1407 W North Temple, Suite 310
Salt Lake City, Utah 84116

April 28, 2017

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT 84111

Attention: Gary Widerburg
Commission Secretary

Re: Docket 08-035-55
Service Quality Standards –June 2013 Service Quality Review Report
Docket No. 13-035-70,
Rocky Mountain Power's Service Quality Review Report

In compliance with the Commission's June 11, 2009 order in Docket 08-035-55 and December 20, 2016 order in Dockets 13-035-01 and 15-035-72, and pursuant to the requirements of Rule R746-313, Rocky Mountain Power submits the Service Quality Review Report for the period January through December 2016.

It is respectfully requested that all formal correspondence and Staff requests regarding this matter be addressed to:

By E-mail (preferred): datarequest@pacificorp.com
bob.lively@pacificorp.com

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

Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Sincerely,

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

UTAH
SERVICE QUALITY
REVIEW

January 1 – December 31, 2016
Report

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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 high 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 have been working to develop mechanisms that comply with these rules and that will supersede the Company's Service Standards Program.

1.2 Rocky Mountain Power Performance Standards[2]

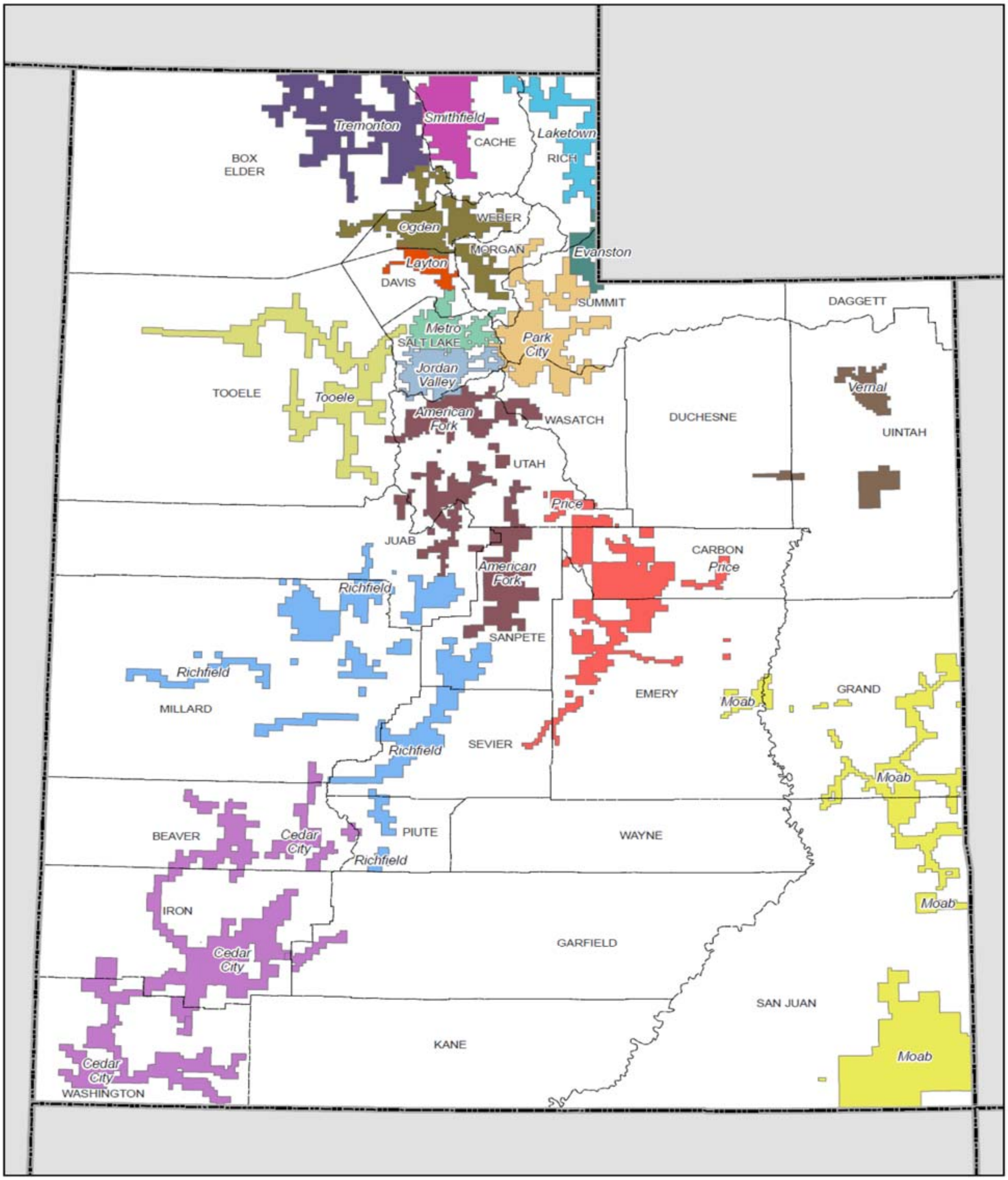
*Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	In 2016 Utah Commission adopted a modified 365-day rolling (rather than calendar year) performance baseline control zone of between 137-187 minutes.
*Network Performance Standard 2: Improve System Average Interruption 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 Circuits	The Company will reduce by 20% the circuit performance indicator (CPI) for a maximum of five underperforming circuits on an annual basis within five years after selection[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 a modified electric service reliability performance baseline notification levels to 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] The Company proposed modifications to its reliability improvement program which are under review by stakeholders. These changes are discussed further 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 experienced underlying interruption duration (SAIDI) and interruption frequency (SAIFI) performance in Utah that was favorable to target and also 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 2016 underlying reliability results fall within 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. Baselines are discussed in Section 2.5. Cause code information, which is reported consistently with past Service Quality Review Reports, is shown 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 were four major events[4] (all of which have been accepted as a major event by the Utah Commission upon recommendation of the Utah Division of Public Utilities) and three significant event days[5] recorded.

Major Event Descriptions

Major Events		
Date	**Cause**	**SAIDI**
February 18-19, 2016	Storm	9.65
April 30 – May 1, 2016	Wind storm	36.86
May 19-20, 2016	Lightning storm	11.29
September 22-24, 2016	Wind and rain storm	34.15
Total		**91.95**

- **February 18-19, 2016**
  Utah experienced a severe windstorm which heavily impacted areas in and around the Salt Lake City Valley with high winds, wet snow and lightning. First, winds gusting above 75 mph blew through the Salt Lake Valley, uprooting trees and launching windborne debris. Thereafter snow followed, impacting travel and loading electrical lines with snow. This major event filing was accepted by the Utah Commission on 5/13/16 in Docket 16-035-13.
- **April 30 - May 1, 2016**
  On the evening of, April 30, 2016, a strong easterly down-sloping wind began severely impacting facilities in Weber and Davis Counties. High winds continued through the next day with gusts reported as high as 91 mph. Wind and tree-related outages broke poles and ripped equipment and mounting hardware. This major event filing was accepted by the Utah Commission on 7/11/16 in Docket 16-035-24.
- **May 19-20, 2016**
  On May 19, 2016, a lightning storm made its way across the northern portion of Utah. The storm brought wind and lightning to the area causing large scale outages to the distribution and transmission network. Transmission feeds were heavily impacted when lightning destroyed static lines which then dropped into transmission lines, causing several circuit breakers to trip and de-energize. As several transmission feeds were lost, loading levels on alternate sources increased, causing those sources to overload and de-energize

[4] Major event threshold shown below:

Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2016	876,438	6.06	5,312,799

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

consistent with reliability standards requirements. This major event filing was accepted by the Utah Commission on 8/16/16 in Docket 16-035-31.

- **<u>September 22-24, 2016</u>**
  On the evening of September 21, 2016, Rocky Mountain Power customers in Tremonton and Smithfield, Utah, began experiencing outages, as a storm bringing high winds and lightning developed. The storm then moved to the south where it continued to grow in strength over the next day and by the afternoon of September 22 it began to heavily impacting customers in the Layton and Ogden operating areas. In addition to the strong wind and lightning, several areas experienced damage caused by a tornado which was accompanied by heavy rains. This weather delayed restoration activities. Over the course of the major event Layton recorded maximum sustained wind speeds of 60 mph, wind gusts of up to75 mph, and approximately 3.45 inches of rain. This major event filing was accepted by the Utah Commission on 11/21/16 in Docket 16-035-44.

Significant Events

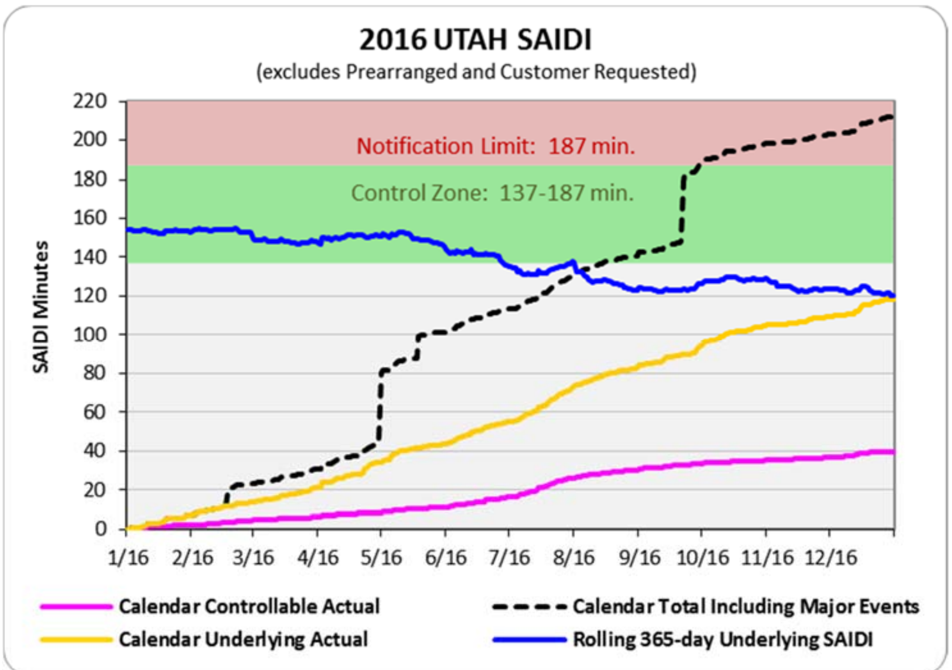
Significant event days add substantially to year-on-year cumulative performance results; fewer significant event days generally result in better reliability for the reporting period, while more significant event days generally mean poorer reliability results. For the year three significant event days were recorded, which account for 7.9 SAIDI minutes; about 7% of the reporting period's underlying 120 SAIDI minutes. These significant events were triggered by weather impacts, loss of supply outages, and pole fires. The extremely small number of significant events is notable and was a primary reason that underlying performance reliability results for the year were well below target and baseline levels.

Significant Event Days					
Dates	**Cause: General Description**	**SAIDI**	**SAIFI**	**% Underlying SAIDI**	**% Underlying SAIFI**
April 3, 2016	Wind & Lightning in Salt Lake City Metro	2.8	0.031	2.4%	3.0%
May 6, 2016	Loss of substation in American Fork	2.6	0.015	2.2%	1.5%
December 16, 2016	Pole fires across the state	2.5	0.015	2.1%	1.4%
	TOTAL	**7.9**	**0.061**	**6.7%**	**5.9%**

2.1 System Average Interruption Duration Index (SAIDI)

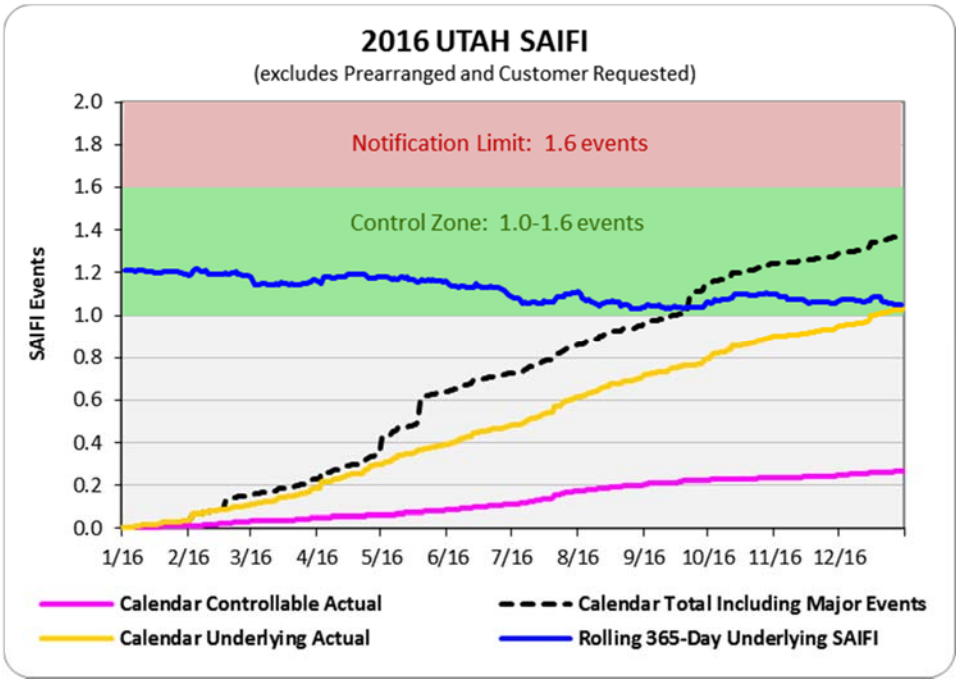
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below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

SAIDI	Reporting Period
Total	212
Underlying	120
Controllable Distribution	40



2.2 System Average Interruption Frequency Index (SAIFI)

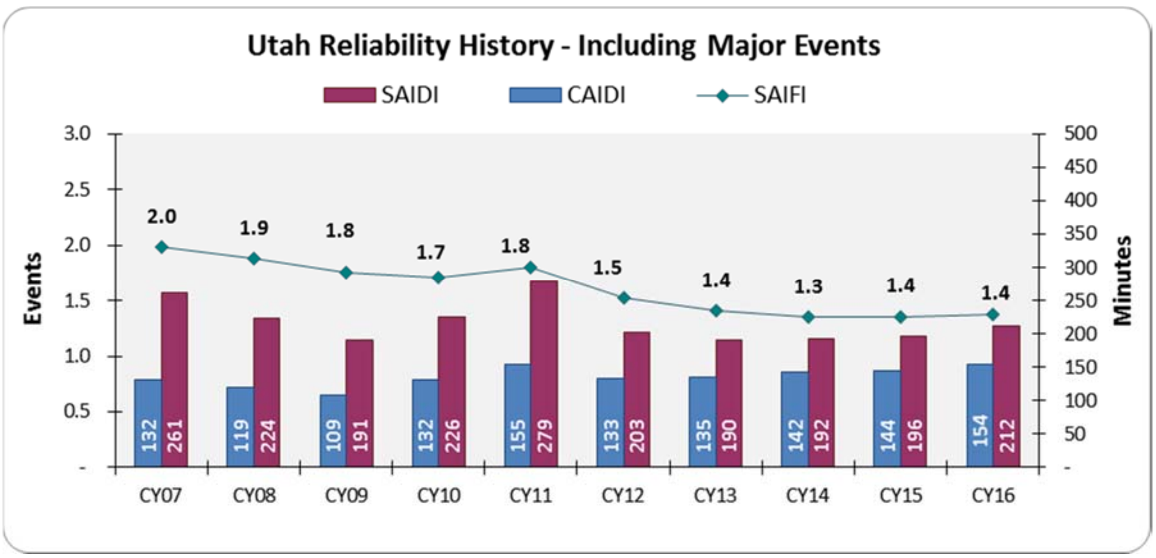
SAIFI	Reporting Period
Total	1.372
Underlying	1.042
Controllable Distribution	0.265

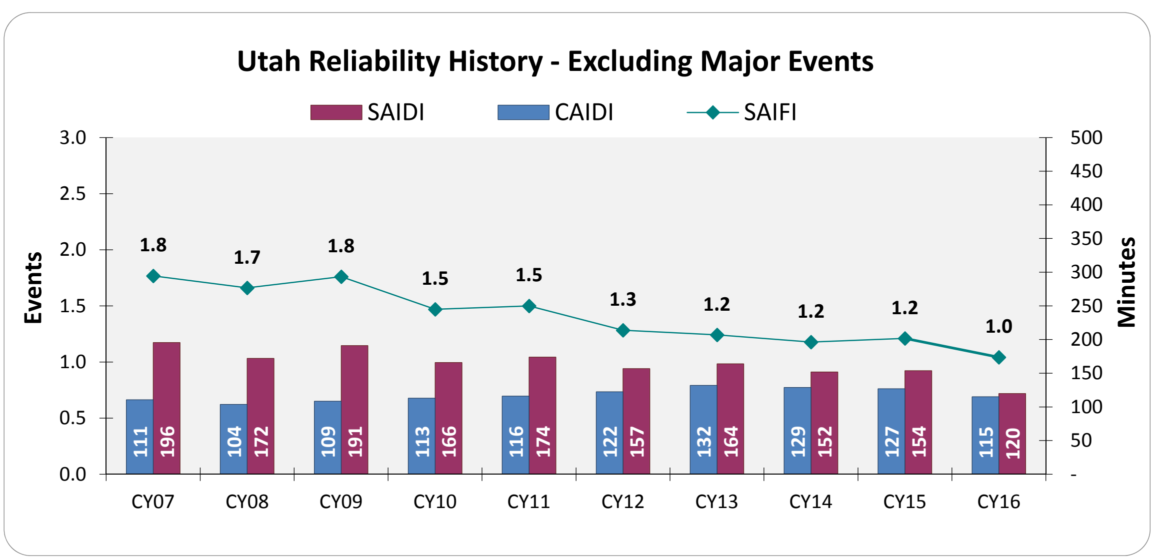


2.3 Reliability History

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 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.

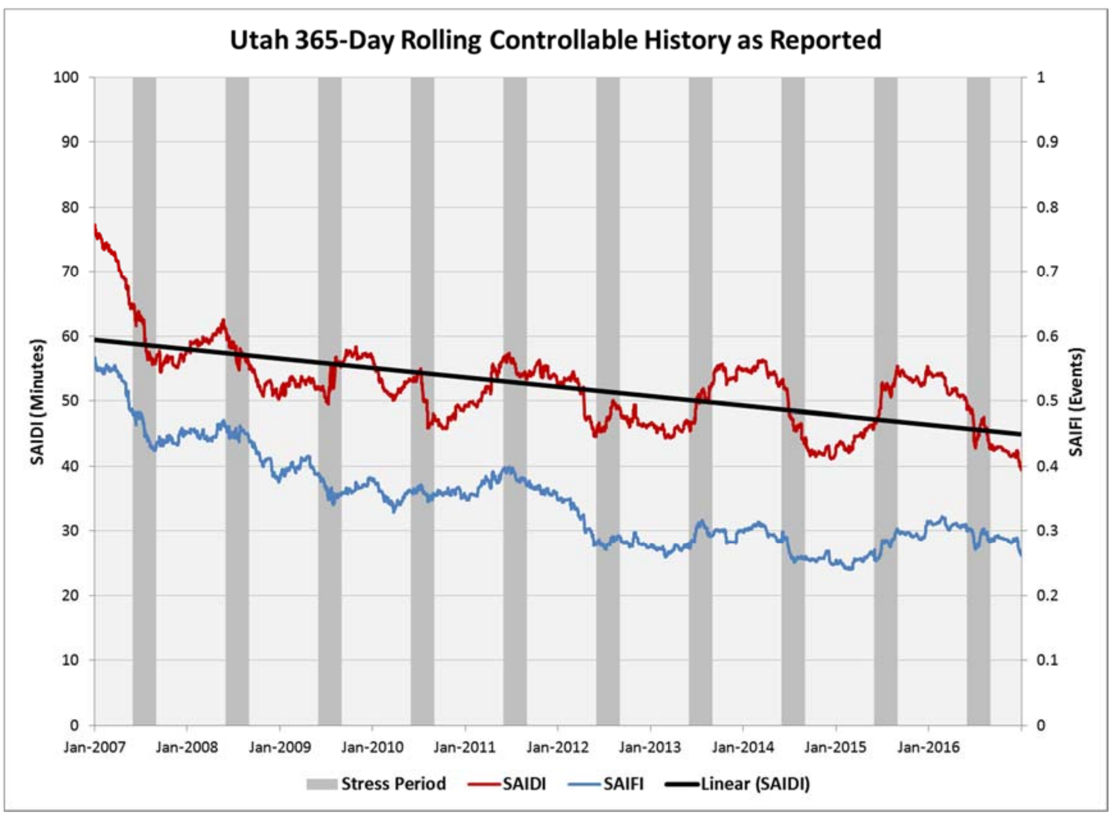




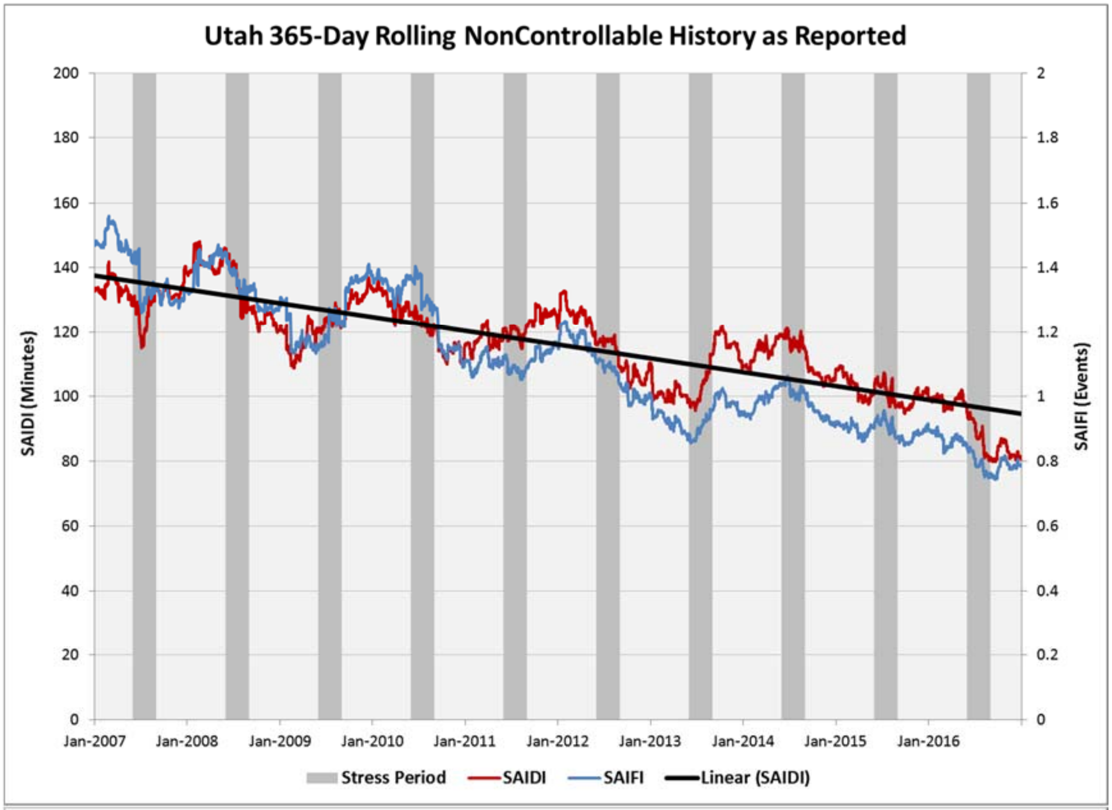
2.4 Controllable, Non-Controllable and Underlying Performance Review

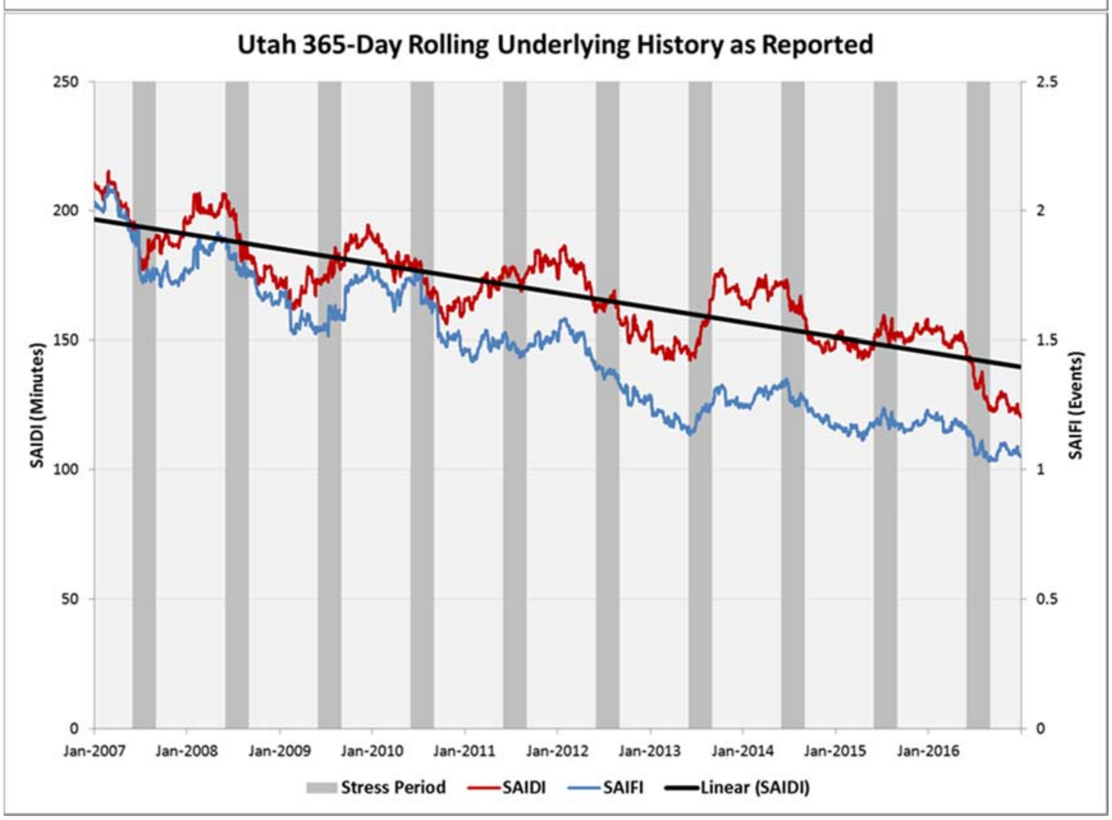
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as developed by engineering resources. This categorization was titled Controllable Distribution outages and recognized that certain types of outages can be cost-effectively avoided. So, for example, animal-caused interruptions, as well as 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[6]. 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.



[6] 3. The Company shall provide, as an appendix to its Service Quality Review reports, information regarding non-controllable outages, including, when applicable, descriptions of efforts made by the Company to improve service quality and reliability for causes the Company has identified as not controllable.
4. The Company shall provide a supplemental filing, within 90 days, consisting of a process for measuring performance and improvements for the non-controllable events.


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


Utah 365-Day Rolling Underlying History as Reported
SAIDI (Minutes)
SAIFI (Events)
0
50
100
150
200
250
0
0.5
1
1.5
2
2.5
Jan-2007
Jan-2008
Jan-2009
Jan-2010
Jan-2011
Jan-2012
Jan-2013
Jan-2014
Jan-2015
Jan-2016
Stress Period
SAIDI
SAIFI
Linear (SAIDI)

2.5 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.

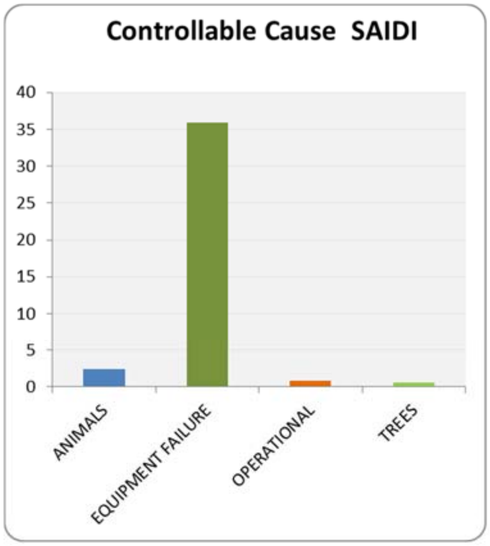
The cause analysis tables below detail SAIDI[7] and SAIFI by direct cause, with separate tables for the company's Controllable metrics and its Underlying metrics. (Both tables exclude major events.) Following the detail tables are pie charts showing the percentages attributed to each cause category with respect to three measures: total incidents, total customer minutes lost and total sustained customer interruptions, again with separate pie charts for Controllable and Underlying.

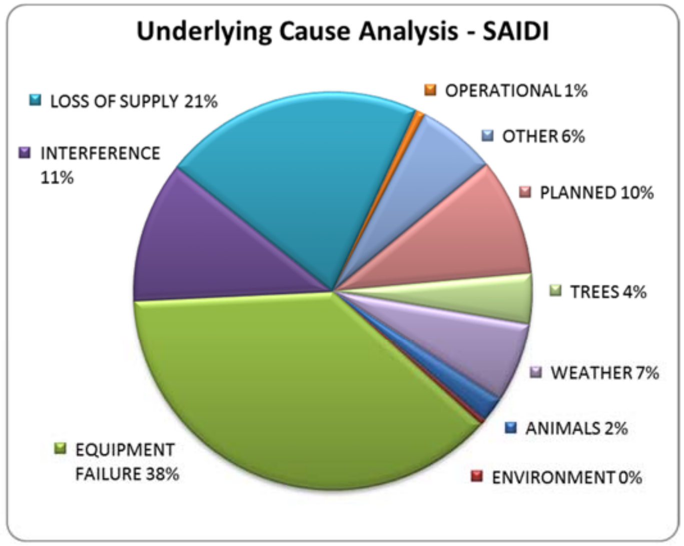
Note that the Underlying cause analysis table includes prearranged outages (*Customer Requested and Customer Notice Given* line items) with subtotals for their inclusion, while the grand totals in the table exclude these prearranged outages so that grand totals align with reported SAIDI and SAIFI metrics 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.

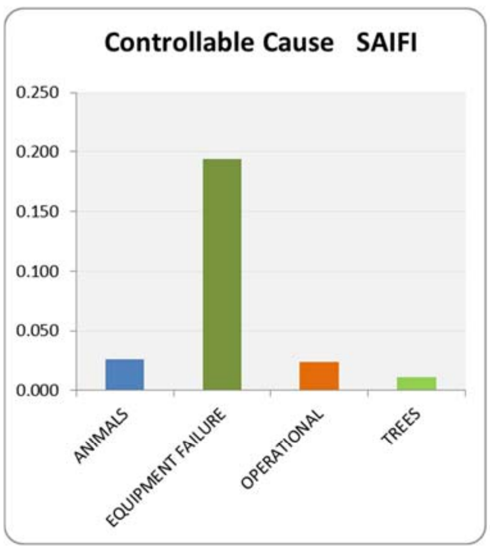
Utah Cause Analysis - Controllable 1/1/2016 - 12/31/2016					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	776,011	8,906	474	0.89	0.010
BIRD MORTALITY (NON-PROTECTED SPECIES)	306,207	5,161	284	0.35	0.006
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	567,409	3,727	62	0.65	0.004
BIRD NEST (BMTS)	27,181	283	32	0.03	0.000
BIRD SUSPECTED, NO MORTALITY	473,939	4,836	144	0.54	0.006
ANIMALS	**2,150,746**	**22,913**	**996**	**2.45**	**0.026**
B/O EQUIPMENT	2,704,468	18,437	518	3.09	0.021
DETERIORATION OR ROTTING	27,961,970	146,535	3,548	31.90	0.167
OVERLOAD	751,746	5,103	87	0.86	0.006
RELAYS, BREAKERS, SWITCHES	842	7	18	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	15,505	77	34	0.02	0.000
EQUIPMENT FAILURE	**31,434,531**	**170,159**	**4,205**	**35.87**	**0.194**
FAULTY INSTALL	213,664	3,948	22	0.24	0.005
IMPROPER PROTECTIVE COORDINATION	108,907	1,457	13	0.12	0.002
INCORRECT RECORDS	11,993	565	23	0.01	0.001
INTERNAL CONTRACTOR	50,721	497	6	0.06	0.001
PACIFICORP EMPLOYEE - FIELD	298,821	11,441	23	0.34	0.013
PACIFICORP EMPLOYEE - SUB	50,096	2,933	8	0.06	0.003
OPERATIONAL	**734,202**	**20,841**	**95**	**0.84**	**0.024**
TREE - TRIMMABLE	507,725	9,967	121	0.58	0.011
TREES	**507,725**	**9,967**	**121**	**0.58**	**0.011**
Utah Including Prearranged	**34,827,204**	**223,880**	**5,417**	**39.7**	**0.255**

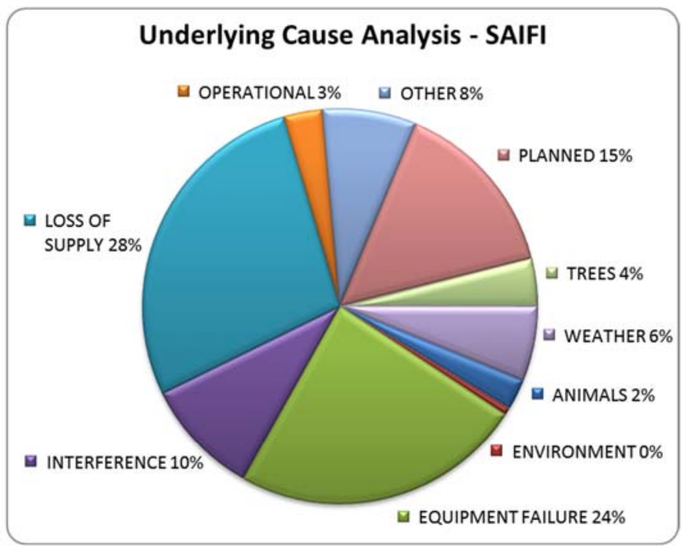
[7] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 876,438 (2016 Utah frozen customer count).

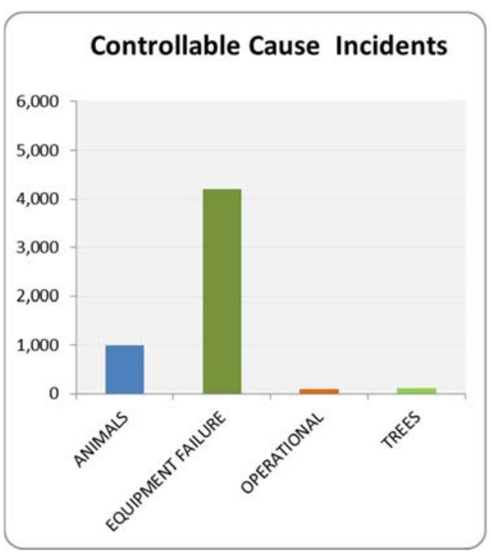
Utah Cause Analysis - Underlying 01/01/2016 - 12/31/2016					
Direct Cause	**Customer Minutes Lost for Incident**	**Customers in Incident Sustained**	**Sustained Incident Count**	**SAIDI**	**SAIFI**
ANIMALS	776,011	8,906	474	0.89	0.010
BIRD MORTALITY (NON-PROTECTED SPECIES)	306,207	5,161	284	0.35	0.006
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	567,409	3,727	62	0.65	0.004
BIRD NEST (BMTS)	27,181	283	32	0.03	0.000
BIRD SUSPECTED, NO MORTALITY	473,939	4,836	144	0.54	0.006
ANIMALS	**2,150,746**	**22,913**	**996**	**2.45**	**0.026**
CONDENSATION / MOISTURE	3,556	17	6	0.00	0.000
CONTAMINATION	130,578	1,781	3	0.15	0.002
FIRE/SMOKE (NOT DUE TO FAULTS)	317,164	3,438	34	0.36	0.004
FLOODING	1,075	9	3	0.00	0.000
ENVIRONMENT	**452,373**	**5,245**	**46**	**0.52**	**0.006**
B/O EQUIPMENT	2,704,468	18,437	518	3.09	0.021
DETERIORATION OR ROTTING	27,961,970	146,535	3,548	31.90	0.167
NEARBY FAULT	85,713	1,687	4	0.10	0.002
OVERLOAD	751,746	5,103	87	0.86	0.006
POLE FIRE	7,995,699	46,664	228	9.12	0.053
RELAYS, BREAKERS, SWITCHES	842	7	18	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	15,505	77	34	0.02	0.000
EQUIPMENT FAILURE	**39,515,943**	**218,510**	**4,437**	**45.09**	**0.249**
DIG-IN (NON-PACIFICORP PERSONNEL)	3,012,631	22,665	243	3.44	0.026
OTHER INTERFERING OBJECT	463,450	5,033	85	0.53	0.006
OTHER UTILITY/CONTRACTOR	156,193	1,574	43	0.18	0.002
VANDALISM OR THEFT	4,261	18	14	0.00	0.000
VEHICLE ACCIDENT	8,407,029	58,562	316	9.59	0.067
INTERFERENCE	**12,043,563**	**87,852**	**701**	**13.74**	**0.100**
FAILURE ON OTHER LINE OR STATION	452	3	22	0.00	0.000
LOSS OF FEED FROM SUPPLIER	955	8	1	0.00	0.000
LOSS OF SUBSTATION	11,286,737	103,444	140	12.88	0.118
LOSS OF TRANSMISSION LINE	10,990,423	149,065	355	12.54	0.170
LOSS OF SUPPLY	**22,278,567**	**252,520**	**518**	**25.42**	**0.288**
FAULTY INSTALL	213,664	3,948	22	0.24	0.005
IMPROPER PROTECTIVE COORDINATION	108,907	1,457	13	0.12	0.002
INCORRECT RECORDS	11,993	565	23	0.01	0.001
INTERNAL CONTRACTOR	50,721	497	6	0.06	0.001
PACIFICORP EMPLOYEE - DISPATCH	51,343	8,064	3	0.06	0.009
PACIFICORP EMPLOYEE - FIELD	298,821	11,441	23	0.34	0.013
PACIFICORP EMPLOYEE - SUB	50,096	2,933	8	0.06	0.003
OPERATIONAL	**785,546**	**28,905**	**98**	**0.90**	**0.033**
OTHER, KNOWN CAUSE	391,758	5,725	134	0.45	0.007
UNKNOWN	6,346,294	64,582	1,102	7.24	0.074
OTHER	**6,738,052**	**70,307**	**1,236**	**7.69**	**0.080**
CONSTRUCTION	255,672	3,102	213	0.29	0.004
CUSTOMER NOTICE GIVEN	20,031,503	119,905	2,852	22.86	0.137
CUSTOMER REQUESTED	287,683	1,115	40	0.33	0.001
EMERGENCY DAMAGE REPAIR	8,767,707	113,817	1,235	10.00	0.130
ENERGY EMERGENCY INTERRUPTION	11,380	63	5	0.01	0.000
INTENTIONAL TO CLEAR TROUBLE	731,719	10,463	79	0.83	0.012
MAINTENANCE	557	1	271	0.00	0.000
PLANNED NOTICE EXEMPT	504,521	8,534	216	0.58	0.010
TRANSMISSION REQUESTED	248,387	7,718	12	0.28	0.009
PLANNED	**30,839,128**	**264,718**	**4,923**	**35.19**	**0.302**
TREE - NON-PREVENTABLE	3,801,245	25,853	423	4.34	0.029
TREE - TRIMMABLE	507,725	9,967	121	0.58	0.011
TREES	**4,308,969**	**35,820**	**544**	**4.92**	**0.041**
FREEZING FOG & FROST	65,199	701	3	0.07	0.001
ICE	4,750	34	6	0.01	0.000
LIGHTNING	2,545,186	23,749	374	2.90	0.027
SNOW, SLEET AND BLIZZARD	1,112,881	7,999	112	1.27	0.009
WIND	3,085,239	23,165	364	3.52	0.026
WEATHER	**6,813,255**	**55,648**	**859**	**7.77**	**0.063**
Utah Including Prearranged	**125,926,142**	**1,042,438**	**14,358**	**143.7**	**1.189**
Utah Excluding Prearranged	**105,102,435**	**912,884**	**11,250**	**119.9**	**1.042**

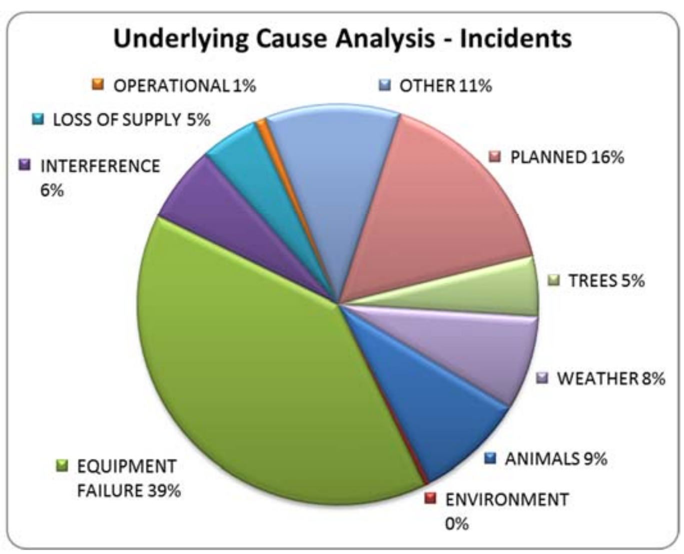

Controllable Cause SAIDI
40
35
30
25
20
15
10
5
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES

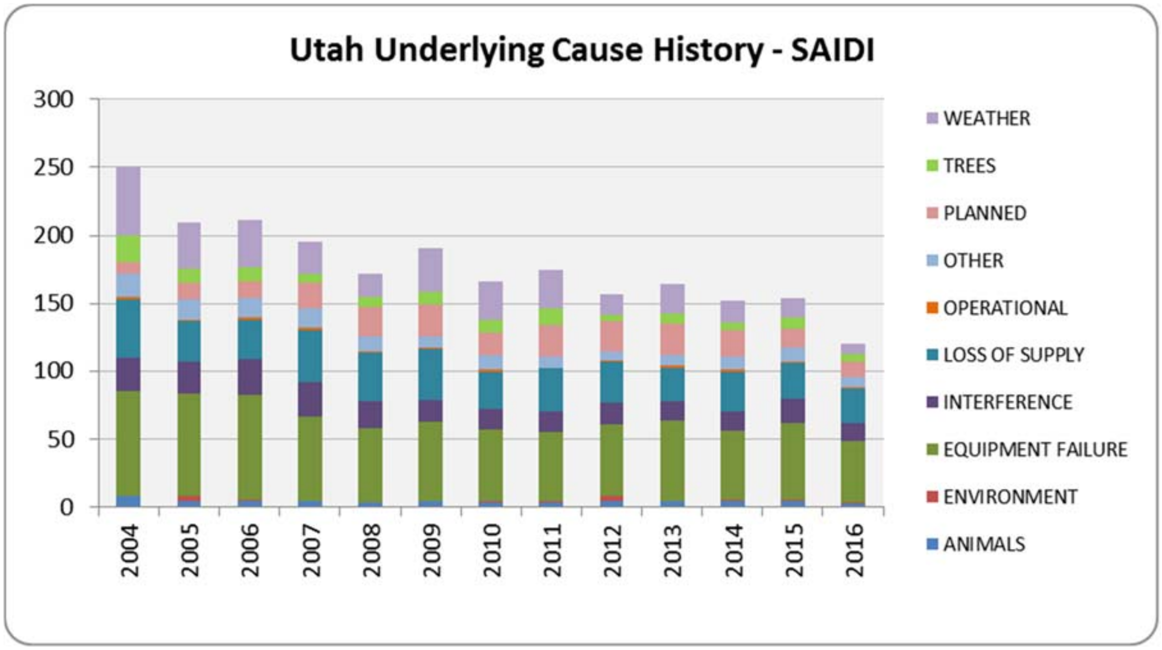

Underlying Cause Analysis - SAIDI
LOSS OF SUPPLY 21%
OPERATIONAL 1%
OTHER 6%
INTERFERENCE 11%
PLANNED 10%
TREES 4%
WEATHER 7%
ANIMALS 2%
EQUIPMENT FAILURE 38%
ENVIRONMENT 0%

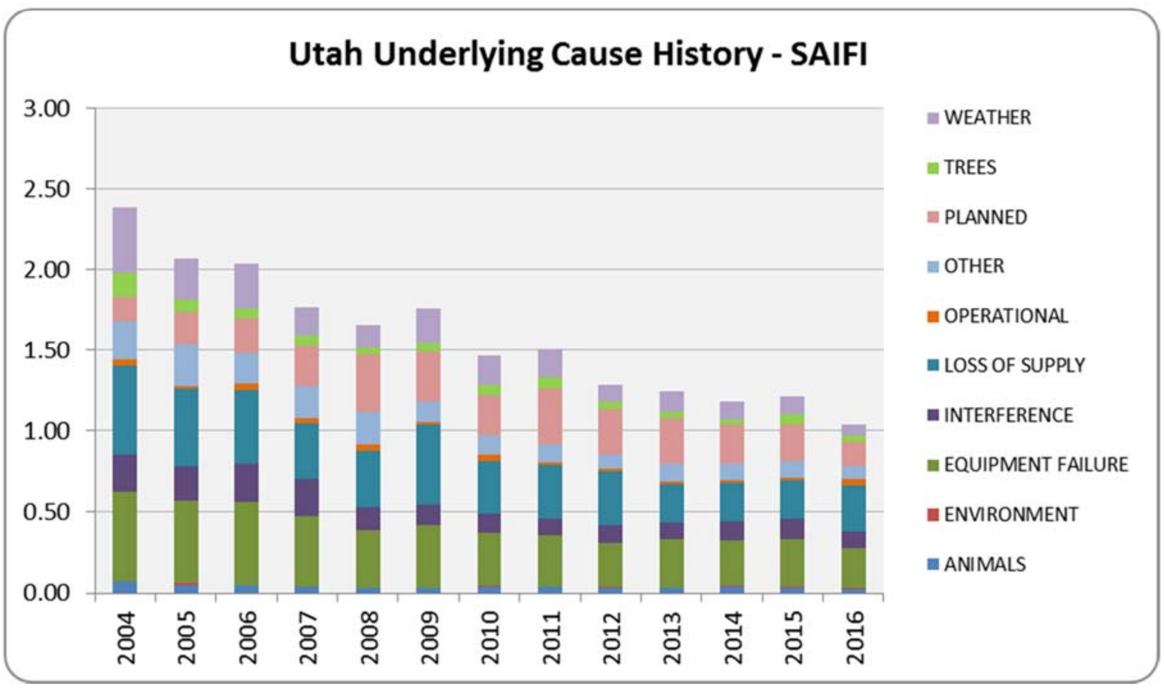

Controllable Cause SAIFI
0.250
0.200
0.150
0.100
0.050
0.000
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - SAIFI
OPERATIONAL 3%
OTHER 8%
PLANNED 15%
LOSS OF SUPPLY 28%
TREES 4%
WEATHER 6%
ANIMALS 2%
ENVIRONMENT 0%
INTERFERENCE 10%
EQUIPMENT FAILURE 24%


Controllable Cause Incidents
6,000
5,000
4,000
3,000
2,000
1,000
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TREES


Underlying Cause Analysis - Incidents
OPERATIONAL 1%
OTHER 11%
LOSS OF SUPPLY 5%
PLANNED 16%
INTERFERENCE 6%
TREES 5%
WEATHER 8%
ANIMALS 9%
EQUIPMENT FAILURE 39%
ENVIRONMENT 0%


Utah Underlying Cause History - SAIDI
300
250
200
150
100
50
0
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

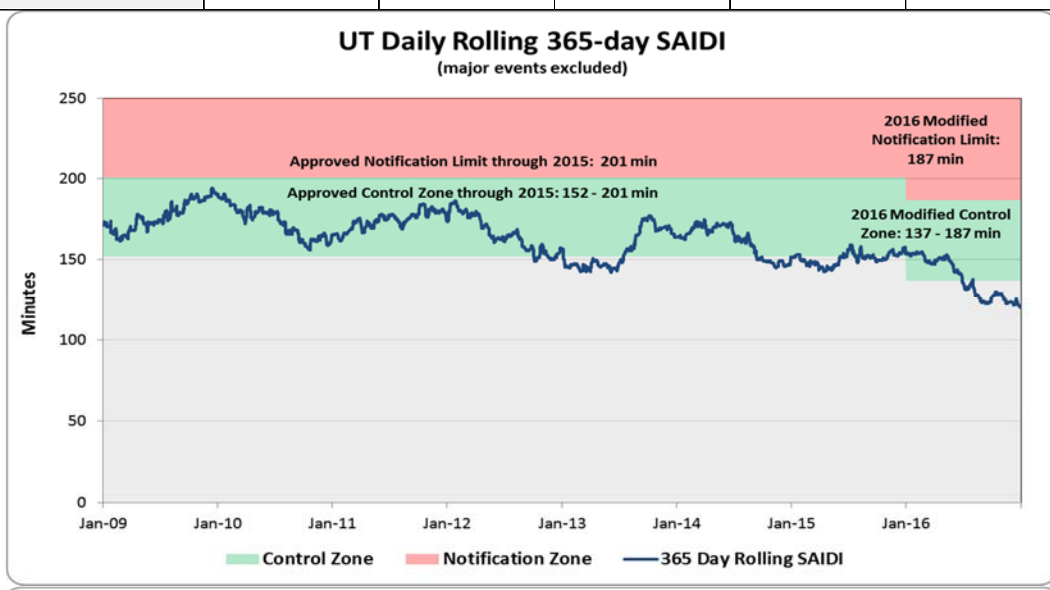

Utah Underlying Cause History - SAIFI
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015
2016
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

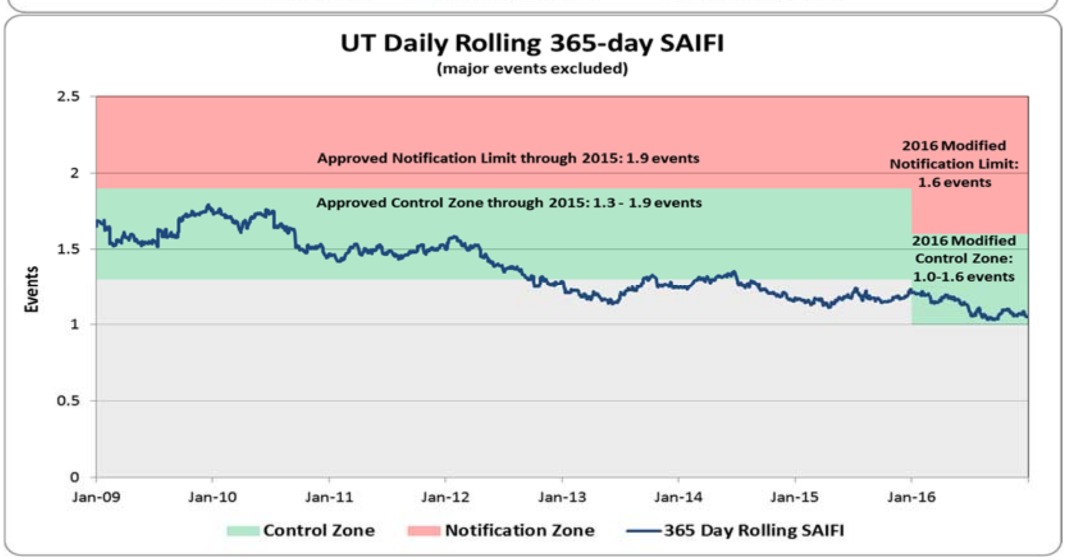
Direct Cause Category	Category Definition & Example/Direct Cause	
Animals	Any problem nest that requires removal, relocation, trimming, etc.; any birds, squirrels or other animals, whether or not remains found.	
	• Animal (Animals) • Bird Mortality (Non-protected species) • Bird Mortality (Protected 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

2.6 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 NOS. 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	-	152	201	-	1.3	1.9
2016 Modified Baseline	162	137	187	1.36	1.0	1.6





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

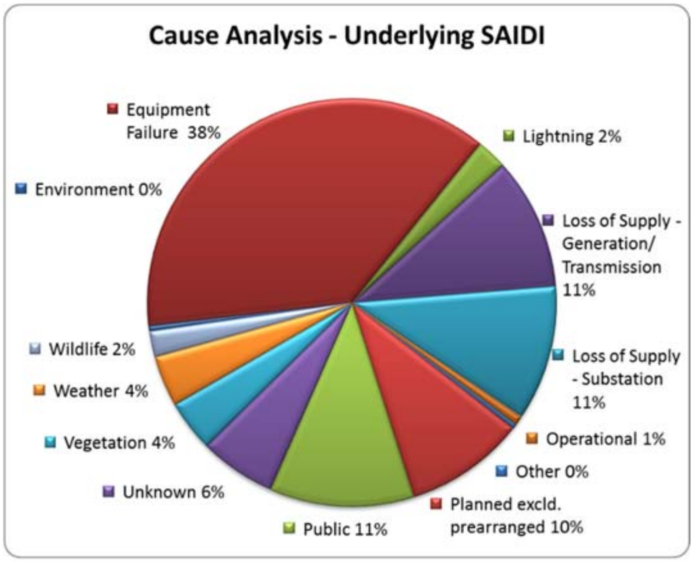
In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Rule R746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least 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.

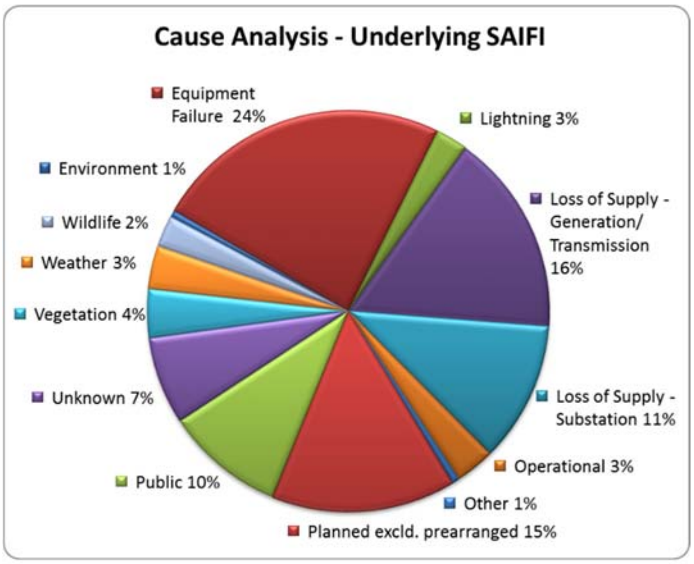
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_e$ are required.

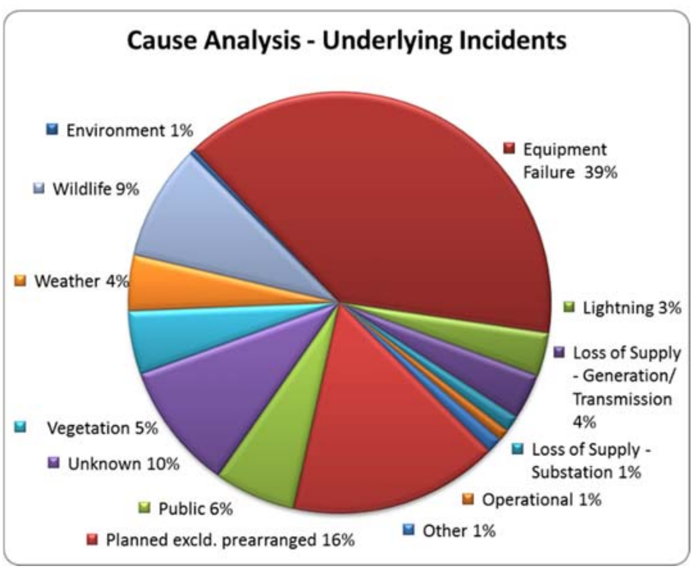
Major Events and Prearranged Excluded*	2012				2013				2014				2015				2016			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	157	1.3	122	0.72	164	1.2	132	0.81	152	1.2	129	1.21	154	1.2	127	1.48	120	1.0	115	1.76
OP AREA																				
AMERICAN FORK	101	0.8	135		126	1.3	99		113	1.0	109		134	1.1	128		92	1.0	93	
CEDAR CITY	279	1.8	154		225	1.8	127		170	1.1	151		238	1.6	146		174	1.5	116	
CEDAR CITY (MILFORD)	363	2.8	129		707	3.3	213		891	3.3	271		334	3.6	92		650	4.9	132	
JORDAN VALLEY	106	0.8	129		106	0.7	145		103	0.7	141		128	1.0	126		100	0.8	131	
LAYTON	105	0.8	131		105	1.0	109		108	0.8	127		122	1.1	109		90	0.9	103	
MOAB	375	3.1	122		284	1.9	147		412	2.3	181		426	3.5	122		278	3.0	93	
OGDEN	153	1.3	117		168	1.4	122		218	1.9	113		175	1.4	123		120	1.0	120	
PARK CITY	184	1.8	100		232	1.5	155		147	1.1	140		247	1.5	162		183	1.6	117	
PRICE	133	1.4	97		514	1.8	293		394	2.2	180		230	1.8	127		340	3.3	104	
RICHFIELD	200	2.0	100		469	3.4	138		181	1.7	104		303	2.2	137		132	1.3	101	
RICHFIELD (DELTA)	329	2.9	113		316	3.7	85		202	1.9	108		536	3.0	180		215	2.1	103	
SLC METRO	129	1.2	112		170	1.2	139		145	1.1	129		107	0.9	125		104	0.9	113	
SMITHFIELD	267	2.6	102		81	0.7	117		114	0.9	126		236	1.6	150		117	1.0	118	
TOOELE	595	3.7	163		137	1.3	103		239	2.1	115		129	1.3	103		161	1.1	151	
TREMONTON	447	3.0	147		335	3.3	102		216	2.0	111		462	4.2	110		399	3.1	129	
VERNAL	236	2.9	82		160	2.1	75		119	1.2	101		68	0.8	87		53	0.6	84	

* except MAIFIe

Utah Cause Category	2012		2013		2014		2015		2016	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	4	0.0	0	0.0	1	0.0	1	0.0	1	0.0
Equipment Failure	53	0.3	60	0.3	51	0.3	56	0.3	45	0.2
Lightning	4	0.0	9	0.1	7	0.1	6	0.1	3	0.0
Loss of Supply - Generation/Transmission	25	0.3	19	0.2	23	0.2	22	0.2	13	0.2
Loss of Supply - Substation	5	0.1	6	0.0	6	0.0	5	0.0	13	0.1
Operational	0	0.0	1	0.0	1	0.0	1	0.0	1	0.0
Other	0	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	22	0.3	24	0.3	20	0.2	14	0.2	11	0.2
Public	16	0.1	14	0.1	15	0.1	18	0.1	14	0.1
Unknown	7	0.1	8	0.1	10	0.1	10	0.1	7	0.1
Vegetation	5	0.1	7	0.0	6	0.0	8	0.1	5	0.0
Weather	11	0.1	12	0.1	8	0.0	8	0.0	5	0.0
Wildlife	4	0.0	4	0.0	4	0.0	5	0.0	2	0.0
UTAH Underlying	**157**	**1.3**	**164**	**1.2**	**152**	**1.2**	**154**	**1.2**	**120**	**1.0**


Cause Analysis - Underlying SAIDI
Equipment Failure 38%
Lightning 2%
Environment 0%
Loss of Supply - Generation/ Transmission 11%
Wildlife 2%
Loss of Supply - Substation 11%
Weather 4%
Operational 1%
Vegetation 4%
Other 0%
Unknown 6%
Planned excld. prearranged 10%
Public 11%


Cause Analysis - Underlying SAIFI
Equipment Failure 24%
Lightning 3%
Environment 1%
Loss of Supply - Generation/ Transmission 16%
Wildlife 2%
Weather 3%
Vegetation 4%
Unknown 7%
Loss of Supply - Substation 11%
Operational 3%
Public 10%
Other 1%
Planned excld. prearranged 15%


Cause Analysis - Underlying Incidents
Environment 1%
Equipment Failure 39%
Wildlife 9%
Weather 4%
Lightning 3%
Loss of Supply - Generation/ Transmission 4%
Vegetation 5%
Loss of Supply - Substation 1%
Unknown 10%
Operational 1%
Public 6%
Other 1%
Planned excld. prearranged 16%

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 has 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 is called Open Reliability Reporting (ORR), and the Company has proposed that during 2017 transition to this approach be completed by finalizing work started with Commission stakeholders to ensure understanding and obtain concurrence. Contained below is explanatory language in addition to the proposed 2017 plan information which would be provided regularly.

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.

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
Program Year xxxx									
American Fork	8	$1.05	4	207,684	269,466	$0.59	$0.15	0	4
Cedar City	2	$4.76	1	79,853	114,614	$2.41	$1.18	1	0
Jordan Valley	17	$0.60	8	317,521	541,182	$0.89	$0.57	1	8
Layton	4	$0.63	2	30,998	38,747	$3.15	$2.38	1	1
Metro	16	$0.38	10	2,619,725	4,422,054	$0.34	$0.19	0	6
Montpelier	1	$0.75	0	-	-	$0.00	$0.00	0	1
Ogden	11	$0.55	6	386,385	734,114	$1.14	$0.54	1	4
Park City	4	$1.23	1	2,669	5,337	$41.97	$12.21	0	3
Price	6	$0.23	3	127,794	137,091	$0.67	$0.94	0	3
Richfield	3	$1.78	1	349	349	$28.35	$17.08	0	2
Smithfield	2	$1.87	0	-	-	$0.00	$0.00	1	1
Tooele	4	$0.42	3	158,168	236,569	$1.24	$0.49	0	1
Tremonton	2	$3.08	1	58,070	105,495	$2.58	$0.59	0	1
Vernal	2	$5.80	1	246	491	$109.98	$0.00	0	1
TOTAL	**82**	**$0.53**	**41**	**3,989,462**	**6,605,509**	**$0.65**	**$0.33**	**5**	**36**

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 12/31/2016
Program Year 17: (CY2016)			
Red mountain 33	IN PROGRESS	1283	1075
Fountain Green 12	IN PROGRESS	266	194
Middleton 24	IN PROGRESS	253	268
Willowridge 11	IN PROGRESS	177	165
Summitt Park 11	IN PROGRESS	116	145
TARGET SCORE = **335**		**419**	**370**
Program Year 16: (CY2015)			
Nibley 21	COMPLETE	179	224
Brighton 12	COMPLETE	270	249
Rattlesnake 22	COMPLETE	456	415
Decker Lake 12	COMPLETE	167	106
Toquerville 31	COMPLETE	475	418
TARGET SCORE = **248**		**309**	**282**
Program Year 15: (CY2014)			
Skull Valley 11	COMPLETE	468	205
Fort Douglas 13	COMPLETE	417	62
Parowan Valley 25	COMPLETE	408	382
Brighton 21	COMPLETE	364	207
Bush 12	COMPLETE	281	251
TARGET SCORE = **248**	Target Met	**310**	**201**

[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.

UTAH

January 1 – December 31, 2016

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 12/31/2016
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	51
Eden 11	COMPLETE	116	195
Bush 11	COMPLETE	228	118
Pioneer 12	COMPLETE	177	79
Grantsville 12	COMPLETE	250	104
TARGET SCORE = 108		**135**	**109**
Program Year 13: (CY2012)			
Fielding 11	COMPLETE	207	260
East Bench 12	COMPLETE	112	51
Clinton 11	COMPLETE	133	30
Redwood 16	COMPLETE	145	50
Orangeville 11	COMPLETE	114	15
TARGET SCORE = **114**	**Target Met**	**142**	**81**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	61
Huntington City 12	COMPLETE	285	39
Magna 15	COMPLETE	140	49
Gunnison 12	COMPLETE	110	96
Capitol 11	COMPLETE	129	77
TARGET SCORE = **134**	**Target Met**	**167**	**64**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	106
North Bench 13	COMPLETE	95	40
Newgate 14	COMPLETE	164	70
Newton 12	COMPLETE	105	55
St Johns 11	COMPLETE	547	285
TARGET SCORE = **162**	**Target Met**	**203**	**111**
Program Year 10: (CY2009)			
Fruit Heights 12	COMPLETE	113	89
Mathis 12	COMPLETE	132	160
Parrish 11	COMPLETE	137	61
Valley Center 11	COMPLETE	169	25
Hammer 15	COMPLETE	95	38
TARGET SCORE = **104**	**Target Met**	**129**	**75**

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 = 85%					
January	February	March	April	May	June
71%	91%	91%	92%	91%	79%
July	August	September	October	November	December
76%	82%	86%	86%	90%	84%

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	115 minutes
Total Performance	154 minutes

2.11 Telephone Service and Response to Commission Complaints

COMMITMENT	GOAL	PERFORMANCE
PS5-Answer calls within 30 seconds	80%	81%
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 year, there were six dates identified as a wide-scale outage days; call statistics are shown in the table below. The outage event on January 4th was an emergency damage repair outage which occurred at the Murder Creek Substation in Albany, Oregon, resulting in approximately 6,500 customer out of service for 9 minutes. On February 2nd a loss of transmission outage occurred in American Fork, Utah, resulting in approximately 7,600 customers out of service for durations ranging from 31 minutes to just under 2 hours. On April 15th a loss of substation event occurred in Stayton, Oregon, when a transformer fuse blew, resulting in approximately 9,000 customers out of service with all outages restored within 2 hours 19 minutes. On August 30th Central Oregon experienced a major event when a loss of transmission outage resulted in approximately 16,500 customers with all restorations completed in 1 hour 7 minutes. On September 12th Casper, Wyoming, experienced a loss of transmission outage when a substation arrestor failed. The outage affected 18,000 customers for 12 minutes. On September 22nd Utah experienced a major event when a storm bringing heavy wind and rain affected customers in Layton and Ogden, most significantly, during the period of heavy calls, a tree took down several spans of transmission line, de-energizing feed to almost 10,000 customers.

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
1/4/2016	15:30	15:44	586	38	15	379	58
	15:45	15:59	1207	126	38	287	39
	16:00	16:14	530	0	30	126	29
	16:15	16:29	517	0	14	148	87
2/2/2016	14:15	14:29	1346	111	1	52	5
	14:30	14:44	852	0	6	97	15
	14:45	14:59	535	0	5	67	19
	15:00	15:15	501	0	1	88	26
4/15/2016	9:30	9:44	924	48	55	401	84
	9:45	9:59	1033	10	14	174	36
	10:00	10:14	622	0	8	145	50
	10:15	10:29	634	0	13	140	56
8/30/2016	10:30	10:44	2490	402	172	596	113
	10:45	10:59	2728	355	10	74	26
	11:00	11:14	762	0	3	69	11
	11:15	11:29	596	0	10	176	74
9/12/2016	14:15	14:29	2065	296	1	54	6
	14:30	14:44	1287	144	4	102	14
	14:45	14:59	454	0	5	129	36
	15:00	15:14	475	0	6	136	43

UTAH January 1 – December 31, 2016

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
9/22/2016	15:45	15:59	1038	0	1	147	5
	16:00	16:14	1160	0	3	28	4
	16:15	16:29	951	0	5	161	14
	16:30	16:44	958	0	3	178	22
	16:45	16:59	1045	0	0	118	36

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 December 2016

Utah

	Description	2016 Events	2016 Failures	2016 % Success	2016 Paid	2015 Events	2015 Failures	2015 % Success	2015 Paid
CG1	Restoring Supply	921,417	0	100.00%	$0	1,051,644	1	100.00%	$75
CG2	Appointments	9,090	11	99.88%	$550	7,357	6	99.92%	$300
CG3	Switching on Power	6,404	1	99.98%	$50	7,068	4	99.94%	$200
CG4	Estimates	1,348	3	99.78%	$150	1,304	10	99.23%	$500
CG5	Respond to Billing Inquiries	1,970	1	99.95%	$50	1,743	9	99.48%	$450
CG6	Respond to Meter Problems	982	1	99.90%	$50	869	1	99.88%	$50
CG7	Notification of Planned Interruptions	119,905	52	99.96%	$2,600	99,852	43	99.96%	$2,150
		1,061,116	**69**	**99.99%**	**$3,450**	**1,169,837**	**74**	**99.99%**	**$3,725**

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

<u>**Preventive Maintenance**</u>

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.

<u>**Corrective Maintenance**</u>

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

Transmission and Distribution Lines

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

Substations and Major Equipment

[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.

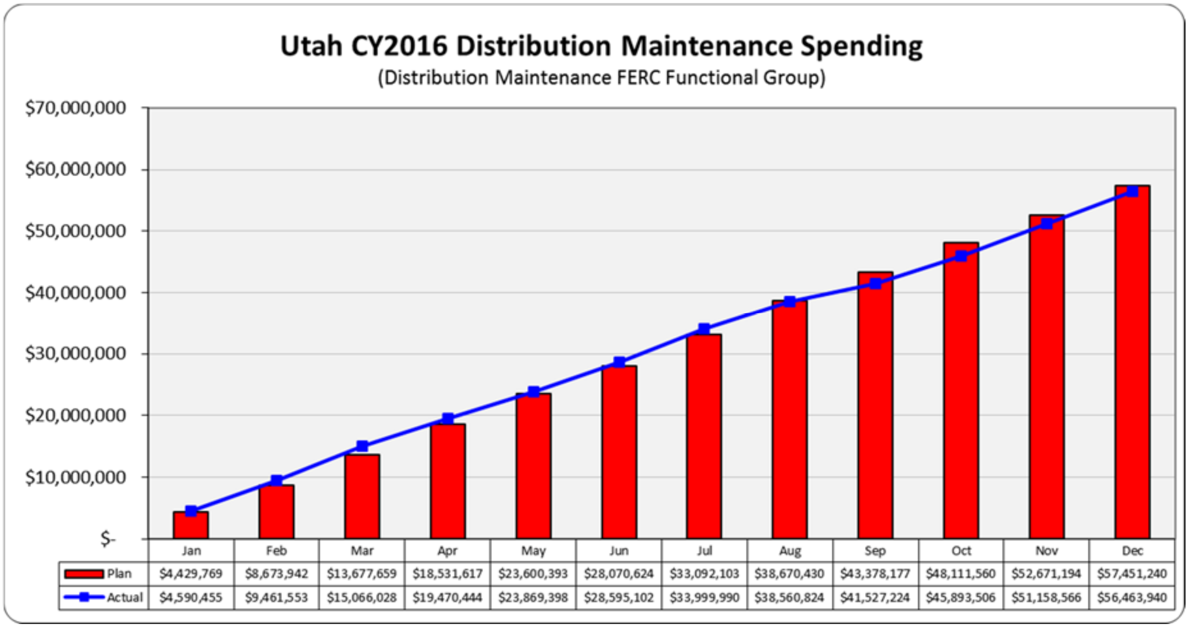
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

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.

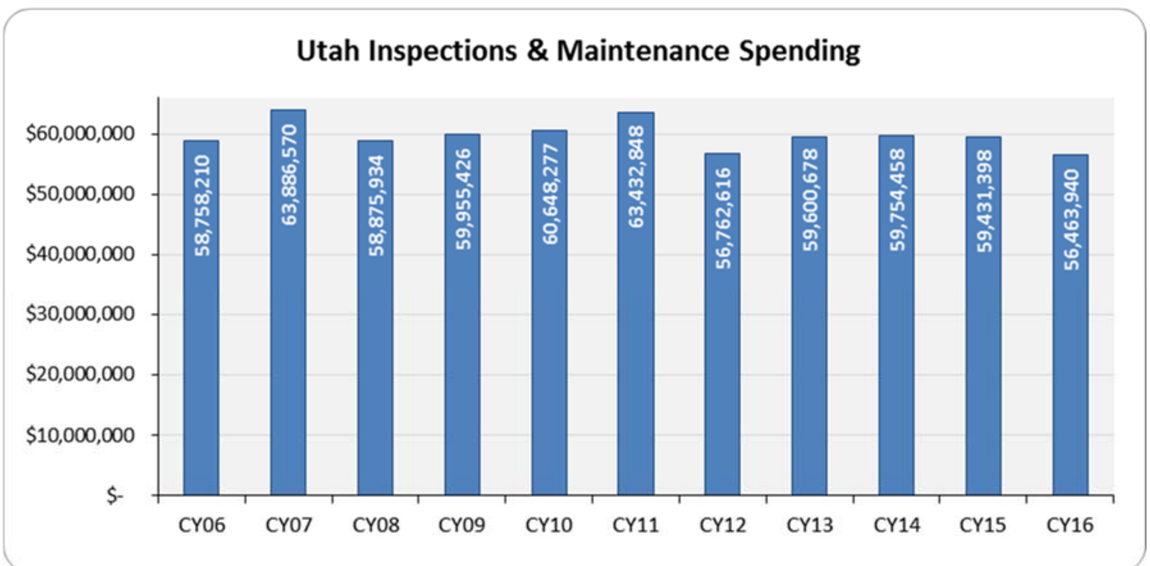
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending[12,13]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$4,429,769	$8,673,942	$13,677,659	$18,531,617	$23,600,393	$28,070,624	$33,092,103	$38,670,430	$43,378,177	$48,111,560	$52,671,194	$57,451,240
Actual	$4,590,455	$9,461,553	$15,066,028	$19,470,444	$23,869,398	$28,595,102	$33,999,990	$38,560,824	$41,527,224	$45,893,506	$51,158,566	$56,463,940

3.2.1 Maintenance Historical Spending

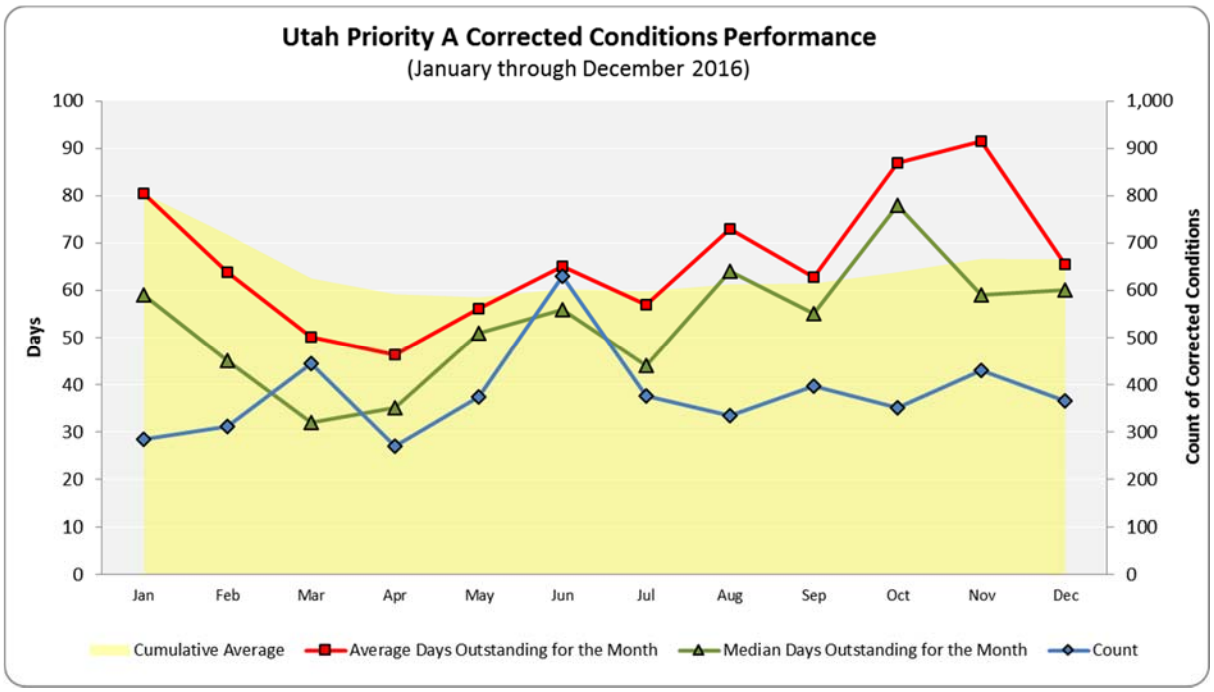


[12] Maintenance spending reflected does not include Vegetation Management and Fault Locating costs, which when reporting under FERC accounting methodology, FERC has traditionally considered maintenance.

[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 A priority 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 A priority 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.



3.3.1 Oldest Outstanding Priority A Conditions In Utah

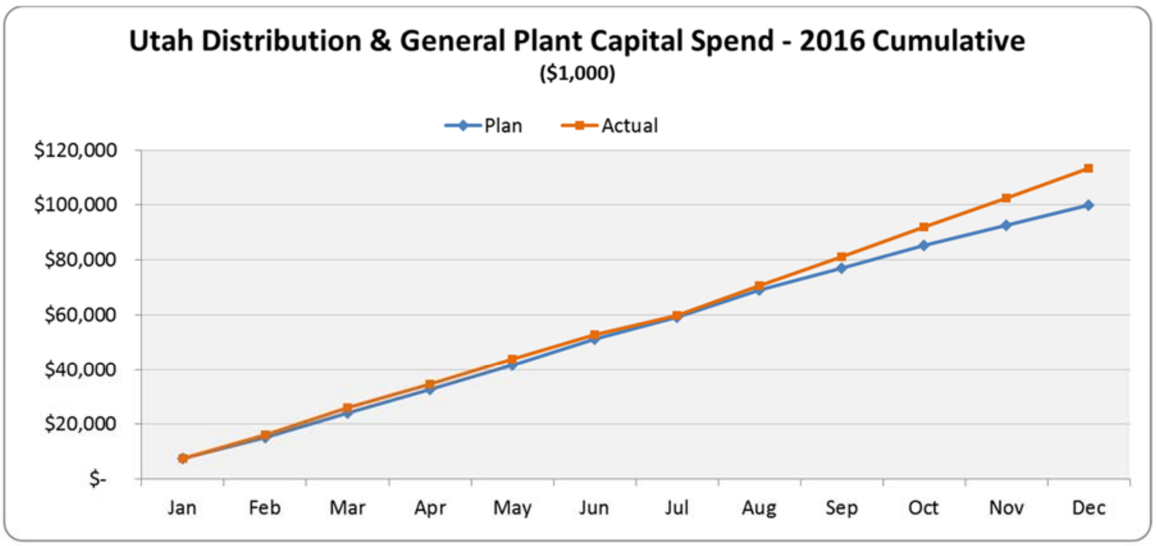
<table>
<tr><th>District</th><th>Map-string</th><th>Facility Point</th><th>Condition</th><th>Inspection Remarks</th><th>Inspection Date</th><th>Completion Date</th><th>Days to Correct</th><th>Circuit</th><th>Explanation</th></tr>
<tr><td>Price</td><td>11415011</td><td>64105</td><td>CLEARSVC</td><td>SERVICE WIRE CLEARANCE OVER ROAD 12'11" RMP 01-06-16</td><td>1/6/16</td><td>3/29/17</td><td>448</td><td>WLG11</td><td>This involved a clearance issue over a road. In order to correct the issue, the customer's weather-head needed to be raised or an inset pole needed to be added. The customer didn't want another pole on their property, so RMP worked with the customer to have their weatherhead raised.</td></tr>
<tr><td>American Fork</td><td>11406002</td><td>265801</td><td>BOINSUL</td><td>LOOSE OR MISSING HARDWARE ON PIN_TOP</td><td rowspan="2">1/11/16</td><td rowspan="2">3/6/17</td><td rowspan="2">420</td><td rowspan="2">ORE12</td><td rowspan="2">These conditions were delayed to coincide with work that installed new poles as part of a road widening project. The project encountered some difficulty in obtaining the necessary easements.</td></tr>
<tr><td>American Fork</td><td>11406002</td><td>265801</td><td>BOPOLE</td><td>ROTTED/SPLIT POLE TOP, REPLACE WITH TALLER POLE</td></tr>
<tr><td>Jordan Valley</td><td>11402001</td><td>290509</td><td>BOPOLE</td><td>DECAY REJECT RESTORE_SR 1.60_SRHR</td><td>1/27/16</td><td>12/27/16</td><td>335</td><td>UNN14</td><td>This was a primary metering pole for Hillcrest High School and it was located in the middle of the sidewalk. The work couldn't be done until the school went on winter break because an extended outage was needed to complete the work.</td></tr>
<tr><td>Metro</td><td>11201001</td><td>351610</td><td>BOXARM</td><td>ARM IS SPLIT_1ARM +2(B)'S</td><td>2/4/16</td><td>3/21/17</td><td>411</td><td>ROS12</td><td>The original condition involved a broken crossarm, however, upon inspection it was determined the pole also needed to be replaced. The pole is owned by CenturyLink, so permission had to be obtained from them prior to performing the work.</td></tr>
</table>

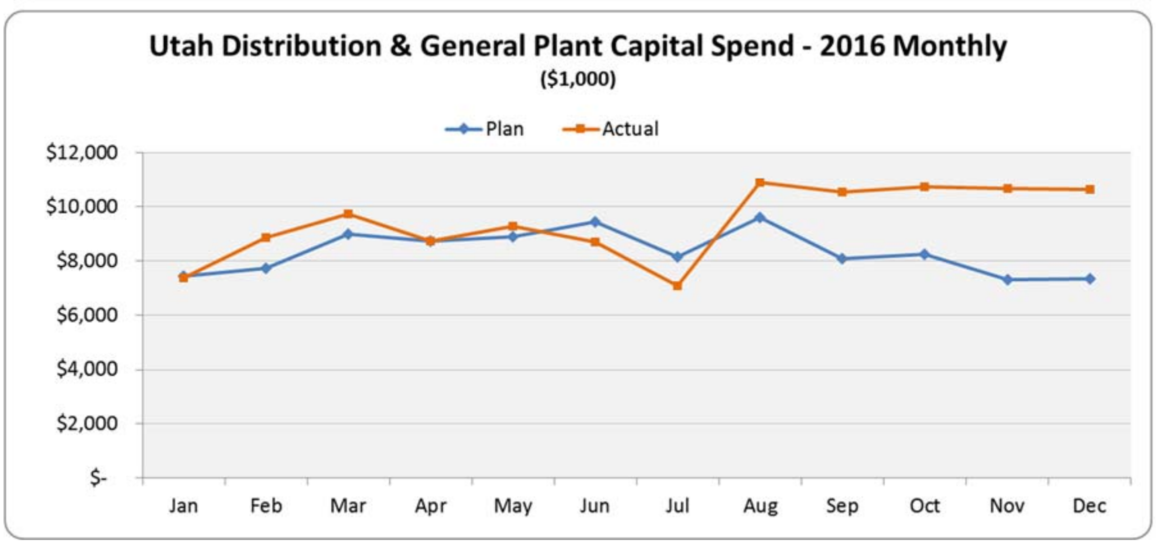
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January –December 2016

Investment	Actuals ($M)	Plan ($M)	Significant Variance Explanations
1. Mandated	$12.3	$7.1	Mandated road relocations, NERC reliability and net metering over plan, (+$4.8M).
2. New Connect	$47.4	$41.2	Residential and commercial new revenue connections over plan, (+$6.0M).
3. System Reinforcement	$10.8	$10.7	
4. Replacement	$37.8	$38.2	
5. Upgrade & Modernize	$4.9	$2.7	Functional upgrade reliability over plan, (+$1.4M).
Total	**$113.2**	**$99.9**	



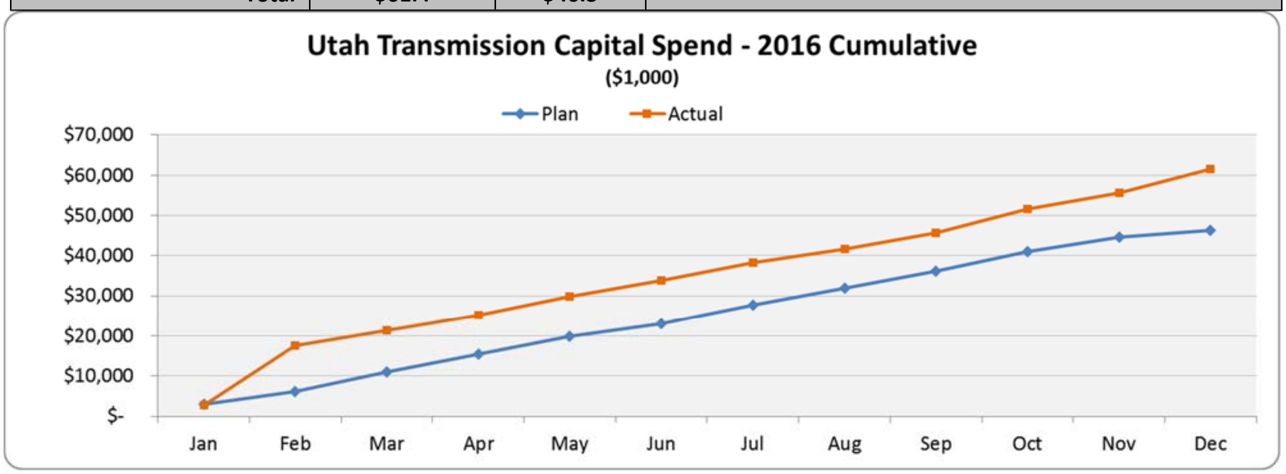


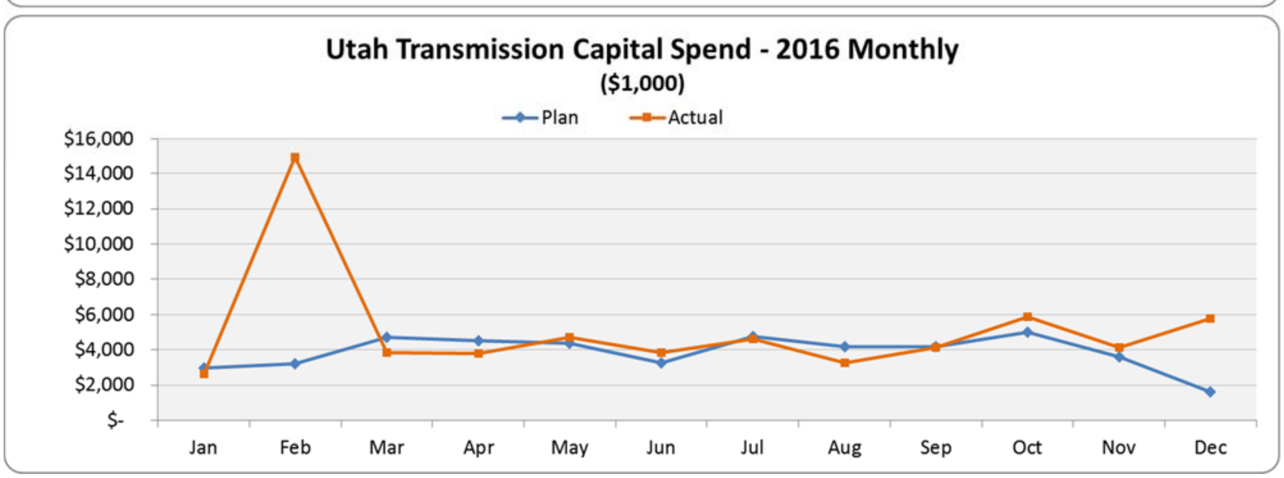
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending – Transmission/Interconnections

January –December 2016

	Investment	Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	$4.7	$3.2	Mandated transmission right-of-way renewals over plan *(primarily BLM & Forest Service permits)*, (+$1.8M).
2.	New Connect	$0.1	$1.8	Industrial new revenue connection under plan *(primarily Proctor & Gamble deferral)*, (-$1.7M).
3.	Local Transmission System Reinforcements	$20.2	$21.4	Local sub-transmission reinforcement over plan, (+$14.0M); feeder and substation reinforcement under plan, (-$12.3M).
**4.	Main Grid Reinforcements / Interconnections	$11.8	$6.2	Syracuse Second Transformer (+$1.5M) and Purgatory Flat New 138kV (+$4.1M) over plan; Holden Irrigation-Fillmore Rebuild (-$2.3M) under plan.
**5.	Energy Gateway Transmission	$12.1	$2.6	Sigurd Red Butte Crystal 345kV Line (+$9.8M) over plan -- *(Note: $9.8M posted in February for a settlement with the construction contractor for current disputed and outstanding changes in work; this impact had previously been forecasted for 2017 due to concerns over finalizing a settlement in 2016).*
6.	Replacement	$11.3	$10.1	Replacements for storm and casualty over plan, (+$1.1M).
7.	Upgrade & Modernize	$1.3	$1.1	
	Total	**$61.4**	**$46.3**	





* 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.

4.3 New Connects

	2015	2016												
	2015	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	**YEAR TO DATE**
Residential														
UT South	866	37	38	71	84	72	83	60	75	100	77	62	65	824
UT North/Metro	4,412	306	281	325	264	270	260	312	396	492	441	641	653	4,641
UT Central	9,264	649	775	626	735	613	707	805	833	715	1,071	748	731	9,008
Total Residential	**14,542**	**992**	**1,094**	**1,022**	**1,083**	**955**	**1,050**	**1,177**	**1,304**	**1,307**	**1,589**	**1,451**	**1,449**	**14,473**
Commercial														
UT South	229	10	13	11	11	24	18	23	26	34	48	36	30	284
UT North/Metro	676	40	47	34	38	44	53	66	89	56	54	87	55	663
UT Central	784	54	54	56	66	63	61	56	95	69	81	79	76	810
Total Commercial	**1,689**	**104**	**114**	**101**	**115**	**131**	**132**	**145**	**210**	**159**	**183**	**202**	**161**	**1,757**
Industrial														
UT South	3	0	0	0	0	0	1	0	0	0	0	0	0	1
UT North/Metro	5	0	0	1	0	0	0	0	0	0	0	0	1	2
UT Central	2	0	0	1	1	0	0	0	0	0	0	0	1	3
Total Industrial	**10**	**0**	**0**	**2**	**1**	**0**	**1**	**0**	**0**	**0**	**0**	**0**	**2**	**6**
Irrigation														
UT South	40	1	3	5	10	13	5	6	4	4	0	1	3	55
UT North/Metro	9	0	1	1	0	0	2	0	0	0	0	1	0	5
UT Central	15	0	0	1	3	1	0	2	0	0	0	1	0	8
Total Irrigation	**64**	**1**	**4**	**7**	**13**	**14**	**7**	**8**	**4**	**4**	**0**	**3**	**3**	**68**
TOTAL New Connects														
UT South	1,138	48	54	87	105	109	107	89	105	138	125	99	98	1,164
UT North/Metro	5,102	346	329	361	302	314	315	378	485	548	495	729	709	5,311
UT Central	10,065	703	829	684	805	677	768	863	928	784	1,152	828	808	9,829
TOTAL New Connects	**16,305**	**1,097**	**1,212**	**1,132**	**1,212**	**1,100**	**1,190**	**1,330**	**1,518**	**1,470**	**1,772**	**1,656**	**1,615**	**16,304**

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 a subject to change for operational purposes and may differ from historical reporting
Laketown and Smithfield new connects are excluded, as a result of an old coding system that places them under ID/ WY WEST and not Utah.
The Town of Eagle Mountain was integrated into the company network in the American Fork district in Feb/Mar 2015. To achieve this changeover, around 6,500 homes and businesses were added as new connects. These connections are removed from the report as not to affect the accurate representation of new connects and the historical volume trends of newly connected customers.
New connects report reflects the volume of all new connections in the system in the reporting period, which does not include temporary connections, that are subsequently removed in the future periods; it is not necessarily an auditable count of new permanent connection for the reporting period.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH
Tree Program Reporting
January 1, 2016 through December 31, 2016
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/ Total Line Miles	1/1/2016-12/31/2016 Miles Planned	1/1/2016-12/31/2016 Actual Miles	01/01/2016-12/31/2016 Ahead/ Behind	1/1/2016-12/31/2015 % Ahead/ Behind	1/1/2014-12/31/2016 Miles Planned	1/1/2014-12/31/2016 Actual Miles	01/01/2014-12/31/2016 Ahead/ Behind	1/1/2014-12/31/2016 % Ahead/ Behind
	column a	*column b*	*column c*	*column d*	*column e*	*column f*	*column g*	*column h*	*column i*
UTAH	11,009	3,669	3,608	-93	98.3%	11,009	11,254	245	102.2%
AMERICAN FORK	824	275	344	69	125.1%	824	824	0	100.0%
CEDAR CITY	1,373	458	515	57	112.4%	1,373	1,373	0	100.0%
JORDAN VALLEY	769	256	216	-40	84.4%	769	767	-2	99.7%
LAYTON	284	95	49	-46	51.6%	284	267	-17	94.0%
MOAB	976	325	124	-201	38.2%	976	976	0	100.0%
OGDEN	885	295	358	63	121.4%	885	977	92	110.4%
PARK CITY	538	179	151	-28	84.4%	538	538	0	100.0%
PRICE	589	196	99	-97	50.5%	589	589	0	100.0%
RICHFIELD	1,340	447	527	80	117.9%	1,340	1,340	0	100.0%
SL METRO	1,206	402	344	-58	85.6%	1,206	1,212	6	100.5%
SMITHFIELD	762	254	290	36	114.2%	762	752	-10	98.7%
TOOELE	481	160	241	81	150.6%	481	481	0	100.0%
TREMONTON	732	244	277	33	113.5%	732	908	176	124.0%
VERNAL	250	83	73	-42	88.0%	250	250	0	100.0%

Distribution cycle $/tree:	$102.12
Distribution cycle $/mile:	$3,460
Distribution cycle removal %	23%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead (behind Schedule	Miles on Schedule	% of miles on/behind Schedule
6,629	784	972	188	6,817	1

Current distribution cycle begain January 1, 2014 and extends until December 31, 2016.

Notes:

Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2016 through December 31, 2016
Column c: Actual overhead distribution pole miles worked during the period January, 2016 through December 31, 2016
Column d: Miles ahead or behind for the period January 1, 2016 through December 31, 2016 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2016 through December 31, 2016 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2014 through December 31, 2016
Column g: Actual overhead distribution pole miles worked during the period January 1 2014 through December 31, 2016
Column h: Miles ahead or behind for the period January 1, 2014 through December 31, 2016 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2014 through December 31, 2016 ((column g÷f)×100). Max = 100%

5.2 Budget

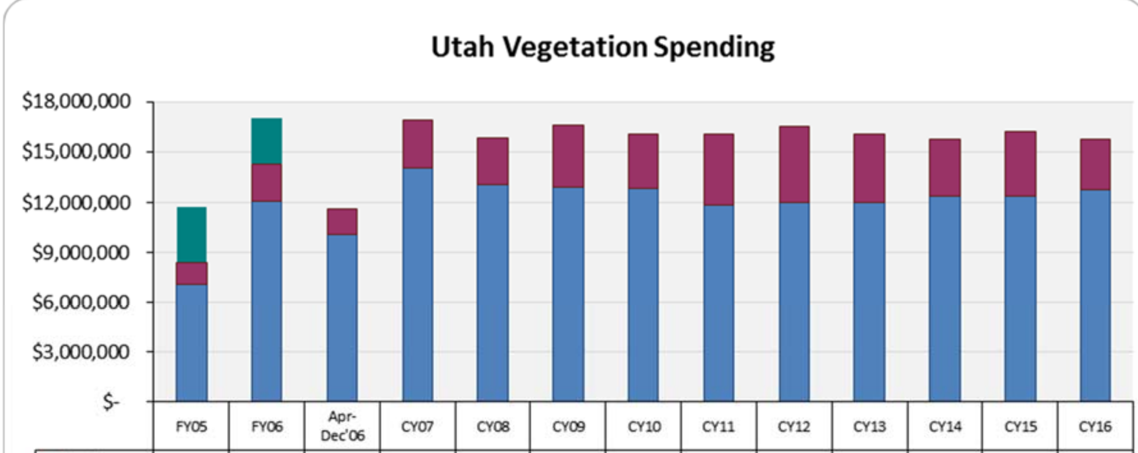
UTAH
Tree Program Reporting

	CY2017	CY2018	CY2019
Distribution	$11,400,000	$11,400,000	$11,400,000
Transmission	$3,760,000	$3,760,000	$3,760,000
Total Tree Budget	$15,160,000	$15,160,000	$15,160,000

Calendar year 2016	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$910,692	$944,470	-$33,778	$263,069	$309,714	-$46,645
Feb	$1,100,162	$944,470	$155,692	$224,075	$309,714	-$85,639
Mar	$1,226,616	$1,086,074	$140,542	$310,467	$356,113	-$45,646
Apr	$1,115,086	$991,671	$123,415	$281,641	$325,180	-$43,539
May	$972,138	$991,671	-$19,533	$312,566	$325,180	-$12,614
Jun	$995,019	$1,038,873	-$43,854	$306,774	$340,646	-$33,872
Jul	$977,373	$850,067	$127,306	$208,606	$278,783	-$70,177
Aug	$1,124,470	$1,086,074	$38,396	$273,293	$356,113	-$82,820
Sep	$871,966	$991,671	-$119,705	$196,619	$325,180	-$128,561
Oct	$931,441	$991,671	-$60,230	$162,069	$325,180	-$163,111
Nov	$1,258,187	$944,470	$313,717	$241,524	$309,714	-$68,190
Dec	$1,284,154	$991,670	$292,484	$235,224	$325,180	-$89,956
Total	**$12,767,302**	**$11,852,852**	**$914,450**	**$3,015,928**	**$3,886,697**	**-$870,769**

Average # Tree Crews on Property (YTD) **64**

5.2.1 Vegetation Historical Spending



	FY05	FY06	Apr-Dec'06	CY07	CY08	CY09	CY10	CY11	CY12	CY13	CY14	CY15	CY16
Miscellaneous	3,306,952	2,666,318											
Transmission	1,351,143	2,273,513	1,489,985	2,809,622	2,777,814	3,716,266	3,180,955	4,245,089	4,483,668	4,070,233	3,360,658	3,873,554	3,015,928
Distribution	7,070,339	12,072,30	10,107,31	14,097,44	13,053,51	12,934,36	12,866,26	11,837,42	12,037,62	11,991,60	12,403,05	12,385,37	12,767,30

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

6 Appendix

6.1 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.

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
1/1-12/31/2016	876,438	6.06	5,312,799
1/1-12/31/2017	897,258	5.74	5,152,204

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.