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October 15, 2021

VIA ELECTRONIC FILING

Attention: Filing Center
Public Utility Commission of Oregon
201 High Street SE, Suite 100
P.O. Box 1088
Salem, OR 97301-3398

RE: UM 2196 - Idaho Power Company's Distribution System Planning (DSP) Report

Dear Filing Center:

Idaho Power Company herewith submits for filing its 2021 Distribution System Planning (DSP) Report in compliance with Order No. 20-485 in Docket No. UM 2005.

Please address all data requests and other communication to:

Electronic: dockets@idahopower.com
Regular Mail: Lisa Nordstrom
Idaho Power Company
1221 W. Idaho Street
Boise, Idaho 83702

Informal questions concerning this filing may be directed to me or Regulatory Policy and Strategy Advisor, Alison Williams, at 208-388-2872 or awilliams@idahopower.com.

Sincerely,

Julia A. Hilton

JAH:sg
Enclosures
cc: Service List – UM 2005

CERTIFICATE OF SERVICE

I hereby certify that on October 15, 2021, I served a true and correct copy of Idaho Power Company's Distribution System Planning Report on the parties in Dockets UM 2005 by e-mail to said person(s) as indicated below.

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DATED: October 15, 2021.

Stacy Gust

Stacy Gust, Regulatory Administrative Assistant

OCTOBER • 2021

2021 DSP

OREGON DISTRIBUTION SYSTEM PLAN

A VIEW FROM ABOVE

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Appendix B: Asset Class Definitions

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GLOSSARY OF ACRONYMS

ADMS—Advanced Distribution Management System

AMI—Advanced Metering Infrastructure

ANSI—American National Standards Institute

BESS—Battery Energy Storage System

CBO—Community-Based Organization

CRM—Customer Relations Management System

CVR—Conservation Voltage Reduction

DER—Distributed Energy Resources

DERMS—Distributed Energy Resource Management System

DG—Distributed Generation

DOE—Department of Energy

DSM—Demand-Side Management

DSP—Distribution System Plan

DR—Demand Response

DVO—Distribution Voltage Optimization

EMS—Energy Management System

EEAG—Energy Efficiency Advisory Group

EPRI—Electric Power Research Institute

EV—Electric Vehicle

FAN—Field Area Network

FERC—Federal Energy Regulatory Commission

FLISR—Fault Locating Isolation Service Restoration

GAAP—Generally Accepted Accounting Principles

GHG—Greenhouse Gas

GIS—Geographic Information System

HCA—Hosting Capacity Analysis

IEEE—Institute of Electrical and Electronic Engineers

IPUC—Idaho Public Utilities Commission

IRP—Integrated Resource Plan

IRPAC—Integrated Resource Plan Advisory Committee

IVCC—Integrated Volt-Var Control System

kV—Kilovolt

kW—Kilowatt

kWh—Kilowatt-Hour

LTC—Load Tap Changer

MAIFI—Momentary Average Interruption Frequency Index

MAIFI-E—Momentary Average Interruption Event Frequency Index

MHz—Megahertz

MW—Megawatt

NREL—National Renewable Energy Laboratory

NWA—Non-Wires Alternative

O&M—Operations and Maintenance

OMS—Outage Management System

OPUC—Public Utility Commission of Oregon

PSPS—Public Safety Power Shutoff

PURPA—*Public Utility Regulatory Policies Act of 1978*

PV—Photovoltaic

QF—Qualifying Facility

SAIDI—System Average Interruption Duration Index

SAIFI—System Average Interruption Frequency Index

SCADA—Supervisory Control and Data Acquisition

SGM—Smart Grid Monitor

T&D—Transmission and Distribution

TWACS—Two-Way Automatic Communication System

V–Volt

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 I of II) presents a holistic view of Idaho Power's current distribution system practices, processes, and investments, and presents a vision to evolve distribution system planning in the future.

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]

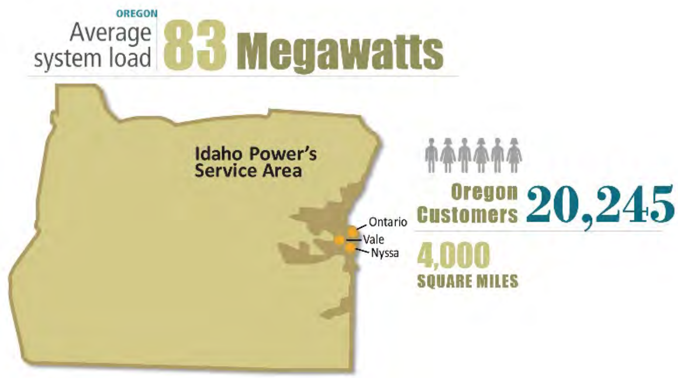
Over nearly two years, OPUC staff, stakeholders, and utilities have engaged in workshops and seminars to discuss distribution system planning possibilities, best practices, and lessons learned from other jurisdictions. These efforts culminated in DSP guidelines from OPUC staff, which were subsequently adopted by the OPUC in Order 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 (this document), focusing on current distribution practices, processes, and assets; and Part II, focusing on evolution of distribution system planning, distribution system pilot projects, and expanded public involvement in distribution system decision-making. Part II of the DSP Report will be completed and filed with the OPUC in summer 2022.

[1] See OPUC UM 2005, Order No. 19-104.

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 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,[2] the median household income (in 2018 dollars) for Ontario, Oregon, is $34,940,[3] compared to $65,740 for Portland, Oregon. Furthermore, in a report released in May 2015,[4] 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 Oregon customers.

DSP Report Components

The OPUC's DSP guidelines identify specific sections for inclusion in parts I and II of a utility's DSP Report. These components are described in brief below and in full in the chapters that follow.

Baseline Data & System Assessment

The first section of this DSP report offers insight into distribution system planning practices and processes, 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.

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

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

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

Hosting Capacity Analysis

Hosting Capacity Analysis (HCA) is a means to identify how much load or generation can be added to segments of the distribution system before those segments are overloaded. In this report, Idaho Power evaluates three options for expanding the scope and value of HCA.

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 and processes to include feedback from customers and communities. The company has already embarked on a robust public involvement effort, having hosted two public workshops to raise awareness and begin hearing feedback on DSP efforts.

Long-Term Distribution System Plan

Recognizing that customer energy needs are shifting, and the distribution system is evolving, Idaho Power will focus its DSP efforts on the following:

- Forecasting near- and long-term electrical demands for each service region
- Developing community advisory-based electrical plans
- Developing proactive near-term local area plans that are achievable and executable before electrical demand overloads facilities or results in reduced service quality

Development of DSP Report Part II.

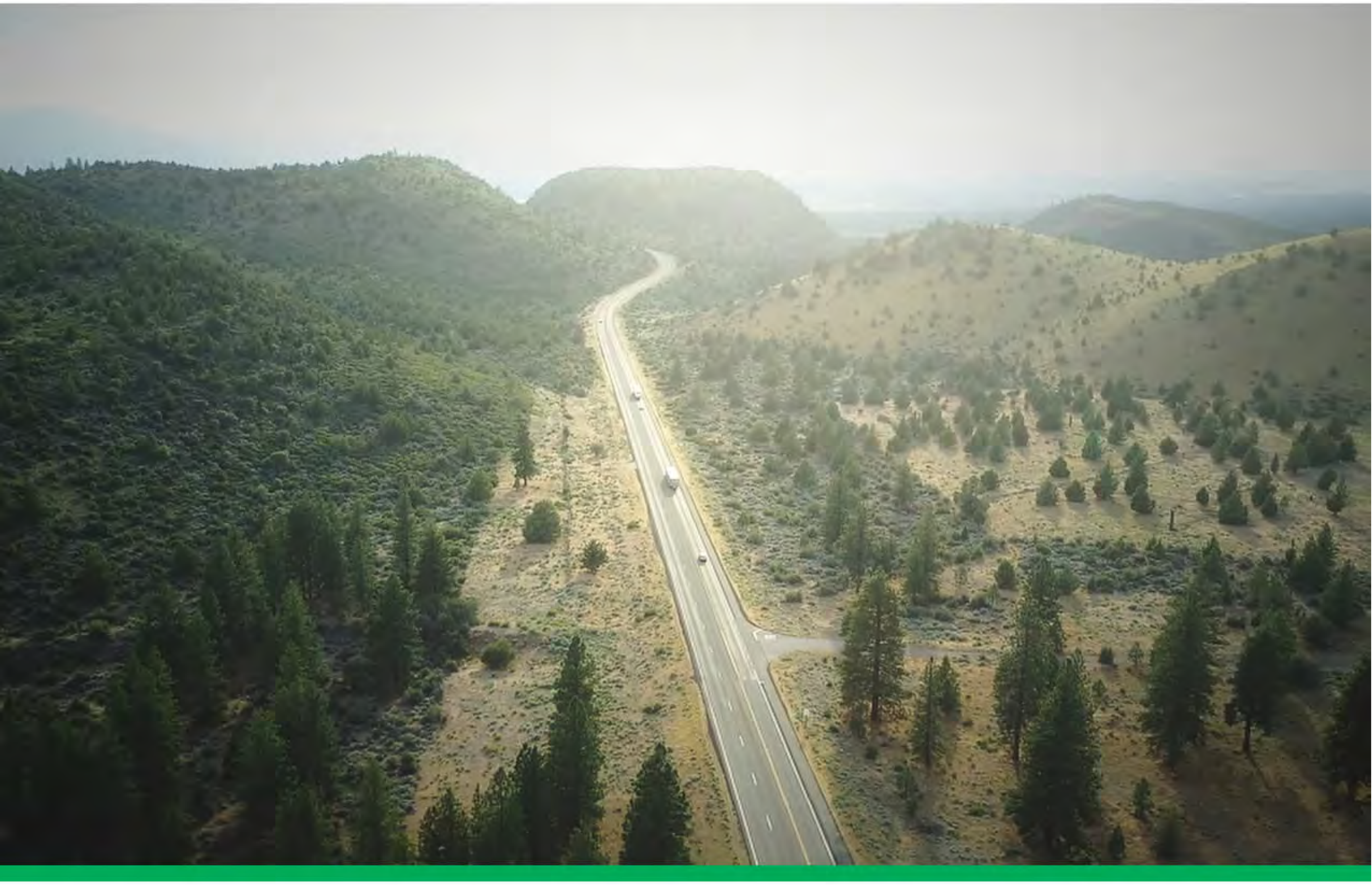
Part II of the DSP Report will focus on efforts to enhance forecasting load growth, distributed energy resource (DER)[5] adoption, and electric vehicle (EV) adoption; grid needs identification; solution identification; and development of a near-term action plan. To accomplish that, Idaho Power will host additional public involvement workshops.

Next Steps in the DSP

In preparation for development of Part II of the DSP Report, Idaho Power will continue to attend and participate in the OPUC's UM 2005 public workshops to provide feedback, insights on Idaho Power's Oregon service area, and to ensure utilities, stakeholders, and the OPUC develop a shared set of principles and terms related to distribution system planning.

[5] Idaho Power is using the OPUC's definition of DERs under Order 20-485, which includes distributed generation, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution system.

To facilitate ongoing feedback, Idaho Power has established a dedicated DSP webpage to host information and engagement opportunities: idahopower.com/DSP. Additionally, interested parties in the DSP process are encouraged to use a dedicated email address, DSP@idahopower.com, to provide input and ask questions outside of the regulatory process.



DSP REPORT:

BASELINE DATA AND SYSTEM ASSESSMENT

BASELINE DATA AND SYSTEM ASSESSMENT

To provide a transparent picture of Idaho Power's distribution system in Oregon, this first section of the DSP Report offers insight into distribution system planning practices and processes, 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.

Idaho Power Asset Assessment Strategy

To provide a comprehensive, long-range plan for managing the replacement of aging and/or condition-based transmission, distribution, and station assets, Idaho Power leverages an asset replacement strategy. In this strategy, assets are prioritized within each asset class based on condition and criticality as the primary replacement drivers. The data provided in tables 1.1 to 1.3 show examples of information used to develop the asset replacement strategy. Individual asset plan criteria may differ by asset class. Table 1.1 lists the factors that may be considered to determine both condition and criticality, while Table 1.2 lists the asset classes included in the strategy, and Table 1.3 lists the distribution asset replacement drivers.

Table 1.1 Condition and criticality factors

Condition Factors Considered	Criticality Factors Considered
Age	Customer outage impact
Test and inspection results	Public and employee impact
Equipment environment	Environmental impact
Past equipment performance	Operational impact
	Megawatt (MW) transfer capability impact
	Strategic (e.g., technology)

Table 1.2 Asset classes included in asset replacement strategy

Distribution	Stations
Overhead circuits (e.g., poles and conductor)	Transformers
Underground cable	Circuit breakers
Line equipment (e.g., regulators, capacitors, reclosers, transformers)	Protective relays
Line switches	Instrument transformers
Distribution relays	Communication equipment

Table 1.3 Asset replacement drivers

Asset Class	Primary Replacement Drivers
Overhead circuits (poles and conductor)	• Customer reliability programs • Condition (patrol inspections)
Underground cable (pre-1989)	• Unjacketed cable • Material condition
Service transformers	• Material condition • Incorporate with other replacement projects
Distribution regulators, capacitors, reclosers	• Regular inspections to identify condition
Line switches	• Material condition • Incorporate with other replacement projects
Station distribution transformers	• Criticality • Material condition/age • Diagnostic testing • Visual and infrared inspections
Station circuit breakers	• Criticality • Material condition/age • Diagnostic testing • Visual and infrared inspections
Station instrument transformers	• Visual and infrared inspections
Communication equipment	• Changes in technology • Factory support
Protective relays	• Factory support • Condition/based on test results • Age/criticality

Reliability Assessment and Reporting

To track reliability—specifically, the performance of distribution circuits, Idaho Power uses industry standard metrics as defined by the Institute of Electrical and Electronics Engineers (IEEE) standard 1366:

- System Average Interruption Duration Index (SAIDI): Outage hours per customer per year
- System Average Interruption Frequency Index (SAIFI): Outages over 5 minutes per customer per year
- Momentary Average Interruption Event Frequency Index (MAIFI-E): Outages less than 5 minutes per customer per year

Idaho Power uses outage data analytics to track various outage causes. The company has tools to track and evaluate trends in failures that result in sustained outages (SAIFI) and momentary interruptions (MAIFI). Additionally, the company uses regularly scheduled line patrols and detailed emergency response patrols to identify specific failure points on the distribution system, such as damaged insulators, cross arms, poles, arrestors, and other equipment. Line maintenance is then done on areas identified in patrols and inspections.

Distribution reliability programs focus on identifying the lowest-performing circuits. Work on the distribution circuits is done on an annual basis to include new distribution advancements, replace aging infrastructure, and conduct maintenance to prevent outages. Outage exposure to customers is reduced by adding protection and sectionalizing devices.

Idaho Power's reliability performance in Oregon is detailed in its annual Electric Service Reliability Report (under OPUC Docket RE 90). The *2020 Electric Service Reliability Report* is included as Appendix A to this report.

The reliability metrics for the last five years are provided in Table 1.4.

Table 1.4 Historical Oregon service area reliability data (average per customer)

Year	SAIDI (hrs/year)	SAIFI (events/year)	MAIFI-E (events/year)
2016	2.88	1.06	2.11
2017	3.66	1.22	2.44
2018	2.47	0.95	3.16
2019	2.01	0.63	2.28
2020	3.09	0.97	2.07

Standards and Inspections

To ensure a high degree of reliability, safety, and power quality, Idaho Power adheres to certain industry standards and practices both operationally and with respect to customers:

- Idaho Power designs, evaluates, and operates the distribution system voltage service to the American National Standards Institute (ANSI) C84.1 voltage standard.
- The company manages loads to prevent thermal overloads on lines and equipment on the distribution system.
- Customers are required to comply with IEEE 519, the Practices and Requirements of Harmonic Control in Electric Power Systems.
- Oregon customers, under the Rule K tariff, are also required to give Idaho Power notice prior to making any significant change in either the amount or electrical character of the customer's load, thereby allowing the company to determine if any changes are needed in the Company's equipment or distribution system.
- Idaho Power also maintains a thorough vegetation management program to limit the interference of vegetation and distribution lines and equipment. Distribution circuits are on a three-year vegetation management cycle. Areas with fast growing trees near lines are trimmed on a shorter cycle, even annually when necessary.

Asset Classes

Idaho Power divides its distribution facilities into the following asset classes: substation transformers, circuit breakers, electromechanical relays, microprocessor relays, smart grid monitors, overhead transformers, pad-mounted transformers, distribution poles, primary overhead line, primary underground line, meters, fuses, switches, regulators, capacitors, reclosers, and sectionalizers.

For each asset class, the total number, average age, age range in years, and industry life expectancy can be found in figures 1.1 to 1.17. Definitions of the asset classes and a table of the asset class data are included as Appendix B to this report.

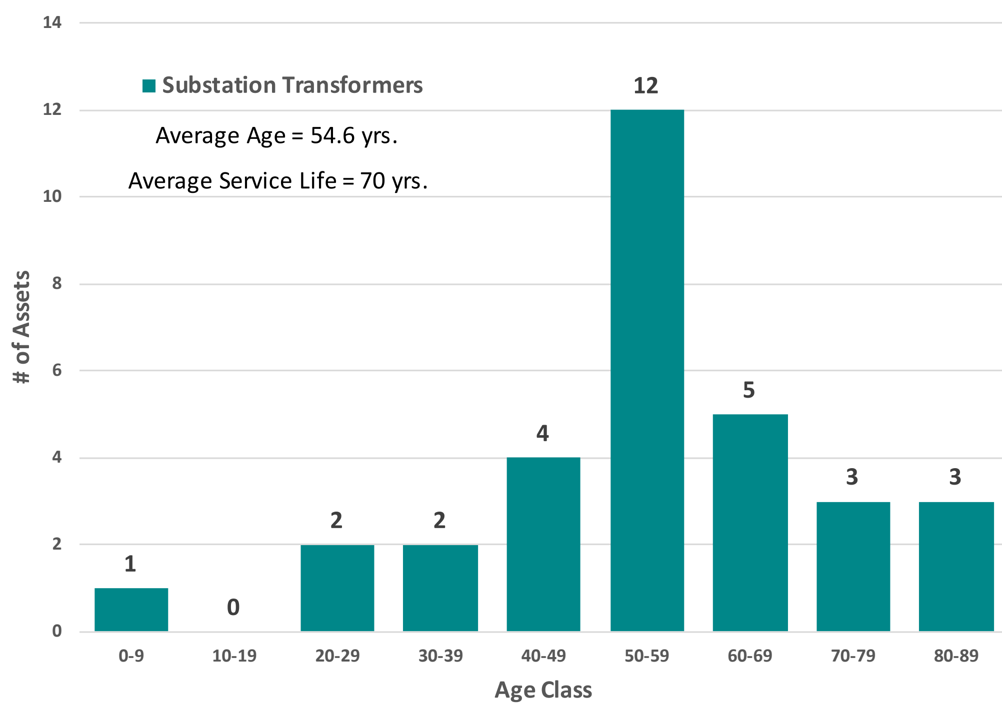


Figure 1.1 Substation transformer data

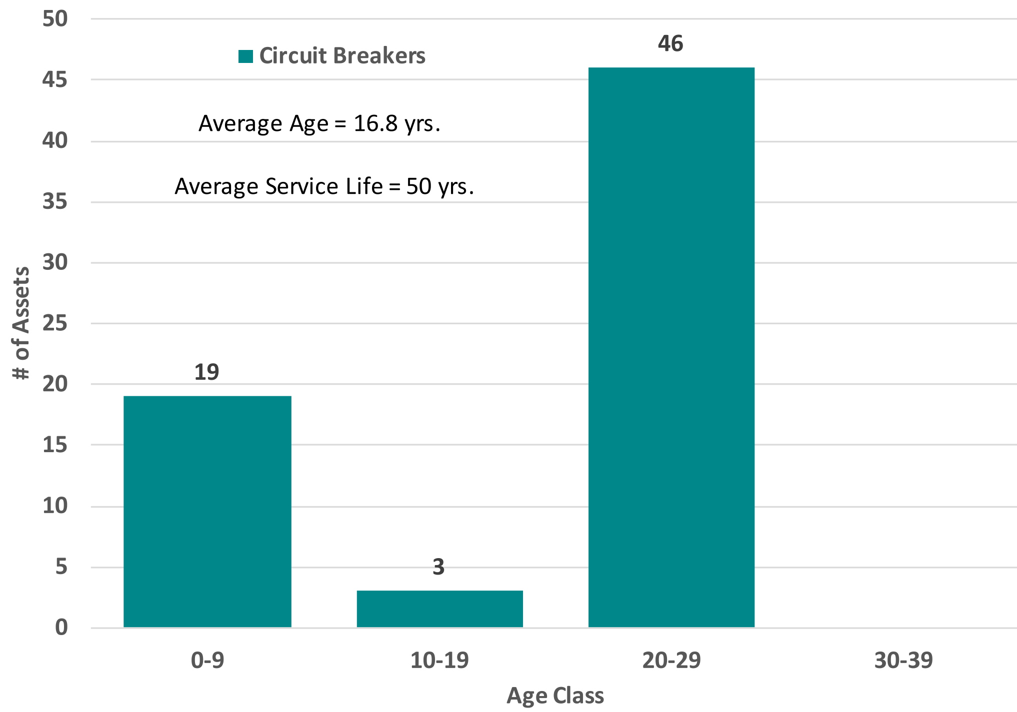


Figure 1.2 Circuit breaker data

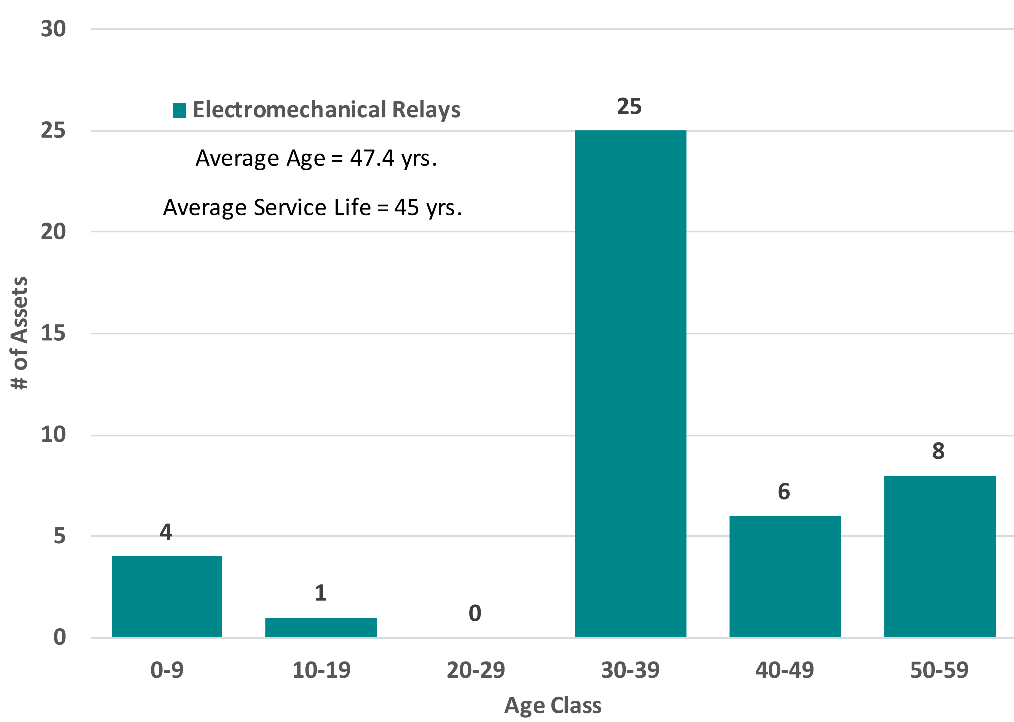


Figure 1.3 Electromechanical relay data

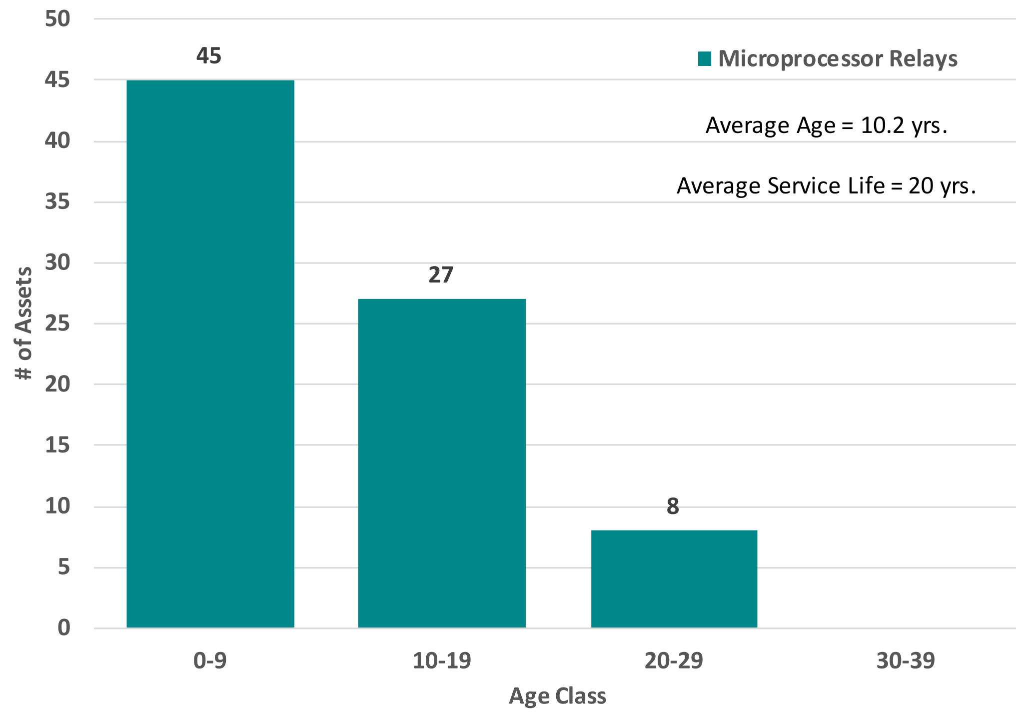


Figure 1.4 Microprocessor relay data

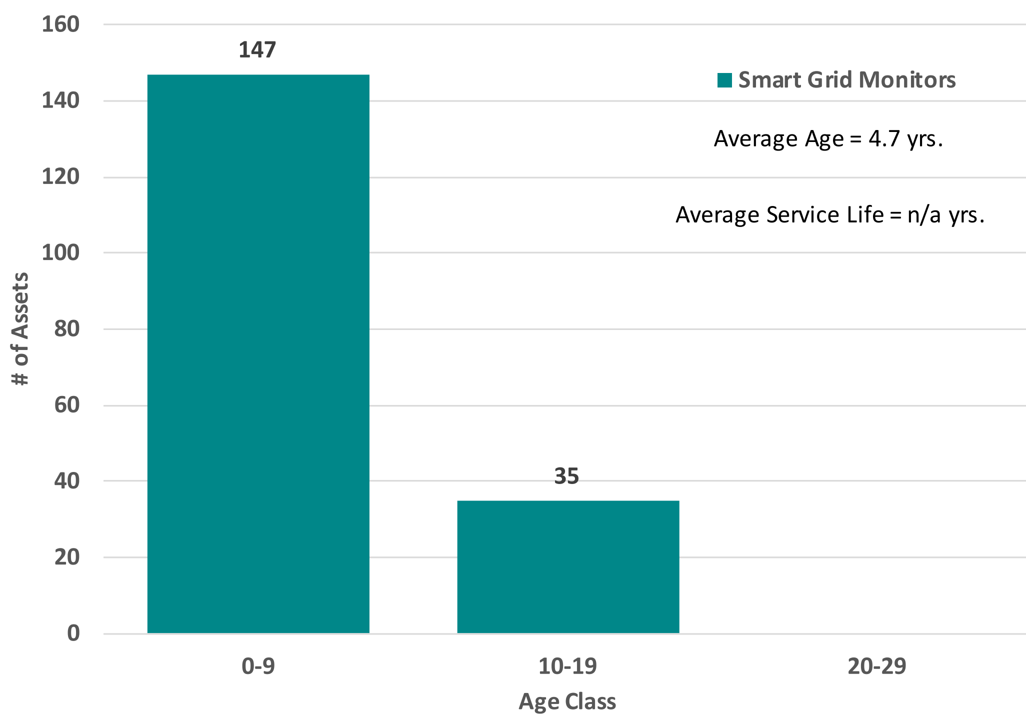


Figure 1.5 Smart grid monitor data

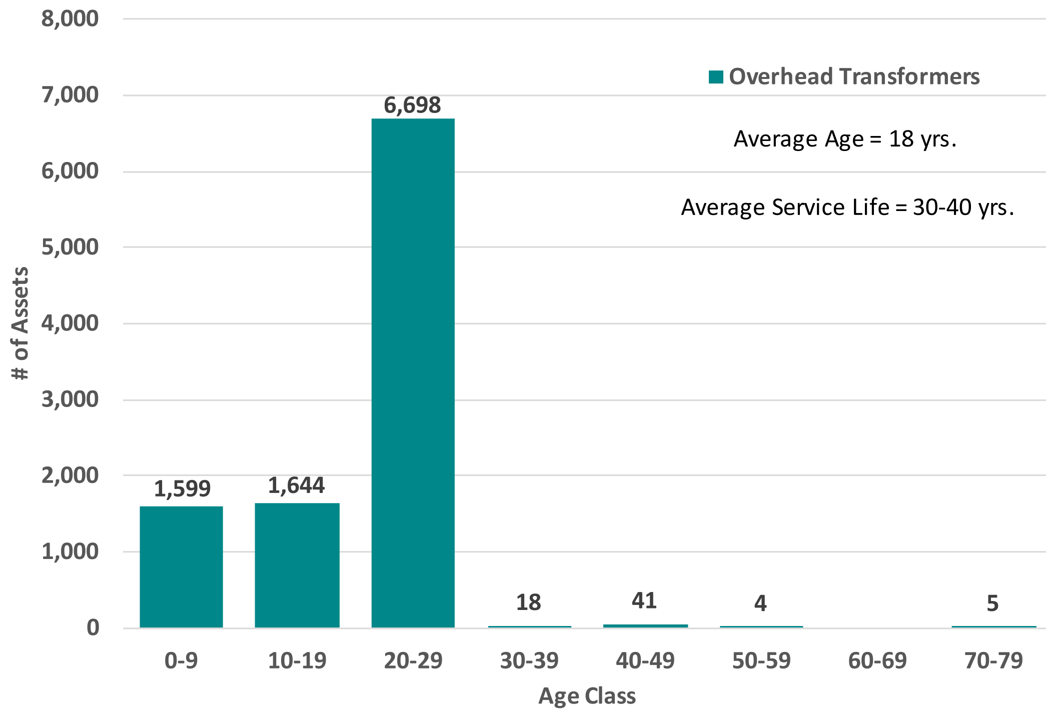


Figure 1.6 Overhead transformer data

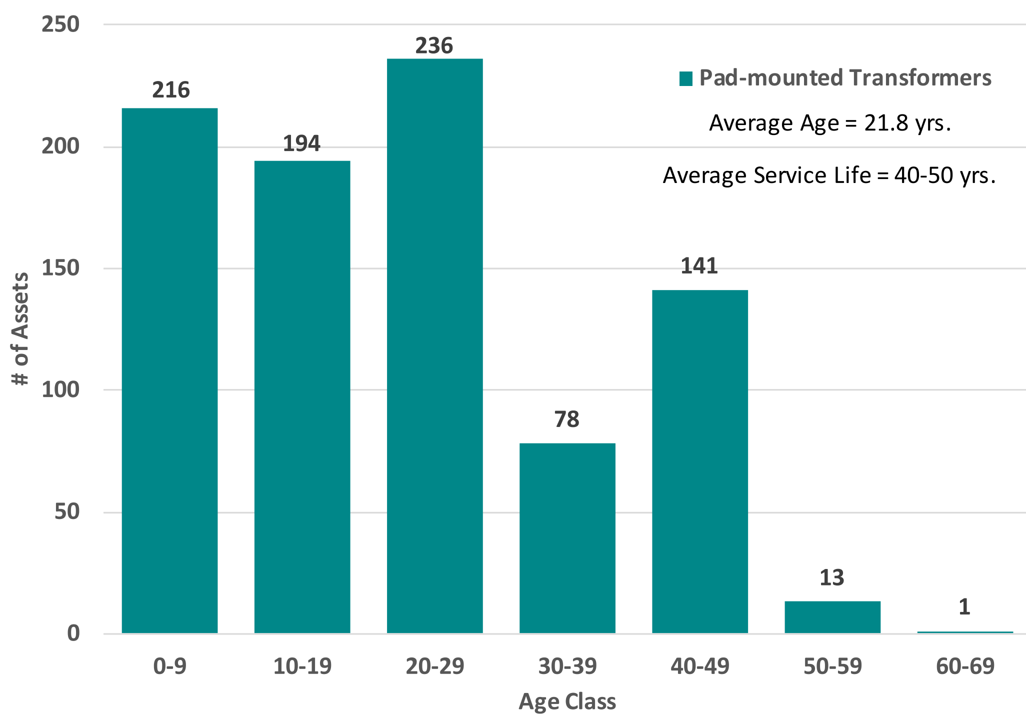


Figure 1.7 Pad-mounted transformer data

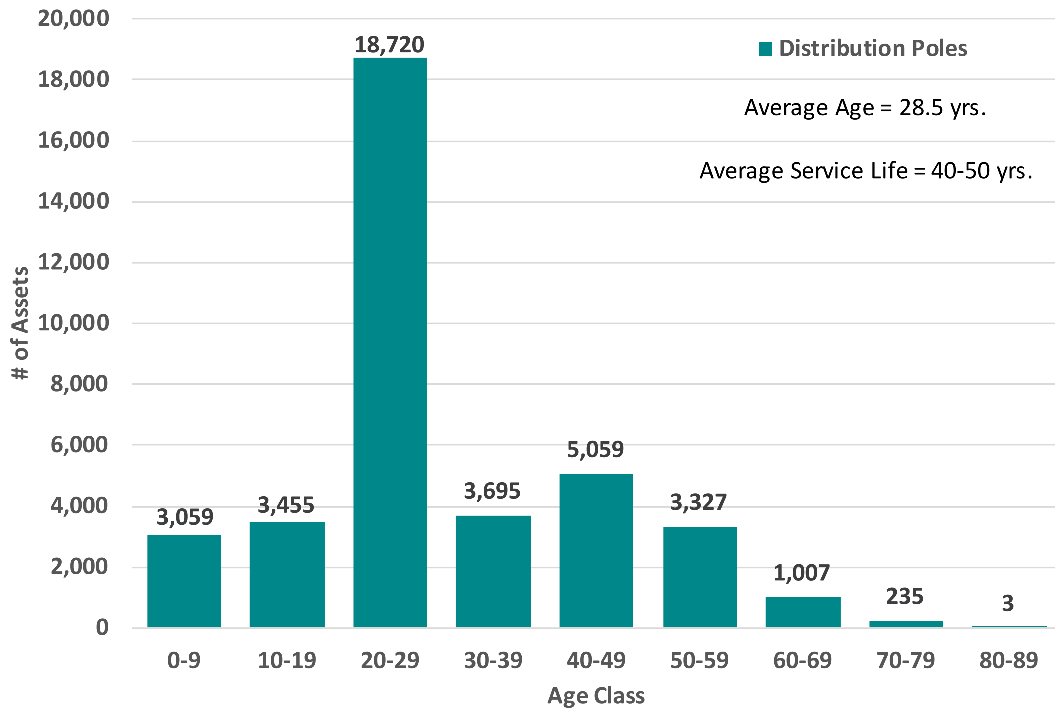


Figure 1.8 Distribution pole data

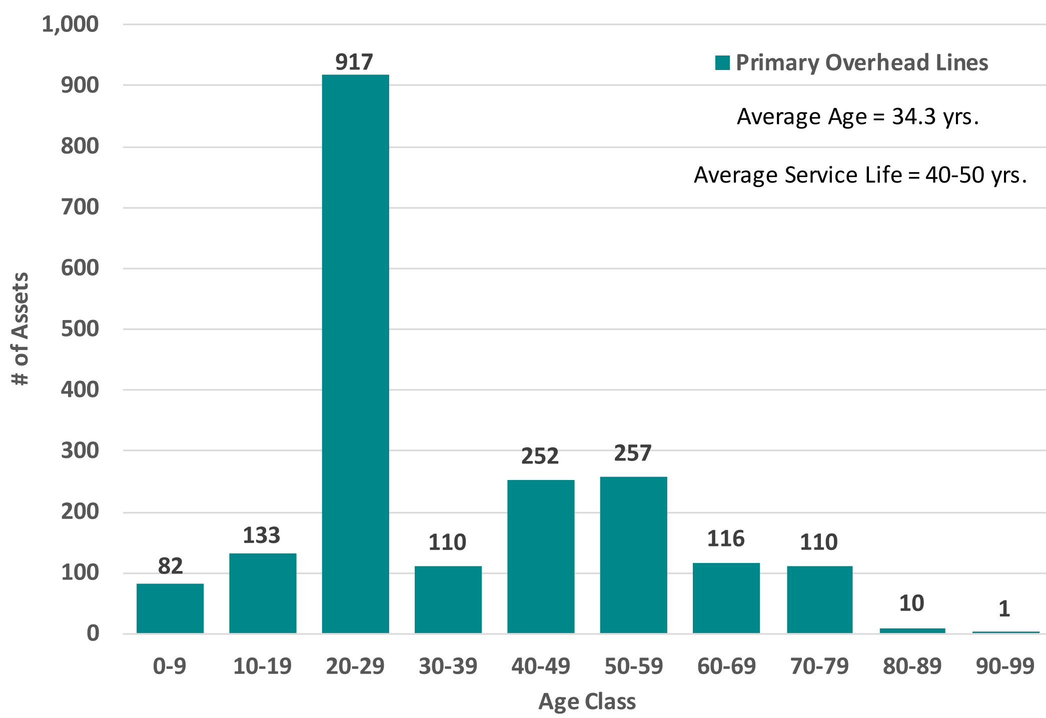


Figure 1.9 Primary overhead line data

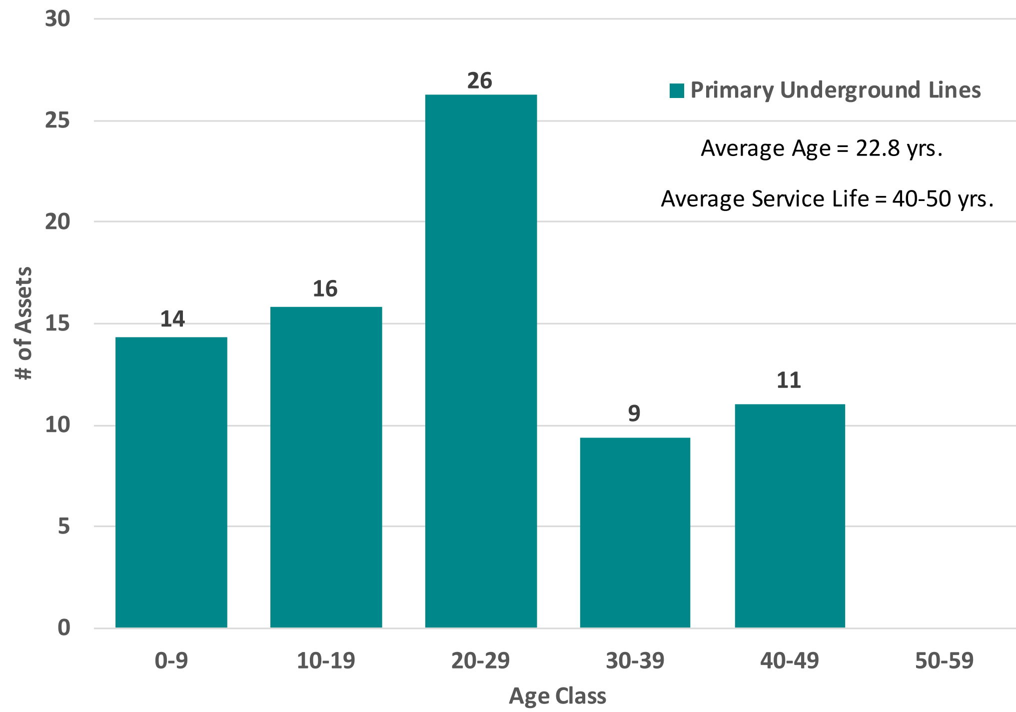


Figure 1.10 Primary underground line data

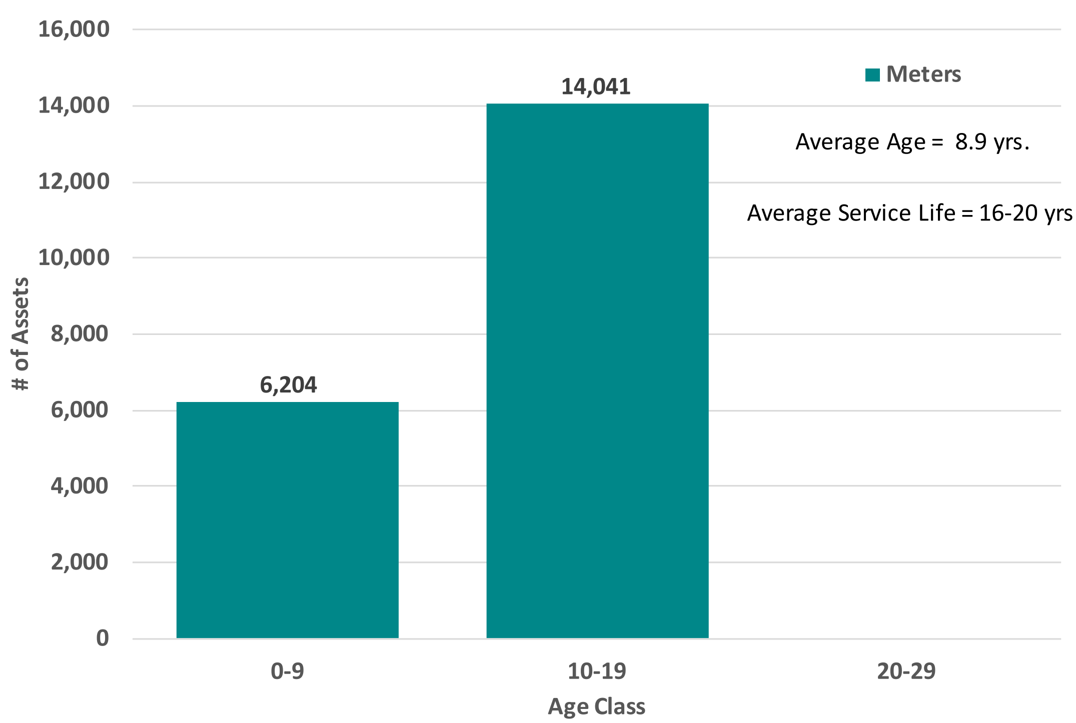


Figure 1.11 Meter data

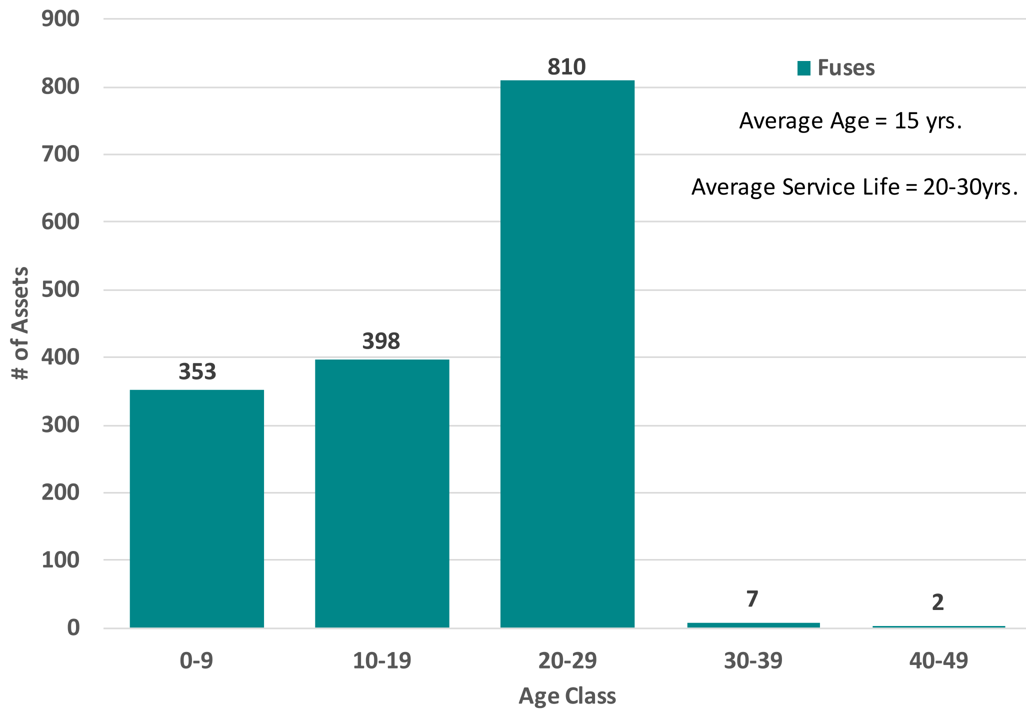


Figure 1.12 Fuse data

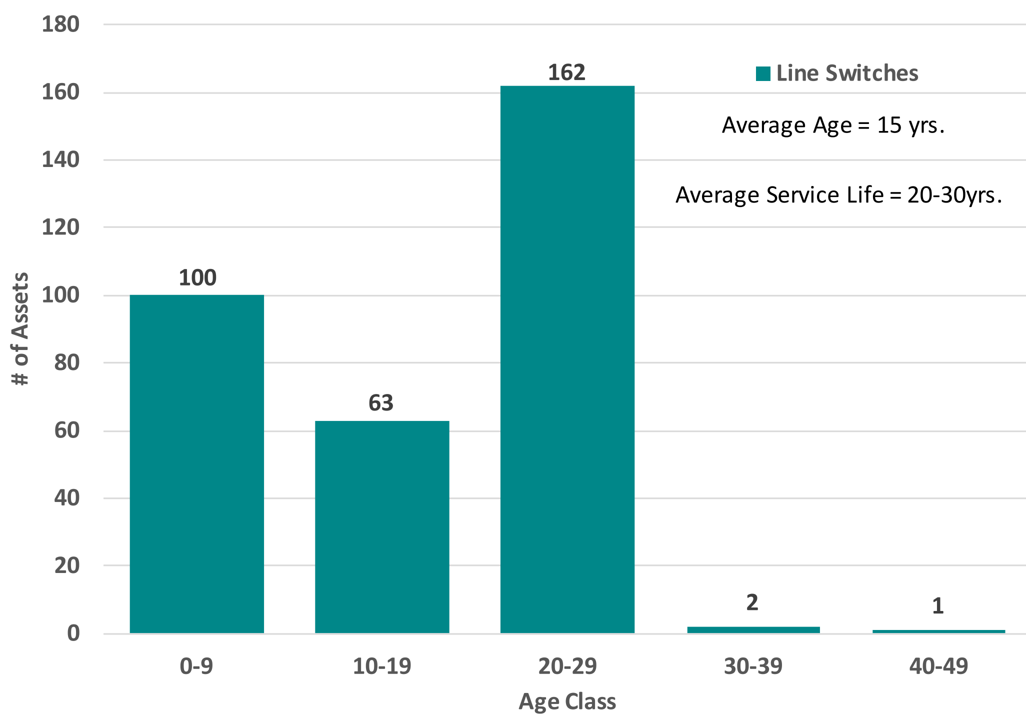


Figure 1.13 Line switch data

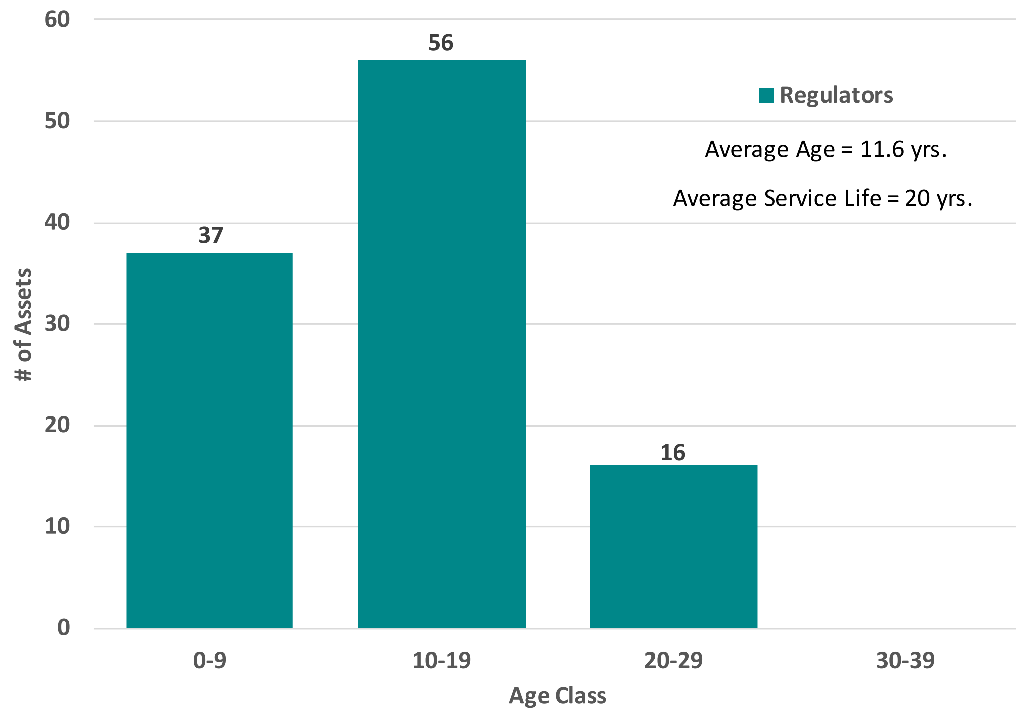


Figure 1.14 Regulator data

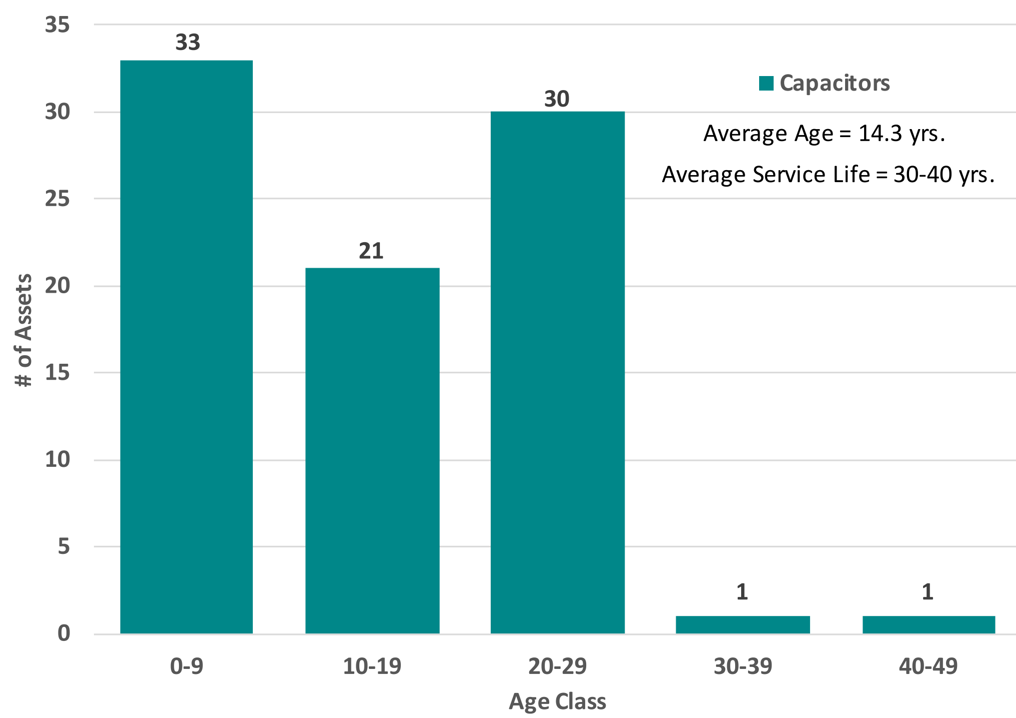


Figure 1.15 Capacitor data

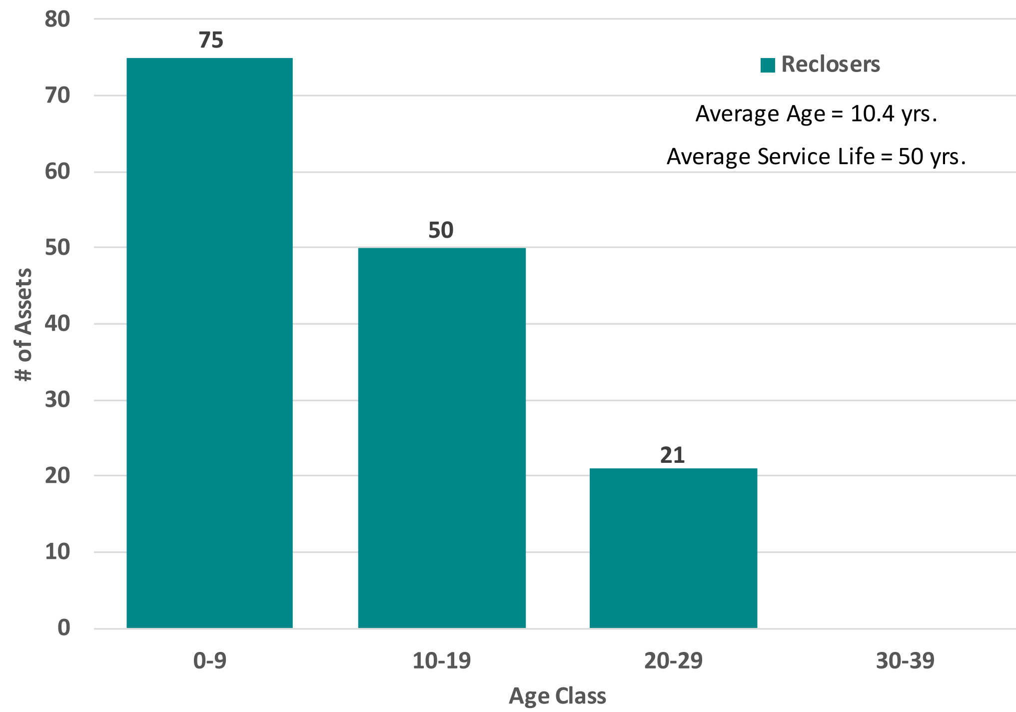


Figure 1.16 Recloser data

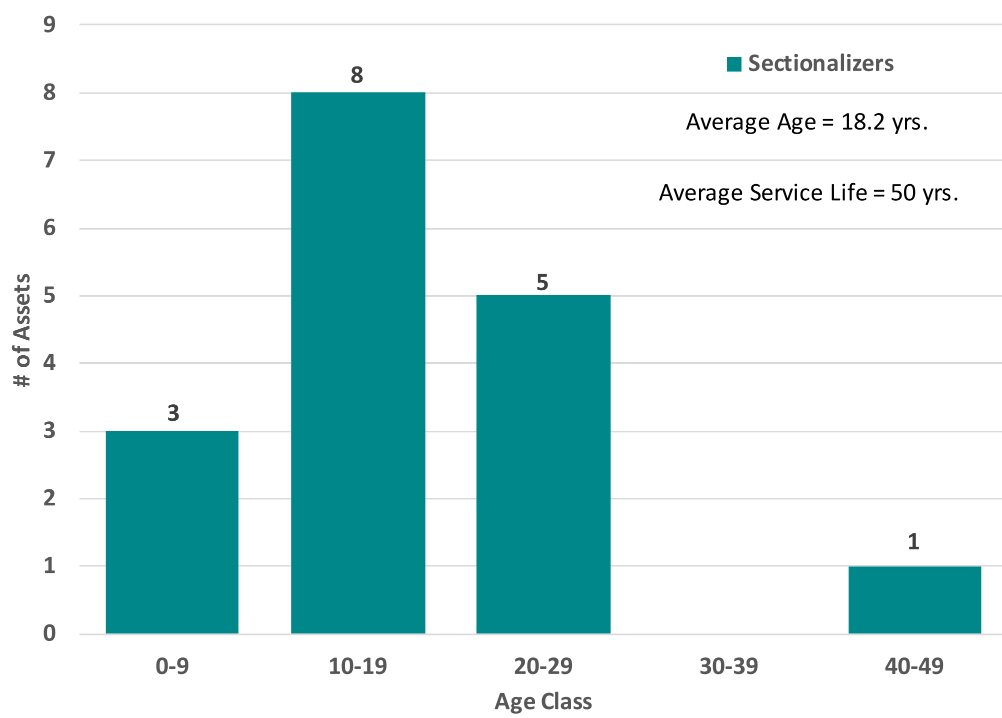


Figure 1.17 Sectionalizer data

Distribution System Monitoring and Control

Idaho Power uses a variety of monitoring and control technologies. One of the technologies in use is supervisory control and data acquisition (SCADA). Of the 29 substations in Oregon that are owned by Idaho Power, 15 use SCADA. While only 52% of the substations are equipped with SCADA, those substations serve 95% of customers in Oregon.

Figure 1.18 SCADA coverage

In addition to SCADA monitoring, Idaho Power has built an Integrated Volt-Var Control system (IVVC) that provides awareness and control of substation load tap changers (LTC), line voltage regulators, and capacitors using a licensed 700-megahertz (MHz) field area network (FAN). IVVC is currently operating on 17 circuits in eastern Oregon, serving about 11,583 of customers (roughly 57%), as illustrated in Figure 1.18. The company also has a distribution relay replacement program in which legacy electro-mechanical circuit relays are replaced with microprocessor-based relays for added control and visibility of the system.

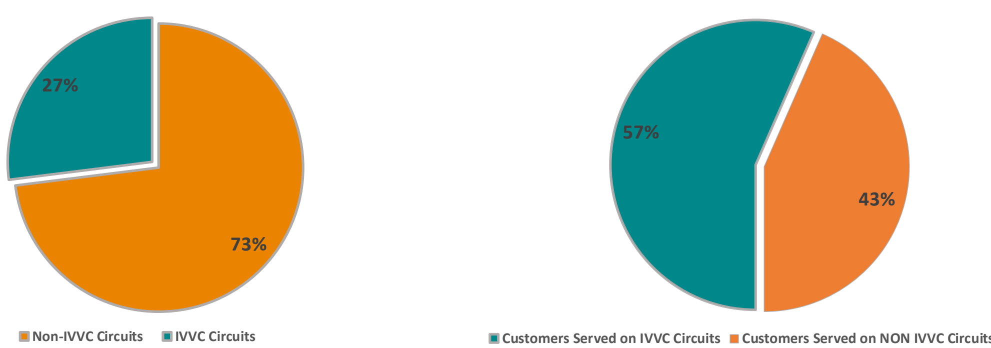


Figure 1.19 IVVC/FAN coverage

In Idaho Power's Oregon service area, nearly 99% of customers have smart meters—known as Advanced Metering Infrastructure (AMI), as shown by customer type in Figure 1.20 and by percent of total customers in Figure 1.21. The smart meters record customer load information on a more granular basis than the historical meters that only recorded monthly totals. Idaho Power's AMI operates on a two-way automatic communication system (TWACS) that sends the information over the power line from the customer meter to the distribution substation where it is collected by the TWACS network server.

Through smart meters, customer energy use is recorded on at least an hourly frequency. This information is made available to customers, through the Idaho Power My Account portal, to empower them to make informed decisions on how to manage their energy use. While these meters support other functionality, such as voltage reads and remote disconnect/connect for some meters, additional functions are often limited due to the low communication bandwidth of the smart meter technology.

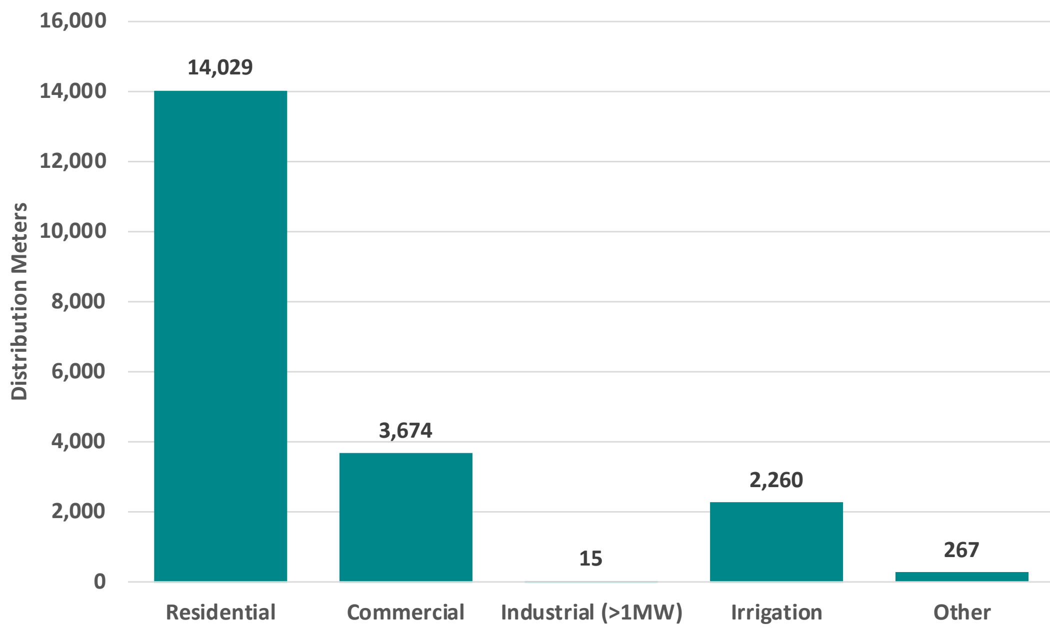


Figure 1.20 Oregon customer meters

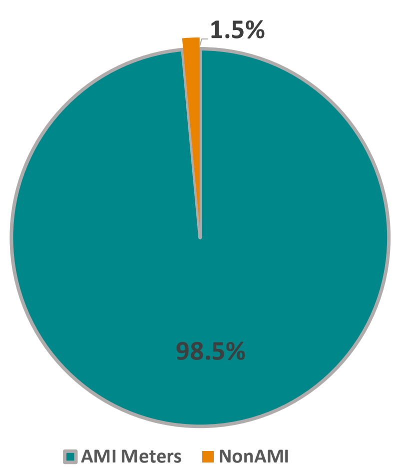


Figure 1.21 Customers with AMI meters

Smart grid monitors (SGM) are devices installed on distribution circuits to assist in outage management. Typically installed beyond reclosers, these devices send an alert to Idaho Power's Outage Management System (OMS) on loss of power. The communication is sent via cellular network. In Oregon, Idaho Power has 38 distribution circuits equipped with SGM, as shown in Figure 1.22.

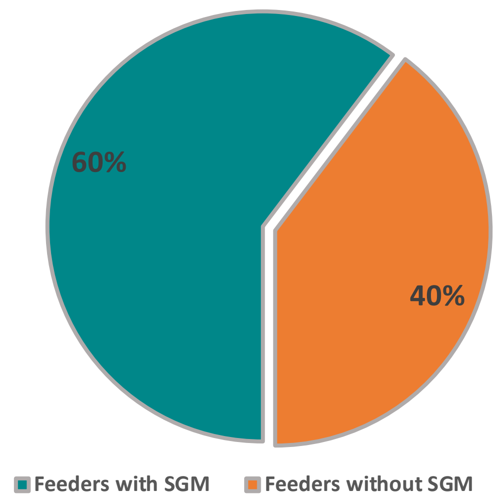


Figure 1.22 Circuits with SGM

Idaho Power uses ION meters to record power quality data, which includes high-frequency, sample-rate voltage and current measurements, as well as outage data. Those ION meters are located at large load customer sites and at customer solar generation sites larger than 3 MW.

Historical Distribution System Spending

Idaho Power's accounting system is built to comply with the Federal Energy Regulatory Commission (FERC) Code of Federal Regulations 18 CFR Part 101—Uniform System of Accounts Prescribed for Public Utilities and US Generally Accepted Accounting Principles (GAAP). Generally, Idaho Power's accounting system is designed to categorize costs based on FERC accounts.

As a result, Idaho Power is unable to report its historical distribution system spending in the categories identified by FERC staff (Requested Categories) because these categories do not directly align with FERC accounts.

For Idaho Power's capital expenditures, investment can be categorized by Plant Types, which is more granular than by FERC account. While these categories allow a greater level of detail, they, too, do not directly align with the requested categories. Idaho Power has provided a crosswalk from Plant Types to the requested categories in Figure 1.23.

FERC Plant Type
Oregon Accounting
2016 — 2020

Plant Type	Spending Categories	Plant Type	Spending Categories
Interconnect Facilities	Asset Renewal New Customer Projects Metering	Underground New Business	System Capacity Upgrades New Customer Projects Metering
Underground Reconstruction	Asset Renewal System Capacity Upgrades System Reliability/Power Quality Upgrades Grid Modernization Preventive Maintenance	Underground Duct Vault	Asset Renewal System Capacity Upgrades System Reliability/Power Quality Upgrades New Customer Projects Grid Modernization Metering Preventive Maintenance
Distribution Stations	Asset Renewal System Capacity Upgrades System Reliability/Power Quality Upgrades New Customer Projects Grid Modernization Preventive Maintenance	Meter Work	Asset Renewal New Customer Projects Metering
Overhead New Business	System Capacity Upgrades New Customer Projects Metering	Overhead Reconstruction	Asset Renewal System Capacity Upgrades System Reliability/Power Quality Upgrades Grid Modernization Preventive Maintenance
Street Lighting	Asset Renewal Preventive Maintenance		

Figure 1.23 FERC account crosswalk to DSP guideline spending categories

Tables 1.5, 1.6, and 1.7 provide historic distribution spending for capital by Plant Type and distribution operations, and maintenance expense. The amounts in these tables reflect approximate Oregon distribution spending using jurisdictional separation factors from the Oregon Supplement of the FERC Form 1, which is filed annually with the OPUC in docket RE 78.

Table 1.5 Oregon allocated distribution capital spending (2016–2020)

Plant Type	2016 Oregon Allocated $	2017 Oregon Allocated $	2018 Oregon Allocated $	2019 Oregon Allocated $	2020 Oregon Allocated $
Interconnect Fac - Dist Lines	140,649	131,604	-8,758	9,227	10,562
Interconnect Fac - Dist Stat	132,045	53,265	-1,859	1,872	-17
Underground Reconstruction	924,910	1,069,197	1,040,617	914,602	940,580
Distribution Stations	696,666	966,996	1,078,255	1,265,364	724,736
Overhead New Business	289,286	195,358	294,459	487,909	318,950
Overhead Reconstruction	1,433,088	1,506,623	1,538,260	1,452,385	1,462,609
Underground Duct Vault	199	393	2,392	2,408	2,032
Underground New Business	312,737	332,944	79,334	269,526	308,698
Street Lighting					125,708
Meter Work	228,030	260,326	248,587	297,723	376,371
Distribution Plant Total	**4,157,610**	**4,516,704**	**4,271,288**	**4,701,016**	**4,270,229**

Table 1.6 Oregon allocated distribution operation expense by FERC account (2016–2020)

Operation	2016 Oregon Allocated $	2017 Oregon Allocated $	2018 Oregon Allocated $	2019 Oregon Allocated $	2020 Oregon Allocated $
(580) Operation Supervision and Engineering	182,004	185,421	193,558	184,260	165,613
(581) Load Dispatching	162,537	167,843	165,089	175,472	174,685
(582) Station Expenses	54,769	65,744	65,091	61,287	61,678
(583) Overhead Line Expenses	264,532	367,043	287,179	303,163	312,671
(584) Underground Line Expenses	42,729	51,462	47,960	50,339	65,102
(585) Street Lighting and Signal System Expenses	3,834	5,531	7,260	2,827	374
(586) Meter Expenses	164,273	167,166	154,207	145,688	153,041
(587) Customer Installations Expenses	67,852	95,901	96,819	91,893	62,394
(588) Miscellaneous Expenses	323,796	303,418	210,092	188,754	168,268
(589) Rents	13,138	16,800	51,200	13,980	13,394
Total Operation	**1,279,465**	**1,426,329**	**1,278,456**	**1,217,662**	**1,177,218**

Table 1.7 Oregon allocated distribution maintenance expense by FERC account (2016–2020)

Maintenance	2016 Oregon Allocated $	2017 Oregon Allocated $	2018 Oregon Allocated $	2019 Oregon Allocated $	2020 Oregon Allocated $
(590) Maintenance Supervision and Engineering	(66,948)	(72,428)	25,729	(11,532)	599
(591) Maintenance of Structures	-	-	(45)	2,535	0
(592) Maintenance of Station Equipment	137,242	164,269	186,320	158,604	141,269
(593) Maintenance of Overhead Lines	1,098,593	1,031,632	1,282,401	1,253,837	1,180,003
(594) Maintenance of Underground Lines	12,064	10,650	9,951	10,080	8,085
(595) Maintenance of Line Transformers	1,154	960	1,729	1,980	1,714
(596) Maintenance of Street Lighting and Signal Systems	27,314	25,841	27,103	11,955	11,945
(597) Maintenance of Meters	30,424	33,498	30,750	30,131	27,868
(598) Maintenance of Miscellaneous Distribution Plant	28,728	18,066	16,109	14,840	8,535
Total Maintenance	**1,268,572**	**1,212,487**	**1,580,045**	**1,472,430**	**1,380,019**

Small Generators

A small generator is defined as a generator of 20 MW or smaller. In eastern Oregon, the company has 20 small generator projects connected to its system, totaling 142 MW of capacity: three hydroelectric projects (13 MW in total), six wind projects (53 MW in total), and 11 solar projects (76 MW in total). Of the 20 small generator projects, 11 are connected to distribution circuits and nine are connected to the transmission system. The 11 projects connected to distribution circuits are listed in Table 1.8.

Idaho Power's latest Oregon Generator Interconnection Activities Report for 2020 is included as Appendix C.

Table 1.8 Small generators in Oregon connected to circuits

Substation	Circuit	Solar Projects	Wind Projects
Adrian	ADRN13	1	
Cairo	CARO11	2	
Holly	HOLY14	1	
Hope	HOPE11	1	
Jamieson	JMSN11	1	
Lime	LIME11		1
Nyssa	NYSA15	1	
Ontario	ONTO24	1	
Unity	UNTY12	1	
Vale	VALE12	1	
	Totals	**10**	**1**

As of October 2021, two small generator projects are queued to connect to the Oregon system: the first is a 3 MW solar project planned to connect to the Ontario 019 circuit in May 2022; the second is also a 3MW solar project planned to connect to the Durkee 011 circuit in Q4 2023.

The map below identifies the *Public Utility Regulation Policies Act of 1978* (PURPA) Qualifying Facilities (QF) interconnected to Idaho Power's system in Oregon.

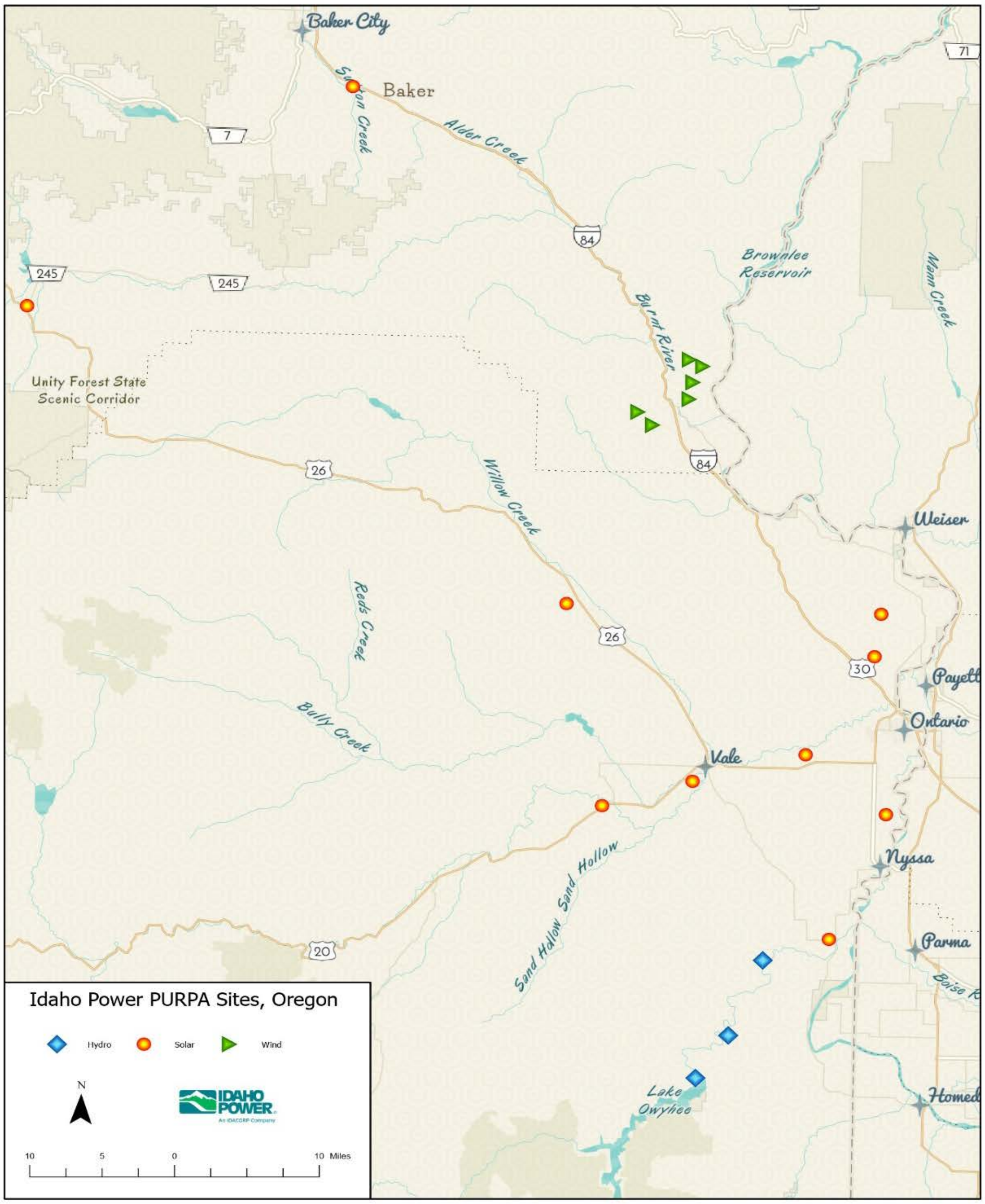


Figure 1.24 PURPA-qualifying facilities in Oregon connected to Idaho Power's system

Electric Vehicles

As of June 2021, 28 EVs were registered within Idaho Power's Oregon service area. This compares to 25 registered EVs as of June 2019. The cumulative registered number of EVs over the last five years is shown in Figure 1.25.

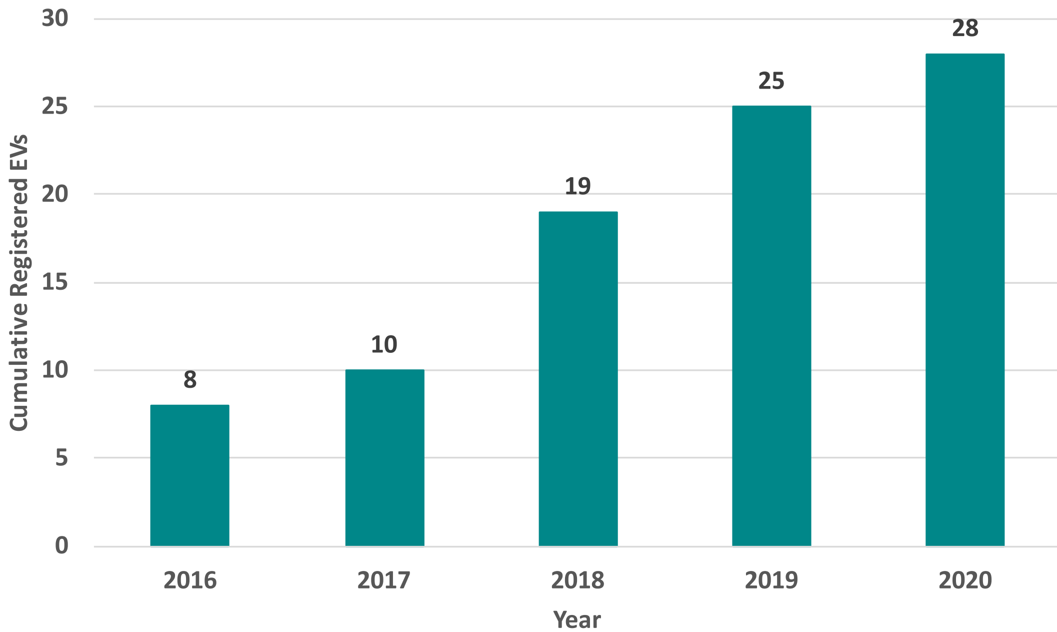


Figure 1.25 Cumulative registered EVs

EV charging infrastructure remains limited in eastern Oregon. However, Idaho Power observes an increase in charging-station use. Across Idaho Power's Oregon service area, there are two privately owned, Level 3 charging stations: the first charging station was installed in July 2018 to the Huntington 012 circuit located in Huntington and the second charging station was connected in September 2020 to the OreIda 011 circuit located in Ontario.

Use of the Ontario charging station is much greater than Huntington. However, both charging stations have experienced a notable increase in use since June 2021. Usage data for both charging stations is shown in the following two tables, denoted in kilowatt-hours (kWh).

Table 1.9 Huntington charging station data

Huntington Charging Station (kWH)													
Year/Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2018								0	560	720	640	640	**2,560**
2019	560	640	640	640	800	880	640	800	880	720	1,120	1,040	**9,360**
2020	1,040	560	560	880	640	880	1,040	1,200	1,520	1,120	1,200	800	**11,440**
2021	960	880	720	1,120	1,040	2,080	1,920	3,040	2,880				**14,640**

Table 1.10 Ontario charging station data

Ontario Charging Station (kWH)													
Year/Month	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**Total**
2020									3,760	17,520	12,400	10,640	**44,320**
2021	12,160	9,760	8,240	14,880	18,160	20,080	27,440	26,480	22,640				**159,840**

Demand Response Programs

Idaho Power operates three summer demand response (DR) programs: A/C Cool Credit, Flex Peak, and Irrigation Peak Rewards.[6] Data from these programs are shown in tables 1.11, 1.12, and 1.13. As a summer peaking utility, Idaho Power does not operate DR programs in winter.

The A/C Cool Credit program is an air conditioner cycling program for residential customers. The cycling is controlled with a switching device installed near the air conditioning unit. The cycling only occurs a few days each summer. Participating customers earn a $5 a month credit on their summer energy bills for participation in this program.

Table 1.11 Oregon A/C Cool Credit data

A/C Cool Credit (Residential)			
Year	**Customers**	**Capacity (MW)**	**Actual Demand Reduction (MW)**
2016	368	0.5	0.4
2017	362	0.5	0.4
2018	337	0.5	0.4
2019	285	0.4	0.3
2020	262	0.4	0.2

Flex Peak is a DR program that offers financial incentives to commercial and industrial customers that can reduce their electrical load when summer demand for energy is high or for other system needs. The program season is from June 15 to August 15 which is typical although the timeframe could be adjusted in the future. A minimum of three events occur during the season with events lasting between two and four hours. Participating customers are notified two hours before the event.

Flex Peak actual demand reduction can, at times, be larger than the program capacity. Capacity is calculated as the sum of the customer-nominated amounts. In some instances, customers reduce more than their nomination.

[6] Idaho Power reports on its three DR programs in an annual OPUC filing in docket UM 1710.

Table 1.12 Oregon Flex Peak data

Flex Peak (Commercial & Industrial)			
Year	Customers	Capacity (MW)	Actual Demand Reduction (MW)
2016	9	12.3	13
2017	9	12	12
2018	9	5.6	2
2019	9	12.2	11.9
2020	8	11.4	7.6

The Irrigation Peak Rewards program offers a financial incentive to irrigation customers for allowing Idaho Power to remotely turn off specific irrigation pumps during the program season (June 15 to August 15).

Table 1.13 Oregon Irrigation Peak Rewards data

Irrigation Peak Rewards (Irrigation)			
Year	Customers	Capacity (MW)	Actual Demand Reduction (MW)
2016	50	7.3	7
2017	50	7	7
2018	50	9.5	9
2019	51	8.8	7.5
2020	51	8.3	8.1

Although Idaho Power leverages its DR programs based on overall system peak needs, Table 1.14 shows the DR capacity for Idaho Power's Oregon service area as a percentage of the demand in the Oregon service area at the time of the total system peak.

Table 1.14 Oregon DR percentage of total system summer peak

	Oregon Load at Total System Peak[1]		Oregon DR Capacity	DR % of Oregon Load at Total System Peak
Year	Date/Time	MW	MW	%
2016	6/29/2016 18:00	122.1	20.1	16.5%
2017	7/7/2017 17:00	120.9	19.5	16.1%
2018	7/9/2018 19:00	118.3	15.6	13.2%
2019	8/5/2019 18:00	115.2	21.4	18.6%
2020	8/18/2020 18:00	111.5	20.1	18.0%

1 These dates and times correspond to Idaho Power's system wide peak. The MWs shown represent the demand in Idaho Power's Oregon service area at the time of the system-wide peak.

IDAHO POWER®
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DSP REPORT:

HOSTING CAPACITY ANALYSIS

HOSTING CAPACITY ANALYSIS

Hosting capacity is the amount of new energy generation or consumption (load) that can be connected to a utility's distribution system without compromising reliability. In turn, HCA can identify how much load or generation can be added to segments of the distribution system before those segments are overloaded. Most often, HCA is used to evaluate where and how much distributed generation (DG)[7] can be added to parts of a utility's distribution system before creating reliability problems and/or necessitating upgrades.

The information below details Idaho Power's initial HCA, as well as an evaluation of three options to evolve the use and frequency of updating the HCA in the future.

Generation-Limited Circuits Map

Idaho Power began by evaluating its distribution circuits in eastern Oregon to determine areas with limited generation hosting capacity. The analysis, utilizing 2020 model data, was conducted using the Electrical Power Research Institute (EPRI) DRIVE tool. The study was based on minimum daytime load, which was approximated as 10% of peak load. While all circuits serving Idaho Power's Oregon customers have some capacity for DG (at sizes of 100 kilowatts [kW] or less), there are six of the 63 circuits with limited capacity for small generators. Thosesix circuits' limited ability to host additional generation capacity is the result of existing connected small generators.

Idaho Power has developed and added a PDF map displaying the eastern Oregon circuits with limited generation hosting capacity to its DSP webpage (see Figure 2.1). The company is constructing a more interactive map with zooming capabilities that will be available online by summer 2022.[8]

[7] For hosting capacity analysis, Idaho Power is focused on distributed generation, not the broader category of DER.

[8] With respect to wildfire, the DSP Guidelines asked utilities to identify circuits in so-called Public Safety Power Shutoff (PSPS) zones. Idaho Power has evaluated its entire service area to determine tiers of wildfire risk and designating Red and Yellow Risk Zones. As of October 2021, Idaho Power does not have any distribution circuits in potential PSPS areas in Oregon, since Idaho Power has no Red Risk Zones in Oregon.

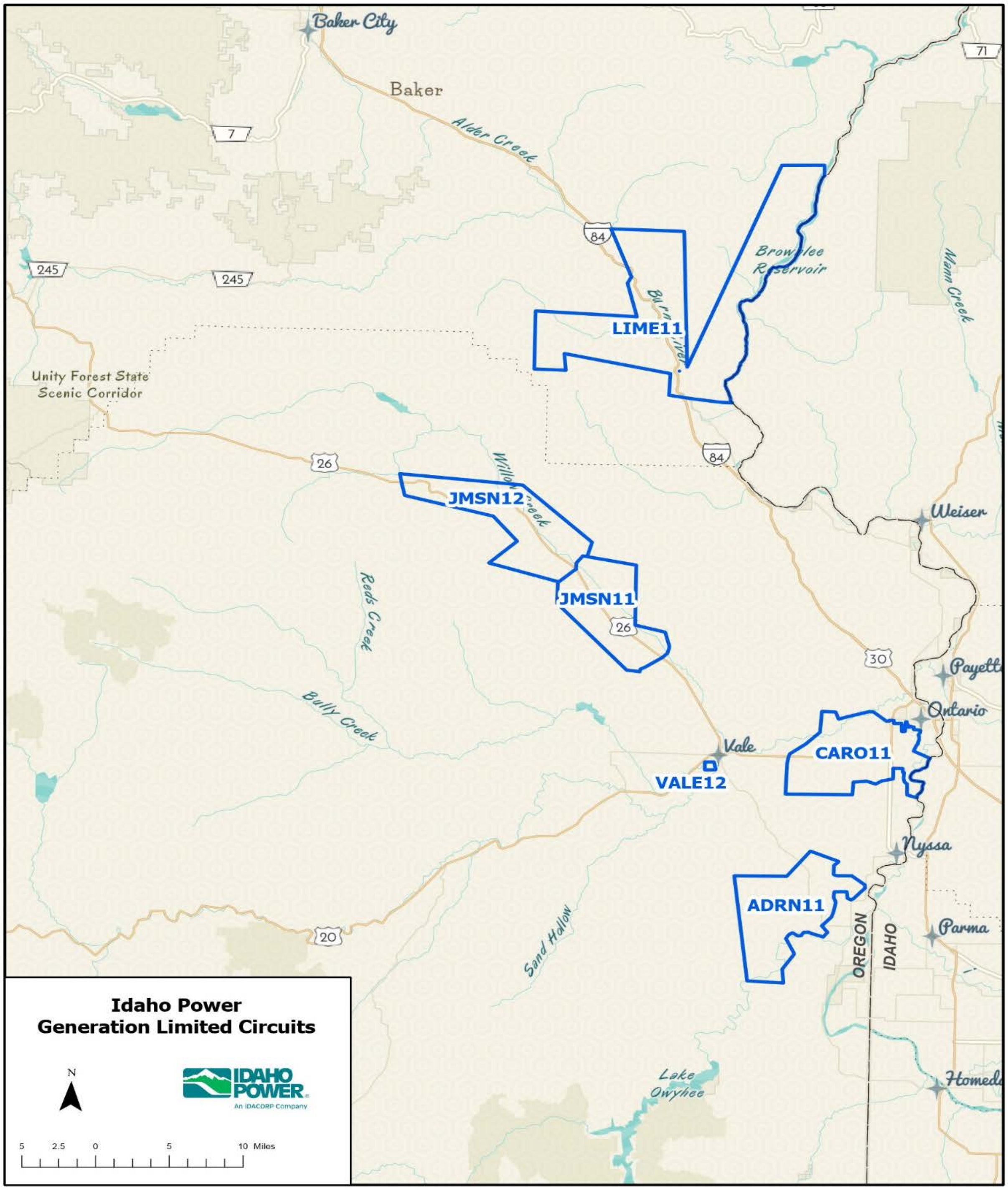

Figure 2.1 Oregon generation capacity limited circuits

Hosting Capacity Analysis Options

Idaho Power's initial HCA is a manual snapshot in time at the feeder level. Idaho Power is evaluating options to make future hosting capacity processes more granular with frequent refresh rates. As requested in the OPUC's Distribution System Planning Guidelines (guidelines), Idaho Power reviewed three options for conducting HCA in the future.

Hosting Capacity Analysis Option 1

In this first option, the primary use of HCA would be to inform grid needs identification and would include the following parameters as listed in the guidelines:

- **Methodology**: stochastic modeling/EPRI DRIVE modeling
- **Geographic granularity**: circuit-level
- **Temporal granularity**: annual minimum daily load
- **Data presentation**: web-based map for the public and available tabular data
- **Refresh frequency**: Annual basis
- **Planned/queued generation information**: Identified with details (e.g., number and size of projects, description, upgrade cost)

To implement Option 1, Idaho Power would use the Synergi software to perform the HCA. Previously, Idaho Power used the EPRI DRIVE software extension for Synergi to determine the maximum hosting capacity on a circuit. DRIVE converts existing Synergi circuit models into a new format and extracts hosting capacity data. The hosting capacity data is then converted into a third format to present the results on a map. Synergi software can perform HCA and present the output on a map, which would eliminate the step of converting the circuit models.

The circuit hosting capacity would be updated annually to incorporate changes to the distribution system, connected load, and connected or planned generation. For each circuit, the maximum remaining hosting capacity for the circuit would be displayed in tabular form. In addition, for each circuit any planned/queued small generation would be listed along with any costs for upgrades. Under this option, the company's existing Generation Capacity-Limited Circuit map would be replaced with a new map that would include the Option 1 HCA information listed above. The map and details would be updated annually.

The cost to implement Option 1 for our Oregon circuits is estimated to be $72,000 annually, driven by labor to update and configure the models but would also leverage existing tools and data already available.

Hosting Capacity Analysis Option 2

The second HCA option would have two main uses: 1) inform grid needs identification and 2) share regularly updated results publicly to inform stakeholders of potential interconnection challenges. Option 2 would include the following parameters as listed in the guidelines:

- **Methodology**: same as Option 1
- **Geographic granularity**: feeder (Idaho Power understands this to mean branches or taps)

- **Temporal granularity**: monthly minimum daily load
- **Data presentation**: same as Option 1
- **Refresh frequency**: monthly
- **Planned/queued generation information**: same as Option 1

For this option, Idaho Power would perform HCA using Synergi software to determine the hosting capacity at each circuit line section and would not be limited to the branch or tap level. This analysis would provide more granularity into the specific circuit areas that have greater amounts of hosting capacity compared to a single hosting capacity value for the entire circuit.

This analysis would be updated monthly or based on changes to the system, load, or generation. From a system operations perspective, the value of providing hosting capacity on a monthly basis would only be realized if Idaho Power were able to control connected generation and limit the production as needed monthly. Monthly production control would be necessary so as not to overload individual circuits and/or necessitate distribution upgrades on certain circuits. Otherwise, the generation hosting capacity would be limited by the lowest capacity identified across all months.

The analysis of the most limiting hosting capacity for each circuit line section would be displayed in the online map. For each circuit, the hosting capacity ranges for the circuit sections would be displayed in tabular form as a percentage of the circuit sections for each month of the year. An example of this format is provided in Table 2.1. For each circuit, any planned/queued small generation would be listed along with any potential upgrade costs.

Table 2.1 Example of monthly hosting capacity tabular data

	Available Hosting Capacity Ranges (MW) for March 2021					
Circuit	**HCA=0**	**0<HCA<=0.1**	**0.1<HCA<=0.5**	**0.5<HCA<=1**	**1<HCA<=2**	**2<HCA<=5**
NYSA11	0%	5%	52%	7%	7%	28%
NYSA12	0%	14%	44%	17%	13%	12%
NYSA13	0%	15%	53%	16%	8%	8%
NYSA14	0%	47%	35%	7%	6%	6%

The cost to implement Option 2 for our Oregon circuits is estimated to be $315,000 annually, driven by the labor required to update and configure models throughout the year and perform the HCA.

Hosting Capacity Analysis Option 3

For HCA Option 3, the main uses would be to inform grid needs identification and to replace portions of interconnection studies. Option 3 would include the following parameters as listed in the Guidelines:

- **Methodology**: iterative modeling
- **Geographic granularity**: line segment
- **Temporal granularity**: hourly assessment
- **Data presentation**: same as Option 1
- **Refresh frequency**: monthly
- **Planned/queued generation information**: same as Option 1

For Option 3, Idaho Power would perform the HCA using Synergi software to determine the hosting capacity at each circuit section. This analysis would be performed for each hour for two days each month—one day to represent the minimum daytime load day and the other day to represent the minimum absolute load day of the month.

The result of the analysis would be 576 values of hosting capacity for each line section—one hosting capacity value for each hour of the two representative days evaluated for each month. The minimum daytime load would be used to determine the hosting capacity DG while the absolute minimum load would be used to determine the hosting capacity for all other DER.

The cost to implement Option 3 for our Oregon circuits is estimated at more than $783,000 annually. The cost is driven by labor to update the circuit models, configure the software, and run the analysis.

Evaluation Summary

Idaho Power evaluated the three HCA options based on seven factors, discussed and summarized in Table 2.2.

Table 2.2 Hosting capacity analysis option summary

Evaluation Parameter	Option 1	Option 2	Option 3
Data Sensitivity Risk	Minimal	Medium	Medium
Result Validation Effort	Minimal	Medium	Extensive
Implementation Concerns	Minimal	Medium	Extensive
Barriers	Minimal	Medium	Extensive
Value to Interconnection Customers	Low	Medium	Medium
Timeline	3 Months	2 Years	3+ Years
Annual Costs	$72,000	$315,000*	$783,000*

*Distribution energy resource management system (DERMS) required to make these options valuable which would be a significant cost addition — roughly $4 million initially with an annual cost of $800,000.

Data Sensitivity Risk. Exists for options 2 and 3. The granularity of data, moving from the circuit level to the branch level could reveal sensitive customer loading information and will need to be mitigated.

Result Validation Effort. Medium for Option 2: the monthly minimum and peak loading will require significant research to validate; for Option 3, peak characterization and minimum daily load profile for each month will take even greater effort.

Implementation Concerns. Exists for options 2 and 3. Implementation will require significant skilled labor commitments and computing time. Idaho Power does not currently have the necessary resources to do this work; staffing would need to be added and trained. The workload for Option 3 would be significantly greater than Option 2.

Barriers. Exists for options 2 and 3. The barriers include obtaining field data, various load profiles, generation profiles, and the need for much greater computing resources.

Value to Interconnection Customers. Present in options 2 and 3. Interconnection customers would be able to see hosting capacity limits on sections of the circuits rather than one value for the entire circuit (Option 1), which may provide more benefit. However, the separate values for different months or hours of the day would not be used as the limiting factor in most cases and would not realize a value to interconnection customers. The value will require the addition of a DERMS, which is beyond the scope of this analysis.

For all options, circuits with fewer than five customers may be excluded from the analysis to protect sensitive customer information. Currently there are five circuits in Oregon with less than five customers. The results of the HCA would not bypass any interconnection requirements.

Idaho Power believes there are implementation concerns and barriers related to options 2 and 3. One barrier is having access to qualified resources during implementation while maintaining existing systems. As noted above, the value of frequently updated HCA—from a system management perspective—is limited without the ability of Idaho Power to control and manage the connected generation. Otherwise, the generation hosting capacity would be limited by the lowest capacity identified across all hours or months that occur when the generation source would be active. For instance, photovoltaic (PV) solar generation would be expected during daylight hours, while hydro and wind could occur any time of day.

To manage connected generation, either monthly or hourly, Idaho Power would implement a DERMS. Bringing a fully functional DERMS online would take four years or more at an initial cost of more than $4 million with ongoing maintenance costs of 20% of the final cost ($800,000 annually). Currently, operational DERMS within the electric utility industry are novel, with few vendors having deployed fully functioning systems.

A DERMS would also require a communication path from each customer generation controller. This would increase the cost of a customer's DG or DER system and require additional cybersecurity measures. The customer's generation system output would be affected by this control system. At specific times, the system output could be restricted to meet system requirements.

Recommendation

As a next step, Idaho Power proposes to move forward with a hybrid option. For this hybrid solution, Idaho Power would provide the hosting capacity information on the circuit section level similar to Option 3. The hosting capacity information would be updated as often as bi-annually based on any changes to the installed equipment, connected load, or connected generation on the circuits. The most limiting hosting capacity based on minimum daytime load for each section would be displayed on the map. The hosting capacity ranges for each circuit would be displayed in tabular form as a percentage of the circuit's total sections. The hosting capacity table would display the most limiting hosting capacity rather than a hosting capacity for each month or hour.

Idaho Power anticipates implementation of the hybrid option by Q3/Q4 2022 at an estimated cost of $72,000 annually due to labor to update the circuit models, configure the software, and conduct the HCA.

DSP REPORT:
COMMUNITY ENGAGEMENT PLAN

COMMUNITY ENGAGEMENT PLAN

A key component of Idaho Power's system planning involves outreach and engagement with customers, communities, and stakeholders. The company leverages working groups and committees in many of its other planning efforts—for example, the company's long-term resource planning efforts rely on the Integrated Resource Planning Advisory Council (IRPAC) to provide comment, feedback, and review of Idaho Power's Integrated Resource Plans (IRP) every two years.

As a new regulatory planning effort, the company's DSP does not yet have an advisory or oversight group like that of other company planning processes. In lieu of a formal group, Idaho Power has leveraged informal virtual workshops to educate, engage, and seek feedback from its Oregon customers, communities, and stakeholders.

Public Workshops

Idaho Power held two virtual public workshops prior to the filing of this DSP Report (part I of II). These workshops were focused on sharing information about Idaho Power's distribution system in eastern Oregon and gathering input from customers, stakeholders, and community members.

Stakeholders in the OPUC's distribution system planning investigation (docket UM 2005) were invited to attend the Idaho Power DSP workshops, but the company's primary engagement efforts involved direct outreach to customers, businesses, communities, and community representatives through Idaho Power's employees that operate in eastern Oregon.

Community Engagement Workshop 1

Idaho Power hosted its first community engagement workshop on August 26, 2021. Participants were introduced to the DSP effort with a brief electrical system education session focusing on power, capacity, and energy concepts. The meeting also provided details about the existing distribution system in Idaho Power's eastern Oregon service area. To create a level of engagement and participation in the virtual setting, workshop participants could answer a series of questions to identify energy-related priorities, items of interest, preferred means of engagement, and DSP-specific topics for future discussion. Results of the questions showed participants' top energy-related objectives are equally divided between cost and reliability. Forward-focused questions identified participants are interested in learning more about how Idaho Power makes distribution investment decisions, develops and evaluates potential pilot projects, hosting capacity maps, and data sharing/use cases. Complete poll results from the first workshop are provided in Appendix D.

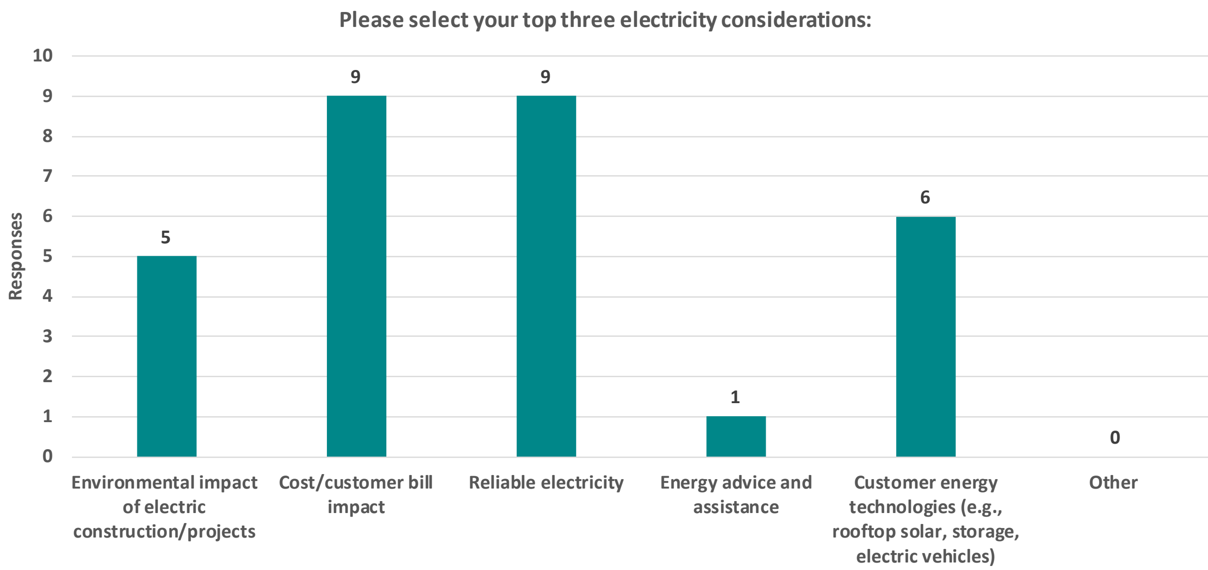

Figure 3.1 Poll question results: top electricity considerations (Workshop 1)

Community Engagement Workshop 2

The company hosted a second community engagement workshop on September 15, 2021. As a result of the information gathered from the first workshop, the second workshop focused on a few discrete topics: a baseline information session on HCA, a presentation on currently accessible personal energy data through Idaho Power's website, and the company's plan to build a DSP-focused community engagement plan.

During the HCA discussion, participants were shown a map of the generation-limited[9] circuits in eastern Oregon. All of Idaho Power's eastern Oregon distribution circuits have capacity for additional DER.

To gain a better understanding of Idaho Power's unique eastern Oregon service area—in which generation can far exceeds local electric demand—participants were shown a map of existing PURPA QF sites as previously seen in Figure 1.24. Participants provided input on how to improve the maps, including being able to identify the size and type of generation for each facility.

Meeting attendees were also shown how to access personal energy data using the My Account customer portal on Idaho Power's website. Following this presentation on available resources for customers to access energy data, participants were asked to share ideas on what data would be useful in helping them make informed decisions regarding their energy use.

[9] A generation-limited circuit is one constrained or unable to accommodate new generation larger than 100 kW.

The primary suggestion was to make it easier to understand how personal energy use relates to energy costs due to the demand on Idaho Power's entire system.

Finally, a discussion was facilitated regarding the needs, challenges, and opportunities of communities and organizations. Knowing that the meeting participants may have different community connections than Idaho Power, the company asked for suggestions of additional individuals and organizations that should be engaged in future workshops to discuss identification of grid needs, solutions, and potential pilot projects. While this line of questioning did not immediately yield additional participant suggestions, it did launch a valuable conversation about how to best approach customers and communities to achieve greater engagement. Some of the suggestions included:

- Translating DSP actions into understandable actions that have real impacts on customers
- Helping the community understand how their input can affect and drive distribution system changes and investments
- Understanding the demographics of the communities to determine additional outreach avenues
- Making meetings more accessible (e.g., alternate timing and location)
- Communicating at a non-technical level that is meaningful for everyone
- Engaging communities through the schools, charitable groups, and cultural and community centers

The two DSP workshop presentations are available on Idaho Power's dedicated DSP webpage: idahopower.com/DSP.

Next Steps in Community Engagement

Looking forward, Idaho Power will host additional public involvement workshops before filing Part II of the DSP Report in summer 2022. A primary focus of the forthcoming workshops will be to discuss identification of grid needs and potential solutions, which could involve technologies other than traditional distribution lines.

A key interactive component of the workshops will involve brainstorming potential DSP pilot projects that would solve an identified distribution system challenge. The goal of Idaho Power's community engagement efforts is to work with customers, community-based organizations (CBO), and stakeholders to develop a community-centered approach to distribution system planning.

Before filing Part II of this DSP Report, Idaho Power will do the following:

- Use billing inserts and media channels to notify customers in eastern Oregon about upcoming DSP efforts and how they can get involved
- Seek out and engage CBOs that operate in eastern Oregon to gain more representative and diverse public input
- Hold public workshops to discuss pilot concept proposals and to learn about and discuss:
    - Community interest in clean energy planning and projects
    - Community energy needs and desires
    - Community barriers to clean energy needs, desires, and opportunities
    - Energy burdens within eastern Oregon communities
    - Community demographics
    - Potential greenhouse gas (GHG) reductions resulting from implementing a "non-wires solution."

Idaho Power will use its DSP webpage at idahopower.com/DSP to post workshop information and relevant content. Participant comments and Idaho Power responses will be collected and synthesized to inform the decision-making process. Idaho Power will track comments to ensure participants receive timely follow-up. Customers and workshop participants will be encouraged to use a dedicated email address, DSP@idahopower.com, to provide input and ask questions outside of the public workshops.

Additionally, Idaho Power will continue to attend and participate in the OPUC's UM 2005 public workshops to provide feedback, insights on Idaho Power's distribution system in eastern Oregon, and to ensure that utilities, stakeholders, and the OPUC are developing a shared set of principles and terms related to the DSP. Idaho Power will also continue to support OPUC staff as they prepare DSP educational materials for the general public. It is Idaho Power's goal to have a collaborative DSP process that encourages community input, meets the community needs, and continues to uphold our core principles of reliable, safe, and affordable energy.

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DSP REPORT:
LONG-TERM DISTRIBUTION SYSTEM PLAN

LONG-TERM DISTRIBUTION SYSTEM PLAN

Idaho Power's DSP Vision

Idaho Power's goal for the distribution system is to continue to safely, reliably, and cost-effectively meet near- and long-term load service requirements. Recognizing that customer energy needs are shifting and that the distribution system is evolving, Idaho Power will focus its DSP efforts on the following:

- Forecasting near- and long-term electrical demands
- Developing community advisory-based electrical plans
- Developing proactive near-term local area plans that are achievable and executable before electrical demand overloads facilities or results in reduced service quality

Ultimately, Idaho Power's objective is to build and operate a flexible system that can adapt to increased demand, technology changes, and an increasing number of customer energy devices.

All DSP efforts will also be considered through the lens of Idaho Power's "Clean Today. Cleaner Tomorrow." goal to provide 100% clean energy by 2045.[10] This goal furthers Idaho Power's legacy of being a leader in clean energy. To realize this voluntary goal, the company will build off its existing foundation of nearly 60% clean resources. To further Idaho Power's movement toward 100% clean energy, the company is also using its IRP process to evaluate GHG reduction pathways. As discussed more below, the company will work to integrate its DSP and IRP processes to ensure both a bottom-up and top-down assessment of system planning.

Roadmap of Planned Improvements

Substation/Distribution Network and Operational Enhancements

Distribution Voltage Optimization (DVO) is the program to apply conservation voltage reduction (CVR) using Idaho Power's new IVVC system. DVO will provide awareness and control of circuit voltages via control of substation LTC, line voltage regulators, and capacitors using a licensed 700 MHz FAN. Idaho Power currently has IVVC operating on 17 circuits in Oregon serving about 11,583 customers. The company will evaluate the potential of applying DVO to circuits with IVVC in Oregon, and look for further system enhancement opportunities.

Idaho Power is pursuing distribution circuit Fault Locating Isolation Service Restoration (FLISR) projects. The FLISR projects will use a phased implementation of distribution circuit fault locating by installing mid-line reclosers, line sensors, and fault locators that will provide

[10] idahopower.com/energy-environment/energy/clean-today-cleaner-tomorrow/

real-time data to SCADA. This will be piloted in the Boise-area with plans to implement in Oregon contingent on Boise-area pilot results. The intent of FLISR projects are to improve customer reliability.

Idaho Power is also currently evaluating the implementation of an Advanced Distribution Management System (ADMS) and consolidating it with the company's existing EMS and OMS to create an efficient and secure single vendor platform.

Building an ADMS would provide significant new modeling and control capabilities for system operators and field personnel including a Geographic Information System (GIS)-based distribution system model with real-time load flow with new advanced applications, such as FLISR. The real-time load flow will improve Idaho Power's operational visibility into the distribution system and provide more direct control to operators, improve reliability to customers and effectively manage additional distributed generation.

The company plans to complete the evaluation phase for ADMS in spring 2022. Anticipated barriers to implementation include the change management required to integrate new technology with current business practices and having access to qualified personnel during implementation while maintaining existing systems.

Investments in DVO and ADMS will collectively improve power quality, hosting capacity, and allow for more efficient and flexible operation of the distribution system. The projects are anticipated to support customer service and reduce customer costs by reducing losses, reducing outage response time, and improving utilization of assets.

Distributed Energy Resource and Renewables Enhancements

The recently approved Idaho Schedule 68 tariff[11] requires new customer generation systems that are inverter-based to use smart inverters as defined by the latest IEEE 1547 standard. The smart inverters have capabilities to modify their output based on system conditions to create more hosting capacity and allow greater penetration on the distribution system. In particular, the recently approved Idaho Schedule 68 tariff requires future customer DERs with smart inverters to provide distribution voltage support. Smart inverters have significant additional capabilities the company could look to leverage in the future; however, this would require company investment in additional communications capabilities, as well as a DERMS.

Adoption of generation technologies (DG and DER) remains low by Idaho Power's eastern Oregon customers, in part because of the company's nationally competitive energy prices.

[11] Schedule 84 in Oregon explains that the net metering services are offered under the Idaho jurisdictional tariff schedule 84. Schedule 84 in Idaho references Idaho Schedule 68 for interconnection requirements.

Idaho Power continues to monitor and evaluate hosting capacity availability and will stay abreast of the industry's renewable energy evolution and standards through engineering associations, such as IEEE.

Transportation Electrification Enhancements

For many years, the company has observed a low EV adoption rate, as noted in the Baseline Data section of this Report. To date there are 28 EVs registered in eastern Oregon. This low adoption could be due to cost, available vehicle class, range concerns, and/or lack of interest, among other factors. Nevertheless, Idaho Power is evaluating opportunities for transportation electrification enhancements.

The company currently uses hosting capacity analytics to identify system load capacity along major transportation corridors and in areas of multi-family housing. Such analysis allows the company to identify potential projects for level 1, 2, and 3 EV charging stations where limited or no system upgrades will be needed.

The company is evaluating load models for commercial sites that have level 1 and 2 charging stations, as well as single family dwellings that have EV charging stations. The data is being used to provide load profiles to evaluate the impact on current system design practices.

Residential service transformer sizing is currently under evaluation for updates to recommended design practices to accommodate residential EV charging. By adjusting long-term design practices, current and future customers may avoid upgrade costs for residential and commercial EV charging.

In the event of sizeable EV growth, Idaho Power could develop EV rates for different customer classes to incentivize preferred charging times.

Idaho Power has supported a community-based electric car sharing offering to scale a three-year program of local partnerships to place electric vehicles at affordable housing communities and provide community access electric vehicles. This support was provided to respond to a United States Department of Energy (DOE) grant opportunity. The program is dependent upon DOE awarding the grant and subsequent community adoption of the EV car-sharing offering.

Customer Information and Demand-Side Management Enhancements

DSM are those efforts and programs available to help customers manage and control their energy use in coordination with Idaho Power and includes both demand response programs and energy efficiency programs. Both the A/C Cool Credit and Irrigation Peak Rewards DR programs use the AMI system to communicate with load control devices. Presently, Idaho Power has approximately 99% coverage with AMI and plans to evaluate extending coverage to 100% of the Oregon service area. And the company's My Account portal allows customers to access their hourly data that is obtained with the AMI system. Extended and easier access to customer energy use data can lead to energy efficiency measures being more readily adopted.

To review potential DSM offerings, Idaho Power meets quarterly with the Energy Efficiency Advisory Group (EEAG), which is comprised of the staffs of both the OPUC and the Idaho Public Utilities Commission (IPUC), environmental organizations, state and local governments, low-income representatives, and representatives from the irrigation, commercial, and industrial sectors.

As part of Idaho Power's IRP, which is developed every two years, the company conducts an evaluation of energy efficiency potential. All cost-effective energy efficiency options are included as a resource in the IRP to reduce future loads. The primary barrier to additional energy efficiency is that many energy-savings measures, especially in the residential sector, are often not cost-effective compared to the cost of other resources that can meet system needs.

Broadly, Idaho Power's demand response programs represent potential reductions of 10% of the system summer peak and represent one of the largest utility demand-response portfolios in the nation proportionate to peak demand. While DR is certainly related to distribution system planning, these programs are primarily evaluated in the IRP process. During preparation of the 2021 IRP (which will be filed with the OPUC in December 2021), the company identified the need to modify demand response programs such that they are available later in the evening and season to address system needs. These time changes may make it challenging for some customers to participate in the programs, but Idaho Power is confident it can continue to expand and evolve demand response to be mutually beneficial for customers and Idaho Power's system.

General Business Enhancements

Idaho Power is evaluating a Customer Relations Management (CRM) solution to integrate various internal systems in support of enhancing customer engagement. The company currently uses several systems and tools that give job function-appropriate employees insight into customer energy information such as electrical usage history, reliability, billing detail, outage history, customer engagement history, and energy efficiency program participation. Marketing and customer communication tools are also in a separate system. By using a single platform that can aggregate the various system data and provide valuable insights, the company can further reach and engage customers with useful information, alerts, and current and new program offers.

The potential benefits of the CRM project include:

- Increased customer engagement through proactive outreach that is targeted to specific needs , such as energy efficiency offers
- Potential to increase DSM program participation by understanding a customer's interests and actions
- Ability to customize Idaho Power's follow-up based on more detailed customer information
- Greater efficiency through streamlining time-intensive processes
- Increased productivity of customer-facing employees by implementing a single source for customer data, including energy consumption and trends, opportunity for DSM program participation, etc.
- Improved visibility for customer-facing employees into what communications a customer received and the actions that followed
- Improved visibility into return on investment for energy efficiency campaigns through tracking of customer engagement and actual results

As with any new technology solution, the CRM project may have barriers to implementation and success, such as unanticipated costs, challenges integrating with legacy systems, and/or successful and streamlined change management.

Idaho Power is also in the process of rebuilding its My Account customer engagement tool to enhance the digital experience for customers. Major areas of the self-service tool are access to billing and payments, alerts and customer profile management, energy usage, and energy efficiency information. The company is also in the process of building a native mobile application (app) for registered My Account users.

The new My Account app will modernize the customer tool with streamlined customer workflows, greater stability, greater scalability, increased development velocity, modern look and feel, and enhanced security best practices. Idaho Power is confident that synergies can be found between these new information technology tools, customer interaction, and DSP efforts.

Transmission Network and Operations Enhancements

Idaho Power uses reliability metrics and analysis tools to identify areas where investments in the transmission system can result in customer reliability improvements. Some of the improvements to aging transmission systems will provide significant capacity and reliability gains. Some examples are the Huntington-Durkee-Quartz transmission line project and the Ontario-Cairo transmission upgrades from 69 kilovolts (kV) to 138 kV, which improves reliability and capacity.

Idaho Power's Local Transmission plan, published on the company's OASIS website, identifies transmission projects in the 1- to 20-year time horizons.[12]

Forecasting Future Technical and Market Potential of DERs

As detailed below, Idaho Power will continue to refine and improve its distribution investment evaluations to determine if DERs could be deployed on the distribution system in place of new distribution system wires or other traditional solutions. These so-called non-wires alternatives (NWA) are discussed in more detail below.

Transitional Planning and Operational Activities

Idaho Power's Planning department has developed and implemented an NWA tool to conduct initial, high-level evaluations comparing traditional grid solutions (e.g., poles, wires, transformers) to non-wires solutions (e.g., microgrids, solar+storage facilities) to ensure the most efficient and cost-effective solution is implemented. Idaho Power's goal is to economically use renewable energy options, thereby deferring (when possible) traditional utility upgrades and more fully using company assets. Idaho Power will continue to enhance the NWA tool to quickly assess existing and innovative technologies and value stream options.

The company will continue to seek and build community engagement in its various planning processes. As noted earlier in this report, Idaho Power has a robust community advisory committee process for the IRP and Electrical Plan development. The company will continue to seek out customers and CBOs that can assist in and inform the development of the company's evolving DSP.

Smart Grid Investment Opportunities

Idaho Power continues to track potential smart grid investments and prioritize options for distribution automation, reliability improvements, microgrid automation, and hosting capacity advancements. As mentioned in the Substation and Distribution Network and Operation Enhancements sections, Idaho Power is pursuing several smart grid-related investments, such as FLISR and ADMS development and implementation.

Idaho Power will continue to monitor industry advancements and cost declines in DG, DERs, and EVs—and evaluate the possibility that these technologies could leverage (alone or in combination) as non-wires solutions. While NWA solutions in eastern Oregon have yet to prove cost-effective, the company will continue to evaluate them, with the belief that successful solutions could increase asset utilization to the benefit of customers and Idaho Power.

[12] Specific transmission projects are identified in Appendix B of Idaho Power's 2018–2019 Local Transmission Plan: oasis.oati.com/woa/docs/IPCO/IPCOdocs/IPCO_Final_2019_Local_Transmission_Plan.pdf

In combination, the FLISR, ADMS, and NWA smart grid investments have the potential to provide customers with more affordable and reliable power.

Opportunities and Benefits for Distribution System Investment

The application of ADMS will enable more efficient use of the distribution system. Along with potential distribution upgrades, ADMS will also improve system reliability and system resiliency.

With respect to individual technologies, Idaho Power is currently evaluating the benefits and value streams associated with distribution-connected battery energy storage systems (BESS). In low growth areas, BESS has the potential to defer some distribution system investments and allow for a higher utilization of system assets. The value streams being considered are transmission and distribution (T&D) deferral, arbitrage, system regulation, and system resource benefits. If realized, these value streams could make the net cost of BESS cost-effective when compared to more traditional capacity-driven distribution projects.

If eastern Oregon continues to grow (by customer size or energy needs), the company may need to increase capacity to serve the area. Such capacity investments could allow for (or enable) greater generation hosting capacity, EV charging capacity, and additional commercial and industrial loads.

Research and Development

In order to stay informed on industry topics, Idaho Power is involved in several areas of industry research. The company participates in the EPRI's P200 Planning and P174 DER Integration programs, which cover topics such as NWA, EV load research, HCA, DER, and microgrid impacts.

Idaho Power actively participates in the development of the IEEE Standard for Interconnection and Interoperability of Distributed Energy Resources (IEEE 1547). The standard undergoes revisions as the industry gains more experience with DERs and other smart grid applications.

Idaho Power follows National Renewable Energy Laboratory's (NREL) recent studies and tools and routinely uses them to inform and assist in the evaluation of grid applications. The company also has a subscription to Wood Mackenzie's industry research and will continue to use that information in IRP and future DSP evaluations.

Future Policy and Planning Interactions

Resource Planning

One of the clear relationships between distribution system planning and integrated resource planning is the ability to consider avoided or deferred distribution investments as a cost offset to potential resource investments. The value of such T&D deferral will be evaluated closely in the DSP process, as well as in the company's IRP. Distribution system planning affects the calculation of the T&D deferral value included in the IRP's energy efficiency cost-effectiveness test and the T&D deferral value of DERs in the IRP resource stack. To the extent that IRPs identify DG/DER in the action plan window (the first two to four years of the IRP), local load forecasts and the distribution plan would be adjusted based on the anticipated peak demand reduction. Examples of DER investments include BESS, PV, and DSM.

Importantly, however, there are differences between the IRP and DSP processes. The IRP analyzes several long-term peak forecast scenarios focused on long-term resource needs. The DSP, on the other hand, analyzes near-term loading scenarios that can stress the local area capacity or operating constraints that may occur at peak or light loads. Further, any DG/DER identified in the IRP does not specify location. The DSP is needed to inform the locational value (or cost) of DG/DER on Idaho Power's system. With these considerations, the IRP and DSP are linked and the results of either informs the other in an iterative process.

Annual Construction Budget for Major T&D Investments

Planning engineers at Idaho Power identify distribution system investment options through multiple studies. For all capacity projects, traditional options are evaluated against NWA solutions. The preferred and cost-effective solution is submitted into the annual capital and operations and maintenance (O&M) budget processes

For capital investment, budgets are project-based. Managers submit capital project proposals to senior management for review. The capital projects are reviewed and approved by the executive management team. From that information, the capital budgets are created and then reviewed and approved by the Idaho Power Board of Directors.

For O&M, budgets are generally based on historical cost center/cost element spend with adjustments for known changes. Managers submit O&M budget requests for senior management review. The budgets are then reviewed and approved by the executive management team and the Idaho Power Board of Directors.

The timing of annual distribution system planning activities and specific deadlines related to broader utility planning and budgeting processes are as follows:

- **May and June**: Capital projects are gathered and reviewed by managers
- **July**: Capital projects are reviewed by senior managers
- **August**: Capital projects are reviewed and approved by executives
- **September**: O&M budgets requested by cost center managers
- **October**: O&M budgets are reviewed and approved by senior managers and executives
- **November**: Capital and O&M budgets are reviewed and approved by Idaho Power Board of Directors

As outlined earlier in the Historical Distribution System Spending section of Baseline System Assessment chapter, the capital budget uses the following plant types for categorizing distribution projects: Interconnect Facilities—Distribution Lines, Underground Reconstruction, Distribution Stations, Overhead New Business, Overhead Reconstruction, Underground Duct Vault, Underground New Business, Nightguard Lighting, Street Lighting, and Meter Purchases.

The O&M budget does not utilize a categorization to separate distribution system expenses from other types of expenses.

Other Major Policy and Planning Efforts

In addition to this new DSP process, Idaho Power has several existing planning and evaluation efforts in place:

NWA solutions review. When capacity constraints are identified, traditional solutions are compared to NWA solutions. If the NWA solution is cost-effective in deferring a traditional project, then the NWA solution is included in the distribution system plans. To date, Idaho Power has not identified a cost-effective NWA solution in eastern Oregon.

Local and regional transmission plans. The transmission plans identify proposed modifications to the transmission system, including timing and scope. These transmission plans are informed by electrical plans (discussed below) to identify the need and location of future transmission lines and substations.

Interconnection studies. Generation and large load generation projects are evaluated when developers request interconnection to the distribution system. Interconnection studies evaluate the potential impact of the new generation on local load and resource forecasts, and the distribution system plan may be adjusted based on frequency and size of both load and resource interconnection requests.

Small area studies. The Distribution Planning engineers study each substation and the connected distribution circuits on a recurring basis. These studies identify grid needs based on projected load growth adjusted for extreme temperatures. The studies also identify solutions to address specific grid needs.

Electrical plans. These studies are based on a jurisdictional land use evaluation of forecasted loads. Electrical plans direct future substation and transmission requirements. Community advisory committees develop community goals and siting criteria to align with community needs. The committee uses these criteria to select preferred locations for future substations and transmission lines. The plans are published on Idaho Power's website. Idaho Power seeks to incorporate language from the electrical plans into jurisdictional comprehensive plans. The latest electric plans can be found at idahopower.com/energy-environment/energy/planning-and-electrical-projects/regional-electric-plans/

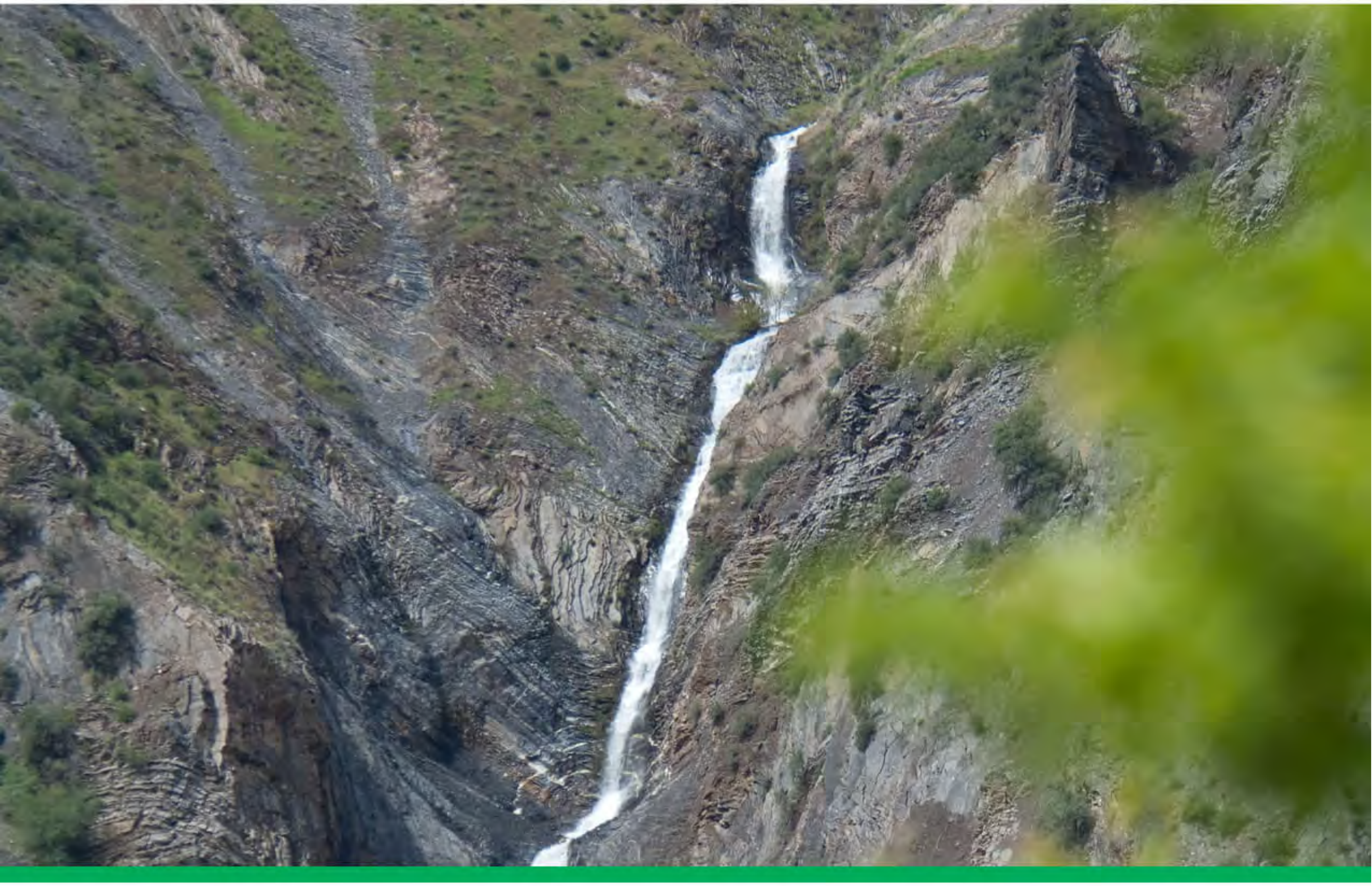
Plans to Monitor and Adapt the Long-Term DSP

The goal of Idaho Power's DSP is three-fold: 1) enhance customer engagement, 2) identify and implement innovative and least-cost technology applications, and 3) maintain reliable, safe, and affordable delivery of power.

To ensure Idaho Power is aware of industry developments and research, the company works closely with professional and industry organizations, such as IEEE's Power Engineering Society, EPRI, and NREL.

The company will continue to hold public workshops to discuss and engage eastern Oregon customers and communities in potential developments, processes, and pilot projects.

Importantly, Idaho Power's long-term DSP must factor in the realities of the company's Oregon service area—a largely rural and minimally populated area with a sizeable portion of customers at, below, or near the poverty line. Idaho Power's distribution system is not likely to evolve or grow at the pace of other Oregon utilities' service areas. While Idaho Power will work toward a DSP future that factors in grid evolution, the company must continue to keep the eastern Oregon context in mind.



DSP REPORT:

DEVELOPMENT OF DSP REPORT PART II

DEVELOPMENT OF DSP REPORT PART II

Idaho Power sees many opportunities to enhance DSP in the near- and long-term. In the 1990s, the company created a Distribution Planning Group in its Planning department, as the need to differentiate between transmission services and load services became more apparent. At first, the Distribution Planning Group primarily focused on load growth and load service requests that impacted the system and led to upgrade requirements. Over the last 10 years, Idaho Power has seen more emphasis on connected generation to the distribution system. And, in the last five years, Idaho Power has seen a need to refine and automate the customer generator interconnection process (due to modest increases in rooftop solar), provide a more flexible large load customer request process, and implement extreme temperature adjustments in circuit-level load forecasts. These changes are just some of the distribution system planning processes that are evolving to support and enhance the customer experience.

One future area of focus for the DSP is enhanced forecasting of customer-sited technologies, such as PV rooftop solar. While Idaho Power's net metering program is relatively small at present compared to other utilities, a future with greater rooftop solar adoption is evident. The company's forecasting tool currently uses historical peaks, local plans, and extreme temperature adjustments to forecast growth. Idaho Power sees a potential to integrate annual net metering customer counts and customer nameplate capacity into the forecast tool to inform the company's decisions and planning. The company is also tracking research being conducted by EPRI and others to address the concern of load masking due to increases in DER.

EV adoption forecasting is a more difficult task, as it is not tied to Idaho Power customer data. EV customer load profiles for the different types of EV vehicle classes will need to be developed. Understanding how demographics relate to usage pattens will also play a role. Idaho Power will investigate additional sources of data for DER and EV adoption forecasting. The Company will also look for ways to match locational DER and EV adoption forecasts with the system level forecast. It is not anticipated that these forecasting adjustments will be implemented prior to the filing of Part II of the DSP Report in summer 2022, but a timeline for implementation will be determined upon further investigation.

These new forecasting methods will provide additional insight and input into ongoing grid needs assessments. Enhanced distribution system and technology forecasting, along with information and feedback from customers and communities in eastern Oregon, will help shape Idaho Power's evaluation of future distribution-level pilot projects.

Finally, in preparation for the filing of DSP Report Part II, Idaho Power is also reviewing the ways that the DSP and the IRP impact one another. Integration of these two planning processes could be facilitated in several ways. For example, distribution-specific DER forecasts could be fed into the IRP process to help inform long-term resource decisions or help determine cost-effective NWA projects. Idaho Power will seek to identify synergies between the IRP and DSP processes that can facilitate more efficient, cost-effective resource investments in the near- and long-term.

APPENDICES

Appendix A: Idaho Power Company 2020 Electric Service Reliability Annual Report

Idaho Power Company 2020 Electric Service Reliability Annual Report

May 2021

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EXECUTIVE SUMMARY

The information in this document presents Idaho Power's 2020 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 2020, Idaho Power served 19,380 customers from 63 distribution circuits served by 30 substations in the far central-eastern portion of Oregon. The composite performance of the circuits in 2020 included the following:

- 699 sustained (greater than five minutes) interruption events
- 18,735 customer interruptions
- 59,845 customer hours out
- System Average Interruption Frequency Index (SAIFI) of 0.97
- System Average Interruption Duration Index (SAIDI) of 3.09 hours
- Momentary Average Interruption Event Frequency Index ($MAIFI_E$) of 2.07

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 2016-2020. Idaho Power's 2020 threshold in Oregon for a major event day (T_{MED}) per the IEEE 1366 definition was a daily SAIDI of 11.87 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 1 major event day in its Oregon service area in 2020. Idaho Power's calculated T_{MED} for 2021 in Oregon is 10.19 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 2019, Idaho Power's Oregon service area SAIFI increased by 0.34 interruptions per customer from 0.63 in 2019 to 0.97 in 2020. Excluding major events, SAIFI increased by 0.31 from 0.63 in 2019 to 0.94 in 2020. The average duration of sustained outages also increased compared to last year; SAIDI increased by 1.08 hours per customer from 2.01 in 2019 to 3.09 in 2020. The increase also occurred when excluding major events, as 2020 saw an increase of 1.17 hours per customer over 2019 (1.70 to 2.87). Finally, $MAIFI_E$ decreased in 2020 compared to 2019 by 0.21 momentary interruption events per customer from 2.28 in 2019 to 2.07 in 2020.

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.

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.

$\mathbf{MAIFI_E}$ – 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.

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

SYSTEM SAIDI, SAIFI AND MAIFI$_E$

System SAIDI

Year	2016	2017	2018	2019	2020
SAIDI	2.88	3.66	2.47	2.01	3.09
SAIDI MedEx	2.88	3.34	2.47	1.70	2.87

Table 1 Five Years of System SAIDI

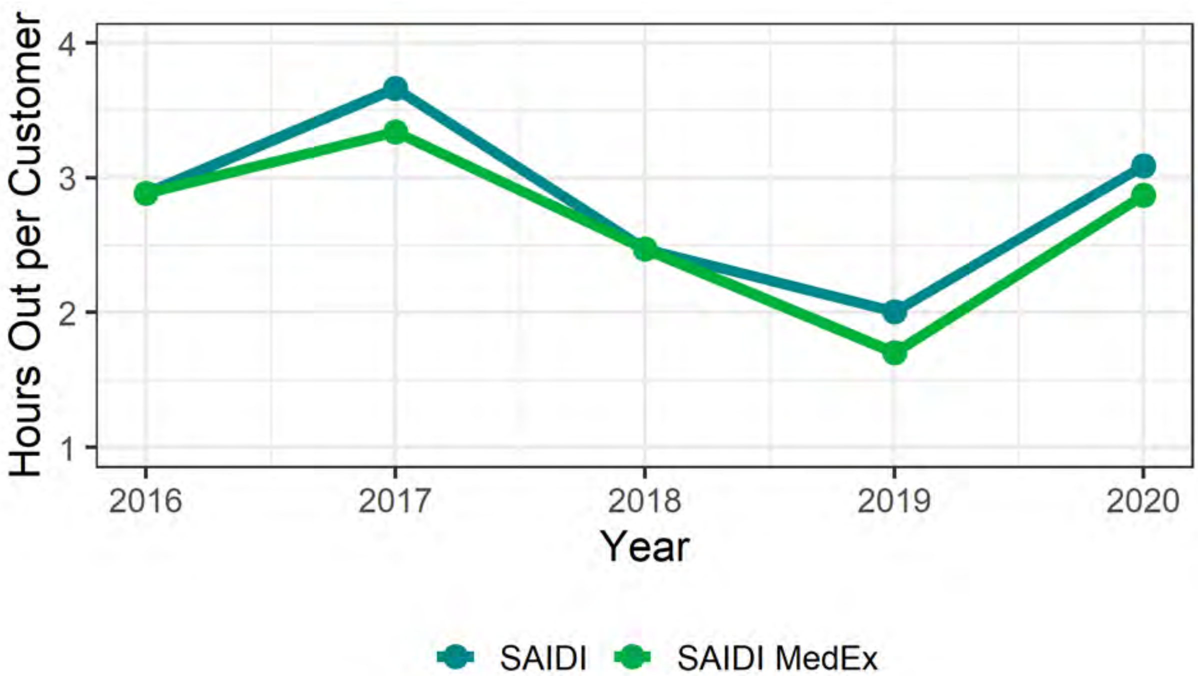


Figure 1 Five Years of System SAIDI

System SAIFI

Year	2016	2017	2018	2019	2020
SAIFI	1.06	1.22	0.95	0.63	0.97
SAIFI MedEx	1.06	1.16	0.95	0.63	0.94

Table 2 Five Years of System SAIFI

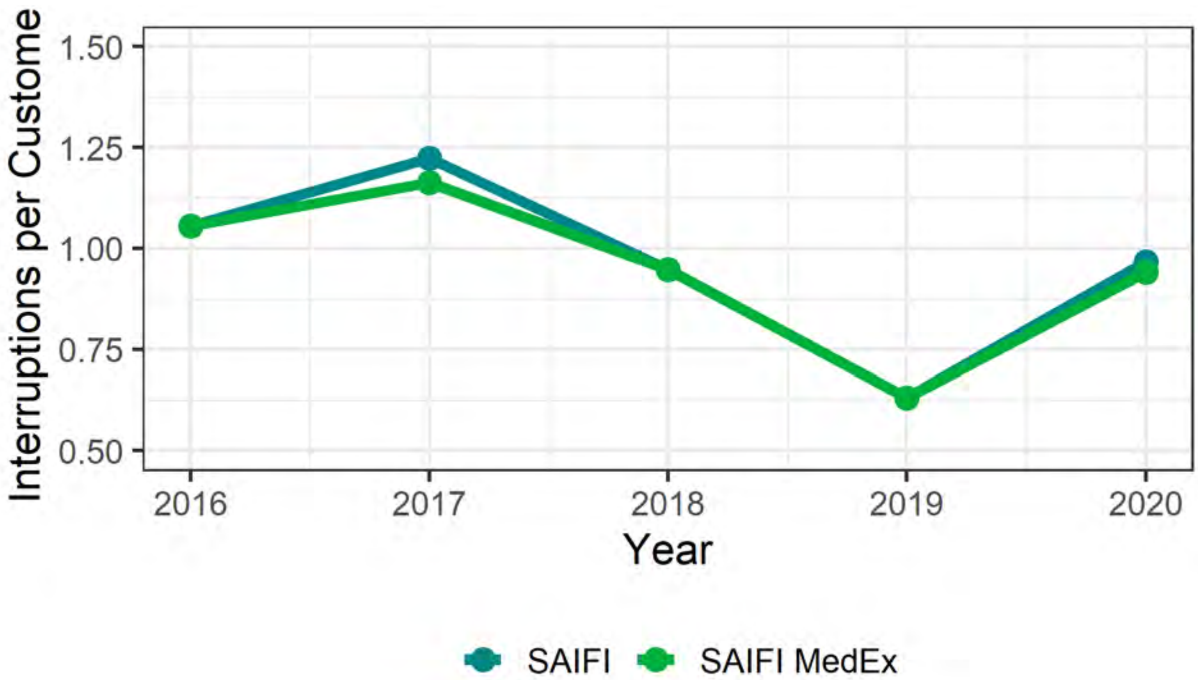


Figure 2 Five Years of System SAIFI

System MAIFI$_E$

Year	2016	2017	2018	2019	2020
MAIFI$_E$	2.11	2.44	3.16	2.28	2.07
MAIFI$_E$ MedEx	2.11	2.44	3.16	2.28	2.07

Table 3 Five Years of System MAIFI$_E$

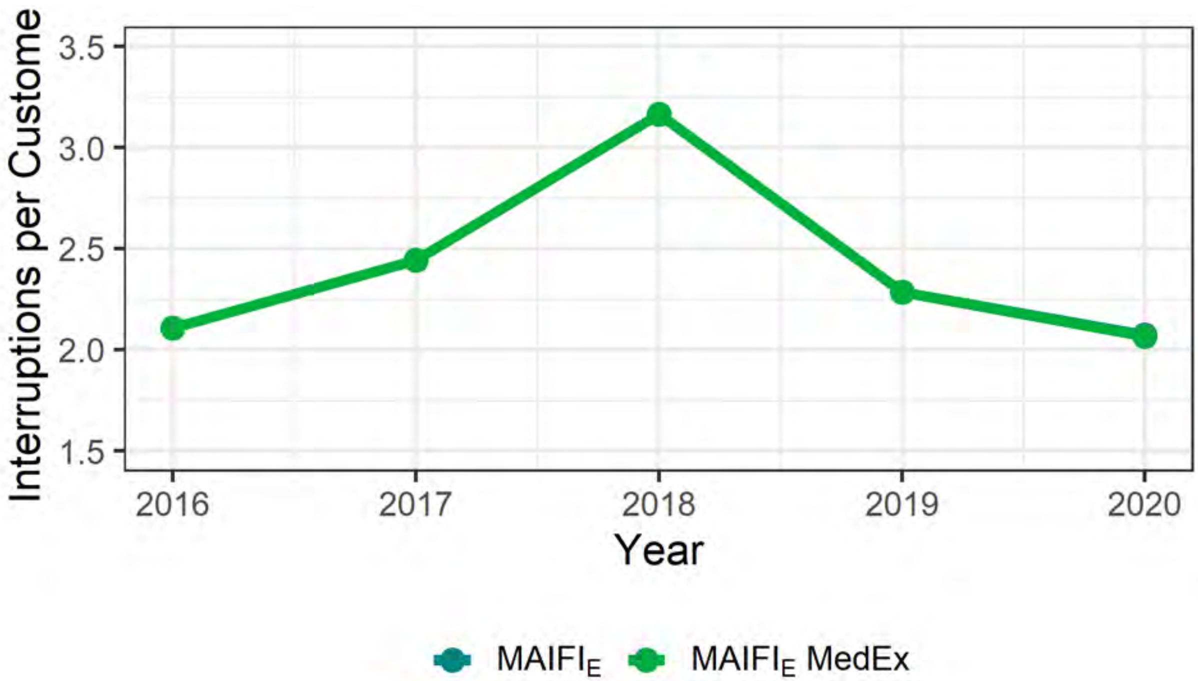


Figure 3 Five Years of System MAIFI$_E$

Sustained Interruption Event Causes

Cause	Number of Sustained Interruption Events 2016	2017	2018	2019	2020	Percent of Total Sustained Interruption Events 2016	2017	2018	2019	2020
Distribution – Equipment	163	277	159	172	150	23.7%	27.5%	24.4%	25.2%	21.5%
Distribution – Lightning	14	17	10	23	8	2.0%	1.7%	1.5%	3.4%	1.1%
Distribution – Other	41	63	46	46	41	6.0%	6.3%	7.1%	6.7%	5.9%
Distribution – Planned	148	114	91	119	133	21.5%	11.3%	14.0%	17.4%	19.0%
Distribution – Public	66	77	59	54	54	9.6%	7.6%	9.1%	7.9%	7.7%
Distribution – Unknown	67	97	72	62	99	9.8%	9.6%	11.1%	9.1%	14.2%
Distribution – Vegetation	28	118	79	91	120	4.1%	11.7%	12.1%	13.3%	17.2%
Distribution – Weather (Non-Lightning)	4	70	16	25	17	0.6%	7.0%	2.5%	3.7%	2.4%
Distribution – Wildlife	111	127	93	82	55	16.2%	12.6%	14.3%	12.0%	7.9%
Loss of Supply – Substation	8	11	7	3	2	1.2%	1.1%	1.1%	0.4%	0.3%
Loss of Supply – Transmission	37	36	19	6	20	5.4%	3.6%	2.9%	0.9%	2.9%
Total	**687**	**1,007**	**651**	**683**	**699**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Table 4 Five Years of Sustained Interruption Event Causes

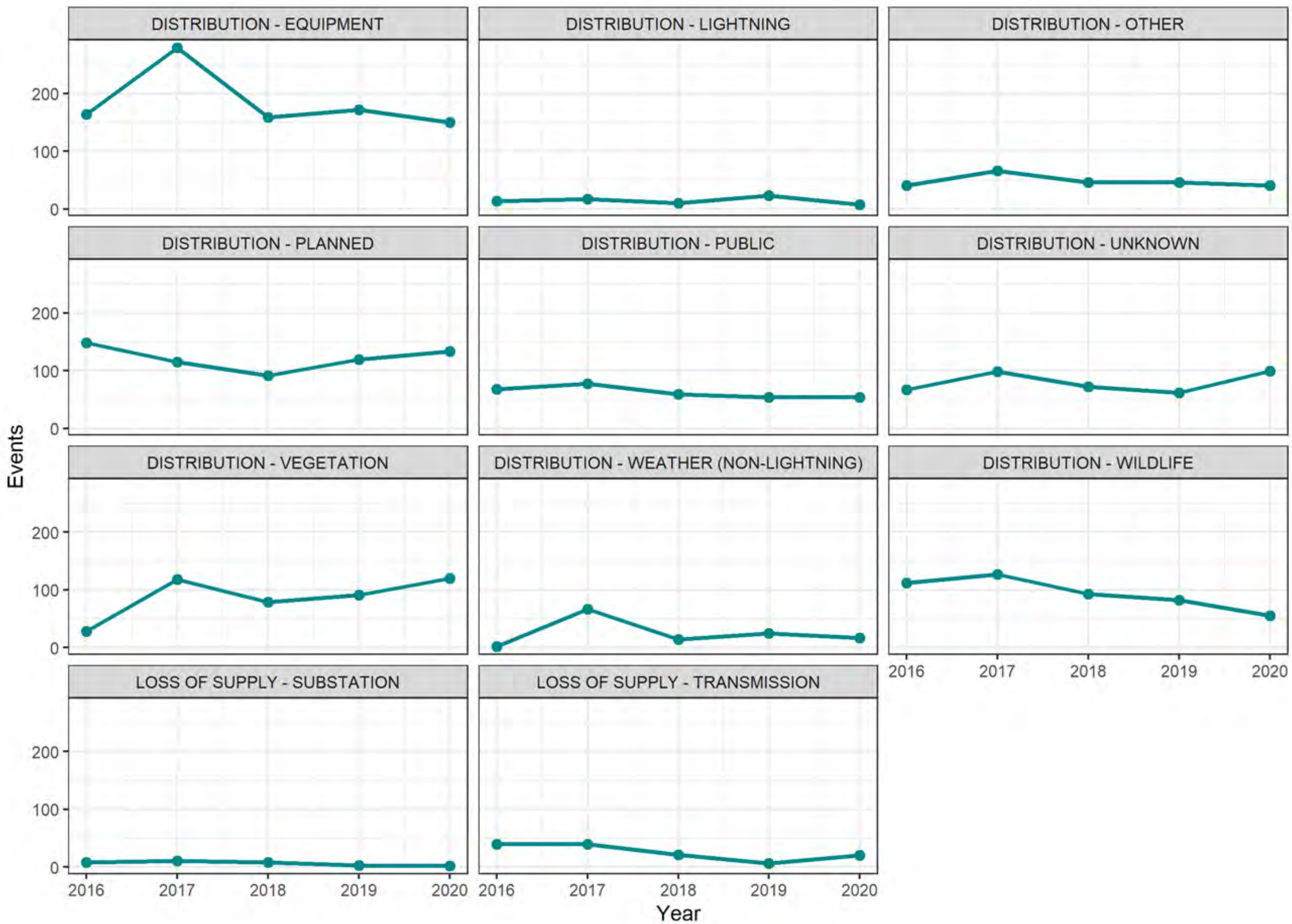


Figure 4 Five Years of Sustained Interruption Events by Cause

Cause	Events	Hours Out	Event Ranking	Hours Out Ranking
Distribution – Equipment	150	545	1	2
Distribution – Lightning	8	32	10	10
Distribution – Other	41	90	7	8
Distribution – Planned	133	532	2	3
Distribution – Public	54	210	6	5
Distribution – Unknown	99	3,304	4	1
Distribution – Vegetation	120	505	3	4
Distribution – Weather (non-Lightning)	17	72	9	9
Distribution – Wildlife	55	147	5	6
Loss of Supply – Substation	2	0	11	11
Loss of Supply – Transmission	20	134	8	7
Total	**699**	**5,572**		

Table 5 2020 Sustained Interruption Event Cause Ranking

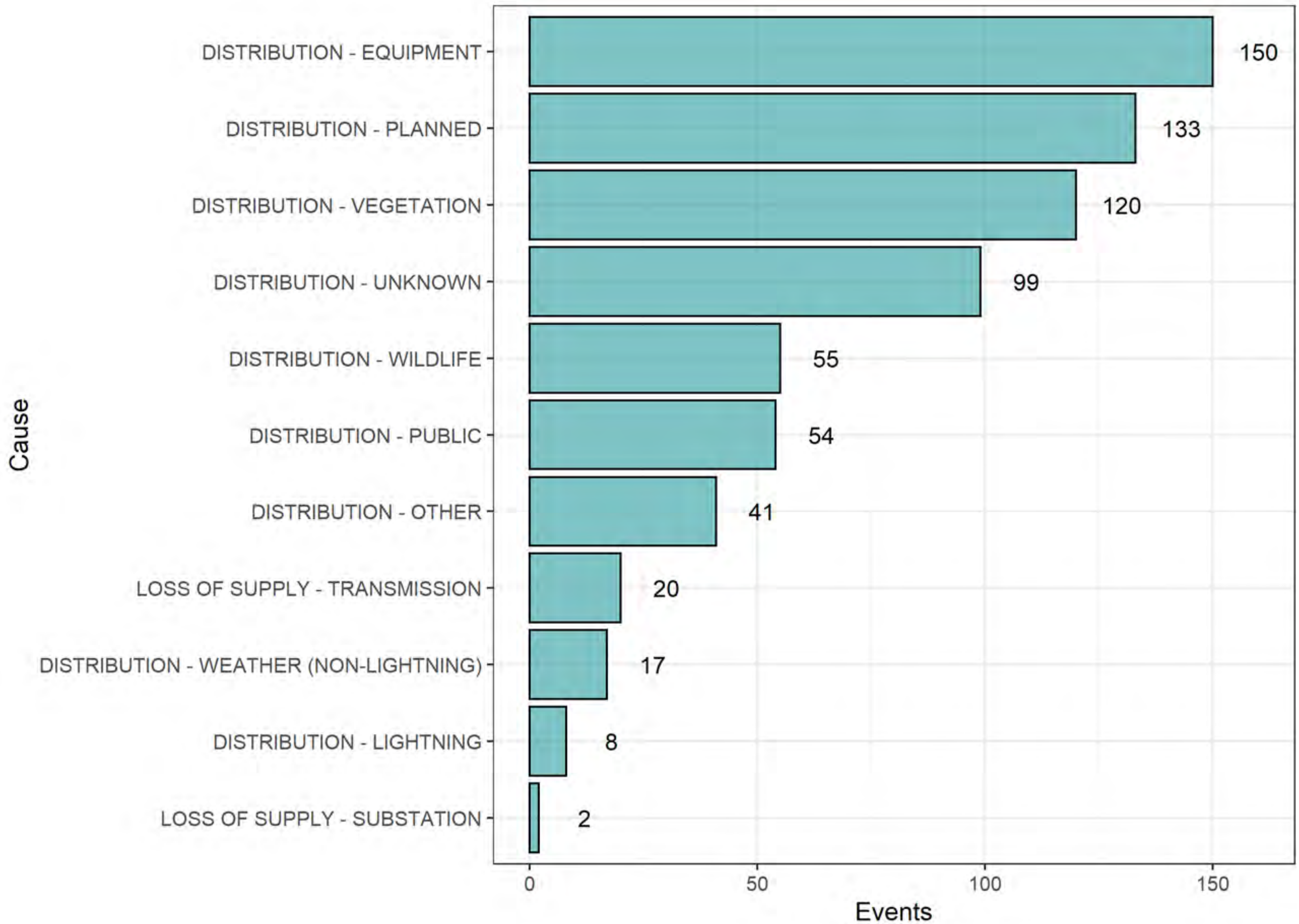


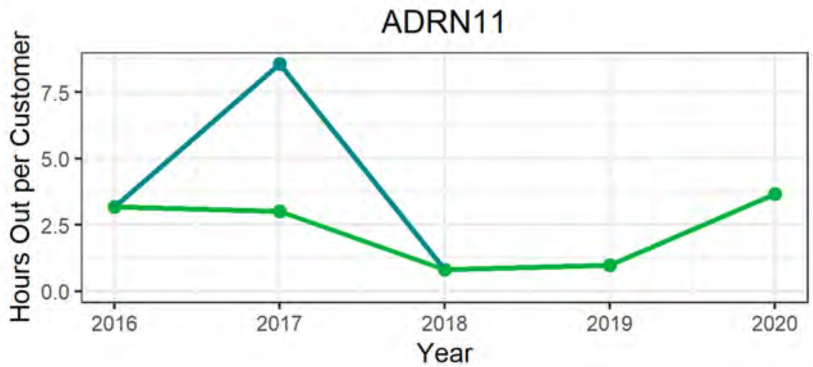
Figure 5 2020 Ranking of Sustained Interruption Event Causes

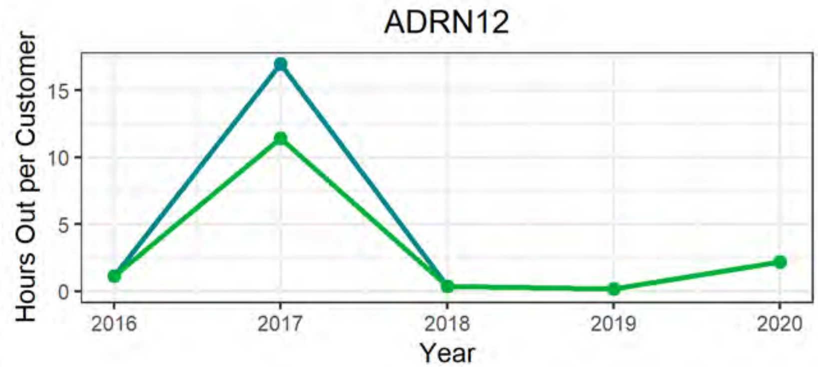
CIRCUIT SAIDI, SAIFI AND MAIFI$_E$

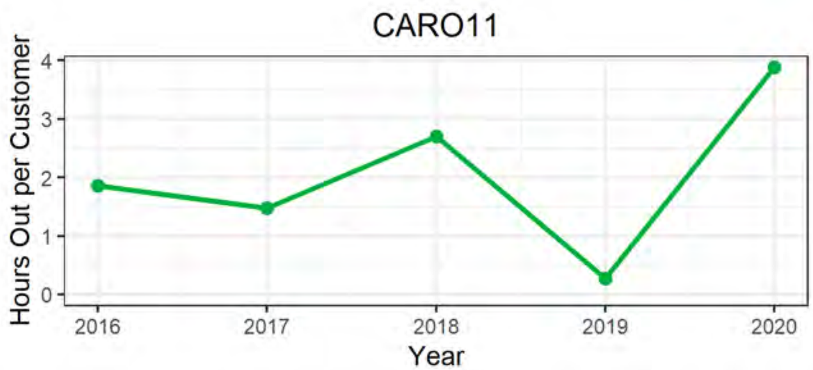
Five Years of Circuit SAIDI

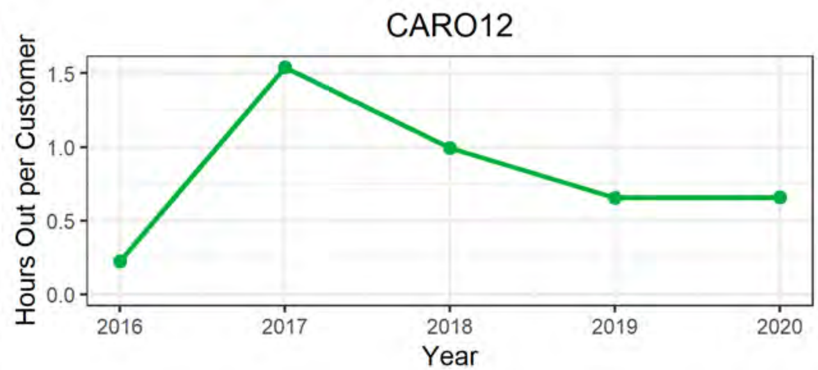
Circuit	2016	2017	2018	2019	2020	2020 MedEx
ADRN11	3.22	8.60	0.83	0.99	3.68	3.68
ADRN12	1.12	17.14	0.41	0.19	2.19	2.19
CARO11	1.83	1.49	2.70	0.28	3.89	3.89
CARO12	0.23	1.56	0.99	0.65	0.66	0.66
CARO13	0.00	0.17	0.13	0.16	0.86	0.86
CWVY11	0.95	0.74	16.00	5.93	11.00	11.00
CWVY12	1.26	7.78	10.77	59.83	10.99	10.99
DRKE11	0.61	8.44	0.48	3.70	2.93	2.93
DUKE11	0.00	1.34	1.90	0.11	0.00	0.00
DWSY11	10.16	15.18	15.68	1.94	13.44	13.44
ESTN11	21.72	13.21	15.40	1.27	11.40	11.40
HCSU11	0.00	0.00	0.00	0.00	0.00	0.00
HFWY11	2.14	2.94	2.60	6.70	7.36	7.36
HFWY12	2.42	4.50	7.87	6.20	7.84	0.29
HGTN11	1.66	0.21	0.01	6.00	3.88	3.88
HGTN12	0.21	0.47	0.03	0.13	3.06	3.06
HMDL12	7.82	2.32	1.67	12.11	1.43	1.43
HOLY11	3.85	1.23	0.09	0.43	0.86	0.86
HOLY12	1.58	7.60	0.41	1.72	0.92	0.92
HOLY13	1.68	0.19	1.35	3.69	1.08	1.08
HOLY14	NA	NA	NA	1.33	0.00	0.00
HOPE11	4.93	1.87	3.32	1.36	6.11	6.11
HRPR11	6.18	8.10	2.03	3.66	14.32	14.32
HRPR12	12.11	21.23	6.02	4.54	9.70	9.70
JMSN11	0.82	0.60	2.24	6.41	3.50	3.50
JMSN12	1.35	2.07	1.10	1.18	2.15	2.15
JNTA11	8.95	6.65	3.93	1.31	10.89	10.89
JNTA12	12.95	7.56	4.73	1.33	12.08	12.08
JNVY11	35.11	11.30	2.59	0.17	17.02	17.02
JNVY12	7.75	10.75	1.70	0.10	16.29	16.29
JNVY31	24.13	14.50	3.37	6.40	19.07	19.07
LIME11	3.84	27.62	5.65	1.47	6.87	6.87
MRBT41	0.67	11.96	2.78	2.61	4.15	4.15
MRBT42	0.29	1.54	2.65	1.78	0.00	0.00
NYSA11	0.89	0.37	0.21	3.23	0.10	0.10
NYSA12	13.97	6.95	1.87	1.12	0.20	0.20
NYSA13	6.68	0.27	0.22	0.77	1.71	1.71
NYSA14	3.65	0.12	0.22	1.21	0.31	0.31
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OIDA11	0.94	1.12	0.78	1.73	2.77	2.77
OIDA12	0.70	2.80	0.00	5.58	0.00	0.00
ONTO14	0.42	0.54	0.00	0.04	0.00	0.00
ONTO18	0.21	0.12	1.48	0.55	0.03	0.03
ONTO19	0.40	0.69	2.05	0.59	0.55	0.55
ONTO20	1.05	0.64	0.51	0.63	0.98	0.98
ONTO23	0.52	4.07	0.28	0.00	0.00	0.00
ONTO24	0.46	5.23	11.00	2.13	0.48	0.48
ONTO25	0.13	0.37	0.12	1.50	0.03	0.03
OYDM11	0.00	3.48	0.28	2.97	0.00	0.00
PNCK11	12.71	0.26	0.69	1.38	27.39	27.39
PNCK12	6.73	3.17	0.00	0.00	4.48	4.48
PRMA12	13.68	7.22	5.04	0.23	0.00	0.00
PRMA42	3.59	12.84	7.15	0.89	5.95	5.95
RKVL11	9.57	4.61	1.29	0.30	17.07	17.07
UNTY11	34.95	27.58	12.35	0.30	5.99	5.99
UNTY12	3.44	17.21	11.57	0.81	6.85	6.85
VALE11	0.17	1.09	0.92	0.33	0.10	0.10
VALE12	0.00	1.07	0.15	0.00	0.00	0.00
VALE13	0.52	3.68	0.69	0.34	3.42	3.42
VALE14	0.11	2.93	6.49	0.31	3.14	3.14
VALE15	4.94	1.82	2.72	0.26	0.48	0.48
WESR13	0.29	3.21	1.89	1.37	1.04	1.04
WESR14	0.85	12.55	6.98	1.62	1.71	1.71

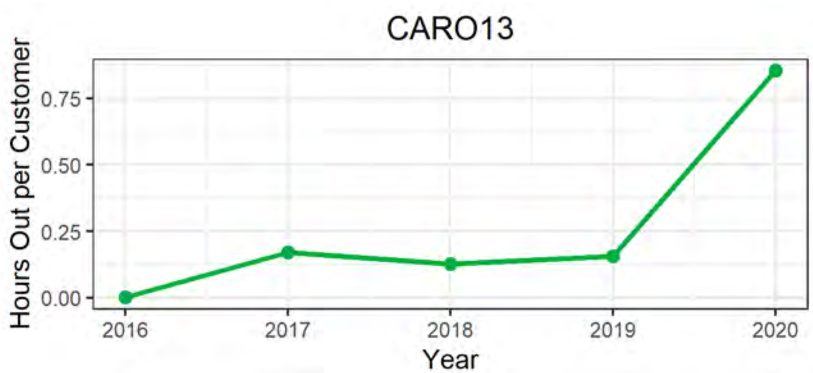
Table 6 Five Years of Circuit SAIDI


ADRN11
Hours Out per Customer
0.0
2.5
5.0
7.5
2016
2017
2018
2019
2020
Year


ADRN12
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year


CARO11
Hours Out per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year


CARO12
Hours Out per Customer
0.0
0.5
1.0
1.5
2016
2017
2018
2019
2020
Year


CARO13
Hours Out per Customer
0.00
0.25
0.50
0.75
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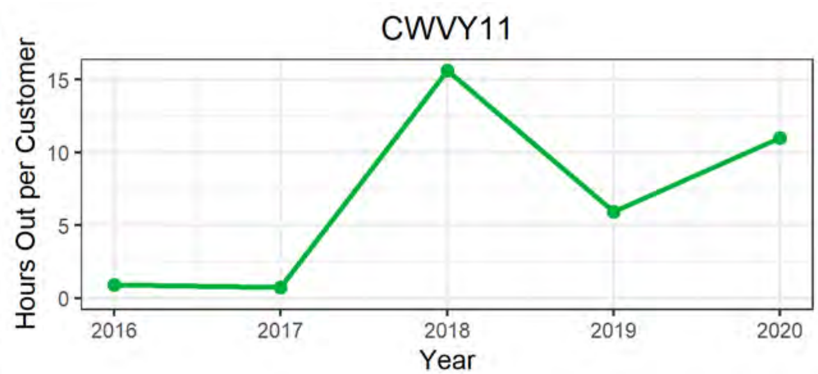
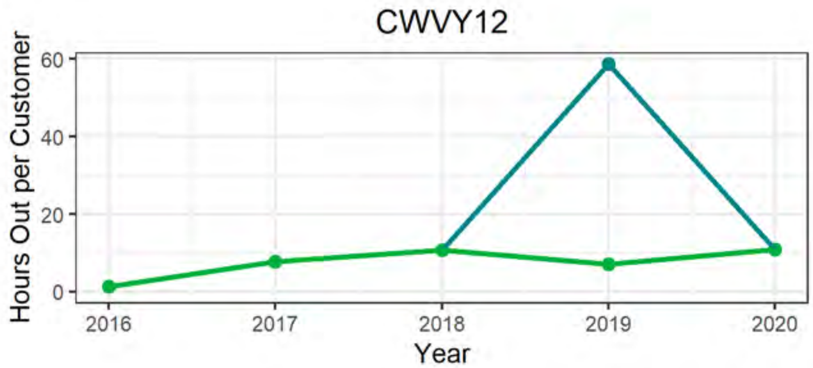
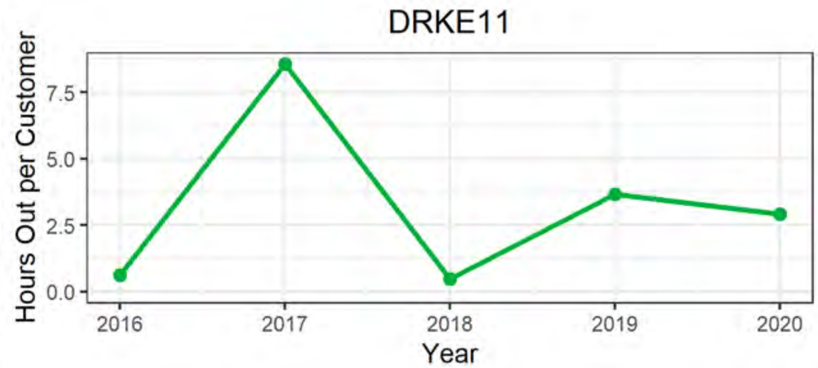
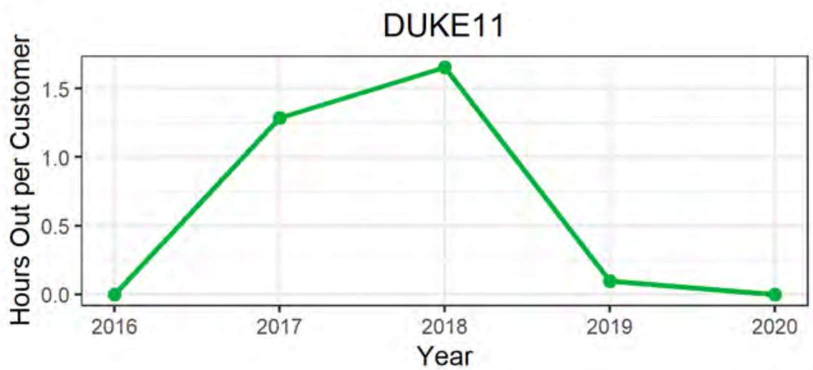
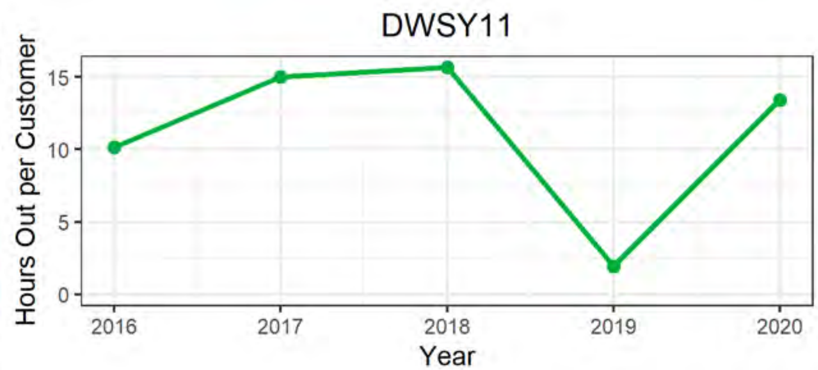
2017
2018
2019
2020
Year

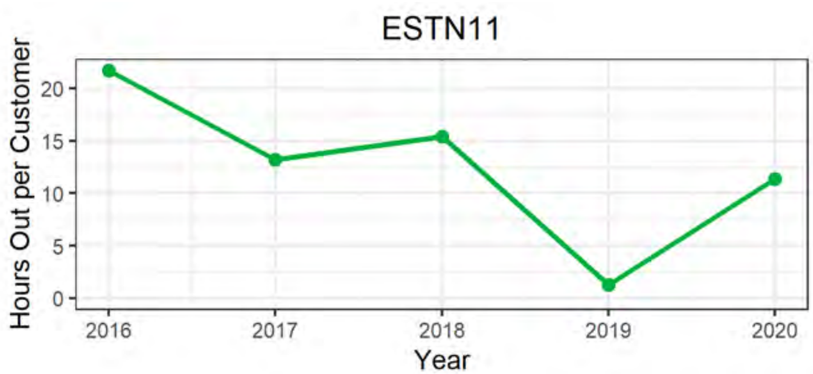

CWVY11
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

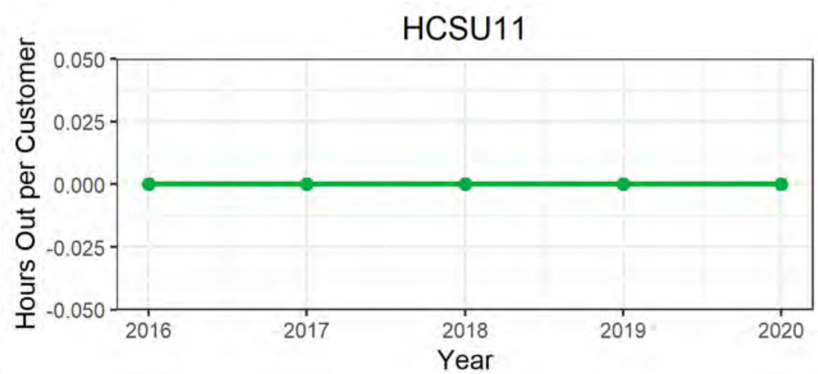

CWVY12
Hours Out per Customer
0
20
40
60
2016
2017
2018
2019
2020
Year


DRKE11
Hours Out per Customer
0.0
2.5
5.0
7.5
2016
2017
2018
2019
2020
Year


DUKE11
Hours Out per Customer
0.0
0.5
1.0
1.5
2016
2017
2018
2019
2020
Year


DWSY11
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year


ESTN11
Hours Out per Customer
0
5
10
15
20
2016
2017
2018
2019
2020
Year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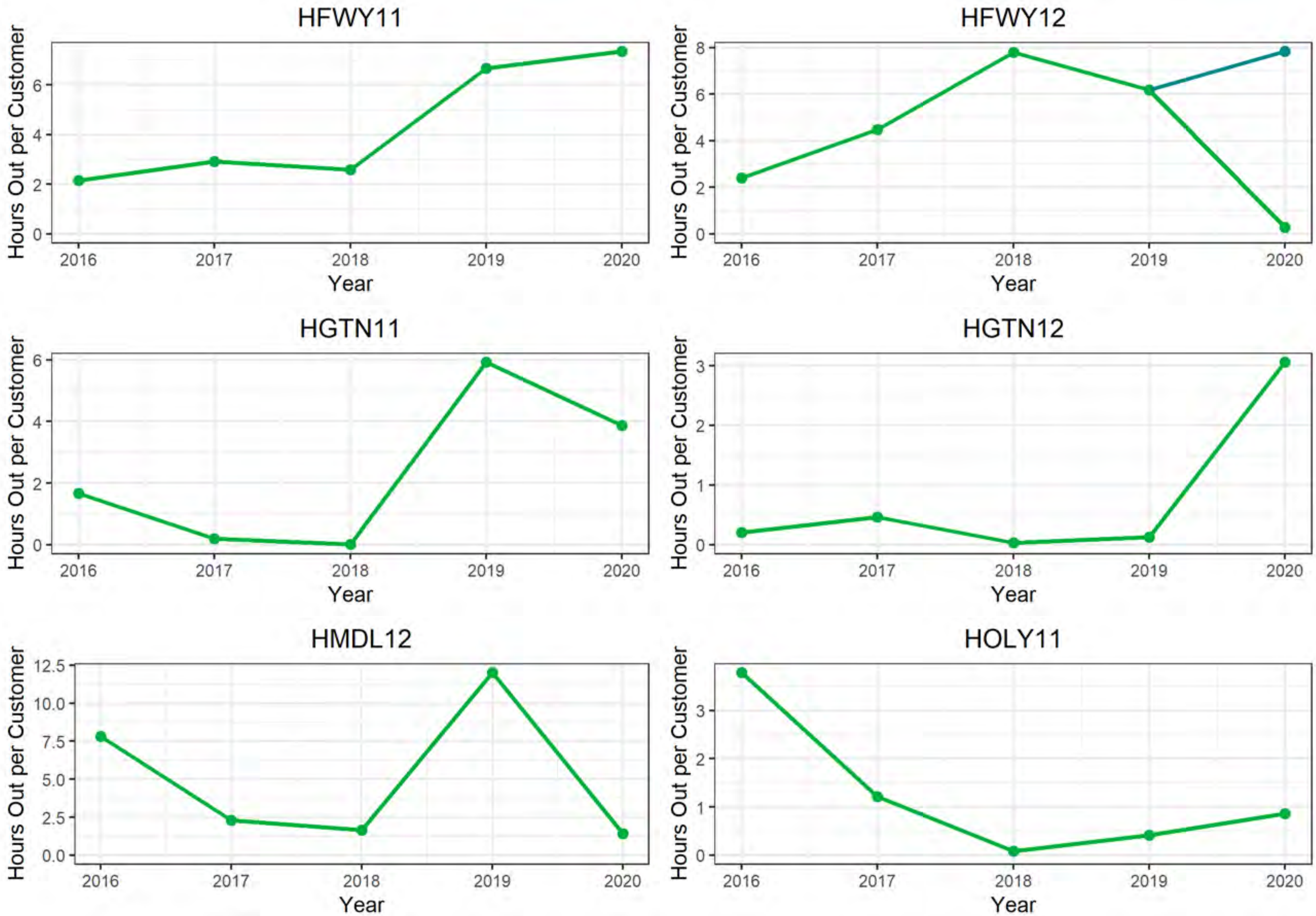
Hours Out per Customer
-0.050
-0.025
0.000
0.025
0.050
2016
2017
2018
2019
2020
Year


HFWY11
Hours Out per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year
HFWY12
Hours Out per Customer
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2
4
6
8
2016
2017
2018
2019
2020
Year
HGTN11
Hours Out per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year
HGTN12
Hours Out per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year
HMDL12
Hours Out per Customer
0.0
2.5
5.0
7.5
10.0
12.5
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2020
Year
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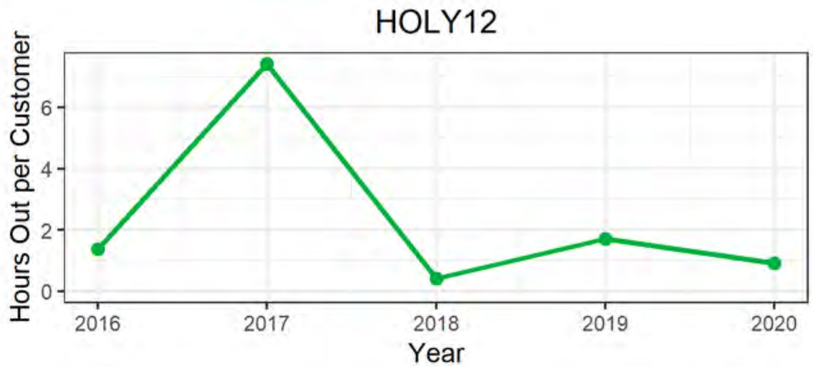
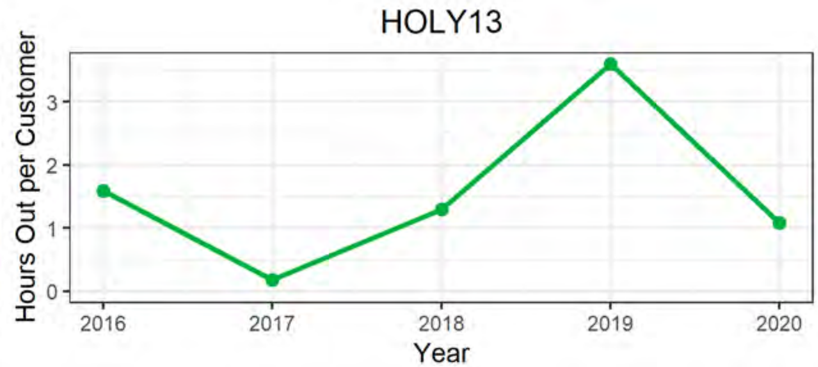
Hours Out per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year


HOLY12
Hours Out per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year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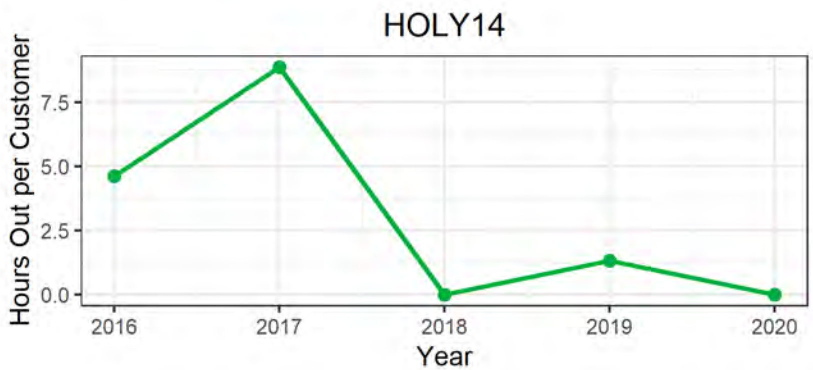
Hours Out per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year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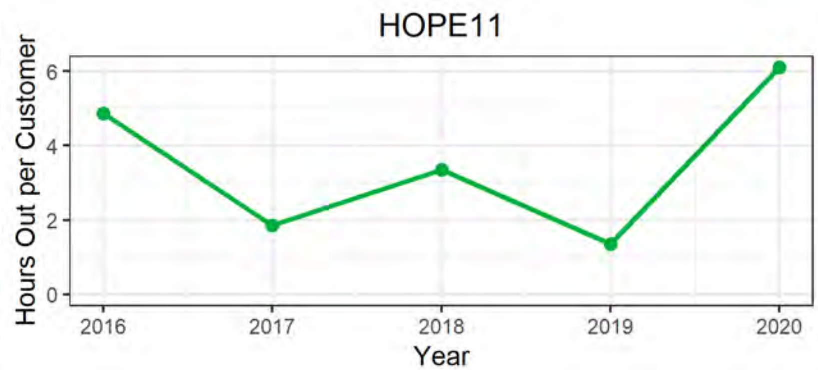
Hours Out per Customer
0.0
2.5
5.0
7.5
2016
2017
2018
2019
2020
Year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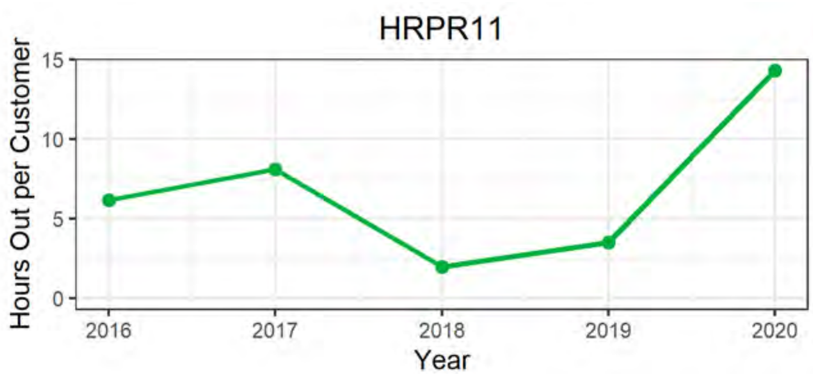
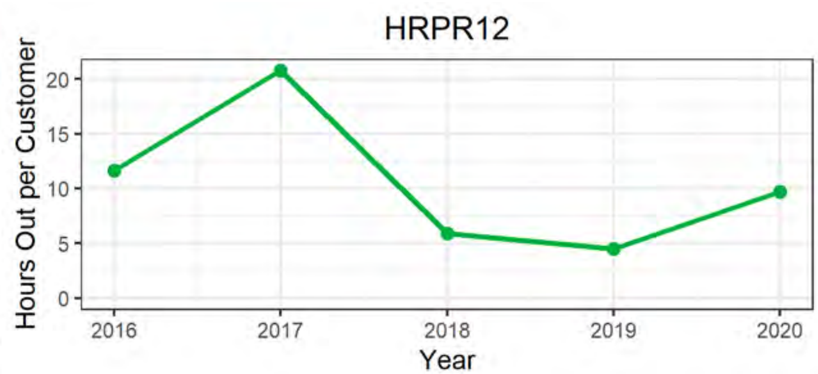
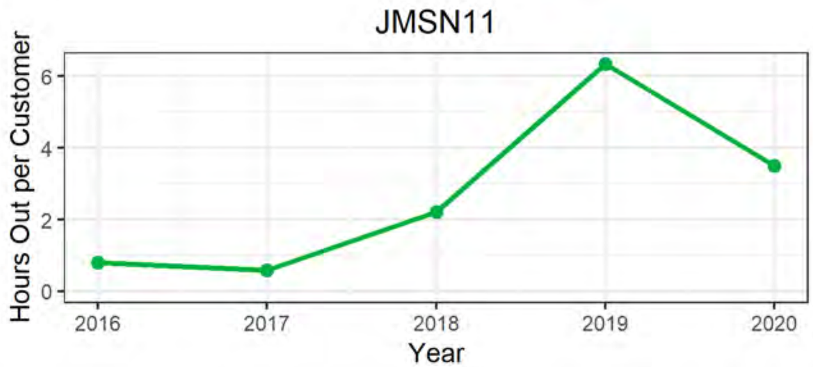
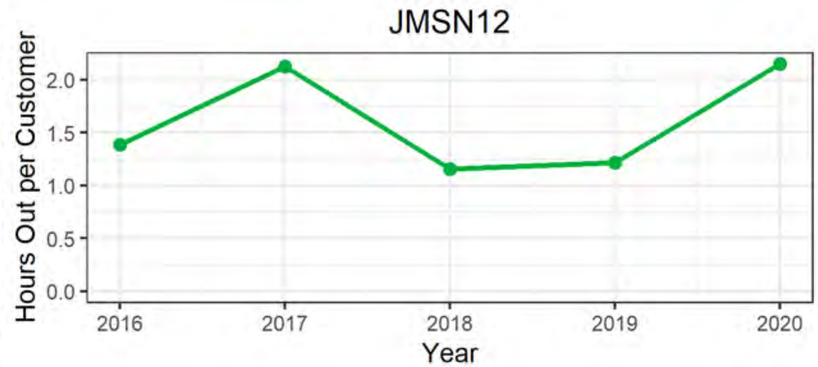
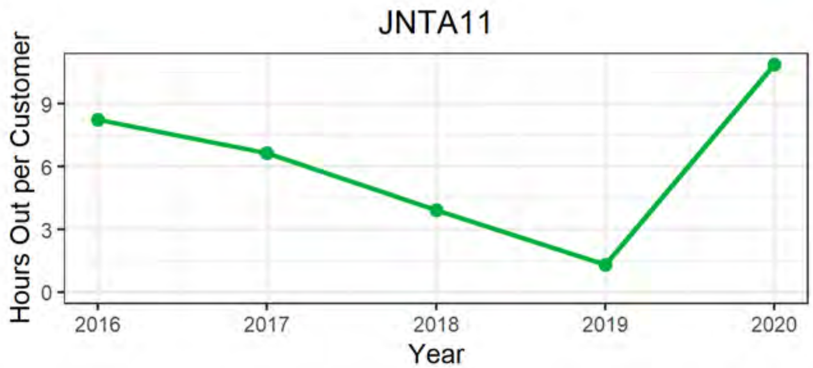
2
4
6
2016
2017
2018
2019
2020
Year

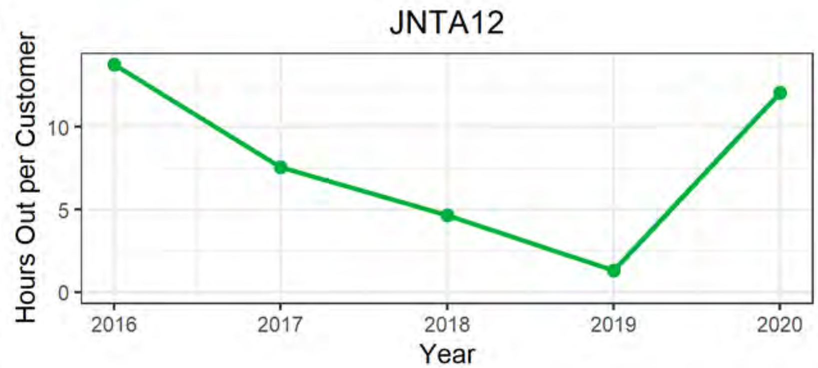

HRPR11
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

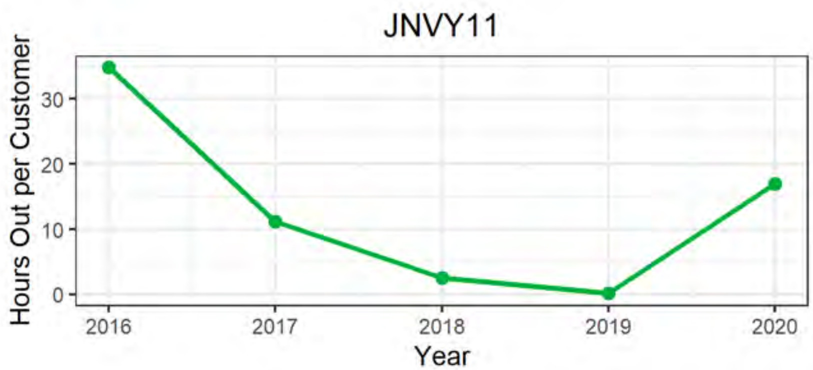

HRPR12
Hours Out per Customer
0
5
10
15
20
2016
2017
2018
2019
2020
Year

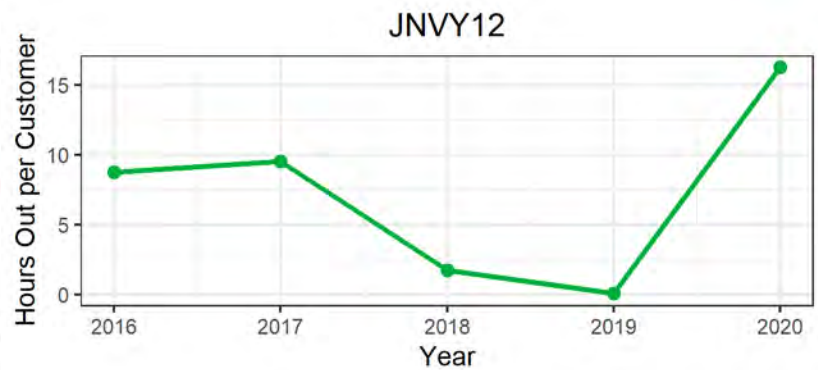

JMSN11
Hours Out per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year


JMSN12
Hours Out per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

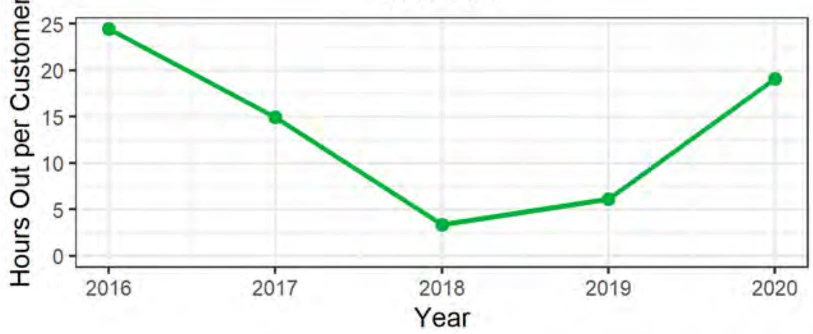

JNTA11
Hours Out per Customer
0
3
6
9
2016
2017
2018
2019
2020
Year


JNTA12
Hours Out per Customer
0
5
10
2016
2017
2018
2019
2020
Year

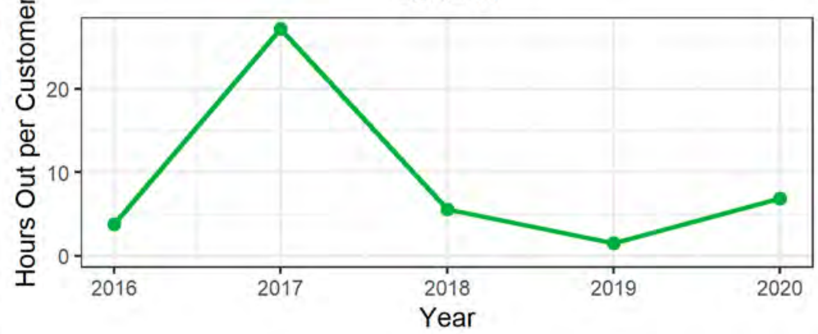

JNVY11
Hours Out per Customer
0
10
20
30
2016
2017
2018
2019
2020
Year


JNVY12
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

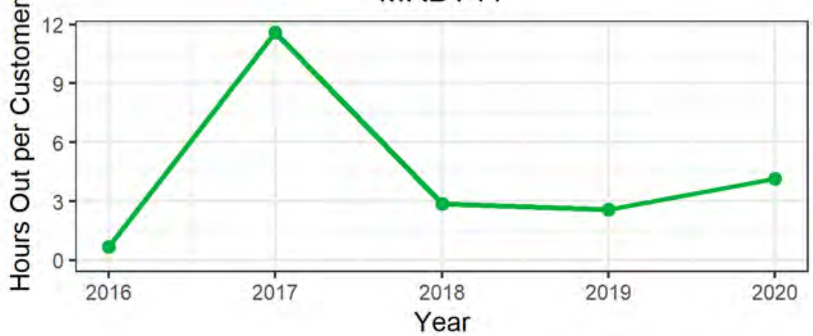
JNVY31



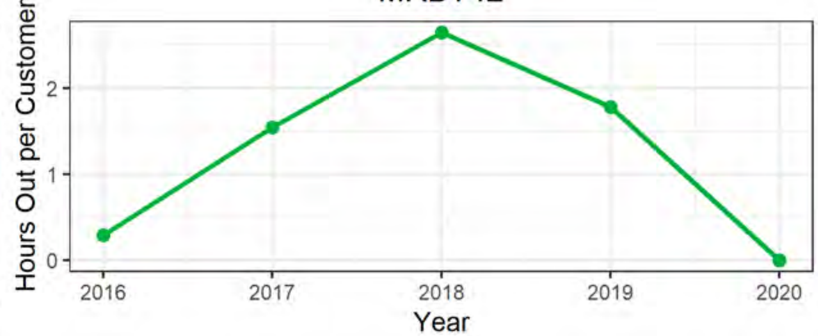
LIME11



MRBT41

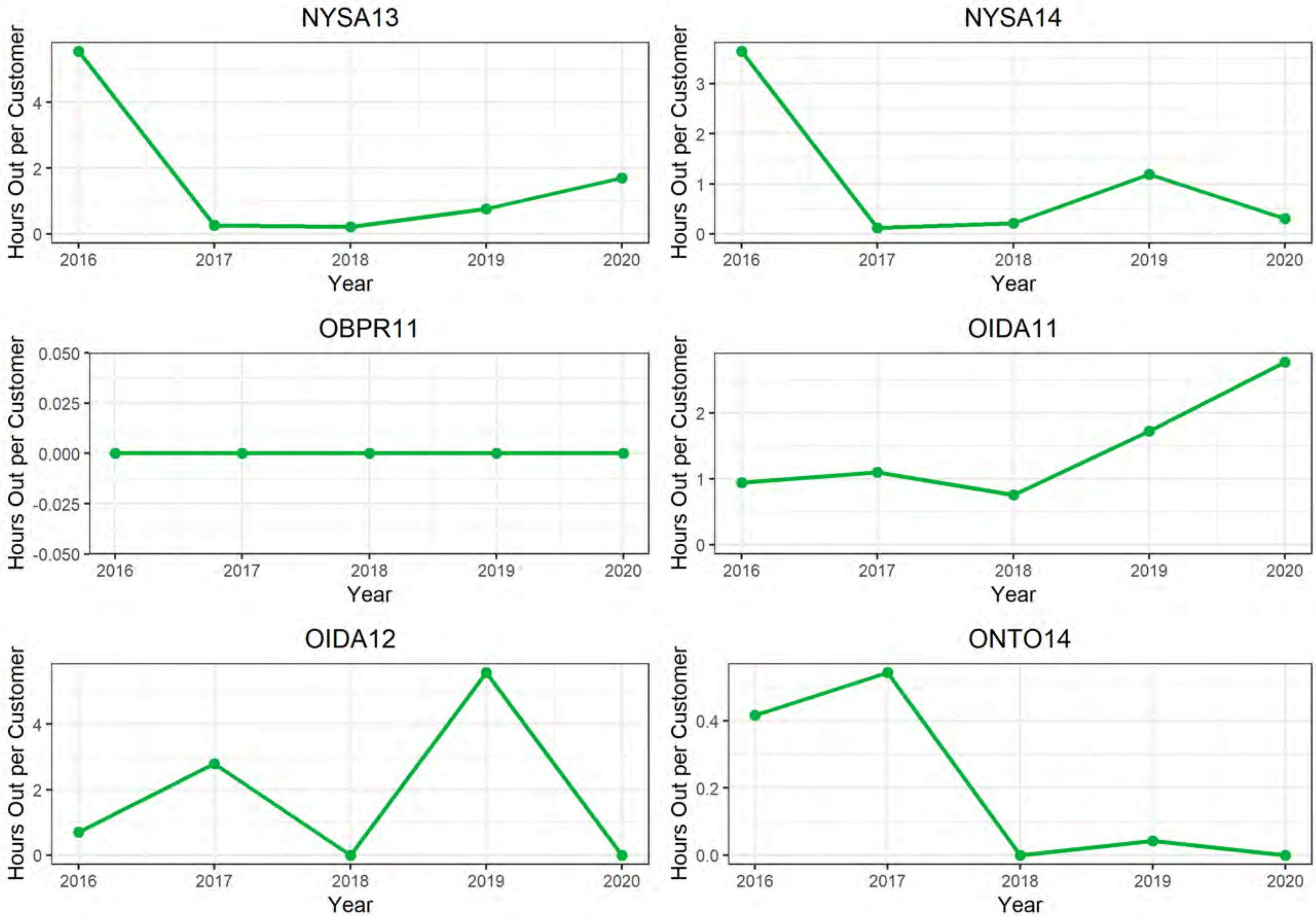


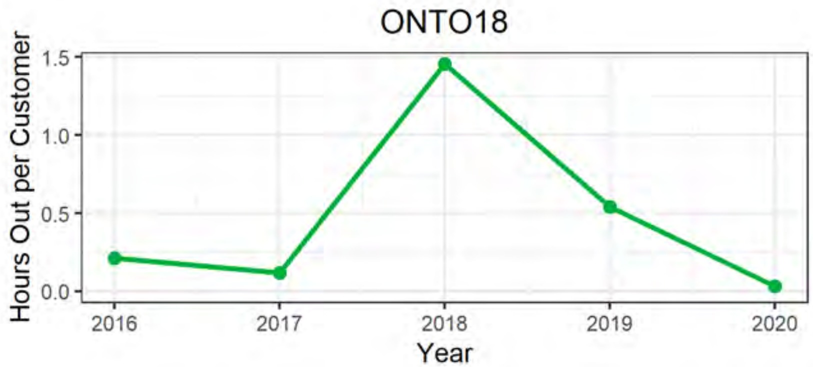
MRBT42

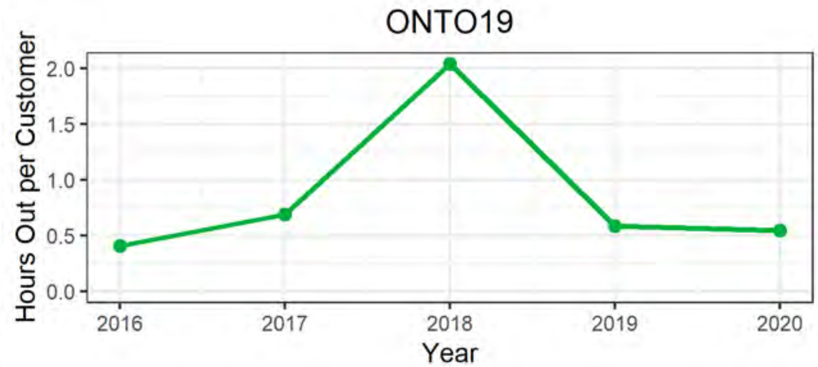


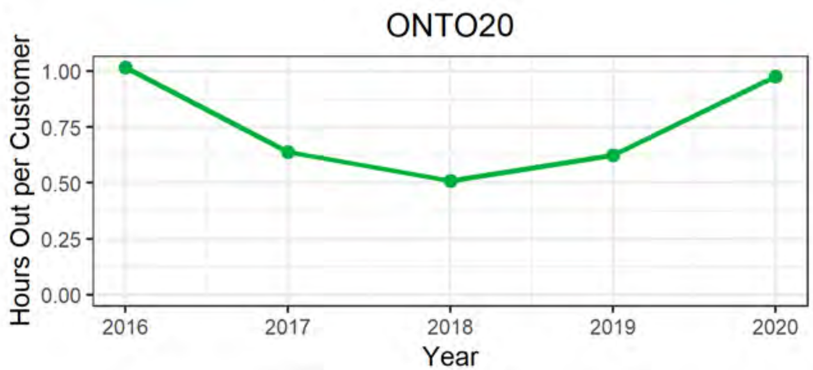
NYSA11

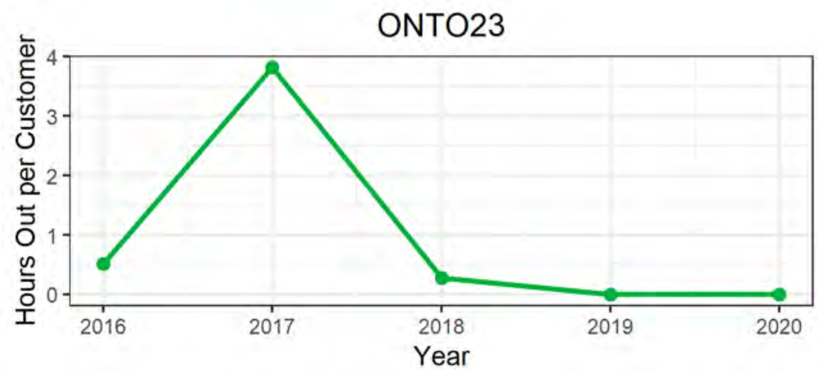
NYSA12

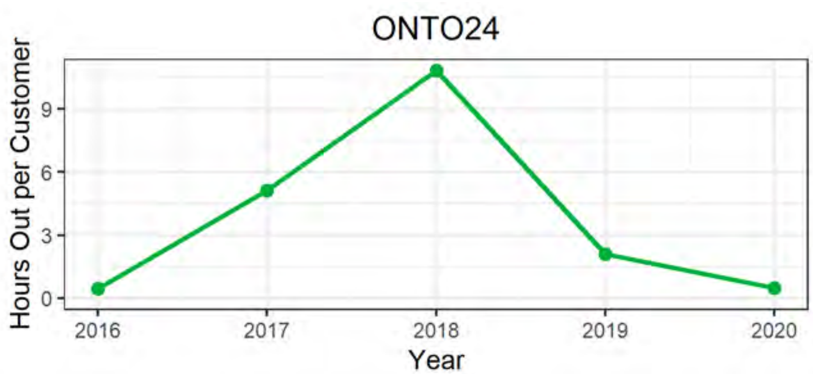

NYSA13
Hours Out per Customer
0
2
4
2016
2017
2018
2019
2020
Year
NYSA14
Hours Out per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year
OBPR11
Hours Out per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year
OIDA11
Hours Out per Customer
0
1
2
2016
2017
2018
2019
2020
Year
OIDA12
Hours Out per Customer
0
2
4
2016
2017
2018
2019
2020
Year
ONTO14
Hours Out per Customer
0.0
0.2
0.4
2016
2017
2018
2019
2020
Year

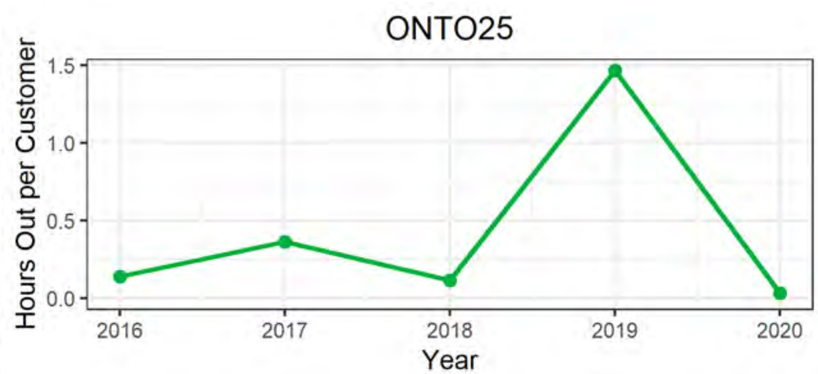

ONTO18
Hours Out per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

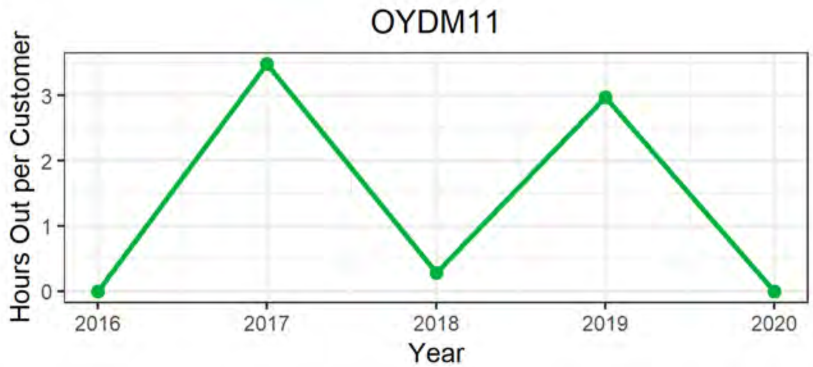

ONTO19
Hours Out per Customer
2.0
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

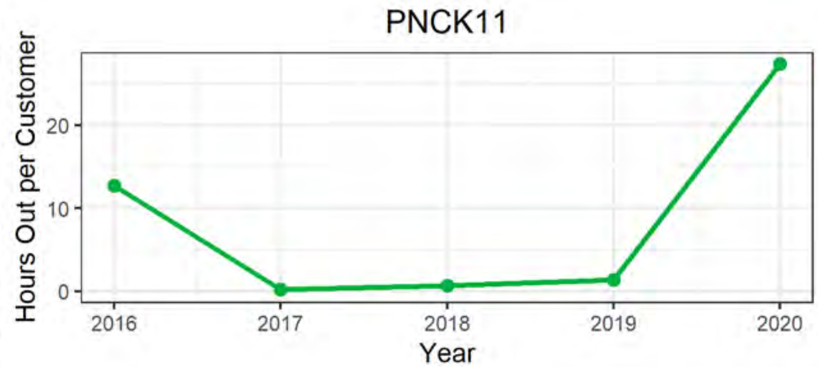

ONTO20
Hours Out per Customer
1.00
0.75
0.50
0.25
0.00
2016
2017
2018
2019
2020
Year

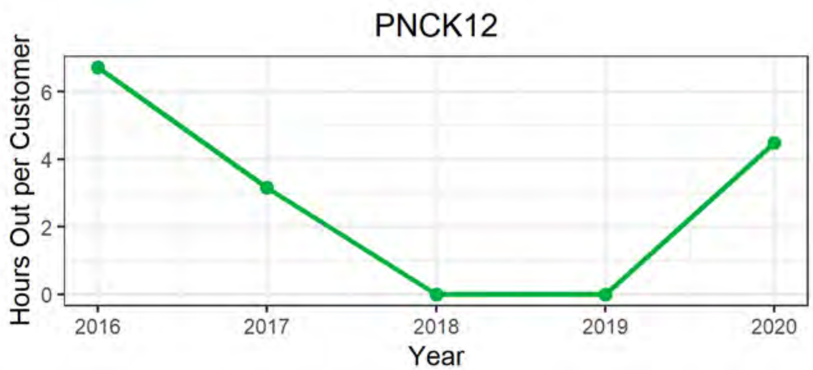

ONTO23
Hours Out per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year

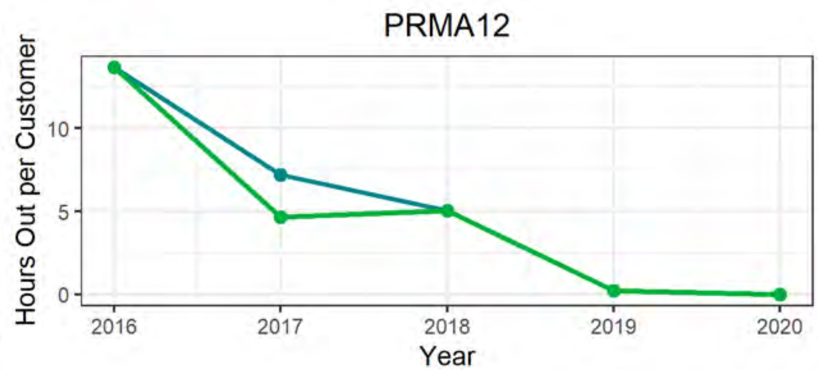

ONTO24
Hours Out per Customer
9
6
3
0
2016
2017
2018
2019
2020
Year

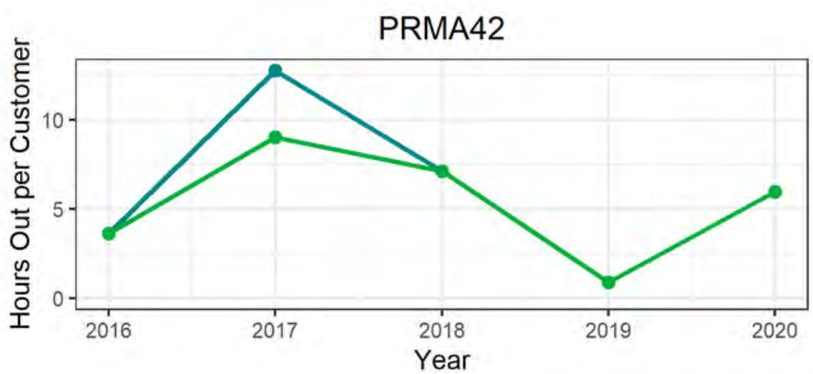

ONTO25
Hours Out per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

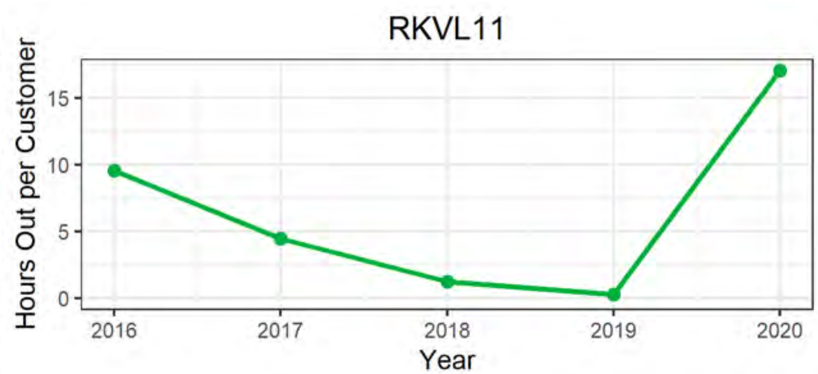

OYDM11
Hours Out per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

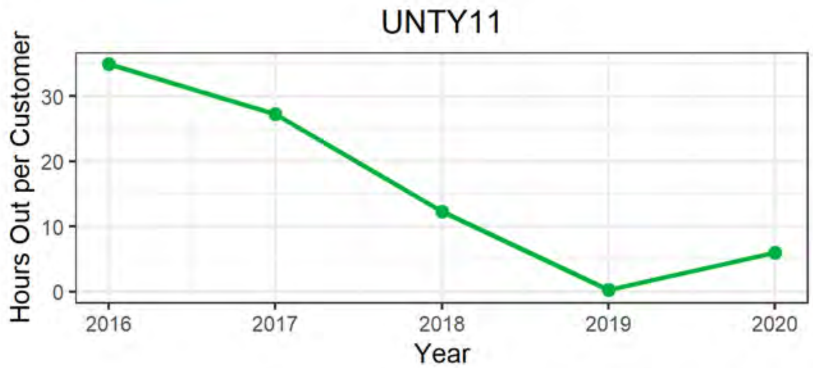

PNCK11
Hours Out per Customer
0
10
20
2016
2017
2018
2019
2020
Year

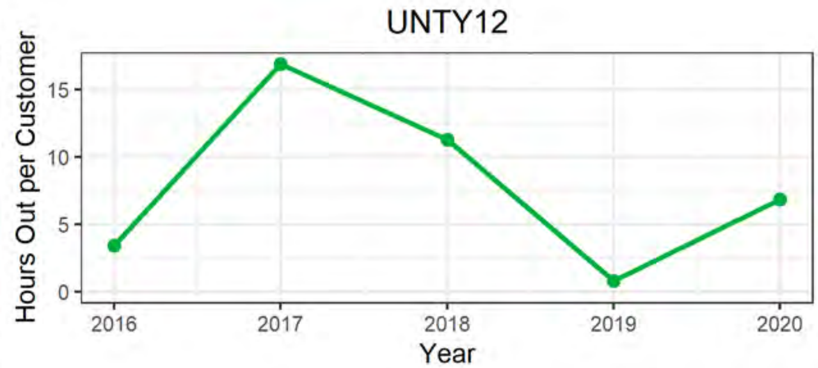

PNCK12
Hours Out per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

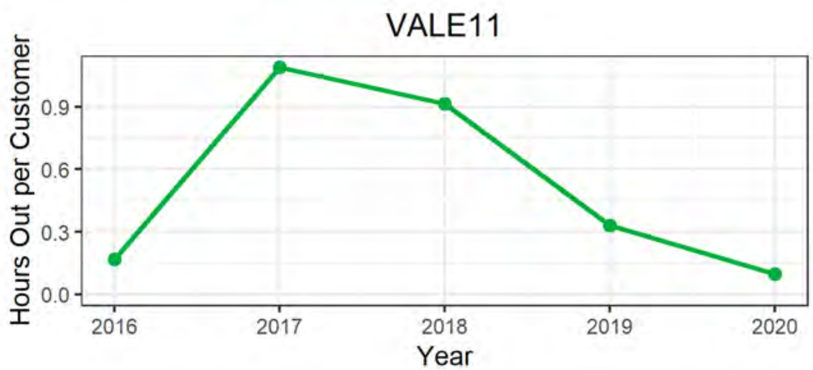

PRMA12
Hours Out per Customer
0
5
10
2016
2017
2018
2019
2020
Year


PRMA42
Hours Out per Customer
0
5
10
2016
2017
2018
2019
2020
Year

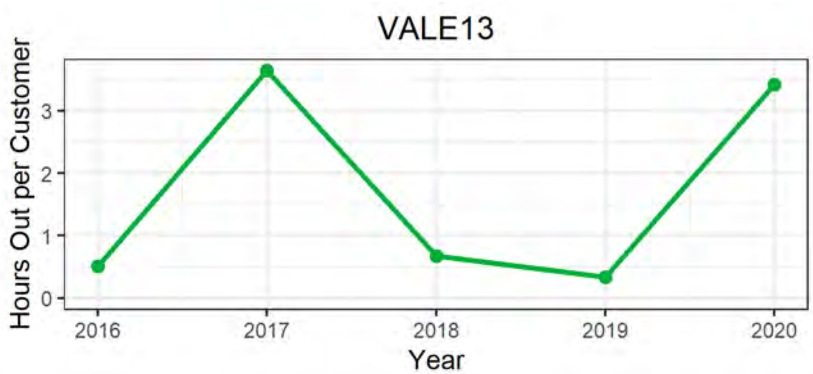

RKVL11
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

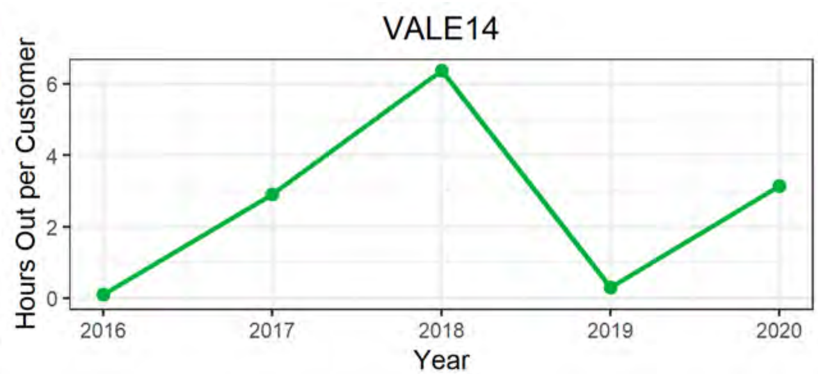

UNTY11
Hours Out per Customer
0
10
20
30
2016
2017
2018
2019
2020
Year


UNTY12
Hours Out per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year


VALE11
Hours Out per Customer
0.0
0.3
0.6
0.9
2016
2017
2018
2019
2020
Year


VALE12
Hours Out per Customer
0.00
0.25
0.50
0.75
1.00
2016
2017
2018
2019
2020
Year


VALE13
Hours Out per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year


VALE14
Hours Out per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

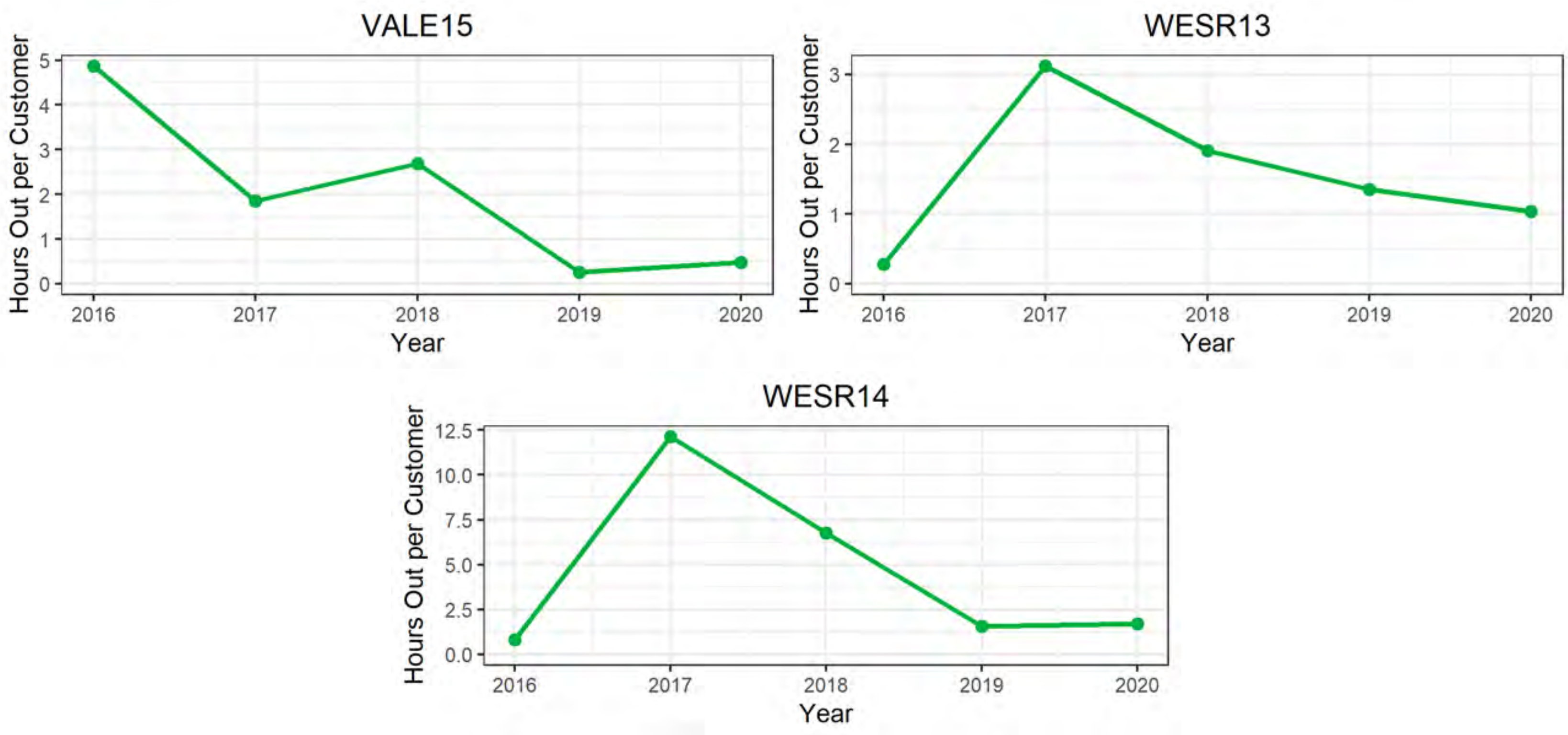
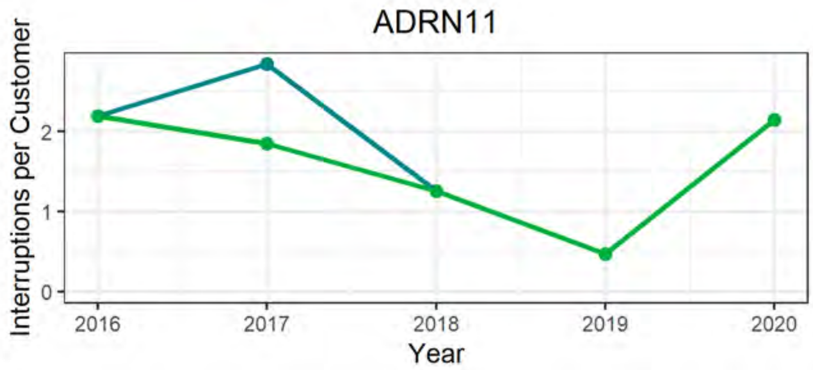


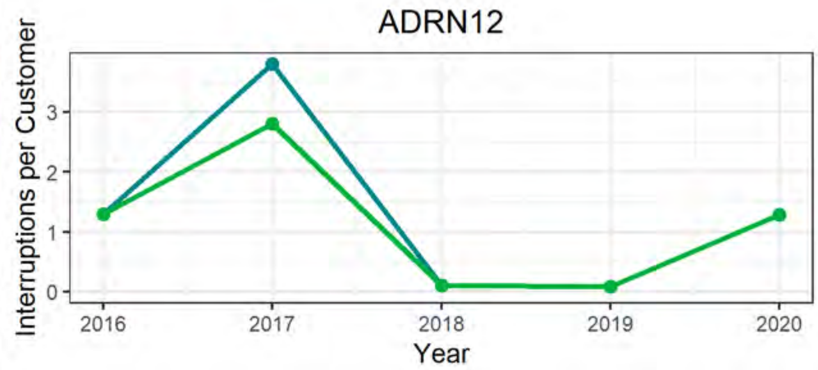
Figure 6 Five Years of Circuit SAIDI

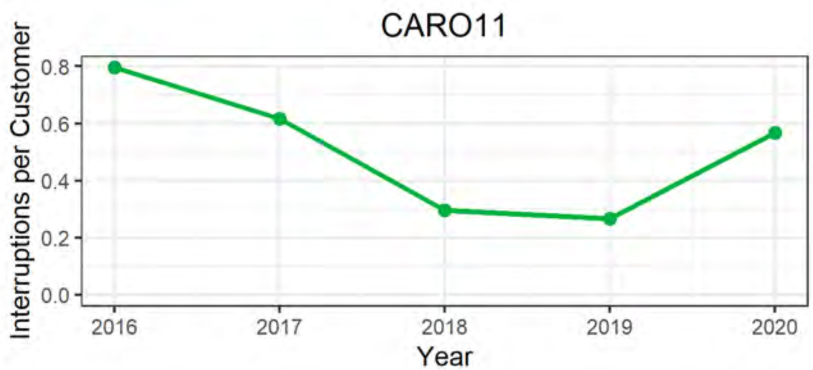
Five Years of Circuit SAIFI

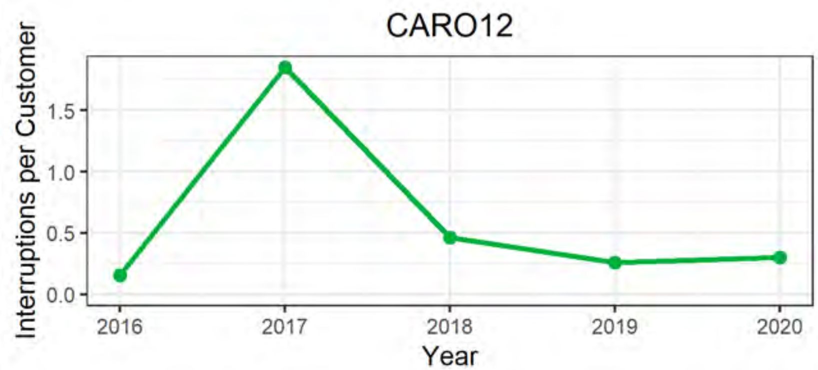
Circuit	2016	2017	2018	2019	2020	2020 MedEx
ADRN11	2.21	2.85	1.29	0.48	2.14	2.14
ADRN12	1.29	3.84	0.11	0.08	1.29	1.29
CARO11	0.79	0.62	0.30	0.27	0.57	0.57
CARO12	0.16	1.87	0.46	0.26	0.30	0.30
CARO13	0.00	0.11	0.06	0.10	1.04	1.04
CWVY11	0.42	1.20	2.14	1.02	2.17	2.17
CWVY12	0.20	1.27	1.13	1.74	2.15	2.15
DRKE11	0.20	2.46	0.18	1.27	1.25	1.25
DUKE11	0.00	1.48	1.04	0.04	0.00	0.00
DWSY11	3.10	2.87	4.63	1.16	4.06	4.06
ESTN11	5.33	4.67	5.00	1.00	4.00	4.00
HCSU11	0.00	0.00	0.00	0.00	0.00	0.00
HFWY11	1.08	1.71	1.23	1.46	1.39	1.39
HFWY12	1.17	2.36	2.32	1.46	1.13	0.21
HGTN11	1.00	0.34	0.01	1.65	1.06	1.06
HGTN12	0.19	0.24	0.01	0.08	1.06	1.06
HMDL12	3.13	1.64	1.13	4.89	1.17	1.17
HOLY11	1.27	0.26	0.08	0.17	0.47	0.47
HOLY12	1.18	1.43	0.24	1.10	0.38	0.38
HOLY13	1.09	0.11	1.37	0.30	0.61	0.61
HOLY14	NA	NA	NA	1.20	0.00	0.00
HOPE11	3.19	1.28	1.57	1.05	1.32	1.32
HRPR11	1.53	1.49	1.10	1.47	4.42	4.42
HRPR12	3.34	3.21	1.04	1.91	3.68	3.68
JMSN11	0.36	0.37	1.23	0.34	1.88	1.88
JMSN12	0.33	1.16	1.07	0.33	1.12	1.12
JNTA11	3.33	1.00	2.03	1.02	3.16	3.16
JNTA12	3.96	1.23	2.24	1.02	3.19	3.19
JNVY11	3.25	2.26	1.11	0.20	4.14	4.14
JNVY12	2.00	2.26	1.16	0.05	3.86	3.86
JNVY31	6.09	3.66	3.01	0.86	4.57	4.57
LIME11	0.77	2.44	1.46	0.53	2.33	2.33
MRBT41	0.50	1.22	2.15	1.59	2.03	2.03
MRBT42	0.22	1.00	3.00	1.55	0.00	0.00
NYSA11	1.36	0.19	0.18	1.44	0.05	0.05
NYSA12	4.42	3.21	1.33	1.24	1.02	1.02
NYSA13	2.36	0.16	0.15	0.34	0.78	0.78
NYSA14	1.47	0.05	0.14	1.29	0.23	0.23
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OIDA11	0.24	0.74	0.29	1.15	1.63	1.63
OIDA12	1.00	2.00	0.00	2.00	0.00	0.00
ONTO14	1.00	1.09	0.00	0.06	0.00	0.00
ONTO18	0.12	0.06	1.12	0.30	0.02	0.02
ONTO19	0.14	0.29	1.22	0.31	0.19	0.19
ONTO20	1.22	0.17	0.32	0.35	0.49	0.49
ONTO23	0.13	2.17	0.21	0.00	0.00	0.00
ONTO24	0.44	1.69	2.85	1.39	0.38	0.38
ONTO25	0.19	0.13	0.17	1.08	0.04	0.04
OYDM11	0.00	0.93	0.13	0.93	0.00	0.00
PNCK11	2.91	0.96	0.25	0.35	4.82	4.82
PNCK12	1.00	1.00	0.00	0.00	1.00	1.00
PRMA12	8.00	3.00	2.33	1.00	0.00	0.00
PRMA42	1.66	4.60	2.64	0.30	2.15	2.15
RKVL11	2.52	2.25	1.00	0.03	5.22	5.22
UNTY11	1.17	6.21	2.15	0.16	2.10	2.10
UNTY12	0.90	6.81	2.06	0.21	1.65	1.65
VALE11	0.10	1.59	0.74	0.14	0.03	0.03
VALE12	0.00	0.50	0.14	0.00	0.00	0.00
VALE13	0.23	1.18	0.33	0.18	0.54	0.54
VALE14	0.05	0.91	1.59	0.12	1.67	1.67
VALE15	2.84	1.37	1.69	0.12	0.20	0.20
WESR13	0.19	2.34	1.08	0.78	0.61	0.61
WESR14	0.43	3.23	3.73	1.23	1.29	1.29

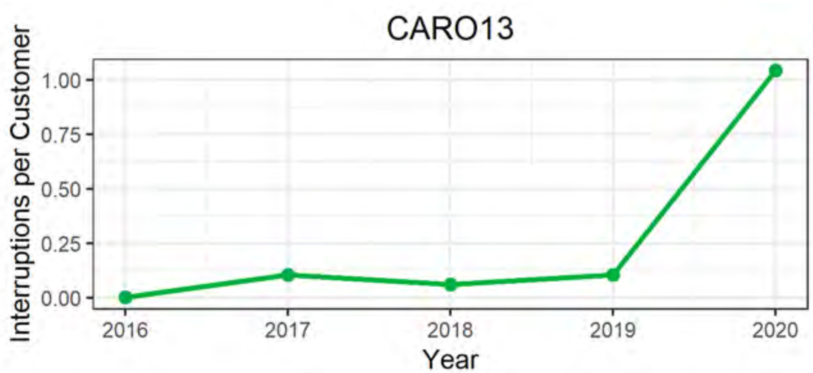
Table 7 Five Years of Circuit SAIFI

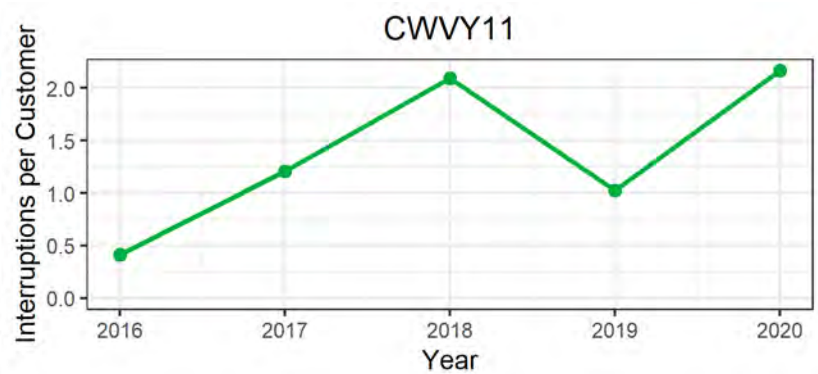

ADRN11
Interruptions per Customer
0
1
2
2016
2017
2018
2019
2020
Year

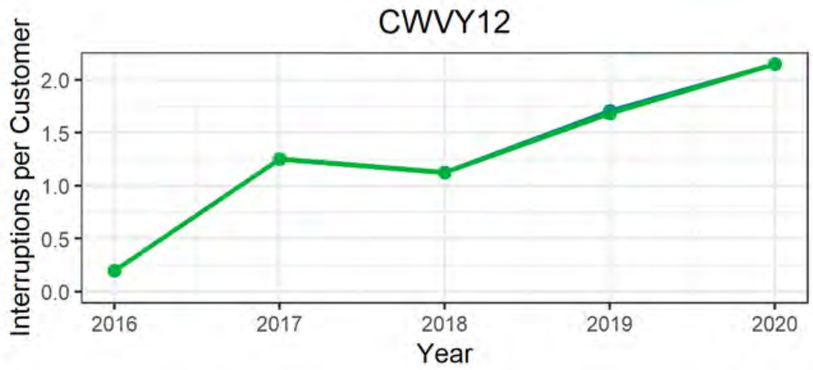

ADRN12
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

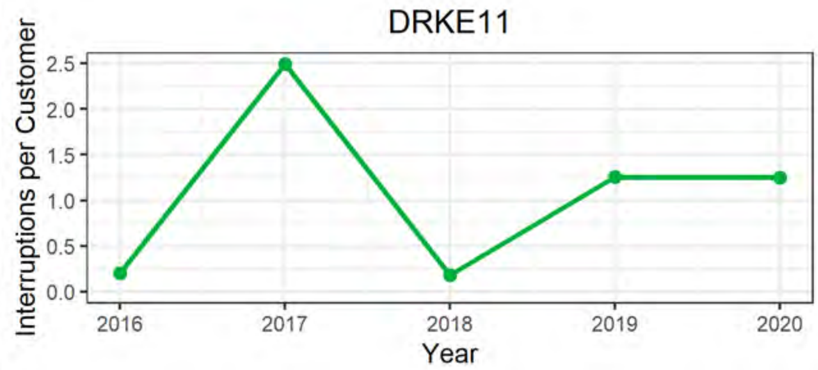

CARO11
Interruptions per Customer
0.0
0.2
0.4
0.6
0.8
2016
2017
2018
2019
2020
Year

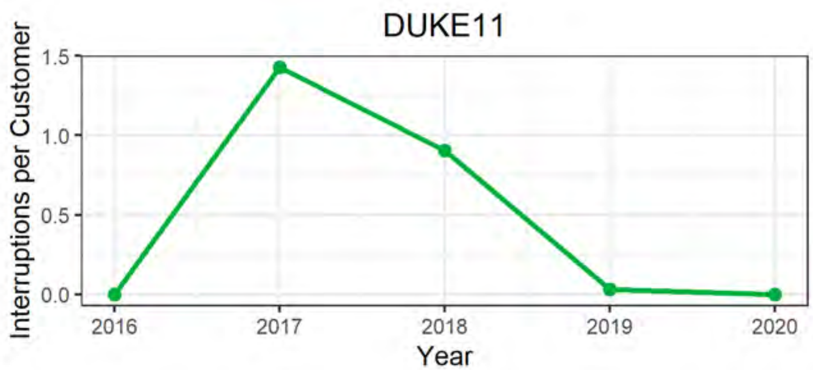

CARO12
Interruptions per Customer
0.0
0.5
1.0
1.5
2016
2017
2018
2019
2020
Year

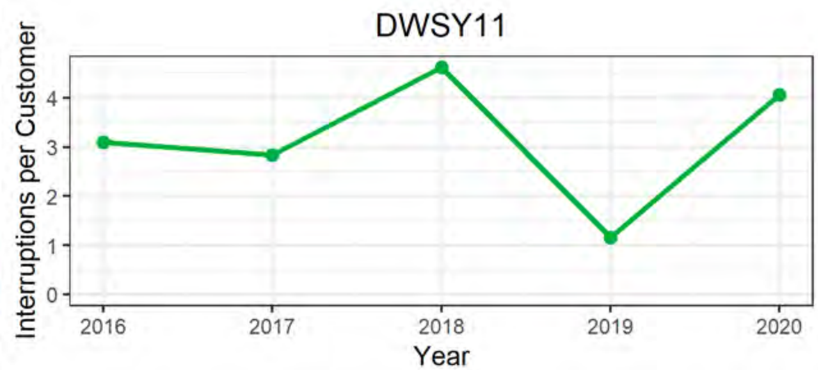

CARO13
Interruptions per Customer
0.00
0.25
0.50
0.75
1.00
2016
2017
2018
2019
2020
Year

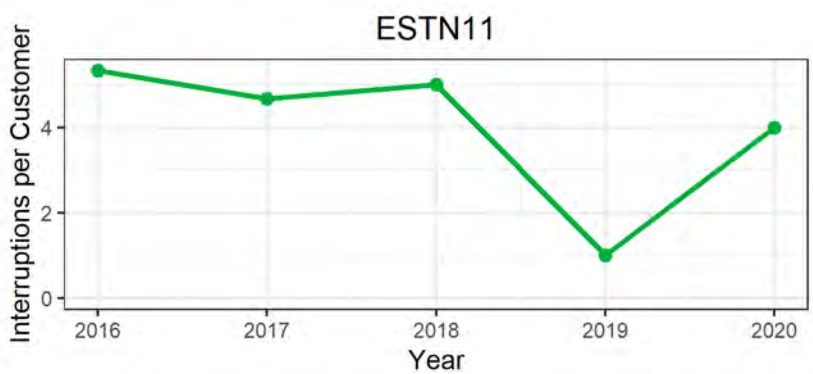

CWVY11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

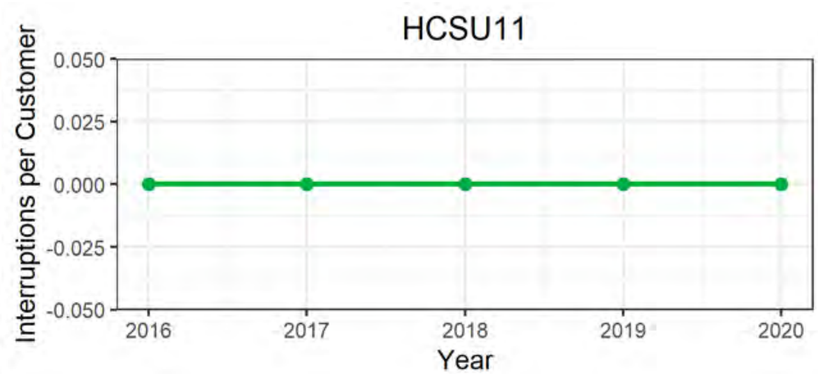

CWVY12
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

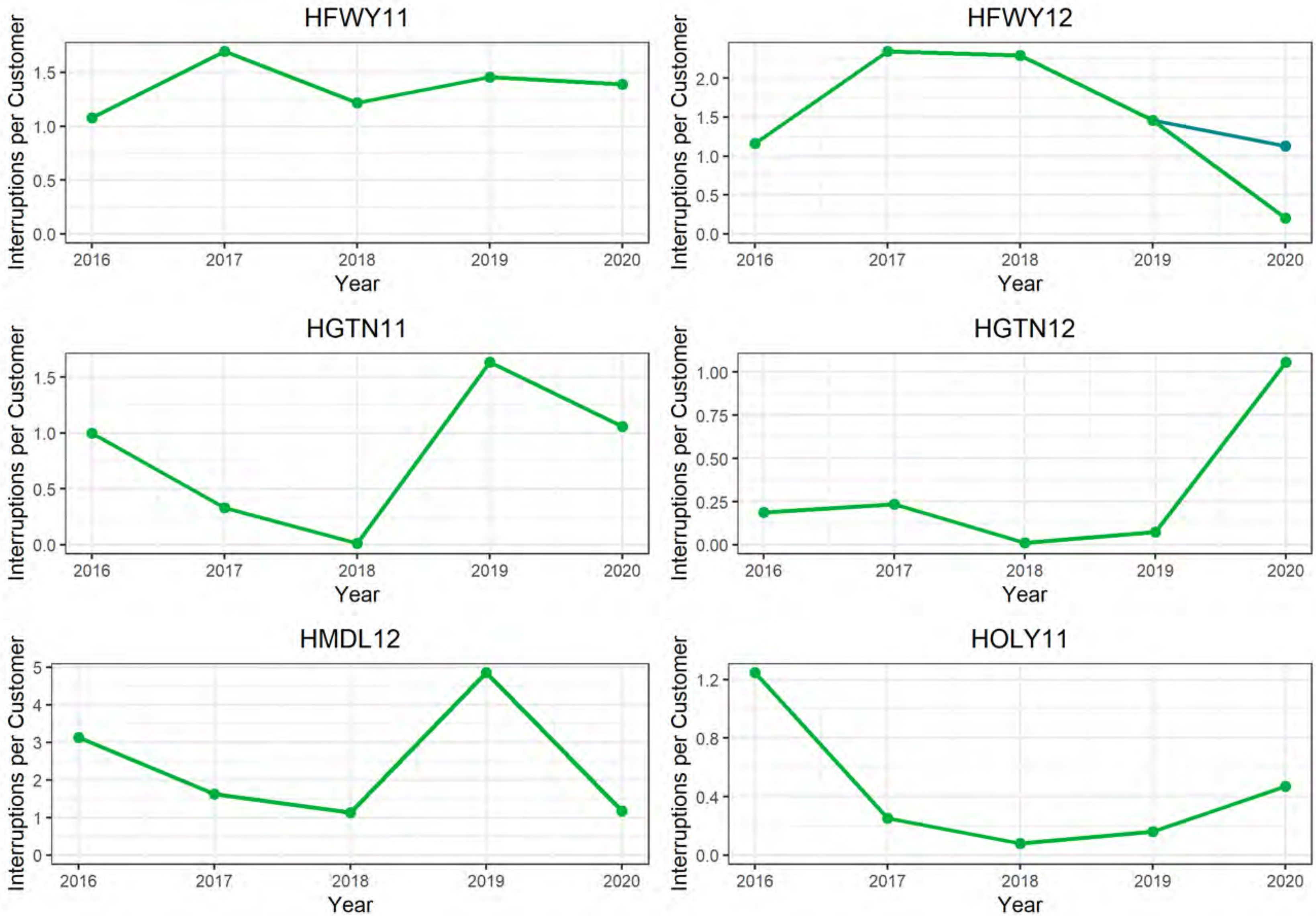

DRKE11
Interruptions per Customer
2.5
2.0
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

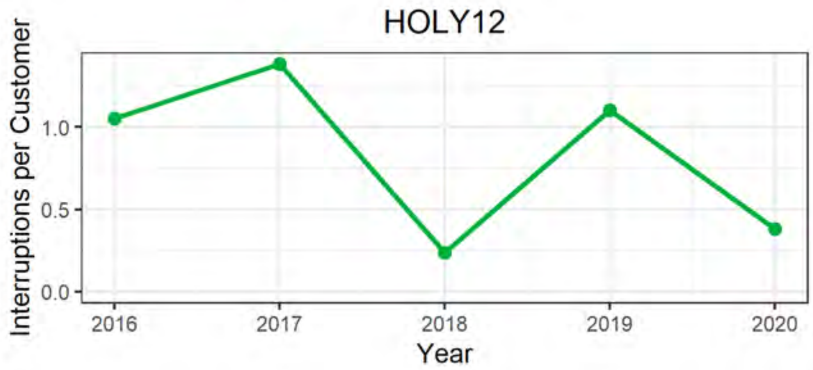

DUKE11
Interruptions per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

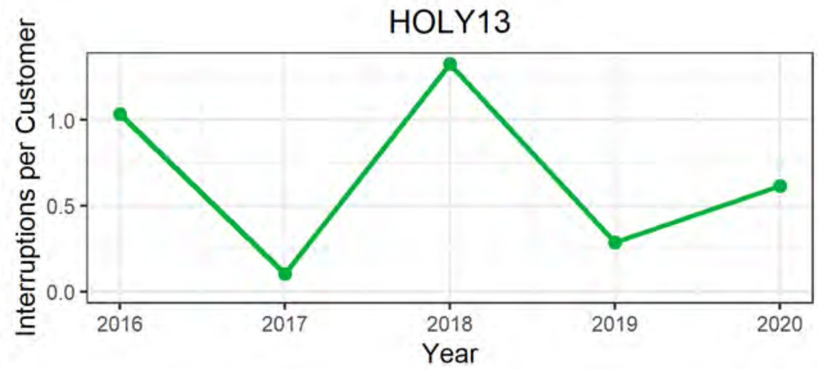

DWSY11
Interruptions per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year

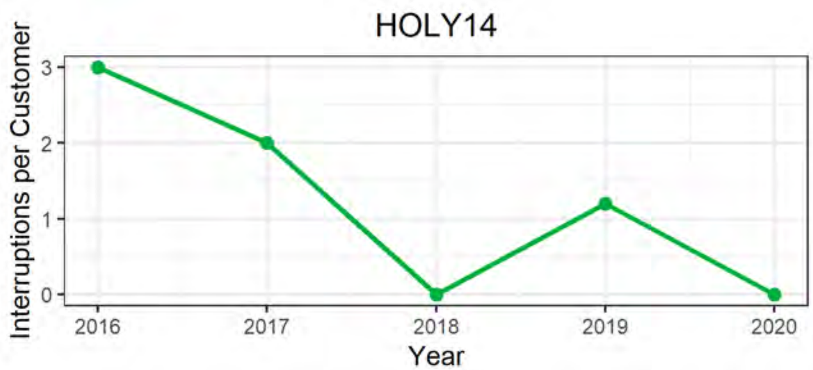

ESTN11
Interruptions per Customer
4
2
0
2016
2017
2018
2019
2020
Year

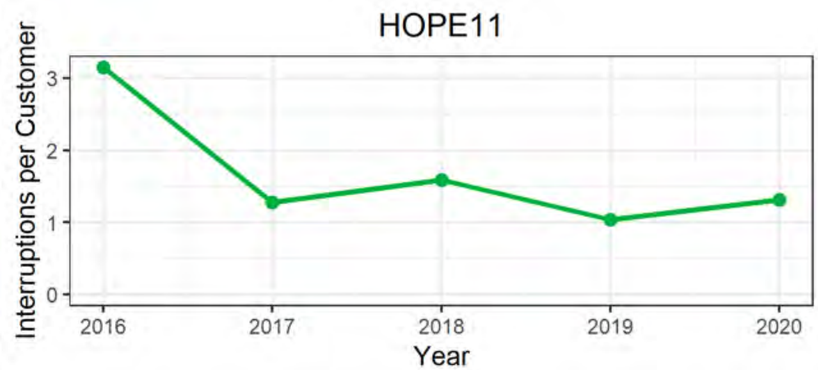

HCSU11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

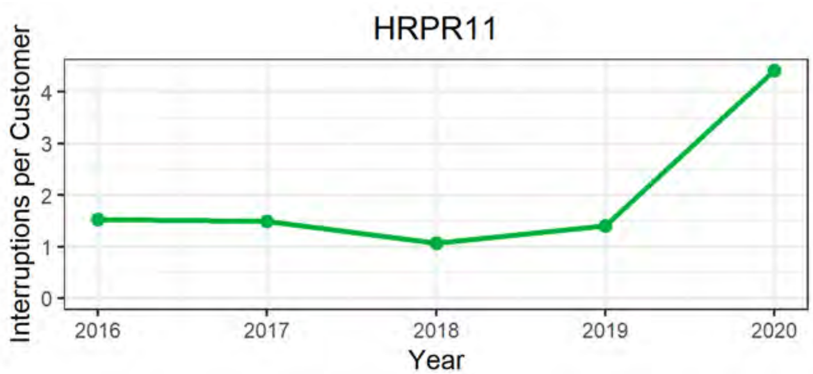

HFWY11
HFWY12
HGTN11
HGTN12
HMDL12
HOLY11
Interruptions per Customer
Year
2016
2017
2018
2019
2020

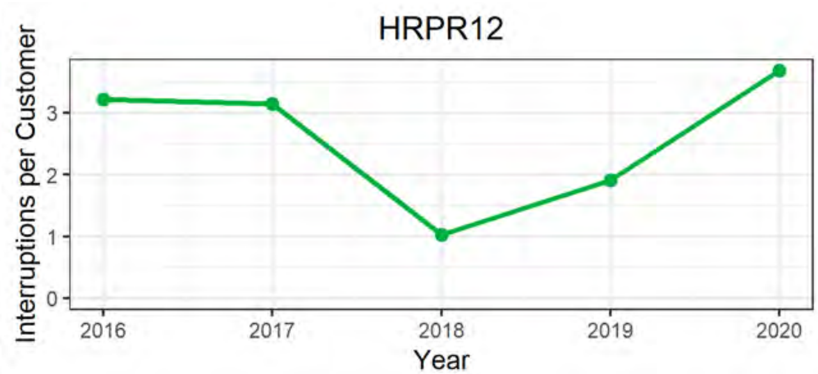

HOLY12
Interruptions per Customer
0.0
0.5
1.0
2016
2017
2018
2019
2020
Year

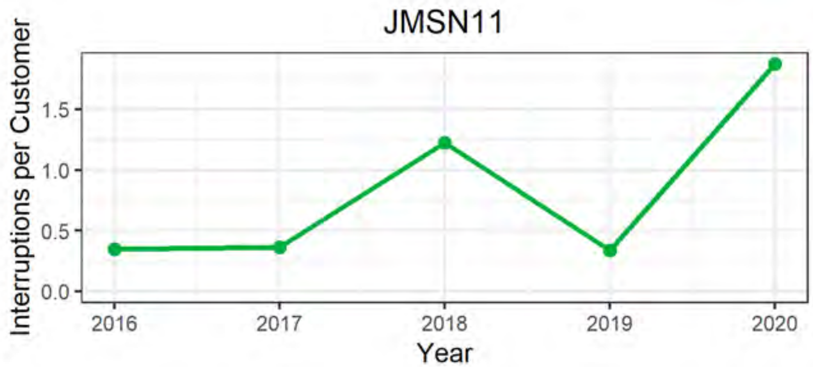

HOLY13
Interruptions per Customer
0.0
0.5
1.0
2016
2017
2018
2019
2020
Year

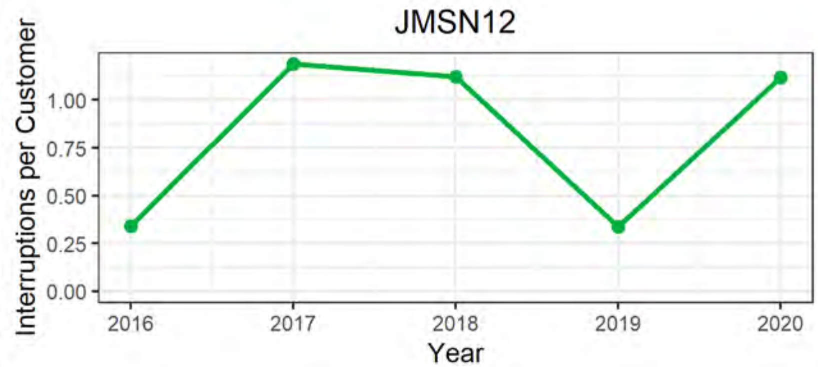

HOLY14
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

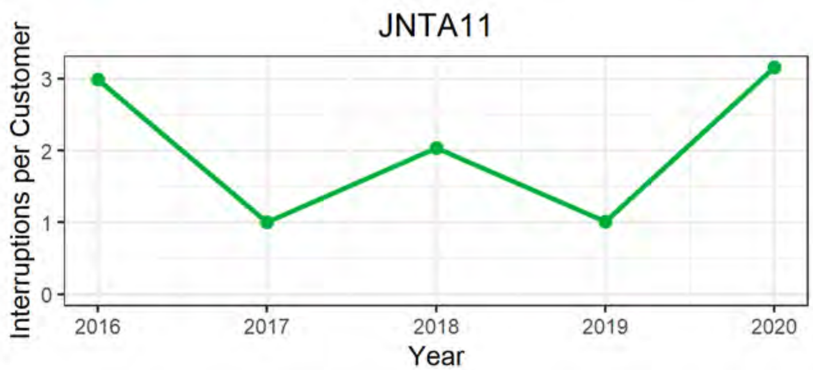

HOPE11
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

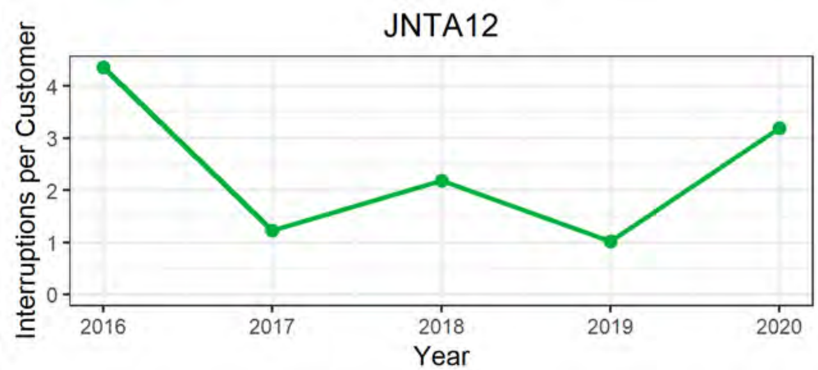

HRPR11
Interruptions per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year

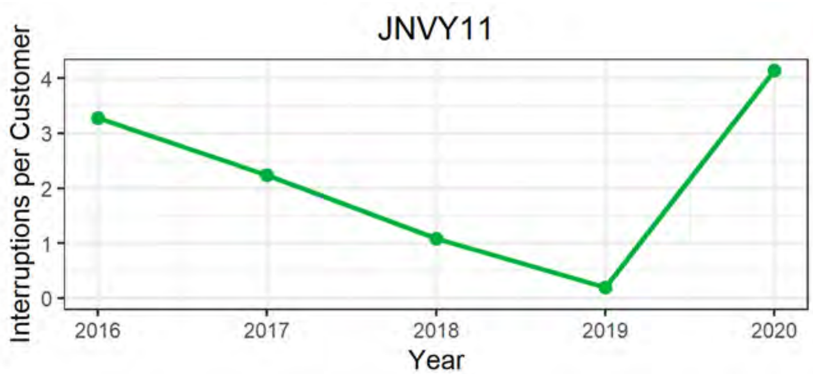

HRPR12
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

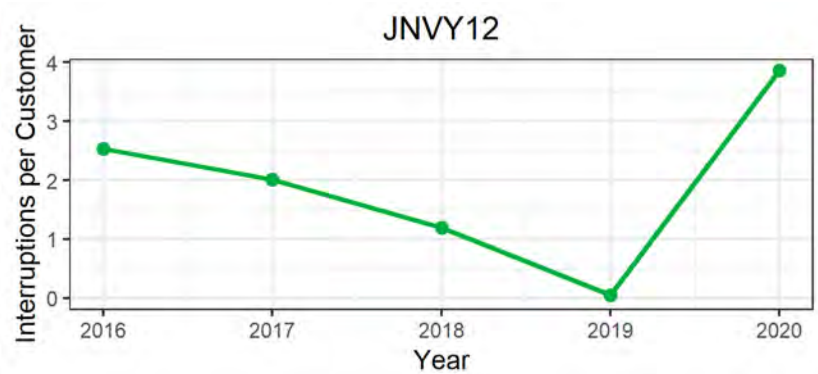

JMSN11
Interruptions per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

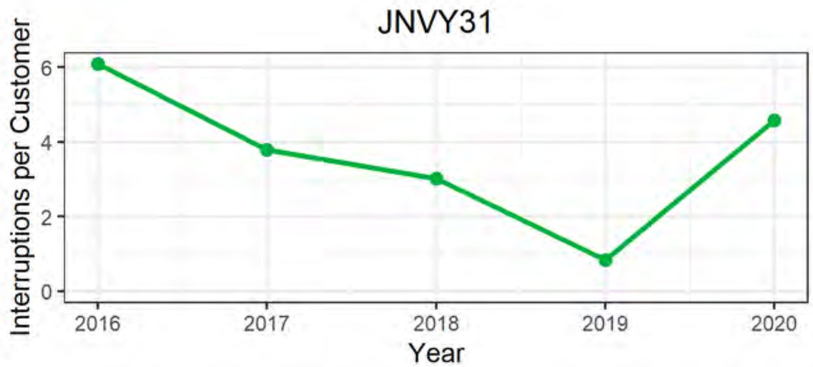

JMSN12
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2016
2017
2018
2019
2020
Year

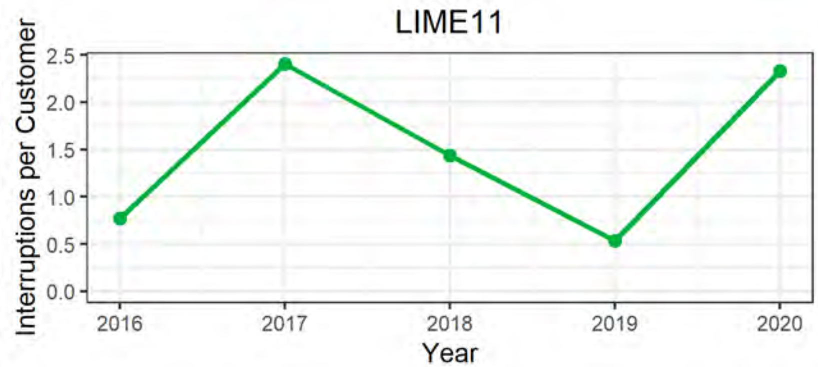

JNTA11
Interruptions per Customer
3
2
1
0
2016
2017
2018
2019
2020
Year

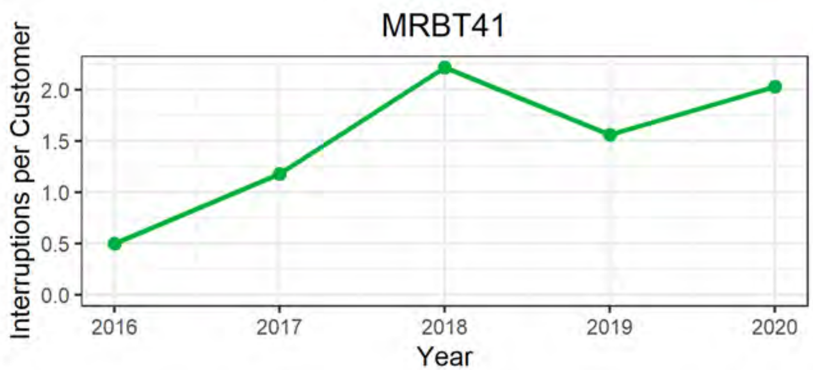

JNTA12
Interruptions per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year

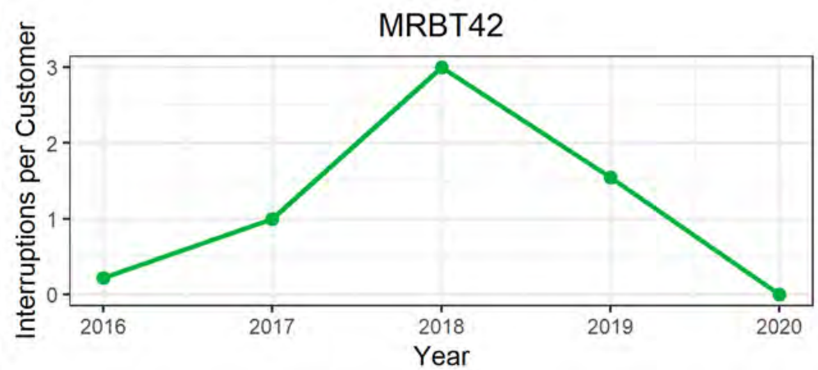

JNVY11
Interruptions per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year

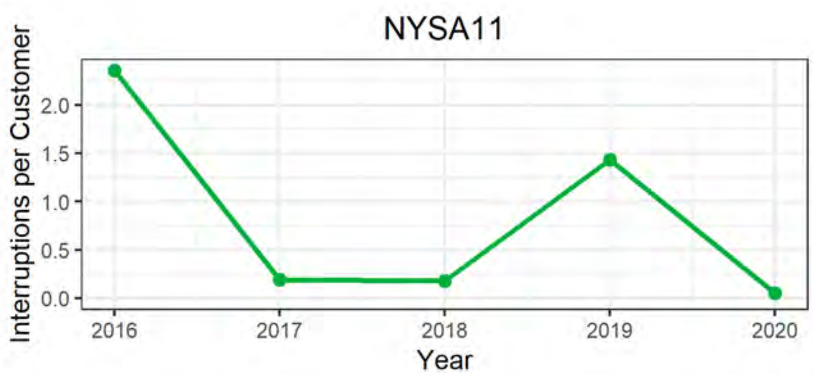

JNVY12
Interruptions per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year

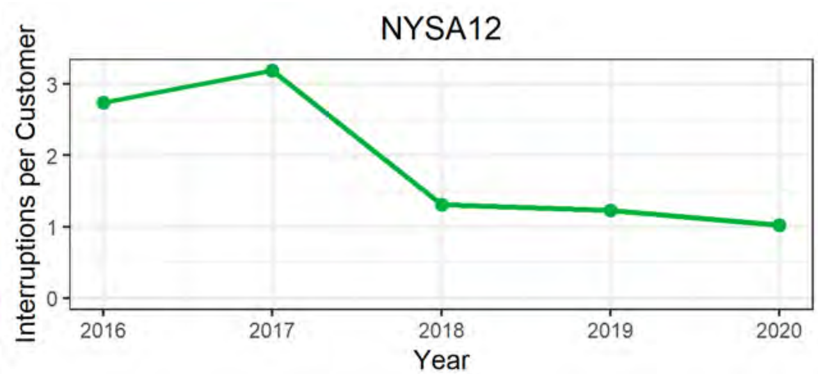

JNVY31
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

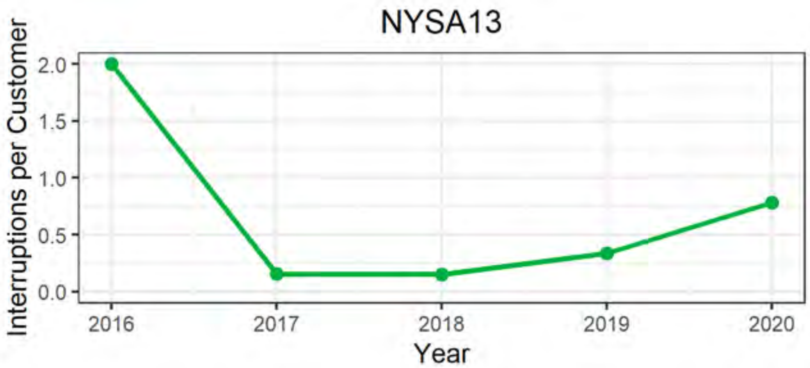

LIME11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2016
2017
2018
2019
2020
Year

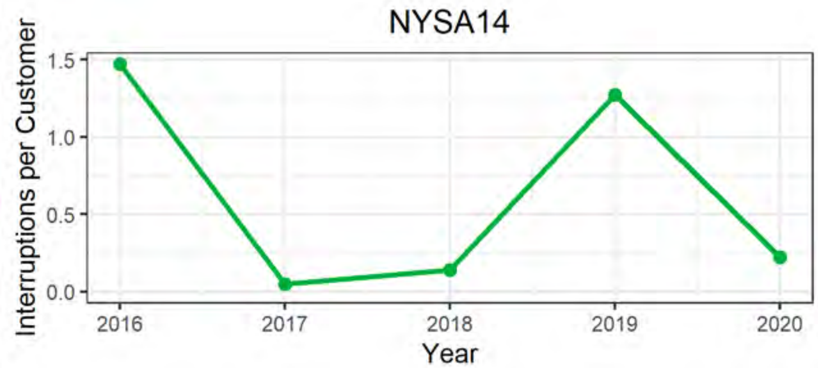

MRBT41
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year


MRBT42
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

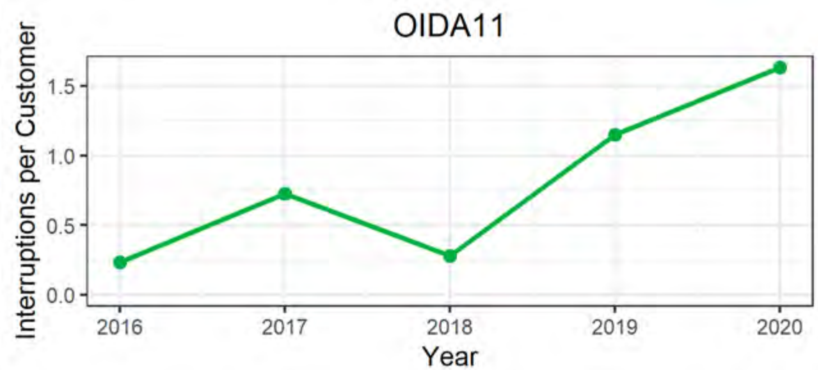

NYSA11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

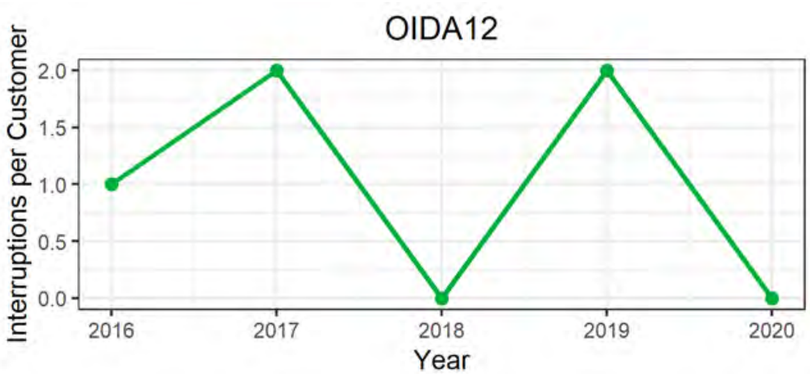

NYSA12
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

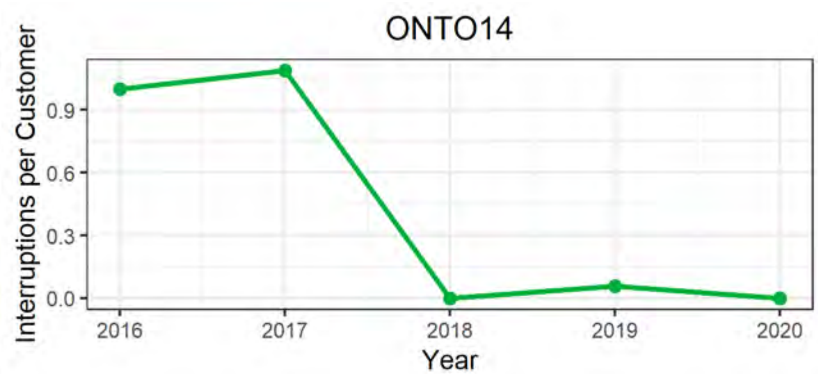

NYSA13
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

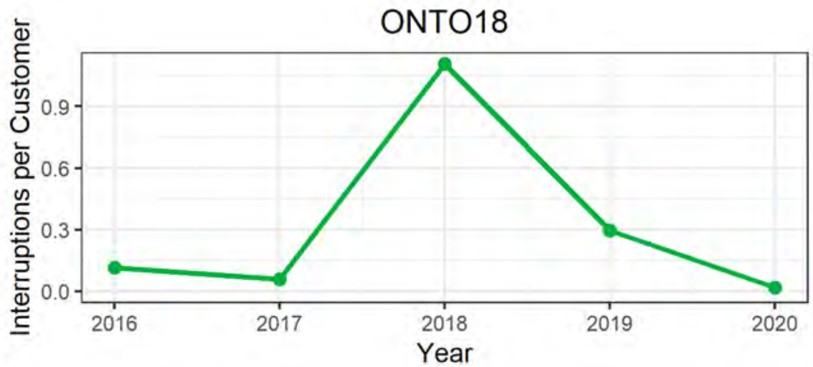

NYSA14
Interruptions per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

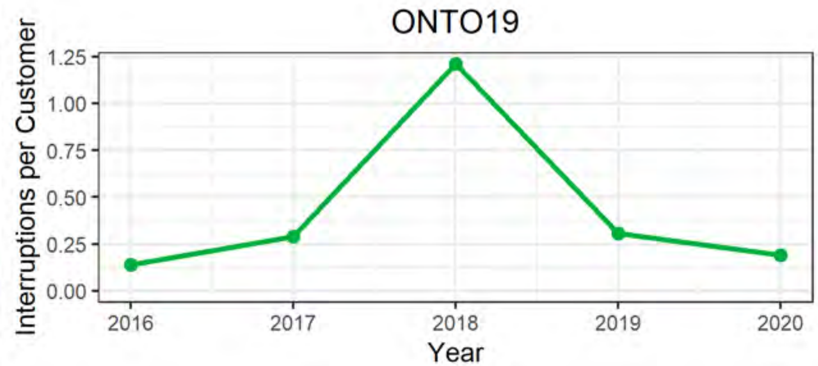

OBPR11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

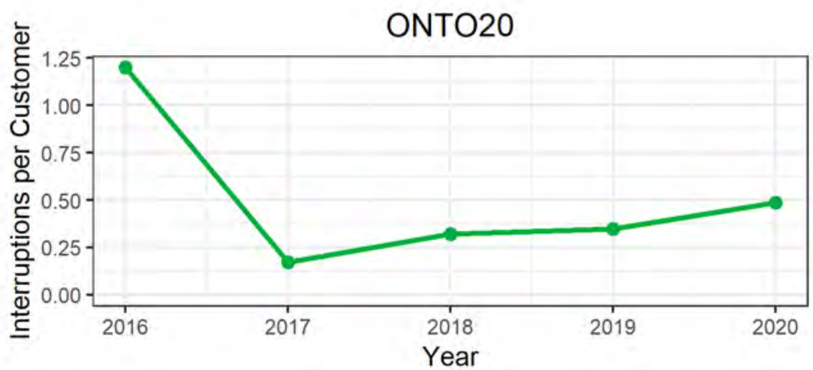

OIDA11
Interruptions per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

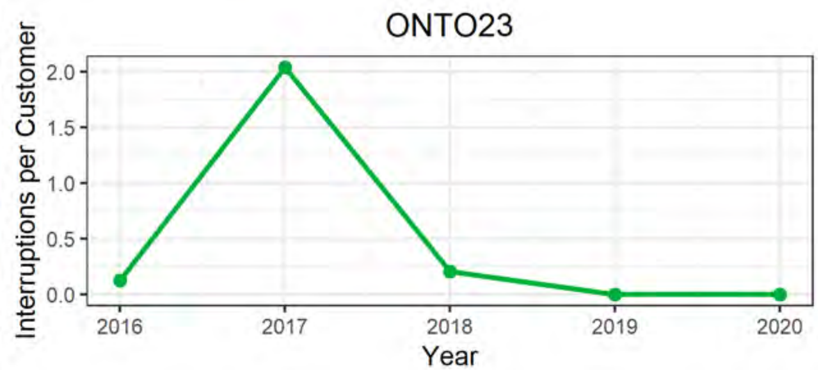

OIDA12
Interruptions per Customer
2.0
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

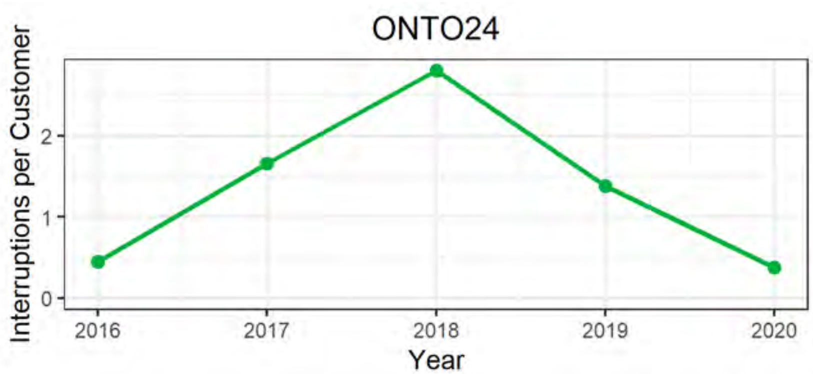

ONTO14
Interruptions per Customer
0.9
0.6
0.3
0.0
2016
2017
2018
2019
2020
Year

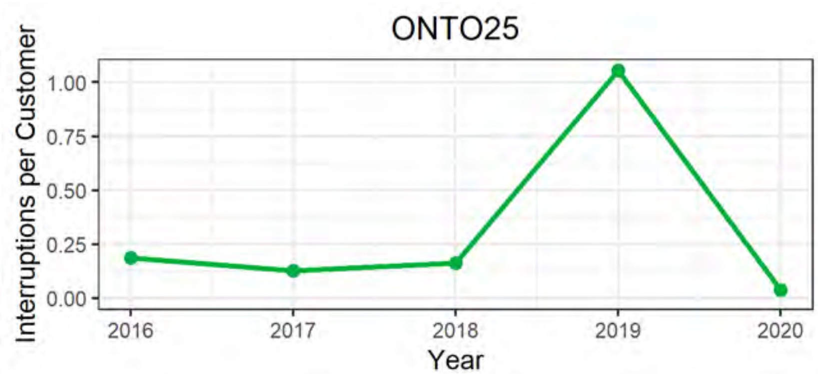

ONTO18
Interruptions per Customer
0.0
0.3
0.6
0.9
2016
2017
2018
2019
2020
Year

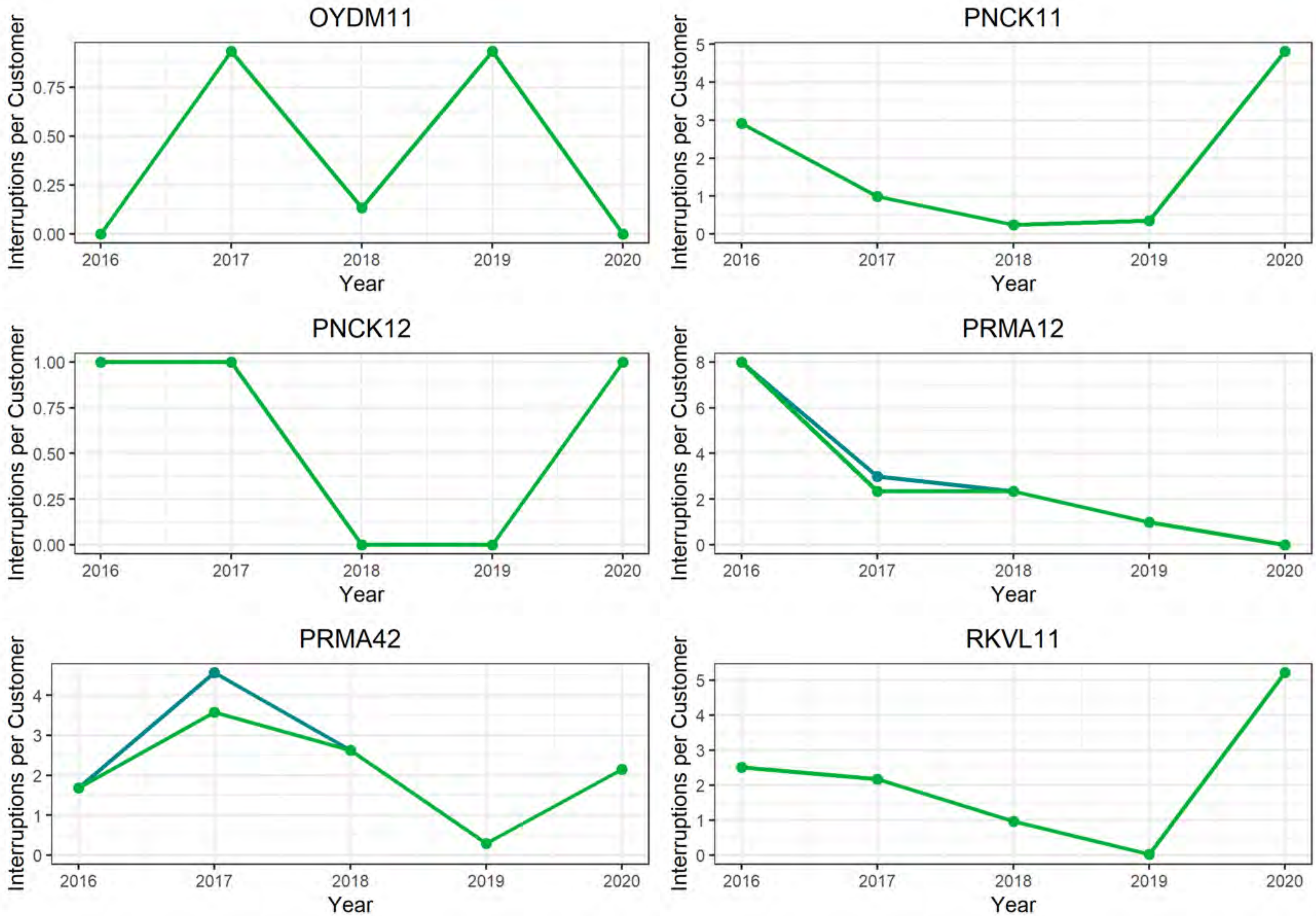

ONTO19
Interruptions per Customer
0.00
0.25
0.50
0.75
1.00
1.25
2016
2017
2018
2019
2020
Year

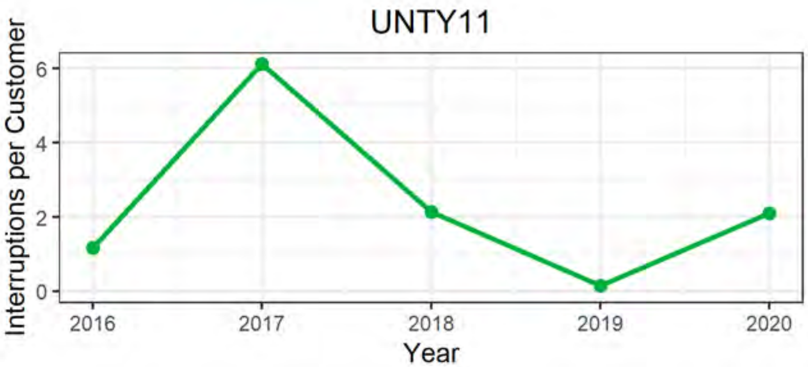

ONTO20
Interruptions per Customer
0.00
0.25
0.50
0.75
1.00
1.25
2016
2017
2018
2019
2020
Year

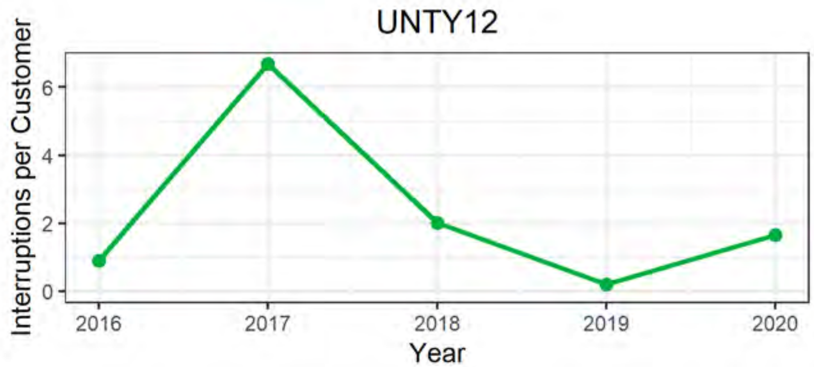

ONTO23
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

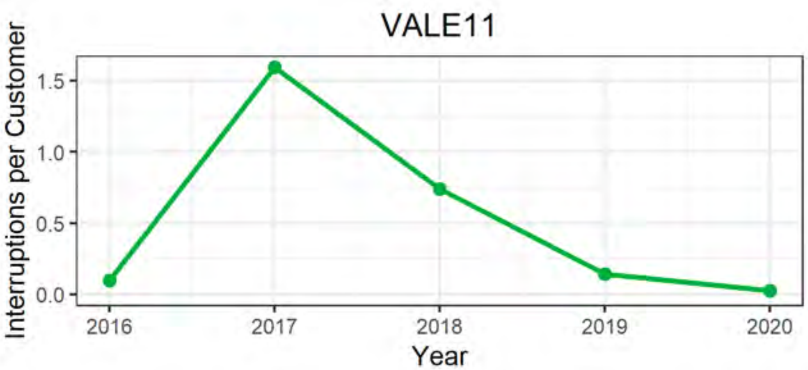

ONTO24
Interruptions per Customer
0
1
2
2016
2017
2018
2019
2020
Year

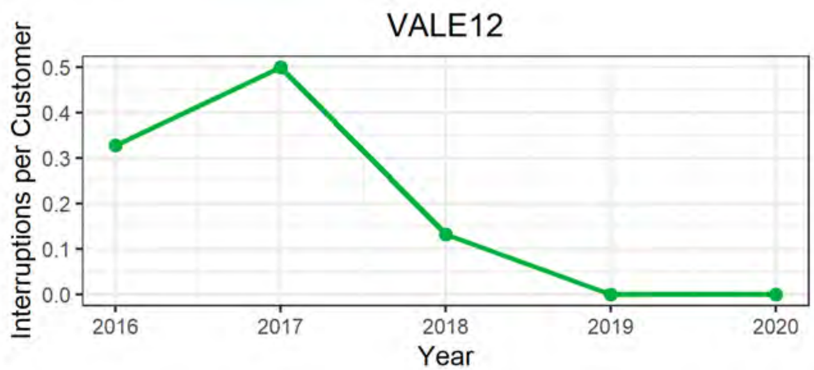

ONTO25
Interruptions per Customer
0.00
0.25
0.50
0.75
1.00
2016
2017
2018
2019
2020
Year

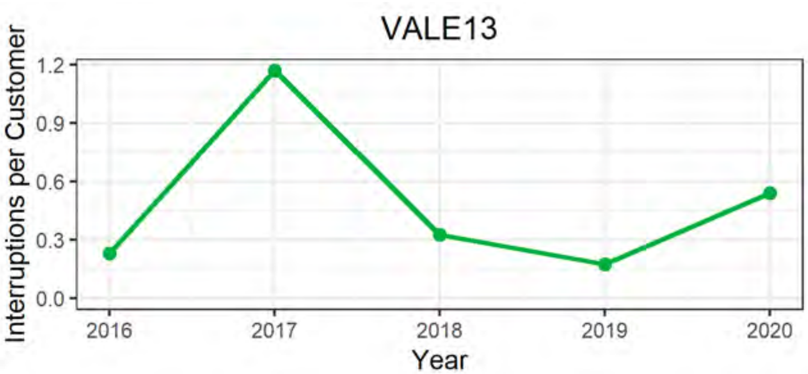

OYDM11
Interruptions per Customer
0.00
0.25
0.50
0.75
2016
2017
2018
2019
2020
Year
PNCK11
Interruptions per Customer
0
1
2
3
4
5
2016
2017
2018
2019
2020
Year
PNCK12
Interruptions per Customer
0.00
0.25
0.50
0.75
1.00
2016
2017
2018
2019
2020
Year
PRMA12
Interruptions per Customer
0
2
4
6
8
2016
2017
2018
2019
2020
Year
PRMA42
Interruptions per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year
RKVL11
Interruptions per Customer
0
1
2
3
4
5
2016
2017
2018
2019
2020
Year

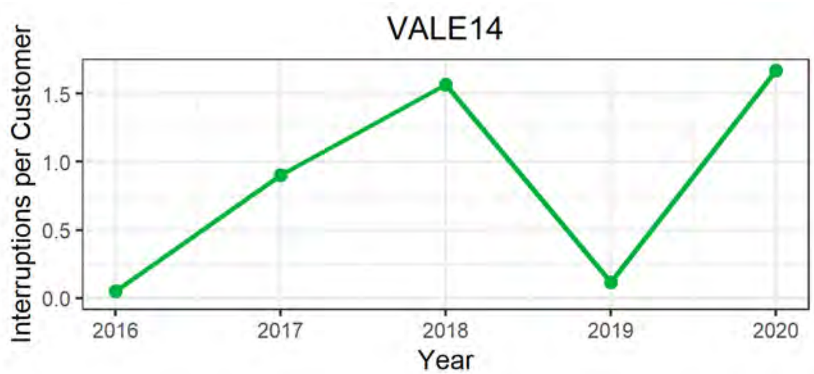

UNTY11
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year


UNTY12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year


VALE11
Interruptions per Customer
0.0
0.5
1.0
1.5
2016
2017
2018
2019
2020
Year


VALE12
Interruptions per Customer
0.0
0.1
0.2
0.3
0.4
0.5
2016
2017
2018
2019
2020
Year


VALE13
Interruptions per Customer
0.0
0.3
0.6
0.9
1.2
2016
2017
2018
2019
2020
Year


VALE14
Interruptions per Customer
0.0
0.5
1.0
1.5
2016
2017
2018
2019
2020
Year

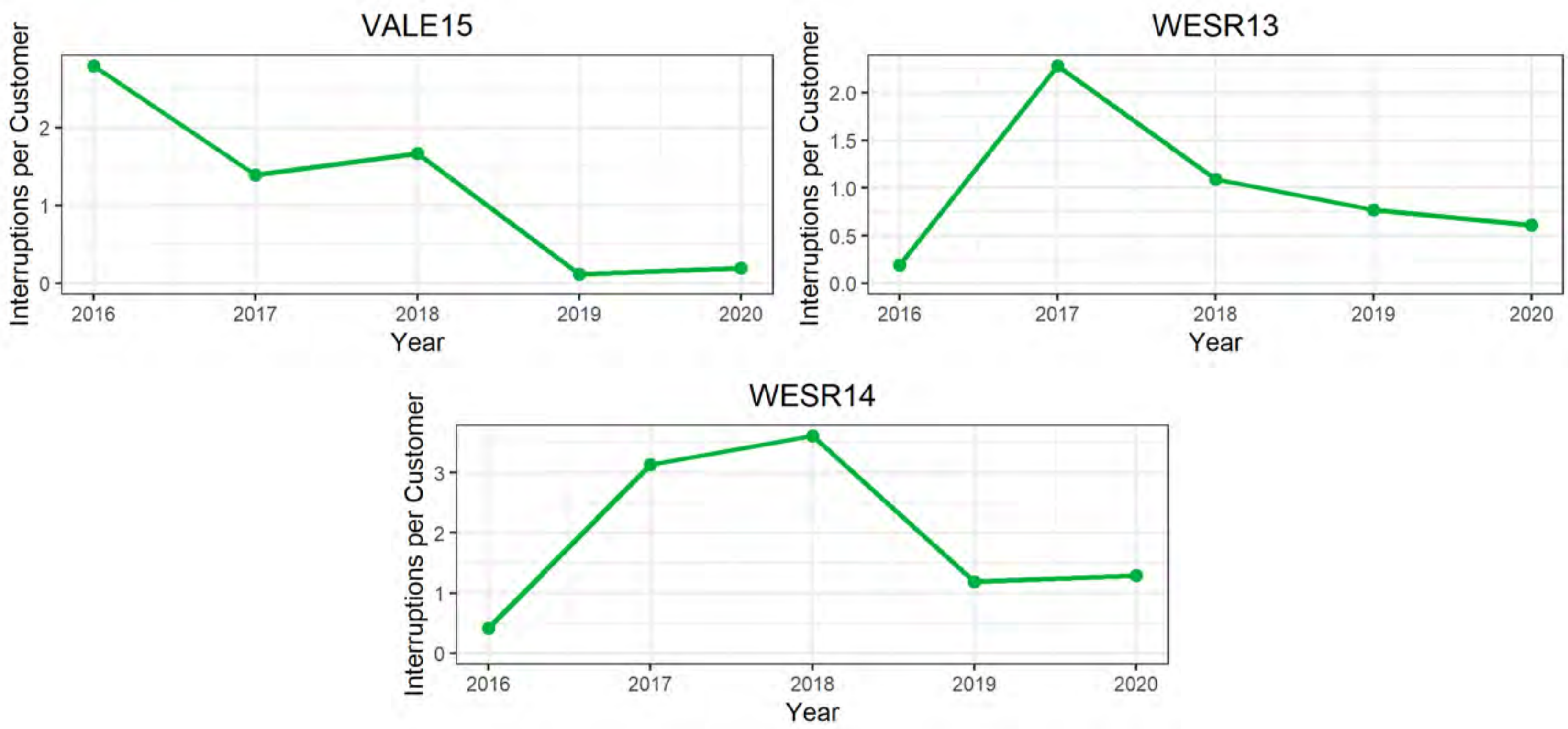
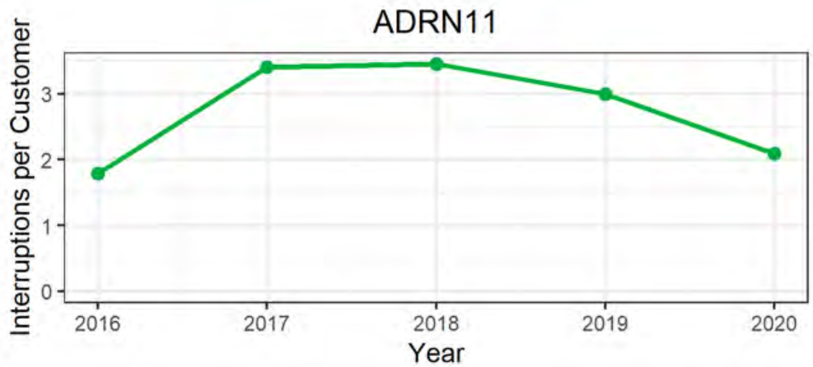


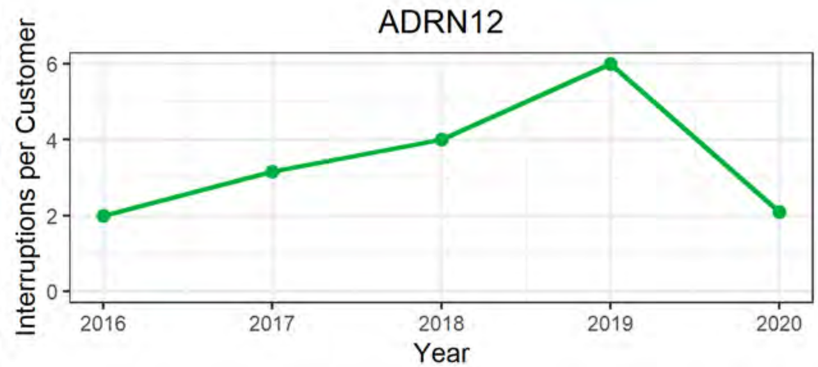
Figure 7 Five Years of Circuit SAIFI

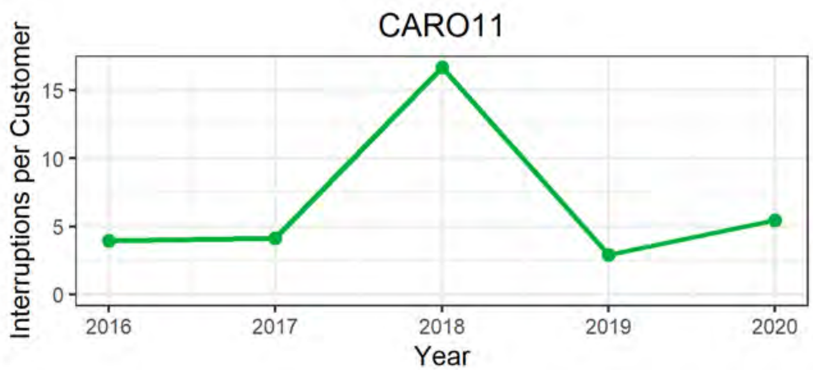
Five Years of Circuit $MAIFI_E$

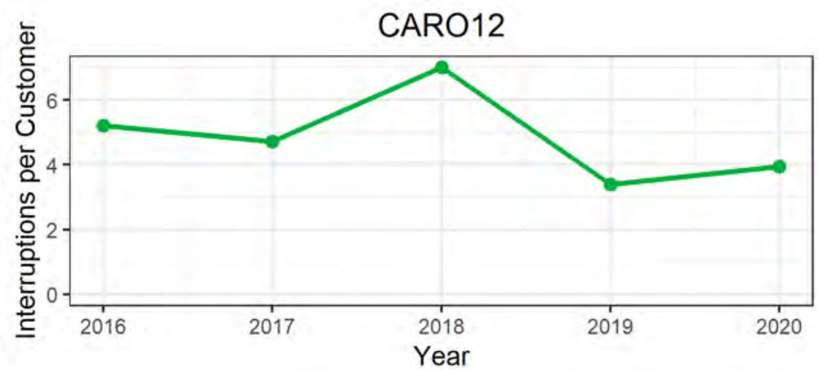
Circuit	2016	2017	2018	2019	2020	2020 MedEx
ADRN11	1.91	3.84	3.50	3.00	2.09	2.09
ADRN12	2.00	6.55	13.20	6.00	2.09	2.09
CARO11	4.01	4.42	11.18	3.10	5.43	5.43
CARO12	5.19	4.66	7.04	3.38	3.95	3.95
CARO13	2.00	0.00	5.00	0.00	0.00	0.00
CWVY11	1.00	8.00	5.00	0.00	0.00	0.00
CWVY12	3.06	6.65	3.00	6.00	0.00	0.00
DRKE11	10.33	18.00	4.00	5.00	3.00	3.00
DUKE11	0.00	2.00	2.00	0.00	0.00	0.00
DWSY11	8.27	7.47	9.00	7.85	4.48	4.48
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	2.64	15.57	1.79	6.29	1.73	1.73
HFWY12	7.25	9.15	6.00	5.17	17.00	17.00
HGTN11	1.00	1.00	2.00	4.00	4.00	4.00
HGTN12	1.00	2.00	0.00	2.00	4.00	4.00
HMDL12	4.72	8.23	6.92	6.52	2.04	2.04
HOLY11	0.00	0.00	0.00	0.00	0.00	0.00
HOLY12	0.00	4.00	6.00	2.00	5.00	5.00
HOLY13	0.42	3.72	2.00	4.00	0.00	0.00
HOLY14	NA	NA	NA	0.00	0.00	0.00
HOPE11	1.00	5.00	2.00	0.00	2.39	2.39
HRPR11	2.09	3.00	2.00	3.00	4.63	4.63
HRPR12	4.96	5.42	3.27	5.03	3.45	3.45
JMSN11	0.00	1.11	0.70	0.94	0.87	0.87
JMSN12	3.00	9.67	7.00	7.00	4.00	4.00
JNTA11	9.00	12.00	9.00	9.00	3.00	3.00
JNTA12	9.25	14.13	9.63	10.00	8.00	8.00
JNVY11	3.66	6.32	6.00	7.00	0.00	0.00
JNVY12	4.00	5.00	2.00	3.00	1.00	1.00
JNVY31	9.28	10.12	7.24	5.00	4.46	4.46
LIME11	1.00	2.19	2.00	2.00	0.60	0.60
MRBT41	0.00	1.00	1.00	1.00	3.00	3.00
MRBT42	0.00	0.00	1.00	1.00	2.00	2.00
NYSA11	1.00	0.00	2.00	1.00	2.00	2.00
NYSA12	5.42	7.15	1.95	0.00	0.00	0.00
NYSA13	0.00	1.26	1.09	1.00	0.52	0.52
NYSA14	1.00	1.35	0.00	1.00	0.00	0.00
OBPR11	0.00	0.00	0.00	0.00	0.00	0.00
OIDA11	4.23	2.00	0.00	0.00	3.00	3.00
OIDA12	0.00	0.00	0.00	0.00	0.00	0.00
ONTO14	1.00	1.00	1.00	1.00	0.00	0.00
ONTO18	0.00	2.00	3.00	4.00	3.00	3.00
ONTO19	1.36	0.00	1.72	1.72	1.34	1.34
ONTO20	0.00	0.00	0.00	2.00	1.00	1.00
ONTO23	2.00	7.00	0.00	0.00	0.00	0.00
ONTO24	0.94	3.28	0.00	0.00	0.68	0.68
ONTO25	0.00	3.00	0.00	0.00	0.00	0.00
OYDM11	0.00	0.00	0.00	0.00	0.00	0.00
PNCK11	3.00	4.00	4.00	4.00	5.00	5.00
PNCK12	0.00	0.00	0.00	0.00	0.00	0.00
PRMA12	3.00	5.00	1.00	0.00	0.00	0.00
PRMA42	4.76	12.23	9.74	6.24	3.15	3.15
RKVL11	6.00	6.00	5.00	6.00	3.00	3.00
UNTY11	1.00	15.00	8.00	7.00	8.05	8.05
UNTY12	1.22	14.85	0.00	0.00	0.00	0.00
VALE11	4.17	4.55	2.86	1.00	1.00	1.00
VALE12	0.00	0.00	0.00	0.00	0.00	0.00
VALE13	4.90	3.73	0.00	0.91	2.89	2.89
VALE14	1.07	2.61	2.00	0.00	0.12	0.12
VALE15	4.51	2.76	2.25	0.00	5.00	4.00
WESR13	0.00	0.27	0.74	4.26	1.26	1.26
WESR14	0.00	2.90	6.00	3.00	2.00	2.00

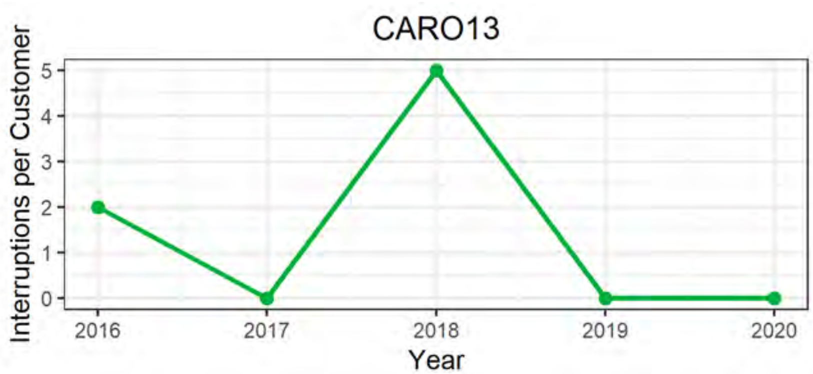
Table 8 Five Years of Circuit $MAIFI_E$

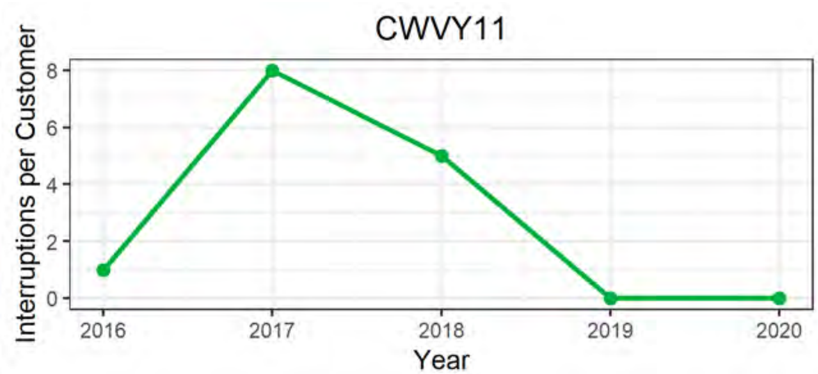

ADRN11
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year

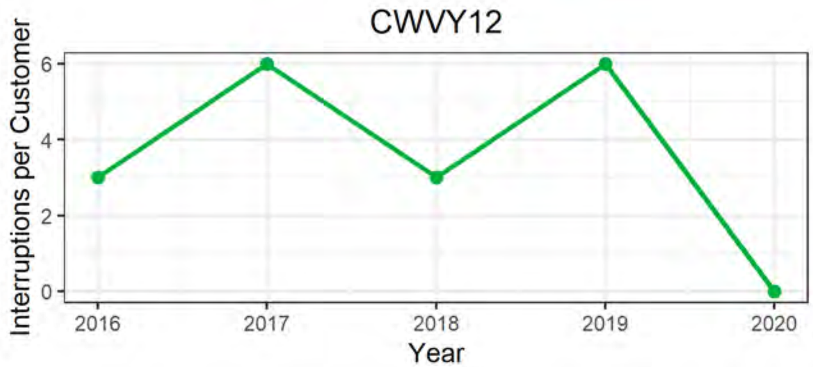

ADRN12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

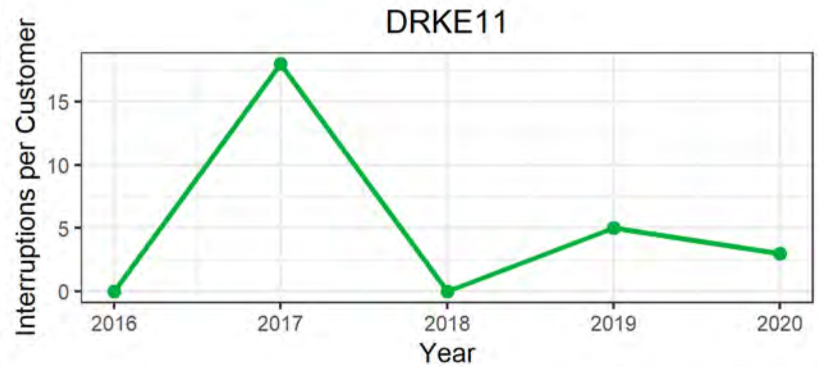

CARO11
Interruptions per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

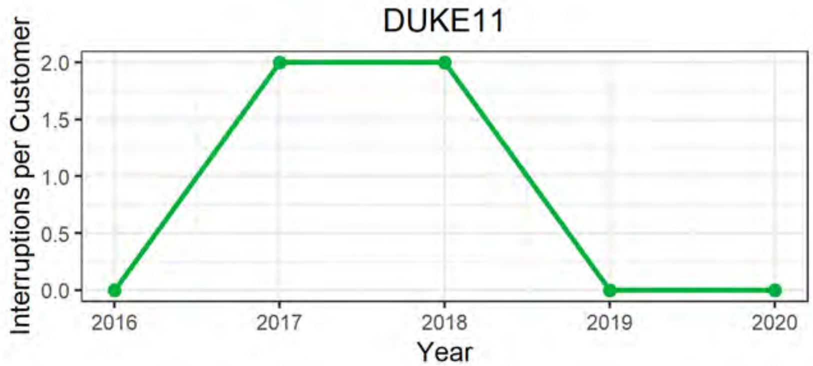

CARO12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

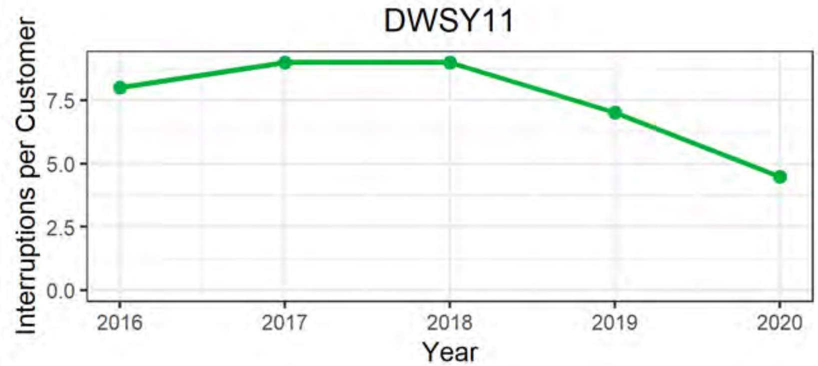

CARO13
Interruptions per Customer
0
1
2
3
4
5
2016
2017
2018
2019
2020
Year

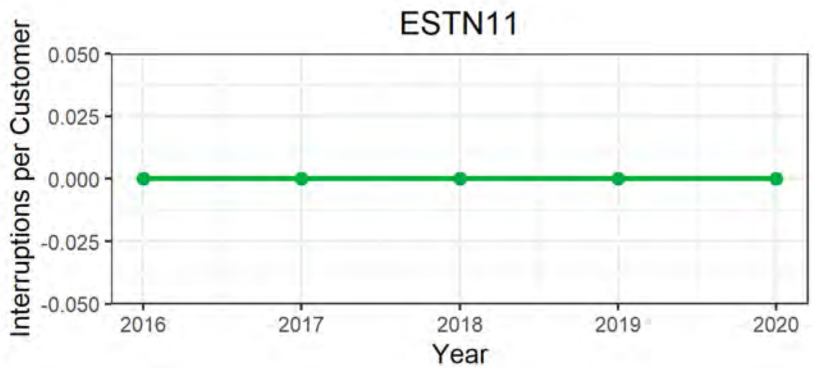

CWVY11
Interruptions per Customer
0
2
4
6
8
2016
2017
2018
2019
2020
Year

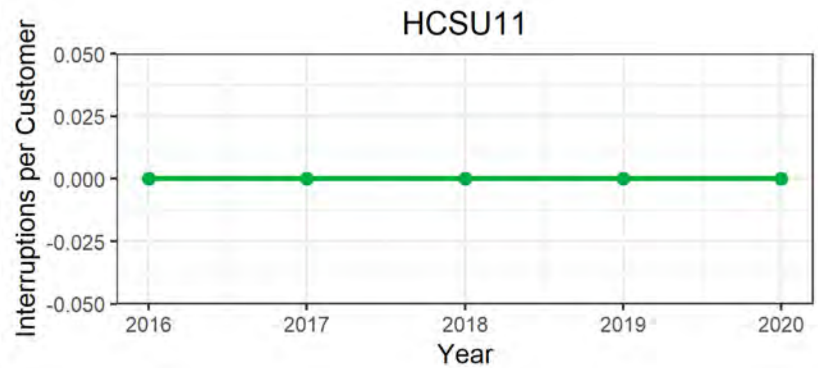

CWVY12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

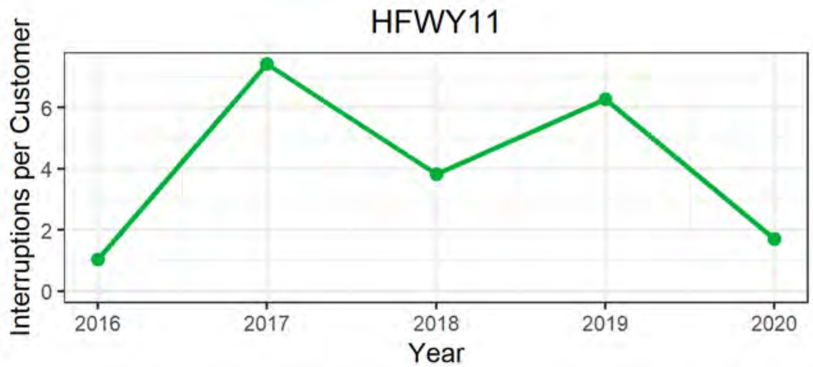

DRKE11
Interruptions per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

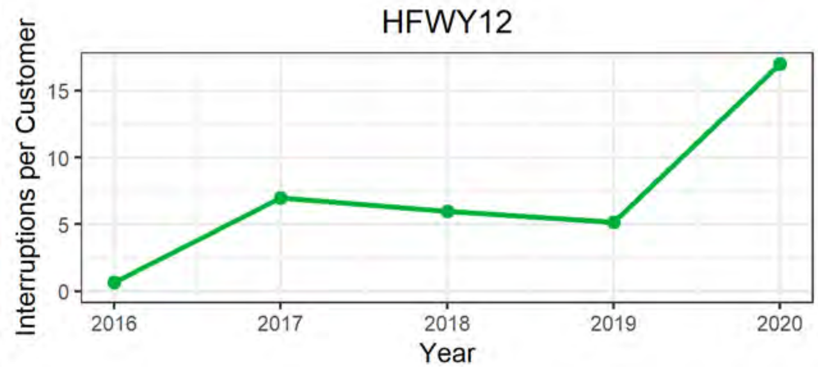

DUKE11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

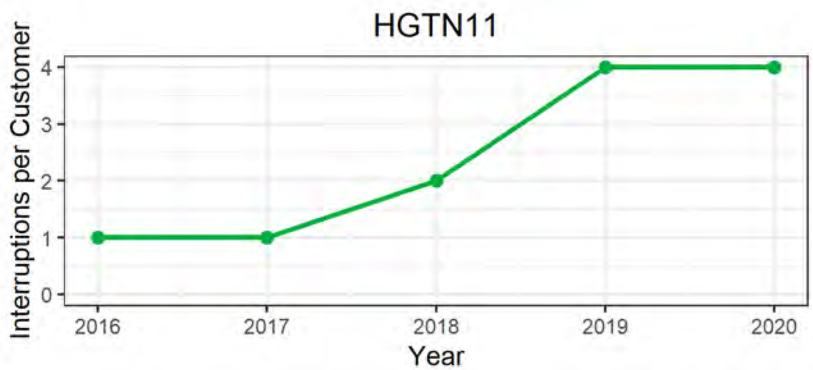

DWSY11
Interruptions per Customer
0.0
2.5
5.0
7.5
2016
2017
2018
2019
2020
Year

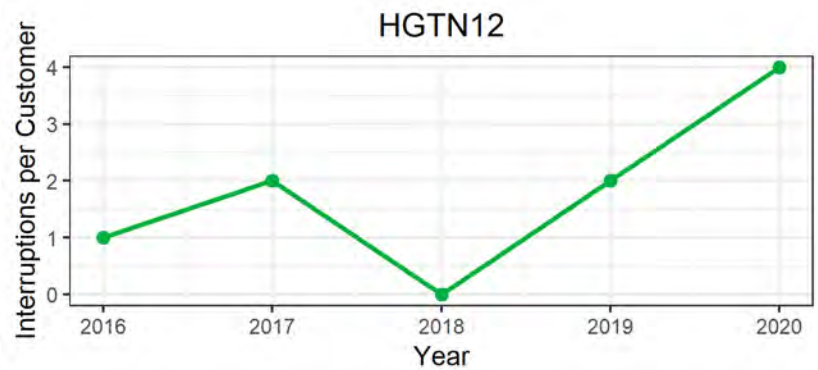

ESTN11
Interruptions per Customer
-0.050
-0.025
0.000
0.025
0.050
2016
2017
2018
2019
2020
Year

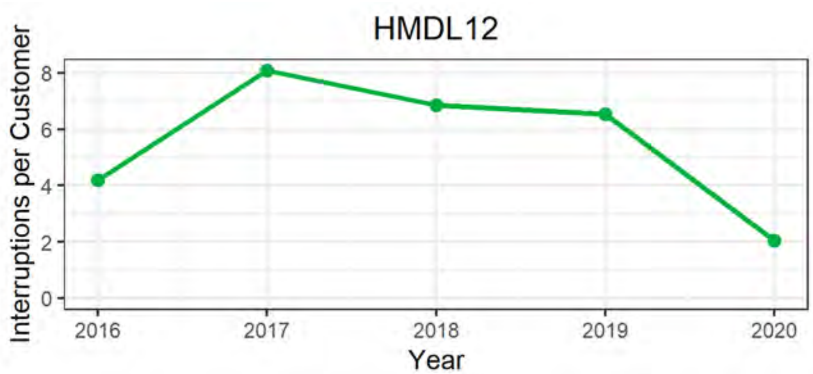

HCSU11
Interruptions per Customer
-0.050
-0.025
0.000
0.025
0.050
2016
2017
2018
2019
2020
Year

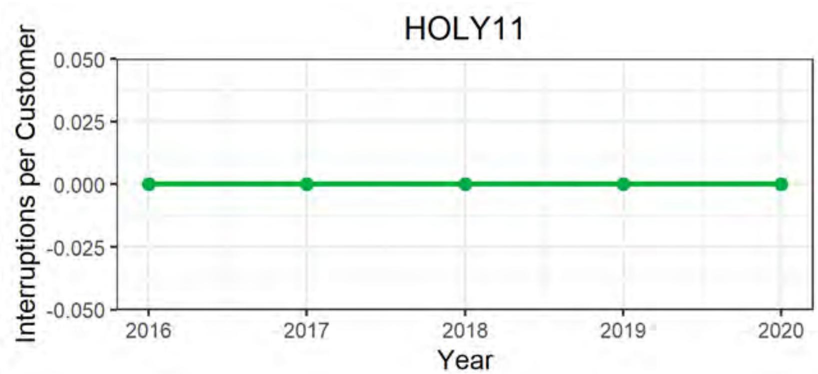

HFWY11
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

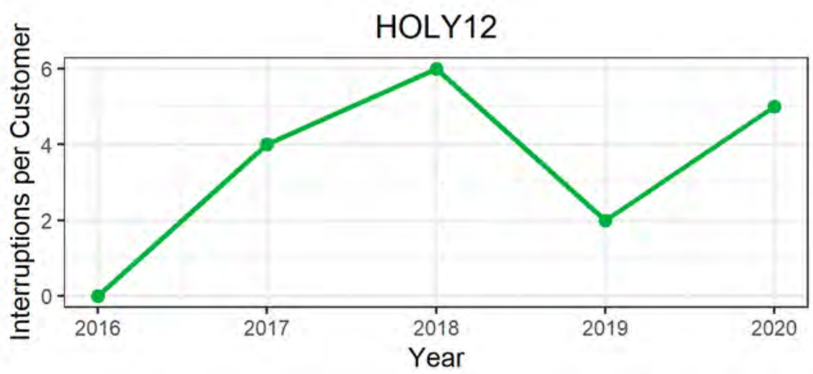

HFWY12
Interruptions per Customer
0
5
10
15
2016
2017
2018
2019
2020
Year

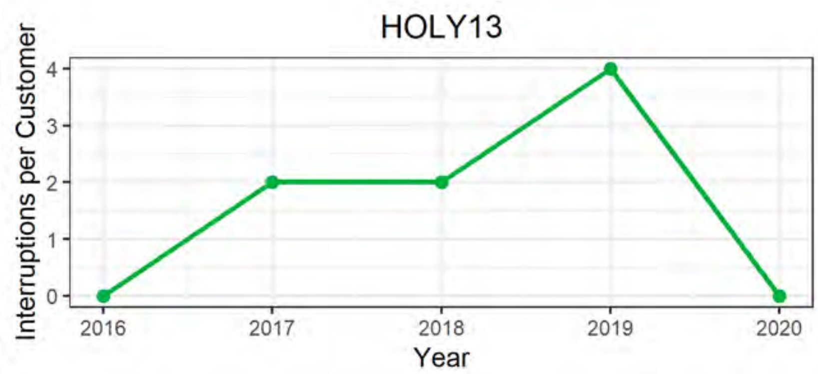

HGTN11
Interruptions per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year

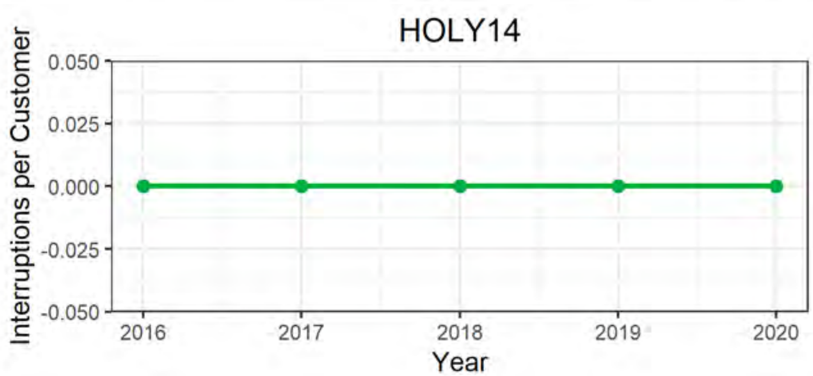

HGTN12
Interruptions per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year

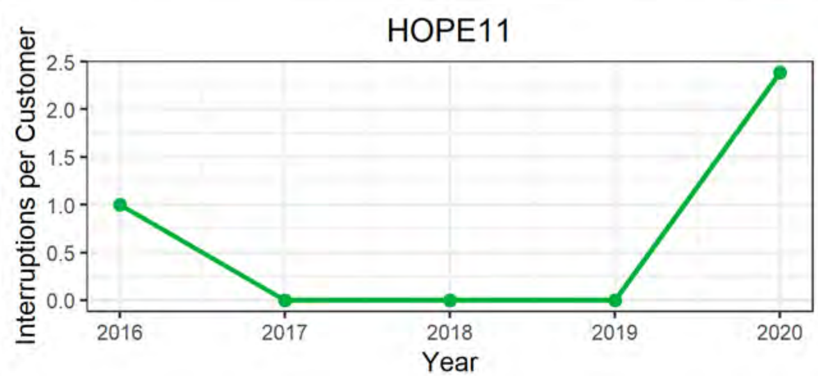

HMDL12
Interruptions per Customer
0
2
4
6
8
2016
2017
2018
2019
2020
Year

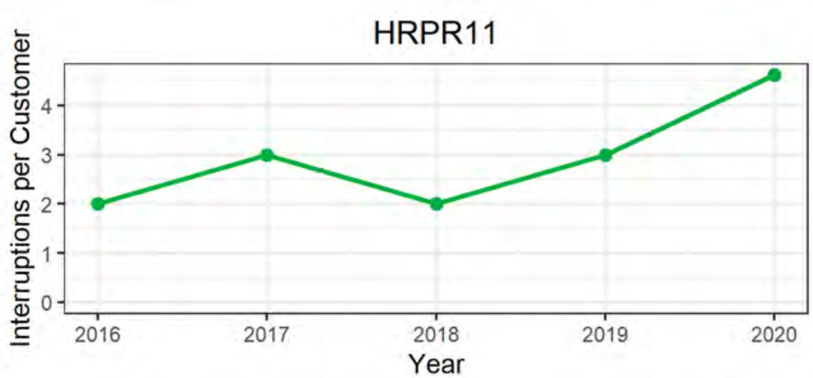

HOLY11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

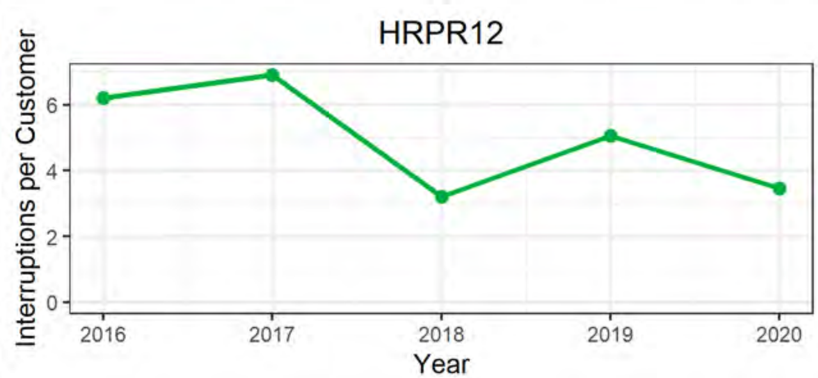

HOLY12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

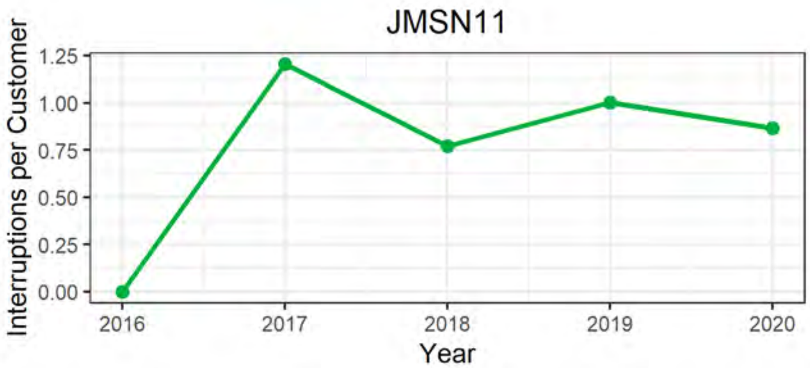

HOLY13
Interruptions per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year

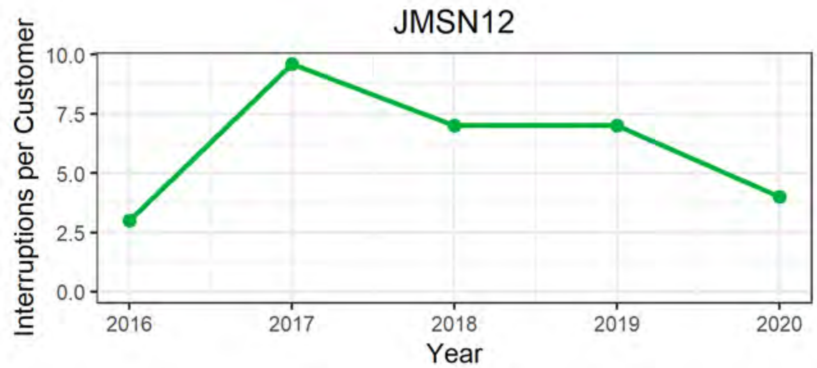

HOLY14
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

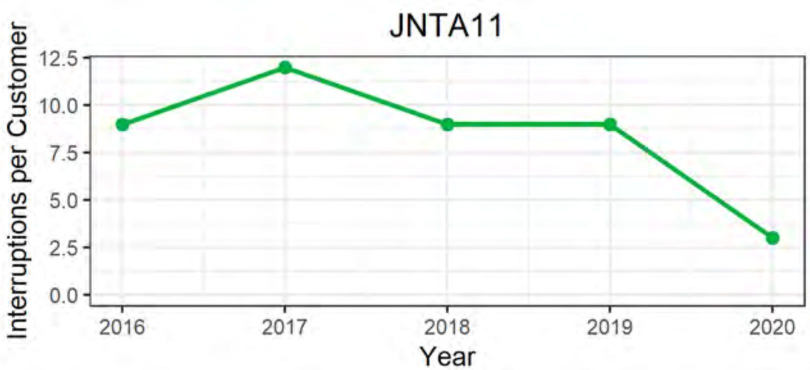

HOPE11
Interruptions per Customer
2.5
2.0
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

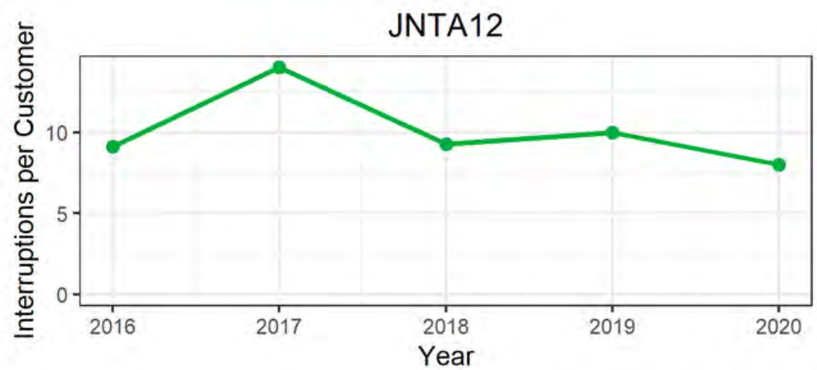

HRPR11
Interruptions per Customer
0
1
2
3
4
2016
2017
2018
2019
2020
Year

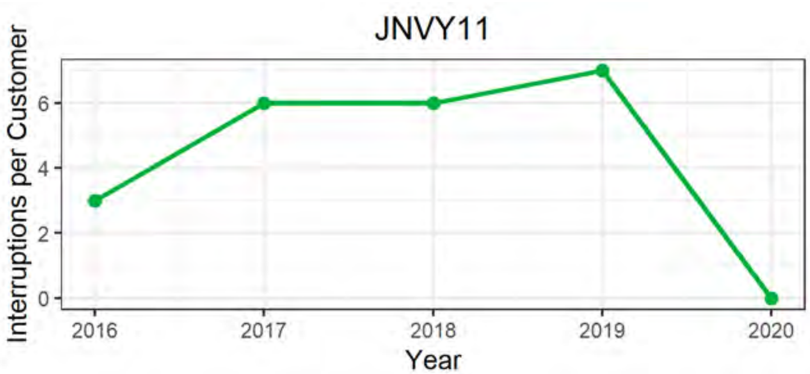

HRPR12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

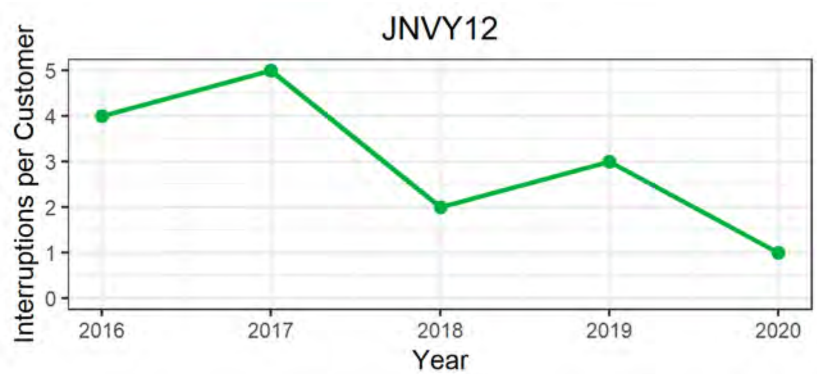

JMSN11
Interruptions per Customer
1.25
1.00
0.75
0.50
0.25
0.00
2016
2017
2018
2019
2020
Year

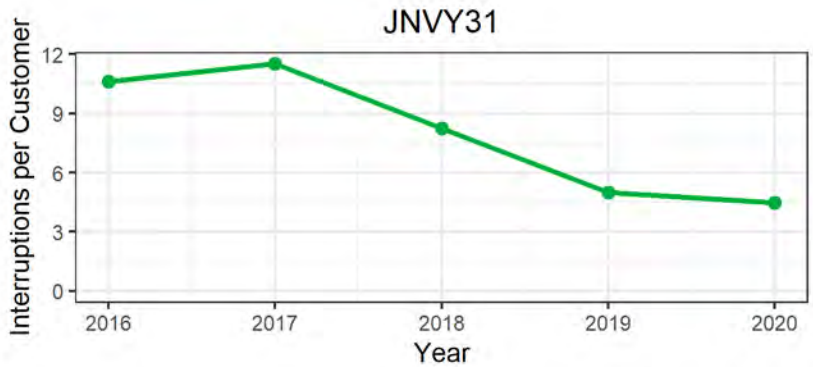

JMSN12
Interruptions per Customer
10.0
7.5
5.0
2.5
0.0
2016
2017
2018
2019
2020
Year

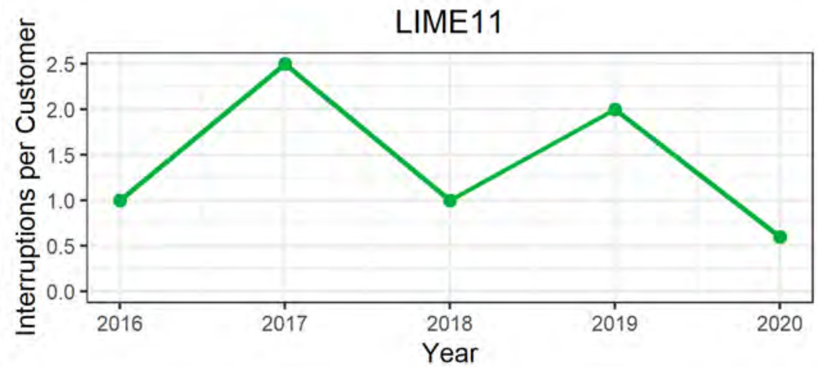

JNTA11
Interruptions per Customer
12.5
10.0
7.5
5.0
2.5
0.0
2016
2017
2018
2019
2020
Year

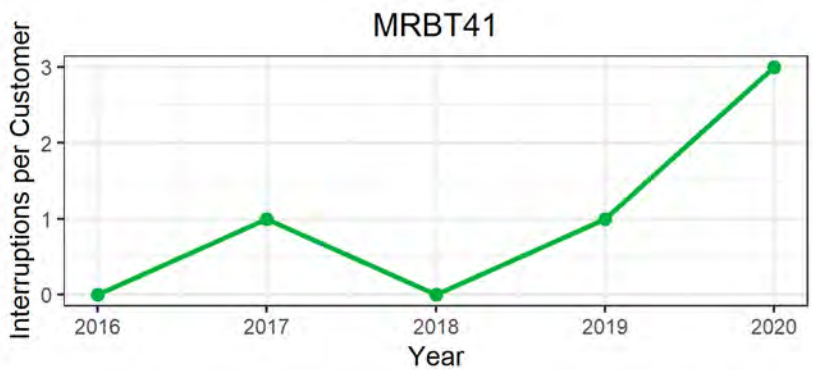

JNTA12
Interruptions per Customer
10
5
0
2016
2017
2018
2019
2020
Year

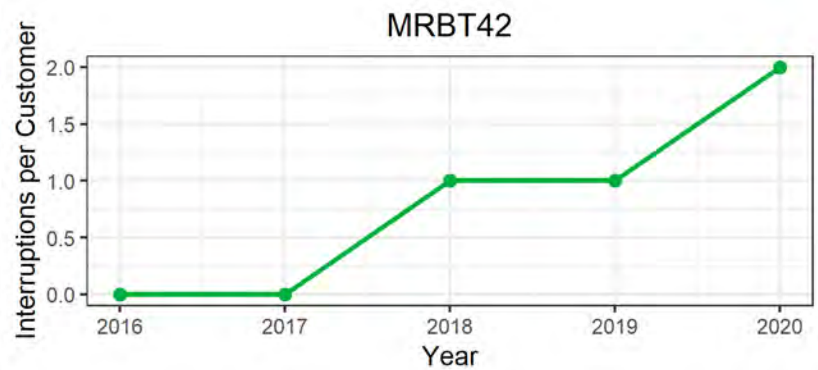

JNVY11
Interruptions per Customer
6
4
2
0
2016
2017
2018
2019
2020
Year

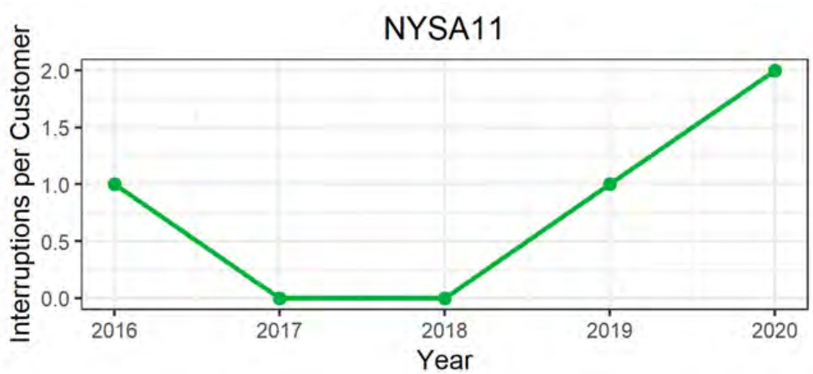

JNVY12
Interruptions per Customer
5
4
3
2
1
0
2016
2017
2018
2019
2020
Year

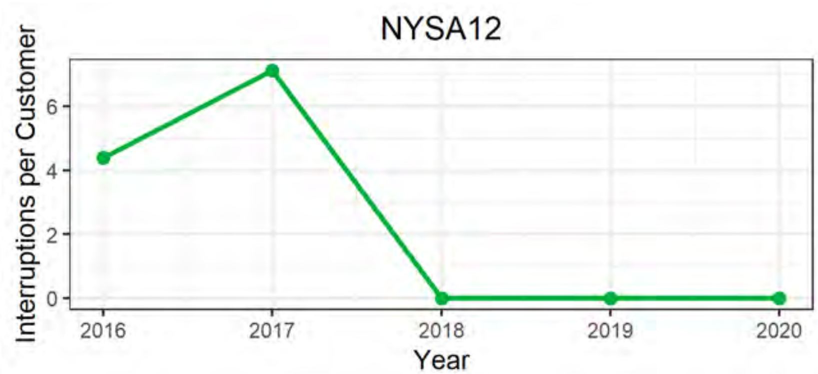

JNVY31
Interruptions per Customer
0
3
6
9
12
2016
2017
2018
2019
2020
Year

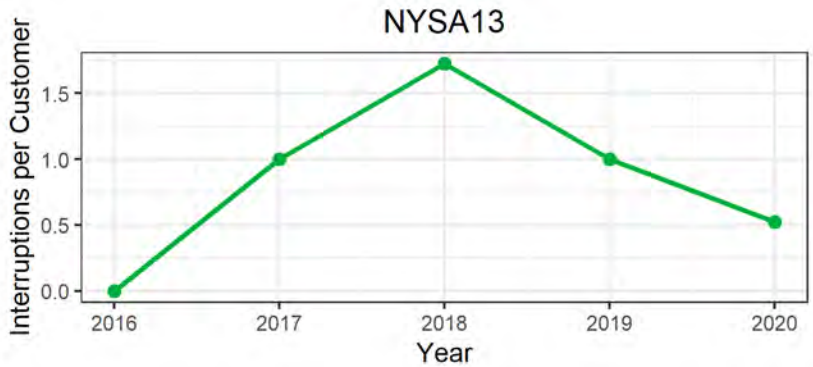

LIME11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2.5
2016
2017
2018
2019
2020
Year

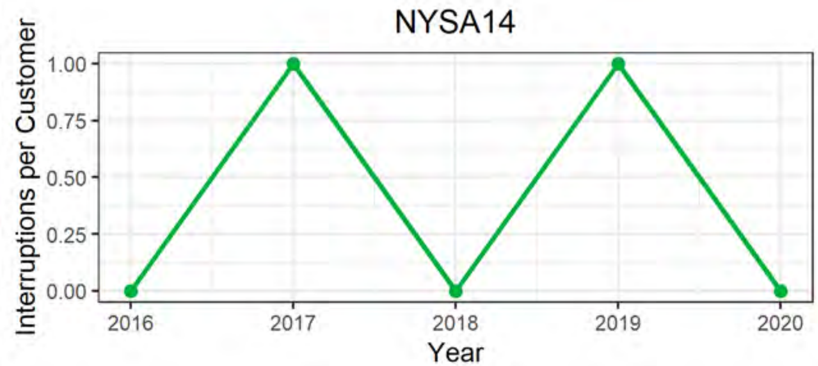

MRBT41
Interruptions per Customer
0
1
2
3
2016
2017
2018
2019
2020
Year


MRBT42
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

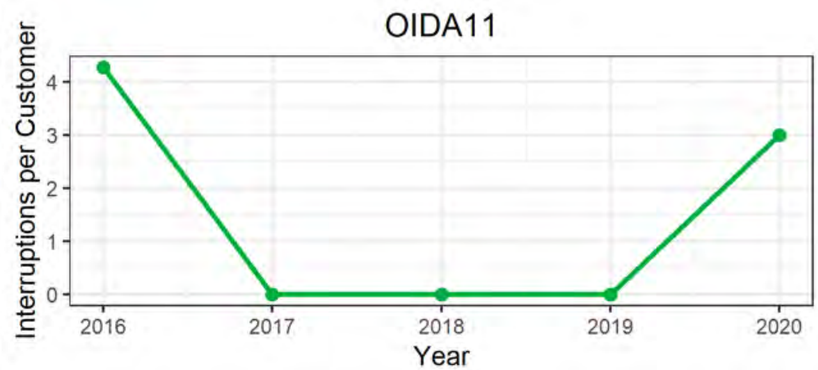

NYSA11
Interruptions per Customer
0.0
0.5
1.0
1.5
2.0
2016
2017
2018
2019
2020
Year

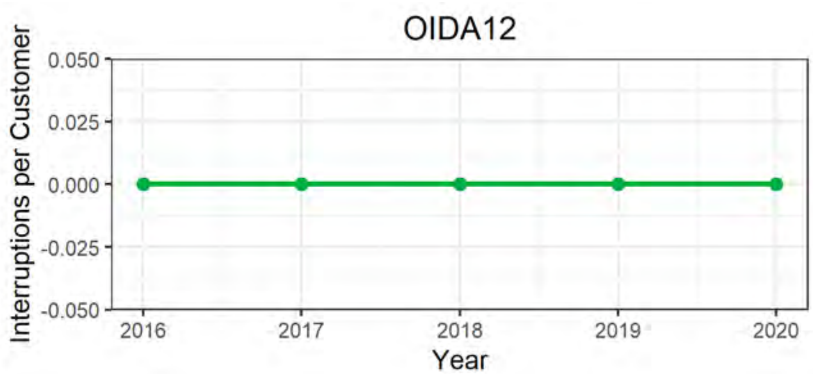

NYSA12
Interruptions per Customer
0
2
4
6
2016
2017
2018
2019
2020
Year

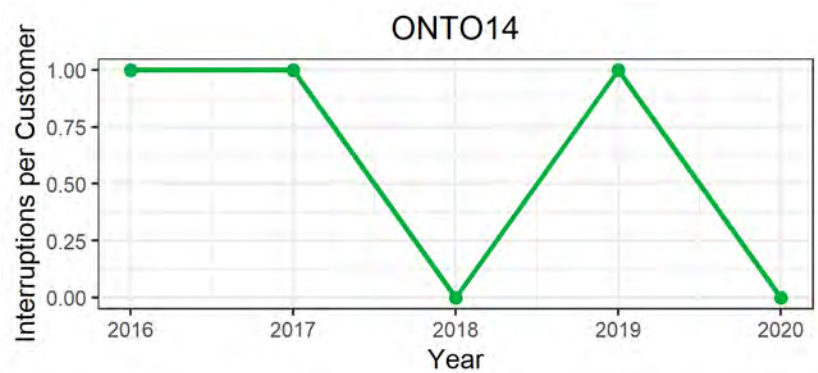

NYSA13
Interruptions per Customer
1.5
1.0
0.5
0.0
2016
2017
2018
2019
2020
Year

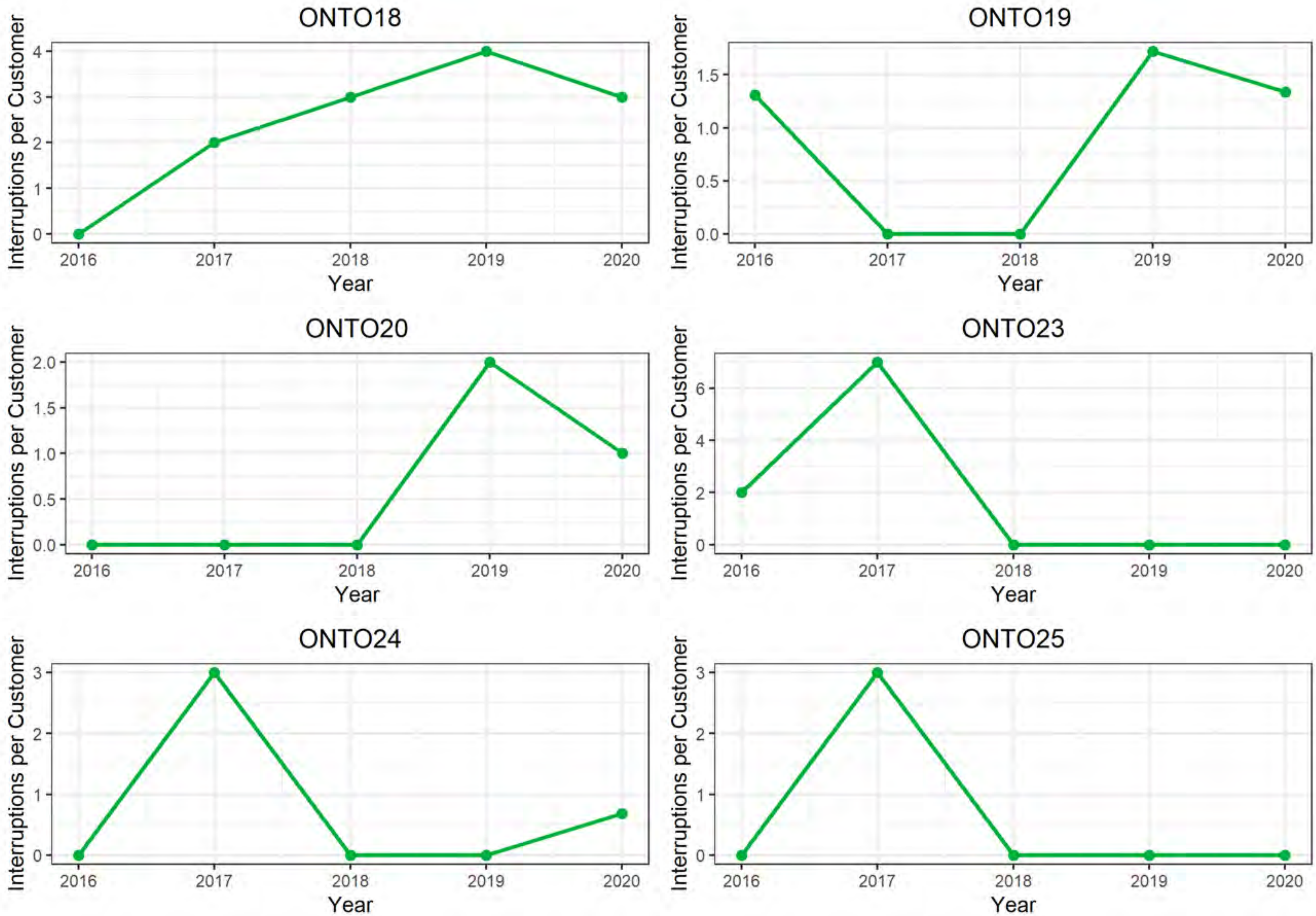

NYSA14
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2016
2017
2018
2019
2020
Year

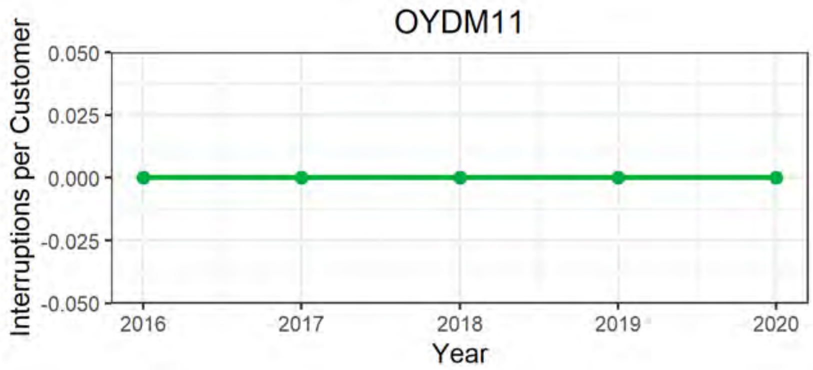

OBPR11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

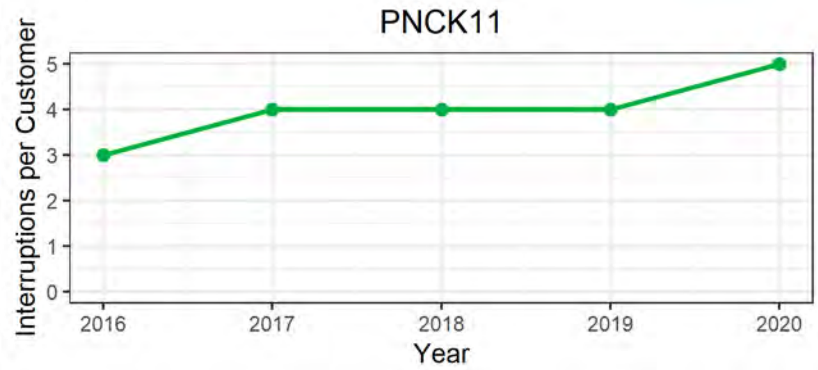

OIDA11
Interruptions per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year

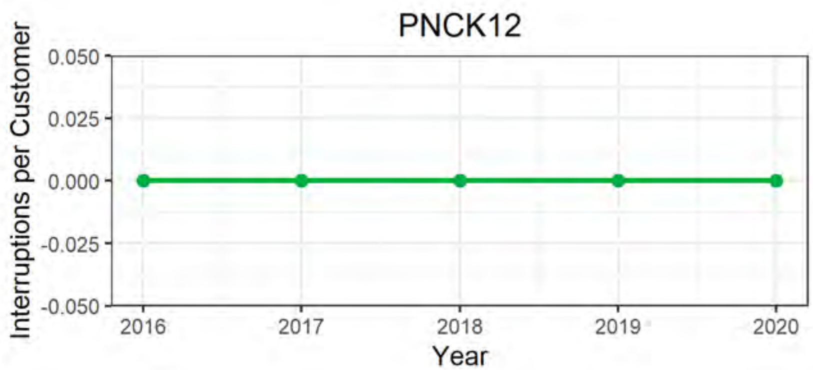

OIDA12
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

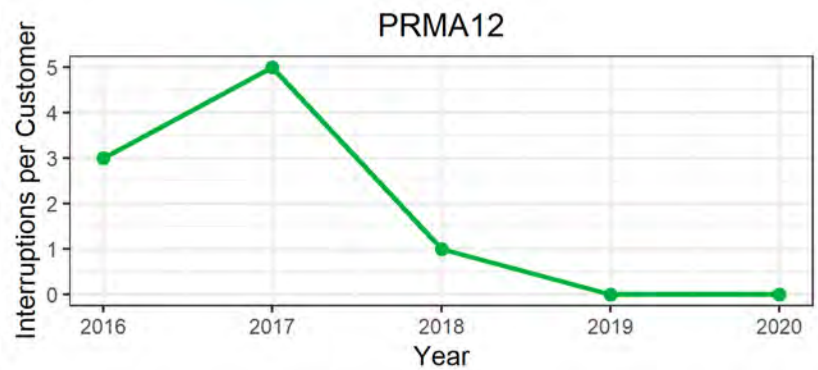

ONTO14
Interruptions per Customer
1.00
0.75
0.50
0.25
0.00
2016
2017
2018
2019
2020
Year

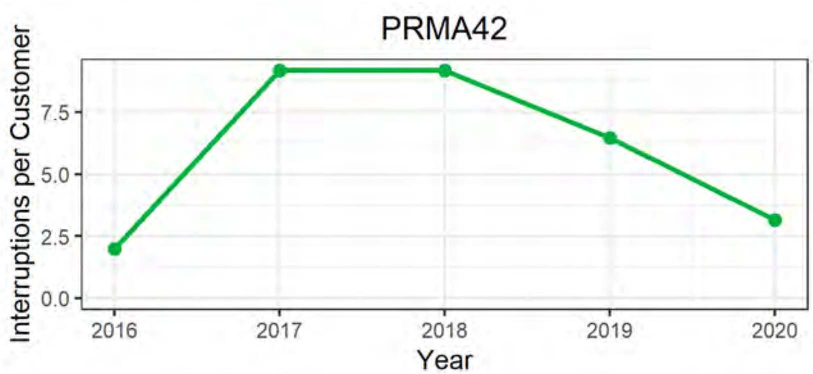

ONTO18
ONTO19
ONTO20
ONTO23
ONTO24
ONTO25
Interruptions per Customer
Year
2016
2017
2018
2019
2020

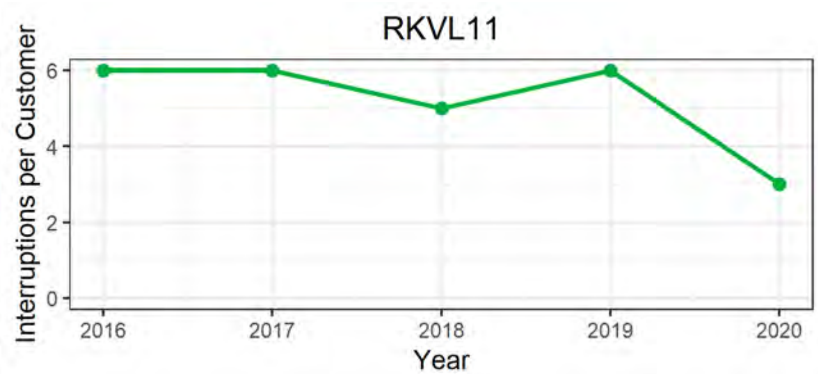

OYDM11
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

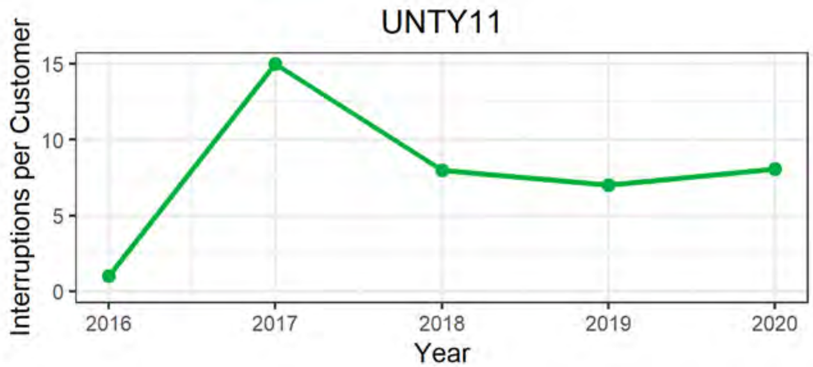

PNCK11
Interruptions per Customer
5
4
3
2
1
0
2016
2017
2018
2019
2020
Year

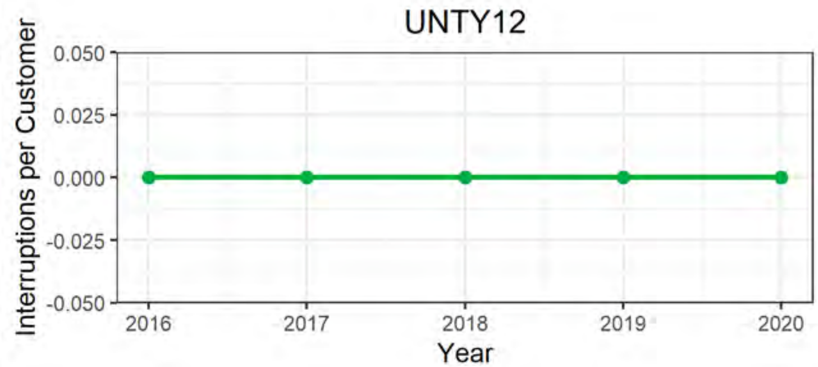

PNCK12
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year

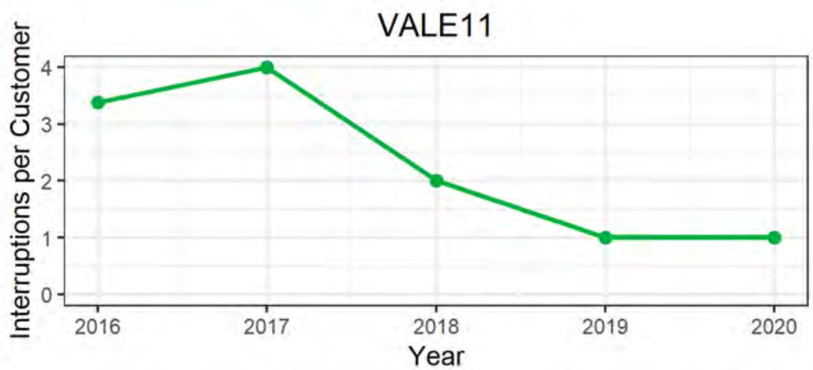

PRMA12
Interruptions per Customer
5
4
3
2
1
0
2016
2017
2018
2019
2020
Year


PRMA42
Interruptions per Customer
7.5
5.0
2.5
0.0
2016
2017
2018
2019
2020
Year

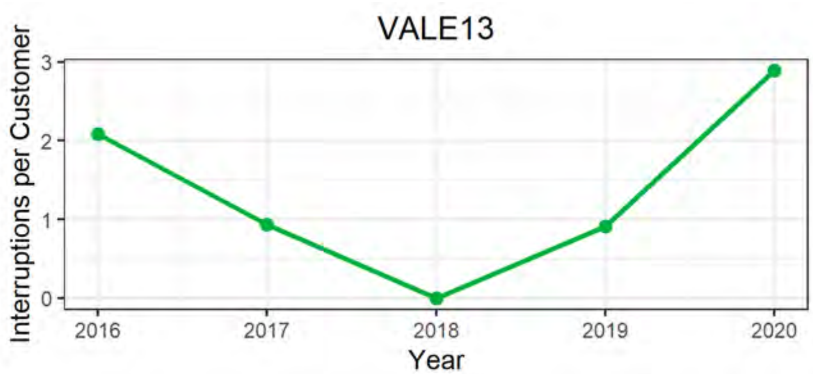

RKVL11
Interruptions per Customer
6
4
2
0
2016
2017
2018
2019
2020
Year

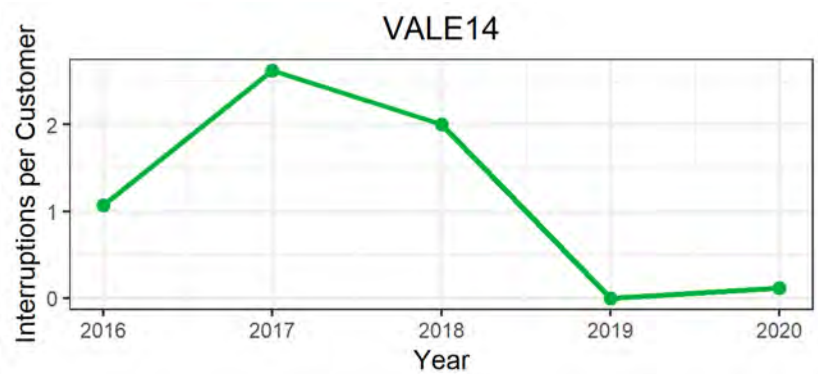

UNTY11
Interruptions per Customer
15
10
5
0
2016
2017
2018
2019
2020
Year


UNTY12
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year


VALE11
Interruptions per Customer
4
3
2
1
0
2016
2017
2018
2019
2020
Year


VALE12
Interruptions per Customer
0.050
0.025
0.000
-0.025
-0.050
2016
2017
2018
2019
2020
Year


VALE13
Interruptions per Customer
3
2
1
0
2016
2017
2018
2019
2020
Year


VALE14
Interruptions per Customer
2
1
0
2016
2017
2018
2019
2020
Year

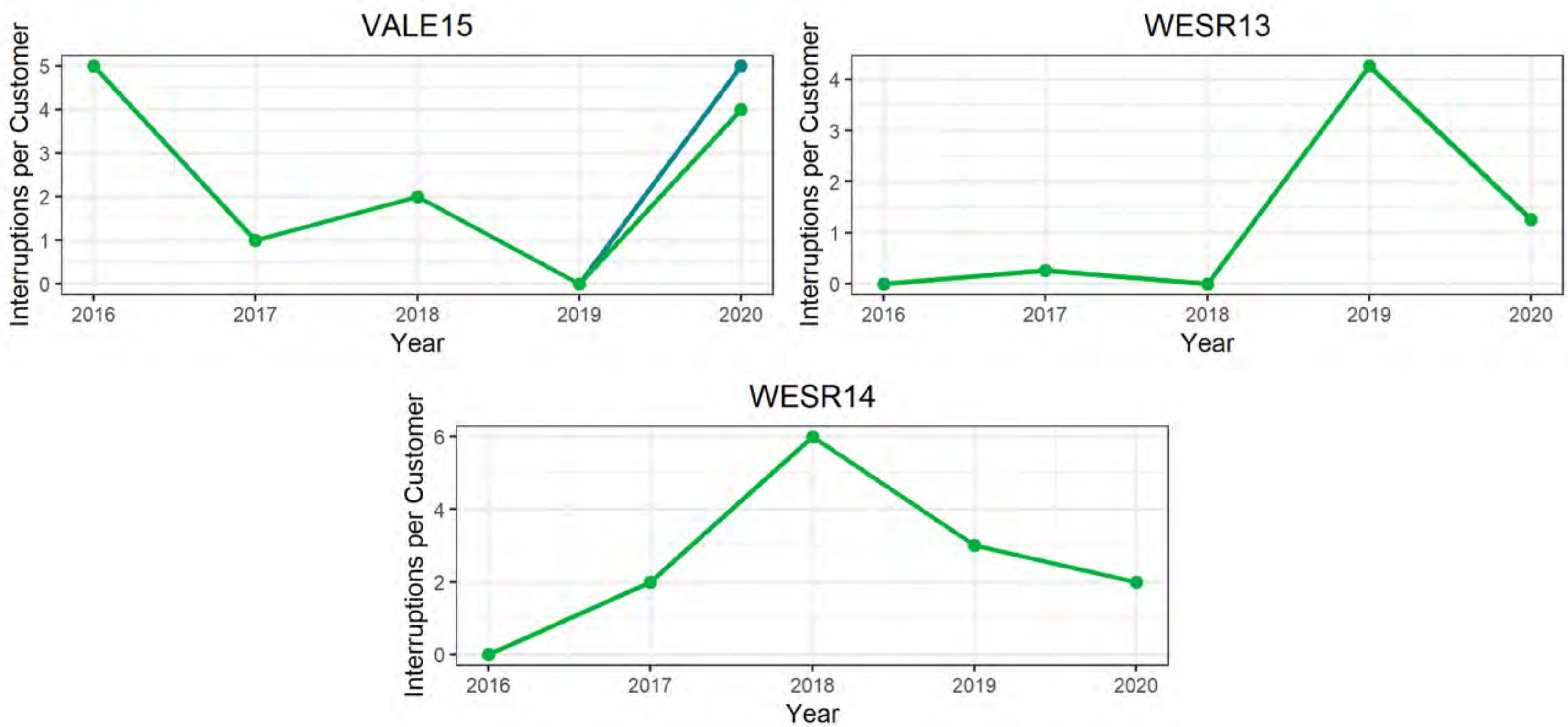


Figure 8 Five Years of Circuit $MAIFI_E$

2020 Descending Indices by Circuit

Circuit	SAIDI	SAIDI MedEx	Circuit	SAIFI	SAIFI MedEx	Circuit	$MAIFI_E$	$MAIFI_E$ MedEx
PNCK11	27.39	27.39	RKVL11	5.22	5.22	HFWY12	17.00	17.00
JNVY31	19.07	19.07	PNCK11	4.82	4.82	UNTY11	8.05	8.05
RKVL11	17.07	17.07	JNVY31	4.57	4.57	JNTA12	8.00	8.00
JNVY11	17.02	17.02	HRPR11	4.42	4.42	CARO11	5.43	5.43
JNVY12	16.29	16.29	JNVY11	4.14	4.14	HOLY12	5.00	5.00
HRPR11	14.32	14.32	DWSY11	4.06	4.06	PNCK11	5.00	5.00
DWSY11	13.44	13.44	ESTN11	4.00	4.00	VALE15	5.00	5.00
JNTA12	12.08	12.08	JNVY12	3.86	3.86	HRPR11	4.63	4.63
ESTN11	11.40	11.40	HRPR12	3.68	3.68	DWSY11	4.48	4.48
CWVY11	11.00	11.00	JNTA12	3.19	3.19	JNVY31	4.46	4.46
CWVY12	10.99	10.99	JNTA11	3.16	3.16	HGTN11	4.00	4.00
JNTA11	10.89	10.89	LIME11	2.33	2.33	HGTN12	4.00	4.00
HRPR12	9.70	9.70	CWVY11	2.17	2.17	JMSN12	4.00	4.00
HFWY12	7.84	0.29	CWVY12	2.15	2.15	CARO12	3.95	3.95
HFWY11	7.36	7.36	PRMA42	2.15	2.15	HRPR12	3.45	3.45
LIME11	6.87	6.87	ADRN11	2.14	2.14	PRMA42	3.15	3.15
UNTY12	6.85	6.85	UNTY11	2.10	2.10	DRKE11	3.00	3.00
HOPE11	6.11	6.11	MRBT41	2.03	2.03	JNTA11	3.00	3.00
UNTY11	5.99	5.99	JMSN11	1.88	1.88	MRBT41	3.00	3.00
PRMA42	5.95	5.95	VALE14	1.67	1.67	OIDA11	3.00	3.00
PNCK12	4.48	4.48	UNTY12	1.65	1.65	ONTO18	3.00	3.00
MRBT41	4.15	4.15	OIDA11	1.63	1.63	RKVL11	3.00	3.00
CARO11	3.89	3.89	HFWY11	1.39	1.39	VALE13	2.89	2.89
HGTN11	3.88	3.88	HOPE11	1.32	1.32	HOPE11	2.39	2.39
ADRN11	3.68	3.68	WESR14	1.29	1.29	ADRN12	2.09	2.09
JMSN11	3.50	3.50	ADRN12	1.29	1.29	ADRN11	2.09	2.09
VALE13	3.42	3.42	DRKE11	1.25	1.25	HMDL12	2.04	2.04
VALE14	3.14	3.14	HMDL12	1.17	1.17	MRBT42	2.00	2.00
HGTN12	3.06	3.06	HFWY12	1.13	0.21	NYSA11	2.00	2.00
DRKE11	2.93	2.93	JMSN12	1.12	1.12	WESR14	2.00	2.00
OIDA11	2.77	2.77	HGTN12	1.06	1.06	HFWY11	1.73	1.73
ADRN12	2.19	2.19	HGTN11	1.06	1.06	ONTO19	1.34	1.34
JMSN12	2.15	2.15	CARO13	1.04	1.04	WESR13	1.26	1.26
WESR14	1.71	1.71	NYSA12	1.02	1.02	JNVY12	1.00	1.00
NYSA13	1.71	1.71	PNCK12	1.00	1.00	ONTO20	1.00	1.00
HMDL12	1.43	1.43	NYSA13	0.78	0.78	VALE11	1.00	1.00
HOLY13	1.08	1.08	HOLY13	0.61	0.61	JMSN11	0.87	0.87
WESR13	1.04	1.04	WESR13	0.61	0.61	ONTO24	0.68	0.68
ONTO20	0.98	0.98	CARO11	0.57	0.57	LIME11	0.60	0.60
HOLY12	0.92	0.92	VALE13	0.54	0.54	NYSA13	0.52	0.52
HOLY11	0.86	0.86	ONTO20	0.49	0.49	VALE14	0.12	0.12
CARO13	0.86	0.86	HOLY11	0.47	0.47	CARO13	0.00	0.00
CARO12	0.66	0.66	HOLY12	0.38	0.38	CWVY11	0.00	0.00
ONTO19	0.55	0.55	ONTO24	0.38	0.38	CWVY12	0.00	0.00
VALE15	0.48	0.48	CARO12	0.30	0.30	DUKE11	0.00	0.00
ONTO24	0.48	0.48	NYSA14	0.23	0.23	ESTN11	0.00	0.00
NYSA14	0.31	0.31	VALE15	0.20	0.20	HCSU11	0.00	0.00
NYSA12	0.20	0.20	ONTO19	0.19	0.19	HOLY11	0.00	0.00
NYSA11	0.10	0.10	NYSA11	0.05	0.05	HOLY13	0.00	0.00
VALE11	0.10	0.10	ONTO25	0.04	0.04	HOLY14	0.00	0.00
ONTO18	0.03	0.03	VALE11	0.03	0.03	JNVY11	0.00	0.00
ONTO25	0.03	0.03	ONTO18	0.02	0.02	NYSA12	0.00	0.00
DUKE11	0.00	0.00	DUKE11	0.00	0.00	NYSA14	0.00	0.00
HCSU11	0.00	0.00	HCSU11	0.00	0.00	OBPR11	0.00	0.00
HOLY14	0.00	0.00	HOLY14	0.00	0.00	OIDA12	0.00	0.00
MRBT41	0.00	0.00	MRBT41	0.00	0.00	ONTO14	0.00	0.00
OBPR11	0.00	0.00	OBPR11	0.00	0.00	ONTO23	0.00	0.00
OIDA12	0.00	0.00	OIDA12	0.00	0.00	ONTO25	0.00	0.00
ONTO14	0.00	0.00	ONTO14	0.00	0.00	OYDM11	0.00	0.00
ONTO23	0.00	0.00	ONTO23	0.00	0.00	PNCK12	0.00	0.00
OYDM11	0.00	0.00	OYDM11	0.00	0.00	PRMA12	0.00	0.00
PRMA12	0.00	0.00	PRMA12	0.00	0.00	UNTY12	0.00	0.00
VALE12	0.00	0.00	VALE12	0.00	0.00	VALE12	0.00	0.00

Table 9 2020 Descending Indices by Circuit

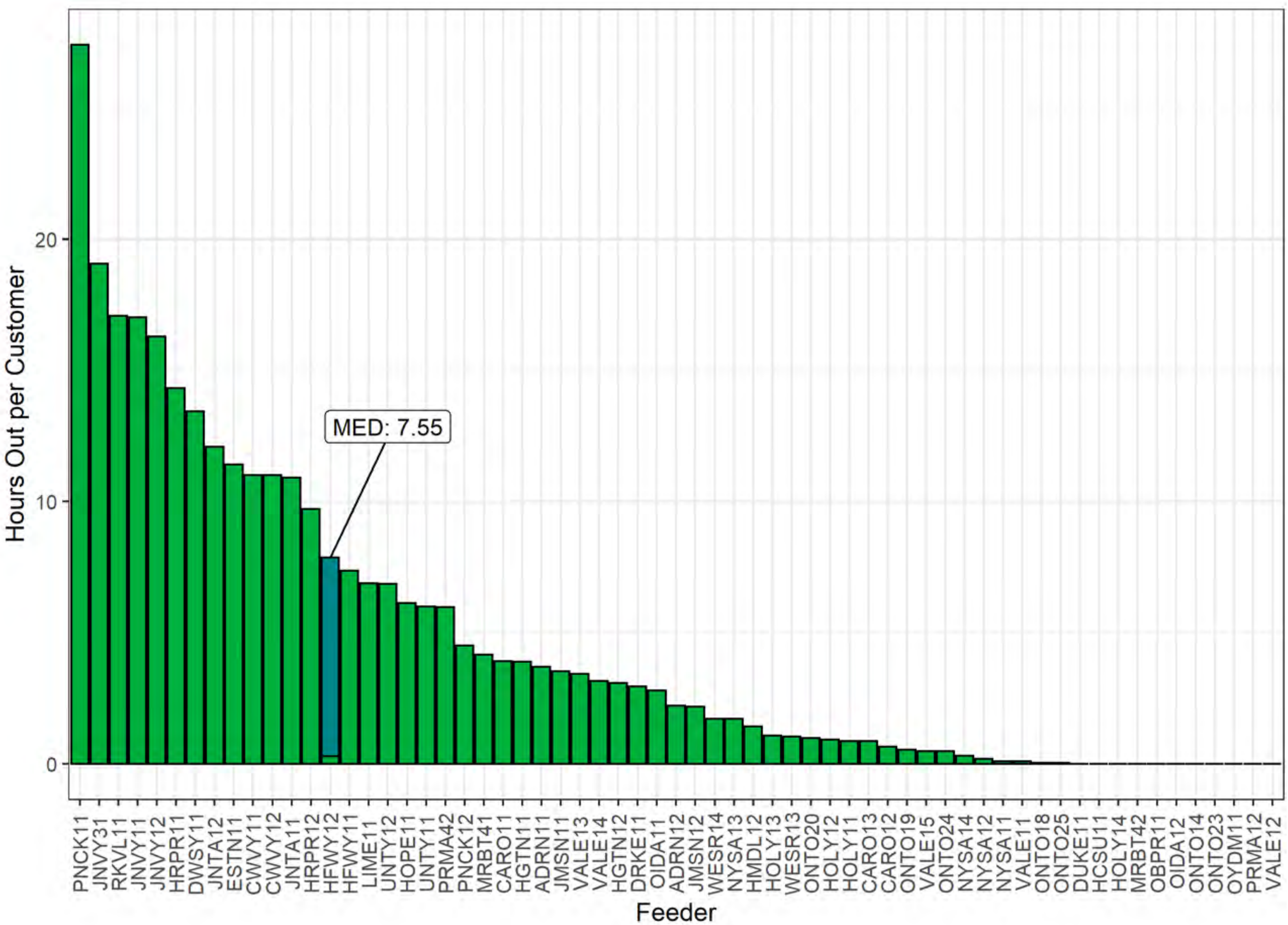


Figure 9 2020 Descending SAIDI by Circuit

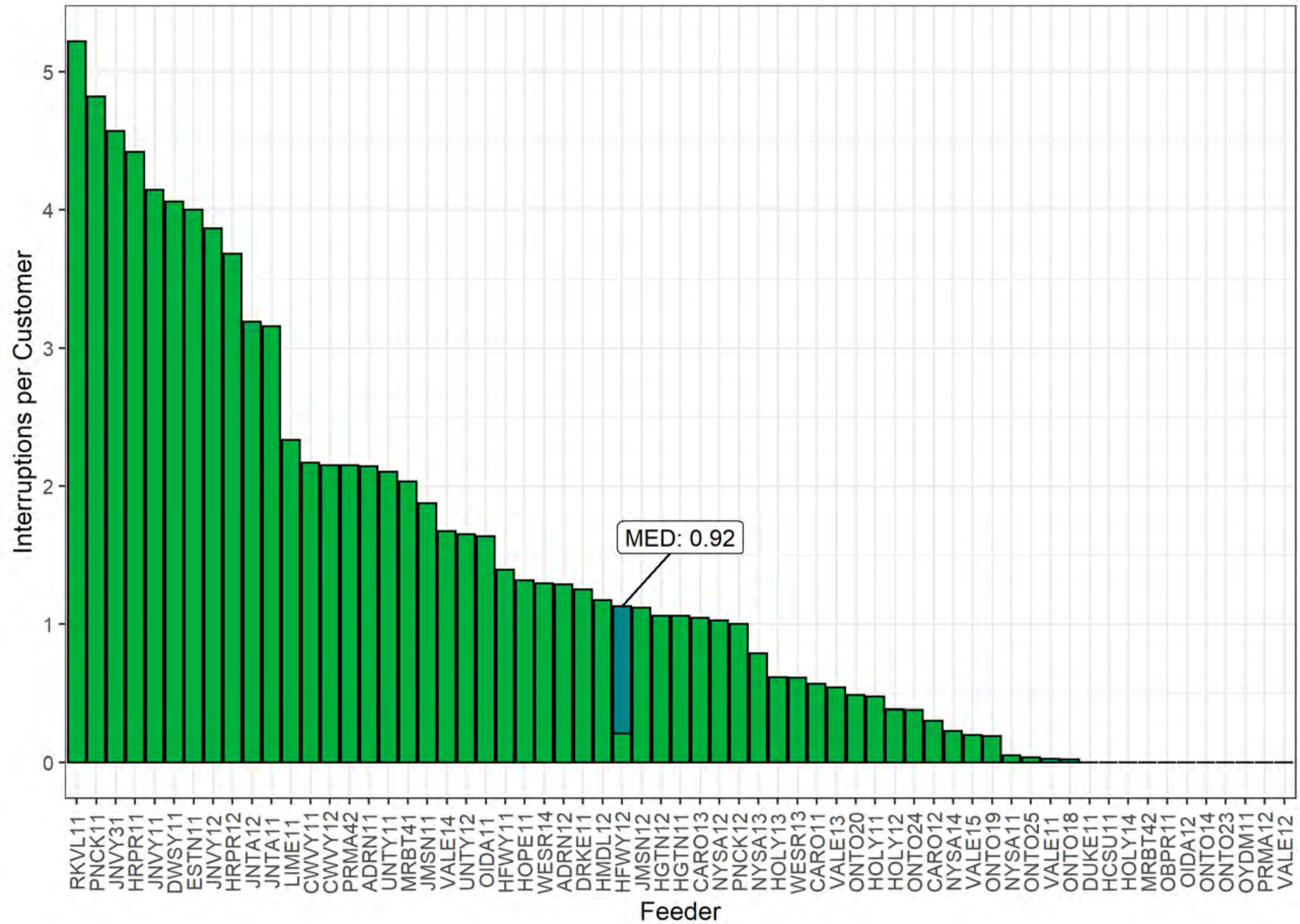


Figure 10 2020 Descending SAIFI by Circuit

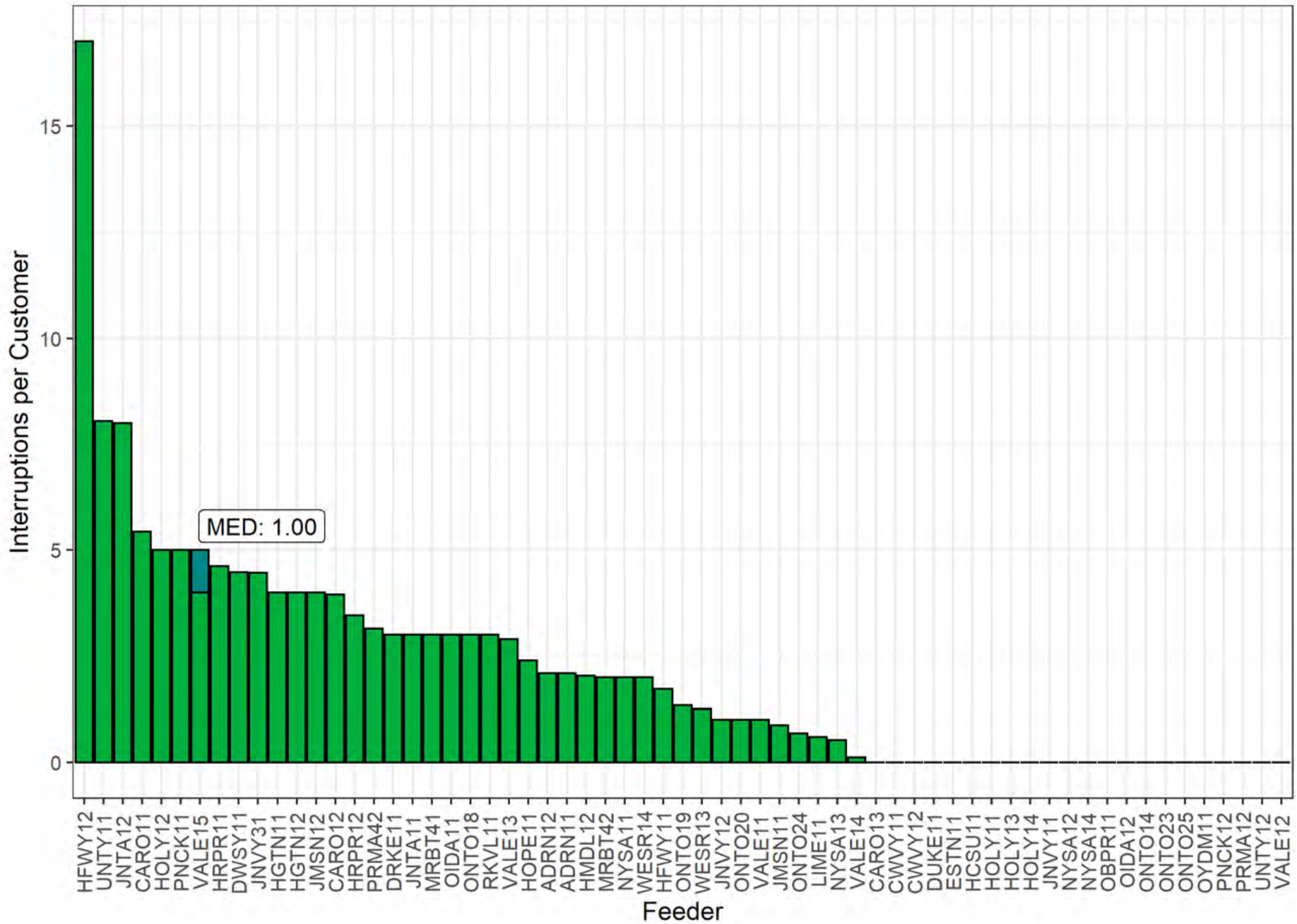


Figure 11 2020 Descending MAIFI$_E$ by Circuit

APPENDIX

Circuit Reference Information

Circuit	Substation	Operating Area	Voltage (kV)	Customers*
ADRN11	Adrian	Western	12.5	411
ADRN12	Adrian	Western	12.5	612
CARO11	Cairo	Western	12.5	1,229
CARO12	Cairo	Western	12.5	90
CARO13	Cairo	Western	12.5	740
CWVY11	Cow Valley	Western	12.5	42
CWVY12	Cow Valley	Western	12.5	112
DRKE11	Durkee	Western	12.5	164
DUKE11	Duke	Western	12.5	29
DWSY11	Drewsey	Western	12.5	185
ESTN11	Easton	Western	12.5	3
HCSU11	Hells Canyon	Western	12.5	2
HFWY11	Halfway	Western	12.5	774
HFWY12	Halfway	Western	12.5	555
HGTN11	Huntington	Western	12.5	88
HGTN12	Huntington	Western	12.5	310
HMDL12	Homedale	Canyon	12.5	146
HOLY11	Holly	Western	12.5	197
HOLY12	Holly	Western	12.5	79
HOLY13	Holly	Western	12.5	171
HOLY14	Holly	Western	12.5	5
HOPE11	Hope	Western	12.5	152
HRPR11	Harper	Western	12.5	110
HRPR12	Harper	Western	12.5	187
JMSN11	Jamieson	Western	12.5	401
JMSN12	Jamieson	Western	12.5	238
JNTA11	Juntura	Western	12.5	63
JNTA12	Juntura	Western	12.5	52
JNVY11	Jordan Valley	Canyon	12.5	90
JNVY12	Jordan Valley	Canyon	12.5	117
JNVY31	Jordan Valley	Canyon	25	347
LIME11	Lime	Western	12.5	120
MRBT41	Malheur Butte	Western	34.5	31
MRBT42	Malheur Butte	Western	34.5	11
NYSA11	Nyssa	Western	12.5	856
NYSA12	Nyssa	Western	12.5	336
NYSA13	Nyssa	Western	12.5	752
NYSA14	Nyssa	Western	12.5	253
OBPR11	Oxbow	Western	12.5	1
OIDA11	Ore-Ida	Western	12.5	672
OIDA12	Ore-Ida	Western	12.5	1
ONTO14	Ontario	Western	12.5	35
ONTO18	Ontario	Western	12.5	870
ONTO19	Ontario	Western	12.5	1,845
ONTO20	Ontario	Western	12.5	1,214
ONTO23	Ontario	Western	12.5	50
ONTO24	Ontario	Western	12.5	712
ONTO25	Ontario	Western	12.5	504
OYDM11	Owyhee Dam	Western	12.5	15
PNCK11	Pine Creek	Western	12.5	94
PNCK12	Pine Creek	Western	12.5	2
PRMA12	Parma	Western	12.5	3
PRMA42	Parma	Western	34.5	193
RKVL11	Rockville	Canyon	12.5	32
UNTY11	Unity	Western	12.5	147
UNTY12	Unity	Western	12.5	239
VALE11	Vale	Western	12.5	1,043
VALE12	Vale	Western	12.5	55
VALE13	Vale	Western	12.5	574
VALE14	Vale	Western	12.5	310
VALE15	Vale	Western	12.5	476
WESR13	Weiser	Western	12.5	197
WESR14	Weiser	Western	12.5	34

Table 10 Circuit Reference Information

*Some circuits have customers in Idaho and Oregon. The counts are for Oregon customers only as of 12/31/2020.

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
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%
2016	2,131.4	97.9	2,229.3	760.3	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.

2020 Major Event Day System Summary

Date	Cause	Customers	CMI	CI	SAIDI (Minutes)	SAIFI	CAIDI (Minutes)
9/7/2020	Tree/Vegetation	19,326	251,430	510	13.01	0.03	493.00

Table 12 2020 MED System Summary

2020 Major Event Day Feeder Summary

Date	Feeder	Customers	CMI	CI	SAIDI (Minutes)	SAIFI	CAIDI (Minutes)
9/7/2020	HFWY12	546	251,430	510	493.00	0.93	493.00

Table 13 2020 MED Feeder Summary

Five Years of Major Event Days

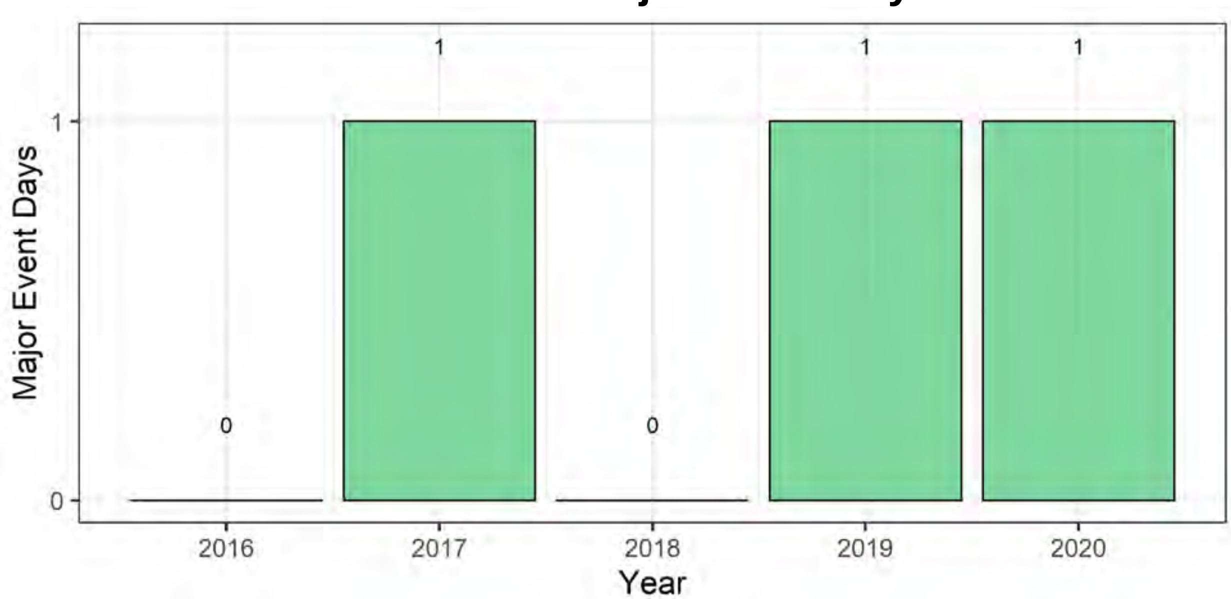


Figure 12 Five Years of MEDs

Cause Category Translation

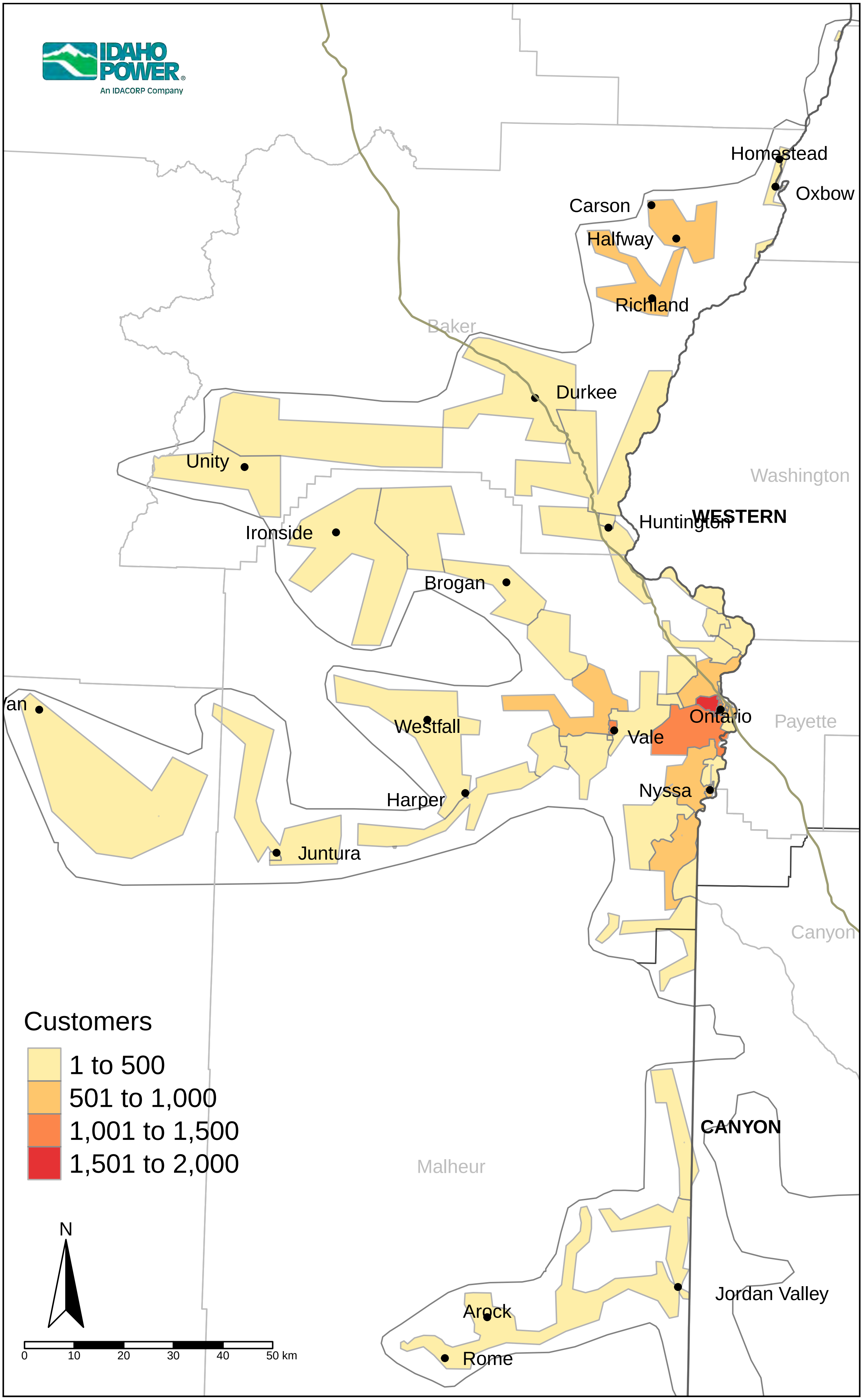
Idaho Power Cause	OAR 860-023-0151 (2)(b) Cause
Loss of Supply – Transmission*	Loss of Supply – Transmission
Loss of Supply – Station*	Loss of Supply – Substation
Corrosion/Rot	Distribution – Equipment
Electrical Failure	Distribution – Equipment
Loose Hardware	Distribution – Equipment
Mechanical Failure	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

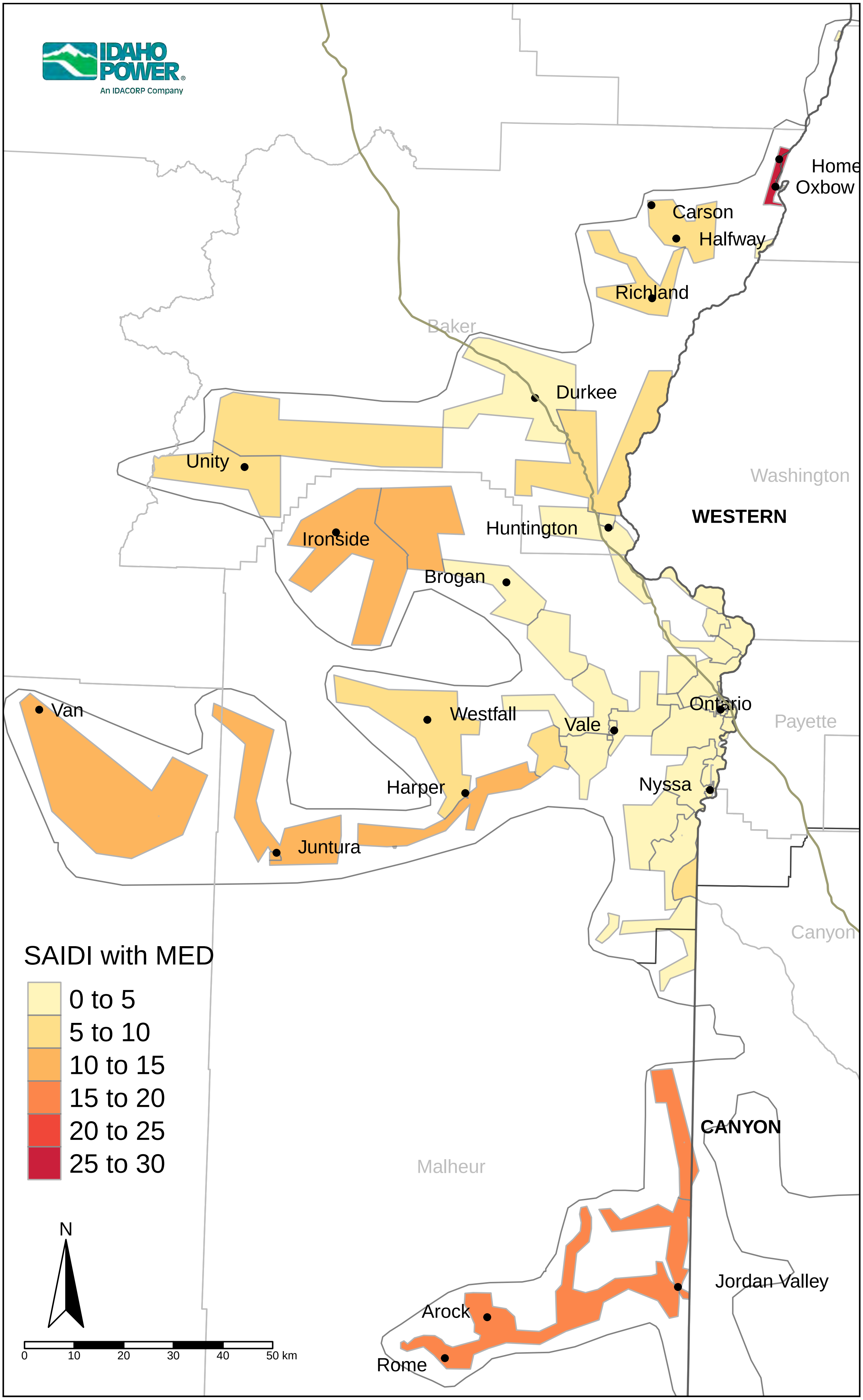
*These are also identified from the Idaho Power SYSTEM field. This field has values for “Transmission”, “Substation”, “Distribution Primary OH”, “Distribution Primary UG”, “Secondary/Service OH” and “Secondary/Service UG”. So, “Loss of Supply – Transmission” in this report includes events where the CAUSE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

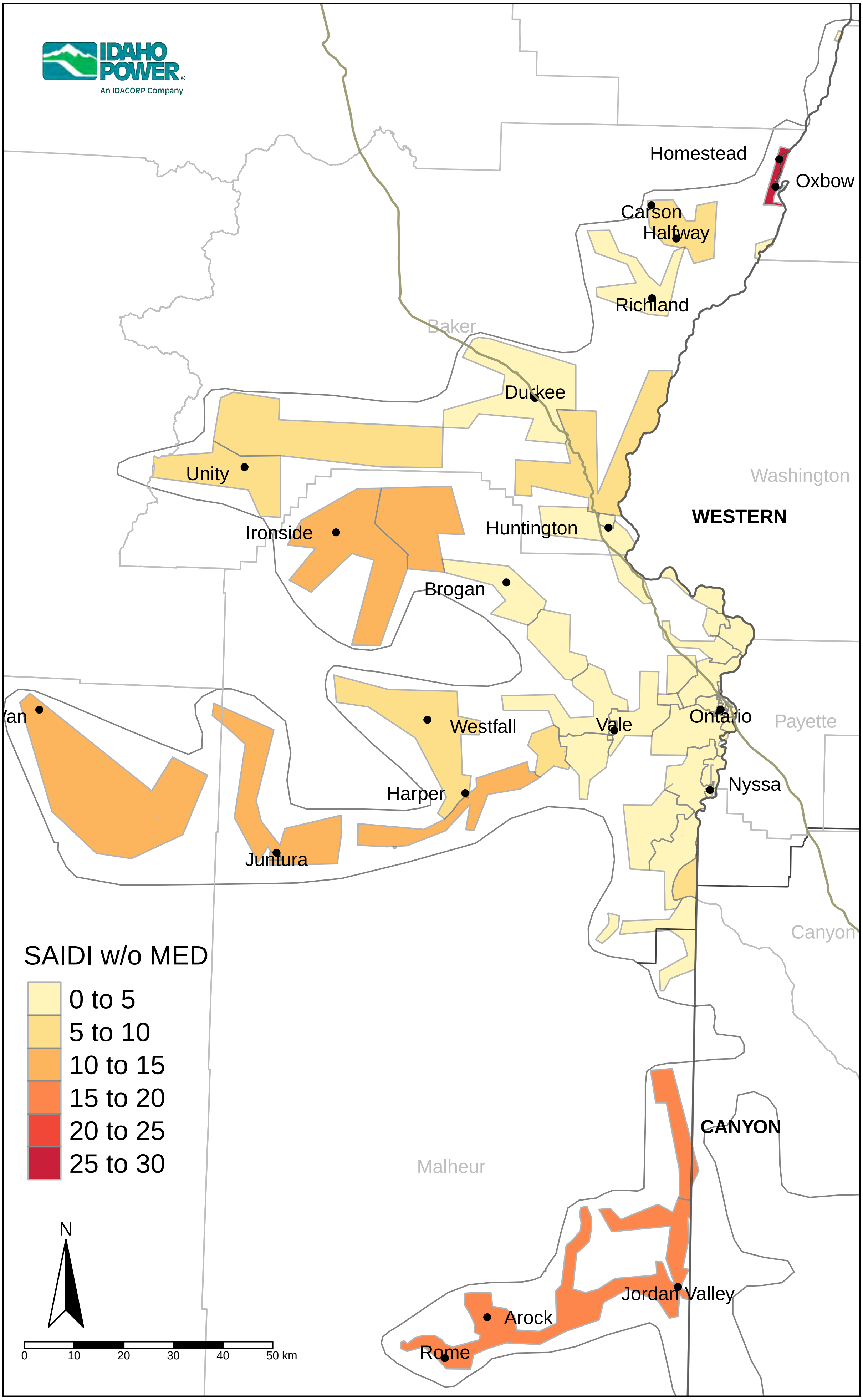
2020 Customers Oregon Area



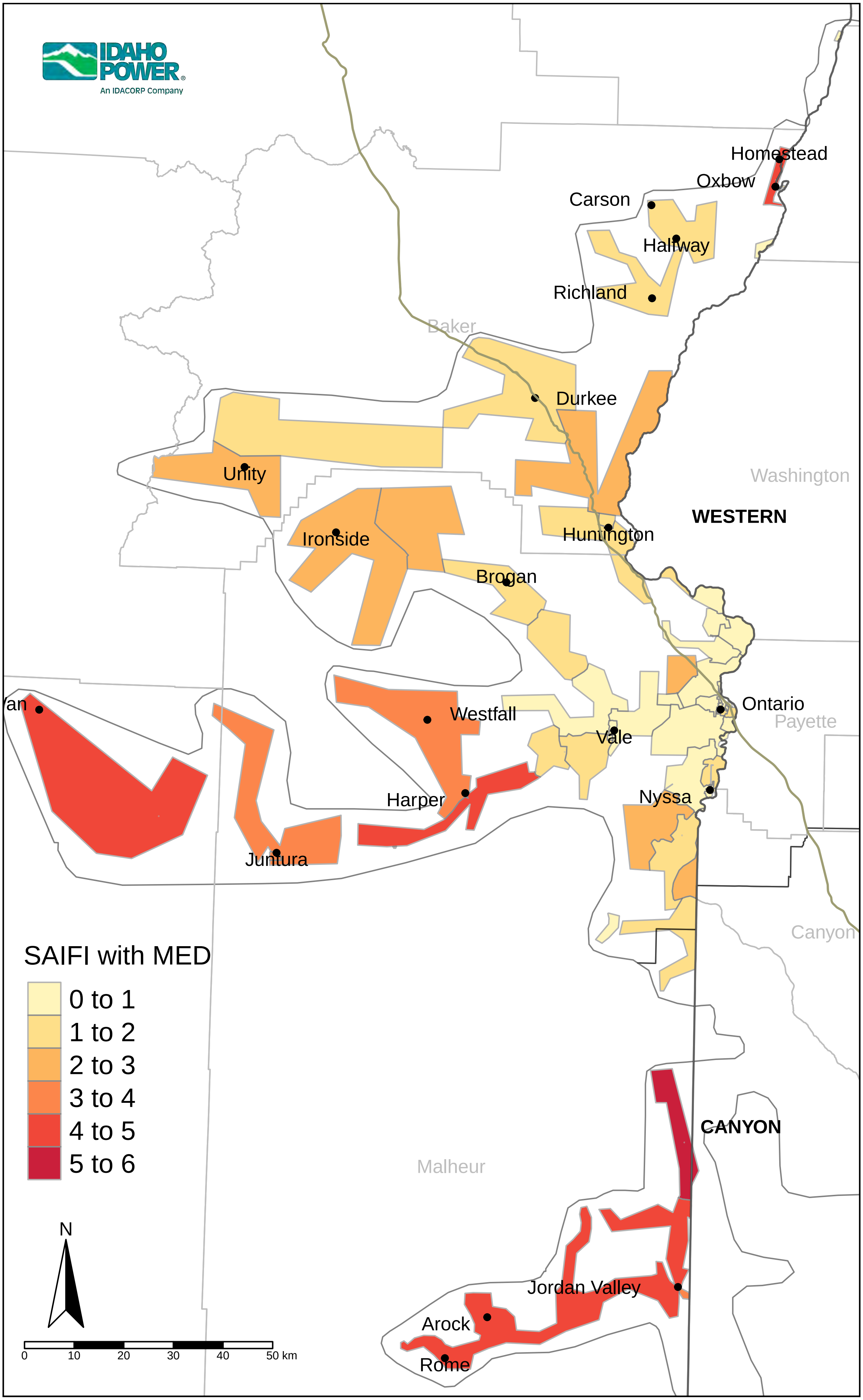
2020 SAIDI with MED Oregon Area



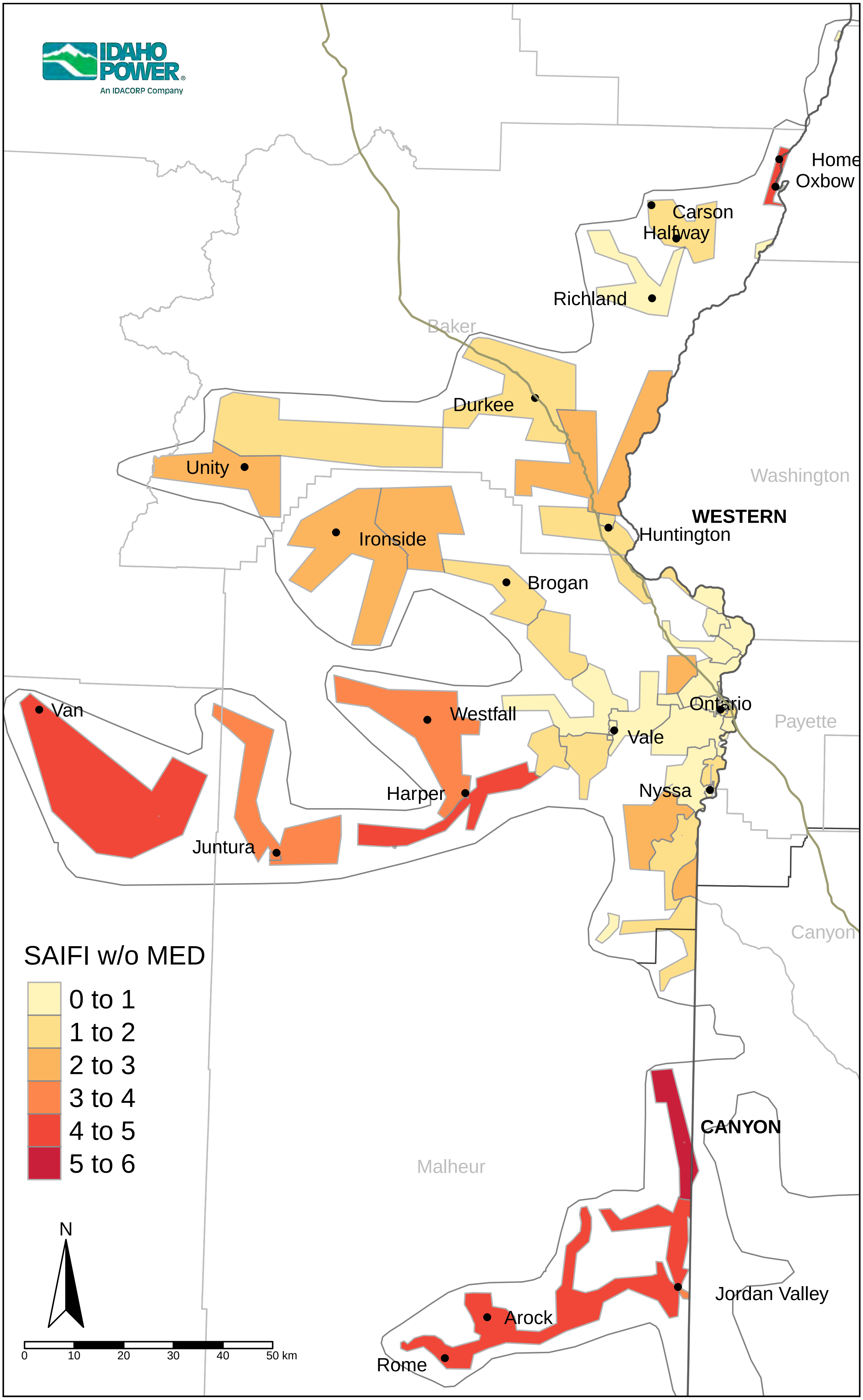
2020 SAIDI w/o MED Oregon Area



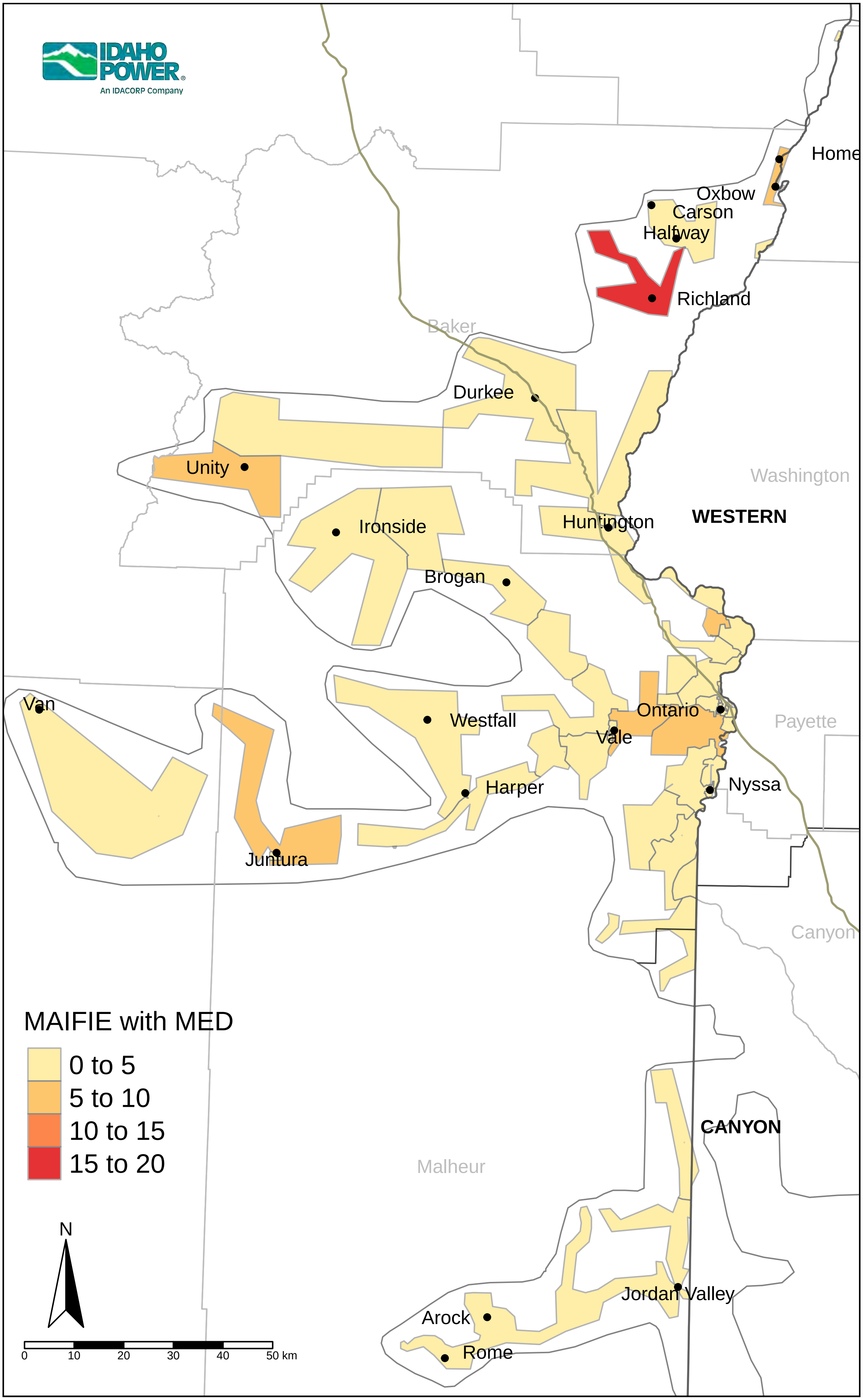
2020 SAIFI with MED Oregon Area



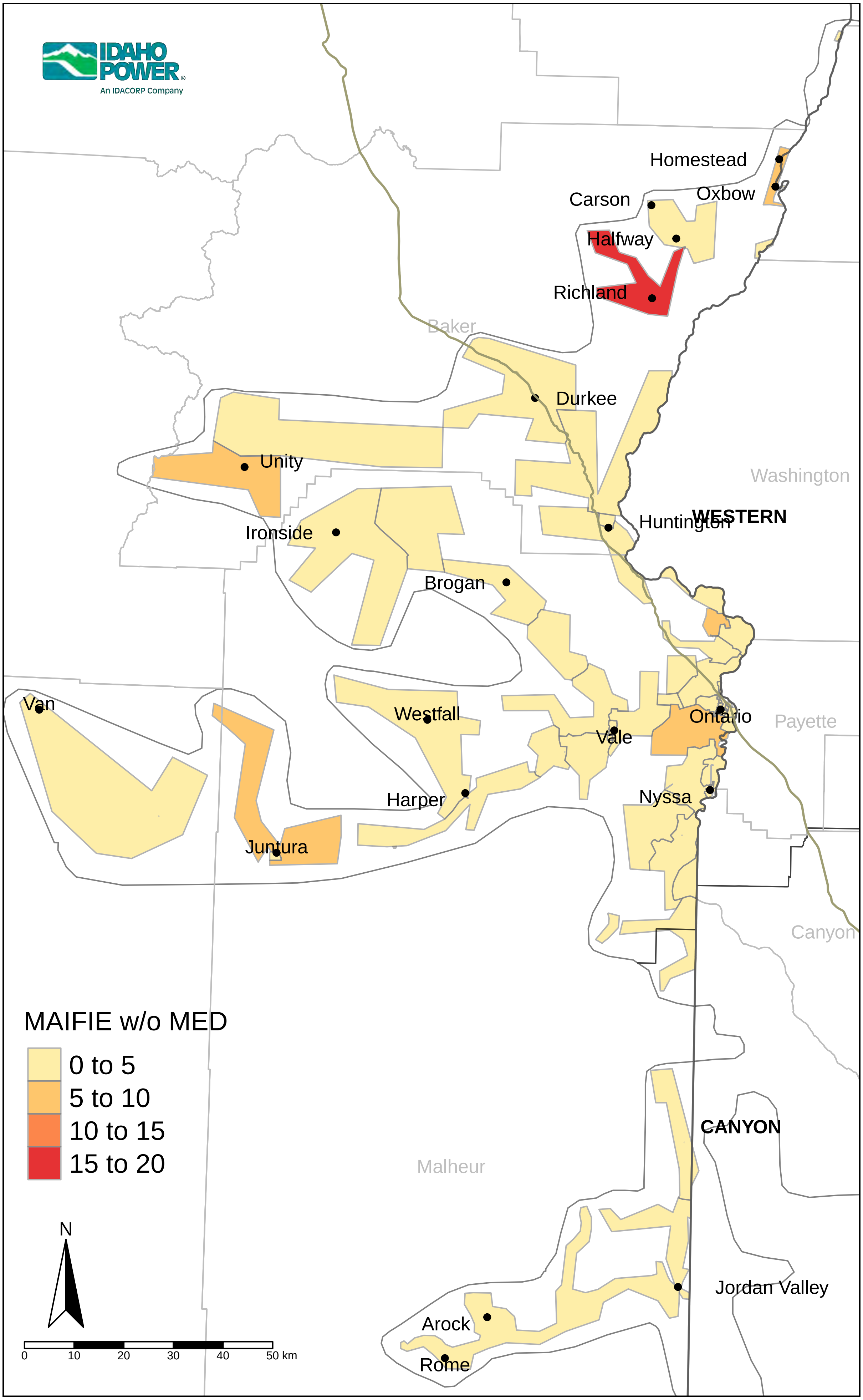
2020 SAIFI w/o MED Oregon Area



2020 MAIFIE with MED Oregon Area



2020 MAIFIE w/o MED Oregon Area



Appendix B: Asset Class Definitions

ASSET CLASS DEFINITIONS

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.

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.

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.

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.

Smart Grid Monitors—These devices are used to monitor voltage on a distribution circuit 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.

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

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

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

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 volts (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.

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

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

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

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.

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

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

Sectionalizers—These devices are used to automatically isolate faulted sections of a distribution circuit 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.

ASSET CLASS DATA AS OF MARCH 2021

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	54.6	70	32	1	0	2	2	4	12	5	3	3		
Circuit Breakers	16.8	50	68	19	3	46								
Electromechanical Relays	47.4	45	44	0	4	1	0	25	6	8				
Microprocessor Relays	10.2	20	80	45	27	8								
Smart Grid Monitors	4.7		182	147	35									
Overhead Transformers	18	30-40	10,009	1,599	1,644	6,698	18	41	4	0	5			
Pad-mounted Transformers	21.8	40-50	879	216	194	236	78	141	13	1				
Distribution Poles	28.5	40-50	38,560	3,059	3,455	18,720	3,695	5,059	3,327	1,007	235	3		
Primary Overhead Line	34.3	40-50	1,988	82	133	917	110	252	257	116	110	10	1	
Primary Underground Line	22.8	40-50	77	14	16	26	9	11						
Meters	8.9	16-20	20,245	6,204	14,041									
Fuses	15	20-30	1,573	353	398	810	7	2	3					
Switches	15	20-30	328	100	63	162	2	1						
Regulators	11.6	20	109	37	56	16								
Capacitors	14.3	30-40	86	33	21	30	1	1						
Reclosers	10.4	50	146	75	50	21								
Sectionalizers	18.2	50	17	3	8	5	0	1						

Appendix C: Idaho Power Company Oregon's Generation Annual Report for 2020

Idaho Power Company's Oregon Generation Annual Report for 2020
860-082-0065(3)

a # complete applications received:

SMALL	0
LARGE	0

b # interconnections completed:

SMALL	4
LARGE	0

c For each Application received:

		IC Type	IC Nameplate
SMALL	n/a		
LARGE	n/a		

d Location by zip code for Proposed and Completed interconnections:

	Completed Facilities	Proposed Facilities
GI 510	97914	
GI 511	97918	
GI 519	97814	
GI 525	97914	

e For each Tier 3 & Tier 4 interconnection approval:

	Basic Telemetry configuration, if applicable
n/a	

f For each Tier 4 interconnection approval:

IC Facilities	Estimated IC Costs	System Upgrades	Total Estimated	Cost Source
n/a				

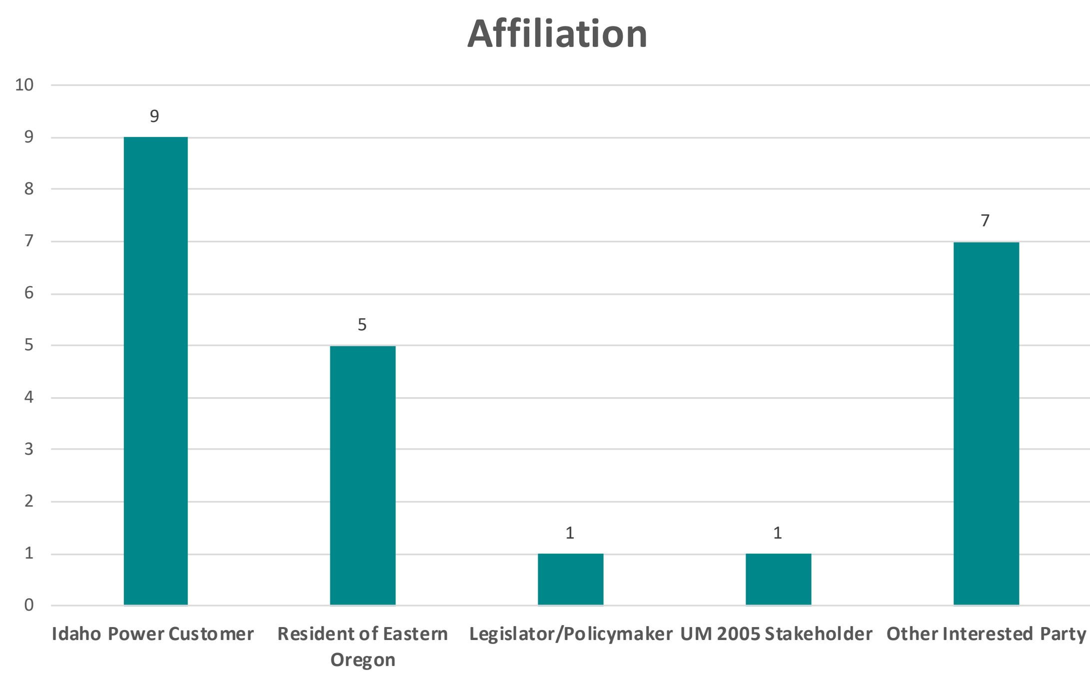
Appendix D: Poll Questions from Workshop 1

POLL QUESTIONS FROM WORKSHOP 1

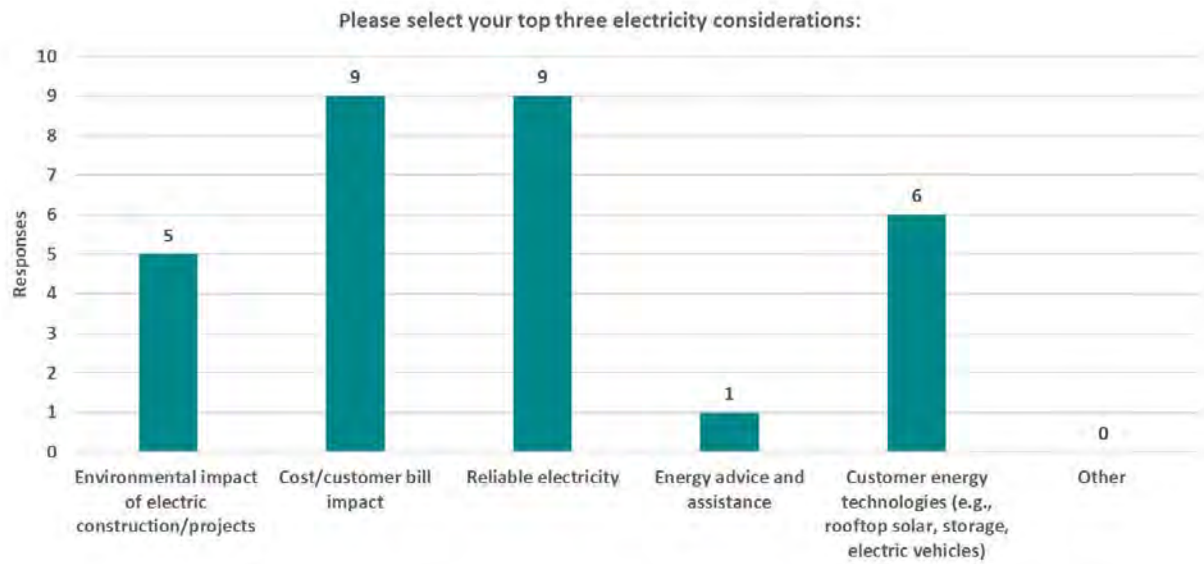
Idaho Power hosted its first community engagement workshop on August 26, 2021. Participants were introduced to the DSP effort with a brief electrical system education session focusing on power, capacity, and energy concepts. The meeting also provided details about the existing distribution system in Idaho Power's eastern Oregon service area.

To create a level of engagement and participation in the virtual setting, workshop participants were asked a series of questions to identify energy-related priorities, items of interest, preferred means of engagement, and DSP-specific topics for future discussion. Results of the poll questions showed that participants' top energy-related objectives are equally divided between cost and reliability. Forward-focused questions identified that participants are interested in learning more about how Idaho Power makes distribution investment decisions, develops and evaluates potential pilot projects, hosting capacity maps, and data sharing/use cases. Complete poll results from Workshop 1 are provided here.

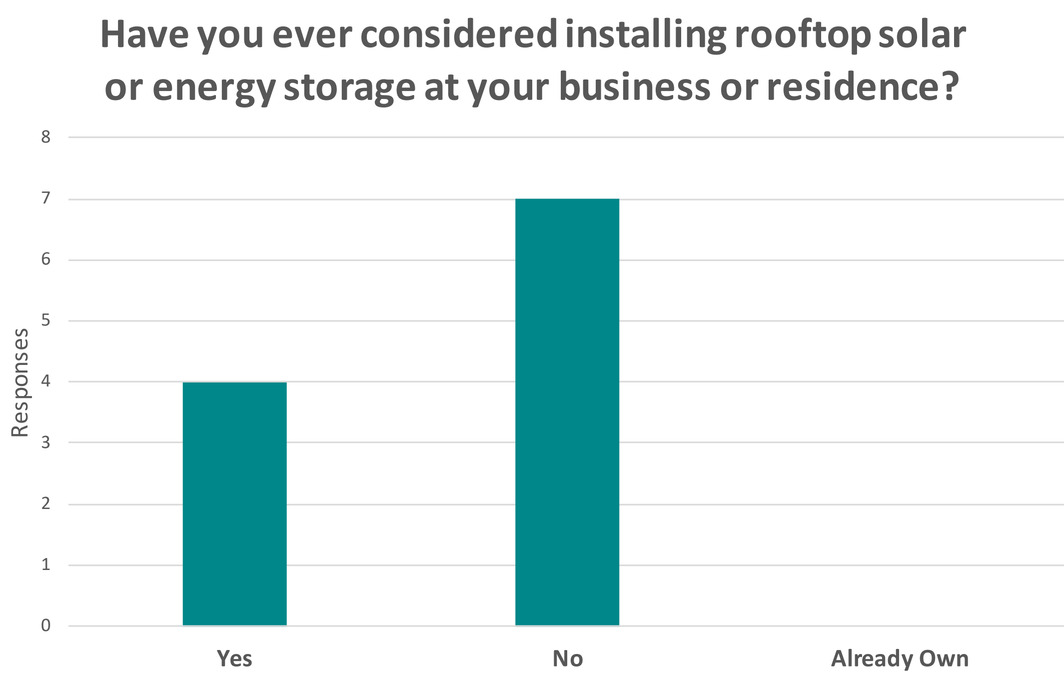
Introduction Question



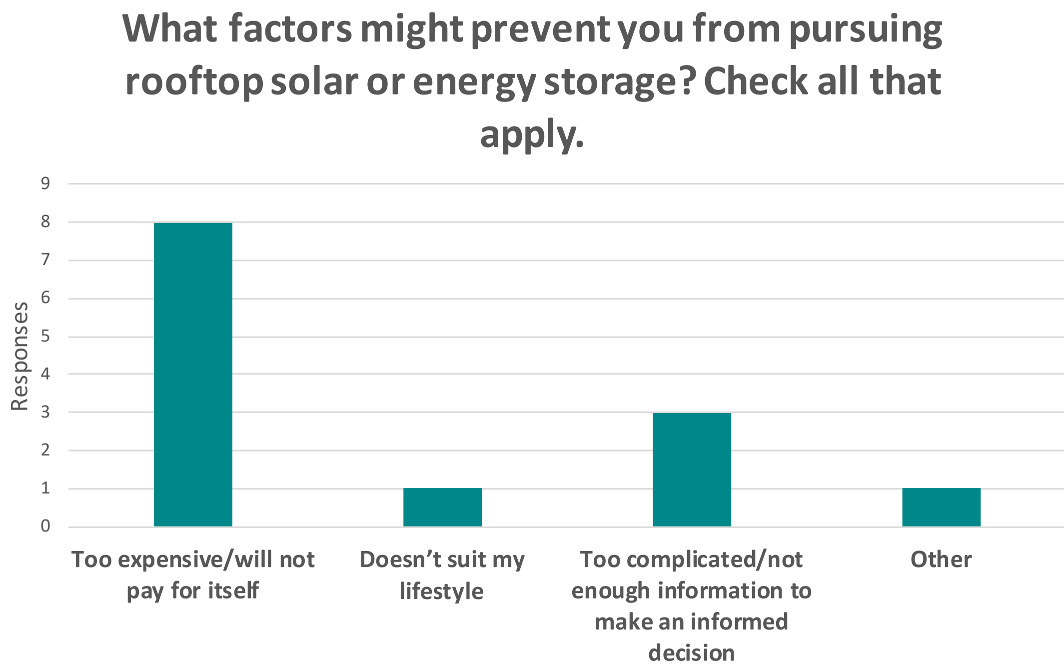
Question 1



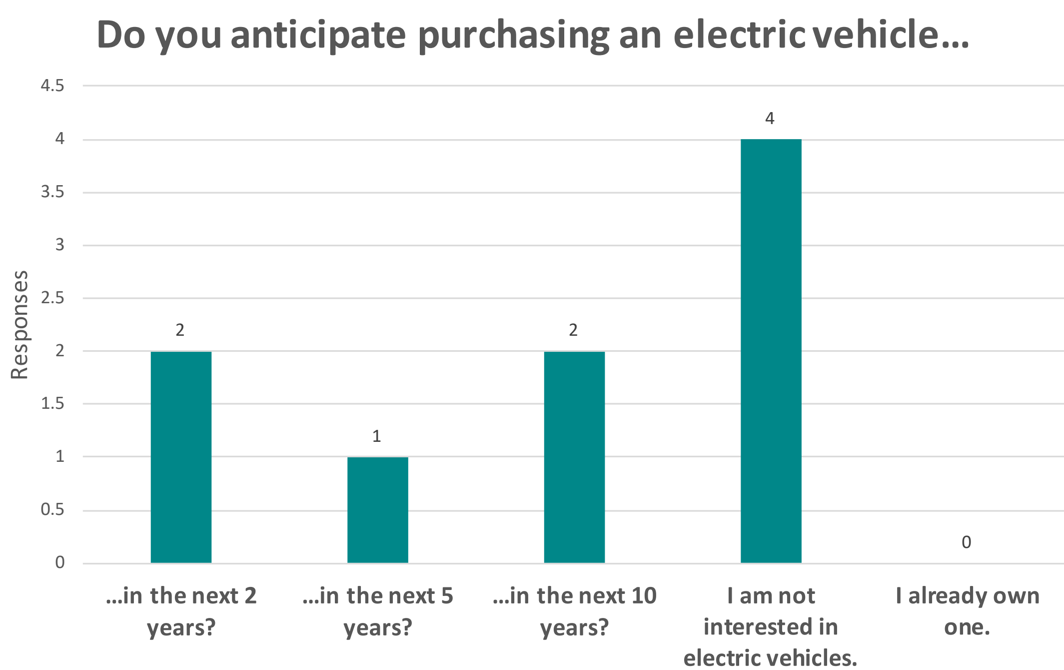
Question 2



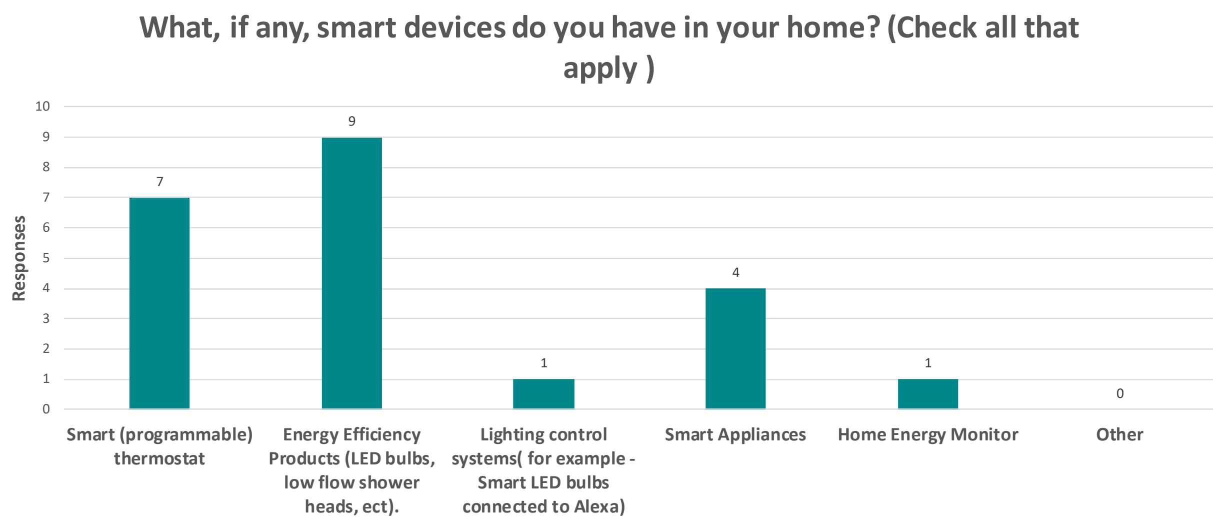
Question 3



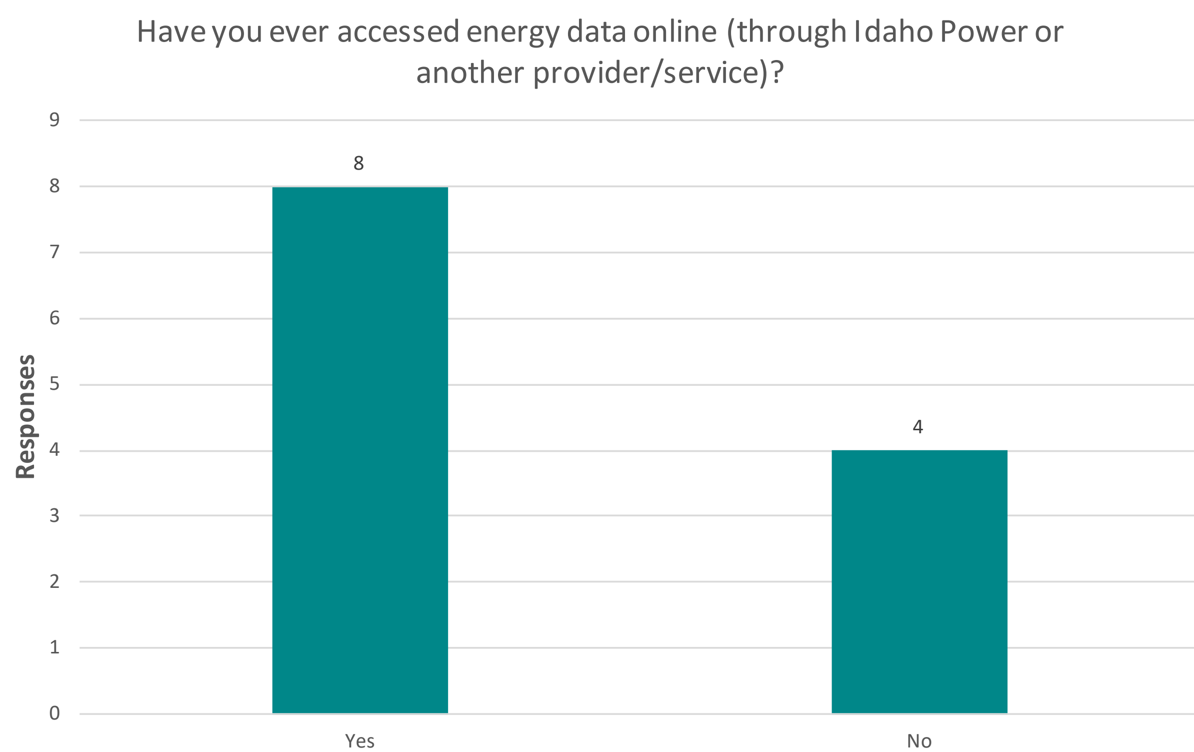
Question 4



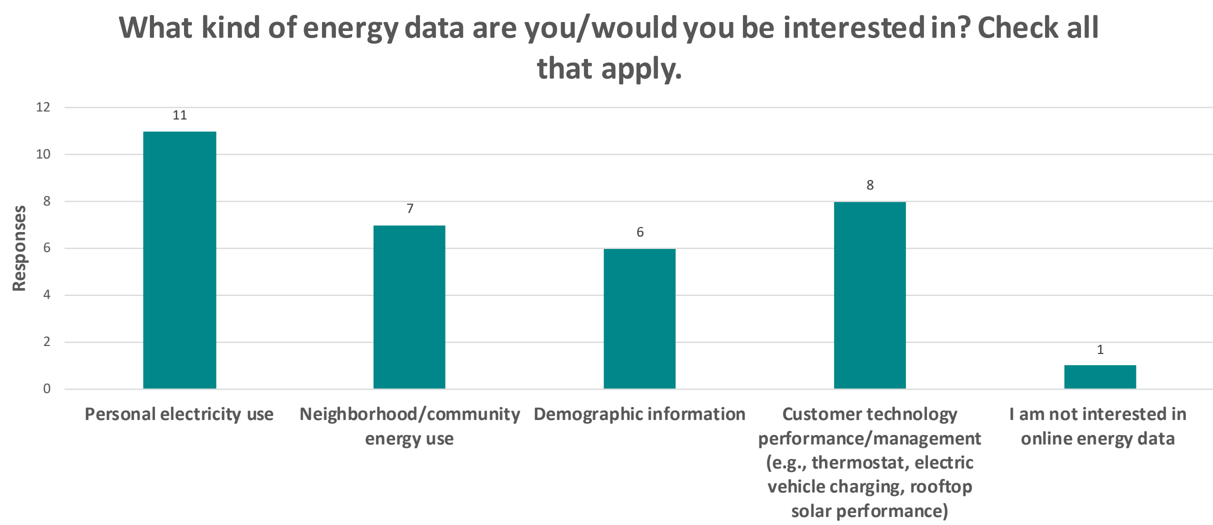
Question 5



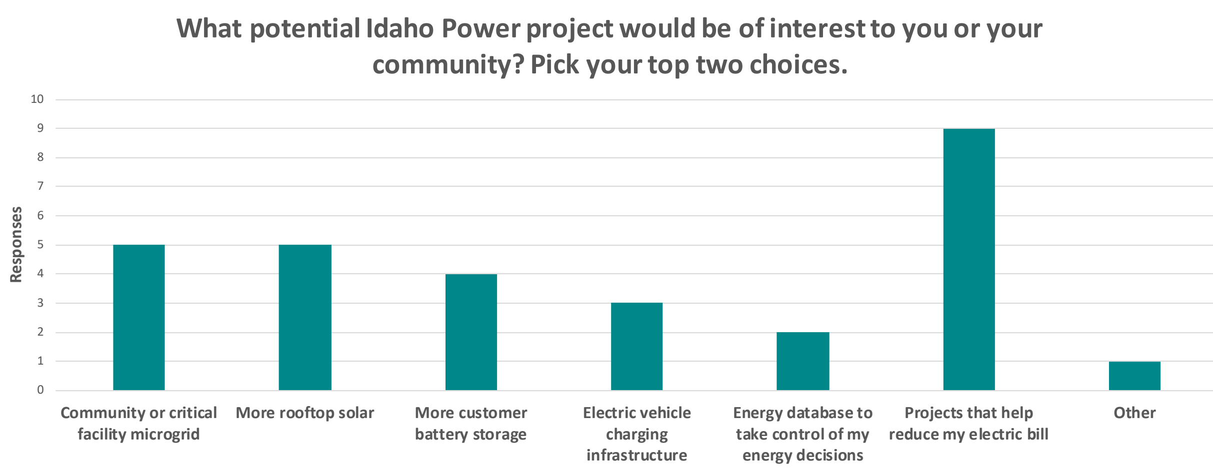
Question 6



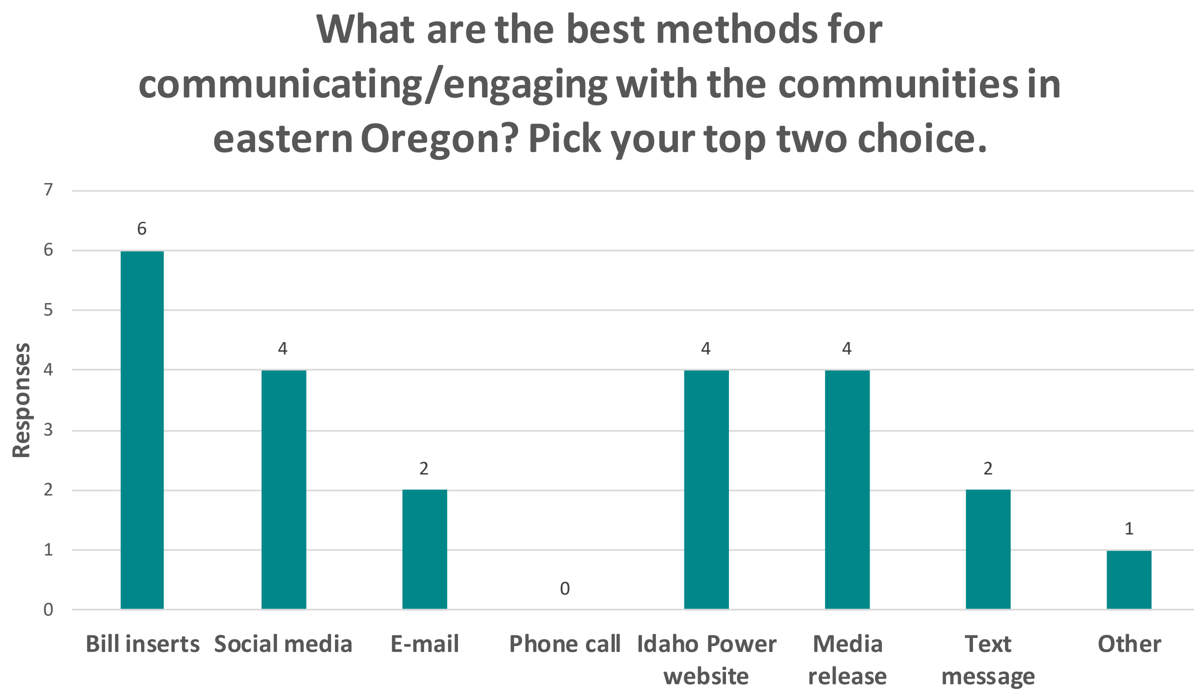
Question 7



Question 8



Question 9



Question 10