ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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November 1, 2023

VIA ELECTRONIC FILING

Utah Public Service Commission
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84114

Attention: Gary Widerburg
Commission Administrator

RE: **Docket No. 23-035-21** – Rocky Mountain Power's Service Quality Review Report

In compliance with the Commission's June 11, 2009 order in Docket No. 08-035-55 and December 20, 2016 order in Docket Nos. 13-035-01 and 15-035-72, and pursuant to the requirements of Rule R746-313, PacifiCorp d.b.a. Rocky Mountain Power ("RMP" or "Company") submits the Service Quality Review Report for the period January through June, 2023.

The Company respectfully requests that all formal correspondence and requests for additional information regarding this filing be addressed to the following:

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Informal inquiries may be directed to Jana Saba at (801) 220-2823.

Sincerely,

Joelle Steward
Senior Vice President, Regulation & Customer and Community Solutions

Enclosures

CERTIFICATE OF SERVICE

Docket No. 23-035-21

I hereby certify that on November 1, 2023, a true and correct copy of the foregoing was served by electronic mail to the following:

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UTAH
SERVICE QUALITY
REVIEW

January 1 – June 30, 2023
Report

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Executive Summary

Rocky Mountain Power (RMP) developed its Customer Service Standards and Service Quality Measures nearly 20 years ago. The standards were developed to demonstrate to customers that the Company is serious about serving them well and willing to back its commitments with cash payments in cases where the Company falls short. The standards also help remind employees about the importance of good customer service. The Company developed these standards by benchmarking its performance against relevant industry reliability and customer service standards. In some cases, Rocky Mountain Power has expanded upon these standards. In other cases, largely where the industry has no established standard, Rocky Mountain Power developed its own metrics, targets, and reporting methods.

Rocky Mountain Power is on target to deliver favorable network performance as measured by System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). The Company extended its year-on-year improvement achieved by completion of reliability projects and efforts that have been put in place. In Docket No. 20-035-22, the Division of Public Utilities (DPU) reviewed Rocky Mountain Power's 2019 service quality and recommended the Public Service Commission of Utah (Commission) establish a work group to review RMP's reliability baseline standards related to SAIDI and SAIFI and make recommendations. The Commission accepted this recommendation and directed RMP and DPU to convene a work group, open to interested parties, to examine RMP's reliability baseline standards and to make recommendations. In accordance with the Commission directive, the parties convened a workgroup that met to discuss new baseline performance standards, which are reflected in this report.

Even with these results, Rocky Mountain Power recognizes the continued impact of any outage to its customers. There were two major events experienced during this reporting period for Utah customers. While major events represent events that exceed reasonable design and operational limits, Rocky Mountain Power recognizes the significant negative impacts to our customers, communities, and other important stakeholders.

Rocky Mountain Power's goal continues to be supplying safe, reliable power to Utah. The Company is dedicated to learning from past service experiences and continuing to make improvements to operations and customer service to ensure it meets Utah's needs.

Below is a summary of RMP's mid-year 2023 performance serving the customers of Utah.

Request for Changes to Service Quality Review Report

In accordance with Commission Rule R746-313-7(3)(g), the Service Quality Review report contains two proposed changes for which RMP requests Commission approval to adopt in future reports. First, the Company requests a modification to the qualification of major events by subdividing the state of Utah into five reliability reporting areas. The Commission approved the current methodology for establishing major event thresholds in its May 30, 2013, Order in Docket No. 13-035-01. The change is described in detail in Section 1.3 under the section titled Major Event Threshold Proposed Change.

Second, RMP requests to modify the Service Quality Review reporting to reflect activities associated with RMP's Wildfire Mitigation Plan[1]. The company has implemented an operational adjustment to the relay settings for protective devices to mitigate wildfire risk that may impact reliability. Therefore, RMP requests the impacts of this operational adjustment be excluded from underlying SAIDI values. The change is described in detail in Section 1.6 under the section titled Elevated Fire Risk Settings Impact on Reliability.

[1] *In the Matter of Rocky Mountain Power's 2023 Wildland Fire Protection Plan*, Docket No. 20-035-44.

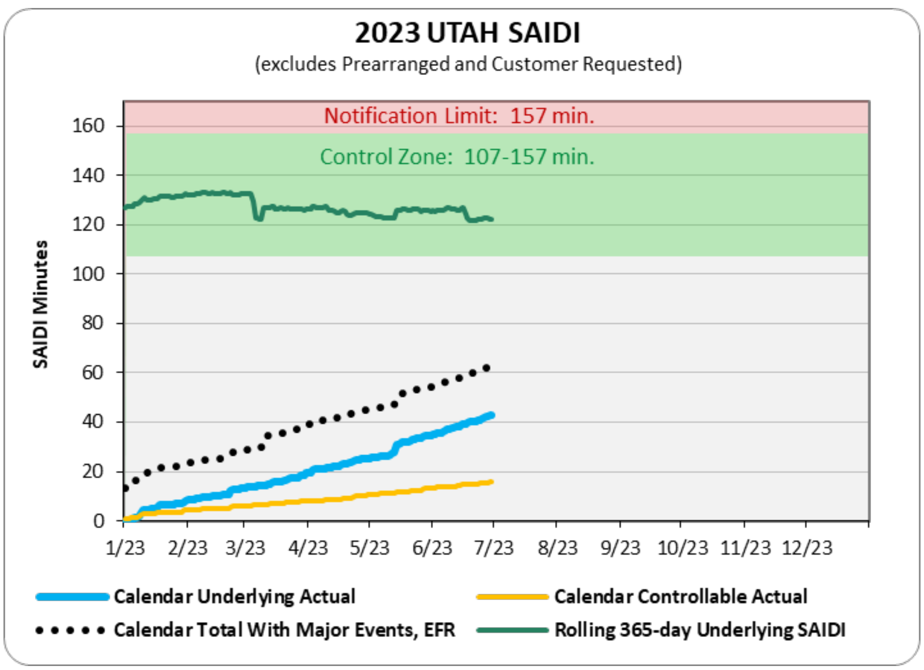
1 Reliability Performance

For the reporting period, the Company's performance is on target to meet the Commissions baseline performance ranges for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). For SAIDI the baseline range is 107-157 minutes, with a notification limit set at 157 minutes. For SAIFI the baseline range is 0.9-1.2 events, with a notification limit of 1.2 events. Graphics in sections 1.1 and 1.2 provide an overview of the biannual underlying and controllable results as they corelate to the control zones and notification limits. In addition, section 1.3 provides details regarding major events and significant events customers experienced.

1.1 System Average Interruption Duration Index (SAIDI)

Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below and in 1.2. The total value includes underlying and major events.

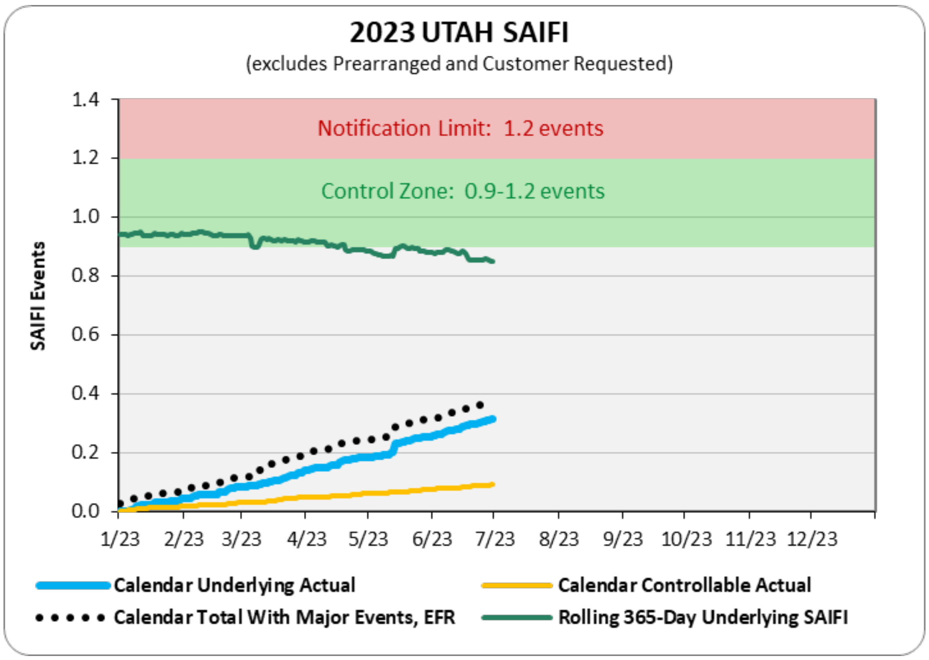
SAIDI	Reporting Period
Total[2]	63
Underlying	43
Elevated Fire Risk (EFR)[3]	0
Controllable Distribution	16



[2] Total SAIDI = Underlying + Elevated Fire Risk (EFR) + Major Events.
[3] Elevated Fire Risk (EFR) settings are more sensitive settings implemented to reduce the risk of wildfires during fire season as described in Section 1.6.

1.2 System Average Interruption Frequency Index (SAIFI)

SAIFI	Reporting Period
Total	0.374
Underlying	0.315
Elevated Fire Risk	0
Controllable Distribution	0.092



1.3 Major and Significant Event Days

In the current reporting period, we observed two major events[4] and one significant event day.[5] Rocky Mountain Power incorporates regional major events into our reports to account for statistical outliers that may not be apparent at the state level. However, there were no regional major events during this period that did not coincide with a state-level major event. Therefore, only state-level major events are represented in this report. It's important to note that regional major events may not always escalate to the level of a state-level major event, and those would be reflected in our underlying metrics.

[4] A Major Event (ME) is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value (Reliability Standard IEEE 1366-2012) based on the 2.5 beta methodology. The values used for the reporting period are shown below:

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2023	1,009,615	4.31	4,352,711

[5] Significant event days are 1.75 times the standard deviation of the company's natural log daily SAIDI results (by state or appropriate reliability reporting region).

Major Events				
Date	**Cause**	**Status**	**Docket**	**SAIDI**
January 1-3, 2023	Snowstorm	Approved	23-035-04	15.08
March 10-11, 2023	Loss of Transmission and Windstorm	Approved	23-035-19	4.62
			Total	**19.7**

January 1-3, 2023

A potent weather system interacted with an atmospheric river over northern and central Utah, resulting in heavy snowfall across the Salt Lake Valley districts and higher elevations of the Park City and American Fork districts on December 31st and January 1, 2023. Snowfall totals varied, with valley locations receiving 8-12 inches and bench locations seeing 12-16 inches, while the Sundance ski resort area in the American Fork district recorded over 50 inches. The high-density snowfall led to substantial damage, with tree limbs breaking under the weight of the snow and 50-foot pine trees toppling near the Sundance ski resort. The damage to Rocky Mountain Power facilities resulted in 32,334 customers experiencing sustained service interruptions.

March 10-11, 2023

From March 10th to 11th, 2023, Utah experienced a severe weather event due to an atmospheric river, causing strong winds and power outages. The situation was exacerbated by a car hitting a transmission pole, affecting approximately 15,000 customers. Despite the challenges, local line maintenance and vegetation crews were able to restore power, with most customers regaining service within three hours. The damage to Rocky Mountain Power facilities resulted in 27,347 customers experiencing sustained service interruptions.

Significant Events

Significant event days add substantially to year-on-year cumulative performance results; fewer significant event days generally result in better reliability for the reporting period while more significant event days generally mean poorer reliability results. During the period, one significant event day was recorded, which account for 3.5 SAIDI minutes, or about 8% of the reporting period's underlying 43 SAIDI minutes. This significant event was triggered by a loss of transmission.

Significant Event Days					
Dates	**Cause: General Description**	**Underlying SAIDI**	**Underlying SAIFI**	**% of Total Underlying SAIDI (43)**	**% of Total Underlying SAIFI (0.315)**
May 14, 2023	Loss of Transmission	3.45	0.029	8%	9.2 %
	TOTAL	**3.45**	**0.029**	**8%**	**11.3%**

Regional Major Events

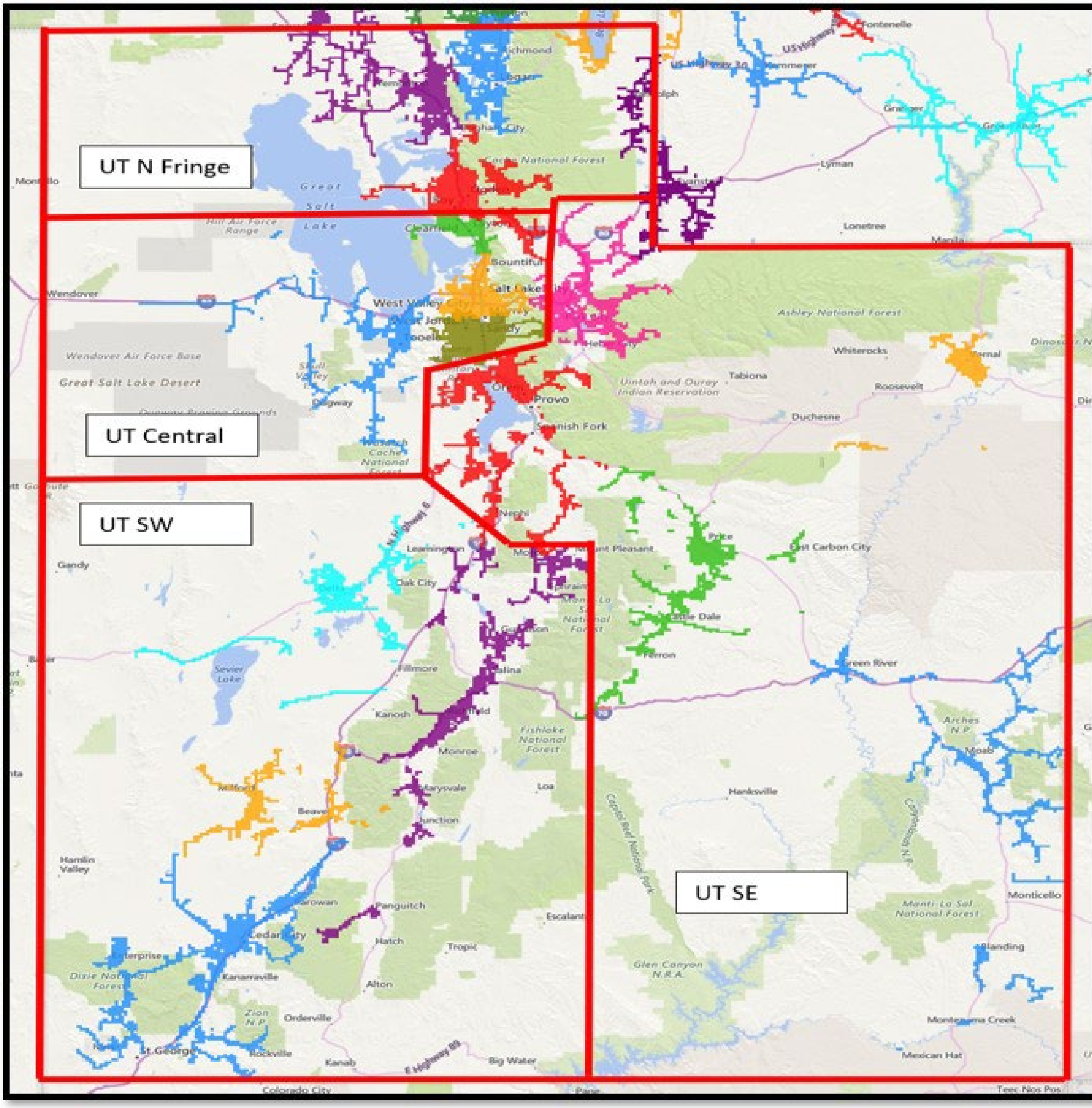
Beginning in 2020, Rocky Mountain Power began categorizing regions where outages in a diverse operating area can be identified as statistical outliers, which would otherwise be hidden by the statistical weighting of some districts. This is in accordance with IEEE Standard 1366-2012 which notes, "[the purpose of major event classification] is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events." Any regional major events that would be listed below are still included in the underlying metrics and are stated in this report for informational purposes.

Regional Major Events				
Date	**Cause**	**Status**	**Docket**	**SAIDI**
March 13-14, 2023	Loss of Transmission (Utah North Fringe – Smithfield Area)	N/A	N/A	3.20
			Regional SAIDI Impact	**14.77**
			State SAIDI Impact	**3.20**

Major Event Threshold Proposed Change

To improve identification of major events and to accurately represent the reliability performance at regional and State level, the company has subdivided the state of Utah into five major event reporting areas to ensure that major events are more equally represented in rural versus urban population areas by eliminating statistical anomalies that may occur in local areas. Statistically, events that exceed the threshold for major event day (TMED) are a result of stresses beyond what is normally expected. By capturing these events at a regional level, it would remove the statistical anomalies from these regions, and provide a more consistent representation of the electric reliability at the State and local level. The proposed reliability reporting areas, and their respective TMED values for 2023, are shown in the table below.

Reliability Reporting Area	Total Customer Count	Threshold for Major Day Event (TMED)	Customer Minutes Lost (CML)
Utah North Fringe	160,065	13.61	2,178,614
Utah Central	587,942	5.59	3,288,723
Utah Southeast	199,607	11.51	2,297,885
Utah Southwest	62,001	21.36	1,324,521
State of Utah	**1,009,615**	**4.31**	**4,351,095**



1.4 Restore Service to 80% of Customers within 3 Hours[6]

RESTORATIONS WITHIN 3 HOURS					
Reporting Period Cumulative = 72%					
January	February	March	April	May	June
56%	79%	79%	79%	60%	79%

[6] The company is currently trending behind the 80% target for restoration within 3 hours. However, it anticipates meeting the target by year end.

1.5 CAIDI Performance

The table below shows the average time, during the reporting period, for outage restoration. This augments previous reporting for the percent of customers whose power was restored within 3 hours of notification of an outage event and uses IEEE industry indices.

CAIDI (Average Outage Duration)	
Underlying Performance	137 minutes
Total Performance	168 minutes

1.6 Elevated Fire Risk Settings Impact on Reliability

As part of the company's Wildfire Mitigation Plan approved by the commission in 2020 (Docket No: 20-035-28), and recently updated and submitted to the commission for approval in 2023 (Docket No: 23-035-44), the company has implemented several operational adjustments to help mitigate wildfire risk. One of these adjustments includes modifications to relay settings for protective devices. Line protective devices, such as reclosers and breakers, are currently deployed on various transmission and distribution lines. When a line trips open due to fault activity, protective devices can be programmed to momentarily open, allow the fault to dissipate, then automatically reclose in an effort to test if the fault is temporary. If the fault is temporary, the line will re-energize resulting in limited impact to customers. If the fault persists (is not temporary) the recloser can remain open, known as “lock-out” state, until the line has been deemed ready to be re-energized. In general, this reclosing operation is beneficial because it reduces the number of sustained outages and improves customer reliability by quickly restoring service after detecting temporary faults. However, the reclosing function creates some degree of ignition risk because energy can be released if a fault is not temporary.

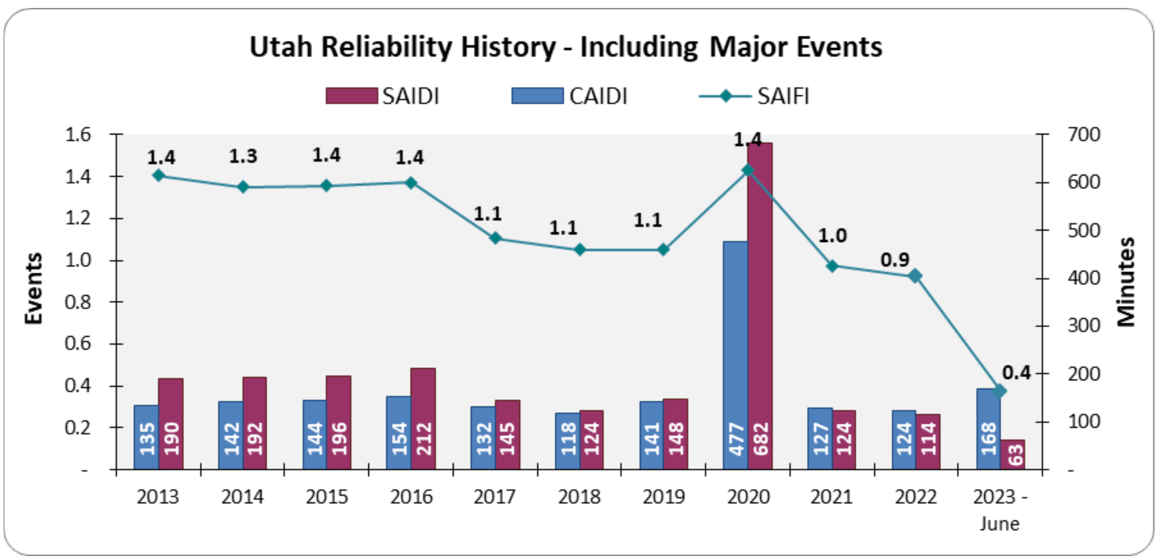
To reduce the risk of potential wildfires, the company has implemented more sensitive settings, referred to as Elevated Fire Risk Settings (EFR). The application of more sensitive settings can have a negative impact to customer reliability. The company is monitoring the impact of these modifications and has documented all outages in circuits with EFR settings separately. Because the company is purposely reducing system reliability in an effort to prevent wildfire risk, the outages in circuits with EFR-enabled settings are presented separately from underlying SAIDI values. The company continues to monitor the impact of these settings to ensure a balance between fire risk mitigation and customer reliability.

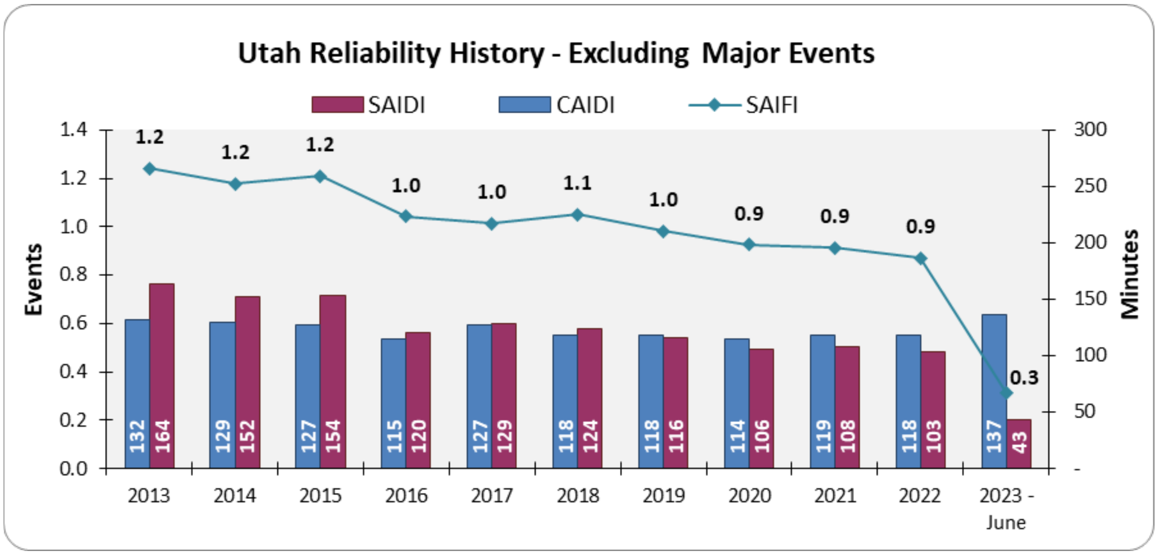
2 Reliability History

Historically the Company has improved reliability as measured by SAIDI and SAIFI reliability indices; at the same time outage response performance (CAIDI) has varied from year to year with no specific trend apparent. The SAIDI and SAIFI trends are further evidenced in Sections 2.2 and 2.3, where 365-day rolling performance trends are depicted. These indices demonstrate the efficacy of the long-term improvement strategies targeted toward reducing the frequency of interruptions that the company under-took after the implementation of its automated outage management system. As previously discussed, this report reflects the updated baselines, which are detailed further in Section 2.3.

It is particularly noteworthy that these two metrics show durable improvement for both underlying and major event performance within the state, meaning that the system is more resilient on a day-to-day basis as well as when extreme weather or other system impacting events occur.

2.1 Utah Reliability Historical Performance

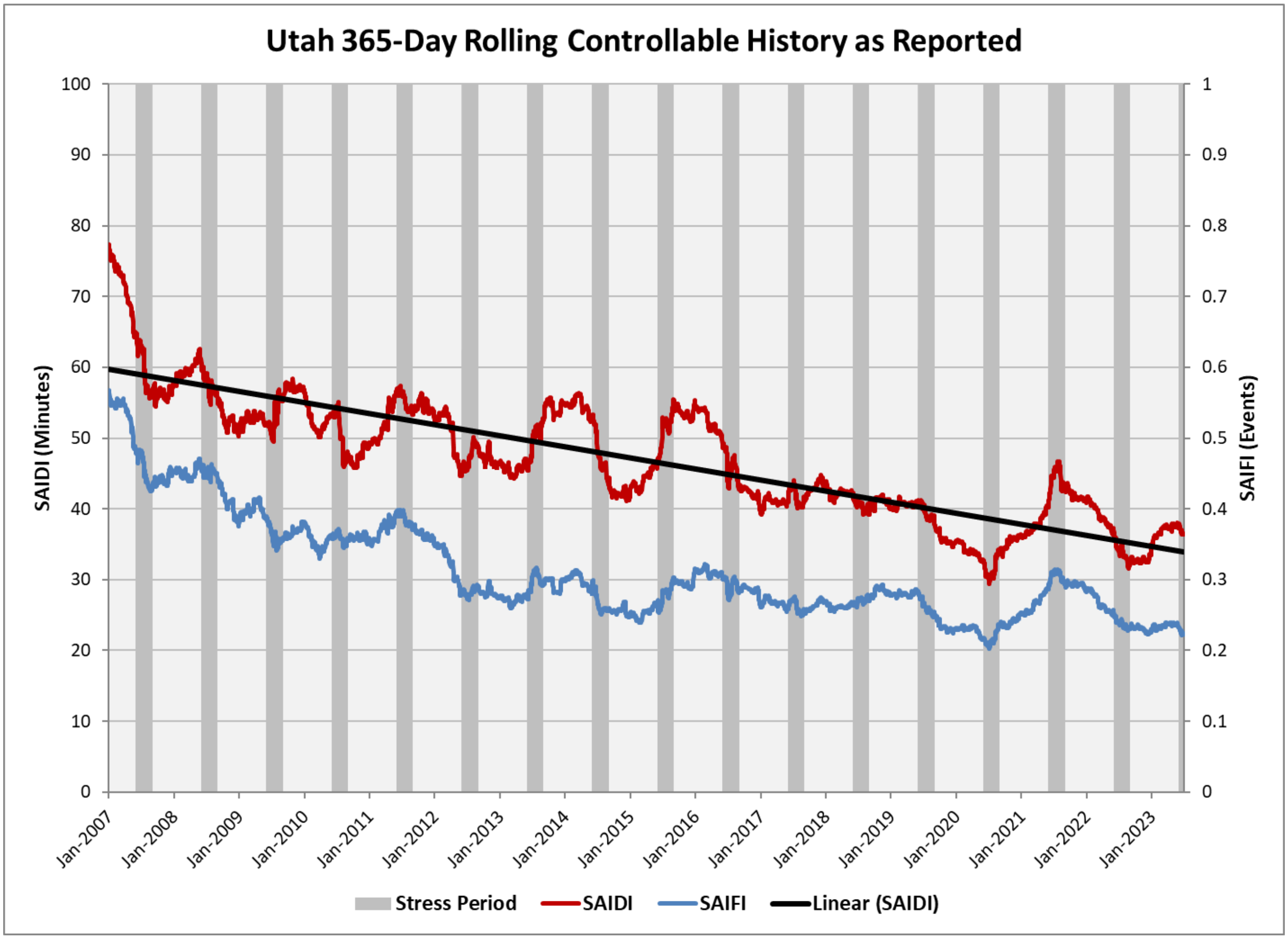


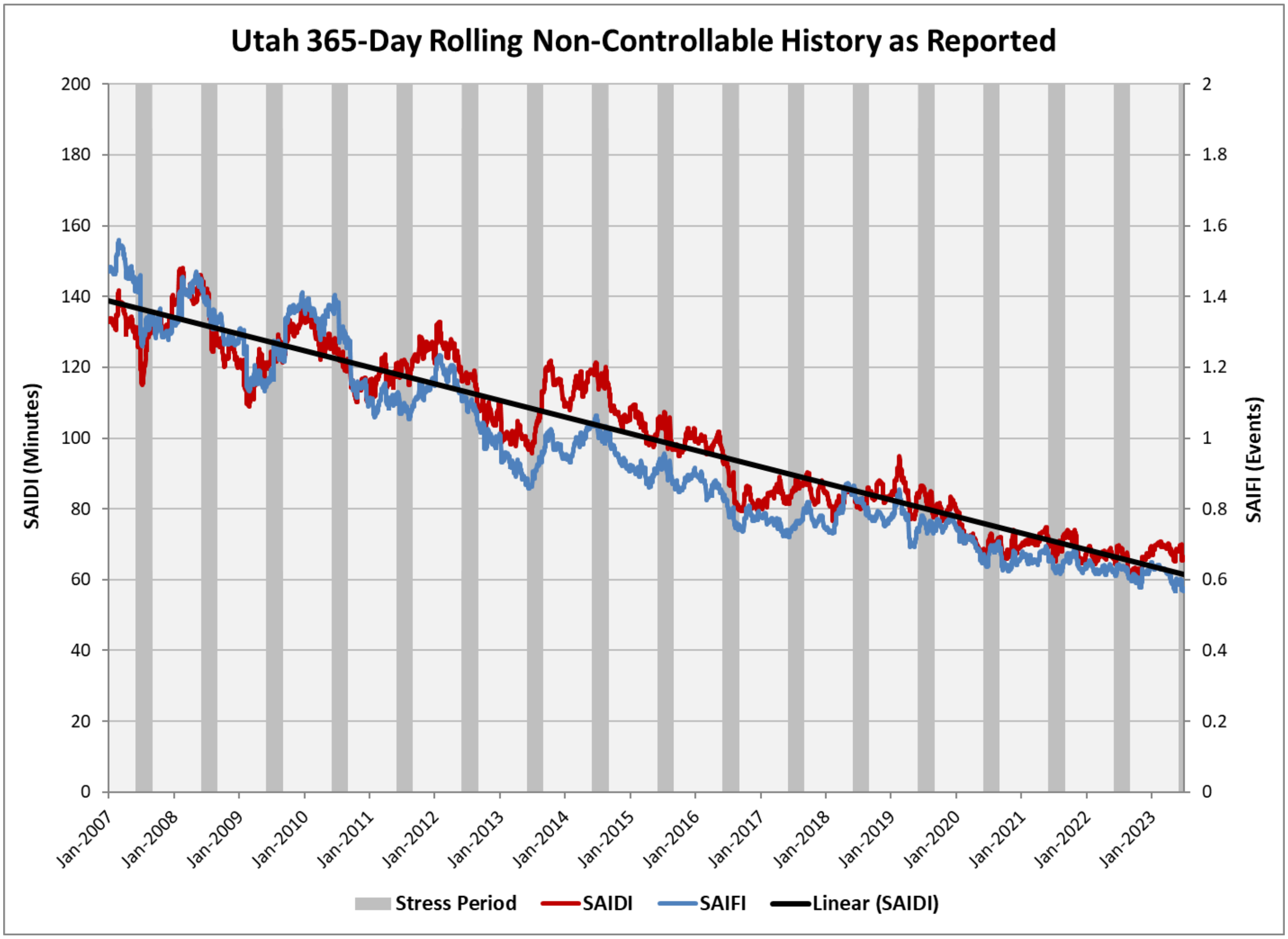


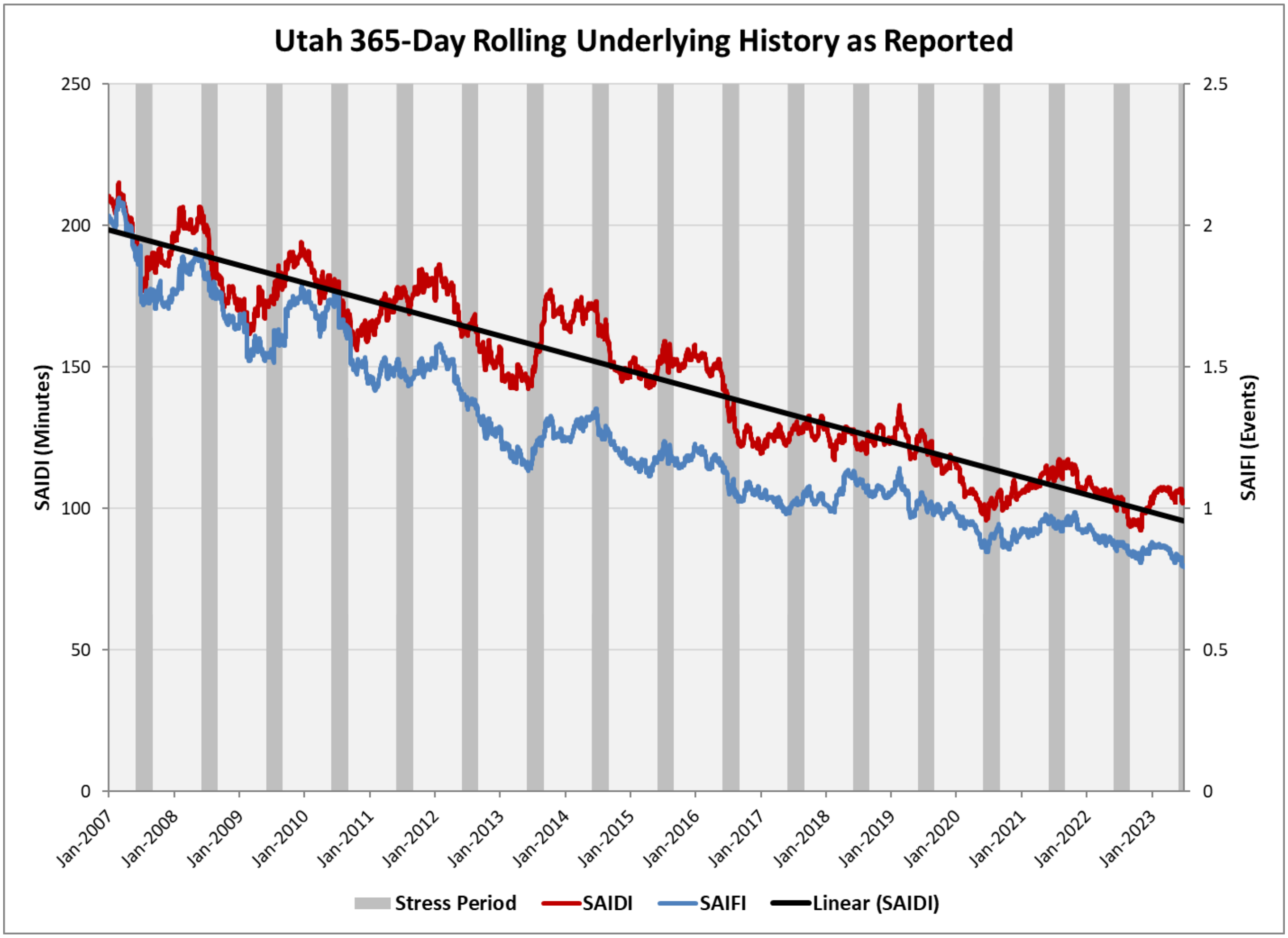
2.2 Controllable, Non-Controllable and Underlying Performance Review

In 2008, the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs. This categorization was titled Controllable Distribution Outages and recognized that certain types of outages can be cost-effectively avoided. As an example, animal-caused or equipment failure interruptions have a less random nature than lightning caused interruptions. Other controllable causes have also been determined and are specified in Section 2.4. Engineers can develop plans to mitigate against controllable distribution outages and provide better future reliability at the lowest possible cost. At that time, there was concern that the Company would lose focus on non-controllable outages. To provide insight into the response and history for those outages, the charts below distinguish between the outage groupings.

The graphic history demonstrates controllable, non-controllable, and underlying performance on a rolling 365-day basis. Analysis of the trends displayed in the charts below shows a general improving trend for all charts. To also focus on non-controllable outages, the Company has continued to improve its resilience to extreme weather using such programs as its visual assurance program to evaluate facility condition. It also has undertaken efforts to establish impacts of loss of supply events on its customers and deliver appropriate improvements when identified. It uses its web-based notification tool for alerting field engineering and operational resources when devices have exceeded performance thresholds to react as quickly as possible to trends in declining reliability. These notifications are conducted regardless of whether the outage cause was controllable or not.


Utah 365-Day Rolling Controllable History as Reported
SAIDI (Minutes)
SAIFI (Events)
100
90
80
70
60
50
40
30
20
10
0
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Jan-2019
Jan-2020
Jan-2021
Jan-2022
Jan-2023
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

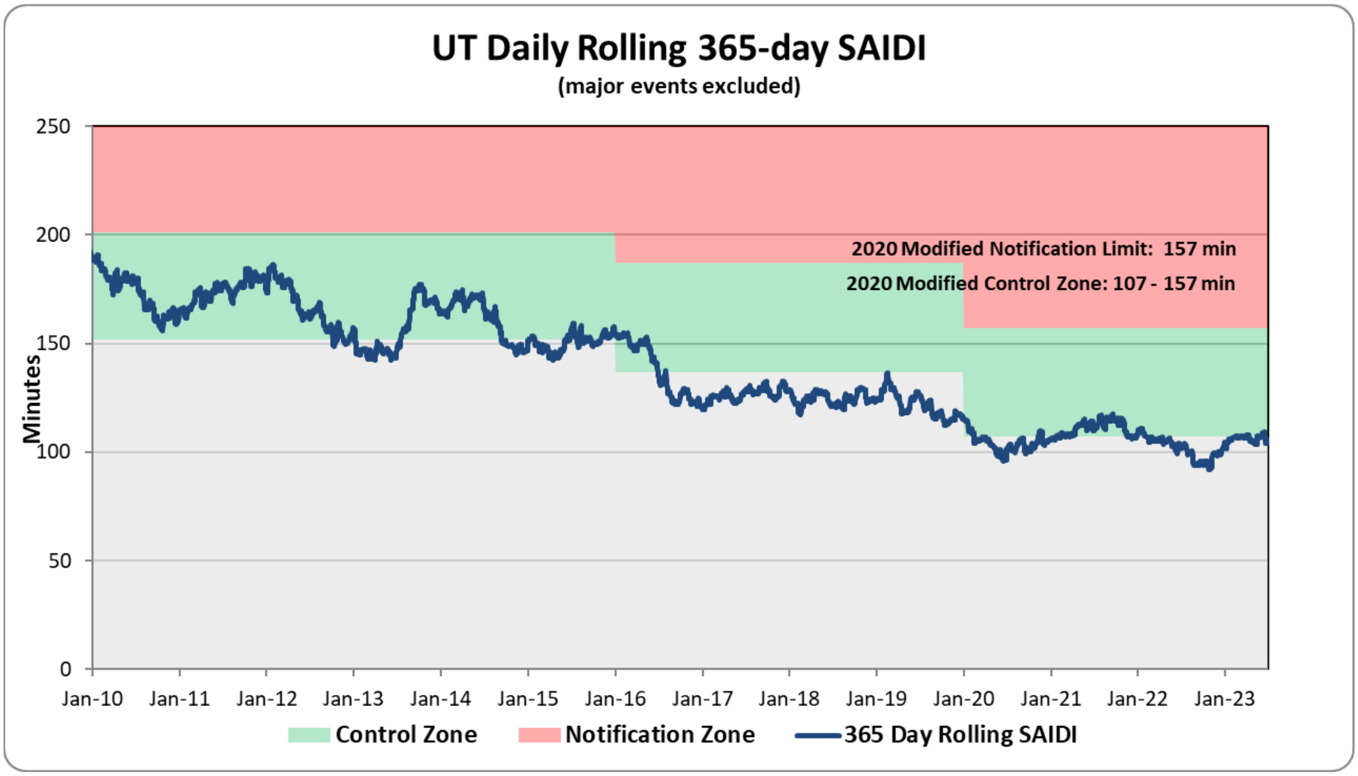

Utah 365-Day Rolling Non-Controllable History as Reported
SAIDI (Minutes)
SAIFI (Events)
200
180
160
140
120
100
80
60
40
20
0
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Jan-2019
Jan-2020
Jan-2021
Jan-2022
Jan-2023
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

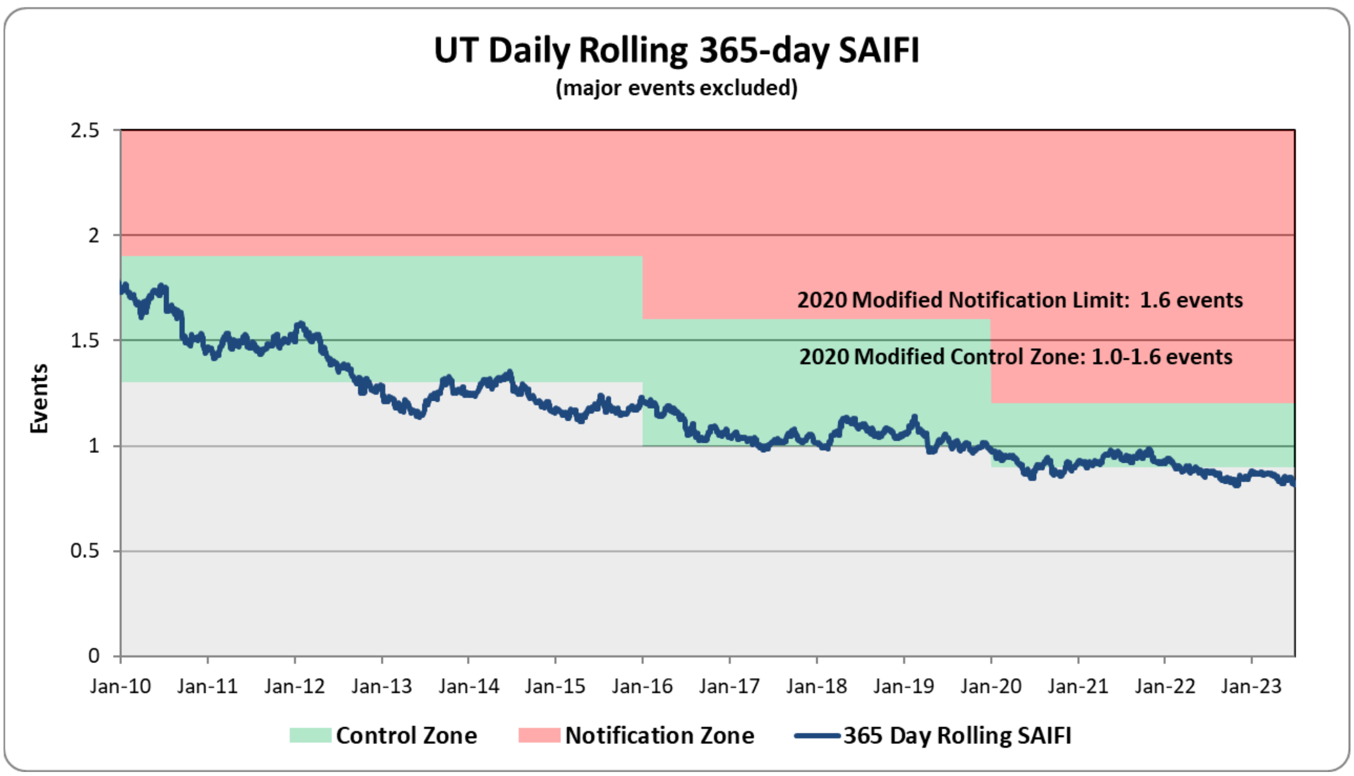


2.3 Baseline Performance

In compliance with Utah Reliability Reporting Rules, the Company developed performance baselines that it subsequently filed for approval (based on 2008-2012 history). The baseline values were calculated using the 12-month moving average data for SAIDI and SAIFI over a 5-year period as the mean, plus or minus approximately two standard deviations. These baselines were approved, but stakeholders advocated that periodically refreshing baseline levels would be beneficial. As a result, on December 20, 2016, the Public Service Commission of Utah approved modified electric service reliability performance baseline notification levels (Docket No. 13-035-01 and 15-035-72). On June 23, 2020, the Commission directed the Company to work with parties to review the baselines. The original and modified baselines are shown below.

	SAIDI (Minutes)		SAIFI (Events)	
	Lower Value Control Zone	Upper Value Control Zone	Lower Value Control Zone	Upper Value Control Zone
Prior Baseline	151	201	1.3	1.9
2016 Modified Baseline	137	187	1.0	1.6
2020 Modified Baseline	107	157	0.9	1.2


UT Daily Rolling 365-day SAIDI
(major events excluded)
Minutes
250
200
150
100
50
0
Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17 Jan-18 Jan-19 Jan-20 Jan-21 Jan-22 Jan-23
2020 Modified Notification Limit: 157 min
2020 Modified Control Zone: 107 - 157 min
Control Zone
Notification Zone
365 Day Rolling SAIDI


UT Daily Rolling 365-day SAIFI
(major events excluded)
Events
2.5
2
1.5
1
0.5
0
Jan-10 Jan-11 Jan-12 Jan-13 Jan-14 Jan-15 Jan-16 Jan-17 Jan-18 Jan-19 Jan-20 Jan-21 Jan-22 Jan-23
2020 Modified Notification Limit: 1.6 events
2020 Modified Control Zone: 1.0-1.6 events
Control Zone
Notification Zone
365 Day Rolling SAIFI

2.4 Reliability Reporting Post-Rule R.746-313 Modifications

In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Administrative Code R746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least partially redundant or segmented differently than has been provided in the past.

The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_E$[7] are required.[8]

Major Events and Prearranged Excluded*	2018				2019				2020				2021				2022				2023 - June			
STATE	SAIDI	SAIFI	CAIDI	$MAIFI_E$	SAIDI	SAIFI	CAIDI	$MAIFI_E$	SAIDI	SAIFI	CAIDI	$MAIFI_E$	SAIDI	SAIFI	CAIDI	$MAIFI_E$	SAIDI	SAIFI	CAIDI	$MAIFI_E$	SAIDI	SAIFI	CAIDI	$MAIFI_E$
Utah	124	1.1	118	2.17	116	1.0	118	2.64	106	0.9	114	3.46	108	0.9	119	1.89	104	0.9	118	0.42	43	0.3	137	0.047
Op Area																								
AMERICAN FORK	85	0.8	109		59	0.6	100		65	0.7	91		56	0.4	144		78	0.6	121		48	0.3	149	
CEDAR CITY	157	1.2	136		160	1.4	114		149	1.3	111		144	1.3	111		110	1.0	110		56	0.6	97	
CEDAR CITY (MILFORD)	226	1.4	164		563	3.2	177		296	1.9	155		270	2.0	133		182	0.9	197		63	0.3	191	
EVANSTON	23	0.2	96		9	0.1	76		12	0.1	192		26	0.2	112		21	0.2	128		61	0.2	254	
JORDAN VALLEY	138	1.1	121		100	0.8	118		99	0.8	121		109	1.0	114		74	0.7	104		23	0.2	142	
LAYTON	132	1.3	101		123	1.4	90		104	1.1	93		119	1.2	96		69	0.6	112		25	0.2	108	
MOAB	111	1.1	102		171	2.0	87		239	1.9	123		146	1.2	126		125	1.2	103		114	0.8	144	
MONTPELIER	34	0.4	94		13	0.2	75		33	0.2	142		78	1.1	73		216	0.9	235		61	0.7	91	
OGDEN	116	1.0	114		153	1.1	139		116	0.9	128		126	1.0	127		119	0.8	141		63	0.3	205	
PARK CITY	165	1.2	143		187	1.1	171		251	1.9	132		121	0.7	166		171	0.9	186		86	0.5	177	
PRICE	203	2.3	90		101	1.9	53		140	1.3	109		64	1.0	63		143	1.5	94		13	0.1	99	
RICHFIELD	173	1.4	125		222	2.2	103		135	1.5	92		213	1.2	175		254	1.8	141		31	0.2	124	
RICHFIELD (DELTA)	176	1.1	163		103	0.8	136		208	1.1	197		340	2.7	128		138	2.0	70		46	0.3	132	
SLC METRO	234	2.0	118		222	1.8	125		189	1.7	108		226	1.9	120		102	1.0	107		34	0.3	123	
SMITHFIELD	96	1.0	99		127	1.5	83		88	0.9	101		80	0.9	86		93	0.8	116		108	1.1	101	
TOOELE	196	1.5	135		146	1.3	110		137	1.0	137		155	1.4	112		192	1.8	104		32	0.4	82	
TREMONTON	151	1.1	137		259	1.6	167		178	1.3	140		92	0.8	117		213	1.9	115		103	0.7	139	
VERNAL	48	0.6	83		58	0.6	99		68	0.7	94		64	0.4	165		86	0.7	127		23	0.1	162	

* Except $MAIFI_E$

Utah Cause Category	2018		2019		2020		2021		2022		June 2023	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	1.0	0.0	0.0	0.0	1.0	0.0	1.0	0.0	0.0	0.0	0.0	0.0
Equipment Failure	48.0	0.3	40.0	0.2	39.0	0.2	42.0	0.3	38.0	0.2	15.5	0.1
Lightning	3.0	0.0	3.0	0.0	1.0	0.0	3.0	0.0	2.0	0.0	1.0	0.0
Loss of Supply - Generation/Transmission	13.0	0.2	9.0	0.1	15.0	0.2	9.0	0.1	10.0	0.1	6.8	0.1
Loss of Supply - Substation	9.0	0.1	11.0	0.1	6.0	0.1	10.0	0.1	15.0	0.2	2.4	0.0
Operational	0.0	0.0	0.0	0.0	1.0	0.0	1.0	0.0	0.0	0.0	0.5	0.0
Other	0.0	0.0	1.0	0.0	1.0	0.0	2.0	0.0	2.0	0.0	2.5	0.0
Planned (excl. Prearranged)	10.0	0.1	9.0	0.1	6.0	0.1	3.0	0.0	2.0	0.0	0.0	0.0
Public	15.0	0.1	16.0	0.1	16.0	0.1	13.0	0.1	11.0	0.1	5.1	0.0
Unknown	6.0	0.1	5.0	0.1	5.0	0.1	5.0	0.1	5.0	0.1	0.0	0.0
Vegetation	5.0	0.0	7.0	0.0	7.0	0.0	6.0	0.0	6.0	0.0	2.9	0.0
Weather	9.0	0.1	11.0	0.1	7.0	0.1	10.0	0.1	11.0	0.1	5.4	0.0
Wildlife	3.0	0.0	2.0	0.0	3.0	0.0	3.0	0.0	2.0	0.0	0.6	0.0
UTAH Underlying	**124**	**1.1**	**116**	**1.0**	**106**	**0.9**	**108**	**0.9**	**104**	**0.9**	**43**	**0.3**

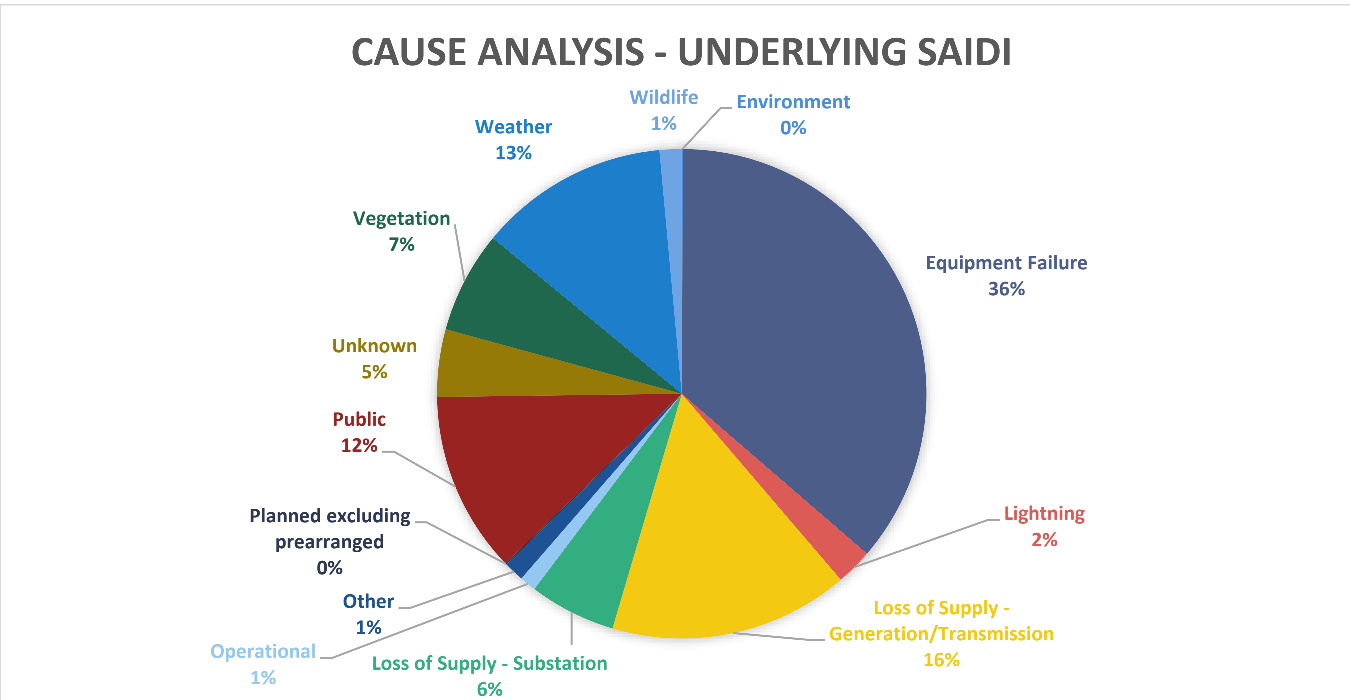
[7] MAIFI is only calculated based on equipment that contains SCADA. Therefore, the metrics provided represent only a portion of the system. $MAIFI_E$ events are measured using the circuit customer count for those circuits where a trip and reclose occurred during the reporting period, and do not include customer counts for circuits where no event was recorded.

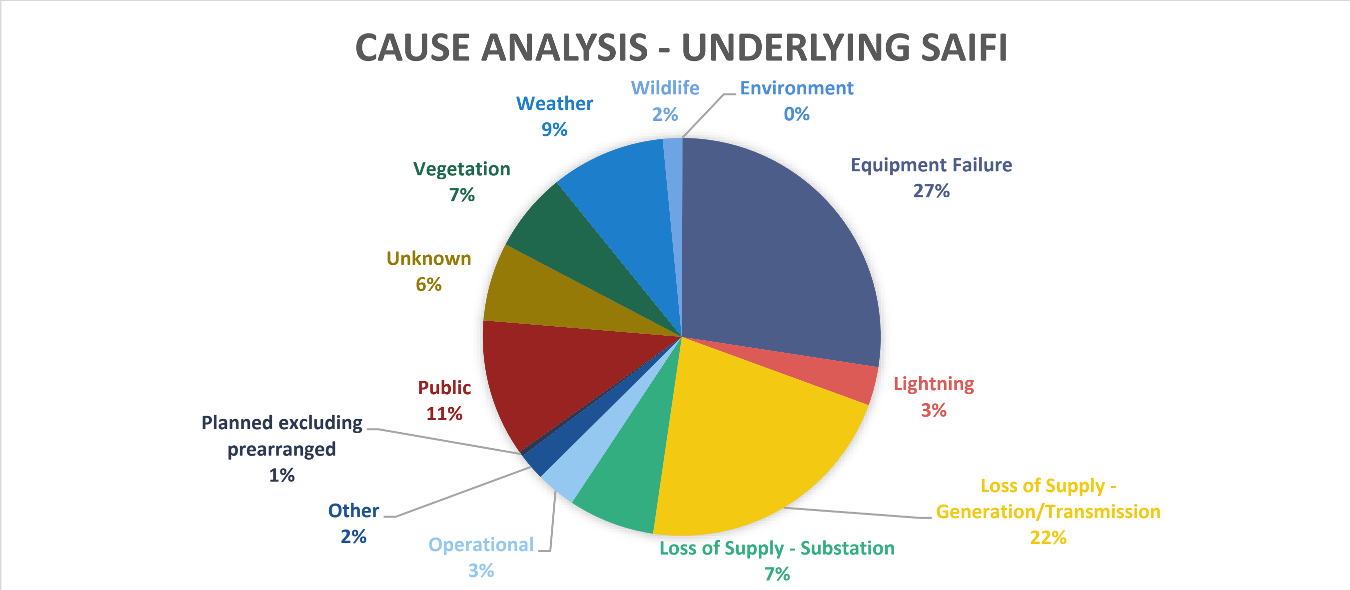
[8] For this report, $MAIFI_E$ is calculated using distribution outage records exclusively while the Company transitions to a new outage data system. In future filings, $MAIFI_E$ calculations will include distribution outage records and trip and reclose events.

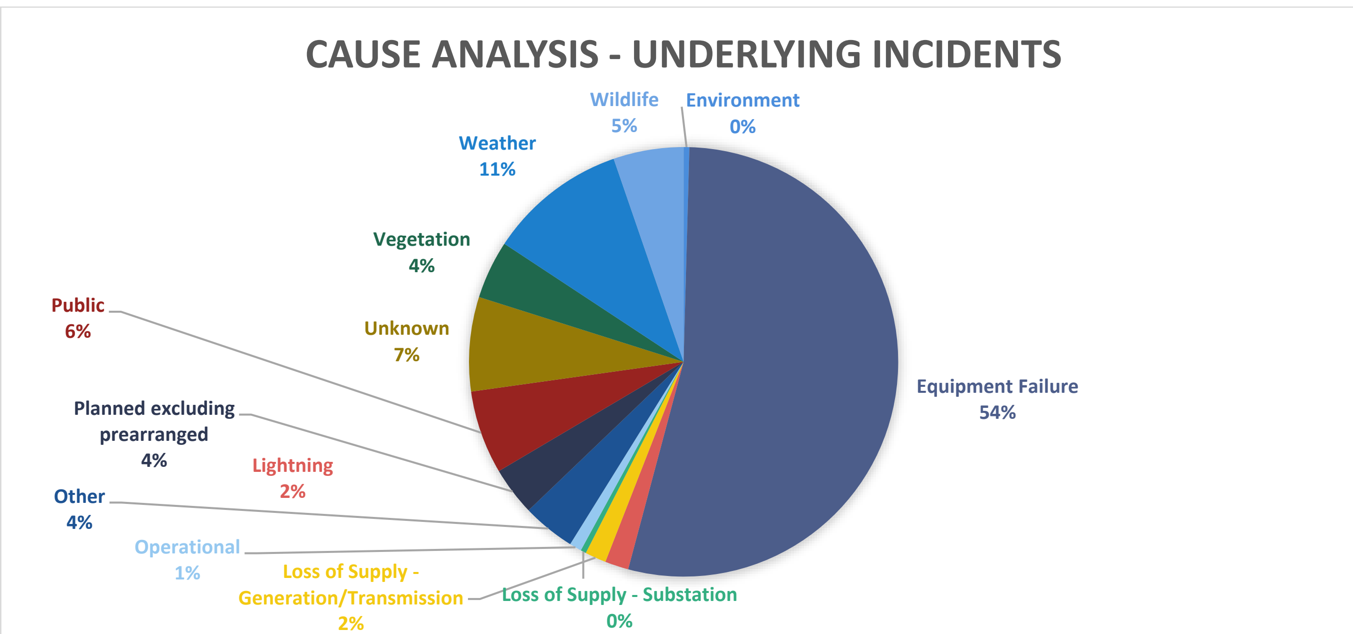
2.5 Cause Analyses – Underlying and EFR

In the following section, we provide a comprehensive analysis of the causes of outages, represented in the form of pie charts. This analysis includes both Underlying outages and those related to Elevated Fire Risk (EFR). It is important to note that during the first half of 2023, the Company did not operate any equipment under EFR settings within the state of Utah. Consequently, the data depicted in the pie charts for this midyear report exclusively represents Underlying outages.

As we approach the end of the year, this report will be augmented with additional cause analysis pie charts to reflect the breakdown of outages that occurred on circuits with EFR enabled. These will be positioned subsequent to the charts for Underlying outages and will delineate the various cause categories along with their respective percentages within EFR outages.




CAUSE ANALYSIS - UNDERLYING SAIFI
Wildlife 2%
Environment 0%
Weather 9%
Equipment Failure 27%
Vegetation 7%
Unknown 6%
Public 11%
Lightning 3%
Planned excluding prearranged 1%
Other 2%
Operational 3%
Loss of Supply - Substation 7%
Loss of Supply - Generation/Transmission 22%


CAUSE ANALYSIS - UNDERLYING INCIDENTS
Wildlife 5%
Environment 0%
Weather 11%
Vegetation 4%
Public 6%
Unknown 7%
Equipment Failure 54%
Planned excluding prearranged 4%
Lightning 2%
Other 4%
Operational 1%
Loss of Supply - Generation/Transmission 2%
Loss of Supply - Substation 0%

3 Improve Reliability Performance in Areas of Concern

Rocky Mountain Power is committed to delivering safe and reliable power. For years, the company has developed, monitored, and tracked reliability metrics in accordance with industry standards and regulatory requirements. Over time, improvements have been made to minimize the negative impact of power interruptions by reducing outage duration and frequency. To continue keeping its commitment to deliver safe and reliable power, Rocky Mountain Power develops a reliability plan annually to identify new projects and programs to continually improve system performance and resilience.

Rocky Mountain Power's reliability plan is a key program that is used to improve system reliability is the development of individual reliability work plans for areas of concern, which is a strategic approach based upon recent trends in performance as measured by customer minutes interrupted (CMI), from which SAIDI is derived. The decision to fund one performance improvement project over another is based on cost effectiveness as measured by the cost per avoided customer minute interruptions. Care is taken to ensure the cost effectiveness measure does not limit funding of improvement projects in areas of low customer density over more densely populated areas.

An area of concern that has been identified are circuits that serve many customers. As a result, Rocky Mountain Power implemented a new mainline sectionalizing guideline to reduce the number of customers exposed per feeder. The guide outlines recommendations for a maximum of 2,250 customers per feeder, which are to be further subdivided into protection zones of no more than 750 customers. A feeder analysis is performed annually to determine which feeders do not meet these recommendations, and then are prioritized based on the greatest amount of risk to reliability.

4 Customer Response

4.1 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	75%[9]
PS6a) Respond to commission complaints within 3 days	95%	100%
PS6b) Respond to commission complaints regarding service disconnects within 4 hours	95%	100%
PS6c) Address commission[10] complaints within 30 days	100%	100%

4.2 Utah Commitment U1

To identify when a 'wide scale' outage has occurred, the company examines call data for customers who have selected either the power emergency or power outage option within the company's call menu. However, to report on performance during a 'wide scale' outage, the company must use network information, which provides information for all call types, not just outage calls. Therefore, using the menu level data the company has identified the time intervals that exceed the agreed upon standard 2,000 calls/hour, and reports the network level statistics for the same intervals.

For the reporting period, there were no days identified as a wide-scale outage day.

[9] As noted in recent reports, Rocky Mountain Power was unable to meet the specified goal due to staffing limitations, primarily caused by labor market dynamics during the COVID-19 pandemic. Despite these challenges, the company has been striving to enhance its performance and has demonstrated consistent improvement. In 2022, the performance rate was 63%. By the first quarter of 2023, this had increased to 70.1%. As of June 2023, the performance rate had further improved to 75%. Rocky Mountain Power continues to work diligently towards achieving its target.

[10] Rocky Mountain Power follows the definitions for informal and formal complaints as set forth in the Utah Code, Title 54, Public Utilities Statutes and Public Service Commission Rules, R746-200-8 Informal review (A) and Commission review (D).

4.3 Utah State Customer Guarantee Summary Status[11]

customer*guarantees* January to June 2023
Utah

	Description	2023 Events	2023 Failures	2023 % Success	2023 Paid	2022 Events	2022 Failures	2022 % Success	2022 Paid
CG1	Restoring Supply	378,960	0	100%	$0	439,065	0	100%	$0
CG2	Appointments	4,095	9	99.78%	$450	5,689	3	99.95%	$150
CG3	Switching on Power	1,966	1	99.95%	$50	1,883	1	99.95%	$50
CG4	Estimates	577	0	100%	$0	889	0	100%	$0
CG5	Respond to Billing Inquiries	637	3	99.53%	$150	548	1	99.82%	$50
CG6	Respond to Meter Problems	372	1	99.73%	$50	306	0	100%	$0
CG7	Notification of Planned Interruptions	71,389	20	99.97%	$1,000	97,183	29	99.97%	$1,450
		457,996	**34**	**99.99%**	**$1,700**	**545,563**	**34**	**99.99%**	**$1,700**

Overall Customer Guarantee performance remains above 99%, demonstrating Rocky Mountain Power's continued commitment to customer satisfaction. Major Events are excluded from the Customer Guarantees program. The program also defines certain exemptions, which are primarily for safety, access to outage site, and emergencies.

[11] Overall guarantee performance remains above 99% demonstrating Rocky Mountain Power's continued commitment to customer satisfaction.

5 Maintenance Compliance to Annual Plan

5.1 T&D Preventive and Corrective Maintenance Programs

Preventive Maintenance

The primary focus of the preventive maintenance (PM) plan is to inspect facilities, identify abnormal conditions[12], and perform appropriate preventive actions upon those facilities. Assessment of policies, including the costs and benefits of delivery of these policies, will result in modifications to them. Thus, local triggers that result in more frequent or more burdensome inspection and maintenance practices have resulted in refinement to some of these PM activities. As the Company continues this assessment, further changes of the policies will result in refinement of the maintenance plan.

Transmission and Distribution Lines

- Visual assurance inspections are designed to identify damage or defects that may endanger public safety or adversely affect the integrity of the electric system.
- Detailed inspections are in depth visual inspections of each structure and the spans between each structure or pad-mounted distribution equipment.[13]
- Pole testing includes a sound and bore to identify decay pockets that would compromise the wood pole's structural integrity.

Substations and Major Equipment

- Rocky Mountain Power inspects and maintains substations and associated equipment to ascertain all components within the substation are operating as expected. Abnormal conditions that are identified are prioritized for repair (corrective maintenance).
- Rocky Mountain Power has a condition-based maintenance program for substation equipment including load tap changers, regulators, and transmission circuit breakers. Diagnostic testing is performed on a time-based interval and the results are analyzed to determine if the equipment is suitable for service or maintenance tasks to be performed. Protection system and communication system maintenance is performed based on a time interval basis.

[12] Condition priorities are as follows:
Priority A: Conditions that pose a potential but not immediate hazard to the public or employees, or that risk loss of supply or damage to the electrical system.
Priority B: Conditions that are nonconforming, but that in the opinion of the inspector do not pose a hazard.
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.
Priority D: Conditions that conform to the NESC and are not reportable to the associated State Commission. Priority G: Conditions that conform to the regulations requirement that was in place when construction took place but do not conform to more recent code adoptions. These conditions are "grandfathered" and are considered conforming.

[13] Effective 1/1/2007, Rocky Mountain Power modified its reliability & preventive planning methods to utilize repeated reliability events to prioritize localized preventive maintenance activities using its Reliability Work Planning methodology. At this time, repeated outage events experienced by customers will result in localized inspection and correction activities rather than being programmatically performed at either the entire circuit or map section level.

Corrective Maintenance

The primary focus of the corrective maintenance plan is to correct the abnormal conditions found during the preventive maintenance process.

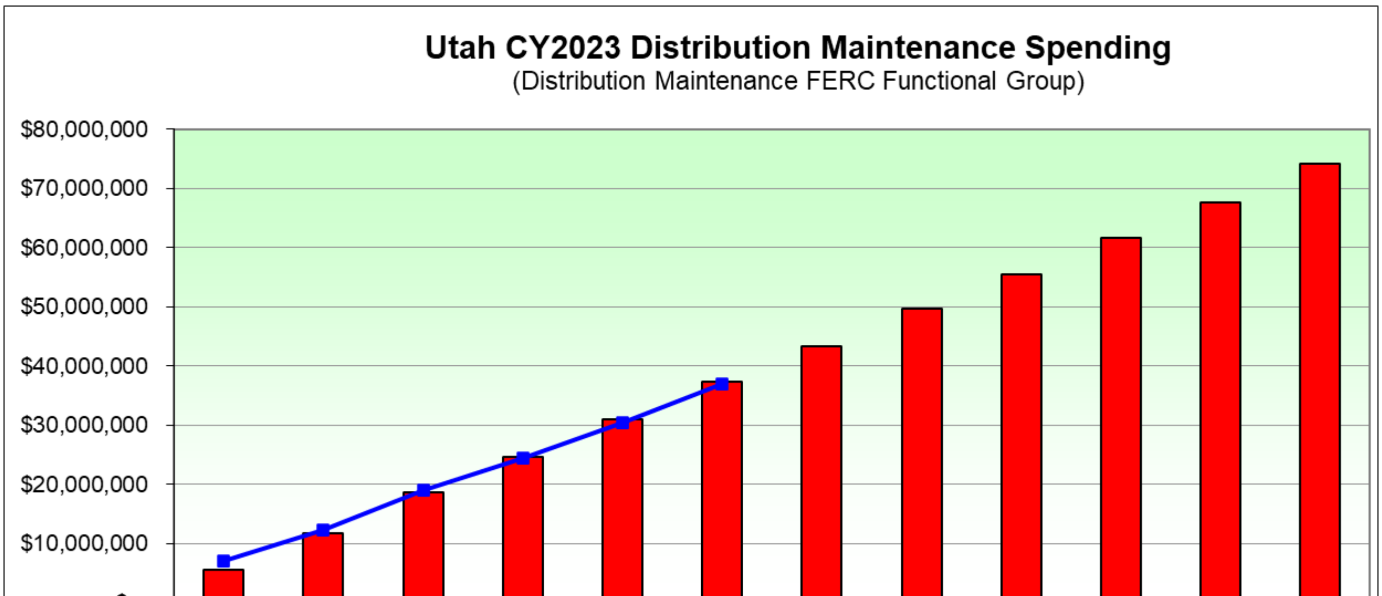
Transmission and Distribution Lines

- Correctable conditions are identified through the preventive maintenance process.
- Outstanding conditions are recorded in a database and remain until corrected.

Substations and Major Equipment

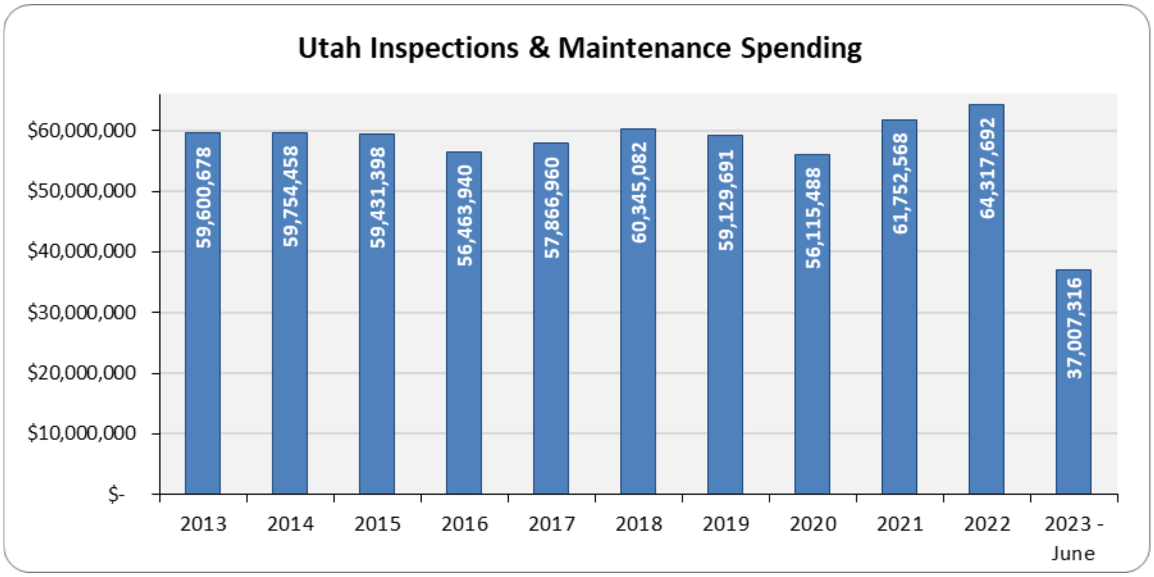
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

5.2 Maintenance Spending - RMV



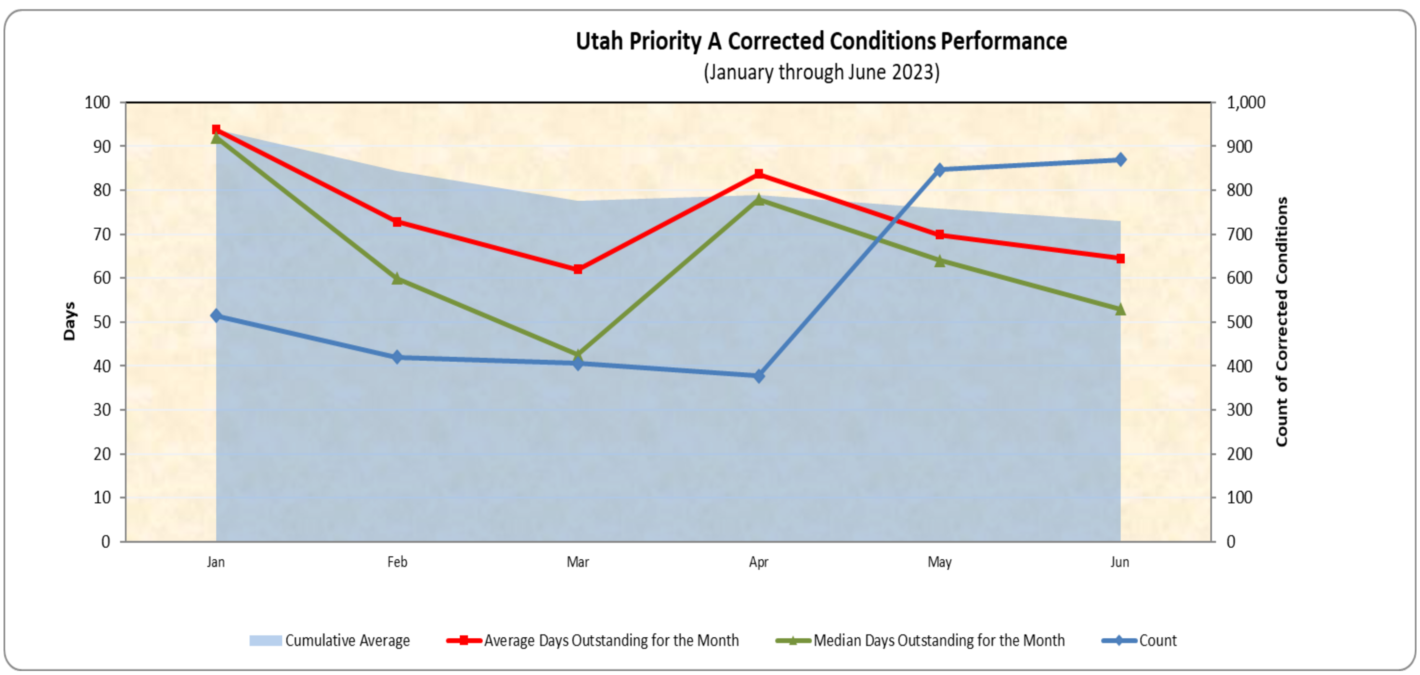
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,558,586	$11,663,02	$18,660,55	$24,628,49	$30,937,92	$37,374,01	$43,246,50	$49,672,91	$55,515,85	$61,656,87	$67,565,99	$74,138,37
Actual	$7,112,540	$12,371,21	$19,027,74	$24,435,41	$30,405,28	$37,007,31						

5.2.1 Maintenance Historical Spending - RMV



5.3 Distribution Priority "A" Conditions Correction History

Rocky Mountain Power is committed to correcting Priority "A" Conditions with an average age of 120 days or less. The Company believes that it is a useful indicator of its commitment to providing safe and reliable service to its Utah customers. As shown in the graph below, Rocky Mountain Power consistently delivers an average age of Priority "A" Conditions well below the 120-day target.

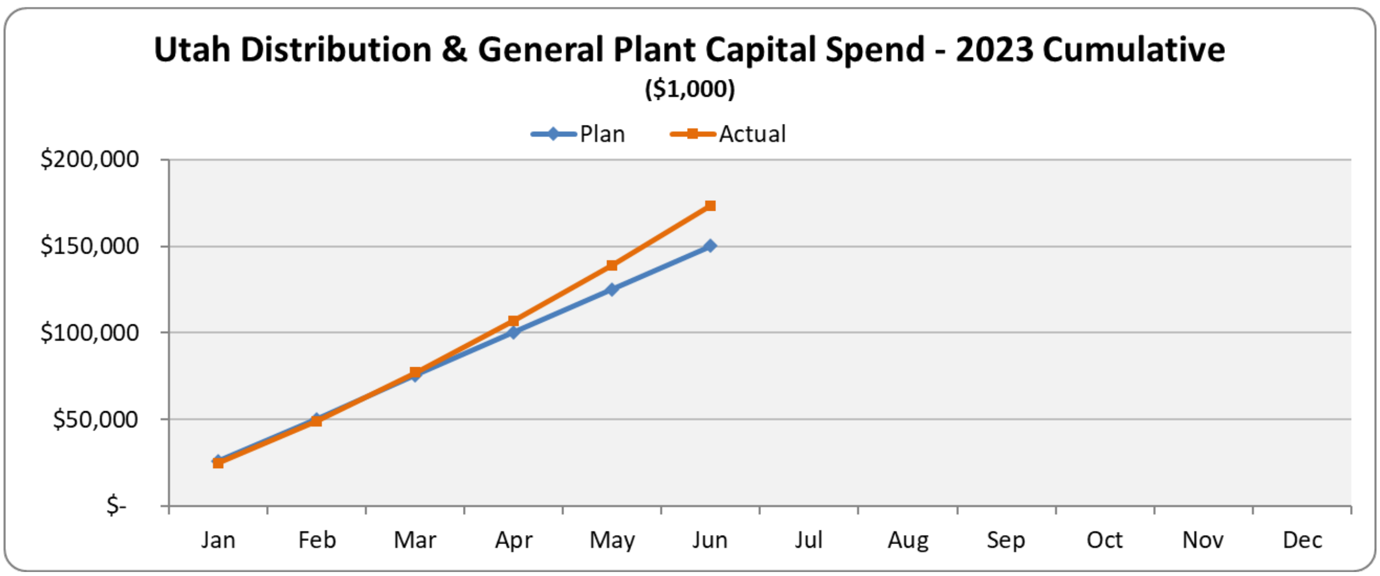


6 Capital Investment

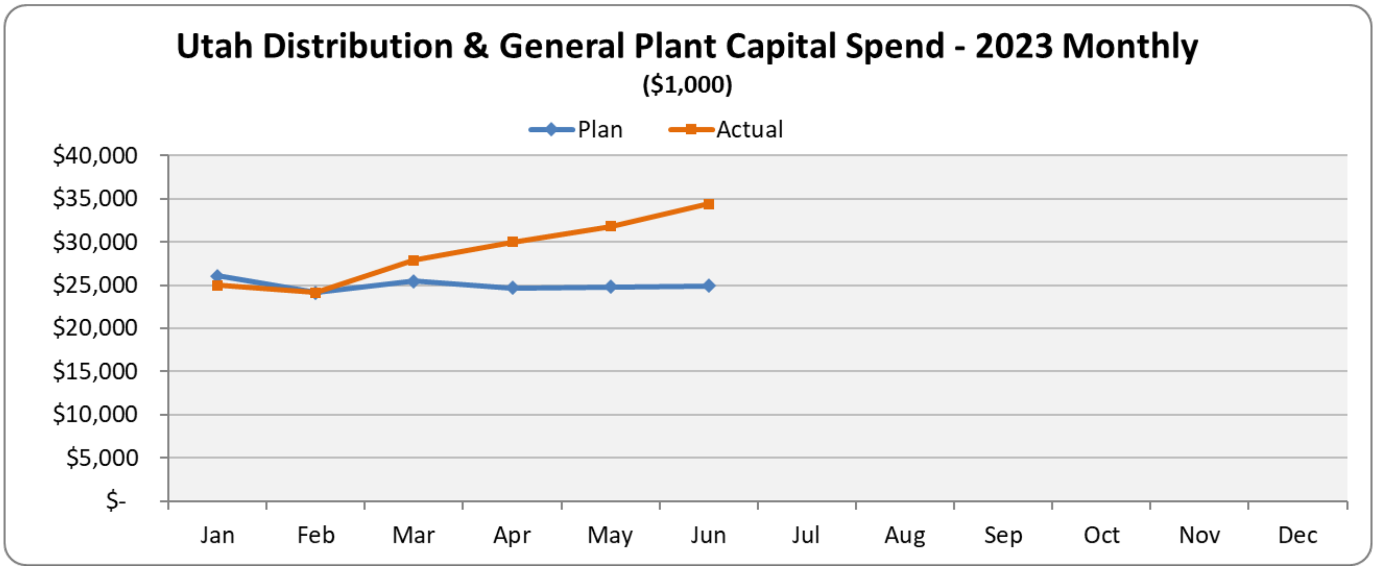
6.1 Capital Spending - Distribution and General Plant[14]

January – June 2022

Investment	Actual ($m)	Plan ($m)	Significant Variances
1. Mandated	$30.1	$18.3	Mandated distribution wildfire mitigation over plan, (+10m).
2. New Connect	$49.7	$37.1	Commercial new revenue connections over plan, (+$6m); residential new revenue connections over plan, (+$6m). 2023 plan anticipated new connection slowdown, which has not occurred.
3. System Reinforcement	$33.2	$32.9	
4. Replacement	$42.1	$34.7	Increased labor and material prices.
5. Upgrade & Modernize	$18.2	$27.2	Feeder improvements under plan, (–$8m — including Automated Metering Infrastructure –$6m).
Total	$173.3	$150.2	



[14] Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

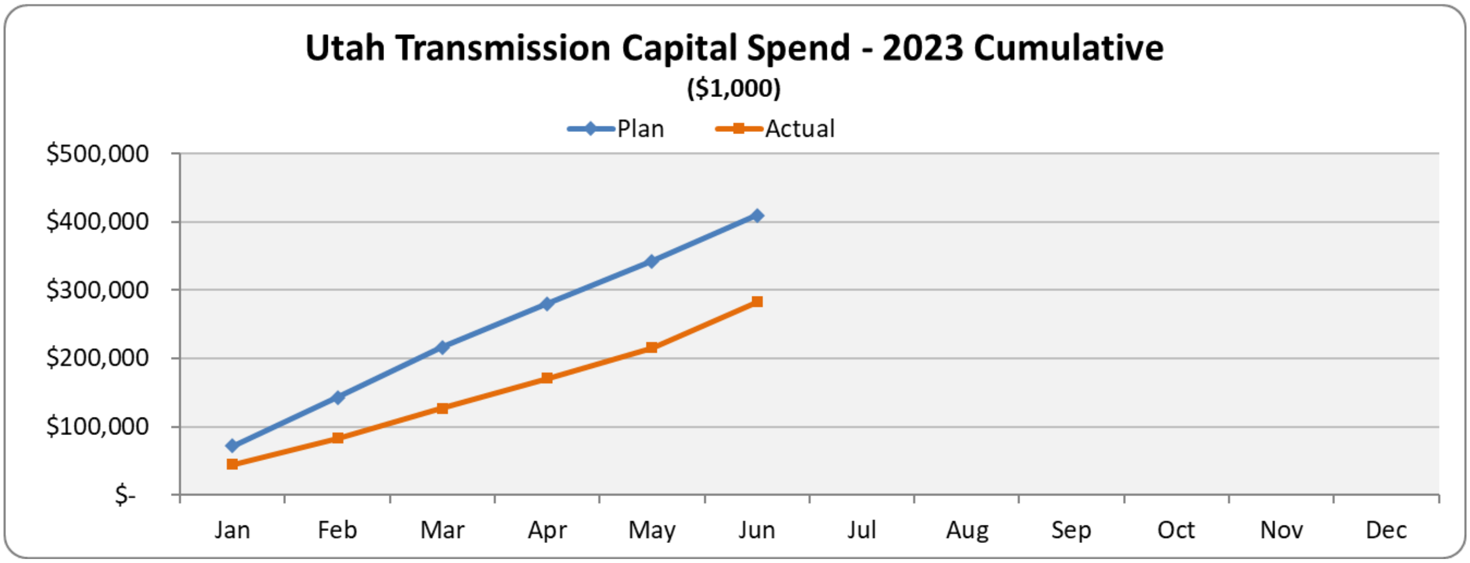


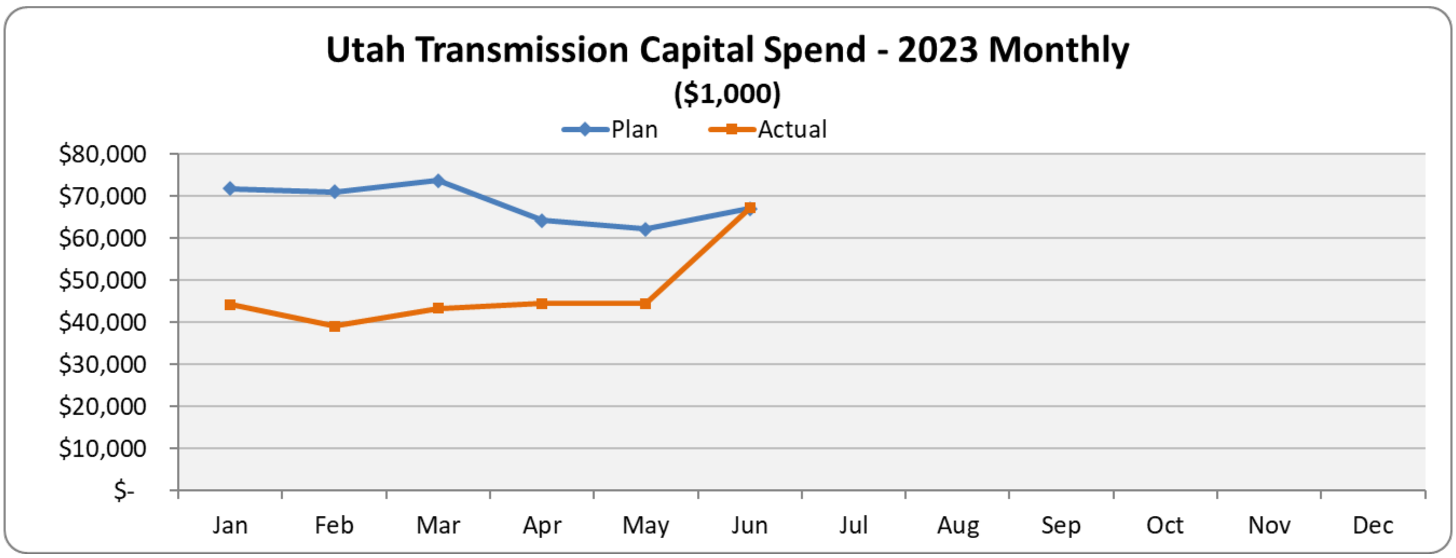
6.2 Capital Spending – Transmission/Interconnections[15]

January – June 2022

Investment	Actual ($m)	Plan ($m)	Significant Variances
1. Mandated	$11.6	$15.0	Wildfire projects timing.
2. New Connect	$6.1	$5.9	
3. Local Transmission System Reinforcements	$4.4	$3.8	
4. Main Grid Reinforcements / Interconnections[16]	$21.0	$33.2	Unidentified main grid/generation interconnections under plan, (–$15m — see note below).[17]
5. Energy Gateway Transmission[8]	$216.2	$340.0	"Gateway South Aeolus Mona 500kV Ln project resequenced after submission of plan, with dollars accelerated into 2022 to advance contractor schedule on project material and foundation work--ensures firm fixed price on material and avoids commodity price risk adjustments later in projects. This contributes to the under spend in 2023 year-to-date on that project, (–$115m). Oquirrh Terminal 345kV Ln over plan, (+$6m) due to increases in material and construction labor, and Gateway Central Limber Area under plan, (–$12m) due to the resequencing of that project after submission of plan."
6. Replacement	$14.1	$10.2	Increased labor and material prices.
7. Upgrade & Modernize	$9.3	$1.9	Substation improvements over plan, (+$8m — including Enhanced Substation Security +$7m).
Total	$282.7	$410.0	

[15] Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.
[16] Main Grid Reinforcement/Interconnections and Energy Gateway Transmission values include a small amount of General Plant $ for communications work.
[17] Unidentified main grid/generation interconnection projects are managed at the program level. Plan funding is 100% allocated to Utah, by necessity, for Plan application purposes only. Actual funding is reallocated to specific projects across PacifiCorp as identified or as customer agreements are signed, not necessarily within the state of Utah.


Utah Transmission Capital Spend - 2023 Cumulative
($1,000)
Plan
Actual
$500,000
$400,000
$300,000
$200,000
$100,000
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


Utah Transmission Capital Spend - 2023 Monthly
($1,000)
Plan
Actual
$80,000
$70,000
$60,000
$50,000
$40,000
$30,000
$20,000
$10,000
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

6.3 New Connects[18]

	2022	2023												
	YEAR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YEAR
Residential														
UT South	2,311	96	142	187	108	149	159							841
UT North/Metro	9,849	734	658	1,416	788	968	958							5,522
UT Central	15,445	790	970	1,061	767	946	1,252							5,786
Total Residential	**27,605**	**1,620**	**1,770**	**2,664**	**1,663**	**2,063**	**2,369**							**12,149**
Commercial														
UT South	387	38	22	24	41	37	41							203
UT North/Metro	1,529	87	70	149	119	149	149							723
UT Central	2,679	147	156	145	138	191	195							972
Total Commercial	**4,595**	**272**	**248**	**318**	**298**	**377**	**385**							**1,898**
Industrial														
UT South	1	0	0	0	0	0	0							0
UT North/Metro	1	0	0	0	0	0	1							1
UT Central	1	0	0	1	0	0	0							1
Total Industrial	**3**	**0**	**0**	**1**	**0**	**0**	**1**							**2**
Irrigation														
UT South	45	3	0	1	6	10	2							22
UT North/Metro	5	0	0	0	0	1	0							1
UT Central	17	0	0	0	1	3	1							5
Total Irrigation	**67**	**3**	**0**	**1**	**7**	**14**	**3**							**28**
TOTAL New Connects														
UT South	2,744	137	164	212	155	196	202							1,066
UT North/Metro	11,384	821	728	1,565	907	1,118	1,108							6,247
UT Central	18,142	937	1,126	1,207	906	1,140	1,448							6,764
TOTAL New Connects	**32,270**	**1,895**	**2,018**	**2,984**	**1,968**	**2,454**	**2,758**							**14,077**

Notes:

- Utah South region includes Moab, Price, Cedar City and Richfield
- Utah North/Metro region includes SLC Metro, Ogden and Layton
- Utah Central region included American Fork, Vernal, Toole, Jordan Valley and Park City
- Region areas are subject to change for operational purposes and may differ from historical reporting.

[18] Adapting to a new data processing tool in 2021 several process improvements were implemented. Temporary connections, previously excluded, are included again allowing earlier reporting of actual installation dates. There is no double counting of new connections because when a permanent connection is established the temporary is replaced, with the original installation date maintained. In 2015 it was decided by our regulation department that we must code all temporary connections as Commercial to be able to apply the commercial billing rates to the contractors who would be using the electricity until a homeowner is in place. As there are quite a lot of residential customers and a much smaller proportion of commercial customers, this skews the volumes considerably, so temporaries were excluded. To include temporary connections now, without misrepresenting the commercial volumes, commercially classed connections are converted to Residential connections when residential dwelling codes are used. This new process is also based on actual installation data rather than customer contract data and is expected to eliminate customer change based interference of historical volumes. 2020 volumes have also been converted to allow comparison of like volumes.

7 Vegetation Management

7.1 Production

UTAH
Tree Program Reporting
January 1, 2023 through June 30, 2023
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles *column a*	1/1/2023-6/30/2023 Miles Planned *column b*	1/1/2023-6/30/2023 Actual Miles *column c*	1/1/2023-6/30/2023 Ahead/Behind *column d*	1/1/2023-6/30/2023 % Ahead/Behind *column e*	1/1/2023-12/31/2025 Miles Planned *column f*	1/1/2023-12/31/2025 Actual Miles *column g*	01/01/2023-12/31/2025 Ahead/Behind *column h*	1/1/2023-12/31/2025 % Ahead/Behind *column i*
UTAH	9,896	3,488	1,925	-1,563	55.2%	3,488	1,925	-1,563	55.2%
AMERICAN FORK	806	102	31	-71	30.1%	102	31	-71	30.1%
CEDAR CITY	1,000	452	362	-89	80.2%	452	362	-89	80.2%
JORDAN VALLEY	764	335	179	-156	53.5%	335	179	-156	53.5%
LAKETOWN	185	185	0	-185	0.0%	185	0	-185	0.0%
LAYTON	309	34	8	-26	23.3%	34	8	-26	23.3%
MOAB	616	150	155	5	103.5%	150	155	5	103.5%
OGDEN	739	350	183	-167	52.3%	350	183	-167	52.3%
PARK CITY	333	173	48	-125	27.7%	173	48	-125	27.7%
PRICE	568	290	134	-156	46.3%	290	134	-156	46.3%
RICHFIELD	1,227	109	109	0	100.0%	109	109	0	100.0%
SL METRO	1,226	565	223	-342	39.5%	565	223	-342	39.5%
SMITHFIELD	543	135	129	-6	95.5%	135	129	-6	95.5%
TOOELE	505	107	80	-28	74.3%	107	80	-28	74.3%
TREMONTON	815	348	134	-214	38.5%	348	134	-214	38.5%
VERNAL	260	153	150	-3	98.0%	153	150	-3	98.0%

Distribution cycle $/tree:	$166.99
Distribution cycle $/mile:	$3,155
Distribution cycle removal %	9.07%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule		% of miles on/behind Schedule
6,597	553	310	(243)		56%

Current distribution cycle begain January 1, 2023 and extends until December 31, 2025.

Notes:
Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2023 through December 31, 2023
Column c: Actual overhead distribution pole miles worked during the period January 1, 2023 through December 31, 2023
Column d: Miles ahead or behind for the period January 1, 2023 through December 31, 2023 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2023 through December 31, 2023 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2023 through December 31, 2025
Column g: Actual overhead distribution pole miles worked during the period January 1 2023 through December 31, 2025
Column h: Miles ahead or behind for the period January 1, 2023 through December 31, 2025 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2023 through December 31, 2025 ((column g÷f)×100). Max = 100%

7.2 Budget

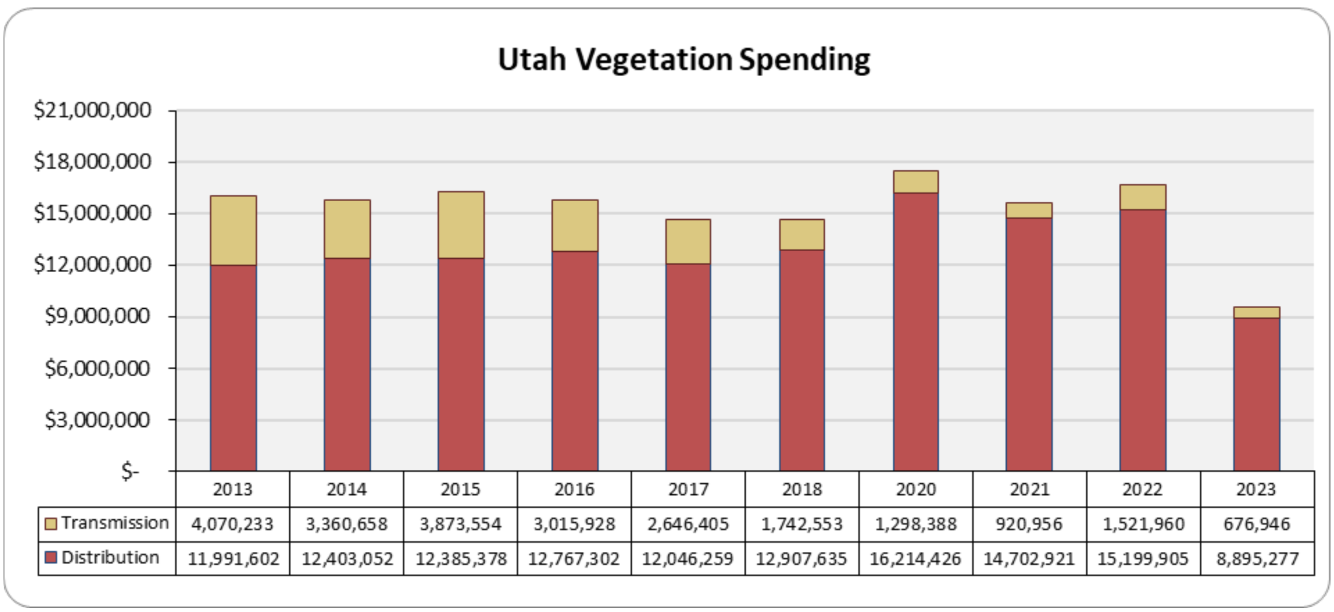
UTAH
Tree Program Reporting
January 1, 2023, through June 30, 2023

	CY2022	CY2023	CY2024
Distribution			
Tree Budget	$15,340,207	$15,340,207	$15,340,207
Transmission			
Tree Budget	$1,643,600	$1,643,600	$1,643,600
Total Tree Budget	$16,983,807	$16,983,807	$16,983,807

	Distribution			Transmission		
	Actuals	**Budget**	**Variance**	**Actuals**	**Budget**	**Variance**
Calendar year 2022						
Jan	$ 1,343,967	$ 1,227,217	$116,751	$ 113,631	$ 131,488	-$17,857
Feb	$ 1,769,420	$ 1,227,217	$542,204	$ 156,515	$ 131,488	$25,027
Mar	$ 1,645,934	$ 1,411,299	$234,635	$ 109,563	$ 151,211	-$41,648
Apr	$ 1,673,870	$ 1,227,217	$446,654	$ 91,515	$ 121,488	-$29,973
May	$ 1,313,413	$ 1,349,938	-$36,526	$ 101,983	$ 144,637	-$42,654
Jun	$ 1,148,673	$ 1,349,938	-$201,265	$ 103,739	$ 144,637	-$40,898
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	$ 8,895,277	$ 7,792,825	$1,102,452	$ 676,946	$ 824,949	$ (148,003)

Average # Tree Crews on Property (YTD) 58

7.2.1 Vegetation Historical Spending[19]



[19] 2023 Vegetation Spending depicted in this chart represents vegetation spend from January 1st through June 31st, 2023. A full complement of 2023 spend for Transmission and Distribution will be provided in the year-end update.

8 Standard Guarantees/Program Summary

8.1 Service Standards Program Summary[20]

8.1.1 Rocky Mountain Power Customer Guarantees[21]

Customer Guarantee 1: Restoring Supply After an Outage	The Company will restore supply after an outage within 24 hours of notification with certain exceptions as described in Rule 25.
Customer Guarantee 2: Appointments	The Company will keep mutually agreed upon appointments, which will be scheduled within a two-hour time window.
Customer Guarantee 3: Switching on Power	The Company will switch on power within 24 hours of the customer or applicant's request, provided no construction is required, all government inspections are met and communicated to the Company and required payments are made. Disconnection for nonpayment, subterfuge or theft/diversion of service is excluded.
Customer Guarantee 4: Estimates For New Supply	The Company will provide an estimate for new supply to the applicant or customer within 15 working days after the initial meeting and all necessary information is provided to the Company and any required payments are made.
Customer Guarantee 5: Respond To Billing Inquiries	The Company will respond to most billing inquiries at the time of the initial contact. For those that require further investigation, the Company will investigate and respond to the Customer within 10 working days.
Customer Guarantee 6: Resolving Meter Problems	The Company will investigate and respond to reported problems with a meter or conduct a meter test and report results to the customer within 10 working days.
Customer Guarantee 7: Notification of Planned Interruptions	The Company will provide the customer with at least two days' notice prior to turning off power for planned interruptions consistent will Rule 25 and relevant exemptions.

[20] In 2012, rules were codified in Utah Administrative Code R746-313. The Company, Commission and other stakeholders worked to develop mechanisms that comply with these rules and supersedes the Company's Service Standards Program.
[21] See Rule 25 for a complete description of terms and conditions for the Customer Guarantee Program.

8.1.2 Rocky Mountain Power Performance Standards[22]

*Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	In 2016 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 137-187 minutes.
*Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	In 2016 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 1.0-1.6 events.
Network Performance Standard 3: Improve Under Performing System Segments	The Company will identify underperforming circuit segments and outline improvement actions and their costs and using the Open Reliability Reporting (ORR) process, evidence the outcome of the ORR process for the circuit segments chosen[23].
*Network Performance Standard 4: Supply Restoration	The Company will restore power outages due to loss of supply or damage to the distribution system within three hours to 80% of customers on average.
Customer Service Performance Standard 5: Telephone Service Level	The Company will answer 80% of telephone calls within 30 seconds. The Company will monitor customer satisfaction with the Company's Customer Service Associates and quality of response received by customers through the Company's eQuality monitoring system.
Customer Service Performance Standard 6: Commission Complaint Response/Resolution	The Company will a) respond to at least 95% of non-disconnect Commission complaints within three working days; b) respond to at least 95% of disconnect Commission complaints within four working hours; and c) resolve 95% of informal Commission complaints within 30 days, except in Utah where the Company will resolve 100% of informal Commission complaints within 30 days.

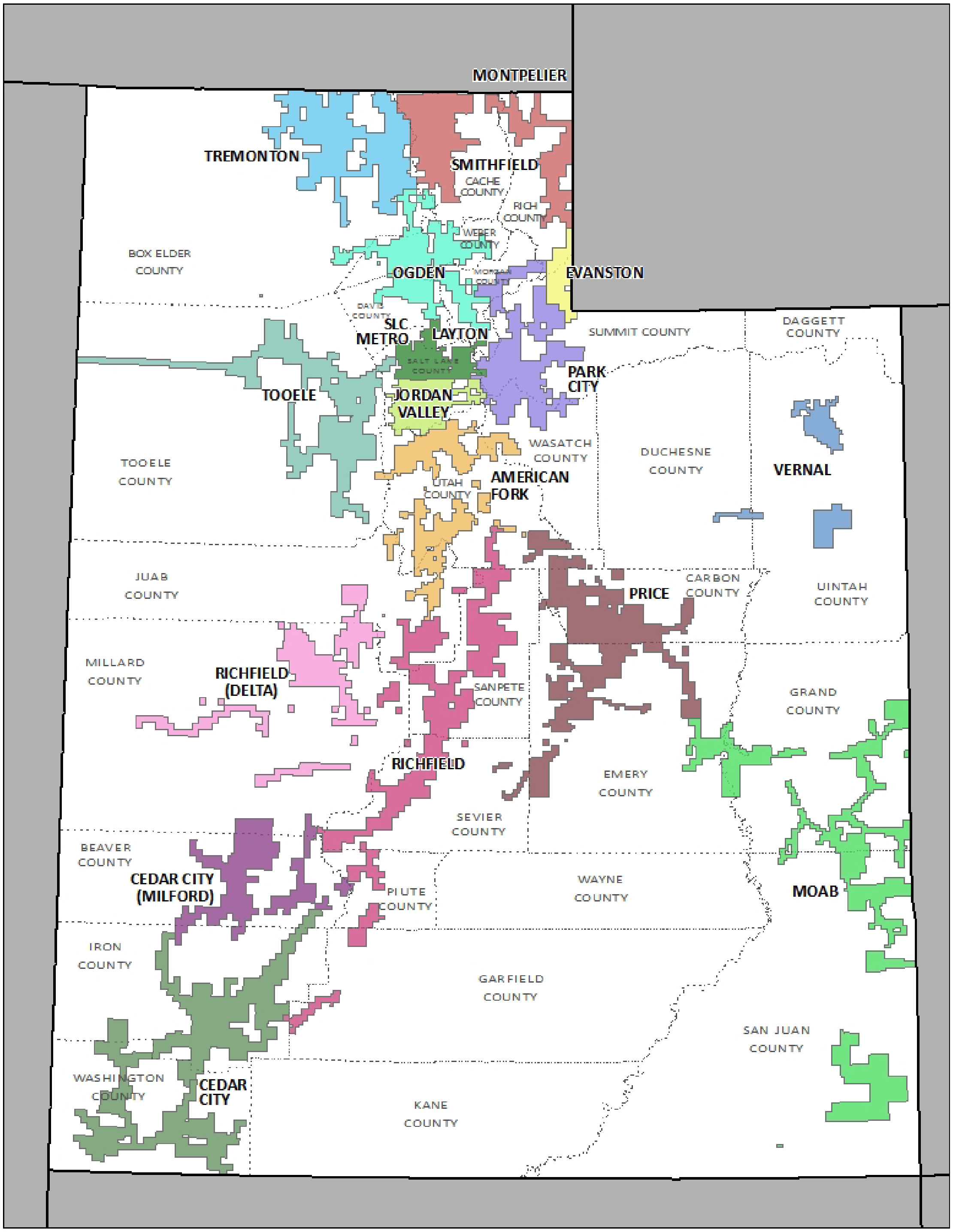
*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude Major Events.

[22] On December 20, 2016, the Public Service Commission of Utah approved modified electric service reliability performance baseline notification levels of 187 SAIDI minutes and 1.6 SAIFI events, with proposed baseline control zones of 137-187 SAIDI and 1.0-1.6 SAIFI (Docket Nos. 13-035-01 and 15-035-72).

[23] On June 1, 2107, in Docket Nos. 15-035-72 and 08-035-55, the Commission approved modified reliability improvement methods with the Company's Open Reliability Reporting (ORR) process, in which the Commission concluded that the process reasonably satisfies the requirements of Utah Administrative Code R746-313-7(3)(e) relating to reporting on electric service reliability for areas whose reliability performance warrants additional improvement efforts. This change is reflected in Section 2.8.

8.1.3 Utah Distribution Service Area Map with Operating Areas/Districts

Below is a graphic showing the specific areas where the Company's distribution facilities are located.



8.2 Cause Code Analysis

The tables below outline categories used in outage data collection. Charts and table in this report use these groupings to develop patterns for outage performance.

Direct Cause Category	Category Definition & Example/Direct Cause
Animals	Any problem nest that requires removal, relocation, trimming, etc.; any birds, squirrels or other animals, whether or not remains found.
	• Animal (Animals) • Bird Mortality (Non-protected species) • Bird Mortality (Protected species)(BMTS) • Bird Nest • Bird or Nest • Bird Suspected, No Mortality
Environment	Contamination or Airborne Deposit (i.e., salt, trona ash, other chemical dust, sawdust, etc.); corrosive environment; flooding due to rivers, broken water main, etc.; fire/smoke related to forest, brush or building fires (not including fires due to faults or lightning).
	• Condensation/Moisture • Contamination • Fire/Smoke (not due to faults) • Flooding • Major Storm or Disaster • Nearby Fault • Pole Fire
Equipment Failure	Structural deterioration due to age (incl. pole rot); electrical load above limits; failure for no apparent reason; conditions resulting in a pole/cross arm fire due to reduced insulation qualities; equipment affected by fault on nearby equipment (e.g., broken conductor hits another line).
	• B/O Equipment • Overload • Deterioration or Rotting • Substation, Relays
Interference	Willful damage, interference or theft, such as gun shots, rock throwing, etc.; customer, contractor or other utility dig-in; contact by outside utility, contractor or other third-party individual; vehicle accident, including car, truck, tractor, aircraft, manned balloon; other interfering object such as straw, shoes, string, balloon.
	• Dig-in (Non-PacifiCorp Personnel) • Other Interfering Object • Vandalism or Theft • Other Utility/Contractor • Vehicle Accident
Loss of Supply	Failure of supply from Generator or Transmission system; failure of distribution substation equipment.
	• Failure on other line or station • Loss of Feed from Supplier • Loss of Generator • Loss of Substation • Loss of Transmission Line • System Protection
Operational	Accidental Contact by PacifiCorp or PacifiCorp's Contractors (including live-line work); switching error; testing or commissioning error; relay setting error, including wrong fuse size, equipment by-passed; incorrect circuit records or identification; faulty installation or construction; operational or safety restriction.
	• Contact by PacifiCorp • Faulty Install • Improper Protective Coordination • Incorrect Records • Internal Contractor • Internal Tree Contractor • Switching Error • Testing/Startup Error • Unsafe Situation
Other	Cause Unknown; use comments field if there are some possible reasons.
	• Invalid Code • Other, Known Cause • Unknown
Planned	Transmission requested, affects distribution sub and distribution circuits; Company outage taken to make repairs after storm damage, car hit pole, etc.; construction work, regardless of if notice is given; rolling blackouts.
	• Construction • Customer Notice Given • Energy Emergency Interruption • Intentional to Clear Trouble • Emergency Damage Repair • Customer Requested • Planned Notice Exempt • Transmission Requested
Tree	Growing or falling trees
	• Tree-Non-preventable • Tree-Trimmable • Tree-Tree felled by Logger
Weather	Wind (excluding windborne material); snow, sleet or blizzard, ice, freezing fog, frost, lightning.
	• Extreme Cold/Heat • Freezing Fog & Frost • Wind • Lightning • Rain • Snow, Sleet, Ice and Blizzard

8.3 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[24] Standard for Reliability Indices.

Sustained Outage

A sustained outage is defined as an outage of greater than 5 minutes in duration.

Momentary Outage Event

A momentary outage is defined as an outage equal to or less than 5 minutes in duration. Rocky Mountain Power has historically captured this data using substation breaker fault counts, but where SCADA (Supervisory Control and Data Acquisition Systems) exist, uses this data to calculate consistent with IEEE 1366-2003.

Reliability Indices

SAIDI

SAIDI (system average interruption duration index) is an industry-defined term to define the average duration summed for all sustained outages a customer experiences in each period. It is calculated by summing all customer minutes lost for sustained outages (those exceeding 5 minutes) and dividing by all customers served within the study area. When not explicitly stated otherwise, this value can be assumed to be for a one-year period.

Daily SAIDI

To evaluate trends during a year and to establish Major Event Thresholds, a daily SAIDI value is often used as a measure. This concept was introduced in IEEE Standard 1366-2003. This is the day's total customer minutes out of service divided by the static customer count for the year. It is the total average outage duration customers experienced for that given day. When these daily values are accumulated through the year, it yields the year's SAIDI results.

SAIFI

SAIFI (system average interruption frequency index) is an industry-defined term that attempts to identify the frequency of all sustained outages that the average customer experiences during a given timeframe. It is calculated by summing all customer interruptions for sustained outages (those exceeding 5 minutes in duration) and dividing by all customers served within the study area.

[24] IEEE adopted Standard 1366-2003 on December 23, 2003. It was subsequently modified in IEEE 1366-2012, but all definitions used in this document are consistent between these two versions. The definitions and methodology detailed therein are now industry standards. Later, in Docket No. 04-035-T13 the Utah Public Utilities Commission adopted the standard methodology for determining major event threshold.

CAIDI

CAIDI (customer average interruption duration index) is an industry-defined term that is the result of dividing the duration of the average customer's sustained outages by the frequency of outages for that average customer. While the Company did not originally specify this metric under the umbrella of the Performance Standards Program within the context of the Service Standards Commitments, it has since been determined to be valuable for reporting purposes. It is derived by dividing PS1 (SAIDI) by PS2 (SAIFI).

$MAIFI_E$

$MAIFI_E$ (momentary average interruption event frequency index) is an industry-defined term that attempts to identify the frequency of all momentary interruption events that the average customer experiences during a given timeframe. It is calculated by counting all momentary operations which occur within a 5-minute time period, as long as the sequence did not result in a device experiencing a sustained interruption. This series of actions typically occurs when the system is trying to re-establish energy flow after a faulted condition and is associated with circuit breakers or other automatic reclosing devices.

Lockout

Lockout is the state of device when it attempts to re-establish energy flow after a faulted condition but is unable to do so; it systematically opens to de-energize the facilities downstream of the device then recloses until a lockout operation occurs. The device then requires manual intervention to re-energize downstream facilities. This is generally associated with substation circuit breakers and is one of the variables used in the Company's calculation of blended metrics.

CEMI

CEMI is an acronym for Customers Experiencing Multiple (Momentary Event and Sustained) Interruptions. This index depicts repetition of outages across the period being reported and can be an indicator of recent portions of the system that have experienced reliability challenges.

ORR

ORR is an acronym for Open Reliability Reporting, which shifts the company's reliability program from a circuit-based metric (CPI) to a targeted approach reviewing performance in a local area, measured by customer minutes lost. Project funding is based on cost effectiveness as measured by the cost per avoided annual customer minute interrupted.

CPI99

CPI99 is an acronym for Circuit Performance Indicator, which uses key reliability metrics of the circuit to identify underperforming circuits. It excludes Major Event and Loss of Supply or Transmission outages. The variables and equation for calculating CPI are:

CPI = Index * ((SAIDI * WF * NF) + (SAIFI * WF * NF) + ($MAIFI_E$ * WF * NF) + (Lockouts * WF * NF))
Index: 10.645
SAIDI: Weighting Factor 0.30, Normalizing Factor 0.029
SAIFI: Weighting Factor 0.30, Normalizing Factor 2.439

$MAIFI_E$: Weighting Factor 0.20, Normalizing Factor 0.70
Lockouts: Weighting Factor 0.20, Normalizing Factor 2.00
Therefore, 10.645 * ((3-year SAIDI * 0.30 * 0.029) + (3-year SAIFI * 0.30 * 2.439) + (3-year $MAIFI_E$* 0.20 * 0.70) + (3-year breaker lockouts * 0.20 * 2.00)) = CPI Score

CPI05

CPI05 is an acronym for Circuit Performance Indicator, which uses key reliability metrics of the circuit to identify underperforming circuits. Unlike CPI99, it includes Major Event and Loss of Supply or Transmission outages. The calculation of CPI05 uses the same weighting and normalizing factors as CPI99.

Performance Types

Rocky Mountain Power recognizes several categories of performance: major events, significant events, and underlying performance. Underlying performance days may be significant event days. Outages recorded during any day may be classified as "controllable" events.

Major Events

A Major Event (ME) is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value (Reliability Standard IEEE 1366-2012) based on the 2.5 beta methodology. The values used for the reporting period and the prospective period are shown below.

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2023	1,009,615	4.31	4,352,711

Significant Events

The Company has evaluated its year-to-year performance and as part of an industry weather normalization task force, sponsored by the IEEE Distribution Reliability Working Group, determined that when the Company recorded a day in excess of 1.75 beta (or 1.75 times the natural log standard deviation beyond the natural log daily average for the day's SAIDI) that generally these days' events are generally associated with weather events and serve as an indicator of a day which accrues substantial reliability metrics, adding to the cumulative reliability results for the period. As a result, the Company individually identifies these days so that year-on-year comparisons are informed by the quantity and their combined impact to the reporting period results.

Underlying Events

Within the industry, there has been a great need to develop methodologies to evaluate year-on-year performance. This has led to the development of methods for segregating outlier days, via the approaches described above. Those days which fall below the statistically derived threshold represent "underlying" performance and are valid. If any changes have occurred in outage reporting processes, those impacts need to be considered when making comparisons. Underlying events include all sustained interruptions, whether of a controllable or non-controllable cause, exclusive of major events, prearranged (which can include short notice emergency prearranged outages), customer requested interruptions and forced outages mandated by public authority typically regarding safety in an emergency.

Controllable Distribution (CD) Events

In 2008, the Company identified the benefit of separating its tracking of outage causes into those that can be classified as "controllable" (and thereby reduced through preventive work) from those that are "non-controllable" (and thus cannot be mitigated through engineering programs); they will generally be referred to in subsequent text as controllable distribution (CD). For example, outages caused by deteriorated equipment or animal interference are classified as controllable distribution since the Company can take preventive measures with a high probability to avoid future recurrences, while vehicle interference or weather events are largely out of the Company's control and generally not avoidable through engineering programs. (It should be noted that Controllable Events is a subset of Underlying Events. The *Cause Code Analysis* section of this report contains two tables for Controllable Distribution and Non-controllable Distribution, which list the Company's performance by direct cause under each classification.) At the time that the Company established the determination of controllable and non-controllable distribution it undertook significant root cause analysis of each cause type and its proper categorization (either controllable or non-controllable). Thus, when outages are completed and evaluated, and if the outage cause designation is improperly identified as non-controllable, then it would result in correction to the outage's cause to preserve the association between controllable and non-controllable based on the outage cause code. The company distinguishes the performance delivered using this differentiation for comparing year to date performance against underlying and total performance metrics.