ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W. North Temple
Salt Lake City, UT 84116

November 1, 2022

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. 22-035-14 – 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 the 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 2022.

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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jana.saba@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah, Suite 2000
Portland, OR 97232

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

Sincerely,

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

Enclosure

CERTIFICATE OF SERVICE

Docket No. 22-035-14

I hereby certify that on November 1, 2022, a true and correct copy of the foregoing was served by electronic mail to the following:

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ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH
SERVICE QUALITY
REVIEW

January 1 – June 30, 2022
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 was one major event experienced during this reporting period for Utah customers. While major events are often extreme events, 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 our mid-year 2022 performance serving the customers of Utah.

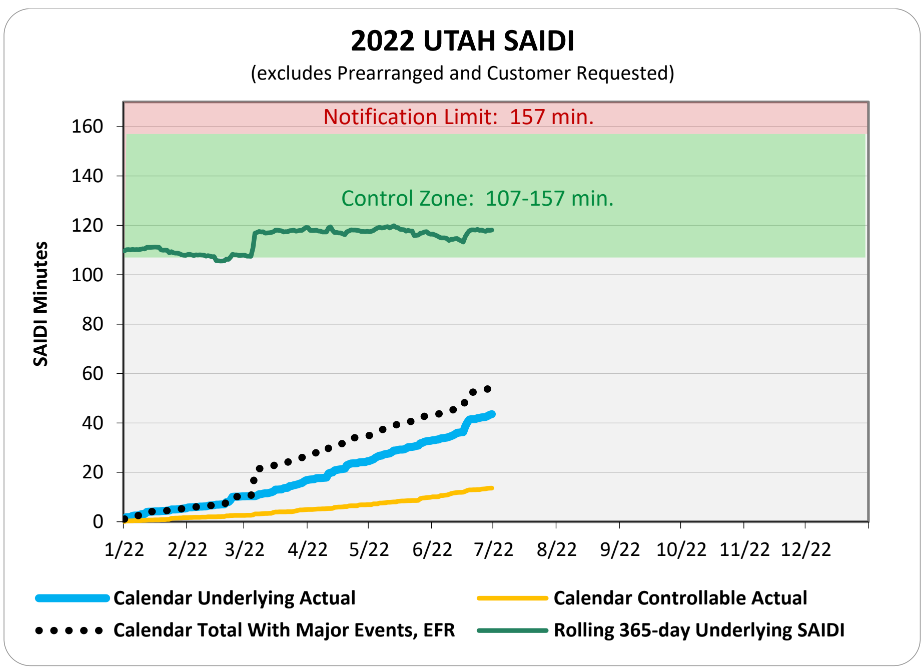
1 Reliability Performance

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)

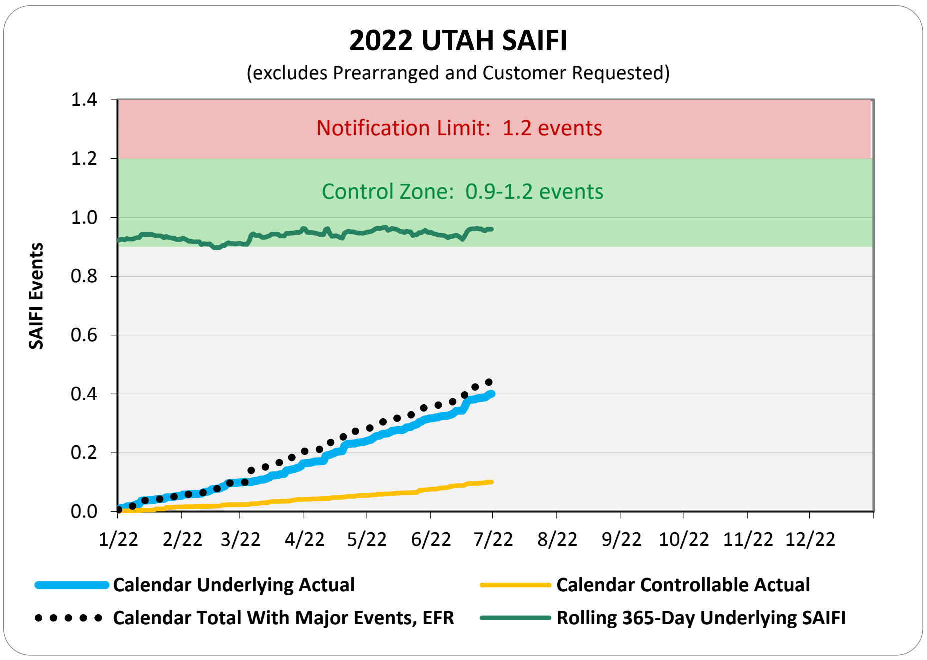
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below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

SAIDI	Reporting Period
Total	55
Underlying	44
Controllable Distribution	14



1.2 System Average Interruption Frequency Index (SAIFI)

SAIFI	Reporting Period
Total	0.443
Underlying	0.400
Controllable Distribution	0.100



1.3 Major and Significant Event Days

For the current reporting period, there was one major event[1] and three significant event days[2]. Rocky Mountain Power has included regional major events to show events that are statistical outliers that may not show up on a state level. These events are still included in the underlying metrics and are found in section 1.1.

Major Events				
Date	**Cause**	**Status**	**Docket**	**SAIDI**
March 5-7, 2022	Snowstorm	Approved	22-035-12	10.58
			Total	**10.58**

March 5-8, 2022

A high-density snowstorm moved across the state between March 5th and 7th, 2022. The weight of this water-heavy snow caused many vegetation-based outages. The most affected areas were Salt Lake City Metro and Jordan Valley. The damage to Rocky Mountain Power facilities resulted in 40,944 customers experiencing sustained service interruptions.

Significant Events

Significant event days add substantially to year-on-year cumulative performance results; fewer significant event days result in better reliability for the reporting period while more significant event days mean poorer reliability results. During the period, three significant event days were recorded, which account for 6.3 SAIDI minutes, or about 14% of the reporting period's underlying 44 SAIDI minutes. These significant events were triggered by weather and loss of supply outages.

Significant Event Days					
Dates	**Cause: General Description**	**Underlying SAIDI**	**Underlying SAIFI**	**% Of Total Underlying SAIDI (44)**	**% Of Total Underlying SAIFI (0.400)**
April 11, 2022	Snow and Wind	1.7	0.017	3.9%	4.3%
June 17, 2022	Wind	2.6	0.012	5.9%	3.0%
June 18, 2022	Wind and Fire Conditions	2.0	0.016	4.5%	4.0%
	TOTAL	**6.3**	**0.045**	**14.3%**	**11.3%**

[1] 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
1/1-12/31/2022	1,002,258	4.38	4,418,888

[2] 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).

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 listed below are still included in the underlying metrics and are noted in this report for informational purposes. During the reporting period no regional major events occurred.

1.4 Restore Service to 80% of Customers within 3 Hours

RESTORATIONS WITHIN 3 HOURS					
Reporting Period Cumulative = 85%					
January	February	March	April	May	June
85%	83%	88%	89%	91%	76%

1.5 CAIDI Performance

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

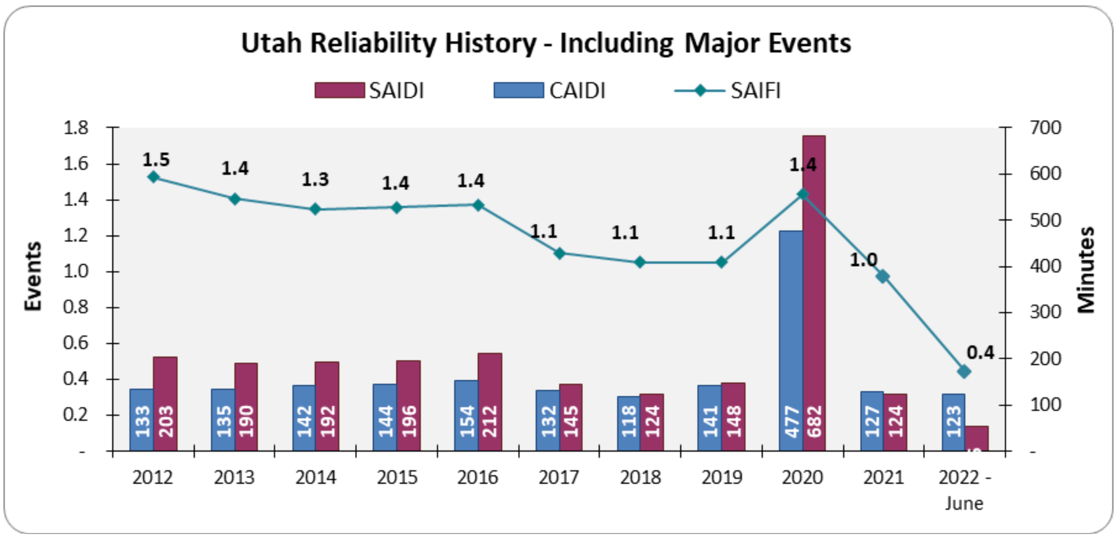
CAIDI (Average Outage Duration)	
Underlying Performance	109 minutes
Total Performance	123 minutes

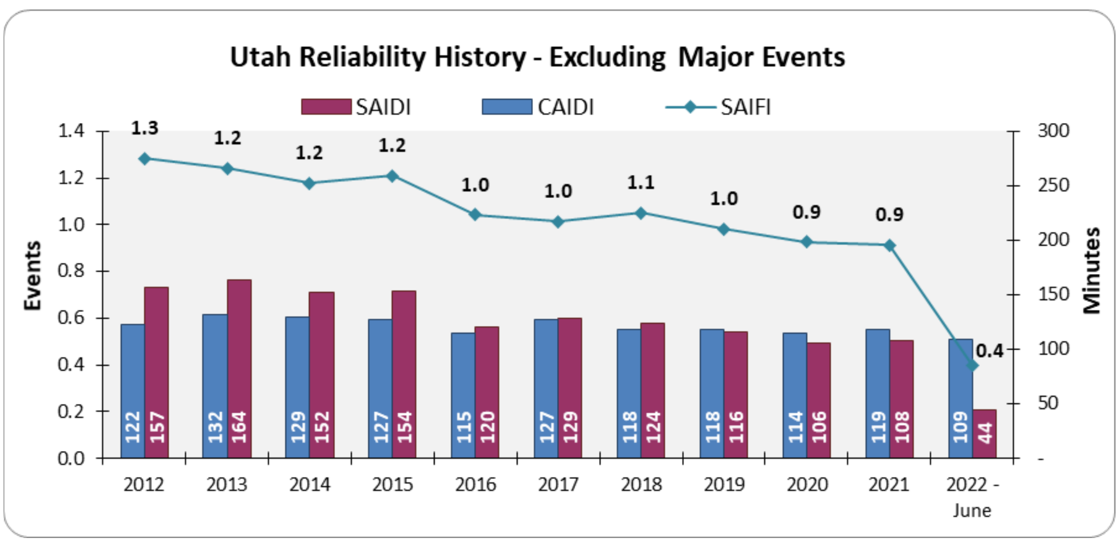
2 Reliability History

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

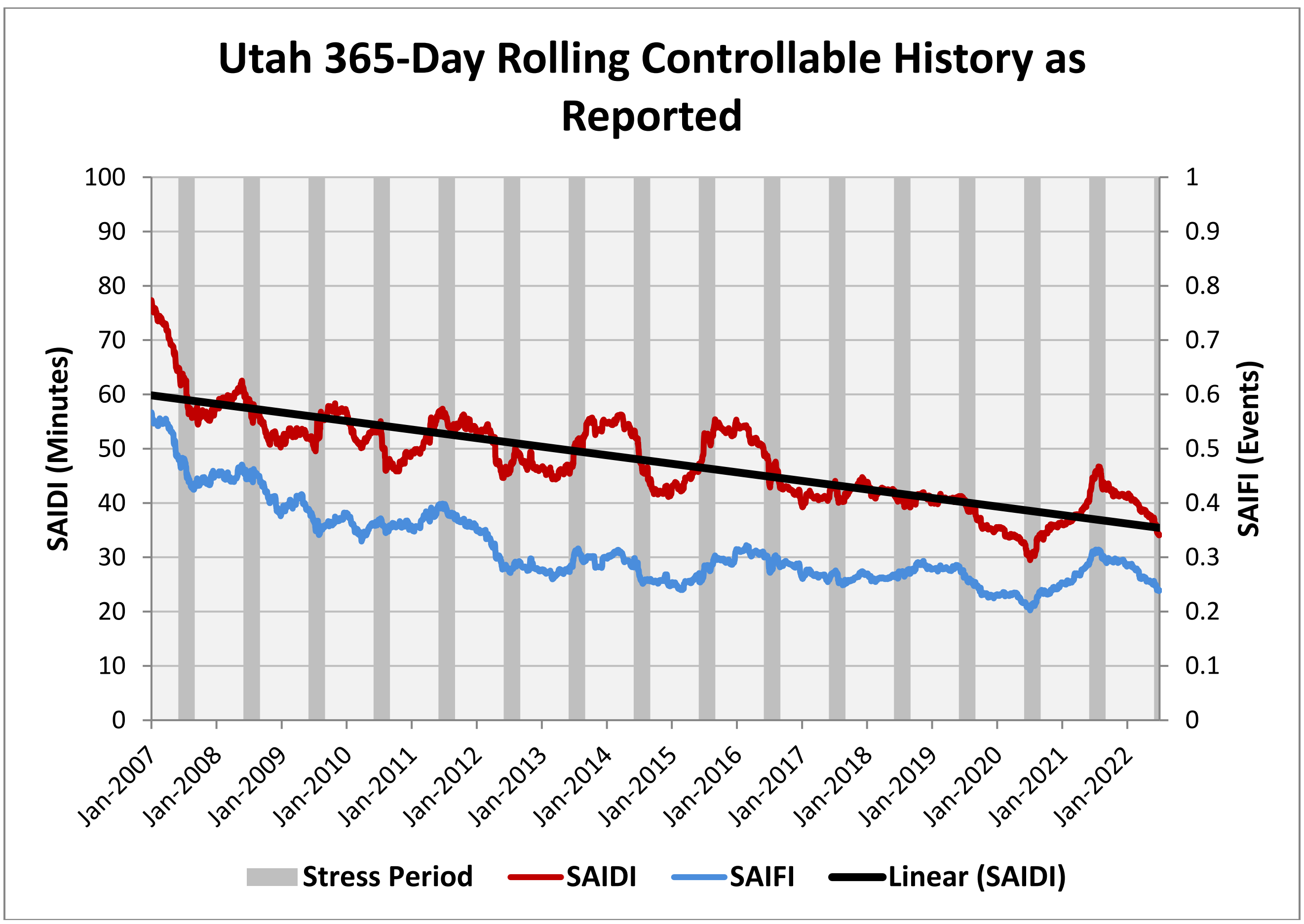


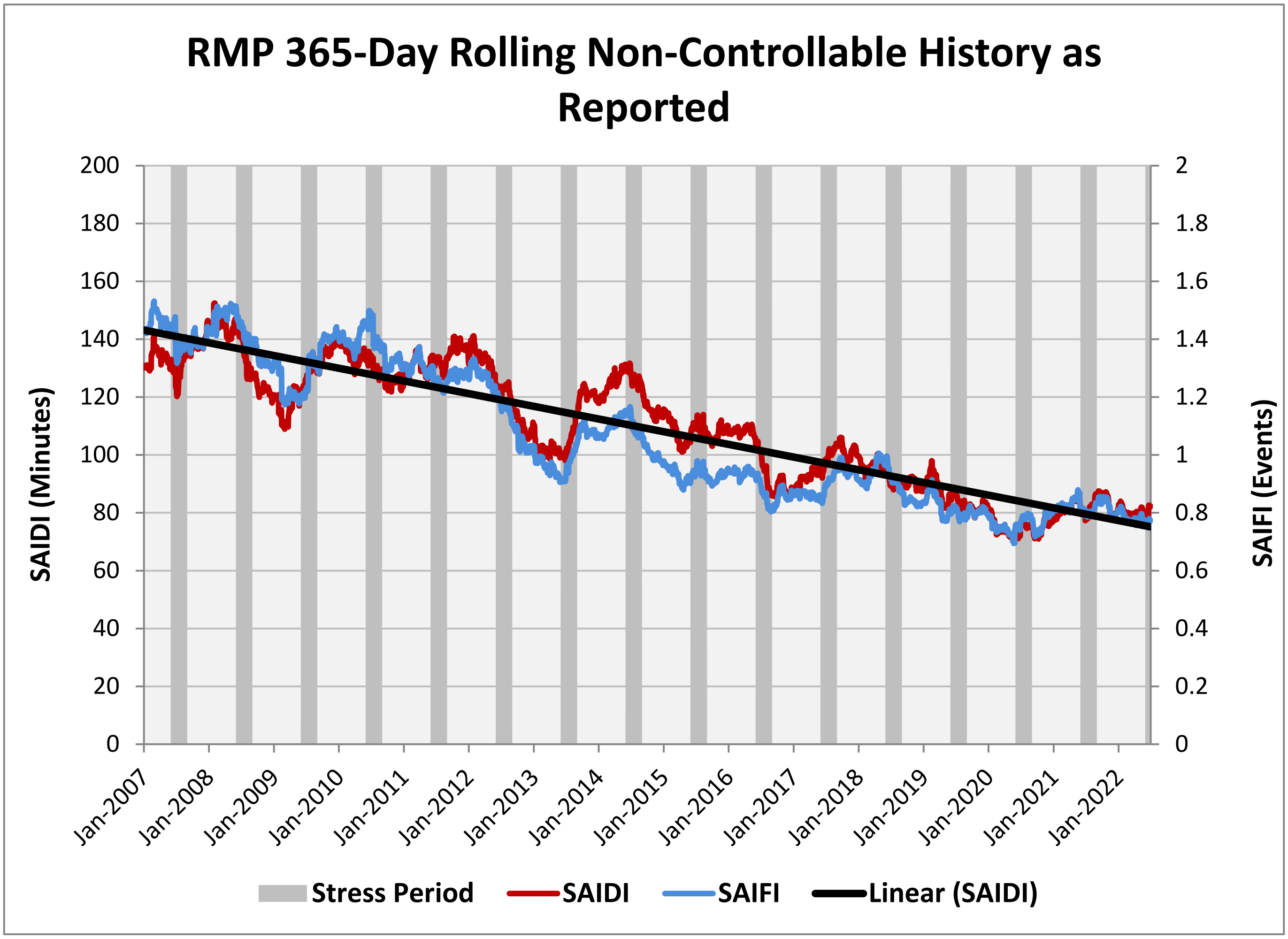


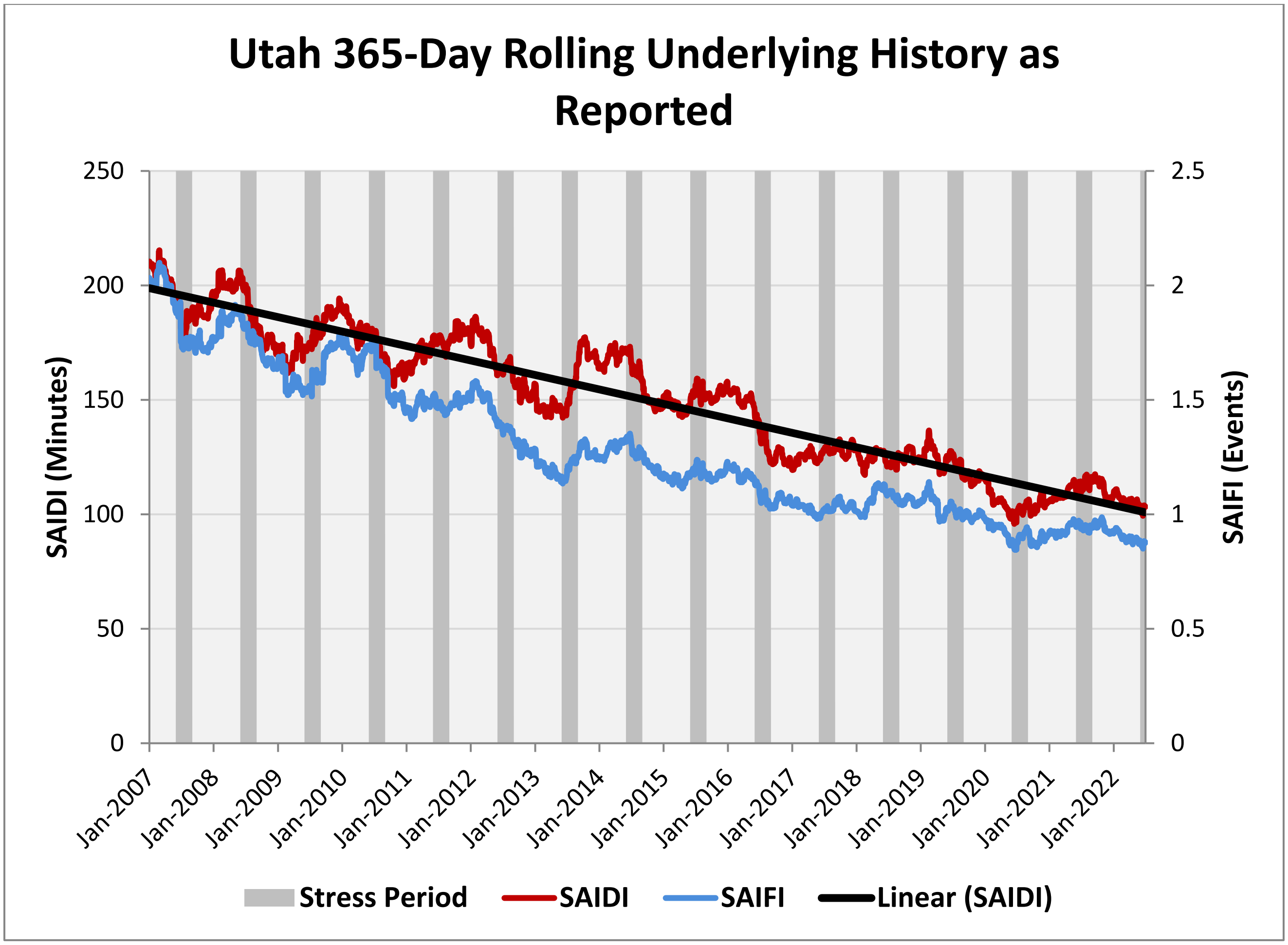
2.2 Controllable, Non-Controllable and Underlying Performance Review

In 2008, the Company introduced a further categorization of outage causes, which it later 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 identified 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 general improving performance for SAIDI and SAIFI. 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.



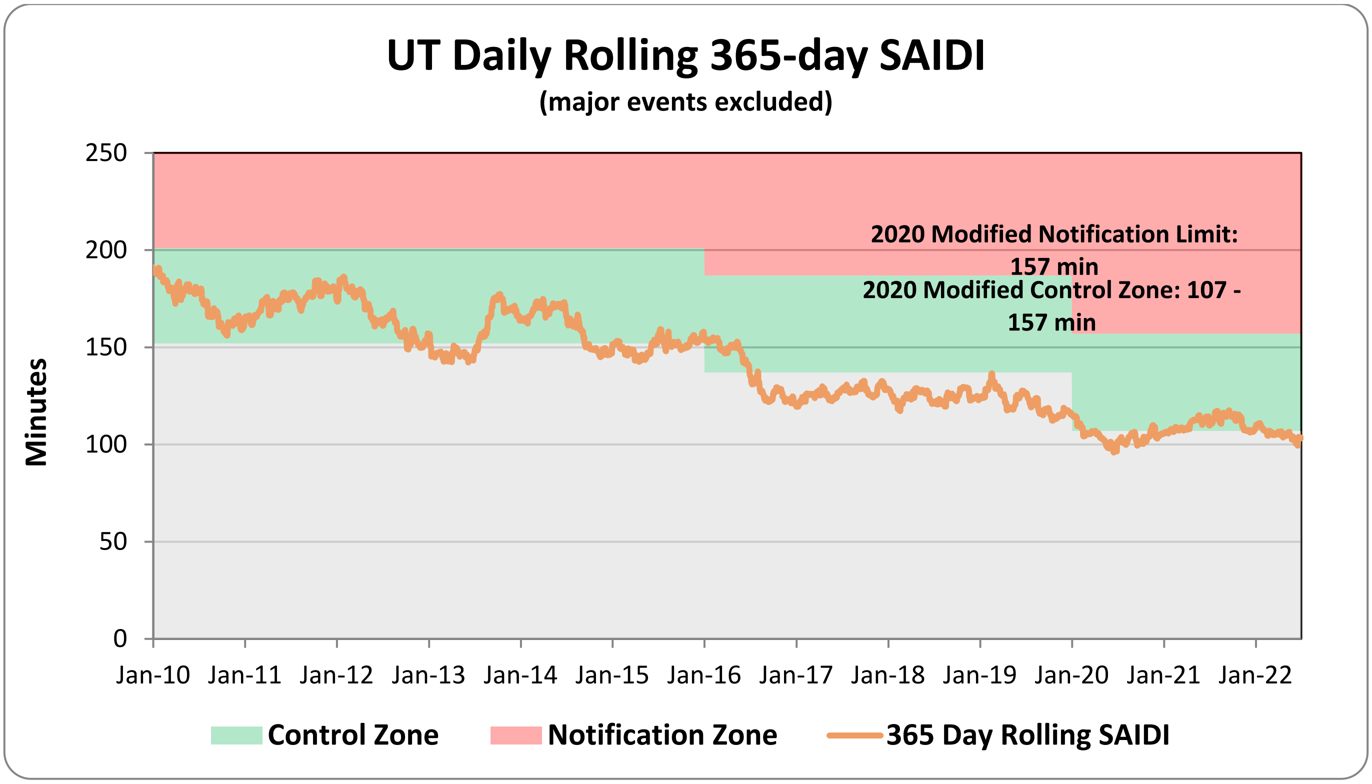

RMP 365-Day Rolling Non-Controllable History as Reported
SAIDI (Minutes)
SAIFI (Events)
200
180
160
140
120
100
80
60
40
20
0
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Jan-2017
Jan-2018
Jan-2019
Jan-2020
Jan-2021
Jan-2022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

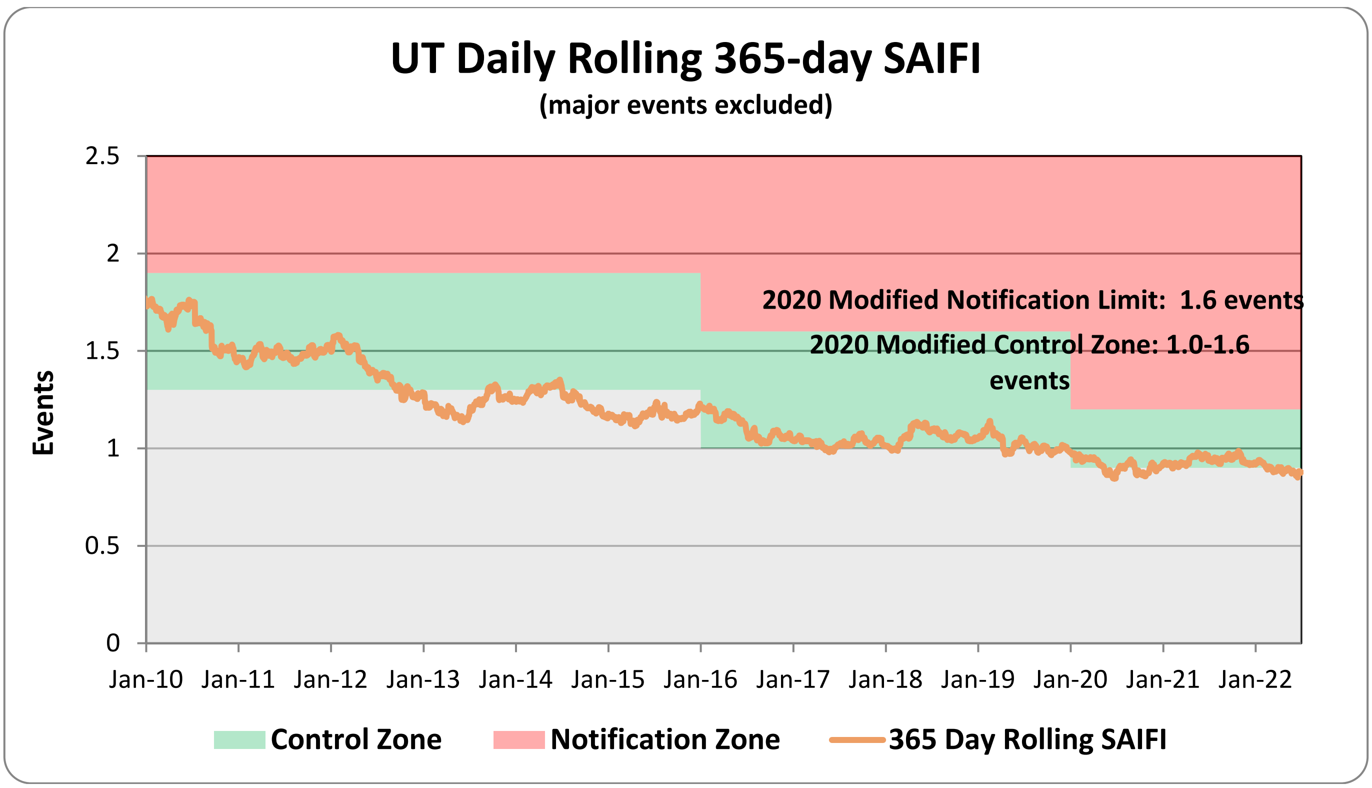


2.3 Baseline Performance

In compliance with Utah Reliability Reporting Rules, the Company developed performance baselines that it then 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
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
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.

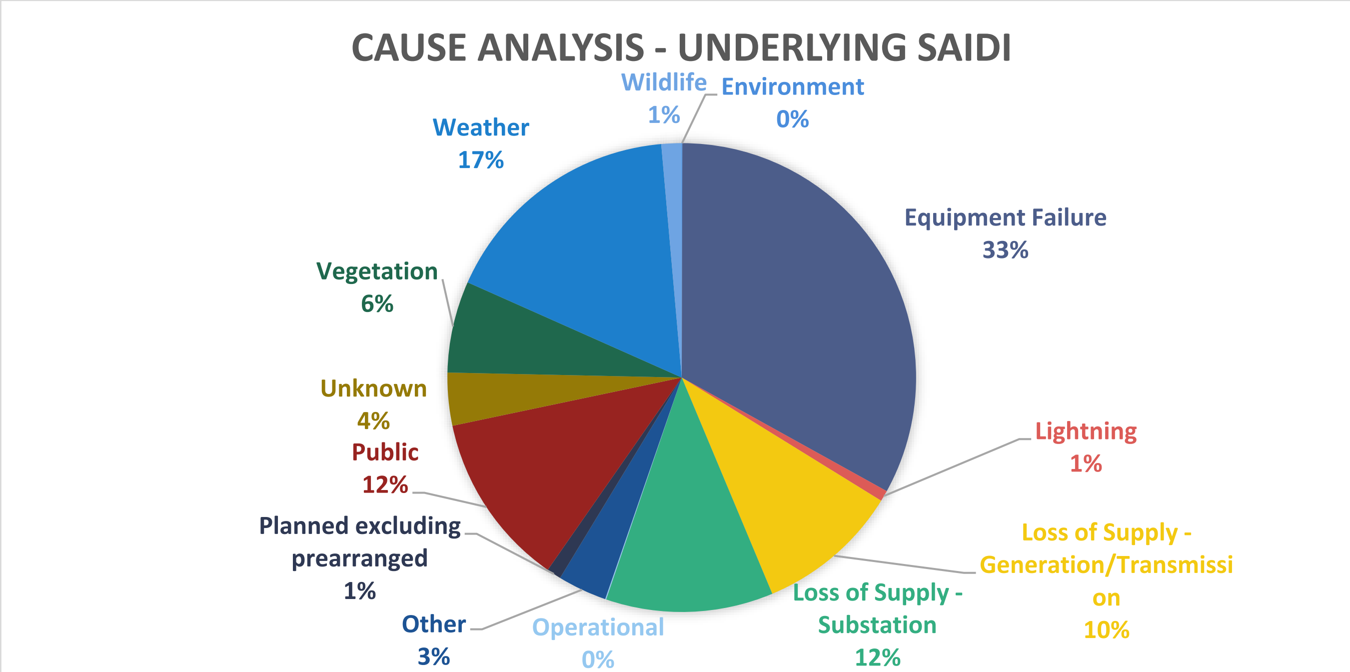
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_e$ are required.

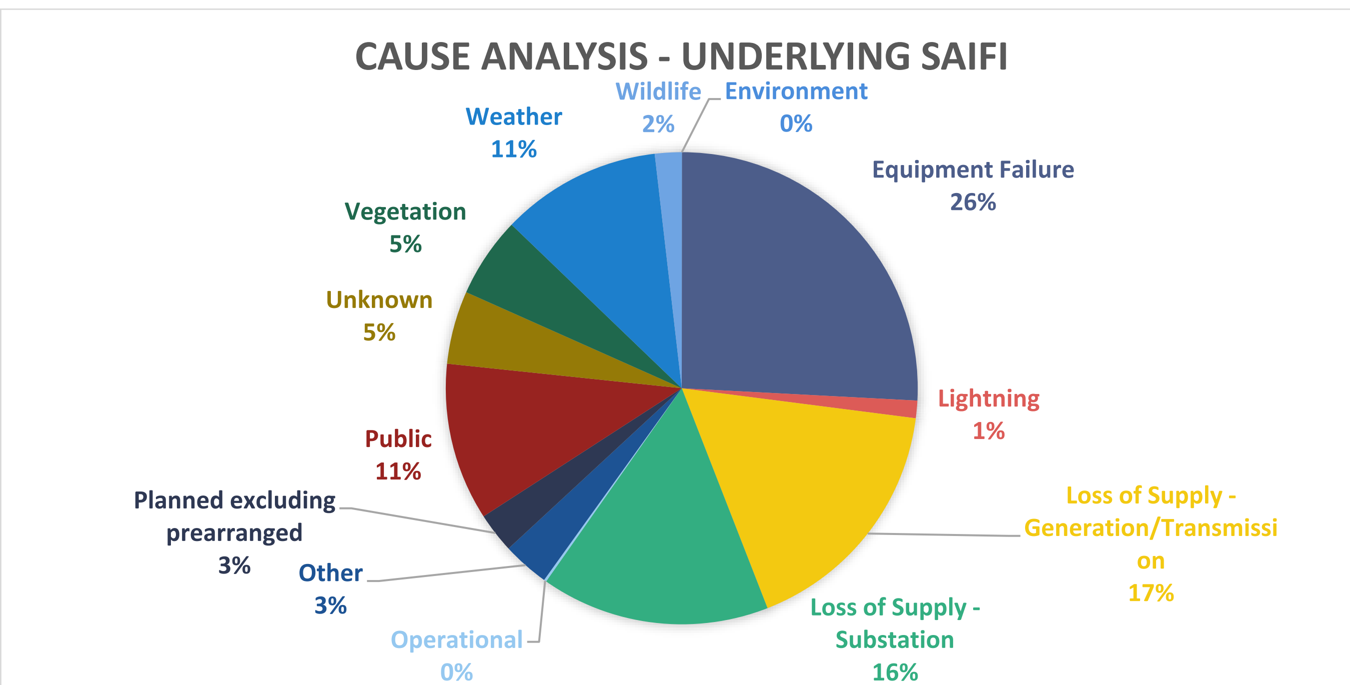
Major Events and Prearranged Excluded*	2017				2018				2019			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	129	1.0	127	1.11	124	1.1	118	2.17	116	1.0	118	2.64
Op Area												
AMERICAN FORK	77	0.8	102		85	0.8	109		59	0.6	100	
CEDAR CITY	183	1.7	109		157	1.2	136		160	1.4	114	
CEDAR CITY (MILFORD)	565	2.5	230		226	1.4	164		563	3.2	177	
EVANSTON	49	0.2	219		23	0.2	96		9	0.1	76	
JORDAN VALLEY	109	0.8	139		138	1.1	121		100	0.8	118	
LAYTON	168	1.1	149		132	1.3	101		123	1.4	90	
MOAB	190	2.4	80		111	1.1	102		171	2.0	87	
MONTPELIER	452	0.7	624		34	0.4	94		13	0.2	75	
OGDEN	119	0.9	138		116	1.0	114		153	1.1	139	
PARK CITY	227	1.4	159		165	1.2	143		187	1.1	171	
PRICE	171	2.5	70		203	2.3	90		101	1.9	53	
RICHFIELD	187	2.0	95		173	1.4	125		222	2.2	103	
RICHFIELD (DELTA)	143	1.4	105		176	1.1	163		103	0.8	136	
SLC METRO	225	2.0	111		234	2.0	118		222	1.8	125	
SMITHFIELD	130	0.9	148		96	1.0	99		127	1.5	83	
TOOELE	140	1.4	100		196	1.5	135		146	1.3	110	
TREMONTON	200	2.0	99		151	1.1	137		259	1.6	167	
VERNAL	77	0.8	96		48	0.6	83		58	0.6	99	

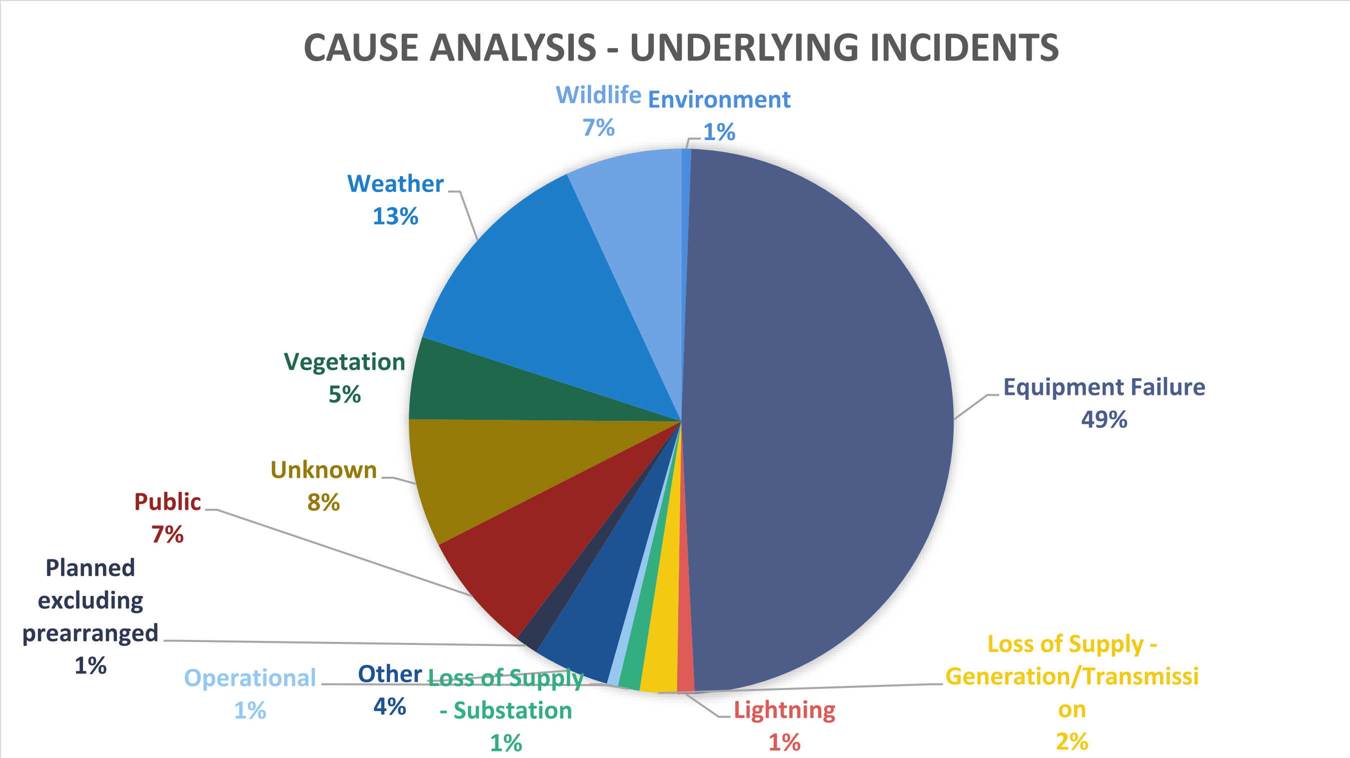
Major Events and Prearranged Excluded*	2020				2021				2022 - June			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	106	0.9	114	3.46	108	0.9	119	1.89	44	0.4	109	0.62
Op Area												
AMERICAN FORK	65	0.7	91		56	0.4	144		60	0.4	146	
CEDAR CITY	149	1.3	111		144	1.3	111		48	0.3	169	
CEDAR CITY (MILFORD)	296	1.9	155		270	2.0	133		142	1.0	144	
EVANSTON	12	0.1	192		26	0.2	112		24	0.2	132	
JORDAN VALLEY	99	0.8	121		109	1.0	114		34	0.3	132	
LAYTON	104	1.1	93		119	1.2	96		57	0.4	146	
MOAB	239	1.9	123		146	1.2	126		90	0.5	200	
MONTPELIER	33	0.2	142		78	1.1	73		7	0.0	198	
OGDEN	116	0.9	128		126	1.0	127		62	0.6	110	
PARK CITY	251	1.9	132		121	0.7	166		1	0.0	108	
PRICE	140	1.3	109		64	1.0	63		47	0.5	103	
RICHFIELD	135	1.5	92		213	1.2	175		53	0.6	92	
RICHFIELD (DELTA)	208	1.1	197		340	2.7	128		37	0.4	103	
SLC METRO	189	1.7	108		226	1.9	120		110	1.5	76	
SMITHFIELD	88	0.9	101		80	0.9	86		68	1.4	47	
TOOELE	137	1.0	137		155	1.4	112		94	1.1	83	
TREMONTON	178	1.3	140		92	0.8	117		32	0.3	96	
VERNAL	68	0.7	94		64	0.4	165		99	1.0	103	

*except MAIFIe

Utah Cause Category	2017		2018		2019		2020		2021		June 2022	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	1	0	1	0	0	0	1	0	1	0	0.0	0.0
Equipment Failure	44	0.2	48	0.3	40	0.2	39	0.2	42	0.3	14.6	0.1
Lightning	3	0	3	0	3	0	1	0	3	0	0.3	0.0
Loss of Supply - Generation/Transmission	13	0.1	13	0.2	9	0.1	15	0.2	9	0.1	4.4	0.1
Loss of Supply - Substation	11	0.1	9	0.1	11	0.1	6	0.1	10	0.1	5.1	0.1
Operational	1	0	0	0	0	0	1	0	1	0	0.0	0.0
Other	0	0	0	0	1	0	1	0	2	0	1.5	0.0
Planned (excl. Prearranged)	8	0.1	10	0.1	9	0.1	6	0.1	3	0	0.4	0.0
Public	15	0.1	15	0.1	16	0.1	16	0.1	13	0.1	5.3	0.0
Unknown	6	0.1	6	0.1	5	0.1	5	0.1	5	0.1	1.6	0.0
Vegetation	6	0	5	0	7	0	7	0	6	0	2.8	0.0
Weather	16	0.1	9	0.1	11	0.1	7	0.1	10	0.1	7.5	0.0
Wildlife	3	0	3	0	2	0	3	0	3	0	0.6	0.0
UTAH Underlying	**129**	**1**	**124**	**1.1**	**116**	**1**	**106**	**0.9**	**108**	**0.9**	**44.3**	**0.4**


CAUSE ANALYSIS - UNDERLYING SAIDI
Wildlife 1%
Environment 0%
Weather 17%
Equipment Failure 33%
Vegetation 6%
Unknown 4%
Public 12%
Lightning 1%
Planned excluding prearranged 1%
Loss of Supply - Generation/Transmission 10%
Loss of Supply - Substation 12%
Other 3%
Operational 0%


CAUSE ANALYSIS - UNDERLYING SAIFI
Wildlife 2%
Environment 0%
Weather 11%
Equipment Failure 26%
Vegetation 5%
Unknown 5%
Lightning 1%
Public 11%
Loss of Supply - Generation/Transmission 17%
Planned excluding prearranged 3%
Other 3%
Loss of Supply - Substation 16%
Operational 0%



3 Improve Reliability Performance in Areas of Concern

Over the past decade the Company has developed approaches, including tools and automated and manual processes, to improve reliability. As it has done so, the Company's ability to diagnose portions of the system requiring improvement has improved. Its legacy "Worst Performing Circuit" program used circuit SAIDI, SAIFI, and MAIFI to evaluate the reliability of a feeder.

The Company then decided that a more targeted approach for developing improvement plans, determining the value of those plans, and monitoring them to ensure that the results met or exceeded the expected targets. This program was called Open Reliability Reporting (ORR) and is a more strategic approach based upon recent trends in performance of the local area as measured by customer minutes interrupted (from which SAIDI is derived). The decision to fund one performance improvement project versus another was based on cost effectiveness as measured by the cost per avoided annual customer minute interrupted. However, the cost effectiveness measure did not limit funding of improvement projects in areas of low customer density where cost effectiveness per customer may not be as high as projects in more densely populated areas.

The Company has moved to another approach to lowering its SAIDI values. The focus of this new program, the Mainline Sectionalizing (MLS) plan, is to limit the number of customers on a feeder to 2250 and to further sectionalize the circuit with reclosers that will each protect 750 customers (or fewer). This will mitigate the number of sustained outages and will also help decrease the number of customers affected by each outage. At the beginning of 2022, the Company approved 12 MLS projects for design and construction in Utah. Four of these projects have anticipated completion dates before the end of this year and the remaining eight are expected to be completed in 2023. The Company is currently evaluating over 100 additional circuits for this program. This program will continue for the foreseeable future.

4 Customer Response

4.1 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	63%
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[3] complaints within 30 days	100%	100%

4.2 Utah Commitment U1

To determine 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 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 was one wide-scale outage day. Call statistics are shown in the table below. On January 3rd, Sunnyside, WA experienced a loss of transmission, which affected approximately 10,100 customers, and Oregon experienced a windstorm that affected about 30,200 customers.

Date	Interval start/finish (MT Time)		Network Total Calls*	Calls received but not delivered**	# Of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds
1/3/2022	9:30	9:44	393	0	83	684	12
	9:45	9:59	416	0	67	702	6
	10:00	10:14	481	0	96	777	11
	10:15	10:29	527	0	120	917	16
	10:30	10:44	558	0	111	931	9
	10:45	10:59	576	0	94	1049	18
	11:00	11:14	564	0	125	939	10
	11:15	11:29	600	0	111	922	16
	11:30	11:44	624	0	100	853	18
	11:45	11:59	594	0	79	891	16
	12:00	12:14	494	0	106	816	18
	12:15	12:29	532	0	93	810	25
	12:30	12:44	525	0	91	1014	12
	12:45	12:59	552	0	96	1250	109
	13:00	13:14	576	0	126	1355	56
	13:15	13:29	527	0	106	1325	17
	13:30	13:44	537	0	117	1287	13
	13:45	13:59	486	0	105	1082	11

[3] 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).

Date	Interval start/finish (MT Time)		Network Total Calls*	Calls received but not delivered**	# Of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds
	14:00	14:14	502	0	99	902	14
	14:15	14:29	584	0	78	803	19
	14:30	14:44	471	0	81	1089	12
	14:45	14:59	504	0	96	1166	9
	15:00	15:14	510	0	92	1012	11
	15:15	15:29	563	0	95	946	10
	15:30	15:44	466	0	92	1670	8
	15:45	15:59	472	0	97	1053	12
	16:00	16:14	484	0	88	1050	19
	16:15	16:29	430	0	86	975	13
	16:30	16:44	475	0	96	848	15
	16:45	16:59	409	0	71	766	13
	17:00	17:14	435	0	61	804	60

4.3 Utah State Customer Guarantee Summary Status

customer*guarantees* January to June 2022

Utah

	Description	2022 Events	2022 Failures	2022 % Success	2022 Paid	2021 Events	2021 Failures	2021 % Success	2021 Paid
CG1	Restoring Supply	439,065	0	100%	$0	688,877	0	100%	$0
CG2	Appointments	5,689	3	99.95%	$150	4,982	1	99.98%	$50
CG3	Switching on Power	1,883	1	99.95%	$50	828	0	100%	$0
CG4	Estimates	889	0	100%	$0	928	0	100%	$0
CG5	Respond to Billing Inquiries	548	1	99.82%	$50	1,067	0	100%	$0
CG6	Respond to Meter Problems	306	0	100%	$0	299	0	100%	$0
CG7	Notification of Planned Interruptions	97,183	29	99.97%	$1,450	108,847	17	99.98%	$850
		545,563	**34**	**99.99%**	**$1,700**	**805,828**	**18**	**99.99%**	**$900**

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.

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[4], 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.[5]
- 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 if 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.

Corrective Maintenance

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

[4] 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.

[5] Effective 1/1/2007, Rocky Mountain Power changed its reliability and preventive planning methods to use 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.

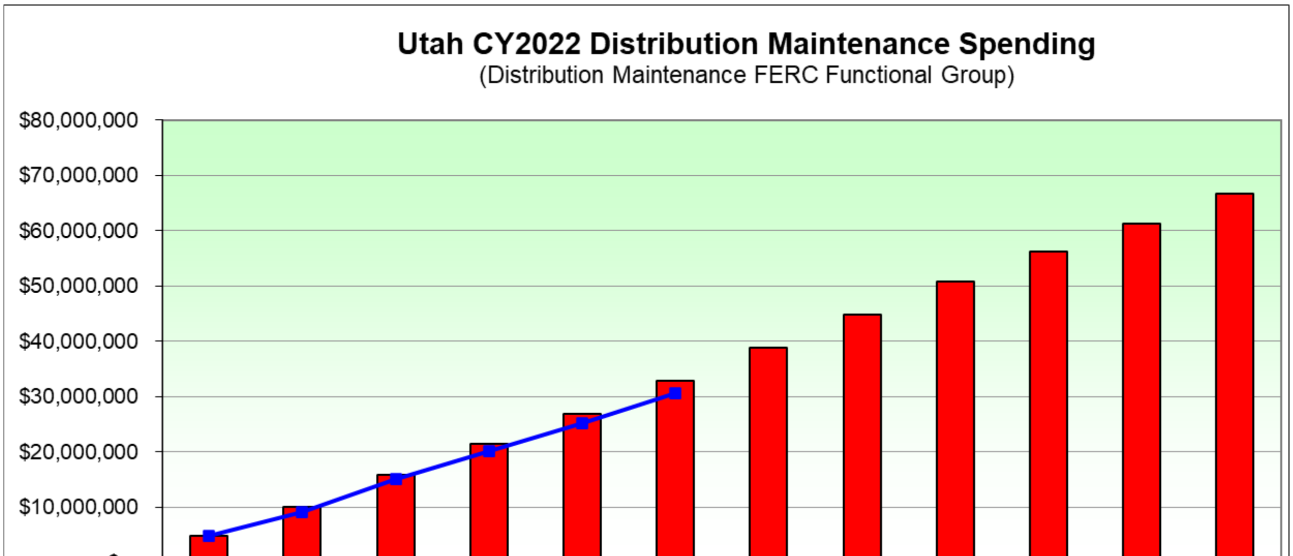
Transmission and Distribution Lines

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

Substations and Major Equipment

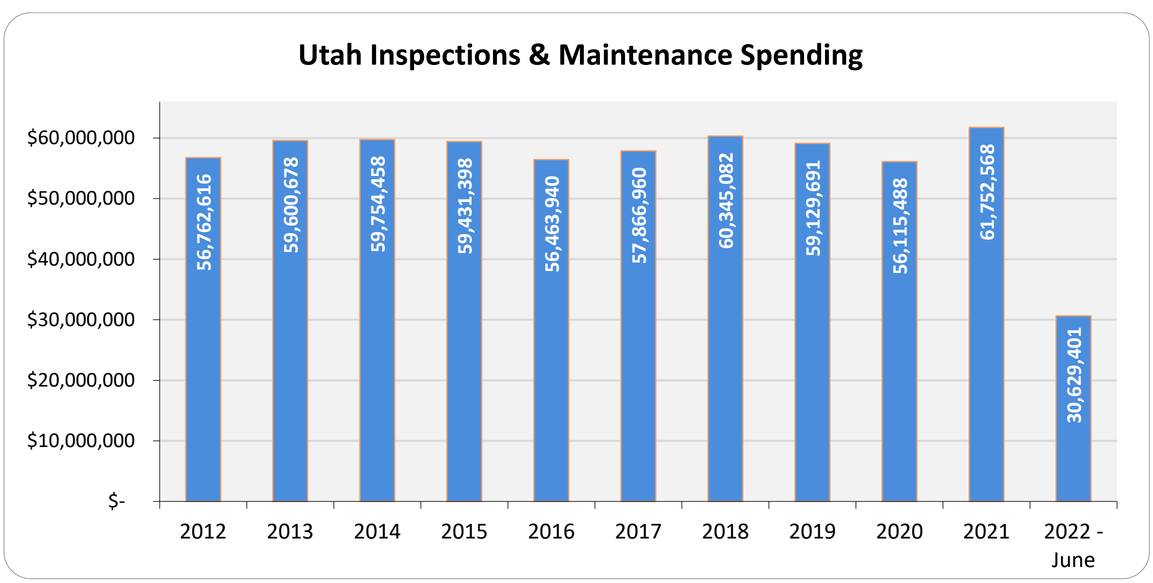
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

5.2 Maintenance Spending - RMV



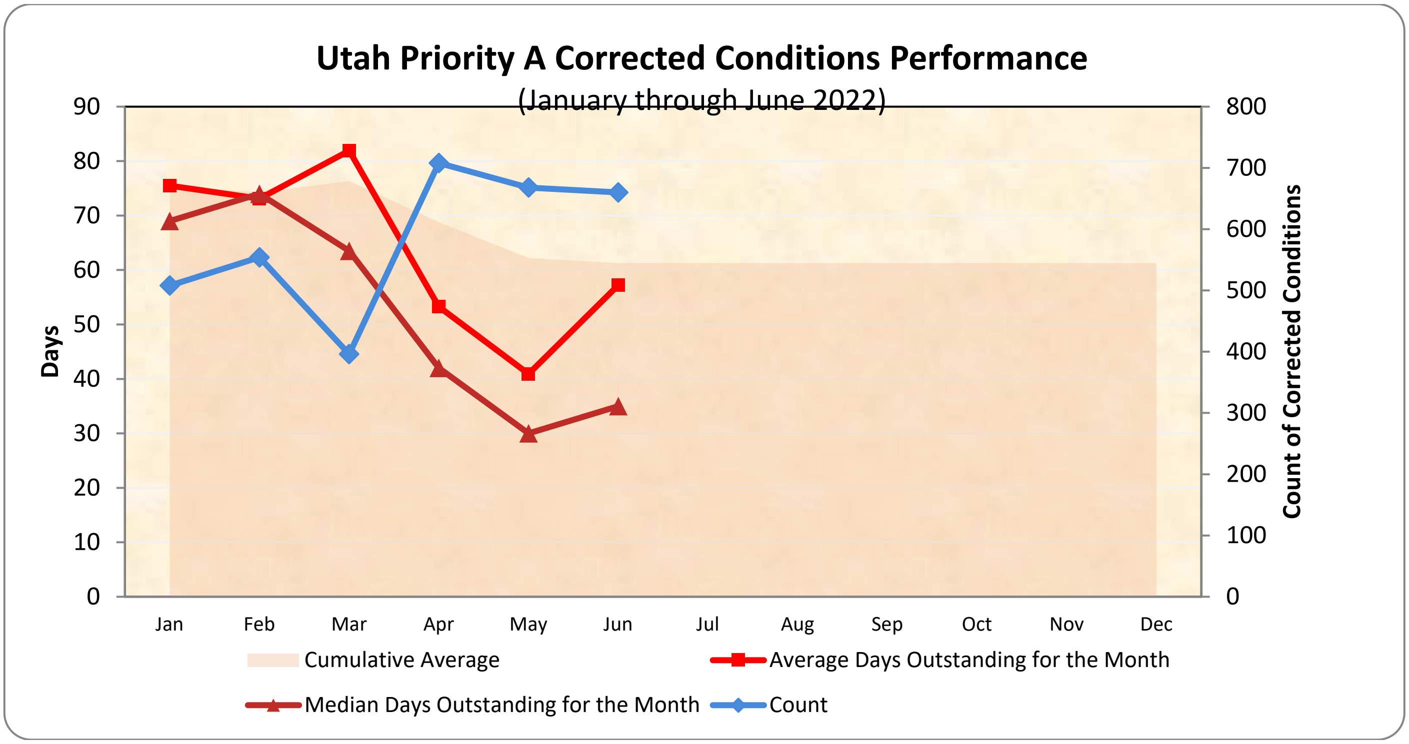
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$4,876,157	$10,032,08	$15,892,04	$21,433,54	$26,789,18	$32,902,32	$38,850,54	$44,851,05	$50,865,68	$56,261,94	$61,197,68	$66,725,02
Actual	$4,909,974	$9,060,897	$15,165,72	$20,218,86	$25,118,11	$30,629,40						

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.

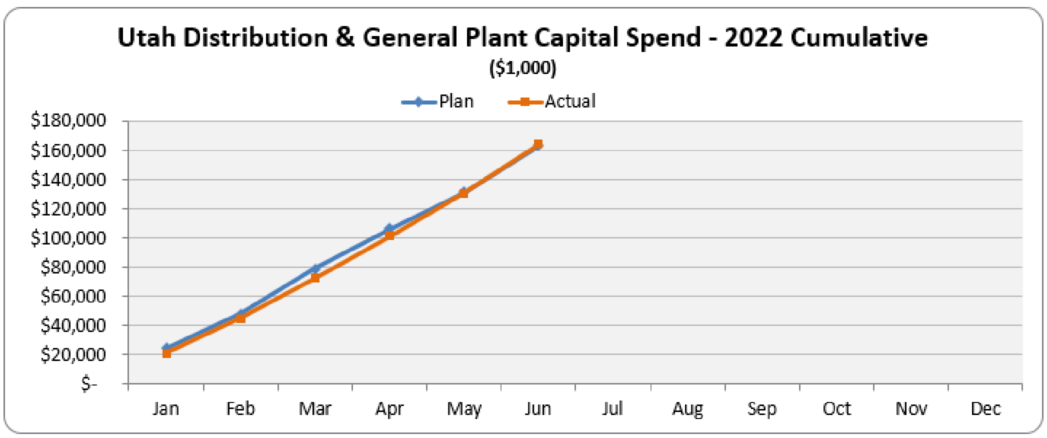


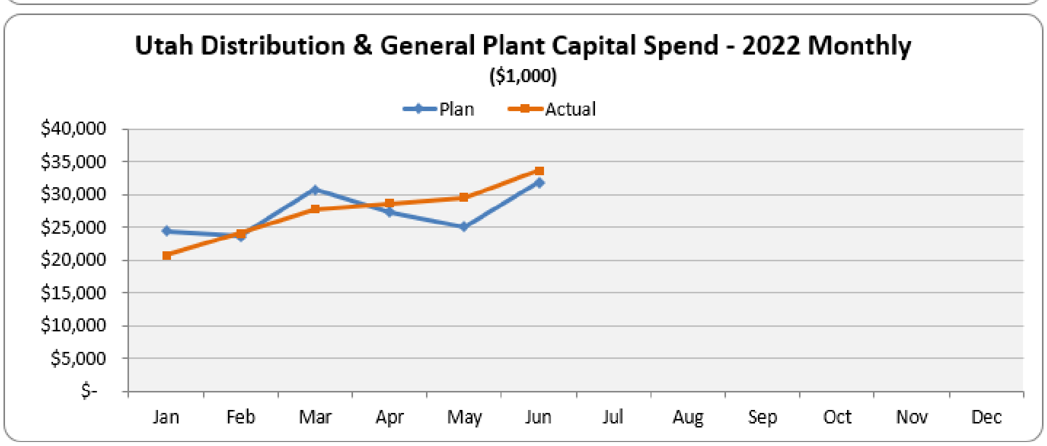
6 Capital Investment

6.1 Capital Spending - Distribution and General Plant

January – June 2022

Investment	Actual ($m)	Plan ($m)	Significant Variances
1. Mandated	$28.9	$21.4	Mandated wildfire mitigation and mandated road relocations over plan, (+$7.5m — including distribution wildfire mitigation program +$5.0m); national/regional regulatory under plan, (–$1.8m — including WestSmart@Scale — $1.8m).
2. New Connect	$48.5	$38.4	Residential and commercial new revenue connections over plan, (+$10.4m). Plan anticipated significant new connection slowdown, which has not occurred.
3. System Reinforcement	$28.6	$27.9	Feeder reinforcements over plan, (+$3.7m); substation reinforcements under plan, (–$2.97m — including Apple Valley Sub –$2.4m, Parkside Mobile Conn –$1.1m, 118th So Property –$3.2m, Stansbury Capacity Incr –$2.0m, 126th South Sub +$5.2m, and 90th South 30 MVA Xfmr +$1.5m).
4. Replacement	$40.2	$35.8	Replacements for underground vaults/equipment and overhead distribution poles over plan, (+$6.0m); replacements for overhead distribution lines/other under plan, (–$2.2m).
5. Upgrade & Modernize	$18.3	$39.5	Feeder improvements and facilities upgrade under plan, (–$22.8m — including Automated Metering Infrastructure –$13.8m, NTO Campus Redevelopment –$8.2m, and SL Downtown 8kV Conversion –$1.2m).
Total	**$164.5**	**$163.1**	





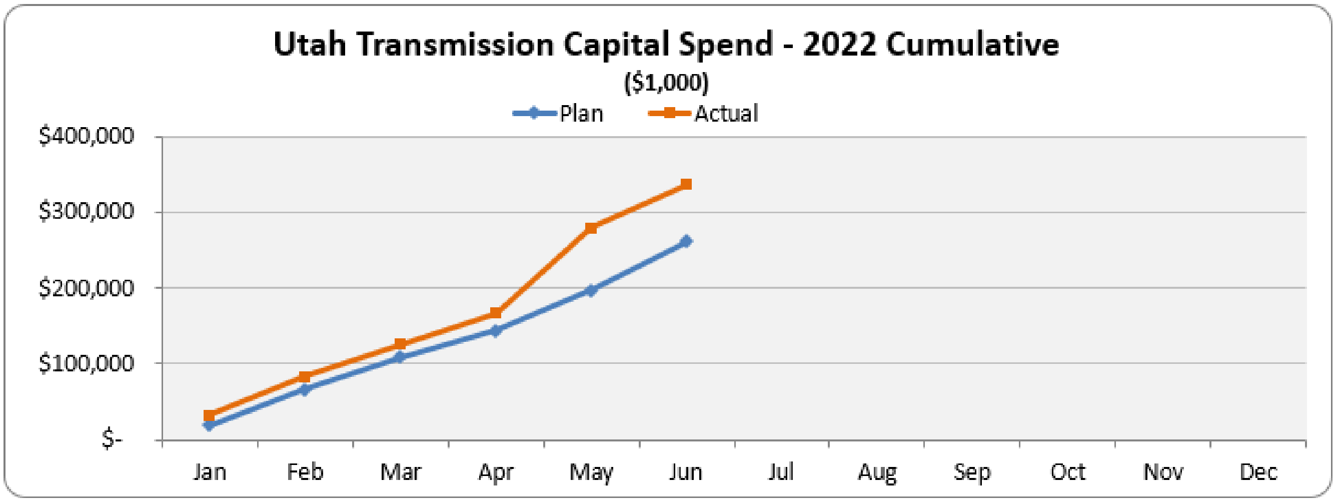
*Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

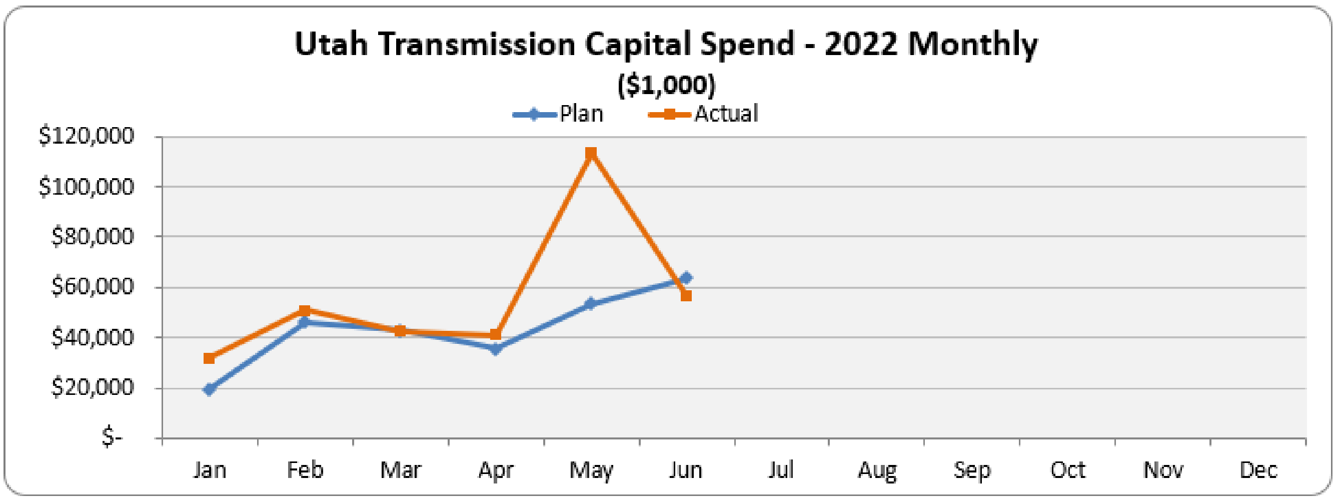
6.2 Capital Spending – Transmission/Interconnections

January – June 2022

Investment		Actual ($m)	Plan ($m)	Significant Variances
1.	Mandated	9.8	28.9	Mandated environmental/avian protection over plan, (+$1.2m); mandated wildfire mitigation and right of way renewals under plan, (–$19.9m — including transmission wildfire mitigation program –$16.8m).
2.	New Connect	2.6	0.3	Industrial new revenue connections over plan, (+$2.4m — including Future Comp +2.5m--*plan $ for this project are under distribution).*
3.	Local Transmission System Reinforcements	4.2	7.3	Subtransmission and substation reinforcements under plan (–$3.2m — including Grantsville Conversion –$1.7m, Magna Cap/Tooele-Pine Canyon Rebuild –$1.6m, and Taylorsville-Granger E Tap 69kV Rebuild –$1.5m).
**4.	Main Grid Reinforcements / Interconnections	26.1	34.7***	Q0155 UAMPS Heber Light & Power under plan due to delay by customer, (–$2.7m); Nibley 138/25 kV Xfmr Nibley-Hyrum City RB under plan, (–$1.2m); unidentified main grid/generation interconnections under plan, see note below*** (–$3.3m).
**5.	Energy Gateway Transmission	280.6	173.8	Increased spend on Gateway South Aeolus Mona 500kV Ln (+$108.9m) to accelerate contractor schedule on project material and foundation work; ensures firm fixed price on material and avoids commodity price risk adjustments later in projects.
6.	Replacement	12.0	15.5	Replacements for substation transformers, substation switchgear/breakers/reclosers, and overhead lines/other under plan, (–$6.6m — including Mobile #6 Failed Xfmr Replacement –$1.4m and Sigurd #6 Failing Xfmr Replacement –$1.1m).
7.	Upgrade & Modernize	1.2	0.7	
	Total	**336.5**	**261.3**	

* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.
** Main Grid Reinforcement/Interconnections and Energy Gateway Transmission values include a small amount of General Plant $ for communications work.
*** 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 - 2022 Cumulative
($1,000)
Plan
Actual
$400,000
$300,000
$200,000
$100,000
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec


Utah Transmission Capital Spend - 2022 Monthly
($1,000)
Plan
Actual
$120,000
$100,000
$80,000
$60,000
$40,000
$20,000
$-
Jan
Feb
Mar
Apr
May
Jun
Jul
Aug
Sep
Oct
Nov
Dec

6.3 New Connects

	2021	2022												
	YEAR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YEAR
Residential														
UT Central Total[6]	17,685	1,295	1,278	1,370	1,591	1,348	1,151	1,180	1,490	1,023	5			11,731
UT North/Metro Total[7]	10,413	854	717	727	634	646	816	537	1,072	733	1			6,737
UT South Total[8]	2,307	173	130	212	163	185	266	167	187	91	0			1,574
Total Residential	**30,405**	**2,322**	**2,125**	**2,309**	**2,388**	**2,179**	**2,233**	**1,884**	**2,749**	**1,847**	**6**			**20,042**
Commercial														
UT Central Total	2,432	227	190	229	168	206	196	147	188	140	1			1,692
UT North/Metro Total	1,563	113	101	133	84	158	146	186	135	169	0			1,225
UT South Total	386	23	25	43	25	24	31	39	23	8	0			241
Total Commercial	**4,381**	**363**	**316**	**405**	**277**	**388**	**373**	**372**	**346**	**317**	**1**			**3,158**
Industrial														
UT Central Total	1	0	0	0	1	0	0	0	0	0	0			1
UT North/Metro Total	1	0	0	0	0	0	1	0	0	0	0			1
UT South Total	1	0	0	0	0	0	0	0	0	0	0			0
Total Industrial	**3**	**0**	**0**	**0**	**1**	**0**	**1**	**0**	**0**	**0**	**0**			**2**
Irrigation														
UT Central Total	9	1	0	0	3	3	1	0	2	2	0			12
UT North/Metro Total	2	0	0	0	2	2	0	0	0	0	0			4
UT South Total	42	0	3	5	7	6	5	3	2	3	0			34
Total Industrial	**53**	**1**	**3**	**5**	**12**	**11**	**6**	**3**	**4**	**5**	**0**			**50**
TOTAL New Connects														
UT Central Total	20,127	1,523	1,468	1,599	1,763	1,557	1,348	1,327	1,680	1,165	6			13,436
UT North/Metro Total	11,979	967	818	860	720	806	963	723	1,207	902	1			7,967
UT South Total	2,736	196	158	260	195	215	302	209	212	102	0			1,849
TOTAL New Connects[9]	**34,842**	**2,686**	**2,444**	**2,719**	**2,678**	**2,578**	**2,613**	**2,259**	**3,099**	**2,169**	**7**			**23,252**

[6] Utah Central region included American Fork, Vernal, Toole, Jordan Valley, and Park City

[7] Utah North/Metro region includes SLC Metro, Ogden, and Layton

[8] Utah South region includes Moab, Price, Cedar City and Richfield

[9] Region areas are subject to change for operational purposes and may differ from historical reporting. Smithfield, Tremonton and Laketown are excluded for consistency with earlier reports that included them under ID/WY WEST and not Utah.

7 Vegetation Management

7.1 Production

UTAH
Tree Program Reporting
January 1, 2022 through June 30, 2022
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles *column a*	1/1/2022-6/30/2022 Miles Planned *column b*	1/1/2022-6/30/2022 Actual Miles *column c*	1/1/2022-6/30/2022 Ahead/Behind *column d*	1/1/2022-6/30/2022 % Ahead/Behind *column e*	1/1/2020-12/31/2022 Miles Planned *column f*	1/1/2020-12/31/2022 Actual Miles *column g*	01/01/2020-12/31/2022 Ahead/Behind *column h*	1/1/2020-12/31/2022 % Ahead/Behind *column i*
UTAH	9,680	3,164	1,359	-1,805	43.0%	9,680	7,876	-1,804	81.4%
AMERICAN FORK	799	393	97	-296	24.8%	799	505	-294	63.2%
CEDAR CITY	999	427	115	-312	26.9%	999	870	-129	87.1%
JORDAN VALLEY	703	225	60	-165	26.7%	703	586	-117	83.4%
LAYTON	307	0	0	0	#DIV/0!	307	297	-10	96.7%
MOAB	625	121	119	-2	98.1%	625	631	6	101.0%
OGDEN	783	184	116	-68	63.0%	783	622	-161	79.4%
PARK CITY	332	159	0	-159	0.0%	332	221	-111	66.6%
PRICE	564	100	2	-98	2.2%	564	446	-118	79.1%
RICHFIELD	1,207	424	220	-204	51.9%	1,207	1,055	-152	87.4%
SL METRO	1,130	266	137	-129	51.5%	1,130	793	-337	70.2%
SMITHFIELD	736	226	202	-24	89.4%	736	669	-67	90.9%
TOOELE	497	250	0	-250	0.0%	497	98	-399	19.7%
TREMONTON	740	334	291	-43	87.1%	740	862	122	116.5%
VERNAL	258	55	0	-55	0.0%	258	221	-37	85.7%

Distribution cycle $/tree:	$135.76
Distribution cycle $/mile:	$3,161
Distribution cycle removal %	9.16%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	% of miles on/behind Schedule
6,588	454	388	(66)	85%

Current distribution cycle begain January 1, 2020 and extends until December 31, 2022.

Notes:
Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2022 through June 30, 2022
Column c: Actual overhead distribution pole miles worked during the period January 1, 2022 through June 30, 2022
Column d: Miles ahead or behind for the period January 1, 2022 through June 30, 2022 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2022 through June 30, 2022 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2020 through December 31, 2022
Column g: Actual overhead distribution pole miles worked during the period January 1 2020 through December 31, 2022
Column h: Miles ahead or behind for the period January 1, 2020 through December 31, 2022 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2020 through December 31, 2022 ((column g÷f)×100). Max = 100%

7.2 Budget

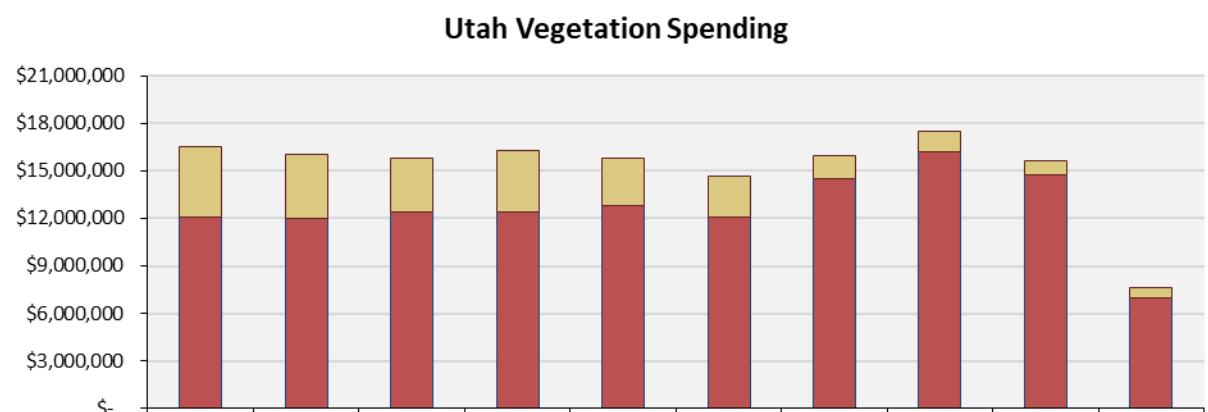
UTAH
Tree Program Reporting
January 1, 2022 through June 30, 2022

	CY2022	CY2023	CY2023
Distribution Tree Budget	$14,885,500	$14,885,500	$14,885,500
Transmission Tree Budget	$1,095,105	$1,095,105	$1,095,105
Total Tree Budget	$15,980,605	$15,980,605	$15,980,605

	Distribution Actuals	Distribution Budget	Distribution Variance	Transmission Actuals	Transmission Budget	Transmission Variance
Calendar year 2022						
Jan	$ 1,061,108	$ 1,177,251	-$116,143	$ 98,864	$ 86,570	$12,295
Feb	$ 1,206,710	$ 1,177,251	$29,459	$ 43,922	$ 86,570	-$42,647
Mar	$ 1,317,199	$ 1,352,287	-$35,088	$ 116,447	$ 99,555	$16,892
Apr	$ 1,078,207	$ 1,235,596	-$157,389	$ 122,561	$ 90,898	$31,663
May	$ 1,218,599	$ 1,235,596	-$16,998	$ 166,246	$ 90,898	$75,348
Jun	$ 1,080,337	$ 1,293,942	-$213,604	$ 145,288	$ 61,814	$83,474
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	$ 6,962,160	$ 7,471,923	-$509,763	$ 693,328	$ 516,304	$ 177,024

Average # Tree Crews on Property (YTD) 67

7.2.1 Vegetation Historical Spending



	2012	2013	2014	2015	2016	2017	2019	2020	2021	2022 - June
Transmission	4,483,668	4,070,233	3,360,658	3,873,554	3,015,928	2,646,405	1,433,587	1,298,388	920,956	693,328
Distribution	12,037,620	11,991,602	12,403,052	12,385,378	12,767,302	12,046,259	14,509,606	16,214,426	14,702,921	6,962,160

8 Standard Guarantees/Program Summary

8.1 Service Standards Program Summary[10]

8.1.1 Rocky Mountain Power Customer Guarantees

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.

Note: See Rule 25 for a complete description of terms and conditions for the Customer Guarantee Program.

[10] 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.

8.1.2 Rocky Mountain Power Performance Standards[11]

*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[12].
*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.

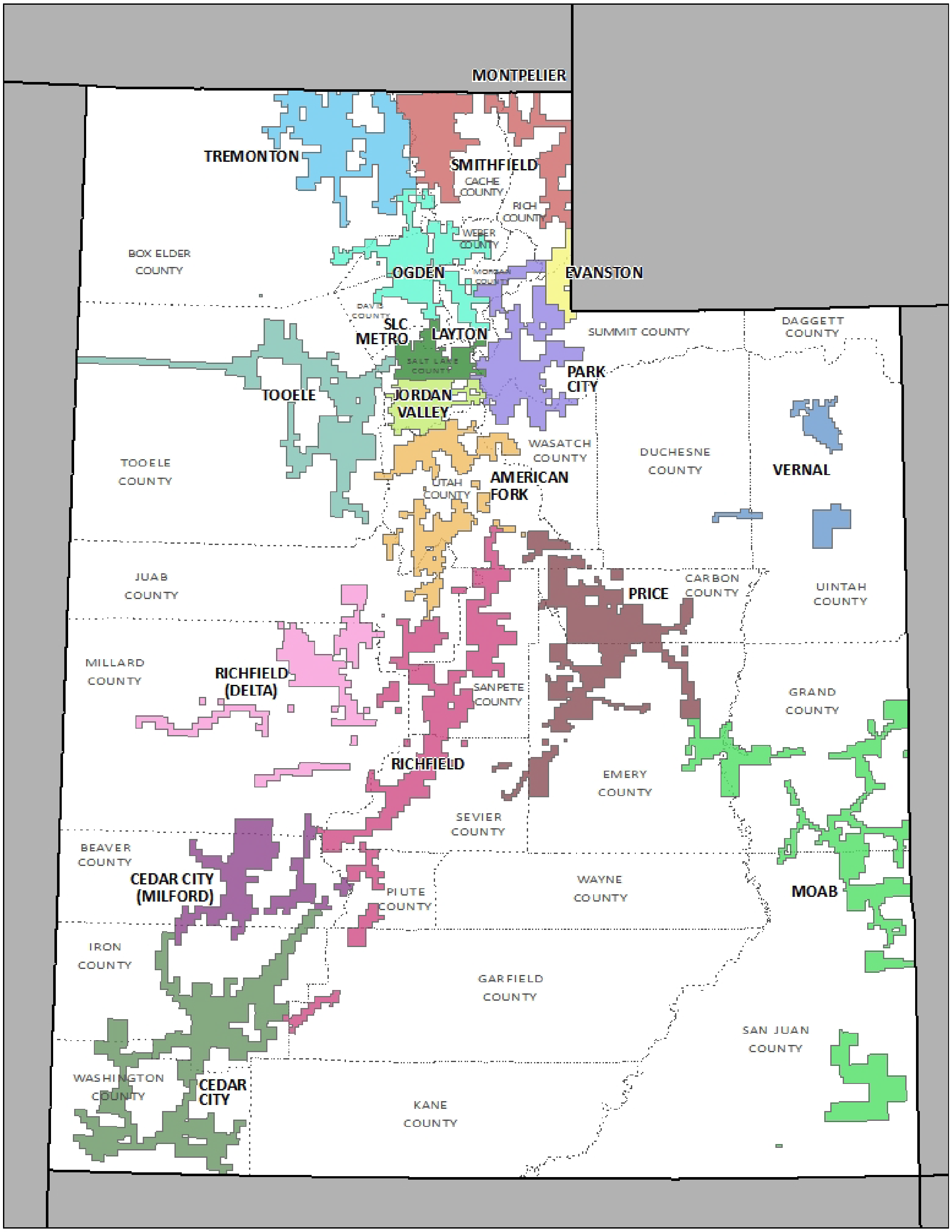
*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude Major Events.

[11] 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).

[12] On June 1, 2107, in Dockets 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 remains are found or not.
	• 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, operator-controlled balloon; other interfering object such as shoes or balloons.
	• 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 whether 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[13] 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.

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).

[13] IEEE 1366-2003 was adopted by the IEEE on December 23, 2003. It was later 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.

$MAIFI_E$

$MAIFI_E$ (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 period if 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 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
1/1-12/31/2022	1,002,258	4.38	4,418,888

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 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.