Docket	:	A.25-06-017
Exhibit Number	:	CA-07-SA
Commissioner	:	M. Baker
Admin Law Judge	:	R. Haga
Witness	:	C. Madison

PUBLIC ADVOCATES OFFICE
CALIFORNIA PUBLIC UTILITIES COMMISSION

APPENDIX B

SUPPORTING ATTACHMENTS TO TESTIMONY

San Francisco, California
December 12, 2025

LIST OF ATTACHMENTS FOR APPENDIX B

Attachment	Title	Bates No.
Attachment 1	Exhibit Liberty-03.	CA-07-0001
Attachment 2	Response (amended) to data request CalAdvocates-LIB-A2506017-015 November 1, 2025.	CA-07-0052
Attachment 3	Response to data request CalAdvocates-LIB-A2506017-031, October 31, 2025.	CA-07-0068
Attachment 4	Response (amended) to data request CalAdvocates-LIB-A2506017-015, November 1, 2025	CA-07-0075
Attachment 5	PG&E, 2019 Wildfire Mitigation Plan, February 9, 2019.	CA-07-0091
Attachment 6	SDG&E, 2019 Wildfire Mitigation Plan, February 9, 2019.	CA-07-0274
Attachment 7	Liberty, 2019 Wildfire Mitigation Plan, February 9, 2019.	CA-07-0441
Attachment 8	Liberty Utilities 2015 Annual Reliability Report.	CA-07-0524
Attachment 9	Liberty Utilities 2016 Annual Reliability Report.	CA-07-0569
Attachment 10	Response to data request CalPA-Liberty-R1810007-002, February 27, 2019.	CA-07-0602
Attachment 11	Liberty Utilities 2018 Annual Reliability Report.	CA-07-0629
Attachment 12	Liberty Utilities 2019 Annual Reliability Report	CA-07-0676
Attachment 13	Liberty Utilities 2020 Annual Reliability Report.	CA-07-0727
Attachment 14	Liberty Utilities 2021 Annual Reliability Report.	CA-07-0781
Attachment 15	Liberty Utilities 2022 Annual Reliability Report.	CA-07-0839
Attachment 16	Liberty Utilities 2023 Annual Reliability Report.	CA-07-0908
Attachment 17	Liberty Utilities 2024 Annual Reliability Report.	CA-07-1040
Attachment 18	Response (amended) to data request CalAdvocates-LIB-A2506017-015, November 1, 2025.	CA-07-1191
Attachment 19	Response to data request CalAdvocates-LIB-A2506017-031, Question 6, October 31, 2025.	CA-07-1199
Attachment 20	Response to data request CalAdvocates-LIB-A2506017-031, Question 4, October 31, 2025	CA-07-1206

Attachment	Title	Bates No.
Attachment 21	Response (amended) to data request CalAdvocates-LIB-A2506017-031, October 24, 2025.	CA-07-1213
Attachment 22	Response (amended) to data request CalAdvocates-LIB-A2506017-001, including tab "Detailed Inspection Results" in the attachment CalAdvocates-LIB-A2506017-001-Q2.xlsx., September 10, 2025.	CA-07-1220
Attachment 23	Response (amended) to data request CalAdvocates-LIB-A2506017-015, November 1, 2025.	CA-07-1236
Attachment 24	Response (amended) to data request CalAdvocates-LIB-A2506017-016, October 24, 2025.	CA-07-1252
Attachment 25	Response (amended) to data request CalAdvocates-LIB-A2506017-001, November 1, 2025.	CA-07-1259
Attachment 26	Pacific Gas and Electric Company. Infrared Inspections of Electric Distribution Facilities. May 15, 2018	CA-07-1270
Attachment 27	Response (amended) to data request CalAdvocates-LIB-A2506017-001, September 10, 2025.	CA-07-1289
Attachment 28	Response to data request CalAdvocates-LIB-A2506017-031, October 31, 2025.	CA-07-1300
Attachment 29	Response to data request CalAdvocates-LIB-A2506017-032, October 31, 2025.	CA-07-1307
Attachment 30	Southern California Edison, 2019 Wildfire Mitigation Plan, February 6, 2019.	CA-07-1317
Attachment 31	Response (amended) to data request CalAdvocates-LIB-A2506017-016, October 24, 2025.	CA-07-1461

ATTACHMENT 1 Exhibit

Liberty-03

Produce of Operations

Application No.:	A.25-06-
Exhibit No.:	Liberty-03
Witnesses:	P. Stoltman A. Lykens S. Moore



(U 933-E)

Mountain View Fire Cost Recovery Application

Before the California Public Utilities Commission

Liberty-03: Prudence of Operations

Tahoe Vista, California

June 20, 2025

CA-07-0002

Liberty-03: Prudence of Operations

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I.

Executive Summary

In this chapter of testimony, Liberty Utilities (CalPeco Electric) LLC ("Liberty") demonstrates that it prudently designed, inspected, maintained, and operated its facilities to provide safe and reliable service to its customers at the time of the Mountain View Fire. Liberty's programs and policies conformed to regulatory requirements and were consistent with industry practices for wildfire mitigation.

Liberty has operated as a utility in California since approximately 2011, when it purchased the utility system from NV Energy and began serving customers previously served by Sierra Pacific Power Company ("Sierra Pacific"). Liberty's operations are small compared to the State's large investor-owned utilities, serving approximately 50,000 customers in the Lake Tahoe region of northern California. Approximately 672 miles of primary overhead distribution lines and 33 miles of overhead transmission lines comprise Liberty's electric system. A significant portion of Liberty's service area lies within areas designated as High Fire Threat Districts ("HFTD"). In the years preceding the Mountain View Fire, Liberty implemented programs and policies to address the evolving wildfire risk landscape and to mitigate the risk of wildfires posed by its equipment, calibrated to the specifics of Liberty's service area, which includes mountainous, densely-forested, and remote terrain, and extreme and variable weather conditions. Enhancing these wildfire mitigation efforts has been an area of focus for Liberty, touching every aspect of its operations—design and construction, inspection and maintenance, and system operation and emergency preparedness.

Liberty's design and construction standards meet the regulatory requirements set forth in the Commission's General Orders ("GO"), including clearance and spacing requirements for conductors, pins, and insulators, and strength and loading requirements for poles. To further mitigate wildfire risk, Liberty focused on hardening its grid, including by using larger wires and crossarms, proactively installing covered conductor, replacing expulsion fuses, and increasing deployment of system automation equipment. For instance, at the time of the Mountain View Fire, Liberty was executing a multi-phase project approved in its 2019 General Rate Case ("GRC") to rebuild the distribution line at issue—the Topaz 1261 Circuit—with larger wire and covered conductor. Liberty also deployed system protection devices to monitor and respond to conditions on its system, reducing risk by detecting and clearing fault conditions. The Topaz 1261 Circuit had two SCADA-enabled automatic reclosers owned

by Liberty, and Liberty's system protection operated as expected on the day of the fire, interrupting fault conditions consistent with the device settings.

Liberty regularly inspected and maintained its electrical facilities. These inspection and maintenance programs helped to ensure Liberty's equipment was kept in safe working order and that potential hazards were timely addressed. Liberty patrolled and inspected poles, conductors, and other equipment pursuant to timelines established in GO 165, and performed intrusive pole inspections and substation inspections on a schedule that met or exceeded regulatory requirements. In 2020, Liberty conducted a system-wide survey and detailed inspection of all overhead distribution facilities, including the specific facilities adjacent to the fire's origin area. These specific facilities had no overdue repairs at the time of ignition. In 2020, Liberty also made strides to modernize its data collection during inspections, prioritizing the transition from paper forms to a dynamic electronic form.

Liberty also had procedures to maintain vegetation in proximity to Liberty's electric facilities, thereby reducing the ignition risk posed by vegetation contacting electric facilities. These included clearance of vegetation around conductors and specified poles to comply with requirements set forth in GO 95 and the Public Resources Code, as well as identification and removal of hazard trees. In 2020, Liberty piloted a LiDAR scan of vegetation clearance across half of its service area to support vegetation management work. This LiDAR scan showed that vegetation clearance at the spans adjacent to the fire's origin area exceeded regulatory requirements. To further reduce wildfire risk, Liberty implemented a Tree Mortality Removal Project to manage fuels resulting from exponentially-increasing rates of tree mortality in its service area. Liberty also implemented its first state-recognized Forest Resilience Corridor in 2020 to proactively thin out vegetation and remove hazard trees along utility rights-of-way in densely-forested areas.

Finally, Liberty's operational procedures and emergency preparedness plans focused on reducing wildfire risk and protecting public safety. Liberty's System Control Center monitored the company's electric system and communicated with field personnel to address system alerts or other unanticipated outages or issues. Liberty worked with a fire science and risk modeling firm to develop and implement wildfire mitigation tools, including its Public Safety Power Shutoff ("PSPS") protocol and a Fire Potential Index ("FPI") that forecasted fire threat using data points such as fuel moisture, temperature, and humidity. To complement these efforts, Liberty installed weather stations across its service area, including on the Topaz 1261 Circuit, the outputs of which were used for Liberty's forecast and modeling tools. Liberty also focused on enhancing its emergency preparedness plans and emergency management

capabilities. On the day of the Mountain View Fire, Liberty field personnel responded within minutes of the fire's ignition to assist with emergency response and to protect public safety.

II.

Overview of Liberty's Service Area and the Specific Facilities at Issue

This section provides an overview of Liberty's service area, including the portion of its service area designated as facing heightened wildfire risk. This section also describes the specific facilities immediately adjacent to the origin area of the Mountain View Fire.

A. Liberty's Service Area Contains Challenging Terrain With High Fire Risk

Liberty is an investor-owned utility that provides electricity to customers in California. Liberty took over Sierra Pacific's California service area in approximately 2011, following the Commission's approval of this transaction in October 2010.[1] Today, in California, Liberty provides electricity to approximately 50,000 residential and commercial/industrial customers across seven counties around the Lake Tahoe area. This service area extends as far north as Portola and as far south as Walker. Approximately 80 percent of Liberty's customers are located in the Lake Tahoe Basin. Liberty's service area contains large swaths of remote and mountainous terrain, with elevations ranging from 9,050 feet in Olympic Valley to just under 5,000 feet at Portola. The vast majority of Liberty's customers—nearly 90 percent—are located at elevations greater than 6,000 feet. Weather conditions in Liberty's service area range between frequent and heavy snowfall during cold winters, and dry and windy conditions and warm temperatures in late summer and early fall. Operating an electric system in this terrain and in these conditions comes with unique challenges. Much of Liberty's service area contains densely-covered forest vulnerable to wildfire spread under certain conditions. And a number of residential communities within Liberty's service area are located in the wildland-urban interface, which increases the potential for wildfires to threaten life safety and cause significant property damage.

Within its service area in California, Liberty operates approximately 672 miles of primary overhead distribution lines, nearly 800 miles of secondary overhead distribution lines, approximately 33 miles of overhead transmission lines, and 12 substations. Liberty also operates a smaller number of underground distribution and transmission lines. Liberty has approximately 120 dedicated employees, many of whom live and work in the area served by Liberty. This includes approximately 6 engineers, 6

[1] *See* D.10-10-017.

designers, 20 linemen, 5 troubleshooters, 5 inspectors, and 72 employees in electric operations, among others.

Liberty's service area is divided into two districts for electric operations, with individual service operations for each district. Liberty's South Lake Tahoe District comprises the portion of the service area in the South Lake Tahoe region, including parts of El Dorado, Mono, and Alpine Counties. Liberty's North Lake Tahoe District comprises the portion of the service area in the North Lake Tahoe region, including parts of Placer, Nevada, Sierra, and Plumas Counties. The 120kV systems out of the Carson Valley, Nevada serve as the primary transmission source for the South Lake Tahoe District, while the 120kV systems out of Truckee and Verdi, California serve as the primary transmission source for the North Lake Tahoe District. The two districts are independent control areas for distribution switching, and distribution interconnection between the two areas is limited.

Liberty's service area encompasses large swaths of territory currently designated as high fire risk areas. In the years following the 2007 wildfires in Southern California, the Commission led two rulemakings to develop regulations to mitigate the risk of wildfires posed by utility facilities: R.08-11-005 and R.15-05-006. Through these rulemakings, the Commission developed and adopted fire threat maps, which tied to new requirements for utility equipment in areas designated as high risk. Prior to the Commission's adopting the final High Fire Threat District ("HFTD") Map in early 2018,[2] the Commission used a fire-threat map for Northern California developed jointly by the University of California at Berkeley and Reax Engineering Inc. ("Reax Map").[3] Under this interim fire-threat map, approximately 26 percent of Liberty's service area was designated as either "very high" or "extreme" fire risk.

The Commission's final HFTD Map, adopted in January 2018, significantly expanded the extent of Liberty's service area designated as fire risk. Liberty actively participated in the development of the proposed rules and the HFTD Map in R.15-05-006 in July 2017.[4] The HFTD Map consisted of three fire-threat areas: Tier 3 extreme fire-threat areas; Tier 2 elevated fire-threat areas; and "Zone 1" areas comprised of Tier 1 High Hazard Zones ("HHZs") from the United States Forest Service and California

[2] D.17-12-024 at 145-146.

[3] D.12-01-032 at 171-172.

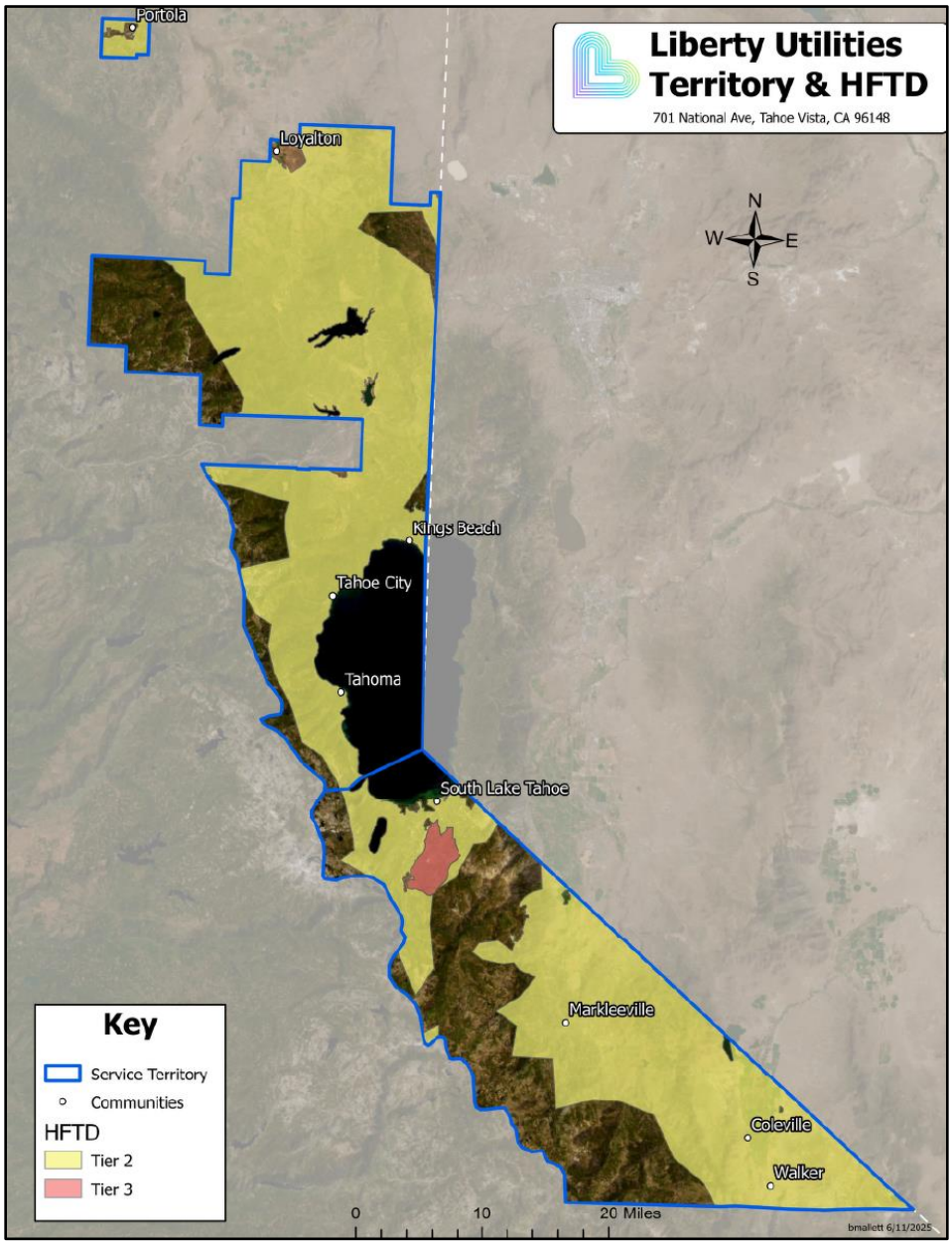
[4] D.17-12-024 at 11-12.

Department of Forestry and Fire Protection ("Cal Fire")'s joint map of Tree Mortality HHZs.[5] The HFTD Map designated approximately 63 percent of Liberty's service area as Tier 2 or Tier 3 HFTD, with almost all of Liberty's electrical equipment and infrastructure (approximately 94 percent) within HFTD Tier 2 and 3 areas. Consistent with its regulatory obligations under these two rulemakings, Liberty incorporated the HFTD designations into its maintenance, inspection, and vegetation management practices.

The area where the Mountain View Fire ignited in Walker, California, is designated as Tier 2 HFTD under the Commission's final HFTD Map, though this area was not designated as a high fire risk area under the interim Reax Map.

[5] *Id.* at 2.

Figure 1: Map of Liberty's Service Area and HFTD Designations



B. Specific Facilities

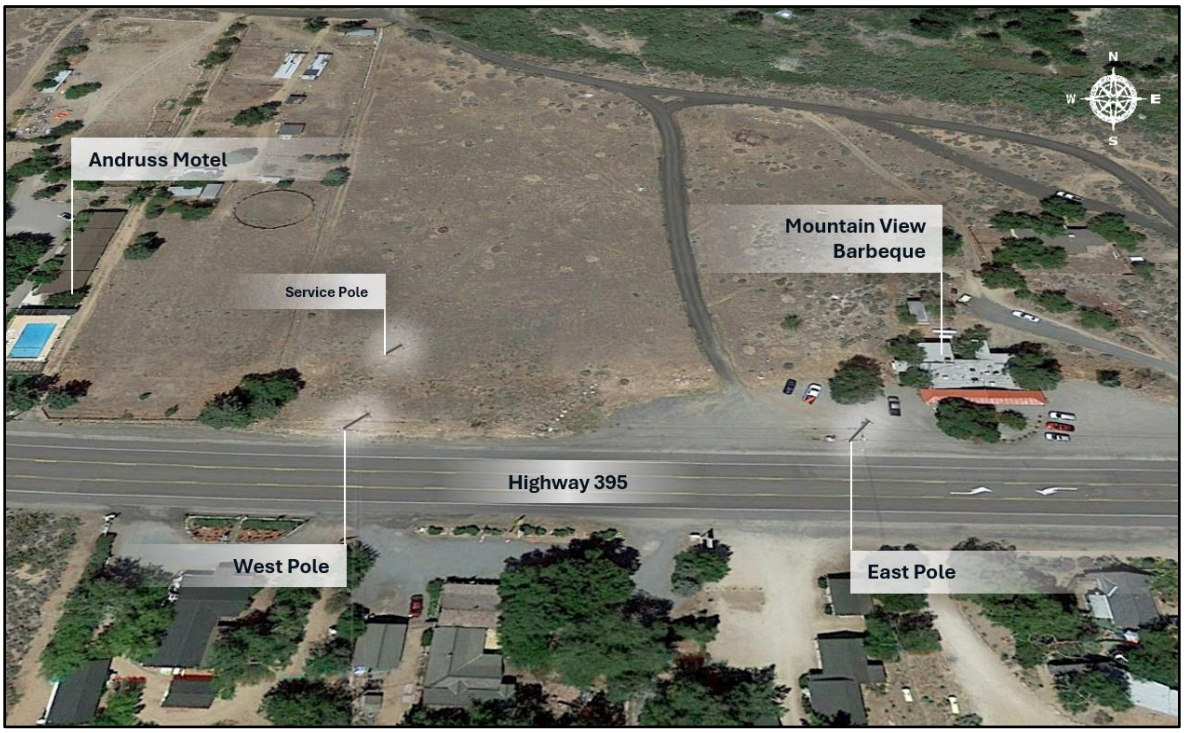
For ease of reference in the Application and this supporting testimony, the specific Liberty poles and overhead facilities near where the Mountain View Fire ignited are identified below and referred to as the "Specific Facilities." The Mountain View Fire ignited near the town of Walker in Mono County, California. As discussed in *Liberty-02: Ignition*, Cal Fire issued a report on the origin and cause of the Mountain View Fire, referred to throughout as the fire agency report. The fire agency report identified

the "most probable cause" of the Mountain View Fire as an "energized conductor contacting the ground" and igniting cured annual grasses.[6] Liberty's facilities adjacent to the origin area identified by the fire agency report are part of the Topaz 1261 Circuit and specifically include the span between Pole 266731 (the "West Pole") and Pole 40288 (the "East Pole"), or the "Subject Span."

The Topaz 1261 Circuit originates from Topaz Substation, an NV Energy substation in Nevada, with Liberty's facilities beginning at the California-Nevada border. Liberty's portion of the circuit is monitored and protected by two remote automatic line reclosers—the 1261 R1 and 1262 R2 Reclosers. The 1262 R2 Recloser is the closest protective device to the Specific Facilities and is located approximately 2.7 miles upstream of the Subject Span. In the first quarter of 2021, the Topaz Circuit served approximately 754 customers. The mainline of the Topaz 1261 Circuit uses four-wire construction, with three phase conductors and a neutral wire. Some of the smaller branch lines of the Topaz 1261 Circuit are single-phase. The Subject Span is parallel to Highway 395, which runs east and west through the town of Walker. The West Pole is adjacent to the Andruss Motel, and the East Pole is adjacent to the Mountain View Barbeque restaurant. Additionally, a triplex service connection ran perpendicular to Highway 395 between the West Pole and a service pole in the grassy field to the north. Figure 2 shows Liberty facilities in and around where the Mountain View Fire originated.

[6] Appendix A to *Liberty-02C: Ignition*, at 21.

Figure 2: Liberty Facilities Near the Origin Area of the Mountain View Fire

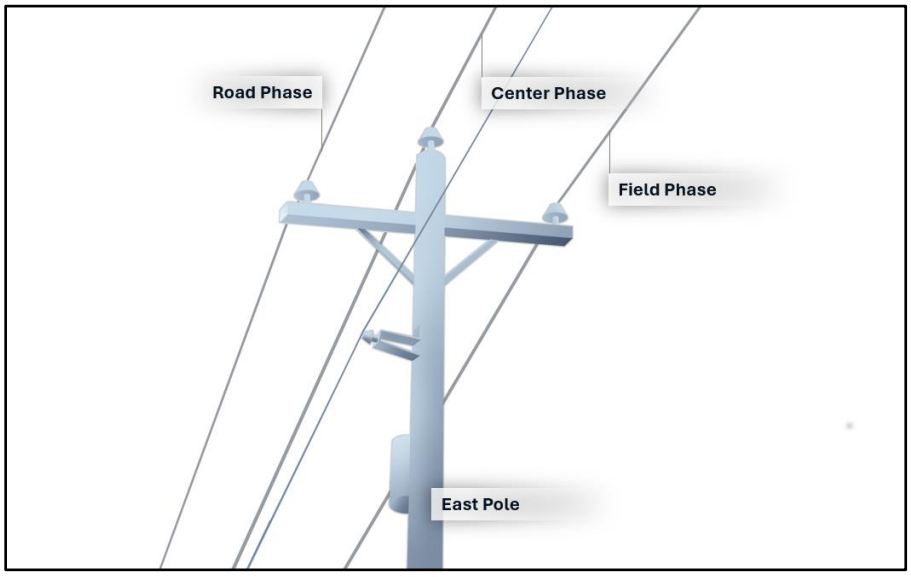


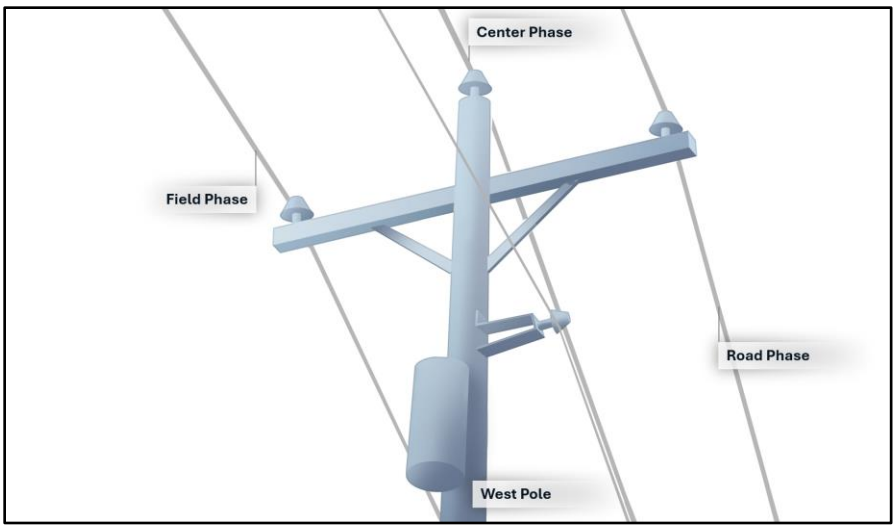
The distribution conductors on the Subject Span are arranged in a triangular crossarm configuration, with the outside phases attached to insulators mounted on crossarms and the center phase elevated and attached to an insulator mounted on the top of the poles. The neutral wire is attached to horizontal insulators mounted to the pole. The conductors on the Subject Span were #4 ACSR (Aluminum Conductor Steel Reinforced), which has a steel core surrounded by aluminum strands. Figure 3 through Figures 4 (Top) and 5 (Bottom): Simplified Graphics Illustrating Configuration of Equipment on the East and West Poles below illustrate the Subject Span and the Specific Facilities.

Figure 3: Post-Fire Image of Triangular Crossarm Configuration of 1261 Topaz Circuit Over the Origin Area of the Mountain View Fire



Figures 4 (Top) and 5 (Bottom): Simplified Graphics Illustrating Configuration of Equipment on the East and West Poles





III.

Liberty Took Steps to Mitigate Wildfire Risk

Although Liberty had not experienced a large wildfire attributed to its electrical infrastructure since taking over from Sierra Pacific in 2011, Liberty recognized the risk of wildfire in its service area and took steps to mitigate that risk. In the years preceding the Mountain View Fire, Liberty expanded its efforts in light of the increasing risk of wildfires across the State due to extreme weather and persistent drought conditions.

Liberty submitted its first Fire Prevention Plan ("FPP") in 2012, pursuant to the Commission's direction in Rulemaking (R.) 08-11-005, the fire safety rulemaking initiated after the 2007 wildfires in Southern California[7] D.12-01-032 established different FPP requirements for utilities operating in Southern California and Northern California. While FPPs were mandatory for investor-owned utilities in Southern California, they were required for investor-owned utilities in Northern California only if the utility determined, with respect to its facilities within high-fire threat areas identified in the Reax Map, that "it is reasonably foreseeable that the probability of 3-second wind gusts exceeding the maximum working stresses for such facilities during a Red Flag Warning is 3% or more during a 50-year period."[8] Liberty analyzed whether this criterion was met using data from Remote Automated Weather Stations ("RAWS") operated by the National Weather Service ("NWS"). Because the available RAWS data did not indicate whether gusts lasted three seconds or more, to promote public safety and a proactive

[7] *See* D.12-01-032, Ordering Paragraph 3, and revisions of D.17-12-024.

[8] D.12-01-032, Ordering Paragraph 3.v.

approach, Liberty assumed that all maximum gusts met the criterion and determined that an FPP was needed for its facilities located within Threat Zones 3 and 4 of the Reax Map.

As noted in Resolution E-4576, Liberty's first FPP identified several programs and procedures aimed at reducing wildfire risk in the relevant high fire threat areas.[9] These included proactive measures during Red Flag conditions, such as patrols of circuits in high-fire areas if wind gusts at peak elevations exceeded 76.5 mph, operational counter measures such as putting reclosers on "fire settings," pausing discretionary maintenance and vegetation management activities, and de-energizing circuits only if no customer required service and the Commission approved an application to do so.

Following implementation of Senate Bill 901 ("SB 901"), which expanded requirements for all utilities to submit a Wildfire Mitigation Plan ("WMP"), Liberty submitted its first WMP in February 2019. In February 2020, Liberty submitted its Revised 2020 Wildfire Mitigation Plan ("2020 WMP"), which the Commission conditionally ratified in June 2020.[10] Liberty's 2020 WMP built upon its 2019 WMP, as well as the plans of other California utilities, and reflected guidance from the Commission. The 2020 WMP allocated $40 million in capital investments for wildfire mitigation-focused asset management and inspection initiatives, system hardening projects, operational practices, and situational awareness tools, as summarized below.

Asset Management and Inspections. Liberty's 2020 WMP outlined goals for its asset management and inspection programs, including conducting the detailed system-wide asset survey described in Section V.A.2 below, upgrading its inspection program to a digital format, continuing its intrusive pole inspection program, and piloting a LiDAR inspection of its distribution system.

Grid Design and System Hardening. Liberty's 2020 WMP committed significant resources to hardening its system, such as installing covered conductor, replacing and upgrading distribution poles, replacing expulsion fuses, investing in grid topology, further deploying system automation equipment, undergrounding certain lines, removing tree attachments, installing larger size conductor under its wire upgrade program, and conducting upgrades and repairs in light of the system-wide asset survey.

Situational Awareness. Liberty's WMP included significant measures to enhance situational awareness. These tools included installing weather stations, developing a Fire Potential Index ("FPI") that uses sophisticated modeling to forecast the level of wildfire risk, increasing deployment of

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[9] Resolution E-4576 (May 24, 2013), at 5-6.

[10] *See* Resolution WSD-007 (Jun. 19, 2020).

monitoring sensors and SCADA-enabled devices including reclosers, and additional monitoring of lines and equipment in elevated fire risk conditions.

Vegetation Management and Inspections. Liberty's WMP focused on its efforts to increase the frequency of vegetation management inspections, conduct detailed inspections and remediation of vegetation to support compliance with clearance requirements, reduce strike potential posed by hazard trees, remove dead and dying trees in high tree mortality areas, and manage fuels. Liberty also planned to develop a formal quality assurance program and to pilot LiDAR inspections of vegetation clearance around poles and conductors.

System Operations and Protocols. Liberty's 2020 WMP outlined its plans to replace older reclosers and the restrictions it places on non-wildfire mitigation work on elevated fire risk days, such as designating a fire safety monitor in each work crew, reviewing daily fire risk ratings, and limiting or refraining from activities such as the use of chainsaws, weed eaters, blasting welding, pole setting, and removal, and replacing conductors off-road or on unimproved roads. The WMP also outlined Liberty's PSPS protocol, based on a newly-developed predictive tool supported by a third-party fire science and risk modeling expert firm engaged by Liberty.

Emergency Planning and Preparedness. Liberty's 2020 WMP focused on enhancing its emergency preparedness and emergency management capabilities. To that end, the WMP described Liberty's plans to hire additional personnel to manage emergency response activities, public safety partnerships, and fire mitigation initiatives and associated training, audit, and outreach.[11] Liberty also planned to conduct emergency response exercises and workshops with local communities and public safety partners regarding wildfire mitigation, emergency planning, and response coordination.

Liberty made significant progress implementing the measures outlined in its 2020 WMP. In a report issued at the end of 2022, the Office of Energy Infrastructure Safety ("OEIS") concluded that Liberty substantially complied with its 2020 WMP and met most of the WMP's quantitative and qualitative targets.[12] OEIS reviewed 45 of 79 initiatives outlined in the 2020 WMP. Of those, OEIS found that Liberty missed five quantitative targets and two qualitative targets. For two of the missed targets, OEIS found that Liberty had achieved more than 95 percent completion.[13] OEIS determined

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[11] In 2020, Liberty hired an Emergency Manager and Fire Protection Specialist.

[12] *See* Office of Energy Infrastructure Safety, *Annual Report on Compliance*, Liberty Utilities' 2020 Wildfire Mitigation Plan, Dec. 2022.

[13] *Id.*

that the missed targets "did not have direct impact on ignition risks on Liberty's system" or "significantly hinder Liberty's ability to mitigate its wildfire risk."[14] OEIS noted that Liberty's performance metrics showed a decrease in ignitions, wire down events, and outages compared to previous years. OEIS also conducted 63 safety inspections and found only four deficiencies, all of which were timely resolved by Liberty.

IV.

Liberty Designed and Constructed Its Facilities to Support Safe and Reliable Operation

Liberty's design and construction standards support its core mission of providing safe and reliable electric service to its customers at reasonable rates. In the years preceding the Mountain View Fire, Liberty designed and constructed its electric system in accordance with GO 95 standards, including conductor clearance and spacing requirements, as well as pole strength and loading requirements. While Liberty acquired the utility system from NV Energy in 2011 and did not originally design and construct the facilities, over time Liberty was working to upgrade, rebuild, and update its system. Liberty focused on system modernization and hardening, including installing covered conductor, identifying and replacing nonexempt hardware (per Cal Fire) including expulsion fuses, removing tree attachments, and deploying additional SCADA-enabled circuit breakers and reclosers. In addition to supporting compliance with regulatory requirements, Liberty recognized that these initiatives would reduce the risk of ignition posed by its overhead electrical equipment. To that end, at the time of the fire, Liberty was proactively rebuilding the Topaz 1261 Circuit (referred to as the "Topaz Line Rebuild Project"). While the Specific Facilities had not yet been rebuilt, they had a triangular crossarm configuration that allowed for greater spacing and clearances between conductors than flat-top configurations with all phases supported by horizontal crossarms.

A. Liberty Designed and Constructed its Electric System to Comply With Regulatory Requirements and to Reduce Wildfire Risk

Design and construction of Liberty's overhead distribution system is governed by Liberty's Overhead Electric Standards. Liberty's Standards Committee has met periodically since acquisition of the facilities to review and evaluate the governing standards. Liberty uses both in-house and outside engineers to support the design and construction of utility facilities.

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[14] *Id.* at 51.

Liberty's design and construction standards conform to the requirements of GO 95. Given the location of its service area, Liberty's Overhead Electric Standards are designed to comply with GO 95's heavy loading requirements. Liberty's standard for new construction of 4-wire overhead distribution facilities at 12.47 kV provides for a minimum of 8-foot, and in most instances 10-foot, crossarms. Conductor clearances mandated by GO 95 are built into Liberty's design standards, along with additional clearance for long spans, deflections by the wind, sag from ice or snow, and elevations above 3,000 feet. Clearance standards are required to be met under all expected operating conditions, including sag from operating load, ice, and wind loading. In some instances Liberty used line spacers to mitigate the potential for line contact at the discretion of field personnel.

The Specific Facilities' conductor clearances at the West Pole were consistent with Liberty's standards and exceeded GO 95 requirements. As noted above, the triangular crossarm configuration provided increased separation between the phase conductors, as well as the neutral wire. The center phase conductor was mounted to an insulator attached to the top of the East and West Poles, while the outer phase conductors were attached to insulators mounted at either end of 8-foot crossarms. Triangular crossarm construction remains consistent with Liberty's Overhead Electric Standards.[15] For this type of construction on distribution facilities, GO 95 mandates a minimum horizontal separation of 17.5 inches between conductors, with the elevated center phase having a vertical separation at least equal to the pin spacing for the voltage class (*i.e.*, 17.5 inches).[16] Post-fire measurements recorded radial clearances of 54 inches between center and road and field phases at the West Pole. Liberty's standards for both poles utilized 8-foot cross arms, with insulators mounted at pre-fabricated through-holes approximately four inches from either end of the crossarms. Based on these dimensions and configuration, the calculated horizontal and vertical clearances at the East and West Poles exceeded of GO 95's requirements.

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[15] For new construction, triangular crossarm construction is typically implemented with 10-foot fiberglass crossarms and extended spacing to satisfy avian protection requirements.

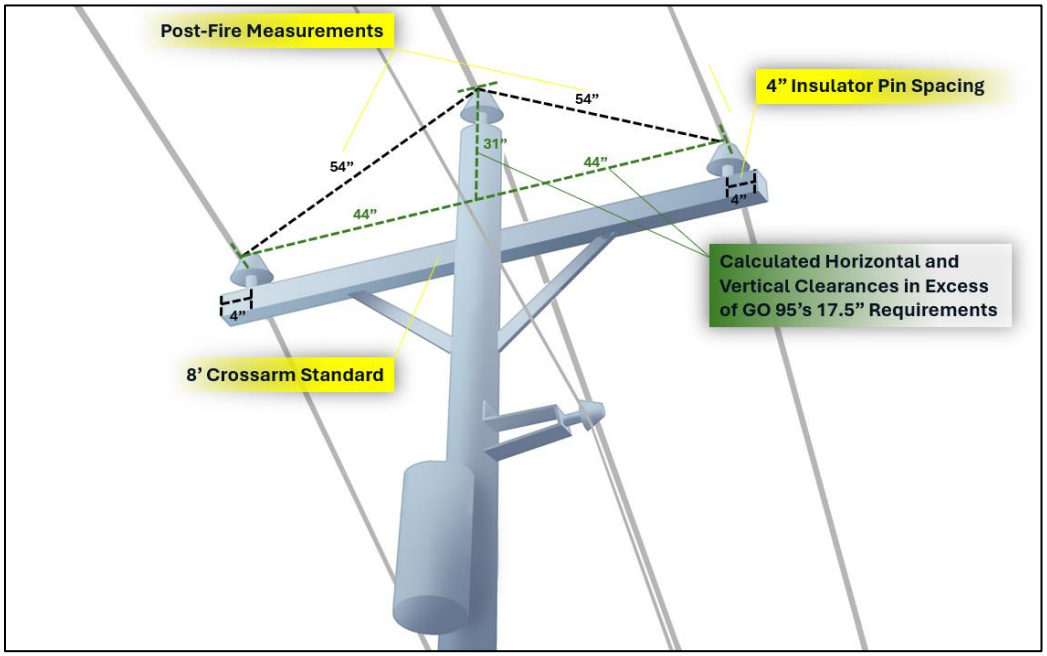
[16] *See* GO 95, Rule 54.4(C)(1)(c) ("When crossarms are used to support conductors of the same circuit at different levels (as in triangular or vertical configuration), the crossarms may be arranged so that the vertical separation of the conductors of the same circuit shall not be less than the pin spacings of Table 2, Case 15."); *id.*, Rule 38, Table 2, Case 15.

Figures 6 (Left) and 7 (Right): Post-Fire Conductor Radial Clearance Measurements at West Pole[17]





Figure 8: Annotated Demonstration of Measured Radial and Calculated Horizontal and Vertical Conductor Clearances



Liberty's overhead electric distribution system is supported by more than 22,000 poles across its service area. These poles range in age from newly installed poles to legacy poles installed by Sierra

[17] Distance of 54 inches between the center and road phase conductors (left photograph) and between center and field phase conductors (right photograph).

Pacific. GO 95 requires that utility poles meet specified "safety factors," *i.e.*, design criteria to accommodate the structural load exerted by wind, ice, and the weight of attached facilities. The calculation of these safety factors is referred to as "pole loading." Liberty performs pole loading calculations through its industry-standard "O-Calc" software on all poles that are being replaced, or have an increase in loading from proposed new attachments, including covered conductor upgrades, consistent with GO 95 and Liberty's "Wood Pole Loading Criteria" standard. The number, size, height (*i.e.* ground clearances) requirements, wind loading, and dead-ending tension of conductors supported by a pole were the primary factors Liberty used to assess pole strength requirements. Liberty designed and constructed poles to meet GO 95's heavy loading standard. Higher class poles were also required for unusually long spans, heavy conductor loads, or heavy equipment installation.

In the years preceding the Mountain View Fire, Liberty also undertook system hardening initiatives aimed at wildfire mitigation, safety, and reliability. For instance, over time Liberty was upgrading and hardening its legacy Sierra Pacific distribution facilities by widening crossarms to increase conductor spacing and upgrading and installing additional poles to make the facilities more resilient and to reduce span lengths. Liberty began installing covered conductor on certain distribution circuits traversing HFTDs. Liberty also initiated a multi-year program to replace expulsion fuses in its service area to further reduce ignition risk. Specifically, Liberty has been replacing conventional fuses that can expel hot particles with non-expulsion fuse types to reduce ignition risk. Liberty prioritized replacement of transformer fusing before turning to tap/lateral fusing to coordinate its system protection schemes.

Liberty undertook the 7300 Line Rebuild project, which involved replacing approximately 15,000 feet of overhead lines with covered conductors near Tahoe City. Likewise, as discussed in more detail below, Liberty undertook the Topaz Line Rebuild Project. When installing covered conductor, Liberty performs pole loading calculations to confirm safety factors and upgrades poles as necessary to appropriately support covered conductor, which is heavier than bare conductor. Another important system hardening initiative was construction of the Sagehen microgrid to serve a research facility run by the University of California, Berkeley. The purpose of this project was to enable Liberty to de-energize during fire season a three-mile distribution line that traverses a high-fire area to serve this single facility. Liberty's 2019 GRC committed $84 million in capital expenditures on system hardening and other initiatives targeting safety and reliability over the rate case period. Several of these projects focused on circuits in areas with exposure to extreme weather conditions, including the Topaz 1261 Circuit.

B. Liberty Was Proactively Rebuilding the Topaz 1261 Circuit to Account for Local Conditions and Mitigate Wildfire Risk

Liberty prioritized the Topaz 1261 Circuit for system hardening because of its location within a Tier 2 HFTD and its exposure to harsh weather conditions. As Liberty explained in its 2019 GRC, the Topaz 1261 Circuit was identified based on its history of more frequent outages, and the rebuild project would improve reliability and "mitigate the risk of fires sparked from downed wires on the circuit."[18] This was a multi-year project and the original design specified upgrading overhead lines from existing #4 ACSR conductor to #2 ACSR conductor. #2 ACSR conductor is larger in diameter, stronger, and able to carry more load. Later phases involved installation of covered conductor. Covered conductor has a protective sheath that protects the conductor from risks associated with contact by animals, vegetation, another line, or the ground, thereby significantly reducing the risk of ignition. The covering also helps protect the equipment from severe winds and extreme cold. Other utilities in California were similarly just beginning to deploy expanded covered conductor programs through distribution reconductoring projects aimed at reducing wildfire risk. The Commission approved the Topaz Line Rebuild Project and scope in D.20-08-030, stating "We find it reasonable to approve the project for it adds to Liberty's system reliability, wildfire risk mitigation, and a stronger circuit system. Costs are approved for this project from 2019 through 2021."[19]

Because of its scale and cost, the Topaz Line Rebuild Project was designed and executed as a multi-phase, multi-year project to minimize the rate impact on customers and support manageable execution by the utility. The project increased wire size, replaced uninsulated wire with covered conductor, and upgraded poles based on GO 95 "heavy" loading standards. Liberty engaged contractors to support design, planning, and execution of the reconductoring project.

The first phase of the project began with Liberty's facilities near the California-Nevada border and closest to NV Energy's Topaz Substation. Phases progressed along the circuit, with the final phase to cover the end of the circuit. In 2020, Liberty completed a total of 3.17 miles of covered conductor replacement and at the time of the Mountain View fire Liberty was in the middle of executing phase five of the project. Indeed, on the morning of the fire, Liberty personnel and contractors were actively working on reconductoring a portion of the circuit approximately one mile northwest of the Specific

[18] D.20-08-030 at 12 ("Topaz Line Rebuild Project").

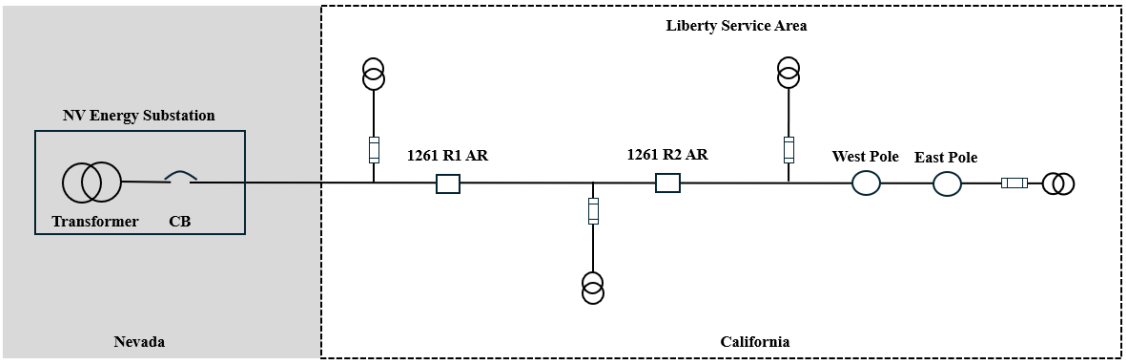
[19] *Id.* at 12-13 (discussing the "Topaz Line Rebuild Project").

Facilities. The Specific Facilities were located near the end of the mainline of the Topaz 1261 Circuit and were part of phase six of the project. Phase six encompassed the last approximately 1.5 miles of the circuit and was completed in 2022.[20]

C. Liberty Deployed Protection Devices to Detect and Respond to Fault Conditions on Its Distribution System

Like other electric utilities, Liberty deploys protection devices to monitor activity on its system and quickly detect and respond to fault conditions that arise. Protection devices on distribution lines include circuit breakers and relays at substations, line reclosers installed on the circuit, and overhead fuses for branch line [and end-of line] protection. These protection devices are designed to work together in a coordinated manner to detect and interrupt fault conditions that occur downstream of their locations, by operating to isolate and de-energize the line section(s) experiencing a fault. Fuses closer to the ends of distribution lines or line segments reduce fault duration and total fault energy, which reduces ignition risk and the potential for conductor damage.

Figure 9: Simplified Illustration of Protection Coordination for the 1261 Topaz Circuit



Liberty was upgrading its system protection devices over time, increasing system automation and installing SCADA-enabled devices including reclosers. In November 2020, Liberty had two remote automatic reclosers on the Topaz 1261 Circuit, the 1261 R1 Recloser and 1261 R2 Recloser.[21] Liberty had recently upgraded both devices to replace aging, oil-filled, models with more modern, SCADA-

[20] The request for proposal (RFP) process for phase six was initiated during the early months of 2021, and construction on phase six was completed in 2022.

[21] As described above, the Topaz 1261 Circuit originated at NV Energy's Topaz Substation and was protected at that end by a substation recloser owned by NV Energy.

capable devices. Specifically, Liberty upgraded the 1261 R1 Recloser in 2015 and the 1261 R2 Recloser around March 2020, installing G&W Viper-S reclosers and Schweitzer Engineering Laboratories controllers.[22] Both reclosers could be remotely controlled, meaning Liberty's system control had the ability to remotely select the operating mode and enable or disable hot line tagging. The R2 Recloser was located approximately 2.8 miles upstream (or source-side) of the Subject Span.

Protection device settings determine how they will operate. Specifically, the settings determine the magnitude and duration of fault current required for the device to operate and de-energize a line. Liberty developed multiple settings to address different situations, including "normal" and "fire mode" conditions. The settings for the 1261 R1 Recloser and 1261 R2 Recloser were designed to coordinate with each other and with NV Energy's system protection at its Nevada substation.

As set forth in *Liberty-02* and discussed further in Section VI.B.3 below, Liberty's protection devices in the area of the Mountain View Fire ignition operated as expected on November 17, 2020.

V.

Liberty Inspected and Maintained Its Facilities Pursuant to Comprehensive Inspection and Maintenance Programs

In 2020, Liberty had comprehensive inspection and maintenance programs for its electric facilities that conformed to Commission regulations. These programs included patrols and detailed inspections of overhead lines, intrusive pole inspections, and substation inspections. Liberty's inspection and maintenance programs mitigated the risk of ignition from electrical infrastructure by identifying and repairing deteriorating equipment and other potential safety hazards in the field. The Specific Facilities were inspected numerous times in the years preceding the Mountain View Fire, and there were no past due repairs at the time of the fire. Liberty also had robust vegetation management programs that mitigated the potential for vegetation to grow or fall into overhead lines and addressed vegetation around poles consistent with regulatory requirements. Given that large parts of Liberty's service area are mountainous, densely-forested, and remote, these programs played a vital role in reducing the risk of ignition posed by vegetation growth near Liberty's overhead electric equipment.

[22] An SEL-351 R2 controller was installed for the 1261 R1 Recloser and an SEL-651 RA controller for the 1261 R2 Recloser.

A. Liberty Inspected Its Overhead Facilities in Accordance With Regulatory Requirements

1. Liberty's Routine Patrols and Detailed Inspections Pursuant to GO 165

GO 165 governs inspection cycles for electric distribution facilities. As set forth in GO 165, a patrol inspection is a "a simple visual inspection, of applicable utility equipment and structures, that is designed to identify obvious structural problems and hazards," which may be conducted "in the course of other company business." Prior to 2019, Liberty performed patrols of overhead lines in rural areas every two years, consistent with GO 165.[23] Depending on the terrain and accessibility of lines, Liberty typically performed these patrols by vehicle or helicopter. As part of the fire safety rulemaking, the Commission updated the frequency of patrols for rural areas in Tier 2 and Tier 3 HFTDs, giving utilities until September 1, 2018 and June 30, 2019 to update their procedures for Tier 3 and Tier 2 HFTDs, respectively.[24] Since performing its detailed systemwide asset survey in 2020, Liberty has performed annual patrols of all overhead lines which are not subject to a detailed inspection in any given year.[25] For patrol inspections, inspectors used hard-copy circuit maps, which they highlighted, dated, and initialed as they completed their patrols.

Liberty also performed detailed inspections of poles, conductors, and other overhead equipment such as pad-mounted transformers, regulators, capacitors, and switching and protective devices.[26] GO 165 defines a "detailed inspection" as an inspection "where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic test, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and recorded."[27] Liberty inspected approximately 20

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[23] Per GO 165, III.A (Definitions), a "rural" area is defined as "those areas with a population of less than 1,000 persons per square mile" as determined by the census bureau. The Mountain View Fire ignited in the Walker Census Designated Place (CDP), which is a "rural" area for purposes of GO 165.

[24] D.17-12-024 at 154-155 (OP 4).

[25] Liberty does not have a separate inspection and patrol program for its transmission lines. Patrols and inspections on overhead transmissions equipment follow the same procedures and are considered part of the same program as patrols and inspections for distribution facilities.

[26] Liberty's procedures prescribed detailed inspections of all submersible transformers and switches every three years, in accordance with GO 165 requirements.

[27] GO 165, III.A(4).

percent of the system annually, meaning that overhead electrical equipment was subject to detailed inspection on a five-year cycle, in line with GO 165 requirements.

Liberty utilized experienced system inspectors and qualified contractors to perform patrols and detailed inspections of its electrical facilities. Inspectors, regardless of whether they were employees or contractors, were certified journeyman linemen. During detailed inspections, inspectors viewed the poles, conductors, and secondary lines from the ground with binoculars, looking for potential safety hazards and issues that could cause service disruptions. The inspectors checked that associated equipment such as transformers, regulators, capacitors, and switching and protective devices were in good condition, that conductors had good clearances, and that facilities were otherwise consistent with Liberty's standards.

Prior to mid-2020, inspectors recorded the results of detailed inspections on paper forms and, if a pole failed inspection, flagged "condition codes" and other infractions on their checklist to identify the specific condition to be remediated, as well as the priority level for repairs. In 2020, Liberty transitioned from hard-copy detailed inspection forms to digital data collection to improve the efficiency and effectiveness of its process. Pursuant to the new process, inspectors recorded detailed inspection data using a questionnaire in Fulcrum, a field data collection and process management software tool. Through Fulcrum, linemen also began to take photographs to document the condition of the pole, conductors, and other equipment.

Conditions identified for remediation by inspectors during patrols and inspections were entered into a database. A physical work order packet was then created and given to a foreman or the engineering team, depending on the type of repair or replacement.[28] Each identified condition was assigned a priority level consistent with GO 95's definition of safety and/or reliability risk.[29] Liberty's repair timelines for conditions identified through inspections were consistent with GO 95 requirements. Once repairs were completed, the paper packet was dated, signed, and returned to be documented in the database.

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[28] Today, work orders are generated in SAP and sent to an assigned employee using a work order management software.

[29] According to GO 95, Level 1 findings are those with an immediate safety and/or reliability risk with high probability for significant impact. Level 2 findings are those with a variable (non-immediate high to low) safety and/or reliability risk. And Level 3 findings are those with an acceptable safety and/or reliability risk.

The Specific Facilities were subject to several patrols in the years prior to the Mountain View Fire. Liberty located records confirming patrols in January 2013, April 2015, and November 2017.[30] No findings were identified for the Specific Facilities during these patrols. In May 2020, the Specific Facilities were subject to detailed inspection by an experienced Liberty journeymen lineman, as part of Liberty's detailed survey of overhead equipment (described in more detail below). The West Pole was inspected on May 6, 2020, and no conditions were identified. The East Pole was inspected on May 6, 2020, and the inspector identified a piece of idle hardware as a Level 3 repair, meaning the condition had to be remediated or reinspected within five years.[31] Both poles were ultimately replaced in 2022 as part of the Topaz Line Rebuild Project, described in detail in Part IV.B. Figure 10 summarizes the detailed inspections of the Specific Facilities in the years preceding the fire:

Figure 10: Table Summarizing Recent Detailed Inspections of the Specific Facilities

	East Pole (Pole 40288)	West Pole (Pole 266731)
Date of Last Detailed Inspection Before Fire	May 6, 2020	May 6, 2020
Findings from Last Detailed Inspection	Condition identified: idle hardware described as "insulator pin on secondary arm, road side" (Level 3 priority)	None
Previous Detailed Inspections	December 21, 2016 (No findings) June 30, 2011 (No findings)	December 20, 2016 (No findings) April 26, 2011 (Conditions identified: "Bolt Covers" and "Guys / Guards Broken / Loose")

[30] Liberty has not located records confirming a patrol of the Specific Facilities between November 2017 and May 2020, when they were subject to a detailed inspection as described herein.

[31] The inspector reported the idle hardware as an "insulator pin on secondary arm, road side." Idle hardware is hardware deemed unnecessary to support the then-current facilities. The idle insulator pin did not pose a safety hazard and was identified as a Level 3 repair.

2. Liberty's Detailed and Comprehensive Systemwide Asset Survey in 2020

In 2020, Liberty deployed Liberty's journeymen linemen and engaged a contractor to perform an asset survey and detailed inspection of all overhead distribution and transmission assets. This survey included detailed visual inspections of the condition of conductors, poles, and other overhead equipment, regardless of when the equipment had last been inspected. Liberty performed this survey to update its inventory for accuracy via photographs and GPS coordinate data, to assess the condition of its assets, to plan remediation projects, and to better assess risks in its electric system. An equipment database was created to store the asset information. During this survey, Liberty performed more than 22,000 detailed inspections of overhead assets and identified a substantial number of GO 95 repairs.

B. Liberty's Intrusive Pole Inspection Program Exceeded Regulatory Requirements

Liberty performed intrusive inspections on all wood poles on a ten-year cycle, including wood poles that had previously passed intrusive inspections.[32] Liberty used a qualified contractor to perform intrusive pole inspections. During these inspections, the contractor excavated around the base of the pole and performed tests on certain poles (*e.g.*, the sound and bore test). If necessary, poles were treated with preservative paste or liquid, or fumigant. Poles determined to be weakened based on shell thickness measurements were either reinforced or replaced. These inspections and treatments ensured the structural integrity of poles and reduced the risk of pole failure. In 2020, Liberty performed intrusive inspections on approximately 3,000 poles.

At the time of the Mountain View Fire, both the West and East Poles had been inspected consistent with Liberty's ten-year inspection cycle. The West Pole was last subjected to an intrusive pole inspection on July 30, 2013. The East Pole was last subjected to an intrusive pole inspection on July 16, 2013. Liberty's records indicate the contractor performed a sound and bore test on and applied fumigant to both poles.

C. Liberty Inspected Its Substations Consistent With Regulatory Requirements

Liberty inspected its substations in accordance with regulatory requirements. As described in its Substation Inspection Plan, Liberty performed quarterly inspections for eleven substations that were

[32] This exceeded the GO 165 requirement of 20 years for wood poles that had previously passed intrusive inspections.

accessible year-round and annual inspections for two substations (Hobart and Stampede) that were not accessible for daily operations. These substation inspections were performed by qualified operators and technicians, who recorded the results of their inspections in a Substation Inspection Report. These substation inspections reduced the risk that equipment failure at a substation could create safety hazards. In 2020, Liberty performed a total of 44 substation inspections on its then-existing 13 substations, with only two that were past due.

D. Liberty's Vegetation Management Programs Mitigated the Risk of Ignition Posed By Vegetation Near Liberty's Overhead Lines

In the years prior to the Mountain View Fire, Liberty had robust vegetation management programs which supported compliance with vegetation management regulations, including GO 95, Rule 35 and Public Resources Code ("PRC") sections 4292 and 4293, and reduced ignition risk.

1. Routine Vegetation Inspections

At the time of the Mountain View Fire, Liberty's routine vegetation management program was detailed in the company's Vegetation Management Plan, which established processes and procedures aimed at preventing vegetation encroachments into regulatory clearance zones, identifying, documenting, and mitigating hazard trees, and prescribing mitigation work.[33]

Liberty used qualified and experienced contractors to perform vegetation management inspections. These contractors were required to be ISA Certified Arborists, state-licensed Registered Professional Foresters, or to otherwise have a minimum of five years' experience in forestry, arboriculture, or horticulture. Vegetation management inspections were generally performed by completing a Level 2: Basic Assessment per ANSI A300 (Part 9) Tree Risk Assessment.[34] During a Level 2 assessment, inspectors carefully examined each tree and its surrounding site by walking around the tree, if there were no customer refusal or access issues. When inspectors assessed vegetation that may encroach on a line, they considered the movement of conductors, the movement of vegetation, and the interrelationships between growth rates,

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[33] At the time, the company was also in the process of developing specialized policies for different vegetation management functions, which were implemented in 2021. For instance, Liberty developed additional volumes focused on hazard trees, post-work verification, customer refusals, etc.

[34] A300 (Part 9) is a set of voluntary national standards and standard practices for Tree, Shrub, and Other Woody Plant Management, established by the American National Standards Institute.

control methods, and inspection frequency. If a tree was determined to have the potential to grow into the clearance distances, or fall into Liberty's facilities, within Liberty's maintenance cycle, inspectors would prescribe mitigation work. For distribution lines, trees were generally pruned to a clearance distance of 12-15 feet from Liberty's overhead lines at the time of mitigation, depending on the growth rate of the trees. If a tree was deemed to be a fall-in risk, it would be removed. By 2019, over 10,000 trees were identified annually for mitigation work.[35]

In the years prior to the Mountain View Fire, Liberty prioritized vegetation management inspections on circuits based on the number of years since the last tree trim, fire risk, circuit outage history, and operating budget. As of 2017 and years prior, Liberty's vegetation management program focused on annual planning, rather than long-term, multi-year planning, and the average number of miles completed each year equated to a vegetation maintenance cycle in excess of 7 years. Recognizing the need to implement improvements to further mitigate the risk of wildfires, Liberty engaged an experienced vegetation management specialist in 2017 to comprehensively review Liberty's vegetation management program and identify an optimum strategy. As a result of this comprehensive review, Liberty requested and received approval in its 2019 GRC for an annual budget of $3.98 million to move to a three-year cycle of vegetation management, a substantial increase in funding compared to previous rate cycles.[36] In 2019, Liberty performed detailed inspections of vegetation along approximately 219 line miles of its overhead electrical lines and equipment, a substantial increase over prior years. In 2020, Liberty exceeded its three-year cycle goal by performing detailed vegetation inspections on approximately 233 line miles.

Liberty managed its tree work inventories and workloads through the Vegetation Management System (VMS) database. This database tracked circuit inspections, notification and tree work progress, provided work orders, and retained historical inspection and tree work data. A tree was added to Liberty's inventory if it was identified as requiring mitigation work. Each tree was assigned its own tree identification number, which could be used to generate new

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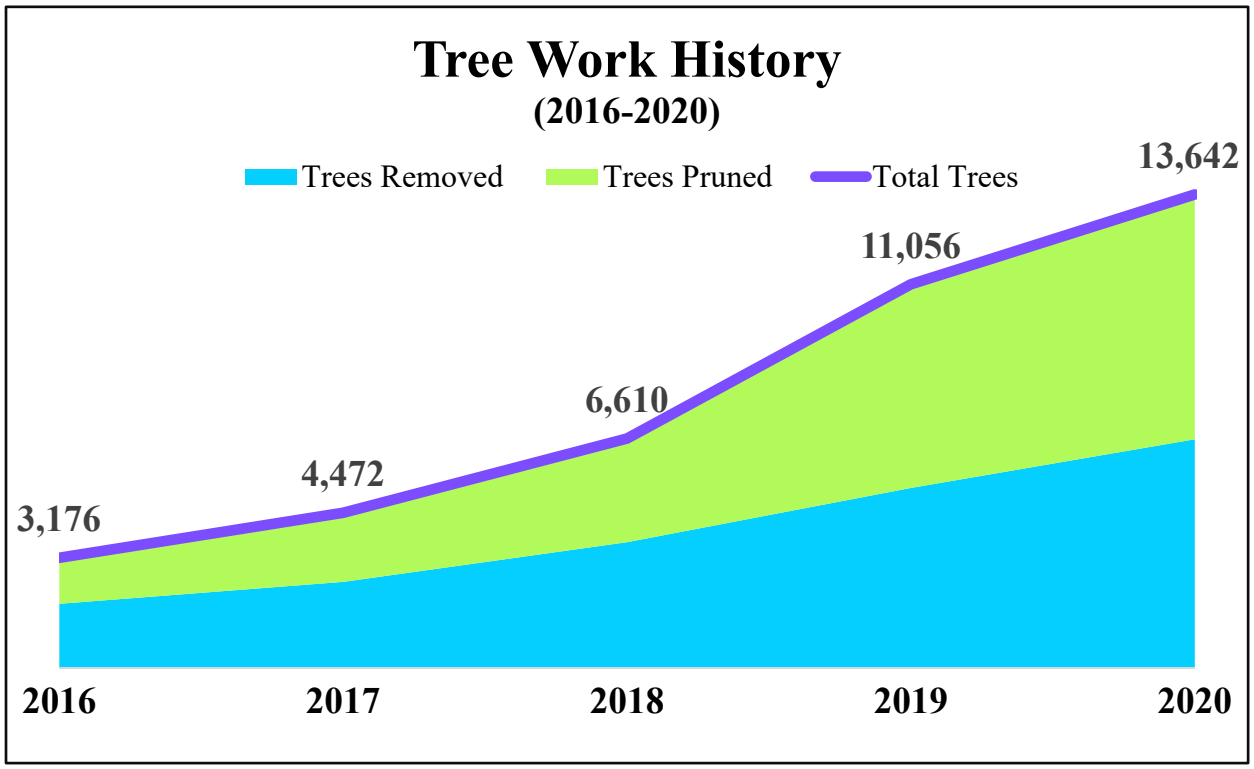
[35] *See* Figure 11 for the total number of trees pruned and removed between 2016-2020. This number includes trees pruned and removed after routine vegetation management inspections and after Liberty's tree mortality patrol inspections, a wildfire mitigation-focused program started at the end of 2017, which is described in more detail below.

[36] *See* D-20.08.030 at 52-54.

inspection records and work orders. Each tree also was assigned a status to track notifications, project progress, and tree work completion. The database retained records for trees that had been identified as hazard trees and removed.

With respect to the Specific Facilities, records show that a pine tree near the West Pole was pruned on March 17, 2017 to meet Liberty's internal 12-foot clearance requirements.

Figure 11: Number of Trees Pruned and Removed by Liberty (2016-2020)



2. <u>Additional Vegetation Management Programs Focused on Wildfire Mitigation</u>

In addition to its routine vegetation management program focused on regulatory compliance, Liberty recognized the need for additional vegetation management inspections and remediation work specifically aimed at reducing wildfire ignition risk. To that end, Liberty inspected the approximately 50 miles of overhead facilities within Tier 3 HFTDs in 2020. Starting in 2021, Liberty replaced these wildfire mitigation-focused vegetation inspections in high fire areas with more comprehensive and efficient annual systemwide LiDAR scans, described in more detail below in Part V.D.4.

Liberty implemented a program—the Tree Mortality Removal Project—to inspect for dead and dying trees throughout its system under its Catastrophic Event Memorandum Account ("CEMA"). Beginning in 2014-15, California saw an exponential increase in tree mortality rates due to persistent drought conditions and bark beetle infestations. Because Liberty's service area contains large swaths of densely-forested areas, including in priority counties identified by the State's Tree Mortality Task Force (El Dorado and Placer Counties), Liberty initiated a program at the end of 2017 to identify and remove dead and dying trees that could pose a fall-in risk or serve as fuel sources for wildfires. During these tree mortality patrols, inspectors conducted Level 1: Limited Visual Assessments per ANSI A300 (Part 9) Tree Risk Assessment from the ground, a vehicle, or by air, depending on terrain, type of infrastructure, and tree type. Inspectors assessed the side of the trees facing the electric facilities for obvious defects. If a condition was identified that could not be sufficiently evaluated based on a Level 1 assessment, a Level 2 assessment was conducted.

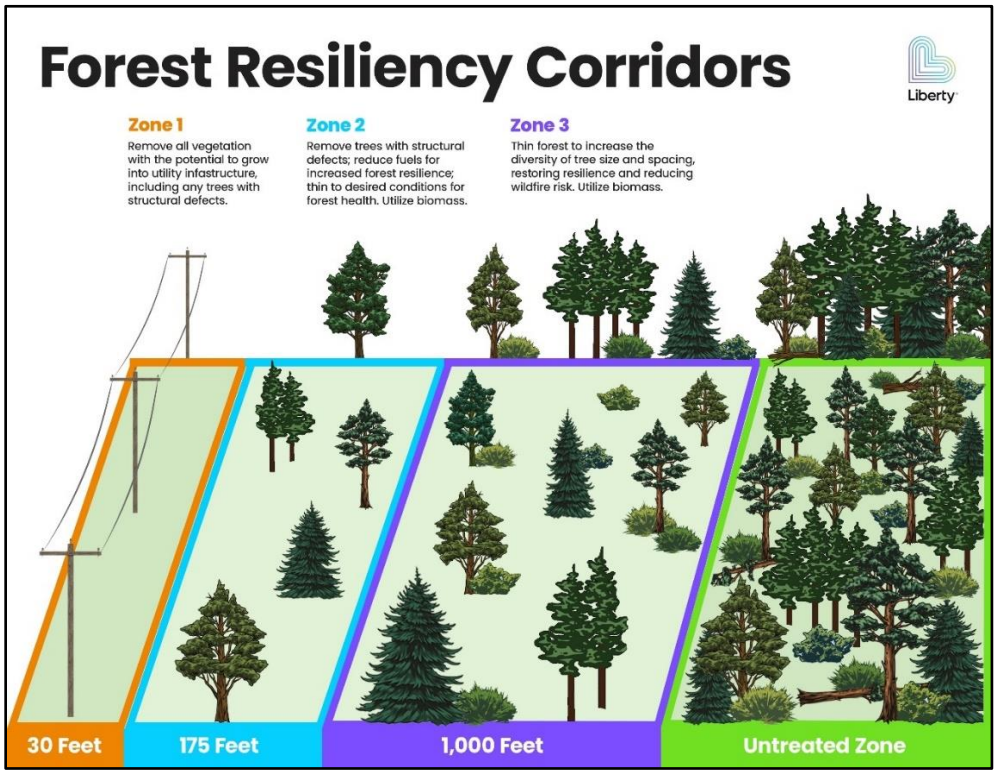
Liberty prioritized tree mortality patrols in parts of its service area where it was aware of high levels of tree mortality and generally planned for these patrols to take place around the middle of its routine vegetation inspection cycles to maximize their impact. Liberty patrolled approximately 164 line miles in 2019 and 331 line miles in 2020. As a result of these tree mortality patrols, Liberty removed 1,539 trees in 2019 and 2,038 trees in 2020. Recognizing an ongoing need for off-cycle tree mortality patrols, as of the 2022 GRC cycle, Liberty incorporated these patrols into its operation and management expenses and no longer tracks the program's costs in its CEMA.

Liberty cleared slash and debris from its vegetation management work. Vegetation left behind from mitigation work, if left untreated, could become a fuel source and present an infestation risk. Liberty's VMP required that any slash measuring less than four inches in diameter must be chipped if it was in a residential area accessible by roads and lopped and scattered in a non-continuous manner outside the utility's right-of-way in a rural or forested area not accessible by road. In 2020, Liberty completed several projects focused on fuel management and reduction of slash, including three community fuel reduction projects in Truckee and South Lake Tahoe and on parcels owned by the California Tahoe Conservancy, where recent vegetation management activities had taken place. Liberty also identified two substations—Squaw Valley and Meyers—for fuel management and slash reduction work. Liberty inspected vegetation

adjacent to the substations, removed hazard trees that had the potential to impact substation facilities, and cleared dead brush, branches, and debris and slash around the substation.

Liberty collaborated with partner organizations—including California State Parks, Lake Tahoe Basin Management Unit, Tahoe National Forest, California Tahoe Conservancy, and Tahoe Fire and Fuels Team—to conduct comprehensive multi-jurisdictional forest resiliency and fuel reduction treatments surrounding critical community infrastructure. The project was approved in October 2019 and granted a categorical exemption from documentation in an Environmental Assessment or Environmental Impact Statement. In 2020, Liberty began to implement its first Forest Resiliency Corridor project, consisting of 55 miles of Liberty power lines on ~7,600 acres of lands managed by the Lake Tahoe Basin Management Unit and the Tahoe National Forest. The project enacted three treatment zones around utility rights-of-way that go above and beyond maintaining compliance obligations (*see* Figure 12). This first resiliency corridor was implemented on the 625 60 kV Kings Beach-Tahoe City transmission line and resulted in the removal of hazardous trees and other vegetation.

Figure 12: Treatment Zones Around a Forest Resiliency Corridor



3. Emergent Vegetation Management Work

In addition to its compliance- and wildfire mitigation-based vegetation work, Liberty responded to vegetation management needs identified outside of its vegetation inspections. For example, Liberty linemen could notify the vegetation management department of necessary mitigation work that they identified during patrols or detailed inspections (referred to as "Tree Tags"). Customers and local agencies could also inform Liberty of emergent vegetation management needs. When the vegetation management team received such notifications, it inspected the site and conducted remediation work as appropriate. Likewise, Liberty had vegetation management crews that stood by for emergency work, such as immediate life, property, or public safety threats posed by extreme weather or accidents.

4. 2020 LiDAR Scan

In October 2020, Liberty conducted a LiDAR scan to evaluate vegetation clearances for approximately half of its service area, including all line miles in Tier 3 HFTDs. The data collected during the LiDAR scan provided a detailed analysis of vegetation conditions and potential encroachments, allowing for quicker and more efficient inspection and remediation work. The LiDAR results also allowed Liberty's vegetation inspectors to focus more attention to identifying hazard trees that pose a fall-in risk during their routine inspections. Although the regulatory clearance distance is four feet for distribution lines, Liberty used a 1.5x safety factor and generated work orders where LiDAR results showed vegetation encroachments within six feet of conductors. After the 2020 LiDAR scan, Liberty's vegetation inspection contractor validated scan results in the field and determined that the scan accurately recorded vegetation clearance distances. Starting in 2021, Liberty has conducted system-wide LiDAR scans for vegetation clearance on an annual basis.

The October 2020 LiDAR scan covered the entire Topaz 1261 Circuit. The Subject Span was listed as "clear," meaning there was no vegetation within 12 feet of the conductors in this span.[37] Thus, the LiDAR scan showed that the Subject Span was compliant with the vegetation

[37] The LiDAR scan identified a total of four trees within 12 feet of the conductors for the adjacent spans on either side of the Subject Span; the closest tree had a specified distance to wire of 5.26 feet, which was still in excess of the 4-foot vegetation clearance requirement set forth in GO 95, Rule 35 and PRC section 4293. On February 17, 2021, Liberty trimmed two trees near the West Pole in response to LiDAR results.

clearance requirements set forth in GO 95, Rule 35 and PRC section 4293. The fire agency report affirmed that the Specific Facilities were maintained in compliance with PRC 4293.[38]

5. Pole Clearing

Liberty performed pole clearing around poles with certain types of electrical equipment that subjected them to the requirements of PRC section 4292.[39] Pole clearing was performed by qualified contractors. The scope of pole clearing included inspection and removal, within a ten-foot radius zone, of all flammable materials within eight feet of ground level, including grasses, brush vegetation, limbs and foliage of living trees, dead and desiccated vegetation, duff, litter, trash, and other debris. Fire resistant landscaping such as lawns or low growing herbaceous vegetation with irrigation, and paved surfaces were exempt from clearance requirements. Contractors conducting pole clearing were also required to report dead, diseased, or dying limbs or trees, and foliage from living trees above eight feet from ground level. Contractors also had to remove or dispose of vegetation waste materials and debris from pole clearing activities located within 100 feet of accessible roads. After completing pole clearing work, contractors were expected to place tags next to the pole number tag identifying the contractor name and year of work completed. Contractors were also expected to take before and after images of each pole.

Prior to the Mountain View Fire, the West Pole was last cleared on September 23, 2020. Figure 13 shows the before and after images of the West Pole, as documented by the contractor who completed the pole clearing work. There was no vegetation growth within a ten-foot radius of the East Pole. As shown in Figure 14, an aerial photograph taken one week after the fire show vegetation clearances around the poles, and the fire agency report affirmed the Specific Facilities were maintained in compliance with PRC 4292.[40]

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[38] Appendix A to *Liberty-02C: Ignition*, at 17 ("Both power poles were in compliance with California Public Resource Code (PRC) Section 4292 and PRC Section 4993 [sic] requirements.").

[39] PRC 4292 and Cal. Code of Regulations Title 14 requires utilities to maintain, in mountainous, forest-covered, brush-covered, and grass-covered areas, a ten-foot radial clearance around poles and towers supporting certain electrical equipment, up to a height of eight feet.

[40] Appendix A to *Liberty-02C: Ignition*, at 17 ("Both power poles were in compliance with California Public Resource Code (PRC) Section 4292 and PRC Section 4993 [sic] requirements.").

Figure 13: Photographs of West Pole Before and After September 23, 2020 Pole Clearing



Figure 14: Photograph of Specific Facilities from November 24, 2020



6. Contractor Oversight

At the time of the Mountain View Fire, Liberty performed post-work verification and quality control audits on its contractors' vegetation management work on an annual basis. In 2020, Liberty's VMP required that a 15% random audit be performed on all contractor work. Liberty also communicated regularly with contractors to ensure that vegetation management work was being conducted in a timely and satisfactory manner. Liberty found that these random audits generally yielded good results. In 2020, Liberty performed quality control of vegetation management inspections on approximately 57 line miles. Since 2020, Liberty has developed the

Post Work Verification Procedure (VM-04), which established a formal quality assurance and quality control program based on more sophisticated sampling methodology, sample size by priority, process assessment, results evaluation, acceptable quality level and conformance level, and descriptions of post work verification.

VI.

Liberty Prudently Operated Its Electric System with a Focus on Monitoring and Mitigating Potential Ignition and Other Public Safety Risks

At the time of the Mountain View Fire, Liberty had procedures and processes designed to promote the safe operation of its electric system and to reduce the risk of ignition. Liberty's system operations center in New Hampshire monitored Liberty's system and coordinated with field personnel to address emergent conditions and other issues. Liberty developed and implemented situational awareness tools to better monitor its system for emergencies and respond to them. Liberty also had a Public Safety Power Shutoff (PSPS) protocol that balanced reducing the risk of ignition on extreme fire weather days with the public safety risks posed by power shutoffs. On the day of the fire, the protection devices on the Topaz 1261 Circuit functioned as intended, and Liberty field personnel responded promptly to issues identified by the System Operator. Liberty field personnel were on scene at the Mountain View Fire mere minutes after the fire's ignition, where they coordinated with firefighters on emergency response and to protect public safety.

A. Liberty's Control Center Continuously Monitored Liberty's Electric System and Coordinated with Local Field Personnel to Respond Promptly to System Issues

Liberty's service area is divided into two districts for electric operations, with the South Lake Tahoe District Operations serving parts of El Dorado, Mono, and Alpine Counties, and the North Lake Tahoe District Operations serving parts of Placer, Nevada, Sierra, and Plumas Counties. The two service areas are fed by different primary transmission sources and are independent control areas for distribution switching. Because of the unique independent configuration, the service areas operate as individual districts during emergencies.

From the time Liberty acquired the utility from NV Energy until the end of 2018, Liberty's system was operated by NV Energy's system control center. In 2018, Liberty began the process of transitioning system control to Liberty Utilities' System Control Center in New Hampshire. This process involved disconnecting remote terminal units from the NV Energy system, connecting them to Liberty's system, and conducting testing to ensure their proper functioning. Liberty field personnel

were trained on Liberty Utilities' Clearance and Control procedures, outlined in its Electric Operating Procedure.[41] By the end of 2018, Liberty's system operations had fully transitioned from NV Energy to Liberty Utilities' System Control Center in New Hampshire.

Liberty's system operations group in New Hampshire coordinated remotely with Liberty's field personnel in California. There was always at least one System Operator on shift monitoring Liberty's grid operations. Liberty's System Operators undergo training on fundamental principles of electric operations and practice for various clearance and control scenarios. Training consists of both formal classroom training and on-the-job training, ranging from around six months of training for operators with more experience to two years of training for an entry-level operator. At the time of the Mountain View Fire, Liberty also had an emergency dispatch group (typically between two and five individuals) on site working alongside the System Operator, to assist with dispatch functions.[42] The System Operator and dispatch team actively communicated with field personnel to address any issues that arose. During emergencies, field operations personnel could also contact the System Operator to request that reclosing functionality be turned off or disabled. The System Operator maintained an operator log of events on Liberty's system, such as device operations and non-reclose requests.

Liberty's System Control Center in New Hampshire operated under Liberty Utilities' Electric Operating Procedure, including procedures governing Clearance and Control and Re-Energization of Circuits. Generally, switching devices on a line or in a substation were not to be operated without permission from the System Operator, except in an emergency condition that endangered life or property or other limited conditions. Similarly, if a switching device was opened for any reason, closing it required permission from the System Operator.

When an outage occurred on its electric system, Liberty field personnel patrolled and visually inspected the impacted line to identify potential safety issues and report and remediate any such issues prior to re-energization. The Electric Operating Procedure included the steps to be taken by a System Operator to ensure safe re-energization of a circuit following an outage. Depending on the circumstances surrounding the outage (*e.g.*, whether there was a non-reclose assurance at the time), the

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[41] The Clearance and Control procedures governed the activities of Liberty in California as well as New Hampshire, where Liberty Utilities (Granite State Electric) Corp. operates an electric system.

[42] At the time of the fire, this dispatch group was responsible for Liberty's electric, water, and gas systems. Since then, Liberty has split the dispatch group by utility function. Now, there are usually one to three dispatchers on-site who are dedicated to addressing outages and other emergencies on Liberty's electric system.

System Operator would investigate the cause prior to re-energizing, such as by contacting field personnel nearby, looking for evidence of a fault, or conducting a Risk Assessment that would evaluate factors such as weather conditions, time of day and location, SCADA information, potential bird, animal, or public contact with facilities, and others. The System Operator could re-energize a circuit only after a Risk Assessment and any necessary line patrols, inspections, and remediation of safety hazards were completed.

On the day of the Mountain View Fire, a System Operator was actively monitoring Liberty's electric operations, and communicated directly with field personnel about scheduled work and outages on the Topaz 1261 Circuit that day, as discussed further in Section VI.D below.

B. Liberty Implemented Operational Tools to Mitigate Wildfire Risk While Protecting Public Safety

In the years preceding the Mountain View Fire, Liberty took significant measures to enhance situational awareness to better predict and prepare for conditions of elevated wildfire risk in its service area. To that end, Liberty engaged a third-party consultant with substantial fire science and risk modeling expertise to support Liberty's development of potential mitigation strategies, craft operational mitigation tools, and support Liberty's ongoing implementation of those tools. These tools and strategies significantly enhanced Liberty's ability to forecast hazardous conditions affecting its system and to mitigate wildfire ignition risk in Liberty's operations.

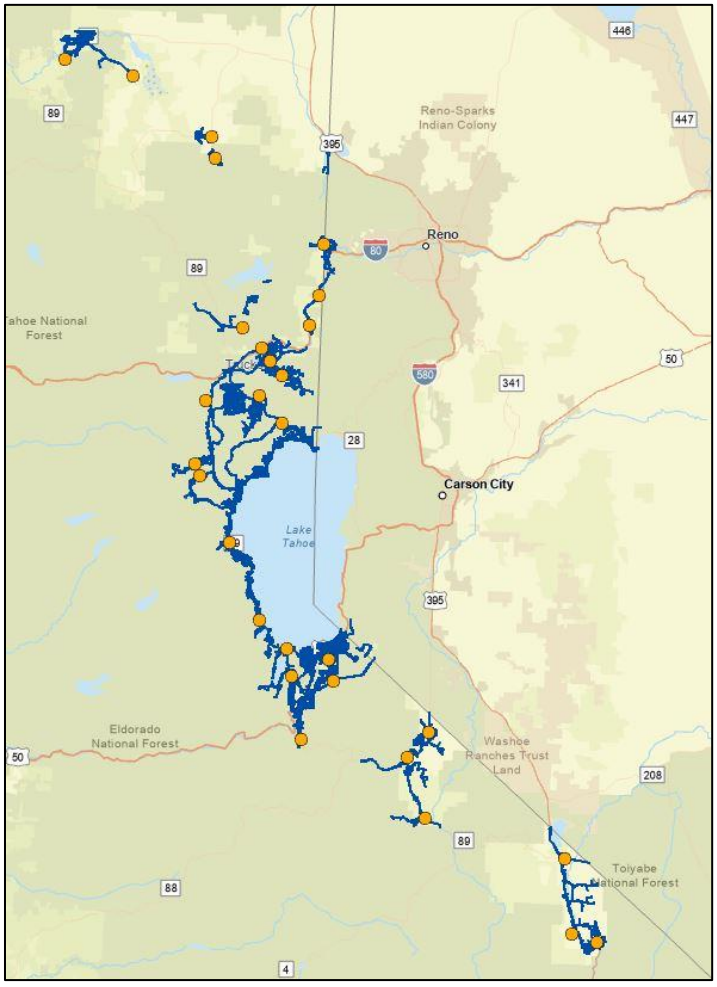
1. Enhanced Situational Awareness Tools

In 2020, with the assistance of the third-party fire science and risk modeling consultant, Liberty developed and implemented a Fire Potential Index ("FPI"), a fire risk modeling tool that used multiple data inputs (*e.g.*, live and dead fuel moisture, "green-up" factor, ambient temperature, relative humidity, and the Fosberg Fire Weather Index ("FFWI")) to calculate a standardized numeric ranking of fire threat at any given time and to obtain a forecast of expected fire weather conditions. Liberty used this index to guide decisions regarding operations and field work. Liberty's FPI tool provided a seven-day forecast for 11 different geographic zones across Liberty's service area, ranking fire risk conditions on a five-category scale: Low, Moderate, High, Very High, and Extreme. Thresholds for these risk rankings were determined through an evaluation of historical fire events and typical seasonal values. Liberty developed its FPI based on risk modeling methodologies implemented by the large investor-owned utilities such as San Diego Gas & Electric Company ("SDG&E") and Pacific Gas and Electric Company ("PG&E").

FPI forecasts were communicated to Liberty's field personnel on a daily basis. In the days preceding the Mountain View Fire, the forecast FPI for the Topaz zone ranged from "Low" to "Moderate" for November 17, 2020, indicating there was no elevated fire threat anticipated. In the updated forecast issued at 6:00 a.m. on November 17, the fire risk was identified as "Low."

To support its wildfire risk modeling and forecasting efforts and to provide high quality observational data, Liberty began installing weather stations to monitor and record ambient conditions across Liberty's service area affecting its system, including wind, humidity, fuel moisture, precipitation and other relevant information. Liberty installed ten weather stations in 2019 and an additional 19 weather stations in 2020. Enhanced collection of weather data provided valuable inputs and improved accuracy for Liberty's PSPS and FPI tools and helped Liberty plan for operations during extreme weather events. At the time of the fire, six weather stations were active on the Topaz 1261 Circuit. Figure 15 depicts the locations of all weather stations that Liberty had installed by the end of 2020.

Figure 15: Map of All Liberty Weather Stations at the Time of the Mountain View Fire



In 2020, Liberty also utilized the ALERTahoe wildfire camera network. The network employed cameras with pan-tilt-zoom capabilities in high fire risk areas throughout Liberty's service area. These cameras provided opportunities for early detection of ignitions and visibility of the conditions on Liberty's system.

2. <u>Public Safety Power Shutoff (PSPS) Protocol</u>

At the time of the Mountain View Fire, Liberty had a PSPS protocol in place as a wildfire mitigation measure of last resort. Liberty's PSPS protocol appropriately balanced the need to reduce the risk of ignition during the most extreme and dangerous fire weather conditions against the risks to customers and the public posed by power shutoffs. This protocol was developed and refined over time, with the assistance of Liberty's fire science and risk modeling consultant.

Following the destructive 2017 wildfire season, the Commission issued Resolution ESRB-8, acknowledging that proactive de-energization "could save lives, protect property, and prevent fires."[43] Resolution ESRB-8 extended the PSPS-related requirements previously imposed on SDG&E to all investor-owned utilities and prescribed additional requirements to enhance PSPS policies and procedures. Senate Bill 901 ("SB 901") was subsequently enacted in September 2018, significantly expanding the statutory requirements for utilities to submit WMPs, including a requirement to include PSPS protocols that would govern de-energization decisions and also mitigate public safety impacts of proactive power shutoffs.

Liberty's 2019 WMP established a basic PSPS protocol that triggered proactive de-energizations based on local meteorological conditions and other risk factors such as fuel moisture and firefighting capabilities. This early version of Liberty's PSPS protocol required the utility to dispatch crews to monitor field conditions when wind speeds reached 50 mph for greater than three seconds and allowed de-energization if wind speeds exceeded that threshold and a line posed a hazard.[44] Liberty undertook an effort to substantially refine and further develop its PSPS protocol for 2020.

Liberty engaged a fire science and risk modeling consultant in 2019 to support developing a more sophisticated PSPS protocol comprising a set of criteria and guidelines for de-energization. This consultant was also supporting other utilities with similar work. Liberty's refined PSPS protocol was implemented and approved by OEIS as part of its 2020 WMP.[45] The PSPS protocol used a predictive tool to capture three fire weather components: (a) Energy Release Component ("ERC");[46] (b) wind gusts;[47] and (c) Fosberg Fire Weather Index

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[43] Resolution ESRB-8 (July 16, 2018) at 9.

[44] Liberty first initiated a small-scale proactive power shutoff event on November 21, 2018, when it de-energized three lines in South Lake Tahoe for approximately three hours, impacting 30 households. Liberty did not have a formal PSPS protocol at the time, but proactively initiated a power shutoff based on weather conditions.

[45] *See* Resolution WSD-007 (Jun. 19, 2020).

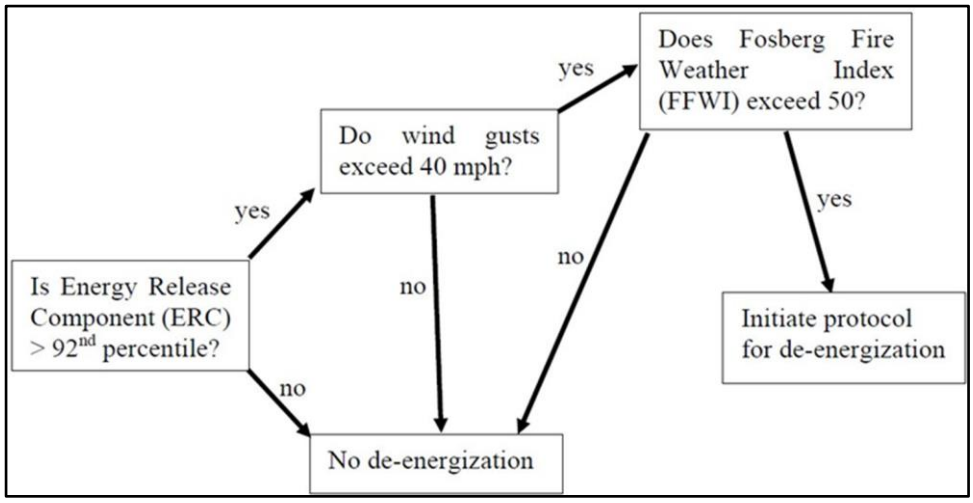
[46] The ERC component primarily measured fuel moisture content and fuel load on a percentile basis relative to seasonal trends. Fire occurrence and size are strongly correlated with ERC. An ERC reading in the 92nd percentile or higher means that the risk of a wildfire spreading out of control is substantial.

[47] The wind gust component measures peak expected wind speeds. The higher the wind gust, the higher the likelihood that a hazard such as animal or debris contact or conductor contact may occur.

("FFWI").[48] Together, these three components were intended to capture the risk of wildfire ignition and spread based on forecasted medium- and long-term environmental conditions and weather conditions. The PSPS protocol also specified that when Liberty declared and implemented a PSPS event, it would conduct proactive patrols on affected circuits to inspect for hazards and provide advanced notice of potential shutoffs to public safety partners and customers to protect public safety.

PSPS was a wildfire mitigation tool of last resort. Based on historical weather observations and archived forecast data, Liberty established de-energization thresholds that sought to balance the benefits of proactively shutting off power to reduce ignition risk during extreme fire weather conditions with the potential public safety risks inherent in any power outage, especially one occurring during fire weather. To that end, for the vast majority of Liberty's PSPS zones, Liberty used the following de-energization thresholds for the three criteria in the protocol—ERC percentile, wind gusts, and FFWI:

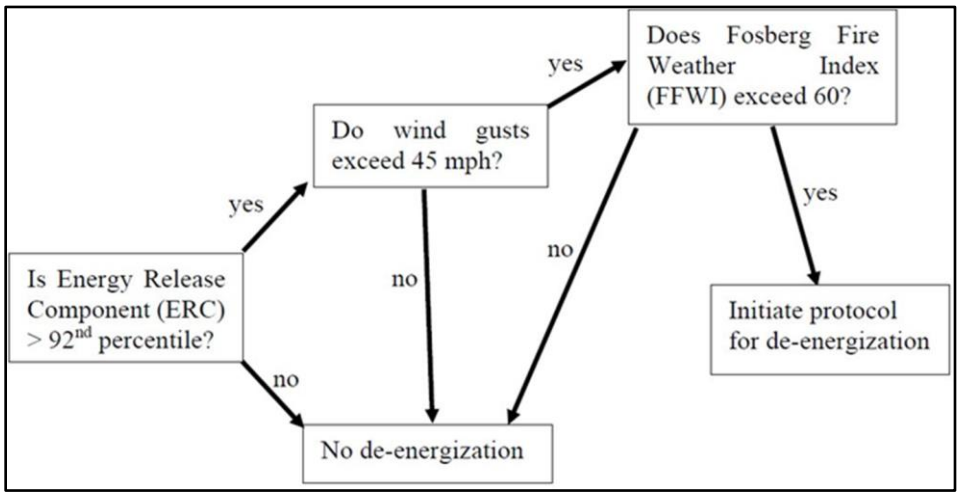
Figure 16: De-Energization Decision Tree for Most of Liberty's PSPS Zones



[48] FFWI is a commonly-used measure of fire risk that takes into account short-term variations in temperature, relative humidity, and wind speed. It does not take into account fuel type, topography, or fuel moisture. The FFWI scale ranges from 0 to 100, with a reading above 50-60 considered high risk. This component complemented the ERC's seasonal considerations by measuring short-term weather conditions conducive to rapidly-spreading fires.

Because the Topaz and Muller 1296 R3 PSPS zones were windier than other PSPS zones under normal weather conditions, Liberty's protocol established slightly higher thresholds for wind gusts and FFWI:

Figure 17: De-Energization Decision Tree for Topaz and Muller 1296 R3 PSPS Zones



In 2019 and 2020, Liberty continued to refine its PSPS protocol, including based on lessons learned from a September 2019 "near miss" event during which it had been preparing to activate a PSPS ahead of predicted dangerous weather conditions that did not come to pass, as well as various tabletop training exercises. On November 2, 2019, Liberty hosted a tabletop exercise with public safety partners to test communication protocols. On June 25, 2020, Liberty held a comprehensive simulated PSPS exercise to test its PSPS protocol and procedures for de-energization, re-energization, incident command, communications, and operational response. This exercise involved 45 internal participants, the Commission, Cal OES, Cal Fire, local fire districts, public safety partners, and critical infrastructure providers, who provided input on successes and areas for improvement. These exercises demonstrated Liberty's ongoing effort to improve its PSPS protocol in partnership with stakeholders and to ensure that Liberty personnel were well-prepared to execute its PSPS protocol.

Liberty also undertook several initiatives to educate customers and the general public about PSPS; it distributed accessible educational brochures, published a web page, and delivered

bill inserts about Liberty's PSPS protocol and notification procedures. These initiatives informed Liberty's customers of how Liberty would make decisions regarding power shutoffs so customers could prepare themselves when they receive shutoff notifications during fire weather conditions.

On November 17, 2020, forecast weather and fire risk modeling did not meet Liberty's approved PSPS criteria for the Topaz 1261 Circuit prior to ignition of the Mountain View Fire.[49] Indeed, in the days leading up to November 17, 2020, the FPI forecasts for the Topaz zone for that day ranged from "Low" to "Moderate." The NWS issued a high wind warning for the area but did not issue a Red Flag Warning.[50] In the NWS's weather briefings in the days leading up to the fire, including on the day of the fire, the NWS noted that there were no heightened fire risk concerns because of favorable moisture content in the area. In fact, the region just had a significant snowfall on November 8, 2020.

3. Recloser Operations

In the years preceding 2020, Liberty installed continuous monitoring sensors and SCADA controls for reclosers. SCADA-capable reclosers allow Liberty to determine fault conditions and outage locations more quickly and decrease its response times. As discussed in Part VI.A, Liberty's system operations transitioned from NV Energy to Liberty Utilities' System Control Center at the end of 2018. In 2020, Liberty's System Control Center in New Hampshire monitored available SCADA data from reclosers in real time. If abnormal activity on a line was detected, an alarm would inform the System Operator of the abnormality. The System Operator would typically be required to acknowledge the alarm. If an alarm did not indicate that a device was open (*e.g.*, an "over current" alarm not accompanied by a trip), the System Operator would evaluate the situation and determine whether a patrol was necessary. Typically, in those instances, the System Operator would coordinate a response by field personnel only if a customer reported an outage. If an alarm indicated that a device was open, the System Operator

[49] The forecast for 6:00 a.m. on November 17, 2020 calculated (a) an ERC of 60.5%; (b) 6-hour average wind gust of approximately 45 miles per hour; and (c) FFWI of 40. As the day went on, forecasts remained below threshold. At noon, the forecast calculated (a) an ERC of 48.9%; (b) wind gusts of 40-45 miles per hour; and (c) FFWI of approximately 30.

[50] Liberty understands that the last Red Flag Warning for the 2020 season was November 6, before the Tahoe region saw its first significant snowfall around November 8.

would call Liberty field personnel to perform a patrol of the relevant facilities. The System Operator also recorded alarms in an operator log.

During fire season, Liberty put its automatic reclosers in "non-reclose mode" or "fire mode," depending on the recloser's capabilities, meaning that the reclosers would not automatically attempt to reclose if they operated to de-energize a section of a circuit. Only after Liberty personnel patrolled and determined that the line was safe to re-energize would the System Operator authorize reclosing. This protective mode added a layer of security to detect potential ignition risks at times of elevated fire risk. "Non-reclose mode" and "fire mode" settings were active on Liberty's automatic reclosers throughout the historic 2020 fire season, which was the largest wildfire season in recorded California history at the time, burning approximately 4.2 million acres (more than 4 percent) of the State. In 2020, at least one recloser or group of reclosers was in "non-reclose mode" or "fire mode" on Liberty's system for a total of approximately 210 days, nearly two-thirds of the calendar year. The R1 and R2 Reclosers on the Topaz 1261 Circuit were in "non-reclose mode" and "fire mode," respectively, from May 29, 2020, until November 10, 2020, a continuous span of 165 days.[51]

These and other reclosers were taken out of fire mode in early November 2020 after the Tahoe region received its first snowfall, which traditionally marked the end of the fire season in the area. NWS data showed that its station at Minden, Nevada, approximately 35 miles northwest of Walker, reported 12 inches of snow on November 8, 2020. As illustrated in Figure 18, photographs taken on November 10, 2020, of two Liberty weather stations on the Topaz 1261 Circuit located within 10 air miles of the Mountain View Fire origin area showed snow cover on the ground just one week prior to the fire. This winter precipitation increased the overall moisture content in the area, which led fire science experts and weather forecasters to believe the fire season had concluded.

[51] Following the fire, the R1 and R2 Reclosers were put back in "non-reclose mode" and "fire mode," until January 28, 2021.

Figure 18: November 10, 2020 Photographs Showing Two Weather Stations on the Topaz 1261 Circuit[52]



LIB-06 Weather Station



LIB-05 Weather Station

Around this time, weather forecasts were tracking additional potential winter storms through mid-November. In the days leading up to the Mountain View Fire, NWS briefings highlighted the potential for strong winds but placed the fire risk as low, given the more favorable moisture content. Just four days before the fire, the local NWS office indicated it would be moving to "off season" fire weather forecasting. In light of this shift in weather and fire risk, and in consultation with its third-party fire science and risk modeling expert, Liberty deactivated fire mode / non-reclose mode on its automatic reclosers, including on the Topaz 1261 Circuit. This decision was made in anticipation of additional winter storms being tracked

[52] These photographs were taken on November 10, 2020, when the Commission's Wildfire Safety Division (now OEIS) inspected these and other weather stations. The LIB-06 weather station is located approximately 2.5 miles northwest of the origin area, and the LIB-05 weather station is located approximately 9 miles northwest of the origin area.

by weather forecasts.[53] Winter storms conditions could potentially result in longer customer outages and public safety concerns if reclosers remained in non-reclose or fire mode. Liberty also was aware that NV Energy, which operated the electric system in territory adjacent to Liberty's, had made a similar determination to take its reclosers out of "fire mode" around November 9.

Liberty's two reclosers on the Topaz 1261 Circuit functioned as expected in response to conditions on the circuit on November 17, 2020. That morning, reconductoring work as part of Liberty's Topaz Line Rebuild Project was ongoing. In connection with this work, the reclosers were placed in "hotline tag" mode for worker safety. The 1261 R2 Recloser recorded a phase-to-phase fault around 9:48 a.m. and operated, de-energizing that portion of the circuit and causing an outage. Following a patrol of the affected line, at 10:41 a.m. the 1261 R2 Recloser was closed, re-energizing the line and restoring power to the affected customers. In coordination with field personnel supervising the reconductoring work, the hotline tag mode was disabled and the 1261 R2 Recloser was returned to normal mode. Shortly after 11:55 a.m., the 1261 R2 Recloser detected a phase-to-phase fault followed by a series of phase-to-ground faults. The 1261 R2 Recloser operated and reclosed consistent with its settings and ultimately locked out, de-energizing the Topaz 1261 Circuit downstream from the 1261 R2 Recloser. Liberty's operational response to the outages and the Mountain View Fire is discussed in more detail below, in Part VI.D.

C. Liberty Strengthened Its Emergency Preparedness and Response Measures

In accordance with GO 166, Liberty had an Emergency Management Plan ("EMP") in 2020 that contained policies and procedures to enhance Liberty's ability to respond to and recover from emergencies of all levels, including natural disasters. These policies and procedures ensured that Liberty personnel were well prepared during emergencies to protect employee and public safety, coordinate with public safety partners, and maintain and restore service. The EMP prescribed procedures for activation of internal response teams and external communications, depending on the severity of an emergency event and the scale of its impact in Liberty's service area. During less serious emergencies (level 4-5), an individual department or Regional Command Center was responsible for

[53] As described in *Liberty-04: External Factors*, rain (and snow at higher elevations) began to fall in the Walker area within hours of the fire's ignition and temperatures dipped to the mid-30s by the morning of November 18.

addressing the emergency, with support from Emergency Management Team members where necessary. With the onset of more serious emergencies (level 1-3), the Incident Command System and an Emergency Management Team were activated to coordinate and direct response and mitigation efforts. During such emergencies, the Emergency Management Team was staffed with Liberty employees tasked with different functional roles (*e.g.*, Incident Commander, Public Information Officer, Safety & Security Officer, Government Liaison, etc.). These more serious emergencies were declared when a disaster or other event may affect several areas of Liberty's electric system and/or where an outage may last longer than 24 hours. Within an hour of the Mountain View Fire, an Incident Command System was activated, with a full Incident Management Team of 10 Liberty employees, to coordinate Liberty's response to the rapidly-evolving emergency.

In 2020, Liberty further enhanced its emergency preparedness and response initiatives to promote public safety. In particular, Liberty added specialized personnel, hiring an Emergency Management Manager to oversee the EMP, emergency response activities, and public safety partnership engagements, and a Fire Protection Specialist to oversee fire prevention initiatives, serve as Liberty's liaison for first responders and public safety partners, and coordinate fire protection-related training for employees and contractors. Liberty also formed a team of internal analysts and consultants to establish and refine its risk modeling capabilities.

Liberty's employees participated in EMP training annually. This training included instructions on the roles and responsibilities of different functional areas during emergencies. Each year, every Emergency Management Team member was required to participate in at least one tabletop exercise or lessons learned post-mortem regarding an actual event or major outage. Given its service area frequently experienced harsh winter weather, Liberty's Emergency Management Team also periodically hosted winter storm exercises—including one on November 10, 2020—to simulate storm-related outages and practice Liberty's coordinated response. These efforts improved Liberty's ability to anticipate and respond to emergencies and facilitated close coordination with Liberty's public agency partners. Throughout 2020, Liberty also hosted 29 meetings with public safety partners, held nine regional PSPS workshops, three PSPS tabletop exercises, and seven regional virtual town halls to inform the communities that it serves about its wildfire safety work.

D. Liberty Responded Promptly to Outages on the 1261 Topaz Circuit and to the Mountain View Fire on November 17, 2020

Liberty had two troubleshooters and two inspectors with primary responsibility for maintaining equipment and responding to field issues in the South Shore District. As discussed above, Liberty was performing reconductoring work on the Topaz 1261 Circuit on November 17, 2020. In light of this and other work that day on the circuit, Liberty field personnel and contractors were nearby and able to respond quickly to outages on the circuit that morning and to the scene of the Mountain View Fire.

Liberty field personnel responded to a small outage at approximately 8:35 a.m. on November 17, 2020, and found a cutout open on a branch line off Wunderlich Way, though were unable to determine the cause of the outage. Following an operation of the 1261 R2 Recloser at 9:48 a.m. and subsequent outage, Liberty's System Operator informed Liberty field personnel who were in the area for the reconductoring work. Liberty field personnel promptly patrolled the section of the Topaz 1261 Circuit located downstream of the 1261 R2 Recloser, including the Subject Span.[54] As a precaution, field personnel removed slack from a stretch of the Topaz 1261 Circuit that was in hot arms where the reconductoring work was being performed. Liberty field personnel notified the System Operator that the 1261 R2 Recloser could be closed and the line was re-energized.

Shortly after 11:55 a.m., Liberty's System Control informed an experienced electrical inspector about the phase-to-ground fault and lockout of the 1261 R2 Recloser. The inspector and a contractor crew identified the fire and immediately investigated, patrolling the spans downstream of the Recloser and quickly locating the fire near the Mountain View Barbeque. The fire was first reported to 911 shortly before noon. Liberty personnel arrived on scene within eight minutes of the first 911 call and within eleven minutes of the outage on the line once the 1261 R2 Recloser operated and locked out. At the request of firefighters, Liberty personnel and contractors quickly responded to the conductor lying on the ground, cutting each end of the separated conductor near the East and West Poles to facilitate first responder access to the scene. Liberty personnel then secured the portion of the conductor hanging down from the insulator to ensure public safety. Liberty field personnel continued to coordinate and offer support to the emergency personnel responding to the Mountain View Fire.

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[54] A Liberty troubleshooter had upgraded a meter at the Mountain View Barbeque adjacent to the East Pole on the morning of November 17, 2020, and likewise observed no issues with the Subject Span or Specific Facilities at that time.

In response to the fire, Liberty field personnel opened certain devices and requested the opening of other devices to support public safety. Liberty initiated an emergency power shutoff for the Topaz 1261 Circuit and communicated actively with customers and public safety partners regarding the status of the fire and the power shutoff.

ATTACHMENT 2

Response (amended) to data request CalAdvocates-LIB-A2506017-015 November 1, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

November 1, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-015
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	September 17, 2025
Due Date:	October 1, 2025
Extension Granted:	October 6, 2025
Response Date:	October 6, 2025
Amended Response Date:	November 1, 2025

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1, where it states:

Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy.

REQUEST NO. 1:

a) Did Liberty request NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?
b) If the answer to (a) is "no," please provide an explanation.
c) If the answer to (a) is "yes," please provide all asset inspection and maintenance

CA-07-0053

records provided to Liberty from NV Energy.

d) If the records identified in (c) exist exclusively in paper format, please provide sufficient detail to permit evaluation of potential digitization or on-site review, including:
    1. An estimate of the total volume of paper records;
    2. The specific location(s) where such records are maintained; and
    3. The approximate date of the earliest available records.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset inspection and maintenance records for the entire utility with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in "Regulatory Commitments" at the time of purchase (attached as Appendix 3 to D.10-10-017), CalPeco planned to conduct business in the same or similar manner as it had under Sierra Pacific's ownership, with regard to the utility's core functions. CalPeco committed, to the extent practicable, to retain the same operations team responsible for operating the utility under Sierra Pacific's ownership, including an intent to maintain local headquarters and to offer then-current operations employees employment with CalPeco at the same locations with responsibilities consistent with their then-existing roles.

    As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased. In addition, on a going forward basis, the two utilities agreed to provide each other reasonable access to their properties to permit inspection of the integrated systems, to perform any relevant work, and to all data, including maintenance records, with respect to the operation and maintenance of each utility's respective portions of the integrated electric systems.
b) See Liberty's response to subpart (a).
c) Liberty is in possession of some inspection and maintenance records from prior to the time of acquisition. Please refer to Liberty's response to CalAdvocates-LIB-A2507017-031, Question 1, subpart (a) and attachments contained therein, which includes some examples of such records.
d) The inspection and maintenance records Liberty has retained from prior to the acquisition in a mix of paper and digital format. Review of Liberty's off-site storage index suggests that Liberty has copies of some inspection and maintenance records dating back to approximately 2008 and some engineering records dating back to the 1970s.

REQUEST NO. 2:

a) Did Liberty conduct a review of NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?

b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what conclusions were reached, and please provide any documentation relevant to (a).
d) If the answer to (a) is "yes," what methodology did Liberty utilize in 2011 to assess the condition of NV Energy's assets?
e) If the answer to (a) is "yes," did Liberty request that NV Energy perform any corrective actions prior to completing the purchase?
f) If the answer to (e) is "yes," list and describe the actions that Liberty requested NV Energy perform and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

REQUEST NO. 3:

a) *After* completing the 2011 purchase, did Liberty conduct a review of NV Energy's asset inspection and maintenance records?
b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what findings resulted, and please provide copies.
d) Following the acquisition, did Liberty implement any system-wide corrective action initiatives based on the condition of NV Energy's assets?
e) If the answer to (d) is "no," please explain why not.
f) If the answer to (d) is "yes," please describe what actions were taken, what were the outcomes, and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1 where it states:

Liberty conducted routine patrols using hard-copy circuit maps. See Liberty-03 at 20. After a reasonable search and diligent inquiry, the Topaz 1261 maps used for Liberty's patrols from 2013, 2015, and 2017 do not indicate any corrective work identified by those patrols.

REQUEST NO. 4:

a) When did Liberty first begin performing routine patrols on the Topaz 1261 circuit?
b) Did Liberty conduct a routine patrol in 2012 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
c) Did Liberty conduct a routine patrol in 2014 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
d) Did Liberty conduct a routine patrol in 2016 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
e) Did Liberty conduct a routine patrol in 2018 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
f) Did Liberty conduct a routine patrol in 2019 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
g) Did Liberty conduct a routine patrol in 2020 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.

AMENDED RESPONSE:

Liberty objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty purchased the California utility system from NV Energy in approximately 2011. After a reasonable search and diligent inquiry, the earliest patrol record for the Topaz 1261 Circuit that Liberty has located is from 2013.
b) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2012.
c) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2014.

d) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2016.
e) Liberty reported in its GO 165 annual report for 2018 that it completed patrols on all 54 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2018.
f) Liberty reported in its GO 165 annual report for 2019 that it completed patrols on all 55 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2019.
g) As explained in *Liberty-03*, Liberty conducted a detailed inspection of the Topaz 1261 Circuit in 2020 and provided those inspection records in its responses to CalAdvocates-LIB-A2506017-001, Question 2 and CalAdvocates-LIB-A2506017-004, Question 2. Liberty also reported in its GO 165 annual report for 2020 that it completed patrols on all 55 of its circuits in that year.

The following questions refer to the Excel file *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, Liberty provided in response to CalAdvocates-LIB-001, question 2.

REQUEST NO. 5:

Referring to the "Detailed Inspection Results" tab:

a) Please clarify the difference between the dates listed in column C ("Inspection Date") and those in column H ("Created Date")?
b) In some cases, the dates in column H ("Created Date") appear earlier than the corresponding dates in column C ("Inspection Date"). Please explain why this occurs?
c) Several cells in column I ("Due Date") are blank. Please clarify what an empty cell in this column represents?
d) In certain instances, the dates in column I ("Due Date") are earlier than the dates in column C ("Inspection Date"). Please explain why this discrepancy exists?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) The dates listed in column C ("Inspection Date") correspond to the dates when an inspector performed a detailed inspection of the relevant pole. The dates listed in column H ("Created Date") correspond to the dates when the inspection record was created in Fulcrum in anticipation of an upcoming inspection. The dates in column H are sometimes earlier than the corresponding dates in column C because an inspection record was typically created prior to the inspection. For some poles, the "created date" and the "inspection date" may be the same, in instances where the inspection record for that pole was created in Fulcrum at the time of the inspection.
b) See Liberty's response to subpart (a).
c) The cells in column I without any data could be blank for a variety of reasons. As part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues identified in the system from prior inspections. Thus, cells in column I could be blank because, for example, Liberty had already addressed the issues identified at the time due dates were systematically populated in the database, or because no issues requiring remediation were identified.
d) Liberty has not identified instances in *CalAdvocates-LIB-A2506017-001-Q2.xlsx* where the dates in column I are earlier than the dates in Column C.

REQUEST NO. 6:

Referring to the "Repaired after Nov 17 2020" tab:

a) In some cases, the dates in column L ("Repair Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
b) In some cases, multiple conditions are listed in column O ("Condition Codes"), but only a single date is recorded in column L ("Repair Date"). Please clarify how these are reconciled.
c) Several dates in column G ("Created Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
d) In many cases, the dates in column I ("Due Date") are set up to five years after the dates in column C ("Inspection Date"). Please clarify how these due dates are determined.
e) Certain assets with "Level 3" priority show "Repair Dates" in column L that occur after the "Due Dates" in column I. Please clarify why this occurs.
f) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning due dates when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: See Liberty's response to Question 5 of this set of data requests.

a) The inspection records in which the dates in column L appear earlier than the dates in column C poles correspond to poles that were replaced in 2020 for which Liberty did not have specific dates of replacement. The date 01/01/2020 was used for those poles to

indicate that the pole replacements were completed in 2020.

b) Due to limitations in Liberty's data collection form during the early stages of its transition from using hard-copy forms to a dynamic electronic inspection form in Fulcrum, only one "Repair Date" field was available for each inspection record for inspections conducted in 2020. A field was available to an inspector to indicate whether all repairs had been completed and another field was available in which to input comments regarding the individual repair(s), including the status of individual conditions identified. Liberty has refined its data collection and repair workflow processes since 2020 and each repair is now tracked as a separate event record.
c) Please refer to Liberty's response to Question 5, subparts (a)-(b) of this set of data requests.
d) The inspection records in which the dates in column I are set up to five years after the dates in column C correspond to poles where the issue(s) identified was assigned a priority Level 3. Consistent with GO 95, Rule 18, Level 3 issues presented low potential safety or reliability risk and Liberty would take action to address them within the timeframes specified by GO 95. Liberty generally used 59 months as the due date for Level 3 issues.
e) As Liberty explained in its response to CalAdvocates-LIB-A2506017-001, Question 5, Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.
f) As set forth in Liberty's response to Question 5(c) of this set of data requests, as part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues in the system from prior inspections corresponding to the timelines set forth in GO 95, Rule 18, based on the date when inspections were performed.

REQUEST NO. 7:

At the time of the Mountain View Fire:

a) As Liberty understands General Order 95, please describe the distinction between Level 1 and Level 2 corrective conditions.
b) As Liberty understands General Order 95, please describe the distinction between Level 2 and Level 3 corrective conditions.
c) Did Liberty document the decision-making process for assigning corrective levels (Level 1, 2, or 3)? If so, explain how. If not, explain why not.
d) What internal training or guidance did Liberty provide to inspectors to ensure alignment with General Order 95 when classifying corrective conditions?
e) What quality assurance measures did Liberty apply to ensure consistency in corrective level assignments across different inspectors or inspection types?
f) Who was responsible for determining whether a corrective condition is classified as Level 1, 2 or Level 3?

g) Please clarify the criteria Liberty used to escalate a condition from Level 3 to Level 2, if applicable?
h) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning priorities (Level 1, Level 2, or Level 3) when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) In accordance with GO 95, Liberty understood Level 1 conditions as those posing immediate safety or reliability risks with high potential for impact, which should be addressed immediately. Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes.
b) Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes. Liberty understood Level 3 conditions as those with a low potential safety or reliability risk, which Liberty attempted to address within the specified timeframes.
c) As evidenced in *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 2, inspectors selected from a menu of condition codes and assigned a priority level to the inspection record. The dynamic electronic inspection form in Fulcrum that inspectors began using for detailed inspections in 2020 also allowed inspectors to input comments regarding the conditions they identified.
d) As explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program. These inspectors classified conditions as Level 1, 2, or 3 in the process of conducting inspections in the field, based on their understanding of GO 95 and their experience and training.
e) Though Liberty did not have a formal quality assurance process, as explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program.
f) See Liberty's response to subpart (d).
g) See Liberty's response to subpart (b).
h) See Liberty's response to subpart (d).

REQUEST NO. 8:

From 2011 to the time of the Mountain View Fire:

a) How many Level 1 corrective work orders did Liberty identify during routine patrol inspections?
    a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
        i. Structure number
        ii. Work Order Number

iii. Notification Number (if applicable)
iv. Equipment Number
v. Inspection Date
vi. Equipment Type
vii. HFTD/HFRA Tier
viii. Priority
ix. Ignition Risk (Y/N)
x. Date Created
xi. Due Date
xii. Revised Due Date (if applicable)
xiii. Priority Change (if applicable)
xiv. Reason for Change (if applicable)
xv. Date Completed
xvi. Latitude in degrees
xvii. Longitude in degrees

b) How many Level 1 corrective work orders did Liberty identify during detailed inspections?
   a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
      i. Structure number
      ii. Work Order Number
      iii. Notification Number (if applicable)
      iv. Equipment Number
      v. Inspection Date
      vi. Equipment Type
      vii. HFTD/HFRA Tier
      viii. Priority
      ix. Ignition Risk (Y/N)
      x. Date Created
      xi. Due Date
      xii. Revised Due Date (if applicable)
      xiii. Priority Change (if applicable)
      xiv. Reason for Change (if applicable)
      xv. Date Completed
      xvi. Latitude in degrees
      xvii. Longitude in degrees

AMENDED RESPONSE:

a) Liberty objects to this Question as vague, ambiguous, and overbroad. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows: Liberty transitioned to Fulcrum for routine patrol records in approximately 2023. Prior to that time, inspectors recorded the results of routine patrol inspections on hard-copy maps and thus, Liberty is unable to provide an Excel file with the requested information for routine patrol inspections in the relevant timeframe due to the significant burden involved with compiling such a file based on

identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

b) Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

Liberty is producing the data requested by this Question in the attachment *CalAdvocates-LIB-A2506017-015-Q8.xlsx*. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records, and refined the information in those fields for accuracy based on a review of the full event history of inspection records with priority level field set as Level 1. As described in *Liberty-03: Prudence of Operations*, prior to 2020, inspectors recorded the results of detailed inspections on hard-copy forms and thus, Liberty is unable to provide an Excel file with the requested information for detailed inspections prior to 2020 due to the significant burden involved with compiling such a file based on identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

REQUEST NO. 9:

At the time of the Mountain View Fire:

a) Did Liberty have a policy for replacing rather than splicing conductors when failures occurred? If so, please provide a copy.
b) Did Liberty have a policy for limiting the number of spliced conductors to a specific number per span? If so, please provide a copy.
c) Did Liberty have a policy specifying the required conductor sag to ensure compliance with GO 95? If so, please provide a copy.
d) Were sag measurements on the Topaz 1261 circuit ever documented?
e) If the answer to (d) is "yes," please provide documentation supporting your answer.
f) If the answer to (d) is "no," please explain why not.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) As referenced in Liberty's response to CalAdvocates-LIB-A2506017-001, Question 8, as of November 17, 2020, Liberty installed splices on conductors in connection with operation of the distribution system. There was no formal policy regarding the installation of splices and the use of splices was based on the experience and expertise of field personnel in the course of repair work.
b) See Liberty's response to subpart (a).
c) Please refer to *Overhead Distribution Conductor Stringing Guide (CON05T)* and *Standard Sagging Practices (CON06T)* of *Overhead Electric Standards.pdf*, which

Liberty provided in response to CalAdvocates-LIB-A2506017-0018, Question 3. Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. For example, refer to the "General Crew Notes" on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Five – As Built.pdf* for directions on sag tables crews should use and to the sag table on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Six – As built.pdf*, both of which Liberty attached to its response to CalAdvocates-LIB-A2506017-0018.

d) Liberty objects to this subpart as vague and ambiguous as framed, including use of the term "sag measurements." Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. Liberty is not aware of any records that would document specific sag measurements for the Topaz 1261 circuit conductors.
e) N/A
f) See Liberty's response to subpart (d).

REQUEST NO. 10:

In Liberty's testimony (LIB-03 at 10), it states that:

While FPPs were mandatory for investor-owned utilities in Southern California, they were required for investor-owned utilities in Northern California only if the utility determined, with respect to its facilities within high-fire threat areas identified in the Reax Map, that "it is reasonably foreseeable that the probability of 3-second wind gusts exceeding the maximum working stresses for such facilities during a Red Flag Warning is 3% or more during a 50-year period." Liberty analyzed whether this criterion was met using data from Remote Automated Weather Stations ("RAWS") operated by the National Weather Service ("NWS"). Because the available RAWS data did not indicate whether gusts lasted three seconds or more, to promote public safety and a proactive approach, Liberty assumed that all maximum gusts met the criterion and determined that an FPP was needed for its facilities located within Threat Zones 3 and 4 of the Reax Map.

a) How many RAWS stations were located within Liberty's service territory at the time of the Mountain View Fire?
b) What distance from Liberty's facilities did the company consider acceptable for RAWS data to be representative?
c) Did Liberty conduct any analysis to compare RAWS data with on-the-ground incident reports of outages or damage?
d) Was Liberty aware of any academic or industry critiques regarding the use of RAWS for fire risk analysis at the time?
e) How did Liberty document its decision to assume all gusts equaled 3-second durations despite the lack of confirmation?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) The RAWS stations that were transmitting data as of November 17, 2020 are publicly

available via MesoWest: https://mesowest.utah.edu/.

b) Liberty considered data from RAWS stations located within 25 miles of its service territory, as described on page 8 and in Attachment 2 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.
c) As further explained in its 2012 Fire Prevention Plan, Liberty took a deliberately conservative approach when assessing whether a Fire Prevention Plan was required for its facilities under R.08-11-005, and ultimately decided to submit one. Please refer to pages 7-8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13, for further explanation of Liberty's methodology for determining whether a Fire Prevention Plan was required, and Attachments 2 and 3 thereto include information regarding the RAWS used for the assessment.
d) Liberty objects to this subpart as vague, ambiguous and overbroad, including its use of the phrase "use of RAWS for fire risk analysis." See Liberty's response to subpart (c).
e) Please refer to page 8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.

The following questions are in regard to Liberty's response to CalAdvocates-LIB-A2506017-001, question 4.

REQUEST NO. 11:

a) Please clarify why intrusive pole inspections on the Topaz 1261 Circuit between the years 2011 and 2020 were only conducted in 2013?
b) Please describe the criteria Liberty used to determine when and where intrusive pole inspections would be performed?
c) Please explain the technical criteria Liberty used to classify poles as "Restorable," "Non-Restorable," or "Hazard"?
d) Who was responsible for assigning poles into each of these categories during the 2013 inspection?
e) Liberty states that corrective work was addressed using hard-copy work packets. Please explain the process for creating, assigning, and closing those packets?
f) Who was responsible for maintaining or archiving the hard-copy packets documenting corrective work?
g) Please provide a sample of three hard-copy work packets referenced in (e).

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty conducted intrusive pole inspections on a circuit basis. 2013 was the year when Liberty scheduled intrusive inspections on the Topaz 1261 Circuit. Pursuant to GO 165, Liberty conducted intrusive inspections on a circuit once every 10 years. Liberty conducted intrusive pole inspections on the Topaz 1261 Circuit again in 2023.

b) Liberty determines its intrusive pole inspection schedule based on when a circuit had previously been inspected. Liberty schedules a circuit for intrusive pole inspections once every 10 years.
c) Please refer to attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* for guidance Liberty provided to its contractor around 2013 on conducting intrusive inspections and criteria for classifying rejected poles.
d) Liberty used a qualified and experienced contractor for intrusive pole inspections. The contractors' personnel were responsible for classifying poles into these categories.
e) Prior to 2020, corrective work identified during Liberty's inspection and maintenance programs was addressed via hard-copy work packets. Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
f) See Liberty's response to subpart (e).
g) For a sample design packet of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, please see attachment *CONFIDENTIAL-8800-0115-0113 Map.pdf*. Since its original response, Liberty has located two additional design packets of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, see confidential attachments *CONFIDENTIAL-8800-0115-0112-Map.pdf* and *CONFIDENTIAL-8800-0115-0114 Map.pdf*.

REQUEST NO. 12:

In Liberty's response to CalAdvocates-LIB-A2506017-001, question 4, it states that:

Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.

a) Since the 2013 intrusive pole inspection, has Liberty made any effort to digitize, scan, or otherwise preserve the hard-copy packets?
b) Please clarify why records showing when corrective work was completed were not located following Liberty's search?
c) How did Liberty verify that poles identified in 2013 inspections as "Non-Restorable" or "Hazard" were in fact replaced?
d) Please describe the oversight mechanisms in place at the time of the 2013 intrusive pole inspection to ensure corrective work identified in inspections was completed.
e) Has Liberty performed any follow-up inspections on the same poles identified in 2013 to confirm that corrective actions were carried out?
f) Did Liberty report the results of the 2013 intrusive pole inspections, including the number of poles requiring corrective work, to any regulatory body?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty maintains some physical records in on-site and off-site storage. While Liberty has scanned some of these records, it has not systematically digitized or scanned all hard-copy work packets. The spreadsheet Liberty provided in its response to CalAdvocates-LIB-A2506017-001, Question 4 was provided to Liberty from its intrusive pole inspection contractor.
b) Liberty did not locate records showing when corrective work was completed due to the passage of time.
c) Liberty verified whether the poles classified as "Non-Restorable" or "Hazard" were replaced using a combination of data sources, including design and installation work order packets, the installation dates of poles available in its GIS database, records of pole inspections available within the Fulcrum database, and field verification.
d) Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
e) Please refer to Liberty's response to subparts (c).
f) In its annual GO 165 report for 2013, Liberty reported the total number of poles that underwent intrusive inspections in 2013. This report did not specify the number of poles intrusively inspected that required corrective work.

REQUEST NO. 13:

a) During the period from 2011 through 2020, did Liberty have any poles in its system that had been treated with cellon gas?
b) If the answer to (a) is yes, provide the number of such poles systemwide.
c) If the answer to (a) is yes, provide the number of such poles on the Topaz 1261 Circuit.
d) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles treated with cellon gas?
e) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles for any other reason?
f) If the answer to parts (d) or (e) is yes, list and explain the actions Liberty has taken to mitigate such potential inaccurate results.
g) What is the median age of wood poles in Liberty's system?
h) What is the median age of wood poles on the Topaz 1261 Circuit?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Liberty further objects to the extent this Question requests information not maintained in the ordinary course of business. Subject to and without waiving these objections, Liberty responds as follows:

a) According to Liberty's intrusive pole inspection results in the relevant timeframe, some poles in its system had been treated with "Penta in Liquid Petrol Gas - Cellon."
b) According to the intrusive pole inspection results available to Liberty, 1,555 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" across all circuits that were subject to intrusive pole inspections during the relevant timeframe.

c) According to the results of the intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, 107 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" at that time. Liberty's standard scope of work for intrusive pole inspections specifies procedures specific to poles treated with cellon gas.
d) Liberty objects to this subpart as vague, ambiguous, and overbroad as framed, including its use of the term "potential inaccuracies." Liberty understands this term to refer to systemic deficiencies or errors identified in the intrusive pole inspection process. Liberty's intrusive pole inspections are performed by a qualified and experienced contractor that provides specialized services to utilities around the country. Liberty has not identified systemic deficiencies associated with its intrusive pole inspections, including on poles treated with cellon gas.
e) See Liberty's response to subpart (d).
f) N/A
g) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles in Liberty's system is approximately 49 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.
h) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles on the Topaz 1261 Circuit, which has been renamed the Topaz 1202 Circuit, is approximately 28 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.

ATTACHMENT 3

Response to data request
CalAdvocates-LIB-A2506017-031, October 31, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-031
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	October 16, 2025
Due Date:	October 30, 2025
Extension Granted:	October 31, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in the accompanying confidentiality declaration. Public disclosure is restricted.

REQUEST NO. 1:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 1:

> *As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased.*

a) Did Liberty obtain any asset condition records from NV Energy prior to assuming control of the Topaz 1261 circuit? If so, please provide copies of these records.
b) What actions, if any, did Liberty take to confirm the accuracy, completeness, and reliability of the inherited asset condition records before assuming operational control of Topaz 1261?

c) After acquisition, did Liberty receive any asset condition records for Topaz 1261? If so, please provide copies.
d) Is Liberty able to provide any evidence it conducted a risk assessment or asset condition survey at or before acquisition? If so, please provide copies of such evidence. If not, explain why.
e) Did Liberty perform any internal audit or gap analysis to understand what records were missing at the time of acquisition? If so, please provide copies of such records. If not, explain why.

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and unintelligible as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset condition records for the entire Topaz 1261 Circuit with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in Liberty's response to CalAdvocates-LIB-A2506017-15, Question 1, Liberty's acquisition in approximately 2011 included files, documents, and papers related to the utility's business and assets being purchased. Thus, Liberty obtained asset condition records from NV Energy as part of the transaction. Liberty is in possession of some asset condition records from prior to the time of acquisition. For example, Liberty has located intrusive inspection results from 2010, see confidential attachment *CONFIDENTIAL-2010 Intrusive Pole Inspection Data.xlsx*, and annual GO 165 reports for 2006-2010, see attachment *2006-2010 GO 165 Annual Reports.pdf*. Liberty is continuing to search for pre-acquisition records related to the Topaz 1261 Circuit and will update this response to the extent identified.
b) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
c) Liberty assumes this subpart seeks information regarding records received from NV Energy given Liberty previously provided Cal Advocates with records of its inspections of the Topaz 1261 Circuit after 2011. See Liberty's responses to subpart (a) and CalAdvocates-LIB-A2506017-15, Question 1.
d) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
e) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.

REQUEST NO. 2:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 4:

> *Liberty located routine patrol records for the Topaz 1261 Circuit from the years 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIBA2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. As explained in Liberty-03, Liberty conducted a detailed inspection on the Topaz 1261 Circuit in the first half of*

2020 and Liberty has not located records confirming a patrol of the Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.

a) Does Liberty maintain any policy defining how long routine patrol or detailed inspection documentation must be retained? If so, please provide copies of such policies.
b) Can Liberty confirm whether GO 165 patrols occurred on Topaz 1261 between 2018 and 2020? If not, is Liberty asserting that patrols were completed but undocumented or that they were never conducted?
c) Has Liberty identified any other circuits besides Topaz 1261 for which it cannot locate records to confirm that a patrol inspection occurred during a given period exceeding two years? If so, what are they?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty adheres to regulatory requirements regarding recordkeeping, and those requirements govern Liberty's general approach with respect to the retention of such documentation.
b) Liberty reported in its GO 165 annual reports for 2018-2020 that it completed patrols on all of its circuits in each of those years (54 circuits in 2018 and 55 circuits in 2019 and 2020). Liberty has not located further documentation of patrols of Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.
c) Liberty continues to research patrol inspections on circuits other than the Topaz 1261 Circuit to identify any responsive circuits, and will update its response to the extent identified.

REQUEST NO. 3:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 5:

Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) Please confirm if Liberty reused electronic inspection records (Fulcrum) from the 2020 asset survey to track conditions found in later years from other inspections.
b) If so, please provide a list of the inspections.
c) If so, please confirm whether the original data was overwritten? What controls, if any, preserved data from previous inspection years?
d) Is Liberty able to produce any evidence distinguishing 2020 findings from later updates in Fulcrum? If so, please provide copies. If not, please explain why not.

RESPONSE:

This response contains confidential attachments. Liberty objects to this question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Fulcrum is a geospatial data collection software that houses different applications. Liberty created an application within Fulcrum for data collection and tracking for the 2020 asset survey. Liberty created additional applications in Fulcrum to collect and track inspection data for routine inspections such as GO 165 detailed inspections occurring between 2021 and 2023. Liberty inspectors used the 2020 asset survey application to collect and track data from some non-routine inspections of certain asset locations after the 2020 asset survey. The spreadsheet Liberty provided in response to CalAdvocates-LIB-A2506017-001, Question 2 contains inspection records on the Topaz 1261 Circuit with a creation date of 2020 from the 2020 asset survey application, which may contain data gathered during certain non-routine inspections performed after the 2020 asset survey. This spreadsheet does not contain data collected and tracked in other applications in Fulcrum, such as those created for GO 165 inspections between 2021 and 2023.
b) See Liberty's response to subpart (a).
c) Each update to an inspection record in the 2020 asset survey application was preserved in the record's event history.
d) Liberty is providing the complete output of Fulcrum inspection records from the 2020 asset survey associated with the Topaz 1261 Circuit in confidential attachment *CONFIDENTIAL-CalAdvocates-LIB-A2506017-31-Q3.csv*. This output is arranged by asset inspection record and contains the full event history for each record.

REQUEST NO. 4:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 6:

> *Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.*

a) Provide an Excel file with a list of all due-date extensions under GO 95, Rule 18 for Topaz 1261 from 2016–2021, including reason codes, elapsed time, and interim risk mitigations.
b) Were any GO 95 extension requests documented with interim risk controls?
c) If the answer to subpart (b) is yes, provide evidence supporting your answer.
d) If the answer to subpart (b) is no, explain why.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including to the extent it seeks information

not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty is not aware of records formally tracking due-date extensions on the Topaz 1261 Circuit in the specified time frame.
b) See response to subpart (a). Liberty is also not aware of records formally tracking interim risk controls associated with due-date extensions on the Topaz 1261 Circuit in the specified time frame.
c) N/A
d) N/A

REQUEST NO. 5:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 4:

> *Please see attachment CalAdvocates-LIB-A2506017-001-Q4.xlsx, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.*

a) Is Liberty able to confirm that some poles may have remained in service through the Mountain View Fire without documented closure?
b) If so, identify all poles still in service that were classified as "Non-Restorable" or "Hazard" in 2013.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Based on data contained within Liberty's GIS database, its Fulcrum database, pole replacement work orders, and field verification, Liberty verified that all poles classified as "Non-Restorable" and "Hazard Poles" in attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, except for one, were replaced prior to November 17, 2020. Liberty is working to determine whether the pole located at latitude/longitude location 38.64995, -119.53329 was in service as of November 17, 2020. This pole is a structural support pole and does not support any energized lines.
b) No poles classified as "Non-Restorable" or "Hazard" in the 2013 intrusive inspection results are still in service today.

REQUEST NO. 6:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 9:

Liberty reviewed the reliability of its electric system on an annual basis…These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening.

a) Why did Liberty not initiate the Topaz 1261 reconductoring or hardening project during 2015–2017 when it had already identified the circuit as one of its worst-performing circuits and highest risks on a known failure-prone circuit?
b) Why were reliability metrics (outage frequency) used over ignition metrics when justifying the need for a covered conductor project?
c) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing not to initiate the Topaz 1261 reconductoring or hardening project during 2015-2017.
d) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing to use reliability metrics over ignition metrics when justifying the need for a covered conductor pilot.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and argumentative as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) As stated in Liberty's 2019 GRC, filed in December 2018 (A-18-12-001), Liberty had been working diligently to replace its aging infrastructure since purchasing the utility from NV Energy in 2011, including the re-conductoring of old lines to enhance safety and reliability. Liberty's capital planning process sought to balance the need to prioritize safety and reliability upgrades with the need to provide service to its customers at a reasonable cost. To that end, in its 2019 GRC filing, Liberty requested and was granted approval to fund the Topaz 1261 Rebuild Project and other safety and reliability projects (e.g., the 7300 Line rebuild project) and undertook those projects over time.
b) Liberty objects to this subpart as assuming facts. As described in Liberty's 2019 GRC, Ex. *Liberty-02: Capital* (at pp. 8-9), both reliability metrics and the occurrence of an ignition event on the Topaz 1261 Circuit drove Liberty's decision to pursue the Topaz 1261 Rebuild Project. As stated in Liberty's testimony, the project would both "increase the reliability of the system" and "mitigate the risk of fires." Indeed, underlying events that affect circuit reliability and cause outages, such as wire-to-wire contact or contact with objects, also carry the potential for ignition.
c) Liberty objects to this subpart as assuming facts. Please refer to Ex. *Liberty-02: Capital*, filed in support of Liberty's 2019 GRC filing (A.18-12-001), for further discussion of Liberty's decision to seek funding for the Topaz 1261 Rebuild Project. Between 2015-2017, Liberty invested in safety and reliability upgrades on its system through other capital projects such as the 625/650 Upgrade project. As the Commission concluded in D.15-03-020, the 625/650 Upgrade project "would increase the reliability and safety of electric power delivery within the Lake Tahoe basin," including "reducing risks of wildfire and vegetation-related outages." *See* D.15-03-020 at 47.
d) Liberty objects to this subpart as assuming facts. See Liberty's response to subparts (b)-(c).

ATTACHMENT 4

Response (amended) to data request CalAdvocates-LIB-A2506017-015, November 1, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

November 1, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-015
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	September 17, 2025
Due Date:	October 1, 2025
Extension Granted:	October 6, 2025
Response Date:	October 6, 2025
Amended Response Date:	November 1, 2025

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1, where it states:

Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy.

REQUEST NO. 1:

a) Did Liberty request NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?
b) If the answer to (a) is "no," please provide an explanation.
c) If the answer to (a) is "yes," please provide all asset inspection and maintenance

records provided to Liberty from NV Energy.

d) If the records identified in (c) exist exclusively in paper format, please provide sufficient detail to permit evaluation of potential digitization or on-site review, including:
    1. An estimate of the total volume of paper records;
    2. The specific location(s) where such records are maintained; and
    3. The approximate date of the earliest available records.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset inspection and maintenance records for the entire utility with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in "Regulatory Commitments" at the time of purchase (attached as Appendix 3 to D.10-10-017), CalPeco planned to conduct business in the same or similar manner as it had under Sierra Pacific's ownership, with regard to the utility's core functions. CalPeco committed, to the extent practicable, to retain the same operations team responsible for operating the utility under Sierra Pacific's ownership, including an intent to maintain local headquarters and to offer then-current operations employees employment with CalPeco at the same locations with responsibilities consistent with their then-existing roles.

    As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased. In addition, on a going forward basis, the two utilities agreed to provide each other reasonable access to their properties to permit inspection of the integrated systems, to perform any relevant work, and to all data, including maintenance records, with respect to the operation and maintenance of each utility's respective portions of the integrated electric systems.
b) See Liberty's response to subpart (a).
c) Liberty is in possession of some inspection and maintenance records from prior to the time of acquisition. Please refer to Liberty's response to CalAdvocates-LIB-A2507017-031, Question 1, subpart (a) and attachments contained therein, which includes some examples of such records.
d) The inspection and maintenance records Liberty has retained from prior to the acquisition in a mix of paper and digital format. Review of Liberty's off-site storage index suggests that Liberty has copies of some inspection and maintenance records dating back to approximately 2008 and some engineering records dating back to the 1970s.

REQUEST NO. 2:

a) Did Liberty conduct a review of NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?

b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what conclusions were reached, and please provide any documentation relevant to (a).
d) If the answer to (a) is "yes," what methodology did Liberty utilize in 2011 to assess the condition of NV Energy's assets?
e) If the answer to (a) is "yes," did Liberty request that NV Energy perform any corrective actions prior to completing the purchase?
f) If the answer to (e) is "yes," list and describe the actions that Liberty requested NV Energy perform and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

REQUEST NO. 3:

a) *After* completing the 2011 purchase, did Liberty conduct a review of NV Energy's asset inspection and maintenance records?
b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what findings resulted, and please provide copies.
d) Following the acquisition, did Liberty implement any system-wide corrective action initiatives based on the condition of NV Energy's assets?
e) If the answer to (d) is "no," please explain why not.
f) If the answer to (d) is "yes," please describe what actions were taken, what were the outcomes, and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1 where it states:

Liberty conducted routine patrols using hard-copy circuit maps. See Liberty-03 at 20. After a reasonable search and diligent inquiry, the Topaz 1261 maps used for Liberty's patrols from 2013, 2015, and 2017 do not indicate any corrective work identified by those patrols.

REQUEST NO. 4:

a) When did Liberty first begin performing routine patrols on the Topaz 1261 circuit?
b) Did Liberty conduct a routine patrol in 2012 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
c) Did Liberty conduct a routine patrol in 2014 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
d) Did Liberty conduct a routine patrol in 2016 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
e) Did Liberty conduct a routine patrol in 2018 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
f) Did Liberty conduct a routine patrol in 2019 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
g) Did Liberty conduct a routine patrol in 2020 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.

AMENDED RESPONSE:

Liberty objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty purchased the California utility system from NV Energy in approximately 2011. After a reasonable search and diligent inquiry, the earliest patrol record for the Topaz 1261 Circuit that Liberty has located is from 2013.
b) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2012.
c) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2014.

d) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2016.
e) Liberty reported in its GO 165 annual report for 2018 that it completed patrols on all 54 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2018.
f) Liberty reported in its GO 165 annual report for 2019 that it completed patrols on all 55 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2019.
g) As explained in *Liberty-03*, Liberty conducted a detailed inspection of the Topaz 1261 Circuit in 2020 and provided those inspection records in its responses to CalAdvocates-LIB-A2506017-001, Question 2 and CalAdvocates-LIB-A2506017-004, Question 2. Liberty also reported in its GO 165 annual report for 2020 that it completed patrols on all 55 of its circuits in that year.

The following questions refer to the Excel file *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, Liberty provided in response to CalAdvocates-LIB-001, question 2.

REQUEST NO. 5:

Referring to the "Detailed Inspection Results" tab:
a) Please clarify the difference between the dates listed in column C ("Inspection Date") and those in column H ("Created Date")?
b) In some cases, the dates in column H ("Created Date") appear earlier than the corresponding dates in column C ("Inspection Date"). Please explain why this occurs?
c) Several cells in column I ("Due Date") are blank. Please clarify what an empty cell in this column represents?
d) In certain instances, the dates in column I ("Due Date") are earlier than the dates in column C ("Inspection Date"). Please explain why this discrepancy exists?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) The dates listed in column C ("Inspection Date") correspond to the dates when an inspector performed a detailed inspection of the relevant pole. The dates listed in column H ("Created Date") correspond to the dates when the inspection record was created in Fulcrum in anticipation of an upcoming inspection. The dates in column H are sometimes earlier than the corresponding dates in column C because an inspection record was typically created prior to the inspection. For some poles, the "created date" and the "inspection date" may be the same, in instances where the inspection record for that pole was created in Fulcrum at the time of the inspection.
b) See Liberty's response to subpart (a).
c) The cells in column I without any data could be blank for a variety of reasons. As part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues identified in the system from prior inspections. Thus, cells in column I could be blank because, for example, Liberty had already addressed the issues identified at the time due dates were systematically populated in the database, or because no issues requiring remediation were identified.
d) Liberty has not identified instances in *CalAdvocates-LIB-A2506017-001-Q2.xlsx* where the dates in column I are earlier than the dates in Column C.

REQUEST NO. 6:

Referring to the "Repaired after Nov 17 2020" tab:

a) In some cases, the dates in column L ("Repair Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
b) In some cases, multiple conditions are listed in column O ("Condition Codes"), but only a single date is recorded in column L ("Repair Date"). Please clarify how these are reconciled.
c) Several dates in column G ("Created Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
d) In many cases, the dates in column I ("Due Date") are set up to five years after the dates in column C ("Inspection Date"). Please clarify how these due dates are determined.
e) Certain assets with "Level 3" priority show "Repair Dates" in column L that occur after the "Due Dates" in column I. Please clarify why this occurs.
f) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning due dates when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: See Liberty's response to Question 5 of this set of data requests.

a) The inspection records in which the dates in column L appear earlier than the dates in column C poles correspond to poles that were replaced in 2020 for which Liberty did not have specific dates of replacement. The date 01/01/2020 was used for those poles to

indicate that the pole replacements were completed in 2020.

b) Due to limitations in Liberty's data collection form during the early stages of its transition from using hard-copy forms to a dynamic electronic inspection form in Fulcrum, only one "Repair Date" field was available for each inspection record for inspections conducted in 2020. A field was available to an inspector to indicate whether all repairs had been completed and another field was available in which to input comments regarding the individual repair(s), including the status of individual conditions identified. Liberty has refined its data collection and repair workflow processes since 2020 and each repair is now tracked as a separate event record.
c) Please refer to Liberty's response to Question 5, subparts (a)-(b) of this set of data requests.
d) The inspection records in which the dates in column I are set up to five years after the dates in column C correspond to poles where the issue(s) identified was assigned a priority Level 3. Consistent with GO 95, Rule 18, Level 3 issues presented low potential safety or reliability risk and Liberty would take action to address them within the timeframes specified by GO 95. Liberty generally used 59 months as the due date for Level 3 issues.
e) As Liberty explained in its response to CalAdvocates-LIB-A2506017-001, Question 5, Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.
f) As set forth in Liberty's response to Question 5(c) of this set of data requests, as part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues in the system from prior inspections corresponding to the timelines set forth in GO 95, Rule 18, based on the date when inspections were performed.

REQUEST NO. 7:

At the time of the Mountain View Fire:

a) As Liberty understands General Order 95, please describe the distinction between Level 1 and Level 2 corrective conditions.
b) As Liberty understands General Order 95, please describe the distinction between Level 2 and Level 3 corrective conditions.
c) Did Liberty document the decision-making process for assigning corrective levels (Level 1, 2, or 3)? If so, explain how. If not, explain why not.
d) What internal training or guidance did Liberty provide to inspectors to ensure alignment with General Order 95 when classifying corrective conditions?
e) What quality assurance measures did Liberty apply to ensure consistency in corrective level assignments across different inspectors or inspection types?
f) Who was responsible for determining whether a corrective condition is classified as Level 1, 2 or Level 3?

g) Please clarify the criteria Liberty used to escalate a condition from Level 3 to Level 2, if applicable?
h) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning priorities (Level 1, Level 2, or Level 3) when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) In accordance with GO 95, Liberty understood Level 1 conditions as those posing immediate safety or reliability risks with high potential for impact, which should be addressed immediately. Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes.
b) Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes. Liberty understood Level 3 conditions as those with a low potential safety or reliability risk, which Liberty attempted to address within the specified timeframes.
c) As evidenced in *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 2, inspectors selected from a menu of condition codes and assigned a priority level to the inspection record. The dynamic electronic inspection form in Fulcrum that inspectors began using for detailed inspections in 2020 also allowed inspectors to input comments regarding the conditions they identified.
d) As explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program. These inspectors classified conditions as Level 1, 2, or 3 in the process of conducting inspections in the field, based on their understanding of GO 95 and their experience and training.
e) Though Liberty did not have a formal quality assurance process, as explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program.
f) See Liberty's response to subpart (d).
g) See Liberty's response to subpart (b).
h) See Liberty's response to subpart (d).

REQUEST NO. 8:

From 2011 to the time of the Mountain View Fire:

a) How many Level 1 corrective work orders did Liberty identify during routine patrol inspections?
    a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
        i. Structure number
        ii. Work Order Number

iii. Notification Number (if applicable)
iv. Equipment Number
v. Inspection Date
vi. Equipment Type
vii. HFTD/HFRA Tier
viii. Priority
ix. Ignition Risk (Y/N)
x. Date Created
xi. Due Date
xii. Revised Due Date (if applicable)
xiii. Priority Change (if applicable)
xiv. Reason for Change (if applicable)
xv. Date Completed
xvi. Latitude in degrees
xvii. Longitude in degrees

b) How many Level 1 corrective work orders did Liberty identify during detailed inspections?
   a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
      i. Structure number
      ii. Work Order Number
      iii. Notification Number (if applicable)
      iv. Equipment Number
      v. Inspection Date
      vi. Equipment Type
      vii. HFTD/HFRA Tier
      viii. Priority
      ix. Ignition Risk (Y/N)
      x. Date Created
      xi. Due Date
      xii. Revised Due Date (if applicable)
      xiii. Priority Change (if applicable)
      xiv. Reason for Change (if applicable)
      xv. Date Completed
      xvi. Latitude in degrees
      xvii. Longitude in degrees

AMENDED RESPONSE:

a) Liberty objects to this Question as vague, ambiguous, and overbroad. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows: Liberty transitioned to Fulcrum for routine patrol records in approximately 2023. Prior to that time, inspectors recorded the results of routine patrol inspections on hard-copy maps and thus, Liberty is unable to provide an Excel file with the requested information for routine patrol inspections in the relevant timeframe due to the significant burden involved with compiling such a file based on

identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

b) Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

Liberty is producing the data requested by this Question in the attachment *CalAdvocates-LIB-A2506017-015-Q8.xlsx*. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records, and refined the information in those fields for accuracy based on a review of the full event history of inspection records with priority level field set as Level 1. As described in *Liberty-03: Prudence of Operations*, prior to 2020, inspectors recorded the results of detailed inspections on hard-copy forms and thus, Liberty is unable to provide an Excel file with the requested information for detailed inspections prior to 2020 due to the significant burden involved with compiling such a file based on identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

REQUEST NO. 9:

At the time of the Mountain View Fire:

a) Did Liberty have a policy for replacing rather than splicing conductors when failures occurred? If so, please provide a copy.
b) Did Liberty have a policy for limiting the number of spliced conductors to a specific number per span? If so, please provide a copy.
c) Did Liberty have a policy specifying the required conductor sag to ensure compliance with GO 95? If so, please provide a copy.
d) Were sag measurements on the Topaz 1261 circuit ever documented?
e) If the answer to (d) is "yes," please provide documentation supporting your answer.
f) If the answer to (d) is "no," please explain why not.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) As referenced in Liberty's response to CalAdvocates-LIB-A2506017-001, Question 8, as of November 17, 2020, Liberty installed splices on conductors in connection with operation of the distribution system. There was no formal policy regarding the installation of splices and the use of splices was based on the experience and expertise of field personnel in the course of repair work.
b) See Liberty's response to subpart (a).
c) Please refer to *Overhead Distribution Conductor Stringing Guide (CON05T)* and *Standard Sagging Practices (CON06T)* of *Overhead Electric Standards.pdf*, which

Liberty provided in response to CalAdvocates-LIB-A2506017-0018, Question 3. Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. For example, refer to the "General Crew Notes" on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Five – As Built.pdf* for directions on sag tables crews should use and to the sag table on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Six – As built.pdf*, both of which Liberty attached to its response to CalAdvocates-LIB-A2506017-0018.

d) Liberty objects to this subpart as vague and ambiguous as framed, including use of the term "sag measurements." Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. Liberty is not aware of any records that would document specific sag measurements for the Topaz 1261 circuit conductors.
e) N/A
f) See Liberty's response to subpart (d).

REQUEST NO. 10:

In Liberty's testimony (LIB-03 at 10), it states that:

While FPPs were mandatory for investor-owned utilities in Southern California, they were required for investor-owned utilities in Northern California only if the utility determined, with respect to its facilities within high-fire threat areas identified in the Reax Map, that "it is reasonably foreseeable that the probability of 3-second wind gusts exceeding the maximum working stresses for such facilities during a Red Flag Warning is 3% or more during a 50-year period." Liberty analyzed whether this criterion was met using data from Remote Automated Weather Stations ("RAWS") operated by the National Weather Service ("NWS"). Because the available RAWS data did not indicate whether gusts lasted three seconds or more, to promote public safety and a proactive approach, Liberty assumed that all maximum gusts met the criterion and determined that an FPP was needed for its facilities located within Threat Zones 3 and 4 of the Reax Map.

a) How many RAWS stations were located within Liberty's service territory at the time of the Mountain View Fire?
b) What distance from Liberty's facilities did the company consider acceptable for RAWS data to be representative?
c) Did Liberty conduct any analysis to compare RAWS data with on-the-ground incident reports of outages or damage?
d) Was Liberty aware of any academic or industry critiques regarding the use of RAWS for fire risk analysis at the time?
e) How did Liberty document its decision to assume all gusts equaled 3-second durations despite the lack of confirmation?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) The RAWS stations that were transmitting data as of November 17, 2020 are publicly

available via MesoWest: https://mesowest.utah.edu/.

b) Liberty considered data from RAWS stations located within 25 miles of its service territory, as described on page 8 and in Attachment 2 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.
c) As further explained in its 2012 Fire Prevention Plan, Liberty took a deliberately conservative approach when assessing whether a Fire Prevention Plan was required for its facilities under R.08-11-005, and ultimately decided to submit one. Please refer to pages 7-8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13, for further explanation of Liberty's methodology for determining whether a Fire Prevention Plan was required, and Attachments 2 and 3 thereto include information regarding the RAWS used for the assessment.
d) Liberty objects to this subpart as vague, ambiguous and overbroad, including its use of the phrase "use of RAWS for fire risk analysis." See Liberty's response to subpart (c).
e) Please refer to page 8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.

The following questions are in regard to Liberty's response to CalAdvocates-LIB-A2506017-001, question 4.

REQUEST NO. 11:

a) Please clarify why intrusive pole inspections on the Topaz 1261 Circuit between the years 2011 and 2020 were only conducted in 2013?
b) Please describe the criteria Liberty used to determine when and where intrusive pole inspections would be performed?
c) Please explain the technical criteria Liberty used to classify poles as "Restorable," "Non-Restorable," or "Hazard"?
d) Who was responsible for assigning poles into each of these categories during the 2013 inspection?
e) Liberty states that corrective work was addressed using hard-copy work packets. Please explain the process for creating, assigning, and closing those packets?
f) Who was responsible for maintaining or archiving the hard-copy packets documenting corrective work?
g) Please provide a sample of three hard-copy work packets referenced in (e).

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty conducted intrusive pole inspections on a circuit basis. 2013 was the year when Liberty scheduled intrusive inspections on the Topaz 1261 Circuit. Pursuant to GO 165, Liberty conducted intrusive inspections on a circuit once every 10 years. Liberty conducted intrusive pole inspections on the Topaz 1261 Circuit again in 2023.

b) Liberty determines its intrusive pole inspection schedule based on when a circuit had previously been inspected. Liberty schedules a circuit for intrusive pole inspections once every 10 years.
c) Please refer to attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* for guidance Liberty provided to its contractor around 2013 on conducting intrusive inspections and criteria for classifying rejected poles.
d) Liberty used a qualified and experienced contractor for intrusive pole inspections. The contractors' personnel were responsible for classifying poles into these categories.
e) Prior to 2020, corrective work identified during Liberty's inspection and maintenance programs was addressed via hard-copy work packets. Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
f) See Liberty's response to subpart (e).
g) For a sample design packet of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, please see attachment *CONFIDENTIAL-8800-0115-0113 Map.pdf*. Since its original response, Liberty has located two additional design packets of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, see confidential attachments *CONFIDENTIAL-8800-0115-0112-Map.pdf* and *CONFIDENTIAL-8800-0115-0114 Map.pdf*.

REQUEST NO. 12:

In Liberty's response to CalAdvocates-LIB-A2506017-001, question 4, it states that:

Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.

a) Since the 2013 intrusive pole inspection, has Liberty made any effort to digitize, scan, or otherwise preserve the hard-copy packets?
b) Please clarify why records showing when corrective work was completed were not located following Liberty's search?
c) How did Liberty verify that poles identified in 2013 inspections as "Non-Restorable" or "Hazard" were in fact replaced?
d) Please describe the oversight mechanisms in place at the time of the 2013 intrusive pole inspection to ensure corrective work identified in inspections was completed.
e) Has Liberty performed any follow-up inspections on the same poles identified in 2013 to confirm that corrective actions were carried out?
f) Did Liberty report the results of the 2013 intrusive pole inspections, including the number of poles requiring corrective work, to any regulatory body?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty maintains some physical records in on-site and off-site storage. While Liberty has scanned some of these records, it has not systematically digitized or scanned all hard-copy work packets. The spreadsheet Liberty provided in its response to CalAdvocates-LIB-A2506017-001, Question 4 was provided to Liberty from its intrusive pole inspection contractor.
b) Liberty did not locate records showing when corrective work was completed due to the passage of time.
c) Liberty verified whether the poles classified as "Non-Restorable" or "Hazard" were replaced using a combination of data sources, including design and installation work order packets, the installation dates of poles available in its GIS database, records of pole inspections available within the Fulcrum database, and field verification.
d) Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
e) Please refer to Liberty's response to subparts (c).
f) In its annual GO 165 report for 2013, Liberty reported the total number of poles that underwent intrusive inspections in 2013. This report did not specify the number of poles intrusively inspected that required corrective work.

REQUEST NO. 13:

a) During the period from 2011 through 2020, did Liberty have any poles in its system that had been treated with cellon gas?
b) If the answer to (a) is yes, provide the number of such poles systemwide.
c) If the answer to (a) is yes, provide the number of such poles on the Topaz 1261 Circuit.
d) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles treated with cellon gas?
e) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles for any other reason?
f) If the answer to parts (d) or (e) is yes, list and explain the actions Liberty has taken to mitigate such potential inaccurate results.
g) What is the median age of wood poles in Liberty's system?
h) What is the median age of wood poles on the Topaz 1261 Circuit?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Liberty further objects to the extent this Question requests information not maintained in the ordinary course of business. Subject to and without waiving these objections, Liberty responds as follows:

a) According to Liberty's intrusive pole inspection results in the relevant timeframe, some poles in its system had been treated with "Penta in Liquid Petrol Gas - Cellon."
b) According to the intrusive pole inspection results available to Liberty, 1,555 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" across all circuits that were subject to intrusive pole inspections during the relevant timeframe.

c) According to the results of the intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, 107 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" at that time. Liberty's standard scope of work for intrusive pole inspections specifies procedures specific to poles treated with cellon gas.
d) Liberty objects to this subpart as vague, ambiguous, and overbroad as framed, including its use of the term "potential inaccuracies." Liberty understands this term to refer to systemic deficiencies or errors identified in the intrusive pole inspection process. Liberty's intrusive pole inspections are performed by a qualified and experienced contractor that provides specialized services to utilities around the country. Liberty has not identified systemic deficiencies associated with its intrusive pole inspections, including on poles treated with cellon gas.
e) See Liberty's response to subpart (d).
f) N/A
g) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles in Liberty's system is approximately 49 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.
h) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles on the Topaz 1261 Circuit, which has been renamed the Topaz 1202 Circuit, is approximately 28 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.

ATTACHMENT 5

PG&E, 2019 Wildfire Mitigation Plan, February 9, 2019

BEFORE THE PUBLIC UTILIITES COMMISSION
OF THE STATE OF CALIFORNIA

FILED
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Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)	**R.18-10-007** (Issued October 25, 2018)

PACIFIC GAS AND ELECTRIC COMPANY'S WILDFIRE MITIGATION PLAN

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February 6, 2019

BEFORE THE PUBLIC UTILIITES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	**R.18-10-007** (Issued October 25, 2018)

PACIFIC GAS AND ELECTRIC COMPANY'S WILDFIRE MITIGATION PLAN

Pursuant to Senate Bill (SB) 901 and the *Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)*, Rulemaking (R.) 18-10-007 (Wildfire OIR) of the California Public Utilities Commission (CPUC or Commission), PG&E submits the attached Wildfire Safety Plan (Plan). SB 901 requires all California electric utilities to prepare plans on constructing, maintaining, and operating their electrical lines and equipment to minimize the risk of catastrophic wildfire. In the Wildfire OIR, the CPUC established a schedule for submission and review of the initial wildfire mitigation plans, and a process for review and implementation of plans to be filed in future years. PG&E is providing this Plan for 2019, consistent with the statutory requirements and direction provided by the CPUC in the Wildfire OIR and in the *Administrative Law Judge's Ruling on Wildfire Mitigation Plan Template, and Adding Additional Parties as Respondents* issued January 17, 2019.

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This Plan describes PG&E's proposed programs and strategies, recognizing that it will take a major collective effort to prevent wildfires. We welcome the input and feedback of our communities, customers, community leaders, first responders, and others to collaboratively solve the unprecedented wildfire risk facing our state.

Respectfully Submitted,

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Dated: February 6, 2019



Pacific Gas and Electric Company
2019 Wildfire Safety Plan

February 6, 2019

CA-07-0095

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Attachments:

A: Fire Potential Index Methodology and Background

B: Critical Services

C: Description of Routine Facilities Inspections

D: Risks and Drivers Identified in RAMP

E: Cost Estimates for 2019 Plan Programs

Glossary of Acronyms and Abbreviations

Acronym	Term/Definition
AHJ	Agency Having Jurisdiction
ALJ Ruling	*Administrative Law Judge's Ruling on Wildfire Mitigation Plan Template, And Adding Additional Parties as Respondents*, issued January 17, 2019 in R.18-10-007
CAL FIRE	California Department of Forestry and Fire Protection
Cal OES	California Office of Emergency Services
CARE	California Alternate Rate for Energy
CEMA	Catastrophic Event Memorandum Account
CEQA	California Environmental Quality Act
CERP	Company Emergency Response Plan
CIRT	Centralized Inspection Review Team
CPUC or Commission	California Public Utilities Commission
CWSP	Community Wildfire Safety Program
D.	Decision
DFM	Dead Fuel Moisture
EAM	Electric Asset Management
EEI	Edison Electric Institute
EOC	Emergency Operations Center
EP&R	Emergency Preparedness and Response
EPIC	Electric Program Investment Charge
ESA	Energy Savings Assistance
ETOR	Estimated Time of Restoration
EVM	Enhanced Vegetation Management

Acronym	Term/Definition
FIA	Fire Index Area
FMEA	Failure Modes and Effects Analysis
FPI	Fire Potential Index
FPP	Fire Prevention Plan
GO	General Order
GRC	General Rate Case
HFTD	High Fire-Threat District
HHZ	High Hazard Zones
IBEW	International Brotherhood of Electrical Workers
ICS	Incident Command Structure
IOU	Investor-Owned Utility
IVR	Integrated Voice Recording
km	Kilometer
kV	Kilovolt
MAA	Mutual Assistance Agreements
mph	miles per hour
NWS	National Weather Service
OA	Operability Assessment
OEM	Original Equipment Manufacturer
OES	Office of Emergency Services
OP	Ordering Paragraph
PEV	Post Enrollment Verification
PG&E or the Company	Pacific Gas and Electric Company

Acronym	Term/Definition
PIH	Pre-installed Interconnection Hubs
Plan	Wildfire Safety Plan
POMMS	PG&E Operational Mesoscale Modeling System
PRC	Public Resources Code
PSPS	Public Safety Power Shutoff
PUC	Public Utilities Code
QA	Quality Assurance
QC	Quality Control
QM	Quality Management
R.	Rulemaking
RAMP	Risk Assessment and Mitigation Phase
REACH	Relief for Energy Assistance through Community Help
ROW	Right-of-Way
SB 901	Senate Bill 901
SCADA	Supervisory Control and Data Acquisition
SDG&E	San Diego Gas & Electric
SIPT	Safety and Infrastructure Protection Teams
SMAP	Safety Model Assessment Proceeding
SMEs	Subject Matter Experts
SmartMeter™	Brand Name for Automated Metering Initiative (AMI)
SOPP	Storm Outage Prediction Model
T&D	Transmission and Distribution
U.S.	United States

Acronym	Term/Definition
USFS	United States Forest Service
VM	Vegetation Management
VP	Vice President
WSIP	Wildfire Safety Inspection Program
WSP or Plan	Wildfire Safety Plan
WSOC	Wildfire Safety Operations Center

1. Introduction and Objectives of Plan

1.1. Executive Summary

Pacific Gas and Electric Company (PG&E or the Company) takes seriously the critical role it plays in preventing wildfires caused by electrical equipment in Northern California. We understand the urgency of the situation, that lives could be at stake and that we need to move even more quickly. This Wildfire Safety Plan (WSP or Plan) describes the enhanced, accelerated, and new programs that PG&E is and will aggressively continue to implement to prevent wildfires in 2019 and beyond. To address increasing wildfire risk, in addition to aggressively implementing new approaches to manage it, PG&E believes shutting off power will likely be necessary and may need to be performed more frequently due to the extreme weather events and dry vegetation conditions. To that end, PG&E is expanding its Public Safety Power Shutoff (PSPS) program to prevent wildfires from occurring and is implementing new ways to reduce its impacts to first responders and vulnerable customers, including those with medical needs.

PG&E submits this Plan pursuant to Senate Bill (SB) 901 requiring all California electric utilities to prepare plans on constructing, maintaining, and operating their electrical lines and equipment to minimize the risk of catastrophic wildfire. The California Public Utilities Commission (CPUC or Commission) established a schedule for submission and review of the initial wildfire mitigation plans, and a process for review and implementation of plans to be filed in future years. PG&E is providing this Plan consistent with the statutory requirements and direction provided by the CPUC in its *Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018)*, Rulemaking (R.) 18-10-007 (Wildfire OIR).

This Plan describes PG&E's proposed programs and strategies, recognizing that it will take a major collective effort to prevent wildfires. We welcome the input and feedback of our communities, customers, community leaders, first responders, and others to collaboratively solve the unprecedented wildfire risk facing our state.

Filing this Plan is an important milestone. But PG&E has not been waiting for regulatory action. Instead, since the October 2017 North Bay wildfires and the 2018 Camp Fire, PG&E has proactively implemented enhanced wildfire safety programs with urgency. In this Plan, PG&E describes the actions we have already taken, and the actions we intend to take, to prevent wildfires in 2019 and beyond. Preventing wildfires outright is likely impossible. However, PG&E is approaching the issue with urgency to do everything we can to prevent our facilities from creating public safety risks. PG&E's efforts include significant expansions in its PSPS program and its situational awareness capabilities, vegetation management, inspections of electric distribution and transmission facilities, system hardening, enhanced controls, and other programs designed to make PG&E's customers and the communities that we serve safer. In designing this approach, PG&E benchmarked with several utilities including San Diego Gas & Electric Company (SDG&E) and several Australian utilities, with variations that reflect differences in our territory or system design.

This work is inherently hazardous and must be done safely, with quality and care. There are execution risks to accomplish the expanded and accelerated scope of work planned by PG&E. The availability of equipment, qualified personnel, and legal/regulatory issues (such as land rights and environmental permitting requirements) can impact the timing and scope of the programs proposed in this Plan. As described more in Section 4 below, PG&E intends to work aggressively to resolve these execution risks as they arise, including working with existing contractors and suppliers to increase available resources as quickly as possible. Going forward, PG&E will continue to enhance and build upon these programs as we learn from our experience and our collaboration with customers, communities, and industry experts.

Table 1 below provides an overview of PG&E's wildfire reduction measures, followed by a summary narrative, describing PG&E's 2019 wildfire related programs.

TABLE 1: 2019 PROGRAM OVERVIEW[1]

Wildfire Reduction Measure	2018 (Approx.)	2019 (Approx.)	Percentage/ Capacity Increase (Approx.)	2019 Planned Work Completion by June[2]
Vegetation Management[3]	160,000 trees removed	375,000 trees removed	235%	42%
	760 miles of fuel reduction, overhang clearing, or Enhanced Vegetation Management (EVM)	2,450 miles of EVM	320%	40%
Inspections - Distribution	517,500 distribution poles for routine inspections	685,000 distribution poles in High Fire Threat District (HFTD) areas with enhanced inspections in five months in addition to routine inspections	130% -400% (excluding substations)	100%
Inspections - Transmission	9,400 transmission structures with enhanced inspections 76,000 routine inspections of transmission structures	40,600 transmission structures with enhanced inspections[4] in four months in addition to routine inspections		100%
Inspections - Substations	960 monthly routine inspections	200 enhanced risk-based inspections in the HFTD areas in four months in addition to routine, monthly inspections		100%
System Hardening[5]	17 circuit miles-tree wire projects	150 circuit miles	880%	30%

1 Numbers in Table 1 are approximated for purposes of presentation in this table.

2 Completion dates are current estimates and may change depending on external factors such as the availability of equipment and qualified personnel, including third-party vendors and suppliers, as well potential legal or regulatory challenges to tree removal, vegetation management, and system hardening.

3 Includes trees removed under PG&E's Drought and Tree Mortality work vegetation management (CEMA) work, accelerated wildfire risk reduction vegetation management (AWRR), and EVM for 2018 and CEMA and EVM for 2019.

4 Including drone and helicopter inspections and climbing of all transmission towers.

5 With the exception of light-duty steel poles, the System Hardening work will be performed for distribution.

TABLE 1: 2019 PROGRAM OVERVIEW[6]
(CONTINUED)

Wildfire Reduction Measure	2018 (Approx.)	2019 (Approx.)	Percentage/ Capacity Increase (Approx.)	2019 Planned Work Completion by June[7]
Situational Awareness	200 weather stations	400 additional weather stations	200%	50%
	9 cameras	70 additional cameras	780%	42%
	N/A	Developing fire spread model capabilities – Phase 1[8]	N/A	100%
Resilience Zones	N/A	At least 1 resilience zone operationalized	N/A	N/A
PSPS	7,100 distribution circuit miles in Program (Tier 3 HFTD areas)	25,200 distribution circuit miles in Program (Tier 2 and Tier 3 HFTD areas)	355%	100%
	370 circuit miles of transmission lines at 70 kilovolt (kV) and below	5,500 circuit miles of transmission lines at 500kV and below	1,485%	100%
	570,000 electric customer premises potentially impacted by PSPS events	5.4 million electric customer premises potentially impacted by PSPS events	950%	100%[9]

The following summary narrative describes in more detail PG&E's wildfire reduction programs and measures:

- Vegetation Management:
    - Expanded Removal of Trees: PG&E forecasts removing approximately

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6 Numbers in Table 1 are approximated for purposes of presentation in this table.

7 Completion dates are current estimates and may change depending on external factors such as the availability of equipment and qualified personnel, including third-party vendors and suppliers, as well potential legal or regulatory challenges to tree removal, vegetation management, and system hardening.

8 Phase 1 includes modeling asset fire spread risks for overhead lines in Tier 2 and Tier 3. Later phases include more granular analysis and refined outputs.

9 All 5.4 million electric customer premises to be notified of the potential for PSPS impacts by June 2019.

375,000 trees in 2019 that have a higher potential to fail including at-risk species in addition to dead, dying or other hazard trees.

- Enhanced Vegetation Management: PG&E will perform EVM on approximately 2,450 circuit miles in HFTD areas by the end of 2019, including targeted removal of vegetation fuels under and adjacent to power lines.

- Inspections:
  - Expanded Inspections: By May 31, 2019, PG&E will perform enhanced inspections of its electrical assets in HFTD areas, including approximately 685,000 distribution poles, 50,000[10] transmission structures, and 200 substations. These enhanced inspections include ground inspections, drone and helicopter inspections where needed, and climbing inspections of every transmission tower.
  - Corrective Actions: PG&E will take immediate action to address any issues identified as an imminent risk to public or employee safety.

- System Hardening: System hardening reduces potential fire risk associated with the overhead distribution system and includes replacing bare overhead conductor with covered conductor, select undergrounding where appropriate, replacing equipment with equipment identified by the California Department of Forestry and Fire Protection (CAL FIRE) as low fire risk, upgrading or replacing transformers to operate with more fire-resistant fluids, and installing more resilient poles to increase pole strength and fire resistance.
  - 2019: PG&E will complete approximately 150 miles of hardening the highest risk circuits in HFTD areas in 2019.
  - Beyond 2019: PG&E will be hardening 7,100 circuit miles in HFTD areas that it has identified through ignition modeling and field analysis as the highest risk. The pace of hardening will accelerate as PG&E aggressively works to resolve supply and qualified personnel challenges.

- Situational Awareness: PG&E is swiftly increasing its situational awareness—its knowledge of local weather and environmental conditions—to obtain real time information on a more granular level. This type of information is critical for both wildfire prevention and PSPS events, and is accessible to respective fire response agencies.

- Enhanced Controls:
  - Reclosers: In 2019, PG&E will add Supervisory Control and Data Acquisition (SCADA) capability to allow for remote reclose blocking. The expanded SCADA capability will enable remote operation of 100 percent of the line reclosers in Tiers 2 and 3 HFTD areas by June 1, 2019.

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10 Inclusive of 9,400 inspections completed in December 2018.

- Additional Measures: PG&E has introduced other measures to prevent potential ignitions, including strengthened personnel work procedures, deploying Safety and Infrastructure Protection Teams (SIPT) with fire-fighting capabilities, and operating heavy-lift helicopters for enhanced fire suppression and restoration efforts, available at CAL FIRE's discretion. These measures will be in place by June 1, 2019.

- Public Safety Power Shutoff:

  - Program Initiation (2018): PG&E implemented its PSPS Program to proactively de-energize lines that traverse Tier 3 HFTD areas under extreme fire risk conditions in 2018. To develop the PSPS Program, PG&E worked extensively with SDG&E to understand and implement best practices from SDG&E's de-energization program, while addressing unique issues presented by PG&E's service area (which differs in terrain, weather, and population).

  - Program Expansion and Criteria Evolution (2019): PG&E is significantly expanding the PSPS program scope to include high voltage transmission lines and the highest fire risk areas (Tier 2 (elevated fire risk) and Tier 3 (extreme fire risk)) as referenced in the HFTD Map adopted by the CPUC. In addition, PG&E is further evaluating its PSPS decision criteria to reduce the level of judgment in the criteria to the extent feasible.

  - Working with Customers: PG&E will be working with customers to provide them with information regarding PSPS events generally, and to provide the most up to date information before and during PSPS events. This includes alerting 5.4 million PG&E electric customer premises of the potential for PSPS events. Extensive customer outreach will begin in the first quarter of 2019 and will continue throughout the year. To the extent possible, PG&E will alert customers that a PSPS event could occur within 48 hours. PG&E is actively exploring and developing additional services and programs to support our customers during PSPS events with a focus in the short term on customers who require a continuous electric supply for life support, as well as critical services (i.e., first responders, hospitals, telecom, and water agencies).

1.2. Plan Overview and Objectives

PG&E's Plan details the aggressive steps that it is taking, and will continue to take, to address the urgent need to prevent wildfires. PG&E will submit its Plan to the Commission annually for review and approval. PG&E expects the Plan will evolve over time as PG&E receives new information, more experience, and input from our communities, first responders, regulators and others through this proceeding and other venues, on how PG&E can best prevent wildfires and improve the overall safety of its

system. In addition to receiving feedback and input through the regulatory process, as part of our collaborative efforts to address the risk of catastrophic wildfires, PG&E is partnering with industry and academic experts. These partnerships, which are described in more detail in Sections 3 and 4, allow PG&E to leverage state-of-the-art thinking in fields that range from wildfire evacuation to probabilistic risk assessment. However, as explained above, PG&E is not waiting for the completion of the regulatory process or review in other venues to act; it is acting now.

One key foundational component informing PG&E's initial Plan is that wildfire risks are differentiated across California. This Plan is intended to reflect that differentiation given the unique design and geography of PG&E's 70,000-square-mile service area, as well as the fact that more than half (52 percent) of PG&E's service area is identified as extreme (Tier 3) or elevated (Tier 2) fire-threat areas according to the CPUC's HFTD Map.[11] The wildfire safety strategies and programs described in this Plan are specifically intended to address PG&E's unique geographic service area.

PG&E's programs are designed to reduce ignition drivers and risk-event frequency associated with overhead electric facilities in high fire-threat areas, as indicated by the CPUC's HFTD Map. To develop the Plan, PG&E extensively analyzed wildfire risk factors to determine which factors have the highest incident rates and potential fire spread characteristics and potential alternatives to determine what additional operational actions, enhancements to existing programs, or other measures that will most effectively address those risks. To achieve the Plan objectives, PG&E will use a risk-based approach, meaning the highest risk areas will be addressed first, and will do more work than outlined in this Plan if it can do so without compromising safety or quality.

As directed by Administrative Law Judge Thomas in the *Administrative Law*

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11 The HFTD Map, adopted by the Commission in January 2018, designates three types of fire threat area: Tier 3 (extreme risk), Tier 2 (elevated risk), and a much smaller Zone 1 (made up of areas on the CAL FIRE/ United States Forest Service (USFS) High Hazard Zones (HHZ) map that are not subsumed within Tier 2 and Tier 3 HFTD areas). *See* Decision (D.) 17-12-024, p. 158, Ordering Paragraph (OP) 12, and Appendix D.

Judge's Ruling on Wildfire Mitigation Plan Template, and Adding Additional Parties as Respondents issued January 17, 2019 (ALJ Ruling), in this section PG&E is providing a summary of the objectives of its 2019 Plan. The ALJ Ruling also directed that objectives be broken down by time period: (1) before the upcoming wildfire season; (2) before the filing of the next WSP; and (3) within five years. For each objective, PG&E has indicated programs that will be completed with these time periods or, in certain cases, over a longer period. PG&E intends to continue to enhance these measures over time. The details regarding the timing of each objective are provided in Table 3 in Section 2.1, and further information about each program is provided in Section 4 of the Plan.

1. **Objective – Vegetation Management:** To address the potential for ignition from contact between PG&E facilities and vegetation through comprehensive vegetation management. PG&E will achieve critical milestones for this objective by the dates described below and will continue these efforts long-term (more than five years).

    - Enhanced Vegetation Management: Focusing vegetation management efforts on high-risk species of vegetation, vegetation with the most potential to come into contact with overhead electric facilities in the highest risk areas, and targeted fuel reductions (e.g., clearing of dry brush): approximately 1,000 circuit miles in HFTD areas by June 30, 2019, with approximately 2,450 circuit miles in total in HFTD areas by December 31, 2019.

2. **Objective – Enhanced Inspections and System Hardening:** To address the potential for ignition as a result of equipment failure through enhanced inspections and system hardening. PG&E plans to achieve critical milestones for this objective by the dates described below.

    - Enhanced and Accelerated Inspection and Repair Programs: Conduct accelerated and enhanced fire ignition-based inspections and repairs of overhead electric facilities in HFTD and adjacent areas. Inspections of all transmission structures, and substations in HFTD areas by May 1, 2019, and for distribution poles in HFTD areas by May 31, 2019. Anything identified as an imminent threat to public safety during an inspection will be addressed immediately.

    - System Hardening: Revising distribution design standards to increase overall strength and mitigate against impacts of external contacts (e.g., vegetation or wire on wire contacts) of approximately: 45 circuit miles by June 30, 2019; 150 circuit miles in total by December 31, 2019; and 7,100 circuit miles over a 10-year time horizon.

3. **Objective – Situational Awareness:** To obtain real-time knowledge of localized conditions that affect wildfire risk in order to operate the system to reduce risk of wildfires, including installing approximately: 200 weather stations and 30 cameras by June 30, 2019; 400 new weather stations in total by September 1, 2019; 71 new cameras in total by December 31, 2019; and 1,300 weather stations within five years. PG&E will grant fire agencies access to control the cameras, consistent with an approach taken by SDG&E.

4. **Objective – Operational Practices:** To perform electric system operations in a manner that reduces the possibility of wildfire ignition in times of elevated fire danger conditions and reduces fire spread including use of PSPS, enhanced operational practices, personnel work procedures, SIPT, and aviation resources. PG&E's goal is to achieve this objective by June 1, 2019, and the refinement of these activities will continue on an ongoing basis.

5. **Objective – Reducing Public Impact:** To reduce the impact on the public of wildfire safety measures. PG&E plans to achieve critical milestones for this objective by June 1, 2019, and will continue to enhance these measures through near-term (before filing the 2020 WSP) and long-term (more than five years) milestones.

    - Sectionalizing and Distribution Circuits: Upgrading devices with SCADA to minimize de-energization impacts and allow for increased targeting of the PSPS program: all existing line reclosers in Tiers 2 and 3 will be SCADA enabled by June 1, 2019 and additional sectionalizing taking place over the next 5+ years.

    - Resilience Zones: Configuring areas that can be isolated from the broader grid and energized by mobile generation during PSPS events: Complete pilot site before June 1, 2019 which will inform and dictate how the program should evolve in the future to better serve the needs of our customers; continue to research and add additional resilience zones as needed.

6. **Objective – Research:** PG&E, in partnership with experts and academics, is researching and evaluating a number of potential innovative technologies to address wildfire risk and will enhance its programs accordingly. Due to the inherent uncertainty of any new technology, the timing of implementation is unknown at this time. PG&E will implement new technologies as they become viable. PG&E will update the CPUC and parties on the progress of and results from this research in its annual WSP submissions.

7. **Objective – Wildfire Response:** To respond more quickly and effectively to major wildfires, regardless of the source of ignition (e.g., third party, lightening, etc.), and to prepare to rebuild and recover from a disaster safely, efficiently, effectively, and consistently. PG&E's plan is to be ready to meet this objective by June 1, 2019 by developing the wildfire response and post-incident recovery capabilities described in this Plan.

This Plan is designed to address the risk of wildfire ignitions associated with

electric facilities located in HFTD areas and to comply with the requirements of SB 901; and, where there are risks that cannot immediately be addressed, includes an expanded PSPS program to prevent wildfires. This Plan does not describe all ongoing operations and maintenance work that PG&E performs and will continue to perform that also help to reduce wildfire risk. Much of this ongoing work is performed in accordance with regulatory safety requirements, such as General Orders (GO) issued by the CPUC and California Public Resources Code (PRC) sections 4292 and 4293 for vegetation management.

This Plan does describe the additional work that PG&E proposes for 2019 to address wildfire risk. This additional work is focused on the high fire-risk areas designated by the CPUC's HFTD Map. As PG&E learns more, it will continue to improve and evolve these programs and may expand or re-prioritize the work described in this Plan. Table 2 below identifies the SB 901 requirements for wildfire mitigation plans, and the location in PG&E's Plan where each requirement is addressed.

TABLE 2: PLAN COMPLIANCE WITH CALIFORNIA PUBLIC UTILITIES CODE (PUC) § 8386(C)

Information Required by PUC § 8386(c)	Location(s) of Required Information in Plan
(1) An accounting of the responsibilities of persons responsible for executing the Plan.	Section 6.1
(2) The objectives of the Plan.	Section 1
(3) A description of the preventive strategies and programs to be adopted by PG&E to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risk.	Section 2.1, Section 4
(4) A description of the metrics PG&E plans to use to evaluate the Plan's performance and the assumptions that underlie the use of those metrics.	Section 6.2
(5) A discussion of how the application of previously identified metrics to previous plan performances has informed the Plan.	Section 6.3
(6) Protocols for disabling reclosers and deenergizing portions of the electrical distribution system that consider the associated impacts on public safety, as well as protocols related to mitigating the public safety impacts of those protocols, including impacts on critical first responders and on health and communication infrastructure.	Section 4.1.1, Section 4.6
(7) Appropriate and feasible procedures for notifying a customer who may be impacted by the deenergizing of electrical lines.	Section 4.6.3
(8) Plans for vegetation management.	Section 4.4
(9) Plans for inspections of PG&E's electrical infrastructure.	Section 4.2
(10) A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of Safety Model Assessment Proceeding (SMAP) and Risk Assessment Mitigation Phase filings.	Section 3.2
(11) A description of how the Plan accounts for the wildfire risk identified in PG&E's Risk Assessment Mitigation Phase filing.	Section 3.2.1
(12) A description of the actions PG&E will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement.	Section 4.3
(13) A showing that PG&E has an adequate sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with PG&E.	Section 5.1.4
(14) Identification of any geographic area in PG&E's service territory that is a higher wildfire threat than is currently identified in a CPUC fire threat map, and where the CPUC should consider expanding the HFTD area based on new information or changes in the environment.	Section 3.4
(15) A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations.	Section 3.1

TABLE 2: PLAN COMPLIANCE WITH CALIFORNIA PUBLIC UTILITIES CODE (PUC) § 8386(C) (CONTINUED)

Information Required by PUC § 8386(c)	Location(s) of Required Information in Plan
(16) A description of how the Plan is consistent with PG&E's disaster and emergency preparedness plan prepared pursuant to P.U. Code§ 768.6.	Section 5.1.1
(17) A statement of how PG&E will restore service after a wildfire.	Section 4.8, Section 5.1.2
(18) Protocols for compliance with requirements adopted by the CPUC regarding activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to utility representatives, and emergency communications.	Section 5.2
(19) A description of the processes and procedures PG&E will use to monitor and audit the implementation of the Plan, identify any deficiencies in the Plan, and monitor and audit the effectiveness of electrical line and equipment inspections.	Section 6.4

2. Program Overview and Climate Change Risk and Strategy

2.1. Overview of Strategies and Programs

Pursuant to PUC Section 8386(c)(3) and the ALJ Ruling, in this section, PG&E provides an overview of the strategies and programs in the Plan to reduce the risk of wildfires. Risk analysis and drivers are addressed in greater detail in Section 3 and PG&E's strategies and programs, as well as the targets, are described in Sections 4 through 6.

In response to the wildfires that occurred in 2017, PG&E initiated the Community Wildfire Safety Program (CWSP) to work closely with fire responders, customers, and communities, to implement new and enhanced safety measures to help reduce the risk of wildfires, as well as improve situational awareness and emergency response. The CWSP utilizes a risk-based approach to identify and address the assets most at risk of wildfire ignition and in areas with greatest potential fire spread. The comprehensive risk assessments performed as part of the CWSP, as well as geospatial modeling on both the volume and the location of fire incidents in PG&E's service area, have significantly informed the development of wildfire and safety programs.

Specifically, the CWSP includes a risk-based vegetation management approach for specific areas of PG&E's service area, such as trimming or removing high-risk tree

species, increased clearing of overhanging branches directly above and around power lines, and removal of vegetation fuels under and adjacent to power lines on a targeted basis.

Similarly, PG&E has transitioned to a risk-based facilities inspection approach for high fire-risk areas, including modified inspection methods and inspection frequencies. The CWSP also includes the use of new situational awareness technologies on the electric system such as high-definition cameras and weather stations.

PG&E's System Hardening Program has been broadened to include a rebuild of overhead distribution circuits in HFTD areas, including replacement of bare wire with insulated conductor, increased strength requirements for poles, installation of new system automation and protection equipment, and potentially targeted undergrounding, all of which will lessen the likelihood of ignitions.

Finally, PG&E has also adopted the PSPS program, or proactive de-energization of lines, using protocols that were based on benchmarking with SDG&E and in accordance with CPUC Resolution ESRB-8. Accordingly, a PSPS event will be implemented for lines that cross Tier 2 and Tier 3 HFTD areas when forecasts predict extreme fire-threat conditions. PG&E has developed and is continuing to improve the processes to identify the applicable conditions for PSPS and when to execute PSPS events, as well as to identify the appropriate channels to communicate possible impacts, in order to maximize wildfire safety while minimizing the disruption to customers and critical services. PG&E is also developing and evaluating ways to alleviate the risks and impacts of PSPS, such as through Resilience Zones. Resilience Zones will allow for important emergency and community services such as first responders, grocery stores, and gas stations to remain energized while the surrounding areas may be de-energized for safety. In addition, PG&E is investigating innovative customer service solutions to alleviate the impact of de-energization on our most vulnerable customers and communities, such as partnering with local OES to provide a safe, energized location for the vulnerable population during PSPS events.

The timeframe for all these strategies and programs can be found in Table 3 below.

TABLE 3: STRATEGY AND PROGRAM TIMEFRAMES[12]

Section	Title	Timeframe
4.1 Operational Practices		
4.1.1	Recloser Operations	Before the upcoming wildfire season
4.1.2	Personnel Work Procedures in Conditions of Elevated Fire Risk	N/A – Ongoing
4.1.3	Safety and Infrastructure Protection Teams	Before the upcoming wildfire season
4.1.4	Aviation Resources	Before the upcoming wildfire season
4.2 Wildfire Safety Inspection Programs		
4.2.1	WSIP, Distribution	Before the upcoming wildfire season
4.2.2	WSIP, Transmission	Before the upcoming wildfire season
4.2.3	WSIP, Substation	Before the upcoming wildfire season
4.3 System Hardening Overview		
4.3.1	Pole Material	Work is ongoing, HFTD completion Target is greater than 5 years
4.3.2	Pole Loading and Replacement	
4.3.3	Conductor	
4.3.4	System Protection	Within next 5 years
4.3.5	Equipment	More than 5 years
4.4 Enhanced Vegetation Management		
4.4.1	Vegetation Trimming and Overhanging Tree Limbs	More than 5 years
4.4.2	HFTD Vegetation Management (VM) Inspection Strategy	Before the next Plan filing
4.4.3	Inspecting Trees with a Potential Strike Path to Power Lines	Before the next Plan filing
4.4.4	At-risk Species Management	More than 5 years
4.4.5	Challenges Associated with Enhanced Vegetation Management	N/A Ongoing
4.4.6	Community and Environmental Impacts	N/A Ongoing
4.5 Enhanced Situational Awareness and Known Local Conditions		
4.5.1	Meteorological Operations and Advanced Situational Awareness	Before the next Plan filing
4.5.2	Fire Spread Modelling – Phase 1	Before the upcoming wildfire season
4.5.3	Weather Stations	Within the next 5 years
4.5.4	Camera Deployment Strategy	Within the next 5 years
4.5.5	Satellite Fire Detection Systems	Before the upcoming wildfire season

12 Timeframe key: (1) before the upcoming wildfire season (estimated to be June 1, 2019 for purposes of this Plan); (2) before the next Plan filing (estimated to be February 2020); (3) within the next 5 years (2024); and (4) more than 5 years (beyond 2024).

TABLE 3: STRATEGY AND PROGRAM TIMEFRAMES[13]
(CONTINUED)

Section	Title	Timeframe
4.5.6	Storm Outage Prediction Model	Before the next Plan filing
4.5.7	Wildfire Safety Operations Center	In place, and will continue to implement new technologies before the next Plan filing
4.6 Public Safety Power Shut-off Program		
4.6.1	PSPS Decision Factors	In place, and will continue to evolve
4.6.2	Strategies to Enhance PSPS Efficiency While Reducing Associated Impacts	N/A
4.6.2.1	Impact Mitigation Through System Sectionalizing	In place, and will continue to identify methods to reduce PSPS impacts before the upcoming wildfire season
4.6.2.2	Resilience Zones	Pilot location operational before the upcoming wildfire season, and will continue to evolve and expand
4.6.2.3	Customer Services and Programs	In place, and will continue to evolve
4.6.3	PSPS Notification Strategies	In place, and will continue to evolve
4.6.3.1	Customer and Community Outreach	In place; PSPS customer outreach is ongoing and will continue before the upcoming wildfire season
4.6.3.2	Mitigating PSPS Impacts on First Responders, Healthcare Facilities, Telecommunication, and Water Utilities	In place, and will continue to identify methods to reduce PSPS impacts before the upcoming wildfire season
4.6.4	Re-energization Strategy	In place, and will continue to evolve
4.7 Alternative Technologies		
4.7.1	Rapid Earth Fault Current Limiter Pilot Project – Demonstration	Within the next 5 years
4.7.2	Enhanced Wires Down Detection Project – Phase 1	Before the next Plan filing
4.7.3	Other Alternative Technologies	N/A
4.8 Post Incident Recovery, Restoration, and Remediation Activities		
4.8.1	Post-Incident Recovery	N/A
4.8.2	Restoration	N/A
4.8.3	Remediation	N/A
4.8.3.1	Environmental Remediation – Debris Flow Modeling	Ongoing

13 Timeframe key: (1) before the upcoming wildfire season (estimated to be June 1, 2019 for purposes of this Plan); (2) before the next Plan filing (estimated to be February 2020); (3) within the next 5 years (2024); and (4) more than 5 years (beyond 2024).

2.2. Climate Change Risks

As required by PUC Section 8386(c)(3) and the ALJ Ruling, this section of PG&E's Plan describes climate change risks in California generally, and PG&E's service area specifically.

California has experienced dramatic environmental changes in recent years, resulting in record drought, unprecedented tree mortality, record rainfall, record heat waves, and extremely strong wind events. In recent years, the number and scope of wildfires in California has also increased substantially. In 2017, California experienced five of the 20 most destructive fires in its history up to that point in time. In November 2018, California experienced two more devastating fires—the Camp Fire in Northern California and the Woolsey Fire in Southern California. The Camp Fire is now considered the most destructive wildfire in California history, with over 80 fatalities and extensive property destruction.

A number of climate-related factors have contributed to the increasing risk of wildfires. For example, bark beetles and drought have contributed to record numbers of dead trees that fuel and amplify wildfires.[14] Since 2010, according to the USFS, approximately 129 million trees have died in California. Moreover, as air temperatures rise, forests and land are drying out, increasing fire risks and creating weather conditions that readily facilitate the rapid expansion of fires.[15]

One of the key findings in the Climate Science Special Report, issued as a part of the Fourth National Climate Assessment in 2017, was that:

> [T]he incidence of large forest fires in the western United States and Alaska has increased since the early 1980s [] and is projected to further increase in those regions as the climate warms, with profound changes to certain ecosystems.[16]

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14 Assembly Floor Analyses, issued August 28, 2018, at p. 5, available at: http://leginfo.legislature.ca.gov/faces/billAnalysisClient.xhtml?bill_id=201720180SB901 (accessed October 2, 2018) ("Assembly Floor Analysis") at p. 5.

15 The Atlantic*, Why the Wildfires of 2018 Have Been So Ferocious,* (August 10, 2018).

16 United States (U.S.) Global Change Research Program, *Climate Science Special Report: Droughts, Floods, and Wildfire*, Chapter 8 (2017).

More recently, the Fourth National Climate Assessment, which was issued in November 2018 as mandated by the United States (U.S.) Congress in the Global Change Research Act of 1990, concluded:

> [W]ildfire trends in the western United States are influenced by rising temperatures and changing precipitation patterns, pest populations, and land management practices. As humans have moved closer to forestlands, increased fire suppression practices have reduced natural fires and led to denser vegetation, resulting in fires that are larger and more damaging when they do occur (Figures 1.5 and 1.2k) (Ch. 6: Forests, KM 1). Warmer winters have led to increased pest outbreaks and significant tree kills, with varying feedbacks on wildfire. Increased wildfire driven by climate change is projected to increase costs associated with health effects, loss of homes and other property, wildfire response, and fuel management.[17]

In short, California has not only entered a "new normal" with regard to the risk, magnitude, and devastating impact of wildfires, but as former Governor Jerry Brown explained, California has entered a "new abnormal" that will continue in the next 20 years.[18] As a result of the new abnormal, wildfire season, when the risk of wildfire is much greater, may span eight months or more of the year.

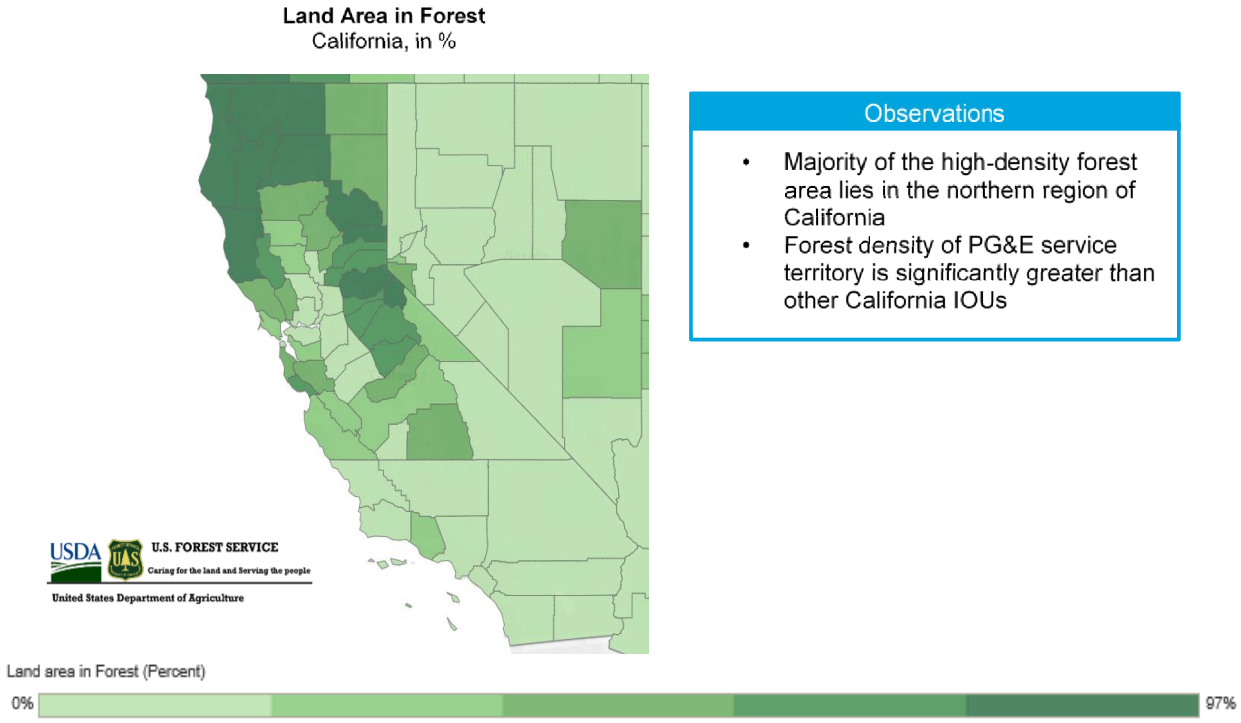
Wildfire risks are not uniform throughout California. PG&E faces especially significant wildfire challenges due to the size and geography of its service area. PG&E's service area is approximately 70,000 square miles and contains substantially more HFTD areas than exist in the service territories of the two other California Investor-Owned Utilities (IOU) combined. As shown in Figure 1 below, according to the USFS, the majority of high-density forest area in California is in Northern California:

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17 U.S. Global Change Research Program, Fourth National Climate Assessment, Volume 2.

18 Los Angeles Times, *Gov. Brown: Mega-fires 'the new abnormal' for California,* (November 11, 2018).

FIGURE 1: HIGH DENSITY FOREST AREA IN NORTHERN CALIFORNIA[19]



Moreover, PG&E has more overhead distribution circuit miles in its service area that traverse HFTD areas than the other two IOUs combined. Approximately 65 percent of California IOUs' overhead distribution circuits located in Tier 2 and Tier 3 HFTD areas are in PG&E's service area. PG&E estimates there are more than 100 million trees adjacent to its overhead power lines with the potential to either grow into or fall into the lines. The strategies and programs described in detail above are specifically intended to address the unique wildfire risks associated with PG&E's service area.

3. Risk Analysis and Drivers

Pursuant to PUC Sections 8386(c)(10), (11), (14), and (15) and the ALJ Ruling, this section of PG&E's Plan addresses wildfire risks, and the drivers associated with these risks. Specifically, this section describes: (1) the methodology used by PG&E for identifying and evaluating wildfire risks; (2) a list of wildfire risks and drivers identified in the 2017 Risk Assessment and Mitigation Phase (RAMP) Report and more recently in PG&E's updated analysis; (3) how PG&E's Plan addresses wildfire risks; (4) an

19 Source: USDA Forest Service, 2017 RPA data.

evaluation of the CPUC's HFTD Map as required by PUC Section 8386(c)(14); (5) electric circuit prioritization based on wildfire risk; (6) PG&E Wildfire Evacuation Study; and (7) use of Probabilistic Assessments.

3.1. Methodology for Identifying and Evaluating Risk

In addition to presenting the risks and drivers analyzed in PG&E's 2017 RAMP Report, this section also discusses the risk identification and analysis that PG&E has performed since that 2017 filing.

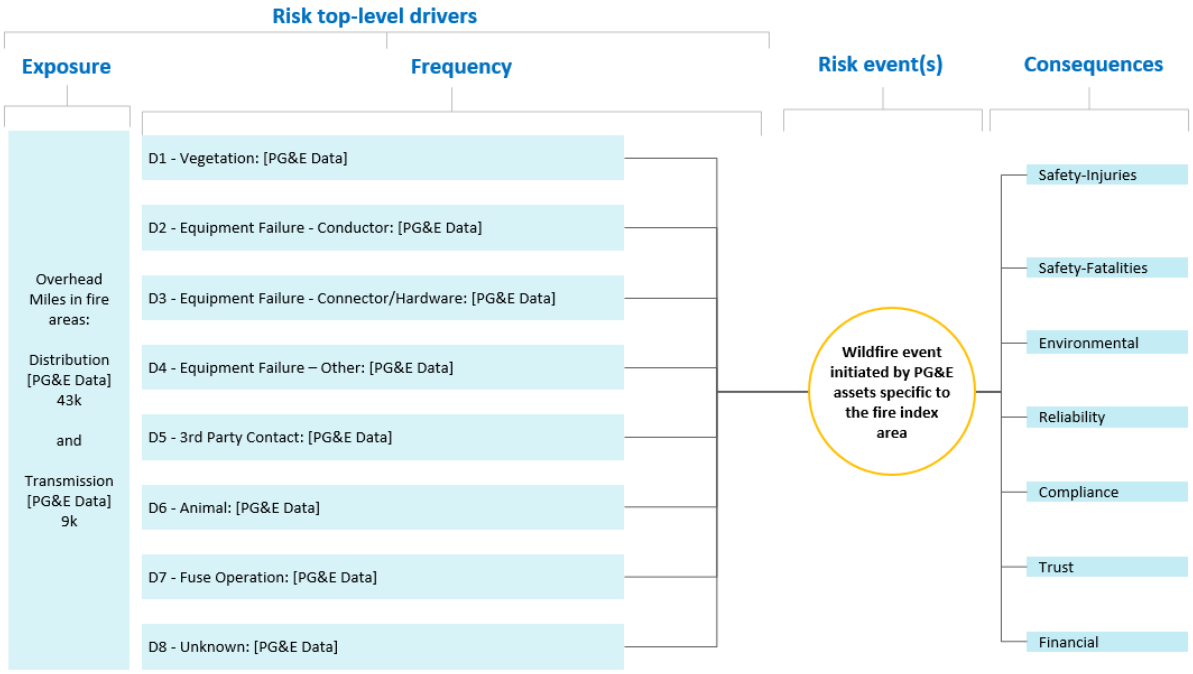
PG&E's 2017 RAMP Report assessed wildfire risk using a common bow-tie risk methodology, where the risk event at the center of the bow-tie is a wildfire event initiated by PG&E assets specific to Fire Index Areas (FIA).[20] PG&E focused its wildfire risk assessment and effectiveness analysis based on this risk event and the specific drivers on the left side of the risk bowtie. This was the approach used in PG&E's 2017 RAMP Report, as shown below in Figure 2 below.[21]

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[20] FIAs were originally developed by the USFS Pacific Southwest Forest and Range Experiment Station (now the Pacific Southwest Research Station) in 1959 and updated in the late 1960s and are still in use today by state (e.g., CAL FIRE) and federal agencies (e.g., USFS). These agencies refer to these areas as Fire Danger Ratings Areas (FDRA). For more information, see Attachment A: Fire Potential Index Methodology and Background.

[21] See PG&E's 2017 RAMP Report, Chapter 11 – Wildfire, Section II for detailed description of risk bow-tie methodology and risk drivers. https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=431187#page=334.

FIGURE 2: WILDFIRE BOW-TIE RISK



Since PG&E filed its 2017 RAMP Report, PG&E's analysis of wildfire risk has continued to evolve. PG&E's 2020 General Rate Case (GRC), filed with the CPUC in December 2018 in Application 18-12-009, describes the evolution and refinement of PG&E's wildfire risk analysis. For this Plan, PG&E has aligned the risk analyses from the 2017 RAMP Report and the 2020 GRC and developed an updated set of wildfire risks and drivers. By analyzing this updated set, PG&E seeks to more effectively address wildfire risk across the service area.[22]

There are some significant refinements between the model used in the 2017 RAMP Report and the one used in the 2020 GRC. First, PG&E revised the number of overhead circuit miles considered to be exposed to wildfire risk based on new guidance from the Commission when it adopted the HFTD Map in January 2018. Second, PG&E updated its risk driver frequency assumptions based on this change in overhead circuit miles, as well as more recent fire incident data. Third, since filing the 2017 RAMP

[22] In future WSP annual filings, PG&E's risk analysis may evolve to more specifically address the risk factors set forth in PUC Section 8386(c)(10)(A) (design, operations, construction and maintenance).

Report, PG&E has undertaken a more comprehensive evaluation of wildfire risk mitigation options, including a detailed assessment of the likelihood that specific mitigations could have reduced the potential risk of particular incidents identified in the fire incident database.

Following the 2017 and 2018 wildfires, PG&E used this updated analysis to help design and implement, via the CWSP, additional programs intended to address wildfire risks as well as improve situational awareness, mitigation, and response. CWSP wildfire programs target risk drivers associated with the highest incidence rates and potential fire spread.[23] Below, PG&E describes the evolution of wildfire risk and drivers analyses as identified in its 2017 RAMP Report and its most current analysis for identifying and evaluating wildfire-related risks through the CWSP.

3.2. List of Wildfire Risks and Drivers

3.2.1. Risks and Drivers Identified in RAMP

PG&E operates and maintains approximately 81,000 circuit miles of overhead distribution line and approximately 18,000 circuit miles of overhead transmission line across its service area. For the 2017 RAMP Report, PG&E measured its exposure to wildfire risk based on FIAs. Approximately 43,000 circuit miles of PG&E's overhead distribution line and 9,000 circuit miles of PG&E's overhead transmission line were within these FIAs for the 2017 analysis.

For additional details relating to risks and drivers identified in RAMP see Attachment D, Risks and Drivers Identified in RAMP.

3.2.2. Risks and Drivers Identified After RAMP

In its 2017 RAMP Report, PG&E committed to update its wildfire risk analysis and modeling and noted that it might propose additional precautionary measures intended to further reduce wildfire risk as more information became available.[24] To

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23 See 2017 RAMP Report, Chapter 11, Wildfire, Section III, Table 11-1.

24 Comments of PG&E (U 39 M) on Safety and Enforcement Division's RAMP Report, May 10, 2018, Section III-A-2, p. 3.

perform a robust and inclusive wildfire risk assessment, and to consider additional practices to address wildfire risks and improve system resiliency, PG&E assembled an internal cross-functional team of experienced professionals, consulted with established risk assessment and management consultants, and benchmarked with other utilities in California, the United States, and Australia with experience in developing wildfire mitigation plans, as well as large-scale system rebuilds after disasters.

The team supplemented the 2017 RAMP Report risk analysis with consideration of two primary sets of additional data: First, the team analyzed ignition source data PG&E reported to the CPUC to determine mitigation program effectiveness at a more granular driver level than in the 2017 RAMP process. In accordance with D.14-02-015, PG&E reports annual fire incidents to the CPUC where: (1) ignition is associated with PG&E powerlines; (2) something other than PG&E facilities burned; and (3) the resulting fire traveled more than one meter from the ignition point. For the risk analysis discussed in this Plan, PG&E used the fire ignitions reported to the CPUC for years 2015 2017 (CPUC-Reportable Ignition Data). The team used this data to model the effects of different combinations and permutations of programs. In performing this analysis, the team assessed the potential reduction of historical ignition events that might have resulted had the proposed programs been in place at that time. In this evaluation, PG&E considered fire ignitions associated with distribution primary, distribution secondary, and transmission lines and equipment.

Second, the team updated the focus on the risk model based on the CPUC's HFTD Map. In January 2018, after submission of the 2017 RAMP Report, the CPUC adopted its HFTD Map.[25] The HFTD Map designates three areas where there is an increased risk from wildfires: Tier 3 (extreme fire risk); Tier 2 (elevated fire risk); and Zone 1 (USFS and CAL FIRE Tree Mortality High Hazard Zone Tier One not included in Tier 3 or Tier 2). The evolution of the HFTD Map is illustrated below in Figure 3.

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25 D.17-12-024, p. 158, OP 12, and Appendix D. *See also* CPUC Fire Safety Rulemaking Background available at: http://www.cpuc.ca.gov/firethreatmaps/ (Fire Safety Rulemaking Background) (Accessed October 22, 2018) (describing the HFTD Map).

FIGURE 3: CPUC MAP EVOLUTION



Table 4 below summarizes the Tier 2, Tier 3, and Zone 1 areas included in the January 2018 HFTD Map:

TABLE 4: CPUC HFTD MAP TIER DEFINITIONS

Tier Level	Definition	Distinctions
HFTD Tier 3 – Extreme Risk	Extreme risk (including likelihood and potential impacts of occurrence) for utility associated wildfires.	Tier 3 is distinguished from Tier 2 by having highest likelihood of fire initiation and growth that would impact people or property from utility-associated fires, and where the most restrictive utility regulations are necessary to reduce utility-fire risk.
HFTD Tier 2 – Elevated Risk	Elevated risk (including likelihood and potential impacts of occurrence) for utility associated wildfires.	Tier 2 is distinguished from Zone 1 and other areas outside the HFTD by having greater likelihood of fire initiation and growth that would impact people or property, from utility-associated wildfires, and where enhanced utility regulation could be expected to reduce utility-fire risk.
HFTD Zone 1 – High Hazard Zones	HHZ on the USFS-CAL FIRE joint map of Tree Mortality HHZs, excluding areas in Tier 3 or Tier 2. These are areas where tree mortality directly coincides with critical infrastructure. They represent direct threats.	Zone 1 is defined as a Tree Mortality HHZ (as determined by California's Tree Mortality Task Force), a subset of Tier 1 of the CPUC HFTD Map. Zone 1 excludes areas in the Elevated Risk of Tier Level 2, and the Extreme Risk of Tier Level 3 risk areas but is included in the HFTD due to specific hazards to utilities. Tree mortality areas are identified by the USFS, CAL FIRE, and other State and Regulatory Agencies as determined by published district maps and are subject to updates.

Once the HFTD Map was approved by the CPUC, PG&E began using it to evaluate how to reduce wildfire risk, in place of the 2017 RAMP FIAs. The HFTD areas are different from, and smaller in size than, the combined FIAs used in the 2017 RAMP Report model. As shown in Tables 5 and 6 below, PG&E owns approximately 25,200 circuit miles of overhead distribution line and 5,563 circuit miles of overhead transmission line in the HFTD areas.[26] PG&E has updated the exposure data input to the wildfire risk model to the lower, more focused number of overhead circuit miles in the HFTD areas.

TABLE 5: APPROXIMATE DISTRIBUTION ASSETS

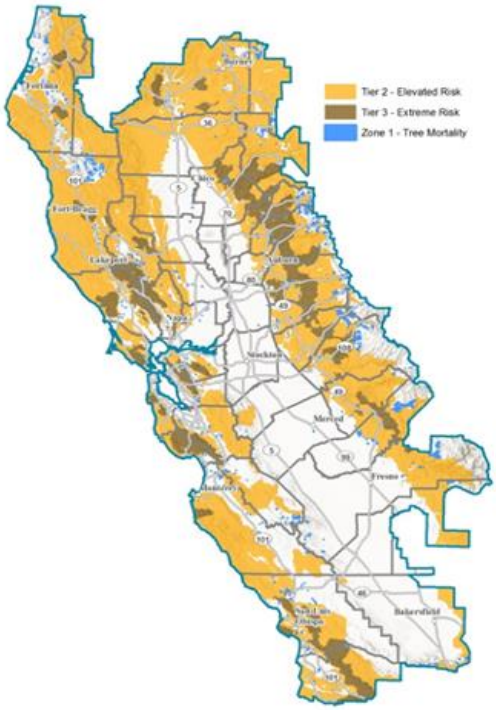
Distribution Overhead Assets	
HFTD Area	**Line Miles***
Zone 1	100
Tier 2	18,000
Tier 3	7,100
Total	**25,200**

TABLE 6: APPROXIMATE TRANSMISSION ASSETS

Transmission Overhead Assets	
HFTD Area	**Line Miles***
Zone 1	25
Tier 2	4,227
Tier 3	1,311
Total	**5,563**

* PG&E operates and maintains approximately 81,000 circuit miles of overhead distribution line and approximately 18,000 circuit miles of overhead transmission line.

Figure 4: PG&E Service Area Fire Threat Map



In addition, PG&E began using wind-related outage data from northeast wind events and CPUC-Reportable Ignition Data to further expand risk insights into the HFTD areas of highest concern. Driver frequency model inputs have been revised to utilize CPUC-Reportable Ignition Data, not all of which were available for use in the 2017

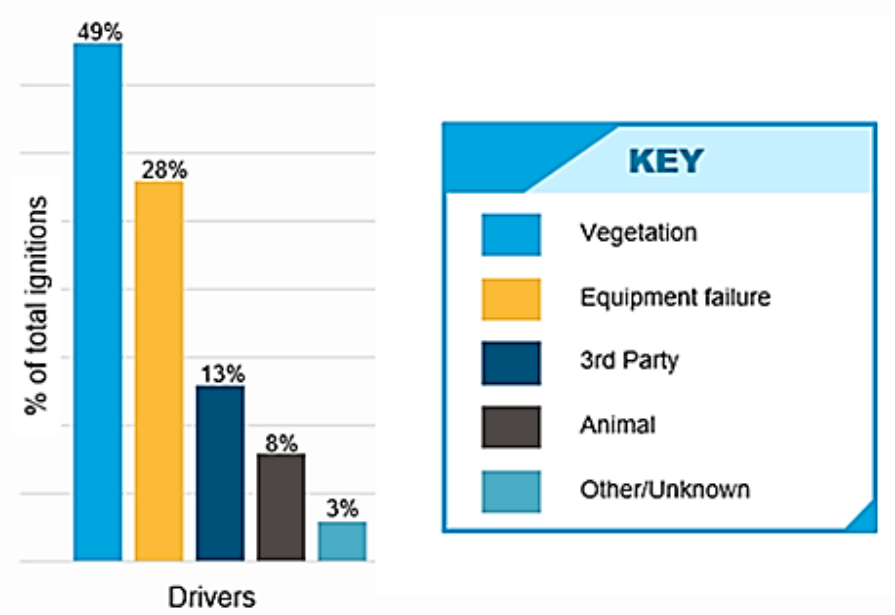
26 The transmission line numbers exclude approximately 165 miles of transmission lines partially-owned, maintained, or operated by PG&E.

RAMP Report. The benefit of using this most recent dataset is to capture the "new abnormal" of wildfire risk that California is experiencing. The Risk Event Frequency for HFTD areas was determined to be 414 events over 2015-2017, with a driver frequency as follows (D = Driver):

- **D1 – Vegetation (49%, 201 ignitions):** Tree, tree limb, or other vegetation contact with conductors that result in fire ignition.
- **D2 – Equipment Failure – Conductor (11%, 47 ignitions):** Failure of conductor resulting in wire down and fire ignition. All three equipment failure categories may be influenced by weather and other environmental factors (e.g., corrosive environment).
- **D3 – Equipment Failure – Connector/Hardware (5%, 19 ignitions):** Failure of connectors, splices, or other connecting hardware resulting in wire down and fire ignition.
- **D4 – Equipment Failure – Other (11%, 44 ignitions):** Failure of other line equipment, such as: poles, insulators, transformers, and capacitors, that leads to fire ignition.
- **D5 – Third-Party Contact (13%, 54 ignitions):** Contact caused by a third party, leading to fire ignition, such as cars hitting poles and Mylar balloon contacts.
- **D6 – Animal (8%, 32 ignitions):** Animal contacts that result in fire ignition, such as birds contacting energized conductors then falling to the ground and causing an ignition.
- **D7 – Fuse Operation (1%, 5 ignitions):** Operation of a fuse for a faulted condition that results in fire ignition from the blown fuse.
- **D8 – Unknown (3%, 12 ignitions):** Situations where PG&E was unable to determine the cause of the ignition; however, it appeared that the ignition may have been attributable to PG&E facilities.

Figure 5 below shows the relative percentages of 2015-2017 ignition drivers for HFTD areas of PG&E's system.

FIGURE 5: 2015-2017 DRIVERS FOR FIRE INCIDENTS IN HFTD TIERS 2 AND 3, AND ZONE 1

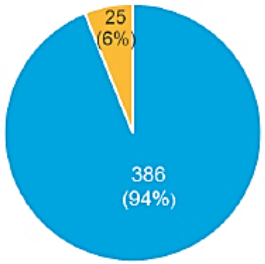


Source: CPUC Fire Incident Data
* Equipment failure includes: conductor, conductor/hardware, fuse operation and other

As shown in Figure 6 below, based on historical data, distribution lines present significantly more risk than transmission, with ignitions per 100 miles nearly three times for the distribution system as compared to the transmission system. Further, while vegetation is the primary driver of ignitions for distribution lines, the primary risk driver for transmission lines-related ignitions are animal actions, with no vegetation-caused ignitions recorded for transmission based on the CPUC-Reportable Ignition Data.

FIGURE 6: IGNITIONS FOR TRANSMISSION AND DISTRIBUTION BY DRIVER

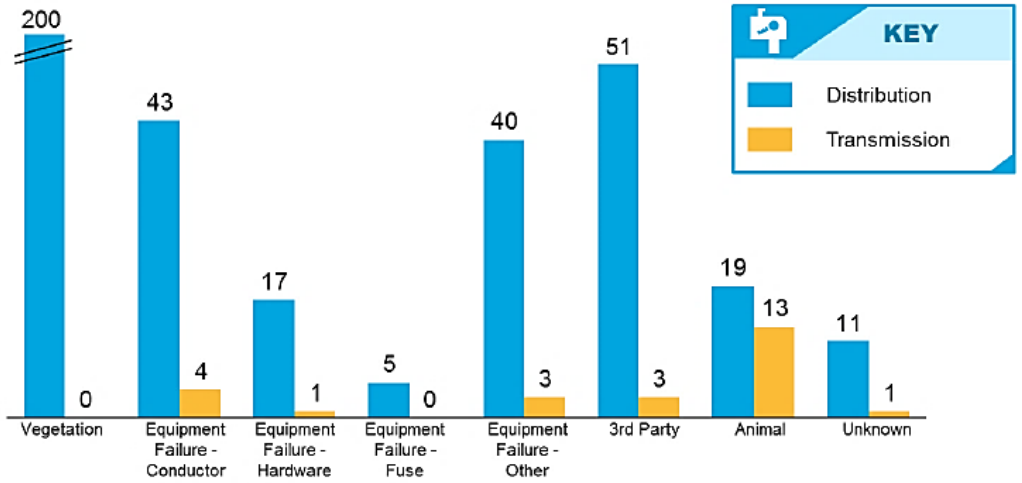
PERCENTAGE OF IGNITIONS, TOTAL



IGNITIONS PER OH CONDUCTOR MILE

	Distribution OH	Transmission OH
Tier 2 Miles	18,000	4,200
Tier 3 Miles	7,100	1,300
Total	**25,100**	**5,500**
Ignitions	386	25
Ignitions per 100 Miles	**1.5**	**0.5**

NUMBER OF IGNITIONS, BY DRIVER



Note: "Equipment Failure-Other" types include:
1. Found flashed insulators at 20/03 including splatter (unknown source)
2. Pole fire leading to broken cross arm, then fire. Fog in area and possible contaminated insulators may be cause of pole fire
3. Sawmill fire

Key Takeaway: Ignitions per 100 miles are nearly 3x for the distribution system as compared to the transmission system

Source: CPUC Fire Incident Data, 2015 – 2017 (http://www.cpuc.ca.gov/CPUCNewsDetail.aspx?id=6442454974)

3.2.3. Risks and Drivers Associated With Design, Construction, Operations and Maintenance

Consistent with PUC Section 8386(c)(10)(A) and the ALJ Ruling, PG&E has identified which of the risks and drivers identified above are associated with five specific categories: (1) design and construction; (2) inspection and maintenance; (3) operational practices; (4) situational/conditional awareness; and (5) response and recovery. In future WSPs, PG&E may include more detailed analysis with risks and drivers associated with design, construction, operations and maintenance, as outlined in SB 901. Table 7 below provides summaries of the risk drivers broken down by the categories identified in SB 901 and the categories in the ALJ Ruling:

TABLE 7: RAMP RISK DRIVERS RELATED TO SB 901 AND ALJ RULING RISK CATEGORIES

	Cause	(1) Design and Construction	(2) Inspection and Maintenance	(3) Operational Practices	(4) Situational/ Conditional Awareness	(5) Response and Recovery
D1	Vegetation	X	X	X	X	N/A
D2	Equipment Failure – Conductor	X	X	X	X	N/A
D3	Equipment Failure – Connector/Hardware	X	X	X	X	N/A
D4	Equipment Failure – Other	X	X	X	X	N/A
D5	Third Party Contact	X				N/A
D6	Animal	X	X	X		N/A
D7	Fuse Operation	X	X	X	X	N/A
D8	Unknown					N/A

3.2.4. Topographic and Climatological Risks

PUC Section 8386(c)(10)(B) also requires consideration of topographic and climatological risk factors. Topography can be an important risk factor for fire danger in certain areas within PG&E's service area. For example, lee-side mountain slopes can be prone to strong downslope winds under certain weather conditions, which can cause increased risk of wires down and/or contact between uninsulated conductors in that area, leading to potential wildfire ignition. Winds can also be funneled through canyons

and mountain passes, resulting in similar effects. PG&E Meteorology's Fire Potential Index (FPI)[27] is applied to the 91 FIAs that cover the entire HFTD area. These areas are intended to capture sections of the service area with consistent fuel, topography, and exposure to meteorological conditions at a more granular level than the HFTD areas for more accurate weather forecasting.

In the 2017 and 2018 wildfire seasons, there was risk of wildfires occurring at almost any time. Historically, extreme fire danger has occurred in PG&E's service area from approximately June through November. Based on weather history, critically extreme fire danger is a rare occurrence—approximately one to two times per year in the most climatologically prone areas and less often in other areas. Based on historical weather patterns, these conditions have most frequently occurred in June and then again in September and October. However, a persistently dry fall and later start to the wet season may result in extreme fire risk extending later into the year. Generally, PG&E considers the following factors to determine when the wildfire season occurs: (1) when CAL FIRE initiates summer preparedness activities and winter preparedness activities; (2) when open burn policies are established at the county level; and (3) when there are more frequent occurrences of FPI days across PG&E's service territory.

The highest fire danger occurs under weather conditions with very low humidity and strong winds. However, temperatures, fuel loading, fuel type, and dead- and live-fuel moisture content are also important factors. PG&E's Meteorology team tracks and models fuel moisture content daily to determine the current state of the fuels as well as how the current season's values compare historically.

PG&E's service area is made up of a wide variety of different microclimates that have distinct seasonal weather characteristics, topography, and fuel types. Due to these differences, the PG&E Meteorology team studies historical fire occurrences by

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27 See Attachment A for an explanation of how the FPI is derived.

dividing the service area into nine different PG&E Fire Danger Climate Zones[28] to determine the significant thresholds of specific fire-danger variables to distinguish between fire danger conditions on a scale from Low to Extreme-Plus.[29] PG&E will continue to collaborate with the San Jose State University (SJSU) Fire Weather Research Laboratory, Atmospheric Data Solutions, and the other IOUs to increase understanding of fuel moisture monitoring and modeling.

PG&E's Meteorology team also completed a 30-year numerical reanalysis across its service area that will help to identify key weather patterns and characteristics that have led to extreme fire danger in the past in order to determine new thresholds for future fire danger modeling.

3.3. How PG&E's Plan Accounts for Wildfire Risks

PUC Section 8386(c)(11) directs utilities to provide a description of how their WSP accounts for risks identified in their RAMP filing. Because PG&E's wildfire risk analysis has continued to evolve since it filed its 2017 RAMP Report, the Plan addresses how PG&E accounts for wildfire risks identified in the RAMP filing as well as risks and drivers identified since that filing.

As discussed above in Section 3.2.2, PG&E utilized CPUC-Reportable Ignition Data to determine risk reduction effectiveness at a more granular driver level than previously performed in the 2017 RAMP process, by modeling different combinations and permutations of programs (in particular, different vegetation management practices and system hardening activities).

This methodology, in conjunction with benchmarking results,[30] informed the basis for the EVM and system hardening programs presented in the 2020 GRC and this

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28 PG&E Fire Danger Climate Zones overlay FIAs.

29 See Attachment A: Fire Potential Index Methodology and Background.

30 Utilities benchmarked against include: Arizona Public Services, Duke Energy (Indiana), Florida Power and Light, PEPCO (Maryland), Portland General Electric, Public Services of New Mexico, Puget Sound Energy, SDG&E, Southern California Edison Company, and Xcel Energy (Colorado).

Plan. Revised driver counts and assessments of risk reduction were then incorporated into the GRC risk model to quantify risk reduction, mitigation effectiveness rankings, and ultimately to assist in calculating the Risk Spend Efficiency values for the mitigations.

3.4. Evaluation of Higher Risk Threat Areas

PUC Section 8386(c)(14) directs utilities to identify any geographic areas in their respective service territories that are "a higher wildfire threat than is currently identified in the commission's fire threat map, and where the commission should consider expanding the HFTD based on new information or changes in the environment." Based upon its review of the HFTD Map and current information, PG&E believes the HFTD Map appropriately identifies areas within PG&E's service territory requiring additional actions to reduce wildfire risk. PG&E will continue to evaluate the inclusion of additional areas requiring wildfire reduction activity in future plans based upon information obtained during the implementation and evaluation of PG&E's Plan.

3.5. Circuit Prioritization Based on Asset Wildfire Risk

To maximize the efficacy of the wildfire risk reduction measures, PG&E's Plan prioritizes circuits targeted for wildfire risk reduction measures using an asset risk-based approach. Under this approach, PG&E evaluates asset wildfire risk for individual circuits and then prioritizes implementation of wildfire risk reduction measures for circuits by their asset wildfire risk.

To enhance the understanding of asset-based wildfire risk, an initial assessment was completed to understand asset failure modes. This was completed by analyzing historical outages and corrective maintenance notifications to inform what asset conditions could lead to failure and related wildfire risk.[31] Once these failure modes were established, PG&E assessed wildfire risk for individual circuits considering three components: (1) likelihood of asset failure; (2) risk of wildfire spread and consequence; and (3) egress risk.

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31 Further details on PG&E's Failure Modes and Effects Analysis (FMEA) process are provided in Section 4.2, below.

The likelihood of an asset failure was determined using a regression analysis to predict higher-than-average performance along a circuit. This analysis, completed at the structure level for transmission assets and at the circuit level for distribution assets, included an assessment of multiple variables including asset condition, asset location, asset characteristics (e.g., age, size, material, etc.), and historical work order data to assess the probability of higher than average expected failures.

To evaluate risk of wildfire spread and consequences, PG&E used the REAX Engineering, a third-party entity, wildfire spread and consequence model, similar to the methodology used to determine the HFTDs on the CPUC's HFTD Map. Wildfire spread considers fuel type, fuel density, topography, weather, wind, and distance from fire station or air suppression station. Wildfire consequence considers population density, structure density, and negative impacts to natural resources. This model developed a comparative risk score across PG&E's service area. Every PG&E structure lies within a certain percentile of spread and consequence based upon the model's analysis. Each percentile corresponds to a relative risk score within the model, correlating a comparative risk score to the electric transmission or distribution asset falling within that percentile.

Finally, an egress risk score was included in the model to understand the ease of entering and exiting a town or unincorporated community in the event of evacuation. This analysis was developed by looking at the number of road miles within a particular census-designated town or unincorporated community and comparing it to the population of that particular census-designated area. Since a road's ability to provide egress varies based upon the type of road, the number of road miles was weighted based upon the type of road (e.g., highways/interstates, country roads, residential roads).

For each circuit, these three scores (i.e., asset failure, wildfire spread and consequence, and egress) were multiplied together to develop an initial relative risk ranking. To prioritize circuits for implementation of specific wildfire risk reduction

measures, PG&E considers operational factors that could affect the implementation of those particular measures. For example, for measures involving circuit inspections, PG&E considered factors such as land and environmental, safety, already planned and scheduled projects, geographic access constraints, weather/wind, community, and customer considerations. These operational considerations were used to shift the timing of the enhanced and accelerated inspection, not to adjust the scope of the measures. Meetings were held with Subject Matter Experts (SMEs) in these program areas to consider relevant factors, and timing was adjusted accordingly.

This updated wildfire risk circuit prioritization presents a more robust approach to assessing potential wildfire risk across PG&E's assets, rather than focusing solely on the spread and consequence risk components. By including additional considerations, PG&E is better positioned to determine, understand, and further reduce wildfire risk using a risk-informed approach.

3.6. Wildfire Evacuation Study

PG&E is partnering with several renowned traffic simulation and evacuation experts to collaborate with a high fire risk community to perform a detailed wildfire evacuation study to examine anticipated traffic conditions and evacuation times associated with various rates of evacuation responses and alternative management strategies that could be used in response to them. The intent of this work is to develop a procedure or methodology that can be applied to any community with a high fire risk to improve their wildfire emergency plans and to inform PG&E's egress risk methodology with additional granularity.

The evacuation study report will document the demand estimation methodology (how many people and vehicles need to be evacuated), the highway capacity estimation, mobilization (trip generation) time distributions and the computed evacuation time estimates (ETE) in tabular and graphical format. The report will also contain a description of the traffic simulation and trip distribution and assignment algorithms utilized in the modeling system, the technical details of the study and the supporting

data. In addition, the report will identify traffic bottlenecks during evacuation and include a detailed discussion of potential improvements to evacuation time.

3.7. Use of Probabilistic Risk Assessments

PG&E is also partnering with the B. John Garrick Institute for the Risk Sciences, University of California Los Angeles (UCLA) to leverage the rigorous modeling used in the nuclear industry to perform thorough and complex wildfire risk assessments and management planning. PG&E has used a probabilistic risk assessment model for over 30 years at its Diablo Canyon Nuclear Power Plant. The model is constantly updated with current plant design and state of the art analysis methodologies. Data from 30 years of industry and plant specific experience is used to model component reliability and unavailability. The model is capable of performing quantitative assessment of risks from a multitude of complex factors, including internal plant failures, seismic events, fire and flooding. Each model element has been independently reviewed by industry peer review teams and the results have been audited on numerous occasions by the Nuclear Regulatory Commission. The model is capable of quantitatively risk ranking over 3,000 individual system components including the transmission lines that supply Diablo Canyon with offsite power. PG&E is planning to develop a similar model for wildfire risks for its electrical assets within HFTD areas.

4. Wildfire Reduction Strategy and Programs

This Plan describes the proactive and aggressive programs that PG&E is undertaking to prevent wildfires in 2019 and beyond. In some cases, these programs significantly expand and accelerate existing work, such as vegetation management and inspections. In other cases, these programs are entirely new, such as system hardening.

PG&E already performs a number of activities that address wildfire risk, across all of its assets in its service area, not just in HFTD areas, in accordance with regulatory and industry standards such as GOs 95 and 165 for the design, procurement, construction, testing, operations, and maintenance of its electrical assets, in particular,

overhead circuit conductors, structures, and equipment. The significant and aggressive expansion, enhancement, and acceleration of wildfire risk mitigation measures that are proposed in this Plan is in addition to PG&E's ongoing regulatory compliance workstreams.

PG&E created the CWSP, managed by PG&E's Wildfire Risk Management team, to support the implementation of large-scale and multi-year programs concerning wildfire risk. As discussed above in Section 3, the Wildfire Risk Management team has performed comprehensive risk assessments and geospatial modeling on both the volume and the location of CPUC-Reportable Fire Incidents from 2015-2017. This detailed analysis has led to the programs and strategies proposed in this Plan, which correlate to the ignition drivers as indicated in Table 8 below.

TABLE 8: CORRELATION OF PROGRAMS TO IGNITION DRIVERS

Section	Program	Vegetation (49%)	Equipment Failure (28%)	Third Party (13%)	Animal (8%)	Other/ Unknown (3%)
4.1	Operational Practices	X	X	X	X	
4.2	Wildfire Safety Inspection Programs		X	X	X	
4.3	System Hardening	X	X	X	X	X
4.4	Enhanced Vegetation Management	X				
4.5	Enhanced Situational Awareness and Known Local Conditions	Enabler to Operational Practices and PSPS Program				
4.6	PSPS Program	X	X			
4.7	Alternative Technologies	Enabler for System Hardening				
4.8	Post Incident Recovery, Restoration and Remediation Activities	N/A	N/A	N/A	N/A	N/A

Below, consistent with the outline adopted in the ALJ Ruling, PG&E provides a more detailed discussion of its:

(1) Operational Practices (Section 4.1)
(2) Wildfire Safety Inspection Programs (Section 4.2)
(3) System Hardening (Section 4.3)
(4) Vegetation Management Plan (Section 4.4)
(5) Enhanced Situational Awareness and Known Local Conditions (Section 4.5)
(6) PSPS Program (Section 4.6)
(7) Alternative Technologies (Section 4.7)
(8) Post Incident Recovery, Restoration and Remediation Activities (Section 4.8)

To provide a more thorough understanding of wildfire risks addressed by the Plan, PG&E has included descriptions of proposed Plan programs in these subsections, as well as routine operations and maintenance activities that also reduce wildfire risk. Under SB 901, proposed wildfire mitigation plans are intended to focus on actions minimizing the "risk of catastrophic wildfire posed by electrical lines and equipment."[32] PG&E's routine operations and maintenance activities may reduce wildfire risks while serving other purposes, such as reliability. Therefore, while routine operations and maintenance activities are not a part of PG&E's Plan, some are described below to provide a more complete picture of all actions PG&E is undertaking that will further reduce wildfire risk.

Table 9 below highlights the work PG&E is planning to complete in 2019; risk reduction measures proposed in this Plan as well as routine operations and maintenance activities. Table 9 also includes targets for 2019 associated with the Plan, the execution risk for each item, and whether the programs are covered in detail in PG&E's Fire Prevention Plan (FPP) submitted in 2018. The items identified in Table 9

32 PUC Section 8386(a).

are discussed in greater detail in the identified sections. Timeframes for the Plan efforts can be found in Table 3, in Section 2.1.

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS[33]

Section	Title	2019 Target	Execution Risk	Included in FPP
Operational Practices				
4.1.1	Recloser Operations	SCADA enable all remaining line reclosers (approximately 285) in Tier 2 and Tier 3 HFTD areas by June 1, 2019. Disable any remaining manual reclosing devices in advance of exposure to elevated wildfire risk conditions. Daily operations conformance with TD-1464B-001 and monitor program for effectiveness.	Qualified personnel or material limitations. Design, estimating or construction delays.	No
4.1.2	Personnel Work Procedures in Conditions of Elevated Fire Risk	Update guidance in TD-1464S and verify annual refresher training is completed for all field employees in advance of exposure to elevated wildfire risk conditions. Incorporate wildfire risk situational awareness into daily briefings.	Unforeseen emergencies can redirect field employees and delay necessary workforce training.	No
4.1.3	Safety and Infrastructure Protection Teams (SIPT)	Obtain and operate a minimum of 25 trucks + 3 trucks for extra coverage and the capability of type 6 wildland engines, staffed with 60 employees through an internal PG&E SIPT in partnership with International Brotherhood of Electrical Workers (IBEW). The SIPT will assist in WSOC[34] decision making by acting as observers on high-fire risk days to inform PSPS decision making, protect PG&E assets, and assist with emergency response as approved and directed by the Agency Having Jurisdiction (AHJ) (e.g., CAL FIRE).	Getting stakeholder buy-in from external firefighter organizations in a timely manner so as to not impact PG&E's ability to hire and onboard employees in time for 2019 fire season.	No
4.1.4	Aviation Resources	Operate four heavy-lift helicopters to aid in fire suppression and restoration efforts by May 2019, available at CALFIRE's discretion.	Delays securing CALFIRE carding by May 2019.[35]	No

33 Numbers in Table 9 are approximated for purposes of presentation in this table.

34 More detailed information concerning the WSOC is provided in Section 4.5.7 below.

35 Carding is the process of reviewing aircraft, support equipment and pilots each year to ensure they all meet the Cal Fire contract requirements. The Federal Government shut down delayed PG&E's request for a 133 Certificate that is required for the Cal Fire carding and contract.

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS (CONTINUED)

Section	Title	2019 Target	Execution Risk	Included in FPP
Wildfire Safety Inspections Programs				
4.2.1	Wildfire Safety Inspection Program (WSIP), Distribution	There are 685,000 poles located in the HFTD areas and adjacent areas with structures in close proximity and high risk of fire spread into the adjacent HFTD. 1) Complete a WSIP enhanced inspection of all 685,000 poles in the HFTD areas by May 31, 2019. 2) Complete high priority corrective actions created from deficiencies identified resulting from these enhanced inspections by June 30, 2019.	1) qualified workforce availability; and 2) materials availability for repairs. Access limitations: 1) inclement weather (snow, rain, wind, washed out roads, etc.); 2) property owner objections; and 3) Access rights (environmental permits, government owned land access permits).	Current program scope not included
4.2.2	WSIP, Transmission	There are approximately 50,000 poles and towers (structures) in the HFTD areas and adjacent areas with structures in close proximity and high risk of fire spread into the adjacent HFTD. 1) Complete a WSIP enhanced inspection of all 50,000 structures by May 1, 2019. (Approx. 9,377 inspections were completed in December 2018.) 2) Complete all high priority corrective actions identified during these inspections by May 31, 2019.	1) qualified workforce availability; and 2) materials availability for repairs. Access limitations: 1) inclement weather (snow, rain, wind, washed out roads, etc.); 2) property owner objections; and 3) Access rights (environmental permits, government owned land access permits). Scheduling Transmission segments out of service (customer impact and clearance process) may limit timeliness of repairs.	Current program scope not included

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS (CONTINUED)

Section	Title	2019 Target	Execution Risk	Included in FPP
4.2.3	WSIP, Substation	There are approximately 200 sites located in HFTD areas. These sites include substations, switching stations, and hydro power houses. 1) Complete-WSIP enhanced inspections for all sites located in HFTD areas by May 1, 2019. 2) Complete all high priority corrective actions created from deficiencies identified resulting from these enhanced inspections by May 31, 2019.	1) qualified workforce availability; and 2) materials availability for repairs. Access limitations due to inclement weather (snow, rain, wind, washed out roads, etc.) Scheduling equipment out of service (customer impact and clearance process) may limit timeliness of repairs.	Current program scope not included
4.3	**System Hardening**			
4.3.1	Pole Material	Complete 45 miles by June 30, 2019, and 150 miles in total by December 31, 2019, of overhead circuit rebuild or replacement in HFTD areas.	Securing necessary materials. Securing adequate number of available trained personnel.	Current program scope not included
4.3.2	Pole Loading and Replacement			
4.3.3	Conductor			
4.3.4	System Protection	Continue to automate the remaining approximately 285 non-SCADA enabled reclosers in Tier 2 and 3 HFTD areas	Securing necessary materials. Securing adequate number of available trained personnel.	Current program scope not included
4.3.5	Equipment	Replace approximately 625 non-exempt fuses/cutouts in HFTD areas.	Securing necessary materials. Securing adequate number of available trained personnel.	Current program scope not included
4.4	**Vegetation Management**			
4.4.1	Vegetation Trimming and Overhanging Tree Limbs	Perform enhanced vegetation management work on approximately 1,000 circuit miles in HFTD areas by June 30, 2019, with approximately 2,450 circuit miles in total by December 31, 2019	Securing adequate available trained tree worker personnel. Working with IBEW and Mutual Assistance, PG&E brought on the maximum available resources in 2018. Variability of number of trees that need to be trimmed/removed per mile.	Current program scope not included

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS (CONTINUED)

Section	Title	2019 Target	Execution Risk	Included in FPP
4.4.2	HFTD VM Inspection Strategy	1) Complete 100% of CEMA Patrols by the end of 2019. 2) Removing or working all dead or dying trees ("CEMA trees") identified by October 1 of the current year, excluding trees affected have third party delays, including environmental permitting requirements, owner refusals, and agency approval or review.		Current program scope not included
4.4.3	Inspecting Trees with a Potential Strike Path to Power Lines	Assess more than 100 million trees with potential strike path on all CEMA Patrols.		Current program scope not included
4.4.4	At-risk Species Management	Perform enhanced vegetation management work on approximately 1,000 circuit miles in HFTD areas by June 30, 2019, with approximately 2,450 circuit miles in total by December 31, 2019.	Securing adequate available trained tree trimming personnel. Number of trees that need to be trimmed/removed per mile given variability in find rate related to high risk tree species.	Current program scope not included
4.4.5	Challenges Associated with EVM			
4.4.6	Community and Environmental Impacts			
4.5	**Situational Awareness**			
4.5.1	Meteorological Operations and Advanced Situational Awareness	Deploy enhanced PG&E Operational Mesoscale Modeling System (POMMS) weather modeling system at 2 kilometers (km) resolution.		Yes
4.5.2	Fire Spread Model – Phase 1	Deploy operational fire spread modeling, driven by POMMS weather model, to allow improved understanding of catastrophic fire risk.		No
4.5.3	Weather Stations	Install 200 weather stations by June 30, 2019, and 400 weather stations in total by September 1, 2019 in HFTD areas.	Material delivery.	No
4.5.4	Camera Deployment Strategy	Operationalize and install 30 HD cameras by June 30, 2019, and 71 HD cameras in total by December 31, 2019, in HFTD Areas.	Installation and delivery of all items depends on single source vendor.	No

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS (CONTINUED)

Section	Title	2019 Target	Execution Risk	Included in FPP
4.5.5	Satellite Fire Detection Systems	Develop, deploy and maintain an automated tool to detect and track new fires as they occur, issue alerts about new fires, as well as simulate the potential spread of new and existing fires.	Operational viability of new Geostationary Operational Environmental Satellite (GOES) West satellite.	Current program scope not included
4.5.6	Storm Outage Prediction Model (SOPP)	Automate analog storm matching and prediction functions in the SOPP model.		Current program scope not included
4.5.7	Wildfire Safety Operations Center (WSOC)	Increase situational awareness by integrating technology and processes intended to reduce wildfire risk into the WSOC to enable PG&E's collaboration with external and internal stakeholders and respond more effectively to wildfires.		No
4.6	**Public Safety Power Shutoff Program**			
4.6.1	PSPS Decision Factors	N/A – in place		
4.6.2	Strategies to Enhance PSPS Efficiency While Reducing Associated Impacts	N/A – see 4.6.2.1 through 4.6.2.3		
4.6.2.1	Impact Mitigation throughout System Sectionalizing	Identify and prioritize mitigation of PSPS impacts to customers where de-energizing the line will not result in a realized wildfire risk reduction.	Securing adequate number of available trained personnel.	No
4.6.2.2	Resilience Zones	Operationalize one resilience zone by June 1, 2019. Evaluate performance and effectiveness through post-event review. Incorporate learnings into future Resilience Zone establishment. Continue efforts to develop Resilience Zones in other towns in alignment with system hardening and targeted sectionalizing efforts.	Reliability of back-up generation equipment. Delays or trained personnel limitations associated with construction crew availability.	No
4.6.2.3	Customer Services and Programs	Continuously refine and further develop strategies that minimize the extent of disruption of grid power.		No

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS (CONTINUED)

Section	Title	2019 Target	Execution Risk	Included in FPP
4.6.3	PSPS Notification Strategies	Attempt to send notifications (Integrated Voice Recording (IVR)), text and email) to all potentially impacted customers, and attempt to notify First Responders, Healthcare Facilities, Telecommunication Providers and Water Utilities in advance of residential notifications prior to a PSPS event. Attempt to provide additional notifications to life support/medical baseline customers prior to a PSPS event if general notifications (IVR, text, email) are unsuccessful.	Weather patterns, and timing of weather. Amount of time available to send advance notifications to customers. Size of impacted population.	No
4.6.3.1	Customer and Community Outreach	Refine customer notification tools and educate customer and communities to prepare for PSPS execution. Complete customer and stakeholder communications prior to potential PSPS initiation.	Changes in regulatory requirements or expectations as a result of R.18-12-005.	No
4.6.3.2	Mitigating PSPS Impacts on First Responders, Healthcare Facilities, Telecommunication, and Water Utilities	Proactively identify PSPS impacts to critical customers and services that support emergency response and preparedness. Ensure sufficient mapping, planning and communication protocols are developed prior to potential PSPS initiation.	Other related or non-related concurrent natural disasters in de-energized areas.	No
4.6.4	Re-energization Strategy	Re-energize only when confirmed safe to do so and only after protection zones are patrolled and clear of defects or damage. Prioritize as directed to maximize public safety and minimize outage impacts and duration.	Large scale events. Extensive facility damage during PSPS event. Trained and qualified workforce limitations. Access to difficult terrain. Aerial patrol limitations. Concurrent natural disasters in de-energized areas impacting workforce availability.	No

TABLE 9: 2019 WILDFIRE SAFETY PLAN TARGETS (CONTINUED)

Section	Title	2019 Target	Execution Risk	Included in FPP
4.7	**Alternative Technologies**			
4.7.1	Rapid Earth Fault Current Limiter Pilot Project	Implement R&D Rapid Earth Fault Current Limiter pilot project.	Untried technology application within PG&E's system.	No
4.7.2	Enhanced Wires Down Detection Project	Complete Phase 1 of Enhanced Wires Down Detection Project	Untried technology application within PG&E's system.	No
4.8	**Post Incident Recovery, Restoration, and Remediation Activities**			
4.8.1	Post-Incident Recovery	N/A	Not Applicable	Yes
4.8.2	Restoration	N/A	Not Applicable	Partially
4.8.3	Remediation	N/A	Not Applicable	Partially

These programs, targets, and PG&E's efforts to plan for and manage these execution risks are discussed in further detail within the individual sections for each program below. The preventative strategies and programs included in this Plan are delineated into the categories identified in the ALJ Ruling[36] in Table 10 below:

TABLE 10: IDENTIFICATION OF ALJ RULING CATEGORIES

PG&E's 2019 Wildfire Safety Plan	ALJ Ruling Categories
4.1 Operational Practices	Operational Practices
4.2 Overview of Inspection Programs	Inspection and Maintenance
4.3 System Hardening Overview	Design and Construction
4.4 Enhanced Vegetation Management	Inspection and Maintenance
4.5 Enhanced Situational Awareness and Known Local Conditions	Situational/Conditional Awareness
4.6 Public Safety Power Shut-off Program	Operational Practices
4.7 Alternative Technologies	Design and Construction
4.8 Post Incident Recovery, Restoration and Remediation Activities	Response and Recovery

36 See ALJ Ruling, Attachment A at p. 3.

4.1. Operational Practices

TABLE 11: OPERATIONAL PRACTICES KEY

Section	Title	Program Mapping	New[37] or Existing, Including Cost Recovery Vehicle	Regulation Compliance	Associated Drivers
4.1.1	Recloser Operations	Reclose Blocking	New - FRMMA[38] & WPMA[39]	Exceeds regulatory requirements	D1 – D6, D8[40]
4.1.2	Personnel Work Procedures in Conditions of Elevated Fire Risk		New – N/A	Exceeds regulatory requirements	Other
4.1.3	Safety and Infrastructure Protection Teams (SIPT)	Fire Fighting Resources	New – CEMA[41]	Exceeds regulatory requirements	Not Applicable
4.1.4	Aviation Resources	Aviation Resources	New – Expense: CEMA; Capital FRMMA / WPMA	Exceeds regulatory requirements	Not Applicable

PG&E has developed a number of enhanced operational practices that are designed to further reduce the risk of wildfires during elevated fire danger conditions.

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37 For each of these charts in this Plan, "New" indicates the program costs have not been subject to Commission review and is followed by the applicable memorandum account.

38 FRMMA represents the memorandum account required by SB 901, PUC Section 8386(j) to track costs of wildfire mitigation measures not otherwise included in revenue requirements, which PG&E submitted for CPUC approval on November 1, 2018. PG&E will track costs incurred before the Plan has been approved in the FRMMA.

39 WPMA represents the memorandum account required by SB 901, PUC Section 8386(e) to track costs incurred to implement the approved Plan. PG&E shall submit the Electric Preliminary Statement for approval by Tier 1 Advice Letter. PG&E will track activity costs incurred pursuant to the approved Plan, but not included in PG&E's approved revenue requirements, in the WPMA.

40 D8 may vary depending on if the cause is known.

41 CEMA represents PG&E's pending Application No. 18-03-015 for approval to increase rates related to the Catastrophic Event Memorandum Account, which includes forecast costs for drought-related work for 2019.

These enhancements relate to: (1) recloser operations; (2) work procedures in conditions of elevated fire risk; (3) PG&E's safety and infrastructure teams; and (4) aviation resources. Each of these Enhanced Operational Practices is explained in greater detail below.[42]

4.1.1. Recloser Operations

PG&E Standard TD-1464B-001 establishes precautions for wildfire risks associated with recloser protection functions. Reclosing devices such as circuit breakers and reclosers are used to quickly and safely de-energize lines when a problem is detected and re-energize lines when the problem is cleared. Using analyses provided by fire officials and PG&E's Meteorology team regarding each year's fire season timeline and exposure, PG&E makes an informed decision on when to disable reclosers during elevated fire conditions in Tier 2 and Tier 3 HFTD areas. In some instances, this practice may reduce potential ignitions from sustained faults.

Following the 2017 wildfires, for the 2018 wildfire season, PG&E implemented the Wildfire Reclosing Disable program to disable automated reclosing during elevated wildfire conditions in Tier 2 and Tier 3 HFTD areas for distribution and transmission lines 115 kV and below.

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42 As explained in detail in Section 4.5, PG&E utilizes state-of-the-art weather forecast model data and information from the National Weather Service (NWS), European Center for Medium Range Forecasting, and from PG&E's proprietary in-house mesoscale forecast model, POMMS, to generate short and medium-term fire danger forecasts across the service area, which inform PG&E's operational procedures.

As part of the reclosing disable process, a fire danger rating per FIA is determined on a daily basis during fire season by PG&E's Meteorology team using PG&E's wildfire danger rating system.[43] If the protection zone[44] of a reclosing device feeds an area with a fire index rating that is very high or extreme for a given day, the automated functionality of the reclosing device, which tests back into the line and potentially re-energizes the line if tested safe, is disabled. When the fire index rating is below very high, a threshold is selected, based upon historical-risk analysis, automated reclosing is enabled. For devices with SCADA, the reclosing functionality is adjusted daily as necessary based on the fire index rating for specific areas.

The Wildfire Reclosing Disable program includes nearly 2,800 reclosing devices on PG&E's distribution lines in Tier 2 and Tier 3 of the HFTD areas. At the end of 2018, approximately 2,100 of the distribution devices in the program were SCADA-enabled and capable of being disabled remotely. If a protection zone does not have SCADA capability in Tier 2 or Tier 3 HFTD areas, PG&E manually disables automated reclosing on these devices based on fire risk conditions as analyzed by PG&E's Meteorology team. These locations are identified and scheduled for disablement prior to the projected beginning of elevated wildfire risk exposure. These manual devices will remain disabled for reclosing until wildfire risk is significantly lower during the year.

PG&E is working to SCADA-enable all line reclosers in Tier 2 and Tier 3 HFTD areas by June 1, 2019. In addition, devices located on nearly 400 transmission lines with voltages of 115 kV and below were included in the 2018 program. Over 95 percent of the transmission line devices are SCADA-enabled and can be disabled remotely, and similar to the distribution devices that are not SCADA-enabled, PG&E will manually disable the remaining devices for the duration of wildfire season.

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43 See Section 4.5.1 below for additional information on how PG&E's Meteorology team derives fire danger ratings.

44 A protection zone is the area or set of electric facilities for which a particular device can isolate electrical service.

Weather and field access challenges could impede the technical work required to SCADA-enable the line reclosers. Distribution line technicians cannot perform the testing and commissioning in the rain, and ground saturated with water impede the installation of new controllers and radio equipment. PG&E has tried to take these issues into consideration in developing the schedule, but unanticipated weather could delay PG&E's implementation timeline.

PG&E will continue to evaluate program effectiveness and build out of SCADA capabilities on the remaining distribution and transmission devices. These efforts will allow for effective and timely remote disabling and re-enabling of reclosing informed by fire danger.

4.1.2. Personnel Work Procedures in Conditions of Elevated Fire Risk

PG&E has established heightened procedures for field personnel to follow when working, traveling, or operating in hazardous fire areas. The procedures supplement instructions contained in fire regulation and use permits issued by the USFS, CAL FIRE, and other agencies that have jurisdictional authority. Procedures that apply during elevated fire risk conditions include:

- A requirement that each crew be equipped with well-maintained firefighting equipment;
- Additional restrictions on burning, welding, blasting, smoking and driving off cleared roads;
- A requirement to patrol lines prior to re-energization after a line trips due to a problem on the line; and
- A requirement to patrol lines prior to replacing blown fuses.

PG&E will train field employees annually on the heightened procedures and provide situational awareness in daily briefings.

4.1.3. Safety and Infrastructure Protection Teams

The Safety and Infrastructure Protection team or "SIPT" will be in place by June 1, 2019, to support PG&E's work in high fire-risk areas. The SIPT will have experience and training in fire prevention and suppression, and emergency medical response. The purpose of the SIPT is to assist WSOC[45] decision making, protect PG&E assets, and assist with emergency response as approved and directed by the AHJ (e.g., CAL FIRE). During emergency situations, the SIPT will work in cooperation with the local fire AHJs and adhere to the Incident Command Structure (ICS).

If a fire is starts at a PG&E work site, the SIPT's first priority is to dial 911. Once first responders are on site, the SIPT will follow the ICS established by the responding agency. In 2018, PG&E contracted SIPT services. In 2019, PG&E will be establishing an internal SIPT organization consisting of a minimum of 25 trucks with the capability of type 6 wildland engines and crews, and 3 additional trucks for extra coverage and sick/vacation relief. The organization will be built in collaboration with the IBEW and external firefighter organizations. The primary execution risk in building the new internal SIPT organization is obtaining support from external stakeholders in a short time frame so as not to impact PG&E's ability to hire and onboard employees for 2019 fire season.

During high fire-hazard conditions, the WSOC may request SIPT to:

- Stage resources in specific locations;
- Standby when PG&E field personnel engage in activities such as switching, hot work, or emergency repairs, as conditions dictate
- Deploy to confirm potential fire threats and provide data;
- Identify potential hazards in Extreme-Plus areas, as needed, during potential PSPS events; and

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45 More detailed information concerning the WSOC is provided in Section 4.5.7 below.

- Provide emergency response to fires, medical emergencies, basic life support, and secure the scene for the protection of PG&E's assets and/or workforce until the AHJ arrives.

Emergency work includes, but is not limited to, the following:

- Asset protection at PG&E facilities and other critical infrastructures;
- Vegetation Management support during wildfire recovery to suppress vegetation-related ignitions;
- Mop up of fire-damaged PG&E assets as permitted by the AHJ; and
- Accompany and support PG&E crews in fire restoration efforts during and after wildfires.

4.1.4. Aviation Resources

PG&E acquired four heavy-lift helicopters in 2018 to enhance wildfire safety and support utility infrastructure projects. The helicopters guarantee heavy-lift resource availability for PG&E facility restoration and construction support during fire season. The helicopters will be fitted with fire suppression equipment and available to aid in suppression efforts under the direction of the agency leading the response (e.g., CAL FIRE), if needed and requested.

4.2. Wildfire Safety Inspection Programs

TABLE 12: WILDFIRE SAFETY INSPECTION PROGRAMS KEY

Section	Title	Program Mapping	New or Existing, Including Cost Recovery Vehicle	Regulation Compliance	Associated Drivers
4.2.1	WSIP, Distribution	N/A	New - FRMMA/ WPMA	Exceeds regulatory requirements	D1, D2, D3, D4, D8[46]
4.2.2	WSIP, Transmission	N/A	New - TO[47]	Exceeds regulatory requirements	D1, D2, D3, D4, D8
4.2.3	WSIP, Substation	N/A	New - FRMMA/ WPMA & TO	Exceeds regulatory requirements	D1, D3, D4, D8

PG&E routinely inspects its distribution, transmission, and substation assets using a variety of methods, including observations when performing work in the area, periodic patrols and inspections, and targeted condition-based and/or diagnostic testing and monitoring. These routine inspections of PG&E's overhead and underground electric systems, including its electric substation inspections, are designed in accordance with GOs 95, 165, and 174 requirements. Basic elements include travel to the asset, ground and air visual observation, detection and assessment of abnormal conditions, notification, prioritization and execution of repairs, and documentation needed for safe and reliable operation.

46 D8 may vary depending on if the cause is known.

47 TO represents PG&E's Federal Energy Regulatory Commission-jurisdictional Transmission Owner (TO) rate case.

In addition to these routine inspections, and as part of PG&E's risk-based wildfire safety efforts, PG&E is conducting accelerated inspections of overhead electric facilities in HFTD areas to facilitate a proactive approach to repairing or replacing components that are at-risk of initiating fires. These accelerated inspections and repairs constitute the Wildfire Safety Inspection Program or WSIP.[48]

To develop the WSIP, PG&E used a risk-based approach including conducting a Failure Modes and Effects Analysis or "FMEA." The focus of the FMEA was to identify single points of failure of electric system components that could lead to fire ignition and then aid in the development of inspection methods that can most appropriately identify the condition of these respective components.

Each line of business performed the FMEA using the following methodology:

1. Establishing a cross-functional team of external professionals and PG&E SMEs with experience in field operations, engineering, and asset management.

2. Reviewing a list of asset components to identify potential single point failure ignition risks for categorization in an asset group.

3. Where available, developing an independent list of failure modes and frequencies from multiple internal and external sources using published reports, internal reports and SME interviews.

4. Mapping components to the final list of failure modes and relevant inspection methods.

5. In some cases, the failure mode does not have a readily observable issue that can be identified via a visual inspection. In those cases, non-destructive and destructive examination methods may be considered.

48 The WSIP was developed and implemented after the 2020 GRC forecast was submitted to the CPUC.

The new and enhanced risk-based approach identifies WSIP work by assessing the risk associated with each asset and by explicitly considering equipment modes of failure. PG&E expects that these efforts will continue to evolve as information is gathered and more is learned. PG&E will use the results of the current inspections to continue to shape a risk informed re-inspection program and schedule for subsequent inspections.

After PG&E identifies areas for WSIP inspections, inspectors are sent out to perform inspections. When an inspector identifies a maintenance condition, the inspector either immediately corrects the condition and records the correction or records the uncorrected deficiency, which is reviewed by a centralized review team. The review team initiates a corrective notification or "tag" in SAP Work Management in order to initiate, assign, plan, execute, and close out repairs to facilities. These tags are assigned a priority based on the risk posed by the condition and urgency of repairs (i.e., Priority A, B, E, or F). The review team process is designed to result in consistent application of the priority classification.

Finally, Geographic Information System (GIS) data concerning the location of electrical facilities is important to many of PG&E's wildfire risk reduction programs, including, but not limited to, inspection efforts and the WSIP, in order to understand the increased wildfire risk for each facility. Mapping and GIS data is also a critical component of PG&E's PSPS program discussed in Section 4.6. PG&E and other IOUs are working collaboratively with state agencies including CAL FIRE, the California Office of Emergency Services (Cal OES), and the CPUC to align utility capabilities and agency data and mapping needs. Recognizing the importance of GIS, PG&E is working to improve its GIS data, including designating a single point of contact at PG&E for all wildfire-related GIS needs.

Significant barriers to WSIP implementation include the availability of a qualified workforce that will enable PG&E to perform the targeted volume of work in the desired timeframe as well as potential limitations on available materials necessary to perform corrective actions within necessary timeframes. PG&E faces market challenges in the implementation of the WSIP program with an intense demand for skilled labor and constraints on the availability of equipment and materials. PG&E recognizes these challenges and is aggressively leveraging its partnering and sourcing strategies to engage the qualified personnel, equipment, and materials necessary to enable the implementation of this plan.

In addition, implementation of the WSIP can be further delayed by weather conditions, delays caused by property owners and governmental agencies, and environmental permitting issues. PG&E's land management and customer care teams work closely with PG&E's inspection teams to overcome these challenges as quickly as possible. PG&E tries to reach out to landowners in advance to obtain consent, but it may still cause some delays. Access limitations due to property owners or permitting constraints are execution risks where the state or federal governments can play a role in supporting PG&E's wildfire prevention efforts.

In the subsections below, PG&E describes its WSIP inspections for different types of facilities (e.g., distribution lines, transmission lines, and substations). For comparison, PG&E also describes the routine inspections for these same facilities in Attachment C.

4.2.1. WSIP Distribution

As discussed above, in late 2018, PG&E conducted a FMEA to better understand any additional inspections and analysis that should be implemented to reduce wildfire risk in addition to the inspections required by GO 165. The FMEA identified failure mechanisms that could be inspected for and repaired as part of an accelerated inspection program focused on fire ignition risk.

In 2019, using this risk-based approach, PG&E is inspecting its distribution structures in HFTD areas, as well as nearby structures in close proximity and high risk of fire spread into the adjacent HFTD area (approximately 685,000 poles across approximately 25,200 miles). These inspections will focus on the failure mechanisms for transformers, conductors, connectors, insulators, fuses, switches, structures, third-party attachments, and splices that can initiate fires. To facilitate these inspections, PG&E will enhance its existing routine inspection program to include wildfire specific elements for 185,000 poles that are due for their five-year inspection cycle in 2019. Additionally, PG&E will conduct wildfire-specific inspections of the remaining 500,000 poles to identify and correct any components that pose a wildfire risk. Furthermore, PG&E will utilize drone inspections for difficult-to-access locations to identify abnormal asset conditions.

PG&E will complete all inspections of distribution poles in HFTD areas by May 31, 2019, and all high priority corrective actions identified by those inspections by June 30, 2019. The timing of any potential corrective actions will depend on the nature of the work; however, consistent with the corrective action prioritization process, PG&E will take immediate action to address any issues identified as an imminent risk to public or workforce safety.

This schedule could be impacted by availability of qualified linemen, access limitations, and outage scheduling limitations. PG&E recognizes these challenges and is aggressively leveraging its partnering and sourcing strategies to engage the qualified personnel necessary to enable the implementation of this plan. PG&E is also coordinating the work in advance to manage access and outage issues.

4.2.2. WSIP Transmission

In late 2018, PG&E conducted a FMEA of transmission assets to better understand any additional inspections and analysis that should be implemented to reduce wildfire risk in addition to the inspections required by GOs 95 and 165. The FMEA identified failure mechanisms that could be inspected as part of an accelerated

inspection program. Beginning in December 2018, and continuing into 2019, using this risk-based approach, PG&E is performing inspections of transmission structures (poles and towers) in HFTD areas, as well as nearby structures outside the HFTD in close proximity and with high risk of fire spread into adjacent HFTD areas (approximately 5,700 miles of transmission line with more than 50,000 structures). These enhanced inspections focus on the failure mechanisms identified from the FMEA based on PG&E and industry information that identified components with a fire ignition risk.

The visual inspections include ground inspection of transmission poles and climbing inspection of transmission towers. The scope of these inspections is beyond the routine detailed ground inspections of a population of the towers and poles.

Drone inspections will be conducted on every structure in the WSIP scope, subject to any FAA restrictions that cannot be resolved,[49] and will complement and further enhance the ground and climbing visual inspections. This new technology was fully developed and deployed in a one-month time frame and incorporated the results of the FMEA. Helicopters will be used for additional aerial inspections for collecting infrared data to determine hot spots on conductors, insulators, and connectors requiring repair.

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49 Drone flight is governed by the Federal Aviation Administration (FAA), Part 107 of the Federal Aviation Regulations (14 CFR Part 107). Among other things, these regulations establish operational restrictions on drone flights which may affect PG&E's ability to conduct drone inspections on every transmission structure in the WSIP scope. PG&E will work with the FAA to resolve operational restrictions to the extent possible.

These infra-red inspections will be performed at strategic times of the year when respective lines are highly loaded. PG&E is also investigating the application of a new helicopter-based inspection technology being employed in Australia. This autonomous image capture employs the use of helicopters and asset-based high definition camera programming to capture images via helicopter mounted cameras at pre-programmed locations. This allows an accurate and rapid capture of images over detailed ground and climbing inspections and drone technology, with equivalent image results as drones. Other elements of the enhanced program include the following:

- The FMEA modes were incorporated into newly developed electronic inspection forms;
- New and enhanced job aids were developed to support the inspection forms;
- The condition prioritization matrix used to assess the priority and timing of corrective actions was adjusted to factor in the results of the FMEA and job aids; and
- Prioritization of the notifications was transferred from the field lineman and supervisor to a multi-discipline review team to establish a focused review process of the potential findings related to the asset condition.

The previously described inspection plan was implemented beginning in December 2018, with nearly 20 percent of the inspections completed by year end. As of the end of January 2019 approximately 56 percent of the inspections have been completed.

In a typical year, PG&E performs as many as 76,000 routine detailed inspections of transmission system poles and towers throughout its service territory.

PG&E will complete all inspections of transmission poles and towers in HFTD areas by May 1, 2019, and high priority corrective actions identified by those inspections by May 31, 2019. The timing of any potential corrective actions will depend on the nature of the work; however, consistent with the corrective action prioritization process,

PG&E will take immediate action to address any issues identified as an imminent risk to public or employee safety.

This schedule could be affected by availability of qualified linemen, access limitations, and outage scheduling limitations. PG&E recognizes these challenges and is aggressively leveraging its partnering and sourcing strategies to engage the qualified personnel necessary to enable the implementation of this plan. PG&E is also coordinating the work in advance to manage access and outage issues.

4.2.3. WSIP Substation

In early 2019, PG&E began performing a FMEA of substation assets to better understand any additional inspections and analysis that should be implemented to reduce wildfire risk in addition to the inspections already performed in accordance with GO 174. The FMEA identified substation assets and their components and linked potential failure causes that could be inspected for as part of an accelerated inspection program. For 2019, using this risk-based approach, PG&E is inspecting approximately 200 sites located in HFTD areas, including substations, switching stations, and hydro power houses, with a specific focus on the failure mechanisms for transformers, conductors, connectors, insulators, switches, poles, and other equipment that can initiate fires. Additional risk focused work includes further evaluation of the risk of catastrophic equipment failure and fire initiation. Incremental efforts will focus on creating a defensible space around substation facilities consistent with CAL FIRE and CPUC recommended guidelines and evaluating and implementing animal abatement methods to prevent animal contact.

PG&E will complete all enhanced inspections of the approximately 200 sites in HFTD areas by May 1, 2019, and any high priority corrective actions identified by those inspections by May 31, 2019. The timing of any potential corrective actions will depend on the nature of the work; however, consistent with the corrective action prioritization process, PG&E will take immediate action to address any issues identified as an imminent risk to public or workforce safety.

This schedule could be affected by availability of qualified linemen, access limitations, and outage scheduling limitations. PG&E recognizes these challenges and is aggressively leveraging its partnering and sourcing strategies to engage the qualified personnel necessary to enable the implementation of this plan. PG&E is also coordinating the work in advance to manage access and outage issues.

4.3. System Hardening Overview

TABLE 13: SYSTEM HARDENING OVERVIEW KEY

Section	Title	Program Mapping	New or Existing, Including Recovery Vehicle	Regulation Compliance	Associated Drivers
4.3.2	Pole Material	Wildfire System Hardening	New - FRMMA/WPMA	Exceeds regulatory requirements	All
4.3.3	Pole Loading and Replacement				
4.3.4	Conductor				
4.3.5	System Protection	Automation and Protection (SCADA)	New – FRMMA/WPMA	Not Applicable	
4.3.6	Equipment	Non-exempt Surge Arrester Replacement Program	New - FRMMA / WPMA & TO (Light Duty Steel Poles)	Exceeds regulatory requirements	D3, D4 - Equipment failure

The System Hardening Program is an ongoing, long-term (more than five years) capital investment program to rebuild portions of PG&E's overhead electric distribution system. Under this program, PG&E is upgrading approximately 7,100 circuit miles in Tier 2 and Tier 3 HFTD areas. This program consists of ignition-risk-modeled and field-identified work that will result in a full rebuild of the overhead distribution system to increase its overall strength, replace aging assets, and reduce risk from external factors, such as vegetation contacting lines.

PG&E initiated the program in 2018, after the 2017 RAMP Report, in which PG&E proposed the targeted replacement of bare overhead conductor with covered conductor in high-risk wildfire areas.[50] As a result of supplemental risk assessment after the 2017 RAMP Report was submitted, the System Hardening Program has been broadened to include targeted pole replacement, replacement of non-exempt equipment, and potential targeted undergrounding. This work will occur based on PG&E's risk modelling of the distribution circuits.

The precise scope of hardening work will be site-specific and dependent on local conditions. Not every measure is effective or necessary at every location. As PG&E implements the system hardening program, we will continue to evaluate the design considering local conditions optimizing the appropriate solution for that location. For example, where appropriate, PG&E may perform some undergrounding of select overhead lines. In addition, bird/animal guards will also be installed where necessary to help prevent electrical contacts and outages. PG&E will continue to update the risk model with asset failure information, utility best practices, and new technology, which will result in a more refined asset investment plan.

PG&E is still in the process of refining its standards for the overhead hardening work, but currently expects that work will include the following components, depending on the specific locations (further details on some of the key components are provided in subsequent sections):

- Primary Conductor Replacement – replacement of bare overhead primary (high voltage) conductor and associated framing with conductor insulated with abrasion-resistant polyethylene coatings (sometimes referred to as covered conductor or tree wire). Installing covered conductor will help to further reduce the likelihood of faults due to line-to-tree contacts, tree-branch contacts, and faults caused by animals. Installing covered conductor will also prevent situations where bare wires

50 PG&E 2017 RAMP Report, pp. 11-21.

slap together in high winds which can generate sparks of molten metal capable of igniting vegetation.

- Secondary Conductor Replacement – replacement of lower voltage (480V and below) conductor with insulated conductor. Installing covered conductor on secondary lines will have similar benefits to installing it on primary lines.

- Replacement of Non-Exempt Equipment – replacement of existing primary line equipment such as fuses/cutouts, and switches with equipment that has been certified by CAL FIRE as low fire risk and therefore exempt from vegetation clearance. This replacement work will eliminate overhead line equipment and devices that may generate exposed electrical arcs, sparks or hot material during their operation.

- Replacement of Overhead Distribution Line Transformers – upgrading transformers to FR3 Fluid as part of PG&E's current equipment standards (PG&E implemented the transition from mineral oil to FR3 in 2014). The newer transformers are filled with fire resistant FR3 insulating fluid, a natural ester derived from renewable vegetable oils—providing improved fire safety, transformer life, increased load capability, and environmental benefits. In addition, new transformers are manufactured to achieve higher Department of Energy electrical efficiency standards.

- Installation of Non-Wood Poles to Increase Pole Strength and Improve Fire Resistance – pole failures present safety hazards and may result in downed conductor faults, which may generate sparks. Furthermore, high-strength poles are needed to support the additional weight of insulated wire. PG&E is also evaluating various new non-wood poles that may provide increased fire resistance and pole strength.

- Upgrades to Electrical Protective Devices and Systems Through Equipment Replacements and Device Programming – this work also involves updating electric control equipment and wiring that may more

effectively identify downed conductor type outages and rapidly operate protective relays.

In 2018, PG&E initiated construction pilots to evaluate various overhead conductor and equipment configurations, including potential undergrounding, as well as to develop best practices. PG&E completed initial tree wire projects on approximately 17 circuit miles of distribution line in 2018. In 2019, PG&E will begin the System Hardening Program with a target of completing 150 circuit miles by the end of the year. In 2020-2022, PG&E forecasts completing work on 600 circuit miles per year during this period, and PG&E intends to complete work on 7,100 circuit miles.

PG&E expects completing the 7,100 circuit miles to take approximately 10 years due to the constraints on available qualified personnel and materials. The most significant potential barriers to completing the planned system hardening are limitations on the supply of necessary materials needed for the volume of work, particularly covered conductor, and the supply of adequately-trained personnel necessary to perform the work in the field. With regard to materials, and covered conductor, PG&E's Supply Chain department is working to satisfy a planned demand of reconductoring 150 circuit miles this year. The supply plan is in place with no anticipated delays or shortages of conductor. We are in the process of identifying external crews to fill the resource needs to construct 150 miles of wildfire hardening work for 2019. The construction of these projects is the highest priority, and the crews will be engaged as the projects are ready for construction.

In this section of its Plan, PG&E describes its system hardening strategies including: (1) pole material; (2) pole loading and replacement requirements; (3) conductors; (4) system protection; and (5) equipment.

4.3.1. Pole Material

The current PG&E distribution standard for overhead construction is open conductor and wood poles. This system is designed and constructed in accordance with GO 95, which suggests utilizing safety factors and clearances. The overhead system is engineered and built with electrical, structural, and mechanical considerations in mind. The poles are designed by PG&E experts utilizing an industry standard tool (O'Calc) to calculate structural integrity (vertical and transverse loading). The conductors are sized appropriately for the electrical loading as well as mechanical integrity in sag and tension. All variables utilized in PG&E's engineering analysis are consistent with or exceed those set by the CPUC.

In the recent years, California has experienced unprecedented wind and drought conditions that have led PG&E to consider installing structures for new construction or reconstruction in high wind areas that are more robust than required by design standards and parameters.

After the 2017 wildfires, PG&E further evaluated the type of materials used on its distribution system. Wood poles are natural products and inherently have some degree of variability. Poles are classified by their materials, which defines their minimum strength capability. However, as poles age, depending on their environment, they may not all react in the same manner. This lack of consistency in pole aging led PG&E to consider and start evaluating non-wood or engineered products to determine if they could have better performance consistency and/or increase fire resiliency.

PG&E initiated evaluation of various types of non-wood poles in 2018 and continues to work with other utilities and industry experts to determine the best product(s) for use in our overhead system. Materials that are being considered include composite, concrete, and steel. Factors being considered include strength capabilities, fire resiliency, ease of installation, and subsequent repairs/replacements as part of the asset lifecycle process. Initial findings indicate that for both strength and fire resiliency capabilities, a pole designed with a composite type material may have advantages over

a pole designed with materials such as steel, wood, or concrete. With respect to concrete poles, there are significant installation challenges, particularly in rural areas, due to their weight. Further, regarding steel poles, benchmarking with other utilities showed challenges related to the accompanying work.

Thus, PG&E is proposing to transition from wood to composite poles for distribution system hardening and fire reduction as the poles become available. These poles will be introduced for use to improve fire resistance and resiliency of poles in the high fire-threat areas. Although not fireproof, composite poles are fire resistant, flame-resistant and self-extinguishing once the heat source is removed. Testing by manufacturers indicates that composite poles retain both strength and integrity to temperatures of at least 1,200°F. Additional testing modeled after the CAL FIRE "fast moving brush fire test" produced limited surface charring and no structural damage. During this test, the poles withstood temperatures in excess of 2,000ºF for 12 minutes without igniting. The added resiliency of non-wood poles should help to further reduce the possibility of downed conductor faults and the potential for fire ignition.

4.3.2. Pole Loading and Replacement

Under the Plan, PG&E is modifying pole loading model parameters and variables in light of historical data of various environmental factors (e.g., wind speed). Sizing for new and replacement distribution pole installations will consider historical peak wind speeds in areas where they exceed the GO 95-assumed wind speeds. In order to maximize the likelihood that poles are strong enough to withstand higher wind speeds, a pole loading calculation must be performed both at the loading conditions assumed by GO 95 conditions (load case) and at a summer peak wind load case (e.g., peak wind for location, 60-degree minimum temperature, no ice).

PG&E will adjust the required setting depth of a pole based on the current Allowable Overturn Moment table and comparing the values to the ultimate potential ground-line moment for a given pole design. This more stringent requirement supersedes previous PG&E requirements for minimum setting depth and will result in a greater amount of available pole strength (strength capacity divided by safety factor) at the equivalent soil overturn strength.

With regard to light duty transmission poles, as part of the System Hardening Program, PG&E will require the use of steel transmission poles in all new construction or refurbishment work except where it would cause an electrical hazard. Increased application of steel transmission poles will reduce the risk of pole failure during a wildfire event, resulting in shorter restoration delays. Installing steel for design purposes can also help increase the force the asset can withstand, which can help avoid wire downs from structure failures or external forces.

4.3.3. Conductor

The replacement of bare conductors with larger covered conductors (also known as tree wire) will further reduce the likelihood of faults due to trees, branches, animals, or birds contacting lines, and will further reduce situations where bare wires slap together in high winds, which can generate sparks or molten metal. The HFTD areas within PG&E's territory has a high volume of vegetation with large overhangs and ground fuels where the covered conductor is an effective risk mitigation. Thus, installation of covered conductors can be effective in providing fire reduction and reliability improvements from contact outages in heavily treed areas and further reduces the potential for failures related to smaller conductors. PG&E is replacing bare overhead distribution primary (high voltage) and secondary conductor with covered conductor in HFTD areas.

There is a limited risk that covered conductor may introduce higher impedance faults compared to bare conductor depending on how the conductor lands on the ground. However, an additional benefit of covered conductor is that it may be less likely to cause an ignition on the ground, as there is a lower potential for arc points along the line due to fewer contact points with the ground. Further, PG&E is currently piloting more sensitive protection for high impedance faults that may mitigate the additional high impedance risk.

The primary covered conductor coating PG&E is using is abrasion resistant crosslinked polyethylene. Crosslinked thermoset polyethylene covering is a new standard, which is an improvement over PG&E's prior standard, non-crosslinked thermoplastic polyethylene covering, because of its:

- Superior temperature resistance due to its higher softening point and cable used for a higher covering rating of 90°C versus 75°C;
- Increased chemical resistance at ambient and elevated temperatures; and
- Higher tensile strength, rigidity and hardness.

4.3.4. System Protection

There are approximately 2,800 reclosing devices on PG&E lines serving Tier 2 and Tier 3 HFTD areas. The devices that have reclosing functionality include substation circuit breakers, line reclosers, and TripSavers. PG&E's automation program will continue to automate these devices to enable selective reclosing functionality and support future protection schemes that may vary during high-risk fire periods. At the end of 2018, approximately 2,100 of the 2,800 reclosing devices serving Tier 2 and Tier 3 HFTD areas were SCADA-enabled. During 2019, PG&E will continue to automate the remaining non-SCADA line reclosers serving the Tier 2 and Tier 3 HFTD areas. In 2020, PG&E will automate the remaining non-SCADA TripSavers serving the Tier 2 and Tier 3 HFTD areas.

Existing distribution line reclosers that are operated for fire safety (e.g., as part of the PSPS or Recloser Disabling programs) were originally installed to optimize electric reliability and limit the number of customers exposed to outages, which can also present serious public safety concerns. These reclosers are often not optimally positioned to isolate the newly designated HFTD areas.

In an effort to further sectionalize distribution circuits and limit the duration as well as the number of customers impacted by PSPS events, PG&E is proposing to install additional line reclosers at Tier 2 and Tier 3 HFTD boundaries. In addition to the automation programs, PG&E is also evaluating different protection schemes and equipment that may further reduce the likelihood of a fire ignition when a system failure occurs. The program includes:

- Fusesavers™: Fusesavers™ enable localized isolation of all phases of a line when a problem is detected on only one or two phases. For example, if a single wire down on a three-phase line is detected, Fusesavers™ can automatically and locally de-energize all three phases. Installing these devices can also create additional points where lines can be segmented to support other wildfire risk reduction programs such as PSPS.

- High Impedance Fault Detection: PG&E is piloting and proposes to deploy newer protection capabilities of reclosers and circuit breakers that increase the ability to detect high impedance faults.

- Increased Protection Sensitivity: PG&E is evaluating the use of more sensitive protection settings and use of fast curves set on reclosers and circuit breakers. The proposed settings and use of fast curves would reduce the amount of energy experienced when a system failure occurs. This may lower the potential for a fire ignition to occur. The proposed protection schemes, however, could reduce the ability to coordinate with protective devices downstream and will lead to an increase in the size and duration of outages.

4.3.5. Equipment

PG&E proposes to eliminate non-exempt overhead line equipment in HFTD areas. Non-exempt equipment is equipment that may generate electrical arcs, sparks, or hot material during its normal operation. Due to these characteristics, PRC Section 4292 requires all utilities to maintain at least a 10-foot clearance of vegetation from the outer circumference of any pole that has non-exempt equipment. However, CAL FIRE tests and certifies some equipment as exempt from the vegetation clearance requirements of PRC Section 4292 where it is determined to be safer to use.

With increasing wildfire risks caused by changing climate conditions, PG&E has created a program to replace non-exempt fuses and cutouts to further reduce fire risk. The replacement of non-exempt equipment with exempt equipment will further reduce fire risk since this equipment is considered “non-expulsion” and does not generate arcs/sparks during normal operation.

Starting in 2019, PG&E forecasts replacing approximately 625 fuses/cutouts, and other non-exempt equipment identified on the pole each year for seven years in Tier 2 and Tier 3 HFTD areas.

4.4. Enhanced Vegetation Management

TABLE 14: ENHANCED VEGETATION MANAGEMENT KEY

Section	Title	Program Mapping	New or Existing, Including Recovery Vehicle	Regulation Compliance	Associated Drivers
4.4.1	Vegetation Trimming and Overhanging Tree Limbs	Enhanced Vegetation Management	New – FHPMA[51]	Exceeds Regulatory Requirements, but generally supports PRC 4293 and GO 95, Rule 35	D1, D6, D8[52]
4.4.2	HFTD VM Inspection Strategy	Enhanced Vegetation Management	New –FHPMA	Exceeds Regulatory Requirements, but generally supports PRC 4293 and GO 95, Rule 35	D1, D6, D8
4.4.3	Inspecting Trees with a Potential Strike Path to Power Lines				
4.4.4	At-risk Species Management				
4.4.5	Challenges Associated with EVM	Enhanced Vegetation Management	New –FHPMA	Exceeds Regulatory Requirements, but generally supports PRC 4293 and GO 95, Rule 35	N/A
4.4.6	Community and Environmental Impacts				

After the 2017 wildfires, PG&E aggressively expanded vegetation management around its assets. In addition, in January 2018, the CPUC adopted the HFTD Map, which drastically increased the amount of PG&E's service area classified as "high fire-threat area." Previously, the fire threat maps published in 2012 had included only a

51 FHPMA represents the Fire Hazard Prevention Memorandum Account established pursuant to decisions issued in R. 08-11-005, in which the CPUC authorized electric IOUs to record costs incurred to comply with D.17-12-024.

52 D8 is dependent upon if the cause is known.

small portion of PG&E's service area (about 15%) around Santa Barbara as "high fire-threat area."[53]

Thus, after the 2018 wildfires, PG&E further expanded vegetation management around its assets. This work is critical because PG&E operates in a heavily forested[54] and vegetated area, particularly compared to the other large California IOUs. To address this risk, in 2018, PG&E began performing EVM work in HFTD areas. Much more aggressive than, and in addition to, ongoing VM programs, the EVM work includes the following activities:

- Overhang Clearing: removing overhanging branches and limbs directly above but outside the radial clearance zone around electric power lines required by regulatory requirements to further reduce the possibility of wildfire ignitions and/or downed wires due to vegetation-conductor contact.

- Targeted Tree Species Work: identifying and trimming or removing specific tree species within the fall or strike zone of power lines that have exhibited a higher pattern of failing; as well as addressing any dead or dying trees.

- Fuel Reduction: performing "ground to conductor" vegetative fuel reduction work to create fire defense zones under and adjacent to power lines in select locations to enhance defensible space for communities, properties, and buildings.

PG&E's baseline and long-standing VM programs are multi-pronged with various elements all designed to:

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53 See D.12-01-032 (January 18, 2012), at 262–63, available at: http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/157605.PDF (showing Reax Map for Northern California and FRAP Map for Santa Barbara County).

54 For representations of the density of forests in PG&E's service territory within California. See pp. 3, 6, 7, 17 and more of https://www.fs.fed.us/pnw/pubs/pnw_gtr913.pdf.

- Proactively conduct tree work that reduces the likelihood of tree failure that could impact electric facilities and pose a public safety risk;
- Comply with State and Federal regulations regarding minimum vegetation clearance for the Electric Transmission & Distribution overhead systems;
- Perform annual inspections (and in HFTD areas, more-frequent-than-annual inspections) so that required vegetation clearances are maintained and hazardous trees are abated;
- Maintain vegetation-to-line clearances, and radial clearances around poles, pursuant to PRC Sections 4292 and 4293, GO 95 Rule 35 and FAC-003-4 (Federal Electric Transmission standard), this includes creating the recommended radial clearance of 12 feet or more at the time of trim for lines in HFTD areas for year-round compliance and risk reduction; and
- Validate that work was done as planned and intended through Quality Control (QC) and Quality Assurance (QA) reviews; including maintaining auditable records of all work done.

While these programs, generally focused on supporting compliance with minimum clearance requirements, are long-standing, they are not static or uninformed by the evolving wildfire risk. The 2019 distribution routine schedule (when each circuit will be inspected and subsequently worked) has been substantially re-aligned based on a relative risk ranking of all circuits to position the highest risk circuits to be worked before the peak of the traditional wildfire season.

In the remainder of this Section, PG&E describes: (1) vegetation trimming and overhang work in HFTD areas; (2) its HFTD area inspection strategy, including inspection qualifications and QA; (3) inspecting trees with a potential strike path to power lines; (4) at-risk tree species management; (5) challenges associated with EVM;

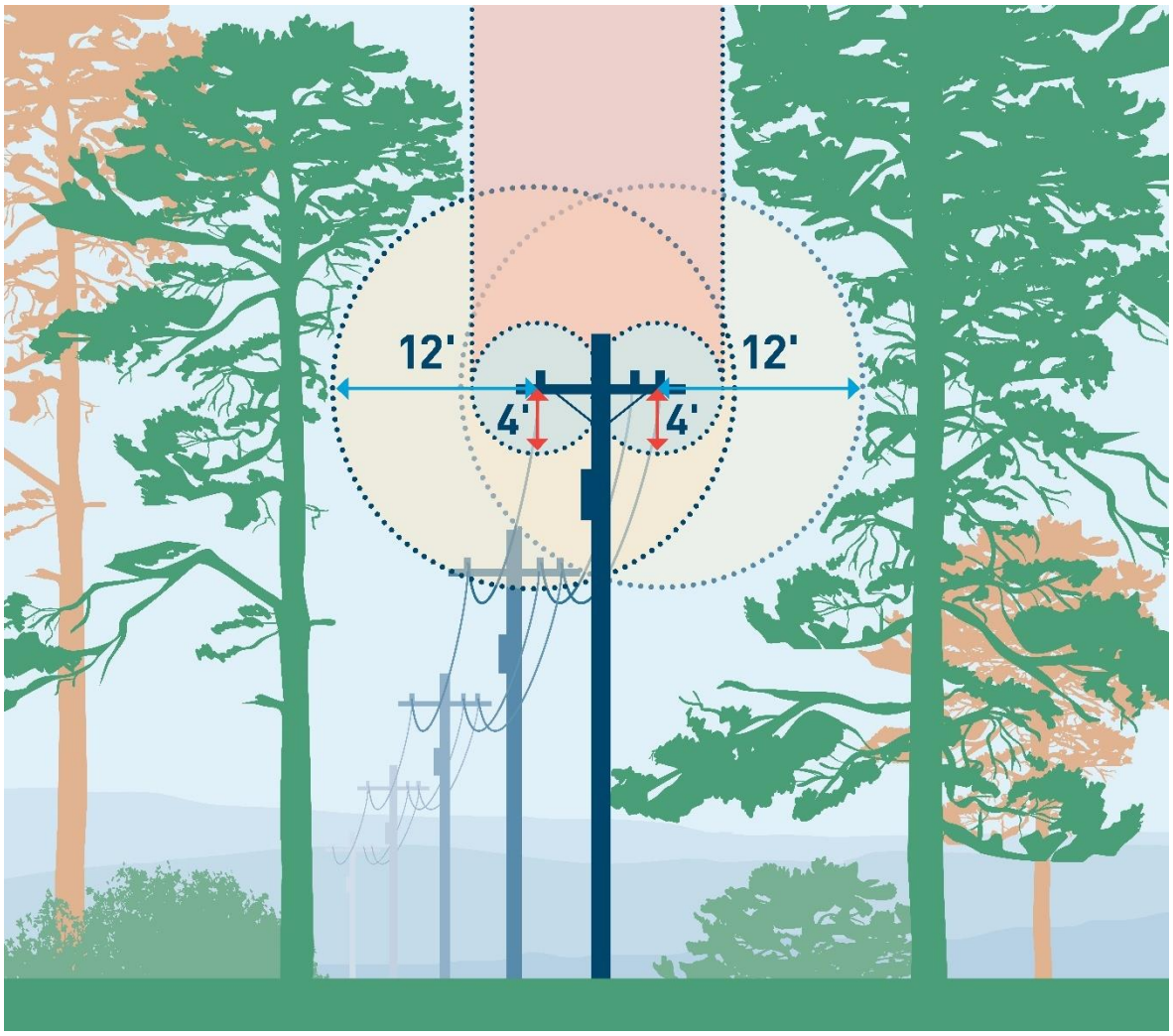
and (6) minimizing community and environmental impacts of vegetation management work.

4.4.1. Vegetation Trimming and Overhanging Tree Limbs

In 2018, PG&E began performing expanded vegetation management work in HFTDs that included the clearing of overhanging vegetation from directly above and around distribution lines. This work is focused on further limiting the possibility of wildfire ignitions and/or downed wires due to vegetation-conductor contact.

For 2019 and beyond, the planned scope of this program is to remove all branches that directly overhang the radial clearance zone around electric distribution lines required by CPUC regulations and California statutes. GO 95, Rule 35 and PRC Section 4293 generally require a four-foot radial clearance between vegetation and electric distribution wires in HTFD areas. By removing overhanging tree limbs, there are fewer tree limbs that could fall or grow into the mandated clearance zones. See Figure 7 below for an illustration of the routine and EVM work.

FIGURE 7: ENHANCED VEGETATION MANAGEMENT



PG&E plans to clear about 2,450 circuit miles of overhangs in HFTD areas in 2019, with an increasing pace in future years. The scale, scope and complexity of this work necessitate that, to address the approximately 25,200 distribution circuit miles in HFTD areas, this program is established as a multi-year effort. As a comparison, over the last five years the maximum number of trees removed by PG&E's drought and tree mortality CEMA program was approximately 225,000 trees. As shown in Table 15 below, in 2019, the EVM program is anticipating trimming or removing approximately 305,000 trees while the CEMA program will still be in effect and is forecast to work approximately 70,000 trees. All of the work reflected in Table 15 is in addition to the more than one million trees PG&E's routine Vegetation Management programs have historically worked or removed annually.

TABLE 15: ANNUAL "ADDITIONAL" TREES WORKED

Trees Worked	2014	2015	2016	2017	2018 (est.)	2019 Forecast
CEMA	8,042	18,557	225,168	156,344	70,000	70,000
EVM + AWRR	–	–	–	–	90,000	305,000
Total	8,042	18,557	225,168	156,344	160,000	375,000

On the electric transmission system, all circuits are planned to be inspected and worked in 2019 to remove overhangs. This scope of overhang removal work will be incorporated into the annual inspection and tree work cycle for all transmission circuits. Due to the historically broader clearances maintained between transmission lines and vegetation and a practice of preventing direct overhangs of transmission lines, the number of trees anticipated to require work to align the electric transmission system with this scope will be significantly less than for the distribution system.

In addition to the initial overhang clearing work, discussed above, PG&E will need to perform annual, follow-up vegetation maintenance work on the sections of line cleared of overhangs, to keep all branches above powerline height from growing back into an overhanging position. As the number of miles initially cleared of overhangs increases, the annual maintenance and upkeep effort will also grow.

In 2018, PG&E also began a Fuel Reduction Program to reduce vegetative fuels under, and up to 15 feet on either side of, power lines located within HFTD areas. This work to create "fire defense zones" can:

- Create safe space between power lines and trees and brush that can act as fuel for wildfires;
- Help slow the spread of fires and improve access for first responders in the event of a wildfire; and
- Enhance defensible space around homes, businesses and properties, improving safety.

For 2019 and beyond, PG&E will work with property owners to perform this work in HFTD areas where property owners support the work and wildfire risk reduction

benefits can be created. The miles of line to be cleared through this effort will depend on various factors including vegetation density, topography, access and environmental considerations. In addition, until PG&E patrols lines, the number of trees that require trimming or removal is not known, impacting the rate at which lines can be cleared.

4.4.2. High Fire-Threat District VM Inspection Strategy

During PG&E's VM inspections, pre-inspectors identify vegetation that may grow too close to conductors or that may fail and contact conductors. PG&E's line clearance qualified tree work contractors then trim or remove trees as necessary to create adequate clearance and abate any hazard trees. More than 3,500 employees and contractors, including experts educated, trained, and certified in arboriculture and forestry, perform annual activities on behalf of PG&E's VM Department, involving approximately:

- 70,000 square miles of service area
- 81,000 miles of overhead distribution power lines
- 18,000 miles of overhead transmission power lines
- An estimated 100 million or more trees with the potential to grow or fall into overhead power lines
- Trimming or removing more than one million trees per year

In HFTD areas, inspections (e.g., drought and tree mortality inspections) are performed at least a second time each year and as often as four times per year in some locations (in Wildland Urban interface areas). From 2014-2017, over 400,000 dead and dying trees were abated by PG&E's drought and tree mortality program (i.e., CEMA), and PG&E removed approximately 70,000 more trees in 2018 and forecasts to remove an additional 70,000 trees in 2019.

Importantly, all trees identified for work by pre-inspectors are evaluated for the urgency of the required tree work. If tree failure is judged to be possibly imminent a

crew will be dispatched the same day. Trees can also be flagged for immediate follow-up work, while trees that require work but showing no near-term risk factors are scheduled following the standard process. The standard cycle time for trees exhibiting no near-term risk factors would be expected to be in the 60-90-day range after the completion of the pre-inspection activity. This means that some trees identified for work in one period (year, quarter, etc.) will not be worked until the next period. While these trees are sometimes referred to as “carryover” trees they do not represent a higher risk or a risk left un-addressed, they are simply trees where the normal work cycle resulted in them falling on the other side of a particular date. If any of these trees had been identified as immediate risk, they would have been addressed immediately.

Pre-inspection is the first step in the vegetation management process. Correctly assessing tree characteristics including species, health, growth rate, and likely failure patterns is critical to prescribing the appropriate vegetation management actions to reduce the wildfire risk from tree-line interactions. The pre-inspectors performing this work are qualified and trained, with many holding industry certifications. PG&E contracts with a limited number of well-established, large-scale vendors to perform this work. Throughout their training and once deployed pre-inspectors follow an established set of procedures for consistency in how the work is performed and findings/ prescriptions recorded.

Beyond the training that the contractors provide to their pre-inspector staffs, PG&E also provides two full days per year of training to all pre-inspectors to align on safety practices, and relevant procedures. In addition, as explained below, PG&E’s VM QA effort is designed to validate that the entire process, starting with pre-inspectors, is creating the desired outcomes and identifies areas where expectations are not being met such that further action, including retraining or re-assigning staff, can be taken. PG&E’s vegetation management program incorporates changing environmental conditions, lessons learned, and new regulations. In the wake of the 2015 Butte Fire, PG&E adapted several practices to address risks identified in that incident. Among

other measures, PG&E initiated additional validation of contractor training programs for pre-inspectors.

For pre-inspectors to move up in their career path, they are required to acquire professional certifications from outside authorities. Specifically, the International Society of Arboriculture grants Certified Arborist and Utility Specialist certifications that directly support and validate proficiency in this kind of work. Maintaining these certifications also requires completing continuing education requirements. In addition, arborists can get certified as a Registered Professional Forester from the California State Board of Forestry and Fire Prevention. A pre-inspector cannot attain the 3rd or 4th step of the career progression without validating their proficiency through acquiring one (or more) of these certifications.

The final step in the vegetation management process is the QA Program to assess the quality work performed in the field. This is accomplished through the physical inspection of a sample of the PG&E system. The objective of the sampling exercise is to estimate the work quality rate for all trees in the geographic area covered by an audit. PG&E uses the results of the QA Program to improve future performance. PG&E has reviewed its QA Program and procedures with third-party experts who have validated that the sampling design in use is appropriate for PG&E's objectives, stating "The use of a cluster sampling design is entirely appropriate for PG&E's objectives…."[55]

4.4.3. Inspecting Trees With a Potential Strike Path to Power Lines

Pursuant to PRC Section 4293 and GO 95, Rule 35, all PG&E vegetation management patrols inspect for hazard trees. A hazard tree is defined as a tree that has been assessed from the ground to pose a potential danger to fall or fail into electrical facilities due to all or a portion of the tree visibly exhibiting poor health or death, disease or decay, structural deficiency, or a compromised root structure. As part

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55 Dr. Karl Snow of Bates White Economic Consulting, PG&E's QA statistical sampling methodology.

of VM inspections PG&E pre-inspectors review all trees that are tall enough and have a feasible path to strike overhead lines. If the pre-inspector identifies a hazard tree that shows indications that it is at risk to fall into the power line it will be marked for treatment, including trimming or removal, and can be prioritized to be worked immediately or in the near-term if conditions warrant.

These physical, ground inspections are being augmented by the capture of LiDAR and related, remote sensing, data that can be thoroughly and consistently analyzed to take measurements, reveal patterns and identify risks in ways that an inspector on the ground cannot do precisely.

In 2018, PG&E captured LiDAR for most of Tier 3, and in 2019 and beyond, plans to capture and analyze data for all Tier 2 and Tier 3 HFTD areas annually. In fact, these annual data captures will, in addition to LiDAR, gather "hyperspectral" and imagery data that can, in combination with machine learning and powerful software solutions, allow for the potential identification of tree species and flag indications of trees that may be dead or dying.[56] Over time, the planned annual collection of this LiDAR, hyperspectral and other data will allow PG&E to assess (a) tree growth patterns; (b) the effectiveness of PG&E's trimming or removal activities; and (c) change detection including third-party activities (like new tree plantings) that may impact powerlines. Overall, the expanded deployment of remote sensing data will support increasing knowledge of the risks facing our powerlines and support the further maturation of our risk management models and approaches.

4.4.4. At-Risk Species Management

PG&E's VM team conducts site visits of vegetation-caused wires-down events as part of its standard tree-caused service interruption investigation process. The data obtained from site visits supports efforts to reduce future vegetation-caused wires-down

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56 To underscore the unprecedented scope of this work, PG&E's 2019 data capture of approximately 25,200 distribution circuit miles is believed to be the world's largest ever hyperspectral data survey.

events. The data collected from these investigations also helps identify failure patterns by tree species that are associated with wires-down events.

In reviewing five years of vegetation-related fire ignitions in Tier 2 and Tier 3 HFTD areas, including the wire-down data, PG&E identified that 10 species of trees[57] were responsible for nearly 75 percent of those incidents. Therefore, as part of the EVM Program, PG&E will focus on removing or trimming trees from these 10 species that are tall enough to strike distribution lines, have a clear path to strike, and exhibit other potential risk factors such as leaning toward a line or are weighting toward a line. This At-Risk Species Management work (also known as Targeted Tree Species Work) focuses on trees that are more than 4 feet from power lines (i.e., not within the scope of the overhang clearing program discussed in Section 4.4.1 above) and will include some taller trees located dozens of feet from power lines.[58] PG&E plans to begin this work in HFTD areas this year. PG&E's operational planning and forecast assume that this work will be performed in conjunction with the overhang clearing work outlined in Section 4.4.1, to maximize efficiencies and limit intrusion upon third-party property.

4.4.5. Challenges Associated With Enhanced Vegetation Management

Completing the expanded and accelerated EVM program faces substantial challenges that PG&E is proactively addressing in conjunction with several partners. The most significant challenge to the EVM program schedule is the limited availability of qualified work force. The most significant challenge to the EVM program schedule is the limited qualified tree workers, which limits the maximum pace of work. PG&E's experience casting a wide net and offering substantial financial incentives to hire additional tree personnel into its service territory in the fall of 2018 identified a maximum

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57 Black Oak, Gray Pine, Tanoak, Coast Live Oak, Live Oak, Ponderosa Pine, Eucalyptus/Blue Gum, Douglas Fir, Valley Oak and Monterey Pine.

58 Note that this program primarily encompasses living trees. PG&E removes the majority of dead and dying trees that have the potential to contact its lines as part of our Drought and Tree Mortality Response Program.

volume of approximately 3,000 qualified tree workers that could be acquired to perform vegetation management activities. Identifying personnel that were qualified to safely perform this hazardous work was challenging.

The challenge of securing increased numbers of qualified personnel is further illustrated by PG&E's recent experience seeking assistance under the utility Mutual Assistance Agreement (MAA) following the Camp Fire. The first step in the Mutual Assistance process is to seek support from within California. However, limited personnel were available due to concurrent emergency response needs in the state. PG&E subsequently expanded its Mutual Assistance request to the Western Regional Mutual Assistance Group, followed by the Mid-West and Texas Regional Mutual Assistance Groups, and eventually all seven regional Mutual Assistance groups in the country. At each expansion of PG&E's request for Mutual Assistance, PG&E was unable to secure the requested number of personnel. PG&E's efforts to locate sufficient VM contractors after the Camp Fire was escalated to the status of a National Response Event, a process established for utility CEOs nationwide following Superstorm Sandy. In the end, the request for VM Mutual Assistance request was made to more than 200 utilities in an effort to locate 700 tree workers and 150 VM pre-inspectors to aid in recovery efforts. From that request, PG&E was only able to secure 223 tree workers and 40 pre-inspectors from across the country. And these workers only stayed for a limited period of time under the Mutual Assistance Agreements.

The limited pool of qualified personnel, whether through hiring or mutual aid, is exacerbated by the particular challenges of performing vegetation management work in Northern California. Not only is logging and tree felling one of the most hazardous industries in the nation, but the Northern California forests pose a very different challenge than most parts of the country. Safely removing a 200+ foot tall tree in proximity of a high voltage distribution line cannot just be performed by anyone with a chain saw. As an illustration, see the below image for the scope of a tree adjacent to powerlines that was removed during the 2018 EVM Program:

The pace of PG&E's multi-year EVM program is based on maintaining the maximum-available resource complement of approximately 3,000 qualified tree workers that could be acquired to perform vegetation management activities, as described above. Therefore, the pace of PG&E's multi-year EVM program is based on maintaining that maximum-available resource complement of approximately 3,000 tree workers. Leveraging that volume of workers, after accounting for the number needed to complete the annual routine vegetation management, results in an approximately 8-year EVM program from 2019 to approximately 2026. Any acceleration of that schedule would require identifying, with high confidence, a sustainable increase in the volume of trained, safe, qualified, line clearance certified tree workers. In order to address this constraint, PG&E is exploring approaches to increase the population of qualified tree workers that could perform this work. For example, PG&E is partnering with our Tree Work Vendors and the IBEW to consider implementing a tree worker apprenticeship program that is intended to create a sustainable pipeline of new qualified personnel.

FIGURE 8: PG&E VEGETATION MANAGEMENT



In exploring how to expand the available pool of qualified personnel to complete this critically important work, PG&E has also solicited help from various sources. On a nationwide level, the Bureau of Labor Statistics' most recent data on the entire "Tree

Trimmers and Pruners" occupation (from May 2017)[59] shows national employment of 41,140 (with 5,830 of those in California). However, only a small subset of these "Tree Trimmer and Pruners" possess the necessary skills and qualifications to work adjacent to powerlines (i.e., being "line clearance certified").

To understand what level of workforce expansion might be possible to PG&E, in 2016 PG&E contracted with a vegetation management consultant to perform a market analysis of what might be possible in terms of bringing additional qualified personnel into California.[60] This consultant identified 46 total tree companies in the United States who were not already working for PG&E. Fifteen of those companies declined to participate in the analysis at all (most were small and regionally based) and 22 only participated in an initial survey stating that they had no interest in working in California due to (among other reasons): liability risk, regulatory/business environmental and insurance requirements, or lack of available qualified personnel to expand. The remaining nine vendors expressed, in aggregate, an ability to mobilize possibly a few hundred qualified personnel to California and generally expressed an interest in only emergency/short-term work, not a willingness to commit long-term to developing a workforce in California (or moving their existing workforce). In sum, while there are, of course, more tree trimmers and pruners throughout the United States, no successful solution has been identified for enticing utility-qualified workers to California for a long-term engagement, based on third-party and PG&E research and analysis.

Another potential challenge to timely completion of the planned vegetation management activities are the numerous legal challenges and requirements that must be navigated, including the need for land rights, local permit requirements, environmental requirements, and other state or federal requirements. These issues may involve concerned landowners and communities, local governments, state

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59 See Bureau of Labor Statistics website, *available at:* https://www.bls.gov/oes/2017/may/oes373013.htm, *last accessed* February 3, 2019.

60 Resource and Market Assessment Report: Utility Line Clearance Contractors.

agencies, or federal agencies, and can cause significant delays in performing vegetation management work. PG&E may even be compelled to seek to obtain assistance from law enforcement or court orders to overcome some of these hurdles. For example, landowners objecting to tree work may prevent tree crews from entering their property: Locking gates, blocking access with vehicles and farm equipment, and occasionally to the extent of threatening them with firearms. Landowners may also threaten legal action, arguing that the extent of the planned tree work exceeds PG&E's land rights. In these cases, local law enforcement agencies will not assist PG&E in enforcing our recorded land rights unless and until PG&E obtains a court order.

As the clearances between conductors and vegetation increase, the vegetation work may also extend to properties adjacent to where PG&E historically trimmed vegetation. This could require PG&E to obtain land rights to those adjacent properties, causing further delay.

PG&E also must coordinate with numerous cities, counties, and other local authorities to obtain local encroachment permits or to manage other local requirements, such as heritage tree ordinances. Some state permitting requirements could cause further delay by triggering review under the California Environmental Quality Act (CEQA). For example, PRC Section 30000 imposes requirements on tree removal in coastal zones. Not only is this requirement administered by many local governments through certified local coastal programs, requiring coordination for each area worked, if a permit is needed, the level of CEQA review is determined separately by each permitting authority. Likewise, CAL FIRE forest practice rules also require approvals for the removal and disposal of trees. Vegetation management activities must also comply with endangered species and fish and game restrictions, which may trigger permitting requirements, as well as restrict when, where, or how the work may be performed (e.g., not during nesting season). Work on federal lands also require permits for tree removal, VM work, or land rights that predate federal ownership of the land.

PG&E's land and environmental management and customer care teams work closely with PG&E's vegetation management team to overcome these challenges as quickly as possible. They coordinate and plan the work in order to reach out to landowners, communities, and local governments to address concerns in advance of the proposed vegetation management activities. They also coordinate with local, state, and federal agencies to obtain necessary permits and conditions. PG&E tries to reach mutually agreeable results with concerned parties, but doing so regularly causes delays and sometimes PG&E must seek court orders. It could be helpful if the CPUC or state legislature addressed these constraints. For example, if the legislature extended PRC Section 4295.5 to also authorize utility tree workers to trim or remove trees or clarified the definition of a "conversion" in the forest practice rules to clearly exclude maintenance of a utility right of way, it could significantly improve the ability to execute vegetation management work. Likewise, legislative action could restrict the discretionary terms attached to encroachment permits.

4.4.6. Community and Environmental Impacts

Vegetation management work in general**,** and the EVM work in particular, has an impact on the communities and properties where work is identified. PG&E proactively communicates to and partners with land owners, government agencies and community organizations on the work we are planning along powerline corridors. As discussed above in Section 4.4.5, communications may result in delays to address concerns or permit requirements. But through this communication**,** opportunities also arise for communities or agencies to leverage the work PG&E is doing to support or enhance community specific plans or efforts. In addition, for the past several years PG&E has provided grant funding to community organizations (generally Fire Safe Councils) to support them in performing community wildfire risk mitigation efforts, like fuel break creation or fuel cleanup efforts, that may not be adjacent to PG&E powerlines and therefore outside of the scope of PG&E's vegetation management programs.

The performance of vegetation management work could create environmental impacts, which PG&E is careful to monitor and manage. For example, PG&E VM contractors are trained on Best Management Practices and Avoidance and Minimization Measures to manage erosion, prevent impacts to sensitive environmental resources (e.g., bird nests, sensitive species and habitats) and protect waterways. Similarly, changing the ecosystem of a stand of trees can create new risks, like exposing a previously protected tree to increased sunlight or wind, that the utility arborists performing PG&E's vegetation management work are conscious of and on the lookout for. Trees that exhibit risk factors (like poor taper) that could be a risk after adjacent tree work is performed may be proactively identified for treatment (trimming or removal). Finally, as described above, all HFTD portions of PG&E's powerline corridors are re-inspected at least twice per year, allowing for the ongoing monitoring of any changes or growth patterns that may have been influenced by previous tree work.

4.5. Enhanced Situational Awareness and Known Local Conditions

TABLE 16: ENHANCED SITUATIONAL AWARENESS AND KNOWN LOCAL CONDITIONS KEY

Section	Section	Program Mapping	New or Existing, Including and Recovery Vehicle	Regulation Compliance	Associated Drivers
4.5.1	Meteorological Operations and Advanced Situational Awareness	Advanced Weather Forecasting	New – FRMMA/WPMA	Exceeds regulatory requirements	All
4.5.2	Fire Spread Modeling	Satellite Fire Detection System	New – FRMMA/WPMA	Exceeds regulatory requirements	All
4.5.3	Weather Stations	Expanded Weather Station Deployment	New – FRMMA/WPMA	Exceeds regulatory requirements	All
4.5.4	Camera Deployment Strategy	Wildfire Cameras	New – FRMMA/WPMA	Exceeds regulatory requirements	All

TABLE 16: ENHANCED SITUATIONAL AWARENESS AND KNOWN LOCAL CONDITIONS KEY (CONTINUED)

Section	Section	Program Mapping	New or Existing, Including and Recovery Vehicle	Regulation Compliance	Associated Drivers
4.5.5	Satellite Fire Detection Systems	Satellite Fire Detection System	New – FRMMA/WPMA	Exceeds regulatory requirements	All
4.5.6	Storm Outage Prediction Model (SOPP)	SOPP Model Automation	New – FRMMA/WPMA	Exceeds regulatory requirements	All
4.5.7	Wildfire Safety Operations Center (WSOC)	Wildfire Safety Operations Center	New – FRMMA/WPMA	Exceeds regulatory requirements	All

PG&E's Enhanced Situational Awareness and Known Local Conditions program was created to actively monitor and/or model potential wildfire occurrences and improve timeliness and response efforts, should an ignition occur. This program plays a key role in PG&E's PSPS program, as well as informing the Wildfire Recloser Disable Program and emergency response efforts. This program includes:

- Installing new weather stations at a density of one station roughly every 20 circuit miles in HFTD areas within PG&E's service area to provide detailed information about temperature, wind speeds and humidity levels. Data from these new stations will provide improved awareness of current fire danger conditions.

- Installing of a network of high-definition cameras that, when complete, will allow PG&E and fire agencies to monitor over 90 percent of PG&E's HFTD areas.

- Working with fire detection algorithm developers at the University of Wisconsin - Madison Space Science and Engineering Center to develop a next generation wildfire detection and alert system that uses satellite imagery to detect wildfires.

- Enhancing PG&E's existing SOPP to incorporate data from new weather stations and new modeling criteria in order to build advanced fire modelling capabilities into PG&E's existing meteorological models.

These new models will help provide advanced warning when weather changes indicate an increase in fire danger and will help PG&E make decisions about when to initiate operational risk reduction measures such as PSPS and the Wildfire Reclosing Disable Program.

In this section of the Plan, PG&E describes: (1) meteorological operations and advanced situational awareness; (2) fire spread modeling; (3) weather stations; (4) PG&E's camera deployment strategy; (5) PG&E's satellite fire detection system; (6) storm outage prediction modeling; and (7) the Wildfire Safety Operations Center or "WSOC."

4.5.1. Meteorological Operations and Advanced Situational Awareness

PG&E's Meteorology team continues to develop new techniques for forecasting fire danger as well as new tools to aid in providing real-time situational awareness during high fire danger conditions. PG&E utilizes state-of-the-art weather forecast model data and information from several public and propriety sources (e.g., the NWS, European Center for Medium Range Forecasting, Global Forecasting System) and from PG&E's proprietary in-house mesoscale forecast model, POMMS, to generate short and medium-term fire danger forecasts across the service area.

The POMMS is a high-resolution weather forecasting model that forecasts important fire weather parameters including wind speed, temperature, relative humidity, and precipitation down to 3-km resolution. Outputs from the POMMS model are then used in the National Fire Danger Rating System and the Nelson Dead Fuel Moisture (DFM) model to derive key fire danger indicators such as DFM, Burning Index, Energy Release Component and Ignition Component. These components are then scaled to produce fire danger ratings, the FPI, for operational use. The FPI is derived daily for 91 FIAs covering the HFTD areas within the PG&E service territory.

In late 2017, it became evident a more granular and real-time fire danger rating system would be needed for understanding and awareness of extreme events. PG&E's Meteorology team, with guidance from fire experts from SDG&E, and SJSU's Fire

Weather Research Lab, developed an enhanced version of the FPI to function as a real-time tool leveraging weather station observations. Several benchmarking sessions with SDG&E were conducted during FPI development. PG&E's Meteorology team plans to utilize a newly completed 30-year model reanalysis (climatology) across the entire PG&E territory along with historical fire occurrence to calibrate and scale this enhanced FPI as well as utilize it in forecast mode.

PG&E plans to further test and make any identified improvements to the POMMS modeling system in 2019 and beyond using High Performance Compute capabilities. Improvements including potentially altering the model configuration or increasing the resolution from 3-km to 2-km if model accuracy can be improved.

Each day, the FPI as well as Red Flag Warnings or Fire Weather Watches from the NWS determine fire danger ratings across the PG&E service area. Operational decisions to reduce the fire ignition risk go into effect each day there is a fire danger rating of "Very High," "Extreme," or "Extreme-Plus", a threshold selected, based upon historical-risk analysis. Daily emails are sent to impacted internal organizations including Electric Operations, Customer Care, Community Affairs, Government Relations, and others, which detail fire danger conditions; fire conditions are also discussed in a daily Electric Operations call.

Extended forecasts that cover a three- to seven-day forecast period are also provided daily to identify upcoming periods of heightened fire weather risk for advanced preparation. The updates provide information about offshore wind events, extreme hot and dry conditions, and dry lightning potential. This information, combined with weekly forecasts from the National Interagency Fire Center – Predictive Services for Northern California (ONCC) and Southern California (OSCC), give advanced warning about significant fire danger.

Lightning strikes cause thousands of fires each year across the United States. PG&E's operational Lightning Detection Network monitors cloud to ground lighting strikes in near real-time. Cloud to ground lightning strikes are recorded at ground

stations across the PG&E service area and are available and displayed in PG&E's geographic information systems. The PG&E Lightning Detection Network also sends email alerts of new lightning strikes to assist with monitoring of real-time events.

4.5.2. Fire Spread Modeling

PG&E also plans to deploy advanced fire spread modeling technology that produces hourly fire spread risk scores for circuits in HFTD areas. The technology to be deployed was chosen after benchmarking sessions with SDG&E. The system will run hundreds of million fire spread simulations daily for all PG&E overhead lines in and adjacent to HFTD areas. The main purpose of the fire spread modeling is to understand the total risk profile in the PG&E territory as well as the highest risk circuits or zones hour by hour for asset related fires of high consequence. The key piece of data is the probability of there being a fire of high consequence generated from any ignition point along Transmission and Distribution (T&D) lines in HFTD areas. The weather inputs utilized in each fire simulation will come from PG&E's POMMS weather model. Asset-based fire spread risk scores for areas potentially impacted by PSPS and circuits will be used to maintain situational awareness and used as an additional factor in considering de-energization. A methodology will be established to combine the fire spread risk score with existing systems for tracking and scaling the overall fire danger and the potential for ignition, specific to FPI and the SOPP model. The system will also be available to be run in real-time for specific existing fires to understand the predicted spread, which will inform public and employee safety, along with emergency management and response efforts.

4.5.3. Weather Stations

Data from weather stations installed in PG&E's service area will be used to help forecast and monitor for high fire-risk weather conditions to help inform implementation of additional measures such as PSPS. Data from these weather stations will also be used to validate model forecasts as discussed above.

PG&E operates more than 200 weather stations within its service area to obtain local weather data in real-time and these data are publicly available through the NWS. This data is utilized to assess current fire danger conditions to facilitate operational decision making and support safe operation of facilities. PG&E plans to deploy an additional 400 weather stations by September 1, 2019, doubling the installation pace from 2018.[61] In the 2020 GRC PG&E forecasted installing approximately 1,300 weather stations in total within five years. Ultimately, PG&E may deploy more than or less than 1,300 stations as it continues to study and learn from these efforts, but 1,300 stations installed by 2022 is the best estimate at this time. It would take years to perform research and modeling to determine the optimum density of weather stations that would provide PG&E with clear knowledge of local conditions in its service territory. In the meantime, PG&E exercised judgment, considering knowledge of its service territory and other utility practices such as those of SDG&E, to decide the density of weather stations to install at this time, which will provide PG&E with sufficiently granular knowledge of local conditions to appropriately guide its wildfire risk reduction measures. The data collected from these stations are made publicly available in near-real time to benefit the public, federal, state, and local agencies.

4.5.4. Camera Deployment Strategy

Wildfire cameras are used by CAL FIRE, Cal OES, and PG&E to identify, confirm, and track wildfires. This allows firefighting agencies to be alerted quickly and to deploy resources directly to the areas where they can have the greatest impact. In 2018, PG&E piloted the installation of nine new cameras in HFTD areas to monitor for fires. In 2019, PG&E plans to install approximately 70 more high-definition cameras to increase PG&E and first responders' situational awareness in HFTD areas in PG&E's service territory. PG&E's goal is to establish roughly 90 percent coverage across these high fire-risk areas by 2022, which may require the installations of approximately

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61 Since PG&E filed the 2020 GRC, PG&E has accelerated installation plans and doubled the number of weather stations it plans to install in 2019.

600 cameras. The high-definition, pan-tilt-zoom cameras will improve PG&E's overall situational awareness and be a valuable tool for assisting the WSOC, first responders, and fire agencies. The cameras currently planned for installation have near infrared capability and a web interface with time lapse functionality to assist with confirmation of fire reports, and monitoring fire progression and environmental conditions. First responders can control the cameras and use the live feeds to quickly confirm, locate, and respond to fires, and to provide that the right resources go to the right area.

4.5.5. Satellite Fire Detection System

PG&E's Meteorology team has deployed a beta version of a state-of-the-art satellite-based fire detection and alerting system and will make this system fully operational before the 2019 fire season. This system leverages fire detection data from the GOES-R series of satellites, as well as polar orbiting satellites MODIS and VIIRS. This system also has the capability to incorporate new fire detection data feeds as they become available. PG&E is working directly with fire detection algorithm developers with the Space Science and Engineering Center at the University of Wisconsin-Madison to procure a customized feed of satellite fire detection data with the lowest latency available. A PG&E-developed web application, modeled on SDG&E's program, displays fire detections as they become available and a customized algorithm monitors incoming fire detections and produces alerts when a new fire is detected. Fire propagation can be monitored as the data refreshes (GOES-R series satellites provide data across the U.S. every 5 minutes and every 1 minute in local areas). This tool will help PG&E react to new and emerging events quickly and make faster operational decisions. Once the system detects a new fire, PG&E plans to initiate fire spread simulations to understand the potential spread of the fire over the next 6 to 24 hours. The fire spread model will be coupled with PG&E's in-house weather model and fuel moisture models, which are discussed above.

4.5.6. Storm Outage Prediction Model

Unplanned outages can pose a fire ignition risk when surface fuels are extremely

dry. When strong winds and dry conditions are present, the risk of fast spreading and catastrophic wildfire increases. The SOPP, a storm damage prediction system developed, maintained, and operated by the Meteorology team on behalf of Electric Emergency Management, is the primary tool PG&E uses to reduce operational risk from adverse weather events that create a high volume of unplanned outages.

Functionally, the SOPP model is a collection of tools and techniques that are employed to predict unplanned outage activity. In its current form, the SOPP model relies heavily on an experienced meteorologist forecaster. PG&E will upgrade and automate the SOPP model to allow for less reliance on the forecaster and greater ability to provide more granular and frequent outage forecasts to support wildfire risk reduction. The result will be an objective weather risk dashboard, which can be updated in near real-time.

4.5.7. Wildfire Safety Operations Center

PG&E's WSOC is a physical facility that serves as the central wildfire-related information hub for PG&E, and monitors, assesses, and directs specific wildfire prevention and response efforts throughout its service area. The WSOC interfaces and collaborates with all lines of business (LOB) and CWSP departments to assist in the deployment of technology, processes and procedures directly related to wildfire prevention, response, and recovery. The WSOC develops the procedures for the WSOC Analyst and Duty Officers to effectively implement or deploy those technologies and resources. The WSOC also coordinates with PG&E's Public Safety Specialist team, which interfaces with CAL FIRE incident commanders and other AHJ incident commanders to oversee the organizational response to wildfire threats and incidents. The WSOC was established in 2018, and its functionality will continue to grow and evolve as situational awareness capabilities expand.

The WSOC monitors for fire ignitions across PG&E's service area in real time, leveraging PG&E weather stations, wildfire camera data, and publicly available weather information, as well as first responder and local and state data. Information also comes

into the WSOC from PG&E field personnel, including Public Safety Specialists and field observers. The WSOC deploys Public Safety Specialists to investigate reported wildfires to gather more incident specific information and report back to the WSOC. Based on incident specific information, the WSOC may create an incident report, which includes wildfire information, PG&E assets threatened or involved, current red flag status, and fire weather information. The WSOC will send the report to a pre-determined distribution list including field staff, control center personnel, executive staff, supporting LOBs and other PG&E emergency responders.

4.6. Public Safety Power Shutoff Program

TABLE 17: PUBLIC SAFETY POWER SHUTOFF PROGRAM KEY

Section	Title	Mapping	New or Existing, including cost recovery vehicle	Regulation Compliance	Associated Drivers
4.6.1	PSPS Decision Factors	Public Safety Power Shutoff	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL
4.6.2.	Strategies to Enhance PSPS Efficiency While Reducing Associated Impacts	Public Safety Power Shutoff	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL
4.6.2.1	Impact Mitigation Through System Sectionalizing	Granular Sectionalizing	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL
4.6.2.2	Resilience Zones	Resilience Zones	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL
4.6.2.3	Customer Services and Programs	Public Safety Power Shutoff	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL
4.6.3	PSPS Notification Strategies	Public Safety Power Shutoff	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL

TABLE 17: PUBLIC SAFETY POWER SHUTOFF PROGRAM KEY (CONTINUED)

Section	Title	Mapping	New or Existing, including cost recovery vehicle	Regulation Compliance	Associated Drivers
4.6.3.1	Customer and Community Outreach	Public Safety Power Shutoff	New – FRMMA/WPMA	Exceeds Regulatory Requirements	ALL
4.6.3.2	Mitigating PSPS Impacts on First Responders, Healthcare Facilities, Telecommunication, and Water Utilities				
4.6.4	Re-energization Strategy				

A Public Safety Power Shutoff or "PSPS" is utilized by PG&E in accordance with Commission Resolution ESRB-8 "to protect public safety."[62] PG&E has developed and is continuing to refine tools and processes to identify applicable conditions, communicate possible impacts, and execute PSPS events. In developing the PSPS program, PG&E performed extensive benchmarking with SDG&E (the domestic utility with the longest history in pro-actively shutting power off to avoid wildfire events) in a variety of areas, including meteorology, operational processes, emergency response, restoration, communications and customer support.

PG&E modeled its PSPS processes and technologies on SDG&E's, as PG&E understands them, to learn from their eight years of experience in this area. Particularly, PG&E emulated SDG&E's methodology for deciding whether to initiate a PSPS event, its PSPS execution decision factors, its early stakeholder communication strategy (including with customers), its method to determine readiness for post-event patrols, and its method to verify the safety of overhead facilities before re-energization. PG&E also leverages a FPI modeled similarly to that of SDG&E, to identify higher-risk lines in correlation with applicable conditions. To further follow with SDG&E's decision

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62 See Resolution Extending De-Energization Reasonableness Notification, Mitigation and Reporting Requirements in D.12-04-024 to all Electric IOUs.

factors, PG&E is implementing several key enhancements in 2019, including increased density of weather stations, improved base meteorological modeling, and an enhanced FPI. PG&E is also engaging with the same company that developed an advanced fire ignition spread model for SDG&E to develop a fire ignition spread model tailored to PG&E's service area to help focus PSPS on the areas of highest risk.

While employing SDG&E's best practices, PG&E developed the PSPS program to fit the attributes of PG&E's service territory. Specifically, PG&E has adapted SDG&E's method to identify decision factors to apply to the unique conditions of PG&E's service area. For example, PG&E has a higher history of vegetation-caused outages than SDG&E due to the density of vegetation in Northern California and the higher circuit miles of overhead conductor. For this reason, PG&E may de-energize at lower wind speeds than SDG&E.

PG&E is focused on maturing this program to most effectively eliminate potential ignitions during extreme weather conditions. In 2019, lines considered for potential PSPS events will include all distribution and transmission lines at all voltages (500 kV and below) that traverse Tier 2 or Tier 3 HFTD areas. In comparison, lines considered for potential PSPS events in 2018 included all distribution lines and transmissions lines at 70 kV or below that crossed Tier 3 HFTD areas. This expansion of the PSPS Program increases the targeted distribution lines from approximately 7,000 circuit miles to approximately 25,200 circuit miles and the targeted transmission lines from approximately 370 circuit miles to approximately 5,500 circuit miles.

As PG&E expands PSPS to higher voltage lines within HFTD areas, it is developing a risk-based process, or Operability Assessments (OA), to assess the wildfire risk of individual transmission lines and structures. Through these OA, initially applied to transmission lines, PG&E will apply a risk-informed methodology to evaluate the potential risks of the line and impacts from de-energization. This risk-informed methodology will guide PSPS decisions, allowing PG&E to de-energize specific, targeted transmission lines to reduce wildfire risk and avoid indiscriminate

de-energization of transmission lines. This will facilitate compliance with federal reliability and operational requirements (e.g., North American Electric Reliability Corporation Reliability Standards, California Independent System Operator Corporation Tariff requirements) and limit wide-area grid reliability risk, while still reducing wildfire risk.

On December 13, 2018, the CPUC opened a rulemaking to examine utility use of de-energization, R.18-12-005. The CPUC acknowledged the relationship between that proceeding and the proceeding overseeing the implementation of SB 901 Wildfire Mitigation Plans (R.18-10-007). The CPUC recognized that Resolution ESRB-8 will remain in effect during the pendency of R.18-12-005 and stated that a detailed examination of de-energization will take place outside of the Wildfire Mitigation Plan Proceeding. Should the outcome of the Commission's separate but related de-energization proceeding direct PG&E to make changes to its PSPS Program, future plans will be revised accordingly.

In the remainder of this section, PG&E describes its: (1) PSPS decision factors; (2) strategies to enhance PSPS efficiency while reducing associated impacts; (3) PSPS notification strategy; and (4) re-energization strategy.

4.6.1. PSPS Decision Factors

No singular factor ultimately determines a PSPS decision. PG&E carefully reviews a combination of several factors when determining if power must be turned off for safety. These include:

- A Red Flag Warning declared by the NWS;
- Low humidity levels, generally 20 percent and below;
- Forecasted sustained winds generally above 25 miles per hour (mph) and wind gusts in excess of approximately 45 mph, depending on location and site-specific conditions such as temperature, terrain and local climate;

- Computer simulated ignition spread and consequence modeling based on current conditions;[63]
- Condition of dry fuel on the ground and live vegetation (moisture content); and
- On-the-ground, real-time wildfire related information from PG&E's WSOC and field observations from PG&E field crews.

Generally, the first trigger for a potential PSPS event is a forecast of fire danger and high wind conditions by PG&E's Meteorology team. With the enhanced situational awareness from increased weather stations, and advanced modelling, PG&E's Meteorology team predicts conditions specific to local geographic areas. Once PG&E's Meteorology team has issued these forecasts, PG&E activates its Emergency Operations Center (EOC), with a designated Officer in Charge. Under the EOC structure, PG&E Planning and Intelligence, Operations, and other ICS teams continually monitor the latest weather forecasts as well as local conditions in areas forecasted for Extreme-Plus conditions. These teams continuously update the Officer in Charge of the real-time status of the factors listed above. While these conditions continue, the Officer in Charge will evaluate whether to call for a PSPS, based on these inputs. The foregoing describes PG&E's 2018 process, and we are continuing to evaluate our criteria to remove as much subjectivity from the decision-making as practical, but there is no singular algorithm that exists today that yields an objective result.

4.6.2. Strategies to Enhance PSPS Efficiency While Reducing Associated Impacts

4.6.2.1. Impact Mitigation Through System Sectionalizing

PG&E will continue upgrading devices with SCADA capability in targeted portions of the HFTD areas to help minimize the impact of PSPS events on customers in low-risk areas adjacent to the HFTD areas. These upgrades will include adding or replacing existing manually operated fuses and switches at strategic locations with new SCADA-enabled Fusesavers™, switches, or reclosers. By isolating the lines closer to

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63 This decision factor is being developed for use in 2019. PG&E previously had only ignition spread modeling based on historic climatology.

the border of the HFTD, fewer customers will be impacted and fewer lines will be de-energized. These improvements will also expedite restoration by reducing the amount of lines requiring a patrol.

4.6.2.2. Resilience Zones

PG&E uses the term “Resilience Zones” to describe projects that will allow PG&E to safely provide electricity to central community resources when PSPS is activated during Extreme-Plus conditions. Customers near Resilience Zones will benefit from the ability to access services such as grocery stores and gas stations while the wider grid is de-energized for safety. Host sites for Resilience Zones are selected in full coordination with the System Hardening Program for safe operation. Resilience Zones are still in a pilot phase, which will inform and dictate how the program should evolve in the future to better serve the needs of our customers.

Resilience Zones are enabled by pre-configured segments of the distribution system that can be quickly isolated from the broader grid when a PSPS is initiated. Using pre-installed interconnection hubs (PIH), PG&E will be able to quickly and safely connect temporary mobile generation to energize the isolated Resilience Zone. Generally, PIHs will consist of a transformer and associated interconnection equipment, ground grid, and grid isolation and protection devices (reclosers and switches). Resilience Zone PIHs may evolve into Resilience Zone Microgrids over time, as preferred resource combinations begin to meet technical requirements, and as PG&E’s capability to operate these systems matures. See Section 4.7.3 for more information on microgrids.

PG&E’s pilot Resilience Zone will operate as needed during 2019’s wildfire season in Angwin, a town situated within the Tier 3 HFTD area in Napa County (Fire Index Area 175). PG&E is working with Pacific Union College to align the operation of the Resilience Zone with the college’s privately-owned cogeneration plant to collaboratively increase resilience for the town of Angwin. Should Extreme-Plus conditions occur, the presence of the Resilience Zone will allow PG&E to safely

energize facilities such as the fire station, gas station, Brookside Apartments, and portions of the Angwin Plaza not already served by the local college's on-campus generation.

PG&E plans on expanding the Resilience Zone workstream for other towns that may be impacted by PSPS. The geographic scope of a potential Resilience Zone will depend on a range of factors including the current grid configuration and safety to energize during Extreme-Plus conditions. Resilience Zones will only be built in areas that meet the following criteria:

- Targeted sectionalizing in the area is not feasible due to grid configuration or other reasons; and
- The area has a sufficiently large hardscape and/or has been sufficiently de-risked of ignition danger through system hardening measures that a temporary mobile generator can safely run during Extreme-Plus conditions.

4.6.2.3. Customer Services and Programs

PG&E's first and most critical objective is to maintain safe grid power to as many customers as possible during potential PSPS events. This objective is achieved through a variety of strategic initiatives and programs as described throughout this Plan. PG&E acknowledges, however, that some customers will lose power during these events, and that it has a role to play in supporting our customers by providing services and programs to help alleviate the safety, financial, and disruptive impacts losing power can cause our customers.

Extending and Expanding 2018 Programs into 2019

PG&E currently offers several services and programs to our customers that can assist before, during and after an emergency including a PSPS event. These programs were available during the 2018 Wildfire season and will continue in 2019. These programs apply broadly to all types of customers and include:

- Proactive Communications: Respecting our customer's right to choose how they want to receive communications from PG&E, we provide a number of communication options, including: orchestrated proactive

notifications via text, email, interactive voice recording, and phone. However, during a PSPS event, PG&E leverages all communication channels to contact customers given the safety implications and potential disruption to their daily schedule. PG&E's electric customer base of 5.4 million premises could potentially be contacted if there is a valid phone number on file.

- 24/7 Information and Updates: PG&E's website provides customers with convenience and flexibility by allowing them to educate themselves on a variety of topics associated with wildfire preparedness. While customers can quickly identify areas impacted by weather or emergency events on the PG&E website, PG&E will also work closely with external media outlets to provide broader awareness, critical insight and capture crowdsourced feedback—all of which promotes more effective communication. In 2018, 2,380,153 customers visited pages related to outages and wildfire safety and preparedness.

- Experienced and Knowledgeable Business Teams: PG&E supports the unique needs of our largest industrial, commercial and agricultural customers with a dedicated team of over 60 account managers handling over 3,500 business customers. In addition to providing updates before, during and after an emergency, the account management team is available to work with critical customers to develop operational plans to prepare for an emergency. This team is assigned based on industry segments allowing for knowledge sharing of best practices and procedures.

- Live Customer Support: PG&E operates four contact centers in the state of California and provides 24/7 emergency live-agent service for customers to report emergencies. Our IBEW Contact Center agents are trained in how to handle customers dealing with natural gas and electric emergencies with specific procedures to escalate life-threatening situations. In 2018, our customer service agents handled

over 448,000 customer calls related to emergencies with an average speed of answer of 8 seconds.

- Mobile Neighborhood Answer Centers: PG&E maintains a local presence in our communities with the deployment of mobile answer centers to support customers during emergencies providing information on service restoration. Mobile answer centers provide a local alternative to live customer support over the phone, in pop-up locations throughout areas where the highest level of impacted customers reside.

- Customer Financial Relief: PG&E acknowledges the financial burden that customers may bear when impacted by an emergency. Over the years PG&E has developed a portfolio of financial solutions for our customers to provide immediate relief from worrying about their utility bill. PG&E offers financial support based on several factors and includes bill adjustments, extended payment plans, suspension of fees and low-income support for customers impacted by emergencies. This is further discussed in Section 5.2 of this Plan. In 2018, PG&E provided over $4.7 million in financial relief to customers impacted by wildfires in 2017/2018.

- Personalized Service for Impacted Customers: PG&E provides a single point of contact for severely impacted wildfire customers to help assist with post fire details. This includes billing, claims, service planning, permitting, etc. This knowledgeable team of experienced and dedicated representatives can support a wide variety of customers or quickly route the customer to those who can assist. This team is currently slated to provide support to over 14,000 residential electric service points and 970 commercial electric service points.

Proposed New Initiatives for 2019 and Beyond

Given the anticipation that PSPS events will become more frequent due to extreme weather events, PG&E is actively exploring and developing additional services

and programs to support our customers during PSPS events. The Company is investigating a wide variety of solutions including commercially available products, partnerships with key community organizations, and services aimed to help our most vulnerable customers/communities.

PG&E's primary focus in the short term will be for those customers who require a continuous electric supply for life support, as well as critical services (i.e., telecom, water agencies, hospitals, and first responders) who provide life support services to our communities. PG&E will work closely with County OES to share information related to our most vulnerable customers to support local first responders in providing important local services to these customers during a PSPS event. PG&E will also continue to provide live customer support for critical services to provide real time updates and information regarding PSPS event impacts, duration, and restoration status.

Below is a list of the types of new programs PG&E is exploring:

- OEM & Retail Partnerships: Utilizing the existing back-up generation marketplace, PG&E would partner with major retailers and equipment suppliers to support onsite back-up generation systems that can provide continuous power during a PSPS event. PG&E would neither own nor operate this equipment, instead helping to facilitate the awareness and benefits an onsite system would provide during an emergency event. With the primary objective to aid in the streamlining of implementing a system that best supports the customer's overall choice and control of managing their energy/emergency needs.

- Collaborative Community Support: In coordination and partnership with local OES and other critical members of the community, community-based solutions would include initiatives such as "Enhanced Cooling Centers" to provide additional services to medical baseline, life support, and our most vulnerable customers. This collaborative effort comprised of community-based organizations, local stakeholders, and first responders would be designed to provide a safe, energized location for those most in need. Included would be the ability to support the

transportation of vulnerable residential customers to and from these centers.

- Grant Program: Partner and engage community-based organizations to develop a grant program to meet the needs of our most vulnerable customers.

- Continuous Power Programs: Continuing the education and support of commercially available options for Business customers (i.e., small business, mid-markets and large enterprise). Utilizing existing non-tariffed and account management channels to customize products and programs based on unique customer operating requirements.

- Partnership With Critical Services: PG&E will build on how it provides live customer support for critical services (i.e., telecom, water agencies, hospitals, and first responders); to provide timely updates and information regarding PSPS event impacts, duration, and restoration status.

- Coordination With Third-Party Commodity Suppliers: As more customers in PG&E territory purchase their gas or electric commodity from a supplier other than PG&E, we recognize the importance of providing Community Choice Aggregation (CCA) programs and Direct Access (DA) providers in our territory timely and relevant updates relating to PSPS events and Wildfire Relief efforts. Prior to PSPS events PG&E notifies CCA and DA providers of the potential PSPS event and the timing of prospective event. As the event gets closer, PG&E continues to provide updates to our CCA and DA partners that may impact our joint customers, including potential impacted customer lists, talking points and any timing changes that may occur. During the PSPS event PG&E CCA Account Managers provide daily updates to the CCA programs on timing, customer status and answer any questions or concerns the CCA brings up that come from our shared customers. As the metering and billing agent for many third-party suppliers, PG&E has worked closely with our partners to administer bill relief for severely impacted customers. PG&E

coordinates regular calls and provides data to third-party suppliers during and after emergency situations. In 2018, PG&E worked with over 50 third-party suppliers representing over 2 million customers.

PG&E will continuously refine and further develop strategies that minimize the extent of disruption of grid power, while enabling increased customer choice and control over safely managing energy needs during an emergency.

4.6.3. PSPS Notification Strategies

Recognizing that de-energization for public safety can burden communities with unintended risks and hardships, PG&E is committed to providing notice to government agencies and providers of critical services when extreme fire danger is forecasted, as well as continuing to refine its PSPS program to reduce the scope and severity of impact on customers.

PG&E will notify its primary government and agency contacts that PG&E is monitoring conditions and that extreme fire danger conditions may cause power outages or require PG&E to shut off power for safety in the coming days. For cities, counties and local agencies, PG&E will use a platform which can send the same message to a list of contacts through multiple channels including phone, text and email. Upon request, PG&E will provide city, county and agency officials with the content of its customer alerts, so they can be shared on channels such as Nixle, Nextdoor, and Reverse 911.

If a PSPS event is forecasted, PG&E will also attempt to send notifications to all potentially impacted customers when and where possible, before, during and after a PSPS event. Notifications will be made through various channels including IVR, text and/or email. When and where possible, PG&E will attempt to notify critical facilities such as hospitals, emergency centers, fire departments, water plants, water utilities/ agencies, schools, and telecommunications providers (critical facilities) in advance of residential customers before an event occurs to help inform their preparedness efforts. During an event, frequent communication via live call outs with detailed event information will be provided to critical facilities to support operational needs if possible.

After an event, PG&E will prioritize critical facilities during restoration when and where technically possible. PG&E will do additional outreach to Medical Baseline and Medical Baseline-eligible customers so that PG&E has their contact information and they know how to prepare. If general notifications (IVR, text and email) are unsuccessful, PG&E will deploy personnel for an in-person notification.

4.6.3.1. Customer and Community Outreach

PG&E has performed significant community outreach to customers and first responders relating to PSPS events to enhance its ability to notify customers if a PSPS event is forecasted and help communities prepare for such events. In 2018, PG&E focused the first year of the program on making sure that the more than 570,000 homes and businesses served by lines in extreme fire-threat areas were aware of possible public safety outages and could take steps to prepare. In 2018, PG&E:

- Reached out to homes and businesses served by lines in extreme fire-threat areas through letters, postcards and emails to share information and help them prepare;
- Held over 450 meetings with community stakeholders (many of which were attended by a member of PG&E's senior leadership team) to talk about wildfire safety efforts and coordination;
- Hosted more than 20 regional informational workshops and open houses as well as additional public meetings and answer centers in key communities on CWSP and PSPS;
- Conducted direct outreach to customers who provide critical services such as hospitals, fire stations, water agencies and telecommunications providers that could be affected by a PSPS event;
- Reached out directly through mail, emails and automated calls to the 19,000 customers who are enrolled in our Medical Baseline Program, as well as direct outreach during the October PSPS event and potential PSPS event in November;

- Conducted outreach to master meter customers about PSPS and provided flyers to share with tenants to raise awareness and help them prepare for possible outages;

- Launched a dedicated website (pge.com/wildfiresafety) and created a search tool where customers can enter their address and learn if they are served by a line that may be turned off for safety during high wildfire threats;

- Continued earned, paid and digital media campaign to raise awareness about CWSP and PSPS and how customers can prepare;

- PG&E's VP of Electric Operations participated in the CPUC's December 2018 Public Safety Power Shutoffs Workshop;

- Communicated and coordinated closely with CPUC, Cal OES, CAL FIRE, and the Governor's office during the October 2018 PSPS event; and

- Provided ongoing support to local Fire Safe Councils through grants and other partnerships including co-sponsored events.

In 2019, PG&E is expanding and building upon these efforts to continue to help keep its customers and communities safe. PG&E intends to notify its 5.4 million electric customer premises of the potential for PSPS impacts and will continue to reach out to customers who live in or near high-fire threat areas. Information will include what customers can expect to experience in their community as a result of our ongoing and expanded wildfire safety efforts. We will continue to educate about steps customers can take to prepare for extreme weather and possible outages. These efforts include:

- Reaching out to customers served by lines in elevated or extreme fire-threat areas, through postcards, bill inserts and other mailers as well as email and social media;

- Supplementing direct communications with earned and paid media;

- Partnering with organizations who support our most vulnerable customer to explore opportunities to provide additional information and services;
- Ongoing briefings with city and county leaders, community leaders, first responders, local offices of emergency services and other public safety authorities to discuss our wildfire safety efforts and how PG&E can coordinate;
- Continuing to hold answer centers and open houses (where needed and appropriate) to engage with local community members and answer questions about our work;
- Looking at how PG&E can improve our PSPS notification processes and providing emergency services agencies with more detailed information and maps to assist with coordination efforts;
- Working to provide more frequent updates around estimated restoration times to customers and communities during a PSPS event through both direct notifications as well as local news, radio, social media and the pge.com website, when and where possible; and
- Doing additional outreach to Medical Baseline and Medical Baseline-eligible customers so that PG&E has their contact information and they know how to prepare.

4.6.3.2. Mitigating PSPS Impacts on First Responders, Health Care Facilities, Telecommunications, and Water Utilities

PG&E is performing direct outreach to customers who provide critical services, such as hospitals, fire stations, water agencies/water utilities and telecommunications providers to confirm PG&E has accurate contact information on file for notification purposes. Another important aspect of PG&E's direct outreach is the importance of having emergency operational plans in place in event of a PSPS. PG&E is committed to providing as much advance notice (as possible) so that our critical service providers

customers can be prepared to implement their emergency operational plans should a power shut down be necessary. PG&E is also committed to developing additional programs in collaboration with first responders, health care facilities, telecommunications, and water utilities. Pursuant to the ALJ Ruling, PG&E is including as Attachment B to this Plan a list of the entities that PG&E considers critical services for purposes of communications related to a PSPS event.[64]

In addition, as mentioned above, PG&E will prioritize sectionalizing locations in a manner that evaluates the potential regional PSPS frequencies, with the goal to minimize the impact to critical customers in off-target areas.

4.6.4. Re-Energization Strategy

PG&E will only restore power following a PSPS event after confirming that it is safe to do so. Crews will patrol all facilities de-energized during a PSPS event to identify any damage that needs to be repaired before re-energizing. To reduce the outage impact to customers, PG&E will use helicopter patrols in areas where visibility is not limited by vegetation. PG&E assigns a task force consisting of supervisors, crews, troublemen, and inspectors to each circuit or portions of a circuit. This structure enables PG&E to patrol and perform step restoration in alignment with the impacted centralized control centers. Step restoration is when a substation is re-energized, and circuits are subsequently safely energized in segments as patrols continue. Any necessary repairs are conducted while patrols continue to allow for restoration to proceed as efficiently as possible.

4.7. Alternative Technologies

[64] ALJ Ruling, Attachment A at p. 5.

TABLE 18: ALTERNATIVE TECHNOLOGIES KEY

Section	Title	Program Mapping	New or Existing, Including Recovery Vehicle	Regulation Compliance	Associated Drivers
4.7.1	Rapid Earth Fault Current Limiter Pilot Project	Rapid Earth Fault Current Limiter Pilot Project	Existing – EPIC[65]	Exceeds regulatory requirements	Not Applicable
4.7.2	Enhanced Wires Down Detection Project	Enhanced Wires Down Detection Project	New – FRMMA/WPMA	Exceeds regulatory requirements	D1 – D6, D8
4.7.3	Other Advanced Technologies	N/A	N/A	Exceeds regulatory requirements	Not Applicable

PG&E is implementing pilot programs to evaluate alternative technologies that may harden and modernize the electrical system and improve operational capabilities. PG&E is implementing pilot programs to evaluate alternative technologies.

65 Electric Program Investment Charge (EPIC) represents initiatives funded through the CPUC's EPIC research, development, and deployment grants.

4.7.1. Rapid Earth Fault Current Limiter Pilot Project

The Rapid Earth Fault Current Limiter Technology has been shown by the Victoria State Government (Australia) to directly reduce the risk of wildfires for single line to ground faults. PG&E has a demonstration project planned in 2019 to test the capabilities of this technology within PG&E's system. The Rapid Earth Fault Current Limiter technology consists of an inductor installed between the substation transformer neutral and ground and tuned to the line to ground capacitance of the circuits fed off of a distribution substation bank. In effect, this technology moves the neutral to the faulted phase during a fault reducing the potential to ground on that line to effectively zero (less than 250V) which significantly reduces the energy available for the fault.

4.7.2. Enhanced Wires Down Detection Project

PG&E has enabled single-phase SmartMeters™ to send real-time alarms to the Distribution Management System under partial voltage conditions (25-75 percent of nominal voltage). Prior to implementation, SmartMeters™ could only provide real-time alarms for the outage state. For three-wire distribution systems, the partial voltage condition indicates one phase feeding the transformer has low voltage or no voltage. Energized or de-energized wires down will create a low voltage condition on transformers through the mechanism of transformer back feed from the inactive phase to the fault. This enhanced situational awareness can help detect and locate downed distribution lines more quickly to enable faster response. Faster response may not only reduce the amount of time the line is down but may also allow first responders to more quickly extinguish wire down-related ignitions if they occur. PG&E is continuing to develop this solution to extend the enhancement to 3-Phase meters and 4-wire distribution systems.

4.7.3. Other Alternative Technologies

In addition, to the pilot programs, PG&E is researching other possible alternative technologies to determine whether they would be feasible and effective in system hardening. PG&E is evaluating emerging sensor technologies that enable real-time

system monitoring and situational awareness and is advancing the use of primary line sensor fault measurements in combination with CYME Power Engineering software fault calculations to display possible primary fault locations for targeting field patrol and accelerating fault locating. PG&E is also developing analytic and dashboard strategies to produce prioritized and actionable information from the correlation of data from multiple sources (e.g., SCADA, SmartMeter™, primary line sensors, and emerging sensor technologies).

Microgrids also continue to be a point of interest and optionality for both our customers and our internal operations in multiple contexts. The ability to island (to disconnect completely from the centralized grid) at key times can allow for sustained backup generation to critical facilities in communities working to respond and recover from wildfires and other natural disasters. PG&E is continuing to explore various paths to meet customer needs (resilience and other), as well as opportunities to support quicker recovery after a PSPS event is called.

4.8. Post-Incident Recovery, Restoration and Remediation Activities

TABLE 19: POST-INCIDENT RECOVERY, RESTORATION AND REMEDIATION ACTIVITIES KEY

Section	Title	Program Mapping	New or Existing, Including Recovery Vehicle	Regulation Compliance	Associated Drivers
4.8.1	Post-Incident Recovery	Not Applicable	N/A – unknown (fact specific)	Regulatory Compliance	Not Applicable
4.8.2	Restoration	Not Applicable	N/A – unknown (fact specific)	Regulatory Compliance	Not Applicable
4.8.3	Remediation	Not Applicable	N/A – unknown (fact specific)	Regulatory Compliance	Not Applicable

Each disaster has unique facts and circumstances. PG&E's post-incident approach empowers teams to rebuild and recover from a disaster safely, efficiently, effectively, and consistently. PG&E is committed to timely, well-coordinated activities between its Service Planning & Design, Gas and Electric Construction, and External Engagement teams.

Regardless of cause, rebuilding and recovery is required for any fire, flood, or explosion that causes damage of a magnitude that warrants major disaster assistance in repairing damage, mitigating loss, lessening hardship, or to alleviate suffering. Typical impacts of a disaster result in destroyed structures, threatened or crippled critical infrastructure, power outages, and forced evacuations. The intensity of disasters can vary on a case-by-case basis and affect utility customers differently, and for varying amounts of time.

4.8.1. Post-Incident Recovery

In the case of a wildfire, before post-incident assessment can begin, PG&E must secure CAL FIRE clearance to access the impacted area. PG&E line workers, inspectors, and estimators will then conduct a damage assessment of PG&E's electrical and gas infrastructure in the approved locations. The quantity of the personnel and timeline dedicated to this effort will depend on the extent of the damaged territory.

Minor asset corrections may be performed at this time where warranted to meet safety requirements.

The Customer Care team will, where appropriate, stand up mobile Answer Centers at appropriate locations. Information gathered during repopulation and via County OES, local fire, and other means can help inform and prioritize restoration and customers return home. Additional information on Public Outreach During and After Wildfires is provided in Section 5.1.3 of this Plan.

4.8.2. Restoration

PG&E will establish the appropriate level Incident Command Structure (ICS) and allocate resources to support the established restoration priorities following the procedures outlined in PG&E's Company Emergency Response Plan (CERP). PG&E will execute the restoration process, including all main line assets, after troublemen and assessment resources troublemen have identified which customers are safe to restore.

When and where possible, the Customer Care team communicate estimated times of restoration for extended outages. Once service is restored, normal billing and credit operations will resume.

4.8.3. Remediation

Community support and rebuild activities will be determined based on PG&E's analysis of the wildfire impact. PG&E will deploy its Remote Estimating Team to prepare designs, estimates, and job packages for critical infrastructure rebuild. Rebuild designs will be executed in accordance with PG&E's new fire-resilience infrastructure standards and design assumptions will be incorporated based on resilience and hardening plans considered. Critical infrastructure rebuild will be executed in parallel with estimating effort and also in accordance with fire resilience engineering standards. PG&E's line crews will rebuild transmission and distribution lines and supporting infrastructure so that it is operable and energized. The quantity of the crews required will be determined based on the extent of the damage. PG&E will assess longer term infrastructure rebuild requirements and determine recommended rebuild design. At this

time in some cases, PG&E may abate fire affected trees that pose a threat to utility lines and conductors and insulators may be cleaned based on the possibility that fire retardant was dropped on the line and/or particulate matter from the smoke plume could have caused a buildup on the line due to incomplete combustion during the fire.

4.8.3.1. Environmental Remediation – Debris Flow Modeling

A part of PG&E's remediation work is concentrated in the planning and response to debris flow hazards specific to the norther regions recently impacted by wildfire. Debris flows are gravity-driven mixtures of soil and water that are intermediate between floods consisting of water and solid to semi-solid landslides consisting of soil and rock. PG&E recognizes that the recent fires in northern California can result in elevated debris hazard due to the abrupt removal of vegetation that can retard hillside erosion, slow downward accumulation of sediment, and limit surface runoff during large storms. Localized erosion associated with debris flows can expose buried pipelines and can exert high impact forces to above ground structures, including electrical transmission towers, shipyards, natural gas facilities, and access roads.

PG&E's debris flow hazard prediction model integrates PG&E infrastructure, past debris flow datasets, local jurisdictional precipitation data, U.S. Geological Survey model results, and other datasets. The model was created to calculate debris flow thresholds and integrate this within PG&E's precipitation forecasts to rapidly predict the location and severity of debris flows in fire areas prior to major storm events.

The Debris Flow Watch is issued when a heightened state of awareness and monitoring is recommended. Work in areas along the base of steep slopes and drainages within and below fire burn areas should be approached with caution and personnel should at all times be cognizant of the surrounding land conditions and weather changes. Periodic check-ins should be conducted with all field personnel. The Debris Flow Warning is issued when continued monitoring of rainfall throughout this storm event indicates the potential for short-duration, intense precipitation that poses a heightened likelihood for initiation of debris flows within vulnerable slopes. The greatest

likelihood is in heavily burned areas at the base of steep slopes and downstream drainages but could also include areas of moderate slopes and along larger creeks.

PG&E's debris flow susceptibility maps show the relative probabilities for debris flow triggering within individual basins and along drainages with a focus on the orange and red zones of greatest concern. Work and personnel should be restricted at the base of slopes, drainages, and creek banks in the identified areas of concern until the Warning is terminated. Field crews should be specifically prepared to respond to debris flow occurrences in these areas and maintain a heightened state of alert with frequent EOC check-ins to obtain information updates and report observed debris flow activity.

To further improve PG&E's debris flow model estimates specific to the wildfire burn zones in northern California, Geosciences and Emergency Preparedness and Response (EP&R) are augmenting the collection and monitoring of rainfall intensity in the fire burn zones. The installation of rain gauges (using cellular or satellite technology) will improve our capability to monitor high concern areas in remote locations and augment NWS and PG&E Meteorology precipitation radar and local weather station data. This information, combined with systematic field reconnaissance (including visual and LiDAR-based mapping) is part of the program to improve debris flow assessment capabilities in northern California. The purpose of improved monitoring will help establish threshold rainfall intensities for debris flow initiation (currently ¼ inch in 15 min). These types of instruments are ideally suited to record rainfall in environmentally sensitive areas as part of PG&E's wildfire monitoring program as well. Long-term monitoring provides situational awareness of potentially hazardous earth movements during the recovery period.

5. Emergency Preparedness and Response

Pursuant to PUC Section 8386(c)(16) and the ALJ Ruling, this section of the Plan describes PG&E's emergency preparedness and response plan, including plans to prepare for and restore service after a wildfire and community outreach and customer support during and after a wildfire.

5.1. PG&E Company Emergency Response Plan

PG&E's overall emergency preparedness and response plan, filed pursuant to PUC Section 768.6 and GO 166, is referred to as the Company Emergency Response Plan or "CERP." PG&E's CERP and associated annexes, one of which is PG&E's FPP, are important tools to prepare PG&E for emergencies of all types.

PG&E's CERP assists personnel to respond in a safe, efficient, and coordinated manner to an emergency affecting gas or electric generation, distribution, storage, and/or transmission systems within the PG&E service area or the people who work in these systems. The CERP is an "all-hazards" plan that provides a broad outline of PG&E's organizational structure, describes actions undertaken in response to emergency situations, and presents a response structure that has clearly defined roles and responsibilities and identifies coordination efforts with external organizations (e.g., government, media, other gas and electric utilities, essential community services, vendors, public agencies, first responders, and contractors). The CERP consists of a base plan, appendices, and annexes. Annexes are detailed emergency response plans for specific operations, functions, or hazards.

PG&E utilizes common emergency response protocols and follows a recognized ICS. The CERP's all-hazards approach applies to any natural disaster or human-caused situation (e.g., fires, floods, storms, earthquakes, terrorist- or cyber-attacks) that threatens life and property or requires immediate action to protect or restore service or critical business functions to the public.

5.1.1. The Plan's Alignment With CERP

The Plan references PG&E's CERP, including specifically the Fire Prevention Plan. The Fire Prevention Plan is a comprehensive set of plans, procedures, processes, and activities related to the prevention, detection, response to, and recovery from ignitions that, if not suppressed, pose a risk of growing into a wildfire. In addition to employing the CERP in responding to wildfires as discussed below, PG&E maximizes the effectiveness of its CERP by:

- Providing its CERP to appropriate representatives from cities and/or counties within PG&E's service area every two years;
- Conducting meetings with these public agencies to provide an overview of the plan and to receive input;
- Working collaboratively with other utilities, participating in trade association meetings, and conducting benchmarking to identify emergency preparedness best practices;
- Reviewing disasters and emergencies that have affected other utilities, examining remedial actions taken, and incorporating updates to its plan, as needed;
- Preparing an after-action report following an activation of its EOC that identifies whether appropriate corrective actions or modifications need to be made to the CERP and other plans; and,
- Conducting annual corporate-wide exercise relative to our PSPS program and wildfire restoration, followed by a robust "After Action Review" and PMO program.

5.1.2. Plans to Prepare for and Restore Service

To support the development of an overall restoration and resource allocation strategy during a wildfire incident, PG&E uses a Restoration Work Plan tool to forecast the systemwide Estimated Time of Arrival and Estimated Time of Restoration (ETOR).

PG&E created the Restoration Work Plan tool to identify geographic areas that may need more personnel to support restoration efforts. The tool utilizes current and forecasted outage and resource counts to estimate the total time of restoration on systemwide, regional, and divisional levels. Historical assessment and restoration times for the current type of incident and geography drive resource productivity assumptions. By comparing the ETOR across all PG&E divisions, incremental resources can be directed toward those areas that need them most, and the need for mutual assistance crews can also be forecasted.

There are many cases where PG&E crews respond to a fire area and perform asset protection, such as pole pre-treatment, and fuel reduction activities ahead of a fire on and near the power line Right-of-Way (ROW) (with approval of the fire suppression AHJ Incident Commander at the Incident Command Post). Activities include:

- Asset Protection – Conducted with an approved wildland fire chemical applied to the base of the wooden facilities, thus helping to prevent ignition of the power pole from direct flame impingement or radiant heat.

- Vegetation Clearing/Fuel Reduction – VM crews may work ahead of the fire to reduce the fuel in and around the facilities and utility ROW using a variety of vegetation clearing/fuel reduction methods.

- Field Readiness – Field personnel will be made available to work directly with the fire suppression Incident Command to identify potential hazards and to provide a safe area for the public and the personnel working onsite. If the power lines need to be de-energized, the crews will perform the task for the fire control personnel. De-energizing the lines removes the likelihood of contact with an energized (hot) conductor should it come down from a burned power pole or be brought down by a hazardous tree or other conditions.

- Operational Controls – Onsite personnel will also be made available to work with fire suppression Incident Command personnel should a

change in tactics be necessary to protect critical generation, T&D system assets.

Once a wildfire is detected, one or more emergency centers may be activated, or other preparatory actions may be taken. These actions include, but are not limited to: conference calls, placing personnel on alert status, reviewing emergency plans, identifying key personnel available for restoration activities, pre-staging personnel, evaluating supplies and equipment, advising employees to pack overnight bags, and canceling or postponing non-critical meetings.

Each emergency center maintains call-out procedures for adequate staffing levels for any and every emergency. For escalating incidents, each LOB maintains appropriate notification processes, electronic mail and paging lists to notify personnel about the emergency and provide reporting and contact information. Personnel report to pre-designated emergency center locations or to another assigned location within the notified time period appropriate to the incident.

5.1.3. Emergency Communications

Emergencies underscore the need for strong communication with customers and the communities PG&E serves. PG&E's ongoing efforts to connect with customers and keep them informed—especially in a time of crisis— cover a variety of communication channels including, among others, our website, customer contact center, account management team, paid advertising, social media, proactive news stories, customer letters/emails/texts, videos, community meetings, customer answer centers, public notices, factsheets, and handouts.

In local emergencies, it is essential for field personnel to coordinate their activities with local public safety and other first responders to provide for the safe restoration of service. As an emergency grows, the necessity for internal and external coordination also grows. When activated, the EOC becomes the single point of coordination for information dissemination. PG&E provides information in many different languages depending upon the targeted population, including English, Spanish, Chinese, Vietnamese, Korean, Hmong, Tagalog, and Russian. PG&E understands that

information will change rapidly during an emergency and our commitment is to share timely updates with our customers. Below, PG&E provides the specific plans for communications before, during, and after a wildfire.

5.1.3.1. Public Outreach Before Potential Wildfires

PG&E communicates to customers and other stakeholders about efforts to prevent, prepare for, and respond to wildfires, as well as safety measures customers can take to help further reduce the risk of wildfires that might impact their homes, businesses, families, employees, or communities. As part of this outreach, PG&E conducts annual electric safety training for first responders, including law enforcement, fire departments, and public works and transportation agencies. PG&E also participates in annual joint exercises with first responders and emergency management partners to enhance and coordinate prevention and preparedness efforts. PG&E meets annually with local, state, and federal agencies and jurisdictions to share FPPs and strategies.

PG&E shares information with customers about the CWSP and other advice to help them prepare for and stay safe during extreme weather events. As part of this program, PG&E communicates directly about our programs including, among others, Situational Awareness including WSOC, PSPS, EVM, System Hardening, and WSIP efforts through its website, customer contact center, account management team, paid advertising, social media, proactive news stories, customer letters/emails/texts, videos, public notices, fact sheets and handouts.

As part of preparedness efforts, PG&E asks customers to visit pge.com/wildfiresafety to enter their address and find out if their home or business is served by an electric line that may be turned off for safety during high wildfire threats and to update their contact information. PG&E will use this information to alert customers in advance of turning off their electric service for safety, when and where possible, via automated calls, texts and emails. There is also information available on this website to help customers prepare a plan for their home or business.

5.1.3.2. Public Outreach During Wildfires

During a wildfire, PG&E conducts public outreach in a variety of ways. PG&E communicates with customers about safety and response efforts through its website, customer contact center, account management team, paid advertising, social media, proactive news stories, customer letters/emails/texts, videos and by attending community meetings as an incident is occurring to provide the latest information. To coordinate resources, PG&E may activate its EOC (at our headquarters in San Francisco), Regional Emergency Centers, and Operational Emergency Centers.

To assist in restoration and recovery, as appropriate, PG&E will stand up a base camp in impacted areas to mobilize resources and safely assess and restore gas and electric services. A team of highly trained and skilled communications and customer representatives are deployed as part of these mobilized response efforts to respond to questions from customer in affected communities, media requests, and local government inquiries in coordination with the EOC.

5.1.3.3. Public Outreach After Wildfires

Once first responders contain portions of a wildfire, PG&E begins work to safely assess for damage and restore gas and electric service to customers. This requires ongoing communication efforts with customers to provide the most up-to-date information about PG&E's response and recovery efforts.

PG&E communicates with customers about safety and response efforts through our website, customer contact center, account management team, paid advertising, social media, proactive news stories, customer letters/emails/texts, videos and by attending community meetings as an incident is occurring to provide updated information.

PG&E also provides detailed information about what services are available to customers who have been directly impacted by wildfires, ranging from bill relief to waiving certain fees to the rebuilding process and how to renew gas and electric service.

5.1.4. Ensuring Adequate Workforce to Restore Service

During any emergency event, PG&E personnel play a central role in restoring power to customers. Personnel must be organized, assigned, directed, tracked, and otherwise managed throughout the duration of an event, to effectively respond. Each emergency center maintains an emergency staffing plan and call-out procedure for adequate staffing for emergencies. For EOC personnel, the EP&R Director maintains an EOC On-call roster with appropriate contact information for key emergency response personnel and is responsible for issuing the call to activate the EOC.

PG&E's workforce undergoes regular trainings and exercises to provide an understanding of emergency preparedness and response plans and practices, in addition to providing an adequate number of qualified personnel to respond. PG&E also coordinates with other utilities and in trade association meetings on emergency preparedness and response issues and exchanges mutual support in large-scale emergencies.

Training is offered on multiple topics and formats, including on the job, in the form of tailboards, as web-based and instructor-led training courses, and through simulated emergency exercises. There is also annual field personnel training to prepare employees for fire season.

Restoring power after a wildfire is a complex task. A safe and expeditious restoration requires significant logistical expertise along with skilled line workers and specialized equipment. Electric or gas power utilities affected by significant outages will turn to the industry's mutual assistance network—a voluntary partnership of electric and gas companies from across the country—to help speed restoration. Mutual assistance is an essential part of the electric and gas power industry's service restoration process and contingency planning. The mutual assistance network is a cornerstone of electric utility operations during emergencies.[66]

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66 Edison Electric Institute Mutual Assistance http://www.eei.org/issuesandpolicy/electricreliability/mutualassistance/Pages/default.aspx, accessed March 29, 2018.

Different types of mutual assistance include, but are not limited to, utilizing local (utility to utility), in-state (California Utilities Emergency Association), regional (Western Region Mutual Assistance Agreement (MAA)), national (Edison Electric Institute (EEI) and American Gas Association), and specific hazard agreements (EEI's Cyber Mutual Assistance Program) which are established through a MAAs, and/or EEI's Resource Allocation Management Program. PG&E has agreements with other utilities to provide assistance on request by furnishing personnel, equipment, and/or expertise in a specified manner. These mutual assistance agreements: (1) are established prior to any specific incident; (2) follow standardized procedures; and (3) require specific authorizations before crews are provided/or received.

Finally, in addition to mutual aid support, PG&E also relies on contractors to help promptly restore service after a major wildfire event. PG&E has contracts in place to use contract crew and/or equipment resources during incidents where company resources alone are not able to restore our electric distribution and transmission infrastructure in a timely manner. Prior to emergency situations, PG&E's Sourcing Department issues contract agreements on an annual basis regarding assistance in restoring electric service during an emergency response. Agreements are established with contractors to provide assistance upon request and include providing personnel, equipment, and/or expertise in a specified manner. In day-to-day operations, PG&E's Sourcing Department works with contractors directly. During an emergency incident, the Planning and Intelligence Contractor Resources Unit is responsible for determining the number of crews needed, managing the contracts, and issuing emergency purchase orders.

PG&E requires contractors to become pre-qualified for safe work practices through PG&E's third-party, ISNetworld, as a condition of any contract award for "medium" or "high" risk work. In addition, contractors are required to confirm that their sub-tier contractors meet PG&E's pre-qualification criteria and have achieved a pre-qualification status through ISNetworld prior to performing any PG&E work.

Contractors are also required to confirm their employees and sub-tier contractors have completed all training required by law and any PG&E-specific required courses prior to conducting PG&E work.

5.2. Customer Support in Emergencies

Support for impacted customers is an important element of PG&E's post-event emergency response. Following the October 2017 Northern California wildfires, PG&E established a series of billing and service modifications and disaster relief to support customers. These measures, included in PG&E's Emergency Consumer Protection Plans, were adopted with Advice 3914-G-A/5186-E-A, effective December 22, 2017, in compliance with Commission Resolution M-4833. On September 7, 2018, PG&E revised its Emergency Consumer Protection Plan, as approved by Advice 3914-G-A/5186-E-A, for residential and non-residential customers in areas covered by a state of emergency proclamation issued by the Governor due to a disaster that affects utility services. This revised plan details the protocols for customer support during emergencies, including wildfires, and are summarized below.

In the sections below, consistent with the requirements of PUC Section 8683(c)(18), PG&E describes specific protocols and procedures related to customer support during and after a wildfire.

5.2.1. Outage Reporting

While PG&E's revised Emergency Consumer Protection Plan does not discuss outage reporting specifically, PG&E has implemented measures to notify customers of a potential electric outage caused by a PSPS event, or other planned or unplanned outages. Outside of customer notifications, PG&E includes emergency alerts and outage information on its website. Starting in 2019, separate colors are being used on the outage map to indicate which type of outage is or may be occurring.

5.2.2. Support for Low Income Customers

In the revised Emergency Consumer Protection Plan, PG&E proposed the following actions to increase support to low-income customers affected by a disaster for

counties covered by a state of emergency proclamation issued by the Governor of California concerning a disaster affecting utility services. With the exception of Relief for Energy Assistance through Community Help (REACH) support, PG&E proposed that the following actions apply to all low-income customers in the designated disaster area to align with California Alternate Rate for Energy (CARE) and Energy Savings Assistance's (ESA) use of county-based community organizations and to be able to apply low-income programs to persons displaced by a disaster:

1. PG&E suspends all CARE eligibility standards and high-usage Post Enrollment Verification (PEV) requests for all customers in impacted counties. PG&E will extend this measure to customers affected by a disaster for a period of one year from the date that the Governor's state of emergency proclamation is issued.

2. PG&E contacts its community outreach contractors and engages additional contractors to inform customers that PG&E will not select them for standard PEV or High Usage PEV for the CARE Program in the impacted disaster area.

3. PG&E communicates with the program administrator of REACH, a PG&E and customer-funded emergency assistance program, to request increasing the assistance cap amount for customers whose homes were red-tagged from $300 to $600. REACH funds will be made available for residential customers whose homes were red-tagged up to this new cap amount until funds are depleted.

4. Impacted and Red-Tagged[67] residential customers are eligible to qualify for ESA participation under PG&E's modified qualification requirements for a period of one year from the date that the Governor's state of emergency

[67] "Red-Tag" or "Red-Tagged" is a designation given by CAL FIRE or by local city and county governmental agencies and/or PG&E personnel to customers whose homes or businesses were destroyed.

proclamation is issued, if the customer lives in the designated affected county and they meet one of the following:

a. The customer states that they lost documentation necessary for income verification because of the disaster; and

b. The customer states that individuals displaced by the disaster reside in the household.

5.2.3. Billing Adjustments

PG&E will temporarily suspend bill estimation for customers identified within or near a disaster area. Once a premise is confirmed Red-Tagged by the County or PG&E personnel, PG&E will discontinue billing and issue a final bill. The final bill will contain charges for usage up to the last valid meter read prior to the start of the disaster. PG&E will also prorate any applicable monthly access charges or minimum charges when discontinuing billing for premises that have been Red-Tagged. For all other customers, post-evacuation, billing will commence after a valid read (based on actual usage) is received via the SmartMeter™ network or by field personnel. If an actual meter reading is unavailable after the evacuation order is lifted, PG&E will bill zero usage during the evacuation period and resume estimating of bills using PG&E estimating protocols.

There may be instances in which PG&E is unable to cease estimated billing attributed to the time period when a home or business was unoccupied, as there is no accurate way to immediately determine exactly which residences were evacuated and when. Evacuation areas are normally described in general terms, and historically customer lists for evacuation areas have not been readily available. PG&E works with CAL FIRE and/or Cal OES to obtain the most accurate information. In the event a customer received a bill with estimated usage during the time they were evacuated, they can contact PG&E, and an account review will be conducted to determine if a billing adjustment is necessary.

5.2.4. Extended Payment Plans

PG&E extends payment arrangements to impacted and red-tagged customers for any outstanding balances on their accounts for the length of time in which the Emergency Consumer Protection Plan is in place for a period of one year from the date that the Governor's state of emergency proclamation is issued. PG&E extends its most lenient payment arrangement term, which requires 10 percent down payment and a repayment period of 12 months, to customers within the designated affected area. Customers are eligible to pay off their outstanding balance sooner if they prefer. PG&E will adjust its technology protocols to enable this group of customers to use self-service technology (Web/IVR) to obtain these arrangements, in addition to calling our Contact Center to speak with a Customer Service Representative to complete this transaction.

5.2.5. Suspension of Disconnection and Nonpayment Fees and Deposit Waivers

PG&E provides the following protections for customers whose homes or businesses were Red-Tagged as a result of a disaster. PG&E will: (1) not disconnect service due to non-payment; (2) waive reconnection fees and return check fees; and (3) waive all security deposit requirements for customers seeking to re-establish service. These protections will remain in place for customers whose premises are Red-Tagged because of the disaster for a period of one year from the date that the Governor's state of emergency proclamation is issued. In addition, PG&E will not charge customers a late fee or report inactive residential customers whose properties were red-tagged because of a disaster to credit bureaus.

5.2.6. Repair Processing and Timing

Although PG&E's revised Emergency Consumer Protection Plan does not discuss repair processing and timing specifically, PG&E will use its best efforts to communicate the ETOR to customers during a PSPS event. Following a wildfire, PG&E will work with the impacted community to communicate priorities and timelines for repairs and restoration.

Repair timing is largely dictated by access to the fire area, total damage to PG&E assets, length of the affected lines, ability to secure materials and repair resources, and the priority of the customer. For example, hospitals, schools, water treatment plants, and other facilities deemed critical by the local community will receive a higher priority for restoration. In the event the fire's damage exceeds the restoration capacity of the local division, a base camp may be established to support the restoration crews, equipment, materials, housing, and incident command staff.

SMEs within operations provide the ETOR for individual outages using several different modeling tools depending on the type of emergency. Restoration timing for the entire affected area is estimated by calculating the projected restoration work hours and dividing by the available restoration crews.

5.2.7. Access to Utility Representatives

Although PG&E's revised Emergency Consumer Protection Plan does not discuss access to utility representatives specifically, multiple channels of communication are available to our communities before, during and after a wildfire, and include, but are not limited, to: PG&E's call center, customer service offices, public affairs representatives, and field teams.

6. Performance Indicators and Monitoring

6.1. Plan Accountability

6.1.1. Executive Level Responsibility

PG&E's Wildfire Risk Management VP is responsible for managing the execution of this Wildfire Safety Plan, annual compliance with PUC Section 8386, and overseeing the CWSP.

TABLE 20: RESPONSIBLE EXECUTIVE

Role	Title	Responsibilities
Head of Wildfire Risk Management efforts	Vice President, Community Wildfire Safety Program	Responsible for oversight and direction of wildfire risk management efforts.

6.1.2. Program Owners

The programs outlined in this Plan are assigned to the following roles as of January 27, 2019. PG&E is currently undergoing leadership re-alignment, and as a result the individuals and roles below are subject to change.

TABLE 21: RESPONSIBLE PROGRAM OWNERS

Program	Role
Operational Practices	Vice President, Electric Operations[68]
Enhanced Inspections – Transmission	Electric Operations Sr. Director, T-Line Enhanced & Accelerated Inspections & Repair
Enhanced Inspections – Distribution	Electric Operations Sr. Director, Wildfire Work Execution
Enhanced Inspections – Substation	Electric Operations Sr. Director, Transmission and Substation Risk Analytics
System Hardening	Electric Operations Sr. Director, Distribution Risk Analytics and Electric Operations Sr. Director, Wildfire Work Execution
Enhanced Vegetation Management	Electric Operations Director, Enhanced Vegetation Management
Enhanced Situational Awareness and Known Local Conditions	Vice President, Electric Operations[69]
Public Safety Power Shutoff	Vice President, Electric Operations[70]

[68] Position currently filled by Vice President, Customer Energy Solution.

[69] Position currently filled by Vice President, Customer Energy Solution.

[70] Position currently filled by Vice President, Customer Energy Solution.

TABLE 21: RESPONSIBLE PROGRAM OWNERS (CONTINUED)

Program	Role
Alternative Technologies	Electric Operations Sr. Director, Distribution Risk Analytics
Post-Incident Recovery, Restoration and Remediation Activities	Incident specific – assigned as necessary post-incident; for example, the Vice President of Customer Energy Solutions is currently overseeing Camp Fire restoration
Emergency Response	Electric Operations, Director, Emergency Preparedness and Response
Customer Communications and Support	Customer Service, Director of Local Customer Experience

6.2. Plan Performance and Evaluation

The programs described in this Plan will be continuously reviewed, evaluated and modified as needed. In addition, ignition drivers are assessed regularly to allow for the continuous re-evaluation and re-design of wildfire risk reduction programs to continually improve the Plan's efficacy at reducing ignition. PG&E will monitor and evaluate both performance of the new strategies and programs described in this Plan and the Plan's efficacy in addressing wildfire risk through assessment of the following areas: (1) System Hardening; (2) Vegetation Management; (3) Operational Practices (e.g., PSPS); (4) Enhanced Inspections; and (5) Situational Awareness. Specifically, PG&E will use targets and indicators to evaluate Plan performance, as described below.

First, each year, PG&E will assess performance of the Plan by evaluating the degree to which it has met the targets set forth in Table 9. A **target** is defined as a specific goal that addresses either the work executed to reduce risk and/or the quality of the work executed. These targets will be refined each year to evaluate PG&E's performance against the goals outlined in the previous year's Plan and to continue to set goals constituting substantial risk reduction. PG&E will assess the extent to which it either (i) exceeds targets and consider potential increases for subsequent periods; or (ii) underperforms targets and identify and address challenges to improve future performance.

Second, as PG&E implements the Plan, it will analyze appropriate metrics –also called indicators – to assess the Plan's performance in reducing wildfire ignitions. An

indicator is used to identify and track a trend resulting from performance of the Plan programs. The indicators will be monitored and analyzed on an ongoing basis. Monitoring trends will help PG&E understand and evaluate the efficacy of the programs. PG&E can use this understanding to guide adjustments and reprioritization of the focus of the programs for continuing improvement.

To undertake the ongoing trend analysis of the indicators, PG&E will collect and analyze data (e.g., number of vegetation-caused outages in HFTD areas). In some cases, historical data is not available because of changes in systems or definitions (e.g., pre-2018 fire risk areas compared to HFTD areas, which were defined by the CPUC in 2018). As a result, PG&E will use available data and, on a going-forward basis, will collect the data required to complete the trend analysis.

PG&E recognizes that when dealing with natural systems it is impossible to predict with certainty year-over-year improvements in indicators, but anticipates that over time, with the investments in the programs and projects described above, the indicators will show improved trends (i.e., reduction in risk). To the extent that indicators do not show improve trends—or trends are not improving as quickly as expected, PG&E may reassess the programs or adjust targets.

Each of these work-performance and work-quality targets, as well as indicators, will be used to evaluate the efficacy of each of the major components of the Plan. Actual work performance targets for 2019 for each program in the Plan are set forth in Table 9 in Section 4 of the Plan. Select work performance targets are discussed in greater detail, as well as work quality targets and indicators, below.

Finally, PG&E has included targets that are intended to enable the CPUC to evaluate compliance with this Plan, as required under PUC Section 8386(h). Substantial compliance with the targets set forth in the Plan, once approved by the CPUC, should demonstrate that PG&E acted prudently and met the CPUC's "reasonable manager" standard, in regard to wildfire risk mitigation. However, as explained throughout this Plan, events outside of PG&E's control, such as qualified

personnel constraints, supply chain disruptions, or permitting and construction delays, could restrict PG&E's ability to meet all of the targets, and should be viewed by the CPUC in context when completing its subsequent compliance evaluation.

6.2.1. Operational Targets

Target #1 Number of Reclosers SCADA Enabled

- The number of reclosers that are converted to be SCADA enabled within the Tier 2 and Tier 3 HFTD areas each year to reduce wildfire risk and increase system resilience.
- The 2019 target is to SCADA enable approximately 285 reclosers in the Tier 2 and Tier 3 HFTD areas. The annual target will be assessed against the actual result achieved.

6.2.2. Inspection Targets

Target #1: Transmission and Distribution Structures and Substations Inspected

- Tracks the distribution and transmission structures and substations inspected under the enhanced inspection programs within HFTD areas and assesses the actual number of structures and substations inspected against the target in this Plan.
- The 2019 target is to inspect approximately 685,000 distribution poles, 50,000[71] transmission structures, and 200 substations within the HFTD areas.

Target #2: Quality of Transmission and Distribution Inspections

- Tracks the quality of T&D Inspections.
- The target is met by achieving a 98 percent "meets expectations" performance during the internal audits.

[71] Inclusive of 9,400 inspections completed in December 2018.

6.2.3. System Hardening Targets and Indicators

Target #1: Miles of System Hardened

- Retired miles of circuits with potential fire risk components within HFTD areas (as identified and prioritized by the distribution wildfire risk model generated in 2018) to reduce wildfire risk through either (1) rebuild of overhead circuitry to current design standards; (2) targeted undergrounding; or (3) elimination of overhead circuitry.

- The 2019 target is approximately 150 circuit miles of system hardening work completed. The annual target will be assessed against the actual result achieved.

Target #2: Quality of the Miles of System Hardening HFTD Areas

- The quality of the system hardening work completed annually in HFTD areas.

- The target is met by achieving a 100 percent "meets expectations" performance during the internal audits.

Indicator #1: Wires Down Events Within HFTD Areas

- The number of wires down events within HFTD areas, when the FPI is rated as very-high or higher, will be trended year-over-year.

Indicator #2: Equipment Caused Ignitions in HFTD Areas

- The number of equipment caused ignitions within HFTD areas will be trended year-over-year.

6.2.4. Vegetation Management Targets and Indicators

Target #1: Miles of Enhanced Vegetation Management Work Completed

- Completed distribution circuit miles of vegetation cleared under the EVM Program scope within high-fire risk areas to reduce

wildfire risk through (1) overhang clearing 4 feet vertical from conductor and (2) high-risk species mitigation.

- A circuit mile is recorded as complete when it is either inspected and determined clear, or when work identified by inspection is recorded as complete. Both overhang clearing and at-risk species mitigation must be recorded as clear/complete for the mile to be recorded as clear.

- The 2019 target is approximately 2,450 circuit miles of EVM work completed in HFTD areas. The annual target will be assessed against the actual result achieved.

Target #2: Completion of Drought and Tree Mortality (CEMA) Patrols

- Complete 100 percent of Drought and Tree Mortality CEMA Patrols by the end of 2019.

Target #3: Completion of Drought and Tree Mortality (CEMA) Work

- Removing or working all dead or dying trees ("CEMA trees") identified by October 1 of the current year, excluding trees affected by third-party delays, including environmental permitting requirements, owner refusals, and agency approval or review.[72]

Target #4: Quality Assurance Results in HFTD Areas

- Measures the results of QA review of EVM and Drought Response Program work performed on electric distribution power line segments within the HFTD area;

- Calculated as a percentage: the number of trees correctly worked to the EVM or Drought and Tree Mortality scope identified during audits divided by all in-scope trees reviewed through audits;

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72 Due to physical and timing constraints, CEMA trees identified late in a calendar year likely cannot be removed in that same calendar year.

- The target is met by achieving a 92 percent “meets expectations” performance in the QA audits. Given that 2019 will be the first full year of the EVM program, QA review will be performed on 100 percent of EVM work.

- Any trees found to have been missed or incorrectly worked through the QA reviews will be reworked to meet the relevant program scope

Indicator #1: Vegetation Caused Outages in HFTD Areas

- The number of vegetation caused outages within HFTD areas, when the FPI is rated as very-high or higher, will be trended year over year.

Indicator #2: Vegetation Caused Ignitions in HFTD Areas

- The number of vegetation caused ignitions within HFTD areas will be trended year over year.

6.2.5. Situational Awareness Targets

Target #1: Weather Stations Installed

- Tracks the number of weather stations installed annually against the annual target.

- The 2019 target is to install approximately 400 additional weather stations. The annual target will be assessed against the actual result achieved.

Target #2: High-definition Cameras Installed

- Tracks the number of high-definition cameras installed annually against the annual target.

- The 2019 target is to install approximately 70 additional high-definition cameras. The annual target will be assessed against the actual result achieved.

6.3. Monitoring and Auditing

PG&E's Wildfire Risk Management organization is responsible for monitoring and auditing the targets specified in the Plan to confirm that PG&E safely and efficiently reduces wildfire risk and consequences within its service area. The Wildfire Risk Organization will evaluate actual performance compared to the targets on an ongoing basis – including at a minimum, annually, as well as rely upon the internal audits described below. The Wildfire Risk Organization will also examine indicators on a regular basis, including at least annually, to assess the efficacy of the Plan performance in reducing ignition risk. In addition, a third party selected from a list developed by the CPUC will audit PG&E's execution of the Plan annually.

This section of the Plan describes: (1) the correction of plan deficiencies; (2) monitoring and auditing the effectiveness of equipment and line inspections; (3) internal electric assessment management QA and QC process; (4) internal auditing; and (5) external auditing.

6.3.1. Corrections to Plan Deficiencies

Upon finding any deficiencies in performance against the Plan or need for improvement in the Plan itself, the PG&E's Wildfire Risk Management organization will be responsible for correcting the deficiencies.

6.3.2. Monitoring and Auditing Effectiveness of Equipment and Line Inspections

The CPUC performs between four and seven audits of PG&E's GO 165 Program on an annual basis. These audits review all parts of the program, including reviews of documentation, field validation of completed patrols and inspections, as well as a review of both pending and completed maintenance work identified on electric corrective action notifications.

In addition, Compliance Supervisors perform desk and field verification of a select number of Overhead and Underground facilities that were inspected in the

previous month. Facilities inspected by both PG&E and contractor Compliance Inspectors are verified including:

1. A minimum of four overhead and four underground facilities must be verified.

2. At least one location must be verified for each inspector that completed a GO 165 Inspection in the previous month.

3. If less than four Compliance Inspectors completed inspections in the previous month, the number of verifications must be split between the inspectors so that the minimum four verifications are performed (for example, three inspectors that performed overhead inspections must have a verification performed for each of the three inspectors and an additional verification performed for one inspector). The additional verification will be rotated between the inspectors in subsequent months.

4. If more than four Compliance Inspectors completed inspections in the previous month, the number of verifications must be equal to the number of inspectors. For example, six verifications are required if six inspectors performed overhead inspection.

6.3.3. Internal Electric Asset Management Quality Assurance and Quality Control Process

The Quality Management (QM) Department within the Electric Asset Management (EAM) organization, executes the Electric Operations QA and QC Program. This program performs independent quality audits and control tests of the electric LOBs. This includes Electric Transmission (Substation and Transmission Lines), Distribution, and Transportation Services. Quality Management has three separate groups: (1) QC Transmission Line and Substation; (2) QC Distribution; and (3) QA.

The QM auditing program procedures and methodologies must satisfy the following principles:

1. **Consistency With the Following Standards:**

   - ASQ/ANSI/ISO 19011:2011: Guidelines for auditing management systems

   - American Society of Quality (ASQ) Code of Ethics

2. **Transparency**

   - QM has the obligation to report truthfully ensuring that assessment findings, audit reports, and conclusions reflect the assessment activities and observations.

3. **Independence**

   - Assessments are performed by personnel who do not have direct responsibility for performing the activities being assessed. They must be free from bias and conflict of interest to maintain an objective state of mind throughout the assessment process so that findings and conclusions are based only on the objective evidence.

QM uses an integrated approach to plan and coordinate audits. Specifically, QM uses an Audit Plan Committee and applies a risk-based methodology to prioritize audits and control tests to be performed. The Audit Plan Committee consists of leadership from Quality Compliance, T&D Compliance, Risk, and LOBs tasked with identifying, refining, and prioritizing quality audits, assessments, and control tests. The Audit Plan Committee meets twice a year to publish a rolling 12-month audit plan. The QM department is designed to focus on the relevant LOB standards and compliance requirements.

In addition, on an as needed basis, both QC groups (T&D) perform focused audits on the restoration efforts during emergency response events.

6.3.4. Internal Auditing

Internal Auditing (IA) provides PG&E with independent, objective assurance of the adequacy of processes and controls to manage business risk. IA's scope of work is to determine whether PG&E's processes, as designed and implemented, are adequate

for (a) identifying and managing key risks; (b) producing accurate, reliable, and timely operating, managerial, and financial information; (c) protecting PG&E resources; (d) complying with applicable laws and regulations, policies, standards, and procedures; and (e) providing an appropriate level of internal governance.

IA does not have mandatory annual audits focused on these processes. Rather, as part of PG&E's process to develop the annual audit plan, IA assesses all risks, including electric Distribution, Transmission and Substation risks. As a result, each year IA typically performs audits over a variety of processes across electric Distribution, Transmission, and Substation.

6.3.5. External Auditing

PG&E is currently conducting a solicitation seeking a third party to review various aspects of the risk reduction measures as part of its CWSP including WSIP. Depending on the quality of performance and value received from the third-party entity, the process may be expanded further to additional potential risk reduction measures.

7. Cost Estimates for 2019 Plan Programs

As required by the ALJ Ruling, in Attachment E, PG&E provides initial cost estimates for each program within this Plan, so that the CPUC and parties may weigh the potential cost implications of measures proposed.[73] The costs reflect PG&E's best estimate of the costs for the proposed programs as of January 31, 2019. Actual costs may vary substantially depending on actual conditions and requirements; costs of labor (impacted by both rate per hour and actual time required to complete work), materials, permit acquisitions, or other necessary resources; weather or other environmental or climatological factors; challenges regarding access rights to perform the work; the projected scope of the program; as well as additional execution risks listed in Table 9.

For three of the larger programs, in addition to the general potential variables noted above, the following are incremental key drivers of our cost estimates for these specific initiatives:

System Hardening:

- Percent of system hardening performed above ground versus underground;
- Ability to secure adequate trained personnel to complete the work;
- Ability to secure necessary equipment and materials to complete the work (e.g., limitations on available conductor);
- Actual number of miles completed;
- Technological improvements/advancements;
- Economies of scale captured in estimates;
- Mix and number of crew required to complete the work per line mile;
- Mix of materials required to complete the work per line mile;

[73] ALJ Ruling at p. 2.

- Our ability to get appropriate clearances due to customer impacts; and
- Ability to bundle work with other efforts.

WSIP Inspections & Repair (transmission, distribution and substation):

- Ability to secure adequate trained personnel to complete the work;
- Ability to obtain appropriate clearances due to system, customer or landowner impacts;
- Actual number of miles completed;
- Extent and type of damages found during the inspections; and
- Ability to bundle work with other efforts.

Vegetation management activities:

- Ability to secure adequate trained personnel to complete the work;
- Actual number of miles completed;
- Volume and type of vegetation identified as requiring work (trim or removal) to meet program scope during inspections;
- Mix of tree trimming required (overhang vs ground to conductor fuel reduction); and
- Mix of trees types (species, heights, diameter, adjacency to other structures or facilities), which impacts level of tree workers and time required to remove a tree.

To most reasonably compare current program costs, PG&E has included the 2019 forecasted spend for those programs in columns labeled *"Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part Not Previously Authorized (§ 8386(j))."* For the costs that are partially recovered in the revenue requirement, several of the program costs have yet to be listed in Attachment E, Cost Estimates for

2019 Plan Programs, and will be submitted to the CPUC subsequently following submission of this Plan. The costs forecasted in Attachment E generally align with those forecasted for 2019 in the 2020 GRC filing. Program cost forecasts that deviate from 2020 GRC (or other previously filed documents e.g., CEMA, EPIC & FHPMA) by approximately 15 percent or more from PG&E's latest forecast have been updated with PG&E's latest forecasted costs. The reasons that the program costs have changed are discussed below.

There are program costs in this Plan that deviate from previously forecast costs. These include the following programs (identified by the section in which they are discussed in the Plan):

- 4.1.3 Safety and Infrastructure Protection Teams: The 2019 cost represented in the CEMA forecast has increased due to the size of the workforce supporting this effort.

- 4.1.4 Aviation Resources: The cost forecasted for 2019 in the 2020 GRC has decreased as PG&E brought the purchase of the helicopters forward into 2018.

- 4.2.4 – 4.2.7 WSIP, Distribution, Transmission and Substation Inspections: The WSIP inspection programs were developed after submission of the 2020 GRC filing and are an incremental wildfire safety cost.

- 4.4 Vegetation Management CEMA Related Costs: The 2019 CEMA forecasted costs have decreased because it was determined that *Fuels Reduction* would be recorded in *the Enhanced Vegetation Management program* for 2019 and thus that portion of the previous CEMA forecast will now be recorded in the 2019 FHPMA. The forecasted number of dead and dying requiring removal has also dropped due to recent trends, including PG&E's significant efforts in recent years to remove these trees, which has reduced the 2019 CEMA forecast as well. In addition,

firefighting crews were included into the original 2019 CEMA forecast, but have since been removed.

- 4.5.2 Weather Stations: The number of weather stations targeted for installation in 2019 has increased from 200, listed in the 2020 GRC filing, to 400 after the submission of the 2020 GRC.

- 4.5.6 WSOC: The WSOC labor component has increased from the 2019 test year forecast as submitted in the 2020 GRC due to additional Public Safety Specialist and WSOC Full Time Employees.

- 4.6.2 PSPS: The forecasted number of PSPS events has increased from the 2020 GRC in response to expansion of the scope.

The ALJ Ruling also requires each utility to explain how it will avoid double counting of costs. PG&E will track the costs incurred for each program by date and planning order, ensuring that costs are not double-counted. Each program's costs will be allocated to the appropriate memorandum account, balancing account, or budget, based on whether the costs are incremental or were included in existing revenue requirements. Where a portion of a program's costs were included in the 2017 GRC, and therefore in the current revenue requirement, PG&E will deduct the proportionate amount from the memorandum account.

8. Additional Information the CPUC May Require

PG&E has developed this risk-informed Plan to reduce the highest wildfire risks within its service area. By prioritizing the highest risk circuits in HFTD areas, PG&E will focus available resources to address the greatest risks. As indicated in the summary chart in Section 4, there are challenges that PG&E is already preparing to address to effectively and expeditiously implement the Plan and achieve PG&E's identified 2019 targets.

There are additional circumstances that could also impact PG&E's ability to successfully implement this Plan. On January 29, 2019, PG&E filed for Chapter 11 under the U.S. Bankruptcy Code in the United States Bankruptcy Court for the Northern District of California. While PG&E expects that this process will assure the Company has access to the capital and resources necessary to support ongoing operations and enable PG&E to continue investing in its systems, infrastructure and critical safety, it is possible that financial issues could hinder PG&E's ability to retain the resources or otherwise fund activities required by the Plan. In addition, during this process, PG&E's activities and expenditures will be subject to review by the Bankruptcy Court.

Finally, this Plan supplements, but does not supersede, PG&E's wildfire related documents, including but not limited to:

- 2020 GRC
- PG&E's Fire Prevention Plan
- PG&E's Wildfire Annex to the CERP
- TD-1464S

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT A

FIRE POTENTIAL INDEX METHODOLOGY AND BACKGROUND

ATTACHMENT A

Fire Potential Index Methodology and Background

Summary

In 2018, Pacific Gas and Electric Company (PG&E) Meteorology, with guidance from fire experts from San Diego Gas & Electric Company (SDG&E), the United States Forest Service (USFS), and San Jose State University's Fire Weather Research Lab, developed the Fire Potential Index (FPI). The central purpose in the development of the new FPI was to create a system that could be optimized to forecast and track fire danger in real-time, a capability that has historically been unavailable when utilizing the National Fire Danger Rating System (NFDRS).

The FPI combines fire weather data (temperature, humidity and wind), live and dead fuel moisture values, and satellite data to rank fire danger on a floating-point scale from 1 (lowest) to 6 (highest), allowing for a more detailed determination of fire danger at the extreme end of the fire danger scale. Threshold values for each rating classification are determined through an evaluation of conditions during historical fire incidents combined with typical seasonal values. The FPI was applied to 91 static geographic areas that are called Fire Index Areas (FIAs);[1] these geographic areas include all Tier 2 and Tier 3 areas as designated by the California Public Utilities Commission (CPUC) High Fire-Threat District (HFTD) Map where PG&E has electric transmission and/or distribution equipment.

The FPI is also combined with PG&E's damage prediction model to better distinguish between typical Extreme fire danger observed during hot and dry conditions, and Extreme-Plus fire danger, which occurs when a confluence of strong, dry, outage producing winds and extremely dry fuels may lead to devastating wildfires.

Background

Prior to 2015, PG&E received fire danger ratings directly from California Department of Forestry and Fire Protection (CAL FIRE) for FIAs in PG&E's service territory. When CAL FIRE discontinued this service in December 2014, PG&E decided to develop a fire danger rating methodology utilizing public and internal data sources to

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[1] FIAs were originally developed by the USFS Pacific Southwest Forest and Range Experiment Station (now the Pacific Southwest Research Station) in 1959 and updated in the late 1960s and are still in use today by state (e.g., CAL FIRE) and federal agencies (e.g., USFS). These agencies refer to these areas as Fire Danger Ratings Areas.

implement actions that could reduce fire ignition risk. PG&E developed and demonstrated a Fire Danger Rating System specific to PG&E's service territory under the Electric Program Investment Change (EPIC) 1.05[2] Program.

The EPIC 1.05 Project Team conducted a review of existing and publicly available fire danger ratings systems and consulted with multiple partners to further refine PG&E's fire danger rating methodology, given the need to evaluate fire danger ratings at a more granular timescale and spatial resolution. A more granular fire danger rating methodology was developed, tested, and deployed, specifically to provide daily fire danger ratings for PG&E's service territory. Key project partners provided valuable guidance and consulting and participated in at least one of two external sharing and coordination meetings. They included:

- CAL FIRE
- USFS
- National Weather Service
- SDG&E
- San Jose State University (SJSU) Fire Weather Research Lab
- Bureau of Land Management
- California Governor's Office of Emergency Services (Cal OES)
- PG&E's Wildfire Risk Council

The result was a system utilizing outputs from the PG&E Operational Mesoscale Modeling System (POMMS), NFDRS[3] and the Nelson Dead Fuel moisture model.[4] This system allows PG&E to forecast the fire danger rating from low to extreme on an hourly basis for each FIA, and is consistent with how CAL FIRE, the USFS, Bureau of Land Management, and Bureau of Indian Affairs evaluate fire danger.

FPI Components

Following the devastating wildfires in October 2017, it became evident that an even more granular fire danger rating system would be needed for understanding and

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2 Voss, M.G EPIC. 2016. New Forecast Methods for Improved Storm Damage Modeling.

3 Deeming, J. E., J. W. Lancaster, M. A. Fosberg, R. W. Furman, and M.J. Schroeder. 1972. The National Fire-Danger Rating System. U.S. Department of Agriculture Forest Service, Rocky Mountain Forest and Range Experiment Station, Research Paper RM-84, Ft. Collins, Colorado. 165 pp. Revised 1974.

4 Nelson, Ralph M. Jr. 2000. Prediction of diurnal change in 10-h fuel stick moisture content. Can. J. For. Res. 30: 1071-1087.

awareness of extreme events. Not only did the FPI provide the fire danger ratings for more precise geographic areas (the 91 FIAs), but the FPI could provide hourly fire danger ratings that could be modeled/forecasted and then tracked in real-time.

The FPI is calculated based on weather conditions and the state of the fuels. A sample is included below, with additional detail on specific conditions and components that factor into the FPI calculation.

WEATHER

Index	Rating	Fosberg Fire Weather Index (FFWI)
1 - 2	Low	<15
2 - 3	Moderate	≥15 - 25
3 - 4	High	≥25 - 40
4 - 5	Very High	≥40 - 60
5 - 6	Extreme	≥60 - 100

Varies minutes to hours

FPI = Fire Potential Index = Weather Conditions (FFWI) + Fuel Conditions

- FFWI (Fosberg Fire Weather Index) combines wind, humidity, and temperature
- Fuel Conditions: Dead Fuel Moisture, Live Fuel Moisture, and Enhanced Vegetation Index (i.e., Green-up)
- FPI calculated for each Fire Index Area; all variables scaled 1 to 6

$$FPI = \left(\frac{Weather + Fuels}{2}\right)$$

FUELS

DFM

Index	Rating	10 hr. Dead Fuel Moisture (DFM)
1 - 2	Very Wet	> 25%
2 - 3	Moist	≤ 25 - 12%
3 - 4	Dry	≤12 - 8%
4 - 5	Very Dry	≤8 - 5%
5 - 6	Extreme	≤5 - 1%

Varies over hours to days

LFM

Index	Rating	Live Fuel Moisture (LFM)
1 - 2	Very Wet	>100%
2 - 3	Moist	≤100 - 81%
3 - 4	Dry	≤80 - 71%
4 - 5	Very Dry	≤70 - 63%
5 - 6	Extreme	≤62 - 45%

Varies over days

EVI

Index	Rating	Enhanced Vegetation Index (EVI)
1 - 2	Very Green	0 - 20%
2 - 3	Green	≥20 - 40%
3 - 4	Transition	≥40 - 60%
4 - 5	Curing	≥60 - 80%
5 - 6	Mostly Cured	≥80 - 100%

Varies over several days to weeks

Weather Conditions

The FPI weather component is calculated using the Fosberg Fire Weather Index (FFWI), an established tool widely used by land managers to evaluate the impacts of short-term weather variations as they relate to fire potential. The FFWI processes meteorological variables (relative humidity, temperature, and sustained wind speed) through a non-linear filter that results in a linear relationship between combined meteorological variables and wildfire behavior. The FFWI is based solely on weather data and can assess potential wildfire behavior over shorter timeframes and in localized areas where high-resolution model data or surface weather observations are available. FFWI values are sourced from POMMS and are calculated at each weather station in a given FIA. Multiple weather stations are mapped to individual FIAs. Web tools can also be utilized in real-time during high fire danger events to ascertain how models compare to actual conditions, thereby providing situational awareness of real-time fire danger conditions.

Fuel Conditions

Fuel conditions are measured through a combination of dead fuel moisture (DFM), live fuel moisture (LFM), and a satellite-derived greenness factor, or Enhanced Vegetation Index (EVI).

Dead Fuel Moisture (DFM)

Most Dead Fuel Moisture can be found on the forest floor and consists of moisture content from organic dead fuel. DFM levels are calculated by gathering data on variables like temperature, humidity, length of day and accumulated rain; as such, DFM data is constantly evolving. DFM values are calculated for each FIA and assigned a 1-to-6 value based on historical thresholds.[5]

Live Fuel Moisture (LFM)

Live Fuel Moisture is the moisture that occurs naturally in living vegetation; more specifically, it is the ratio of water weight to dry weight in any particular sample. Data for LFM is expressed as a percentage; a metric of 100% signifies a sample of vegetation consisting of 50% water. In California, LFM values have been found in excess of 200%.[6] Unfortunately, LFM measurements have also been sparse and lacking in agency coordination. Inconsistencies with sampling equipment and methods have also contributed to uncertainty in these analyses; PG&E is working with the SJSU Fire Weather Science Lab to better understand and improve LFM measurement and modeling. As with DFM, LFM is scaled from 1-to-6, with 1 signifying significant wetness and 6 as the driest possible.

Enhanced Vegetation Index (EVI)

The Enhanced Vegetation Index is an index that is derived from satellite data that detects and tracks the condition (green to cured) of vegetation. EVI is particularly useful when tracking the life cycle of annual grass crops but can also be leveraged to determine areas of intense bark-beetle damage or drought impacts. The life cycle of plants from 'Green-up' to transition to completely cured can be both modeled and observed. As annual grasses and perennials flourish, fires are much less likely to start and spread; as annual grasses begin to transition, usually in late spring into summer,

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[5] Ref Nelson, R.M., Jr., 2000. Prediction of diurnal change in10-h fuel stick moisture content. Canadian Journal of Forest Research, 30:1071-1087. https://pdfs.semanticscholar.org/3022/2d17ecc4c3ff15b029602329436c13594e22.pdf).

[6] National Wildfire Coordinating Group S-290 Intermediate Wildland Fire Behavior Course Unit 10.

and then cure in the summer and into fall, the probability of fire ignitions increase. Plant cycles are dependent on atmospheric conditions such as the timing and amount of rain (soil moisture) temperature, wind (ventilation) relative humidity and solar radiation. The PG&E FPI utilizes a 'Green-up' component that is scaled from 1-to-6 and is based on EVI percentile calculations; this data is generally updated every 8 days.

Extreme-Plus Fire Danger

In 2018, PG&E created a new Extreme-Plus fire danger category to better distinguish between the more typical extreme fire danger observed in California during hot and dry conditions and the rare concurrence of extreme fire weather conditions (strong, dry, outage producing winds) with extremely dry fuels. The Extreme-Plus fire danger category seeks to capture conditions that may lead to ignitions of rapidly spreading catastrophic wildfires. Extreme-Plus conditions are gauged on a scale that combines PG&E's storm damage model with its fire danger model (FPI); the storm damage model's underlying logic seeks to predict the likelihood of outages, caused by either equipment or vegetation, that could become an ignition source. An Extreme-Plus fire danger forecast is a principal factor in consideration of a Public Safety Power Shutoff (PSPS) event, which is a program that PG&E implemented following the 2017 wildfires as an additional precautionary measure to further reduce the risk of wildfire ignitions. An Extreme-Plus rating is not considered final or published internally until it is vetted by the supervising meteorologist and reviewed in conjunction with leadership from the Community Wildfire Safety Program and the Wildfire Safety Operations Center.

Storm Damage Modeling (SOPP)

PG&E's Meteorology department supplies Electric Operations with daily weather guidance; this guidance includes Storm Damage Modeling (SOPP), which highlights potential adverse weather across the PG&E service territory over a 10-day timeframe. SOPP details any expected outage activity in each of PG&E's 19 geographic Divisions over a 4-day period, along with an estimate of the number of troublemen and crew resources required for assessment and repair. SOPP is also able to project the expected timing of meteorological risk during weather events and assign a scale of 1-to-5 to each division depending on forecasted outage activity. Because outage-producing wind speeds can vary based on exposure, topography, directionality, vegetation, seasonality, and other factors, no single criteria exists for what can constitute an outage-producing wind. However, certain general relationships have been

established in SOPP that allow PG&E to project ranges of wind speeds that produce outage activity.

Conclusion

The ultimate goal of PG&E's fire danger rating system is to further reduce the risk of fire ignitions caused by utility operations. PG&E has followed a path based on SDG&E's in its development and testing of a more streamlined fire danger index. When fire danger ratings are very high or above in any fire danger rating area, a number of mitigating measures can go into effect. These may include, but are not limited to, disabling automatic reclosing, limiting any type of hot work, prohibiting off-road travel, and the evaluation of real-time and forecast conditions for a PSPS.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT B

CRITICAL SERVICES

ATTACHMENT B

Critical Services

The California Public Utilities Commission currently defines “essential customers” as those that are exempt from rotating outages and has established a process for customers to apply for essential customer status. For purposes of Public Safety Power Shut-Off (PSPS) events, Pacific Gas and Electric Company (PG&E) has a separate process for identifying customers that provide “critical services” such as first responders, health care facilities, operators of telecommunications infrastructure, and water agencies/utilities. PG&E prioritizes customers providing critical services for restoration and communication during PSPS events.

Because the Administrative Law Judge Ruling[1] requiring a list of entities considered essential services is addressing PSPS events, PG&E is using the definition of “critical” services in this Attachment. For the sake of customer privacy, PG&E provides a list of categories for the entities that would qualify as providing critical services, instead of specific customer names. Entities are listed in order of priority for restoration and communication during a PSPS event.

Critical First Responders:

- Immediate Response Needs – Police Stations
- Immediate Response Needs – Fire Stations
- 911 Dispatch Centers

Healthcare facilities:

- Immediate Response Needs – Hospitals and Surgical Centers
- Kidney Dialysis / Blood Organ Banks
- General Hospitals and Skilled Nursing Facilities

Telecommunications Infrastructure:

- Immediate Response Needs – Critical Telecom Infrastructure

Water Agencies/Utilities:

- Water Treatment Facilities
- Sewage Plants

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1 Administrative Law Judge’s Ruling on Wildfire Mitigation Plan Template, and Adding Additional Parties as Respondents, issued January 17, 2019 in R.18-10-007.

Others:

- Emergency Operation Centers (Federal, State, County)
- Schools
- Prisons and Jails
- Government agencies essential to national defense
- Major evacuation centers/Shelters
- Major local public transportation centers (Bay Area Rapid Transport, ferries)
- Major national public transportation centers (airports)
- Local/state/national government staging sites

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT C

DESCRIPTION OF ROUTINE FACILITIES INSPECTIONS

ATTACHMENT C

Description of Routine Facilities Inspections

1. Routine Distribution Line Inspection

The Overhead Patrols and Inspections Program, focused on safety and reliability, is designed to comply with General Orders (GO) 95 and 165, resulting in inspections of Pacific Gas and Electric Company (PG&E) electric facilities to identify conditions that may pose a hazard or the risk of an ignition. The Overhead Patrols and Inspections Program is primarily focused on the identification, assessment, prioritization, and documentation of abnormal conditions (e.g., conditions that could impact safety or reliability such as damaged or missing critical components), regulatory conditions (e.g., specific field conditions PG&E has determined must be identified regardless of impact to safety or reliability, such as missing high voltage signs), and third-party caused conditions that negatively impact safety or reliability (e.g., unauthorized attachments, structures built too close to facilities). These conditions may occur due to operational use, degradation, deterioration, environmental changes, or third-party actions.

In addition, there are several preventive and corrective maintenance programs that are focused on maintaining assets, replacing assets or targeted service reliability improvements, such as the Pole Test and Treat Program and line equipment inspections and testing. Consistent with GO 165, there are three defined levels of these routine distribution line inspections as follows:

- A patrol inspection is a simple visual inspection, of applicable utility equipment and structures, that is designed to identify obvious structural problems and hazards. Patrol inspections may be carried out in the course of other company business. Overhead patrols of equipment and conductors are required to be completed every year in High Fire Threat District (HFTD) areas.

- A detailed inspection is where individual pieces of equipment and structures are carefully examined, visually and through use of routine diagnostic tests, as appropriate, and (if practical and if useful information can be so gathered) opened, and the condition of each rated and

recorded. Overhead detailed inspections of equipment and conductors are required to be completed every five years in HFTD areas.

- An intrusive inspection is defined as one involving movement of soil, taking samples for analysis, and/or using more sophisticated diagnostic tools beyond visual inspections or instrument reading. For wood poles that are over 15 years old and have not been previously subjected to intrusive inspections, an intrusive inspection must be performed. For wood poles that have previously passed an intrusive inspection, the follow-on intrusive inspection interval is 20 years.

PG&E's programs are designed to meet or exceed the GO 165 minimum requirements in HFTD areas. For example, PG&E performs intrusive inspections on wood poles that have previously passed an intrusive inspection approximately every 10 years or if conditions call for testing.

In addition to identifying and resolving immediate safety or reliability hazard conditions, a Compliance Inspector is required to identify and document the field scenarios that impact safety and reliability. All overhead assessments must be performed using visual observations and may also include diagnostic testing (e.g., hammer sound test, bore tests) to verify pole integrity. The work resulting from the GO 165 inspection program is prioritized based on several factors when evaluating an abnormal condition, including both the probability and impact of a failure or exposure to the public or workers. PG&E's Distribution organization is directed to identify deficient conditions, create corrective notifications, and assign priority as described in Section 4.2 of the Wildfire Safety Plan.

2. Routine Transmission Line Inspection

Similar to the role of inspections and patrols for electric distribution, inspection and patrol procedures are a key element of the preventive maintenance program for PG&E's electric transmission lines. These actions reduce the potential for component failures and facility damage and facilitate a proactive approach to repairing or replacing identified, degraded or damaged components. PG&E's transmission procedures include the following regular transmission inspection activities:

- A patrol inspection is a visual observation to identify abnormalities (e.g., obvious structural problems or hazards) or circumstances that will

negatively impact safety. All overhead transmission line facilities are patrolled annually. An overhead patrol may be performed by walking, driving, or flying (helicopter only), and are conducted in a manner that will identify deficient conditions.

- A detailed inspection is a visual observation of individual components, structures and equipment; operational readings; and component testing (e.g., hammer test) to identify abnormalities or circumstances that will negatively impact safety, reliability, or asset life. Detailed inspection frequencies vary depending on voltage, structure type (wood or steel), and foundation location relative to bodies of water. A detailed ground, aerial, or climbing inspection of the asset looks for deficiencies or circumstances that will negatively impact safety, reliability, or asset life. Individual elements and components are examined carefully through visual and/or routine diagnostic tests, and each abnormal condition is graded and/or recorded.

- An infrared inspection uses infrared cameras, affixed to helicopters, to capture heat data of individual components to identify deficiencies requiring further attention. Infrared inspections may be performed in conjunction with overhead inspections, but must not be considered as, or substituted for, an overhead inspection. Infrared inspections are performed annually in Tier 3 HFTD areas and every three years in Tier 2 HFTD areas. Infrared inspections are performed in late spring or early summer when line loading and favorable weather facilitates effective infrared readings.

- A non-routine patrol or inspection may be conducted on an ad-hoc basis given conditions including, but not limited to, storm restoration.

PG&E's Transmission organization identifies deficient conditions, creates corrective notifications, and assigns priority as described in Section 4.2 of the Wildfire Safety Plan.

3. Routine Substation Inspection

PG&E's Substation Inspection Program uses a time-based inspection interval. Routine substation inspections are scheduled to be performed based on the substation type.[1] For example, Type 1 is monthly, and Type 2 is every other month. The type and frequency are based on the substation criticality matrix that PG&E developed utilizing industry best practices. PG&E evaluates the risk of each substation based upon public and employee safety, system criticality, security, and environmental risk.

The Substation Inspection Program activities include:

- Inspecting the substation and equipment for damage or abnormal conditions.
- Inspecting all other items appropriate to the substation and its equipment.
- Documenting and reporting any abnormal conditions found in the substation and documenting any repairs, services or other work performed.

At a minimum, qualified personnel perform a visual and/or auditory (if applicable) inspection of substation equipment and facilities, whether in service or not, in compliance with GO 174 requirements. PG&E's Substation organization identifies notable conditions, creates corrective notifications, and assigns priority as described in Section 4.2 of the Wildfire Safety Plan.

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[1] The Substation Inspection Program does not include maintenance work such as unplanned or corrective maintenance, on-line condition monitoring, infrared and corona inspections or testing.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT D

RISKS AND DRIVERS IDENTIFIED IN RAMP

ATTACHMENT D

Risks and Drivers Identified in RAMP

As discussed in its 2017 Risk Assessment Mitigation Phase (RAMP) Report, Pacific Gas and Electric Company's (PG&E) total expenditure in 2016 for all wildfire risk-related activities was approximately $750 million.[1] Most of this expenditure, about $435 million, was directed to vegetation management (routine and drought and tree mortality work) around PG&E's overhead transmission and distribution lines, the biggest driver of wildfire risk for distribution lines, primarily in areas that are now designated as High Fire Threat District (HFTD) areas.[2] Other expenditures and infrastructure replacement programs to control wildfire risk included patrols and inspections of PG&E's overhead electric facilities; preventive maintenance of equipment and poles; replacement of overhead conductor, overhead distribution equipment, and poles that are at risk of failing; installation of protective equipment (e.g., fuses and reclosers) that isolates circuit segments when abnormal conditions are detected; funding of local Fire Safe Councils[3] for fire detection and fuel reduction projects in local communities; and the development and enhancement of engineering design standards, training, and operational procedures to minimize wildfire risk. PG&E refers to these existing programs as "controls."[4] The table below provides a list of these controls identified in the 2017 RAMP Report, followed by a description of each control.

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1 See 2017 RAMP Report, Chapter 11, Wildfire, Section III, Table 11-1.

2 As described below, the California Public Utilities Commission (Commission) has recently changed its classification system for high fire-threat areas. Some areas previously classified as high fire-threat areas were not included in the Commission's HFTD Map.

3 Fire Safe Councils are community-based, self-governed groups that focus on fire safety. They distribute fire safety materials, teach fire-safe home construction techniques, conduct fuel reduction projects, fund defensible space projects around homes and escape routes, sponsor lookout towers, and form community safety networks.

4 For definition purposes in this Wildfire Safety Plan (Plan or WSP), PG&E considers "controls" to be safety or compliance programs already in place, though not necessarily included in prior GRC-approved budgets, and "mitigations" to be specific additional or enhancement programs with primary goals beyond compliance, with specific start and end dates and a project budget, or an additional proposed activity not previously identified.

Wildfire Risk Controls

Line No.	Control #	Control
1	C1	Overhead Patrols and Inspections
2	C2	Vegetation Management
3	C3	CEMA Vegetation Management
4	C4	Non-Exempt Equipment Replacement
5	C5	Overhead Conductor Replacement
6	C6	Animal Abatement
7	C7	Protective Equipment
8	C8	Overhead Equipment Replacement
9	C9	Deteriorated Pole Replacement
10	C10	Wood Pole Bridging
11	C11	Design Standards
12	C12	Restoration, Operational, Procedures, and Training

- C1 – Overhead Patrol and Inspections: PG&E patrols and inspects its overhead electric facilities to identify damaged facilities and other conditions that may pose a risk of wildfire ignition. Patrols and inspections are performed annually in urban and high-risk wildfire areas, and biannually in rural areas.
- C2 – Vegetation Management: PG&E's Vegetation Management (VM) Program was developed in accordance with General Order (GO) 95, Rule 35, and Public Resources Code (PRC) Sections 4292 and 4293. The program includes inspection and identification of vegetation that poses a potential safety hazard, as well as clearing and removal of vegetation, and quality assurance. The main components of this work are the routine VM Program, vegetation control, and quality assurance.
- C3 – CEMA Vegetation Management: This control includes five initiatives intended to address the vegetation impacts associated with prolonged drought conditions. The five initiatives are as follows:
  1) Enhanced Vegetation Inspection and Mitigation – Additional ground and air inspection on selected circuits in high fire threat areas to further reduce the potential for changing forest conditions to result in vegetation and power line conflicts.

2) Wild Land Urban Interface Protection – Additional VM inspections in Local Reliability Areas (LRA)[5] and greater clearance of poles in high fire danger LRAs.
3) Fuel Reduction and Emergency Response Access – Funding Fire Safe Councils to support fuel reduction in high fire danger areas around PG&E's electric distribution facilities.
4) Early Detection of Forest Disease/Infection – Forming cooperative information sharing with universities, California Department of Forestry and Fire Protection (CAL FIRE) and the USFS on forest health.
5) Early Detection and Response to Wildfires – Funding fire lookouts, aerial patrols, and fire detection cameras located near PG&E's electric distribution facilities.

- C4 – Non-Exempt Equipment Replacement: The planned replacement of equipment non-exempt from PRC 4292 requirements with exempt equipment. Exempt equipment is identified by CAL FIRE as having lower fire risk.
- C5 – Overhead Conductor Replacement: Programs under which overhead conductor is either proactively replaced through a targeted program or replaced after a failure occurs. Conductor replacement work in high-risk wildfire areas and conductor with higher likelihood of failure is prioritized.
- C6 – Animal Abatement: The installation of new equipment or retrofitting existing equipment with protection measures intended to reduce animal contacts. This includes avian protection on distribution and transmission poles, such as jumper covers, bushing covers, perch guards, or perching platforms.
- C7 – Protective Equipment: The installation of new equipment (e.g., fuses, reclosers, and SCADA installations) that isolates equipment when abnormal system conditions are detected.
- C8 – Overhead Equipment Replacement: Proactive identification and replacement of critical, deteriorating overhead distribution equipment, such as cross-arms, transformers, capacitors, reclosers, and switches. Equipment is identified through the Patrol and Inspections control (C1) or through *ad hoc* inspection.

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5 LRAs are areas where primary responsibility to respond to fires rests with local authorities, e.g., fire departments.

- C9 – Deteriorated Pole Replacement: The identification and replacement of deteriorated wood distribution and transmission poles, including intrusive inspection work (pole test and treat) and replacement or remediation. GO 165 mandates testing on a 20-year cycle depending on the installation date. PG&E's program tests poles approximately every 10 years—exceeding the inspection cycle compliance requirements—and incorporates wood preservation practices that also go beyond compliance. These factors allow PG&E to identify and mitigate the decay of wood which reduces failures.
- C10 – Wood Pole Bridging: The installation of a wire which connects the through-bolt of all phases of a distribution wood pole in order to reduce the probability of a pole fire occurring due to current traveling through the wooden cross arms. These pole fires tend to occur after a light rain due to possibility of increased leakage currents through the insulators.
- C11 – Design Standards: The general standards for proper application of equipment for safe and reliable operation.
- C12 – Restoration, Operational Procedures and Training: The procedures contained in Utility Standard TD-1464S[6] and Utility Bulletin TD-1464B-001[7] for increased Wildfire controls when a FIA has a rating of Very High, Extreme, or Extreme Plus.

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6 Utility Standard TD-1464S "Fire Danger Precautions in Hazardous Fire Areas" establishes precautions when working, travelling, or operating in hazardous fire areas.

7 Utility Bulletin TD-1464B-001 "Fire Index Patrol and Non-Reclose Process" contains PG&E's reclosing device operating practices in effect in 2018.

PACIFIC GAS AND ELECTRIC COMPANY

ATTACHMENT E

COST ESTIMATES FOR 2019 PLAN PROGRAMS

Attachment E: Cost Estimates for 2019 Plan Programs

Plan Section	Program/Strategy (§8386(c)(3))	Mapped Programs	Asset Addressed: Pole, Line, Equipment	Estimated Annual Cost: 2019 Capital (1,000s)	Estimated Annual Cost: 2019 Expense (1,000s)	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part Not Previously Authorized (§ 8386(j))		Identify any Aspects of Plan/Strategy and Associated Funding That Is or Will Be Addressed in Another Case (Identify the Case) (§ 8386(j))	Identify Any Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking Is Prevented (§ 8386(j))	Previously Included in RAMP? (Provide Reference) (§ 8386 (c) (11))	Evaluation Metric(s) (§ 8386 (c)(4))	Assumptions Underlying Metric (§ 8386 (c)(4))
4	**Wildfire Safety Strategy and Programs**					**Capital**	**Expense**					
4.0	PMO	PMO	N/A - Operations	$500	$8,000	N	N	None	FRMMA / WPMA	Not included	N/A	N/A
4.1	**Operational Practices**											
4.1.1	Recloser Operations	Reclose Blocking (Manual)	All	-	-	N/A	N/A	None	N/A	Yes, See Mitigation #M1	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.1.2	Personnel Work Procedures in Conditions of Elevated Fire Risk	N/A	N/A - Operations	-	-	N/A	N/A	None	N/A	Not included		
4.1.3	Safety and Infrastructure Protection Teams	Safety and Infrastructure Protection Team	N/A - Operations	$6,200	$12,300	N	N	None	CEMA	Not included		
4.1.4	Aviation Resources	Aviation	N/A - Operations	$2,100	$2,400	N	N	Cap: None Exp: None	Cap: FRMMA / WPMA Exp: CEMA	Not included		
4.2	**Wildfire Safety Inspection Programs**											
4.2.1	WSIP, Distribution	Distribution Inspection / Repair	All	$220,000-$620,000	$130,000-$200,000	Partial, GRC 2017-2019 ($14M)	Partial, GRC 2017-2019 ($6M)	None	FRMMA / WPMA	Not included	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.2.2	WSIP, Transmission	Transmission Inspection / Repair	All	$282,000-$402,000	$162,000-$167,000	N	N	TO	N/A	Not included		
4.2.3	WSIP, Substation	Distribution Substation Inspection / Repair	All	$2,000-$3,000	$1,000-$2,000	N	Partial, GRC 2017-2019 ($0.5M)	None	FRMMA / WPMA	Not included		
		Transmission Substation Inspection/Repair	All	–	$1,000-$2,000	N/A	N	TO	N/A	Not included		
4.3	**System Hardening**											
4.3.1	Pole Material	Wildfire System Hardening	All	$236,900	–	Partial, GRC 2017-2019 ($7M)	N/A	None	FRMMA / WPMA	Partially, See Mitigation M6, M7, M8 & M9	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.3.2	Pole Materials (Transmission)	Light Duty Steel Poles for Transmission	Pole	$500	-	N	N/A	TO	N/A	Not included		
4.3.2	Pole Loading and Replacement (Distribution)	Wildfire System Hardening	All	$236,900	–	Partial, GRC 2017-2019 ($7M)	N/A	None	FRMMA / WPMA	Partially, See Mitigation M6, M7, M8 & M9		

Plan Section	Program/Strategy (§8386(c)(3))	Mapped Programs	Asset Addressed: Pole, Line, Equipment	Estimated Annual Cost: 2019 Capital (1,000s)	Estimated Annual Cost: 2019 Expense (1,000s)	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part Not Previously Authorized (§ 8386(j))		Identify any Aspects of Plan/Strategy and Associated Funding That Is or Will Be Addressed in Another Case (Identify the Case) (§ 8386(j))	Identify Any Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking Is Prevented (§ 8386(j))	Previously Included in RAMP? (Provide Reference) (§ 8386 (c)(11))	Evaluation Metric(s) (§ 8386 (c)(4))	Assumptions Underlying Metric (§ 8386 (c)(4))
4.3.3	Conductor	Wildfire System Hardening	All	$236,900	–	Partial, GRC 2017-2019 ($7M)	N/A	None	FRMMA / WPMA	Partially, See Mitigation M6, M7, M8 & M9		
4.3.4	System Protection	Automation and Protection (SCADA)	Equipment	$15,600	$300	Partial, GRC 2017-2019 ($1M)	Partial, GRC 2017-2019	None	FRMMA / WPMA	Not included		
4.3.5	Equipment	Non-exempt Surge Arrester Replacement Program	Equipment	$71,600	–	* Program shift to replace therefore cost recorded in Cap	Partial, GRC 2017-2019 ($6M)	None	FRMMA / WPMA	Yes, See Mitigation M5		
4.4	**Enhanced Vegetation Management**											
4.4.1	Vegetation Trimming and Overhanging Tree Limbs	Enhanced Vegetation Management	N/A Operations	–	$338,300	N/A	N	None	FHPMA	Partially, See Mitigation # M3 & M4	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.4.2	High Fire-Threat District VM Inspection Strategy											
4.4.3	Inspecting Trees with a Potential Strike Path to Power Lines											
4.4.4	At-risk Species Management											
4.4.5	Challenges Associated With Enhanced Vegetation Management											
4.4.6	Community and Environmental Impacts											
Other	CEMA Costs	CEMA – Drought Tree Mortality	N/A Operations	–	$85,900	N/A	N	None	CEMA	Yes, See C1		
Other	Substation Vegetation Management	Sub Veg Mgt (T)-identified in WSIP	N/A Operations	–	$2,000 - $4,000	N/A	N	TO	N/A	Not included		
		Sub Veg Mgt (D)-identified in WSIP	N/A Operations	–	$4,000 - $5,000	N/A	Partial, GRC 2017-2019 ($0.2M)	None	FRMMA / WPMA	Not included		
4.5	**Enhanced Situational Awareness**											
4.5.1	Meteorological Operations and Advanced Situational Awareness	See Programs Below	N/A Operations	–	–	N/A	N	None	N/A	Not included	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.5.2	Fire Spread Modeling	See 4.5.5	N/A Operations	–	–	N/A	N	None	N/A	Not included		
4.5.3	Weather Stations	Expanded Weather Station Deployment	N/A Operations	$8,200	$300	N	N	None	FRMMA / WPMA	Not included		
4.5.4	Camera Deployment Strategy	Wildfire Cameras	N/A Operations	–	$4,600	N/A	N	None	FRMMA / WPMA	Not included		
4.5.5	Satellite Fire Detection Systems	Satellite Fire Detection System	N/A Operations	–	$400	N/A	N	None	FRMMA / WPMA	Not included		

Plan Section	Program/Strategy (§8386(c)(3))	Mapped Programs	Asset Addressed: Pole, Line, Equipment	Estimated Annual Cost: 2019 Capital (1,000s)	Estimated Annual Cost: 2019 Expense (1,000s)	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part Not Previously Authorized (§ 8386(j))		Identify any Aspects of Plan/Strategy and Associated Funding That Is or Will Be Addressed in Another Case (Identify the Case) (§ 8386(j))	Identify Any Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking Is Prevented (§ 8386(j))	Previously Included in RAMP? (Provide Reference) (§ 8386 (c)(11))	Evaluation Metric(s) (§ 8386 (c)(4))	Assumptions Underlying Metric (§ 8386 (c)(4))
4.5.6	Storm Outage Prediction Model (SOPP)	SOPP Model Automation	N/A Operations	–	$200	N/A	N	None	FRMMA / WPMA	Not included		
4.5.7	Wildfire Safety Operations Center	Wildfire Safety Operations Center	N/A Operations	$700	$15,900	N	N	None	FRMMA / WPMA	Not included		
Other	Advanced Fire Modeling	Advanced Fire Modeling	N/A Operations	–	$1,600	N/A	N	None	FRMMA / WPMA	Not included		
4.6	**Public Safety Power Safety Shutoff**											
4.6.1	PSPS Decision Factors	Public Safety Power Shutoff	N/A Operations	–	$16,500	N/A	N	None	FRMMA / WPMA	Not included	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.6.2	Strategies to Enhance PSPS Efficiency While Reducing Associated Impacts											
4.6.3	PSPS Notification Strategies											
4.6.4	Re-energization strategy											
4.6.2.1	Impact Mitigation through System Sectionalizing	Granular Sectionalizing	All	$5,200	–	N	N/A	None	FRMMA / WPMA	Not included		
4.6.2.2	Resilience Zones	Resilience Zones	All	$10,600	–	N	N/A	None	FRMMA / WPMA	Not included		
4.6.2.3	Customer Services and Programs	N/A - Costs and program scope are still being finalized	N/A	–	–	N/A	N/A	None	FRMMA / WPMA	Not included		
4.7	**Alternative Technologies**											
4.7.1	Rapid Earth Fault Current Limiter Pilot Project	Rapid Earth Current Fault Limiter	All	–	$7,000	N/A	Yes, Recovered in EPIC	EPIC	N/A	Not included	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets	See Section 4, Table 9: 2019 Wildfire Safety Plan Targets
4.7.2	Enhanced Wires Down Detection Project	Enhanced Wire Down Detection	Equipment	$2,100	$200	N	N	N	FRMMA / WPMA	Not included		
4.7.3	Other Alternative Technologies	N/A	N/A	–	–	N/A	N/A	None	N/A	Not included		
4.8	**Post Incident Recovery, Restoration and Remediation**											
4.8.1	Post-Incident Recovery	N/A	N/A	–	–	N/A	N/A	None	N/A	Not included	N/A	N/A
4.8.2	Restoration	N/A	N/A	–	–	N/A	N/A	None	N/A	Not included	N/A	N/A
4.8.3	Remediation	N/A	N/A	–	–	N/A	N/A	None	N/A	Not included	N/A	N/A
Other	**Support**											
Other	IT Costs	N/A	N/A - Operations	$16,000 - $33,000	$13,000 - $18,000	N	Partial	TO	FRMMA / WPMA	Not included	N/A	N/A

ATTACHMENT 6

SDG&E, 2019 Wildfire Mitigation Plan, February 9, 2019

BEFORE THE PUBLIC UTILIITES COMMISSION
OF THE STATE OF CALIFORNIA

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Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007 (Issued October 25, 2018)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) WILDFIRE MITIGATION PLAN

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February 6, 2019

BEFORE THE PUBLIC UTILIITES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007 (Issued October 25, 2018)

SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) WILDFIRE MITIGATION PLAN

In accordance with the January 17, 2019 Ruling of Administrative Law Judge Thomas,[1] and California Senate Bill 901,[2] San Diego Gas & Electric Company (SDG&E) submits its Wildfire Mitigation Plan, which is included as Attachment A hereto.

Respectfully submitted,

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Dated: February 6, 2019

[1] *ADMINISTRATIVE LAW JUDGE'S RULING ON WILDFIRE MITIGATION PLAN TEMPLATE, AND ADDING ADDITIONAL PARTIES AS RESPONDENTS*, dated January 17, 2019.
[2] California Senate Bill 901 (SB 901), enacted in 2018, adopted new provisions of Public Utilities Code Section 8386 requiring all California electric utilities to prepare, submit and implement annual wildfire mitigation plans that describe the utilities' plans to construct, operate and maintain their electrical lines and equipment in a manner that will help minimize the risk of catastrophic wildfires caused by those electrical lines and equipment.

ATTACHMENT A

SAN DIEGO GAS & ELECTRIC COMPANY
WILDFIRE MITIGATION PLAN

San Diego Gas & Electric Company

Wildfire Mitigation Plan

February 6, 2019



Exhibit No.:
CA-07-0278

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Executive Summary

The number and severity of wildfire events across the western United States has shown a marked increase in recent years. As a direct result of the hazards associated with operating an electric system in a fire-prone region, San Diego Gas & Electric Company (SDG&E or Company) has made wildfire safety, prevention, mitigation, and recovery a central tenet of its culture. Over the past decade, SDG&E's business strategies have evolved to reflect a risk-informed approach wherein wildfire is identified as the primary public safety risk. SDG&E has hardened a significant number of facilities to address the risk of wildfire in its service territory. In recognition of the vast impacts wildfire has on public safety and the environment, this Wildfire Mitigation Plan (Plan) addresses SDG&E's efforts to mitigate the risk of wildfire ignitions.

SDG&E's efforts to mitigate the risk of wildfire and enhance grid resilience began over a decade ago after San Diego experienced some of the most destructive wildfires in the county's history. Initially, this involved establishing a Company-wide fire-awareness culture and prioritizing safe work practices. SDG&E hired subject matter experts in firefighting, fire science, and meteorology who have developed and implemented programs to enhance situational awareness, which increases SDG&E's ability to monitor and understand the wildfire environment. This level of understanding led to changes in operational procedures to reduce the potential for ignitions associated with utility infrastructure during periods of elevated fire potential. SDG&E established customer and local agency outreach programs to educate customers and stakeholders on the wildfire risk and maintain open lines of communication during hazardous conditions.

Additionally, SDG&E continues to focus on hardening its electric transmission and distribution systems, particularly in rural areas where vegetation, weather conditions, and topography often align to increase the potential for catastrophic wildfire growth (i.e., the high fire threat district). Infrastructure hardening projects have targeted high-risk fire areas to increase electric system resiliency and reduce wildfire ignition potential. SDG&E's vegetation management program also mitigates wildfire risk and supports electric system resiliency by maintaining proper tree and brush clearances to minimize vegetation-related impacts.

With the increasing impacts from climate change, community growth, and other societal forces, SDG&E's wildfire risk mitigation strategy will continue to evolve. Plans to expand system hardening projects and incorporate additional wildfire mitigation activities into SDG&E's resilience practices have been included in its pending General Rate Case (GRC) in an effort to best position the Company to achieve its goal to mitigate wildfire risk.

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1 Objectives of the Wildfire Mitigation Plan

1.1 Plan Purpose

The purpose of this Plan is to provide, in accordance with state law, a plan for wildfire[1] mitigation that will be reviewed and approved by the California Public Utilities Commission (CPUC or Commission) after consultation and review by state fire experts at the California Department of Forestry and Fire Protection (CalFire). Once approved, SDG&E will utilize this Plan as a framework to reasonably manage wildfire risk until the CPUC approves a subsequent Plan (on an approximately annual basis). SDG&E anticipates that this initial Plan cycle will last 18 months, with subsequent Plans on a calendar year period.[2] SDG&E's Plan and its implementation need to be flexible to adapt to changing circumstances, weather, funding, and other variables that cannot be known in advance.

This Plan complies with P.U. Code § 8386(c), as modified by Senate Bill (SB) 901,[3] and the Administrative Law Judge's Ruling issued on January 17, 2019.[4] Table 1 below sets forth the SB 901 required elements for wildfire mitigation plans and identifies the location in this Plan where each requirement is provided.

Table 1: Plan Compliance with P.U. Code § 8386(c)

Information Required by P.U. Code § 8386(c)	Location(s) of Required Information in Plan
(1) An accounting of the responsibilities of persons responsible for executing the Plan.	Section 6.1
(2) The objectives of the Plan.	Section 1.2
(3) A description of the preventive strategies and programs to be adopted by SDG&E to minimize the risk of its electrical lines and equipment causing catastrophic wildfires, including consideration of dynamic climate change risk.	Section 2; Section 4
(4) A description of the metrics SDG&E plans to use to evaluate the Plan's performance and the assumptions that underlie the use of those metrics.	Section 6.2
(5) A discussion of how the application of previously identified metrics to previous plan performances has informed the Plan.	Section 6.3

[1] A wildfire is a large, destructive fire that spreads quickly over woodland or brush.

[2] Per California Public Utilities Code (P.U. Code) § 8386(e), the CPUC shall approve this Plan within three months of its submission, unless the CPUC determines that the three-month deadline cannot be met and issues an order extending the deadline. Considering this timing, SDG&E expects this Plan will cover the time period from when the CPUC approves the Plan through December 2020.

[3] Stats. 2018, Ch. 626.

[4] R.18-10-007, *Administrative Law Judge's Ruling on Wildfire Mitigation Plan Template, and Adding Additional Parties as Respondents* (January 17, 2019) (ALJ Ruling).

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Information Required by P.U. Code § 8386(c)	Location(s) of Required Information in Plan
(6) Protocols for disabling reclosers and deenergizing portions of the electrical distribution system that consider the associated impacts on public safety, as well as protocols related to mitigating the public safety impacts of those protocols, including impacts on critical first responders and on health and communication infrastructure.	Section 4.1.2; Section 4.7
(7) Appropriate and feasible procedures for notifying a customer who may be impacted by the deenergizing of electrical lines.	Section 4.7.3
(8) Plans for vegetation management.	Section 4.4
(9) Plans for inspections of SDG&E's electrical infrastructure.	Section 4.2
(10) A list that identifies, describes, and prioritizes all wildfire risks, and drivers for those risks, throughout the electrical corporation's service territory, including all relevant wildfire risk and risk mitigation information that is part of Safety Model Assessment Proceeding and Risk Assessment Mitigation Phase filings.	Section 3.3
(11) A description of how the Plan accounts for the wildfire risk identified in SDG&E's Risk Assessment Mitigation Phase filing.	Section 3.4
(12) A description of the actions SDG&E will take to ensure its system will achieve the highest level of safety, reliability, and resiliency, and to ensure that its system is prepared for a major event, including hardening and modernizing its infrastructure with improved engineering, system design, standards, equipment, and facilities, such as undergrounding, insulation of distribution wires, and pole replacement.	Section 4.3
(13) A showing that SDG&E has an adequate sized and trained workforce to promptly restore service after a major event, taking into account employees of other utilities pursuant to mutual aid agreements and employees of entities that have entered into contracts with SDG&E.	Section 5.2.3
(14) Identification of any geographic area in SDG&E's service territory that is a higher wildfire threat than is currently identified in a CPUC fire threat map, and where the CPUC should consider expanding the high fire threat district based on new information or changes in the environment.	Section 3.4

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Information Required by P.U. Code § 8386(c)	Location(s) of Required Information in Plan
(15) A methodology for identifying and presenting enterprise-wide safety risk and wildfire-related risk that is consistent with the methodology used by other electrical corporations.	Section 3.2
(16) A description of how the Plan is consistent with SDG&E's disaster and emergency preparedness plan prepared pursuant to P.U. Code § 768.6	Section 5.2
(17) A statement of how SDG&E will restore service after a wildfire.	Section 5.2
(18) Protocols for compliance with requirements adopted by the CPUC regarding activities to support customers during and after a wildfire, outage reporting, support for low-income customers, billing adjustments, deposit waivers, extended payment plans, suspension of disconnection and nonpayment fees, repair processing and timing, access to utility representatives, and emergency communications.	Section 5.3.1
(19) A description of the processes and procedures SDG&E will use to monitor and audit the implementation of the Plan, identify any deficiencies in the Plan, and monitor and audit the effectiveness of electrical line and equipment inspections.	Section 6.4

In addition to complying with state law, this Plan also complies with the ALJ Ruling in that it is organized according to the SB 901 wildfire mitigation template and includes the following additional elements:

- Plans for wildfire mitigation on transmission infrastructure, in addition to infrastructure for distribution of electricity;[5]
- Cost estimates for each item in the [wildfire mitigation plan] in order for the Commission to weigh the potential cost implications of measures proposed in the plans;[6]
- Description of planned wildfire mitigation that exceeds existing requirements, either because of "known local conditions" that exceed those standards or other reasons;[7]
- Comparison of current WMP to prior fire prevention plans, so it is clear what new strategies the utility intends to implement,[8] and

[5] This is incorporated throughout this Plan.
[6] Costs are discussed in Section 7.1 and cost estimates are provided in Appendix A.
[7] *See* Appendix A.
[8] *See* Section 7.2.

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- A table entitled "§8386(c)(3)(4)(8)(9): Wildfire Mitigation Strategies and Programs," with the additional column for categories added.[9]

1.2 Plan Objectives

Consistent with state law and objectives, this Plan is founded upon the goal of minimizing the probability that the various components of SDG&E's electric system might become the original or contributing source of ignition for a wildfire. Wildfire safety, prevention, mitigation, and recovery are a central priority for SDG&E. The programs, initiatives, and plans described in this Plan highlight many of the efforts SDG&E has made and will continue to make to mitigate wildfire risk. Building upon its existing Fire Prevention Plan (FPP),[10] SDG&E further examined various improvements and further enhancements that could be made to its Community Fire Safety Program[11] to meet its and the state's wildfire mitigation objectives. While many of SDG&E's strategies and programs are already in place, this Plan is continually evolving and in an effort for continuous improvement, SDG&E expects that additional programs and enhancements will be implemented and refined.

The threat of wildfire has increased throughout California and the region over the past several years, which as discussed in greater detail herein, may be attributed to a variety of factors such as drought, climate change, bark beetle infestations, and development and population growth in fire-prone areas. Over the past ten years, SDG&E has taken significant steps to address wildfire risks and continues to evaluate opportunities to mitigate the risk. To that end, SDG&E has proposed several wildfire risk mitigation programs and activities in its Test Year (TY) 2019 GRC application, which is still awaiting Commission action.[12] Given that devasting wildfires have become a regular occurrence in California, SDG&E needs to begin implementing and accelerating programs that address wildfire risk.

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[9] *See* Appendix B. As directed by the ALJ Ruling (at 3), to the extent SDG&E has the information in its possession in time for this Plan filing, it is included.

[10] Pursuant to Commission General Order (GO) 166, electric utilities are required to have a fire prevention plan that describes the measures the electric utility intends to implement, both in the short run and in the long run, to mitigate the threat of powerline fire ignitions. SDG&E's FPP is filed annually with the CPUC on October 31. In 2016, the California Legislature passed SB 1028, which required electric utilities to annually prepare and submit a wildfire mitigation plan for CPUC review. Since SDG&E was required to submit an FPP and an SB 1028 wildfire mitigation plan, it filed one plan that met both sets of requirements. SDG&E's current FPP is available here: https://www.sdge.com/sites/default/files/documents/SDGE_Fire_Prevention_Plan_2018.pdf

[11] SDG&E's Community Fire Safety Program is an effort that not only examines the electric system to provide prudent means of delivering power to customers, but also involves working with representatives from approximately 40 different groups, including water districts, schools, the County of San Diego, fire agencies, telecommunications companies, disability rights groups, and residents, to establish and maintain appropriate communication measures in the event that an emergency situation arises.

[12] Application (A.) 17-10-007.

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2 Preventive Strategies and Programs

SDG&E's approach to minimizing the risk of its electrical infrastructure causing catastrophic wildfires involves a three-pronged approach, integrating efforts in:

- **Operations and Engineering** – how SDG&E builds and maintains its electric system to be fire hardened;
- **Situational Awareness and Weather Technology** – focuses on SDG&E's ability to monitor and understand the fire environment; and
- **Customer Outreach and Education** – concentrates on communication and collaboration with regional stakeholders and customers.

SDG&E's wildfire mitigation strategy involves processes and programs to understand wildfire risk, conditions, and behaviors to provide the Company and its customers with time and information to take appropriate action; build, construct, and operate a fire-hardened electric distribution and transmission system in a manner that minimizes the possibility of igniting a fire; educate customers and stakeholders on wildfire risk; and support customers affected by outages.

The following sections provide a high-level overview of SDG&E's planned wildfire prevention strategies and programs for the next 18 months, or until the CPUC approves a subsequent Plan.[13] These preventative strategies and programs are summarized in Sections 2.1 through 2.3 and discussed in greater detail in Sections 4 and 5.

2.1 Operations and Engineering

Operating an electric system includes an element of risk. SDG&E designs and implements preventative strategies, in the way in which it constructs and operates its electric transmission and distribution system, to mitigate risks, including wildfire risk associated with those facilities. These efforts include implementing special operating plans based on wildfire conditions, inspecting and maintaining system infrastructure, managing vegetation that could impact the safe and reliable operation of the system, and hardening efforts to improve the resiliency of the system.

SDG&E has established four Operating Conditions (i.e., Normal, Elevated, Extreme, and Red Flag Warning (RFW)) to monitor the wildfire potential throughout its service territory in order to guide and inform operating decisions related to recloser settings, testing procedures, work restrictions, and sensitive relay settings. Depending on the severity of the Operating Conditions

[13] The Commission has long recognized the necessity of utilities being afforded the appropriate flexibility to use management discretion to assess and respond to emergent risks and needs as they arise. Because wildfire risk is affected by climate change and local conditions, and because many of the programs and activities described in this Plan are in their early stages of development and deployment, such flexibility is especially important in this context. If such circumstances arise, SDG&E will make changes, as appropriate, to its wildfire mitigation efforts consistent with the Commission's expectation that utilities will exercise operational discretion and flexibility to maintain safe, reliable, and resilient service for their customers, and will inform the Commission should such necessary potential changes significantly deviate from this Plan.

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relative to the wildfire potential, SDG&E could choose to implement certain operating protocols for its recloser and sensitive relay settings.

SDG&E also uses its established Operating Conditions to guide and inform its maintenance activities designed to minimize the possibility of its electrical system becoming the source of ignition. SDG&E has an obligation to serve and sometimes must perform work in dangerous conditions. As conditions increase in severity, work activities can still be performed, but additional mitigation requirements might be needed, and in some situations, work activity could be ceased altogether for safety reasons. During Extreme or RFW Operating Conditions, most overhead work will cease.[14]

SDG&E employs additional fire prevention and mitigation resources, depending on the Operating Condition. SDG&E will integrate contracted fire resources with construction and maintenance crews to provide onsite fire prevention, ignition mitigation, and emergency services. SDG&E also has a contracted, full-time Industrial Fire Brigade (IFB), which are specially trained resources in electrical and flammable liquids fires and are made available to external fire agencies.

In addition to operating and work restriction protocols, SDG&E proactively maintains its electric system through its inspection and maintenance efforts. SDG&E regularly inspects the condition of its electric infrastructure and established a specific program focused on Tier 2 and Tier 3 of its High Fire Threat District (HFTD).[15] SDG&E conducts additional inspections, which are above required standards, when extreme conditions are forecasted. SDG&E also maintains its vegetation management program to keep trees and brush clear of electric powerlines and poles.

Finally, SDG&E invests in fire-hardening its electric system through various programs, which aim to strengthen and modernize the electrical system to improve the ability to meet wildfire prevention and mitigation goals. These programs include design and construction, redesign efforts, and infrastructure replacement.

These Operations and Engineering programs are discussed in greater detail in Sections 4.1 through 4.4, below.

[14] In very rare circumstances, it is possible that not doing repair work on powerlines creates a higher risk than performing the work. In these cases, SDG&E will take additional steps to mitigate the potential of a fire.

[15] The CPUC led the development of a statewide fire threat map to designate areas where there is an elevated risk for powerline fires, and where enhanced fire safety regulations would apply. The CPUC fire map, which depicts the HFTD is available here: https://ia.cpuc.ca.gov/firemap/. These high fire threat areas are referred to the HFTD. Tier 2 fire threat areas depict areas where there is an elevated risk (including likelihood and potential impacts on people and property) from utility associated wildfires. Tier 3 fire threat areas depict areas where there is an extreme risk (including likelihood and potential impacts on people and property) from utility associated wildfires. SDG&E implemented the HFTD as required by Commission Decision (D.) 17-12-024. Tiers 2 and 3 of the HFTD are roughly analogous to and replace SDG&E's Fire Threat Zone (FTZ) and High Fire Threat Area (HFRA), respectively.

2.2 Situational Awareness and Weather Technology

SDG&E has developed a situational awareness and weather technology program, devoting time and resources to adapt the Company's operations, emergency preparedness, emergency response, and risk mitigation efforts to the changing climate conditions across its service territory. To support SDG&E's situational awareness and weather technology program, the Company:

- Deployed over 175 weather stations across its service territory to closely monitor fire weather conditions impacting electric infrastructure;
- Own or utilize, in cooperation with the University of California San Diego (UCSD), over 100 cameras to enhance situational awareness around wildfire;
- Shared weather data with external weather agencies, fire agencies, the general public, and academia;
- Utilize high-performance supercomputing clusters to integrate weather data with operational activities and systems (Santa Ana Wildfire Threat Index (SAWTI), Fire Potential Index (FPI), and the Wildfire Risk Reduction Model Operational System (WRRM-Ops));
- Developed models to determine the potential of wildfires and to understand wildfire growth patterns. The FPI effectively communicates wildfire potential within each of SDG&E's districts; WRRM-Ops integrates the latest weather and geographic information system (GIS) technology to understand wildfire growth patterns across the region);
- Strengthened its focus on wildfire preparedness by creating a Fire Science and Climate Adaptation business organization, which consists of meteorologists, community resiliency experts, fire coordinators, and project management personnel.

Moving forward, SDG&E intends to rely on its situational awareness and meteorological technologies to support proactive and real time operational practices with the objective of reducing the likelihood that its electric facilities and operations will be the source of ignition for a wildfire.

Furthermore, through ongoing data sharing and collaboration with external agencies, SDG&E's objective is to innovate and invest in technology that will decrease the risk of catastrophic wildfire fueled by high winds. Situational awareness and weather technology is discussed in further detail in Sections 4.5 and 4.6, below.

2.3 Customer Outreach and Education

SDG&E does not operate alone in mitigating wildfires; customers, elected officials, non-profit support organizations, and first responders all play a vital role in achieving wildfire prevention and mitigation. SDG&E has built and maintains a multi-level outreach and education strategy to create public awareness of fire threats, fire prevention, and support during a wildfire or de-energizing event.

SDG&E works with community leaders, government agencies, and the public to collaboratively discuss fire-safety processes regarding public safety. These collaborations provide a forum for public education as well as an opportunity to exchange improvement ideas and practices. In

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addition to collaborations with the community and the public, SDG&E partners with nearly 100 non-profit organizations, such as first responder associations, councils, and fire departments to coordinate, train, and support preparedness and response activities.

SDG&E also maintains a website devoted to electric, gas, wildfire, and tree safety, as well as public safety power shutoffs, emergency preparedness, and outages.[16] SDG&E uses additional channels of communication to provide education and information materials through brochures, pocket-cards, radio and print media, mobile phones, and social media through Facebook and Twitter.

During an extreme weather event, SDG&E provides additional customer and outreach support through a targeted communication strategy. SDG&E informs its customers of expected severe weather conditions and directly notifies affected customers, either through established points of contact or through phone and text of the potential of a Public Safety Power Shutoff (PSPS). In areas most at-risk, SDG&E has established Community Resource Centers (CRCs) that are designed to provide information and aid to affected customers through a collaboration of SDG&E and volunteer organizations. CRCs are places residents can go to get water and snacks, charge their phones, and obtain up-to-date information on outages. A map and further information on CRCs may be found on SDG&E's website.[17]

The details of SDG&E's Customer Outreach and Education programs are provided in Sections 4.7 and 5, below.

3 Risk Analysis and Risk Drivers

3.1 Risk Overview

Consistent with P.U. Code § 8386(a), SDG&E constructs, maintains, and operates its system in a manner that is designed to mitigate the risk of catastrophic wildfire posed by electric infrastructure. As part of this risk-informed approach, SDG&E utilizes its risk framework, modeled after risk management standard ISO 31000.[18] This framework consists of an enterprise risk management governance structure, which addresses the roles of employees at various levels ranging up to SDG&E's Board of Directors, as well as various risk processes and tools.

One such process is SDG&E's six-step enterprise risk management process. This six-step process is aligned with the Cycla Corporation's 10-Step Evaluation Method, which was adopted by the Commission "as a common yardstick for evaluating maturity, robustness, and thoroughness of utility Risk Assessment and Mitigation Models and risk management frameworks."[19]

The enterprise risk management process is both a "bottoms-up" and "top-down" approach. It takes input from the risk managers and the risk owners to ultimately finalize SDG&E's

[16] https://www.sdge.com/wildfire-safety.
[17] https://www.sdge.com/wildfire-safety/community-resource-centers.
[18] ISO 31000 is a family of standards relating to risk management codified by the International Organization for Standardization.
[19] D.16-08-018 at 195, Ordering Paragraph 4.

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enterprise risk registry (Risk Registry). The Commission defines a Risk Registry as "[a]n inventory of enterprise risks at a snapshot in time that summarizes (for a utility's management and/or stakeholders such as the CPUC) risks that a utility may face. The [Risk Registry] must be refreshed on a regular basis and can reflect the changing nature of a risk; for example, risks that were consolidated together may be separated, new risks may be added, and the level of risks may change over time."[20]

SDG&E's identified enterprise-level risks, including safety-related and wildfire-related risks, are presented in its Risk Registry. Each risk has one or more risk owner(s), a member of the senior management team who is ultimately responsible and accountable for the risk, and one or more risk manager(s), who is responsible for ongoing risk assessments and overseeing implementation of risk plans. Each risk in the Risk Registry has an associated set of mitigations (i.e., projects or programs that reduce the likelihood of the risk and/or negative consequences should the risk occur). Notwithstanding these risk management and mitigation efforts, however, adverse events will occur. When that happens, SDG&E's efforts, including implementation of response plans, development of role and responsibility descriptions and checklists, and facilitation of training and exercises, are designed to prepare the Company to respond safely and effectively to those adverse events that occurred despite mitigation efforts.

The six steps of SDG&E's risk management process are shown in Figure 1 below and discussed in further detail in the following sections. SDG&E's approach is consistent with the CPUC's guidance on risk management.

Figure 1: Risk Management Process



[20] D.18-12-014 at 16-17.

3.1.1 Risk Identification

Step 1 of SDG&E's risk management process is risk identification, which as defined by ISO 31000, is the process of finding, recognizing, and describing risks. It includes the identification of risk sources, events, their causes and potential consequences. To begin SDG&E's six-step process, the Enterprise Risk Management (ERM) organization annually reaches out to the various business units across the Company to update existing risk information and identify enterprise-level risks that emerged since the prior assessment. This is completed through interviews and meetings with risk owners and managers.

3.1.2 Risk Analysis

Risk analysis, as defined by ISO 31000, is the process to comprehend the nature of risk and to determine the level of risk. This is Step 2 in SDG&E's risk management process and it provides a basis for risk evaluation and decisions about risk mitigation. SDG&E uses a tool for risk analysis referred to as the risk "bow tie," which is depicted in Figure 2 below. The risk bow tie "consists of the Risk Event in the center, a listing of drivers on the left side that potentially lead to the Risk Event occurring, and a listing of Consequences on the right side that show the potential outcomes if the Risk Event occurs."[21] A driver, also referred to as trigger, is a "factor that could influence the likelihood of occurrence of a Risk Event. A driver may include external events or characteristics inherent to the asset or system."[22] It is critical to note that a risk driver (or trigger) is an indication that a risk event could occur. It does not reflect actual conditions or threatened conditions. Typically, mitigations address various drivers of a given risk. SDG&E performs a bow tie analysis to summarize the risk information.

SDG&E's risk analysis results in a risk score. A risk score is a "[n]umerical representation of qualitative and/or quantitative risk assessment that is typically used to relatively rank risks and may change over time."[23]

As stated in ISO 31000, risk analysis is undertaken with varying degrees of details depending on the risk and the availability of data and resources. SDG&E utilizes a combination of qualitative and quantitative analyses to analyze their risks. Further, for purposes of future Risk Assessment Mitigation Phase (RAMP) and GRC filings, SDG&E, along with the other California investor-owned utilities (IOUs), will employ the risk management processes and methods set forth in D.18-12-014.

3.1.3 Risk Evaluation and Prioritization

Step 3 in SDG&E's risk management process is risk evaluation, which is the process of comparing the results of risk analysis. As stated above, SDG&E's methodology for conducting risk evaluation in future RAMP proceedings will be based on D.18-12-014. SDG&E leverages the information from its risk assessment and evaluation to develop its prioritization. On an annual basis, the ERM organization facilitates a risk prioritization session where risk owners discuss the relative ranking of the enterprise risks and achieve consensus around risk priorities.

[21] D.18-12-014 at 16.
[22] D.18-12-014 at 16.
[23] D.18-12-014 at 18.

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3.1.4 Risk Mitigation Plan Development and Documentation

Based on the analysis and evaluation of risks, Step 4 of SDG&E's risk management process involves developing and documenting risk mitigation plans by risk owners and managers to capture the state of the risk given current controls and any proposed additional mitigations.[24] The risk owners then present their key risk mitigation plans to SDG&E's senior management team and discuss the feasibility and prudency of those proposed plans.

3.1.5 Risk-Informed Investment Decisions and Risk Mitigation Implementation

Steps 1 through 4 of SDG&E's risk management process are inputs into Step 5, the Company's investment planning process. The investment planning process is SDG&E's current process for prioritizing funding based on risk-informed priorities and input from operations. At least one member of the ERM organization participates in this process, together with many of the risk owners and risk managers, to align the efforts undertaken on the risk front with decisions made from an operational and financial perspective.

3.1.6 Monitoring and Review

SDG&E strives for continuous improvements of its enterprise risk management process. In Step 6 of its risk management process, SDG&E monitors various mitigation efforts through indicators[25] and periodically commissions third-party maturity assessments.

3.1.7 Methodological Advances

The Commission has adopted "minimum required elements for risk and mitigation analysis in the [RAMP] and [GRC]."[26] These minimum required elements include: building a Multi Attribute Value Function (MAVF); identifying risks for the IOUs' respective Risk Registries; risk assessment and risk ranking in preparation for RAMP; selecting enterprise risks for RAMP; and mitigation analysis for risks in RAMP.

These new minimum required elements are largely methodological in nature, and the Commission has noted that these risk tools represent "a big improvement" by "dramatically advanc[ing] the utility's ability to assess and prioritize risks."[27] The new methodology "achieves steps toward a more uniform and quantitative risk-based decisionmaking framework"[28] amongst the large California IOUs. SDG&E plans to reflect this new methodology in its upcoming RAMP filing, which is currently scheduled for November 2019.

[24] A Control is defined as "Currently established measure that is modifying risk." A Mitigation is defined as "Measure or activity proposed or in process designed to reduce the impact/consequences and/or likelihood/probability of an event." *See* D.18-12-014 at 16-17.
[25] D.18-12-014 at 26.
[26] D.18-12-014 at 2.
[27] D.18-12-014 at 44.
[28] D.18-12-014 at 2.

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3.1.8 SDG&E's Risk Assessment Mitigation Phase Report

The Risk Assessment Mitigation Phase is a procedural requirement established by the Commission and is considered to be "an initial phase of each utility's GRC proceeding."[29] The purpose of RAMP is "to examine the utility's assessment of its key risks and its proposed programs for mitigating those risks."[30] SDG&E (concurrently with Southern California Gas Company) was the first utility to file a RAMP Report (2016 RAMP Report).[31]

To determine which risks should be included in its 2016 RAMP, SDG&E utilized the risk assessment from its 2015 Risk Registry. The 2015 Risk Registry, completed in September 2015, was used as the basis for identifying the RAMP risks, because it was the most current risk registry available at the time that SDG&E was preparing its 2016 RAMP Report.

SDG&E's 2015 Risk Registry used a 7x7 Risk Evaluation Framework (REF), also referred to as the 7x7 matrix, to evaluate the level of risks and differentiate risks from one another by gauging their frequency of occurrence against their potential impact. In the REF, risk scores are calculated from two inputs: impact and frequency. The impact, or consequence, is the "effect of the occurrence of a Risk Event."[32] The frequency is the "number of events generally defined per unit of time."[33] Both the impact and frequency inputs are measured on a scale from one to seven.

The REF considers several attributes when measuring impact, including the attribute called "Health, Safety, and Environmental Impact." SDG&E included risks in its RAMP that had an impact score of four or higher for the Health, Safety, and Environmental attribute, based on the 2015 Risk Registry. This selection criteria was based on discussions with the Commission's Safety and Enforcement Division (SED) and with stakeholders during a workshop in the Safety Model Assessment Proceeding (S-MAP) and memorialized in D.16-08-018 (for SoCalGas and SDG&E only). The 7x7 matrix defined a score of four in the Health, Safety, and Environmental impact category as "Permanent/Serious Injuries or Illnesses: Few serious injuries or illnesses to the public or employees. Significant and short-term impacts to environment."

Using the selection criteria above, SDG&E's 2016 RAMP Report consisted of 17 of the Company's key safety risks and plans for mitigating those risks. Each of the 17 risks had a dedicated risk chapter in the 2016 RAMP Report. Wildfire-related risks were presented as risk chapters in SDG&E's 2016 RAMP.

[29] D.14-12-025 at 31.
[30] D.14-12-025 at 31.
[31] In accordance with D.14-12-025 and D.16-08-018, the 2016 RAMP Report was filed on November 30, 2016 in proceeding Investigation (I.) 16-10-015.
[32] D.18-12-014 at 16.
[33] D.18-12-014 at 17.

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3.2 Wildfire Risks – Prioritization and Drivers

SDG&E has a separate and distinct risk in its Risk Registry dedicated to the risk of catastrophic wildfires (Wildfire Risk). In the Wildfire Risk, the event[34] itself (i.e., the center of the bow tie) is a wildfire. As discussed in SDG&E's 2016 RAMP, the description of this risk is an uncontrollable fire possibly consuming structures caused by failure of SDG&E equipment, vegetation contact with SDG&E equipment, foreign object contact with SDG&E equipment, failure of third-party equipment attached to SDG&E assets, and/or slow response and inadequate awareness due to lack of coordination with other agencies.

The threat of wildfire has increased throughout California over the past several years, which in turn causes the Wildfire Risk to be the number one risk in SDG&E's risk register. This increased threat is due to a variety of factors including drought, climate change, bark beetle infestations, and population growth into fire-prone areas. Environmental conditions such as dried fuels (e.g., chaparral) and severe wind events can turn a wildfire that might otherwise be quickly contained by firefighting resources into a wildfire. As discussed throughout this Plan, SDG&E has established programs and implemented strategies to monitor threat levels as time passes, with a focus on how to mitigate further changes that are observed.

SDG&E described its wildfire-related risks in its 2016 RAMP Report as follows below. It is important to note that the listed potential risk drivers (or triggers) are just an indication that a risk event could occur, and do not reflect actual conditions or threatened conditions:

Risk: Wildfire Caused by SDG&E Equipment, Including Third-Party Pole Attachments[35]

Potential Drivers: Include, but are not limited to, the following:

- **Downed Conductor**: A downed conductor (or "wire down") occurs when a conductor drops or breaks from its designed location on the pole and cross arm and ends up on the ground, sometimes in an energized mode. A wire down can result from a variety of factors, many of which are outside of SDG&E's control.
- **General Equipment Failure**: Electric equipment failure can be a source of a downed conductor or ignition. Failure of components such as connector, hot line clamps, and insulators can result in wire failure and end up in a wire down situation, sometimes in the energized mode.
- **Weather-Related Failure of SDG&E Equipment**: Weather plays a large part in the potential failure of SDG&E equipment. Excessive wind, lightning, and exposure to weather over time can degrade the integrity of the electrical components and lead to failure of one or more of the electrical parts causing a failure of the conductor.

[34] Risk Event is defined as "An occurrence or change of a particular set of circumstances that may have potentially adverse consequences and may require action to address. In particular, the occurrence of a Risk Event changes the levels of some or all of the Attributes of a risky situation." D.18-12-014 at 18.
[35] All wildfire issues and mitigations are included within SDG&E's Wildfire Risk. SDG&E has risks in its Risk Registry for Electric Infrastructure Integrity and Climate Change Adaptation, however, the portions of those risks that relate to wildfire issues and mitigations are accounted for within the Wildfire Risk.

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- **Contact by Foreign Object**: Foreign objects coming into contact with SDG&E's facilities can also present sources of ignition. For example, Mylar balloons are highly conductive and will result in phase to phase faulting. In the worst-case this can cause the conductor to fail and land in an energized mode, causing arcing and sparking in dry conditions. In addition, vehicular contact will bring down conductors, and sometimes the entire pole, resulting in conductors laying on the ground in an energized fashion.
- **Failure of Third-Party Attachments**: As mandated by the CPUC, SDG&E must allow communication infrastructure providers to attach to utility poles when space is available. These providers may not properly install or inspect their equipment. This has led to contact of these attachments with the electrical facilities, leading to fire related incidents.
- **Vegetation Contact**: During storms and severe wind events, branches are shed by trees in the vicinity of SDG&E facilities. These can fall on conductors leading to conductor failure or, in the case of palm fronds, phase to phase contact and a cascade of sparks. In addition, trees that are many feet away from an energized conductor sometimes uproot and fall on the conductor, causing failure or sparking.
- **Not Observing Operational Procedures**: SDG&E revises its protocols and procedures based on certain conditions. For example, during red flag or fire warnings, SDG&E and its contractors may not perform welding or other activities that may generate potential ignition sources. If an employee or contractor does not adhere to such a procedure, it can cause an adverse consequence.
- **Lack of Internal or External Coordinated Response**: A well-coordinated response to a downed conductor aids in the suppression of a fire as well as the de-energization of the conductor in a safe manner. Lack of coordination could lead to uncontrolled fire, electrical exposure to first responders, and possibly, injury or death.
- **Extreme Force of Nature Events**: SDG&E's overhead electrical facilities are fully exposed to the elements. Significant weather and wind-related events can cause a variety of problems related to equipment failure and downed conductors. Also, continual exposure to natural elements can degrade or weaken key components, conditions which may not be found until the following, scheduled inspection and repair cycle.
- **Climate Change Adaptation Impacts on Wildfires Caused by SDG&E Equipment:** Despite the proactive approach to mitigating fire risk, increases in temperature and prolonged periods of drought in the decades to come will likely lead to high risk fire areas expanding from the foothills and mountains into the lower elevation coastal canyons and wildland interfaces that were previously considered at lower risk for fire growth. These prolonged periods of drought will also likely result in a longer wildfire season, potentially extending the focus of our threat monitoring and potential response from the fall months to year-round -- with the greatest increased threat in the spring and summer months.[36]

[36] SDG&E 2016 RAMP Report, Chapter SDG&E-1 at SDG&E 1-7 – 1-9.

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These climate trends have already been realized across the region, culminating in previously unseen wildfire outbreaks across coastal San Diego County in May of 2014. SDG&E also employed the help of the Skycrane in San Diego on July 1, 2016 (earlier than in prior years), in response to an increase in summertime wildfire activity across the region. Based upon the most recent climate science, these trends are likely to continue and worsen into the future.[37]

Potential Consequences: If one of the risk drivers listed above were to occur, resulting in an incident, the potential consequences, in a reasonable worst-case scenario could include:[38]

- Personal injuries to the public, employees and contractors, including numerous fatalities;
- Damage to third party real and personal property;
- Damage and loss of SDG&E assets or facilities;
- Operational and reliability impacts;
- Claims and litigation; and
- Erosion of public confidence.

SDG&E's Wildfire Risk, including its risk drivers, has evolved since its 2016 RAMP. Generally, SDG&E incorporates lessons learned from its prior Risk Registry cycles consistent with Step 6 of its risk management process, discussed in Section 3.1.8 above. In an effort to streamline the presentation of enterprise risks, in recent years the language in the Risk Registry itself has been tightened and, in some cases, generalized. That said, the risk-related information for the Wildfire Risk has not been significantly revised since SDG&E's 2016 RAMP. For example, the 2015 Risk Registry, on which SDG&E's 2016 RAMP was based, included potential drivers of "Downed Conductor in Santa Ana Conditions" and "Weather Related Failure of SDG&E Equipment." In the 2018 Risk Registry, these two potential drivers have been incorporated into the more generalized potential driver of "Equipment Failure." Further, the 2015 Risk Registry had a stand-alone potential driver of "Lack of Internal or External Coordinated Response." This is no longer a stand-alone potential driver and has now been incorporated into the potential drivers of "Equipment Failure" and "Not Observing Operational Restrictions." Similarly, while climate change-related items were discussed as potential drivers to the Wildfire Risk in the 2016 RAMP, in the 2018 Risk Registry, SDG&E has explicitly made "Climate Change" and "Critical Burning Conditions"[39] separate potential drivers given their importance and impacts to the region.

[37] SDG&E 2016 RAMP Report, Chapter SDG&E-1 at SDG&E 1-9. Since 2016, these climate trends have continued and worsened across the region, culminating in wind-driven wildfire outbreaks across San Diego County during atypical periods that include December 2017 and July 2018. In response to an increase in overall wildfire activity across the region, SDG&E now employs the Skycrane year-round.

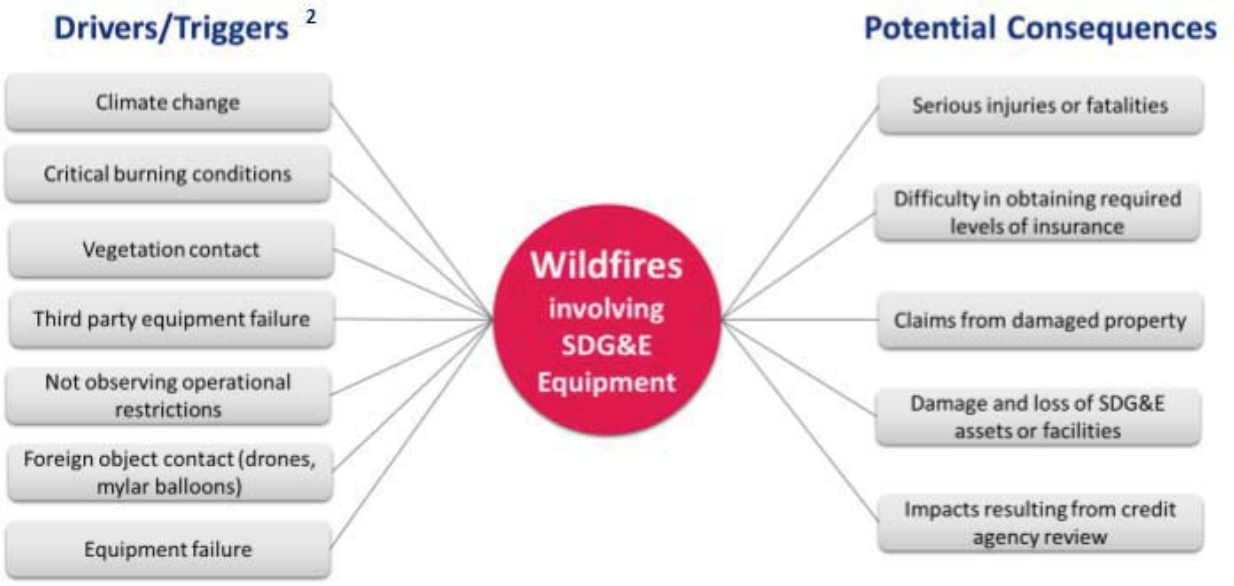
[38] SDG&E 2016 RAMP Report, Chapter SDG&E-1 at SDG&E 1-10. It is important to note that a potential worst-case scenario, such as one used to assess residual risk impacts and frequency, may not necessarily contain all drivers or triggers.

[39] Critical Burning Conditions refer to the combination of current fuel conditions and weather on any given day that could lead to the potential of a critical fire.

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Figure 2 below provides the risk bow tie, which summaries the most recent Wildfire Risk and risk driver information from SDG&E's 2018 Risk Registry:

Figure 2: Wildfire Risk Bow Tie



[2] Risk Drivers/Trigger: an indication that a risk could occur. It does not reflect actual or threatened conditions.

In accordance with the ALJ Ruling, the table below maps the potential Wildfire Risk drivers from Figure 2 to one or more of the categories of: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and (5) Response and Recovery.

Table 2: Categorization of Wildfire Risk Drivers

Wildfire Risk Drivers	ALJ Ruling Categorization(s)
Climate Change	Situational/Conditional Awareness
Critical Burning Conditions	Situational/Conditional Awareness
Vegetation Contact	Inspection and Maintenance; Design and Construction
Third Party Equipment Failure	Inspection and Maintenance; Design and Construction
Not Observing Operational Restrictions	Operational Practices; Situational/Conditional Awareness
Foreign Object Contact (i.e., Drones, Mylar Balloons)	Response and Recovery; Design and Construction
Equipment Failure	Design and Construction; Inspection and Maintenance

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3.2.1 Safety Model Assessment Proceeding

In addition to the information presented in SDG&E's 2016 RAMP Report, SDG&E described how it models and assesses wildfires in its Safety Model Assessment Proceeding (S-MAP) Application.[40] In its S-MAP proceeding, SDG&E explained its quantitative method for prioritizing wildfire-related hardening projects including the Fire Risk Mitigation (FiRM) program and the Wildfire Risk Reduction Model (WRRM). A detailed discussion of FiRM is provided in Section 4.3.9 below and the WRRM is discussed briefly here and in more detail in Section 4.5.5 below.

Due to the complexity of Wildfire Risk, SDG&E developed a sophisticated modeling tool, the WRRM, which is a computer-based model that has the ability to create probability distributions for: ignitions rates by equipment type and external causes, fire growth potentials, and values at risk. Using these probabilities, SDG&E can run simulations of wildfire risk that can be configured for all weather types, or specific weather patterns.

Since the submission of SDG&E's S-MAP Application, there have been further enhancements to the WRRM. The WRRM was used as the foundation for a separate operational version of the model known as WRRM-Ops, which is now operational to support emergency operations and performs over 10 million virtual fire behavior simulations every day. WRRM-Ops provides SDG&E additional data that is important to maintaining situational awareness. While SDG&E uses WRRM-Ops operationally, it is one data point used for planning and decision-making purposes.

3.3 RAMP Risk-Informed Wildfire Mitigation Plan

As explained in the wildfire chapter of the 2016 RAMP Report, SDG&E performs a broad range of activities related to fire prevention and mitigation. The effectiveness of several of these activities is a performance measure for many SDG&E employees, some of whom are directly or indirectly responsible for contributing to and/or performing the mitigation efforts. Core to the mitigation activities are system design, construction, operation, maintenance, and inspection aimed at reducing the potential for SDG&E facilities to become the source of ignition for a fire. Nevertheless, SDG&E has an obligation to serve, and the range of operating conditions faced in the SDG&E service territory continue to present some risk that SDG&E facilities might be associated with ignition for a fire, regardless of how diligent these practices may be.

This Plan builds upon SDG&E's 2016 RAMP and TY 2019 GRC by putting forth refinements, continuations, and enhancements to the mitigation activities presented therein. Such programs are described in greater detail in Section 4 of this Plan.

[40] *See* A.15-05-002.

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3.4 Wildfire Threat Zones

SDG&E historically identified geographic boundaries that were used for wildfire projects, programs, and operations. In 2008, the CPUC initiated various proceedings that focused on the creation of new statewide fire safety maps.[41] SDG&E participated in these proceedings, which led to the development of what would become known as the HFTD map.[42] The geographic areas delineated by that map allow utilities to prioritize their efforts. The CPUC hosts a webpage specifically for communicating the purpose of the HFTD development, as well as being the official repository of the actual map data.[43]

Since the adoption of those maps by the CPUC in early 2018, SDG&E has modified relevant operational practices to be consistent with the new maps. State law requires the utilities to re-evaluate its service territory and identify areas that may pose elevated risk that are not currently identified in the CPUC's existing fire threat map, and where the CPUC should consider expanding the HFTD based on new information or changes in the environment.[44] SDG&E has considered the potential and has identified certain wildland urban interface and coastal areas that possess high amounts of native and non-native vegetation, which under certain circumstance, could contribute to a wildfire if an ignition took place under extreme weather conditions. Therefore, SDG&E intends to perform relevant assessments to determine whether these areas warrant inclusion in the HFTD.

4 Wildfire Prevention Strategy and Programs

SDG&E's wildfire prevention strategies and programs are comprised of three prongs: operations and engineering, situational awareness and weather technology, and customer education and outreach. SDG&E's strategies and programs are described in the following sections, organized in these three groups.

Consistent with the ALJ Ruling, for each identified preventative strategy or program in Section 4 of this Plan, the workpapers in Appendix A provide detailed information on: (1) whether the program/strategy is existing or new; (2) if existing, the proceeding where the program/strategy costs have been subjected to Commission review; (3) if new, identification of any memorandum account where related costs are being tracked and an explanation of how double tracking is prevented;[45] (4) whether the program/strategy is implemented in compliance with existing

[41] Commission Rulemaking (R.) 08-11-005 and R.15-05-006.
[42] *See* discussion in Section 2.1 above, in particular footnote 15.
[43] http://www.cpuc.ca.gov/firethreatmaps/
[44] P.U. Code § 8386(c)(14).
[45] SDG&E filed Advice Letter 3333-E on January 16, 2019 requesting to establish the Fire Risk Mitigation Memorandum Account (FRMMA) pursuant to P.U. Code § 8386(j). As stated in Advice Letter 3333-E, SDG&E has wildfire mitigation projects and programs pending before the CPUC in its TY 2019 GRC. If such projects and programs are approved in the TY 2019 GRC or other applicable proceedings, SDG&E will reconcile the activities recorded in the FRMMA with final CPUC decisions so that there is no overlap in cost recovery. Further, in accordance with P.U. Code § 8386(e), following approval of this Plan, SDG&E plans to establish a separate memorandum account to track costs incurred to implement the Plan. SDG&E's interpretation of the memorandum account pursuant to P.U. Code §8386(e) is that this

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regulations or exceeds current regulatory requirements; (5) if a program/strategy is identified as meeting a current regulatory requirement, a citation to the associated order, rule, or code; (6) a description of how the implementation of the program/strategy mitigates one or more of the wildfire risks or drivers identified in the Plan. Additionally, each of the identified preventive strategies and programs is delineated into one of the following categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and (5) Response and Recovery.

4.1 Operational and Engineering Practices

4.1.1 Operating Conditions

Using its situational awareness capabilities and a formalized escalation approach, SDG&E monitors the potential for wildfire throughout its service territory on a daily basis. As the conditions for wildfires increase, SDG&E can deploy additional layers of safeguards, or as a last resort, it might choose to shut-off power to certain areas of its service territory in the interest of public safety.

SDG&E uses a variety of situational awareness inputs to determine the appropriate operating environment given current and expected wildfire conditions. Among these inputs for situational awareness are the Fire Potential Index (FPI), Santa Ana Wildfire Threat Index (SAWTI), and field observations. These are summarized below and discussed in greater detail within Section 4.5 of this Plan.

- **Fire Potential Index:** Using its meteorological staff and over 30 years of historical weather data from the National Weather Service, local airports, and its own proprietary database, SDG&E prepares a daily detailed forecast of weather conditions relevant to SDG&E's operations. The forecasts are a combination of weather parameters and vegetation conditions and are used to create the FPI forecast. The FPI is used for operational decision-making to reduce fire threats and risks. It is developed daily and provides a rolling seven-day forecast of the potential for wildfires so that SDG&E personnel can plan and prepare.
- **Santa Ana Wildfire Threat Index:** The SAWTI is a web-based tool, developed in a public/private collaboration, that classifies the wildfire threat potential associated with the Santa Ana winds. It uses wind speed, humidity, and fuel conditions to determine the potential severity of an event in terms of its impact on the fire environment. The SAWTI is updated daily by the United States Forest Service (U.S. Forest Service) Geographic Area Coordination Center. They generate a six-day forecast of large wildfire potential, which will result in one of four classification levels from "marginal" to "extreme." The SAWTI is also used for operational decision-making to reduce wildfire threats and risks.
- **Field Observations:** SDG&E strategically positions field personnel throughout its service territory based on system conditions, weather, and wildfire potential, which may be considered a threat to SDG&E facilities. Field observers inform operational decisions by

account will track the costs incurred to implement the Plan in its entirety thus making it a tracking account for which SDG&E will not seek future cost recovery.

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providing real-time input regarding onsite conditions, such as, debris, vegetation, and system status.

SDG&E established four Operating Conditions to monitor wildfire potential and among other thing, inform decisions regarding recloser settings, sensitive relay settings, testing procedures, and work restrictions. These Operating Conditions are: Normal Condition, Elevated Condition, Extreme Condition, and RFW Condition, which are summarized below and discussed in more detail in Appendix C.[46]

- **Normal Condition** is declared when it has been determined by SDG&E that the burn environment is not conducive for catastrophic wildfires within its service territory. The FPI forecast is in the range of 1 through 11.
- **Elevated Condition** is declared when SDG&E determines that the burn environment has become conducive to wildfires within its service territory. The FPI forecast is in the range of 12 to 14.
- **Extreme Condition** is declared when SDG&E determines that a combination of high winds, low relative humidity, and the burn environment will create critical wildfire weather conditions in its service territory. The FPI forecast is 15 or above, and specific areas of SDG&E's service territory have the potential for catastrophic wildfires.
- **RFW Condition** is declared by the National Weather Service when high winds and low relative humidity are forecasted to occur for an extended period. During these conditions, there is the potential for catastrophic wildfires. Depending on the weather zone impacted by the declared RFW and communicated by SDG&E's meteorological staff, various operational restrictions and procedures appropriate to each impacted operating district will be triggered and implemented.

4.1.2 Recloser Protocols[47]

SDG&E has deployed overhead distribution reclosers, with a particular focus in the HFTD. A recloser is a switching device that is designed to detect and interrupt momentary faults (i.e., a sudden undesirable significant increase in current from either external forces or equipment malfunction). The device has the ability to reclose automatically and open back up if a fault is still detected. The automated reclosing feature can be disabled, so if a device detects a fault it will trip open and remain open. These overhead distribution reclosers allow SDG&E to operate its system in a variety of configurations depending on input from its meteorologists, known localized conditions, and its declared Operating Condition. They also provide SDG&E the ability to sectionalize various elements of its distribution system to efficiently manage system operations and reliability, which results in quicker restoration times for customers. The

[46] Appendix C provides SDG&E's current chart of Operating Conditions. During drought conditions or periods of very dry weather, SDG&E may periodically operate more conservatively than noted in the Operating Conditions chart.

[47] For protocols for de-energizing portions of the electrical distribution system, refer to Section 4.7 herein.

overhead distribution reclosers and other Supervisory Control and Data Acquisition (SCADA)-controlled reclosers are managed remotely by SDG&E.

Under Normal Conditions, overhead distribution reclosers operate to clear faults by isolating the least amount of customers and reducing the overall exposure to the electric system. Under Elevated Conditions, SDG&E has seen a need to make overhead distribution reclosers operate faster and more sensitively in order to clear faults in a manner to reduce the energy of the fault as much as possible. By reducing the resultant energy of a fault, the probability of causing significant damage to the surrounding area is reduced. Because of this need, SDG&E has developed the ability to enable more sensitive relay settings on overhead distribution reclosers. These sensitive relay settings improve both the sensitivity of fault detection, and the speed at which faults are cleared. These sensitive settings can clear faults on distribution circuits up to a full second faster than normal settings, reducing fault energy up to 66%. These more sensitive settings are remotely enabled via SCADA, allowing for real-time adjustments triggered by adverse weather conditions.[48]

Along with a wide deployment of distribution overhead reclosers with sensitive setting functionality, SDG&E has also installed a subset of pulse reclosers within the HFTD that have the added functionality of reducing fault energy during reclosing operations. Pulse reclosers can operate at significantly reduced energy flows during reclosing operations, which reduces the probability of a source ignition resulting in damage to facilities and the surrounding area.

In an Elevated Condition or higher, all distribution reclosing functions are disabled on circuits located within the HFTD but may include other circuits if the burn environment is conducive to large wildfires. If needed, SDG&E may enable the sensitive relay setting for overhead distribution reclosers in areas of most adverse wildfire weather conditions.

4.1.3 Other Special Work Procedures

SDG&E has designated the type of work activity that can be performed for each of the Operating Conditions.[49] As conditions increase in severity, work activities may still be performed, but some might have additional mitigation requirements. In other situations, work activity might cease. The following summarizes the work activity guidelines for each Operating Condition.

- Normal Condition: Normal operating procedures are followed with baseline tools and equipment.
- Elevated Condition: Certain work activities may require additional mitigation measures in order to proceed with work. The additional mitigative measures will be documented.
- Extreme and RFW Conditions: Most overhead work activities will cease, except where not performing the work creates a greater risk than doing so. In those cases where work needs to be performed, an SDG&E fire coordinator is consulted, and any required

[48] A sensitive relay profile alters the settings of the isolating device to reduce the exposure of fault current by reducing the relay trip time and lowering the pick-up values, which makes the device both very fast and very sensitive, so faults will clear as quickly as possible.

[49] How these Operating Conditions are determined is explained in detail in Section 4.1.1 above.

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additional mitigation steps are implemented. Status of the work, ceased or continued, will be documented.

These guidelines are generally sufficient for most routine types of activities performed in the wildland areas, which consist of undeveloped areas covered in native vegetation. For non-routine, or especially hazardous work, SDG&E's Fire Coordination group is consulted to determine if additional mitigation requirements are needed.

4.1.3.1 Project Activity Levels

The U.S. Forest Service relies on the Project Activity Level (PAL) system, which was designed to help fire and timber resource managers establish the level of industrial precaution for the following day. PAL utilizes outputs from the National Fire Danger Rating System (NFDRS) to inform decisions aimed at reducing the risk of fire on National Forest land, particularly in the timber or mountain areas, and applies to the Cleveland National Forest. Forests receive a daily announcement of the forecasted PAL for the next day, and it is an indication of any additional work restrictions or mitigation measures that will be necessary to perform work in the designated area.

4.1.4 Fire Coordination - Firefighting Assets and Resources

An important line of defense against the ignition of fires is a well-equipped, well-trained, and alert workforce. SDG&E endeavors to emphasize a culture of fire prevention within the Company. To that end, SDG&E has established programs, acquired resources, and adopted work rules and complementary training programs designed to minimize the likelihood that SDG&E's facilities or field work will be associated with the ignition of a fire.

4.1.4.1 Wildfire Infrastructure Protection Teams (Contract Fire Resources)

SDG&E contracts for wildfire prevention and ignition suppression services, Contract Fire Resources (CFRs), from mid-June through the end of November. SDG&E may extend CFR coverage into other months depending on Operating Conditions or when specific needs arise. These CFRs accompany SDG&E construction crews and other electric workers to provide site specific fire prevention and ignition mitigation during the work day. The CFRs also standby in case of crew member medical emergencies that may occur while work is being performed. During RFW events or when the FPI is "extreme," additional CFRs are deployed with electric troubleshooters in the field so that ignitions that may result from work performed by a troubleshooter can be suppressed quickly especially in high fire risk areas. A typical CFR strike team includes five engines (trucks) and a leader. The fire suppression engines that CFRs predominately use are ICS Type VI, which carries two qualified fire fighters, firefighting hose, valves, and approximately 300 gallons of water.

4.1.4.2 Aviation Firefighting Program

SDG&E has developed and implemented an effective, year-round aerial firefighting program to support the fire agencies in its service territory. SDG&E has an agreement with the County of San Diego, CalFire, and the Orange County Fire Authority for aerial firefighting. Dispatch of SDG&E's aviation firefighting assets is performed through CalFire.

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As discussed in this Plan, the threat of wildfire risk throughout California and the region is ongoing and year-round. When wildfires occur north of SDG&E's service territory, there is the potential that CalFire may divert other aerial firefighting resources to emerging wildfires in other parts of the state. This can lead to reduced aerial firefighting capability in the San Diego region. Currently, SDG&E has a lease for year-round use of an Aircrane firefighting helitanker. To further mitigate the threat of a year-round wildfire risk, SDG&E plans to enter into a one-year lease for an additional firefighting helitanker, a Sikorsky S-60, which unlike the Aircrane, has night fly capability.

4.1.4.3 Industrial Fire Brigade

SDG&E has contracted a full-time Industrial Fire Brigade (IFB), which is available 24-hours a day, year-round. The IFB differs from the CFRs in that, the IFB is specially trained in fighting fires involving electrical equipment (in particular substations and large transformers) as well as flammable liquids. The IFB members are housed in facilities located near the geographical center of the SDG&E service territory and are fully equipped to handle utility-related fire emergencies.

The IFB incorporates a portable fire-suppression trailer equipped with 300 gallons of Class B alcohol resistant firefighting foam, 500 pounds of chemical extinguishing agent, a 500 gallon-per-minute monitor, and hoses designed to work with hydrants or other fire apparatus. SDG&E also provides three additional trailers to strategic fire agencies that are proximate to key SDG&E facilities.

The IFB is also responsible for the development of comprehensive pre-emergency response plans for each SDG&E facility. These plans are developed for SDG&E's high-value assets first, including SDG&E's power plants, peaker stations, and extra-high-voltage substations, and are designed to significantly improve emergency response at each of these facilities.

4.1.4.4 Fire Coordination Personnel

As discussed in Section 5.2.3.2 below, SDG&E employs a full-time staff of five fire coordinators. The current fire coordinators on staff have over 150 years of fire suppression, prevention, and fire behavior experience collectively.

4.1.4.5 Ignition Management Program

SDG&E has established an Ignition Management Program (IMP), which tracks ignitions and potential ignitions and perform root cause analysis on each ignition or potential ignition to detect patterns or correlations. Such ignition or potential ignition events will be assigned to a mitigation owner from the business unit most logically positioned to eliminate or reduce future events of a similar nature. To that end, SDG&E is considering employing a forensic fire coordinator to implement and manage this program.

4.1.4.6 Fuel Management

Protection of SDG&E's electric system from wildfires is critical to system reliability and first responder and public safety. Wildfires burning near electric facilities pose a threat to public and firefighter safety and can also affect reliability if circuits fault because of smoke columns. Fuel management projects can lower the risk of catastrophic wildfires by reducing and

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removing wildland fuel accumulations, such as live and dead vegetation. SDG&E, in partnership with fire departments, fire safe councils, and other stakeholders will seek to implement a comprehensive fuels management program to reduce wildfire fuel accumulations.

SDG&E has been involved with the following fuel management projects and initiatives:

- Member of the National Cohesive Wildland Fire Management Strategy – Western Regional Strategy Committee, which is a coalition of federal partners and other stakeholders committed to working together toward fire resilient landscapes, creation of fire adapted communities, and effective fire response through the treatment (reduction) of wildland fuels;
- Establishment of the Campo Indian Reservation fuel break, an approximately 50-acre fuel break adjacent to the international border and along the 500 kilovolt (kV) Southwest Powerlink;
- Funding of the Sunrise Powerlink Fire Mitigation Grant Program (CPUC mandated), which annually awards grants to eligible parcels to fund defensible space, structure hardening, and community fire protection projects;
- 4,000 acres of SDG&E lands currently receiving fuel treatment (by Realty Services) for the removal of wildland fuels;
- Various other projects/initiatives in the conception phase[50] with Orange County Fire, CalFire, and Camp Pendleton Fire.

4.2 Inspection Plan

SDG&E has formalized inspection plans for each of its three electrical infrastructure categories: distribution systems, substation systems, and transmission systems.

4.2.1 Distribution System Inspection

4.2.1.1 SDG&E Corrective Maintenance Program Inspections

SDG&E is required to inspect its electric distribution system according to Commission GO 165. GO 165 establishes inspection cycles and record-keeping requirements for utility distribution equipment. In general, utilities must patrol their systems once a year in urban areas and HFTD Tier 2 and Tier 3. Patrols in rural areas outside of HFTD Tier 2 and Tier 3 are required to be performed once every two years. SDG&E, however, exceeds the basic requirements and performs patrols in all areas on an annual basis. In addition to the patrols, utilities must conduct detailed inspections at a minimum every 3-5 years, depending on the type of equipment. For detailed inspections, the utilities' records must specify the condition of inspected equipment, any problems found, and a scheduled date for corrective action. Utilities are required to perform intrusive inspections of distribution wood poles depending on the age and condition of the pole and prior inspection history.

[50] The first phase (stage) of any fuel treatment project is the "concept phase" wherein the project is conceptualized and discussed amongst various stakeholders. In this instance, SDG&E is working with the Orange County Fire Department to conceive possible fuel treatment (vegetation reduction) projects.

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SDG&E's Corrective Maintenance Program (CMP) is an inspection program, which consists of six different inspection categories with various, corresponding inspection cycle intervals per program. These are summarized in Table 3 below. These inspections are required by GO 165 unless otherwise noted.

Table 3: SDG&E Distribution System Inspection Cycle Intervals

Inspection Categories	Inspection Cycle Interval (in years)
• **Overhead Detailed** ○ Electric distribution structures and equipment ○ Electric distribution equipment on Communication Infrastructure Provider (CIP) poles ○ Electric distribution equipment on transmission poles	5
• **Underground Detailed**	
○ Underground Above Ground Dead-front, Internal and External Inspections (AGDF)	5
○ Underground Above Ground Live-front, Internal and External Inspections (AGLF)	5
○ Underground Subsurface with Equipment, Internal Inspections (SS3)	3
○ Underground Oil and Gas Switch Inspections (SW3)	3
• **Underground Subsurface without Equipment, Internal Inspections (SS10)**[51]	10
• **Wood Pole Intrusive Inspections (POIN)** ○ Electric distribution wood poles	10
• **Patrol (PATROL)**[52] ○ Electric distribution both overhead and underground structures and equipment ○ SDG&E owned or operated streetlights are inspected for structural problems or hazards.	1
• **QA/QC Inspections (HFTD Tier 3)**[53] ○ High Fire Threat District Tier 3	3

[51] This inspection type is not mandated by GO 165, however, SDG&E continues to perform this type of inspection.

[52] Although GO 165 allows for a two-year cycle, SDG&E patrols rural areas outside of Tier 2 and Tier 3 of the HFTD on a one-year cycle.

[53] As discussed in Section 4.2.1.2 below, these inspections exceed the requirements of GO 165.

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4.2.1.2 Quality Assurance/Quality Control Inspections in HFTD Tier 3

SDG&E has implemented Quality Assurance/Quality Control (QA/QC) standards and programs throughout its service territory, with a special focus in the HFTD during fire season. These inspections exceed the requirements of GO 165. These proactive programs are designed to identify potential structural and mechanical problems before they fail. SDG&E has performed QC inspections of its overhead electric distribution poles in high risk fire areas with a focus on identifying items for which maintenance would improve fire safety and reliability, with a goal of mitigating the probability that SDG&E's overhead electric system, facilities, and equipment will provide the source of ignition for a fire. These QC inspections were conducted through 2016,[54] after which, SDG&E decided to continue the QC inspections in the subsequent years. In 2018, when the CPUC adopted the statewide fire threat map, SDG&E began applying the QA/QC three-year cycle to the newly defined HFTD Tier 3.

In addition, SDG&E performs a system maintenance patrol (similar to those specified by GO 165) of the entire overhead electric system in the HFTD on an annual basis. Safety related non-conformances identified in those patrols are scheduled for follow up repair.

Over the years, SDG&E has enhanced its system-management programs. Inspection and repair of SDG&E's electric system have particularly intensified in the HFTD, with CPUC mandated annual patrols in the HFTD Tier 3.

During 2016 to 2018, SDG&E performed QA/QC inspections on an average of 15,000 poles annually (approximately one-third of the distribution poles) in its then-existing "extreme" and "very high" fire threat areas. SDG&E continues to conduct the QA/QC detailed inspections in the newly defined HFTD Tier 3. Annual adjustments to the HFTD map, if any, will be reflected in the scope of this QA/QC program.

4.2.1.3 Monitoring and Auditing

SDG&E utilizes various reports to monitor its CMP progress, for both inspections and repairs. In addition, regular monthly meetings are held with various internal construction and operations centers to discuss detailed CMP progress.

Upon completion of prescribed actions necessitated by the CMP and the QA/QC inspections, SDG&E conducts an audit to ascertain the effectiveness of the inspections. This audit is run by SDG&E's operational and engineering managers, who are responsible for certain districts. They typically select about 1.5% of the combined (overhead and underground) territories and assess their conditions to see if the appropriate improvements have been properly carried out.

4.2.2 Substation System Inspection

Substation inspections are CPUC mandated and while they are conducted primarily for reliability, they have incidental wildfire mitigation benefits. The main goal of the Substation System Inspection and Maintenance Program is to promote safety for SDG&E personnel and contractors by providing a safe operating and construction environment. Additional goals

[54] Pursuant to an agreement with SED (formerly the Consumer Protection and Safety Division) as approved by D.10-04-047.

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include: meeting all of the requirements of GO 174, achieving a level of station availability satisfactory to SDG&E as well as assuring compliance with all sections of the California Independent System Operator (CAISO) Transmission Control Agreement (TCA). These are accomplished through inspection and managed maintenance of the electrical transmission and distribution substations.

4.2.2.1 Inspection Frequencies

SDG&E's routine substation inspections are completed at reoccurring cycles as described in Table 4 below. Planned frequency is the cycle for which maintenance is regularly initiated. Acceptable frequency is the planned frequency plus the due time or condition tolerance within which maintenance shall be completed to be in compliance with filed maintenance practices.

Table 4: Inspection Frequencies

Inspection	Planned Frequency	Acceptable Frequency
Substation Security Check	Once per week	9 per 12 weeks
Substation Inspection	Once per month (Priority 1); Once per two months (Priority 2)	10 per every 12 months (Priority 1); 5 per every 12 months (Priority 2)
Substation Infrared Inspection	12-month Trigger	Due in 15 months

4.2.3 Transmission System Inspection

All SDG&E transmission system facilities covered by the Transmission Inspection practice are routinely inspected using visual and infrared inspection techniques. Inspections are completed by both ground and air. Non-routine inspections are scheduled depending on operational need. Inspections/patrols of all structures, attachments, and conductor spans are performed to identify facilities and equipment that may not meet California Public Resources Code (PRC) §§ 4292 and 4293 or GO 95 and GO 128 rules. SDG&E annually evaluates its maintenance practice to ensure that inspection intervals meet or exceed regulatory requirements.

4.2.3.1 Inspection/Patrol Types

To maintain transmission system reliability, SDG&E conducts a variety of inspection types to promote the safety of the general public as well as the personnel engaged in the maintenance and operation of overhead and underground electrical facilities. Inspections/patrols are prioritized based on safety, reliability, and operational need. The types of inspections/patrols that are performed are summarized in Table 5 below.

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Table 5: Inspection Types

Inspection Types	Inspection Cycle (Years)
Fault/Safety Patrol	As Needed
Detailed Overhead & Underground Inspection/Patrol	Three
Visual and Infrared Overhead Inspection/Patrol	Annual
Special Inspection	As Needed
Climbing Inspection	As Needed
Wood Pole Ground Line Inspection and Treatment	Ten
Miscellaneous Inspection	As Needed

In addition to the inspections/patrols specified in the maintenance practice, SDG&E conducts an additional aerial patrol of 69kV transmission lines in HFTD Tier 3 prior to September 1st each year. Conditions of concern related to fire safety that are identified are addressed, as specified in GO 95 Rule 18.

4.2.3.2 Access Road Maintenance

SDG&E performs maintenance of a majority of its access roads on a two-year cycle, barring any permitting or agency delays. Road segments are tracked electronically to document the date and type of maintenance performed, who performed the maintenance, and which roads have biological or cultural restrictions. This road maintenance program is designed to provide SDG&E crews reliable access to transmission structures. Many public agencies utilize SDG&E's transmission access roads to traverse the back country and respond to wildfires that may be in the area.

4.2.4 Geographic Information System Data

Geographic information system (GIS) data of electric infrastructure qualifies as critical energy infrastructure information under federal law and as such, should be not be disclosed to the public.[55] SDG&E handles requests for GIS data of its electric infrastructure on a case-by-case basis and if disclosure is warranted, will provide the requested information confidentially. In response to the increasing desire to have the GIS data of electric facilities available to support statewide emergency preparedness, SDG&E is collaborating with agency stakeholders to find the best solution to provide the requested information in a timely manner. The initial step that

[55] 18 Code of Federal Regulations (CFR) § 388.113. Specifically, critical energy infrastructure information is defined as "specific engineering, vulnerability, or detailed design information about proposed or existing critical infrastructure that: (i) relates details about the production, generation, transportation, distribution of energy; (ii) could be useful to a person in planning an attack on critical infrastructure; (iii) is exempt from mandatory disclosure under the Freedom of Information Act, 5 USC § 552; and (iv) does not simply give the general location of the critical infrastructure." 18 CFR § 388.113(c)(2).

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SDG&E plans to take to support this effort is to develop an ESRI Cloud Managed Services infrastructure for the controlled sharing of the requested information.

4.3 System Hardening Plan

SDG&E consistently evaluates, in consultation with vegetation management, environmental services, and construction services, prudent changes and improvements to its physical assets that could be made to harden the system against wildfire risk. SDG&E has implemented preventative operations, along with a construction and maintenance plan consistent with these evaluations. SDG&E has programs underway to strengthen and modernize its system as discussed in more detail below.

4.3.1 Design and Construction Standards

SDG&E has advocated for modernizing the rules and regulations governing the design and construction of overhead electric and communications facilities. To reflect the more stringent design and construction standards adopted by the Commission and to improve the performance of the SDG&E electric system in terms of meeting fire-prevention goals, the SDG&E Facilities Design Manual was modified to include an entirely new section aimed at providing guidance for hardening circuits against the risk of fire. These modifications include both proactive measures designed to reduce the incidence of ignitions and reactive measures by which SDG&E can respond to the threat of fires and mitigate the threat of fires.

4.3.2 Testing and Deploying Emerging Technologies

SDG&E continues to evaluate and incorporate new technologies and equipment into its overhead electric system. SDG&E's Electric Distribution Engineering department is responsible for evaluating and creating new equipment and use standards for emerging and pre-commercial technologies. Using equipment failure data, the department makes recommendations regarding which technologies should be incorporated into the SDG&E system and which could be improved prior to application. This department evaluates new types of technologies which may improve electric reliability and public safety and gives special attention to technologies that may contribute to SDG&E's fire safety goals and objectives. As an example, SDG&E is beginning to apply and analyze more advanced fault-clearing equipment that contain algorithms to improve the ability of the system to clear "wire-down" faults more quickly, which will serve to reduce the potential such faults might provide an ignition source.

4.3.3 Facility Analysis

In addition to adding, redesigning, and replacing facilities and elements as described above, SDG&E has implemented more stringent monitoring and inspection programs in the HFTD, which will intensify its efforts to identify facilities or elements that may need repair. As an example of these efforts, SDG&E is developing the use of pole-loading algorithms which more accurately calculate working loads and stresses. In addition, SDG&E coordinates these activities with communications infrastructure providers who jointly use SDG&E's poles and facilities.

SDG&E also maintains a comprehensive outage database, which is used for reliability measurement and reporting purposes. Correlations between outages and locations are analyzed to determine whether certain equipment is prone to outage or has the potential to be

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an ignition source. This analysis is then matched to weather and other environmental conditions. Where it is determined that certain types of hardware have higher incidents of failure and potentially a higher incidence rate for ignition, they are replaced or prioritized for replacement. Vegetation Management, which is discussed in Section 4.4 below, also maintains a comprehensive outage database. Outages related to trees and or vegetation are investigated, documented, and the results analyzed to determine if additional pruning or removal measures are warranted to prevent any reoccurrence.

SDG&E uses three-dimensional light detection and ranging (LiDAR) surveys throughout its service territory. The most prevalent use of LiDAR has been for engineering and design purposes on the electric transmission system, including areas in the HFTD. In particular, this technology is being used to perform aerial scans of the 69kV transmission system in the HFTD on a three-year cycle. These surveys provide detailed three-dimensional depictions of SDG&E facilities, terrain, vegetation, and other obstacles in the vicinity of SDG&E's facilities. Once the LiDAR and imagery data is processed, it can be ingested into Computer-Aided Design (CAD) tools such as Power Line System Computer-Aided Design and Drafting (PLS-CADD). PLS-CADD can then be used to determine wire tensions, sag and sway, and can be used to calculate the structure mechanical loading (i.e., pole loading).

It can also analyze the clearances to vegetation, ground or other wires to verify compliance with GO 95 or other relevant standards. If potential issues are discovered along the 69kV system in the HFTD, SDG&E will address them per GO 95 requirements and SDG&E standards. In 2013, SDG&E began applying this same technology extensively on the distribution system through the FiRM program (described in Section 4.3.9 below), which has fire hardened over 7,000 poles and 350 miles of conductor to date in the HFTD. New distribution programs such as PRiME (described in Section 4.3.10 below), will utilize this technology as well.

4.3.4 Oversight of Activities in the Rural Areas

In 2016, SDG&E formed an Electric Risk Analysis (ERA) team to address safety and reliability risks for electric distribution infrastructure across the entire service territory with continued focus on reviewing equipment failures that cause wire down events.[56] The ERA oversees the evaluation of equipment data to support the various fire-hardening activities using these principles:

- Inform and utilize risk-informed prioritizations to address risk-mitigation;
- Improve design specifications to reduce the potential for igniting fires;

[56] In early 2010, SDG&E formed a multi-disciplinary technical team of subject matter experts called the Reliability Improvements in Rural Areas Team (RIRAT). RIRAT was tasked with: developing a multi -dimensional understanding of the complex fire-risk issue within the SDG&E service territory; assessing the conditions which pose the greatest risks related to fire; determining the level of risk mitigation that could be provided by various proposed projects; and assigning priorities to capital and operating programs and projects that could address fire-related risks in the high fire risk areas. In 2016, the RIRAT was replaced with the ERA team.

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- Consider and, to the extent prudent and cost-effective, employ technology-based solutions to reduce fire risks and improve overall system reliability and safety;
- Systematically consider and evaluate options such as:
  - Fire-hardening sections of feeder circuits or individual circuit branches;
  - Strategic undergrounding to reduce the exposure of ignition from overhead facilities;
  - Adjusting protective equipment by revising settings, balancing loads, adding reclosers, replacing expulsion fuses with CalFire approved fuses, replace/remove high risk assets, and/or reduce fuse size; and,
  - Employing new construction standards and/or technologies, such as insulated overhead conductors, wireless fault indicators, "off-grid" solutions, and advanced reclosers;
- Replace higher-risk equipment based upon statistical analytics.

4.3.5 Asset Management

SDG&E is in the process of developing and implementing an asset management program to align with its overall risk management objectives. The new asset management system conforms with ISO 55000, an international standard that specifies the requirements for the establishment, implementation, maintenance, and improvement of an asset management system. Benefits of such a system may include enhanced asset safety, improved performance, managed risk, demonstrated compliance, and improved efficiencies and effectiveness of assets and operations. Asset Management is a critical element of SDG&E's focus on creating a sustainable and high-quality Safety Management System for electric operations.

SDG&E believes asset management will provide a means to optimize the Company's risk, performance, and investments while meeting or exceeding safety and regulatory objectives. A comprehensive asset management system will provide the access to and integration of data throughout the asset life cycle to develop analysis and a health index for critical assets. Using a health index of its assets, SDG&E can identify which assets have a likelihood of failure and the respective consequence(s) of the failure(s). Based on this information, asset strategies would be evaluated and implemented to manage the asset in a manner that aligns with SDG&E's overall risk management strategy. Asset management intersects with wildfire mitigation and prevention when failed assets located in the HFTD can potentially be the source of an ignition.

4.3.6 Overhead Transmission and Distribution Fire Hardening

SDG&E is committed to the fire hardening of its 69kV transmission and associated 12kV distribution system located in the HFTD. This hardening effort is a multi-faceted approach that starts with enhanced design criteria. Previous lines were constructed to withstand working loads under stress of 56 miles per hour (mph) wind speeds. The new electric lines are designed to withstand working loads under the stress of 85 mph wind speeds, and in some specific cases, up to 111 mph based on known local wind conditions. The new lines are being designed utilizing steel poles instead of wood. Steel poles are a more reliable construction material, giving more confidence in their designed strength and are more resilient should a fire occur leading to faster restoration times. These new steel pole facilities are being installed in

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conjunction with the application of higher strength conductors and increased spacing between lines beyond the requirements of GO 95, resulting in a decrease in the likelihood of energized lines coming into contact with one another or arcing after being struck by flying debris. In addition, SDG&E's current design standards now reflect the use of the enhanced design criteria, steel poles over wood poles, high strength conductor, and increased conductor spacing in the HFTD. To date, SDG&E has hardened 19% of the HFTD by installing over 15,000 new steel poles and plans on further investment to continue to these efforts.

4.3.7 Underground Circuit Line Segments

The Commission approved a tariff rule change for SDG&E,[57] which allows for conversion of existing primary voltage overhead facilities to underground facilities along public streets and roads, and on public lands and private property in more fire prone areas where undergrounding is the preferred method to reduce fire risk and enhance reliability. SDG&E formed a team with expertise in the undergrounding of distribution systems and facilities to evaluate the undergrounding of circuit segments located in the HFTD within primarily the County of San Diego jurisdiction. These experts provided the County of San Diego with an understanding of the potential for undergrounding portions of the overhead system to mitigate the risk of fire and the results are being used on circuit analysis to propose underground portions where feasible. Conferences with County management and leadership are in progress to gain agreement on individual project prioritization. Design on these conversions are scheduled to begin in 2019 with anticipated construction in 2020.

In addition, SDG&E is evaluating undergrounding distribution lines in strategic situations, where a small amount of undergrounding would have a large impact by reducing a significant risk or limiting exposure to Public Safety Power Shutoffs for critical customers and communities.

4.3.8 Cleveland National Forest Fire Hardening

SDG&E currently operates and maintains a network of electric facilities located within the Cleveland National Forest (CNF). In 2016, SDG&E received a Master Special Use Permit (MSUP) to operate and maintain facilities within CNF. Specifically, the MSUP allows SDG&E to develop a series of projects and activities aimed at increasing the safety and reliability of existing electric facilities within and near the CNF. Final approval for these projects and associated permits have been received and work has been on-going since 2016.

These projects will increase safety and reliability of SDG&E's system by fire hardening existing electric infrastructure that currently serves the U.S. Forest Service, emergency service facilities (i.e., fire, communication, and other), campgrounds, homes, businesses, and other customers within the CNF and surrounding areas. The projects include the fire hardening of facilities and select undergrounding of several existing 12kV and 69kV electric facilities spread throughout an approximately 880 square mile area in the eastern portion of San Diego County. The existing electric lines located within CNF also extend outside of CNF boundaries. The overall project includes operational components complementing SDG&E's Community Fire Safety Program,

[57] D.14-01-002, adopting Tariff Rule 20D.

which in turn includes community outreach, new fire prevention measures, and enhanced emergency response.

The project design was based on various recommendations addressing fire prevention and the U.S. Forest Service's environmental values and aesthetics. Using an analytical matrix reflecting elements of fire risks and environmental concerns, SDG&E and the U.S. Forest Service collaborated to determine which sections of the electric system should be upgraded. Each segment required a custom solution based on many factors, including the location of the customer being served by the distribution system, the topography of the land, and various biological, cultural, and environmental factors.

Construction commenced on the Cleveland National Forest project in late 2016 and is planned to continue through 2020. Through November 2018, there have been a total of 63 miles of electric transmission and distribution lines fire hardened. This includes 45 miles of 69kV transmission lines and 516 structures replaced with steel and 18 miles of 12kV distribution lines and 302 structures replaced with steel. For 2019, SDG&E plans to replace 28 miles of 69kV transmission lines and 243 structures as well as 22 miles of distribution lines and 308 structures. SDG&E plans to complete construction on fire hardening activities on this project in 2020.

4.3.9 Fire Risk Mitigation

In 2013, SDG&E established the FiRM program,[58] an overhead distribution fire hardening re-building effort. The goal of the FiRM program is to address fire risk by hardening facilities in the HFTD by replacing aged line elements, utilizing advanced technology, and by safeguarding facilities by designing for known local weather conditions. FiRM is also tasked with developing a multi-year plan for the rebuilding of circuits of greatest fire-related risk. Prioritization and scoping of each FiRM project are driven largely by analysis using the WRRM and input from multiple stakeholders in the Company including operations and engineering.

Factors considered in the prioritization and scoping process include, but are not limited to, recent occurrences of a "wire-down," wind and weather conditions, fire risks, outage history, conductor size and type, condition of equipment, environmental conditions, and resulting customer impacts. FiRM projects are scoped on a circuit-by-circuit basis by considering various risk factors. Risk mitigation methods include fire-hardening older conductor and poles, as well as other targeted fire risk mitigation methods of the circuit, including removal of equipment, long span elimination, and advanced technology implementation (namely, falling conductor protection and LiDAR survey data captured via Unmanned Aerial Vehicles (UAVs)).

To date, the FiRM program is currently 24% complete having replaced over 7,000 poles and 350 miles of wire. SDG&E plans to continue this effort for the foreseeable future as there are still 1,100 miles of aged high-risk conductor remaining within the HFTD in SDG&E's service territory. At this current rate of reconductoring approximately 84 miles of high-risk conductor per year, it will take SDG&E approximately 13 years to complete this focused effort with the current

[58] This program was requested in SDG&E's TY 2019 GRC (A.17-10-007), which is still pending. Funding levels and associated activities are dependent on the outcome of this pending GRC.

resources and budget. However, given the California fires of 2017 and 2018 and the elevated risk climate change has brought to the state, SDG&E is planning to accelerate this effort to replace these older line elements by 2025 (years 2019-2025). The increased scope of work would begin engineering and design in 2019 and construction in 2020.

4.3.10 Pole Risk Mitigation and Engineering

The Pole Risk Mitigation and Engineering (PRiME) program[59] was developed by SDG&E to assess pole strength and integrity considering loading conditions, third party attachments, localized weather conditions, and remaining pole strength throughout SDG&E's service territory. PRiME does not overlap with existing programs, such as FiRM or CNF. SDG&E's goal is to perform pole loading assessments on 170,000 wood distribution poles throughout its service territory. PRiME will focus its efforts in HFTD Tier 3 and Tier 2. Assessments on SDG&E's highest risk poles within Tier 3 and Tier 2 of the HFTD will be completed prior to poles located outside of the HFTD. Poles identified that require construction activities through assessment and follow-up analysis, will be remediated as they are identified. SDG&E anticipates performing approximately 700 pole remediations in 2019 and estimates approximately 1,700 pole remediations in 2020. At the current rate, it is anticipated that remediation activities will be completed in eleven years within the HFTD. However, SDG&E is planning to accelerate this effort to complete remediation activities by 2027 (years 2019-2027). The increased scope of work would begin engineering and design in 2019 and construction in 2020.

The tools and information have improved significantly over time, and the PRiME program leverages these improvements including LiDAR imaging of the structures and lines, PLS-CADD modeling software, weather, inspection, and third-party attachment data to take SDG&E well beyond the visual to a full engineering analysis of its overhead assets. This program allows SDG&E to mitigate asset integrity risks within the HFTD.

4.3.11 Expulsion Fuse Replacement

SDG&E continues to enhance its electric distribution system and reduce equipment with potential ignition sources. With the consistent analysis of data, new fire prevention methods and a continued effort by vendors to satisfy California's increasing fire threats, SDG&E is constantly rethinking and analyzing equipment. SDG&E's engagement with vendors to require equipment to be approved by CalFire as an exemption equipment[60] has educated many vendors with the concerns and issues facing not just SDG&E, but all utilities in California. Vendors have understood this challenge and proposed several new products. The new program

[59] This program was requested in SDG&E's TY 2019 GRC (A.17-10-007), which is still pending. Funding levels and associated activities are dependent on the outcome of this pending GRC.

[60] CalFire is the primary fire protection agency with the responsibility for enforcing the requirement for a 10-foot clearing of vegetation around poles or towers. CalFire has the discretion to grant temporary exemptions for equipment that has successfully passed CalFire's defined exemption procedure, which includes a test to determine if the equipment can be classified as fire safe, by not creating arcs, sparks or hot particles that would ignite flammable vegetation. Upon successful completion of the test, the equipment is required to be installed for several years to ensure operation of the equipment does not ignite a flammable vegetation. PRC § 4292.

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detailed below, highlights SDG&E's efforts and continuous strive to reduce ignition sources within the HFTD.

When the distribution system experiences a fault or overcurrent, there are fuses connected to the system to protect its integrity and isolate the fault. These expulsion fuses are designed to operate by creating a significant expulsion within the fuse, resulting in the fuse opening and isolating the fault, and in turn limiting further damage of other equipment. Because of this internal expulsion, the fuses are equipped with a venting system that sends a discharge of energy out of the fuse and into the atmosphere. This external discharge has the potential to ignite flammable vegetation.

To mitigate this potential, SDG&E has developed a three-year program[61] to proactively replace existing expulsion fuses within the HFTD with CalFire approved power fuses.[62] There are approximately 7,100 expulsion fuses in SDG&E's HFTD, and this new program is designed to lessen the chance for an ignition source in the HFTD by reducing external discharges or venting required for the existing expulsion fuses and reducing the energy associated with the fuse operation. In 2019, this program will prioritize the replacement of the expulsion fuses to the CalFire approved power fuses by starting in the Tier 3 HFTD and then moving to Tier 2 HFTD. SDG&E anticipates completing this program by 2021.

4.3.12 Hotline Clamps

Through equipment failure analysis related to wire down outages, SDG&E has identified high risk connectors known as "hotline clamps" that SDG&E intends to replace as part of the Hotline Clamp program. SDG&E has utilized the QA/QC inspections discussed in Section 4.2.1.2 above to identify over 6,000 structure locations with this type of connector within the HFTD. This maintenance program to replace these connectors is planned to begin in 2019, and will continue through 2025.

4.3.13 Wire Safety Enhancement

The Wire Safety Enhancement (WiSE) program[63] is designed to mitigate risk by hardening electric distribution overhead infrastructure and protection systems. WiSE addresses public safety risks in wildland urban interfaces where conductor or connection equipment failures may cause wildfires, and near dense urban populations (e.g., schools, public gatherings) where the likelihood of public contact may be increased.

Conductor equipment failure can pose serious risks to public and employee safety due to potential ignitions in fire vulnerable areas as well as causing serious injuries or fatalities due to touch or step potentials. Although WiSE was originally developed to harden the distribution

[61] This program is new and was not requested in SDG&E's TY 2019 GRC (A.17-10-007). If approved, funding for this program will utilize the FRMMA, which will be subject to a reasonableness review in SDG&E's TY 2022 GRC.

[62] The power fuses are equipment that have been previously granted an exemption from CalFire.

[63] This program was included in SDG&E's 2016 RAMP and TY 2019 GRC (A.17-10-007) as the Small Conductor Replacement Program. Funding levels and associated activities are dependent on the outcome of SDG&E's pending GRC.

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system outside the Tier 3 and Tier 2 HFTD, recent events such as the California wildfires of 2017 and 2018 have provided evidence of the increasing risk to communities within the wildland urban interface. These factors, coupled with record wind speeds and dry vegetation measured in San Diego's coastal canyons in recent months, have caused the need to refocus this program to mitigate potential ignitions within the wildland urban interface located outside the HFTD.

WiSE will apply new technologies to update equipment with hardened construction standards and materials. The resulting infrastructure enhancements may include wire upgrade, connector replacements, switch placements or replacements, long span removals, strategic undergrounding, and modifications to advanced protection systems. Design considerations will be driven by area-specific conditions that could include anti-corrosion materials for connectors or conductors, replacement of wood poles where fire hardening is beneficial, replacing bare wire with covered conductor to reduce wire downs caused by foreign object contact (e.g., avian, vegetation, Mylar balloon, etc.), and strengthening conductors that are vulnerable to high wind storm events.

WiSE will focus on utilizing multi-attribute risk modeling to drive optimal risk reduction with considerations for factors including, but not limited to historic wire down events, projected wire down failures by asset type, proximity to vegetation, condition or age of assets, inspection records, susceptibility of corrosion, meteorology conditions, length of the conductor span, proximity to dense or sensitive public areas (e.g., schools, residences, parks, etc.), and conductors that cross major freeways or roadways. The risk model will be focused on these risk parameters within the wildland urban interface boundary first. In 2019 through 2020, WiSE will prioritize the highest risk circuit elements within the wildland urban interface and commence hardening efforts.

4.3.14 Covered Conductor

SDG&E's vegetation profiles in the HFTD and the wildland urban interface consist mostly of sparse trees and heavy brush. In general, the overhead electrical equipment in these areas are not in close proximity to dense vegetation. Given this specific vegetation profile, SDG&E has focused its hardening efforts on installing high tensile strength conductors to reduce the risk of downed wire; increasing phase spacing to reduce the risk of wire to wire contact; installing steel or composite structures sized to withstand high wind conditions; and deploying advanced protection systems designed to detect and isolate issues quickly and minimize the energy produced when faults occur. SDG&E believes this is a prudent approach for reducing the risk of wildfire to much of its system.

SDG&E also sees the benefits of a targeted approach to installing covered conductor in areas where electric infrastructure is near dense vegetation. However, there are factors that need to be considered when installing covered conductor. If a covered conductor fails and falls to the ground, it is possible that a high impedance fault would occur. High impedance faults, even with sensitive relay settings enabled can be very difficult to detect, leading to the potential for downed energized wires.

Today, SDG&E has over five miles of covered conductors installed where its overhead electrical equipment is in close proximity to dense vegetation and where outage history supports this

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type of installation. SDG&E believes the use of covered conductor in certain applications can be beneficial and will continue to utilize covered conductors in those applications.

4.3.15 Fire Threat Zone Advanced Protection

The Fire Threat Zone Advanced Protection (FTZAP) program[64] develops and implements advanced protection technologies within substations and on the electric distribution system to: reduce and/or mitigate the risks of utility caused fire incidents; create higher visibility and situational awareness in fire prone areas; and allow for the implementation of new relay standards with improved coordination in locations where it is difficult due to lower fault currents.

More advanced technologies such as microprocessor-based relays with phasor measurement (PMU) capabilities, automation controllers, sectionalizing capabilities, line monitors, direct fiber lines, and communication radios comprise a portfolio of devices being installed in substations and on distribution circuits to allow for a more comprehensive protection system along with greater situational awareness via SCADA in the fire prone areas of the HFTD. This portfolio of advanced technology allows SDG&E to implement new protection systems, such as:

- **Falling Conductor Protection** designed to trip distribution overhead circuits before broken conductors can reach the ground;
- **Sensitive Ground Fault** for detecting high impedance faults resulting from downed overhead conductors;
- **Sensitive Profile Relay Settings** enabled remotely on distribution equipment during red flag events to reduce fault energy and fire risk;
- **High Accuracy Fault Location** for improved response time to any incident on the system;
- **Event Reporting** for post analysis of system disturbances or outages;
- **SCADA Communication** to all field devices being installed for added situational awareness; and
- **Protection Integration with Private LTE** as a means of facilitating the communication infrastructure needs.

In 2019, FTZAP aims to replace aging infrastructure in substations such as obsolete 12kV substation circuit breakers, electro-mechanical relays, and Remote Terminal Units (RTUs) with new circuit breakers, microprocessor-based relays, and RTUs that facilitate the requirements of SDG&E's advanced protection systems. On the distribution circuits, FTZAP works with the FiRM program to strategically install and/or replace sectionalizing devices, line monitors, direct fiber lines, and communication radios to facilitate the requirements of SDG&E's advanced protection systems.

[64] This program was requested in SDG&E's TY 2019 GRC (A.17-10-007), which is still pending. Funding levels and associated activities are dependent on the outcome of this pending GRC.

4.3.16 LTE Communication Network

SDG&E plans to deploy long-term evolution (LTE) using a dedicated radio frequency (RF) spectrum. This will improve the overall reliability of SDG&E's communication network, which is critical for fire prevention and public safety. This RF spectrum will be lower frequency with higher transmit power levels, which will allow the LTE network to operate over broader areas and in the presence of foliage. LTE is a globally recognized standard, with a very broad ecosystem made up of multiple vendors that provide equipment that is certified inter-operable. This effectively eliminates the risk of deploying equipment that could be stranded due to a vendor's support being eliminated. It also allows SDG&E to deploy equipment that best fits a particular deployment, whereas proprietary systems generally have a limited number of configurations, there are myriad LTE configurations available to select from.

The LTE network significantly increases the reliability of remote communication, which is critical for the technology discussed in Section 4.3.15 (Fire Threat Zone Advanced Protection) to function as intended. In addition, there are currently holes in the coverage of third party communication providers in the rural areas of east county San Diego that limit SDG&E's ability to communicate with field personnel during red flag crew deployments and Emergency Operations Center activations. The installation of LTE in Tier 3 and Tier 2 of the HFTD will reduce these gaps, allowing for more timely and reliable communication and information from SDG&E's field crews to emergency management leadership in these critical situations.

4.3.17 Automated Reclosers

As part of its Community Fire Safety Program, and as discussed in Section 4.1.2 above, SDG&E has completed a large deployment of overhead distribution reclosers, focusing heavily on the HFTD. While recent Operating Conditions typically have not allowed for the enabling of automated reclosing,[65] this equipment allows SDG&E to operate its system with significantly reduced energy flows during reclosing operations and provides the ability to sectionalize various elements of the distribution system to better manage system operations and reliability. Additionally, SDG&E has associated these remote SCADA controlled sectionalizing devices with specific wind anemometer locations, allowing for targeted applications of the Public Safety Power Shutoff to the areas that pose the most significant real time system condition risk of wildfire.

4.3.18 Public Safety Power Shutoff Engineering Enhancements

This program mitigates the impact to customers and communities involved in Public Safety Power Shutoff (PSPS) events by adding remote sectionalizing devices. Additional remote sectionalizing devices allow PSPS events to be more precise, which reduces the outage impact to customers. SDG&E is evaluating locations for these sectionalizing devices and based upon the results of the analysis, SDG&E plans to install additional units in 2019 and 2020.

[65] *See* Section 4.1.1

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4.3.19 Pole Replacement and Reinforcement

The Pole Replacement and Reinforcement program replaces deteriorated wood poles identified through inspections. Wood pole damage is attributed to numerous factors including, but not limited to, the loss of original preservative treatment experienced with Penta-Cellon poles,[66] the presence of fungi decay, and bird and/or termite damage. The Pole Replacement and Reinforcement program is designed to comply with GO 165.

In 2019, the wood pole intrusive inspections are cycling though structures located in the HFTD. Pole replacements associated with deteriorated structures found on these intrusive inspections reduce the risk of ignitions by preventing wood pole failures. In addition, poles replaced in these areas will be constructed to SDG&E's improved design criteria, meaning they will be replaced with a steel pole that will meet the known local wind conditions of the area. For poles identified for replacement in Tier 3 of the HFTD, SDG&E intends to accelerate the replacement including the design, engineering, and construction of the new structures faster than the required six-month time frame mandated by the general orders. This will reduce the risk of wildfire by replacing poles that fail inspection on an accelerated schedule within the highest risk areas.

4.3.20 Backup Power for Resilience

The National Academy of Sciences defines "resilience" as the ability to prepare and plan for, absorb, recover from, and more successfully adapt to adverse events. During extreme fire threats, SDG&E will likely de-energize power lines that serve backcountry communities. To mitigate some of the impact to these communities, SDG&E intends to implement a Backup Power for Resilience project, which will provide back-up power to critical infrastructure (i.e., fire stations, Community Resource Centers, and others) in these areas. This project focuses on investing in infrastructure to provide back-up power to strategic locations. SDG&E's plan to deploy these backup facilities furthers the integration of technology in support of the safe and reliable operation of the distribution grid. This project will help customers most impacted by extreme fire weather events receive resilience benefits.

As part of this Plan, SDG&E will continue to pursue this initiative with the intent of establishing support in areas that will help mitigate the impact of these extreme weather events on its most impacted communities, while also providing overall grid resiliency and other electrical distribution grid operations and services. Other critical service providers (i.e., water agencies, communication providers, and others) should also consider enhancements to improve their resiliency.

SDG&E is also expanding upon or developing new programs and strategies, leveraging backup power for resilience to mitigate the risk associated with Public Safety Power Shutoffs. These programs are specifically related to resilient internet connectivity at fire stations, the expansion of the Community Resource Center Network and the potential development of a grant program

[66] Pentachlorophenol is a pesticide and Cellon is a preservative treatment for wood poles used by the DOW Chemical Company to inject pentachlorophenol using a liquid petroleum gas such as propane.

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for portable generation targeted at residential customers are further discussed in Section 4.7.5 below.

4.4 Vegetation Management Plan

As part of its efforts to make its electric system more resilient, particular to wildfires, as well as comply with relevant Commission rules and state law, SDG&E designed and actively maintains a vegetation management program aimed at keeping trees and brush clear of electric power lines.[67] SDG&E's vegetation management program involves several components, such as: tracking and maintaining a database of trees and poles that are located close to electric infrastructure; regular patrolling, pruning, and identifying and removing hazardous trees and replacing with the right tree at the right place; pole maintenance with pole brushing and clearing; training first responders in electrical and fire awareness; and red flag operations. These program components are discussed in more detail below.

4.4.1 Tree Database

Early in the inception of its vegetation management program, SDG&E created an electronic database to track and manage trees in close proximity to its electric infrastructure. SDG&E's database contains records for over 460,000 known, specific trees located near its electric power lines. Inventory trees are defined as those with the potential of impacting the power lines by encroachment and/or tree failure within three years of inspection date. All trees in SDG&E's database are monitored using known species growth rates, with additional consideration given to the amount of rainfall occurring during periods affecting overall tree growth, and past pruning practices. Each inventory tree is assigned a unique alpha-numeric identification number within the electronic database, which allows the activity history of each tree to be tracked.

4.4.2 Patrol and Pruning

To comply with Commission rules as well as state and federal laws, SDG&E developed and maintains a vegetation management work plan, which is a schedule-based approach to its operations to ensure that applicable lines within its service territory are inspected each year. SDG&E divides its service territory into distinct zones known as Vegetation Management Areas (VMA). SDG&E's activities in each VMA are driven by a master schedule that identifies specific activities that are calendared to take place in each VMA every year. The activities include: pre-inspection, audit of pre-inspection work, tree pruning and removal, pole brushing and post trim and brushing audits. This process is managed through SDG&E's Vegetation Management System, an electric tracking system which was developed to store records of the vegetation management program activities.

[67] SDG&E's vegetation management program complies with current regulatory requirements, such as GO 95, Rule 35 and PRC §§ 4292 and 4293, and in some areas, exceeds the minimum regulatory requirements. It also follows the North American Electric Reliability Corporation (NERC) vegetation reliability standard FAC-003-04.

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SDG&E has historically utilized a contractor workforce[68] to perform the vegetation management program activities of tree pre-inspection, tree pruning and removals, pole brushing, and quality assurance. Work performed by the contractor workforce is recorded and issued via work orders within the vegetation management program electronic work management system. During pre-inspection activity, trees in proximity to SDG&E's powerlines are inspected and evaluated and the tree condition in the database is updated accordingly. Each tree is visited by a certified arborist on an annual cycle. The annual inspections are routine maintenance and hazard tree assessments are performed to verify that inventory trees will remain compliant for the duration of the cycle and/or is pruned according to accepted standards and clearances. Trees that will not maintain compliance or have the potential to impact powerlines within the annual pruning cycle are identified to be worked on by the tree contractor. After the pre-inspection activity, a quality assurance audit is performed to verify the quality and accuracy of the inspection activities and tree listing prior to initiating a tree trim work order. Based on a field inspection, the auditor randomly samples at least 10 percent of the pre-inspection work to validate the completeness and accuracy of the data from the pre-inspection. Once the results are reviewed and the audit finalized, the trimming work is assigned to a tree contractor who completes the pruning and/or removal activity.

During the tree pruning activity, the contractor determines what pruning and/or removal is required to achieve the required clearances to maintain annual compliance. Over time, SDG&E has established, as part of its routine operations, maximum post-pruning clearances and the removal of all tree branches that overhang the conductors. Where prudent and achievable, SDG&E's contract tree crews prune vegetation back to 12 feet (or more) in alignment with CPUC GO 95, Rule 35, Appendix E guidelines. The clearances obtained are determined by factors such as species, tree growth, wind sway, and proper pruning practices. Tree growth rates can be categorized based on species. For example, species such as eucalyptus may grow 12-15 feet within a year. Therefore, fast-growing species may require a post-pruning clearance of at least 16-20 feet to remain compliant with minimum clearance requirements for the annual cycle.

SDG&E tree contractors follow American National Standards Institute (ANSI) A300 industry tree standards and the concept of directional pruning, which fosters the health of a tree while maximizing clearance and extending the pruning cycle. All tree branches overhanging conductors are considered a potential risk, therefore, SDG&E removes all branches that cross the vertical plane of the conductors from the conductor to the top of the tree. Once the work is completed, the tree crew updates the tree information and records the work performed in the database and Vegetation Management System. On average, SDG&E prunes approximately 175,000 trees each year and removes approximately 8,500 non-compatible trees.

The scoping operations for complete tree removals includes the chipping of all material and removal of the debris off-site. The only material left on site during tree removals is the larger wood (> 6-8-inch diameter). Any large debris left is positioned to prevent movement of the

[68] SDG&E manages its contractor safety through ISN and holds its contractors accountable for their performance. Contractors are expected to adhere to the same safety-related protocols as SDG&E employees.

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material by gravity. All debris associated with pruning and removal operations is removed from watercourses to prevent flooding or degradation of water quality. Tree removal operations that may occur in sensitive environmental areas are reviewed to determine protocols that must be followed to protect species and habitat.

As explained in Section 2.1 above, the Commission has refined and remapped the fire threat areas in California and established the HFTD. This also changed the areas where increased minimum clearances apply. It is within these newly-defined areas that SDG&E continues increased, annual hazard tree inspections and performs maximum post-pruning clearances. Prior to fire season, SDG&E requires vegetation management contractors to perform annual training on hazard tree assessment. This refresher training helps set the stage for a second inspection, and a corresponding tree-hazard evaluation is performed for each tree within the HFTD. The tree evaluation includes 360-degree assessment of every tree within the "strike zone" of the conductors and maximizes the time-of-trim clearances. The strike zone includes the area adjacent to powerlines with trees that are tall enough to potentially strike the overhead facilities if the tree were to fail. To the extent unsafe clearances exist, an order to clear vegetation is issued and trimming is completed prior to September 1st of each year. These activities ensure safe minimum vegetation clearances are achieved prior to the peak fire season.

4.4.3 Enhanced Inspections, Patrols, and Trimming

In response to the ongoing and increasing threat of wildfire risk throughout California and the region, SDG&E will take steps to enhance its vegetation management program to further mitigate wildfire risk in the HFTD. In particular, SDG&E will enhance its routine inspections within the annual cycle, increase the amount of off-cycle patrols, and expand its tree trim scope.

During the annually scheduled routine inspection activity, the pre-inspection scope for all VMAs will be increased to include trees within the strike zone of transmission and distribution electric facilities. Trees tall enough to strike overhead electric lines will be assessed for hazardous conditions and tree crown height will be reduced or removed to prevent a line strike from either whole tree failure or limb break out. This would include dead, dying and diseased trees, live trees with structural defect, and locations with dense tree population that could strike as a result from wind exposure. Greater consideration will be given to environmental conditions that can impact a tree's relationship to the electric facilities such as wind sway and line sag. This same scope and criteria will be applied during an off-cycle tree patrol of all VMAs within SDG&E's service territory. These additional patrols will be timed to occur mid-cycle with the routine inspection to ensure all lines are reviewed twice annually and applying the enhanced scope.

SDG&E's tree trim scope will be increased to achieve a 25 feet clearance post-trim within the HFTD where feasible between trees and electric facilities. This is a significant increase over the average 12 feet of clearance that SDG&E currently achieves post-trim. There may be some barriers to achieving this goal. Environmental agencies, land agencies, and customers may oppose the tree pruning at this new clearance level, however, SDG&E hopes to work through these issues to achieve the desired wildfire risk mitigation. The trees targeted for enhanced

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trimming are the trees within the strike zone as described above. All tree operations will employ the concept of directional pruning wherein all branches growing towards the lines will be rolled back to direct the growth away from the lines and to increase the post-trim clearance. These activities are expected to incrementally decrease the risk of tree branches coming into contact with electric facilities either by encroachment by growth or limb or complete tree failure.

4.4.4 Technology

As an added enhancement to the tree inspection activity, SDG&E utilizes LiDAR to assist in directing inspectors to trees that are outside the utility right of way that are tall enough to fall and strike powerlines. This helps to ensure all trees are properly assessed during the inspection. SDG&E is researching future use of LiDAR to identify change detection on poles and equipment, and as a compliance component for post construction and post pruning activities. Currently, LiDAR acquisition, classifying of the data, and modeling of the data is very time consuming and costly. The turnaround time for information has not yet proven to support such use cases in the field.

As another tool in the management of its inventory trees, SDG&E has in recent years implemented the use of Tree Growth Regulators (TGR), which is a chemical application that dramatically reduces the new shoot growth of trees. Results have shown that the use of TGR can reduce the frequency of pruning some species up to three years. An added benefit of using TGR is that it provides growth reduction, root and leaf enhancement, and in some instances can help with disease and insect protection.

SDG&E is beginning to integrate more data science into its vegetation management plan in an effort to have a more analytical approach. The first step, which is planned for 2019, is to data-mine the full vegetation management dataset and investigate additional operational uses for the database containing the full inventory of the over 460,000 trees managed. The goal of this initiative is to leverage machine learning and artificial intelligence techniques to correlate SDG&E's extensive vegetation and meteorological datasets to gain additional insights on how atmospheric conditions impact growth rate of certain species and identifying certain high-risk vegetation areas.

4.4.5 Quality Assurance

Upon completion of the tree pruning/removal activity within a VMA, a certified arborist performs a quality assurance (QA) audit on a representative sample of completed work to ensure compliance with scoping requirements. During the QA audit, the certified arborist also performs a cursory inspection of all the powerlines within the VMA for any trees that will not remain in compliance with applicable regulatory requirements until the next trim cycle. The results are then reviewed with SDG&E and the contractor to determine if any additional work is required.

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4.4.6 Hazard Tree Removal and Right Tree-Right Place

SDG&E implemented and maintains a system-wide tree removal program to remove problematic species such as eucalyptus and palms. In addition, SDG&E established a "Right Tree-Right Place" program to assist customers in the selection of tree species and planting locations with the goals of minimizing interference with nearby powerlines and facilities, and maximizing energy saving and environmental benefits with carbon sequestration. SDG&E also offers free tree replacements in the event that an existing tree cannot be maintained safely near powerlines and should be removed rather than trimmed. Notably, SDG&E has, for the 16th consecutive year, been recognized by the National Arbor Day Foundation as a "Tree Line USA" utility company in recognition of "best practices" combining worker education and training, public outreach, quality tree care, and system reliability.

Hazard tree evaluation is a critical component of SDG&E's vegetation management program operations in the effort to reduce tree-related outages and avoid fire ignitions. SDG&E utilizes International Society of Arboriculture-certified arborists to perform its hazard tree inspections. These individuals also receive annual hazard tree inspection training to stay current with best practices. SDG&E has actively pursued the removal of non-compatible tree species such as eucalyptus with known tendencies for branch or trunk failure, and trees that were dead, dying or structurally defective. When a tree is considered a hazard, meaning that it poses a threat that will not hold until the scheduled trim date or is found to be out of compliance with clearance requirements, the tree is pruned on a priority basis, sooner than it would be under the Master Schedule. Such trees are generally pruned the same day as inspected, within 24-48 hours, or within a few weeks, depending on the severity of the hazard, as determined by the person evaluating the tree.

SDG&E has also initiated off-cycle, additional patrols of selected species such as bamboo and Century plants. These species are unpredictable and fast-growing and therefore pose a unique challenge to manage near powerlines. As such, these incremental patrols help target and remove such problematic species before they can become a danger. In addition, SDG&E implemented a broader scope in the removal of palms adjacent to its powerlines. SDG&E targets palms for removal that are located up to 65 feet away, that have the potential to shed fronds onto the powerlines and possibly cause an outage or fire.

4.4.7 Pole Brushing

SDG&E performs pole brushing in the State Responsibility Area (SRA) of the state in compliance with PRC § 4292. This requirement is regulated by CalFire, the agency with primary responsibility for fire suppression in those areas. Pole brushing involves clearing vegetation, flammable brush, and other materials around the base of electric power poles in an effort to prevent pole equipment-related ignition sources. Currently, there are approximately 84,000 distribution and transmission structures that are inspected annually to comply with PRC § 4292. SDG&E manages approximately 35,000 poles within the SRA that are designated as subject poles that carry "non-exempt" equipment. To further reduce potential ignition sources, SDG&E's Vegetation Management team works closely with SDG&E's FiRM team and engineering to reduce the number of non-exempt powerline components by replacing such

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equipment, where feasible, with exempt equipment, which should also reduce the potential for pole attachments to become an ignition source.

Since 2003, SDG&E uses a three-phase approach to more effectively manage subject poles. This approach includes: chemical pole brushing, mechanical pole brushing, and re-clear pole brushing. Chemical pole brushing involves clearing all vegetation from around the pole base and applying an Environmental Protection Agency (EPA) approved herbicide. SDG&E treats approximately 10,000 poles, during the fall and winter months, with a pre-emergent herbicide to minimize vegetative re-growth and reduce overall maintenance costs. Not all subject poles can be treated with herbicide due to environmental constraints, which include considerations such as slope, proximity to water, proximity to trees and other vegetation, and customer approval.

SDG&E annually performs various types of pole brushing and does so during different times of the year. Mechanical pole brushing involves the removal of vegetation from around the pole base using mechanical means. Mechanical brushing is typically performed in the spring months. Re-clear pole brushing, performed in summer months, involves removing any additional flammable vegetation which has grown into, or blown into, the required clearance area since the last maintenance activity. The need to revisit a subject pole multiple times is not uncommon due to leaf litter blown back into the managed clearance zone during windy conditions, and due to the growth of weeds and grasses that cannot be easily controlled by mechanical clearing or herbicide treatments. Trees adjacent to subject poles also require pruning to keep dead, dying or diseased tree limbs, branches, and foliage from encroaching into the radius of the cleared circle from ground up to the height of the electrical conductors.

4.4.8 Electric Equipment Training

As previously mentioned, CalFire performs inspections in compliance with PRC §§ 4292 and 4293 in the SRAs. SDG&E provides electrical equipment training to CalFire representatives so that SDG&E is maintaining proper clearances of vegetation to conductors and equipment prior to the start of the fire season. While CalFire inspections have been jointly performed with SDG&E, this training is intended for CalFire to better understand the operation of the electric system and which equipment should be targeted to best prevent an ignition source. This training can be used by CalFire while they are conducting their day to day operations and inspections.

4.4.9 Red Flag Operations

During elevated or extreme weather events that could lead into a designated RFW, SDG&E's vegetation management contractors are kept informed of these conditions allowing them time to relocate crews into safe work areas. In instances of emergency tree pruning during extreme fire conditions, additional fire equipment and/or support from the contracted, professional fire services may be utilized.

In advance of a forecasted RFW, vegetation management will determine if patrols are warranted to re-assess tree conditions in advance of, during, or immediately following red flag events. SDG&E's Meteorology team will work with the Fire Coordination and Vegetation

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Management departments to determine where this activity should occur. These inspections are incremental to the routine cyclical inspections performed by this group.

4.5 Situational Awareness Protocols and Determination of Local Conditions

Wildfire has been identified as the greatest weather-related risks to SDG&E, due to the region's complex topography, lack of summer and early fall rains, and susceptibility to dry Santa Ana winds that can accelerate fire growth. Because of the known wildfire risk and the potential impacts on utility operations, SDG&E has taken a multitude of steps to adapt to the changing climate conditions across its service territory.

Although the risk of fire is a year-round reality, there are certain recurring environmental and weather conditions that contribute to abnormally high fire risk in the SDG&E service territory. SDG&E's fire prevention and risk mitigation activities operate year-round with intensive data gathering and data analysis so that, when these abnormal and dangerous conditions occur, SDG&E is prepared to mobilize personnel and resources to abate, mitigate, and respond to these conditions. The sections to follow provide a description of the situational awareness platform that has been developed by SDG&E to mitigate wildfire risk.

4.5.1 Fire Science and Climate Adaptation Department

A large part of being prepared for and mitigating the threat of fire is recognizing the fact of environmental and situational evolutions. SDG&E's service territory has experienced drought and increased tree mortality, which compound the severity of and threat of the potential for an ignition. In recognition of these changing conditions, SDG&E restructured resources and, in early 2018, established a Fire Science and Climate Adaption (FS&CA) department comprised of meteorologists, community resiliency experts, fire coordinators, and project management personnel. The department's purpose is responding to and strategizing for the ever-changing utility industry's fire preparedness activities and programs. As climate change, community growth, and other evolutionary trends continue to impact the region, the FS&CA department must likewise evolve to address and provide situational awareness around emerging threats to utility infrastructure.

4.5.2 SDG&E Meteorological Capabilities and Technologies

4.5.2.1 SDG&E Meteorology Team

SDG&E has five full-time degreed and experienced meteorologists on staff with expertise in program management, utility forecasting, data science, and Southern California fire weather. Their responsibilities include analyzing historical weather and, importantly, monitoring incoming weather data in real-time. They also provide a detailed daily forecast of weather conditions relevant to SDG&E's operations.

4.5.2.2 SDG&E Weather Network

SDG&E owns and operates a network of over 175 weather stations that are physically located on electric distribution and transmission poles and provide temperature, humidity, and wind observations every 10 minutes. This allows weather conditions to be monitored in near real-time on every distribution circuit and transmission line across the fire-prone areas of the SDG&E service territory. Each weather station location was carefully selected by SDG&E

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meteorologists based on their knowledge of the local terrain and its influence on meteorological conditions.

The siting process begins with a detailed examination of the terrain along a given circuit or tie line using a combination of Google Earth, topographical maps, and subject matter expertise of known local wind conditions. Once a site has been identified, a field visit is conducted to visually confirm the lay of the land and suitability for a weather station. Some circuits and tie lines cross dozens of miles through complex terrain, requiring additional weather stations to adequately monitor all areas of concern. These siting protocols ensure sufficient data granularity to provide SDG&E clear knowledge of the local weather conditions in its service territory. This data informs day-to-day operational decision-making at all levels of the Company to enhance situational awareness and mitigate the risks associated with wildfires and other adverse weather conditions. Additionally, the SDG&E weather station network supports SDG&E's Community Fire Safety Program and SDG&E strategic initiatives. SDG&E's weather station network is set forth in Appendix D.

SDG&E's weather data is available to all SDG&E employees, weather agencies, fire agencies, educational facilities, and the general public. There are a number of locations and applications where the data may be viewed, including the publicly available SDG&E Weather Awareness System at: http://sdgeweather.com. This site includes graphical images to visualize data and links to additional data, camera sites, and forecasts, and is scalable for a variety of devices, including tablet or hand-held.

The SDG&E weather network will continue to evolve in the years to come to maintain effective situational awareness and data quality. As the region faces the impacts of a changing climate, plans are being made to expand the weather network into high-impact wildland urban interfaces where more extreme weather and fire conditions may occur. Strategic weather station relocations are also planned to account for changes on the landscape and an increased understanding of climatological wind patterns in the SDG&E service territory.

4.5.2.3 Meteorology High-Performance Computing Program

SDG&E owns four high-performance computing clusters that are used to generate high quality weather data that is incorporated directly into operations. Collectively, nearly 2,000 compute core hours of high-performance computing are used per day to generate operational products, including the SAWTI, FPI, and WRRM-Ops. The forecast data generated by the supercomputers is shared with several partners, including the U.S. Forest Service, who disseminate the data through their public website, and the National Weather Service.

SDG&E plans to continue the production of forecast products into the foreseeable future. As science evolves and new technologies become available, SDG&E will use its computing clusters to integrate the new methodologies in order to maintain forecast reliability and situational awareness.

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4.5.3 Fire Potential Index

The FPI was developed by SDG&E subject matter experts to communicate the wildfire potential on any given day to promote safe and reliable operations. This seven-day forecast product, which is produced daily, classifies the fire potential based on weather and fuels conditions and historical fire occurrences within each of SDG&E's eight operating districts. This is also shared with local fire agencies, emergency responders, and the National Weather Service.

The FPI reflects key variables, such as the state of seasonal grasses across the service territory (green-up), fuels (ratio of dead fuel moisture component to live fuel moisture component), and weather (sustained wind speed and dew point depression). Each of these variables is assigned a numeric value and those individual numeric values are summed to generate a fire potential value from zero (0) to seventeen (17), each of which expresses the degree of fire threat expected for each of the seven days included in the forecast. The numeric values are classified as "normal," "elevated," and "extreme." Further detail on the various FPI components is provided in Appendix E.

The FPI development team, consisting of SDG&E meteorologists and fire coordinators, has validated the FPI values and its usefulness by recreating historical values dating back to 2002. The historical results bore a very strong correlation to actual fire events in terms of the severity of past fires and, in particular, provided very accurate information as to when the risks of uncontrolled and large-scale fires were high. SDG&E expects to tie proactive and reactive operational practices and measures to the FPI values, with the further expectation that SDG&E will be able to reduce the likelihood its facilities and operations will be the source of ignition for a fire during times when the risk of fire as measured by the FPI elevated or extreme.

Moving forward, SDG&E will continue enhancing the predictors that contribute to the FPI, including live fuel moisture and green-up, to modernize the data inputs and better leverage the high-performance computing environment.

4.5.4 Santa Ana Wildfire Threat Index

SDG&E, the U. S. Department of Agriculture, the U.S. Forest Service, and the University of California Los Angeles (UCLA), in collaboration with CalFire, the Desert Research Institute, and the National Weather Service unveiled a web-based tool in September 2014 to classify the fire threat potential associated with the Santa Ana winds that are directly linked to the largest and most destructive wildfires in Southern California. The SAWTI categorizes Santa Ana winds based on anticipated fire potential and uses several meteorological and fuel moisture variables generated from the Weather Research and Forecasting (WRF) Model to forecast the index out to 6 days.[69] In addition to the index, a 30-year climatology of weather and fuels has been developed to help put current and future events into perspective.
The SAWTI calculates the potential for large wildfire activity based on the strength, extent, and duration of the wind, dryness of the air, dryness of the vegetation, and greenness of the grasses. Similar to the hurricane-rating system (category 1-5), the SAWTI compares current environmental data to climatological data and correlates it with historical wildfires to rate the

[69] The SAWTI is depicted in Appendix F.

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Santa Ana wind event on a scale from “marginal” to “extreme.” To help the region prepare for hazardous conditions, information from the SAWTI is issued daily to fire agencies and other first-responders, which has led to specific preparedness and operational decisions based on the likelihood of a catastrophic wildfire fueled by Santa Ana winds. The public also has access to SAWTI to make personal safety decisions.

SDG&E is committed to maintaining the data flow used in SAWTI production for the U.S. Forest Service, who now issues this product daily. As technologies in weather forecasting and fuels predictions evolve, the new science will be integrated into operations to support the ongoing production of SAWTI.

4.5.5 Wildfire Risk Reduction Model – Operational System

Significant intel related to the wildfire potential is also gathered from SDG&E’s WRRM-Ops, which integrates the latest weather and GIS technology to understand wildfire growth patterns across the region (running 6,000 fire growth simulations per second on SDG&E’s super-computer and able to simulate 10 million fires in a single night). WRRM-Ops assesses the areas of highest fire danger before a wildfire begins so preventative measures can be taken to enhance public safety and ensure the reliable operation of the electric system. This model uses simulations generated from weather conditions, historical fire and outage history, and vegetation data to evaluate the wildfire risk within the SDG&E service territory.

WRRM-Ops is also able to simulate the growth and potential impact of a wildfire anywhere in the SDG&E service territory should an ignition begin. Integrating all of the aforementioned weather data developed by SDG&E, the WRRM-Ops model can conduct an analysis to determine the immediate threats, enabling quick decision making to help decrease the impacts of wildfire.

In 2019, this technology will be enhanced by migrating a fully operational version of the application to a cloud hosted environment, enabling SDG&E to operate this model through native mobile applications built for its subject matter experts and leadership. SDG&E is developing the capability to simulate wildfire growth and conduct vulnerability assessments from the field while responding to a wildfire incident.

4.5.6 Camera Networks and Fire Detection

Currently, SDG&E utilizes a total of 107 cameras that enhance situational awareness around wildfire. Twenty of these cameras are owned by SDG&E, while 87 cameras are supported by SDG&E in collaboration with UCSD as part of the High Performance Wireless Research and Education Network (HPWREN). Of these 87 cameras, 72 are static and 16 are high-definition pan-tilt-zoom “Alert SDG&E Cameras,” which are capable of remote directional and zoom control.

The Alert SDG&E Camera network is a state-of-the-art camera network designed to monitor wildfire activity and enhance situational awareness for SDG&E and its first responders and the communities they serve. SDG&E partnered with UCSD and the University of Nevada to deploy this network of 16 live-stream pan-tilt-zoom mountaintop cameras, which allows for quicker identification and triangulation of wildfires. Alert SDG&E Cameras are heavily used by CalFire’s

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Monte Vista Dispatch Center to aid in better locating and sizing up wildfires for initial attack prior to the arrival of first responders.

SDG&E will maintain a close working relationship with UCSD in the years to come, supporting the HPWREN program and the evolution of the situational awareness cameras across the region for all wildfire community stakeholders and residents.

4.6 Climate Change Adaptation

Between January 1st and December 16th of 2018, 6,266 fires were reported by CalFire across the state of California with a burn area totaling 876,131 acres. This is a decrease of 16 fires during the same period in 2017, but an increase of 554,474 acres burned and stands at 111% and 375% of the 5-year averages of fires and acres burned, respectively.[70] While these numbers are exacerbated by dry conditions produced by well-below average rainfall statewide during the winter of 2017-2018, data ranging back to 1984 across San Diego County confirms that the number of high fire potential days each year has increased since the early 2000s. These trends are projected to continue as a combination of factors leads to increases in both fire season duration and severity through the end of the century.[71]

A 2013 study by the National Oceanic and Atmospheric Administration (NOAA) National Environmental Satellite, Data, and Information Service (NESDIS) group found that the effects of climate change will not significantly alter the frequency of Santa Ana wind events, which typically occur 2-5 days per month between October and March and have contributed to the growth of several of the largest wildfires in Southern California history. However, due to overall warming across the region, Santa Ana winds are likely to bring higher temperatures and lower humidity that will increase the fire potential with each event.[72] Because Santa Ana wind events typically deliver the warmest conditions to the coastal communities, increases in fire potential may also extend to the coastal canyons and wildland urban interface areas that historically have not been as high of a wildfire concern. The warmer temperatures are also expected to enhance evaporation and transpiration even outside of Santa Ana events, which will deplete fuel moistures at faster rates. When coupled with longer dry periods, increases in tree mortality due to drought, and increased warmth, this will result in longer fire seasons across the Southwest.

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[70] CalFire Incident Information: Number of Fires and Acres. http://cdfdata.fire.ca.gov/incidents/incidents_stats?year=2018.

[71] Melillo et al. 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, 841 pp. doi:10.930/J0Z31WJ2; Kent 2015: *Climate Change and Fire in the Southwest.* ERI Working Paper No. 34. Ecological Restoration Institute and Southwest Fire Science Consortium, Northern Arizona University: Flagstaff, AZ. 6 pp. http://swfireconsortium.org/wp-content/uploads/2015/06/Yocom_Climate_Fire_SW.pdf; CEP (Climate Education Partners) 2014: *San Diego, 2050 is Calling.* http://www.sandiego.edu/2050/.

[72] Kunkel et al. 2013: *Regional Climate Trends and Scenarios for the U.S. National Climate Assessment*. Part 5. Climate of the Southwest U.S., NOAA Technical Report NESDIS 142-5, 79 pp.

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San Diego Foundation/SCRIPPS projects that in 2050 there will be longer and more extreme fire seasons and by 2100 the probability of large fires in Southern California could increase by 30%. Though the general consensus is that fire seasons will lengthen and become more severe through the coming century, there are still several unknowns that may alter fire behavior including shifts in vegetation type and the rebound rates of fuels in burned areas.[73] It has been suggested that some vegetation types will be unable to adapt to the temperature increases, which would initially lead to an ample supply of dead fuels to carry fire but would eventually result in a decline in fuels coverage unless the vegetation was phased out by species more apt to handle the hotter temperatures.[74] In addition, assuming the fires fully consume the fuels, increases in fire activity will eventually become limited until enough vegetation can grow back to support fire growth.[75]

4.6.1 Operational Response

4.6.1.1 Operating Conditions

The forecasts provided by the SDG&E Meteorology team, including the FPI, inform the operating condition used by SDG&E's electric system operators. There are four Operating Conditions used for these purposes, Normal, Elevated, Extreme, and Red Flag Warning, which are described in Section 4.1.1 above as well as in Appendix C.

The daily weather forecast, and Operating Condition are broadcast Company-wide by electronic media enabling all personnel whose activities are affected by the declaration of the operating condition to take action – the forecast, particularly when the threat of fire is high or rising, will be updated and rebroadcast as conditions warrant and as the staff meteorologists determine is appropriate. The forecast is broadcast in real-time to a large audience of SDG&E employees. Personnel receiving these weather forecasts are trained to adjust their activities, duties, and priorities based upon the Operating Condition reported by the staff meteorologists.

Generally, as actual or forecasted wind speeds measured in terms of both sustained winds (the average wind speed across ten-minute intervals) and wind gusts (the highest wind speed occurring during a three-second period within a ten-minute interval) increase, the operating condition will change (or be elevated), from "normal" to "elevated," or "extreme," or "red flag warning," depending on environmental and weather conditions and the strength of the winds being experienced or forecasted. With each step-change in the Operating Condition, personnel are placed on appropriate levels of alert. In addition, the level of system monitoring and, ultimately, system operations and activities, are elevated according to the prevailing Operating Condition. Most importantly, as wind speeds increase, SDG&E deploys an increasing number of field crews, troubleshooters, and wildland fire prevention resources to areas with the highest winds and where the greatest threat of fire exists, so as to increase the probability that the risk of an ignition will be minimized.

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[73] Kent 2015: *Climate Change and Fire in the Southwest.* ERI Working Paper No. 34; Westerling et al. 2006: *Warming and Earlier Spring Increase Western U.S. Forest Wildfire Activity.* Science, Vol. 313 no. 5789, pp. 940-943. doi:10.1126/science.1128834

[74] Kent 2015: *Climate Change and Fire in the Southwest.* ERI Working Paper No. 34.

[75] Kent 2015: *Climate Change and Fire in the Southwest.* ERI Working Paper No. 34.

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4.6.2 Wireless Fault Indicators

The Wireless Fault Indicators program will install wireless fault indicators on SDG&E's electric distribution system. Wireless fault indicators are used to continuously monitor distribution circuits to locate faults more efficiently and accurately due to rapid pinpointing of line faults. When coupled with the On-Ramp Wireless system, the wireless fault indicator will communicate information to distribution system operators. This allows the operators to dispatch electric troubleshooters closer to the exact fault location, which supports quicker identification and isolation of the fault so that service restorations may begin. Wireless fault indicators provide detection and indication of electrical faults in the electric power distribution networks of the utility. Currently, the status of the indicators (tripped or reset) must be checked by visual inspection. This method takes a considerable amount of time as it involves driving to the field, patrolling the line to locate the tripped fault circuit indicator, and repairing the line. In addition, there is no way to validate that the existing indicator is working properly. The new wireless fault indicator employs wireless communications technologies to remotely monitor their status.

4.6.3 Advanced Weather Station Integration and Forecast

The Advanced Weather Station Integration and Forecast program seeks to further modernize the SDG&E weather network, which is currently the most granular, fully operational network of its kind anywhere in the country. This weather network brings superior situational awareness for the weather conditions impacting SDG&E's electric and gas system, supporting daily operations and emergency operations. The weather network also serves as a data foundation for high performance computer modeling which generates multiple analytical tools that are used across the organization. SDG&E's planned modifications to the system will include the replacement of aging sensors and equipment with the latest technology. This will include new thermometers, hygrometers, anemometers, batteries, solar panels, modems, and in some cases pyranometers. These actions will help ensure the weather network will continue running efficiently into the future.

The SDG&E weather network has become an integral aspect of the Community Fire Safety Program. The weather information is used to calibrate models such as the FPI and the SDG&E Outage Prediction Model which gives the Company the ability to anticipate when critical fire weather conditions or strong storms are approaching the area, allowing proactive preparedness measures to be taken. The weather network is also one of the primary pieces of intelligence that is used when, and if, the decision is made to de-energize portions of the electric system during times of critical fire weather conditions. In addition, this information is also shared with SDG&E's stakeholders. The typical lifespan of SDG&E's meteorological instrumentation is five to ten years. Proactive maintenance of SDG&E's weather network will be an important component for the future success of its Community Fire Safety Program.

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4.7 Public Safety Power Shutoff Protocols

4.7.1 Strategy for Minimizing Public Safety Risk During High Wildfire Conditions

SDG&E has an obligation to operate its system safely. This obligation requires SDG&E to de-energize circuits (i.e., turn off power) when necessary to protect public safety (Public Safety Power Shutoff or PSPS). SDG&E is statutorily authorized to do so under P.U. Code §§ 399.2(a) and 451, consistent with D.12-04-024 and Commission Resolution ESRB-8. Any decision to de-energize circuits for public safety is made in consultation with SDG&E's Emergency Operations Center (EOC), Meteorology, and Electric System Operations leadership. Typically, it is expected, but not required, that the FPI would be "extreme" or there would be a "red flag warning" in effect when a PSPS decision is made.

Following any PSPS event, as specified in Resolution ESRB-8, SDG&E submits a report to SED within 10 business days after each de-energization event, as well as after high-threat events where notifications were provided to local government, agencies, and customers of possible de-energization though no de-energization occurred. Reports to SED include at a minimum the following information:

- The local communities' representatives contacted prior to de-energization, the date on which they were contacted, and whether the areas affected by the de-energization are classified as Zone 1, Tier 2, or Tier 3 as per the definition in GO 95, Rule 21.2-D.
- If not able to provide customers with notice at least 2 hours prior to the de-energization event, an explanation is provided in the report.
- The number and nature of complaints received as the result of the de-energization event and include claims that are filed against the IOU because of de-energization.
- A detailed description of the steps taken to restore power.
- The address of each community assistance location during a de-energization event, describe the location (in a building, a trailer, etc.), describe the assistance available at each location, and give the days and hours that it was open.

4.7.2 Public Safety Power Shutoff Protocols

A PSPS is a last resort measure to reduce wildfire risk. To that end, SDG&E takes great pride of the reliable service it provides to its customers. While the FPI and the National Weather Service's RFW declarations drive the Operating Condition, SDG&E considers a wide variety of inputs to determine whether to de-energize portions of its system. SDG&E leverages a multitude of situational awareness data and input from its subject matter experts when considering the need for a PSPS event, though experience with this program has indicated that it is not appropriate to use a prescriptive technique to determine when to use PSPS as wildfire conditions are dynamic and not every situation is the same. In determining whether to employ a PSPS in a given area of its system, SDG&E considers a variety of facts such as:

- Weather conditions
- Vegetation conditions
- Field observations
- Information from first responders

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- Flying debris
- Meteorology
- Expected duration of conditions
- Location of any existing fires
- Wildfire activity in other parts of the state affecting resource availability

Utility operating experience is required to analyze all of the various inputs and make the decision how to manage risk to the communities affected.

4.7.3 Re-energization Protocols

If SDG&E determines it is necessary to employ a PSPS for portions of its system, re-energization will take place after the SDG&E Weather Network shows that wind speeds have decreased, and SDG&E weather forecasts indicate that winds will not re-accelerate above dangerous levels. All lines that have been de-energized are inspected for damage before re-energization may occur. Once a line is patrolled and any needed repairs are prioritized, the area may be re-energized in segments, leveraging the next open sectionalizing device to safely expedite the process.

4.7.4 Communication Practices

In advance of the peak of fire season, SDG&E will conduct ongoing education campaigns in five languages (English, Spanish, Chinese, Filipino, Vietnamese) regarding how to be prepared for emergencies in the event of a wildfire, natural disaster or major outage. This education campaign will also encourage customers to sign up for outage notifications, with the goal of raising awareness about SDG&E's PSPS procedures.

In the days leading up to a potential or imminent PSPS and during an active event, SDG&E establishes and maintains contact with customers that it believes may be impacted via various channels (use in-language where possible) communicating which Community Resource Centers are open and keeping the media and the public aware of the number of customers impacted and activities/restoration efforts by SDG&E crews. Key stakeholders, elected officials, and first responders are also communicated with through a variety of channels and personnel. SDG&E has specific teams or personnel assigned to directly contact local and state elected officials and critical customers, including water utilities and agencies affected by a PSPS. SDG&E's call center, social media, and website provide ongoing and available resources for communication and education for the overall customer base.

SDG&E monitors wildfire conditions seven to ten days ahead, providing forecasts to operational management and emergency operations staff so they have knowledge and time to prepare. Additionally, in certain extreme conditions, this advanced awareness is provided to key external stakeholders. If extreme fire weather conditions are forecasted and materializing, and the National Weather Service has the potential to issue a RFW, SDG&E begins to coordinate with local government agencies, community-based organizations, and emergency responders through its key account, company relations, and fire coordination teams. These SDG&E teams maintain contact throughout the event, providing updated information and a conduit for external stakeholders to communicate to SDG&E. SDG&E will also initiate proactive communication with customers through traditional methods and social media, driving traffic to

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SDG&E's fire preparedness website https://www.sdge.com/wildfire-safety or https://sdgenews.com/ for more information. SDG&E's call center is also available to address customer questions and concerns.

SDG&E also proactively contacts customers with the potential to be affected by a PSPS upon the issuance of a RFW or extreme fire weather conditions. SDG&E contacts these customers directly, through its Enterprise Notification System (ENS), with a message to ensure they are aware. SDG&E's ENS sends outbound messages through phone, email, and text. These messages typically increase in urgency as the certainty of a PSPS approaches. SDG&E's social media accounts and its website are also updated with the latest information.

For medical baseline customers within an affected PSPS area, the ENS captures a positive physical response through the phone message when the customer is contacted. If no positive response is obtained, a second live attempt is made through SDG&E's call center to contact the medical baseline customer. If the second attempt fails, SDG&E will dispatch field personnel to deliver the message in person.

Critical customers,[76] such as health, water, communication, and education facilities within a potential PSPS area are also contacted through the ENS. Contact is also made through assigned SDG&E key account personnel. Notification will take place beforehand, so these customers can prepare and plan for a potential PSPS.

Moving forward, SDG&E will continue to integrate technology and data into the ENS in an effort to provide its customers with customized, timely, and precise information regarding SDG&E's Community Fire Safety Program. The customer notification processes have recently undergone significant refinement, which will continue as SDG&E receives feedback and lessons learned from PSPS events. Specific areas of focus will be an update to the base software of the ENS that will enhance SDG&E's ability to serve its customers by adding two-way texting capabilities and synching the ENS with our GIS and weather network to provide more targeted and timely alerting.

4.7.5 Mitigating the Public Safety Impact of PSPS Protocols

SDG&E manages and mitigates the impacts of a PSPS event through collaborations with key stakeholders in the wildfire response community. SDG&E has collaborated with approximately 40 stakeholders representing local schools, water districts, disability rights advocates, consumer groups, and fire departments.

SDG&E partners on a regular and ongoing basis with the following agencies to address a range of fire prevention and emergency activities:

- **San Diego County Fire Chiefs' Association** – provide monthly written and oral updates while encouraging feedback and comments on planning, response, recovery, and communications programs;

[76] Appendix G provides a listing of entities SDG&E considers to be priority essential services.

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- **CalFire and the San Diego County Fire Authority** – engage in daily communications related to aerial firefighting and contract management of the year-round Aircrane program;
- **County Unified Disaster Council** – receive and provide quarterly updates on regional planning and response programs while building relationships with 18 cities, the County of San Diego, and participating Special Districts;
- **County Office of Emergency Services** – as needed, but no less than quarterly to discuss and agree on emergency planning, response, recovery, and communications needs;
- **All Fire Agencies in San Diego County** – including cities, fire districts, military, and tribal annually to provide in-service training on electric and natural gas safety, response, Incident Command integration with utilities, and communications to ensure response coordination during wildfire and other emergencies; and
- **Fire Dispatch Centers** – provide bi-annual communications training and requirements related to electric and natural gas incidents and emergencies.

SDG&E is and will continue to be a member of the California Utilities Emergency Association (CUEA), a collaboration between electric, natural gas, water, and telecommunications utilities in California. CUEA serves as a point of contact for critical infrastructure utilities and the California Office of Emergency Services and other governmental agencies before, during and after an event.

SDG&E has and continues to collaborate with UCSD on the development and maintenance of HPWREN, the UCSD partnership project led by the San Diego Supercomputer Center and the Scripps Institution of Oceanography's Institute of Geophysics and Planetary Physics, supporting internet-data applications in the research, education, and public safety realms. In addition to the camera network discussed in Section 4.5.6 above, SDG&E has also worked with UCSD to leverage HPWREN to provide internet connectivity to fire stations across remote portions of San Diego County. SDG&E will continue to collaborate with UCSD, investing in this critical communication backbone, providing resilient situational awareness, and communications during PSPS events.

In 2018, SDG&E held customer meetings with those affected by PSPS events to garner feedback on customers' thoughts and feelings before, during, and after a PSPS event. Overwhelmingly customers voiced a need to have a gathering place in the area affected that would be reasonably easy to get to and would have a place for them to charge cell phones and obtain current information about the PSPS event. By September 1, 2018, SDG&E, in working with the communities most affected, developed the concept of a Community Resource Center and located 9 centers in areas most likely to be affected by a PSPS. These centers offered affected customers a place to gather, charge cell phones, obtain current information and obtain things like bottled water, light snacks, and ice for temporary refrigeration. These centers were powered by portable generation provided by SDG&E and were in areas where there was not a reasonably close place to travel to where power was not shut off. This was highly successful and welcomed by affected customers. For 2019, SDG&E intends to examine the northern area of its service territory to determine where additional centers can be established. These centers would be similar to the ones in the south except for the need for generation as the

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communities affected by PSPS events in the north are likely near areas that are not subjected to PSPS. In those cases, the centers would be opened primarily for cell phone charging and obtaining up to date information on the PSPS event.

SDG&E has also received feedback from residential customers impacted by PSPS events that the desire to obtain smaller generators for their homes but do not possess the financial capability to acquire one. Therefore, SDG&E is considering the potential of the creation of a Generator Grant Program (GGP), administered by a neutral third party, to grant residential customers the funding for the express need to acquire and be able to use a portable generator during outages, in particular PSPS events. SDG&E foresees the current greatest need to be in the residential customer grouping that is currently residing in the back country of San Diego, likely subject to a PSPS event, for example those customers currently under the medical base line tariff or who are dependent on well water. This program is currently in the conceptual phase and carries with it the need to identify all aspects of cost recovery.

4.8 Alternative Technology

Throughout this Plan, SDG&E identifies and discusses new technologies and strategies aimed at reducing the probability of an ignition event as well as minimizing public exposure to hazardous conditions during period of high fire risk. The relevant technologies that provide better situational awareness, faster isolation, or minimized energy transfer are discussed in Section 4.1.2, Section 4.3.2, Section 4.3.11, Section 4.3.14, Section 4.3.15, and Section 4.4.4.

4.9 Post Incident Activities

SDG&E's post-wildfire incident recovery, restoration, and remediations activities are discussed in detail in Section 5.2.1.6 below.

5 Emergency Preparedness and Response

5.1 Emergency Management

SDG&E manages emergencies in alignment with the state Standardized Emergency Management System (SEMS) and federal National Incident Management System (NIMS), to align across all levels of utility, government, and agency activity. The Company utilizes a utility-compatible Incident Command Structure (ICS) as an all-hazards framework to manage emergency incidents and events. ICS is the combination of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure and serves as the mechanism to direct those functions during an emergency response.

The SDG&E Emergency Management (EM) organization is responsible for coordinating emergency management activities and activation of the Emergency Operations Center (EOC). The department's mission is to support effective, efficient, and collaborative planning, preparedness, response, and recovery processes for all hazards and risks, including those associated with wildfire and RFW incidents enterprise-wide. EM's mission is accomplished through an integrated and collaborative approach including internal and external stakeholder

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engagement, benchmarking, plan development, training, exercising, and a continuous quality assurance and improvement process via the after-action review (AAR) process.[77]

EM is comprised of four divisions: Emergency Services and Business Resumption (ESBR), Operational Field and Emergency Readiness (OFER), Aviation Services, and EM Information Technology (IT). The collective work of these groups consists of preparing for, responding to and recovering from incidents that may impact SDG&E operations.

5.1.1 SDG&E Emergency Operations Center

SDG&E's EOC serves as the location from which centralized emergency management is coordinated. To respond and recover effectively from all hazards and threats, like wildfires, SDG&E established an EOC with cross-functional teams representing every major business line within the Company and functions within a utility-compatible ICS. The activation of the EOC assembles the internal subject matter experts to assess and provide situational awareness to internal and external stakeholders, overarching incident objectives, planning, anticipation, response, communications, and coordination. External EM partners such as the County of San Diego Office of Emergency Services (OES) and California OES (Cal OES) are provided with situational awareness up 24-48 hours in advance or as soon as operationally feasible; additionally, those partners are embedded within SDG&E's EOC during emergency conditions.

5.2 Disaster and Emergency Preparedness Plan

5.2.1 Company Emergency Response Plan Overview

The Company Emergency Response Plan (CERP) and risk specific response plans provide a framework by which SDG&E can effectively coordinate the Company's pre-incident and response/recovery activities to a given threat or hazard. Pursuant to the CERP, the Utility Incident Commander or Officer-in-Charge (OIC), is ultimately responsible for incident management and support activities respectively. While a Utility Incident Commander or OIC may delegate authority, they cannot delegate the responsibilities outlined in the Wildfire Annex or the CERP.

5.2.1.1 Phases of Operation

There are three phases of emergency operations:

- **Pre-Incident:** Pre-incident planning activity in anticipation of an incident occurrence.
- **Response:** Period spanning from when the incident occurs, and a response team is stood up, until the response team has demobilized and transitioned operations to long-term recovery.
- **Recovery:** Spanning the period from when the response team has demobilized and transitioned to long-term recovery, until all recovery operations have been completed.

5.2.1.2 Incident Conditions

Certain fire-related criteria initiate SDG&E's notification process. The following are the criteria that triggers such communications:

[77] The AAR process is discussed in further detail in Section 5.2.1.6 below.

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- Fires during an FPI of 14 or greater;
- Any uncontrolled fire within 1 mile of a transmission line;
- Any fire where SDG&E is potentially related to the cause regardless of the FPI;
- Any fire regardless of FPI that is:
    - Expected to escape initial attack/exceed 10 acres, or
    - Has impacted or may have a direct impact on any SDG&E facilities, or
    - Is expected to draw significant social or media attention

5.2.1.3 Pre-Incident Planning

Pre-incident planning is a key element in preparing for the risk of Wildfire and being able to react to an actual Wildfire. SDG&E must be aware of and be prepared to react to mitigate impacts from any wildfire within SDG&E's service territory. If SDG&E becomes aware of a potential incident expected to have adverse impacts on its system, Fire Coordination will consult with the SDG&E Meteorologists daily to come to agreement on fire potential and burning conditions based on the weather forecast, fuel conditions, current fire activity, availability of firefighting resources, and other relevant factors.

If an incident is anticipated, Emergency Management will begin to coordinate pre-incident activities with a day-ahead call focused on assessing real-time and forecasted weather conditions, operational resource needs and response plans, customer and stakeholder notification plans, EOC staffing needs and timing, and will provide projections for incident impacts. Proactive notifications are completed to customers and key external stakeholders during this phase of the response for incidents where there is advanced warning.

5.2.1.4 Response

Response to and during a wildfire requires immediate assessment and incident characterization, the communication of appropriate situational awareness and the development of an incident planning cycle to facilitate the collection, assessment and dissemination of relevant wildfire incident information. Should an ignition occur, a field Fire Coordinator will deploy to the jurisdictional fire agencies Incident Command Post (ICP) to provide real-time situational awareness to SDG&E. The Fire Coordinator serves as the agency liaison between first responder agencies and the SDG&E Utility Incident Commander. Field operations is responsible for scene safety, along with command and control of the incident to recover the system and restore customers. The EOC's focus is on the incident's "big picture," managing and deconflicting critical information, communicating to customers and key external stakeholders, and providing operational support and strategic and policy-level decision-making. De-mobilization planning remains a focus during the response phase to ensure adequate recovery of the system.

A wildfire may require de-energization of electric distribution circuit(s), and transmission tie line(s) for public or first responder safety. The OIC will carefully examine whether de-energization is required based on input from the field response and EOC responders, consistent with the PSPS protocols discussed in Section 4.7 above.

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5.2.1.5 Crew Mobilization and Deployment Strategy

During an extreme operating condition or red flag warning condition, the management of the SDG&E Electric Regional Operations, Electric Distribution Operations and Electric Grid Operations control centers work in collaboration with SDG&E's Meteorology to coordinate the assignment of appropriate and needed resources to each of the affected regional operating districts. At minimum, electric troubleshooters and personnel from the Wildland Fire Prevention resources are made available for immediate response to address fire threats or events. If the event is more severe, additional resources will be coordinated and assigned to manage the event. Field personnel may be assigned to observe an area forecasted to experience the most adverse weather conditions – these personnel are under instructions to report flying debris, vegetation damage, or significant conductor movement. Based on these field observations, SDG&E deploys appropriate resources to address the fire threats posed by these conditions.

SDG&E has four mobile command trailers (MCT) and one new, state of the art, self-contained Tactical Command Vehicle (TCV), which provide a response space with land, mobile, radio, video, and internet capabilities. Additionally, four tactical communications trailers with internet capabilities are available to support the ICS structure during emergency response and restoration activities. During the high-risk fire season, these assets are staged in districts located within the HFTD. SDG&E's district personnel are trained annually on the assets operations and maintenance to ensure these assets remain effective and functional.

5.2.1.6 Recovery and Post Incident Activities

Recovery from a wildfire is just as important as the response to a wildfire. The location, extent, and severity of the wildfire and its impacts to SDG&E's infrastructure and customers are rigorously tracked, assessed, and prioritized to identify mitigation or improvement measures available when recovering for safe and swift restoration.

SDG&E continually reviews its program delivery, decision making processes, and responses to emergencies to ensure we can improve and better serve our customers. Through its Quality Assurance and AAR process, the planning, response, and recovery processes are evaluated across relevant internal response groups. Observations will address the following areas:

- Plan execution;
- Response structure;
- Activation and mobilization for the incident;
- Circumstances that contributed to, enhanced, or resulted in improvement opportunities in incident management or communications;
- Process execution and effectives;
- Communications strategy;
- Media interactions;
- Logistics support; and
- Financial tracking and support.

Based on lessons learned, emergency response plans are updated, processes and standards are enhanced, and training exercises are designed to stress test lessons learned and improvements

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to support a continuously improved response. SDG&E will continue to review ongoing recovery operations and use its findings of post incident activities to drive improvements across the organization's resilience, response, and recovery programs.

5.2.2 Community Outreach and Public Awareness

SDG&E has created a multi-level approach to community education and outreach related to public awareness of fire threats, fire prevention, and emergency preparedness. Plans for community outreach and public awareness before, during, and after a wildfire, including language notification in English, Spanish, Chinese, Filipino, and Vietnamese, will be made where feasible. In-language communications will apply to videos, collateral, and print advertising before and after wildfires. These materials have previously educated customers about how to be prepared for wildfires and encouraged them to sign up for outage notifications and updates through SDG&E's My Account portal. SDG&E anticipates continuing this outreach messaging to further prepare customers for PSPS.

Notifications during wildfires are currently confined to English due to the language and translation limitations of SDG&E's current notification system. Messages in this system are also customized and recorded shortly before each event in many cases, and as such, providing additional in-language notifications in a timely manner are currently not feasible.

The key elements of SDG&E's multi-level approach to community education and outreach are described in further detail below.

5.2.2.1 Fire Safety Stakeholder Collaboration and Communication

In 2009, SDG&E customers and community leaders were invited to participate in a fire safety collaboration process, which was facilitated by a federal mediator. Approximately 40 stakeholders – representing various sections, such as local schools, water districts, disability rights advocates, consumer groups, and fire departments – worked with SDG&E for more than a year to develop a joint fire prevention plan. The process produced more than 100 potential solutions aimed at preventing the occurrence of major fires. SDG&E has implemented many of these solutions as identified by the stakeholders, including deactivating automatic reclosers, hardening its overhead electric system, replacing wood poles with stronger steel poles and larger conductors, and undergrounding portions of the electrical system, where feasible. As discussed in the following sections, SDG&E frequently invites community leaders, government agencies, and the public at-large to participate in a collaborative fire-safety process to continue dialogue and partnerships regarding public safety.

5.2.2.2 Partnering with Organizations Dedicated to Readiness and Response

SDG&E partners with approximately 98 non-profit organizations dedicated to readiness and response to wildfires and emergencies. SDG&E facilitates coordinated multi-agency preparedness, participates in the annual County of San Diego wildland drills, underwrites philanthropic grants to support San Diego County wildfire readiness, and works closely with media and key stakeholders to promote wildfire preparation initiatives in the San Diego region. SDG&E is a member of the CUEA, who serves as a point of contact for critical infrastructure utilities and the Cal OES and other governmental agencies before, during, and after an event.

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5.2.2.3 First Responder Outreach Program

SDG&E works with local emergency response agency leadership to ensure continued awareness of electric and natural gas safety protocols and collaboration on roles and responsibilities for mutual emergency preparedness including, but not limited to wildfires. SDG&E works with all local, state, and federal fire agencies, regional dispatch centers, law enforcement and other emergency management partner agencies to ensure effective command, coordination, and communications in preparing for and responding to incidents. This is accomplished through training, exercises, relationship development and utilization of the Utility ICS.

5.2.2.4 Community Resource Centers

As a result of community meetings held in the most at-risk communities in SDG&E's service area, SDG&E established Community Resource Centers (CRCs) to help communities in real-time during extreme weather events. Currently, SDG&E has identified eight customer-owned facilities located within the HFTD to serve as CRCs during extreme weather events. SDG&E may establish more CRCs should the need arise.[78]

As discussed in Section 4.7.5, if SDG&E anticipates that power will be off for an extended period, CRCs may open in affected areas. The CRC locations selected by SDG&E were identified through a rigorous process, which included input from fire and meteorological experts, as well as consideration of those areas most prone to extreme weather, as indicated by historical data. The CRCs, if activated for a PSPS event that lasts longer than twenty-four hours in duration, will be powered using a portable back-up generator connected through a manual transfer switch. Once activated, the CRC will operate in roughly 10 hour shifts from 8:00am through 6:00pm daily, until power to the affected community has been restored. SDG&E subject matter experts will collaborate with volunteer staff at an activated CRC to provide, to the extent possible, updates and real-time information directly to the community impacted. Other volunteer organizations will provide bottled water and light snacks to provide temporary relief to residents in the area.

5.2.2.5 Community Outreach

SDG&E is proud to support non-profit organizations whose programs promote emergency preparedness and safety at home and in communities within its service territory. In 2012, SDG&E began providing funds to charitable organizations committed to regional and local emergency preparedness and fire safety, such as 2-1-1 San Diego, the American Red Cross, and the Burn Institute, plus several volunteer fire departments, CERTS, and Fire Safe Councils. In compliance with Resolution ESRB-8, SDG&E held a series of workshops regarding its PSPS practices. The purpose of these workshops was to educate stakeholders and obtain feedback from elected officials, community leaders, government agencies, and appropriate tribal organizations. SDG&E has incorporated much of the feedback into its public safety initiatives and continues to maintain an ongoing dialogue and partnerships with these stakeholders.

[78] Further information on CRCs may be found here: https://www.sdge.com/wildfire-safety/community-resource-centers.

5.2.2.6 Community Communication

SDG&E provides regular proactive communications to residents and businesses located in the HFTD. Aside from English and Spanish, communications material will also be produced in other languages, including Chinese, Filipino, and Vietnamese. These fire-safety and emergency communications include, but are not limited to:

- Community events, emergency preparedness workshops for businesses, public participation meetings, and backup generator safety workshops;
- Informational and emergency preparedness mailings to customers in the HFTD;
- Educational and general awareness advertising campaign focused on SDG&E's preparations for the fire season and the preparations SDG&E's customers should make to be ready for emergencies. This campaign includes a series of newspaper ads that run in community newspapers in the HFTD. SDG&E plans to run ads in Spanish, Chinese, Filipino (ads in English), and Vietnamese publications as well. These ads also encourage customers to sign up for outage notifications through the My Account portal;
- Educational information disseminated through a bill newsletter or special insert included in customer bills. An electronic version is emailed to paperless customers;
- Distribution of a co-branded "newsletter" with the American Red Cross, the San Diego Office of Emergency Services, and the San Diego County Fire Chiefs' Association;
- Distribution of a small "pocket-card," that easily folds and fits in an automobile glove box or emergency kit, which outlines how to be emergency-ready;
- Distribution of "refrigerator magnets" bearing important emergency information;
- The provision of weather information and system-outage status on SDGE.com;
- Dissemination of information regarding emergency-preparedness events via social media, such as Twitter and Facebook;
- Publication of information for SAFE San Diego Education and Outreach events in the community following an emergency.

In addition to routine outreach and communications, SDG&E augments its effort to communicate with customers when fire-threat conditions are elevated or extreme. SDG&E has instituted an early warning system advising customers that a RFW has been declared by the National Weather Service and dangerously high winds are expected. SDG&E also establishes communications with local water districts, telecommunications infrastructure providers, the San Diego County Office of Education, the San Diego County Office of Emergency Services, and the American Red Cross as soon as possible following the declaration of a RFW. SDG&E assembles a team of subject matter experts to provide updates on the status of the SDG&E system and weather conditions.

As alert conditions are elevated, SDG&E also contacts, directly and indirectly, Medical Baseline customers, including life support and temperature sensitive customers. Under severe threats of emergencies, where SDG&E cannot contact these customers via our outbound-dialer system,

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SDG&E will send field personnel to make personal contact and, failing all else, to leave door hangers alerting the customer of the situation.

5.2.2.7 Emergency Preparedness Safety Website

SDG&E maintains a publicly accessible website focused on safety, including natural gas safety, electric safety, wildfire safety, tree safety, emergency preparedness, generator safety, and outage information, and can be found at http://www.sdge.com/safety. SDG&E's emergency preparedness brochures, traffic radio IDs, newspaper advertisements, digital ads, and social media postings via Facebook and Twitter, have been used to drive customers to the Company's wildfire safety section: http://www.sdge.com/wildfire-safety. Additional fire or weather-related webpages are actively maintained throughout the incident by SDG&E and are accessible using the following addresses:

- Weather web pages: http://sdgeweather.com
- Community Resource Centers: http://www.sdge.com/ resource-centers

5.2.3 Trained Workforce and Mutual Assistance

5.2.3.1 Employee Workforce and Training

SDG&E's approach to a trained workforce involves a three-pronged approach under the ICS framework, integrating training and exercises for field Utility Incident Commanders, EOC responders, and executives. Field operational responders are required to participate in Utility ICS training and required to follow Electric Standard Practice No. 113.1 (ESP 113.1), which specifically addresses wildland fire prevention and fire safety. The annual ICS training cycle of operational leaders, field responders, and supporting personnel includes cross-functional training workshops and exercises covering all-hazards as well as the deployment of field training advisors to ensure continuous improvement on practical application in the field. Additionally, SDG&E actively trains its own resources with the appropriate electric distribution and transmission operational skills. A summary of the types and numbers of SDG&E's current field resources is provided in Table 6 below.

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Table 6: SDG&E Field Resources

Resource Type	Number	Description
Distribution Field Crews		
Journeyman Status ▪ Troubleman ▪ Working Foreman ▪ Journeyman	 42 35 164	Trained resources to work on SDG&E's high voltage, overhead and underground distribution system. They perform inspections and maintenance, assess system damages, make repairs to restore service, and serve as SDG&E's first responders.
Apprentice Lineman	39	Serve as compliments to field crews, training under the direct supervision of Journeyman Lineman and Working Foreman.
Line Assistants	12	Compliments the field crews as part of their training, working in direct supervision of the Journeyman Lineman and Working Foreman.
	(total: 292)	
Supervisors ▪ Construction ▪ Temporary	 27 8	Provides management, field safety, and operational oversight and technical support for field crews in each of SDG&E's nine districts.
	(total: 35)	
Transmission Field Crews		
▪ Journeyman ▪ Working Foreman ▪ Patrollers ▪ Wash Crews ▪ Line Assistant	10 4 2 2 1	Trained resources to work on SDG&E's transmission system, performing inspections and maintenance, assessing system damages, making repairs to restore service, and serving as SDG&E's first responders.
Construction Supervisor	5	Provides management, field safety, and operational oversight and technical support for field crews.
Trainer	1	Provides transmission-specific training to line crews.

SDG&E has a qualified EOC response workforce with over 450 Federal Emergency Management Agency-certified responders, equivalent to 10% of the total workforce. These responders are certified in the functions of ICS including command, operations, planning, logistics and finance. EOC responders, which include responder executives, are qualified annually in order to maintain their emergency response proficiency. Additionally, SDG&E's EOC collaborates annually with internal and external stakeholder organizations to conduct a Company-wide wildfire workshop, tabletop, functional or full-scale exercise prior to October, the beginning of fire season. Following the training and exercise, the EOC utilizes findings to develop an AAR to highlight positive response elements, areas for improvement, and corrective actions.

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5.2.3.2 Fire Coordination

SDG&E employs a full-time staff of five fire coordinators. The current fire coordinators on staff have over 150 years of fire suppression, prevention, and fire behavior experience collectively. The fire coordinators serve as the direct link between SDG&E and emergency-response agencies. They also serve as SDG&E's single point of contact for fire agencies and utilize Incident Command System protocols during incidents, provide periodic updates to both firefighters and SDG&E personnel, establish radio and communications assignments, assist in the coordination of activities related to de-energizing and re-energizing power lines, and update on-scene personnel, control centers, service dispatch, and the SDG&E regional operations centers as to the status of each incident.

The Fire Coordinators are active in professional forums, seminars, and training throughout the service territory to ensure state-of-the-art fire practices are incorporated into SDG&E operations and practices. They also participate in engineering and operational meetings to advise SDG&E personnel regarding fire threats and prevention. The Fire Coordinators also share information with the firefighting agencies within the SDG&E service territory and, on a rotating basis, provide those agencies with electrical and gas safety training.

In addition, the Fire Coordinators provide wildfire prevention training to SDG&E personnel who work in wildland areas of the service territory. This annual training utilizes SDG&E's Electric Standard Practice No. 113.1 – Operations and Maintenance Wildland Fire Prevention Plan (ESP 113.1) to educate employees about the activities that present a risk of igniting a wildfire. The plan provides a fire risk and mitigation matrix based on work activity and the FPI to set a minimum level of requirements for fire prevention, work restrictions, and fire tools for suppressing small, witnessed ignitions. SDG&E requires that contractors and consultants also undergo wildland fire prevention training and that they follow SDG&E's ESP 113.1.

SDG&E Fire Coordination also participates in county-wide wildland fire drills that include electric utility scenarios, provide instructors for electric safety for CalFire's Truck Academy and the Heartland Firefighter Recruit Academy training.

5.2.3.3 Mutual Assistance and Contractors

Mutual assistance is an essential part of the energy industry's contingency planning and restoration process. Utility and electric service companies impacted by a major outage event are able, under mutual assistance, to augment the size of their workforce by 'borrowing' restoration workers form other companies. When called up, a utility company will send trained and qualified skilled restoration workers along with specialized equipment, oversight management and support personnel to assist the restoration efforts of a fellow utility/electric service company.

SDG&E is a member of multiple emergency associations to facilitate mutual assistance and maintains active mutual assistance agreements with the following organizations: California Utilities Emergency Association; Western Regional Mutual Assistance Group; Western Energy Institute; Edison Electric Institute; and the American Gas Association.

The decision to deploy a response team or request mutual assistance is facilitated by SDG&E Emergency Management group and determined by the OIC in consultation with key operations directors and executives.

5.3 Customer Support in Emergencies

SDG&E provides emergency residential and non-residential customer protections and available communications for wildfire victims, as ordered by the CPUC.[79]

SDG&E will post explanations of the protections offered to affected customers on a special landing page on SDGE.com, with a contact telephone number for more details of eligibility and protections available and promote the page with social media campaigns. In addition, SDG&E will make every effort possible to contact impacted customer to bring awareness to these protections. An Energy Service Specialist (ESS) or an account executive will make these calls. Finally, SDG&E will send an email to wildfire victims, for those customers who are identified with an email address.

5.3.1 Protocols for Compliance with Requirements to Support Customers

5.3.1.1 Customer Protections and Contact

Customers eligible for the wildfire residential and non-residential customer protections described below are those directly impacted by the fires and identified as such by SDG&E or who have self-reported as being impacted. Directly impacted customers would include those without electric service or those needing to re-locate (either temporarily or permanently) due to fire damage.

5.3.1.2 Description of Adopted Consumer Protections

The Commission in Resolution M-4835 required SDG&E to adopt certain residential and non-residential customer protections for December 2017 wildfire victims. These customer protections are described in the following sections and unless otherwise noted, each apply to both residential and non-residential customers.

5.3.1.3 Outage Reporting

Throughout the lifecycle of a potentially dangerous incident, it is important that the customer is adequately informed and prepared at all times. It is the responsibility of the SDG&E Customer Communication Center to ensure that this is the case.

SDG&E's omnichannel approach utilizing media, which includes but is not limited to: radio, newspapers, website, direct mail, and social media, provides a constant source of information that serves to educate its customers. All information is most readily accessible on the SDG&E website (sdge.com/sdgenews.com), which is available in both English and Spanish. The main areas of focus pertain to wildfire safety, emergency preparedness, PSPS, and emergency resource centers.

[79] Commission Resolution M-4835 (January 11, 2018). SDG&E filed Advice Letter 3177-E on January 26, 2018 in compliance with Resolution M-4835, which was made effective December 7, 2018.

Exhibit No.:
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After extreme fire weather conditions are forecasted and the National Weather Service potentially issues a RFW, SDG&E begins to coordinate with local government agencies, community-based organizations, and emergency responders. Proactive communications are then initiated with customers via SDG&E's ENS and social media driving traffic to SDG&E's fire preparedness website or sdgenews.com for more information. This information is also linked to a news center, managed by the media relations team, that runs a blog-style article of all the latest updates on the emergency. As the conditions persist and the likelihood of a PSPS event becomes more certain, the proactive communications to customers increase in urgency. The communications also become more specific to customers who are most likely to experience a PSPS.

5.3.1.4 Support for Low Income Customers/Medical Baseline

In support of customer protections pursuant to Commission Resolution M-4835, SDG&E takes the following actions for all low-income customers in the fire-impacted areas within SDG&E's service territory to align with the California Alternate Rate for Energy (CARE) and Energy Savings Assistance (ESA) programs as follows:

- Freeze all standard and high-usage reviews for CARE program eligibility standards and high-usage post enrollment verification (PEV) requests for all customers in the impacted areas within SDG&E's service territory.
- Partner with the United Way, the administrator of its Neighbor-to-Neighbor program that provides emergency bill assistance, to increase the bill assistance cap amount for impacted customers from $200 to $400.
- Modify the ESA program by allowing impacted customers to self-certify if: 1) the customer states they lost documentation necessary for income verification of a fire, or 2) if the customer states that individuals displaced by the wildfires reside in the household.
- Immediately following a fire, SDG&E deploys outreach representatives to the field to support American Red Cross and County of San Diego assistance centers. These outreach representatives help customers download the mobile outage map to stay up to date on estimated restoration times, promote and enroll them in programs like CARE and ESA and connect them to the vast array of services provided by San Diego emergency services.
- SDG&E also works with the local Community Based Organizations (CBOs) to help connect customers with emergency related information, outage information, and program information. These CBOs also help to refer customers in need to San Diego emergency services for further information and assistance. SDG&E will continue to work with the local CBOs to place an emphasis on the additional measures available to low-income customers.

In addition to the protections for the low-income customers discussed above, SDGE will freeze all recertification for medical baseline customers in the impacted areas within SDG&E's service territory.

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5.3.1.5 Billing Adjustments

SDG&E will provide additional billing assistance for residential customers. Where the customer's residential structure has been destroyed, SDG&E will waive closing bills that include charges from the previous regular read date up until the dates the fires occurred, along with charges from the prior month of billing. For non-residential customers, where the structure has been destroyed, closing bill amounts from the previous regular read date up to the dates fires occurred will be waived. However, non-residential customers will be held responsible for charges billed for any months prior to the fires.

5.3.1.6 Deposit Waivers

SDG&E will waive deposit requirements for customers who are seeking to re-establish service at either the same location or a new location.

5.3.1.7 Extended Payment Plans

SDG&E will extend payment arrangements with a 0% down payment and offers a repayment period of 12 months to all impacted customers.

5.3.1.8 Suspension of Disconnection and Nonpayment Fees

For customers impacted by fires, SDG&E will suspend disconnection for non-payment and associated fees, waive the deposit and late fee requirements for affected customers who pay their utility bills late, and not report late payments by customers who are eligible for these protections to credit reporting agencies or to other such services.

SDG&E identifies the premises of customers impacted by the fires that are not capable of receiving utility services and discontinues billing these premises. SDG&E does not currently charge a disconnect charge, however, customers impacted by the fires will not be charged a reconnection charge, nor will a deposit be required.

5.3.1.9 Repair Processing and Timing (Move In – Move Out)

SDG&E initiates best efforts to expedite move-in and move-outs to support Californians returning to their homes and establishing service in new locations, and to monitor and track the time from when service requests are submitted to SDG&E to when services are provided to customers. If a customer advises SDG&E that they are relocating to another location due to the damage to their home, SDG&E will make every attempt to have service available to the customer on the requested day. Additionally, SDG&E will track the time from when the service is requested to the time it is completed.

5.3.1.10 Access to Utility Representatives

Customers and stakeholders have a variety of SDG&E representatives available to them to receive information and communicate concerns. These include: SDG&E's Call Centers, Regional Public Affairs, Customer Care – Key Accounts, and Fire Coordination.

- **Call Centers:** The call centers provide a way in which any customer, or concerned person, can contact SDG&E and obtain information before, during, or after an event.

Exhibit No.:
CA-07-0352

SDG&E's call centers monitor events as they approach and adjust resource needs accordingly throughout the event.

- **Regional Public Affairs:** SDG&E has assigned specific people to develop and maintain relationships with local elected officials. As an event approaches, the SDG&E resource will establish and maintain contact with their key stakeholder. The SDG&E representative provides answers to questions and addresses concerns.
- **Customer Care – Key Accounts:** SDG&E has identified key and critical accounts for which it assigns a specific resource to establish and maintain contact during an event. The SDG&E representative reaches out to the customer as the event develops and maintains contact until the event is over.
- **Fire Coordination**: The Fire Coordinators are experienced in fire behavior, fire prevention, and firefighting techniques. The Fire Coordinators serve as the direct link between SDG&E and emergency-response agencies. They also serve as the single point of contact for the fire agency Incident Command System, provide periodic updates to fire emergency personnel and SDG&E personnel, establish radio and communications assignments, assist in the coordination of activities related to de-energizing and re-energizing power lines, and update on-scene personnel, control centers, service dispatch, and the SDG&E regional operations centers as to the status of each incident.

6 Performance Metrics and Monitoring

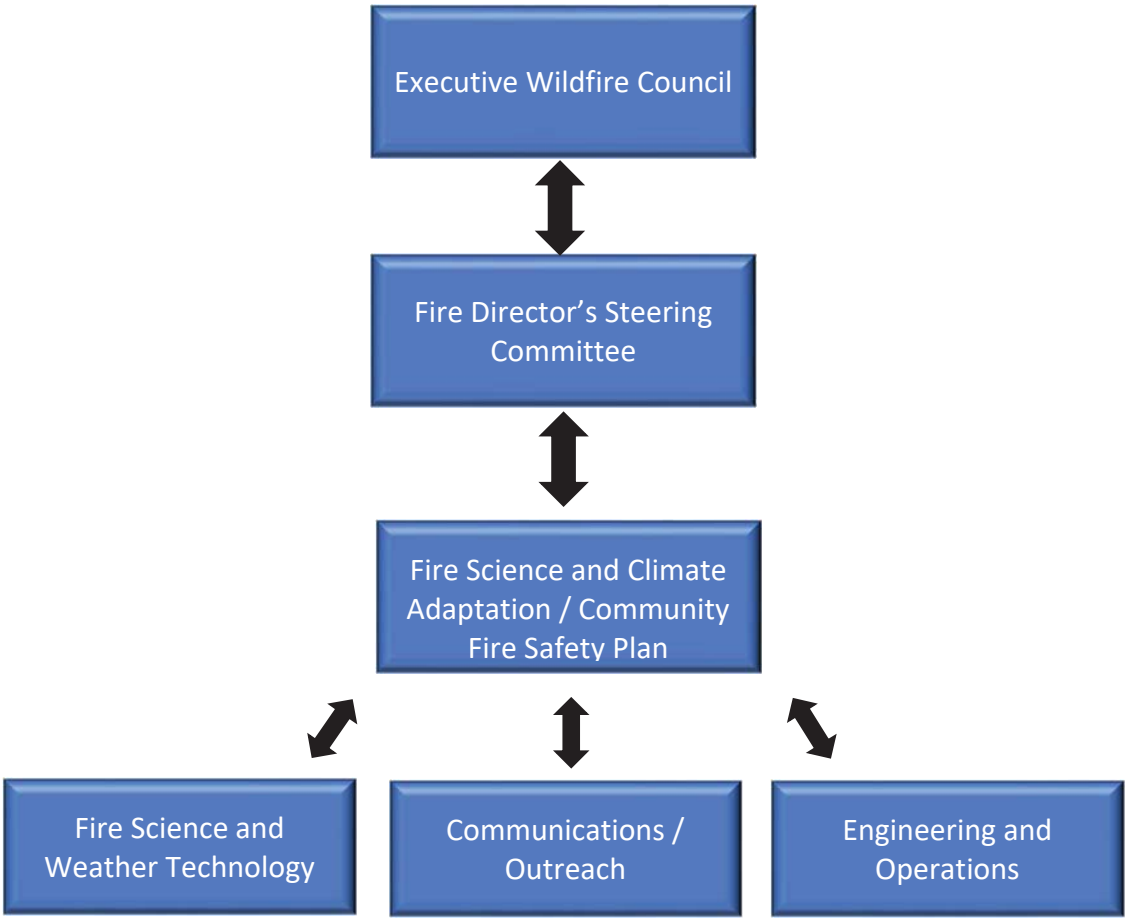
6.1 Plan Ownership and Execution

While the Director of the Fire Science & Climate Adaptation department (the wildfire risk manager) and the Vice President (VP) of Electric System Operations (the wildfire risk owner) have primary responsibility for owning, executing, and auditing this Plan, wildfire mitigation at SDG&E is a Company-wide, inter-departmental effort involving resources and programs across utility functions. As such, SDG&E has developed a cross-functional organization to govern the development and implementation of its wildfire mitigation strategy. Wildfire mitigation and response concepts and ideas can be originated and developed anywhere within SDG&E; however, their prioritization, resourcing, implementation, and tracking is governed by the Company's cross-functional organizations.

SDG&E's wildfire mitigation governance organization involves three teams and one functional department, each with specific responsibility to the successful development and implementation of the Company's wildfire mitigation strategy. Members of each team represent functions across the organization and range from executive-level to individual process or program owners and subject matter experts. The governance bodies include: Executive Wildfire Council, Fire Directors Steering Committee, Community Fire Safety Plan, and the Fire Science & Climate Adaption Department.

Exhibit No.: (SDG&E-13)
CA-07-0353

Figure 3: Wildfire Mitigation Governance Structure



6.1.1 Executive Wildfire Council

The Executive Wildfire Council establishes SDG&E's overall wildfire mitigation and response strategy. It assigns ownership and resources to support a coordinated, collaborative, and cross-functional approach to wildfire mitigation. The Executive Wildfire Council meets monthly to review SDG&E's overall performance in mitigating and responding to wildfires as well as to set Company strategy and prioritize resources.

The Executive Wildfire Council consists of the following SDG&E executives:

- President
- Chief Operations Officer (Host)
- Senior VP – Electric Operations
- VP – Electric System Operations
- VP – Electric Engineering & Construction
- VP – General Counsel
- VP – Enterprise Risk Management & Compliance
- VP – State Governmental Affairs & External Affairs

Exhibit No.: (SDG&E-04)
CA-07-0354

- VP – Customer Services
- VP – Regulatory Affairs
- Director – Fire Science & Climate Adaptation (Co-Host)

6.1.2 Fire Directors Steering Committee

The Fire Directors Steering Committee meets monthly and provides support, guidance, and oversight of SDG&E's wildfire mitigation and response programs established by the Executive Wildfire Council. The committee will also monitor the status and implementation of SDG&E's Wildfire Mitigation Plan and overall Community Fire Safety Program efforts being implemented and developed.

Members of the Fire Directors Steering Committee include:

- Director – Fire Science & Climate Adaptation (Host)
- Director – Emergency Management & Aviation
- Director – Electric Distribution Operations
- Director – Electric Grid Operations
- Director – Electric Engineering
- Director – Transmission & Substation Operations
- Director – Electric Regional Operations
- Director – Enterprise Risk Management
- Director – Asset Management
- Director – Regional Public Affairs
- Director – Marketing & Communications
- Director – Customer Care
- Assistant General Counsel/Senior Counsel
- Fire Mitigation & Climate Adaptation Manager (Co-Host)
- Quantitative Risk & Controls Manager
- Fire Coordination Manager
- Transmission Construction & Maintenance (TCM) Construction Operations Manager

6.1.3 Community Fire Safety Plan Committee

The Community Fire Safety Plan Committee is a group of managers, process owners, and subject matter experts who meet monthly and track the implementation of identified wildfire mitigation programs and processes. Members of this committee are responsible for the individual wildfire mitigation and response programs that make up the Community Fire Safety Plan.

Members of the Community Fire Safety Plan include:

- Fire Mitigation & Climate Adaptation Manager (Host)
- Fire Mitigation & Climate Adaptation Program Manager
- Fire Coordination Manager and support
- Meteorology Program Manager and support

Exhibit No.: (SDG&E-07)
CA-07-0355

- Quantitative Risk & Controls Manager and support
- Assistant General Counsel/Senior Counsel
- Marketing Communications Manager and support
- Communications Manager
- Customer Outreach & Engagement Supervisor
- Customer Programs Specialist
- Electric Engineering Team Lead and support
- Compliance Program Manager, Asset Management and support
- Construction Operations Manager TCM
- Vegetation & Pole Integrity Manager
- System Forester
- Emergency Operations Program Advisor
- Electric Distribution Engineering Manager and support
- Electric Distribution Operations Team Lead and support
- Electric Engineering Principal Engineer
- Manager – Transmission & Distribution Assets and support
- Compliance Management Manager & Technical Advisor

6.1.4 Fire Science and Climate Adaptation

A large part of being prepared for and mitigating the threat of fire is recognizing the fact of environmental and situational evolutions. The SDG&E service territory, along with the entire region, has experienced drought, sporadic precipitation, and increased tree mortality which compound the severity of and threat of the potential for a wildfire ignition. In recognition of these changing conditions and the constant need to adapt, SDG&E took a leap forward in restructuring resources to form a department, Fire Science and Climate Adaptation (FS&CA), which is comprised of meteorologists, community resiliency experts, fire coordinators, and project management personnel. Established in the second quarter of 2018, the department currently consists of 14 employees under the direction of the Director of FS&CA and maintains the sole purpose of responding to and strategizing for the ever-changing utility industry's fire preparedness activities and programs.

6.1.5 Wildfire Mitigation Plan Accountability and Ownership

The FS&CA department, led by the Director of FS&CA, is responsible for managing the production, compilation, and finalization of SDG&E's annual Wildfire Mitigation Plan to reflect the planned activities to comply with the requirements of P.U. Code § 8386(c).

The VP of Electric System Operations owns wildfire risk and ultimately has responsibility and accountability for the successful execution of SDG&E's Wildfire Mitigation Plan. The Executive Wildfire Council, described in Section 6.1.1 above, will use the process described above, involving the Fire Directors Steering Committee, the Community Fire Safety Plan, and the FS&CA department to oversee the execution of the Wildfire Mitigation Plan.

Exhibit No.: (SDG&E-02)
CA-07-0358

6.2 Metrics to Evaluate Plan Performance

As required by P.U. Code § 8386(c)(4), SDG&E includes the following metrics that are intended to enable the Commission to evaluate compliance with this Plan. Substantial compliance with the metrics set forth in the final Plan (once approved by the Commission) should demonstrate that SDG&E acted prudently and met the Commission's "reasonable manager" standard, in regard to wildfire risk mitigation. However, events outside of SDG&E's control, such as skilled labor resource constraints, supply chain disruptions, or permitting and construction delays, could restrict SDG&E's ability to meet all of the approved metrics, and should be viewed by the Commission in context when completing its subsequent compliance evaluation.

In this section, SDG&E offers metrics to use to evaluate its Plan's performance. These metrics are presented below consistent with the three-prong approach discussed in Section 2 above of Operations and Engineering; Situational Awareness and Weather Technology; and Customer Outreach and Education. For each of the three prongs, SDG&E presents metrics for each of the Plan's identified preventive strategies and/or programs put forth in Sections 4 and 5 (e.g., Operational Practices, System Hardening).

The target for a given metric is critically important to accurately evaluate the item of measure. To that end, SDG&E believes that the unit of measure for metrics should be clear and understandable without requiring a substantial explanation. For example, if two additional weather stations are proposed to be installed, how would one know if that was a significant addition? SDG&E contends that a more meaningful measurement would include informational data to provide context of how many weather stations are currently installed in its service territory and/or provide a target that demonstrates SDG&E has substantially complied with the Plan. The concept of substantial compliance is to determine if the results of a metric are consistent with expectations as communicated in the Plan given that each year differs based on a variety of factors, such as weather patterns. SDG&E will evaluate its metrics relative to its forecast (i.e., cost and number of widget estimates) and will strive to establish trends overtime.

Each metric alone does not necessarily imply that SDG&E's Plan is or is not successful. Rather, the metric should be viewed collectively to demonstrate that progress has been made in the respective areas and the data is moving in the right direction.

SDG&E recognizes that there are many metric-related efforts underway in other proceedings before the CPUC. For example, there is a specific Metrics Working Group led by the CPUC's Safety and Enforcement Division ongoing in the S-MAP.[80] SDG&E will incorporate metrics from other proceedings, as necessary and appropriate. Given that metrics are an evolving area of interest, SDG&E looks forward to working with stakeholders to further discuss relevant metrics.

[80] A.15-05-002 (cons.).

SDGE-0357
CA-07-0357

6.2.1 Operations and Engineering Metrics

6.2.1.1 Operational and Engineering Practices

Metric: Percentage of reclosers that protect the HFTD that are disabled during elevated or extreme FPI conditions.

Target: 95-100%.

As discussed Section 4.1.2, reclosers are utilized to allow SDG&E to (1) operate its system to incorporate input from its meteorologists, known localized conditions, and its declared Operating Conditions; and (2) sectionalize elements of its distribution system. This is a new metric for SDG&E. Rather than measure this metric as a snapshot in time, SDG&E suggests that this metric be measured over the compliance period of this Plan.

6.2.1.2 Inspection Plan

Metric: Percentage of inspections completed pursuant to GO 165 within a 12-month period.

Target: 95-100%.

As discussed Section 4.2.1.1, SDG&E inspects its electric distribution system according to CPUC GO 165. SDG&E's CMP is a significant mitigation for wildfire risk given SDG&E's large presence of electric distribution infrastructure. CMP is a robust inspection program that includes higher risk overhead distribution infrastructure in the HFTD. SDG&E performs overhead visual inspections on a five-year cycle. SDG&E also performs a patrol inspection annually across its entire service territory.

This metric illustrates SDG&E's productivity and effectiveness with regards to SDG&E's performance and management with its CMP. The data for this metric is readily available and is intended to be measured as of December 31 of each year.

6.2.1.3 System Hardening Plan

Metric: Number of miles system hardened in the HFTD.

Target: 90-100%.

As discussed Section 4.3, SDG&E has numerous programs either underway or in development to strengthen and modernize its system. This metric is intended to be an index of the major programs discussed in Section 4.3, which includes the Cleveland National Forecast, FiRM, and PRiME programs. These three programs form the core of SDG&E's fire hardening plans as they focus on high risk equipment in the HFTD, reducing the chances of an ignition in the areas where an ignition would be the most devastating.

The overall progress for the metric will be equally weighted between all three programs, and measured as:

- FiRM: % of system miles hardened compared to Plan's assumptions (weighted 33%)
- CNF: % of system miles hardened compared to Plan's assumptions (weighted 33%)
- PRiME: % of poles replaced compared to Plan's assumptions (weighted 33%)

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While this is data that SDG&E is currently collecting, it may or may not be used for this specific purpose. Therefore, as a multitude of programs, this is a new metric for SDG&E. SDG&E proposes to measure this metric as of December 31 of each year. This metric is an execution metric, that will measure SDG&E's adherence to the approved Plan, measuring actual miles hardened and poles replaced against the level ranges stated in in Appendix A for these programs.

6.2.1.4 Vegetation Management Plan

Metric: Percentage of vegetation inspections completed in the HFTD.

Target: 95-100%.

As discussed Section 4.4, SDG&E has designed and maintains its robust vegetation management program aimed at keeping trees and brush clear of electrical infrastructure. SDG&E considers this to be a critical program targeted to mitigate the risk driver of vegetation contact. SDG&E has existing metrics related to vegetation management. That said, SDG&E is proposing this metric specifically for the purpose of evaluating this Plan's performance. SDG&E proposes to measure this metric over the compliance period of this Plan.

The inspection activity for this metric will include the assessment of all trees in the HFTD that are within the strike zone of the electric facilities that may impact the lines by encroachment and/or limb or complete tree failure per GO 95, Rule 35 and PRC § 4293. In addition to this inspection, SDG&E plans to perform a second patrol within the entire HFTD during each calendar year of the Plan following the same criteria as above. The metric measure for these activities will be line miles completed and will be documented via line mapping and the Vegetation Management tree inventory electronic database.

6.2.1.5 Public Safety Power Shutoff Protocols

Metric: Percentage of PSPS impacted metered customers notified of the potential PSPS in advance.

Target: 90-100%.

As discussed Section 4.7, SDG&E de-energizes circuits when necessary to protect public safety in certain circumstances. PSPS is one tool SDG&E uses as a last resort to mitigate wildfire risk. SDG&E believes that the intent behind this metric is to provide its customers with the most accurate information possible before a PSPS event occurs, enabling customers to anticipate and prepare for the event. For purposes of this metric, "in advance" refers to any reasonable amount of time prior to the de-energization of the impacted circuit. "Notified" in the context of measuring this metric refers to SDG&E using the customer's preferred communication channel, as stated to SDG&E, to communicate the potential for a PSPS event for which they will be impacted. While PSPS is not a new tool for SDG&E, this metric does not exist for SDG&E today. Further, SDG&E does not currently collect the data required to measure this metric. SDG&E plans to measure this metric over the compliance period of the Plan.

6.2.1.6 Alternative Technologies

Refer to Section 6.2.1.3 regarding System Hardening Plan.

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6.2.1.7 Post Incident Recovery, Restoration, and Remediation Activities

Refer to Section 6.2.1 regarding Operations and Engineering as well as Section 6.2.3 Customer Outreach and Education.

6.2.2 Situational Awareness and Weather Technology

6.2.2.1 Situational Awareness and Determination of Local Conditions

Metric: Percentage of weather stations operational during RFW or extreme FPI.

Target: 95-100%.

SDG&E has installed weather stations throughout its service territory with a particular focus on the HFTD. The weather stations are intended to enable SDG&E to monitor weather conditions in near real-time on every distribution circuit and transmission line across the fire-prone areas of the SDG&E service territory to monitor the severity of the fire weather conditions. SDG&E believes this is a critical tool to help mitigate the risk of wildfire because this data informs day-to-day operational decision-making at all levels of the Company, including Electric Distribution, Transmission, and Emergency Operations to enhance situational awareness and mitigate the risks associated with wildfires and other adverse weather conditions. Although weather stations are of critical importance, like many other technology, issues arise. This is a new metric that SDG&E has developed for the purpose of evaluating the Plan's performance and SDG&E's situational awareness. SDG&E is currently collecting the data necessary for this metric. SDG&E plans to measure this metric over the compliance period of the Plan.

6.2.2.2 Situational Awareness Tools

Metric: Percentage of business days annually that the FPI is published.

Target: 95-100%.

The FPI is an internally developed, seven day forecast tool that is intended to reflect the potential for large wildfire across the SDG&E service territory on any given day based on weather and fuels conditions and historical fire occurrences within each of SDG&E's eight operating districts. The situational awareness provided by the FPI is a foundational component of this Plan and informs the operations and maintenance of the electric system 365 days a year. Although SDG&E has the data to produce this metric, this is a new metric for SDG&E. SDG&E proposes that this metric be evaluated over the compliance period of the Plan.

Metric: Percentage of days annually that the WRRM-Ops model is functional during elevated or extreme FPI Conditions.

Target: 95-100%

The WRRM-Ops model assesses the areas of highest fire danger before a wildfire begins so preventative measures can be taken to enhance public safety and maintain reliable operation of the electric system. WRRM-Ops is also able to simulate the growth and potential impact of a wildfire anywhere in the SDG&E service territory should an ignition begin. This technology and enhanced situational awareness is foundational to SDG&E's ability to anticipate, prepare for, react to, and recover from wildfire events impacting our service territory. Through this metric,

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SDG&E is intending to show that this mitigation tool is able to support emergency operations at all times a wildfire may occur.

SDG&E currently tracks and has access to the data required for this metric. That said, this is a new metric for SDG&E. SDG&E recommends that this metric be evaluated over the compliance period of the Plan.

6.2.3 Customer Outreach and Education

6.2.3.1 Emergency Management

Metric: Percentage of SDG&E's EOC responders that are trained in ICS.

Target: 95-100%.

As discussed in Section 5.1, SDG&E utilizes an Incident Command Structure to manage emergency incidents and events. ICS is an essential element within the nationally recognized SEMS and is the framework for responding to and managing emergencies and disaster involving multiple jurisdictions and agencies. SDG&E utilizes ICS to standardize all elements of its response structure so that it may be consistently translated to and easily understood by internal and external partners and stakeholder agencies to respond in an effective and integrated manner to all hazards. Due to the importance of ICS, SDG&E requires all EOC responders trained in ICS.

Beginning primarily in 2018, SDG&E collects the data that will be used to compute this metric; however, this is a new metric developed for evaluating the Plan's performance. SDG&E suggests evaluating this metric as of December 31 of each year.

6.2.3.2 Disaster and Emergency Preparedness

Metric: Number of internal and external emergency response preparedness trainings conducted.

Target: 95-100%.

SDG&E applies a comprehensive approach to emergency response and preparedness. This includes annual trainings, workshops, and exercises with internal and external stakeholders. Examples of such trainings are EOC and field leadership ICS training and table top exercises. The training cycle and emergency responder participants may vary from year-to-year. In fact, many of the trainings are based on two-year cycles. Accordingly, the number of trainings may also vary in a given year. Further, through SDG&E's After-Action Review Process, SDG&E measures effectiveness through continuous improvement and tracking of corrective actions.

To determine the progress for this metric, SDG&E plans to measure the percentage of trainings conducted compared to the Plan's assumptions. The Plan's assumptions, as expressed in ranges, are provided in Appendix A. SDG&E plans to evaluate this metric as of December 31 of each year.

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Metric: Percentage of fire agencies in the SDG&E service territory that receive hazard training, including fire.

Target: 95-100%.

As addressed in Section 5.2, SDG&E coordinates and trains local first responders, including all 54 fire agencies in its service territory. This is largely accomplished through SDG&E's First Responder Outreach Program. As part of this program to date, 100% of local fire agencies in San Diego County have participated in utility safety trainings, emergency preparedness briefings, and contingency planning exercises. The same opportunities are made available to other first responder agencies and stakeholders such as local law enforcement and government. This metric is intended to demonstrate the extensive efforts undertaken by SDG&E to partner with other key stakeholders in its service territory. SDG&E currently tracks and measures liaison activities in compliance with P.U. Code § 965.5, 49 CFR 192.615, and GO 112-F. SDG&E proposes to evaluate the metric over the compliance period of this Plan.

6.2.3.3 Customer Support During Emergencies

Refer to Section 6.2.1.5 regarding PSPS advanced notifications.

6.3 Application of Previously Identified Metrics to Inform Plan

As part of its annual GO 166 FPP effort, SDG&E previously developed two metrics to evaluate its Fire Prevention Plan performance: CPUC Reportable Ignitions, and Transmission and Distribution Wires Down. These metrics, along with SDG&E's history of wildfire mitigation and response, have informed the development of this Plan by allowing SDG&E to gain experience with tracking fire-relevant data and subsequently developing and planning new metrics. SDG&E's initial metrics were developed to focus on fire ignitions and physical incidents that could be the precursor to an ignition (e.g., wires down).

SDG&E does not recommend that these initial metrics be used to determine compliance with this Plan as they are not controllable. Subsequent metrics presented in this Plan should track data that may be used to directly or indirectly measure effectiveness of SDG&E's fire prevention, mitigation, and response program impacts. For example, as explained above, tracking the number of miles system hardened is presented to measure aspects of SDG&E's fire prevention and mitigation efforts. SDG&E intends to collectively review a portfolio of metrics data over time and believes, as this data is collected, it will prove useful to SDG&E and stakeholders to show progress and trends.

As SDG&E's wildfire mitigation, prevention and response continues to evolve, and additional potential metrics are evaluated, updates may be integrated.

6.3.1 CPUC Reportable Ignitions

CPUC reportable ignitions, as defined in D.14-02-015, are associated with electric overhead powerlines anywhere in the SDG&E service territory. In 2017, there were 23 reportable fires in SDG&E's service territory that met the D.14-02-015 definition. Of these 23, 7 were contained to less than 10 acres and the remaining 16 were contained to less than one quarter of an acre. In 2018, there were a total of 26 reportable fires, all of which were contained to less than 100

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acres, 24 of the 26 were contained to less than 10 acres, and 21 of the 26 contained to less than 0.25 acres.

6.3.1.1 Transmission and Distribution Wires Down

Transmission and Distribution Wires Down are the number of electric transmission and distribution wires downed within SDG&E's HFTD. The data used for this metric is the number of instances where an electric transmission or primary distribution conductor falls to the ground or on to a foreign object (within the SDG&E HFTD). For 2017, SDG&E had 47 such instances within the HFTD. In 2018, SDG&E had 41 wire-down events in the HFTD.

6.4 Process and Procedure Descriptions

6.4.1 Monitoring and Correcting Deficiencies

The owners of this Plan described in Section 6.1 above will execute, monitor, review, and address deficiencies in SDG&E's approach to wildfires. The structure is integrated both across the entire SDG&E organization as well as through its reporting hierarchy. With regular monthly meetings of each group, this structure allows for wide collaboration and information gathering, as well as the ability to inform, plan, act, and improve within a compressed timeline, when needed. This structure will also allow any operational or strategic changes to be communicated and captured within SDG&E's approach to wildfire mitigation and response.

In 2018, SDG&E created a new group in the FS&CA department to closely monitor the Community Fire Safety Plan and this Plan. This monitoring and continuous improvement process for wildfires at SDG&E can start with any employee or any one of the three groups involved in the governance structure, though this newly formed group, Fire Mitigation and Climate Adaptation, will monitor and track this Plan implementation with the Community Fire Safety Plan. This group meets monthly to review the implementation status of wildfire mitigation and emergency management initiatives as well as to monitor the Plan's performance against metrics. The Community Fire Safety Plan will report the status, including variances, of SDG&E's performance to the Fire Directors Steering Committee.

The Fire Directors Steering Committee will discuss and create plans to address any variances against the Plan, as well as to discuss any new ideas or strategies that could be immediately assigned and implemented. The members of the Fire Directors Steering Committee will implement any necessary corrections or adjustments within existing operational and budgetary constraints. It will also report the status, plans, and variances to the Executive Wildfire Council. The Fire Directors Steering Committee will also make recommendations or request additional funding or resources to address existing variances.

The Executive Wildfire Council will address strategic considerations and guide the organization to address wildfire mitigation efforts efficiently.

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7 Additional Information Required by the CPUC

7.1 Cost Information

In response to the ALJ Ruling, SDG&E has also included in Appendix A, "cost estimates for each activity in the WMP in order for the Commission to weigh the potential cost implications of measures proposed in the plans." SDG&E has included transmission-related activities in this Plan pursuant to the ALJ Ruling,[81] however, because these activities are regulated by the Federal Energy Regulatory Commission, SDG&E has only included cost estimates for those activities that are CPUC jurisdictional.

SDG&E presents its cost estimates in direct dollars, in 2019 dollars given that this Plan is being filed in 2019 for mitigation activities planned for 2019. Further, consistent with SDG&E's presentation in its 2016 RAMP Report and 2019 GRC workpapers, the cost estimates are provided in ranges of dollars and shown separately for Operations and Maintenance (O&M) and capital expenditures. These cost estimates will be further refined both in future RAMP and GRC filings and represent SDG&E's current knowledge at a snapshot in time. To the extent that conditions change, the cost estimates put forth herein may be updated in future filings.

SDG&E is presenting O&M cost estimates in this Plan relative to its 2018 authorized revenue requirement, which was established in the 2016 GRC and approved by the CPUC in D.16-06-054. The basis for presenting costs in this Plan compared to SDG&E's 2018 authorized revenue requirement is that it is consistent with P.U. Code § 8386(j), which requires SDG&E to track costs incurred for fire risk mitigation that are not otherwise covered in SDG&E's revenue requirements. This approach is also consistent with the table included in Appendix B of the ALJ Ruling, specifically the column requesting "Costs Currently in Revenue Requirement."

For SDG&E, 2018 revenue requirement is what is implemented in rates as of the date of this Plan. The 2018 revenue requirement was only intended to be in rates through December 31, 2018, however, SDG&E's TY 2019 GRC, which requested its new revenue requirement be effective on January 1, 2019 is still pending. Since SDG&E is awaiting the outcome of its 2019 GRC, no revenue requirement has been authorized by the CPUC.

Additionally, SDG&E is presenting O&M cost estimates in this Plan on an incremental basis to 2018 authorized revenue requirement. SDG&E's O&M is presented in the GRC as one or more cost centers summarized in a workpaper or work group. While these O&M workpapers are comprised of various components, such as activities, labor, and non-labor, not all activities are presented in the GRC in that granular manner. Therefore, identifying the annual costs associated with a particular activity embedded in base business workpapers is challenging and would require further assumptions.

Capital, however, is being presented in this Plan as the entire cost, not just incremental, of the program for each year of the compliance period, which SDG&E is proposing to be through 2020. SDG&E forecasts capital for multiple years leading up to and including the test year in its GRCs and as the total direct cost of the program. However, SDG&E generally manages capital over a GRC cycle. Therefore, capital shown in this Plan is consistent with the GRC presentation. Since

[81] ALJ Ruling at 2.

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projects generally span several years, considering capital costs over a limited timeframe (e.g., one year) typically does not represent the entire mitigation.

In addition, costs for these mitigation activities will be converted into revenue requirement when recording costs to any authorized memorandum account(s) and at the time SDG&E seeks cost recovery in a future GRC or other applicable proceeding(s). While cost estimates provided in the Plan represent forecasts, actual revenue requirement will be recorded to memorandum accounts.

Many (but not all) of the programs and activities described in this Plan have been included in and will be funded through SDG&E's GRC rates. However, the Commission has not yet issued a decision in SDG&E's pending 2019 GRC (A.17-10-007), which was filed on October 6, 2017, and as such SDG&E does not know at this time what funding will be authorized.

There may be programs in the Plan for which SDG&E has revised its assumptions and cost forecasts compared to the 2019 GRC. In such instances, SDG&E reiterates that GRCs are generally managed over the cycle and, especially as it related to capital, projects take time to ramp up to the GRC levels. This is particularly true given the uncertainty associated with the timeliness and outcome of a GRC decision. SDG&E also believes that wildfire-related risk mitigation activities and spending will be reviewed through the requirements set forth in D.14-12-025 for Accountability Reporting.

While SDG&E has included preliminary cost estimate ranges, as required, both SB 901 and the OIR make clear that this proceeding, and the Plan itself, are not cost recovery exercises. Instead, pursuant to the statute, SDG&E will track the costs for the programs and activities detailed throughout this Plan, and in the future seek recovery for any incremental costs in the appropriate procedural forum. For cost recovery purposes, demonstrating substantial compliance with the Commission-approved Plan requirements should facilitate the Commission's subsequent just and reasonable review.

7.2 Comparison of Wildfire Mitigation Plan and Fire Prevention Plan

This 2019 Wildfire Mitigation Plan is similar to SDG&E's prior FPPs in that both describe SDG&E's overall fire mitigation plan and the various programs and initiatives that are currently in place. Both describe SDG&E's three prong approach to wildfire mitigation under the general areas of: operations and engineering, situational awareness and weather technology, and customer outreach and education. Both describe the weather awareness system that SDG&E has developed and uses, as well as the tools that are in place to improve situational awareness and provide real-time monitoring of fire potential and fuel conditions. Both describe the types of system hardening programs that are in place, the parameters SDG&E operates from during various levels of weather extremes, and how SDG&E contacts and educates its various customer groups.

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This Plan, however, has been expanded to comply with the numerous specific requirements in SB 901.[82] These requirements include, among other things, a discussion on risk elements identified, the strategies that SDG&E has employed (or plans to employ) to further mitigate the potential of an ignition source associated with electric facilities, cost estimates of those mitigations, the inclusion of metrics designed to measure the completeness of the various stated programs and initiatives, a discussion on SDG&E's overall emergency preparedness and response programs, and an explanation on Plan governance and oversight. For the 2019-2020 period, this Plan includes and describes new wildfire mitigation strategies and programs that were not included in the FPP. These are summarized below.

For Operations and Engineering, SDG&E intends to:

- Implement a comprehensive fuels management program with the goal of protecting communities and electric facilities;
- Collaborate with agency stakeholders to find the best solution to provide GIS data;
- Accelerate its FiRM and PRiME programs to increase the overall hardening of the electric system;
- Establish programs to replace expulsion fuses and remove hotline clamps;
- Develop and implement an asset management program to meet stakeholder and regulatory requirements found in ISO 55000;
- Initiate the WiSE program to mitigate risk by hardening electric distribution overhead infrastructure and protection systems in wildland urban interfaces;
- Evaluate and update covered conductor projects on FiRM planned for 2020;
- Deploy LTE using a dedicated radio frequency (RF) spectrum to improve the overall reliability of SDG&E's communication network;
- Re-examine and expand the current vegetation management database to improve patrols and pruning requirements; and
- Enhance vegetation management program by increased inspections, patrols, and trimming.

In the area of Situational Awareness and Weather Technology, SDG&E intends to:

- Rebuild and update 60 of its weather stations with the latest technology in key locations;
- Develop predictive indicators to support SDG&E's vegetation management program through the use of big data analytics;
- Mobilize and cloud base the WRRM-Ops model to provide SDG&E's fire coordinators with the ability to simulate current conditions in the field so that it can be examined by decision makers in the Emergency Operations Center during critical times;
- Enhance the FPI and add additional cameras to the system to provide for greater and more specific coverage in weather prone areas;

[82] Because the WMP requirements are more extensive than the FPP's, SDG&E believes that the FPP requirement will become redundant and the Commission should consider eliminating it once the WMPs are approved.

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- Operationalize the daily weather briefing into an app so that it can be easily obtained in the field;
- Acquire a second firefighting helicopter for dispatch by CalFire for active firefighting and patrolling of electric lines when needed; and
- Continue an Ignition Management Program (IMP) to track ignitions and potential ignitions, and perform root cause analysis on each ignition or potential ignition to detect patterns or correlations.

For Customer Outreach and Education, SDG&E plans to:

- Improve community outreach and education by adding additional Community Resource Centers for use during PSPS events;
- Target fire stations in the backcountry and work to secure internet communication and camera access for them during a PSPS events; and
- Implement a Backup Power for Resilience project, which will provide back-up power to critical infrastructure (i.e., fire stations, Community Resource Centers, and other critical infrastructure).

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Appendix A

Workpapers to SDG&E's Wildfire Mitigation Plan

Consistent with the ALJ Ruling, for each identified preventative strategy or program in Section 4 of this Plan, the workpapers in this Appendix provide detailed information on: (1) whether the program/strategy is existing or new; (2) if existing, the proceeding where the program/strategy costs have been subjected to Commission review; (3) if new, identification of any memorandum account where related costs are being tracked and an explanation of how double tracking is prevented; (4) whether the program/strategy is implemented in compliance with existing regulations or exceeds current regulatory requirements; (5) if a program/strategy is identified as meeting a current regulatory requirement, a citation to the associated order, rule, or code; (6) a description of how the implementation of the program/strategy mitigates one or more of the wildfire risks or drivers identified in the Plan. Additionally, each of the identified preventive strategies and programs is delineated into one of the following categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and (5) Response and Recovery.

In response to the ALJ Ruling, SDG&E has also included in this Appendix, "cost estimates for each activity in the WMP in order for the Commission to weigh the potential cost implications of measures proposed in the plans." SDG&E has included transmission-related activities in this Plan pursuant to the ALJ Ruling, however, because these activities are regulated by the Federal Energy Regulatory Commission, SDG&E has only included cost estimates for those activities that are CPUC jurisdictional.

SDG&E presents its cost estimates in direct dollars, in 2019 dollars given that this Plan is being filed in 2019 for mitigation activities planned for 2019. Further, consistent with SDG&E's presentation in its 2016 RAMP Report and 2019 GRC workpapers, the cost estimates are provided in ranges of dollars and shown separately for Operations and Maintenance (O&M) and capital expenditures. These cost estimates will be further refined both in future RAMP and GRC filings and represent SDG&E's current knowledge at a snapshot in time. To the extent that conditions change, the cost estimates put forth herein may be updated in future filings.

SDG&E is presenting O&M cost estimates in this Plan relative to its 2018 authorized revenue requirement, which was established in the 2016 GRC and approved by the CPUC in D.16-06-054. The basis for presenting costs in this Plan compared to SDG&E's 2018 authorized revenue requirement is that it is consistent with P.U. Code § 8386(j), which requires SDG&E to track costs incurred for fire risk mitigation that are not otherwise covered in SDG&E's revenue requirements.

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Response to Change in Operating Conditions

Plan Cross-Reference: Section 4.1.1

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Response to change in Operating Conditions is an existing strategy.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by changing how SDG&E operates (i.e., enabling or disabling reclosing, enabling or disabling sensitive protection settings, limiting or not limiting certain construction activities) to reduce the risk of creating an ignition during periods of elevated, extreme, and Red Flag Warning conditions.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This strategy was included in the Design, Operations and Maintenance mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-15 at SDGE 15-10 – SDGE 15-11).

Costs: The job activities described in this strategy are performed on a day to day basis by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its Fire Risk Mitigation Memorandum Account (FRMMA), which is pending before the CPUC in Advice Letter 3333-E, to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

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Recloser Protocols

Plan Cross-Reference: Section 4.1.2

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Recloser Protocols is an existing strategy.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by disabling reclosing and enabling sensitive relay settings that can both more easily detect faults and trip faster when a fault is detected, limiting the fault energy. Both features when enabled during high risk operating conditions reduce the chance of ignitions.

This falls under the Operation Practices mitigation category.

RAMP: This strategy was included in the Design, Operations and Maintenance mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-15 at SDGE 15-10 – SDGE 15-11).

Costs: The job activities described in this strategy are performed on a day to day basis by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: (SDG&E-370)
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Other Special Work Procedures

Plan Cross-Reference: Section 4.1.3

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Other Special Work Procedures is an existing strategy.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by restricting certain high-risk construction activities within the HFTD during elevated or higher operating conditions.

This falls under the Operational Practices mitigation category.

RAMP: This strategy was included in the Design, Operations and Maintenance mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-15 at SDGE 15-10 – SDGE 15-11).

Costs: The job activities described in this strategy are performed on a day to day basis by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

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Wildfire Infrastructure Protection Teams (Contract Fire Resources)

Plan Cross-Reference: Section 4.1.4.1

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Wildfire Infrastructure Protection Teams (Contract Fire Resources) is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by providing fire suppression capability proximate to SDG&E work or operational activities during extreme weather events.

This falls under the Response and Recovery mitigation category.

RAMP: This program was included in the Rapid Response mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015 at Chapter SDG&E-1 at SDGE 1-15).

Costs: Costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. While there are forecasted costs for this program requested and pending before the CPUC in A.17-10-007, in this Plan this program has been expanded beyond the levels in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Wildfire Infrastructure Protection Teams (Contract Fire Resources)	**2019**		**2020**	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$0.7	$1.1	$0.7	$1.1

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Aviation Firefighting Program

Plan Cross-Reference: Section 4.1.4.2

Objective Time Frame: This program that will continue over the compliance period of this Plan.

New/Existing: The aviation firefighting is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by providing aerial firefighting capability throughout SDG&E's service territory and beyond.

This falls under the Response and Recovery mitigation category.

RAMP: This program was included in the Rapid Response mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015 at Chapter SDG&E-1 at SDGE 1-15).

Costs: Certain costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs to expand this program for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007. However, in this Plan SDG&E is proposing to expand its Aviation Firefighting Program beyond the levels in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Aviation Firefighting Program	**2019**		**2020**	
	Low	**High**	**Low**	**High**
Incremental O&M (Directs, 2019$ in MM)	$6.0	$9.0	$6.0	$9.0

Exhibit No. 273
CA-07-0373

Industrial Fire Brigade

Plan Cross-Reference: Section 4.1.4.3

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: The Industrial Fire Brigade is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by being available full-time to fight fires involving electrical equipment and flammable liquids.

This falls under the Response and Recovery mitigation category.

RAMP: This program was included in the Rapid Response mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015 at Chapter SDG&E-1 at SDGE 1-15).

Costs: Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: (SDG&E-07)
CA-07-0374

Ignition Management Program

Plan Cross-Reference: Section 4.1.4.5

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: The Ignition Management Program is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the harmful impacts of wildfires on both electric infrastructure and fire prone communities, regardless of the cause of the ignition of those fires.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: It was not presented in SDG&E's 2016 RAMP Report.

Costs: SDG&E plans to utilize current resources within the Emergency Management work group to fund the job activities discussed in this program. Accordingly, SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: CA-07-0375

Fuel Management Program

Plan Cross-Reference: Section 4.1.4.6

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: The Fuel Management Program is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program will mitigate the harmful impacts of wildfires on both electric infrastructure and fire prone communities, regardless of the cause of the ignition of those fires.

This falls under the Inspection and Maintenance mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Fuel Management Program	**2019**		**2020**	
	Low	**High**	**Low**	**High**
Incremental O&M (Directs, 2019$ in MM)	$0.4	$0.6	$0.7	$0.9

Exhibit No. 376
CA-07-0376

Distribution System Inspection

Plan Cross-Reference: Section 4.2.1

Objective Time Frame: This an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Distribution System Inspection is an existing program, and includes SDG&E's Corrective Maintenance Program inspections, Quality Assurance and Quality Control inspections, and Monitoring and Auditing process.

Meet or Exceed Regulations: SDG&E's Corrective Maintenance Program inspections meet the regulatory requirements of GO 165. SDG&E's Quality Control inspections meet and exceed the GO 165 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by inspecting SDG&E facilities to identify nonconformances that could lead to equipment failures before they occur. Preventing equipment failure within the HFTD reduces the risk of ignitions caused by equipment failure.

This falls under the Inspection and Maintenance mitigation category.

RAMP: This program was included in the Inspection, Repair, Maintenance & Replacement Programs mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-13 – 1-14, SDGE 1-16; Chapter SDG&E-15 SDGE 15-10 – SDGE 15-11).

Costs: The job activities described in this inspection program are performed on a day to day basis by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this program.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: CA-07-0377

Substation System Inspection

Plan Cross-Reference: Section 4.2.2

Objective Time Frame: This an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Substation System Inspection is an existing program.

Meet or Exceed Regulations: This program meets the regulatory requirements of GO 174.

Risk Mitigation: This program mitigates the risk of wildfire by inspecting SDG&E facilities to identify nonconformances that could lead to equipment failures before they occur. Preventing equipment failure within the HFTD reduces the risk of ignitions caused by equipment failure.

This falls under the Inspection and Maintenance mitigation category.

RAMP: This program was included in the Design, Operations and Maintenance mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-15 at SDGE 15-10 – SDGE 15-11).

Costs: The job activities described in this inspection program are performed on a day to day basis by the Substation Construction and Maintenance work group. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this program.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: CA-07-0378

Transmission System Inspection

Plan Cross-Reference: Section 4.2.3

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Transmission System Inspection is an existing program.

Meet or Exceed Regulations: This program meets the requirements of the maintenance plan filed with CAISO. Lines are inspected to ensure conformance with California Public Resources Code (PRC) §§ 4292 and 4293, as well as GO 95 and GO 128 rules.

Risk Mitigation: This program mitigates the risk of wildfire by inspecting SDG&E facilities to identify nonconformances that could lead to equipment failures before they occur. Preventing equipment failure within the HFTD reduces the risk of ignitions caused by equipment failure.

This falls under the Inspection and Maintenance mitigation category.

RAMP: This program was included in the Design, Operations and Maintenance mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-15 at SDGE 15-10 – SDGE 15-11).

Costs: Costs for this program are O&M expenditures related to SDG&E's transmission system and not CPUC jurisdictional. These costs will be recovered through SDG&E's Transmission Owner (TO) 5 formula rate case filed with the Federal Energy Regulatory Commission (FERC).

Exhibit No.: (SDG&E-19)
CA-07-0379

Geographic Information Systems Data

Plan Cross-Reference: Section 4.2.4

Objective Time Frame: This is program that will continue over the compliance period of this Plan.

New/Existing: Geographic Information Systems Data is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by sharing GIS information with other agencies and stakeholders to improve collaboration and overall emergency event response.

This falls under the Response and Recovery mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: SDG&E plans to utilize current resources to fund the job activities discussed in this program. Accordingly, SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

CA-07-0380

Design and Construction Standards

Plan Cross-Reference: Section 4.3.1

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Design and Construction Standards is an existing strategy. The Design and Construction Standards described in this strategy have already been completed and take input from multiple work groups to publish. However, SDG&E is constantly striving to improve through new methods or technologies to mitigate risk. The development of the covered conductor standards described in Section 4.3.14 is an example of this.

Meet or Exceed Regulations: This strategy meets and exceeds the requirements of GO 95 by leveraging SDG&E's extensive weather network to design to known local conditions based on SDG&E's wind map. While GO 95 requires utilities to design to "known local conditions," it does not require utilities to have the weather network in place to identify the known local conditions. This strategy also meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by establishing design criteria that will withstand the extreme weather condition brought on by Santa Ana winds within the HFTD.

This falls under the Design and Construction mitigation category.

RAMP: This strategy was included in the Design and Engineering Approaches mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for performing the updating and creation of standards were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

CA-07-0381

Testing and Deploying Emerging Technologies

Plan Cross-Reference: Section 4.3.2

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Testing and Deploying Emerging Technologies is an existing strategy.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by looking for new technologies to deploy such as the CalFire approved fuse (discussed in Section 4.3.11), and the falling conductor protection technology (discussed in Section 4.3.15) that reduce the risk of ignitions within the HFTD.

This falls under the Design and Construction mitigation category.

RAMP: Testing and Deploying Emerging Technologies was not presented in SDG&E's 2016 RAMP Report as a specific strategy. However, programs such as Fire Threat Zone Advanced Protection which developed from this strategy were presented in the 2016 RAMP Report.

Costs: The job activities described in this strategy are performed on a day to day basis by the Distribution Engineering work group. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

CA-07-0382

Facility Analysis

Plan Cross-Reference: Section 4.3.3

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Facility analysis is an existing program.

Meet or Exceed Regulations: This program exceeds regulations as these are not part of the GO 165 inspection plan filed with the CPUC. These inspections utilize multiple data sources including outage information and LiDAR in addition to what is identified with visual inspections to assess the risk of a facility.

Risk Mitigation: This program mitigates the risk of wildfire by analyzing SDG&E facilities to identify facility locations that have a higher probability of failure based on engineering data and outage history. This information is used by capital programs, such as FiRM and PRiME, along with other tools to prioritize replacements.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This program was included in the System Modernization mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-12 at SDGE 12-14).

Costs: The job activities described in this program are performed on a day to day basis by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this program.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

CA-07-0383

Oversight of Activities in the Rural Areas

Plan Cross-Reference: Section 4.3.4

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Oversight of Activities in the Rural Areas is an existing strategy.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451, as there is no regulatory requirement to have an oversight team evaluate proposed mitigations within the HFTD.

Risk Mitigation: This strategy mitigates the risk of wildfire by creating an oversight team that evaluates the impact of the proposed mitigations to ensure the most critical wildfire risks are addressed.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: While not explicitly presented as a mitigation in the 2016 RAMP Report, this team developed many of the mitigations presented in the 2016 RAMP Report.

Costs: The job activities performed by this team occur on a day to day basis. The members represent and support multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this program.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: (SDG&E-14)
CA-07-0384

Asset Management

Plan Cross-Reference: Section 4.3.5

Objective Time Frame: This new program will continue over the compliance period of this Plan.

New/Existing: Asset Management is a new program. The Asset Management work group is a new work group proposed in A.17-10-007. If authorized, it will perform the asset management work activities on an annual basis in an ongoing manner.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451 by developing and implementing an asset management program that conforms with ISO 55000, which is not required by regulation.

Risk Mitigation: This program mitigates the risk of wildfire by developing an asset health index for facilities located within the HFTD. Developing the asset health index will aid in prioritizing inspections, repairs, and replacements for at risk facilities.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This program was not presented in the 2016 RAMP Report, but was listed as a "RAMP Post-Filing" program in A.17-10-007.

Costs: Forecasted costs for this program were requested and are pending before the CPUC in A.17-10-007. It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Asset Management	2019		2020	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$1.2	$1.8	$1.7	$2.5

Exhibit No.: (SDG&E-07)
CA-07-0385

Overhead Transmission and Distribution Fire Hardening

Plan Cross-Reference: Section 4.3.6

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan. At the current rate, SDG&E plans to complete the wood to steel program by 2025.

New/Existing: Overhead Transmission and Distribution Fire Hardening is an existing program.

Meet or Exceed Regulations: This program meets and exceeds GO 95 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by fire hardening transmission and distribution lines within the HFTD.

This falls under the Design and Construction mitigation category.

RAMP: This program was included in the Inspection, Repair, Maintenance & Replacement Programs mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-13 – SDGE 1-14).

Costs: Transmission costs for this program will be recovered through SDG&E's TO5 Formula Rate Case filed with FERC. Associated distribution costs, such as underbuilt distribution on the transmission lines or distribution lines identified as connected actions for transmission jobs, are included in SDG&E's GRC.

Associated distribution work was authorized in D.16-06-054 for the 2016 GRC cycle. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. It is SDG&E's intent to record the distribution-related costs associated with this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Overhead Transmission and Distribution Fire Hardening	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM) (Distribution-related Only)	$4.4	$6.6	$3.9	$5.8
Incremental O&M (Directs, 2019$ in MM)	$0.09	$0.33	$0.08	$0.29

CA-07-0388

Underground Circuit Line Segments

Plan Cross-Reference: Section 4.3.7

Objective Time Frame: This new program will continue over the compliance period of this Plan. SDG&E plans to continue the 20D program as well as strategic undergrounding on an ongoing annual basis.

New/Existing: Underground Circuit Line Segments is a new program.

Meet or Exceed Regulations: This program meets the regulatory framework established in Tariff 20D.

Risk Mitigation: This program mitigates the risk of wildfire by undergrounding overhead lines, reducing the risk of ignitions.

This falls under the Design and Construction mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan, as the 20D program was being established but had not been finalized when SDG&E filed A.17-10-007. Costs for this program will vary with the planned scope of work. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Underground Circuit Line Segments	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$1.2	$1.8	$4.9	$7.3

Exhibit No.: (SDG&E-37)
CA-07-0387

Cleveland National Forest Fire Hardening

Plan Cross-Reference: Section 4.3.8

Objective Time Frame: This is an existing program that will continue over the compliance period of this Plan. This program is planned to be completed by 2021.

Metric: Miles of circuits hardened.

New/Existing: Cleveland National Forest Fire Hardening is an existing program.

Meet or Exceed Regulations: This program meets and exceeds GO 95 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by fire hardening transmission and distribution lines within the HFTD.

This falls under the Design and Construction mitigation category.

RAMP: This program was included in the Inspection, Repair, Maintenance & Replacement Programs mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-13 – SDGE 1-14).

Costs: Transmission costs for this program will be recovered through SDG&E's TO5 Formula Rate Case filed with FERC. Associated distribution costs, such as underbuilt distribution on the transmission lines or distribution lines identified as connected actions for transmission jobs, are included in SDG&E's GRC. Associated distribution work was authorized in D.16-06-054 for the 2016 GRC cycle. Forecasted costs are also pending before the CPUC in A.17-10-007 for the 2019 GRC cycle.

To the extent additional distribution-related costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Cleveland National Forest Fire Hardening	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM) (Distribution-related Only)	$47.7	$58.3	$55.8	$68.2
Incremental O&M (Directs, 2019$ in MM)	$0.95	$2.9	$1.1	$3.4
Miles of Transmission Circuits Hardened	25	31	27	33
Miles of Distribution Overhead Circuits Hardened (Excludes Transmission Underbuilt)	20	24	18	22
Miles of Distribution Overhead to Underground	15	19	4	6

CA-07-0388

Fire Risk Mitigation (FiRM)

Plan Cross-Reference: Section 4.3.9

Objective time frame: SDG&E is seeking approval for this existing program over the compliance period of this Plan. As stated in Section 4.3.9, the FiRM program plans to accelerate the amount of circuit mileage hardened per year to complete the program in seven years (2019-2025) from the originally planned twelve years.

Metric: Miles of Distribution circuit hardened.

New/Existing: FiRM is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451 by proactively targeting high risk conductor with known high failure rates and replacing them before they fail. The new construction meets and exceeds GO 95 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by hardening the distribution system to known local wind conditions, reducing the risk of equipment failure in high wind. Additionally, the FiRM program installs high tensile strength conductors that are less likely to fail than the aged small wire that exists today.

This falls under the Design and Construction mitigation category.

RAMP: This program was included in the Inspection, Repair, Maintenance & Replacement Programs mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-13 – SDGE 1-14).

Costs: Costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007. However, in this Plan SDG&E is proposing to accelerate the FiRM program beyond the levels forecasted in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

FiRM Program	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$49.5	$60.5	$79.2	$96.8
Incremental O&M (Directs, 2019$ in MM)	$0	$0	$.60	$1.8
Miles of Circuit Hardened	81	99	121.5	148.5

Pole Risk Mitigation and Engineering (PRiME)

Plan Cross-reference: Section 4.3.10

Objective Time Frame: This new program will continue over the compliance period of this Plan.

Metric: Number of poles hardened.

New/Existing: PRiME is a new program. As discussed in Section 4.3.10, the PRiME program within the HFTD plans to be completed by 2027.

Meet or Exceed Regulations: This program meets and exceeds GO 95 requirements for overhead structures.

Risk Mitigation: This program mitigates the risk of wildfire by replacing at risk and aging distribution structures within the HFTD.

This falls under the Design and Construction mitigation category.

RAMP: PRiME was presented in the 2016 RAMP Report[1] in the Premature Overhead Failure proposed mitigation to Electric Infrastructure Integrity risk (*see* I.16-10-015, Chapter SDG&E-12 at SDG&E 12-17). The reason for that risk association was because PRiME was intended to be a system wide program (i.e., not limited to the HFTD). That said, SDG&E recognized in its Electric Distribution – Capital workpapers in A.17-10-007 that PRiME also helps to mitigate the risk of wildfire by reducing the potential for a fire ignition (*see* A.17-10-007, Exhibit 75 at 804). Given the recent California Fires, SDG&E is prioritizing the HFTD with this program, and this has included it in this Plan.

Costs: Forecasted costs for this program were first requested in A.17-10-007, which is pending before the CPUC. However, in this Plan SDG&E is proposing to accelerate PRiME beyond the levels forecasted in A.17-10-007 beginning in 2020. While the forecasted costs in A.17-10-007 were presented for the entire system, the cost estimates included below only include the activities related to wildfire mitigation.

It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

PRiME	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$14.4	$21.6	$36.8	$55.2
Incremental O&M (Directs, 2019$ in MM)	$0.29	$1.0	$0.74	$2.8
Poles Replaced	560	840	1,360	2,040

[1] PRiME was renamed from Post Construction True-Up Quality Assurance and Quality Control which was presented in the 2016 RAMP Report. The program was presented as PRiME in A.17-10-007.

Expulsion Fuse Replacement

Plan Cross-reference: Section 4.3.11

Objective Time Frame: This new program will continue over the compliance period of this Plan. This program is planned to be completed in three years (2021).

New/Existing: Expulsion Fuse Replacement is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451 by protectively replacing at risk fuses with CalFire approved fuses.

Risk Mitigation: This program mitigates the risk of wildfire by replacing existing expulsion fuses with fuses that are CalFire approved as a mitigation to wildfire risk.

This falls under the Design and Construction mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Expulsion Fuse Replacement	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$7.8	$11.6	$7.8	$11.6

CA-07-0391

Hotline Clamps

Plan Cross-reference: Section 4.3.12

Objective Time Frame: This new program will continue over the compliance period of this Plan. This program is planned to be completed in six years (2024).

New/Existing: The programmatic replacement of Hotline Clamps is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451 by replacing high risk connectors.

Risk Mitigation: This program mitigates the risk of wildfire by reducing a potential wire down that occurs when this particular clamp fails.

This falls under the Design and Construction mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan, as the analysis of this type of failure was recently completed and not available when SDG&E filed A.17-10-007. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Hotline Clamps	2019		2020	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$1.2	$1.8	$2.4	$3.6

Exhibit No.: 2
CA-07-0392

Wire Safety Enhancement (WiSE)

Plan Cross-reference: Section 4.3.13

Objective Time Frame: This new program will continue over the compliance period of this Plan. SDG&E plans to continue this program into 2021 and will continue to monitor weather and wind conditions in areas outside the HFTD for wildfire risk mitigation in future years.

New/Existing: WiSE is a new program.

Meet or Exceed Regulations: This program meets and exceeds GO 95 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by fire hardening distribution circuits in high fire risk areas outside the HFTD.

This falls under the Design and Construction mitigation category.

RAMP: WiSE was presented in the 2016 RAMP Report as the Small Conductor Replacement Program (*see* I.16-10-015, Chapter SDG&E-12 at SDGE 12-15 – SDGE 12-17). At the time of the 2016 RAMP Report, it was presented as a mitigation to Electric Infrastructure Integrity risk with goals to harden circuit elements (similar to FiRM, but outside the HFTD), in urban areas where downed wire could cause public safety hazards. However, in the recent red flag warning high wind events of 2017 and 2018, SDG&E has noticed high winds and drier conditions outside the HFTD, thus wanted a program to address these concerns. WiSE has been repurposed as wildfire risk mitigation and therefore included in this Plan to address fire concerning areas outside the HFTD before moving into the urban areas.

Costs: Forecasted costs for this program were first requested in A.17-10-007, which is pending before the CPUC, as the Small Conductor Replacement Program. While the forecasted costs in A.17-10-007 were presented for the entire system, the cost estimates included below only include the activities related to wildfire mitigation.

It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

WiSE	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$1.8	$3.0	$4.2	$6.7
Incremental O&M (Directs, 2019$ in MM)	$0.04	$0.15	$0.08	$0.34

CA-07-0393

Covered Conductor

Plan Cross-reference: Section 4.3.14

Objective Time Frame: This new program will continue over the compliance period of this Plan.

New/Existing: Covered Conductor is a new program.

Meet or Exceed Regulations: This program meets or exceeds GO 95 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by installing conductor that will be resistant to phase to phase faults caused by third-party objects and vegetation.

This falls under the Design and Construction mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan. It is SDG&E's intent to record the incremental costs incurred by utilizing covered conductor, which are not planned to start until 2020, in the FRMMA for evaluation at a later time. As SDG&E is developing both the criteria and standards for this program, the actual scope for 2020 is unknown at this time, which accounts for the wide forecasted range.

Covered Conductor	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$0	$0	$0	$20

CA-07-0394

Fire Threat Zone Advanced Protection

Plan Cross-reference: Section 4.3.15

Objective Time Frame: This new program will continue over the compliance period of this Plan.

New/Existing: Fire Threat Zone Advanced Protection is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451 by installing advanced protection and communications on substation and distribution circuit infrastructure.

Risk Mitigation: This program mitigates the risk of wildfire by installing the sectionalizing devices, relays, and controls to enable advanced protection features, including sensitive profile settings, sensitive ground fault detection, down conductor detection, and falling conductor protection.

This falls under the Design and Construction mitigation category.

RAMP: This program was included in the Design and Engineering Approaches mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Forecasted costs for this program were requested and are pending before the CPUC in A.17-10-007. It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Fire Threat Zone Advanced Protection	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$2.4	$3.6	$3.4	$5.2

CA-07-0395

LTE Communication Network

Plan Cross-reference: Section 4.3.16

Objective Time Frame: This new program will continue over the compliance period of this Plan. This program is planned to finish deployment in the HFTD by 2021.

New/Existing: LTE Communication Network is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by enabling more reliable communication for all the remote devices that depend on communication to function as intended. In addition, it provides another means of communication for crews during red flag deployments.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: LTE Communication Network was not presented in the 2016 RAMP Report.

Costs: Forecasted costs for this program were requested and are pending before the CPUC in A.17-10-007. It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

LTE Communication Network	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$8.8	$13.2	$36	$52

Automated Reclosers

Plan Cross-reference: Section 4.3.17

Objective Time Frame: This is a completed program that will remain in effect over the compliance period of this Plan.

New/Existing: Automated Reclosers is an existing, completed program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire through the pulse closing technology when reclosing is enabled. In addition, these devices help to minimize impacts to customers during PSPS events.

This falls under the Design and Construction mitigation category.

RAMP: Automated Reclosers were not part of the 2016 RAMP Report.

Costs: Costs for this program were authorized in D.16-06-054 for the 2016 GRC cycle. There are no new, incremental costs associated with this program.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time.

CA-07-0397

Public Safety Power Shutoff Engineering Enhancements

Plan Cross-reference: Section 4.3.18

Objective Time Frame: This new program will continue over the compliance period of this Plan.

New/Existing: The Public Safety Power Shutoff Engineering Enhancements is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the exposure of customers to PSPS events by installing additional sectionalizing devices so that SDG&E is able to take a targeted approach during de-energized events, impacting only the necessary customers.

This falls under the Response and Recovery mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Public Safety Power Shutoff Enhancements	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$0.4	$0.7	$0.4	$0.7

Exhibit No.: (SDG&E-07)
CA-07-0398

Pole Replacement and Reinforcement

Plan Cross-reference: Section 4.3.19

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Pole Replacement and Reinforcement is an existing program. This annual program spans the entire service territory. The scope of this program will vary depending on the prior year's intrusive inspection results.

Meet or Exceed Regulations: This program meets GO 165 inspection and maintenance requirements. In addition, pole replacements are constructed to meet or exceed GO 95 requirements.

Risk Mitigation: This program mitigates the risk of wildfire by replacing poles found in poor condition through visual or intrusive inspections.

This falls under the Inspection and Maintenance mitigation category.

RAMP: This program was included in the Inspection, Repair, Maintenance & Replacement Programs mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-13 – SDGE 1-14).

Costs: Costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007. However, in this Plan SDG&E is proposing to expand this program beyond the levels in A.17-10-007. In this Plan, costs for this program have been prorated based on the estimated number of poles to be replaced within the HFTD.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Pole Replacement and Reinforcement	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$10.6	$16.0	$10.6	$16.0
Incremental O&M (Directs, 2019$ in MM)	$0.1	$0.25	$0.1	$0.25

CA-07-0399

Backup Power for Resilience

Plan Cross-reference: Section 4.3.20

Objective Time Frame: This new program will continue over the compliance period of this Plan.

New/Existing: Backup Power for Resilience is a new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by focusing on investing in infrastructure to provide back-up power to strategic locations to minimize the impact that PSPS events have on the communities impacted.

This falls under the Response and Recovery mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: While there are forecasted costs for this program requested and pending before the CPUC in A.17-10-007, in this Plan the Backup Power for Resilience program has been expanded beyond the levels in A.17-10-007.

It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Backup Power for Resilience	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$2.4	$3.6	$5.4	$8.0
Incremental O&M (Directs, 2019$ in MM)	$0.5	$0.9	$1.0	$1.6

Tree Database

Plan Cross-reference: Section 4.4.1

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: The Vegetation Management Tree Database is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451, GO 95, PRC § 4293, and North American Electric Reliability Corporation (NERC) reliability standard FAC-003-4 by allowing the timely capture and management of vegetation near electrical lines and equipment. The system "PowerworkZ" (PWZ) was developed inhouse to meet the specific needs for SDG&E by enabling historical tracking of all vegetation management work activities.

Risk Mitigation: This program mitigates the risk of wildfire by providing a schedule-driven system that enables the management of a tree population with current and historic information including the growth rates, health, and status of all trees within SDG&E's inventory. This system allows for pre-planning and documentation of all work.

This falls under the Inspection and Maintenance mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for this program were approved through a one-way balancing account in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested via a two-way balancing account and are pending before the CPUC in A.17-10-007. If the two-way balancing account is approved in A.17-10-007, it would allow SDG&E to recover costs above the authorized GRC levels. SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

CA-07-0401

Patrol and Pruning

Plan Cross-reference: Section 4.4.2

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Patrol and Pruning is an existing program.

Meet or Exceed Regulations: This program meets or exceeds GO 95, PRC §§ 4292 and 4293, and NERC FAC-003-4.

Risk Mitigation: This program mitigates the risk of wildfire by increasing the frequency of tree inspections beyond an annual assessment of trees that have the potential to impact the overhead electrical facilities. The patrol is in addition to the routinely-scheduled inspection of trees and includes the assessment of the hazard potential of all trees within striking distance of the lines. Patrol and Pruning activities take place before the onset of the most dangerous fire weather conditions which occur during the fall.

This falls under the Inspection and Maintenance mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for this program were approved through a one-way balancing account in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested via a two-way balancing account and are pending before the CPUC in A.17-10-007. If the two-way balancing account is approved in A.17-10-007, it would allow SDG&E to recover costs above the authorized GRC levels. SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

February 6, 2018
CA-07-0402

Enhanced Inspections, Patrols, and Trimming

Plan Cross-reference: Section 4.4.3

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Enhanced inspections, patrols, and trimming is a new program.

Meet or Exceed Regulations: This program meets or exceeds GO 95, PRC §§ 4292 and 4293, and NERC FAC-003-4.

Risk Mitigation: This program mitigates the risk of wildfire by both increasing the frequency of vegetation inspections, and by increasing the minimum vegetation clearance from the lines to 25' where achievable.

This falls under the Inspection and Maintenance mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Enhanced Inspections Patrols and Trimming	2019		2020	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$2.4	$3.6	$2.4	$3.6

February 2019
CA-07-0403

Technology (Vegetation Management)

Plan Cross-reference: Section 4.4.4

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Technology (Vegetation Management) is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451, GO 95, PRC §§ 4292 and 4293, and NERC FAC-003-4.

Risk Mitigation: This program mitigates the risk of wildfire by utilizing historical and contextual data to forecast where vegetation management operations may be focused or prioritized. GIS and database analyses using metrics including vegetation type, weather, topography, outage history can help predict where tree failures are likely to occur. SDG&E has implemented the use of LiDAR to enhance its inspection operations and to validate vegetation clearances. The use of this technology is intended to only supplement these activities and will be integrated on a limited basis.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for this program were approved through a one-way balancing account in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested via a two-way balancing account and are pending before the CPUC in A.17-10-007. If the two-way balancing account is approved in A.17-10-007, it would allow SDG&E to recover costs above the authorized GRC levels. SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

CA-07-0404

Quality Assurance

Plan Cross-reference: Section 4.4.5

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Quality Assurance is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451, GO 95, PRC §§ 4292 and 4293, and NERC FAC-003-4.

Risk Mitigation: This program mitigates the risk of wildfire by measuring all work performed by contractors to validate that they meet or exceed the Scopes of Work, and are in compliance with the requirements of GO 95, Rule 35 and Public Resources Codes 4292 and 4293. This includes the activities of pre-inspection, tree pruning and removal, and pole brush clearing. Included in the Scope of Work for Quality Assurance, the contractor performs a full patrol of all overhead primary and transmission lines to confirm minimum clearance requirements will be maintained until the next pre-inspection activity. The Quality Assurance inspection serves as a de facto mid-cycle patrol of the lines and provides an additional opportunity to identify hazardous trees.

This falls under the Inspection and Maintenance mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for this program were approved through a one-way balancing account in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested via a two-way balancing account and are pending before the CPUC in A.17-10-007. If the two-way balancing account is approved in A.17-10-007, it would allow SDG&E to recover costs above the authorized GRC levels. SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

CA-07-0405

Hazard Tree Removal and Right Tree-Right Place

Plan Cross-reference: Section 4.4.6

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Hazard Tree Removal and Right Tree-Right Place is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451, GO 95, PRC §§ 4292 and 4293, and NERC FAC-003-4 by preventing fire ignition caused by tree-line contacts. Right Tree-Right Place is the concept of replacing incompatible trees located near power lines with compatible species that do not pose a threat to electrical infrastructure.

Risk Mitigation: This program mitigates the risk of wildfire by removing hazardous trees (i.e., dead, dying, diseased, structural defective) that could shed a limb or fall onto a powerline and cause an ignition. SDG&E targets for removal species, such as eucalyptus and palm, with known growth and failure patterns. As a standard pruning practice, SDG&E also proactively removes all tree branches overhanging the conductor to reduce the chance of impact with the power lines. SDG&E's Right Tree-Right Place program follows the concept of planting trees near powerlines that will not encroach upon or require maintenance near power lines. The Right Tree-Right Place program provides for higher reliability, public safety, reduced maintenance costs, and preserves the health of trees.

This falls under the Inspection and Maintenance mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for this program were approved through a one-way balancing account in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested via a two-way balancing account and are pending before the CPUC in A.17-10-007. If the two-way balancing account is approved in A.17-10-007, it would allow SDG&E to recover costs above the authorized GRC levels. SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Pole Brushing

Plan Cross-reference: Section 4.4.7

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Pole Brushing is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the regulations set forth in PRC § 4292 to prevent the ignition and propagation of fire caused by SDG&E pole-mounted equipment.

Risk Mitigation: This program mitigates the risk of wildfire by performing inspection, customer communications, and multiple brushing activities within the annual cycle including mechanical brush, herbicide application and re-clear. These activities are scheduled in sequence to ensure compliance for the duration of the annual cycle. The timing of the pole brushing activities prevents vegetation from recurring within the cleared radius of the subject poles. Additionally, SDG&E conducts pole brushing on approximately 3,000 poles that are not subject to the clearance requirements in areas with flammable vegetation, steep slope, or adjacent to wildland interfaces where a fire could propagate.

This falls under the Inspection and Maintenance mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: The job activities described in this program are performed on a day to day basis by the Vegetation Management work group. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business within Electric Distribution O&M. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Electric Equipment Training

Plan Cross-reference: Section 4.4.8

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Electric Equipment Training is new program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by jointly inspecting SDG&E facilities with CalFire to better understand wildfire risk and site-specific hazards.

This falls under the Inspection and Maintenance mitigation category.

RAMP: SDG&E's Vegetation Management program was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-16).

Costs: Forecasted costs for this program were requested and are pending before the CPUC in A.17-10-007 for the 2019 GRC cycle. It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Electric Equipment Training	2019		2020	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$0.024	$0.036	$0.024	$0.036

Red Flag Operations (Vegetation Management)

Plan Cross-reference: Section 4.4.9

Objective Time Frame: This program will continue over the compliance period of this Plan. This program has high variability as the utilization will depend on the number of red flag events, and the amount of circuits forecasted to be impacted by red flag events.

New/Existing: Red Flag Operations (Vegetation Management) is a new program.

Meet or Exceed Regulations: This program meets or exceeds GO 95, PRC §§ 4292 and 4293, and NERC FAC-003-4 by conducting additional vegetation inspections around red flag events.

Risk Mitigation: This program can mitigate the risk of wildfire by proactively staging inspectors in known areas of high fire potential, such as large tree density and high wind corridors, to monitor for conditions that may cause an ignition in the upcoming red flag event.

This falls under the Inspection and Maintenance mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: This program is being presented for the first time in this Plan. It is SDG&E's intent to record costs for this program in the FRMMA for evaluation at a later time.

Red Flag Operations (Vegetation Management)	2019		2020	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$0.30	$0.90	$0.30	$0.90

CA-07-0409

Fire Science and Climate Adaption Department

Plan Cross-reference: Section 4.5.1

Objective Time Frame: This strategy that will continue over the compliance period of this Plan.

New/Existing: The Fire Science and Climate Adaption Department is a new strategy, created in 2018. The FS&CA department is responsible to manage wildfire risk. It also has the responsibility of producing, compiling, and finalizing SDG&E's reoccurring Wildfire Mitigation Plan to reflect the planned activities to achieve the requirements of P.U. Code § 8386(c). In addition, many of the existing situational awareness tools (e.g., SAWTI and FPI) are managed through this department.

Meet or Exceed Regulations: The establishment of the Fire Science and Climate Adaption Department is a fire mitigation strategy, which meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates risk by enhancing the ability to anticipate, prepare for, react to, and recover from significant fire weather events.

This falls primarily under the Situational/Conditional Awareness mitigation category.

RAMP: While this department was not presented in the 2016 RAMP Report, several of the situation awareness tools managed by this new department were included in the Monitoring and Detection mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14 and SDGE 1-17).

Costs: Certain costs for this strategy were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs to expand aspects of this strategy for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007. However, this department in its current form was not included in A.17-10-007 as it was not established when SDG&E filed its 2019 GRC. Accordingly, in this Plan SDG&E is proposing to expand this strategy beyond the levels in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Fire Science and Climate Adaption Department	**2019**		**2020**	
	Low	**High**	**Low**	**High**
Incremental O&M (Directs, 2019$ in MM)	$1.6	$2.4	$1.6	$2.4

CA-07-0410

Meteorological Capabilities and Technologies

Plan Cross-reference: Section 4.5.2

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Meteorological Capabilities and Technologies is an existing strategy. As stated in Section 4.5.2, SDG&E has five full-time degreed and experienced meteorologists on staff with expertise in program management, utility forecasting, data science, and Southern California fire weather. SDG&E owns and operates a network of over 175 weather stations that are physically located on electric distribution and transmission poles and provide temperature, humidity, and winds observation every 10 minutes. SDG&E owns four high-performance computing clusters that are used to generate high quality weather data that is incorporated directly into operations.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by supporting the SDG&E situational awareness capabilities.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This strategy was included in the Monitoring and Detection mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14 and SDGE 1-17).

Costs: Please refer to the Fire Science and Climate Adaption Department workpaper.

CA-07-0411

Fire Potential Index (FPI)

Plan Cross-reference: Section 4.5.3

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Fire Potential Index is an existing strategy. As stated in Section 4.5.3, the FPI was developed by SDG&E subject matter experts to communicate the wildfire potential on any given day to promote safe and reliable operations.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by classifying the fire potential based on weather and fuels conditions and historical fire occurrences within each of SDG&E's eight operating districts. This is also shared with local fire agencies, emergency responders, and the National Weather Service.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This strategy was included in the Monitoring and Detection mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14 and SDGE 1-17).

Costs: Please refer to the Fire Science and Climate Adaption Department workpaper.

February 2017
CA-07-0412

Santa Ana Wildfire Threat Index (SAWTI)

Plan Cross-reference: Section 4.5.4

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Santa Ana Wildfire Threat Index is an existing strategy. As stated in Section 4.5.4, the SAWTI categorizes Santa Ana winds based on anticipated fire potential and uses several meteorological and fuel moisture variables generated from the Weather Research and Forecasting (WRF) Model to forecast the index out to six days.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by leveraging big data and analytics to assess the wildfire potential associated with an approaching weather event and sharing that information with stakeholder in the community and the public.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This strategy was included in the Monitoring and Detection mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14 and SDGE 1-17).

Costs: Please refer to the Fire Science and Climate Adaption Department workpaper.

February 2018
CA-07-0413

Wildfire Risk Reduction Model – Operational System (WRRM-Ops)

Plan Cross-reference: Section 4.5.5

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: WRRM-Ops (Fire Behavior Modeling) is an existing program. As stated in Section 4.5.5, significant intelligence related to the wildfire potential is also gathered from SDG&E's WRRM-Ops, which integrates the latest weather and GIS technology to understand wildfire growth patterns across the region.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by assessing the areas of highest fire danger before a wildfire begins so preventative measures can be taken to enhance public safety and ensure the reliable operation of the electric system.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This program was included in the Monitoring and Detection mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14 and SDGE 1-17).

Costs: While there are forecasted costs for this program requested and pending before the CPUC in A.17-10-007, in this Plan the WRRM-Ops program has been expanded beyond the levels in A.17-10-007. It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

WRRM-Ops	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$0.3	$0.5	$0.3	$0.5

February 2018
CA-07-0414

Camera Networks and Fire Detection

Plan Cross-reference: Section 4.5.6

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Camera Networks and Fire Detection is an existing strategy. As stated in Section 4.5.6, SDG&E utilizes a total of 107 cameras that enhance situational awareness around wildfire. Twenty of these cameras are owned by SDG&E, while 87 cameras are supported by SDG&E in collaboration with the University of California San Diego (UCSD) as part of the High Performance Wireless Research and Education Network (HPWREN).

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire by enhancing situational awareness and improving SDG&E's ability to react to wildfires on the landscape. These cameras are also heavily used by CalFire.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This strategy was included in the Monitoring and Detection mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14 and SDGE 1-17).

Costs: Please refer to the Fire Science and Climate Adaption Department workpaper.

CA-07-0415

Climate Change Adaptation

Plan Cross-reference: Section 4.6

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Climate Change Adaptation is an existing strategy. As stated in Section 4.6, data ranging back to 1984 across San Diego County confirms that the number of high fire potential days has increased since the early 2000's. These trends are projected to continue as a combination of factors leads to increases in both fire season duration and severity through the end of the century.

Meet or Exceed Regulations: This strategy meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This strategy mitigates the risk of wildfire through tracking and better understanding the impact that our changing climate is likely to have on the fire environment.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This strategy was included in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-8 – SDGE 1-9 and Chapter SDG&E-14).

Costs: Incremental, forecasted costs related to Climate Change Adaptation pending in A.17-10-007 are not included in this Plan as they are not associated with wildfire. Accordingly, SDG&E is not seeking or anticipating incremental costs associated with this program at this time.

CA-07-0418

Wireless Fault Indicators

Plan Cross-reference: Section 4.6.2

Objective Time Frame: This program will continue over the compliance period of this Plan. This program is planned for completion in 2021.

New/Existing: Wireless Fault Indicators is an existing program.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by providing awareness to where faults occurred so that remote cameras can be directed to see if an ignition took place. This program helps to minimize the consequence of a fire should it occur.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: This program was included in the Design and Engineering Approaches mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-1 at SDGE 1-14).

Costs: Costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Wireless Fault Indicators	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$0.48	$0.72	$0.48	$0.72

Advanced Weather Station Integration and Forecast

Plan Cross-reference: Section 4.6.3

Objective Time Frame: This program will continue over the compliance period of this Plan.

New/Existing: Advanced Weather Station Integration and Forecast is a new program. As stated in Section 4.6.3, the Advanced Weather Station Integration and Forecast program seeks to further modernize the SDG&E weather network.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by continuously monitoring the wildfire environment across the SDG&E service territory using the best tools available.

This falls under the Situational/Conditional Awareness mitigation category.

RAMP: Because this is a new program, it was not presented in the 2016 RAMP Report.

Costs: While there are costs for this program requested and pending before the CPUC in A.17-10-007, in this Plan the Advanced Weather Station Integration and Forecast program has been expanded beyond the levels in A.17-10-007.

It is SDG&E's intent to record costs for this program in the FRMMA. Once a decision in A.17-10-007 is implemented, SDG&E will reconcile the amounts for purposes of the FRMMA.

Advanced Weather Station Integration and Forecast	2019		2020	
	Low	High	Low	High
Capital (Directs, 2019$ in MM)	$0.5	$0.7	$0.5	$0.7

Strategy for Minimizing Public Safety Risk During High Wildfire Conditions

Plan Cross-reference: Section 4.7.1

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Public Safety Power Shutoff Protocols is an existing strategy. As stated in Section 4.7, SDG&E has an obligation to operate its system safely. This obligation requires SDG&E to de-energize circuits (i.e., turn off power) when necessary to protect public safety (Public Safety Power Shutoff or PSPS).

Meet or Exceed Regulations: This strategy meets and exceeds P.U. Code §§ 399.2(a) and 451, D.12-04-024, and Commission Resolution ESRB-8.

Risk Mitigation: This strategy mitigates the risk of wildfire by de-energizing power lines that are experiencing extreme fire weather conditions.

This falls under the Operation Practices mitigation category.

RAMP: This strategy was not presented in the 2016 RAMP Report.

Costs: The job activities that occur during a PSPS event are performed by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Public Safety Power Shutoff Protocols

Plan Cross-reference: Section 4.7.2

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Public Safety Power Shutoff Protocols is an existing strategy. As stated in Section 4.7.2, if SDG&E determines it is necessary to employ a PSPS for portions of its system, re-energization will take place after the SDG&E Weather Network shows that wind speeds have decreased, and SDG&E weather forecasts indicate that winds will not re-accelerate above dangerous levels.

Meet or Exceed Regulations: This strategy meets and exceeds P.U. Code §§ 399.2(a) and 451, D.12-04-024, and Commission Resolution ESRB-8.

Risk Mitigation: This strategy mitigates the risk of wildfire by confirming that electrical lines are structurally sound and free of debris after the extreme fire weather conditions have ceased.

This falls under the Operation Practices mitigation category.

RAMP: This strategy was not presented in the 2016 RAMP Report.

Costs: The job activities that occur during a PSPS event are performed by multiple work groups. Costs for performing this work were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Exhibit No.: (SDG&E-20)
CA-07-0420

Communication Practices

Plan Cross-reference: Section 4.7.4

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Communication Practices related to Public Safety Power Shutoff is an existing program. As stated in Section 4.7, in advance of the peak of fire season, SDG&E will conduct ongoing education campaigns in five languages (English, Spanish, Chinese, Filipino, Vietnamese) regarding how to be prepared for emergencies in the event of a wildfire, natural disaster or major outage. SDG&E anticipates that this education campaign will also encourage customers to sign up for outage notifications, with the goal of raising awareness about SDG&E's PSPS procedures. SDG&E will also be updating its Enterprise Notification System (ENS) to enhance customer service.

Meet or Exceed Regulations: This program meets and exceeds P.U. Code §§ 399.2(a) and 451, D.12-04-024, and Commission Resolution ESRB-8.

Risk Mitigation: This program mitigates the risk of wildfire by its association to de-energizing power lines that are experiencing extreme fire weather conditions.

This falls under the Operation Practices mitigation category.

RAMP: SDG&E's Customer Communications and First Responder Training was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-3 at SDGE 3-16 and SDGE 3-17).

Costs: Certain costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007. However, in this Plan SDG&E is proposing to expand the Communication Practices related to the Public Safety Power Shutoff program beyond the levels in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Communication Practices related to Public Safety Power Shutoff	**2019**		**2020**	
	Low	**High**	**Low**	**High**
Incremental O&M (Directs, 2019$ in MM)	$2.0	$3.0	$2.0	$3.0
Capital (Directs, 2019$ in MM)	$0.50	$0.70	$0.50	$0.70

Mitigating the Public Safety Impact of PSPS Protocols

Plan Cross-reference: Section 4.7.5

Objective Time Frame: This is an ongoing strategy that will continue over the compliance period of this Plan.

New/Existing: Mitigating the Public Safety Impact of PSPS Protocols is an existing strategy. As stated in Section 4.7.5, SDG&E manages and mitigates the impacts of a PSPS event through collaborations with key stakeholders in the wildfire response community.

Meet or Exceed Regulations: This strategy meets and exceeds P.U. Code §§ 399.2(a) and 451, D.12-04-024, and Commission Resolution ESRB-8.

Risk Mitigation: This strategy mitigates the risk of wildfire by mitigating the risk associated with Public Safety Power Shutoff.

This falls under the Operation Practices and Response and Recovery mitigation category.

RAMP: SDG&E's Customer Communications and First Responder Training was included as a mitigation in the 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-3 at SDGE 3-16 and SDGE 3-17).

Costs: Please refer to the Fire Science and Climate Adaption Department workpaper.

Exhibit No.: (SDG&E-02)
CA-07-0422

Emergency Management Operations

Cross-reference: Sections 4.1.4.2, 4.1.4.3, and 5.1

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: This is an existing program that supports effective, efficient, and collaborative planning, preparedness, response, and recovery processes for all hazards and risks, including those associated with wildfire and RFW incidents enterprise-wide.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by effectively coordinating the SDG&E's pre-incident and response/recovery activities during periods of high wildfire risk and/or wildfire activity, which is inclusive of Aviation Services' operation of air resources, and SDG&E's full operational response to Red Flag Warning or extreme FPI activation and response.

This falls under the Operational Practices and Response and Recovery mitigation categories.

RAMP: This program was addressed in the Customer Communications and First Responder Training mitigation in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-3 at SDGE 3-16 – SDGE-17).

Costs: Certain costs for this program were approved in D.16-06-054 for the 2016 GRC cycle. Forecasted costs for this program for the 2019 GRC cycle were requested and are pending before the CPUC in A.17-10-007. However, in this Plan SDG&E is proposing to expand the Emergency Management Operations program beyond the levels in A.17-10-007.

To the extent additional costs are incurred that are not otherwise covered in SDG&E's revenue requirements, it is SDG&E's intent to record those costs in its FRMMA to be evaluated at a later time. SDG&E will reconcile the amounts in the FRMMA, as necessary, once a decision in A.17-10-007 is implemented.

Emergency Management Operations	2019		2020	
	Low	High	Low	High
Incremental O&M (Directs, 2019$ in MM)	$4.0	$6.0	$4.0	$6.0
Emergency Response Preparedness Trainings Conducted	225	250	225	250

Exhibit No.: (SDG&E-07)
CA-07-0423

Disaster and Emergency Preparedness Plan

Cross-reference: Section 5.2

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: This is an existing program. As stated in Section 5.2.1, SDG&E's Company Emergency Response Plan (CERP) and risk specific response plans provide a framework by which SDG&E can effectively coordinate SDG&E's pre-incident and response/recovery activities to a given threat or hazard.

Meet or Exceed Regulations: This program meets and exceeds the requirement to furnish and maintain a safe and reliable utility system in accordance with P.U. Code § 451.

Risk Mitigation: This program mitigates the risk of wildfire by effectively planning and documenting SDG&E's pre-incident and response/recovery activities during periods of high wildfire risk and/or wildfire activity.

This falls under the Response and Recovery mitigation category.

RAMP: This program was addressed in the Customer Communications and First Responder Training mitigation and the Workforce Planning risk chapter in SDG&E's 2016 RAMP Report (*see* I.16-10-015, Chapter SDG&E-3 at SDGE 3-16 – SDGE 3-17; Chapter SDG&E-17).

Costs: Please refer to the Emergency Management Operations workpaper.

CA-07-0424

Customer Support in Emergencies

Cross-reference: Section 5.3

Objective Time Frame: This is an ongoing program that will continue over the compliance period of this Plan.

New/Existing: Customer Support in Emergencies is an existing program to accommodate for the impacts from wildfire. Consumer protections are for more than just wildfires, they cover all emergencies. As stated in Section 5.3, SDG&E provides emergency residential and non-residential customer protections and available communications for wildfire victims, as ordered by the CPUC.

Meet or Exceed Regulations: SDG&E's Customer Support in Emergencies program meets or exceeds Resolution M-4835.

Risk Mitigation: This program mitigates the risk of wildfire impacts to customers by providing consumer protections to customers impacted by wildfire.

This falls under the Response and Recovery mitigation category.

RAMP: This program was not included in the 2016 RAMP Report.

Costs: General customer support related costs were authorized through D.16-06-054 for the 2016 GRC cycle by funding base business. Forecasted costs are also pending CPUC approval in A.17-10-007 for the 2019 GRC cycle. There are no incremental costs associated with this strategy as consumer protection costs in emergencies are addressed through a separate mechanism.

Upon the Governor of California declaring a state of emergency because of a disaster, SDG&E will make an advice filing and begin recording costs for each applicable event to the Emergency Customer Protections Memorandum Account (ECPMA). Costs that are incurred outside of a state of emergency are funded through current resources, as noted above.

CA-07-0425

Monitoring and Correcting Deficiencies

Plan Cross-Reference: Section 6.4.1

Objective Time Frame: This strategy will continue over the compliance period of this Plan.

New/Existing: Monitoring and Correcting Deficiencies is a new strategy. It will execute, monitor, review, and address deficiencies in SDG&E's approach to wildfires, consistent with SDG&E's Plan. This strategy allows for wide collaboration and information gathering, as well as the ability to inform, plan, act, and improve within a compressed timeline, when needed.

Meet or Exceed Regulations: This strategy meets and exceeds the requirements set forth in P.U. Code § 8386, as amended by Senate Bill 901.

Risk Mitigation: This strategy mitigates the risk of wildfire by closely monitoring and evaluating the initiatives and programs designed to mitigate fire and enable course correction as necessary.

This strategy is associated with the all of the mitigation categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and (5) Response and Recovery.

RAMP: Because this is a new strategy, it was not presented in SDG&E's 2016 RAMP Report.

Costs: Please refer to the Fire Science and Climate Adaption Department workpaper.

CA-07-0428

Appendix B

Table – § 8386(c)(3)(4)(8)(9): Wildfire Mitigation Strategies and Programs

Per the ALJ Ruling (at 2-3), SDG&E provides the following table. The table summarizes information included in Section 4 of SDG&E's Wildfire Mitigation Plan. To the extent SDG&E had the information in its possession in table for this Plan filing, it is included.

Wildfire Mitigation Strategies and Programs [1]

Program / Strategy	Categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and/or (5) Response and Recovery	Asset Addressed (Ex: line, poles, etc.)	2019 Cost Estimate - Direct Capital (2019$ in MM)[2]	2019 Cost Estimate - Incremental O&M (2019$ in MM)[3]	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference)[4]	Compliance Requirement? (Provide code or GO reference)[5]	Identify any Aspects of Plan/Strategy and Associated Funding That Is or Will Be Addressed in Another Case (Identify Case)[6]	Identify Any Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking Is Prevented[7]	Previously included in RAMP? (Provide Reference)[8]	Evaluation Metric(s)[9]	Assumptions Underlying Metric[10]
OPERATIONAL PRACTICES										% of reclosers that protect the HFTD that are disabled during elevated or extreme FPI conditions	Refer to Section 6.2 of Wildfire Mitigation Plan
Response to Change in Operating Conditions	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Recloser Protocols	Operation Practices	reclosers	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Other Special Work Procedures	Operation Practices	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Wildfire Infrastrucure Protection Teams	Response and Recovery	various	$ -	$0.7 - $1.1	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Aviation Firefighting Program	Response and Recovery	various	$ -	$6.0 - $9.0	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Industrial Fire Brigade	Response and Recovery	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Ignition Management Program	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	No		
Fuel Management Program	Inspection and Maintenance	various	$ -	$0.4 - $0.6	No	PUC § 451	-	-	No		
PLANS FOR INSPECTION										% of inspections completed pursuant to GO 165 within a 12-month period	Refer to Section 6.2 of Wildfire Mitigation Plan
Distribution System Inspection	Inspection and Maintenance	various	$ -	$ -	D.16-06-054	GO 165	TY2019 GRC	-	Yes		
Substation System Inspection	Inspection and Maintenance	various	$ -	$ -	D.16-06-054	GO 174	TY2019 GRC	-	Yes		
Transmission System Inspection	Inspection and Maintenance	various	$ -	$ -	No - FERC	GO 95, GO 128, PRC §§ 4292 and 4293	-	-	Yes		
Geographic Iinformation System Data	Response and Recovery	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	No		
SYSTEM HARDENING										Number of miles system hardened in the HFTD	Refer to Section 6.2 of Wildfire Mitigation Plan
Design and Construction Standards	Design and Construction	various	$ -	$ -	D.16-06-054	GO 95, PUC § 451	TY2019 GRC	-	Yes		
Testing and Deploying Emerging Technologies	Design and Construction	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	No		
Facility Analysis	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	GO 165	TY2019 GRC	-	Yes		
Oversight of Activities in the Rural Areas	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	No		
Asset Management	Situational/Conditional Awareness	various	$ -	$1.2 - $1.8	No	PUC § 451	TY2019 GRC	-	No		
Overhead Transmission and Distribution Fire Hardening	Design and Construction	lines	$4.4 - $6.6	$0.09 - $0.33	D.16-06-054	GO 95	TY2019 GRC	-	Yes		
Underground Circuit Line Segments	Design and Construction	lines	$1.2 - $1.8	$ -	No	Tariff Rule 20D	-	-	No		
Cleveland National Forest Fire Hardening	Design and Construction	lines	$47.7 - $58.3	$0.95 - $2.9	D.16-06-054	GO 95	TY2019 GRC	-	Yes		
Fire Risk Mitigation	Design and Construction	lines	$49.5 - $60.5	$ -	D.16-06-054	GO 95, PUC § 451	TY2019 GRC	-	Yes		
Pole Risk Mitigation and Engineering	Design and Construction	poles	$14.4 - $21.6	$0.29 - $1.0	No	GO 95	TY2019 GRC	-	Yes		
Explusion Fuse Replacement	Design and Construction	fuses	$7.8 - $11.6	$ -	No	PUC § 451	-	-	No		
Hotline Clamps	Design and Construction	clamps	$ -	$1.2 - $1.8	No	PUC § 451	-	-	No		
Wire Safety Enhancement	Design and Construction	conductor	$1.8 - $3.0	$0.04 - $0.15	No	GO 95	TY2019 GRC	-	Yes		
Covered Conductor	Design and Construction	conductor	$ -	$ -	No	GO 95	-	-	No		
Fire Threat Zone Advanced Protection	Design and Construction	protection equipment	$2.4 - $3.6	$ -	No	PUC § 451	TY2019 GRC	-	Yes		
LTE Communication Network	Situational/Conditional Awareness	commincation equipment	$8.8 - $13.2	$ -	No	PUC § 451	TY2019 GRC	-	No		
Automated Reclosers	Design and Construction	reclosers	$ -	$ -	D.16-06-054	PUC § 451	-	-	No		
Public Safety Power Shutoff Engineering Enhancements	Response and Recovery	sectionalizing devices	$0.4 - $0.7	$ -	No	PUC § 451	-	-	No		
Pole Replacement and Reinforcement	Inspection and Maintenance	poles	$10.6 - $16.0	$0.1 - $0.25	D.16-06-054	GO 165, GO 95	TY2019 GRC	-	Yes		
Backup Power for Resilience	Response and Recovery	various	$2.4 - $3.6	$0.5 - $0.9	No	PUC § 451	TY2019 GRC	-	No		

CA-07-0428

Wildfire Mitigation Strategies and Programs [1]

Program / Strategy	Categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and/or (5) Response and Recovery	Asset Addressed (Ex: line, poles, etc.)	2019 Cost Estimate - Direct Capital (2019$ in MM)[2]	2019 Cost Estimate - Incremental O&M (2019$ in MM)[3]	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference)[4]	Compliance Requirement? (Provide code or GO reference)[5]	Identify any Aspects of Plan/Strategy and Associated Funding That Is or Will Be Addressed in Another Case (Identify Case)[6]	Identify Any Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking Is Prevented[7]	Previously included in RAMP? (Provide Reference)[8]	Evaluation Metric(s)[9]	Assumptions Underlying Metric[10]
VEGETATION MANAGEMENT										% of vegetation inspections completed in the HFTD	Refer to Section 6.2 of Wildfire Mitigation Plan
Tree Database	Inspection and Maintenance	lines	$ -	$ -	D.16-06-054	PUC § 451, GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	TY2019 GRC	TTBA	Yes		
Patrol and Pruning	Inspection and Maintenance	lines	$ -	$ -	D.16-06-054	GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	TY2019 GRC	TTBA	Yes		
Enhanced Inspections, Patrols, and Trimming	Inspection and Maintenance	lines	$ -	$2.4 - $3.6	No	GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	-	-	No		
Technology	Situational/Conditional Awareness	lines	$ -	$ -	D.16-06-054	PUC § 451, GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	TY2019 GRC	TTBA	Yes		
Quality Assurance	Inspection and Maintenance	lines	$ -	$ -	D.16-06-054	PUC § 451, GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	TY2019 GRC	TTBA	Yes		
Hazard Tree Removal and Right Tree-Right Place	Inspection and Maintenance	lines	$ -	$ -	D.16-06-054	PUC § 451, GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	TY2019 GRC	TTBA	Yes		
Pole Brushing	Inspection and Maintenance	lines	$ -	$ -	D.16-06-054	PRC § 4292	TY2019 GRC	-	Yes		
Electric Equipment Training	Inspection and Maintenance	lines	$ -	$0.024 - $0.036	No	PUC § 451	TY2019 GRC	-	No		
Red Flag Operations	Inspection and Maintenance	lines	$ -	$0.30 - $0.90	No	GO 95, PRC §§ 4292 and 4293, NERC FAC-003-4	-	-	No		
SITUATIONAL AWARENESS										% of weather stations operational during RFW or extreme FPI	Refer to Section 6.2 of Wildfire Mitigation Plan
Fire Science and Climate Adaptation Department	Situational/Conditional Awareness	various	$ -	$1.6 - $2.4	D.16-06-054	PUC § 451	TY2019 GRC	-	No		
Meterological Capabilities and Technologies	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Fire Potential Index	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Santa Ana Wildfire Threat Index	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Wildfire Risk Reduction Model - Operational System	Situational/Conditional Awareness	various	$0.3 - $0.5	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Camera Networks and Fire Dectection	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Climate Change Adaptation	Situational/Conditional Awareness	various	$ -	$ -	D.16-06-054	PUC § 451	-	-	Yes		
Wireless Fault Indicators	Situational/Conditional Awareness	fault indicators	$0.48 - $0.72	$ -	D.16-06-054	PUC § 451	TY2019 GRC	-	Yes		
Advanced Weather Station Integration and Forecast	Situational/Conditional Awareness	various	$0.5 - $0.7	$ -	No	PUC § 451	TY2019 GRC	-	No		

CA-07-0426

Wildfire Mitigation Strategies and Programs [1]

Program / Strategy	Categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Conditional Awareness, and/or (5) Response and Recovery	Asset Addressed (Ex: line, poles, etc.)	2019 Cost Estimate - Direct Capital (2019$ in MM)[2]	2019 Cost Estimate - Incremental O&M (2019$ in MM)[3]	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference)[4]	Compliance Requirement? (Provide code or GO reference)[5]	Identify any Aspects of Plan/Strategy and Associated Funding That Is or Will Be Addressed in Another Case (Identify Case)[6]	Identify Any Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking Is Prevented[7]	Previously included in RAMP? (Provide Reference)[8]	Evaluation Metric(s)[9]	Assumptions Underlying Metric[10]
PUBLIC SAFETY POWER SHUTOFF										% of PSPS impacted metered customers notified of the potential PSPS in advance	Refer to Section 6.2 of Wildfire Mitigation Plan
Strategy for MinimizIng Public Safety Risk	Operation Practices	various	$ -	$ -	D.16-06-054	D.12-04-024, Res ESRB-8, PUC §§ 399.2(a) and 451	TY2019 GRC	-	No		
Public Safety Power Shutoff Protocols	Operation Practices	various	$ -	$ -	D.16-06-054	D.12-04-024, Res ESRB-8, PUC §§ 399.2(a) and 451	TY2019 GRC	-	No		
Communication Practices	Operation Practices	various	$0.50 - $0.70	$2.0 - $3.0	D.16-06-054	D.12-04-024, Res ESRB-8, PUC §§ 399.2(a) and 451	TY2019 GRC	-	Yes		
Mitigating the Public Safety Impact of PSPS Protocols	Operation Practices/Recovery and Response	various	$ -	$ -	D.16-06-054	D.12-04-024, Res ESRB-8, PUC §§ 399.2(a) and 451	TY2019 GRC	-	Yes		

NOTES:

[1] This table summarizes the detailed information provided in Section 4 of SDG&E's Wildfire Mitigation Plan.

[2] Reflects capital cost estimates for 2019, see Appendix A for additional information including cost estimates for 2019 and 2020. Since projects generally span several years, considering capital costs over a limited timeframe (e.g., one year) typically does not represent the entire mitigation.

[3] Reflects O&M cost estimates for 2019 see Appendix A for additional information including cost estimates for 2019 and 2020. Total O&M costs are not available. SDG&E is presenting O&M cost estimates in this Plan relative to its 2018 authorized revenue requirement, which was established in the 2016 GRC and approved by the CPUC in D.16-06-054.

[4, 5, 6, 8] See Appendix A for details.

[7] SDG&E filed Advice Letter 3333-E to establish the Fire Risk Mitigation Memorandum Account (FRMMA), which is still pending before the CPUC . As such, no costs are being recorded in the FRMMA. SDG&E has established a General Rate Case Memorandum Account (GRCMA) to record the shortfall or overcollection resulting from the difference between the revenue requirement and corresponding rates in effect on January 1, 2019 and the final revenue requirement and corresponding rates adopted by the CPUC in a decision for A.17-10-007. Currently, no costs are being recorded in the GRCMA.

[9, 10] See Wildfire Mitigation Plan Section 6.2.

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Appendix C

SDG&E Operating Conditions Chart

CONDITION	Normal Condition **Fire Potential Index 1-11** Fuel and weather conditions are no longer conducive to significant fire growth. Based on fire indices and Fire Coordinator / Meteorologist Recommendation	Elevated Condition **Fire Potential Index 12-14** The burn environment of a specific area or district has become conducive for a large wildfire within the SDG&E service territory.	Extreme Condition **Fire Potential Index 15 and above** An extreme operating condition will be declared when the burn environment of a specific area or district has become conducive for a catastrophic wildfire within the SDG&E service territory. .	Red Flag Condition (NWS) RFW: Relative Humidity ≤ 15%, with sustained winds ≥ 25 mph and/or frequent gusts ≥ 35 mph (duration ≥ 6 hours) Declared by NWS
	Distribution	**Distribution**	**Distribution**	**Distribution** | **Transmission**
HIGH FIRE THREAT DISTRICT	No change to reclosing policy. Line will be tested by recloser action.	All reclosers will be turned off.	All reclosers will be turned off. Enable Sensitive Relay Setting at direction of EDO.	All reclosers will be turned off. Enable Sensitive Relay Setting at direction of EDO.
		TESTING	**TESTING**	**TESTING**
		Distribution	**Distribution**	**Distribution**
		SGF and/or/with FCP Targets: Patrol entire line or line segment before energizing. **Non-SGF Targets:** Patrol line segment to load-side sectionalizing device before energizing. **HLT or Sensitive Relay Settings:** Patrol entire line or line segment, including load-side sectionalizing device before energizing.	**SGF and/or/with FCP Targets:** Patrol entire line or line segment, including load-side sectionalizing device before energizing. **Non-SGF Targets:** Patrol line segment to load-side sectionalizing device before energizing. **HLT or Sensitive Relay Settings:** Patrol entire line or line segment, including load-side sectionalizing device before energizing.	**SGF and/or/with FCP Targets:** Patrol entire line or line segment, including load-side sectionalizing device before energizing. **Non-SGF Targets:** Patrol line segment to load-side sectionalizing device before energizing. **HLT or Sensitive Relay Settings:** Patrol entire line or line segment, including load-side sectionalizing device before energizing.
		If a Distribution outage is caused by a Transmission/Substation outage, Distribution may re-energize without a patrol, at the direction of EDO Management. EDO will not consider the possibility of miscoordination on operating device, regardless of trip target. If multiple devices trip open, a patrol must be completed.	If a Distribution outage is caused by a Transmission/Substation outage, the Distribution overhead will be isolated and a patrol of the line must be complete prior to energizing. EDO will not consider the possibility of miscoordination on operating device, regardless of trip target. If multiple devices trip open, a patrol must be completed. **A Patrol must be complete until a cause is identified prior to energizing, if no cause is found at the direction of EDO Leadership, step-wise restoration may occur.** Crew Deployment Plan Activated by District	EDO will not consider the possibility of miscoordination on operating device, regardless of trip target. If multiple devices trip open, a patrol must be completed. **A Patrol must be complete until a cause is identified prior to energizing, if no cause is found at the direction of EDO Leadership, step-wise restoration may occur.** Crew Deployment Plan Activated Staging Sites Include: All C&O Centers Viejas, Santa Ysabel, Jamul, Del Mar, Fallbrook At a > 56 mph wind gust forecast, EDO will stage field observers, close to affected areas.

Appendix D

SDG&E Weather Station Networks

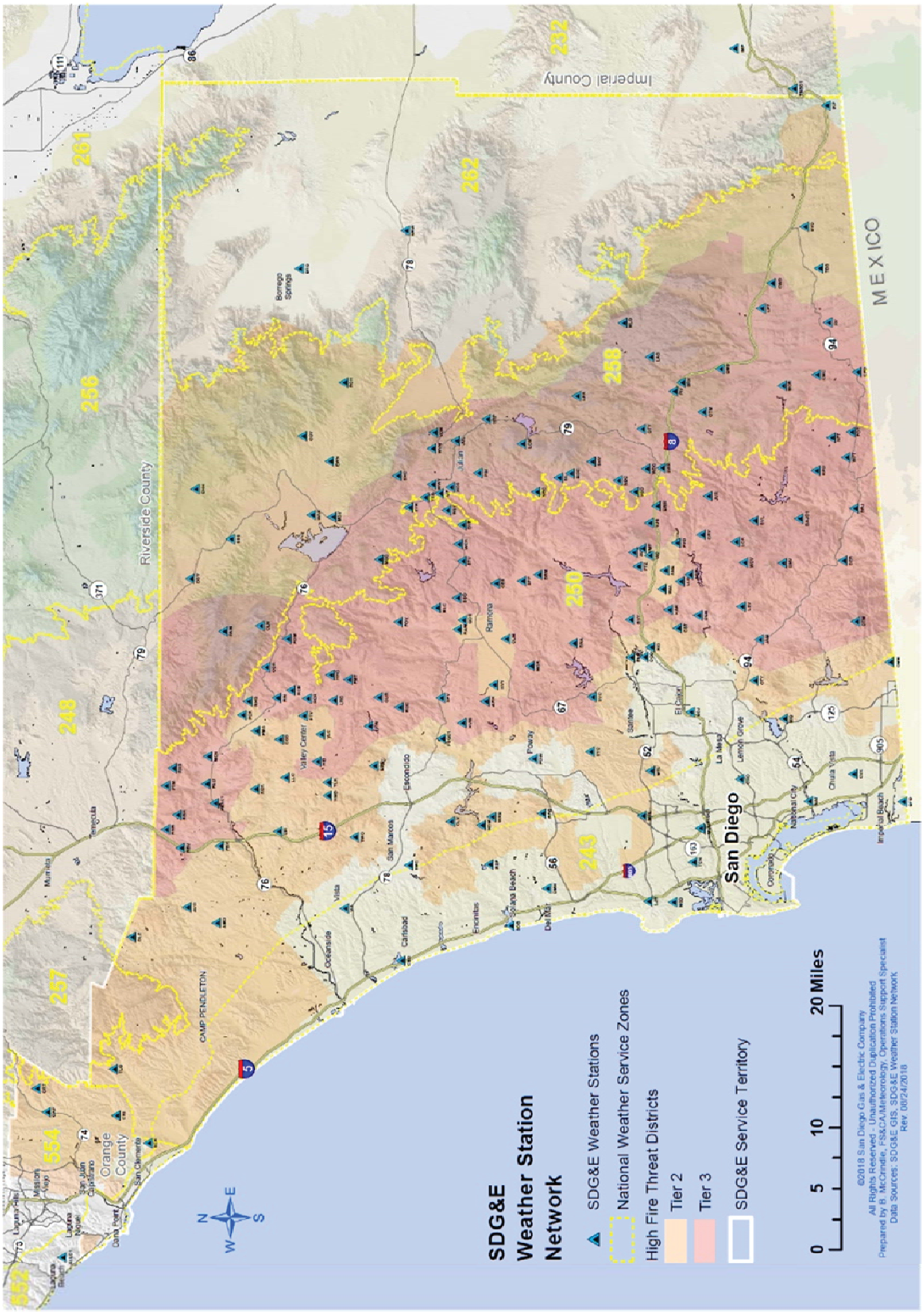


Exhibit No.: CA-07-0432

Appendix E

Fire Potential Index Components

FPI Green-Up Component

The state of native grasses, or Green-Up Component, of the FPI is determined using satellite data for various locations. This component is rated on a 0-to-5 scale ranging from very wet (or "lush") to very dry (or "cured"). The scale is tied to the Normalized Difference Vegetations Index (NDVI), which ranges from 0 to 1, as follows:

Very Wet/Lush: **0.65 to 1.00**	**0.60 to 0.64**	**0.55 to 0.59**	**0.50 to 0.54**	**0.40 to 0.49**	**Very Dry/Cured** **0 to 0.39**
0	1	2	3	4	5

FPI Fuels Component

The Fuels Component of the FPI measures the overall state of potential fuels which could support a wildfire. Values are assigned based on the overall state of available fuels (dead or live) for a fire using the following equation:

FC = FD / LFM

Where FC represents Fuels Component in the scale below, FD represents 10-hour Dead Fuel Moisture (using a 1-to-3 scale), and LFM represents Live Fuel Moisture (percentage).

The product of this equation represents the fuels component that is reflected in the FPI as follows:

Very Wet					**Very Dry**
1	**2**	**3**	**4**	**5**	**6**

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FPI Weather Component

The weather component of the FPI represents a combination of sustained wind speeds and dew-point depression as determined using the following scale:

Dewpoint/Wind	≤5 knots	6 to 10	11 to 16	17 to 22	23 to 28	≥29 knots
≥50ºF	4	4	4	5	5	
40ºF to 49ºF	3	3	4	4	5	5
30ºF to 39ºF	3	3	3	4	4	5
20ºF to 29ºF	3	3	3	3	3	4
10ºF to 19ºF	2	2	2	2	2	3
<10ºF	0	1	1	1	1	2

Final Computed Fire Potential Index

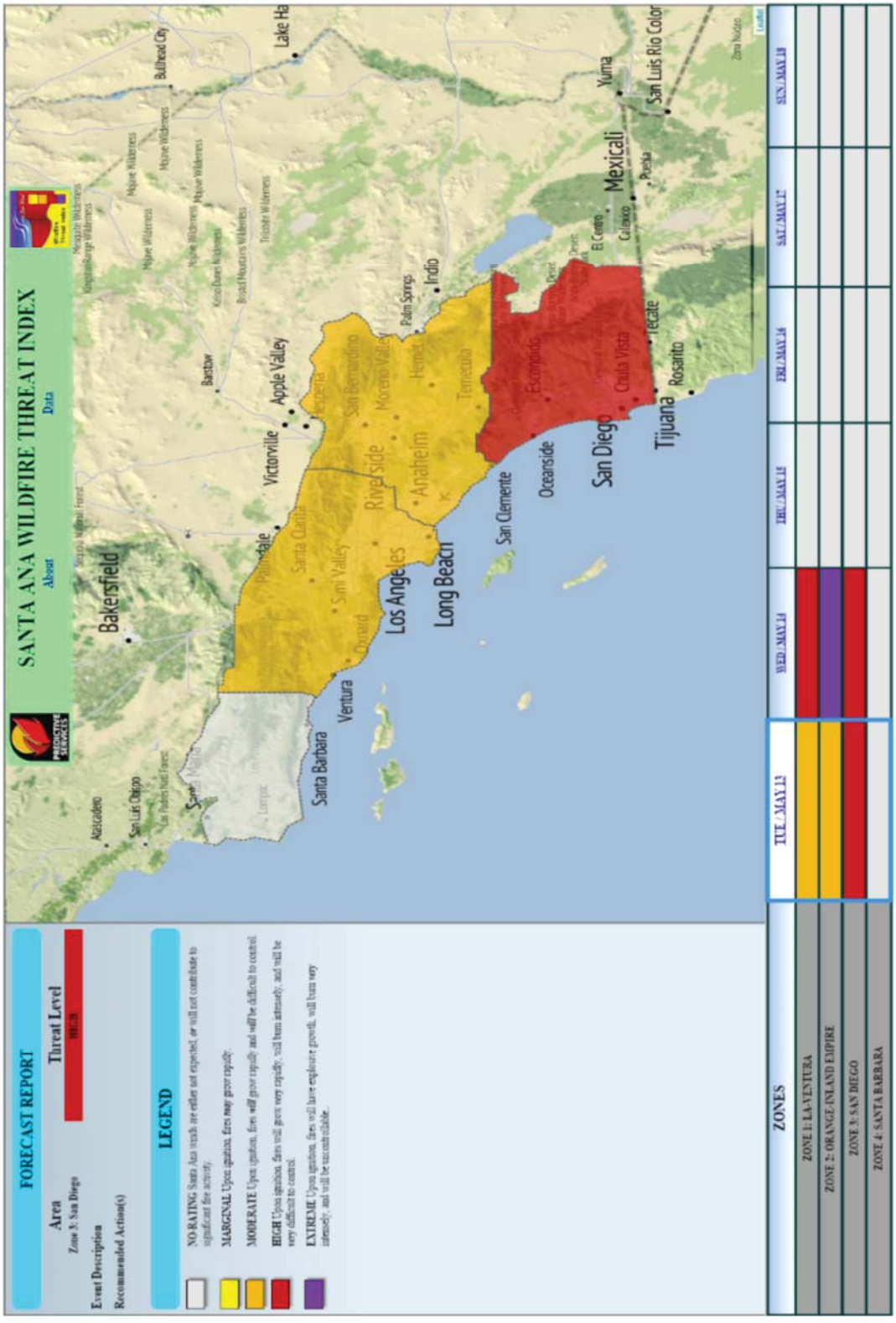
The individual numeric values representing the three variables reflected in the FPI, shown above, are combined and placed on the following scale:

Normal	Elevated	Extreme
≤ 11	**12 to 14**	**≥ 15**

CA-07-0434

Appendix F

Santa Ana Wildfire Threat Index



Appendix G

List of Priority Essential Services

Municipal Fire and Law Enforcement

City of Del Mar
City of El Cajon
City of Encinitas
City of Imperial Beach
City of La Mesa
City of Lemon Grove
City of National City
City of Poway
City of San Juan Capistrano
City of San Clemente
City of Carlsbad
City of Chula Vista
City of Coronado
City of Solana Beach
City of Vista
City of Dana Point
City of Mission Viejo
City of Escondido
City of Oceanside
City of San Marcos
City of San Diego
City of Santee
County of San Diego
County of Orange
State of California Highway Patrol

Non-Municipal Fire Departments

Alpine Fire Protection Dist.
Barona Fire Department
Bonita-Sunnyside Fire Protection
Borrego Springs Fire Department
Campo Band of Mission Indians Fire Department
Cal Fire
Deer Springs Fire Protection
Julian Cuyamaca Fire District
Lakeside Fire Protection
Manzanita Fire Department
Mesa Grande Band of Mission Indians Fire Department
North County Fire
Pala Band of Mission Indians Fire Department
Pauma Band of Mission Indians Fire Department
Rancho Santa Fe Fire Department
Rincon Fire Department
San Miguel Fire Protection District
Sycuan Kumeyaay Indians Fire Department
Viejas Band of Kumeyaay Indians Fire Department
Valley Center Fire Protection

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Communication Providers

AT&T
Clear Channel Radio DIP
Cox Communications Inc.
KNSD
KBNT Channel 17
Midwest TV Inc
Sprint Nextel Corporation
Time Warner Cable
T-Mobile USA Inc
U S Sprint Co
Verizon Wireless

Hospitals

Scripps Media Inc
Alvarado Hospital
Coronado Hospital
Grossmont Hospital
Kaiser Permanente
Mercy Hospital and Medical Center
Mission Hospital
Palomar Pomerado Health
Paradise Valley Hospital
Rady Children's Hospital
Saddleback Memorial Medical Center
Scripps Mercy Hospital – Chula Vista
Sharp Chula Vista – Medical Center
Sharp Memorial Hospital
Tri City Medical Center
UCSD Medical Center
VA Medical Center

CA-07-0437

Water Utilities/Agencies/Waste Water

Borrego Water District
Descanso Comm. Water Dist.
Fallbrook Public Utility District
Harrison Park Mutual Water Co.
Helix Water District
Julian Comm. Service District
Lakeside Water District
Leucadia Co. Water Dist.
Moulton Niguel Water Dist.
Municipal Water Dist.
Olivenhain Municipal Water District
Otay Water District
Padre Dam Mun. Water Dist.
Palomar Mtn. Mun. Water Dist.
Rainbow Mu. Water Dist.
Rancho Pauma Mtg. Water Co.
San Dieguito Water Dist.
San Elijo Joint Powers Authority
San Diego County Water Authority
South Coast Water District
South Orange County Wastewater Authority
San Diego Metropolitan Wastewater Department
Santa Margarita Water Dist.
Sweetwater Authority
Vallecitos Water Dist.
Vista Irrigation Dist.
Valley Center Mun Water Dist.
Yuima Mun. Water Dist.

Schools

Alpine Union School District
Bonsall Union School District
Borrego Unified School District
Cajon Valley Union School District
Cardiff School District
Carlsbad Unified School District
Dehesa Elementary School District
Escondido Union High School District
Escondido Union School District
Fallbrook Union High School District
Fallbrook Union School District
Grossmont Union High School District
Jamul-Dulzura School District
Julian Charter School
Julian Union High School District
Julian Union School District
Lakeside Union School District
Mountain Empire Unifieid School District
Ramona Unified School District
San Diego Unified School District
San Pasqual Union School District
SD County Office of Education
Spencer Valley School
Vallecitos School District
Valley Center/Pauma Unified School District

CA-07-0438

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007 (Issued October 25, 2018)

NOTICE OF AVAILABILITY OF SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E) WILDFIRE MITIGATION PLAN

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Attorney for
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February 6, 2019

CA-07-0439

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007 (Issued October 25, 2018)

NOTICE OF AVAILABILITY OF
SAN DIEGO GAS & ELECTRIC COMPANY'S (U 902 E)
WILDFIRE MITIGATION PLAN

Pursuant to Rule 1.9(d) of the Rules of Practice and Procedure of the California Public Utilities Commission (Commission), San Diego Gas & Electric Company (SDG&E) hereby provides notice that it has electronically filed with the Commission's docket office its

WILDFIRE MITIGATION PLAN.

The Plan is available on SDG&E's website as of February 6, 2019 at the following link:

https://www.sdge.com/node/11401.

The Plan may also be obtained by contacting:

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Regulatory Case Manager
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Respectfully submitted,
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Attorney for
SAN DIEGO GAS & ELECTRIC COMPANY

February 6, 2019

ATTACHMENT 7

Liberty, 2019 Wildfire Mitigation Plan, February 9, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

FILED
02/06/19
02:58 PM

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	Rulemaking 18-10-007 (Filed October 25, 2018)

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC'S (U 933-E) SUBMISSION OF ITS WILDFIRE MITIGATION PLAN PURSUANT TO SENATE BILL 901 (2018)

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February 6, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	Rulemaking 18-10-007 (Filed October 25, 2018)

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC'S (U 933 E) SUBMISSION OF ITS WILDFIRE MITIGATION PLAN PURSUANT TO SENATE BILL 901 (2018)

In accordance with the December 7, 2018 Assigned Commissioner's Scoping Memo and Ruling ("Scoping Memo"), Liberty Utilities (CalPeco Electric) LLC ("Liberty CalPeco") submits its Wildfire Mitigation Plan. The Wildfire Mitigation Plan follows the template provided in the January 17, 2019 Administrative Law Judge's Ruling.

I. Introduction and Background

Given recent catastrophic wildfires in California, the state passed Senate Bill ("SB") 901 in late 2018. This bill requires utilities to adopt wildfire mitigation plans, the details of which are at the discretion of the California Public Utilities Commission ("Commission" or "CPUC") for investor-owned utilities. In response, the Commission issued an Order Instituting Rulemaking ("OIR") in the Utility Wildfire Mitigation Plans (SB 901) filed under Rulemaking (R.) 18-10-007. The OIR provides guidance to utilities about the framework and content of the Wildfire Mitigation Plan and a timeline and process for review and implementation moving forward. In this initial OIR, the Commission requires that utilities submit plans by February 6, 2019. The Commission will review these plans and issue a decision

in mid-2019. Due to limited time in developing the document for filing, the Commission understands that the plans may not be exhaustive and envisions the plans evolving over time.

II. Liberty CalPeco's Wildfire Mitigation Plan

Liberty CalPeco has applied a thoughtful approach in developing a holistic strategy to mitigate utility-posed wildfire risks pursuant to SB 901. The process included a strategic, risk-based evaluation that resulted in efforts to improve operational practices, fortify existing preventative and response plans, and coordinate responsibilities within the utility to monitor and enhance the plan over time. Liberty CalPeco looks forward to working with the Commission and other parties to continually improve its Wildfire Mitigation Plan.

Respectfully submitted,

/s/ Sharon Yang

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February 6, 2019

Liberty Utilities (CalPeco Electric) LLC's
Wildfire Mitigation Plan

CA-07-0445

NAVIGANT

Liberty Utilities (CalPeco Electric), LLC

Wildfire Mitigation Plan



Assisted by:
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Reference No.: 207670
February 4, 2019

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Prepared for Liberty Utilities (CalPeco Electric), LLC. (U 933-E)

CA-07-0446

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DISCLAIMER

The State of California and the California Public Utilities Commission (Commission or CPUC) mandated through Order Instituting Rulemaking (OIR) that the electric utilities develop a "Wildfire Mitigation Plan" pursuant to Senate Bill (SB) 901. In Rulemaking (R.) 18-10-007, The Commission provided a specific outline that the electric utilities were to follow in the development of their Wildfire Mitigation Plans. Electric utilities' Wildfire Mitigation Plans (WMP or Plan) aim to reduce utility-posed wildfire risks while creating a process for review and implementation throughout the iteration filings of the Plan.

Liberty Utilities (CalPeco Electric), LLC (Liberty CalPeco) retained Navigant Consulting, Inc. (Navigant) as support in the development of their Wildfire Mitigation Plan. Navigant's approach in supporting the development of Liberty CalPeco's Wildfire Mitigation Plan included:

- **Data Requests**: Navigant requested data, reports, and prior plans to be incorporated into their proposed Plan.

- **Interviewed Liberty Personnel**: A series of interviews were held with Liberty CalPeco personnel to determine specific actions and strategies to be included along with site inspection of select equipment and infrastructure.

- **Plan Development**: Navigant developed a Wildfire Mitigation Plan based on the direction and information provided to Navigant by Liberty CalPeco.

- **Review of the Plan**: Liberty CalPeco reviewed and approved their Wildfire Mitigation Plan outlined in this report.

Navigant assisted Liberty CalPeco in preparing this report for filing, based on the information and plans the utility provided. The information presented in this report represents Navigant's professional judgment based on the information available at the time this report was prepared with Liberty CalPeco's overall decision-making. Navigant is not responsible for the reader's use of, or reliance upon, the report, nor any decisions based on the report. NAVIGANT MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESSED OR IMPLIED. Readers of the report are advised that they assume all liabilities incurred by them, or third parties, as a result of their reliance on the report, or the data, information, findings and opinions contained in the report.

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INTRODUCTION

Given recent, catastrophic wildfires in California, the state passed Senate Bill (SB) 901 in late 2018. This bill requires utilities to adopt wildfire mitigation plans; the details of which are at the discretion of the California Public Utilities Commission (Commission or CPUC) for Investor-Owned Utilities (IOUs). In response, the Commission issued an Order Instituting Rulemaking (OIR) in the Utility Wildfire Mitigation Plans (SB 901) filed under docket number Rulemaking (R.) 18-10-007. The OIR provides guidance to the utilities it governs about the framework and content of the Wildfire Mitigation Plan (WMP or Plan) and a timeline and process for review and implementation moving forward.[1] In this initial OIR, the Commission requires that utilities submit plans by February 6, 2019. The Commission will then review the plans and issue a decision in mid-2019. Due to limited time in developing the document for filing, the Commission understands that the Plans may not be perfectly robust and envision iterations of the Plan evolving over time.

Liberty Utilities (CalPeco Electric) LLC (Liberty CalPeco) has applied a thoughtful approach in developing a holistic strategy to mitigate utility-posed wildfire risks pursuant to SB 901.The process included a strategic, risk-based evaluation that resulted in efforts to improve operational practices, embellish existing preventative and response plans, and coordinate responsibilities within the utility to monitor and enhance the Plan overtime.

[1] The Commission oversees the following utilities: Pacific Gas & Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Liberty CalPeco, Bear Valley Electric Service (BVES), and Pacific Power.

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1. OBJECTIVES OF THE PLAN

1.1 Objectives and Approach

This application by Liberty CalPeco responds to SB 901 and the Commission's related OIR. Specifically, the following aims to fulfill the requirements detailed in Public Utilities Code (PUC) Section 8386, which has been modified by SB 901. The 2018 OIR to *Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901* outlines these requirements. At a high-level, the OIR includes an outline that directs IOUs to frame the Plan to incorporate: prioritization of territory-wide wildfire risks; an overview of (existing and new) strategies, protocols, plans, and programs; a description of situational awareness practices; metrics to monitor the Plan's performance; protocols for communicating with customers regarding emergency events; and cost estimates for each proposed investment. Liberty CalPeco assessed the items laid out in the approved framework and applied potential projects, solutions, and enhancements to current operational practices and standards.

Liberty CalPeco's intentions of the Plan not only align with fulfilling the Commission's requirements, but also aim to demonstrate its commitment to delivering electricity reliably and safely throughout its unique mountainous service territory with consideration of the utility's fire risk. Liberty CalPeco therefore understands how local known conditions require additional measures to ensure catastrophic events (such as the devastating wildfires experienced in the fall months of 2017 and 2018) are mitigated and prevented by the items proposed in this Plan. As information is collected, procedures are implemented, and metrics are assessed, annual changes will be made to the Plan for enhancements or for any items deemed necessary by the Commission. Liberty CalPeco will track the effectiveness of the objectives through internal monitoring and auditing. Pending approval from the Commission, the timeframe for implementing the Plan's objectives will begin before the next filing for the Plan. Some aspects of the Plan's objectives could take place before the upcoming wildfire season, as several existing measures are ongoing. Others will be accomplished by the determined schedules presented in this filing. Liberty CalPeco will adjust timeframes for executing Plan elements throughout the evolution of the Plan and subsequent filings.

Additionally, Liberty CalPeco understands that approval of this Plan does not guarantee any form of cost recovery, and that specific items may be challenged by the Commission. The Commission will weigh the potential cost implications of measures proposed in the Plan during the approval process.

To address the objectives detailed above, the report includes the following sections:

- **Section 2** provides an overview of Liberty CalPeco's fire prevention strategies.
- **Section 3** outlines determined system risks and risk drivers.
- **Section 4** details Liberty CalPeco's operational practices, system hardening, vegetation management, situational awareness, and public safety power shut-off plans to mitigate risks identified in Section 3.
- **Section 5** summarizes emergency preparedness plans as they relate to wildfires.
- **Section 6** identifies metrics to monitor Liberty CalPeco's fire mitigation tactics and Plan performance over time.
- **Section 7** summarizes the cost implications that the utility may incur when implementing specific items of the Plan.

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2. DESCRIPTION OF PREVENTATIVE STRATEGIES

This section provides an overview of the preventative strategies and programs currently existing as well as proposed in the Wildfire Mitigation Plan. The categories listed below help delineate how measures are framed and risks are addressed through the development of the Plan. The information provided includes the overarching plan components, supporting examples of programs implemented or proposed, and a discussion surrounding the timing of proposed implementations.

The development process of the Plan included substantial deliberation along with the identification of successful elements of existing programs, plans, and procedures. This process informed senior leadership on any gaps or actions that may be an additional necessity in the timeframe after adopting the utility's Fire Prevention Plan and responding to the requirements of SB 901. The performance and effectiveness of the Fire Prevention Plan was therefore evaluated under these new requirements. Liberty CalPeco incorporated existing plans, programs, and procedures from the prior Fire Prevention Plan into the currently proposed Wildfire Mitigation Plan with consideration that the Fire Prevention Plan would not capture complete requirements outlined in current SB 901 and subsequent OIR form.

2.1 Strategy & Program Overview

Existing and proposed wildfire preventative strategies can be categorized into five main mechanisms that align with utility best practices. Together, the five components create a comprehensive wildfire preparedness and response plan with a principal focus on stringent construction standards, fire prevention through system design, proactive operations and maintenance programs, and well-socialized operating procedures and staff training.

- **Design & Construction:** These strategies consist of system, equipment, and structure design and technical upgrades. The practices in this category aim to improve system hardening to prevent contact between infrastructure and fuel sources, such as vegetation. For example, Liberty CalPeco plans to upgrade priority lines with covered wire, mitigating the risk of bare line contact with vegetation or other fuel sources.
- **Inspection & Maintenance:** These strategies consist of assessment and diagnostic activities as well as associated corrective actions. The practices in this category aim to ensure all infrastructure is in working condition and vegetation adheres to defined minimum distance specifications.
- **Operational Practices:** These strategies consist of proactive, day-to-day actions taken to mitigate wildfire risks. The practices in this category aim to ensure preparedness in high-risk situations, such as dry and windy climatological conditions. For example, "fire mode" is initiated during the summer months, typically in early June through early November. Fire mode enables high speed tripping of all transmission lines with no reclosing (one trip to lockout). As a second example, should the weather forecast predict the National Fire Danger Rating System (NFDRS) Red Flag Warning conditions, the responsible parties will begin to prepare the system for a potential de-energization event, if deemed necessary.
- **Situational & Conditional Awareness:** These strategies consist of methods to improve system visualization and awareness of environmental conditions. The practices in this category aim to provide tools to improve the other components of the plan. For example, Liberty CalPeco's

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weather station installation project will improve coordination with local agencies and enhance weather incident monitoring.

- **Response & Recovery:** These strategies consist of procedures to react to de-energization, wildfire, or other related emergencies. Practices referenced aim to formalize protocols for these situations for adequate response and recovery.

In addition to these efforts, Liberty CalPeco has issued an Emergency Preparedness Plan, as included in Appendix C, customer support and communications protocols, as well as performance metrics to monitor its plan over time.

2.1.1 Implementation Timeline Overview

Each of the components outlined above have several strategies and programs, many of which have already been implemented, but could take several years or longer to complete. Other strategies and programs are in the evaluation, pre-approval, or proposal stages and will be implemented in the near future or upon the Commission's approval of the plan. The strategies and programs fall into four "implementation" timeframes: (A) already implemented; (B) implemented before the upcoming fire season, as defined by California Department of Forestry and Fire Protection (CAL FIRE) and the California Department of Forestry; (C) implemented before the next plan filing with the CPUC; and (D) implemented within the next five years. Table 2-1 below outlines the strategy and program and their implementation (start) timelines. The schedules of execution are described in greater detail within Section 4 of this Plan.

Table 2-1. Implementation Timeline

Mitigation Area	Preventive Strategies / Program	Timeframe to Implement
Operational Practices	Infrastructure Protection Teams	A
	Emergency Preparedness and Response Protocols	B
	Automation, Reclosers and Fast Curve Settings	A
	(Supervisory Control and Data Acquisition) SCADA	A
Inspection Plans	Proactive Patrols and Equipment Inspections	A
	Geographic Information System (GIS) Mapping	A
	Tree Attachment Inventory Inspection	C
System Hardening Upgrades	Fusing	C
	Covered Conductor Program	C
	Pole Loading & Replacement	A
	Undergrounding Distribution Lines	B
	Substation Facility Replacement/Enhancement	D

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Vegetation Management	Vegetation Management Program	A
	Regular and Off-Cycle Inspections	A
Situational Awareness Protocols	Weather Stations	B
	Weather Monitoring	B
Public Safety Power Shut-Off Protocols	Public Safety Power Protocols	B

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3. RISK ANALYSIS AND RISK DRIVERS

3.1 Risk Methodology

As mentioned above, Liberty CalPeco recognizes that it operates within a high-risk wildfire environment while providing operational reliability and safety in electricity delivery. Minimizing risk occurs through capital investment planning, enhanced operational practices, as well as related programs and procedures. Resulting from Decision (D.) 14-12-025[2], the Commission revised the general rate case plan to support the adoption of a risk-based approach in ratemaking practice. This helps provide guidance, transparency, and methods in assessing vulnerabilities in utility operations to aid prioritization of revenue requirement allocators and capital investment projects when setting retail rates.[3]

Liberty CalPeco, is continuing to develop a framework for risk-based decision-making and recently introduced the initial construct in its 2019 General Rate Case (GRC) application.[4] Proposed mitigation items within this Plan were determined based on some aspects, of the risk-based decision-making tool that is still being refined. This also incorporated utility leadership deliberation and external guidance resulting in refinement of proposed measures and strategies. Additionally, the process to identify risks and drivers produced underlying assumptions that shaped prioritization of measure execution. Liberty CalPeco plans to include a final version of its risk assessment tool in its next GRC application filing, benefiting future Plan iterations during reassessment periods.

Risk-Based Decision-Making Framework
At a high level, the risk-based decision-making framework will use a qualitative approach to address potential risk drivers and will quantify the risk through multiplier calculations and heat map plotting. These determinations help inform utility leadership in preparing for capital and expense planning among mitigating fire, safety, and reliability concerns.

The framework is based on an Enterprise Risk Management structure in that Liberty CalPeco's parent company, Algonquin Power and Utilities Corporation (APUC), addresses highest level risk issues and is responsible for decision-making corporate-wide in the event of a shared risk area. This risk determination methodology is consistent with all utilities under APUC and share common material concerns expressed by California utilities within High Fire-Threat District (HFTD) regions. The methodology is presented as a scale to determine risk severity. These are ranked from one to five, after assessment, and then plotted on a heat map to illustrate low and high-risk grades. Figure 3-1 depicts an example of this.

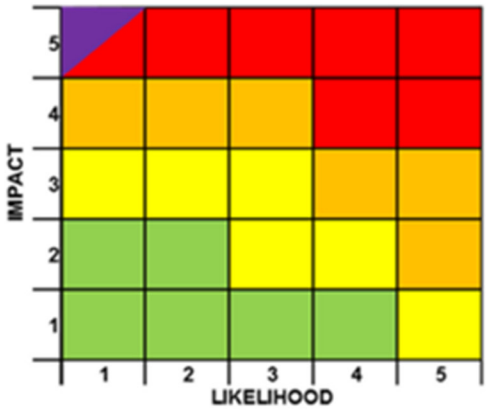
[2] CPUC. Filled December 4, 2014. "Decision 14-12-025 in Rulemaking 13-11-006." http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K549/143549328.PDF.

[3] CPUC. 2015. "2016 Liberty CalPeco General Rate Case Application." http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M170/K774/170774569.pdf.

[4] Liberty CalPeco. "General Rate Case Application 2019 – 2021 A.17-05-004" submitted on May 1, 2017, which is pending decision.

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Figure 3-1. Example of Liberty CalPeco Risk-Based Heat Map



Source: Liberty CalPeco GRC 2019 Application

To combat and control classified risk, APUC has identified "Risk Advisors" from each regional area, who then oversee and evaluate potential risks within the utility. This process is carried out with both a top-down and bottom-up approach to classify areas of greatest operational concern through repetitive assessment cycles to identify, evaluate, communicate, and mitigate risks. When risks fall out of reasonable management through routine protocols, guidance plans are developed to control and monitor the growing risk.

The risk management process is comprised of multiple steps including: risk identification; analysis; evaluation and scoring; decision-making; and monitoring.

When evaluating risk impacts, five categories have been defined by Liberty CalPeco.

1. Safety
2. Legal Compliance
3. Strategic
4. Reputational
5. Financial

This methodology is consistent with the approaches to identify risk from other electric utilities and corporations. Fundamentally, these methodologies share a common construct: identifying system and operational threats, characterize risk, assign roles for appropriate measures, prescribe remedies based on anticipated risk reduction and resource availability, and monitor the effectiveness of the strategy. This similar process is echoed by small utilities such as BVES as well as large IOUs such as SCE.[5]

Risk Assessment Mitigation Phase

Another result of D. 14-12-025 in R. 13-11-006[6] is the order of large electric utilities to report a framework of how the electric utility plans to assess and determine risk to support efforts for minimization and

[5] SCE, "Southern California Edison Company's Risk Assessment and Mitigation Phase Report." November 15, 2018. http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/B2ADFEF6506791E9882583460074389A/$FILE/I.18-11-006%20SCE%202018%20RAMP%20Report.pdf.

[6] *See "*Safety Model Assessment Proceeding (A.15-05-002, et. al.)" http://cpuc.ca.gov/General.aspx?id=9099.

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mitigation. The Risk Assessment Mitigation Phase (RAMP) along with the Safety-Model Assessment Proceeding (S-MAP) are required to be integrated into the large utility's GRC applications. Liberty CalPeco is considered a small utility by the Commission and therefore is not mandated to direct resources to develop the RAMP or S-MAP. Liberty CalPeco, instead, introduced its initial risk-based decision-making framework, as ordered by the Commission.

The following describes the service territory and how certain conditions are considered when determining risk factors and drivers.

3.2 Service Territory Description

Due to Liberty CalPeco's geographic location within California, the electric utility operates within unique climatological and topographical conditions. This section provides an overview of the Liberty CalPeco service territory, key system aspects, and potential considerations as they relate to wildfires.

Liberty CalPeco serves approximately 49,000 electric customers in California, in and around the Lake Tahoe Basin. Liberty CalPeco's California service territory differs greatly from the three large IOUs in California. Customers are located in portions of Placer, El Dorado, Nevada, Sierra, Plumas, Mono, and Alpine Counties. Almost 80 percent of customers reside or operate within the Lake Tahoe Basin. The biggest population center is the City of South Lake Tahoe.

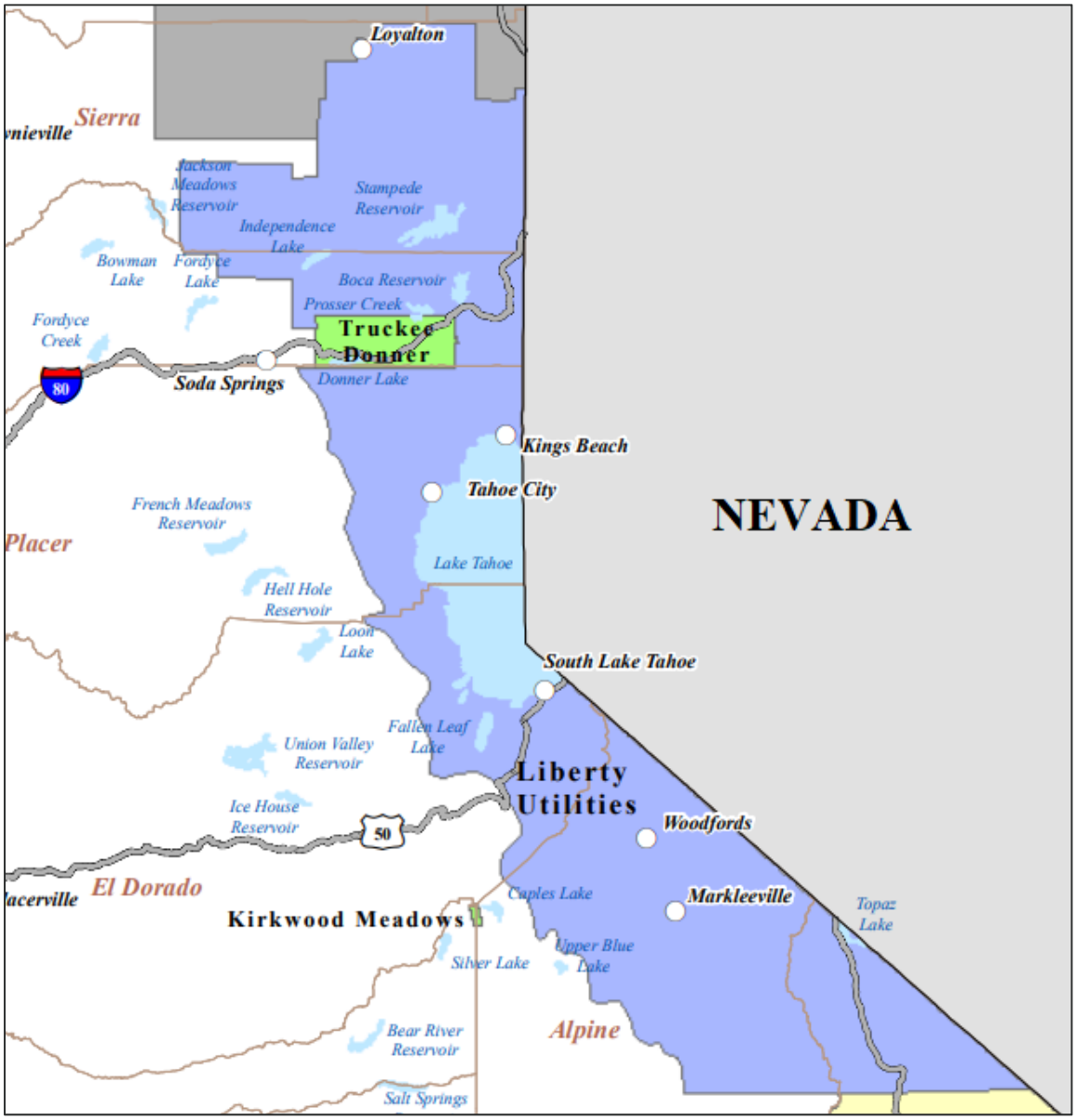
The Liberty CalPeco service territory extends from Portola in the north to Markleeville and Topaz Lake in the south. The terrain mountainous and heavily forested, with elevations ranging from 9,050 feet in Squaw Valley to just under 5,000 feet at Portola. Most of Liberty CalPeco's customer base is located at elevations greater than 6,000 feet.

Electric load reflects the economic activities in the area. The region has little manufacturing or heavy industry. The economy of the Tahoe Basin is dominated by tourism with the major businesses being hotels, motels, and ski resorts. Approximately half of the electricity Liberty CalPeco delivers is to residential customers and approximately 60 percent of residential accounts are second-family homes or rentals. Electric demand peaks for Liberty CalPeco in the winter period, particularly during Christmas week when tourism is highest.

Liberty CalPeco has two regions that operate independently. The North Lake Tahoe Region is supplied from the North Truckee substation, and includes the communities of Squaw Valley, Northstar, Portola and Loyalton. The South Lake Tahoe Region is supplied from the Buckeye, Muller and Topaz substations in Nevada, and includes the City of South Lake Tahoe along with the communities of Markleeville, Coleville and Walker. Interconnection between the two regions is minimal.
Figure 3.2 on the following page illustrates the service territory.

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Figure 3-2. Map of Liberty CalPeco Service Territory



Source: California Energy Commission, 2015

Given its parcels of an alpine climate, Liberty CalPeco must also consider the following when making decisions on risk and implementing plans related to wildfire mitigation: (1) electrical system design and assets, (2) geographic territory and climate conditions, (3) local load profile.

- **Electrical System Design & Assets:** Liberty CalPeco owns and operates 78 miles of overhead 60 kilovolt (kV) transmission lines, 20 miles of 120 kV overhead transmission lines, less than one mile of underground 60 kV and 120 kV transmission, 1,400 miles of overhead distribution circuit miles, 480 miles of underground distribution circuit miles, 14 sub-stations and one diesel-fueled 12-megawatt emergency/peaking generating facility. The risk of these assets to ignite a wildfire were considered when creating the Plan.

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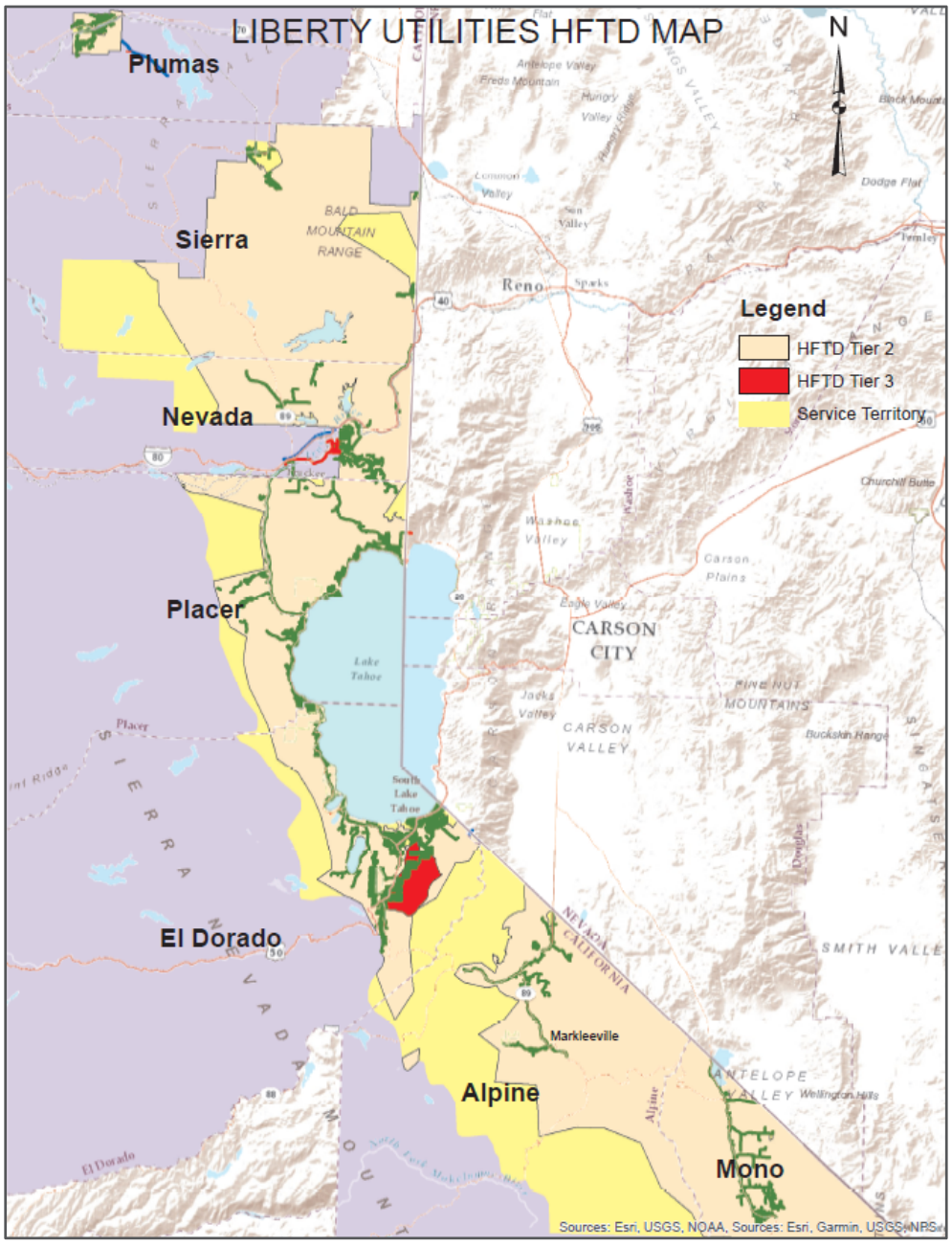
- **Geographic Territory and Climate Conditions:** The service area is located in Tier 2 and Tier 3 HFTD as defined by the adopted state-wide fire-threat map, resulting from R. 15-05-006. The area is heavily forested in a mountainous climate zone with limited access to many regions of the service area. Customer residencies reach up to 9,050 feet in elevation and weather conditions consist of dense snowpack during the winter months with dry conditions, wind, and warm temperatures in late summer to early fall. Liberty CalPeco also recognizes that there are local known conditions such as heavy snowfall, which require unique system upgrades and infrastructure enhancements.
- **Local Load Profile:** Liberty CalPeco experiences seasonal load swings between the winter and summer months with peaks in the winter and high-load hours from 5 p.m. to 10 p.m. This is primarily due to increased demand from seasonal population influx, vacation home visits, and an increase in resort loads. Liberty CalPeco's load profile matches that of the surrounding mountainous service territories and differs greatly from the larger IOUs in California, having average air conditioning load until the later parts of summer, and flattening out in other seasonal conditions. Of the 49,000 customers, 57 percent are residential while 43 percent are commercial.

3.3 Service Territory Wildfire Risk Areas

There are several wildfire risk assessment designations from various organizations, including the Commission, CAL FIRE, the Sierra Front Interagency Dispatch Center (SFIDC), and the US Department of Agriculture (USDA). Each designation provides a different perspective of potential fire danger. For example, the USDA's NFDRS assesses fire threats at the county-level based on weather, while CAL FIRE includes four fire-hazard severity zones based on various factors. Figure 3-3 on the following page illustrates the designation for fire threat within Liberty CalPeco's territory.

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Figure 3-3. Liberty CalPeco High Fire Threat Districts



Source: Liberty CalPeco, Fire Prevention Plan, 2018

Based on the map, there are several regions with high and very high fire threat ratings throughout the service area bordering Nevada. In order to maintain awareness of fire-prone risks as those conditions arise, Liberty CalPeco monitors several fire maps and assessment systems regularly and has created procedures and protocols, accordingly. Table 3-1 below outlines the various rating systems and Liberty CalPeco's service territory rating within that system.

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Table 3-1. Wildfire Risk Assessments in Liberty CalPeco Service Territory

Agency and / or Rating Name	Scope of Fire Risk Rating	Risk Rating
CPUC, Fire-Threat Map Adopted January 19, 2018[7]	Areas or zones where enhanced fire safety regulations in D. 17-12-024 will apply[8]	HFTD; Mostly Tier 2 (elevated risk) with some Tier 3 (extreme risk) areas.
USDA Forest Service, NFDRS[9]	County-Level assessment of fire danger for that day or the next day based on fuels, weather, topography, and risks	Identifies the number of days of High to Very High Fire Danger Levels
CAL FIRE, California Fire Hazard Severity Zone Map Update Project[10]	City and County-level assessments of fire "hazard" zones	Moderate, High, and Very High Fire Hazard Severity Zones
SFIDC[11], Sierra Front Wildfire Cooperators	Interagency monitors and mobilizes local resources against identified fire threat within the Sierra Front area	Risk boundary covers eastern region service area, which lies in Tier 2 and Tier 3 HFTD[12]

There are also specific areas with high risks and would be more adversely affected in a wildfire or emergency. These areas consist of Tier 3 designation, dense vegetation coverage and accessibility due to remote locations. The cities/regions identified include: Squaw Valley, Tahoe City, Brockway, Truckee, and Meyers.

These areas are mountainous and heavily forested. Liberty CalPeco has infrastructure operating within these regions, creating challenges in upgrading the infrastructure and maintaining visibility on the lines. Specifically, infrastructure changes and some maintenance operations require the use of helicopters to access overhead lines both within and outside of the Tahoe basin due to inaccessibility. Specially-trained line staff are required to foster operational efficiently in such a challenging environment.

As described above, the service territory's high elevation means the area consists of a heavily treed, mountainous environment, which is highly vulnerable to wildfires under the right conditions. Liberty CalPeco understands this risk and has prepared its fire mitigation plans accordingly. Furthermore, it has complied with all fire-safety regulations adopted to date, including those set out in GO 95, 165, and 166.

[7] CPUC, Commission Fire Safety Rulemaking Background 2018, http://www.cpuc.ca.gov/firethreatmaps/.

[8] CPUC, "Commission Adopts New Fire-Safety Regulations," December 14, 2017, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352402.PDF.

[9] USDA Forest Service, "National Fire Danger Rating System," https://www.fs.usda.gov/detail/inyo/home/?cid=stelprdb5173311.

[10] CAL FIRE, Wildland Hazard & Building Codes Cities for which CAL FIRE has made recommendations on Very High Fire Hazard Severity Zones (VHFHSZ), http://www.fire.ca.gov/fire_prevention/fire_prevention_wildland_zones_maps_citylist.

[11] The SFIDC compiles local information such as lighting strike maps, local weather updates as well as national updates such as the National Interagency Fire Center, National Incident Management Situation Report, and preceding resources indicated in Table 3-1.

[12] SFIDC, Webmap of Territory Ownership, 2012, http://sierra-front.net/sites/default/files/SFIDC_Webmap_ownership.JPG

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3.4 Wildfire Risks and Drivers

Liberty CalPeco pursued an assessment methodology to identify and prioritize wildfire risks. This effort determined which facilities and electrical assets would meet criteria for inclusion in the utility's Fire Prevention Plan, pursuant to R. 08-11-005.[13] The plan influenced the prioritization of risk drivers in the development of the WMP. The process and key considerations are detailed at a high-level in this section.

3.4.1 Prioritized Risks and Risk Drivers

To identify risks and understand each risk's potential for starting wildfires, Liberty CalPeco first analyzed wildfire drivers and how these may change over time. To perform this task, information from evaluating wind loading design standards, substation construction design standards, and equipment operations was compared to owned electrical assets through internal review. Additionally, this required an overall territory assessment to include unique conditions that may exacerbate weather events that lead to wildfire. This drew from information gathered from meteorological monitoring platforms and determinations to help identify potential hazards. The utility then applied this knowledge, which culminated in an approach to mitigate wildfire risks. This is later discussed in Section 4.1.

According to the US Forest Service (USFS), there are three essential elements in the "fire triangle": heat, fuel, and oxygen.[14] The first, heat, provides the initial ignition of fire and helps it spread. The second, fuel is any form of combustible material; combustibility is mainly defined by moisture content. Finally, the third, oxygen, is a chemical that supports the burning; most fires require roughly 16 percent oxygen content and the air contains roughly 21 percent. The conditions necessary for these elements to come together have created an increasing number of wildfires in recent years.[15] For example, increasing complexity of implementing fire suppression and fuel treatment programs have resulted in accumulations of debris, such as leaves, branches, excessive overgrowth, and dead vegetation. Additionally, drought patterns, due to climate change, have increased and continue to be exacerbated by these conditions.

Liberty CalPeco has faced challenges with winter storms and wind gusts resulting in regional and/or equipment damage. For example, in July 2017, the service territory experienced a wildfire that burned several poles within the city of Floriston, prompting generators to assist in restoring service during the subsequent 38-hour outage.[16] Other incident events have been recorded and categorized by principle cause as discussed within this Plan.

Given the elements of the fire triangle with this recent wildfire, Liberty CalPeco understands there are contributing factors to documented outage events in which ignition could be caused by utility infrastructure assets and proximity to combustion materials, such as trees and dry vegetation. Once these materials come into contact, by way of weather conditions, inadvertent contact, or by other means, the risk for wildfire becomes extremely high. For this reason, Liberty CalPeco analyzed its reliability data and determined general causes for outage incidents. The analysis focused on recent data and examined outage-related events caused by vegetation contacting bare wire and wire down occurrences. Table 3-2 shows the results of the analysis.

[13] Rulemaking 15-05-006 is the successor to R. 08-11-005 regarding new fire-safety regulations.

[14] US Forest Service Smokey Bear, "Elements of Fire", 2018, https://smokeybear.com/en/about-wildland-fire/fire-science/elements-of-fire.

[15] US Forest Service Smokey Bear, "Fire Science", 2018, https://smokeybear.com/en/about-wildland-fire/fire-science.

[16] Liberty CalPeco, "2017 System Reliability Report" Response to Commission D. 16-01-008

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Table 3-2. Liberty CalPeco Analysis of Wildfire Risk Events (2011-2018)

Risk Event [Outages]	Count	Percent of Total
Total Vegetation-Bare Line Contact	**128**	**57%**
Caused by Vegetation Proximity	76	34%
Caused by Weather or Third Party	52	23%
Total Wire Down Event	**96**	**43%**
Caused by Weather	74	33%
Caused by Vegetation	9	4%
Caused by Third Party	2	1%
Caused by Equipment Failure	11	5%

Source: Liberty CalPeco, 2018

As illustrated by the table above, bare line contact and wire down events pose the greatest risk for wildfires in the Liberty CalPeco system. These events are mainly driven by vegetation coming into contact with energized wires under a variety of conditions. This makes sense given the dense tree coverage found in the mountainous terrain. Weather also contributes to bare line contact in both the summer and winter months, with a majority recorded during winter due to snowpack from intense winter storms, and wind being the primary driver during the dry, summer conditions. From these outage reports, Liberty CalPeco understands the overall system has vulnerabilities. While in compliance with design standards, the system may require countermeasures to ensure hazardous conditions of peak elevation and wind gusts are mitigated by a hardened electrical utility network.

3.5 Fire-Threat Territory Evaluation

R. 18-10-007 requires that, if applicable, the Plan shall include an evaluation of fire-threat territory expansion if an assessment by the utility has been performed. Unlike large utilities that have electrical equipment not in presently identified high risk fire territory, all of Liberty CalPeco service area is in Tier 2 and Tier 3 HFTD. In as much a related study to assess whether HFTD areas should be expanded or modified is not necessary or appropriate. The designations for Tier 2 and Tier 3 HFTD by the Commission align with the utility's current understanding of elevated risk areas within and around the service territory. If deemed necessary by the utility or the Commission at a later date, Liberty CalPeco will conduct these evaluations to determine enhancements to these districts and include them in future Plan filings.

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4. WILDFIRE PREVENTION STRATEGY & PROGRAMS

Liberty CalPeco has developed a comprehensive Fire Prevention Plan as well as mentioned in Section 2, which significantly influenced the development of this Plan. Specifically, the Fire Prevention Plan was activated in response to Commission General Order (GO) 166, Standards for Operation, Reliability, and Safety During Emergencies and Disasters. The Plan builds off those strategies and also draws from existing efforts to meet the Commission's GO 95[17], Overhead Electric Line Construction, which specifies rules around the design, implementation, maintenance, and replacement of all overhead electric utility facilities. The SB 901 filing will provide updates on existing and planned programs while offering insight into potential mitigation investments.

Strategies and programs proposed in this Wildfire Mitigation Plan will be reviewed annually, prior to each iteration filing of the Plan, to evaluate progress and determine if items should be added or modified. Cost recovery for these mitigation items is not guaranteed. To account for this, electric utilities are authorized to implement two wildfire mitigation plan memorandum accounts (MA) in compliance with PUC Section 8386 (c)(2)(4)(j). Liberty CalPeco filed its first Advice Letter (AL) (No. 110-E) on December 21, 2018, establishing a Fire Risk Mitigation MA (FRMMA) to capture costs incurred by activities in developing the Plan otherwise not defined in the revenue requirement. Upon acceptance of this Plan, Liberty CalPeco will file a second AL to establish a second MA to track costs incurred when implementing the Plan. Liberty CalPeco will cease tracking costs in the FRMMA upon activation of the second MA, and instead, record costs associated with risk mitigation items not covered through rates.[18] The FRMMA will remain active to track additional costs associated with activities not included in the Wildfire Mitigation Plan approved by the Commission. Maintaining this accounting process will prevent issues with double-tracking.

The details of the overall strategy of the proposed Wildfire Mitigation Plan is presented in Section 4.1.

4.1 Risk Mitigation Strategy

Using a basic approach of the developing risk-based decision-making approach outlined in Section 3, Liberty CalPeco enhanced its existing wildfire mitigation practices to address the health and level of risk drivers such as aging infrastructure and equipment or contact with vegetation. The strategy includes several components addressing concerns spanning across the entire system along with enhanced operational practices. This section provides existing and planned mitigation techniques for each.

Expanding on Liberty CalPeco's existing Fire Prevention Plan, the following captures areas of utility-posed risk along with mitigation tools to reduce the chances of wildfire within the service territory. The mitigation area, tools, and rationales are identified in Table 4-1 below.

[17] Latest revision issued in May of 2018, CPUC Decision No. 18-05-042

[18] Liberty CalPeco will propose to track identified ongoing strategic items to the currently authorized FRMMA until the second WMP-related MA is established and initiated. Liberty CalPeco will reclassify appropriate costs, as necessary, to the second MA upon approval.

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Table 4-1. Risk Mitigation Items

Mitigation Area	Mitigation Tool / Program	Rationale
Operational Practices	Infrastructure Protection Teams	Ensure staff is prepared to mobilize in high-risk and emergency situations
	Emergency Preparedness and Response Protocols	Ensure protocols are up-to-date with the latest mandates and best practices
	Fire Mode, Automation, Reclosers & Fast Curve Settings	Mitigate downed wires and reduce energy at potential fault locations
	SCADA	Promotes faster response to outage notifications
Inspection Plans	Proactive Patrols	Reduce risk by conducting regular system inspections to identify at risk areas
	Equipment Inspections	Regular patrols that identify aging infrastructure or equipment that pose a fire risk
	Geographic Information System (GIS)	Leverage tool to account for equipment inventory and provide available data to the Commission and CAL FIRE when necessary
	Tree Attachment Inventory Inspection	Mitigate contact of ignition (heat) fuel sources by increasing distance between sources
System Hardening Upgrades	Fusing	Mitigate downed wires and reduce energy at potential fault locations
	Covered Conductor Program	Mitigate contact of ignition source (heat) by covering the wire.
	Pole Loading	Determine if structural integrity of the pole is within calculated threshold
	Undergrounding Distribution Lines	Significantly reduces fire risk while maintaining aesthetic quality of the surrounding environment
	Substation Facility Replacement/Enhancement	Modernize aging capital infrastructure to mitigate fire risk
Vegetation Management	Vegetation Management Program	Mitigate wildfire risk conditions by removing fuel source and patrolling lines
	Regular and Off-Cycle Inspections	Readily deploy staff/contractors when notified of leaning or fallen vegetation or when encountered on routine patrols.
Situational Awareness Protocols	Weather Stations	Improves forecasting and de-energization and restoration plans
	Weather Monitoring	Forecasts potential hazards; promotes quick response time
Public Safety Power Shut-Off Protocols (PSPS)	Public Safety Power Protocols	Mitigates wildfire risk conditions by shutting off the power and removing potential ignition (heat) source

Based on the items identified, Liberty CalPeco evaluated the impact for risk mitigation, feasibility, and cost-effectiveness of each item. The items that passed the initial screening are included in Liberty CalPeco wildfire mitigation portfolio and described in the next section. Liberty CalPeco will continue to

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monitor all items not currently planned for inclusion and continue to explore new technologies as they arise.

4.2 Operational Practices

Operational practices encompass standard company procedures that relate to wildfires, including vegetation management, turning on/off high-speed line clearing, inspection and maintenance, and Public Safety Power Shut-off Protocols (PSPS). These practices help the utility manage risk on a day-to-day basis through its operations.

4.2.1 High-Speed Clearing (Automatic Reclosers & Fast-Curve Sensitive Relay Settings)

High speed clearing refers to the ability to clear faults using automatic breakers, reclosers with fast-curve sensitive relay settings. Traditionally electrical circuits were designed to automatically open and close to detect and isolate faults. In many cases the relays would make three attempts to isolate a fault condition, each potential attempt could cause an electrical spark, which could be a source of ignition. Presently all transmission line, originating from a Liberty CalPeco substation, have a Fire Mode setting, which enables high-speed clearing with no circuit reclosing (one trip to lockout). Today, many utilities are implementing modern controls on the distribution lines that allow them to designate two settings: a normal setting and a wildfire setting (fire mode). The latter setting allows utilities to reduce the number of corrective attempts to prevent sparks. This will be coupled with SCADA technology for remote control of the equipment Liberty CalPeco categorizes this mitigation strategy under *(3) Operational Practices.* The list below details Liberty CalPeco plans with regard to these technologies.

- **SCADA Installations**: Liberty CalPeco has installed SCADA system-wide, which will allow for remote control of its system. Currently, Liberty CalPeco has SCADA installed on certain parts of its system but will expand its rollout. SCADA will control the automatic reclosers and fast-curve settings. Additionally, remote monitoring of system assets will promote faster outage response.

- **Automatic Recloser Upgrades**: Liberty CalPeco plans to upgrade existing reclosers with modern reclosers using electronic supervisory controls. This technology provides the settings necessary to reduce electrical sparks, while also helping to mitigate power outages. The rollout of this technology will begin in 2019. See Table 4-2 for a schedule of rollout.

Cost Estimates
Costs associated with replacing reclosers are approved capital expenditures within the 2019 GRC. Considering materials, labor, vouchers, and engineering needs, total recloser replacements are estimated to be roughly $735,000 with $440,000 anticipated for the first six and approximately $293,000 for the second year's efforts.

The planned recloser replacements for distribution lines are listed in Table 4-2 below.

Table 4-2. Planned Recloser Replacements

Year	Quantity	Notes
2019	6	SCADA Controls
2020	4	SCADA Controls

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4.2.2 Elevated Weather Events and Red Flag Warning Operations

Liberty CalPeco has relationships with several weather monitoring and forecast agencies to assist in planning against hazardous storm and wind conditions. The details of these efforts are presented in Section 4.6.1. Upon developing the Fire Prevention Plan resulting from D.12-01-032 pursuant to R. 08-11-005, Liberty CalPeco approached criteria for inclusion through an assessment of data from 1) Red Flag Warnings, 2) infrastructure and equipment design standards, 3) wind data, and 4) GIS mapping.

Specifically referencing Red Flag Warnings and wind data, the utility determined the Fire Weather Zone Boundaries spanned areas within the service territory (Zone 271, 272, and 273). Historical data as far as ten years back was collected for each occurrence to initiate evaluation of wind data for each identified Red Flag Warning. To track wind data, the National Weather Service (NWS) Remote Automatic Weather Stations were mapped through GIS that covered 25 miles of the service territory.

During Red Flag Warnings, wind gust data from the NWS as well as peak elevation zone reports (from Bliss State Park)[19] are monitored and discerned for when gusts last three-seconds or more. Depending on conditions, the Manager in Charge or the On-call Supervisor will direct responsive action to appropriate utility staff.[20] This operational procedure remains an ongoing practice in abating weather-related risks. Liberty CalPeco categorizes this mitigation strategy under *(3) Operational Practices*.

Cost Estimates
Activities operating under Red Flag Warnings take place during normal operations and are covered through the GRC. Therefore, no additional funding is required for implementation.

4.2.3 Wildfire Infrastructure Protection Teams

During the process of developing this Plan, Liberty CalPeco has roles for a team that addresses risk items related to wildfires and remediation actions that overlap with responsibilities of administrative, engineering and operations, energy resources, field team, and emergency response staff. Liberty CalPeco has assigned roles and responsibilities, of which align with department heads or their designees, to manage approved strategies identified to mitigate wildfire risk from utility infrastructure. Liberty CalPeco categorizes this mitigation strategy under *(3) Operational Practices*.

The procedures associated with this Wildfire Infrastructure Protection Team (WIPT) are with the leadership of the Vice President (VP) of Operations, or his designee, for day-to-day management of system-hardening and operational practices to mitigate wildfires. Regarding emergency events, decisions requiring responsive action must be prompt to ensure systems are operating safely and reliably. Liberty CalPeco has a comprehensive plan in place with detailed protocols that address this. Section 5 details these roles and responsibilities identified in Liberty CalPeco's Emergency Management Plan.

Cost Estimates
Activities related to the WIPT will take place during normal operations and are covered through the GRC. Therefore, no additional funding is required for implementation.

[19] Western Regional Climate Center. 2018. "DL Bliss State Park California." https://wrcc.dri.edu/cgi-bin/rawMAIN.pl?caCDLB.

[20] Liberty CalPeco. Pursuant to Commission D. 12-01-032. "Fire Prevention Plan for Overhead Electric Facilities."

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4.3 Inspection and Maintenance

Inspection plays an important role in wildfire prevention. Liberty CalPeco currently patrols its system regularly and plans to increase the frequency of inspections. As described in Section 4.1, inspection procedures play a significant role within the Vegetation Management Plan. Liberty CalPeco categorizes this mitigation strategy under *(2) Inspection and Maintenance.* The list below outlines current and future considerations that increase the efficacy of inspection protocols:

- **On-Ground Inspection:** Manual inspections include both system and vegetation patrols. Currently, Liberty CalPeco has a detailed system patrol process complying with GO 165 requirements, which includes annual patrols for most system infrastructure. Tier 3 area circuits, given their high-fire risk status, are patrolled more frequently, on a bi-annual basis. As for vegetation inspections, Liberty CalPeco monitors vegetation during its system patrols and also directs a contractor to conduct additional inspections and vegetation management.

- **Equipment Inspection:** Recognizing the hazards of equipment that operate high voltage lines, Liberty maintains a formal inspection and maintenance program for distribution, transmission and substation equipment. Transmission and distribution equipment are patrolled every one to two years with a detailed inspection performed every three years. Substations are inspected quarterly with substation relays being maintained every 3 to 6 years, depending on the type of relays as well as staffing availability.

- **Vegetation Inspection and Maintenance:** When conducting routine maintenance that involves preventative inspection, Liberty CalPeco responds to high-risk fuel sources with efforts to remove identified vegetation, as needed. This maintenance work occurs once every three years per circuit. Pursuant to GO 95, Rule 35 and Public Resources Code (PRC) 4293 Clearance Exempt trees, Liberty CalPeco will maintain a record of exempt trees with recommendations or corrective actions. Liberty CalPeco also performs inspections of vegetation concerns when either service calls are made or utility employees or vegetation management contractors identify at-risk vegetation while performing day-to-day operations.

- **GIS Data Requests:** Liberty CalPeco currently tracks and maps specific items of its electrical infrastructure as needed. Current practices do not include the sharing of GIS information outside of vendor relationships or regulatory requests. In understanding the importance of collaborating with key agencies, such as the Commission and CAL FIRE, and Liberty CalPeco plans to provide its data in accordance with Commission proceeding I. 17-06-027, Pole OII Phase I, which relates to sharing pole databases. The efforts to track poles are described in detail in Section 4.4.2. Additionally, the utility will provide information to stakeholder agencies on a case-by-case basis with responsibility of the GIS Manager or their designee. Costs for this effort are associated with normal operations and administrative hours.

Future considerations are being evaluated to enhance inspection procedures. Liberty CalPeco will engage vendors and request quotes related to the following technologies over the next year:

- **LIDAR Ground Inspections:** Currently, Liberty CalPeco is evaluating the effectiveness of LIDAR inspections. These inspections involve using vehicles that perform imagery and mapping technology to view vegetation growth proximity to the electrical equipment. Liberty CalPeco is currently assessing the effectiveness of this type of inspection. Pending feasibility and approval, Liberty CalPeco will create a deployment plan for year 2020.

- **Infrared Inspections:** Liberty CalPeco plans to evaluate the effectiveness of an Infrared Inspection Program. At the present time, Liberty CalPeco has requested price quotes to perform an evaluation. An infrared inspection uses a device that determines the relative temperature of

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equipment on the electrical system. The infrared inspection can detect, using temperature reading, equipment that may fail in service.

Cost Estimates
Activities related inspection activities will be covered will take place during normal operations and are covered through the GRC. Therefore, no additional funding is required for implementation.

4.4 System Hardening Plans

System hardening relate directly to system infrastructure or design enhancements or modifications. Traditionally, Liberty CalPeco designed its system to provide reliable and safe power to customers; its system design aligns closely with other California utilities. For example, most utilities in California have bare wires, given the focus on reliability. However, considering intensified wildfire conditions, the utility has considered enhancing its system designs and upgrades to include evaluating wildfire risk in system hardening efforts while remaining in compliance with construction mandates. The sections below detail the steps taken to improve hardening, based on the risk-mitigation evaluation.

4.4.1 Covered Conductor

Covered conductors are any conductors (wires) protected by layers of insulation, so the conductors are protected when energized. Vendors have designed these wires, so they can withstand contact with vegetation and/or other debris. Bare wires have traditionally been used throughout California because they provide a reliable and cost-effective solution to delivering energy to customers. However, Liberty CalPeco has recently reevaluated its system design in the context of wildfire risk and decided to, where appropriate (i.e. based on wildfire risk), replace bare conductors with covered conductors. This timeline is determined on a five-year scale, though may be adjusted with each iteration of the Plan.

Reconductoring Prioritization Plan
Reconductoring of bare electrical lines will be performed in various locations in Liberty CalPeco's Tier 2 and Tier 3 HFTD. Several factors drive the ability to begin reconductoring. These factors include: (1) Receipt of the construction permit by regulatory authorizes, (2) availability of material, (3) resources to perform the work, and (4) line clearance (maintaining reliability). Liberty CalPeco envisions to begin reconductoring in 2019 as the first two projects were prioritized based on the ability to receive the construction permit within the same year.

Tahoe City Line 7300
This project comprises reconductoring of Tahoe City Line 7300 to enhance electric service reliability and improve the safety and operational integrity of the electric grid. The project includes reconductoring segments of the 15,000 feet of overhead lines out of the Tahoe City Substation as described in the pending 2019 General Rate Case (GRC) application.[21] The prioritization for reconductoring the line was primarily driven by the need to replace failing equipment and proactively installing grid hardening assets.

Topaz Line 1261
This project is the reconductoring of Topaz Line 1261 to enhance electric service reliability and improve the safety and operational integrity of the electric grid. The project includes reconductoring segments

[21] Liberty CalPeco. "A1812001 2019 General Rate Case Application," December 3, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M245/K570/245570209.PDF.

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7,500 feet of overhead lines out of the Topaz Substation.[22] The project also involves pole replacement based on loading standards (GO 95) for "Heavy" and "Grade A" loading along the 7,500 feet of overhead conductors. New poles along with covered conductors will replace aging equipment over the span of the line. This circuit supports rural customers and is noted in consecutive reliability reports (2016, 2017) as the worst performing circuit within Liberty CalPeco's service territory.[23] This area frequently experiences hazardous weather conditions such as high winds and below freezing temperatures. This paired with the deterioration of the infrastructure has resulted in higher risk of improper wire sag along with conductors breaking under ice and snow strain.

These projects are presently in the "permitting stage" with construction expected to in late 2019. They were originally designed to use bare conductor replacements but based on the wildfire risk assessment, the projects will be re-designed to use covered conductors. Incorporating this element supports the Plan's goal of mitigating potential wildfire risk with the installation of covered conductors.

Cost Estimates

Liberty CalPeco approximates the typical overhead construction costs to be $438,000 per mile. After determining additional costs via covered wire, the estimate increases around 40 percent yielding $614,000 per mile not including pole replacements. Liberty CalPeco propose to reconductor 1-2 miles per year which will include pole replacement where necessary based on GO 95 for Heavy Loading and Class A construction. These projects are referenced in the GRC application pending Commission approval.[24] Liberty CalPeco will track additional costs of covered wire materials to the FRMMA (until the second MA is approved), as these efforts enhance fire protection strategy.

Future considerations are under constant review as inspections help direct the need to replace and enhance overhead conductors and electrical facilities. Liberty CalPeco has compiled an initial priority list of distribution circuits that would mitigate wildfires using covered conductors. Based on the risk, some circuits will have the entire circuit reconductored and other circuits will have portions of circuits reconductored. Liberty CalPeco categorizes this mitigation strategy under *(1) Design and Construction*.

The lists below provide the prioritization for planned enhancements and distribution lines to be evaluated.

1. Tahoe City 7300 – (approximate total circuit length: 58 miles).
2. Topaz 1261 – (approximate total circuit length: 54 miles).
3. Meyers 3400 – This circuit originates in Tier 3 HFTD; (approximate total circuit length 15 miles).
4. Stateline – Meyers 640 – (approximate total circuit length: 8 miles).
5. Meyers 3300 – This circuit originates in Tier 3 HFTD; (approximate total circuit length 53 miles).
6. Squaw Valley 7201 – (approximate total circuit length: 12 miles).
7. Brockway 5100 – (approximate total circuit length: 2 miles).
8. Tahoe City 7200 – (approximate total circuit length: 5 miles).
9. Truckee – Squaw Valley 609 Truckee 7202 (underbuilt) – (approximate total circuit length 10 miles).

[22] Liberty CalPeco. "A1812001 2019 General Rate Case Application," December 3, 2018. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M245/K570/245570209.PDF.

[23] Ibid.

[24] Ibid.

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Table 4-3 below shows the circuits, by year, which reconductoring will begin and the estimated amount of reconducting (covered conductors) that will be completed each year. Base on available resources, material, weather conditions and line clearances, the amount of covered conductor installed each year will vary.

Table 4-3. Planned Circuit Reconductoring Start Date

Year	Circuit Number(s)	Miles
2019	Tahoe City 7300	1-2
	Topaz 1261	1-2
2020	Meyers 3400	1-2
	Stateline to Meyers 640	1-2
2021	Meyers 3300	1-2
2022	Squaw Valley 7201	1-2
2023	Tahoe City 7300	1-2

4.4.2 Pole Loading and Replacement

Pole loading assessments are performed in compliance with the requirement of GO 95 rule 44. In that requirement, the utility must make available, if requested, all pole loading testing data to regulators in support of managing statewide electrical infrastructure standards. Liberty CalPeco understands that failing poles pose both a safety, reliability, and fire risk and seek to enhance current conditions through this assessment. To conduct these calculations, Liberty CalPeco utilizes industry-standard software. The assessment is performed after accounting for pole locations, physical inspections, equipment installed, and proposed additional equipment.

Pole Replacement Program

As part of the efforts outline in Section 4.4.1, Liberty CalPeco will be reconductoring segments of its circuits starting 2019. In adopting the plan to replace bare wires with covered conductors, Liberty CalPeco will perform a pole loading calculations as well as pole health evaluation to determine the strength and weight baring ability to support the covered wire. If the calculation results in any pole failing the assessment, a pole replacement will take place for those at risk. This practice will continue throughout the covered conductor replacement program. At the present time, Liberty CalPeco does not have an estimate of number of poles that will require replacement but expects the majority of poles will require replacement. Liberty CalPeco categorizes this mitigation strategy under *(1) Design and Construction*.

Cost Estimates

To conduct these pole loading calculations, Liberty CalPeco requires annual software licenses as well as operational costs for pole testing. Annually, approximately $16,765 is spent on software costs with each pole requiring generally two hours of evaluation, at an hourly figure of around $50. This is an operations and general revenue expense and is to be recovered through the GRC.

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Additional expenses will be required if pole loading tests fail when preparing for the install of covered conductors. Liberty CalPeco anticipates each pole replacement to cost approximately $12,000 to $15,000.

4.4.3 Fusing

Fuses (Fusing) refer to protective devices that protect the distribution system from faulted or damaged lines and equipment. Historically, Liberty CalPeco, other utilities in California, and utilities across the country have used conventional fuses to protection “lines”. These conventional fuses, when operated, expel hot particles and gases, which can start fires. In contrast, current limiting fuses, that traditionally were used for protecting “equipment” expel no materials, limits the available fault current, and in many cases can reduce the duration of faults. The use of both conventional and current limiting fuses provides for a high level of reliability. In order to mitigate fires, Liberty CalPeco proposes to replace conventional fuses with current limiting fuses on much of its system. Single phase, two phase and three phase lateral lines that are protected with conventional fuses will be replaced with current limiting fuse. In additional, pole mounted transformers that have conventional fuses will be replaced with current limiting fuses. There are specific locations and types of equipment, that based on operating requirements, where conventional fuses must still be used. Liberty CalPeco plans the fuse replacement rollout over-time principally focused on higher risk wildfire prone circuits. Liberty CalPeco categorizes this mitigation strategy under *(1) Design and Construction*.

Liberty CalPeco will implement this plan as an ongoing effort, set to complete all investment upgrades within the span of 10 years. All costs will be tracked in the proposed FRMMA.

Table 4-4 shows the number of fuses that will be replaced:

Table 4-4. Planned Fuse Replacements

Fuse Replacements	Quantity
Total Number of Fuse	13,466
Number of Fuse Locations	6,741
Location Replaced Per Month	60
Years to Replace	9
Annual Cost of Fuse Changeouts ($)	721,550

4.4.4 Substation Design Hardening

Liberty CalPeco has made recent applications to modernize or rebuild system components after assessing their assets on the basis of reliability, safety, and age of the system equipment.[25] Liberty CalPeco has identified two substations that pose a potential wildfire risk and will be addressed with the

[25] CPUC. 2018. “Liberty CalPeco General Rate Case Application.” & CPUC. 2015. “Liberty CalPeco General Rate Case Application.”

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approval of the Plan. Liberty CalPeco categorizes this mitigation strategy under *(1) Design and Construction*.

Brockway Substation

The existing Brockway Substation is a 60-year old facility constructed using wooden poles and wooden cross-arms (Wood Box Construction). (See Figure 4-1). The 60kv and 14.4kv high voltage lines are attached using insulators to the extremely dried out wooden poles and wooden cross-arm. The substation has obsolete Oil Circuit Breakers (OCB), which operate (close/open) to de-energize circuits when a fault occurs (e.g. equipment failure, contact with vegetation, etc.). An industry recognized “failure mode” of OCB is the ignition of the large quantity of oil located in the circuit breaker that can result in an uncontrolled fire. The flaming oil can very quickly result in quick fire spread, posing a potential wildfire situation. Modern substation circuit breakers use “vacuum” or “gas” instead of “oil” to interrupt the power flow or fault current. The OCB, being 60-years old, can operate much slower then modern vacuum or gas circuit breakers. During an event (wire down, failed equipment, etc.), the faster power is shut down, reducing the risk of vegetation ignition.

Figure 4-1. Brockway Substation



The substation is surrounded by large very heavy tree growth on three of the four sides of the substation perimeter as illustrated in Figure 4-2. The proximity of the substation equipment to vegetation causes an additional concern that the substation could cause a wildfire.

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The substation was recently examined by Todd Conradson, Division Chief Fire Marshal for the North Tahoe Fire Department. The substation examination was requested by Liberty CalPeco due to the heighten fire risk the substation could create.

After inspecting the facility, the Division Chief Fire Marshal stated in his letter; “The facility has a history of fire and we fear that if left unaddressed, additional fires will occur.” In order to mitigate the fire risk, the Division Chief Fire Marshal, based on his expert knowledge, recommended changes to the substation. These recommended changes include:

- Replacement of the wooded structure supporting the high voltage equipment;
- Relocation of the substation out of the residential neighborhood.

Appendix B is a copy of the letter received from the Lake Tahoe Fire Department. The suggestions and recommendation made by the Lake Tahoe Fire Department will be accomplished with Liberty CalPeco proposed substation investments.

Figure 4-2. Brockway Substation Surrounding Area



As part of the Plan, Liberty CalPeco proposes to replace the obsolete substation equipment with modern equipment and relocate the substation to a location that increases the distance of electrical equipment to vegetation. In place of the wooden structure, a steel structure will be used as it has no fire risk. The obsolete OCBs will be replaced with high-speed vacuum breakers. The vacuum breakers have no oil that can catch fire. To mitigate wildfires, prudency would dictate relocating the substation further away from

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heavy tree conditions. Liberty CalPeco has an alternate site for the substation away from heavy tree conditions. The utility proposes the use of an existing owned land parcel at Kings Beach.

Although these substations meet design standards referenced under GO 174, Rules for Electric Utility Substations, modernizing the substation and relocating to a reduced fire-risk parcel will significantly reduce the risk of fire in this relatively densely populated area while improving the safety, reliability, and efficiency of electrical service.

Stateline Substation

Similar to the Brockway substation, a portion of the existing Stateline Substation has a 60-year old Wooden Box Construction design along with obsolete OCBs, as well (See Figure 4-3). The wooden poles, wooden cross-arms and OCBs in the substation have the same concerns as identified above in the Brockway description.

Figure 4-3. Stateline Substation



As part of the Plan, Liberty CalPeco also proposes to replace the replace the obsolete old wood box construction with a modern design. In place of the wooden structure, a steel structure will be used as it poses no fire risk. The obsolete OCB will be replaced with high-speed vacuum breakers. The existing transformer will be replaced with a new unit.

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This modern design will significantly reduce the risk of fire in this relatively densely populated area while improving the safety, reliability, and efficiency of electrical service.

Cost Estimates and Expense Actions:
Liberty CalPeco recently requested permission to replace the Brockway Substation under Advice Letter (AL) 64-E-A.[26] The request was primarily based on the increase load growth in the area. Resolution E-4929 denied the request indication the increase in load did not justify the substation cost.[27] Liberty CalPeco has not previously requested permission to replace the identified portion of the Stateline Substation.

The cost of the substation upgrades for wildfire mitigation planning is not addressed in Liberty CalPeco's 2019 GRC application, which is pending decision. Liberty CalPeco estimates the cost of replacing the Brockway Substation to be $13 million and to upgrade the Stateline Substation to be $3.5 million. Therefore, Liberty CalPeco requests by approval of this Wildfire Mitigation Plan, and that the Commission authorize Liberty CalPeco to establish a second MA to track and recover the expenses related to the substation replacement and upgrade project not included in approved capital investment projects.

4.4.5 Undergrounding

Liberty CalPeco has existing and planned underground wire infrastructure driven by Tariff Rule 20 (Rule 20)[28] . Three levels of project classification exist under Rule 20[29]. Of which, Rule 20A projects are based upon the criteria of public interest and scenic value. Projects funded by Rule 20A are recovered through electric retail rates.

Liberty CalPeco is currently working on two underground projects within the Lake Tahoe Basin that are associated with the Rule 20A Underground Overhead Lines Tariff. The first, In El Dorado County, undergrounds approximately 3,000 feet of overhead conductor at an estimated cost of $1,426,480. The second project is within Placer County and undergrounds approximately 1,760 feet of overhead conductor at an estimated cost of $5,963,740. Although these two underground projects are funded by Rule 20A Tariff, the work will mitigate wildfire events, thus helping meet the objectives of this Plan. Liberty CalPeco categorizes this mitigation strategy under *(1) Design and Construction*.

4.4.6 Tree Attachment Removal

Tree attachments are pieces of electrical infrastructure fastened to trees for infrastructural support. Since there is no approved standard for the attachments, the tree attachments introduce risk. Liberty CalPeco makes a consistent ongoing effort to eliminate these attachments to the trees. These pole attachment risks exist throughout the utility's distribution system.

Several challenges exist to expedite the elimination of tree attachments. The tree attachments took place over the many years with limited documentation on where these tree attachments have taken place.

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[26] Liberty CalPeco. February 23, 2018. "Advice Letter 64-E-A (U 933-E)." https://california.libertyutilities.com/uploads/LU%20AL%2064-E-A.pdf.

[27] Commission. August 23, 2018. "Resolution E-4929." http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M223/K876/223876696.PDF.

[28] Rule 20 was established on September 19, 1967 under D. 73078 where electric utilities were directed to report annually on amounts for undergrounding allocation.

[29] CPUC. "Undergrounding," http://www.cpuc.ca.gov/General.aspx?id=4403.

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Many of these tree attachments are on private property which requires the coordination with the residence.

To determine the location of the tree attachment, Liberty leverages vegetation inspections, pole assessment inspection programs, and other capital improvement programs to locate these tree attachments. Once the tree attachment is located, Liberty CalPeco accurately maps each tree attachment location. Once the location is documented, Liberty CalPeco actively works with getting the necessary authorization from the residence or if necessary from local agencies to eliminate the tree attachment. In many cases the elimination of tree attachments requires the authorization to install one or more addition poles. While tree attachment removals are not specifically mandated, the elimination will further reduce wildfire risk in Liberty CalPeco's unique service territory. Liberty CalPeco categorizes this mitigation strategy under *(1) Design and Construction.*

Plan Execution
Liberty CalPeco commits to removing approximately 60 service tree attachments per year between North and South Lake Tahoe. Table 4-5 below outlines an approximate account of existing tree attachments in relation to the substations in this selected region.

Table 4-5. Service Tree Attachments Approximation

Substation	Number of Tree Attachments
Brockway	1041
Squaw Valley	289
Tahoe City	1950
Stateline	1071
Meyers	1914

Cost Estimates
Current estimates reflect approximately $7,000 per pole/tree for attachment removal to be captured and tracked through the FRMMA until the second WMP-related MA is established and authorized.

4.5 Vegetation Management Plan

Liberty CalPeco has a vegetation management plan in place, which is implemented by utility staff in conjunction with third-party contractors. Recently, Liberty CalPeco increased planned expenditures for the vegetation management plan from $2.5 million to approximately $4 million annually.[30]. This particularly will aid in the frequency of inspection as well as add value to existing clearing practices as tree mortality continues to rise in the area due to climate change.

The utility created the Vegetation Management Plan with wildfire prevention, improving system reliability, and scenic value in mind as well as meeting the requirements set forth in GO 95. The plan will be reviewed and updated the sooner of three-years, or as-needed due to changes in regulation or conditions. The plan includes four main components: routine vegetation maintenance, off-cycle tree work, quality control, and resource protection. Liberty CalPeco categorizes this mitigation strategy under *(2) Inspection & Maintenance*.

[30] Liberty CalPeco, "2019 GRC Application."

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4.5.1 Plan Components

- **Routine Vegetation Maintenance:** This scope of work involves preventative inspection, and typical operations to trim and remove excess foliage that may come in contact with electrical assets along with meeting requirements on clearances. Liberty CalPeco mobilizes utility foresters, contracted or employed arborists, and tree-trimming contractors to meet these objectives.
- **Off-Cycle Tree Work:** This scope of work encompasses maintenance efforts beyond routine inspection practices outlined in rules established by GO 165. In these instances, the Vegetation Management Department has been made aware by line staff or notifications from external sources (referred to as Tree Tags) such as neighboring or local agencies, triggering remediation of the identified tree or vegetation source.
- **Quality Control:** This scope of work ensures the implementation and metric reporting of the Vegetation Management Plan through performed control audits of the contractor's work. Under this scope, a minimum of 15 percent random audits will be carried out throughout the year.
- **Resource Protection:** This scope of work determines the management of natural resources with objectives to protect the environment, support principles of ecological sustainable development, eradicate non-native species, control hazardous materials, and clear brush and fuel sources to bolster surrounding ecosystems.

Liberty CalPeco requires its contractor or utility employee to document and submit for review all work completed. Additionally, the clearance specifications must comply with the Commission's GO 95 Rule 35 Vegetation Management and Appendix E Guidelines to Rule 35 (trimming guidelines). For Liberty CalPeco in particular these specifications permit that the minimal allowable radial clearance of bare line conduction from vegetation within a high fire-threat district is 48 inches. Any vegetation under these conditions within the 48-inch clearance must be trimmed to at least 12-feet all year long pursuant to D. 17-12-024, which resulted in a revision to GO 95.[31] However, the contractor or Liberty CalPeco may determine that additional clearance may be prudent based on growth factors or weather conditions, in which case the trimming may be greater than 12-feet. In terms of other specifications, Liberty CalPeco will consider the removal of any fast-growing trees, rotten or diseased trees, and healthy trees hanging over or leaning towards the power lines.

To ensure quality, Liberty CalPeco will conduct frequent checks of the contractor's work through detailed, routine inspections and patrols of its overhead circuits. Any discrepancies discovered will be categorized by priority level (e.g. emergency, urgent, or routine) and subsequently corrected by the contractor. Liberty CalPeco meets with contractors and staff regularly to provide the status of work completed and upcoming work, such as tree removals, special support requests, corrective and emergent vegetation order status, and other items pertinent to progress of the work.

Liberty CalPeco recently submitted in its 2019 GRC application program enhancements to the vegetation management program resulting in the increase of annual expenditure, mentioned above. Recommendations currently proposed include an optimized vegetation maintenance cycle with determined schedules based on fire risk, vegetation regrowth information, and reliability data. In

[31] General Order 95 includes (a) a High Fire-Threat District, (b) maps of the High Fire-Threat District, and (c) new fire-safety regulations.

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consultation with Western Environmental Consultants, Inc., four key system attributes were considered in determining these enhancements:[32]

1. Historically low tree-caused outages
2. Potential tree density reduction within the ROW
3. Potential fire risk from regrowth or hazardous trees
4. Potential for significant bark beetle eradication increasing fire risk from fallen trees

Continuing enhancements to the Vegetation Management Plan will be crucial as fire seasons become prolonged and intensified due to changing climate conditions paired with excess fuel sources. Some of the enhancements Liberty CalPeco is evaluating surround wildfire mitigation. For example, in addition to replacing fuses, changing hardware on subject poles in high threat fire districts may exempt these fixtures from various requirements. The remaining pole clearing work would be emphasized in these HFTD areas. Increasing the frequency of vegetation inspections and tree work cycles is also being considered.

4.5.2 Identifying At-Risk Vegetation

Invasive species removal, hazardous tree removal, and other at-risk fuel sources are identified through operations outlined in Vegetation Management Plan components. To the extent Liberty CalPeco is able to identify through contracted arborists or field work personnel, efforts are ongoing that address and/or eradicate flora that pose heightened risk to vegetation management success. Liberty CalPeco identifies hazardous trees for removal using determinations made by GO 95 Rule 35[33] and PRC 4293.[34]

In 2018, Liberty CalPeco implemented procedures to address the increase of tree deaths due to bark beetle infestations as a result of increased drought conditions. In 2019, the utility will submit an application to activate their first Tree Mortality Catastrophic Event MA (CEMA) to recover tracked costs incurred over the last year and anticipates the tree removal program continuing for several years. Liberty CalPeco's service territory contains two of the ten highest priority counties identified by California's Tree Mortality Task Force (El Dorado and Placer Counties).

Since 2015, these concerns have grown with the exponential increase of tree mortality rates. Liberty CalPeco has determined that efforts to curb this issue is no longer manageable with current staffing levels. In response, costs have been identified that exceed current budgets by $1 million annually. Upon authorization, these additional costs will be tracked and recovered through the Tree Mortality CEMA.

Environmental Risk Mitigation

[32] Liberty CalPeco, "2019 General Rate Case: Chapter 4: Vegetation Management Program." November 30, 2018, pg. 3.

[33] General Order 95 Rule 35 states:" When a supply or communication company has actual knowledge, obtained either through normal operating practices or notification to the company, that dead, rotten or diseased trees or dead, rotten or diseased portions of otherwise healthy trees overhang or lean toward and may fall into a span of supply or communication lines, said trees or portions thereof should be removed."

[34] Public Resources Code 4293 states: "Dead trees, old decadent or rotten trees, trees weakened by decay or disease and trees or portions thereof that are leaning toward the line which may contact the line from the side or may fall on the line shall be felled, cut, or trimmed so as to remove such hazard."

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Liberty CalPeco ensures efforts to mitigate wildfire risk are not impacting its surrounding environment based upon best practices in tree, brush, and undergrowth removal. Along with meeting state regulations as well as the guidelines determined by the California Environmental Quality Act (CEQA) and National Environmental Policy Act (NEPA), Liberty CalPeco does not engage in activities where significant lots of trees are removed, leading to issues such as erosion. The utility understands it's prudent to protect endangered or sensitive species, wherever necessary, and collaborates with local agencies to identify environmental risks that may pose a threat to the surrounding ecosystems. Principally, Liberty CalPeco considers forest health as the greatest concern when implementing its vegetation management plan.

Vegetation management activities also comply with the United States Migratory Bird Treaty Act of 1918 and the Endangered Species Act. Employees and vegetation management contractors are required to report conditions observed in the field prior to executing vegetation maintenance practices. In addition, reports of this nature will include the following:

- Evidence of nests greater than 12 inches diameter occurring on power company equipment (poles, cross arms, transformers)
- Evidence of nests occurring on or in trees requiring removal for compliance with PRC 4293 or GO 95, Rule 35
- Evidence of any and all dead or injured birds and their location if found in the vicinity of the facilities

4.6 Protocols on Situational Awareness and Determination of Local Conditions

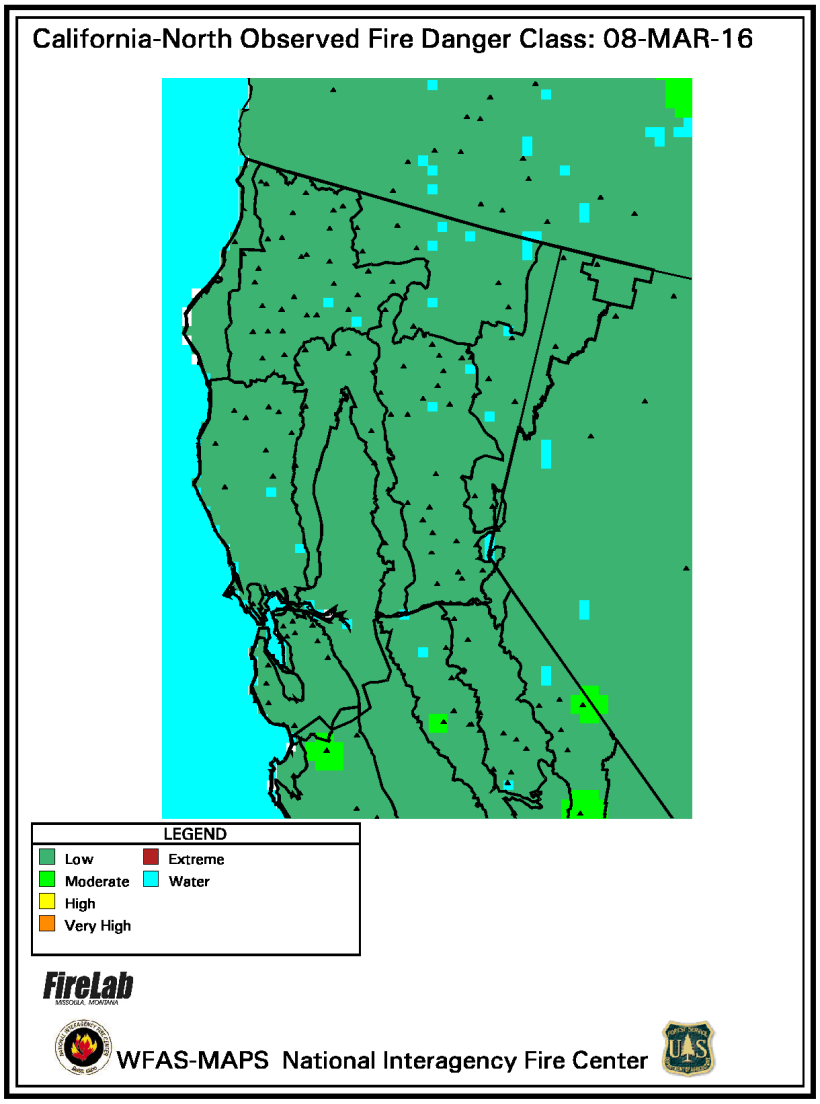
Liberty CalPeco monitors the USDA NFDRS regularly in conjunction with weather conditions along with other sets of information, such as wind speed in and around the service territory or dry lightning, which often is an ignition source for wildfires. This section of the Plan describes the meteorological services utilized to maintain situational awareness within the service territory.

4.6.1 Weather Monitoring

Figure 4-4 provides an example of real-time NFDRS rating system information monitored. This section details how Liberty CalPeco monitors conditions and how it will enhance this monitoring. Liberty CalPeco categorizes this mitigation strategy under *(4) Situational/Conditional Awareness*.

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Figure 4-4. NFDRS California North Observed Fire Danger Class Example



Source: USFS Adjective Class Rating, 2016

The USFS maintains an “adjective class rating” of fire danger along with a color code system. For any condition other than “Low” the preparedness team will assemble. The vegetation management department monitors forecasts related to the likelihood that customers and utility assets could be impacted by wildfires. As conditions achieve the higher tiered levels, additional notifications, staging, and operating procedures are effectuated with each step.

Likewise, Liberty CalPeco maintains close contact with local weather station personnel and broadcast media. As conditions raise to Extreme, all personnel are on the highest level of alert. Operating personnel are mustered to serve communication notices under high-threat conditions. With experts collaborating and closely monitoring the operations of the electrical grid, Liberty CalPeco increases situational awareness allowing for coordinated planning, response, and communications. Vigilance and timely responses assure public safety and reduce risk events that could impact electrical facilities, customers, utility staff, and the environment.The adjective class rating provided by the USFS Wildland Fire Assessment System is located in Table 4-6 below.

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Table 4-6. USFS Adjective Class Rating

Fire Danger Rating / Color Code	Description
Low (L) (Dark Green)	Fuels do not ignite readily from small firebrands although a more intense heat source, such as lightning, may start fires in duff or punky wood. Fires in open cured grasslands may burn freely a few hours after rain, but woods fires spread slowly by creeping or smoldering, and burn in irregular fingers. There is little danger of spotting.
Moderate (M) (Light Green or Blue)	Fires can start from most accidental causes, but with the exception of lightning fires in some areas, the number of starts is generally low. Fires in open cured grasslands will burn briskly and spread rapidly on windy days. Timber fires spread slowly to moderately fast. The average fire is of moderate intensity, although heavy concentrations of fuel, especially draped fuel, may burn hot. Short-distance spotting may occur but is not persistent. Fires are not likely to become serious and control is relatively easy.
High (H) (Yellow)	All fine dead fuels ignite readily, and fires start easily from most causes. Unattended brush and campfires are likely to escape. Fires spread rapidly and short-distance spotting is common. High-intensity burning may develop on slopes or in concentrations of fine fuels. Fires may become serious and their control difficult unless they are attacked successfully while small.
Very High (VH) (Orange)	Fires start easily from all causes and, immediately after ignition, spread rapidly and increase quickly in intensity. Spot fires are a constant danger. Fires burning in light fuels may quickly develop high intensity characteristics such as long-distance spotting and fire whirlwinds when they burn into heavier fuels.
Extreme (E) (Red)	Fires start quickly, spread furiously, and burn intensely. All fires are potentially serious. Development into high intensity burning will usually be faster and occur from smaller fires than in the very high fire danger class. Direct attack is rarely possible and may be dangerous except immediately after ignition. Fires that develop headway in heavy slash or in conifer stands may be unmanageable while the extreme burning condition lasts. Under these conditions the only effective and safe control action is on the flanks until the weather changes or the fuel supply lessens.

Liberty CalPeco monitors weather, vegetation, and other conditions and takes additional monitoring and communication activies when conditions are conducive to causing wildfires. The adjective class rating tabled above is one of multiple sources of information. During the higher levels of potential wildfire threat, Liberty CalPeco prioritizes efforts to staff additional personnel and take enhanced monitoring actions to increase situational awareness and be prepared to take additional preventative and mitigating actions.

4.6.2 Weather Station Install Project

Since weather stations have been identified as a risk-mitigation strategy, Liberty CalPeco plans to install 13 weather stations starting 2019, with 10 already purchased. The locations were determined while working with the NWS, in which areas were prioritized based existing weather station locations and associated data currently available. The locations identified considered several factors. First, Liberty CalPeco looked at existing weather stations that are publicly available through the Mesowest Network.

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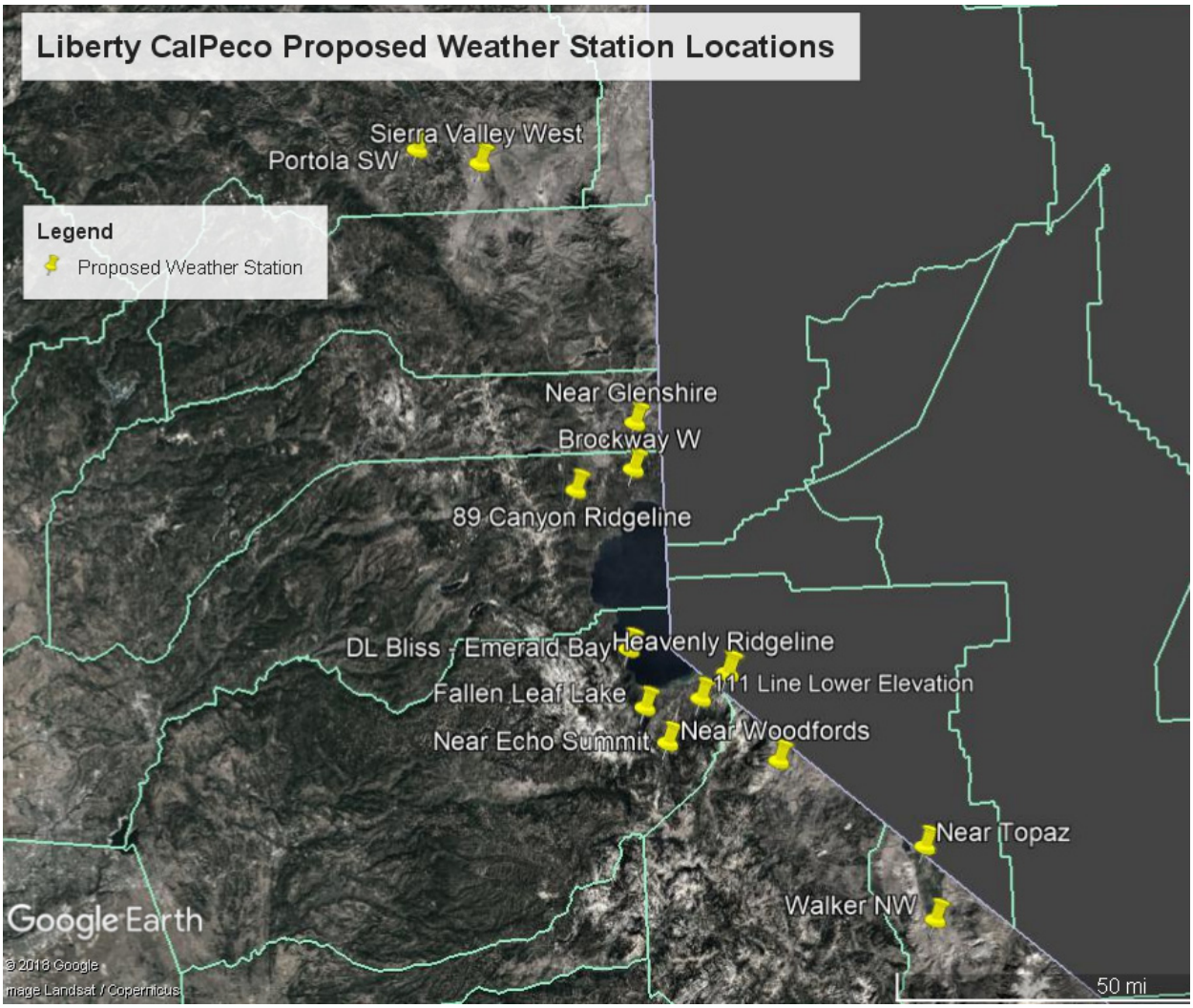
Next, gaps were identified within the service territory where a weather station would be beneficial. Finally, potential wildfire impact and prevailing weather trends finalized the determinations.

The vendor consulted was Western Weather, similarly used by the larger IOUs. This will assist Liberty CalPeco in addressing weather monitoring gaps within its service territory. Sensors embedded in the station's operational control will communicate with Liberty CalPeco through wireless information delivery to assist in data gathering to monitor conditions that may lead to an emergency response. Liberty CalPeco categorizes this mitigation strategy under *(4) Situational/Conditional Awareness*.

Cost Estimates

Install of the 13 weather stations is planned for the next two years. The costs for all 13 approximate $148,720 with 10 already been approved. The costs will be tracked through the FRMMA until authorization of the second MA. Figure 4-5 illustrates the proposed site options. Liberty CalPeco will evaluate the effectiveness and benefits of the weather stations and will determine for the next planned filing with the Commission if additional weather stations should be installed.

Figure 4-5. Proposed Weather Station Locations



4.7 Public Safety Power Shut-off Protocols

PSPS refers to the proactive de-energization of the grid in high-fire danger conditions. This is a preventative measure to help keep customers, employees, and the public safe. As explained in Section 3, a combination of ignition sources, high wind, low humidity, and available dry fuel from nearby materials, such as vegetation, can raise the likelihood of a wildfire. Liberty CalPeco proposed that through the PSPS that electrical infrastructure does not become a source of ignition when conditions are conducive to wildfires. While Liberty CalPeco will attempt to control the management of fuel sources through its vegetation management program, it will lower the likelihood that its electric system could become a source of ignition by implementing PSPS in certain high-risk fire danger conditions, as described in this section.

Liberty CalPeco faces substantial wildfire risk due to its climatic, weather, and topographical conditions, as described in Section 3, and therefore, monitors information such as the USFS NFDRS and wind speeds regularly. These two components help to indicate when the service territory is under extreme fire danger conditions. If the NFDRS is "red" or "orange," signaling high fire danger, Liberty CalPeco will begin taking precautionary actions, including intensive monitoring of forecasted wind speeds, local and surrounding weather monitoring, and local forecasts. Liberty CalPeco will act accordingly, based on information gained from these and other sources. Liberty CalPeco's wildfire mitigation procedures include two aspects: field operations and communications. The first includes the planned actions of service crews and other Liberty CalPeco staff. The second course of action is related to communication including stakeholders, media, and government agencies. Liberty CalPeco maintains detailed handbooks related to these activities and monitors practices of other California utilities. Liberty CalPeco categorizes this mitigation strategy under *(5) Response and Recovery*. Table 4-7 below outlines these procedures.

Table 4-7. PSPS Procedures

Fire Conditions	Planned Actions	Planned Notifications
Forecasted Extreme Fire Weather Conditions	• Monitor existing wind speed in "at risk" locations • Determine if conditions warrant specific actions • Communicate with Customer Service to ensure accurate communications with stakeholders	• Notify local government and agencies35 • Post notification of potential power outages on website and social media as well as live outage map36 • Issue press release to local media
Imminent Extreme Fire Weather Conditions (Wind Speeds measured at 50 mph for > 3 seconds)	• Dispatch crews to monitor field conditions for dangerous conditions throughout service area and "at risk" locations • When conditions are appropriate, De-energize power lines that may pose a hazard	• Continue to coordinate with local government and agencies • Update notifications on website and social media to warn of potential for power shutoff • Issue updated press release to local media

[35] For example, http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K569/151569654.PDF communication requirements for large IOUs.

[36] Liberty CalPeco, "Outage Map," https://california.libertyutilities.com/portola/residential/emergencies/electrical/outages-map.html.

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Validated Extreme Fire Weather Conditions (Wind Speeds measured at 55 mph or greater for > 3 seconds)	• Monitor local wind gusts and de-energize circuits when conditions are appropriate • Patrol service area and "at risk" areas to monitor actual conditions • De-energize additional power lines as needed	• Continue to coordinate with local government and agencies • Update notifications on website and social media • Send notification via Interactive Voice Response (IVR) • Issue updated press release to local media • Notify Commission and Warning Center at the Office of Emergency Services
Weather Subsides to Safe Levels	• Validate that extreme fire weather conditions have subsided to safe levels37 • During fire season, conduct field inspections and patrols of de-energized facilities • Restore power once equipment assessment is completed	• Continue to coordinate with local government and agencies • Update notifications on website, social media and IVR • Issue updated press release to local media

The decision to de-energize electric facilities for public safety is complex and dependent on many factors including and not limited to fuel moisture; aerial and ground firefighting capabilities; active fires that indicate fire conditions; situational awareness provided by fire agencies, the NWS and the USFS; and local meteorological conditions of humidity and winds.[38]

Under extreme fire danger, when de-energization is deemed necessary, Liberty CalPeco crews will shut off at-risk circuits, lines, and other infrastructure either manually or using remote controlled SCADA devices. Liberty CalPeco will continue to work closely with local stakeholders that own or operate critical facilities, including hospitals and water system operations, and coordinate with first responders, such as police and fire departments, to ensure critical facilities remain operational and/or have back-up plans when PSPS is in effect. Additionally, Liberty CalPeco will update these plans in accordance with changes to the Commission proceeding 18-12-005, OIR to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions.

4.7.1 Re-Energization Strategy

Once Liberty CalPeco has confirmed that extreme conditions have subsided to the point that an energized grid does not pose a threat, the utility will begin re-energizing its de-energized power lines. Liberty CalPeco categorizes this mitigation strategy under *(5) Response and Recovery*.

Once a decision to re-energize has been made Liberty CalPeco will:

[37]Safe levels are defined as wind speeds in the affected area calming below 50 mph for a minimum period of 20 minutes. Crews may extend the calm period beyond 20 minutes, if they assess that further wind gusts greater than 50 mph are likely.

[38] Commission Safety and Enforcement Division, Resolution ESRB-8, July 12, 2018.

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- Patrol lines prior to re-energization.
- Inform all media and partners of the successful conclusion of the de-energization and provide an update when power has been restored.
- Inform all customers who were impacted by the De-Energization event that power has been restored via Everbridge (email, voice, and/or text).
- Post the time of power restoration(s) on website and social media at the conclusion of the de-energization event.
- Follow up with media and partners to ensure successful communication and to determine if additional steps or efforts would be beneficial in the future.
- Provide a report to the Director of the Safety and Enforcement Division provided no later than 10 business days after the conclusion of the shut-off event that includes (i) an explanation of the decision to shut off power; (ii) all factors considered in the decision to shut off power, including wind speed, temperature, humidity, and moisture in the vicinity of the de-energized circuits; (iii) the time, place, and duration of the shut-off event; (iv) the number of affected customers, broken down by residential, medical baseline, commercial/industrial, and other; (v) any wind-related damage to overhead power-line facilities in the areas where power is shut off; (vi) a description of the notice to customers and any other mitigation provided; and (vii) any other matters the utility believes are relevant to the Commission's assessment of the reasonableness of Liberty CalPeco's decision to shut off power.

The process used to re-energize lines will be updated to conform with changes mandated in the Commission proceeding 18-12-005, OIR to Examine Electric Utility De-Energization of Power Lines in Dangerous Conditions.

4.8 Emerging Technologies and Alternative Strategies

Liberty CalPeco is continuing the evaluation of new technologies and approaches to determine if they can could reduce the probability of an ignition event and/or reduce public exposure to a hazardous condition by providing better situational awareness, faster isolation, or other means to reduce wildfires. As described in Section 4.3, Liberty CalPeco is evaluating LIDAR and Infrared Tools to possibly improve the Inspection process.

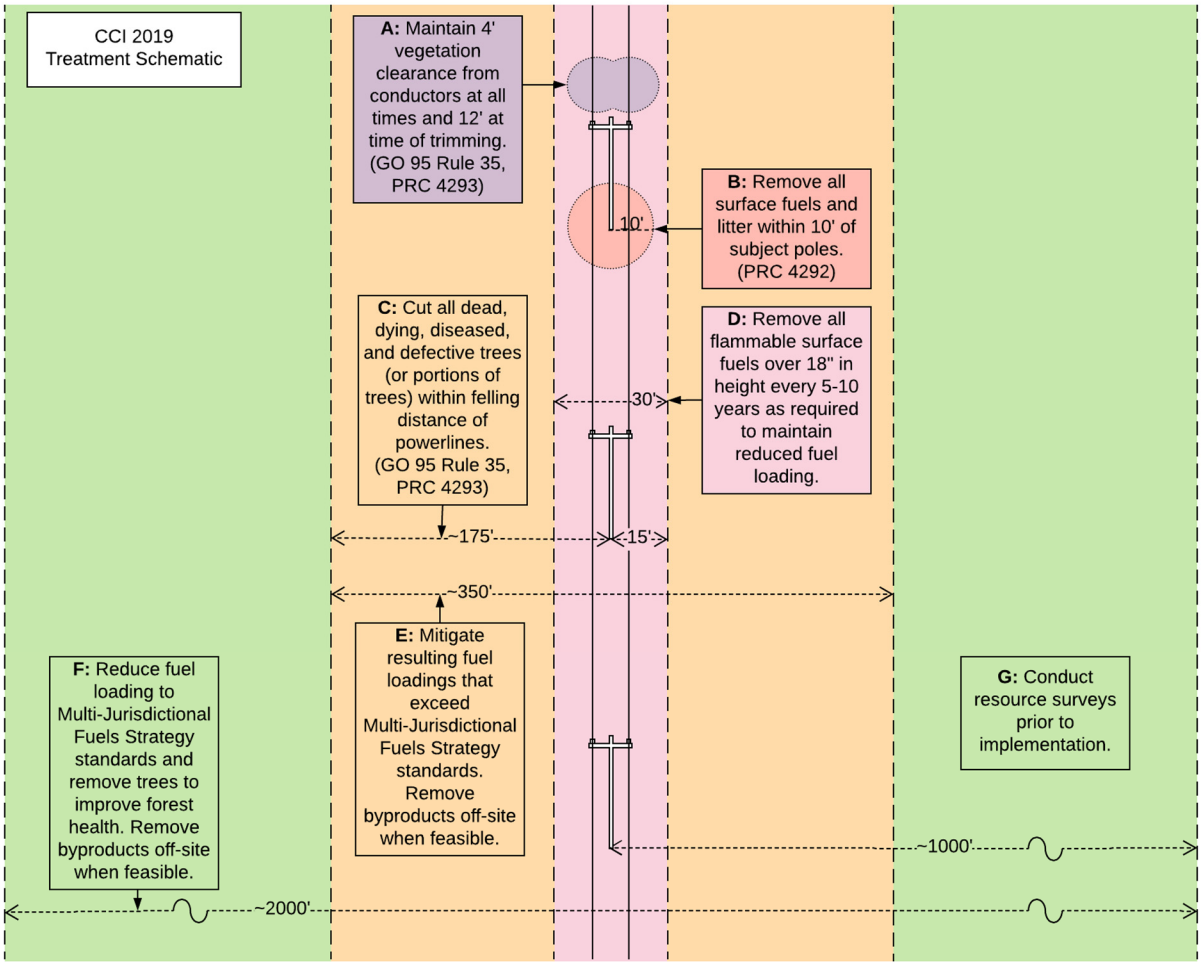
4.8.1 Forest Resiliency Corridor Development

Liberty CalPeco's partner at the California Tahoe Conservancy is preparing to apply for a grant for the Forest Resiliency Corridor (FRC), which addresses approximately 2,300 acres of land managed by participating agencies within 2019. This grant represents a collaborative effort between federal, state and local agencies to conduct comprehensive multi-jurisdictional forest resiliency and fuels reduction treatments that aim to 1) create resilience corridors, 2) aid in resource surveys in support of future efforts, and 3) assist in conducting forest management research along with investigating innovative technology opportunities. The draft version of the Grant Scope of Work entails the creation of resilient corridors within the right-of-way (ROW) around powerlines. The work will leverage all ignition prevention practices already required by regulations but with significant additional fuel reduction (vegetation clearances), pest management, and biomass utilization activities. Liberty CalPeco categorizes this mitigation strategy under *(3) Operational Practices*.

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It the Grant is approved and the CPUC approves this investment, Liberty CalPeco plans to complete the work depicted in Figure 4-6 by March 30, 2022.

Figure 4-6. FRC Project Draft Schematic



Items A, B, and C are designed with the primary intention to reduce ignition risk originating from powerlines pursuant to current regulation. Item A maintains four feet of vegetation clearance from powerlines at all times with consideration of appropriate vegetation growth between removal treatments. Item B illustrates efforts to remove all combustible material within ten feet of subject poles, which are more likely to ignite fires due to either the location or associated equipment and infrastructure. Item C aligns with regulations that require cutting, trimming, or removal of trees that may fail and ultimately make contact with lines. Item D illustrates removal of flammable surface that exist over 18 inches in height within 15 feet of either side of the pole's center line. Plans to complete item D align with execution goals of items A, B, and C. However, item D is not required by current regulation, but will aid in enhancing the efforts of the Wildfire Mitigation Plan and are essential to the success of the Forest Resiliency Corridor.

Fuels and timber generated from the execution of Items A, B, and C are left on site for decomposition. To address accumulation of fuels that pose risk within 175 feet of powerlines, Item E was planned with the intention to reduce additional forest fuels and utilize biomass to mitigate fuel loading resulting from implementation of the previous plan items. Item F captures additional fuels reduction, pest management, prescribed fires, and continued biomass utilization activities that are within approximately 1,000 feet of

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powerlines. Lastly, Item G highlights the requirement to conduct resource surveys throughout the corridors prior to forest management projects, which could impact the timeline of efforts when certifying NEPA and CEQA documents. All items listed will provide additional benefits in reducing fuels and improving forest resiliency. Support for this work is echoed by the USFS and Tahoe Fire and Fuels Team.

Funding and Cost Estimate

Pending grant approval and allocation determination, Liberty CalPeco plans to invest an additional $661,030, beyond GRC approved activities, to support of the overall $10 million Grant benefit to the forest surrounding powerlines. Thousands of acres still remain within the resilience corridor areas, and Liberty CalPeco anticipates that agencies will likely seek funding in the future as successes projects are recorded.

These items (A, B, C, and D) listed in Figure 4-6 are at the sole financial responsibility of Liberty CalPeco and will be included as a match within this grant. Estimates for Items A, B, and C approximate $1,636,000 with costs tracked through the Vegetation Management Balancing Account (VMBA), authorized through the 2016 GRC application. Item D costs are also at the sole responsibility of Liberty CalPeco with costs estimated at $400,000. These costs will be tracked through the proposed FRMMA. Costs associated with Item E will be shared by Liberty CalPeco and funding from the grant, estimated at $261,030 (also matching funds) and tracked through the FRMMA. Matching funds approximate $2,297,030. Item F will be funded solely by the grant, if awarded, and Item G will be recovered through rates.

FRC Compliance

Current regulations addressed through this effort include Governor Gavin Newson's Executive Order N-05-19, which emphasized the need for agencies within the state to take immediate action to protect communities and forests from wildfire threat.[39] Commission's GO 95 Rule 35, and California Public Resources Code Sections 4292 and 4293, which require vegetation clearance around powerlines and certain poles to reduce the risk of wildfire ignitions. Participation in the Forest Resiliency efforts will include coordination in federal and non-federal project implementation, surveys of at-risk vegetation, ignition hazard reduction and ROW fuels reduction.

4.9 Post Incident Recovery, Restoration, and Remediation

Liberty CalPeco has an Emergency Management Plan (See Appendix C) in place to recovery from major emergencies including Wildfires. The Company's Emergency Response Plan (ERP) uses a tiered level approach to implement an Incident Command System (ICS). The ICS is an organized approach to effectively control and manage emergency operations depending on the level of the emergency.

Primary Objectives of ERP

During emergency situations and disasters:
1. Protect the life, safety and health of employees and the public.
2. Protect the property and assets of the Company and Public.
3. Protect the environment.
4. Provide for the expeditious restoration of service and return to normal operations.
5. Provide prepared and trained employees as well as pre-developed plans and information to manage events.

[39] Executive Department State of California. "Executive Order N-05-19." January 8, 2019. https://www.gov.ca.gov/wp-content/uploads/2019/01/1.8.19-EO-N-05-19.pdf.

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Regional Command Centers at Lake Tahoe

The initial, or lower level emergencies will use the individual department or to initially address emergency situations using the incident command system. These centers are responsible for command and control of all phases of the emergency in their region. If additional support is required, it will be supplemented with support from the Emergency Management Team. The ICS may be activated to assist in resource and information coordination during an emergency or may be activated for large scale or complex emergencies. In a major emergency, the overall management will be under the responsibility of the Incident Commander. The ICS function will be to coordinate and direct all response and mitigation efforts.

Emergency Management Team

This team is activated with the onset of a major emergency event, in response to an event. This team initially provides support to the regional activities and may consist of any or all of the following positions: the Policy Director, Public Information Officer, Safety & Security Officer, Emergency Response Liaison, and one or more of the affected operating or administrative managers. This is the team that will in part staff the Incident Commander Center if a major event occurs. The additional members of the ICS/Emergency Management Team who also may be activated for any event to either support the regional activities or staff the ICS if activated include: Operations Leader, Logistics Leader, Planning Leader, Financial/Regulatory Leader and Services Leader. An organization chart showing the make-up of the fully staffed Emergency Management Team.

Incident Command System Organization

This center can be activated to provide additional resources support, in a major emergency and coordination, centralized information coordination and policy direction as necessary to support the activation of a single, or multiple Regional Command Centers. EOCs will also be activated by the ICS/Emergency Management Team to coordinate emergency information and support utility operations, emergencies, or any other company emergency situations. Either of Liberty CalPeco offices may be designated as the Incident Command Post during emergencies depending upon accessibility, where the ICS can be most effective and the specific type of emergency. The ICS is activated to provide resource support and information to the regional offices while each regional operation maintains the responsibility for field operations related to assessment, recovery, and restoration.

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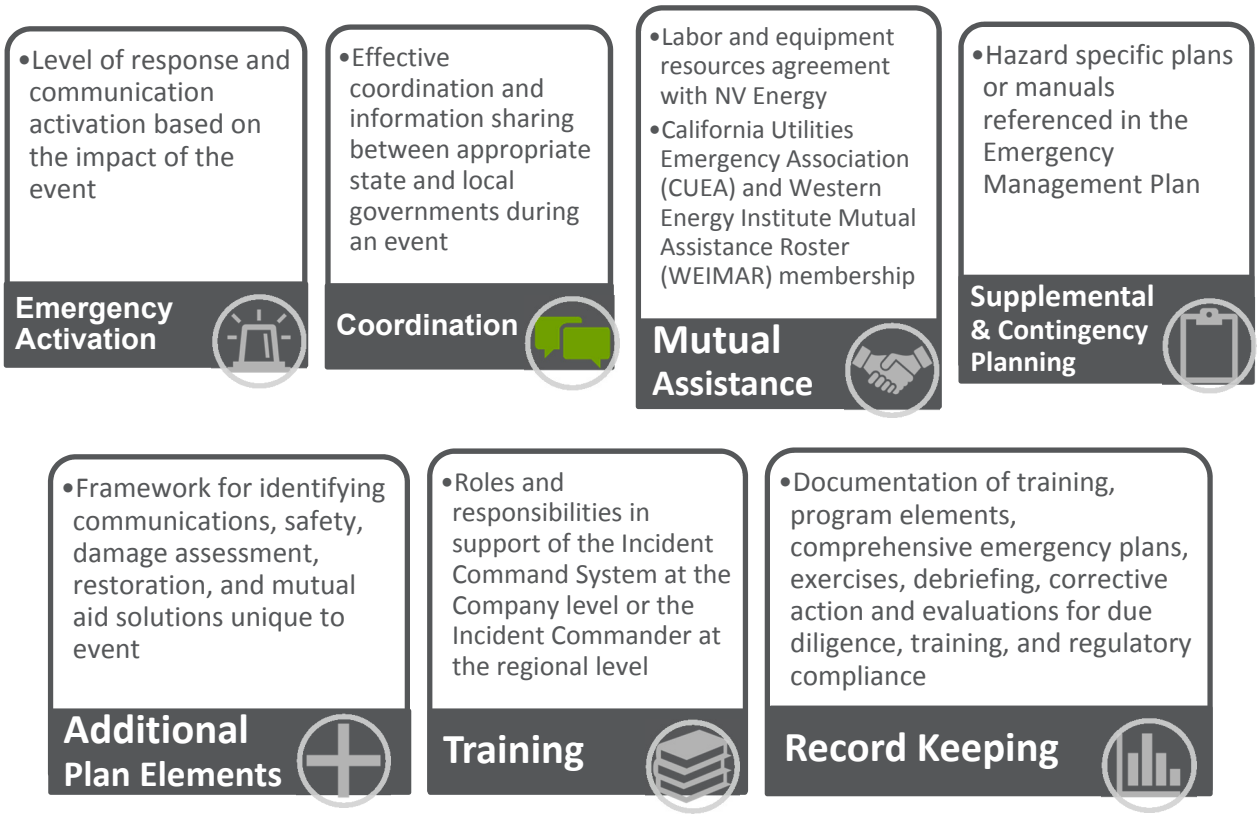
5. EMERGENCY PREPAREDNESS AND RESPONSE

As referenced in Section 4.9, Liberty CalPeco has created a Corporate Emergency Management Plan to manage the consequences resulting from unexpected loss of infrastructure and equipment. The plan provides an emergency response framework for active response and recovery preparedness, resource planning, and practice training. Liberty CalPeco categorizes this mitigation strategy under *(5) Response and Recovery*. This section details these plans, including compliance, and roles and responsibilities for executing the plan.

5.1 Plan Overview

Liberty CalPeco understands the importance of proactive planning and coordinating closely with local governments, agencies, and customers. The Corporate Emergency Management Plan reflects those philosophies. Specifically, the plan addresses the following: emergency activation, coordination, mutual assistance, supplemental and contingency planning, additional plan elements, training, and record keeping. Figure 5-1 below describes these components with further detail on the more comprehensive components below.

Figure 5-1. Emergency Preparedness and Response Components



Due to Liberty CalPeco's unique service territory, there are several key stakeholders that will be involved in emergency preparedness and response. These stakeholders include local governments and agencies as well as location-specific organizations, including critical facilities, resorts, and business groups. With

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this understanding, Liberty CalPeco has outlined all key stakeholders. Table 5-1 provides the stakeholder list. Liberty CalPeco will review the list annually and update it, as needed.

Table 5-1. Liberty CalPeco Emergency Preparedness and Response Stakeholder List

Stakeholder Group	Description
Customers	• Any person, organization, or critical facility receiving electricity from Liberty CalPeco
Local Government / Critical Agencies	• Primary Care Hospitals • Public Utility Districts (Truckee Donner, South Tahoe) • Counties (Alpine, El Dorado, Mono, Nevada, Placer, Plumas, Sierra) • Cities/Towns (Portola, South Lake Tahoe, Truckee) • Telecommunications • Water/Water Treatment • Public Safety Dispatch Centers • Law enforcement/holding facilities • Local tribal governmental agencies • Fire operations facilities • Transportation equipment and facilities • Local Emergency Planning Committees • CAL FIRE • California Department of Transportation • USFS • Sierra Front Wildfire Cooperators • CPUC SED
Mutual Assistance Agreements	• NV Energy • Western Energy Institute Mutual Assistance Roster • California Utilities Emergency Association
Commission	• Utility Safety Branch • Energy Branch • Energy Division • Office of Emergency Services Warning Center • Others, as requested

Source: Liberty CalPeco Emergency Management Plan

Emergency Activation

Emergency and disaster response are both characterized into one of five levels of activation based on the risk of impacts as a result of the event. This determination will then direct immediate engagements and activate prescribed protocols associated with that incident impact level. Table 5-2 below describes the action and communication plans associated with each activation level starting with Level 5, small impact events:

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Table 5-2. Liberty CalPeco Activation Levels for Emergency/Disaster Response

Level		Description	Action
5	Small Impact Event (Localized Response Condition)	Minor disruption of operating systems, business systems, or electric service that can be managed with existing resources at the local or department level.	Normal activity, daily internal crew assignments
4	Moderate Impact Event (Heightened Alert)	An event that maximizes the resources and management capability of the local region and may require additional resources and support.	Possible crew transfer between areas; utility Contractor crews (overhead line and tree) limited to normal daily complement.
3	Serious Impact Event (Enhanced Support)	A disaster or major emergency that may affect several areas of our electric system and may require the services of all operations personnel.	Regional or System ICS may be initiated and Regional EOC's may be opened. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.
2	Major Impact Event (Comprehensive Support)	A disaster or major emergency that affects several areas of our electric system and requires the services of all operations personnel.	Regional or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.
1	Catastrophic Impact Event (Emergency Support)	A disaster or major emergency requiring a corporate response to minimize corporate risk. This level requires policy guidance, strategic planning, and coordination of internal and external resources, internal communication and coordination, dissemination of public information.	Regional and/or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.

Source: Liberty CalPeco Emergency Management Plan

Supplemental & Contingency Planning

Liberty CalPeco acknowledges in their Emergency Management Plan that no single plan can foresee all the needs or contain all the information necessary to respond to each event. As a result, the utility references a number of supplemental plans and manuals that address specific hazards in the Emergency Management Plan. Their supplemental plans include Fire Prevention Plans, Outage Communication Plans, Mutual Assistance Agreements, Operations Procedures Manuals, and Spill Response Plans.

Additional Plan Elements

The Emergency Plan provides a framework for identifying unique solutions for events in the areas described in Table 5-3.

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Table 5-3. Liberty CalPeco Additional Emergency Plan Elements

Area	Actions
Communications	• Prior to an emergency, media contact information is updated annually. Information will be disseminated to the public through the media advising customer what to do to prepare for extended outages and what emergency supplies may be necessary to keep on hand. • During an emergency, the media is contacted with detailed outage information. Local governmental agencies, municipalities and media outlets within the service territory are also contacted. • Liberty CalPeco will initiate its outbound call program, Everbridge, to deliver critical information. The primary point of customer contact is through telephone information via live customer contact or the Interactive Voice Response and messaging system as well as email or Short Message Service (SMS).
Governmental & Regulatory Communications	• During an emergency, the utility will provide communications to the highest level of city or county Emergency Operations Center activated • The Commission requires reporting for Safety and for substantial outages
Safety	• Prior to an emergency, the utility provides on-going public electric safety courses and information so that the Public will be prepared when an emergency event occurs. Electric Trade Personnel, including Ground person, helpers, apprentices, journeyman lineman, trouble men, inspectors etc., are provided the highest level of safety and skills training to perform in both daily and emergency situations. • During an emergency, the utility will respond to Immediate Life Safety Issues as the top priority.
Damage Assessment	• During an emergency, company crews, linemen, troublemen, electric inspectors, utility designers and/or engineers will be first called for damage assessment. • All damage will be recorded by the teams on circuit maps using standardized symbols. • To the extent practicable, downed or damaged facilities shall be isolated, secured and warnings applied utilizing cones, warning tape or other barriers or warnings.
Restoration	• This element identifies general prioritization guidelines for restorations as restoration depends upon a number of factors including safety, accessibility, availability of repair parts, and availability of personnel.
Mutual Aid	• The type, size and duration of an emergency event will determine, in varying degrees, the amount of resources required to respond to the event. • Resource requests may include trade and non-trade personnel to assist in safety stand-by, damage assessment, planning or liaison activities, or materials and equipment necessary to facilitate restoration of utilities.

Source: Liberty CalPeco Emergency Management Plan

Training

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Liberty CalPeco employees participate in Emergency Management Plan training annually. They are trained on the roles and responsibilities of each functional area in support of the ICS at the Company level or the Incident Commander at the regional level. In addition, emergency response exercises are designed so employees can gain practice in the use of the plan and as a test of the plan's effectiveness. The utility participates in regional exercises to train employees and exercise the Emergency Management Plan.

Record Keeping
All electronic communication pertaining to training, program elements, comprehensive emergency plans, exercises, debriefing, corrective action and evaluations will be submitted to the local internal emergency mailbox and Corporate Headquarters. These records will be examined during debriefing and corrective action exercises.

5.1.1 Plan Compliance

The emergency preparedness and response plans described in this section comply with Public Utilities Code Section 768.6 and 8386[40,41]. Specifically, the plan complies with the following mandates:

- Sharing of plan with relevant cities and counties to provide input and feedback.
- Plans to update and improve the plan at least every two years.
- Accounting of responsibilities of persons responsible for executing the plan.
- Appropriate and feasible procedures for notifying customers who may be impacted.
- Plans to prepare for and restore service, including workforce mobilization.
- Plans for community outreach and public awareness before, during, and after a wildfire.
- Emergency communications that includes plans to translate messages into the top three languages in CA based on census data.
- Protocols for compliance with Commission reporting guidelines.

As the Commission develops new mandates, Liberty CalPeco will update its plan accordingly.

5.2 Plan Organizational Structure and Functions

The plan will be implemented by key utility staff, working closely with the stakeholders listed in Section 5.1. The staff involved include the Incident Commander, Public Information Officer, Safety and Security Officer, Government Liaison, Emergency Response Liaison, Operations Leader, Logistics Leader, Planning Leader, Financial/Regulatory Leader, and Services Leader. All implementation staff are highly qualified and will ensure prompt communications and restoration of service. These members will be critical to maintaining customer and system safety. Table 5-4 below outlines each staff member's role in implementation of the plan and their relevant qualifications.

[40] FindLaw, California Code – PUC 768.6, https://codes.findlaw.com/ca/public-utilities-code/puc-sect-768-6.html.

[41] FindLaw, California Code – PUC 8386, https://codes.findlaw.com/ca/public-utilities-code/puc-sect-8386.html.

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Table 5-4. Liberty CalPeco Plan Implementation Roles and Responsibilities

Staff Member	Role
Incident Commander	• Normally the President of the Company, they are the "individual in charge" establishing a clear chain of command, control of information and emergency coordination.
Public Information Officer	• Works with the Incident Commander or as support to the Regional Incident Commanders to develop communication strategies and content of all information to be disseminated pertaining to the emergency
Safety and Security Officer	• Provides review of emergency operation activities to ensure work is being performed safely, ensures public safety around facilities that may be energized and assists in prioritization of safety related matters. • Provides for the protection and security of company employees and assets, mitigates damage to facilities, and ensure effective coordination with law enforcement agencies.
Government Liaison	• Communicates with key local, state or federal government authorities and officials regarding emergency activities and information
Emergency Response Liaison	• Provides a link between the utility and external agencies to keep them informed regarding any impacts the event may have on the utility's ability to provide or restore service.
Operations Leader	• Responsible for the management of all tactical operations directly applicable to the emergency response. • Provides direction to the frontline field personnel in damage assessment and priorities and requests resources necessary to restore service.
Logistics Leader	• Responsible for providing the equipment, supplies and personnel that the operations needs to respond to the emergency. • May engage contract or mutual aid services in support of the emergency. • Schedules manpower or resources to cover additional emergency operations periods.
Planning Leader	• Provides analysis of emergency information and situations and develops plans to be used during the response and recovery operations to fully return electric service as quickly as possible for the least cost.
Financial/Regulatory Leader	• Responsible for ensuring that funds are available as need for the emergency. • Provides tracking of costs of the response and recovery and ensuring that records are maintained throughout the event and sufficient to apply for regulatory relief or outside funding from resources like FEMA
Services Leader	• Provides any support services need to manage the emergency which may include human resources or administrative support.

Source: Liberty CalPeco Emergency Management Plan

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5.3 Customer Support in Emergencies

Response to a catastrophic event is critical to the customer. In addition to emergency personnel, Liberty CalPeco is aware that the utility has a crucial role in providing immediate support activities resulting from local and state-level emergencies. The protocols listed below reflect disaster customer protection measures during and after a wildfire incident. These considerations arise from the scope determined in Resolutions M-4833 and M-4835,[42] which guide utilities to implement procedures to protect customers in the event of pronounced states of emergency. Liberty CalPeco is weighing decisions surrounding these activities as decisions are finalized for R. 18-03-011. Further, the utility seeks to meet compliance and accommodate necessary response actions. Internal discussions will continue to investigate billing options as well as develop a vital customer support plan specific to these types of devastating events. Liberty CalPeco categorizes this mitigation strategy under *(5) Response and Recovery*.

The following protocols intend to provide assistance to customers affected by catastrophic events such as recent wildfires in 2017 and 2018. The Commission has established requirements that guide electric utilities to develop response efforts to wildfire-impacted communities. The items below detail these proposed procedures as part of the Plan drawing from existing emergency and communications plans as well as the proposed Wildfire Mitigation Plan Communications Protocol outlined in Section 4.9.1.

- **Outage Reporting:** Administrative staff members will work to create an internal code within the Outage Management System to identify outages related to wildfires.
- **Support for Low Income Customers:** Low income, or CARE, customers will be offered Special Payment Arrangements resulting from a fire-related outage, if necessary.
- **Billing Adjustments:** Billing will be suspended until the customer receives power again.
- **Deposit Waivers:** Liberty CalPeco will consider, on a case-by-case basis, waiving deposits for customers that have to rebuild due to a wildfire.
- **Extended Payment Plans**: In the event the customer has suffered a tremendous loss, (property or home), due to wildfires, special consideration would be granted on a case-by-case basis for payment extension.
- **Suspension of Disconnection and Nonpayment Fees:** Collection activities (after three months) because of nonpayment would be suspended for wildfire-impacted neighborhoods.
- **Repair Processing and Timing:** Timing for repair procedures will be determined based upon the severity of wildfire impact. During emergencies, Liberty CalPeco will expedite repair processing as incidents are recorded. Mutual aid programs will be engaged, if necessary, in conjunction with the Corporate Emergency Response plan. The utility will follow up with electrical contractors to ensure efforts for remediation are executed.
- **Access to Utility Representatives:** If the utility offices are not impacted by fire, operations will resume, and CSRs and Managers on-Duty would be available to assist customer concerns. However, if offices are affected by fire, nearby offices as well as Corporate support will be available to customers. Resulting from fire, Liberty CalPeco proposes to address concerns and common questions through an “open house” with the public.

[42] Quasi-legislative R. 18-03-011 OIR Regarding Emergency Disaster Relief Program to Support California Residents was issued April 2, 2018 which built upon Resolutions M-4833 and M-4835 adopted previously and remains ongoing while decisions for M-4833 and M-4835 have been initiated for interim protection.

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6. PERFORMANCE METRICS AND MONITORING

In addition to a robust mitigation strategy, Liberty CalPeco developed performance metrics to monitor their efforts over time. The goal of these metrics is to provide a data-driven evaluation of performance to help Liberty CalPeco determine the effectiveness of the Plan and identify areas of improvement. The performance plan is comprised of two components: Roles and responsibilities and Metrics reporting. Liberty CalPeco categorizes this mitigation strategy under *(3) Operational Practices*.

6.1 Roles and Responsibilities

The overall roles and responsibilities for the performance metrics align closely to the departments that oversee the implementation process of each of the strategies outlined in the broader plan. The VP of Operations, or their designee, will oversee implementation, ensuring staff follow procedures and protocols. They are also responsible for managing the execution of the performance monitoring. This includes providing guidance to staff and leading the development of reports. The staff responsible for each metric area will aggregate relevant metrics at the direction of the VP of Operations or their designee. For example, Customer Service Representative teams may assume responsibility for tracking customer-related metrics.

6.2 Metrics Reporting

As described above, metrics will play a critical role in overall Plan continuity. Liberty CalPeco intends for the metrics to inform them about the progress of wildfire mitigation and determine potential gaps that may arise over time as conditions change. That said, the metrics proposed in this Plan reflect current plans mentioned previously. Upon Plan approval, Liberty CalPeco will create targets for each of the metrics based on industry standards and benchmarks. The utility will also plan to revisit the metrics annually and update them as needed. Table 6-1 details Liberty CalPeco's proposed metrics.

Table 6-1. Proposed Wildfire Prevention Plan Metrics

	Metric	Rationale	Risk Reduction Assumption
Fire Incidents	Number of utility-caused fires	Determination of Plan's overall effectiveness	Fire frequency will reduce by maintaining a hardened system and commitment to these operational practices
Infrastructure	Number of Wildfire Risk Events (e.g. number of bare line contact with vegetation)	Assess if plan has reduced risk events	Accounting for incidents will, overtime, show risk reduction in fire ignition.
	Number of Fuse Replaced Annually	Determine if plan is on schedule	An increase in the number of current limiting fuses will mitigation wildfires
	Length of Bare Wire Covered Annually	Determine if plan is on schedule	An increase in the number of miles of covered conductors will mitigation wildfires

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	Number of Recloser Replacements or Upgraded Annually	Determine if plan is on schedule	Reclosers with sensitive setting and high-speed clearing will mitigate wildfires
	Substation Replacement and Upgrade -Narrative on project progress	Assess reliability and safety improvements	Elimination of wooden box structures and oil circuit breakers will mitigate risk
	Weather Station Installation	Determine if deployment plan is on schedule	An increase in the number of weather stations will mitigation wildfires
Operations	Average Time for Clearance Permissions from Local Agencies	Assess mitigation plan constraints and timelines	A reduction in the amount of time to clear vegetation will reduce risk
Operations	Vegetation Management Investment and inspections	Assess value after increasing budget in inspection procedures; clearances	Determine if an increase or decrease in vegetation follow-up results from increase budget.
Customer Service	Number of Customer Service Calls about identified and confirmed at-risk Vegetation	Assess if plan has reduced customer concerns and risk events	Track vegetation service calls on customer responsibility and Liberty vegetation.
PSPS Narrative	Number of PSPS Events	Monitor the number of PSPS events over time as an indicator of changing climatic and weather patterns	Determine the effective of procedures for PSPS events.

Liberty CalPeco staff will track metrics throughout the year or as material occurrences arise (e.g. outage report, off-cycle tree clearing notification, weather conditions) and produce internal monthly updates. Liberty CalPeco will prepare formal reports, aggregating the monthly metrics, for review by the leadership at Liberty CalPeco on a semi-annual schedule. The reports will evaluate whether the metrics are below, meeting, or exceeding their targets. The reports will also include brief updates and correction plans for metrics below target. Liberty CalPeco leadership will provide feedback and additional guidance as necessary.

Metric monitoring and reporting will ensure aspects of the Plan will be carried out and accounted for in implementation. These reports will guide decision-making in modifying or enhancing the Plan for future compliance of PUC Section 8386 and more importantly, strengthen Liberty CalPeco's efforts to mitigate potential wildfires in the face of California's new normal.

6.3 Application of Prior Metrics to Previous Plan Performance

This report is the first annual Wildfire Mitigation Plan submitted to the Commission for approval. Therefore, past plan metrics are not available at this time to evaluate past plan performance. However, in developing this Plan, consideration of wildfire risk events, their drivers, and feasible project implementation informed the metrics outlined above.

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6.4 Wildfire Mitigation Plan Monitoring and Auditing

Liberty CalPeco will monitor efforts of the Plan quarterly and report on its effectiveness on an annual basis. Quarterly reports of the Plan's current progress and risk reduction impact will be developed and circulated to appropriate utility staff to engender collaborative discussion to make changes to approved strategies. The VP of Operations, or their designee, will update leadership with recommendations or proposed action in enhancing the Plan's objectives overtime.

Liberty CalPeco shall engage one of the Commission-approved intendent evaluators to assess compliance with its plan. It is expected that the evaluator will consult with and operate under the guidance and direction of the Safety and Enforcement Division, issue a report annually, and determine if the electric utility has failed to provide funding or investment into any activities approved within its Plan.

6.4.1 Correcting Plan Deficiencies

Achieving a robust, all-encompassing Plan to mitigate wildfire risk from the utility is the primary objective of this document. Staff responsible for assigned mitigation areas have the role of vetting current procedures and recommending changes or enhancements to build upon weak strategies in the Plan. Either due to unforeseen circumstances, regulatory changes, emerging technologies, or other rationales, deficiencies within the Plan will be sought out and reported to the Commission in the form of an updated Plan on an annual basis. The VP of Operations, or their designee, will be responsible for spearheading discussions on correcting deficiencies when updating the Wildfire Mitigation Plan for its annual filing.

6.4.2 Effectiveness of Equipment and Line Inspections

Liberty CalPeco's compliance with Commission regulations ensures that facilities are inspected and repaired in accordance with GO 165 program standards, referenced in Section 4.3. Any issues found impacting safety and reliability are addressed as outlined in that program. In addition to this maintenance program, Liberty CalPeco is constantly evaluating its facilities while performing other activities such as outage patrols, new business planning, engineering studies, pole replacements, and related field work. Monitoring the effectiveness of inspection practices will occur through ongoing tracking and annually review of findings resulting from internal process.

The VP of Operations, or their designee, will review concerns found during routine field work and equipment and line inspections. Liberty CalPeco will use this information as a method to assess the effectiveness of inspection procedures. The review process will take place annually where inspection records will be reviewed, deficiencies will be identified, and corrective action will be determined. An internal report will be provided to the utility's leadership in deliberation of future strategies. Related strategies that mitigate wildfire risk will then be identified and proposed within the next iteration of the Plan.

Aggregating this data will guide future decision-making on the direction of wildfire mitigation strategy with the intention that incidents will become less frequent or hazardous system-wide.

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7. POTENTIAL COST IMPLICATIONS

The approval of the Wildfire Mitigation Plan does not guarantee cost recovery through electric utility ratemaking practices; however, the Commission asks to include cost estimates and actuals associated with mitigation strategies within this Plan that might have a potential cost impact going forward. Liberty CalPeco will track incurred costs and expenses related to the execution of objectives through an activated second MA following this application's decision. Until then, costs will be tracked through the current FRMMA. The Commission will then weigh considerations of cost implications as a result of each proposed and pre-approved mitigation strategy, program, or protocol. Those items will cost implications from the implementation of this Plan are identified and detailed in Appendix A.

This section presents an aggregation of cost estimates determined by utility staff over the period of the Plan development. These figures represent conservative, industry-standard vendor pricing with consideration of additional expenditures of updated and modern investments as well as availability of material for procurement. The compiled cost estimates are high-level figures. (See Table 7-1 below.)

Table 7-1. Estimated Plan Cost Implications

Mitigation item	Cost Estimated	Notes	Cost Recovery
Automatic Reclosers	$7,350,000	Total	GRC
Covered Conductors	$614,000	Per Mile	GRC / FRMMA[43]
Pole Loading and Replacement	$12,000 - $15,000	Per Pole	GRC / FRMMA
Fuse Replacement	$721,550	Annual	FRMMA
Substation Design Hardening	$16,500,000	Total	GRC / FRMMA
Undergrounding	$7,290,220	Total	GRC
Tree Attachment Removal	$420,000	Annual	FRMMA
Vegetation Management Plan	$4,000,000	Annual	GRC
Forest Resiliency Corridor	$661,000	Contribution above share	FRMMA
Weather Station Installations	$148,720	Total	FRMMA

[4343] The FRMMA will track ongoing costs as well as approved Plan strategies until a second MA is established and approved.

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APPENDIX A. WILDFIRE MITIGATION STRATEGIES & PROGRAMS

§8386 (c) (3)(4)(8)(9): Wildfire Mitigation Strategies and Programs

Program/Strategy (§ 8386(c)(3))	Asset Addressed (Ex: line, poles, etc. (§ 8386(c)(3))	Annual Cost (Capital v. Expense) (Scoping Memo at 4: "In evaluating the proposed plans the Commission may weigh the potential cost implications of measures proposed in the plans")	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part that is Not Previously Authorized (§ 8386(j))	Compliance Requirement? (Provide Code/GO Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part that is Not Compliance	Identify any Aspects of Plan/Strategy and Associated Funding That is or Will Be Addressed in Another Case (Identify the Case (§ 8386(j))	Identify Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking is Prevented (§ 8386(j))	Previously Included in RAMP? (Provide Reference) (§ 8386 (c)(11))	Evaluation Metric(s) (§ 8386 (c)(4))	Assumptions Underlying Metric (§ 8386 (c)(4))	Categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Condition al Awareness, and/or (5) Response and Recovery
OPERATIONAL PRACTICES										
Automatic Reclosers & Fast-Curve Settings	Automatic Circuit Reclosers and Controls including SCADA	$735,000 (total project) // Capital	Yes	NA	2019 GRC application pending approval	NA	NA	deployment schedule is on track for completion	• Remote monitoring of system assets promotes faster outage response • Supervisory controls will provide the settings necessary to reduce electrical ignition, while also helping to mitigate power outages	(3) Operational Practice
Elevated Weather Events Operations (e.g. during Red Flag Warnings)	All Circuit Recloser Settings, Trip Savers; At-Risk Circuits	Standard Business Operations // Expense	Yes	D.12-01-032 pursuant to R. 08-11-005; PU Code Sections 451 and 399.2(a)	NA	NA	NA	Number of Red Flag Warnings during fire season	Fire frequency will reduce by maintaining a hardened system and commitment to these operational practices	(3) Operational Practice
Wildfire Infrastructure Protection Teams	All System Assets	Standard Business Operations // Expense	Yes	PU Code Sections 451 and 399.2(a); GO 166	Pending 2019 GRC application	NA	NA	Coordination during risk events captured and tracked	Rationale: Ensure staff is prepared to mobilize in high-risk and emergency situations	(3) Operational Practice
PLANS FOR INSPECTION										
On-Ground Routine Inspections	All Equipment and Infrastrucutre Assets	Standard Business Operations // Expense	Yes	GO 165	Pending 2019 GRC application	NA	NA	NA	NA	(2) Inspection and Maintenance
Equipment Asset Inspections	Equipment Assets	Standard Business Operations // Expense	Yes	GO 165	Pending 2019 GRC application	NA	NA	Planned inspections are carried out	Rationale: Regular patrols that identify aging infrastructure or equipment that pose a fire risk	(2) Inspection and Maintenance
Vegetation Risk Inspections	All Assets near Vegetation	Approx. $4 million annually (as part of the Vegetation Maintenance Expense)	Yes	GO 95, Rule 35 and Public Resources Code (PRC) 4293; D.17-12-024	Pending 2019 GRC application	Vegetation Management Balancing Account	NA	NA	NA	(2) Inspection and Maintenance

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§8386 (c) (3)(4)(8)(9): Wildfire Mitigation Strategies and Programs										
Program/Strategy (§ 8386(c)(3))	Asset Addressed (Ex: line, poles, etc. (§ 8386(c)(3))	Annual Cost (Capital v. Expense) (Scoping Memo at 4: "In evaluating the proposed plans the Commission may weigh the potential cost implications of measures proposed in the plans")	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part Not Previously Authorized (§ 8386(j))	Compliance Requirement? (Provide Code/GO Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part that is Not Compliance	Identify any Aspects of Plan/Strategy and Associated Funding That is or Will Be Addressed in Another Case (Identify the Case (§ 8386(j))	Identify Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking is Prevented (§ 8386(j))	Previously Included in RAMP? (Provide Reference) (§ 8386 (c)(11))	Evaluation Metric(s) (§ 8386 (c)(4))	Assumptions Underlying Metric (§ 8386 (c)(4))	Categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Condition al Awareness, and/or (5) Response and Recovery
SYSTEM HARDENING										
Pole Loading & Replacement	All Distribution Poles	$16,765 is spent on software license costs; 2 hours per pole evaluation at $50 per hour; $12,000 - $15,000 per pole // Capital	Yes	GO 95 Rule 44	NA	Proposed Wildfire Mitigation Memorandum Account	NA	Number of pole replacements	Rationale: Determine if structural integrity of the pole is within calculated threshold	(1) Design and Construction
Covered Conductors	Prioritized Lines: Tahoe City Line 7300; Topaz Line 1261	Between $614,000 and $1,228,000 per year: -Overhead construction costs + additional costs via (1-2 miles) covered wire are $614,000 per mile // Capital	Yes	NA	NA	Proposed Wildfire Mitigation Memorandum Account	NA	Determine if plan is on schedule	Rationale: Mitigate contact of ignition source (heat) by covering the wire.	(1) Design and Construction
Fusing	Replace Conventional Fuses	$721, 550 // Capital	No	NA	NA	Proposed Wildfire Mitigation Memorandum Account	NA	Determine if plan is on schedule	Rationale: Mitigate downed wires and reduce energy at potential fault locations	(1) Design and Construction
Substation Design Hardening	Brockway Substation; Stateline Substation	$16,500,000 for total proposed costs // Capital	No	GO 174	Brockway presented in 2019 GRC application	Proposed Wildfire Mitigation Memorandum Account	NA	Assess reliability and safety improvements	Rationale: Modernize aging capital infrastructure to mitigate fire risk	(1) Design and Construction
Tree Attachment Removal	All Tree Attachments	$7,000 per pole/tree for attachment removal; yielding $420,000 annually // Expense	No	NA	NA	Proposed Wildfire Mitigation Memorandum Account	NA	Number of service tree attachments removed per year	• Pole attachment risks exist throughout the utility's distribution system	(1) Design and Construction

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§8386 (c) (3)(4)(8)(9): Wildfire Mitigation Strategies and Programs

Program/Strategy (§ 8386(c)(3))	Asset Addressed (Ex: line, poles, etc. (§ 8386(c)(3))	Annual Cost (Capital v. Expense) (Scoping Memo at 4: "In evaluating the proposed plans the Commission may weigh the potential cost implications of measures proposed in the plans")	Costs Currently Reflected in Revenue Requirement? (Provide Decision Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part that is Not Previously Authorized (§ 8386(j))	Compliance Requirement? (Provide Code/GO Reference) If for Only Part of Budget, Identify the $ for that Part and Explain Part that is Not Compliance	Identify any Aspects of Plan/Strategy and Associated Funding That is or Will Be Addressed in Another Case (Identify the Case (§ 8386(j))	Identify Memorandum Accounts Where Costs of Program/Strategy Are Being Tracked and Explain How Double Tracking is Prevented (§ 8386(j))	Previously Included in RAMP? (Provide Reference) (§ 8386 (c)(11))	Evaluation Metric(s) (§ 8386 (c)(4))	Assumptions Underlying Metric (§ 8386 (c)(4))	Categories: (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, (4) Situational/Condition al Awareness, and/or (5) Response and Recovery
VEGETATION MANAGEMENT										
Routine Vegetation Maintenance	All Assets near Vegetation	Approx. $4 million annually // Expense	Yes	GO 95 Rule 35; Public Resources Code Sections 4292 & 4293	Pending 2019 GRC application	Vegetation Management Balancing Account	NA	Assess value after increasing budget in inspection procedures; clearances	Determine if an increase or decrease in vegetation follow-up results from increase budget.	(2) Inspection and Maintenance
Tree Mortality Removal Project	All Assets near Affected Vegetation	>$1 million annually // Expense	No	GO 95 Rule 35; Public Resources Code Section 4293	E-3238	Proposed Tree Mortality CEMA	NA	NA	NA	(2) Inspection and Maintenance
Forest Resiliency Corridor Development	All Assets within the ROW Corridor	Proposed Liberty CalPeco required contribution for grant: $661,030 // Expense	No	GO 95 Rule 35; Public Resources Code Sections 4292 & 4293; Executive Order N-05-19	Pending 2019 GRC application	Proposed Wildfire Mitigation Memorandum Account	NA	NA	NA	(2) Inspection and Maintenance
SITUATIONAL AWARENESS										
Weather Stations	13 Weather Station being installed	$75,000 averaged annually; total approx. cost for all 13 stations: $148,720 // Capital	No	NA	NA	Proposed Wildfire Mitigation Memorandum Account	NA	Number of weather stations installed	Rationale: Improves forecasting and de-energization and restoration plans	(4) Situational / Conditional Awareness
Weather Monitoring	All Assets	Standard Business Operations // Expense	Yes	D.12-01-032 pursuant to R. 08-11-005; ESRB-8	NA	Proposed Wildfire Mitigation Memorandum Account	NA	NA	NA	(4) Situational / Conditional Awareness
RESPONSE & RECOVERY										
PSPS Events	All Assets	Standard Business Operations // Expense	Yes	NA	R. 18-12-005	NA	NA	Monitor the number of PSPS events over time as an indicator of changing climatic and weather patterns	Determine the effective of procedures for PSPS events.	(5) Response and Recovery
Post Incident Recovery; Resotration & Remediation	All Assets	Standard Business Operations // Expense	Yes	Resolutions M-4833 & M-4835	R. 18-03-011 & R. 18-12-005	NA	NA	NA	NA	(5) Response and Recovery

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APPENDIX B. LAKE TAHOE FIRE LETTER OF SUPPORT

North Tahoe Fire Protection District

Michael S. Schwartz, Fire Chief

Todd Conradson, Fire Marshal

222 Fairway Drive
P.O. Box 5879
Tahoe City, CA 96145
530.583.6911
Fax 530.583.6909
conradson@ntfire.net

January 28, 2019

Travis Johnson, P.E.
Vice President, Operations
Liberty Utilities (California)
Travis.Johnson@libertyutilities.com

Mr. Johnson,

The purpose of this letter is to express concerns over the condition of Liberty Utilities' Brockway substation located at the corner of Deer and Cutthroat in Kings Beach. After looking at the substation on 1-22-2019, the Fire District has great concern over the potential for fire from that facility and the threat to the local community.

The various wood beams supporting the high voltage electrical equipment are split, twisted and warped. It is questionable if that structure is still safe and it appears its condition is no longer functioning as it was engineered at the time it was built. If this structure was to fail it is likely to cause a fire, and being located in the middle of a residential neighborhood, it will threaten the homes and lives of the residents in that area.

That facility has a history of fire and we fear that if left unaddressed, additional fires will occur. I am sure you are aware of the recent catastrophic fires in California caused by the failure of electrical equipment. We are now aware of the hazard your substation is posing to the residential area of Kings Beach and are concerned it has the potential to create a devastating fire given the weather conditions at the time of a failure.

It is the desire and recommendation of the North Tahoe Fire Protection District to relocate the Brockway substation out of the residential area. It is our understanding that Liberty Utilities has alternate locations available that are better suited for that use and not in close proximity to residential homes. Given the location and degrading condition of the current facility, the availability of other sites, and the threat it poses to the surrounding area, the Fire District believes it is a timely solution to an identified problem.

Thank you for your consideration,

Division Chief Todd Conradson, Fire Marshal
North Tahoe Fire Protection District

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APPENDIX C. EMERGENCY MANAGEMENT PLAN

This Emergency Management Plan's formatting has been modified for inclusion within Appendix C.

Liberty Utilities		933 Eloise Avenue South Lake Tahoe, California 96150 530-541-1949		
GENERAL PROCEDURE		Proc. #:	**8800-100-300-007**	
Description:	Emergency Management Plan	Revision #:	4	Pages: 18

1.0 Purpose

The purpose of Liberty Utilities Emergency Management Plan (Plan) is to enhance the Company's capability to respond to and recover from emergencies of all levels including natural disasters. The plan provides the framework and organizational structure to manage the consequences resulting from unexpected loss of infrastructure and equipment through active response and recovery preparedness, resource planning and practice training exercises. The plan is updated as necessary during the continuous cycle of planning, response, recovery and mitigation.

2.0 Objectives

During emergency situations and disasters to:

1. Protect the life, safety and health of employees and the public.
2. Protect the property and assets of the Company and Public.
3. Protect the environment.
4. Provide for the expeditious restoration of service and return to normal operations.
5. Provide prepared and trained employees as well as pre-developed plans and information to manage events.

3.0 Emergency Response Organizational Structure & Functions

Emergency Preparedness efforts are aimed at providing the organizational structure, resources, and disaster response training necessary for consolidated and effective Company-wide response. The utility industry is designed to deal with normal to moderate emergencies as part of normal operations. On the occasions that the size and scope of an emergency reaches beyond the resource and response capabilities of a specific department or area, additional emergency response efforts can be activated under this plan to any level necessary to provide the appropriate resource, information, communication and coordination.

CA-07-0505

The model for the Company's Emergency Response Organization uses a tiered level approach to implement an Incident Command System (ICS). The ICS is an organized approach to effectively control and manage emergency operations should emergency levels reach level 3, 2 or 1, as described under section 4.2. The initial tiers, level 5 or level 4, use the individual department or **Regional Command Centers** to initially address emergency situations using the incident command system.

These centers are responsible for command and control of all phases of the emergency in their region and can be supplemented with support from the **Emergency Management Team** members without the official activation of the **Incident Command System (ICS)/Incident Command Post.** Support may include any or all of the following: Executive policy support, Security, Safety, Communications, Operations, Finance, Logistics, Services and/or Liaisons. Additionally, with or without multiple emergency command centers activated, an **ICS** may be activated at either the North or South location to assist in resource and information coordination during an emergency or may be activated for large scale or complex emergencies. The Incident Command Post operates under the ICS for emergency management and when the ICS is activated, the overall management will be under the responsibility of the **Incident Commander**. The ICS function will be to coordinate and direct all response and mitigation efforts inside the perimeter.

1. **Description/Responsibilities of Regions** -The two regions operate independent control areas. The North Lake Region is predominantly sourced from the 120kV system out of Truckee and includes the Squaw Valley, Northstar, Portola and Loyalton areas. The South Lake Region is sourced mainly from the 120kV system out of the Carson Valley and includes the Markleeville, Coleville and Walker areas. Interconnection between the two regions is minimal; due to the independent configuration of the regions, they operate individually during most emergencies. NV-Energy supplies all energy to the Company and all transmission level control is administered through NV Energy Electric System Control Center. Each Regional Manager is responsible for establishing a working relationship with local police, fire, City and County Emergency Planners and for participating with Local Emergency Planning Committees.

2. **Regional Incident Command Centers (ICC)** - These centers represent the first level, Level 5 or Level 4, of command and control of an emergency from the individual region. Most all emergencies are managed at these levels. All field operations and activities are controlled from these centers and field command and control is not transferred to the company ICS if it is activated in support of an emergency event. The South Lake Tahoe Office and the North Lake Tahoe office each function independently for the management of emergencies contained within their areas and is equipped with information and communications equipment for such purpose. Regional Centers coordinate resource support between one another when feasible. Essential Functions Include:
    a. Primary emergency response with assigned emergency personnel.
    b. Designation of a **Regional Incident Commander - the person**
    c. Distribution System Control, switching and operations directives
    d. Damage Assessment, life safety issues assessment, and establishment of response priorities.

e. Management of emergency response resources (materials, equipment, manpower). f. Prioritization of Restorations
g. Resource Mobilization, Allocation and Acquisition
h. Communication & Coordination with Public Safety, Local Governments, Media & Customers
i. Regulatory Reporting as may be necessary

3. **Emergency Management Team-** This team is activated with the onset of an emergency event (Level 3, 2 or 1), in anticipation of an emergency event, or in response to an event with corporate risk, with or without operational damages or deficiencies. This team initially provides support to the regional activities and may consist of any or all of the following positions: the Policy Director, Public Information Officer, Safety & Security Officer, Emergency Response Liaison, and one or more of the affected operating or administrative managers. This is the team that will in part staff the Incident Commander Center if the Level 3, 2 or 1 has been attained. The additional members of the ICS/Emergency Management Team who also may be activated for any event to either support the regional activities or staff the ICS if activated include: Operations Leader, Logistics Leader, Planning Leader, Financial/Regulatory Leader and Services Leader. An organization chart showing the make-up of the fully staffed Emergency Management Team and full-function ICS is attached to the Plan and EOC Organization Attachment.

a. *Incident Commander* - This is normally the President of the Company; however, this responsibility may be delegated to a manager depending upon the emergency at hand. There will be a single Incident Commander appointed for each working shift who will serve as the overall Incident Commander when the ICS is activated. The Incident Commander will be the "individual in charge" establishing a clear chain of command, control of information and emergency coordination. When the Incident Commander is called upon to assist the Regional Incident Commander, but the ICS has not yet been activated, this individual will serve as a policy resource to the Regional Incident Commander.

i. Provides policy guidance and approval for strategies, actions and activities.
ii. Communicates directly with the Corporate Headquarters
iii. Responsible authority for strategy and content of Public Information and Company Communications

b. *Public Information Officer (PIO)* - Works in conjunction with the Incident Commander or as support to the Regional Incident Commanders to develop communication strategies and content of all information to be disseminated pertaining to the emergency event(s).

i. Strategy and content of press conferences, news releases, and other media activities.
ii. PIO to act as liaison with national and local media and governmental operations centers.
iii. Employee/Company communications: status, instructions, and updates as necessary.

c. *Safety & Security Officer* - Provides review of emergency operation activities to ensure work is being performed safely, ensures public safety around facilities that may be energized and assists in prioritization of safety related matters. Provides for the protection and security of company employees and assets, mitigates damage to facilities, and ensure effective coordination with law enforcement agencies.

i. Provides security and control of unauthorized, unplanned activities or security violations.

ii. Provides command and control for evacuation of facilities. iii. Provides direct coordination with federal, state or local law enforcement agencies. iv. Provides for employee and public safety

d. *Government Liaison* - Communicates with key local, state or federal government authorities and officials regarding emergency activities and information.

i. Provide information to officials regarding the status of the company's ability to provide/restore service.

ii. Provide periodic updates based on information gathered at the Regional Control Center and /or Emergency Operations Center.

iii. Relay messages regarding governmental representatives' concerns, offers of assistance etc.

e. *Emergency Response Liaison* - Provides a link between the utility and external agencies to keep them informed regarding any impacts the event may have on the utility's ability to provide/restore service.

i. Communicate with local, state, and federal emergency managers and emergency operation centers to keep them appraised of the status of the event(s) and assist in coordination of emergency response efforts as necessary.

ii. Assist in coordination and communication with other utilities, local or regional government entities, and emergency response agencies as necessary.

iii. Provide guidance and strategy in company emergency response plans, centers and procedures.

f. *Operations Leader* - Responsible for the management of all tactical operations directly applicable to the emergency response. Provides direction to the frontline field personnel in damage assessment and priorities and requests resources necessary to restore service. Areas of responsibility include distribution, transmission, emergency generation and customer service.

g. *Logistics Leader* - Responsible for providing the equipment, supplies and personnel that the operations needs to respond to the emergency. May engage contract or mutual aid services in support of the emergency. Schedules manpower or resources to cover additional emergency operations periods.

h. *Planning Leader* - Provides analysis of emergency information and situations and develops plans to be used during the response and recovery operations to fully return electric service as quickly as possible for the least cost. Facilitates implementation of action plans.

i. *Financial/Regulatory Leader* - Responsible for ensuring that funds are available as need for the emergency. Provides tracking of costs of the response and recovery and ensuring that records are maintained throughout the event and sufficient to apply for regulatory relief or outside funding from resources like FEMA. This leader is also responsible for risk management and claims.

j. *Services Leader* - This area provides any support services need to manage the emergency situation which may include human resources or administrative support.

4. **Incident Command System(ICS) Organization -** This center can be activated to provide additional resources support, levels 3, 2 or 1, and coordination, centralized information coordination and policy direction as necessary to support the activation of a single, or multiple Regional Command Centers ; the activation is typical when the emergency or combination of events becomes significant in nature, poses significant Company risk or requires response, support or coordination for or from multiple areas. EOCs can also be activated by the ICS/Emergency Management Team to coordinate emergency information and support utility operations, emergencies, or any other company emergency situations. Either office may be designated as the Incident Command Post during emergencies depending upon accessibility, where the ICS can be most effective and the specific type of emergency. The ICS is activated to provide resource support and information to the regional offices while each regional operation maintains the responsibility for field operations related to assessment, recovery and restoration. The Emergency Management Team/ICS is supported by the EOCs and is activated to the level of support required for the specific emergency; this team may provide the following functions:

   a. Policy guidance, strategic planning and decision making.
   b. Operations/ Resource Support and coordination from activated Regional Command Centers.
   c. Logistics and resource procurement, support, scheduling and allocation.
   d. Planning, engineering, and technical support as needed for situation assessment and recovery.
   e. Finance/Procurement of materials, resources and supplies
   f. Media & Employee Communications/ Public Information dissemination, both internally and externally
   g. Liaison to Governmental EOC and information exchange and coordination with state and local emergency agencies and governments.
   h. Safety & Security for employees, work sites, and the general public.
   i. Administrative Support and documentation of events, decision making, resource allocation etc.
   j. Regulatory & Legal assessments in support of strategic decisions.

4.0 Emergency Activation:

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1. **Activation Levels -** There are five levels of activation for emergency / disaster response. See Table 2 for additional details on the Operating Conditions and Typical Storm Levels related to each Activation Level.

   a. **Activation Level 5 – Small Impact Event (Localized Response Condition)**:The minor disruption of operating systems, business systems, or electric service that can be managed with existing resources at the local or department level. Often an On Call Supervisor or a regional manager serves as the Regional Incident Commander throughout the emergency; other assistance is activated as the Regional Incident Commander deems necessary. Outage is typically restored within 1 – 12 hours.
   Action: Normal activity, daily internal crew assignments.
   Communication Characteristics:
      - Crisis attracts little of no attention
      - Public and/or media are virtually unaware
      - Email notification to 911@algonquinpower.com

   b. **Activation Level 4 – Moderate Impact Event (Heightened Alert)**: The occurrence of an event that maximizes the resources and management capability of the local region and may require additional resources and support. Often an On Call Supervisor or a regional manager serves as the Regional Incident Commander throughout the emergency; other assistance is activated as the Regional Incident Commander deems necessary. Outage is typically restored within 12 – 24 hours.
   Action: Normal activity, daily internal crew assignments. Possible crew transfer between areas. Utility Contractor crews (overhead line and tree) limited to normal daily complement, as needed.
   Communication Characteristics:
      - Crisis situation may/may not have occurred; the situation is attracting slow but steady media coverage
      - The public at large is aware of the situation/event but is attracting very little attention
      - Email notification to 911@algonquinpower.com

   c. **Activation Level 3 – Serious Impact Event (Enhanced Support)**: The occurrence of a disaster or major emergency that may affect several areas of our electric system and may require the services of all operations personnel. The On Call Supervisor may serve as the initial Regional Incident Commander but will relinquish that position to the ICS Incident Commander. Outage is typically longer than 24 hours.
   Action: Regional or System ICS may be initiated and Regional EOC's may be opened. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.
   Communication Characteristics:
      - Crisis causes growing attention from local and regional media
      - Affected and potentially affected parties threaten to talk to the media
      - Email notification to 911@algonquinpower.com, with return 10 min confirmation

d. **Activation Level 2 – Major Impact Event (Comprehensive Support)**: The occurrence of a disaster or major emergency that affects several areas of our electric system and requires the services of all operations personnel. The On Call Supervisor may serve as the initial Regional Incident Leader but will relinquish that position to the regional EOC Incident Commander and then the ICS Incident Commander. Liberty Utilities may provide resources to other agency EOC's as needed for more efficient and effective communications on the event and/or electrical system issues. Outage is typically longer than 24 hours.

Action: Regional or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.

Communication Characteristics:

- Media are reaching out to employees and non-communication staff for information about the crisis
- Broadcast and print media are on-site for live coverage
- In addition to the media, stakeholders and community partners are present at site
- Email notification to 911@algonquinpower.com, with phone call per protocol to confirm receipt

e. **Activation Level 1 – Catastrophic Impact Event (Emergency Support)**: The occurrence of a disaster or major emergency of requiring a corporate response to minimize corporate risk. This level requires policy guidance, strategic planning, and coordination of internal and external resources, internal communication and coordination, dissemination of public information. The field supervisor may serve as the Regional initial Incident Leader but will relinquish that position to the ICS Incident Commander. Liberty Utilities may provide resources to other agency EOC's as needed for more efficient and effective communications on the event and/or electrical system issues. Outage will typically affect more than 50% of our customer base and be longer than 72 hours.

Action: Regional and/or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.

Communication Characteristics:

- Public health & safety is concerned
- National or international media are covering as major news
- Major government attention is present
- There is real or potential environmental harm
- One or more groups are expressing anger or outrage
- Email notification to 911@algonquinpower.com, with phone call per protocol to confirm receipt

2. **Activation Authorities:**

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a. Emergency Management Team: The authority to activate the entire Emergency Management Team rests with the President or the designated alternate. Authority may be delegated to responsible Managers of Operations and Administrative Services to activate an Emergency Management Team as initial response to emergency situations. The President will designate where the Emergency Management Team will locate on initial activation. Administrative Support will assist with notification of the Emergency Management Team.
b. Incident Command Center (ICC): The activation of the full Incident Command Center, the location of the ICC as well as the levels and functions to be utilized are within the authority of the President or designee. In the absence of the President, the Emergency Management team will be the decision making body related to activation of the ICS and the level of activation.
c. Regional Incident Command Center(s); any Team Leader, Manager, or their alternates can activate their own organization to the level of support required to respond to any event.

5.0 Coordination with State and Local Governments:

The Business Manager for each region is responsible for establishing and maintaining a relationship with local governmental agencies and for providing a liaison with the appropriate agency during an emergency event. Emergency Management Team members representing Safety & Security, Emergency Response Liaison, and Public Information Officer can be utilized to assist in effective coordination and information between State and Local Government agencies.

Liberty Utilities is an active participant and supporter of state and local emergency response efforts including Local Emergency Planning Committees (LEPC), California Utility Emergency Association (CUEA), Sierra Front Wildfire Cooperators and local county offices of emergency services.

6.0 Mutual Assistance Agreements:

The Company has negotiated a Mutual Assistance Agreement for labor and equipment resources with NV Energy. Liberty Utilities is also a member of the CUEA and Western Energy Institute Mutual Assistance Roster.

7.0 Supplemental & Contingency Planning Resources:

No single plan can foresee all the needs or contain all the information necessary to respond to every event. By design, Emergency Management Plans are concise, uncluttered and with sufficient direction to reference information or detail contingency plans that can be obtained in other hazard specific plans or manuals. Many subject areas (i.e. load curtailment, hazardous material response, etc.) contain significant detail and complexity and are too cumbersome to include in any emergency response or business recovery plan. The following is a partial list of contingency plans or manuals may be included, in part, or as reference, to the Emergency Management Plan.

1. **Supplemental (Contingency) plans:**

a. Fire Prevention Plans
b. Outage Communication Plans
c. Mutual Assistance Agreements
d. Operations Procedure Manuals
e. Spill Response Plans
f. Business Continuity Plans

8.0 Emergency Plan Additional Elements

This Emergency Plan does not attempt to provide solutions for specific emergency scenarios; instead it provides a general framework for identifying solutions unique to the emergency situation at hand.

1. **Communications:** The Incident Commander serves as the spokesperson unless that function is specifically delegated by the Incident Commander; delegation is typically to an individual trained in the function of the Public Information Officer. Other Company personnel shall refrain from disseminating information to anyone.

   The Public Information Officer (PIO) is responsible for ensuring that relevant information is distributed in a timely manner to the general public via the news media. The PIO serves as the primary point of contact at the company for news media inquiries. This individual also facilitates communications between news reporters and other company representatives. The PIO or alternate should be available throughout the outage to provide periodic updates to the news media. If practical, the PIO should be on site at the Incident Command Center. The PIO is responsible for maintaining up-to-date telephone and fax listings for news media outlets.

   a. Prior to an Emergency- The PIO will update annually all media contact information. Information will be disseminated to the public through the media advising customer what to do to prepare for extended outages and what emergency supplies may be necessary to keep on hand. Customers will be given information on safety around downed power lines and other safety precautions to observe during an event. Media outlets will be provided with emergency contact information for the utility including names and contact information for each regional office as well as the PIO. The PIO will ensure that operations contact lists are up to date with both primary and secondary contact information available. The PIO will create standard messaging for common events. Pre-developed information can be found in the Communications Attachment to this plan.
   b. During an Emergency - The Incident Commander or designee contacts the PIO and provides outage information for distribution to media; the PIO contacts the media with outage information including the following:
      i. When did the outage begin?
      ii. What caused the outage?
      iii. How many customers are affected?
      iv. Where are they located?
      v. What are we doing about the outage?

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vi. When do we expect service to be restored?

vii. vii. A telephone number customer can call for information?

viii. A description of safety hazards such as downed power lines?

c. Notifications – A contact list of the local governmental agencies, municipalities and media outlets within our service territory has been developed. During a major outage or emergency which affects a significant number of our customers, an email is sent to the respective personnel and agencies and media to provide information, detail and status of the outage. As the outage or emergency continues, status update emails and / or phone calls will be made to keep the agencies and media informed. Once the outage has concluded and the system is back to normal, a final email will be sent to close out the communication of the incident.

d. Customer Information/Contact - The primary point of customer contact is telephone information via live customer contact or the Interactive Voice Response and messaging system.

i. High Call Volumes: Customer Service Representatives (CSR) will pick up as many incoming calls as possible in the individual offices. During periods of High Call Volume the customer service centers utilize an Interactive Voice Response (IVR) system that will allow customers to receive customized messages about outages that are being addressed in the Tahoe Region. It will also allow for emergency calls to be routed to a live customer service representative for life support or life threatening emergencies. This system will also allow the customer to receive a call back regarding their outage if they choose that option.

ii. Customer Service Representatives will be able to develop custom IVR messages that will be heard by the customers on the IVR system for any calls that are not answered by a live CSR. Standard emergency message consists of: Day, Month, Time, General Areas Affected, Cause (if known), and Estimated Restoration Time (if known). A follow-up message with more specific information can be recorded as more information is received. The IVR system is capable of automated callbacks if the customer selects this option from the outage script. iii. The Customer Services Manager or the designated alternate may approve a request for mutual assistance as a Requesting Utility. The Company has Mutual Assistance agreements established with NV Energy and other utilities in case call volume or phone access prevent the Company from handling calls directly.

iii. Following the emergency event, the PIO or designee provides the media outlets used during the event with a wrap-up of information regarding the resolution of the emergency and any final information for the public. Customers who requested a return call following the event will be messaged by phone. These steps finalize the emergency communications with the public.

2. **Governmental & Regulatory Communications** - In nearly all emergency events the utility is closely involved with local law enforcement, medical and fire agencies. In larger Emergencies City and County Emergency Management representatives provide coordinating responsibilities in responding to the event. In escalating emergency events, additional coordinating resources, such as an Emergency Response Liaison and/or a Government Liaison, can be activated by the Incident Commander.

   a. During emergency events the Company will provide communications to, or a liaison to, the highest level of city or county Emergency Operations Center activated. This is accomplished through Emergency Response Liaison or Government Liaison who are both members of the Emergency Management Team.
   b. If an emergency event is large enough to initiate the activation of a State level Emergency Operations Center or Regional Emergency Operations Center, the Emergency Response Liaison will communicate with the State activated EOC. The California State coordination will be through the California Utilities Emergency Association (CUEA) Emergency Operations Center. The CUEA operates as a Utility Branch of the State Standardized Emergency Management System (SEMS) and reports directly to the State Operations Center (SOC) in Sacramento.
   c. The Company is a member of the California Utilities Emergency Association (CUEA) which provides emergency planning, training, resource assistance, and operates the Utility Emergency Operations Center as the Utility Branch for the Office of Emergency Services (OES) at the State EOC. The Company Emergency Response Liaison is a responder to the CUEA EOC, which is co-located with the State Operations Center.
   d. The California Public Utility Commission (CPUC) requires reporting for Safety and for substantial outages. Guidelines for reporting to the CPUC utility commissions follow this section in Table 1. Reporting forms and checklists are also contained in the Regulatory Reporting Attachment to this plan.

TABLE I: Reporting Guidelines for Public Utility Commission

The following is a summary of reporting requirements. The Corporate Regulatory Manager should be consulted for any discrepancies or questions regarding reporting of incidents or events. The table is a guideline only.

California Public Utility Commission = CPUC, Office of Emergency Services (OES) at the State EOC

What:	Defined:	Report To:	When:	How:
Major Outage	**Customers simultaneous and non-momentary outage of 1/2 Customers (Approx. 23,000)**	**1) OES Warning Center** **2) CPUC Energy Division**	**1) OES Within 1 hour,** **2) CPUC within 1 hour,** **3) CPUC every 4 hours with updates**	**1) OES 800 number** **2) Energy Branch Phone Mail** **3) Phone mail or e-mail as per Energy Division request.**

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Sustained Outage	**A. Outage lasting over 24 hours or expected to total over 60,000 customer hours (or an event likely to lead to such a situation)** **B. Outages expected to accrue over 300,000 cust. hours.**	**1) CPUC Energy Division**	**1) A. By 9:00 AM the next Business Day** **2) B. CPUC Energy Branch within 1 hour**	**1) Energy Branch Phone Mail**
Notable or Newsworthy	**Event involving facilities or personnel reported in two media markets or in national media.**	**1) CPUC Energy Division** **2) CPUC Utility Safety Branch**	**1) CPUC Energy Branch within 1 hour** **2) Safety Branch within 2 hours during working hours and 4 hours outside of working hours.**	**1) Energy Branch Phone Mail** **2)Safety Branch** **a) Report at http://www.cpuc.ca.gov/emrep/** **b) Follow up with email or fax within 24-hours** **Formal Report *20* days**

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TABLE I: Reporting Guidelines for Public Utility Commission (Cont.)

What:	Defined:	Report To:	When:	How:
Load Shed / Rolling Blackout	Loss of power supply leading to extensive load shedding or rolling blackout. Imminent or Planned Load Curtailment or Rotating Outages of Firm Load.	1) CPUC Energy Division	1) CPUC within 1 hour and every time a new circuit is interrupted.	1) Energy Branch Phone Mail
Injury / Fatality	Fatality or personal injury rising to the level of in-patient hospitalization.	1) CPUC Utility Safety Branch 2) CPUC Energy Branch	1) Safety Branch within 2 hours during working hours and 4 hours outside of working hours. 2) Energy Branch within 1hour	1) Safety Branch a) Report at http://www.cpuc.ca.gov/emrep/ b) Follow up with email or fax within 24-hours c) Formal Report *20* days 2) Energy Branch Phone Mail
Damage to Property	Damage to property of the utility or others estimated to exceed $50,000 and are attributable or allegedly attributable to utility owned facilities.	1) CPUC Utility Safety Branch	1) Safety Branch within 2 hours during working hours and 4 hours outside of working hours.	1) Report at http://www.cpuc.ca.gov/emrep/ 2) Follow up with email or fax within 24-hours 3) Formal Report *20* days

(EHS will participate in all reporting and investigation of injury, fatality or damage incidents according to 8800-100-200-001- Incident Reporting and Investigation Procedure)

3. **Safety** - This Plan requires a "Safety First" response to all emergencies; the safety of employees, contractors, assisting crews, and the general public is to be ensured at all times.

a. Public Safety - The Company provides on-going public electric safety courses and information so that the Public will be prepared when an emergency event occurs. These programs are provided year round to all levels of schools, business, service clubs and also trade shows and expositions. Additionally the Company routinely provides electric safety training to local and regional law enforcement, fire, county and state transportation, and other emergency response agencies. Public Safety Training is the responsibility of all.

   i. During an emergency event, the Company may utilize Stand-By personnel, trained in general electrical safety, to "Observe and Report" electric hazard conditions, and assist in "Perimeter Safety" around identified hazards due to unsafe conditions until qualified electric personnel arrive. The Public shall heed all warnings and barriers placed by the Company to secure hazards.

b. Employee Safety - Personnel safety is identified as a key element within this Emergency Response Plan. Electric Trade Personnel, including Ground person, helpers, apprentices, journeyman lineman, trouble men, inspectors etc., are provided the highest level of safety and skills training to perform in both daily and emergency situations.

   i. Only "Qualified" and trained personnel may perform safety sensitive functions including switching, de-energizing, overhead and underground operations, repairing and assessing damage.

   ii. To ensure employee safety (and public safety as well), the design, installation and operation of equipment and automatic protection schemes for transmission and substation equipment must remain in place, protection schemes may not be by-passed by any employee .

   iii. Employees will follow procedures which are in accordance with OSHA 1910.269 regulations.

   iv. Non-Trade personnel that are utilized in assistance with emergency repair (metering, meter reading, construction, etc.) must be trained in general electric safety before assisting in emergency field response.

c. During An Emergency Event - The Company will respond to Immediate Life Safety Issues as the top priority. Once a hazardous situation is reported, immediate response will be provided by line crews, trouble man, inspectors or other trained personnel to assess and make the situation safe by de-energizing, supporting, removing, repairing, or barricading and providing for Safety Stand-By personnel as necessary.

   i. All field response employees shall have safety training which is aligned with their respective roles.

   ii. All electrical switching and reporting shall be handled through the appropriate Controlling Parties to ensure both employee and public safety.

   iii. The Company will provide regular public information, typically in the form of media messages or alerts, regarding unsafe or hazardous areas or conditions that the public should be kept informed about.

   iv. In the event of an area emergency that is life or property threatening, the Emergency Alert System (EAS) can be enabled through the local or county Emergency Management or Public Safety office. The Company will advise the Emergency Management agencies when such alert is essential.

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v. Public Safety Agencies will be utilized as necessary for traffic control and perimeter safety until qualified personnel arrive to clear the hazard situation. Agencies will be used if necessary to control public disturbances and establish safety controls for the public.

vi. Employees are monitored for appropriate meal breaks, hours worked and safety compliance; when emergencies are expected to last more than 24Hours, shifts will be established to cover work and employees will be given appropriate rest periods.

vii. Weather and road conditions are monitored for worsening conditions such that workers do not become stranded at remote work locations.

viii. Work may be curtailed, even if customers remain out of service, until safe work conditions prevail.

4. **Damage Assessment** - The designated Incident Commander is responsible for determining how damage assessment will be best achieved for the specific emergency situation and other functions to be performed by specific individuals. The Incident Commander may delegate the responsibility, or a piece of the responsibility, to the Manager(s) or other qualified individual(s), or retain this responsibility.

a. The designated Damage Assessment Leader(s) will then become responsible for assembling, assigning and setting priorities for Damage Assessment Teams in accordance with Restoration Priority Guidelines or priorities established by the Incident Commander.

b. Company Crews, Linemen, Troublemen, Electric Inspectors, Utility Designers and/or engineers will be first called for damage assessment; Company personnel will be augmented as necessary and approved by the Incident Commander with Contractors and/or mutual aid parties.

c. Company Teams will be given priority patrol assignments along with difficult hazards and locations unfamiliar to visiting teams.

d. Documentation of Damage: All damage will be recorded by the teams on the circuit maps IN RED. The standard symbols shown below shall be used.

i. Standard Symbols :

F = Blown line Fuse
B = Tree Branch on Line
P = Primary Span Down - Provide # ____
S = Secondary Span Down - Provide # ____
PB = Poles Broken - Provide # ____
PL = Poles Leaning - Provide # ____ (Correction Required)
SV= Service(s) Down - Provide # ____
TR = Transformer(s) Down - Provide # ____
OIL = Oil spill, Clean up needed; Identify PCB or Non-PCB

e. Damage Assessment Teams shall take the following standard supplies to the field to perform assessments: Clip Board, Circuit Map Books, Red Pens, Pencils or pens, Patrol Report Forms, Area or Street Maps, Stores Request Forms, PCB Oil Test Kit, Digital Camera (with charged battery), Warning Tape, Cones and Barriers.

f. All maps and related information shall be returned to the Damage Assessment Leader as soon as practicable for restoration decision making.

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g. To the extent practicable, downed or damaged facilities shall be isolated, secured and warnings applied utilizing cones, warning tape or other barriers or warnings.

5. **Restoration** - Service restoration is unique to each emergency and prioritizing restorations may depend upon a number of factors including safety, accessibility, availability of repair parts, availability of personnel as well as other factors. This element of the plan identifies general prioritization guidelines for restorations, but allows for the Incident Commander or designee to alter priorities according to the circumstances of the emergency and in coordination with essential load customers and government agencies involved.

a. General Restoration Guidelines include:

i. Restoring radial transmission and substations first;

ii. Followed next by addressing distribution circuits with "Essential Customers" such as health care facilities, utilities, public safety, governmental facilities and lifeline customers.

iii. Subsequently, circuits with the greatest number of customers are prioritized;

iv. Next in line are primary taps followed by secondary lines.

v. Finally individual services which are accessible and serviceable can be addressed. vi. Essential Customers: Below is the priority list of these types of Customers; specific contact information and locations of each "Essential Customers" may be found in the Customer Information Attachment to this Plan. Priority assumes circuits, equipment and services are accessible and repairable.

1. Health Care Facilities
    a) Primary Care Hospitals
2. Utility Services/Districts
    a) Public Utility Districts
    b) Telecommunications
    c) Water/Water Treatment
    d) Pipeline
3. Public safety agencies
    a) Public Safety Dispatch Centers
    b) Law enforcement facilities/holding facilities
    c) Fire operations facilities
    d) Transportation equipment and facilities
4. Government facilities
5. Green Cross/Life Line

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6. **Mutual Aid** - The Incident Commander has responsibility for mobilizing resources, contracting for additional assistance and supplies, and calling for assistance from neighboring utilities through Mutual Aid Agreements.
    a. The type, size and duration of an emergency event will determine, in varying degrees, the amount of resources required to respond to the event. The Regional Operations do not have enough resources to respond to a large emergency event without supplementing manpower, equipment or materials from other sources.
    b. The Incident Commander will direct the requests for additional internal (company) and external resources; The Incident Commander must approve the use of Mutual Aid.
    c. Requests may be made for efficiency and not for exhausted resources. Resource requests may include trade and non-trade personnel to assist in safety stand-by, damage assessment, planning or liaison activities, or materials and equipment necessary to facilitate restoration of utilities.

9.0 Training

Liberty Utilities employees receive Emergency Management Plan training annually. All employees are trained and their commitment is critical to the successful Plan implementation during an emergency. Instruction includes specific training on the roles and responsibilities of each functional area in support of the ICS at the Company level or the Incident Commander at the regional level. With a finite workforce, employees may be called upon to support areas outside their normal job assignments with appropriate training. In addition, emergency response exercises are executed annually so employees gain practice in the use of the plan as well as test the plan for effectiveness. The Company participates in regional exercises to train employees and exercise the Emergency Management Plan.

10.0 Record Keeping

Recordkeeping is essential to all programs especially the EMP. All training, program elements, comprehensive emergency plans, exercises, debriefing, corrective action and evaluations must all be documented and accessible.
Records are retained for the following reasons:

- Due diligence
- Training (lessons learned)
- Regulatory requirements

All electronic communication such as emails, meeting minutes, resource plans, and incident progress reports will be submitted to the local internal emergency mailbox. Copies of these reports will also be submitted to Corporate Headquarters. Retention of these records is critical as they will be examined during debriefing and corrective action exercises.

berty Utilities

TABLE 2

Storm Event Level	Operating Condition	Operating Conditions and Storm Levels: Expected % of Customers w/o Service & Duration (1)	Expected Number of Trouble Locations / Devices (2)	Expected Number & Types of Crews	Typical Event Frequency	Weather Indices: Snow (wet / inches)	Ice Accretion (inches)	Tree Foliage: Leaves on	Tree Foliage: Leaves off	Wind Impact (mph)	Wind Only (mph)
5	Small Impact Event (Localalized Response Conditions)	> 2,500 & < 4,499 customers	0 - 4 Locations or Devices of Trouble	Normal activity, daily internal crew assignments.	5 - 75 times per year	≤ 2"	< 0.25			≤ 25	< 25 Gusts to 25
		AND				≤ 4"	< 0.50	✓		≤ 10	
		>1 & <12 hour ERT for full system service restoration									
4	Moderate Impact Event (Heightened Alert)	> 4,500 & < 9,999 customers	2 - 10 Locations or Devices of Trouble	Normal activity, daily internal crew assignments. Possible crew transfer between areas. Utility Contractor crews (overhead line and tree) limited to normal daily complement, as needed.	5 - 15 times per year	≤ 6"	< 0.25	✓		≥ 25	15 - 25 Gusts to 45
		AND				≤ 8"	0.25 - 0.50	✓		15 - 25	
		>12 & < 24 hour ERT for full system service restoration				≤ 10"	0.50 - 0.75	✓	✓	≤ 10	
3	Serious Impact Event (Enhanced Support)	> 10,000 & < 19,999 customers	3 - 15 Locations or Devices of Trouble	Regional or System ICS may be initiated and Regional EOC's may be opened. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	0 - 5 times per year	≤ 6"	0.10 - 0.25	✓	✓	≥ 35	35 - 45 Gusts to 55
		AND				≤ 8"	0.25 - 0.50	✓	✓	25 - 35	
		> 24 hour ERT for full system service restoration				≤ 10"	0.50 - 0.75	✓	✓	15 - 25	
						≤ 12"	0.75 - 1.00	✓	✓	< 15	
2	Major Impact Event (Comprehensive Support)	> 20,000 to < 50% customers	> 5 Locations or Devices of Trouble	Regional or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Once every 1 to 10 Years	≤ 12"	0.25 - 0.50	✓	✓	≥ 35	45 - 55 Gusts to 75
		AND				≤ 14"	0.50 - 0.75	✓	✓	25 - 35	
		> 24 hour ERT for full system service restoration				≤ 16"	0.75 - 1.00	✓	✓	15 - 25	
						≤ 18"	1.00 - 1.50	✓	✓	< 15	
1	Catastrophic Impact Event (Emergency Support)	> 50% customer interruptions	> 10 Locations or Devices of Trouble	Regional and/or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Once every 10 to 25 Years	≤ 15"	0.50 - 0.75	✓	✓	≥ 35	≥ 55 Gusts to > 75
		OR					0.75 - 1.00	✓	✓	≥ 25	
		> 72 hour ERT for full system service restoration					1.00 - 1.50	✓	✓	≥ 15	
							> 1.50	✓	✓	Any	

LU CA Electric Emergency Incident Levels and Classification Guidelines

Classifications	Level 5: Small Impact Event	Level 4: Moderate Impact Event	Level 3: Serious Impact Event	Level 2: Major Impact Event	Level 1: Catastrophic Impact Event
Expected # of Customers w/o Service & Duration (1)	> 2,500 & < 4,499 customers AND > 1 hr & < 12 Hr ERT for full service restoration	> 4,500 & < 9,999 customers AND > 12 hr & < 24 Hr ERT for full service restoration	> 10,000 & < 19,999 customers AND >24 hour ERT for full system service restoration	> 20,000 to < 50% customers AND > 24 hour ERT for full service restoration	> 50% customer interruptions OR > 72 hour of ERT for full service restoration
Expected Number & Types of Crews	Normal activity, daily internal crew assignments.	Normal activity, daily internal crew assignments. Possible crew transfer between areas. Utility Contractor crews (overhead line and tree) limited to normal daily complement, as needed	Regional or System ICS may be initiated and Regional EOC's may be opened. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Regional or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed.	Regional and/or System ICS will be initiated. All available Ops personnel are utilized. Utility Contractor, Mutual Aid Assistance, tree crews, and support functions such as logistics will be used as needed. CPUC notification required.
Email	DL ON Oakville 911 Level 5	DL ON Oakville 911 Level 4	DL ON Oakville 911 Level 3	DL ON Oakville 911 Level 2	DL ON Oakville 911 Level 1

CA-07-0523

ATTACHMENT 8

Liberty Utilities 2015 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2015

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15, 2016

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2015 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents five years (2011 through 2015) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as "TMED". Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric's reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric's daily SAIDI values for the prior five years. CalPeco Electric's TMED value for 2015 was 94.35 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 5 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

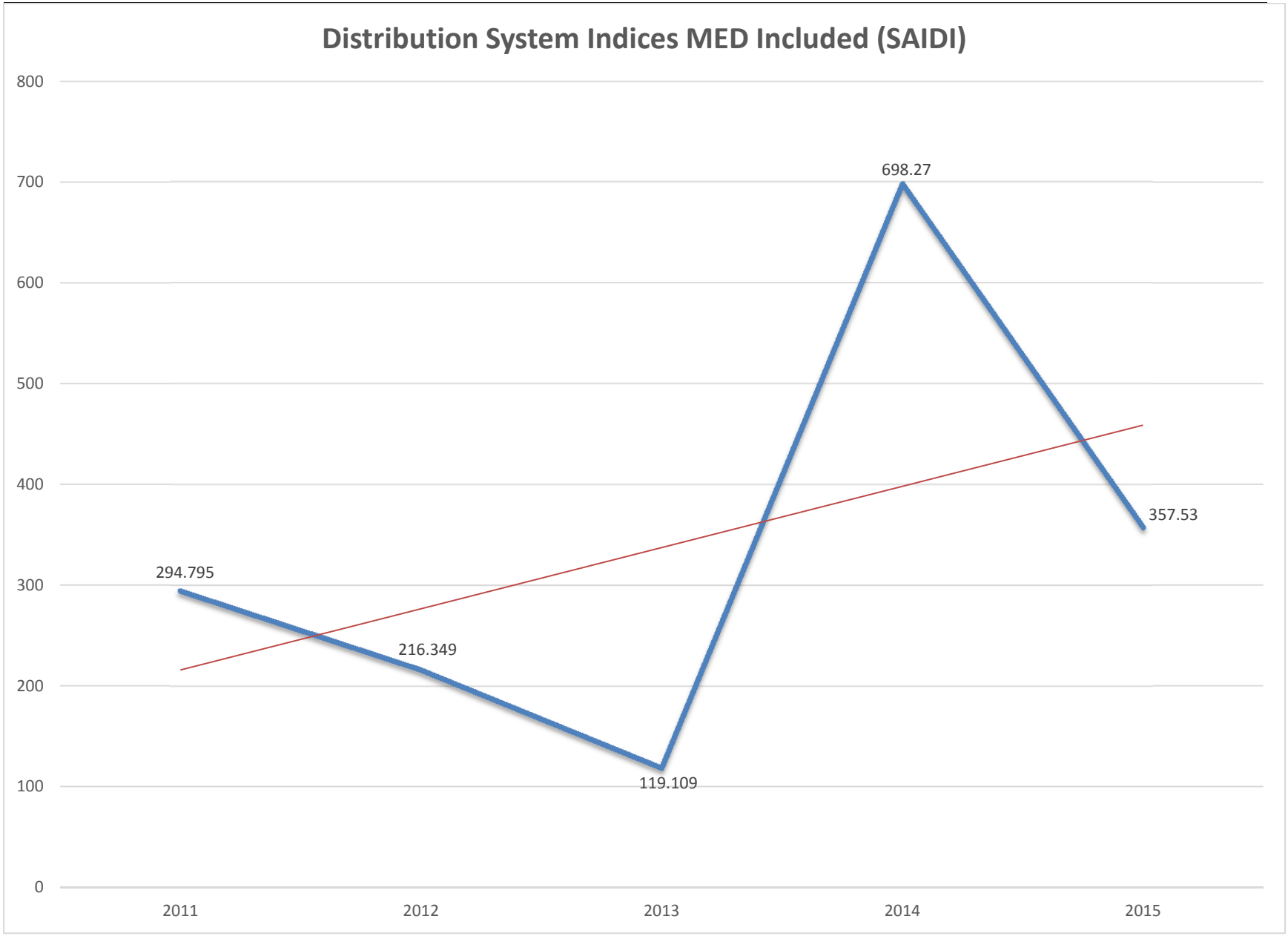
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 5 Years (Years in Business)

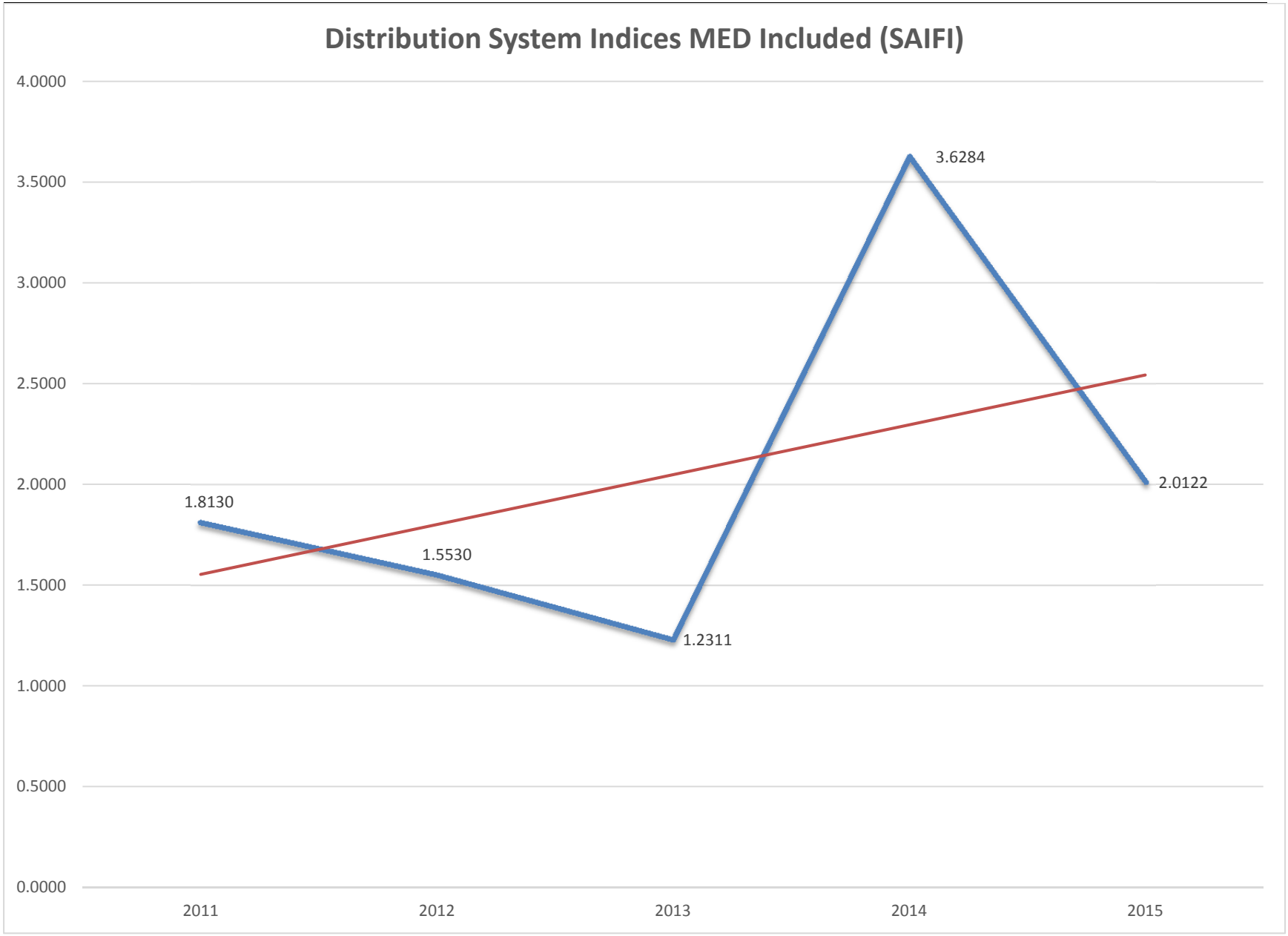
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2015	357.531	2.0122	177.68	1.15	357.53	2.0122	177.68	1.15
2014	698.273	3.6284	192.44	2.15	352.37	2.4039	146.58	2.15
2013	119.109	1.2311	96.75	2.08	119.11	1.2310	96.79	2.08
2012	216.349	1.5530	139.31	2.75	216.35	1.5530	139.31	2.75
2011	294.795	1.8130	162.60	1.88	192.22	1.2460	154.27	1.88

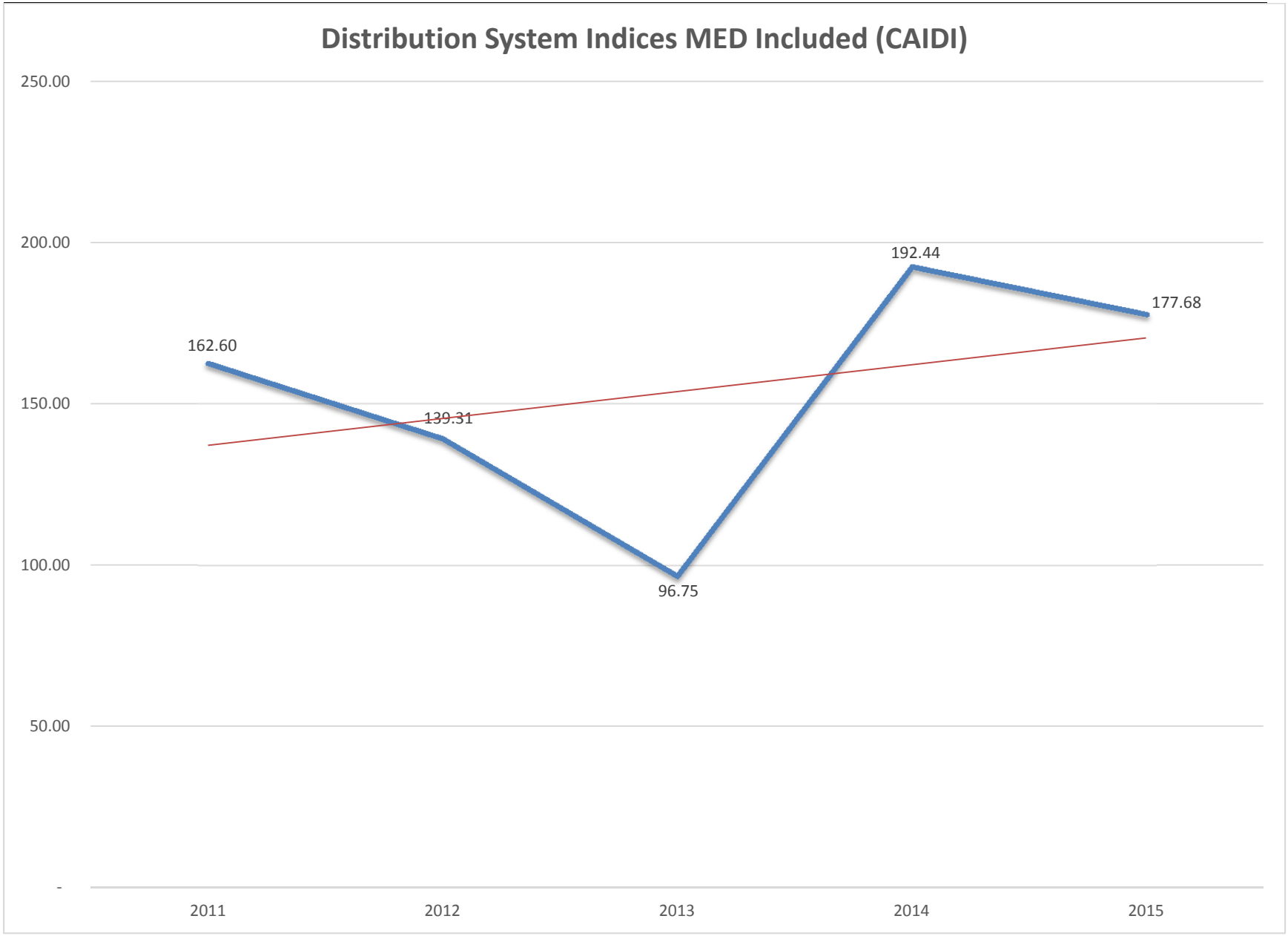
II. Transmission System Indices (MED Included and Excluded)

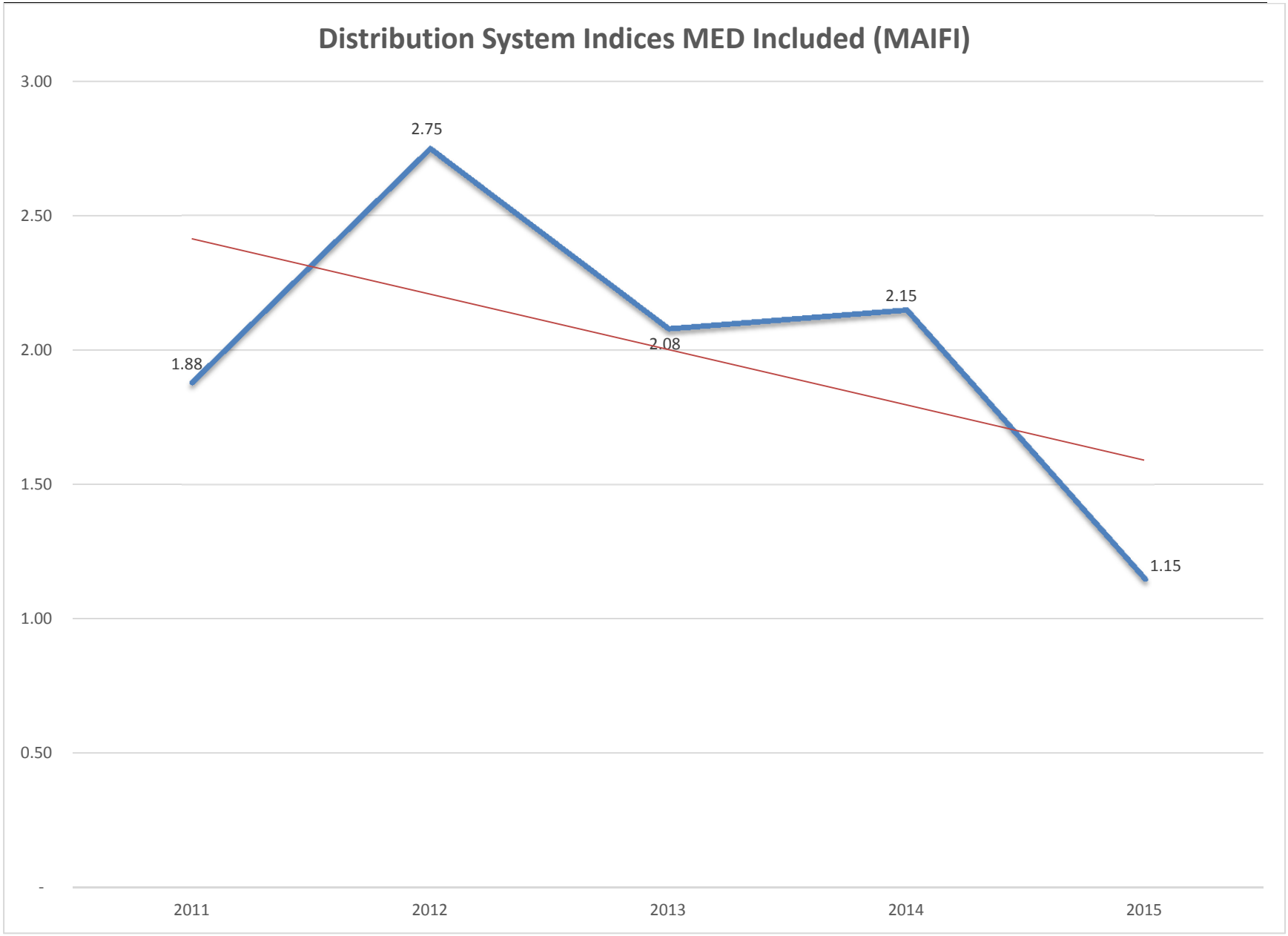
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

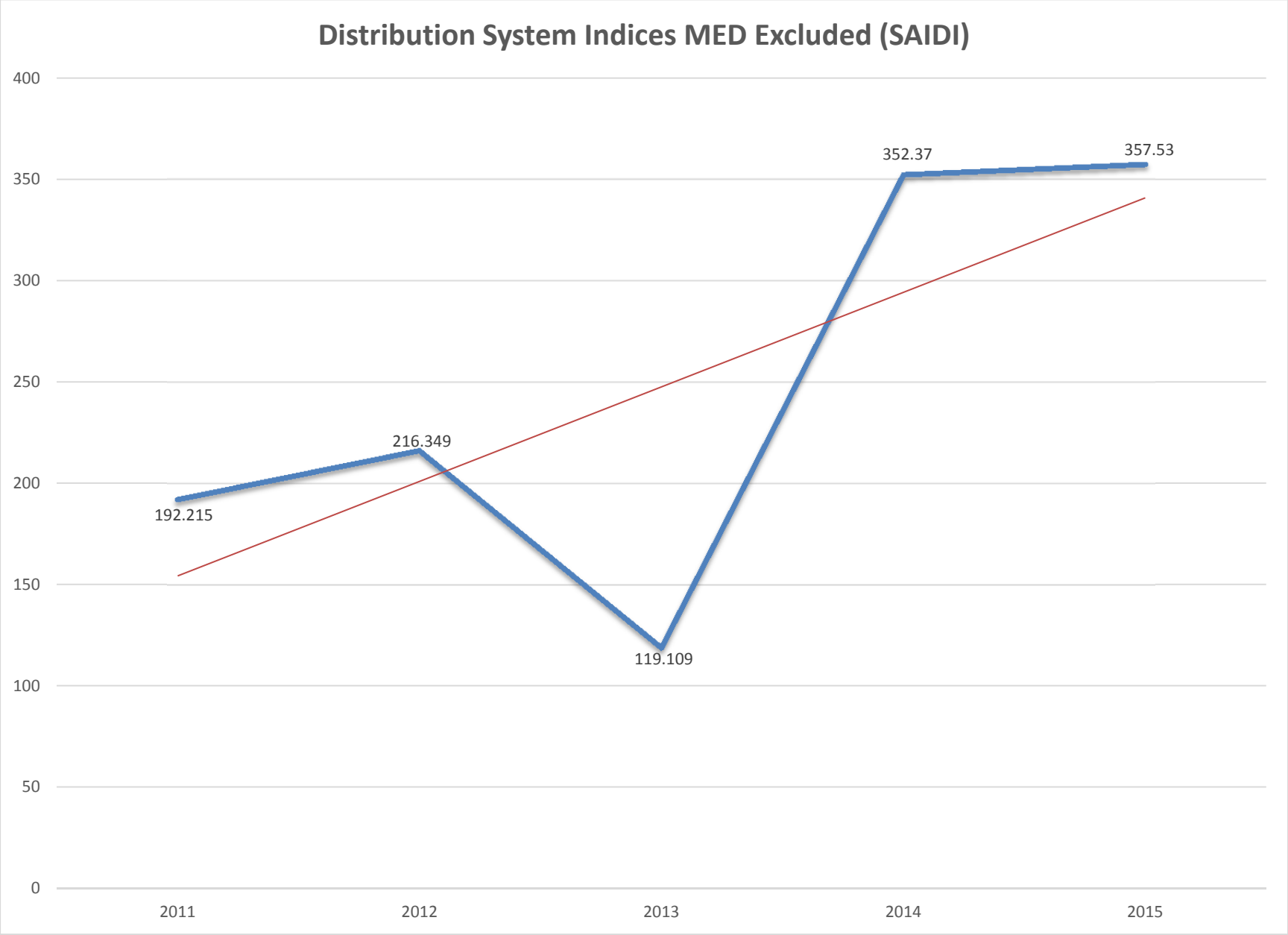
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 5 years (year in business) with linear trend line (TMED included and excluded).

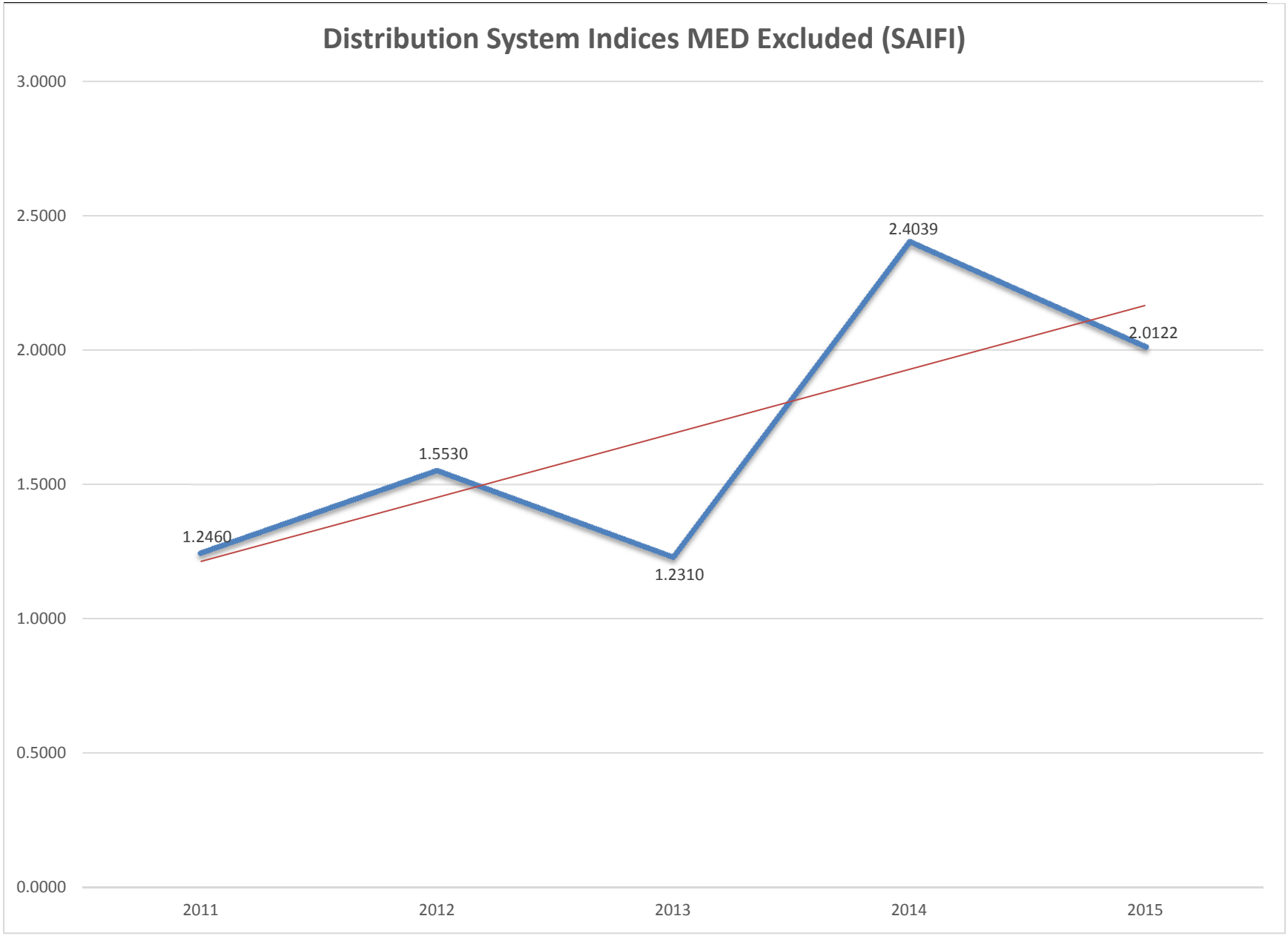

Distribution System Indices MED Included (SAIDI)
800
700
600
500
400
300
200
100
0
698.27
357.53
294.795
216.349
119.109
2011
2012
2013
2014
2015

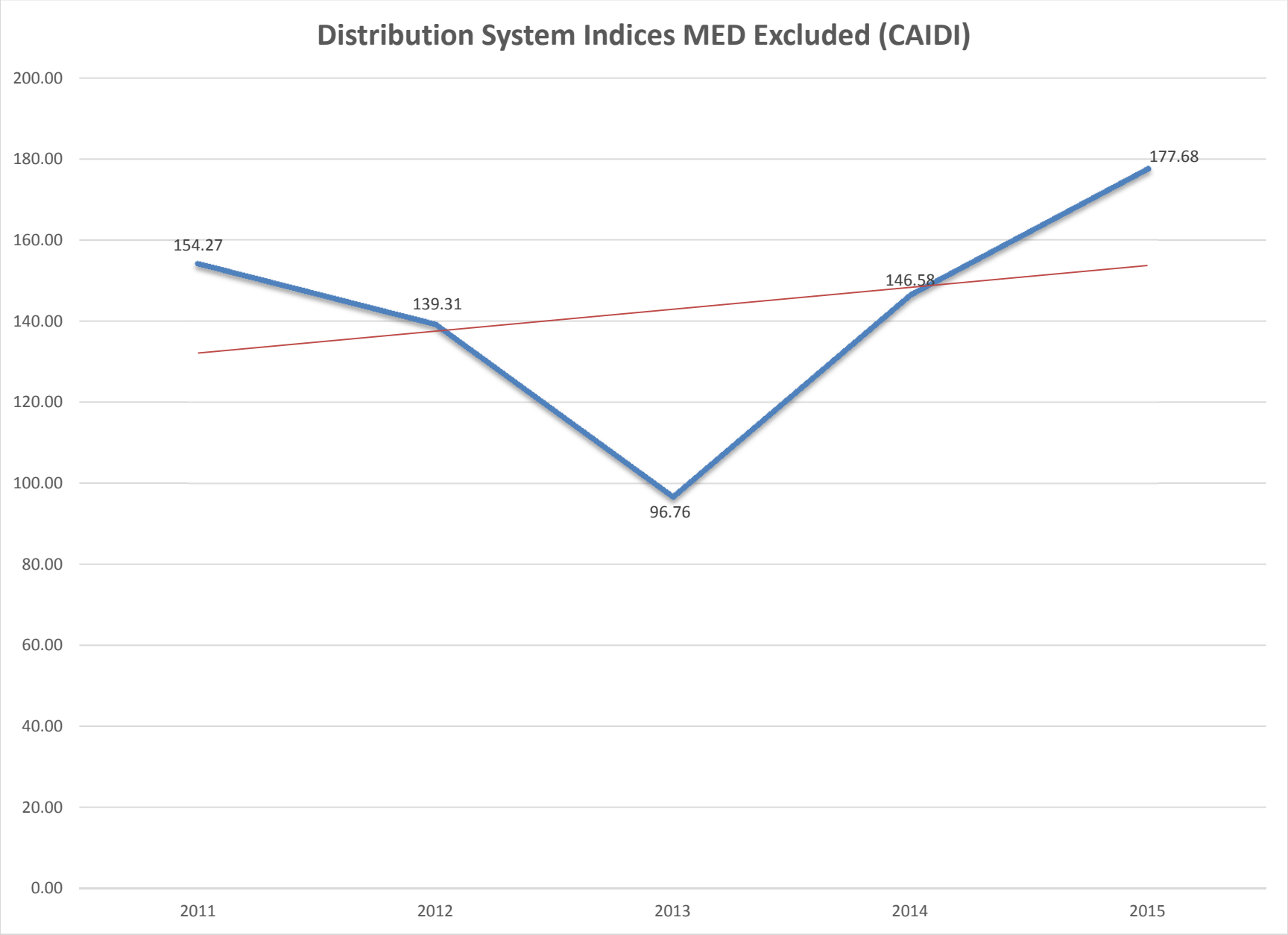

Distribution System Indices MED Included (SAIFI)
4.0000
3.5000
3.0000
2.5000
2.0000
1.5000
1.0000
0.5000
0.0000
1.8130
1.5530
1.2311
3.6284
2.0122
2011
2012
2013
2014
2015

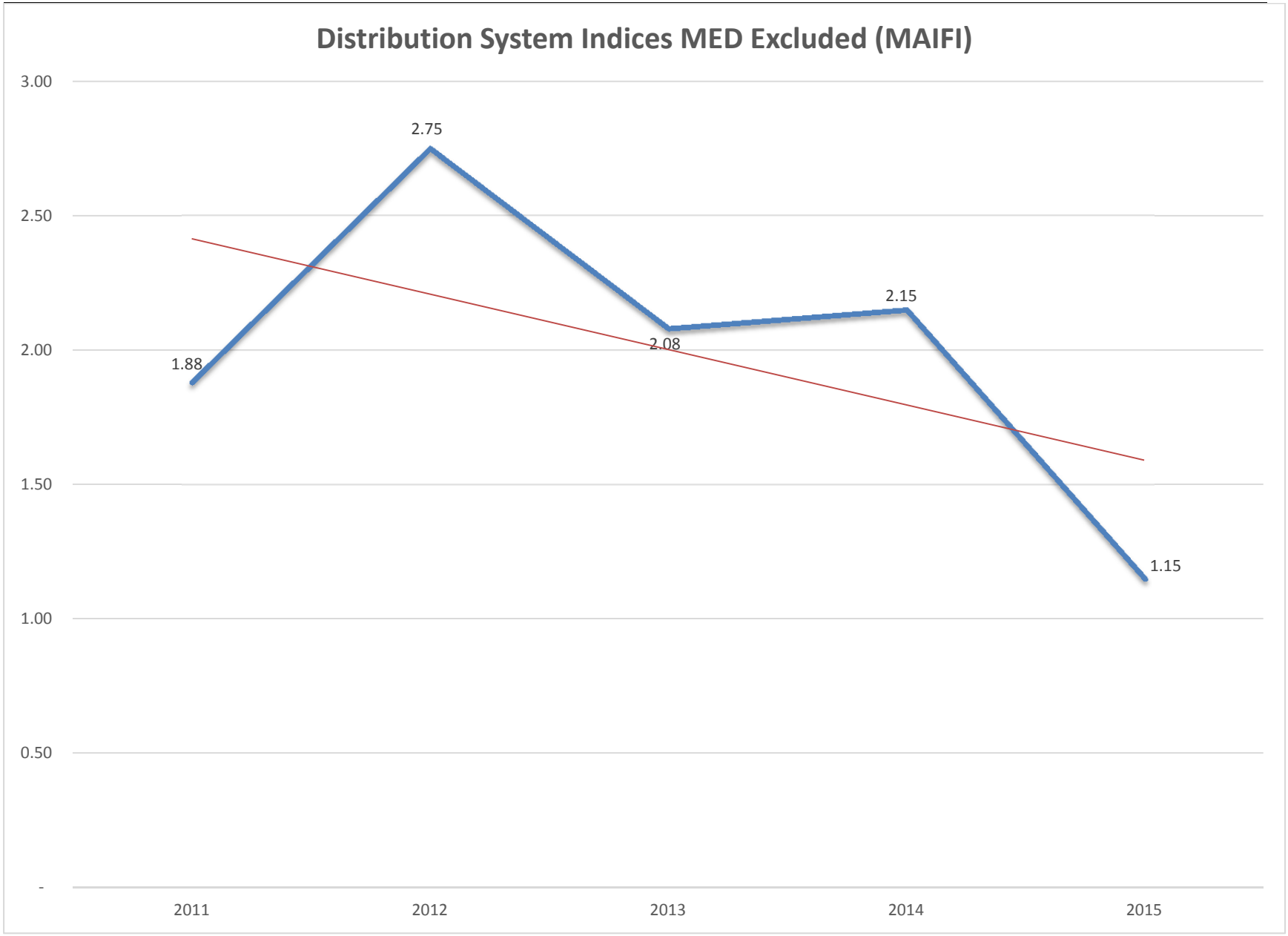

Distribution System Indices MED Included (CAIDI)
250.00
200.00
150.00
100.00
50.00
-
162.60
139.31
96.75
192.44
177.68
2011
2012
2013
2014
2015


Distribution System Indices MED Included (MAIFI)
3.00
2.50
2.00
1.50
1.00
0.50
-
2.75
2.15
2.08
1.88
1.15
2011
2012
2013
2014
2015


Distribution System Indices MED Excluded (SAIDI)
400
350
300
250
200
150
100
50
0
192.215
216.349
119.109
352.37
357.53
2011
2012
2013
2014
2015


Distribution System Indices MED Excluded (SAIFI)
3.0000
2.5000
2.0000
1.5000
1.0000
0.5000
0.0000
1.2460
1.5530
1.2310
2.4039
2.0122
2011
2012
2013
2014
2015


Distribution System Indices MED Excluded (CAIDI)
200.00
180.00
160.00
140.00
120.00
100.00
80.00
60.00
40.00
20.00
0.00
154.27
139.31
96.76
146.58
177.68
2011
2012
2013
2014
2015


Distribution System Indices MED Excluded (MAIFI)
3.00
2.50
2.00
1.50
1.00
0.50
-
2.75
1.88
2.08
2.15
1.15
2011
2012
2013
2014
2015

2) Division (or District) Reliability Indices for the past 10 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

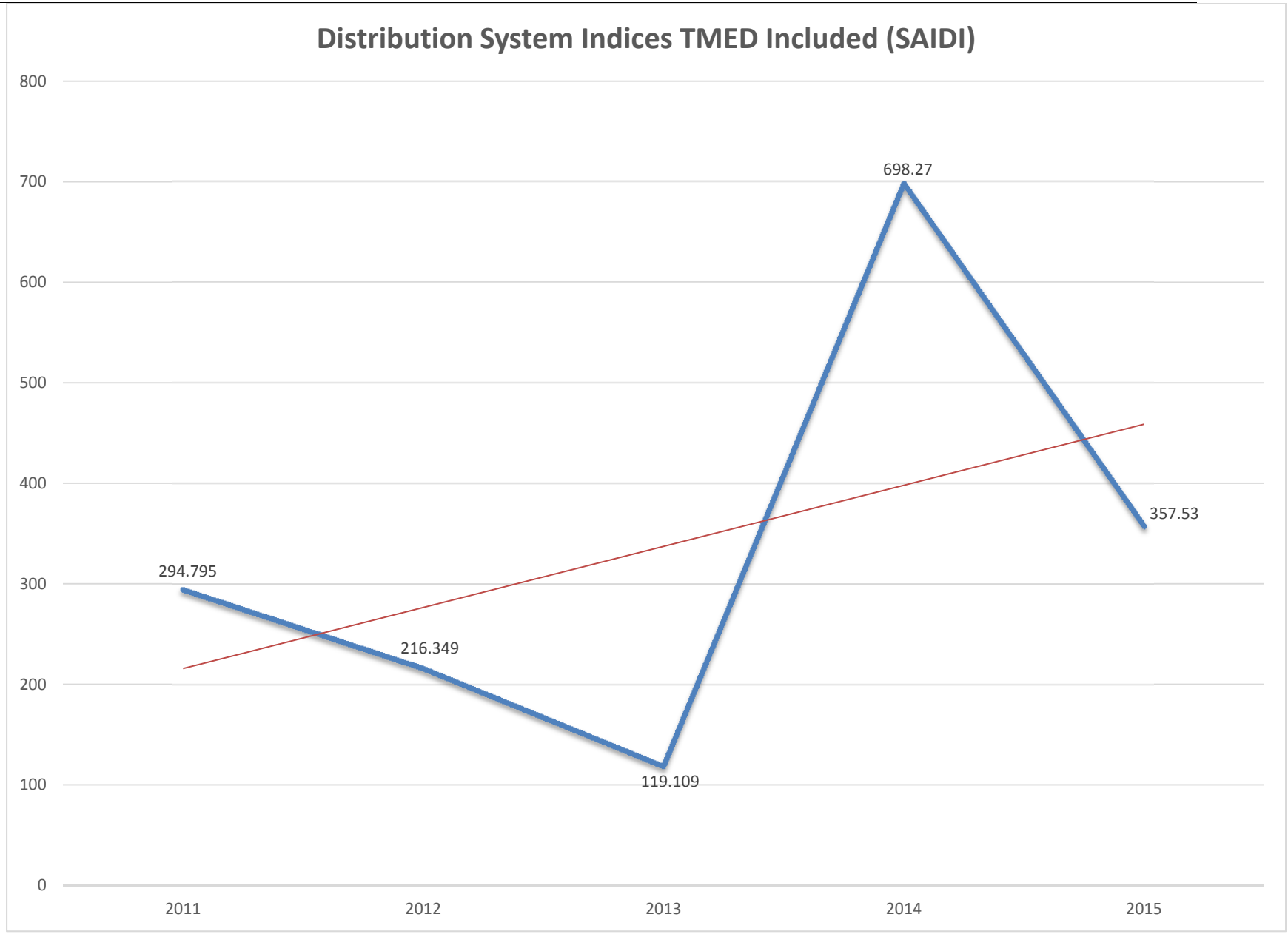
3) System and Division indices based on IEEE 1366 for the past 5 years including planned outages and including and excluding TMED

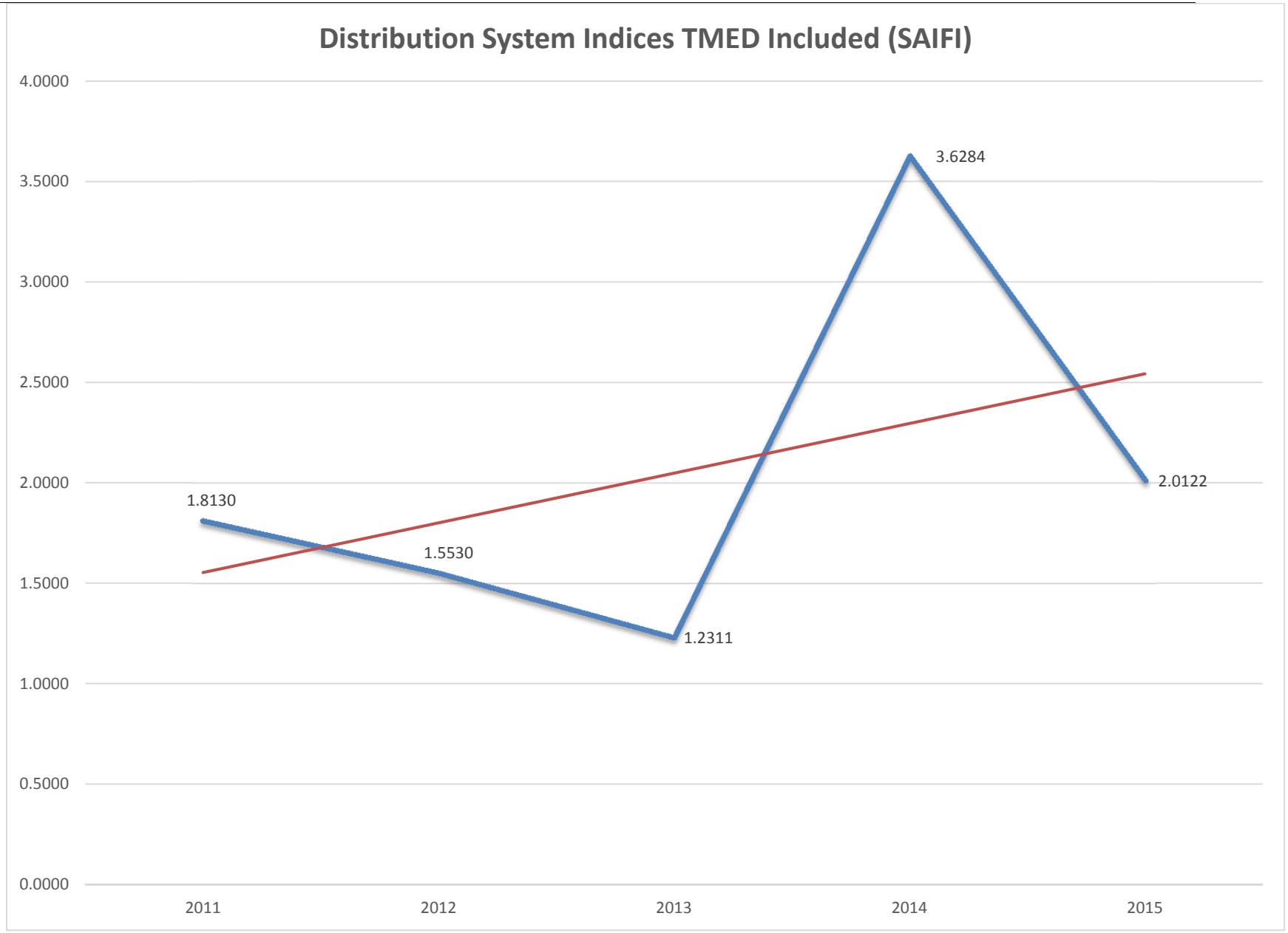
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

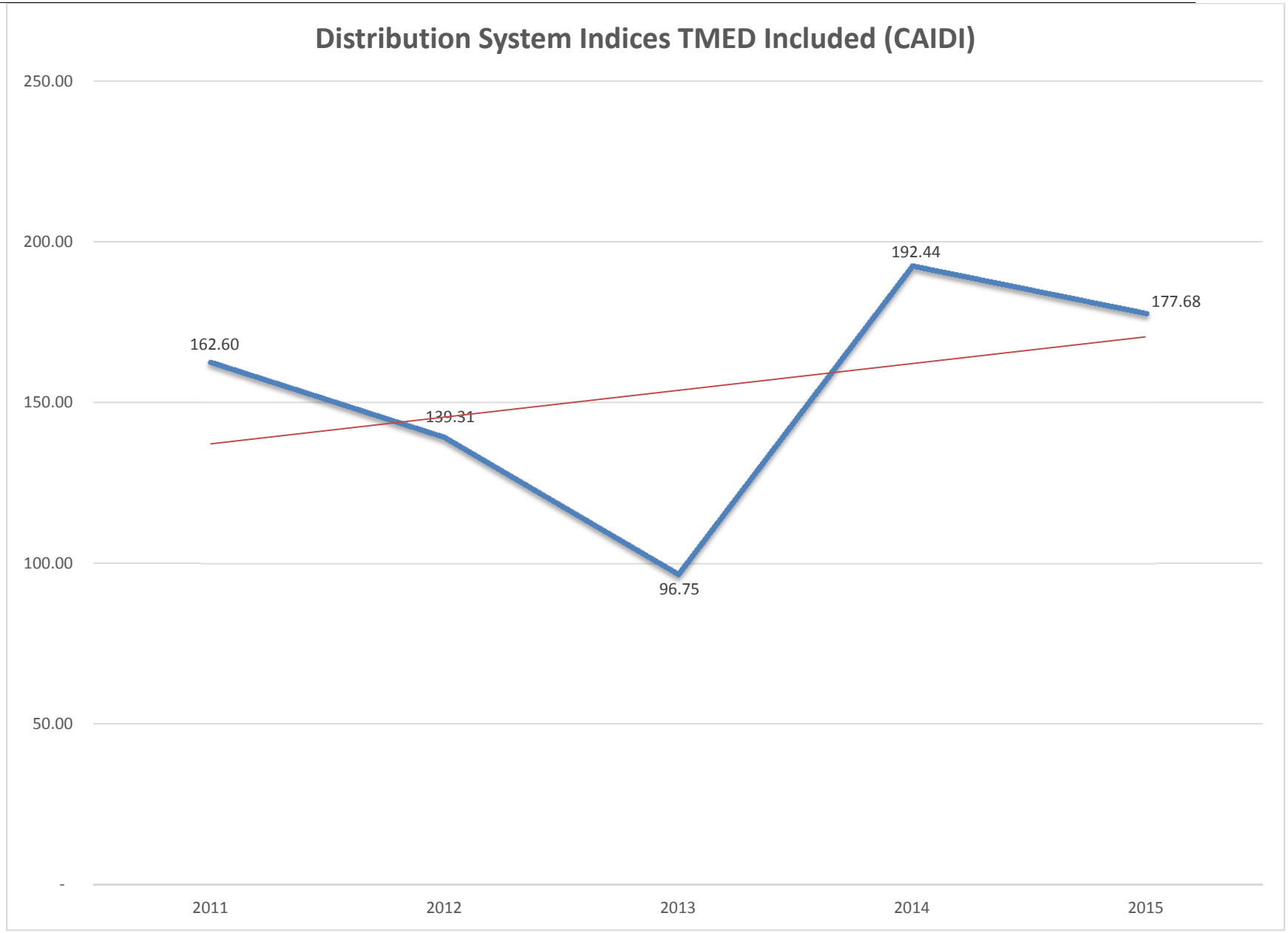
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 5 Years (Years in Business)

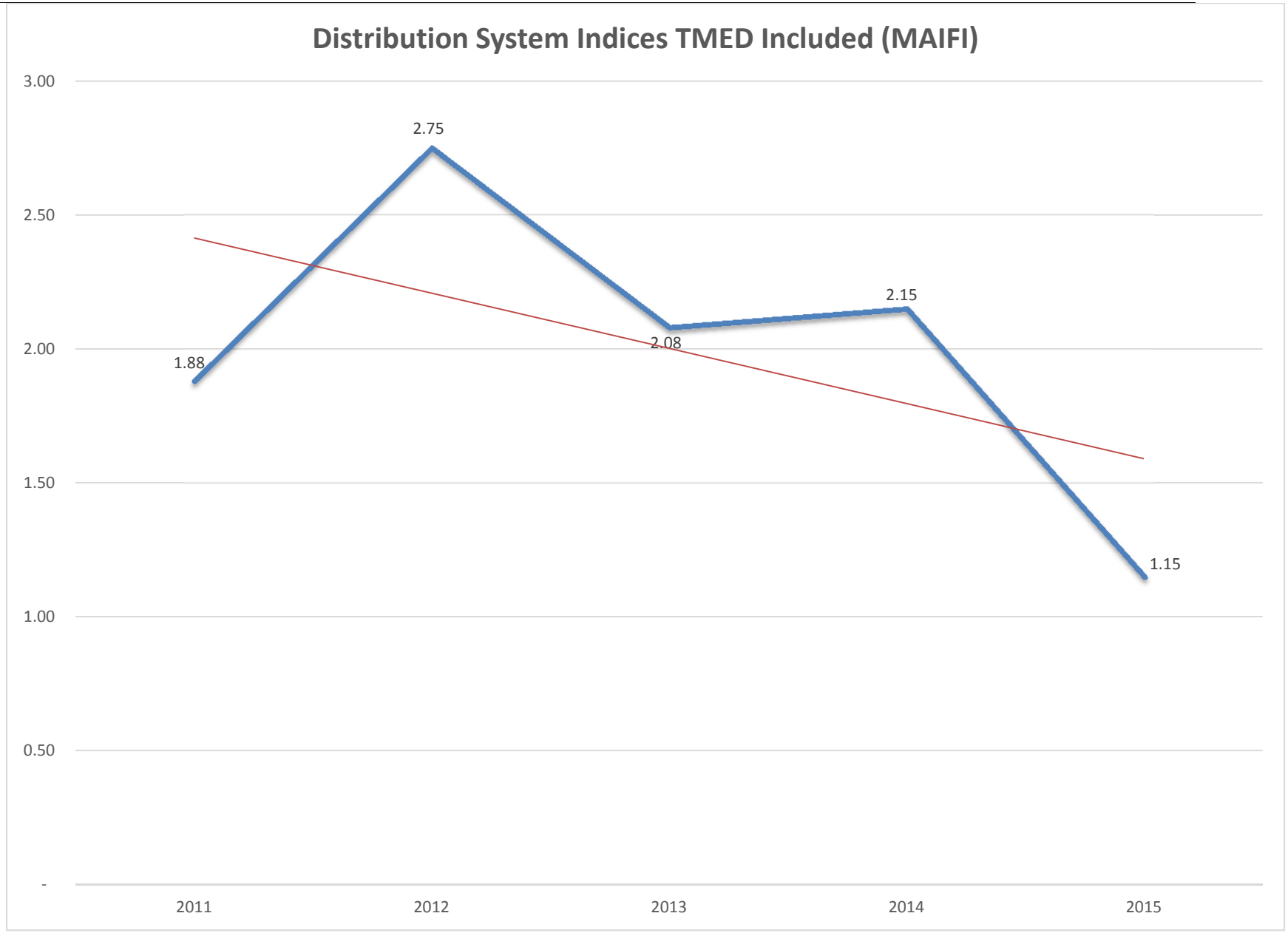
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2015	357.531	2.0122	177.68	1.15	207.868	1.7409	119.40	1.15
2014	698.273	3.6284	192.44	2.15	323.745	2.2384	144.63	2.15
2013	119.109	1.2311	96.75	2.08	119.168	1.2311	96.79	2.08
2012	216.349	1.5530	139.31	2.75	170.439	1.5490	110.03	2.75
2011	294.795	1.8130	162.60	1.88	147.351	1.3207	111.57	1.88

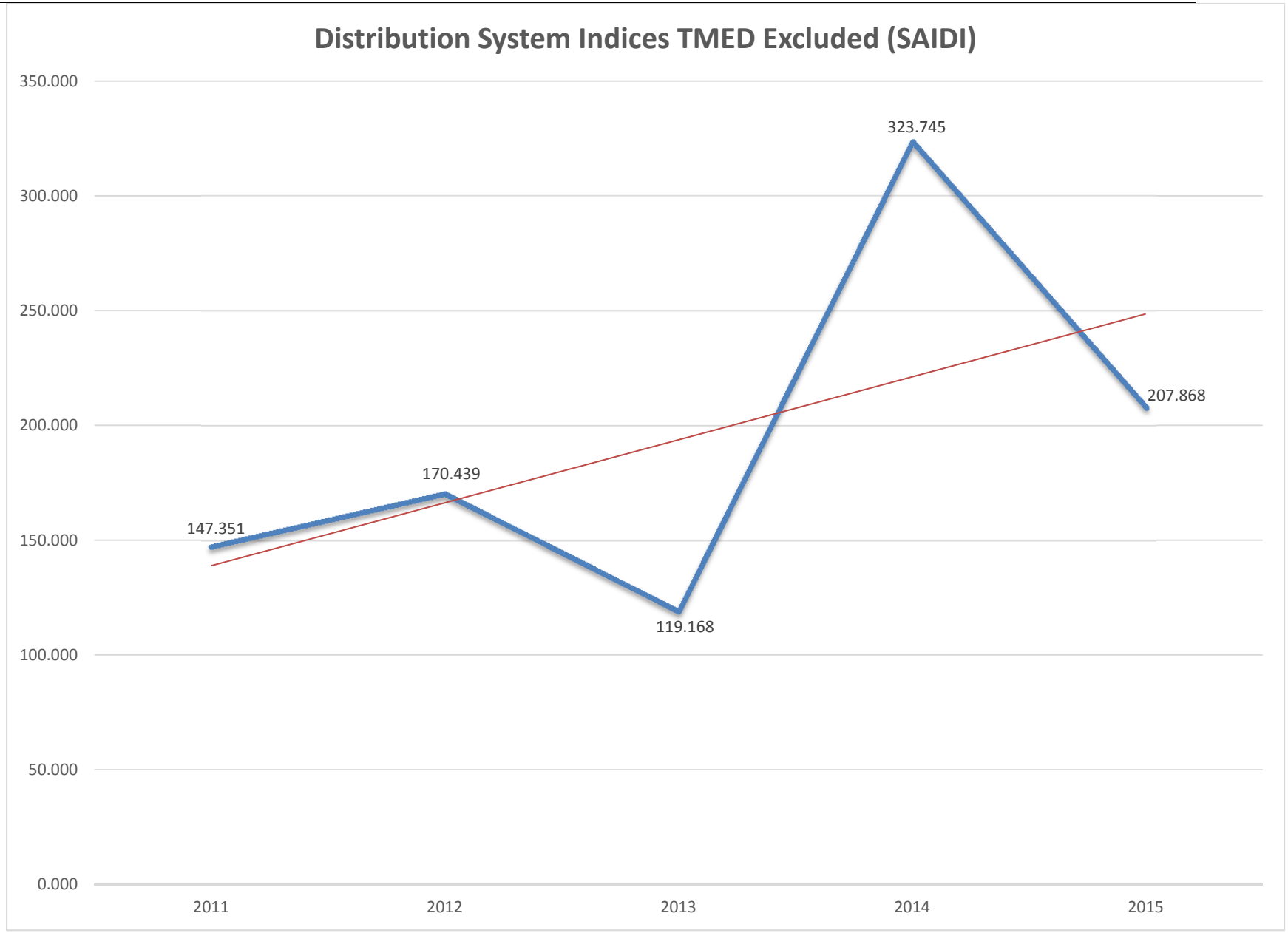
CalPeco Electric has been in business for 5 years and therefore does not have 10 years of data.

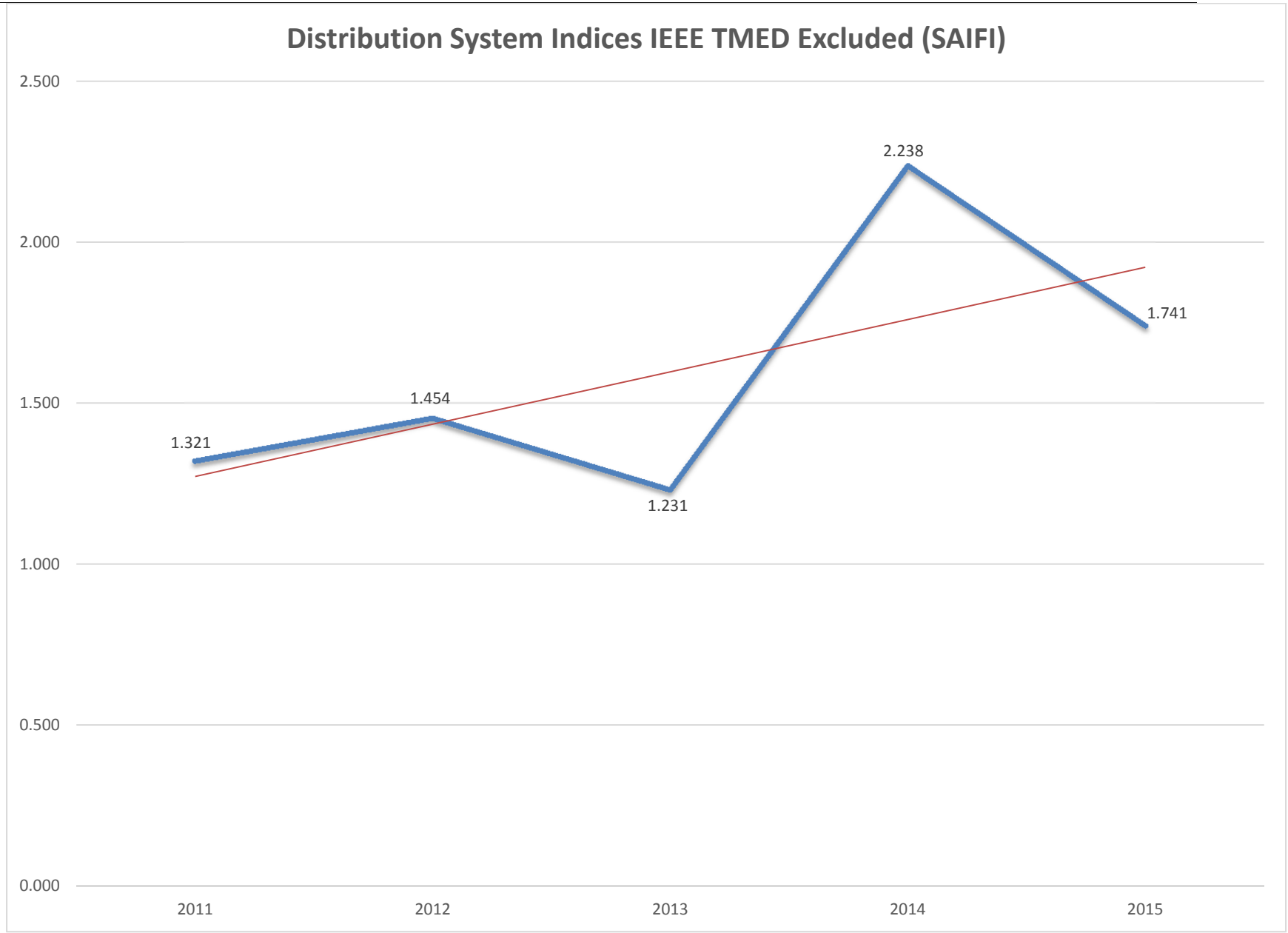

Distribution System Indices TMED Included (SAIDI)
800
700
600
500
400
300
200
100
0
698.27
357.53
294.795
216.349
119.109
2011
2012
2013
2014
2015

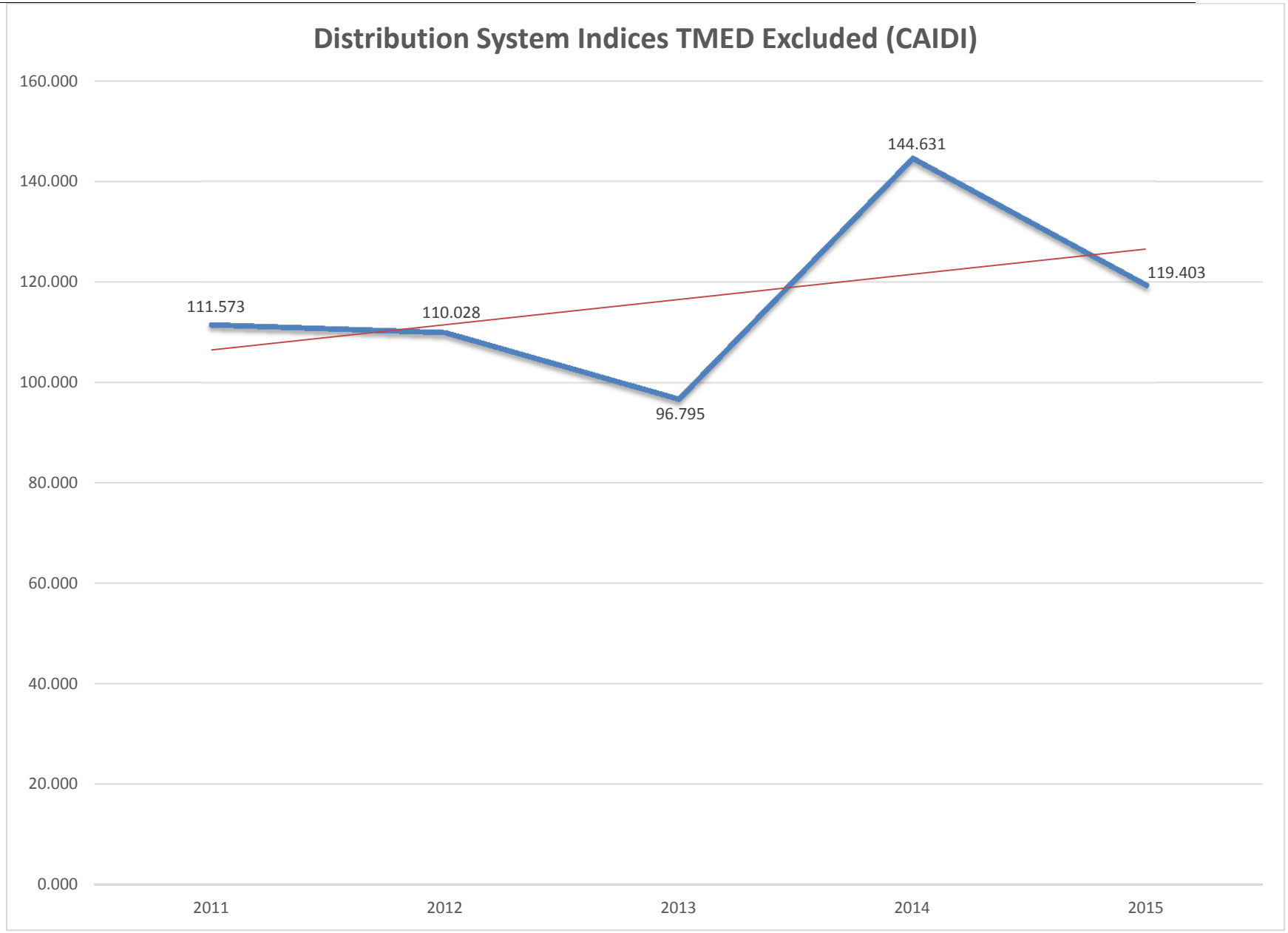

Distribution System Indices TMED Included (SAIFI)
4.0000
3.5000
3.0000
2.5000
2.0000
1.5000
1.0000
0.5000
0.0000
1.8130
1.5530
1.2311
3.6284
2.0122
2011
2012
2013
2014
2015

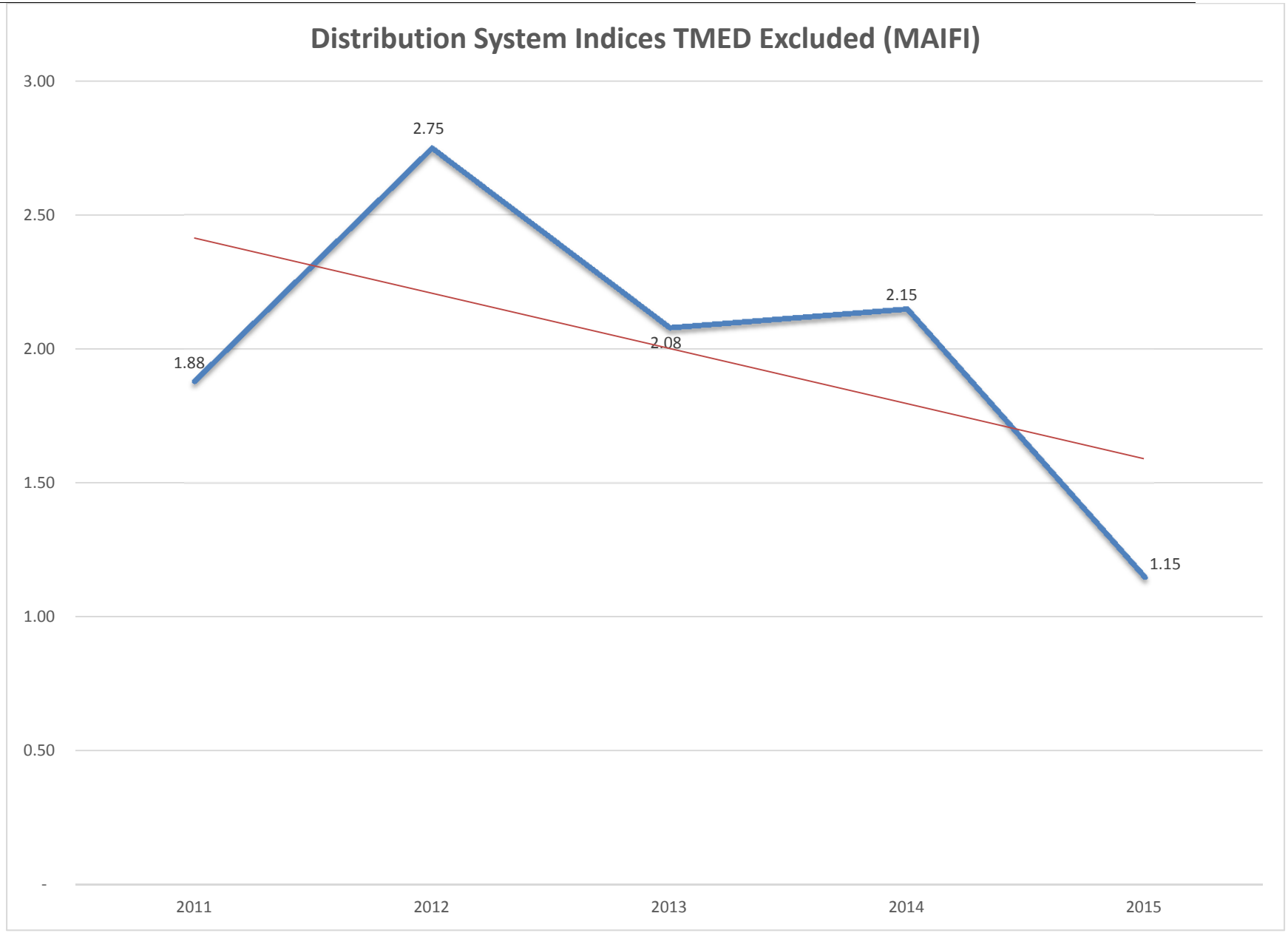

Distribution System Indices TMED Included (CAIDI)
250.00
200.00
150.00
100.00
50.00
-
162.60
139.31
96.75
192.44
177.68
2011
2012
2013
2014
2015


Distribution System Indices TMED Included (MAIFI)
3.00
2.50
2.00
1.50
1.00
0.50
-
2.75
2.15
2.08
1.88
1.15
2011
2012
2013
2014
2015


Distribution System Indices TMED Excluded (SAIDI)
350.000
300.000
250.000
200.000
150.000
100.000
50.000
0.000
147.351
170.439
119.168
323.745
207.868
2011
2012
2013
2014
2015


Distribution System Indices IEEE TMED Excluded (SAIFI)
2.500
2.000
1.500
1.000
0.500
0.000
1.321
1.454
1.231
2.238
1.741
2011
2012
2013
2014
2015

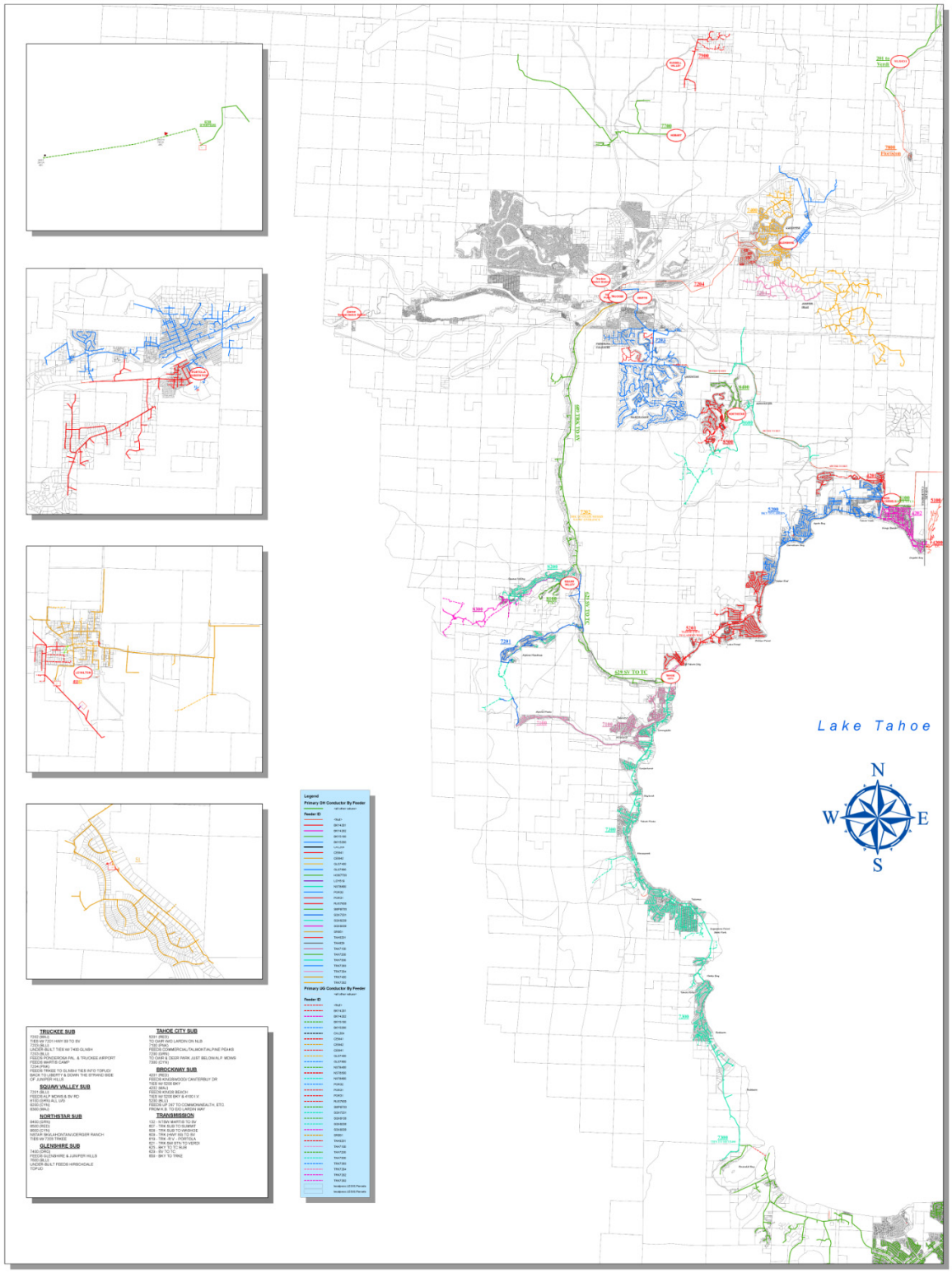

Distribution System Indices TMED Excluded (CAIDI)
160.000
140.000
120.000
100.000
80.000
60.000
40.000
20.000
0.000
111.573
110.028
96.795
144.631
119.403
2011
2012
2013
2014
2015


Distribution System Indices TMED Excluded (MAIFI)
3.00
2.50
2.00
1.50
1.00
0.50
-
2.75
2.15
2.08
1.88
1.15
2011
2012
2013
2014
2015

b. The number, date, and location of planned outages

Circuit	District	Number of Planned Outages By Year				
		2015	2014	2013	2012	2011
[redacted]						

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261	Tahoe	744	Muller	75.5	90.7%	9.3%	3	3003	0.016
1296	Tahoe	622	Topaz	70.9	76.2%	23.8%	8	1065	0.016

Note: Preferred Metric is Circuit SAIDI

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;
II. A historical record of the metric;
III. An explanation of why it was on the deficiency list again;
IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and
V. A quantitative description of the utility's expectation for that circuit's future performance.

III. Language to explain how the IOUs’ include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions:

WPC- Worst Performing Circuits

CB- Circuit Breaker

AR- Automatic re-closer

<u>Assumptions</u>

- Our analysis excludes planned outages and TMED outages

II. A clear explanation of the utility’s process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated Circuit SAIDI. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering and Planning Manager, and Vice President of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	4/25/2015	Trees / Snow Storm	Lake Tahoe	4,120	17.148	0.0951
2	2/14/2015	NV Energy Outage	Lake Tahoe	3,587	3.478	0.0828
3	12/11/2015	Wire Down	Lake Tahoe	3,587	23.895	0.0828
4	2/6/2015	Trees	Lake Tahoe	3,548	1.884	0.0819
5	8/11/2015	Line Maintenance Issue	Lake Tahoe	3,000	1.039	0.0693
6	2/20/2015	Switching	Lake Tahoe	3,000	2.285	0.0693
7	5/24/2015	NV Energy Outage: Birds/Animals	Lake Tahoe	3,000	17.092	0.0693
8	7/4/2015	NV Energy Outage: Lightning / Blow Fuse	Lake Tahoe	3,000	7.7575	0.0693
9	7/7/2015	NV Energy Outage: Lightning / Blow Fuse	Lake Tahoe	3,000	1.385	0.0693
10	7/7/2015	NV Energy Outage: Lightning / Blow Fuse	Lake Tahoe	3,000	0.416	0.0693

*Based on customer impact

A tha

7) Summary list of 2015 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2015 = 94.35

Date of Outage		**2/6/2015**								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
Total Number of Customers Out of Service		1,100	878	2,600	8	2,000	3,548	425	1,100	93
Customers Interrupted - Hours Into the Event Day *	**0**	1,100	878	2,600	8	2,000	3,548	425	1,100	93
	0.5	**150**	878	2,600	8	2,000		425	1,100	93
	1		878	2,600	8	2,000		425	1,100	93
	1.5		878	2,600	8	2,000		425	1,100	93
	2		878	2,600		2,000		425		93
	3		878	2,600		2,000		425		93
	3.5		878	2,600		2,000		425		93
	4		878	2,600		2,000		425		93
	4.5		878	2,600		2,000		425		93
	5		878	2,600		2,000		425		93

Date of Outage		2/6/2015								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
	5.5		878	2,600		2,000		425		93
	6		878	2,600		2,000		425		93
	6.5		878	2,600		2,000		425		93
	7		878	2,600		2,000		425		93
	7.5		878	2,600		1,500		425		93
	8			2,600		1,500		425		93
	8.5			2,600		1,500		425		93
	9			2,600		1,500		425		93
	9.5			2,600		1,500		425		93
	10			2,600		1,500		425		93
	10.5			2,600		1,500		425		93
	11			2,600				425		93
	11.5			2,600				425		93
	12			2,600				425		93
	12.5			2,600				425		93
	13			2,600				425		93
	13.5			2,600				425		93
	14			2,600				425		93
	14.5			2,600				425		93
	15			2,600				425		93
	15.5			2,600				425		93
	16			2,600				425		93
	16.5			2,600				425		93

PUBLIC VERSION - R[illegible]

Date of Outage		**2/6/2015**								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
	17			2,600				425		93
	17.5			2,600				425		93
	18			2,600				425		93
	18.5			2,600				425		93
	19			2,600				425		93
	19.5			2,600				425		93
	20			2,600				425		93
	20.5			2,600				425		93
	21			2,600				425		93
	21.5			2,600				425		93
	22			2,600				425		93
	22.5			2,600				425		93
	23			2,600				425		93
	23.5			2,600				425		93
	24			2,600				425		93
2/7/2015	**0.5**			2,600				425		93
	1			2,600				425		93
	1.5			2,600				425		93
	2			2,600				425		93
	2.5			2,600				425		93
	3			2,600				425		93
	3.5			2,600				425		93
	4			2,600				425		93

PUBLIC VERSION - R[illegible]

Date of Outage		**2/6/2015**								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
	4.5			2,600				425		93
	5			2,600				425		93
	5.5			2,600				425		93
	6			2,600				425		93
	6.5			2,600				425		93
	7			2,600				425		93
	7.5			2,600				425		93
	8			2,600				425		93
	8.5			2,600				425		93
	9			2,600				425		93
	9.5			2,600				425		93
	10			2,600				425		93
	10.5			2,600				425		93
	11			2,600				425		93
	11.5			2,600				425		93
	12							425		93
	12.5							425		93
	13							425		93
	13.5							425		93
	14							425		93
	14.5							425		93
	15							425		93
	15.5							425		93

PUBLIC VERSION - R[illegible]

Date of Outage		**2/6/2015**								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
	16							425		93
	16.5							425		93
	17							425		93
	17.5							425		
	18							425		
	18.5							425		
	19							425		
	19.5							425		
	20							425		
	20.5							425		
	21							425		
	21.5							425		
	22							425		
	22.5							425		
	23							425		
	23.5							6		
	24							6		
2/8/2015	**0.5**							6		
	1							6		
	2							6		
	3							6		
	4							6		
	5							6		

PUBLIC VERSION - R[illegible]

Date of Outage		**2/6/2015**								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
	6							6		
	7							6		
	8							6		
	9							6		
	10							6		
	11							6		
	12							6		
	13							6		
	14							6		
	15							6		
	16							6		
	17							6		
	18							6		
	19							6		
	20							6		
	21							6		
	22							6		
	23							6		
	24							6		
2/9/2015	**1**							6		
	2							6		
	3							6		
	4							6		

Date of Outage		**2/6/2015**								
Description of Outage		NV Energy Outage – High Winds			Trees – High Winds					
Location		Lake Tahoe (Truckee)	Lake Tahoe (Muller)	Lake Tahoe (Truckee)	Lake Tahoe (Tahoe City)	Lake Tahoe (Tahoe City)	Lake Tahoe (Meyers)	Lake Tahoe (Topaz)	Lake Tahoe (Portola)	Lake Tahoe (Truckee)
	5							6		
	6							6		
	7							6		

* Customers reflected in the time increments include all customers experiencing outages at that point in time. The event day begins at midnight.

8) Historical 10 largest unplanned outage events for the past 10 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.0	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.0	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.5	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	.067	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

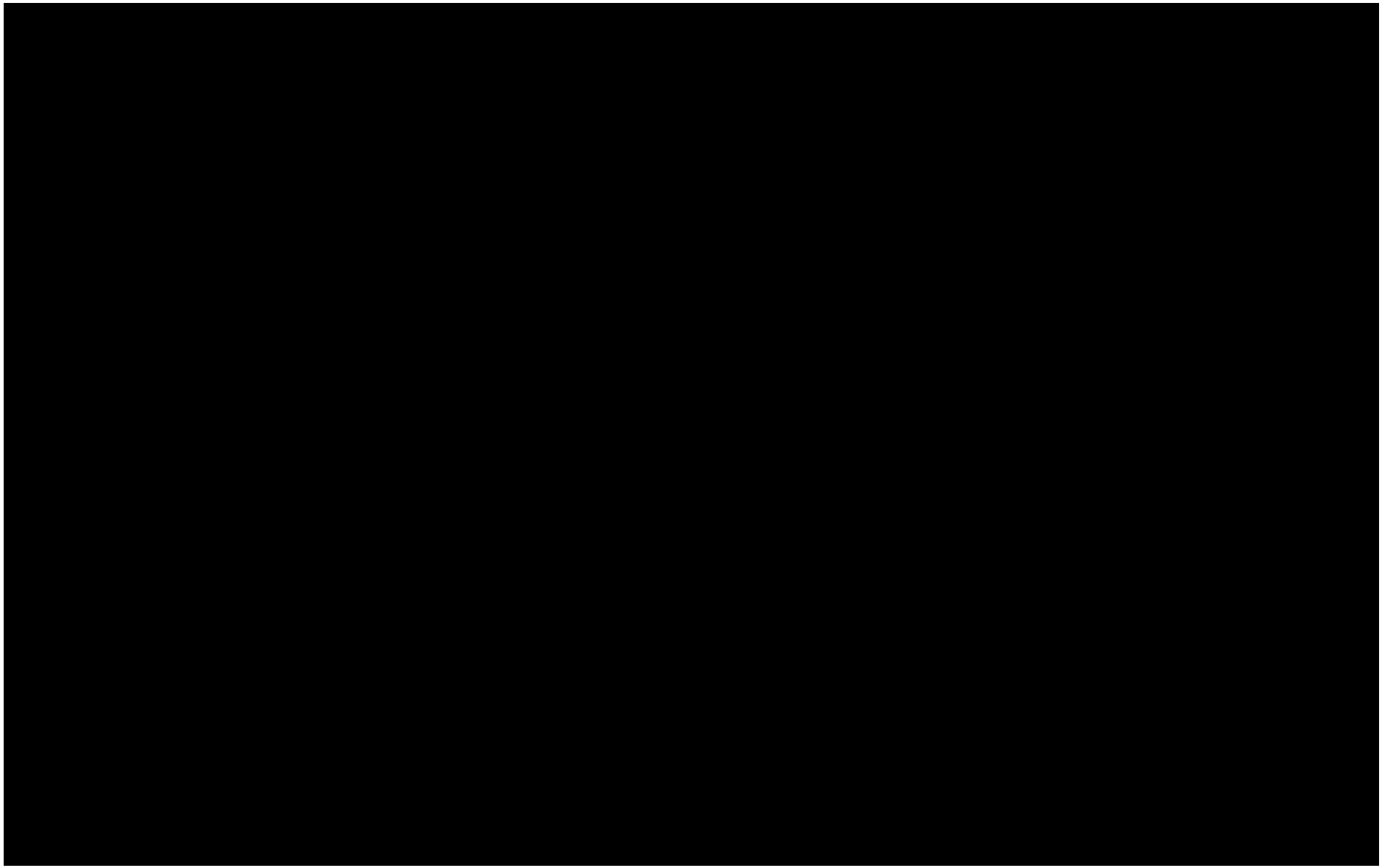
Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1	NV Energy Outage	5/9/2011	24,550	3.02	74,059.17	Yes
2	Relays	2/17/2011	8,005	3.40	12,738.90	No
3	Overcurrent	3/20/2011	4,396	0.98	4,396.00	No
4	Trees	5/25/2011	4,120	10.23	21,658.83	No
5	Trees	11/18/2011	4,120	21.50	15,792.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
6	Lateral Fuse	3/16/2011	3,957	2.96	11,739.10	No
7	Bird/Animal	9/24/2011	3,885	0.25	769.50	No
8	Hardware Failure	9/12/2011	3,475	1.12	2,780.42	No
9	Relays	1/25/2011	3,201	1.68	5,388.35	No
10	Trees	6/29/2011	3,200	4.35	11,786.67	No

9) Number of customer inquiries on reliability data and the number of days per response

There have been zero customer inquiries on reliability data to date.

Appendix A: 5 Years of Planned Outage Data -- PUBLIC VERSION --

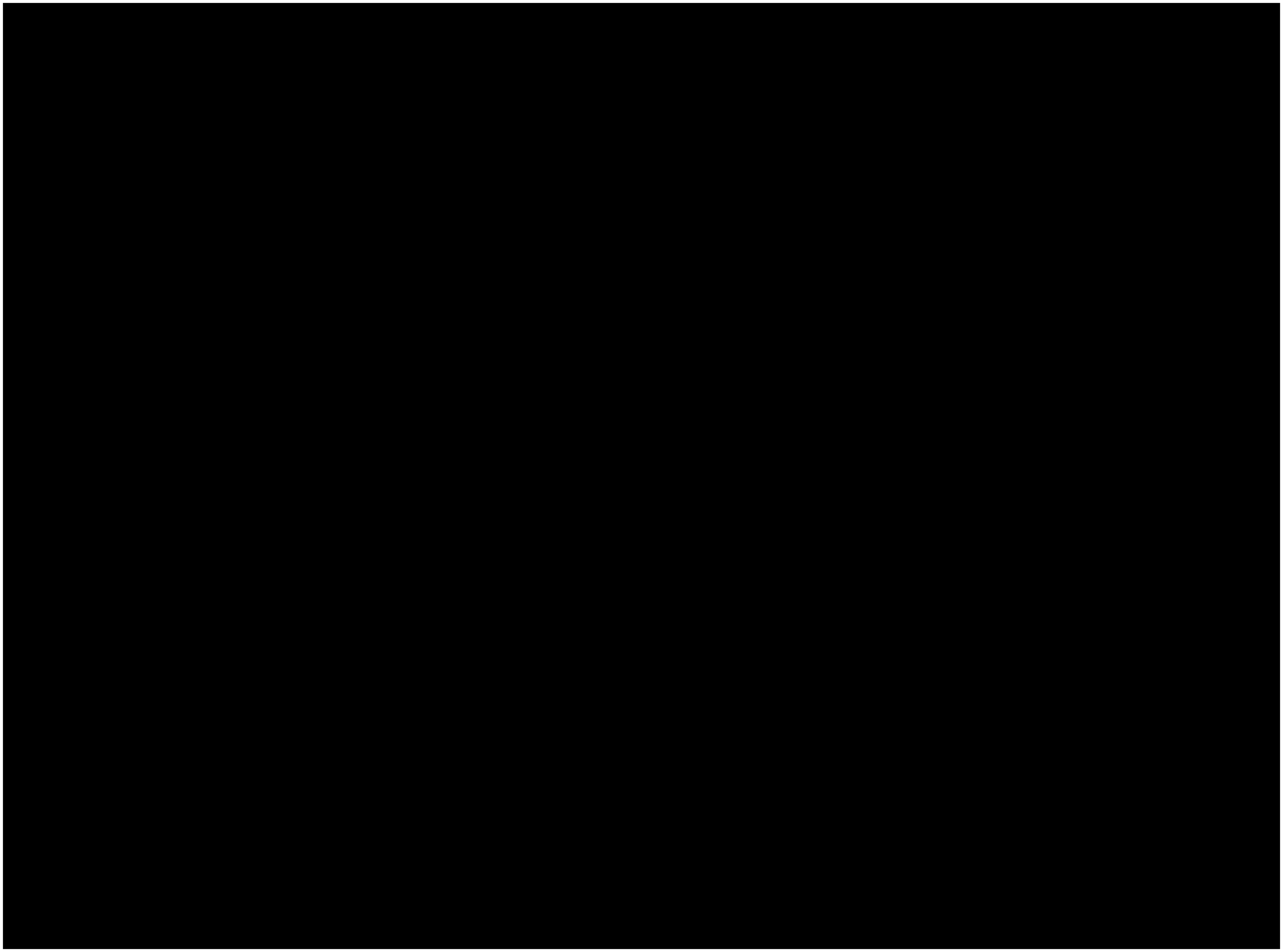




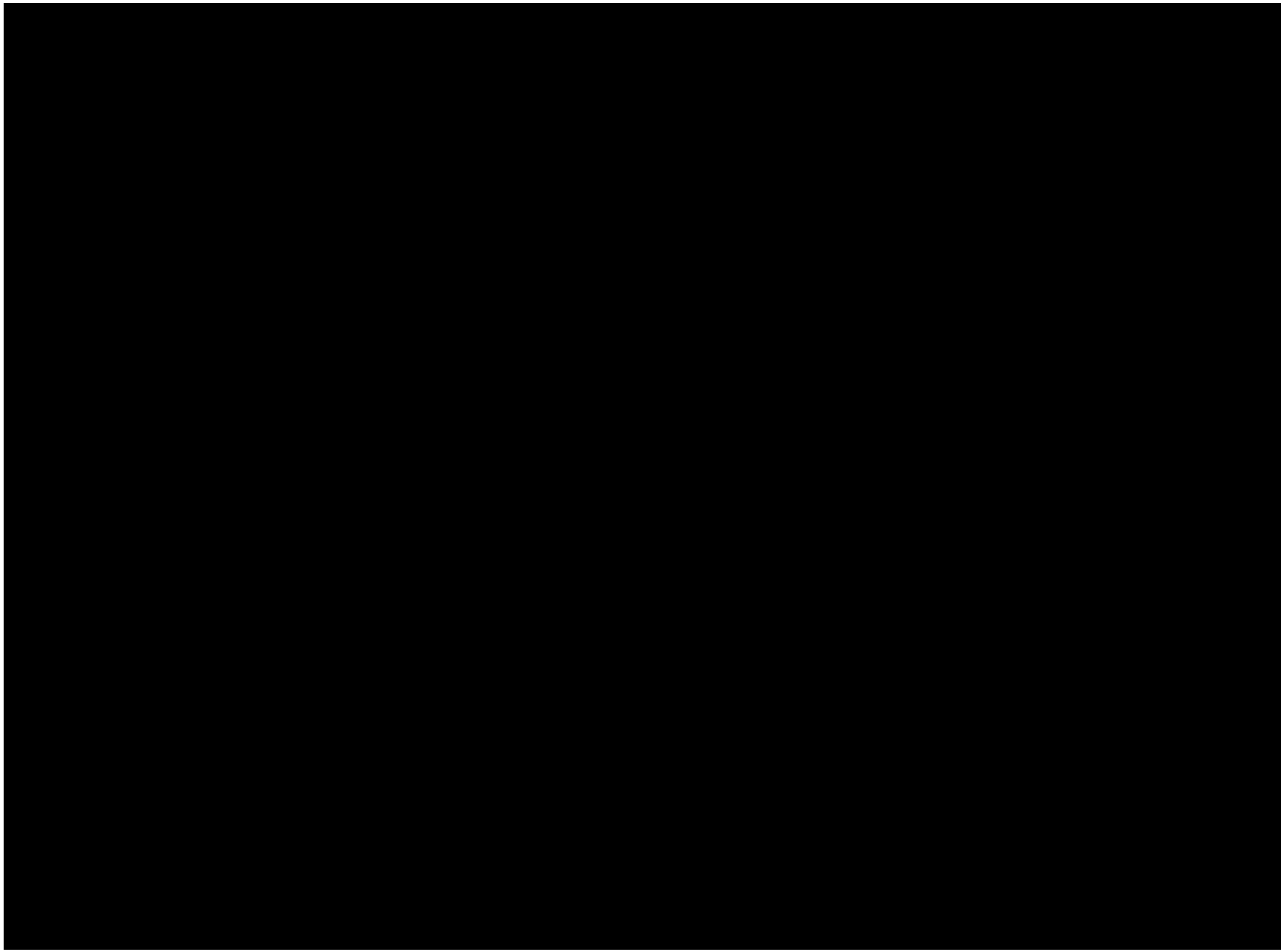
PUBLIC VERSION - R.14-07-013



PUBLIC VERSION - R.14-07-013



PUBLIC VERSION - R.14-07-013



PUBLIC VERSION - R.14-07-007



PUBLIC VERSION - R14-04-010

ATTACHMENT 9

Liberty Utilities 2015 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2016

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

Prepared for

California Public Utilities Commission

July 15, 2017

CA-07-0570

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2016 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents six years (2011 through 2016) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2016 was 104.57 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 6 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

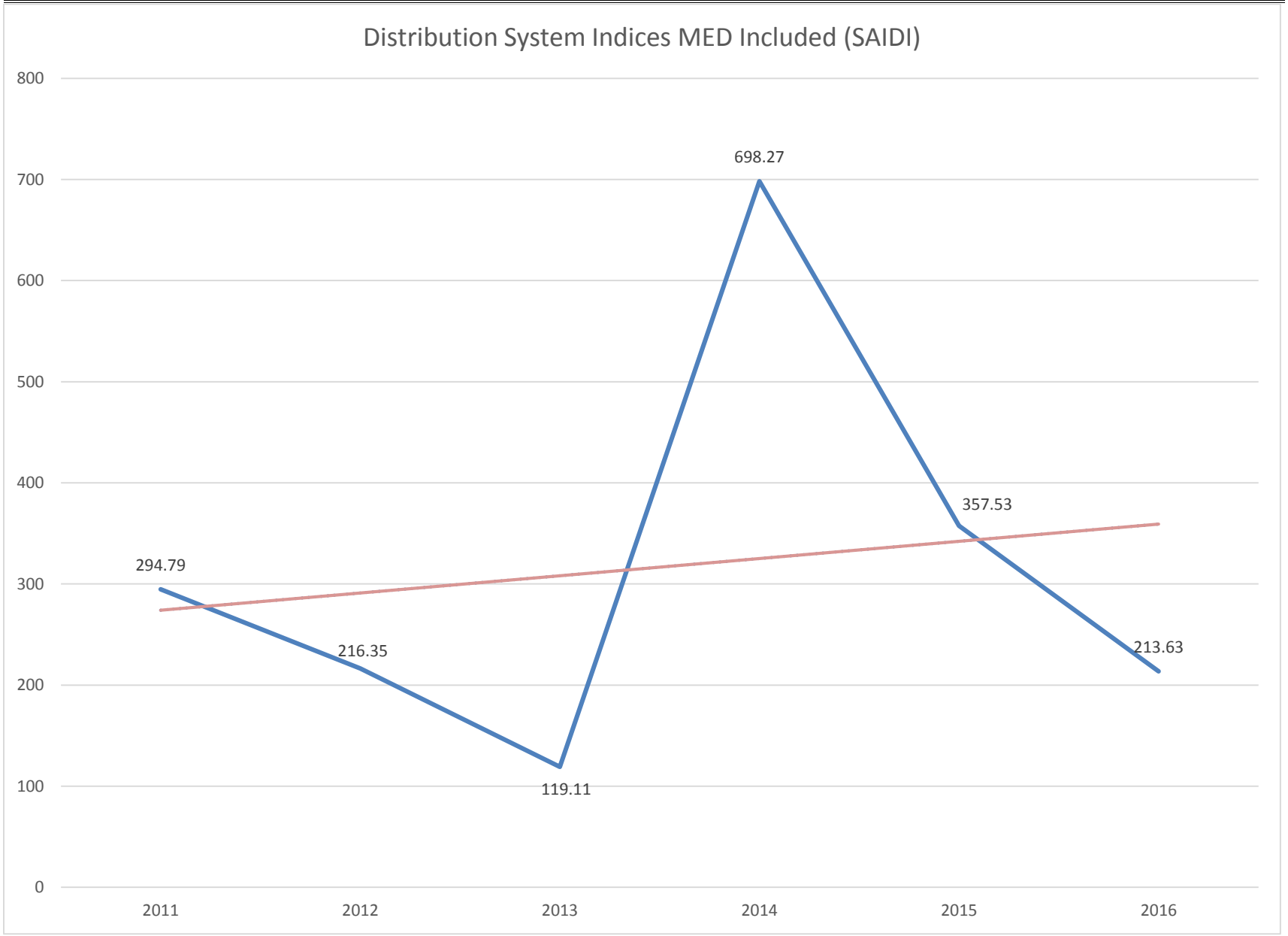
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 5 Years (Years in Business)

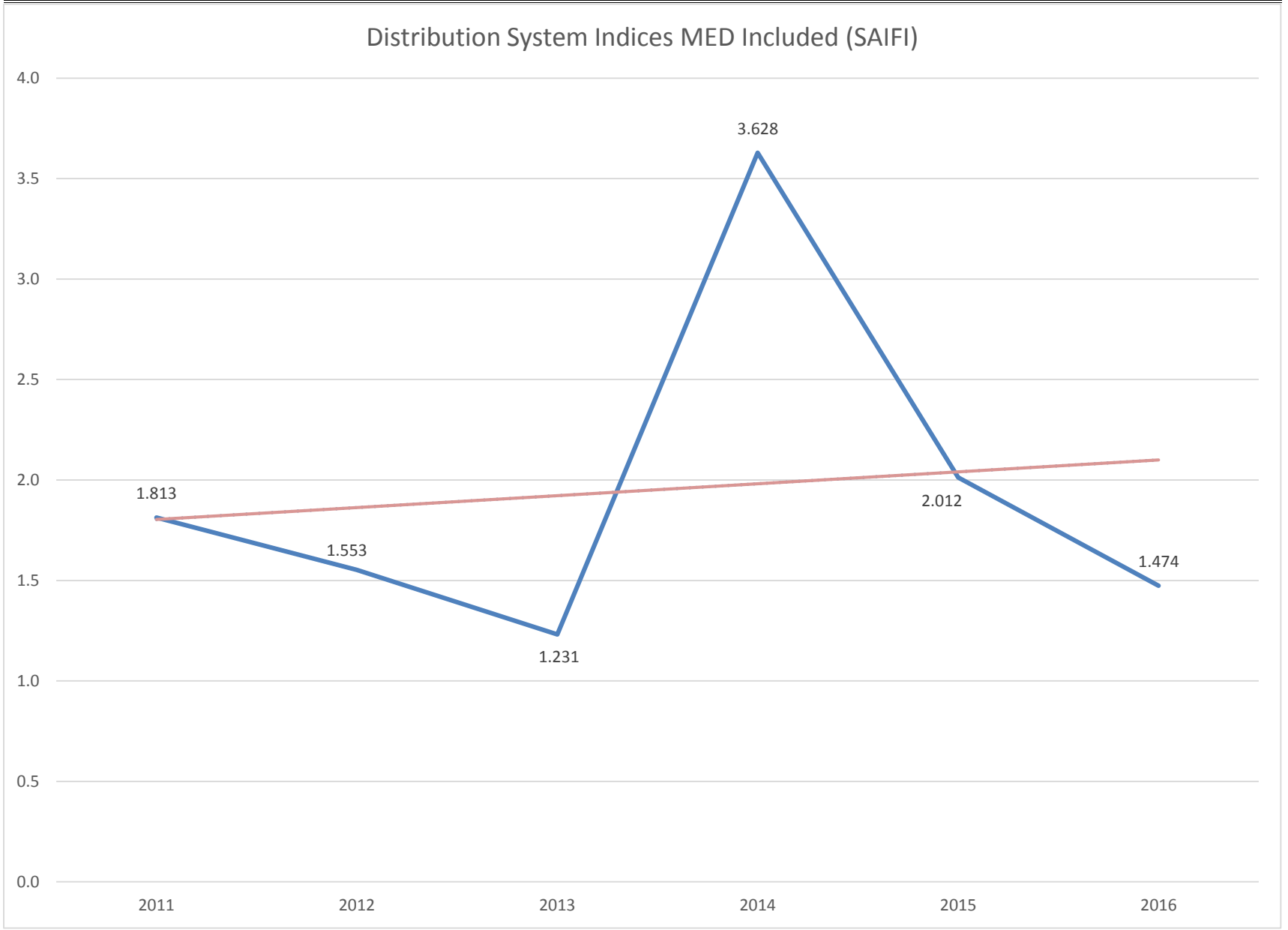
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2016	213.63	1.4735	144.98	1.08	213.63	1.4735	144.98	1.08
2015	357.53	2.0122	177.68	1.15	357.53	2.0122	177.68	1.15
2014	698.27	3.6284	192.44	2.15	352.37	2.4039	146.58	2.15
2013	119.11	1.2311	96.75	2.08	119.11	1.2310	96.79	2.08
2012	216.35	1.5530	139.31	2.75	216.35	1.5530	139.31	2.75
2011	294.79	1.8130	162.60	1.88	192.22	1.2460	154.27	1.88

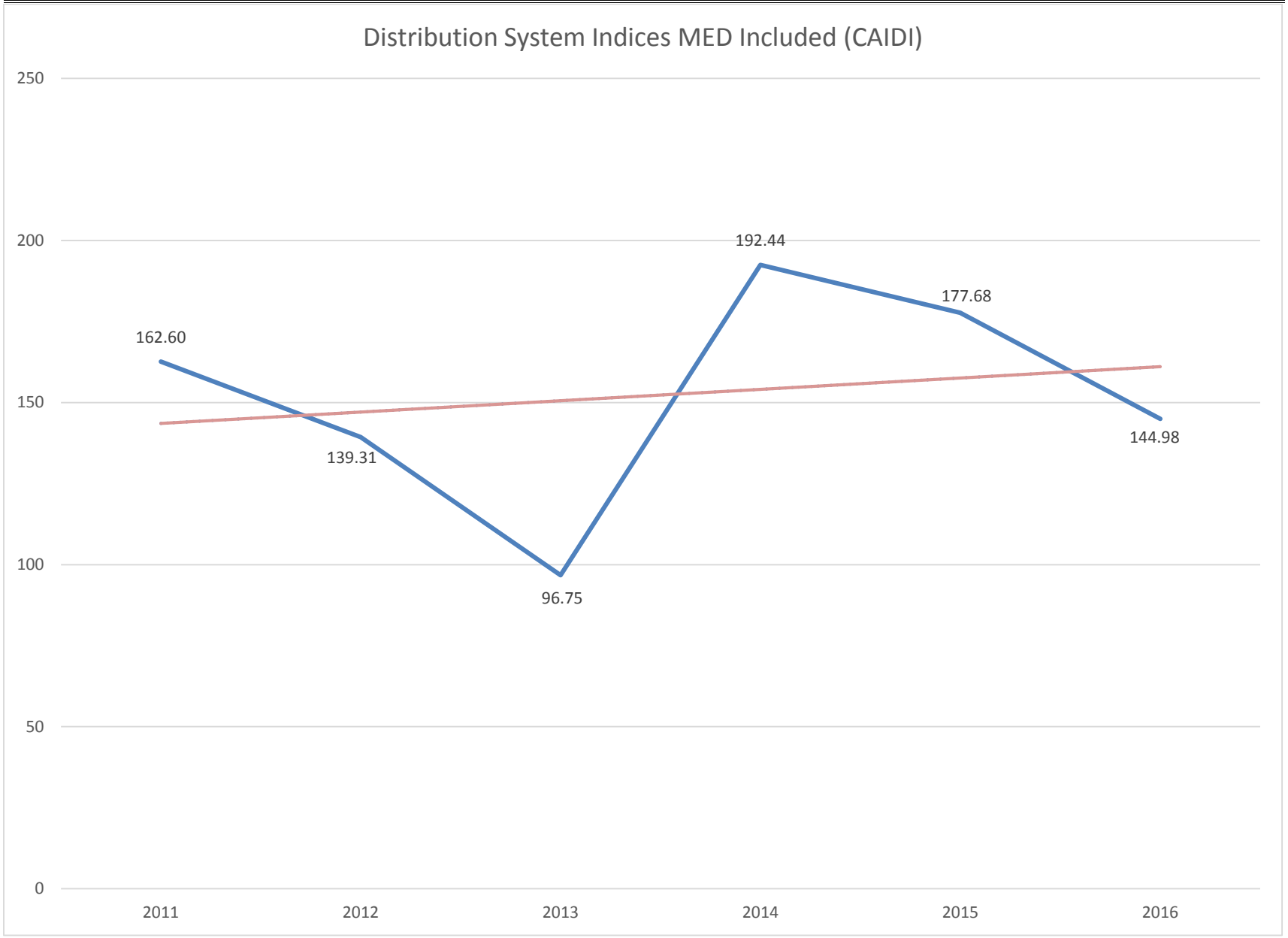
II. Transmission System Indices (MED Included and Excluded)

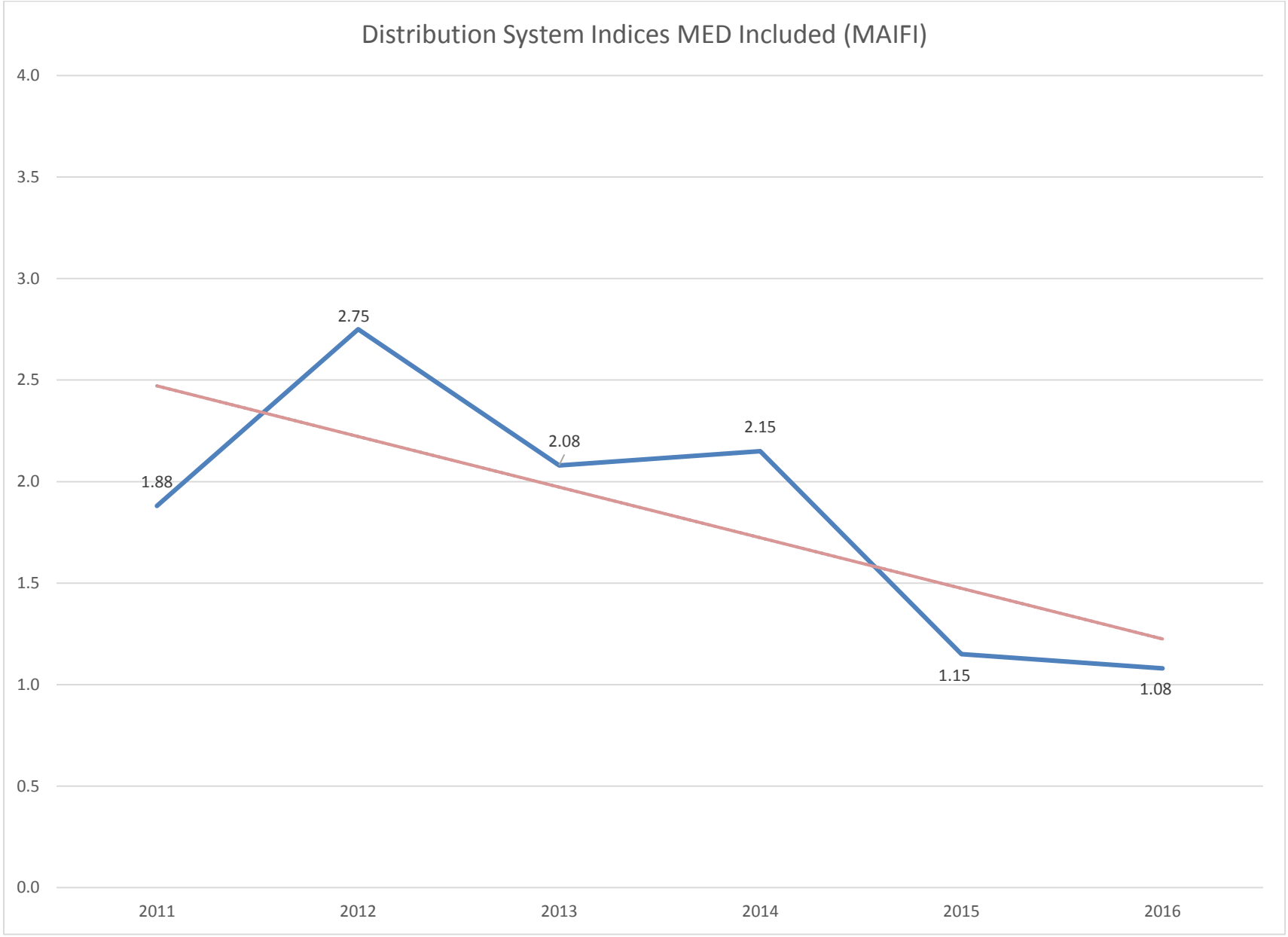
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

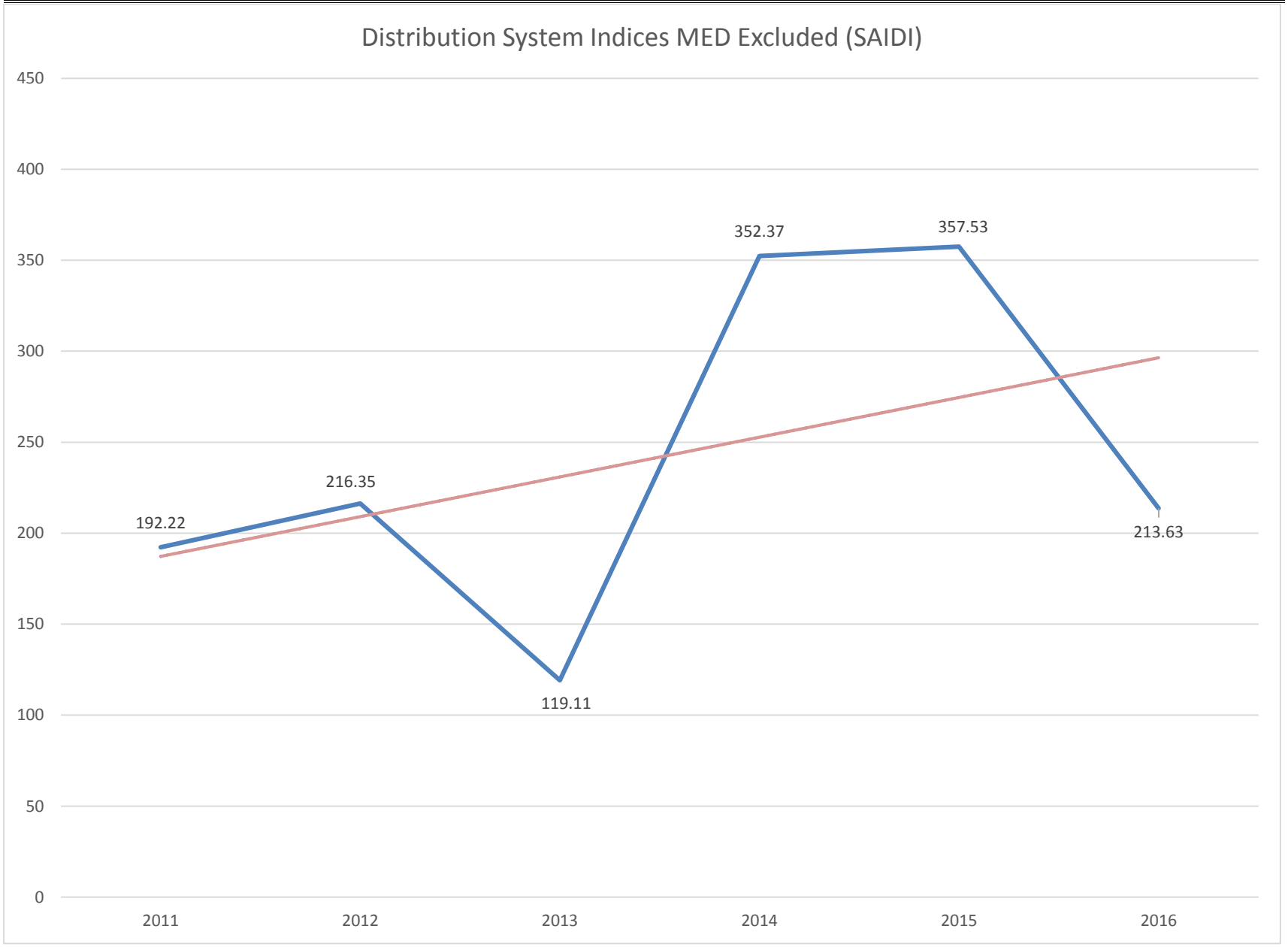
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 6 years (year in business) with linear trend line (TMED included and excluded).

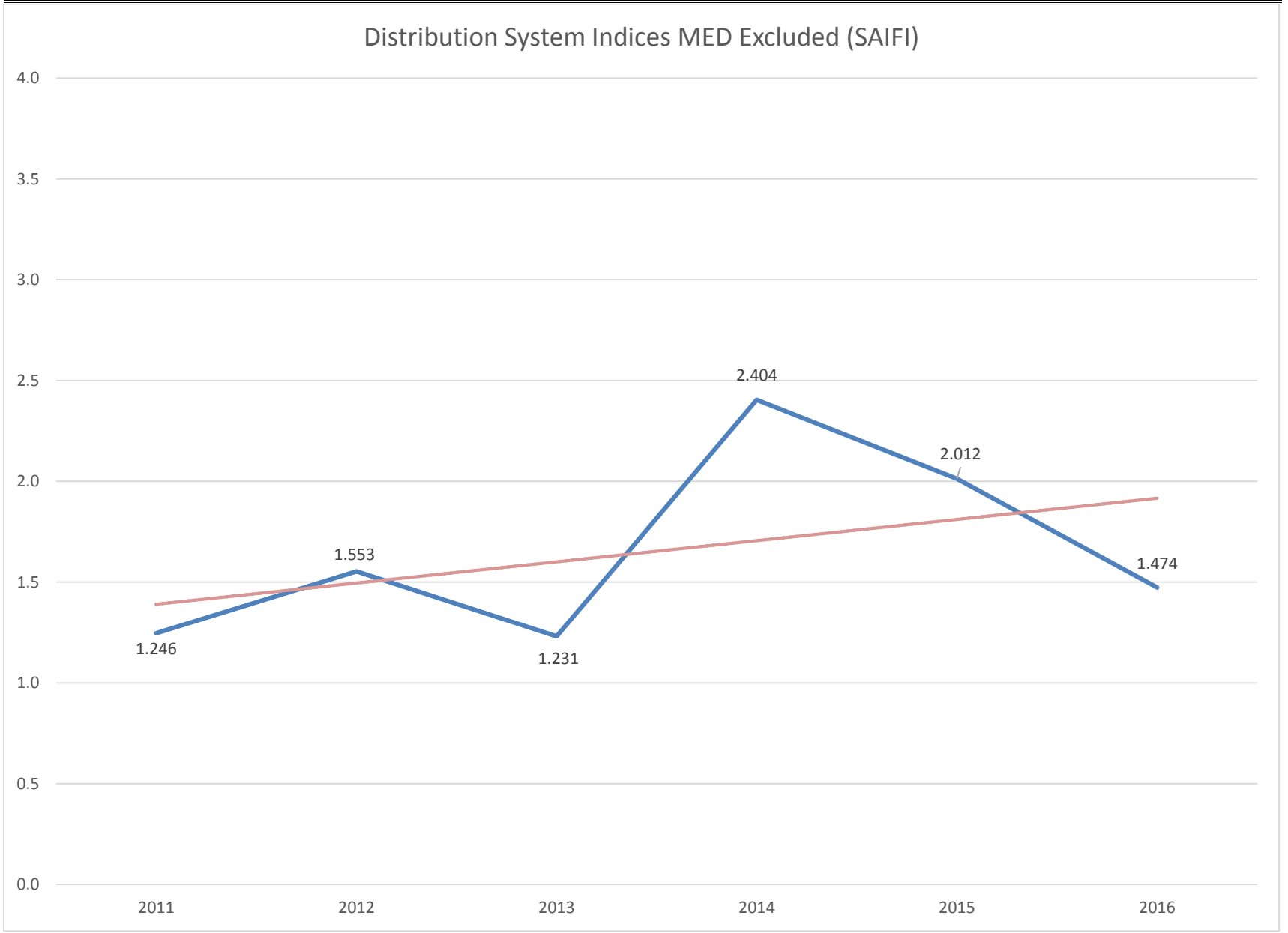

Distribution System Indices MED Included (SAIDI)
800
700
600
500
400
300
200
100
0
294.79
216.35
119.11
698.27
357.53
213.63
2011
2012
2013
2014
2015
2016

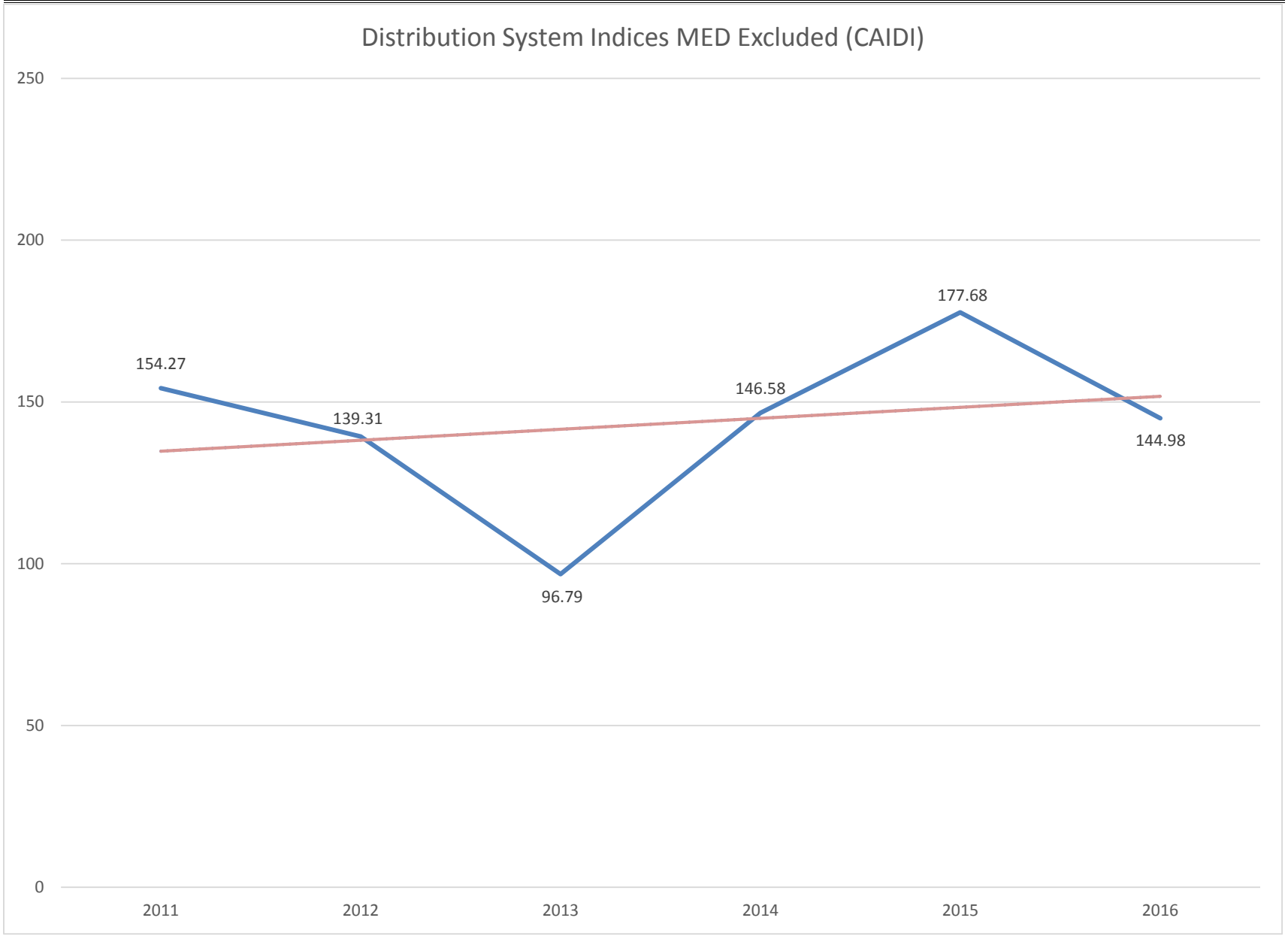

Distribution System Indices MED Included (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.813
1.553
1.231
3.628
2.012
1.474
2011
2012
2013
2014
2015
2016

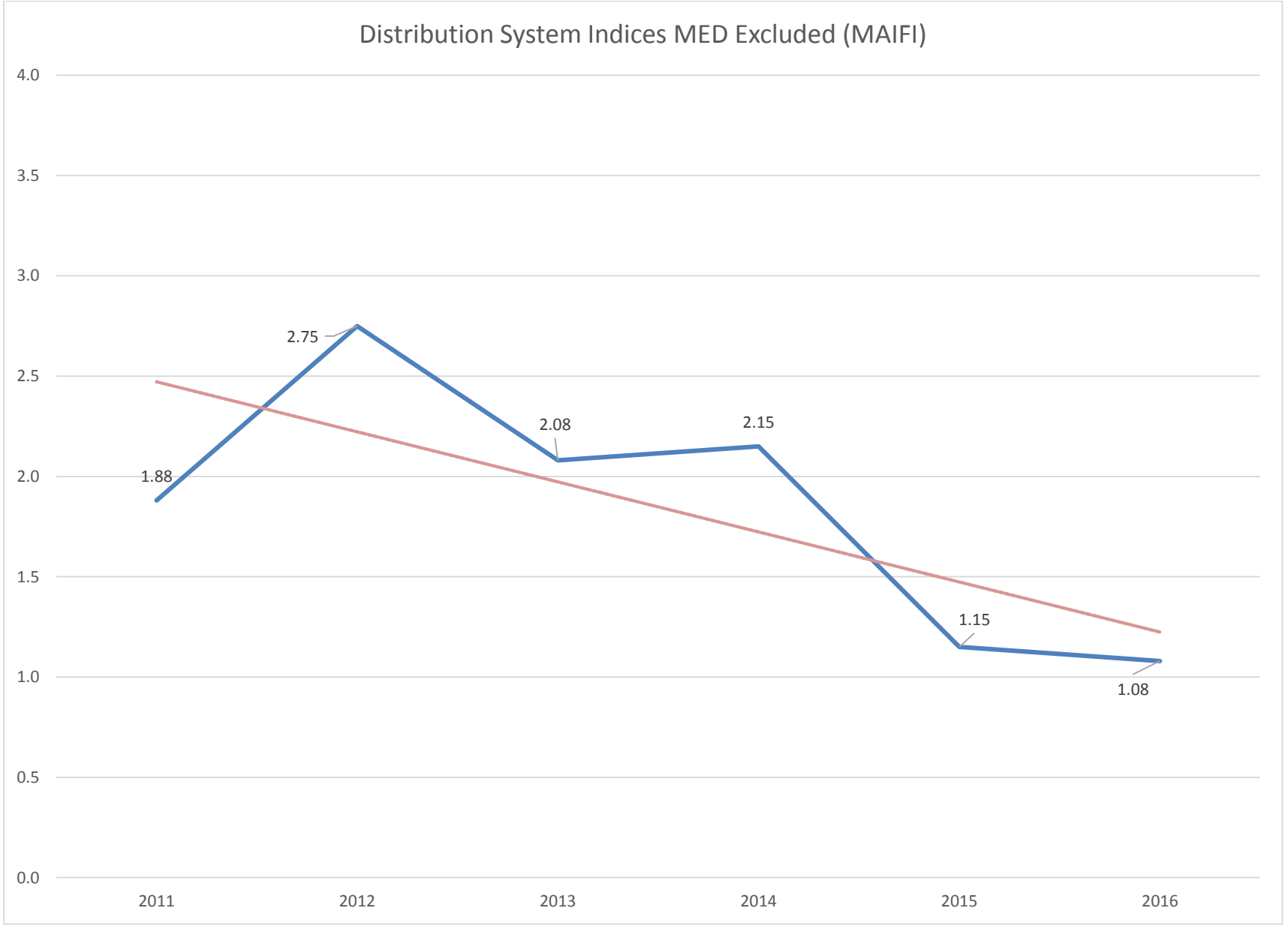

Distribution System Indices MED Included (CAIDI)
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
144.98
2011
2012
2013
2014
2015
2016


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
1.88
2.08
2.15
1.15
1.08
2011
2012
2013
2014
2015
2016


Distribution System Indices MED Excluded (SAIDI)
450
400
350
300
250
200
150
100
50
0
192.22
216.35
119.11
352.37
357.53
213.63
2011
2012
2013
2014
2015
2016


Distribution System Indices MED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.246
1.553
1.231
2.404
2.012
1.474
2011
2012
2013
2014
2015
2016


Distribution System Indices MED Excluded (CAIDI)
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
144.98
2011
2012
2013
2014
2015
2016


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
1.88
2.08
2.15
1.15
1.08
2011
2012
2013
2014
2015
2016

2) Division (or District) Reliability Indices for the past 10 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

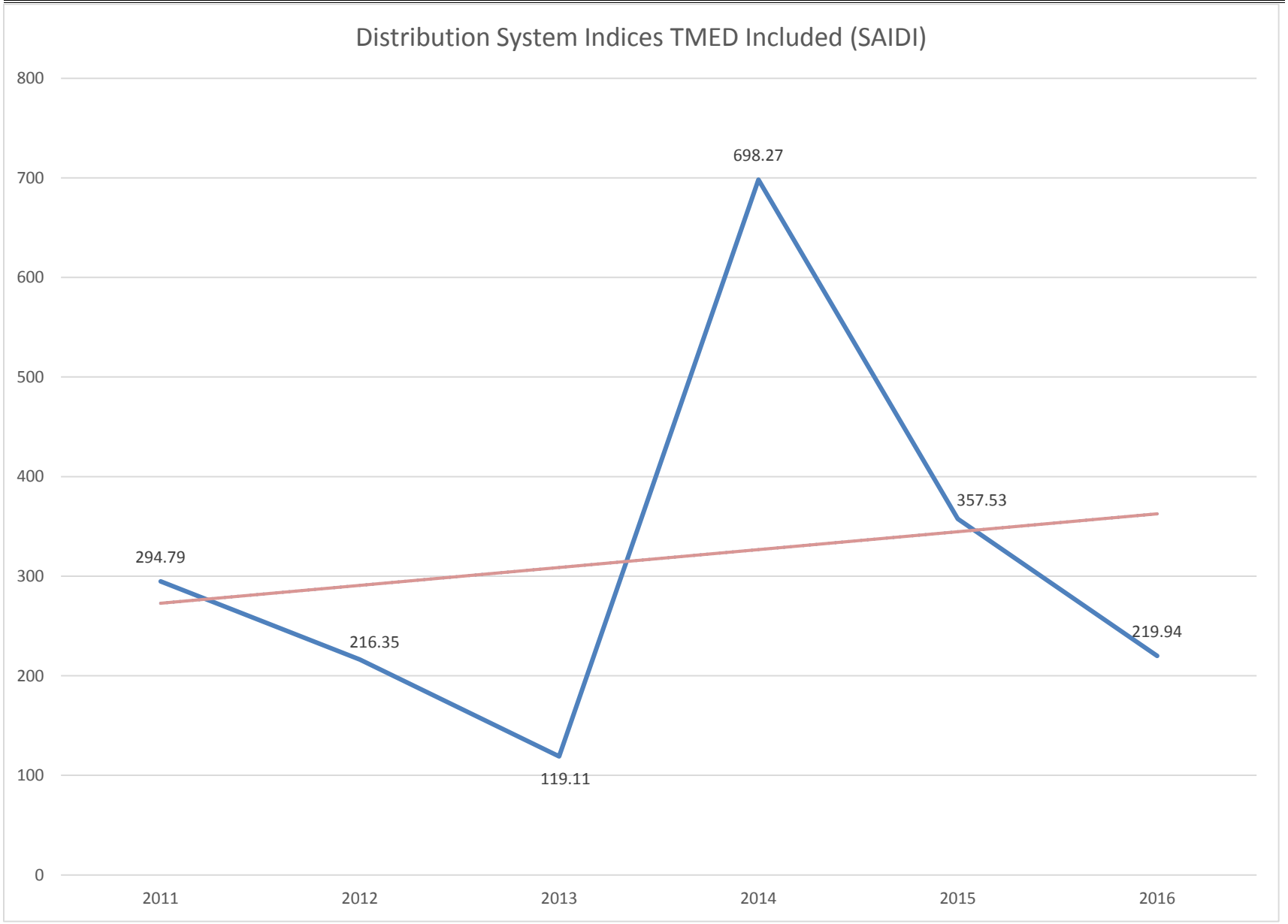
3) System and Division indices based on IEEE 1366 for the past 6 years including planned outages and including and excluding TMED

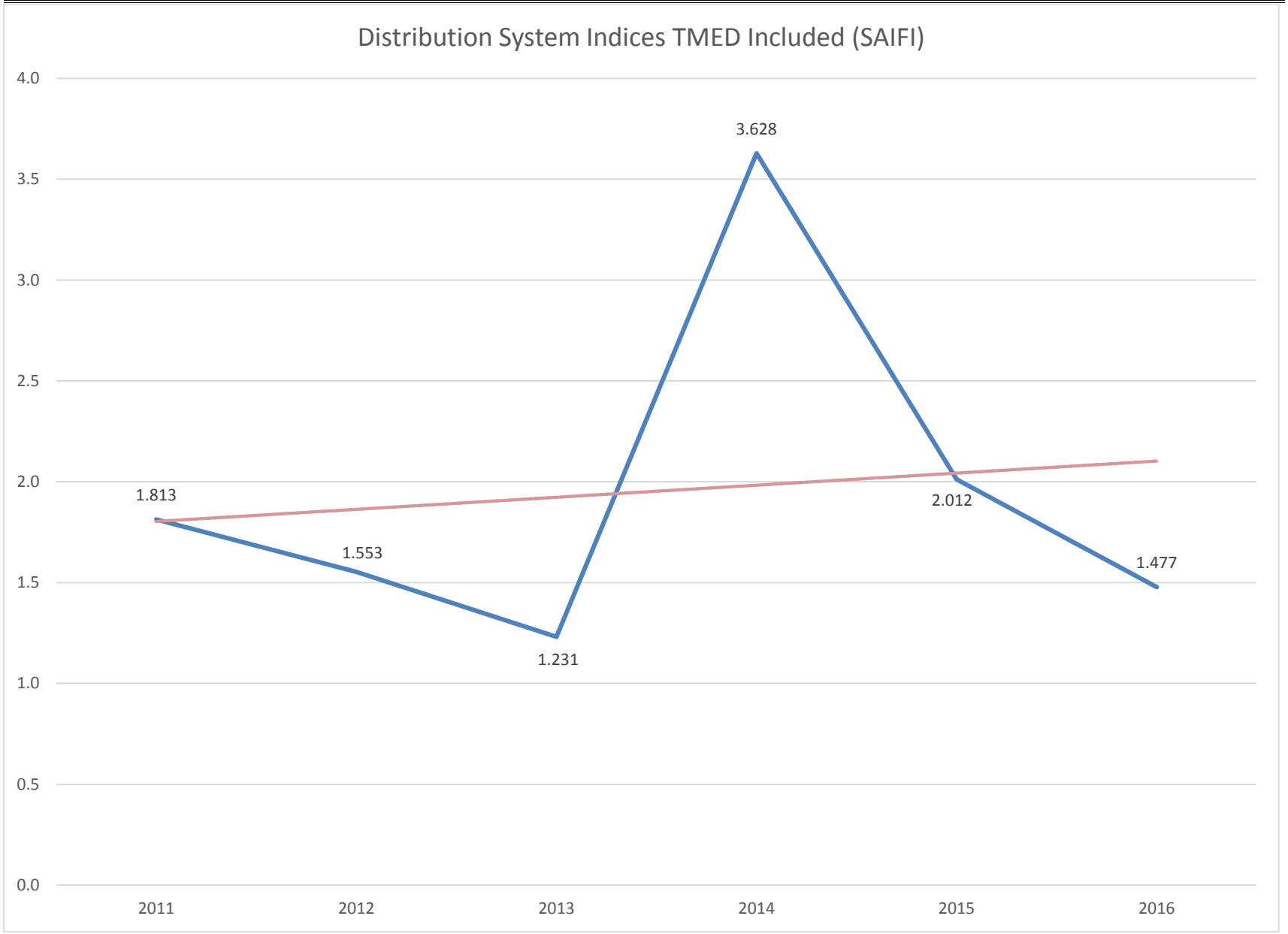
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

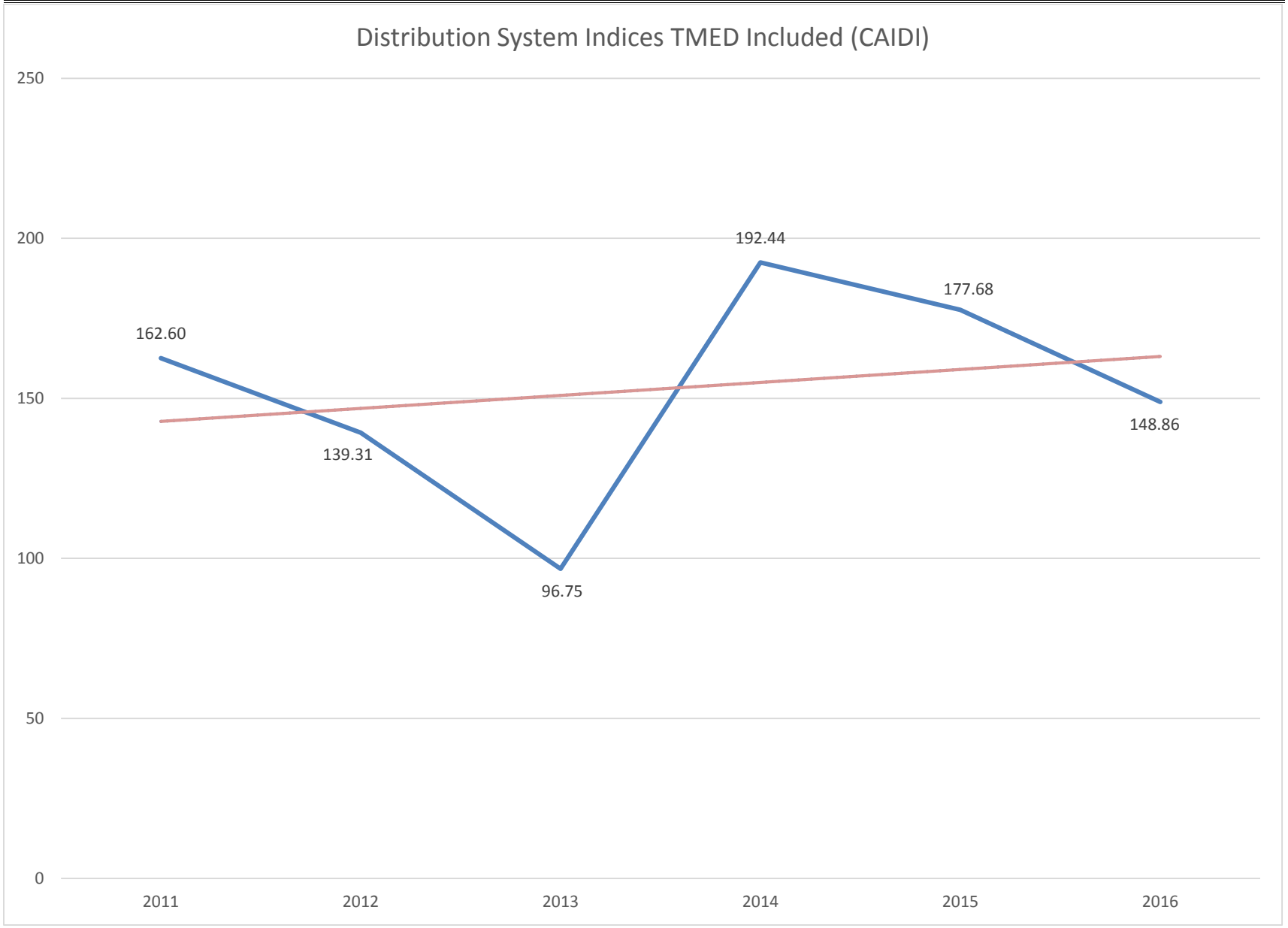
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 6 Years (Years in Business)

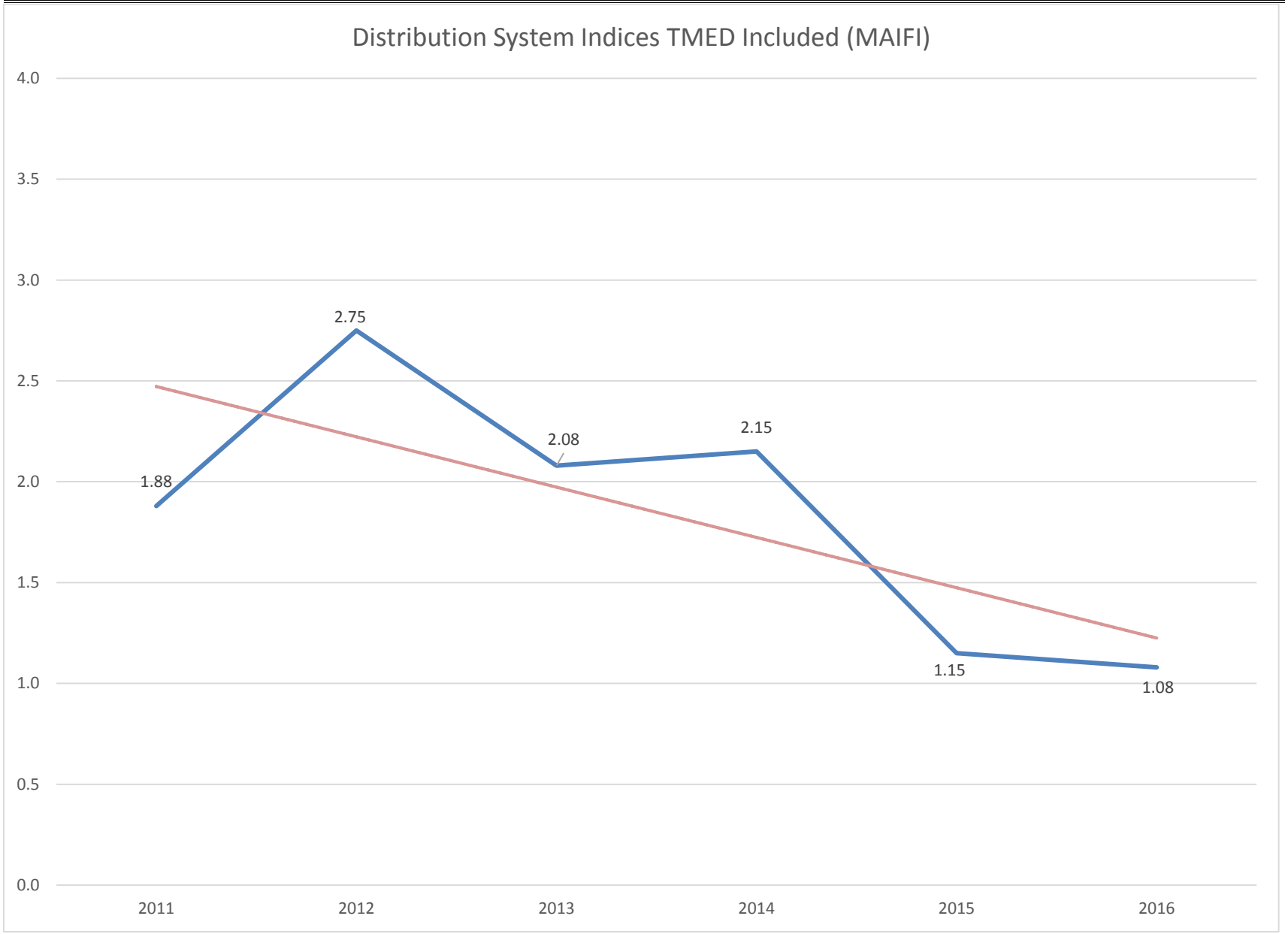
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2016	219.938	1.4774	148.86	1.08	219.938	1.4774	148.86	1.08
2015	357.531	2.0122	177.68	1.15	207.868	1.7409	119.40	1.15
2014	698.273	3.6284	192.44	2.15	323.745	2.2384	144.63	2.15
2013	119.109	1.2311	96.75	2.08	119.168	1.2311	96.79	2.08
2012	216.349	1.5530	139.31	2.75	170.439	1.5490	110.03	2.75
2011	294.795	1.8130	162.60	1.88	147.351	1.3207	111.57	1.88

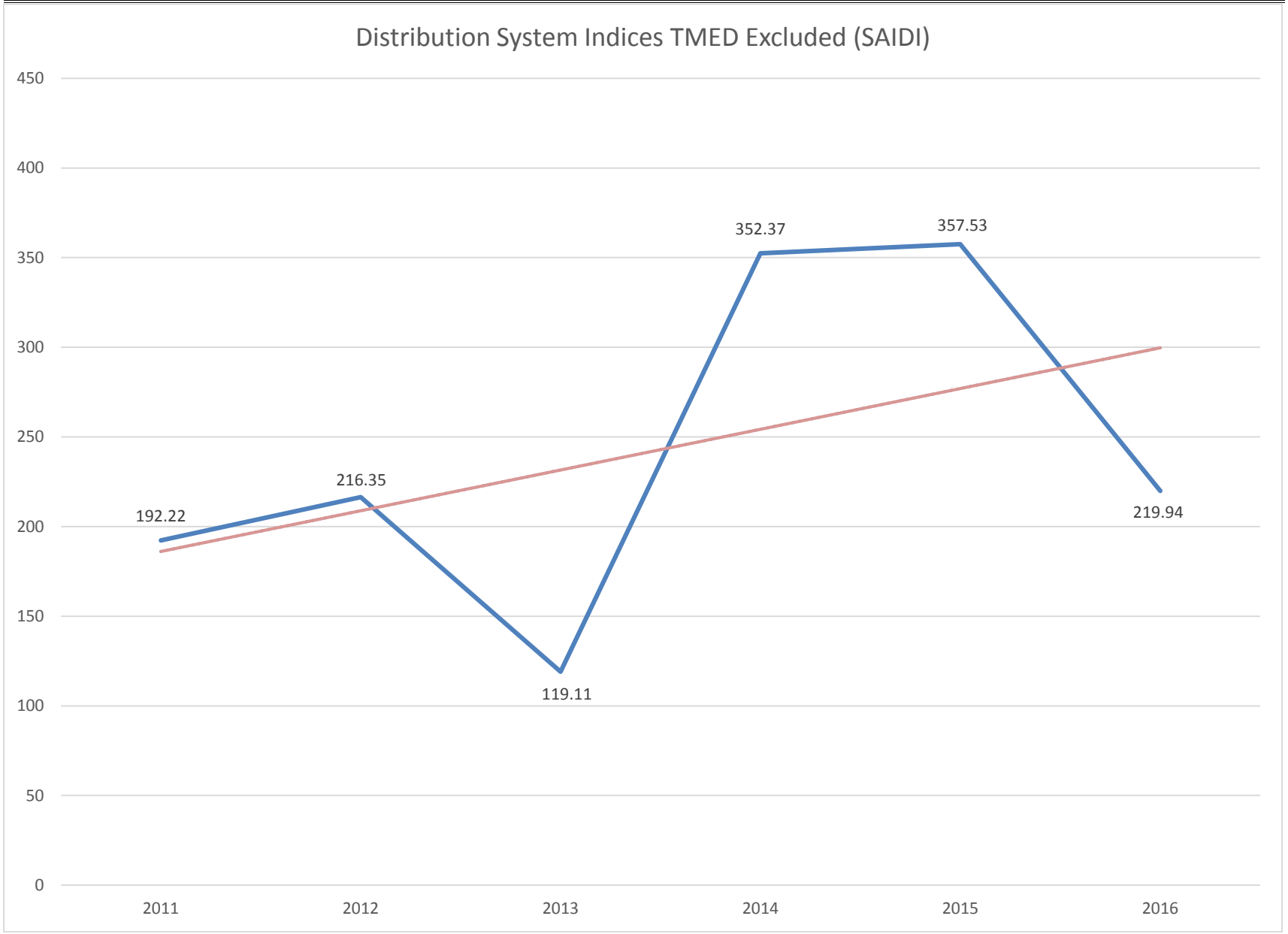
CalPeco Electric has been in business for 6 years and therefore does not have 10 years of data.

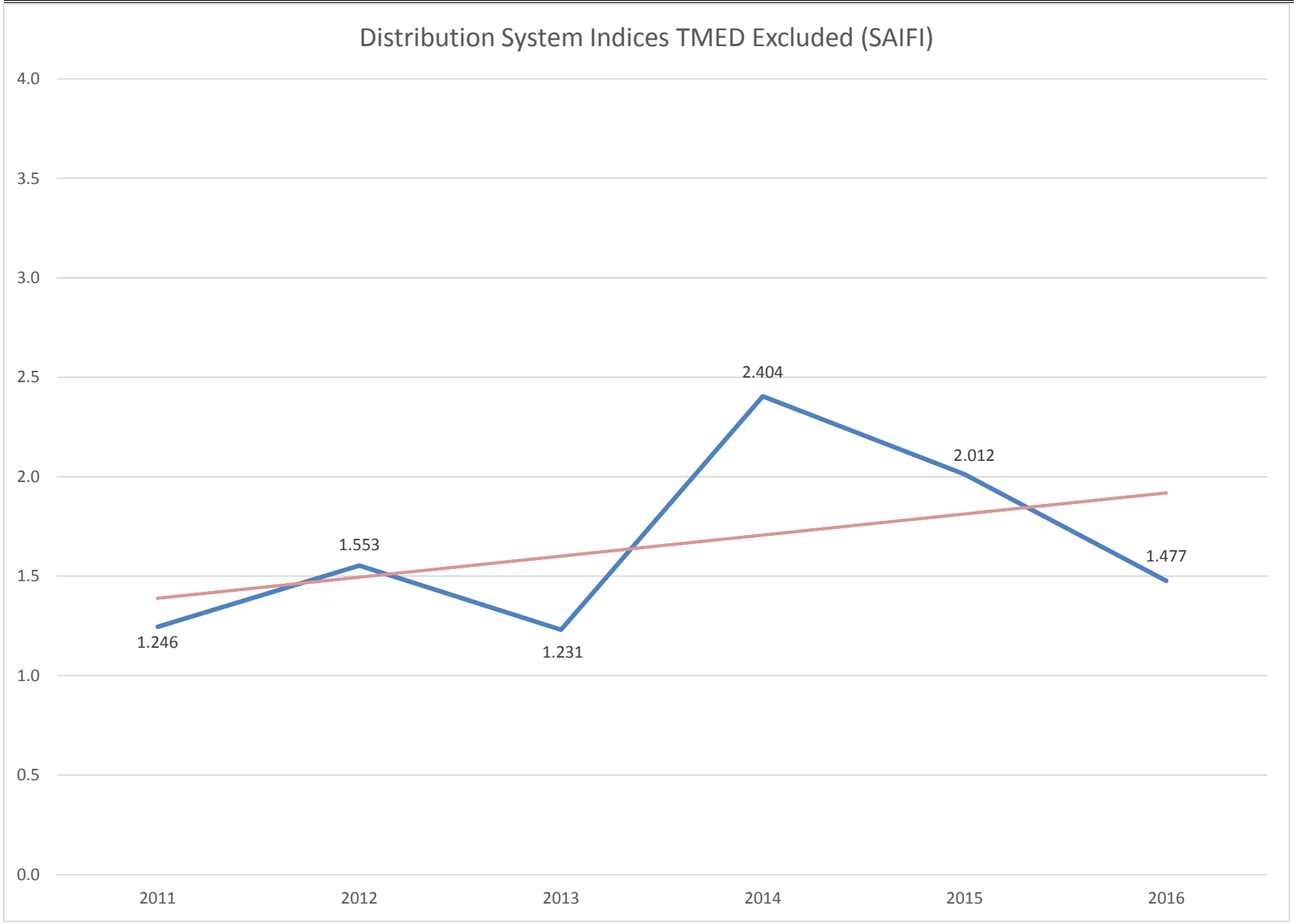

Distribution System Indices TMED Included (SAIDI)
800
700
600
500
400
300
200
100
0
294.79
216.35
119.11
698.27
357.53
219.94
2011
2012
2013
2014
2015
2016

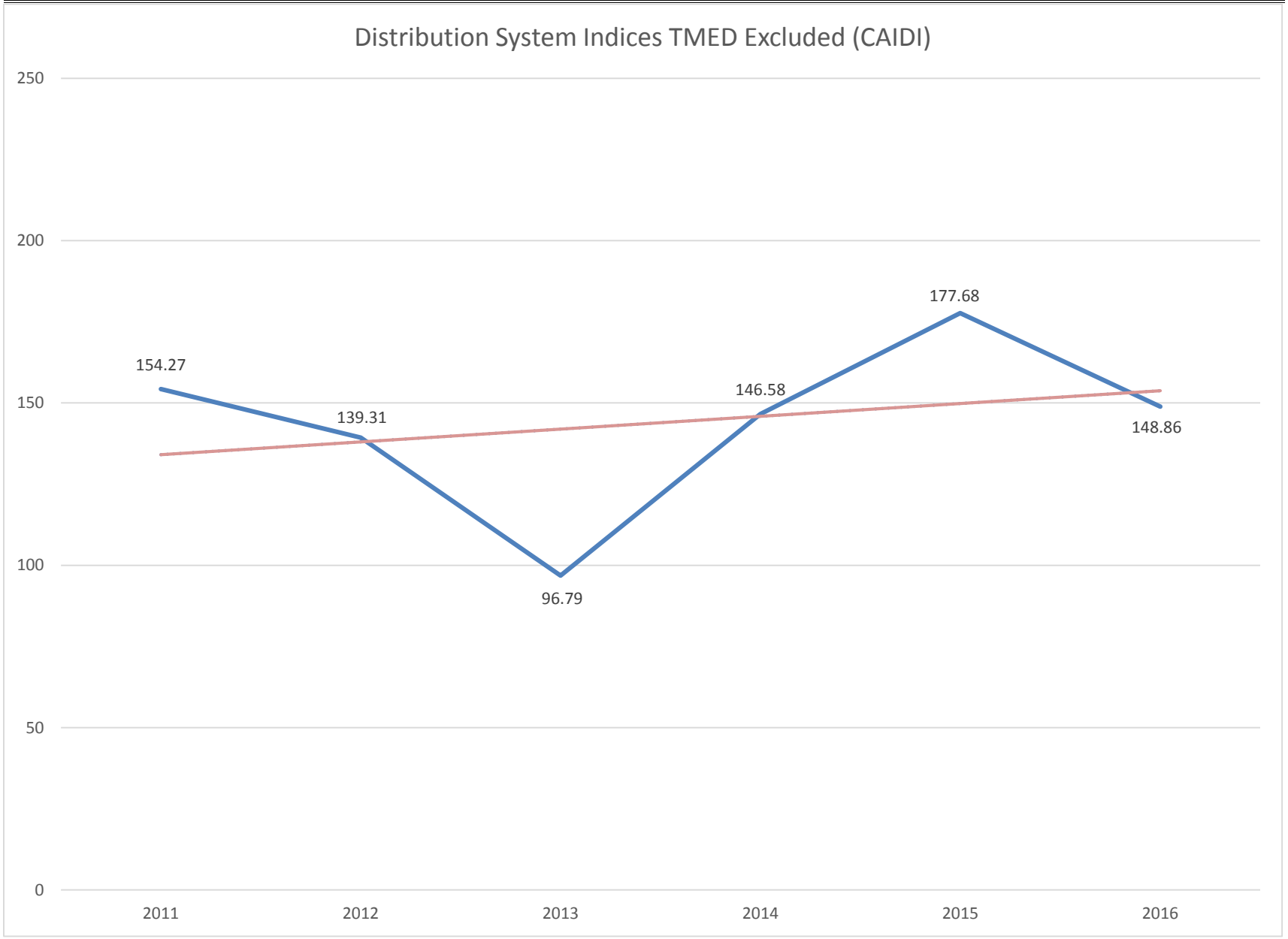

Distribution System Indices TMED Included (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.813
1.553
1.231
3.628
2.012
1.477
2011
2012
2013
2014
2015
2016

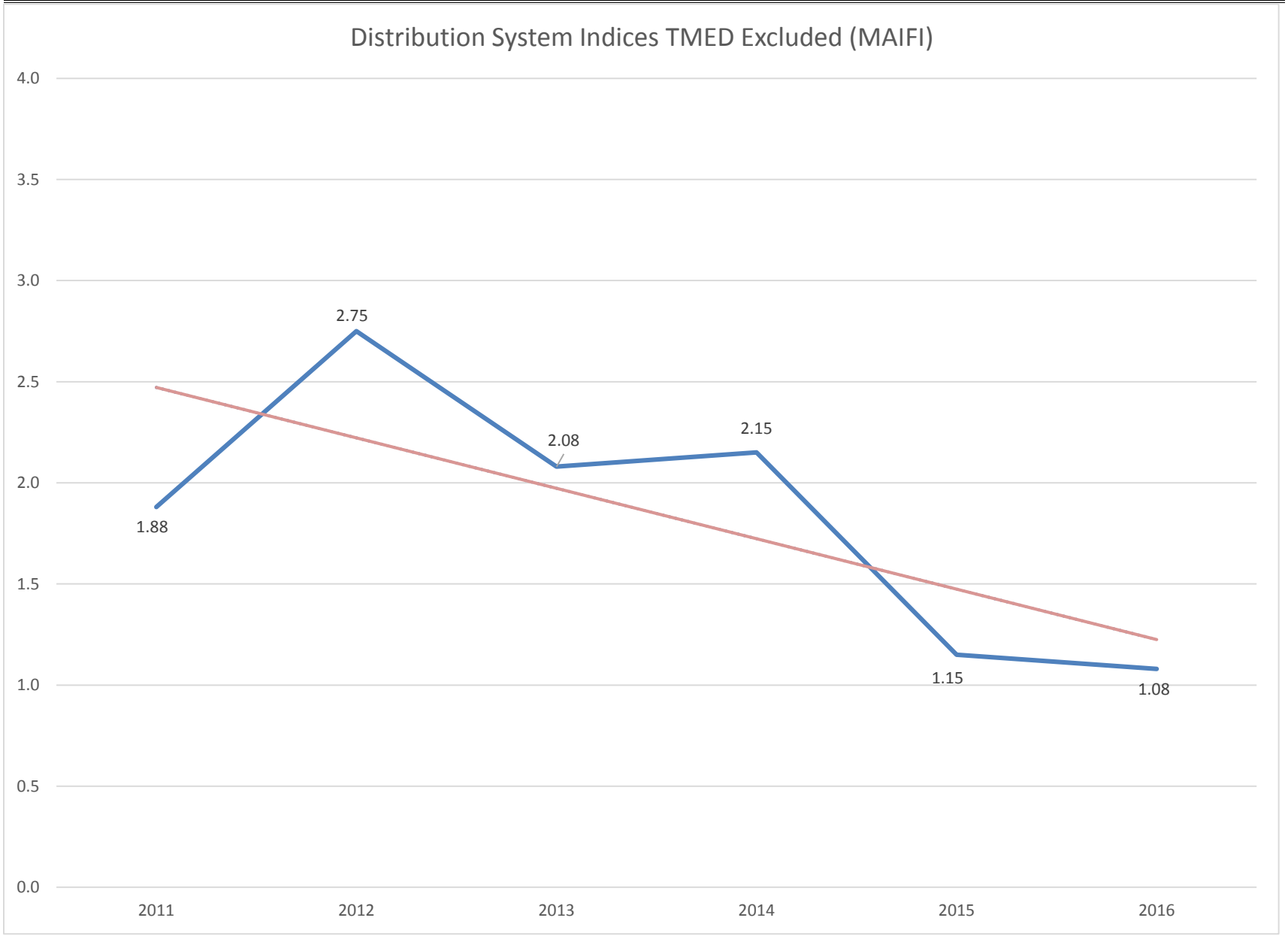

Distribution System Indices TMED Included (CAIDI)
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
148.86
2011
2012
2013
2014
2015
2016


Distribution System Indices TMED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
1.88
2.08
2.15
1.15
1.08
2011
2012
2013
2014
2015
2016


Distribution System Indices TMED Excluded (SAIDI)
450
400
350
300
250
200
150
100
50
0
192.22
216.35
119.11
352.37
357.53
219.94
2011
2012
2013
2014
2015
2016


Distribution System Indices TMED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.246
1.553
1.231
2.404
2.012
1.477
2011
2012
2013
2014
2015
2016

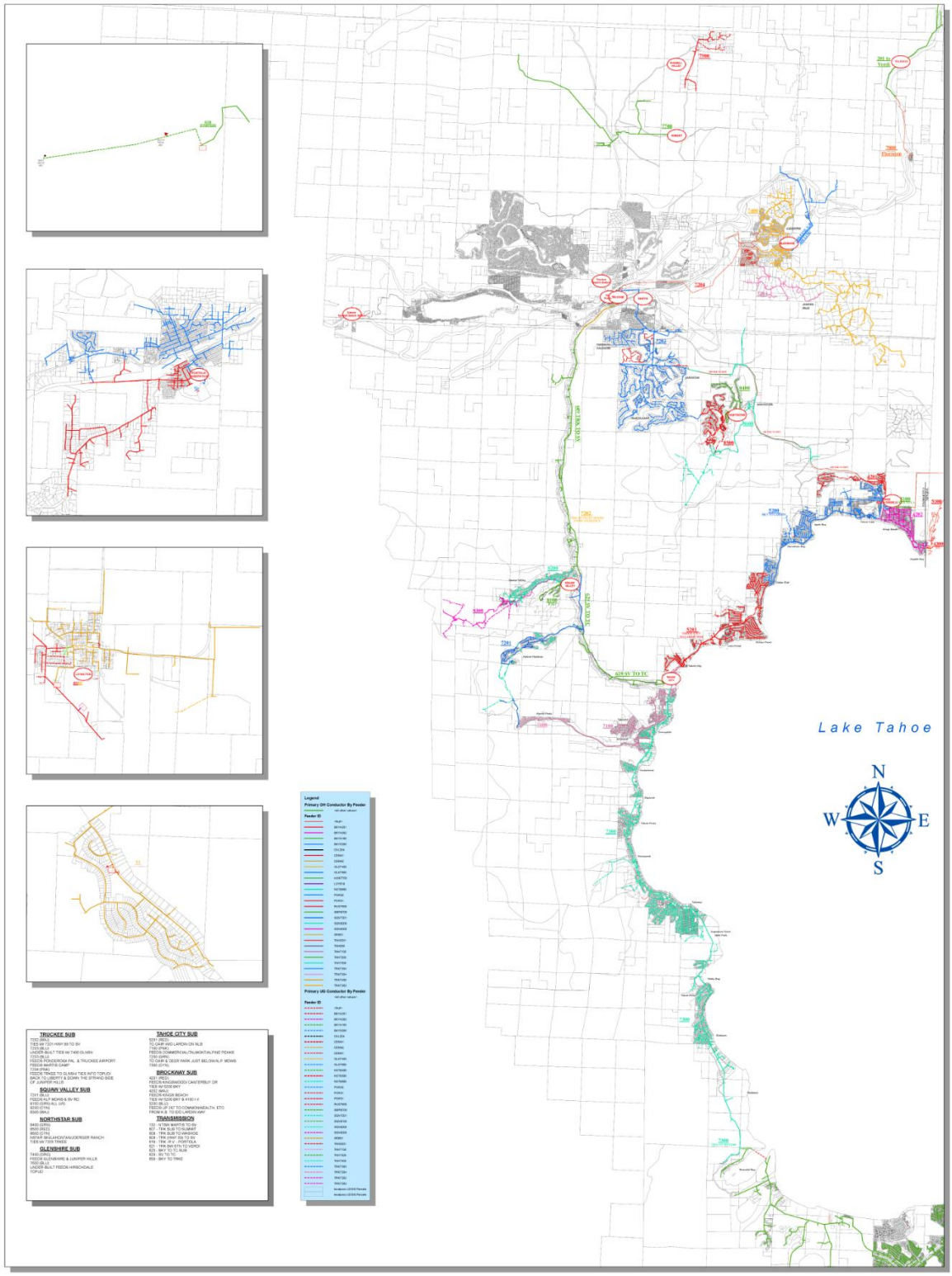

Distribution System Indices TMED Excluded (CAIDI)
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
148.86
2011
2012
2013
2014
2015
2016


Distribution System Indices TMED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.15
1.08
2011
2012
2013
2014
2015
2016

b. The number, date, and location of planned outages

Circuit	District	Number of Planned Outages By Year					
		2016	2015	2014	2013	2012	2011
31	Tahoe		1				
32	Tahoe	1					
41	Tahoe	1					
201	Tahoe				1		
204	Tahoe	1					
619	Tahoe					1	
650	Tahoe		1			1	
1296	Tahoe		5	1			
2200	Tahoe		1	1			
2300	Tahoe		1	2		1	
3100	Tahoe					1	1
3101	Tahoe			2	2		
3200	Tahoe		1			1	
3300	Tahoe		3			2	
3400	Tahoe		5		2	4	
3500	Tahoe		1				
3501	Tahoe		2	2	4	1	1
4201	Tahoe	1					
4202	Tahoe				2	5	1
5100	Tahoe				1	1	
5200	Tahoe		4	1	1	3	
5201	Tahoe	5	4	1		1	
7100	Tahoe			1	1	4	
7200	Tahoe		1	1	1	2	
7201	Tahoe	1	2	1			
7202	Tahoe		2	3	1		
7203	Tahoe		2	2	4		
7300	Tahoe	6	4	16	4	5	2
7400	Tahoe	1	1				1
7600	Tahoe		1				1
7700	Tahoe			1			
7800	Tahoe			2			
8200	Tahoe	3	2	4			1
8300	Tahoe		6			2	
8400	Tahoe						
8500	Tahoe	1			1	2	
8600	Tahoe		4			2	

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	790	Topaz	75.5	90.7%	9.3%	8	1338	10.0
7201	Tahoe	603	Squaw Valley	33.0	63.0%	37%	1	1030	1.2

Note: Preferred Metric is Circuit SAIDI

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

The calculated circuit SAIDI for the Topaz 1261 circuit in 2016 was 1,338 customer outage minutes.

II. A historical record of the metric;

The Topaz 1261 circuit had a SAIDI score of 3,003 customer outage minutes in 2015. The circuit SAIDI score reduced to 1,338 customer outage minutes in 2016.

III. An explanation of why it was on the deficiency list again;

The 1261 circuit experienced high circuit SAIDI in 2016 due to multiple circuit lockouts, wire slapping during windy conditions, and loss of supply.

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

Through 2016, CalPeco Electric has invested over $500,000 to replace aging poles throughout the circuit. Additionally, over $100,000 has been invested to upgrade and replace conductor in areas that have low capacity, extensive splices, or damage from wire slapping. The conductor upgrade and replacement project continues through 2017 with a budget of $100,000.

V. A quantitative description of the utility's expectation for that circuit's future performance.

With a combined total of over $700,000 invested by the end of 2017 to improve the Topaz 1261 circuit, CalPeco Electric expects the quantity of sustained outages due to wire slapping in windy conditions to be significantly reduced. In 2016, this circuit experienced twelve outages that were suspected wire slapping events and accounted for 780 customer outage minutes.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions:

WPC- Worst Performing Circuits

CB- Circuit Breaker

AR- Automatic re-closer

Assumptions

- Our analysis excludes planned outages and TMED outages

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated Circuit SAIDI. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering and Planning Manager, and Vice President of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	3/13/2016	Loss of Source – External System	Lake Tahoe	6,882	6.21	0.1411
2	10/16/2016	Wind / Trees	Lake Tahoe	4,125	8.80	0.0845
3	10/4/2016	Underground Fault	Lake Tahoe	4,125	21.89	0.0845
4	3/22/2016	Downed Wire	Lake Tahoe	4,125	7.74	0.0845
5	3/13/2016	Car / Pole	Lake Tahoe	3,517	4.87	0.0812
6	1/1/2016	Failed Overhead Hardware	Lake Tahoe	3,500	8.92	0.0717
7	3/1/2016	Trees	Lake Tahoe	3,258	2.07	0.0668
8	6/29/2016	Underground Fault	Lake Tahoe	2,859	4.89	0.0586
9	8/23/2016	Primary Contact – 3rd Party	Lake Tahoe	2,772	3.31	0.0568
10	6/15/2016	Trees	Lake Tahoe	2,732	4.70	0.0560

*Based on customer impact

7) Summary list of 2016 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2016 = 104.57

CalPeco Electric did not experience an event in 2016 where the daily SAIDI was higher than the calculated TMED. Therefore, CalPeco Electric did not experience any Major Events in 2016 which would be excludable per IEEE 1366.

8) Historical 10 largest unplanned outage events for the past 10 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	.067	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers -hours affected	CPUC Major Event?
1	NV Energy Outage	5/9/2011	24,550	3.02	74,059.17	Yes
2	Relays	2/17/2011	8,005	3.40	12,738.90	No
3	Overcurrent	3/20/2011	4,396	0.98	4,396.00	No
4	Trees	5/25/2011	4,120	10.23	21,658.83	No
5	Trees	11/18/2011	4,120	21.50	15,792.33	No
6	Lateral Fuse	3/16/2011	3,957	2.96	11,739.10	No
7	Bird/Animal	9/24/2011	3,885	0.25	769.50	No
8	Hardware Failure	9/12/2011	3,475	1.12	2,780.42	No
9	Relays	1/25/2011	3,201	1.68	5,388.35	No
10	Trees	6/29/2011	3,200	4.35	11,786.67	No

9) Number of customer inquiries on reliability data and the number of days per response

CalPeco Electric received one reliability inquiry in 2016. A response letter was sent out on November 3rd, addressing the customer's question about reliability investments in the Coleville community.

Date Received	Date Responded	Description of Inquiry
10/15/2016	11/3/2016	Inquiring about power outages in the Coleville community, specifically during windy conditions, and what CalPeco Electric is doing to improve the reliability.

ATTACHMENT 10

Response to data request
CalPA-Liberty-R1810007-002, February 27, 2019

Public Advocates Office
California Public Utilities Commission

505 Van Ness Avenue
San Francisco, CA 94102
Phone: (415) 703-2544
Fax: (415) 703-2057

http://publicadvocates.cpuc.ca.gov

PUBLIC ADVOCATES OFFICE DATA REQUEST

R. 18-10-007: Wildfire Mitigation Plans Rulemaking

Date: February 22, 2019

To: **AnnMarie Lett**
Liberty Utilities
Phone: (562) 319-4751
Email: annmarie.lett@libertyutilities.com

From: **Nathaniel Skinner**
Project Coordinator
Phone: (415) 703-1393
Email: nws@cpuc.ca.gov

Shelby Chase
Regulatory Analyst
Phone: (415) 703-5402
Email: shelby.chase@cpuc.ca.gov

David Lievanos
Utilities Engineer
Phone: (415) 703-2552
Email: david.lievanos@cpuc.ca.gov

Nils Stannik
Utilities Engineer
Phone: (415) 703-1889
Email: nils.stannik@cpuc.ca.gov

Charlyn Hook
Attorney
Phone: (415) 703-3050
Email: charlyn.hook@cpuc.ca.gov

Re: Data Request No. CalPA-Liberty-R1810007-002
Responses Due: February 27, 2019

INSTRUCTIONS

You are instructed to answer the following Data Requests in the above-captioned proceeding, with written, verified responses per Public Utilities Code §§ 309.5 and 314, and Rules 1.1 and 10.1 of the California Public Utilities Commission's Rules of Practice and Procedure. Restate the text of each request prior to providing the response. For any questions, email the Public Advocates Office contact(s) above with a copy to the Public Advocates Office attorney.

Each Data Request is continuing in nature. Provide your response as it becomes available, but no later than the due date noted above. If you are unable to provide a response by this date, notify the Public Advocates Office as soon as possible, with a written explanation as to why the response date cannot be met and a best estimate of when the information can be provided. If you acquire additional information after providing an answer to any request, you must supplement your response following the receipt of such additional information.

Identify the person providing the answer to each data request and his/her contact information. Responses should be provided both in the original electronic format, if available, and in hard copy. (If available in Word format, send the Word document and do not send the information as a PDF file.) All electronic documents submitted in response to this data request should be in readable, downloadable, printable, and searchable formats, unless use of such formats is infeasible. Each page should be numbered. If any of your answers refer to or reflect calculations, provide a copy of the supporting electronic files that were used to derive such calculations, such as Excel-compatible spreadsheets or computer programs, with data and formulas intact and functioning. Documents produced in response to the data requests should be Bates-numbered, and indexed if voluminous. Responses to data requests that refer to or incorporate documents should identify the particular documents referenced by Bates-numbers or Bates-range.

If a request, definition, or an instruction, is unclear, notify the Public Advocates Office as soon as possible. In any event, answer the request to the fullest extent possible, specifying the reason for your inability to answer the remaining portion of the Data Request.

DEFINITIONS

Unless the request indicates otherwise, the following definitions are applicable in providing the requested information.

1. The terms "document," "documents," or "documentary material" include, without limitation, the following items, whether in electronic form, printed, recorded, or written or reproduced by hand: reports, studies, statistics, projections, forecasts, decisions, and orders, intra-office and interoffice communications, correspondence, memoranda, financial data, summaries or records of conversations or interviews, statements, returns, diaries, calendars, work papers, graphs, notebooks, notes, charts, computations, plans, drawings, sketches, computer printouts, summaries of records of meetings or conferences, summaries or reports of investigations or negotiations, opinions or reports of consultants, photographs, bulletins, records or representations or publications of any kind (including microfilm, videotape, and records however produced or reproduced), electronic or mechanical or electrical records of any kind (including, without limitation, tapes, tape cassettes, discs, emails, and records) other data compilations (including without limitation, input/output files, source codes, object codes, program documentation, computer programs, computer printouts, cards, tapes, discs and recordings used in automated data processing, together with the programming instructions and other material necessary to translate, understand, or use the same), and other documents or tangible things of whatever description which constitute or contain information within the scope of these data requests.

2. "Relating to" means concerning, addressing, referring, discussing, commenting upon, analyzing, mentioning or involving in any way.

3. "Identify":
   a. When used in reference to a person includes stating his or her full name, his or her most recent known business address and telephone number, and his or her present title or position;
   b. When used in reference to documents includes stating the nature of the document (e.g., letter, memorandum), the date (if any), the title of the document, the identity of the author and/or the document, the location of the document, the identity of the person having possession, control or custody of the document, and the general subject matter of the document.

4. "CPUC" as used herein refers to the California Public Utilities Commission.

5. "Liberty" as used herein refers to Liberty Utilities and/or its affiliates.

DATA REQUESTS

Unless otherwise stated, all page and section references refer to Liberty Utilities' 2019 Wildfire Mitigation Plan.

Question 1

Does Liberty propose any cost- or efficiency-based metrics to track or indicate progress on any of its proposed programs in the Wildfire Mitigation Plan (for example: cost per mile reconductored, person-hours per device installed, cost per tree removed, etc.)? If so, please provide. If not, please explain why.

LIBERTY CALPECO RESPONSE: Liberty CalPeco has not proposed any cost or efficiency-based metrics to track progress. Liberty CalPeco does track various costs mentioned in its regular recorded costs. For example, cost per mile re-conductored and labor per device installed will be captured in the specific capital work order for each job performed. Liberty CalPeco also tracks the costs for tree removal in its O&M expenses.

Question 2

On page 19, *Chapter 4.3 Inspection and Maintenance, Equipment Inspection* states

> "Substations are inspected quarterly with substation relays being maintained every 3 to 6 years, depending on the type of relays as well as staffing availability."

On page 30, *Chapter 4.5.2 Identifying At-Risk Vegetation* states:

> "Since 2015, these concerns have grown with the exponential increase of tree mortality rates. Liberty CalPeco has determined that efforts to curb this issue is no longer manageable with current staffing levels. In response, costs have been identified that exceed current budgets by $1 million annually."

Will Liberty be creating additional staff positions to help with these mitigation activities? If so, please provide a description of each position including job duties, how this position will have a direct effect on wildfire mitigation efforts, and when the position is expected to be filled by. If not, please describe what activities or changes will be made to these programs to ensure adequate staffing for mitigation measures.

LIBERTY CALPECO RESPONSE: Liberty CalPeco does not plan on creating additional staff positions to help with the mitigation activities described in its WMP. Liberty CalPeco will rely on additional contract personnel to perform the proposed mitigation activities.

Question 3

On page 20, *Chapter 4.4.1 Covered Conductor* states:

"Liberty CalPeco has recently reevaluated its system design in the context of wildfire risk and decided to, where appropriate (i.e. based on wildfire risk), replace bare conductors with covered conductors. This timeline is determined on a five-year scale, thought may be adjusted with each iteration of the Plan."

a. What percent of the total number of conductors in Liberty's service territory will be replaced upon completion of this project?
b. What percent of the total number of conductors in Liberty's service territory will be replaced before the next filing of this plan?

LIBERTY CALPECO RESPONSE:

a. Approximately 2% over the five-year project.
b. Approximately 0.4%, assuming a new WMP will be submitted at the same time next year.

Question 4

On page 20, *Chapter 4.4.1 Covered Conductor*, states:

"Tahoe City Line 7300

This project comprises reconductoring of Tahoe City Line 7300 to enhance electric service reliability and improve the safety and operational integrity of the electric grid. The project includes reconductoring segments of the 15,000 feet of overhead lines out of the Tahoe City Substation as described in the pending 2019 General Rate Case (GRC) application. The prioritization for reconductoring the line was primarily driven by the need to replace failing equipment and proactively installing grid hardening assets."

How was failing equipment on Tahoe City Line 7300 identified? Please provide any reports or analysis that supports this request.

LIBERTY CALPECO RESPONSE: The reconductoring of the Tahoe City 7300 circuit is a multi-phased reliability improvement that has been ongoing since at least 2011 when Liberty CalPeco took ownership of the service territory. The project aimed to provide increased safety, reliability and operational flexibility of the electric system in Lake Tahoe.

During the severe winter storms of 2017, heavy winds, ice, and snow load took down several segments of the Tahoe City 7300 circuit that were comprised primarily of aging #2 copper or aluminum conductor. These portions of the circuit were identified as "failing" as they did not have the structural integrity to withstand the conditions in the area.

Most importantly, Liberty Utilities is looking to conduct a pilot project with covered conductor in year 1 of the WMP. The Tahoe City 7300 circuit provides a great opportunity since this phase of the

project is already permitted for construction in 2019, and is in a heavily forested area where covered conductor can help mitigate fire risk.

Question 5

On pages 20-21, *Chapter 4.4.1 Covered Conductor,* states:

> "Topaz Line 1261
>
> This project is the reconductoring of Topaz Line 1261 to enhance electric service reliability and improve the safety and operational integrity of the electric grid. The project includes reconductoring segments 7,500 feet of overhead lines out of the Topaz Substation. The project also involves pole replacement based on loading standards (GO 95) for "Heavy" and "Grade A" loading along the 7,500 feet of overhead conductors. New poles along with covered conductors will replace aging equipment over the span of the line. This circuit supports rural customers and is noted in consecutive reliability reports (2016, 2017) as the worst performing circuit within Liberty CalPeco's service territory. This area frequently experiences hazardous weather conditions such as high winds and below freezing temperatures. This paired with the deterioration of the infrastructure has resulted in higher risk of improper wire sag along with conductors breaking under ice and snow strain. These projects are presently in the "permitting stage" with construction expected to in late 2019. They were originally designed to use bare conductor replacements but based on the wildfire risk assessment, the projects will be re-designed to use covered conductors. Incorporating this element supports the Plan's goal of mitigating potential wildfire risk with the installation of covered conductors."

a. Given that both this project and Tahoe City Line 7300 reconductoring are expected to start construction in late 2019, how will both progress and schedule to completion be affected?

b. What strategies, if any, can be enacted to ensure that construction on both lines is not delayed during winter months?

c. How was "aging" equipment identified? Please include criteria and metrics evaluated, and any other considerations Liberty took into account when making these decisions.

d. Topaz Line 1261 is cited as the worst performing circuit in Liberty's territory, yet Liberty's 2017 Electric System Reliability Annual Report lists Tahoe circuits 201 and 7202 as the top two worst performing circuits. Please explain this inconsistency.

LIBERTY CALPECO RESPONSE:

a. Pending a timely decision in this proceeding, the original schedule for the two projects should not be affected.

b. Liberty CalPeco took into account winter months when creating the schedule for the various phases of the projects.

c. Aging equipment is identified as capital assets in excess of 30 years old.

d. The WMP incorrectly stated Topaz line 1261 as a worst performing line in 2017. The Topaz line 1261 was the worst performing circuit in 2015 and 2016. The 201 and 7202 circuits surpassed the Topaz line 1261 line in 2017 due to the severe winter storms experienced in the Lake area, which did not impact the Topaz line1261 as severely.

Question 6

On page 21, *Chapter 4.4.1 Covered Conductor* states that Liberty proposes to reconductor 1-2 miles per year. On the same page, the list for prioritization of distribution lines to be evaluated approximates the circuit length of each line in miles.

a. Are the number of circuit miles equal to geographic miles, or the product of the miles of line and circuits per line?

b. Please provide the number of total geographic miles for each of the nine lines listed.

c. Please provide the number of geographic miles that will be reconductored for each of the nine lines listed.

LIBERTY CALPECO RESPONSE:

a. Geographic miles.

b.

Line	Miles
Tahoe City 7300	58
Topaz 1261	54
Meyers 3400	15
640	8
Meyers 3300	53
Squaw Valley 7201	12
Brockway 5100	2
Tahoe City 7200	5
609/Truckee 7202	10

c. Same as response to Qusetion 6.b.

Question 7

On page 22, *Table 4-3 Planned Circuit Reconductoring Start Date* implies that multiple projects will be started before previous lines are fully reconductored. Please provide the underlying assumptions and rationale for reconductoring multiple lines at the same time, compared to concentrating resources on the highest priority lines.

LIBERTY CALPECO RESPONSE: Liberty CalPeco has two main regions, North Lake Tahoe and South Lake Tahoe. Each region has multiple circuits that feed shorter primary taps for service to isolated Forest Service Summer Tracts. These tracts are in mountainous, heavily wooded areas with limited access during late Fall/Winter seasons. Liberty CalPeco considers these shorter taps as its highest priority, and the reconductoring can be easily completed by regional construction crews. Once these shorter taps are complete, Liberty CalPeco can combine the forces of the North and South Tahoe regions to complete the larger main line re-conductoring projects.

Question 8

Please provide Liberty's fire risk threat maps overlaying the transmission and distribution lines that have been proposed for reconductoring in a file format readable by Google Earth or ArcGIS. Distinguish between transmission and distribution lines in your response. Please identify the specific portions of each line that will be reconductored and distinguish them by year.

LIBERTY CALPECO RESPONSE: The requested map files are attached in the Export zip folder.

Question 9

On page 23, *4.4.3 Fusing* states:

> "In order to mitigate fires, Liberty CalPeco proposes to replace conventional fuses with current limiting fuses on much of its system. Single phase, two phase and three phase lateral lines that are protected with conventional fuses will be replaced with current limiting fuse. In additional, pole mounted transformers that have conventional fuses will be replaced with current limiting fuses. There are specific locations and types of equipment, that based on operating requirements, where conventional fuses must still be used."

a. How many fuses on the total system in Liberty's service territory will remain conventional fuses?
b. What percent of the total fuses on Liberty's system is this?

LIBERTY CALPECO RESPONSE: Liberty CalPeco's goal is to replace all conventional fuses with current limiting fuses or other non-expulsion isolating devices. However, the limitations of current limiting fuses do not allow for coordination above certain fuse sizes. Therefore, Liberty

CalPeco will continue to explore new technology such as cut-out mounted reclosers or Trip-Savers to continue to allow for protection coordination while also mitigating wildfire risk.

Table 4-4, on page 23 of the WMP, identifies a nine-year timeline for replacing all conventional fuses in Liberty CalPeco's service territory. In the first few years, Liberty CalPeco will focus on replacing transformer fuses and small tap fuses that coordinate with existing protection equipment. This will allow for the continued elimination of conventional fuses while other technologies are investigated.

Question 10

On page 23, *4.4.3 Fusing* states:

> "Liberty CalPeco will implement this plan as an ongoing effort, set to complete all investment upgrades within the span of 10 years."

a. Please provide support for the assumption that 60 fuses will be able to be replaced every month.
b. Will fuse replacement continue year-round, or only during specific months with less severe weather?
c. This project is expected to span 10 years. Has Liberty considered options as to how to complete this project with an accelerated schedule (e.g., increase staffing so more fuses can be replaced each month)?

LIBERTY CALPECO RESPONSE:

a. Liberty CalPeco's Operations Department has committed to replace fuses in 30 locations in North Lake Tahoe and in 30 locations in South Lake Tahoe each month.
b. Fuse replacements can continue year-round, weather permitting.
c. Liberty has not currently considered options. For the current version of the WMP, Liberty CalPeco focused on timelines that could be completed by internal work forces. The WMP can be reviewed and updated in future revisions of the plan.

Question 11

On page 23, *4.4.6 Tree Attachment Removal* states:

> "Liberty CalPeco commits to removing approximately 60 service tree attachments per year between North and South Lake Tahoe."

a. The total number of tree attachments listed in Table 4-5 *Service Tree Attachments Approximation* is 6,265. At the rate of removing 60 service tree attachments per year, this project will not be completed for over 100 years. Does

Liberty support this timeline, or has Liberty considered options to accelerate the completion of this project?

LIBERTY CALPECO RESPONSE: Liberty CalPeco is not satisfied with this timeline, but due to the complexities in removing tree attachments, including coordinating with customers and obtaining easements, Liberty CalPeco prefers to initially focus its limited resources on projects such as re-conductoring and fuse replacement, which has a more significant impact of wildfire mitigation. Liberty will re-assess its plans for removing tree attachments in future versions of its WMP.

Question 12

On page 28, *Chapter 4.5 Vegetation Management Plan* states:

> "Liberty CalPeco has a vegetation management plan in place, which is implemented by utility staff in conjunction with third-party contractors. Recently, Liberty CalPeco increased planned expenditures for the vegetation management plan from $2.5 million to approximately $4 million annually. This particularly will aid in the frequency of inspection as well as add value to existing clearing practices as tree mortality continues to rise in the area due to climate change."

a. How specifically will the requested increase in expenditures "add value" to the existing clearing practices?
b. Please provide any calculations supporting how the frequency of inspections will increase given the total amount allocated towards more inspections.
c. Why will Liberty's vegetation management plan not be reviewed before every filing of the wildfire mitigation plan after evaluation of the data collected and trends observed over the previous year?

LIBERTY CALPECO RESPONSE:

a. The increase in expenditures will allow for more inspections and tree work resources, which will help Liberty CalPeco maintains a 3-year maintenance cycle.
b. A larger budget for inspections allows Liberty CalPeco to hire additional contract inspectors, which will allow for more trees and powerlines to be inspected every year. Liberty CalPeco plans to use five contract inspectors this year for routine inspections. Last year, Liberty CalPeco used three contract inspectors for routine inspections.
c. Liberty CalPeco's vegetation management plan is reviewed and updated on an as-needed basis.

Question 12

How often is each tree in proximity to Liberty's equipment evaluated for trimming?

LIBERTY CALPECO RESPONSE: Liberty CalPeco's current proposal in its GRC is to inspect trees on a three-year cycle.

Question 13

On page 29, *Chapter 4.5.1 Plan Components* states:

> "In terms of other specifications, Liberty CalPeco will consider the removal of any fast growing trees, rotten or diseased trees, and healthy trees hanging over or leaning towards the power lines."

a. How will these trees be identified?
b. Please explain why Liberty has not been executing this previously.

LIBERTY CALPECO RESPONSE:

a. These trees are identified during routine, CEMA, and GO 165 inspections. Trees may also be identified when reported by customers or public agencies.
b. Liberty CalPeco has been executing this under its current vegetation management practices.

Question 14

On page 30, *Chapter 4.5.2 Identifying At-Risk Vegetation* states:

> "In 2018, Liberty CalPeco implemented procedures to address the increase of tree deaths due to bark beetle infestations as a result of increased drought conditions. In 2019, the utility will submit an application to activate their first Tree Mortality Catastrophic Event MA (CEMA) to recover tracked costs incurred over the last year and anticipates the tree removal program continuing for several years. Liberty CalPeco's service territory contains two of the ten highest priority counties identified by California's Tree Mortality Task Force (El Dorado and Placer Counties)."

a. Please attach the procedures that have been established to address the increase of tree deaths due to bark beetle infestations.
b. How long have bark beetles been identified as a problem near Liberty equipment?

LIBERTY CALPECO RESPONSE:

a. Please see the attached file, "SCHEDULE A – Scope of Work."
b. Four consecutive years (2012-2015) of severe drought resulted in many stressed trees in the Tahoe basin. The weakened state of the forest combined with warmer temperatures created ideal conditions for bark beetle populations to thrive. We began realizing an increase in tree mortality in 2015 and were attempting to address the problem through routine vegetation management

inspections and off-cycle tag work. By the summer of 2017 the numbers of dead/dying trees had reached a level that could not be managed under Liberty's current vegetation management program and budget. At that time, Liberty started planning for a program to specifically address dead and dying trees. The program was launched at the end of 2017 and expenses have been tracked in a CEMA account.

Question 15

On page 30, *Chapter 4.5.2 Identifying At-Risk Vegetation* states:

> "Liberty CalPeco has determined that efforts to curb this issue is no longer manageable with current staffing levels. In response, costs have been identified that exceed current budgets by $1 million annually. Upon authorization, these additional costs will be tracked and recovered through the Tree Mortality CEMA."

How will an increase in costs lessen the issue of low staffing levels?

LIBERTY CALPECO RESPONSE: As described in response to Question 2, Liberty CalPeco will utilize contract personnel to perform mitigation activities, including the tree mortality program.

Question 16

On page 32, *Chapter 4.6.1 Weather Monitoring* states:

> "Likewise, Liberty CalPeco maintains close contact with local weather station personnel and broadcast media. As conditions raise to Extreme, all personnel are on the highest level of alert. Operating personnel are mustered to serve communication notices under high-threat conditions. With experts collaborating and closely monitoring the operations of the electrical grid, Liberty CalPeco increases situational awareness allowing for coordinated planning, response, and communications."

What are the specific protocols and procedures are enacted that increase situational awareness?

LIBERTY CALPECO RESPONSE:

Please see Section 4.7, Table 4-7 of Liberty CalPeco's WMP for the specific protocols that take place during a high-threat condition. In addition to maintaining close contact with local weather station personnel and broadcast media, Liberty CalPeco will be monitoring its newly installed local weather stations.

Question 17

On page 33, *Chapter 4.6.1 Weather Monitoring* states:

"Liberty CalPeco monitors weather, vegetation, and other conditions and takes additional monitoring and communication activities when conditions are conducive to causing wildfires. The adjective class rating tabled above is one of multiple sources of information. During the higher levels of potential wildfire threat, Liberty CalPeco prioritizes efforts to staff additional personnel and take enhanced monitoring actions to increase situational awareness and be prepared to take additional preventative and mitigating actions."

a. How will staffing of additional personnel be accomplished in a prompt manner to adequately prepare for planned mitigation actions?

b. Please specify what additional monitoring and communication activities are taken when conditions are conducive to causing wildfires.

LIBERTY CALPECO RESPONSE:

a. Liberty CalPeco management will redirect operations personnel from non-essential construction activities so they are available for mitigation measures, as needed. In addition, Liberty CalPeco will reach out to local contractors to ensure staff are available and ready to mobilize should they be needed.
b. Liberty CalPeco personnel are registered for weather alerts by county for high wind and red flag warnings. When those conditions are met, Liberty CalPeco follows protocols as outlined in its Fire Prevention Plan. Liberty CalPeco is currently installing weather stations on facilities throughout its service territory, and once completed there will be additional weather monitoring added to the plan.

Question 18

Other IOUs have developed Public Safety Power Shut-off protocols that ensure every customer will be notified in advance of a de-energization event, whether it be through phone call, SMS text, social media, or field representative welfare checks.

Please describe Liberty's current notification procedures for de-energization under "Imminent Extreme Fire Weather Conditions[1]" (i.e., notification to customers through social media, Liberty's website, local media, or other methods).

LIBERTY CALPECO RESPONSE: As part of Liberty CalPeco protocol, in advance of a Public Safety Power Shut-Off, Everbridge will be used as the primary method to notify customers (text, email, and voice messages). In addition, messages will be pushed out on: 1) Twitter 2) Facebook and 3) the planned outage section of Liberty's website. Signs will be placed in strategic locations, if possible.

Question 19

[1] Page 35, Table 4-7 PSPS Procedures

On page 37, *Chapter 4.7.1 Re-energization Strategy* states:

> "Once a decision to re-energize has been made Liberty CalPeco will: Inform all customers who were impacted by the De-energization event that power has been restored via Everbridge (email, voice, and/or text)."

Has Liberty considered the use of these services through Everbridge to notify all customers about the possibility of a PSPS event? Please explain any alternatives considered, and the reasoning for what programs were considered and rejected for customer notification protocols for "Imminent Extreme Fire Weather Conditions."

LIBERTY CALPECO RESPONSE: Yes, Everbridge will be used prior to a Public Safety Shut-off and once again after a decision is made to re-energize. Everbridge was used to notify customers prior to a about the November 21st, 2018 de-energization event in the South Lake Tahoe region. Because Everbridge covers email, voice, and text and is currently operating at Liberty CalPeco, no other technology is required.

Question 20

On page 37, *Chapter 4.8.1 Forest Resiliency Corridor Development* states:

> "This grant represents a collaborative effort between federal, state and local agencies to conduct comprehensive multi-jurisdictional forest resiliency and fuels reduction treatments that aim to 1) create resilience corridors, 2) aid in resource surveys in support of future efforts, and 3) assist in conducting forest management research along with investigating innovative technology opportunities."

a. Define "resilience corridors" as it fits with the context of this Plan.
b. Explain how resilience corridors will support Liberty's efforts in mitigating the risk of wildfires.

LIBERTY CALPECO RESPONSE:

a. Please see page 38 of Liberty CalPeco's WMP, which illustrates the Forest Resiliency Corridor concept and defines the work to be completed within each segment of the illustration.
b. Liberty CalPeco's strategy of creating resilience corridors around its powerlines leverages the ignition prevention work required by regulation with additional fuel reduction, pest management, and biomass utilization activities. These activities further reduce the risk of ignitions originating from utility infrastructure, improve forest health, provide greenhouse gas emissions reduction benefits, and reduce potential fire impacts near infrastructure, regardless of where the ignition originates.

Question 21

On page 48, *Chapter 6.2 Metrics Reporting* states:

> "Upon Plan approval, Liberty CalPeco will create targets for each of the metrics based on industry standards and benchmarks."

Please prepare and provide an end-of-year target of what Liberty will use to evaluate their success in mitigating wildfire risk for each activity Liberty has proposed.

LIBERTY CALPECO RESPONSE: Liberty CalPeco has not developed an end of year target of what it will use to evaluate its success in mitigating wildfire risk. It is premature to develop such targets, as Liberty CalPeco does not yet know which of its proposed activities will be authorized in its WMP. Once the WMP is approved, Liberty CalPeco will finalize the metric targets.

Question 22

Referencing *Table 6-1 Proposed Wildfire Prevention Plan Metrics* on pages 48-49:

a. How will "determining if plan is on schedule" quantitatively or qualitatively determine the activities' effectiveness in reducing risk?
b. If the Plan is successful, the number of wildfire risk events should be reduced. Since these incidents cannot be accounted for, how will it be assessed if the plan has reduced risk events?
c. How will the value of vegetation management investment and inspections be determined?
d. What data will be collected by monitoring the number of PSPS events over time as an indicator of changing climatic and weather patterns?

LIBERTY CALPECO RESPONSE: Once Liberty CalPeco's WMP is approved, Liberty CalPeco will be able to develop specific metrics and specific data to be collected to monitor its effectiveness in reducing wildfire risk.

Please send your response to the Originator, and a copy of your response to Project Coordinator and e-copies to the following Public Advocates Office representatives:

(none)

Please provide the above information as it becomes available but no later than the due date identified above. If you are unable to provide the information by this date, please notify the Originator **at least** 3 days before the data request is due and provide your best estimate of when the information can be provided. Please identify the person who provides the response and his/her phone number and email address.

END OF REQUEST

SCHEDULE A - SPECIFICATIONS AND SCOPE OF WORK:

Fire Hazard and Public Safety Prevention Measures Due to Tree Mortality;

Accelerated Vegetation Inspections

i. Methodology

On October 30, 2015 Governor Edmund G. Brown proclaimed a state of emergency to exist in the State of California due to the vast tree mortality in several regions of the state. The tree mortality was caused by the long-term drought, which made trees susceptible to epidemic infestations of native bark beetles. At the time of the emergency proclamation, the United States Forest Service estimated that over 22 million trees were dead. According to the United Stated Department of Agriculture, the number of dead tree in California had grown to 102 million by November 2016.

Liberty CalPeco's service territory contains two of the ten highest priority counties identified by California's Tree Mortality Task Force, and the tree mortality in these two counties has grown exponentially since 2015. In Placer County, tree mortality has grown from 80,000 dead trees in 2015 to 557,000 dead trees in 2016, and in El Dorado County tree mortality has grown from 200,000 dead trees in 2015 to 1,359,000 dead trees in 2016.

Liberty CalPeco's current Vegetation Management Plan is structured around a three-year maintenance cycle. Due to the nature of the current VMP and the risks associated with increasing tree mortality in the vicinity of Liberty's facilities, Liberty CalPeco has identified the need to inspect for dead and dying trees throughout its entire system by performing an accelerated inspection of the circuits.

ii. Scope of Work

Contractor shall survey Liberty CalPeco's electrical distribution and sub-transmission facilities as directed by the Vegetation Program Manager. The survey will consist of a Level 1 inspection, involving a basic visual ground inspection of trees or populations of trees to identify dead and dying trees. Additionally, contractor shall inspect for imminent hazards, GO 95 Rule 35 or PRC 4293 compliance infractions. Some examples include, but are not limited to clearance encroachments, large cavities in trees, dead or broken branches, fungal fruiting bodies (conks), large cracks, or severe leans. Work will be inventoried and prescribed for work to be issued to Liberty CalPeco's current tree contractor as needed and depending on the tree condition identified.

The following list details common types of tree conditions that may be observed within Liberty CalPeco's service territory that will be identified and prescribed for tree work during the Accelerated

Level 1 Assessment. This list may be used as reference, but is not intended to be exhaustive. The Contractor should also incorporate knowledge, professional judgment and skill when performing the inspection.

- Dead Trees or Dead parts of Green trees
    - Parts included dead limbs overhanging conductors
    - Dead tops
    - Dead trees
    - Trees that are >50% dead
- Defects in Live Trees or parts of Live Trees
    - A crack that goes completely through a stem or branch
    - Weak branch unions (V-shaped) that is also associated with a crack completely through the branch or attachment
    - Decay where less than 1/3 of the tree or part's diameter is sound (2/3 or greater is affected by the decay)
    - Presence of Fungal Fruiting Bodies –
        - Phaeolus schweinitzii (Velvet Top) conks present (normally occurs on Jeffrey and Lodgepole pine) – One or more conks
        - Echinodontium tinctorium (Indian Paint Fungus) – one or more conks on true fir or hemlock
        - Laetipous sulphureus (Chicken of the Woods) – one or more conks; normally effects lodgepole pine or Jeffrey Pine
        - Phellinus tremulae – occurs on mature and over-mature aspen trees; trees with one or more large conks (>6" size conks)
    - Cankers
        - With associated fruiting bodies
        - Single or multiple cankers with decay that affects more than 1/2 of a trees circumference
    - Root Damage and Root Disease
        - Recently leaning trees or trees with evidence of recent root lifting or soil movement
        - Inadequate root support, with more than ½ of the root system within the drip line severed, broken, undermined or decayed by erosion or excavation.
    - Leans
        - Any tree leaning with an angle greater than 45° from vertical
        - Uncorrected lean compounded by an unbalanced crown shape weighted in the direction of the lean

iii. <u>Process for Performing Inspections along Distribution Circuits</u>

1. Contractor shall survey the Liberty CalPeco's distribution and sub-transmission systems, document, and inventory dead and dying trees that may pose an increased risk to the facilities. Additionally, contractor shall document and inventory compliance clearance encroachments and any other imminent vegetation related hazards to the electrical facilities (E.g. large cavities in trees, dead or broken branches, fungal fruiting bodies (conks), large cracks, or severe leans in whole tree or parts of trees).

2. The inspection shall originate at the Substation or point of electrical supply to Liberty CalPeco from which the circuit is supplied electricity and continue away from the substation in the direction of the flow of electricity.

3. Contractor shall document and inventory all pertinent information described in Section iv – Data Collection

4. Contractor shall make appropriate tree trimming or removal prescriptions necessary to achieve conformance with the regulation. Contractor shall use Liberty CalPeco's Unit Tree Work Matrix when prescribing tree trimming or removal (See Section v).

5. Contractor shall mark each tree requiring trimming or removal with Fluorescent Pink Tree Marking paint. ***All trees requiring trimming to alleviate the danger will be designated by marking a dot on the tree on the power line side at 4.5 feet above ground. All trees that require removal to alleviate the danger will be designated by marking a "x" on the tree on the power line side at 4.5 feet above ground.***

iv. <u>Data Collection and Management</u>

Contractor shall verify, revise or collect all pertinent tree information as requested by Liberty CalPeco. Data collection field tablets and software will be provided by Liberty CalPeco and will be stored and maintained in Liberty CalPeco's databse.

v. <u>Targets and Scheduling</u>

The Contractor shall adhere to Liberty CalPECo's annual plan for accelerated inspection work and shall report progress of completed work on the last day of each month. The contractor shall adhere to monthly target schedules as required by Liberty CalPECo. Liberty CalPECo reserves the right to make changes to the circuit work schedule at any time and for any reason.

The following circuits are anticipated for accelerated inspection work vegetation management activities for 2018:

Circuit Name and Number	Estimated Line Miles	Month of Pre-Inspection Completion
Tahoe City 5201	21.4	February

Tahoe City 7300	57.7	April
Muller 1296	43.5	April
Meyers 3400 S.1 & 2	27	May
Tahoe City 7100	13.2	May
Kings Beach – Tahoe City 625	15.4	June
Kings Beach – Truckee 650	14.2	June
Northstar 8600	16.5	June
Stateline 2200	0.25	June
Stateline 2300	3	June
Stateline 3101	15.7	June
Truckee – Squaw Valley 132	12.2	July
Stateline 3501	13.8	July
Tahoe City – Squaw Valley 629	6.3	August
Truckee - Squaw Valley 609	9.5	August
Truckee 7202	12.1	August
Squaw Valley 8200	4.9	September
Squaw Valley 8300	1.5	September
California 204	3.6	September
Washoe/Farad 7800	6	September
Glenshire 7400	32.6	October
Glenshire 7600	5.2	November
Marble – Portola 619	6.05	November
Stateline – Meyers 640	7.9	November

vi. <u>Customers</u>

1. Liberty Utilities places a very high priority on the good will of its customers. They are to be treated with courtesy. Prior to performing tree inspections on private property, the Contractor shall first make a reasonable attempt to explain to the customer: The Company he/she represents, that they have been contracted with Liberty CalPeco to perform tree inspections and that they will be on the customer's property briefly to accomplish this work.

2. Whenever a customer complaint/claim is received by the Contractor, the Contractor shall immediately notify the Company Project Manager. The Contractor's Supervisor, upon receipt of the complaints/claims, shall investigate the matter within a 48 hour period and make a diligent effort to resolve the complaint/claim. Liberty CalPeco shall be notified of

resolutions or if no resolution is reached and shall have the right to resolve or not resolve the matter in its discretion.

3. If Contractor cannot assess a tree for access and/or any other reason, the Contractor shall immediately initiated the following steps:

    a. Inspector shall attempt to make contact with the customer. If contact cannot be made and the inspection be accomplished due to the inability to access the property, inspector shall complete a *Vegetation Management – Contact Attempt Tracking Form* and submit it to the Vegetation Project Manager. A copy of the form will be provided by the Company to the Contractor prior to the start of work.

    b. Refusals: If the inspector is denied permission to access the property from the customer the information shall be documented and submitted to the Company Project Manager. The Contractor shall complete and document all contact and attempts to resolve the refusal using a *Vegetation Management Refusal Form* and provide the documentation to the Vegetation Project Manager. The contractor shall notify the Company no later than 3 working days after the refusal is initiated. A copy of the form will be provided by the Company to the Contractor prior to the start of work.

vii. Obtaining Permission for the Removal or Major Trimming of Trees

Owners of trees that require removal or that require trimming which may remove more than 30% of a tree's overall live crown or height shall be notified by the Contractor. The Contractor shall petition the landowner to sign Liberty Utilities' *Tree Work Notification Form* completed and filled-in as appropriate for the work prescribed by the Contractor. Should written notification by the owner be unattainable and no other reasonable options exist, the Contractor shall document on a *Vegetation Management - Contact Attempt Tracking Form* all attempts made to contact the owner. The Contractor shall submit a copy of the form and photo documentation of the tree and facilities to the Company Project Manager.

Completed Tree Work Notification Forms and Contact Attempt Forms shall be treated as Confidential Information. These forms shall be submitted to the Company Project Manager on a weekly basis for filing and retention.

viii. Safety to the Public

The Contractor shall at all times conduct the work in a manner so as to safeguard the public from injury to persons and property damage. The Contractor is to use all necessary protection for its

employees and to guard against interference with the normal operation of power circuits. Should the Contractor cause damage to the Company's facilities or be involved in an accident involving its facilities or a member of the public, while performing work for the Company, the Contractor shall notify the Project Manager as soon as possible.

ix. Supervision of Contractor Employees

Contractor shall provide adequate supervision to its employees at all times and at no additional cost to the Company. Contractor's supervisor shall verify that their employees work meets Liberty Utilities standards, applicable State Regulations, and this Scope of Work.

x. Personnel and Equipment Requested by Liberty Utilities

Personnel

Liberty CalPeco is requesting the Contractor to provide the following personnel full-time to perform the required work during the designated time periods:

January 1st through March 31st:

- Two Utility Forester I or II

April 1st through December 31st:

- Three Utility Forester I or II

Unless otherwise excused or agreed to by Liberty CalPeco, Contractor shall provide qualified employees to perform the required work. Depending on scheduling and timing, the Company and Contractor may agree to increase or decrease the number of requested staff to ensure that the inspection is completed within the designated time frame. Contractor shall provide documentation of the qualification of the contracted employees to Liberty CalPeco prior to performing work, but any such review by the Company shall not relieve Contractor of its obligations to provide experienced and qualified and fully trained employees on the job, nor shall such review constitute any acceptance, acknowledgement or waiver on the part of liberty CalPeco that such employees are competent and or qualified. All contractor employees shall be trained in advance by the Contractor and at the Contractor's expense. Liberty Utilities will reserve the right to reasonably request the removal of any Contractor employee at any time throughout the term of the contract and Contractor shall remove such employees at Liberty CalPeco's request at no additional cost or expense to the Company.

Materials

Contractor shall supply all materials required to perform the duties of the contract. Materials required to be supplied to employees by the Contractor include, but are not limited to the following:

- Class E Hardhats
- DOT approved safety vest
- Range finder or similar equipment for measuring heights and distances
- Minimum of two 18" tall orange safety cones with reflective strips
- Digital Camera
- 4X4 vehicle
- Handheld devices or computers necessary to collect required data
- Safety glasses
- Diameter tape
- Cellular phone
- Backpack Firefighting pump with the ability to carry up to five gallons of water (during fire season)
- Shovel
- Fire rake
- Tree marking paint
- Office supplies

xi. Tree Trimming and Removal Prescriptions

TRIMS

Brush Trim (BT) – Vegetation that is less than 4" diameter at breast height (dbh) that is trimmed to obtain 10' to 15' of clearance from the conductors. Brush units are equal to 10 cubic yards of material when stacked. Brush units are inventoried in increments of .25 units.

Top Direct/Crown Reduction (TD) – Removal of the top portion of the tree to lessen the overall height of the tree to achieve desired clearances of 10' to 15' from the conductors. These trees are normally growing directly below the conductors.

Side Direct (SD) – Removal of lateral branches originating from the main trunk/bole of the tree when only the side portion of the tree is growing into the minimum allowable distance to the power lines. On conifers, limbs shall be removed back to the trunk/main bole of the tree. On deciduous trees, limbs shall be pruned back to a proper lateral branch or to the trunk/main bole of the tree. Desired clearances at the time of pruning shall be between 10' and 15' from conductors.

"V" Trim (VT) – Removal of entire lateral branches from the center of the tree to main leaders, while side branches are allowed to grow on the outside of the tree to obtain desired clearance of 10' to 15' at the time of pruning.

Overhang (OV) – Removal of branches directly overhanging the open wire conductors that are within 10 feet to the wires and require pruning for desired clearances. Branches in this category shall not be dead and have no structural defect.

Coated Service/ Aerial Cable (CT) – Trimming of branches for coated service drop, coated aerial cable or support wires to reduce strain or abrasion on wires only. Clearances at the time of pruning shall be approximately 2 feet.

REMOVALS

Brush Removals (BR) – Removal of vegetation that is less than 4" DBH. Final cuts are made at or below 4.5 feet to the ground. Stumps will be treated with either Sporax (conifers) or herbicide (deciduous). Brush units are equal to 10 cubic yards of material when stacked. Brush units are inventoried in increments of .25 units.

Tree Removals/Non-Hazard (R) – Removing 100% of the canopy of a tree and the final cuts are made at or below 4.5 feet above the ground. Stumps are treated with either Sporax (conifers) or herbicide (deciduous trees). Trees in the "R" category will typically be trees with in the right-of-way that require removal to obtain clearance requirements of 10 to 15 feet at the time of trimming. This type of work includes removal of green trees within 10 feet of the conductors that do not overhang the conductors. These trees have no evidence of structural defect and are not dead. Units will be based on the following size classes:

R1 4.0" < 11.9" dbh

R2 12.0" < 23.9" dbh

R3 24" < 35.9" dbh

R4 >36" dbh

Note – R3 and R4 tree removals will occur in extremely rare situations.

FACILITY PROTECTS

Facility Protect Overhang Minor (FOA) – Pruning or removal of dead or structurally unsound limbs located within any distance to and that are above the conductor and that have the potential to fail into the facilities. Limbs must be of sufficient size to cross-phase.

- Minor work: Removing a portion of the tree where the work removes 1/3 or less of the crown and the final cuts are made more than 4.5 feet above the ground

Facility Protect Overhang Major (FOB) –Pruning or removal of dead or structurally unsound limbs located within any given distance to and that are above the conductor and that have the potential to fail into the facilities. Limbs must be of sufficient size to damage facilities.

- Major work: Removing a portion of the tree where the work removes 1/3 or more of the crown and the final cuts are made more than 4.5 feet above the ground.
- Removal of all branches occurring over the conductors (clear to sky).

Facility Protect Trim Minor (FTA) – Removal of a portion of a tree not overhanging the conductors, but located within any given distance to the conductors that has the potential to fail and come into contact with the facilities due to structural defect or tree mortality. Tree work in this category may include:

- Removing a portion of a tree where the work removes 1/3 or less of the crown and the final cuts are made more than 4.5 feet above the ground.
- Minor facility protect trims can include but are not limited to removing one or more structurally unsound branches, removing a dead top on a live tree, removing a single stem of a multi-stemmed tree, removing a forked top, etc.

Facility Protect Trim Major (FTB) – Removal of a portion of a tree not overhanging the conductors, but located within any given distance to the conductors that has the potential to fail and come into contact with the facilities due to structural defect or tree mortality. Tree work in this category may include:

- Removing a portion of a tree where the work removes more than a 1/3 of the crown and the final cuts are made more than 4.5 feet above the ground.
- Major facility protect trims can include but are not limited to removing multiple structurally unsound branches, removing all of the canopy of a tree but leaving the bole standing, removing a single large branch that includes more than 1/3 of the crown, etc.

Facility Protect Removal/Remove and Treat (F) – Removing 100% of the canopy of a tree and the final cuts are made at or below 4.5 feet above the ground. Stumps are treated with Sporax (conifers). Trees in the "F" category will typically be trees within any given distance to the conductors that require removal to prevent the tree or the portions of the tree from failing and coming into contact with the electrical conductors. This type of work includes trees requiring removal that show evidence of structural defect making them susceptible to failure or are dead. Units will be based on the following size classes:

F1 4.0" < 11.9" dbh

F2 12.0" < 23.9" dbh

F3 24" < 35.9" dbh

F4 >36" dbh

WORK DIFFICULTY CLASSES FOR REMOVALS

As described below, in addition to a trim type, all work prescribed for **Removal** or **Facility Protection** will be categorized according to the difficulty of work completion.

Work Difficulty – Class A

- Property owner does all clean-up
- Drop and walk, tree is felled
- Debris clean-up is only lop and scatter
- Debris clean-up is only piling of brush
- Chipping debris less than 4 inch diameter where the location is chipper accessible (within 100 ft.), and it is a small volume of debris (equal to or less than 10 cubic yds. when stacked)

Work Difficulty – Class B

- All other work not in Class A, for example:
- Work must be pieced, lowered, tied off and directed
- Large wood must be cut into numerous smaller sections
- Chipping debris less than 4 inch diameter where the location is chipper accessible (within 100 feet), and it is large volume of debris (more than 10 cubic yards when stacked)

***Note**: Work that has any activity falling into Class B should be classified as "B". For example, if a tree must be pieced down but the property owner will do all clean up; the Work Difficulty is still Class B.*

***Note**: By contract, a Tree Contractor is responsible to clean-up debris less than 4 inches in diameter unless specified otherwise in the Tree Work Notification Form or on the work request.*

***Note: Multi-stemmed trees** are defined as trees connected at or above ground level where there is no evidence of soil existing between the boles of the trees. For the purpose of trimming, multi-stemmed trees with no evidence of soil separating the trees will be inventoried as one unit. For the purpose of removal, multi-stemmed trees that split below 4.5 feet, each stem will be inventoried as an individual unit; multi-stemmed trees that split above 4.5 feet from the ground will be inventoried as one unit.*

ATTACHMENT 11

Liberty Utilities 2018 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2018

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15, 2019

CA-07-0630

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2018 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents eight years (2011 through 2018) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2018 was 198.88 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 8 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

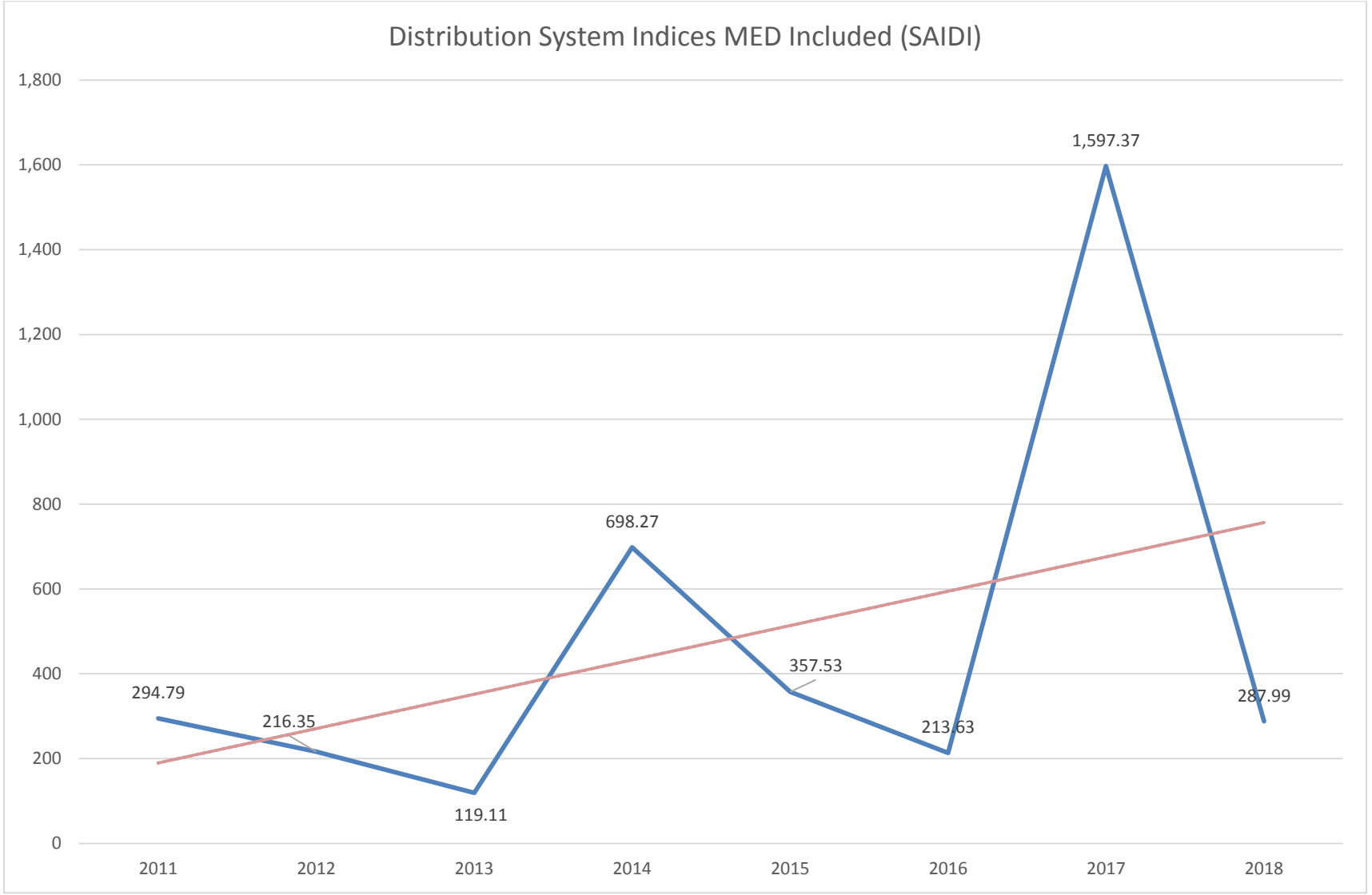
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 7 Years (Years in Business)

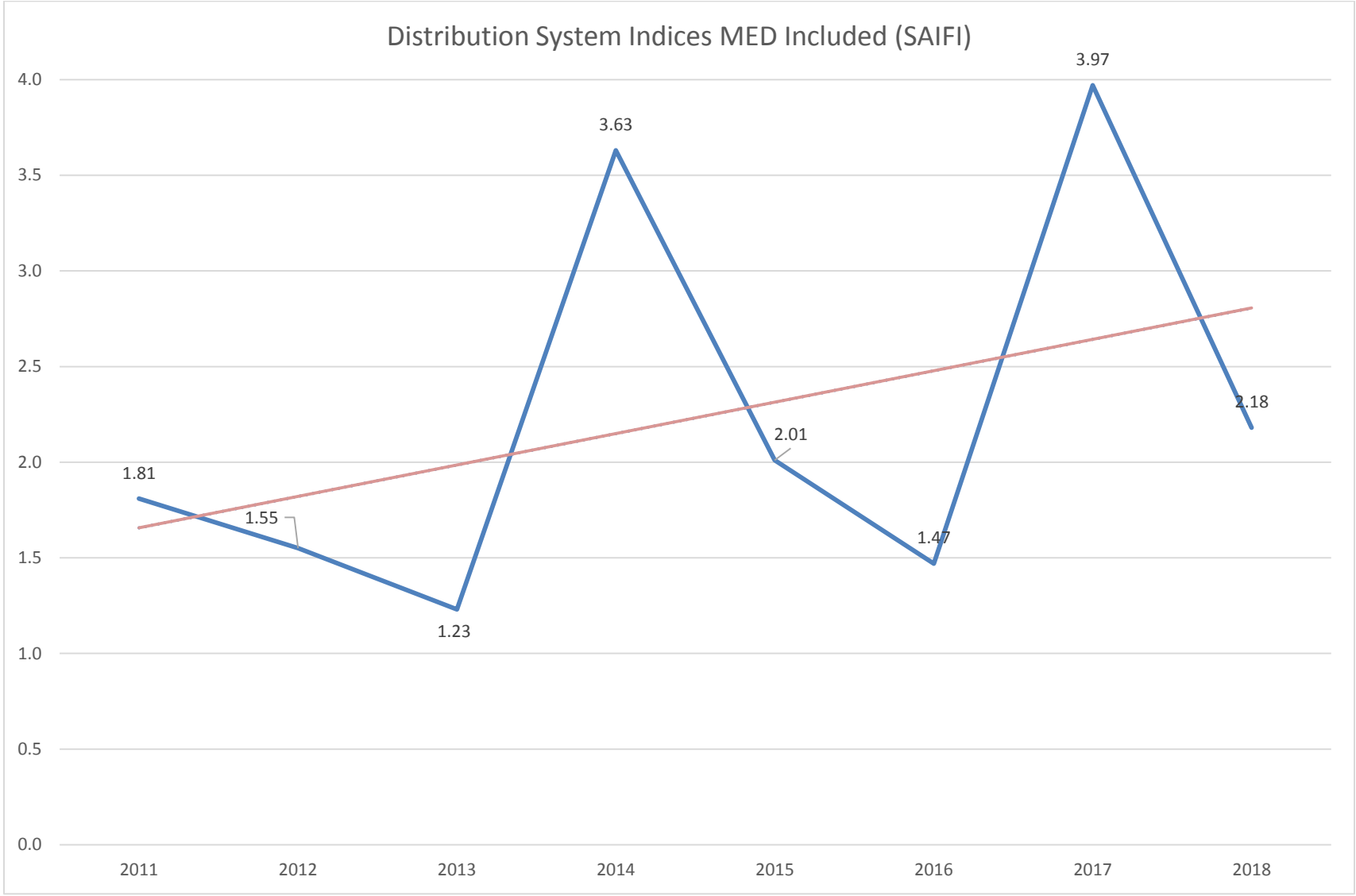
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

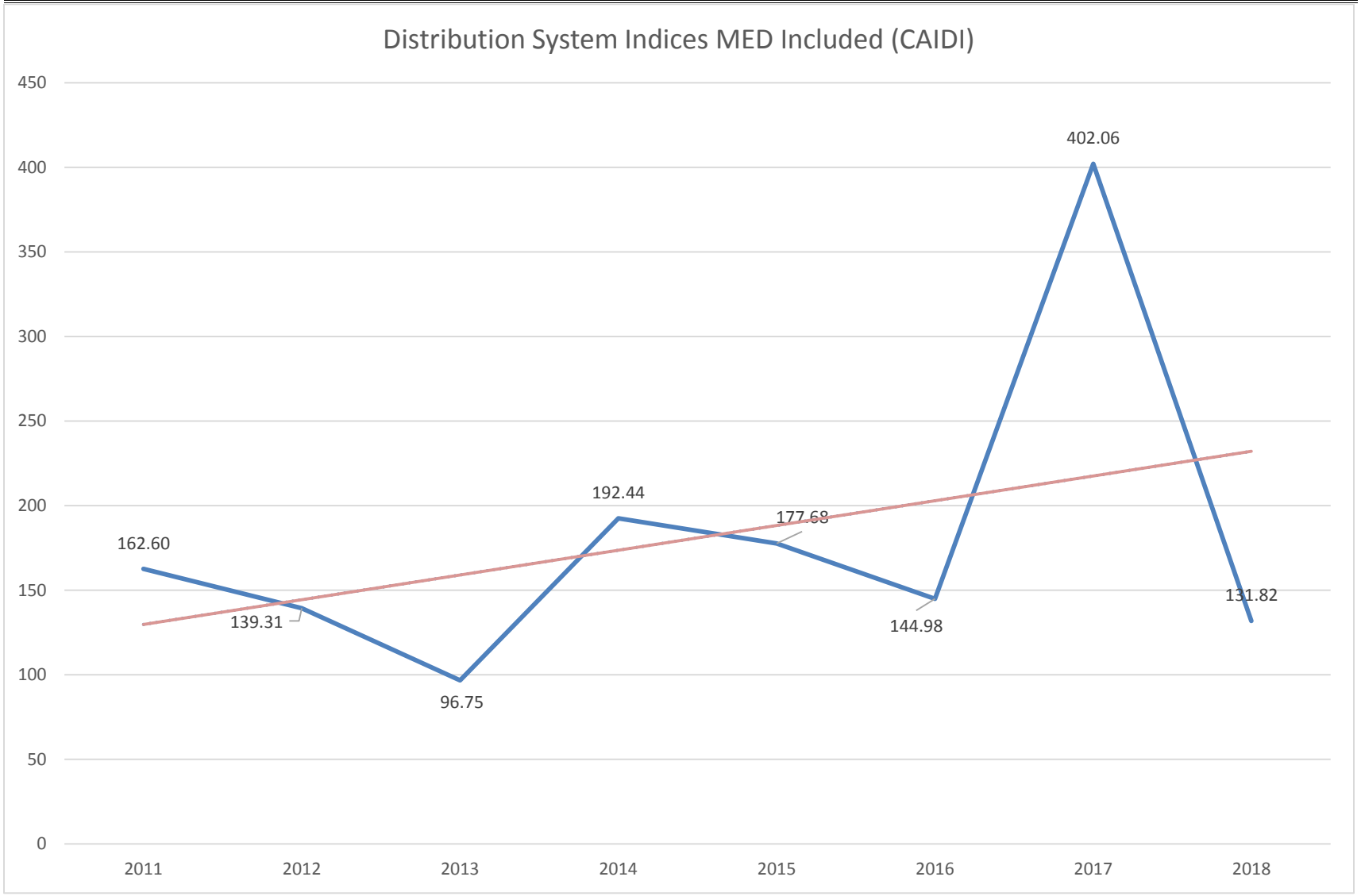
II. Transmission System Indices (MED Included and Excluded)

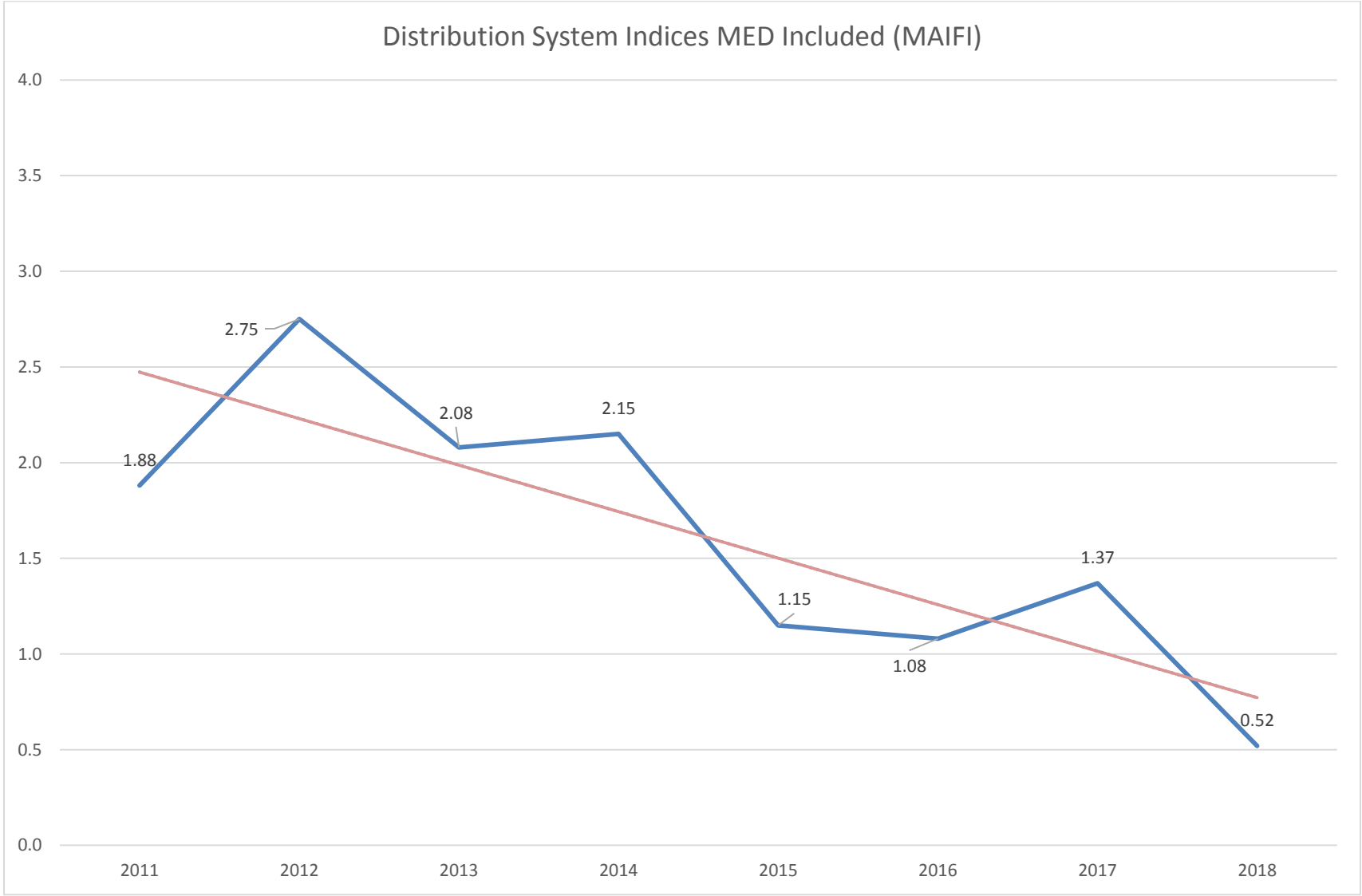
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

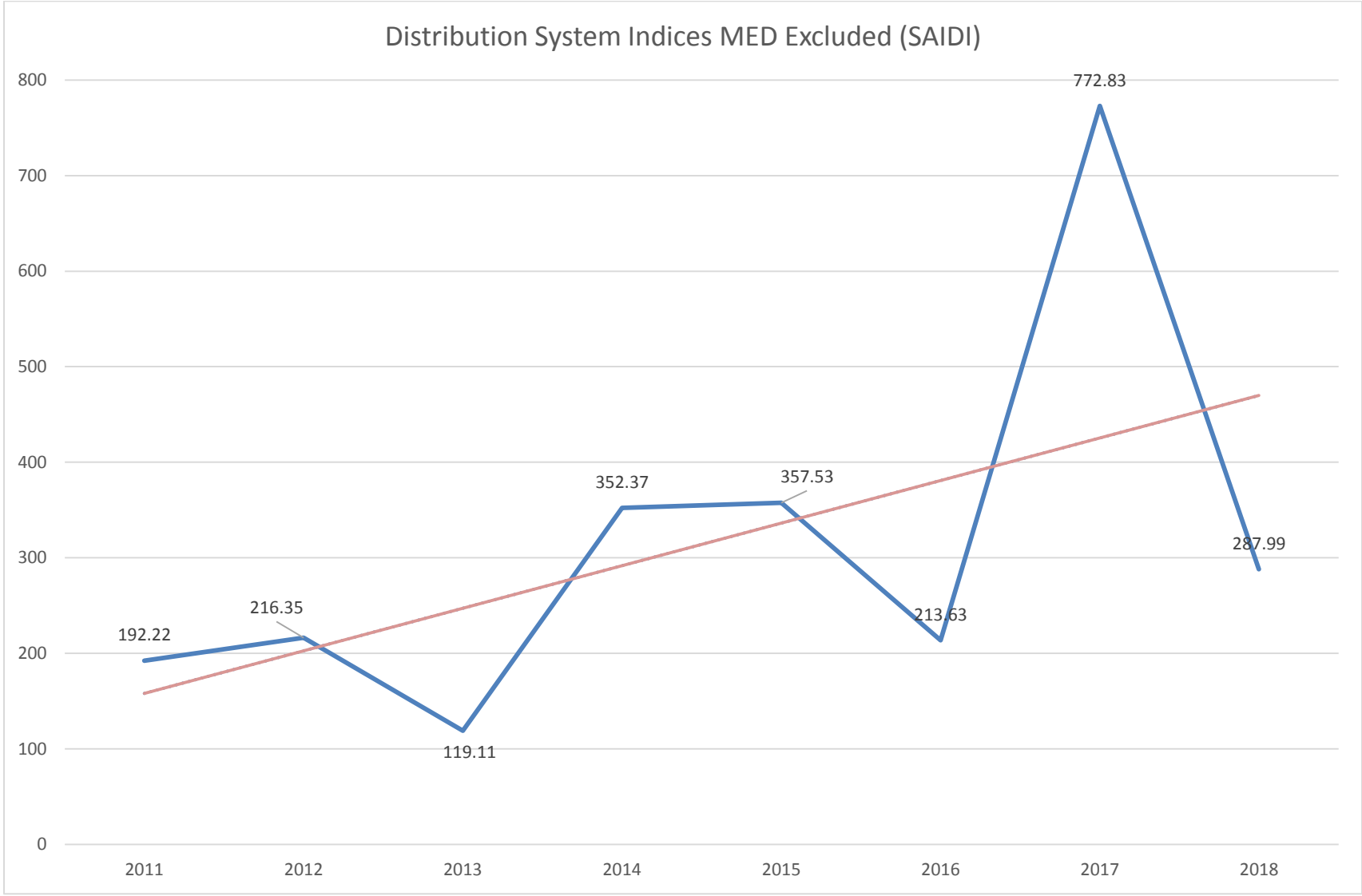
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 8 years (years in business) with linear trend line (TMED included and excluded).

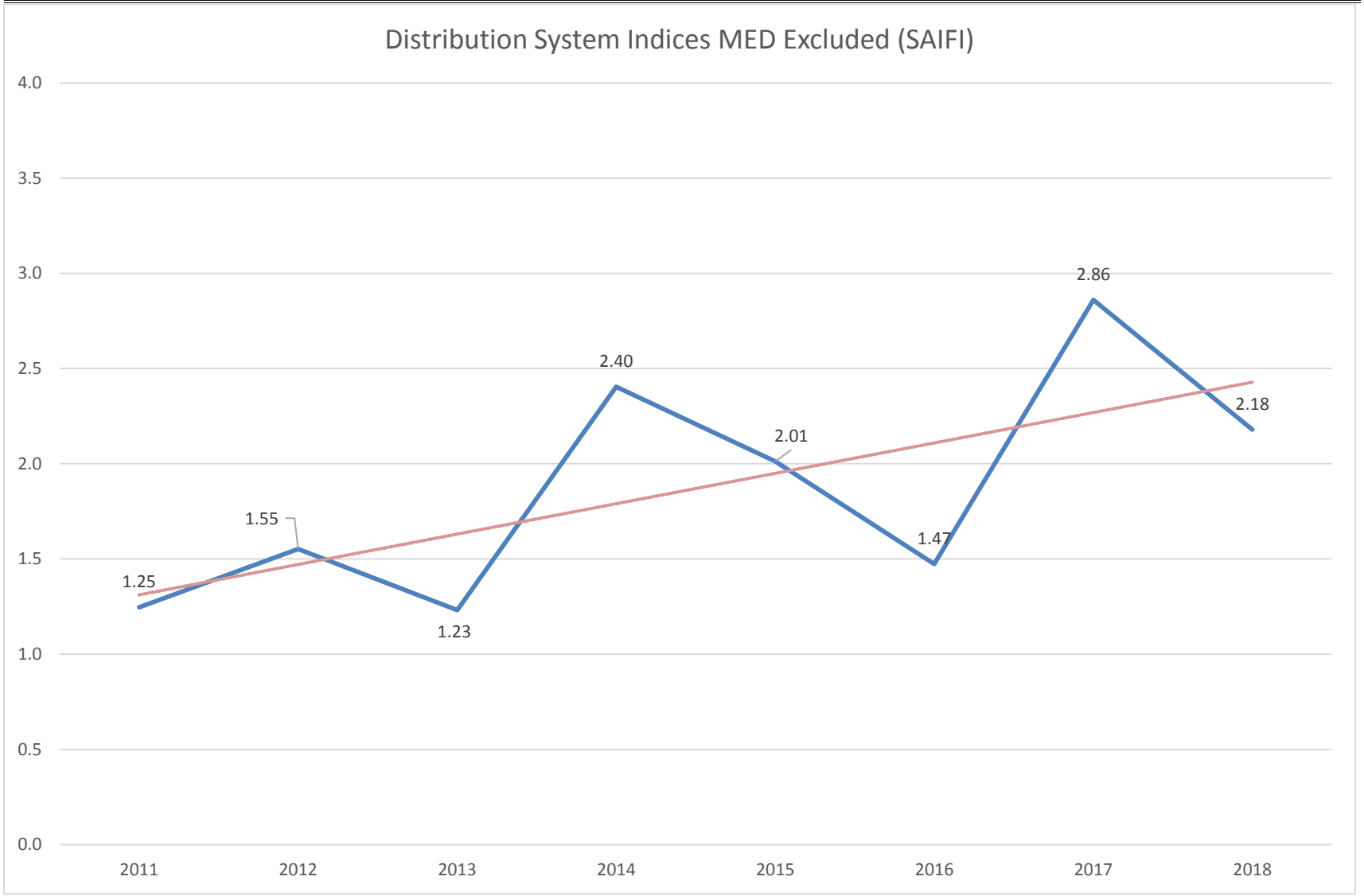

Distribution System Indices MED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
213.63
1,597.37
287.99
2011
2012
2013
2014
2015
2016
2017
2018

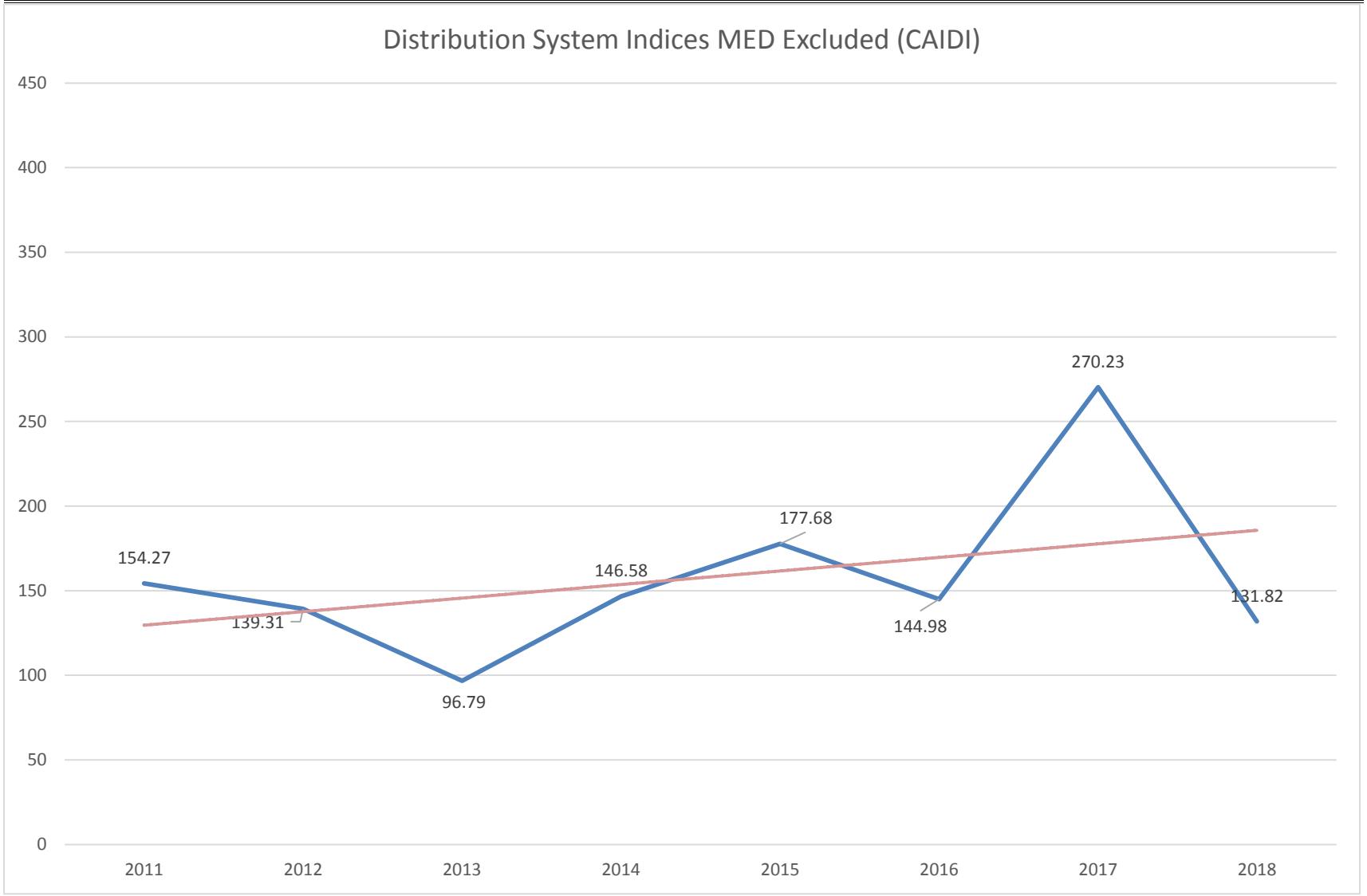

Distribution System Indices MED Included (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.47
3.97
2.18
2011
2012
2013
2014
2015
2016
2017
2018

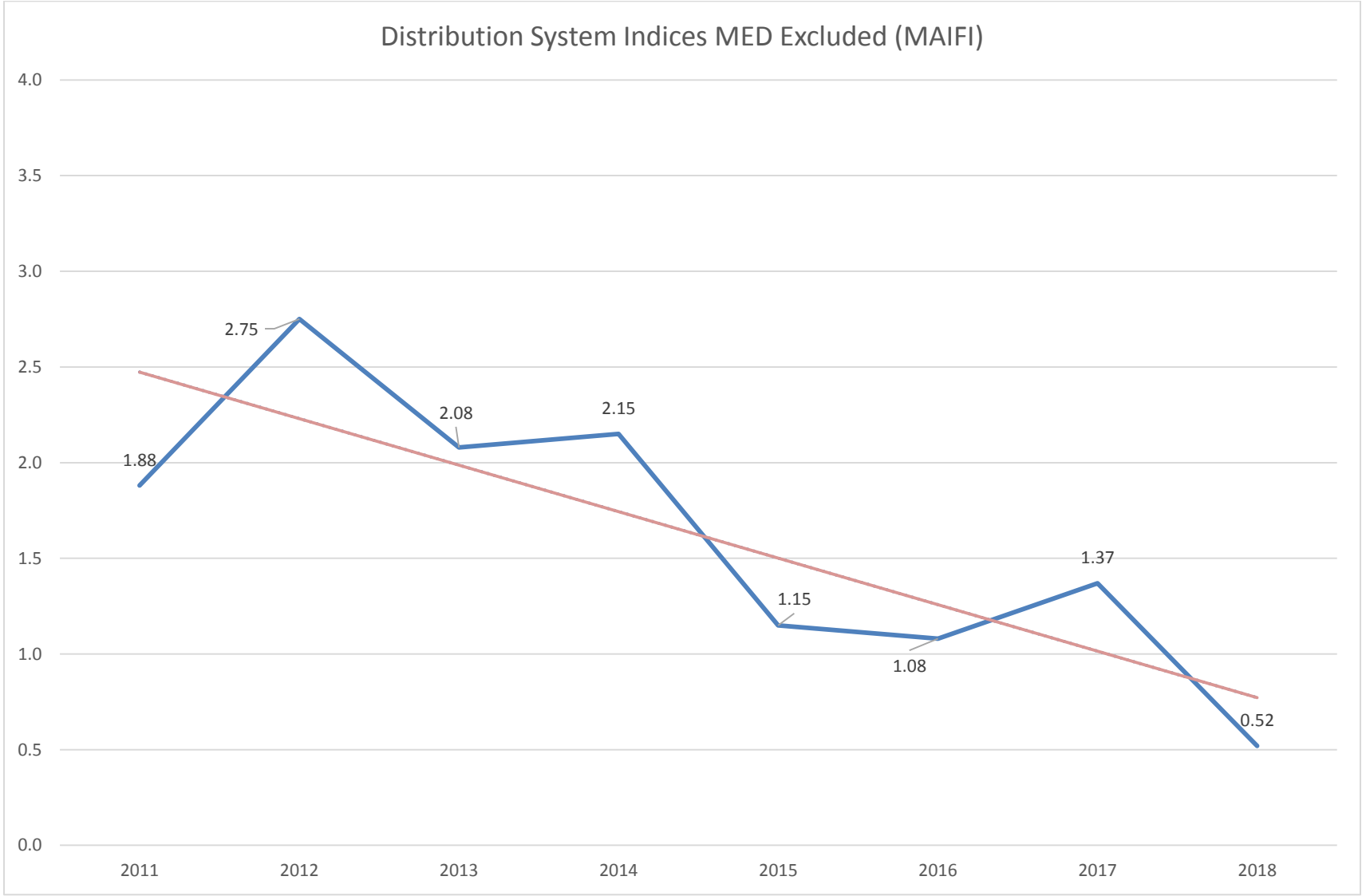

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
2011
2012
2013
2014
2015
2016
2017
2018
162.60
139.31
96.75
192.44
177.68
144.98
402.06
131.82


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.15
1.08
1.37
0.52
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices MED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
213.63
772.83
287.99
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices MED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.47
2.86
2.18
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
144.98
270.23
131.82
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
2011
2012
2013
2014
2015
2016
2017
2018

2) Division (or District) Reliability Indices for the past 8 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

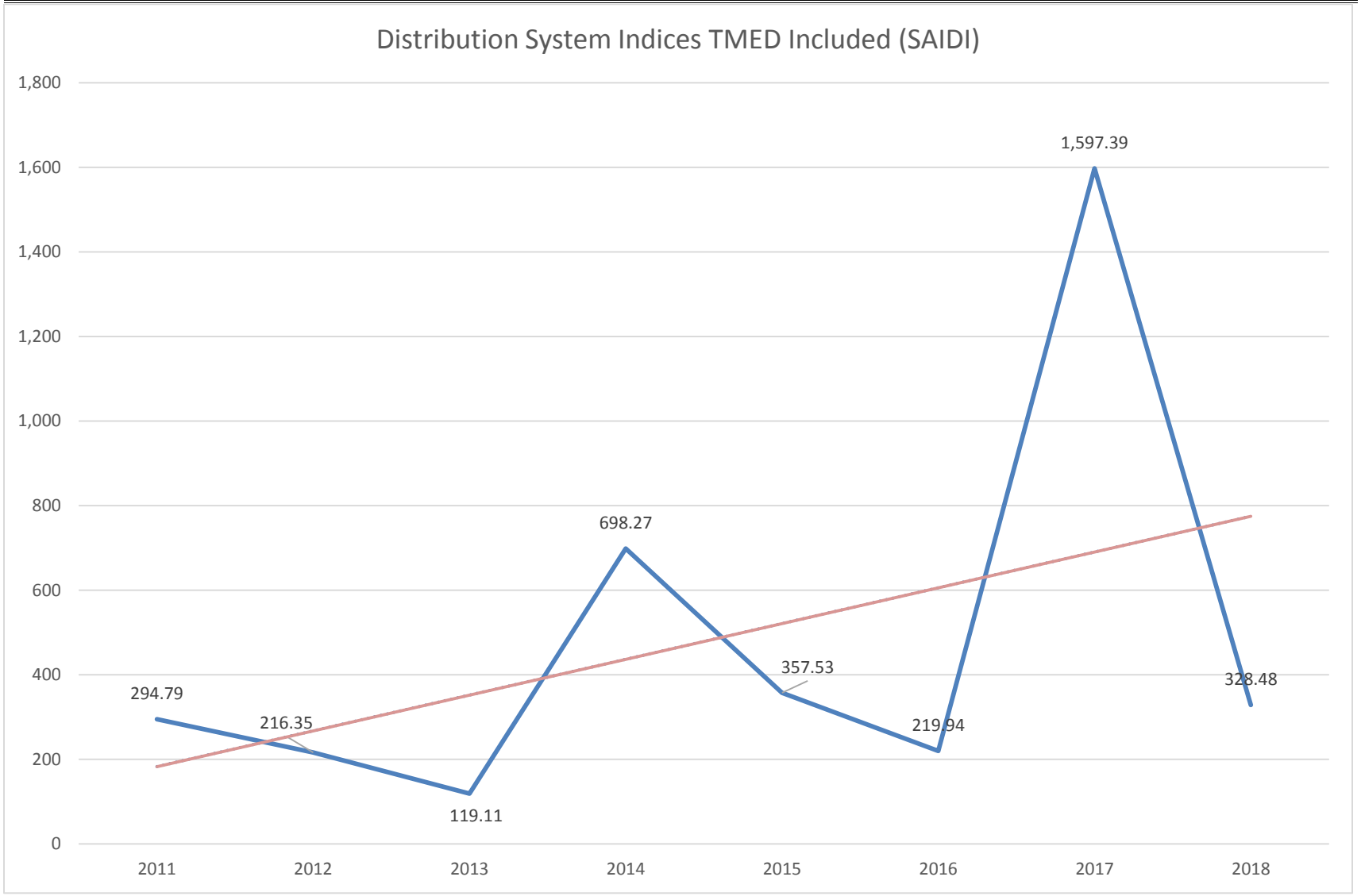
3) System and Division indices based on IEEE 1366 for the past 8 years including planned outages and including and excluding TMED

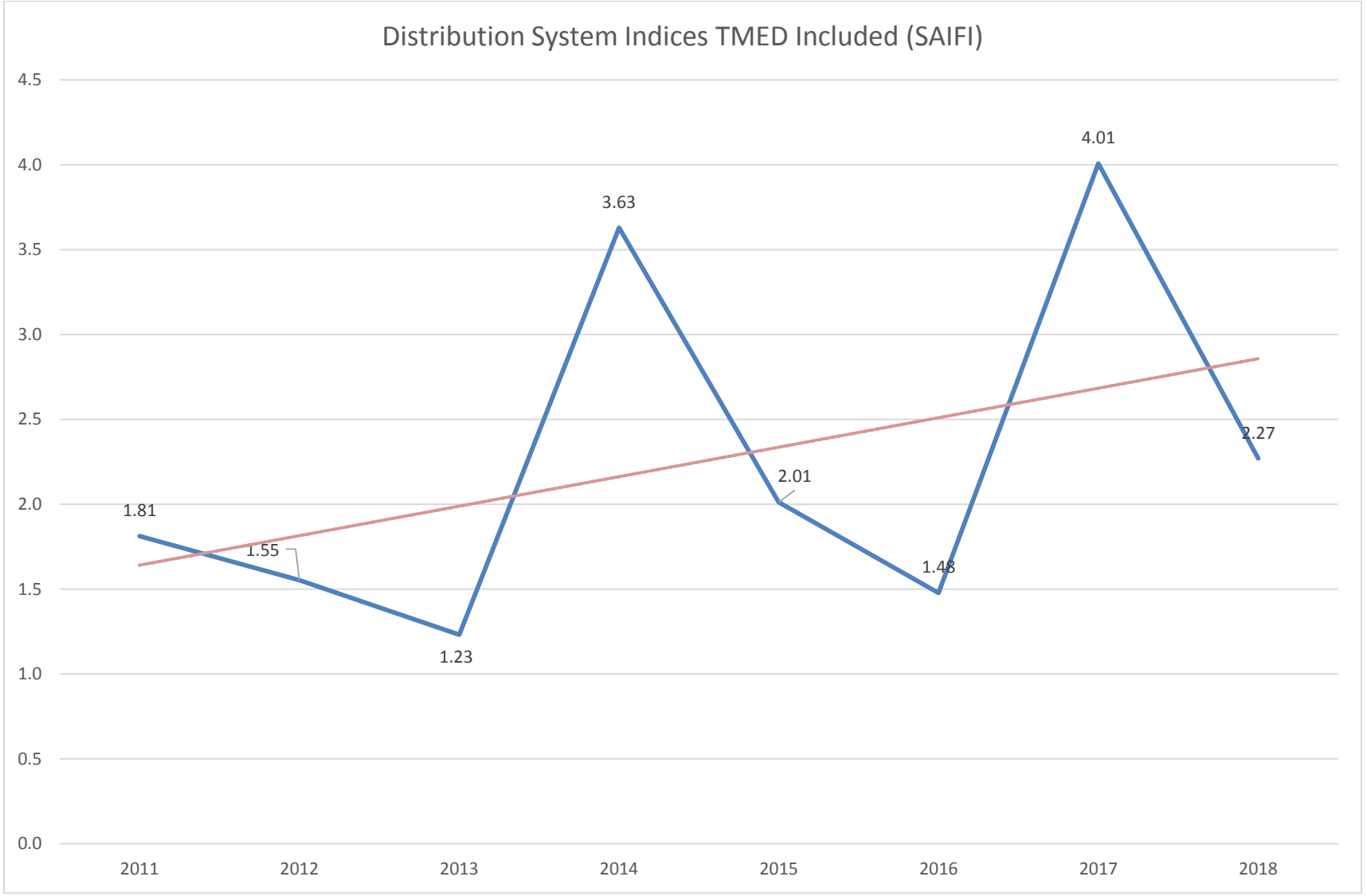
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

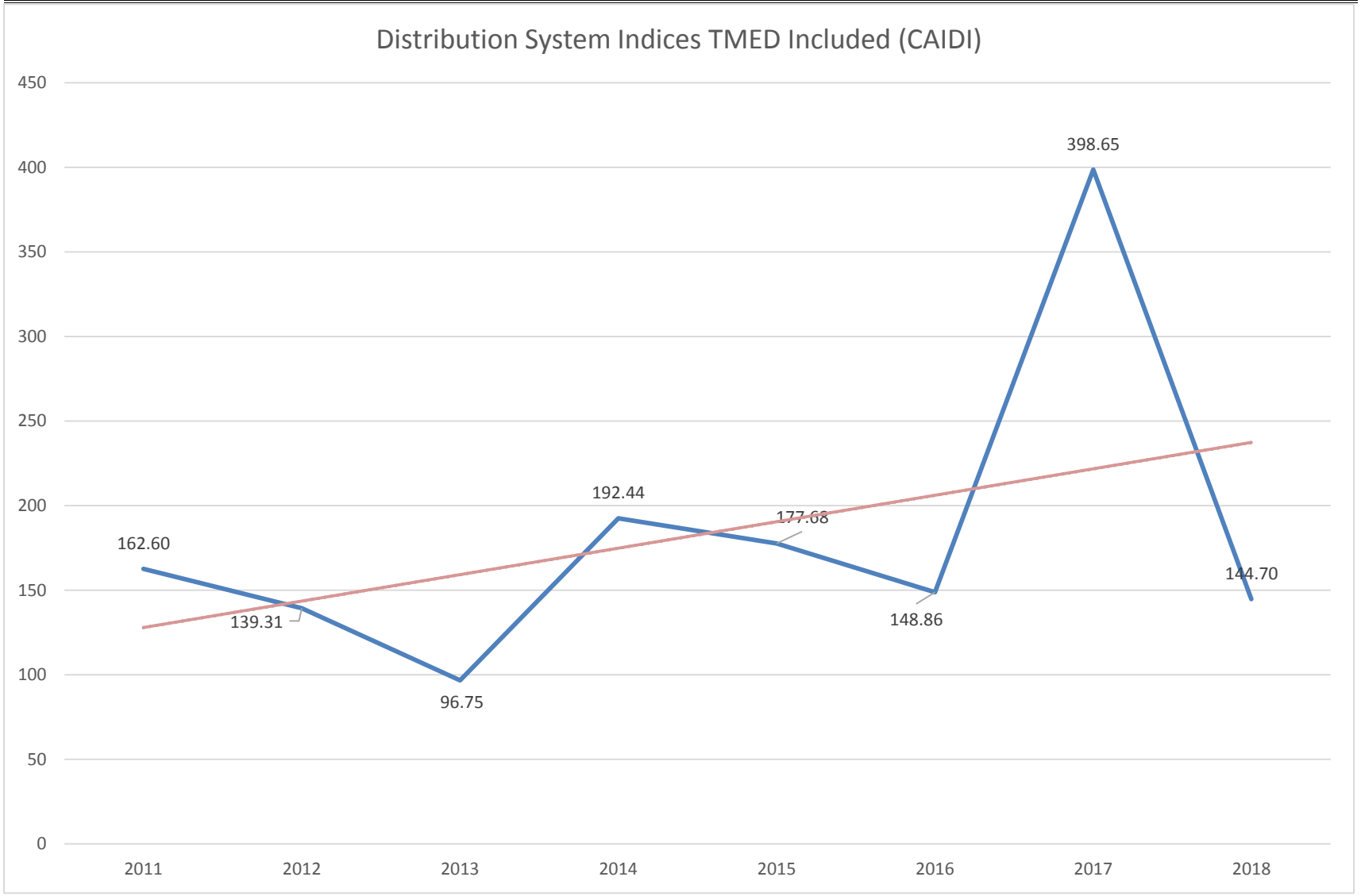
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 7 Years (Years in Business)

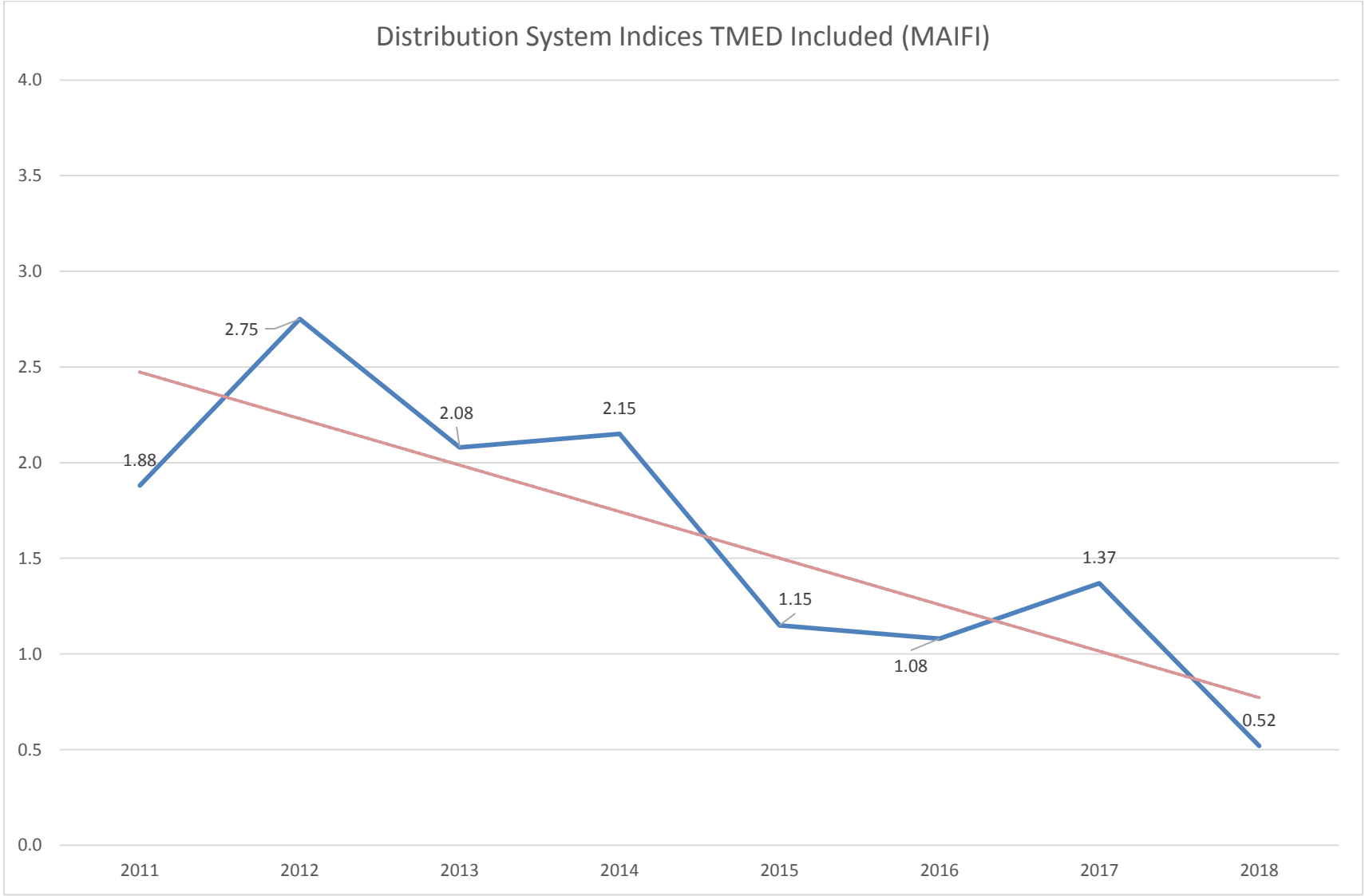
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2018	328.48	2.27	144.70	0.52	328.48	2.27	144.70	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

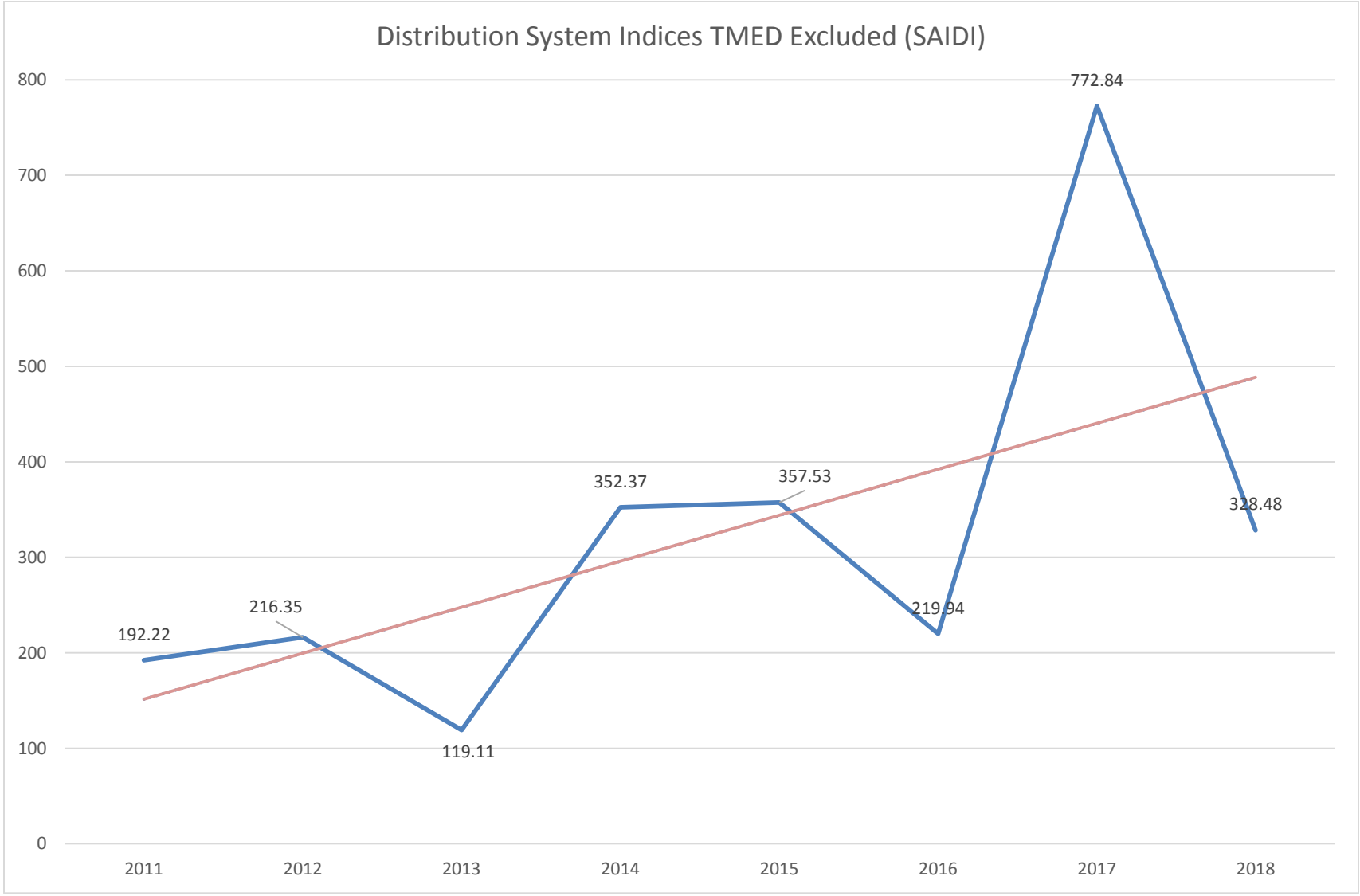
CalPeco Electric has been in business for 8 years and therefore does not have 10 years of data.

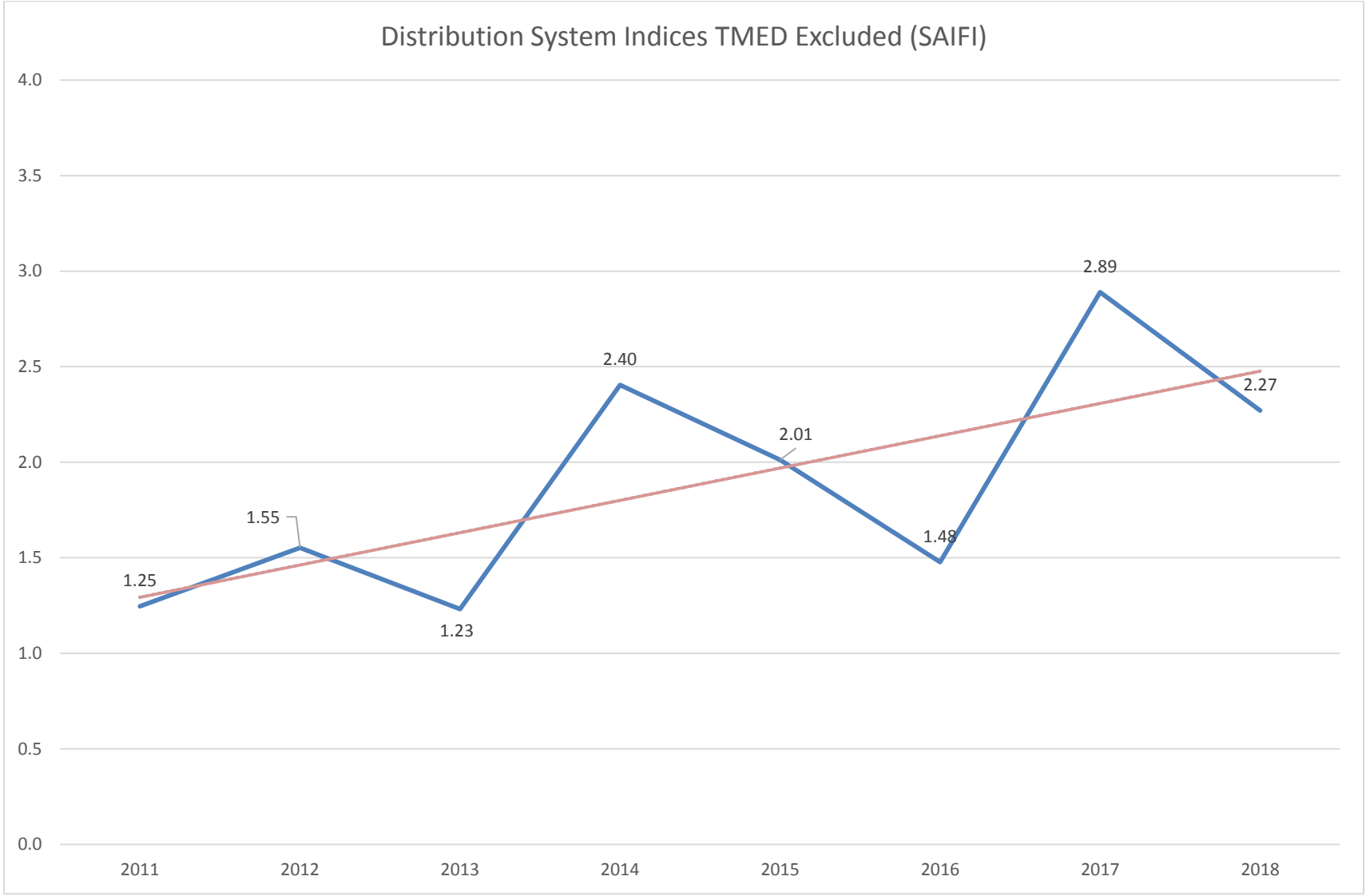

Distribution System Indices TMED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
219.94
1,597.39
328.48
2011
2012
2013
2014
2015
2016
2017
2018

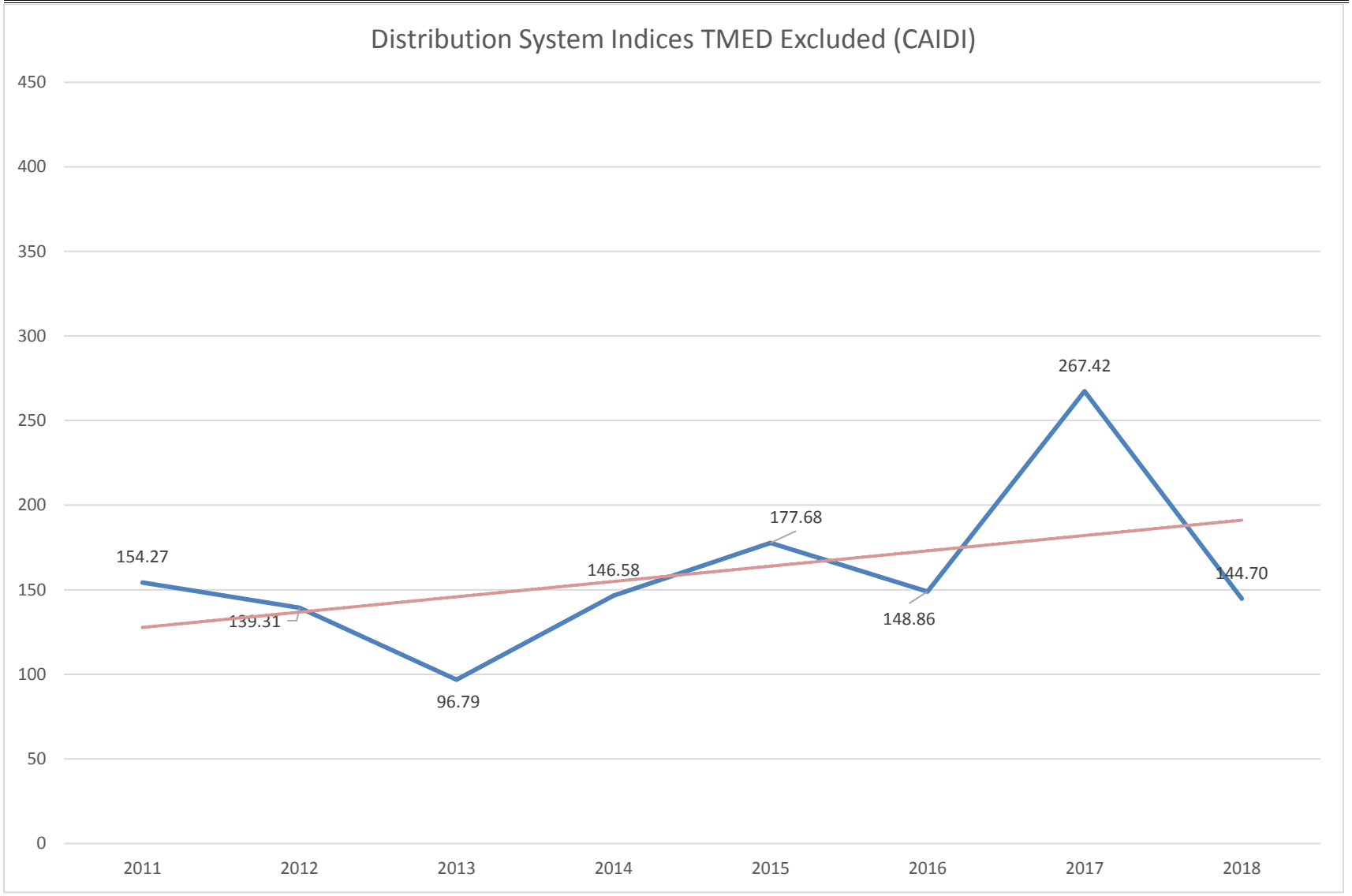

Distribution System Indices TMED Included (SAIFI)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.48
4.01
2.27
2011
2012
2013
2014
2015
2016
2017
2018

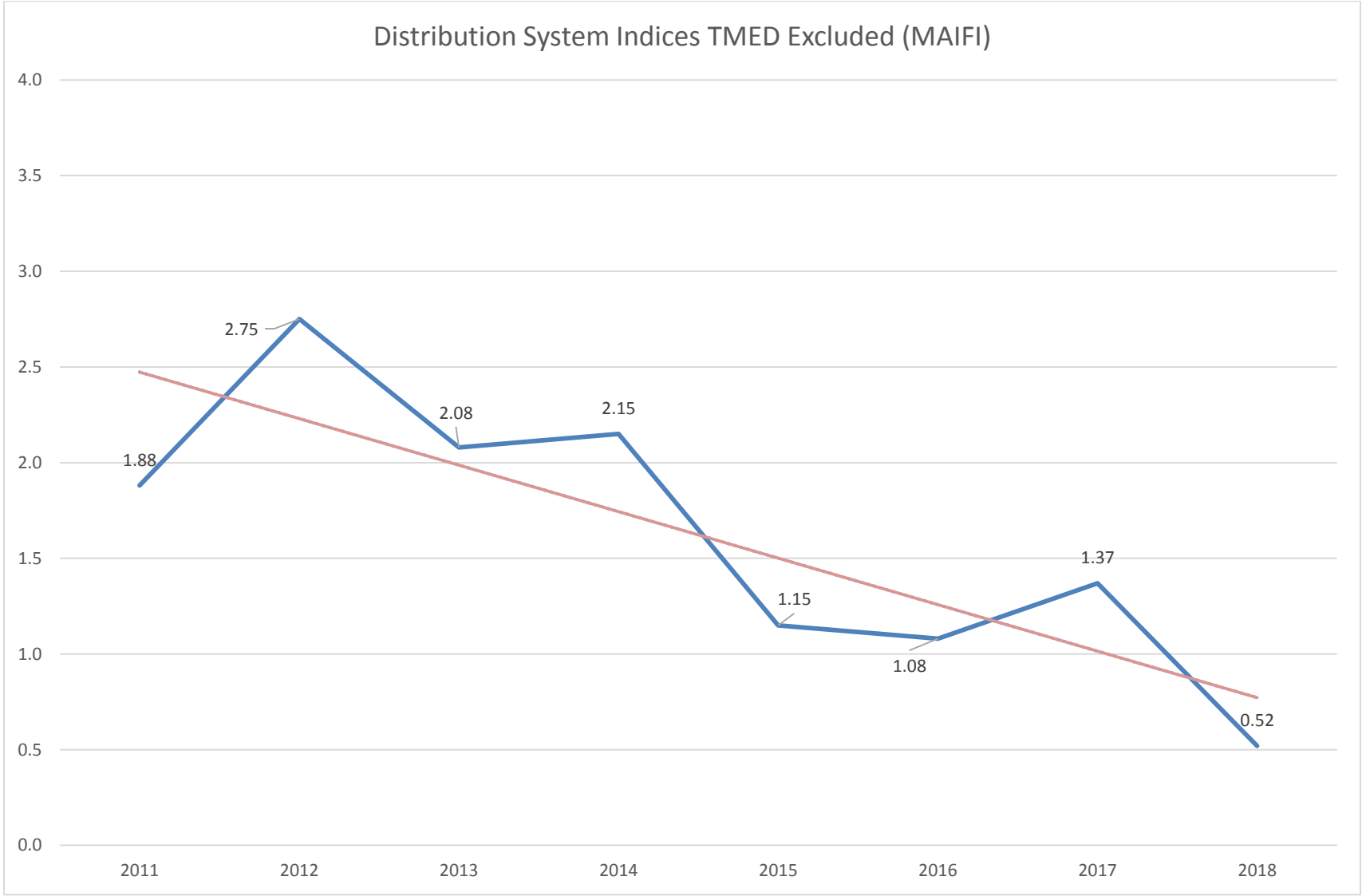

Distribution System Indices TMED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
148.86
398.65
144.70
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices TMED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.15
1.08
1.37
0.52
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices TMED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
219.94
772.84
328.48
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices TMED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2011
2012
2013
2014
2015
2016
2017
2018
1.25
1.55
1.23
2.40
2.01
1.48
2.89
2.27

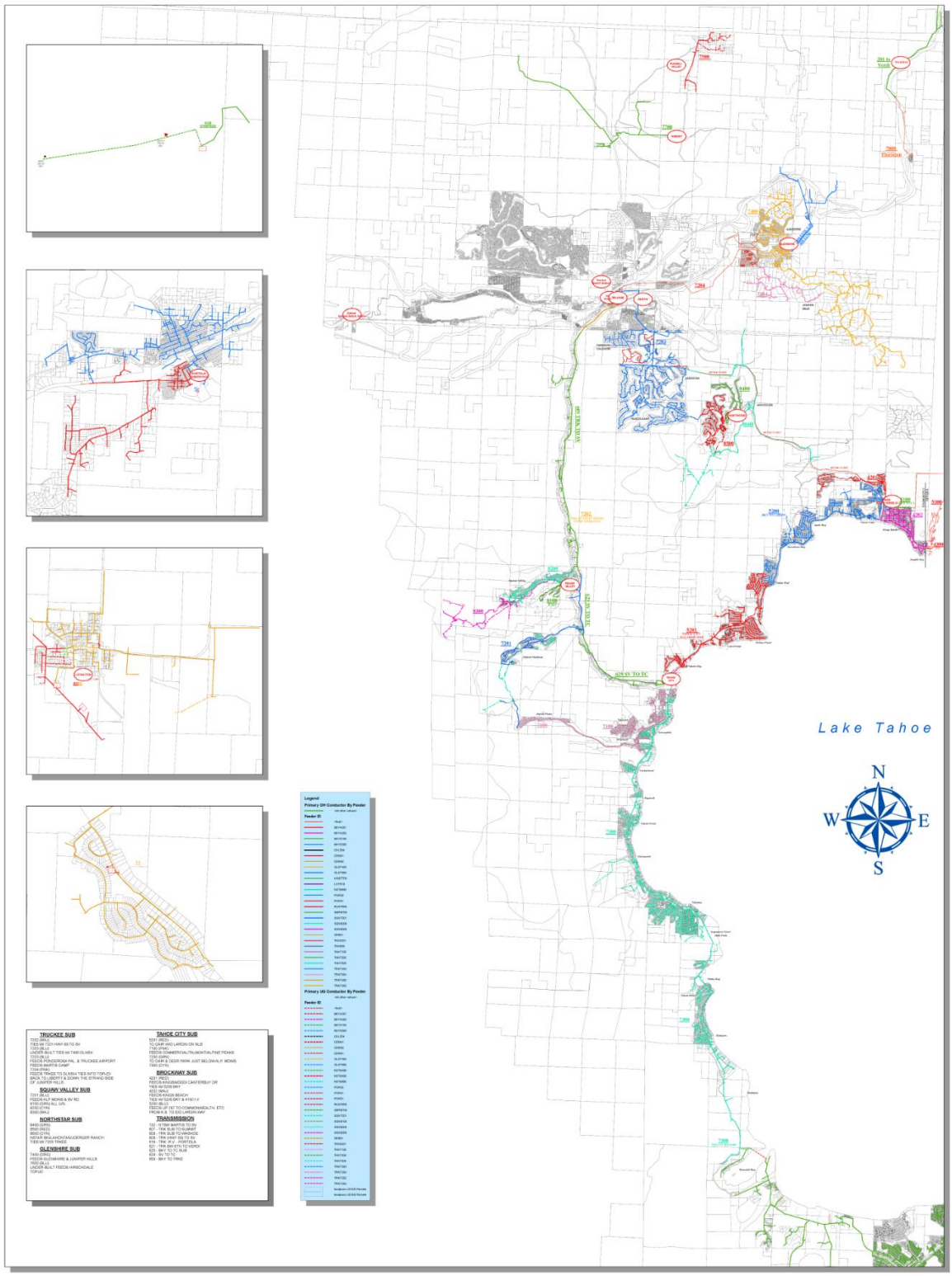

Distribution System Indices TMED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
148.86
267.42
144.70
2011
2012
2013
2014
2015
2016
2017
2018


Distribution System Indices TMED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
2011
2012
2013
2014
2015
2016
2017
2018

b. The number, date, and location of planned outages

Circuit	Number of Planned Outages By Year							
	2018	2017	2016	2015	2014	2013	2012	2011
31	1			1				
32		2	1					
41			1					
201	7					1		
204			1					
619							1	
650				1			1	
1261	1							
1296	1	2		5	1			
2200				1	1			
2300	1			1	2		1	
3100	5	1					1	1
3101					2	2		
3200	5			1			1	
3300	10	2		3			2	
3400	4	3		5		2	4	
3500		6		1				
3501	3			2	2	4	1	1
4201	1		1					
4202	3	4				2	5	1
5100						1	1	
5200	4	1		4	1	1	3	
5201	1	5	5	4	1		1	
7100	2	1			1	1	4	
7200	1			1	1	1	2	
7201		4	1	2	1			
7202	1	1		2	3	1		
7203	2			2	2	4		
7300	14	5	6	4	16	4	5	2
7400	8	2	1	1				1
7600	1			1				1
7700					1			
7800					2			
8200	2	7	3	2	4			1
8300	1	2		6			2	
8400	7							
8500			1			1	2	
8600				4			2	

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
201*	Tahoe	64	Washoe	8.7	99.8%	0.2%	4	2722	3.5
1261	Tahoe	746	Topaz	70.9	76.2%	23.8%	8	2393	8.4

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Washoe 201 circuit was noted as a deficient circuit in 2017 as well as 2018. The 3 year average circuit SAIDI score remains high due to significant outages in 2017 from wildfire and severe winter storms.

There were only 2 unplanned outages in 2018 for the 201 circuit, both due to a loss of source from a third party owned substation. Over 90% of the average circuit SAIDI score was accumulated during the 2017 winter storms and wildfire.

The historical metric for Washoe 201:

- 2018 – 2,722.9
- 2017 – 2,698.9
- 2016 – 269.2
- 2015 – 200.9

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line in difficult terrain, sourced by an NV Energy substation in Nevada. The line has been rebuilt in 2014 and Liberty completed a voltage conversion in 2018 so that the entire circuit is now 24.9kV.

The circuit performance in 2018 was similar to historical records, excluding 2017. The 2017 performance is an outlier and does not accurately reflect the condition of this circuit. Liberty expects this circuit will no longer be a deficient circuit no later than 2020 when the 2017 data is removed from the average.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Vice President of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	5/17/2018	Third Party - Switching	Lake Tahoe	17,315	104.89	0.3723
2	12/12/2018	Loss of Source – External System	Lake Tahoe	7,552	0.97	0.1623
3	10/17/2018	Trees	Lake Tahoe	7,398	18.34	0.1591
4	12/12/2018	Loss of Source – External System	Lake Tahoe	7,089	0.91	0.1524
5	10/3/2018	Hardware Failure	Lake Tahoe	4,678	8.97	0.1005
6	6/9/2018	Trees - Major Storm	Lake Tahoe	4,485	8.28	0.0964
7	11/12/2018	Unknown	Lake Tahoe	4,154	9.46	0.8932
8	1/4/2018	Unknown	Lake Tahoe	3,529	0.91	0.0758
9	12/12/2018	Loss of Source – External System	Lake Tahoe	3,434	0.44	0.0738
10	8/4/2018	Loss of Source – External System	Lake Tahoe	2,721	10.41	0.0585

*Based on customer impact

7) Summary list of 2018 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2018 = 198.88

CalPeco Electric did not experience an event in 2018 where the daily SAIDI was higher than the calculated TMED.

8) Historical 10 largest unplanned outage events for the past 10 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	.067	3,488.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

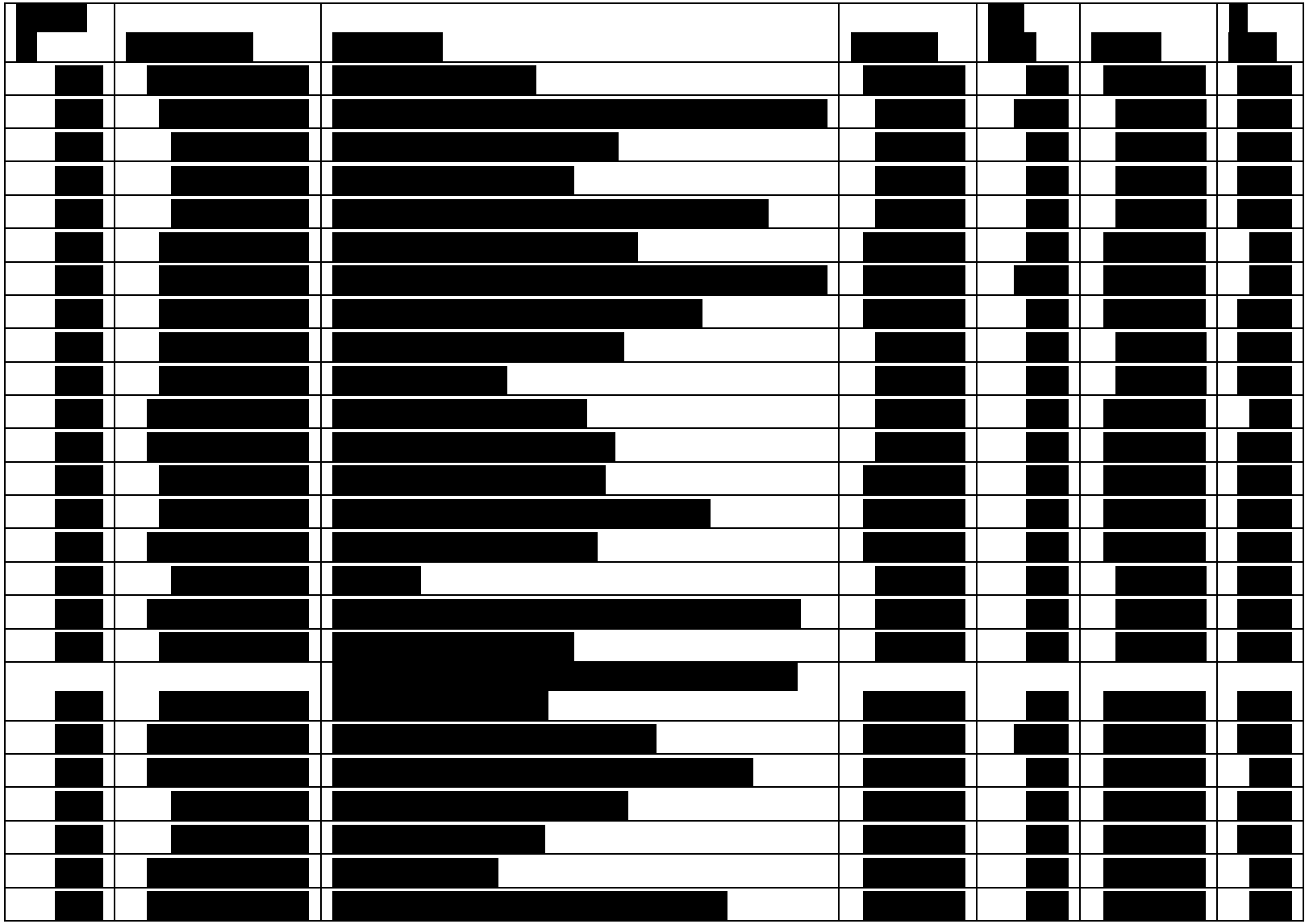
Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	5/9/2011	24,550	3.02	74,059.17	Yes
2	Relays	2/17/2011	8,005	3.40	12,738.90	No
3	Overcurrent	3/20/2011	4,396	0.98	4,396.00	No
4	Trees	5/25/2011	4,120	10.23	21,658.83	No
5	Trees	11/18/2011	4,120	21.50	15,792.33	No
6	Lateral Fuse	3/16/2011	3,957	2.96	11,739.10	No
7	Bird/Animal	9/24/2011	3,885	0.25	769.50	No
8	Hardware Failure	9/12/2011	3,475	1.12	2,780.42	No
9	Relays	1/25/2011	3,201	1.68	5,388.35	No
10	Trees	6/29/2011	3,200	4.35	11,786.67	No

9) Number of customer inquiries on reliability data and the number of days per response

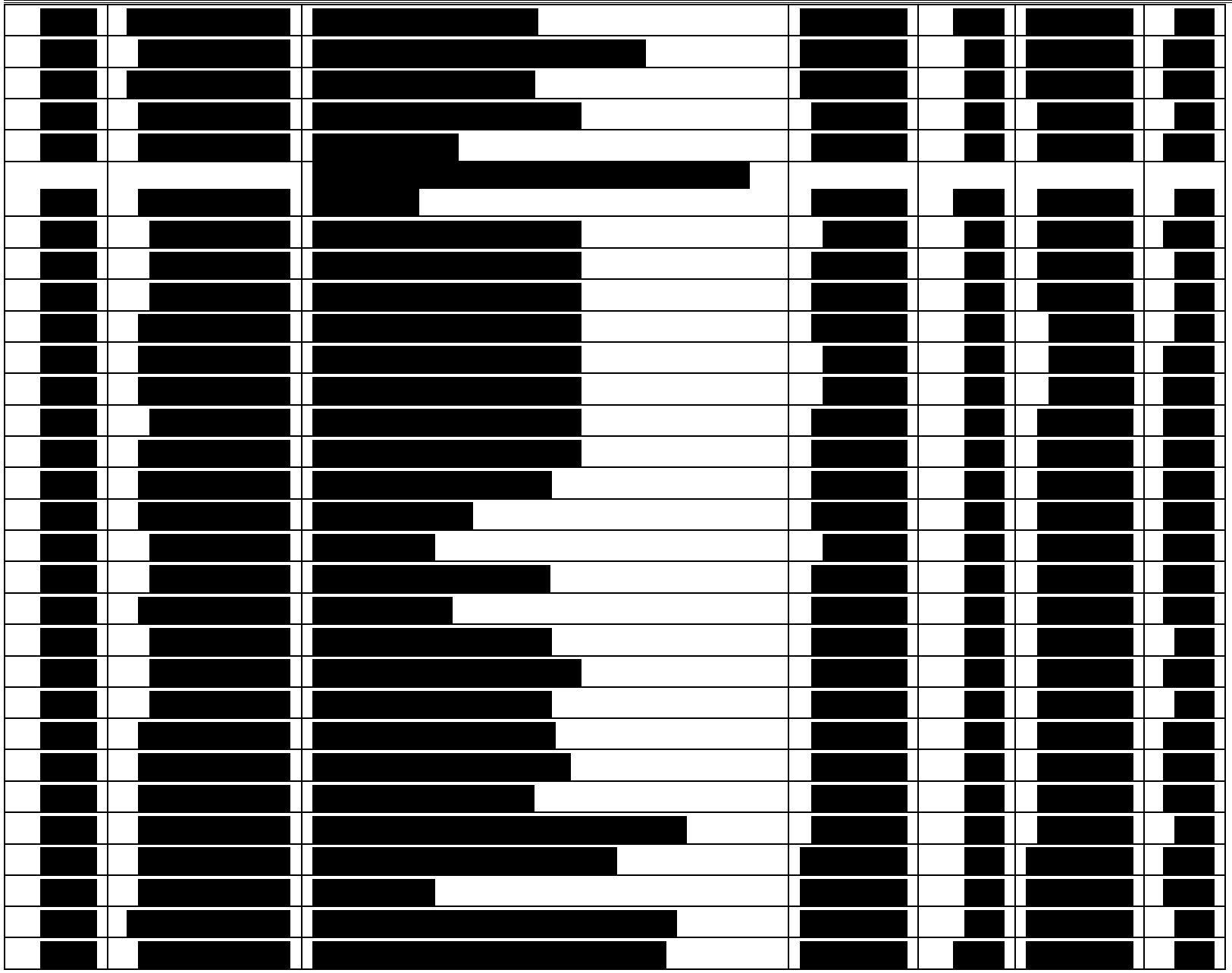
CalPeco Electric did not receive any reliability inquiries in 2018.

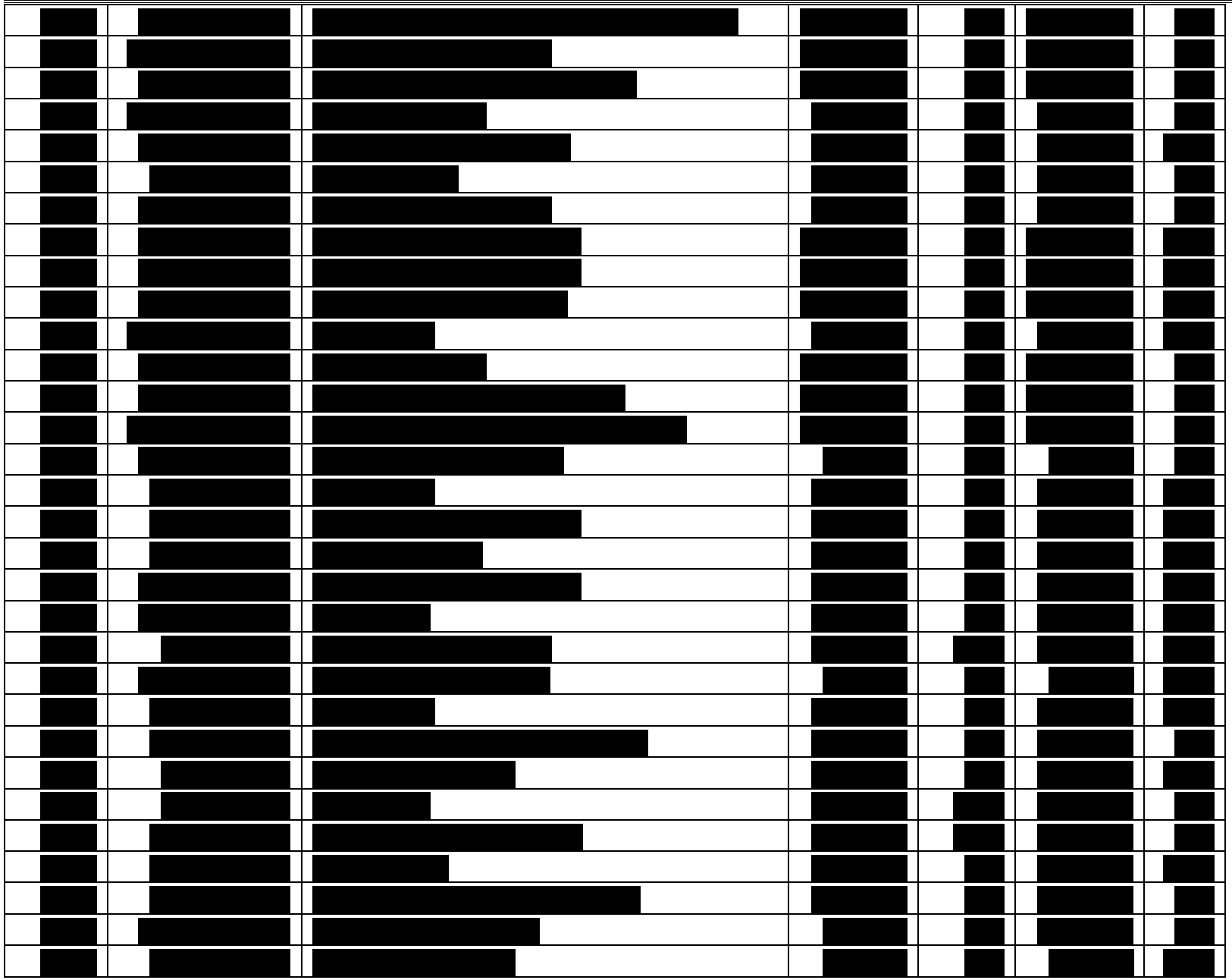
Date Received	Date Responded	Description of Inquiry

Appendix A: 7 Years of Planned Outage Data

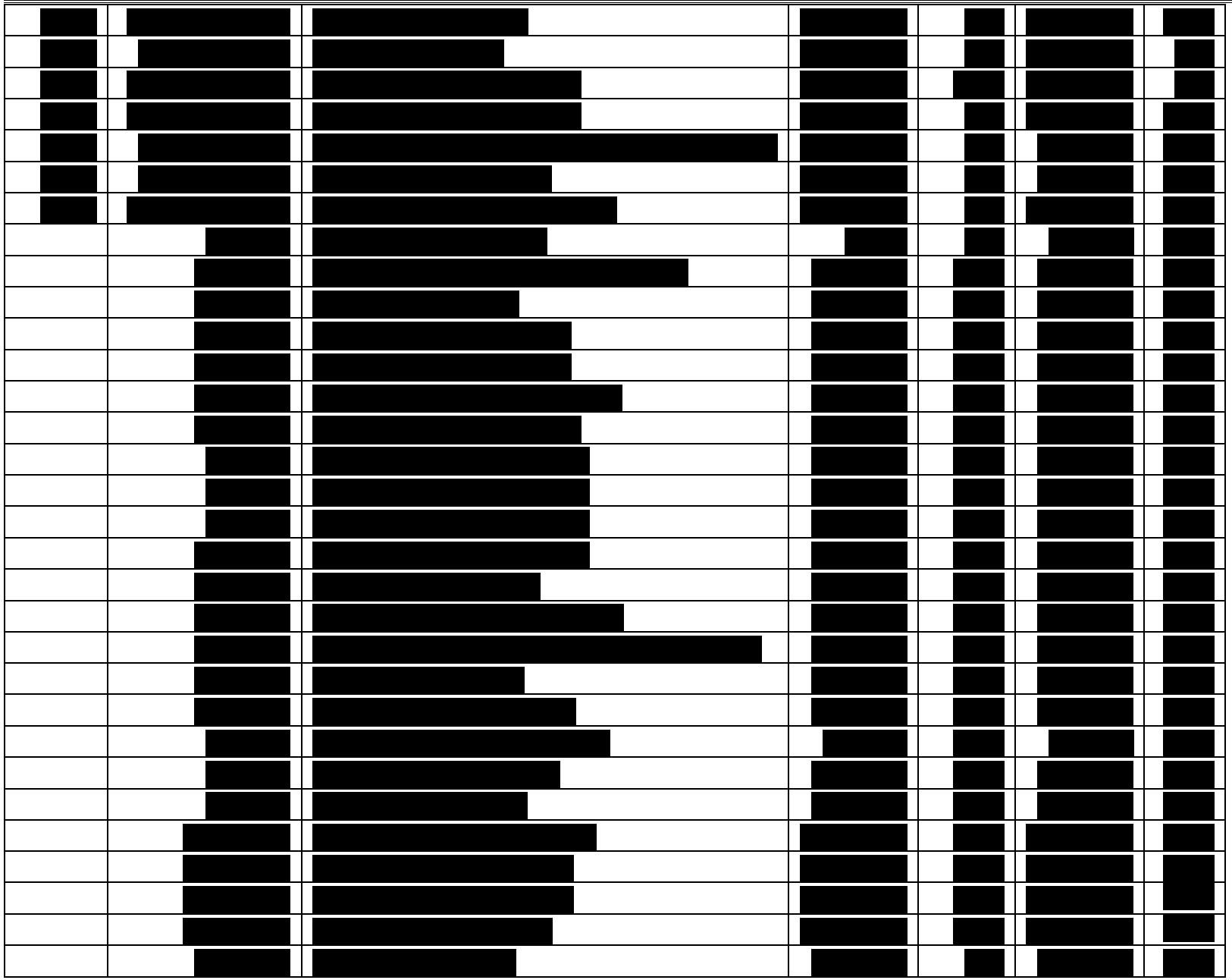






















ATTACHMENT 12

Liberty Utilities 2019 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2019

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

February 1ST, 2020

CA-07-0677

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2019 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents nine years (2011 through 2019) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2019 was 171.00 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 9 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

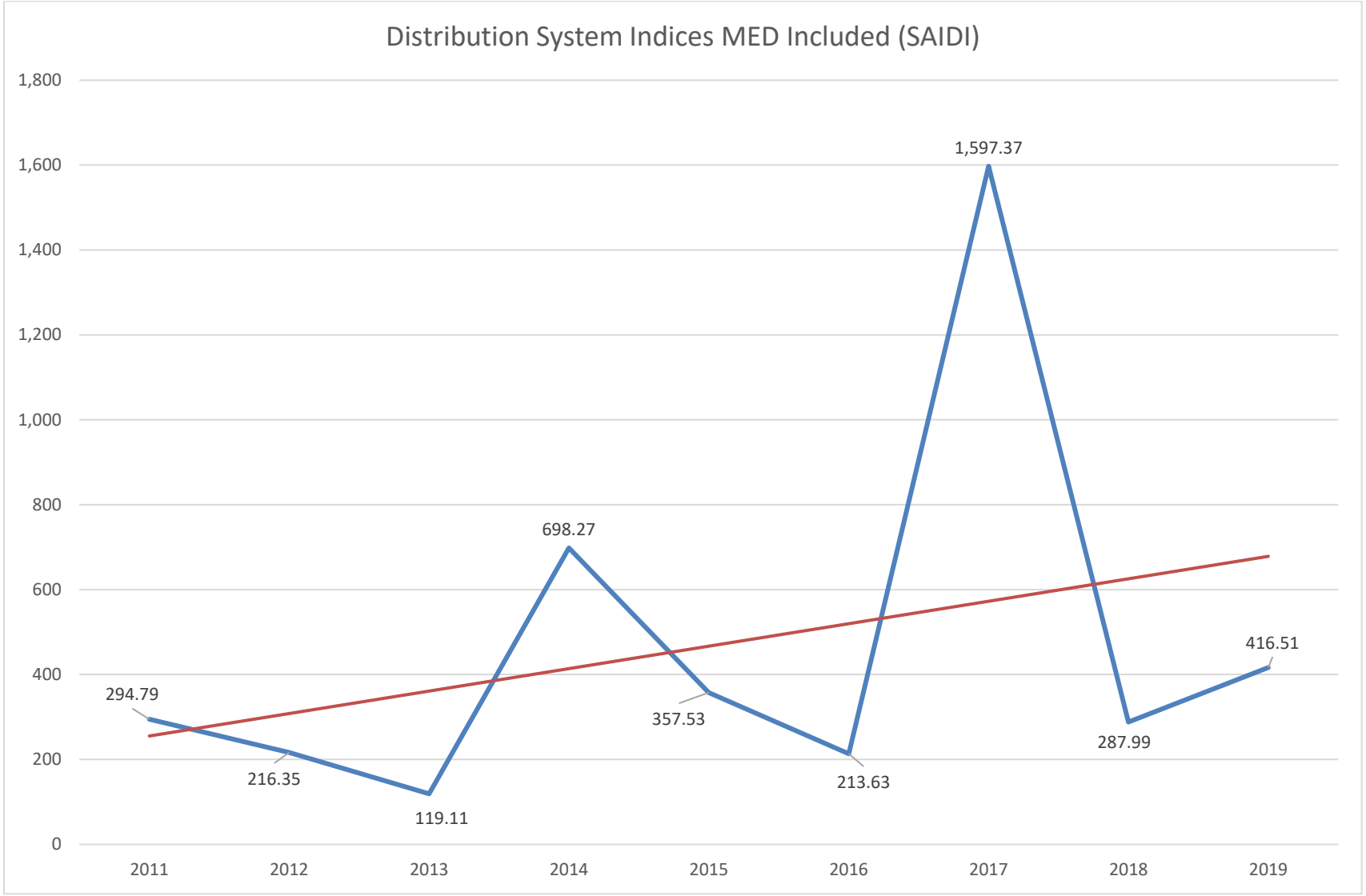
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 9 Years (Years in Business)

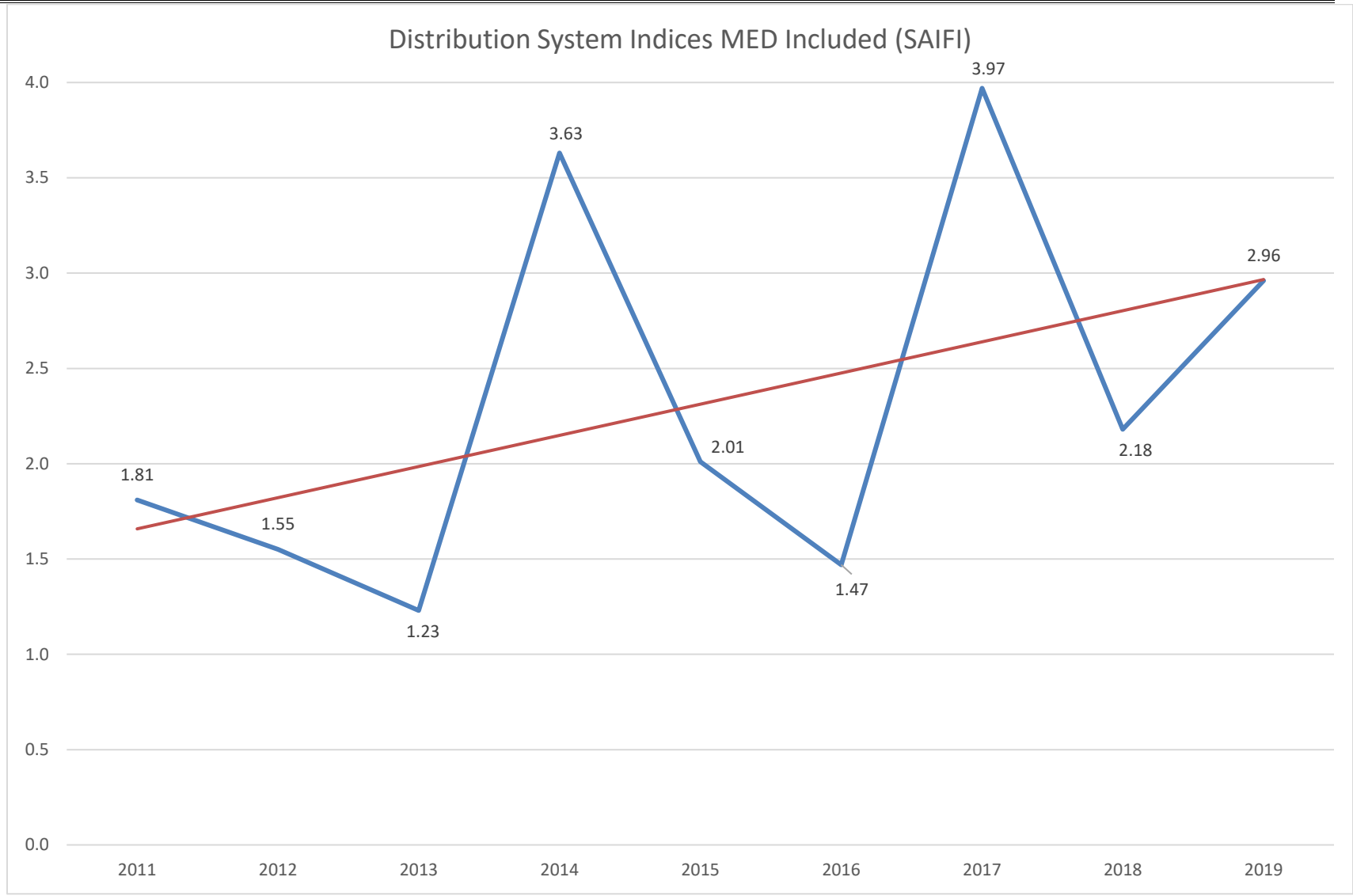
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

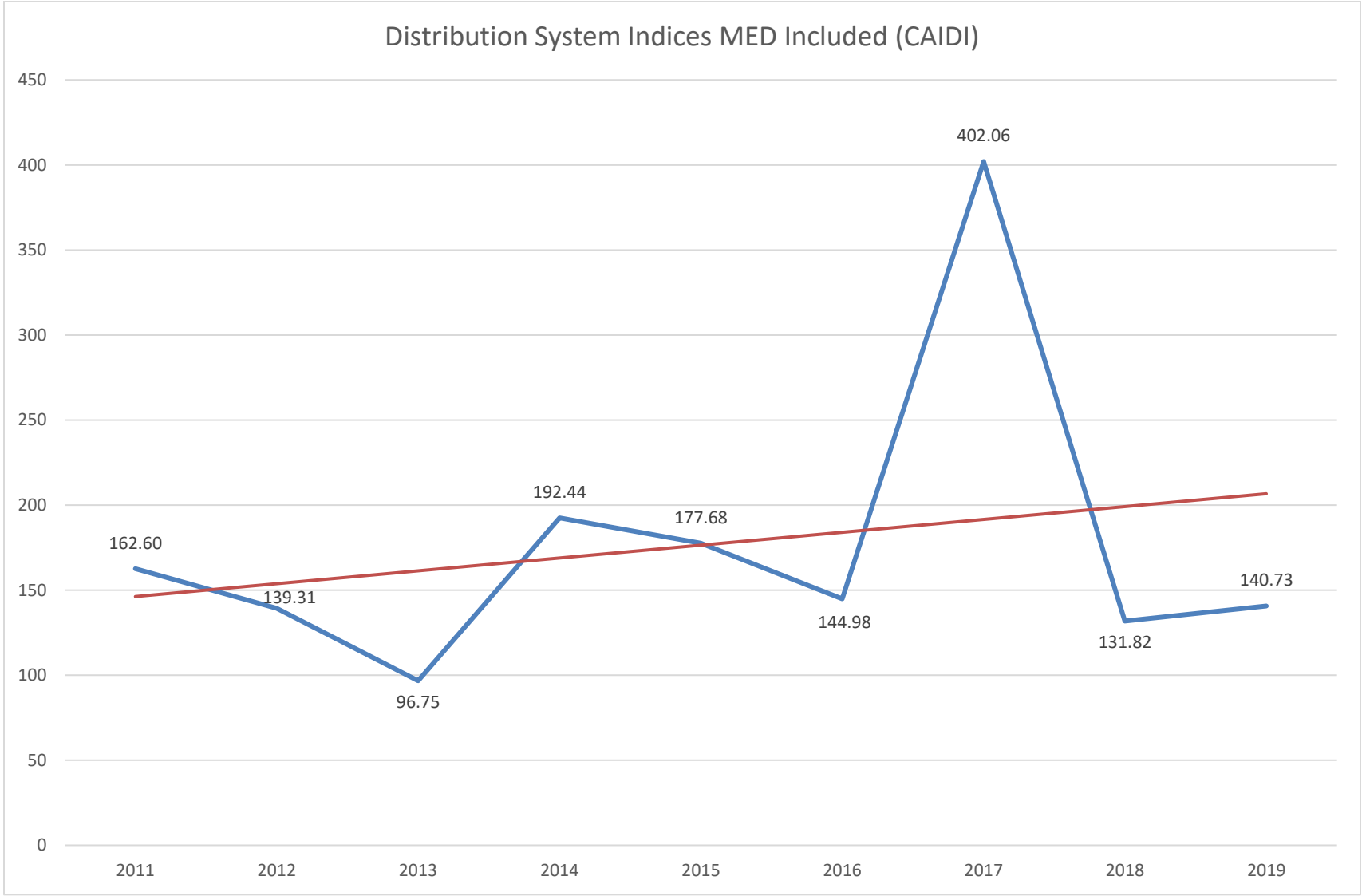
II. Transmission System Indices (MED Included and Excluded)

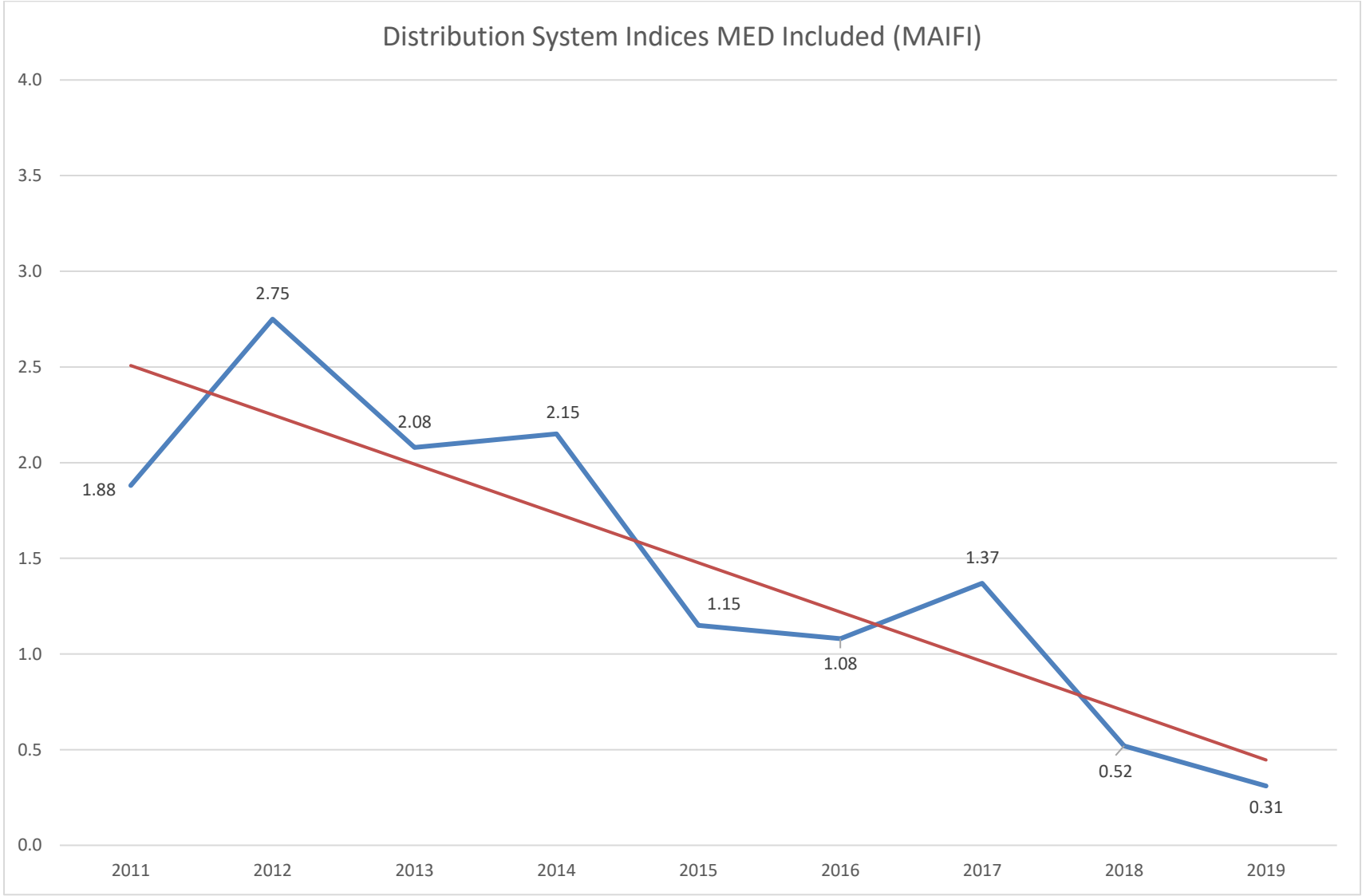
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

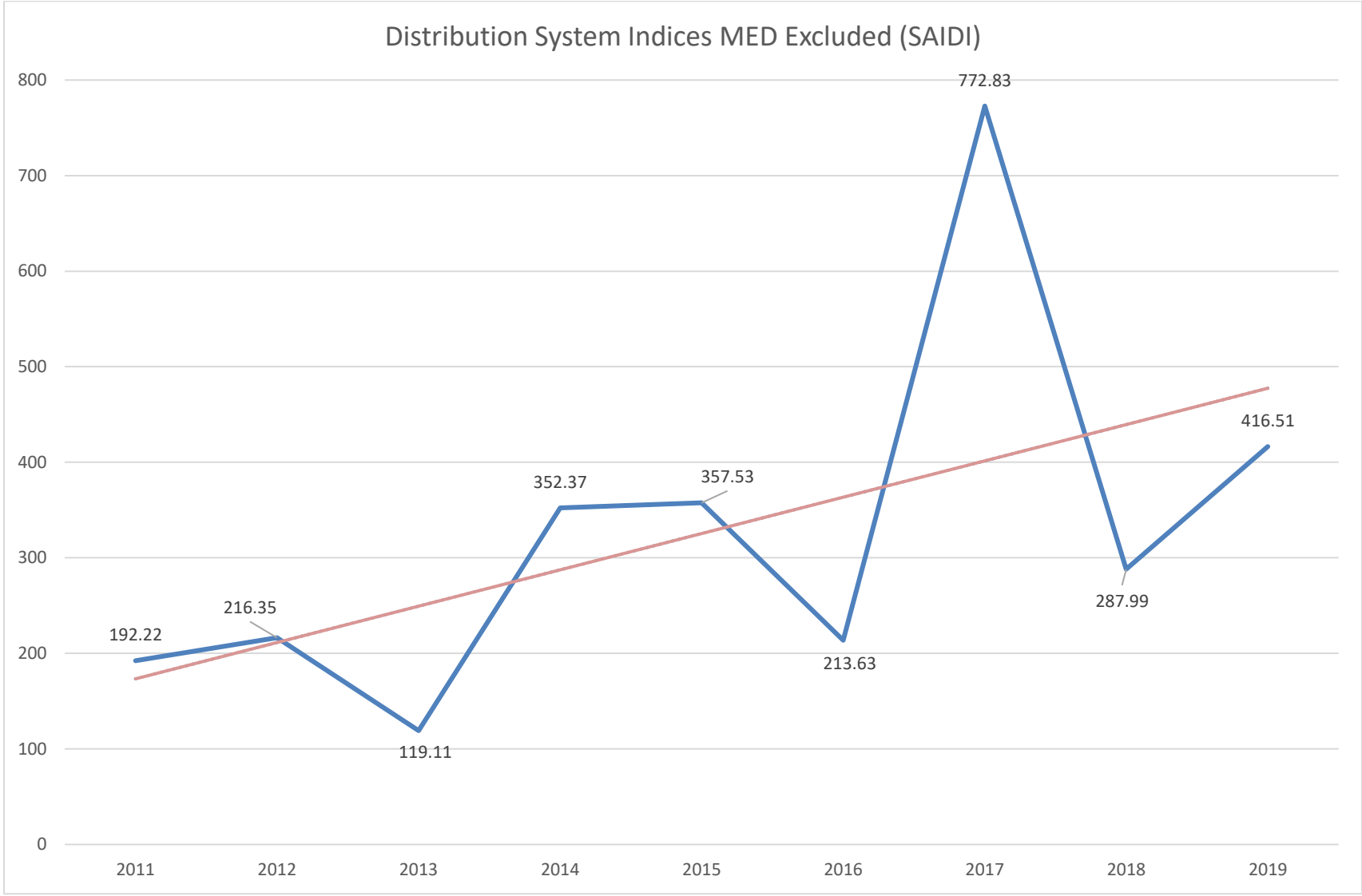
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 9 years (years in business) with linear trend line (TMED included and excluded).

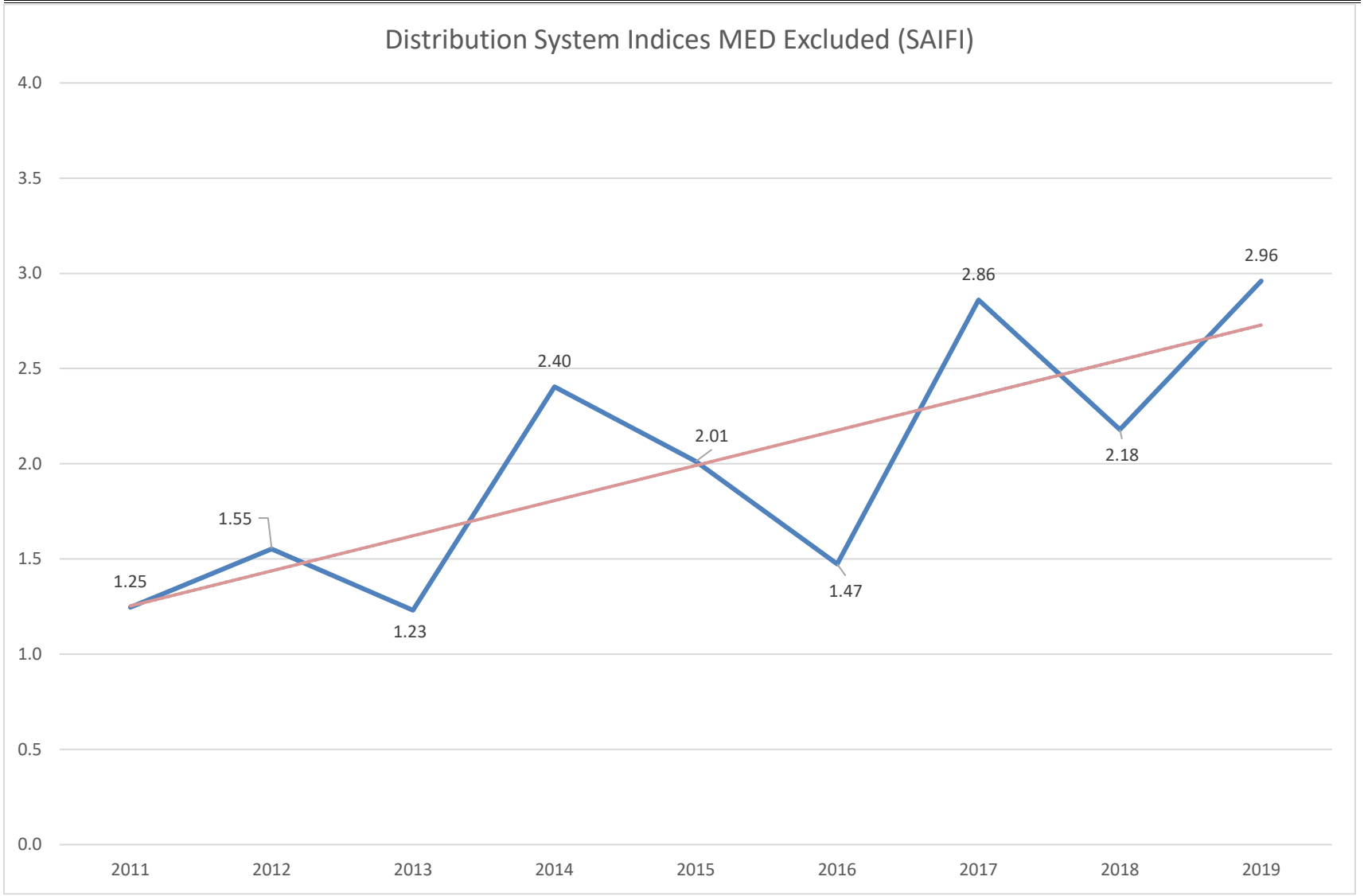

Distribution System Indices MED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
213.63
1,597.37
287.99
416.51
2011
2012
2013
2014
2015
2016
2017
2018
2019

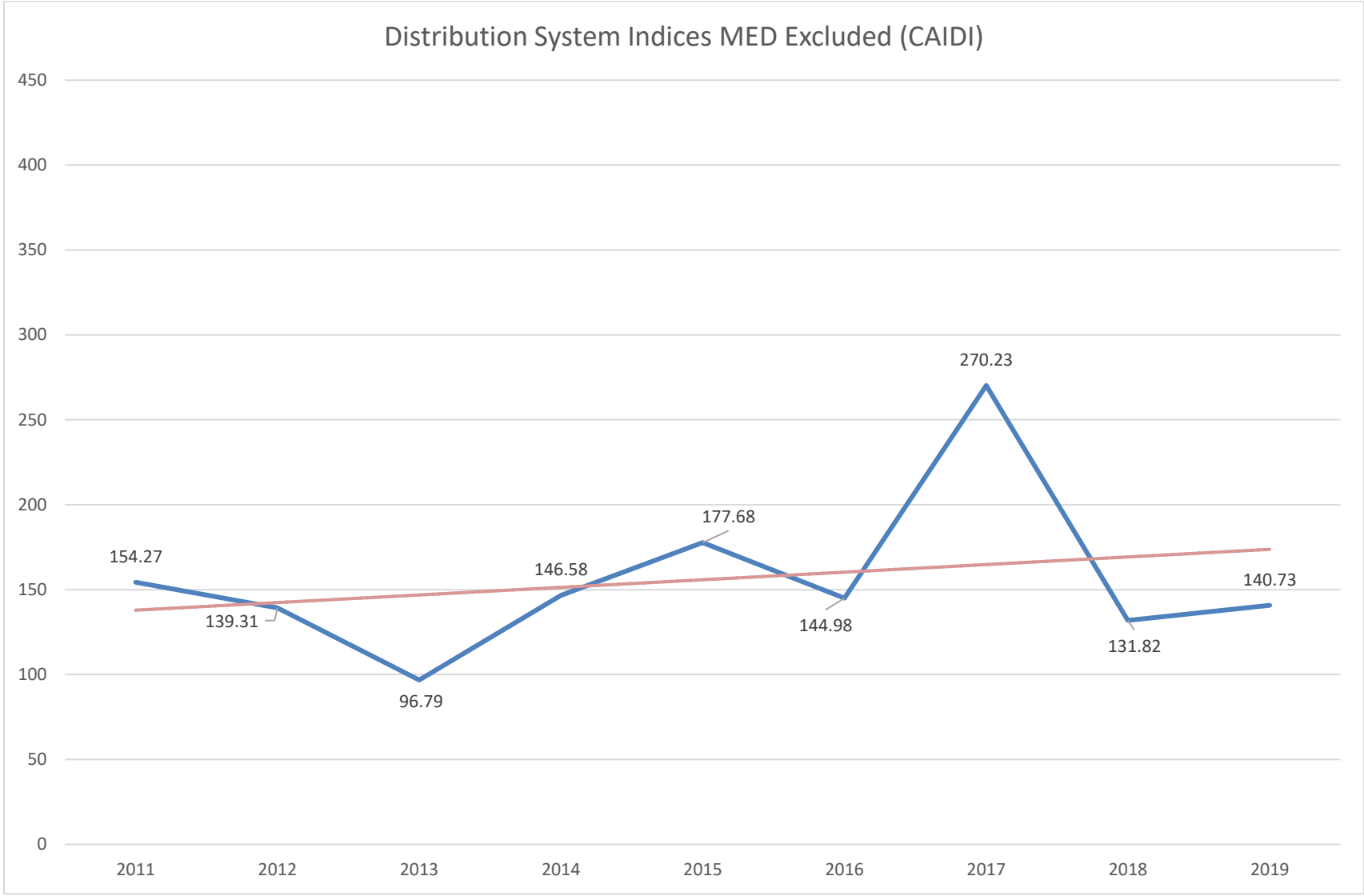

Distribution System Indices MED Included (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.47
3.97
2.18
2.96
2011
2012
2013
2014
2015
2016
2017
2018
2019

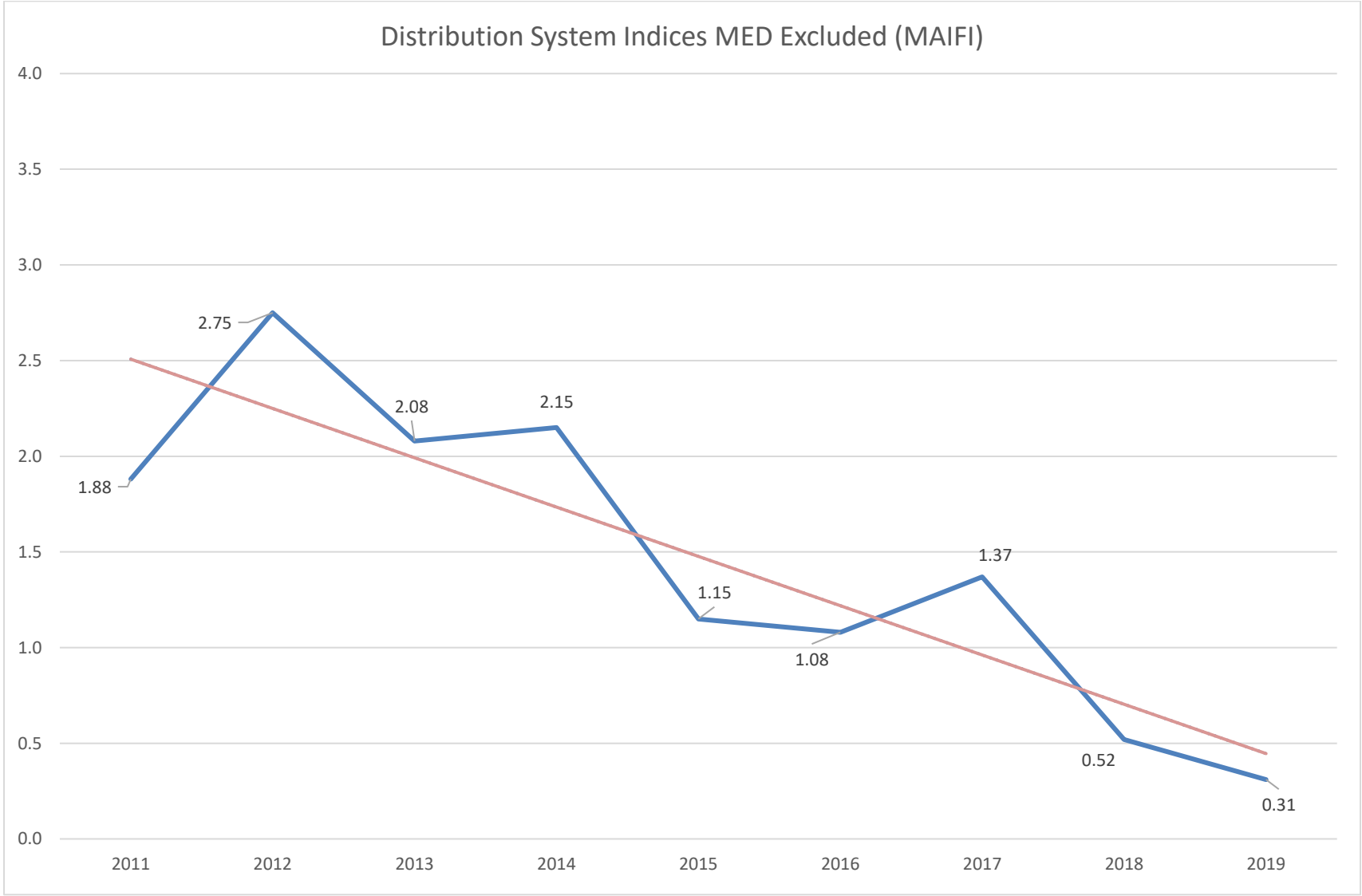

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
144.98
402.06
131.82
140.73
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
213.63
772.83
287.99
416.51
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.47
2.86
2.18
2.96
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
144.98
270.23
131.82
140.73
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.88
2.75
2.08
2.15
1.15
1.08
1.37
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019

2) Division (or District) Reliability Indices for the past 9 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

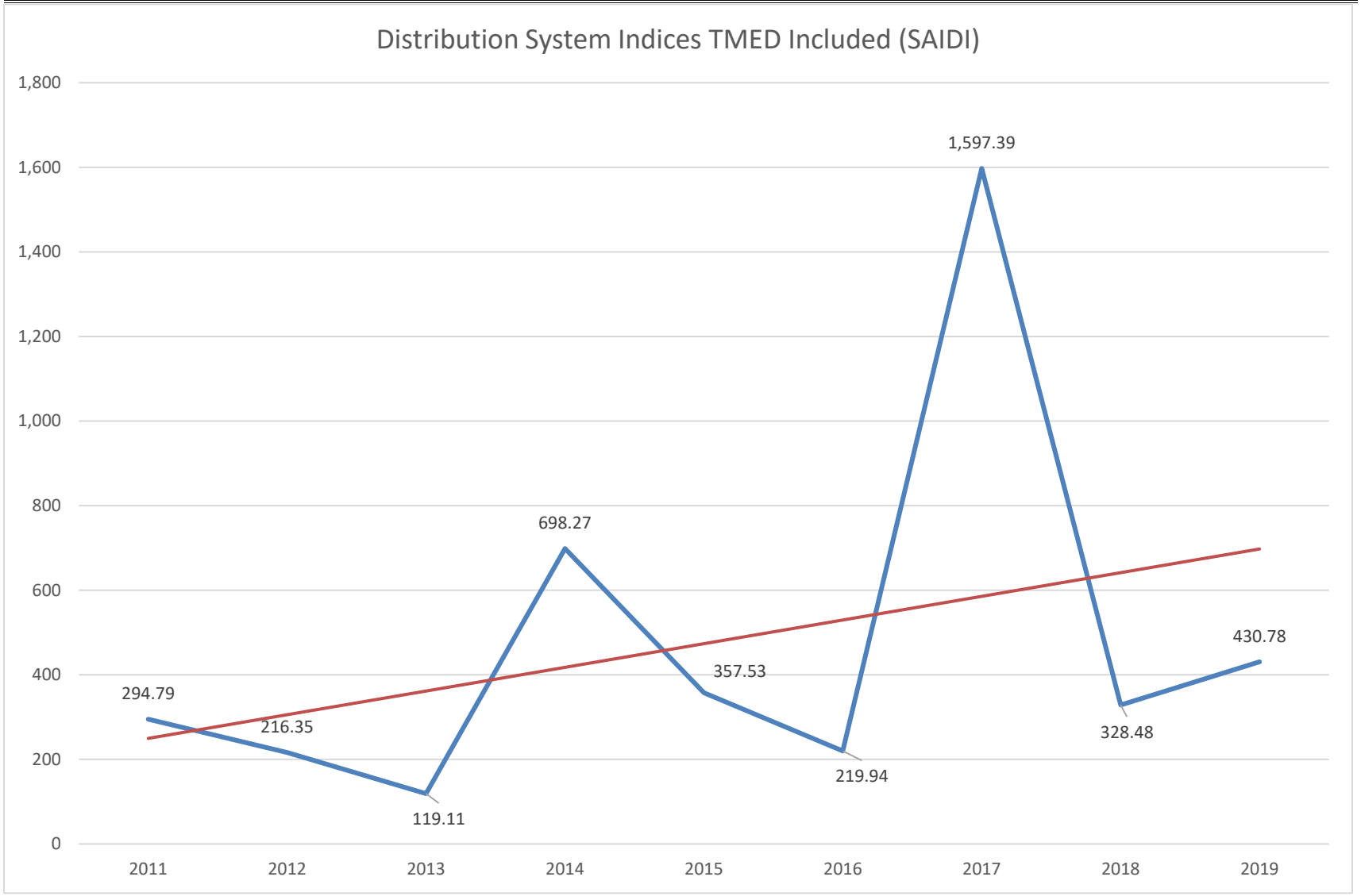
3) System and Division indices based on IEEE 1366 for the past 9 years including planned outages and including and excluding TMED

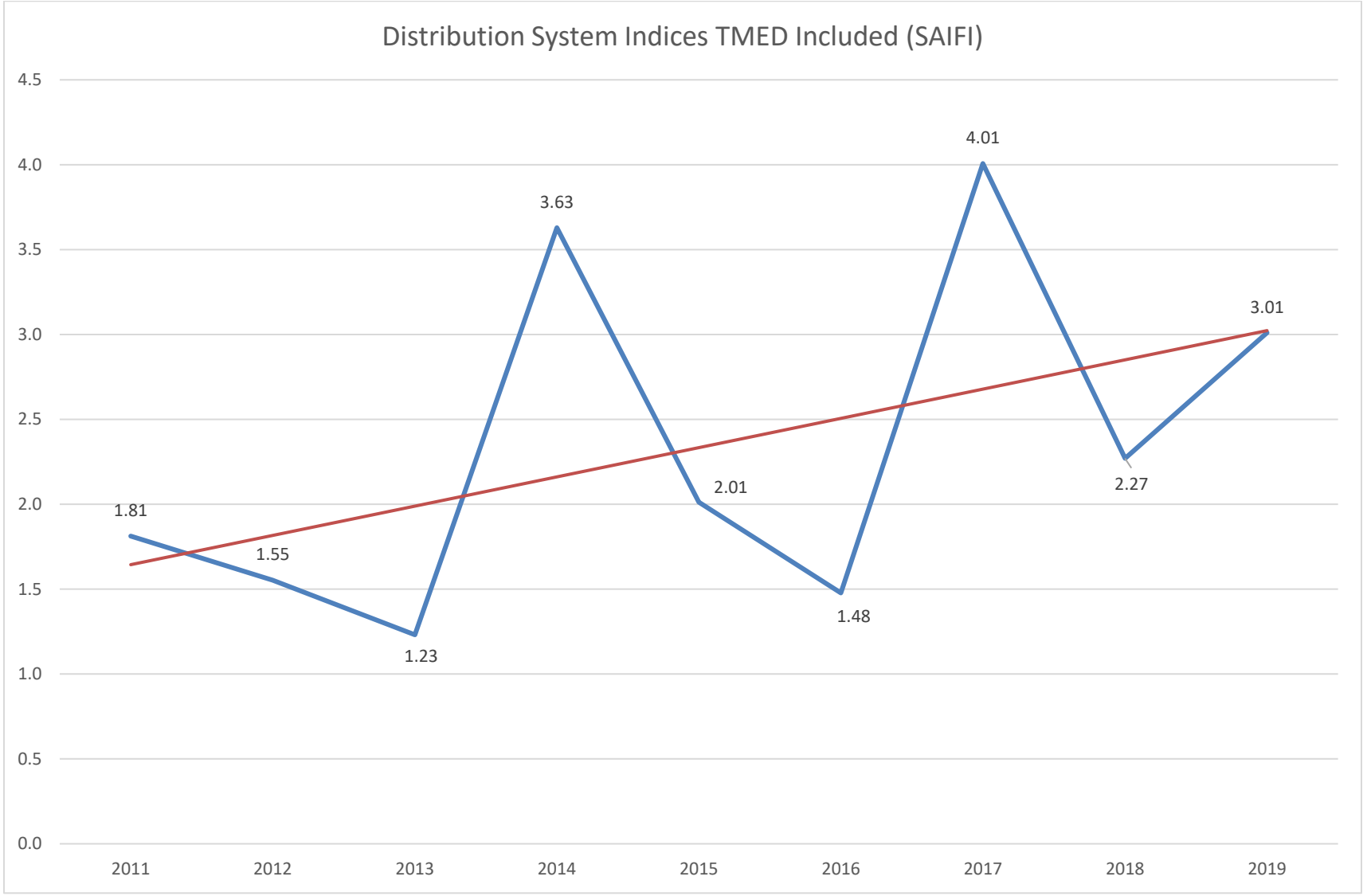
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

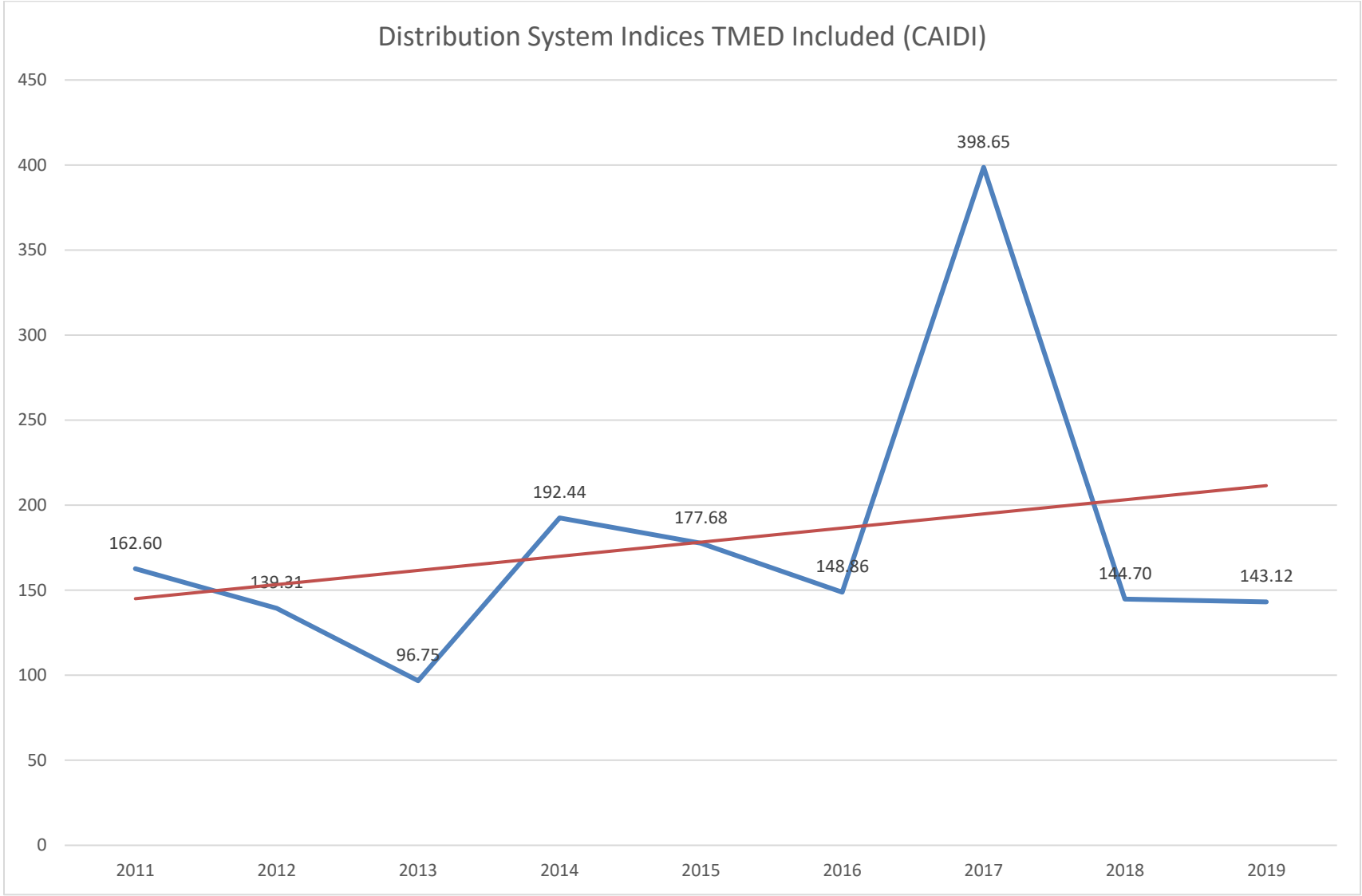
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 9 Years (Years in Business)

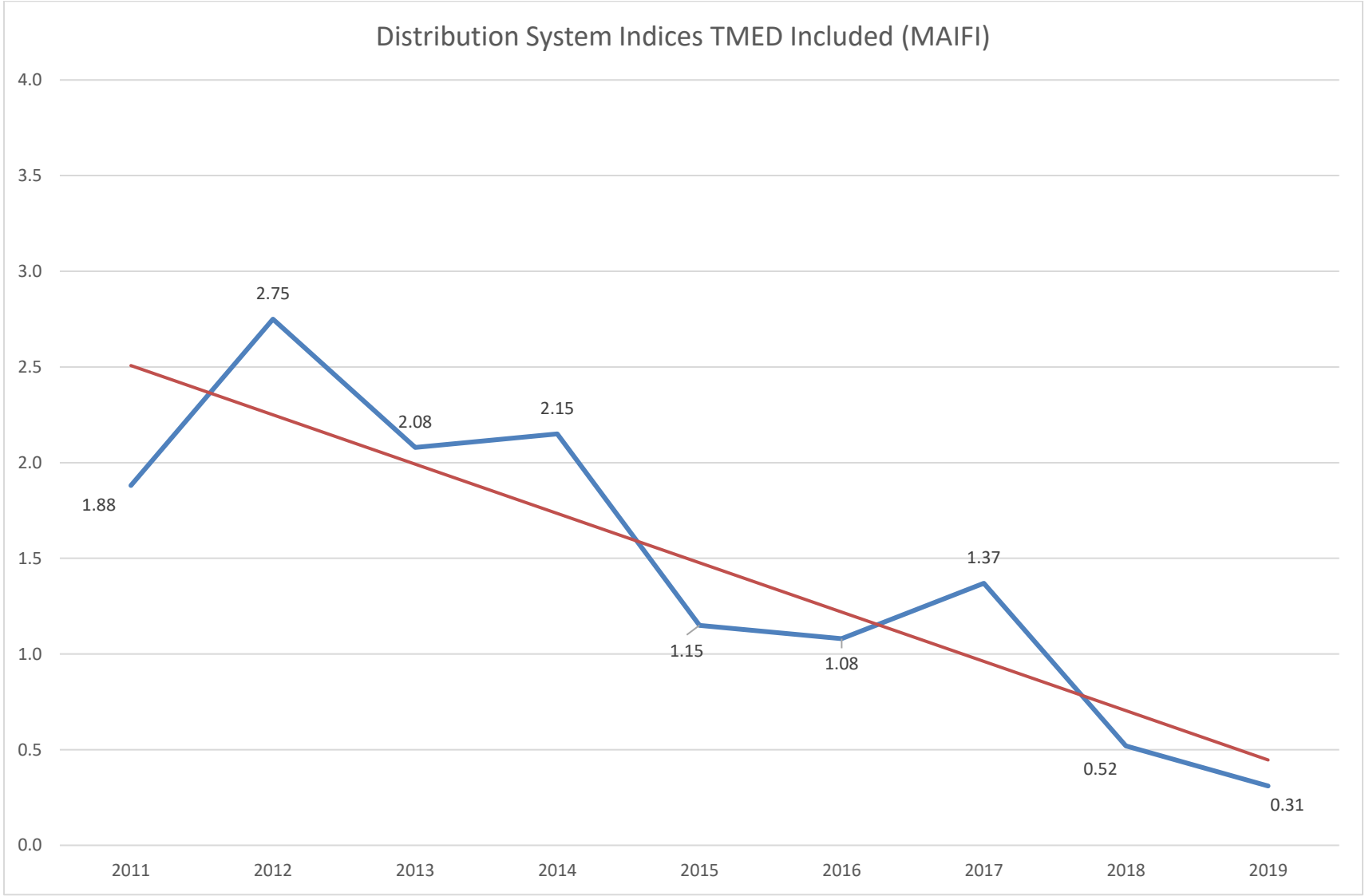
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.70	0.52	328.48	2.27	144.70	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

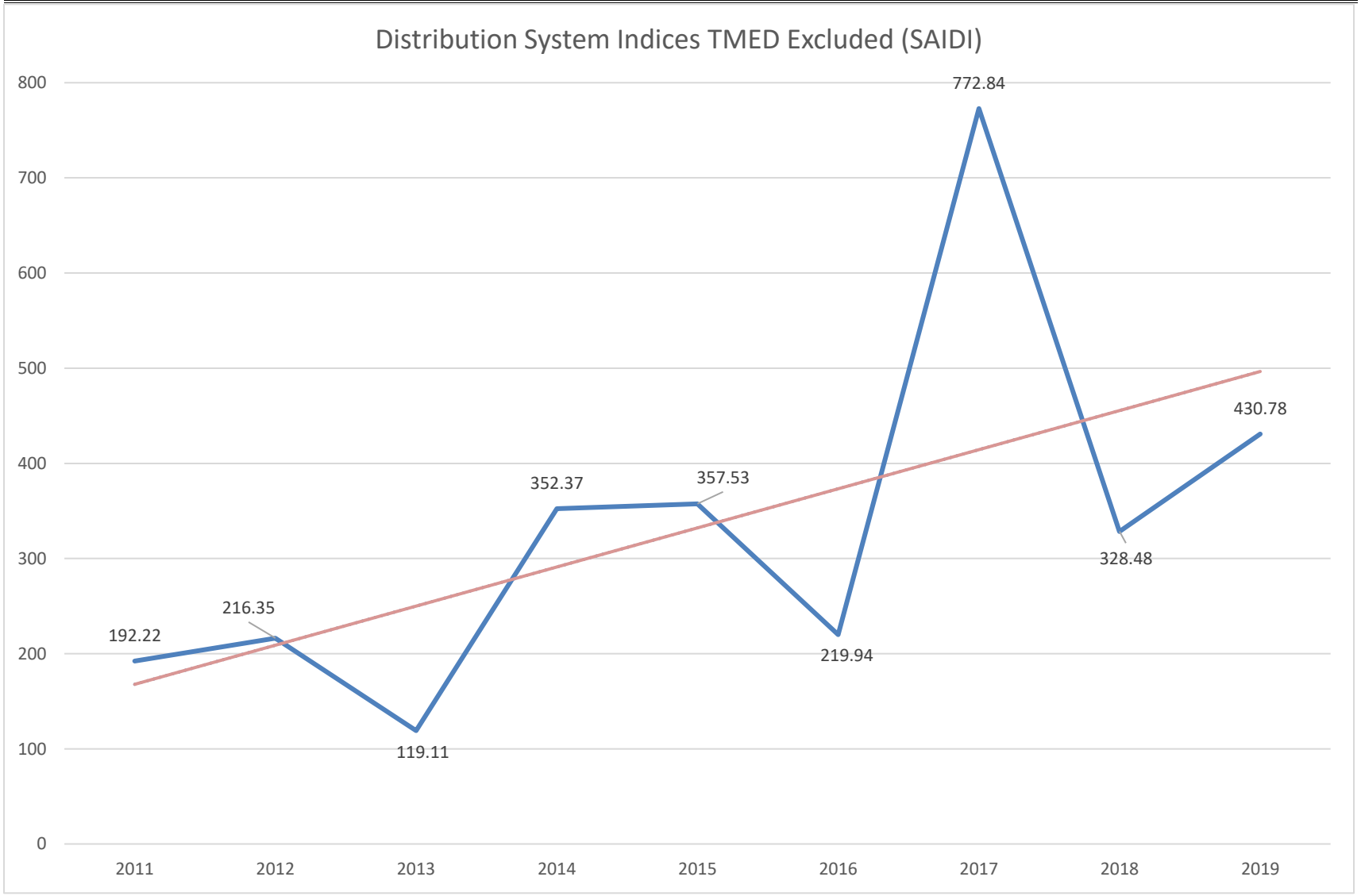
CalPeco Electric has been in business for 9 years and therefore does not have 10 years of data.

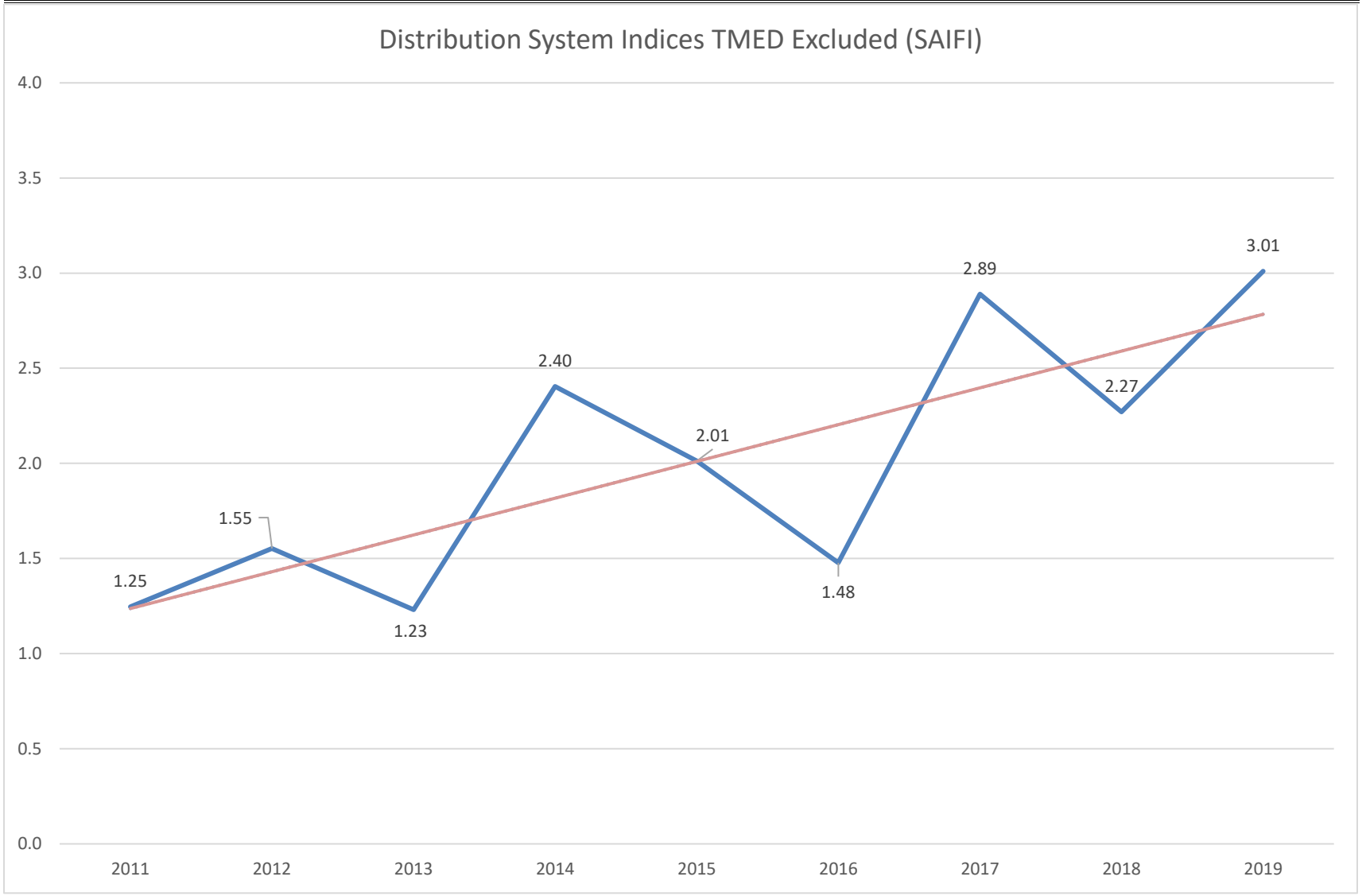

Distribution System Indices TMED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
219.94
1,597.39
328.48
430.78
2011
2012
2013
2014
2015
2016
2017
2018
2019

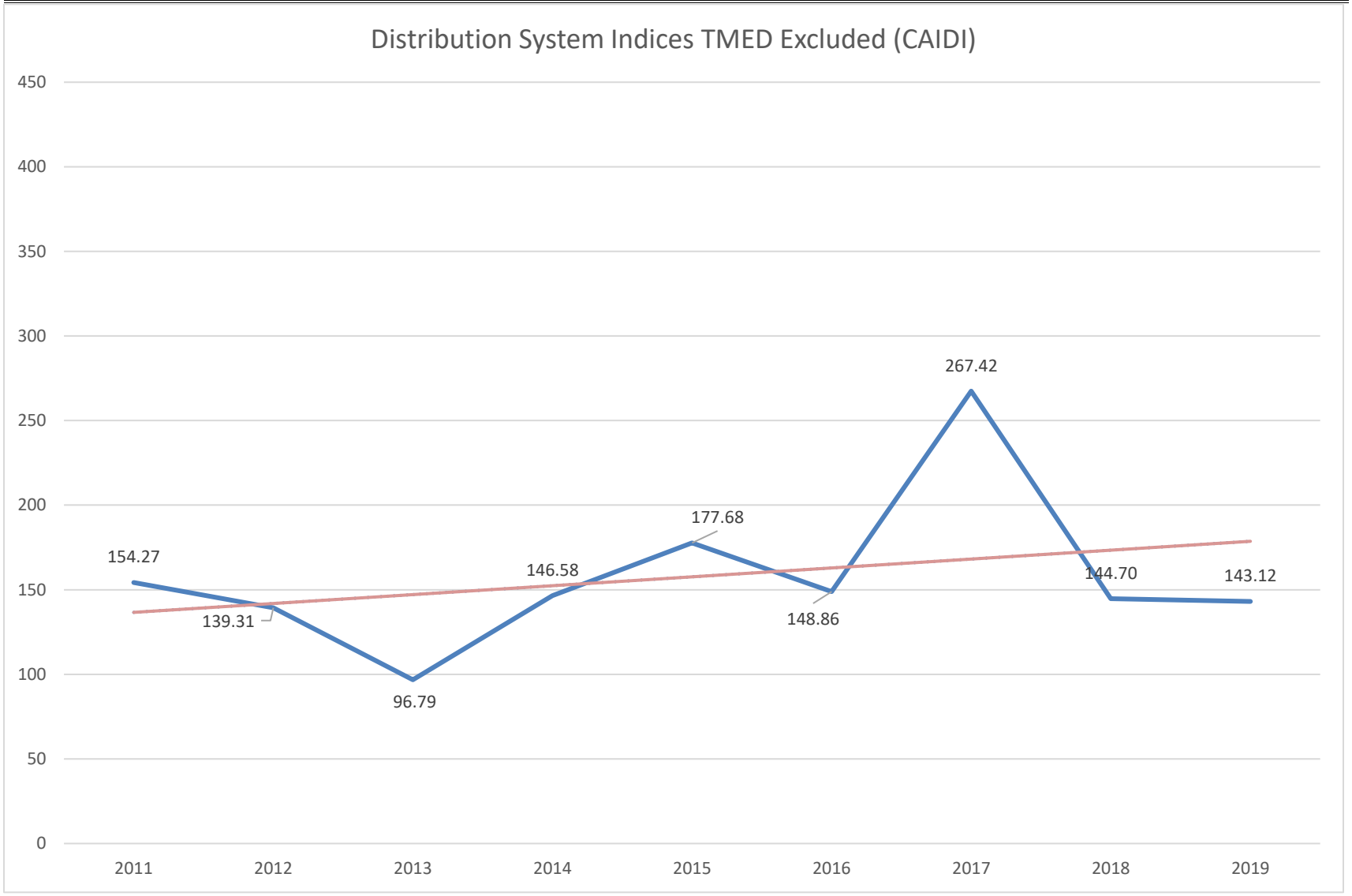

Distribution System Indices TMED Included (SAIFI)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.48
4.01
2.27
3.01
2011
2012
2013
2014
2015
2016
2017
2018
2019

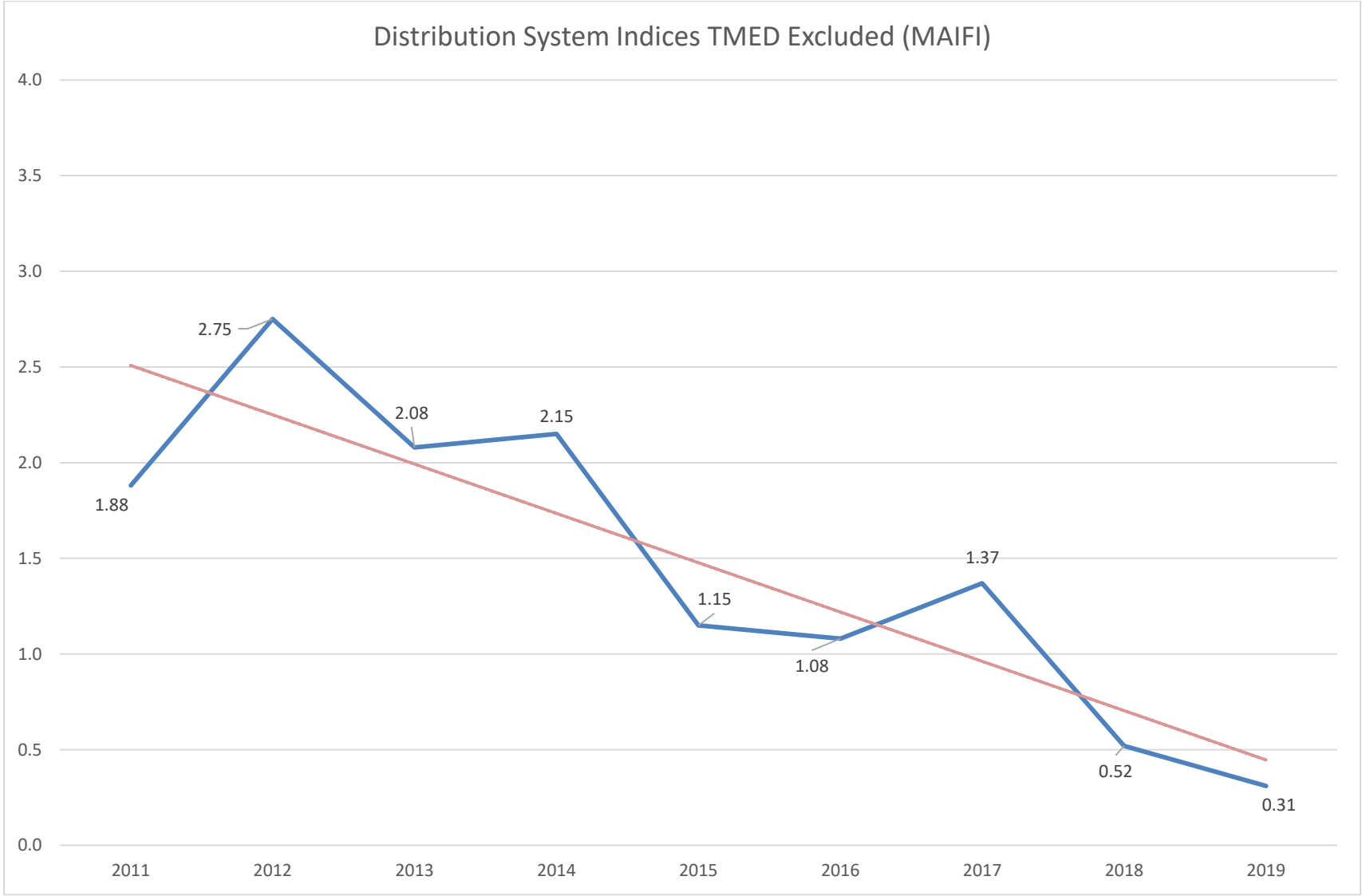

Distribution System Indices TMED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
148.86
398.65
144.70
143.12
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
219.94
772.84
328.48
430.78
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.48
2.89
2.27
3.01
2011
2012
2013
2014
2015
2016
2017
2018
2019

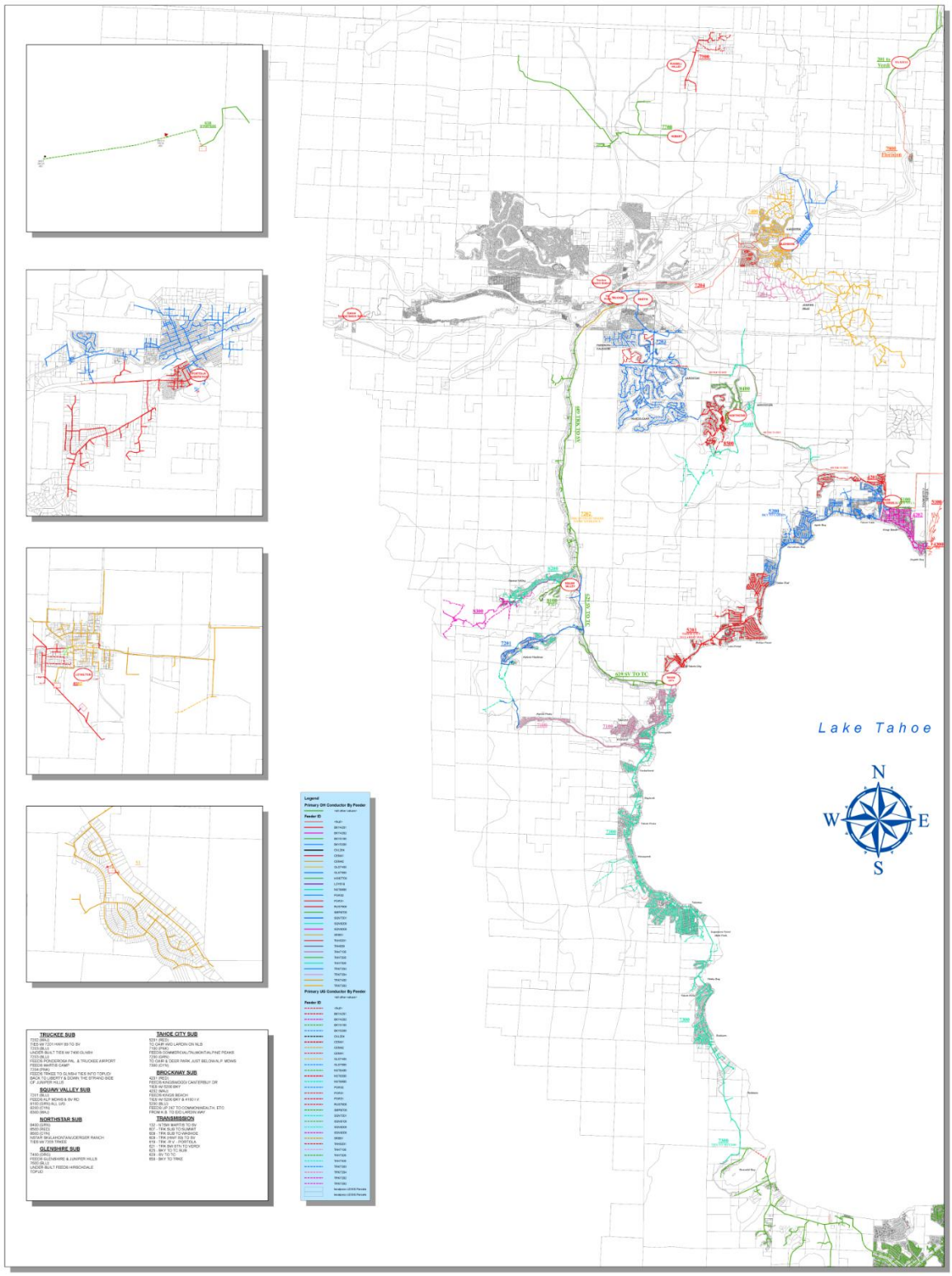

Distribution System Indices TMED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
148.86
267.42
144.70
143.12
2011
2012
2013
2014
2015
2016
2017
2018
2019


Distribution System Indices TMED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019

b. The number, date, and location of planned outages

Circuit	Number of Planned Outages By Year								
	2019	2018	2017	2016	2015	2014	2013	2012	2011
31		1			1				
32	1		2	1					
41				1					
201		7					1		
204	2			1					
619								1	
650					1			1	
1261	1	1							
1296		1	2		5	1			
2200	1				1	1			
2300	1	1			1	2		1	
3100	8	5	1					1	1
3101	3					2	2		
3200	3	5			1			1	
3300	8	10	2		3			2	
3400	2	4	3		5		2	4	
3500	15		6		1				
3501	3	3			2	2	4	1	1
4201	1	1		1					
4202	5	3	4				2	5	1
5100							1	1	
5200	5	4	1		4	1	1	3	
5201	8	1	5	5	4	1		1	
7100	1	2	1			1	1	4	
7200	1	1			1	1	1	2	
7201	1		4	1	2	1			
7202	3	1	1		2	3	1		
7203	3	2			2	2	4		
7300	20	14	5	6	4	16	4	5	2
7400	4	8	2	1	1				1
7600	1	1			1				1
7700						1			
7800						2			
7900	1								
8200	1	2	7	3	2	4			1
8300	1	1	2		6			2	
8400		7							
8500				1			1	2	
8600					4			2	

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	749	Topaz	70.9	76.2%	23.8%	7	3040	7.12
201*	Tahoe	64	Washoe	8.7	99.8%	0.20%	4	2931	7.83

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1261 circuit was noted as a deficient circuit in 2018 as well as 2019. The 3 year average circuit SAIDI score remains high due to significant outages in 2017 from wildfire and severe winter storms and an outage on March 22, 2019 which lasted approx. 58hrs. If the March 22nd, 2019 outage is excluded from the data, the Topaz 1261 circuit would not have been considered a deficient circuit in 2019.

There were 25 unplanned outages in 2019 for the 1261 circuit, 3 were due to a loss of source from a third party owned substation, 6 were due to equipment/hardware failure, 3 were weather related, 1 was due to trees,1 was due to an operations error and the rest were unknown.

The historical metric for Topaz 1261:

- 2019 – 3,040.6
- 2018 – 2,393.8
- 2017 – 3,004.5
- 2016 – 1930.4

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada. Approximately 10,000ft of this line will be will be rebuilt in 2020.

The circuit performance in 2019 was higher than historical records, excluding 2017. The 2017 performance is an outlier and does not accurately reflect the condition of this circuit. Liberty expects this circuit will no longer be a deficient

circuit no later than 2021 when the 2017 data is removed from the average and the planned rebuild is complete in 2020.

The Washoe 201 circuit was noted as a deficient circuit in 2017, 2018 as well as 2019. The 3 year average circuit SAIDI score remains high due to significant outages in 2017 from wildfire and severe winter storms.

There were only 5 unplanned outages in 2019 for the 201 circuit, 4 were due to a loss of source from a third party owned substation and the 5th time the substation was de-energized due to a brush.

The historical metric for Washoe 201:

- 2019 – 2931.6
- 2018 – 2,722.9
- 2017 – 2,698.9
- 2016 – 269.2

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line in difficult terrain, sourced by an NV Energy substation in Nevada. The line has been rebuilt in 2014 and Liberty completed a voltage conversion in 2018 so that the entire circuit is now 24.9kV.

The circuit performance in 2019 was similar to historical records, excluding 2017. The 2017 performance is an outlier and does not accurately reflect the condition of this circuit. Liberty expects this circuit will no longer be a deficient circuit no later than 2020 when the 2017 data is removed from the average.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Vice President of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	10/1/2019	Third Party - Contractor Dig In	Lake Tahoe	10490	51.79	0.22223
2	2/22/2019	Equipment Failure	Lake Tahoe	8560	35.36	0.1814
3	10/3/2019	Third Party - Contractor Dig In	Lake Tahoe	7841	1.83	0.1661
4	2/26/2019	Hardware Failure	Lake Tahoe	4485	19.96	0.0950
5	1/18/2019	Tree	Lake Tahoe	4448	8.93	0.0942
6	3/6/2019	Hardware Failure	Lake Tahoe	4448	4.62	0.0942
7	11/11/2019	Animal	Lake Tahoe	4245	3.24	0.0899
8	9/21/2019	Third Party – Line Contact	Lake Tahoe	3712	2.05	0.0786
9	6/7/2019	Animal	Lake Tahoe	3529	2.09	0.0748
10	6/7/2019	Tree	Lake Tahoe	3507	6.76	0.0743

*Based on customer impact

7) Summary list of 2019 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2018 = 171.00

CalPeco Electric did not experience an event in 2019 where the daily SAIDI was higher than the calculated TMED.

8) Historical 10 largest unplanned outage events for the past 8 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1411.38	No
4	Hardware Failure	2/26/2019	4,485	3.5	15697.5	No
5	Tree	1/18/2019	4,448	1.76	7828.48	No
6	Hardware Failure	3/6/2019	4,448	0.82	3647.36	No
7	Animal	11/11/2019	4,245	0.6	2547	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1596.16	No
9	Animal	6/7/2019	3,529	0.47	1658.63	No
10	Tree	6/7/2019	3,507	1.51	5295.57	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	.067	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

9) Number of customer inquiries on reliability data and the number of days per response

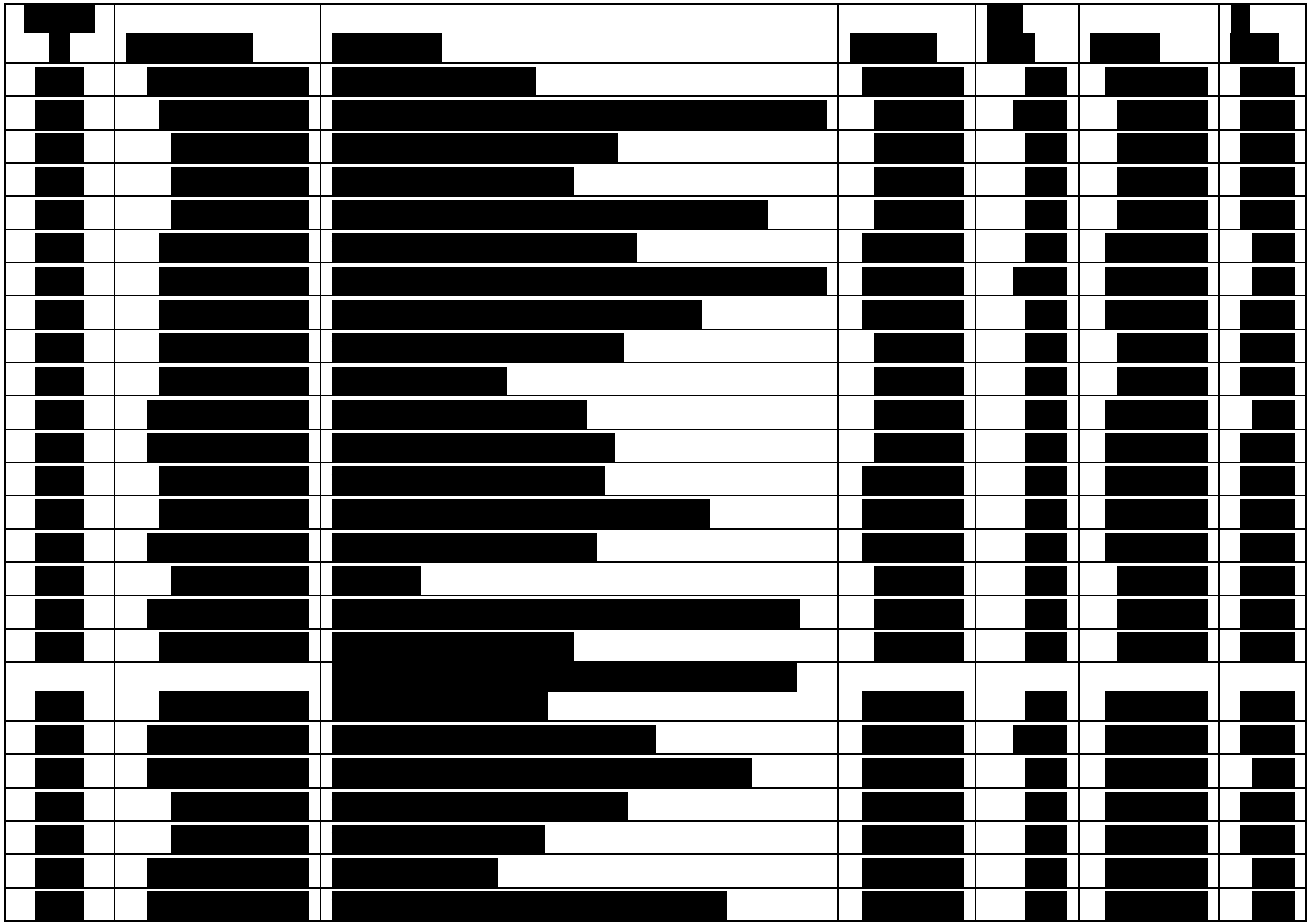
CalPeco Electric did not receive any reliability inquiries in 2019.

Date Received	Date Responded	Description of Inquiry

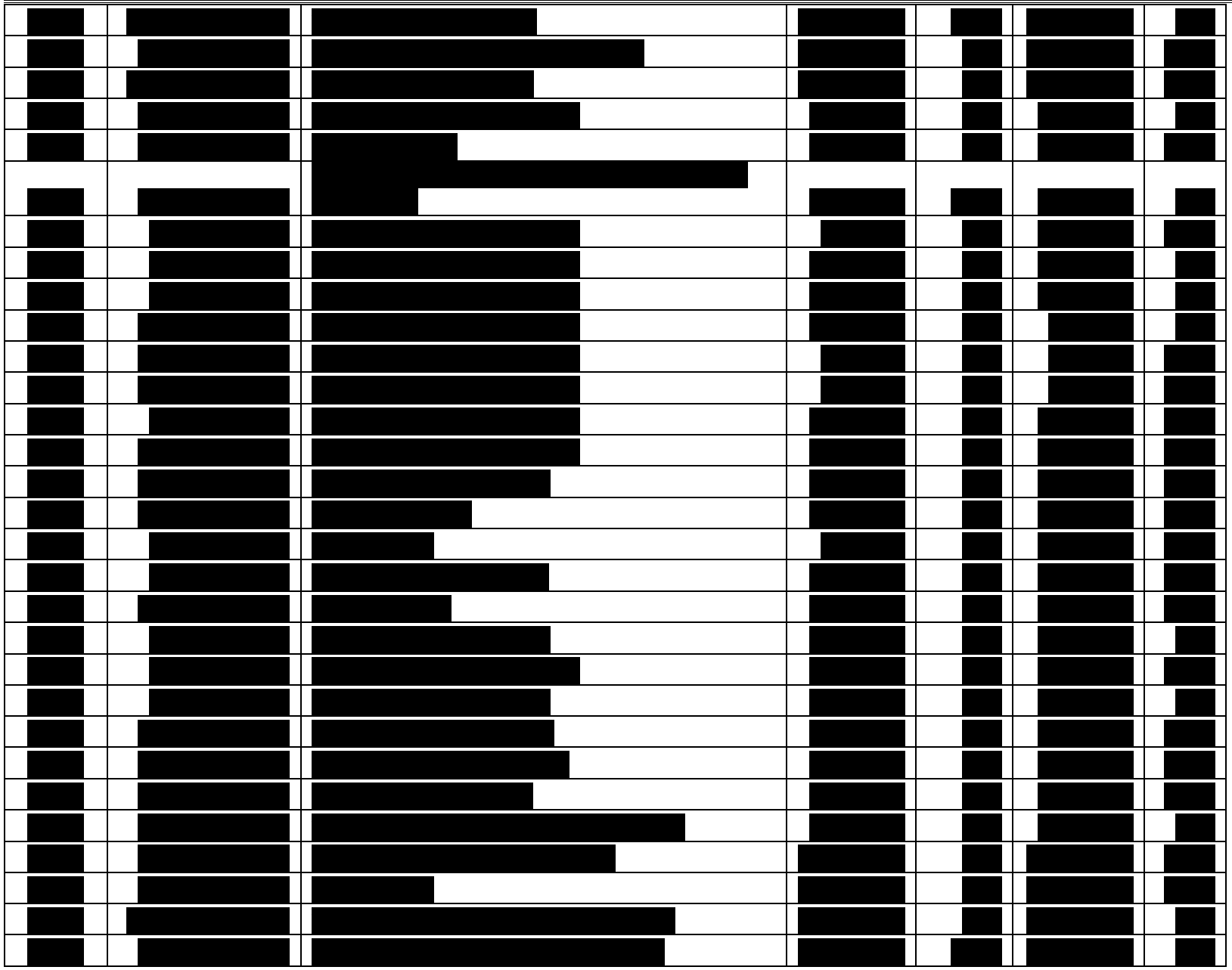
10) List of PSPS's in 2019

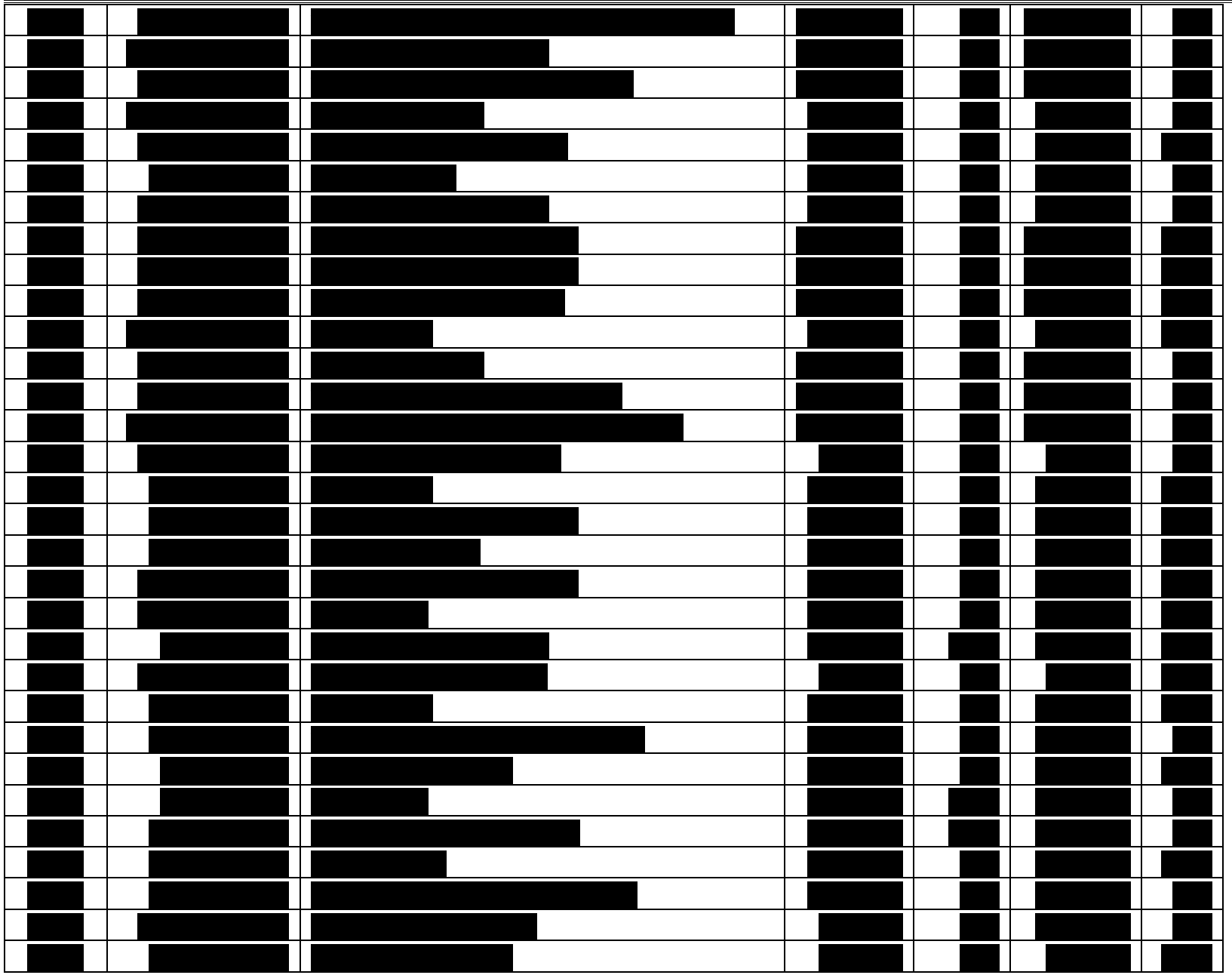
CalPeco Electric did not have any PSPS events in 2019.

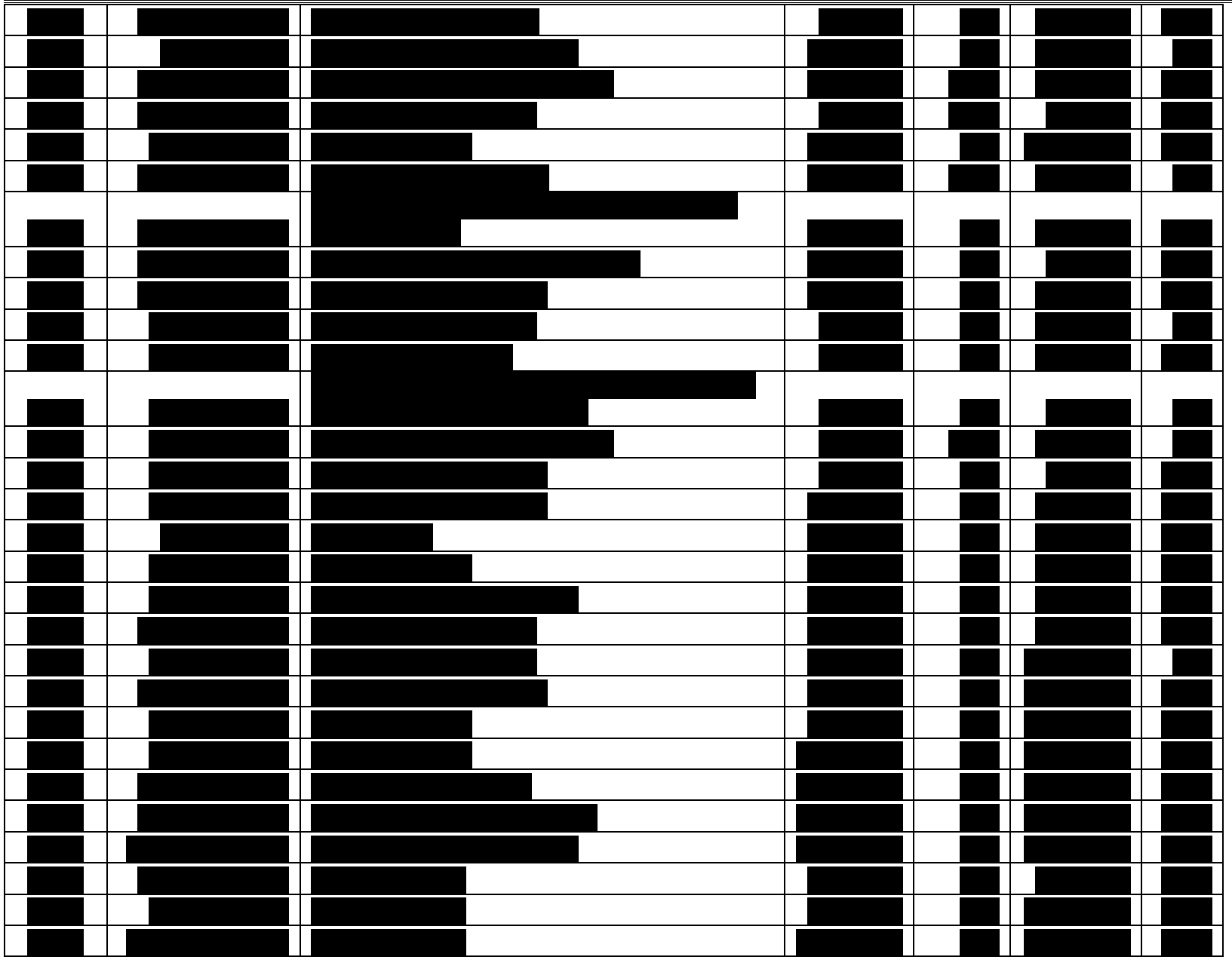
Appendix A: 8 Years of Planned Outage Data -- PUBLIC VERSION --



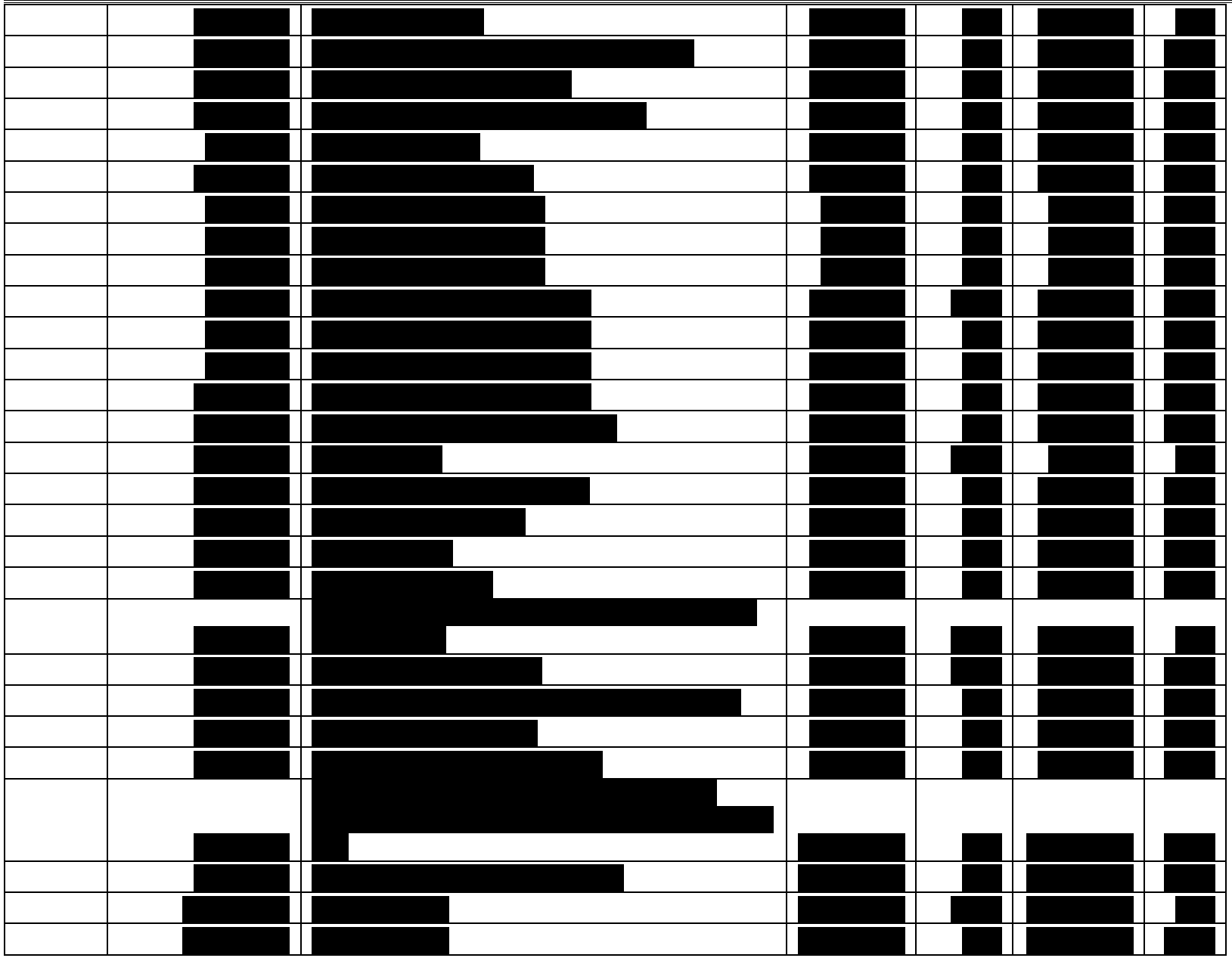










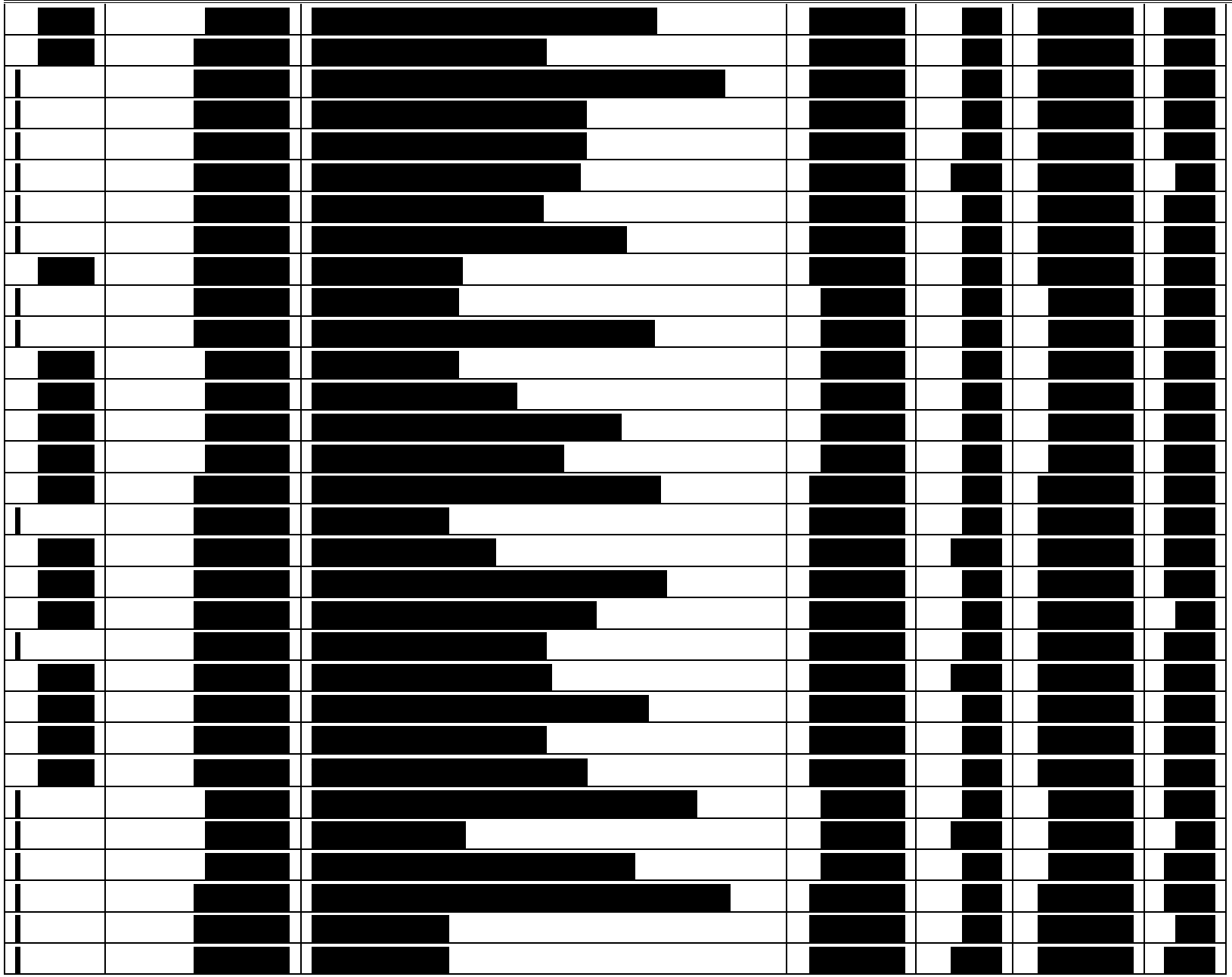


















ATTACHMENT 13

Liberty Utilities 2020 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2020

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15, 2021

CA-07-0728

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2020 has been prepared in response to CPUC Decision 16-01-008, which established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC ("Liberty").

Liberty does not provide transmission services and does not have an Open Access Transmission Tariff (OATT). Therefore, data is presented for distribution services only. All statistics and calculations include forced distribution outages. Forced distribution outages are those that are not pre-arranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

Outages are tracked/recorded using the Responder OMS system and supplemented with dispatch emails when an incident is not logged. Dispatch is notified of outages from customer calls, device alarms, line crew, or another third party. An incident ID# is created and a troubleman will go investigate the nature of the incident. If it is a customer issue, the customer is told to contact an electrician. If the incident is an outage, efforts are made to restore customers in a timely manner. Once restored the incident ID is closed with the time of restoration and saved in Responder Archive.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.

2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.

3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.

4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

Liberty presents ten years (2011- 2020) of data, which represents the period in which Liberty Utilities has owned the utility.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days ("MED") instead of CPUC Major Events. An IEEE MED is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as "TMED". Thus, any day in which the total system SAIDI exceeds TMED is excluded from Liberty's reliability results. The applicable TMED value is calculated at the end of each year using Liberty's daily SAIDI values for the prior five years. Liberty's TMED value for 2020 was 189.04 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 10 Years

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

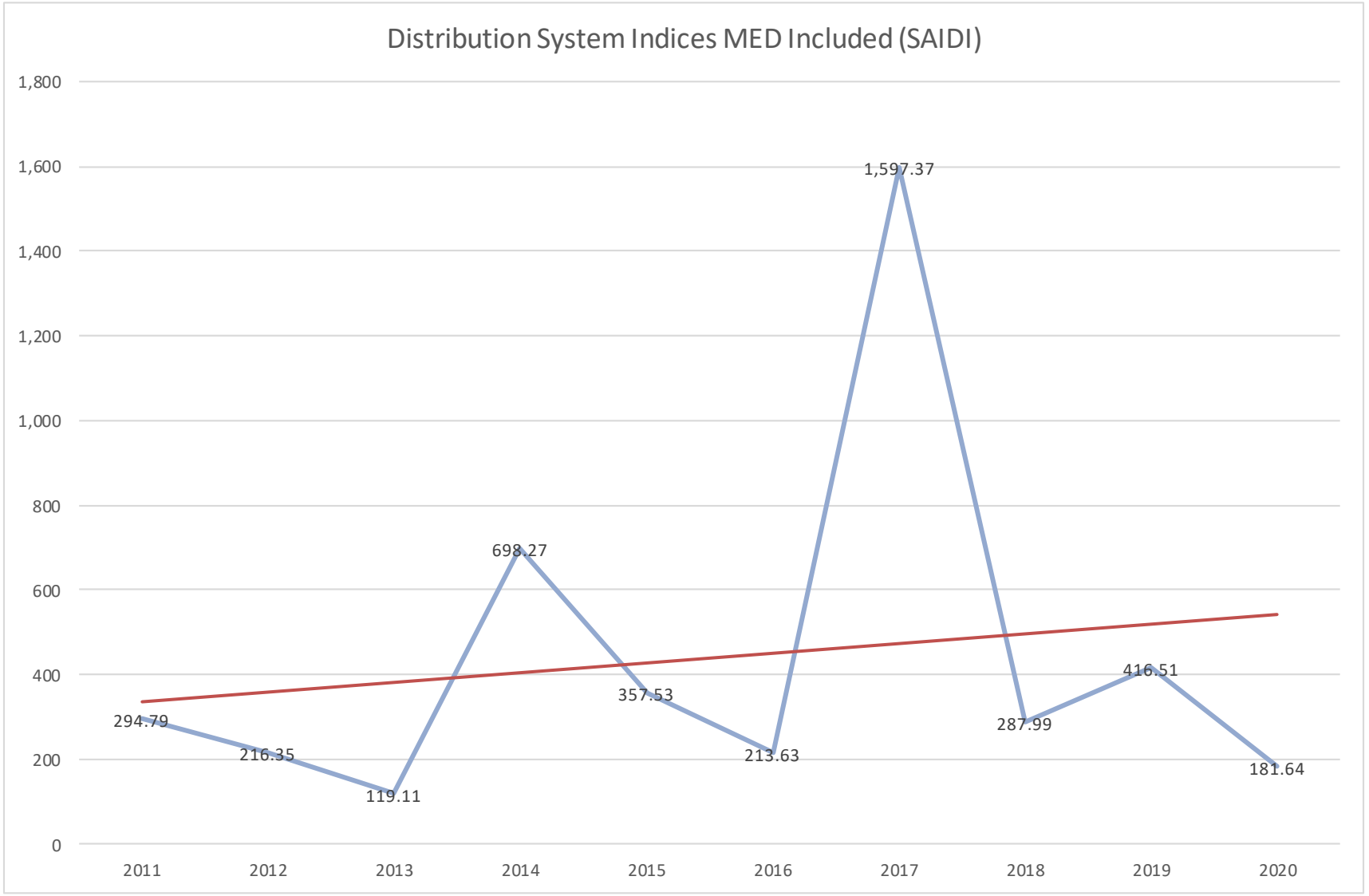
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 10 Years (Years in Business)

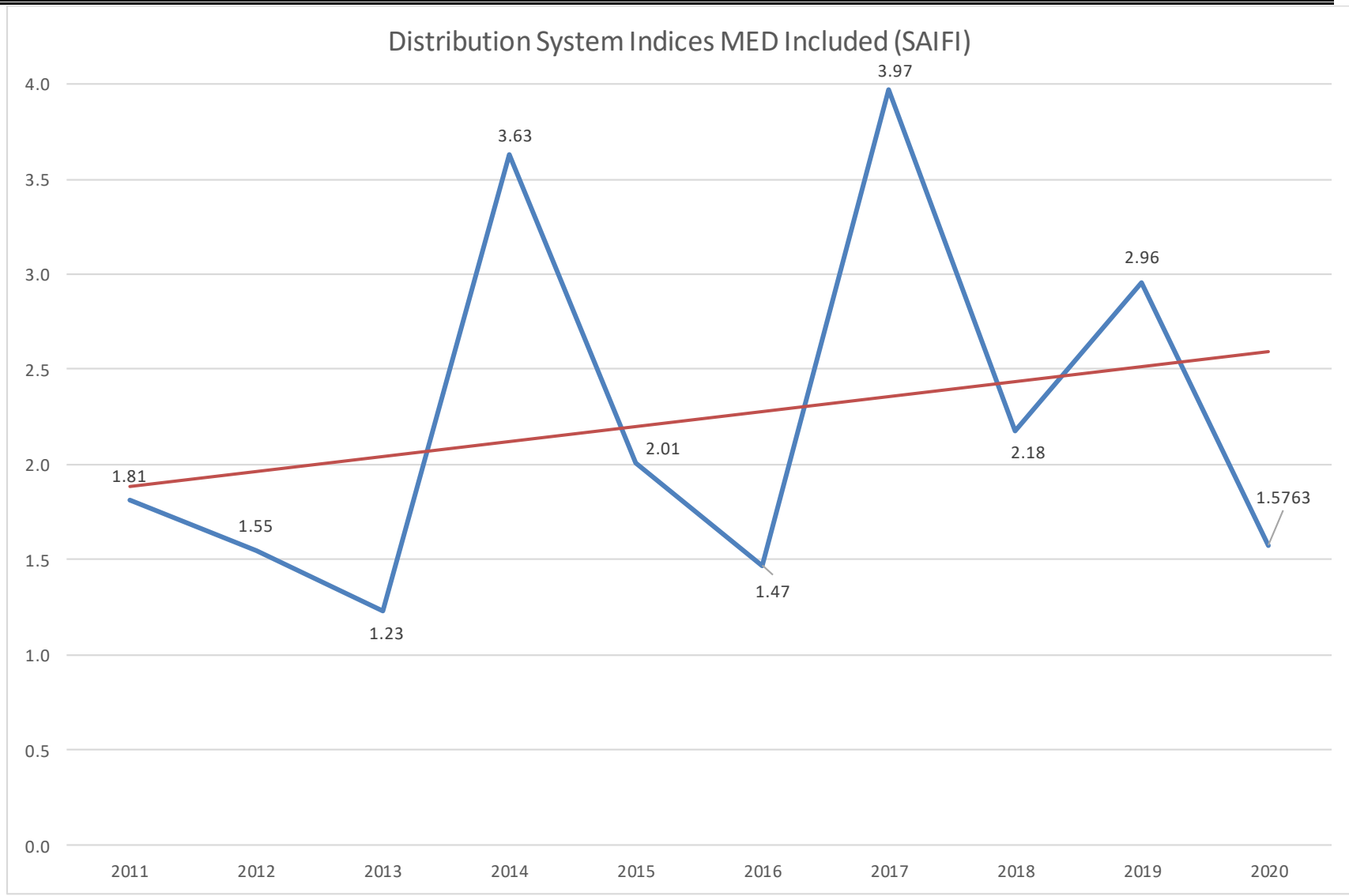
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2020	181.64	1.57	115.23	0.313	181.64	1.57	115.23	0.313
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1,597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

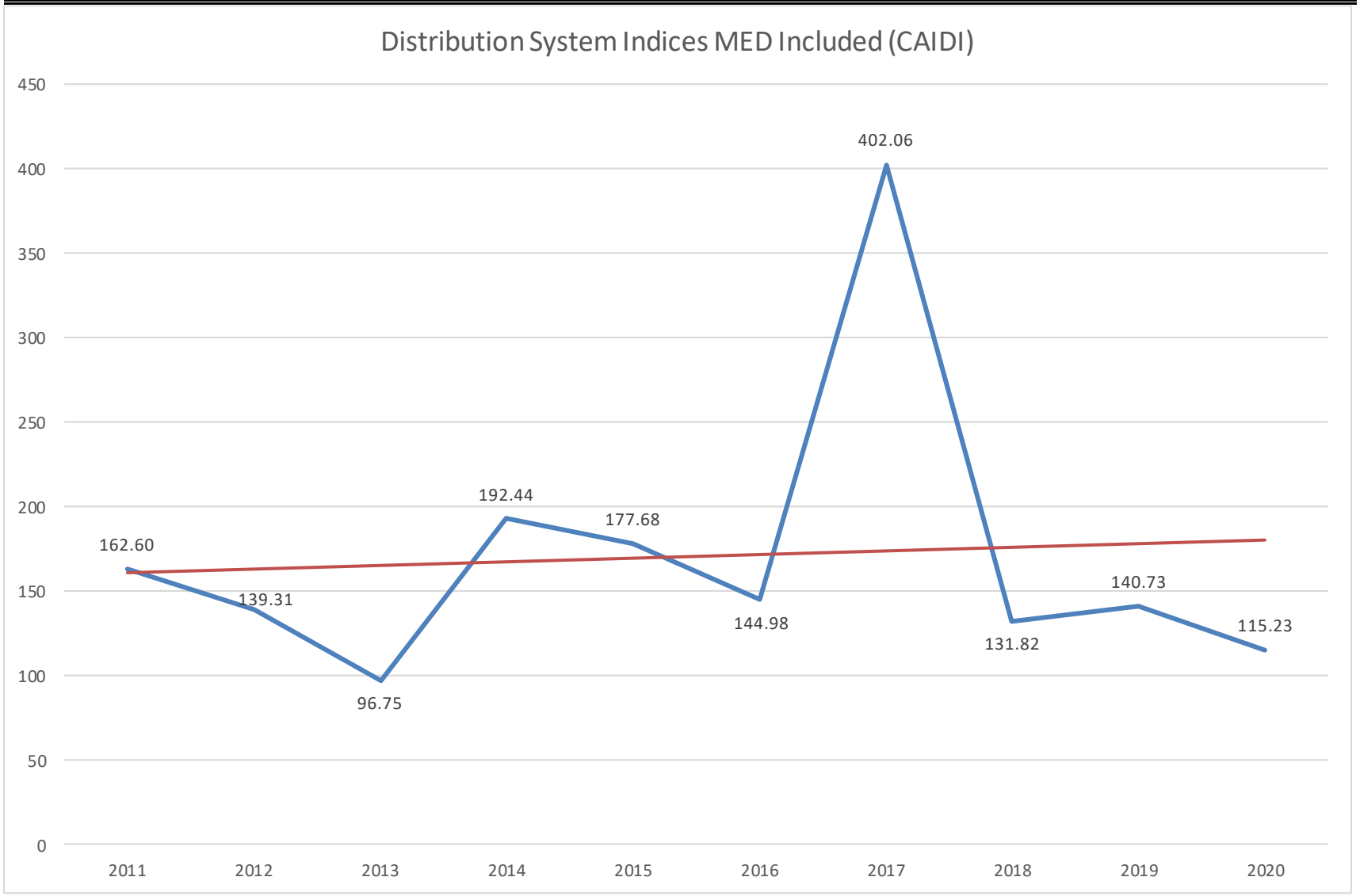
II. Transmission System Indices (MED Included and Excluded)

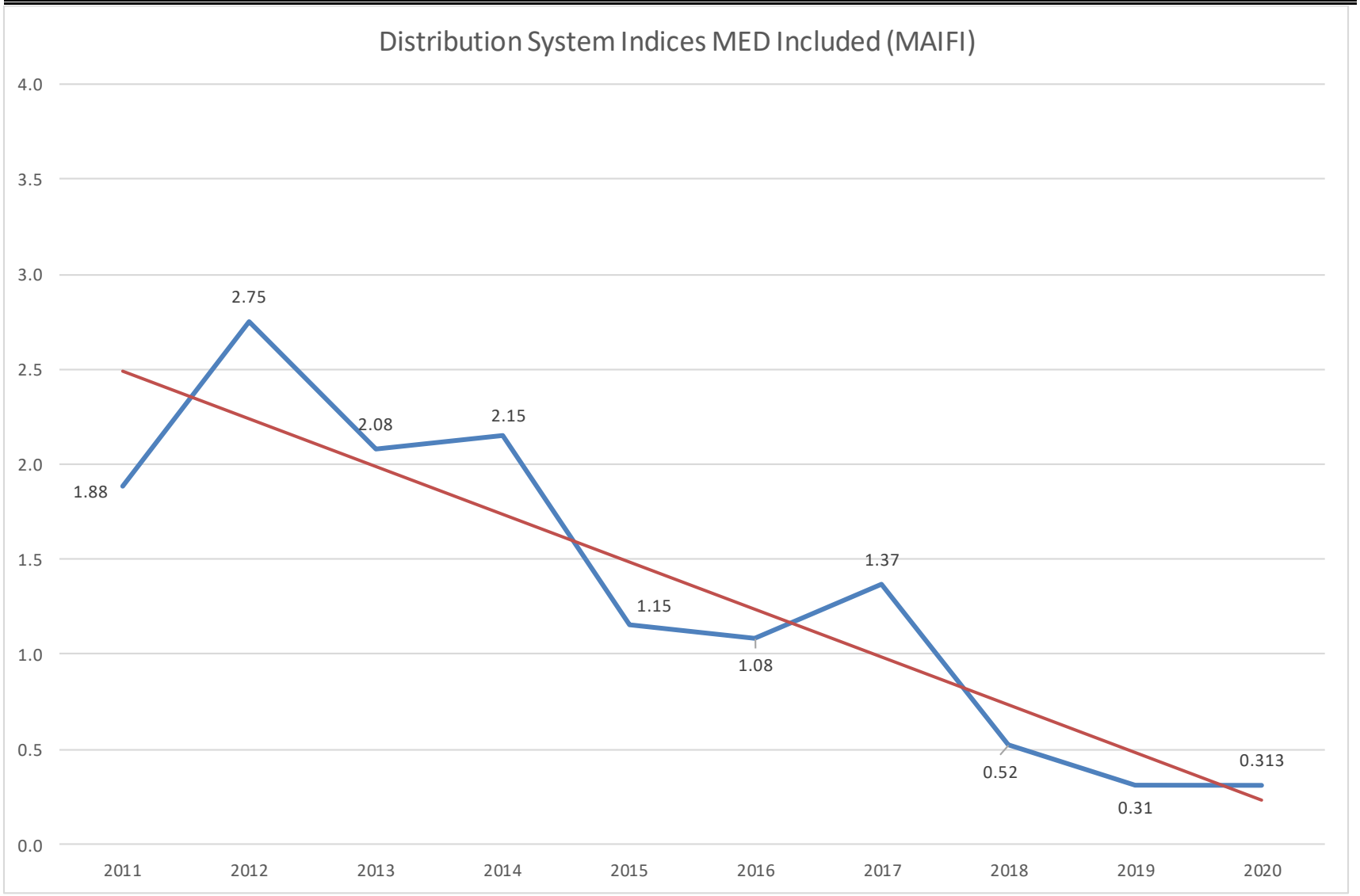
Liberty does not own Transmission.

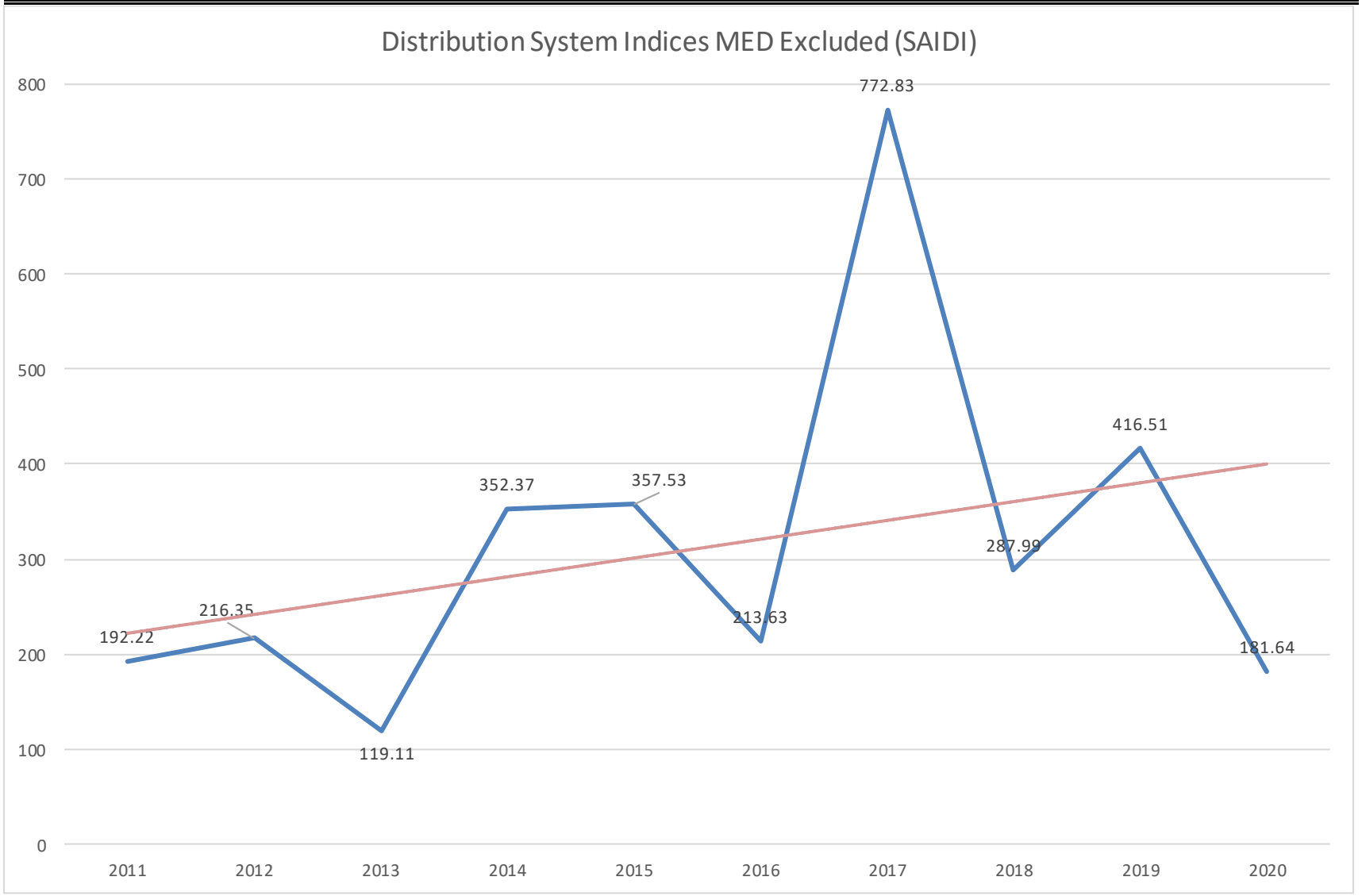
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 10 years (years in business) with linear trend line (TMED included and excluded).

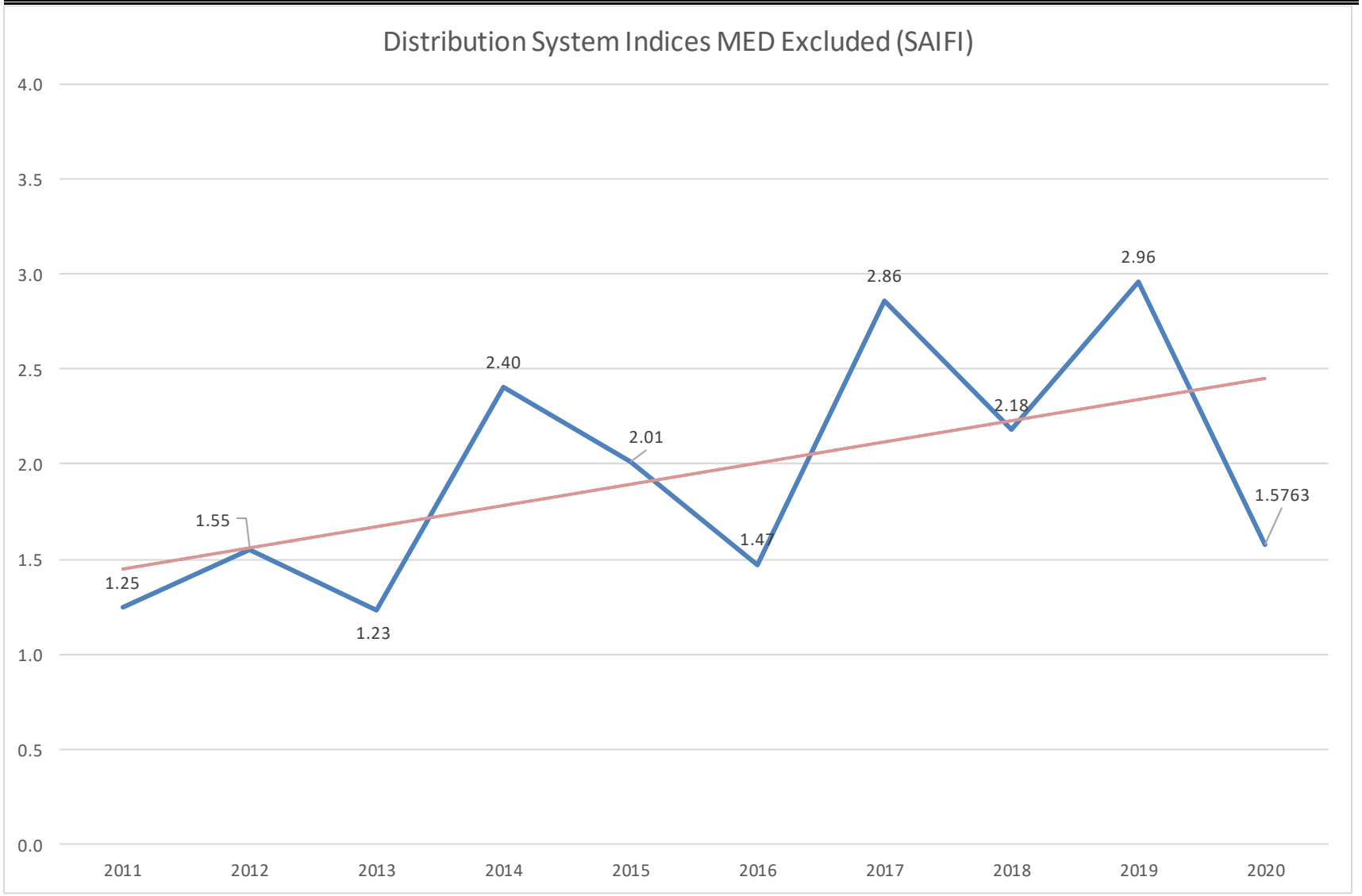

Distribution System Indices MED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
213.63
1,597.37
287.99
416.51
181.64
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

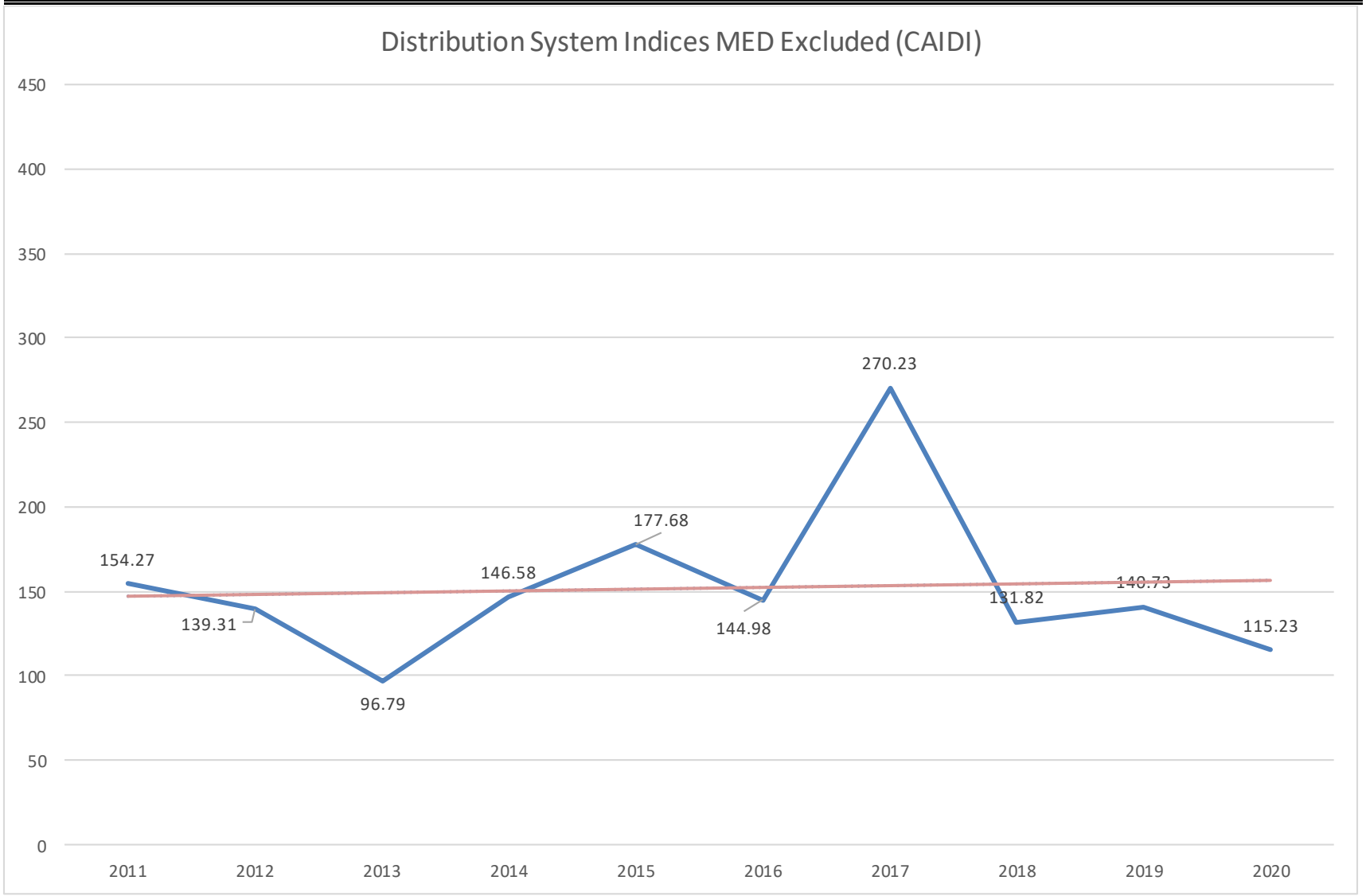

Distribution System Indices MED Included (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.47
3.97
2.18
2.96
1.5763
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

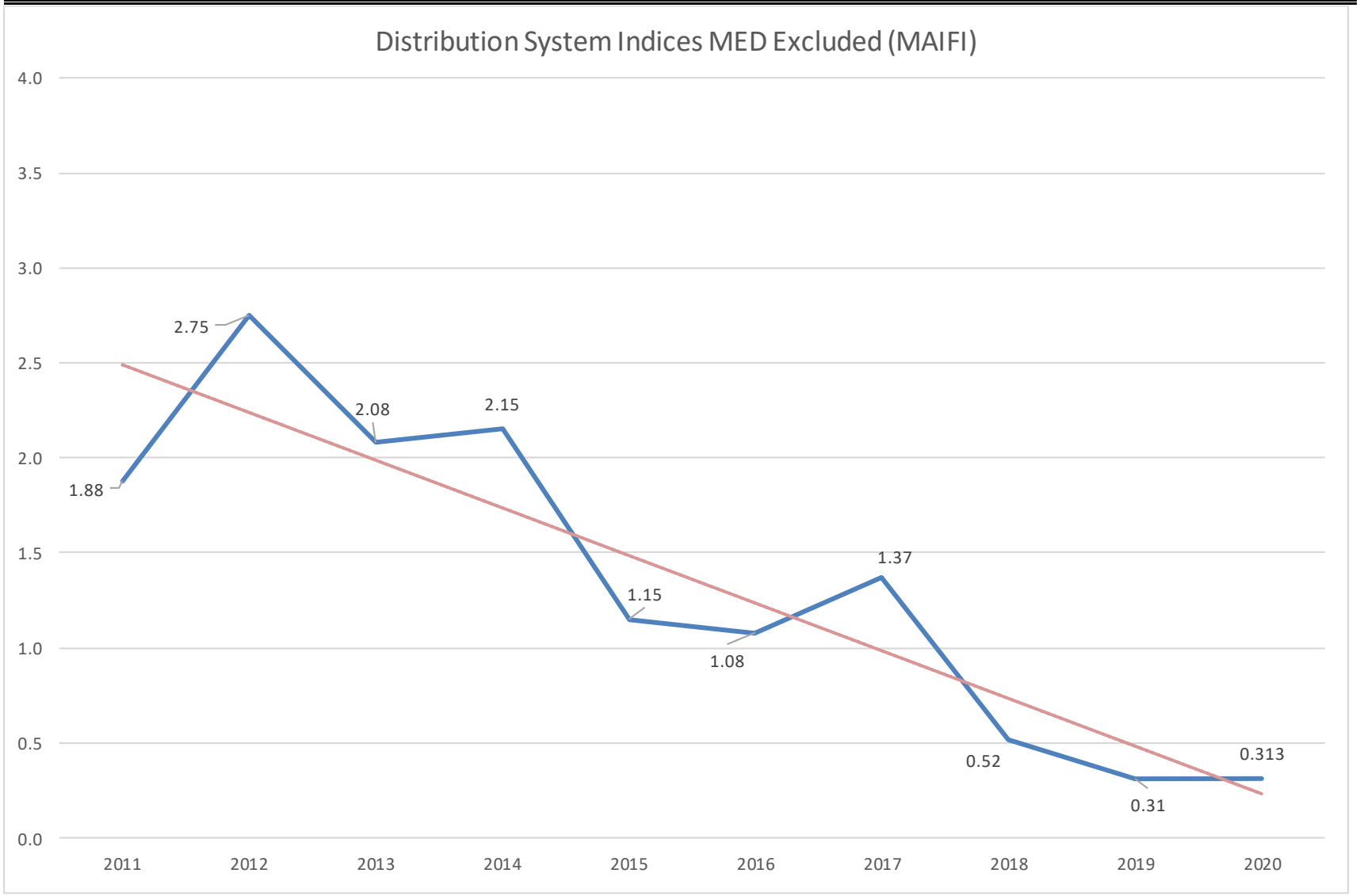

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
144.98
402.06
131.82
140.73
115.23
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.15
1.08
1.37
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
213.63
772.83
287.99
416.51
181.64
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.47
2.86
2.18
2.96
1.5763
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
144.98
270.23
131.82
140.73
115.23
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

2) Division (or District) Reliability Indices for the past 10 years

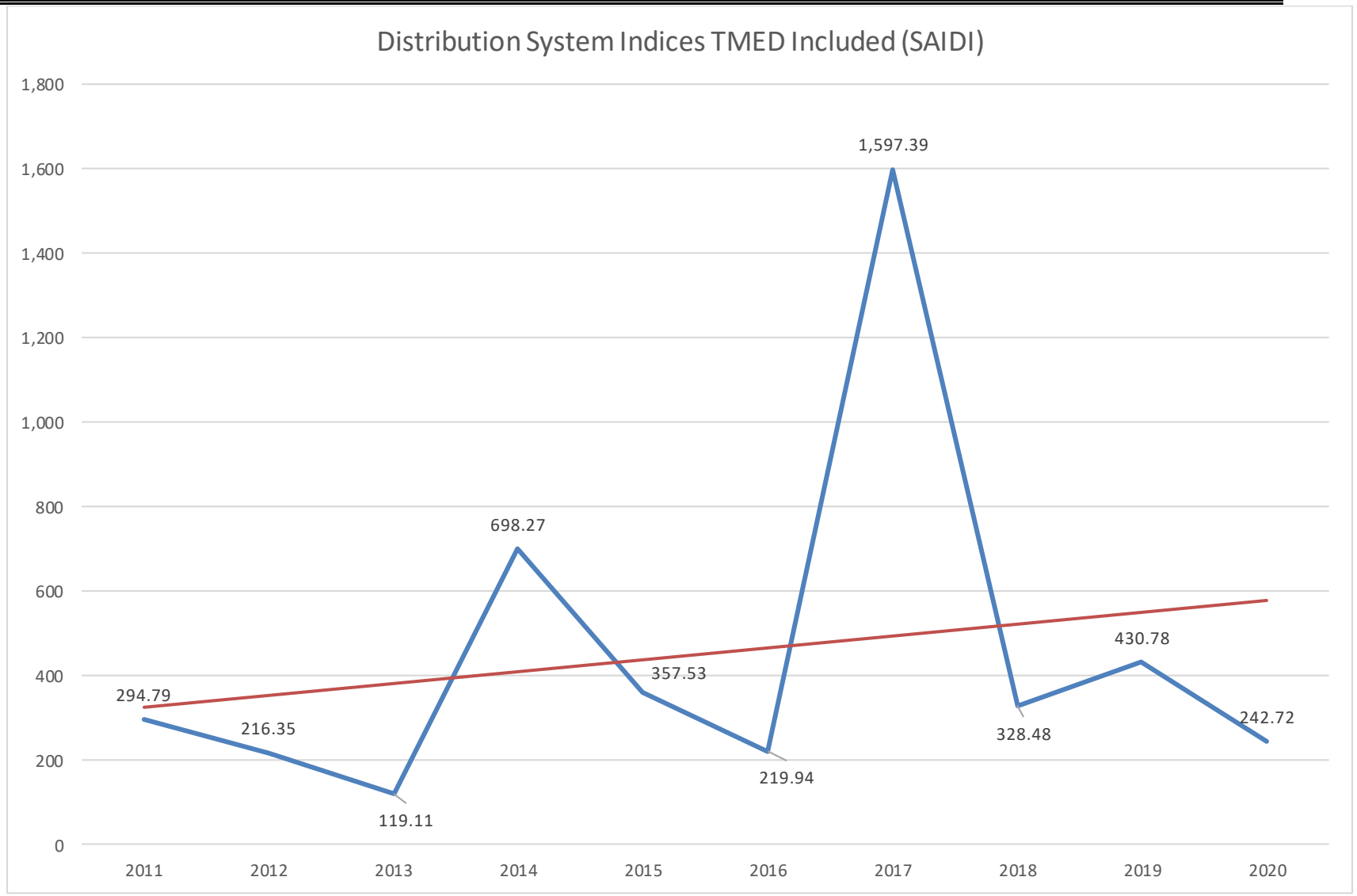
Liberty has one division, Lake Tahoe. See section 1 for indices.

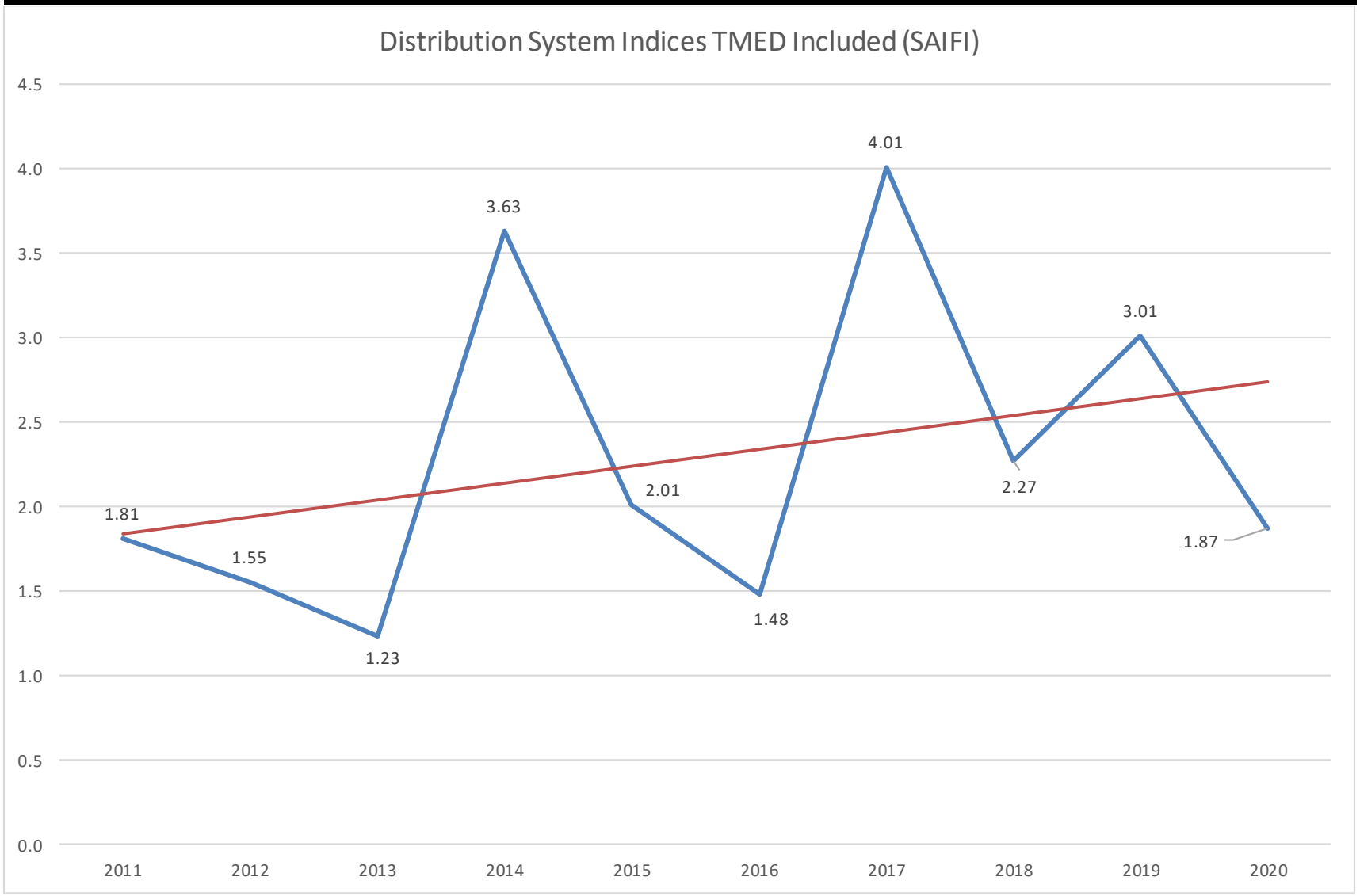
3) System and Division indices based on IEEE 1366 for the past 10 years including planned outages and including and excluding TMED

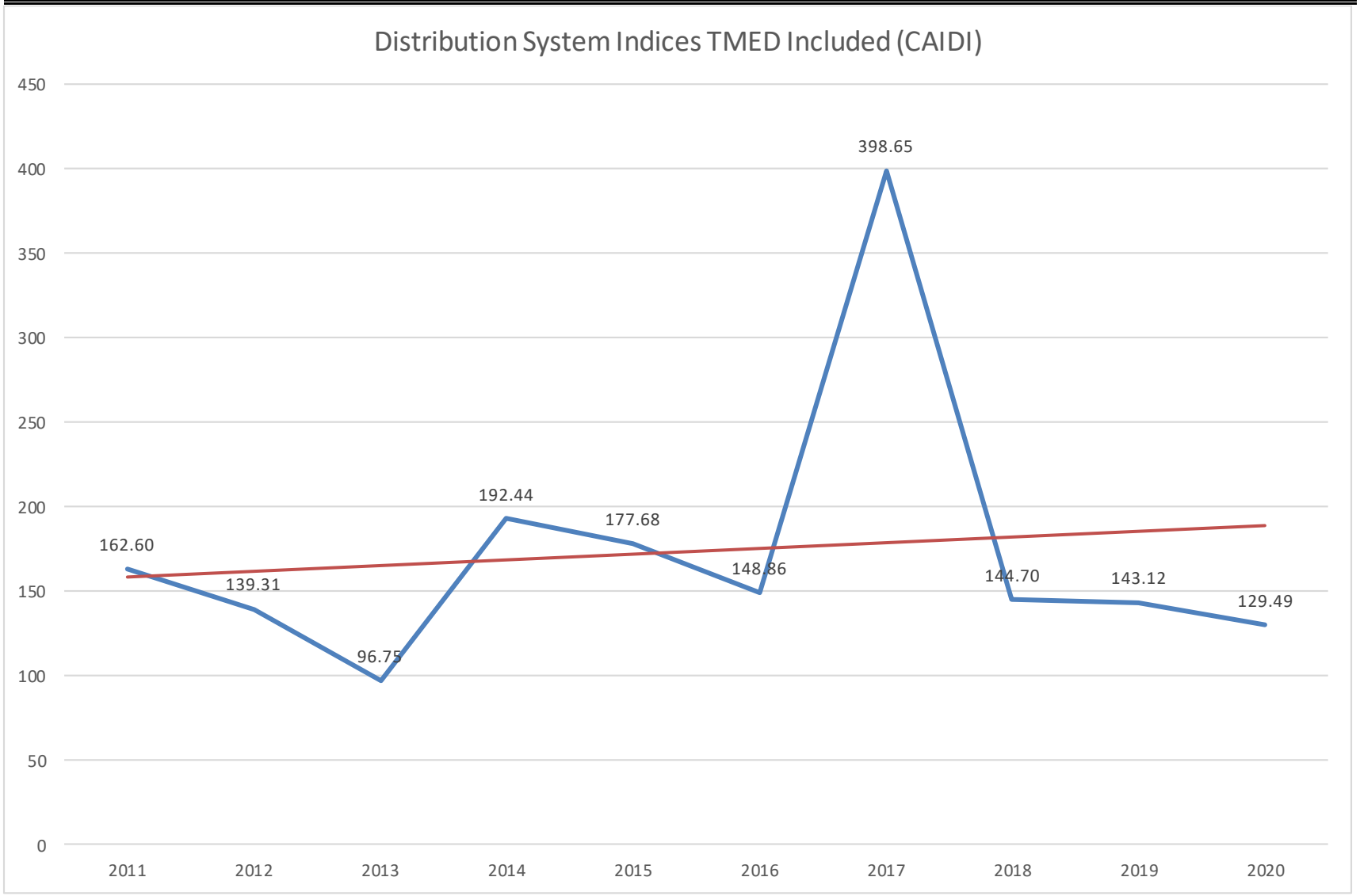
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

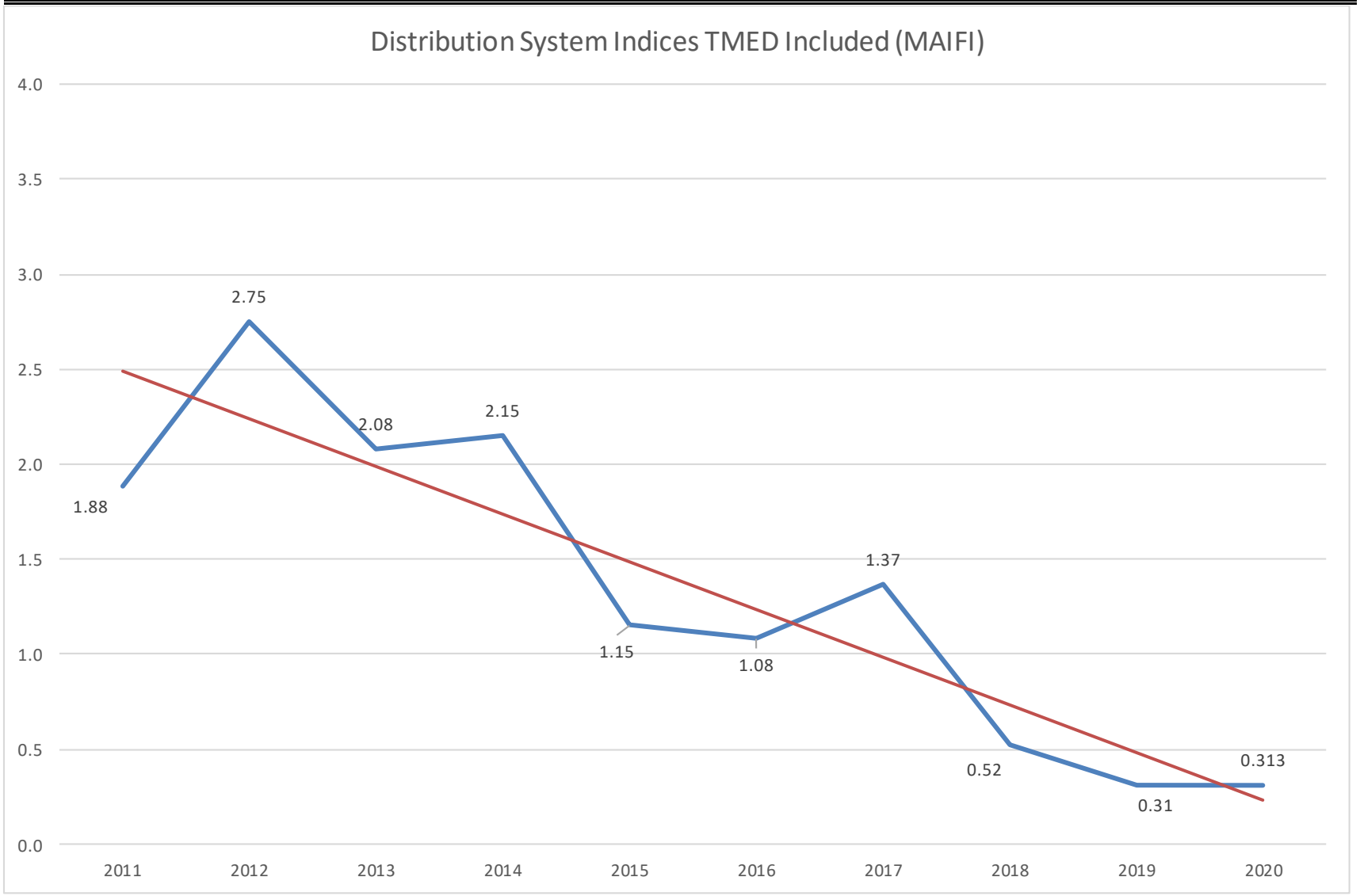
Liberty Utilities (CalPeco Electric), LLC
Distribution Historical System Reliability Data 10 Years (Years in Business)

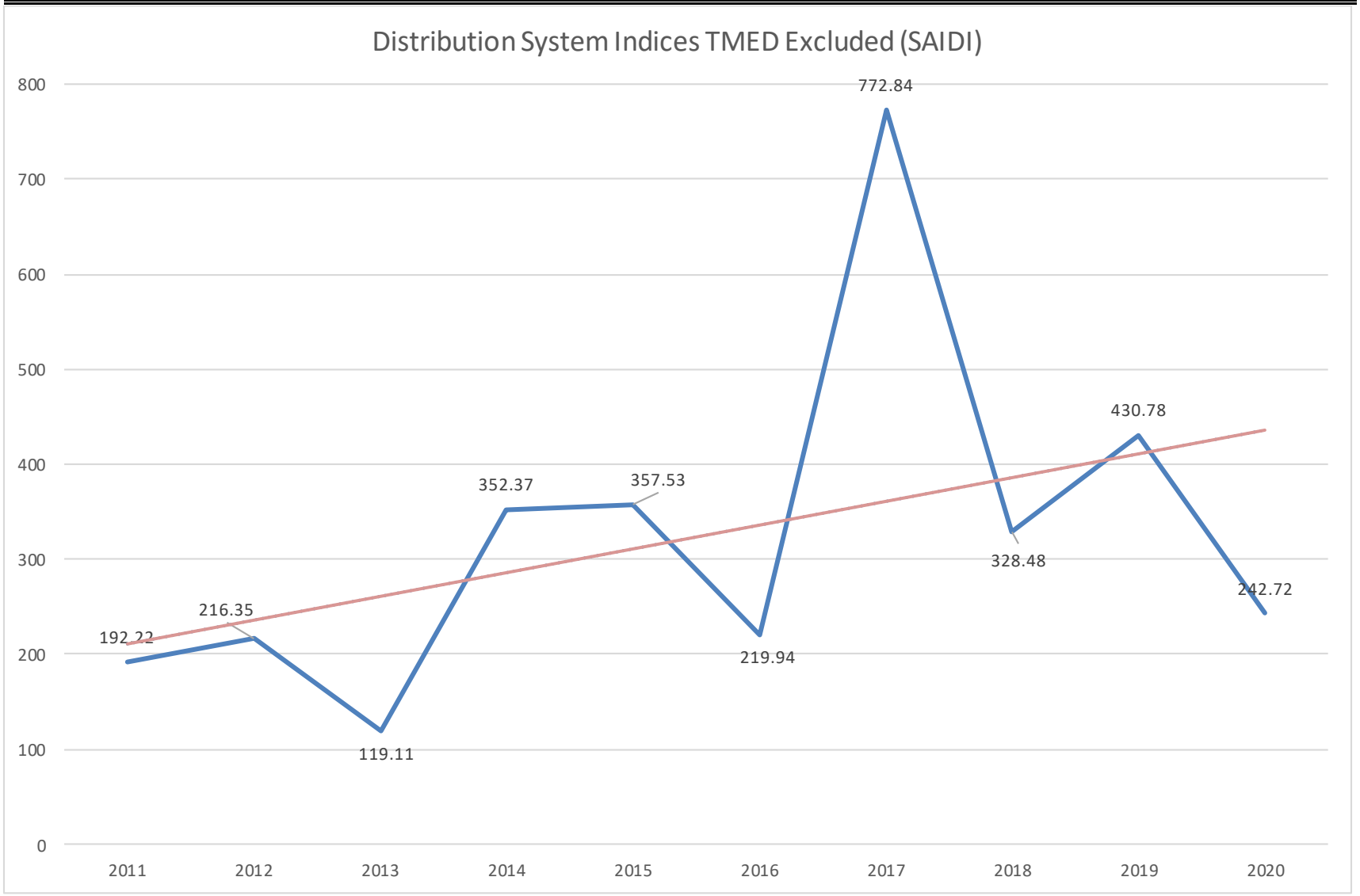
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2020	242.72	1.87	129.49	0.313	242.72	1.87	129.49	0.313
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.70	0.52	328.48	2.27	144.70	0.52
2017	1,597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.40	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75
2011	294.79	1.81	162.60	1.88	192.22	1.25	154.27	1.88

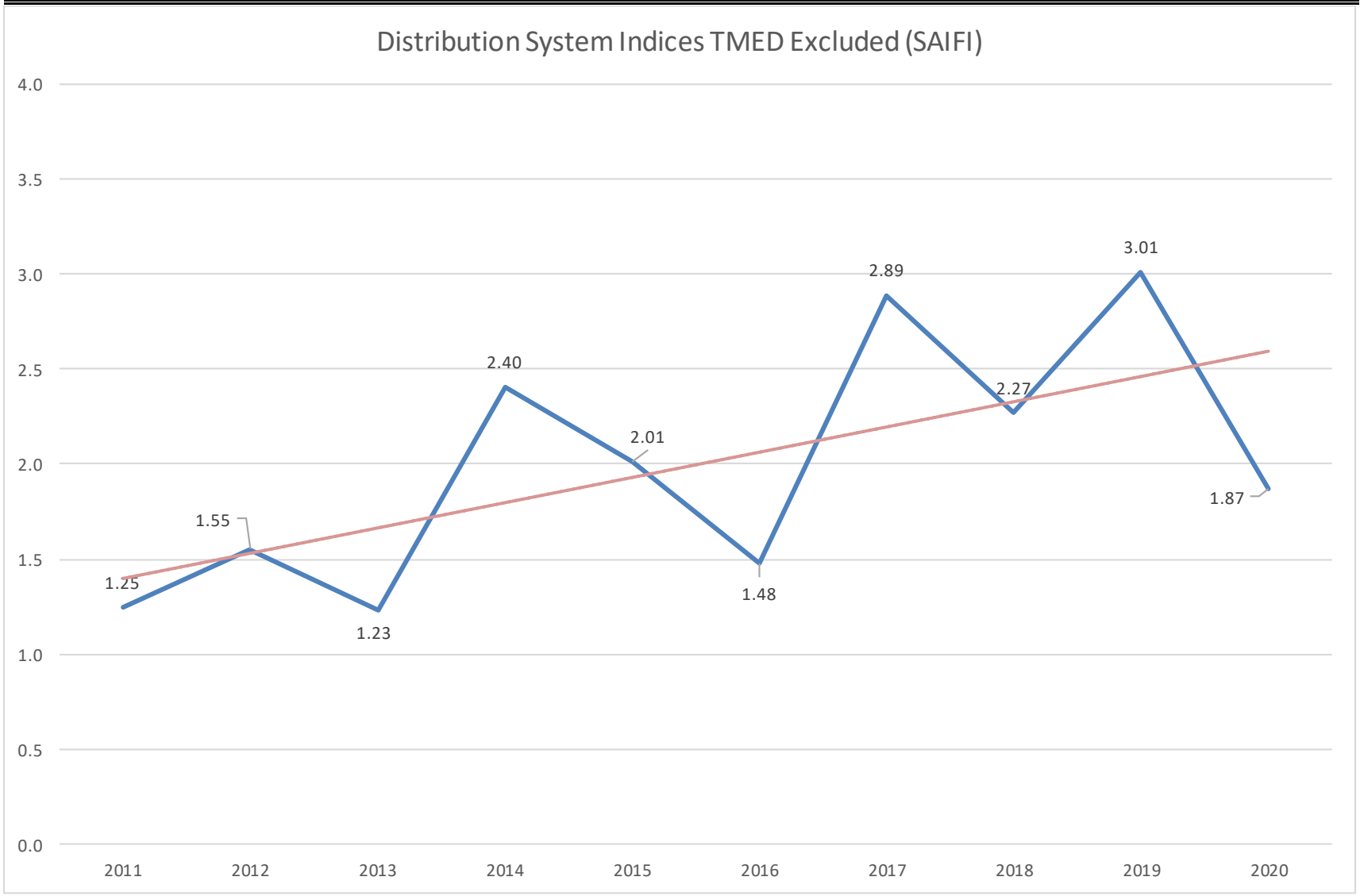

Distribution System Indices TMED Included (SAIDI)
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
294.79
216.35
119.11
698.27
357.53
219.94
1,597.39
328.48
430.78
242.72
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

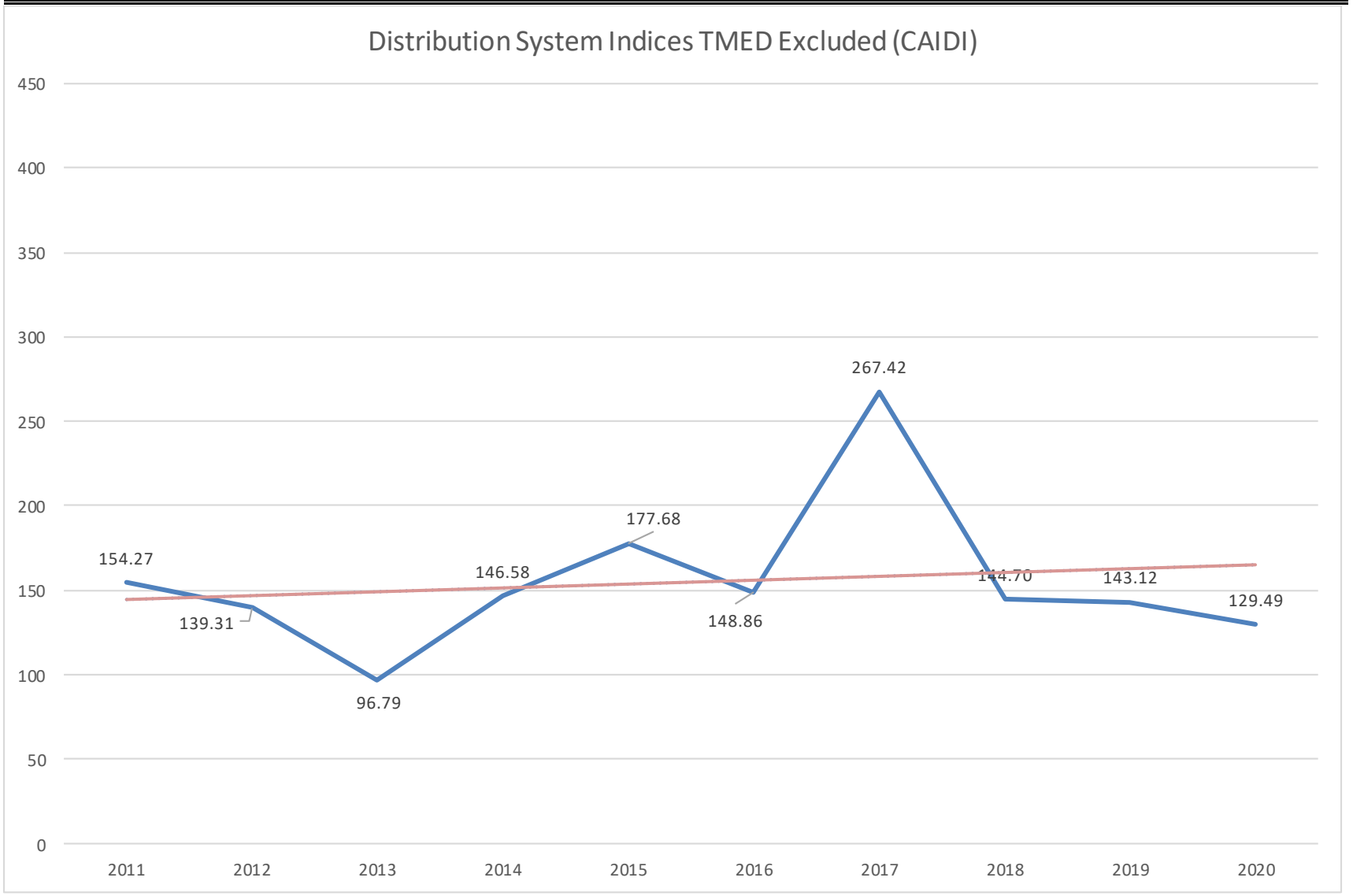

Distribution System Indices TMED Included (SAIFI)
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.81
1.55
1.23
3.63
2.01
1.48
4.01
2.27
3.01
1.87
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

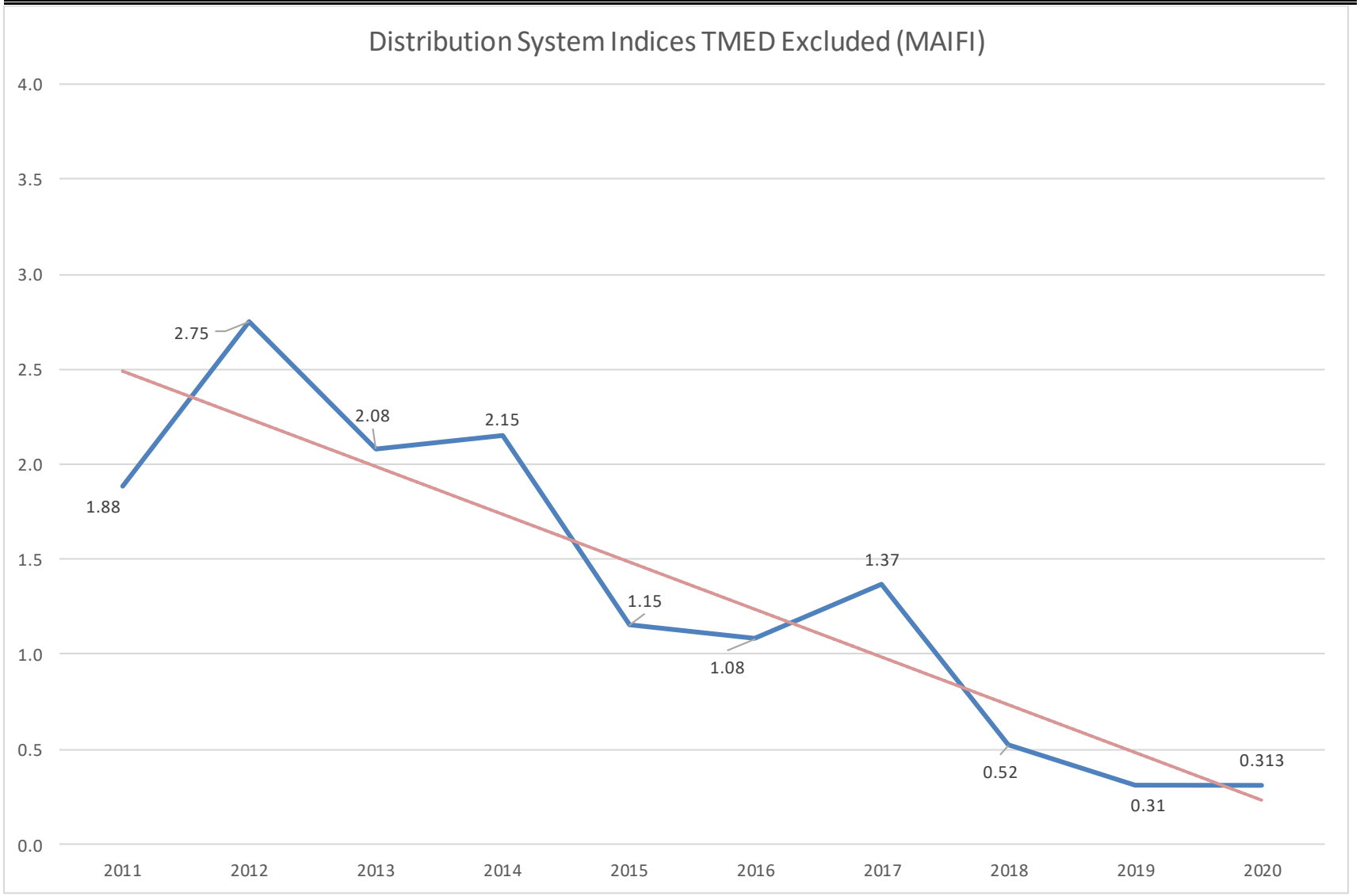

Distribution System Indices TMED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
162.60
139.31
96.75
192.44
177.68
148.86
398.65
144.70
143.12
129.49
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Excluded (SAIDI)
800
700
600
500
400
300
200
100
0
192.22
216.35
119.11
352.37
357.53
219.94
772.84
328.48
430.78
242.72
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Excluded (SAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.25
1.55
1.23
2.40
2.01
1.48
2.89
2.27
3.01
1.87
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020


Distribution System Indices TMED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
154.27
139.31
96.79
146.58
177.68
148.86
267.42
144.70
143.12
129.49
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

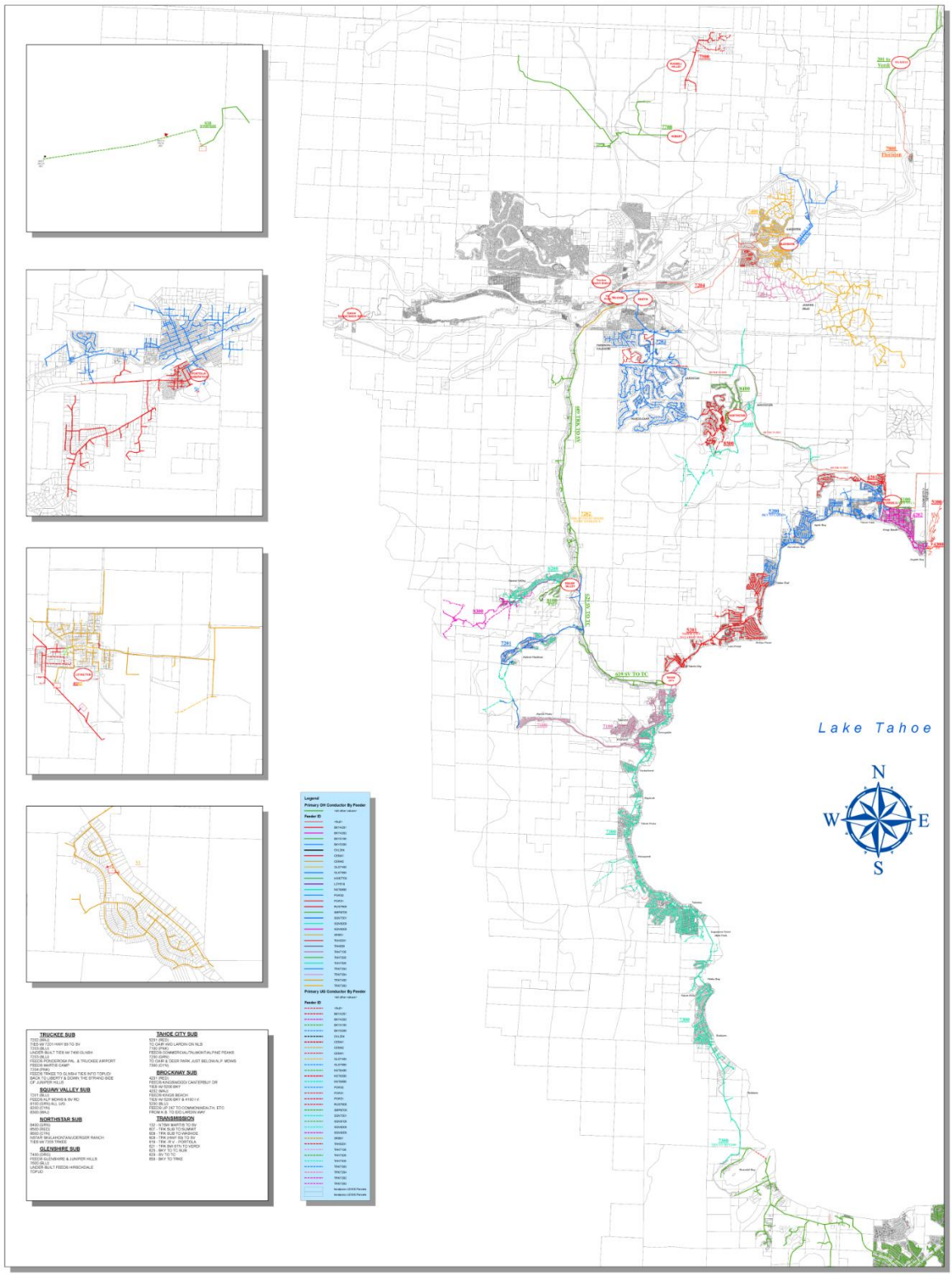

Distribution System Indices TMED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.88
1.37
1.15
1.08
0.52
0.313
0.31
2011
2012
2013
2014
2015
2016
2017
2018
2019
2020

b. The number, date, and location of planned outages

Circuit		Number of Planned Outages By Year								
	2020	2019	2018	2017	2016	2015	2014	2013	2012	2011
31	3		1			1				
32	4	1		2	1					
41	6				1					
201			7					1		
204		2			1					
619									1	
650						1			1	
1261	7	1	1							
1296	2		1	2		5	1			
2200		1				1	1			
2300		1	1			1	2		1	
3100	2	8	5	1					1	1
3101	3	3					2	2		
3200	1	3	5			1			1	
3300	3	8	10	2		3			2	
3400	1	2	4	3		5		2	4	
3500	6	15		6		1				
3501		3	3			2	2	4	1	1
4201		1	1		1					
4202	2	5	3	4				2	5	1
5100	1							1	1	
5200	1	5	4	1		4	1	1	3	
5201		8	1	5	5	4	1		1	
7100	4	1	2	1			1	1	4	
7200		1	1			1	1	1	2	
7201	1	1		4	1	2	1			
7202	3	3	1	1		2	3	1		
7203		3	2			2	2	4		
7300	8	20	14	5	6	4	16	4	5	2
7400	1	4	8	2	1	1				1
7600		1	1			1				1
7700	4						1			
7800							2			
7900	2	1								

8200	1	1	2	7	3	2	4			1
8300	1	1	1	2		6			2	
8400	1		7							
8500	2				1			1	2	
8600						4			2	

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	749	Topaz	70.9	76.2%	23.8%	5	2615	5.66
31	Tahoe	671	Portola	15.5	88%	11.9%	2	594	2.82

Note: Preferred Metric is the average of circuit SAIDI over a three-year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of "deficient" WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1261 circuit was noted as a deficient circuit in 2018, 2019 and 2020. The three-year average circuit SAIDI score remains high due to an operations error causing an outage on March 22, 2019 that lasted approximately 58 hours, and a fire that occurred on November 17, 2020 causing widespread outages over the circuit that were restored over the course of 12 hours.

There were 22 unplanned outages in 2020 for the 1261 circuit, two were due to weather conditions, three were due to device failure, one was due to fuse operation, six were due to the Coleville fire and the rest were unknown.

The historical metric for Topaz 1261:

- 2020 – 2,615.2
- 2019 – 3,040.6
- 2018 – 2,393.8
- 2017 – 3,004.5
- 2016 – 1,930.4

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada.

The circuit performance in 2020 was higher than historical records. The events in 2019 and 2020 were outliers resulting from extreme weather

conditions and do not accurately represent the overall performance of the system.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top two Worst Performing Circuits ("WPC") are determined based on the calculated average of circuit SAIDI over a three-year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years of data are included and averaged to account for anomalies and track the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

Liberty's regional engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to Liberty's business manager, engineering manager, and vice president of operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	7/28/2020	Operations Error	Lake Tahoe	5,291	4.43	0.1081
2	8/24/2020	CB Lockout, Lightning possible	Lake Tahoe	3,835	7.68	0.0783
3	11/6/2020	Unknown	Lake Tahoe	3,728	5.94	0.0762
4	8/12/2020	Wind/Debris	Lake Tahoe	3,724	2.58	0.0761
5	9/10/2020	Animal	Lake Tahoe	3,451	1.27	0.0705
6	9/6/2020	Animal	Lake Tahoe	3,266	3.47	0.0667
7	10/23/2020	Animal	Lake Tahoe	3,266	1.13	0.0667
8	7/28/2020	Animal	Lake Tahoe	2,555	1.46	0.0522
9	7/2/2020	Device failure	Lake Tahoe	2,555	2.14	0.0522
10	7/28/2020	Operations Error	Lake Tahoe	2,555	1.38	0.0522

*Based on customer impact

7) Summary list of 2019 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

TMED as of 2019 = 189.04

Liberty did not experience an event in 2020 where the daily SAIDI was higher than the calculated TMED.

8) Historical 10 largest unplanned outage events for the past 8 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Operations Error	7/28/2020	5,291	0.68	3,597.8	No
2	CB Lockout, Lightning possible	8/24/2020	3,835	1.63	6,251.1	No
3	Unknown	11/6/2020	3,728	1.30	4,846.4	No
4	Wind/Debris	8/12/2020	3,724	0.56	2,085.44	No
5	Animal	9/10/2020	3,451	0.30	1,035.3	No
6	Animal	9/6/2020	3,266	0.86	2,808.7	No
7	Animal	10/23/2020	3,266	0.28	914.5	No
8	Animal	7/28/2020	2,555	0.46	705.8	No
9	Device failure	7/2/2020	2,555	1.43	3,653.6	No
10	Operations Error	7/28/2020	2,555	0.68	1,737.4	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40,701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37,835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1,411.4	No
4	Hardware Failure	2/26/2019	4,485	3.50	15,697.5	No

5	Tree	1/18/2019	4,448	1.76	7,828.5	No
6	Hardware Failure	3/6/2019	4,448	0.82	3,647.4	No
7	Animal	11/11/2019	4,245	0.60	2,547.0	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1,596.2	No
9	Animal	6/7/2019	3,529	0.47	1,658.6	No
10	Tree	6/7/2019	3,507	1.51	5,295.6	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91,301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14,218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6,958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6,420.1	No
7	Unknown	11/12/2018	4,154	1.76	7,338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8,072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	215,600	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.40	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.8	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.0	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.3	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.8	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.9	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.0	No
7	Trees	3/1/2016	3,258	0.50	1,683.3	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.1	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.3	No
10	Trees	6/15/2016	2,732	8.15	3,822.7	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	0.67	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

9) Number of customer inquiries on reliability data and the number of days per response

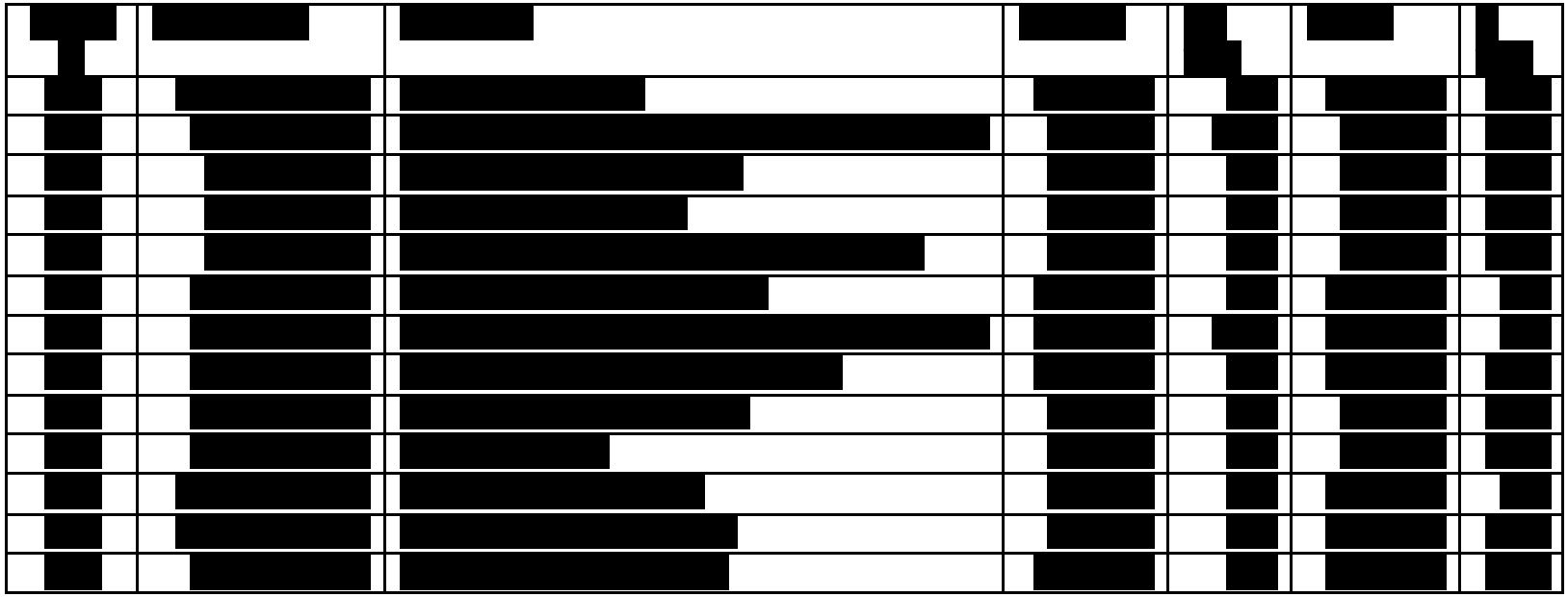
Liberty did not receive any customer inquiries on reliability data in 2020.

Date Received	Date Responded	Description of Inquiry

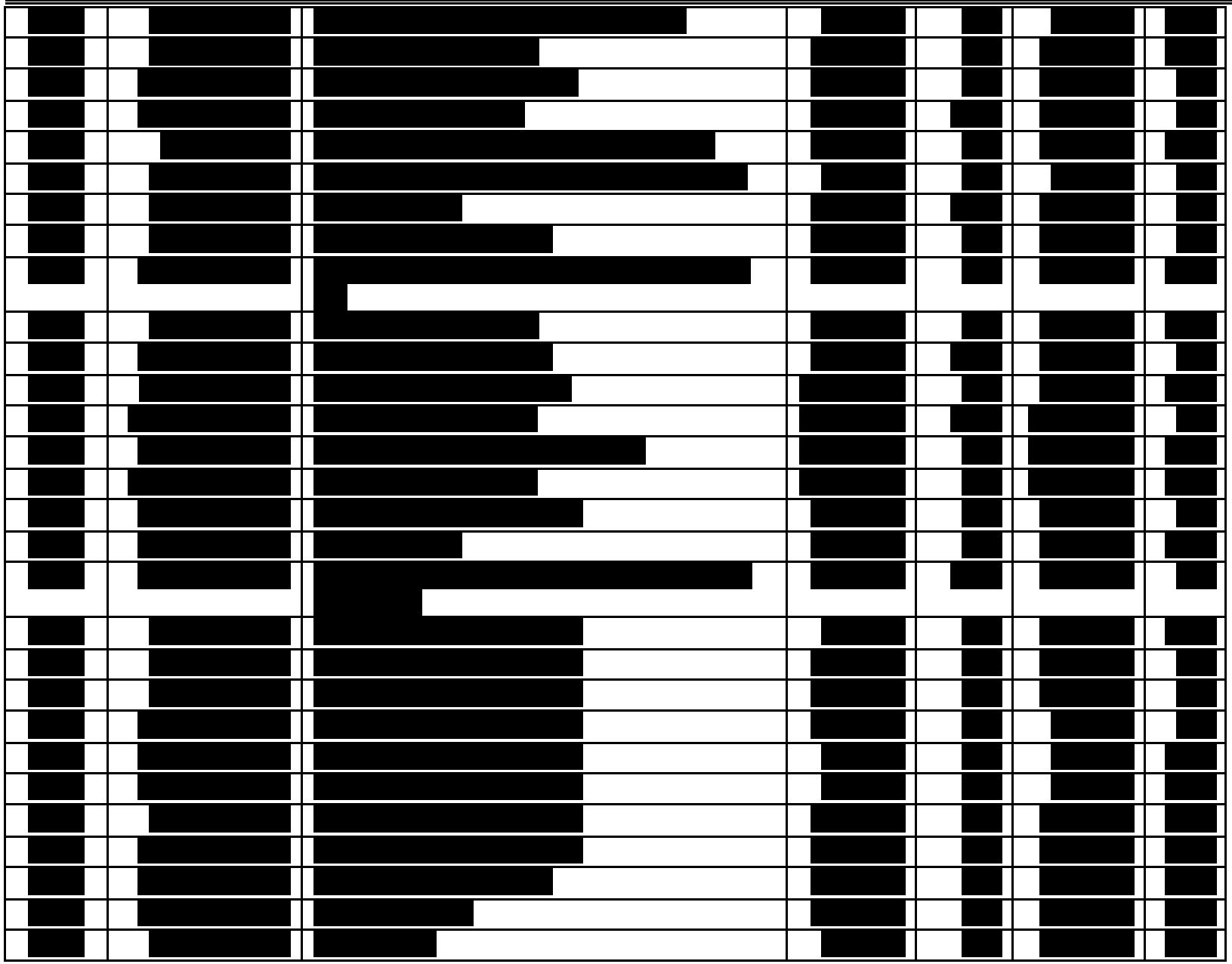
10) List of PSPS's in 2020

Liberty did not have any PSPS events in 2020.

Appendix A: 9 Years of Planned Outage Data -- PUBLIC VERSION --

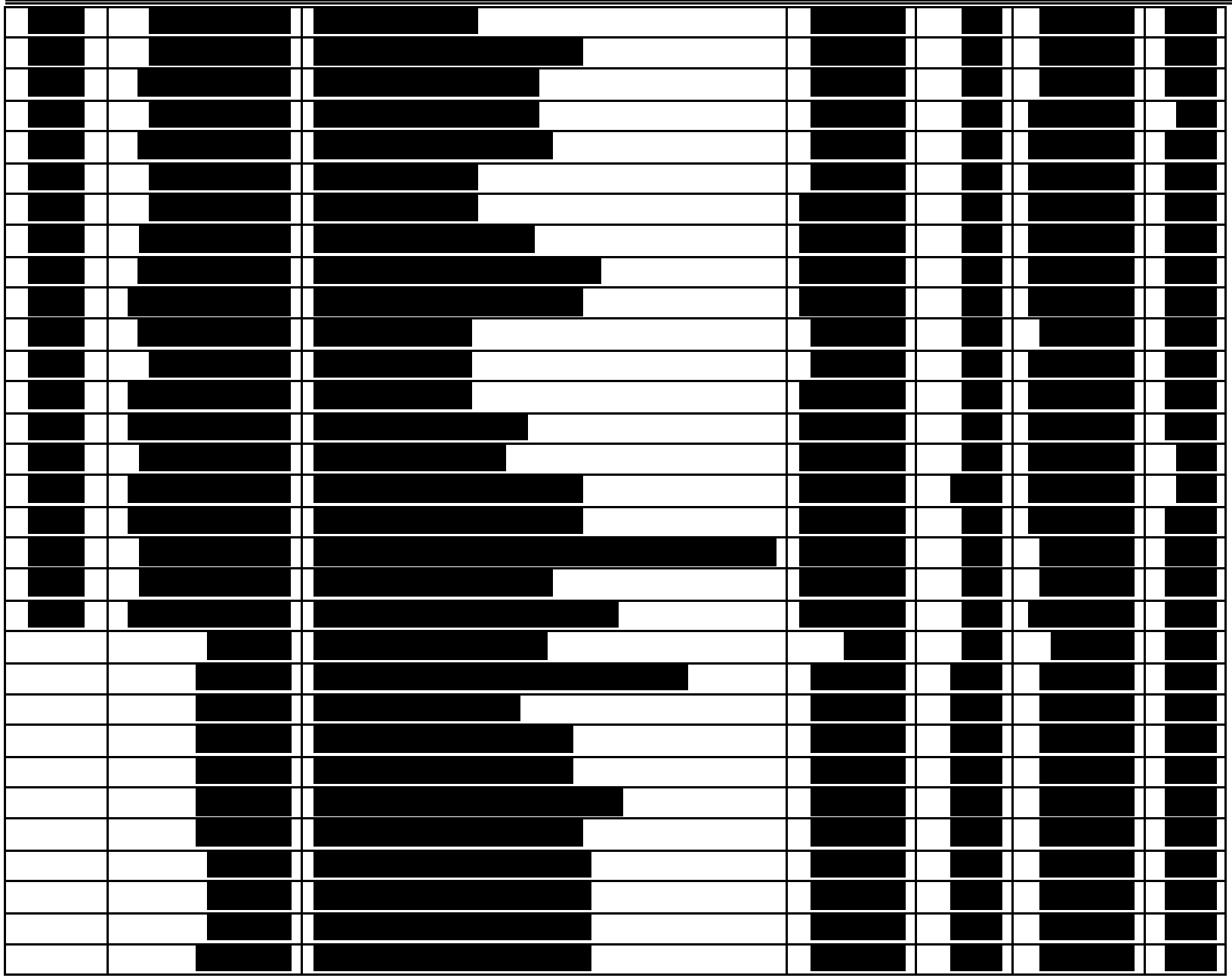












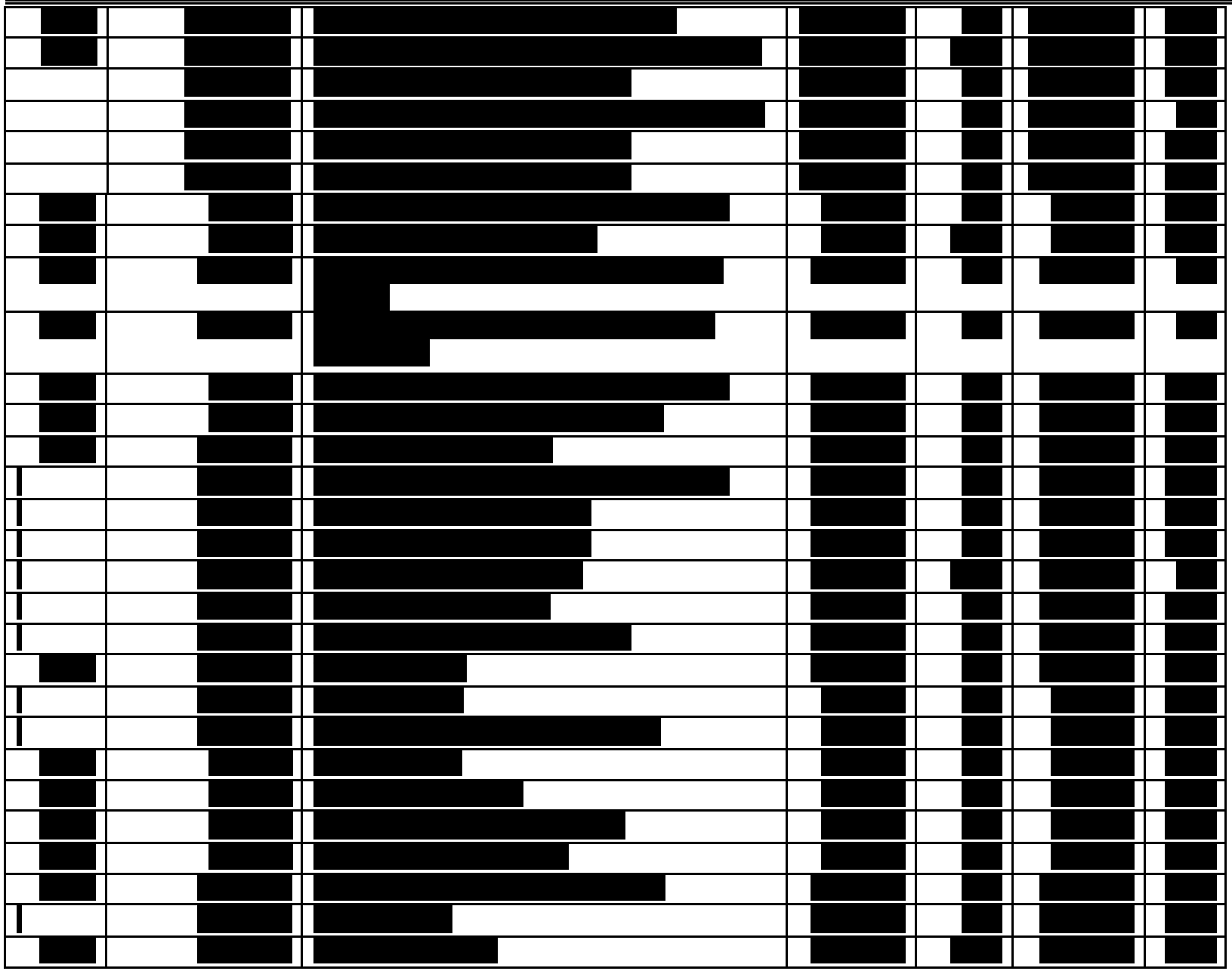








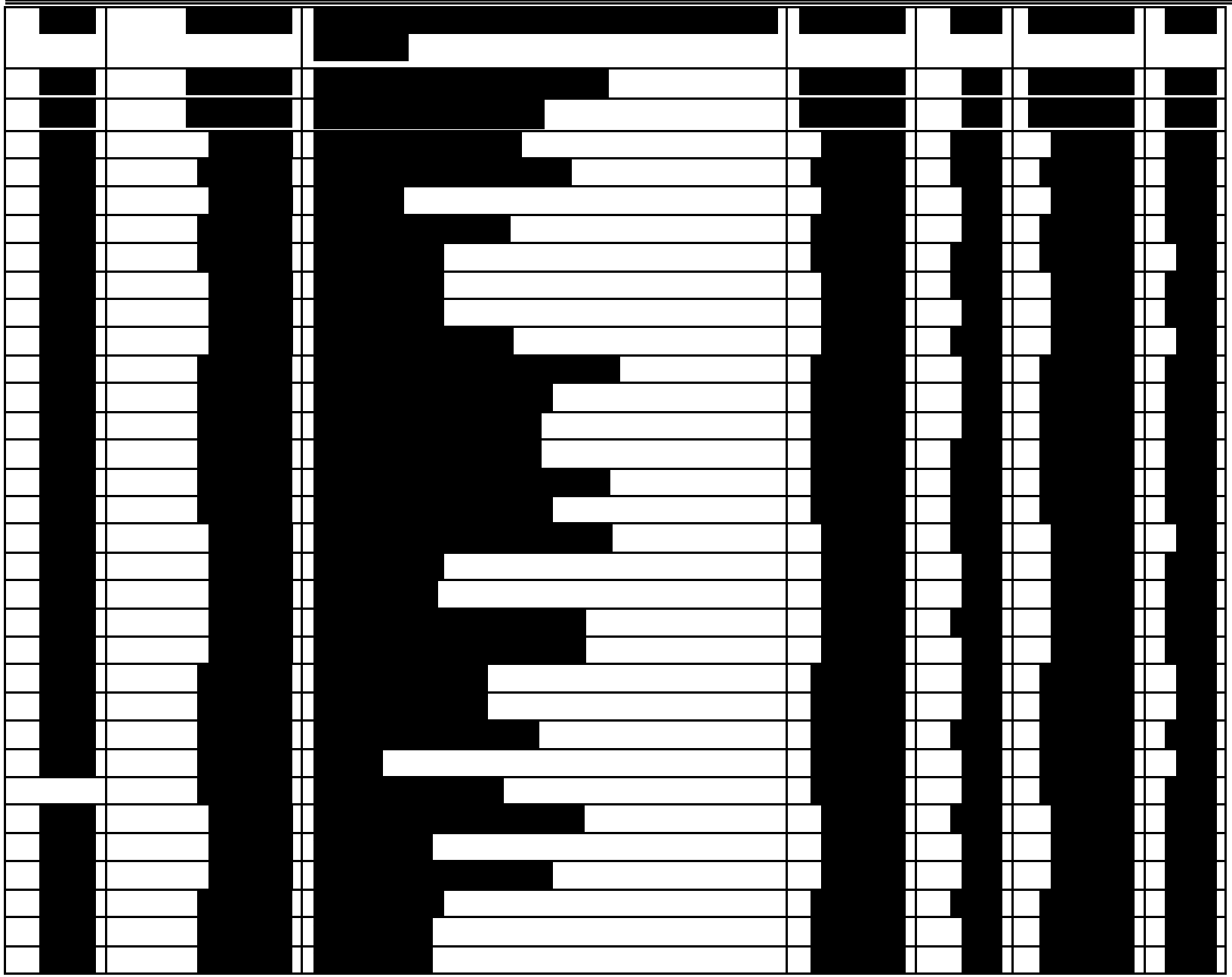




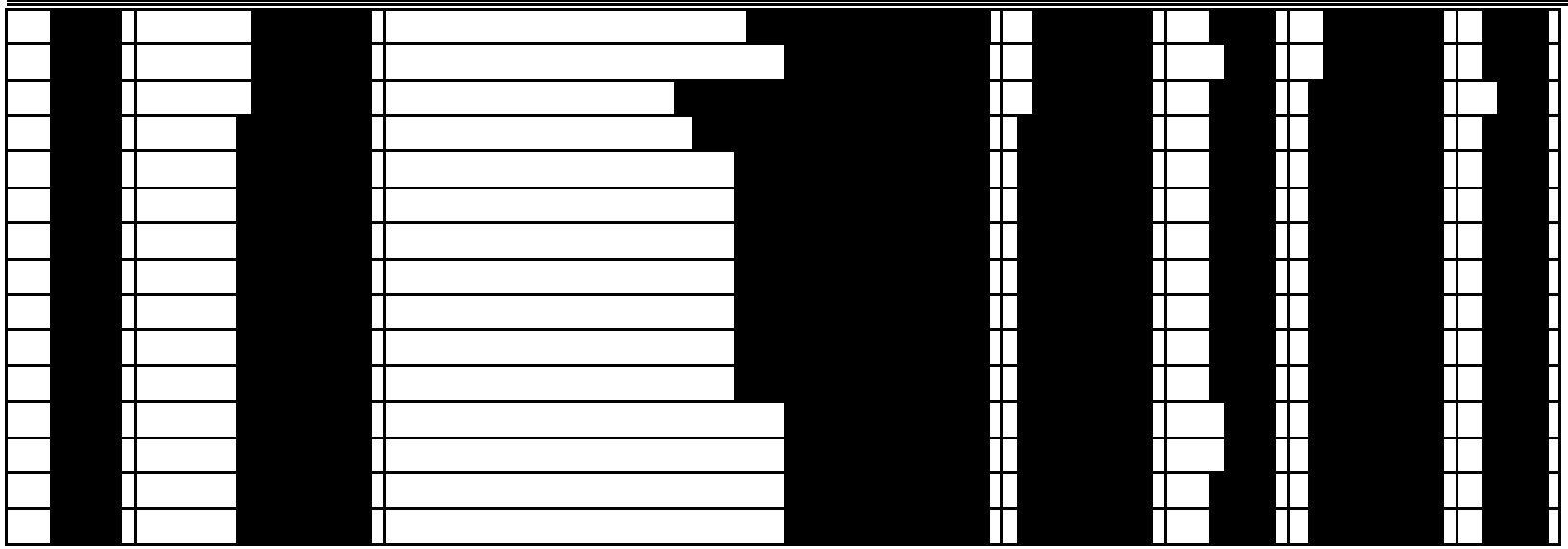












ATTACHMENT 14

Liberty Utilities 2021 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2021

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15th, 2022

CA-07-0782

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2021 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore, data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents ten years (2012 through 2021) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2021 was 176.44 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 10 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

Liberty Utilities (CalPeco Electric), LLC

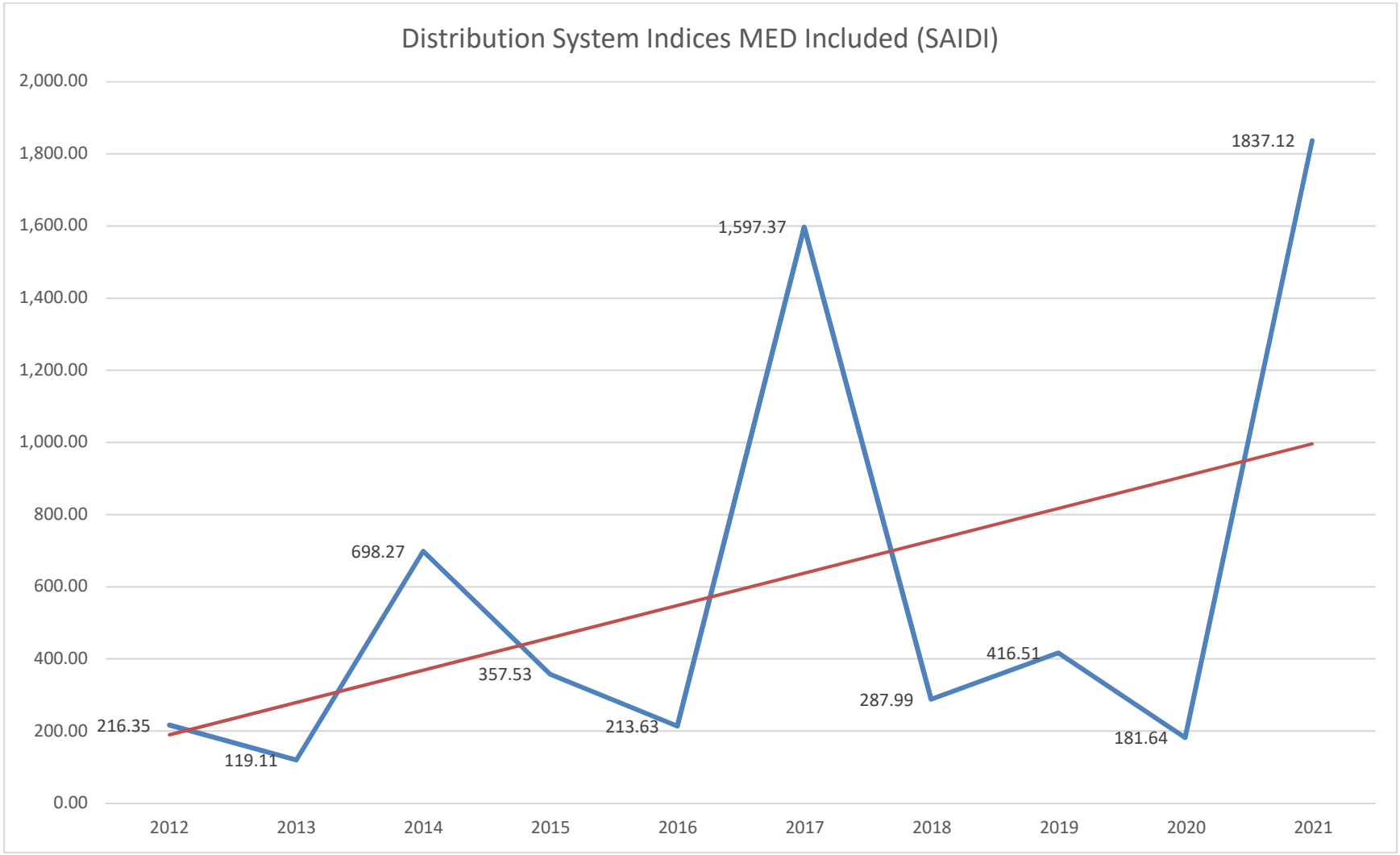
Distribution Historical System Reliability Data 10 Years (Years in Business)

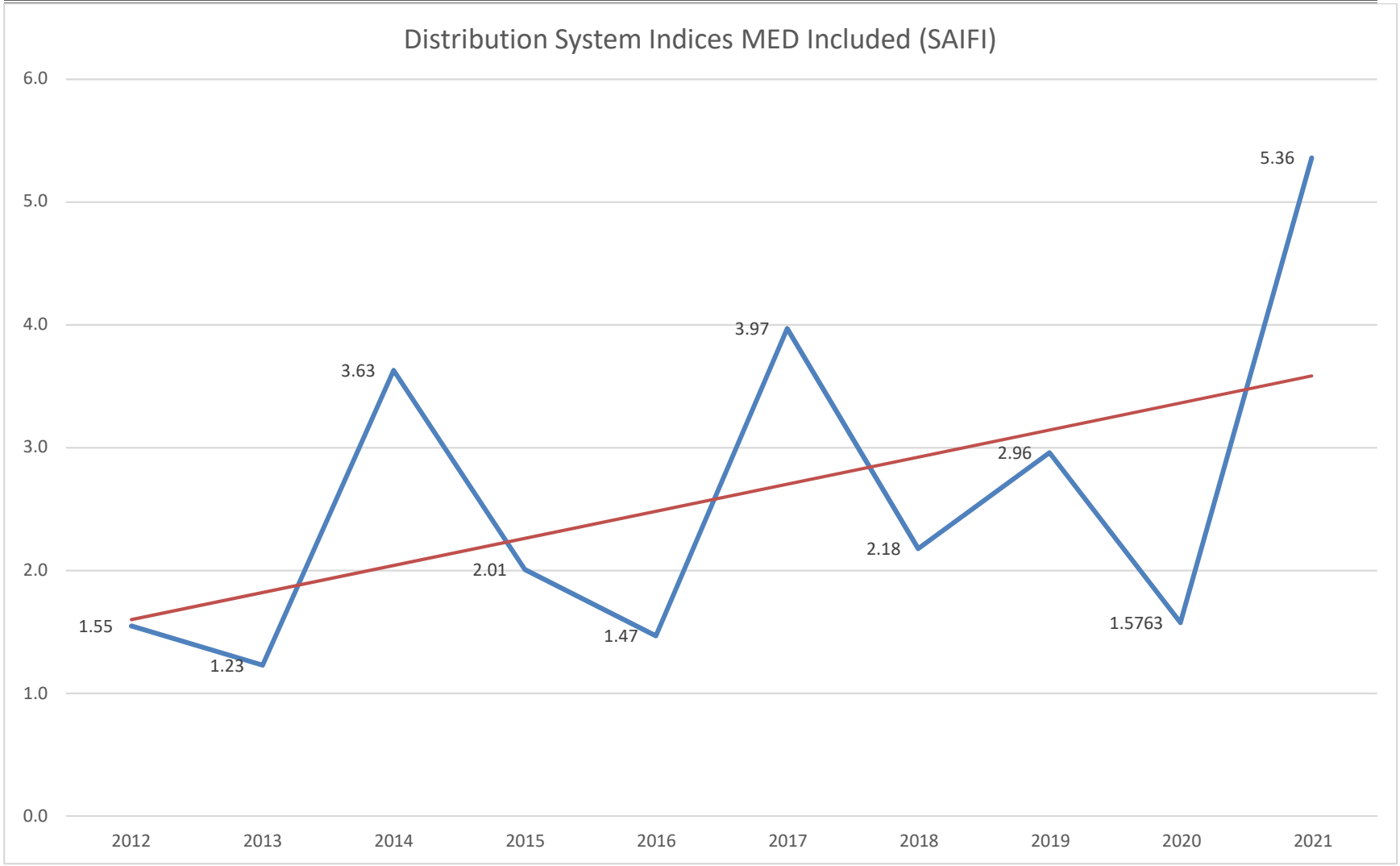
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2021	1837.12	5.36	342.74	0.548	916.28	4.60	199.19	0.548
2020	181.64	1.57	115.23	0.313	181.64	1.57	115.23	0.313
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.4	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75

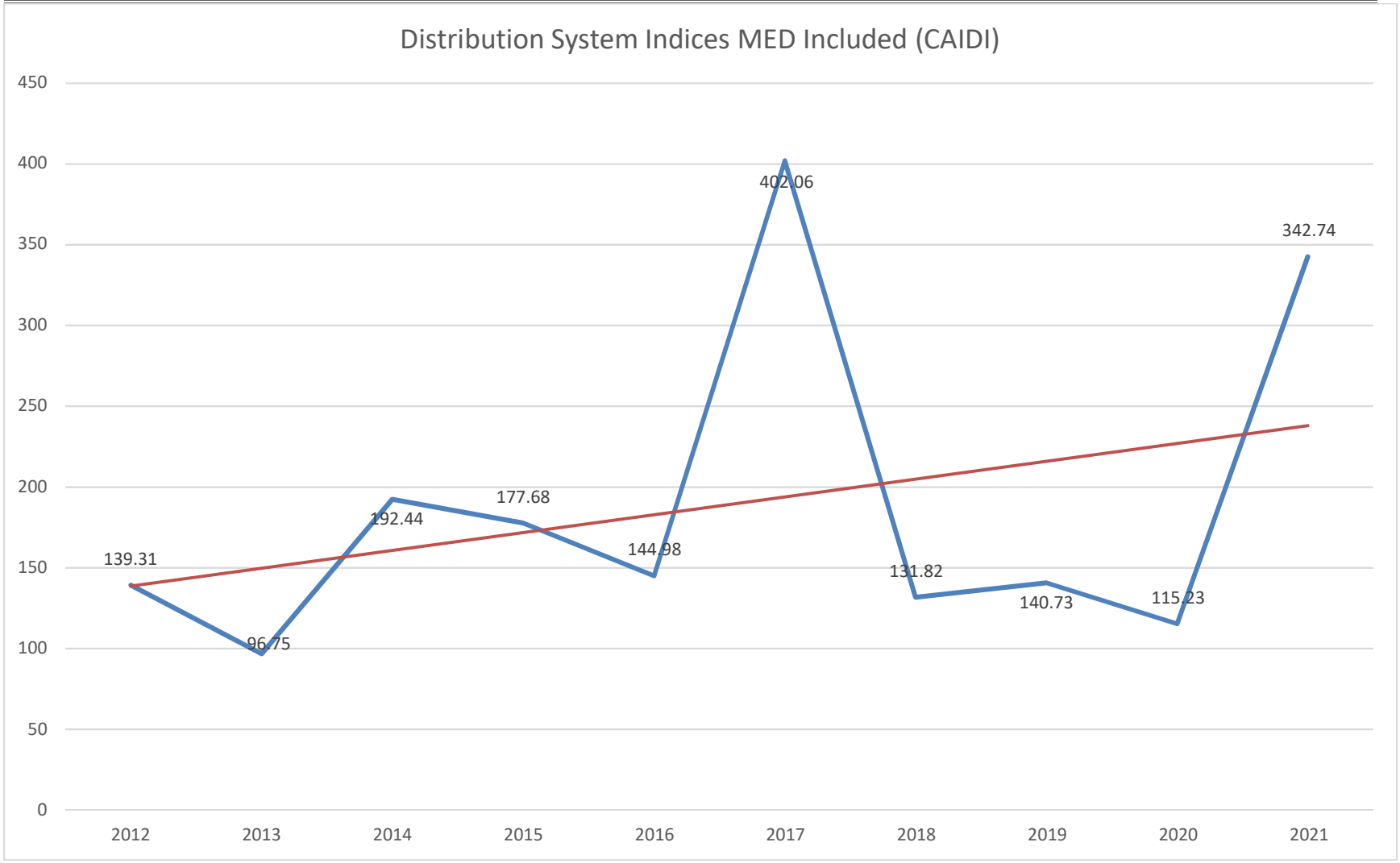
II. Transmission System Indices (MED Included and Excluded)

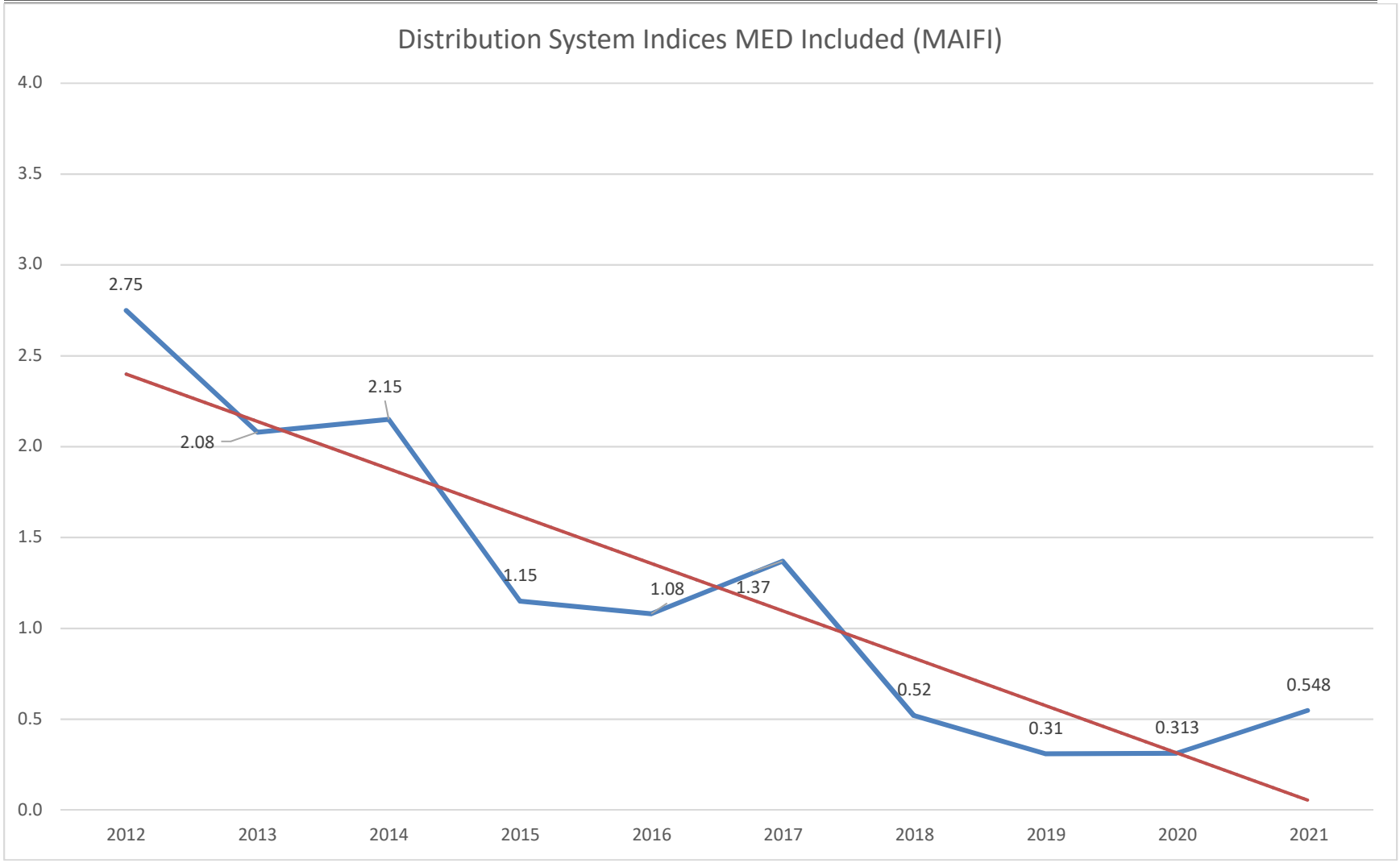
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

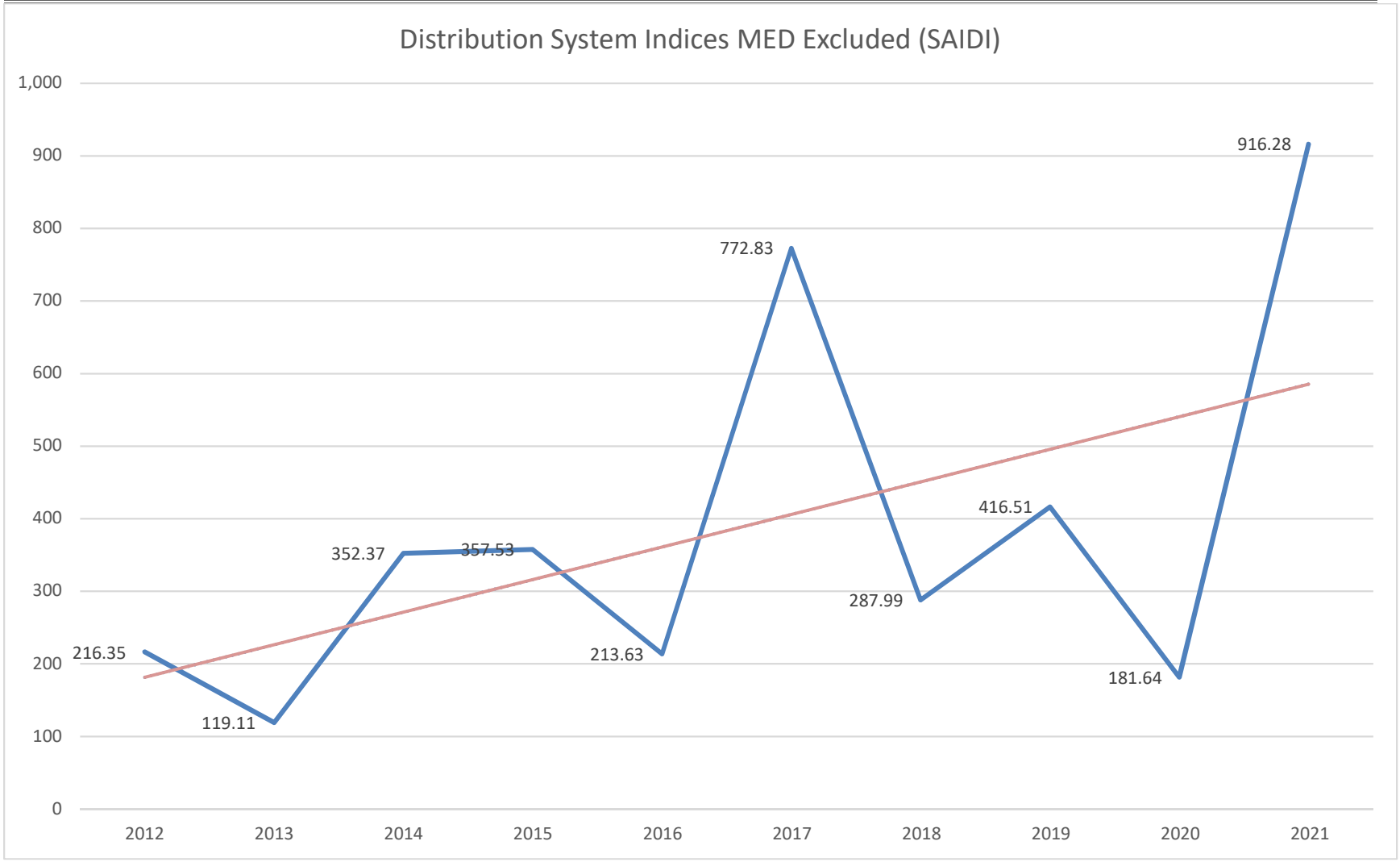
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 10 years with linear trend line (TMED included and excluded).

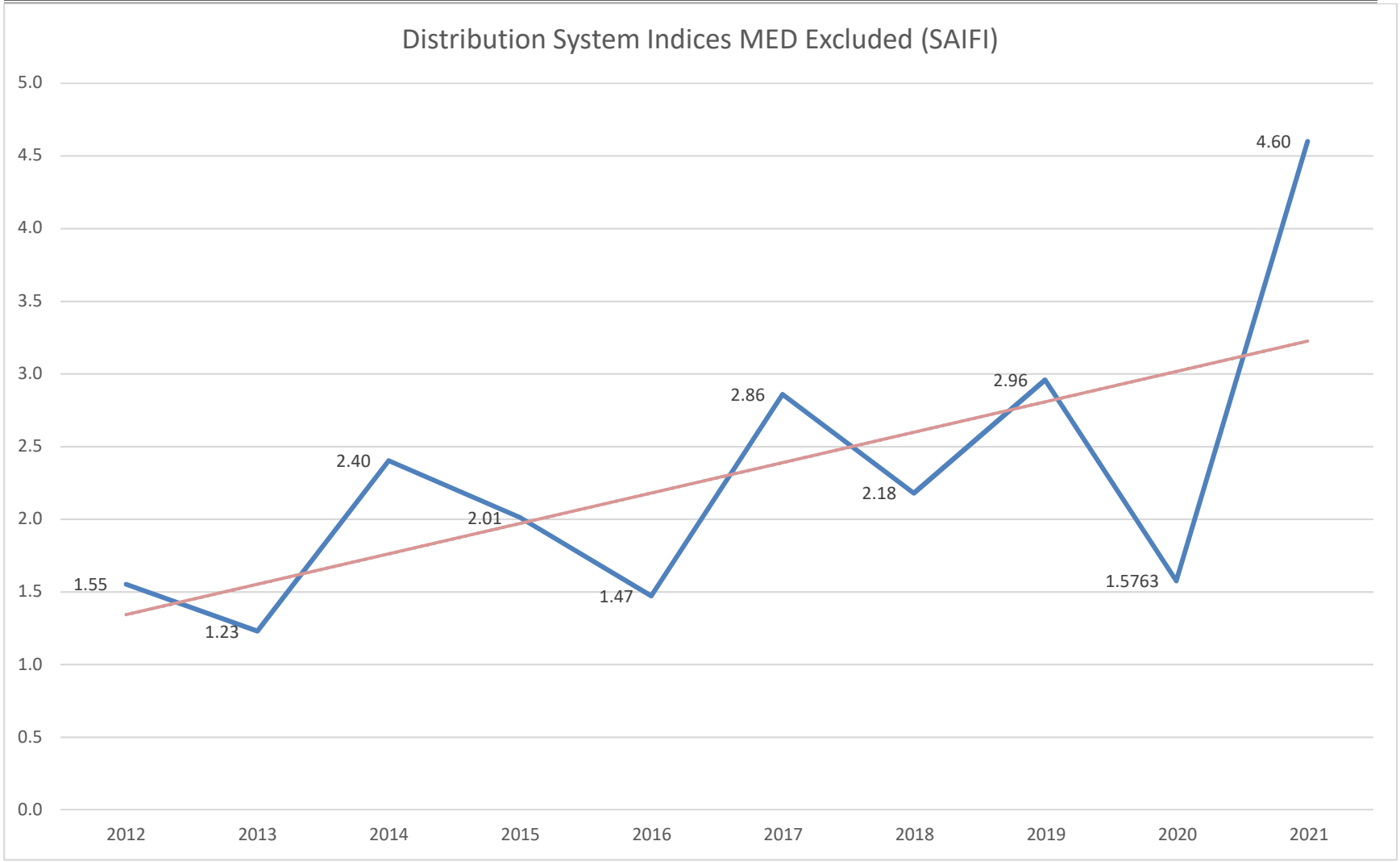

Distribution System Indices MED Included (SAIDI)
2,000.00
1,800.00
1,600.00
1,400.00
1,200.00
1,000.00
800.00
600.00
400.00
200.00
0.00
216.35
119.11
698.27
357.53
213.63
1,597.37
287.99
416.51
181.64
1837.12
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

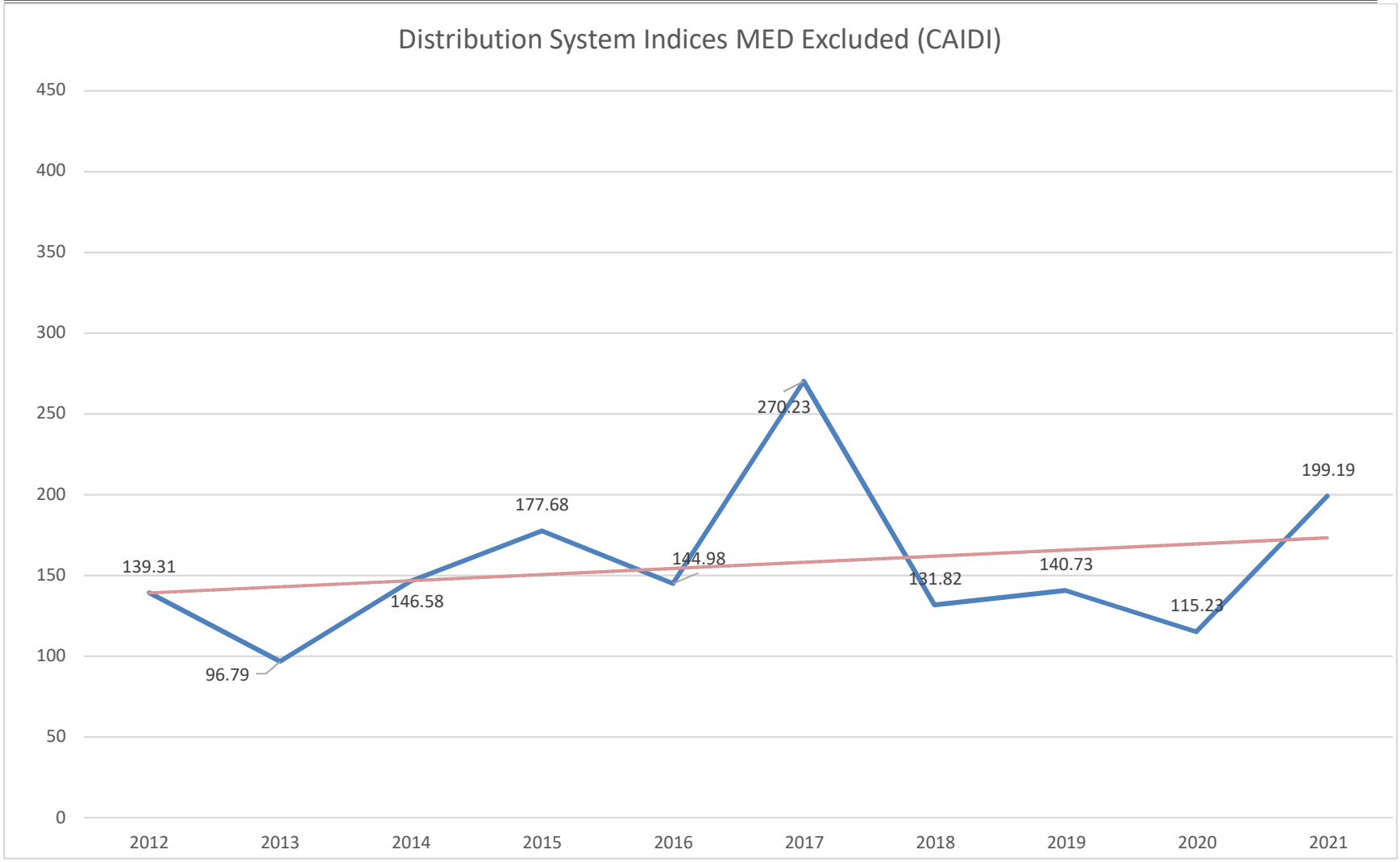

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1.55
1.23
3.63
2.01
1.47
3.97
2.18
2.96
1.5763
5.36
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

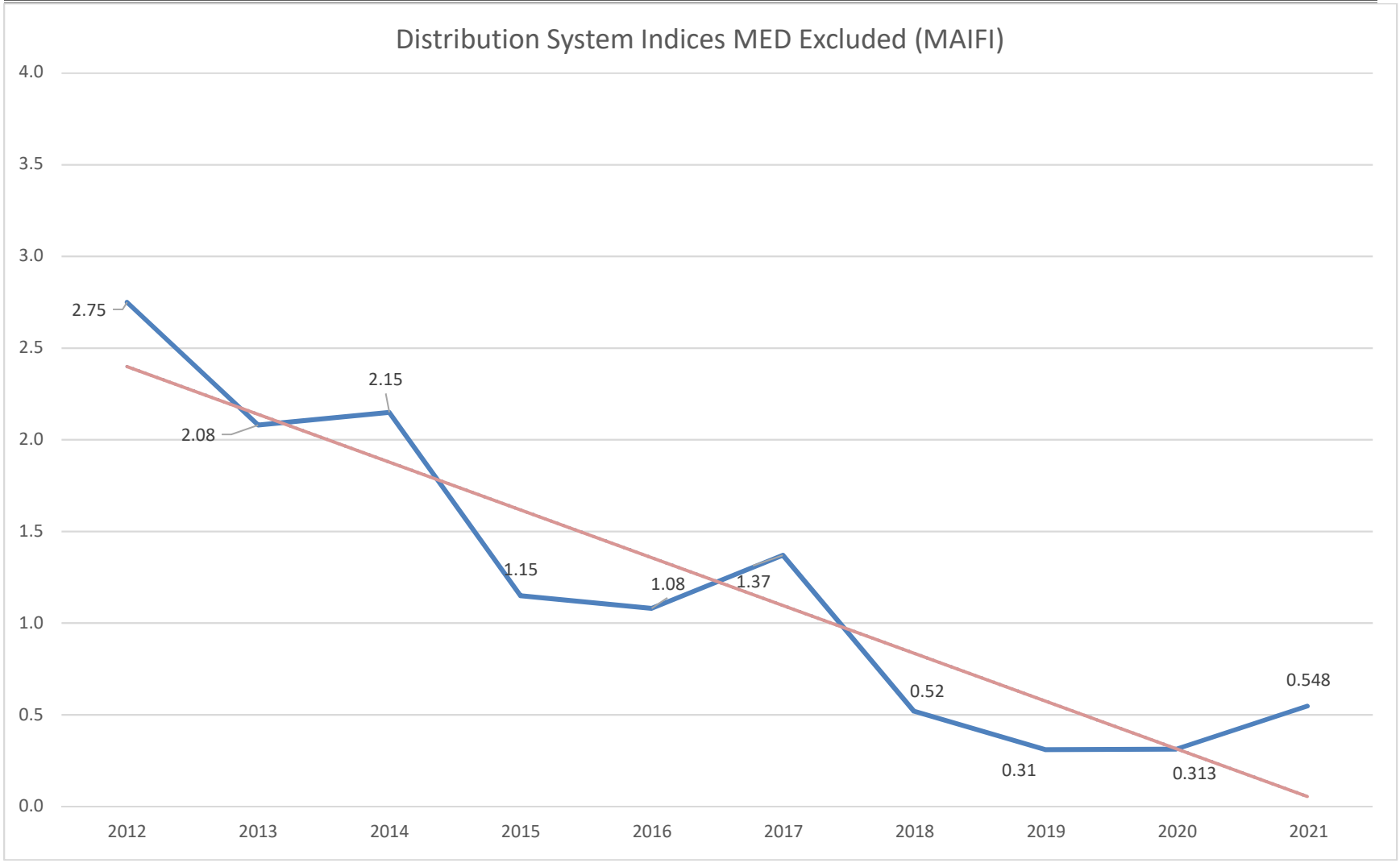

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
139.31
96.75
192.44
177.68
144.98
402.06
131.82
140.73
115.23
342.74
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Excluded (SAIDI)
1,000
900
800
700
600
500
400
300
200
100
0
216.35
119.11
352.37
357.53
213.63
772.83
287.99
416.51
181.64
916.28
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Excluded (SAIFI)
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.55
1.23
2.40
2.01
1.47
2.86
2.18
2.96
1.5763
4.60
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
139.31
96.79
146.58
177.68
144.98
270.23
131.82
140.73
115.23
199.19
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

2) Division (or District) Reliability Indices for the past 10 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

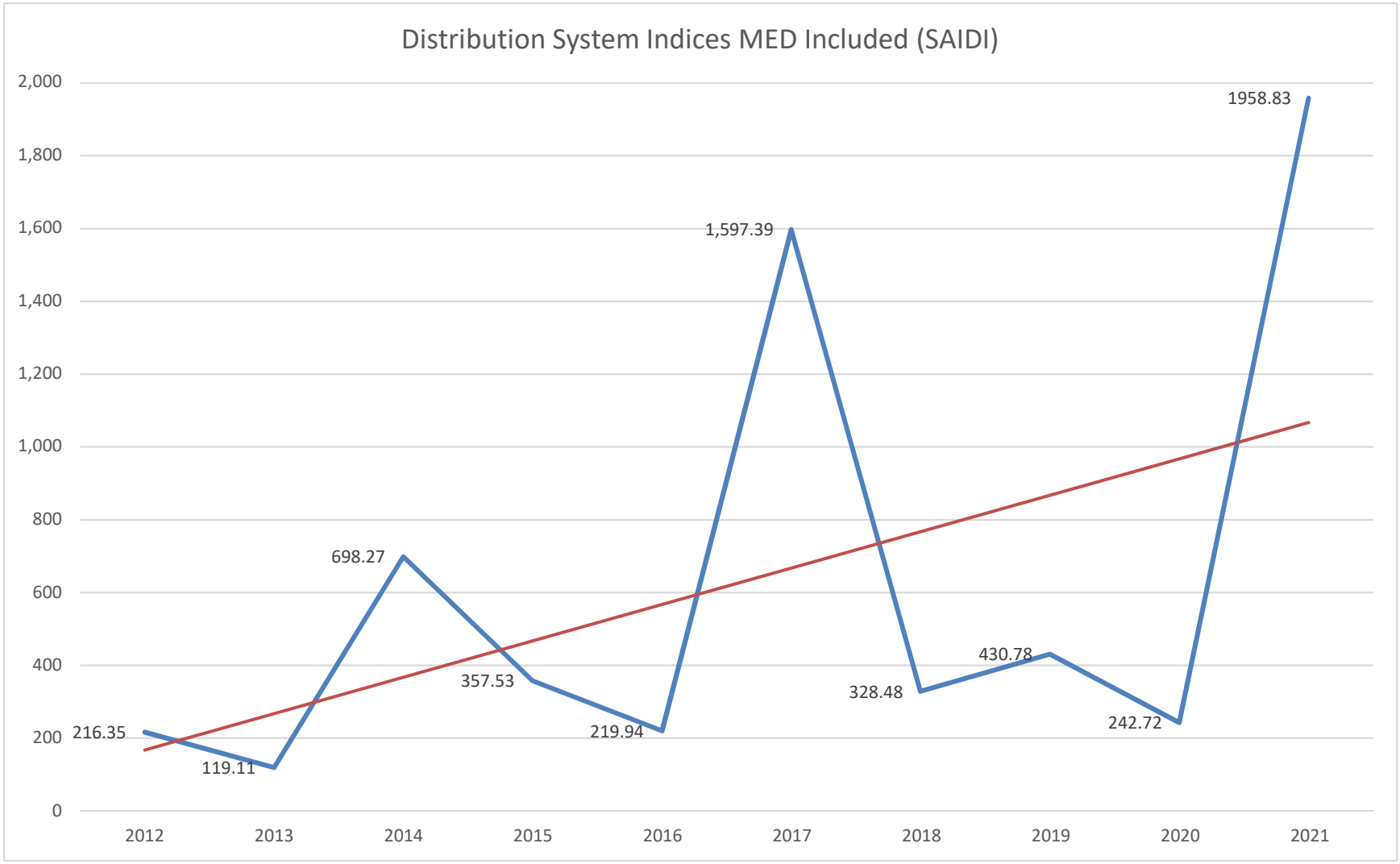
3) System and Division indices based on IEEE 1366 for the past 10 years including planned outages and including and excluding MED

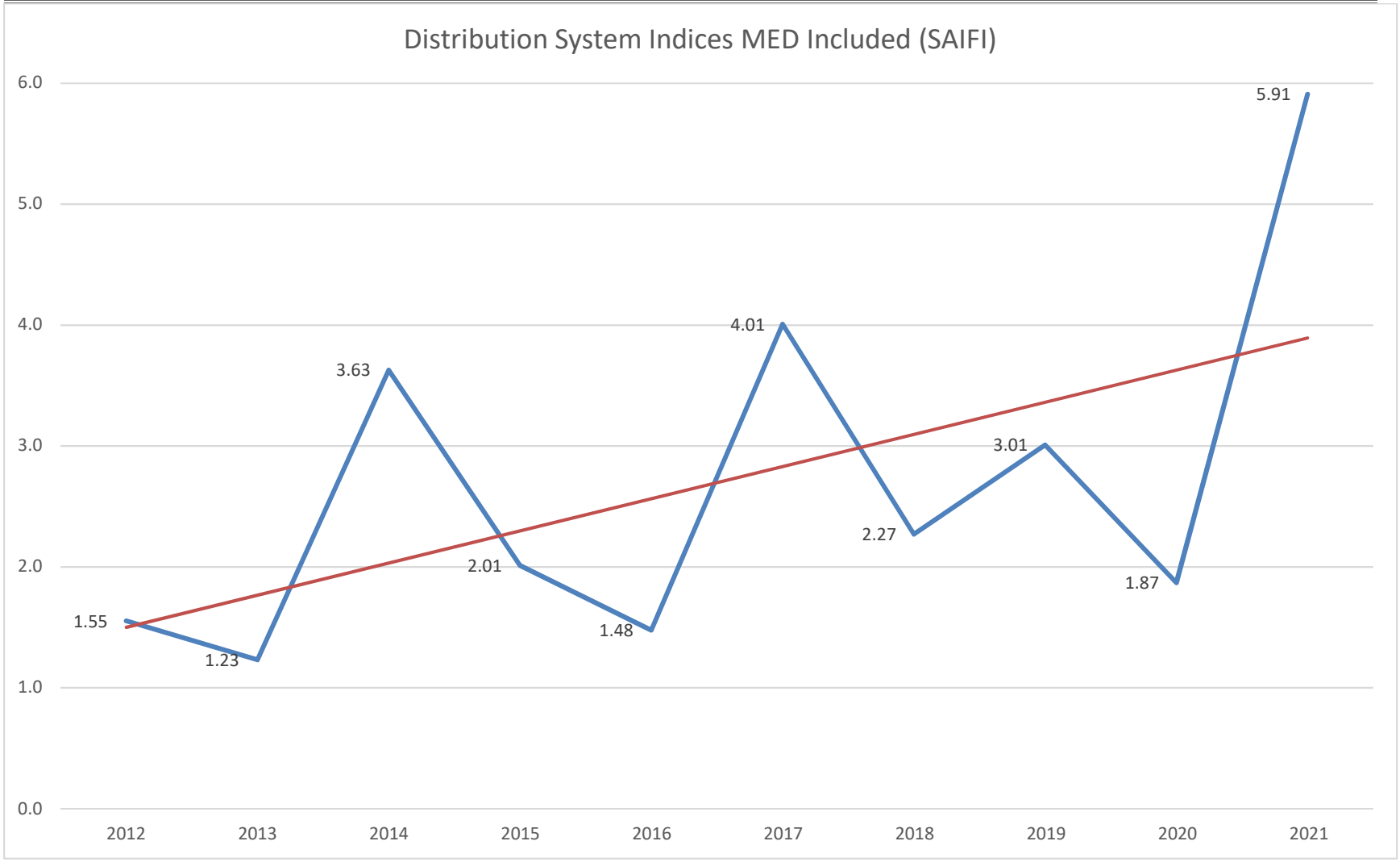
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

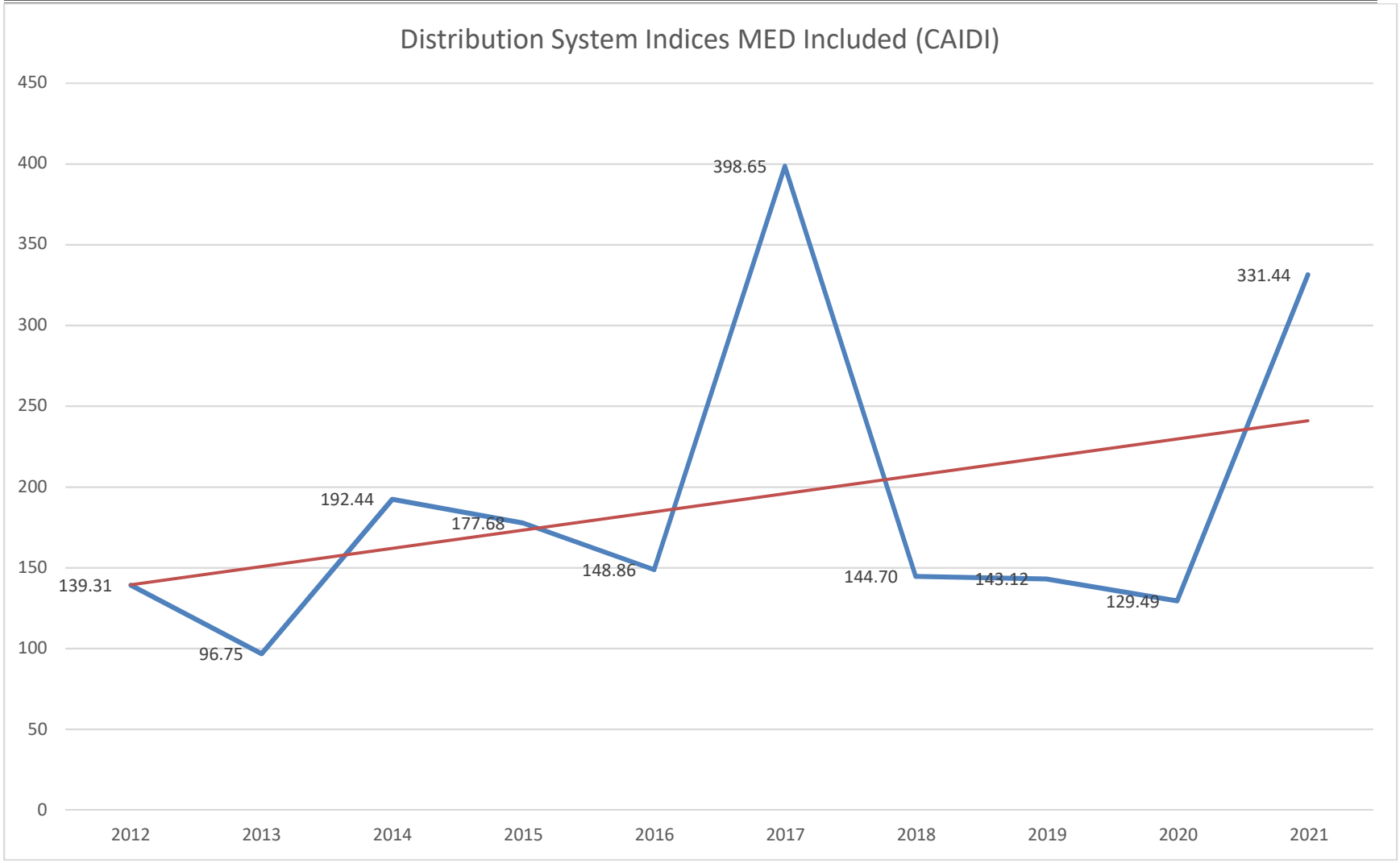
Liberty Utilities (CalPeco Electric), LLC

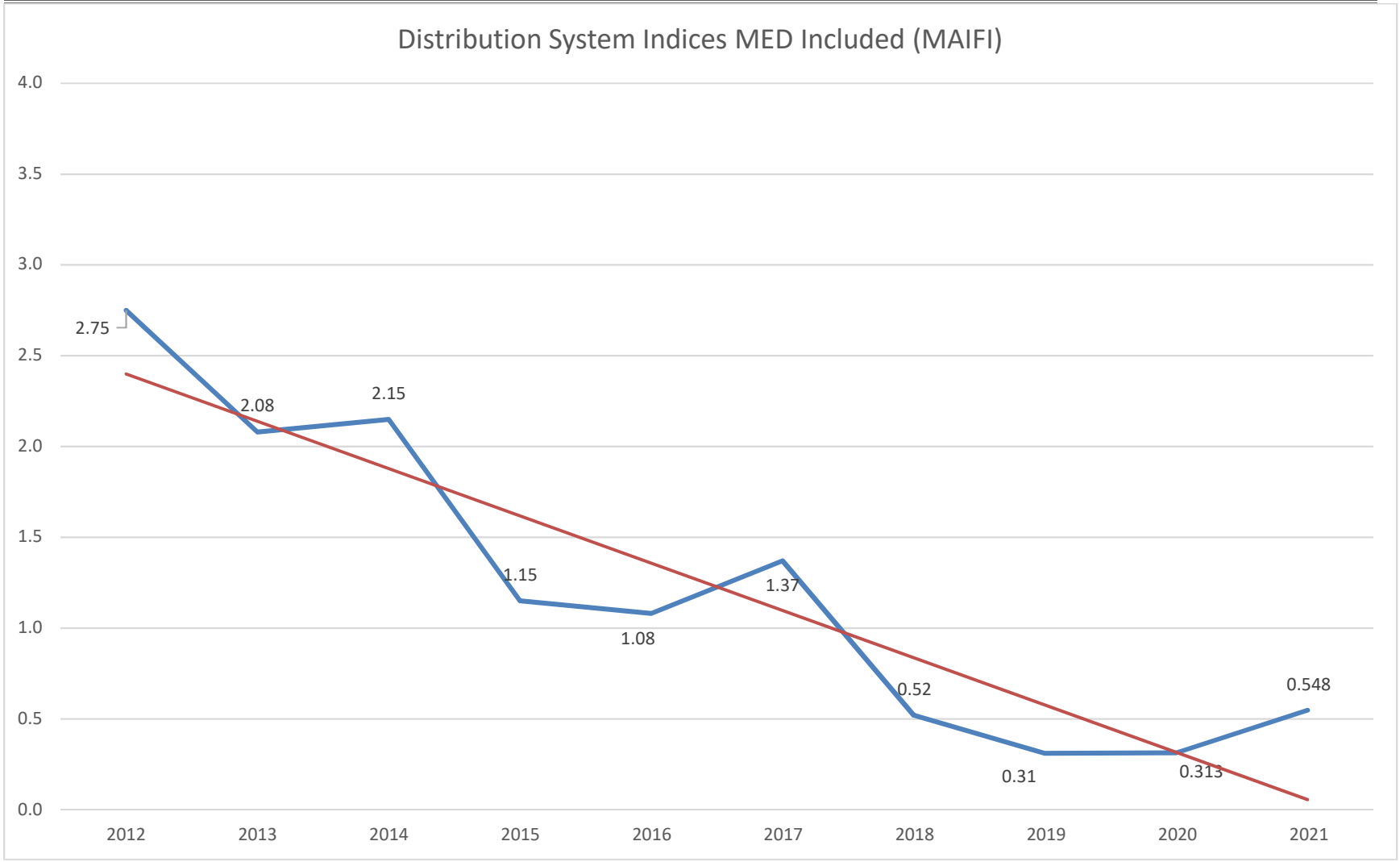
Distribution Historical System Reliability Data 10 Years (Years in Business)

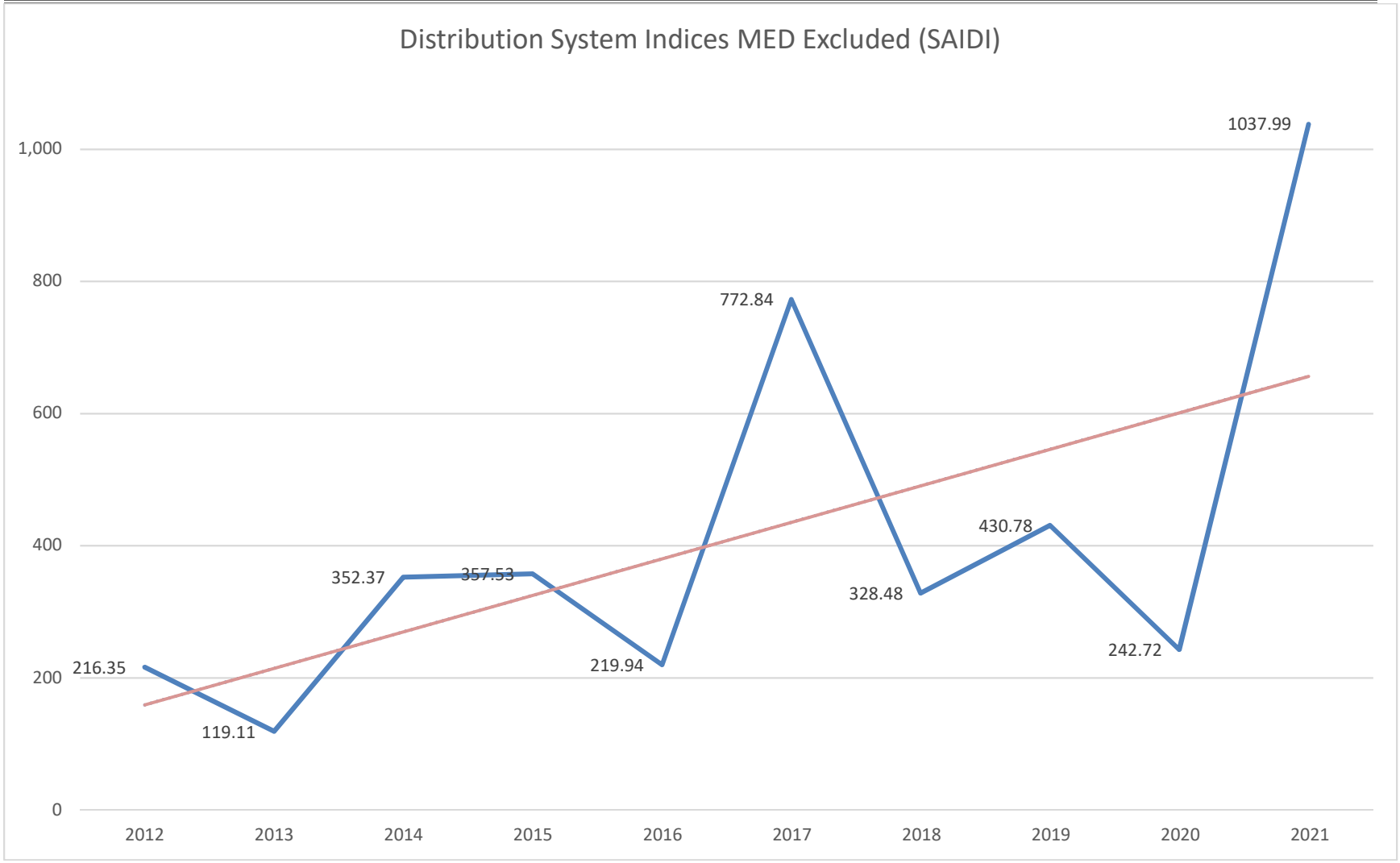
	TMED Included				TMED Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2021	1958.83	5.91	331.44	0.548	1037.99	5.14	201.94	0.548
2020	242.72	1.87	129.49	0.313	242.72	1.87	129.49	0.313
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.7	0.52	328.48	2.27	144.7	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.4	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08
2012	216.35	1.55	139.31	2.75	216.35	1.55	139.31	2.75

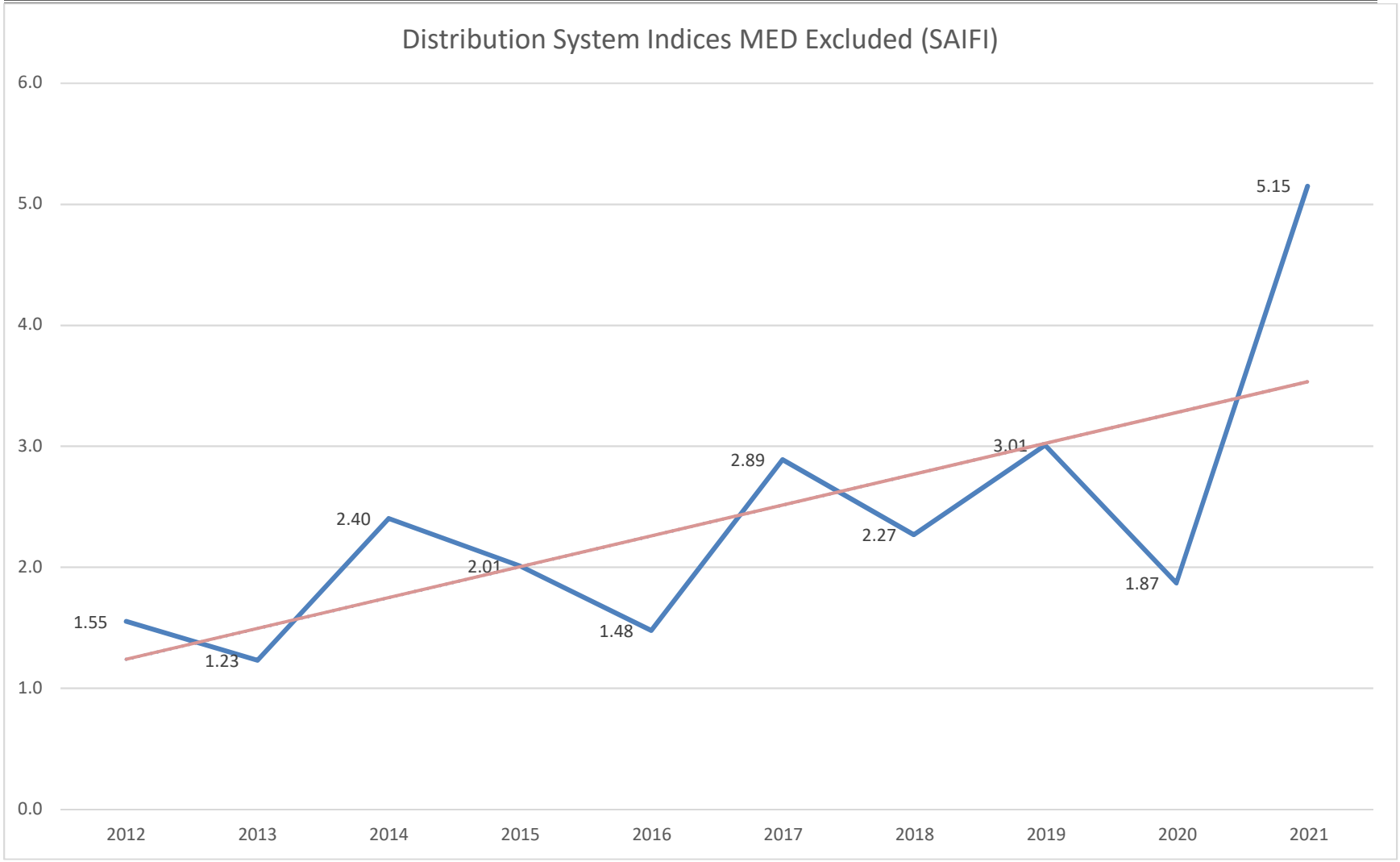

Distribution System Indices MED Included (SAIDI)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
216.35
119.11
698.27
357.53
219.94
1,597.39
328.48
430.78
242.72
1958.83
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

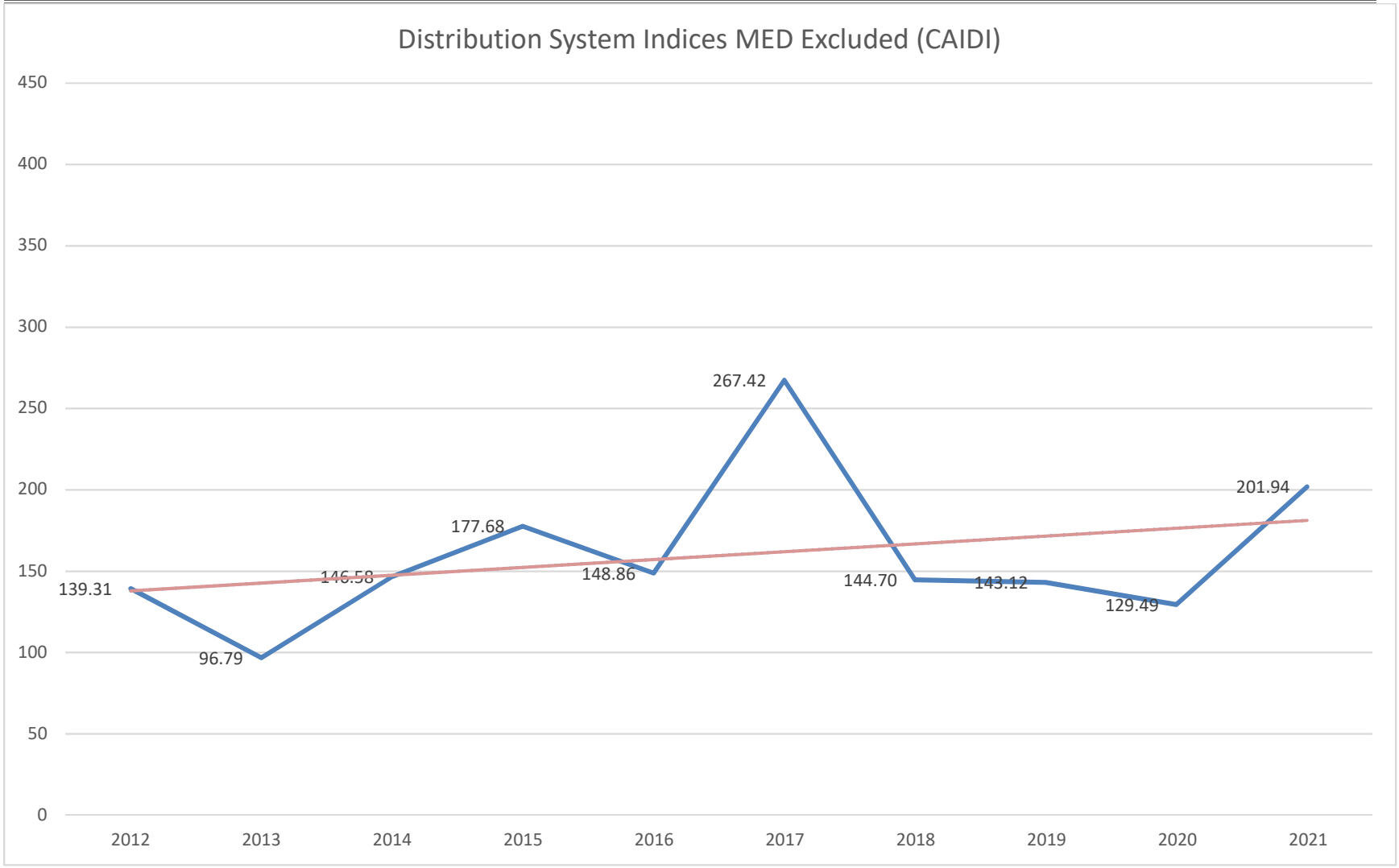

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1.55
1.23
3.63
2.01
1.48
4.01
2.27
3.01
1.87
5.91
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

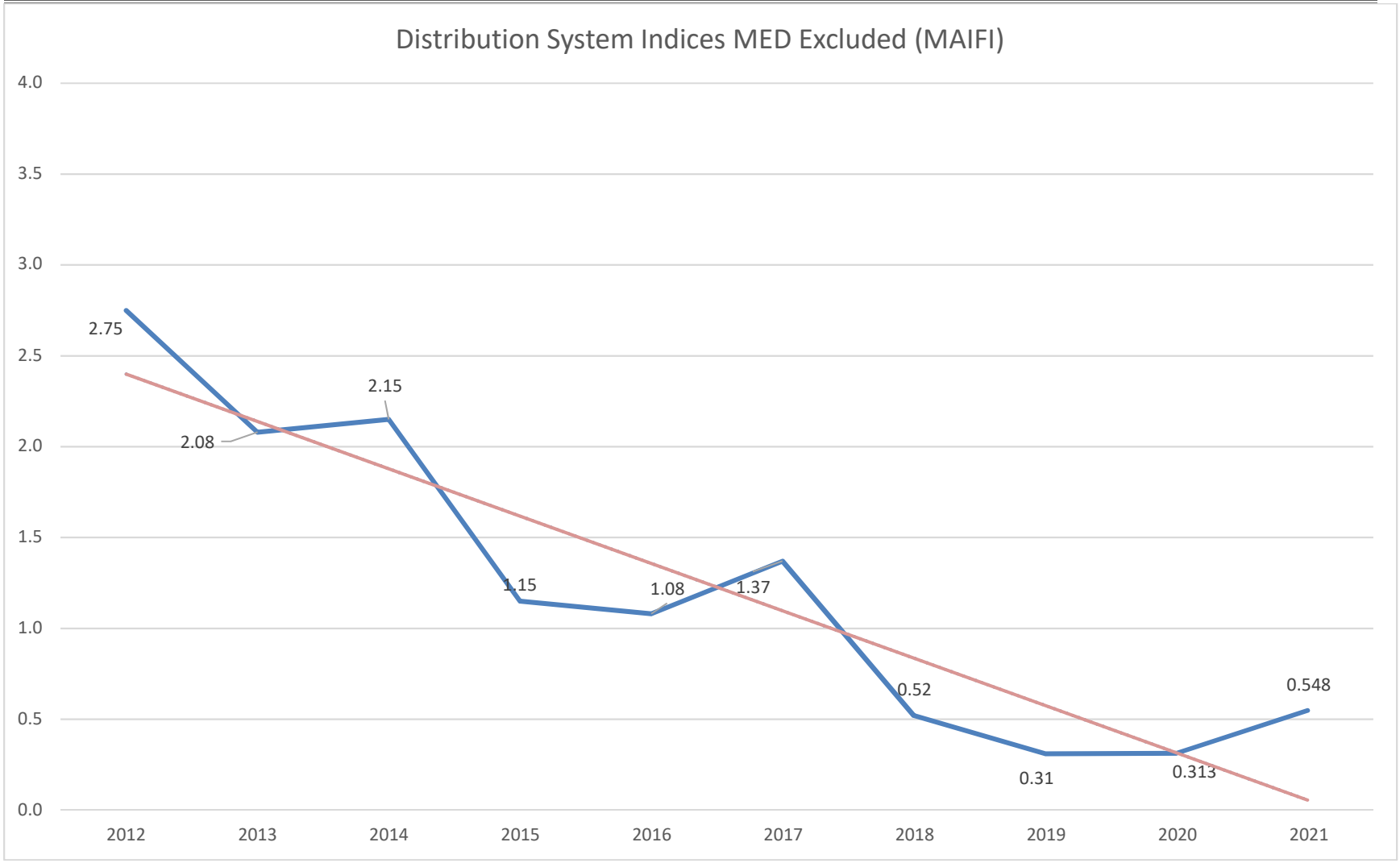

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
139.31
96.75
192.44
177.68
148.86
398.65
144.70
143.12
129.49
331.44


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Excluded (SAIDI)
1,000
800
600
400
200
0
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021
216.35
119.11
352.37
357.53
219.94
772.84
328.48
430.78
242.72
1037.99


Distribution System Indices MED Excluded (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1.55
1.23
2.40
2.01
1.48
2.89
2.27
3.01
1.87
5.15
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

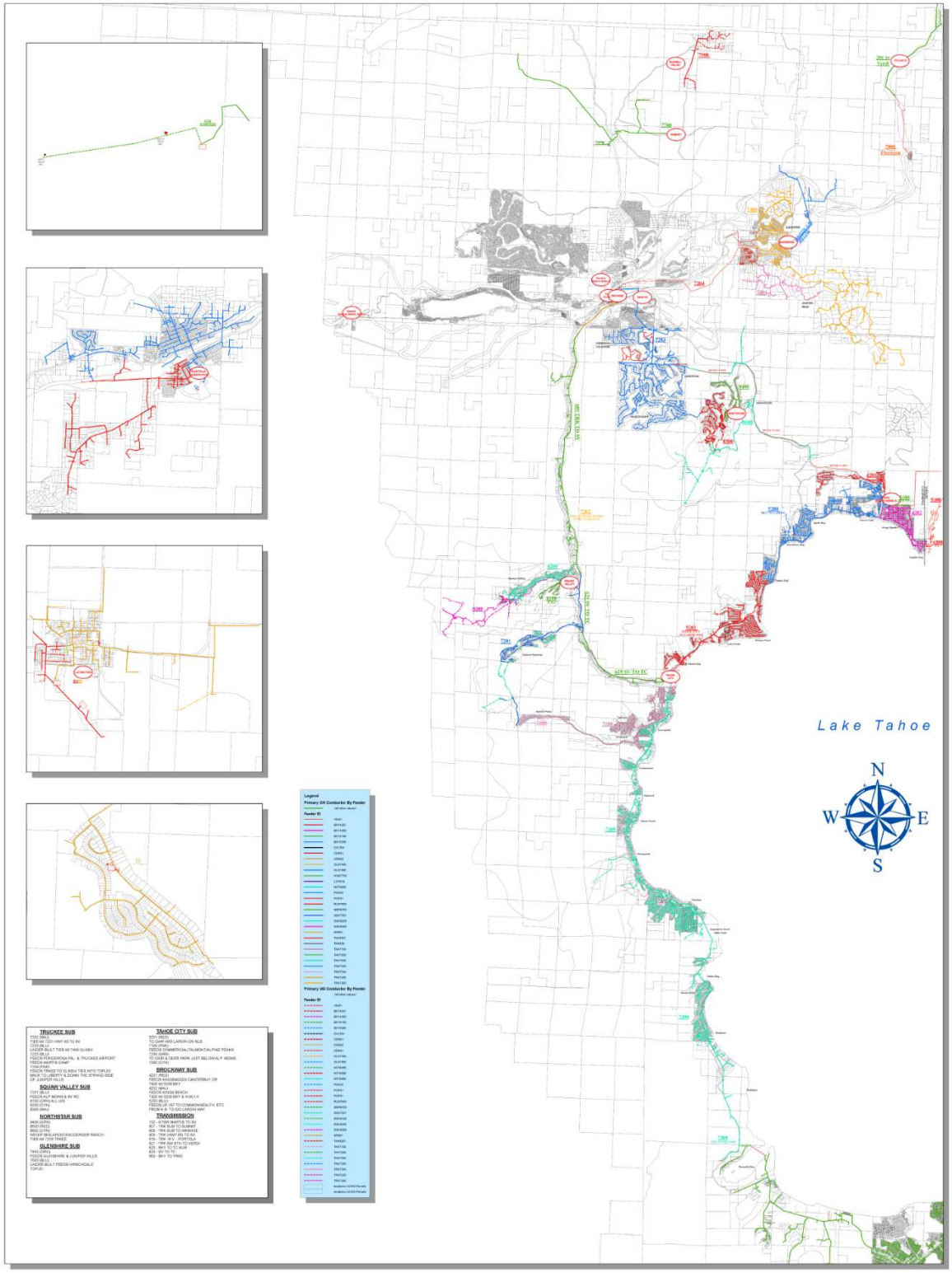

Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
139.31
96.79
146.58
177.68
148.86
267.42
144.70
143.12
129.49
201.94
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.75
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
2012
2013
2014
2015
2016
2017
2018
2019
2020
2021

Circuit	District	Number of Planned Outages By Year									
		2021	2020	2019	2018	2017	2016	2015	2014	2013	2012
31	Tahoe	5	3		1			1			
32	Tahoe	17	4	1		2	1				
41	Tahoe		6				1				
201	Tahoe	3			7					1	
204	Tahoe	1		2			1				
619	Tahoe										1
650	Tahoe							1			1
1261	Tahoe	5	7	1	1						
1296	Tahoe		2		1	2		5	1		
2200	Tahoe	1		1				1	1		
2300	Tahoe	2		1	1			1	2		1
3100	Tahoe	7	2	8	5	1					1
3101	Tahoe	5	3	3					2	2	
3200	Tahoe	22	1	3	5			1			1
3300	Tahoe	19	3	8	10	2		3			2
3400	Tahoe	23	1	2	4	3		5		2	4
3500	Tahoe	9	6	15		6		1			
3501	Tahoe	7		3	3			2	2	4	1
4201	Tahoe	3		1	1		1				
4202	Tahoe	8	2	5	3	4				2	5
5100	Tahoe	1	1							1	1
5200	Tahoe		1	5	4	1		4	1	1	3
5201	Tahoe	2		8	1	5	5	4	1		1
7100	Tahoe	4	4	1	2	1			1	1	4
7200	Tahoe			1	1			1	1	1	2
7201	Tahoe	4	1	1		4	1	2	1		
7202	Tahoe	1	3	3	1	1		2	3	1	
7203	Tahoe	2		3	2			2	2	4	
7300	Tahoe	14	8	20	14	5	6	4	16	4	5
7400	Tahoe	4	1	4	8	2	1	1			
7600	Tahoe			1	1			1			
7700	Tahoe		4						1		
7800	Tahoe								2		
7900	Tahoe		2	1							
8200	Tahoe	2	1	1	2	7	3	2	4		
8300	Tahoe		1	1	1	2		6			2
8400	Tahoe		1		7						
8500	Tahoe	1	2				1			1	2
8600	Tahoe							4			2

b. The number, date, and location of planned outages

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	845	Topaz	56.98	75.6%	24.4%	3	3029	6.38
3300	Tahoe	3562	Meyers	56.95	90.7%	9.3%	2	980	1.88

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1261 circuit was noted as a deficient circuit in 2019, 2020, and 2021. The 3-year average circuit SAIDI score remains high due to an operations error causing an outage on March 22, 2019 which lasted approx. 58hrs, and a fire that occurred on November 17, 2020 causing widespread outages over the circuit that were restored over the course of 12 hours.

There were 14 unplanned outages in 2021 for the 1261 circuit, 4 were due to wildfire and loss of source, 5 were due to fuse operations, 2 were due to equipment operation from vegetation, 1 was due to device failure, and 2 were unknown causes.

The historical metric for Topaz 1261 based on a 3-year average:

- 2021 – 3028.6
- 2020 – 2,615.2
- 2019 – 3,040.6
- 2018 – 2,393.8
- 2017 – 3,004.5

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada.

The circuit performance in 2021 measured alone was around average compared to historical values. The events in 2019 and 2020 were outliers

resulting from extreme weather conditions and do not accurately represent the average performance of the system.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Vice President of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	7/28/2021	CB Lockout	Lake Tahoe	10812	15.5224	0.2156
2	12/15/2021	Recloser Lockout	Lake Tahoe	5348	11.8368	0.1066
3	12/14/2021	Wire Down	Lake Tahoe	4530	33.3307	0.0903
4	7/29/2021	Lighting	Lake Tahoe	4522	5.3199	0.0902
5	12/14/2021	Device failure	Lake Tahoe	4387	50.1236	0.0875
6	10/7/2021	Loss of Source	Lake Tahoe	4374	0.5233	0.0872
7	10/8/2021	Loss of Source	Lake Tahoe	4374	30.2642	0.0872
8	12/24/2021	CB Lockout	Lake Tahoe	4368	0.0871	0.0871
9	12/13/2021	CB Lockout	Lake Tahoe	4362	35.5737	0.0870
10	2/25/2021	Loss of Source	Lake Tahoe	4183	3.0861	0.0834

*Based on customer impact

7) Summary list of 2021 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	7/16/2021	Fire	Lake Tahoe	1152	562.3210	0.0229
2	12/15/2021	Storm	Lake Tahoe	36881	338.6680	0.7354

TMED as of 2020 = 176.84

8) Historical 10 largest unplanned outage events for the past 9 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	7/28/2021	10812	1.2	12,974	No
2	Recloser Lockout	12/15/2021	5348	1.85	9,894	No
3	Wire Down	12/14/2021	4530	6.15	27,860	Yes
4	Lighting	7/29/2021	4522	0.98	4,447	No
5	Device failure	12/14/2021	4387	9.55	41,896	Yes
6	Loss of Source	10/7/2021	4374	0.1	437	No
7	Loss of Source	10/8/2021	4374	5.78	25,296	No
8	CB Lockout	12/24/2021	4368	1.7	7,426	No
9	CB Lockout	12/13/2021	4362	6.82	29,734	No
10	Loss of Source	2/25/2021	4183	0.62	336	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Operations Error	7/28/2020	5,291	0.68	3597.8	No
2	CB Lockout, Lightning possible	8/24/2020	3,835	1.63	6251.05	No
3	Unknown	11/6/2020	3,728	1.3	4846.4	No
4	Wind/Debris	8/12/2020	3,724	0.56	2085.44	No
5	Animal	9/10/2020	3,451	0.3	1035.3	No
6	Animal	9/6/2020	3,266	0.86	2808.7	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
7	Animal	10/23/2020	3,266	0.28	914.5	No
8	Animal	7/28/2020	2,555	0.46	705.8	No
9	Device failure	7/2/2020	2,555	1.43	3653.6	No
10	Operations Error	7/28/2020	2,555	0.68	1737.4	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1411.38	No
4	Hardware Failure	2/26/2019	4,485	3.5	15697.5	No
5	Tree	1/18/2019	4,448	1.76	7828.48	No
6	Hardware Failure	3/6/2019	4,448	0.82	3647.36	No
7	Animal	11/11/2019	4,245	0.6	2547	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1596.16	No
9	Animal	6/7/2019	3,529	0.47	1658.63	No
10	Tree	6/7/2019	3,507	1.51	5295.57	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1		8/19/2012	8,677	1.08	9,400.08	No
2	Overhead Hardware/Material	11/29/2012	4,200	.067	3,488.33	No
3	Trees	4/1/2012	4,120	12.70	37,471.67	No
4	Hardware Failure	4/13/2012	4,120	2.95	12,154.00	No
5	Trees	5/24/2012	4,120	0.73	3,021.33	No
6	Bird/Animal	6/28/2012	3,587	0.47	1,673.93	No
7	Weather/Lightning	7/23/2012	3,548	1.16	909.50	No
8	Car/Pole	7/16/2012	3,315	8.83	2,724.17	No
9	Bird/Animal	5/11/2012	3,201	2.48	7,949.15	No
10	Bird/Animal	6/25/2012	1,967	5.60	11,015.20	No

9) Number of customer inquiries on reliability data and the number of days per response

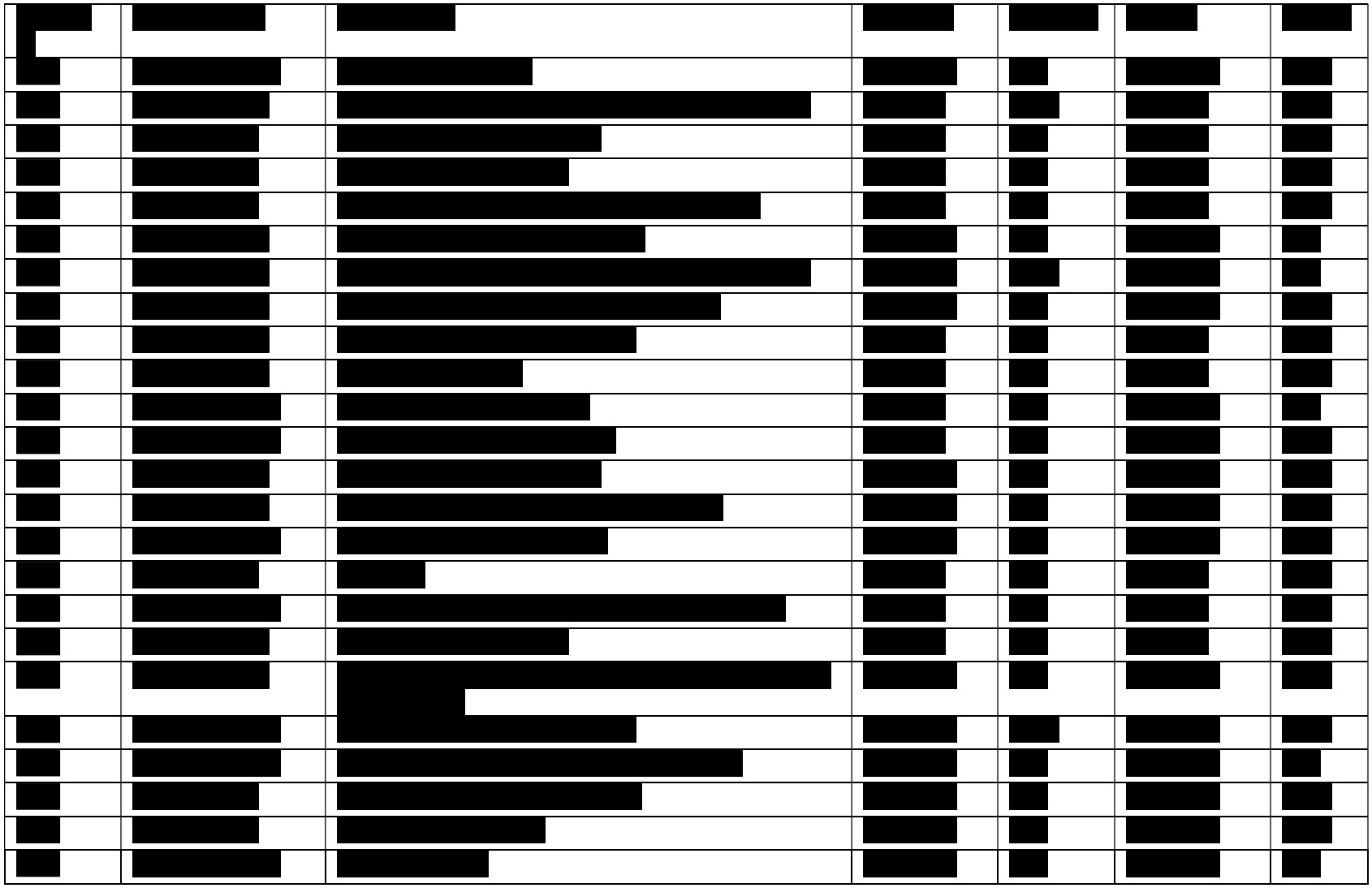
CalPeco Electric did not receive any reliability inquiries in 2021.

Date Received	Date Responded	Description of Inquiry

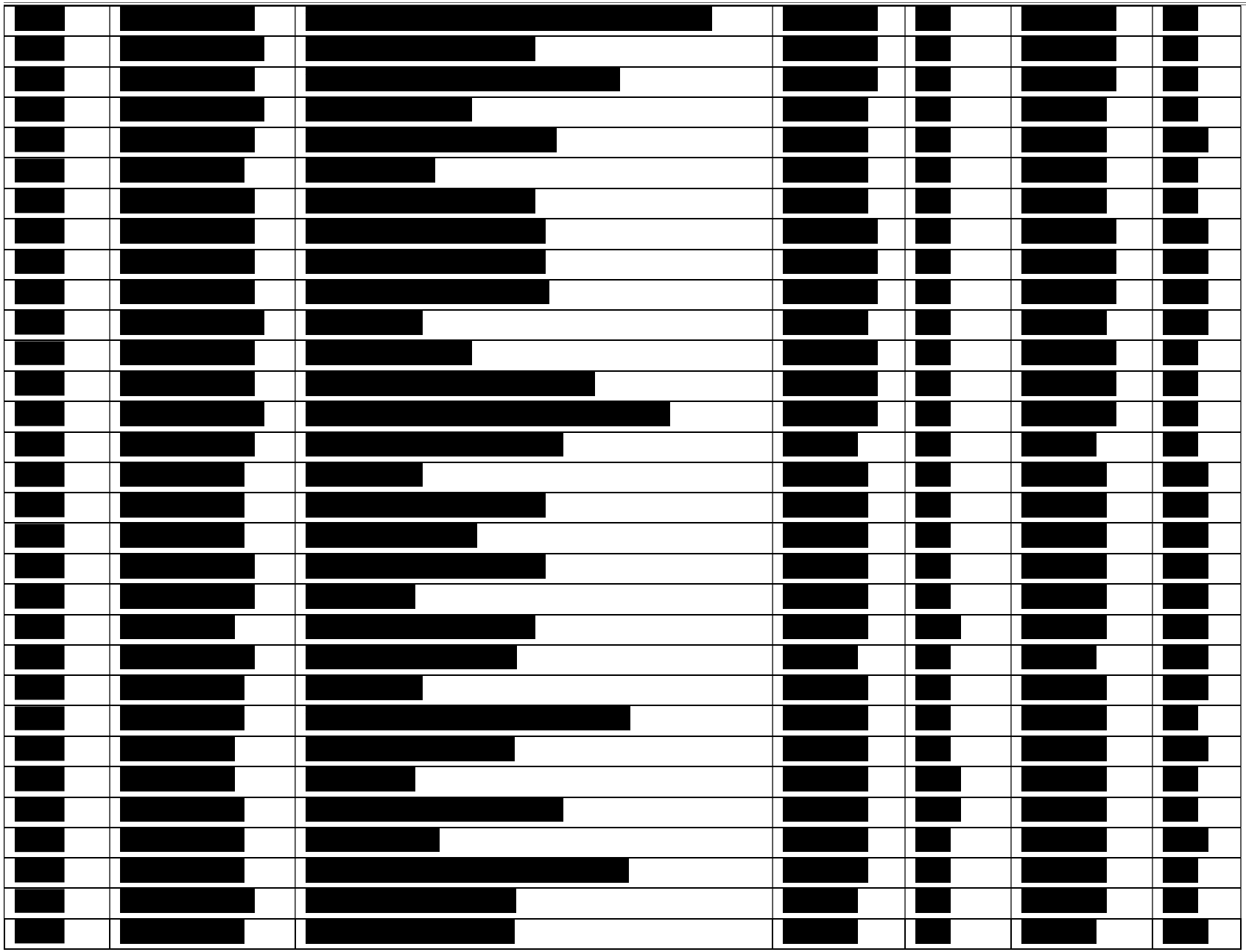
10) List of PSPS's in 2021

CalPeco Electric did not have any PSPS events in 2021.

Appendix A: 9 Years of Planned Outage Data -- PUBLIC VERSION --







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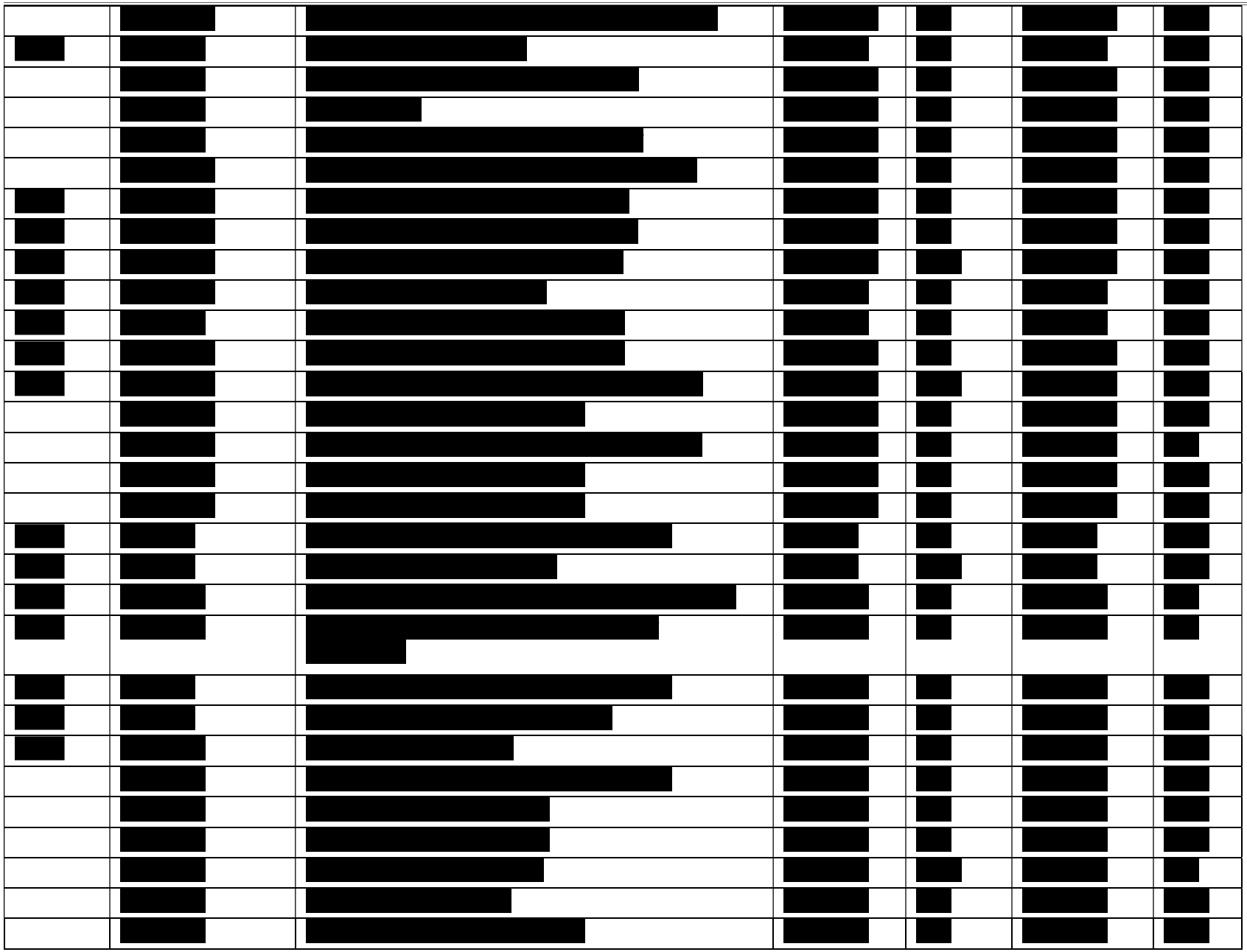


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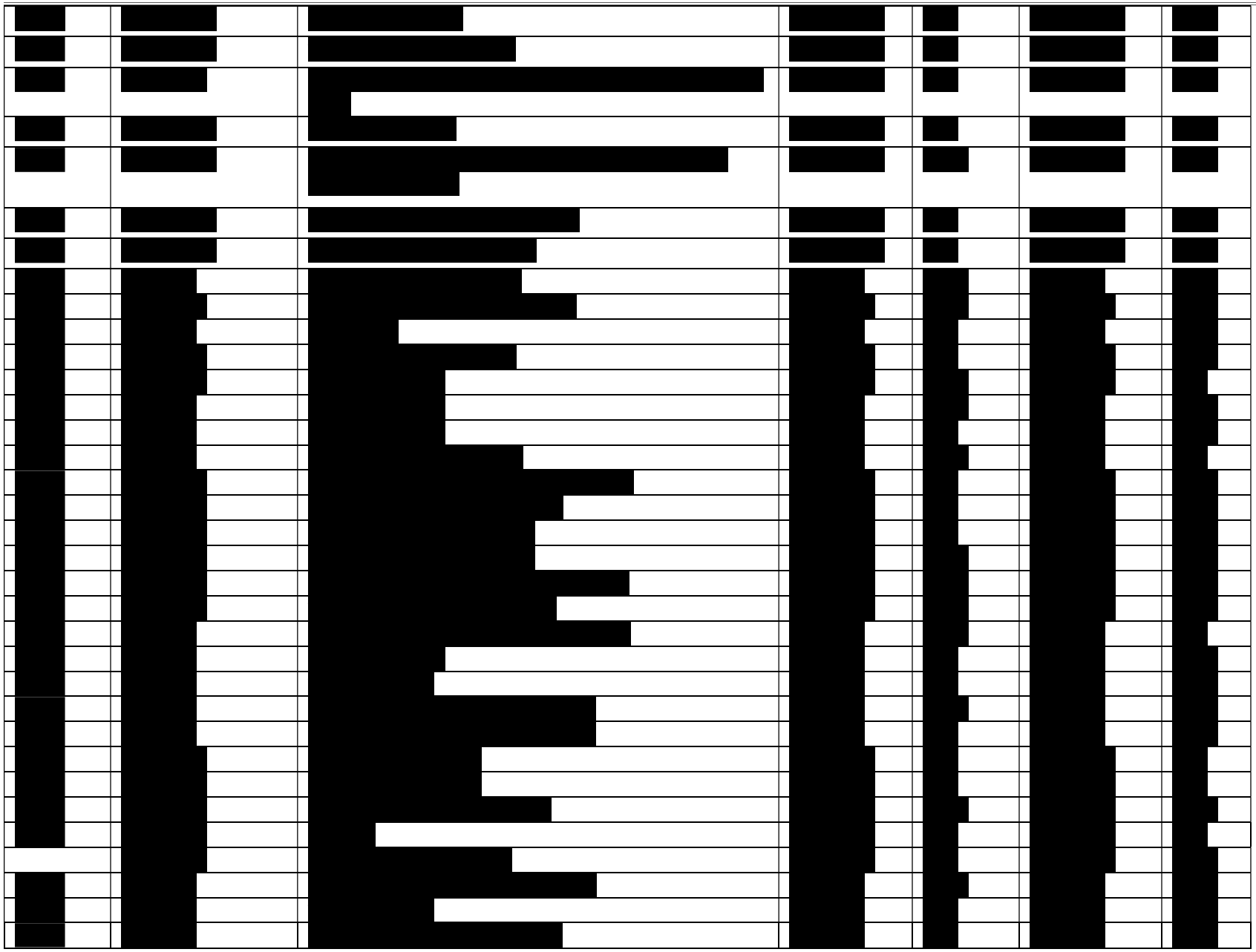


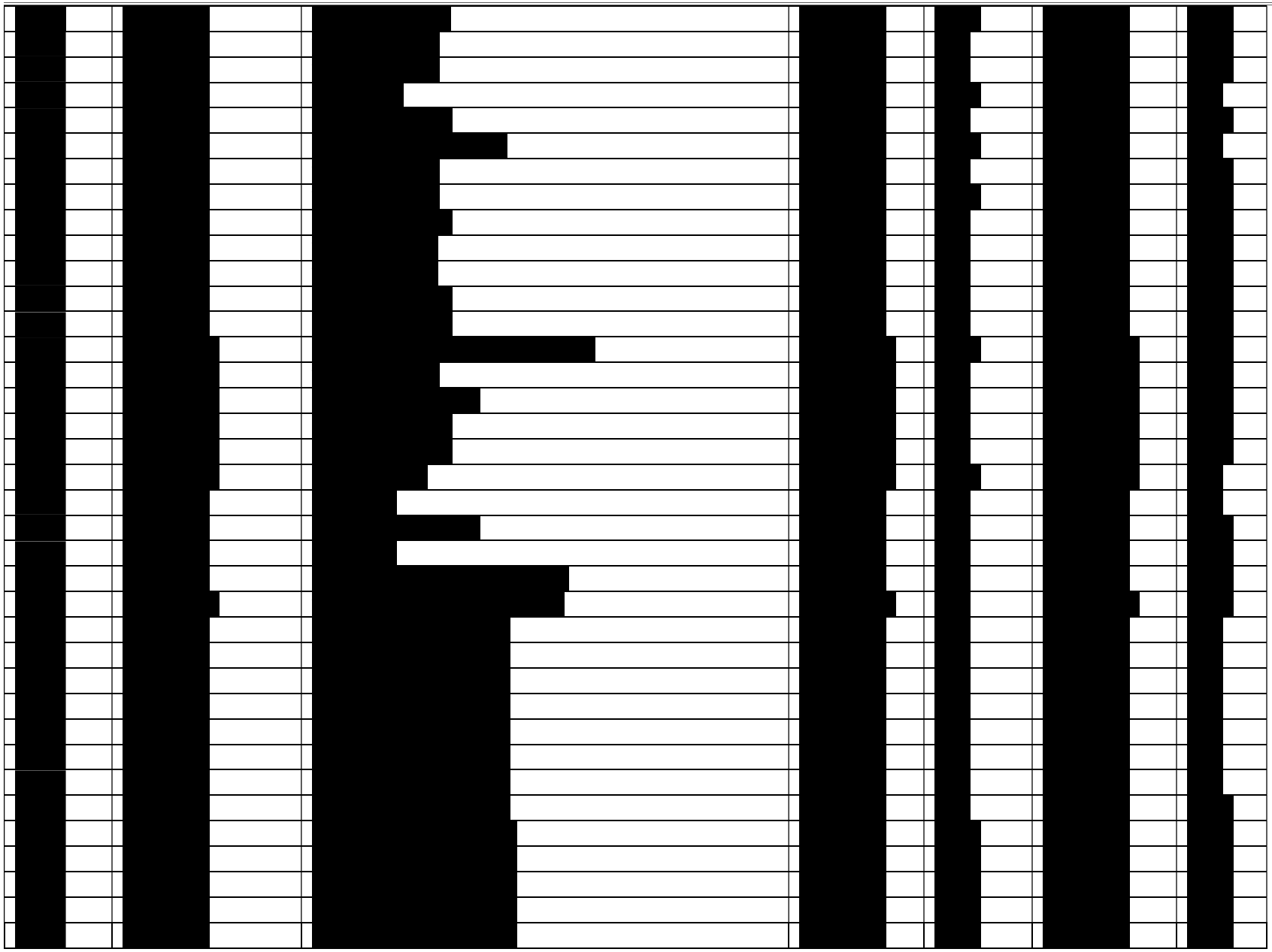


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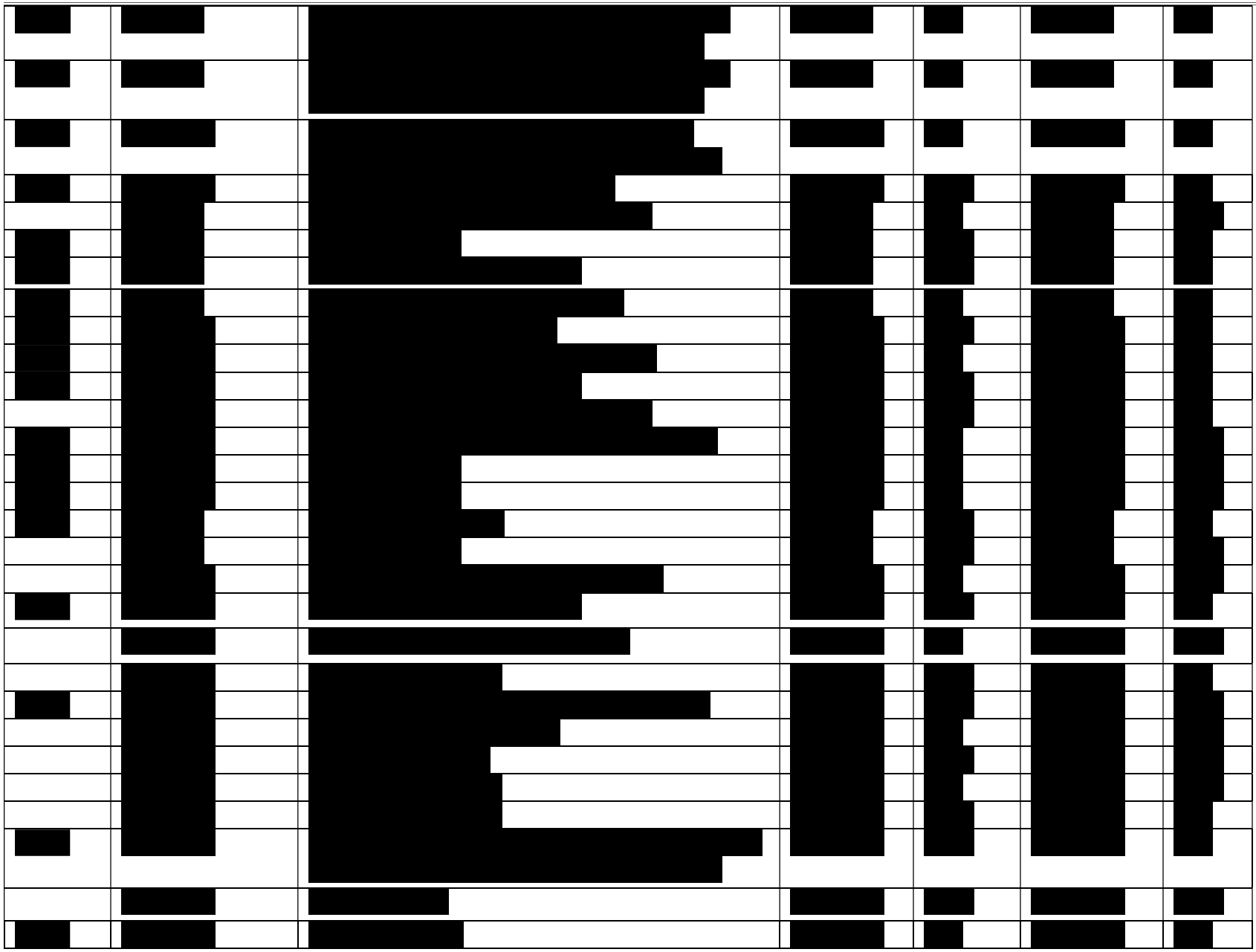
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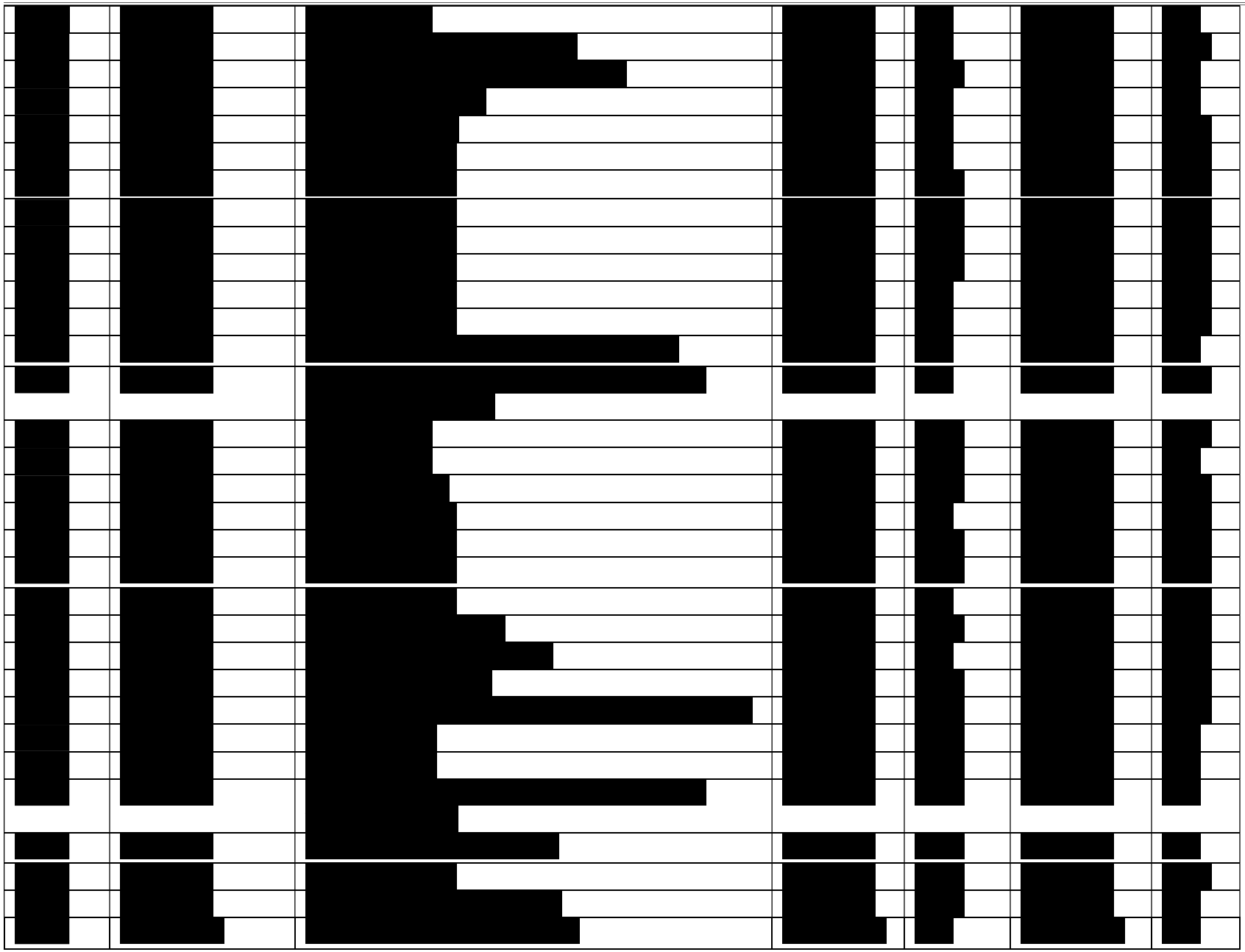


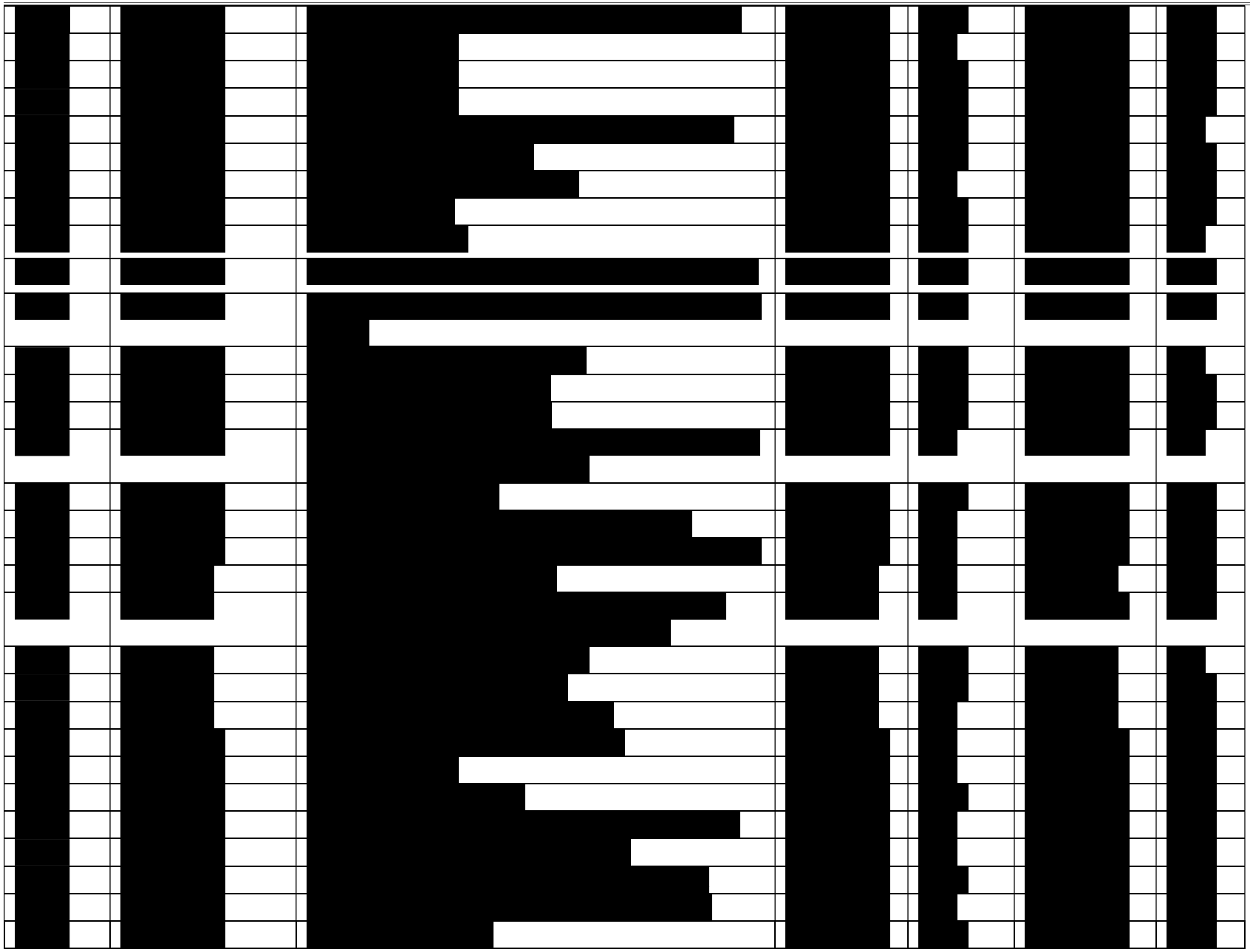














ATTACHMENT 15

Liberty Utilities 2022 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2022

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15th, 2023

CA-07-0840

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2022 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore, data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents ten years (2013 through 2022) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2013, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2022 was 105.07 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 10 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

Liberty Utilities (CalPeco Electric), LLC

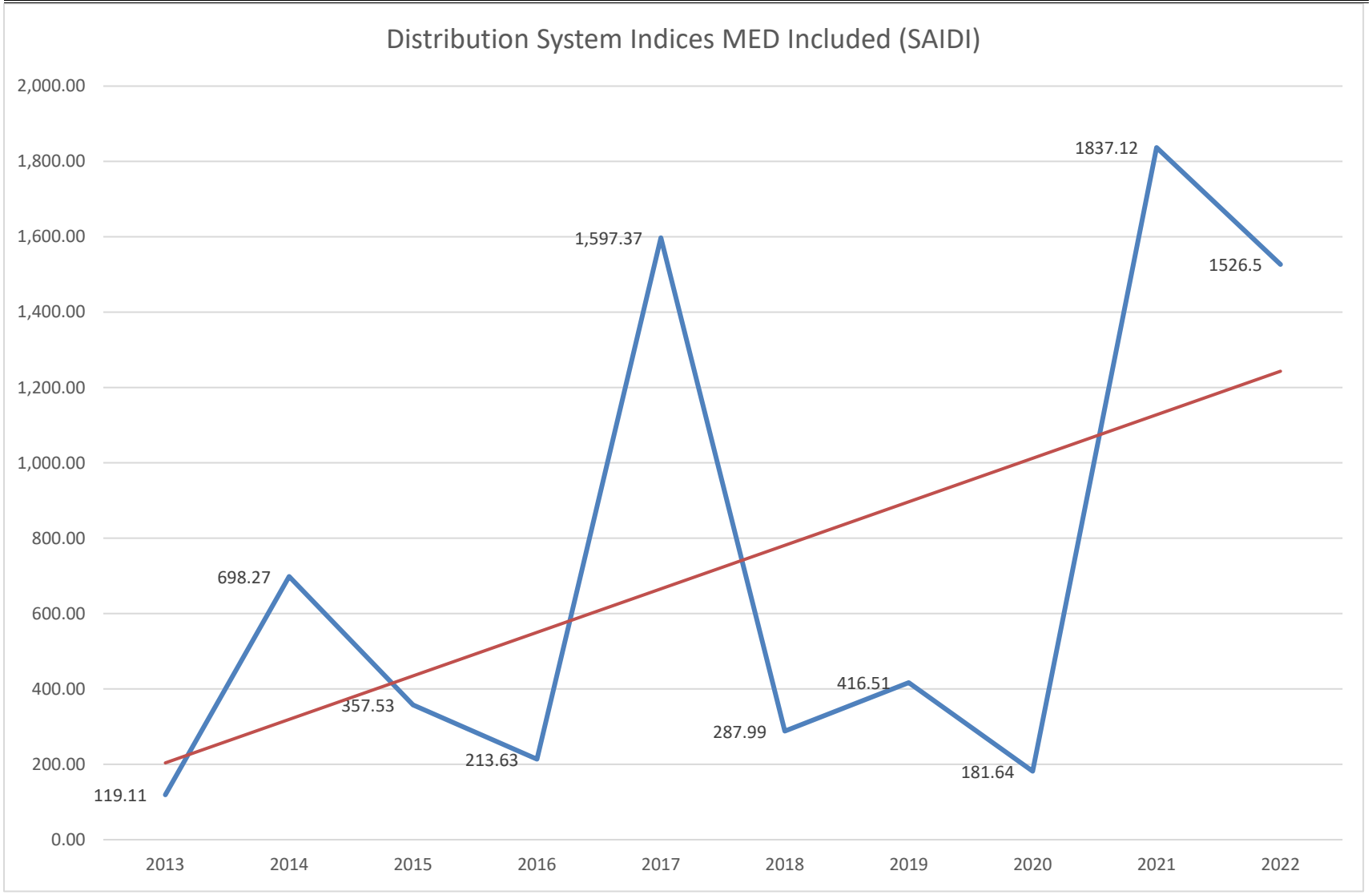
Distribution Historical System Reliability Data 10 Years (Years in Business)

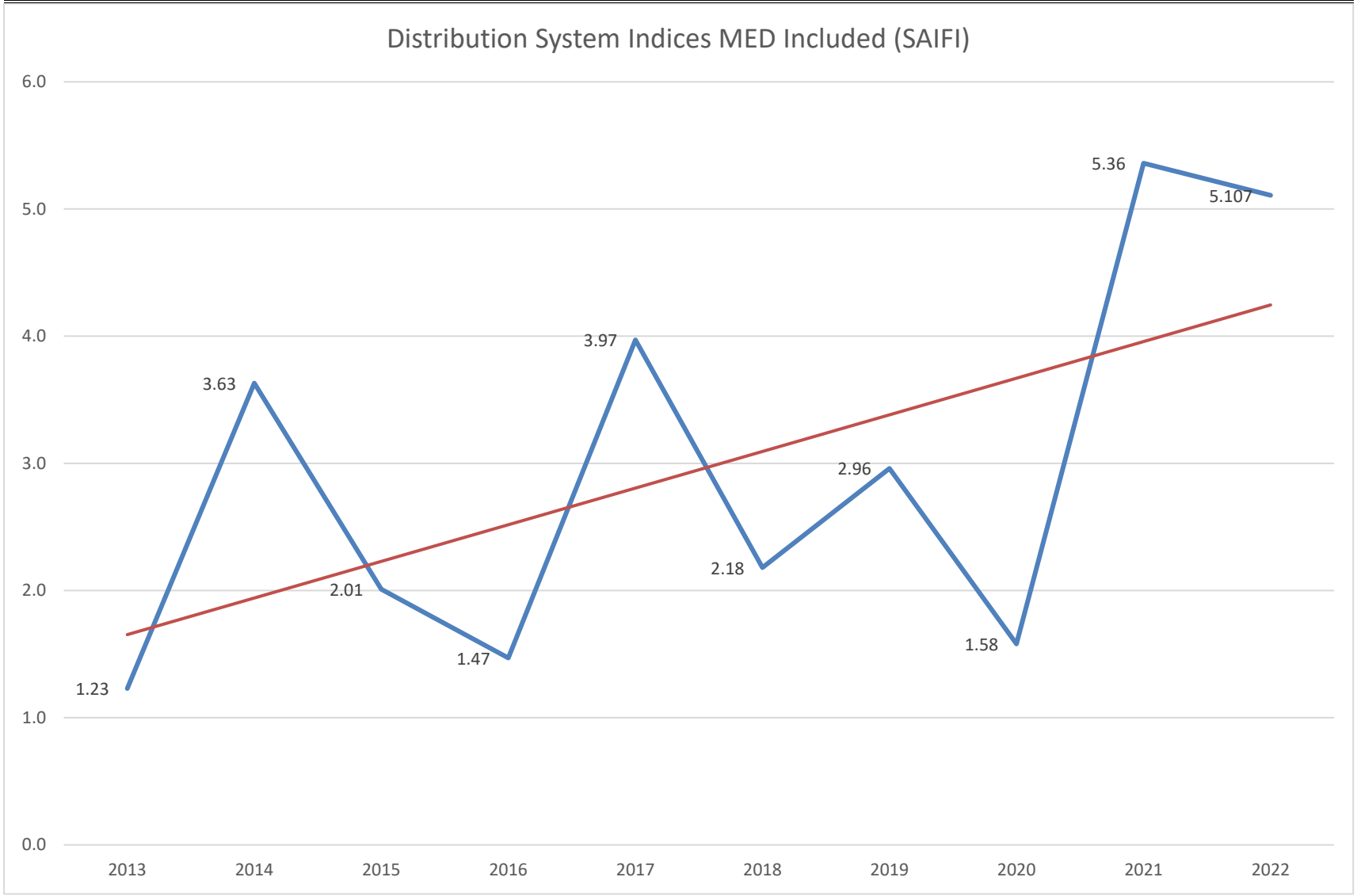
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2022	1526.5	5.107	298.87	0.113	470.75	3.471	135.65	0.113
2021	1837.12	5.36	342.74	0.548	916.28	4.60	199.19	0.548
2020	181.64	1.57	115.23	0.313	181.64	1.57	115.23	0.313
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.4	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08

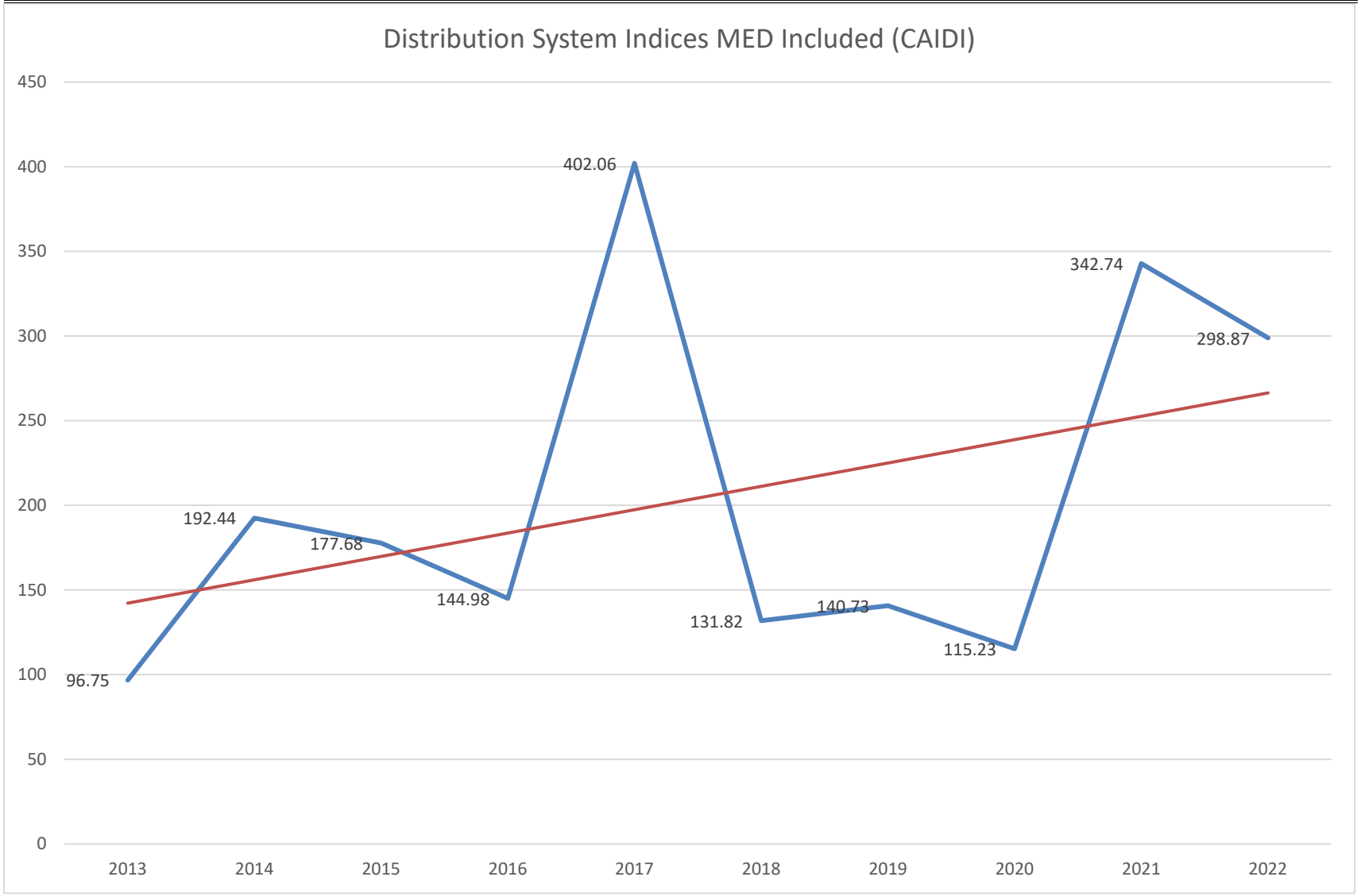
II. Transmission System Indices (MED Included and Excluded)

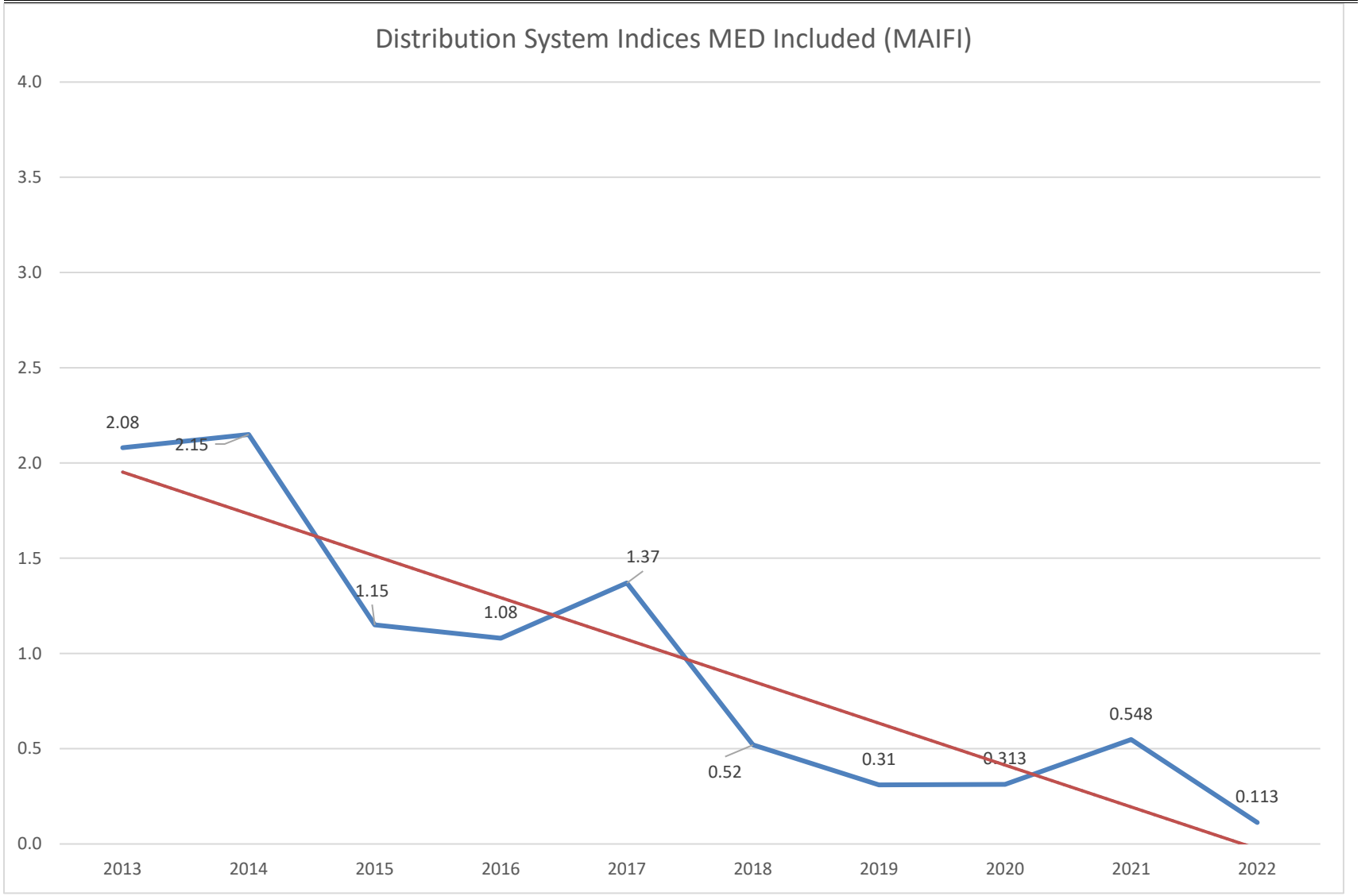
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

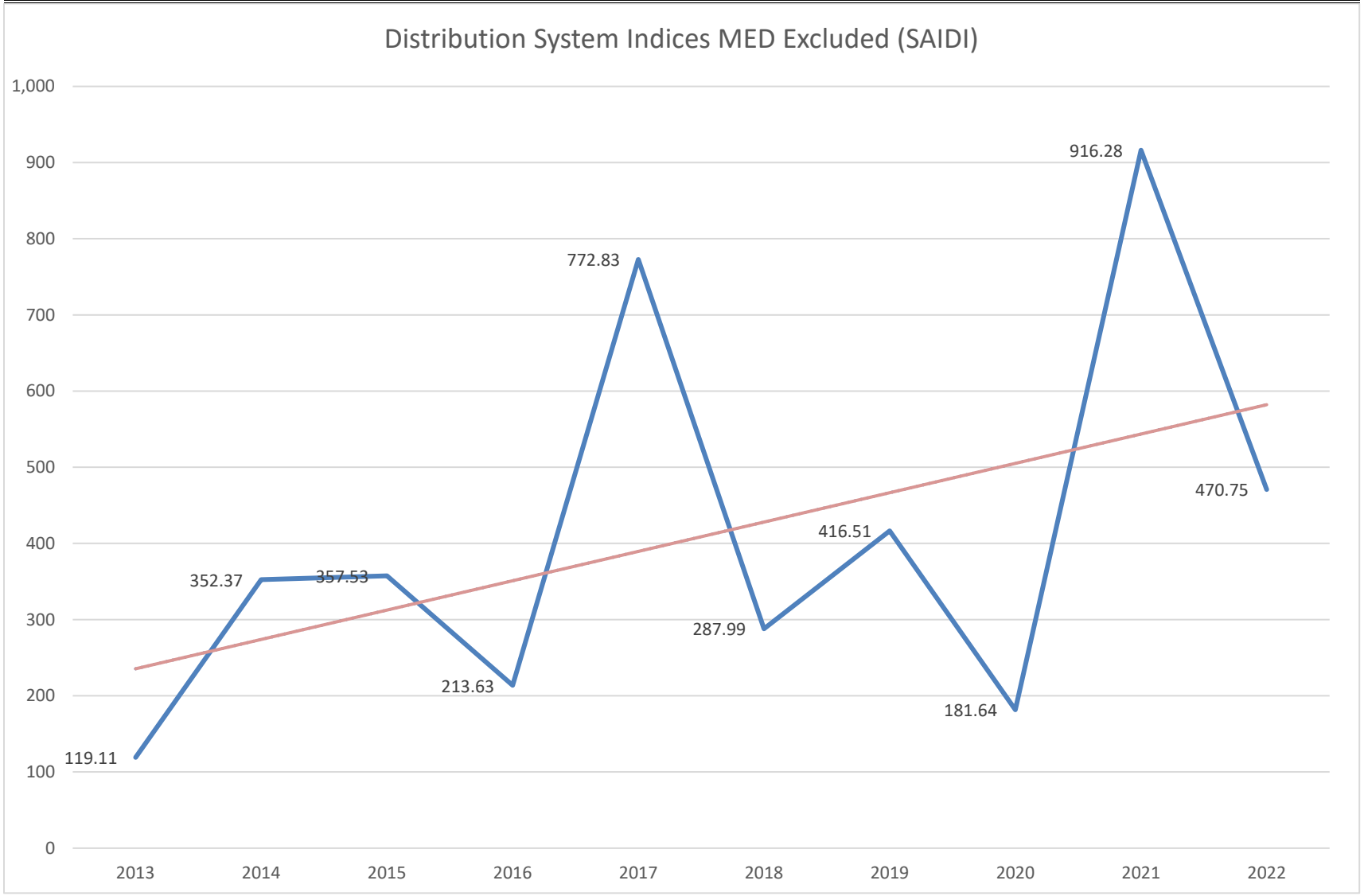
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 10 years with linear trend line (TMED included and excluded).

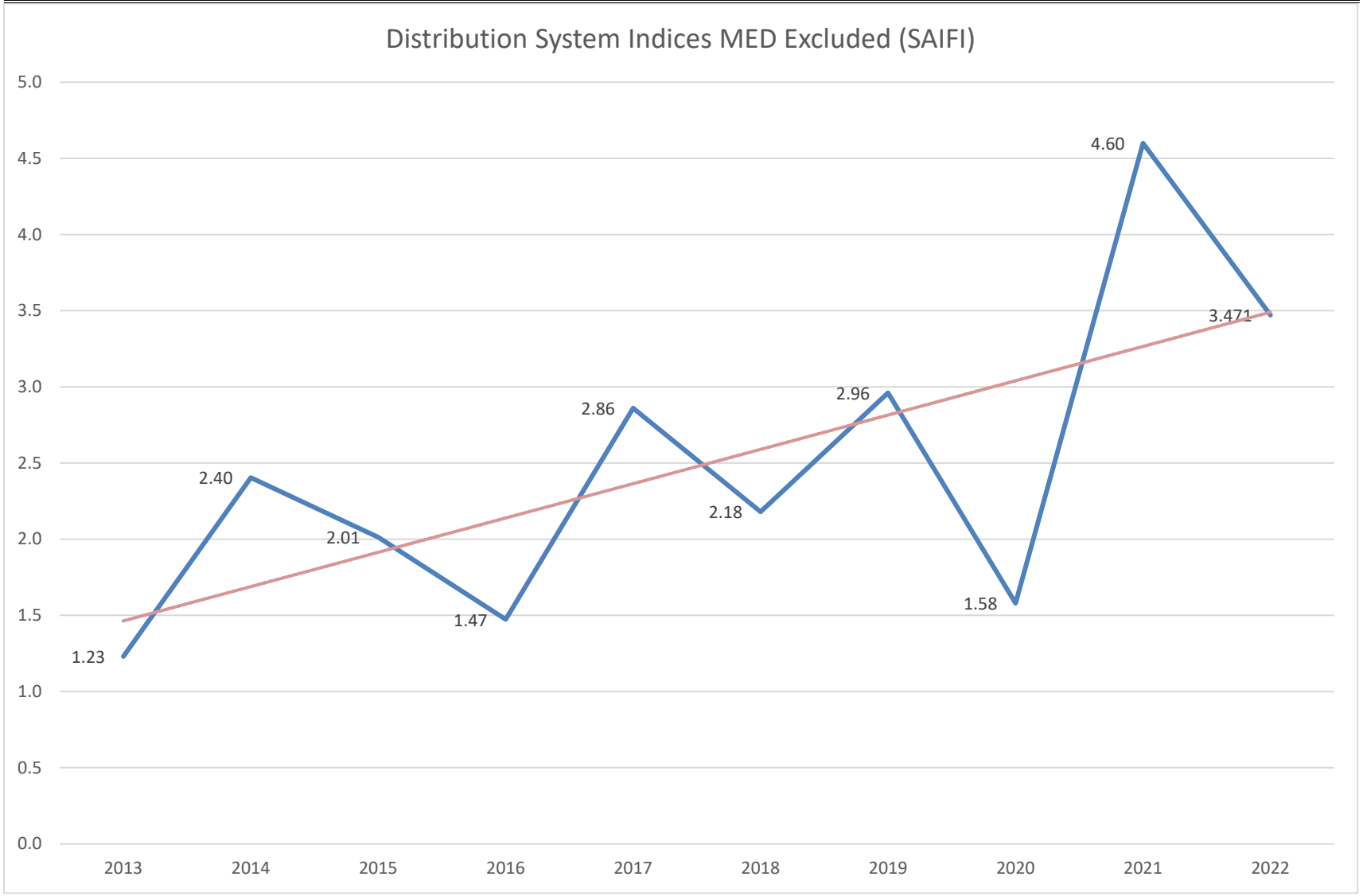

Distribution System Indices MED Included (SAIDI)
2,000.00
1,800.00
1,600.00
1,400.00
1,200.00
1,000.00
800.00
600.00
400.00
200.00
0.00
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
119.11
698.27
357.53
213.63
1,597.37
287.99
416.51
181.64
1837.12
1526.5

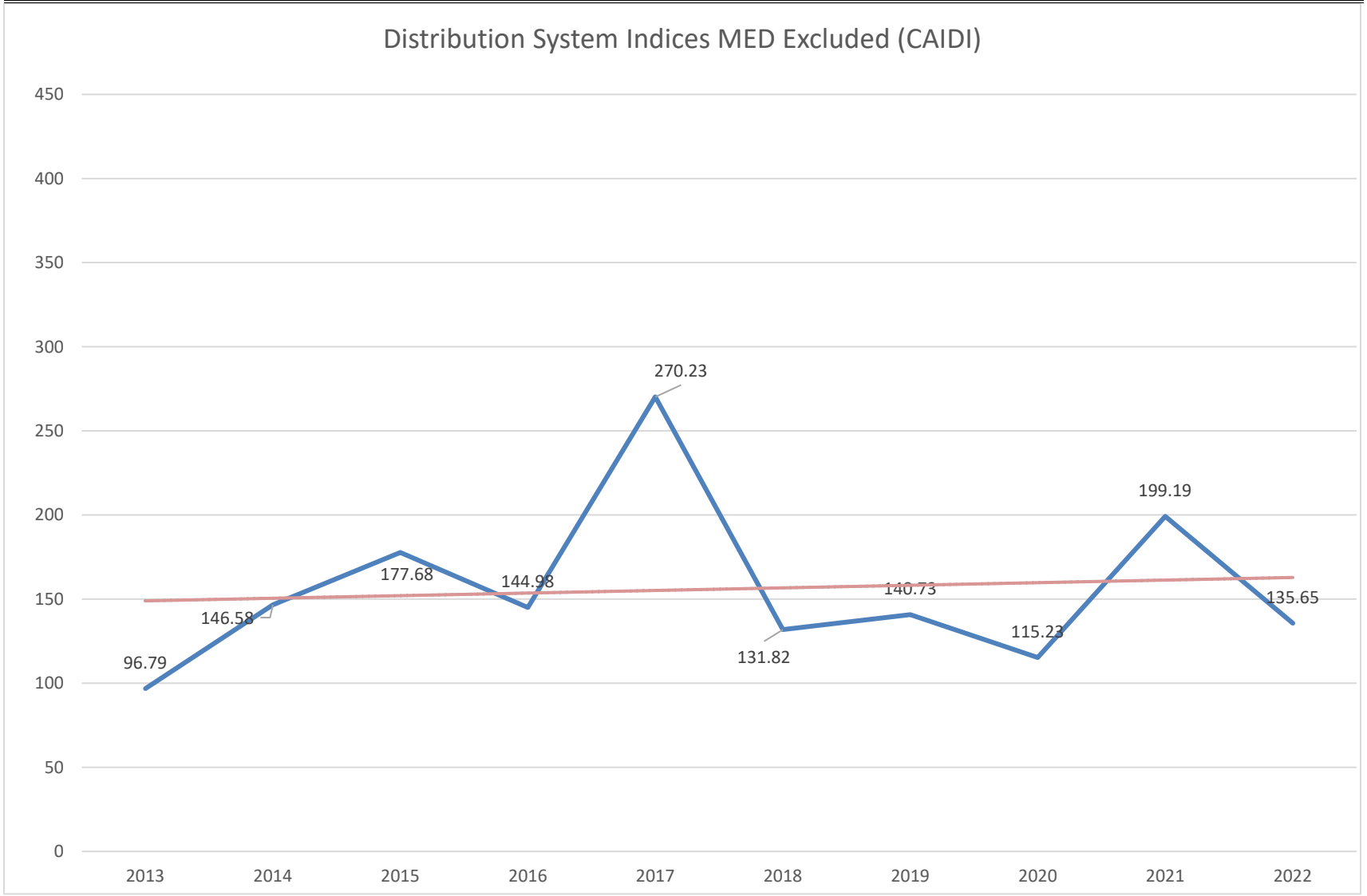

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1.23
3.63
2.01
1.47
3.97
2.18
2.96
1.58
5.36
5.107
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

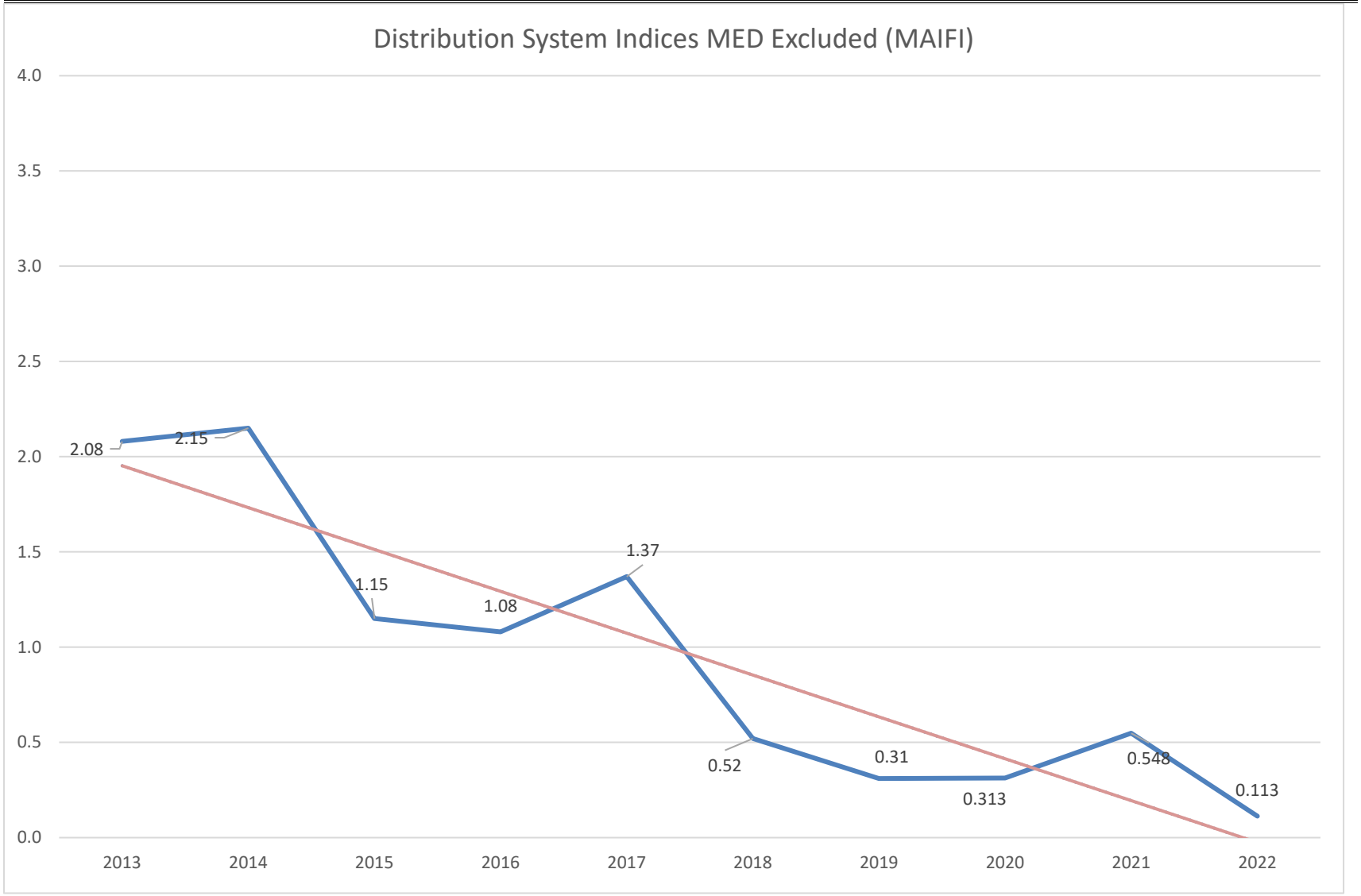

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
96.75
192.44
177.68
144.98
402.06
131.82
140.73
115.23
342.74
298.87
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (SAIDI)
1,000
900
800
700
600
500
400
300
200
100
0
119.11
352.37
357.53
213.63
772.83
287.99
416.51
181.64
916.28
470.75
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (SAIFI)
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.23
2.40
2.01
1.47
2.86
2.18
2.96
1.58
4.60
3.471
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
96.79
146.58
177.68
144.98
270.23
131.82
140.73
115.23
199.19
135.65
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

2) Division (or District) Reliability Indices for the past 10 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

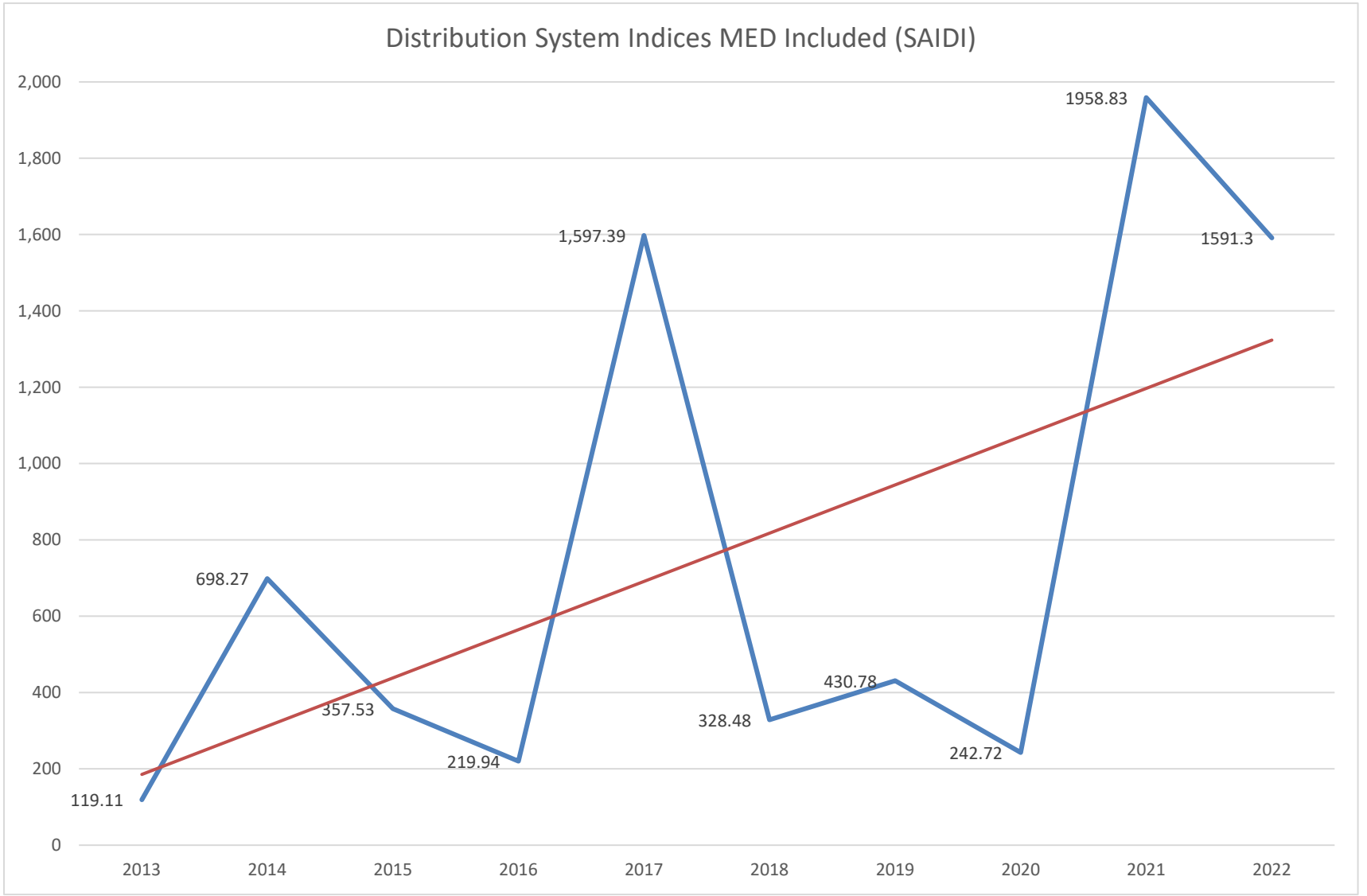
3) System and Division indices based on IEEE 1366 for the past 10 years including planned outages and including and excluding MED

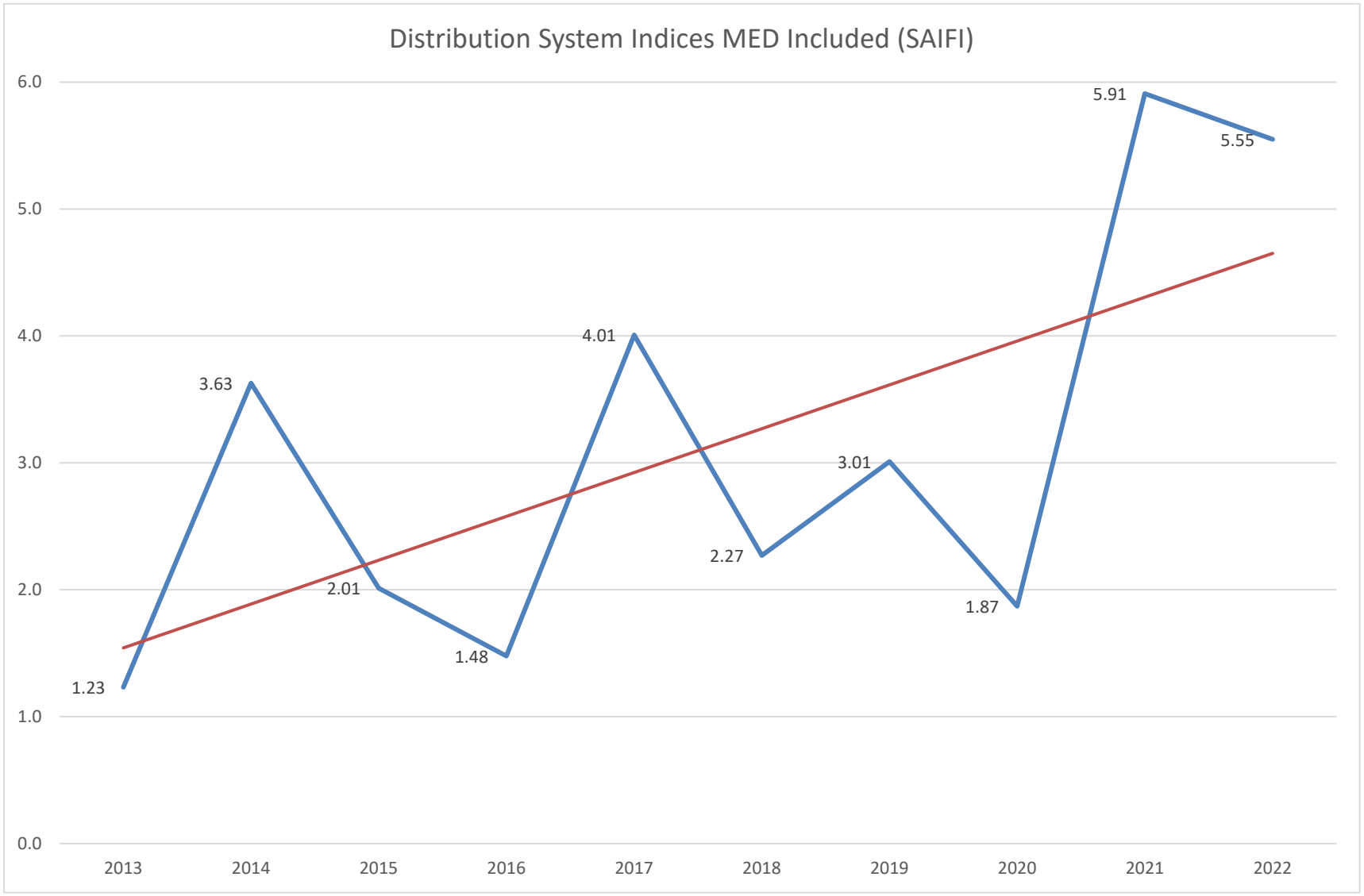
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

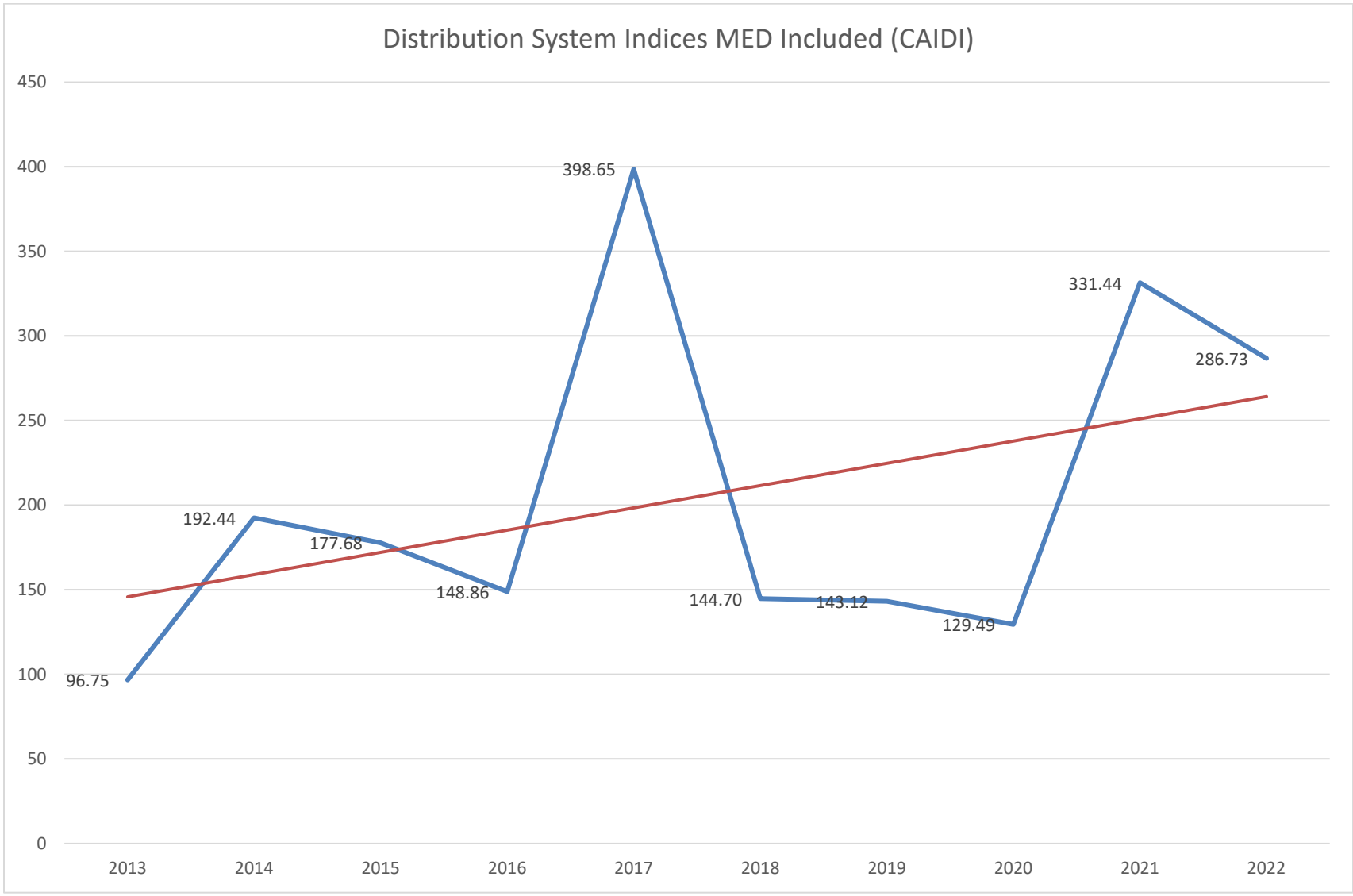
Liberty Utilities (CalPeco Electric), LLC

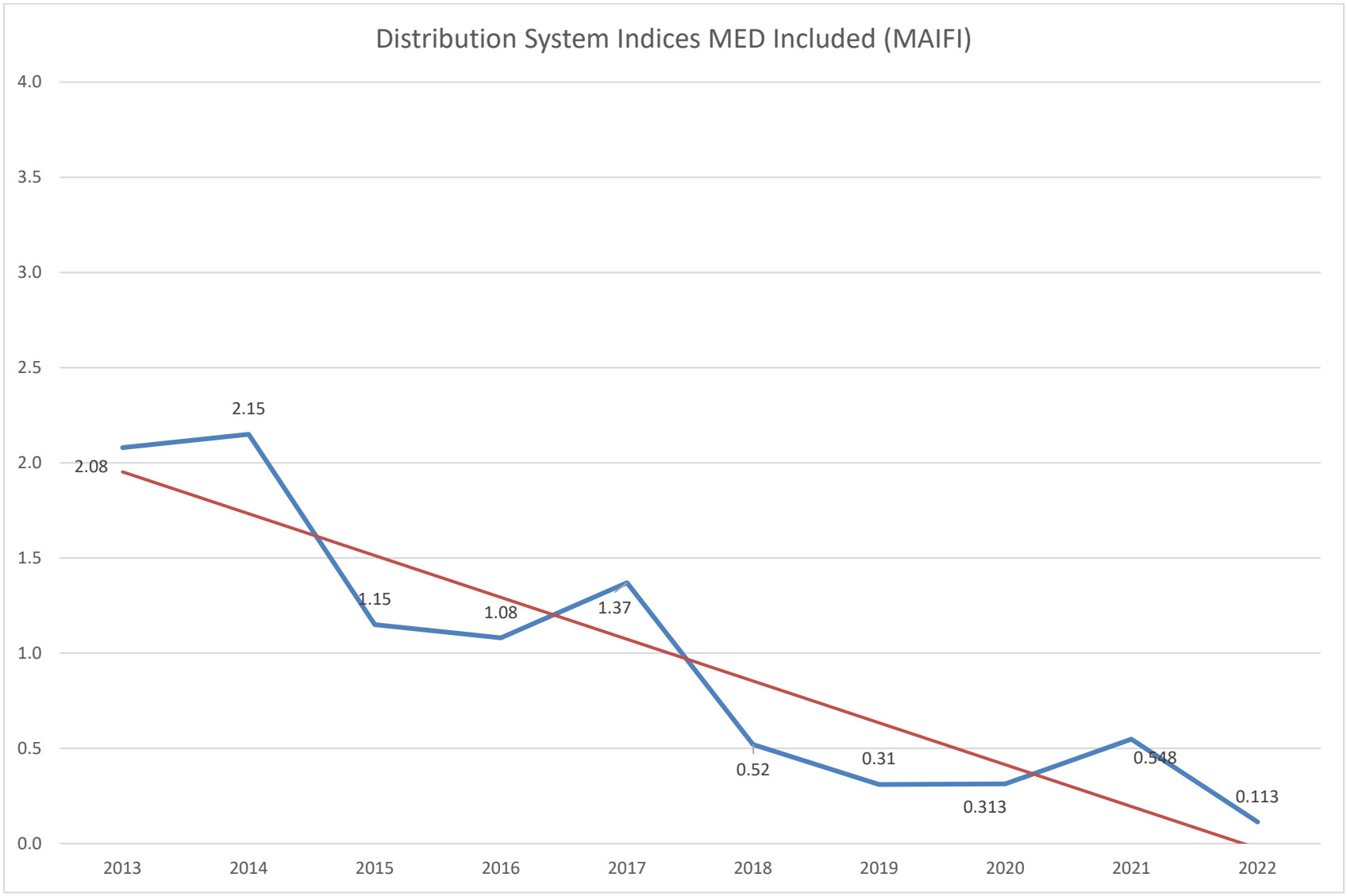
Distribution Historical System Reliability Data 10 Years (Years in Business)

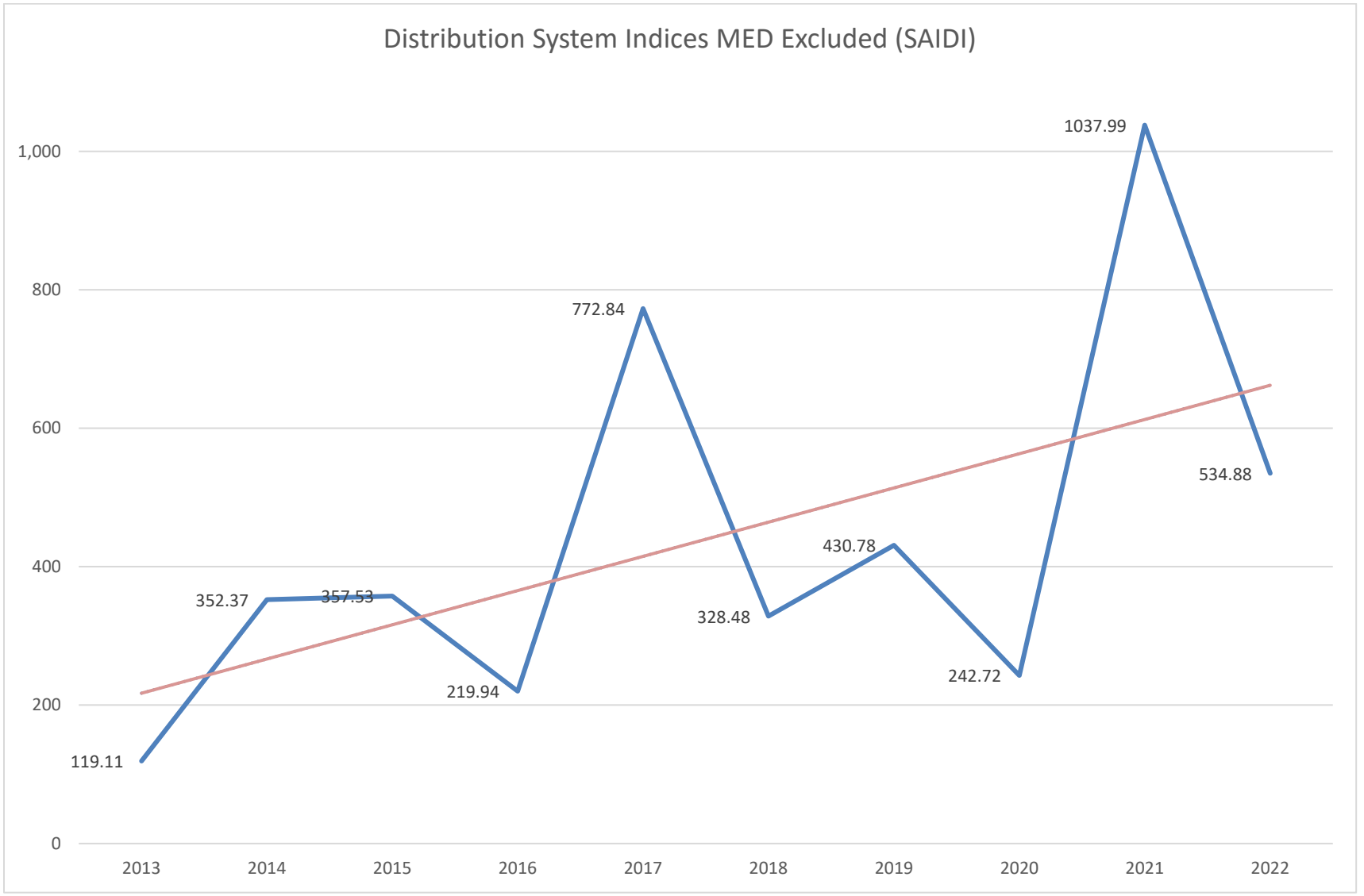
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2022	1591.3	5.55	286.73	0.113	534.88	3.91	136.72	0.113
2021	1958.83	5.91	331.44	0.548	1037.99	5.14	201.94	0.548
2020	242.72	1.87	129.49	0.313	242.72	1.87	129.49	0.313
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.7	0.52	328.48	2.27	144.7	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.4	146.58	2.15
2013	119.11	1.23	96.75	2.08	119.11	1.23	96.79	2.08

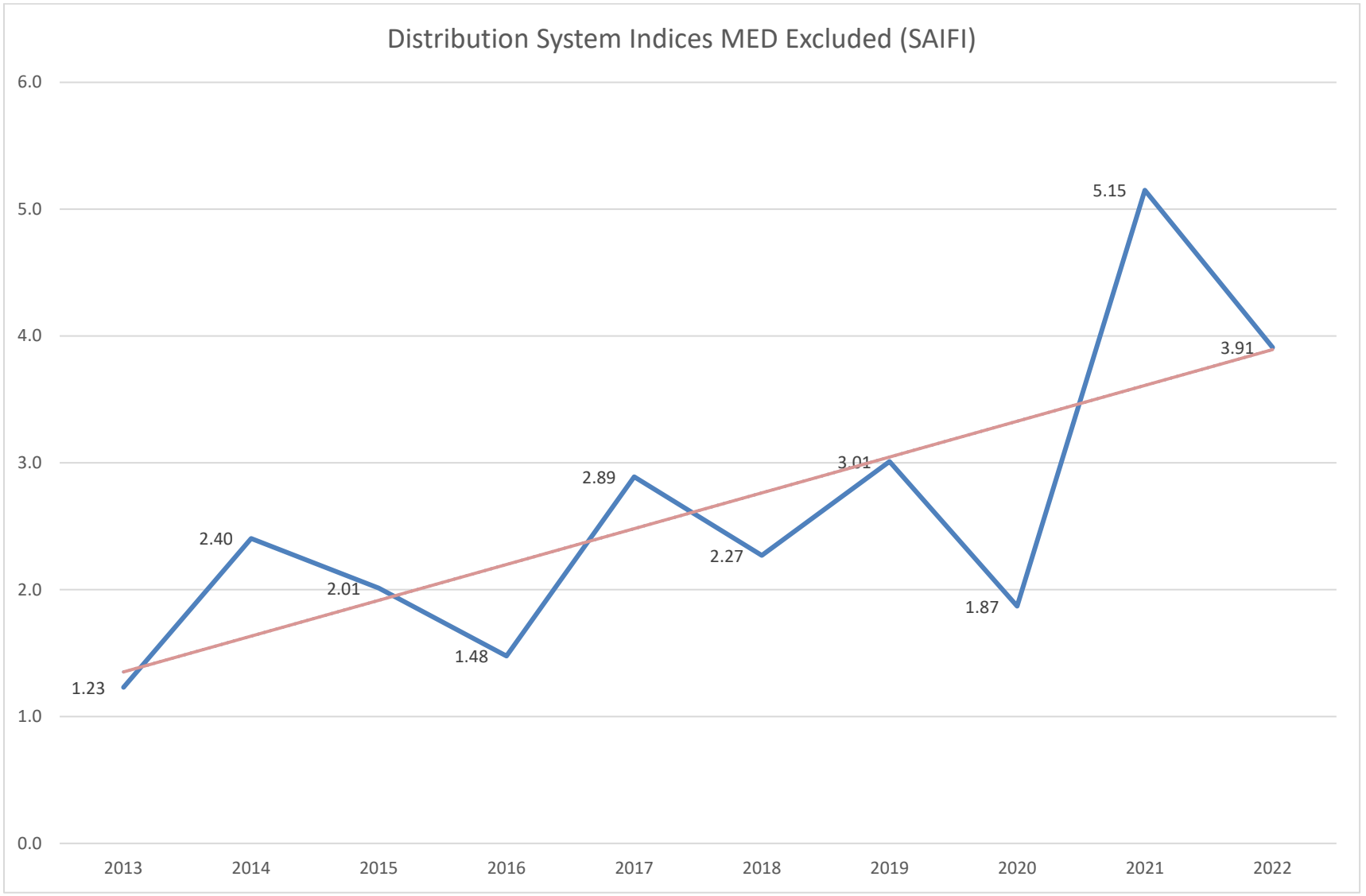

Distribution System Indices MED Included (SAIDI)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
119.11
698.27
357.53
219.94
1,597.39
328.48
430.78
242.72
1958.83
1591.3
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

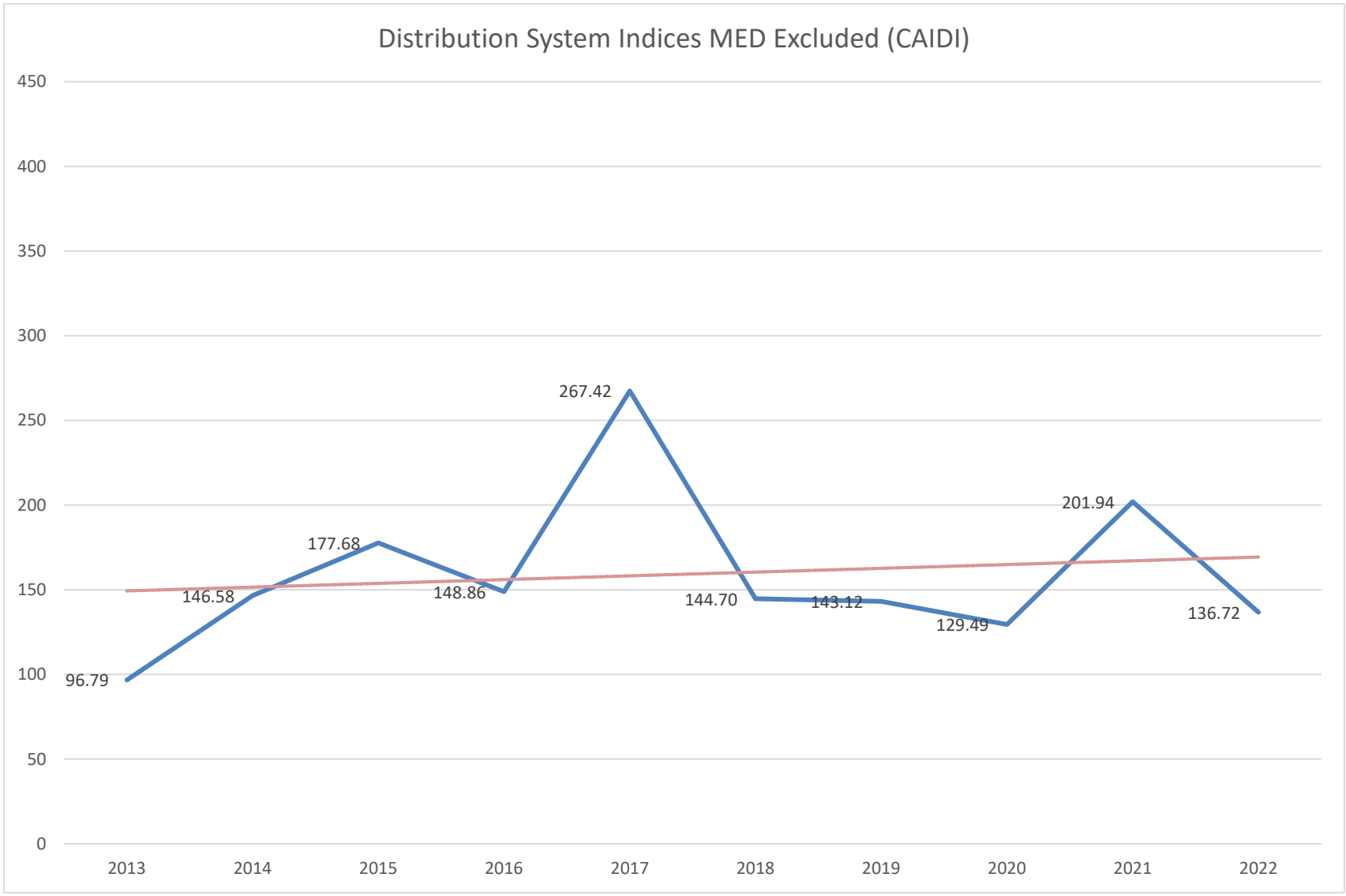

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1.23
3.63
2.01
1.48
4.01
2.27
3.01
1.87
5.91
5.55
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

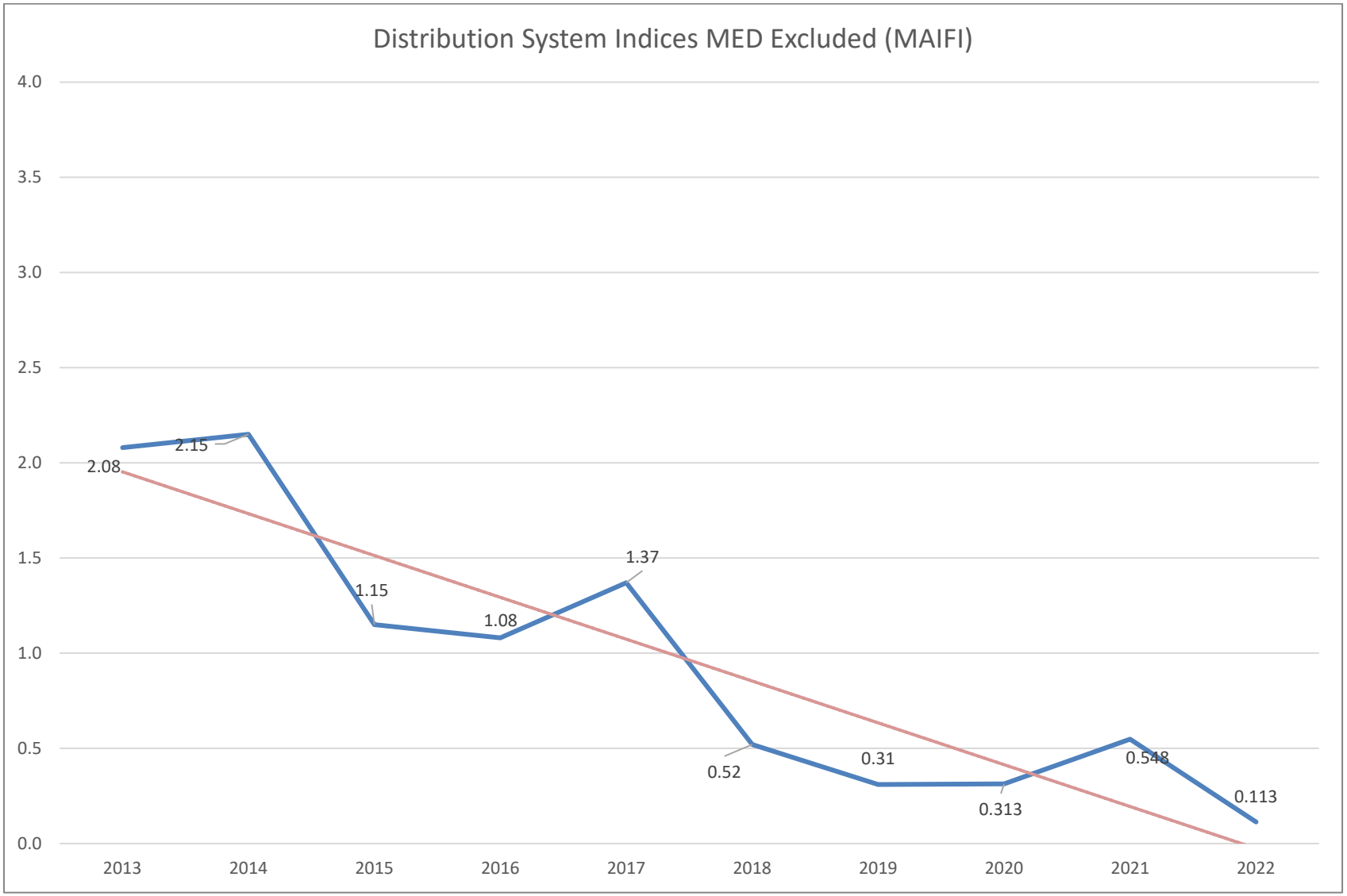

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
96.75
192.44
177.68
148.86
398.65
144.70
143.12
129.49
331.44
286.73
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (SAIDI)
1,000
800
600
400
200
0
119.11
352.37
357.53
219.94
772.84
328.48
430.78
242.72
1037.99
534.88
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1.23
2.40
2.01
1.48
2.89
2.27
3.01
1.87
5.15
3.91
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022

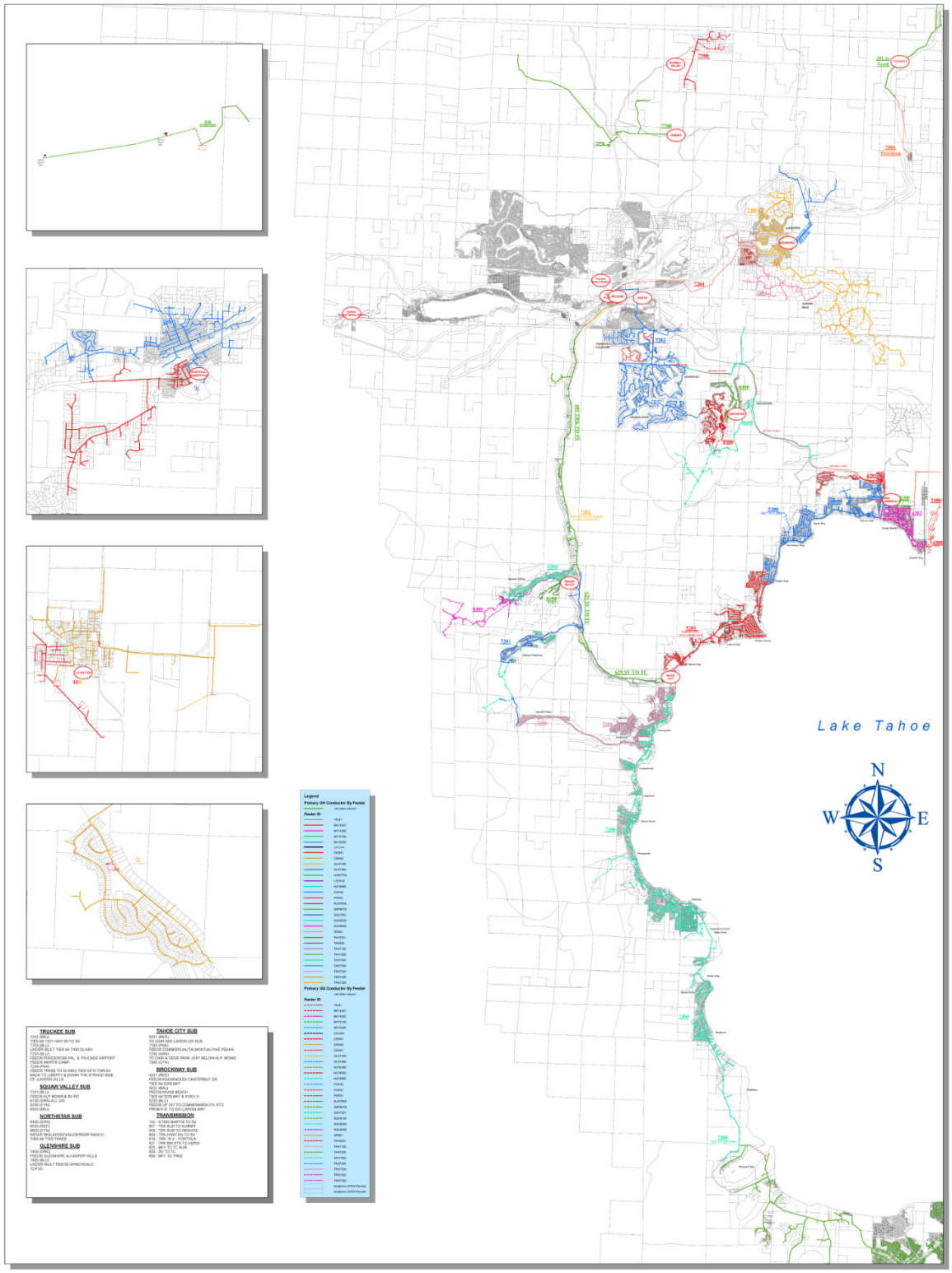

Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
96.79
146.58
177.68
148.86
267.42
144.70
143.12
129.49
201.94
136.72
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2013
2014
2015
2016
2017
2018
2019
2020
2021
2022
2.08
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113

Circuit	District	Number of Planned Outages By Year									
		2022	2021	2020	2019	2018	2017	2016	2015	2014	2013
31	Tahoe	2	5	3		1			1		
32	Tahoe	4	17	4	1		2	1			
41	Tahoe	2		6				1			
42	Tahoe	2									
51	Tahoe	2									
201	Tahoe	1	3			7					1
204	Tahoe	1	1		2			1			
257	Tahoe										
1261	Tahoe	7	5	7	1	1					
1296	Tahoe	1		2		1	2		5	1	
2200	Tahoe		1		1				1	1	
2300	Tahoe	1	2		1	1			1	2	
3100	Tahoe	12	7	2	8	5	1				
3101	Tahoe	11	5	3	3					2	2
3200	Tahoe	6	22	1	3	5			1		
3300	Tahoe	16	19	3	8	10	2		3		
3400	Tahoe	12	23	1	2	4	3		5		2
3500	Tahoe	4	9	6	15		6		1		
3501	Tahoe	10	7		3	3			2	2	4
4201	Tahoe	4	3		1	1		1			
4202	Tahoe	6	8	2	5	3	4				2
4203	Tahoe										
5100	Tahoe		1	1							1
5200	Tahoe	9		1	5	4	1		4	1	1
5201	Tahoe	7	2		8	1	5	5	4	1	
7100	Tahoe	7	4	4	1	2	1			1	1
7200	Tahoe				1	1			1	1	1
7201	Tahoe	3	4	1	1		4	1	2	1	
7202	Tahoe	3	1	3	3	1	1		2	3	1
7203	Tahoe	3	2		3	2			2	2	4
7204	Tahoe	1									
7300	Tahoe	13	14	8	20	14	5	6	4	16	4
7400	Tahoe		4	1	4	8	2	1	1		
7600	Tahoe	1			1	1			1		
7700	Tahoe	3		4						1	
7800	Tahoe									2	
7900	Tahoe	1		2	1						
8100	Tahoe										
8200	Tahoe		2	1	1	2	7	3	2	4	
8300	Tahoe			1	1	1	2		6		
8400	Tahoe			1		7					
8500	Tahoe	1	1	2				1			1
8600	Tahoe								4		
8700	Tahoe										

b. The number, date, and location of planned outages

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261*	Tahoe	845	Topaz	56.98	75.6%	24.4%	9	2313	5.59
3300*	Tahoe	3546	Meyers	56.95	90.7%	9.3%	8	1868	4.87

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1261 circuit was noted as a deficient circuit in 2020, 2021, and 2022. The 3-year average circuit SAIDI score remains high due to a fire that occurred on November 17, 2020, causing widespread outages over the circuit that were restored over the course of 12 hours.

There were 24 unplanned outages in 2022 for the 1261 circuit.

The historical metric for Topaz 1261 based on a 3-year average:

- 2022 - 2313
- 2021 – 3028
- 2020 – 2615

There are currently no plans in place that would remedy loss of source outages, which account for majority of the outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada.

The circuit performance in 2022 measured alone was above average compared to historical values. The event in and 2020 were outliers resulting from extreme weather conditions and do not accurately represent the average performance of the system.

The Meyers 3300 circuit was noted as a deficient circuit in 2021, and 2022. The 3-year average circuit SAIDI score remains high due extreme weather condition the past two years causing widespread outages over the circuit that in some cases took multiple days to restore. These condition resulted in multiple MED’s.

There were 57 unplanned outages in 2022 for the 3300 circuit.

The historical metric for Meyers 3300 based on a 3-year average:

- 2022 - 1868
- 2021 – 980
- 2020 – 132

Majority of SAIDI point was attributed by MED's. Plans to remedy the loss of source outages are complete in which a new breaker was installed allowing for dual sources coming into the sub. Efforts to replace outdated infrastructure is being planned, including overhead and underground conductors within coming years

The circuit performance in 2022 measured alone was far above average due to extreme weather conditions. This is not normally the case as seen in prior years. Future performance is expected to improve based on normal weather conditions and infrastructure improvements.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of

interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Senior Director of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	12/11/2022 5:14	CB Lockout	Lake Tahoe	4573	134.07	0.09
2	12/11/2022 2:55	CB Lockout	Lake Tahoe	4013	96.26	0.08
3	12/12/2022 17:45	CB Lockout	Lake Tahoe	6382	76.96	0.13
4	12/11/2022 8:45	CB Lockout	Lake Tahoe	2290	56.75	0.05
5	12/11/2022 5:14	CB Lockout	Lake Tahoe	2357	56.26	0.05
6	12/11/2022 4:49	Blown Fuse	Lake Tahoe	698	46.28	0.01
7	12/11/2022 0:43	CB Lockout	Lake Tahoe	3559	40.73	0.07
8	12/31/2022 12:59	CB Lockout	Lake Tahoe	4400	32.97	0.09
9	12/10/2022 22:58	PTR Lockout	Lake Tahoe	484	31.41	0.01
10	12/31/2022 14:02	Loss of Source	Lake Tahoe	4273	29.06	0.09

*Based on customer impact

7) Summary list of 2022 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	12/11/2022	Storm	Lake Tahoe	32400	635.65	0.64
2	12/12/2022	Storm	Lake Tahoe	13000	154.67	0.26
3	12/31/2022	Storm	Lake Tahoe	36723	266.06	0.73

TMED as of 2021 = 105.07

8) Historical 10 largest unplanned outage events for the past 10 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	12/11/2022	4573	66.7	112,064	YES
2	CB Lockout	12/11/2022	4013	20.1	80,461	YES
3	CB Lockout	12/12/2022	6382	28.3	64,328	YES
4	CB Lockout	12/11/2022	2290	34.0	47,436	YES
5	CB Lockout	12/11/2022	2357	20.0	47,022	YES
6	Blown Fuse	12/11/2022	698	55.4	38,681	YES
7	CB Lockout	12/11/2022	3559	9.6	34,048	YES
8	CB Lockout	12/31/2022	4400	11.0	27,554	YES
9	PTR Lockout	12/10/2022	484	68.7	26,256	NO
10	Loss of Source	12/31/2022	4273	7.6	24,287	YES

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	12/11/2022 5:14	4573	66.7	112,064	YES
2	CB Lockout	12/11/2022 2:55	4013	20.1	80,461	YES
3	CB Lockout	12/12/2022 17:45	6382	28.3	64,328	YES
4	CB Lockout	12/11/2022 8:45	2290	34.0	47,436	YES
5	CB Lockout	12/11/2022 5:14	2357	20.0	47,022	YES
6	Blown Fuse	12/11/2022 4:49	698	55.4	38,681	YES

7	CB Lockout	12/11/2022 0:43	3559	9.6	34,048	YES
8	CB Lockout	12/31/2022 12:59	4400	11.0	27,554	YES
9	PTR Lockout	12/10/2022 22:58	484	68.7	26,256	NO
10	Loss of Source	12/31/2022 14:02	4273	7.6	24,287	YES

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	7/28/2021	10812	1.2	12,974	No
2	Recloser Lockout	12/15/2021	5348	1.85	9,894	No
3	Wire Down	12/14/2021	4530	6.15	27,860	Yes
4	CB Lockout, Lighting	7/29/2021	4522	0.98	4,447	No
5	Device failure	12/14/2021	4387	9.55	41,896	Yes
6	Loss of Source	10/7/2021	4374	0.1	437	No
7	Loss of Source	10/8/2021	4374	5.78	25,296	No
8	CB Lockout	12/24/2021	4368	1.7	7,426	No
9	CB Lockout	12/13/2021	4362	6.82	29,734	No
10	Loss of Source	2/25/2021	4183	0.62	336	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Operations Error	7/28/2020	5,291	0.68	3597.8	No
2	CB Lockout, Lightning possible	8/24/2020	3,835	1.63	6251.05	No
3	Unknown	11/6/2020	3,728	1.3	4846.4	No
4	Wind/Debris	8/12/2020	3,724	0.56	2085.44	No
5	Animal	9/10/2020	3,451	0.3	1035.3	No
6	Animal	9/6/2020	3,266	0.86	2808.7	No
7	Animal	10/23/2020	3,266	0.28	914.5	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
8	Animal	7/28/2020	2,555	0.46	705.8	No
9	Device failure	7/2/2020	2,555	1.43	3653.6	No
10	Operations Error	7/28/2020	2,555	0.68	1737.4	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1411.38	No
4	Hardware Failure	2/26/2019	4,485	3.5	15697.5	No
5	Tree	1/18/2019	4,448	1.76	7828.48	No
6	Hardware Failure	3/6/2019	4,448	0.82	3647.36	No
7	Animal	11/11/2019	4,245	0.6	2547	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1596.16	No
9	Animal	6/7/2019	3,529	0.47	1658.63	No
10	Tree	6/7/2019	3,507	1.51	5295.57	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Wire Down Transformer	7/4/2013	5,650	9.82	10,816.02	No
2	Tree Trimming	8/14/2013	4,800	2.35	4,334.50	No
3	Car/Pole	10/25/2013	3,548	0.40	1,419.20	No
4	Cable Failure	8/7/2013	3,475	8.50	4,412.50	No
5	Trees	3/14/2013	3,315	0.30	1,049.75	No
6	Hardware Failure	3/6/2013	3,000	8.13	14,740.00	No
7	Weather/Lightning	7/2/2013	3,000	2.10	6,300.00	No
8	Weather/Lightning	7/25/2013	2,042	3.46	911.83	No
9	Bird/Animal	10/5/2013	2,000	4.00	2,108.00	No
10	Unknown Cause	6/30/2013	2,000	0.76	1,533.33	No

9) Number of customer inquiries on reliability data and the number of days per response

CalPeco Electric did not receive any reliability inquiries in 2022.

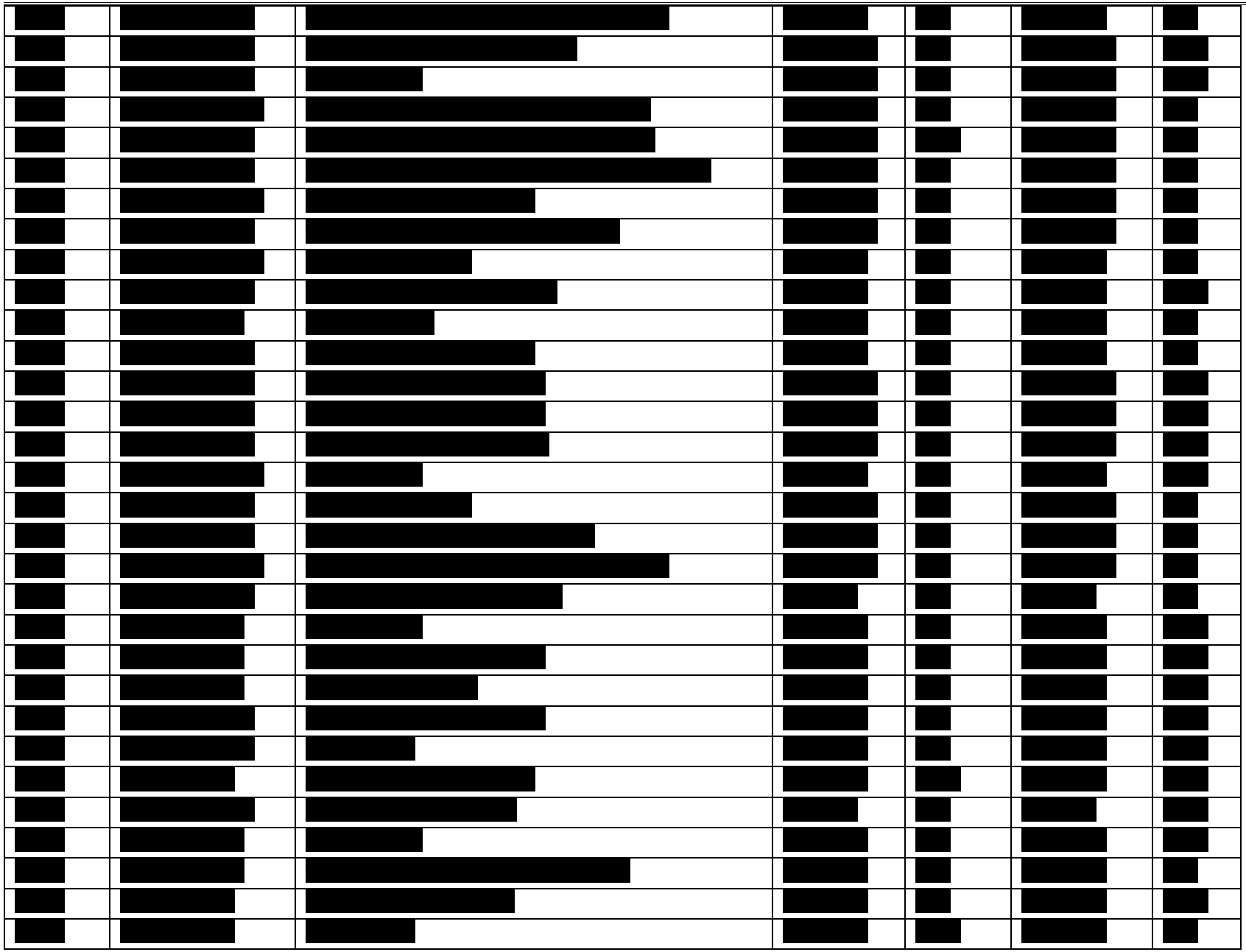
Date Received	Date Responded	Description of Inquiry

10) List of PSPS's in 2022

CalPeco Electric did not have any PSPS events in 2022.

Appendix A: 10 Years of Planned Outage Data -- PUBLIC VERSION --

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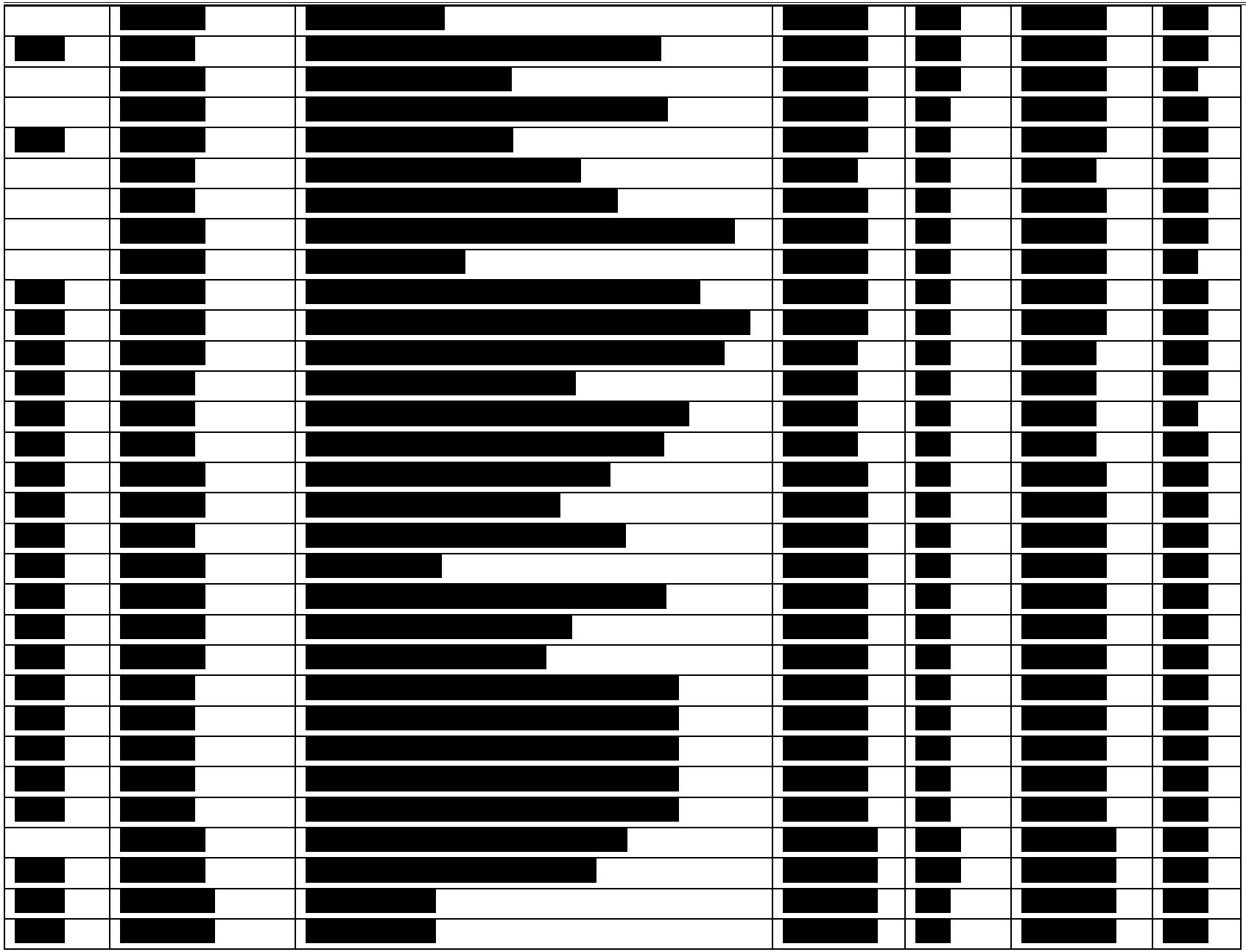


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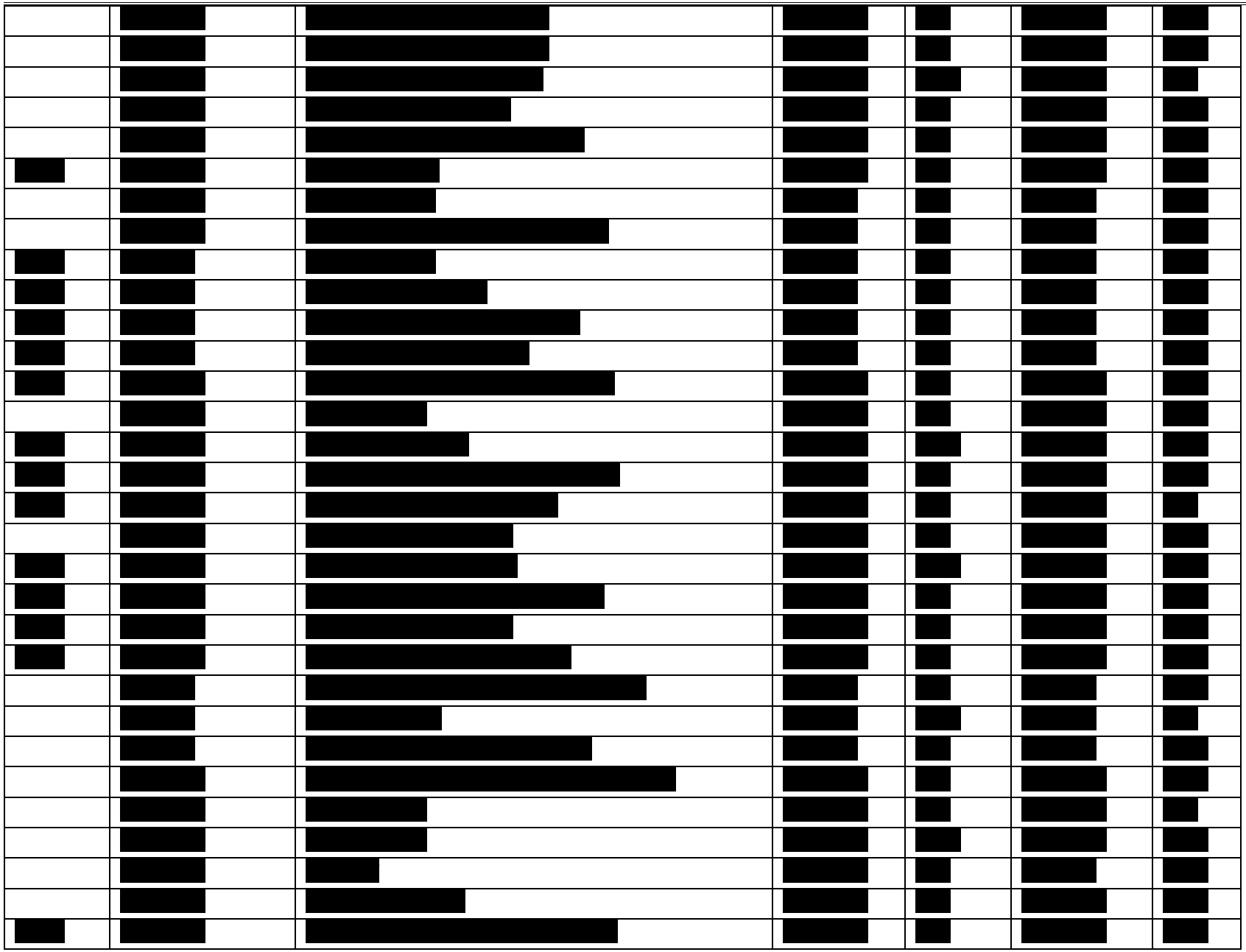
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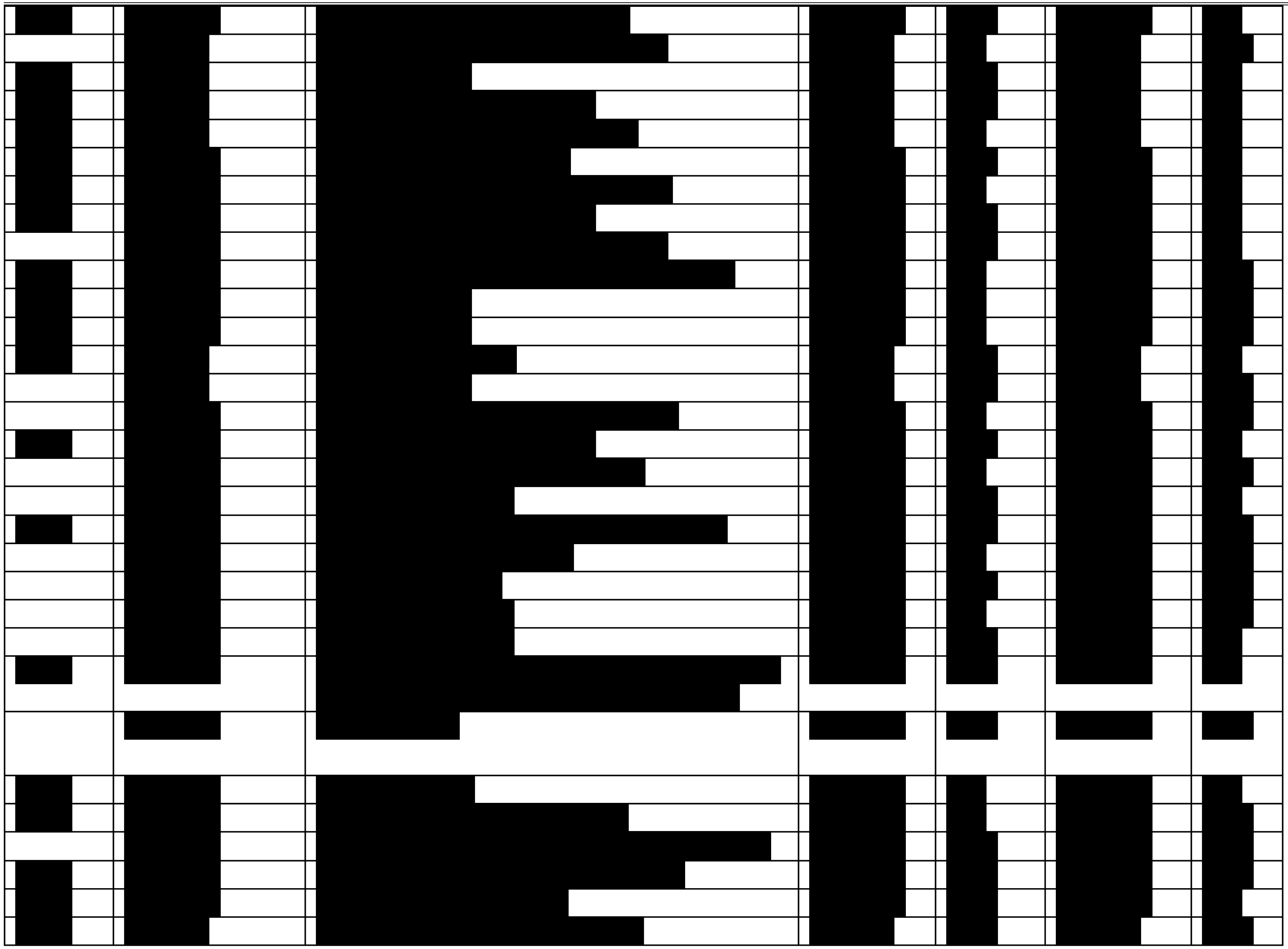


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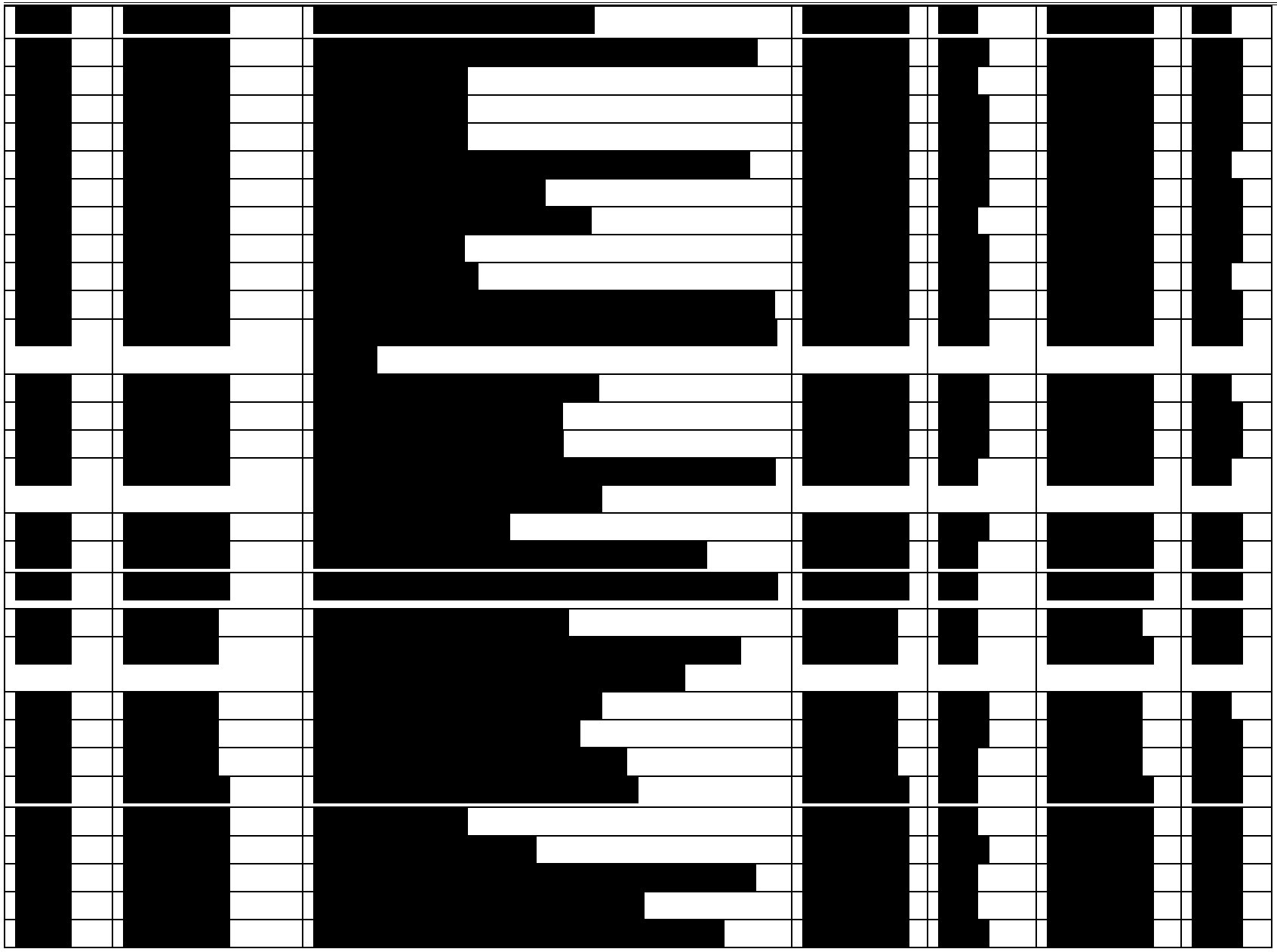


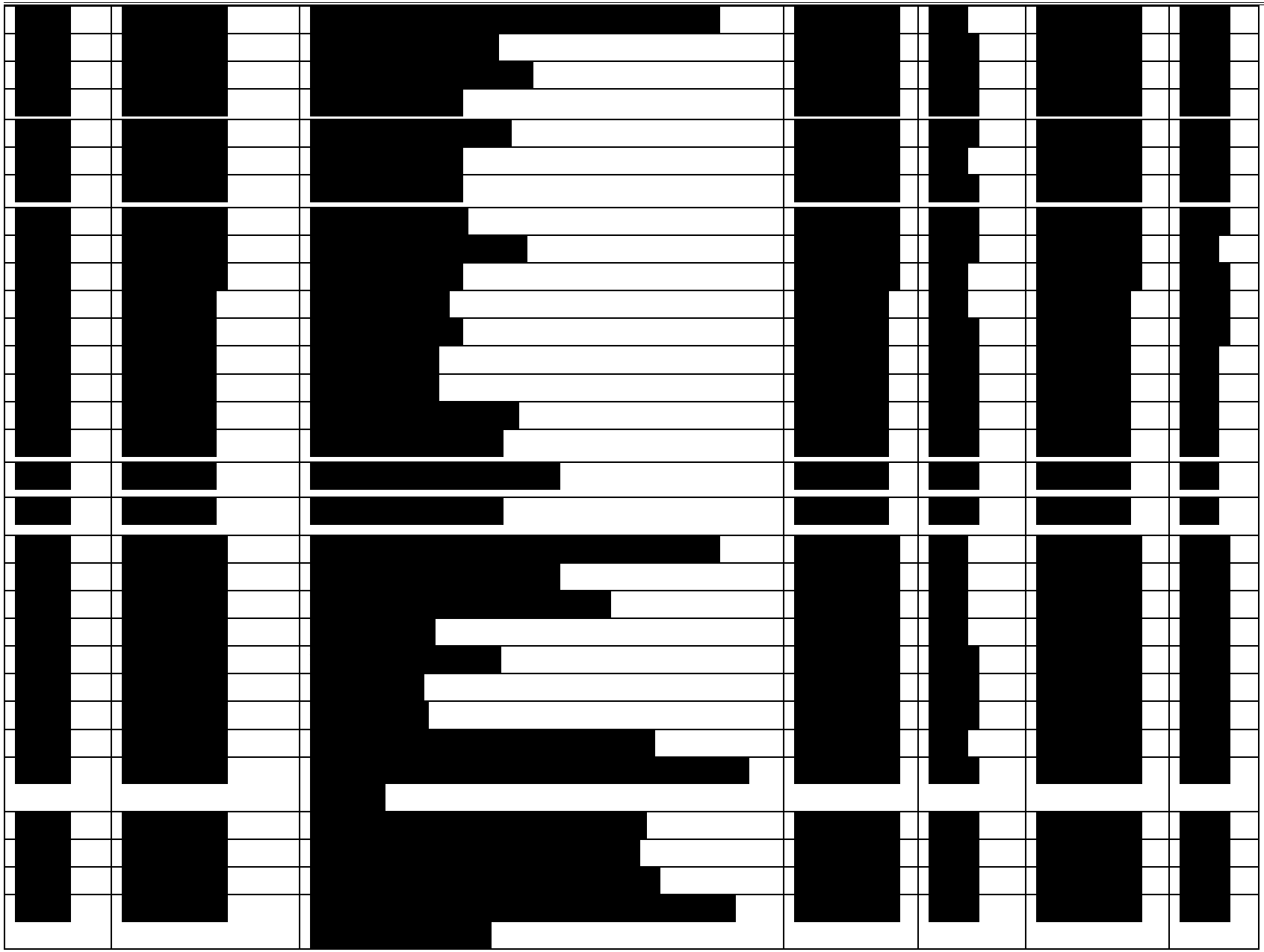


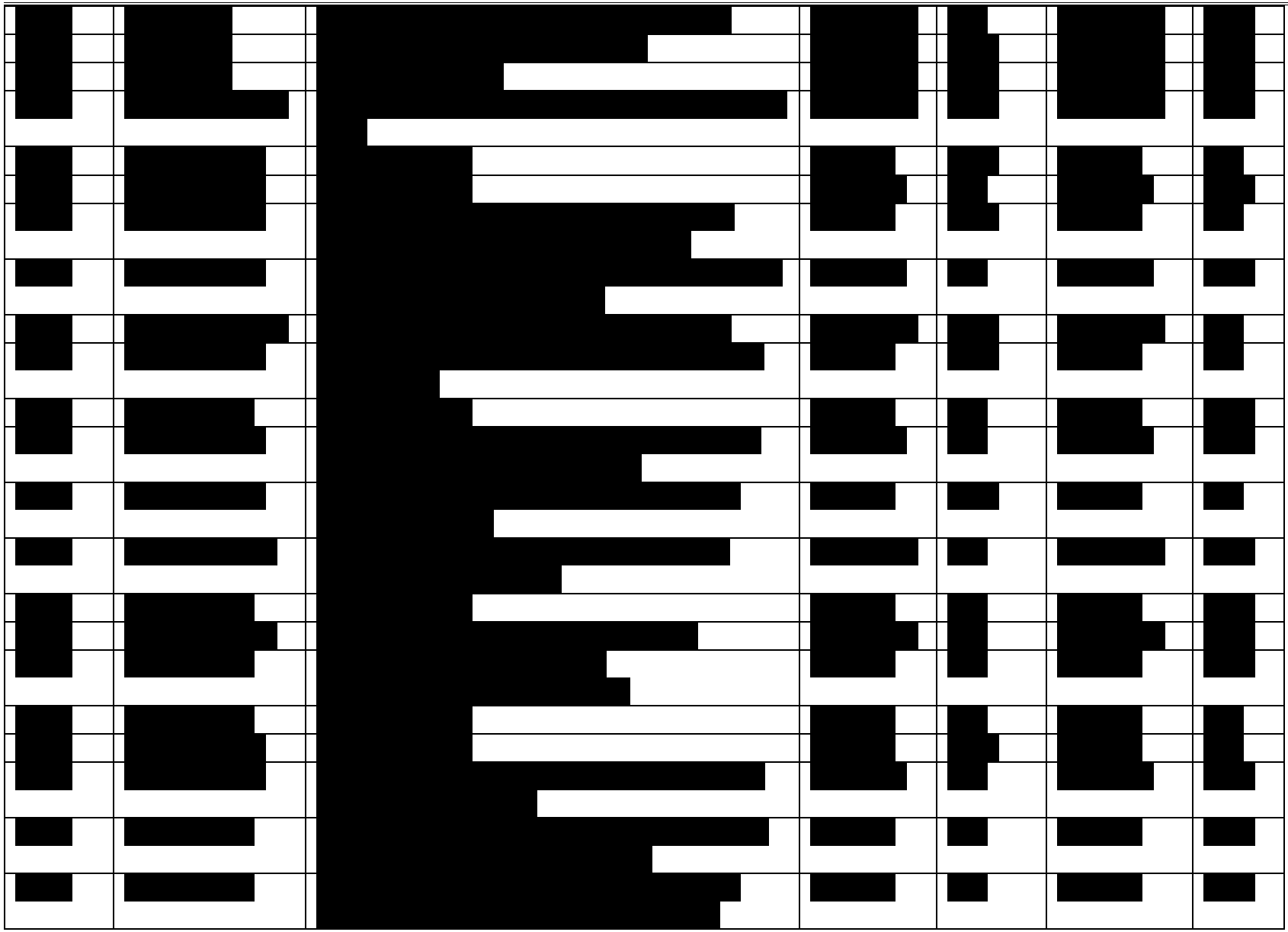


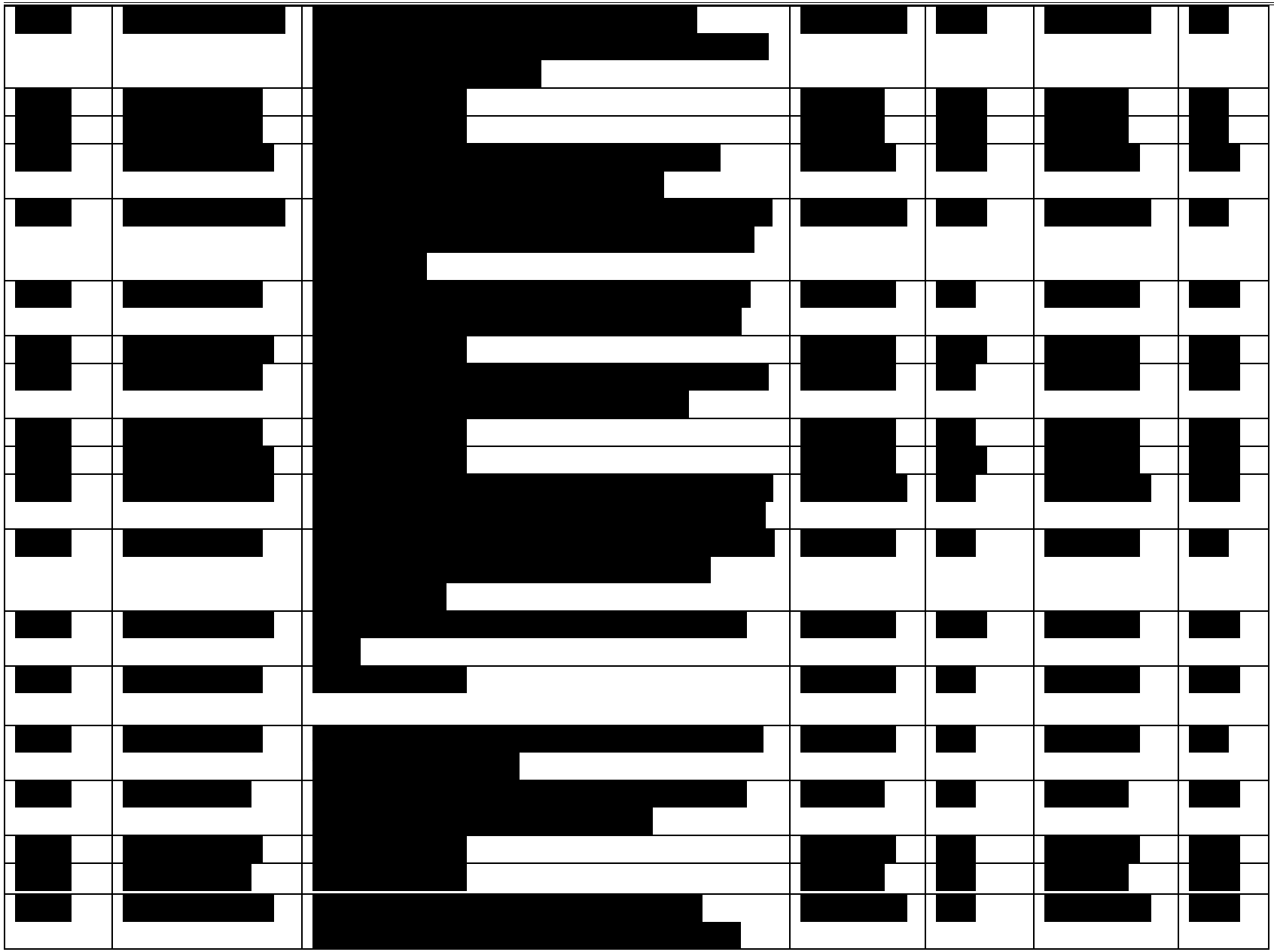














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ATTACHMENT 16

Liberty Utilities 2023 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2023

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15th, 2024

CA-07-0909

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2023 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore, data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents ten years (2014 through 2023) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

Beginning in 2014, the measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as “TMED”. Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric’s reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric’s daily SAIDI values for the prior five years. CalPeco Electric’s TMED value for 2023 was 78.78 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 10 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

I. Distribution System Indices (Major Event included and excluded)

Liberty Utilities (CalPeco Electric), LLC

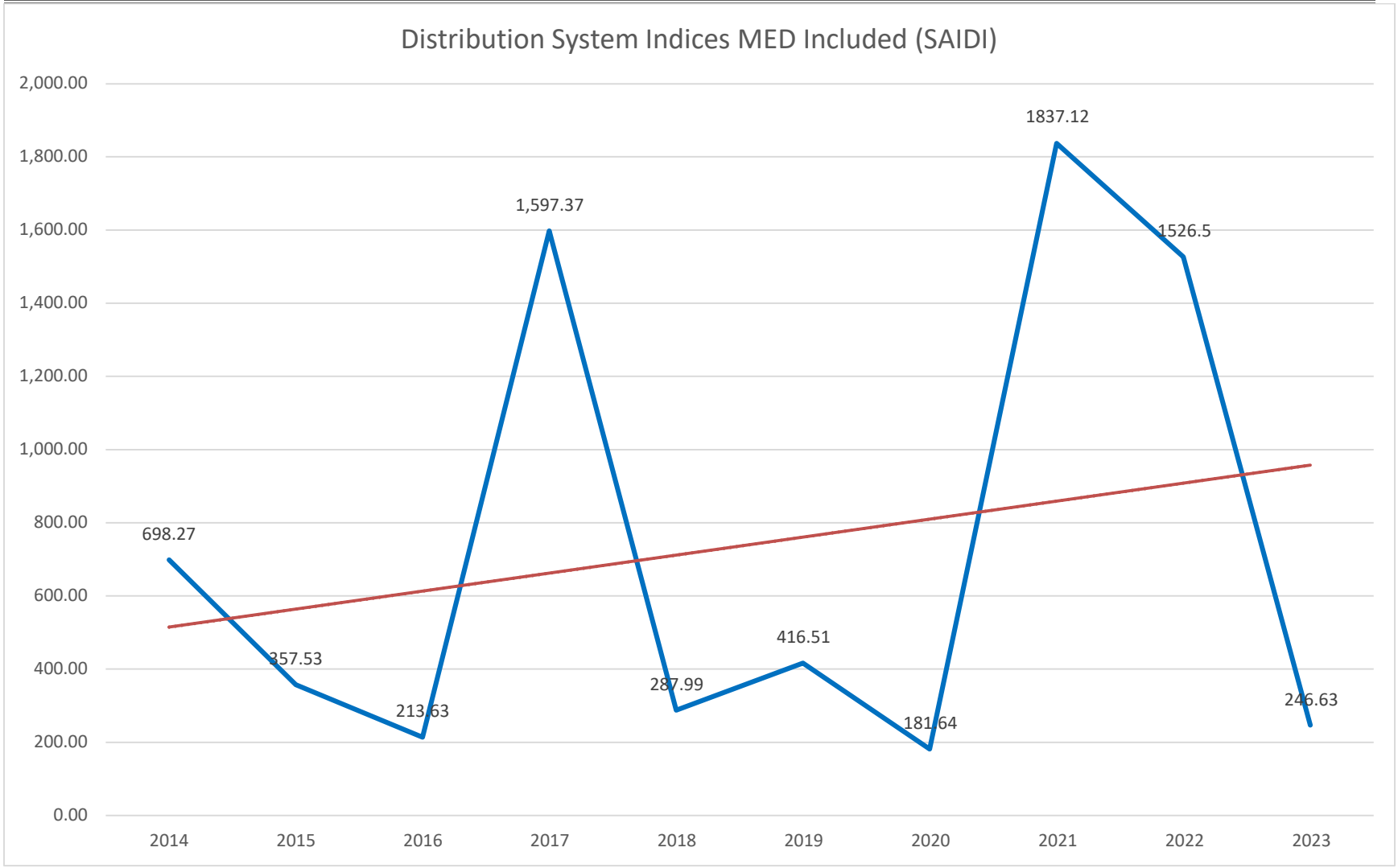
Distribution Historical System Reliability Data 10 Years (Years in Business)

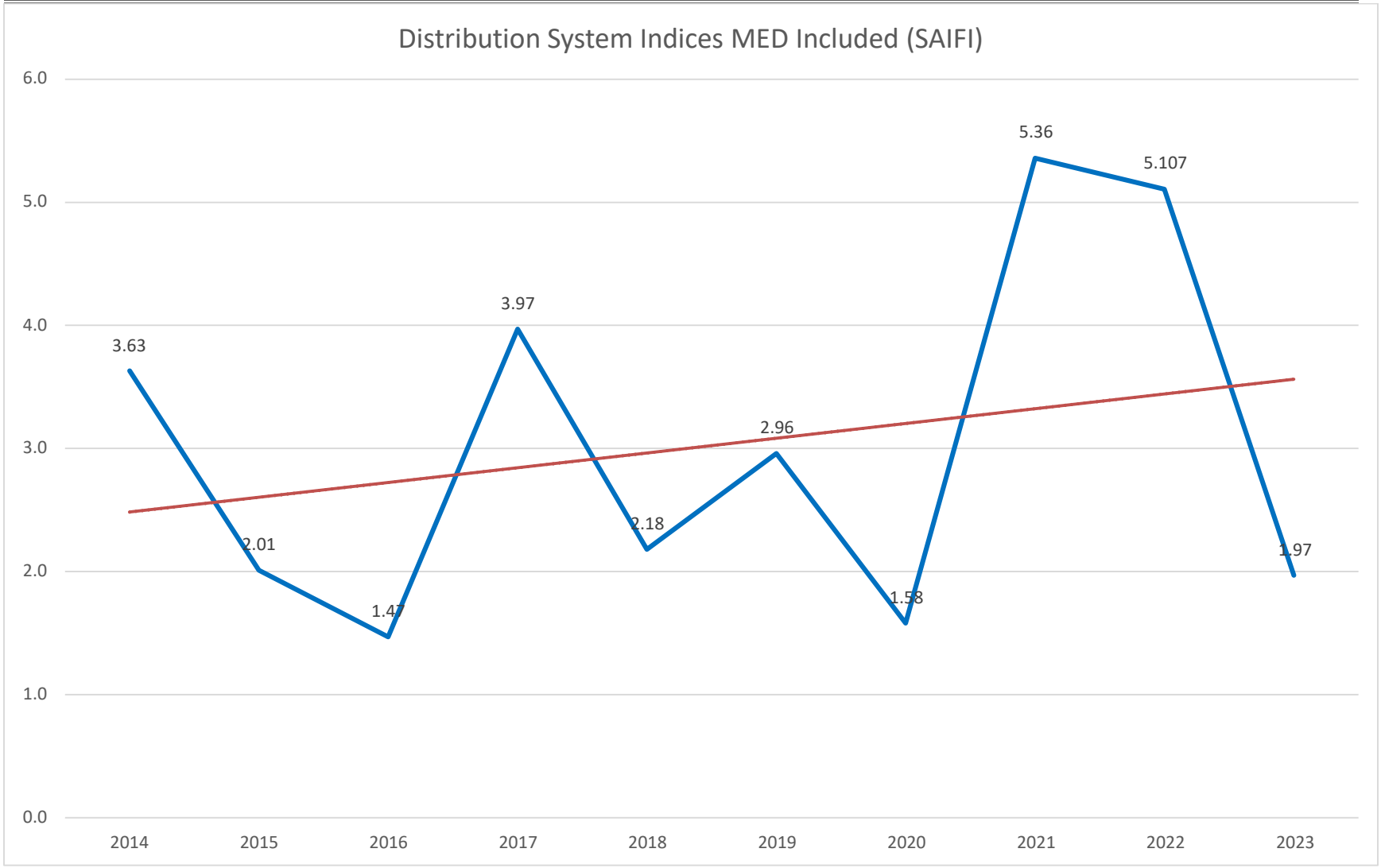
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2023	246.63	1.97	125.19	.292	246.63	1.97	125.19	.292
2022	1526.5	5.107	298.87	0.113	470.75	3.471	135.65	0.113
2021	1837.12	5.36	342.74	0.548	916.28	4.60	199.19	0.548
2020	181.64	1.57	115.23	0.313	181.64	1.57	115.23	0.313
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.4	146.58	2.15

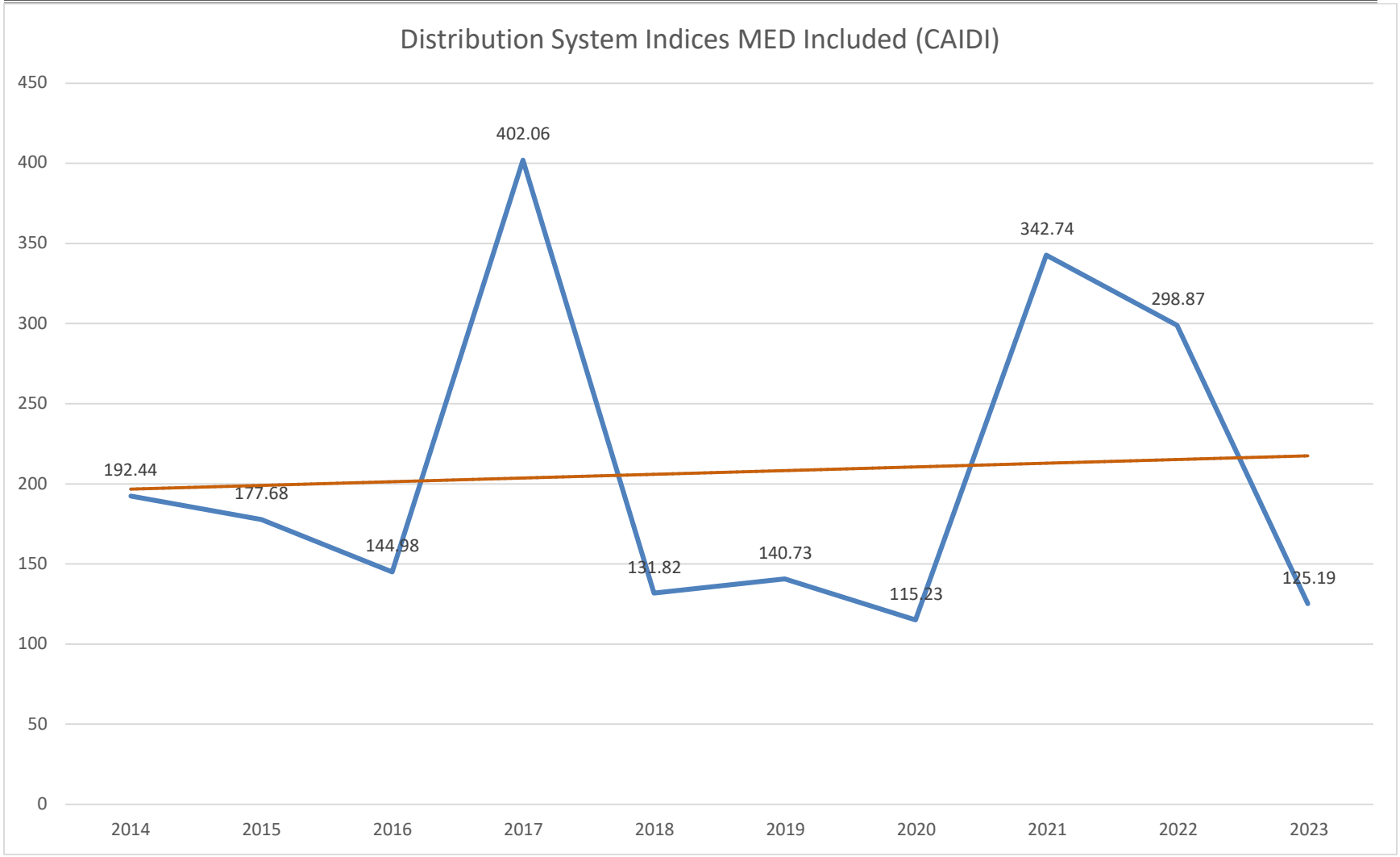
II. Transmission System Indices (MED Included and Excluded)

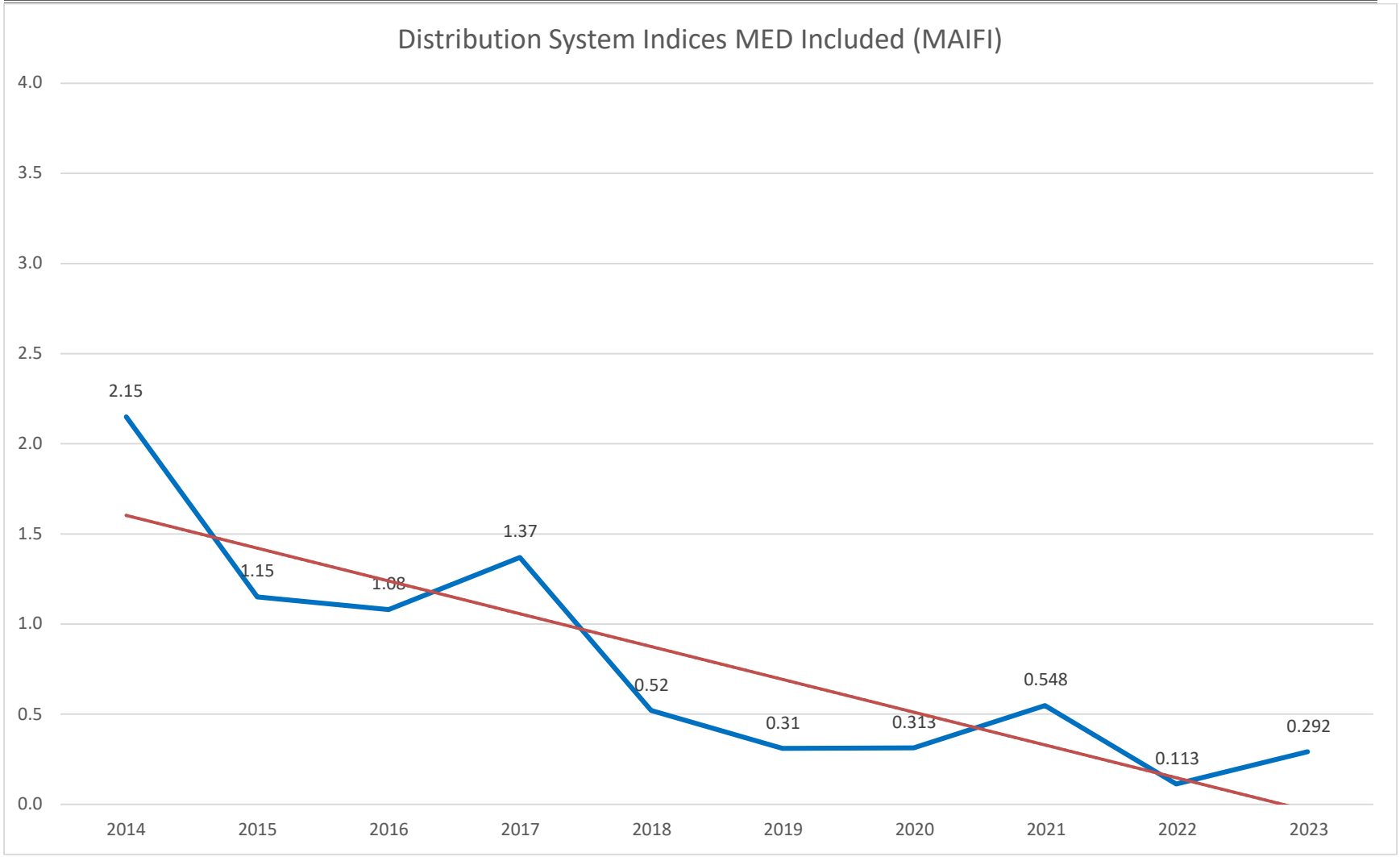
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

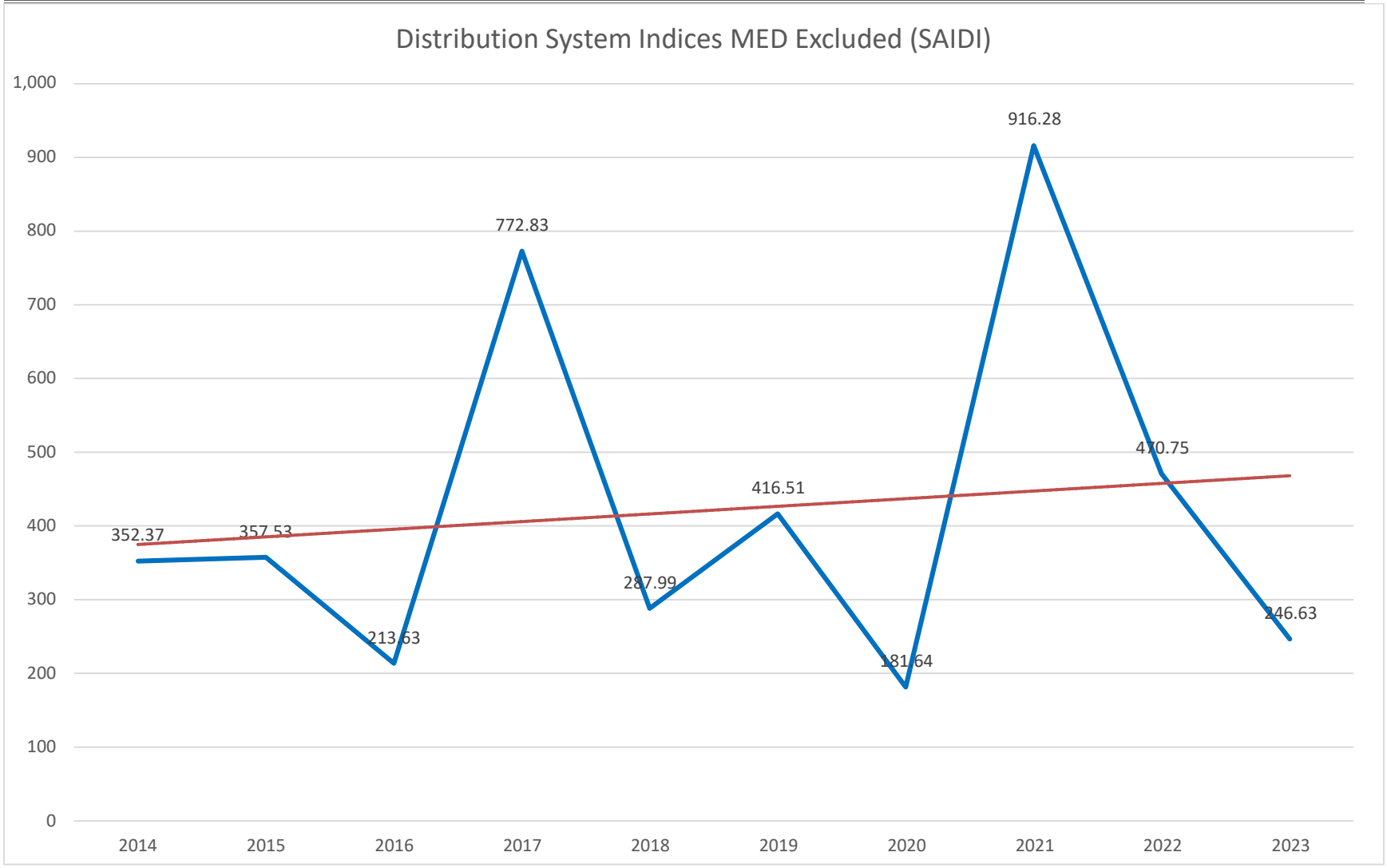
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 10 years with linear trend line (TMED included and excluded).

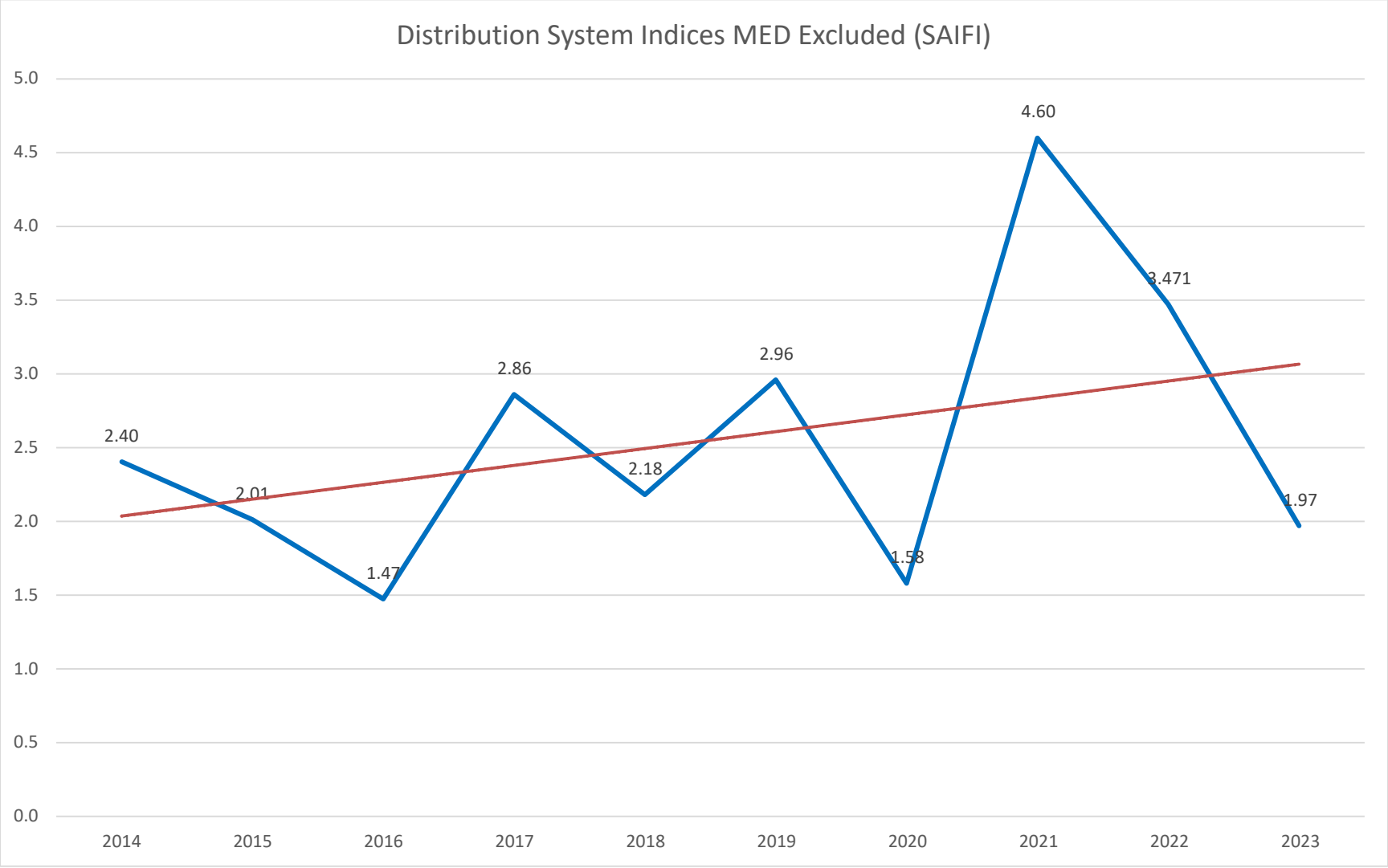

Distribution System Indices MED Included (SAIDI)
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1,800.00
1,600.00
1,400.00
1,200.00
1,000.00
800.00
600.00
400.00
200.00
0.00
698.27
357.53
213.63
1,597.37
287.99
416.51
181.64
1837.12
1526.5
246.63
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

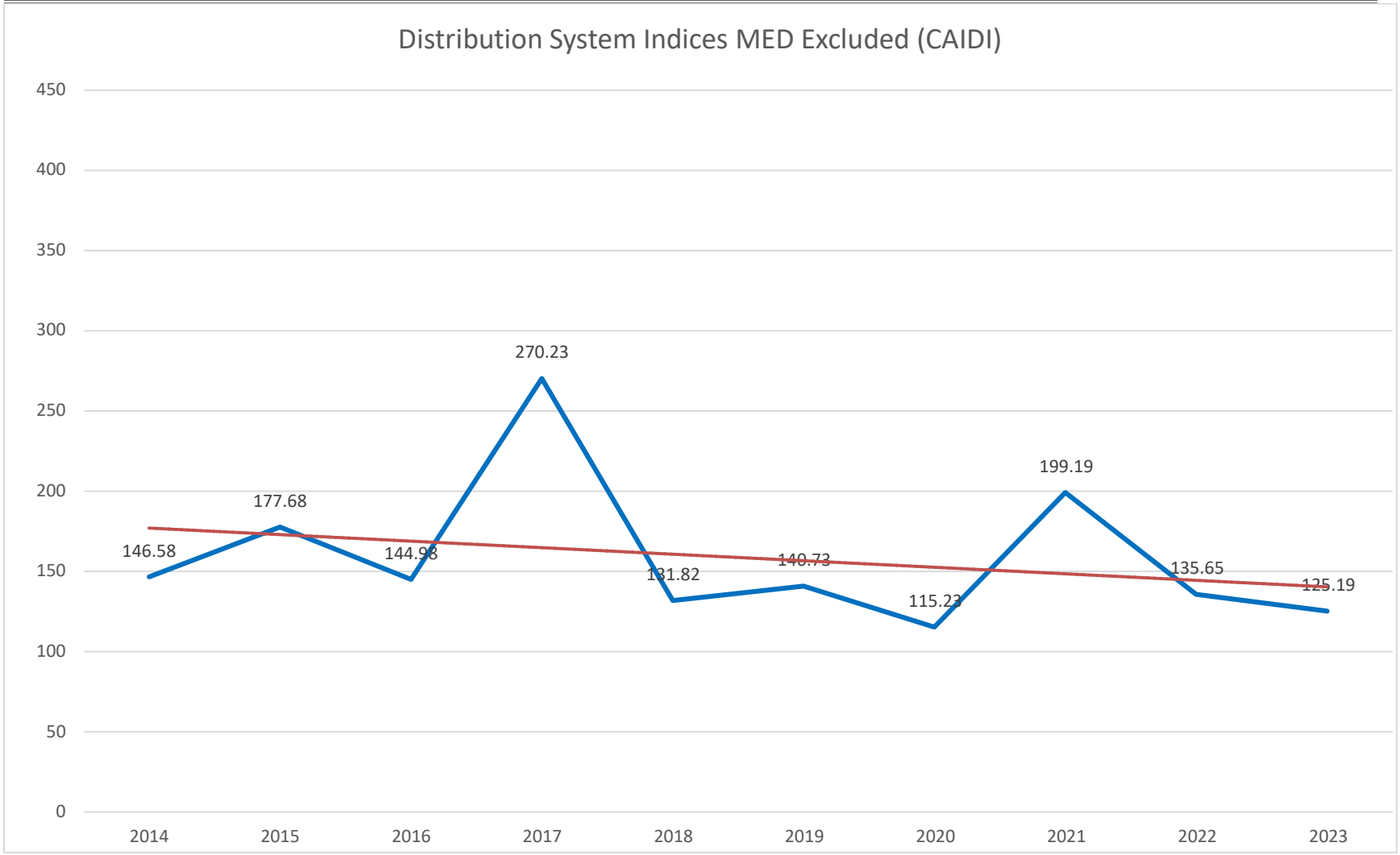

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
3.63
2.01
1.47
3.97
2.18
2.96
1.58
5.36
5.107
1.97
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

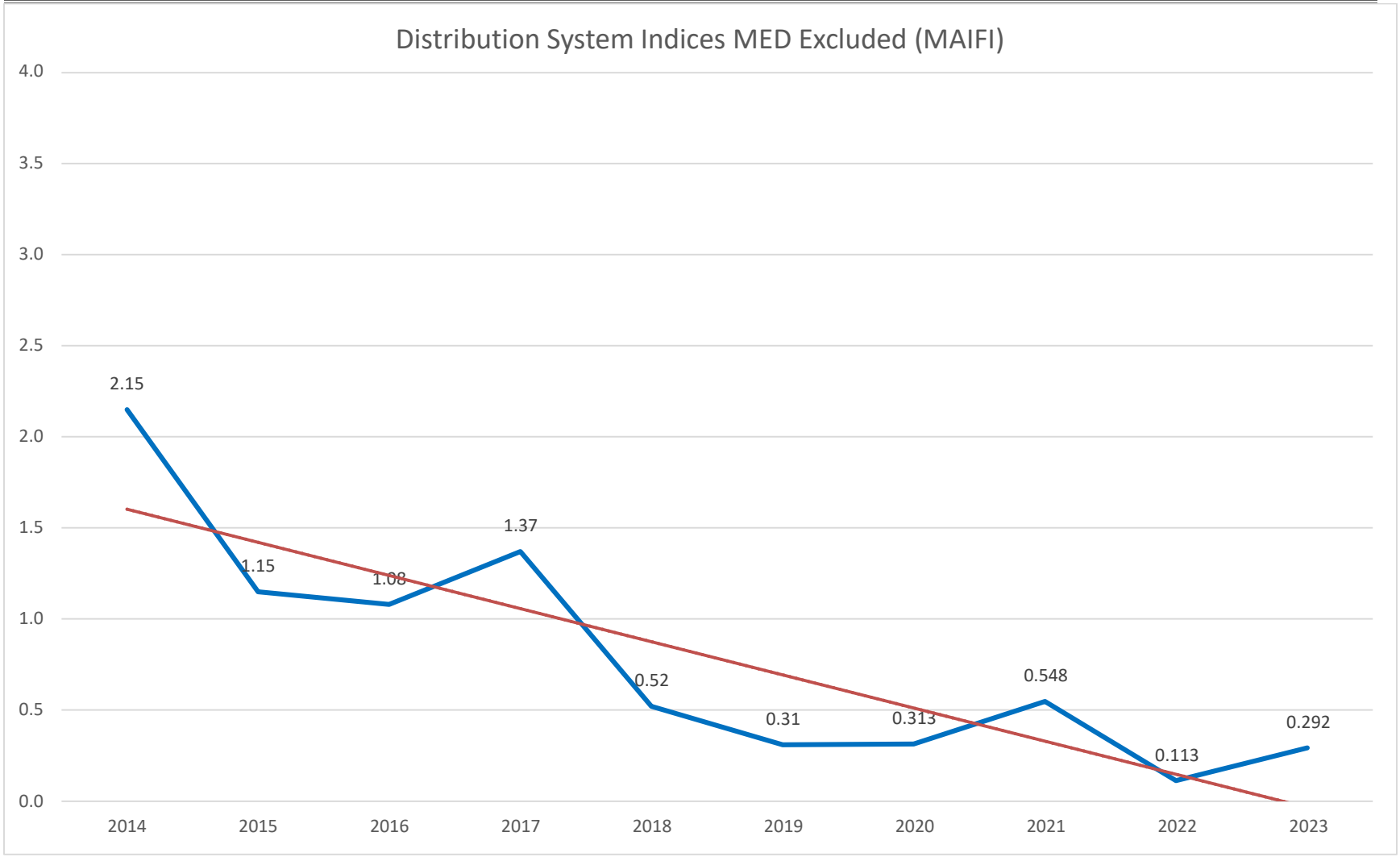

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
192.44
177.68
144.98
402.06
131.82
140.73
115.23
342.74
298.87
125.19
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.292
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (SAIDI)
1,000
900
800
700
600
500
400
300
200
100
0
352.37
357.53
213.63
772.83
287.99
416.51
181.64
916.28
470.75
246.63
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (SAIFI)
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.40
2.01
1.47
2.86
2.18
2.96
1.58
4.60
3.471
1.97
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
146.58
177.68
144.98
270.23
131.82
140.73
115.23
199.19
135.65
125.19
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.292
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

2) Division (or District) Reliability Indices for the past 10 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

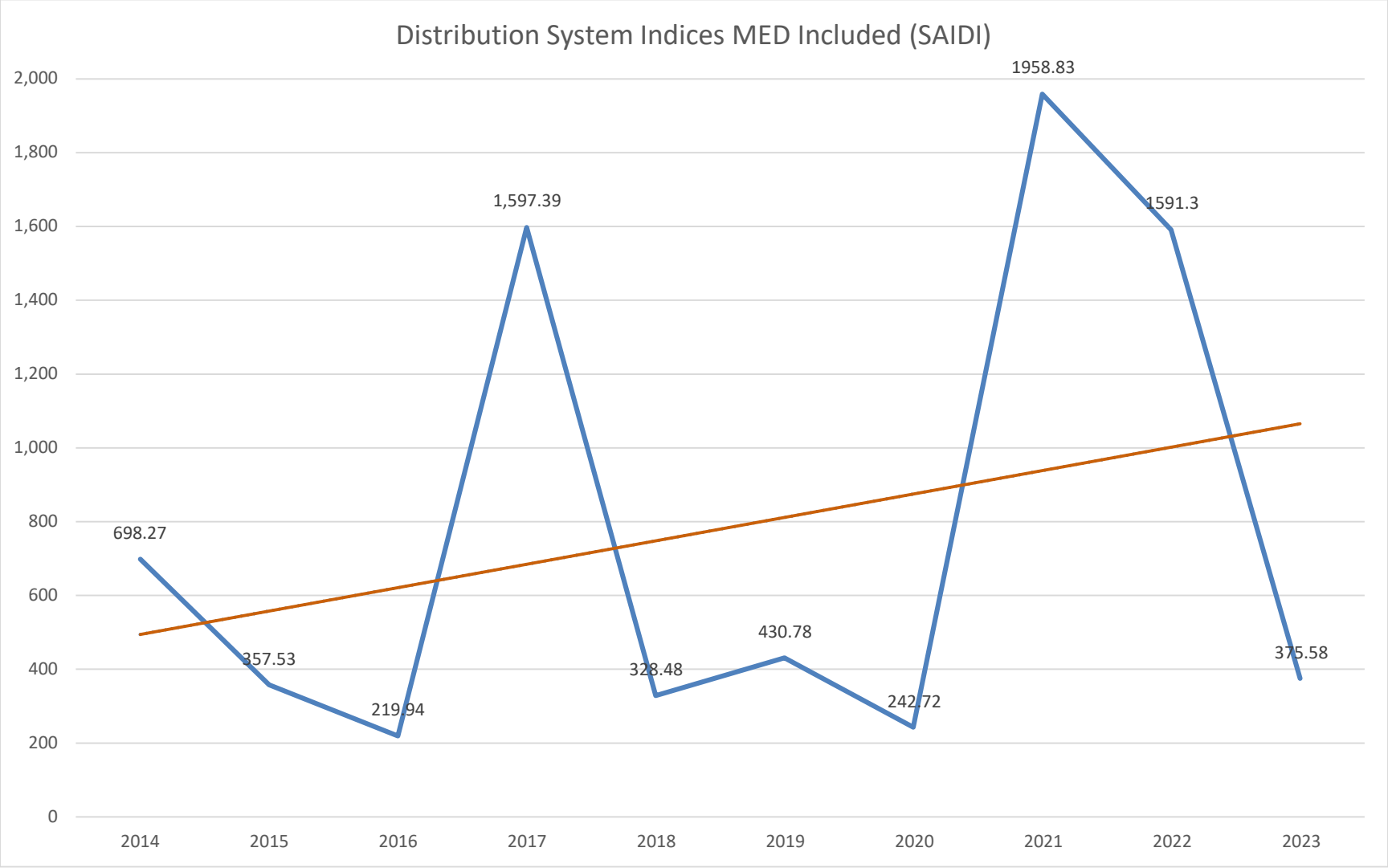
3) System and Division indices based on IEEE 1366 for the past 10 years including planned outages and including and excluding MED

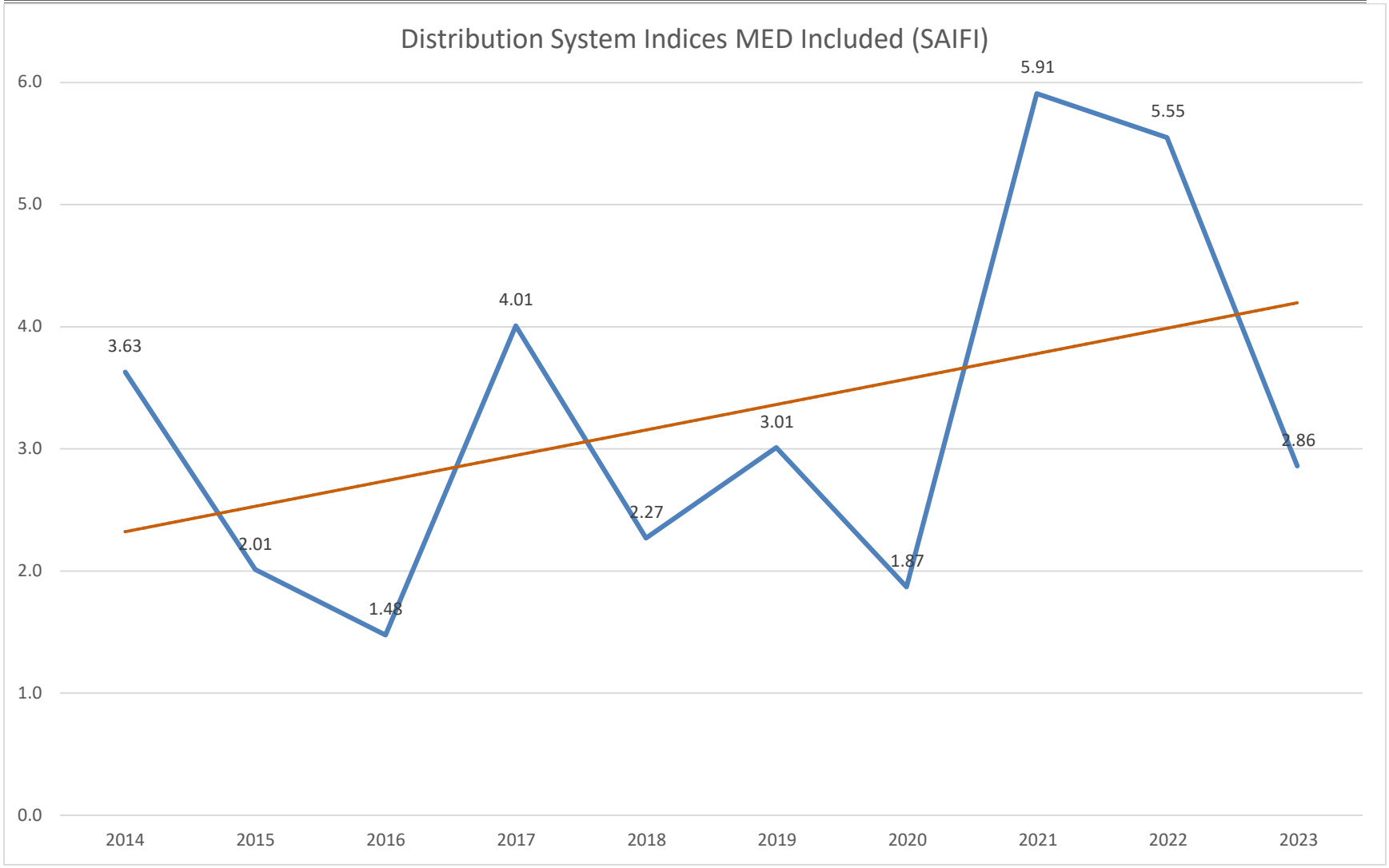
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

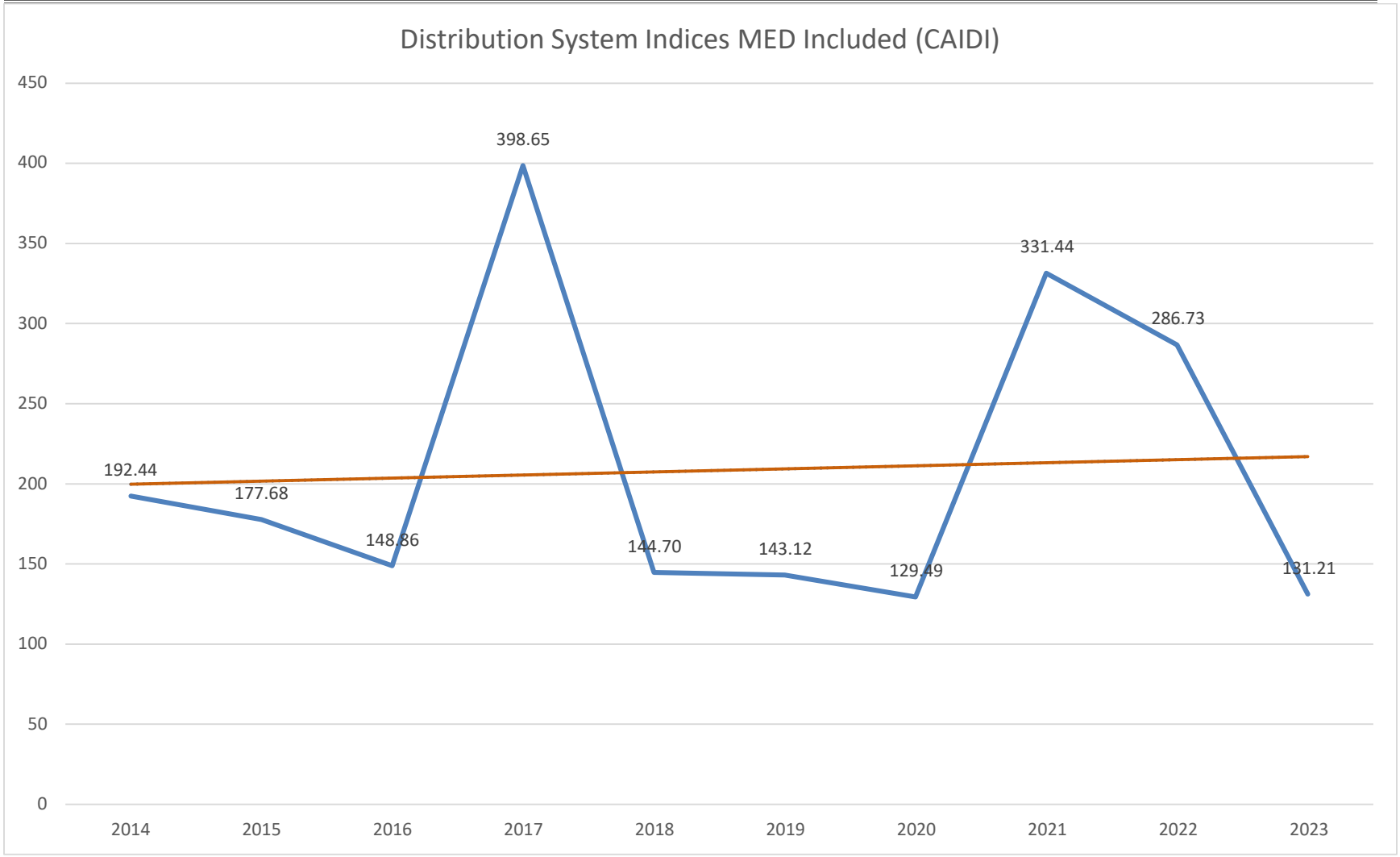
Liberty Utilities (CalPeco Electric), LLC

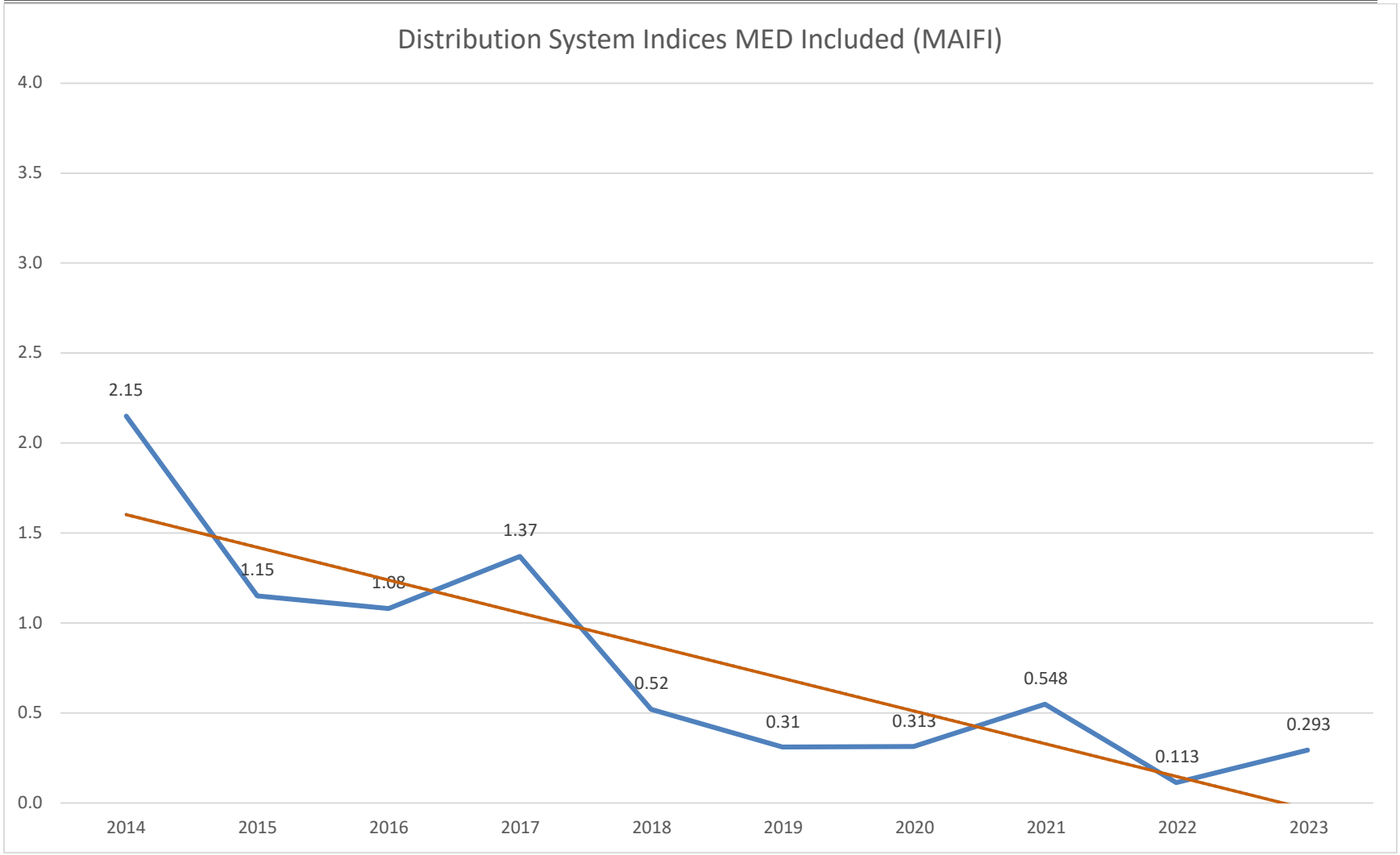
Distribution Historical System Reliability Data 10 Years (Years in Business)

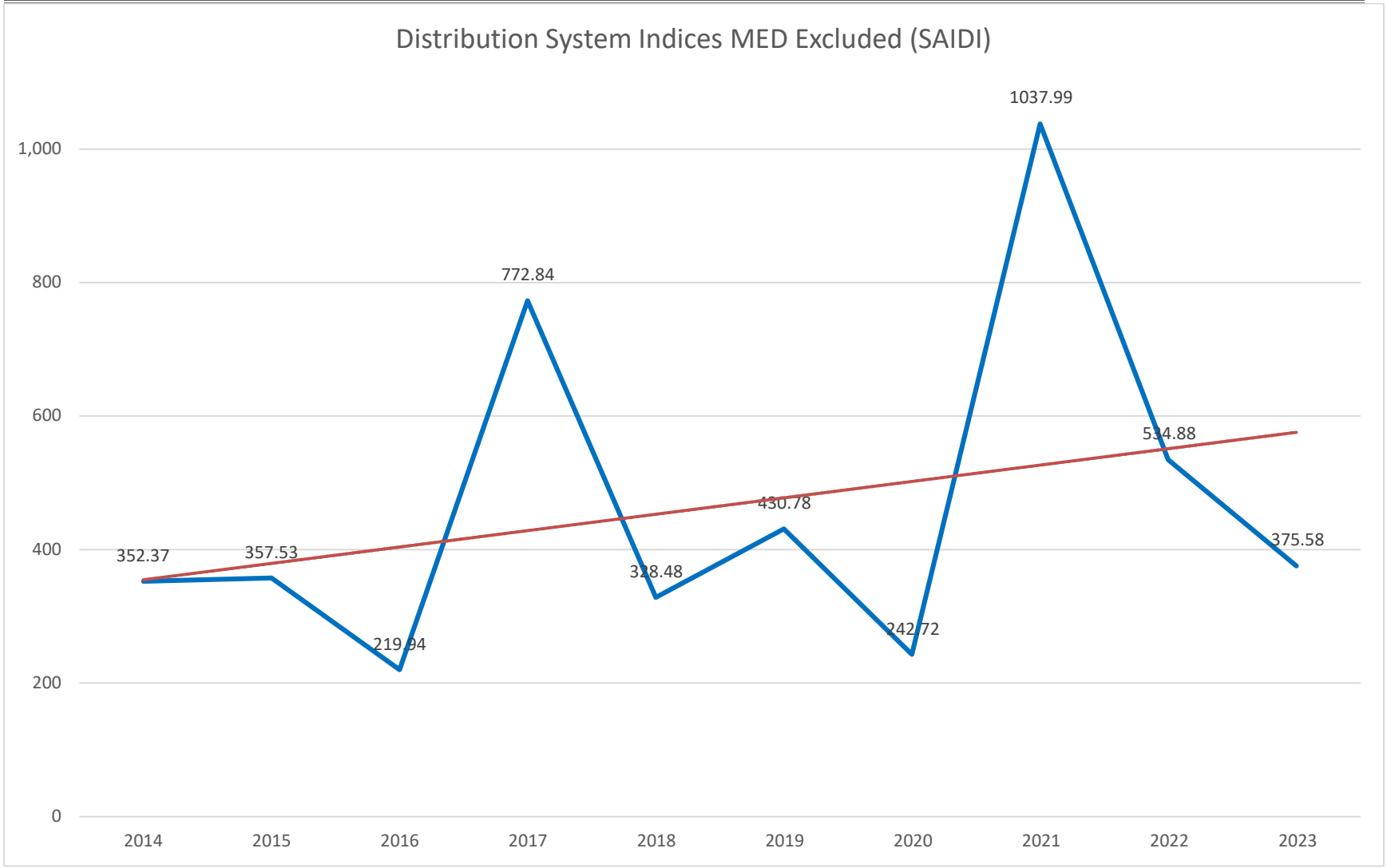
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2023	375.58	2.86	131.21	.293	375.58	2.86	131.21	.293
2022	1591.3	5.55	286.73	0.113	534.88	3.91	136.72	0.113
2021	1958.83	5.91	331.44	0.548	1037.99	5.14	201.94	0.548
2020	242.72	1.87	129.49	0.313	242.72	1.87	129.49	0.313
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.7	0.52	328.48	2.27	144.7	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15
2014	698.27	3.63	192.44	2.15	352.37	2.4	146.58	2.15

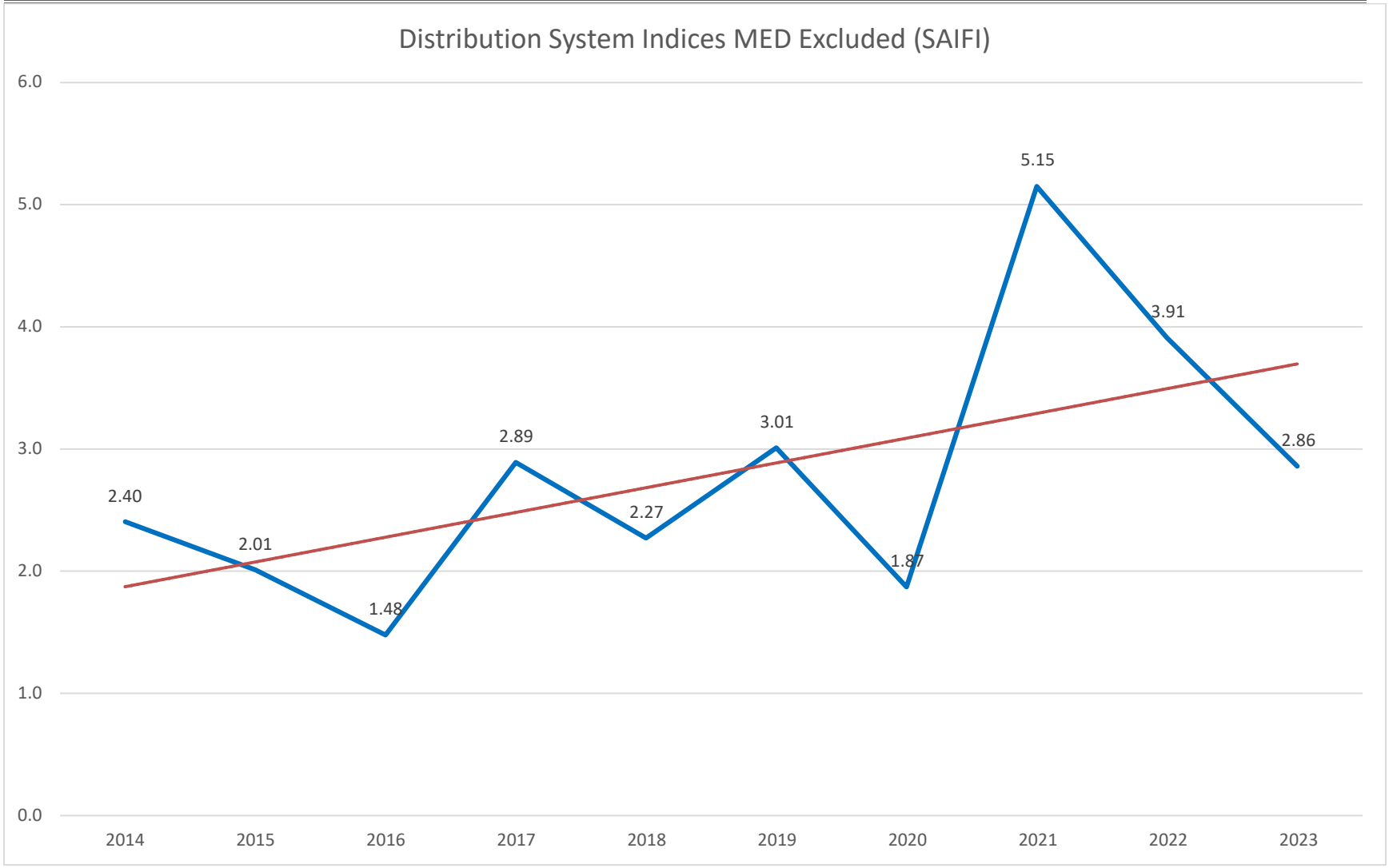

Distribution System Indices MED Included (SAIDI)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
698.27
357.53
219.94
1,597.39
328.48
430.78
242.72
1958.83
1591.3
375.58
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

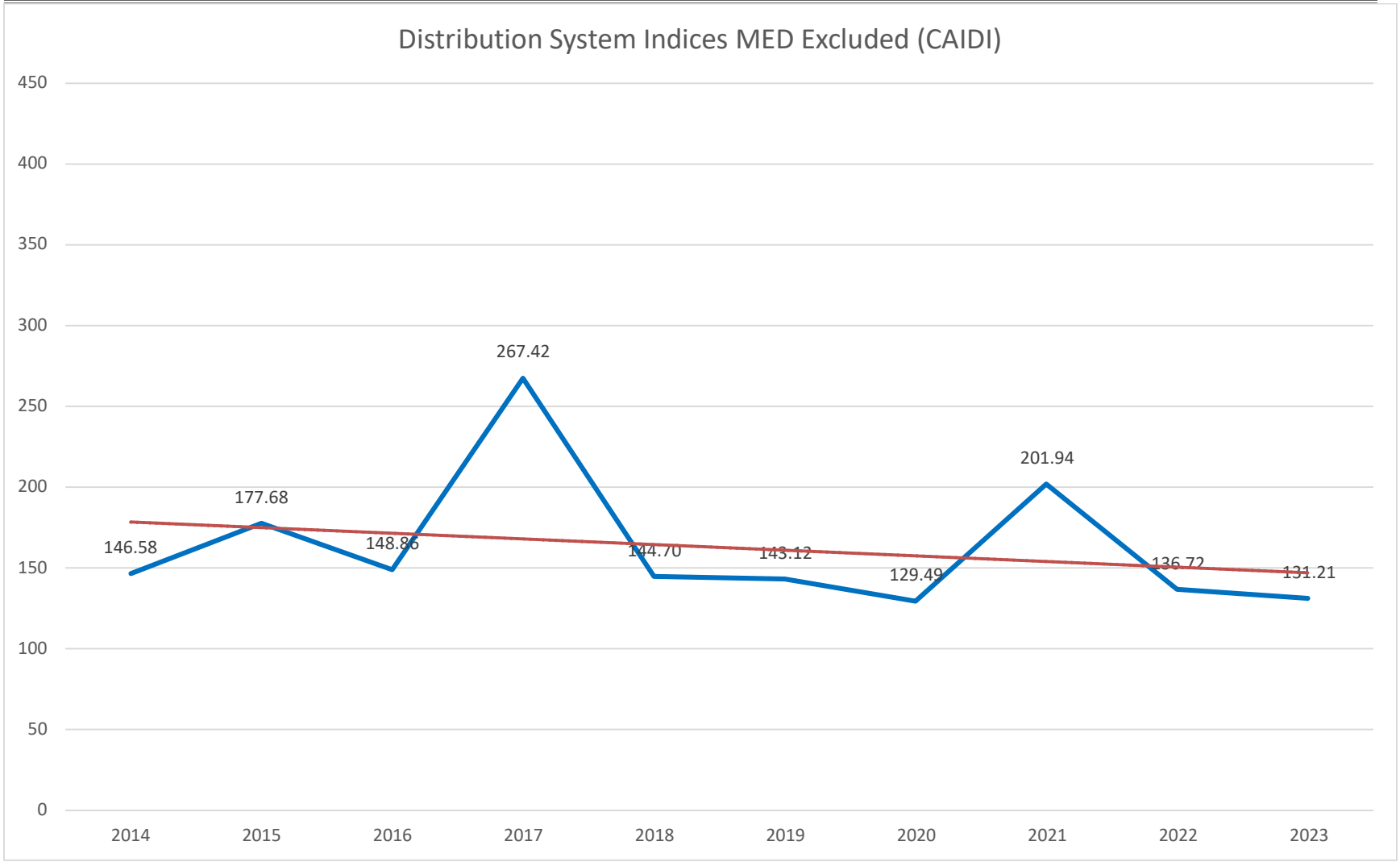

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
3.63
2.01
1.48
4.01
2.27
3.01
1.87
5.91
5.55
2.86
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

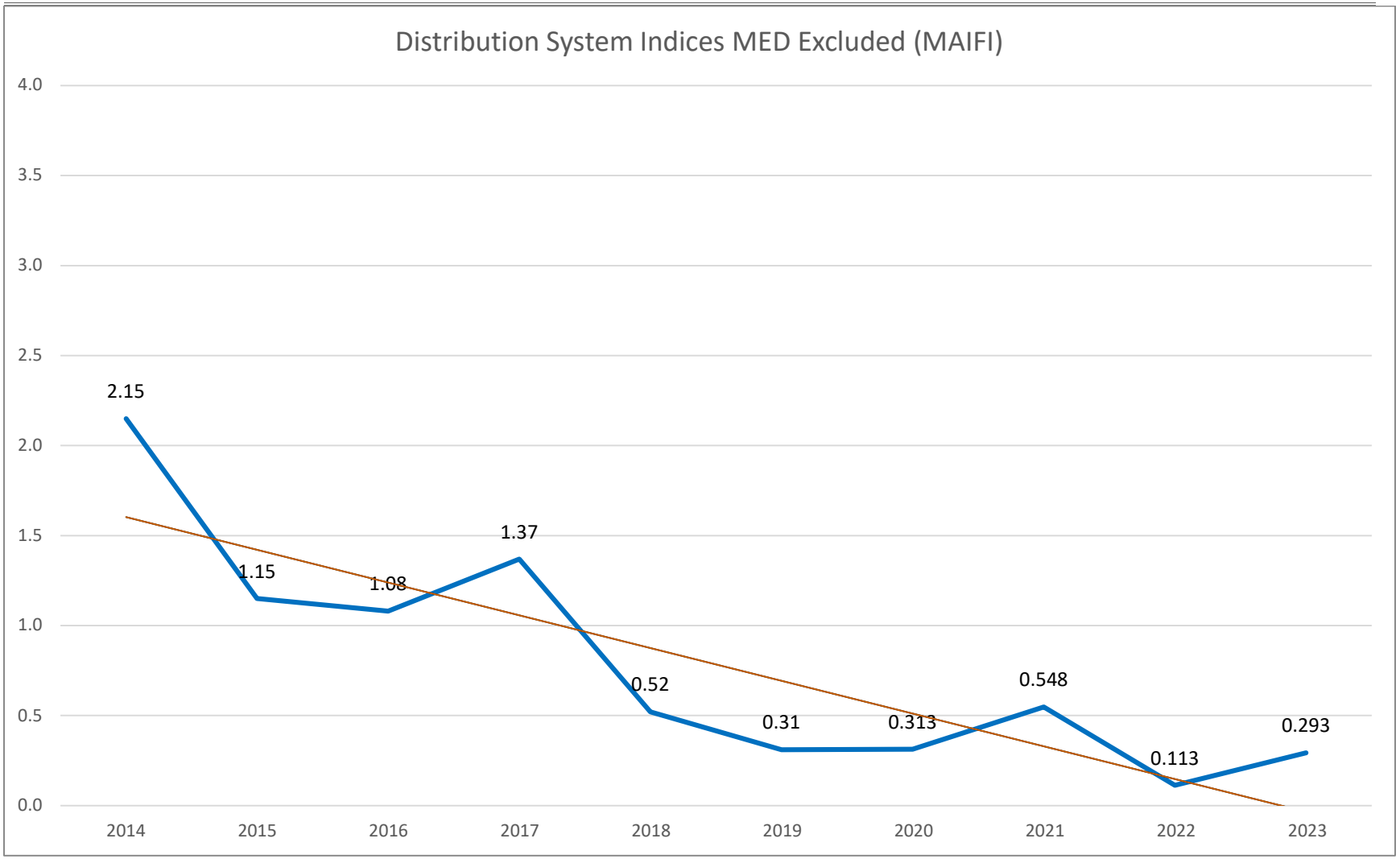

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
192.44
177.68
148.86
398.65
144.70
143.12
129.49
331.44
286.73
131.21
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.293
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (SAIDI)
1,000
800
600
400
200
0
352.37
357.53
219.94
772.84
328.48
430.78
242.72
1037.99
534.88
375.58
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2.40
2.01
1.48
2.89
2.27
3.01
1.87
5.15
3.91
2.86
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

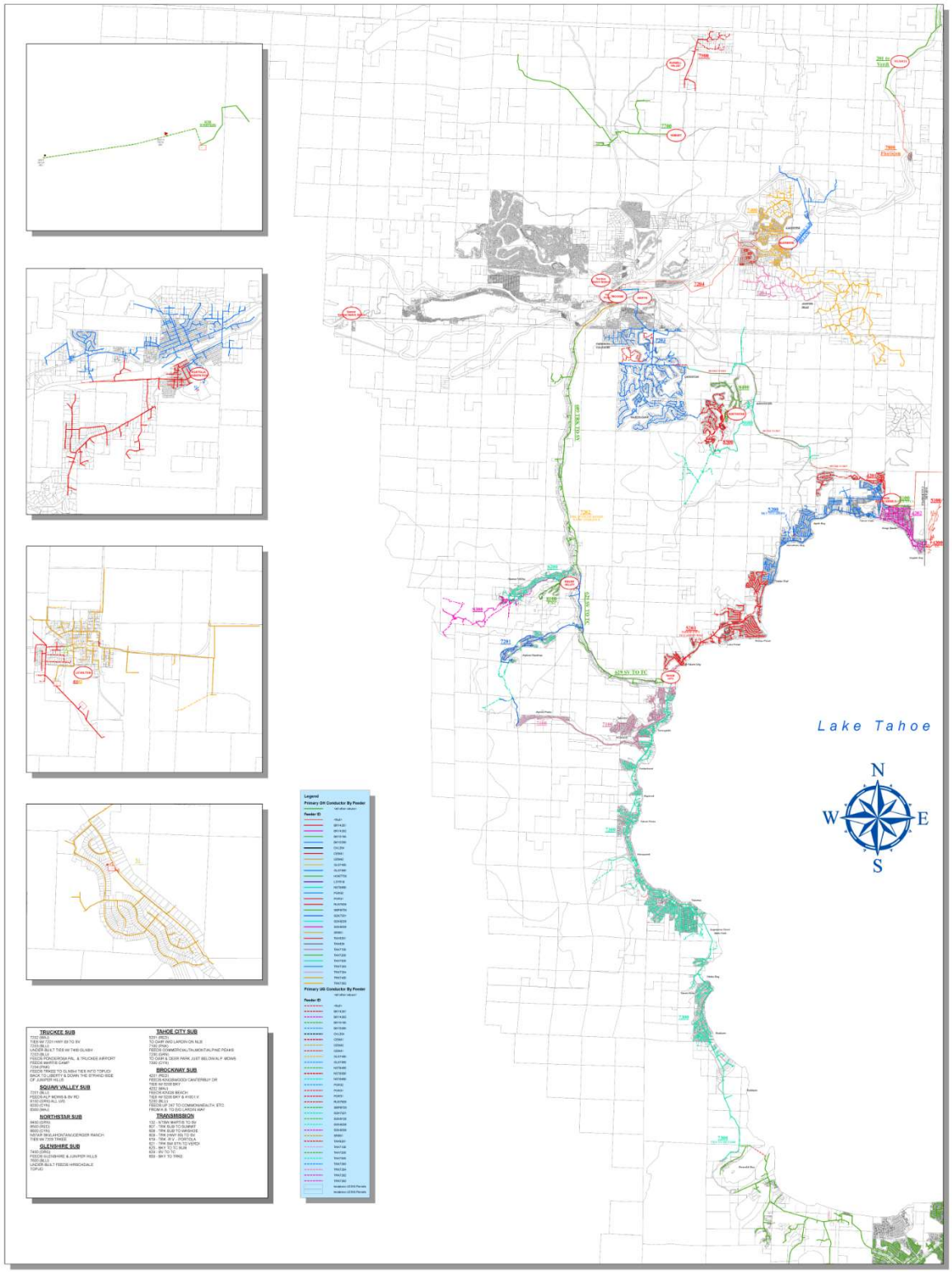

Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
146.58
177.68
148.86
267.42
144.70
143.12
129.49
201.94
136.72
131.21
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.15
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.293
2014
2015
2016
2017
2018
2019
2020
2021
2022
2023

b. The number, date, and location of planned outages

Circuit	District	Number of Planned Outages By Year									
		2023	2022	2021	2020	2019	2018	2017	2016	2015	2014
31	Tahoe	3	2	5	3		1			1	
32	Tahoe	4	4	17	4	1		2	1		
41	Tahoe		2		6				1		
42	Tahoe		2								
51	Tahoe	4	2								
201	Tahoe		1	3			7				
204	Tahoe		1	1		2			1		
257	Tahoe										
1202	Tahoe	10	7	5	7	1	1				
1296	Tahoe	4	1		2		1	2		5	1
2200	Tahoe	1		1		1				1	1
2300	Tahoe	26	1	2		1	1			1	2
3100	Tahoe	120	12	7	2	8	5	1			
3101	Tahoe	81	11	5	3	3					2
3200	Tahoe	88	6	22	1	3	5			1	
3300	Tahoe	148	16	19	3	8	10	2		3	
3400	Tahoe	65	12	23	1	2	4	3		5	
3500	Tahoe	170	4	9	6	15		6		1	
3501	Tahoe	139	10	7		3	3			2	2
4201	Tahoe	14	4	3		1	1		1		
4202	Tahoe	1	6	8	2	5	3	4			
4203	Tahoe										
5100	Tahoe	1		1	1						
5200	Tahoe	36	9		1	5	4	1		4	1
5201	Tahoe	9	7	2		8	1	5	5	4	1
7100	Tahoe	4	7	4	4	1	2	1			1
7200	Tahoe	1				1	1			1	1
7201	Tahoe	9	3	4	1	1		4	1	2	1
7202	Tahoe	2	3	1	3	3	1	1		2	3
7203	Tahoe		3	2		3	2			2	2
7204	Tahoe		1								
7300	Tahoe	16	13	14	8	20	14	5	6	4	16
7400	Tahoe	6		4	1	4	8	2	1	1	
7600	Tahoe	2	1			1	1			1	
7700	Tahoe	3	3		4						1
7800	Tahoe										2
7900	Tahoe	2	1		2	1					
8100	Tahoe	1									
8200	Tahoe	15		2	1	1	2	7	3	2	4
8300	Tahoe	1			1	1	1	2		6	
8400	Tahoe				1		7				
8500	Tahoe		1	1	2				1		
8600	Tahoe									4	
8700	Tahoe	1									

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1202*	Tahoe	753	Topaz	59.14	94.0%	6.0%	6	2422.39	7.44
3300*	Tahoe	3603	Meyers	56.66	90.6%	9.4%	5	1591.99	4.09

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1202 (previously 1261) circuit was noted as a deficient circuit in 2020, 2021, 2022, and 2023. The 3-year average circuit SAIDI score remains high due to extreme weather conditions over the past 3 years.

There were 27 unplanned outages in 2023 for the 1202 circuit.

The historical metric for Topaz 1202 based on a 3-year average:

- 2023 – 1925
- 2022 - 2313
- 2021 – 3028

There are currently no plans in place that would remedy loss of source outages, which account for several outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada.

The circuit performance in 2023 measured alone was below average compared to historical values. This circuit often experiences events considered to be outliers resulting from extreme weather conditions. 10 of the unplanned outages for this circuit in 2023 were caused by weather.

The Meyers 3300 circuit was noted as a deficient circuit in 2021, 2022, and 2023. The 3-year average circuit SAIDI score remains high because of extreme weather conditions over the past 3 years that caused widespread power outages over the circuit, some of which took days to restore. Additionally, the 3300 circuit has

outdated and aging underground infrastructure as well as conductor failures in the winter which cause large and long-lasting outages.

There were 27 unplanned outages in 2023 for the 3300 circuit.

The historical metric for Meyers 3300 based on a 3-year average:

- 2023 - 1928
- 2022 – 1868
- 2021 – 980

The majority of the SAIDI points in 2023 were caused by wind and tree falls, while the outages that individually contributed the most SAIDI points were caused by motor vehicle accidents and wire down incidents. Efforts to replace outdated infrastructure are being planned, including overhead and underground conductors and covered conductors within coming years.

The circuit performance in 2023 measured alone was above average compared to historical events due to extreme weather conditions. Future performance is expected to improve based on normal weather conditions and infrastructure improvements.

III. Language to explain how the IOUs' include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Senior Director of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	11/2/2023 5:55:00	Faulted Underground Cable	Lake Tahoe	4,214	26.56192	0.084026241
2	1/5/2023 1:15	CB Lockout	Lake Tahoe	4400	12.15679	0.08773504
3	1/4/2023 20:29	CB Lockout	Lake Tahoe	1588	11.51341	0.031664374
4	3/14/2023 16:39	CB Lockout	Lake Tahoe	4264	7.90716	0.08502323
5	7/29/2023 15:16	CB Lockout	Lake Tahoe	2296	7.834998	0.045781739
6	9/19/2023 8:15	CB Lockout	Lake Tahoe	3560	6.520767	0.070985623
7	1/14/2023 22:35	Broken Pole, all 3 phases down	Lake Tahoe	154	5.999083	0.003070726
8	1/15/2023 8:27	CB Lockout	Lake Tahoe	4277	5.454727	0.085282447
9	10/15/2023 17:18	CB Lockout	Lake Tahoe	2301	5.046958	0.045881438
10	5/18/2023 20:34	Recloser Lockout	Lake Tahoe	746	4.8609	0.014875077

*Based on customer impact

7) Summary list of 2023 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

There was no ME for 2023.

8) Historical 10 largest unplanned outage events for the past 10 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Faulted Underground Cable	11/2/2023	4,214	128.59	22201.78	NO
2	CB Lockout	1/5/2023	4400	22.87	10161.25	NO
3	CB Lockout	1/4/2023	1588	6.1	9623.48	NO
4	CB Lockout	3/14/2023	4264	1.55	6609.20	NO
5	CB Lockout	7/29/2023	2296	171.14	6548.88	NO
6	CB Lockout	9/19/2023	3560	17.87	5450.38	NO
7	Broken Pole, all 3 phases down	1/14/2023	154	34.9	5014.33	NO
8	CB Lockout	1/15/2023	4277	1.17	4559.33	NO
9	CB Lockout	10/15/2023	2301	1.02	4218.50	NO
10	Recloser Lockout	5/18/2023	746	7.3	4062.98	NO

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	12/11/2022	4573	66.7	112,064	YES
2	CB Lockout	12/11/2022	4013	20.1	80,461	YES

3	CB Lockout	12/12/2022	6382	28.3	64,328	YES
4	CB Lockout	12/11/2022	2290	34.0	47,436	YES
5	CB Lockout	12/11/2022	2357	20.0	47,022	YES
6	Blown Fuse	12/11/2022	698	55.4	38,681	YES
7	CB Lockout	12/11/2022	3559	9.6	34,048	YES
8	CB Lockout	12/31/2022	4400	11.0	27,554	YES
9	PTR Lockout	12/10/2022	484	68.7	26,256	NO
10	Loss of Source	12/31/2022	4273	7.6	24,287	YES

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	12/11/2022 5:14	4573	66.7	112,064	YES
2	CB Lockout	12/11/2022 2:55	4013	20.1	80,461	YES
3	CB Lockout	12/12/2022 17:45	6382	28.3	64,328	YES
4	CB Lockout	12/11/2022 8:45	2290	34.0	47,436	YES
5	CB Lockout	12/11/2022 5:14	2357	20.0	47,022	YES
6	Blown Fuse	12/11/2022 4:49	698	55.4	38,681	YES
7	CB Lockout	12/11/2022 0:43	3559	9.6	34,048	YES
8	CB Lockout	12/31/2022 12:59	4400	11.0	27,554	YES
9	PTR Lockout	12/10/2022 22:58	484	68.7	26,256	NO
10	Loss of Source	12/31/2022 14:02	4273	7.6	24,287	YES

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	7/28/2021	10812	1.2	12,974	No
2	Recloser Lockout	12/15/2021	5348	1.85	9,894	No

3	Wire Down	12/14/2021	4530	6.15	27,860	Yes
4	CB Lockout, Lighting	7/29/2021	4522	0.98	4,447	No
5	Device failure	12/14/2021	4387	9.55	41,896	Yes
6	Loss of Source	10/7/2021	4374	0.1	437	No
7	Loss of Source	10/8/2021	4374	5.78	25,296	No
8	CB Lockout	12/24/2021	4368	1.7	7,426	No
9	CB Lockout	12/13/2021	4362	6.82	29,734	No
10	Loss of Source	2/25/2021	4183	0.62	336	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Operations Error	7/28/2020	5,291	0.68	3597.8	No
2	CB Lockout, Lightning possible	8/24/2020	3,835	1.63	6251.05	No
3	Unknown	11/6/2020	3,728	1.3	4846.4	No
4	Wind/Debris	8/12/2020	3,724	0.56	2085.44	No
5	Animal	9/10/2020	3,451	0.3	1035.3	No
6	Animal	9/6/2020	3,266	0.86	2808.7	No
7	Animal	10/23/2020	3,266	0.28	914.5	No
8	Animal	7/28/2020	2,555	0.46	705.8	No
9	Device failure	7/2/2020	2,555	1.43	3653.6	No
10	Operations Error	7/28/2020	2,555	0.68	1737.4	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40701.2	No

2	Equipment Failure	2/22/2019	8,560	4.42	37835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1411.38	No
4	Hardware Failure	2/26/2019	4,485	3.5	15697.5	No
5	Tree	1/18/2019	4,448	1.76	7828.48	No
6	Hardware Failure	3/6/2019	4,448	0.82	3647.36	No
7	Animal	11/11/2019	4,245	0.6	2547	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1596.16	No
9	Animal	6/7/2019	3,529	0.47	1658.63	No
10	Tree	6/7/2019	3,507	1.51	5295.57	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	NV Energy Outage	9/27/2014	27,046	4.27	115,396.27	Yes
2	Flashing	7/20/2014	26,000	5.12	2,690.45	Yes
3	Tree-Green	12/11/2014	15,853	4.03	63,940.43	No
4	Relay Failure	9/23/2014	8,900	0.22	1,928.33	No
5	Trees	3/11/2014	3,587	1.83	6,521.17	No
6	Weather/Lightning	7/20/2014	3,587	0.75	2,690.25	No
7	Trees	8/30/2014	3,587	0.30	1,195.67	No
8	Trees	1/30/2014	3,548	4.25	2,109.00	No
9	Bird/Animal	8/31/2014	3,548	0.50	1,774.00	No
10	Trees	7/20/2014	3,500	5.00	17,266.67	No

9) Number of customer inquiries on reliability data and the number of days per response

CalPeco Electric did not receive any reliability inquiries in 2023.

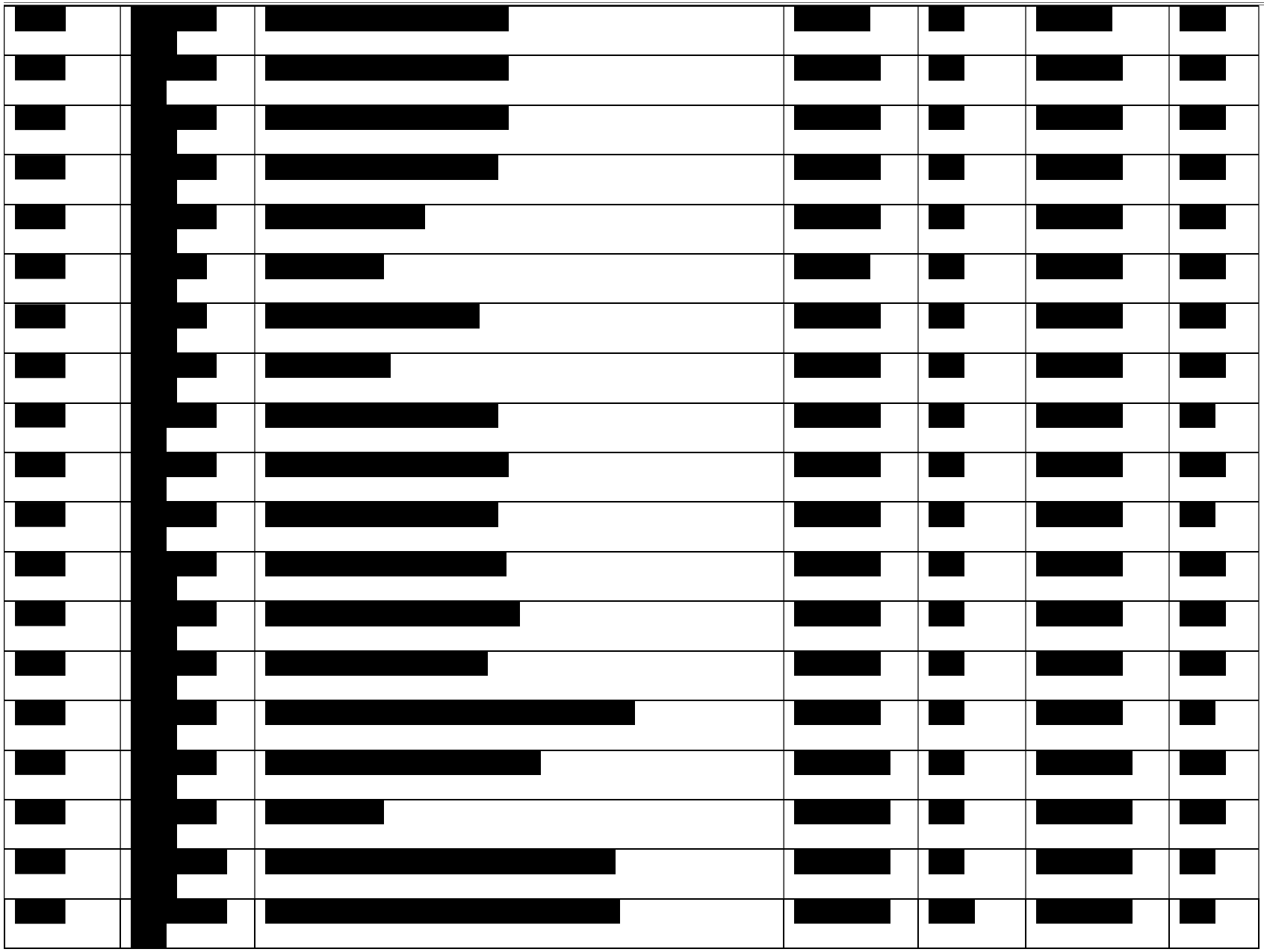
Date Received	Date Responded	Description of Inquiry

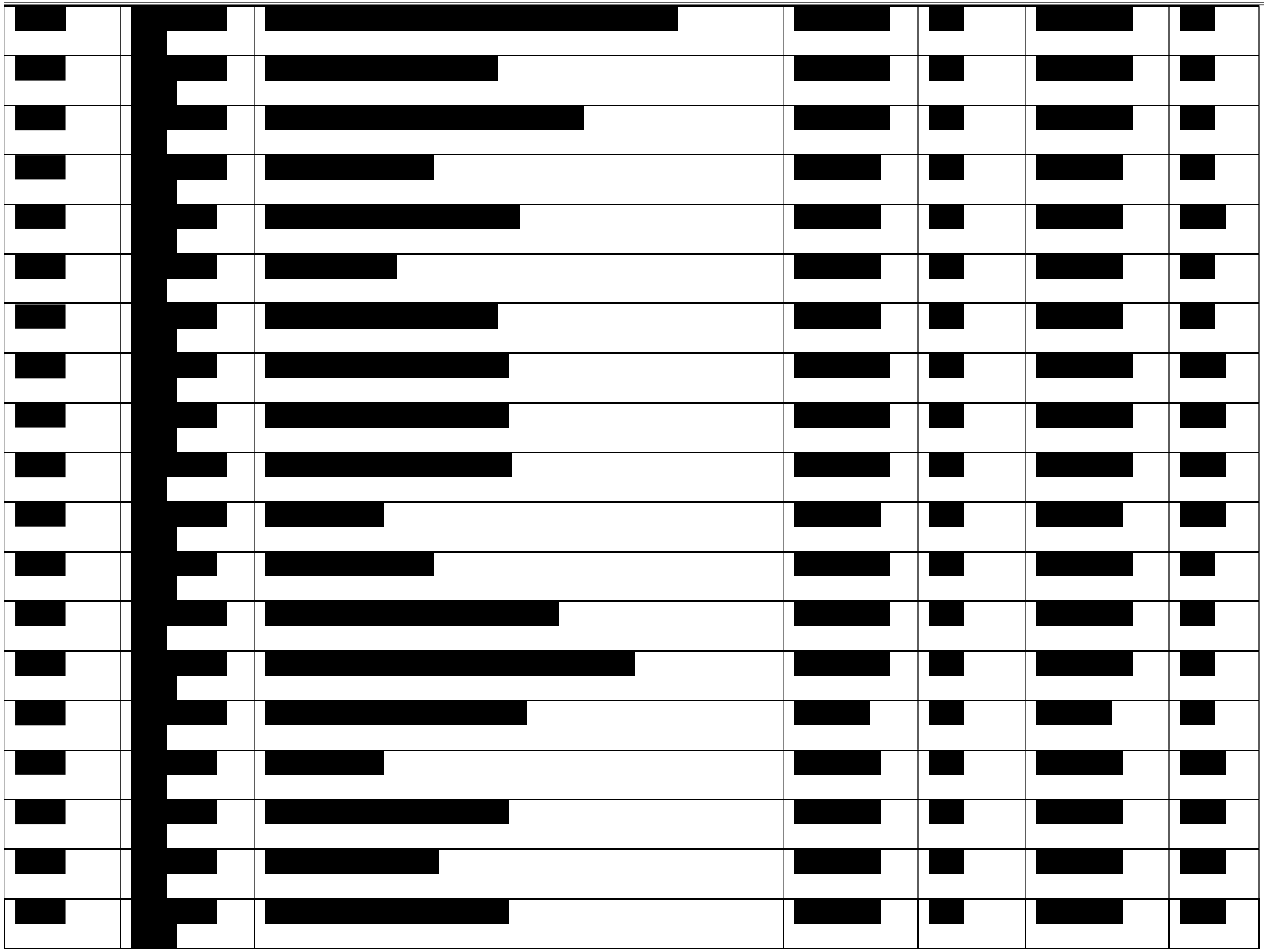
10) List of PSPS's in 2023

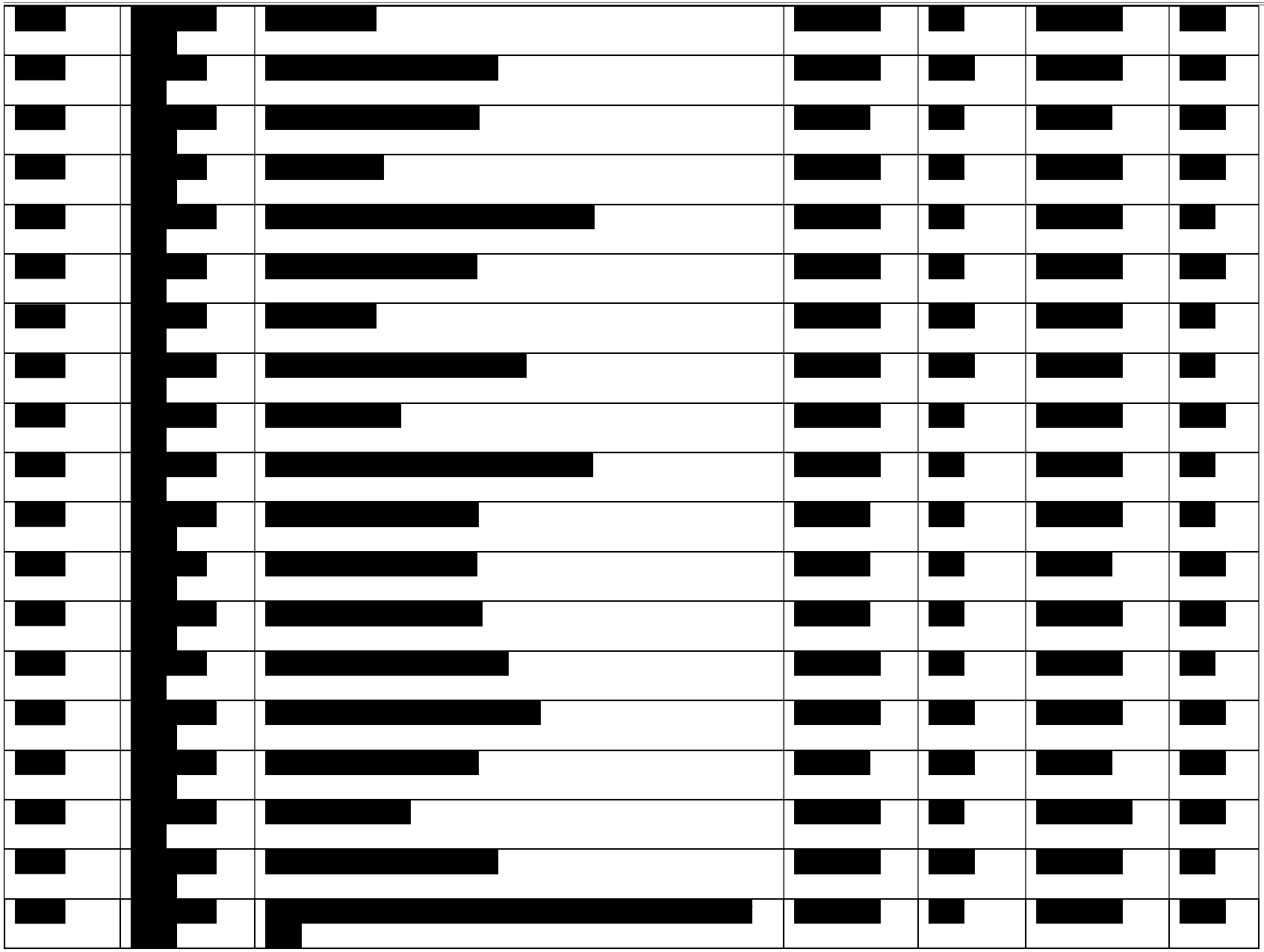
CalPeco Electric did not have any PSPS events in 2023.

Appendix A: 10 Years of Planned Outage Data -- CONFIDENTIAL VERSION --

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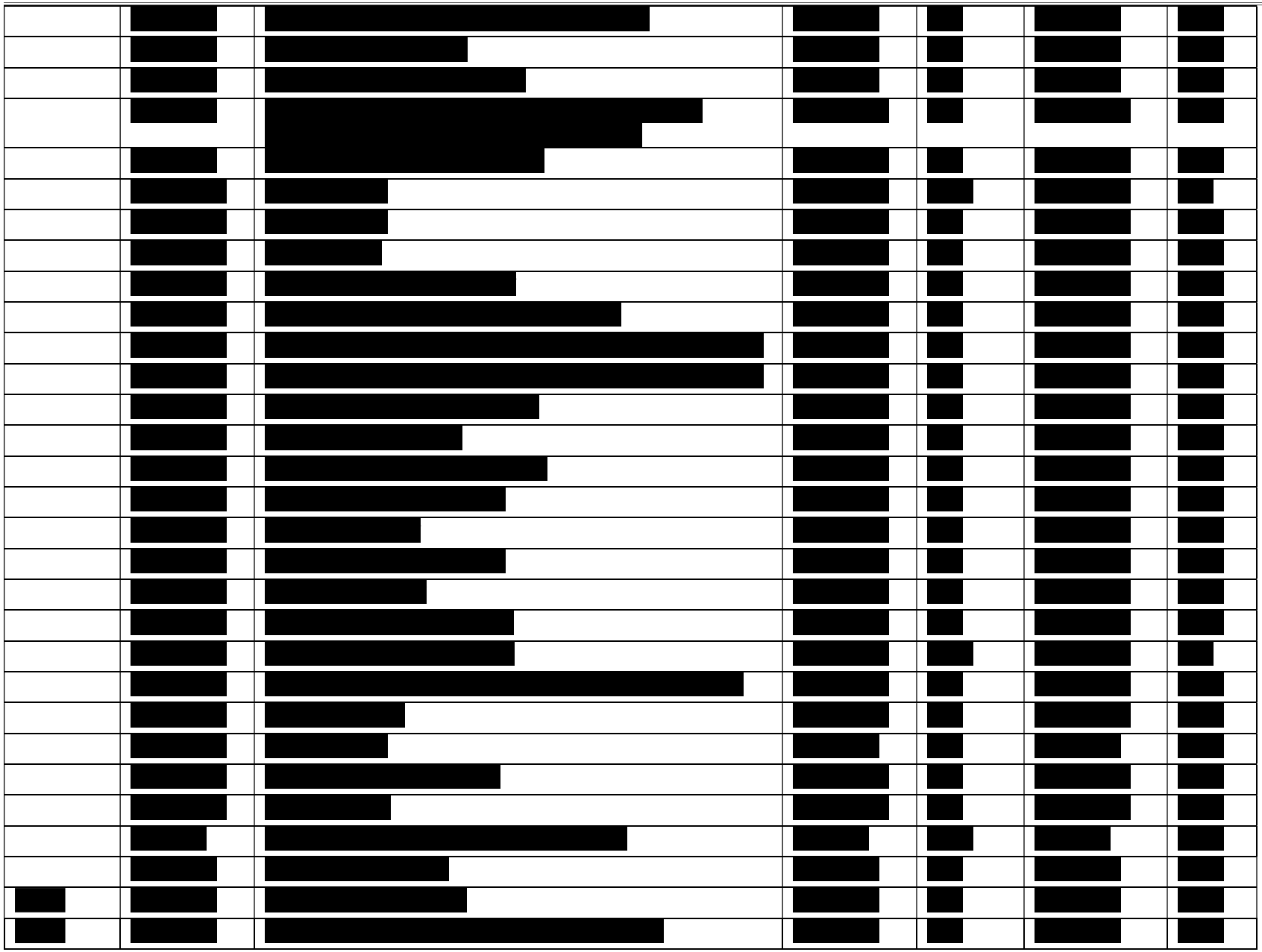


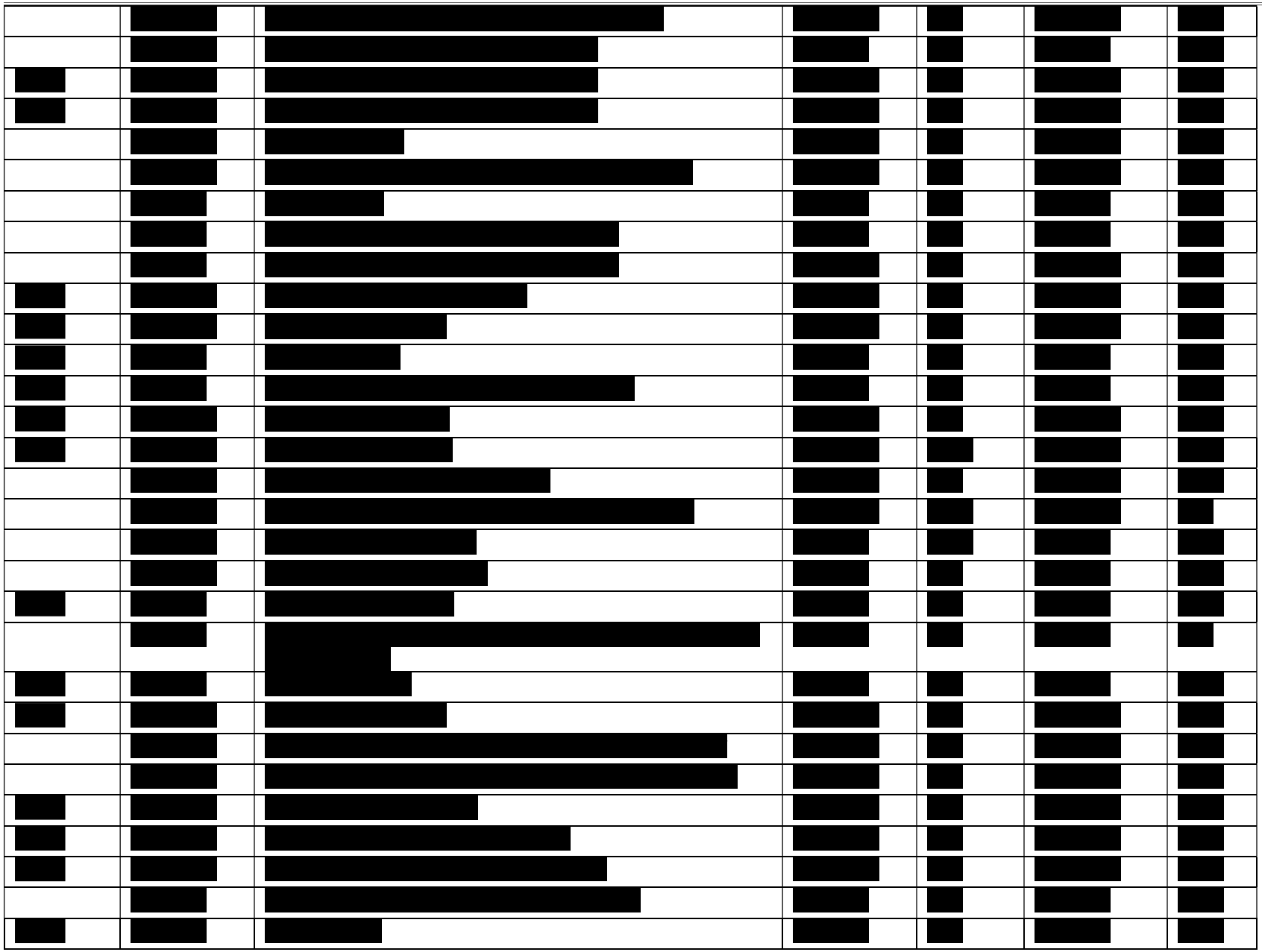




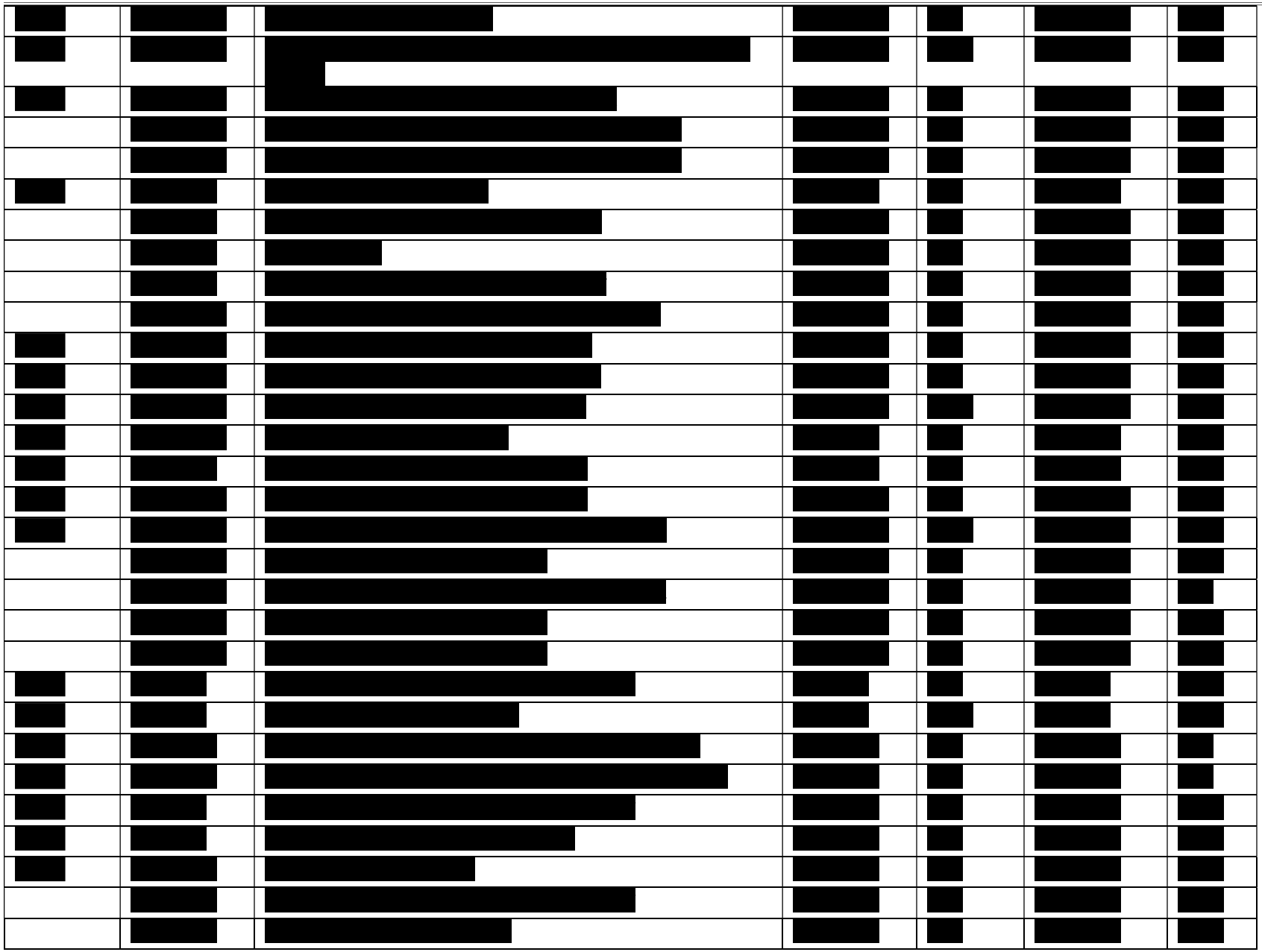


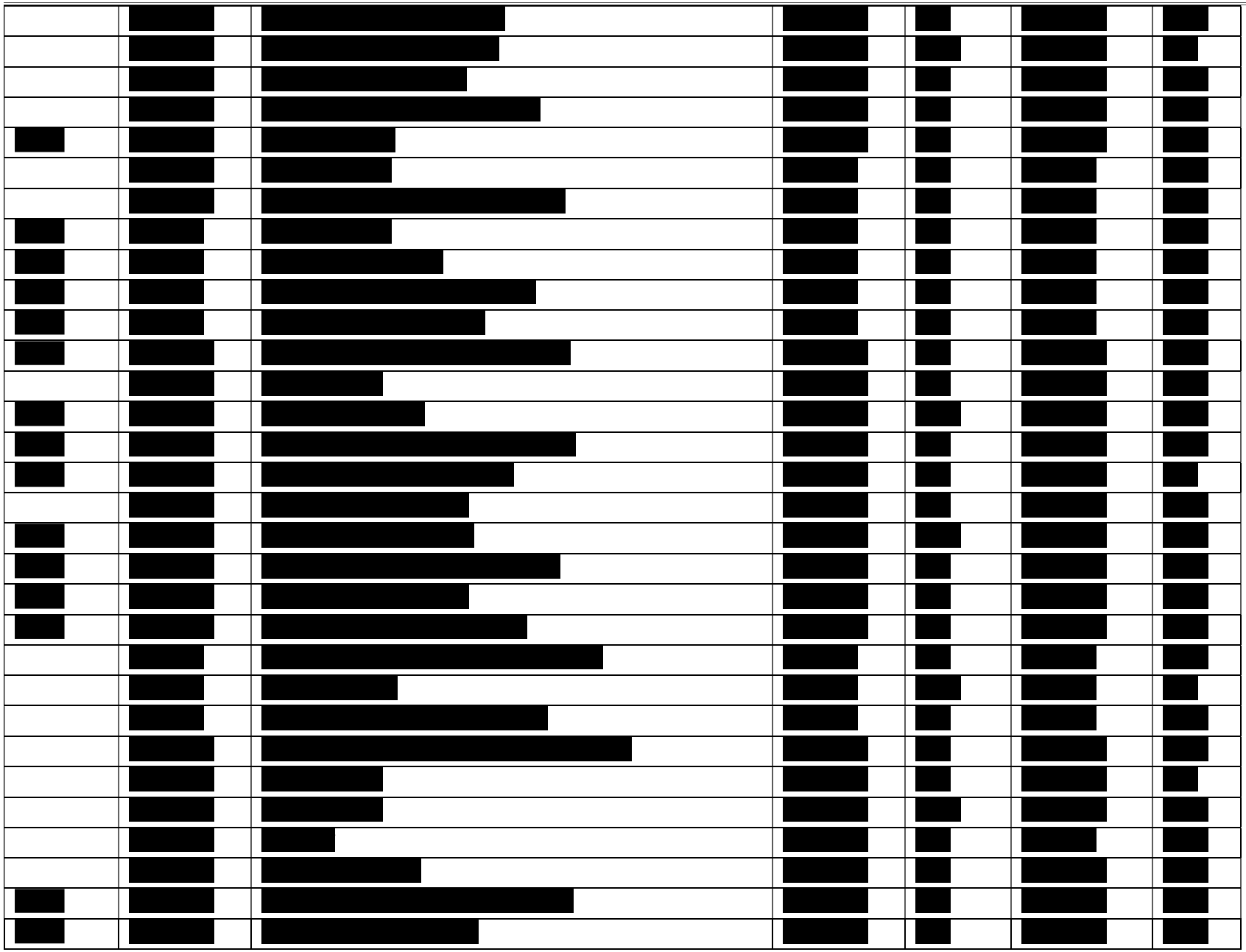






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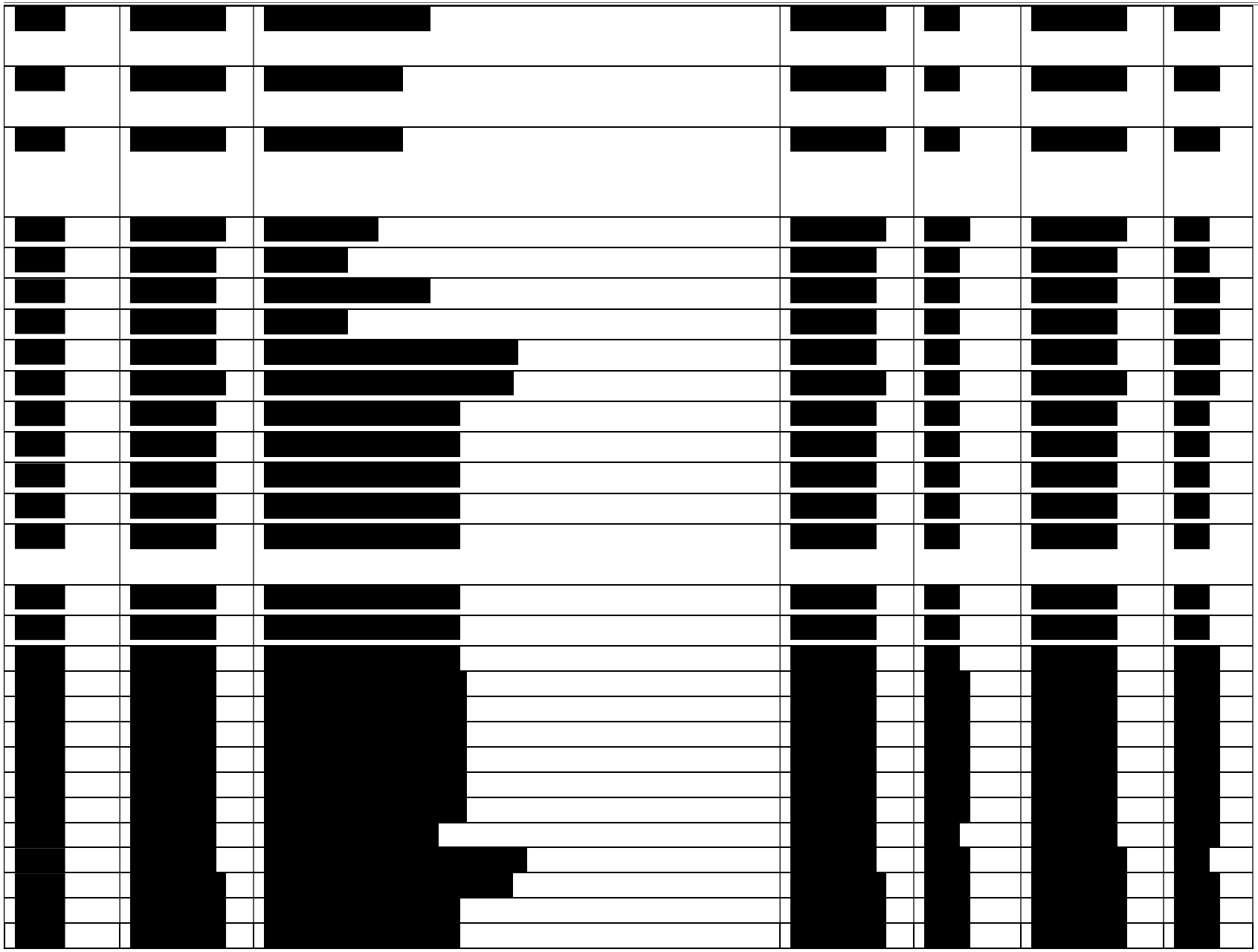




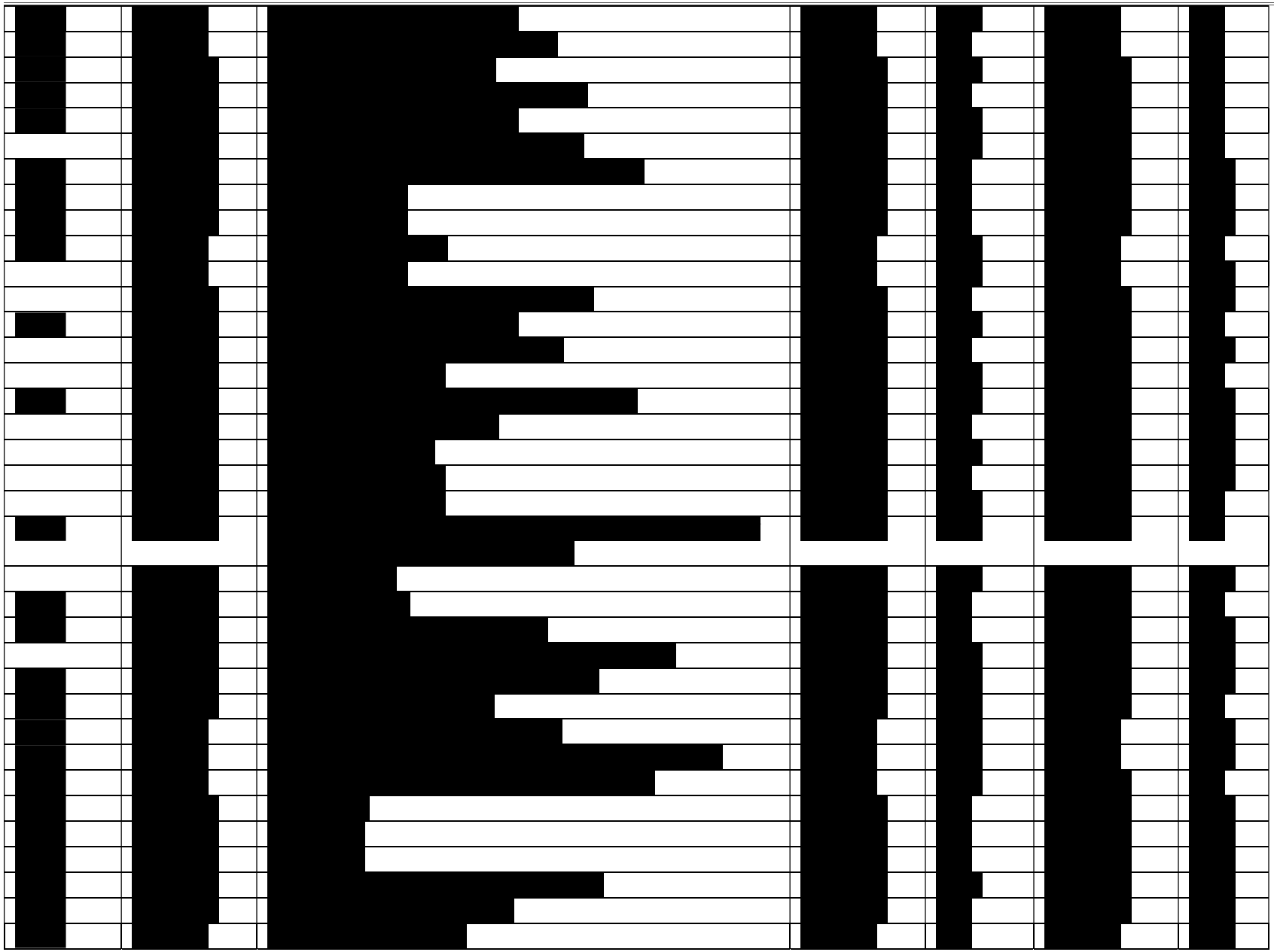


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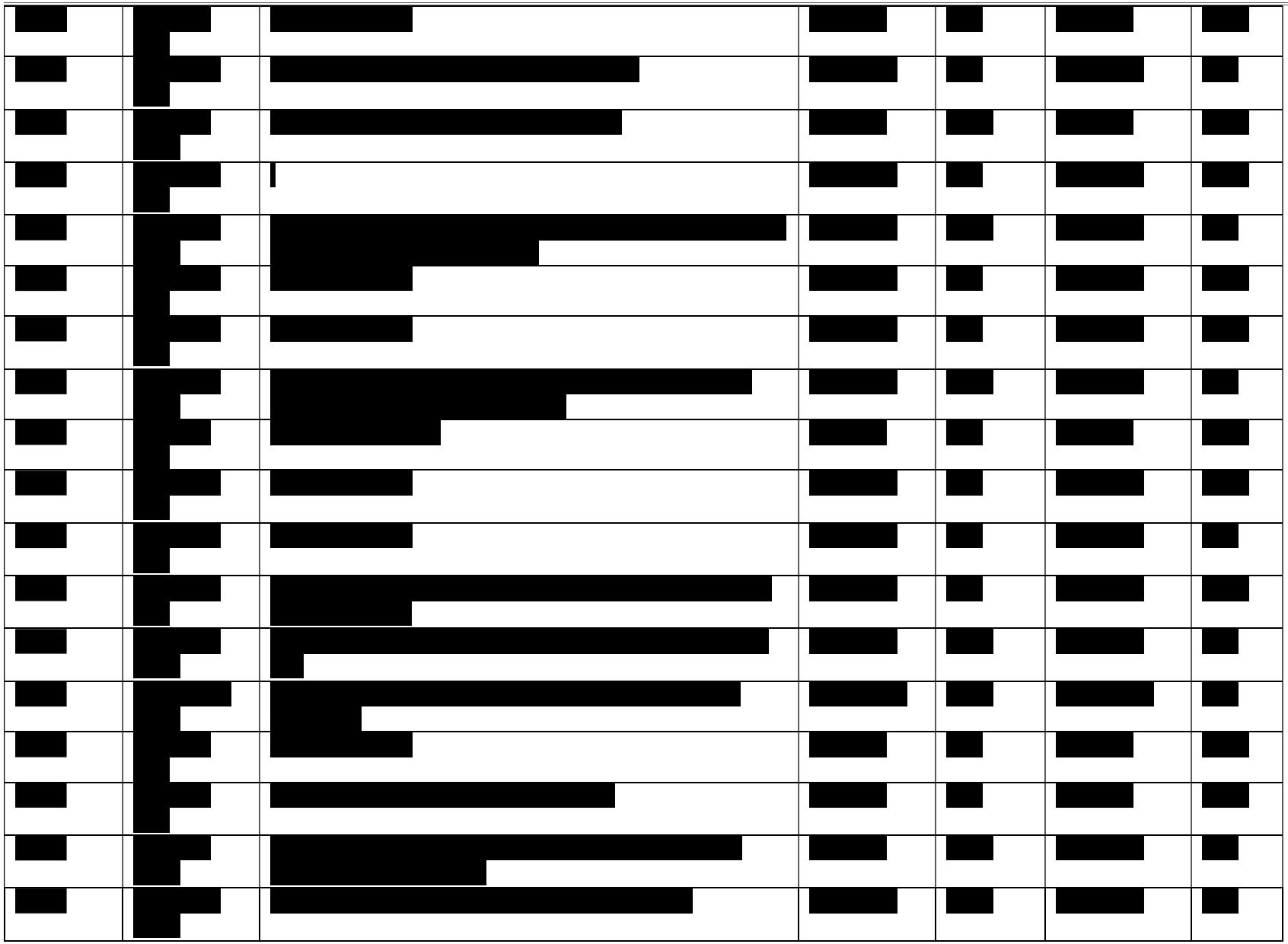














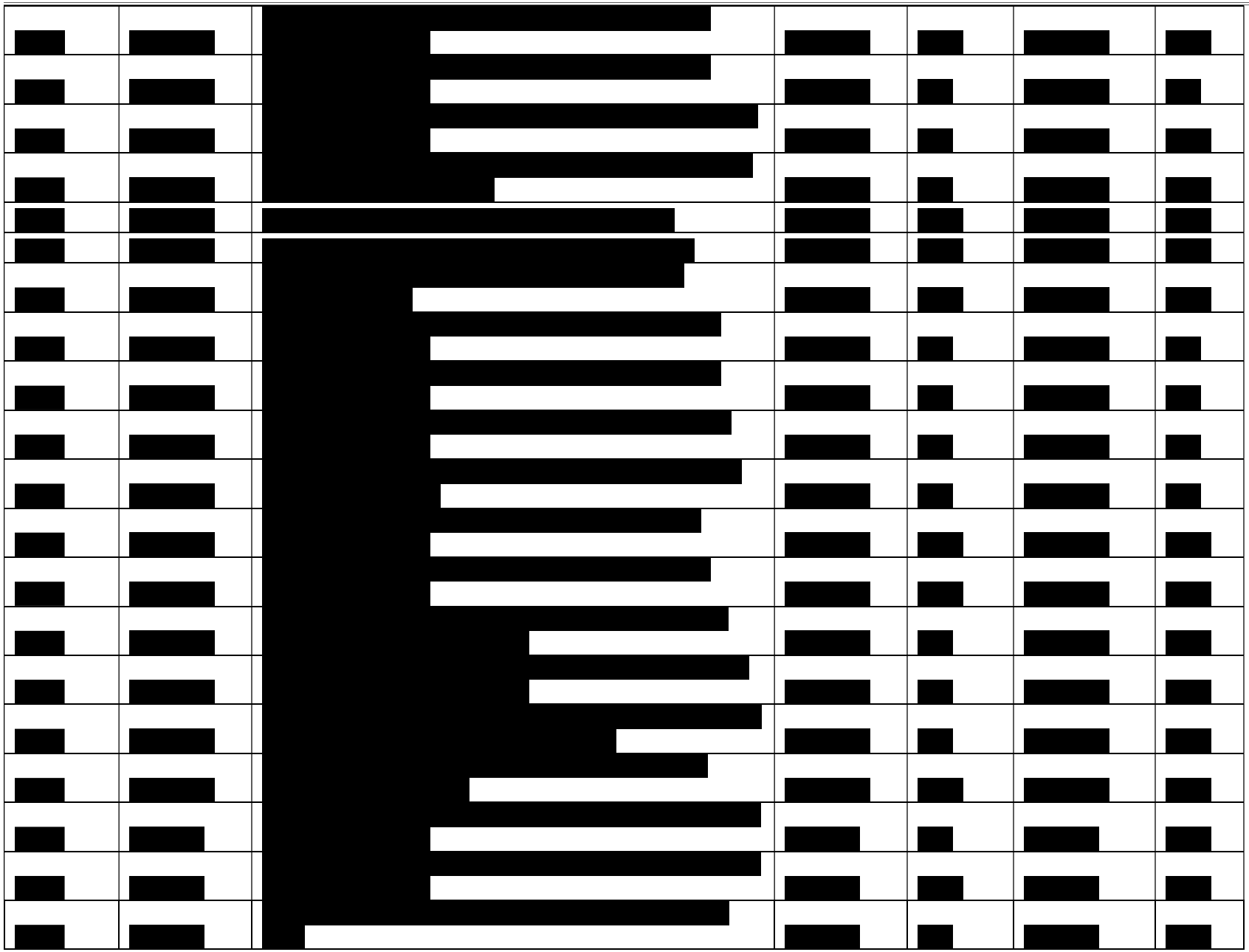


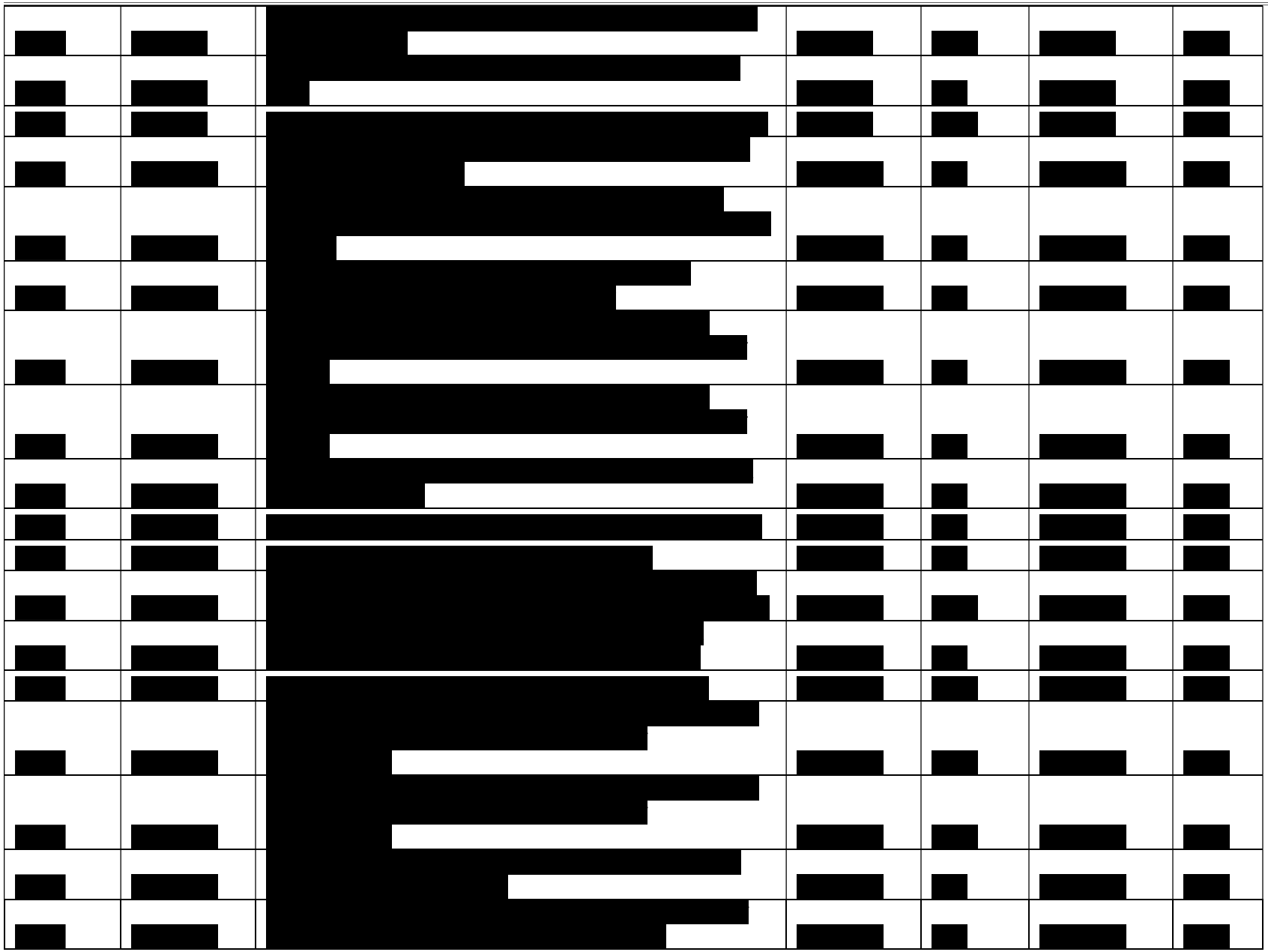






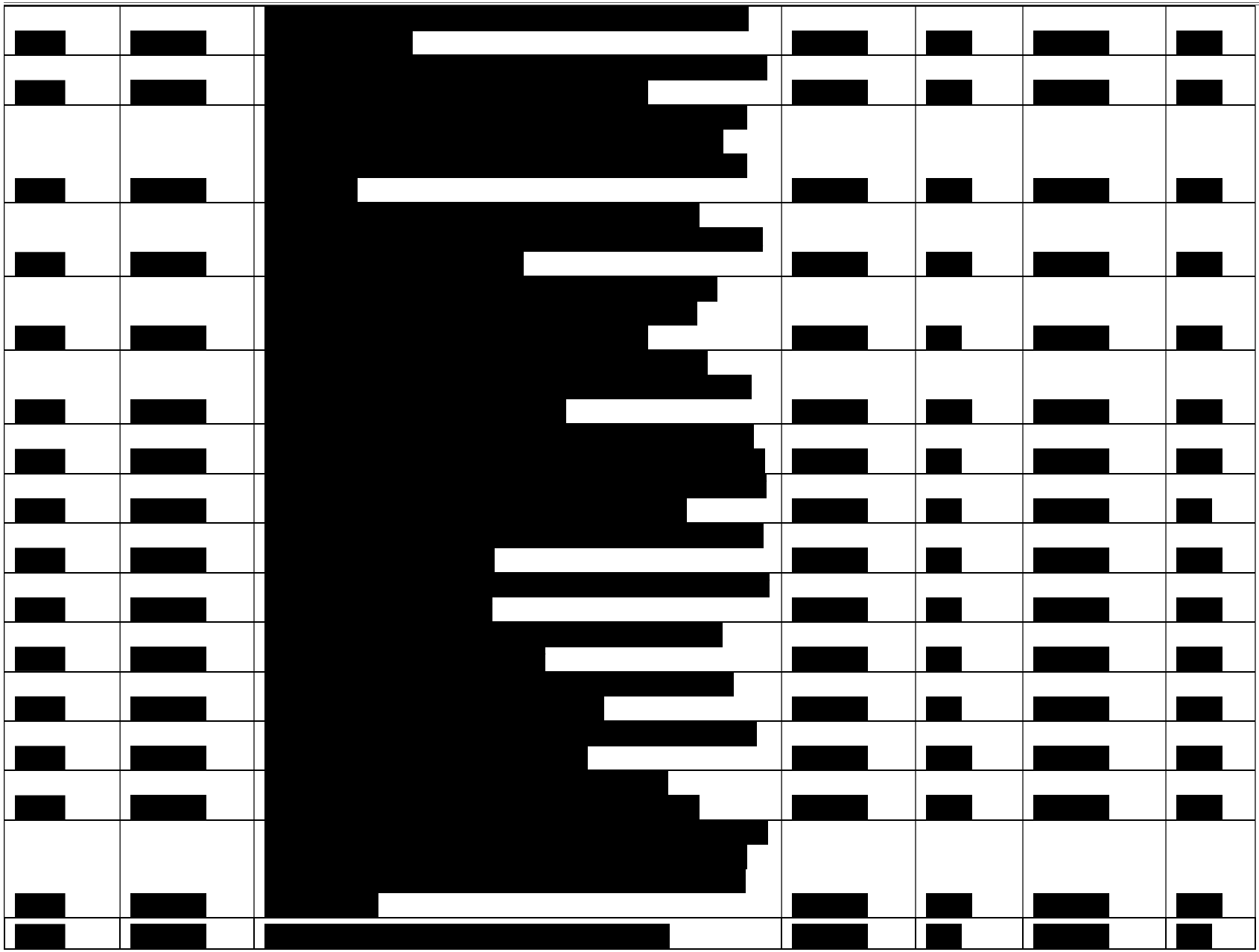


























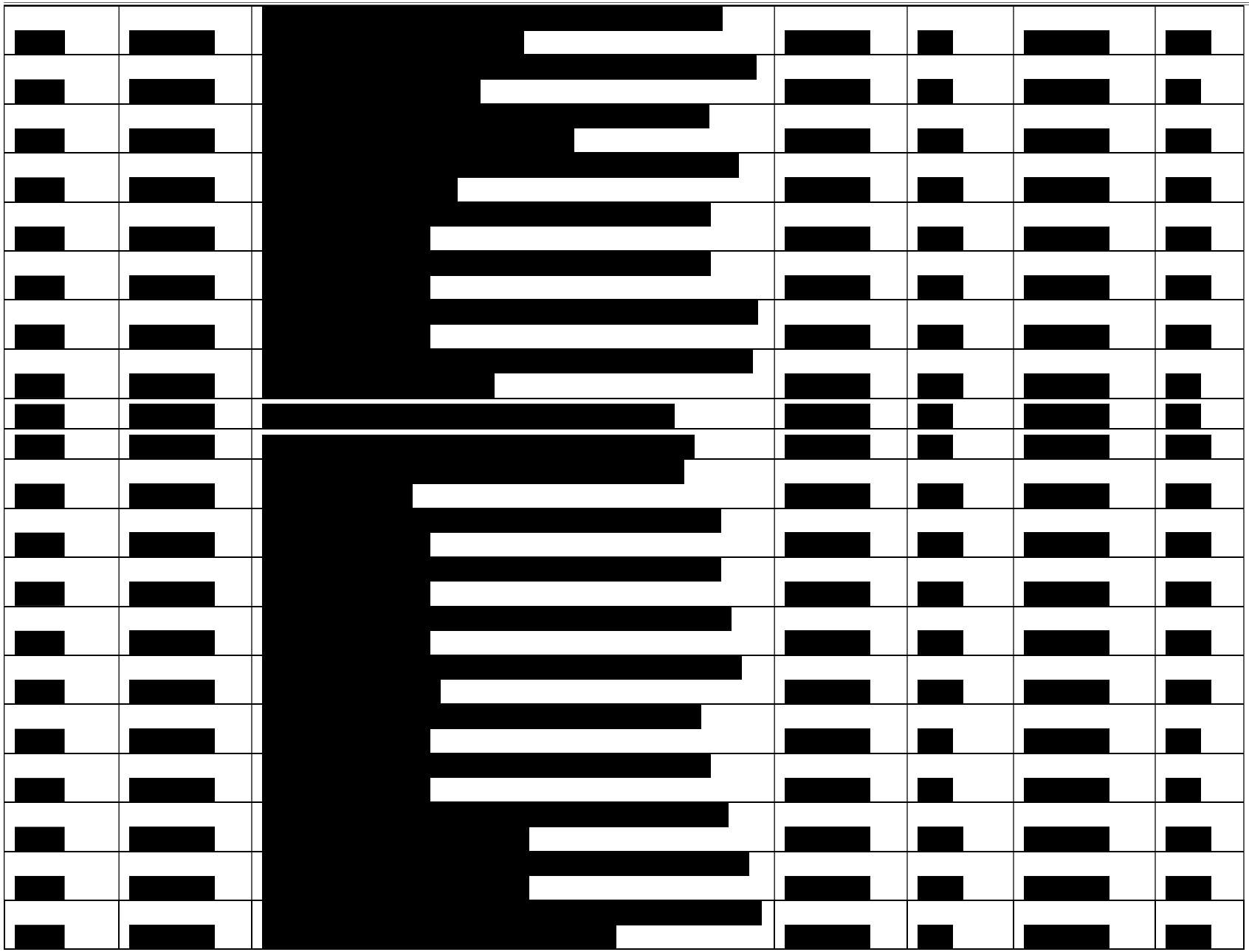






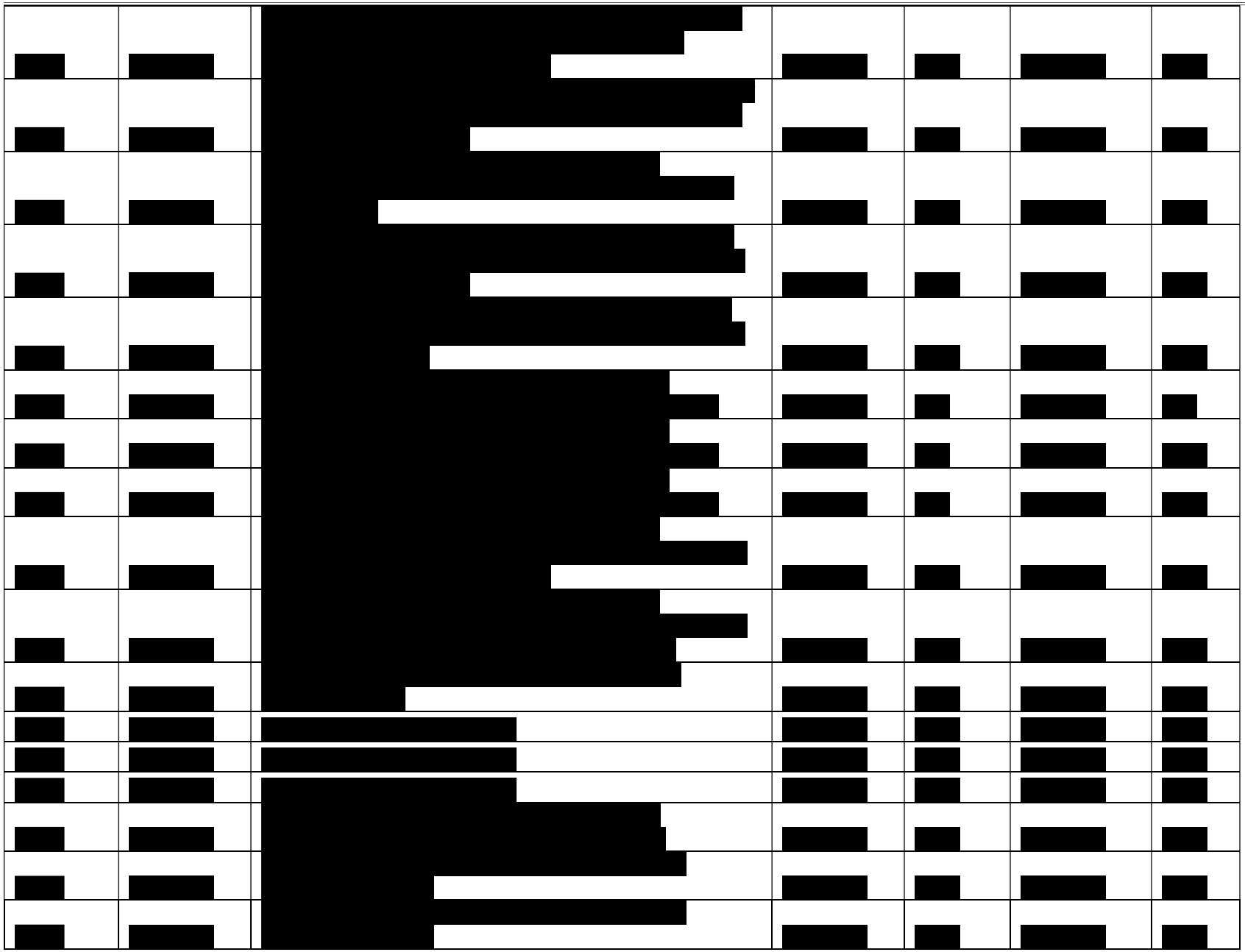


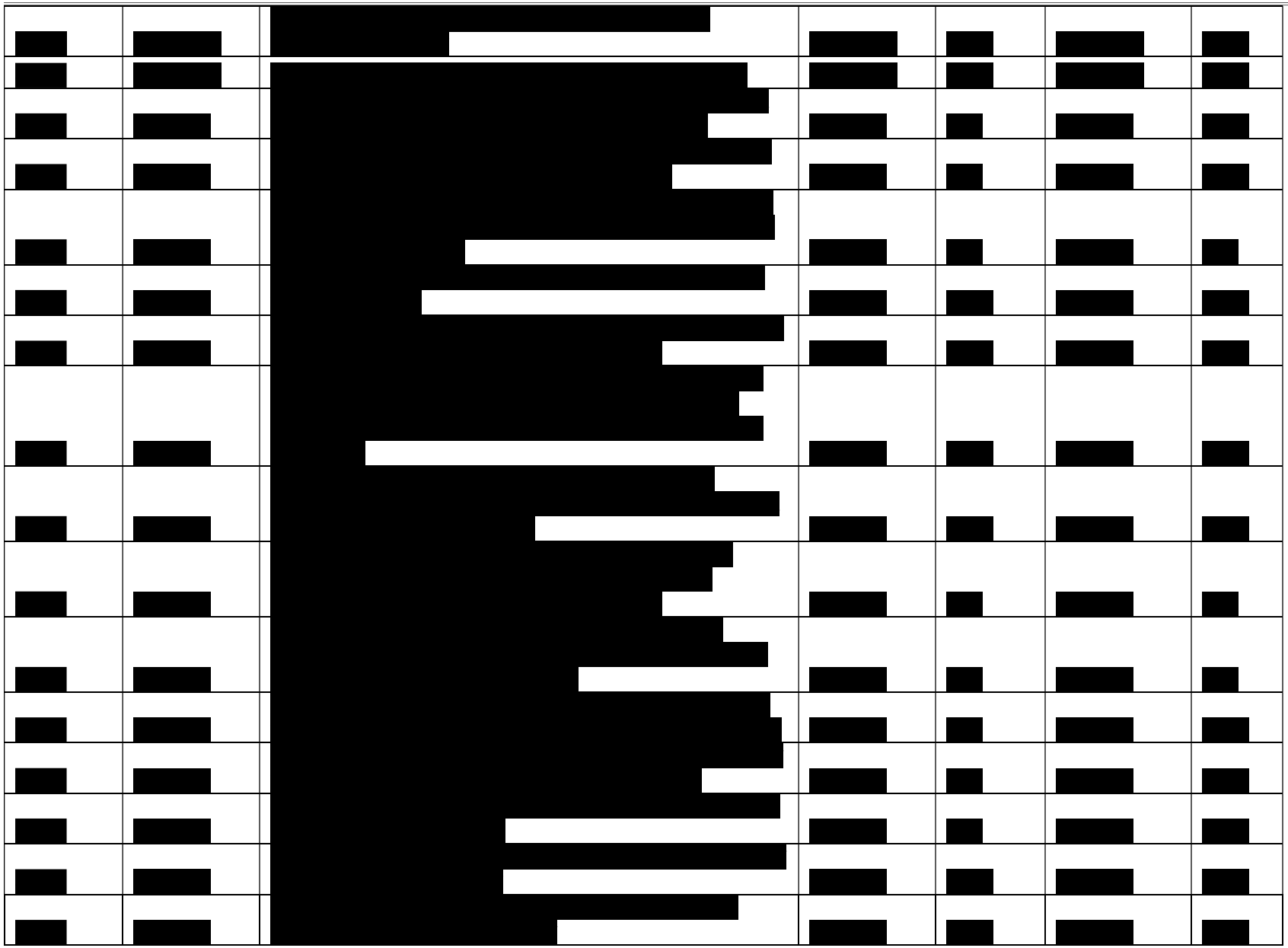




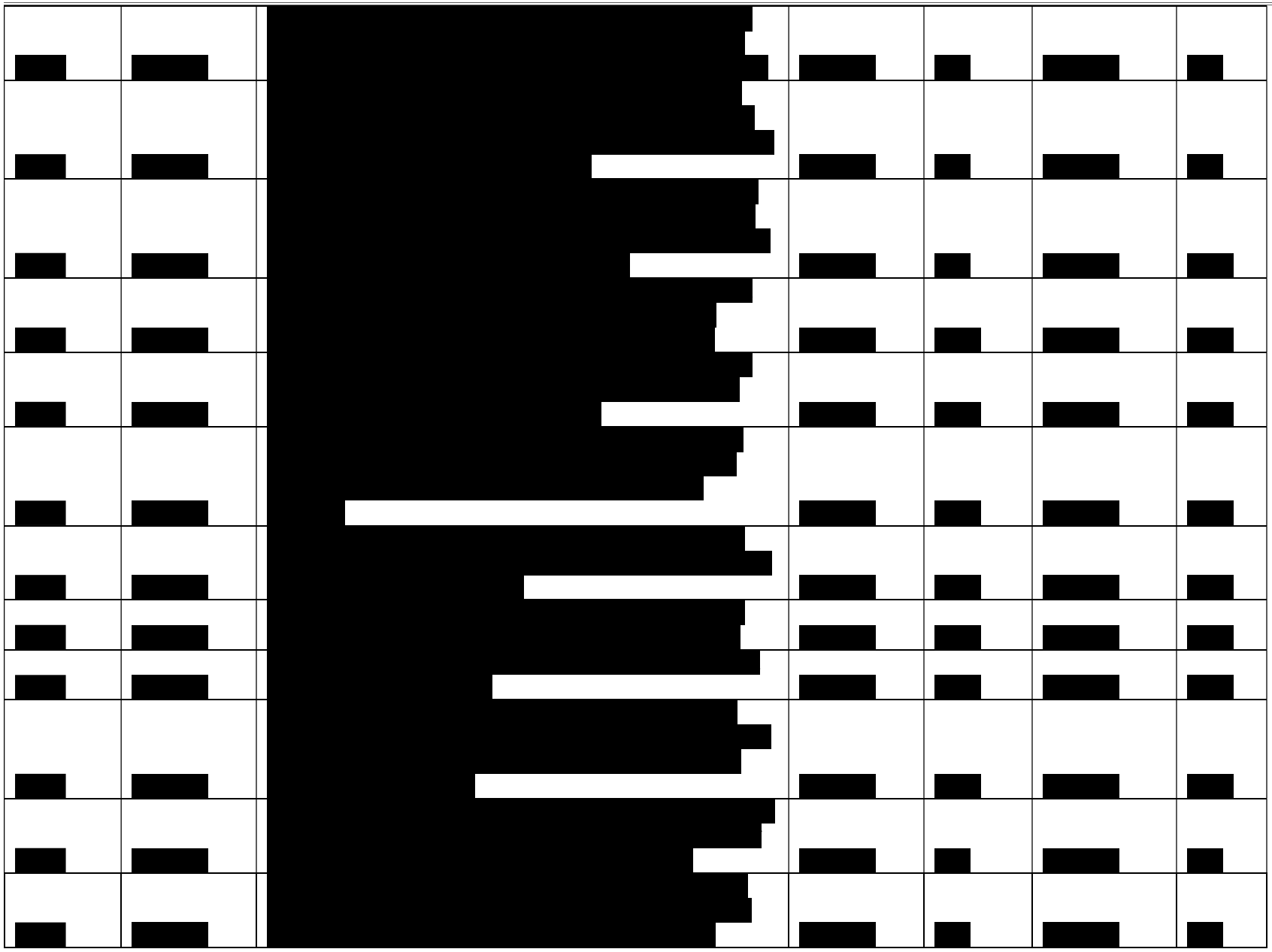




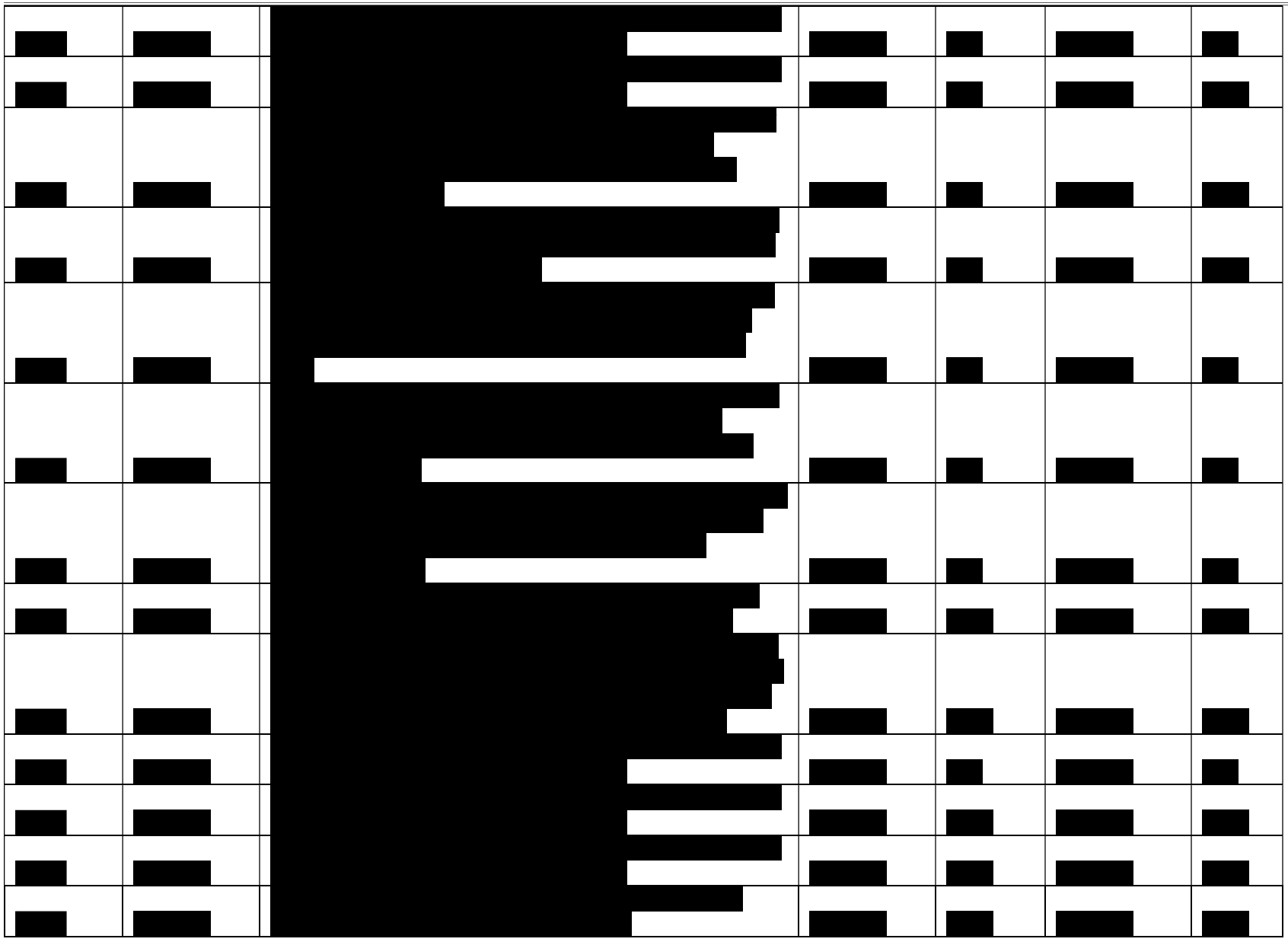




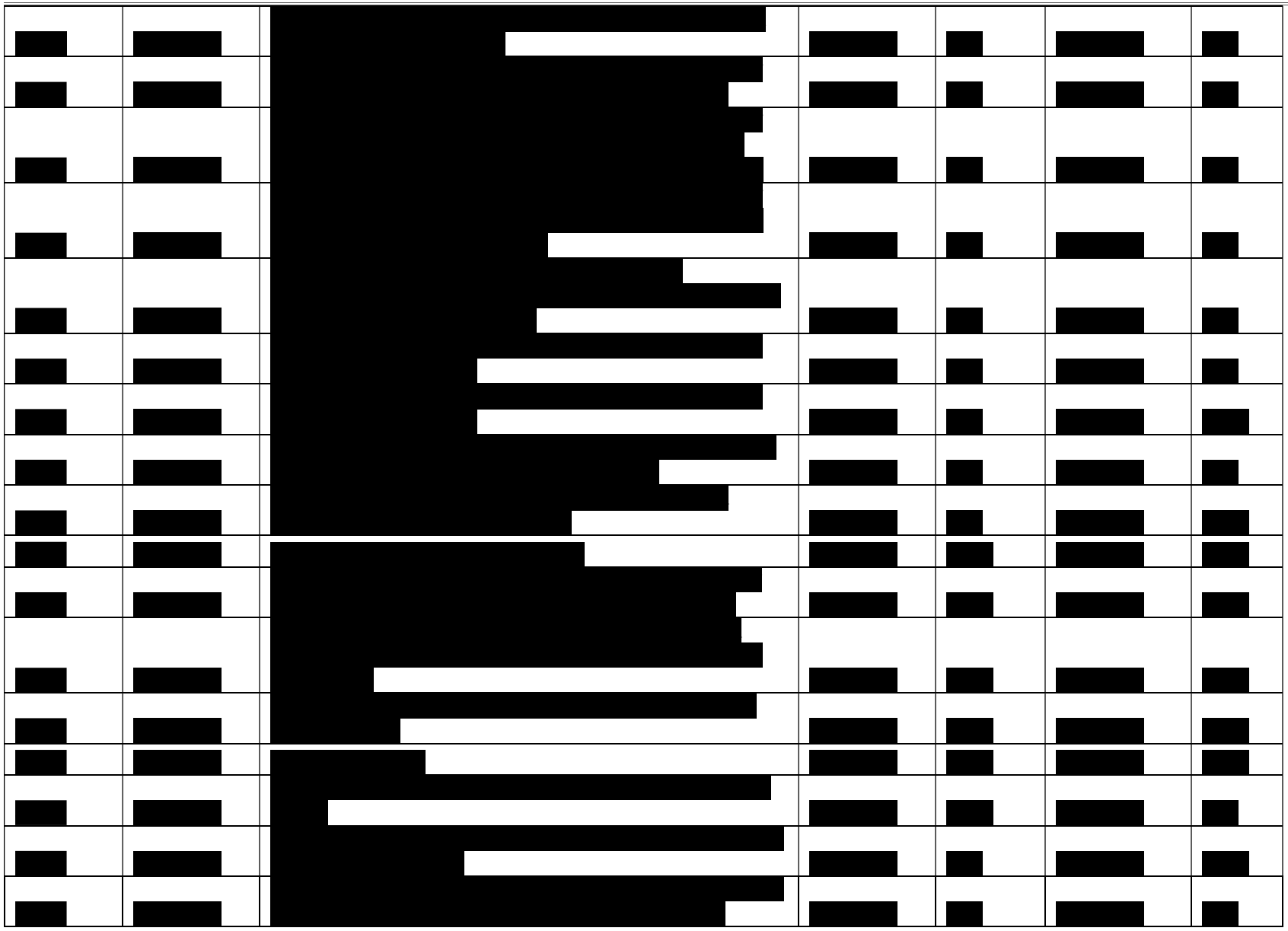


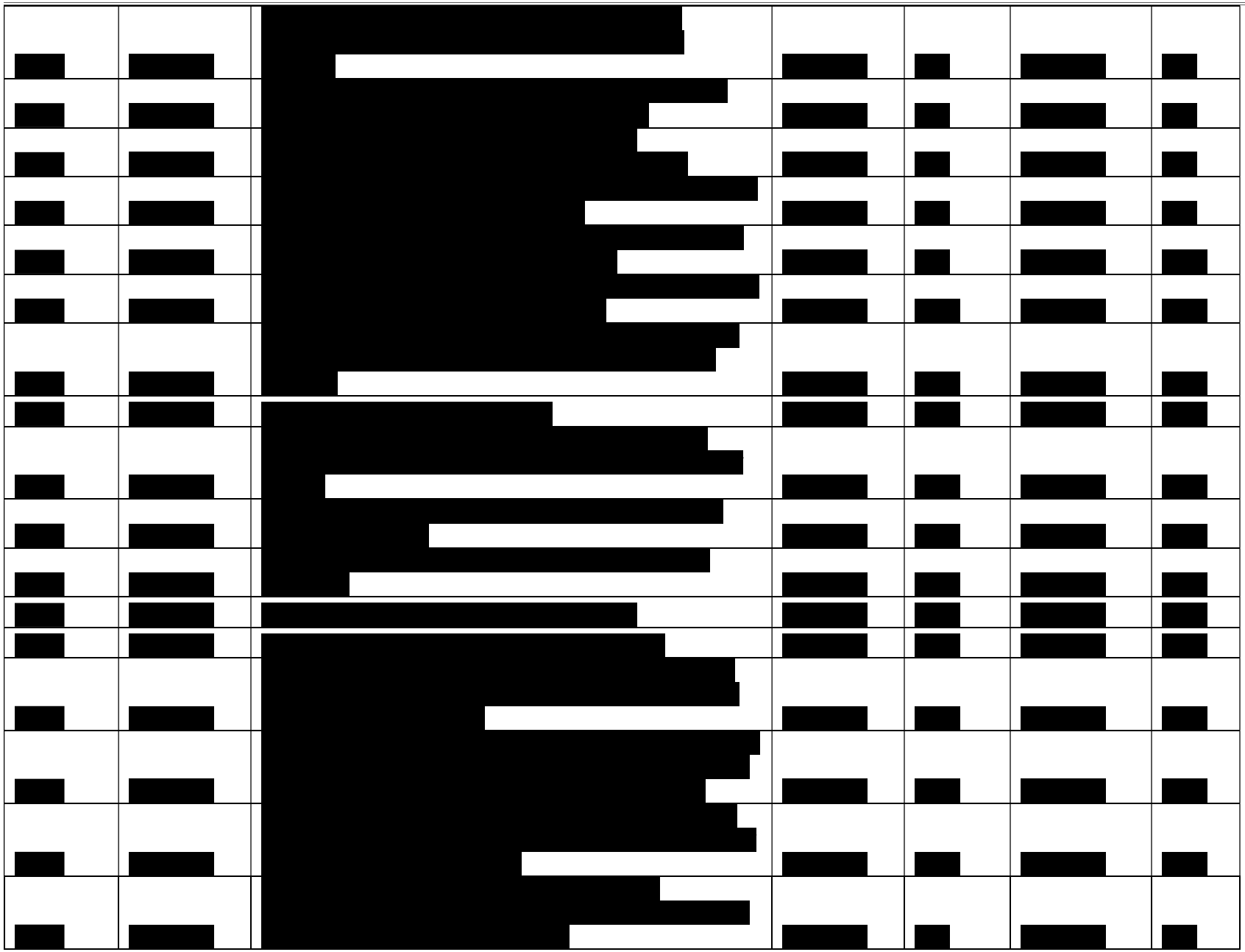


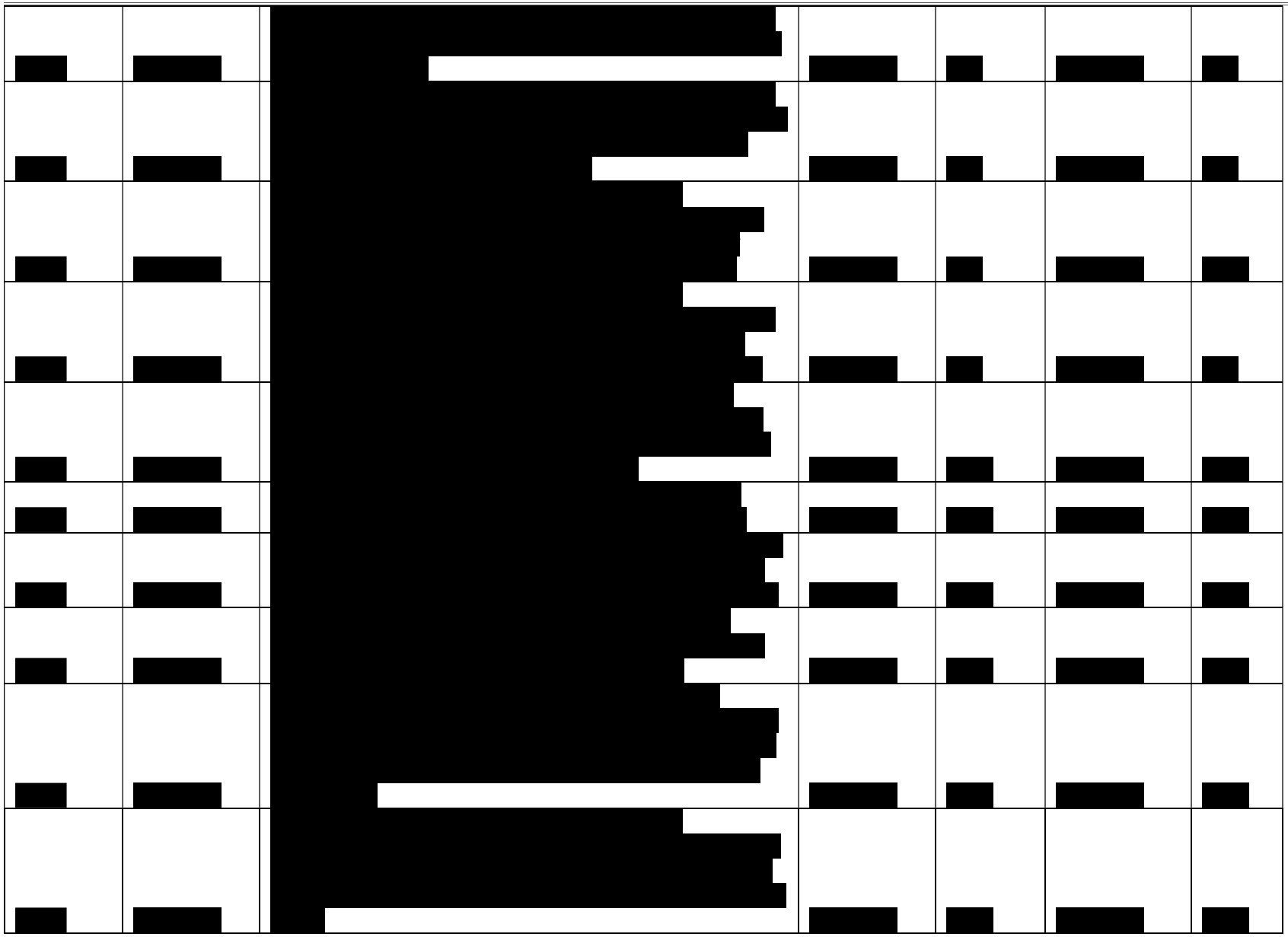






















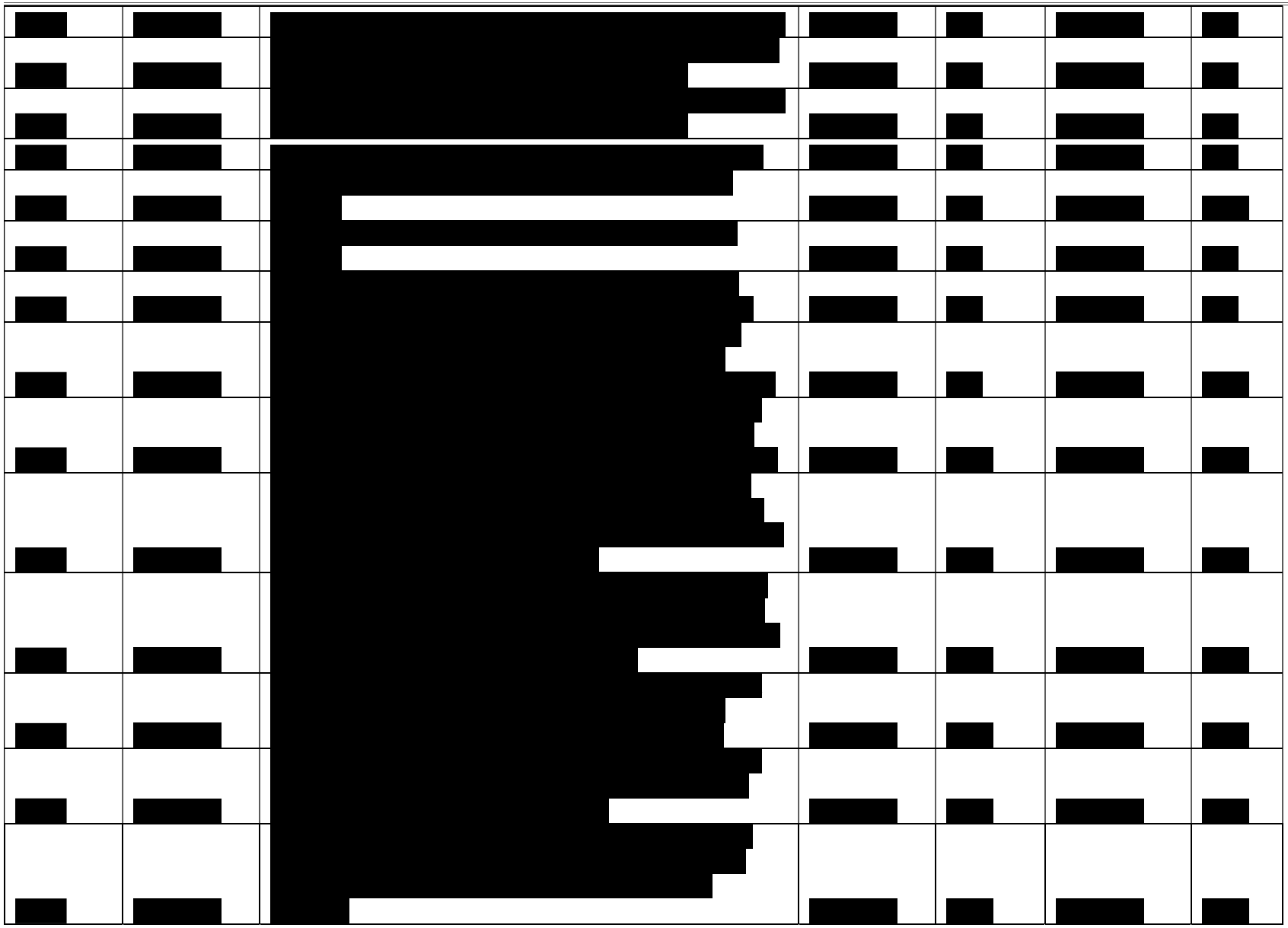


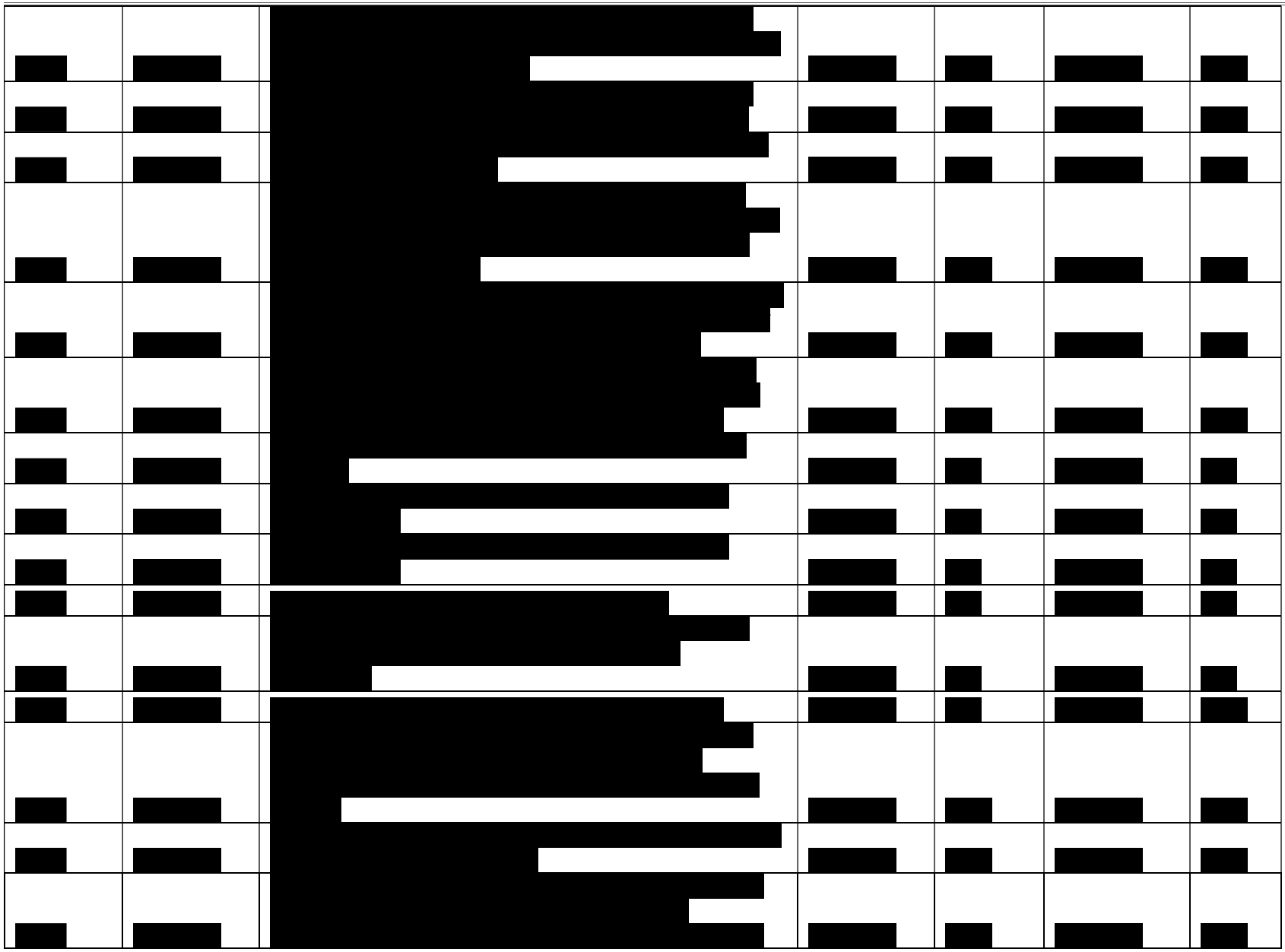






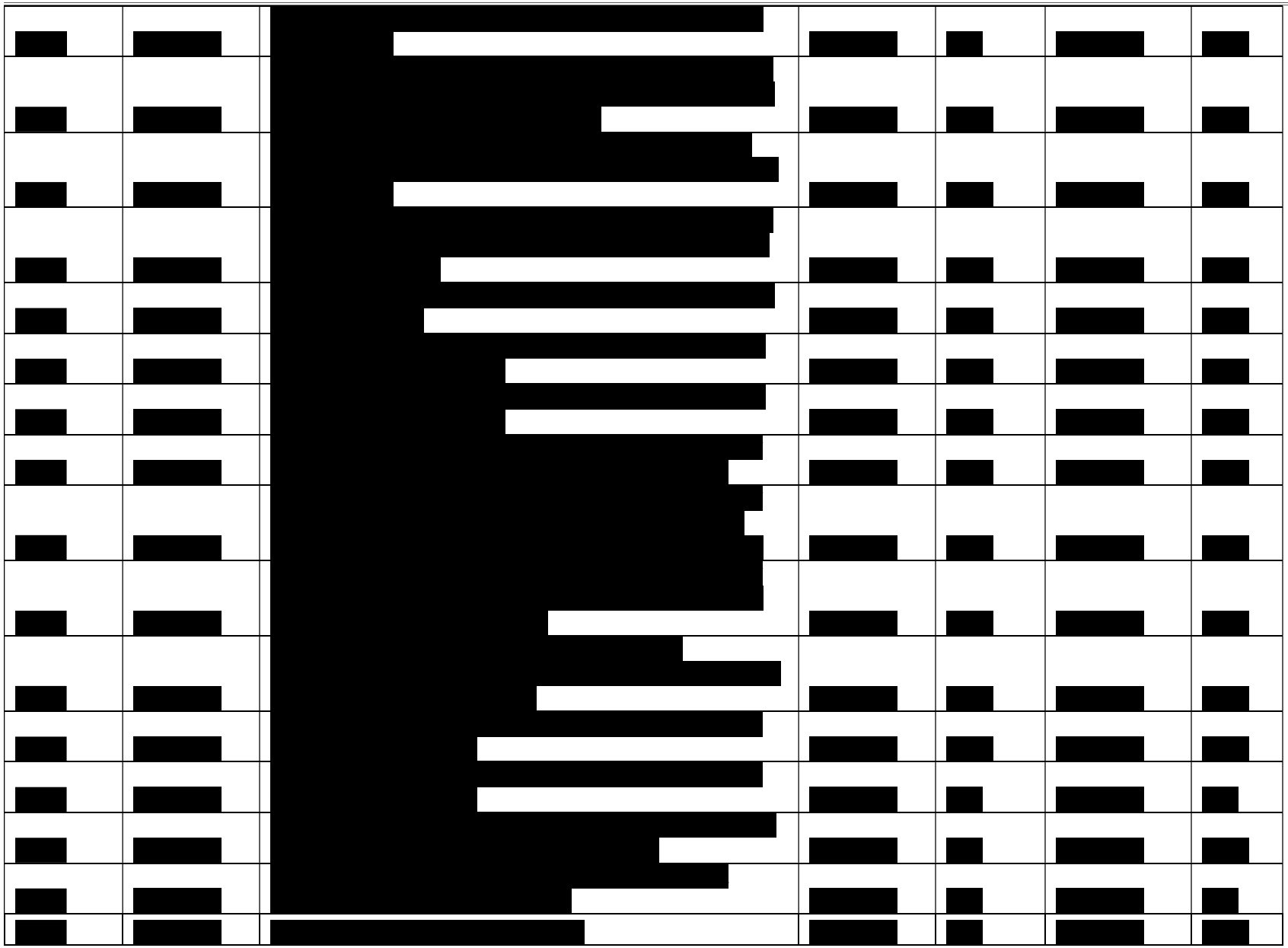


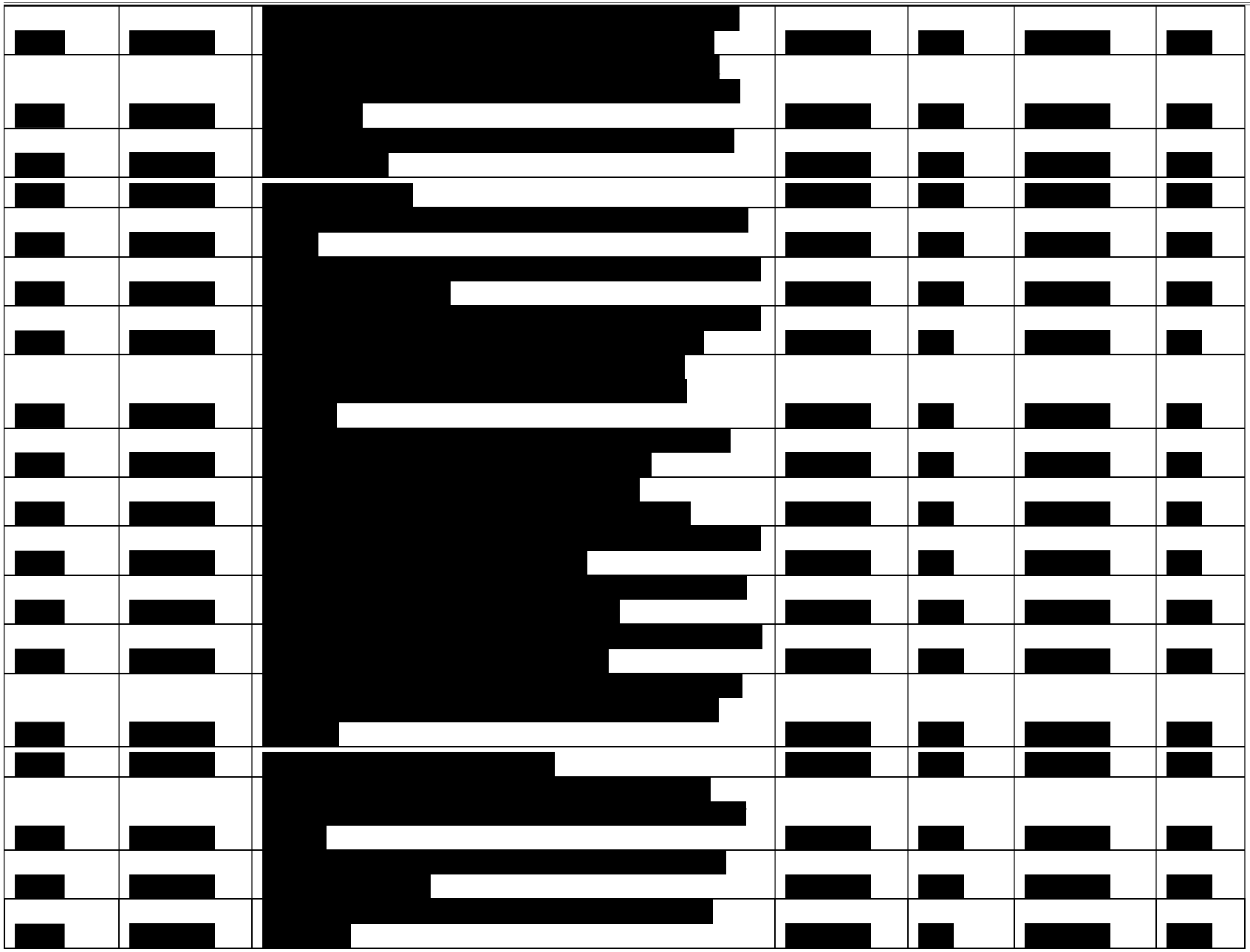


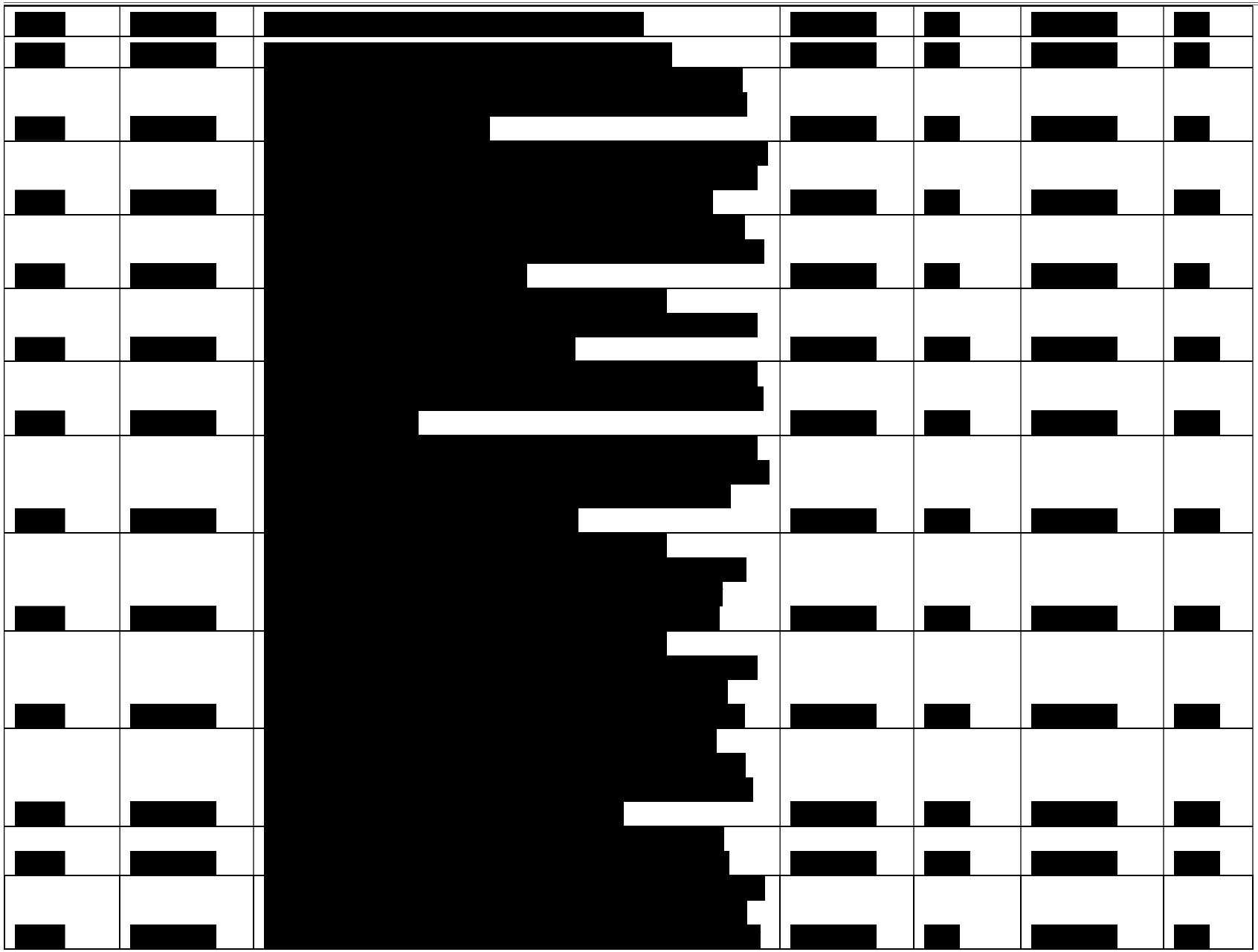










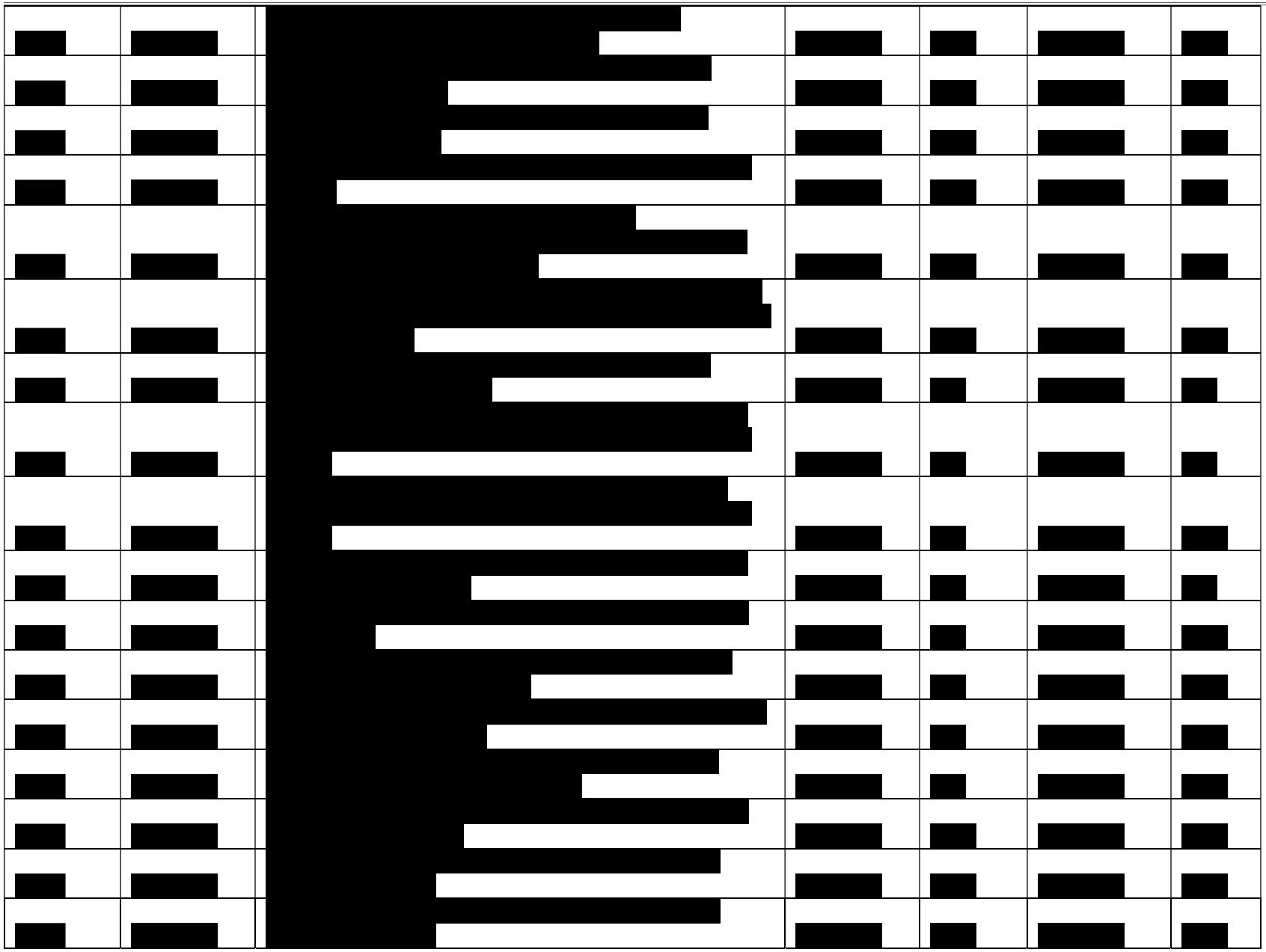


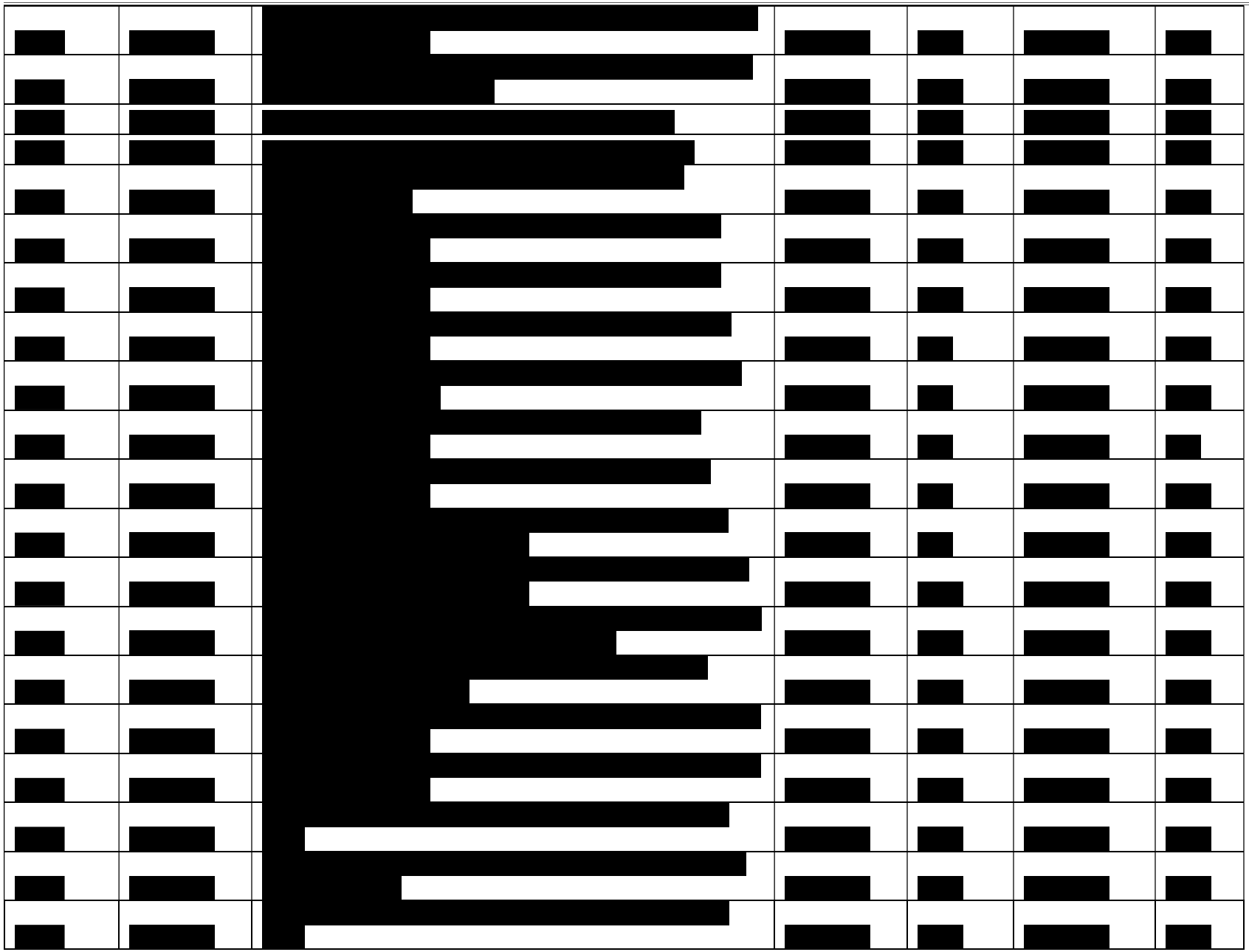






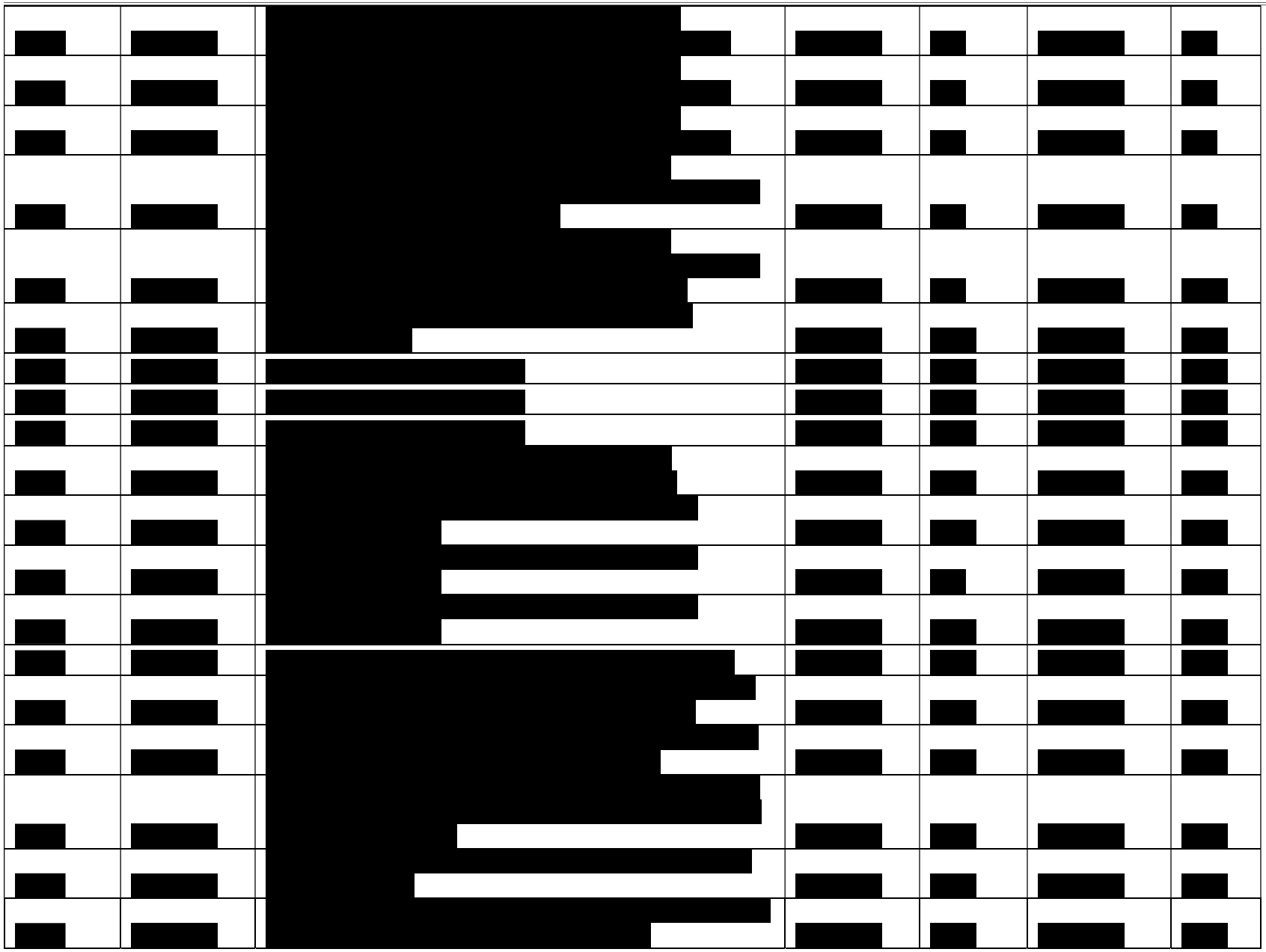






















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ATTACHMENT 17

Liberty Utilities 2024 Annual Reliability Report



ELECTRIC SYSTEM RELIABILITY ANNUAL REPORT

2024

LIBERTY UTILITIES (CALPECO ELECTRIC) LLC (U 933 E)

-- PUBLIC VERSION --

Prepared for

California Public Utilities Commission

July 15th, 2025

CA-07-1041

EXECUTIVE SUMMARY

The Electric System Reliability Annual Report for 2024 has been prepared in response to CPUC Decision 16-01-008, which was approved January 20, 2016. Decision 16-01-008 established reliability recording, calculation, and reporting requirements for Liberty Utilities (CalPeco Electric) LLC.

CalPeco Electric does not provide transmission services. CalPeco Electric does not have an Open Access Transmission Tariff (OATT). Therefore, data is presented for the distribution services only. All statistics and calculations include forced distribution outages. Forced outages are those that are not prearranged. For the purposes of this report, sustained outages are outages that lasted more than five minutes in duration, while momentary outages are outages that lasted five minutes or less in duration.

The reliability indicators that are tracked are as follows:

1. SAIDI (System Average Interruption Duration Index) - minutes of sustained outages per customer per year.
2. SAIFI (System Average Interruption Frequency Index) - number of sustained outages per customer per year.
3. MAIFI (Momentary Average Interruption Frequency Index) - number of momentary outages per customer per year.
4. CAIDI (Customer Average Interruption Duration Index) – is the average time required to restore service to a utility customer.

CalPeco Electric presents ten years (2015 through 2024) of data, which represents the period in which Liberty Utilities purchased CalPeco Electric from NV Energy.

The measurement of each reliability performance indicator excludes IEEE Major Event Days (MED) instead of CPUC Major Events. An IEEE Major Event Day is defined in IEEE-1366, Section 4.5 as a day in which the daily system SAIDI exceeds a threshold value. These threshold major event days are referred to as "TMED". Thus, any day in which the total system SAIDI exceeds TMED is excluded from CalPeco Electric's reliability results. The applicable TMED value is calculated at the end of each year using CalPeco Electric's daily SAIDI values for the prior five years. CalPeco Electric's TMED value for 2024 was 92.23 minutes of daily system SAIDI. Other reliability indices in this report are not calculated using methodologies or formulas exactly as described in the IEEE guide for electric power Distribution Reliability indices (IEEE-1366).

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1) System Indices for the Last 10 Years (Years CalPeco Electric in business)

a. Separate tables with SAIDI, SAIFI, MAIFI and CAIDI (Major Event Day (MED)) included and excluded.

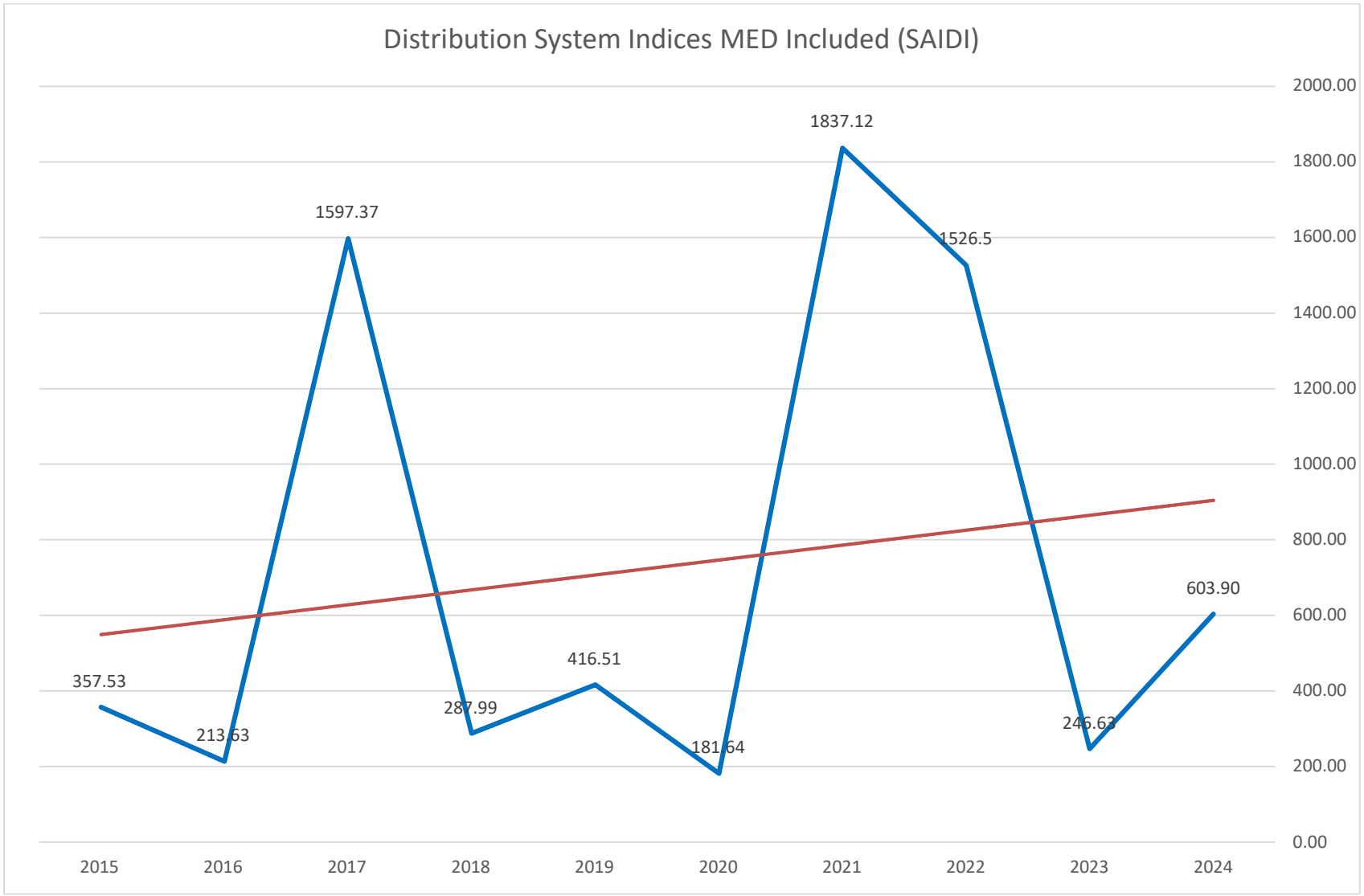
I. Distribution System Indices (Major Event included and excluded)

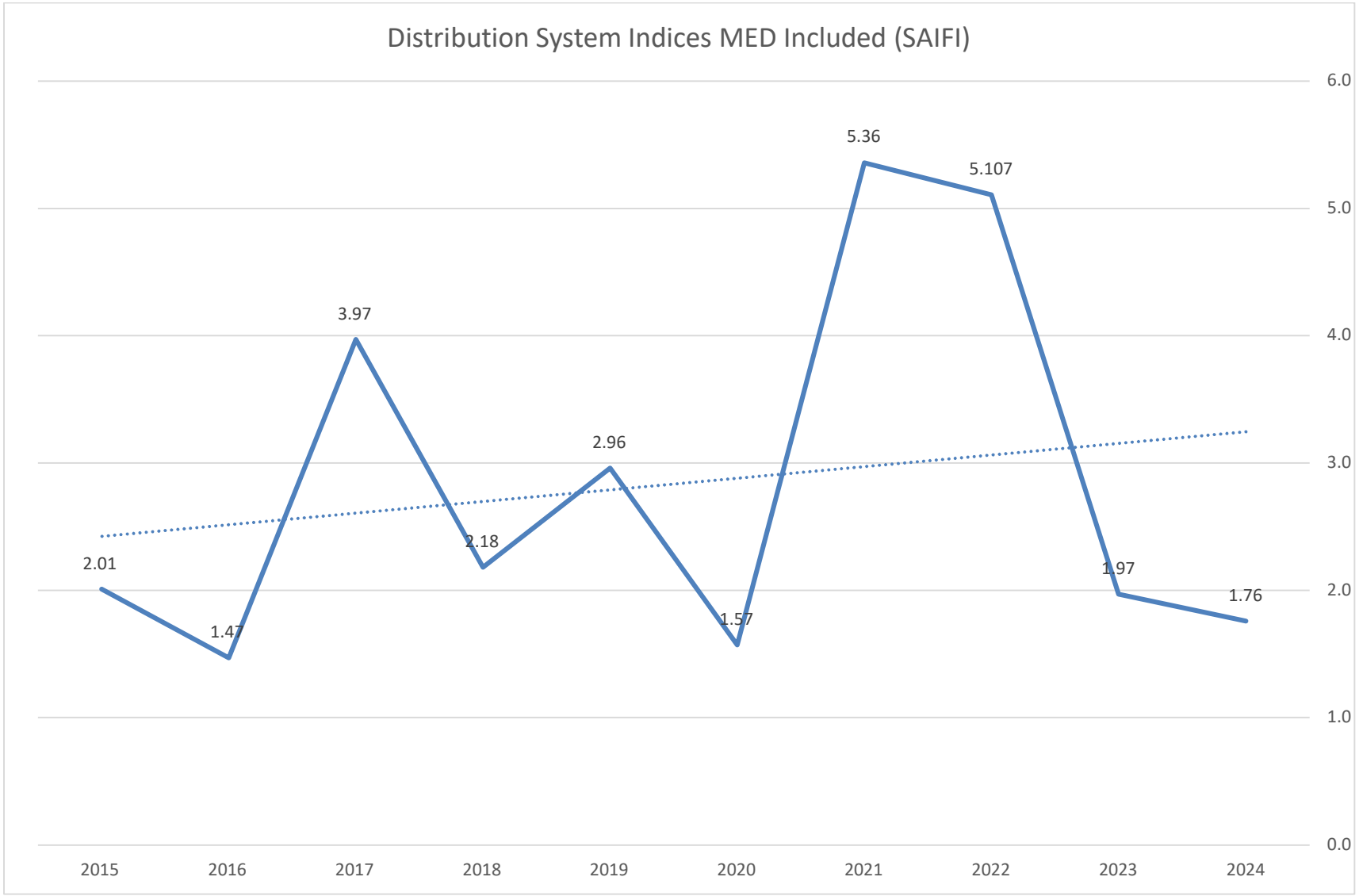
Liberty Utilities (CalPeco Electric), LLC Distribution Historical System Reliability Data 10 Years (Years in Business)								
	Major Event Included				**Major Event Excluded**			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2024	603.90	1.76	343.49	0.05	317.57	1.90	167.17	0.06
2023	246.63	1.97	125.19	.292	246.63	1.97	125.19	.292
2022	1526.5	5.107	298.87	0.113	470.75	3.471	135.65	0.113
2021	1837.12	5.36	342.74	0.548	916.28	4.60	199.19	0.548
2020	181.64	1.57	115.23	0.313	181.64	1.57	115.23	0.313
2019	416.51	2.96	140.73	0.31	416.51	2.96	140.73	0.31
2018	287.99	2.18	131.82	0.52	287.99	2.18	131.82	0.52
2017	1597.37	3.97	402.06	1.37	772.83	2.86	270.23	1.37
2016	213.63	1.47	144.98	1.08	213.63	1.47	144.98	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15

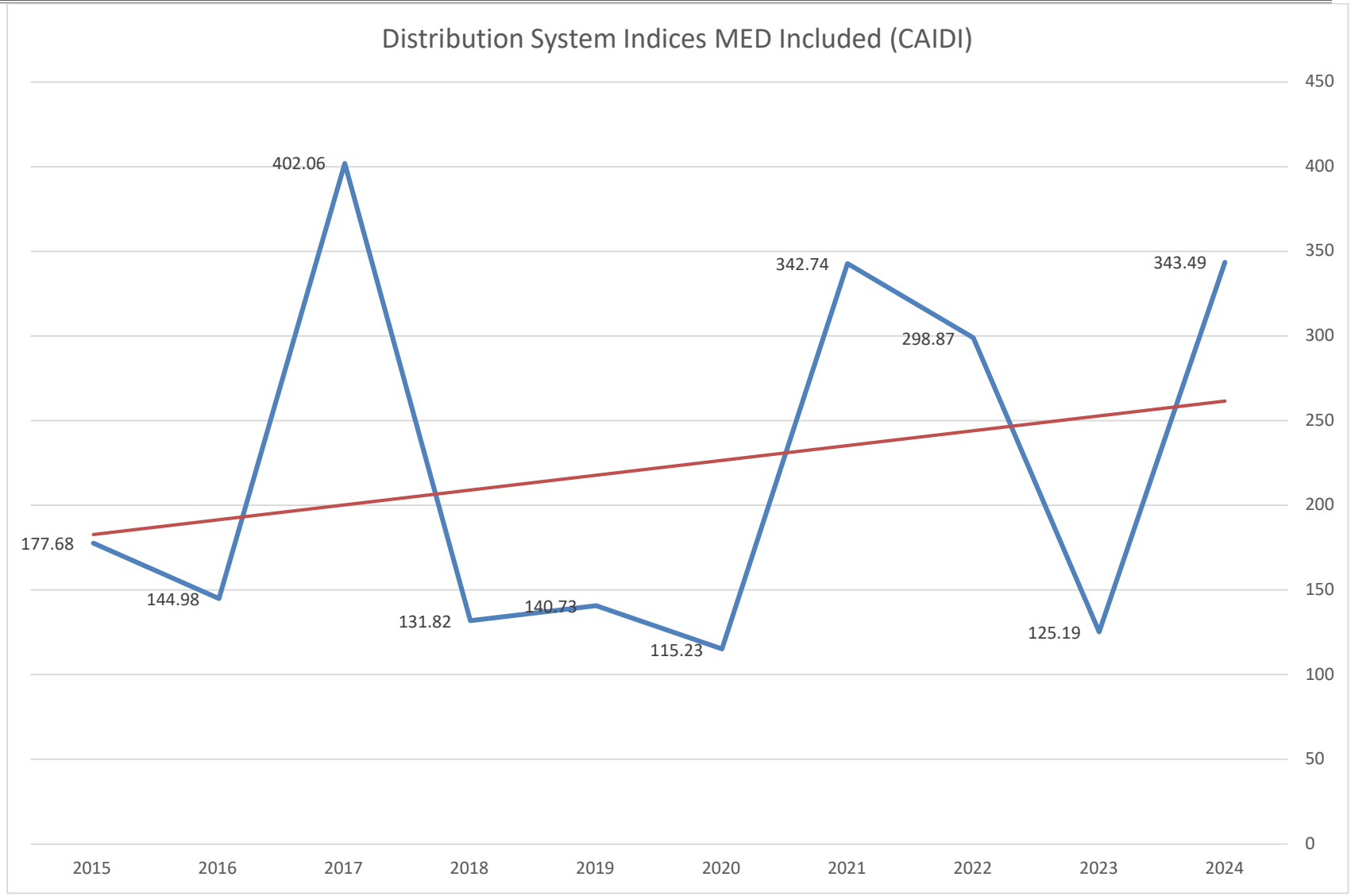
II. Transmission System Indices (MED Included and Excluded)

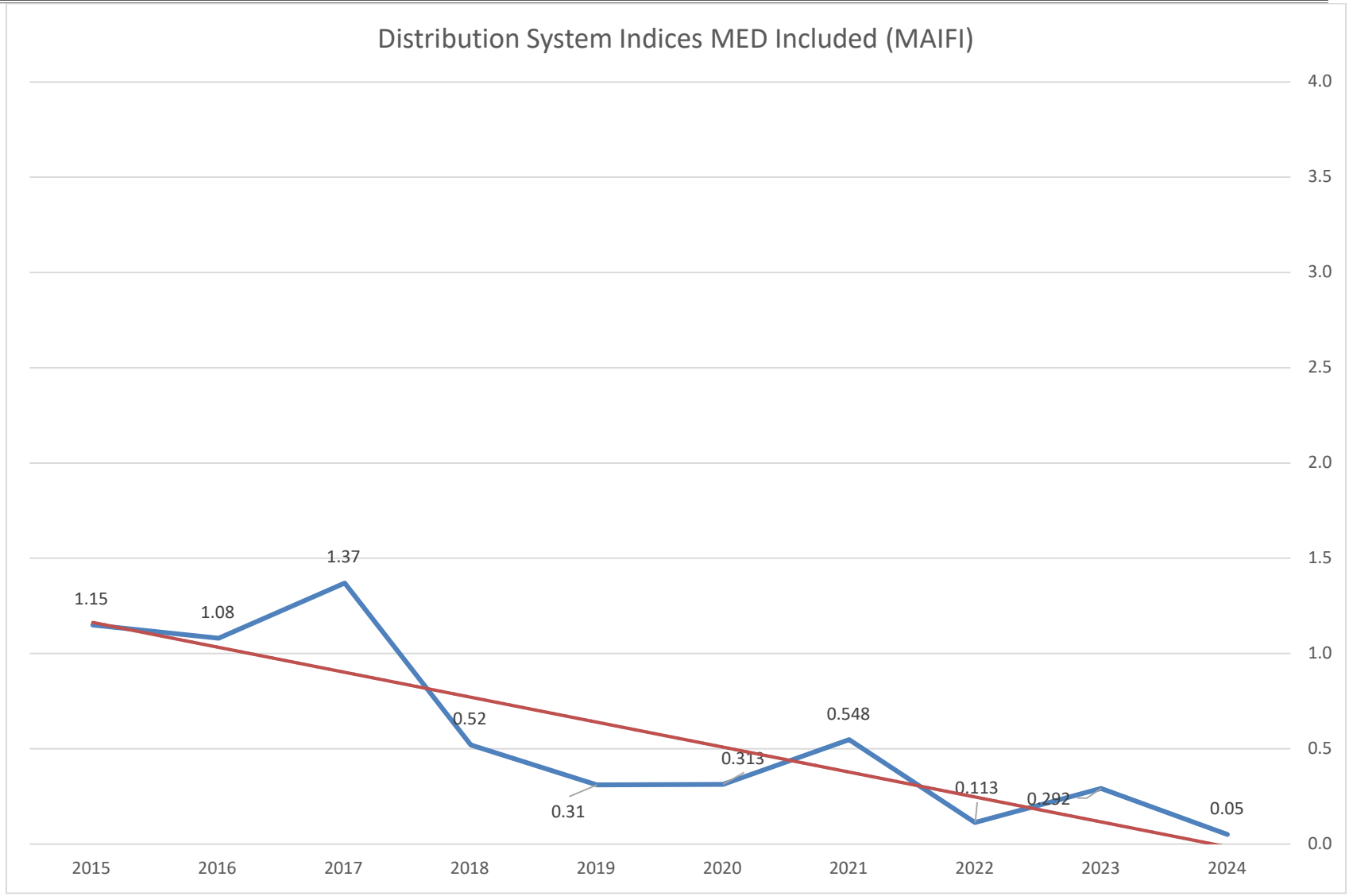
Liberty Utilities (CalPeco Electric), LLC does not own Transmission.

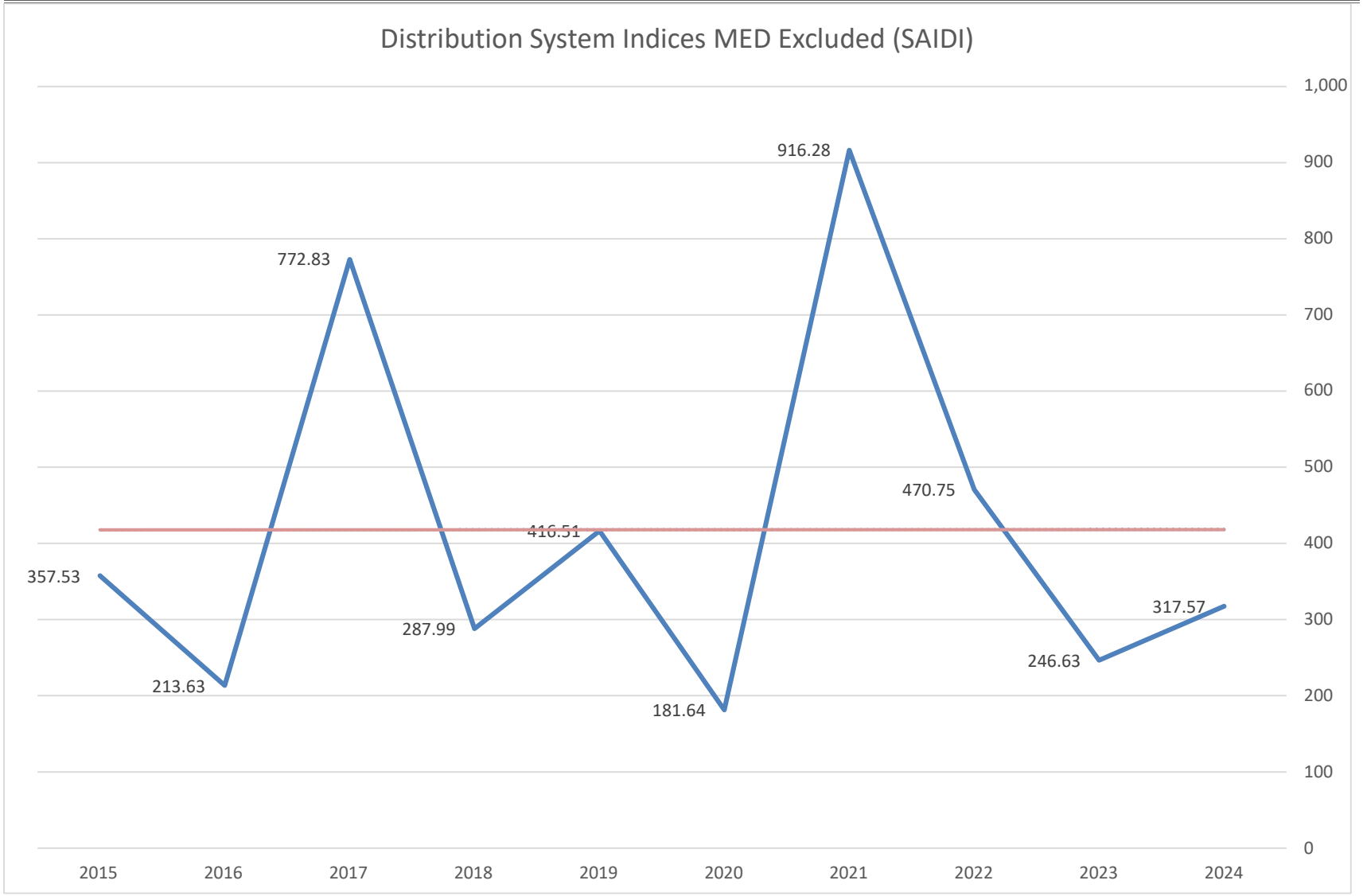
b. Separate charts showing a line graph of distribution system SAIDI, SAIFI, MAIFI, and CAIDI for the past 10 years with linear trend line (TMED included and excluded).

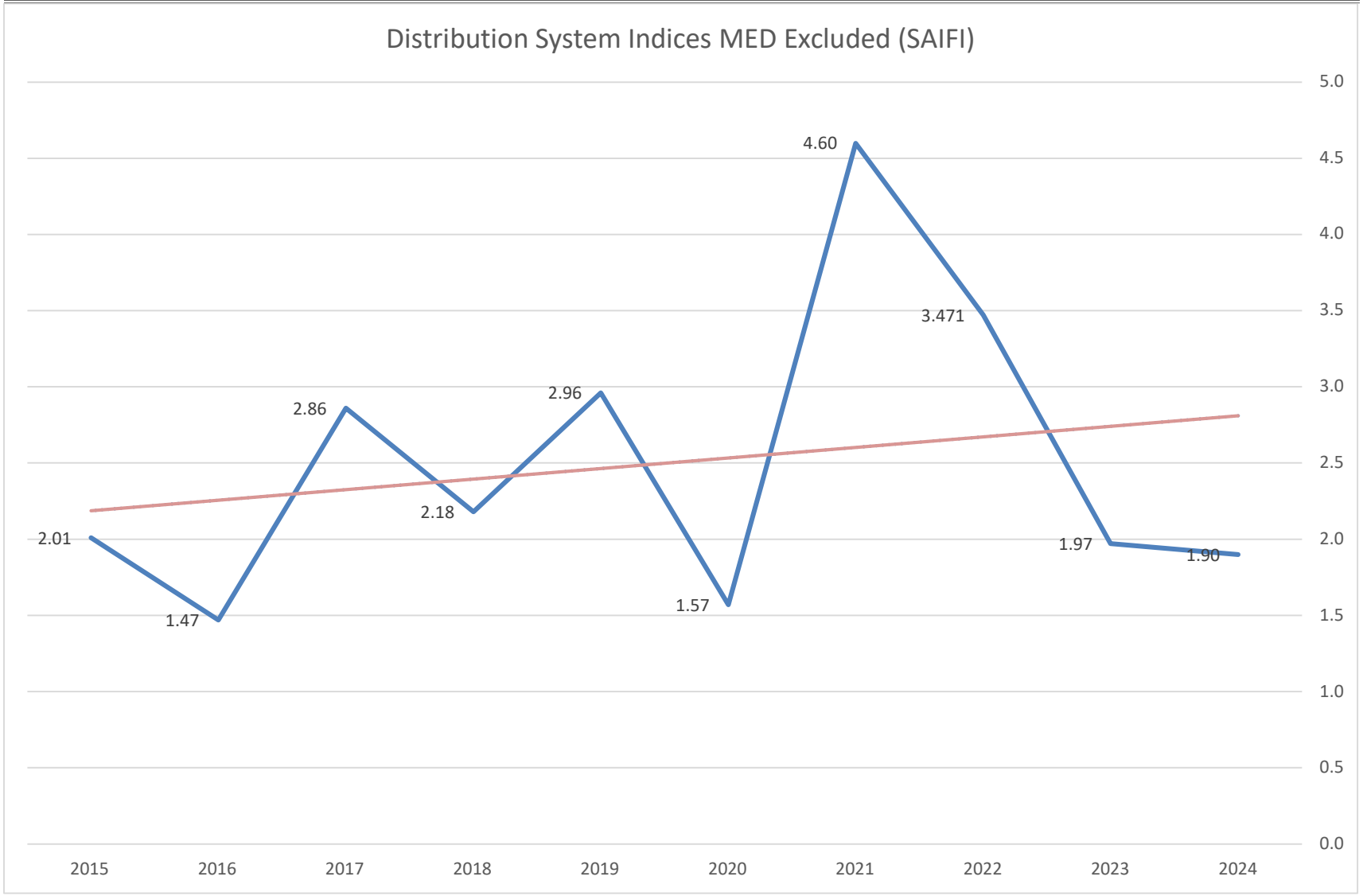

Distribution System Indices MED Included (SAIDI)
2000.00
1800.00
1600.00
1400.00
1200.00
1000.00
800.00
600.00
400.00
200.00
0.00
357.53
213.63
1597.37
287.99
416.51
181.64
1837.12
1526.5
246.63
603.90
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

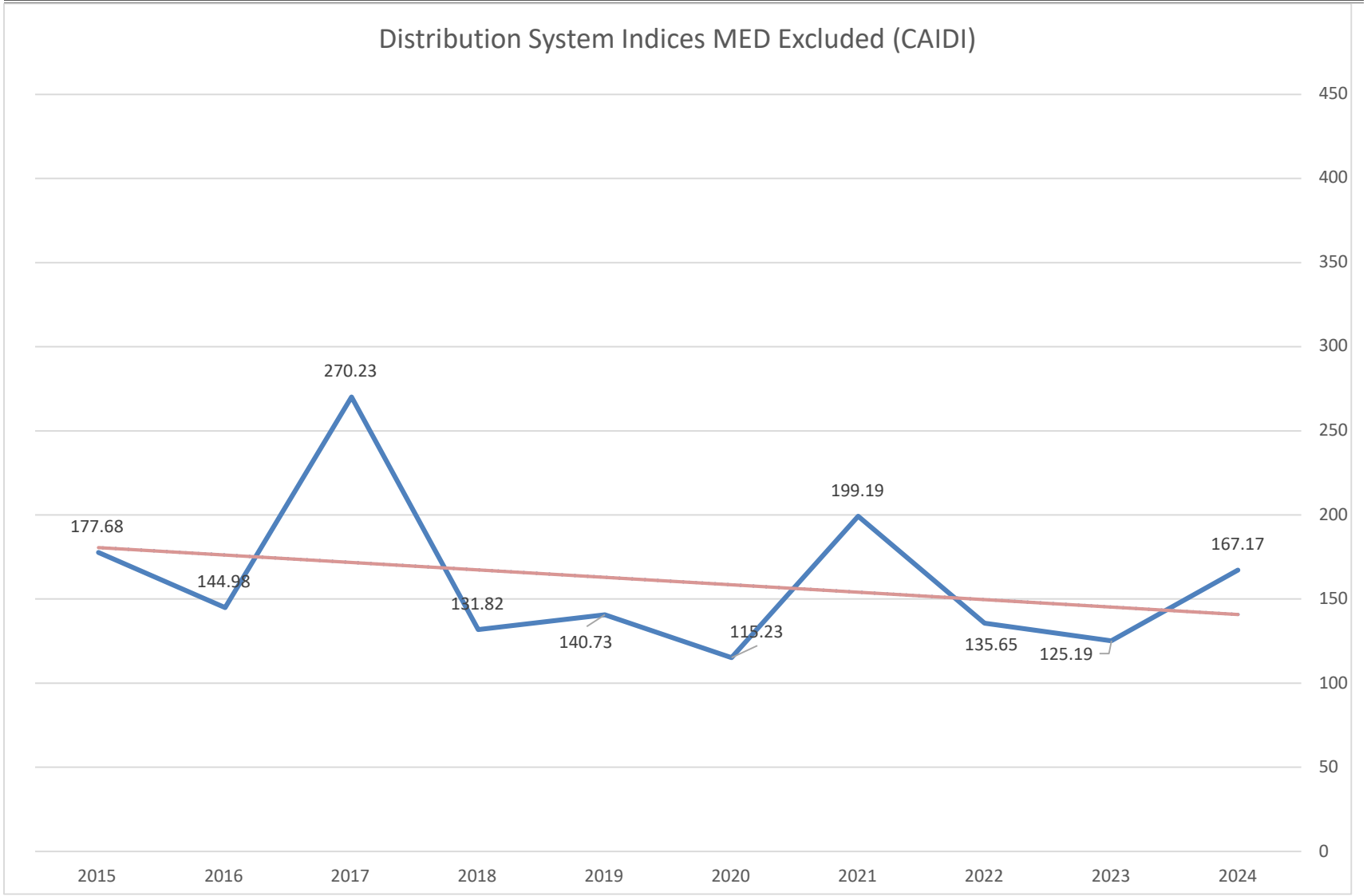

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2.01
1.47
3.97
2.18
2.96
1.57
5.36
5.107
1.97
1.76
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

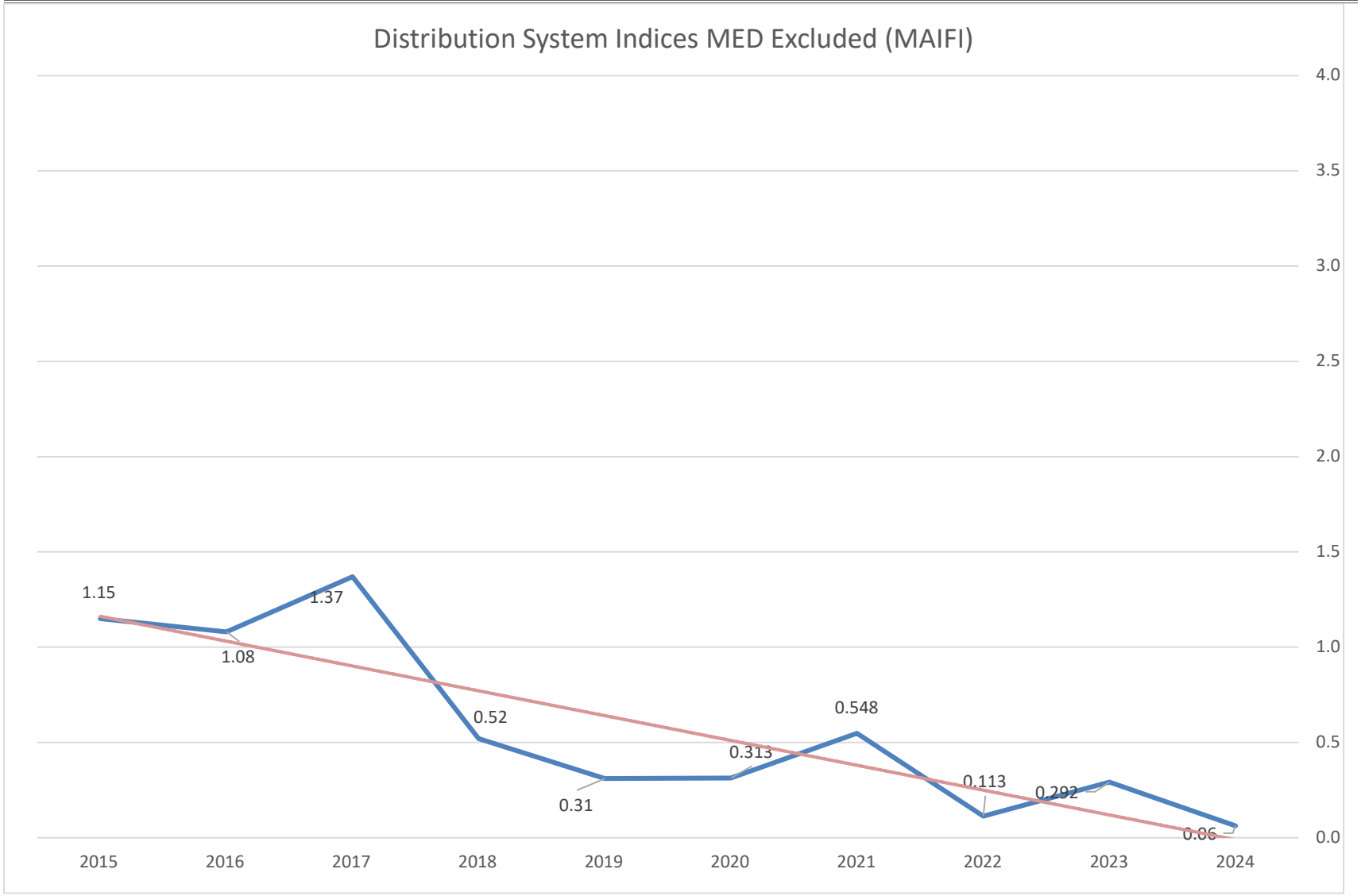

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
177.68
144.98
402.06
131.82
140.73
115.23
342.74
298.87
125.19
343.49
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.292
0.05
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Excluded (SAIDI)
1,000
900
800
700
600
500
400
300
200
100
0
357.53
213.63
772.83
287.99
416.51
181.64
916.28
470.75
246.63
317.57
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Excluded (SAIFI)
5.0
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
2.01
1.47
2.86
2.18
2.96
1.57
4.60
3.471
1.97
1.90
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
177.68
144.98
270.23
131.82
140.73
115.23
199.19
135.65
125.19
167.17
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024



2) Division (or District) Reliability Indices for the past 10 years

Liberty Utilities (CalPeco Electric), LLC has one division, Lake Tahoe. See section 1 for indices.

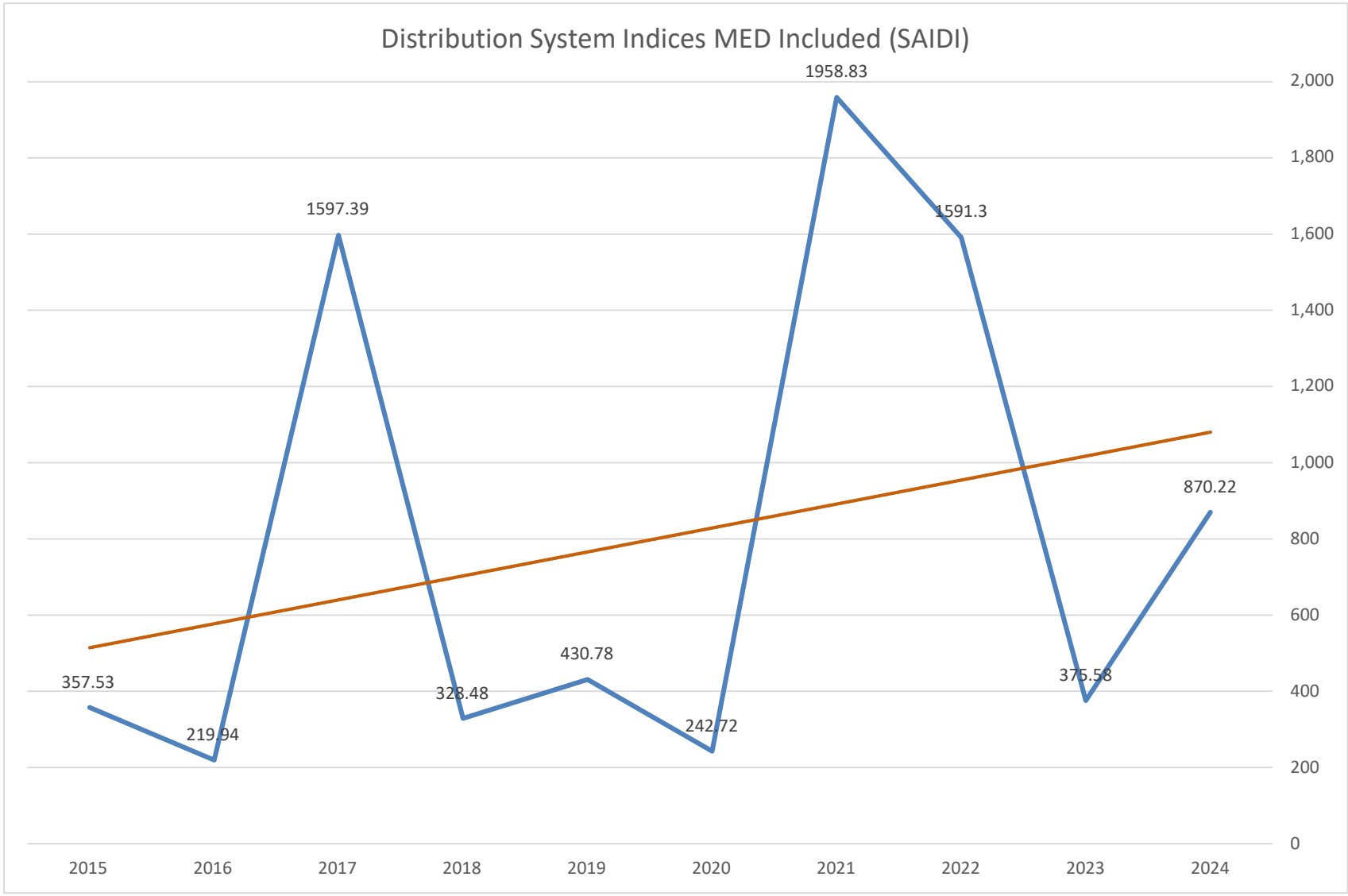
3) System and Division indices based on IEEE 1366 for the past 10 years including planned outages and including and excluding MED

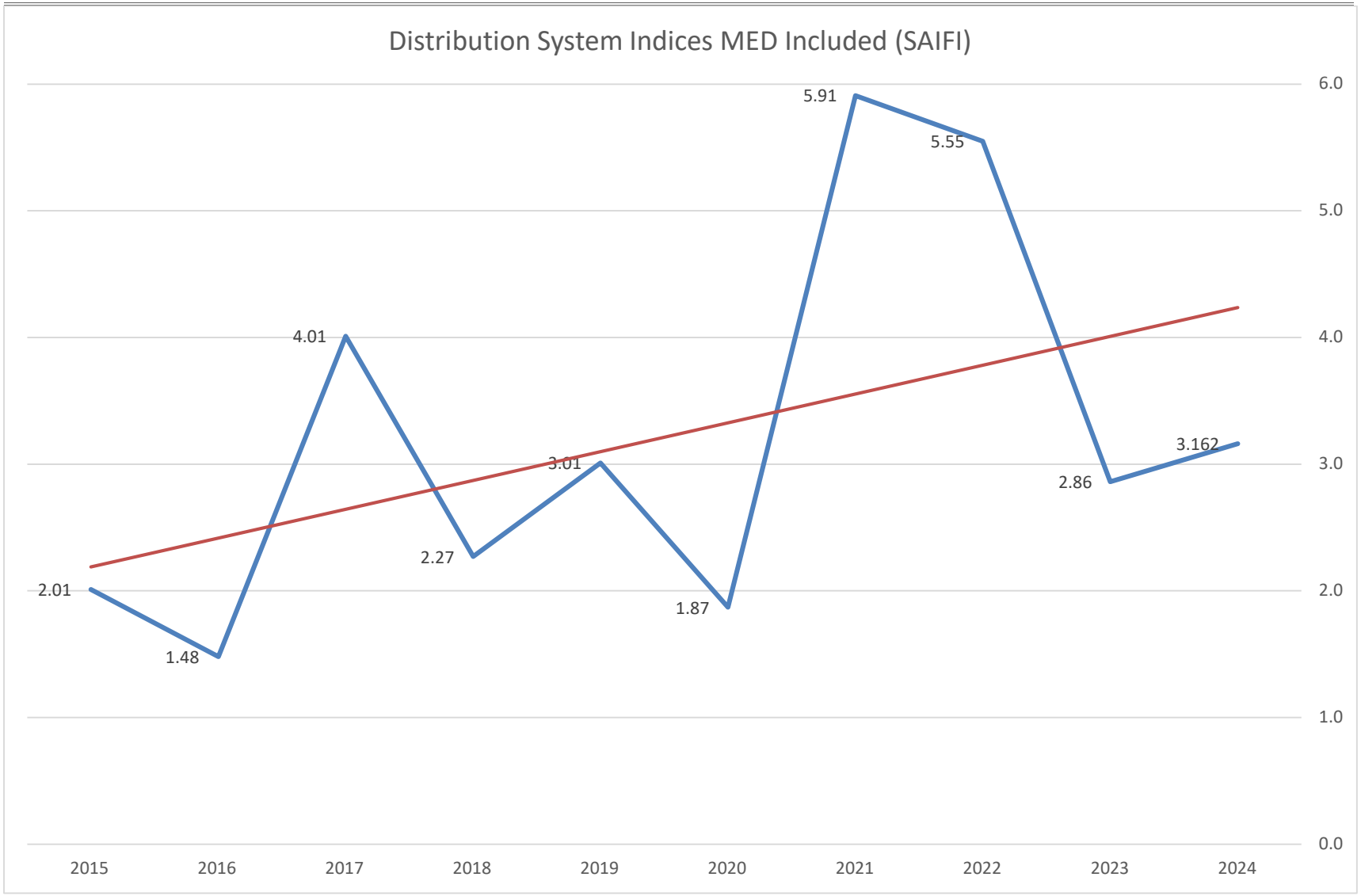
a. SAIDI, SAIFI, MAIFI, and CAIDI Data

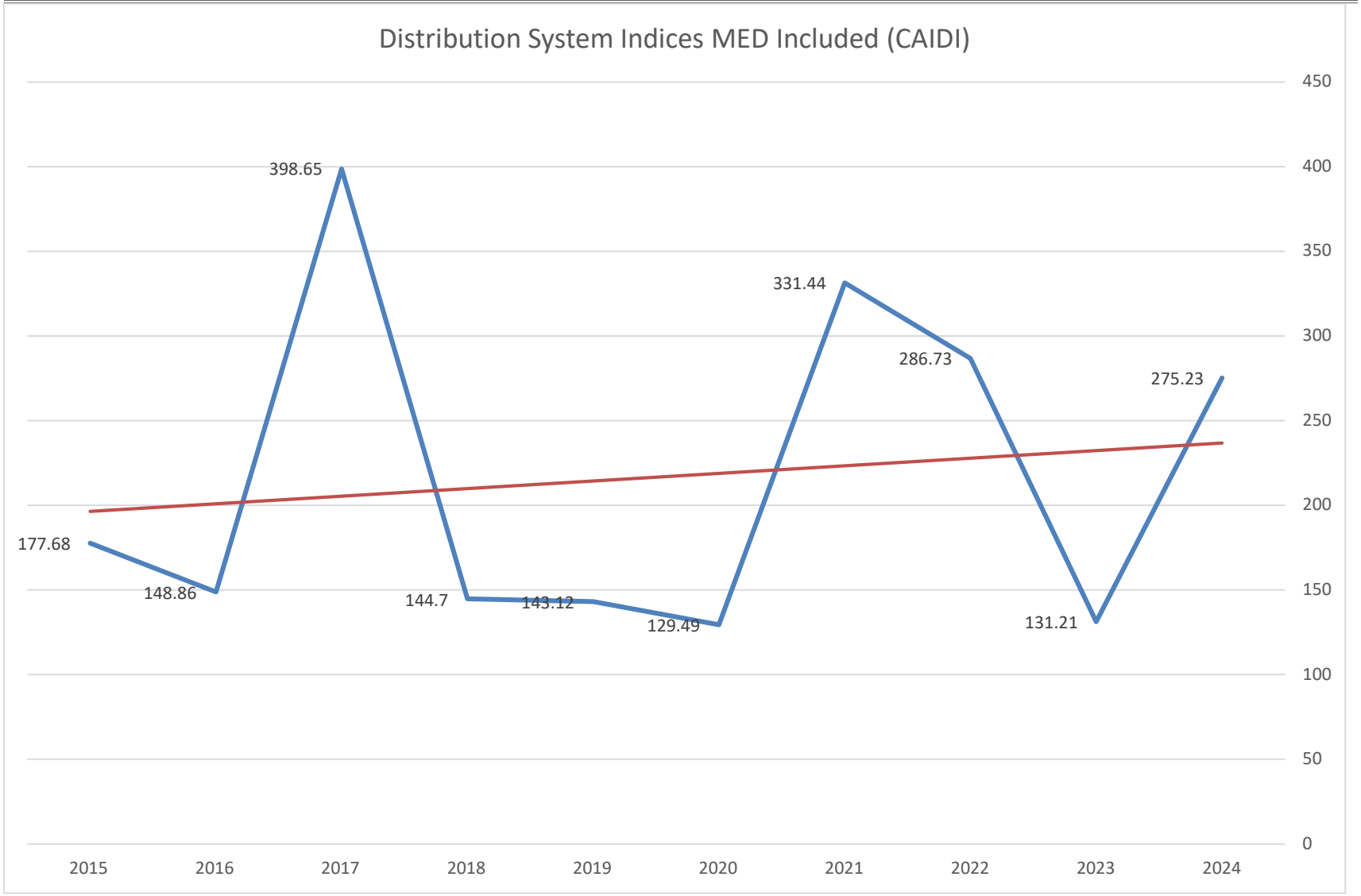
Liberty Utilities (CalPeco Electric), LLC

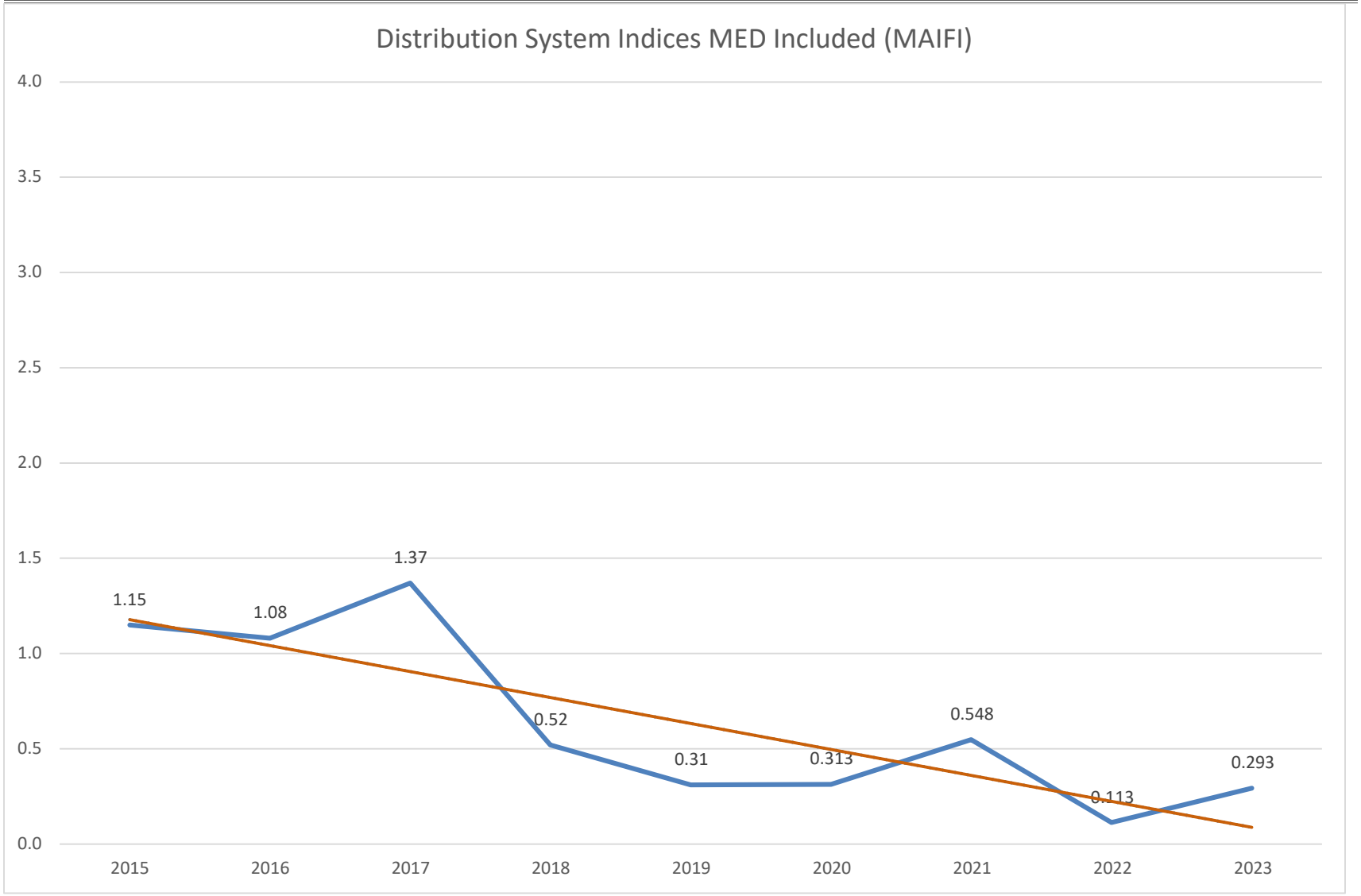
Distribution Historical System Reliability Data 10 Years (Years in Business)

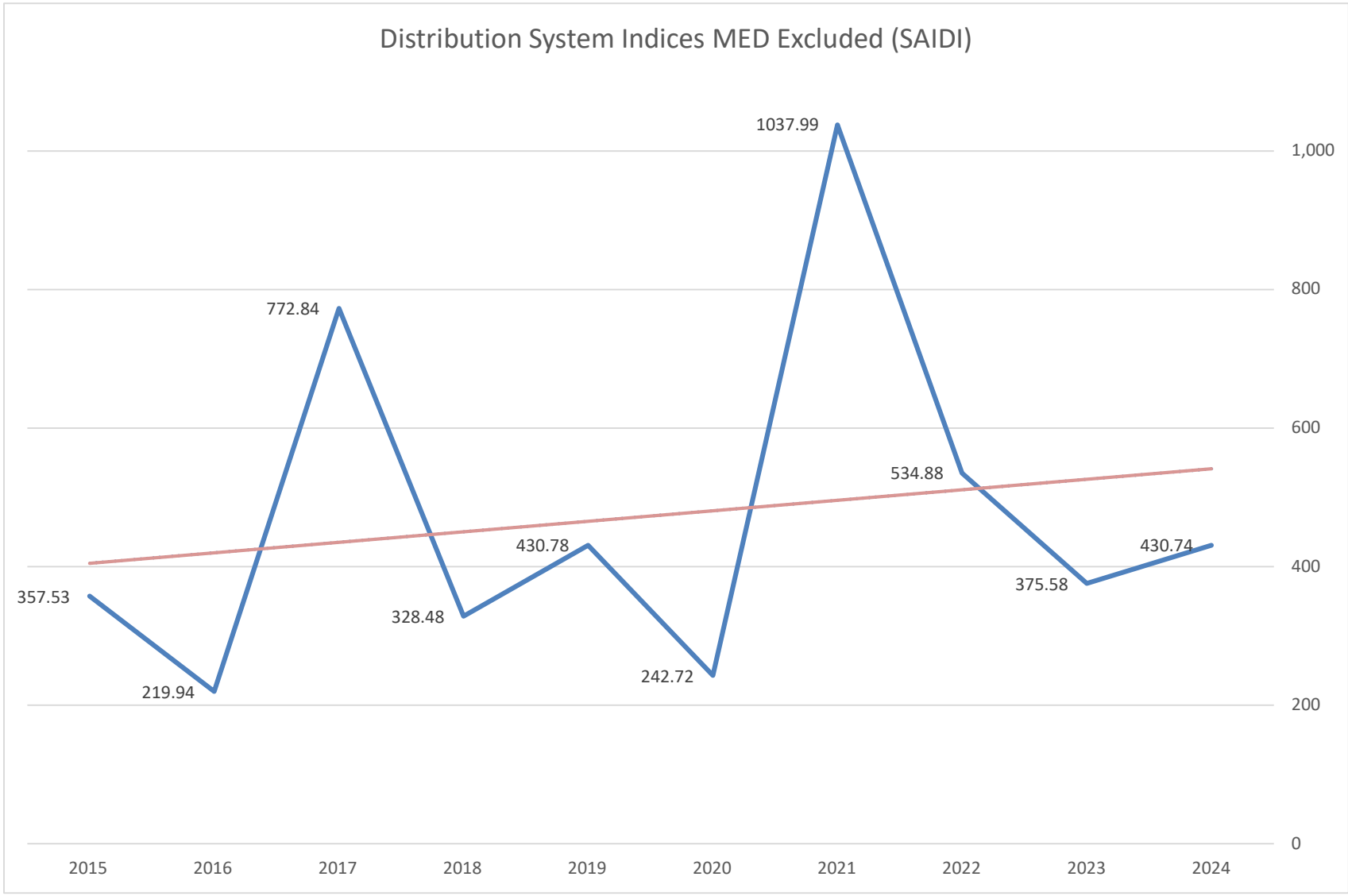
	Major Event Included				Major Event Excluded			
Year	SAIDI	SAIFI	CAIDI	MAIFI	SAIDI	SAIFI	CAIDI	MAIFI
2024	870.22	3.162	275.23	0.08	430.74	2.474	174.09	0.08
2023	375.58	2.86	131.21	.293	375.58	2.86	131.21	.293
2022	1591.3	5.55	286.73	0.113	534.88	3.91	136.72	0.113
2021	1958.83	5.91	331.44	0.548	1037.99	5.14	201.94	0.548
2020	242.72	1.87	129.49	0.313	242.72	1.87	129.49	0.313
2019	430.78	3.01	143.12	0.31	430.78	3.01	143.12	0.31
2018	328.48	2.27	144.7	0.52	328.48	2.27	144.7	0.52
2017	1597.39	4.01	398.65	1.37	772.84	2.89	267.42	1.37
2016	219.94	1.48	148.86	1.08	219.94	1.48	148.86	1.08
2015	357.53	2.01	177.68	1.15	357.53	2.01	177.68	1.15

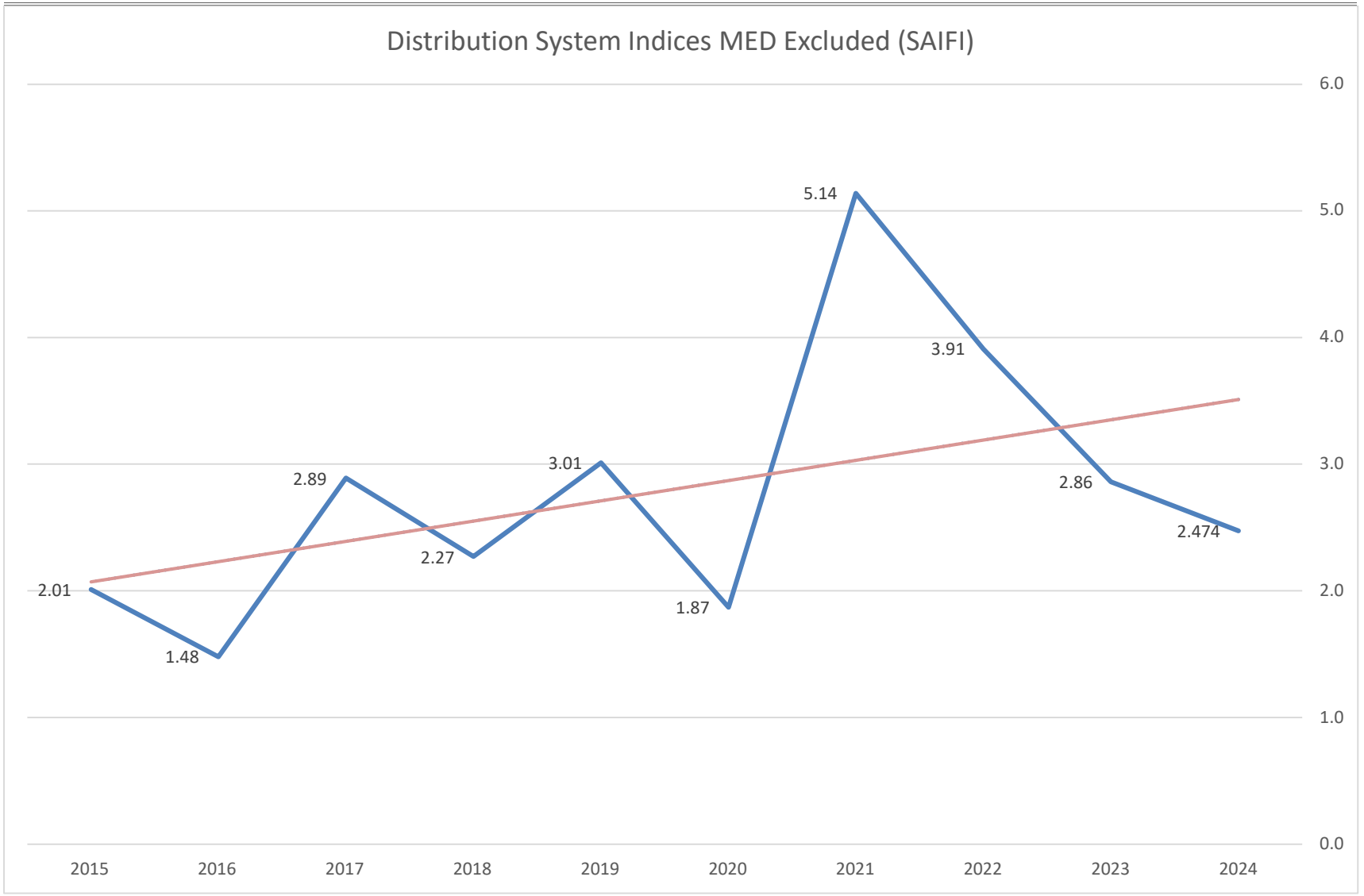

Distribution System Indices MED Included (SAIDI)
2,000
1,800
1,600
1,400
1,200
1,000
800
600
400
200
0
357.53
219.94
1597.39
328.48
430.78
242.72
1958.83
1591.3
375.58
870.22
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

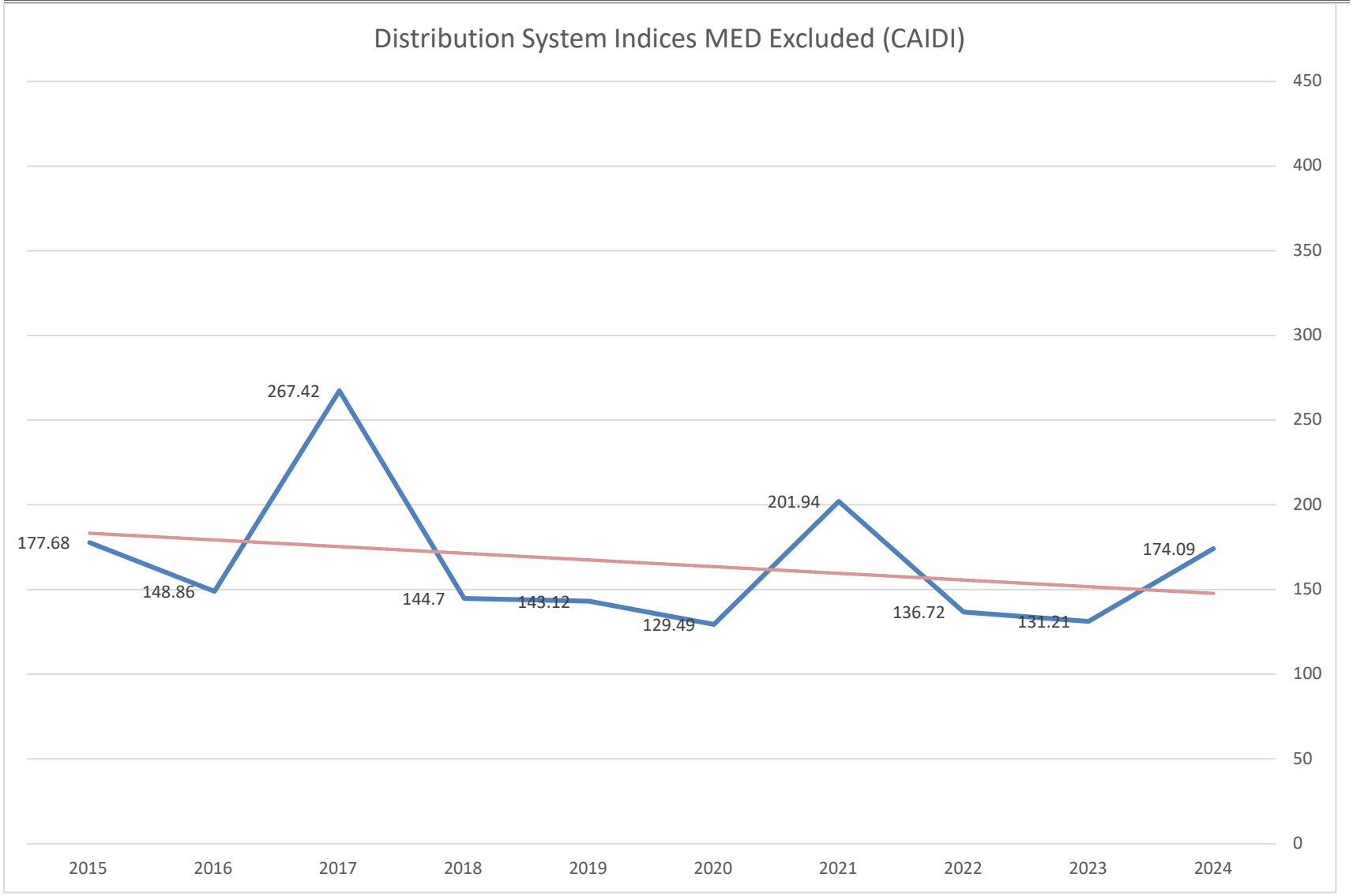

Distribution System Indices MED Included (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2.01
1.48
4.01
2.27
3.01
1.87
5.91
5.55
2.86
3.162
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

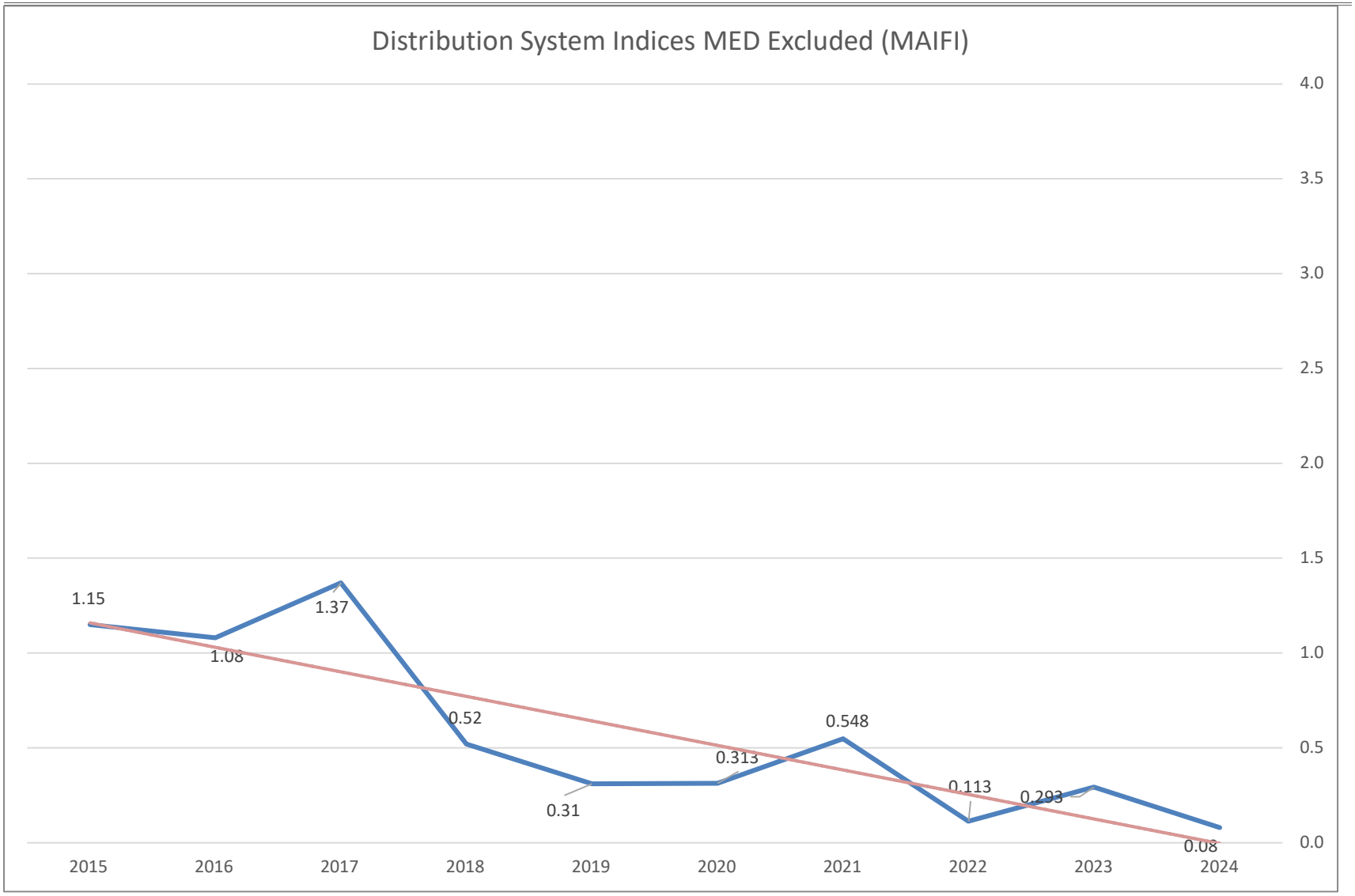

Distribution System Indices MED Included (CAIDI)
450
400
350
300
250
200
150
100
50
0
398.65
331.44
286.73
275.23
177.68
148.86
144.7
143.12
129.49
131.21
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Included (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.293
2015
2016
2017
2018
2019
2020
2021
2022
2023


Distribution System Indices MED Excluded (SAIDI)
1037.99
772.84
534.88
430.78
430.74
357.53
328.48
375.58
219.94
242.72
1,000
800
600
400
200
0
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Excluded (SAIFI)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
2.01
1.48
2.89
2.27
3.01
1.87
5.14
3.91
2.86
2.474
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024


Distribution System Indices MED Excluded (CAIDI)
450
400
350
300
250
200
150
100
50
0
177.68
148.86
267.42
144.7
143.12
129.49
201.94
136.72
131.21
174.09
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

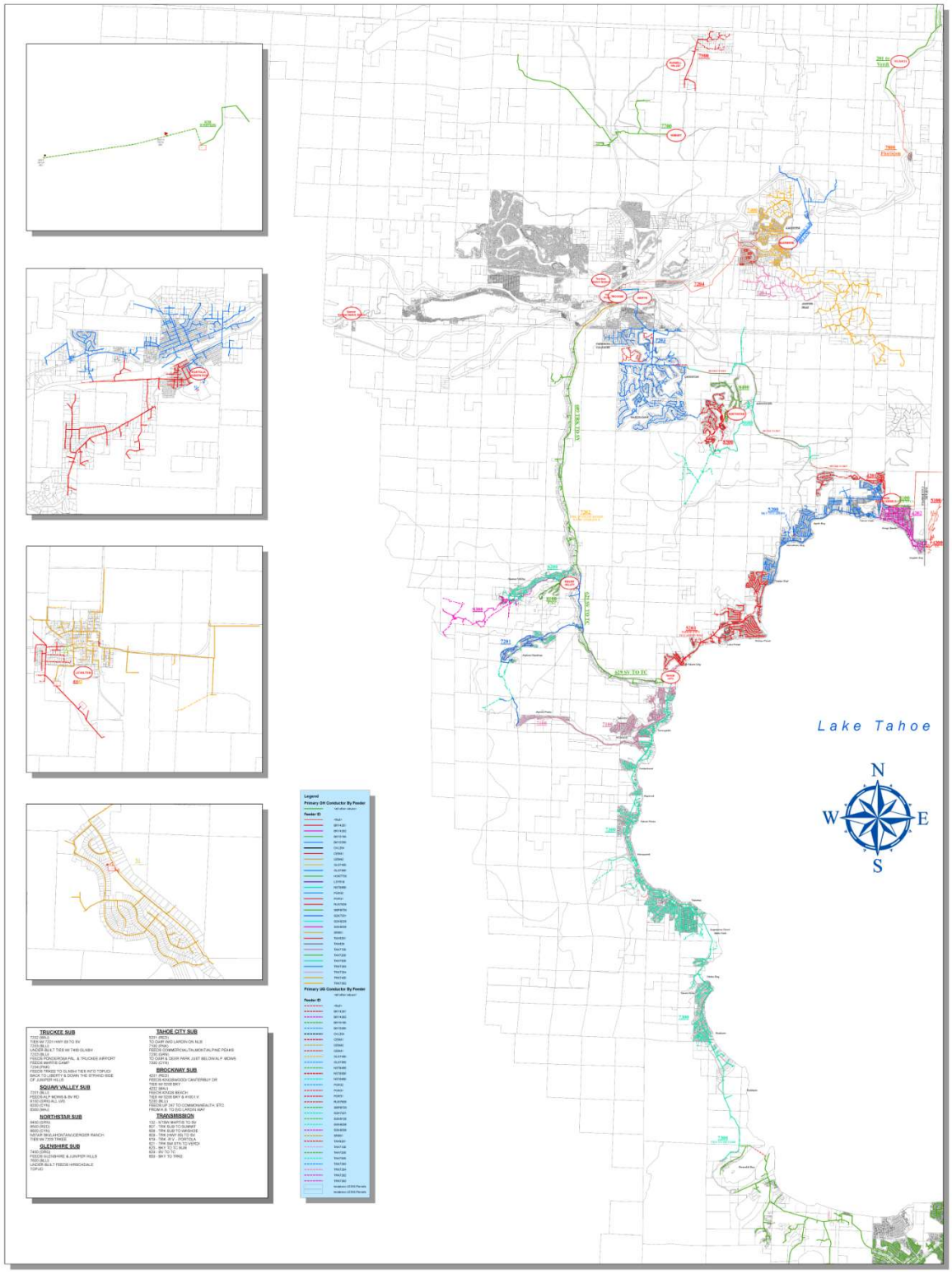

Distribution System Indices MED Excluded (MAIFI)
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1.15
1.08
1.37
0.52
0.31
0.313
0.548
0.113
0.293
0.08
2015
2016
2017
2018
2019
2020
2021
2022
2023
2024

b. The number, date, and location of planned outages

Circuit	District	Number of Planned Outages By Year									
		2024	2023	2022	2021	2020	2019	2018	2017	2016	2015
31	Tahoe	6	3	2	5	3		1			1
32	Tahoe	8	4	4	17	4	1		2	1	
41	Tahoe	2		2		6				1	
42	Tahoe			2							
51	Tahoe	2	4	2							
201	Tahoe			1	3			7			
204	Tahoe			1	1		2			1	
257	Tahoe	1									
1261	Tahoe		10	7	5	7	1	1			
1296	Tahoe	16	4	1		2		1	2		5
2200	Tahoe		1		1		1				1
2300	Tahoe	3	26	1	2		1	1			1
3100	Tahoe	16	120	12	7	2	8	5	1		
3101	Tahoe	6	81	11	5	3	3				
3200	Tahoe	13	88	6	22	1	3	5			1
3300	Tahoe	26	148	16	19	3	8	10	2		3
3400	Tahoe	44	65	12	23	1	2	4	3		5
3500	Tahoe	20	170	4	9	6	15		6		1
3501	Tahoe	4	139	10	7		3	3			2
4201	Tahoe	3	14	4	3		1	1		1	
4202	Tahoe	5	1	6	8	2	5	3	4		
4203	Tahoe										
5100	Tahoe	1	1		1	1					
5200	Tahoe	7	36	9		1	5	4	1		4
5201	Tahoe	19	9	7	2		8	1	5	5	4
7100	Tahoe	21	4	7	4	4	1	2	1		
7200	Tahoe		1				1	1			1
7201	Tahoe	8	9	3	4	1	1		4	1	2
7202	Tahoe	4	2	3	1	3	3	1	1		2
7203	Tahoe	3		3	2		3	2			2
7204	Tahoe			1							
7300	Tahoe	71	16	13	14	8	20	14	5	6	4
7400	Tahoe	2	6		4	1	4	8	2	1	1
7600	Tahoe	1	2	1			1	1			1
7700	Tahoe		3	3		4					
7800	Tahoe										
7900	Tahoe	1	2	1		2	1				
8100	Tahoe		1								
8200	Tahoe	2	15		2	1	1	2	7	3	2

8300	Tahoe		1			1	1	1	2		6
8400	Tahoe	1				1		7			
8500	Tahoe			1	1	2				1	
8600	Tahoe										4
8700	Tahoe		1								

4) Service territory map including divisions of districts



5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages Per Year	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1202*	Tahoe	753	Topaz	59.1	94.0%	6.0%	0	370	4.68
3400	Tahoe	3,261	Meyers	66.1	82.0%	18.0%	2	835	4.04

Note: Preferred Metric is the average of circuit SAIDI over a 3 year period.

* A circuit that has been identified as deficient in the previous year's report.

II. Any circuit appearing on this list of “deficient” WPC circuits that also appeared on the previous year's list would be marked by an asterisk. For each asterisked circuit, each utility shall provide the following information:

I. An explanation of why it was ranked as a "deficient" circuit, i.e., the value of the metric used to indicate its performance;

II. A historical record of the metric;

III. An explanation of why it was on the deficiency list again;

IV. An explanation of what is being done to improve the circuit's future performance and the anticipated timeline for completing those activities (or an explanation why remediation is not being planned); and

V. A quantitative description of the utility's expectation for that circuit's future performance.

The Topaz 1202 (previously 1261) circuit was noted as a deficient circuit in 2020, 2021, 2022, 2023, and 2024. The 3-year average circuit SAIDI score remains high due to extreme weather conditions over the past 3 years.

There were 14 unplanned outages in 2024 for the 1202 circuit.

The historical metric for Topaz 1202 based on a 3-year average:

- 2024 – 370
- 2023 – 1925
- 2022 - 2313

There are currently no plans in place that would remedy loss of source outages, which account for several outages experienced by customers on this circuit. The circuit is a radial line, sourced by an NV Energy substation in Nevada.

The circuit performance in 2024 measured alone was below average compared to historical values. This circuit often experiences events considered to be outliers resulting from extreme weather conditions. 2 of the unplanned outages for this circuit in 2024 were caused by weather.

III. Language to explain how the IOUs’ include a cost effectiveness review as part of their respective internal review processes for circuit remediation projects.

I. Definitions of terms, acronyms, limitations, and assumptions;

Definitions

WPC- Worst Performing Circuits

Assumptions

Our analysis excludes planned outages and TMED outages.

II. A clear explanation of the utility's process to determine the worst performing circuits:

The top 2 Worst Performing Circuits (WPC) are determined based upon the calculated average of circuit SAIDI over a 3 year period. This index is calculated on sustained outages by taking the total customer minutes of interruption and dividing by the number of customers on the circuit. Three years' worth of data is included and averaged in order to account for anomalies and tracking the impact of phased improvement projects.

III. A clear explanation of the utility's process to determine cost-effective remediation projects. This shall include why the utility may decide to implement a project to address one worst performing circuit issue while deciding to not implement a project to address a different worst performing circuit.

The Regional Engineer presents proposals for reliability improvement projects along with a circuit analysis, cost-benefit analysis, and details on customer impact to the Business Manager, Engineering Manager, and Senior Director of Operations. Collectively, the group determines which projects to approve or suggest alternatives and further analysis.

6) Top 10 major unplanned power outage events within a reporting year

a. The cause of each outage event; and

b. The location of each outage event.

Rank	Outage Date	Cause	Location	Customer Impact	SAIDI	SAIFI
1	2/20/2024	Equipment	Lake Tahoe	4479	4.26082579	0.091101393
2	11/11/2024	Equipment	Lake Tahoe	4310	8.9874981	0.087663989
3	8/13/2024	Act Of Man	Lake Tahoe	4286	5.07569059	0.087175836
4	3/25/2024	Equipment	Lake Tahoe	3812	12.0919061	0.077534832
5	7/7/2024	Animal	Lake Tahoe	3808	11.3856605	0.077453473
6	8/1/2024	Planned	Lake Tahoe	3510	2.1820421	0.071392251
7	6/11/2024	Planned	Lake Tahoe	3494	17.0012407	0.071066816
8	3/8/2024	UNKNOWN	Lake Tahoe	3721	1.69649173	0.075683921
9	2/20/2024	Equipment	Lake Tahoe	3188	2.55649547	0.064842876
10	1/13/2024	Animal	Lake Tahoe	3185	1.54986203	0.065099642

*Based on customer impact

7) Summary list of 2024 TMED per IEEE 1366

a. The number of customers without service at periodic intervals for each TMED;

b. The cause of each Major Event (ME); and

c. The location of each ME.

Date	# of Customers w/o Service	Cause of ME	Location of ME
3/1/2024	7857	Loss of Supply/Weather	Lake Tahoe
8/11/2024	51	Loss of Supply/Planned	Lake Tahoe

8) Historical 10 largest unplanned outage events for the past 10 years*

*Based on Customers Affected

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Equipment	2/20/2024	4479	35.5	3,491	NO
2	Equipment	11/11/2024	4310	1.7	7,365	NO
3	Act Of Man	8/13/2024	4286	1.4	4,159	NO
4	Equipment	3/25/2024	3812	13.9	9,908	NO
5	Animal	7/7/2024	3808	2.5	9,330	NO
6	Planned	8/1/2024	3510	3.4	1,788	NO
7	Planned	6/11/2024	3494	16.3	13,931	NO
8	UNKNOWN	3/8/2024	3721	1.9	1,390	NO
9	Equipment	2/20/2024	3188	35.5	2,095	NO
10	Animal	1/13/2024	3185	2.3	1,264	NO

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Faulted Underground Cable	11/2/2023	4,214	128.59	22201.78	NO
2	CB Lockout	1/5/2023	4400	22.87	10161.25	NO
3	CB Lockout	1/4/2023	1588	6.1	9623.48	NO
4	CB Lockout	3/14/2023	4264	1.55	6609.20	NO
5	CB Lockout	7/29/2023	2296	171.14	6548.88	NO
6	CB Lockout	9/19/2023	3560	17.87	5450.38	NO
7	Broken Pole, all 3 phases down	1/14/2023	154	34.9	5014.33	NO
8	CB Lockout	1/15/2023	4277	1.17	4559.33	NO
9	CB Lockout	10/15/2023	2301	1.02	4218.50	NO
10	Recloser Lockout	5/18/2023	746	7.3	4062.98	NO

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	12/11/2022	4573	66.7	112,064	YES
2	CB Lockout	12/11/2022	4013	20.1	80,461	YES
3	CB Lockout	12/12/2022	6382	28.3	64,328	YES
4	CB Lockout	12/11/2022	2290	34.0	47,436	YES
5	CB Lockout	12/11/2022	2357	20.0	47,022	YES
6	Blown Fuse	12/11/2022	698	55.4	38,681	YES

7	CB Lockout	12/11/2022	3559	9.6	34,048	YES
8	CB Lockout	12/31/2022	4400	11.0	27,554	YES
9	PTR Lockout	12/10/2022	484	68.7	26,256	NO
10	Loss of Source	12/31/2022	4273	7.6	24,287	YES

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	12/11/2022 5:14	4573	66.7	112,064	YES
2	CB Lockout	12/11/2022 2:55	4013	20.1	80,461	YES
3	CB Lockout	12/12/2022 17:45	6382	28.3	64,328	YES
4	CB Lockout	12/11/2022 8:45	2290	34.0	47,436	YES
5	CB Lockout	12/11/2022 5:14	2357	20.0	47,022	YES
6	Blown Fuse	12/11/2022 4:49	698	55.4	38,681	YES
7	CB Lockout	12/11/2022 0:43	3559	9.6	34,048	YES
8	CB Lockout	12/31/2022 12:59	4400	11.0	27,554	YES
9	PTR Lockout	12/10/2022 22:58	484	68.7	26,256	NO
10	Loss of Source	12/31/2022 14:02	4273	7.6	24,287	YES

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	CB Lockout	7/28/2021	10812	1.2	12,974	No
2	Recloser Lockout	12/15/2021	5348	1.85	9,894	No
3	Wire Down	12/14/2021	4530	6.15	27,860	Yes
4	CB Lockout, Lighting	7/29/2021	4522	0.98	4,447	No
5	Device failure	12/14/2021	4387	9.55	41,896	Yes
6	Loss of Source	10/7/2021	4374	0.1	437	No
7	Loss of Source	10/8/2021	4374	5.78	25,296	No

8	CB Lockout	12/24/2021	4368	1.7	7,426	No
9	CB Lockout	12/13/2021	4362	6.82	29,734	No
10	Loss of Source	2/25/2021	4183	0.62	336	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Operations Error	7/28/2020	5,291	0.68	3597.8	No
2	CB Lockout, Lightning possible	8/24/2020	3,835	1.63	6251.05	No
3	Unknown	11/6/2020	3,728	1.3	4846.4	No
4	Wind/Debris	8/12/2020	3,724	0.56	2085.44	No
5	Animal	9/10/2020	3,451	0.3	1035.3	No
6	Animal	9/6/2020	3,266	0.86	2808.7	No
7	Animal	10/23/2020	3,266	0.28	914.5	No
8	Animal	7/28/2020	2,555	0.46	705.8	No
9	Device failure	7/2/2020	2,555	1.43	3653.6	No
10	Operations Error	7/28/2020	2,555	0.68	1737.4	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Contractor Dig In	10/1/2019	10,490	3.88	40701.2	No
2	Equipment Failure	2/22/2019	8,560	4.42	37835.2	No
3	Third Party - Contractor Dig In	10/3/2019	7,841	0.18	1411.38	No

4	Hardware Failure	2/26/2019	4,485	3.5	15697.5	No
5	Tree	1/18/2019	4,448	1.76	7828.48	No
6	Hardware Failure	3/6/2019	4,448	0.82	3647.36	No
7	Animal	11/11/2019	4,245	0.6	2547	No
8	Third Party – Line Contact	9/21/2019	3,712	0.43	1596.16	No
9	Animal	6/7/2019	3,529	0.47	1658.63	No
10	Tree	6/7/2019	3,507	1.51	5295.57	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Third Party - Switching	5/17/2018	17,315	2.51	91301.9	No
2	Loss of Source – External System	12/12/2018	7,552	0.1	755.2	No
3	Trees	10/17/2018	7,398	6.32	14218.8	No
4	Loss of Source – External System	12/12/2018	7,089	0.1	708.9	No
5	Hardware Failure	10/3/2018	4,678	3.61	6958.1	No
6	Trees - Major Storm	6/9/2018	4,485	9.38	6420.1	No
7	Unknown	11/12/2018	4,154	1.76	7338.7	No
8	Unknown	1/4/2018	3,529	0.2	705.8	No
9	Loss of Source – External System	12/12/2018	3,434	0.1	343.4	No
10	Loss of Source – External System	8/4/2018	2,721	2.96	8072.3	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	1/10/17	22,000	26.12	5,745,66.7	No
2	Loss of Source – External System	8/28/2017	8,643	1.15	9,939.5	No
3	Major Storm	1/8/2017	4,497	9.75	43,845.8	No
4	Major Storm	2/8/2017	4,497	2.58	11,617.3	No
5	Trees	4/7/2017	4,497	1.91	8,619.3	No
6	Trees/Major Storm	2/22/2017	4,105	1.68	6,910.1	No
7	Major Storm	1/5/2017	3,517	8.72	30,656.5	No
8	Major Storm	2/21/2017	3,517	0.4	1,406.8	No
9	Underground Fault	5/30/2017	3,486	2.82	9,818.9	No
10	Carp/Pole	6/6/2017	3,486	1.97	6,855.8	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Loss of Source – External System	3/13/2016	6,882	0.75	5,046.80	No
2	Wind/Trees	10/16/2016	4,125	1.75	7,150.00	No
3	Underground Fault	10/4/2016	4,125	4.31	17,793.30	No
4	Downed Wire	3/22/2016	4,125	1.70	6,294.80	No
5	Car/Pole	3/13/2016	3,517	1.00	3,957.90	No
6	Failed Overhead Hardware/Material	1/1/2016	3,500	5.50	7,250.00	No
7	Trees	3/1/2016	3,258	0.50	1,683.30	No
8	Underground Fault	6/29/2016	2,859	8.42	3,975.10	No
9	Primary Contact – 3rd Party	8/23/2016	2,772	5.15	2,693.25	No
10	Trees	6/15/2016	2,732	8.15	3,822.70	No

Rank	Description	Date	Customers Affected	Longest Interruption (hours)	Customers-hours affected	CPUC Major Event?
1	Storm	4/25/2015	4,120	6.50	12,380.00	No
2	Underground Fault	2/14/2015	3,587	0.50	2,511.00	No
3	Downed Wire	12/11/2015	3,587	10.00	17,251.00	No
4	Trees	2/6/2015	3,548	0.50	1,360.00	No
5	Bird/Animal	5/24/2015	3,000	6.50	12,340.00	No
6	Fire	2/20/2015	3,000	0.50	1,650.00	No
7	Weather/Lightning	7/4/2015	3,000	2.00	5,600.00	No
8	Weather/Lightning	7/7/2015	3,000	0.25	1,000.00	No
9	Operations	8/11/2015	3,000	0.25	750.00	No
10	Weather/Lightning	8/7/2015	3,000	1.75	5,400.00	No

9) Number of customer inquiries on reliability data and the number of days per response

CalPeco Electric did not receive any reliability inquiries in 2024.

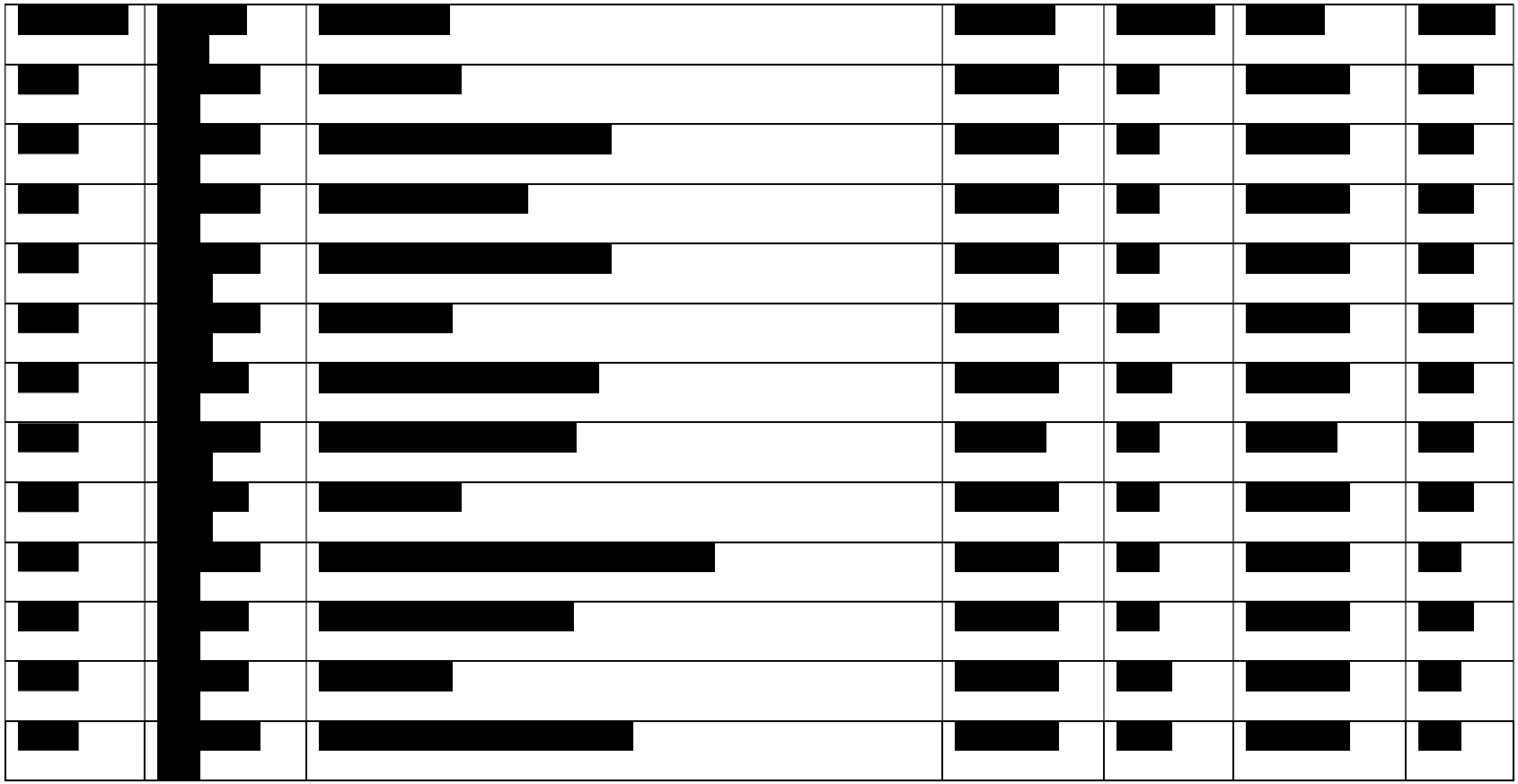
Date Received	Date Responded	Description of Inquiry

10) List of PSPS's in 2024

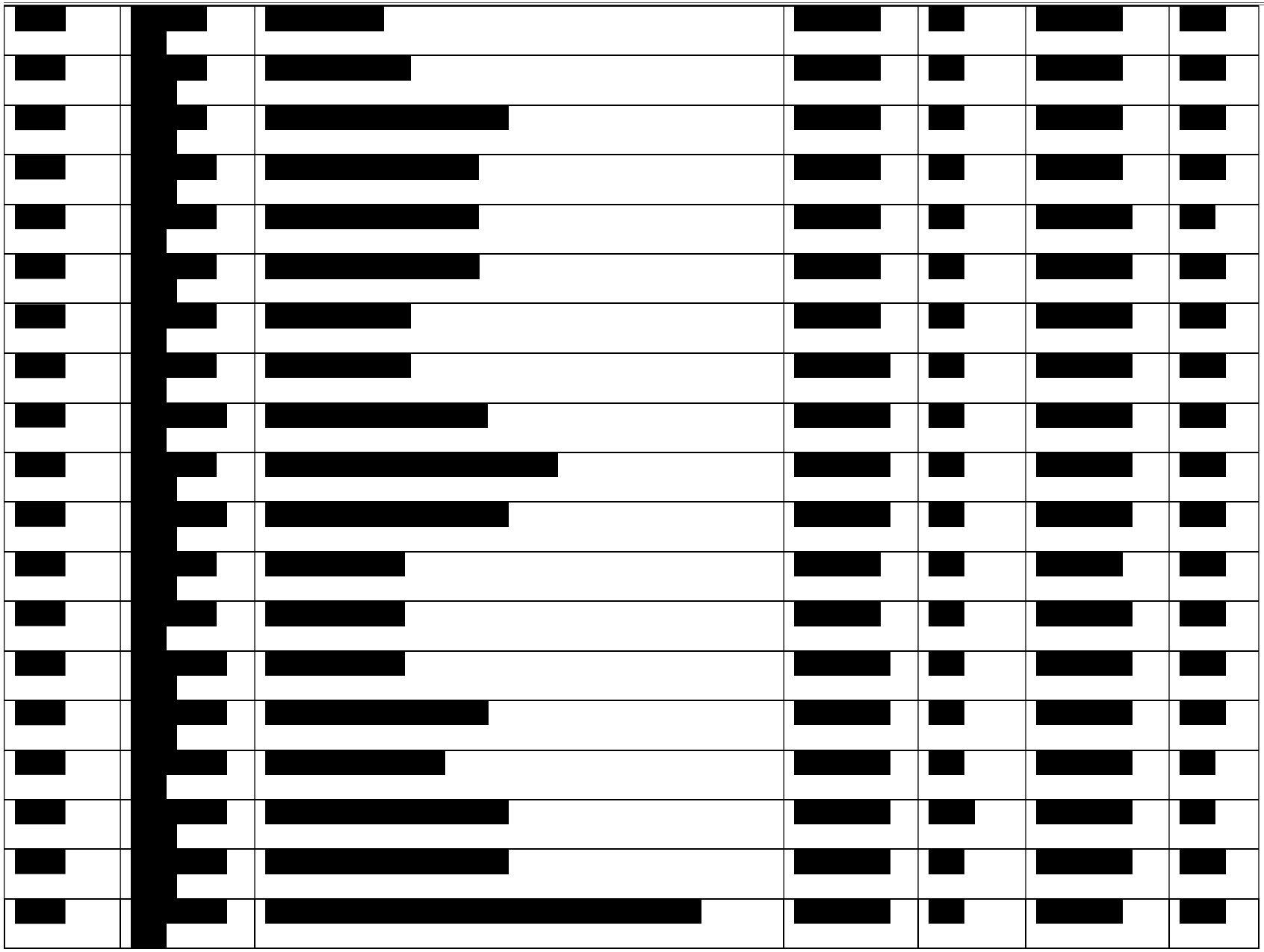
OUTAGE ID	CREATED DATE	DESCRIPTION	OUT DATE	OUT TIME	IN DATE	IN TIME
120033506	11/22/2024 8:01	Muller 1296-R3	11/22/2024	9:02	11/22/2024	20:55
120033226	11/20/2024 4:35	Muller 1296-R3 and R4	11/20/2024	5:33	11/20/2024	22:22

120032672	11/11/2024 8:16	Muller 1296	11/11/2024	9:15	11/11/2024	15:30
120033227	11/20/2024 4:38	PTR Muller 1296-R4	11/20/2024	5:33	11/20/2024	22:35
120032697	11/11/2024 10:50	Fuses P278665	11/11/2024	9:15	11/12/2024	0:35
120033541	11/22/2024 21:12	Fuse P122646	11/22/2024	21:48	11/23/2024	1:13

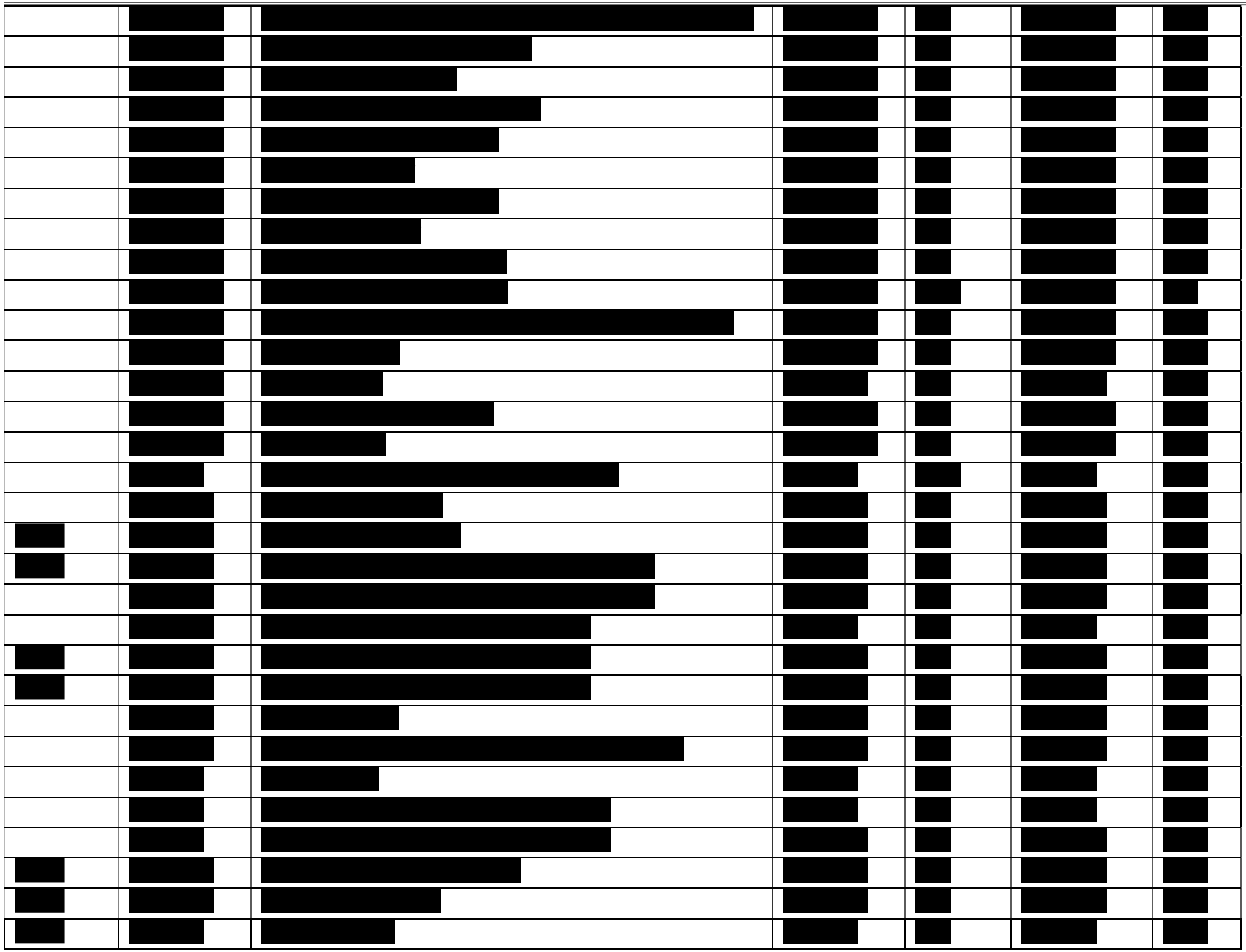
Appendix A: 10 Years of Planned Outage Data -- PUBLIC VERSION --



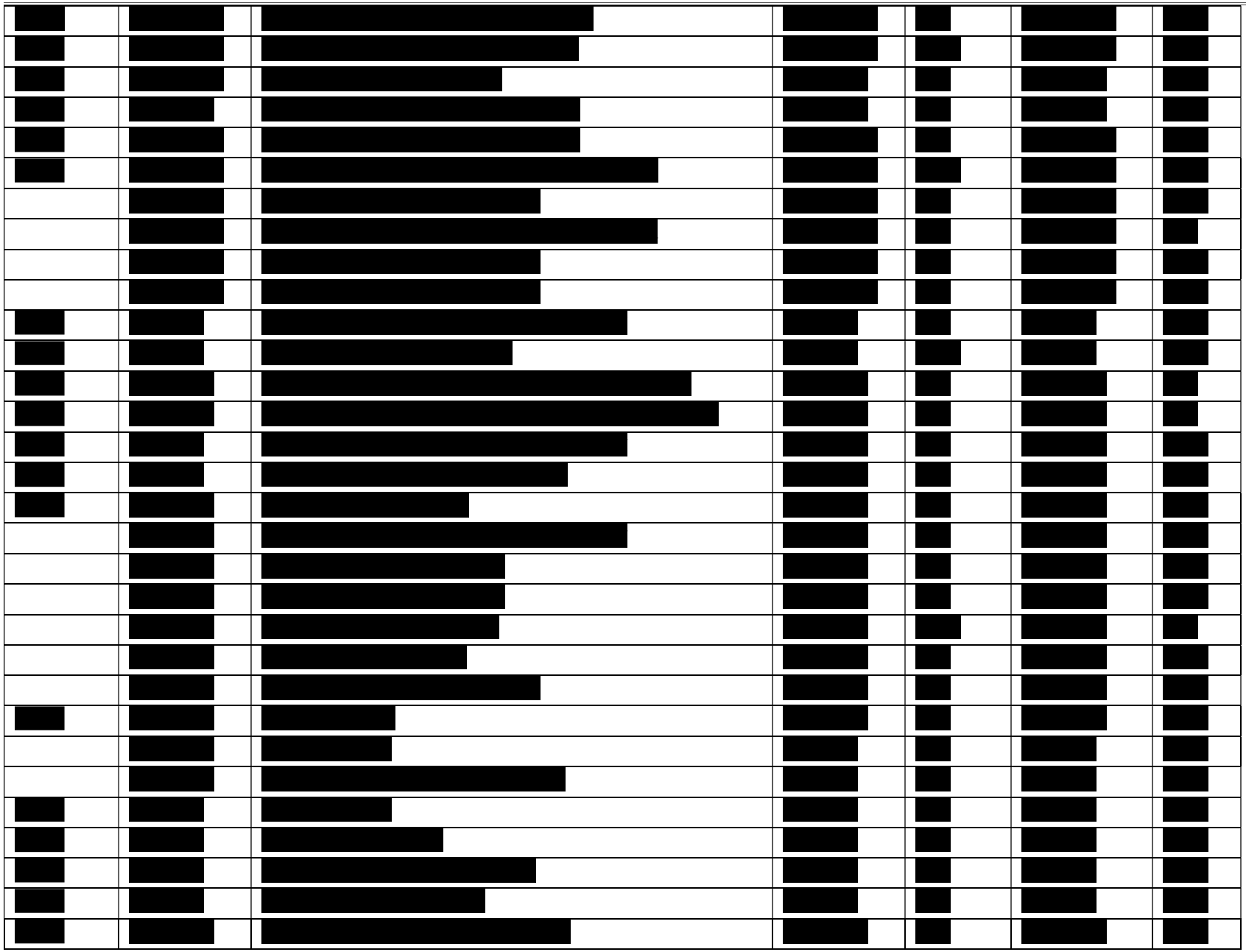


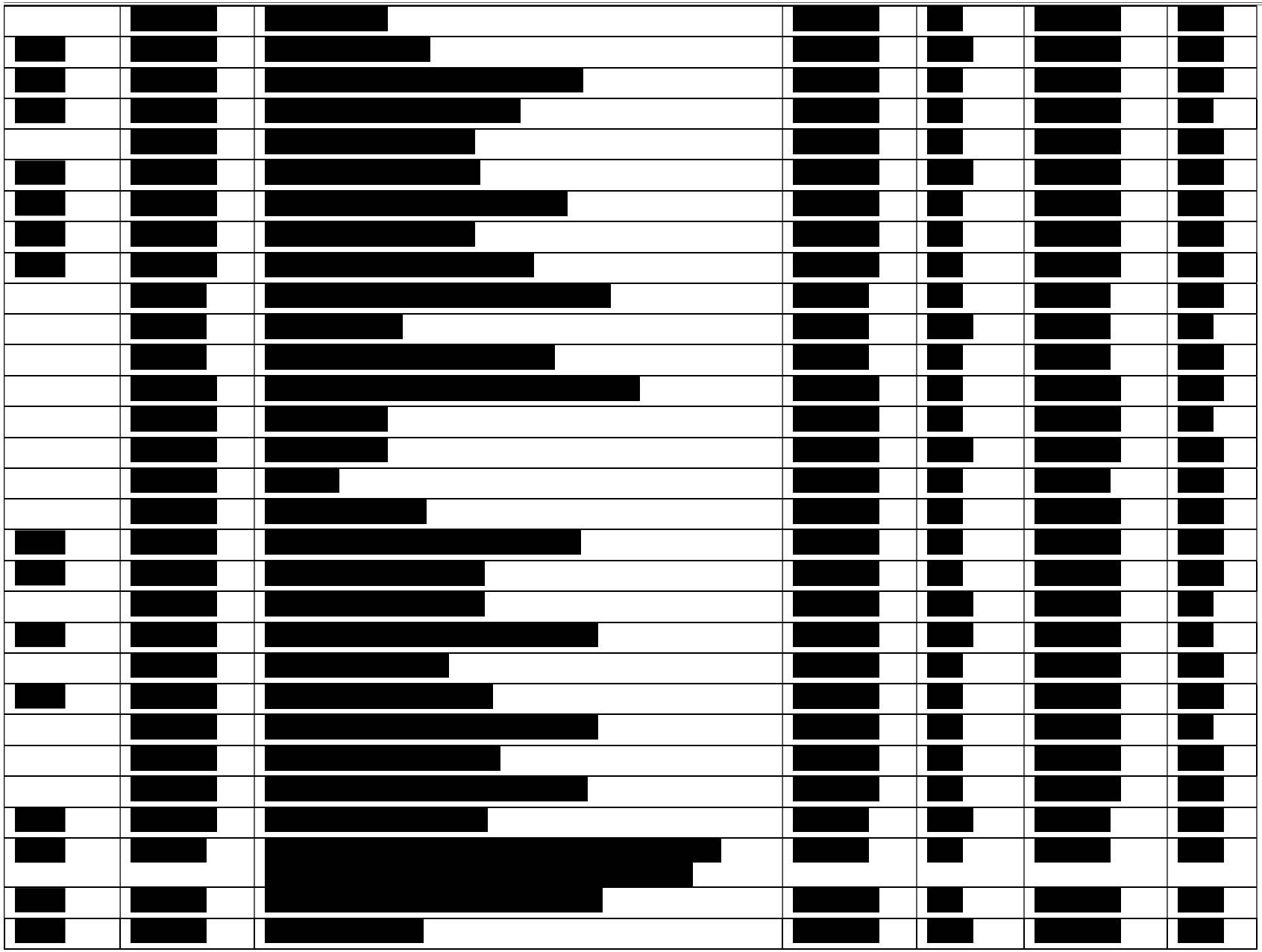


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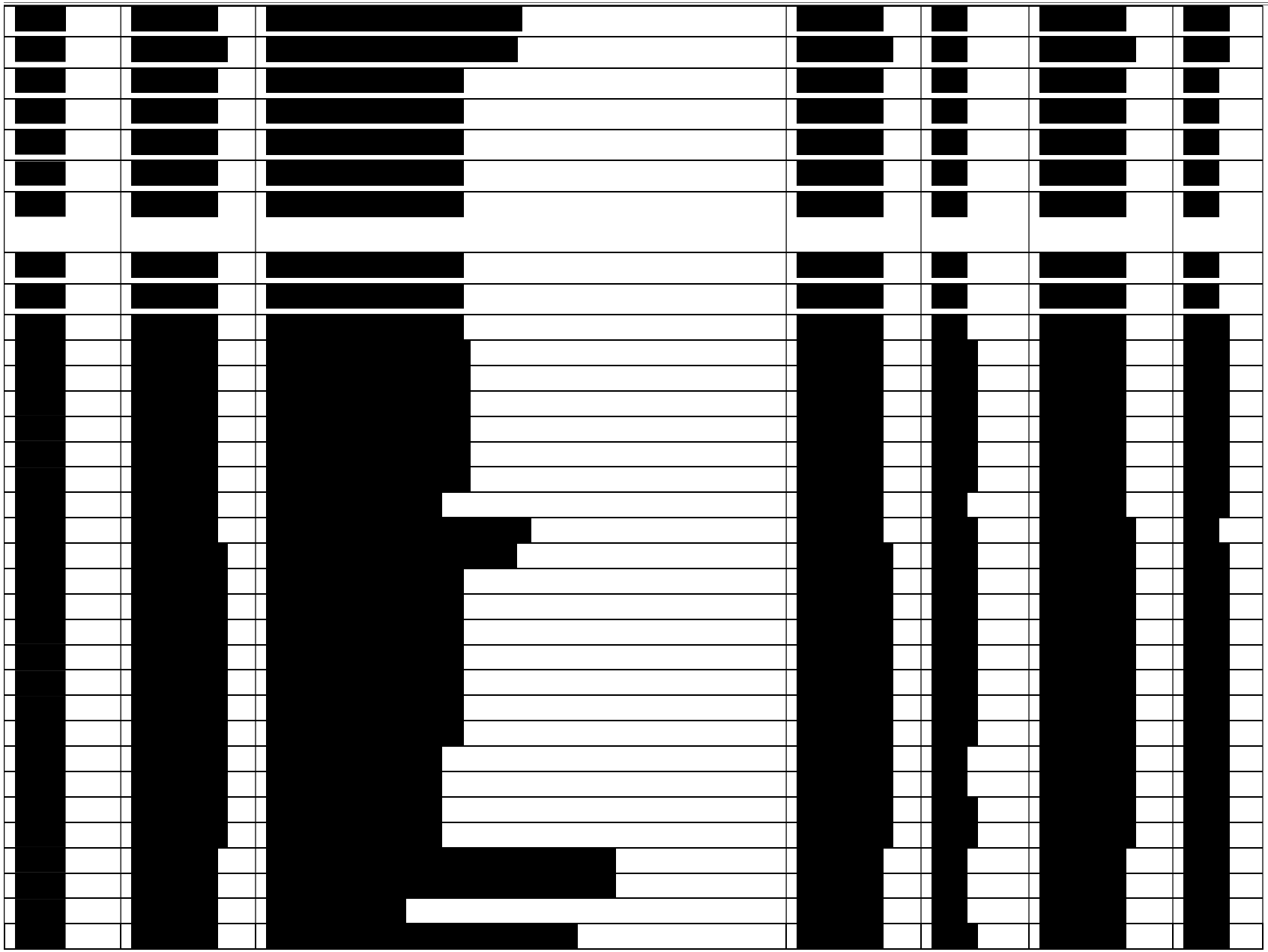


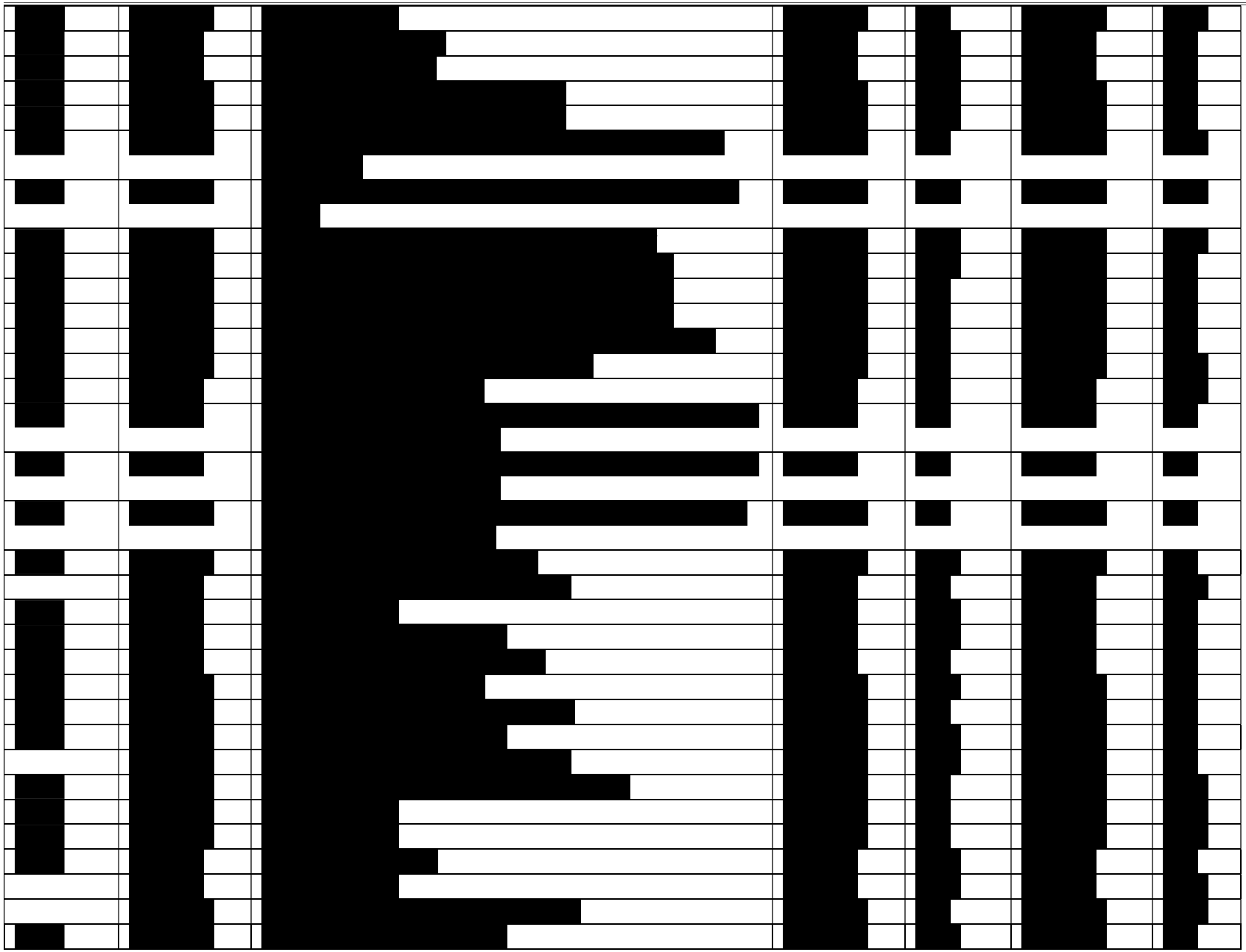


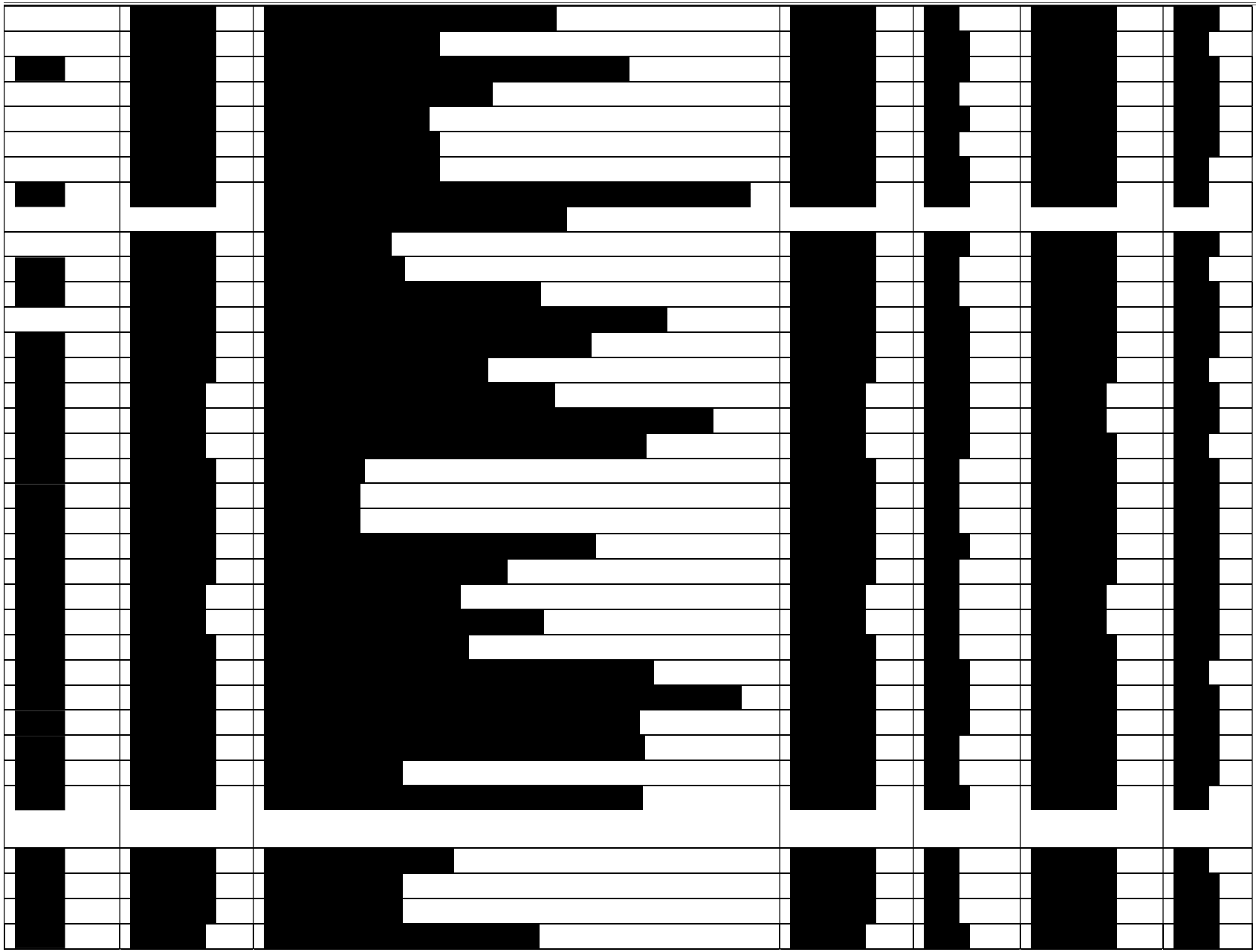


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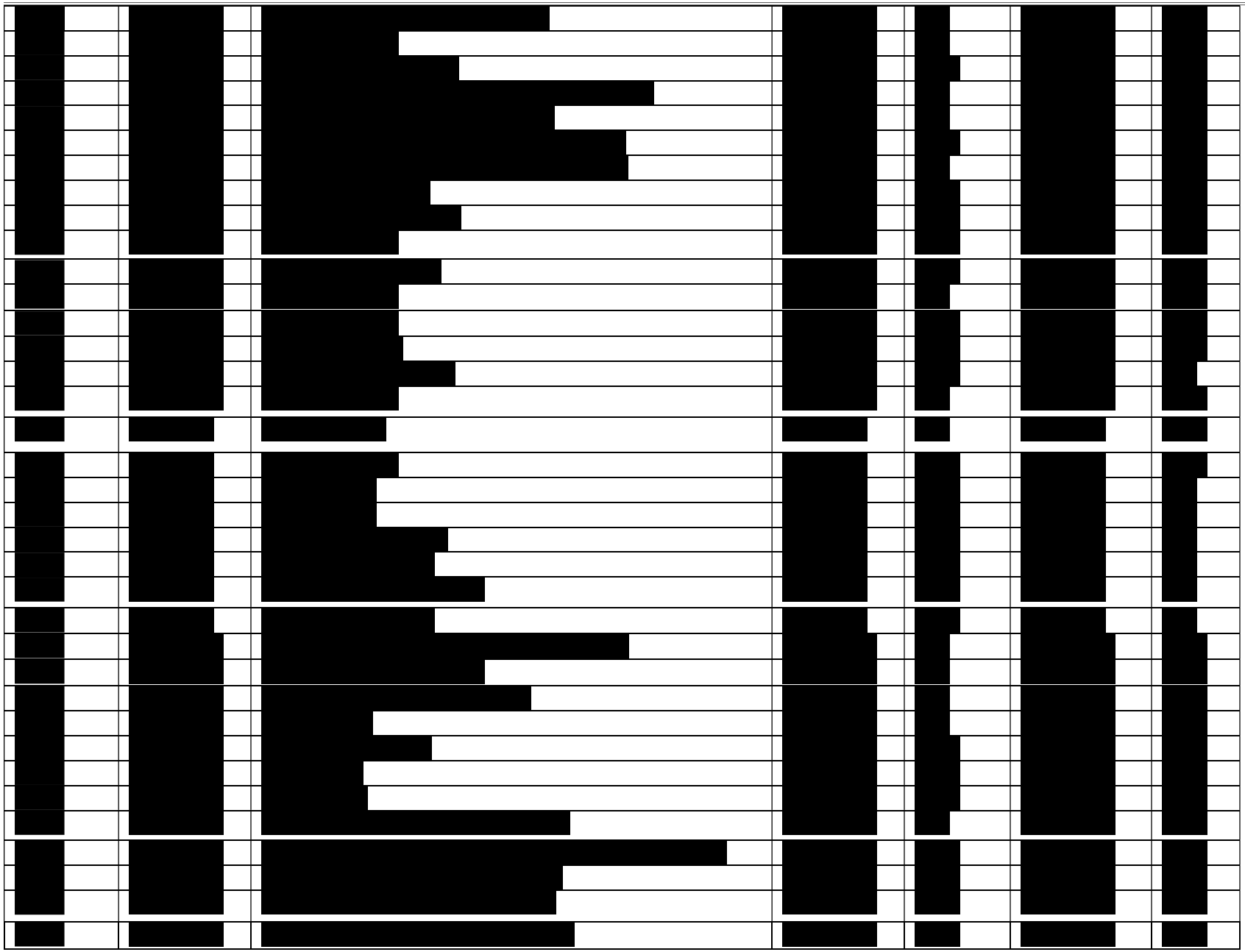




















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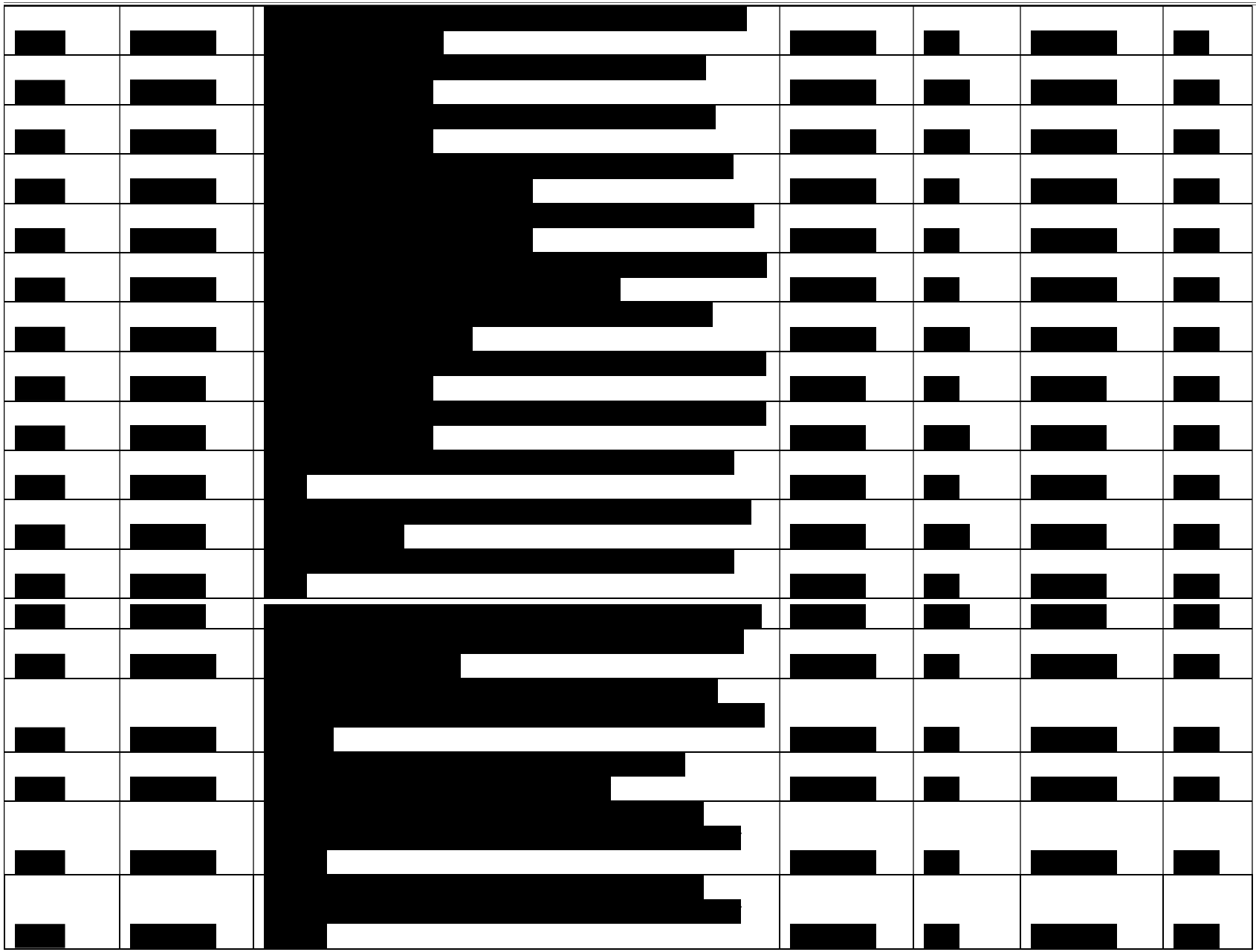








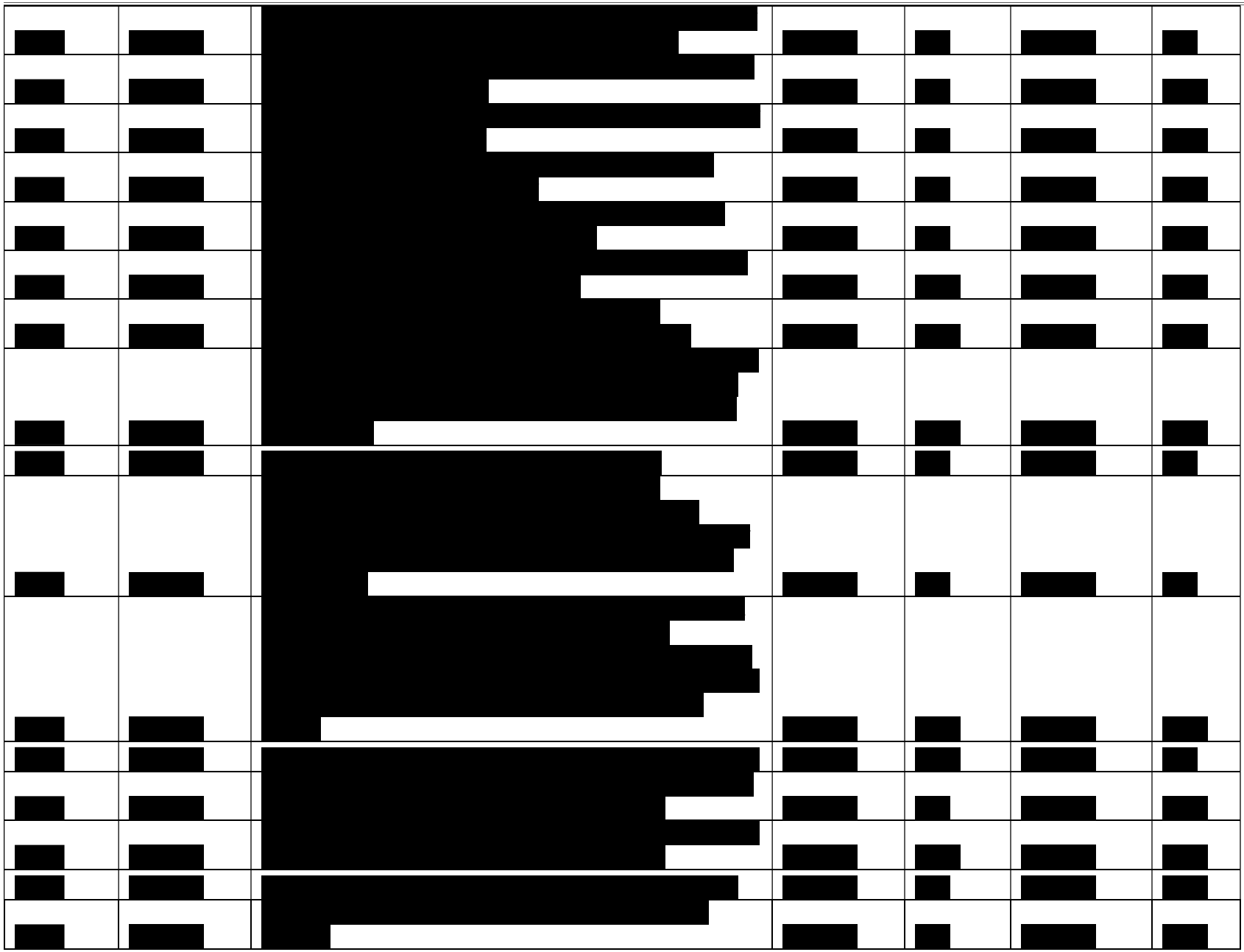


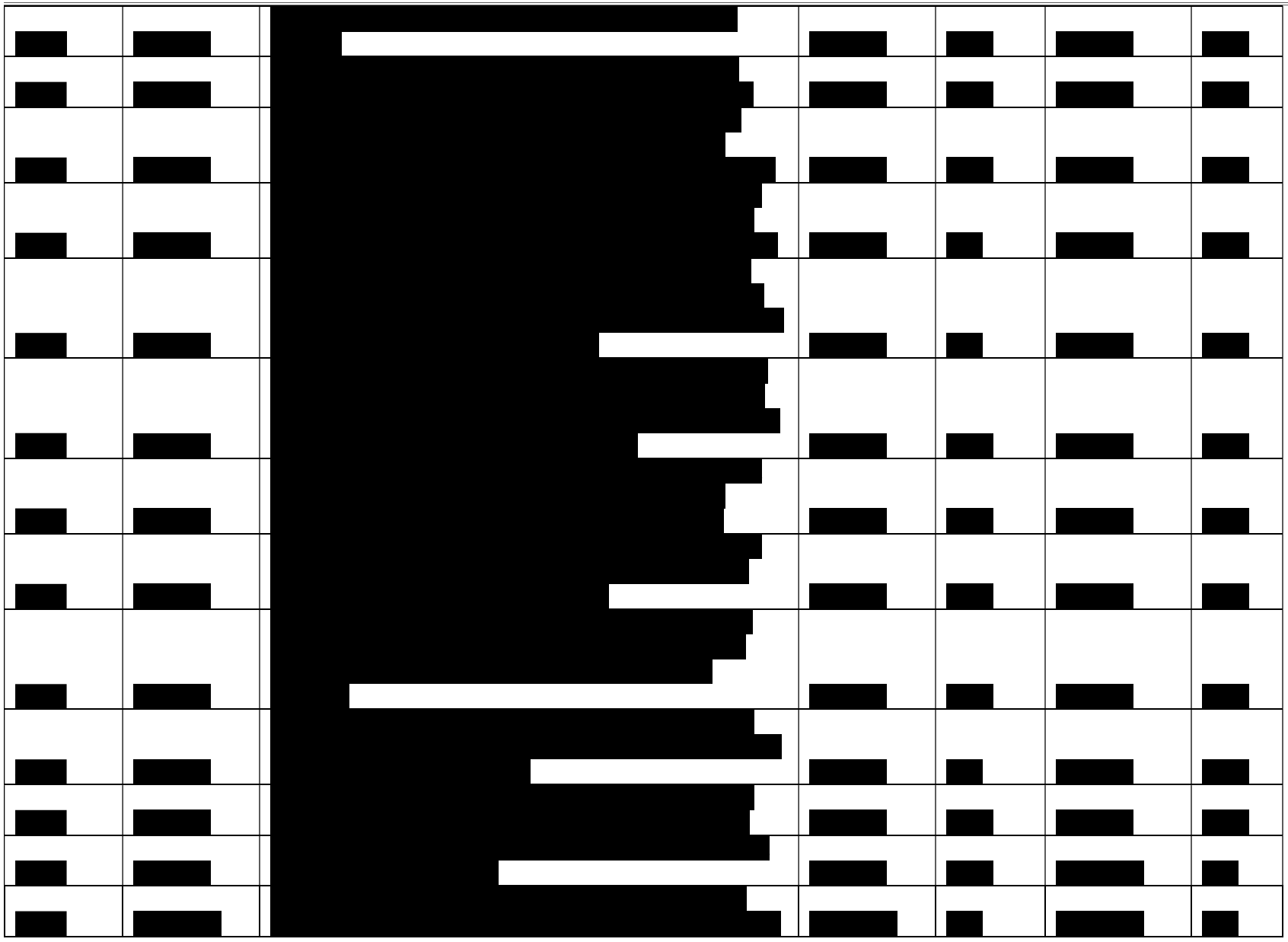




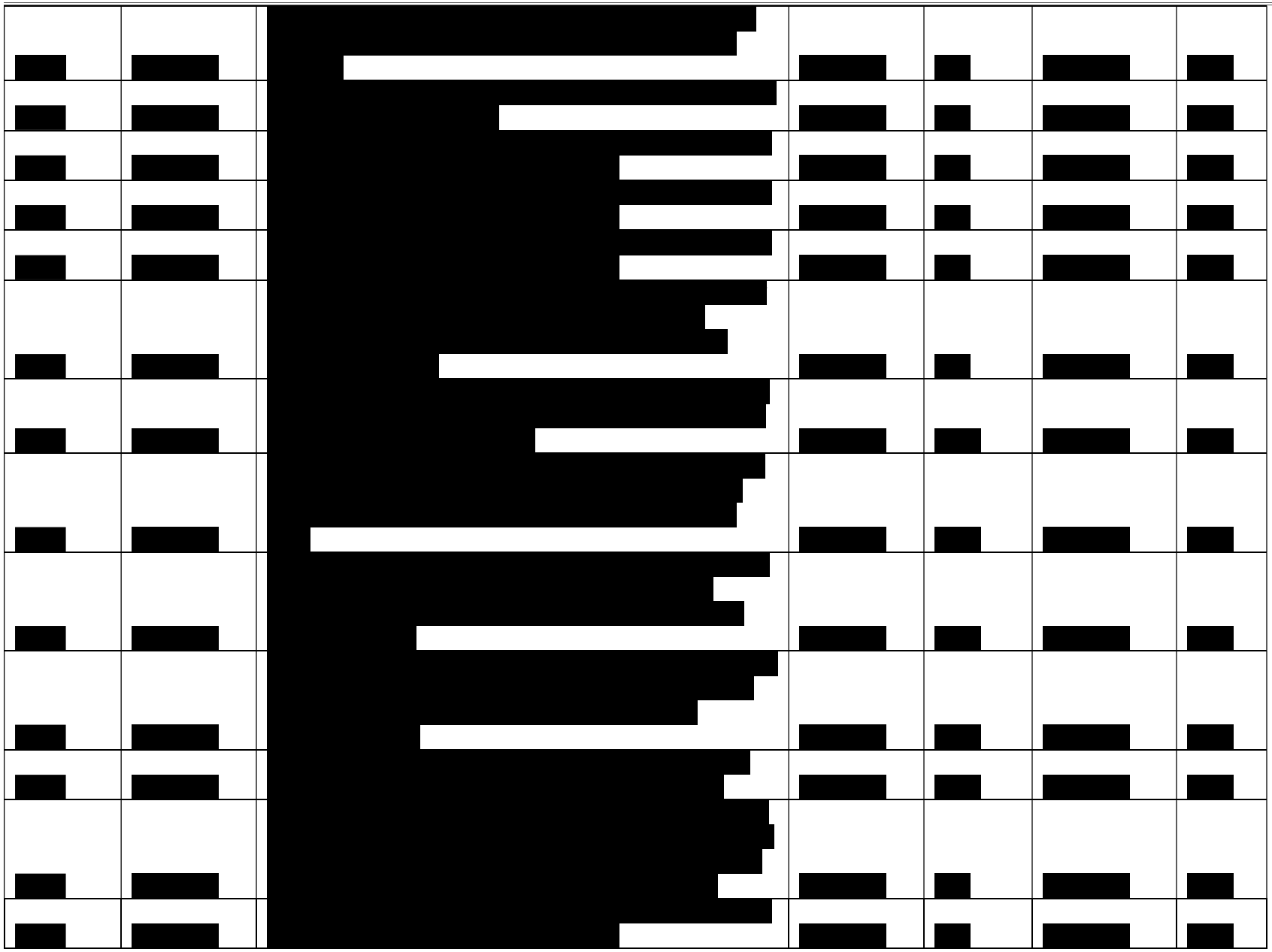




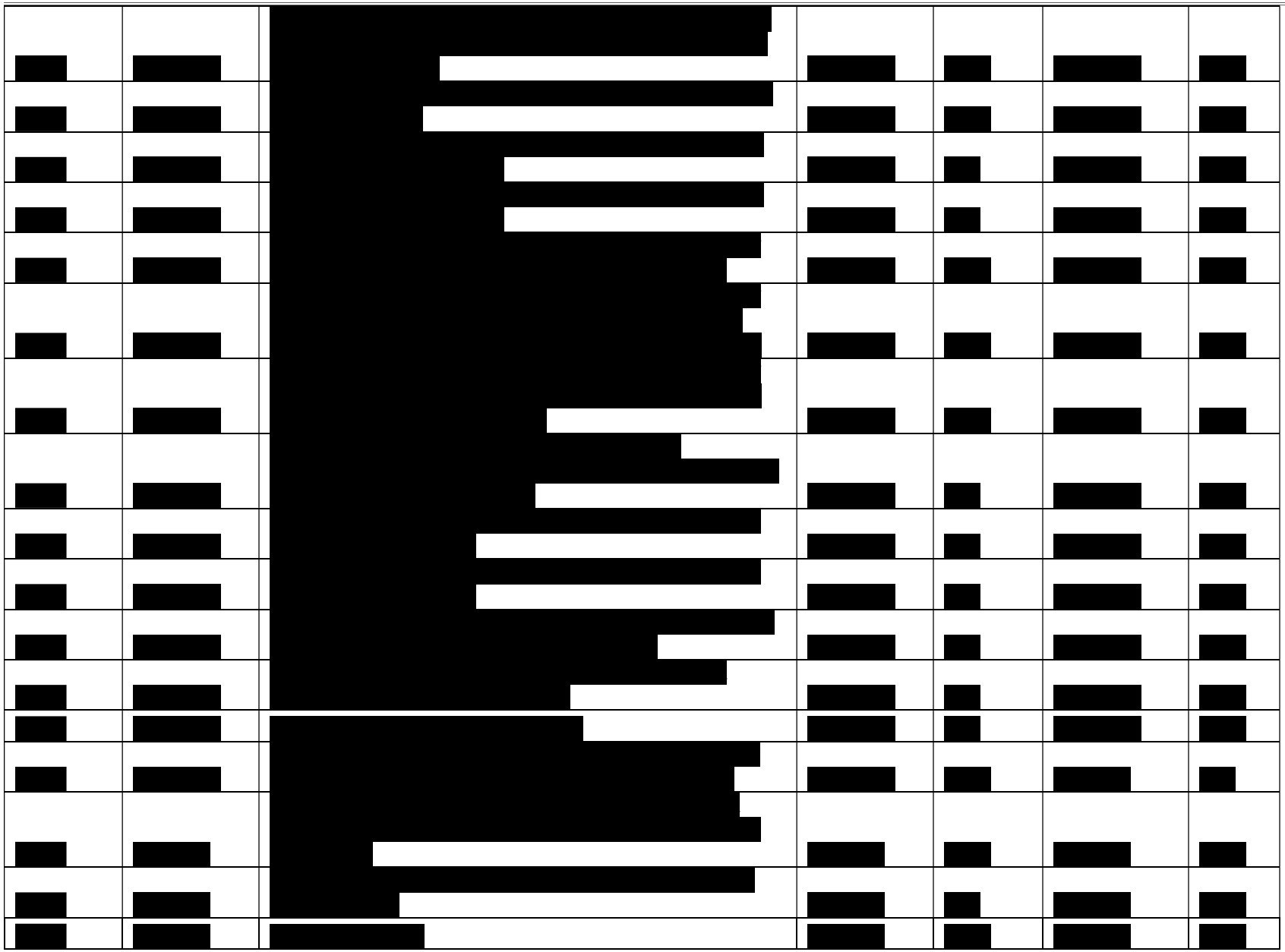




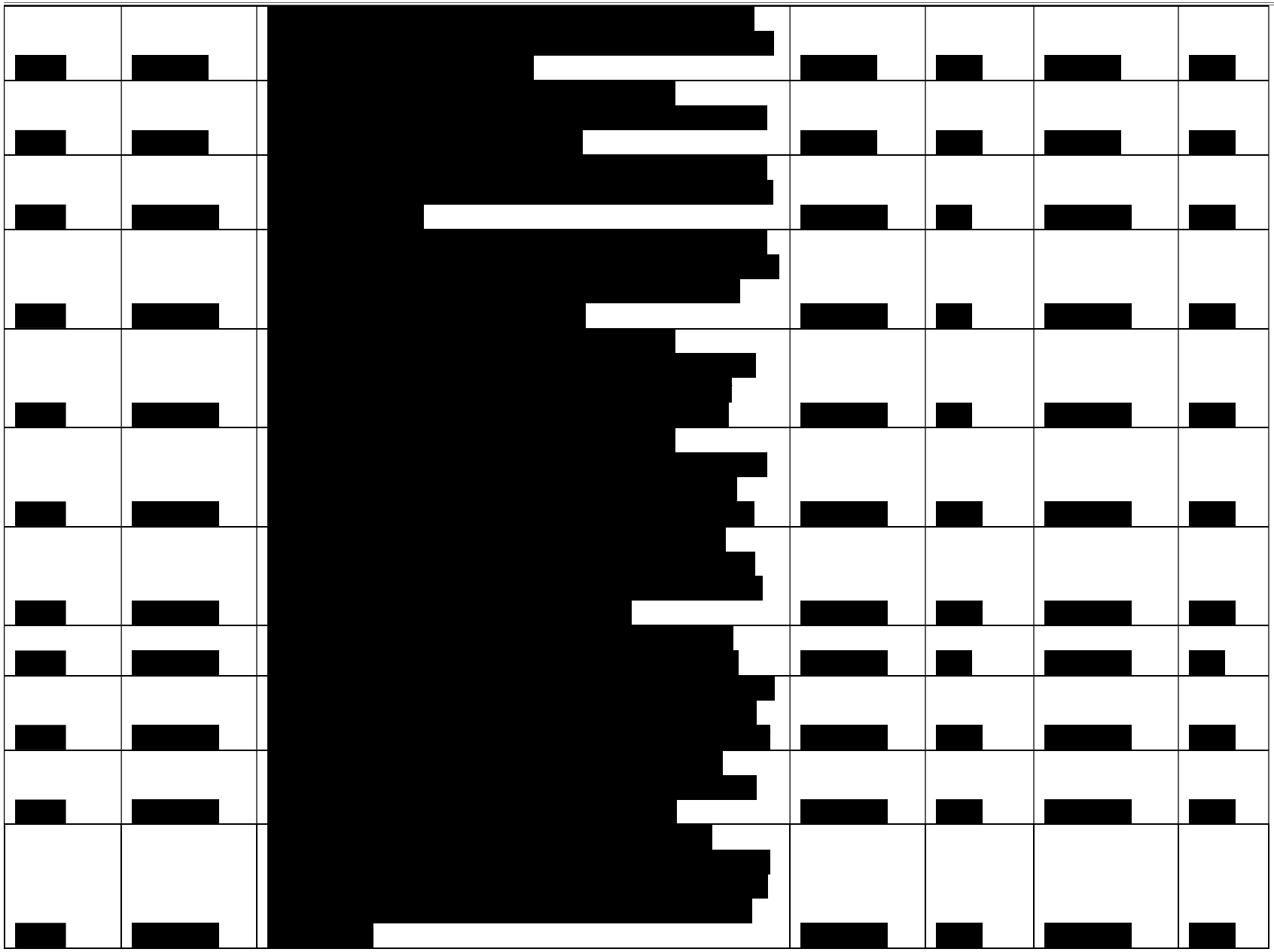












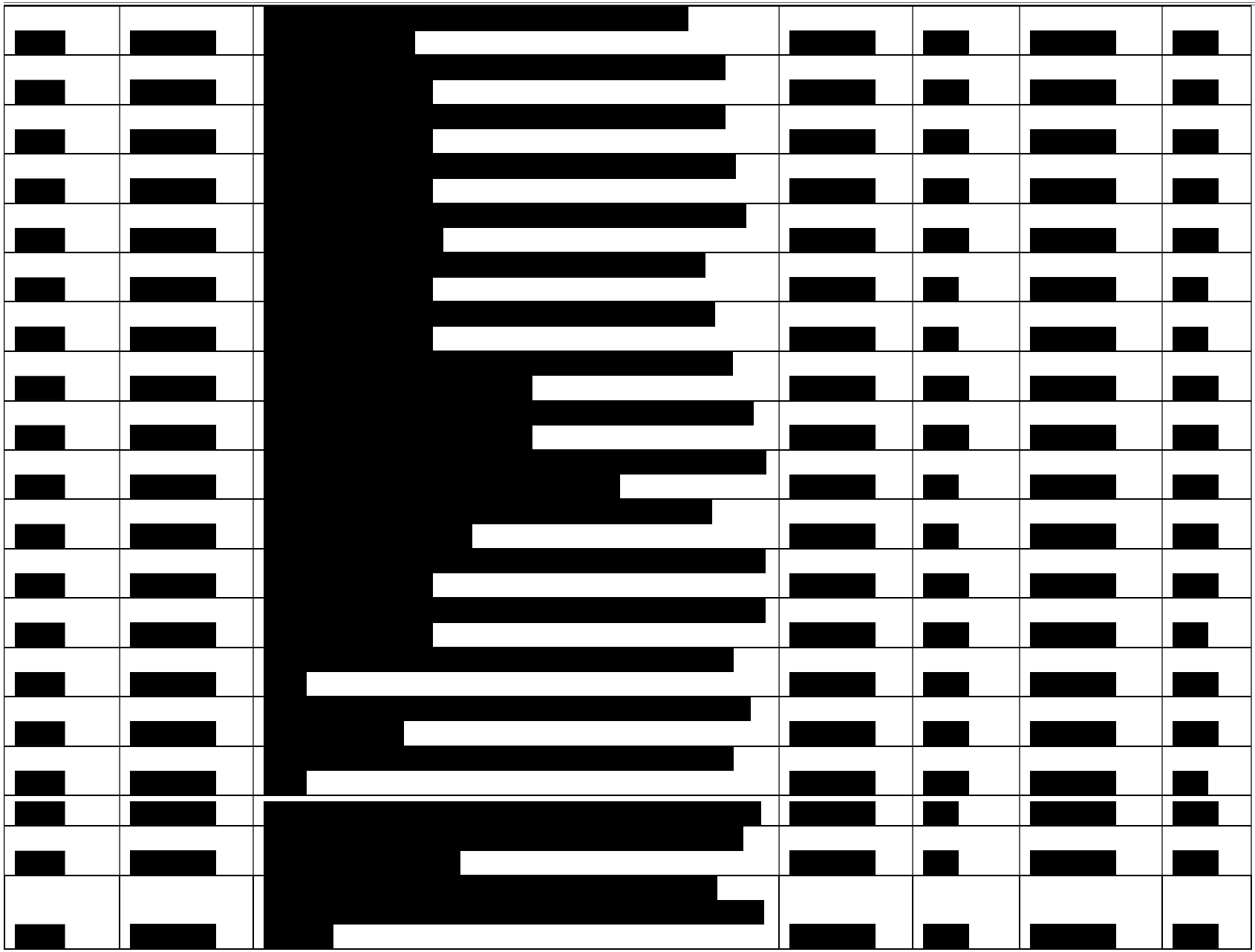








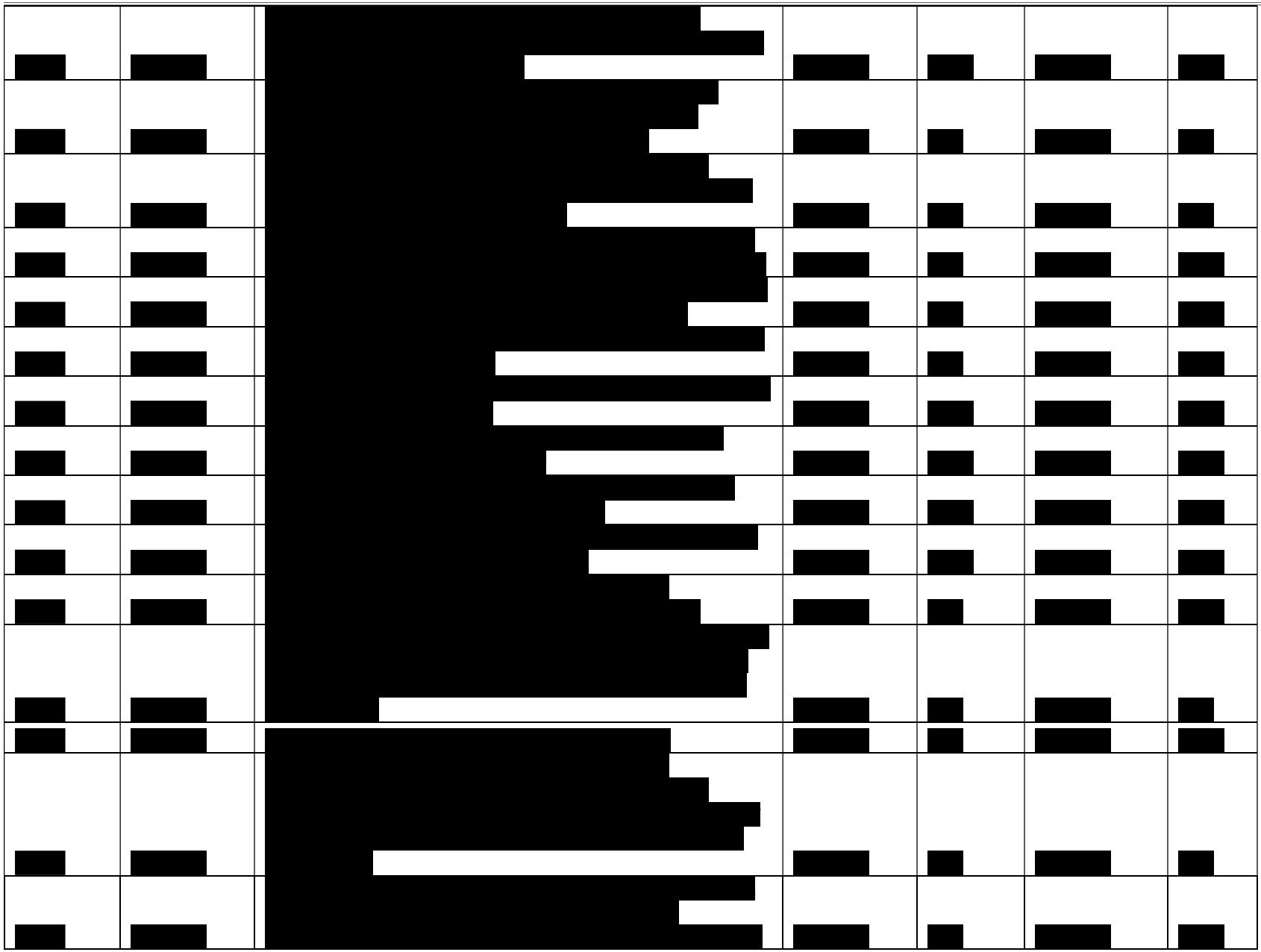






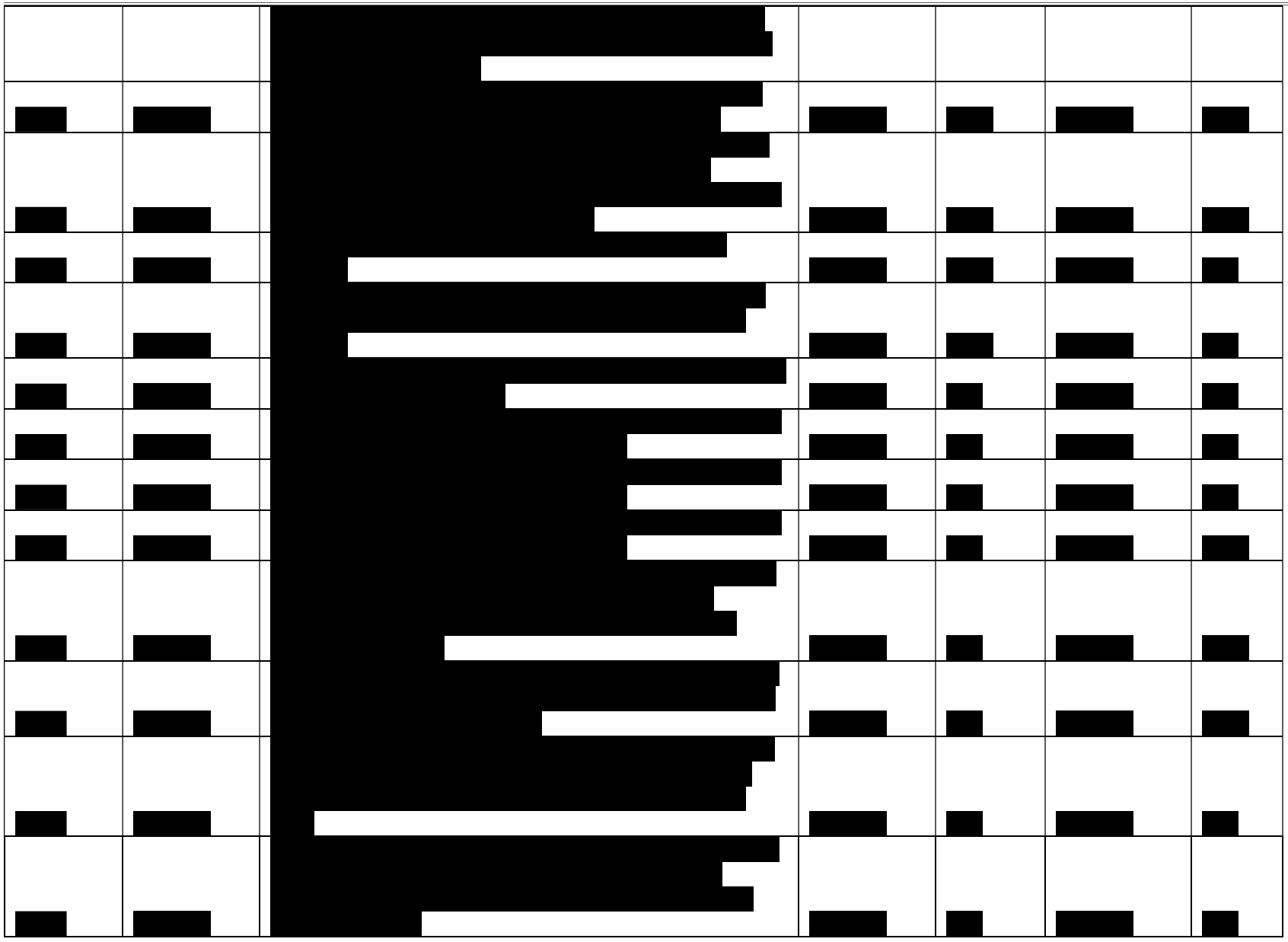




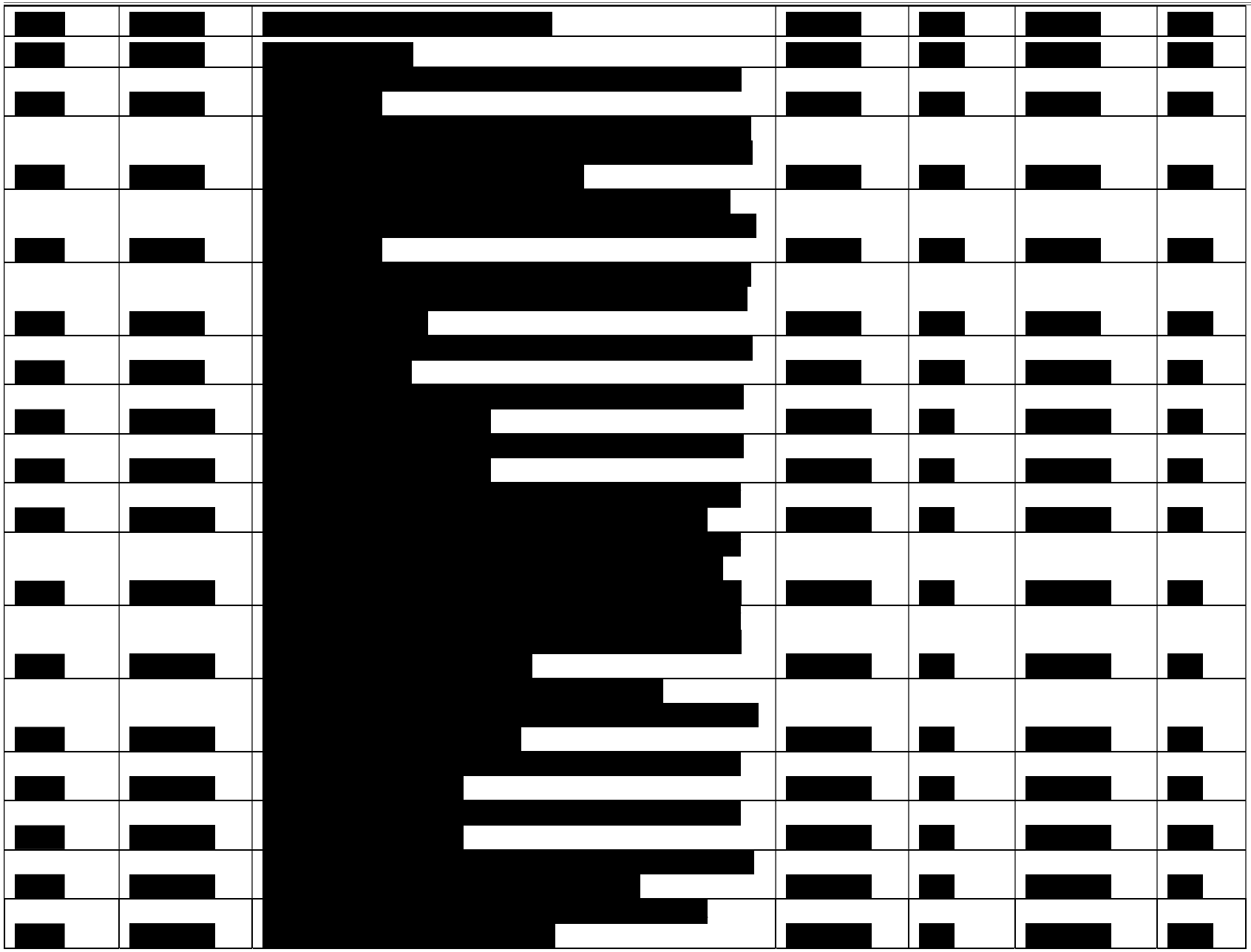
















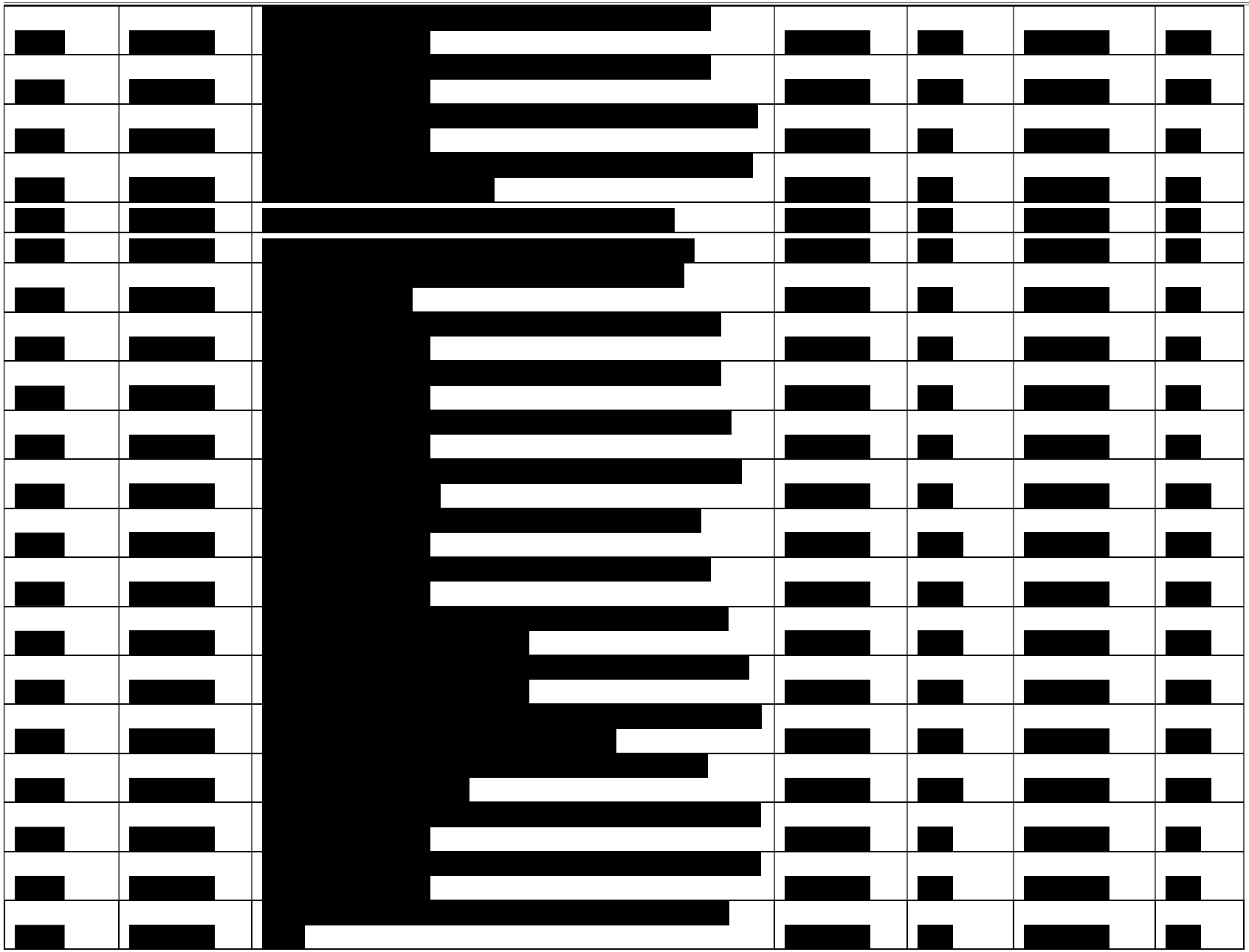


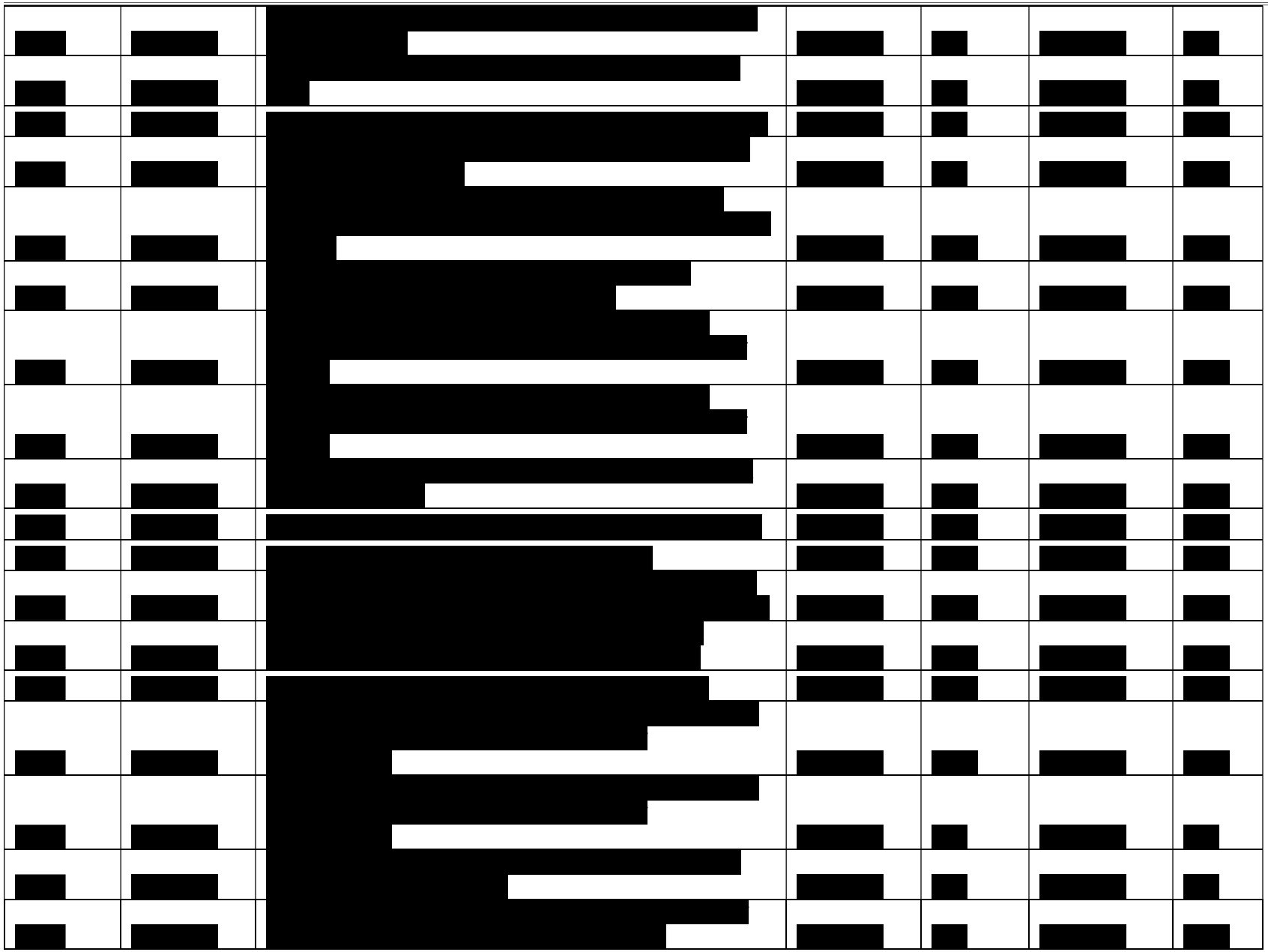






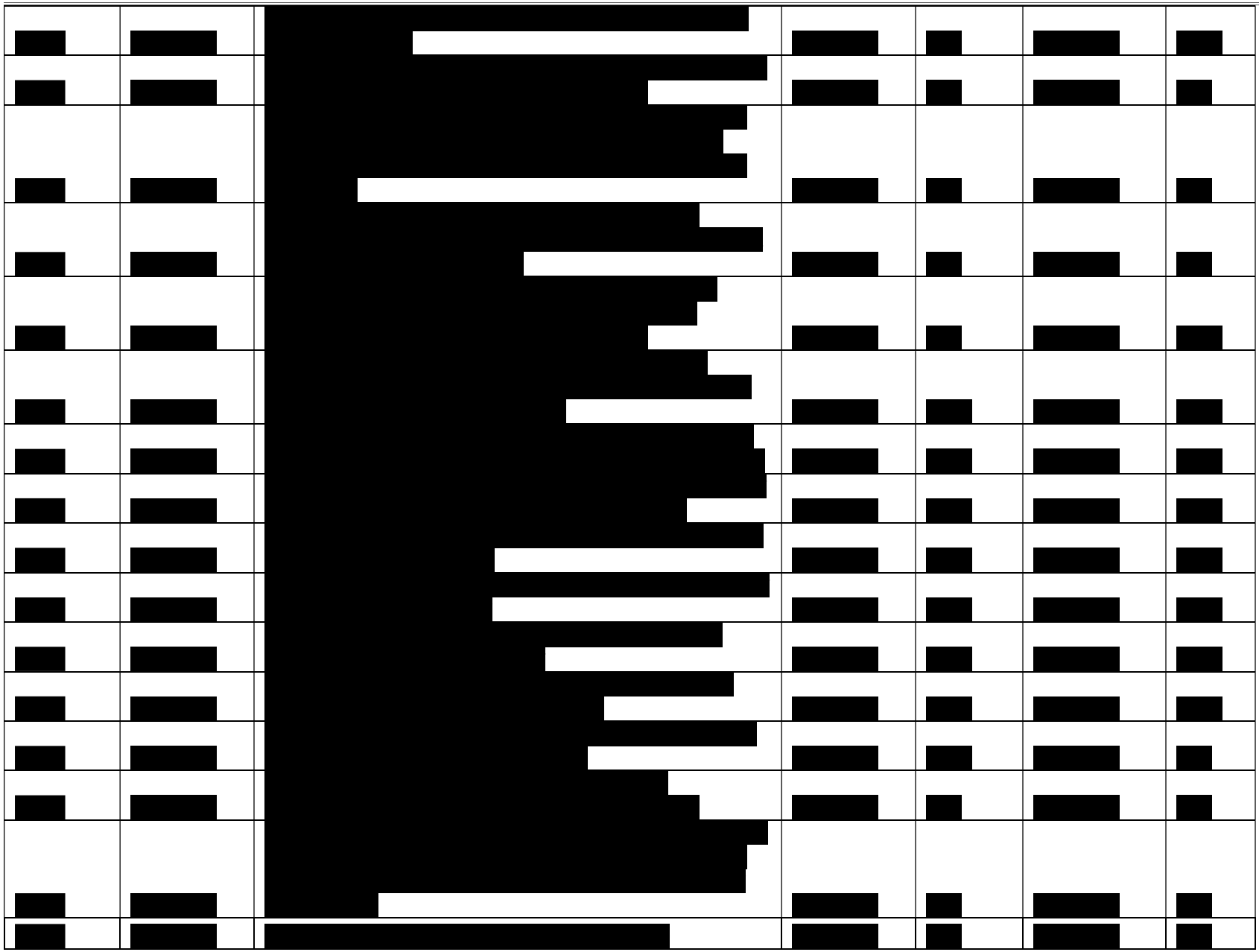














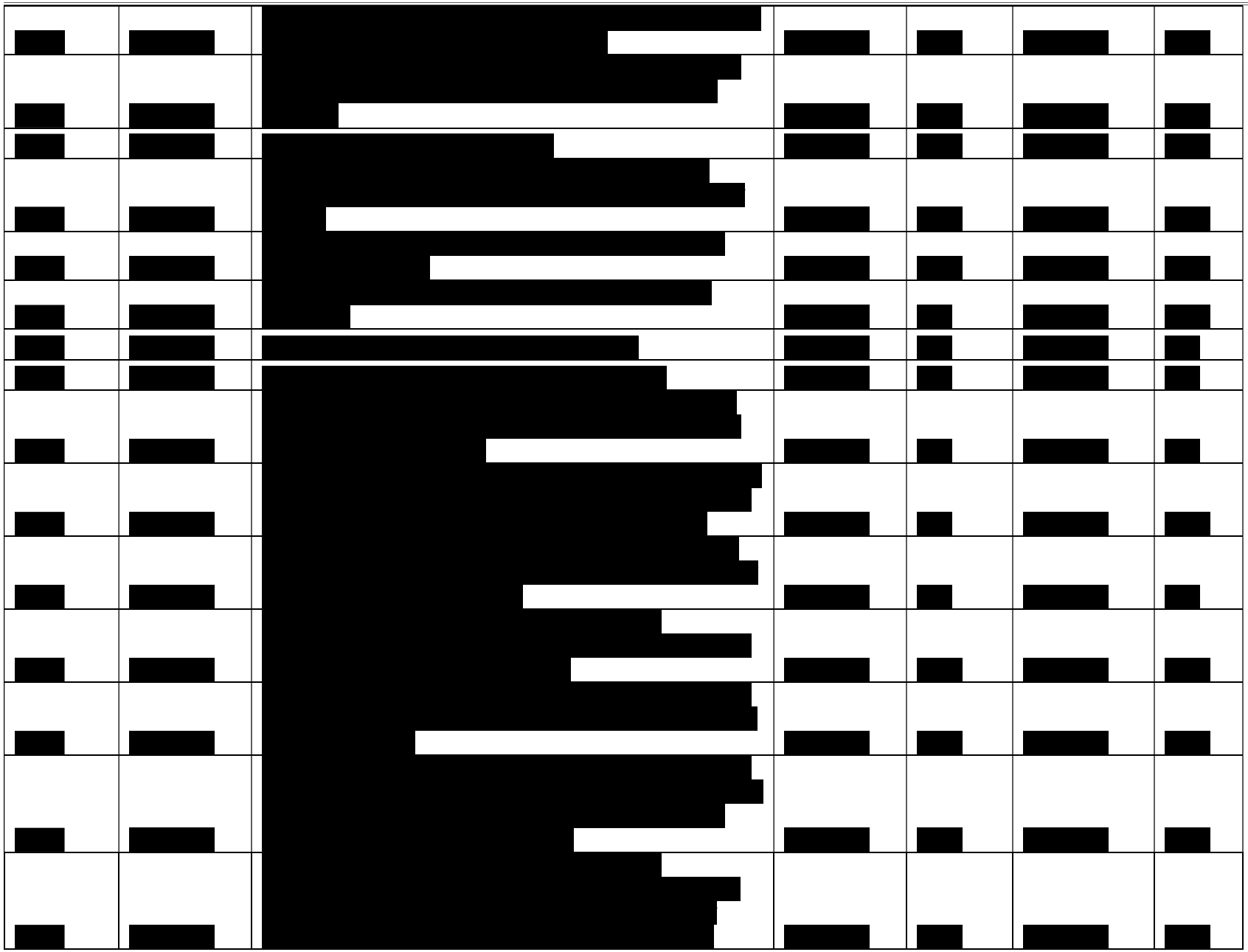












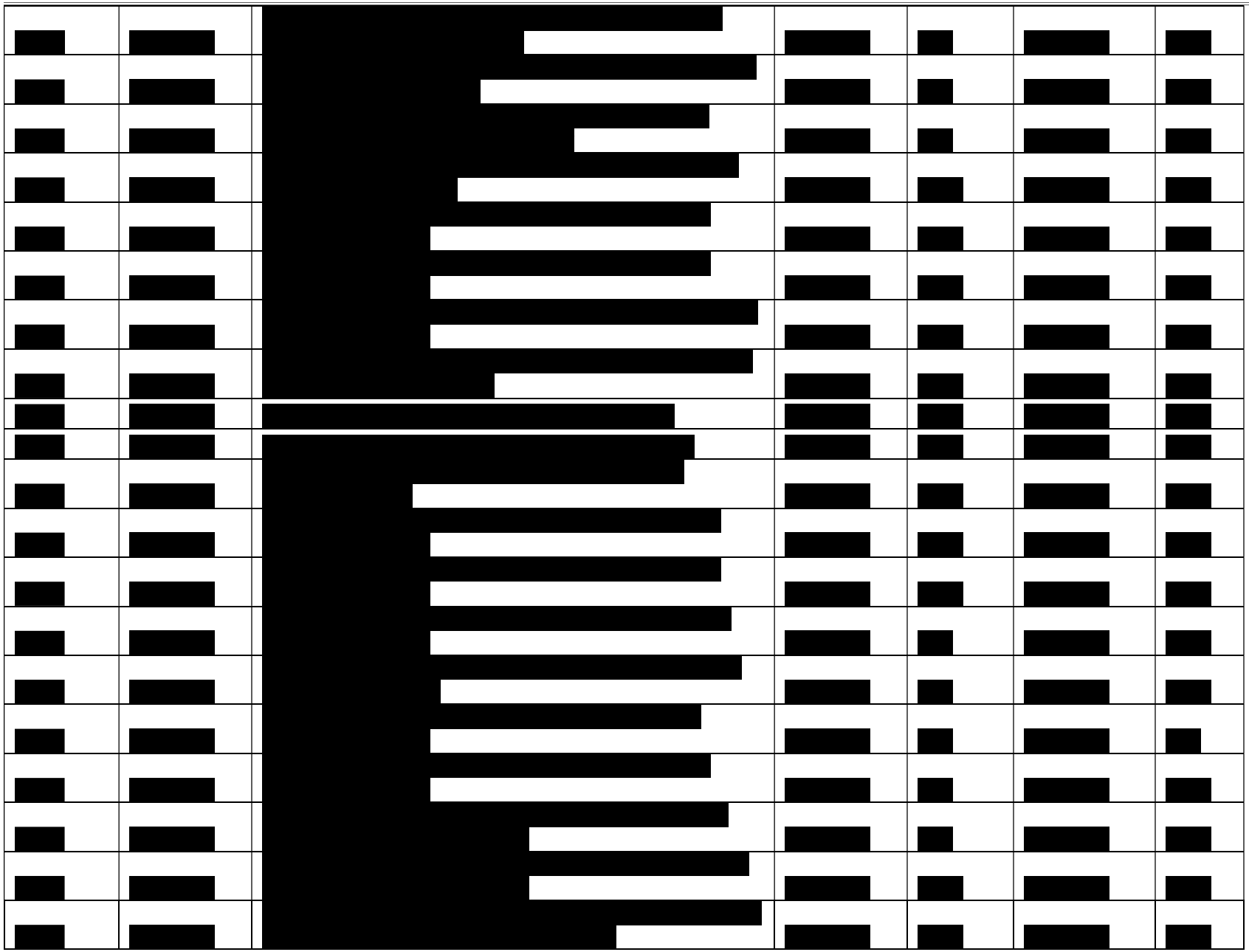








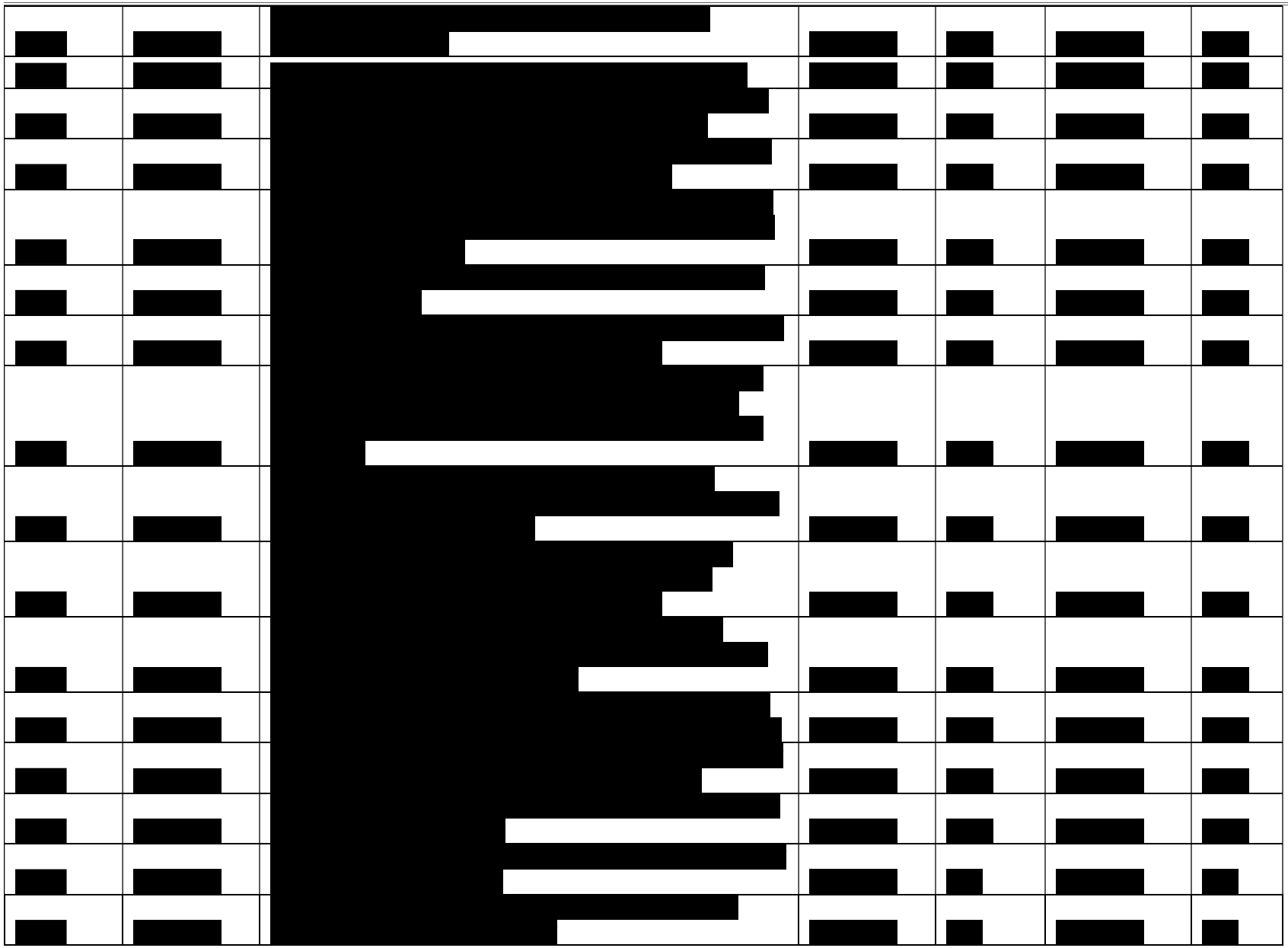




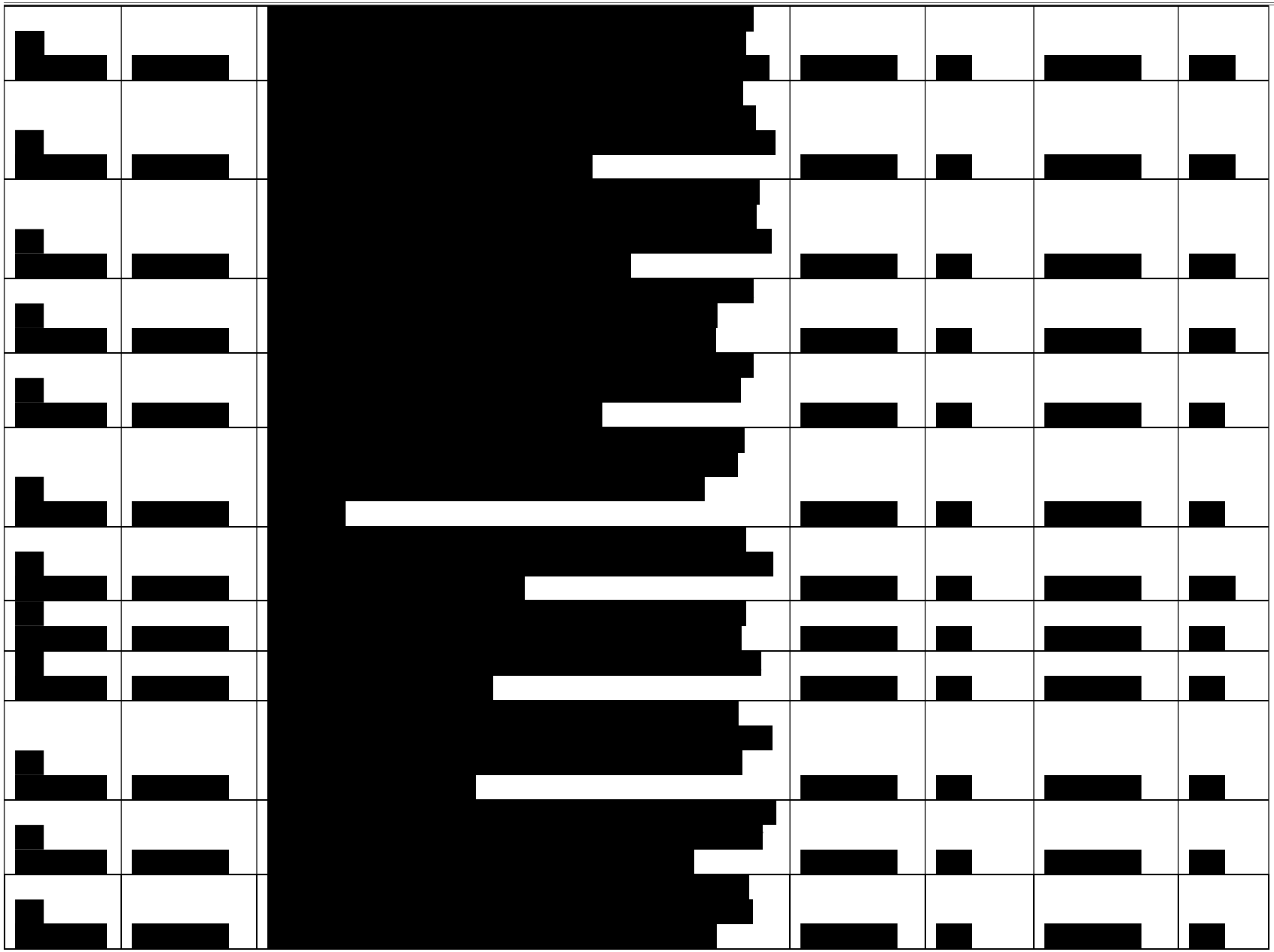




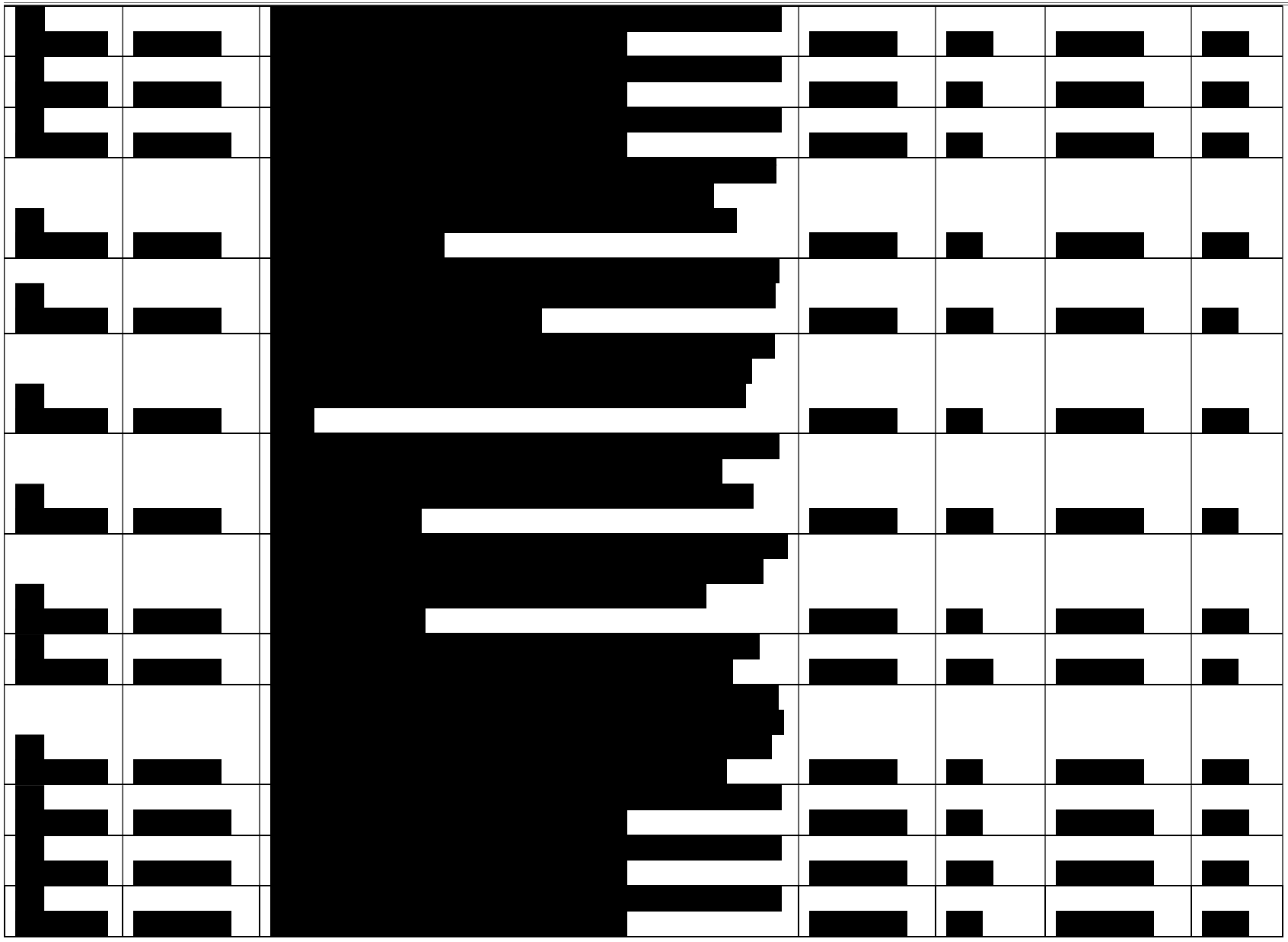




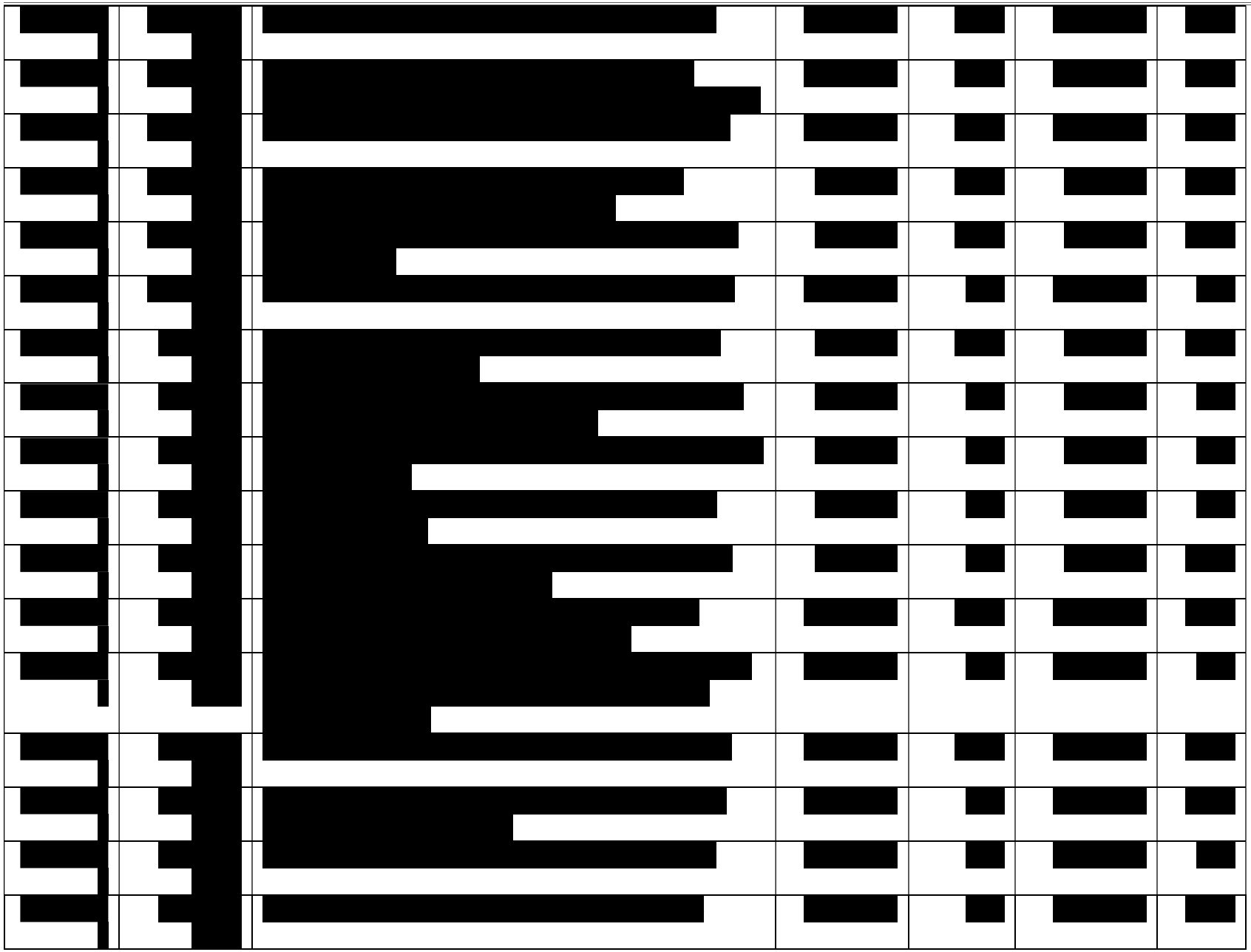




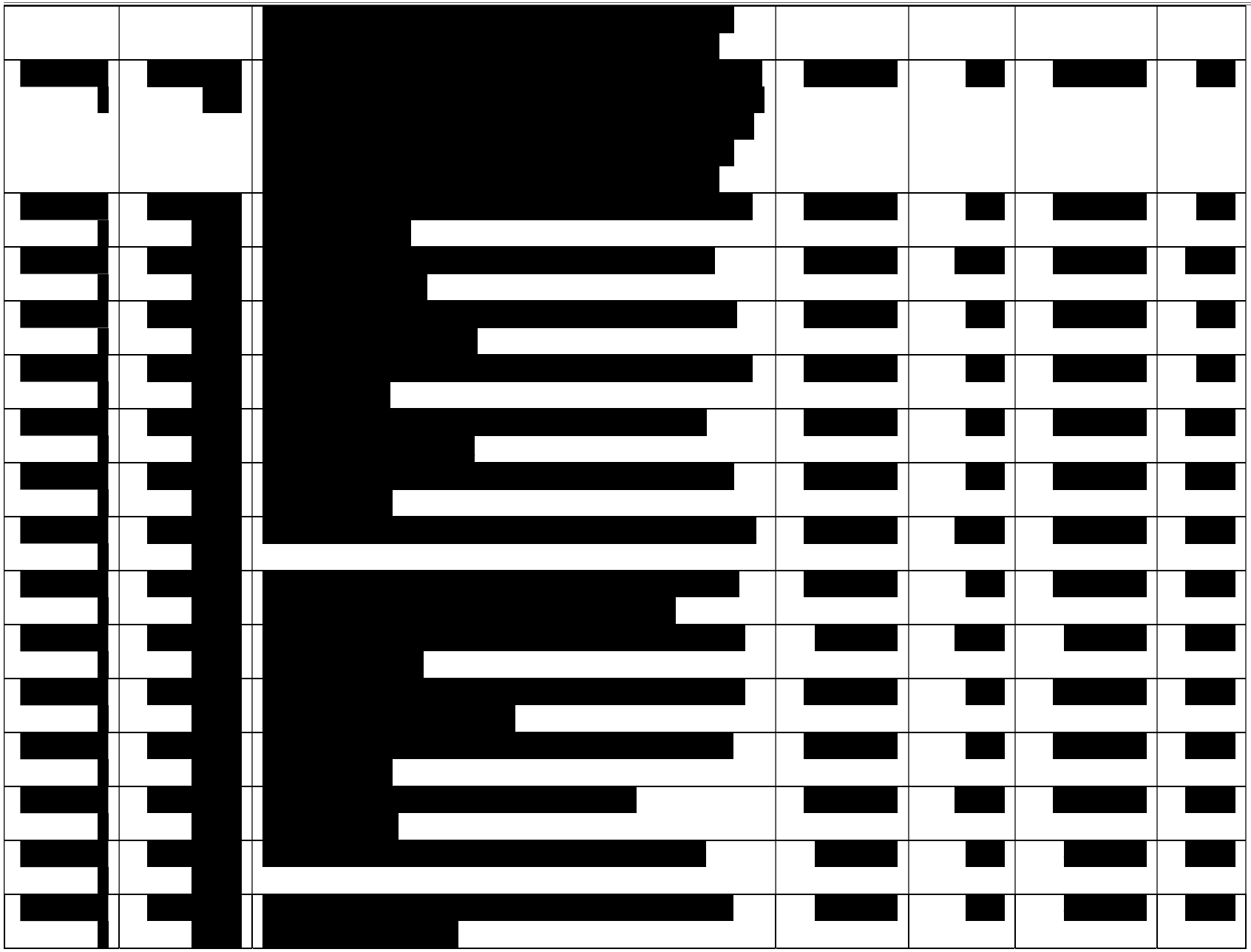


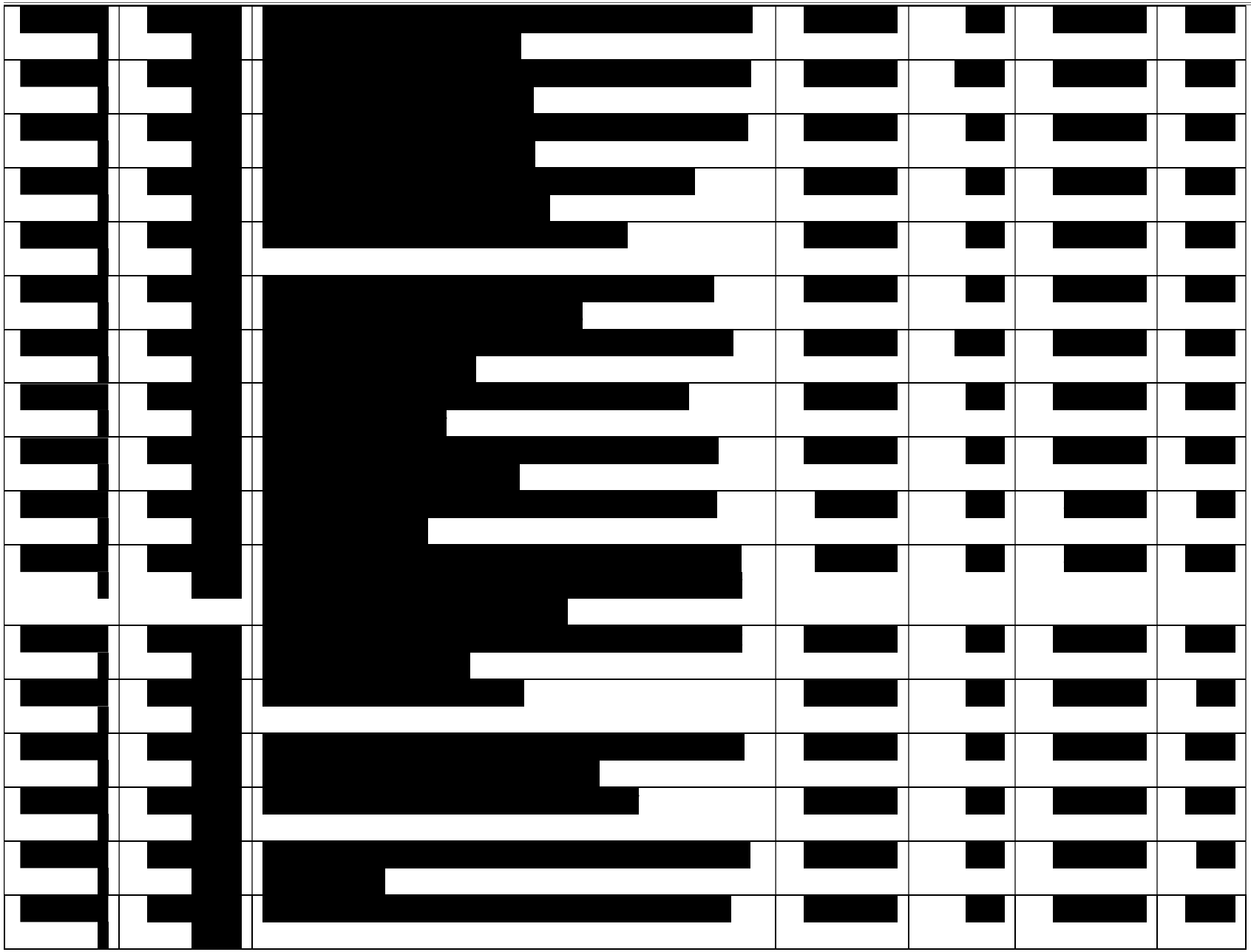


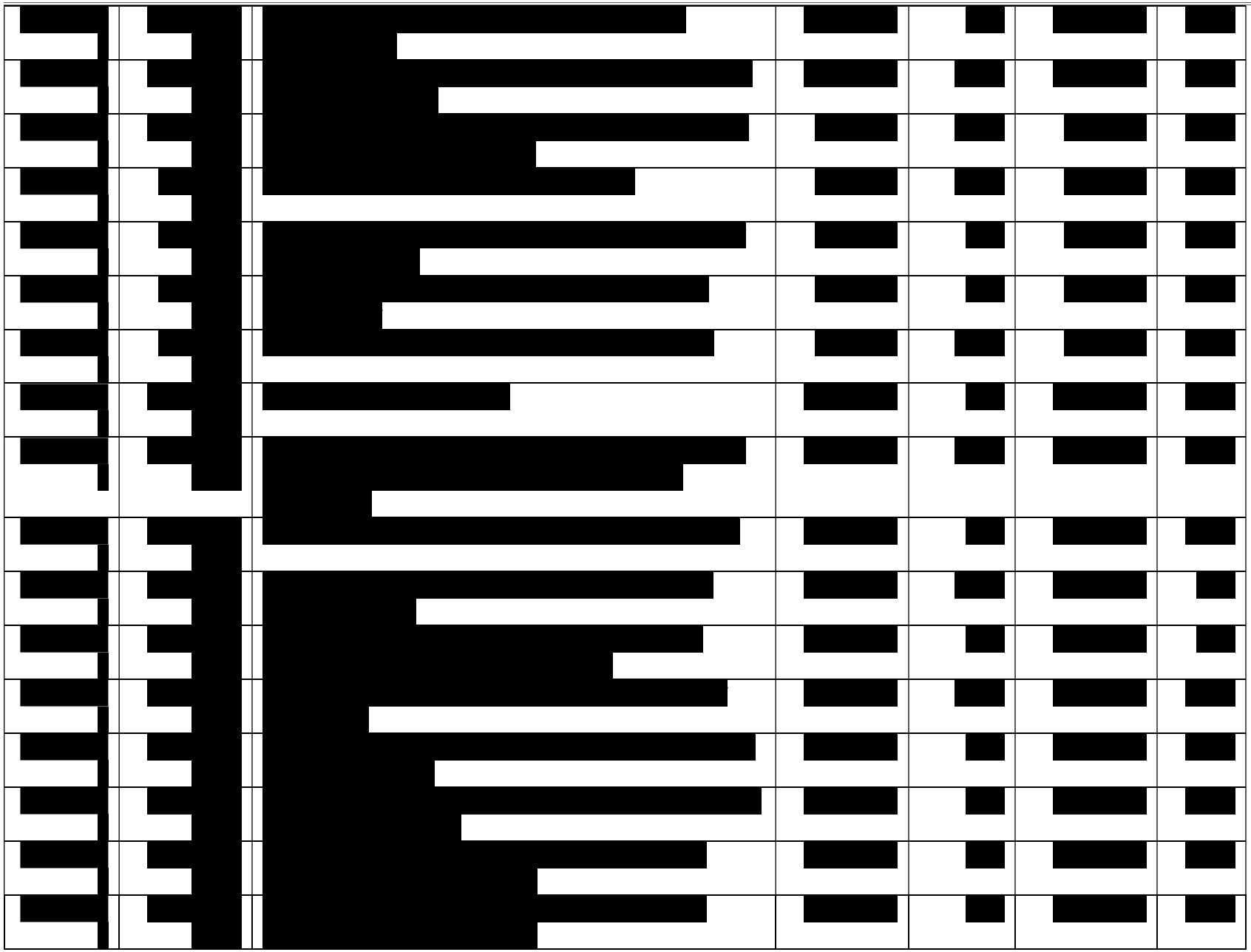






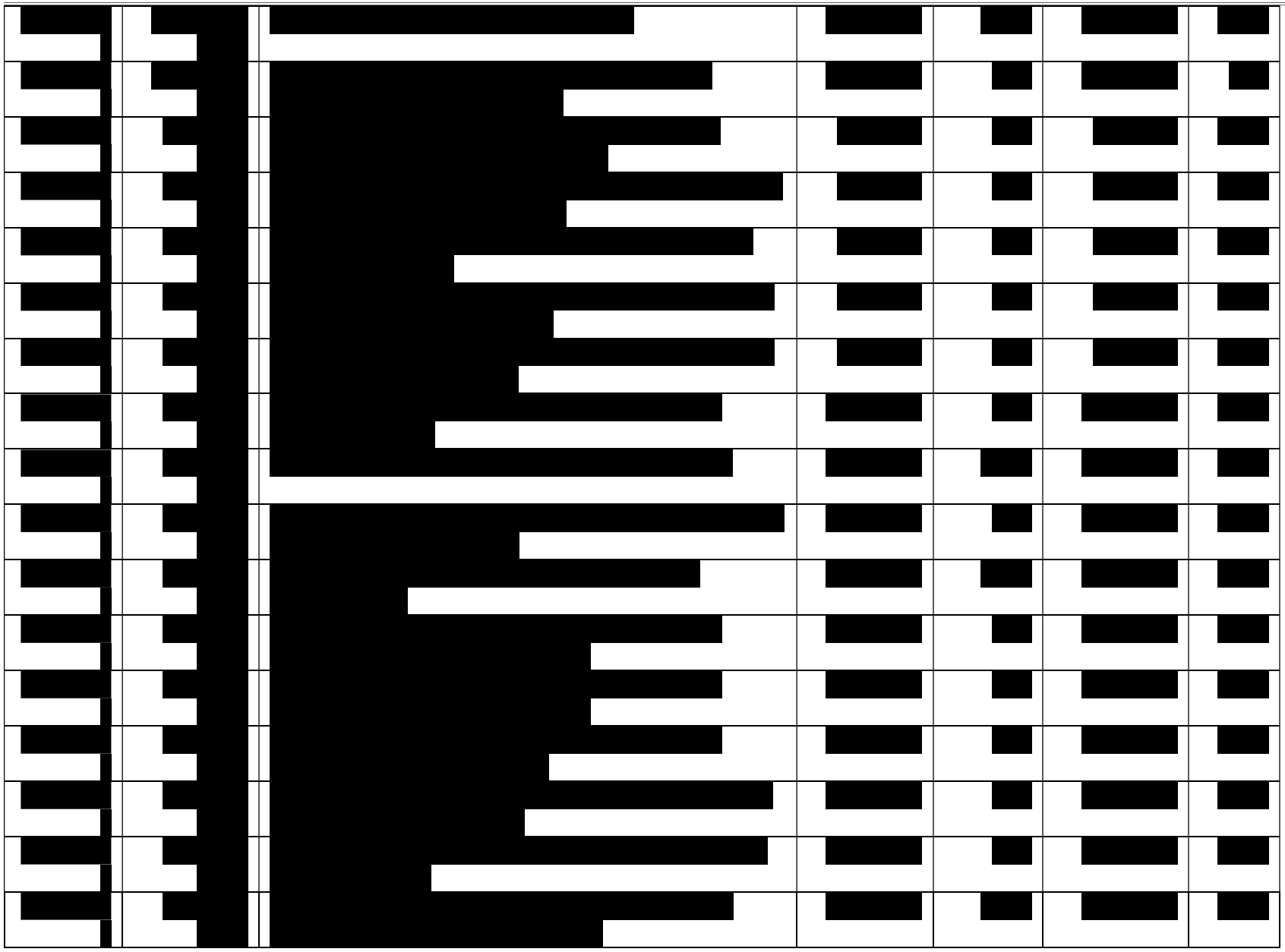


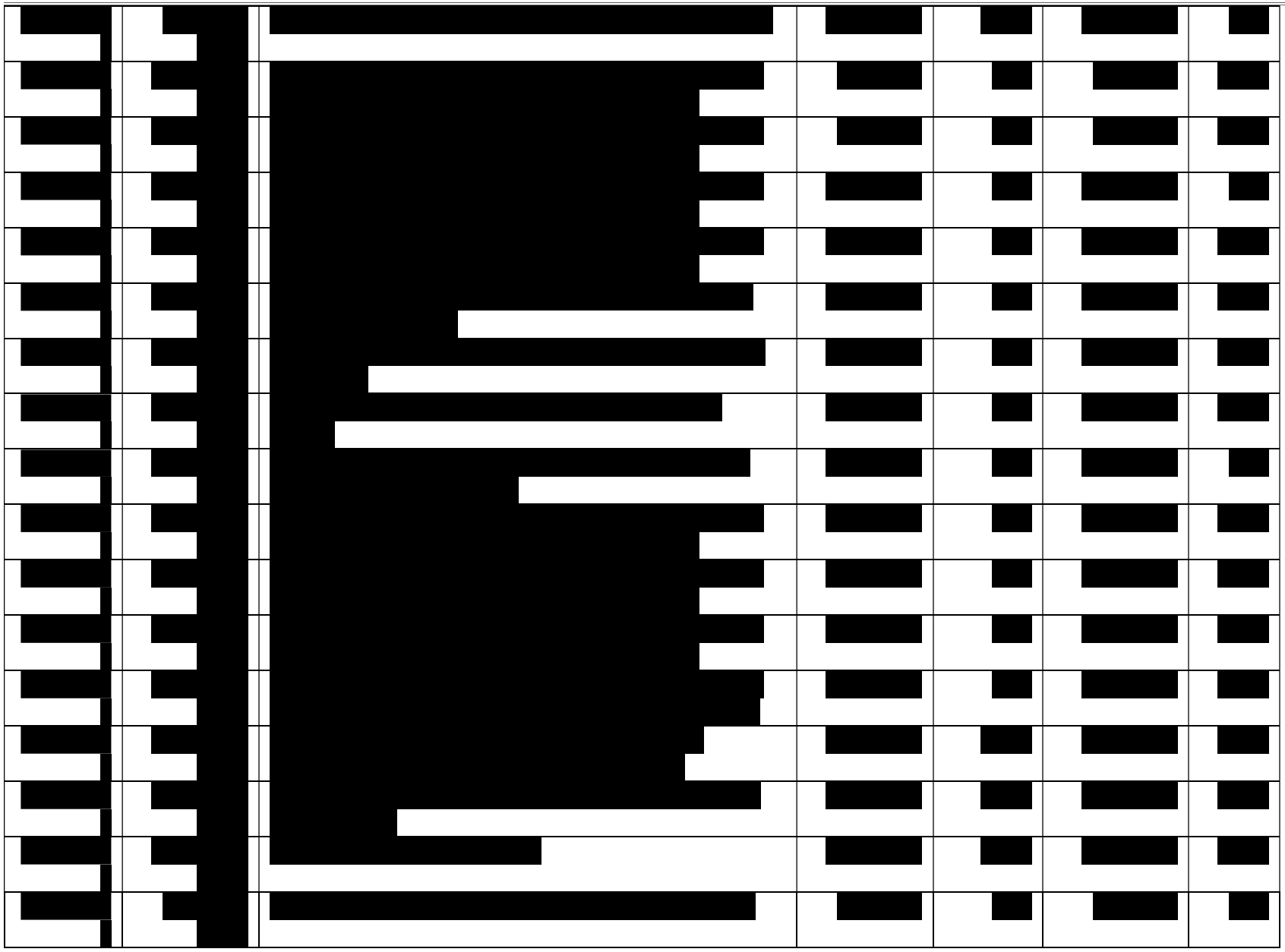


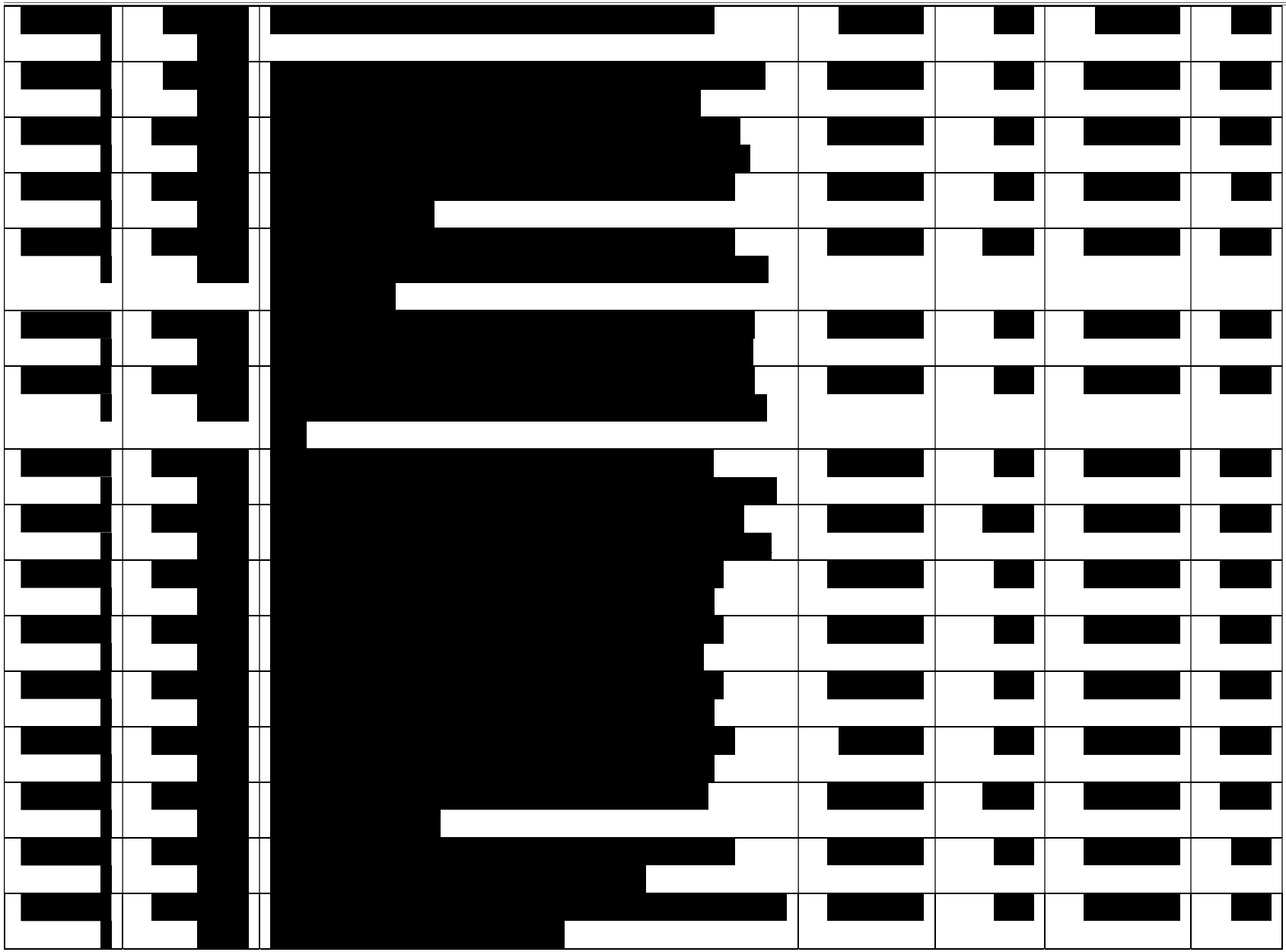




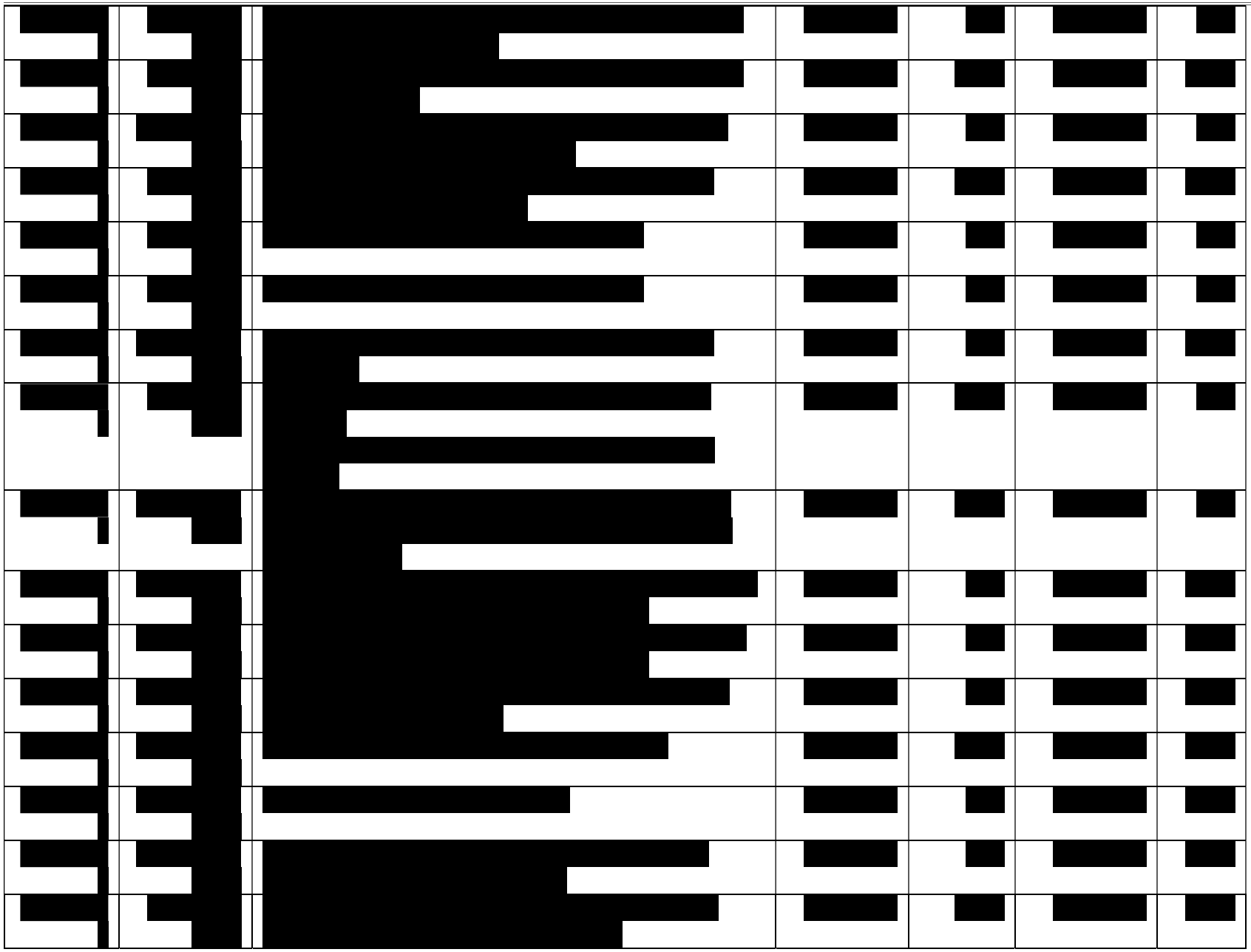


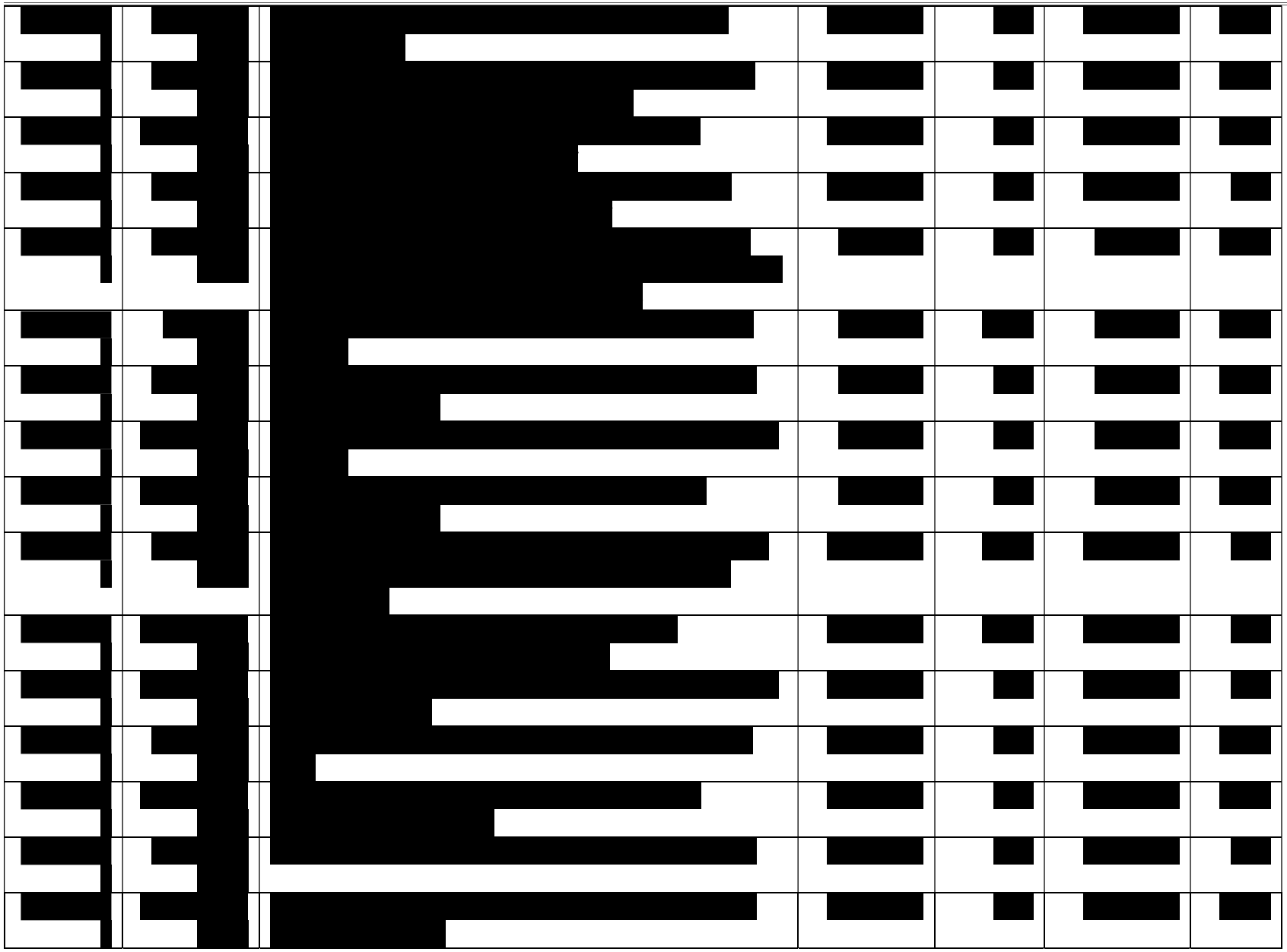


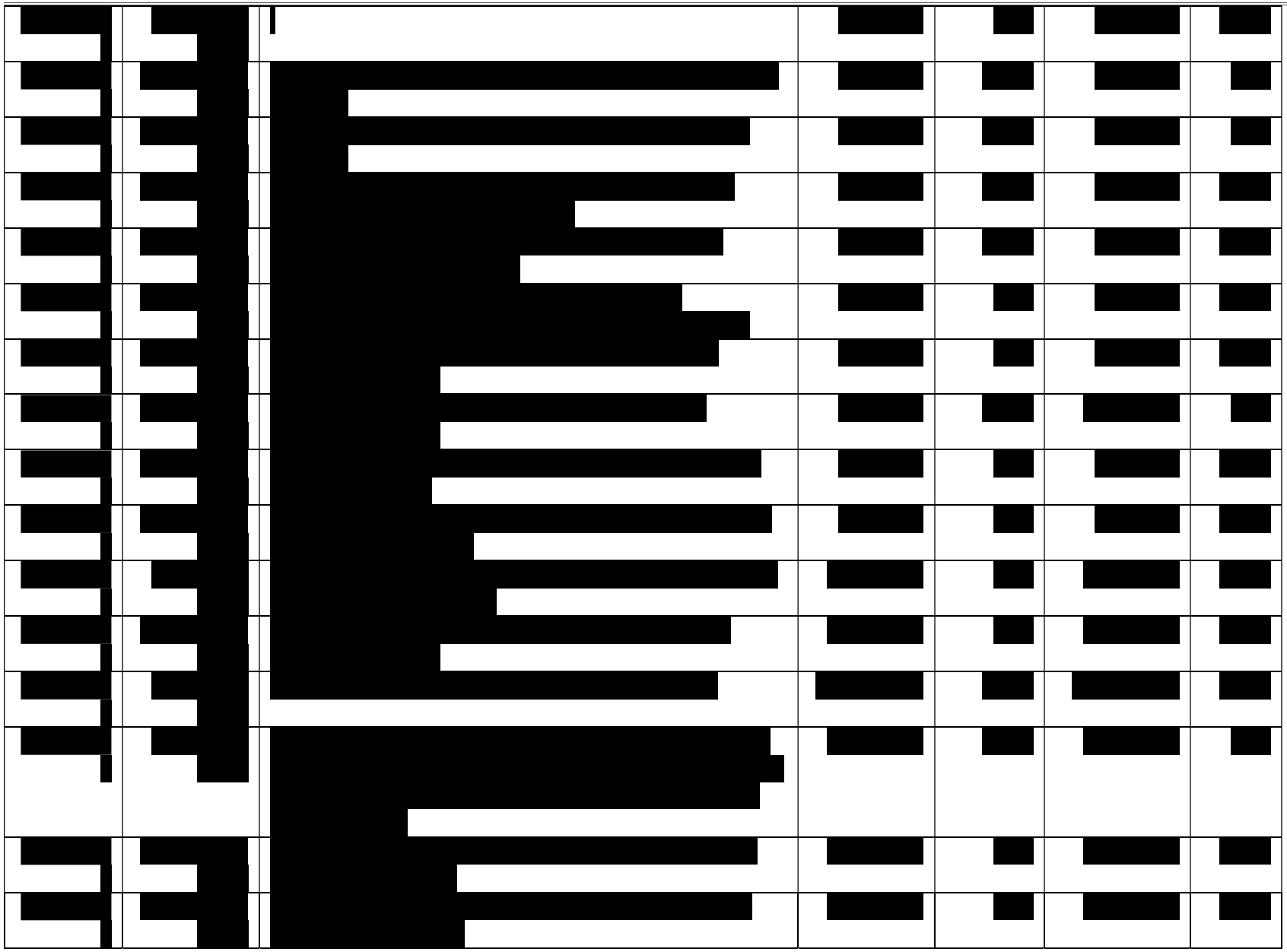








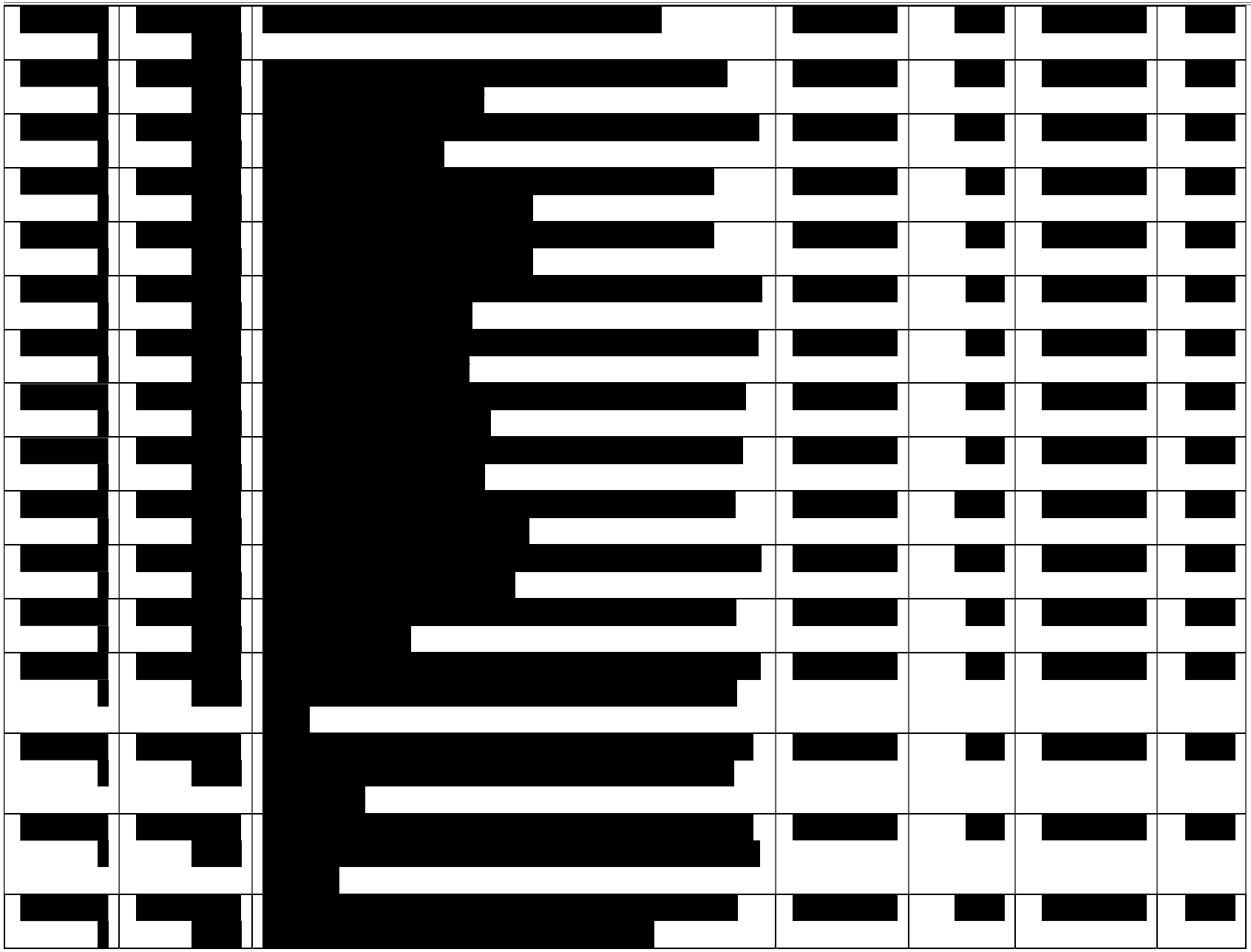


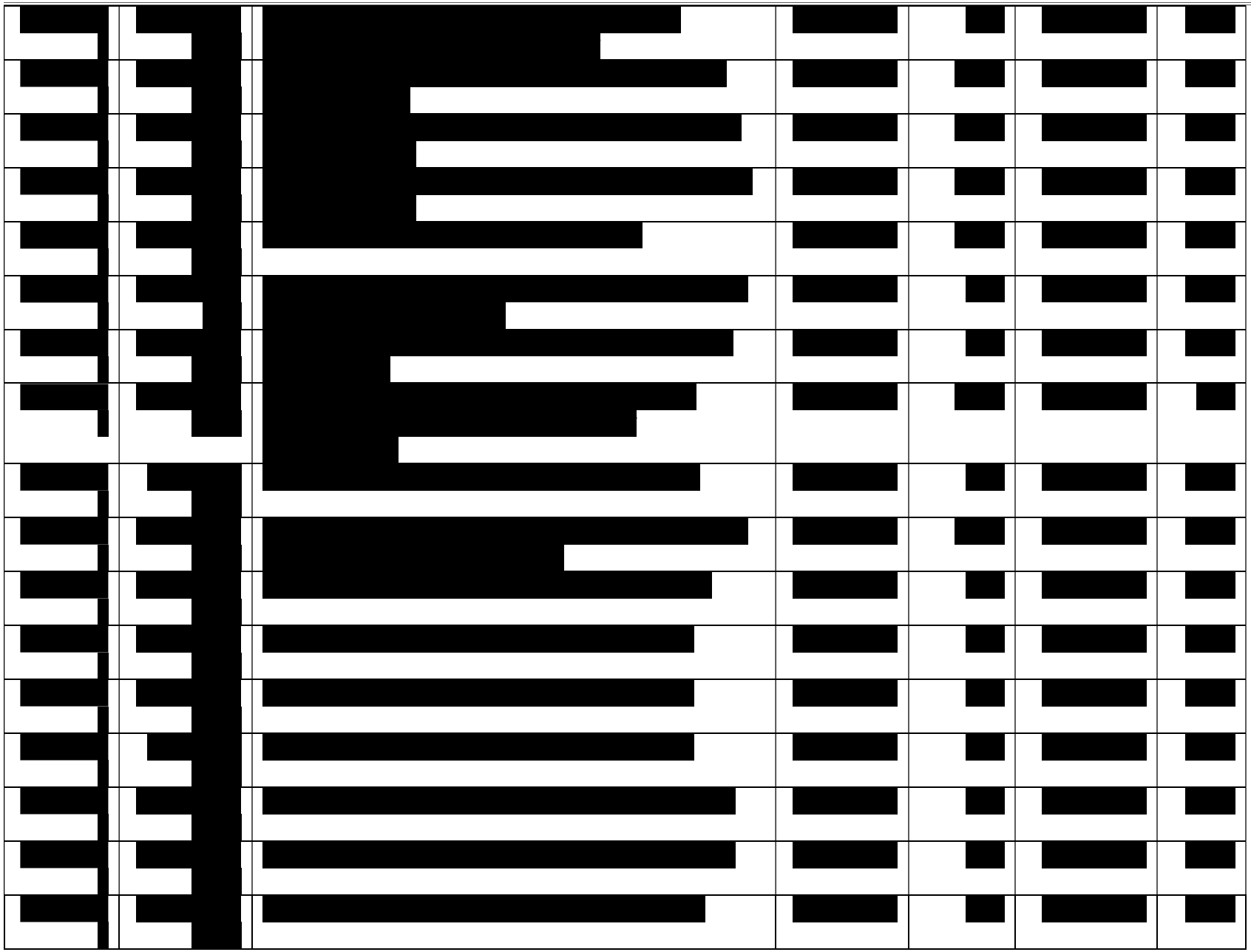




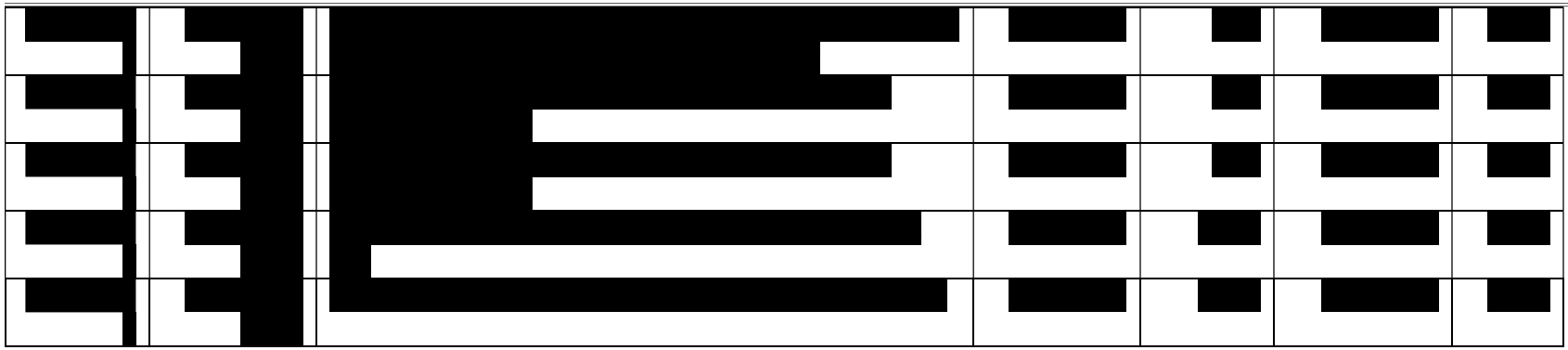












ATTACHMENT 18

Response (amended) to data request CalAdvocates-LIB-A2506017-015, November 1, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

September 11, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-004
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
Cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	August 20, 2025
Due Date:	September 4, 2025
Extension Granted:	September 11, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in accompanying confidentiality declaration. Public disclosure is restricted.

REQUEST NO. 1:

Please provide a list of all inspection programs conducted on the Topaz 1261 circuit from 2010-2020.

For the purposes of this question, "inspection programs" include routine or annual patrols, overhead detailed, infrared inspections, and intrusive pole inspections."

RESPONSE:

Liberty objects to this Question as overbroad and vague and ambiguous as framed. Liberty understands this Question to refer to Liberty inspection programs. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to

and without waiving its objections, Liberty responds as follows: Liberty conducted inspections on the Topaz 1261 Circuit as part of the following inspection programs during the specified time frame:

- Routine patrol inspection
- Detailed inspection
- Intrusive pole inspection
- 2020 system-wide asset survey

REQUEST NO. 2:

Please provide all asset inspection records for each of the programs listed in Question 1 conducted on the Topaz 1261 circuit for 2010-2020.

For the purposes of this question, "inspection records" include forms, photos, and any other records that show how and when the inspection was performed, what the inspector looked at, and what defects, if any, were identified.

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as overbroad and vague and ambiguous as framed. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: As described in *Liberty-03: Prudence of Operations*, in 2020 Liberty modernized its data collection during detailed inspections and transitioned from hard-copy forms to a dynamic electronic detailed inspection form. For detailed inspection records from 2020, please refer to the attachment *Topaz 1261 2020 Inspection Records.pdf* from Liberty's Fulcrum database. Prior to 2020, Liberty conducted detailed inspections and patrols using hard-copy forms and circuit maps. Given the passage of time, Liberty is producing the following records it located after conducting a reasonable search and diligent inquiry for records related to pre-2020 inspections:

- Routine patrol inspection records, in the confidential attachment *CONFIDENTIAL-Topaz 1261 Patrol Records.pdf*
- Detailed inspection forms and related records between 2011-2019, in the attachment *Topaz 1261 Pre-2020 Inspection and Repair Records (Part 1).pdf* as located by Liberty and in the attachment *Topaz 1261 Pre-2020 Inspection and Repair Records (Part 2).pdf* as located by Liberty's outside counsel from the civil litigation associated with the Mountain View Fire

For intrusive pole inspection records, please refer to *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, attached to Liberty's Response to CalAdvocates-LIB-A2506017-001, Question 4.

REQUEST NO. 3:

Please populate the following table regarding asset inspections performed on the Topaz 1261 circuit.

Provide a separate table for each year from 2010 through 2020:

Inspection Program	Total Number of Inspections	Total Number of Quality Program Audits	Total Number of Inspections that failed Quality Program Audits
Patrol			
Detailed			
Infrared			
Intrusive Pole			

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed, including its use of the term "Quality Program Audits." Liberty understands the term "Quality Program Audits" to refer to a formalized quality assurance/quality control (QA/QC) program. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Liberty did not have a formalized program for QA/QC for asset inspections during the specified time frame. While Liberty personnel did audit some inspection records, there was not a standard process for tracking and recording such reviews.

REQUEST NO. 4:

The following questions pertain to Liberty's routine or patrol inspection practices and procedures at the time of the Mountain View Fire.

a) Describe how routine or patrol inspections are conducted (foot, vehicle, etc.).
b) Under what conditions were inspectors expected to stop and exit their vehicles to conduct a more thorough inspection?
c) Provide justifications for the answer in (b).
d) How were inspectors trained to recognize when the conditions warrant further examination?
e) Did Liberty have a practice or procedure in place to record or monitor the number of times where inspectors left their vehicles to perform more detailed inspections?
f) If the answer to (e) is "yes," please provide documentation that is used to track or monitor the number of times this occurred on the Topaz 1261 circuit from 2010 to 2020.
g) If the answer to (e) is "no," please explain why not.
h) Did Liberty have a practice or procedure that provided requirements for conducting routine patrol inspections in circumstances where the inspector determines that conditions warrant further examination?
i) Please provide a copy of any practice manuals or procedures that provided requirements for conducting routine patrol inspections in circumstances where the inspector determines that "conditions warrant further examination".

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) As described in *Liberty-03: Prudence of Operations*, Part V.A.I, Liberty typically conducted patrol inspections by vehicle or helicopter.

b) – c) Consistent with GO 165, patrol inspections are simple visual inspections to identify obvious hazards requiring remediation; Liberty separately conducted detailed inspections, during which inspectors viewed the poles, conductors, and secondary lines from the ground. To the extent required by field conditions to complete a general visual assessment, inspectors are trained to make reasonable efforts to conduct their assessment, which includes exiting the vehicle to find a better vantage point. During patrol inspections, inspectors noted any issues they identified on hard-copy circuit maps, and identified issues were then entered into hard-copy work order packets for remediation.

d) All inspectors were journeymen linemen, who had training and experience working on electrical facilities after completing an apprenticeship program.

e) – i) Please refer to Liberty's response to subparts (b)-(c) of this Question.

REQUEST NO. 5:

This question refers to Liberty's asset inspection practices.

a) How does Liberty define industry-leading in the context of its asset inspection programs?
b) Did Liberty consider its practices as industry-leading at the time of the Mountain View Fire?
c) If so, how often does Liberty review and update its standards to ensure they remain industry-leading?
d) What specific element(s) of Liberty's inspection programs does Liberty consider to be industry-leading?
e) What specific industry benchmarks did Liberty use to determine that its practices are industry-leading?
f) Provide any third-party assessments or rankings that recognize Liberty's inspection as industry-leading.

RESPONSE:

Liberty objects to this Question as overbroad and vague and ambiguous as framed. Liberty understands the reference to "its asset inspection activities" to refer to the inspection programs identified in Liberty's response to Question 1 of this set of data requests. Subject to and without waiving its objections, Liberty responds as follows: Liberty considers "industry-leading" to generally refer to actions or standards of larger electric utilities which go above and beyond industry standards and practices, as that phrase is described in Liberty's Response to Question 6 of this set of data requests.

REQUEST NO. 6:

This question refers to Liberty's asset inspection practices.

a) How does Liberty define "industry practices?"
b) How does Liberty define "industry standards?"

c) Provide an example or clear distinction between "industry practices" and "industry standards."
d) What sources did Liberty use to determine "industry practices" in 2020?
e) How often does Liberty review and update its programs to align with current "industry practices?"
f) What sources did Liberty use to determine "industry standards" in 2020?
g) How often does Liberty review and update its programs to align with current "industry standards?"

RESPONSE:

Liberty objects to this Question as overbroad and vague and ambiguous as framed. Liberty understands "asset inspection practices" to refer to the inspection programs Liberty identified in its response to Question 1 of this set of data requests. Subject to and without waiving these objections, Liberty responds as follows: Liberty understands industry standards and practices to refer to standards, procedures, techniques, and operations generally accepted and followed by electric utilities, including, but not limited to, those required by regulation. As Liberty explained in *Liberty-03: Prudence of Operations*, Liberty inspected its overhead facilities in accordance with regulatory requirements and its programs and policies were consistent with industry practices for wildfire mitigation.

REQUEST NO. 7:

Provide a copy of Liberty's Distribution Integrity Maintenance Program manual in effect at the time of the Mountain View Fire.

RESPONSE:

Liberty did not have any manual titled "Distribution Integrity Maintenance Program."

REQUEST NO. 8:

Regarding asset inspection activities performed on the Topaz 1261 circuit in 2010 through 2020:
a) Identify all internal (i.e., conducted by Liberty) quality assurance or quality control reports regarding asset inspections and maintenance on the Topaz 1261 circuit.
b) Provide a copy of each quality assurance or quality control report identified in part (a).

RESPONSE:

Liberty objects to this Question as vague and ambiguous as to the term "asset inspection activities." Liberty understands "asset inspection activities" to refer to the inspection programs Liberty identified in its response to Question 1 of this set of data requests. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

In the specified time frame, when contractors performed remediation work, a Liberty inspector accompanied them in the field, providing contemporaneous oversight over contractor work. As explained in Liberty's Response to Question 3 of this set of data requests, Liberty did not have a

formalized program for quality assurance/quality control (QA/QC) for asset inspections during the specified time frame.

REQUEST NO. 9:

Regarding asset inspection activities performed on the Topaz 1261 circuit from 2010 through 2020:

a) Identify all external (i.e., conducted by external auditors, consultants, independent evaluators, or other entities) quality assurance or quality control reports regarding asset inspections and maintenance on the Topaz 1261 circuit.
b) Provide a copy of each quality assurance or quality control report identified in part (a).

RESPONSE:

Liberty objects to this Question as overbroad and vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows: Please refer to Liberty's response to Question 3 of this set of data requests.

REQUEST NO. 10:

Regarding infra-red (IR) inspection activities (if applicable) performed on the Topaz 1261 circuit between 2010 and 2020:

a) Please provide an Excel spreadsheet of all recorded operating currents for the Topaz 1261 circuit at the time of each IR inspection.
b) Were IR inspections conducted during a time period when the Topaz 1261 circuit was heavily loaded (e.g., during peak loading months such as July through October, and/or at peak times of the day)? If not, please explain why.

RESPONSE:

Please refer to Liberty's response to Question 3 of CalAdvocates-LIB-A2506017-001.

REQUEST NO. 11:

Cal Advocates understands that IR inspections are most effective when conducted during peak loading months (e.g., July to October), especially at peak times of the day.

a) Is the statement above accurate? Explain why or why not.
b) Please provide Liberty's current standards or procedures regarding how and when to conduct IR inspections on distribution facilities.
c) Did Liberty keep a record of the load at the time the IR inspection was conducted on each segment of the Topaz 1261 circuit? If so, please provide a copy of each record.
d) Did Liberty schedule and conduct IR inspections during the time when the load is at or near the maximum on the Topaz 1261 circuit?
e) Please describe how Liberty conducted the IR inspection, including whether it was conducted from the ground or air.
f) When did Liberty begin to use IR inspections to examine its electric distribution facilities?
g) At the time of the Mountain View Fire, did Liberty have a standard or protocol for how and when to conduct IR inspections?

h) If the answer to (g) is "yes," please provide a copy of the standard
i) If the answer to (g) is "no," please explain why not.

RESPONSE:

Liberty objects to this Question as overbroad and vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows: Please refer to Liberty's response to Question 3 of CalAdvocates-LIB-A2506017-001.

ATTACHEMNT 19

Response to data request CalAdvocates-LIB-A2506017-031, Question 6, October 31, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-031
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	October 16, 2025
Due Date:	October 30, 2025
Extension Granted:	October 31, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in the accompanying confidentiality declaration. Public disclosure is restricted.

REQUEST NO. 1:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 1:

> *As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased.*

a) Did Liberty obtain any asset condition records from NV Energy prior to assuming control of the Topaz 1261 circuit? If so, please provide copies of these records.
b) What actions, if any, did Liberty take to confirm the accuracy, completeness, and reliability of the inherited asset condition records before assuming operational control of Topaz 1261?

c) After acquisition, did Liberty receive any asset condition records for Topaz 1261? If so, please provide copies.
d) Is Liberty able to provide any evidence it conducted a risk assessment or asset condition survey at or before acquisition? If so, please provide copies of such evidence. If not, explain why.
e) Did Liberty perform any internal audit or gap analysis to understand what records were missing at the time of acquisition? If so, please provide copies of such records. If not, explain why.

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and unintelligible as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset condition records for the entire Topaz 1261 Circuit with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in Liberty's response to CalAdvocates-LIB-A2506017-15, Question 1, Liberty's acquisition in approximately 2011 included files, documents, and papers related to the utility's business and assets being purchased. Thus, Liberty obtained asset condition records from NV Energy as part of the transaction. Liberty is in possession of some asset condition records from prior to the time of acquisition. For example, Liberty has located intrusive inspection results from 2010, see confidential attachment *CONFIDENTIAL-2010 Intrusive Pole Inspection Data.xlsx*, and annual GO 165 reports for 2006-2010, see attachment *2006-2010 GO 165 Annual Reports.pdf*. Liberty is continuing to search for pre-acquisition records related to the Topaz 1261 Circuit and will update this response to the extent identified.
b) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
c) Liberty assumes this subpart seeks information regarding records received from NV Energy given Liberty previously provided Cal Advocates with records of its inspections of the Topaz 1261 Circuit after 2011. See Liberty's responses to subpart (a) and CalAdvocates-LIB-A2506017-15, Question 1.
d) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
e) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.

REQUEST NO. 2:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 4:

> *Liberty located routine patrol records for the Topaz 1261 Circuit from the years 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIBA2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. As explained in Liberty-03, Liberty conducted a detailed inspection on the Topaz 1261 Circuit in the first half of*

2020 and Liberty has not located records confirming a patrol of the Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.

a) Does Liberty maintain any policy defining how long routine patrol or detailed inspection documentation must be retained? If so, please provide copies of such policies.
b) Can Liberty confirm whether GO 165 patrols occurred on Topaz 1261 between 2018 and 2020? If not, is Liberty asserting that patrols were completed but undocumented or that they were never conducted?
c) Has Liberty identified any other circuits besides Topaz 1261 for which it cannot locate records to confirm that a patrol inspection occurred during a given period exceeding two years? If so, what are they?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty adheres to regulatory requirements regarding recordkeeping, and those requirements govern Liberty's general approach with respect to the retention of such documentation.
b) Liberty reported in its GO 165 annual reports for 2018-2020 that it completed patrols on all of its circuits in each of those years (54 circuits in 2018 and 55 circuits in 2019 and 2020). Liberty has not located further documentation of patrols of Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.
c) Liberty continues to research patrol inspections on circuits other than the Topaz 1261 Circuit to identify any responsive circuits, and will update its response to the extent identified.

REQUEST NO. 3:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 5:

Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) Please confirm if Liberty reused electronic inspection records (Fulcrum) from the 2020 asset survey to track conditions found in later years from other inspections.
b) If so, please provide a list of the inspections.
c) If so, please confirm whether the original data was overwritten? What controls, if any, preserved data from previous inspection years?
d) Is Liberty able to produce any evidence distinguishing 2020 findings from later updates in Fulcrum? If so, please provide copies. If not, please explain why not.

RESPONSE:

This response contains confidential attachments. Liberty objects to this question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Fulcrum is a geospatial data collection software that houses different applications. Liberty created an application within Fulcrum for data collection and tracking for the 2020 asset survey. Liberty created additional applications in Fulcrum to collect and track inspection data for routine inspections such as GO 165 detailed inspections occurring between 2021 and 2023. Liberty inspectors used the 2020 asset survey application to collect and track data from some non-routine inspections of certain asset locations after the 2020 asset survey. The spreadsheet Liberty provided in response to CalAdvocates-LIB-A2506017-001, Question 2 contains inspection records on the Topaz 1261 Circuit with a creation date of 2020 from the 2020 asset survey application, which may contain data gathered during certain non-routine inspections performed after the 2020 asset survey. This spreadsheet does not contain data collected and tracked in other applications in Fulcrum, such as those created for GO 165 inspections between 2021 and 2023.
b) See Liberty's response to subpart (a).
c) Each update to an inspection record in the 2020 asset survey application was preserved in the record's event history.
d) Liberty is providing the complete output of Fulcrum inspection records from the 2020 asset survey associated with the Topaz 1261 Circuit in confidential attachment *CONFIDENTIAL-CalAdvocates-LIB-A2506017-31-Q3.csv*. This output is arranged by asset inspection record and contains the full event history for each record.

REQUEST NO. 4:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 6:

> *Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.*

a) Provide an Excel file with a list of all due-date extensions under GO 95, Rule 18 for Topaz 1261 from 2016–2021, including reason codes, elapsed time, and interim risk mitigations.
b) Were any GO 95 extension requests documented with interim risk controls?
c) If the answer to subpart (b) is yes, provide evidence supporting your answer.
d) If the answer to subpart (b) is no, explain why.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including to the extent it seeks information

not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty is not aware of records formally tracking due-date extensions on the Topaz 1261 Circuit in the specified time frame.
b) See response to subpart (a). Liberty is also not aware of records formally tracking interim risk controls associated with due-date extensions on the Topaz 1261 Circuit in the specified time frame.
c) N/A
d) N/A

REQUEST NO. 5:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 4:

> *Please see attachment CalAdvocates-LIB-A2506017-001-Q4.xlsx, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.*

a) Is Liberty able to confirm that some poles may have remained in service through the Mountain View Fire without documented closure?
b) If so, identify all poles still in service that were classified as "Non-Restorable" or "Hazard" in 2013.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Based on data contained within Liberty's GIS database, its Fulcrum database, pole replacement work orders, and field verification, Liberty verified that all poles classified as "Non-Restorable" and "Hazard Poles" in attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, except for one, were replaced prior to November 17, 2020. Liberty is working to determine whether the pole located at latitude/longitude location 38.64995, -119.53329 was in service as of November 17, 2020. This pole is a structural support pole and does not support any energized lines.
b) No poles classified as "Non-Restorable" or "Hazard" in the 2013 intrusive inspection results are still in service today.

REQUEST NO. 6:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 9:

Liberty reviewed the reliability of its electric system on an annual basis…These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening.

a) Why did Liberty not initiate the Topaz 1261 reconductoring or hardening project during 2015–2017 when it had already identified the circuit as one of its worst-performing circuits and highest risks on a known failure-prone circuit?
b) Why were reliability metrics (outage frequency) used over ignition metrics when justifying the need for a covered conductor project?
c) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing not to initiate the Topaz 1261 reconductoring or hardening project during 2015-2017.
d) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing to use reliability metrics over ignition metrics when justifying the need for a covered conductor pilot.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and argumentative as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) As stated in Liberty's 2019 GRC, filed in December 2018 (A-18-12-001), Liberty had been working diligently to replace its aging infrastructure since purchasing the utility from NV Energy in 2011, including the re-conductoring of old lines to enhance safety and reliability. Liberty's capital planning process sought to balance the need to prioritize safety and reliability upgrades with the need to provide service to its customers at a reasonable cost. To that end, in its 2019 GRC filing, Liberty requested and was granted approval to fund the Topaz 1261 Rebuild Project and other safety and reliability projects (e.g., the 7300 Line rebuild project) and undertook those projects over time.
b) Liberty objects to this subpart as assuming facts. As described in Liberty's 2019 GRC, Ex. *Liberty-02: Capital* (at pp. 8-9), both reliability metrics and the occurrence of an ignition event on the Topaz 1261 Circuit drove Liberty's decision to pursue the Topaz 1261 Rebuild Project. As stated in Liberty's testimony, the project would both "increase the reliability of the system" and "mitigate the risk of fires." Indeed, underlying events that affect circuit reliability and cause outages, such as wire-to-wire contact or contact with objects, also carry the potential for ignition.
c) Liberty objects to this subpart as assuming facts. Please refer to Ex. *Liberty-02: Capital*, filed in support of Liberty's 2019 GRC filing (A.18-12-001), for further discussion of Liberty's decision to seek funding for the Topaz 1261 Rebuild Project. Between 2015-2017, Liberty invested in safety and reliability upgrades on its system through other capital projects such as the 625/650 Upgrade project. As the Commission concluded in D.15-03-020, the 625/650 Upgrade project "would increase the reliability and safety of electric power delivery within the Lake Tahoe basin," including "reducing risks of wildfire and vegetation-related outages." *See* D.15-03-020 at 47.
d) Liberty objects to this subpart as assuming facts. See Liberty's response to subparts (b)-(c).

ATTACHMENT 20

Response to data request CalAdvocates-LIB-A2506017-031, Question 4, October 31, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-031
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	October 16, 2025
Due Date:	October 30, 2025
Extension Granted:	October 31, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in the accompanying confidentiality declaration. Public disclosure is restricted.

REQUEST NO. 1:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 1:

> *As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased.*

a) Did Liberty obtain any asset condition records from NV Energy prior to assuming control of the Topaz 1261 circuit? If so, please provide copies of these records.
b) What actions, if any, did Liberty take to confirm the accuracy, completeness, and reliability of the inherited asset condition records before assuming operational control of Topaz 1261?

c) After acquisition, did Liberty receive any asset condition records for Topaz 1261? If so, please provide copies.
d) Is Liberty able to provide any evidence it conducted a risk assessment or asset condition survey at or before acquisition? If so, please provide copies of such evidence. If not, explain why.
e) Did Liberty perform any internal audit or gap analysis to understand what records were missing at the time of acquisition? If so, please provide copies of such records. If not, explain why.

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and unintelligible as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset condition records for the entire Topaz 1261 Circuit with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in Liberty's response to CalAdvocates-LIB-A2506017-15, Question 1, Liberty's acquisition in approximately 2011 included files, documents, and papers related to the utility's business and assets being purchased. Thus, Liberty obtained asset condition records from NV Energy as part of the transaction. Liberty is in possession of some asset condition records from prior to the time of acquisition. For example, Liberty has located intrusive inspection results from 2010, see confidential attachment *CONFIDENTIAL-2010 Intrusive Pole Inspection Data.xlsx*, and annual GO 165 reports for 2006-2010, see attachment *2006-2010 GO 165 Annual Reports.pdf*. Liberty is continuing to search for pre-acquisition records related to the Topaz 1261 Circuit and will update this response to the extent identified.
b) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
c) Liberty assumes this subpart seeks information regarding records received from NV Energy given Liberty previously provided Cal Advocates with records of its inspections of the Topaz 1261 Circuit after 2011. See Liberty's responses to subpart (a) and CalAdvocates-LIB-A2506017-15, Question 1.
d) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
e) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.

REQUEST NO. 2:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 4:

> *Liberty located routine patrol records for the Topaz 1261 Circuit from the years 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIBA2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. As explained in Liberty-03, Liberty conducted a detailed inspection on the Topaz 1261 Circuit in the first half of*

2020 and Liberty has not located records confirming a patrol of the Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.

a) Does Liberty maintain any policy defining how long routine patrol or detailed inspection documentation must be retained? If so, please provide copies of such policies.
b) Can Liberty confirm whether GO 165 patrols occurred on Topaz 1261 between 2018 and 2020? If not, is Liberty asserting that patrols were completed but undocumented or that they were never conducted?
c) Has Liberty identified any other circuits besides Topaz 1261 for which it cannot locate records to confirm that a patrol inspection occurred during a given period exceeding two years? If so, what are they?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty adheres to regulatory requirements regarding recordkeeping, and those requirements govern Liberty's general approach with respect to the retention of such documentation.
b) Liberty reported in its GO 165 annual reports for 2018-2020 that it completed patrols on all of its circuits in each of those years (54 circuits in 2018 and 55 circuits in 2019 and 2020). Liberty has not located further documentation of patrols of Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.
c) Liberty continues to research patrol inspections on circuits other than the Topaz 1261 Circuit to identify any responsive circuits, and will update its response to the extent identified.

REQUEST NO. 3:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 5:

Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) Please confirm if Liberty reused electronic inspection records (Fulcrum) from the 2020 asset survey to track conditions found in later years from other inspections.
b) If so, please provide a list of the inspections.
c) If so, please confirm whether the original data was overwritten? What controls, if any, preserved data from previous inspection years?
d) Is Liberty able to produce any evidence distinguishing 2020 findings from later updates in Fulcrum? If so, please provide copies. If not, please explain why not.

RESPONSE:

This response contains confidential attachments. Liberty objects to this question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Fulcrum is a geospatial data collection software that houses different applications. Liberty created an application within Fulcrum for data collection and tracking for the 2020 asset survey. Liberty created additional applications in Fulcrum to collect and track inspection data for routine inspections such as GO 165 detailed inspections occurring between 2021 and 2023. Liberty inspectors used the 2020 asset survey application to collect and track data from some non-routine inspections of certain asset locations after the 2020 asset survey. The spreadsheet Liberty provided in response to CalAdvocates-LIB-A2506017-001, Question 2 contains inspection records on the Topaz 1261 Circuit with a creation date of 2020 from the 2020 asset survey application, which may contain data gathered during certain non-routine inspections performed after the 2020 asset survey. This spreadsheet does not contain data collected and tracked in other applications in Fulcrum, such as those created for GO 165 inspections between 2021 and 2023.
b) See Liberty's response to subpart (a).
c) Each update to an inspection record in the 2020 asset survey application was preserved in the record's event history.
d) Liberty is providing the complete output of Fulcrum inspection records from the 2020 asset survey associated with the Topaz 1261 Circuit in confidential attachment *CONFIDENTIAL-CalAdvocates-LIB-A2506017-31-Q3.csv*. This output is arranged by asset inspection record and contains the full event history for each record.

REQUEST NO. 4:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 6:

> *Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.*

a) Provide an Excel file with a list of all due-date extensions under GO 95, Rule 18 for Topaz 1261 from 2016–2021, including reason codes, elapsed time, and interim risk mitigations.
b) Were any GO 95 extension requests documented with interim risk controls?
c) If the answer to subpart (b) is yes, provide evidence supporting your answer.
d) If the answer to subpart (b) is no, explain why.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including to the extent it seeks information

not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty is not aware of records formally tracking due-date extensions on the Topaz 1261 Circuit in the specified time frame.
b) See response to subpart (a). Liberty is also not aware of records formally tracking interim risk controls associated with due-date extensions on the Topaz 1261 Circuit in the specified time frame.
c) N/A
d) N/A

REQUEST NO. 5:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 4:

> *Please see attachment CalAdvocates-LIB-A2506017-001-Q4.xlsx, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.*

a) Is Liberty able to confirm that some poles may have remained in service through the Mountain View Fire without documented closure?
b) If so, identify all poles still in service that were classified as "Non-Restorable" or "Hazard" in 2013.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Based on data contained within Liberty's GIS database, its Fulcrum database, pole replacement work orders, and field verification, Liberty verified that all poles classified as "Non-Restorable" and "Hazard Poles" in attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, except for one, were replaced prior to November 17, 2020. Liberty is working to determine whether the pole located at latitude/longitude location 38.64995, -119.53329 was in service as of November 17, 2020. This pole is a structural support pole and does not support any energized lines.
b) No poles classified as "Non-Restorable" or "Hazard" in the 2013 intrusive inspection results are still in service today.

REQUEST NO. 6:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 9:

Liberty reviewed the reliability of its electric system on an annual basis…These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening.

a) Why did Liberty not initiate the Topaz 1261 reconductoring or hardening project during 2015–2017 when it had already identified the circuit as one of its worst-performing circuits and highest risks on a known failure-prone circuit?
b) Why were reliability metrics (outage frequency) used over ignition metrics when justifying the need for a covered conductor project?
c) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing not to initiate the Topaz 1261 reconductoring or hardening project during 2015-2017.
d) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing to use reliability metrics over ignition metrics when justifying the need for a covered conductor pilot.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and argumentative as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) As stated in Liberty's 2019 GRC, filed in December 2018 (A-18-12-001), Liberty had been working diligently to replace its aging infrastructure since purchasing the utility from NV Energy in 2011, including the re-conductoring of old lines to enhance safety and reliability. Liberty's capital planning process sought to balance the need to prioritize safety and reliability upgrades with the need to provide service to its customers at a reasonable cost. To that end, in its 2019 GRC filing, Liberty requested and was granted approval to fund the Topaz 1261 Rebuild Project and other safety and reliability projects (e.g., the 7300 Line rebuild project) and undertook those projects over time.
b) Liberty objects to this subpart as assuming facts. As described in Liberty's 2019 GRC, Ex. *Liberty-02: Capital* (at pp. 8-9), both reliability metrics and the occurrence of an ignition event on the Topaz 1261 Circuit drove Liberty's decision to pursue the Topaz 1261 Rebuild Project. As stated in Liberty's testimony, the project would both "increase the reliability of the system" and "mitigate the risk of fires." Indeed, underlying events that affect circuit reliability and cause outages, such as wire-to-wire contact or contact with objects, also carry the potential for ignition.
c) Liberty objects to this subpart as assuming facts. Please refer to Ex. *Liberty-02: Capital*, filed in support of Liberty's 2019 GRC filing (A.18-12-001), for further discussion of Liberty's decision to seek funding for the Topaz 1261 Rebuild Project. Between 2015-2017, Liberty invested in safety and reliability upgrades on its system through other capital projects such as the 625/650 Upgrade project. As the Commission concluded in D.15-03-020, the 625/650 Upgrade project "would increase the reliability and safety of electric power delivery within the Lake Tahoe basin," including "reducing risks of wildfire and vegetation-related outages." *See* D.15-03-020 at 47.
d) Liberty objects to this subpart as assuming facts. See Liberty's response to subparts (b)-(c).

ATTACHMENT 21

Response (amended) to data request CalAdvocates-LIB-A2506017-031, October 24, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-031
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	October 16, 2025
Due Date:	October 30, 2025
Extension Granted:	October 31, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in the accompanying confidentiality declaration. Public disclosure is restricted.

REQUEST NO. 1:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 1:

> *As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased.*

a) Did Liberty obtain any asset condition records from NV Energy prior to assuming control of the Topaz 1261 circuit? If so, please provide copies of these records.
b) What actions, if any, did Liberty take to confirm the accuracy, completeness, and reliability of the inherited asset condition records before assuming operational control of Topaz 1261?

c) After acquisition, did Liberty receive any asset condition records for Topaz 1261? If so, please provide copies.
d) Is Liberty able to provide any evidence it conducted a risk assessment or asset condition survey at or before acquisition? If so, please provide copies of such evidence. If not, explain why.
e) Did Liberty perform any internal audit or gap analysis to understand what records were missing at the time of acquisition? If so, please provide copies of such records. If not, explain why.

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and unintelligible as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset condition records for the entire Topaz 1261 Circuit with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in Liberty's response to CalAdvocates-LIB-A2506017-15, Question 1, Liberty's acquisition in approximately 2011 included files, documents, and papers related to the utility's business and assets being purchased. Thus, Liberty obtained asset condition records from NV Energy as part of the transaction. Liberty is in possession of some asset condition records from prior to the time of acquisition. For example, Liberty has located intrusive inspection results from 2010, see confidential attachment *CONFIDENTIAL-2010 Intrusive Pole Inspection Data.xlsx*, and annual GO 165 reports for 2006-2010, see attachment *2006-2010 GO 165 Annual Reports.pdf*. Liberty is continuing to search for pre-acquisition records related to the Topaz 1261 Circuit and will update this response to the extent identified.
b) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
c) Liberty assumes this subpart seeks information regarding records received from NV Energy given Liberty previously provided Cal Advocates with records of its inspections of the Topaz 1261 Circuit after 2011. See Liberty's responses to subpart (a) and CalAdvocates-LIB-A2506017-15, Question 1.
d) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
e) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.

REQUEST NO. 2:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 4:

> *Liberty located routine patrol records for the Topaz 1261 Circuit from the years 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIBA2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. As explained in Liberty-03, Liberty conducted a detailed inspection on the Topaz 1261 Circuit in the first half of*

2020 and Liberty has not located records confirming a patrol of the Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.

a) Does Liberty maintain any policy defining how long routine patrol or detailed inspection documentation must be retained? If so, please provide copies of such policies.
b) Can Liberty confirm whether GO 165 patrols occurred on Topaz 1261 between 2018 and 2020? If not, is Liberty asserting that patrols were completed but undocumented or that they were never conducted?
c) Has Liberty identified any other circuits besides Topaz 1261 for which it cannot locate records to confirm that a patrol inspection occurred during a given period exceeding two years? If so, what are they?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty adheres to regulatory requirements regarding recordkeeping, and those requirements govern Liberty's general approach with respect to the retention of such documentation.
b) Liberty reported in its GO 165 annual reports for 2018-2020 that it completed patrols on all of its circuits in each of those years (54 circuits in 2018 and 55 circuits in 2019 and 2020). Liberty has not located further documentation of patrols of Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.
c) Liberty continues to research patrol inspections on circuits other than the Topaz 1261 Circuit to identify any responsive circuits, and will update its response to the extent identified.

REQUEST NO. 3:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 5:

Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) Please confirm if Liberty reused electronic inspection records (Fulcrum) from the 2020 asset survey to track conditions found in later years from other inspections.
b) If so, please provide a list of the inspections.
c) If so, please confirm whether the original data was overwritten? What controls, if any, preserved data from previous inspection years?
d) Is Liberty able to produce any evidence distinguishing 2020 findings from later updates in Fulcrum? If so, please provide copies. If not, please explain why not.

RESPONSE:

This response contains confidential attachments. Liberty objects to this question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Fulcrum is a geospatial data collection software that houses different applications. Liberty created an application within Fulcrum for data collection and tracking for the 2020 asset survey. Liberty created additional applications in Fulcrum to collect and track inspection data for routine inspections such as GO 165 detailed inspections occurring between 2021 and 2023. Liberty inspectors used the 2020 asset survey application to collect and track data from some non-routine inspections of certain asset locations after the 2020 asset survey. The spreadsheet Liberty provided in response to CalAdvocates-LIB-A2506017-001, Question 2 contains inspection records on the Topaz 1261 Circuit with a creation date of 2020 from the 2020 asset survey application, which may contain data gathered during certain non-routine inspections performed after the 2020 asset survey. This spreadsheet does not contain data collected and tracked in other applications in Fulcrum, such as those created for GO 165 inspections between 2021 and 2023.
b) See Liberty's response to subpart (a).
c) Each update to an inspection record in the 2020 asset survey application was preserved in the record's event history.
d) Liberty is providing the complete output of Fulcrum inspection records from the 2020 asset survey associated with the Topaz 1261 Circuit in confidential attachment *CONFIDENTIAL-CalAdvocates-LIB-A2506017-31-Q3.csv*. This output is arranged by asset inspection record and contains the full event history for each record.

REQUEST NO. 4:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 6:

> *Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.*

a) Provide an Excel file with a list of all due-date extensions under GO 95, Rule 18 for Topaz 1261 from 2016–2021, including reason codes, elapsed time, and interim risk mitigations.
b) Were any GO 95 extension requests documented with interim risk controls?
c) If the answer to subpart (b) is yes, provide evidence supporting your answer.
d) If the answer to subpart (b) is no, explain why.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including to the extent it seeks information

not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty is not aware of records formally tracking due-date extensions on the Topaz 1261 Circuit in the specified time frame.
b) See response to subpart (a). Liberty is also not aware of records formally tracking interim risk controls associated with due-date extensions on the Topaz 1261 Circuit in the specified time frame.
c) N/A
d) N/A

REQUEST NO. 5:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 4:

> *Please see attachment CalAdvocates-LIB-A2506017-001-Q4.xlsx, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.*

a) Is Liberty able to confirm that some poles may have remained in service through the Mountain View Fire without documented closure?
b) If so, identify all poles still in service that were classified as "Non-Restorable" or "Hazard" in 2013.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Based on data contained within Liberty's GIS database, its Fulcrum database, pole replacement work orders, and field verification, Liberty verified that all poles classified as "Non-Restorable" and "Hazard Poles" in attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, except for one, were replaced prior to November 17, 2020. Liberty is working to determine whether the pole located at latitude/longitude location 38.64995, -119.53329 was in service as of November 17, 2020. This pole is a structural support pole and does not support any energized lines.
b) No poles classified as "Non-Restorable" or "Hazard" in the 2013 intrusive inspection results are still in service today.

REQUEST NO. 6:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 9:

Liberty reviewed the reliability of its electric system on an annual basis…These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening.

a) Why did Liberty not initiate the Topaz 1261 reconductoring or hardening project during 2015–2017 when it had already identified the circuit as one of its worst-performing circuits and highest risks on a known failure-prone circuit?
b) Why were reliability metrics (outage frequency) used over ignition metrics when justifying the need for a covered conductor project?
c) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing not to initiate the Topaz 1261 reconductoring or hardening project during 2015-2017.
d) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing to use reliability metrics over ignition metrics when justifying the need for a covered conductor pilot.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and argumentative as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) As stated in Liberty's 2019 GRC, filed in December 2018 (A-18-12-001), Liberty had been working diligently to replace its aging infrastructure since purchasing the utility from NV Energy in 2011, including the re-conductoring of old lines to enhance safety and reliability. Liberty's capital planning process sought to balance the need to prioritize safety and reliability upgrades with the need to provide service to its customers at a reasonable cost. To that end, in its 2019 GRC filing, Liberty requested and was granted approval to fund the Topaz 1261 Rebuild Project and other safety and reliability projects (e.g., the 7300 Line rebuild project) and undertook those projects over time.
b) Liberty objects to this subpart as assuming facts. As described in Liberty's 2019 GRC, Ex. *Liberty-02: Capital* (at pp. 8-9), both reliability metrics and the occurrence of an ignition event on the Topaz 1261 Circuit drove Liberty's decision to pursue the Topaz 1261 Rebuild Project. As stated in Liberty's testimony, the project would both "increase the reliability of the system" and "mitigate the risk of fires." Indeed, underlying events that affect circuit reliability and cause outages, such as wire-to-wire contact or contact with objects, also carry the potential for ignition.
c) Liberty objects to this subpart as assuming facts. Please refer to Ex. *Liberty-02: Capital*, filed in support of Liberty's 2019 GRC filing (A.18-12-001), for further discussion of Liberty's decision to seek funding for the Topaz 1261 Rebuild Project. Between 2015-2017, Liberty invested in safety and reliability upgrades on its system through other capital projects such as the 625/650 Upgrade project. As the Commission concluded in D.15-03-020, the 625/650 Upgrade project "would increase the reliability and safety of electric power delivery within the Lake Tahoe basin," including "reducing risks of wildfire and vegetation-related outages." *See* D.15-03-020 at 47.
d) Liberty objects to this subpart as assuming facts. See Liberty's response to subparts (b)-(c).

ATTACHMENT 22

Response (amended) to data request CalAdvocates-LIB-A2506017-001, including tab "Detailed Inspection Results" in the attachment CalAdvocates-LIB-A2506017-001-Q2.xlsx., September 10, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

November 1, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-015
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	September 17, 2025
Due Date:	October 1, 2025
Extension Granted:	October 6, 2025
Response Date:	October 6, 2025
Amended Response Date:	November 1, 2025

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1, where it states:

Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy.

REQUEST NO. 1:

a) Did Liberty request NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?
b) If the answer to (a) is "no," please provide an explanation.
c) If the answer to (a) is "yes," please provide all asset inspection and maintenance

records provided to Liberty from NV Energy.

d) If the records identified in (c) exist exclusively in paper format, please provide sufficient detail to permit evaluation of potential digitization or on-site review, including:
    1. An estimate of the total volume of paper records;
    2. The specific location(s) where such records are maintained; and
    3. The approximate date of the earliest available records.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset inspection and maintenance records for the entire utility with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in "Regulatory Commitments" at the time of purchase (attached as Appendix 3 to D.10-10-017), CalPeco planned to conduct business in the same or similar manner as it had under Sierra Pacific's ownership, with regard to the utility's core functions. CalPeco committed, to the extent practicable, to retain the same operations team responsible for operating the utility under Sierra Pacific's ownership, including an intent to maintain local headquarters and to offer then-current operations employees employment with CalPeco at the same locations with responsibilities consistent with their then-existing roles.

    As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased. In addition, on a going forward basis, the two utilities agreed to provide each other reasonable access to their properties to permit inspection of the integrated systems, to perform any relevant work, and to all data, including maintenance records, with respect to the operation and maintenance of each utility's respective portions of the integrated electric systems.
b) See Liberty's response to subpart (a).
c) Liberty is in possession of some inspection and maintenance records from prior to the time of acquisition. Please refer to Liberty's response to CalAdvocates-LIB-A2507017-031, Question 1, subpart (a) and attachments contained therein, which includes some examples of such records.
d) The inspection and maintenance records Liberty has retained from prior to the acquisition in a mix of paper and digital format. Review of Liberty's off-site storage index suggests that Liberty has copies of some inspection and maintenance records dating back to approximately 2008 and some engineering records dating back to the 1970s.

REQUEST NO. 2:

a) Did Liberty conduct a review of NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?

b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what conclusions were reached, and please provide any documentation relevant to (a).
d) If the answer to (a) is "yes," what methodology did Liberty utilize in 2011 to assess the condition of NV Energy's assets?
e) If the answer to (a) is "yes," did Liberty request that NV Energy perform any corrective actions prior to completing the purchase?
f) If the answer to (e) is "yes," list and describe the actions that Liberty requested NV Energy perform and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

REQUEST NO. 3:

a) *After* completing the 2011 purchase, did Liberty conduct a review of NV Energy's asset inspection and maintenance records?
b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what findings resulted, and please provide copies.
d) Following the acquisition, did Liberty implement any system-wide corrective action initiatives based on the condition of NV Energy's assets?
e) If the answer to (d) is "no," please explain why not.
f) If the answer to (d) is "yes," please describe what actions were taken, what were the outcomes, and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1 where it states:

Liberty conducted routine patrols using hard-copy circuit maps. See Liberty-03 at 20. After a reasonable search and diligent inquiry, the Topaz 1261 maps used for Liberty's patrols from 2013, 2015, and 2017 do not indicate any corrective work identified by those patrols.

REQUEST NO. 4:

a) When did Liberty first begin performing routine patrols on the Topaz 1261 circuit?
b) Did Liberty conduct a routine patrol in 2012 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
c) Did Liberty conduct a routine patrol in 2014 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
d) Did Liberty conduct a routine patrol in 2016 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
e) Did Liberty conduct a routine patrol in 2018 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
f) Did Liberty conduct a routine patrol in 2019 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
g) Did Liberty conduct a routine patrol in 2020 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.

AMENDED RESPONSE:

Liberty objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty purchased the California utility system from NV Energy in approximately 2011. After a reasonable search and diligent inquiry, the earliest patrol record for the Topaz 1261 Circuit that Liberty has located is from 2013.
b) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2012.
c) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2014.

d) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2016.
e) Liberty reported in its GO 165 annual report for 2018 that it completed patrols on all 54 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2018.
f) Liberty reported in its GO 165 annual report for 2019 that it completed patrols on all 55 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2019.
g) As explained in *Liberty-03*, Liberty conducted a detailed inspection of the Topaz 1261 Circuit in 2020 and provided those inspection records in its responses to CalAdvocates-LIB-A2506017-001, Question 2 and CalAdvocates-LIB-A2506017-004, Question 2. Liberty also reported in its GO 165 annual report for 2020 that it completed patrols on all 55 of its circuits in that year.

The following questions refer to the Excel file *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, Liberty provided in response to CalAdvocates-LIB-001, question 2.

REQUEST NO. 5:

Referring to the "Detailed Inspection Results" tab:
a) Please clarify the difference between the dates listed in column C ("Inspection Date") and those in column H ("Created Date")?
b) In some cases, the dates in column H ("Created Date") appear earlier than the corresponding dates in column C ("Inspection Date"). Please explain why this occurs?
c) Several cells in column I ("Due Date") are blank. Please clarify what an empty cell in this column represents?
d) In certain instances, the dates in column I ("Due Date") are earlier than the dates in column C ("Inspection Date"). Please explain why this discrepancy exists?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) The dates listed in column C ("Inspection Date") correspond to the dates when an inspector performed a detailed inspection of the relevant pole. The dates listed in column H ("Created Date") correspond to the dates when the inspection record was created in Fulcrum in anticipation of an upcoming inspection. The dates in column H are sometimes earlier than the corresponding dates in column C because an inspection record was typically created prior to the inspection. For some poles, the "created date" and the "inspection date" may be the same, in instances where the inspection record for that pole was created in Fulcrum at the time of the inspection.
b) See Liberty's response to subpart (a).
c) The cells in column I without any data could be blank for a variety of reasons. As part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues identified in the system from prior inspections. Thus, cells in column I could be blank because, for example, Liberty had already addressed the issues identified at the time due dates were systematically populated in the database, or because no issues requiring remediation were identified.
d) Liberty has not identified instances in *CalAdvocates-LIB-A2506017-001-Q2.xlsx* where the dates in column I are earlier than the dates in Column C.

REQUEST NO. 6:

Referring to the "Repaired after Nov 17 2020" tab:

a) In some cases, the dates in column L ("Repair Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
b) In some cases, multiple conditions are listed in column O ("Condition Codes"), but only a single date is recorded in column L ("Repair Date"). Please clarify how these are reconciled.
c) Several dates in column G ("Created Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
d) In many cases, the dates in column I ("Due Date") are set up to five years after the dates in column C ("Inspection Date"). Please clarify how these due dates are determined.
e) Certain assets with "Level 3" priority show "Repair Dates" in column L that occur after the "Due Dates" in column I. Please clarify why this occurs.
f) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning due dates when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: See Liberty's response to Question 5 of this set of data requests.

a) The inspection records in which the dates in column L appear earlier than the dates in column C poles correspond to poles that were replaced in 2020 for which Liberty did not have specific dates of replacement. The date 01/01/2020 was used for those poles to

indicate that the pole replacements were completed in 2020.

b) Due to limitations in Liberty's data collection form during the early stages of its transition from using hard-copy forms to a dynamic electronic inspection form in Fulcrum, only one "Repair Date" field was available for each inspection record for inspections conducted in 2020. A field was available to an inspector to indicate whether all repairs had been completed and another field was available in which to input comments regarding the individual repair(s), including the status of individual conditions identified. Liberty has refined its data collection and repair workflow processes since 2020 and each repair is now tracked as a separate event record.
c) Please refer to Liberty's response to Question 5, subparts (a)-(b) of this set of data requests.
d) The inspection records in which the dates in column I are set up to five years after the dates in column C correspond to poles where the issue(s) identified was assigned a priority Level 3. Consistent with GO 95, Rule 18, Level 3 issues presented low potential safety or reliability risk and Liberty would take action to address them within the timeframes specified by GO 95. Liberty generally used 59 months as the due date for Level 3 issues.
e) As Liberty explained in its response to CalAdvocates-LIB-A2506017-001, Question 5, Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.
f) As set forth in Liberty's response to Question 5(c) of this set of data requests, as part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues in the system from prior inspections corresponding to the timelines set forth in GO 95, Rule 18, based on the date when inspections were performed.

REQUEST NO. 7:

At the time of the Mountain View Fire:

a) As Liberty understands General Order 95, please describe the distinction between Level 1 and Level 2 corrective conditions.
b) As Liberty understands General Order 95, please describe the distinction between Level 2 and Level 3 corrective conditions.
c) Did Liberty document the decision-making process for assigning corrective levels (Level 1, 2, or 3)? If so, explain how. If not, explain why not.
d) What internal training or guidance did Liberty provide to inspectors to ensure alignment with General Order 95 when classifying corrective conditions?
e) What quality assurance measures did Liberty apply to ensure consistency in corrective level assignments across different inspectors or inspection types?
f) Who was responsible for determining whether a corrective condition is classified as Level 1, 2 or Level 3?

g) Please clarify the criteria Liberty used to escalate a condition from Level 3 to Level 2, if applicable?
h) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning priorities (Level 1, Level 2, or Level 3) when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) In accordance with GO 95, Liberty understood Level 1 conditions as those posing immediate safety or reliability risks with high potential for impact, which should be addressed immediately. Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes.
b) Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes. Liberty understood Level 3 conditions as those with a low potential safety or reliability risk, which Liberty attempted to address within the specified timeframes.
c) As evidenced in *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 2, inspectors selected from a menu of condition codes and assigned a priority level to the inspection record. The dynamic electronic inspection form in Fulcrum that inspectors began using for detailed inspections in 2020 also allowed inspectors to input comments regarding the conditions they identified.
d) As explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program. These inspectors classified conditions as Level 1, 2, or 3 in the process of conducting inspections in the field, based on their understanding of GO 95 and their experience and training.
e) Though Liberty did not have a formal quality assurance process, as explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program.
f) See Liberty's response to subpart (d).
g) See Liberty's response to subpart (b).
h) See Liberty's response to subpart (d).

REQUEST NO. 8:

From 2011 to the time of the Mountain View Fire:

a) How many Level 1 corrective work orders did Liberty identify during routine patrol inspections?
    a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
        i. Structure number
        ii. Work Order Number

iii. Notification Number (if applicable)
iv. Equipment Number
v. Inspection Date
vi. Equipment Type
vii. HFTD/HFRA Tier
viii. Priority
ix. Ignition Risk (Y/N)
x. Date Created
xi. Due Date
xii. Revised Due Date (if applicable)
xiii. Priority Change (if applicable)
xiv. Reason for Change (if applicable)
xv. Date Completed
xvi. Latitude in degrees
xvii. Longitude in degrees

b) How many Level 1 corrective work orders did Liberty identify during detailed inspections?
   a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
      i. Structure number
      ii. Work Order Number
      iii. Notification Number (if applicable)
      iv. Equipment Number
      v. Inspection Date
      vi. Equipment Type
      vii. HFTD/HFRA Tier
      viii. Priority
      ix. Ignition Risk (Y/N)
      x. Date Created
      xi. Due Date
      xii. Revised Due Date (if applicable)
      xiii. Priority Change (if applicable)
      xiv. Reason for Change (if applicable)
      xv. Date Completed
      xvi. Latitude in degrees
      xvii. Longitude in degrees

AMENDED RESPONSE:

a) Liberty objects to this Question as vague, ambiguous, and overbroad. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows: Liberty transitioned to Fulcrum for routine patrol records in approximately 2023. Prior to that time, inspectors recorded the results of routine patrol inspections on hard-copy maps and thus, Liberty is unable to provide an Excel file with the requested information for routine patrol inspections in the relevant timeframe due to the significant burden involved with compiling such a file based on

identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

b) Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

Liberty is producing the data requested by this Question in the attachment *CalAdvocates-LIB-A2506017-015-Q8.xlsx*. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records, and refined the information in those fields for accuracy based on a review of the full event history of inspection records with priority level field set as Level 1. As described in *Liberty-03: Prudence of Operations*, prior to 2020, inspectors recorded the results of detailed inspections on hard-copy forms and thus, Liberty is unable to provide an Excel file with the requested information for detailed inspections prior to 2020 due to the significant burden involved with compiling such a file based on identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

REQUEST NO. 9:

At the time of the Mountain View Fire:

a) Did Liberty have a policy for replacing rather than splicing conductors when failures occurred? If so, please provide a copy.
b) Did Liberty have a policy for limiting the number of spliced conductors to a specific number per span? If so, please provide a copy.
c) Did Liberty have a policy specifying the required conductor sag to ensure compliance with GO 95? If so, please provide a copy.
d) Were sag measurements on the Topaz 1261 circuit ever documented?
e) If the answer to (d) is "yes," please provide documentation supporting your answer.
f) If the answer to (d) is "no," please explain why not.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) As referenced in Liberty's response to CalAdvocates-LIB-A2506017-001, Question 8, as of November 17, 2020, Liberty installed splices on conductors in connection with operation of the distribution system. There was no formal policy regarding the installation of splices and the use of splices was based on the experience and expertise of field personnel in the course of repair work.
b) See Liberty's response to subpart (a).
c) Please refer to *Overhead Distribution Conductor Stringing Guide (CON05T)* and *Standard Sagging Practices (CON06T)* of *Overhead Electric Standards.pdf*, which

Liberty provided in response to CalAdvocates-LIB-A2506017-0018, Question 3. Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. For example, refer to the "General Crew Notes" on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Five – As Built.pdf* for directions on sag tables crews should use and to the sag table on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Six – As built.pdf*, both of which Liberty attached to its response to CalAdvocates-LIB-A2506017-0018.

d) Liberty objects to this subpart as vague and ambiguous as framed, including use of the term "sag measurements." Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. Liberty is not aware of any records that would document specific sag measurements for the Topaz 1261 circuit conductors.
e) N/A
f) See Liberty's response to subpart (d).

REQUEST NO. 10:

In Liberty's testimony (LIB-03 at 10), it states that:

While FPPs were mandatory for investor-owned utilities in Southern California, they were required for investor-owned utilities in Northern California only if the utility determined, with respect to its facilities within high-fire threat areas identified in the Reax Map, that "it is reasonably foreseeable that the probability of 3-second wind gusts exceeding the maximum working stresses for such facilities during a Red Flag Warning is 3% or more during a 50-year period." Liberty analyzed whether this criterion was met using data from Remote Automated Weather Stations ("RAWS") operated by the National Weather Service ("NWS"). Because the available RAWS data did not indicate whether gusts lasted three seconds or more, to promote public safety and a proactive approach, Liberty assumed that all maximum gusts met the criterion and determined that an FPP was needed for its facilities located within Threat Zones 3 and 4 of the Reax Map.

a) How many RAWS stations were located within Liberty's service territory at the time of the Mountain View Fire?
b) What distance from Liberty's facilities did the company consider acceptable for RAWS data to be representative?
c) Did Liberty conduct any analysis to compare RAWS data with on-the-ground incident reports of outages or damage?
d) Was Liberty aware of any academic or industry critiques regarding the use of RAWS for fire risk analysis at the time?
e) How did Liberty document its decision to assume all gusts equaled 3-second durations despite the lack of confirmation?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) The RAWS stations that were transmitting data as of November 17, 2020 are publicly

available via MesoWest: https://mesowest.utah.edu/.

b) Liberty considered data from RAWS stations located within 25 miles of its service territory, as described on page 8 and in Attachment 2 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.
c) As further explained in its 2012 Fire Prevention Plan, Liberty took a deliberately conservative approach when assessing whether a Fire Prevention Plan was required for its facilities under R.08-11-005, and ultimately decided to submit one. Please refer to pages 7-8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13, for further explanation of Liberty's methodology for determining whether a Fire Prevention Plan was required, and Attachments 2 and 3 thereto include information regarding the RAWS used for the assessment.
d) Liberty objects to this subpart as vague, ambiguous and overbroad, including its use of the phrase "use of RAWS for fire risk analysis." See Liberty's response to subpart (c).
e) Please refer to page 8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.

The following questions are in regard to Liberty's response to CalAdvocates-LIB-A2506017-001, question 4.

REQUEST NO. 11:

a) Please clarify why intrusive pole inspections on the Topaz 1261 Circuit between the years 2011 and 2020 were only conducted in 2013?
b) Please describe the criteria Liberty used to determine when and where intrusive pole inspections would be performed?
c) Please explain the technical criteria Liberty used to classify poles as "Restorable," "Non-Restorable," or "Hazard"?
d) Who was responsible for assigning poles into each of these categories during the 2013 inspection?
e) Liberty states that corrective work was addressed using hard-copy work packets. Please explain the process for creating, assigning, and closing those packets?
f) Who was responsible for maintaining or archiving the hard-copy packets documenting corrective work?
g) Please provide a sample of three hard-copy work packets referenced in (e).

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty conducted intrusive pole inspections on a circuit basis. 2013 was the year when Liberty scheduled intrusive inspections on the Topaz 1261 Circuit. Pursuant to GO 165, Liberty conducted intrusive inspections on a circuit once every 10 years. Liberty conducted intrusive pole inspections on the Topaz 1261 Circuit again in 2023.

b) Liberty determines its intrusive pole inspection schedule based on when a circuit had previously been inspected. Liberty schedules a circuit for intrusive pole inspections once every 10 years.
c) Please refer to attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* for guidance Liberty provided to its contractor around 2013 on conducting intrusive inspections and criteria for classifying rejected poles.
d) Liberty used a qualified and experienced contractor for intrusive pole inspections. The contractors' personnel were responsible for classifying poles into these categories.
e) Prior to 2020, corrective work identified during Liberty's inspection and maintenance programs was addressed via hard-copy work packets. Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
f) See Liberty's response to subpart (e).
g) For a sample design packet of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, please see attachment *CONFIDENTIAL-8800-0115-0113 Map.pdf*. Since its original response, Liberty has located two additional design packets of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, see confidential attachments *CONFIDENTIAL-8800-0115-0112-Map.pdf* and *CONFIDENTIAL-8800-0115-0114 Map.pdf*.

REQUEST NO. 12:

In Liberty's response to CalAdvocates-LIB-A2506017-001, question 4, it states that:

Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.

a) Since the 2013 intrusive pole inspection, has Liberty made any effort to digitize, scan, or otherwise preserve the hard-copy packets?
b) Please clarify why records showing when corrective work was completed were not located following Liberty's search?
c) How did Liberty verify that poles identified in 2013 inspections as "Non-Restorable" or "Hazard" were in fact replaced?
d) Please describe the oversight mechanisms in place at the time of the 2013 intrusive pole inspection to ensure corrective work identified in inspections was completed.
e) Has Liberty performed any follow-up inspections on the same poles identified in 2013 to confirm that corrective actions were carried out?
f) Did Liberty report the results of the 2013 intrusive pole inspections, including the number of poles requiring corrective work, to any regulatory body?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty maintains some physical records in on-site and off-site storage. While Liberty has scanned some of these records, it has not systematically digitized or scanned all hard-copy work packets. The spreadsheet Liberty provided in its response to CalAdvocates-LIB-A2506017-001, Question 4 was provided to Liberty from its intrusive pole inspection contractor.
b) Liberty did not locate records showing when corrective work was completed due to the passage of time.
c) Liberty verified whether the poles classified as "Non-Restorable" or "Hazard" were replaced using a combination of data sources, including design and installation work order packets, the installation dates of poles available in its GIS database, records of pole inspections available within the Fulcrum database, and field verification.
d) Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
e) Please refer to Liberty's response to subparts (c).
f) In its annual GO 165 report for 2013, Liberty reported the total number of poles that underwent intrusive inspections in 2013. This report did not specify the number of poles intrusively inspected that required corrective work.

REQUEST NO. 13:

a) During the period from 2011 through 2020, did Liberty have any poles in its system that had been treated with cellon gas?
b) If the answer to (a) is yes, provide the number of such poles systemwide.
c) If the answer to (a) is yes, provide the number of such poles on the Topaz 1261 Circuit.
d) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles treated with cellon gas?
e) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles for any other reason?
f) If the answer to parts (d) or (e) is yes, list and explain the actions Liberty has taken to mitigate such potential inaccurate results.
g) What is the median age of wood poles in Liberty's system?
h) What is the median age of wood poles on the Topaz 1261 Circuit?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Liberty further objects to the extent this Question requests information not maintained in the ordinary course of business. Subject to and without waiving these objections, Liberty responds as follows:

a) According to Liberty's intrusive pole inspection results in the relevant timeframe, some poles in its system had been treated with "Penta in Liquid Petrol Gas - Cellon."
b) According to the intrusive pole inspection results available to Liberty, 1,555 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" across all circuits that were subject to intrusive pole inspections during the relevant timeframe.

c) According to the results of the intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, 107 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" at that time. Liberty's standard scope of work for intrusive pole inspections specifies procedures specific to poles treated with cellon gas.
d) Liberty objects to this subpart as vague, ambiguous, and overbroad as framed, including its use of the term "potential inaccuracies." Liberty understands this term to refer to systemic deficiencies or errors identified in the intrusive pole inspection process. Liberty's intrusive pole inspections are performed by a qualified and experienced contractor that provides specialized services to utilities around the country. Liberty has not identified systemic deficiencies associated with its intrusive pole inspections, including on poles treated with cellon gas.
e) See Liberty's response to subpart (d).
f) N/A
g) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles in Liberty's system is approximately 49 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.
h) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles on the Topaz 1261 Circuit, which has been renamed the Topaz 1202 Circuit, is approximately 28 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.

ATTACHMENT 23

Response (amended) to data request CalAdvocates-LIB-A2506017-015, November 1, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

November 1, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-015
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	September 17, 2025
Due Date:	October 1, 2025
Extension Granted:	October 6, 2025
Response Date:	October 6, 2025
Amended Response Date:	November 1, 2025

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1, where it states:

Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy.

REQUEST NO. 1:

a) Did Liberty request NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?
b) If the answer to (a) is "no," please provide an explanation.
c) If the answer to (a) is "yes," please provide all asset inspection and maintenance

records provided to Liberty from NV Energy.

d) If the records identified in (c) exist exclusively in paper format, please provide sufficient detail to permit evaluation of potential digitization or on-site review, including:
    1. An estimate of the total volume of paper records;
    2. The specific location(s) where such records are maintained; and
    3. The approximate date of the earliest available records.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset inspection and maintenance records for the entire utility with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in "Regulatory Commitments" at the time of purchase (attached as Appendix 3 to D.10-10-017), CalPeco planned to conduct business in the same or similar manner as it had under Sierra Pacific's ownership, with regard to the utility's core functions. CalPeco committed, to the extent practicable, to retain the same operations team responsible for operating the utility under Sierra Pacific's ownership, including an intent to maintain local headquarters and to offer then-current operations employees employment with CalPeco at the same locations with responsibilities consistent with their then-existing roles.

    As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased. In addition, on a going forward basis, the two utilities agreed to provide each other reasonable access to their properties to permit inspection of the integrated systems, to perform any relevant work, and to all data, including maintenance records, with respect to the operation and maintenance of each utility's respective portions of the integrated electric systems.
b) See Liberty's response to subpart (a).
c) Liberty is in possession of some inspection and maintenance records from prior to the time of acquisition. Please refer to Liberty's response to CalAdvocates-LIB-A2507017-031, Question 1, subpart (a) and attachments contained therein, which includes some examples of such records.
d) The inspection and maintenance records Liberty has retained from prior to the acquisition in a mix of paper and digital format. Review of Liberty's off-site storage index suggests that Liberty has copies of some inspection and maintenance records dating back to approximately 2008 and some engineering records dating back to the 1970s.

REQUEST NO. 2:

a) Did Liberty conduct a review of NV Energy's asset inspection and maintenance records *before* completing the 2011 purchase?

b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what conclusions were reached, and please provide any documentation relevant to (a).
d) If the answer to (a) is "yes," what methodology did Liberty utilize in 2011 to assess the condition of NV Energy's assets?
e) If the answer to (a) is "yes," did Liberty request that NV Energy perform any corrective actions prior to completing the purchase?
f) If the answer to (e) is "yes," list and describe the actions that Liberty requested NV Energy perform and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

REQUEST NO. 3:

a) *After* completing the 2011 purchase, did Liberty conduct a review of NV Energy's asset inspection and maintenance records?
b) If the answer to (a) is "no," please explain why not.
c) If the answer to (a) is "yes," what findings resulted, and please provide copies.
d) Following the acquisition, did Liberty implement any system-wide corrective action initiatives based on the condition of NV Energy's assets?
e) If the answer to (d) is "no," please explain why not.
f) If the answer to (d) is "yes," please describe what actions were taken, what were the outcomes, and please provide relevant records.

AMENDED RESPONSE:

a) See Liberty's response to Question 1 of this set of data requests.
b) See Liberty's response to Question 1 of this set of data requests.
c) See Liberty's response to Question 1 of this set of data requests.
d) See Liberty's response to Question 1 of this set of data requests.
e) See Liberty's response to Question 1 of this set of data requests.
f) See Liberty's response to Question 1 of this set of data requests.

The following questions refer to Liberty's response to CalAdvocates-LIB-A2506017-001, question 1 where it states:

Liberty conducted routine patrols using hard-copy circuit maps. See Liberty-03 at 20. After a reasonable search and diligent inquiry, the Topaz 1261 maps used for Liberty's patrols from 2013, 2015, and 2017 do not indicate any corrective work identified by those patrols.

REQUEST NO. 4:

a) When did Liberty first begin performing routine patrols on the Topaz 1261 circuit?
b) Did Liberty conduct a routine patrol in 2012 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
c) Did Liberty conduct a routine patrol in 2014 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
d) Did Liberty conduct a routine patrol in 2016 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
e) Did Liberty conduct a routine patrol in 2018 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
f) Did Liberty conduct a routine patrol in 2019 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.
g) Did Liberty conduct a routine patrol in 2020 on the Topaz 1261 circuit? If not, please state the basis for your decision not to patrol. If so, explain why the records of these inspections were not previously provided in response to CalAdvocates-LIB-A2506017-001, question 1.

AMENDED RESPONSE:

Liberty objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty purchased the California utility system from NV Energy in approximately 2011. After a reasonable search and diligent inquiry, the earliest patrol record for the Topaz 1261 Circuit that Liberty has located is from 2013.
b) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2012.
c) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2014.

d) As explained in *Liberty-03: Prudence of Operations,* Part V.A.1, Liberty located routine patrol records for the Topaz 1261 Circuit from 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIB-A2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. Liberty has not located a patrol record for the Topaz 1261 Circuit for 2016.
e) Liberty reported in its GO 165 annual report for 2018 that it completed patrols on all 54 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2018.
f) Liberty reported in its GO 165 annual report for 2019 that it completed patrols on all 55 of its circuits in that year. Liberty has not located further documentation of a patrol of Topaz 1261 Circuit in 2019.
g) As explained in *Liberty-03*, Liberty conducted a detailed inspection of the Topaz 1261 Circuit in 2020 and provided those inspection records in its responses to CalAdvocates-LIB-A2506017-001, Question 2 and CalAdvocates-LIB-A2506017-004, Question 2. Liberty also reported in its GO 165 annual report for 2020 that it completed patrols on all 55 of its circuits in that year.

The following questions refer to the Excel file *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, Liberty provided in response to CalAdvocates-LIB-001, question 2.

REQUEST NO. 5:

Referring to the "Detailed Inspection Results" tab:
a) Please clarify the difference between the dates listed in column C ("Inspection Date") and those in column H ("Created Date")?
b) In some cases, the dates in column H ("Created Date") appear earlier than the corresponding dates in column C ("Inspection Date"). Please explain why this occurs?
c) Several cells in column I ("Due Date") are blank. Please clarify what an empty cell in this column represents?
d) In certain instances, the dates in column I ("Due Date") are earlier than the dates in column C ("Inspection Date"). Please explain why this discrepancy exists?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) The dates listed in column C ("Inspection Date") correspond to the dates when an inspector performed a detailed inspection of the relevant pole. The dates listed in column H ("Created Date") correspond to the dates when the inspection record was created in Fulcrum in anticipation of an upcoming inspection. The dates in column H are sometimes earlier than the corresponding dates in column C because an inspection record was typically created prior to the inspection. For some poles, the "created date" and the "inspection date" may be the same, in instances where the inspection record for that pole was created in Fulcrum at the time of the inspection.
b) See Liberty's response to subpart (a).
c) The cells in column I without any data could be blank for a variety of reasons. As part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues identified in the system from prior inspections. Thus, cells in column I could be blank because, for example, Liberty had already addressed the issues identified at the time due dates were systematically populated in the database, or because no issues requiring remediation were identified.
d) Liberty has not identified instances in *CalAdvocates-LIB-A2506017-001-Q2.xlsx* where the dates in column I are earlier than the dates in Column C.

REQUEST NO. 6:

Referring to the "Repaired after Nov 17 2020" tab:

a) In some cases, the dates in column L ("Repair Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
b) In some cases, multiple conditions are listed in column O ("Condition Codes"), but only a single date is recorded in column L ("Repair Date"). Please clarify how these are reconciled.
c) Several dates in column G ("Created Date") occur before the corresponding dates in column C ("Inspection Date"). Please explain why this occurs.
d) In many cases, the dates in column I ("Due Date") are set up to five years after the dates in column C ("Inspection Date"). Please clarify how these due dates are determined.
e) Certain assets with "Level 3" priority show "Repair Dates" in column L that occur after the "Due Dates" in column I. Please clarify why this occurs.
f) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning due dates when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows: See Liberty's response to Question 5 of this set of data requests.

a) The inspection records in which the dates in column L appear earlier than the dates in column C poles correspond to poles that were replaced in 2020 for which Liberty did not have specific dates of replacement. The date 01/01/2020 was used for those poles to

indicate that the pole replacements were completed in 2020.

b) Due to limitations in Liberty's data collection form during the early stages of its transition from using hard-copy forms to a dynamic electronic inspection form in Fulcrum, only one "Repair Date" field was available for each inspection record for inspections conducted in 2020. A field was available to an inspector to indicate whether all repairs had been completed and another field was available in which to input comments regarding the individual repair(s), including the status of individual conditions identified. Liberty has refined its data collection and repair workflow processes since 2020 and each repair is now tracked as a separate event record.
c) Please refer to Liberty's response to Question 5, subparts (a)-(b) of this set of data requests.
d) The inspection records in which the dates in column I are set up to five years after the dates in column C correspond to poles where the issue(s) identified was assigned a priority Level 3. Consistent with GO 95, Rule 18, Level 3 issues presented low potential safety or reliability risk and Liberty would take action to address them within the timeframes specified by GO 95. Liberty generally used 59 months as the due date for Level 3 issues.
e) As Liberty explained in its response to CalAdvocates-LIB-A2506017-001, Question 5, Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.
f) As set forth in Liberty's response to Question 5(c) of this set of data requests, as part of its transition to digital inspection records and effort to refine its electronic data collection and tracking processes over time, in approximately 2023 Liberty systematically entered due dates for issues in the system from prior inspections corresponding to the timelines set forth in GO 95, Rule 18, based on the date when inspections were performed.

REQUEST NO. 7:

At the time of the Mountain View Fire:

a) As Liberty understands General Order 95, please describe the distinction between Level 1 and Level 2 corrective conditions.
b) As Liberty understands General Order 95, please describe the distinction between Level 2 and Level 3 corrective conditions.
c) Did Liberty document the decision-making process for assigning corrective levels (Level 1, 2, or 3)? If so, explain how. If not, explain why not.
d) What internal training or guidance did Liberty provide to inspectors to ensure alignment with General Order 95 when classifying corrective conditions?
e) What quality assurance measures did Liberty apply to ensure consistency in corrective level assignments across different inspectors or inspection types?
f) Who was responsible for determining whether a corrective condition is classified as Level 1, 2 or Level 3?

g) Please clarify the criteria Liberty used to escalate a condition from Level 3 to Level 2, if applicable?
h) Provide any standards, procedures, job aids, or other documentation that describes Liberty's process for assigning priorities (Level 1, Level 2, or Level 3) when conditions requiring repair are identified during inspections.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) In accordance with GO 95, Liberty understood Level 1 conditions as those posing immediate safety or reliability risks with high potential for impact, which should be addressed immediately. Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes.
b) Liberty understood Level 2 conditions as those posing at least moderate safety or reliability risks, which Liberty attempted to address within the specified timeframes. Liberty understood Level 3 conditions as those with a low potential safety or reliability risk, which Liberty attempted to address within the specified timeframes.
c) As evidenced in *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 2, inspectors selected from a menu of condition codes and assigned a priority level to the inspection record. The dynamic electronic inspection form in Fulcrum that inspectors began using for detailed inspections in 2020 also allowed inspectors to input comments regarding the conditions they identified.
d) As explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program. These inspectors classified conditions as Level 1, 2, or 3 in the process of conducting inspections in the field, based on their understanding of GO 95 and their experience and training.
e) Though Liberty did not have a formal quality assurance process, as explained in Liberty's response to CalAdvocates-LIB-A2506017-004, Question 4, all inspectors were journeymen linemen, with training and experience working on electrical facilities after completing an apprenticeship program.
f) See Liberty's response to subpart (d).
g) See Liberty's response to subpart (b).
h) See Liberty's response to subpart (d).

REQUEST NO. 8:

From 2011 to the time of the Mountain View Fire:

a) How many Level 1 corrective work orders did Liberty identify during routine patrol inspections?
    a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
        i. Structure number
        ii. Work Order Number

iii. Notification Number (if applicable)
iv. Equipment Number
v. Inspection Date
vi. Equipment Type
vii. HFTD/HFRA Tier
viii. Priority
ix. Ignition Risk (Y/N)
x. Date Created
xi. Due Date
xii. Revised Due Date (if applicable)
xiii. Priority Change (if applicable)
xiv. Reason for Change (if applicable)
xv. Date Completed
xvi. Latitude in degrees
xvii. Longitude in degrees

b) How many Level 1 corrective work orders did Liberty identify during detailed inspections?
   a. Please provide an Excel file. Each asset work order should be in a row. The file should contain the following columns of data:
      i. Structure number
      ii. Work Order Number
      iii. Notification Number (if applicable)
      iv. Equipment Number
      v. Inspection Date
      vi. Equipment Type
      vii. HFTD/HFRA Tier
      viii. Priority
      ix. Ignition Risk (Y/N)
      x. Date Created
      xi. Due Date
      xii. Revised Due Date (if applicable)
      xiii. Priority Change (if applicable)
      xiv. Reason for Change (if applicable)
      xv. Date Completed
      xvi. Latitude in degrees
      xvii. Longitude in degrees

AMENDED RESPONSE:

a) Liberty objects to this Question as vague, ambiguous, and overbroad. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows: Liberty transitioned to Fulcrum for routine patrol records in approximately 2023. Prior to that time, inspectors recorded the results of routine patrol inspections on hard-copy maps and thus, Liberty is unable to provide an Excel file with the requested information for routine patrol inspections in the relevant timeframe due to the significant burden involved with compiling such a file based on

identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

b) Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

Liberty is producing the data requested by this Question in the attachment *CalAdvocates-LIB-A2506017-015-Q8.xlsx*. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records, and refined the information in those fields for accuracy based on a review of the full event history of inspection records with priority level field set as Level 1. As described in *Liberty-03: Prudence of Operations*, prior to 2020, inspectors recorded the results of detailed inspections on hard-copy forms and thus, Liberty is unable to provide an Excel file with the requested information for detailed inspections prior to 2020 due to the significant burden involved with compiling such a file based on identifying, collecting, and reviewing hard-copy records for its entire electric system over a nearly 10-year period.

REQUEST NO. 9:

At the time of the Mountain View Fire:

a) Did Liberty have a policy for replacing rather than splicing conductors when failures occurred? If so, please provide a copy.
b) Did Liberty have a policy for limiting the number of spliced conductors to a specific number per span? If so, please provide a copy.
c) Did Liberty have a policy specifying the required conductor sag to ensure compliance with GO 95? If so, please provide a copy.
d) Were sag measurements on the Topaz 1261 circuit ever documented?
e) If the answer to (d) is "yes," please provide documentation supporting your answer.
f) If the answer to (d) is "no," please explain why not.

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving these objections, Liberty responds as follows:

a) As referenced in Liberty's response to CalAdvocates-LIB-A2506017-001, Question 8, as of November 17, 2020, Liberty installed splices on conductors in connection with operation of the distribution system. There was no formal policy regarding the installation of splices and the use of splices was based on the experience and expertise of field personnel in the course of repair work.
b) See Liberty's response to subpart (a).
c) Please refer to *Overhead Distribution Conductor Stringing Guide (CON05T)* and *Standard Sagging Practices (CON06T)* of *Overhead Electric Standards.pdf*, which

Liberty provided in response to CalAdvocates-LIB-A2506017-0018, Question 3. Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. For example, refer to the "General Crew Notes" on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Five – As Built.pdf* for directions on sag tables crews should use and to the sag table on page 1 of *CONFIDENTIAL-Topaz Line Rebuild - Phase Six – As built.pdf*, both of which Liberty attached to its response to CalAdvocates-LIB-A2506017-0018.

d) Liberty objects to this subpart as vague and ambiguous as framed, including use of the term "sag measurements." Conductor sag is taken into account at the time of design and construction to support regulatory compliance and is subject to visual inspection during Liberty's inspections. Liberty is not aware of any records that would document specific sag measurements for the Topaz 1261 circuit conductors.
e) N/A
f) See Liberty's response to subpart (d).

REQUEST NO. 10:

In Liberty's testimony (LIB-03 at 10), it states that:

While FPPs were mandatory for investor-owned utilities in Southern California, they were required for investor-owned utilities in Northern California only if the utility determined, with respect to its facilities within high-fire threat areas identified in the Reax Map, that "it is reasonably foreseeable that the probability of 3-second wind gusts exceeding the maximum working stresses for such facilities during a Red Flag Warning is 3% or more during a 50-year period." Liberty analyzed whether this criterion was met using data from Remote Automated Weather Stations ("RAWS") operated by the National Weather Service ("NWS"). Because the available RAWS data did not indicate whether gusts lasted three seconds or more, to promote public safety and a proactive approach, Liberty assumed that all maximum gusts met the criterion and determined that an FPP was needed for its facilities located within Threat Zones 3 and 4 of the Reax Map.

a) How many RAWS stations were located within Liberty's service territory at the time of the Mountain View Fire?
b) What distance from Liberty's facilities did the company consider acceptable for RAWS data to be representative?
c) Did Liberty conduct any analysis to compare RAWS data with on-the-ground incident reports of outages or damage?
d) Was Liberty aware of any academic or industry critiques regarding the use of RAWS for fire risk analysis at the time?
e) How did Liberty document its decision to assume all gusts equaled 3-second durations despite the lack of confirmation?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) The RAWS stations that were transmitting data as of November 17, 2020 are publicly

available via MesoWest: https://mesowest.utah.edu/.

b) Liberty considered data from RAWS stations located within 25 miles of its service territory, as described on page 8 and in Attachment 2 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.
c) As further explained in its 2012 Fire Prevention Plan, Liberty took a deliberately conservative approach when assessing whether a Fire Prevention Plan was required for its facilities under R.08-11-005, and ultimately decided to submit one. Please refer to pages 7-8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13, for further explanation of Liberty's methodology for determining whether a Fire Prevention Plan was required, and Attachments 2 and 3 thereto include information regarding the RAWS used for the assessment.
d) Liberty objects to this subpart as vague, ambiguous and overbroad, including its use of the phrase "use of RAWS for fire risk analysis." See Liberty's response to subpart (c).
e) Please refer to page 8 of *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 13.

The following questions are in regard to Liberty's response to CalAdvocates-LIB-A2506017-001, question 4.

REQUEST NO. 11:

a) Please clarify why intrusive pole inspections on the Topaz 1261 Circuit between the years 2011 and 2020 were only conducted in 2013?
b) Please describe the criteria Liberty used to determine when and where intrusive pole inspections would be performed?
c) Please explain the technical criteria Liberty used to classify poles as "Restorable," "Non-Restorable," or "Hazard"?
d) Who was responsible for assigning poles into each of these categories during the 2013 inspection?
e) Liberty states that corrective work was addressed using hard-copy work packets. Please explain the process for creating, assigning, and closing those packets?
f) Who was responsible for maintaining or archiving the hard-copy packets documenting corrective work?
g) Please provide a sample of three hard-copy work packets referenced in (e).

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty conducted intrusive pole inspections on a circuit basis. 2013 was the year when Liberty scheduled intrusive inspections on the Topaz 1261 Circuit. Pursuant to GO 165, Liberty conducted intrusive inspections on a circuit once every 10 years. Liberty conducted intrusive pole inspections on the Topaz 1261 Circuit again in 2023.

b) Liberty determines its intrusive pole inspection schedule based on when a circuit had previously been inspected. Liberty schedules a circuit for intrusive pole inspections once every 10 years.
c) Please refer to attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* for guidance Liberty provided to its contractor around 2013 on conducting intrusive inspections and criteria for classifying rejected poles.
d) Liberty used a qualified and experienced contractor for intrusive pole inspections. The contractors' personnel were responsible for classifying poles into these categories.
e) Prior to 2020, corrective work identified during Liberty's inspection and maintenance programs was addressed via hard-copy work packets. Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
f) See Liberty's response to subpart (e).
g) For a sample design packet of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, please see attachment *CONFIDENTIAL-8800-0115-0113 Map.pdf*. Since its original response, Liberty has located two additional design packets of certain poles identified as needing replacement in the Topaz 1261 Circuit intrusive pole inspections conducted in 2013, see confidential attachments *CONFIDENTIAL-8800-0115-0112-Map.pdf* and *CONFIDENTIAL-8800-0115-0114 Map.pdf*.

REQUEST NO. 12:

In Liberty's response to CalAdvocates-LIB-A2506017-001, question 4, it states that:

Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.

a) Since the 2013 intrusive pole inspection, has Liberty made any effort to digitize, scan, or otherwise preserve the hard-copy packets?
b) Please clarify why records showing when corrective work was completed were not located following Liberty's search?
c) How did Liberty verify that poles identified in 2013 inspections as "Non-Restorable" or "Hazard" were in fact replaced?
d) Please describe the oversight mechanisms in place at the time of the 2013 intrusive pole inspection to ensure corrective work identified in inspections was completed.
e) Has Liberty performed any follow-up inspections on the same poles identified in 2013 to confirm that corrective actions were carried out?
f) Did Liberty report the results of the 2013 intrusive pole inspections, including the number of poles requiring corrective work, to any regulatory body?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed and unduly burdensome. Subject to and without waiving these objections, Liberty responds as follows:

a) Liberty maintains some physical records in on-site and off-site storage. While Liberty has scanned some of these records, it has not systematically digitized or scanned all hard-copy work packets. The spreadsheet Liberty provided in its response to CalAdvocates-LIB-A2506017-001, Question 4 was provided to Liberty from its intrusive pole inspection contractor.
b) Liberty did not locate records showing when corrective work was completed due to the passage of time.
c) Liberty verified whether the poles classified as "Non-Restorable" or "Hazard" were replaced using a combination of data sources, including design and installation work order packets, the installation dates of poles available in its GIS database, records of pole inspections available within the Fulcrum database, and field verification.
d) Based on the understanding of current Liberty personnel, poles identified as needing replacement were provided to the engineering team, which then worked with a contractor to design new poles. The contractor would provide the final design packet to Liberty and Liberty's operations team would coordinate installation of the new poles according to the specifications and update Liberty's records accordingly.
e) Please refer to Liberty's response to subparts (c).
f) In its annual GO 165 report for 2013, Liberty reported the total number of poles that underwent intrusive inspections in 2013. This report did not specify the number of poles intrusively inspected that required corrective work.

REQUEST NO. 13:

a) During the period from 2011 through 2020, did Liberty have any poles in its system that had been treated with cellon gas?
b) If the answer to (a) is yes, provide the number of such poles systemwide.
c) If the answer to (a) is yes, provide the number of such poles on the Topaz 1261 Circuit.
d) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles treated with cellon gas?
e) Has Liberty identified any potential inaccuracies associated with intrusive inspections on poles for any other reason?
f) If the answer to parts (d) or (e) is yes, list and explain the actions Liberty has taken to mitigate such potential inaccurate results.
g) What is the median age of wood poles in Liberty's system?
h) What is the median age of wood poles on the Topaz 1261 Circuit?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Liberty further objects to the extent this Question requests information not maintained in the ordinary course of business. Subject to and without waiving these objections, Liberty responds as follows:

a) According to Liberty's intrusive pole inspection results in the relevant timeframe, some poles in its system had been treated with "Penta in Liquid Petrol Gas - Cellon."
b) According to the intrusive pole inspection results available to Liberty, 1,555 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" across all circuits that were subject to intrusive pole inspections during the relevant timeframe.

c) According to the results of the intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, 107 poles were listed as having been treated with "Penta in Liquid Petrol Gas - Cellon" at that time. Liberty's standard scope of work for intrusive pole inspections specifies procedures specific to poles treated with cellon gas.
d) Liberty objects to this subpart as vague, ambiguous, and overbroad as framed, including its use of the term "potential inaccuracies." Liberty understands this term to refer to systemic deficiencies or errors identified in the intrusive pole inspection process. Liberty's intrusive pole inspections are performed by a qualified and experienced contractor that provides specialized services to utilities around the country. Liberty has not identified systemic deficiencies associated with its intrusive pole inspections, including on poles treated with cellon gas.
e) See Liberty's response to subpart (d).
f) N/A
g) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles in Liberty's system is approximately 49 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.
h) As of the date of this response, according to data available within Liberty's GIS software, the median age of wood poles on the Topaz 1261 Circuit, which has been renamed the Topaz 1202 Circuit, is approximately 28 years. Liberty's GIS data is updated periodically and may not fully reflect Liberty's assets currently in the field.

ATTACHMENT 24

Response (amended) to data request CalAdvocates-LIB-A2506017-016, October 24, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 24, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-016
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	September 18, 2025
Due Date:	October 2, 2025
Extension Granted:	October 6, 2025
Response Date:	October 6, 2025
Amended Response Date:	October 24, 2025

In Liberty's testimony (LIB – 03 at 23), it states that:

> *In 2020, Liberty deployed Liberty's journeymen linemen and engaged a contractor to perform an asset survey and detailed inspection of all overhead distribution and transmission assets. This survey included detailed visual inspections of the condition of conductors, poles, and other overhead equipment, regardless of when the equipment had last been inspected.*
>
> *Liberty performed this survey to update its inventory for accuracy via photographs and GPS coordinate data, to assess the condition of its assets, to plan remediation projects, and to better assess risks in its electric system. An equipment database was created to store the asset information. During this survey, Liberty performed more than 22,000 detailed inspections of overhead assets and identified a substantial number of GO 95 repairs.*

CA-07-1253

REQUEST NO. 1:

Provide an Excel file that contains **all corrective work** created by the 2020 asset survey affecting the Topaz 1261 circuit.

Each corrective work order should be in a row. The file should contain the following columns of data:

a) Structure number
b) Work Order Number
c) Notification Number (if applicable)
d) Equipment Number
e) Inspection Date
f) Equipment Type
g) HFTD/HFRA Tier
h) Priority
i) Ignition Risk (Y/N)
j) Date Created
k) Due Date
l) Revised Due Date (if applicable)
m) Priority Change (if applicable)
n) Reason for Change (if applicable)
o) Date Completed
p) Latitude in degrees
q) Longitude in degrees

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

Please note that the 2020 asset survey also functioned as a detailed inspection on the Topaz 1261 Circuit. Liberty is producing the data requested by this Question in attachment *CalAdvocates-LIB-A2506017-016-Q1.xlsx.* As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records. Please see Liberty's responses to CalAdvocates-LIB-A2506017-0015, Questions 5-6.

REQUEST NO. 2:

a) What criteria or risk-ranking methodology did Liberty use to prioritize corrective work orders after the 2020 asset survey?
b) Have all corrective work orders identified in 2020 asset survey been completed?
c) If the answer to (b) is "yes," please provide documentation supporting your response.
d) If the answer to (b) is "no," please provide an Excel file of all open corrective work orders identified in the 2020 asset survey affecting the Topaz 1261 circuit.

Each corrective work order should be in a row. The file should contain the following columns of data:

a. Structure number
b. Work Order Number
c. Notification Number (if applicable)
d. Equipment Number
e. Inspection Date
f. Equipment Type
g. HFTD/HFRA Tier
h. Priority
i. Ignition Risk (Y/N)
j. Date Created
k. Due Date
l. Revised Due Date (if applicable)
m. Priority Change (if applicable)
n. Reason for Change (if applicable)
o. Date Completed
p. Latitude in degrees
q. Longitude in degrees

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) After the 2020 asset survey, Liberty generally prioritized corrective work orders by their priority level, accounting for location within HFTDs.
b) Give the larger number of issues identified from the asset survey and its systemwide nature, as of today, Liberty is still addressing small number of corrective work orders identified during the asset survey.
c) N/A
d) Please refer to attachment *CalAdvocates-LIB-A2506017-016-Q1.xlsx*, which includes corrective work identified on the Topaz 1261 Circuit as part of the 2020 asset survey, whether they have been addressed or remain open. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records. Please see Liberty's responses to CalAdvocates-LIB-A2506017-0015, Questions 5-6.

REQUEST NO. 3:

At the time of the Mountain View Fire:

a) How did Liberty track the progress of corrective work order completions identified in the 2020 asset survey.
b) Did Liberty have a written policy governing the management of asset surveys?
c) If the answer to (b) is "yes," please identify and produce a copy of that policy.

d) If the answer to (b) is "no," please explain why not.
e) What quality assurance processes did Liberty use to verify inspection results?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty generally tracked completed repair work in the dynamic digital data collection tool used during the inspections. In approximately 2023, a dashboard was created in an asset tracking application to track the progress of corrective work. In early 2025, Liberty transitioned to using another asset tracking application, also equipped with a dashboard.
b) The 2020 system survey was the first undertaken by Liberty to support its WMP initiatives by documenting the condition of its assets and updating its inventory. Liberty did not have a formal policy for this survey and Liberty used qualified inspectors to complete the survey, overseen by experienced operations personnel.
c) N/A
d) See Liberty's response to subpart (b).
e) Please refer to Liberty's responses to CalAdvocates-LIB-A2506017-004, Questions 4(d) and 8.

REQUEST NO. 4:

a) What prompted Liberty to conduct a systemwide asset survey in 2020?
b) Was the survey required or recommended by a regulatory authority?
c) Did Liberty's internal assessments identify risks or deficiencies prior to 2020 that led to the survey?
d) Were external events (e.g., storms, wildfire concerns, equipment failures) a factor in the decision?

AMENDED RESPONSE:

a) As referenced in *Liberty-03: Prudence of Operations* (at p. 23) and in Liberty's response to Question 3(b)-(d) of this set of data requests, the 2020 system survey was undertaken by Liberty to support its WMP initiatives by documenting the condition of its assets and updating its inventory.
b) Liberty is not aware that the survey was required or recommended by a regulatory authority. See Liberty's response to subpart (a).
c) No single event or risk was the impetus for the 2020 system survey. See Liberty's response to subpart (a).
d) No single event or risk was the impetus for the 2020 system survey. See Liberty's response to subpart (a).

REQUEST NO. 5:

a) On what exact date did Liberty begin the 2020 asset survey?
b) On what exact date did Liberty complete the 2020 asset survey?
c) Were inspections conducted continuously during 2020 or in specific time blocks?

d) Did seasonal conditions (e.g., weather, fire season) affect when inspections were performed?
e) How did Liberty determine the survey would cover all overhead distribution and transmission assets?
f) Did the survey involve visual inspection only, or were diagnostic tools or measurements also used?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) According to inspection records available in Fulcrum, the first inspection that took place on Liberty's electric system in 2020 occurred around April 9.
b) According to inspection records available in Fulcrum, the last inspection that took place on Liberty's electric system in 2020 occurred around December 18.
c) Liberty objects to the terms "continuously" and "specific time blocks" as vague and ambiguous. Liberty conducted inspections between approximately April and December 2020.
d) Liberty objects to this subpart as vague and ambiguous, including its use of the term "seasonal conditions." As with any other field operations, inspections may be impacted from time to time by severe weather conditions such storms or snow. The system survey was completed in 2020. Please refer to Liberty's response in subpart (c).
e) Please refer to Liberty's response to Question 4 of this set of data requests.
f) The survey involved visual inspection.

REQUEST NO. 6:

a) Did Liberty perform intrusive inspections on every pole in the Topaz 1261 Circuit in 2013, or only a subset?
b) If only a subset, what criteria were used to select which poles received intrusive inspections?
c) Please provide the total number of poles on the Topaz 1261 Circuit in 2013 and the number actually inspected.
d) Were there any poles on the Topaz 1261 Circuit that had never received an intrusive inspections prior to 2020?
e) Did Liberty follow any technical standards or guidelines in 2013 to classify poles as "Restorable," "Non-Restorable," or "Hazard"?
f) If the answer to (e) is "yes," please identify and produce a copy of any technical standards or guidelines.
g) How many poles were classified under each category in 2013?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it

purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

a) As Liberty schedules intrusive pole inspections on a circuit basis, the entire Topaz 1261 Circuit was inspected by Liberty's intrusive pole inspection contractor in 2013.
b) N/A
c) Due to limitations in Liberty's historic GIS information, the passage of time, pole replacements and the redesign that occurred as part of the Topaz Line Rebuild Project, Liberty is unable to provide the precise total number of poles on the Topaz 1261 Circuit in 2013. As indicated in *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 4, Liberty's contractor conducted intrusive inspections on 1,463 poles on the Topaz 1261 Circuit in 2013.
d) Please refer to Liberty's responses to subparts (a) and (b) of this set of data requests.
e) Please refer to Liberty's response to CalAdvocates-LIB-A2506017-0015, Question 11 and attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* thereto.
f) Please refer to Liberty's response to CalAdvocates-LIB-A2506017-0015, Question 11 and attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* thereto.
g) Please refer to *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, attached to Liberty's response CalAdvocates-LIB-A2506017-001, Question 4, which contains tabs listing the poles classified under each category in 2013 on the Topaz 1261 Circuit.

ATTACHMENT 25

Response (amended) to data request CalAdvocates-LIB-A2506017-001, November 1, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

September 10, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-001
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
Cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	August 19, 2025
Due Date:	September 3, 2025
Extension Granted:	September 10, 2025

REQUEST NO. 1:

Provide an Excel file that contains all corrective work identified in 2010-2020 by the routine or annual patrol program affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the following columns of data:

a) Structure number
b) Work Order Number
c) Notification Number (if applicable)
d) Equipment Number
e) Inspection Date
f) Equipment Type
g) HFTD/HFRA Tier
h) Priority
i) Ignition Risk (Y/N)
j) Date Created
k) Due Date

l) Revised Due Date (if applicable)
m) Priority Change (if applicable)
n) Reason for Change (if applicable)
o) Date Completed
p) Latitude in degrees
q) Longitude in degrees.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: As explained in *Liberty-03: Prudence of Operations*, Liberty conducted routine patrols using hard-copy circuit maps. *See* Liberty-03 at 20. After a reasonable search and diligent inquiry, the Topaz 1261 maps used for Liberty's patrols from 2013, 2015, and 2017 do not indicate any corrective work identified by those patrols.

REQUEST NO. 2:

Provide an Excel file that contains all corrective work identified in 2010 - 2020 by the detailed inspection program affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the same columns of data listed in Question 1 above.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

Liberty is producing the data requested by this Question in the tab "Detailed Inspection Results" in the attachment *CalAdvocates-LIB-A2506017-001-Q2.xlsx*. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records. This spreadsheet contains detailed inspection records from 2020 for the entire Topaz 1261 Circuit, regardless of whether corrective work was identified from the inspection. As described in *Liberty-03: Prudence of Operations*, prior to 2020, inspectors recorded the results of detailed inspections on physical forms and thus, Liberty is unable to provide an Excel file with the requested information for detailed inspections prior to 2020.

REQUEST NO. 3:

Provide an Excel file that contains all corrective work identified in 2010 - 2020 by any infrared inspection programs affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the same columns of data listed in Question 1 above.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Liberty did not have an infrared inspection program during the specified time frame.

REQUEST NO. 4:

Provide an Excel file that contains all corrective work identified in 2010 - 2020 by the intrusive pole inspection program affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the same columns of data listed in Question 1 above.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

Please see attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.

REQUEST NO. 5:

a) What constituted an asset work order being "overdue," according to Liberty's policies at the time of the Mountain View Fire?

b) What were considered valid reasons for delays in remediating asset work orders, according to Liberty policies at the time of the Mountain View Fire?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as to the term "asset work order" and "valid reasons for delays." Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty understands the term "asset work order" to refer to conditions requiring corrective actions in relation to a Liberty asset. At the time of the Mountain View Fire, Liberty assigned due dates for conditions based on the regulatory requirements set forth by GO 95, Rule 18. An "overdue" condition is one that is past the due date assigned by Liberty and applicable regulatory requirements.

b) Liberty understands the phrase "valid reasons for delays" to refer to reasons by which remediation times may be extended beyond the deadlines prescribed by regulatory requirements. Not all conditions were compliance-based issues. Those conditions not related to compliance were not subject to regulatory requirements. For compliance-based conditions, Liberty attempted to complete all remediation by the assigned due dates. For some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. GO 95, Rule 18(A)(2)(b) allows such "reasonable circumstances" to justify an extension of correction times.

REQUEST NO. 6:

a) How did Liberty assess the wildfire risk associated with overdue asset work orders at the time of the Mountain View Fire?

b) What criteria did Liberty use to determine whether an overdue asset work order posed an immediate wildfire risk?

c) At the time of the Mountain View Fire, what role did fire risk play in determining the priority classification of conditions (with respect to asset work orders)?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as to the term "asset work order." Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty understands the term "asset work order" to refer to conditions requiring corrective actions in relation to a Liberty asset. Liberty assessed the wildfire risk associated with asset work orders by assessing whether an asset was located within the Commission's High Fire Threat District and assigning the corresponding due dates as set forth in GO 95, Rule 18. As explained in its response to Question 5 of this set of data requests, Liberty attempted to complete all compliance-based conditions by the assigned due dates.

b) - c) Please see Liberty's response to subpart (a).

REQUEST NO. 7:

Please provide all records of any asset maintenance notifications on the Topaz 1261 circuit that were open as of November 17, 2020. Provide a spreadsheet with a row for each notification.

Please provide the following columns of data:

a) Structure number
b) Work Order Number
c) Equipment Number
d) Inspection Date
e) Equipment Type
f) HFTD/HFRA Tier
g) Priority
h) Ignition Risk (Y/N)
i) Date Created
j) Due Date
k) Revised Due Date (if applicable)
l) Priority Change (if applicable).
m) Reason for Change (if applicable)
n) Date Completed
o) Latitude in degrees
p) Longitude in degrees

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not kept in the ordinary course of business. Subject to and without waiving these objections, Liberty responds as follows: Liberty understands this Question to be asking for conditions that were identified on or before November 17, 2020, and not yet remediated as of November 17, 2020. Because Liberty transitioned to Fulcrum for detailed inspection records in 2020 and that database does not include asset inspection records performed using hard-copy forms prior to 2020, Liberty can provide a list of poles inspected in 2020 which had repairs performed after November 17, 2020. Many of these repairs appear to be associated with conditions identified in detailed inspections conducted in 2020, but some may not be. Please see the tab "Repaired After Nov 17, 2020" in *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, attached to Liberty's Response to Question 2 of this set of data requests. Please note that Liberty did not track some of the information requested by this Question.

REQUEST NO. 8:

In the ten years prior to the Mountain View Fire (2010 - 2020), were any splices installed on the conductor on the Topaz 1261 16kV circuit? If so, provide an Excel spreadsheet with the following information for each splice installed:

a) Date the splice was determined to be necessary.
b) Structure number at the upstream end of the span where the splice was installed.
c) Structure number at the downstream end of the span where the splice was installed.
d) Method(s) used to identify the need for a splice.
e) Work order number used to install splice.
f) Date work order was created.
g) Date work order was completed.

RESPONSE:

Liberty objects to this Question as overly burdensome to the extent it seeks records and information not kept in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Liberty installed splices on the Topaz 1261 Circuit as needed in connection with operation of the distribution system. As referenced in *Liberty-02: Ignition*, splices were present on the lines in the Subject Span. *See* Liberty-02 at 7. After a reasonable search and diligent inquiry, Liberty has not located records showing when and where splices were installed on the Topaz 1261 Circuit or methods used to identify the need for splice installation.

REQUEST NO. 9:

In the ten year period leading up to the Mountain View Fire (2010 - 2020), was the Topaz 1261 circuit reviewed under Liberty's circuit reliability program?

a) Provide a list of any recommendations that resulted from any reviews in the 10 year period leading up to the Mountain View Fire.
b) Under the program's risk assessment process, what was the Topaz 1261 circuit ranked?
c) Was the Topaz 1261 circuit's rank determined by an overall average circuit score?
d) Were there any circuit segments of the Topaz 1261 circuit that scored high enough to warrant an urgent replacement?
e) If the answer to (d) is "yes", provide a list of the relevant circuit segments (i.e. structure numbers at each end).

RESPONSE:

a) - e) Liberty objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Consistent with D.16-01-008, Liberty reviewed the reliability of its electric system on an annual basis. Liberty's reliability reports are publicly available on the Commission's website at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/electric-reliability/electric-system-reliability-annual-reports. These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening. As explained in SCE-03: Prudence of Operations (pp. 17-18), the Topaz 1261 Rebuild

Project was a Commission-approved multiyear project designed to improve circuit reliability and mitigate wildfire risk on Liberty's portion of the Topaz 1261 Circuit. As of November 17, 2020, Liberty was in the process of implementing phase five of the project.

REQUEST NO. 10:

Provide an Excel spreadsheet listing all ignitions in 2010 through 2020 on the Topaz 1261 Circuit.

Each ignition should be a row. Provide the following data as columns:

a) Ignition date
b) Ignition time
c) Latitude of ignition
d) Longitude of ignition
e) Number of nearest pole
f) Acres burned
g) Cause, if identified
h) Whether the ignition was a CPUC-reportable incident (Y/N)
i) Whether Liberty had any asset corrective notifications at the ignition location, that were open at the time of the ignition (Y/N)
j) Whether the ignition was linked to an asset corrective notification that existed at the time (Y/N)
k) ID number of the nearest protective device upstream of the ignition
l) Longitude in degrees of the device identified in part (k)
m) Latitude in degrees of the device identified in part (k)
n) Whether the device identified in part (k) tripped

RESPONSE:

Liberty objects to this Question as overly burdensome to the extent it seeks records and information not kept in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving these objections, Liberty responds as follows: Liberty is not subject to ignition reporting under D.14-02-015. From the start of Liberty's operations in approximately 2011 to 2020, Liberty is not aware of any ignitions associated with the Topaz 1261 Circuit prior to November 17, 2020.

REQUEST NO. 11:

Provide an Excel spreadsheet listing all wire-down events in 2010 through 2020 on the Topaz 1261 circuit. Each wire-down event should be a row. Provide the following data as columns:

a) Date of wire-down event
b) Time of wire-down event
c) Latitude of wire-down event

d) Longitude of wire-down event
e) Number of nearest pole
f) Cause, if identified
g) Whether Liberty had any asset corrective notifications at the location, that were open at the time of the wire-down event (Y/N)
h) Whether the wire-down event was linked to an asset corrective notification that existed at the time (Y/N)
i) ID number of the nearest protective device upstream of the wire-down event
j) Longitude in degrees of the device identified in part (i)
k) Latitude in degrees of the device identified in part (i)
l) Whether the device identified in part (i) tripped

RESPONSE:

Liberty objects to this Question as overly burdensome to the extent it seeks records and information not kept in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving these objections, Liberty responds as follows: Please see *CalAdvocates-LIB-A2506017-001-Q11.xlsx*, which contains available information in Liberty's possession regarding reported wire down events between 2016-2020. Liberty identified these events by querying its outage management system (OMS) for wire down events and reviewing the comments and resolution to determine if a valid wire down condition existed.

As explained in *Libery-03: Prudence of Operations* (pp. 32-33), Liberty's system was operated by NV Energy's system control center for a portion of the time period requested in this Question. Liberty's records for the requested data date back to approximately 2016. Please note that Liberty did not track the information requested in subparts (g)-(h) of this Question in relation to wire down events and that Liberty is producing the information requested in subparts (c)-(d) and (j)-(k) in the projected coordinate system format (NAD_1983_UTM_Zone_11N) as maintained in its GIS.

REQUEST NO. 12:

Please provide an Excel spreadsheet listing each outage that occurred from 2010 - 2020 on the Topaz 1261 circuit (or any portion of the Topaz 1261 circuit). The spreadsheet should list each outage in a row, with the following column headings:

a) Circuit segment ID #
b) Date of outage
c) Start time of outage
d) Cause of outage
e) For outages due to equipment failures, please state the specific type of equipment that failed. (for example: transformer failure, conductor failure, splice failure, etc.)
f) Outage duration in minutes
g) The type of protective device that tripped
h) The equipment number of the protective device that tripped
i) Latitude in degrees of the protective device that tripped

j) Longitude in degrees of the protective device that tripped

RESPONSE:

Liberty objects to this Question as overbroad to the extent that it seeks information prior to the start of its operation in approximately 2011, when it purchased the utility system from NV Energy. Subject to and without waiving these objections, Liberty responds as follows: Please see *CalAdvocates-LIB-A2506017-001-Q12.xlsx*, which contains the available outage information in Liberty's possession between 2016-2020. As explained in *Libery-03: Prudence of Operations* (pp. 32-33), Liberty's system was operated by NV Energy's system control center for a portion of the time period requested in this Question. Liberty's records for the requested data date back to approximately 2016. Please note that Liberty did not track the information requested in subpart (a) of this Question in relation to outages and that Liberty is producing the information requested in subparts (i)-(j) in the projected coordinate system format (NAD_1983_UTM_Zone_11N) as maintained in its GIS.

REQUEST NO. 13:

Provide a complete list of all wildfire risk mitigation measures Liberty developed or implemented between 2010 and November 2020.

a) Among the identified wildfire risk mitigation measures, which ones were proactive (that is, not implemented in response to specific, prior safety failures)?
b) How did Liberty determine the necessity and priority of the proactive wildfire risk mitigation measures identified in your response to part (a)?
c) What criteria or guidelines did Liberty follow in developing and implementing wildfire risk mitigation measures during the specified period?

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Liberty further objects to the extent that this Question seeks information prior to the start of its operation in approximately 2011, when it purchased the utility system from NV Energy. Liberty further objects to the term "proactive" in subparts (a) and (b). Wildfire mitigation measures are generally based on a utility's specific risk profile and past experience and are intended to proactively mitigate future wildfire risk. Distinguishing between measures that are "proactive" and those "in response to specific, prior safety failures" is not possible. Subject to and without waiving its objections, Liberty responds as follows:

Please refer to attachments *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, *Wildfire Mitigation Plan (2019).pdf*, *Revised 2020 Wildfire Mitigation Plan.pdf*, and *2021 Wildfire Mitigation Plan Update (Public Version).pdf*. for detailed information regarding Liberty's wildfire mitigation efforts during the specified time frame. Although Liberty had not experienced a large wildfire attributed to its electrical infrastructure since taking over from Sierra Pacific in 2011, Liberty recognized the risk of wildfires within its service area and took steps to mitigate that risk. Liberty's opening testimony described wildfire risk mitigation measures that Liberty had adopted or was in the process of developing as of November 2020 (*see, e.g.*, Liberty-03 at 10-13), including:

- Patrols of circuits in high-fire areas during high wind conditions
- Implementing “fire settings” for reclosers
- Pausing discretionary maintenance and vegetation management activities during fire threat conditions
- Conducting a detailed system-wide asset survey
- Piloting a LiDAR inspection of its distribution system for vegetation clearance
- Installing covered conductor, including on the Topaz 1261 Circuit
- Undergrounding certain lines
- Installing larger size conductors
- Replacing and upgrading distribution poles
- Replacing expulsion fuses
- Deploying monitoring sensors and SCADA-enabled devices
- Installing weather stations to support situational awareness
- Developing a Fire Potential Index (FPI) to forecast wildfire risk
- Implementing a Public Safety Power Shutoff (PSPS) program
- Increasing the frequency of vegetation management inspections
- Removing dead and dying trees in high tree mortality areas
- Hiring additional personnel to manage emergency response activities

ATTACHMENT 26

Pacific Gas and Electric Company.
Infrared Inspections of Electric Distribution Facilities.
May 15, 2018

Infrared (IR) Inspections of Electric Distribution Facilities

SUMMARY

This utility procedure establishes requirements for performing infrared (IR) inspections (i.e., thermography) on overhead (OH) and underground (UG) electric distribution facilities, excluding substations. This procedure also explains the permitted use of non-utility-graded IR cameras by restoration employees and other employees who are infrequent users. Finally, this procedure defines roles and responsibilities for employees who perform IR inspections, as well as the roles and responsibilities for implementing this procedure.

Level of Use: Informational Use

TARGET AUDIENCE

The target audience includes the following PG&E employees:

- Electric distribution planning and operations
- Compliance
- Asset strategy reliability
- Electric distribution asset strategy and development
- Electric maintenance and construction (M&C)
- Power quality
- Restoration and control
- Service planning and design
- Project delivery

SAFETY

Wear personal protective equipment (PPE) at all times when performing IR inspections. This includes, but is not limited to, flame-resistant (FR) clothing, hard hats, safety glasses, and suitable footwear.

BEFORE YOU START

WEAR appropriate PPE.

USE the appropriate IR camera.

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Infrared (IR) Inspections of Electric Distribution Facilities

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PROCEDURE STEPS

1 General Information

1.1 Compliance inspectors and outside contractors perform IR inspections on electric distribution facilities; however, restoration employees, contractors, and other infrequent users can be responsible for performing some of the actions described in this procedure, depending on the job.

1.2 Background

1. USE IR imaging and temperature-measuring systems as diagnostic tools in both electric transmission and distribution (T&D) system inspections and in preventive maintenance programs. IR imaging can accurately identify and initiate the repair or replacement of faulty devices, equipment, and components.

2. Based on industry specifications, connectors require lower operating temperatures than their respective conductors. When the connector's temperature is greater than the temperature of its respective conductor, a higher-resistance connection exists and a failure is likely, but not precisely predicted. Connector degradation occurs faster with an increase in load or temperature.

3. Conductor manufacturers recommend that the usual maximum operating temperature for tensioned, bare conductor be limited to 75° Centigrade (C) (i.e., 167° Fahrenheit [F]).

4. Conductor manufacturers recommend that the usual maximum operating temperature for insulated conductor be limited to the following temperatures:

   - 75°C (167°F) for high molecular weight polyethylene (HMWPE) material
   - 90°C (194°F) for cross-linked polyethylene (XLPE) material
   - 105°C (221°F) for ethylene propylene rubber (EPR) material

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Infrared (IR) Inspections of Electric Distribution Facilities

1.3 Equipment

1. USE IR imaging systems to detect and record all heat radiating in an imaging system's field of view.

   a. The IR camera uses an image-scanning technique to specifically identify heat radiating from a target and the target's background. These units capture and store heat images pictorially for immediate or future evaluation.

   b. Using these units, the operator can PINPOINT the hottest spot on the observed target.

2. USE only a utility-grade IR camera when performing IR inspections.

3. USE either utility-grade or non-utility-grade IR cameras as an aid for troubleshooting facilities or equipment known to have power-quality issues.

4. USE non-utility-grade IR cameras to identify hot spot connections or equipment when troubleshooting or performing work verification.

NOTE

DO NOT USE non-utility-grade IR cameras to perform regulatory-mandated IR inspections (managed by the compliance department) or IR inspections performed under the PG&E IR program (managed by the asset strategy department).

2 Requirements and Recommendations

2.1 Implementation

1. This IR procedure was developed as a key element of a preventive maintenance program. The recommended maintenance priorities provided in Table 1, "Corrective Maintenance Priorities for Overhead Distribution Facilities," on Page 6, and Table 2, "Corrective Maintenance Priorities for Underground Distribution Facilities," on Page 8, reduce the risk of component failures, prevent further facility damage, and facilitate a proactive approach to repairing or replacing components identified as abnormal.

2. When performing IR inspections, ENSURE that line equipment (e.g., capacitor banks, line regulators, line reclosers) are in service and are carrying load.

NOTE

BE AWARE that thermography scanning requires the conductor to be energized and carrying load current.

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2.2 Scheduling Recommendations

When operational needs allow, COMPLETE the following tasks:

1. SCHEDULE IR inspections starting in July and finishing no later than October.

2. If IR inspections are scheduled during circuit off-peak hours, PERFORM load transfers to increase the circuit's normal loading to approximately 40% rated load of the electrical equipment being inspected.

2.3 Equipment Specifications

PERFORM the following actions:

1. ENSURE that video-imaging equipment using IR technology to inspect UG electric distribution facilities meets the following specifications:

   a. The system must be sealed.

   b. The equipment must be portable.

2. ENSURE that video-imaging equipment used for OH IR inspections includes the following features:

   a. Ability to store images for future analysis.

   b. Adjustable, ambient temperature and emittance settings.

   c. Ability to interchange lenses.

3. ENSURE that approved, utility-grade and non-utility-grade IR cameras meet all specifications listed in Attachment 4, "Minimum Specifications for Approved Infrared Cameras."

2.4 Records and Documentation

1. When conducting IR inspections under a specific maintenance activity type, PERFORM the following actions:

   a. USE Form TD-2022P-01-F01, "Infrared Inspection Log" (SEE Attachment 1), to record required information. The "Infrared Inspection Log" is available either in hard copy or electronically on PG&E mobile devices.

      (1) DETERMINE the appropriate maintenance priority based on the temperature values found in Table 1 on Page 6 and Table 2 on Page 8.

      (2) IF there is obvious physical damage,

      THEN TAKE corrective action immediately.

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2.4 (continued)

b. USE Form TD-2022P-01-F02, "Infrared Data Sheet" (SEE Attachment 2), to report identified, abnormal, compelling conditions. The "Infrared Data Sheet" is available either in hard copy or electronically on PG&E mobile devices.

(1) DETERMINE the appropriate maintenance priority based on the temperature values found in Table 1 on Page 6 and Table 2 on Page 8.

(2) IF there is obvious physical damage,

THEN TAKE corrective action immediately.

c. REPORT defective/damaged components on Form 62-0113, "Material Problem Report" (SEE Attachment 3), AND RETAIN the report for additional analysis as described in Utility Standard SCM-2106S, "Material Problem Report Standard."

d. UPLOAD the completed Form TD-2022P-01-F02 to SAP's Electric Compliance (EC) Notification.

2.5 Determining Corrective Maintenance Priorities

When determining corrective maintenance priorities, READ the "Notes in reference to Table 1," under Table 1 on Page 7, and under "Notes in reference to Table 2," on Page 9, AND PERFORM the following actions:

1. REFER to Table 1 on Page 6 and Table 2 on Page 8 to assess and prioritize the relative severity of the conditions found during an inspection.

2. USE the measured temperatures and temperature differentials provided in the tables to make these determinations described in Step 2.5.1 above.

a. Table 1 on Page 6 and Table 2 on Page 8 describe the methods used when performing IR Inspections. Those methods are:

(1) **Differential Temperature analysis** – Refers to relative temperature values of a hotspot with respect to other parts of the equipment with similar conditions.

(2) **Absolute Temperature analysis** – Refers to actual temperature values measured from the hotspot.

3. Between methods (1) and (2) above, the most reliable is the differential temperature analysis because, unlike the absolute temperature analysis, it is minimally affected by environmental factors such as ambient temperature, humidity, and emissivity.

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Infrared (IR) Inspections of Electric Distribution Facilities

2.5 (continued)

Table 1. Corrective Maintenance Priorities for Overhead Distribution Facilities

Differential Temperature (ΔT) Analysis			
Distribution Facilities	**Condition**	**Temperature Differential (ΔT)**	**Priority/Due Date**
Arrester cutouts and pot-head termination	Normal	ΔT ≤ 10°C ΔT ≤ 18°F	No maintenance required.
	Minor	10°C < ΔT ≤ 25°C 18°F < ΔT ≤ 45°F	Write EC tag with Priority E. Complete within **180** days.
	Medium	25°C < ΔT ≤ 45°C 45°F < ΔT ≤ 81°F	Write EC tag with Priority B. Complete within **90** days.
	Severe	ΔT > 45°C ΔT > 81°F	Write EC tag with Priority B. Complete within **30** days.
Connector and switch	Normal	ΔT ≤ 25°C ΔT ≤ 45°F	No maintenance required.
	Minor	25°C < ΔT ≤ 45°C 45°F < ΔT ≤ 81°F	Write EC tag with Priority E. Complete within **180** days.
	Medium	45°C < ΔT ≤ 60°C 81°F < ΔT ≤ 108°F	Write EC tag with Priority B. Complete within **90** days.
	Severe	ΔT > 60°C ΔT > 108°F	Write EC tag with Priority B. Complete within **30** days.

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Infrared (IR) Inspections of Electric Distribution Facilities

2.5 (continued)

Table 1. Corrective Maintenance Priorities for Overhead Distribution Facilities (continued)

Absolute Temperature (T) Analysis			
Distribution Facilities	**Condition**	**Temperature Limits**	**Priority/Due Date**
Arrester cut-outs and pot-head termination	Normal	$T_{hot\ spot} \leq 70°C$ $T_{hot\ spot} \leq 158°F$	No maintenance required.
	Minor	$71°C < T_{hot\ spot} \leq 80°C$ $160°F < T_{hot\ spot} \leq 176°F$	Write EC tag with Priority E. Complete within **180** days.
	Medium	$80°C < T_{hot\ spot} \leq 85°C$ $176°F < T_{hot\ spot} \leq 185°F$	Write EC tag with Priority B. Complete within **90** days.
	Severe	$T_{hot\ spot} \geq 85°C$ $T_{hot\ spot} \geq 185°F$	Write EC tag with Priority B. Complete within **30** days.
Connector and switch	Normal	$T_{hot\ spot} \leq 85°C$ $T_{hot\ spot} \leq 185°F$	No maintenance required.
	Minor	$85°C < T_{hot\ spot} \leq 105°C$ $185°F < T_{hot\ spot} \leq 221°F$	Write EC tag with Priority E. Complete within **180** days.
	Medium	$105°C < T_{hot\ spot} \leq 120°C$ $221°F < T_{hot\ spot} \leq 248°F$	Write EC tag with Priority B. Complete within **90** days.
	Severe	$T_{hot\ spot} > 120°C$ $T_{hot\ spot} > 248°F$	Write EC tag with Priority B. Complete within **30** days.

Notes in Reference to Table 1 (Page 6 and Page 7):

1. If the IR component has already failed, significant damage, or its condition results in significant exposure to the general public, write an EC tag with Priority A, and take corrective action immediately. Refer to the *Electric Distribution Preventive Maintenance Manual* (*EDPM Manual*) for more information.
2. Create the EC tag, and complete the required action(s) within the due date as shown in the Table 1 "Priority/Due Date" column.
3. For live-front terminations on pad-mounted transformers or equipment, use the OH temperature-differential values to determine priorities as shown in Table 1 in the "Temperature Limits" column.
4. Table 1 **does not apply** to transformer tanks. When working with transformer tanks, refer to Numbered Document 068178, "Distribution Transformer Temperature," Table 1, "Transformer Temperatures–Mineral Oil Filled," on Page 2, and Table 2, "Transformer Temperatures–Natural Ester Filled," on Page 3.
5. Temperature conversion factor: °C = (°F – 32) X (5/9)
6. Temperature differential: $°C_{diff} = (°F_{diff}) / 1.8$

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2.5 (continued)

Table 2. Corrective Maintenance Priorities for Underground Distribution Facilities

Differential Temperature Rise Analysis			
Distribution Facilities	**Condition**	**Temperature Differential (ΔT)**	**Priority/Due Date**
Elbow and termination	Normal	ΔT ≤ 6°C ΔT ≤ 11°F	No maintenance required.
	Medium	6°C < ΔT ≤ 20°C 11°F < ΔT ≤ 36°F	Write EC tag with Priority B. Complete within **60** days.
	Severe	ΔT > 20°C ΔT > 36°F	Write EC tag with Priority B. Complete within **30** days.
Joint/splice and switch	Normal	ΔT ≤ 6°C ΔT ≤ 11°F	No maintenance required.
	Medium	6°C < ΔT ≤ 12°C 11°F < ΔT ≤ 22°F	Write EC tag with Priority B. Complete within **60** days.
	Severe	ΔT > 12°C ΔT > 22°F	Write EC tag with Priority B. Complete within **30** days.
Absolute Temperature (T) Analysis			
Distribution Facilities	**Condition**	**Temperature Limits**	**Priority/Due Date**
Elbow and termination	Normal	$T_{hot\ spot} \leq 80°C$ $T_{hot\ spot}t \leq 176°F$	No maintenance required.
	Medium	$80°C < T_{hot\ spot} \leq 88°C$ $176°F < T_{hot\ spot} \leq 190°F$	Write EC tag with Priority B. Complete within **60** days.
	Severe	$T_{hot\ spot} > 88°C$ $T_{hot\ spot} > 190°F$	Write EC tag with Priority B. Complete within **30** days.
Joint/splice and switch	Normal	$T_{hot\ spot} \leq 85°C$ $T_{hot\ spot} \leq 185°F$	No maintenance required.
	Medium	$85°C < T_{hot\ spot} \leq 120°C$ $185°F < T_{hot\ spot} \leq 248°F$	Write EC tag with Priority B. Complete within **60** days.
	Severe	$T_{hot\ spot} \geq 120°C$ $T_{hot\ spot} \geq 248°F$	Write EC tag with Priority B. Complete within **30** days.

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2.5 (continued)

Notes in Reference to Table 2 (Page 8):

1. If the IR component has already failed, has significant damage, or its condition results in significant exposure to the general public, write an EC tag with Priority A, and take corrective action immediately. Refer to the *EDPM Manual* for more information.
2. Create the electric corrective (EC) tag, and complete the required action(s) within the due date as shown in the Table 2 "Priority/Due Date" column.
3. For live-front terminations on pad-mounted transformers or equipment, use the OH temperature-differential values to determine priorities as shown in Table 2 on Page 8.
4. Table 1 **does not apply** to transformer tanks. When working with transformer tanks, refer to Numbered Document 068178, Table 1 on Page 2, and Table 2 on Page 3.
5. For underground switches, the delta temperature values shown in Table 2 are between **switch components and the bushing-elbow interface.**
6. Temperature conversion factor: °C = (°F – 32) X (5/9)
7. Temperature differential: $°C_{diff} = (°F_{diff}) / 1.8$

3 Procedures

3.1 Setting Up the IR Camera

1. To obtain accurate measurements, it is critical to ESTABLISH the IR imaging-system setup parameters for **emissivity and background temperature**.

   a. USE other imaging-system setup parameters primarily to record initial or future evaluations of heat radiating from a target and its background.

2. SET the emissivity value at 0.95. This eliminates the need to set the background temperature. In this case, the target is considered a black body, totally reflective, and nontransmissive.

   a. With highly emissive targets, the actual reflected energy is so small with respect to the emitted energy that the temperature measurement is well within reason for predictive maintenance applications.

   b. As the emissivity value of the target decreases, the influence of background radiation increases and, consequently, so does the potential for errors based on background temperature settings.

   c. If the emissivity value is set at less than 0.95 and the background temperature setting is adjusted inaccurately, the chances are greater that the target's resulting temperature measurement will contain errors than if the emissivity value were set at 0.95.

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Infrared (IR) Inspections of Electric Distribution Facilities

3.1 (continued)

EXAMPLE

When the emissivity setting is less than 0.95 and the background temperature setting is **higher** than the actual background temperature, the target temperature measurement is lower than it should be. However, if the background temperature setting is **lower** than the actual background temperature, then the target temperature measurement is higher than it should be. The measurement deviation is compounded as the emissivity setting decreases from 0.95.

d. Setting the emissivity value at 0.95:

(1) Eliminates the need to determine exact emissivity and background temperature values.

(2) Simplifies the system operation.

(3) Results in reasonably accurate measurements.

EXAMPLE

When taking IR measurements on OH systems where the ceiling (sky) is unlimited, determining an accurate background temperature is nearly impossible. Most targets have dark surfaces with emittance values very close to 0.95.

3.2 IR Inspection Measurement Points

Figures 1 through Figure 8, "Infrared Inspection Measurement Points," on Page 12, display the temperature measurement points on various conductor assemblies.

3.3 IR Scanning Techniques

1. If the thermal image's color pallet shows an elevated differential temperature between the targeted component and conductor/cable, FOLLOW the steps below:

a. CENTER the targeted component in the viewer or sight of the IR scanning device, AND OBSERVE the measured temperatures. SEE the measurement points in Figure 1 through Figure 8 on Page 12.

b. SCAN approximately 1 to 2 feet of the conductor/cable entering and/or leaving the targeted image, AND OBSERVE the measured temperatures. SEE the measurement points in Figure 1 through Figure 8 on Page 12.

c. TAKE load readings **if a compelling abnormal condition is identified**.

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3.3 (continued)

d. For radial, live-front terminations without adjacent component(s) on the same phase, COMPARE the phase connector to other phase connectors, AND TAKE load readings **if a compelling abnormal condition is identified**.

e. For looped, live-front terminations, COMPARE the connector temperatures on the same phase to each other, AND TAKE a load reading on each cable **if an abnormal condition is found**. This helps to ensure the temperature differential is not load related.

NOTE

Due to load imbalances, a temperature difference between different phases of cables on the same circuit is an expected condition and does not, in itself, indicate any anomalies.

2. If the temperature differential is within the normal value shown in Table 1 on Page 6 and Table 2 on Page 8, but the temperature-absolute value exceeds the normal value shown in Table 1 and Table 2, PERFORM the following actions:

a. CREATE a temporary load transfer (recommended) to increase the load viewed by the targeted component.

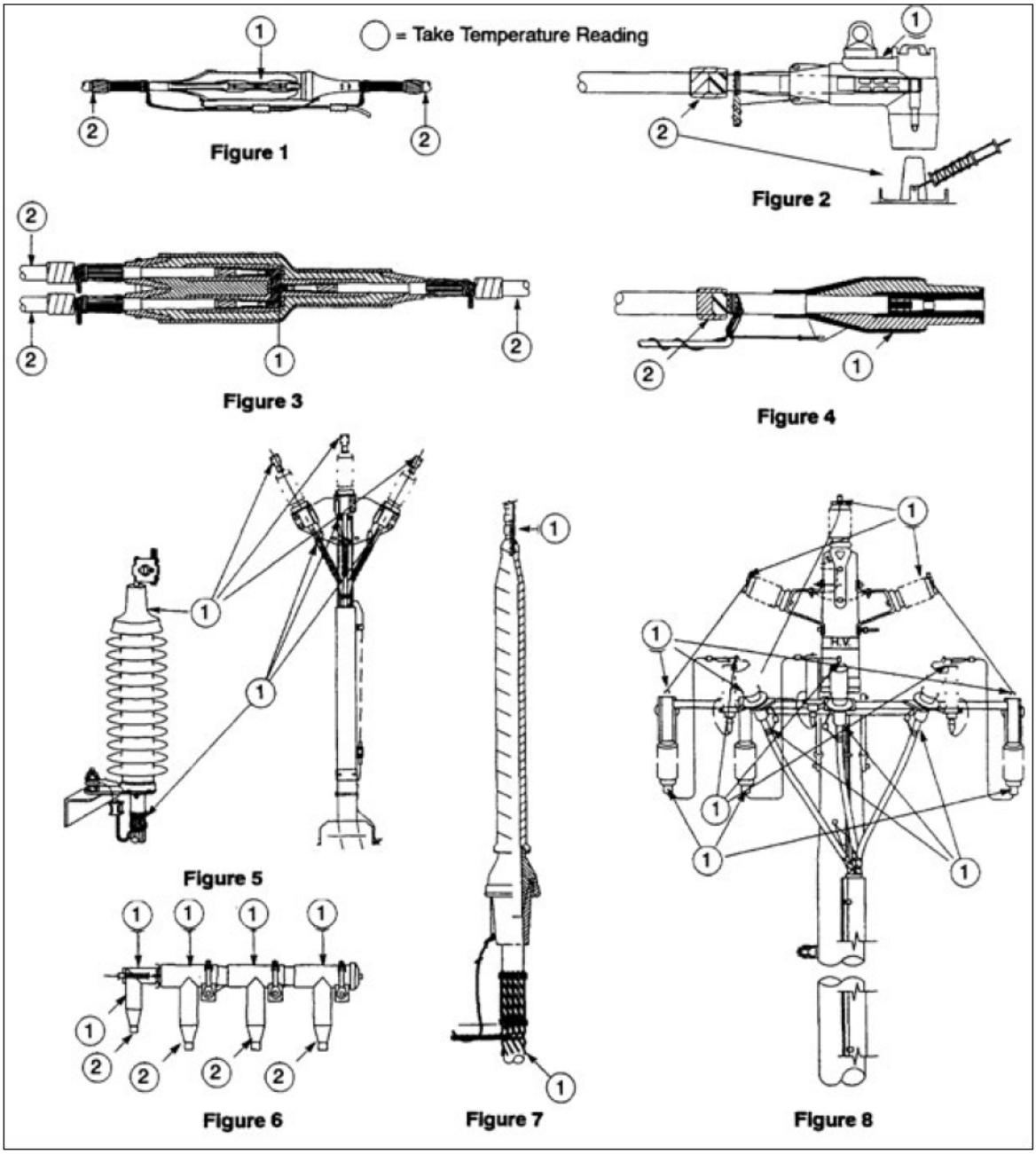
b. REPEAT the IR inspection on the same component.

c. RECORD the findings.

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Infrared (IR) Inspections of Electric Distribution Facilities

3.3 (continued)



Figures 1–Figure 8
Infrared Inspection Measurement Points

Notes:

1. Numbers ① and ② are the measurement points referred to in Subsection 3.3, "IR Scanning Technique," Step 1 through Step 2, starting on Page 10.
2. Observe excessive temperature readings for figures that only designate measurement points. ①

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3.4 Using an IR Camera to Identify Hot Transformers and UG Switches

The IR camera provides thermal images that can identify transformer tanks with high temperatures caused by high loading. Thermal images also identify switch tanks with high temperatures caused by internal switch problems. When imaging transformer and switch tanks, PERFORM the following actions:

1. When identifying a transformer tank with a high temperature, TAKE the actions described in Numbered Document 068178, Table 1 on Page 2, and Table 2 on Page 3.

2. When identifying an oil switch tank with a temperature higher than its cable terminations, CREATE an EC tag with Priority A to replace the switch immediately.

4 Implementation Roles

4.1 The senior director in charge of electric asset strategy has the following responsibilities:

1. DEVELOP AND OVERSEE a prioritized plan that meets the requirements of this procedure. The plan must include performance measures and schedules for reporting progress on the systemwide annual plan.

2. COMPILE a systemwide annual plan based on area-specific submittals. ENSURE that the plan and periodic status reports are available on a schedule determined by the distribution asset management electric operation engineering senior director.

3. IMPLEMENT a quality assurance program to assess compliance with this procedure and to support continuous improvement.

4. DEVELOP AND OVERSEE the funding and forecasting necessary to comply with this procedure.

5. MONITOR progress, AND VERIFY compliance with this procedure.

4.2 The director in charge of restoration compliance operations has the following responsibilities:

1. DEVELOP annual plans to identify and request the resources necessary to achieve all of the area-specific requirements described in this procedure. These annual plans identify area-specific objectives for inspecting and maintaining electric distribution equipment. In addition, the plans provide for the training needed to achieve the area-specific requirements described in this procedure.

2. SUBMIT annual plans AND periodic status reports on a schedule determined by the electric distribution maintenance manager.

4.3 Compliance managers ENSURE that area employees are aware of and comply with the area-specific requirements described in this procedure.

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4.4 Directors, managers, and supervisors who direct the inspection and maintenance of electric distribution facilities have the following responsibilities:

1. ENSURE the work necessary to comply with this procedure is performed safely, efficiently, and in a timely manner.

2. Accurately TRACK AND REPORT work progress.

4.5 Supervisors have the following responsibilities:

1. ENSURE that employees who perform facility assessments and subsequent maintenance are qualified to perform their assigned tasks.

2. Periodically CHECK employees' work to verify its accuracy and completeness, as well as the timely and succinct recordkeeping of the work.

4.6 Employees assigned facility inspection and maintenance tasks have the following responsibilities:

1. PERFORM assignments efficiently and safely. ENSURE not only personal safety, but also public safety. Employees must only perform work for which they are qualified.

2. When necessary, NOTIFY supervisors of any additional training, equipment, or resources required to efficiently and safely perform work.

4.7 IF IR inspections are performed by outside contractors,

THEN SEE Attachment 5, "Guideline for Validating Overhead (OH) Infrared (IR) Inspection Contract Work," for additional instructions.

END of Instructions

DEFINITIONS

Abnormal conditions: A condition that impacts or has the potential to adversely impact safety, service reliability, or asset life. Typically, these are conditions where the facility may fail to perform the function for which it was installed.

Ambient temperature: The prevailing temperature in the immediate vicinity of an object or target; the temperature of the target's environment.

Background temperature: The temperature(s) of the surrounding scene reflected off the target.

Component temperature: The temperature of the targeted surface being evaluated.

Distribution facilities: Any conductors or associated equipment operating at voltages up to 50,000 volts (V), namely 50 kilovolts (kV).

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Infrared (IR) Inspections of Electric Distribution Facilities

DEFINITIONS (continued)

Emissivity: The relative ability of a surface to emit heat by radiation. Emissivity is the ratio of the heat emitted by a surface compared to that emitted by a black body.

Emittance value: The ratio of the intensity of thermal radiation at a given wavelength or spectral waveband from a target to the thermal radiation emitted by a black body with the same temperature as the target.

Field of view: The size of the scene surrounding the target, as observed by the infrared (IR) scanner and expressed as the ratio between the size of the scene surrounding the target and the distance between the target and the scanner.

Infrared notification: A form or electronic record used as a checklist to identify and record a specific, abnormal maintenance condition(s) that impacts safety, service reliability, or asset life.

Infrequent users: Employees including troublemen, crew foremen, and supervisors who use IR cameras to perform qualitative analysis to help assess the condition of energized electric distribution facilities. Infrequent users are not engaged in everyday IR inspections.

Input form: A form or electronic record used in the field as a checklist to record a specific, abnormal maintenance condition(s) that impacts safety, service reliability, or asset life. The recorded information is used to create an Electric Preventive Corrective Maintenance (EPCM) Notification.

Inspection: In this procedure, “inspection” refers to IR inspections using thermal imaging equipment to observe differential patterns of IR radiation. These patterns provide specific information about a structure system, object, or target. An inspection can also refer to a special type of diagnostic test using IR thermography.

Inspection cycle: Established schedules ensuring that facilities are inspected at durations based on calendar years. Inspections must be performed and completed within the calendar year for which they are scheduled.

Inspection log: A form or electronic record used to document inspections and identify abnormalities that require correction or a follow-up inspection.

Priority: The urgency to perform repairs identified in a notification.

Reference temperature: The temperature of a like piece of equipment at the same location as that registering the component (“fault”) temperature.

Reflective: The ability of a target to reflect or send back rays. A mirror has a reflective surface with respect to visible light.

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Infrared (IR) Inspections of Electric Distribution Facilities

DEFINITIONS (continued)

Temperature differential (also known as "temperature rise"): The difference in temperature between the component (fault) temperature and the reference temperature.

Thermography: Any photographic, videotape, computer-generated, or graphic record of information derived from an IR inspection.

Transmissive: The ability of a medium to allow electromagnetic radiation to pass through it without being reflected or absorbed (i.e., sending or transmitting rays from one point to another). Glass is highly transmissive to visible light.

Utility-grade IR cameras: IR cameras that meet the minimum specification listed in Attachment 4, "Minimum Specifications for Approved Infrared Cameras."

Non-utility-grade IR cameras: IR cameras available to infrequent users who are not performing overhead or underground inspections. See Attachment 4 for more details.

IMPLEMENTATION RESPONSIBILITIES

The senior director in charge of asset management is responsible for approving, revising, and distributing this procedure.

Supervisors must ensure that the tailboard for this procedure is delivered by 07/15/2018 (procedure's effective date).

GOVERNING DOCUMENT

NA

COMPLIANCE REQUIREMENT / REGULATORY COMMITMENT

NA

REFERENCE DOCUMENTS

Developmental References:

- *Aluminum Electrical Conductor Handbook*
- Infraspection Institute Manuals:
  - *Infrared Inspection Manual*
  - *Infrared Methodology and Technology Manual*
  - *Infraspection Instruction Manual, Level II*

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REFERENCE DOCUMENTS (continued)

Developmental References (continued):

- Institute of Electrical and Electronic Engineers (IEEE) documents:
  - *Automatic Diagnosis System of Electrical Equipment Using Infrared Thermography*
  - *Robotized inspection of power lines with infrared vision*
- Utility Standard TD-2301S, "Patrols and Detailed/Intrusive Inspections of Electric Overhead and Underground Distribution Facilities"

Supplemental References:

- *Electric Distribution Preventive Maintenance (EDPM) Manual*
- Numbered Document 068178, "Distribution Transformer Temperature"
- Utility Standard SCM-2106S, "Material Problem Report Standard"

APPENDICES

NA

ATTACHMENTS

Attachment 1, Form TD-2022P-01-F01, "Infrared Inspection Log"

Attachment 2, Form TD-2022P-01-F02, "Infrared Data Sheet"

Attachment 3, Form 62-0113, "Material Problem Report"

Attachment 4, Minimum Specifications for Approved Infrared Cameras

Attachment 5, Guideline for Validating Overhead (OH) Infrared (IR) Inspection Contract Work

DOCUMENT RECISION

This utility procedure cancels and supersedes Utility Procedure TD-2022P-01, "Infrared Inspection of Electric Distribution Facilities," Rev. 0, dated 12/20/2013.

This utility procedure also moves the following two bulletins to **For Reference Only (FRO)**:

- Utility Bulletin TD-2022B-001, "Revised Corrective Maintenance Priorities Tables when Performing Infrared Inspections," Rev. 0, dated 04/17/2015.
- Utility Bulletin TD-2022B-002, "Infrared Cameral Approved for Restoration and Infrequent Users," Rev. 0, dated 02/15/2017.

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Infrared (IR) Inspections of Electric Distribution Facilities

DOCUMENT APPROVER

[redacted] Senior Manager
Distribution Standards Engineering

DOCUMENT OWNER

[redacted] Senior Manager
Distribution Standards Engineering

DOCUMENT CONTACTS

[redacted] Senior Electric Standards Engineer

REVISION NOTES

Where?	What Changed?
Summary	• Added a sentence to explain the permitted use of non-utility graded IR cameras by restoration and infrequent uses.
Section 2.5, "Determining Corrective Maintenance Priorities"	• Incorporated the information communicated in Utility Bulletin TD-2022B-001: o Split former Table 1 into Table 1 and Table 2. o Revised temperature values and required time to complete the corrective action.
Attachment 4 and Attachment 5	• Added these two new attachments.

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ATTACHMENT 27

Response (amended) to data request CalAdvocates-LIB-A2506017-001, September 10, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

September 10, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-001
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
Cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	August 19, 2025
Due Date:	September 3, 2025
Extension Granted:	September 10, 2025

REQUEST NO. 1:

Provide an Excel file that contains all corrective work identified in 2010-2020 by the routine or annual patrol program affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the following columns of data:

a) Structure number
b) Work Order Number
c) Notification Number (if applicable)
d) Equipment Number
e) Inspection Date
f) Equipment Type
g) HFTD/HFRA Tier
h) Priority
i) Ignition Risk (Y/N)
j) Date Created
k) Due Date

l) Revised Due Date (if applicable)
m) Priority Change (if applicable)
n) Reason for Change (if applicable)
o) Date Completed
p) Latitude in degrees
q) Longitude in degrees.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: As explained in *Liberty-03: Prudence of Operations*, Liberty conducted routine patrols using hard-copy circuit maps. *See* Liberty-03 at 20. After a reasonable search and diligent inquiry, the Topaz 1261 maps used for Liberty's patrols from 2013, 2015, and 2017 do not indicate any corrective work identified by those patrols.

REQUEST NO. 2:

Provide an Excel file that contains all corrective work identified in 2010 - 2020 by the detailed inspection program affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the same columns of data listed in Question 1 above.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

Liberty is producing the data requested by this Question in the tab "Detailed Inspection Results" in the attachment *CalAdvocates-LIB-A2506017-001-Q2.xlsx*. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records. This spreadsheet contains detailed inspection records from 2020 for the entire Topaz 1261 Circuit, regardless of whether corrective work was identified from the inspection. As described in *Liberty-03: Prudence of Operations*, prior to 2020, inspectors recorded the results of detailed inspections on physical forms and thus, Liberty is unable to provide an Excel file with the requested information for detailed inspections prior to 2020.

REQUEST NO. 3:

Provide an Excel file that contains all corrective work identified in 2010 - 2020 by any infrared inspection programs affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the same columns of data listed in Question 1 above.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Liberty did not have an infrared inspection program during the specified time frame.

REQUEST NO. 4:

Provide an Excel file that contains all corrective work identified in 2010 - 2020 by the intrusive pole inspection program affecting the Topaz 1261 circuit.

Each asset work order should be in a row. The file should contain the same columns of data listed in Question 1 above.

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

Please see attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.

REQUEST NO. 5:

a) What constituted an asset work order being "overdue," according to Liberty's policies at the time of the Mountain View Fire?

b) What were considered valid reasons for delays in remediating asset work orders, according to Liberty policies at the time of the Mountain View Fire?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as to the term "asset work order" and "valid reasons for delays." Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty understands the term "asset work order" to refer to conditions requiring corrective actions in relation to a Liberty asset. At the time of the Mountain View Fire, Liberty assigned due dates for conditions based on the regulatory requirements set forth by GO 95, Rule 18. An "overdue" condition is one that is past the due date assigned by Liberty and applicable regulatory requirements.

b) Liberty understands the phrase "valid reasons for delays" to refer to reasons by which remediation times may be extended beyond the deadlines prescribed by regulatory requirements. Not all conditions were compliance-based issues. Those conditions not related to compliance were not subject to regulatory requirements. For compliance-based conditions, Liberty attempted to complete all remediation by the assigned due dates. For some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. GO 95, Rule 18(A)(2)(b) allows such "reasonable circumstances" to justify an extension of correction times.

REQUEST NO. 6:

a) How did Liberty assess the wildfire risk associated with overdue asset work orders at the time of the Mountain View Fire?

b) What criteria did Liberty use to determine whether an overdue asset work order posed an immediate wildfire risk?

c) At the time of the Mountain View Fire, what role did fire risk play in determining the priority classification of conditions (with respect to asset work orders)?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as to the term "asset work order." Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty understands the term "asset work order" to refer to conditions requiring corrective actions in relation to a Liberty asset. Liberty assessed the wildfire risk associated with asset work orders by assessing whether an asset was located within the Commission's High Fire Threat District and assigning the corresponding due dates as set forth in GO 95, Rule 18. As explained in its response to Question 5 of this set of data requests, Liberty attempted to complete all compliance-based conditions by the assigned due dates.

b) - c) Please see Liberty's response to subpart (a).

REQUEST NO. 7:

Please provide all records of any asset maintenance notifications on the Topaz 1261 circuit that were open as of November 17, 2020. Provide a spreadsheet with a row for each notification.

Please provide the following columns of data:

a) Structure number
b) Work Order Number
c) Equipment Number
d) Inspection Date
e) Equipment Type
f) HFTD/HFRA Tier
g) Priority
h) Ignition Risk (Y/N)
i) Date Created
j) Due Date
k) Revised Due Date (if applicable)
l) Priority Change (if applicable).
m) Reason for Change (if applicable)
n) Date Completed
o) Latitude in degrees
p) Longitude in degrees

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not kept in the ordinary course of business. Subject to and without waiving these objections, Liberty responds as follows: Liberty understands this Question to be asking for conditions that were identified on or before November 17, 2020, and not yet remediated as of November 17, 2020. Because Liberty transitioned to Fulcrum for detailed inspection records in 2020 and that database does not include asset inspection records performed using hard-copy forms prior to 2020, Liberty can provide a list of poles inspected in 2020 which had repairs performed after November 17, 2020. Many of these repairs appear to be associated with conditions identified in detailed inspections conducted in 2020, but some may not be. Please see the tab "Repaired After Nov 17, 2020" in *CalAdvocates-LIB-A2506017-001-Q2.xlsx*, attached to Liberty's Response to Question 2 of this set of data requests. Please note that Liberty did not track some of the information requested by this Question.

REQUEST NO. 8:

In the ten years prior to the Mountain View Fire (2010 - 2020), were any splices installed on the conductor on the Topaz 1261 16kV circuit? If so, provide an Excel spreadsheet with the following information for each splice installed:

a) Date the splice was determined to be necessary.
b) Structure number at the upstream end of the span where the splice was installed.
c) Structure number at the downstream end of the span where the splice was installed.
d) Method(s) used to identify the need for a splice.
e) Work order number used to install splice.
f) Date work order was created.
g) Date work order was completed.

RESPONSE:

Liberty objects to this Question as overly burdensome to the extent it seeks records and information not kept in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Liberty installed splices on the Topaz 1261 Circuit as needed in connection with operation of the distribution system. As referenced in *Liberty-02: Ignition*, splices were present on the lines in the Subject Span. *See* Liberty-02 at 7. After a reasonable search and diligent inquiry, Liberty has not located records showing when and where splices were installed on the Topaz 1261 Circuit or methods used to identify the need for splice installation.

REQUEST NO. 9:

In the ten year period leading up to the Mountain View Fire (2010 - 2020), was the Topaz 1261 circuit reviewed under Liberty's circuit reliability program?

a) Provide a list of any recommendations that resulted from any reviews in the 10 year period leading up to the Mountain View Fire.
b) Under the program's risk assessment process, what was the Topaz 1261 circuit ranked?
c) Was the Topaz 1261 circuit's rank determined by an overall average circuit score?
d) Were there any circuit segments of the Topaz 1261 circuit that scored high enough to warrant an urgent replacement?
e) If the answer to (d) is "yes", provide a list of the relevant circuit segments (i.e. structure numbers at each end).

RESPONSE:

a) - e) Liberty objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows: Consistent with D.16-01-008, Liberty reviewed the reliability of its electric system on an annual basis. Liberty's reliability reports are publicly available on the Commission's website at: https://www.cpuc.ca.gov/industries-and-topics/electrical-energy/infrastructure/electric-reliability/electric-system-reliability-annual-reports. These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening. As explained in SCE-03: Prudence of Operations (pp. 17-18), the Topaz 1261 Rebuild

Project was a Commission-approved multiyear project designed to improve circuit reliability and mitigate wildfire risk on Liberty's portion of the Topaz 1261 Circuit. As of November 17, 2020, Liberty was in the process of implementing phase five of the project.

REQUEST NO. 10:

Provide an Excel spreadsheet listing all ignitions in 2010 through 2020 on the Topaz 1261 Circuit.

Each ignition should be a row. Provide the following data as columns:

a) Ignition date
b) Ignition time
c) Latitude of ignition
d) Longitude of ignition
e) Number of nearest pole
f) Acres burned
g) Cause, if identified
h) Whether the ignition was a CPUC-reportable incident (Y/N)
i) Whether Liberty had any asset corrective notifications at the ignition location, that were open at the time of the ignition (Y/N)
j) Whether the ignition was linked to an asset corrective notification that existed at the time (Y/N)
k) ID number of the nearest protective device upstream of the ignition
l) Longitude in degrees of the device identified in part (k)
m) Latitude in degrees of the device identified in part (k)
n) Whether the device identified in part (k) tripped

RESPONSE:

Liberty objects to this Question as overly burdensome to the extent it seeks records and information not kept in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving these objections, Liberty responds as follows: Liberty is not subject to ignition reporting under D.14-02-015. From the start of Liberty's operations in approximately 2011 to 2020, Liberty is not aware of any ignitions associated with the Topaz 1261 Circuit prior to November 17, 2020.

REQUEST NO. 11:

Provide an Excel spreadsheet listing all wire-down events in 2010 through 2020 on the Topaz 1261 circuit. Each wire-down event should be a row. Provide the following data as columns:

a) Date of wire-down event
b) Time of wire-down event
c) Latitude of wire-down event

d) Longitude of wire-down event
e) Number of nearest pole
f) Cause, if identified
g) Whether Liberty had any asset corrective notifications at the location, that were open at the time of the wire-down event (Y/N)
h) Whether the wire-down event was linked to an asset corrective notification that existed at the time (Y/N)
i) ID number of the nearest protective device upstream of the wire-down event
j) Longitude in degrees of the device identified in part (i)
k) Latitude in degrees of the device identified in part (i)
l) Whether the device identified in part (i) tripped

RESPONSE:

Liberty objects to this Question as overly burdensome to the extent it seeks records and information not kept in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it purchased the California utility system from NV Energy. Subject to and without waiving these objections, Liberty responds as follows: Please see *CalAdvocates-LIB-A2506017-001-Q11.xlsx*, which contains available information in Liberty's possession regarding reported wire down events between 2016-2020. Liberty identified these events by querying its outage management system (OMS) for wire down events and reviewing the comments and resolution to determine if a valid wire down condition existed.

As explained in *Libery-03: Prudence of Operations* (pp. 32-33), Liberty's system was operated by NV Energy's system control center for a portion of the time period requested in this Question. Liberty's records for the requested data date back to approximately 2016. Please note that Liberty did not track the information requested in subparts (g)-(h) of this Question in relation to wire down events and that Liberty is producing the information requested in subparts (c)-(d) and (j)-(k) in the projected coordinate system format (NAD_1983_UTM_Zone_11N) as maintained in its GIS.

REQUEST NO. 12:

Please provide an Excel spreadsheet listing each outage that occurred from 2010 - 2020 on the Topaz 1261 circuit (or any portion of the Topaz 1261 circuit). The spreadsheet should list each outage in a row, with the following column headings:

a) Circuit segment ID #
b) Date of outage
c) Start time of outage
d) Cause of outage
e) For outages due to equipment failures, please state the specific type of equipment that failed. (for example: transformer failure, conductor failure, splice failure, etc.)
f) Outage duration in minutes
g) The type of protective device that tripped
h) The equipment number of the protective device that tripped
i) Latitude in degrees of the protective device that tripped

j) Longitude in degrees of the protective device that tripped

RESPONSE:

Liberty objects to this Question as overbroad to the extent that it seeks information prior to the start of its operation in approximately 2011, when it purchased the utility system from NV Energy. Subject to and without waiving these objections, Liberty responds as follows: Please see *CalAdvocates-LIB-A2506017-001-Q12.xlsx*, which contains the available outage information in Liberty's possession between 2016-2020. As explained in *Libery-03: Prudence of Operations* (pp. 32-33), Liberty's system was operated by NV Energy's system control center for a portion of the time period requested in this Question. Liberty's records for the requested data date back to approximately 2016. Please note that Liberty did not track the information requested in subpart (a) of this Question in relation to outages and that Liberty is producing the information requested in subparts (i)-(j) in the projected coordinate system format (NAD_1983_UTM_Zone_11N) as maintained in its GIS.

REQUEST NO. 13:

Provide a complete list of all wildfire risk mitigation measures Liberty developed or implemented between 2010 and November 2020.

a) Among the identified wildfire risk mitigation measures, which ones were proactive (that is, not implemented in response to specific, prior safety failures)?
b) How did Liberty determine the necessity and priority of the proactive wildfire risk mitigation measures identified in your response to part (a)?
c) What criteria or guidelines did Liberty follow in developing and implementing wildfire risk mitigation measures during the specified period?

RESPONSE:

Liberty objects to this Question as vague, ambiguous, and overbroad as framed. Liberty further objects to the extent that this Question seeks information prior to the start of its operation in approximately 2011, when it purchased the utility system from NV Energy. Liberty further objects to the term "proactive" in subparts (a) and (b). Wildfire mitigation measures are generally based on a utility's specific risk profile and past experience and are intended to proactively mitigate future wildfire risk. Distinguishing between measures that are "proactive" and those "in response to specific, prior safety failures" is not possible. Subject to and without waiving its objections, Liberty responds as follows:

Please refer to attachments *Fire Prevention Plan for Overhead Electric Facilities (2012).pdf*, *Wildfire Mitigation Plan (2019).pdf*, *Revised 2020 Wildfire Mitigation Plan.pdf*, and *2021 Wildfire Mitigation Plan Update (Public Version).pdf*. for detailed information regarding Liberty's wildfire mitigation efforts during the specified time frame. Although Liberty had not experienced a large wildfire attributed to its electrical infrastructure since taking over from Sierra Pacific in 2011, Liberty recognized the risk of wildfires within its service area and took steps to mitigate that risk. Liberty's opening testimony described wildfire risk mitigation measures that Liberty had adopted or was in the process of developing as of November 2020 (*see, e.g.*, Liberty-03 at 10-13), including:

- Patrols of circuits in high-fire areas during high wind conditions
- Implementing “fire settings” for reclosers
- Pausing discretionary maintenance and vegetation management activities during fire threat conditions
- Conducting a detailed system-wide asset survey
- Piloting a LiDAR inspection of its distribution system for vegetation clearance
- Installing covered conductor, including on the Topaz 1261 Circuit
- Undergrounding certain lines
- Installing larger size conductors
- Replacing and upgrading distribution poles
- Replacing expulsion fuses
- Deploying monitoring sensors and SCADA-enabled devices
- Installing weather stations to support situational awareness
- Developing a Fire Potential Index (FPI) to forecast wildfire risk
- Implementing a Public Safety Power Shutoff (PSPS) program
- Increasing the frequency of vegetation management inspections
- Removing dead and dying trees in high tree mortality areas
- Hiring additional personnel to manage emergency response activities

ATTACHMENT 28

Response to data request
CalAdvocates-LIB-A2506017-031, October 31, 2025

Liberty Utilities (CalPeco Electric) LLC
933 Eloise Avenue
South Lake Tahoe, CA 96150
Tel: 800-782-2506
Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-031
Requesting Party:	Public Advocates Office
Originator:	Charles Madison, Charles.Madison@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
Date Received:	October 16, 2025
Due Date:	October 30, 2025
Extension Granted:	October 31, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in the accompanying confidentiality declaration. Public disclosure is restricted.

REQUEST NO. 1:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 1:

> *As part of the transaction, there was an exchange of information related to Sierra Pacific's assets, and CalPeco's acquisition of the utility included files, documents, and papers related to the utility's business and the assets being purchased.*

a) Did Liberty obtain any asset condition records from NV Energy prior to assuming control of the Topaz 1261 circuit? If so, please provide copies of these records.
b) What actions, if any, did Liberty take to confirm the accuracy, completeness, and reliability of the inherited asset condition records before assuming operational control of Topaz 1261?

c) After acquisition, did Liberty receive any asset condition records for Topaz 1261? If so, please provide copies.
d) Is Liberty able to provide any evidence it conducted a risk assessment or asset condition survey at or before acquisition? If so, please provide copies of such evidence. If not, explain why.
e) Did Liberty perform any internal audit or gap analysis to understand what records were missing at the time of acquisition? If so, please provide copies of such records. If not, explain why.

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and unintelligible as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including in seeking asset condition records for the entire Topaz 1261 Circuit with no time limitation and detailed information related to Liberty's acquisition of the utility nearly 15 years ago. Liberty further objects to this Question to the extent that it seeks information that is not relevant to this proceeding. Subject to and without waiving its objections, Liberty responds as follows:

a) As set forth in Liberty's response to CalAdvocates-LIB-A2506017-15, Question 1, Liberty's acquisition in approximately 2011 included files, documents, and papers related to the utility's business and assets being purchased. Thus, Liberty obtained asset condition records from NV Energy as part of the transaction. Liberty is in possession of some asset condition records from prior to the time of acquisition. For example, Liberty has located intrusive inspection results from 2010, see confidential attachment *CONFIDENTIAL-2010 Intrusive Pole Inspection Data.xlsx*, and annual GO 165 reports for 2006-2010, see attachment *2006-2010 GO 165 Annual Reports.pdf*. Liberty is continuing to search for pre-acquisition records related to the Topaz 1261 Circuit and will update this response to the extent identified.
b) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
c) Liberty assumes this subpart seeks information regarding records received from NV Energy given Liberty previously provided Cal Advocates with records of its inspections of the Topaz 1261 Circuit after 2011. See Liberty's responses to subpart (a) and CalAdvocates-LIB-A2506017-15, Question 1.
d) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.
e) Liberty has not identified specific records and information that it understands to be responsive to this request given the passage of time.

REQUEST NO. 2:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 4:

> *Liberty located routine patrol records for the Topaz 1261 Circuit from the years 2013, 2015, and 2017, which Liberty attached to its response to CalAdvocates-LIBA2506017-004, Question 2. During that time frame, GO 165 required patrol inspections on overhead facilities in rural areas once every two years. As explained in Liberty-03, Liberty conducted a detailed inspection on the Topaz 1261 Circuit in the first half of*

2020 and Liberty has not located records confirming a patrol of the Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.

a) Does Liberty maintain any policy defining how long routine patrol or detailed inspection documentation must be retained? If so, please provide copies of such policies.
b) Can Liberty confirm whether GO 165 patrols occurred on Topaz 1261 between 2018 and 2020? If not, is Liberty asserting that patrols were completed but undocumented or that they were never conducted?
c) Has Liberty identified any other circuits besides Topaz 1261 for which it cannot locate records to confirm that a patrol inspection occurred during a given period exceeding two years? If so, what are they?

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty adheres to regulatory requirements regarding recordkeeping, and those requirements govern Liberty's general approach with respect to the retention of such documentation.
b) Liberty reported in its GO 165 annual reports for 2018-2020 that it completed patrols on all of its circuits in each of those years (54 circuits in 2018 and 55 circuits in 2019 and 2020). Liberty has not located further documentation of patrols of Topaz 1261 Circuit between November 2017 and the 2020 detailed inspection.
c) Liberty continues to research patrol inspections on circuits other than the Topaz 1261 Circuit to identify any responsive circuits, and will update its response to the extent identified.

REQUEST NO. 3:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 5:

Liberty was in the early stages of its transition to digital inspection record collection and tracking in 2020 and Liberty initially used the same electronic inspection records from the 2020 asset survey to track additional information regarding the same poles from later inspections. As a result, the spreadsheet Liberty generated from its database and provided in response to CalAdvocates-LIB-A2506017-001, Question 2 is not limited to issues, condition codes, and repair dates from the 2020 asset survey; rather the spreadsheet also includes issues, condition codes and repair dates associated with certain inspections after 2020 for the same poles.

a) Please confirm if Liberty reused electronic inspection records (Fulcrum) from the 2020 asset survey to track conditions found in later years from other inspections.
b) If so, please provide a list of the inspections.
c) If so, please confirm whether the original data was overwritten? What controls, if any, preserved data from previous inspection years?
d) Is Liberty able to produce any evidence distinguishing 2020 findings from later updates in Fulcrum? If so, please provide copies. If not, please explain why not.

RESPONSE:

This response contains confidential attachments. Liberty objects to this question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Fulcrum is a geospatial data collection software that houses different applications. Liberty created an application within Fulcrum for data collection and tracking for the 2020 asset survey. Liberty created additional applications in Fulcrum to collect and track inspection data for routine inspections such as GO 165 detailed inspections occurring between 2021 and 2023. Liberty inspectors used the 2020 asset survey application to collect and track data from some non-routine inspections of certain asset locations after the 2020 asset survey. The spreadsheet Liberty provided in response to CalAdvocates-LIB-A2506017-001, Question 2 contains inspection records on the Topaz 1261 Circuit with a creation date of 2020 from the 2020 asset survey application, which may contain data gathered during certain non-routine inspections performed after the 2020 asset survey. This spreadsheet does not contain data collected and tracked in other applications in Fulcrum, such as those created for GO 165 inspections between 2021 and 2023.
b) See Liberty's response to subpart (a).
c) Each update to an inspection record in the 2020 asset survey application was preserved in the record's event history.
d) Liberty is providing the complete output of Fulcrum inspection records from the 2020 asset survey associated with the Topaz 1261 Circuit in confidential attachment *CONFIDENTIAL-CalAdvocates-LIB-A2506017-31-Q3.csv*. This output is arranged by asset inspection record and contains the full event history for each record.

REQUEST NO. 4:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-15, question 6:

> *Liberty attempted to complete all compliance-based conditions by the assigned due dates, though, for some conditions, factors beyond Liberty's control, such as permitting, customer refusal, access difficulties, and emergencies such as the Covid-19 pandemic, may cause Liberty to require additional time to complete the remediation. Pursuant to GO 95, Rule 18(A)(2)(b), such "reasonable circumstances" can justify an extension of the remediation timeframe. Some Level 3 issues identified may also fall into conditions listed in GO 95, Appendix J, for which issues may be addressed as opportunity maintenance.*

a) Provide an Excel file with a list of all due-date extensions under GO 95, Rule 18 for Topaz 1261 from 2016–2021, including reason codes, elapsed time, and interim risk mitigations.
b) Were any GO 95 extension requests documented with interim risk controls?
c) If the answer to subpart (b) is yes, provide evidence supporting your answer.
d) If the answer to subpart (b) is no, explain why.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as overbroad and unduly burdensome, including to the extent it seeks information

not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty is not aware of records formally tracking due-date extensions on the Topaz 1261 Circuit in the specified time frame.
b) See response to subpart (a). Liberty is also not aware of records formally tracking interim risk controls associated with due-date extensions on the Topaz 1261 Circuit in the specified time frame.
c) N/A
d) N/A

REQUEST NO. 5:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 4:

> *Please see attachment CalAdvocates-LIB-A2506017-001-Q4.xlsx, which contains available data related to intrusive pole inspections conducted on the Topaz 1261 Circuit in 2013, the only year between 2011 and 2020 in which such inspections were performed on this circuit. This spreadsheet contains three tabs for corrective work identified by these inspections: "Restorable" – poles that were identified for reinforcement; "Non-Restorable" – poles that were identified for replacement; and "Hazard Poles" – poles that were identified for urgent replacement. Liberty addressed corrective work using hard-copy work packets during the specified time frame; following a reasonable search and diligent inquiry, Liberty has not located records showing when the corrective work was completed.*

a) Is Liberty able to confirm that some poles may have remained in service through the Mountain View Fire without documented closure?
b) If so, identify all poles still in service that were classified as "Non-Restorable" or "Hazard" in 2013.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Based on data contained within Liberty's GIS database, its Fulcrum database, pole replacement work orders, and field verification, Liberty verified that all poles classified as "Non-Restorable" and "Hazard Poles" in attachment *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, except for one, were replaced prior to November 17, 2020. Liberty is working to determine whether the pole located at latitude/longitude location 38.64995, -119.53329 was in service as of November 17, 2020. This pole is a structural support pole and does not support any energized lines.
b) No poles classified as "Non-Restorable" or "Hazard" in the 2013 intrusive inspection results are still in service today.

REQUEST NO. 6:

Referring to Liberty's response to CalAdvocates-LIB-A2506017-01, question 9:

Liberty reviewed the reliability of its electric system on an annual basis…These reliability reports identified the Topaz 1261 as a circuit that experienced more frequent outages. As a result of these findings and because the Topaz 1261 Circuit is exposed to harsh weather conditions, Liberty prioritized this circuit for system hardening.

a) Why did Liberty not initiate the Topaz 1261 reconductoring or hardening project during 2015–2017 when it had already identified the circuit as one of its worst-performing circuits and highest risks on a known failure-prone circuit?
b) Why were reliability metrics (outage frequency) used over ignition metrics when justifying the need for a covered conductor project?
c) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing not to initiate the Topaz 1261 reconductoring or hardening project during 2015-2017.
d) Provide any internal reports, presentations, or other documentation of the decision-making that led to Liberty choosing to use reliability metrics over ignition metrics when justifying the need for a covered conductor pilot.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and argumentative as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) As stated in Liberty's 2019 GRC, filed in December 2018 (A-18-12-001), Liberty had been working diligently to replace its aging infrastructure since purchasing the utility from NV Energy in 2011, including the re-conductoring of old lines to enhance safety and reliability. Liberty's capital planning process sought to balance the need to prioritize safety and reliability upgrades with the need to provide service to its customers at a reasonable cost. To that end, in its 2019 GRC filing, Liberty requested and was granted approval to fund the Topaz 1261 Rebuild Project and other safety and reliability projects (e.g., the 7300 Line rebuild project) and undertook those projects over time.
b) Liberty objects to this subpart as assuming facts. As described in Liberty's 2019 GRC, Ex. *Liberty-02: Capital* (at pp. 8-9), both reliability metrics and the occurrence of an ignition event on the Topaz 1261 Circuit drove Liberty's decision to pursue the Topaz 1261 Rebuild Project. As stated in Liberty's testimony, the project would both "increase the reliability of the system" and "mitigate the risk of fires." Indeed, underlying events that affect circuit reliability and cause outages, such as wire-to-wire contact or contact with objects, also carry the potential for ignition.
c) Liberty objects to this subpart as assuming facts. Please refer to Ex. *Liberty-02: Capital*, filed in support of Liberty's 2019 GRC filing (A.18-12-001), for further discussion of Liberty's decision to seek funding for the Topaz 1261 Rebuild Project. Between 2015-2017, Liberty invested in safety and reliability upgrades on its system through other capital projects such as the 625/650 Upgrade project. As the Commission concluded in D.15-03-020, the 625/650 Upgrade project "would increase the reliability and safety of electric power delivery within the Lake Tahoe basin," including "reducing risks of wildfire and vegetation-related outages." *See* D.15-03-020 at 47.
d) Liberty objects to this subpart as assuming facts. See Liberty's response to subparts (b)-(c).

ATTACHMENT 29

Response to data request
CalAdvocates-LIB-A2506017-032, October 31, 2025

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Fax: 530-544-4811

October 31, 2025

Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

Data Request No.:	CalAdvocates-LIB-A2506017-032
Requesting Party:	Public Advocates Office
Originator:	Amanda Asadi, Amanda.Asadi@cpuc.ca.gov
	Aaron Louie, Aaron.Louie@cpuc.ca.gov
	Patrick Huber, Patrick.Huber@cpuc.ca.gov
cc:	Matthew Karle, Matthew.Karle@cpuc.ca.gov
	Cal Advocates Wildfire Discovery CalAdvocates.WildfireDiscovery@cpuc.ca.gov
Date Received:	October 16, 2025
Due Date:	October 30, 2025
Extension Granted:	October 31, 2025

Attachments to these responses contain information marked confidential in accordance with applicable law and regulation. The basis for confidentiality is set forth in the accompanying confidentiality declaration. Public disclosure is restricted.

Public Safety Power Shutoffs (PSPS)

REQUEST NO. 1:

Provide redacted (non-confidential) versions of the following documents:

a) Response CalAdvocates-LIB-A250607-011, attachment "CONFIDENTIAL-2019-08-20 Liberty Utilities de-energization thresholds"; and
b) Response CalAdvocates-LIB-A250607-011, attachment "CONFIDENTIAL-Emergency Response PSPS Playbook."

RESPONSE:

Liberty will provide redacted versions of the "CONFIDENTIAL-2019-08-20 Liberty Utilities de-energization thresholds" and "CONFIDENTIAL-Emergency Response PSPS Playbook."

Outages

REQUEST NO. 2:

Liberty's response to Data Request CalAdvocates-LIB-A2506017-001, Question 11 excel "CalAdvocates-LIB-A2506017-001-Q11" provides **wire down events** in 2016 through 2020 on Topaz 1261 circuit. Provide documentation of the work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided) performed for the following Incident IDs:

- 13401
- 7710
- 12711

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and overbroad as framed, including with respect to its reference to "work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided)." Subject to and without waiving its objections, Liberty responds as follows: See *CONFIDENTIAL-Attachment to CalAdvocates-LIB-A2506017-032, Q2.zip* for records from Liberty's Outage Management System (OMS) that describe Liberty's response to the outage and reference corrective actions.

REQUEST NO. 3:

Liberty's response to Data Request CalAdvocates-LIB-A2506017-001, Question 12 in Excel file "CalAdvocates-LIB-A2506017-001-Q12" provides **outage events** in 2016 through 2020 on the Topaz 1261 circuit. Provide documentation of the work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided) performed for the following Incident IDs:

- 6264
- 7313
- 7314
- 7386
- 7392
- 7589
- 7641
- 7648
- 7755
- 7764
- 9054

- 12687
- 12703
- 12711
- 13123
- 13211
- 13401
- 13934
- 13939
- 14405
- 15270
- 15336
- 15337
- 15339
- 15414
- 15763
- 16693
- 17187
- 17188
- 17340
- 17554
- 17555
- 17574
- 17767
- 17921
- 18165
- 18203
- 19501
- 20230
- 20233
- 21042
- 21347
- 21408
- 22003
- 22668
- 22740
- 22993
- 23101
- 23105
- 24277
- 24279
- 24360
- 25414
- 25635
- 25895

- 26618
- 26776
- 27841
- 27967
- 28018
- 28024
- 28225

RESPONSE:

This response contains confidential attachments. Liberty objects to this Question as vague, ambiguous and overbroad as framed, including with respect to its reference to "work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided)." Subject to and without waiving its objections, Liberty responds as follows: See *CONFIDENTIAL-Attachment to CalAdvocates-LIB-A2506017-032, Q3.zip* for records from Liberty's Outage Management System (OMS) that describe Liberty's response to the outage and reference corrective actions.

REQUEST NO. 4:

In Liberty's 2016 Electric System Reliability Report, page 22, Liberty states:[1]

> With a combined total of over $700,000 invested by the end of 2017 to improve the Topaz 1261 circuit, CalPeco Electric expects the quantity of sustained outages due to wire slapping in windy conditions to be significantly reduced. In 2016, this circuit experienced twelve outages that were suspected wire slapping events and accounted for 780 customer outage minutes.

a) List the Incident IDs of the twelve outages that were suspected wire slapping events.
b) List the Incident IDs of any other outages from 2015 through 2020 that were suspected wire slapping events.
c) If the Incident IDs in subparts (a) or (b) were not listed in Question 2 or Question 3 above, provide documentation of the work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided) performed.

RESPONSE:

a) Based on review of historical outage data and OMS records, Liberty identified seven outages in 2016 that were identified as suspected wire slapping events. Liberty identified these events by reviewing historical outage data for outages where the cause codes or remarks explicitly indicated wire-slapping-related causes. Liberty identified and confirmed Incident IDs in its OMS for each outage event and provides them below. After a reasonable search and diligent inquiry, Liberty has not identified additional outages in 2016 that were identified as suspected wire slapping events as

[2] Liberty's 2016 Electric Service Reliability Report, July 15, 2017. Accessed at: https://files.cpuc.ca.gov/egy_Reliability_GO165Reports/ReliabilityRpts/2016/Liberty_2016_Reliability_Annual_Report.pdf

referenced in the 2016 Electric System Reliability Report. As explained in *Liberty-03: Prudence of Operations* (at pp. 32-33), Liberty's system was operated by NV Energy's system control center during the time frame specified in this Question.

- 101
- 6264
- 7067
- 7144
- 7159
- 7392
- 7648

b) Based on review of historical outage data and OMS records, Liberty identified thirty-one outages on the Topaz 1261 Circuit from 2015 through 2020 that were identified as suspected wire slapping events. Liberty identified wire slapping events by reviewing historical outage data for outages where the cause codes or remarks explicitly indicated wire-slapping-related causes. Liberty does not have Incident IDs for nine outages in 2015 identified as suspected wire-slapping events in its historical outage data because Liberty's OMS records date back to approximately 2016. For outages from 2016 to 2020, Liberty identified and confirmed Incident IDs in its OMS for each outage. Liberty identified one incident in its 2017 historical outage data that does not have a corresponding OMS record. As explained in *Liberty-03: Prudence of Operations* (at pp. 32-33), Liberty's system was operated by NV Energy's system control center for a portion of the time frame specified in this Question. The following are Incident IDs from OMS for outages identified as suspected wire slapping events from 2017 through 2020 that were not already included in subpart (a):

- 7755
- 8658
- 12703
- 13123
- 15270
- 17187
- 17190
- 17340
- 17574
- 17921
- 22711
- 24277
- 24279
- 27841

c) This response contains confidential attachments. Liberty objects to this subpart as vague, ambiguous and overbroad as framed, including with respect to its reference to "work order or corrective actions (i.e., the entire record in Liberty's Outage

Management System (OMS) for the Incident ID provided)." Subject to and without waiving its objections, Liberty responds as follows: See *CONFIDENTIAL-Attachment to CalAdvocates-LIB-A2506017-032, Q4.zip* for records in Liberty's OMS for the Incident IDs identified in subparts (a) and (b) that are not being provided in response to Questions 2 or 3 of this set of data requests and that describe Liberty's response to the outage and reference corrective actions. With respect to the nine outages in 2015 identified in Liberty's historical outage data, Liberty is unable to provide OMS records because its OMS records date back to approximately 2016. For an incident described as number "814" in its 2017 historical outage data, Liberty has not located a corresponding OMS record after a reasonable search and diligent inquiry. As explained in *Liberty-03: Prudence of Operations* (at pp. 32-33), Liberty's system was operated by NV Energy's system control center for a portion of the time frame specified in this Question.

REQUEST NO. 5:

Liberty's 2019 Reliability report shows that Topaz 1261 circuit had a total of 25 outages, see breakdown of outages in Table 1. Liberty's response to Data Request CalAdvocates-LIB-A2506017-001, Question 12 shows that Topaz 1261 circuit had a total of 21 outages, see breakdown of outages in Table 1.

Table 1. Comparison of Liberty's 2019 Reliability Report compared to Liberty's Response to Data Request CalAdvocates-LIB-A2506017-001, Question 12.

2019 Reliability Report[2]	**Liberty's response to Data Request CalAdvocates-LIB-A2506017-001, Question 12[3]**
3 – Loss of source from a third party owned substation	6 – 3rd Party Outage
6 – equipment/hardware failure	2 – deterioration 2 – device failed
3 – weather related	1 – flying debris
1 – trees	2 – tree- broken limb
1 – operations error	
	1 – animal
	1 – non-company activities
	2 – planned outage
11 – unknown[4]	4 – unknown
Total – 25	Total – 21

[3] Liberty's 2019 Electric Service Reliability Report, February 1, 2020. Accessed at: https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/infrastructure/electric-reliability-reports/2019_peco.pdf

[4] Liberty's response to Data Request CalAdvocates-LIB-A2506017-001, September 10, 2025, Question 12, Excel file "CalAdvocates-LIB-A2506017-001-Q12.xlsx"

[5] Liberty's 2019 Reliability Report at 22. "There were 25 unplanned outages in 2019 for the 1261 circuit, 3 were due to a loss of source from a third party owned substation, 6 were due to equipment/hardware failure, 3 were weather related, 1 was due to trees,1 was due to an operations error and the rest were unknown." The number of unknown outages was calculated from 25 – 3 – 6 – 3 – 1 – 1 = 11.

Explain the discrepancy between the number and types of outages between Liberty's 2019 Reliability Report and Liberty's response to data request CalAdvocates-LIB-A2506017-001, Question 12.

RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows: Based on review of Liberty's OMS and historical outage data, Liberty has identified 20 outages affecting the Topaz 1261 Circuit in 2019. Incident ID 23177 should not have been listed as an outage in the attachment to CalAdvocates-LIB-A2506017-001, Question 12 given Liberty's OMS data indicates the event affected zero customers and the outage is not included in historical outage data. Liberty will amend its response to CalAdvocates-LIB-A2506017-001 to provide an updated attachment. Liberty has not identified additional outages affecting the Topaz 1261 Circuit referenced in the 2019 Electric System Reliability Report.

REQUEST NO. 6:

Regarding Liberty's 2015 Electric System Reliability Report, page 21, Liberty states:[5]

5) Top two worst performing circuits (WPC) excluding TMED

I. For each of these circuits each utility shall include the following information in its annual report: 1) Circuit Name; 2) District/Division; 3) Customer Count; 4) Substation name; 5) Circuit-miles; 6) Percentage underground, or "% UG"; 7) Percentage overhead or "% OH"; 8) Number of mainline/feeder/backbone outages resulting in the operation of either a circuit breaker ("CB") or automatic re-closer ("AR"); and, 9) its preferred reliability metric.

Circuit	District	Customer Count	Substation Name	Circuit Miles	Facilities		Number of Mainline/ Feeder/Backbone Outages	*Circuit SAIDI	Circuit SAIFI
					OH	UG			
1261	Tahoe	744	Muller	75.5	90.7%	9.3%	3	3003	0.016
1296	Tahoe	622	Topaz	70.9	76.2%	23.8%	8	1065	0.016

Note: Preferred Metric is Circuit SAIDI

In the excerpt above, Circuit 1261 appears to be linked with Substation Muller while Circuit 1296 appears to be linked with Substation Topaz. In the Application, Exhibit Liberty-03, page 7, Liberty states "The Topaz 1261 Circuit originates from Topaz Substation, an NV Energy substation in Nevada." In Liberty's response to Data Request CalAdvocates-LIB-A2506017-011, question 7, Liberty states "As described therein, de-energization thresholds were the same in all PSPS zones other than the Topaz 1261 and Muller 1296 circuit zones."

Explain the discrepancy and provide any amended information.

[6] Liberty's 2015 Electric Service Reliability Report, July 15, 2016. Accessed at: https://files.cpuc.ca.gov/egy_Reliability_GO165Reports/ReliabilityRpts/2015/Liberty_2015_Reliability_Annual_Report.pdf

RESPONSE:

The table from the 2015 Electric System Reliability Report contains an error. The substation name "Muller" should be in the second row of the fourth column associated with Circuit 1296, and the substation name "Topaz" should be in the first row of the fourth column associated with Circuit 1261.

REQUEST NO. 7:

In Liberty's 2015 Electric System Reliability Report, pages 25-31, Liberty shows that Lake Tahoe (Topaz) was affected by an outage due to "Trees – High Winds" from February 6, 2015 through February 9, 2015.

a) Confirm that Liberty correctly identified the Topaz 1261 circuit for the referenced outage.
b) At exactly what date and time did this outage due to "Trees – High Winds" begin?
c) At exactly what date and time did this outage due to "Trees – High Winds" end?
d) Provide the Incident ID and provide documentation of the work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided) performed.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and overbroad as framed, including with respect to its reference to "work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided)." Subject to and without waiving its objections, Liberty responds as follows: Liberty notes that its OMS records date back to approximately 2016. As explained in *Liberty-03: Prudence of Operations* (at pp. 32-33), Liberty's system was operated by NV Energy's system control center during the time frame specified in this Question. Based on review of historical outage data:

a) Liberty correctly identified the Topaz 1261 Circuit for the referenced outage.
b) This outage began at 6:30 a.m. on February 6, 2015.
c) This outage ended at 2:28 a.m. on February 9, 2015.
d) Liberty is unable to provide OMS records related to this outage because its OMS records date back to approximately 2016.

REQUEST NO. 8:

In Liberty's 2015 Electric System Reliability Report, pages 25-26, Liberty shows that Lake Tahoe (Muller) was affected by an outage due to "NV Energy Outage – High Winds" from February 6, 2015 through February 6, 2015.

a) Confirm that Liberty correctly identified the Muller 1296 circuit for the referenced outage.
b) At exactly what date and time did this outage due to "NV Energy Outage – High Winds" begin?
c) At exactly what date and time did this outage due to "NV Energy Outage – High Winds" end?

e) Provide the Incident ID and provide documentation of the work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided) performed.

RESPONSE:

Liberty objects to this Question as vague, ambiguous and overbroad as framed, including with respect to its reference to "work order or corrective actions (i.e., the entire record in Liberty's Outage Management System (OMS) for the Incident ID provided)." Subject to and without waiving its objections, Liberty responds as follows: Liberty notes that its OMS records date back to approximately 2016. As explained in *Liberty-03: Prudence of Operations* (at pp. 32-33), Liberty's system was operated by NV Energy's system control center during the time frame specified in this Question. Based on review of historical outage data:

a) Liberty correctly identified the Muller 1296 circuit for the referenced outage.
b) This outage began at 12:06 p.m. on February 6, 2015.
c) This outage ended at approximately 7:15 p.m. on February 6, 2015.
e) Liberty is unable to provide OMS records related to this outage because its OMS records date back to approximately 2016.

ATTACHMENT 30

Southern California Edison,
2019 Wildfire Mitigation Plan, February 6, 2019

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) 2019 WILDFIRE MITIGATION PLAN

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Dated: **February 6, 2019**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) 2019 WILDFIRE MITIGATION PLAN

Southern California Edison Company (SCE) hereby submits its 2019 Wildfire Mitigation Plan (WMP). The WMP consists of the following:

Chapter 1: Objectives of the Plan
Chapter 2: Description of the Preventive Strategies and Programs to Minimize the Risk of Electrical Distribution and Transmission Infrastructure-Causing Wildfires (Including Consideration of the Dynamic Climate Change Risk)
Chapter 3: Risk Analysis and Risk Drivers
Chapter 4: Wildfire Prevention Strategies and Programs
Chapter 5: Emergency Preparedness and Response
Chapter 6: Performance Metrics and Monitoring
Chapter 7: Any Other Information that the CPUC May Require (Cost Information)
Appendix A: List of Acronyms
Appendix B: Categorization of Strategies and Programs
Appendix C: List of SCE Design, Engineering and Construction Standards
Appendix D: List of Fast Growing Trees
Appendix E: List of SCE Field Workers, Support Personnel and Contract Crews
Appendix F: Comparison of WMP to 2018 Fire Prevention Plan

CA-07-1329

Respectfully submitted,

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February 6, 2019



Southern California Edison

2019 Wildfire Mitigation Plan

February 6, 2019

CA-07-1331

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1 OBJECTIVES OF THE PLAN

1.1 INTRODUCTION

California's wildfire risk has increased in recent years due to climate change, drought, and other factors such as increased development in the wildland-urban interface and significant build-up of fuel, including on federal and state forest lands. The full magnitude of the increased threat and the significance of its consequences did not become apparent until 2017, when California experienced five of the most destructive fires in its history. The 2017 and subsequent fires in 2018 fires — eight of the 20 most destructive wildfires in California history occurred in 2017 and 2018, destroying more than 31,000 structures (double the number consumed by the other twelve)[1] — emphasize that California's wildfire risk has increased to the point where the safety of our communities requires additional measures designed to address the higher level of wildfire risk. To this end, California Senate Bill 901 (SB 901), enacted in 2018, adopted new provisions of Public Utilities Code (PUC) Section 8386 requiring all California electric utilities to prepare, submit and implement annual wildfire mitigation plans that describe the utilities' plans to construct, operate and maintain their electrical lines and equipment in a manner that will help minimize the risk of catastrophic wildfires associated with those electrical lines and equipment.

This ***Southern California Edison 2019 Wildfire Mitigation Plan*** describes strategies, programs and activities that are in place, being implemented or are under development by Southern California Edison (SCE or Company) to proactively address and mitigate the threat of electrical infrastructure-associated ignitions that could lead to wildfires, further harden the electric system against wildfires and enhance wildfire suppression efforts, meeting the requirements of PUC Section 8386 in accordance with the California Public Utilities Commission (CPUC or Commission) rulemaking to implement it.[2] The 2019 Wildfire Mitigation Plan (WMP) applies to all of SCE's internal organizations and contractors with responsibility for the design, engineering, construction, operation, inspection, and maintenance of SCE's electrical infrastructure.

The mitigation strategies and programs described in this WMP are specifically intended to address unique features of SCE's service territory such as topology, weather, infrastructure, potential wildfire risks, and grid configuration. As such, there will and should be some differences with the other large investor-owned utilities' (IOUs) plans due to differences in their respective service areas and grid configurations.

In addition to the descriptions of strategies and programs, in subsequent chapters, SCE includes 2019 goals and metrics to enable the Commission to evaluate SCE's compliance with the WMP. Substantial compliance with the objective metrics set forth in the WMP (when approved by the Commission) will demonstrate that SCE prudently operated its system, and met the Commission's "prudent manager" standard regarding wildfire risk mitigation. Additionally, when feasible and appropriate, SCE will attempt to complete fire mitigation work and activities in excess of the goals set forth in subsequent chapters, which, if performed, would be an acceleration of future years' fire mitigation activities. This WMP also details additional potential work that SCE may undertake in 2019. Certain risks outside of SCE's reasonable control, such as skilled labor resource constraints, supply chain disruptions, permitting and construction delays, and other unexpected events, could negatively impact SCE's ability to meet all of

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1 *See* http://www.fire.ca.gov/communications/downloads/fact_sheets/Top20_Destruction.pdf.

2 *See* Appendix A for a list of all acronyms used in this Wildfire Mitigation Plan.

the approved metrics, and should be considered by the Commission when completing its subsequent compliance evaluation.

In response to Administrative Law Judge Thomas' January 17, 2019 Ruling (Ruling), SCE has included cost estimates for each activity in Chapter 4 of this WMP in order for the Commission to weigh the potential cost implications of measures proposed in the plans. SCE has included preliminary cost estimates for the scope of work underlying the 2019 compliance goals, and for the scope of work underlying potential acceleration of future years' activities, where applicable. It is important to keep in mind, however, that both SB 901 and the Order Instituting Rulemaking (R.)18-10-007 make clear that this proceeding, and the WMP itself, are not cost recovery exercises. Instead, pursuant to the statute, SCE will track the costs for programs and activities detailed throughout this WMP, and in the future seek recovery for any incremental costs in the appropriate procedural forum. For cost recovery purposes, demonstrating substantial compliance with the Commission-approved WMP requirements should facilitate the Commission's subsequent reasonableness review of the costs recorded to SCE's SB 901 or other appropriate memorandum account.

In addition, the Commission has long recognized that utilities need appropriate flexibility to use management discretion to assess and respond to emergent risks and as they arise. Because wildfire risk is affected by climate change effects and local conditions, and because many of the programs and activities described in this WMP are in the early stages of development and deployment, such flexibility will be especially important. If such circumstances arise, SCE will make changes, as appropriate, to its wildfire risk mitigation efforts consistent with the Commission's expectation that utilities will exercise operational discretion and flexibility to maintain safe, reliable, and resilient service for their customers, and will inform the Commission should such changes in 2019 significantly deviate from this WMP. In the event that it is necessary and appropriate to make mid-year changes, or in the event that exogenous factors necessitate a deviation from the specific goals set forth herein, SCE will seek timely approval from the Commission for such changes or deviations.[3]

Finally, many (but not all) of the programs and activities described herein will be funded through either SCE's Grid Safety and Resiliency Program (GSRP) Application (A.18-09-002) or Commission-approved General Rate Case (GRC) rates. The Commission has not yet issued a Proposed Decision in SCE's pending 2018 GRC (A.16-09-001), which was filed on September 1, 2016. Notably, SCE's 2018 GRC, and the specific programmatic funding requests set forth therein, was based on needs and risks that in some cases are very different than the needs and risks California faces today. The 2018 GRC was litigated on the record in that proceeding, which reflected realities as they existed then. Given the unprecedented risks that wildfires now pose to the public and the electric system, SCE must retain the utility discretion to effectively counter those emergent threats as necessary once a decision in the GRC is approved.

1.2 PLAN OBJECTIVES

The primary objective of this WMP is to set forth an actionable, measurable, and adaptive plan for 2019 to reduce the risk of potential wildfire-causing ignitions associated with SCE's electrical infrastructure in High Fire Risk Areas (HFRA).[4] Additional 2019 objectives include protecting public safety, implementing

[3] SCE will make such notifications to the Commission through a letter to the Director of the Safety and Enforcement Division (SED), or as otherwise directed by the Commission.

[4] As further described in Chapter 3, SCE had previously identified locations in its service area as high fire risk prior to the release of the most recent CPUC High Fire Threat District maps with Tier 2 and Tier 3 designation

measures that further harden SCE's electric system against wildfires and improve system resiliency, enhancing wildfire suppression efforts by improving fire agencies' ability to detect and respond to emerging fires in coordination with utility emergency management personnel, reducing the impact of wildfires and wildfire mitigation efforts on the public, and effectively communicating with customers, community groups, and other stakeholders about how to prepare for, prevent, and mitigate wildfires in SCE's HFRA (including, when appropriate, through preemptive de-energization events).

This WMP is focused on 2019 activities and include overviews of existing programs, practices and standards; enhancements recently enacted and being implemented; and new and developing efforts to further reduce potential electrical infrastructure-associated ignitions in HFRA. Several strategies and programs in this WMP are multi-year efforts designed to target the highest risk drivers for potential wildfire-causing ignitions. In Chapter 3, SCE provides a description of its methodologies for identifying and prioritizing action on wildfire risk factors, with the recognition that there are potential tradeoffs between risk mitigation measures. SCE anticipates that as it gains new and additional information about factors affecting the nature of wildfire risk, it will assess its performance against each annual WMP. Each subsequent year's WMP will be adjusted and improved to continually focus on activities mitigating the highest wildfire risks. Accordingly, consistent with the requirements in PUC Section 8386 and the Ruling, this WMP sets forth SCE's 2019 compliance plan to minimize wildfire risk. Over time and cumulatively, the success of the individual programs and activities in this WMP are expected to result in an overall reduction of controllable fire ignition events associated with SCE's electrical infrastructure.

1.2.1 BEFORE UPCOMING WILDFIRE SEASON

In Chapter 4, SCE identifies activities for strategies and programs that it will complete in 2019 in HFRA. This chapter includes a description of those activities addressing the highest wildfire-risk issues. SCE plans on completing those activities before the traditional beginning of the annual fire season,[5] and Chapter 4 includes the corresponding goals for these wildfire risk mitigation activities.

1.2.2 BEFORE THE NEXT WILDFIRE MITIGATION PLAN FILING[6]

Chapter 4 of this WMP describes the programs and activities SCE intends to complete by year-end 2019. SCE's objective with regard to this timeframe is to complete all of the described activities and meet or exceed its 2019 goals in such areas as (but not limited to) operational practices, inspections, system hardening, vegetation management, situational awareness, Public Safety Power Shut-Off (PSPS), alternative technologies, and post-incident recovery, restoration, and remediation strategies and programs. These goals are further described in subsequent chapters.[7]

1.2.3 WITHIN THE NEXT FIVE YEARS

In some cases because of resource constraints or because they are necessarily longer-term efforts, some of the programs and activities set forth herein are scheduled to take place over longer time frames (up

(*see* Decision (D.)17-12-024). Accordingly, SCE's definition of HFRA for purposes of this WMP includes areas beyond the CPUC Tier 2 and Tier 3 designations including, for example, previously designated HFRA.

5 The traditional beginning of the wildfire season in Southern California is early summer, but increasingly California has experienced wildfires year-round.

6 SCE interprets this category to mean the programs and activities in Chapter 4 that will be completed by year-end 2019. Given that the schedule for next year's WMP filing has not been set, SCE generally understands this category to represent those strategies and programs that will be completed in 2019.

7 Goals are described in Chapters 3 through 6.

to five years and beyond). For example, SCE's Wildfire Covered Conductor Program (WCCP) is a long-term program for which full deployment will go beyond five years, due in part to supply chain and skilled labor installation resource availability. As described in Section 4.3, SCE is attempting to accelerate and expand this program to install more covered conductor in HFRA, this year and within the next five years, beyond the amount contemplated in SCE's GSRP. These longer-term programs are described in Chapter 4, and the discussion therein further delineates between shorter- and longer-term objectives within those programs.

2 DESCRIPTION OF THE PREVENTIVE STRATEGIES AND PROGRAMS TO MINIMIZE THE RISK OF ELECTRICAL DISTRIBUTION AND TRANSMISSION INFRASTRUCTURE-CAUSING WILDFIRES (INCLUDING CONSIDERATION OF THE DYNAMIC CLIMATE CHANGE RISK)

2.1 INTRODUCTION

Fire mitigation has been an integral part of SCE's operational practices for years, and SCE has several existing policies, programs, and procedures in place that directly or indirectly manage or reduce this risk. Over time, SCE has adopted additional fire mitigation programs to adjust to changes in fire-related conditions as well as technological advances and improved operational practices. SCE continues to evaluate and implement new technologies and operating practices to further mitigate the potential for ignitions and to better respond to high wildfire risk conditions.

In early 2018, in response to the significantly increased wildfire risk, SCE created a program management office (PMO) consolidating SCE's fire mitigation efforts and focused on protecting public safety and system resiliency. SCE charged the PMO with the following overarching objectives: (1) executing near-term actions to further mitigate increased wildfire risk; (2) developing enhancements to its operational plans for long-term strategies related to wildfire prevention, public safety, and related grid resiliency; and (3) integrating SCE's wildfire mitigation strategies with existing programs. The PMO analyzed historical SCE fire ignition data, reviewed current fire mitigation strategies, and researched potential enhancements focused on fire prevention (avoiding ignitions), aiding suppression activities by others (speeding up confirmation and assessment of fires), and system resiliency (withstanding fires). The PMO also researched external existing and emerging utility fire mitigation strategies related to risk management and asset management for applicability to SCE's wildfire mitigation efforts.

The PMO's efforts led to SCE's GSRP, which is a portfolio of new programs and mitigation measures primarily focused on preventing wildfire ignitions associated with electrical distribution infrastructure in HFRA. GSRP's focus areas are: (1) further grid hardening; (2) enhanced situational awareness; and (3) enhanced operational practices. SCE filed its GSRP Application with the Commission in September 2018 seeking approval of, and cost recovery for, incremental costs to implement the program over the 2018 to 2020 period. Given the increased wildfire risk, SCE began implementing GSRP in 2018 and will continue to implement GSRP activities in 2019 while program and cost recovery approval is pending.[8] This WMP includes, but is not limited to, the programs and mitigation measures described in the GSRP Application and supporting testimony. Most of the programs and mitigation measures in the GSRP will be implemented over multiple years (i.e., not completed in 2019), such as the full deployment of covered conductor in HFRA.

Since filing its GSRP Application, SCE has continued to review and refine the strategies and programs described in that filing. This WMP includes efforts to assess acceleration of some GSRP elements and development of programs that go beyond the scope of GSRP. For example, as set forth in GSRP, SCE plans to deploy at least 96 circuit miles of covered conductor in HFRA in 2019. Notwithstanding execution risks such as skilled-labor resource constraints, supply chain disruptions, and unanticipated events, SCE will attempt to install additional covered conductor in HFRA in 2019. This WMP also includes

[8] *See* D.19-01-019 (establishing the Grid Safety and Resiliency Program Memorandum Account effective September 10, 2018).

potential new mitigation activities, such as targeted undergrounding in HFRA that SCE will further evaluate in 2019, as further discussed in Chapter 4.

The strategies, programs, and activities included in this WMP, with associated goals and metrics to demonstrate compliance with their implementation, are an effective approach to reduce fire-related risk for SCE's customers in the near term (based on current information) and allow for refinement and improvement over time. As new information is obtained and experience is gained with implementing these mitigation programs, SCE will continue to assess, evaluate, and enhance its wildfire risk mitigation strategies, programs, and activities and implement new programs, methods, and technologies if determined to be effective risk-mitigation solutions.

2.2 RISK OF CLIMATE CHANGE EFFECTS

For over a century, SCE has designed its electrical system with the primary goal of providing safe, reliable, and affordable power. This design includes many decades of engineering experience and the adoption of new technologies over time. SCE's design practices continue to advance with the addition of newer safety- and reliability-related technologies. As part of this advancement, it is important to understand and adapt to the "new normal" and the challenges climate change brings. The greater intensity and year-round frequency of fire danger is driving the need for further evolution, hardening, and strengthening of the grid—particularly in HFRA in SCE's service territory. As one of the nation's largest electric utilities, SCE's service territory is approximately 50,000 square miles located in central, coastal, and Southern California. SCE's electrical system encompasses approximately 52,000 circuit miles of transmission and distribution overhead power lines, with more than 19,000 of those circuit miles traversing HFRA.[9] As detailed in this WMP, SCE is developing and implementing ways to further prevent, mitigate, and withstand the wildfire threat associated with its service territory and HFRA.

Experts had predicted that decades from now climate change would increase the risk of these uncharacteristically large and severe wildfires, including a potential increase in the total area burned.[10] These projected impacts are happening now, and regrettably much faster than some earlier climate forecasts. Shortly after the Mendocino Complex Fire in July of 2018, then-Governor Brown explained that "[t]he more serious predictions of warming and fires to occur later in the century, 2040 or 2050, they're now occurring in real time."[11] California's recently-released Fourth Climate Change Assessment—while acknowledging that projecting future wildfires is complicated—nonetheless notes the potential for greater fire risk in the future and particularly "mass fires" burning large areas simultaneously.[12] Moreover, the California Department of Forestry and Fire Protection (CAL FIRE) has

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9 Approximately 13,000 circuit miles of distribution lines and 6,000 circuit miles of transmission lines. Unless otherwise noted, references to "distribution level circuit miles" refer to distribution primary voltages only.

10 Tania Schoennagel et al., Adapt to More Wildfire in Western North American Forests as Climate Changes, (May, 2017), *available at* http://www.pnas.org/content/pnas/114/18/4582.full.pdf.

11 Jaclyn Cosgrove et al., California fires rage, and Gov. Jerry Brown offers grim view of fiery future, L.A. Times (Aug. 2018), *available at* http://www.latimes.com/local/lanow/la-me-ln-california-fires-20180801-story.html.

12 Bedsworth, Louise, Dan Cayan, Guido Franco, Leah Fisher, Sonya Ziaja (2018). Statewide Summary Report. California's Fourth Climate Change Assessment. Publication number: SUMCCCA4-2018-013, *available at* http://www.climateassessment.ca.gov/state/docs/20180827-StatewideSummary.pdf.

concluded that "[c]limate change has rendered the term 'fire season' obsolete, as wildfires now burn on a year-round basis across the State."[13]

This recent increase in the size of, and destruction caused by, fires in the wildland-urban interface, increased population density and development in the wildland-urban interface, and the extremity of weather conditions, marks a significant change in the state's firefighting and fire prevention posture, and an increased need for comprehensive, year-round mitigation and preparedness efforts. The state's recent wildfires are proving that historical mitigation and preparedness efforts are not sufficient to adequately address the current hazards and risks associated with wildfires in California—it is therefore essential for all stakeholders to change the way we approach wildfire mitigation efforts. SCE agrees with Governor Newsom's statement that there should be "no greater emphasis, energy, and sense of urgency than on the issue of public safety."[14]

Wildfires in the Southern California region in SCE's service territory, and the damage they cause, are influenced by many factors including a dry and warm climate, Santa Ana winds, severe droughts, and extensive development in wildland-urban interface. The Southern California region and the rest of SCE's service territory is expected to continue to warm through this century. Climate studies also predict more severe droughts in California in future years.[15] And although there is uncertainty in future predicted changes to Santa Ana wind events, in late 2017, Southern California was subjected to "unprecedented" strong winds that had the potential to carry palm fronds and other debris from long distances into utility lines.[16] The projected increased climate warming, future prolonged periods of drought, and more potentially frequent extreme Santa Ana winds will continue to exacerbate wildfire risk conditions in Southern California. Given these projected conditions, SCE will continue to adapt its strategies and programs to mitigate wildfire risks. SCE's efforts to mitigate wildfire risks will also continue to be informed by dynamic climate change risks as well as other factors that will be described in subsequent, annual WMP filings with the Commission.

2.2.1 PRELIMINARY FIRE SEASON OUTLOOK

Although it is too early to know with precision or certainty, SCE currently expects this year's annual fire season in Southern California to begin around mid-May, and to have a somewhat-above-normal number of fire events based on: precipitation to date (above normal) and associated vegetation growth; forecast precipitation (normal); forecast Santa Ana and associated wind events (normal); and other climate and weather factors.

Weather conditions during the March through May timeframe will have impacts on the start, and to some extent, the severity of this year's fire season. This preliminary forecast is a shortened summary of SCE's Preliminary Fire Season Outlook, prepared by an SCE Fire Scientist, and finalized on January 25,

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13 *See* CAL FIRE 2018 Strategic Fire Plan, p. 10.

14 USA Today (January 9, 2019), *available at* https://www.usatoday.com/story/news/2019/01/08/california-wildfires-gavin-newsom-pledges-105-funding/2521015002/.

15 *See, e.g.*, California's 4th Climate Change Assessment, Los Angeles Region Report, *available at* http://www.climateassessment.ca.gov/regions/docs/20180928-LosAngeles.pdf.

16 In December 2017, the state for the first time experienced "purple" (i.e., extreme) winds capable of reaching 80 mph. *See* Associated Press, California wind hits unprecedented high—and so does fire danger L.A. Times (December 7, 2017), *available at* http://www.latimes.com/local/lanow/la-me-lnpurple-wind-map-20171207-story.html.

2019. While CAL FIRE typically issues a similar report for the entire state, as a result of the shutdown of the federal government in early 2019, this report was not kept current for a period of time.[17]

2.3 OVERVIEW OF PREVENTIVE STRATEGIES AND PROGRAMS

SCE's suite of mitigation strategies, programs and performance management in this WMP addresses:

- Risk analyses of wildfire frequencies and consequences (Chapter 3)
- Operational practices, inspection programs, system hardening programs, vegetation management programs, situational awareness tools and strategies, and de-energization protocols to minimize wildfire ignitions, aid suppression activities by others, and/or improve system resiliency (Chapter 4)
- Alternative technology assessments to continually improve SCE's equipment and practices (Chapter 4)
- Post-incident recovery, restoration, and remediation activities to safely and effectively restore service and minimize damage after a wildfire occurs (Chapter 4)
- Emergency preparedness and response plans to effectively prepare for and communicate with first responders, customers, community groups, and other stakeholders before, during and after a wildfire (Chapter 5)
- Programs to support customers that have been impacted by a disaster (Chapter 5)
- Performance metrics to evaluate compliance with this WMP (Chapter 6)
- Comparison of the past Fire Prevention Plans (FPP) to this WMP and how previous metrics informed this WMP (Chapter 6)
- Description for how SCE will monitor and audit this WMP and identify and correct deficiencies (Chapter 6)
- Cost information for SCE's programs and strategies included in Chapter 4 (Chapter 7)[18]

Several of SCE's strategies and programs in use now are not limited to any particular timeframe, and are instead situational, and based on certain real-world events, such as Red Flag Warnings (RFW) and other high fire-risk conditions. For example, SCE's PSPS protocols are only triggered when conditions pose a significant threat to the public. These conditions are predominantly weather- and vegetative fuel-related and not associated with particular time periods (e.g., in 2019, or within 5 years). Similarly, SCE's emergency preparedness and response plans, its post-incident recovery, restoration, and remediation activities, and its programs to support customers impacted by a wildfire are event-driven and are not timeframe-dependent. SCE's operational practices are also not time-dependent, and certain practices are triggered by RFW and other high fire risk conditions. Additionally, these practices are updated as SCE gains new information and adopts improved practices. Furthermore, all administrative-related

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[17] The Fire Season Outlook (https://gacc.nifc.gov/oscc/predictive/outlooks/myfiles/assessment.pdf) is a rolling four-month prediction of above/below normal fire activity that comes from the United States Forest Service (USFS) (Predictive Services). Due to the shutdown of the federal government, this report was not updated until February 1, 2019. The report's current forecast is consistent with the analysis conducted by SCE's Fire Scientist.

[18] Several of the programs and strategies included in this WMP are large efforts that will require administrative and other support such as organizational change management. SCE anticipates the need for additional support resources and any such incremental costs would be tracked in the appropriate memorandum account. Except where noted in this WMP, these potential incremental costs are not reflected in Chapter 7, but will be tracked in the SB 901 OIR Memorandum Account, and reviewed in SCE's 2021 GRC, as appropriate.

programs such as risk analyses, performance metrics, and monitoring of this WMP will be performed at regular or annual intervals.

In general, this WMP describes certain programs that SCE will attempt to complete on an accelerated basis in order to mitigate wildfire risks as quickly as possible. However many of the programs are multi-year and programmatic in nature, i.e., there is a startup period with limited initial implementation followed by full implementation that expands as processes and methods mature. For these multi-year programs that are further described in subsequent chapters, SCE has set 2019 goals.

2.3.1 BEFORE UPCOMING WILDFIRE SEASON

As described in Chapter 4, SCE has identified activities and goals it plans to achieve in 2019 in HFRA. Several of SCE's strategies and programs include prioritized deployments that focus on assets associated with the highest risk first. SCE's approach also allows for rapid deployment of some strategies across HFRA with relatively minimal expense. For example, SCE prioritized the use of current-limiting fuses (CLF) in HFRA and began applying a more sensitive fast curve trip setting for remote-controlled automatic reclosers (RAR) and circuit breaker relays to allow for more rapid clearing of faults during Red Flag Warnings and other high fire risk conditions. While the overall system hardening activities will continue throughout 2019 and beyond, SCE will attempt to accelerate completion of these specific activities. In Section 4.2, SCE describes its inspection programs, which are currently predominantly driven by time-based compliance requirements, and how it is focusing completion of certain inspections for HFRA. For example, as part of its Annual Grid Patrol (AGP) program SCE will visually inspect approximately 380,000 poles and associated equipment in HFRA by August 31 of each year. SCE has also recently initiated a new inspection effort referred to as enhanced overhead inspections (EOI). This effort began in late 2018, and continued into 2019. Under it, SCE will complete enhanced overhead inspections on all transmission and distribution circuits within HFRA, including the approximately 450,000 transmission and distribution pieces of equipment on those circuits within HFRA. SCE is attempting to accelerate these enhanced inspections to complete them by the height of the upcoming wildfire season. One goal of the EOI effort is to shift from a schedule-driven, compliance-based approach to a risk-based approach to address the evolving wildfire threat.

2.3.2 BEFORE THE NEXT WILDFIRE MITIGATION PLAN FILING

SCE interprets this category of strategies and programs to mean the strategies and programs in Chapter 4 that will be completed by year-end 2019.[19] In Chapter 4, SCE describes numerous activities that have 2019 completion goals. These strategies and programs include operational practices, inspections, system hardening, vegetation management, situational awareness, PSPS protocols, alternative technologies, and post-incident recovery, restoration and remediation.

2.3.3 WITHIN THE NEXT FIVE YEARS

Many of SCE's strategies and programs in Chapter 4 are multi-year efforts and are anticipated to continue beyond 2019. Several of SCE's inspection programs have time-period compliance requirements to inspect SCE's electrical infrastructure within the next five years. Other programs such as covered conductor, RAR, fusing mitigation, weather stations, and high definition (HD) cameras are multi-year efforts.

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[19] Given that the schedule for next year's WMP filing has not been set, SCE generally understands this category to represent those strategies and programs that will be completed in 2019.

2.4 CHAPTER ORGANIZATION AND STRUCTURE

SCE has organized this WMP based on the SB 901 Wildfire Mitigation Plan Template included in the Ruling, with minor exceptions. The Ruling requires several levels of categorization for each of SCE's strategies and programs. Due to time limitations, these categorizations are included, in tabular format, in Appendix B. SCE has also organized its subsequent chapters as follows:

- Overview of the Program: This section includes a high-level overview of existing strategies and programs, GSRP activities and new and/or enhanced activities developed since the GSRP filing;
- Existing Programs: This section provides a description of existing programs that have wildfire risk mitigation benefits;
- Additional actions taken in HFRA: This section focuses on SCE's targeted wildfire risk programs and activities that are directed toward HFRA. This section also includes explanations of the work SCE will be conducting in HFRA in 2019; and
- Activities and 2019 Goals: This section includes, in tabular format, the list of additional activities to be performed in HFRA and associated 2019 goals, as well as a description of the evidence SCE will use to demonstrate compliance with and achievement of those goals.

The chapters also include a few key categories including activities, goals, metrics, and indicators defined as follows:

- **Activities**: "Activities" are specific actions conducted in HFRA that are execution-focused (e.g., covered conductor installation) and directed at reducing wildfire risk. Activities are measurable and auditable, and each will have a "goal" (as defined below).
- **2019 Goals**: "Goals" are assigned to each activity and provide the measurable target SCE aims to achieve in 2019 (e.g., circuit miles of covered conductor installed). While SCE will endeavor to meet or exceed the goals, to the extent that resource constraints, material delays, weather delays, and/or other necessary tradeoffs do not allow SCE to achieve the specific values that this WMP targets, SCE will demonstrate in the required after-the-fact compliance report why its performance constituted substantial compliance with the WMP.[20]
- **Metrics**: "Metrics" are intended to capture WMP performance at a higher level than activities. These may track progress of a broader set of activities (e.g., miles hardened including but not limited to covered conductor) or quality of execution.[21]
- **Indicators**: The three "indicators," further discussed in Chapter 6, evaluate information over time, and reflect the long-term outcomes that the activities (cumulatively and over time) are intended to influence. Although "indicators" will identify long-term trends, they are not related to compliance performance evaluation in 2019, because the drivers of the indicators include certain uncontrollable factors. For example, ignitions-per-year is a key indicator that will be tracked. However, this indicator can be subject to variation over time related to exogenous events such as severe drought and extreme wind. The uncontrollable variation in certain indicators makes it difficult to target accurate, achievable, and numerical goals over a short time period.[22] Indicators require assessment over time to identify trends before proposing performance goals in future WMP submissions.

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[20] SCE recognizes that certain work covered by this WMP is subject to mandatory, prescriptive regulatory requirements.

[21] Both "metrics" and "goals" will be used to demonstrate SCE's substantial compliance with this WMP.

[22] Indicators reviewed over a short period of time could lead to either false-negative results (e.g., an increase in ignitions in 2019 could be driven by an unusually high number of extreme weather events) or false-positive results (e.g., a significant reduction in ignitions in 2019 could be driven by an unusually small number of extreme weather events).

3 RISK ANALYSIS AND RISK DRIVERS

3.1 METHODOLOGY FOR IDENTIFYING AND EVALUATING ENTERPRISE-WIDE SAFETY RISK AND WILDFIRE-RELATED RISK

SCE follows a comprehensive risk management evaluation protocol to assess and mitigate enterprise-wide safety risks. The CPUC has recently adopted two new risk-mitigation procedures: the Safety Model Assessment Proceedings (S-MAP) and the Risk Assessment Mitigation Phase (RAMP). The purpose of the S-MAP is to: (1) allow parties to understand the models the utilities propose to use to prioritize programs/projects intended to mitigate risks; and (2) allow the CPUC to establish standards and requirements for those models. In each utility's RAMP, the utility will "describe[e] how it plans to assess its risks, and to mitigate and minimize such risks."[23] Each utility's RAMP filing should be consistent with the direction provided in the S-MAP. The RAMP submission, "as clarified or modified in the RAMP proceeding, will then be incorporated into the large energy utility's GRC filing."[24]

Pursuant to the RAMP process, SCE deployed a new multi-attribute probabilistic risk evaluation model to evaluate safety risks (including safety-related risks and the associated probability and consequences of potential events). As part of this process, SCE utilizes a risk-informed decision-making process to identify, evaluate, mitigate, and monitor enterprise risks, including risks associated with wildfires.[25] This process enables the company to explicitly include risk considerations in SCE's decision-making for work identification, prioritization, and funding and resource allocation. Senior leaders employ the framework to review the risk analyses and mitigation plans in place to manage enterprise risks. Though risk management has always been an essential part of the management toolkit for strategic, business, and operational planning, over the last few years, risk-informed planning has become a much more explicit and essential component of decision-making.

SCE annually identifies and evaluates the key risks that the enterprise and its customers face, with a focus on safety risks, such as wildfire risk, utilizing a multi-step process from both a top-down and bottoms-up approach, as described below:

- **Top-down review of enterprise-level risks:** This effort is aimed at assessing the breadth of activities ongoing at SCE, in the state, and in the utility industry to identify key risks. It includes a review of industry trends and research, public policy efforts, legislative activities, key CPUC and other regulatory proceedings, major SCE initiatives, and critical business functions. The team also compiles feedback on current and emerging enterprise-level risks through company-wide surveys and direct discussions with SCE leadership.
- **Bottom-up review of SCE Enterprise Risk Register:** SCE maintains an enterprise risk register that captures and assesses risks from across the enterprise, based on interviews and feedback from working groups throughout the organization.
- **Consolidation and aggregation:** SCE aggregates the risks identified through the above processes to evaluate which risks have potential major safety consequences, including consolidation of duplicate and similar risks.
- **Review and refinement with senior leadership:** Through leadership review and assessment, further refinements are made as appropriate.

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[23] *See* D.14-12-025, p. 3.

[24] *See* D.14-12-025, p. 3.

[25] A detailed discussion of the application of SCE's Risk Informed Decision Making Process to Wildfire Risk is included in SCE's GSRP filing.

3.1.1 METHODOLOGY CONSISTENCY WITH OTHER UTILITIES

Over the past several years, there have been significant steps taken by California utilities and the Commission to align on the foundational frameworks and methods used to identify and evaluate enterprise risks. This began in earnest in 2013, when the Commission issued an Order Instituting Rulemaking to Develop a Risk-Based Decision-Making Framework to Evaluate Safety and Reliability Improvements and Revise the Rate Case Plan for Energy Utilities (R.13-011-006). This rulemaking established two primary processes for achieving consistency across utilities: (1) S-MAP, which is focused on developing a uniform methodology and framework for risk identification and evaluation across utilities; and, (2) RAMP, in which utilities implement the methodologies and framework adopted in S-MAP.

Through these processes, SCE and other California utilities (Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), and San Diego Gas & Electric Company (SDG&E)), have implemented generally consistent methods for risk identification and evaluation. For example, utilities have risk management frameworks that are consistent with the Cycla Corporation 10-step risk assessment framework.[26]

Most recently in the S-MAP process, the Commission issued a Decision Adopting Safety Model Assessment Proceeding (S-MAP) Settlement Agreement with Modifications.[27] In this Decision, the Commission adopted certain guidelines for California utilities to more uniformly and quantitatively assess risk within the RAMP and GRC proceedings. This Decision adopted, with a few modifications, the Settlement Agreement that SCE had worked at great length with other California utilities to develop, in collaborative partnership with external stakeholders.[28] The intent of this Decision was to help drive consistency in the approach and methods used to evaluate risk among utilities.

While this Decision applies on a prospective basis to future utility RAMP reports (i.e., those starting in 2019), California utilities, including SCE, have already incorporated many of the tenets of this Decision into their respective risk assessment processes. For example, one of the requirements includes the use of a Multi-Attribute Value Framework (MAVF) and probabilistic methods in the evaluation of risk. PG&E in their 2017 RAMP report, and SCE in its 2018 RAMP report, implemented many of the MAVF principles, and deployed probabilistic methods in the evaluation of enterprise safety risks; this included the assessment of wildfire-related risk. In 2019, SoCalGas and SDG&E will submit their RAMP reports using the MAVF principles.

While each utility will necessarily tailor specific aspects of these risk assessment frameworks to best align with their internal planning and decision-making processes, utilities have taken significant steps to align with and implement the overall risk analysis frameworks envisioned by the Commission.

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[26] In D.16-08-018, p.2, the Commission adopted the Cycla Corporation 10-Step Evaluation Method as a common yardstick for evaluating how mature, robust, and thorough utility risk assessment and mitigation models and risk management frameworks are. See each utility's latest RAMP report for discussion on alignment to this framework.

[27] D.18-12-014.

[28] Settling Parties include PG&E, SCE, SoCalGas, SDG&E, (collectively, the Joint Utilities or JU); The Utility Reform Network (TURN), and Energy Producers and Users Coalition and Indicated Shippers (EPUC/IS) (collectively, the Joint Intervenors or JI); and the Office of the Ratepayer Advocates. SB 854 (Stats. 2018, ch. 51) amended Pub. Util. Code § 309.5(a) so that the former Office of Ratepayer Advocates is now named the Public Advocate's Office of the Public Utilities Commission.

3.2 IDENTIFICATION, DESCRIPTION AND PRIORITIZATION OF WILDFIRE RISKS AND DRIVERS FOR THOSE RISKS

This section summarizes SCE's approach for wildfire-specific issues as evaluated in its 2018 RAMP report. SCE filed its RAMP report with the Commission in November 2018. Since filing its RAMP report, SCE has continued to enhance and update its wildfire risk analyses. A description of these updates subsequent to the submission of its RAMP report is described at the end of this section.

In preparing its RAMP report, SCE further refined its understanding of the fundamental elements that enable fires to ignite, the statistical trends associated with fires across California, particularly those associated with electrical power lines, the historically reported ignitions associated with SCE's grid infrastructure, and the geographic locations within SCE's service area that represent the greatest wildfire risk. SCE began by analyzing ignitions that occurred in its service territory from 2015 through 2017 that were of significant size and were reportable to the Commission.[29] The first step was to determine the parts of its system that are at the highest risk of ignition, followed by a detailed analysis of drivers and outcomes for wildfire ignitions in those areas.

3.2.1 RISK TRANCHING AND PRIORITIZATION

SCE analyzed the frequency and consequence of ignitions by categorizing its system based on two factors: system voltage level (e.g., distribution voltage or transmission voltage) and HFRA designation. As detailed below, because the vast majority of electrical infrastructure-related ignitions associated with SCE's system have been located on the distribution voltage-level system during the analyzed period, that system has been categorized in a higher-risk tranche for purposes of this WMP. HFRA are areas in SCE's service territory where there is an elevated hazard for the ignition and rapid spread of fires associated with electrical equipment due to strong winds, abundant dry vegetation, and other environmental conditions. HFRA represents approximately 35 percent of SCE's service territory. As defined by SCE and as shown below, this includes those locations with Tier 2 or Tier 3 designations identified in the most recent CPUC High Fire Threat District (HFTD) maps,[30] a self-imposed buffer of 200 feet around the CPUC-designated Tier 2 and Tier 3 areas, and those locations within the SCE service territory previously identified as high fire risk prior to the release of the most recent CPUC maps. Collectively, HFRA are those areas with the highest potential frequency and consequences of wildfire ignition events, which includes a consideration of topographical and climatological risk factors. In the interests of public safety, SCE chose to include certain non-Tier 2 and Tier 3 areas in its definition of HFRA, because those areas were previously identified as high fire risk by SCE. SCE is currently in the process of performing a detailed evaluation of these areas to determine which of these areas should remain designated as high fire risk. Further details of this HFRA evaluation are discussed within Section 3.4. As discussed herein, going forward SCE will continue to use local conditions and other factors to evaluate its service territory for wildfire risk and will recommend additions or removal of HFRA areas in future plans.

Over the 2015-2017 time period, SCE experienced 302 reportable ignition events associated with electrical infrastructure within its service territory. 92 percent of these ignitions occurred at distribution

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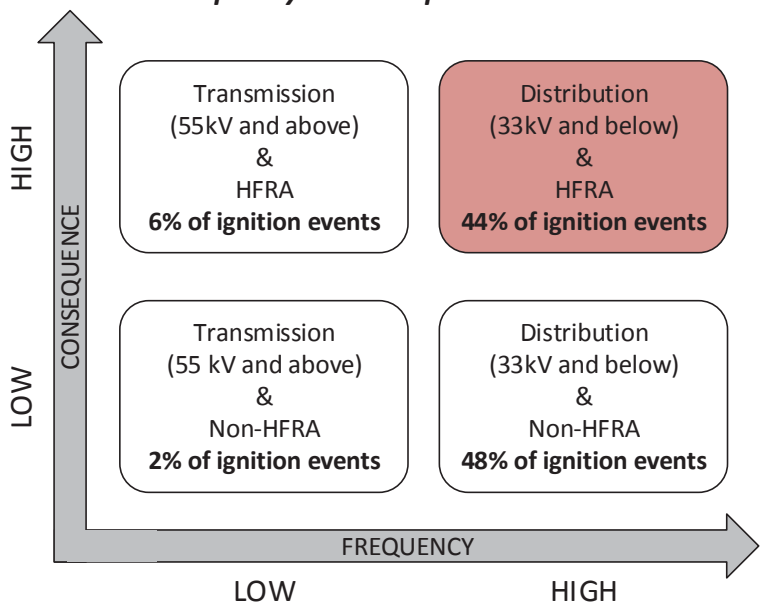
[29] Pursuant to D.14-02-015, reportable fire events are any events where utility facilities are associated with the following conditions: (a) a self-propagating fire of material other than electrical and/or communication facilities, (b) the resulting fire traveled greater than one linear meter from the ignition point, and (c) the utility has knowledge that the fire occurred.

[30] http://www.cpuc.ca.gov/firethreatmaps/

level voltages (33 kilovolt (kV) and below), while eight percent occurred at subtransmission and transmission level voltages (55 kV and above). When analyzed based on presence in HFRA, 50 percent of these ignitions occurred in HFRA, and 50 percent occurred outside of HFRA.

Based on both frequency and consequence considerations, four tranches of SCE assets for wildfire risk analysis are illustrated in figure 3-1 below. SCE identified distribution equipment within SCE's HFRA as the specific tranche of assets that poses the most significant wildfire risk. SCE considers the tranche of HFRA distribution assets, representing approximately 44 percent of all ignition events associated with SCE during the studied period, to have the highest frequency and the highest potential consequence of ignitions of the four tranches. Therefore, SCE's risk analyses performed to date have prioritized evaluation and mitigation of wildfire risk within this tranche.

Figure 3-1
Four Tranches of SCE Assets for Risk Analysis
Based on Frequency & Consequence Considerations



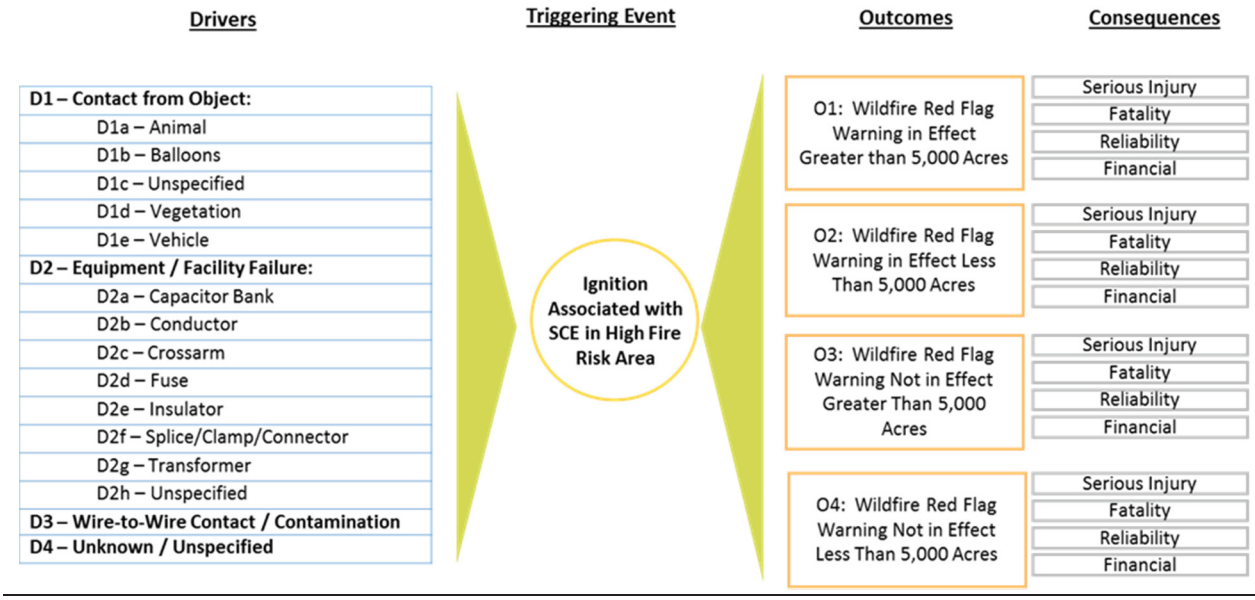
3.2.1.1 Risk Bowtie

For the tranche of risk associated with SCE's distribution equipment in HFRA, SCE developed and performed a risk bowtie analysis that includes risk drivers, triggering events, outcomes, and consequences.[31] SCE defined wildfire risk as "ignition associated with SCE's Distribution equipment in HFRA," specifically focused upon ignition associated with overhead distribution equipment. The risk bowtie, as presented within SCE's 2018 RAMP report, is shown below in Figure 3-2:

[31] Please refer to Investigation (I.)18-11-006 - SCE 2018 RAMP Report, Chapter 2 for a description of the bowtie methodology used by SCE, and Chapter 10 for a description of the Wildfire risk bowtie.

Figure 3-2

Risk Bowtie for ignition associated with SCE's distribution equipment in HFRA



3.2.1.2 Risk Drivers

SCE's risk driver analysis identified and studied four major categories of drivers:

1. D1 - Contact from object, which includes external factors that cause SCE's equipment to fail, or to function as an ignition source to foreign material;
2. D2 - Equipment/facility failure, which includes events caused by failure of SCE equipment, independent of events listed in D1;
3. D3 - Wire-to-wire contact/contamination; and,
4. D4 - Unknown/unspecified.

Data for the drivers resulting in ignitions associated with SCE's distribution infrastructure in HFRA are shown in Table 3-1.

Table 3-1
Breakdown of Contact from Object and Equipment/Facility Failure-Related Fires
(Distribution Voltage Infrastructure in HFRA from 2015-2017)

Suspected Initiating Event	Count	Percentage
D1 - Contact From Object	70	53%
D2 - Equipment/Facility Failure	40	30%
D3 - Wire-to-Wire Contact/Contamination	6	5%
D4 - Unknown/Unspecified	16	12%
Total	**132**	**100%**

D1 - Contact From Object	Count	Percentage
D1a - Animal	15	11%
D1b - Balloons	14	11%
D1c - Other	10	8%
D1d - Vegetation	22	17%
D1e - Vehicle	9	7%
Total	**70**	**53%**

D2 - Equipment/Facility Failure	Count	Percentage
D2a - Capacitor Bank	2	2%
D2b - Conductor	12	9%
D2c - Crossarm	1	1%
D2d - Fuse	1	1%
D2e - Insulator	5	4%
D2f - Splice/Clamp/Connector	8	6%
D2g - Transformer	3	2%
D2h - Unspecified	8	6%
Total	**40**	**30%**

D3 - Wire-to-Wire Contact/Contamination	Count	Percentage
Wire-to-Wire Contact/Contamination	6	5%
Total	**6**	**5%**

D4 - Unknown/Unspectified	Count	Percentage
Unknown/Unspecified	16	12%
Total	**16**	**12%**

In order to map drivers to (1) Design and Construction, (2) Inspection and Maintenance, (3) Operational Practices, and (4) Situational/Conditional Awareness, and (5) Response and Recovery, SCE first mapped its mitigations to these categories. SCE then mapped its drivers against mitigations, as shown in Table 3-2 below. Within SCE's RAMP report, mitigations were not mapped to Driver D3 (wire-to-wire contact) because of the small number of ignitions occurring due to this driver during the 3-year period analyzed. Mitigations were not mapped to Driver D4 due to limited data available regarding this type of ignition.

Table 3-2
Mapping of RAMP Drivers to Mitigations and Categories

Applicable RAMP Control/Mitigation	Drivers	(1) Design and Construction	(2) Inspection and Maintenance	(3) Operational Practices	(4) Situational/ Conditional Awareness	(5) Response and Recovery
C1 - Overhead Conductor Program (Bare + Covered)	D1, D2	Yes				
C2 - FR3 Overhead Distribution Transformers	D2	Yes				
M1 - Wildfire Covered Conductor Program	D1, D2	Yes				
M2 - RAR & Fast Curve Settings	N/A*	Yes		Yes		
M3 - PSPS Protocols and Support Functions	N/A*			Yes	Yes	
M4 - Infrared Inspection Program	D2		Yes			
M5 - Expanded Vegetation Management	D1		Yes	Yes		
M7 - Enhanced Situational Awareness	N/A*				Yes	Yes
M8 - Fusing Mitigation	D2	Yes				
M9 - Fire Resistant Poles	N/A*	Yes				Yes

* For purpose of risk modelling in SCE's 2018 RAMP report, these mitigations were modeled to affect outcomes only. As such, these particular mitigations were not directly mapped to drivers.

3.2.1.3 Risk Outcomes and Consequences

SCE identified four potential outcomes for ignitions associated with SCE in HFRA. These four outcomes are differentiated based on RFW conditions and wildfire size (see Figure 3-2):

1. O1 – Wildfire/RFW in Effect/Greater than 5,000 acres (0.8% of outcomes)
2. O2 – Wildfire/RFW in Effect/Less than 5,000 acres (31.0% of outcomes)
3. O3 – Wildfire/RFW Not in Effect/Greater than 5,000 acres (0.2% of outcomes)
4. O4 – Wildfire/RFW Not in Effect/Less than 5,000 acres (68.1% of outcomes)

For each of these outcomes, SCE estimated the potential public safety (serious injuries, fatalities), reliability, and financial impacts. The safety consequences were analyzed using historical data from both California Department of Forestry and Fire Protection (CAL FIRE) and the National Fire Protection Association (NFPA). Reliability consequences were analyzed utilizing data from SCE's Outage Database and Reliability Metrics (ODRM) system. Financial consequences were analyzed using a combination of national insurance databases, national firefighting cost data, restoration cost studies, and CAL FIRE data.

3.2.1.4 Wildfire Risks and Drivers Identified After RAMP Report

Since filing its RAMP report in November 2018, SCE has continued to refine its analyses and processes, and evaluate additional data as it becomes available.

Transmission Ignition Data

As shown in Figure 3-1, 6 percent of ignitions in SCE's HFRA (19 ignition events over three years) were associated with SCE's transmission system during years 2015-2017. The following table shows the breakdown of these 19 ignition events:

Table 3-3
Breakdown of Contact from Object and Equipment/Facility Failure-Related Fires
(Transmission Voltage Infrastructure in HFRA from 2015-2017)

Suspected Initiating Event	Count	Percentage
Contact From Object	14	74%
Equipment/Facility Failure	1	5%
Other, Unknown, Contamination	4	21%
Total	**19**	**100%**

Contact From Object	Count	Percentage
Animal	6	32%
Balloons	3	16%
Other	2	11%
Vegetation	1	5%
Vehicle	2	11%
Total	**14**	**74%**

Equipment/Facility Failure	Count	Percentage
Other	1	5%
Total	**1**	**5%**

Other, Unknown, Contamination	Count	Percentage
Other	1	5%
Unknown	2	11%
Contamination	1	5%
Total	**4**	**21%**

The limited quantity of ignitions associated with transmission infrastructure has limited the analysis performed based on historical ignitions. Section 3.2.1.5 below describes the future planned analysis that includes transmission infrastructure.

3.2.1.5 Expansion of Analysis beyond Historical Ignition Data (Activity RA-1)

In developing the RAMP report, the analysis was based on historical ignition events in HFRA. SCE is currently in the process of analyzing 2018 fire ignition data. In addition to incorporating CPUC-reportable 2018 historical ignition data (preliminary data indicates there were 46 reported ignitions across SCE's HFRA) into its analysis to identify trends and changes among ignition drivers, SCE will incorporate additional engineering and operational subject matter expertise into its risk analysis performed in 2019, and data collected through inspections of equipment in HFRA, including distribution, transmission, and substation infrastructure. Additionally, in its 2019 risk analysis (to inform the 2020 WMP), SCE will include an analysis of equipment that were not associated with reportable historical ignitions in HFRA, but that could potentially lead to an ignition, such as lightning arresters, poles, protective relays, switches, etc. SCE is also currently developing a fire consequence model at a circuit segment level, which will further inform the prioritization for various mitigations based on wildfire risk exposure. The

Company will perform an analysis for various mitigations, including, when appropriate, potential undergrounding of lines.

3.3 DESCRIPTION OF HOW THE WILDFIRE MITIGATION PLAN ACCOUNTS FOR THE WILDFIRE RISKS IDENTIFIED IN THE RAMP

SCE's WMP includes activities to mitigate the wildfire risks identified above. The impact of a mitigation is estimated in terms of its ability to reduce driver frequency, to reduce the probability of an outcome occurring, and/or to reduce the severity of consequences when an outcome occurs. This section identifies how the strategies and programs described in Chapter 4 are aligned with the controls and mitigations discussed and analyzed in the wildfire chapter of SCE's RAMP report,[32] and how each mitigation affects the drivers, outcomes, and/or consequences associated with wildfire risks.

The following table summarizes the elements of the WMP that were assessed in RAMP, and the corresponding drivers, outcomes, and consequences impacted by elements of the plan as analyzed and modelled in RAMP. As the table shows, the WMP is a comprehensive portfolio of activities that collectively addresses both the left-hand side of the bowtie (i.e., drivers) and the right-hand side of the bowtie (i.e., outcomes and consequences).

Table 3-4
Alignment of WMP strategies and programs to RAMP control/mitigation

WMP Topic	Applicable RAMP Control/Mitigation	Drivers	Outcomes	Consequences
Operational Practices	M2 - RAR & Fast Curve Settings	-	O1, O2	All
Plans for Inspections of Electrical Infrastructure	M4 - Infrared Inpsection Program	D2	-	-
System Hardening to Achieve Highest Level of Safety, Reliabilty and Resiliency	C1 - Overhead Conductor Program (Bare + Covered)	D1, D2	-	-
	C2 - FR3 Overhead Distribution Transformers	D2	-	-
	M1 - Wildfire Covered Conudctor Program	D1, D2	-	-
	M2 - RAR & Fast Curve Settings	-	O1, O2	All
	M8 - Fusing Mitigation	D2	-	-
	M9 - Fire Resistant Poles	-	All	All
Vegetation Management Plan	CM1 - Vegetation Management	discussed but not modeled in RAMP		
	M5 - Expanded Vegetation Management	D1	-	-
Protocols on Situational Awareness	M7 - Enhanced Situational Awareness	-	All	All
Protocols on Public Safety Power Shut-Off	M3 - PSPS Protocols and Support Functions	-	O1	All

NOTE: There are additional elements in each of these WMP categories that were not directly addressed in RAMP; for a description of these additional elements, see Chapter 4.

In Table 3-4, the "WMP Topic" column refers to the section of Chapter 4 where each of these mitigations are discussed in greater detail. The "Applicable RAMP Control/Mitigation" column refers to the name of the RAMP activity, along with an abbreviated notation of whether the activity was classified as a compliance activity, control, or mitigation.[33] The "Drivers, Outcomes, and Consequences" columns indicate the potential positive impact of the applicable control or mitigation to the corresponding element of the bowtie diagram.[34]

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[32] Please refer to I.18-11-006 - SCE 2018 RAMP Report, Chapter 10, pages 10-22 - 10-42 for a detailed description of controls and mitigations analyzed in RAMP.

[33] CM = Compliance. This is an activity required by law or regulation. Compliance activities were not risk analyzed in the RAMP report. C = Control. This is an activity performed prior to 2018 to address the risk, and which may continue through the RAMP period. M = Mitigation. This is an activity commencing in 2018 or later to affect this risk. Both Controls and Mitigations were modeled in SCE's RAMP report.

[34] Please refer to I.18-11-006 - SCE 2018 RAMP Report, Chapter 10 for a description of the Driver, Outcome and Consequence mapping for each analyzed mitigation.

3.3.1 WMP ELEMENTS IDENTIFIED IN RAMP

Below is a description of the specific WMP elements and their expected impact on risk bowtie components as analyzed in RAMP.

3.3.1.1 Operational Practices

3.3.1.1.1 RAMP Mitigation M2 – Remote-Controlled Automatic Reclosers and Fast Curve Settings

RAR are protective devices for mainline conductor that can automatically interrupt faults. The RAR are programmed with special fast curve settings that can be remotely toggled to provide faster or more selective "fault clearing" to further reduce fire ignition risks and reduce service interruptions for SCE customers. Fast curve settings modify the relay fault detection curve, providing faster fault detection and interruption. These fast curve settings reduce the fault clearing time, reducing heat and arcing therefore reducing the possibility of ignition. This mitigation is primarily designed to be implemented during Red Flag Warnings or other high fire risk conditions.

3.3.1.2 Plans for Inspections of Electrical Infrastructure

3.3.1.2.1 RAMP Mitigation M4 – Infrared Inspection Program

SCE is deploying a biennial Infrared (IR) Inspection Program for overhead distribution lines within HFRA. The IR program identifies "hot spots" on distribution system equipment that indicate potential equipment failures. Inspection findings will be prioritized in accordance with SCE's Distribution Inspection and Maintenance Program (DIMP) manual and given appropriate system remediation timeframes.

3.3.1.3 System Hardening to Achieve Highest Level of Safety, Reliability and Resiliency

3.3.1.3.1 RAMP Control C1 – Overhead Conductor Program

SCE's Overhead Conductor Program (OCP) addresses public safety risks associated with wire-down events. This program includes both reconductoring and installation of branch line fuses (BLF). Reconductoring and branch line fusing are intended to target and remedy overhead conductor susceptible to failure due to overcurrent.

3.3.1.3.2 RAMP Control C2 – FR3 Overhead Distribution Transformers

Under this program, SCE will replace existing overhead distribution transformers (which are primarily filled with mineral oil) with overhead distribution transformers filled with ester fluid (such as Envirotemp FR3 Fluid).[35] Ester fluid is a derivative of renewable vegetable oil and has a higher flash point rating than mineral oil. This decreases the likelihood that the fluid and/or fluid vapors will ignite and remain ignited during a catastrophic event.

3.3.1.3.3 RAMP Mitigation M1 – Wildfire Covered Conductor Program

Installing covered conductor on SCE's system is an enhanced mitigation technique for reducing wildfire ignition risks, as compared to bare conductor. The covered conductor SCE is proposing to deploy as part of this mitigation utilizes a robust three-layer design. The design can prevent arcing caused by contact with a tree limb or other vegetation, another conductor, or a metallic balloon. In addition, the covering

[35] As part of routine maintenance and inspections in HFRA, SCE assesses the condition of existing transformers and will replace failing units with ester fluid-filled transformers.

on the conductor (the "insulation") helps reduce the frequency of contact-related circuit interruptions that can lead to wire-down events.

3.3.1.3.4 RAMP Mitigation M2 – Remote-Controlled Automatic Reclosers and Fast Curve Settings

This mitigation is expected to reduce the frequency of only those drivers that lead to RFW condition outcomes (O1 and O2). However, given constraints associated with the RAMP model structure, SCE represented this mitigation as not impacting any drivers (i.e., they are not "causal" factors for fires). Instead, for RAMP modeling purposes, SCE represented this mitigation as impacting all consequences associated with O1 and O2 (i.e., they are "preventive" factors for fires).[36]

3.3.1.3.5 RAMP Mitigation M8 – Fusing Mitigation

SCE plans to install or replace fuses at branch line locations in the HFRA. First, SCE will install new CLF at branch line locations. Second, SCE will replace existing fuses with CLF on circuits that traverse HFRA. This program is intended to reduce the risk of fire ignitions associated with SCE's distribution lines and equipment by reducing fault energy.

3.3.1.3.6 RAMP Mitigation M9– Fire-Resistant Poles

If pole replacements are required at locations where SCE is installing covered conductor in HFRA, SCE will use fire-resistant poles instead of traditional wood poles.[37] These poles will be composite material poles or other types of fire-resistant poles.[38]Use of the poles is intended to improve distribution system resiliency, increasing the chances that SCE equipment, including conductor, will remain intact should a wildfire occur.

3.3.1.4 Vegetation Management Plan

3.3.1.4.1 RAMP Compliance Control CM1 – Vegetation Management

SCE's existing Vegetation Management program reduces wildfire risk and meets current laws and regulations. The benefits of this activity were included in SCE's assessment of baseline wildfire risk, but SCE did not evaluate the specific risk reduction resulting from this compliance activity as it is prescriptively required. In other words, the impact of this activity on drivers, outcomes, and consequences was not explicitly modeled.

3.3.1.4.2 RAMP Mitigation M5 – Expanded Vegetation Management

SCE's expanded vegetation management effort will assess the structural condition of trees in HFRA that are not dead or dying, but could fall into or otherwise impact electrical facilities. These trees may be as far as 200 feet away from SCE's electrical facilities. Trees determined to pose a potential risk to electrical facilities due to their structural or site condition will be removed or otherwise addressed, where feasible.

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[36] SCE notes that reducing wildfire risk by implementing more sensitive protective settings and the blocking of reclosing will increase reliability consequences associated with faults that do not ignite wildfires. Because non-wildfire-related faults were not included within the scope of RAMP, the negative reliability impact of M2 was not reflected in the RAMP risk analysis.

[37] *See* section 4.3.3.4 for additional detail. Covered conductor is heavier than bare conductor and in some cases may require stronger replacement poles.

[38] Includes wood poles with a protective wrap specifically designed to withstand wildfires or steel poles.

3.3.1.5 Protocols on Situational Awareness

3.3.1.5.1 RAMP Mitigation M7 – Enhanced Situational Awareness

This mitigation will enhance SCE's wildfire situational awareness by deploying micro weather stations and HD cameras across its HFRA, developing a high-resolution weather model, enhanced meteorology capability and a high-performing computing platform for fire potential index modeling.

3.3.1.6 Protocols on Public Safety Power Shut-Off

3.3.1.6.1 RAMP Mitigation M3 – Public Safety Power Shutoff Protocol and Support Functions

SCE has recently instituted a formalized PSPS where it may de-energize selected circuits in HFRA to reduce the chances of fire ignitions during extreme and potentially dangerous fire conditions. This practice is aimed at keeping the public, SCE customers, and electrical workers safe.

3.4 EVALUATION OF NON-CPUC HFRA

3.4.1 SCE HFRA BACKGROUND

In December 2017, the CPUC adopted new fire-safety regulations, which included a requirement for the IOUs to integrate into their operations a new HFTD map, which indicates areas in California that are affected by Tree Mortality High Hazard Zones (HHZ, or Tier 1) or represent an elevated (Tier 2) or extreme (Tier 3) wildfire risk due to utility infrastructure-associated ignitions. These tiers drive certain maintenance, inspection, and vegetation management criteria/inspection intervals of overhead assets in high fire-threat areas as described in later sections. Prior to the creation of the CPUC HFTD Map, SCE utilized multiple sources to specify which areas in SCE's service area historically represented a high fire risk. Currently, SCE maintains HFRA maps that are a combination of historical map boundaries (based on past fire management and response experiences), CAL FIRE's Fire Hazard Severity Zone (FHSZ) maps, and most recently the CPUC HFTD map. SCE considers all three categories (i.e., Tier 2, Tier 3, and non-CPUC historical high fire risk areas) to be "HFRA."

SCE HFRA designation has implications on the way SCE designs, constructs, operates, inspects, and maintains its grid. In addition, there have been significant changes across SCE's service territory with respect to development/urbanization, system design/configuration, vegetation health, and climate change over the past few decades.[39] Going forward, SCE will assess if the areas currently designated as HFRA that are beyond the CPUC HFTD continue to pose significant wildfire risk sufficient to remain designated as HFRA. SCE's HFRA designations will be updated as a result of the assessment in 2019. Additionally, SCE will continue to assess areas in its service territory that are not currently within a HFRA and will add new areas that pose high fire risk due to changing conditions.

As shown in table 3-5 below, SCE designates approximately 35 percent of SCE's service area to be high fire risk.

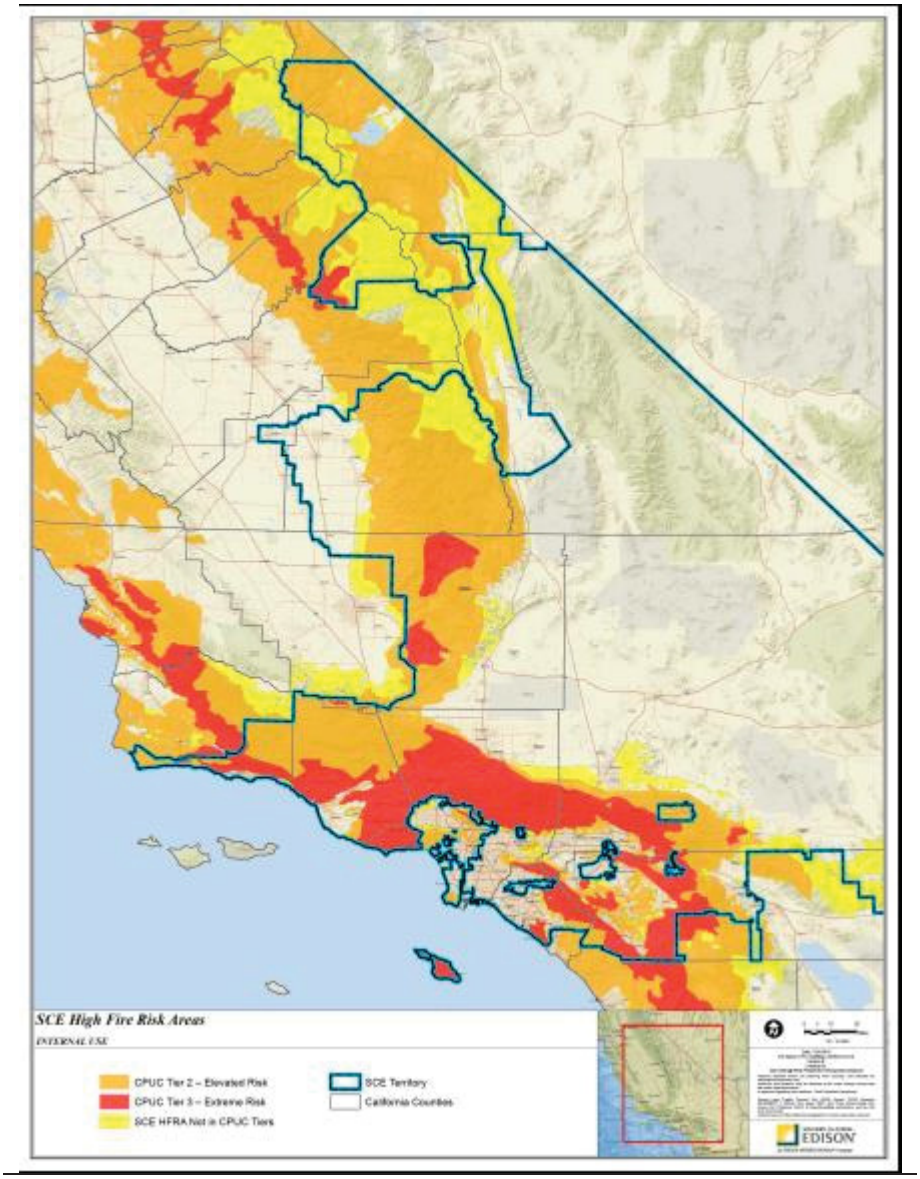
[39] SCE's HFRA designation takes into account the effects and realities of climate change at large, but does not rely on a particular "meteorological or climatological study."

Table 3-5
HFRA in SCE's Service Territory

	Area (Sq. Miles)	Percent of Service Area
CPUC Tier 3 – Extreme Risk	4,708	9 percent
CPUC Tier 2 – Elevated Risk	9,573	18 percent
SCE HFRA Not in CPUC Tiers	4,212	8 percent
TOTAL	**18,493**	**35 percent**

Figure 3-3 below shows the geographical representation of SCE's HFRA, as well as CPUC HFTD.

Figure 3-3
SCE'S HFRA



3.4.2 ACTIONS WITHIN HFRA

3.4.2.1 Changing Definitions of SCE's High Fire Risk Areas (Activity EVAL-1)

Beginning in September 2018, a team consisting of SCE employees with subject matter expertise in fire management/response, fire behavior/fuels, meteorology, maintenance/inspection, grid operations, vegetation management, and geospatial analysis embarked on a project to evaluate these non-CPUC HFRA (divided geospatially into over approximately 1,000 space areas or "polygons"). The evaluation of these areas considered several criteria, including, but not limited to, the presence of overhead assets, density of development/urbanization, vegetation density/type/health, typical wind speed, and circuit design/operation. The objective of this team is to determine whether to retain or exclude the areas under evaluation as "SCE HFRA." SCE will document the reasoning used to determine the final disposition of each of the polygons during the 2019 HFRA evaluation.

If an area is no longer included within SCE's non-CPUC HFRA, that area may be excluded from adhering to protocols associated with maintenance and inspection, grid operating restriction, and reassessment of protection devices in HFRA. Existing protective devices are likely to remain in place as they also provide a valuable reliability benefit. If a non-CPUC HFRA is removed from SCE's HFRA, SCE will reach out to the customers in the affected area and inform them of the changes. Additional details on operational and customer impacts is discussed in subsequent sections.

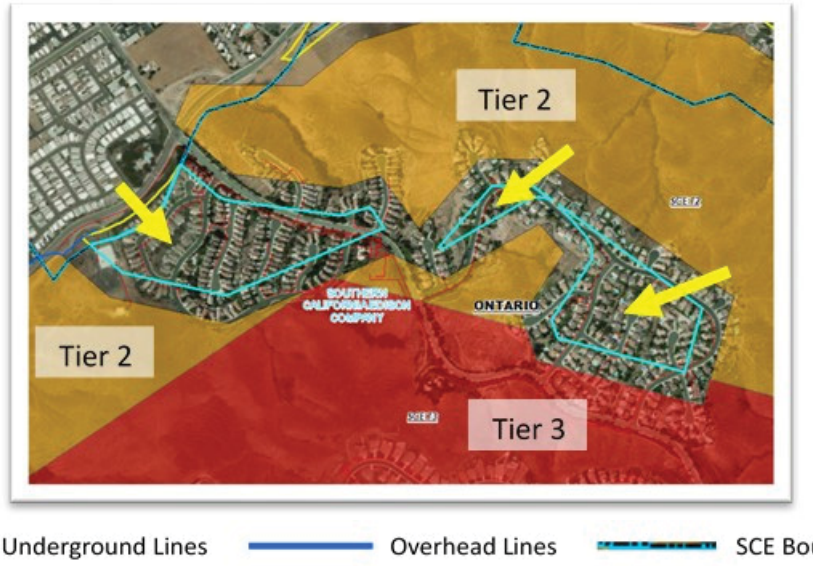
3.4.2.1.1 Non-CPUC HFRA Recommended for Exclusion from SCE HFRA

Examples of the kinds of polygons that will be removed from SCE's definition of HFRA going forward include but are not limited to non-CPUC HFRA that now have non-combustible landscapes, have become urbanized since they were originally included as HFRA, or have subsequently been undergrounded.

3.4.2.1.2 Example of non-CPUC HFRA polygon to be excluded

Figure 3-4 below is an example of a non-CPUC HFRA polygon that is surrounded by CPUC Tier 2 and Tier 3; however it is fully urbanized, and the circuitry is completely underground. There is a low probability of a wildfire associated with utility electrical equipment in an urbanized area where circuitry is undergrounded.

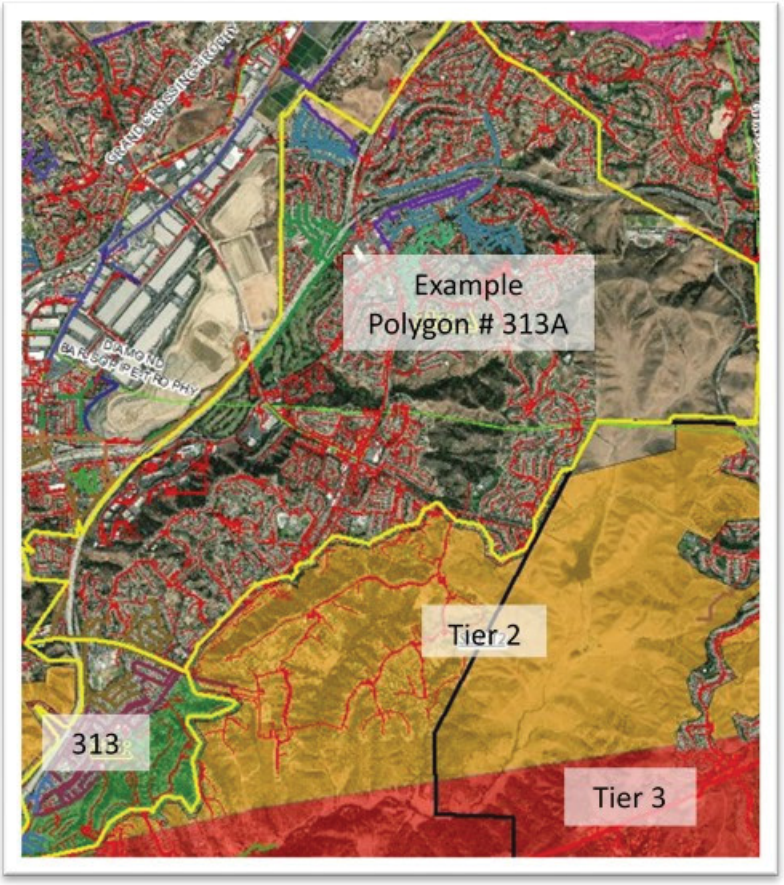
Figure 3-4
Example of a Non-CPUC HFRA Polygon Recommended for Exclusion



3.4.2.1.3 Non-CPUC HFRA Recommended for Retention

Figure 3-5 below illustrates an example of a non-CPUC HFRA that would remain in SCE HFRA. The non-CPUC HFRA has been sub-divided into two areas – one recommended to remain as non-CPUC HFRA and one to be removed. This area has a mix of both overhead and underground circuitry, but it has different adjacencies and proximities to CPUC Tier 2 and Tier 3. Underground circuitry is in red, and the other colored lines (purple and blue) are overhead lines. The primary polygon (#313A) is recommended to be removed as it is highly developed, the areas bordering CPUC Tier 2 are all underground, and there is low vegetation density. However, the subdivided polygon #313 has overhead circuitry that traverses in and out of the CPUC HFTD. Other considerations include a previous fire in this region and homes that border Tier 2, highlighted in green, are in a hilly area with high vegetation density and have prominent, prevailing winds. This creates a higher probability for a fire to propagate into the adjacent hills. Therefore, this area is recommended to be retained as non-CPUC HFRA.

Figure 3-5
Example of a Non-CPUC HFRA Polygon Recommended for Retention



3.4.2.2 Maintenance and Inspection Impacts

Electrical infrastructure assets are to be inspected, maintained, and repaired in accordance with General Orders (GO) 95, 128, and 165. Non-CPUC HFRA that are considered SCE HFRA will be treated as a Tier 2 (elevated) fire-threat.

3.4.2.3 Grid Operating Restriction Impacts

SCE restricts certain operations and switching procedures in HFRA during RFW and elevated fire weather threats. These operating restrictions are defined in SCE's System Operating Bulletin (SOB) 322 that outlines the operational protocols for overhead distribution and subtransmission equipment within HFRA. These guidelines include RFW restrictions, switching protocols, enabling of protective devices such as RAR and patrolling requirements in HFRA.[40] Additional detail on these restrictions and protocols can be found in Section 4.1.

3.4.2.4 Reassessment of Protection Devices in HFRA

SCE deploys certain protective devices, such as RAR and Circuit Breaker (CB) relays, on overhead systems in HFRA in accordance with SCE's SOB 322 and the operational restrictions contained therein. These protective devices are programmed to enable RAR/CB recloser blocking and fast curve settings during

[40] SCE is in the process of revising Standard Operating Bulletin (SOB) 322 to enable blocking of reclosers and execute PSPS during non-RFW weather events.

RFWs.[41] When a HFRA boundary is changed or otherwise moved, a reassessment of the protective devices in the affected areas will be conducted and an appropriate action plan developed. Whether these changes are due to periodic CPUC fire-threat map revisions and/or an internal HFRA assessment as noted above, these reassessments may trigger design/programming changes, device installation/relocation/removal, and system/database revisions.

3.4.2.5 Customer Impacts

As part of its communication strategy supporting awareness and education of SCE's wildfire prevention and mitigation strategies, SCE has sent various communications and conducted community "Town Hall" meetings with customers located within and adjacent to HFRA.

If communities or areas are newly considered as HFRA due to fire-threat map changes or other evolving wildfire risks, outreach efforts, as further described in Section 4.5.4, will be conducted to help keep customers notified and aware of the impacts.

3.5 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
RA-1	Expansion of risk analysis	Conduct risk analysis which includes, but is not limited to, 2018 fire ignition data, additional distribution and transmission information, and consequence modeling to evaluate wildfire risk at a circuit segment level	• Completed risk analysis • Updated list of prioritized wildfire drivers and risk mitigation efforts
EVAL-1	Evaluation of HFRA boundaries	Complete evaluation of non-CPUC HFRA for retention or exclusion	• A final disposition determination for each polygon • Documentation identifying the criteria used to determine each polygon's final disposition

[41] See Section 4.1 for further explanation.

4 WILDFIRE PREVENTION STRATEGY AND PROGRAMS

This section describes the strategies and programs SCE has implemented, is in process of implementing, and will implement to mitigate the threat of electrical infrastructure-related wildfires and their consequences within its service territory. The strategies and programs also include activities to increase grid resiliency, enhance wildfire suppression, reduce the impact of wildfires and wildfire mitigation efforts on the public, and improve outreach and education with customers, community groups, and other stakeholders about how to prepare for, prevent, and mitigate wildfires in SCE's HFRA. SCE's strategies and programs are described in the following sections.

4.1 OPERATIONAL PRACTICES

Grid Operations is responsible for monitoring and operating SCE's electric system. During significant events, Grid Operations personnel act as SCE's accountable representatives in matters concerning the real-time operation of the system and coordinate activities with external agencies such as fire agencies and emergency response personnel. Grid Operations is also responsible for applying SOBs, which encompass operating protocols, remedial actions, communication and notification protocols, ratings and limits of lines and equipment, and system protection schemes. Qualified employees (e.g., Troublemen, Senior Patrolmen, Foremen, or Field Supervisors) may contact Grid Operations at any time to request a line or line segment be temporarily de-energized or place sectionalizing equipment into "non-automatic" settings to promote public and employee/contractor safety and system reliability. To reduce power line ignitions during extreme weather conditions, overhead subtransmission and distribution lines and line sections are subject to operating restrictions described in SCE's SOB 322 and summarized below.

4.1.1 OPERATIONAL CONSIDERATIONS

4.1.1.1 Red Flag Warning Program

The Red Flag Fire Prevention Program, internally referenced at SCE as the RFW Program, is a statewide wildfire awareness and prevention program in which SCE is a participant along with other key stakeholders such as CAL FIRE, California Office of Emergency Services (Cal OES), U.S. Forest Service (USFS), National Weather Service, and various city and county fire agencies. The program utilizes available CAL FIRE forces, cooperating fire agencies, utilities, citizens' groups, and news media to inform the general public of the potential for major wildland fires and the need to be aware of and exercise fire safe practices to lessen the damage and loss to California watershed, resources, life, and property.

The "Red" in the RFW Program refers to the Santa Ana Wildfire Threat Index (SAWTI)[42] which is produced by the USFS, the National Interagency Coordination Center's Predictive Services and other collaborators to categorize Santa Ana conditions in Southern California according to fire potential. The threat index uses a predictive model that incorporates moisture levels of dead and live vegetation and weather models, including wind speeds and atmospheric moisture, to produce a six-day forecast for potentially large fires. There are five threat categories, purple being the most extreme. The purple category was utilized for the first time in 2017, highlighting the evolving wildfire threat. SCE will activate RFW measures during a Red Flag warning or more severe event, such as a Purple Flag warning. For ease of reference in this WMP, "Red Flag warning" means Red Flag or greater conditions.

[42] SAWTI website: https://fsapps.nwcg.gov/psp/sawti/

SCE's FPP,[43] in compliance with D.14-05-020, is currently applied during RFW conditions (regardless of measured wind speed). It requires specific actions to be taken regardless of the affected area being HFRA or wind speeds not exceeding design criteria for the affected overhead lines. It does not require or depend on real-time wind speed measurements or monitoring. The FPP has historically been updated annually by SCE's Business Resiliency team and/or when changes are made to SOB 322 (which is further described below).

In counties under a RFW, SCE vehicles operating in or near HFRA display temporary "Red Flag Fire Patrol" vehicle signs. Fire agencies pre-deploy personnel and equipment in high fire hazard areas to spot and extinguish fires in their incipient stage. Non-fire agency personnel serve as lookouts, able to spot fires in the incipient stage and quickly notify fire agencies to respond. The presence of these "Red Flag Fire Patrol" placarded vehicles may also serve as a deterrent to arsonists.

When SCE's operating organizations receive notice that a RFW has been issued in their respective operating areas, they adhere to the following:

- "Red Flag Fire Patrol" signs are displayed on vehicles
- Work in HFRA (both emergency and non-emergency) is only performed when the following requirements are met, with limited exceptions:[44]
    - Activities are under the direct observation of the crew foreman or site lead;
    - When the crew can maintain adequate communications (using 900 MHz, cellular, satellite phone, etc.) with other SCE personnel and SCE's Distribution Operations Centers;
    - The crew has fire suppression equipment accessible in the immediate area of the work being performed that would facilitate an immediate response to an ignition (shovels, water backpack, ABC fire extinguisher); and
    - Local weather conditions, terrain, and surrounding vegetation would permit the crew to extinguish a fire resulting from the work being performed.
- The opening of remote-controlled air break pole switches (e.g., Remote Transmission Switches, Remote Controlled Switches), are (when possible) performed under visual observation to detect abnormalities.
- Crews remain on alert for fires or possible fires while working in or passing through fire hazard areas and fires are accurately reported to the appropriate switching or control center as soon as possible.

Further, where hot work (e.g., arc welding/cad welding, burning, grinding, brazing, thawing pipes, etc.) is performed, each work site develops a site-specific Hot Work Plan. The Hot Work Plan identifies hazards and control measures associated with hot work activities.

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[43] 2018 Southern California Edison Fire Prevention Plan: http://www.cpuc.ca.gov/uploadedfiles/cpuc_public_website/content/safety/electric_safety_and_reliability/filings/2018%20sce%20go%20166.pdf

[44] Limited exceptions include when work performed in an area devoid of flammable materials (e.g., parking lot, commercial area, agricultural lands, bare ground, work indoors, etc.) and where sparks or flame are not expected to be emitted.

4.1.1.1.1 Operation of Distribution Voltage Lines in HFRA

SOB 322 is used to standardize the operation of distribution voltage lines traversing HFRA. This operating bulletin imposes operating restrictions on designated overhead distribution lines to reduce the risk of wildfires when the National Weather Service issues a RFW and/or SCE determines there is an elevated fire weather threat that warrants additional protective measures.

Specifically, SOB 322 requires all circuit breakers and reclosers protecting the portions of circuits traversing through HFRA be set to not automatically re-energize following initial activation until the RFW expires and/or elevated fire weather conditions sufficiently abate. In the event protective relays on these circuit breakers operate to interrupt the flow of electricity, the line is not re-energized until the line is patrolled and deemed safe.

SOB 322 also specifies which SCE personnel are responsible for triggering and releasing these restrictions—this proactive approach minimizes any potential delays in responding to events and helps SCE staff to be fully aware of the responsibilities associated with their roles.

Blocking the reclosing feature of these relays can be set remotely on nearly all overhead reclosing devices throughout SCE's service territory. This automated functionality is an important feature that allows system operators located in centralized control facilities to quickly change the reclosing settings (automatic versus blocked) without the need to send crews to actual field locations.[45]

SCE conducts annual reviews of SOB 322 to proactively reevaluate its distribution circuits in HFRA to verify that the automatic switches can be blocked from reclosing in the event of a RFW or other elevated fire weather threats. SCE also reviews the few non-automated distribution circuits in HFRA to confirm that the recloser is non-automatic and operating properly.

4.1.1.1.2 Operation of Subtransmission Voltage Lines in HFRA

In addition to the operation of distribution lines, SCE also utilizes SOB 322 to standardize the operation of subtransmission voltage lines traversing HFRA. This imposes operating restrictions on designated overhead subtransmission lines to reduce the risk of wildfires when a RFW is issued or other elevated fire weather threats are identified. Specifically, SOB 322 requires all circuit breakers feeding subtransmission lines traversing HFRA be made non-automatic until the RFW expires or other elevated fire weather conditions sufficiently abate. With very few exceptions, the operation of subtransmission lines is similar to that of SCE's distribution lines, noted above.

4.1.1.1.3 Patrolling Requirements in HFRA

During a RFW or other elevated fire weather threat, if a distribution or subtransmission line or line section in the HFRA experiences a fault and the line relays, it is not re-energized until patrolled. A patrol, while operating restrictions are in effect, includes a visual check of all overhead main line and branch line conductors and equipment. A line section may be isolated and re-energized after a patrol with no cause found. Subsequent line sections may then be patrolled, isolated and re-energized until the faulted line section is found or the entire line and equipment has been patrolled. Fast curve settings, described further below, are temporarily disabled on all upstream interrupting devices for each section that is re-energized during the restoration to avoid undesirable circuit interruptions during the restoration

[45] A small population of reclosers/circuit breakers are set to be blocked year-round or can only be manually tested by control room personnel after a patrol of the line has been conducted.

process. When a line or line section relays with a fault located, the remaining upstream and downstream line sections are patrolled prior to re-energizing.

Once the patrol has been completed, whether the problem was found and isolated or there was no cause found, the line or line section recloser remains non-automatic until the RFW expires or other elevated fire weather conditions sufficiently abate.

This additional patrolling may cause longer outages for customers but is required for safety reasons prior to re-energization.

4.1.1.1.4 Distribution Blocking for RAR and Circuit Breakers

RAR are protective devices applied to mainline conductors that can automatically interrupt faults. SCE has existing RAR, and plans to install additional RAR, which will permit SCE to remotely block reclosing in SCE's HFRA during a RFW or other elevated fire weather threat. The RAR will provide faster and more selective "fault clearing" to further reduce fire ignition risks and lessen service interruptions for SCE customers. If RAR protection is unavailable, SCE blocks reclosing at the substation CB. A thorough patrol of the circuit is required prior to isolating the fault condition and restoring power.

4.1.1.1.5 Fast Curve Settings for RAR and Circuit Breakers

Fast curve settings modify the relay fault detection curve, providing faster fault detection and interruption. SCE has developed and started deploying fast curve settings on distribution voltage RAR and CB on circuits that traverse HFRA. These fast curve settings reduce the fault clearing time, which reduces heat and arcing, and as a result, the likelihood of ignition. Like the blocking of reclosers, fast curve settings can be remotely activated or de-activated by SCE system operators through SCE's monitoring and control radio network. Lastly, if a fault interrupts a circuit when fast curve settings are enabled, SCE will only re-energize these lines after a patrol of the line has been performed and it is safe to do so.

4.1.1.1.6 Air Operations

SCE utilizes its Aircraft Operations department (Air Operations), which operates a fleet of helicopters and unmanned aerial vehicles (UAV (i.e., drones)), to assist in patrolling distribution and transmission lines. Air Operations also provides as-needed, aerial surveillance (e.g., line/equipment inspections, burn scar analyses, debris flow analyses, etc.) following fire and weather-related storms. As conditions allow, Air Operations also assists in the transport of personnel and material to remote locations.

4.1.1.1.7 Annual SOB 322 Review (Activity OP-1)

In 2019, SCE will review and update SOB 322 to reflect lessons learned from past elevated fire weather threats, including those where a RFW was not issued. Additionally, SCE will integrate, where applicable, new and improved data from its situational awareness resources to bolster risk-informed decision making and improve operational effectiveness during elevated fire weather threats.

4.1.2 WILDFIRE INFRASTRUCTURE PROTECTION TEAMS

SCE has permanent Fire Management Officers and specialized experts with fire service and electrical backgrounds that monitor, respond to and provide information on fires affecting, or determined to have the potential to affect, SCE infrastructure. During an active fire event, the team provides a weekly update report to the CPUC. These personnel represent SCE during fire incidents, often embedding in the fire management structure and serving as a liaison to it. They help coordinate SCE's response to fires by

providing information to manage the bulk electric system, repair damage, restore the electric system, and safely gain access to begin restoration work. These personnel maintain close working relationships with fire and emergency management agencies throughout the service territory and serve as consultants and subject matter experts on fire risk management. They provide actionable and timely information to responsible personnel throughout SCE. They also enhance first responder safety by developing and delivering Electrical Safety for First Responders Awareness Training.

SCE's staff includes a team of meteorologists who are members of the American Meteorological Society and who are specifically educated in Atmospheric Sciences. SCE's meteorologists support pre-incidents by monitoring evolving weather, fuel and other conditions that might lead to fire event events and other hazardous conditions. In addition, these meteorologists coordinate the installation of weather stations; work with vendors to deploy high resolution weather models; develop new tools and products to support SCE's Situational Awareness Center; explore new models to predict fire potential; and support incidents and pre-incidents by providing meteorological expertise (including on a twenty-four hour, seven-day-a-week schedule at SCE's Situational Awareness Center during activated incident management conditions). SCE also employs Geographic and Information System (GIS) specialists that provide support for various mapping activities, such as working with SCE's meteorologists to aggregate data to inform decision making.

4.1.2.1 GIS Data Availability

Real-time information is vital to the success of mitigation activities and incident management and provides a necessary common operating picture of how impacts to SCE infrastructure during an incident may affect local communities. SCE is currently engaged in an effort that regularly provides GIS data, such as general SCE infrastructure locational information, outage maps and related vegetation databases to local governments in SCE's service territory, CAL FIRE, Cal OES, and the CPUC prior to any active incident.[46] SCE will continue to work with local and state government to further improve GIS data sharing practices.

During an active incident, SCE designates a point of contact for all external agencies and establishes open lines of communication with affected local communities as well as the California State Warning Center (CSWC) and the CPUC's SED. Regular, ongoing situational updates on the status of the incident including maps of circuits affected and impacts to local communities due to de-energization are continually shared and actively updated for the duration of the incident.

4.1.2.2 Additional Staffing (Activity OP-2)

In 2018, SCE hired one meteorologist, one fire management officer, and one fire scientist. SCE plans to hire one additional meteorologist in 2019. Increasing fire risk has placed a significant strain on SCE's fire management officers, who also support system planning efforts related to grid resiliency. The additional fire management officer will help SCE continue to timely respond to fire incidents and coordinate with first responders. The new fire scientist will help build and mature complex fire models designed to predict wildfire ignition and propagation by considering multiple variables such as weather, fuel, and asset conditions. As further described in Section 4.5, these models will inform SCE's Incident Management Team (IMT) of severe fire conditions which may require deployment of PSPS in HFRA. The additional meteorologist will support the tasks described above. Moving forward, SCE will continue to

[46] GIS data that SCE provides includes general locations of SCE infrastructure and is not considered critical energy infrastructure information (CEII) under federal law.

evaluate the need for additional fire management experts to support the Wildfire Infrastructure Protection Team.

4.1.3 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
OP-1	Annual SOB 322 Review	Review and update SOB 322 to reflect lessons learned from past elevated fire weather threats and integrate, where applicable, new and improved data from its situational awareness resources	Updated SOB 322
OP-2	Wildfire Infrastructure Protection Team Additional Staffing	Hire one additional meteorologist	Human Resources record of date hired

4.2 PLANS FOR INSPECTIONS OF ELECTRICAL INFRASTRUCTURE

4.2.1 PROGRAM OVERVIEW

SCE's distribution, subtransmission, transmission, and substation facilities are inspected or patrolled annually through its DIMP, Transmission Inspection and Maintenance Program (TIMP), Substation Inspection and Maintenance Program (SIMP), and the Quality Oversight/Quality Control groups to facilitate compliance with state and federal requirements. SCE's inspection and maintenance programs are designed to proactively identify and remediate potential equipment/facility failure. These inspection and maintenance programs help reduce potential ignition events and improve reliability and grid resiliency by replacing failed or failing equipment. Because certain inspection programs are linked with routine maintenance programs, this section provides descriptions and activities for both.

4.2.2 EXISTING INSPECTION AND MAINTENANCE PROGRAMS

4.2.2.1 Distribution Inspection and Maintenance Program

DIMP helps SCE maintain public and worker safety and regulatory compliance by completing scheduled detailed inspections and AGP in conformance with GO 165, and performing distribution infrastructure maintenance, as described in SCE standards and in accordance with GO 95, GO 128, and prudent utility practice. The purpose of DIMP is to 1) provide procedures, instructions, and guidance to the field inspectors who perform detailed inspections and patrols of distribution equipment and 2) outline criteria to prioritize inspection findings and schedules to complete repairs and replacements of distribution infrastructure based on the condition of each asset and its potential for impact on safety and reliability, considering various factors.

The maintenance aspect of DIMP focuses on the repair or replacement of distribution infrastructure identified through SCE's inspection programs, equipment, and structures that fail in service, and engineering analyses, for the safety of the public, contractors, and SCE personnel.

DIMP uses a three-priority rating system designed to identify and prioritize action items to resolve safety and reliability issues. A Priority 1 issue typically requires action as soon as the issue is discovered, either

by fully remediating the condition, or by temporarily repairing the equipment or structure to allow for follow-up corrective action. An example would be a broken cross arm on a pole.

Priority 2 issues are considered to be lower risk and therefore may be resolved that day or within 24 months based on the existing safety or reliability condition and location. However, if the Priority 2 issue is located within HFRA and poses a potential fire risk, remediation work will be completed within 12 months. In an extreme fire threat area or Tier 3, the maximum remediation time is within 6 months.

Priority 3 issues currently do not require near-term remediation as they do not pose material safety, reliability, or fire risks, and will either be repaired or re-evaluated at or before the next detailed inspection. Beginning June 30, 2019, new Priority 3 issues will require remediation within 60 months pursuant to D.18-05-042.

Below is a Risk Assessment Matrix to illustrate the relationship between reliability and safety. The Risk Assessment Matrix provides inspectors guidelines to assign a reasonable timeframe for the correction or re-inspection of any distribution facility condition.

Figure 4-6
Risk Assessment Matrix

Reliability (Failure Risk)	No/Slight Impact	Minor Impact	Moderate Impact	High Impact
Component Failure could lead to System Failure	Priority 2 Action Required 13-24 Months	Priority 2 Action Required 4-12 Months	Priority 2 Action Required 0-3 Months	Priority 1 Action Required Immediately
Component Has Failed No significant risk to system	Priority 3/No Action Required Only 95/128 Infractions Recorded	Priority 2 Action Required 13-24 Months	Priority 2 Action Required 4-12 Months	Priority 2 Action Required 0-3 Months
Potential Component Failure	Priority 3/No Action Required Only 95/128 Infractions Recorded	Priority 3/No Action Required Only 95/128 Infractions Recorded	Priority 2 Action Required 13-24 Months	Priority 2 Action Required 4-12 Months
	Safety (People/Property/Environment)			

The major programs within DIMP are further described below.

4.2.2.1.1 Overhead Detail Inspection Program

The purpose of the Overhead Detail Inspection (ODI) program is to perform a close in-depth inspection of SCE's overhead electrical distribution facilities, such as poles, capacitors, switches, transformers, conductors, guy wires and risers, with the intent to identify and document visually apparent conditions. ODI inspectors also verify the accuracy of asset information and facility inventory mapping references for appropriate corrective actions. ODI adheres to GO 165 inspection frequency of 5 years for detailed inspections.

Inspectors identify and perform certain maintenance tasks during the course of the detailed inspections. ODI inspectors make minor repairs at the "public" level while at the site, to the extent possible, rather than having other SCE personnel return later to make the repairs. The public level is typically an area that is readily accessible to the general public, approximately 8 feet up from the ground level for a utility pole. Examples of typical minor repairs are installing new visibility strips, replacing damaged ground molding at the public level, installing guy guards, installing pole tags, and removing unauthorized attachments. For conditions that cannot be repaired during the inspection, the ODI inspectors document and prioritize items for follow-up corrective action in accordance with the priority classifications described above. These routine maintenance repairs and replacements resulting from ODI are considered preventative maintenance and have secondary wildfire risk mitigation benefits. The inspector will also identify, document and report any safety or reliability conditions created by communication company activities on inspected poles that result in General Order (GO) 95 and/or GO 128 infractions, and GO 95 and/or GO 128 infractions created on or near distribution facilities by non-utility third parties that are not subject to CPUC jurisdiction, such as unauthorized attachments.

4.2.2.1.2 Annual Grid Patrol

The purpose of the AGP is to visually inspect SCE's overhead and above-ground underground electrical distribution facilities every year to identify and document obvious safety and reliability conditions that require corrective action.[47] AGP adheres to or exceeds the inspection frequencies required within GO 165. The grid patrol inspector performs a simple visual inspection of publicly-accessible electrical distribution facilities within the assigned inspection area. Annual patrols are performed primarily from ground vehicles but can also be performed by foot or by aircraft. When conducting annual patrols, the inspectors also assess visible portions of distribution underground systems such as pad-mounted transformers, vault lids, and vent pipes. Like ODI, these inspectors document and prioritize items for follow-up corrective action in accordance with the priority classifications described above. These routine maintenance repairs and replacements resulting from AGP are considered preventative maintenance and have secondary wildfire risk mitigation benefits.

4.2.2.1.3 Underground Detail Inspection Program

The purpose of the Underground Detail Inspection (UDI) program is to perform an in-depth inspection of SCE's underground distribution facilities and pad-mounted equipment including structures, switches, transformers, visible cables, and associated components. UDI inspectors identify and document safety hazards and visually apparent conditions, and verify the accuracy of asset information and facility inventory mapping references for appropriate corrective actions. UDI adheres to GO 165 inspection frequencies of three years for subsurface facilities and five years for pad-mounted facilities. Inspectors identify and perform certain maintenance tasks and minor repairs during these detailed inspections. Typical minor repairs can include such things as installing new signage, structure tags, securing vault lids and removing debris. Like the ODI program, for conditions that cannot be repaired during the inspection, the UDI inspectors document and prioritize items for follow-up corrective action in accordance with the priority classifications described above. The crews are typically comprised of a lineman and a groundman who have received specialized training to work in underground vaults and near energized high voltage equipment. These routine maintenance repairs and replacements resulting from UDI are considered preventative maintenance and have secondary wildfire risk mitigation benefits.

[47] In many cases, the ODI can satisfy the AGP requirement for compliance purposes.

4.2.2.2 Transmission Inspection and Maintenance Program

SCE's TIMP helps maintain public and worker safety and regulatory compliance by completing scheduled inspections of subtransmission and transmission assets, in conformity with GO 165, and performing transmission maintenance, in accordance with GO 95, GO 128, SCE standards, and prudent utility practice. The purpose of TIMP is to 1) provide procedures, instructions, and guidance to field inspectors who perform detailed inspections and patrols and 2) specify guidelines to prioritize and complete repairs and replacements of transmission infrastructure based on the condition of each asset and its potential for impact on safety and reliability, considering various factors. Any abnormal conditions, such as a broken cross arm or damaged tower footings identified through TIMP are repaired immediately if categorized as a Priority 1 condition. Priority 2 conditions are corrected within 12 months in Tier 2 HFRA, within 6 months in Tier 3 HFRA, and within 36 months in non-HFRA.

SCE conducts annual routine patrols of overhead lines, communication circuits, above-ground equipment, and overhead components of underground circuits, such as riser poles, terminations, and lightning arrestors. Rights-of-way inspections are incorporated into transmission circuit patrols and are not considered a separate inspection program. Detailed inspections of overhead lines, communication circuits, underground lines and vaults are conducted every three years. Patrols and detailed inspections are performed and completed by Senior Patrolmen or qualified Linemen.

Additional inspections are performed on overhead lines that run through densely populated urban areas, more rugged rural areas, or geographic locations facing severe weather or environmental conditions (e.g., high winds, coastal areas exposed to salt, etc.). Inspections are also performed after unplanned events, such as severe weather, fires, and equipment malfunctions. Inspectors document any discrepancies, which are evaluated against construction and compliance standards to determine the item's priority level and sets the timeframe for corrective action.

SCE's underground subtransmission and transmission lines, along with the structures housing the lines, require routine inspections to detect and remedy any degradation. SCE performs these activities on a predetermined schedule to comply with the requirements of GO 128. At a minimum, all overhead components including riser poles, terminations and lightning arrestors are inspected annually under GO 95. Annual inspections also include the examination of transmission components within each substation. Inspections of the underground components, which include vaults, cable, splices, and shield arrestors, are inspected at a minimum once every three years. Emergent line inspections to assess component or structural damage are performed after unplanned events, such as severe weather, lightning, fires, equipment malfunction, and other incidents that may have caused circuit interruption or damage.

Transmission maintenance is driven by inspection results or Infrastructure Replacement Program activities. Sometimes, field observations lead to projects to address emergent issues in a particular grid or equipment or structure type. In other instances, projects are identified through SCE's Transmission Infrastructure Replacement program, which identifies maintenance work for items such as conductor and switch replacements using grid and/or engineering analyses. SCE initiated its Transmission Infrastructure Replacement program in 2013 to address safety and/or reliability risk resulting from issues with aging transmission infrastructure that were identified but had not led to equipment failure. The criteria for projects identified in this program includes the replacement of obsolete or deteriorated assets.

4.2.2.3 Substation Inspection and Maintenance

SIMP helps SCE maintain public and worker safety and regulatory compliance by completing scheduled inspections, in conformance with GO 174, and by performing maintenance and testing of equipment, as described in SCE standards and in accordance with prudent utility practice. SIMP also facilitates SCE's testing of its protection systems to meet regulatory requirements and commitments, such as North American Electric Reliability Corporation (NERC) reliability standards.[48] This protection system testing consists of routine inspection and maintenance in conjunction with repairs and replacement of equipment, such as distribution relays, as necessary. Distribution relays less than 66 kV in HFRA have 6-year test intervals, while those that are outside of HFRA are inspected every 12 years.

4.2.2.4 Pole Inspections

SCE's pole inspection programs are included in this section. The repair and replacement of poles resulting from these inspections are described in Section 4.3.

4.2.2.4.1 Intrusive Pole Inspection Program

The purpose of the Intrusive Pole Inspection (IPI) program is to evaluate SCE's wood poles using visual and internal examination of the poles to identify and document damage or decay requiring remediation. GO 165 requires intrusive inspections for all poles at least 15-years old, or older, to be completed using a 10-year cycle. Intrusive inspections involve drilling into the pole's interior to identify and measure the extent of internal decay, if any. Inspectors will apply a preservative to poles that pass the inspections to reduce the likelihood of future decay when conditions warrant.[49] Inspectors may also perform a visual inspection on poles that are in the inspection grid but that are younger than 15 years old to look for signs of obvious external damage. The inspector analyzes the integrity of the pole and classifies it for repair or replacement, as necessary. Approximately 10,000 poles are identified for repair or replacement each year through this program across SCE's service territory. IPI is an integral part of the Deteriorated Pole Program established in 1997; the Deteriorated Pole Program is further discussed in Section 4.3.

4.2.2.4.2 Pole Loading Program

The Pole Loading Program (PLP) is an inspection and remediation program to identify poles that do not meet safety factor requirements of GO 95 and SCE's internal design and construction standards territory for repair or replacement. PLP's goal is to assess the structural loading capabilities of the approximately 1.4 million poles in SCE's service territory to meet current design standards by 2021, and to continue addressing pole overloading issues by 2025. This program is designed to verify that the structural integrity of existing poles is sufficient to withstand anticipated wind loads acting on poles including wind loading in high wind areas within SCE's service territory. PLP prioritizes assessment of poles in HFRA. Although the CPUC requires a design wind pressure of 6 pounds per square foot (with 0.5 inches of radial ice) or 8 pounds per square foot (no ice), SCE adopted higher wind loading design standards of 12, 18, and 24 pounds per square foot in addition to the standards for 6 and 8 pounds. This is based on meteorological studies in areas with higher wind velocities. The wind-loading criteria that SCE applies is based on specific line locations and potential wind speeds at those locations. SCE will continue to assess pole conditions and replace poles, where applicable, based on the higher wind loading criteria outlined above. All poles that require replacement are prioritized based on their safety factor and on whether

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[48] For example, NERC Reliability Standard PRC-005-6 – protection system, automatic reclosing, and sudden pressure relaying maintenance.

[49] Preservatives are applied in conformance with the regulations of the California Department of Pesticide Regulation. In 2016 and 2017, 99.76% of passing poles had preservatives applied.

the pole is in HFRA. SCE typically replaces wood poles with new wood poles that meet or exceed SCE's current standards, and in some circumstances, SCE utilizes light weight steel poles for its subtransmission overhead system or composite poles for its distribution overhead system. PLP has secondary wildfire risk mitigation benefits.

4.2.2.5 Quality Oversight / Quality Control

SCE's Quality Oversight / Quality Control group performs independent evaluation of activities that impact the safe, reliable, and affordable delivery of electricity and partners with organizations throughout Transmission and Distribution (T&D) to correct quality gaps. The Quality Oversight / Quality Control group assesses compliance with GO 95, 128, 165, and 174 in addition to various SCE maintenance, inspection, and construction standards.

Current Quality Oversight / Quality Control programs include inspection of distribution overhead and underground construction by SCE and contract crews. The group also assesses performance quality of compliance-driven inspection programs such as ODI, UDI, and IPI; performs quality assessments of vendor-performed pole loading calculations for PLP; and assesses performance quality of vendor-performed steel stub pole repairs.

4.2.3 ADDITIONAL ACTIONS TAKEN IN HFRA

4.2.3.1 Enhanced Overhead Inspections and Remediation (Activity IN-1 and IN-2)

In light of rapidly evolving wildfire risks, SCE continues to review and assess its inspection and maintenance programs to keep pace with the evolution of wildfire threats. Historically, SCE's inspection and maintenance programs have been developed and executed with a focus on regulatory compliance, and multiple inspection programs have been established over time to meet additional compliance obligations.

To address the evolving wildfire risk beyond existing programs, SCE commenced the EOI initiative with two primary goals. The first goal is to conduct inspections of all overhead transmission and distribution structures (approximately 50,000 transmission structures and 380,000 distribution structures) and equipment in HFRA with a focus on potential ignition risk conditions. These inspections started in late 2018, and SCE is attempting to complete them before the start of the height of the 2019 wildfire season. Inspections are being conducted by qualified electrical workers, and remediation identified during these inspections will be categorized using the three-priority rating system as described in Section 4.2.2.1. Remediation activities likely will include, but are not limited to, vegetation pruning/removals and the repair or replacement of overhead structures and equipment, such as conductors, poles, cross arms, insulators, and transformers. As part of the EOI effort, SCE will also assess and deploy additional system hardening measures to reduce ignition risk or increase grid resiliency, as appropriate, based on conditions observed. These measures may include, but are not limited to, wildlife protection (e.g., critter guards), long span mitigations (e.g., installation of line spacers, reconductoring, cross arm replacement), and the application of fire-retardant coatings to poles and in some cases surrounding vegetation.

The second goal of the EOI initiative is focused on SCE's desire to evolve from a compliance-based approach to a risk-based approach that adequately addresses the evolving wildfire threat. Inspection results will be analyzed in light of SCE's existing inspection, maintenance and capital programs, a risk-based inspection and remediation model will be explored, and lessons learned from the EOI initiative will be studied. The results of these analyses will serve as a foundation for a risk-based inspection and maintenance strategy that is likely to impact the objectives, design, and tactics of existing inspection and

maintenance programs moving forward. Furthermore, SCE anticipates that these findings may also influence future design, engineering, construction, and operational standards/procedures to assess wildfire risks throughout the asset lifecycle.

4.2.3.2 Quality Oversight / Quality Control of EOI (Activity IN-3)

SCE's Quality Oversight / Quality Control group will perform independent quality control (QC) inspections on approximately 7,500 transmission and distribution structures in HFRA based on EOI in 2019. These QC inspections will be performed utilizing sampling to ascertain the effectiveness of the EOI inspections. The QC inspections exceed the requirements of GO 165. Any conditions identified as part of the QC process will be remediated. Additionally, in 2019, SCE will further refine and adjust its sampling methodology using a risk-based prioritization for differing wildfire risk levels within HFRA.

4.2.3.3 Distribution Infrared Inspection Program (Activity IN-4)

The Distribution IR Inspection program, which SCE began in 2017, provides for routine, ground-based infrared inspections of overhead distribution facilities in HFRA. SCE conducted IR inspection on overhead distribution energized facilities on all circuits in HFRA in 2017-2018. The infrared inspections are performed using infrared cameras (heat-sensing cameras), which may find deterioration-indicating conditions not visible to the human eye. IR inspections can detect a wide range of anomalies, including, but not limited to, failing switch and fuse contacts, poor connections, loose bushings, overloaded/failing transformers, and other issues that can result in component failure. The findings are evaluated and prioritized per SCE's current DIMP and addressed in the respective remediation timeframes. As described in SCE's GSRP application and supporting testimony, SCE will conduct another cycle of IR inspections of overhead distribution energized facilities on all circuits in HFRA over 2 years, in 2019-2020.

4.2.3.4 Transmission Infrared and Corona Inspection Initiative (Activity IN-5)

In addition to the EOI initiative noted above in Section 4.2.3.1, SCE launched a Transmission IR and Corona inspection effort focused on certain subtransmission and transmission (hereafter collectively referred to as transmission) lines in HFRA. This effort, which started in the first quarter of 2019, seeks to perform an IR and Corona scan of all overhead transmission facilities and equipment located in HFRA.[50] Specialized infrared and ultraviolet (Corona) light cameras are typically mounted to helicopters and the line is flown, with special attention paid to splices, conductor connection/attachment points, and insulators. The IR scan detects temperature differences and heat signatures of components, which may indicate problems (not visible to the naked eye) that could result in component/conductor failure. The Corona scan detects the degree of electric discharge or 'leakage' due to the ionization of air surrounding high voltage electric components, which, if substantial enough, could result in an arc flash or mechanical component failure. In addition, a high-definition camera takes pictures of anomalies found for review. A remediation plan is developed for anomalies and integrated with any needed repair or replacement resulting from the physical EOI of transmission assets. To further mitigate wildfire ignition risks, the results from this initiative will be factored into the continuous improvement of SCE's TIMP and Quality Oversight/Quality Control programs and the design and construction of transmission facilities.

4.2.4 ACTIVITIES AND 2019 GOALS

[50] Industry standard practice is to IR scan transmission lines operating at 40% or higher of rated line capacity. SCE is evaluating the ability to capture IR images at lower rating capacities.

Activity	Description	2019 Goal	Compliance Evidence
IN-1	Distribution Enhanced Overhead Inspections and Remediation in HFRA	1) Complete visual inspection of all distribution circuits in HFRA before 5/31 2) Remediate all conditions that create a fire risk in accordance with CPUC requirements	Enhanced Overhead Inspection and Maintenance records
IN-2	Transmission Enhanced Overhead Inspections and Remediation in HFRA	1) Complete visual inspection of all transmission circuits in HFRA before 5/31 2) Remediate all conditions that create a fire risk in accordance with CPUC requirements	Enhanced Overhead Inspection and Maintenance records
IN-3	Quality Oversight / Quality Control of EOI	1) Perform quality review on approximately 7,500 Transmission and Distribution structures in HFRA based on EOI inspections	Quality Oversight / Quality Control records
IN-4	Infrared Inspection of energized overhead distribution facilities and equipment	1) Inspect 50% of overhead circuit lines in HFRA 2) Remediate conditions as required based on inspection results	Infrared inspection records
IN-5	Infrared Inspection, Corona Scanning, and High Definition imagery of energized overhead transmission facilities and equipment	1) Complete IR, Corona, and HD image scanning of all overhead transmission lines in HFRA that are loaded to 40% of rated capacity or higher 2) Integrate remediation with EOI activities	Infrared inspection records

4.3 SYSTEM HARDENING TO ACHIEVE HIGHEST LEVEL OF SAFETY, RELIABILITY, AND RESILIENCY

4.3.1 PROGRAM OVERVIEW

SCE's system hardening effort is largely an ongoing, multi-year program focused on wildfire prevention (i.e., reducing ignitions) and enhancing system resiliency (i.e., reducing damage to electrical infrastructure from fires). For example, replacing standard "bare" overhead conductor with "covered" conductor in HFRA is expected to significantly reduce ignitions caused by foreign objects such as palm fronds, metallic balloons, debris, etc. Additionally, use of composite/fire retardant poles provides a two-fold benefit. First, such an approach improves system resiliency and reduces damage to electrical facilities by ensuring poles do not burn and result in attached equipment (e.g., conductor, transformers, etc.) falling to the ground. Second, it reduces restoration time as composite poles are more fire-resistant, thereby reducing the amount of poles needing replacement.

To address the increased wildfire risk, SCE is implementing many of the activities described in the GSRP and this WMP, as well as assessing the potential to accelerate certain activities described in its GSRP

application. Even if SCE is successful at accelerating certain activities, programs such as SCE's WCCP in HFRA will be a long-term program.

SCE's grid hardening activities in this chapter primarily targets the distribution system (with some also being applicable to higher-voltage subtransmission and transmission lines) in HFRA due to the higher risk of fire ignition from distribution power lines compared to transmission-level power lines. As noted in Chapter 3, in 2019, SCE will conduct additional risk-based analyses focused on its subtransmission and transmission infrastructure in HFRA to consider additional wildfire mitigation programs and activities.

4.3.2 EXISTING SYSTEM HARDENING PROGRAMS

SCE's existing system hardening strategies have evolved over time and provide wildfire risk mitigation. For example, automated equipment such as circuit breakers, and RAR are standard pieces of equipment throughout SCE's service territory and are used to quickly detect faults, isolate circuits, and restore electric service to customers. RAR have been used at the high-fire boundaries in SCE's service territory for decades, and SCE has had reclosing restrictions on distribution lines traversing HFRA since the 1950s. As described in Section 4.1, RAR and circuit breakers on distribution lines prevent reclosing following a fault, which lessens the potential for ignitions from distribution line faults during RFW events or other high wildfire risk conditions. SCE also has the capability to remotely disable groups of reclosers during RFW events or other high wildfire risk conditions. SCE has previously targeted HFRA to mitigate wildfire risk. For example, sensitive ground schemes have previously been deployed in HFRA; sensitive ground schemes reduce the magnitude of current delivered to ground faults and allow for lower, more sensitive ground protection settings, thus minimizing ignition risk. While three-phase and phase-to-phase fault currents are not reduced, these schemes do provide a reduction in energy for ground faults.

SCE follows several principles when designing its system, including using wider easements and rights-of-way (ROW), and clearing buffers around substations to reduce the possibility of ignition due to debris contacting substation equipment.

Over the years, SCE has implemented many infrastructure replacement and improvement programs. These programs help mitigate wildfire risk and include replacement programs designed to mitigate in-service failures for aging distribution and transmission assets (e.g., wooden poles, overhead conductors, relays, etc.) and replacements for safety purposes. SCE reviews its multi-year plan for these infrastructure programs during the annual operating plan process and, as necessary, reprioritizes and adjusts program accordingly. These infrastructure programs, outlined in detail in SCE's 2018 GRC filing, include, for example, OCP and the Deteriorated Pole Program, and are described below.

As part of SCE's equipment and hardware selection process, SCE uses the CAL FIRE Power Line Fire Prevention Field Guide, which identifies utility equipment that has increased safety margins and a lower likelihood of causing ignitions. The guide was created to collectively document utility best practices for line construction with safer equipment and materials. Beyond the Power Line Fire Prevention Field Guide, SCE may use additional fire resilient materials, where available, and after evaluating the relative tradeoffs of using such materials. The following sections include summaries of SCE's major existing system hardening programs that have wildfire risk mitigation benefits.

4.3.2.1 Design and Construction Standards

SCE has traditionally designed its system to safely deliver reliable and affordable power to customers, and these efforts often provide direct or indirect wildfire mitigation benefits. SCE has detailed standards

for design, engineering, and construction that supplement or exceed minimum regulatory requirements for all of SCE's electrical infrastructure.[51] Additionally, SCE regularly reviews and updates these standards based on new requirements, construction methods, technologies, etc. Design and construction standard changes that SCE has made or is making to further mitigate wildfire risks are described below.

4.3.2.2 Overhead Conductor Program

SCE's OCP is a long-term program that pre-dates this WMP, and which is aimed at reducing the risks associated with downed energized conductors and covers all of SCE's service area. OCP evaluates and reconductors small wire circuits with the greatest public safety risks from a wire down event. OCP prioritizes circuits based on various factors, including circuits that serve many customers and are in densely populated areas where reliability and public safety risks from human contact with a downed wire are greatest, not the wildland-urban interface that is typical of HFRA. Even though OCP's primary focus is not specifically wildfire risk mitigation, it does have important secondary wildfire risk mitigation benefits, such as preventing wire down events that could have led to ignitions.[52]

4.3.2.3 Deteriorated Pole Program

SCE's Deteriorated Pole Program was established pursuant to the distribution pole inspection program in compliance with GO 165, which became effective in 1997. As discussed in Section 4.2, GO 165 requires intrusive inspections for all poles at least 15 years old, or older, to be completed within 10 years of program inception. Thereafter, it requires all poles to be intrusively inspected by the time they are 25 years old and then re-inspected at least once every 20 years. SCE completed its first cycle of intrusive inspections in 2007 and continues intrusive inspections through the IPI program. SCE's Deteriorated Pole Program replaces poles throughout its service territory based on the results of these inspections, as described below.

Besides poles identified because of the formal inspection program, poles identified as deteriorated per other programs may be submitted to the Deteriorated Pole Program for replacement based on their external condition. If these poles meet the criteria for external decay outlined in the program standard, they are prioritized according to the standards described above for replacement in the Deteriorated Pole Program. Like OCP, to the extent this program reduces the risk of deteriorated pole failures in HFRA, it has important secondary wildfire risk mitigation benefits.

4.3.2.4 Capacitor Bank Replacement Program

Capacitor banks are used in SCE's distribution system to regulate the voltage to usable levels by compensating for load inductance and to maintain adequate voltage levels (at least 95% of nominal service voltage levels). Inadequate voltage could damage customers' electrical equipment and appliances. Serious voltage drops resulting from inadequate capacitance could conceivably lead to grid collapse. SCE replaces capacitor banks under two criteria: age-based replacements or inspection driven replacements. Inspection of the capacitor banks is part of SCE's preventive maintenance program. Once every five years, each capacitor bank in SCE's system is inspected for proper operation, corrosion, leaking

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[51] These include, for example, Distribution Overhead Construction Standards, Distribution Design Standards, Transmission Overhead Construction Standards, Transmission Design and Right-of-Way Manual, and many others. For a complete list of all of SCE's design, engineering and construction standards please see Appendix C.

[52] In the context of this WMP, "secondary wildfire risk mitigation benefits" means that the program was not primarily designed in the first place to reduce wildfire risk, but it nonetheless has wildfire risk mitigation benefits.

oil, and loose connections. Capacitor banks requiring replacement or repair are recorded and prioritized for follow-up work. The expected average time to wear out of an overhead capacitor bank is estimated at about 30 years, at which time failure rates begin to increase. To the extent this program reduces risk related to capacitor bank failures located in HFRA, it has important secondary wildfire risk mitigation benefits.

4.3.2.5 Automatic Reclosers Replacement Program

Automatic reclosers (AR) are used in distribution circuits to interrupt power to a portion of the circuit. They act much like a circuit breaker. However, instead of being at the upstream-most end of the circuit, ARs are typically located toward the end of the circuit. AR are typically installed for two reasons - safety and reliability. When a fault occurs downstream of an AR, the AR opens before the circuit breaker in the substation responds to the fault, thus minimizing customer service interruptions. Only the downstream portion of the circuit is interrupted, and all customers upstream of the AR remain energized.

AR are replaced based on age or reactively when they fail. The AR Replacement program is only for the age-based replacement of AR. The estimated time to wear out of an AR is estimated at about 25 years, at which time the failure rate begins to increase. To the extent this program reduces AR failure and/or AR-associated ignitions in HFRA, it has important secondary wildfire risk mitigation benefits.

4.3.2.6 PCB Transformers Replacement Program

For a period of about 20 years, transformer manufacturers distributed transformers and other oil-filled electrical equipment containing insulating oil with polychlorinated biphenyls (PCB) to utilities in the United States. While SCE never specifically ordered transformers containing PCB oil, many transformers were received and installed with oil contaminated with PCB. SCE instituted a proactive PCB transformer replacement program for suspected PCB-contaminated transformers. SCE's proactive PCB Transformer Replacement program, with its accelerated replacement rate, will significantly reduce the balance of all PCB-contaminated transformers by 2025. To the extent this program reduces risk related to transformer equipment failure in HFRA, it has important secondary wildfire risk mitigation benefits.

4.3.2.7 Transmission Line Rating Remediation

SCE has been conducting a Transmission Line Rating study to identify transmission lines with potential clearance issues. As part of this study, SCE completed an initial survey of all of SCE's California Independent System Operator (CAISO)-controlled transmission lines built before 2005. Based on the results of that survey, SCE prioritized the transmission line discrepancies requiring line clearance remediation. A discrepancy is any condition found in the field requiring remediation to meet GO 95 requirements during peak loading conditions. Discrepancies have been prioritized based on criteria such as line sag when operating at or below 130 degrees Fahrenheit, and potential risk to public safety and system reliability based on location of span, terrain, encroachment type, and extent of deviation from standards.

In 2015, SCE developed a plan to remediate all CAISO discrepancies over a ten-year period, from 2016 to 2025. The ten-year plan was developed with input from NERC and the Western Electricity Coordinating Council (WECC).

Besides the CAISO discrepancies, NERC/WECC requested that SCE perform studies on the non-CAISO controlled lines (radial lines). This study was completed in 2015 and requires additional discrepancies to be remediated by 2030, as agreed to by SCE and NERC/WECC. To the extent this program reduces risk

related to transmission line discrepancies in HFRA, it has important secondary wildfire risk mitigation benefits.

4.3.2.8 Road and Rights-of-Way Maintenance

SCE performs both proactive and reactive road and ROW maintenance. This work is required to provide field crews with safe access to SCE facilities. SCE's roads and ROW are also used by fire agencies as fire breaks and for access during other emergencies. Road and ROW maintenance activities include annual grading, repairs of damaged storm drains, repairs of access roads, and annual brush clearing along access roads to allow safe passage of vehicles and equipment. Transmission ROW clearing also includes weed abatement on parcels of property owned by SCE along transmission ROW, as required by city or county fire codes. These practices have important secondary wildfire risk mitigation, response time, and fire suppression benefits.

4.3.2.9 Insulator Washing

Insulator washing is performed by spraying high-pressure water on to subtransmission and transmission insulators to remove contaminants such as salt, dirt, or automobile exhaust. Excessive contamination on an insulator reduces its ability to insulate the energized line from the grounded support structure, which may cause lines to short circuit. Insulator washing is performed through various means. SCE typically uses specially equipped water trucks with a derrick and water nozzle to direct a high-pressure stream of water safely onto the insulators while the line remains in service.

In 2015, SCE moved away from a "calendar-based" wash schedule to a "condition-based" wash program. This updated program requires a visual inspection of a circuit to show contamination or signs of imminent failure, such as arcing or buzzing, before washing is conducted. If no signs of contamination are evident, the circuit will continue to be monitored until it is deemed necessary to perform a wash. Beach areas with high salt levels and high traffic volume require more frequent washing than a desert area with dryer air and less exhaust from traffic. To the extent this program reduces risk related to insulator ignitions in HFRA, it has important secondary wildfire risk mitigation benefits.

4.3.3 SYSTEM HARDENING ACTIONS IN HFRA

SCE's system hardening actions in HFRA are largely based on the GSRP, which contemplates broader, more advanced measures than those described in its 2018 GRC. The GSRP is a comprehensive program, incorporating leading practices and mitigation measures selected based on their effectiveness and with appropriate consideration of resource allocation and alternatives. For example, SCE introduced the use of fire-resistant composite poles and crossarms in HFRA. For system protection, SCE prioritized the use of current limiting fuses in HFRA and began applying a more sensitive fast curve trip setting for RAR and circuit breaker relays to allow for a more rapid clearing of faults during Red Flag Warning and other high fire risk conditions. These and other GSRP measures will help enhance the safety of the electrical system and make it more resilient during wildfires, consistent with state policy. Additionally, SCE is endeavoring to accelerate and expand certain GSRP activities and initiate additional programs beyond GSRP to further harden the grid as described below.

4.3.3.1 Design and Construction Standards

In 2018, SCE updated its Distribution Design Standards (DDS) and Distribution Overhead Construction Standards (DOH) to expand the use of wildfire mitigating measures in HFRA. For example, DOH and DDS were updated to specify the use of covered conductor in re-conductoring projects in HFRA. Covered

conductor has robust, insulating, and protective layers; replacing bare conductor with covered conductor is an effective way to mitigate contact-related faults.

SCE also updated its DDS and DOH to evaluate and consider the use of composite poles and composite crossarms in HFRA applications. The composite poles SCE is installing are coated with a fiber reinforced polymer (FRP) laminate which is fire resistant. Similar fire-resistant material is wrapped around the composite pole to create a shield which helps protect the pole and further increases fire resistance. A shielded composite pole resists ignition and can maintain its strength in fire conditions. Composite crossarms have a longer service life, greater strength and are more fire resistant than wood crossarms. SCE is using fire resistant composite crossarms and poles with shielding for pole replacements, when appropriate, to increase resiliency and reduce potential outage impacts resulting from a fire event.

Additionally, SCE updated its DDS BLF requirements to prioritize CLF in HFRA. CLF are selected for HFRA applications because they can limit peak fault current, provide faster fault clearing for most faults, and reduce fault energy by up to 25 times compared to a conventional fuse. Reducing fault energy lowers the risk of possible ignition when a fault occurs. CLF also help minimize impacts to customer electric service reliability from fast curve operating settings.

In 2018, SCE converted its overhead transformer design requirements when replacing obsolete or failing overhead transformers to utilize ester fluid (such as FR3) instead of mineral oil. Transformers with ester-based insulating fluid have a much higher flash point compared with conventional mineral oil-immersed units and will further reduce the possibility of transformer failures becoming the source of wildfire ignitions.

SCE has updated its construction standards to increase line spacer usage and to install wildlife protection, such as covers, tubing, and covered jumper wire. Additional overhead line spacers in HFRA will improve system resiliency from conductor to conductor faults. Wildlife protection shields overhead equipment, such as transformer bushings, fuses, cable terminations and arrestors, from animal-related contact faults, and other contact-related faults associated with vegetation and metallic balloons. These new construction standards will help reduce ignitions associated with SCE's electric infrastructure.

In 2019, SCE intends to refine its DOH requirements for connector selection for HFRA application to prioritize the use of CAL FIRE-exempt connectors such as bolted wedges.

4.3.3.2 Conductor

4.3.3.2.1 Wildfire Covered Conductor Program (Activity SH-1)

WCCP is a new, long-term program that began in 2018 (as part of GSRP) and is aimed at replacing standard bare overhead conductor with covered conductor in HFRA. This program is anticipated to significantly reduce contact-from-object ignition risks. As discussed in Chapter 3, contact from object faults in SCE's HFRA during the analyzed historical period were associated with more than one-half (53 percent) of suspected wildfire-initiating events. SCE's risk analysis demonstrates that application of covered conductor should be an effective approach to reduce ignitions associated with electrical infrastructure in SCE's HFRA. The reduction of faults should also decrease the frequency of wire down events. In combination with other mitigation measures such as advanced protective relays, automatic reclosers with fast curve settings, and CLF, the benefits of covered conductor significantly outweigh the increased cost of covered conductor (compared to bare conductor), and the associated modest increase

in-wind loading. The covered conductor also offers significantly better safety protection for the public in the limited cases of high impedance faults, as tests and studies have demonstrated that incidental contacts with energized conductor that is covered do not result in injuries. Given the significant wildfire mitigation benefits, SCE is targeting the proactive replacement of approximately 5,500 circuit miles of existing bare distribution primary overhead conductor in HFRA by 2025. SCE has prioritized its circuit re-conductoring plan based on a weighting of ignition consequence, ignition frequency, and mitigation effectiveness factors, such as wind loading considerations, number of historical vegetation faults, and number of historical wire down events. In 2018, SCE began deploying covered conductor in HFRA and installed 84 circuit miles as part of GSRP. SCE is targeting completing approximately 600 circuit miles by year-end 2020, focused on portions of nine at-risk circuits in HFRA. SCE selected these circuits based on a combination of their environmental footprint, asset characteristics and potential HFRA impact. Where appropriate, pole replacements and transformer replacements driven by this re-conductoring will be fire-resistant composite poles and ester fluid transformer, respectively. Additionally, in covered conductor systems, SCE will employ other accessories to combat contact-related faults, including dead-end covers, termination covers, fuse covers, arrester covers, wildlife guards, and transformer bushing covers. Bare conductors remaining in high wind areas (which in some, but not all, cases overlap with HFRA), will be retrofitted with insulated overhead wire spacers or have the pole reconfigured to "Ridge Pin" construction to reduce the potential of wires contacting each other. Furthermore, vibration dampers may also be installed to reduce conductor fatigue.

SCE may use aerial bundled cable in limited areas as an alternative to covered conductor. Installation of aerial bundled cable would likely be in areas with narrower spaces, to remediate tree attachments, and areas with dense vegetation that cannot be trimmed. Aerial bundled cable is more complicated to make connections with, making it more suited for long runs with few equipment and tap lines. Additionally, the increased weight of aerial bundled cable will lead to shorter spans and more pole replacements. Both covered conductor and aerial bundled cable have comparable benefits regarding preventing contact from objects, however covered conductors are more economical for most applications.

WCCP is a multi-year program, and in 2019 SCE will install at least 96 miles of covered conductor in HFRA. Given the significant amount of covered conductor targeted under this program and the wildfire risk mitigation benefits it provides, SCE will endeavor to install more circuit miles of covered conductor in HFRA in 2019 and accelerate installation in subsequent years. Additionally, SCE is assessing expanding the WCCP to deploy covered conductor across all Tier 3 HFRA over multiple years, starting in 2019. This assessment along with accelerated installation under GSRP could increase the 2019 total amount of covered conducer installed, in HFRA, to approximately 290 circuit miles.

4.3.3.2.2 Undergrounding Overhead Conductor (Activity SH-2)

Undergrounding overhead distribution lines, which typically have been used to mitigate aesthetic impacts in high-traffic urban areas, is a wildfire risk mitigation option in HFRA. While underground systems can help reduce the risk of wildfires and increase reliability during high winds and storms, they also take longer and cost much more to construct,[53] maintain, and repair – particularly in mountainous regions and those with steep terrain. In some cases, undergrounding may be infeasible due to local geology (e.g., bedrock, granite, etc.). Further, placing lines underground is less efficient than installing covered conductor, since underground lines take longer to construct, are difficult to inspect, may have shorter life expectancy than covered conductors and often have extended duration restoration times when there are outages. SCE will continue to work with local communities to pursue undergrounding in

[53] Underground systems can cost up to 10 times more than overhead systems – roughly $3 million per mile.

HFRA using its existing Tariff Rule 20. Additionally, and as part of its continued efforts to reduce wildfire risk, in 2019, SCE will conduct an evaluation to determine the highest risk portions of its HFRA and assess SCE's circuits around those areas that may be inaccessible should a fire occur and where SCE's circuits are critical to first responders to determine if there are certain sections that should be undergrounded. This evaluation may lead to engineering and design of targeted underground facilities in 2019 with potential construction commencing in late 2019/early 2020.

4.3.3.3 Equipment

Equipment-related efforts that are underway include changes to distribution transformer fluid requirements, improving conductor resiliency with the use of overhead line spacers and wildlife protection covers, and expanding the use of CAL FIRE-exempt equipment. SCE began deploying distribution transformers with ester-based insulating fluids in 2018, with the vast majority of HFRA new installations including ester fluid transformers. As part of WCCP, SCE began deploying wildfire protection such as critter guards to prevent animal contact and incidental contact from vegetation and metallic balloons.

In 2019, SCE intends to expand its conductor resiliency effort with use of line spacers on existing conductors by developing standard installation practices. Line spacers are installed to maintain the separation of overhead conductors. SCE expects the expanded use of line spacers to existing conductors will improve grid resiliency by preventing outages and associated fault impacts from conductor-to-conductor contacts. Additionally, SCE intends to further enhance grid resiliency by developing standard installation practices for vibration dampers. Vibration dampers are hardware attached to conductors (usually near insulators) which helps reduce conductor connection and attachment degradation from vibration.

Additionally, in 2019, SCE is piloting 50 CAL FIRE-exempt surge arresters in field conditions to learn more about their operations and installation before deploying them as a standard in HFRA in the future. SCE is also expanding the use of CAL FIRE-exempt connectors such as the bolted wedge connector. These new and alternative technologies are further discussed in Section 4.7.

4.3.3.4 Fire-Resistant Composite Poles and Composite Crossarms (Activity SH-3)

SCE is planning to install fire-resistant composite poles and composite cross-arms in HFRA. As part of re-conductoring work to install covered conductors in HFRA, SCE will conduct pole loading assessments on existing poles to determine if pole replacement is required. If the pole loading analysis shows that minimum safety factors would not be met when installing covered conductor, SCE will install fire-resistant composite poles with a fire protective shield (or other fire-resistant poles) instead of traditional wood poles. These poles are specifically designed to withstand wildfires and will harden the distribution system and reduce the risk of a wire down event. Extensive fire testing studies have shown that a fire protective shield will protect the pole and further increases fire resistance, enabling the pole to withstand an "extreme" wildfire. SCE began installing composite poles and composite cross arms in 2018. As part of WCCP, SCE will utilize either composite poles (or other fire-resistant poles) for replacements in HFRA. Based on historical pole replacements due to reconductoring and the miles of covered conductor targeted in 2019, SCE expects to replace at least 1,100 wood poles with fire-resistant composite poles (including a fire protective shield) in HFRA. Consistent with SCE's efforts to accelerate and expand its WCCP, in 2019, SCE may replace up to approximately 2,300 additional wood poles (i.e., for a total of approximately 3,400) with composite poles (or other fire-resistant poles should material supply constraints limit the availability of fire-resistant composite poles).

4.3.3.5 Protection and Isolation (Activity SH-4, SH-5, and SH-6)

In 2018, SCE adopted a branch line protection strategy that will install new (and replace some) existing devices to minimize fault energy. These devices will include CLF, CAL FIRE-exempt expulsion fuses, and single-phase reclosers. Additionally, SCE will continue deploying fast curve settings to circuit breakers and remote automatic reclosers in HFRA. These approaches are intended to assist in minimizing wildfire ignition risks by clearing faulted conditions rapidly, thus reducing the fault energy. In 2019, SCE plans to install/replace devices at least 7,500 branch line locations in HFRA. In addition to the fault energy reduction, the placement of CLF is expected to improve electric circuit reliability by segmenting faulted circuits to smaller line sections.

SCE will continue to install RAR for mainline circuit protection and reliability improvements. SCE will update existing RAR control settings to allow fast curve interrupting operating strategies. SCE plans to install RAR in at least 50 new HFRA locations in 2019 and install fast curve settings in at least 150 existing HFRA locations.

SCE will update settings on existing relays where possible and replace relays where necessary to allow fast curve interrupting operating strategies. Completed quantities may vary in 2019 depending on where SCE can install additional RAR most efficiently.

SCE began implementing fast curve trip settings for RAR and circuit breaker relay settings in 2018. In 2019, SCE will develop a plan to continue to install fast curve settings on circuit breaker relays in HFRA.

4.3.4 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
SH-1	Covered Conductor	Install at least 96 circuit miles of covered conductor in HFRA	1) List of circuits and associated miles of covered conductor installation 2) Record of completed work orders of covered conductor construction
SH-2	Evaluation of Undergrounding in HFRA	Conduct evaluation of undergrounding for HFRA	Assessment of undergrounding in HFRA
SH-3	Composite Poles and Crossarms	Install at least 1,100 composite poles	1) List of circuits and associated number of composite pole installations 2) Record of completed work orders of covered conductor construction
SH-4	Branch Line Protection Strategy	Install at least 7,500 CLF in HFRA locations	Record of completed work (i.e. work orders), including circuit, fuse location and installation date
SH-5	Remote Controlled Automatic Reclosers Installations	Install at least 50 new RAR	Record of completed work (i.e. work orders), including location and installation date
SH-6	Remote Controlled Automatic Reclosers Setting Updates	Update at least 150 existing RAR settings	1) List of RAR/CBs for fast curve settings change 2) Record of completed work of RAR/CB settings (OD43), including circuit, device number, relay change date for fast curves
SH-7	Circuit Breaker Fast Curve	1) Develop engineering plan to upgrade remaining CB relays and update settings 2) Conduct CB upgrades and setting updates according to plan	1) CB Upgrade plan 2) List of CBs for upgrade and fast curve settings 3) Record of relay upgrade (work order) and record of completed relay settings completed (OD43)

4.4 VEGETATION MANAGEMENT PLAN

4.4.1 PROGRAM OVERVIEW

SCE's vegetation management program involves the ongoing activities related to tree inspection, pruning, and removal, and weed abatement in proximity to SCE's distribution and transmission lines. SCE's vegetation management program is designed to comply with vegetation-related regulations,

including but not limited to GO 95 Rule 35, Public Resources Code (PRC) Sections 4291, 4292 and 4293, and NERC Reliability Standard FAC-003.

4.4.2 EXISTING VEGETATION MANAGEMENT PROGRAMS

SCE's distribution and transmission lines are inspected annually for compliance with state and federal vegetation management requirements. During these inspections, vegetation that requires pruning to maintain required clearances from the lines is scheduled for pruning or removal. The pruning takes into consideration a tree's anticipated growth over twelve months. Fast-growing species, or trees in HFRA, may need additional inspections or removal to maintain compliance. SCE engages contractors to inspect, prune, and remove trees, and to abate weeds. See Appendix D for list including fast-growing tree species which require removals.

4.4.2.1 Pole Brushing

SCE maintains poles with non-exempt attachments in HFRA that require 10 feet of radial brush clearance at the base of the pole in accordance with PRC Section 4292. These poles are inspected annually and brush clearing is performed as required to maintain compliance. This work is performed by contractors and is performed separately from other vegetation management activities. In 2019, SCE will continue to inspect and clear brush around the population of poles with non-exempt attachments, as required.

4.4.2.2 Supplemental Vegetation Inspections in HFRA

SCE's vegetation management program includes supplemental vegetation inspections such as Canyon Patrols and At-Risk Circuit Patrols. Canyon Patrols are performed annually on approximately 120 canyons to verify the circuits are free from vegetation encroachment into the minimum vegetation clearance distance. The canyons included for inspection are typically selected based on higher risk factors such as high winds, terrain, ingress/egress issues, type of electrical facilities, or limited fire-fighting capabilities. Additionally, At-Risk Circuit Patrols are performed, at least once per calendar year, on circuits that have a history of multiple vegetation-caused circuit interruptions. In 2019, SCE plans to continue performing Canyon and At-Risk Circuit Patrols.

4.4.2.3 Operation Santa Ana

Operation Santa Ana is a joint patrol effort with state and local fire authorities to facilitate understanding of each agency's roles and responsibilities and to provide cross-training opportunities. Each year, SCE's Vegetation Management staff meets with and accompanies local, county, and/or state fire agency personnel to perform these supplemental patrols of overhead power lines in HFRA. These patrols focus on electrical facilities and adherence to PRC Sections 4292 and 4293 vegetation-related requirements. Any vegetation conditions identified during these patrols that need to be remediated will be completed in accordance with SCE's vegetation management program. Operation Santa Ana is typically performed during a 3-4 month window with Los Angeles and Riverside County areas being completed by September 1, and the Ventura and San Bernardino County areas completed by the end of October. SCE plans to continue Operation Santa Ana in 2019.

4.4.2.4 Vegetation Management Program Re-Design

SCE's current vegetation management program is described in two key program documents: the Transmission Vegetation Management Plan and the Vegetation Management Operations Manual.

SCE's vegetation management program is currently undergoing a comprehensive redesign and restructuring. The staged deployment of the revised vegetation management program is anticipated to

commence in early 2019 and continue into 2020. Enhancements reflected in SCE's revised vegetation management program include, but are not limited to: expanded administrative controls; comprehensive Quality Control and Quality Assurance activities; increased focus on hazard tree removals/mitigation; and increased identification and removal of vegetation overhangs.[54]

CPUC GO 95, Appendix E recommends a minimum clearance of 12 feet for circuits 2.4 kV to 72 kV be established during pruning in areas that are designated as Extreme and Very High Fire Threat Zones as specified in GO 95, Case 14, Table 1.[55] SCE has determined, based on the high fire threat in its service territory, that it will implement the CPUC's recommendations in HFRA, where practical. While it is SCE's objective to achieve a 12-foot clearance, some conditions may limit SCE from achieving those clearances, such as particular tree species, woody stem exemption trees,[56] prior pruning practices, maturity of the trees, customer concerns or refusals, or other factors. These restrictions will be documented in SCE's vegetation management database. Once deployed, it is anticipated that it will take 12 to 18 months to complete the first inspection and pruning cycle reflecting the 12-foot recommended clearance in HFRA. In other cases, there may be a need to prune trees more than 12 feet to manage the growth of the tree or to meet ANSI 300 standards for tree pruning. These decisions are made by certified arborists on a case-by-case basis.

The revised vegetation management program is modifying SCE's approach to vegetation management under and around transmission lines. Directly under conductors, SCE will clear all trees and brush which could potentially grow into the compliance clearance space around the conductors. In addition, the area between the outer-most conductors and the ROW border will be cleared of brush and trees that have the potential to strike electric facilities. Where foot patrols or normal helicopter patrols are insufficient to evaluate the clearance, SCE will use LiDAR technology to identify trees along the ROW border that can potentially contact conductors during high wind events. Additionally, and where achievable, SCE plans to maintain a 30-foot clearance between conductors and vegetation for power lines 115kV and above. The 30-foot clearance is recommended as part of GO 95, Appendix E. SCE's calculation of the 30-foot clearance will incorporate line dynamics (sag and sway).

The Pacific Southwest Region of the Department of Agriculture, USFS has been integral in helping SCE and other electric utilities cope with the increased risks associated with wildfires, drought, and bark beetle epidemic. Currently, SCE and other electric utilities are working with the USFS to negotiate master service agreements to expedite a broad range of vegetation management activities on Forest Service Lands, such as the process for trimming and removal of trees. This master service agreement is expected to be finalized in first quarter 2019.

SCE has also set up funding agreements with state and federal environmental resource agencies including the California Department of Fish and Wildlife, the U.S. Army Corps of Engineers, and the U.S. Fish and Wildlife Service to provide either dedicated staff and/or the ability for personnel to make SCE's

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54 While the revised vegetation management program will be deployed in 2019 through 2020, some aspects of the program such as removal of vegetation overhangs will take multiple years to complete the initial cycle.

55 *See* D.17-12-024.

56 Section (a)(3)(A) of Section 1257 of PRC 4293. (A) Exempt Trees must meet all of the following criteria, as confirmed by a Certified Arborist or a Registered Professional Forester: 1. The tree or limb must be six (6) inches or more from the line at all times. 2. The size of the tree or limb at the conductor level must be at least six (6) inches in diameter. 3. The tree must not have "scaffold branches," below eight and one-half feet from the ground (so the tree cannot be easily climbed).

projects in HFRA a priority. The funding agreements allow for faster processing of environmental permits which are needed to carry out certain vegetation management/fuels reduction activities. This allows SCE to work with the agencies on prioritizing activities that better position the company to obtain timely approvals in HFRA.

4.4.3 ADDITIONAL ACTIVITIES IN HFRA

To further help mitigate wildfires, SCE has and will perform additional vegetation management activities in HFRA that are beyond those ongoing activities required by GO 95 (Rule 35), PRC Sections 4291, 4292 and 4293, and Federal Energy Regulatory Commission (FERC) Reliability Standard FAC-003. These enhanced activities are described below.

4.4.3.1 Hazard Tree Removals (Activity VM-1)

As set forth in SCE's GSRP application, SCE proposes to expand its vegetation management activities to begin assessing the structural condition of trees in HFRA that are not dead or dying but could nevertheless fall into or otherwise impact electrical facilities and potentially lead to ignitions and outages. These trees can be located up to 200 feet on either side of SCE's electrical facilities, an area designated as the Utility Strike Zone, which is significantly beyond the 4-foot clearance requirement in HFRA.

SCE's risk assessment methodology is based upon American National Standards Institute (ANSI) A300 and the International Society of Arboriculture Tree Risk Assessment Qualification Training Manual. As discussed in SCE's 2018 GSRP application, SCE's assessment methodology considers the attributes of the tree, the site conditons, impact to the infrastructure, and the likelihood of failure.

To implement the Hazard Tree Management program (HTMP),[57] arborists certified by the International Society of Arboriculture (ISA) perform these assessments and determine appropriate mitigation. SCE's HTMP assists the arborists by detailing a consistent approach to be applied to all trees assessed in SCE's service territory. In HFRA, SCE defines all trees within the Utility Strike Zone that have the potential to strike the conductors or fall within the Minimum Violation Clearance Distance (MVCD) as "subject trees." After assessment, a subject tree can remain a "subject tree" or be classified as a "hazard tree" or "reliability tree." A hazard tree has conditions within the tree that pose an expected risk to electrical facilities. A reliability tree is considered a healthy tree but is located in an area in which site conditions pose an expected risk. Both hazard and relibility trees are risk-ranked and removed based on expected risk to the infrastructure.

The tree-specific risk assessment will identify if the tree should be mitigated to reduce an expected risk. Trees that are determined to potentially threaten electrical facilities and require mitigation will be included in SCE's tree inventory for tracking purposes. Mitigation may include: heavy topping, removal of limbs, or the removal of the entire tree. Post-inspection of work prescribed by a tree assessment inspector is performed by an independent quality control contractor. Post-tree removal, inspection and quality review includes evaluation and mitigation of any potential risks that may arise from the work, such as erosion and windshear.

Some tree removals may require enhanced efforts to obtain property owner approval and leveraging new laws such as Assembly Bill (AB) 2911. SCE is currently finalizing these additional hazard tree removal

[57] Part of Expanded Vegetation Management Activities described in SCE's GSRP Application.

procedures and anticipates beginning the enhanced efforts in early 2019. Under this program, SCE anticipates that it will perform at least 125,000 tree-specific threat assessments and mitigate, through removal or trimming, at least 7,500 trees in 2019. It is currently estimated that it will take approximately 5 to 8 years to complete the first pass of assessments and mitigation in HFRA.

4.4.3.2 Expanded Pole Brushing (Activity VM-2)

SCE is expanding its pole brushing (i.e., brush clearance around poles) activities to inspect and clear brush to a 10-foot radial clearance on at least 25,000 additional poles within HFRA in 2019.[58] These additional poles are not part of PRC Section 4292 requirements but their surrounding brush is being cleared or maintained to further reduce ignition risk and increase grid resiliency.

4.4.3.3 Expanded Clearance Distances at Time of Maintenance (Activity VM-3)

The CPUC-required minimum clearance in HFRA is 4 feet; however, when achievable, SCE has historically trimmed trees at the time of maintenance to a greater distance. Under its revised vegetation management program, consistent with recommended guidance in D.17-12-024, SCE is expanding, where possible, the clearance distance in HFRA at time of maintenance to at least 12 feet for line voltages between 2.4kV and 69kV. However, conditions beyond SCE's control such as customer refusals may limit SCE from achieving the recommended 12-foot clearance in all instances. Once the new vegetation management program is deployed starting in 2019, it is anticipated that it will take 12 to 18 months to achieve the increased clearance distance at time of maintenance in HFRA.

4.4.3.4 DRI Quarterly Inspections and Tree Removals (Activity VM-4)

Due to climate change effects, drought and bark beetle infestation, California is facing an epidemic of dead and dying trees. As a result of the drought emergency, SCE established the Drought Relief Initiative (DRI) as a separate and distinct program from SCE's ongoing vegetation management activities. All DRI activities occur within HFRA. Activities and expenses for the DRI are tracked separately, as costs are recovered through the Drought Catastrophic Event Memorandum Account (Drought CEMA). Under its DRI, SCE conducts quarterly inspections in Tier 2 and Tier 3 HFRA for tree mortality to identify and remove dead, dying, or diseased trees affected by drought conditions. Identified dead, dying, or diseased trees are removed in accordance with SCE's vegetation management program.

4.4.3.5 LiDAR Inspection Program (Activity VM-5)

SCE utilizes light detection and ranging technology (LiDAR), to inspect select transmission lines, particularly in rugged and hard-to-access areas, in order to meet FAC 003-4, GO 95-Rule 35 and PRC Section 4293 (see below for more detail) to maintain appropriate clearances between SCE's lines and vegetation. LiDAR is a surveying method that measures distance to a target by illuminating the target with pulsed laser light and measuring the reflected pulses with a sensor. Differences in laser return times can then be used to make digital three-dimensional representations of the target. LiDAR is an efficient and effective method to assess vegetation clearances, a key component of SCE's wildfire prevention and mitigation plan. In 2019, SCE plans to conduct LiDAR inspections of approximately 1,000 conductor miles in HFRA to identify potential subject trees for assessment under HTMP or potential vegetation clearance issues.

[58] SCE is exploring the use of fire retardant spray around poles as an alternative to brush clearing.

4.4.4 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
VM-1	Hazard Tree Mitigation program	1) Perform at least 125,000 tree-specific threat assessments in HFRA 2) Perform at least 7,500 risk-based tree removals or mitigations in HFRA	1) List of tree assessments performed 2) List of risk-based tree removals or mitigations performed following tree assessments 3) Customer refusal forms for trees identified for removal but where the customer refused to allow removal
VM-2	Expanded Pole Brushing	1) Inspect and clear brush to 10 feet radial clearance at the base of the pole (at least 25,000) poles 2) Clear brush as necessary to achieve 10 feet of clearance	1) List of poles inspected 2) List of poles cleared of brush
VM-3	Expanded clearance distances at time of maintenance	Obtain tree-to-line clearance distance of 12 feet, as achievable, in HFRA at time of maintenance for line voltages of 2.4kV to 69kV	Records of tree pruning activities to achieve 12 feet of clearance, or documentation of reason why clearance could not or did not need to be achieved (e.g., customer refusals, woody stem trees, etc.)
VM-4	DRI quarterly inspections and removals	1) Perform all quarterly DRI inspections. 2) Remove identified dead, dying, or diseased trees in accordance with SCE's vegetation management program	1) Inspection records 2) DRI tree removal records
VM-5	LiDAR Inspections of Transmission (220 kV and above)	LiDAR inspect at least 1,000 conductor miles in HFRA (results from LiDAR inspections will be used to inform of subject trees assessed under the Hazard Tree Mitigation program)	1) Invoices 2) Flight logs

4.5 PROTOCOLS ON SITUATIONAL AWARENESS (INCLUDING INFORMATION GAINED FROM SITUATIONAL AWARENESS TOOLS)

4.5.1 PROGRAM OVERVIEW

Situational awareness is an integral part of emergency management, and it is imperative SCE has a granular understanding of what is happening across its service territory prior to and during emergency events. SCE's Watch Office monitors activities on a 24/7 basis, notifies response teams when action is

needed, and updates SCE's management on evolving events. The Watch Office is co-located within the Emergency Operations Center (EOC), which was upgraded in 2016 and serves as the training center for SCE's Incident Management Teams. In the newly-established Situational Awareness Center, SCE maintains meteorologists and GIS (i.e., mapping) specialists on staff, and uses various measures to monitor evolving weather, fuel, and other conditions that might lead to fire events and other hazardous conditions.

SCE is further enhancing its situational awareness capabilities by leveraging more detailed circuit-level information to better understand how weather conditions might impact public safety and utility infrastructure in HFRA. This includes creation of a high-resolution weather model specific to SCE's service territory and strategically installing weather stations to enhance the high-resolution weather model and provide real-time data near circuits in HFRA. This data will be collected and analyzed for potential weather impacts by meteorologists and GIS specialists in the Situational Awareness Center. SCE is also installing HD cameras to help communities in HFRA, fire responders and utility staff maintain visual awareness of potential fire events in real time.

4.5.2 ADDITIONAL ACTIONS TAKEN IN HFRA

4.5.2.1 Weather Stations (Activity SA-1)

The size of SCE's service territory and its diverse topography necessitates granular weather data, which requires a dense network of weather stations to monitor location-specific, real-time conditions in HFRA to enable operational decision making. For example, Southern California's mountains have rapid elevation changes and differing canyon orientations, which need to be taken into account to determine the .number of weather stations necessary for monitoring HFRA across SCE's service territory. While there are numerous public weather stations, SCE utilizes data from trusted and validated sources[59] to determine where to site additional weather stations. A guiding principle in building out the network is to have an adequate number of weather stations installed. Weather stations will ideally be placed on locations with varied elevations (i.e., on ridge or hill tops, and valley or canyon locations). Distribution circuits in HFRA are in scope for siting SCE weather stations. Circuits that have shorter length, uniform topography and similar weather characteristics will require fewer weather stations to be installed. Weather station data will be used for real-time monitoring and historical data analysis. Wind and relative humidity data will allow for granular fire weather monitoring on a circuit by circuit basis. Weather stations will also provide observed wind, relative humidity, and temperature values that will be utilized to optimize the Weather Research and Forecasting (WRF) model configurations. Statistical analyses utilizing historical weather data can be used in post-processing to deliver increasingly accurate wind forecasts.

SCE has already begun to enhance existing weather models by installing 125 weather stations in key HFRA locations in 2018. In 2019, SCE will install at least 315 weather stations in HFRA. These weather stations will enhance the resolution of existing weather models and provide real-time information to assist in making key operational decisions during wildfire risk conditions, including the use of proactive de-energization protocols.

[59] Trusted weather data sources include Remote Automated Weather Stations (RAWS) under the National Interagency Fire Center (NFIC), the National Weather Service and the Federal Aviation Administration.

4.5.2.2 Fire Potential Index and Santa Ana Wildfire Threat Index (Activity SA-2)

The SCE Fire Potential Index (FPI) is an internal tool used to estimate wildfire potential based on actual weather and fuel conditions. Inputs include wind, the dryness of the air near the ground, and how receptive existing fuels are to fire, with specific inputs involving the moisture content of the vegetation. The FPI is used in conjunction with wind thresholds to identify areas that are likely to have significant fire activity which could threaten communities and SCE infrastructure. The FPI is currently the best method for assessing fire potential across SCE's extensive service territory due to it being customizable in addressing specific fire thresholds across different weather climates.

In 2019 SCE will begin Phase II of the FPI project intended to increase capability by adding more granular weather data, expanding the coverage to all of SCE's service territory, and integrating historical weather data. This allows SCE to observe detailed weather and fuel conditions, as well as the potential for fire activity at the circuit level. This level of data will clarify which circuits will be impacted the most during weather events, reducing the number of circuits monitored for possible de-energization, and thereby reducing the number of customers affected. Adding historical weather data allows for better calibration and the ability to put current events into historical context for better decision making.

The FPI has three categories that relate weather and fuel conditions to fire activity; the categories are Normal, Elevated, and Extreme. "Normal" means that fuels are generally unsupportive of fire activity despite the potential for extreme weather events. "Elevated" suggests that fuels are receptive to ignitions, and in the event of any critical weather, fires could spread quickly. "Extreme" implies that fuels are very dry and will support significant fire activity with dangerous rates of spread during critical weather events.

SCE also uses the SAWTI issued by USFS, which measures the severity of Santa Ana winds with respect to the potential for large fires to occur. This index assesses weather and fuel conditions to generate a threat level associated with Santa Ana wind events. The index extends out six days showing four threat levels that range from Marginal to Extreme. The SAWTI covers much of Southern California and SCE's service territory. SCE uses this index to gauge the overall severity of a forecasted or ongoing Santa Ana wind events across affected SCE districts and as additional validation of the Fire Weather Watches and RFW provided by the National Weather Service.

4.5.2.3 Meteorological Resources

SCE staffs its Situational Awareness Center with a team of in-house meteorologists who have a specialized understanding of fire-weather characteristics. All the meteorologists are members of the American Meteorological Society and hold degrees in Atmospheric Sciences. This team of professionals uses the aforementioned forecasting tools and weather stations to develop comprehensive weather forecasts starting 4-7 days in advance of any predicted severe weather event. This information is provided to impacted departments and incident management personnel and is critical in shaping response and mitigation activities for potential wildfire events. SCE continues to produce and refine forecasts as the potential event approaches; these updates and refinements are essential inputs for identifying impacted circuits so that field personnel can be dispatched to at-risk locations to monitor real-time conditions.

4.5.2.4 Deployment and Support of Situational Awareness Cameras (Activity SA-3)

SCE is installing pan-tilt-zoom (PTZ) HD cameras throughout its HFRA to enable fire agencies and SCE fire management personnel to address emerging wildfires more quickly, helping mitigate potential safety

risks to the public and preventing damage to electric infrastructure. The PTZ HD camera views transmit into SCE's Watch Office and are used by SCE's IMT when deciding how to deploy crews and make other operational decisions.

PTZ HD cameras can help in spotting smoke and assessing conditions in real-time.[60] In particular, PTZ HD cameras can save time in verifying and assessing a fire's severity instead of sending fire crews to perform this assessment. Between 2018 and 2020, SCE is targeting installation of up to 160 PTZ HD cameras on approximately 80 towers within HFRA to achieve up to 90 percent visual coverage of SCE's HFRA. In 2019, SCE will install at least 62 cameras on 31 towers in HFRA.

4.5.2.5 High Performance Computer Weather Modeling System (Activity SA-4)

In 2019, SCE will procure and install a High-Performance Computing Cluster (HPCC) that will generate forecasts of weather and fuel conditions at high resolution. Greenness of the vegetation, moisture content of the dead and live fuels, relative humidity, and wind data from the HPCC will be used to comprehensively assess wildfire risk across the area (e.g., HPCC will compute FPI). Having this information will enable SCE to more accurately understand the fuel's receptivity to fire. In addition, this dataset will be used to run fire spread models which will determine potential risks of past, current, and future event scenarios. Furthermore, the HPCC will be used to generate and store weather and fuel conditions over a 30-plus-year period which will provide valuable insight into the nature of wildfire behavior and allow SCE to relate weather and fuel parameters to historical fire occurrences.

4.5.2.6 Develop Asset Reliability & Risk Analytics Capability (Activity SA-5)

This effort seeks to: (1) develop capabilities in predicting an asset's overall wildfire-related risk; and (2) given an asset's risk, prioritize work, repairs, and/or replacement(s) to minimize potential wildfire ignitions. SCE will utilize its existing analytics platform to develop composite risk models that can be used to predict risk as it relates to distribution assets, vegetation health, and extreme weather events that could impact public safety, including wildfire ignitions. These risk models will be used to enhance existing processes, including the following:

- Identifying which assets should be prioritized for replacement or upgrade based on the environment they operate in and their asset characteristics (i.e., number of splices, conductor type; fusing, etc.);
- Analyzing forecasted and historical weather conditions;
- Conducting and prioritizing maintenance;
- Analyzing asset types; and
- Analyzing operational data (such as load, duty cycle, etc.).

Using these analytics to prioritize mitigation efforts on the highest risk assets in HFRA will help target SCE's actions to reduce overall ignition risk. This program also proposes advanced analytic capabilities for streaming grid data (smart meter, supervisory control and acquisition data (SCADA), etc.) to improve advanced fault detection. This capability will allow SCE to use artificial intelligence, machine learning, and predictive modeling on real-time data to identify early warning signs of potential faults, to quickly identify a fault that has occurred, and to more rapidly respond to remediate a public safety risk. SCE intends to complete the implementation of the Asset Reliability and Risk Analytics tools in 2019.

[60] Camera feeds are publically accessible at www.alertwildfire.org

4.5.3 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
SA-1	Additional Weather Stations	Install at least 315 units in HFRA	1) Installation Guidelines 2) Production order/invoice 3) Weather station location master tracker
SA-2	Fire Potential Index Phase II	Enhance capabilities of FPI by increasing granularity, adding historical climatology data, and expanding to cover all of SCE's service territory	1) Statement of Work 2) Sign in sheets from trainings
SA-3	Additional HD Cameras	Install at least 62 cameras on 31 towers	1) Production order/Invoice 2) HD camera location master tracker
SA-4	High-Performing Computer Weather Modeling System	Procure and install High Performance Computing Cluster weather and fuels modeling system	1) Production Order/invoice 2) Sign in sheets from trainings
SA-5	Develop Asset Reliability & Risk Analytics Capability	Complete implementation of the Asset Reliability and Risk Analytics tools	Demonstration of tool

4.6 PROTOCOLS ON PUBLIC SAFETY POWER SHUT-OFF

4.6.1 STRATEGY TO MINIMIZE PUBLIC SAFETY RISK DURING HIGH WILDFIRE CONDITIONS AND DETAILS OF THE CONSIDERATIONS

SCE employs guidelines to be prepared to proactively de-energize circuits within HFRA if data sources indicate that extreme local weather conditions pose an imminent and significant threat to public safety associated with wildfire risk. The significant variability of weather and environmental conditions across SCE's service territory, coupled with climate change effects, severe drought/bark beetle issues, require flexible de-energization guidelines that can be used under a variety of weather and physical circumstances and electrical system operating conditions. SCE's protocol, officially titled Public Safety Power Shut-Off, consists of a set of de-energization criteria and guidelines with a wide variety of factors that are considered.

SCE utilizes aspects of the National Incident Management System to manage its emergency and resiliency operations. Consistent with this methodology, execution of SCE's PSPS protocol is overseen by a specialized Task Force in the Incident Command Structure under the Operations Section Chief. The Task Force is composed of representatives from key internal departments to manage the necessary public safety notifications to critical care customers, essential service providers, business customers and local governments potentially affected by its use. The Task Force is responsible for monitoring and considering conditions and relevant information before recommending the de-energization of any SCE circuit(s).

4.6.2 TACTICAL AND STRATEGIC DECISION-MAKING PROTOCOL FOR INITIATING A PSPS/DE-ENERGIZATION

SCE is refining the tactical and strategic decision-making protocols needed to consistently consider the factors required to initiate pro-active de-energization internally and through the ongoing PSPS Order Instituting Rulemaking (OIR) process initiated by the CPUC. The complexities of the service territory, including size, topography, wind and weather patterns, and the uncertainty of weather events, make it difficult to predict exact locations where pro-active de-energization would or should be consistently considered.

The decision to preemptively shutoff power requires consideration of many complexities both known and unknown. Therefore, execution of de-energization is ultimately based on the judgment of the IMT and the considerations that follow are intended to provide a framework to assist the IMT in exercising this discretion:

- Potential impacts to customers and communities;
- RFW issued by the National Weather Service for fire weather zones that contain SCE circuits in HFRA;
- SCE meteorologists' assessments of known local conditions, including wind speeds (sustained and gusts), humidity and temperature, fuel moisture, fuel loading and data from SCE weather stations (including real-time data);
- Real-time situational awareness information from personnel positioned in HFRA areas identified as potentially at risk, areas located near circuits identified for inclusion on the circuit monitoring list, and in other areas identified during the incident as at risk of being subject to extreme weather conditions;
- Input from SCE Fire Management experts;[61]
- Input from SCE's Vegetation Management team as appropriate;
- Input from local and state fire authorities with specific concerns regarding the potential consequences of wildfires in select locations;
- Alternative ways to re-route power to affected areas;
- Awareness of mandatory or voluntary evacuation orders in place;
- Expected impact of de-energizing circuits on essential services;
- Other operational considerations to minimize potential wildfire ignitions, including the blocking of reclosers on the identified circuit(s);
- On-going fire activity throughout SCE's service territory and California in general;
- Progress of customer notification processes; and
- Ongoing notifications to local governments and public officials.

The IMT considers the factors above when determining if de-energization of specific locations within HFRA is necessary.

4.6.3 STRATEGY TO PROVIDE FOR SAFE AND EFFECTIVE RE-ENERGIZATION OF ANY AREA THAT WAS DE-ENERGIZED DUE TO PSPS PROTOCOL

When fire risk conditions subside to safe levels and safe conditions are validated by field resources, SCE will begin patrolling impacted circuits to check for any condition that could potentially present a public safety hazard when re-energizing circuits. Once field resources confirm that it is safe to re-energize the

[61] *See* Chapter 5.B.

circuit(s), power will be restored, and local government and customers will be notified of re-energization. The order in which circuits are re-energized will depend on many factors including, but not limited to, customer safety and well-being, consideration of affected essential services, damage to electrical and other infrastructure, and circuit design/topology.

4.6.4 SCE STANDARDS RELATIVE TO CUSTOMER COMMUNICATIONS, INCLUDING CONSIDERATION FOR THE NEED TO NOTIFY PRIORITY ESSENTIAL SERVICES

SCE is committed to providing timely notification to potentially-impacted local governments, public safety agencies, the CPUC, the California State Warning Center, and customers prior to, during, and after a de-energization event, with special consideration of impacts to local governments and public safety agencies, as well as critical care customers, essential service providers, and business customers. SCE's PSPS plan sets the following guidelines for these notifications and SCE seeks to execute them when it is feasible; however, given particular urgent and unforeseen circumstances, these timelines may vary.

- **4-7 days ahead** of forecasted fire conditions in a HFRA, SCE meteorologists will begin predictive modeling to assess potential impacts to infrastructure that may require SCE to implement a PSPS de-energization event. At this stage, the accuracy and granularity of forecasts will not enable SCE to identify potentially impacted customers with a high level of confidence, so no notifications will be made.
- **3 days ahead** of the forecast event, SCE meteorologists will continue to refine predictive models and will place IMT on alert for activation 2 days ahead of the forecast event.
- **2 days ahead** of the forecast event, predictive models begin to improve in accuracy, and SCE activates its IMT. To the extent possible, SCE begins coordinating closely with local government and agencies (e.g., first responders) on a possible PSPS de-energization event. A specialized Task Force will work to identify impacted circuits. SCE will begin its customer notifications process in the following order:
    1. Local government and public safety agencies
    2. Critical care customers
    3. Essential service providers
    4. Business and residential customers
- **1 day ahead** of the forecast event, if fire conditions are imminent, the SCE meteorology team continues to refine its predictive models using more accurate forecasting capabilities to narrow down the affected circuits and customers. At this stage, SCE continues to work closely with local government and agencies on a possible power shutoff and will make additional notifications to impacted customers and local governments.

4.6.4.1 De-Energization Notifications (Activity PSPS-1)

If extreme fire conditions are validated by field resources, SCE weather stations, or other situational awareness means, SCE may decide to de-energize impacted circuit(s) and will make every attempt to notify local government, public safety agencies, and customers when this decision is made. In 2019, if SCE decides to de-energize circuit(s), SCE will continue to make notifications to local government, public safety agencies, the CPUC, the California State Warning Center, and customers, throughout the event when important updates are available. If the forecasted conditions do not materialize, SCE will notify local government and customers that the planned de-energization event has been cancelled.

As discussed in its 2018 GSRP Application, SCE utilizes its Emergency Outage Notification System (EONS) to quickly create and deliver customized outage communications in the customers' digital channel(s) of preference (smartphone, SMS text, email, TTY and social media) regarding de-energization events. In 2019, SCE will enhance EONS notification capabilities to expand in-language notifications based on customer preference including, but not limited to, Spanish, Chinese, and Cantonese.

4.6.5 PROTOCOLS FOR MITIGATING THE PUBLIC SAFETY IMPACTS OF THESE PROTOCOLS, INCLUDING IMPACTS ON FIRST RESPONDERS AND ON HEALTH AND COMMUNICATION INFRASTRUCTURE

SCE continues to host meetings and provide information to county Offices of Emergency Management (OEM), local and tribal governments, public safety agencies and community members (including selected groups through specialized workshops) that may be impacted by circuits that traverse HFRA in SCE's service territory. These meetings enable SCE to provide information regarding its PSPS protocol and its wildfire mitigation efforts. These meetings, and SCE's planning efforts surrounding wildfires and PSPS, are conducted in compliance with PUC Section 768.6. Additionally, SCE uses these opportunities to convey the importance of community resiliency in the event of any outage, irrespective of cause, and to receive important feedback from its customers and to incorporate this feedback into its planning process and the PSPS protocol.

SCE has begun and plans to continue holding regular meetings with public safety agencies including fire agencies, law enforcement agencies and emergency management agencies to continue the dialogue around PSPS and to collaborate on mitigation strategies and event protocols. SCE will also provide updates to those cities in HFRA as needed. Meeting topics include, but are not limited to:

- How circuits were identified as being high fire risk and subject to PSPS
- Overview of criteria and other factors used to determine if a circuit will be de-energized
- Customer and agency notification process before and during an event
- Information on SCE's Incident Command System structure during an event
- Requests for local governments and other agencies to provide SCE with information on situational awareness and other concerns with de-energizing particular circuits
- The process to request circuit re-energization from SCE
- The process used to undertake re-energization of circuits after a PSPS event
- The provision of GIS layers of HFRA circuits to aid in emergency planning process

SCE's engagement with local governments includes the following:

- Information (via email) on its PSPS protocol and its wildfire mitigation efforts to representatives of approximately 235 cities, counties, and unincorporated communities with HFRA circuits (Note: Unincorporated communities are included in outreach to counties)
- Offers to meet and meetings with key city and county personnel to further review and discuss any of the topics presented
- Offers to provide maps of HFRA Circuits – both PDF and GIS layers
- Requests for local governments and other agencies to provide SCE information on critical facilities/essential service providers and other concerns resulting from de-energizing particular circuits
- Upon request, SCE has presented at city council and local Public Safety Commission meetings

SCE holds "Outage Schools" throughout the year for business and residential customers. These meetings are designed to help customers understand what to expect during an outage, including an outage related to PSPS. Outage schools will continue annually throughout SCE's service territory and topics include:

- The process for determining the extent of an outage (damage assessment)
- Information on notification process during an outage
- Details on SCE's PSPS
- Outage restoration information

4.6.5.1 Essential Service Providers

SCE considers the following customer categories as essential service providers:

- Government and other agencies providing essential fire, police, and prison services
- Government agencies essential to the national defense
- Hospitals and skilled nursing facilities
- Communication utilities, as they relate to public health, welfare, and security, including telephone utilities
- Radio and television broadcasting stations used for broadcasting emergency messages, instruction, and other public information related to the electric curtailment emergency
- Water and sewage treatment utilities identified as necessary for services such as firefighting

SCE respects the privacy of its customers and submits the categories above as those considered essential service providers rather than a complete list of customers in those categories. Because customers move in and away from locations, providing a list of customers would only be valid for the date and time for which that list was retrieved from SCE's systems.

SCE actively engages with its essential service provider community through designated single-contact resources at SCE from its Local Government Affairs department and Business Customer Division. These direct contact resources "own" the relationship with these customers, agencies and/or utilities for all business needs with SCE and in PSPS events. SCE also hosts Outage Schools throughout the year where outage notifications, communications and PSPS are discussed, and SCE is expanding its meeting invitation to the essential service provider community.

4.6.5.2 Critical Care Customers

SCE's critical care customers are those customers enrolled in SCE's Medical Baseline program whose physician has indicated that the medical equipment in use at the home is for life sustaining purposes and absent electricity for two or more hours the customer would be at risk. SCE considers these customers the most vulnerable of its medical baseline customers and therefore takes added measures to facilitate the safety of these customers.

Every year, SCE sends an annual medical baseline letter to all customers enrolled in the Medical Baseline program within SCE's service territory (currently approximately 92,000 customers). The letter encourages and reminds these customers to have an emergency back-up plan for when outages occur and requests that they contact SCE so that the SCE has their most up-to-date contact information for use in the event of power outages. Additionally, the letter reminds them that SCE can send alerts and notifications through an alternate preferred method of contact that they provide to SCE. The most recent letter was delivered in June 2018 and another round of letters will be sent in 2019.

For all of SCE's medical baseline customers, outage notifications are provided through the customers primary and alternate preferred methods of communication (email, text, SMS). If a customer with the critical care designation cannot be reached via their preferred communication method, further safeguards are taken to make contact with the customer. SCE's Consumer Affairs office will begin personal attempts to reach these customers; if unsuccessful, they will send a field representative to the customer's home to attempt in-person contact. If contact is not made at the property, SCE will leave a notice of the visit and ask the customer to contact SCE directly. In circumstances when an outage is forecast to exceed 12 hours in duration, SCE will again attempt to reach the medical baseline customer through outbound calls from Consumer Affairs, and if unreachable, will send a field representative to the customer's residence in order to perform a welfare check.

4.6.5.3 General Outreach

SCE will send an annual letter to customers that live in HFRA informing them of the following: (1) the potential for a PSPS de-energization event in their area; (2) details on the notification process during an event; and (3) criteria informing SCE's PSPS protocol. In these letters, SCE will also include information on how best to prepare for an outage regardless of cause, how to sign up for the Medical Baseline Program, SCE contact information, and directions for accessing SCE's website where additional details on SCE's wildfire mitigation activities may be found. Customer outreach is further described in Section 5.2.

4.6.5.4 Community Workshops

SCE has conducted an extensive series of community meetings within its service territory to provide information on SCE's fire mitigation activities including its potential use of the PSPS de-energization protocol. SCE subject matter experts presented at the meetings and answered questions related to a variety of topics including:

- The state's "new normal" with respect to climate change impacts on wildfires
- System hardening and engineering practices
- Vegetation management
- Situational awareness (weather monitoring)
- PSPS protocol
- Safety during outages

SCE strives to continuously improve plans and protocols around wildfire response. In support of this, SCE will regularly solicit feedback through additional meetings with public safety agencies and impacted communities to provide an opportunity for a dialogue on the event and potential process changes from lessons learned. SCE will continue to evaluate opportunities for improving our plans and protocols using this feedback, as appropriate. Community workshops are further described in Section 5.2.

4.6.5.5 PSPS/De-energization Protocol Support

4.6.5.5.1 Line Patrols

In addition to the customer outreach efforts discussed above, a critical component of SCE's PSPS protocol is to assess potential for extreme fire risk conditions with the help of line patrols and monitoring functions (including troublemen and supporting crews) in the field prior to making the decision to de-energize. Operationally, SCE will deploy line patrol crews to assess circuit conditions prior to de-energization and before restoring service to confirm it is safe to re-energize.

4.6.5.5.2 Customer Contact Center

SCE provides customer support during PSPS/de-energization events via its Customer Contact Center (CCC), and anticipates additional resources to support the incremental increase in call volumes associated with these events.

4.6.5.5.3 Mobile Generator Deployment

SCE is working collaboratively with local governments, first responders and essential service providers to provide awareness of PSPS and to educate them on the importance of developing a resiliency plan that addresses back-up power needs for their facilities which provide critical life and safety functions. Many of these customers are required by law or industry standard to have back-up generation in place to sustain critical operations in the event of a power outage, regardless of outage type. Other customers not required to have back-up generation are encouraged to consider adding this capability if they feel they have critical needs that must continue in a power outage.

However, if essential service providers are unable to sustain critical life/safety operations during an extended power outage, SCE will consider requests to provide temporary mobile backup generation. Through the existing PSPS communication plan noted above in Section 4.6.4, SCE will coordinate closely with the emergency management community at the county level to identify and prioritize back-up generation needs in the following order:

Priority Order	Essential Service Provider Category
1. Life Safety Emergencies	Hospitals Skilled Nursing Facilities Public Safety Agencies
2. Public Health Emergencies	Water/Wastewater
3. Communication Failures	Telecommunications

If the Incident Commander determines there is a critical need for temporary back-up generation for one of the essential service providers noted above, the PSPS Task Force, which resides under the Operations Section of the Incident Command Structure, will be responsible for determining the appropriate sizing and installation requirements, and work with contract partners, vendors and the appropriate internal T&D field crews to coordinate deployment and installation. Once the event has concluded and power has been restored, this same task force will confirm the generator is removed and returned to the vendor.

4.6.5.6 Community Outreach Vehicles

SCE's customers may be without power for extended periods due to wildfire mitigation efforts, including PSPS activation and/or planned outages associated with hardening the grid and installing technologies that reduce wildfire risk. Although SCE has developed a public outreach plan in support of PSPS, including overall wildfire awareness and preparation, SCE expects that some customers will need assistance in receiving critical messages from SCE, public agencies, first responders, news agencies, social media, etc. SCE plans to deploy Community Outreach Vehicles[62] equipped with back-up power so that

[62] Due to procurement challenges with the Portable Community Power Trailers, SCE, as an interim solution, is evaluating alternatives, including retrofitting existing SCE vehicles to provide these services during PSPS events or other extended outages.

customers can charge their personal devices (mobile phones, tablets, laptops, etc.) and continue to receive information/updates from SCE about the outage, listen for relevant public safety broadcasts, and/or connect with friends and family concerned with their well-being during PSPS events. The Community Outreach Vehicles can typically be deployed to affected areas within 8 hours across the service territory, and their deployment will be managed through the IMT and PSPS Task Force.

4.6.6 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
PSPS-1	De-Energization Notifications	1) Notify applicable public safety agencies and local governments of possible de-energization 2) Notify CalOES through the State Warning Center of possible de-energization 3) Notify the CPUC of possible de-energization 4) Enhance EONS to include in-language messages	1) ESRB-8 Report(s) filed with the CPUC 2) EONS Production Order/Invoice

4.7 ALTERNATIVE TECHNOLOGIES

4.7.1 PROGRAM OVERVIEW

Through ongoing assessment and refinement of its programs, SCE continues to explore technologies that will reduce the probability of an ignition event and/or reduce public exposure to a hazardous condition during periods of high fire risk. SCE has implemented and continues to assess additional engineering solutions to provide better situational awareness, faster isolation of faults, and/or minimized energy transfer. As part of this process, SCE will pilot limited deployments to build confidence that the new technology will be useful and effective in mitigating identified causes of wildfire ignitions. A summary of additional technologies being considered for studies and pilots are described below. To the extent that SCE pursues such programs and activities, they will be set forth in future years' plans.

In 2019, SCE will evaluate and consider the following technologies for application on the distribution system. If equipment described below proves to be an effective fire risk mitigation technology, it may be included in the proposed program work discussed above in Chapter 4C.

4.7.2 ADDITIONAL ACTIONS WITHIN HFRA

4.7.2.1 Alternative Technology Pilots (Activity AT-1)

4.7.2.1.1 CAL FIRE Exempt Surge Arrester

A surge arrester is a device designed to channel lightning or other surge voltages to ground to protect the circuit or equipment from flashover due to excessive voltage. Equipment that is rated as CAL FIRE exempt is designed to limit such arcs/sparks or hot particles sufficiently to prevent the ignition of flammable vegetation. SCE is piloting a CAL FIRE-exempt surge arrester in field conditions to learn more

about its operating characteristics before deploying it as a potential new standard for all HFRA. Under the pilot, SCE plans to install these surge arresters at 50 locations in 2019 to evaluate their field performance.

4.7.2.1.2 Meter Alarming for Downed Energized Conductor

Meter alarming for downed energized conductor (MADEC) is a machine-learning algorithm that leverages existing smart meter data to detect the presence of downed, energized conductors. In 2018, SCE started a pilot for a proactive program to de-energize downed conductors based on smart meter input with the MADEC algorithm. SCE plans to complete this pilot in 2019. Rapid detection of downed wire has public safety benefits and can allow for more rapid clearing of energized downed conductor to reduce ignition risk.

4.7.2.2 GSRP Wildfire Mitigation Program Study (Activity AT-2)

4.7.2.2.1 Distribution Fault Anticipation

Distribution Fault Anticipation (DFA) is a predictive algorithm that leverages electrical system measurements to recognize current and voltage signatures indicative of potential pending equipment failures. DFA alerts SCE of potential equipment weaknesses/failures to allow for proactive remediation, thus avoiding faults and minimizing ignition risks. Under this pilot, SCE is investigating the use of DFA to predict failures based on voltage and current signatures for proactive mitigation. In 2019, SCE will implement at least 10 DFA devices in HFRA as part of the pilot to evaluate their field performance. Given the potential wildfire risk mitigation benefits it provides, SCE will attempt to implement up to approximately 50 additional DFA devices in 2019.

4.7.2.2.2 Advanced Unmanned Aerial Study

As described in SCE's GSRP Application, the Advanced Unmanned Aerial Systems (UAS) study project will inform and advance SCE's existing UAS program by exploring the capabilities of Beyond Visual Line of Sight (BVLOS) flight. SCE's UAS program is developing the capability to expedite patrolling utility lines following a PSPS event or other extended outage, to more quickly and safely restore power to customers. In 2019, SCE plans to explore BVLOS UAS capabilities to patrol utility lines.

4.7.2.3 Alternative Technology Evaluations (Activity AT-3)

4.7.2.3.1 Rapid Earth Fault Current Limiter and Arc Suppression Coil

Rapid Earth Fault Current Limiter (REFCL) and Arc Suppression Coils (ASC) are substation devices that limit ground fault current levels and increase ground fault protection sensitivity. These technologies have the potential to substantially limit the amount of energy released in the event of a downed power line, or ground fault, and help reduce fire ignition risks. The REFCL device expands on conventional ASC technology to allow for fault location and further improve fire ignition reductions. SCE will evaluate this technology in 2019.

4.7.2.3.2 Alternate Fault Detection Technology

In 2019, SCE will evaluate alternate fault detection technologies to improve fault identification beyond traditional overcurrent protection methods. These detection systems may help identify faults more quickly and help to minimize fault energy and related ignition risks. This includes technologies for reducing fault energy associated with circuit reclosing, and fault detection schemes which employ voltage, or other measurements, to improve fault detection beyond traditional overcurrent.

4.7.2.3.3 Fire-Resistant Wood Poles with Protective Barrier

A fire-resistant wood pole is created by applying surface treatments, such as wrapping a sacrificial composite shield around the pole. The use of fire-resistant poles will enhance the resiliency of SCE's infrastructure in HFRA and help with rapid restoration. In 2019, SCE will assess the use of a fire-retardant wrap around existing wood poles as a sacrificial layer from fire.

4.7.2.3.4 Substation Class Electronic Fuses

Substation class electronic fuses are devices that are controlled by high speed electronic measurement devices. These fuses can be remotely programmed to activate enhanced fusing protection during high fire risk conditions (e.g., high wind), while limiting service reliability impacts during normal conditions. Additionally, reduced fault energy in the mainline circuitry would help reduce ignition risk. An alternate application of this current-limiting technology is the capability to remotely control energy reduction for highly loaded portions of circuitry. In 2019, SCE will evaluate substation-class electronic fuses for potential deployment in the future.

4.7.2.3.5 Single Phase Reclosers

Single phase reclosers are CAL FIRE-exempt electronic reclosers capable of "gang operation." Gang operation allows for the de-energization of all three phases due to a single-phase fault to prevent energized wire down situations. SCE intends to expand its branch line protection strategy to include single phase recloser applications by development of standard installation practices in 2019.

4.7.2.4 Alternative Technology Implementation (Activity AT-4)

4.7.2.4.1 Vibration Dampers

Vibration dampers are hardware attached to conductors (usually near insulators) to inhibit conductor fatigue from vibration. Under certain conditions vibration dampers can help keep conductor connections and attachments from degrading due to vibration. SCE intends to expand its conductor resiliency effort with vibration damper applications for existing conductors by development of standard installation practices in 2019.

4.7.2.4.2 Ridge Pin Construction

Ridge Pin construction is sometimes referred to as triangular construction due to the shape created by the conductor arrangement. This configuration increases vertical separation between the center phase conductor and the two outside conductor phases to further reduce the potential for conductor-to-conductor contact. Under this configuration, the distance between poles can be larger than span distances utilizing horizontal construction and still maintain conductor clearances in turbulent wind conditions. This type of conductor orientation can be used in difficult terrain conditions where access roads below the conductor may not allow the installation of line spacers. SCE intends to expand its conductor resiliency effort with ridge pin construction for existing conductors by the development of standard rebuild practices in 2019.

4.7.2.4.3 Expanded Connector Selection in HFRA

SCE has expanded its CAL FIRE-exempt connector options to include the bolted wedge connector. In 2019, SCE intends to refine its distribution overhead standards requirements for connector selection for HFRA application.

4.7.3 ACTIVITIES AND 2019 GOALS

In 2019, SCE will continue to explore and implement alternative technologies as part of its grid hardening efforts to reduce the probability of an ignition event and/or reduce public exposure to a hazardous condition during periods of high fire risk. The following table details performance measures for SCE's alternative technology goals.

Activity	Description	2019 Goal	Compliance Evidence
AT-1	Alternative Technology Pilots	1) Pilot installation of 50 CAL FIRE-exempt surge arrestor units in target locations 2) Pilot meter alarming for downed energized conductor	1) Results of 50 CAL FIRE-exempt surge arrestor pilot 2) Results of meter alarming pilot for downed energized conductor
AT-2	GSRP Wildfire Mitigation Program Study	1) Evaluate distributed fault anticipation technology and conduct pilot installation of at least 10 DFA devices 2) Evaluate BVLOS UAS capabilities	1) Results of distributed fault anticipation technology assessment and pilot 2) Evaluation of results of BVLOS of UAS
AT-3	Alternative Technology Evaluations	1) Evaluate REFCL/ASC 2) Evaluate alternate fault detection technology 3) Evaluate fire retardant barrier for wood poles 4) Evaluate substation-class electronic fuses 5) Evaluate branch line protection to include single phase reclosing	1) Assessment of REFCL/ASC feasibility 2) Assessment of technologies for reducing fault energy 3) Assessment and development of specifications of fire-retardant barriers for wood poles 4) Assessment of substation-class electronic fuses 5) Assessment of single phase reclosing
AT-4	Alternative Technology Implementation	1) Develop standard installation practices for Aeolian vibration dampers 2) Develop standard installation practices for ridge pin construction for conductor rebuild 3) Update DOH requirements for connector selection in HFRA	1) Publish vibration damper installation procedure 2) Publish ridge pin construction installation procedure 3) Publish updated connector selection requirements document

4.8 POST INCIDENT RECOVERY, RESTORATION AND REMEDIATION ACTIVITIES

Post-incident recovery, restoration, and remediation activities are important for SCE customer public safety and infrastructure resiliency. As such, SCE follows the recovery, restoration, and remediation guidelines established by CPUC standards for disaster and emergency preparedness plans pursuant to PUC Section 768.6 through its Storm Plan, which is included in SCE's annual GO 166 compliance filing. The plan is designed for disaster preparation and safe and efficient restoration for any type of outages caused by exogenous natural forces. Additional details on post-incident activities are provided in Section 5.2.1.1.

SCE's emergency response plans are periodically reviewed, evaluated, and updated to maintain continued effectiveness in protecting public and employee health and safety, and minimizing damage to public and private property as well as SCE infrastructure. Additionally, after incidents, SCE incorporates lessons learned into its emergency preparation and response plans to further refine its processes including post-incident activities. Additional details on emergency preparedness and disaster response activities are provided in Section 5.1.

SCE may conduct post-wildfire debris-flow assessments to identify and safeguard SCE assets in high-risk debris-flow areas after wildfires. The post-wildfire debris-flow assessment framework uses United States Geological Survey (USGS) modeling to identify areas of high-debris-flow risk. An analysis is conducted to identify substation, transmission, sub-transmission, distribution and telecom assets that could be potentially impacted. Mitigation options will be determined based on the results. Also, for areas of concern, SCE monitors predicted rainfall data.

5 EMERGENCY PREPAREDNESS AND RESPONSE

SCE strives to minimize the impacts of any disruptive event regardless of the size or scope, while consistently focusing attention on the Company's most critical systems and infrastructure. In the utility industry, including at SCE, business resiliency has traditionally been rooted in storm response. That paradigm has evolved to align more closely with emergency management programs at the local, state and national level. The terms emergency management and resiliency are broader in scope than traditional utility storm response and include preparing for all risks, threats and hazards a utility may experience.

5.1 EMERGENCY PREPAREDNESS AND RESPONSE PLAN OVERVIEW

SCE's Business Resiliency organization has led the development of emergency preparedness and response plans based on National Incident Management System (NIMS) and Incident Command System (ICS) principles and protocols as developed by the Federal Emergency Management Agency (FEMA). SCE's preparedness and response plans build upon SCE's continuity protocols and SOBs related to disaster preparedness and response, and involve input from subject matter experts across the company. This cross-functional approach to emergency preparedness and response planning has resulted in emergency action plans that facilitate an effective company-wide response to incidents of varying sizes and emergency disruptions, including wildfire response operations. Emergency preparedness and response plans are periodically reviewed, evaluated, and updated to maintain continued effectiveness in protecting public and employee health and safety, and minimizing damage to public and private property as well as SCE infrastructure.

SCE's emergency preparedness and response plans consider numerous hazards that have been identified as potentially impacting the SCE's service territory and the grid, including earthquakes, cybersecurity, and wildfires. These plans are developed to streamline SCE response efforts, inform critical actions and decision-making, determine roles and responsibilities of SCE first responders, and maximize SCE's ability to respond and recover following any type of disruptive incident. By undertaking comprehensive planning efforts and utilizing these plans, SCE aims to minimize the impacts of these incidents on customers and communities. SCE's emergency preparedness and response plans make available critical information for incident response and recovery team members to implement an efficient, effective, and safe response to any type of incident, disruption, or disaster.

5.1.1 EMERGENCY RESPONSE ORGANIZATION STRUCTURE

SCE employs the ICS as the basis for the Company's Emergency Response Organization (ERO) structure. Trained personnel are assigned the responsibility for key functions within the ICS structure to manage a wide range of incidents ranging from a routine unplanned outage to a major disaster, such as an earthquake or wildfire. Utilization of the ICS structure facilitates SCE's effective response to incidents based on their relative scale and impact to customers.

Key components of SCE's ERO structure are the Emergency Operations Center and the company's IMT. During a major incident (including wildfires), the IMT will manage the organization, assignment, direction, and tracking of relevant resources, both material-and personnel-related. IMT members are regularly trained regarding their roles and responsibilities regarding all types of hazards. The ERO structure facilitates SCE's ability to streamline response efforts and direct skilled personnel towards the most critical restoration priorities.

5.1.1.1 Incident Command System

The ICS is a standardized all-hazards incident management approach that achieves the following:

- Allows the integration of facilities, equipment, personnel, procedures, and communications operating within a common organizational structure;
- Enables a coordinated response among jurisdictions and functional agencies, both public and private through interaction with the IMT; and
- Establishes common processes for planning and managing resources, as well as determining and setting objective and priorities

ICS is used by all levels of government—federal, state, and local—and by many non-governmental organizations and the private sector. ICS is also applicable across disciplines, typically structured to facilitate activities in five major functional areas: Command; Operations; Planning; Logistics; and Finance/Administration. These functional areas may or may not be activated based on the needs of the incident. By utilizing ICS in SCE's planning, training, and response structures, the company is better able to communicate and integrate with local, county, state, and federal response efforts. Utilizing ICS has proven to be beneficial when coordinating response efforts with SCE's government and non-governmental partners in training exercises and during real-world incidents.

5.1.1.2 Mutual Assistance

Currently, SCE is party to multiple mutual assistance agreements, which provide a mechanism to quickly obtain or supply emergency assistance prior to, during, or after an incident that affects generation, transmission, distribution or other SCE facilities. Assistance can be received or supplied in the form of personnel, equipment, materials, and other associated services. Having a robust mutual assistance program is necessary to effectively respond to and restore power following complex and/or large incidents. To access or supply mutual assistance resources, SCE maintains the following mutual assistance agreements:

- California Utilities Emergency Association (CUEA) among California utilities
- Western Region Mutual Assistance Agreement for Electric Utilities (WRMAG), a regional agreement
- Edison Electric Institute (EEI), a national mutual assistance program

These mutual assistance agreements have been pre-established in advance of future incidents, are standardized across utilities, and outline specific requirements and authorizations before crews are received or deployed. SCE regularly participates in mutual assistance calls, planning efforts, and coordinating body meetings, and has provided mutual assistance to other utilities in large-scale emergencies.

In addition to a robustly-trained SCE workforce and mutual assistance agreements, SCE can utilize contractors to assist in restoring service following a major incident, including wildfires, as described in Section 5.2.4 below.

5.2 DESCRIPTION OF HOW THE PLAN IS CONSISTENT WITH DISASTER AND EMERGENCY PREPAREDNESS PLAN PURSUANT TO PUBLIC UTILITY CODE SECTION 768.6

As described below, SCE's 2019 WMP is consistent with the PUC Section 768.6's requirements to have disaster and emergency preparedness plans. Details of these plans are reported to the Commission pursuant to GO 166.

5.2.1 PROGRAM OVERVIEW

SCE follows the restoration guidelines established by CPUC standards for disaster and emergency preparedness plans pursuant to PUC 768.6 through its Storm Plan, which is included as part of its annual GO 166 compliance filing.

5.2.1.1 SCE Storm Plan

The SCE Storm Plan is an effort to respond to emergency incidents resulting in disruptions to the electrical system. It describes the operations and policies that guide how the company plans for, addresses, and responds to emergency electrical incidents using the ICS structure adapted with utility-specific solutions. The plan is designed to facilitate safe and efficient restoration for any type of outages caused by exogenous natural forces by:

- Development of accurate situational awareness and the distribution of a consistent common operating picture;
- Consistent use of the ICS response structure, organization and principles;
- Application of pre-determined restoration priorities; and
- Application of pre-determined processes to manage emergency functions/roles:
    - Damage Assessment
    - Field Resources
    - Mutual Assistance
    - Communications

The intent of the Storm Plan is to help SCE prepare for and respond to storms cohesively across all applicable functions using common protocols, terminology, and organizational structures aligned with nationally-recognized best practices. It outlines how SCE will collaborate with the communities it serves in preparing for and responding to emergency events; this may include things such as pre-staging of field resources or equipment in advance of forecasted weather events. The Storm Plan objectives include:

- Defining the criteria for activating and deactivating the SCE Storm Plan;
- Outlining the communications strategy and notification procedures by which SCE will communicate with its customers, the public at large, appropriate state and local government agencies, essential service providers and critical care customers, and other important stakeholders in the restoration process; and
- Providing an overview of the strategies that SCE will use to employ mutual assistance to share resources with other utilities in order to expedite the restoration of service to customers.

5.2.2 EMERGENCY COMMUNICATIONS

SCE has a comprehensive plan for communicating with its customers during emergencies, especially during outages. SCE's current process includes automated outbound notification to customers through each customer's preferred method of contact when an outage occurs, as outage restoration times are determined or shifted, and upon conclusion of the outage. This schedule of notifications applies to repair

(unplanned) outages and maintenance (scheduled) outages. For maintenance outages, SCE provides advance notice to customers at least three days prior to the outage, but usually up to two weeks in advance. These notifications are followed with an automated reminder call twenty-four hours ahead of the scheduled outage. Further, SCE's Outage Map on SCE.com provides customers with information regarding outages that are affecting their service location.

Following the 2017 wildfires, SCE enhanced its emergency communication plans, focusing on building awareness about the importance of wildfire mitigation and how SCE is undertaking critical work in HFRA. Components include proactive communications and education about wildfire and emergency preparedness as well as communications and awareness during and following wildfire events. As part of GSRP, SCE implemented phase one of its new Emergency Outage Notification System (EONS) in fall 2018. This new system has the capability to execute high-volume notifications within very short timeframes, enabling SCE to reach a large number of customers in areas potentially subject to PSPS.

As discussed in Section 4.6, in 2019, SCE will enhance EONS' capabilities to expand in-language notifications based on customer preference including, but not limited to, Spanish, Mandarin, and Cantonese. SCE relies on customers' self-identification of their preferred language. SCE is committed to continuous improvement in all areas of its wildfire mitigation efforts and will examine the feasibility of using Census data, and other methods, in 2019.

5.2.3 ADDITIONAL ACTIONS TAKEN WITHIN HFRA

5.2.3.1 Communications and Education about Wildfire / Emergency Preparedness:

5.2.3.1.1 Annual Wildfire Customer Direct Mailer (Activity DEP-1)

The annual wildfire awareness direct mailer is a proactive communication solution that allows SCE to target specific areas of its territory with important customer information. As SCE began its campaign to raise wildfire awareness for customers who reside in HFRA, it sent a direct mailer that focused on the "new normal" in California, SCE wildfire mitigation efforts, and PSPS. Approximately 1.5 million customers in HFRA received this letter via direct mail. SCE plans to send the 2019 direct mailer by May 31.

5.2.3.1.2 Local Government Education and Engagement (Activity DEP-1)

SCE has held several meetings with local government officials regarding SCE's overall wildfire mitigation efforts, with discussions focused on educating local governments about the PSPS de-energization process and how the company will communicate and work with government agencies and emergency operations during outages. These meetings were helpful in understanding local government's needs before, during, and after PSPS events. SCE will continue these meetings in 2019 to further educate local government officials, enhance partnerships, increase awareness, and discuss lessons learned.

5.2.3.1.3 Community Meetings (Activity DEP-1)

SCE has conducted several community meetings in HFRA to provide SCE customers who may be impacted by a PSPS event an opportunity to hear firsthand from SCE staff and other community leaders or agencies about the "new normal" in California and what that means to them; how to be prepared and remain resilient; information about SCE's wildfire mitigation efforts; and to share their questions and concerns. These forums allow SCE to obtain up-to-date customer information that is critical for outreach during events. SCE intends to continue customer engagement efforts in HFRA in 2019 and will develop its 2019 community meeting plan and conduct meetings accordingly.

5.2.3.1.4 SCE.com

At SCE's website (SCE.com), customers can find content regarding important utility information and specifics about their individual SCE account. SCE has created a dedicated, interactive and informative landing page where customers can increase their awareness about SCE's wildfire mitigation efforts, learn techniques and considerations that can help prepare them to be more resilient during major events and receive up-to-date information regarding outages in their area. SCE is studying opportunities, and benchmarking with other utilities across the nation, on meaningful enhancements to its website in 2019 to improve the customer experience and PSPS awareness.

5.2.3.1.5 Executing Annual IMT Training Focused On Wildfire Response (Activity DEP-2)

SCE is currently updating its annual IMT training plan which focuses on wildfire mitigation and emergency preparedness. Internally, this will include seminars for IMT members that support execution of wildfire response and protocols for de-energization. Additionally, a series of training exercises utilizing wildfire scenarios that include testing de-energization protocols will be conducted in 2019. These opportunities are in addition to regular IMT trainings and exercises that are required annually as part of SCE's response organization.

5.2.3.2 Communications and Awareness During and Following Wildfire Events

SCE uses a combination of methods for reaching customers during and following wildfire events based primarily on impacted customer population. These methods are described below:

- Toll-free (1-800) phone line staffed with trained resources in SCE's customer contact center who receive calls from impacted customers as a priority; they provide customer-service-related protections to customers.
- Home page alerts on SCE.com that drive customers to a dedicated webpage regarding consumer protections.
- Targeted paid social media campaigns to areas specifically impacted by a disaster (e.g., a wildfire) to inform customers about emergency protections available to those impacted by a specific disaster.
- Trained staff deployed to local assistance centers to work in-person with impacted customers, and advertising on city/county websites about services offered by SCE at these venues.
- Media releases to inform customers about protections and to drive customers to reach SCE through its website or via the toll-free (1-800) phone line.
- Outreach to partnering community-based organizations that serve income-eligible customers to enable awareness of customer-service protections for their organizations' staff who might be working with SCE customers.

5.2.4 SHOWING THAT THE UTILITY HAS AN ADEQUATE AND TRAINED WORKFORCE TO PROMPTLY RESTORE SERVICE AFTER A MAJOR EVENT TAKING INTO ACCOUNT MUTUAL AID AND CONTRACTORS

SCE maintains an adequate and trained workforce ready to provide assistance during emergencies. As described above, SCE has a Storm Plan to respond to emergencies that can vary in scope and size and which may require the activation of mutual assistance to restore power in a safe and timely manner. SCE also has a robust ICS training program for employees identified as emergency responders and currently has approximately 540 employees that have gone through the ICS training program. These

IMT are placed on rotations, and when their teams are on call they are required to respond to the EOC within two hours, with limited exceptions. These teams are specifically structured to have multiple back-ups available, so that response and recovery efforts can be conducted 24 hours a day for several days or even weeks. Moreover, SCE has a large field workforce (both employees and contractors) that is highly skilled and able to restore service during and after a major event.[63] SCE's field workforce has many years of experience, on average, which allows it to effectively respond to major events. SCE also employs contract resources that can be reassigned to assist with a major event.

IMT and EOC capabilities are tested regularly both via real-world incidents such as windstorms, wildfires, and PSPS, and via exercises and drills that all team members are required to participate in annually. These exercises, drills, and real-world activations provide an opportunity for team members to utilize their training, refresh their skills, and learn on the job. During exercises and drills, team members are also evaluated on their performance and given real-time feedback on areas for improvement and best practices.

In addition to SCE's internal response and recovery capabilities, SCE maintains existing mutual assistance agreements with outside providers to meet restoration objectives, as described in Section 5.1. These mutual assistance agreements are activated in incidents which exceed the capacity of SCE's crews and emergency contracting capabilities. The IMT and EOC maintain visibility on the workforce and incidents, maintaining situational awareness of any staffing shortages or other potential shortages, looking ahead at potential needs and requesting appropriate support via additional internal staffing, emergency contracts, or mutual assistance. These requirements are captured in SCE's Storm Plan.

Recognizing the impacts of climate change, the increasing wildfire risk within SCE's service territory, and the potential for numerous PSPS-related EOC activations, SCE is evaluating the need for additional trained staff members and more robust capabilities in its IMT structure. To mitigate these needs, SCE is implementing additional training and exercise opportunities in 2019 to increase team capacity. (Activity DEP-3)

[63] Please see Appendix E for a list documenting the current (approximate) number of SCE field workers, support personnel and contract crews.

5.2.5 ACTIVITIES AND 2019 GOALS

Activity	Description	2019 Goal	Compliance Evidence
DEP-1	Customer Education and Engagement	1) Conduct a direct mail campaign to inform customers in HFRA 2) Develop Local Government Education and Engagement Community Meeting plan 3) Execute Local Government Education and Engagement Community Meeting according to plan	1) Copy of letter and customer list 2) Schedule/Plan of community meetings 3) Presentation materials, sign-in sheet, invitee list
DEP-2	Emergency Responder Training	1) Wildfire response training for new or existing responders 2) Conduct internal IMT Training around wildfire response and de-energization protocols	1) Training sign-in sheets 2) Training/Seminar materials, exercise notes, log of attendees/sign-in sheet
DEP-3	Bolster Incident Management & Incident Support Team members	1) Determine positions that need enhanced staffing 2) Train, exercise, and qualify new staff to meet identified need	1) List of new positions created, or number of personnel needed in existing positions 2) Roster of newly trained personnel

5.3 CUSTOMER SUPPORT IN EMERGENCIES

5.3.1 PROGRAM OVERVIEW

SCE's Emergency Disaster Relief program provides customers impacted by disasters certain protections on their SCE accounts. This program complies with Commission regulations and requirements, including, but not limited to, Resolution M-4833, Resolution M-4835, and D.18-08-004.

The following customer protections are included in SCE's Emergency Disaster Relief program: support for low-income customers, billing adjustments, deposit waivers, extended payment plans, and suspension of disconnection and non-payment fees. These protections remain in effect for one year from the date of the disaster event included in the Governor's state of emergency proclamation.

SCE works with appropriate city and county agencies to identify and verify homes and small businesses in SCE's service territory that were destroyed or damaged by wildfires. SCE conducts field verifications to validate the information and places each home or small business into one of the two following eligibility categories:

- Homes and small businesses destroyed by a disaster are considered total losses, and their accounts are flagged in SCE's Customer Service system as eligible for protections as outlined in the Emergency Disaster Relief program. These accounts remain flagged until the customers establish replacement residences or small businesses for one year from the date of the event included in the Governor's state of emergency proclamation, or as otherwise specified or extended by CPUC order.

- Homes and small businesses damaged by a disaster are not considered total losses. These accounts are flagged in SCE's system and are eligible for protections as outlined in Resolution M-4833, Resolution M-4835 and D.18-08-004.

SCE's dedicated customer support representatives are trained on emergency customer protections and provide information to customers about eligibility for SCE's Emergency Disaster Relief program, and the processes to receive appropriate assistance. Upon receipt of lists of impacted customers from relevant building and safety departments, SCE reaches out to customers directly using customer-indicated preferred contact methods to provide targeted messages about their customer-protection eligibility.

The section below includes information about these customer protection and disaster relief programs. SCE has also included information related to its outage reporting and repair processing and timing.

5.3.2 ACTIONS TAKEN TO SUPPORT CUSTOMERS DURING AND AFTER A WILDFIRE

SCE takes specific actions to support customers during and after wildfires, including:

- Providing support to low-income customers
- Facilitating billing adjustments
- Offering account deposit waivers
- Extending payment plans
- Suspending disconnection and non-payment fees
- Providing access to utility representatives
- Submitting outage reports
- Communicating repair processing and timing

These activities are described in the sections below:

5.3.2.1 Providing Support for Low-Income Customers

SCE partners with a network of more than 100 non-profit community and faith-based organizations across its service territory. Through these alliances, SCE helps eligible customers enroll in income-qualified programs, including the California Alternate Rates for Energy (CARE) program, the Family Electric Rate Assistance (FERA) program, the Energy Assistance Fund (EAF), and the Energy Savings Assistance (ESA) program.

Within SCE's Customer Service business unit, the group responsible for the CARE program identifies and flags CARE customers impacted by a disaster. All CARE program standard- and high-usage post-enrollment eligibility verification requests for these customers are frozen, which allows impacted customers who have pending verification requests to remain in the CARE program for one year from the date of the disaster event without any further affirmative customer action.

SCE partners with the United Way of Greater Los Angeles, its EAF program administrator, to provide an additional, one-time bill payment assistance amount of $100 for eligible, impacted customers. This is in addition to the standard one-time $100 EAF bill credit, amounting to a total one-time assistance amount of $200 for customers impacted by a disaster who apply and qualify for the EAF grant.

The ESA program is a direct-install program that offers income-qualified customers energy efficiency-related services and measures at no cost. The ESA program can provide benefits to income-qualified customers whose homes are damaged by wildfires, and who qualify for replacement of existing appliances. SCE educates low-income customers impacted by a disaster about the ESA program and, if customers are interested, deploys its ESA contractors to customers' homes to confirm ESA program qualification and assists in the enrollment process.

5.3.2.2 Facilitating Billing Adjustments

SCE discontinues billing and closes the service accounts for customers whose homes or small businesses were destroyed by a disaster from the date of the disaster event included in the Governor's state of emergency proclamation. However, SCE maintains these customers' account information and history to support their rebuilding efforts and transfers the customers' information to their new residences or small businesses, and re-establishes their credit history.

SCE suspends bill estimation for customers impacted by disasters, including those customers who were away from their residences or businesses when evacuations were ordered. In some instances, this takes SCE additional time to compile and verify the dates when the residences and businesses were unoccupied due to a disaster. SCE works with the appropriate city and county agencies to identify and verify homes and small businesses in SCE's service territory that were destroyed or damaged by wildfires and follows up with field verifications. Upon contact from customers who receive bills based on estimated usage for the times they were evacuated, SCE conducts an account review and makes appropriate billing adjustments. If a customer is billed during the evacuation period based on actual electricity usage, SCE considers adjusting customer bills under specific circumstances, even if the customer's residence or business was not destroyed in the disaster. In addition, SCE adjusts minimum charges for evacuated customers, as appropriate.

5.3.2.3 Offering Account Deposit Waivers

SCE customers who request utility service re-activation and have been identified as impacted by wildfires are not required to provide security deposits for their accounts.

5.3.2.4 Extending Payment Plans

Though SCE identifies customers whose homes or small businesses were destroyed or damaged during the disaster, SCE relies on its customers to contact SCE and self-certify their particular, disaster-related financial situation. SCE works with impacted customers who contact SCE to establish reasonable payment arrangements based on individual customer need. SCE works with impacted customers to establish an initial payment no greater than 20 percent of the amount due, and the remaining amount due to be paid in equal installments over at least 12 billing cycles for customers with prior arrearages, and exceed at least eight billing cycles for other impacted customers. SCE customers are eligible to pay off their arrearages at any time (sooner), if they prefer.

5.3.2.5 Suspending Disconnection and Non-payment Fees

As part of its regular business practice, SCE does not assess or charge disconnection fees for destroyed homes or small businesses. Upon identification of impacted customers, SCE immediately confirms that customer accounts are flagged, suspends disconnection for non-payment, waives late fees and deposit requirements, and discontinues late payment reports to credit reporting agencies.

SCE keeps the accounts of residential and small business customers whose homes or small businesses were damaged by disaster active for one year, to support their home or small business re-building efforts.

5.3.2.6 Providing Access to Utility Representatives

Following a disaster event, SCE communicates disaster-related information to its communities via multiple channels, including, but not limited to, a designated, toll-free (1-800) SCE Customer Support phone line available Monday-Friday, 6 a.m.- 9.p.m. and Saturdays, 8 a.m.-5 p.m., and representatives deployed to Local Assistance Centers (LAC), ready to assist impacted customers to offer available protections. In addition, SCE makes the information regarding the disaster relief programs, the eligibility requirements for these programs, and how customers can inform SCE regarding their circumstances available on SCE.com.

5.3.2.7 Submitting Outage Reports

Commission requirements for outage reporting include notifications to customers about outages and reporting on outages pursuant to GO 166 and ESRB-8.

5.3.2.7.1 Notifications to Customers about Outages

SCE provides targeted and customized messages to customers regarding potential PSPS outage events, as well as repair and maintenance outages. They include notifications on potential time and duration of outages, update alerts, and restoration messages. These are communicated to customers through a variety of methods such as customer-stated, preferred methods of contact (e-mail, text, and/or SMS) and direct mailers (for maintenance outages).

Additionally, SCE posts emergency alerts, outage information, and restoration updates on its website, SCE.com, where impacted customers can view outage details.

5.3.2.7.2 G.O 166, Standards for Operation, Reliability, and Safety during Electric Emergencies and Disaster – Reporting Requirements

SCE submits reports to the CPUC within required timeframes for various outage types and circumstances, as detailed in GO 166, Standards for Operation, Reliability, and Safety during Electric Emergencies and Disaster. The following table provides a summary:

Outage Type/Circumstance	Report Requirements	Report Submitted to CPUC
Every time circuit block interruption is intended.	• Start time and anticipated curtailment or rotating outage duration • Interruptible load for firm-load rotating outage blocks/groups and sub-blocks/groups • Total amount of interruptible load curtailments or firm load outages, and major firm load interruption locations • SCE's emergency contact person and numbers	As soon as possible.
Outages expected to accrue to more than 300,000 customer hours, exceed 300	• Possible outage cause • Time and location of initiating event • Approximate number and location of impacted customers	Within one hour.

Outage Type/Circumstance	Report Requirements	Report Submitted to CPUC
megawatts of interrupted load, or affect more than 10% of customers.	• Work necessary to restore service • Estimated service restoration time • SCE's event contact person and numbers	
Emergencies involving SCE facilities or personnel, likely to be reported statewide or in more than one major media market.	• Where, when, how, and what happened • Effects on electric service • Injuries, hospitalizations, or casualties • Property damage • Steps taken to resolve the emergency • Time when the situation is expected to return to normal • SCE's emergency contact person and numbers	Within one hour.
Interruptions to bulk power supply that are likely to lead to an ISO-declared Stage 2 or 3 emergency on or before the next business day.	• Interruption cause • Time and location of initiating event • Factors that would mitigate or worsen the emergency • Location and number of customers potentially impacted • Expected duration of the low-capacity situation • SCE's event contact person and numbers	Within one hour.
Outages affecting more than 30,000 customers, or lasting over 24 hours for 2,500 customers, or expected to total over 60,000 customer hours, or for situations likely to lead to such outages.	• Interruption cause and time • Name and location of impacted facilities • Outage start and end times • Location and number of impacted customers • Number of customers for whom the outage exceeded four hours • When service will be restored • SCE's event contact person and numbers	By 9:00 a.m. the next business day.
Outages associated with Office of Emergency Services (OES)-declared states of emergency, not otherwise reportable under the criteria above	• Outage cause • Outage start and end times • Location and number of impacted customers • Number of customers for whom the outage exceeded four hours • When service will be restored • Emergency crew movement between regions • Mutual-assistance requests to other utilities • SCE's event contact person and numbers	As soon as possible.

5.3.2.7.3 ESRB-8 Reporting Requirements

IOUs are required to submit a report to the Director of SED within 10 business days after each de-energization event, and after high-threat events where the IOU provided notifications to local government, agencies, essential services, and customers of possible de-energization but no de-energization occurred. These reports must include at a minimum the following information:

- A list of the local communities' representatives the IOU contacted prior to de-energization, the date on which they were contacted, and whether the areas impacted by the de-energization are classified as Zone 1, Tier 2, or Tier 3 as per the definition in GO 95, Rule 21.2-D.
- An explanation if the IOU is not able to provide customers with notice at least 2 hours prior to the de-energization event.
- Summary of the number and nature of complaints received as the result of the de-energization event, including claims that are filed against the IOU because of de-energization.
- Detailed description of the steps the utility took to restore power.
- The address of each community assistance location during a de-energization event, describing the location (in a building, a trailer, etc.) and describing the assistance available at each location, including the days and hours that it was open.

5.3.2.7.4 Communicating Repair Processing and Timing

During and following a disaster event, repair and power restoration timelines are largely dependent on access to the damaged area, damage to SCE assets, ability to secure materials and repair resources, and customer restoration priority. Essential services and facilities associated with safety will receive a higher restoration priority, when feasible. SCE communicates repair and restoration priority status to customers via its website, SCE.com. In addition, SCE makes efforts to communicate estimated restoration times to customers through their preferred or alternate methods of contact. These communications typically take place at the beginning of an outage and continue throughout the duration of the outage period and restoration efforts.

In 2018, SCE implemented Customer Crew Communications (C3) into its Outage Management System (OMS) which allows crews to enter outage information directly into the system. This enhancement allows SCE to provide customers with more timely, accurate outage status and creates a direct flow of information from SCE's field personnel into the OMS, which then pushes information directly to customers. Further customer benefits include SCE's ability provide information on estimated arrival times and other restoration details more accurately.

On SCE's website, the dedicated outage page has undergone enhancements in 2018. The outage map progress tracker, a customer-facing graphic, now has intuitive reasoning built in that more thoroughly displays several steps in the outage process, providing customers with the current status and what to expect next. The information includes the type of outage, such as maintenance or repair, estimated restoration time, crew arrival information, and number of customers impacted. Additionally, this page continues to link customers to helpful and relevant information such as outage tips and preparedness.

6 PERFORMANCE METRICS AND MONITORING

This chapter identifies SCE's management overseeing this WMP and includes the operating unit(s) and department(s) responsible for carrying out the activities described in the previous chapters. SCE describes the controllable metrics that are different from the activity goals. Like the activity goals, these metrics are used to demonstrate compliance of this WMP. This section also describes indicators that will be used for tracking purposes. Section 6.3 then provides background information on historical measures. Lastly, Section 6.4 describes SCE's monitoring and auditing process, and corrective actions (if necessary).

6.1 SCE MANAGEMENT RESPONSIBLE FOR EXECUTING THE WILDFIRE MITIGATION PLAN

SCE's 2019 goal planning process assigns overall responsibility for the WMP at the executive level and responsibility for individual activities to specific operating units and departments.

6.1.1 EXECUTIVE LEVEL WITH OVERALL RESPONSIBILITY

Phil Herrington, SCE's senior vice president of T&D, has overall responsibility for this WMP.

6.1.2 SCE OPERATING UNIT RESPONSIBILITY SPECIFIC TO EACH COMPONENT OF THE PLAN

Mitigation Activities	Operating Unit and Department
Risk Analysis: • Expansion of Risk Analysis (RA-1)	Finance; Enterprise Risk Management
Evaluation of HFRA: • Evaluation of HFRA boundaries (EVAL-1)	T&D; Grid Modernization & Resiliency
Operational Practices: • Annual SOB 322 Review (OP-1) • Wildfire Infrastructure Protection Team Additional Staffing (OP-2)	T&D; Transmission, Substation & Operations (OP-1) Safety, Security & Business Resiliency; Business Resiliency (OP-2)
Inspections: • Distribution Enhanced Overhead Inspections and Remediation in HFRA (IN-1) • Transmission Enhanced Overhead Inspections and Remediation in HFRA (IN-2) • Quality Oversight / Quality Control program based on EOI (IN-3) • Infrared Inspection of hot spots on overhead distribution facilities and equipment (IN-4) • Infrared Inspection, Corona Scanning, and High Definition imagery of overhead	T&D; Distribution and Transmission, Substation & Operations

Mitigation Activities	Operating Unit and Department
transmission facilities and equipment (IN-5)	
System Hardening: • Covered Conductor (SH-1) • Evaluation of Undergrounding in HFRAs (SH-2) • Composite Poles and Cross Arms (SH-3) • Branch Line Protection Strategy (current limiting fuses, CLFs) (SH-4) • Remote Controlled Automatic Reclosers Installations (SH-5) • Remote Controlled Automatic Reclosers Setting Updates (SH-6) • Circuit Breaker Fast Curve (SH-7)	T&D; Distribution and Transmission, Substation & Operations
Vegetation Management: • Hazard Tree Removal program (VM-1) • Expanded Pole Brushing (VM-2) • Expanded clearance distances at time of maintenance (VM-3) • DRI quarterly inspections and removals (VM-4) • LiDAR Inspections of Transmission (VM-5)	T&D; Distribution (Vegetation Management)
Situation Awareness: • Additional Weather Stations (SA-1) • Fire Potential Index Phase II (SA-2) • Additional HD Cameras (SA-3) • High-Performing Computer Weather Modeling System (SA-4) • Develop Asset Reliability & Risk Analytics Capability (SA-5)	Safety, Security & Business Resiliency; Business Resiliency
Protocols on Public Safety Power Shut-Off: • De-Energization Notifications (PSPS-1)	Safety, Security & Business Resiliency; Business Resiliency
Alternative Technologies: • Alternative Technology Pilots (AT-1) • GS&RP Wildfire Mitigation Program Study (AT-2) • Alternative Technology Evaluations (AT-3)	T&D; Asset Management, Strategy & Engineering

Mitigation Activities	Operating Unit and Department
• Alternative Technology Implementation (AT-4)	
Emergency Preparedness: • Customer Education and Engagement (DEP-1) • Emergency Responder Training (DEP-2) • Bolster Incident Management & Incident Support Team (DEP-3)	Safety, Security & Business Resiliency; Business Resiliency (DEP-2, DEP-3) Customer Service; Customer Service Operations Division (Consumer Affairs) (DEP-1)

6.2 METRICS TO EVALUATE THE PERFORMANCE OF THE PLAN AND UNDERLINING ASSUMPTIONS

6.2.1 METRICS

This section describes the performance metrics that will be used to assess compliance with this WMP. Mitigation plans in the GSRP are currently under review by the CPUC; accordingly, the relevant GSRP-related performance metrics in this WMP may be updated in future years' plans based on the CPUC's review and eventual decision in A.18-09-002.

In order to assess compliance with this WMP, SCE has included a set of performance metrics that are both "controllable" and "quantifiable." A controllable metric is one that SCE has the ability to control or influence the outcome through planned activities. A quantifiable metric is one that is measurable. Uncontrollable metrics are those that are outside of SCE's control. For example, the number of car hit pole events or the number of RFW days. SCE's metrics defined in this chapter are intended to track progress to specific goals to evaluate this WMP's performance.

In addition to metrics, this section describes indicators that do not evaluate compliance performance in 2019 because drivers contributing to the indicators include uncontrollable factors, making it difficult to set accurate, achievable, and numerical goals in 2019. Indicators are included in this WMP to evaluate trends that can help inform current and future strategies and programs. For example, SCE will continue to track and analyze the number of ignitions using the CPUC-reportable ignitions criteria as an indicator. However, given that a subset of ignitions can be caused by uncontrollable events unrelated to SCE's electrical equipment, this value will continue to be tracked in 2019 for informational purposes, and is not being used as a 2019 performance-based compliance metric with a specific target in this section.

Cumulatively, the success of the individual programs and activities in this WMP are expected to result in an overall reduction of controllable fire ignition events. Table 6.6 below summarizes the work streams and associated performance metrics. Not all activities described in previous chapters are considered performance metrics and do not appear in the table below. Both activities and performance metrics are relevant to WMP compliance evaluation. Further below SCE describes these metrics.

Table 6-6
Metrics

Work Stream	Performance Metric	Unit of Measurement	2019 Goal
Vegetation Management	Enhanced Vegetation Management	The number of trees removed as part of HTMP (VM-1)	7,500 trees
	Quality Control Inspections in HFRA	Circuit miles inspected	400 Transmission circuit miles 450 Distribution circuit miles
	Drought CEMA Program Trees Removed in HFRA	The number of trees removed as part of DRI	30,000 trees forecast
System Hardening	Wildfire Covered Conductor Program (WCCP) Miles Hardened	The number of circuit miles replaced with covered conductor (SH-1)	At least 96 circuit miles re-conductored
Operational Practices	Fuses Installed	The count of fuses installed on un-fused branch lines (SH-4)	At least 7,500 fuses
Situational Awareness	Weather Stations Installed	Count of weather stations installed (SA-1)	At least 315 weather stations
	HD Cameras Installed	Count of HD cameras installed (SA-3)	At least 62 HD Cameras
Patrols & Inspections	Enhanced Overhead Inspections (EOI) in HFRA	Inspect all Distribution, sub-transmission and transmission overhead lines in HFRA	100% of overhead lines in HFRA inspected

6.2.1.1 Vegetation Management

Vegetation, particularly palm fronds, are common foreign objects that contact conductors. Dry vegetation can also act as fuel in case of a wildfire. Therefore, enhancing SCE's vegetation management program is a priority in HFRA. Vegetation Management activities include tree trimming and tree removal in proximity to utility power lines and weed abatement around overhead structures in HFRA. SCE employs contractors to perform the work and performs quality control inspections on the completed work. To measure the success of SCE's vegetation management activities, the following three metrics will be used: (1) Enhanced Vegetation Management, (2) QC inspections in HFRA, and (3) Drought CEMA Program trees removed in HFRA.

6.2.1.1.1 Enhanced Vegetation Management

This metric measures the number of trees (including palms) removed as part of HTMP. HTMP expands vegetation management activities to assess the structural condition of trees in HFRA that are not dead or dying, but could nevertheless fall into or otherwise impact electrical facilities and potentially lead to ignitions and outages. These trees can be located up to 200 feet on either side of SCE's electrical facilities, significantly beyond the 4-foot clearance requirement in HFRA. The Hazard Tree Mitigation Program is described in more detail in Section 4.4.

6.2.1.1.2 Quality Control Inspections in HFRA

SCE will perform Quality Control compliance inspections in HFRA to verify compliant contractor work. The 2019 goal is to inspect vegetation adjacent to approximately 400 transmission circuit miles and approximately 450 distribution circuit miles.

6.2.1.1.3 CEMA Program Trees Removed in HFRAs

As described in Section 4.4, SCE established the DRI as a separate and distinct program from SCE's ongoing vegetation management activities. Under the DRI, SCE plans to remove approximately 30,000 trees in HFRA in 2019 that are dead, dying, or diseased, and that could impact SCE's electrical facilities.

6.2.1.2 System Hardening

SCE's system hardening programs are designed to reduce the risk of wildfire ignitions associated with be electrical infrastructure.

6.2.1.2.1 Wildfire Covered Conductor Program Miles Hardened

As discussed in Chapter 3, 53 percent of fire ignition events from 2015 to 2017 were on distribution voltage-level infrastructure in HFRA and due to contact from external objects (e.g., palm fronds, metallic balloons, debris) and an additional two percent from wire-to-wire contact. To reduce the probability of these ignitions, SCE is replacing existing overhead conductor with covered conductor that insulates and protects electrical lines against contacts from foreign objects and against power lines coming into contact with each other during high wind events. This program's performance will be measured by the execution of replacing overhead bare conductor with covered conductor in HFRA which has a 2019 goal of installing at least 96 circuit miles of covered conductor.

6.2.1.3 Operational Practices

6.2.1.3.1 Fuses Installed

Equipment or facility failure accounts for 30 percent of fire ignition events associated with electrical infrastructure based on SCE's CPUC-reportable ignitions data from 2015 to 2017. A fuse serves to protect an overloaded circuit by interrupting the flow of electricity. Fuses have the ability to limit the amount of energy associated with a fault, which minimizes the ignition potential. Currently, many of SCE's HFRA circuits have un-fused branch lines. SCE plans to install CLF on these un-fused branch lines to further minimize ignition risk. The 2019 performance metric that will be used to measure this program's effectiveness is the number of fuses installed in HFRA. The 2019 goal is to install at least 7,500 CLFs in HFRA.

6.2.1.4 Situational Awareness

The above mitigation activities can significantly lessen the likelihood of fire ignition events, but there are factors, such as severe weather events, that are uncontrollable. SCE relies on technologies and weather experts to better anticipate and plan for these occurrences. The following activities can help improve situational awareness prior to and during such events.

6.2.1.4.1 Weather Stations Installed

SCE is focused on accessing real time information about wildfire risk at a more granular level. This will help SCE better understand how weather conditions might impact utility infrastructure and public safety in HFRA. Additional details on the benefits of these weather stations are in Section 4.5. The performance

metric proposed to measure how effectively this program is executed is the number of weather stations installed, with a goal of at least 315 units in 2019.

6.2.1.4.2 HD Cameras Installed

As discussed in Section 4.5, additional HD cameras in HFRA may help fire agencies respond more quickly if an ignition occurs. The performance metric to measure how effectively this program is executed is the number of cameras installed, with a target of 62 HD cameras installed in 2019.

6.2.1.5 Patrols and Inspections

6.2.1.5.1 Enhanced Overhead Inspections in HFRA

SCE plans to inspect all distribution, sub-transmission and transmission overhead lines in HFRA in 2019. Any issues found through these enhanced inspections will follow SCE's existing process for work prioritization as described in Section 4.2.

6.2.2 INDICATORS

SCE will use indicators to track values that are not used to evaluate WMP compliance performance in 2019. Additional analysis over time is needed to potentially adjust indicators for uncontrollable factors before considering proposing them as performance goals in future plan filings.

Table 6-7
Indicators

Indicators	Unit of Measurement
Wire Downs on Circuits in HFRA	Count of wire down events on HFRA circuits
Ignitions on Circuits in HFRA	Count of all ignitions on HFRA circuits associated with contact from object or equipment failures
Counts of all faults on Circuits in HFRA	Count of all faults on HFRA circuits associated with contact from object or equipment failures

6.2.2.1 Wire Downs on Circuits in HFRA

The Wire Downs indicator is a count of all events involving conductors that contact the ground or foreign object on circuits in HFRA.

6.2.2.2 Ignitions on Circuits in HFRA

A count of CPUC-reportable ignitions in SCE's service territory that meet the following conditions:

a. A self-propagating fire of material other than electrical and/or communication facility; and
b. The resulting fire traveled greater than one linear meter from the ignition point; and
c. The utility has knowledge that the fire occurred

SCE's ignition data collection process includes a variety of fields to track ignition data including start time, location, size, and drivers covering contact from object and equipment. To the extent the information is known, SCE documents it in its system.

6.2.2.3 Counts of all faults in HFRA Circuits categorized by driver

SCE will track counts of all faults on HFRA circuits associated with contact from object or equipment failures.

6.3 HISTORICAL INDICATORS AND METRICS

Fire mitigation has been an integral part of SCE's operational practices for years. SCE collects fire-related data to improve its wildfire mitigation efforts. This section documents the CPUC-reportable ignitions as the current and historical primary indicator used to track wildfires associated with electrical equipment.

6.3.1 CPUC REPORTABLE IGNITIONS INDICATORS

The primary indicator that the Commission tracks for wildfires associated with electrical infrastructure is known as "reportable ignitions."[64] A reportable ignition is any event where utility facilities are associated with the following conditions:

(a) A self-propagating fire of material other than electrical and/or communication facility, and

(b) The resulting fire traveled greater than one linear meter from the ignition point, and

(c) The utility has knowledge that the fire occurred.

SCE began tracking ignitions in May 2014. Because the 2014 dataset reflected partial annual counts, SCE used data from 2015 to 2017 in its risk analyses; these risk analyses influenced the wildfire mitigation programs and mitigation measures proposed within the GSRP Application. CPUC-reportable ignition data from 2015 to 2017 tracked 302 ignitions associated with SCE utility equipment, with 133 of these ignitions located within HFRA. SCE is in the process of analyzing 2018 fire ignition data. In addition to incorporating additional 2018 historical ignition data reportable to the CPUC, SCE will supplement this analysis in 2019 as described in Section 3.2.

6.3.2 OUTAGE DATABASE AND RELIABILITY METRICS

ODRM is a database that is used to gather information about electrical outages. Since January 2006, SCE has recorded all unplanned outages that affect a single line transformer or more on SCE's electrical system. For all such outages, every restoration step, the associated time, customers affected and associated outage cause (if known) are recorded.

6.4 COMPARISON OF THE WILDFIRE MITIGATION PLAN WITH THE FIRE PREVENTION PLAN (FPP)

SCE's 2017 FPP describes measures implemented to mitigate the threat of overhead powerline-associated ignitions and/or equipment-related ignitions within SCE's service territory. The FPP outlined SCE's use of applicable RFW methods in HFRA and assigned responsibilities of organizational units in preventing ignitions:

- D.12-01-032 required SCE to prepare a FPP to identify 3-second wind gusts in real time and address situations where all three of the following conditions occur simultaneously: 1) 3-second wind gusts exceeding the structural or mechanical design standards for the affected overhead powerline facilities, 2) these 3-second gusts occur during a period of high fire danger, and 3) the affected facilities are located within a high fire threat area.

[64] *See* D.13-02-015. Reportable ignitions do not include fires that cause damage to utility facilities but whose ignition is not associated with utility facilities are excluded from this requirement.

- D14-05-020 modified D.12-01-032 and eliminated the requirement to identify 3-second wind gusts in real time if a utility does not deploy fire-prevention measures that rely on real time observations of wind gusts. D.14-05-020 required SCE to "identify the parts of its service territory where it is reasonably foreseeable that the following conditions may occur simultaneously: 1) 3-second wind gusts exceed the structural or mechanical design standards for the affected overhead powerline facilities, 2) these 3-second gusts occur during a RFW, 3) the affected facilities are in a high fire threat area; and 4) that "[i]n making this determination, the utility shall use a minimum probability of 3 percent over a 50-year period that 3-second wind gusts which exceed the design standards for the affected facilities will occur during a RFW in a high fire-threat area."

In 2018, SCE completed a comprehensive update to its FPP that included many elements in this WMP. The 2018 FPP update encompassed all CPUC requirements identified in previous versions of the FPP and included additional strategies and programs focused on fire prevention, including the following items:

- System hardening
- Recent engineering and technical solutions
- Vegetation Management program improvements
- Operational enhancements (e.g., PSPS)
- Situational Awareness Center upgrades
- Weather monitoring and modeling improvements
- External engagement and outreach

A comparison of all elements included in the 2018 FPP and this WMP can be found in Appendix F.

6.5 COMPLIANCE, CORRECTIONS AND MONITORING PROCESSES AND PROCEDURES

6.5.1 MONITORING AND AUDITING OF THE PLAN

Protecting public and employee safety is a core value for SCE. This WMP is focused on identifying, prioritizing and executing mitigation programs and activities to further protect the public, customers, employees and contractors, and the grid from evolving and increasing wildfire risk. In accordance with SB 901, SCE's performance metrics described herein will measure the effectiveness of SCE's strategies and programs described in previous chapters.

SCE will use a performance dashboard as the platform to track progress on the wildfire mitigation metrics/activities included in this WMP and to illustrate progress in a visual manner. Progress towards 2019 goals of individual activities and higher-level metrics will be updated and reported on a monthly basis to SCE senior leadership. In accordance with PUC Section 8386, SCE will file a report with the CPUC addressing SCE's compliance with its 2019 WMP by March 31, 2020.

In addition to the required compliance report, SCE will maintain the compliance documentation described for each activity and make such documentation available to the independent evaluator upon request.

Additionally, SCE's internal Audit Department provides independent evaluations and assessments of risk management, governance, and controls to improve the effectiveness of Company operations. The annual audit plan is developed with input from SCE management and approved by the Board of Directors' Audit Committee each February. The annual audit plan may include evaluation of specific mitigation programs or activities included in the WMP.

6.5.2 IDENTIFYING AND CORRECTING ANY DEFICIENCIES IN THE PLAN

Progress towards 2019 goals of individual activities and higher-level metrics will be monitored by the PMO and management to enable SCE to address any potential performance challenges. All stakeholders are empowered to suggest improvement opportunities, including: field crews conducting work in HFRA, management reviewing results or trends, or formal internal or external auditors. The owner of each mitigation program or activity will be responsible for developing and implementing corrective actions for improvement opportunities encountered during implementation or for metrics that are off-track or trending negatively.

Ensuring implementation of corrective actions and overall monitoring of the metrics will be the responsibility of the applicable organization. These organizations will report to T&D executive leadership through existing channels.

6.5.3 MONITORING AND AUDITING THE EFFECTIVENESS OF WILDFIRE MITIGATION PROGRAMS

SCE has already started executing many aspects of this WMP, and the Company will continue to assess and evaluate the effectiveness of each mitigation program or activity. As noted in Section 6.2.2, analysis of indicators over time will help inform the effectiveness of SCE's mitigation strategies and programs and will provide data to continually improve and adjust these efforts accordingly. By evaluating trends of events linked to specific drivers for circuits that have gone through one or more wildfire mitigation programs and activities, SCE will assess how effective the mitigations are at preventing future ignitions. SCE's ability to measure the effectiveness of wildfire mitigation programs will be limited in 2019 and will require years of observation in HFRA to develop a complete view on the effectiveness of SCE's wildfire risk mitigation efforts.

7 ANY OTHER INFORMATION THAT THE CPUC MAY REQUIRE

7.1 COST INFORMATION

The following table provides potential cost implications of the strategies and programs described in Chapter 4 of this WMP.

7.1.1 EXPLANATION OF HOW DOUBLE TRACKING IN MEMORANDUM ACCOUNTS IS PREVENTED

SCE's new mitigation strategies/programs identified in Table 7-1 include three memorandum accounts (MA) that SCE will use to track its incremental costs, as appropriate. These memorandum accounts include the GSRP MA, SB 901 MA, and the Fire Hazard Prevention Memorandum Account (FHPMA). SCE has and will set up separate accounting in its SAP system to track cost for each MA. The separate accounting will ensure that SCE does not account for these incremental costs more than once. Moreover, SCE will seek cost recovery for the incremental costs in the SB 901 MA and the FHPMA in its 2021 GRC. In its 2021 GRC, SCE will be delineate these separate incremental costs by the activities described in the WMP and will demonstrate that the costs are incremental. Prior to seeking cost recovery, SCE will also assess and review the entries to these memorandum accounts for quality oversight purposes and will make adjustments should it find errors. SCE will have a similar accounting structure to ensure incremental costs recorded to its FHPMA are not also recorded elsewhere. Additionally, SCE will monitor these accounts and make adjustments when appropriate if costs are determined to be non-incremental.

SB 901 Activity Identifier	Activity/Program	2019 Cost (Capital) ($M) ($Nominal) (2019 Goal)	2019 Cost (O&M) ($M) ($Nominal) (2019 Goal)	2019 Cost (Capital) ($M) ($Nominal) (2019 Expansion/ Acceleration)	2019 Cost (O&M) ($M) ($Nominal) (2019 Expansion/ Acceleration)	Costs Currently reflected in Revenue Requirement	Funding that is or will be Addressed in Another Case	Memo accounts where the cost of program/ strategy are being tracked
AT-1	Alternative Technology Pilots	0.2	N/A	N/A	N/A	2018 GRC Pending	2018 GRC and/or 2021 GRC	Potentially SB 901 MA
AT-2	GSRP Wildfire Mitigation Program Study	N/A	0.6	1.4	N/A	No	GSRP Application and potentially pending 2018 GRC and/or 2021 GRC	GSRP MA and potentially SB 901 MA
AT-3	Alternative Technology Evaluations	N/A	0.0	N/A	N/A	Cross-organization labor costs included in 2018 GRC Pending (labor costs not included in cost estimate)	2018 GRC and/or 2021 GRC	Potentially SB 901 MA
AT-4	Alternative Technology Implementation	N/A	Cross-organization labor costs included in 2018 GRC	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
IN-1	Distribution Enhanced Overhead Inspections and Remediation in HFRA	102.8	144.9	N/A	N/A	No	2018 GRC and/or 2021 GRC	SB 901 MA
IN-2	Transmission Enhanced Overhead Inspections and Remediation in HFRA	9.9	25.0	N/A	N/A	No	2018 GRC and/or 2021 GRC	SB 901 MA
IN-3	Quality Oversight / Quality Control of EOI	N/A	Part of Division Overhead costs included in 2018 GRC	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
IN-4	Infrared Inspection of energized overhead distribution facilities and equipment	N/A	0.5	N/A	N/A	No	GSRP Application	GSRP MA
IN-5	Infrared Inspection, Corona Scanning, and High Definition imagery of energized overhead Transmission facilities and equipment	N/A	5.7	N/A	N/A	No	2021 GRC	SB 901 MA
N/A	AGP – Drive by of overhead Distribution facilities and equipment	N/A	Included in ODI	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Automatic Reclosers Replacement Program	2.4	N/A	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Capacitor Bank Replacement Program	18.1	N/A	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Detailed inspection of Transmission facilities and equipment	N/A	5.7	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Deteriorated Pole Program	251.2	N/A	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Insulator Washing	N/A	1.2	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	IPI – Intrusive pole inspections to identify rot and decay	N/A	6.1	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	ODI – Detailed inspections of Distribution overhead facilities and equipment	N/A	8.6	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Overhead Conductor Program	143.9	N/A	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	PCB Transformers Replacement Program	1.5	N/A	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Performance of joint patrols with fire agencies	N/A	See Supplemental Inspections of HFRA line item	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Pole Brushing	N/A	See Supplemental Inspections of HFRA line item	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Pole Loading Program	N/A	26.4	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	PSPS/De-energization Protocol Support Costs	N/A	4.3	N/A	N/A	No	GSRP Application	GSRP MA
N/A	Road and Right-of-Way Maintenance	N/A	3.9	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Substation Inspection and Maintenance	N/A	2.2	N/A	N/A	2018 GRC Pending	2018 GRC	N/A

SB 901 Activity Identifier	Activity/Program	2019 Cost (Capital) ($M) ($Nominal) (2019 Goal)	2019 Cost (O&M) ($M) ($Nominal) (2019 Goal)	2019 Cost (Capital) ($M) ($Nominal) (2019 Expansion/ Acceleration)	2019 Cost (O&M) ($M) ($Nominal) (2019 Expansion/ Acceleration)	Costs Currently reflected in Revenue Requirement	Funding that is or will be Addressed in Another Case	Memo accounts where the cost of program/ strategy are being tracked
N/A	Supplemental inspections of HFRA	N/A	69.1 (Distribution) 11.3 (Transmission)	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
N/A	Transmission Line Rating Remediation	157.9	8.2	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
OP-1	Annual SOB 322 Review	N/A	Cross-organization labor costs included in 2018 GRC	N/A	N/A	2018 GRC Pending	2018 GRC	N/A
OP-2	Wildfire Infrastructure Protection Team Additional Staffing	N/A	0.5	N/A	N/A	No	GSRP Application	GSRP MA
PSPS-1	De-Energization Notifications	N/A	1.3	N/A	N/A	No	GSRP Application	GSRP MA
SA-1	Additional Weather Stations	5.4	0.6	6.0	0.6	No	GSRP Application	GSRP MA
SA-2	Fire Potential Index Phase II	N/A	0.6	N/A	N/A	No	GSRP Application	GSRP MA
SA-3	Additional HD Cameras	2.3	2.6	2.8	4.3	No	GSRP Application	GSRP MA
SA-4	High-Performing Computer Weather Modeling System	3.8	0.1	N/A	N/A	No	GSRP Application	GSRP MA
SA-5	Develop Asset Reliability & Risk Analytics Capability	0.5	N/A	N/A	N/A	No	GSRP Application	GSRP MA
SH-1	Covered Conductor	47.4	1.0	133.7	2.7	No	GSRP Application and potentially pending 2018 GRC and/or 2021 GRC	GSRP MA and potentially SB 901 MA
SH-2	Evaluation of Undergrounding in HFRA	0.0	0.0	3.1	0.1	No	2021 GRC	SB 901 MA
SH-3	Composite Poles and Crossarms	5.1	0.1	15.6	0.3	No	GSRP Application and potentially pending 2018 GRC and/or 2021 GRC	GSRP MA and potentially SB 901 MA
SH-4	Branch Line Protection Strategy	46.1	0.9	52.3	1.1	No	GSRP Application	GSRP MA
SH-5	Remote Controlled Automatic Reclosers Installations	4.9	0.1	N/A	N/A	No	2021 GRC	FHPMA
SH-6	Remote Controlled Automatic Reclosers Setting Updates	N/A	0.3	N/A	N/A	No	GSRP Application	GSRP MA
SH-7	Circuit Breaker Fast Curve	9.1	0.2	N/A	N/A	No	GSRP Application	GSRP MA
VM-1	Hazard Tree Mitigation program (HTMP)	N/A	25.5	N/A	56.9	No	GSRP Application	GSRP MA
VM-2	Expanded Pole Brushing	N/A	0.9	N/A	9.6	No	2021 GRC	SB 901 MA
VM-3	Expanded clearance distances at time of maintenance	N/A	28.0	N/A	N/A	No	2021 GRC	FHPMA
VM-4	DRI quarterly inspections and removals	N/A	41.5	N/A	N/A	No	Drought CEMA	Drought CEMA
VM-5	LiDAR Inspections of Transmission	N/A	3.7	N/A	N/A	No	2021 GRC	SB 901 MA

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Appendix A

List of Acronyms

A.	Application
AB	Assembly Bill
ACS	Arc Suppression Coils
AGP	Annual Grid Patrol
Air Operati	SCE's Air Operations department
ANSI	American National Standards Institute
AR	automatic reclosers
BLF	Branch Line Fuses
BVLOS	Beyond Visual Line of Sight
C3	Customer Crew Communications
CAISO	California Independent System Operator
CAL FIRE	California Department of Forestry and Fire Protection
Cal OES	California Office of Emergency Services
CARE	California Alternate Rates for Energy
CB	Cicuit Breaker
CCC	Customer Contact Center
CEII	critical energy infrastructure information
CEMA	Catastrophic Event Memorandum Account
CLF	current-limiting fuses
CPUC	California Public Utilities Commission or Commission
CSWC	California State Warning Center
CUEA	California Utilities Emergency Association
D.	Decision
DDS	Distribution Design Standards
DFA	Distribution Fault Anticipation
DIMP	Distribution Inspection and Maintenance Program
DOH	Distribution Overhead Constuction Standards
DRI	Drought Relief Initiative
EEI	Edison Electric Institute
EOC	SCE's Emergency Operations Center
EOI	enhanced overhead inspections
EONS	Emergency Outage Notification System
EPUC/IS	Energy Producers and Users Colation and Indicated Shippers
ERO	Emergency Response Organization
ESA	Energy Savings Assistance
FEMA	Federal Emergency Management Agency
FERA	Family Electric Rate Assistance
FERC	Federal Energy Regulatory Commission
FHPMA	Fire Hazard Prevention Memorandum Account
FHSZ	Fire Hazard Severity Zone
FPI	Fire Potential Index
FPP	Fire Prevention Plan
FRP	fiber reinforced polymer
GIS	Geographic and Information System
GO	General Order
GRC	General Rate Case
GSRP	Grid Safety and Resiliency Program

HD	high definition
HFRA	High Fire Risk Areas
HFTD	High Fire Threat District
HHZ	High Hazard Zones
HPCC	High Performance Computing Cluster
HTMP	Hazard Tree Management Program
I.	Investigation
ICS	Incident Command System
IMT	Incident Management Team
IOUs	Investor-Owned Utilities
IPI	Intrusive Pole Inspection program
IR	Infrared
ISA	Internationl Society of Arborculture
LAC	Local Assistance Center
LiDAR	light detection and ranging technology
MA	Memorandum Account
MADEC	meter alarming for downed energy conductor
MAVF	Multi-Attribute Value Framework
MVCD	Minimum Violation Clearance Distance
NERC	North American Reliability Corporation
NFPA	National Fire Protection Association
NIFC	National Interagency Fire Center
NIMS	National Incident Management System
OCP	Overhead Conductor Program
ODI	Overhead Detail Inspection program
ODRM	Outage Database and Reliability Metrics
OEM	Offices of Emergency Management
OIR	Order Instituting Rulemaking
OMS	Outage Management System
PCB	polychlorinated biphenyls
PG&E	Pacific Gas and Electric Company
PLP	Pole Loading Program
PMO	Program Mangement Office
PRC	Public Resources Code
PSPS	Publlic Safety Power Shut-Off
PTZ	pan-tilt-zoom
PUC	Public Utilities Code
QC	quality control
R.	Rulemaking
RAMP	Risk Assessment Mitigation Phase
RAR	remote-controlled automatic reclosers
RAWS	Remote Automated Weather Stations
REFCL	Rapid Earth Fault Current Limiter
RFW	Red Flag Warnings
ROW	rights-of-way
Ruling	January 17, 2019 Administrative Law Judge Ruling
SAWTI	Santa Ana Wildfire Threat Index

SB 901	Senate Bill 901
SCADA	supervisory control and acquisition data
SCE	Southern California Edison Company or Company
SDG&E	San Diego Gas & Electric Company
SED	Safety and Enforcement Division
SIMP	Substation Inspection and Maitenance Program
S-MAP	Safety Model Assessment Proceedings
SOB	Standard Operating Bulletin
SoCalGas	Southern California Gas Company
T&D	SCE's Transmission and Distribution business unit
TIMP	Transmission Inspection and Maintenance Program
TURN	The Utility Reform Network
UAS	Advanced Unmanned Aerial Systems
UAV	unmanned aerriel vehicle
UDI	Underground Inspection Program
USFS	U.S. Forest Service
USGS	United States Geological Survey
WCCP	Wildfire Covered Conductor Program
WECC	Western Electricity Coordinating Council
WMP	Wildfire Mitigation Plan
WRF	Weather Research and Forecasting
WRMAG	Western Region Mutual Assistance Agreement for Electric Utilities

Appendix B

Categorization of Strategies and Programs

SB 901 Category	SB 901 Activity Identifier	Activity/Program	Existing or New Work	Asset Addressed (Ex. lines, poles, etc.)	Previously Included in RAMP?	Evaluation Metric	Assumptions Underlying Metric
Design and Construction	AT-1	Alternative Technology Pilots	Existing	Surge arrestors, MADEC	No	1) Pilot installation of 50 CAL FIRE-exempt surge arrestor units in target locations 2) Pilot meter alarming for downed energized conductor	Engineering research
Design and Construction	AT-2	GSRP Wildfire Mitigation Program Study	New	All distribution line equipment/hardware	No	1) Evaluate distributed fault anticipation technology and conduct pilot installation of at least 10 DFA devices 2) Evaluate BVLOS UAS capabilities	Based on GSRP
Design and Construction	AT-3	Alternative Technology Evaluations	New	Vibration dampers, Line spacers, fuses , single phase reclosers, poles and crossarms	No	1) Evaluate REFCL/ASC 2) Evaluate alternate fault detection technology 3) Evaluate fire retardant barrier for wood poles 4) Evaluate substation-class electronic fuses 5) Evaluate branch line protection to include single phase reclosing	Engineering research
Design and Construction	AT-4	Alternative Technology Implementation	Existing	Vibration dampers, Line spacers, fuses , single phase reclosers, poles and crossarms	No	1) Develop standard installation practices for Aeolian vibration dampers 2) Develop standard installation practices for ridge pin construction for conductor rebuild 3) Update DOH requirements for connector selection in HFRA	Engineering research
Design and Construction	N/A	Automatic Reclosers Replacement Program	Existing	Automatic Reclosers	No	N/A: Existing program / not new program	N/A
Design and Construction	N/A	Capacitor Bank Replacement Program	Existing	Capacitor Banks	No	N/A: Existing program / not new program	N/A
Design and Construction	N/A	Deteriorated Pole Program	Existing	Poles	No	N/A: Existing program / not new program	N/A
Design and Construction	N/A	Insulator Washing	Existing	Insulators	No	N/A: Existing program / not new program	N/A
Design and Construction	N/A	Overhead Conductor Program	Existing	Conductor, poles, equipment	Yes	N/A: Existing program / not new program	N/A
Design and Construction	N/A	PCB Transformers Replacement Program	Existing	Transformers	No	N/A: Existing program / not new program	N/A
Design and Construction	N/A	Road and Right-of-Way Maintenance	Existing	Roads, line clearances	No	N/A: Existing program / not new program	N/A
Design and Construction	N/A	Transmission Line Rating Remediation	Existing	Transmission lines	No	N/A: Existing program / not new program	N/A
Design and Construction	SH-1	Covered Conductor	New	Conductor	Yes	Install at least 96 circuit miles of covered conductor in HFRA	Availability of material and design, engineering, and construction resources
Design and Construction	SH-2	Evaluation of Undergrounding in HFRA	New	Conductor	No	Conduct evaluation of undergrounding for HFRA	Management judgement
Design and Construction	SH-3	Composite Poles and Crossarms	New	Poles and crossarms	Yes	Install at least 1,100 composite poles	Circuit miles of covered conductor installed and material availability
Design and Construction	SH-4	Branch Line Protection Strategy	New	Fuses and Fuse Savers	Yes	Install at least 7,500 CLF in HFRA locations	Forecast included in GSRP
Design and Construction	SH-5	Remote Controlled Automatic Reclosers Installations	New	Remote Automatic Reclosers	Yes	Install at least 50 new RARs	Expansion of branch line segments for de-energization
Design and Construction	SH-6	Remote Controlled Automatic Reclosers Setting Updates	New	Remote Automatic Reclosers	Yes	Update at least 150 existing RAR Settings	Forecast included in GSRP
Design and Construction	SH-7	Circuit Breaker Fast Curve	New	Relays and Substation Automation	Yes	1) Develop engineering plan to upgrade remaining CB relays and update settings 2) Conduct CB upgrades and setting updates according to plan	Further assessment of remaining CB relays requires each unit to be reviewed
Inspection and Maintenance	IN-1	Distribution Enhanced Overhead Inspections and Remediation in HFRA	New	Circuits	No	1) Complete visual inspection of all distribution circuits in HFRA before 5/31 2) Remediate all conditions that create a fire risk in accordance with CPUC requirements	Assets are identified in SAP with a high fire indicator
Inspection and Maintenance	IN-2	Transmission Enhanced Overhead Inspections and Remediation in HFRA	New	Circuits	No	1) Complete visual inspection of all transmission circuits in HFRA before 5/31 2) Remediate all conditions that create a fire risk in accordance with CPUC requirements	Assets are identified in SAP with a high fire indicator
Inspection and Maintenance	IN-3	Quality Oversight / Quality Control of EOI	Existing	Transmission & Distribution Structures	No	1) Perform quality review on approximately 7,500 Transmission and Distribution structures in HFRA based on EOI inspections	Assets are identified in SAP with a high fire indicator
Inspection and Maintenance	IN-4	Infrared Inspection of energized overhead distribution facilities and equipment	New	Circuit Lines	Yes	1) Inspect 50% of overhead circuit lines in HFRA 2) Remediate conditions as required based on inspection results	Forecast included in GSRP

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SB 901 Category	SB 901 Activity Identifier	Activity/Program	Existing or New Work	Asset Addressed (Ex. lines, poles, etc.)	Previously Included in RAMP?	Evaluation Metric	Assumptions Underlying Metric
Inspection and Maintenance	IN-5	Infrared Inspection, Corona Scanning, and High Definition imagery of energized overhead Transmission facilities and equipment	New	Circuit Lines	No	1) Complete IR, Corona, and HD image scanning of all overhead transmission lines in HFRA that are loaded to 40% of rated capacity or higher 2) Integrate remediation with EOI activities	Management judgement
Inspection and Maintenance	N/A	AGP – Drive by of overhead Distribution facilities and equipment	Existing	Overhead Distribution equipment and above ground underground equipment	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	Detailed inspection of Transmission facilities and equipment	Existing	Above ground and underground Transmission equipment	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	IPI – Intrusive pole inspections to identify rot and decay	Existing	Wood Distribution and Transmission/Distribution wood poles	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	ODI – Detailed inspections of Distribution overhead facilities and equipment	Existing	Overhead Distribution equipment and above ground underground equipment	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	Performance of joint patrols with fire agencies	Existing	Conductor, poles, towers and equipment	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	Pole Brushing	Existing	Conductor, poles, equipment	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	Pole Loading Program	Existing	Wood, composite, Light Weight Steel poles	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	Substation Inspection and Maintenance	Existing	Distribution Relays	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	N/A	Supplemental inspections of HFRA	Existing	Conductor, poles, towers and equipment	No	N/A: Existing program / not new program	N/A
Inspection and Maintenance	VM-1	Hazard Tree Mitigation program (HTMP)	New	Conductor, poles, equipment	Yes	1) Perform at least 125,000 tree-specific threat assessments in HFRA 2) Perform at least 7,500 risk-based tree removals or mitigations in HFRA	Threat assessments derived from an anticipated production rate for 2019 Risk-based removal forecast from GSRP
Inspection and Maintenance	VM-2	Expanded Pole Brushing	New	Conductor, poles, equipment	No	1) Inspect all poles that require 10 feet of radial brush clearance at the base of the pole (at least 25,000) 2) Clear brush as necessary to achieve 10 feet of clearance	Based on acceleration of existing program
Inspection and Maintenance	VM-3	Expanded clearance distances at time of maintenance	New	Conductor, poles, equipment	No	Obtain tree-to-line clearance distance of 12 feet, as achievable, in HFRA at time of maintenance for line voltages of 2.4kV to 69kV	Pursuant to D.17-12-024, pp. 100-102, 12' is a CPUC recommendation
Inspection and Maintenance	VM-4	DRI quarterly inspections and removals	Existing	Conductor, poles, equipment	No	1) Perform all quarterly DRI inspections. 2) Remove identified dead, dying, or diseased trees in accordance with SCE's vegetation management program	Based on DRI program inspection cadence
Inspection and Maintenance	VM-5	LiDAR Inspections of Transmission	New	Conductor, poles, equipment	No	LiDAR inspect at least 1,000 conductor miles in HFRA (results from LiDAR inspections will be used to inform of subject trees assessed under the Hazard Tree Mitigation program)	Management judgement
Operational Practices	OP-1	Annual SOB 322 Review	Existing	N/A	No	Review and update SOB 322 to reflect lessons learned from past elevated fire weather threats and integrate, where applicable, new and improved data from its situational awareness resources	N/A
Operational Practices	OP-2	Wildfire Infrastructure Protection Team Additional Staffing	New	N/A	No	Hire one additional Meteorologist	Based on GSRP
Operational Practices	PSPS-1	De-Energization Notifications	New	N/A	Yes	1) Notify applicable public safety agencies and local governments of possible de-energization 2) Notify CalOES through the State Warning Center of possible de-energization 3) Notify the CPUC of possible de-energization 4) Enhance EONS to include in-language messages	Based on GSRP

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SB 901 Category	SB 901 Activity Identifier	Activity/Program	Existing or New Work	Asset Addressed (Ex. lines, poles, etc.)	Previously Included in RAMP?	Evaluation Metric	Assumptions Underlying Metric
Response and Recovery	N/A	PSPS/De-energization Protocol Support Costs	New	N/A	Yes	Line Patrols, Customer Call Center support, Mobile Generator Deployment, Community Outreach Vehicles	Based on GSRP
Situational/Conditional Awareness	SA-1	Additional Weather Stations	New	Weather stations	Yes	Install at least 315 Units in HFRA	Reduced GSRP forecast pursuant to supply chain constraints
Situational/Conditional Awareness	SA-2	Fire Potential Index Phase II	New	N/A	Yes	Enhance capabilities of FPI by increasing granularity, adding historical climatology data, and expanding to cover all of SCE's service territory	Based on GSRP
Situational/Conditional Awareness	SA-3	Additional HD Cameras	New	HD Cameras	Yes	Install at least 62 cameras on 31 Towers to monitor HFRA	Forecast included in GSRP
Situational/Conditional Awareness	SA-4	High-Performing Computer Weather Modeling System	New	N/A	Yes	Procure and install High Performance Computing Cluster weather and fuels modeling system	Based on GSRP
Situational/Conditional Awareness	SA-5	Develop Asset Reliability & Risk Analytics Capability	New	N/A	No	Complete implementation of the Asset Reliability and Risk Analytics tools	Based on GSRP

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Appendix C

List of SCE Design, Engineering and Construction Standards

(as of Jan 18, 2019)

SCE Design, Engineering and Construction Standards List

As of Jan. 18, 2019

Distribution Overhead Construction Standards (DOH)
Distribution Operations and Maintenance Policies and Procedures (DOM)
Distribution Underground Construction Standards (DUG)
Electrical Service Requirements (ESR)
Distribution Design Standards (DDS)
Underground Structures Standards (UGS)
Pole Loading Manual (PLM)
Applicant Distribution Design Standards (ADS)
Distribution Substation Planning Criteria and Guidelines Document (DSP)
Electrical Construction Station (ECS)
Electrical Design Station Layout (EDSL)
Electrical Design Station Wiring (EDSW)
Contact Diagrams for Control and Instrument Switches (M-4505)
Internal Wiring Diagrams for Relays (M-6379)
Substation Operations and Maintenance Policy and Procedures (SOM)
Electrical Construction Station (ECS 3-A)
Electrical Construction Station (ECS 3-B)
Electrical Construction Station (ECS 3-C)
Electrical Design Station Wiring (EDSW-A)
Electrical Design Station Wiring (EDSW-B)
Electrical Design Station Wiring (EDSW-C)
Transmission Overhead Construction Standards (TOH)
Transmission Underground Construction Standards (TUG)
Transmission Design and Right-of-Way Manual (TDR)
Transmission Operations and Maintenance Policies and Procedures (TOM)
Transmission Overhead Construction Standards (TOH)
Transmission Planning Criteria (TPC)
Transmission System Protection Philosophy & Relay Setting Guidelines
Transmission Telecommunications Construction Standards (TTCS)
Transmission Telecommunications Planning and Design Manual (TTPD)
Subtransmission Planning Criteria and Guidelines
Subtransmission System Line Relay Criteria & Guidelines
Subtransmission System Protection Philosophy & Relay Setting Guidelines

Appendix D

Fast Growing Trees

Tree Species Names and Growth Rates

Species Name	Growth Rate
Acacia-Bbw	Medium
Ailanthus	Fast
Albizzia	Medium
Alder, White	Medium
Almond	Medium
Ash	Fast
Aspen	Slow
Athel	Medium
Avocado	Medium
Bamboo	Fast
Banana	Slow
Bay	Slow
Birch	Slow
Bird of Paradise	Medium
Bottle	Slow
Bottlebrush	Sbw
Brisbane Box	Medium
Buckeye	Slow
Camphor	Medium
Carob	Medium
Carrotwood	Medium
Casuarina	Medium
Catalpa	Medium
Cedar	Slow
Century Plant	Slow
Cherry	Medium
Chinaberry	Medium
Citrus	Slow
Coral	Medium
Cottonwood	Fast
Cow Itch	Slow
Crape Myrtle	Slow
Cypress	Slow
Deodara	Slow
Dogwood	Slow
Elder, Box	Medium
Elderberry	Medium
Elm	Fast
Eucalyptus	Fast
Eugenia	Medium
Ficus	Medium
Fg	Medium
Fir	Slow
Floss, Silk	Medium
Ginkgo	Slow
Golden Rain	Slow
Grevillea	Fast
Hackberry	Medium
Jacaranda	Fast
Joshua	Slow
Juniper	Slow
Lemon	Medium
LiqAmber-Gum	Medium
Locust	Fast
Magnolia	Slow
Maple	Medium
Melaleuca	Medium
Mesquite	Medium
Mimosa	Slow
Monkey Puzzle	Slow
Mulberry	Fast
Myoporum	Slow
Oak	Slow
Oleander	Slow
Olive	Medium
Orange	Medium
Orchid	Medium
Other	Medium
Palm	Fast
Palo Verde	Slow
Pear	Medium
Pecan	Fast
Pepper	Fast
Persimmon	Medium
Pine	Medium
Pistache	Medium
Pistachio	Medium
Pittysporum	Medium
Plum	Medium
Podocarpus	Medium
Poplar	Fast
Privet	Medium
Redwood	Medium
Rubber	Medium
Salt Cedar	Medium
Sequoia	Slow
Spruce	Medium
Sumac	Medium
Sycamore	Fast
Tallow	Medium
Tulip	Fast
Unknown	Medium
Vine	Fast
Walnut	Fast
Willow	Fast
Yucca	Slow
Zelkova	Medium

Approximate Growth Rate:
(S} Slow: 0 to 3 feet Annually
(M) Medium: 3.1 to 6 feet Annually
(F) Fast: More than 6 feet Annually

Appendix E

SCE Field Workers, Support Personnel and Contract Crews

(as of Jan 18, 2019)

Distribution - Field Crews	**3976**	
Foreman Electl Crew	157	Trained resources to work on SCE's high voltage, overhead and underground distribution system. They perform inspections and maintenance, assess system damages, make repairs to restore service, and serve as SCE's first responders.
Journeyman Lineman	554	
Troubleman	200	
Splcr Sr Cble	18	
Streetlight Repairman	27	
Lineman, Apprentice	207	Serve as compliments to field crews, training under the direct supervision of Journeyman Lineman and Foreman.
Groundman	352	Compliments the field crews as part of their training, working in direct supervision of the Journeyman Lineman and Foreman.
Sup, Field	77	Provides management, field safety, and operational oversight and technical support for field crews in each of the SCE's district locations.
Sup, General Foreman	69	
Form Troubleman Training	4	
PSPECs	103	Coordinates outages, laying out jobs and customer contacts
Sup, Project General Sup	38	Oversees contract crews site training, safety
Field Service Rep	138	1st responders - identify problems and stand by to ensure site is secure
Meter Technicians	99	
MGR - Metering Field Ops	3	
Sr Sup, Ops	27	
Sr Sup, Engy Del / Distrib	17	
Planners/Designers	680	Damage assessments - support the field crews by conducting assessments, order material, and other admin support
Construction Material Coordinator	56	
Construction/Maintenance Clerk/Specialist/Supervise	257	
Supervise Construct/Maint Acct	50	
Meter Support Specialist	7	
Spclst Fld Svcs Support	4	
Inspector-Surveillance	32	
Contractors	800	Avg 200 crew (4-Man Crew)
Transmission, Substations & Operations - Field Crews	**1353**	
Journeyman Lineman	102	Trained resources to work on SCE's high voltage, overhead and underground distribution system. They perform inspections and maintenance, assess system damages, make repairs to restore service, and serve as SCE's first responders.
Splcr Sr Cble	33	
Patrolman Sr	32	
Right of Way Equipment Operator	5	
Safety & Environmental Specialist	2	
Groundman	11	Compliments to field crews, training under the direct supervision of Journeyman Lineman (i.e. JM Battery Electricians, Construction Electricians, Substation Cable Splicers) and Foreman.
Lineman, Apprentice	65	
Apprentice Substn Elctrcn	30	
Electn Appr Battry	3	
Electn Appr Cnstrn	6	
Hlpr Electl Constr	20	
Splcr Appr Subs Cable	3	
Sup, General Foreman	13	Provides management, field safety, and operational oversight and technical support for maintenance & test crews.
Substation Electrician	154	
Sup, Apparatus	5	
Sup, Cnstrn	12	
Sup, Substn Ops	5	
Sup, Tech Spec	1	
Supr Road R/W	4	
Sr Sup, Maint / Test	45	
PSPECs	9	Coordinates outages, laying out jobs and customer contacts
Electn Battry	6	1st responders - identify problems, stand by to ensure site is secure, analyze grid flow, and support construction (i.e. civil)
Electn Constrn	44	
Form Dstrbn Aprts	16	
Mech Structural	17	
Operator, System	131	
Opr Substation	112	
Opr Trainee	5	
Power Sys Ops Specialist	45	
Power Systems Planner 3	4	
Splcr Subs Cable	8	
Techn Dstrbn Aprts	42	
Techn Electl Aprats Test/Test A	4	
Technician, Test	92	
Technician, Test Supervising	56	
Transformer Helper	6	
Transformer Specialist	15	
Transformer Specialist Foreman	4	
Utilityman Terrtrl	16	
Welder Cnstrn	3	
Working Foreman - CFF	6	
Working Form CFF Elect Const	4	
Materials Mgmt, Advisor	12	Damage assessments - support the field crews by conducting assessments, order material, and other admin support
Planners	81	
Contractors	64	Avg 16 crews (4-Man Crew)
Telecom	13	
Form Cable	8	1st responders - identify problems, stand by to ensure site is secure, analyze grid flow, and construction
Planner	1	
Trans Telecom PSPEC	4	
Grand Total	**5342**	

Appendix F

Comparison of WMP to 2018 Fire Prevention Plan

Program/Strategy	Comparison of WMP to Prior Fire Prevention Plan
OPERATIONAL PRACTICES	
Red Flag Warning Program	WMP / FPP
Operation of Sub-Transmission Voltage Lines - Red Flag	WMP / FPP
Operation of Distribution Voltage Lines - Red Flag	WMP / FPP
Recloser Restrictions (e.g., Fast Curve Settings)	WMP / FPP
Aircraft Operations	WMP / FPP
Public Safety Power Shut-Off Protocol & Notifications	WMP / FPP
Monitoring and Enhancements	WMP Only
Wildfire Infrastructure Protection Teams	WMP / FPP
PLANS FOR INSPECTIONS OF ELECTRICAL INFRASTRUCTURE	
Distribution Inspection and Maintenance Program	WMP / FPP
Overhead Detail Inspection Program	WMP / FPP
Annual Grid Patrol	WMP Only
Underground Detail Inspection Program	WMP Only
Distribution Maintenance	WMP Only
Transmission Inspection and Maintenance Program	WMP / FPP
Substation Inspection and Maintenance	WMP Only
Intrusive Pole Inspection Program	WMP / FPP
Pole Loading Program	WMP / FPP
Quality Oversight / Quality Control	WMP Only
High Fire Risk Area (HFRA) - Enhanced Overhead Inspections	WMP Only
HFRA - Infrared Inspection Program	WMP / FPP
SYSTEM HARDENING (SAFETY, RELIABILITY & RESILIENCY)	
Overhead Conductor Program	WMP / FPP
Deteriorated Pole Program	WMP Only
Wildfire Covered Conductor Program	WMP / FPP
Underground Conductor	WMP / FPP
Poles	WMP Only
Protection and Isolation	WMP / FPP
Alternative Technologies	WMP / FPP
VEGETATION MANAGEMENT PLAN	
Compliance: NERC FAC-003-4	WMP / FPP
Compliance: CPUC General Order 95, Rule 35	WMP / FPP
Compliance: Public Resource Code 4292	WMP / FPP
Compliance: Public Resource Code 4293	WMP / FPP
Weed Abatement Program	WMP / FPP
Enhanced Vegetation Management Activities in HFRAs	WMP / FPP
Operation Santa Ana	WMP / FPP
Hazard Tree Removals	WMP / FPP
Pole Brushing	WMP / FPP
Expanded Clearance Distances at Time of Maintenance	WMP Only
DRI Quarterly Inspections and Tree Removals	WMP Only
LiDAR Inspection Program	WMP / FPP
PROTOCOLS ON SITUATIONAL AWARENESS	
HFRA - Weather Stations	WMP / FPP
HFRA - Meteorological Resources	WMP / FPP
HFRA - Deployment and Support of Situational Awareness Cameras	WMP / FPP

PROTOCOLS ON PUBLIC SAFETY POWER SHUT-OFF	
Strategy to Minimize Public Safety Risk...	WMP / FPP
Strategy to Provide for Safe and Effective Re-energization…	WMP / FPP
SCE Standards Relative to Customer Communications…	WMP / FPP
Protocols for Mitigating the Public Safety Impacts…	WMP / FPP

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Implement Electric Utility Wildfire Mitigation Plans Pursuant to Senate Bill 901 (2018).	R.18-10-007

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to the Commission's Rules of Practice and Procedure, I have this day served a true copy of **SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) 2019 WILDFIRE MITIGATION PLAN** on all parties identified on the attached service list(s) R.18-10-007. Service was effected by one or more means indicated below:

☒ Transmitting the copies via e-mail to all parties who have provided an e-mail address.

☒ Placing the copies in sealed envelopes and causing such envelopes to be delivered by U.S. Mail to the offices of the Assigned ALJ(s) or other addressee(s).

ALJ Peter V. Allen
ALJ Sarah R. Thomas
California Public Utilities Commission
Division of Administrative Law Judges
505 Van Ness Avenue
San Francisco, CA 94102

Executed on **February 6, 2019,** at Rosemead, California.

/s/ Edith Leon
Edith Leon
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CPUC Home

CALIFORNIA PUBLIC UTILITIES COMMISSION
Service Lists

PROCEEDING: R1810007 - CPUC - OIR TO IMPLEM
FILER: CPUC
LIST NAME: LIST
LAST CHANGED: FEBRUARY 5, 2019

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ATTACHMENT 31

Response (amended) to data request CalAdvocates-LIB-A2506017-016, October 24, 2025

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Liberty Utilities (CalPeco Electric) LLC

A.25-06-017
WEMA

The Public Advocates Office

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Requesting Party:	Public Advocates Office
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Date Received:	September 18, 2025
Due Date:	October 2, 2025
Extension Granted:	October 6, 2025
Response Date:	October 6, 2025
Amended Response Date:	October 24, 2025

In Liberty's testimony (LIB – 03 at 23), it states that:

> *In 2020, Liberty deployed Liberty's journeymen linemen and engaged a contractor to perform an asset survey and detailed inspection of all overhead distribution and transmission assets. This survey included detailed visual inspections of the condition of conductors, poles, and other overhead equipment, regardless of when the equipment had last been inspected.*
>
> *Liberty performed this survey to update its inventory for accuracy via photographs and GPS coordinate data, to assess the condition of its assets, to plan remediation projects, and to better assess risks in its electric system. An equipment database was created to store the asset information. During this survey, Liberty performed more than 22,000 detailed inspections of overhead assets and identified a substantial number of GO 95 repairs.*

CA-07-1462

REQUEST NO. 1:

Provide an Excel file that contains **all corrective work** created by the 2020 asset survey affecting the Topaz 1261 circuit.

Each corrective work order should be in a row. The file should contain the following columns of data:

a) Structure number
b) Work Order Number
c) Notification Number (if applicable)
d) Equipment Number
e) Inspection Date
f) Equipment Type
g) HFTD/HFRA Tier
h) Priority
i) Ignition Risk (Y/N)
j) Date Created
k) Due Date
l) Revised Due Date (if applicable)
m) Priority Change (if applicable)
n) Reason for Change (if applicable)
o) Date Completed
p) Latitude in degrees
q) Longitude in degrees

RESPONSE:

Liberty objects to this Question as vague and ambiguous. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

Please note that the 2020 asset survey also functioned as a detailed inspection on the Topaz 1261 Circuit. Liberty is producing the data requested by this Question in attachment *CalAdvocates-LIB-A2506017-016-Q1.xlsx.* As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records. Please see Liberty's responses to CalAdvocates-LIB-A2506017-0015, Questions 5-6.

REQUEST NO. 2:

a) What criteria or risk-ranking methodology did Liberty use to prioritize corrective work orders after the 2020 asset survey?
b) Have all corrective work orders identified in 2020 asset survey been completed?
c) If the answer to (b) is "yes," please provide documentation supporting your response.
d) If the answer to (b) is "no," please provide an Excel file of all open corrective work orders identified in the 2020 asset survey affecting the Topaz 1261 circuit.

Each corrective work order should be in a row. The file should contain the following columns of data:

a. Structure number
b. Work Order Number
c. Notification Number (if applicable)
d. Equipment Number
e. Inspection Date
f. Equipment Type
g. HFTD/HFRA Tier
h. Priority
i. Ignition Risk (Y/N)
j. Date Created
k. Due Date
l. Revised Due Date (if applicable)
m. Priority Change (if applicable)
n. Reason for Change (if applicable)
o. Date Completed
p. Latitude in degrees
q. Longitude in degrees

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Subject to and without waiving its objections, Liberty responds as follows:

a) After the 2020 asset survey, Liberty generally prioritized corrective work orders by their priority level, accounting for location within HFTDs.
b) Give the larger number of issues identified from the asset survey and its systemwide nature, as of today, Liberty is still addressing small number of corrective work orders identified during the asset survey.
c) N/A
d) Please refer to attachment *CalAdvocates-LIB-A2506017-016-Q1.xlsx*, which includes corrective work identified on the Topaz 1261 Circuit as part of the 2020 asset survey, whether they have been addressed or remain open. As described in *Liberty-03: Prudence of Operations,* Liberty transitioned to Fulcrum for detailed inspection records in 2020 and has continued to refine its data collection process since that time. Liberty has included select data fields that Liberty understands to be responsive to this Question, to the extent available in Liberty's records. Please see Liberty's responses to CalAdvocates-LIB-A2506017-0015, Questions 5-6.

REQUEST NO. 3:

At the time of the Mountain View Fire:

a) How did Liberty track the progress of corrective work order completions identified in the 2020 asset survey.
b) Did Liberty have a written policy governing the management of asset surveys?
c) If the answer to (b) is "yes," please identify and produce a copy of that policy.

d) If the answer to (b) is "no," please explain why not.
e) What quality assurance processes did Liberty use to verify inspection results?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) Liberty generally tracked completed repair work in the dynamic digital data collection tool used during the inspections. In approximately 2023, a dashboard was created in an asset tracking application to track the progress of corrective work. In early 2025, Liberty transitioned to using another asset tracking application, also equipped with a dashboard.
b) The 2020 system survey was the first undertaken by Liberty to support its WMP initiatives by documenting the condition of its assets and updating its inventory. Liberty did not have a formal policy for this survey and Liberty used qualified inspectors to complete the survey, overseen by experienced operations personnel.
c) N/A
d) See Liberty's response to subpart (b).
e) Please refer to Liberty's responses to CalAdvocates-LIB-A2506017-004, Questions 4(d) and 8.

REQUEST NO. 4:

a) What prompted Liberty to conduct a systemwide asset survey in 2020?
b) Was the survey required or recommended by a regulatory authority?
c) Did Liberty's internal assessments identify risks or deficiencies prior to 2020 that led to the survey?
d) Were external events (e.g., storms, wildfire concerns, equipment failures) a factor in the decision?

AMENDED RESPONSE:

a) As referenced in *Liberty-03: Prudence of Operations* (at p. 23) and in Liberty's response to Question 3(b)-(d) of this set of data requests, the 2020 system survey was undertaken by Liberty to support its WMP initiatives by documenting the condition of its assets and updating its inventory.
b) Liberty is not aware that the survey was required or recommended by a regulatory authority. See Liberty's response to subpart (a).
c) No single event or risk was the impetus for the 2020 system survey. See Liberty's response to subpart (a).
d) No single event or risk was the impetus for the 2020 system survey. See Liberty's response to subpart (a).

REQUEST NO. 5:

a) On what exact date did Liberty begin the 2020 asset survey?
b) On what exact date did Liberty complete the 2020 asset survey?
c) Were inspections conducted continuously during 2020 or in specific time blocks?

d) Did seasonal conditions (e.g., weather, fire season) affect when inspections were performed?
e) How did Liberty determine the survey would cover all overhead distribution and transmission assets?
f) Did the survey involve visual inspection only, or were diagnostic tools or measurements also used?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Subject to and without waiving its objections, Liberty responds as follows:

a) According to inspection records available in Fulcrum, the first inspection that took place on Liberty's electric system in 2020 occurred around April 9.
b) According to inspection records available in Fulcrum, the last inspection that took place on Liberty's electric system in 2020 occurred around December 18.
c) Liberty objects to the terms "continuously" and "specific time blocks" as vague and ambiguous. Liberty conducted inspections between approximately April and December 2020.
d) Liberty objects to this subpart as vague and ambiguous, including its use of the term "seasonal conditions." As with any other field operations, inspections may be impacted from time to time by severe weather conditions such storms or snow. The system survey was completed in 2020. Please refer to Liberty's response in subpart (c).
e) Please refer to Liberty's response to Question 4 of this set of data requests.
f) The survey involved visual inspection.

REQUEST NO. 6:

a) Did Liberty perform intrusive inspections on every pole in the Topaz 1261 Circuit in 2013, or only a subset?
b) If only a subset, what criteria were used to select which poles received intrusive inspections?
c) Please provide the total number of poles on the Topaz 1261 Circuit in 2013 and the number actually inspected.
d) Were there any poles on the Topaz 1261 Circuit that had never received an intrusive inspections prior to 2020?
e) Did Liberty follow any technical standards or guidelines in 2013 to classify poles as "Restorable," "Non-Restorable," or "Hazard"?
f) If the answer to (e) is "yes," please identify and produce a copy of any technical standards or guidelines.
g) How many poles were classified under each category in 2013?

AMENDED RESPONSE:

Liberty objects to this Question as vague and ambiguous as framed. Liberty further objects to this Question as unduly burdensome to the extent it seeks information not maintained by Liberty in the ordinary course of business. Liberty further objects to this Question to the extent it seeks information from prior to the start of Liberty's operations in approximately 2011, when it

purchased the California utility system from NV Energy. Subject to and without waiving its objections, Liberty responds as follows:

a) As Liberty schedules intrusive pole inspections on a circuit basis, the entire Topaz 1261 Circuit was inspected by Liberty's intrusive pole inspection contractor in 2013.
b) N/A
c) Due to limitations in Liberty's historic GIS information, the passage of time, pole replacements and the redesign that occurred as part of the Topaz Line Rebuild Project, Liberty is unable to provide the precise total number of poles on the Topaz 1261 Circuit in 2013. As indicated in *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, attached to Liberty's response to CalAdvocates-LIB-A2506017-001, Question 4, Liberty's contractor conducted intrusive inspections on 1,463 poles on the Topaz 1261 Circuit in 2013.
d) Please refer to Liberty's responses to subparts (a) and (b) of this set of data requests.
e) Please refer to Liberty's response to CalAdvocates-LIB-A2506017-0015, Question 11 and attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* thereto.
f) Please refer to Liberty's response to CalAdvocates-LIB-A2506017-0015, Question 11 and attachment *CONFIDENTIAL-Liberty Intrusive Pole Inspection Guidance.pdf* thereto.
g) Please refer to *CalAdvocates-LIB-A2506017-001-Q4.xlsx*, attached to Liberty's response CalAdvocates-LIB-A2506017-001, Question 4, which contains tabs listing the poles classified under each category in 2013 on the Topaz 1261 Circuit.