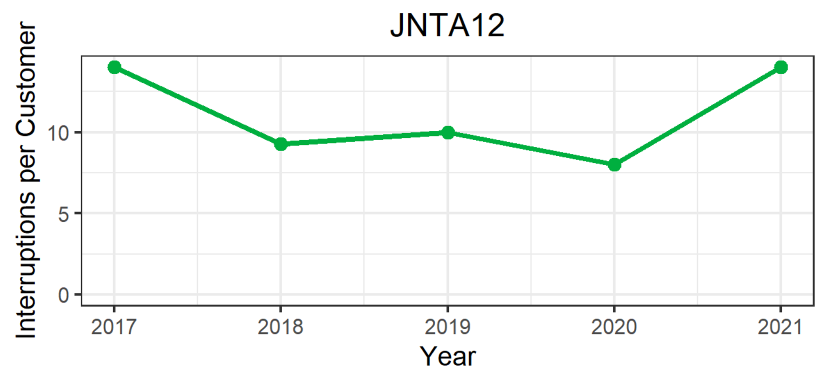

HRPR11
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year

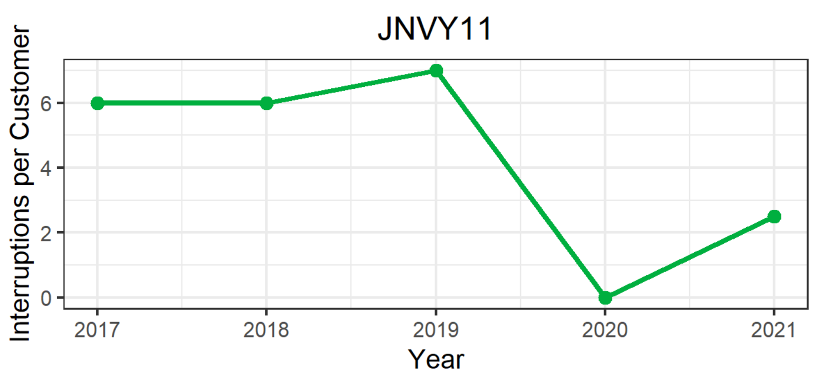

HRPR12
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year

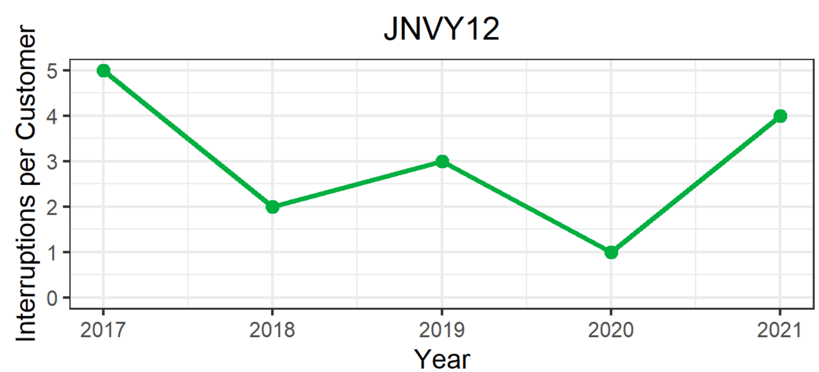

JMSN11
Interruptions per Customer
1.25
1.00
0.75
0.50
0.25
0.00
2017
2018
2019
2020
2021
Year

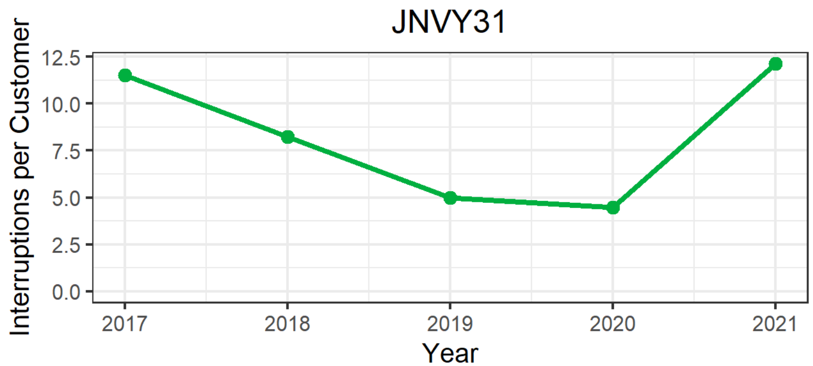

JMSN12
Interruptions per Customer
10.0
7.5
5.0
2.5
0.0
2017
2018
2019
2020
2021
Year

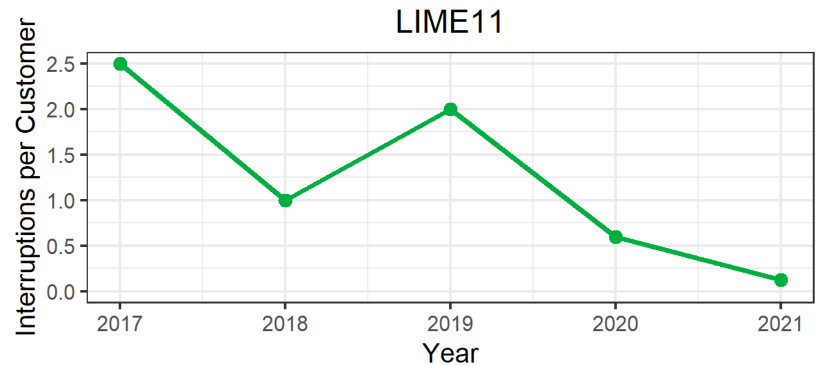

JNTA11
Interruptions per Customer
12.5
10.0
7.5
5.0
2.5
0.0
2017
2018
2019
2020
2021
Year

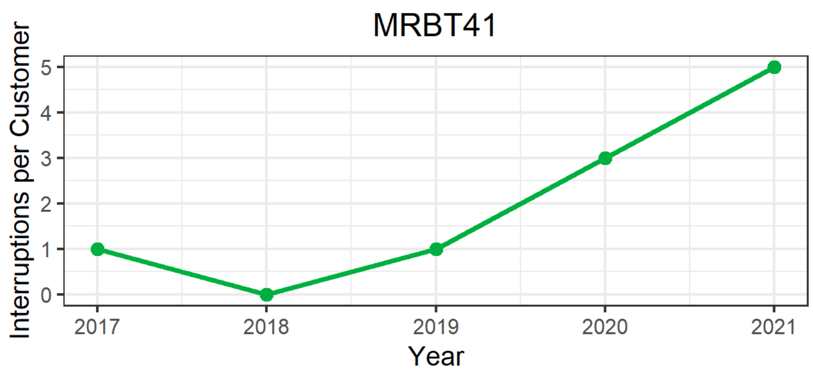

JNTA12
Interruptions per Customer
10
5
0
2017
2018
2019
2020
2021
Year

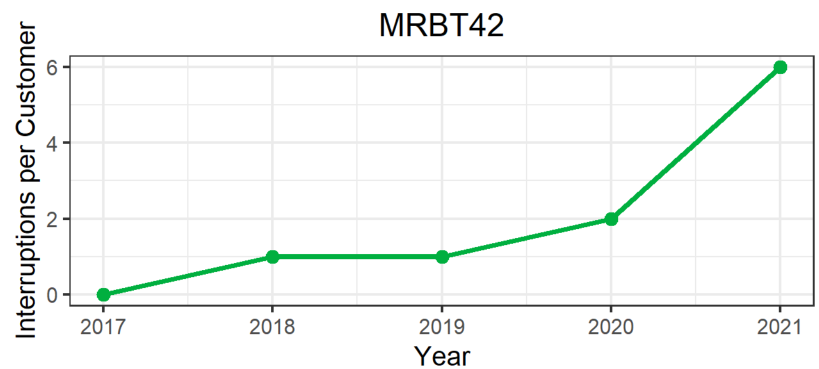

JNVY11
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year

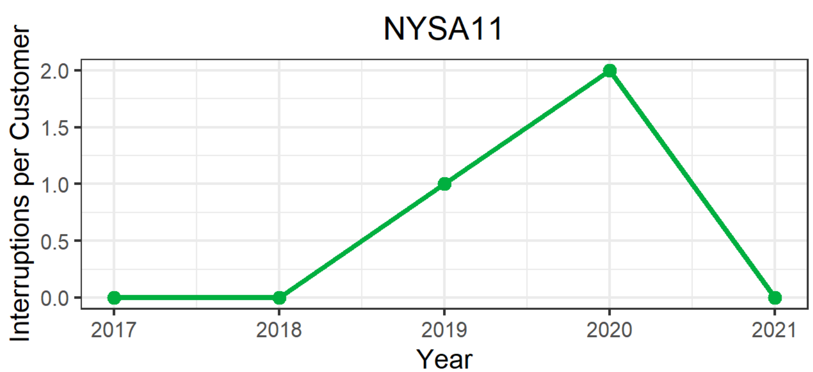

JNVY12
Interruptions per Customer
5
4
3
2
1
0
2017
2018
2019
2020
2021
Year

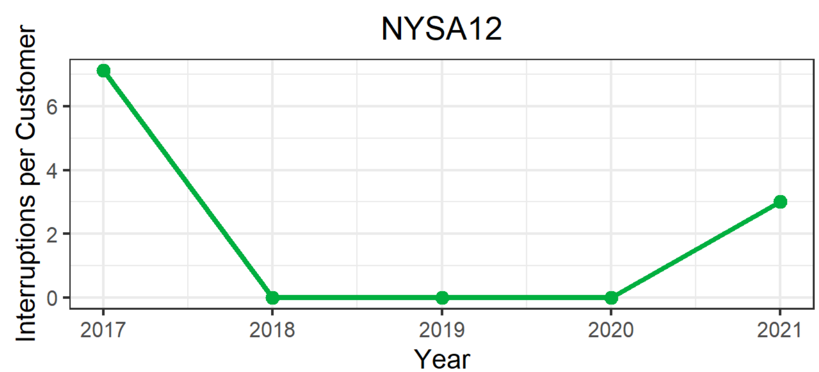

JNVY31
Interruptions per Customer
12.5
10.0
7.5
5.0
2.5
0.0
2017
2018
2019
2020
2021
Year

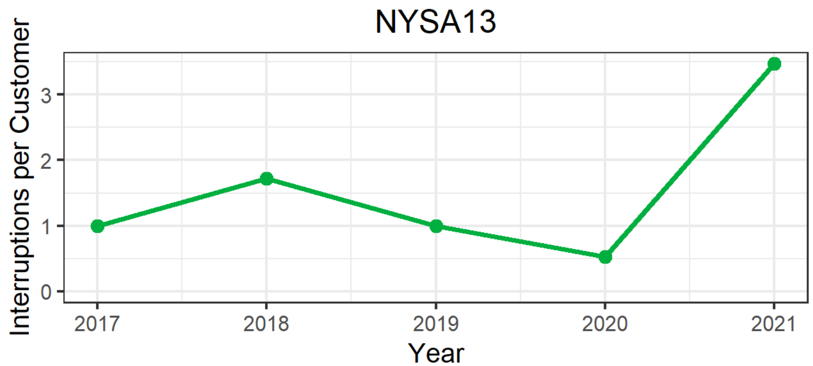

LIME11
Interruptions per Customer
2.5
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

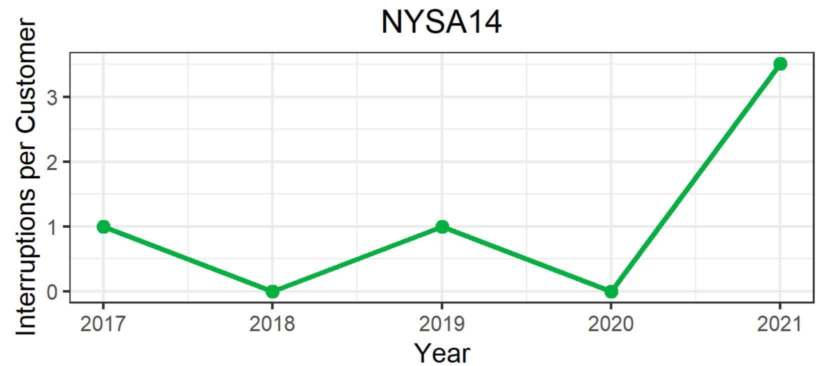

MRBT41
Interruptions per Customer
5
4
3
2
1
0
2017
2018
2019
2020
2021
Year

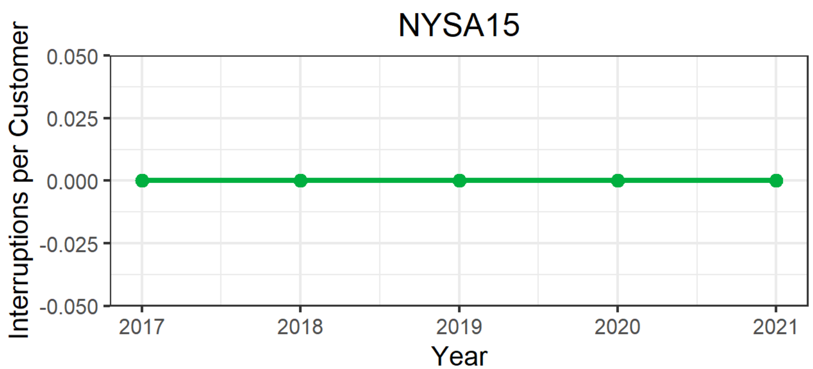

MRBT42
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year

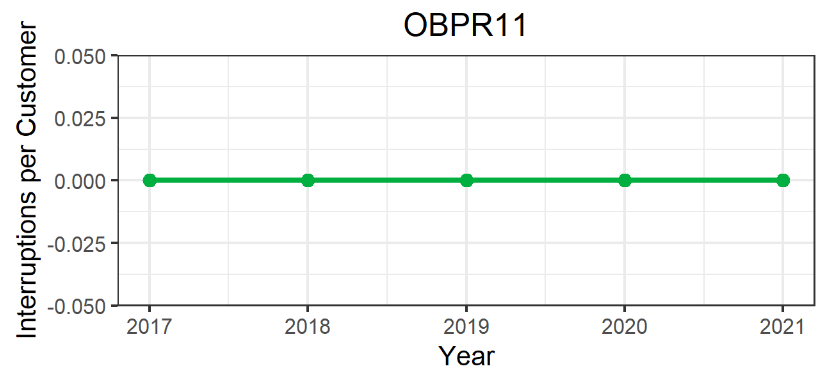

NYSA11
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

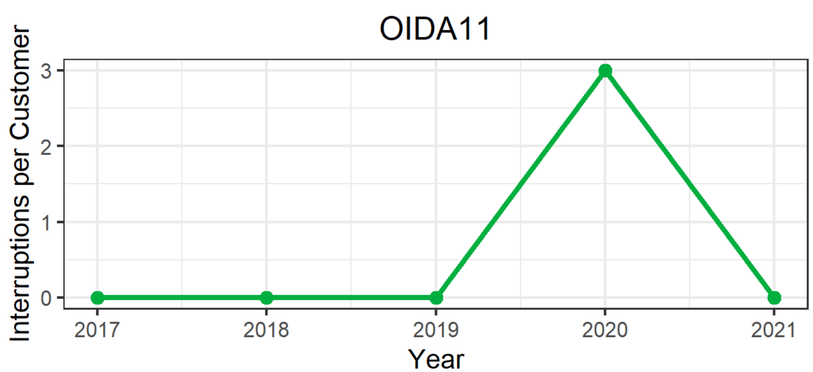

NYSA12
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year

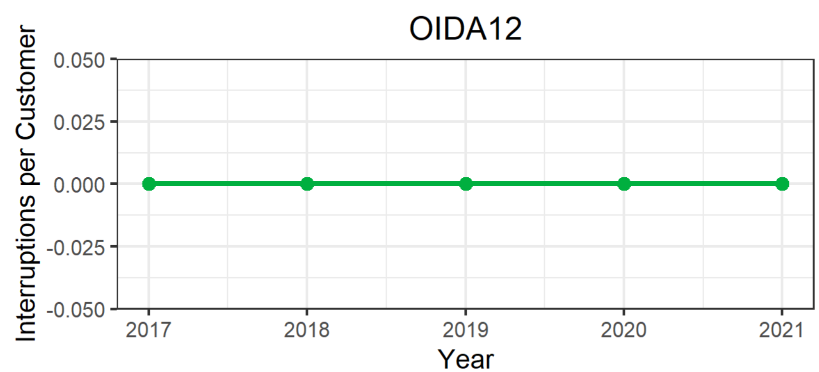

NYSA13
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

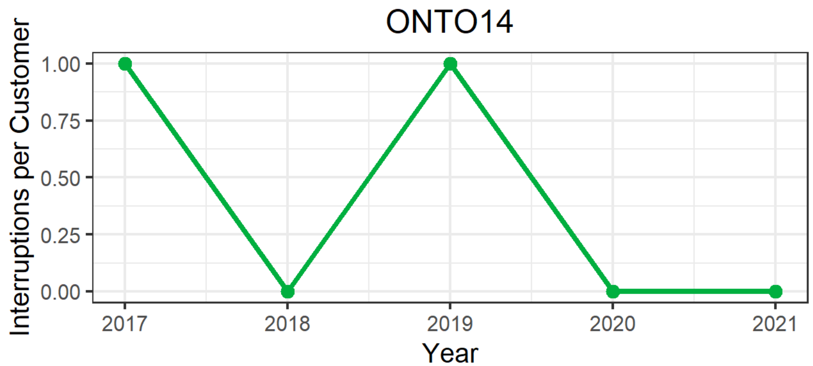

NYSA14
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

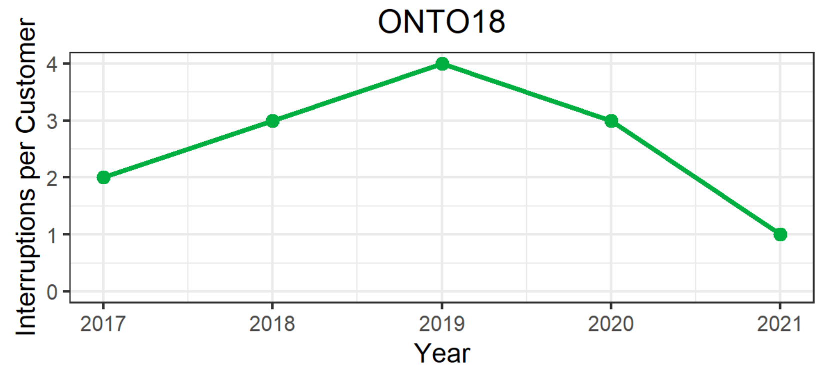

NYSA15
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

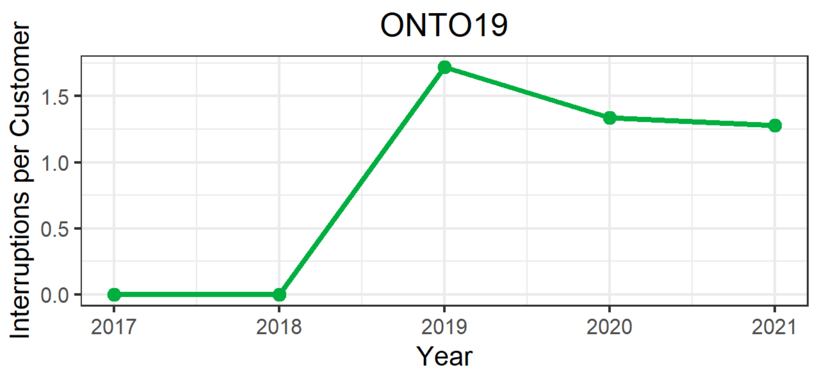

OBPR11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

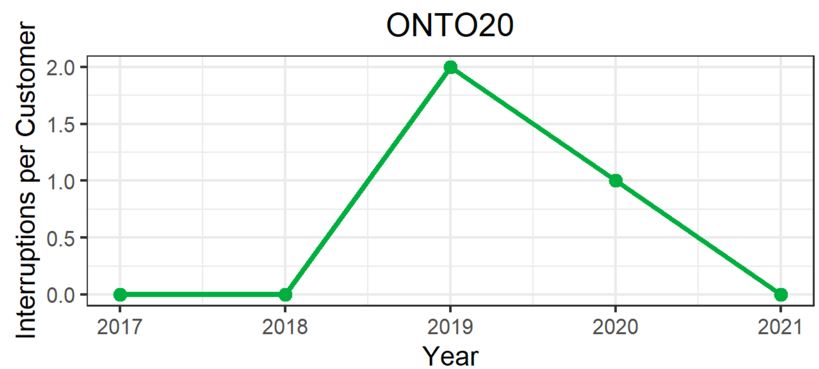

OIDA11
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

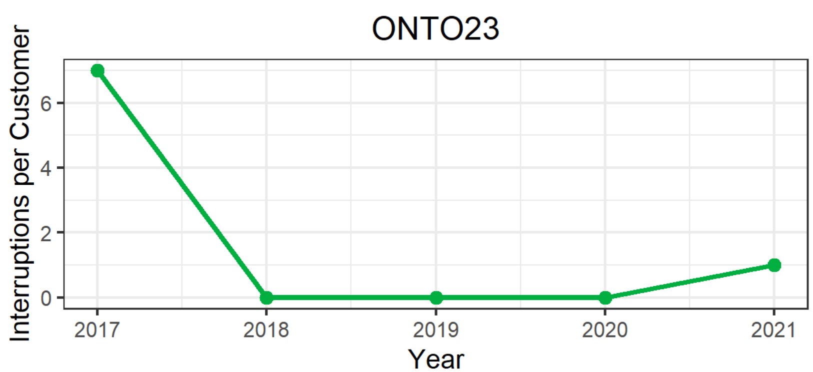

OIDA12
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

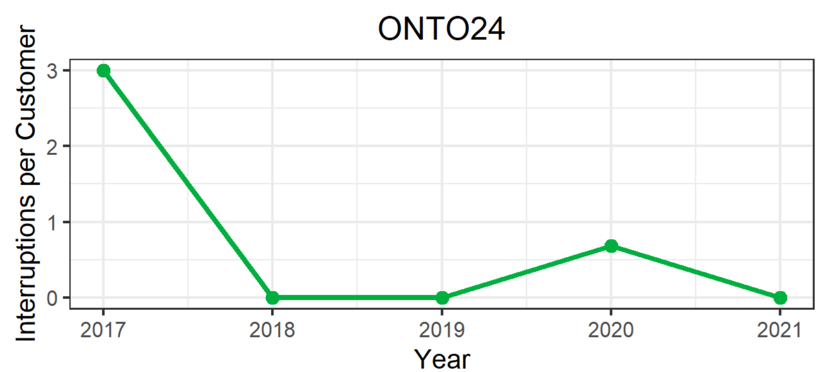

ONTO14
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2017
2018
2019
2020
2021
Year

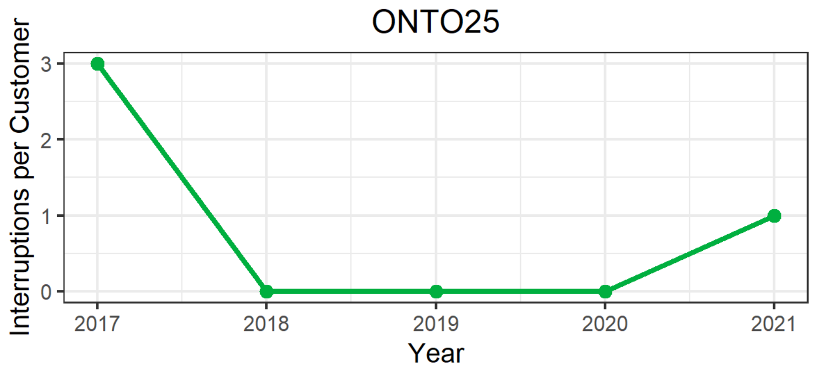

ONTO18
Interruptions per Customer
4
3
2
1
0
2017
2018
2019
2020
2021
Year

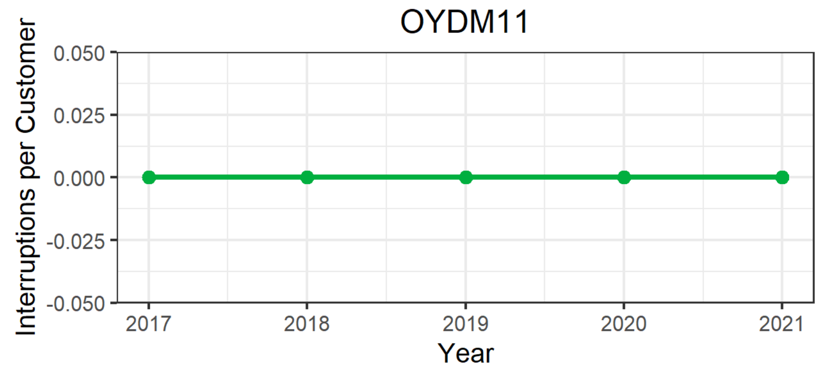

ONTO19
Interruptions per Customer
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

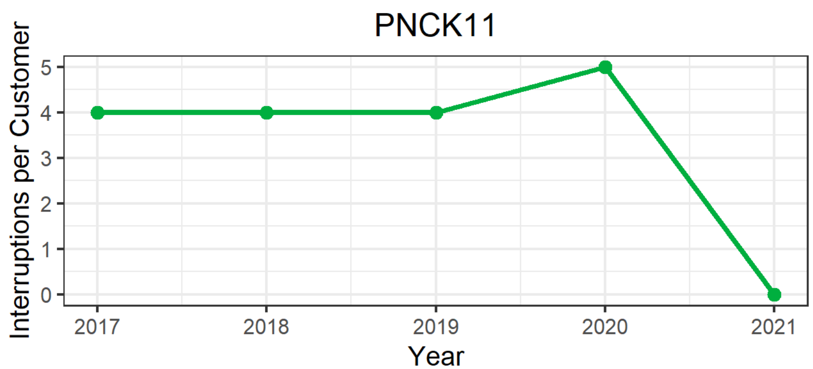

ONTO20
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2017
2018
2019
2020
2021
Year

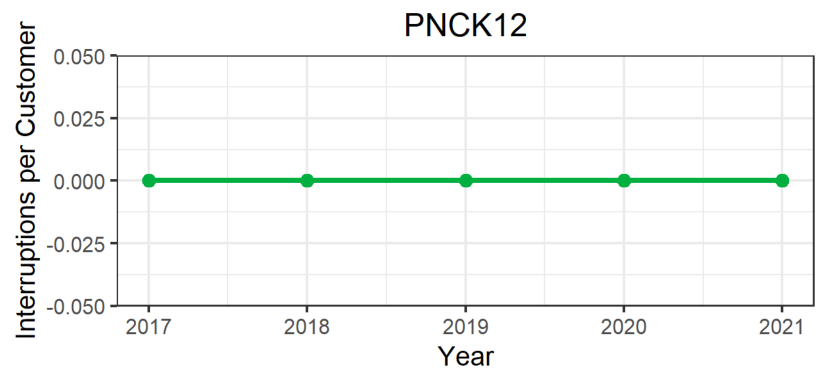

ONTO23
Interruptions per Customer
6
4
2
0
2017
2018
2019
2020
2021
Year

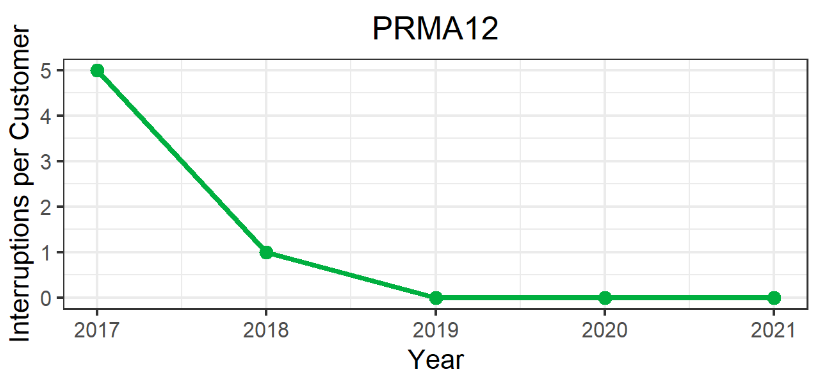

ONTO24
Interruptions per Customer
3
2
1
0
2017
2018
2019
2020
2021
Year

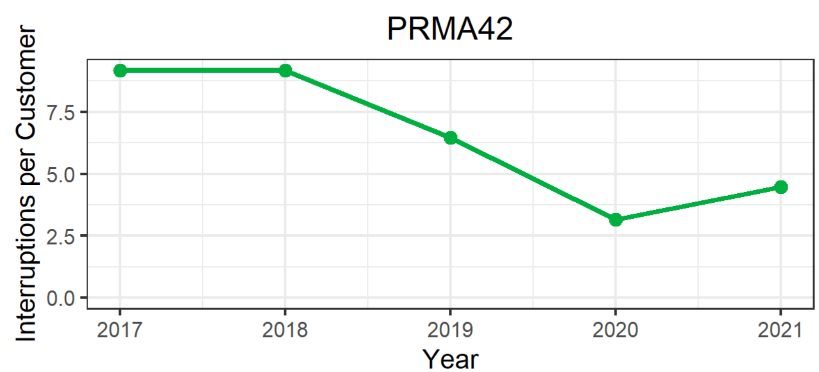

ONTO25
Interruptions per Customer
0
1
2
3
2017
2018
2019
2020
2021
Year

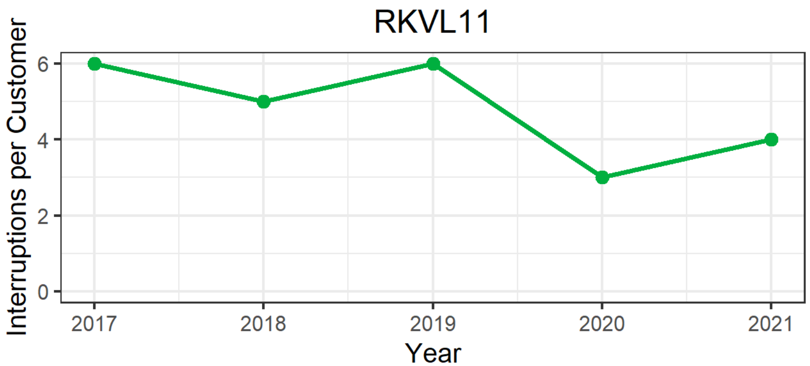

OYDM11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year

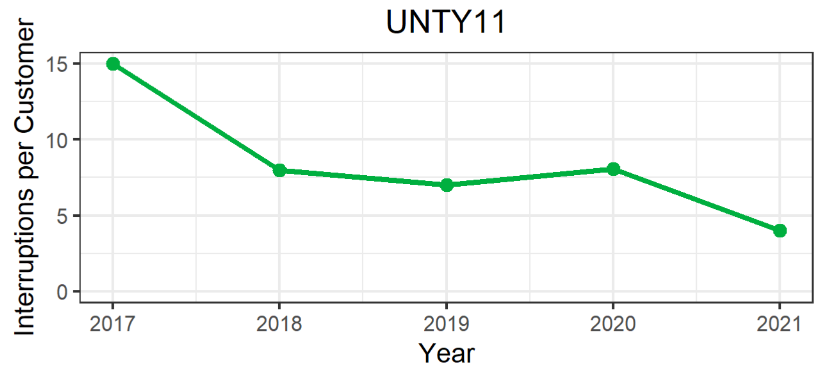

PNCK11
Interruptions per Customer
0
1
2
3
4
5
2017
2018
2019
2020
2021
Year

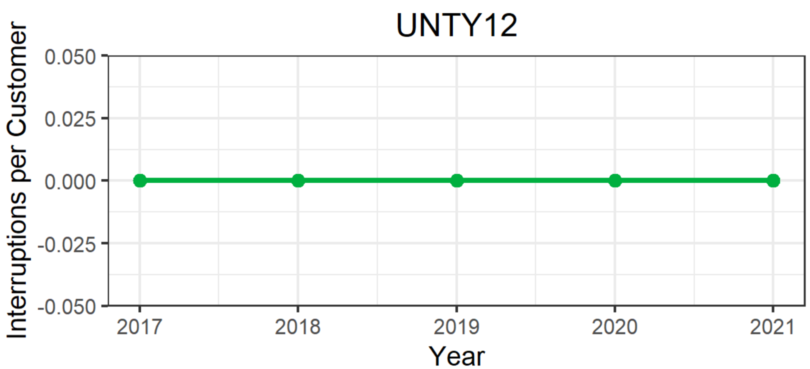

PNCK12
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2017
2018
2019
2020
2021
Year


PRMA12
Interruptions per Customer
0
1
2
3
4
5
2017
2018
2019
2020
2021
Year


PRMA42
Interruptions per Customer
0.0
2.5
5.0
7.5
2017
2018
2019
2020
2021
Year


RKVL11
Interruptions per Customer
0
2
4
6
2017
2018
2019
2020
2021
Year


UNTY11
Interruptions per Customer
0
5
10
15
2017
2018
2019
2020
2021
Year


UNTY12
Interruptions per Customer
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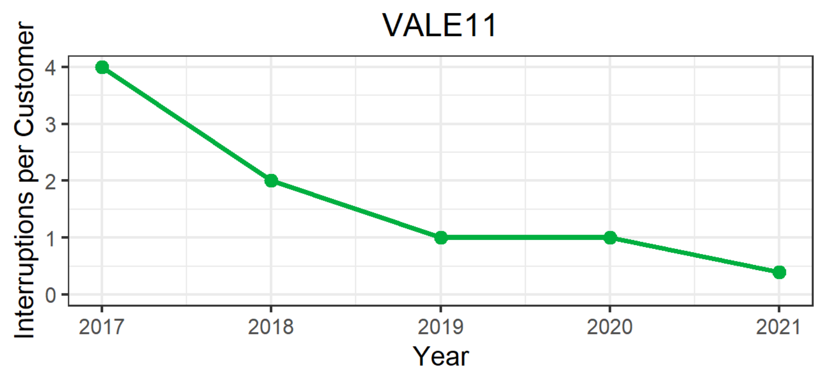
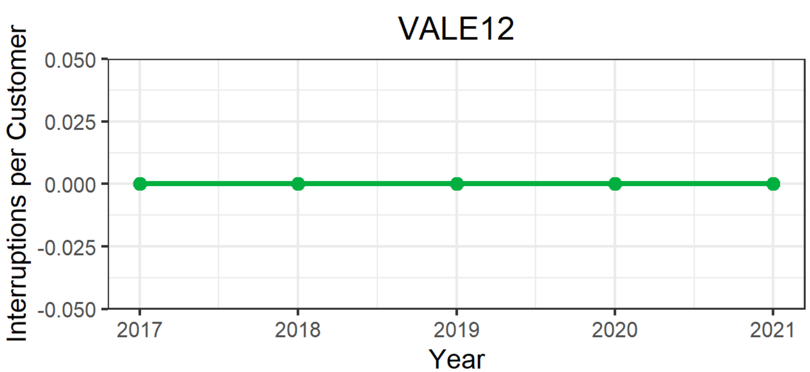
-0.025
0.000
0.025
0.050
2017
2018
2019
2020
2021
Year


VALE11
Interruptions per Customer
0
1
2
3
4
2017
2018
2019
2020
2021
Year


VALE12
Interruptions per Customer
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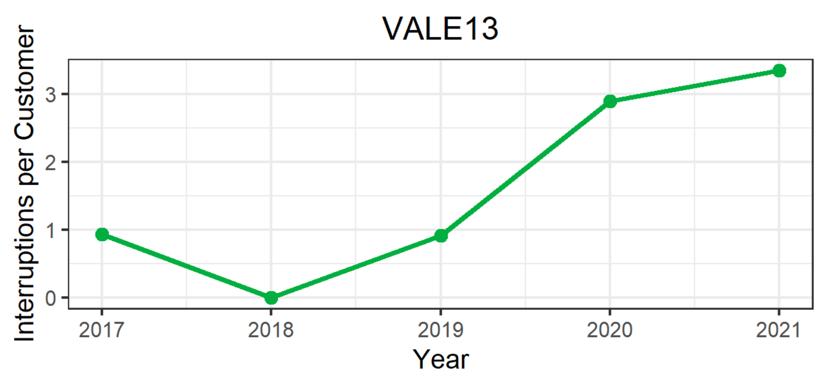
-0.025
0.000
0.025
0.050
2017
2018
2019
2020
2021
Year


VALE13
Interruptions per Customer
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1
2
3
2017
2018
2019
2020
2021
Year

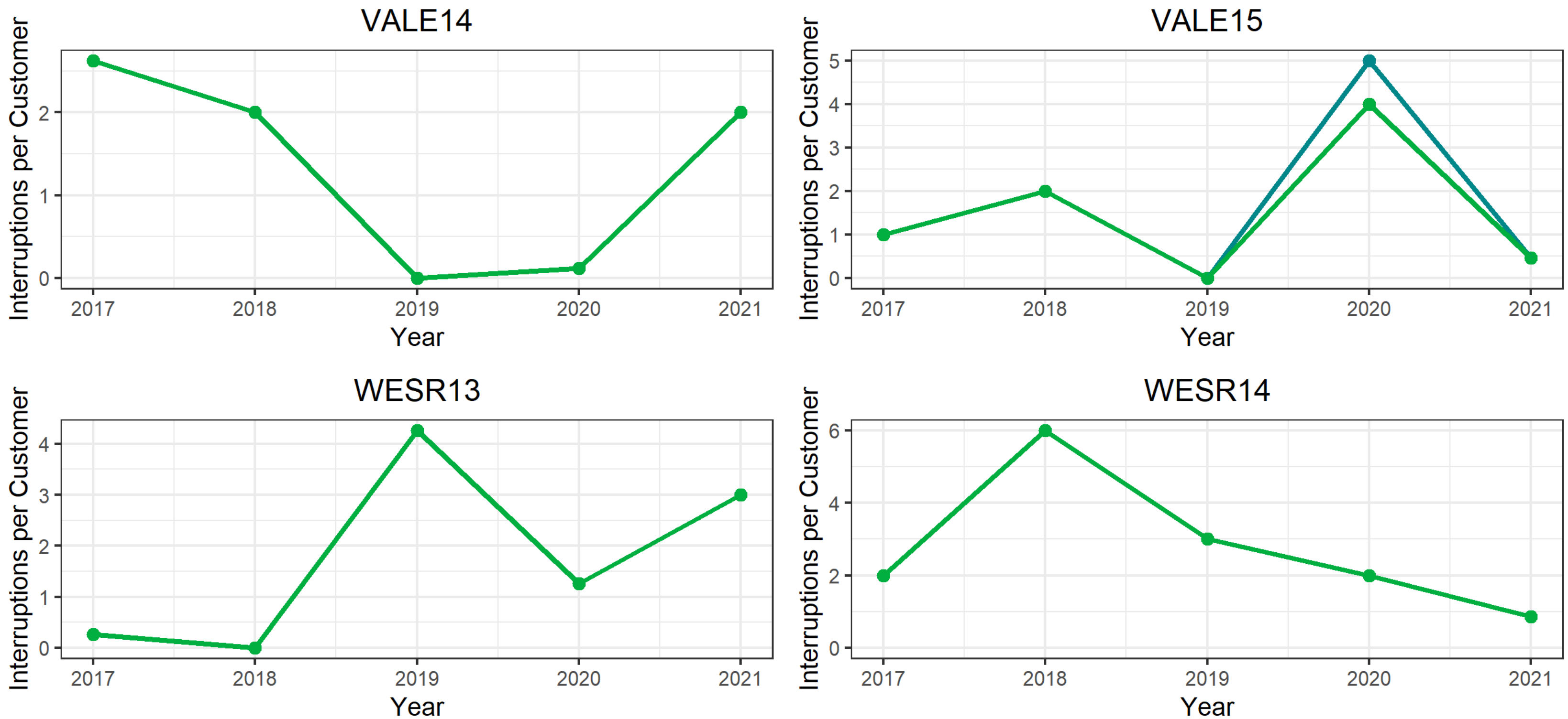


Figure 8 Five Years of Circuit $MAIFI_E$

2021 Descending Indices by Circuit

Circuit	SAIDI	SAIDI MedEx	Circuit	SAIFI	SAIFI MedEx	Circuit	$MAIFI_E$	$MAIFI_E$ MedEx
NYSA15	329.78	329.78	ESTN11	7.00	7.00	JNTA12	14.00	14.00
ESTN11	36.14	36.14	PRMA42	6.51	6.51	JNVY31	12.13	12.13
JNTA12	34.56	34.56	HRPR12	5.86	5.86	DWSY11	9.85	9.85
HRPR12	25.32	25.32	HRPR11	5.18	5.18	ADRN12	7.59	7.59
JNTA11	20.88	20.88	PRMA12	4.67	4.67	ADRN11	6.07	6.07
DWSY11	20.21	20.21	JNTA12	4.09	4.09	MRBT42	6.00	6.00
HRPR11	15.33	15.33	WESR14	3.89	3.89	MRBT41	5.00	5.00
JNVY31	13.73	13.73	HOPE11	3.75	3.75	HOLY12	5.00	5.00
PNCK12	12.97	12.97	CWVY12	3.73	3.73	HMDL12	4.71	4.71
PRMA42	12.50	12.50	CARO13	3.14	3.14	PRMA42	4.47	4.47
WESR14	8.70	8.70	DWSY11	3.14	3.14	CARO12	4.05	4.05
CWVY12	8.55	8.55	JNTA11	3.05	3.05	JNVY12	4.00	4.00
DUKE11	8.18	8.18	DUKE11	3.00	3.00	JMSN12	4.00	4.00
UNTY12	7.66	7.66	VALE11	2.94	2.94	RKVL11	4.00	4.00
PRMA12	6.61	6.61	UNTY12	2.92	2.92	UNTY11	4.00	4.00
HOPE11	6.46	6.46	ADRN12	2.90	2.90	NYSA14	3.51	3.51
MRBT42	6.29	6.29	WESR13	2.62	2.62	NYSA13	3.47	3.47
ADRN12	6.21	6.21	ADRN11	2.49	2.49	VALE13	3.35	3.35
MRBT41	5.28	5.28	NYSA12	2.39	2.39	WESR13	3.00	3.00
WESR13	5.26	5.26	JMSN12	2.29	2.29	NYSA12	3.00	3.00
HMDL12	5.10	5.10	JMSN11	2.24	2.24	JNVY11	2.51	2.51
CARO13	4.71	4.71	HMDL12	2.12	2.12	CARO11	2.48	2.48
JMSN12	4.34	4.34	UNTY11	2.12	2.12	CWVY12	2.00	2.00
VALE11	4.10	4.10	OIDA11	2.08	2.08	VALE14	2.00	2.00
ADRN11	3.93	3.93	CWVY11	2.05	2.05	HRPR12	1.57	1.57
OYDM11	3.87	3.87	PNCK12	2.00	2.00	HOLY13	1.31	1.31
CARO11	3.78	3.78	NYSA15	1.85	1.85	ONTO19	1.28	1.28
NYSA12	3.49	3.49	VALE13	1.67	1.67	ONTO18	1.00	1.00
VALE13	3.15	3.15	VALE14	1.66	1.66	ONTO25	1.00	1.00
OIDA11	3.05	3.05	CARO11	1.38	1.38	ONTO23	1.00	1.00
LIME11	2.92	2.92	JNVY31	1.38	1.38	DRKE11	1.00	1.00
JNVY12	2.64	2.64	NYSA14	1.38	1.38	JNTA11	1.00	1.00
HFWY11	2.58	2.58	VALE15	1.32	1.32	HRPR11	1.00	1.00
ONTO19	2.52	2.52	MRBT42	1.27	1.27	JMSN11	0.98	0.98
CARO12	2.42	2.42	ONTO24	1.21	1.21	HOPE11	0.91	0.91
UNTY11	2.37	2.37	MRBT41	1.09	1.09	WESR14	0.86	0.86
DRKE11	2.35	2.35	CARO12	1.07	1.07	HFWY11	0.70	0.70
NYSA14	2.14	2.14	LIME11	1.05	1.05	VALE15	0.46	0.46
JMSN11	2.09	2.09	VALE12	1.02	1.02	VALE11	0.39	0.39
CWVY11	1.96	1.96	OYDM11	1.00	1.00	LIME11	0.13	0.13
ONTO24	1.94	1.94	JNVY12	1.00	1.00	NYSA11	0.00	0.00
VALE14	1.68	1.68	HFWY12	0.85	0.85	HFWY12	0.00	0.00
NYSA11	1.42	1.42	NYSA11	0.76	0.76	HGTN11	0.00	0.00
HOLY13	1.35	1.35	ONTO19	0.70	0.70	HGTN12	0.00	0.00
ONTO23	1.23	1.23	HOLY13	0.59	0.59	HOLY14	0.00	0.00
VALE15	1.18	1.18	DRKE11	0.52	0.52	HOLY11	0.00	0.00
HGTN11	1.06	1.06	HFWY11	0.52	0.52	DUKE11	0.00	0.00
HFWY12	0.86	0.86	ONTO23	0.46	0.46	ESTN11	0.00	0.00
HOLY11	0.85	0.85	HGTN11	0.40	0.40	HCSU11	0.00	0.00
NYSA13	0.72	0.72	HOLY11	0.39	0.39	CARO13	0.00	0.00
VALE12	0.70	0.70	NYSA13	0.30	0.30	CWVY11	0.00	0.00
HOLY12	0.64	0.64	ONTO20	0.24	0.24	VALE12	0.00	0.00
ONTO20	0.54	0.54	ONTO18	0.18	0.18	ONTO24	0.00	0.00
HGTN12	0.52	0.52	HOLY12	0.15	0.15	OYDM11	0.00	0.00
ONTO18	0.32	0.32	HGTN12	0.15	0.15	PNCK11	0.00	0.00
ONTO25	0.11	0.11	ONTO25	0.05	0.05	PNCK12	0.00	0.00
JNVY11	0.09	0.09	RKVL11	0.03	0.03	PRMA12	0.00	0.00
RKVL11	0.05	0.05	JNVY11	0.02	0.02	UNTY12	0.00	0.00
PNCK11	0.00	0.00	HOLY14	0.00	0.00	ONTO20	0.00	0.00
OIDA12	0.00	0.00	HCSU11	0.00	0.00	NYSA15	0.00	0.00
ONTO14	0.00	0.00	PNCK11	0.00	0.00	OBPR11	0.00	0.00
OBPR11	0.00	0.00	OIDA12	0.00	0.00	OIDA11	0.00	0.00
HOLY14	0.00	0.00	ONTO14	0.00	0.00	OIDA12	0.00	0.00
HCSU11	0.00	0.00	OBPR11	0.00	0.00	ONTO14	0.00	0.00

Table 9 2021 Descending Indices by Circuit

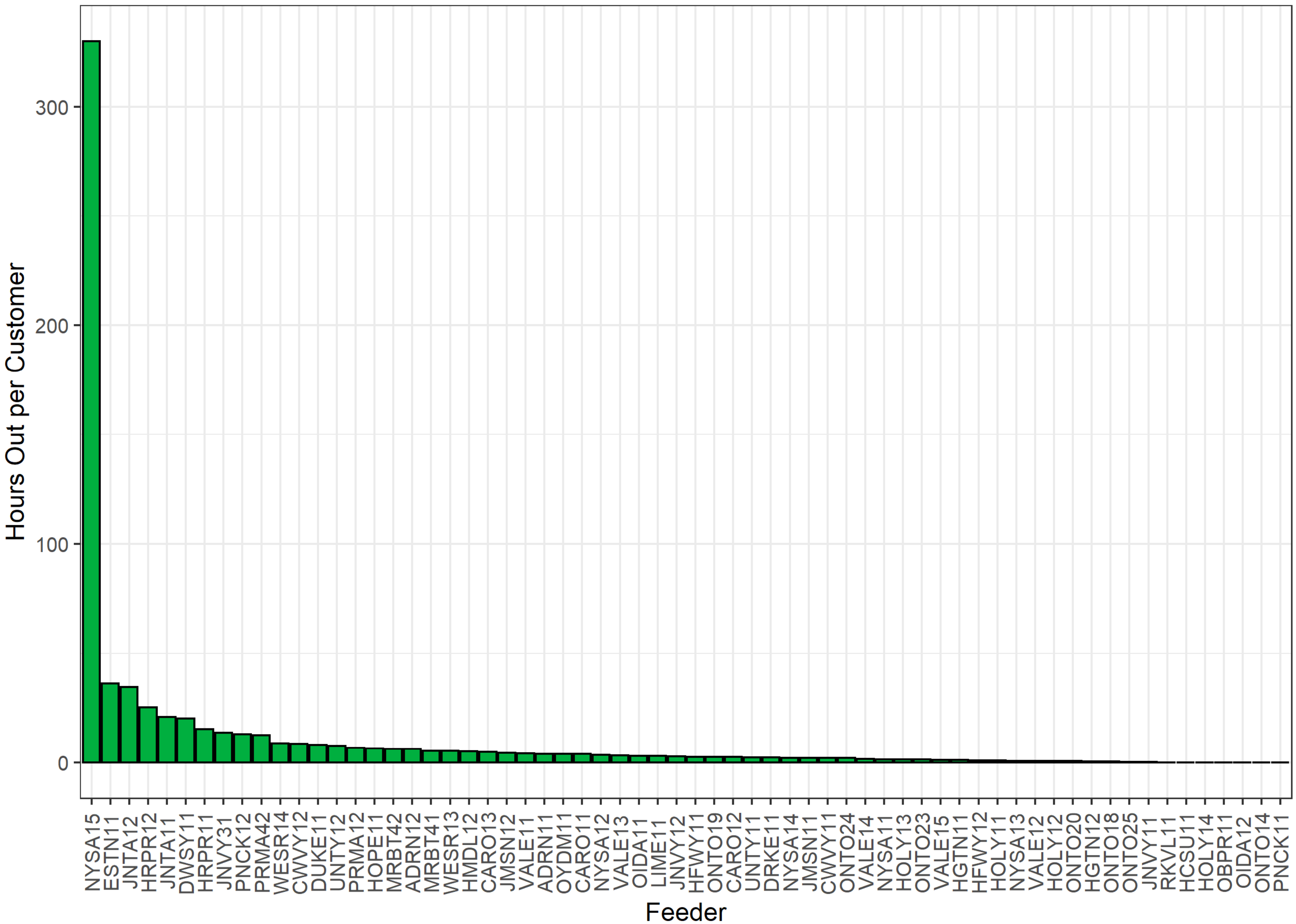


Figure 9 2021 Descending SAIDI by Circuit

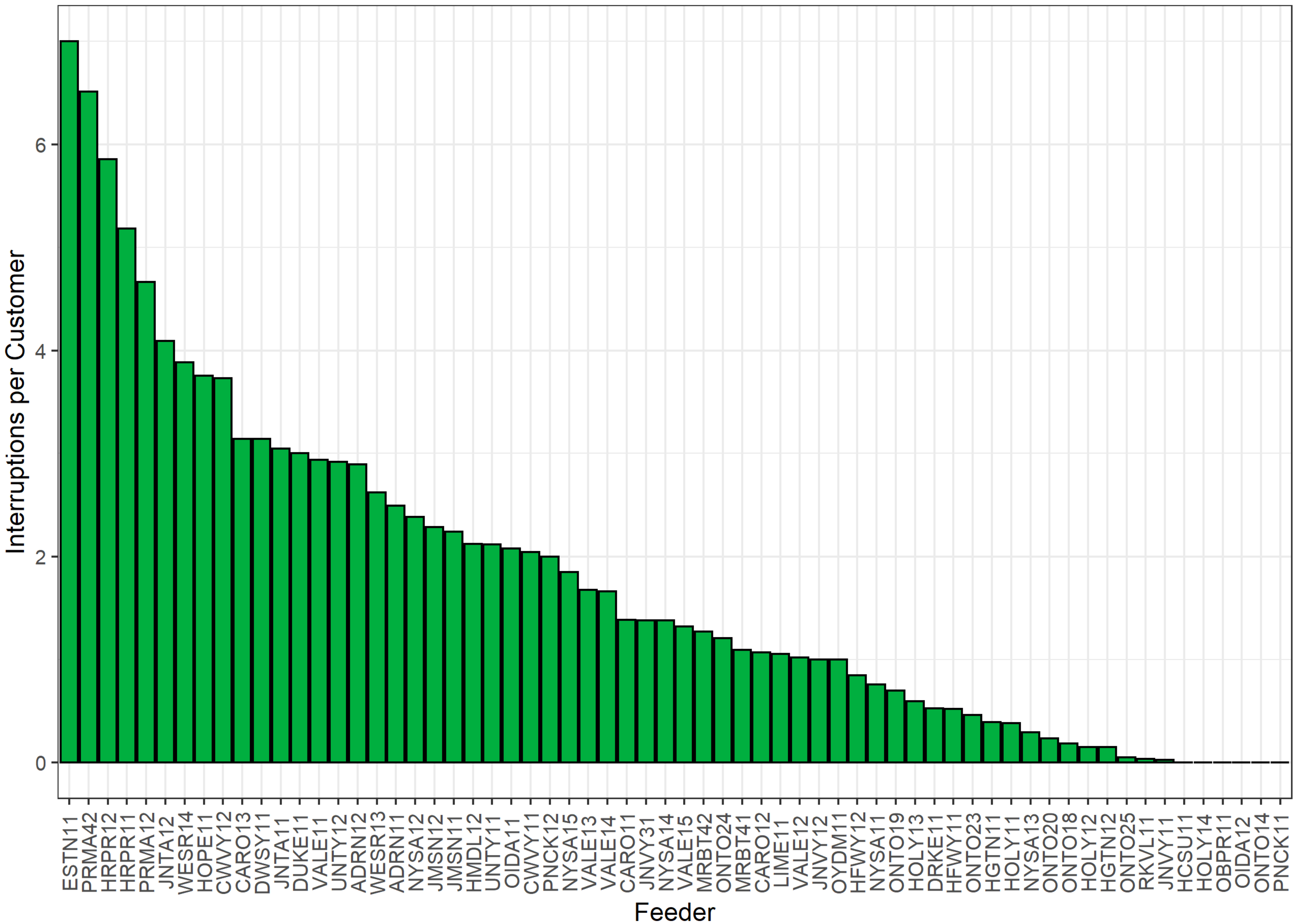


Figure 10 2021 Descending SAIFI by Circuit

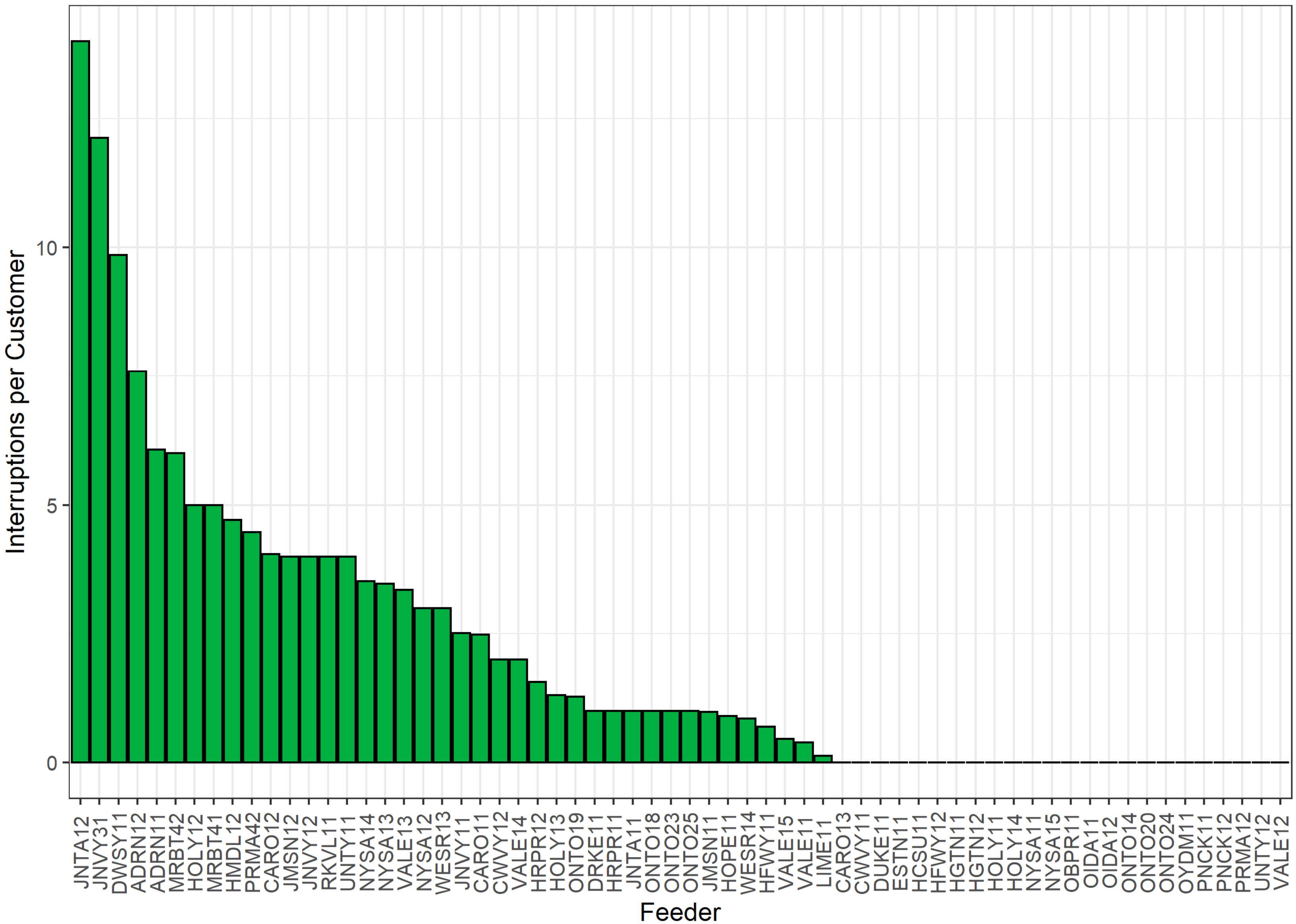


Figure 11 2021 Descending MAIFI$_E$ by Circuit

APPENDIX

Circuit Reference Information

Circuit	Substation	Operating Area	Voltage (kV)	Customers*
ADRN11	Adrian	Western	12.5	415
ADRN12	Adrian	Western	12.5	615
CARO11	Cairo	Western	12.5	1,240
CARO12	Cairo	Western	12.5	89
CARO13	Cairo	Western	12.5	738
CWVY11	Cow Valley	Western	12.5	43
CWVY12	Cow Valley	Western	12.5	113
DRKE11	Durkee	Western	12.5	162
DUKE11	Duke	Western	12.5	28
DWSY11	Drewsey	Western	12.5	188
ESTN11	Easton	Western	12.5	2
HCSU11	Hells Canyon	Western	12.5	2
HFWY11	Halfway	Western	12.5	784
HFWY12	Halfway	Western	12.5	559
HGTN11	Huntington	Western	12.5	91
HGTN12	Huntington	Western	12.5	313
HMDL12	Homedale	Canyon	12.5	154
HOLY11	Holly	Western	12.5	200
HOLY12	Holly	Western	12.5	79
HOLY13	Holly	Western	12.5	170
HOLY14	Holly	Western	12.5	5
HOPE11	Hope	Western	12.5	154
HRPR11	Harper	Western	12.5	111
HRPR12	Harper	Western	12.5	194
JMSN11	Jamieson	Western	12.5	402
JMSN12	Jamieson	Western	12.5	239
JNTA11	Juntura	Western	12.5	65
JNTA12	Juntura	Western	12.5	53
JNVY11	Jordan Valley	Canyon	12.5	86
JNVY12	Jordan Valley	Canyon	12.5	118
JNVY31	Jordan Valley	Canyon	25.0	349
LIME11	Lime	Western	12.5	114
MRBT41	Malheur Butte	Western	34.5	32
MRBT42	Malheur Butte	Western	34.5	11
NYSA11	Nyssa	Western	12.5	852
NYSA12	Nyssa	Western	12.5	322
NYSA13	Nyssa	Western	12.5	771
NYSA14	Nyssa	Western	12.5	254
NYSA15	Nyssa	Western	12.5	13
OBPR11	Oxbow	Western	12.5	1
OIDA11	Ore-Ida	Western	12.5	682
OIDA12	Ore-Ida	Western	12.5	1
ONTO14	Ontario	Western	12.5	35
ONTO18	Ontario	Western	12.5	865
ONTO19	Ontario	Western	12.5	1,872
ONTO20	Ontario	Western	12.5	1,218
ONTO23	Ontario	Western	12.5	50
ONTO24	Ontario	Western	12.5	718
ONTO25	Ontario	Western	12.5	522
OYDM11	Owyhee Dam	Western	12.5	15
PNCK11	Pine Creek	Western	12.5	96
PNCK12	Pine Creek	Western	12.5	2
PRMA12	Parma	Western	12.5	3
PRMA42	Parma	Western	34.5	195
RKVL11	Rockville	Canyon	12.5	32
UNTY11	Unity	Western	12.5	150
UNTY12	Unity	Western	12.5	238
VALE11	Vale	Western	12.5	1,043
VALE12	Vale	Western	12.5	56
VALE13	Vale	Western	12.5	583
VALE14	Vale	Western	12.5	317
VALE15	Vale	Western	12.5	483
WESR13	Weiser	Western	12.5	196
WESR14	Weiser	Western	12.5	35

Table 10 Circuit Reference Information

*Some circuits have customers in Idaho and Oregon. The counts are for Oregon customers only as of 12/31/2021.

Five Years of System Pole and Trench Miles

Year	Overhead (OH) Pole Miles	Underground (UG) Trench Miles	Distribution All Miles	Transmission Line (Structure/Pole) Miles*	Percent OH / UG
2021	2,113.5	97.4	2,210.9	757.6	95%/5%
2020	2,113.2	94.0	2,207.2	757.3	95%/5%
2019	2,113.6	100.8	2,214.4	757.3	95%/5%
2018	2,113.0	99.9	2,212.9	757.0	95%/5%
2017	2,114.5	98.9	2,213.5	759.4	96%/4%

Table 11 Five Years of System Pole and Trench Miles

*Transmission line miles include some lines that do not directly serve customer load.

2021 Major Event Day System Summary

Date	Cause	Customers	CMI	CI	SAIDI (Minutes)	SAIFI	CAIDI (Minutes)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 12 2021 MED System Summary

2021 Major Event Day Feeder Summary

Date	Feeder	Customers	CMI	CI	SAIDI (Minutes)	SAIFI	CAIDI (Minutes)
N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table 13 2021 MED Feeder Summary

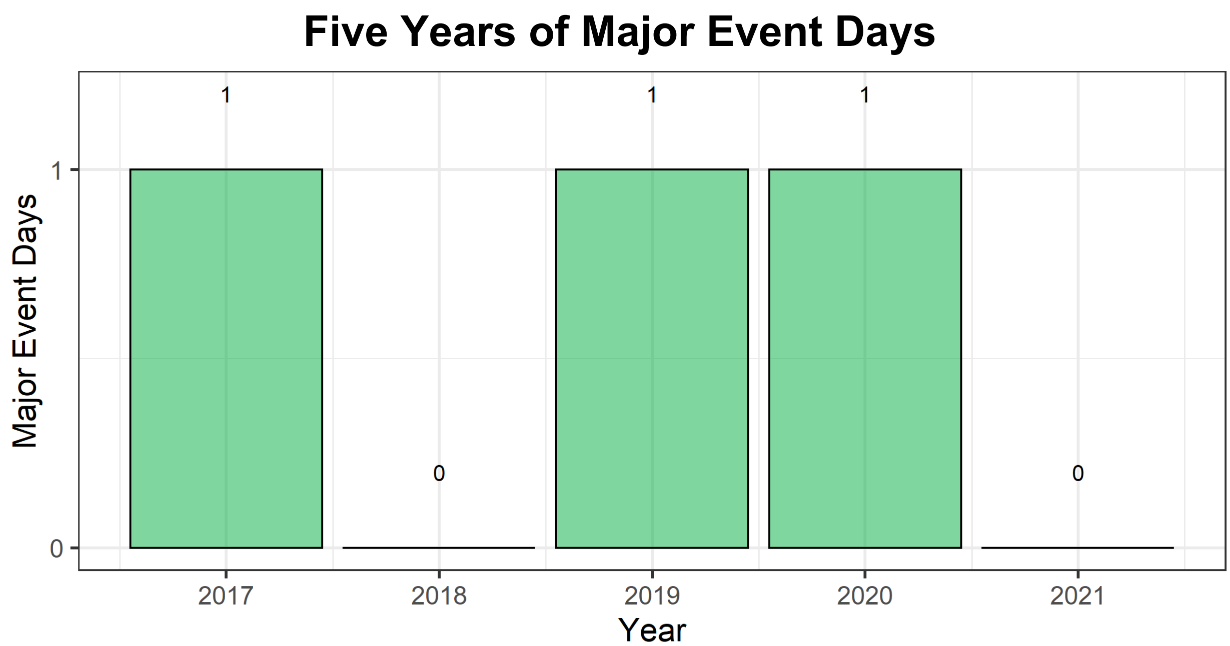


Figure 12 Five Years of MEDs

Cause Category Translation

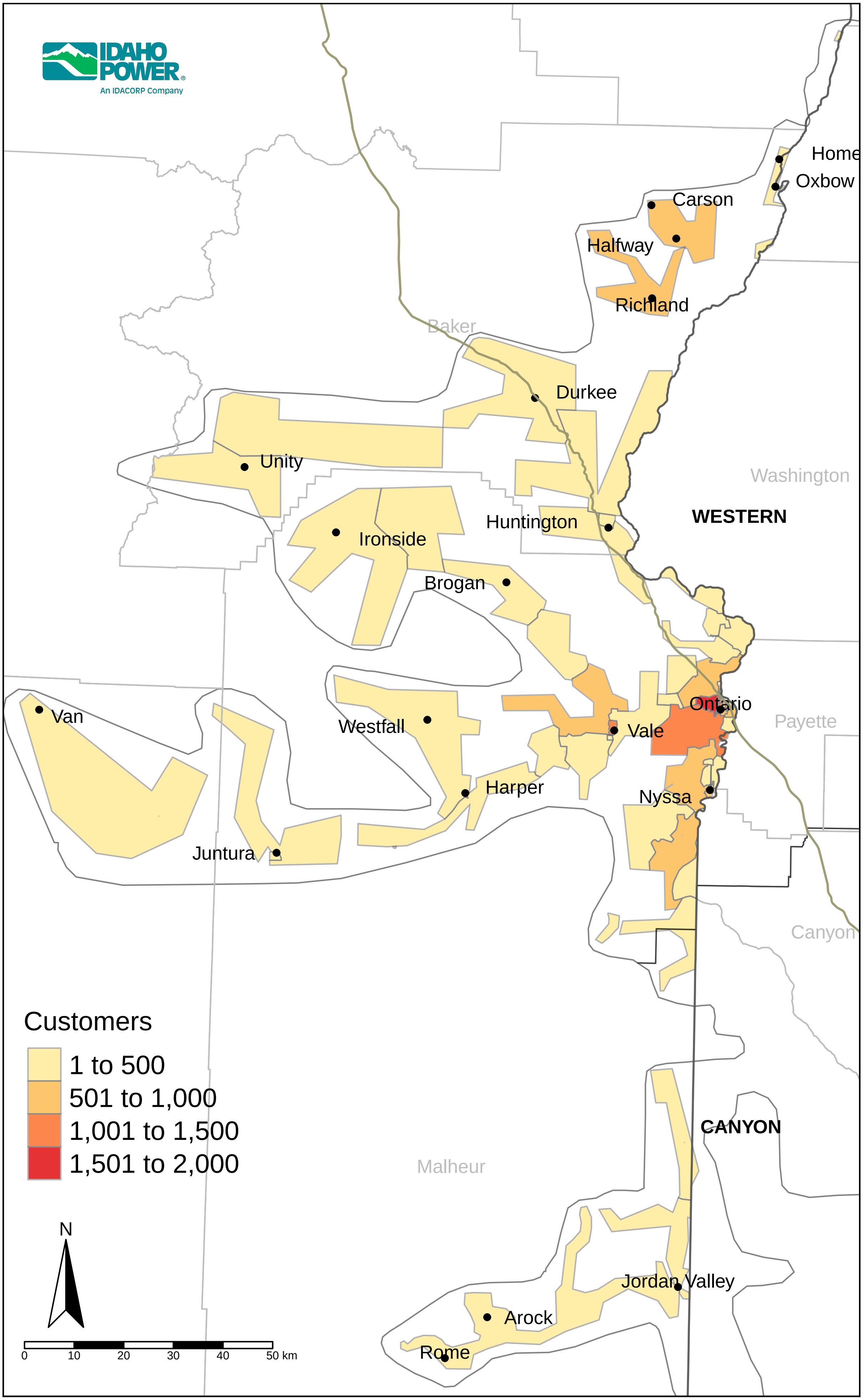
Idaho Power Cause	OAR 860-023-0151 (2)(b) Cause
Loss of Supply – Transmission*	Loss of Supply – Transmission
Loss of Supply – Station*	Loss of Supply – Substation
Corrosion/Rot	Distribution – Equipment
Electrical Failure	Distribution – Equipment
Loose Hardware	Distribution – Equipment
Mechanical Failure	Distribution – Equipment
Improper Installation	Distribution – Equipment
Contamination	Distribution – Equipment
Lightning	Distribution – Lightning
Other IPC Circuit	Distribution – Other
Other (Define in Comments)	Distribution – Other
Safety Precaution	Distribution – Other
Utility Operating Error	Distribution – Other
Planned Maintenance	Distribution – Planned
Structures (Signs, Buildings)	Distribution – Public
Construction/Dig-in	Distribution – Public
Foreign Object (Pipe, Kite, Tree Trim)	Distribution – Public
Vandalism	Distribution – Public
Vehicle Collision	Distribution – Public
Momentary (Tripping)	Distribution – Unknown
Unknown	Distribution – Unknown
Tree/Vegetation	Distribution – Vegetation
Loading/Unloading (Snow, Ice)	Distribution – Weather (Non-Lightning)
Unstable Earth	Distribution – Weather (Non-Lightning)
Load Shed/Transfer	Distribution – Weather (Non-Lightning)
Wildland/Building Fire	Distribution – Weather (Non-Lightning)
Overload/Cold Load	Distribution – Weather (Non-Lightning)
Bird – NonRaptor	Distribution – Wildlife
Bird – Raptor	Distribution – Wildlife
Large Animal (Livestock)	Distribution – Wildlife
Small Animal	Distribution – Wildlife

Table 14 Cause Category Translation

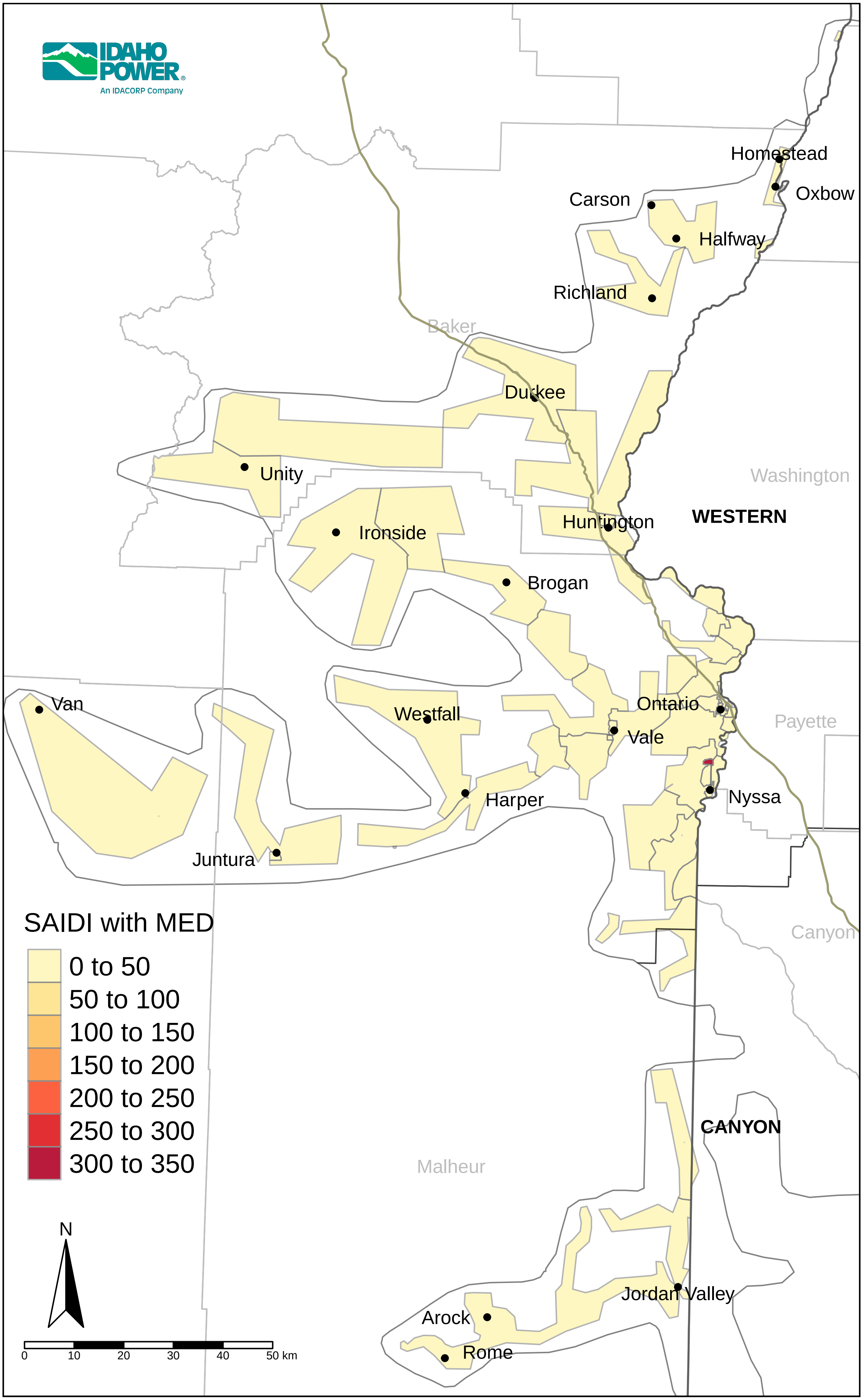
*These are also identified from the Idaho Power SYSTEM field. This field has values for “Transmission”, “Substation”, “Distribution Primary OH”, “Distribution Primary UG”, “Secondary/Service OH” and “Secondary/Service UG”. So, “Loss of Supply – Transmission” in this report includes events where the CAUSE field was “Loss of Supply – Transmission” **or** the SYSTEM field was “Transmission”, and “Loss of Supply – Substation” includes events where the CAUSE field was “Loss of Supply – Station” **or** the SYSTEM field was “Substation”.

MAPS

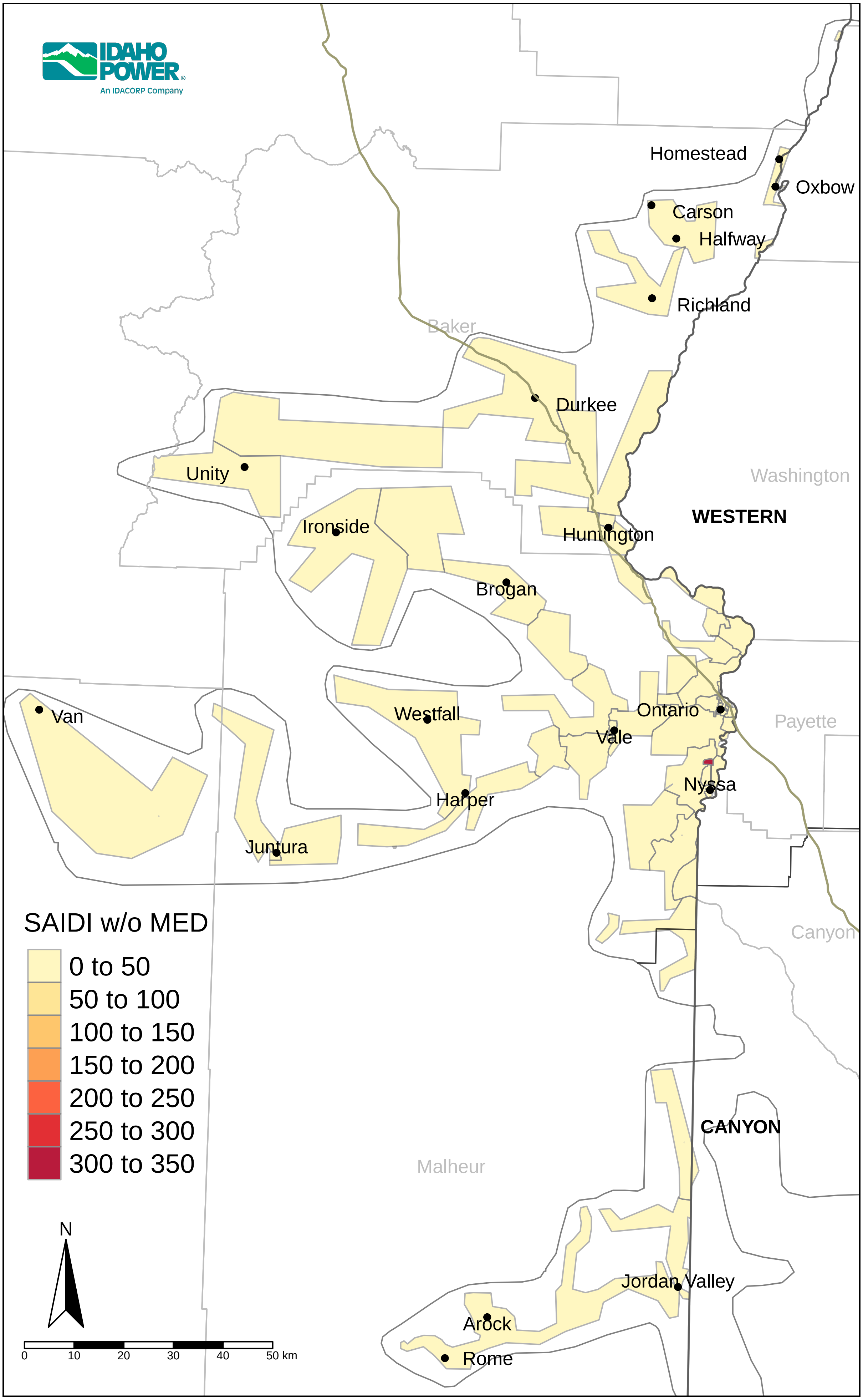
2021 Customers Oregon Area



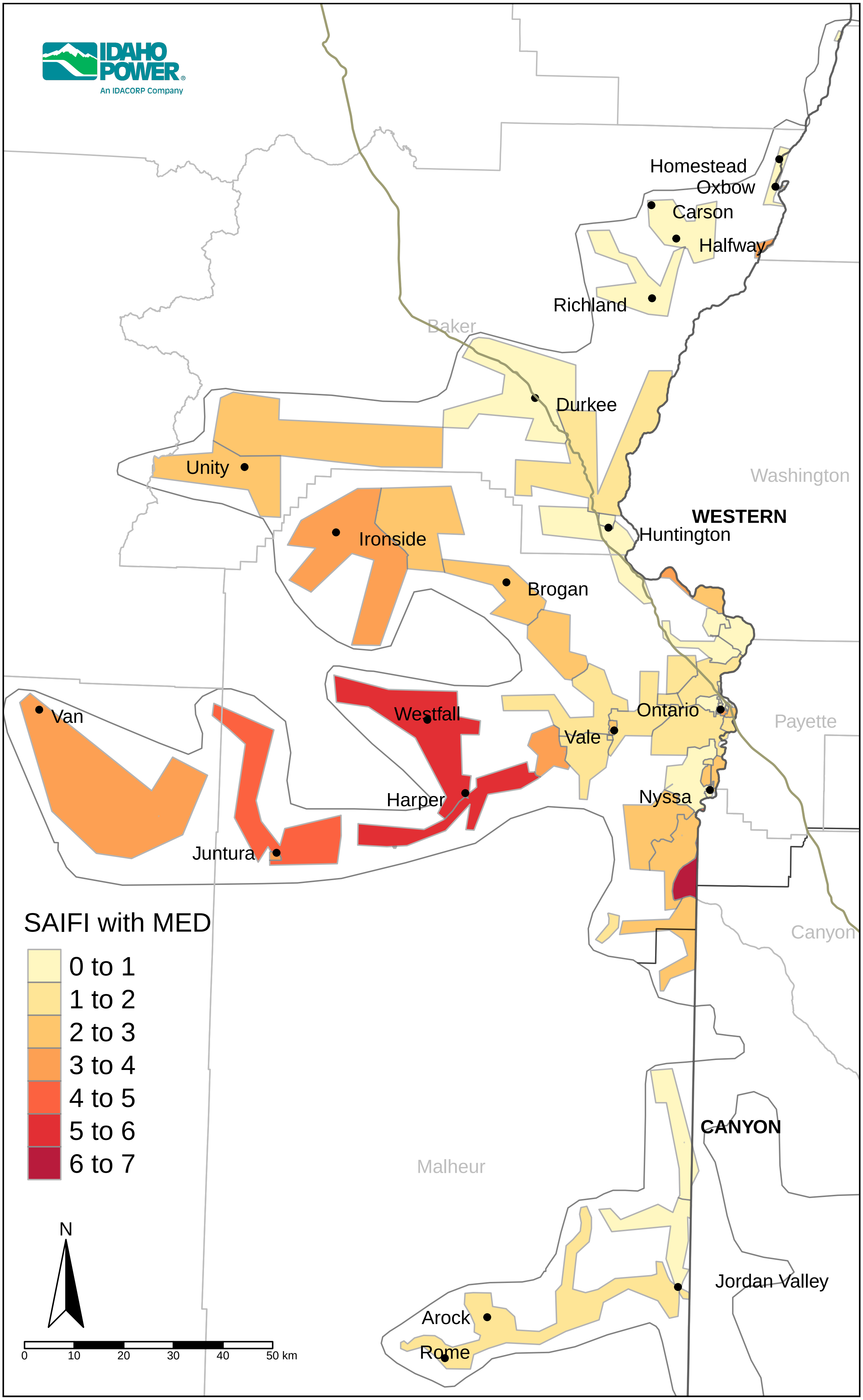
2021 SAIDI with MED Oregon Area



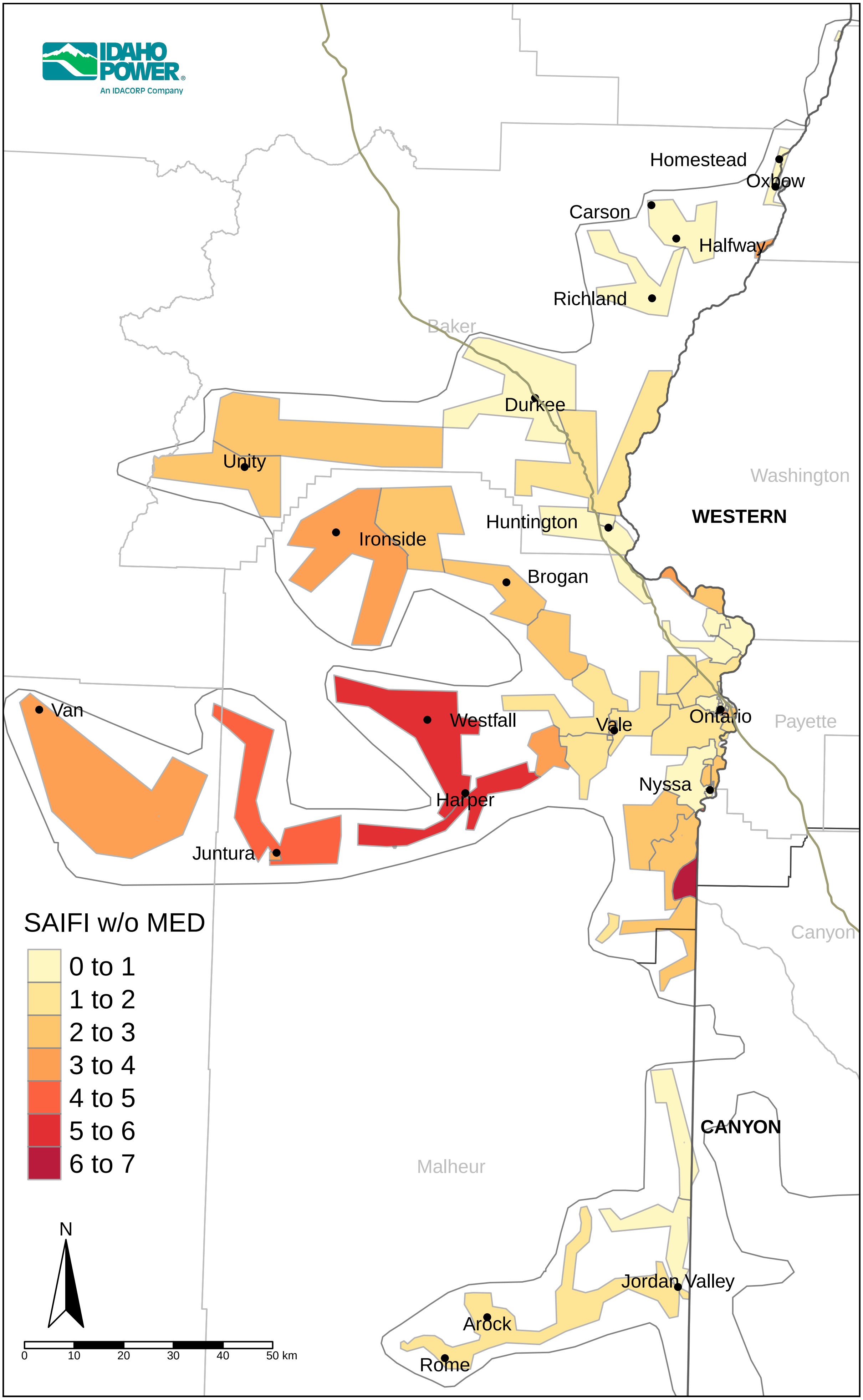
2021 SAIDI w/o MED Oregon Area



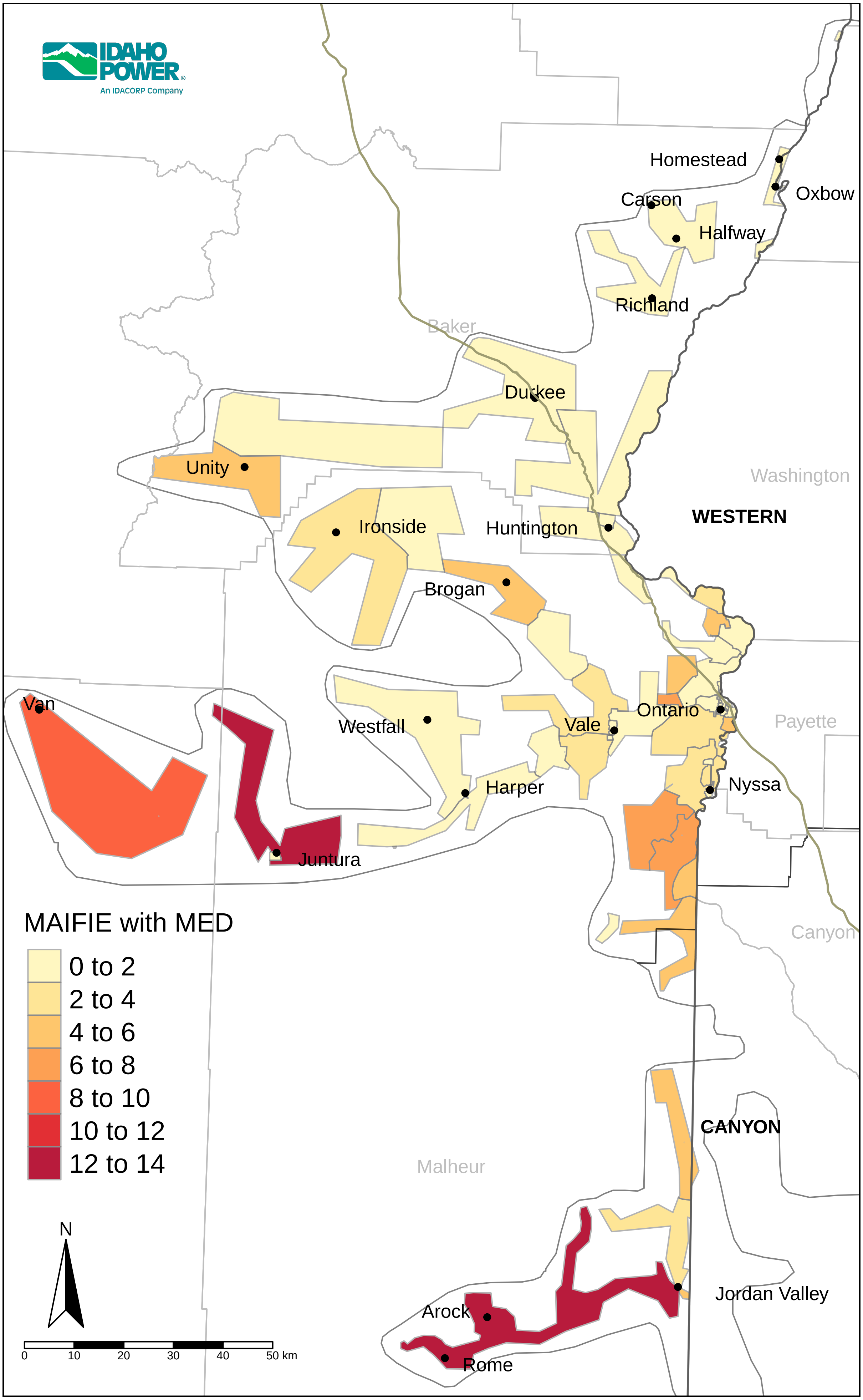
2021 SAIFI with MED Oregon Area



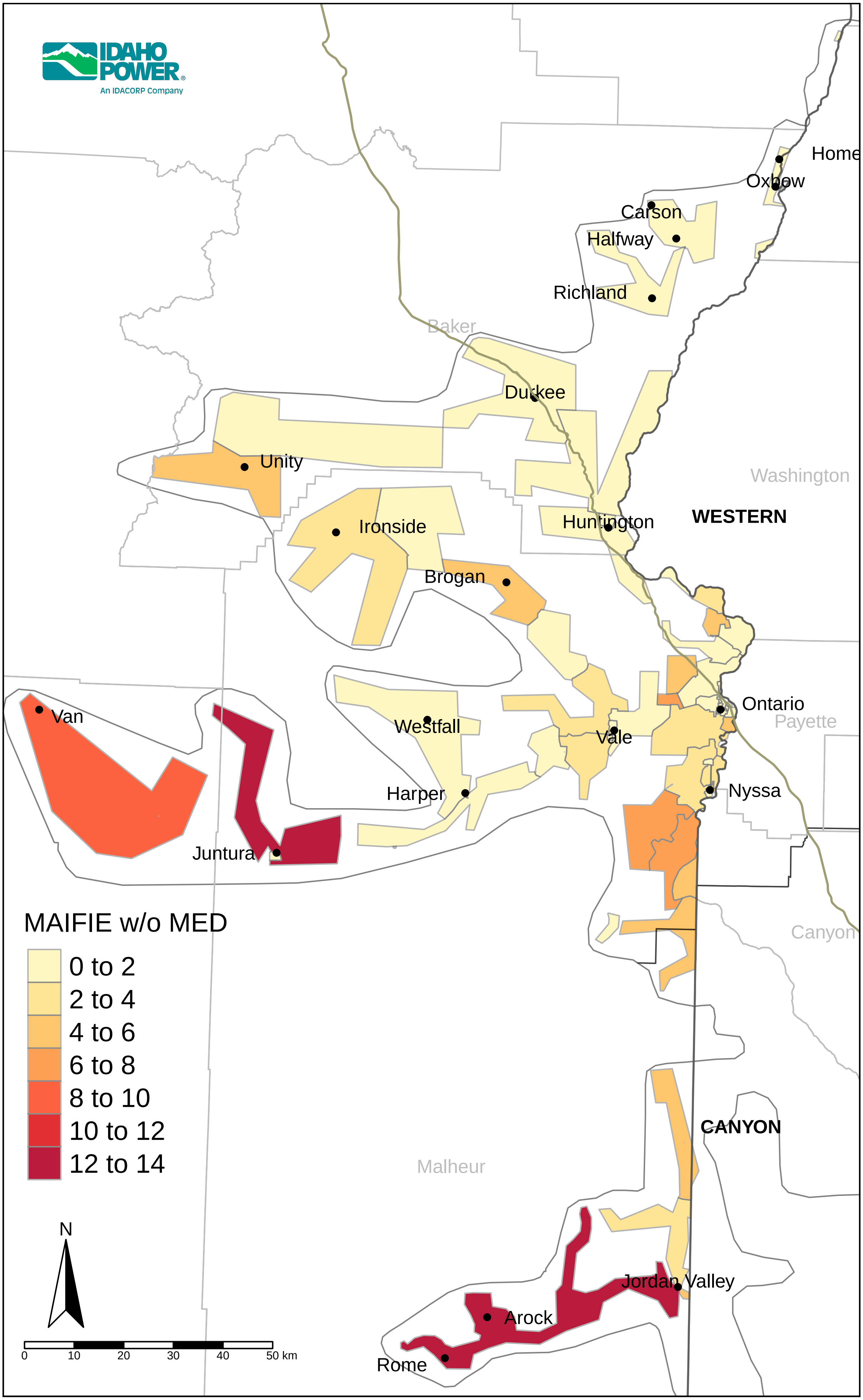
2021 SAIFI w/o MED Oregon Area



2021 MAIFIE with MED Oregon Area



2021 MAIFIE w/o MED Oregon Area



Appendix B: Asset Class Definitions

ASSET CLASS DEFINITIONS

Capacitors—These devices help adjust the power factor and voltage on distribution feeders and allow electricity to be distributed more efficiently.

Circuit Breakers—These devices are automatic, high-voltage electric switches typically installed inside of substations. They are protective devices that are used to interrupt current during fault and overload conditions.

Distribution Poles—The poles support overhead conductors for distribution feeders and may also have other feeder hardware mounted on them.

Electromechanical Relays—These devices are part of a protection system that monitors current and voltage readings to identify system fault conditions and then use physical moving parts to send (relay) a response to protective equipment to isolate the fault.

Fuses—These devices are used to isolate faults and protect other equipment from overloads by melting when their rated current is exceeded.

Meters—These devices are used to measure the amount of energy delivered to customers.

Microprocessor Relays—These devices are part of a protection system that monitors current and voltage readings with a microprocessor to identify system fault conditions and then send (relay) a response to equipment to isolate the fault condition.

Overhead Transformers—These devices are installed on distribution poles and transform distribution feeder voltage to a lower voltage that may be used by customers.

Pad-mounted Transformers—These devices are installed on the ground and transform distribution feeder voltage to a lower voltage that may be used by customers

Primary Overhead Lines—Conductor or wires that are installed on distribution poles and insulators to carry electricity to customers. These lines are typically operated at 12,470 V or 35,000 V.

Primary Underground Lines—Conductor or wires that are installed underground using conduits and vaults to carry electricity to customers. These lines are typically operated at 12,470 V or 35,000 V.

Reclosers—These devices are automatic, high-voltage electric switches that are typically installed on distribution feeders. Reclosers are used to isolate a section of a distribution feeder in fault or overload conditions to minimize the number of customers without service.

Regulators—These devices are used to maintain proper voltage levels to customers. The devices monitor the voltage level and adjust the output voltage to compensate for changes in the source voltage or the load current.

Sectionalizers—These devices are used to automatically isolate faulted sections of a distribution feeder once an upstream protective device, such as a circuit breaker or recloser, has interrupted the fault current. Sectionalizers are typically installed downstream of a recloser.

Smart Grid Monitors (SGM)—These devices are used to monitor voltage on a distribution feeder and may also monitor ambient temperature and wind speed. The monitored data is sent to a central database where it is analyzed for outage indication.

Substation Transformer—These devices transform electric energy from one voltage to another and typically connect a transmission system to a distribution system. The rating of the transformer is based on the primary and secondary voltage and is designed to meet the peak demand capacity.

Switches—These are manually operated devices on the distribution feeder which can close to connected conductors or open to separate them electrically.

ASSET CLASS DATA AS OF JULY 2022

Asset Classes	Average Age	Service Life	Total #	Age range of Assets										
				0–9	10–19	20–29	30–39	40–49	50–59	60–69	70–79	80–89	90–99	100+
Substation Transformer	53	70	33	2	0	2	2	4	12	4	4	3		
Circuit Breakers	17.4	50	68	20	3	45								
Electromechanical Relays	51	45	41	0	2	1	0	19	11	8				
Microprocessor Relays	11.5	20	83	42	34	6	0	1						
Smart Grid Monitors	5		181	117	64									
Overhead Transformers	18.6	30-40	10,096	1,658	1,654	6,714	19	1	5	0	5			
Pad-mounted Transformers	21.1	40-50	924	266	180	247	80	126	24	1				
Distribution Poles	29.2	40-50	38,545	3,238	3,351	18,449	3,563	4,899	3,469	1,331	242	3		
Primary Overhead Line	35.3	40-50	1,990	80	133	910	102	249	257	120	125	10	1	
Primary Underground Line	21.8	40-50	82	20	14.3	27	10	9.5	1					
Meters	8.9	16-20	20,136	1,770	2,765	8,489	3,246	2,145	934	471	267	41	7	1
Fuses	17	20-30	1,592	375	341	866	8	2	1					
Switches	15.6	20-30	330	102	65	160	2	1						
Regulators	12.1	20	113	40	51	22								
Capacitors	14.5	30-40	85	33	20	30	1	1						
Reclosers	11.3	50	144	73	47	24								
Sectionalizers	20.2	50	16	2	7	6	0	0	1					

Extreme Temperature Forecasting Planning Limits

PLANNING LIMIT OPERATING PHILOSOPHY

Knowing that the extreme temperature forecasting will build in more operational flexibility in the normal temperature years and fostering greater reliability in the extreme temperature years, the planning team implemented extreme temperature forecasting. The planning limits were developed by a technical team made up of subject matter experts from a several Idaho Power stakeholder departments.

PLANNING LIMIT RESULTS

Substation Transformer Summer Rating

Recommendation for distribution load serving substation transformers: The technical team recommends targeting 98% of nameplate as a planning limit threshold for summer peaking transformers in extreme temperature years.

Recommendation for tie-bank transformers: The technical team recommends planning a 100% of nameplate as a planning limit threshold for summer peaking tie-bank transformers in extreme temperature years.

Recommendation for tie-bank transformers with N-1 contingency: The technical team recommends planning a 110% of the nameplate rating as a planning limit threshold for summer peaking network tie-bank transformers in extreme temperature years. Radial tie-bank transformers are limited to 100% as a planning limit threshold for summer peaking in extreme temperature years. Increased ratings above 110% of nameplate will require specific approval from the Substation Apparatus department.

Substation Transformer Winter Rating

Recommendation for distribution load serving substation transformers: The technical team recommends planning a 110% winter planning limit for distribution transformers in extreme temperature years. Increased ratings above 110% of nameplate may be assigned based on specific approval from the Substation Apparatus Department.

Recommendation for tie-bank transformers: The technical team recommends planning a 110% winter planning limit for tie-bank transformers in extreme temperature years.

Recommendation for tie-bank transformers with N-1 contingency: The technical team recommends planning a 120% winter planning limit rating for network tie-bank transformers in extreme temperature years. Radial tie-bank transformers are 110%. Increased ratings above 120% of nameplate will require specific approval from the Substation Apparatus department.

*Any changes to transformer ratings need documentation for Planning and Operations.

Summer/Winter Feeder Ratings

Recommendation for distribution 12.5 kV feeders: The technical team recommends a 10 MVA planning limit for summer and winter overhead and underground 12.5 kV feeders.

Recommendation for distribution 34.5 kV feeders: The technical team recommends a 20 MVA planning limit for summer and winter 34.5 kV feeders. On a case-by-case basis, based on feeder SAIFI performance and topology, Regional Planning, Reliability Engineering, and other stakeholders (such as Operations and Customer Service) will determine if changing the planning limit is warranted.

*Any changes to feeder ratings need documentation for Planning and Operations.

Appendix D: UM 1911 (Transmission and Distribution Substation Loading Analysis)

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1911

IDAHO POWER COMPANY

ATTACHMENT 1

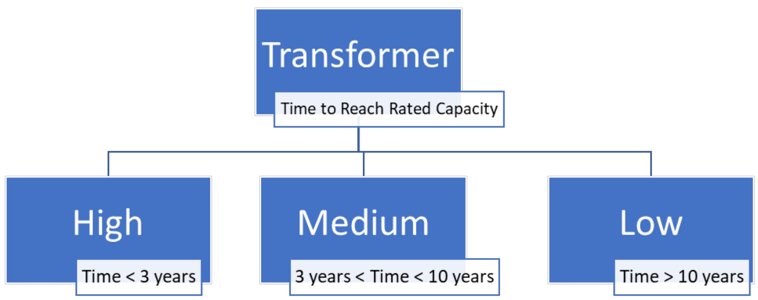
TRANSMISSION AND DISTRIBUTION SUBSTATION LOADING ANALYSIS

July 1, 2021

TRANSMISSION AND DISTRIBUTION SUBSTATION LOADING ANALYSIS

There are currently no transmission-related projects in Oregon that the Company believes could be deferred through the use of sited generation. The following table provides information related to distribution equipment. The Company's locational analysis was focused on substation transformers, given that these assets are usually the limiting factor in a distribution system. The Company collected data for each of the 30 substation transformers that serve load in Oregon including: transformer name, rated capacity, peak load, and growth rate.

The number of years needed to reach the rated capacity of each transformer was calculated using the transformer rated capacity, the transformer peak load, and the transformer load growth rate. Each transformer was given the label of high-, medium- or low-value depending on the number of years before each reaches its rated capacity, as follows:



The results of the transformer-by-transformer analysis are shown in the table below.

Distribution Transformers Relative Distribution Capacity Deferral Value

Transformer	Substation	High/Medium/Low
WESRT061	WEISER	High
ADRNT061	ADRIAN	Low
CAROT061	CARO	Low
CWVYT061	COW VALLEY	Low
DRKET061	DURKEE	Low
DUKET061	DUKE	Low
DWSYT061	DREWSEY	Low
HFWYT061	HALFWAY	Low
HGTNT061	HUNTINGTON	Low
HMDLT061	HOMEDALE	Low
HMDLT062	HOMEDALE	Low
HOLYT061	HOLLY	Low
HOPET061	HOPE	Low
HRPRT061	HARPER	Low
JMSNT061	JAMIESON	Low
JNTAT061	JUNTURA	Low
JNVYT061	JORDAN VALLEY	Low
JNVYT062	JORDAN VALLEY	Low
LIMET061	LIME	Low
MRBTT061	MALHEUR BUTTE	Low
NYSAT061	NYSSA	Low
NYSAT062	NYSSA	Low
OIDAT061	ORE-IDA	Low
ONTOT134	ONTARIO	Low
ONTOT135	ONTARIO	Low
PNCKT061	PINE CREEK	Low
PRMAT061	PARMA	Low
PRMAT062	PARMA	Low
UNTYT061	UNITY	Low
VALET061	VALE	Low