ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

1407 W North Temple, Suite 330
Salt Lake City, Utah 84114

November 1, 2019

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. 19-035-19 –** Rocky Mountain Power's Service Quality Review Report
Docket 08-035-55 – Service Quality Standards – June 2013 Service Quality Review Report
Docket No. 13-035-01 – Rocky Mountain Power's Service Quality Review Report
Docket No. 15-035-72 – 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 ("Company") submits the Service Quality Review Report for the period January through June 2019.

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

By E-mail (preferred): datarequest@pacificorp.com
utahdockets@pacificorp.com
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
Vice President, Regulation

Enclosures

ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH
SERVICE QUALITY
REVIEW

January 1 – June 30, 2019
Report

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Rocky Mountain Power has a number of Performance Standards and Customer Guarantee service quality measures and reports currently in place. These standards and measures are reflective of Rocky Mountain Power's performance (both customer service and network performance) in providing customers with improving levels of service. The Company developed these standards and measures using industry standards for collecting and reporting performance data where they exist. In other cases, largely where the industry has no established standards, Rocky Mountain Power has developed metrics, reporting and targets. These existing standards and measures can be used over time, both historically and prospectively, to measure the quality of service delivered to our customers. In 2012 the Company and stakeholders collaboratively developed reliability reporting rules that were intended to replace the Service Standards Program. This report reflects those changes and captures the state rules. In 2016 the Company worked with the Division of Public Utilities to establish a method to recognize fundamental changes in the performance of the network allowing for updates to performance baselines. These changes are also incorporated into this document.

1 Service Standards Program Summary[1]

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.

[1] 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.

1.2 Rocky Mountain Power Performance Standards[2]

*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[3].
*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.

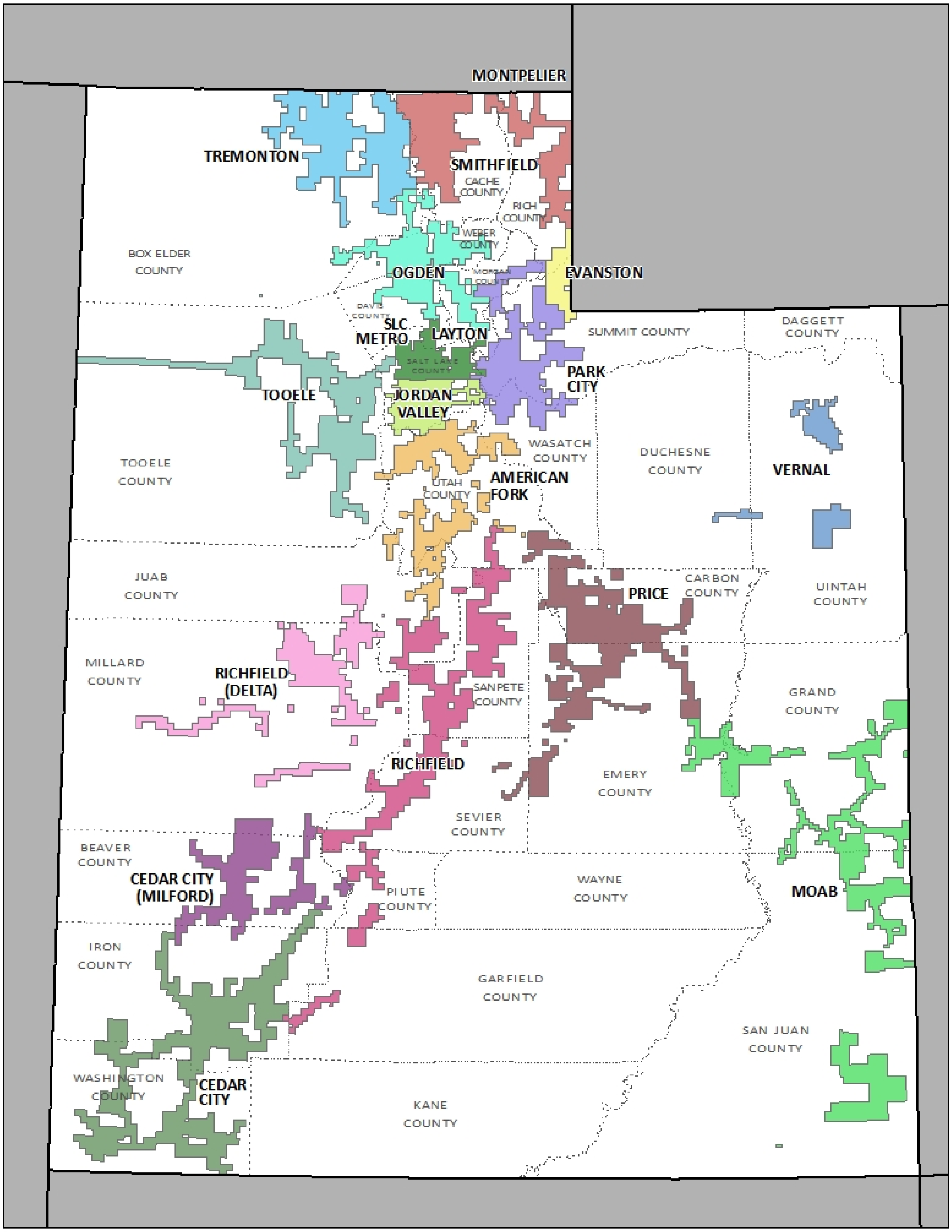
*Note: Performance Standards 1, 2 & 4 are for underlying performance days and exclude Major Events.

[2] 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).

[3] 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.

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.



2 RELIABILITY PERFORMANCE

For the reporting period, the Company's performance was on target for delivering system average interruption duration index (SAIDI) performance and system average interruption frequency index (SAIFI), within the performance baseline range (SAIDI between 137-187 minutes and SAIFI between 1.0 and 1.6 events). Results for the underlying performance can be seen in subsections 2.1 and 2.2 below, where the Company's current underlying reliability results are shown with the Company's control zones, which are colored green in the graphic. History reflecting these metrics is displayed in Sections 2.3 and 2.4. Cause code information, which is reported consistently with past Service Quality Review Reports, is shown in Section 2.5. Baselines are discussed in Section 2.6. Finally, Section 2.7 contains reporting information complies with features outlined in Utah Title 746.313.

During the reporting period, there was one major event[4] and four significant event days[5] were recorded.

Major Event Descriptions

Major Events		
Date	**Cause**	**SAIDI**
March 28-31, 2019	Snow storm	23.96
	Total	**23.96**

- **<u>March 28-31, 2019</u>**
  On the evening of March 28th the Salt Lake City Metro operating area experienced outages as a result of a spring snowstorm. The event significantly impacted service as wet heavy snow containing significate moisture content began weighing down trees limbs and equipment which eventually failed, downing numerous sections of distribution lines. The event caused hundreds of localized outages slowing restoration as vegetation and line crews worked to clear debris and repair equipment. During the three day event, over 600 sustained customer outages were experienced, affecting 46,056 customers, with more than 4,085 customers experiencing interruptions lasting over 24 hours. On the morning of March 29th the total customers without power peaked at 22,890, the result of 348 concurrent outages being addressed by the response teams. The Salt Lake City Metro area sustained 91% of all customer minutes interrupted and 78% of all customer outages. Weather and tree related outages accounted for 87% of all customer minutes lost and 71% of all customer outages. Over 500 employees were involved in the restoration activities. This major event filing was approved by the Utah Commission on June 11, 2019 in Docket 19-035-21.

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 year four significant event days were recorded, which account for 12.3 SAIDI

[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
1/1-12/31/2019	946,168	5.08	4,809,295

[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).

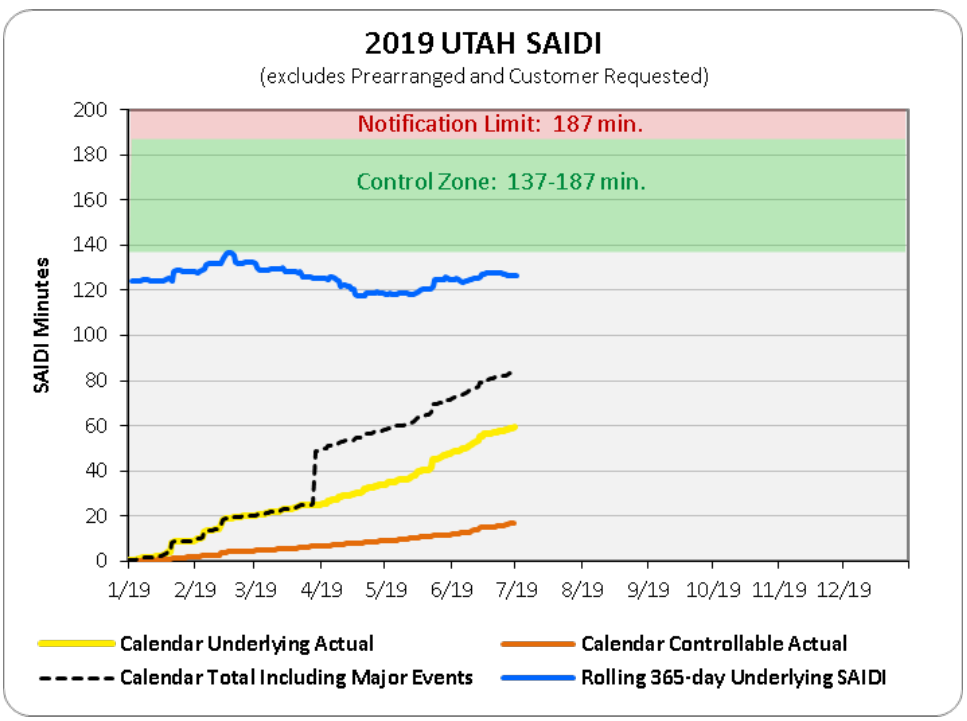
minutes, or about 21% of the reporting period's underlying 59 SAIDI minutes. These significant events were triggered by weather and loss of supply outages.

Significant Event Days					
Dates	Cause: General Description	Underlying SAIDI	Underlying SAIFI	% of Total Underlying SAIDI (59)	% of Total Underlying SAIFI (0.532)
January 21, 2019	Winter storm	4.5	0.032	8%	6%
February 5, 2019	Snow Storm	2.1	0.019	3%	4%
February 13, 2019	Equipment failure and loss of substation	2.5	0.018	4%	3%
May 23, 2019	Storm	3.3	0.021	6%	4%
	TOTAL	12.3	0.090	21%	17%

2.1 System Average Interruption Duration Index (SAIDI)

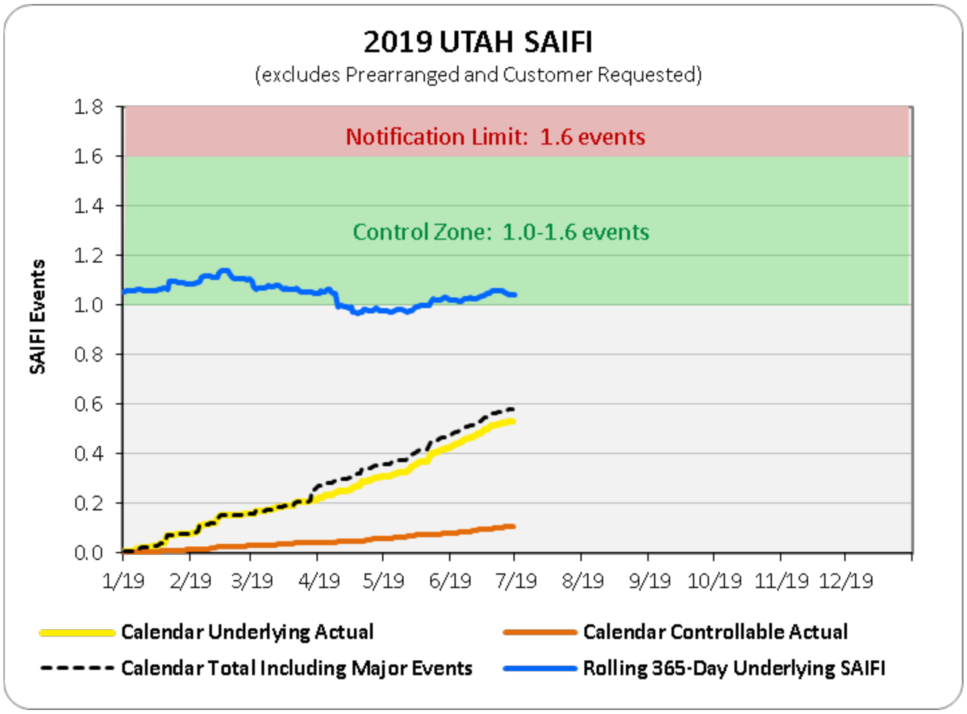
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below and in 2.2.

SAIDI	Reporting Period
Total	83
Underlying	59
Controllable Distribution	17



2.2 System Average Interruption Frequency Index (SAIFI)

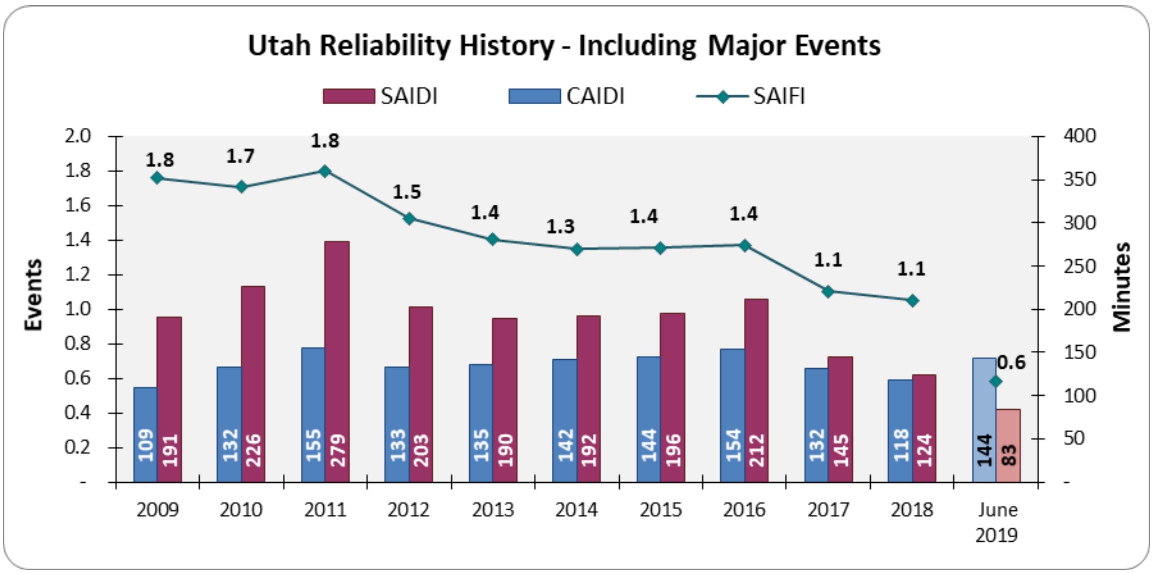
SAIFI	Reporting Period
Total	0.581
Underlying	0.532
Controllable Distribution	0.109

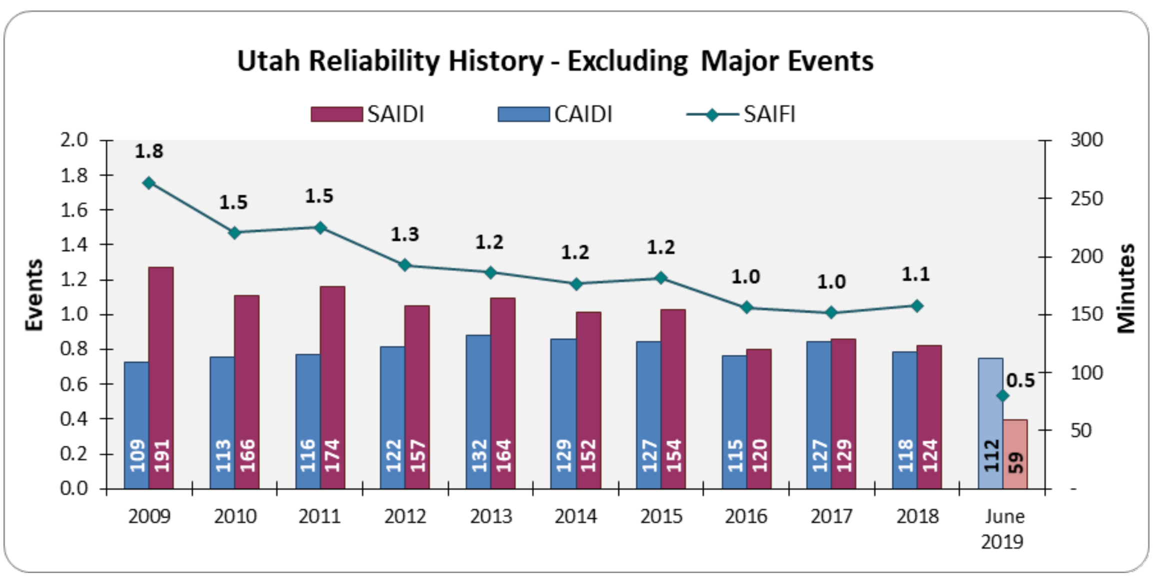


2.3 Reliability History

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 2.4 and 2.6, where 365-day rolling performance trends are depicted. These indices (shown in the history charts below and in Sections 2.4 and 2.6) 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. In recognition of the improved performance the Commission directed the Company to work with the Division to develop processes to establish modified performance baselines, which are detailed further in Section 2.6.

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.

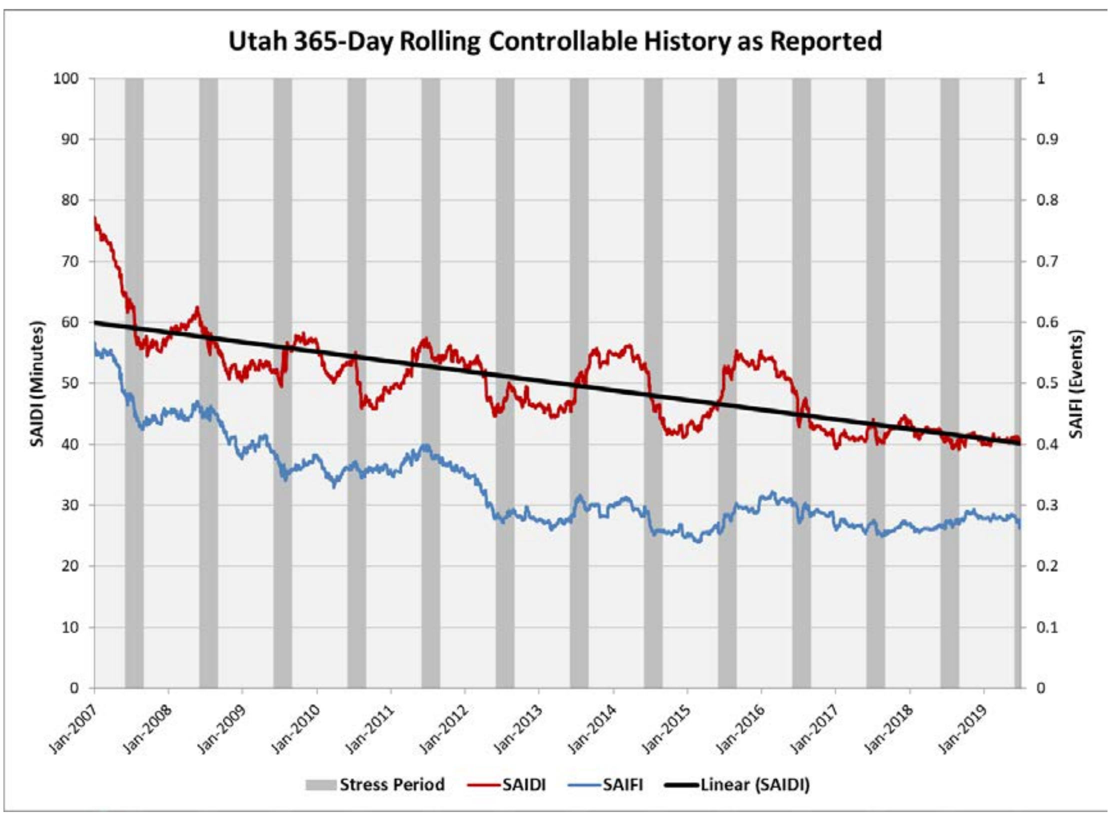


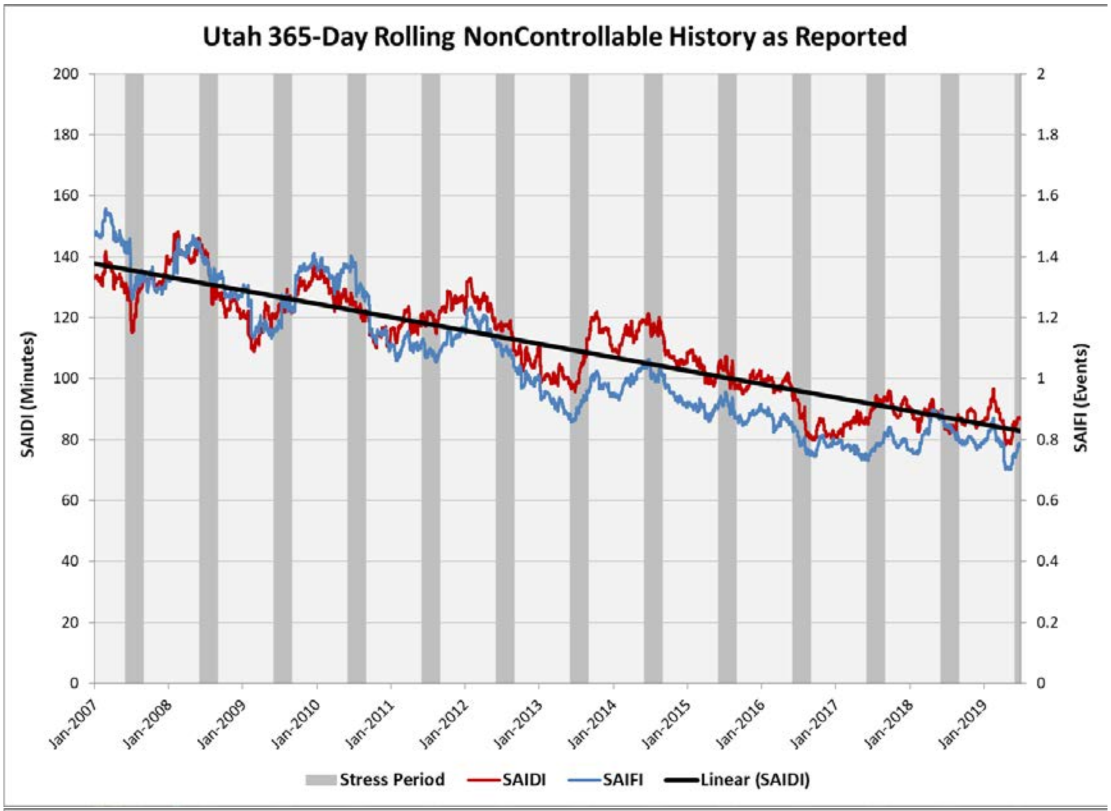


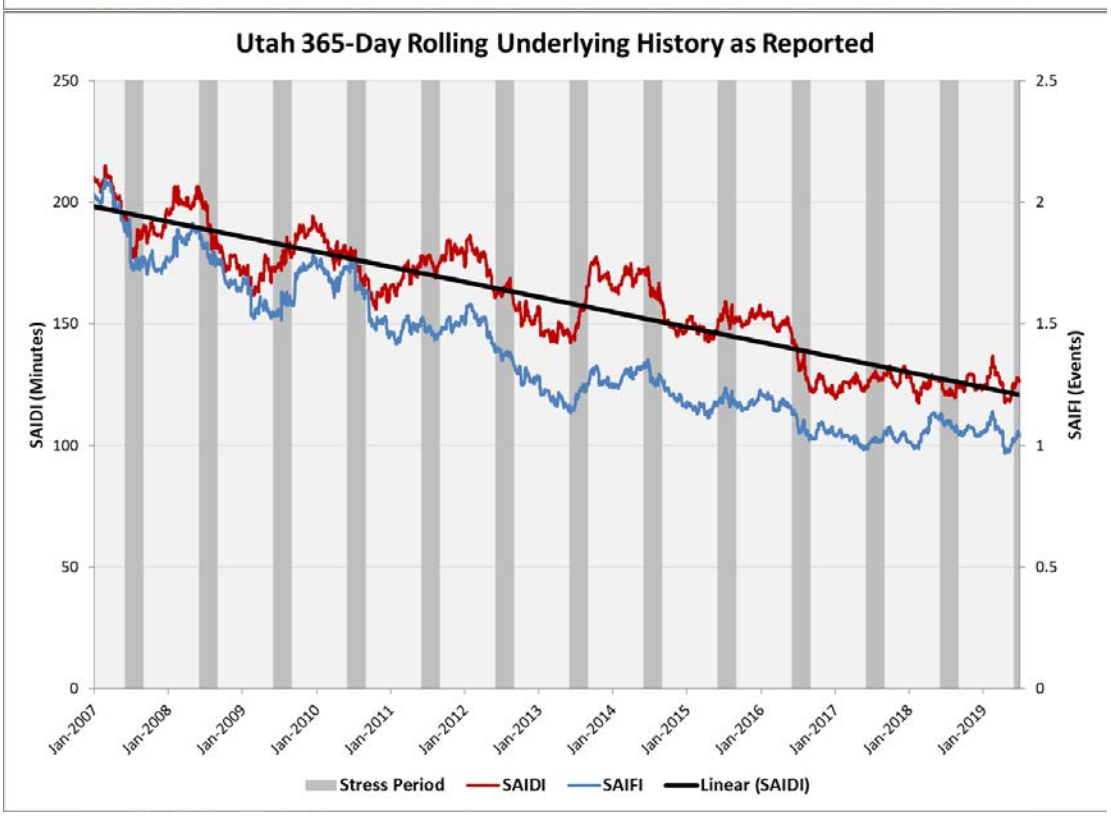
2.4 Controllable, Non-Controllable and Underlying Performance Review

In 2008, the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as developed by engineering resources. 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 causes have also been determined and are specified in Section 2.5. 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. In order to provide insight into the response and history for those outages, the charts below distinguish amongst 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. In order 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 in order 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 NonControllable 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
Stress Period
SAIDI
SAIFI
Linear (SAIDI)


Utah 365-Day Rolling Underlying History as Reported
SAIDI (Minutes)
SAIFI (Events)
250
200
150
100
50
0
2.5
2
1.5
1
0.5
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
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

2.5 Cause Code Analysis

The tables below outline categories used in outage data collection. Subsequent charts and table 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 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

2.5.1 Underlying Cause Analysis Tables (Pre-Title 746-313 Modification)

Certain types of outages typically result in a large amount of customer minutes lost, but are infrequent, such as Loss of Supply outages. Others tend to be more frequent, but result in few customer minutes lost.

The cause analysis tables below detail SAIDI[6] and SAIFI by direct cause, with separate tables for the company's Controllable metrics and its Underlying metrics. (Both tables exclude major events.) Following the detail tables are pie charts showing the percentages attributed to each cause category with respect to three measures: total incidents, total customer minutes lost and total sustained customer interruptions, again with separate pie charts for Controllable and Underlying.

Note that the Underlying cause analysis table includes prearranged outages (*Customer Requested, Customer Notice Given, and Planned Notice Exempt* line items) with subtotals for their inclusion, while the grand totals in the table exclude these prearranged outages so that grand totals align with reported SAIDI and SAIFI metrics for the period. The following pie and historical cause detail reflect the cause category performance; these charts exclude prearranged outages, to align with the underlying reportable results. Following the charts, a table of definitions provides descriptive examples for each direct cause category. Further cause analysis is explored in Section 2.7.

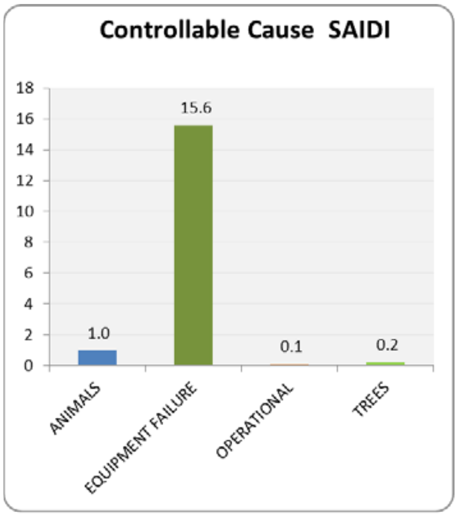
Utah Cause Analysis - Controllable 1/1/2019 - 6/30/2019					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	535,187	4,063	203	0.57	0.004
BIRD MORTALITY (NON-PROTECTED SPECIES)	182,215	1,520	62	0.19	0.002
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	151,332	2,885	25	0.16	0.003
BIRD NEST (BMTS)	29,489	130	26	0.03	0.000
BIRD SUSPECTED, NO MORTALITY	41,670	460	41	0.04	0.000
ANIMALS	**939,893**	**9,058**	**357**	**0.99**	**0.010**
B/O EQUIPMENT	1,706,625	17,103	333	1.80	0.018
DETERIORATION OR ROTTING	12,974,736	73,743	2,597	13.71	0.078
OVERLOAD	31,444	968	10	0.03	0.001
RELAYS, BREAKERS, SWITCHES	-	-	9	-	-
STRUCTURES, INSULATORS, CONDUCTOR	29,687	90	24	0.03	0.000
EQUIPMENT FAILURE	**14,742,492**	**91,904**	**2,973**	**15.58**	**0.097**
FAULTY INSTALL	47,737	460	17	0.05	0.000
IMPROPER PROTECTIVE COORDINATION	9,871	161	5	0.01	0.000
INCORRECT RECORDS	13,535	76	12	0.01	0.000
INTERNAL CONTRACTOR	12,715	275	3	0.01	0.000
PACIFICORP EMPLOYEE - FIELD	18,942	192	10	0.02	0.000
PACIFICORP EMPLOYEE - SUB	328	2	1	0.00	0.000
OPERATIONAL	**103,128**	**1,166**	**48**	**0.11**	**0.001**
TREE - TRIMMABLE	188,961	965	47	0.20	0.001
TREES	**188,961**	**965**	**47**	**0.20**	**0.001**
Utah Including Prearranged	**15,974,474**	**103,093**	**3,425**	**16.88**	**0.109**

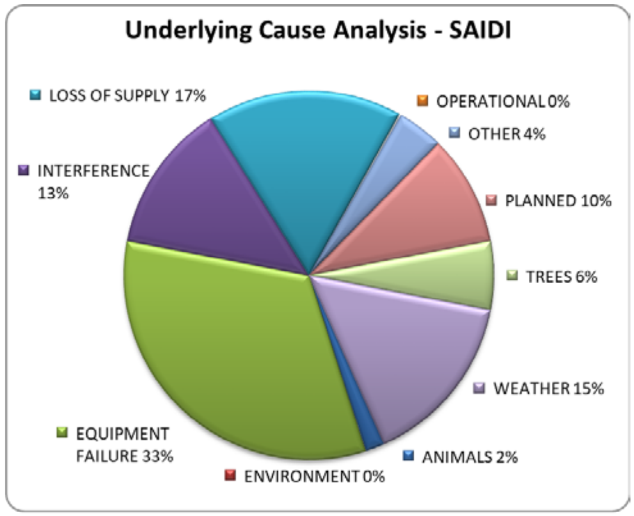
[6] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 946,168 (2019 Utah frozen customer count).

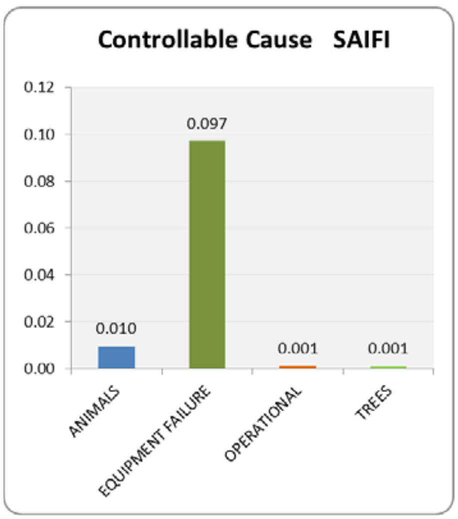
UTAH

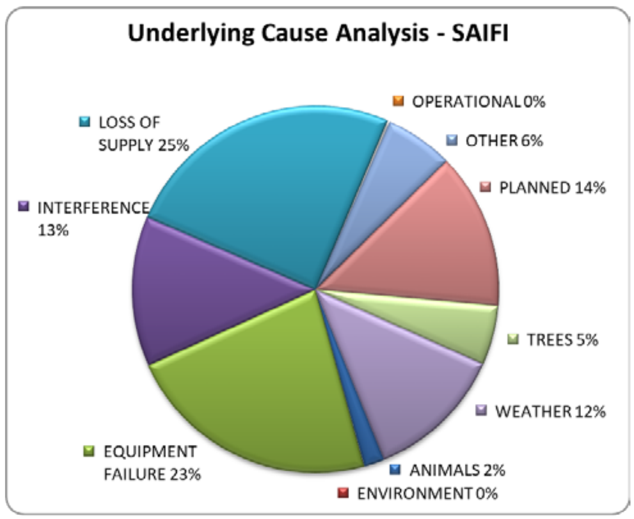
January 1 – June 30, 2019

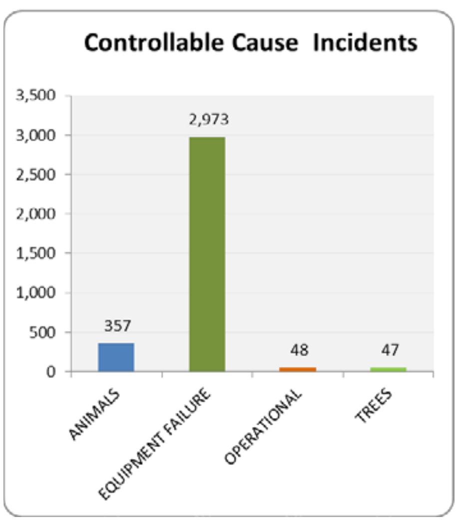
Utah Cause Analysis - Underlying 1/1/2019 - 6/30/2019					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	535,187	4,063	203	0.57	0.004
BIRD MORTALITY (NON-PROTECTED SPECIES)	182,215	1,520	62	0.19	0.002
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	151,332	2,885	25	0.16	0.003
BIRD NEST (BMTS)	29,489	130	26	0.03	0.000
BIRD SUSPECTED, NO MORTALITY	41,670	460	41	0.04	0.000
ANIMALS	**939,893**	**9,058**	**357**	**0.99**	**0.010**
CONDENSATION / MOISTURE	15,989	78	3	0.02	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	11,316	15	2	0.01	0.000
FLOODING	3,334	10	1	0.00	0.000
ENVIRONMENT	**30,639**	**103**	**6**	**0.03**	**0.000**
B/O EQUIPMENT	1,706,625	17,103	333	1.80	0.018
DETERIORATION OR ROTTING	12,974,736	73,743	2,597	13.71	0.078
NEARBY FAULT	4,765	45	3	0.01	0.000
OVERLOAD	31,444	968	10	0.03	0.001
POLE FIRE	3,791,304	21,264	129	4.01	0.022
STRUCTURES, INSULATORS, CONDUCTOR	29,687	90	24	0.03	0.000
EQUIPMENT FAILURE	**18,538,560**	**113,213**	**3,096**	**19.59**	**0.120**
DIG-IN (NON-PACIFICORP PERSONNEL)	1,195,091	12,454	117	1.26	0.013
OTHER INTERFERING OBJECT	816,791	10,359	47	0.86	0.011
OTHER UTILITY/CONTRACTOR	275,879	3,130	34	0.29	0.003
VANDALISM OR THEFT	14,486	114	9	0.02	0.000
VEHICLE ACCIDENT	5,081,407	40,760	165	5.37	0.043
INTERFERENCE	**7,383,654**	**66,817**	**372**	**7.80**	**0.071**
LOSS OF SUBSTATION	4,404,645	46,074	46	4.66	0.049
LOSS OF TRANSMISSION LINE	5,159,576	79,264	150	5.45	0.084
LOSS OF SUPPLY	**9,564,221**	**125,338**	**196**	**10.11**	**0.132**
FAULTY INSTALL	47,737	460	17	0.05	0.000
IMPROPER PROTECTIVE COORDINATION	9,871	161	5	0.01	0.000
INCORRECT RECORDS	13,535	76	12	0.01	0.000
INTERNAL CONTRACTOR	12,715	275	3	0.01	0.000
PACIFICORP EMPLOYEE - FIELD	18,942	192	10	0.02	0.000
PACIFICORP EMPLOYEE - SUB	328	2	1	0.00	0.000
OPERATIONAL	**103,128**	**1,166**	**48**	**0.11**	**0.001**
OTHER, KNOWN CAUSE	224,497	3,200	51	0.24	0.003
UNKNOWN	2,064,771	27,248	461	2.18	0.029
OTHER	**2,289,268**	**30,448**	**512**	**2.42**	**0.032**
CONSTRUCTION	139,823	2,200	69	0.15	0.002
CUSTOMER NOTICE GIVEN	19,008,512	84,929	1,342	20.09	0.090
CUSTOMER REQUESTED	476,027	3,113	11	0.50	0.003
EMERGENCY DAMAGE REPAIR	4,322,090	55,229	439	4.57	0.058
INTENTIONAL TO CLEAR TROUBLE	1,000,229	11,569	36	1.06	0.012
PLANNED NOTICE EXEMPT	62,065	698	39	0.07	0.001
PLANNED	**25,008,747**	**157,738**	**1,936**	**26.43**	**0.167**
TREE - NON-PREVENTABLE	3,179,393	25,490	256	3.36	0.027
TREE - TRIMMABLE	188,961	965	47	0.20	0.001
TREES	**3,368,354**	**26,455**	**303**	**3.56**	**0.028**
FREEZING FOG & FROST	7,794	10	1	0.01	0.000
ICE	125,105	651	8	0.13	0.001
LIGHTNING	1,562,682	16,065	172	1.65	0.017
SNOW, SLEET AND BLIZZARD	4,521,815	26,049	328	4.78	0.028
WIND	2,395,762	18,843	210	2.53	0.020
WEATHER	**8,613,159**	**61,618**	**719**	**9.10**	**0.065**
Utah Including Prearranged	**75,839,623**	**591,954**	**7,545**	**80.15**	**0.626**
Utah Excluding Prearranged	**56,293,019**	**503,214**	**6,153**	**59.50**	**0.532**

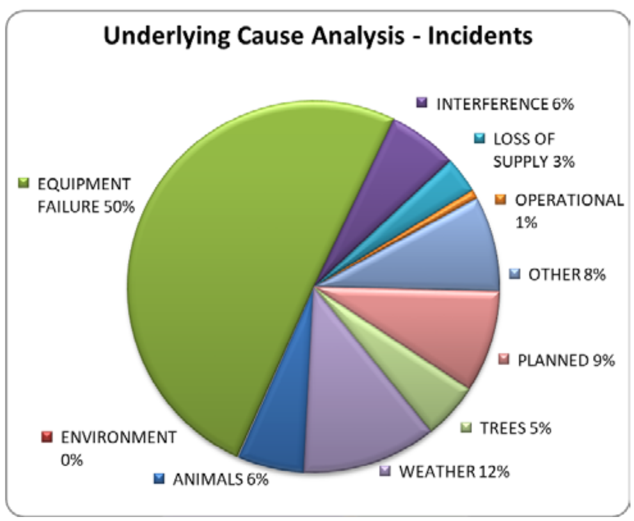

Controllable Cause SAIDI
18
16
14
12
10
8
6
4
2
0
1.0
15.6
0.1
0.2
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES

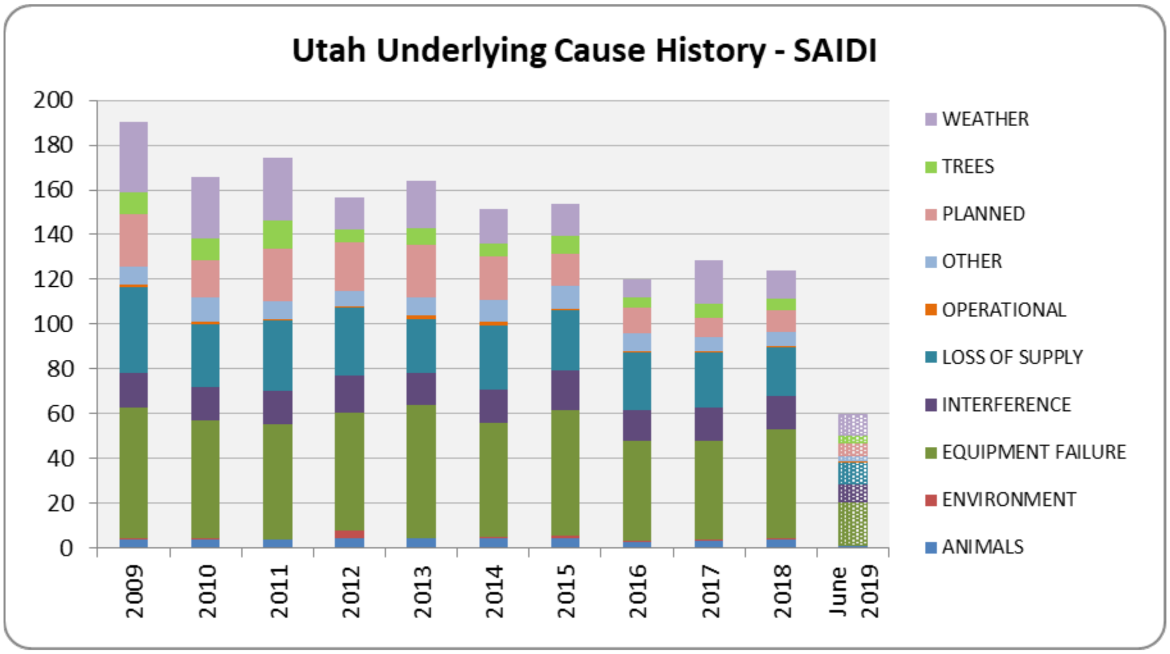

Underlying Cause Analysis - SAIDI
LOSS OF SUPPLY 17%
OPERATIONAL 0%
OTHER 4%
INTERFERENCE 13%
PLANNED 10%
TREES 6%
WEATHER 15%
EQUIPMENT FAILURE 33%
ANIMALS 2%
ENVIRONMENT 0%

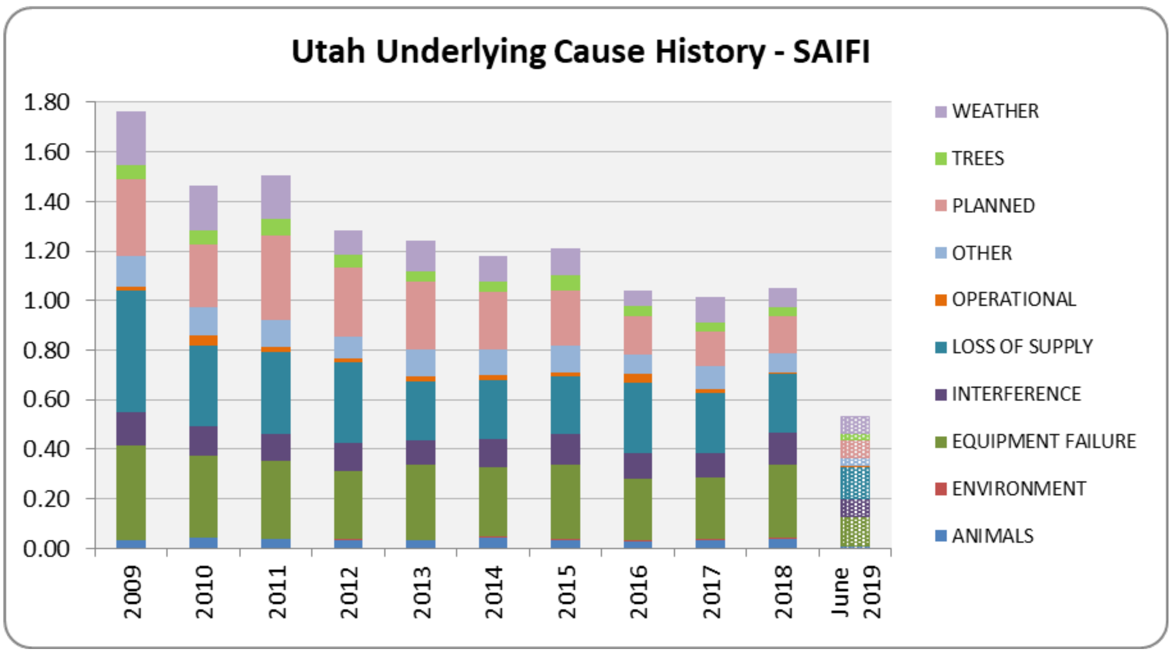

Controllable Cause SAIFI
0.12
0.10
0.08
0.06
0.04
0.02
0.00
0.010
0.097
0.001
0.001
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - SAIFI
OPERATIONAL 0%
LOSS OF SUPPLY 25%
OTHER 6%
PLANNED 14%
INTERFERENCE 13%
TREES 5%
WEATHER 12%
EQUIPMENT FAILURE 23%
ANIMALS 2%
ENVIRONMENT 0%


Controllable Cause Incidents
3,500
3,000
2,500
2,000
1,500
1,000
500
0
357
2,973
48
47
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - Incidents
INTERFERENCE 6%
LOSS OF SUPPLY 3%
EQUIPMENT FAILURE 50%
OPERATIONAL 1%
OTHER 8%
PLANNED 9%
TREES 5%
ENVIRONMENT 0%
WEATHER 12%
ANIMALS 6%

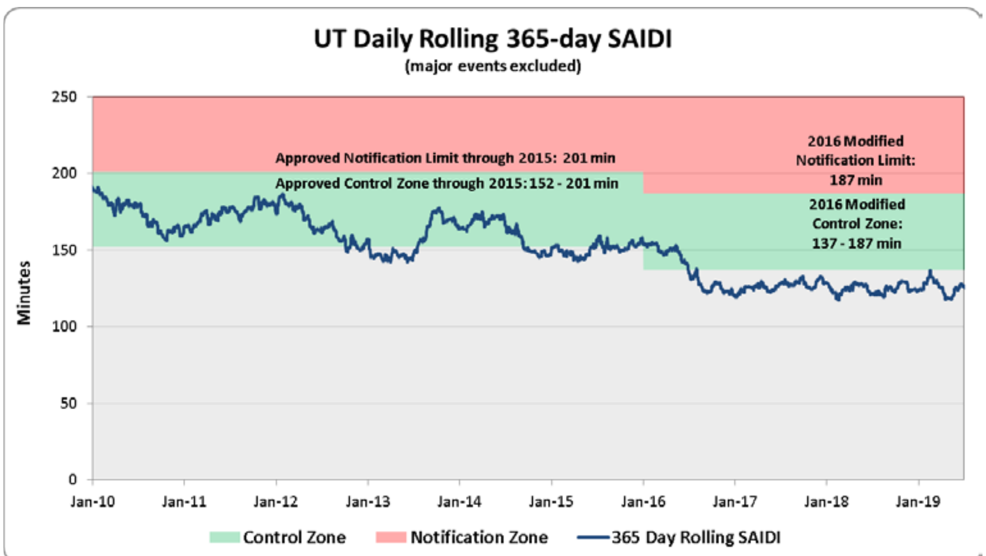

Utah Underlying Cause History - SAIDI
200
180
160
140
120
100
80
60
40
20
0
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
June 2019
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

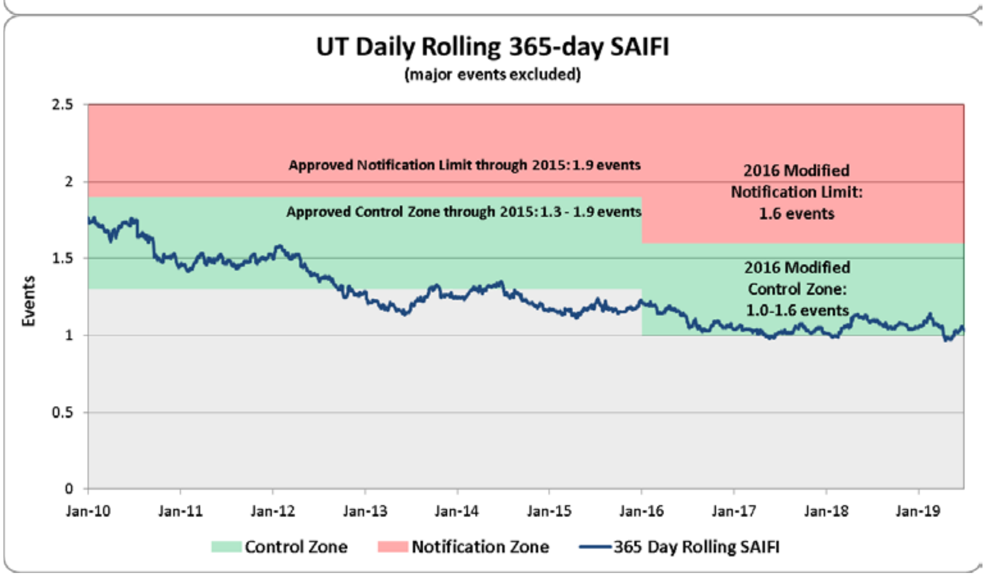

Utah Underlying Cause History - SAIFI
1.80
1.60
1.40
1.20
1.00
0.80
0.60
0.40
0.20
0.00
2009
2010
2011
2012
2013
2014
2015
2016
2017
2018
June 2019
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

2.6 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). 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). The original and modified baselines are shown below.

	SAIDI (Minutes)			SAIFI (Events)		
	Average	Lower Value Control Zone	Upper Value Control Zone	Average	Lower Value Control Zone	Upper Value Control Zone
Prior Baseline	-	105	200	-	0.9	1.7
2016 Modified Baseline	151	137	187	1.25	1.0	1.6





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

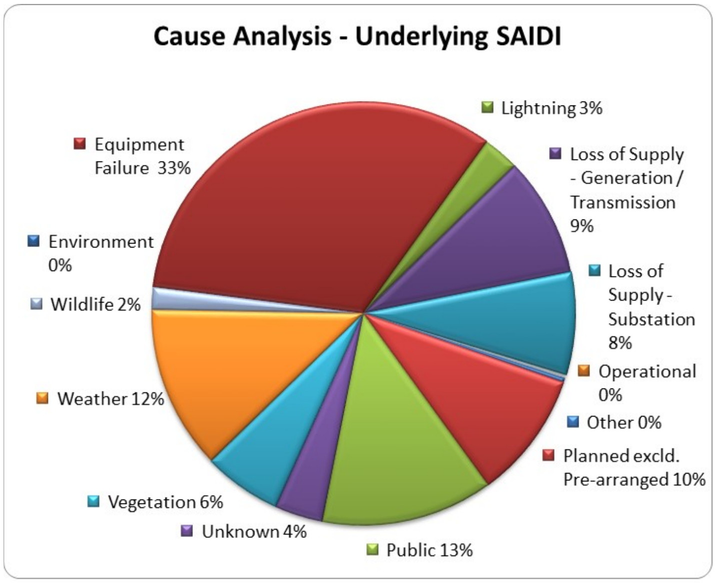
In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Administrative Code R746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least partially redundant or segmented differently than has been provided in the past. Thus, in order to include both, the new required segmentation in addition to the pre-reporting rule segmentation was considered the ideal reporting approach. As this report evolves, certain of these redundancies may be eliminated.

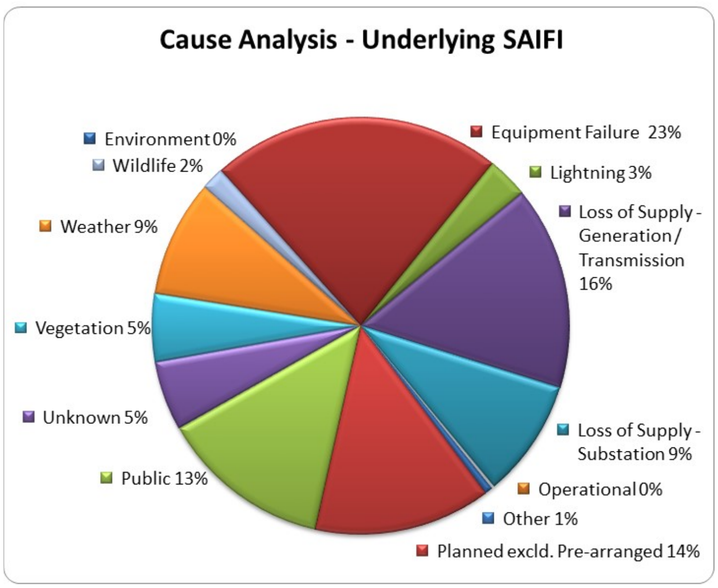
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_e$[7] are required.

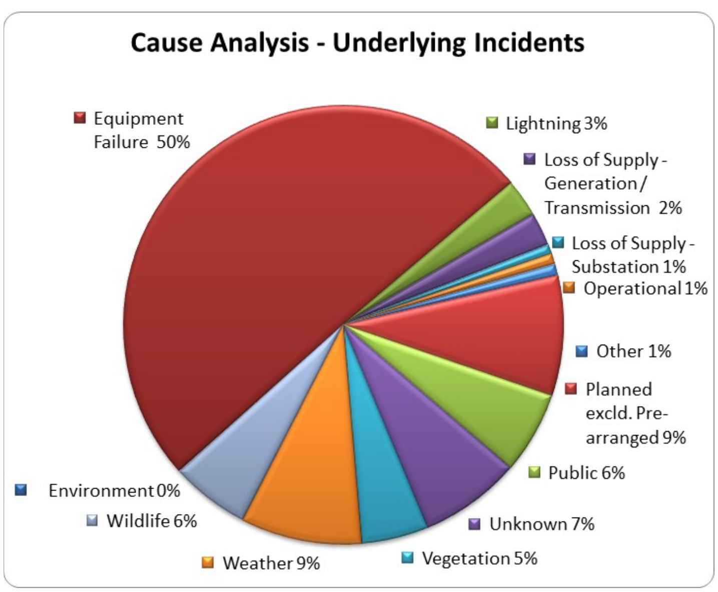
Major Events and Prearranged Excluded*	2014				2015				2016				2017				2018				2019 thru June			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	152	1.2	129	1.21	154	1.2	127	1.48	120	1.0	115	1.76	129	1.0	127	1.11	124	1.1	118	2.17	59	0.5	112	1.78
OP AREA																								
AMERICAN FORK	113	1.0	109		134	1.1	128		92	1.0	93		77	0.8	102		85	0.8	109		30	0.3	88	
CEDAR CITY	170	1.1	151		238	1.6	146		174	1.5	116		183	1.7	109		157	1.2	136		109	1.0	108	
CEDAR CITY (MILFORD)	891	3.3	271		334	3.6	92		650	4.9	132		565	2.5	230		226	1.4	164		213	1.4	155	
JORDAN VALLEY	103	0.7	141		128	1.0	126		100	0.8	131		109	0.8	139		137	1.1	121		56	0.4	130	
LAYTON	108	0.8	127		122	1.1	109		90	0.9	103		115	0.8	149		90	0.9	101		44	0.5	88	
MOAB	412	2.3	181		426	3.5	122		278	3.0	93		190	2.4	80		111	1.1	103		48	0.4	118	
OGDEN	218	1.9	113		175	1.4	123		120	1.0	120		119	0.9	138		116	1.0	114		80	0.6	133	
PARK CITY	147	1.1	140		247	1.5	162		183	1.6	117		227	1.4	159		165	1.2	143		70	0.5	128	
PRICE	394	2.2	180		230	1.8	127		340	3.3	104		171	2.5	69		203	2.3	90		67	1.1	63	
RICHFIELD	181	1.7	104		303	2.2	137		132	1.3	101		187	2.0	95		173	1.4	125		136	1.3	107	
RICHFIELD (DELTA)	202	1.9	108		536	3.0	180		215	2.1	103		139	1.3	105		171	1.0	163		66	0.3	198	
SLC METRO	145	1.1	129		107	0.9	125		104	0.9	113		114	1.0	111		120	1.0	118		54	0.5	119	
SMITHFIELD	114	0.9	126		236	1.6	150		117	1.0	118		139	0.9	149		96	1.0	99		39	0.9	42	
TOOELE	239	2.1	115		129	1.3	103		161	1.1	151		140	1.4	100		196	1.5	135		95	1.0	98	
TREMONTON	216	2.0	111		462	4.2	110		399	3.1	129		200	2.0	99		151	1.1	137		101	0.7	150	
VERNAL	119	1.2	101		68	0.8	87		53	0.6	84		77	0.8	96		48	0.6	82		37	0.4	91	

Utah Cause Category	2014		2015		2016		2017		2018		2019 thru June	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	1	0.0	1	0.0	1	0.0	1	0.0	1	0.0	0	0.0
Equipment Failure	51	0.3	56	0.3	45	0.2	44	0.2	48	0.3	20	0.1
Lightning	7	0.1	6	0.1	3	0.0	3	0.0	3	0.0	2	0.0
Loss of Supply - Generation/Transmission	23	0.2	22	0.2	13	0.2	13	0.1	13	0.2	5	0.1
Loss of Supply - Substation	6	0.0	5	0.0	13	0.1	11	0.1	9	0.1	5	0.0
Operational	1	0.0	1	0.0	1	0.0	1	0.0	0	0.0	0	0.0
Other	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	20	0.2	14	0.2	11	0.2	8	0.1	10	0.1	6	0.1
Public	15	0.1	18	0.1	14	0.1	15	0.1	15	0.1	8	0.1
Unknown	10	0.1	10	0.1	7	0.1	6	0.1	6	0.1	2	0.0
Vegetation	6	0.0	8	0.1	5	0.0	6	0.0	5	0.0	4	0.0
Weather	8	0.0	8	0.0	5	0.0	16	0.1	9	0.1	7	0.0
Wildlife	4	0.0	5	0.0	2	0.0	3	0.0	3	0.0	1	0.0
UTAH Underlying	**152**	**1.2**	**154**	**1.2**	**120**	**1.0**	**129**	**1.0**	**124**	**1.1**	**59**	**0.5**

[7] MAIFIe 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.


Cause Analysis - Underlying SAIDI
Lightning 3%
Loss of Supply - Generation / Transmission 9%
Loss of Supply - Substation 8%
Operational 0%
Other 0%
Planned excld. Pre-arranged 10%
Public 13%
Unknown 4%
Vegetation 6%
Weather 12%
Wildlife 2%
Environment 0%
Equipment Failure 33%


Cause Analysis - Underlying SAIFI
Equipment Failure 23%
Lightning 3%
Loss of Supply - Generation / Transmission 16%
Loss of Supply - Substation 9%
Operational 0%
Other 1%
Planned excld. Pre-arranged 14%
Public 13%
Unknown 5%
Vegetation 5%
Weather 9%
Wildlife 2%
Environment 0%


Cause Analysis - Underlying Incidents
Equipment Failure 50%
Lightning 3%
Loss of Supply - Generation / Transmission 2%
Loss of Supply - Substation 1%
Operational 1%
Other 1%
Planned excld. Pre-arranged 9%
Public 6%
Unknown 7%
Vegetation 5%
Weather 9%
Wildlife 6%
Environment 0%

2.8 Improve Reliability Performance in Areas of Concern

Over the past decade the Company has developed approaches, including tools, automated and manual processes and methods to improve reliability. As it has done so, the Company's ability to diagnose portions of the system requiring improvement has improved, which yields its legacy "Worst Performing Circuit" program obsolete, as described in section 2.8.4. As a result it devised a more contemporary approach to identifying improvement plans, determining the value of those plans and monitoring to ensure that results delivered meet or exceed expected targets. This program was named Open Reliability Reporting (ORR).

The ORR process shifts the Company's reliability program from a circuit-based view reliant on blended reliability metrics (using circuit SAIDI, SAIFI and MAIFI) to a more strategic and targeted 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 is based on cost effectiveness as measured by the cost per avoided annual customer minute interrupted. However, the cost effectiveness measure will 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.

2.8.1 Reliability Work Plans

The Company has worked to improve reliability through Reliability Work Plans. To assist in identification of problem areas, Area Improvement Teams (AIT) meetings and Frequent Interrupters Requiring Evaluation (FIRE) reports have been established. On a daily basis the Company systems alert operations and engineering team members regarding outages experienced at interrupting devices (circuit breakers, line reclosers and fuses). When repetition occurs, it is an indicator that system improvements may be needed. On a routine basis, local operations and engineering team members review the performance of the network using geospatial and tabular tools to look for opportunities to improve reliability. As system improvement projects are identified, cost estimates of reliability improvement and costs to deliver that improvement are prepared. If the project's cost effectiveness metrics are favorable, i.e. low cost and high avoidance of future customer minutes interrupted, the project is approved for funding and the forecast customer minutes interrupted are recorded for subsequent comparison. This process allows individual districts to take ownership and identify the greatest impact to their customers. Rather than focusing on a large area at high costs, districts can focus on problem areas or devices.

2.8.2 Project approvals by district

The identification of projects is an ongoing process throughout the year. An approval team reviews projects weekly and once approved, design and construction begins. Upon completion of the construction, the project is identified for follow up review of effectiveness. One year after completion, routine assessments of performance are prepared. This comparison is summarized for all projects for each year's plans, and actual versus forecast results are assessed to determine whether targets were met or if additional work may be required. The table below is provided to demonstrate the measures the Company believes represents cost/effectiveness measures that are important in determining the success of the projects that have been completed.

UTAH

January 1 – June 30, 2019

2016-2019 District Projects*									
Approval Metrics			Effectiveness Metrics						In Progress
District	Project count	Budgeted Cost/CML	Plans Meeting Goals (>1 year since project completion)	Estimated Avoided annual CML	Actual Avoided annual CML	Budgeted Cost per annual avoided CML	Actual Cost per annual avoided CML	Plans Not Meeting Goals (not included in metrics)	Plans waiting for information
American Fork	21	$0.92	12	1,447,307	1,235,340	$0.44	$0.01	0	9
Cedar City	4	$1.44	2	1,299,750	460,854	$0.49	$0.00	0	2
Jordan Valley	57	$1.92	20	4,031,279	1,932,735	$0.50	$0.01	4	33
Layton	10	$0.80	7	2,886,658	3,336,232	$0.36	$0.00	0	3
Moab	7	$7.48	4	2,648,960	525,152	$0.27	$0.22	0	3
Montpelier	2	$0.29	1	600,000	3,372,083	$0.30	$0.00	1	0
Ogden	36	$1.12	16	2,807,492	2,802,038	$0.36	$0.01	2	18
Park City	17	$0.63	9	1,068,420	1,689,094	$0.16	$0.05	1	7
Price	4	$3.55	1	464,286	530,577	$0.14	$0.00	1	2
Richfield	8	$9.35	5	1,999,071	229,787	$0.63	$0.02	0	3
SLC Metro	44	$1.88	19	3,161,806	2,276,010	$0.34	$0.07	0	25
Smithfield	9	$1.03	2	40,527	16,120	$0.67	$0.00	1	6
Tooele	12	$1.53	4	1,020,693	171,969	$0.28	$0.00	1	7
Tremonton	3	$0.61	2	312,361	659,947	$0.39	$0.19	0	1
Vernal	4	$0.79	4	264,277	325,614	$0.42	$0.00	0	0
Total	238	$1.52	108	24,052,888	19,563,550	$0.39	$0.03	11	119

*Metrics cover projects approved between 7/1/2016 and 6/30/2019

2.8.3 Reduce CPI for Worst Performing Circuits by 20%

Prior to the Open Reliability Reporting process, the Company reviewed circuits for performance. One of the measures that it used was called circuit performance indicator (CPI), which was a blended weighting of key reliability metrics covering a three-year period. The higher the number, the poorer the blended performance the circuit is delivering. As part of the Company's Performance Standards Program, it annually selected a set of Worst Performing Circuits for improvements, which were to be completed within two years of selection. Within five years of selection, the average performance of the five-selection circuits must have improved by at least 20% (as measured by comparing current performance against baseline performance).

2.8.4 Circuit Performance Score Updates for Prior-Year Selections

Annually, the company tracked the performance of circuits designated in the Worst Performing Circuits program, until the Program Year has successfully met the target score.

WORST PERFORMING CIRCUITS	STATUS	BASELINE[8]	Performance 6/30/19
Program Year 17: (CY2016)			
Red Mountain 33	COMPLETE	1283	1,244
Fountain Green 12	COMPLETE	266	151
Middleton 24	COMPLETE	253	258
Willowridge 11	COMPLETE	177	116
Summit Park 11	COMPLETE	116	37
TARGET SCORE = **335**		**419**	**361**
Program Year 16: (CY2015)			
Nibley 21	COMPLETE	179	266
Brighton 12	COMPLETE	270	117
Rattlesnake 22	COMPLETE	456	443
Decker Lake 12	COMPLETE	167	49
Toquerville 31	COMPLETE	475	191
TARGET SCORE = **248**	**Target Met**	**309**	**213**
Program Year 15: (CY2014)			
Skull Valley 11	COMPLETE	468	146
Fort Douglas 13	COMPLETE	417	78
Parowan Valley 25	COMPLETE	408	277
Brighton 21	COMPLETE	364	186
Bush 12	COMPLETE	281	130
TARGET SCORE = **248**	**Target Met**	**310**	**163**

[8] RMP transitioned fully to applying CPI99 rather than CPI05 based on prior review with Stakeholders where the limitations of CPI05 were explored. Due to inclusion of major event and transmission outages, reporting period comparisons yielded a limited ability to identify the benefits of improvements made for each of the circuits. The application of CPI99 proved to demonstrate more consistently how performance comparisons could be made.

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 6/30/19
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	114
Eden 11	COMPLETE	116	128
Bush 11	COMPLETE	228	104
Pioneer 12	COMPLETE	177	181
Grantsville 12	COMPLETE	250	53
TARGET SCORE = 108	**Target Met**	**135**	**116**
Program Year 13: (CY2012)			
Fielding 11	COMPLETE	207	67
East Bench 12	COMPLETE	112	16
Clinton 11	COMPLETE	133	59
Redwood 16	COMPLETE	145	72
Orangeville 11	COMPLETE	114	65
TARGET SCORE = **114**	**Target Met**	**142**	**56**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	88
Huntington City 12	COMPLETE	285	71
Magna 15	COMPLETE	140	35
Gunnison 12	COMPLETE	110	122
Capitol 11	COMPLETE	129	64
TARGET SCORE = **134**	**Target Met**	**167**	**76**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	49
North Bench 13	COMPLETE	95	84
Newgate 14	COMPLETE	164	41
Newton 12	COMPLETE	105	65
St Johns 11	COMPLETE	547	145
TARGET SCORE = **162**	**Target Met**	**203**	**77**
Program Year 10: (CY2009)			
Fruit Heights 12	COMPLETE	113	63
Mathis 12	COMPLETE	132	112
Parrish 11	COMPLETE	137	19
Valley Center 11	COMPLETE	169	46
Hammer 15	COMPLETE	95	20
TARGET SCORE = **104**	**Target Met**	**129**	**52**

Note: Goals were met for Program Years 1 through 13 and filed in prior reporting periods; however, data for Program Years 10-13 are retained in this report in order to show circuit selections over a longer period of history for discussion purposes.

2.9 Restore Service to 80% of Customers within 3 Hours

RESTORATIONS WITHIN 3 HOURS					
Reporting Period Cumulative = 86%					
January	February	March	April	May	June
87%	81%	87%	90%	86%	87%

2.10 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	112 minutes
Total Performance	144 minutes

2.11 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	87%
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[9] complaints within 30 days	100%	100%

[9] 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).

2.12 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, in order 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 two dates (February 25th and 28th) identified as a wide-scale outage days; call statistics are shown in the table below. From February 25th through March 5th areas across Oregon and Northern California began experiencing outages as the result of a severe weather event which brought a substantial accumulation of snow heavily impacting equipment. On the morning of February 25th customer outages in Oregon and California peaked at over 57,000 customers, many of which took days to restore, due to limited accessibility. A second storm on February 28th dropped more snow causing a second event peak of over 21,000 customers. Crews worked around the clock, clearing debris, surveying damage and restoring power.

Date	Interval start/finish (Mountain Time)		Network Total Calls*	Calls received but not delivered**	# of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds
2/25/2019	8:00	8:14	864	35	18	538	51
	8:15	8:29	943	0	21	281	69
	8:30	8:44	880	0	35	436	101
	8:45	8:59	810	0	15	311	104
	9:00	9:14	876	5	27	336	68
	9:15	9:29	823	0	18	385	81
	9:30	9:44	877	2	21	303	101
	9:45	9:59	814	13	45	476	153
	10:00	10:14	868	43	70	470	151
	10:15	10:29	897	64	62	456	141
	10:30	10:44	854	42	27	336	102
	10:45	11:00	893	68	40	373	124
	11:00	11:14	818	7	13	187	56
	11:15	11:29	855	15	12	148	40
	11:30	11:44	836	0	10	157	35
	11:45	11:59	942	23	17	234	62
	12:00	12:14	1196	76	31	168	38
	12:15	12:29	901	0	22	350	94
	12:30	12:44	881	0	3	106	10
	12:45	12:59	980	0	11	205	38
	13:00	13:14	1062	0	19	418	97
	13:15	13:29	880	0	20	229	100
	13:30	13:44	780	0	14	184	47
	13:45	13:59	950	55	31	303	92
	14:00	14:14	778	7	7	111	29
	14:15	14:29	887	0	2	65	8
	14:30	14:44	779	0	10	200	47
	14:45	14:59	778	14	18	221	66
	15:00	15:14	797	0	14	188	48
	15:15	15:29	736	4	20	224	62
	15:30	15:44	784	0	7	239	10
	15:45	15:59	755	0	2	69	8

UTAH

January 1 – June 30, 2019

Date	Interval start/finish (Mountain Time)		Network Total Calls*	Calls received but not delivered**	# of Calls Abandoned from Agent Queue	Max Delay Time Seconds***	ASA Seconds
	16:00	16:14	721	0	4	96	12
	16:15	16:29	788	0	4	122	11
	16:30	16:44	784	5	6	125	15
	16:45	16:59	804	0	5	200	15
2/28/2019	8:00	8:14	1932	648	26	770	36
	8:15	8:29	1356	623	153	1459	571
	8:30	8:44	1150	612	113	1359	259
	8:45	8:59	1124	669	0	22	22
	9:00	9:14	1074	610	0	0	0
	9:15	9:29	1030	659	0	0	0
	9:30	9:44	753	373	0	0	0
	9:45	9:59	773	0	0	0	0
	10:00	10:14	757	85	130	3	2
	10:15	10:29	890	479	8	7	3
	10:30	10:44	1078	760	0	7	2
	10:45	11:00	994	679	0	36	3
	11:00	11:14	868	494	0	4	2
	11:15	11:29	816	303	0	1	1
	11:30	11:44	799	277	0	1	1
	11:45	11:59	790	314	0	0	0
	12:00	12:14	800	338	0	2	2
	12:15	12:29	1058	626	0	1	1
	12:30	12:44	930	647	0	2	0
	12:45	12:59	791	579	0	0	0
	13:00	13:14	740	531	0	2	2
	13:15	13:29	793	568	0	0	0
	13:30	13:44	829	617	0	0	0
	13:45	13:59	852	652	0	0	0
	14:00	14:14	840	626	0	0	0
	14:15	14:29	890	677	0	0	0
	14:30	14:44	752	325	0	0	0
	14:45	14:59	775	309	0	0	0
	15:00	15:14	855	319	1	262	262
	15:15	15:29	792	286	1	158	11
	15:30	15:44	756	294	5	167	41
	15:45	15:59	680	276	0	79	5
	16:00	16:14	625	235	2	239	7
	16:15	16:29	631	246	1	224	5
	16:30	16:44	603	235	0	42	3
	16:45	16:59	506	172	0	62	7

Twenty First Century, an external Interactive Voice Response system, was utilized.
* All customers attempting to reach PacifiCorp Network.
** When Twenty First Century is manually invoked, the AT&T Network returns a courtesy message to non-outage callers. This includes repeated attempts.
*** Longest time any customer waited.

2.13 Utah State Customer Guarantee Summary Status

customer*guarantees*

January to June 2019

Utah

		2019				2018			
	Description	Events	Failures	% Success	Paid	Events	Failures	% Success	Paid
CG1	Restoring Supply	503,912	0	100%	$0	511,017	0	100%	$0
CG2	Appointments	4,567	2	99.96%	$100	4,475	5	99.89%	$250
CG3	Switching on Power	1,901	0	100%	$0	2,578	4	99.84%	$200
CG4	Estimates	676	2	99.70%	$100	643	2	99.69%	$100
CG5	Respond to Billing Inquiries	1,181	4	99.66%	$200	1,357	2	99.85%	$100
CG6	Respond to Meter Problems	379	1	99.74%	$50	891	4	99.55%	$200
CG7	Notification of Planned Interruptions	84,929	19	99.98%	$950	62,281	18	99.97%	$900
		597,545	**28**	**99.99%**	**$1,400**	**583,242**	**35**	**99.99%**	**$1,750**

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.

3 MAINTENANCE COMPLIANCE TO ANNUAL PLAN

3.1 T&D Preventive and Corrective Maintenance Programs

Preventive Maintenance

The primary focus of the preventive maintenance plan is to inspect facilities, identify abnormal conditions[10], 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 variations of the policies will result in refinement to 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.[11]
- 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.

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.

[10] The primary focus of the preventive maintenance plan is to inspect facilities, identify abnormal conditions, and perform appropriate preventive actions upon those facilities. 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.

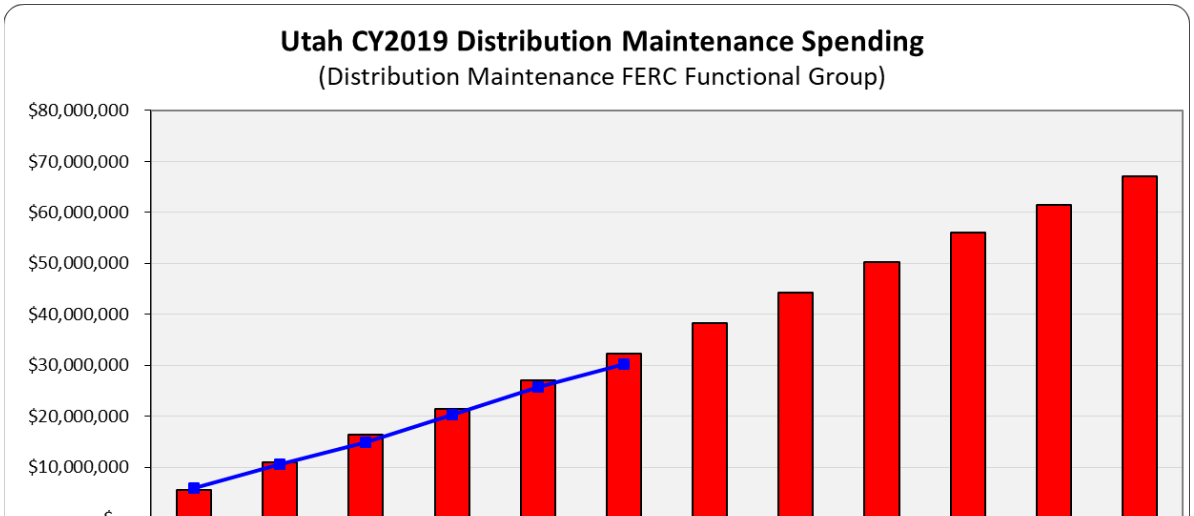
Priority D: Conditions that conform to the NESC and are not reportable to the associated State Commission. Priority G: Conditions that conform to the regulations requirement that was in place when construction took place but do not conform to more recent code adoptions. These conditions are "grandfathered" and are considered conforming.

[11] 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.

Substations and Major Equipment

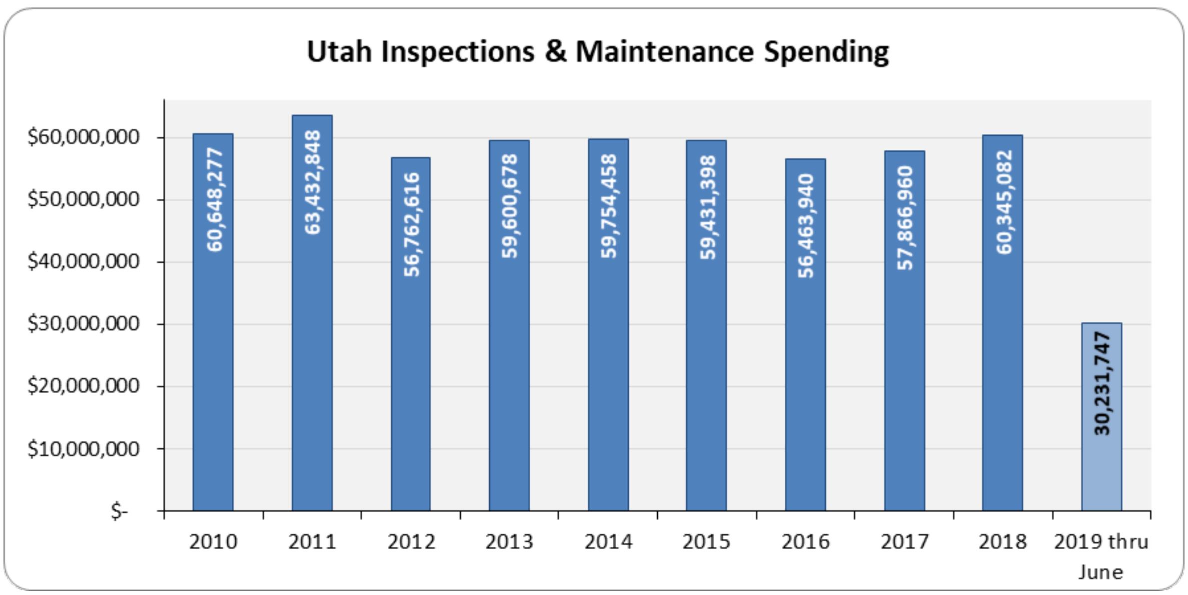
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending[12,13]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,640,418	$11,046,774	$16,391,780	$21,530,259	$26,987,244	$32,256,285	$38,211,503	$44,283,187	$50,274,054	$56,023,295	$61,444,626	$67,001,121
Actual	$5,871,293	$10,684,531	$14,957,950	$20,401,279	$25,766,569	$30,231,747						

3.2.1 Maintenance Historical Spending

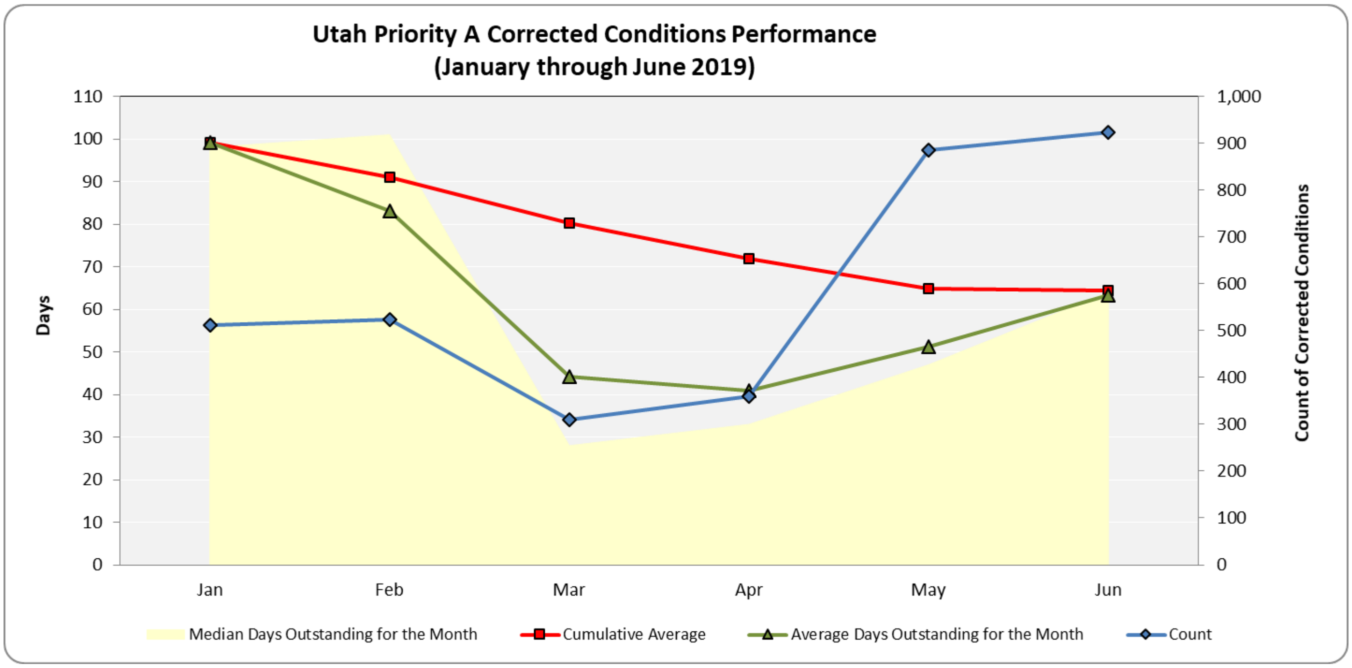


[12] Maintenance spending reflected does not include Vegetation Management and Fault Locating costs, which when reporting under FERC accounting methodology, FERC has traditionally considered maintenance.

[13] The Utah distribution maintenance total year plan of $63.8m is overstated by $6.4m due to a misplaced system allocated entry in the plan. The Utah distribution maintenance plan should be $57.4m. The overall PacifiCorp plan is correct as actual expenses for the misplaced plan item will be incurred in the correct department for which no plan exists.

3.3 Distribution Priority "A" Conditions Correction History

The Company reports history of Priority "A" corrections. This reporting element dates back to Docket-04-035-070, which expired on December 31, 2011. In this commitment the Company was required to correct distribution Priority "A" conditions on average within 120 days. After the commitment expired, stakeholders requested the Company continue to report the information, believing it to be a useful indicator of work delivered by the Company. As can be seen in the chart below, the company has consistently delivered the average age of Priority "A" conditions well below the 120 day target. In the graphic below, with the Company's identification of Fire High Consequence Areas (HFCA) early in the year, a pre-fire season inspection in the elevated threat area was undertaken which resulted in a seasonal spike in points inspected.



3.3.1 Oldest Outstanding Priority A Conditions in Utah

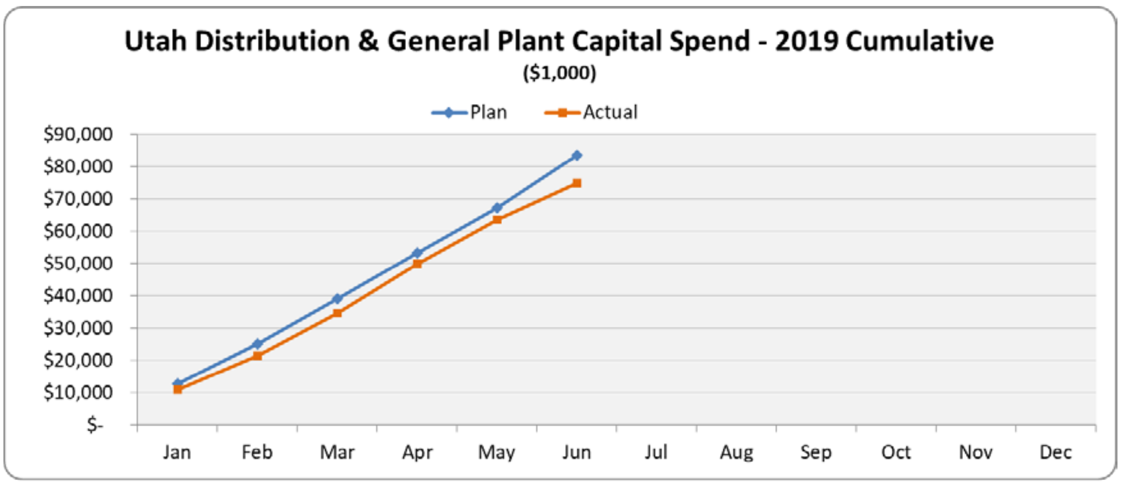
District	Plant Locality/ Mapstring	Structure #/ Facility Point	Condition	Inspection Remarks	Inspection Date	Anticipated Completion Date	Explanation
Main Grid/ UT	078002	503, 686, 474, 472, 478, 505, 508, 385,	LATMISMB	Conditions on members of lattice structures.	7/3/2018	Oct-Nov	This line underwent an engineering study to determine whether to rebuild the whole line and the materials, wood poles or steel poles. Steel poles were the chosen solution which is a long lead item. The materials have begun arriving and work is underway, expected to complete in early fall.
Metro	11201002.0	356602	COOTHER	SWITCH GEAR HAS A BROKEN SPRING 6550379	7/16/2018	September	Condition for a broken spring in the PMH serving Greencore. Working to find an acceptable time with Greencore and repairs of two other switches in the International Center. It is scheduled to be completed within the next month.
Main Grid/ UT	7800208	350, 341, 349, 190, 340	LATMISMB	Conditions on members of lattice structures.	7/17/2018	Oct-Nov	This line underwent an engineering study to determine whether to rebuild the whole line and the materials, wood poles or steel poles. Steel poles were the chosen solution which is a long lead item. The materials have begun arriving and work is underway, expected to complete in early fall.
Metro	11402001.0	019803 & 019704	POLEREPL	POLE NEEDS TO BE REPLACED	8/3/2018	September	This is part of a customer project and is awaiting customer installation of conduits. Scheduled for early fall.
Metro	11401001.0	196783	XFRMOIL	LEAKING TRANSFORMER 6558903	12/5/2018	September	Project is scheduled to be completed in early fall.

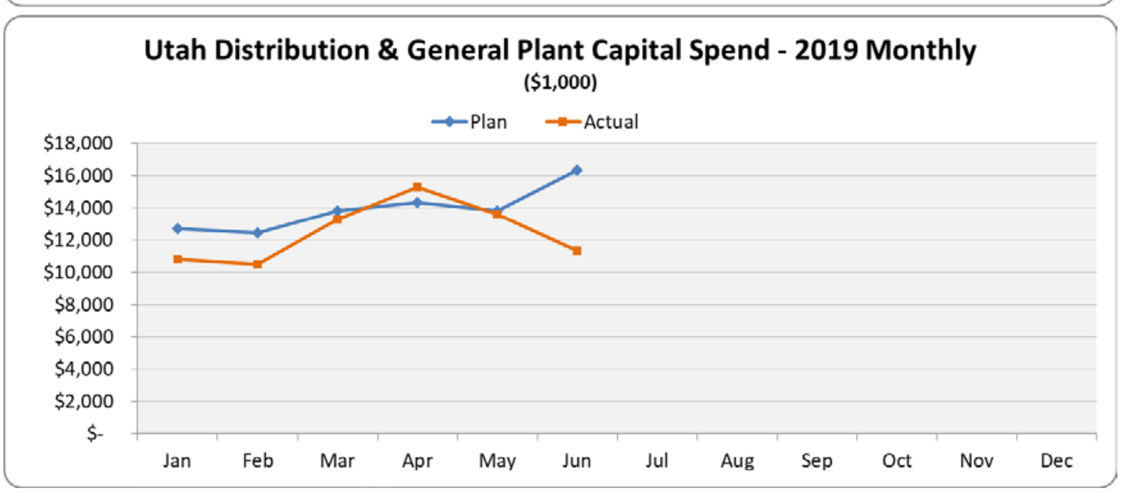
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January – June 2019

Investment		Actuals ($M)	Plan ($M)	Significant Variance Explanations
1.	Mandated	$4.8	$4.3	
2.	New Connect	$29.5	$24.0	Residential and industrial new revenue connections over plan, (+$5.1M).
3.	System Reinforcement	$7.4	$6.1	Substation reinforcement over plan, (+$1.1M).
4.	Replacement	$25.1	$24.5	Replacements for overhead distribution lines over plan, (+$2.8M); replacements for storm & casualty under plan, (-$2.0M).
5.	Upgrade & Modernize	$8.0	$24.5	Functional distribution and substation reliability upgrades over plan, (+$2.7M); feeder improvements under plan (-$18.9M - including -$18.8M for advanced metering infrastructure).
	Total	**$74.8**	**$83.5**	



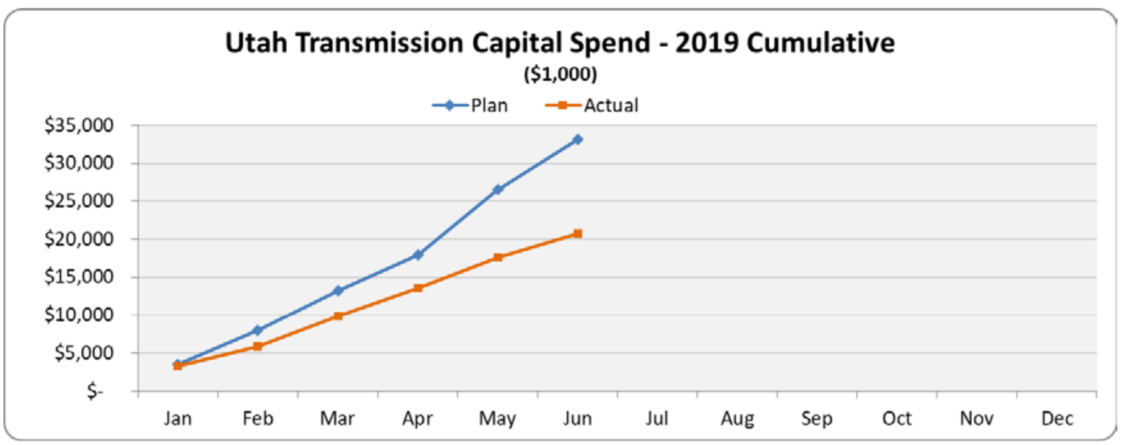


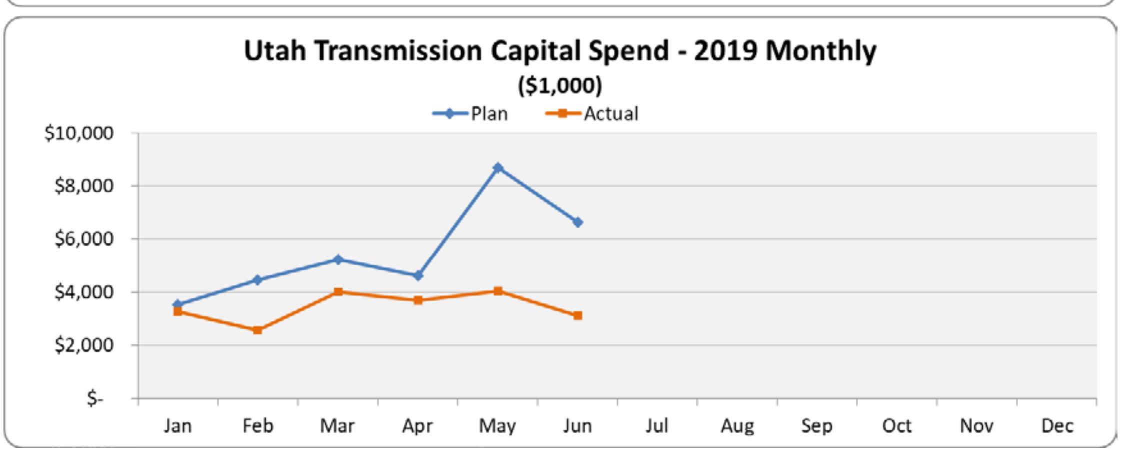
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending – Transmission/Interconnections

January – June 2019

Investment		Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	1.3	4.5	Mandated right of way renewals under plan, (-$3.4M).
2.	New Connect	1.3	0.5	
3.	Local Trans-mission System Reinforcements	3.7	6.1	Substation reinforcement over plan, (+$1.0M); sub-transmission reinforcement under plan, (-$3.5M).
**4.	Main Grid Reinforcements / Interconnections	5.3	13.6	Naples 138-12.5 kV New Substation project re-sequenced, (-$0.9M); 90th Bus Tie Breaker project in-service delayed to Oct 2019, (-$1.0M); permitting delays shifting Bull River Saratoga Rebuild project in-service to 2020, (-$1.5M); unidentified generation interconnections under plan, (-$4.0M).
**5.	Energy Gateway Transmission	0.8	1.5	
6.	Replacement	7.9	6.0	Replacements for overhead transmission poles over plan, (+$1.4M).
7.	Upgrade & Modernize	0.5	0.8	
	Total	**20.7**	**33.2**	





* 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.

4.3 New Connects

	2018	2019												
	YEAR	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	YEAR
Residential														
UT South	1,486	94	147	97	97	95	60	-	-	-	-	-	-	590
UT North/Metro	6,443	269	667	372	625	462	343	-	-	-	-	-	-	2,738
UT Central	12,236	826	1,140	820	844	947	627	-	-	-	-	-	-	5,204
Total Residential	**20,165**	**1,189**	**1,954**	**1,289**	**1,566**	**1,504**	**1,030**	**-**	**-**	**-**	**-**	**-**	**-**	**8,532**
Commercial														
UT South	262	14	13	14	15	22	17	-	-	-	-	-	-	95
UT North/Metro	762	66	26	47	73	67	91	-	-	-	-	-	-	370
UT Central	980	105	54	78	94	62	69	-	-	-	-	-	-	462
Total Commercial	**2,004**	**185**	**93**	**139**	**182**	**151**	**177**	**-**	**-**	**-**	**-**	**-**	**-**	**927**
Industrial														
UT South	0	0	0	0	0	0	0	-	-	-	-	-	-	0
UT North/Metro	9	0	0	0	0	0	0	-	-	-	-	-	-	0
UT Central	2	0	0	1	2	0	0	-	-	-	-	-	-	3
Total Industrial	**11**	**0**	**0**	**1**	**2**	**0**	**0**	**-**	**-**	**-**	**-**	**-**	**-**	**3**
Irrigation														
UT South	67	0	0	5	7	8	4	-	-	-	-	-	-	24
UT North/Metro	7	0	0	1	0	0	2	-	-	-	-	-	-	3
UT Central	24	0	0	1	3	1	1	-	-	-	-	-	-	6
Total Irrigation	**98**	**0**	**0**	**7**	**10**	**9**	**7**	**-**	**-**	**-**	**-**	**-**	**-**	**33**
TOTAL New Connects														
UT South	1,815	108	160	116	119	125	81	-	-	-	-	-	-	709
UT North/Metro	7,221	335	693	420	698	529	436	-	-	-	-	-	-	3,111
UT Central	13,242	931	1,194	900	943	1,010	697	-	-	-	-	-	-	5,675
TOTAL New Connects	**22,278**	**1,374**	**2,047**	**1,436**	**1,760**	**1,664**	**1,214**	**-**	**-**	**-**	**-**	**-**	**-**	**9,495**

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.
Smithfield and Laketown are excluded because the report was developed using an old coding system that included them under ID/ WY WEST and not Utah.
Temporary connections used to be included in our reports because there is no coding involved and, therefore, was no way to accurately remove them. They did not double count new connections because when a permanent connection was established the temporary went away. 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 skewed the volumes considerably and made historic trend comparison useless. We have, therefore, done what we can, to eliminate temporary connections from our reporting since that time.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH
Tree Program Reporting
January 1, 2019 through June 30, 2019
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2019-6/30/2019 Miles Planned	1/1/2019-6/30/2019 Actual Miles	1/1/2019-6/30/2019 Ahead/Behind	1/1/2019-6/30/2019 % Ahead/Behind	1/1/2017-12/31/2019 Miles Planned	1/1/2017-12/31/2019 Actual Miles	01/01/2017-12/31/2019 Ahead/Behind	1/1/2017-12/31/2019 % Ahead/Behind
	column a	*column b*	*column c*	*column d*	*column e*	*column f*	*column g*	*column h*	*column i*
UTAH	10,747	1,592	1,301	-291	82%	9,018	8,240	-778	91%
AMERICAN FORK	830	172	149	-23	87%	701	633	-68	90%
CEDAR CITY	1,378	260	162	-98	62%	1,155	991	-164	86%
JORDAN VALLEY	774	118	33	-85	28%	630	576	-54	91%
LAYTON	299	3	0	-3	0%	245	267	22	109%
MOAB	630	62	124	62	200%	523	644	121	123%
OGDEN	885	147	163	16	111%	796	662	-134	83%
PARK CITY	551	76	0	-76	0%	462	397	-65	86%
PRICE	592	50	35	-15	70%	493	472	-21	96%
RICHFIELD	1,344	266	209	-57	79%	1,120	1,020	-100	91%
SL METRO	1,235	173	154	-19	89%	1,072	981	-91	92%
SMITHFIELD	765	148	112	-36	76%	641	581	-60	91%
TOOELE	480	0	0	0	0%	405	236	-169	58%
TREMONTON	734	81	160	79	198%	565	604	39	107%
VERNAL	250	36	0	-36	0%	210	176	-34	84%

Distribution cycle $/tree:	$127.96
Distribution cycle $/mile:	$3,313
Distribution cycle removal %	7%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	% of miles on/behind Schedule
6,575	1,161	164	-997	14%

Current distribution cycle begain January 1, 2017 and extends until December 31, 2019.

Notes:

Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2019 through June 30, 2019
Column c: Actual overhead distribution pole miles worked during the period January 1, 2019 through June 30, 2019
Column d: Miles ahead or behind for the period January 1, 2019 through June 30, 2019 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2019 through June 30, 2019 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2017 through December 31, 2019
Column g: Actual overhead distribution pole miles worked during the period January 1 2017 through December 31, 2019
Column h: Miles ahead or behind for the period January 1, 2017 through December 31, 2019 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2017 through December 31, 2019 ((column g÷f)×100). Max = 100%

5.2 Budget

UTAH

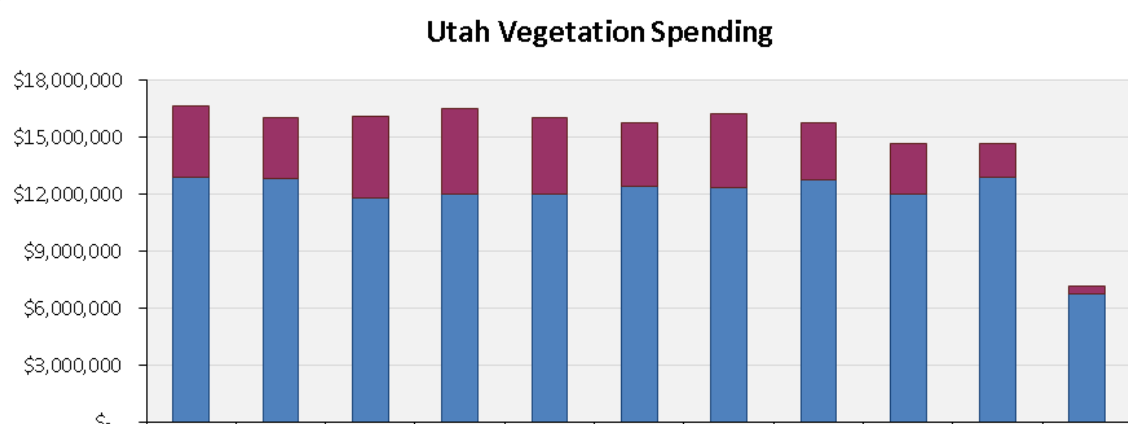
Tree Program Reporting

	CY2019	CY2020	CY2021
Distribution	$11,750,259	$11,750,259	$11,750,259
Transmission	$2,046,558	$2,046,558	$2,046,558
Total Tree Budget	$13,796,817	$13,796,817	$13,796,817

Calendar Year 2019	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$1,123,264	$867,811	$255,453	$24,261	$170,546	-$146,285
Feb	$845,478	$1,090,565	-$245,087	$28,894	$170,546	-$141,652
Mar	$1,070,419	$979,188	$91,231	$70,843	$170,546	-$99,703
Apr	$1,284,150	$979,188	$304,962	$69,515	$170,546	-$101,031
May	$1,132,149	$979,188	$152,961	$64,163	$170,546	-$106,383
Jun	$1,297,399	$1,090,565	$206,834	$144,703	$170,546	-$25,843
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	$6,752,859	$5,986,505	$766,354	$402,379	$1,023,276	-$620,897

Average # Tree Crews on Property (YTD) **57**

6 Vegetation Historical Spending



	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	June 2019
Transmission	3,716,266	3,180,955	4,245,089	4,483,668	4,070,233	3,360,658	3,873,554	3,015,928	2,646,405	1,742,553	402,379
Distribution	12,934,364	12,866,264	11,837,421	12,037,620	11,991,602	12,403,052	12,385,378	12,767,302	12,046,259	12,907,635	6,752,859

Miscellaneous = storm and casualty, line extension work, special request projects, administrative.

7 Appendix

7.1 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[14] 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 a given 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
In order 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 time-frame. 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).

[14] IEEE 1366-2003 was adopted by the IEEE 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.

$MAIFI_E$

$MAIFI_E$ (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 time-frame. 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 (RPI) 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 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
1/1-12/31/2019	946,168	5.08	4,809,295

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 situation.

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.

CERTIFICATE OF SERVICE

Docket No. 19-035-19

I hereby certify that on November 1, 2019, a true and correct copy of the foregoing was served by electronic mail to the following:

Utah Office of Consumer Services

Cheryl Murray	cmurray@utah.gov
Michele Beck	mbeck@utah.gov

Division of Public Utilities

dpudatarequest@utah.gov

Assistant Attorney General

Patricia Schmid	pschmid@agutah.gov
Justin Jetter	jjetter@agutah.gov
Robert Moore	rmoore@agutah.gov
Steven Snarr	stevensnarr@agutah.gov

Rocky Mountain Power

Data Request Response Center	datarequest@pacificorp.com
Jana Saba	jana.saba@pacificorp.com; utahdockets@pacificorp.com

Mary Penfield
Adviser, Regulatory Operations