ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH
SERVICE QUALITY
REVIEW

January 1 – June 30, 2015
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 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 recently-adopted state rules.

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.

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 Regulations 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[1]

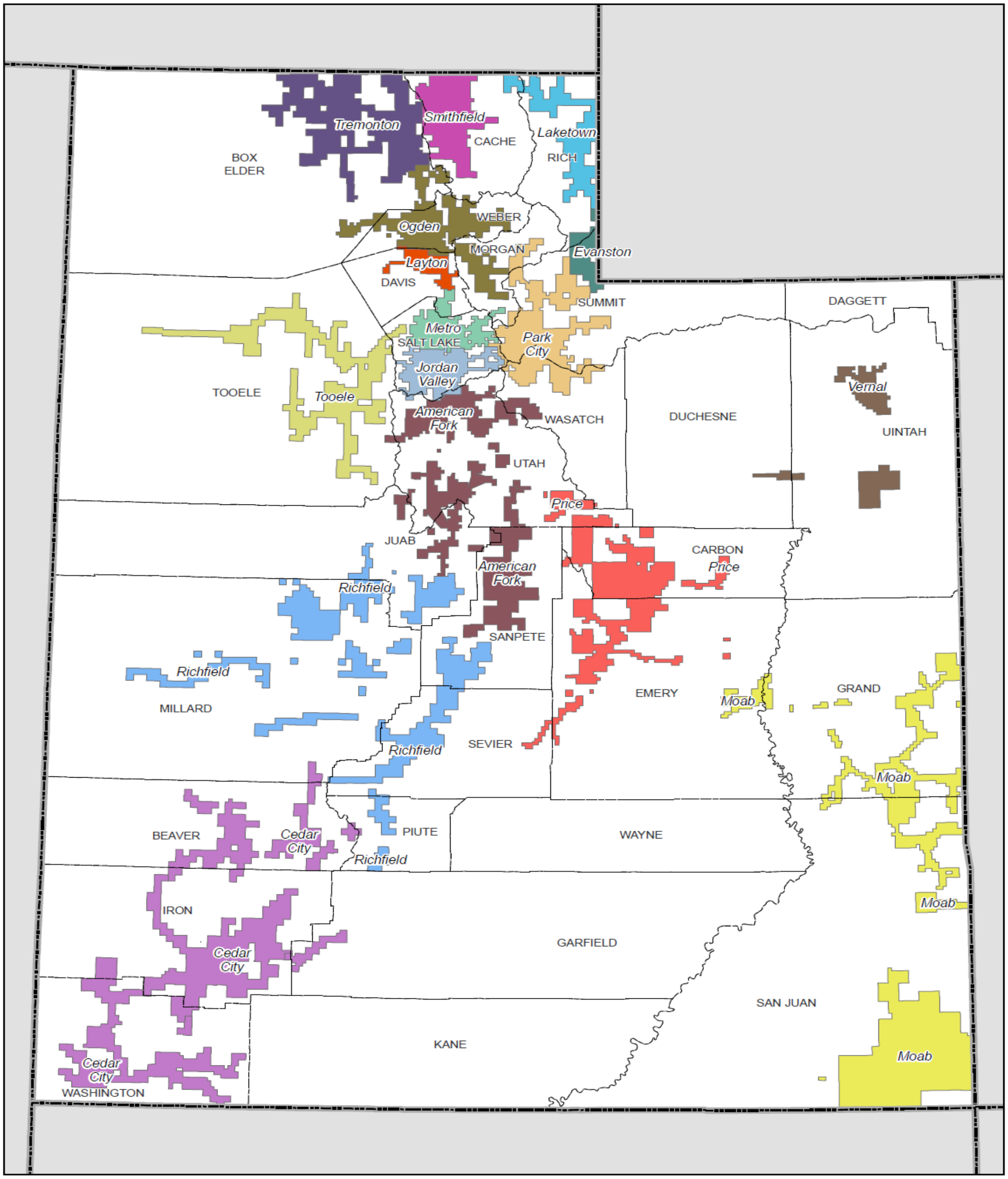
*Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	Utah Commission adopted baselines recognizing 365-day rolling (rather than calendar) performance levels of between 152-201 minutes.
*Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	Utah Commission adopted baselines recognizing 365-day rolling (rather than calendar) performance levels of between 1.3-1.9 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.
*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.

[1] In 2012, rules were codified in Utah Regulations 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.

1.3 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

As shown in charts under subsections 2.1 and 2.2 below, the Company's 2015 underlying reliability results fall within the Company's control zones, which are shown as green in the graphic. History reflecting these metrics is displayed in Sections 2.3 and 2.4. Baselines are explored 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.

In 2015, there was one major event[2] (which was accepted as a major event by the Utah Commission upon recommendation of the Utah Division of Public Utilities) and two significant event days[3] recorded.

Utah Major Events 2015		
Date	**Cause**	**SAIDI**
April 14-16, 2015	Wind and snow storm	34.47
	TOTAL	**34.47**

- **April 14-16, 2015**
  A spring storm brought light rain, followed by high winds and heavy, wet snowfall to various regions of Utah causing substantial damage to Rocky Mountain Power's facilities and a significant impact on its reliability performance from April 14, 2015 through April 16, 2015. Early in the event light rain, which coincided with salt and pollution-laden hardware, caused pole fires which necessitated replacement of a significant amount of poles and crossarms. As the storm continued, wind-blown and snow-laden trees toppled into electrical facilities, blowing fuses, pulling wire down or breaking poles. This major event filing was accepted by the Utah Commission on 7/8/15 in Docket 15-035-54.

Utah Significant Event Days 2015			
Date	**Cause: General Description**	**Underlying SAIDI**	**% of Total Underlying SAIDI (152)**
March 2, 2015	Winter storm. Loss of transmission line in Richfield	3.2	4.3%
April 24, 2015	Loss of transmission/weather-wind in Layton.	2.6	3.6%
	TOTAL	**5.8**	**7.9%**

[2] Major event threshold shown below:

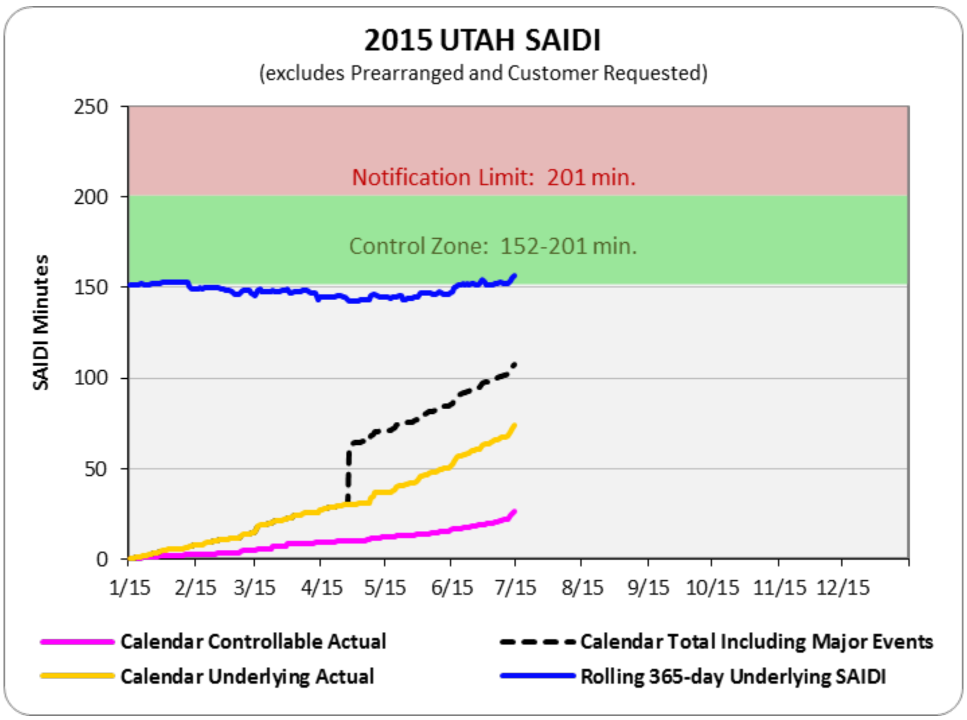
Effective Date	Customer Count	ME Threshold SAIDI	ME Customer Minutes Lost
1/1-12/31/2015	869,108	6.52	5,669,347

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

2.1 System Average Interruption Duration Index (SAIDI)

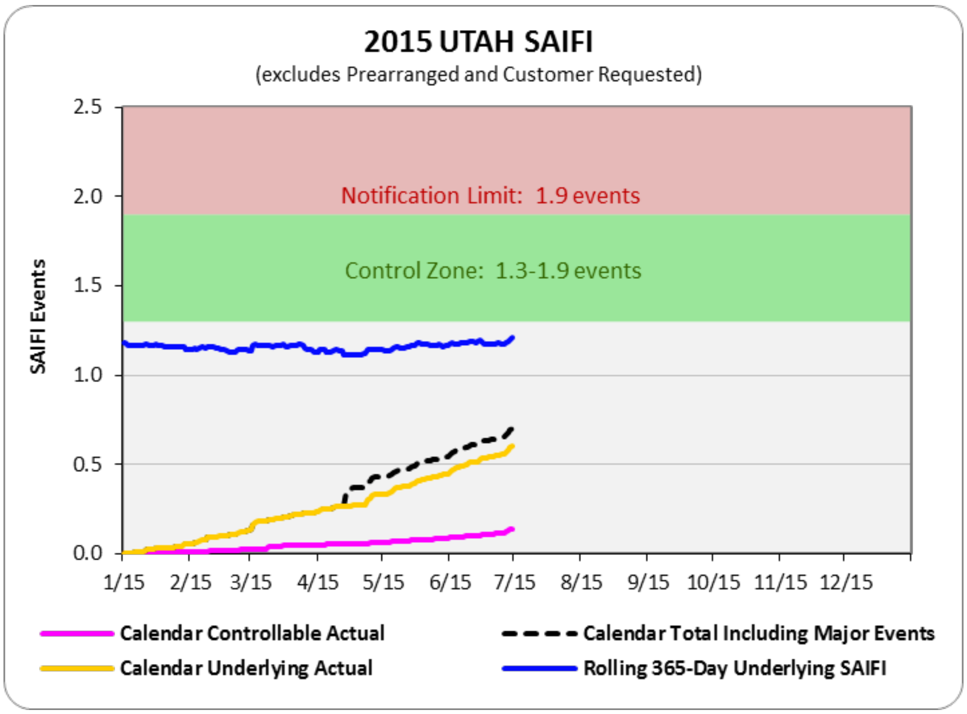
Over time the Company has made system changes to minimize how many customers are affected for any given outage. This approach has resulted in improvements to both outage duration and outage frequency, and has yielded improved performance as delivered to customers, as generally shown in the graphic below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

Utah - SAIDI	January 1 – June 30, 2015
Total	108
Underlying	74
Controllable Distribution	26



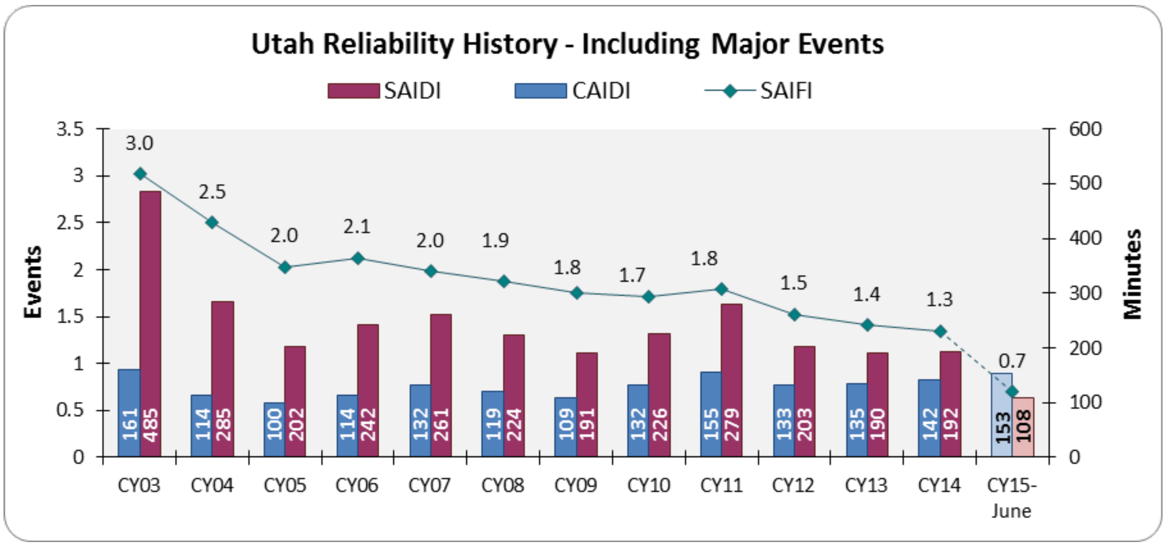
2.2 System Average Interruption Frequency Index (SAIFI)

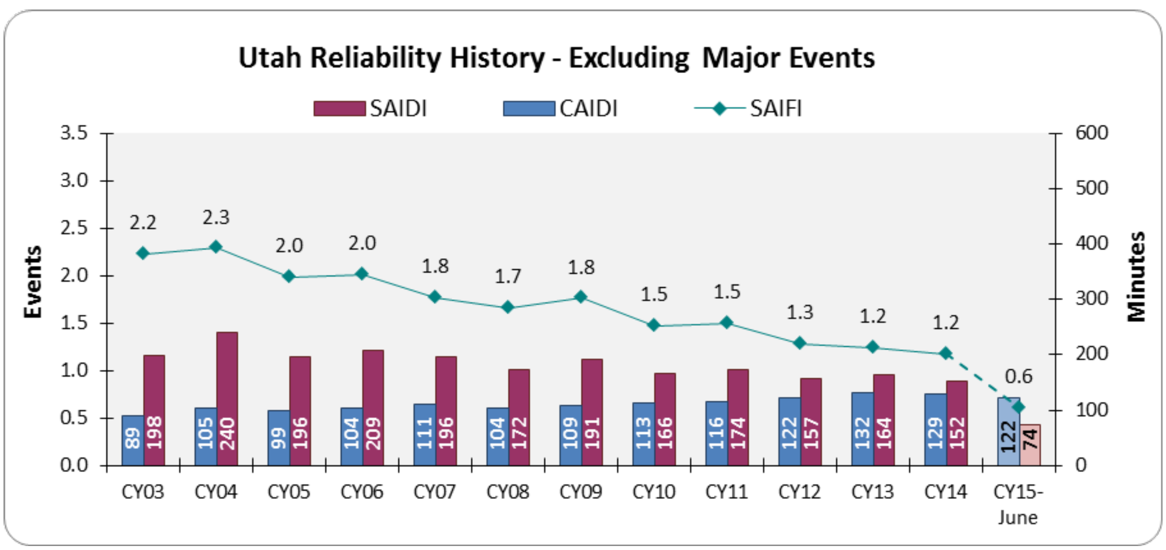
Utah - SAIFI	January 1 – June 30, 2015
Total	0.702
Underlying	0.605
Controllable Distribution	0.141



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. 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.

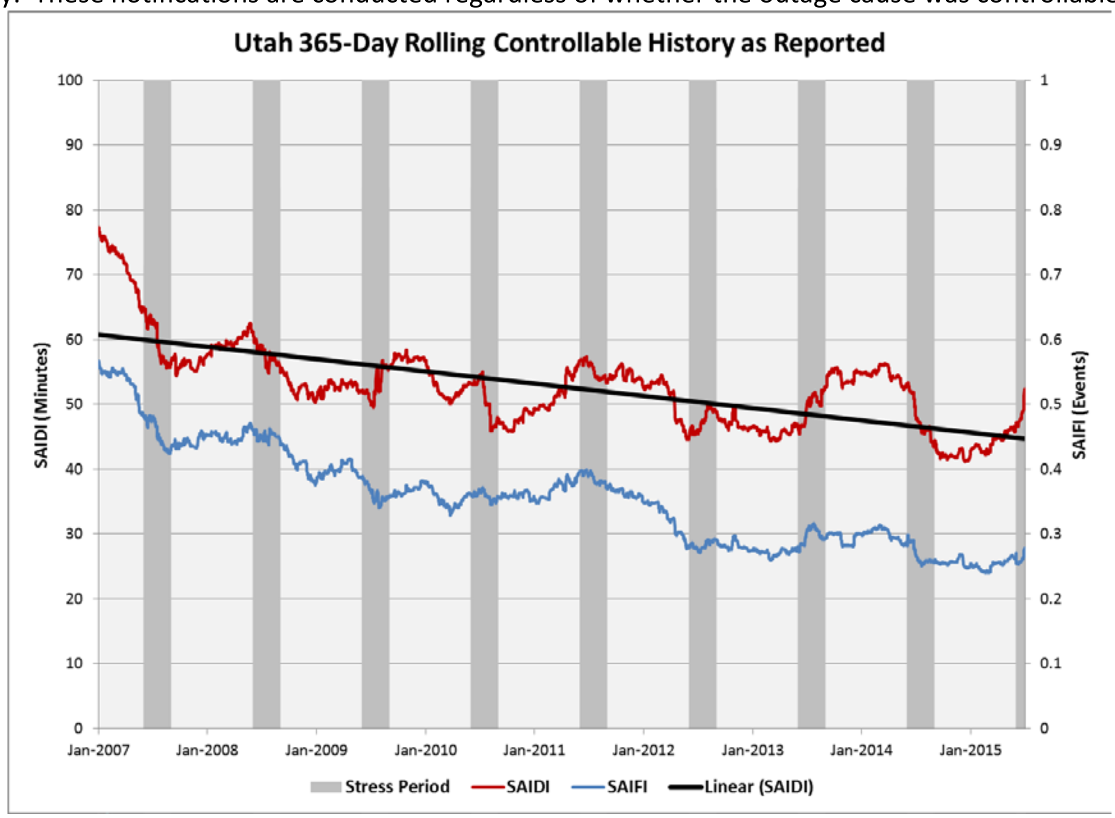




2.4 Controllable, Non-Controllable and Underlying Performance Review

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[4]. In order to provide insight into the response and history for those outages, the charts below distinguish amongst the outage groupings.

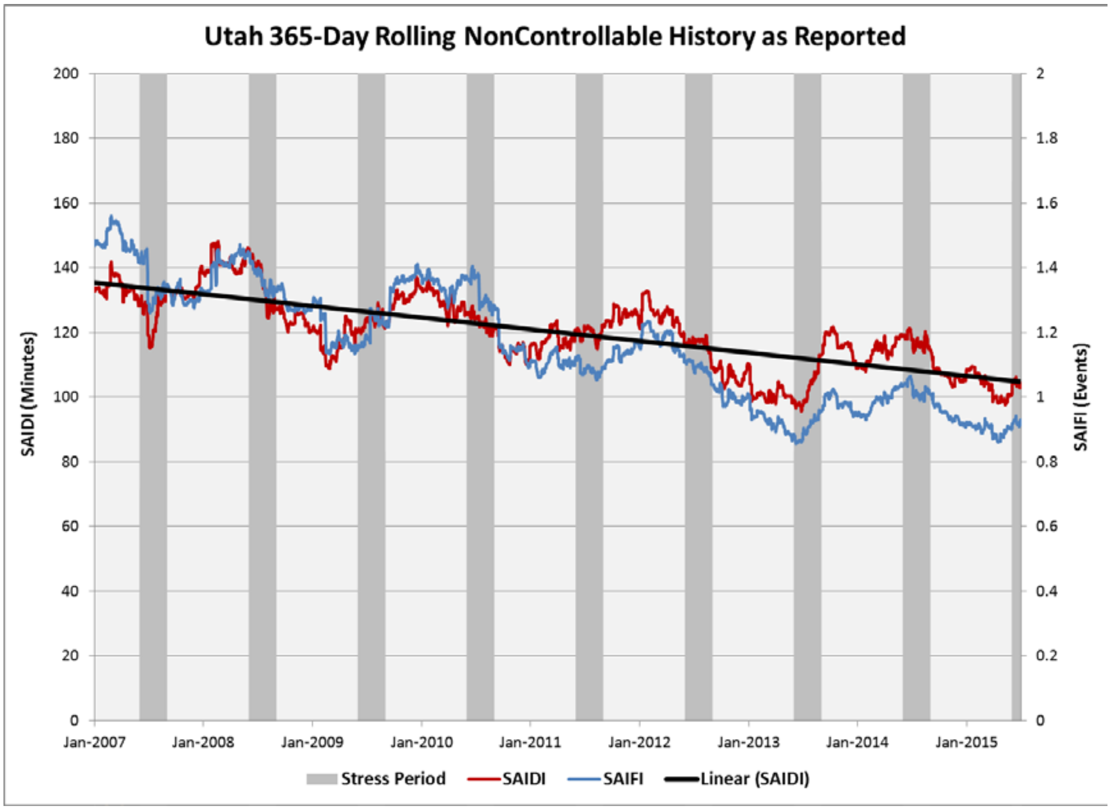
The graphic history demonstrates controllable, non-controllable and underlying performance on a rolling 365-day basis. Analysis of the trends displayed in the charts below shows a general improving trend for all charts. In order to also focus on non-controllable outages, the Company has continued to 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.

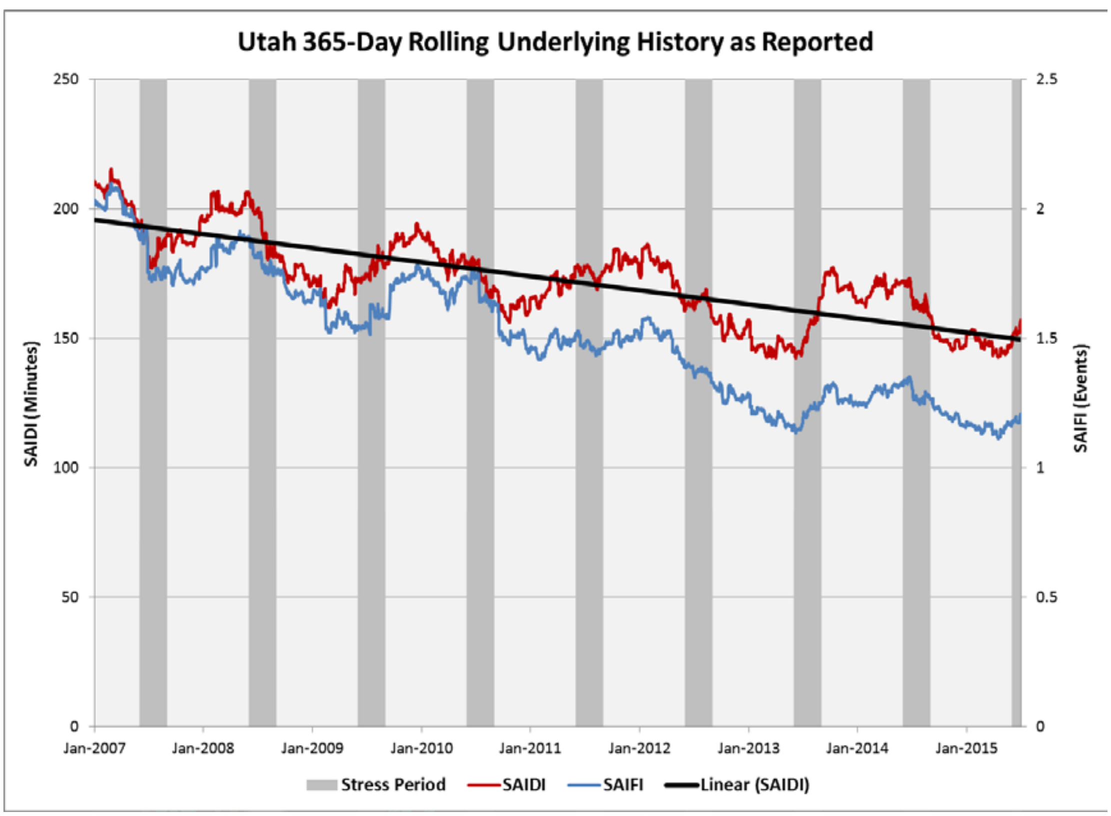


[4] 3. The Company shall provide, as an appendix to its Service Quality Review reports, information regarding non-controllable outages, including, when applicable, descriptions of efforts made by the Company to improve service quality and reliability for causes the Company has identified as not controllable.
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

January 1 – June 30, 2015





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[5] 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. However, for ease of charting, the pie charts reflect the rollup-level cause category rather than the detail-level direct cause within each category. Therefore, the pie charts for Underlying include prearranged causes (listed within the *planned* category). Following the pie 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 01/01/2015 - 06/30/2015

Direct Cause	Customer Minutes Lost for Incident	Customers in Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	701,196	4,737	179	0.81	0.005
BIRD MORTALITY (NON-PROTECTED SPECIES)	620,661	5,761	113	0.71	0.007
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	160,633	935	37	0.18	0.001
BIRD NEST (BMTS)	272,420	1,260	37	0.31	0.001
BIRD SUSPECTED, NO MORTALITY	178,255	1,412	45	0.21	0.002
ANIMALS	**1,933,165**	**14,105**	**411**	**2.22**	**0.016**
B/O EQUIPMENT	2,465,813	16,717	306	2.84	0.019
DETERIORATION OR ROTTING	15,699,863	70,377	2,497	18.06	0.081
OVERLOAD	1,677,137	12,449	145	1.93	0.014
RELAYS, BREAKERS, SWITCHES	279	6	21	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	22,148	9	27	0.03	0.000
EQUIPMENT FAILURE	**19,865,240**	**99,558**	**2,996**	**22.86**	**0.115**
FAULTY INSTALL	78,361	647	17	0.09	0.001
IMPROPER PROTECTIVE COORDINATION	22,259	207	9	0.03	0.000
INCORRECT RECORDS	54,005	2,573	28	0.06	0.003
INTERNAL CONTRACTOR	1,286	119	2	0.00	0.000
PACIFICORP EMPLOYEE - FIELD	112,335	2,386	13	0.13	0.003
PACIFICORP EMPLOYEE - SUB	-	-	-	-	-
OPERATIONAL	**268,246**	**5,932**	**69**	**0.31**	**0.007**
TREE - TRIMMABLE	701,636	3,253	57	0.81	0.004
TREES	**701,636**	**3,253**	**57**	**0.81**	**0.004**
Utah Including Prearranged	**22,768,287**	**122,848**	**3,533**	**26.20**	**0.141**

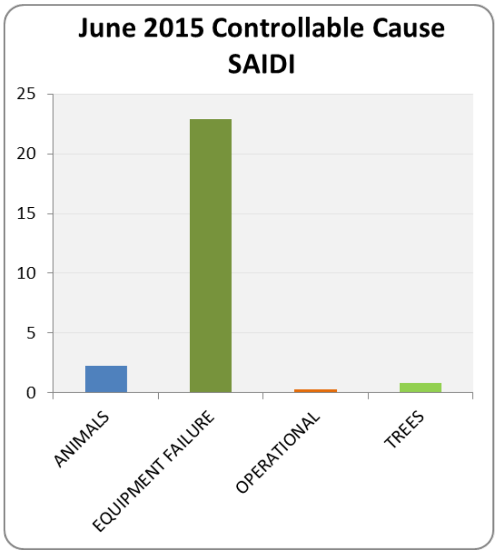
[5] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 869,108 (2015 Utah frozen customer count).

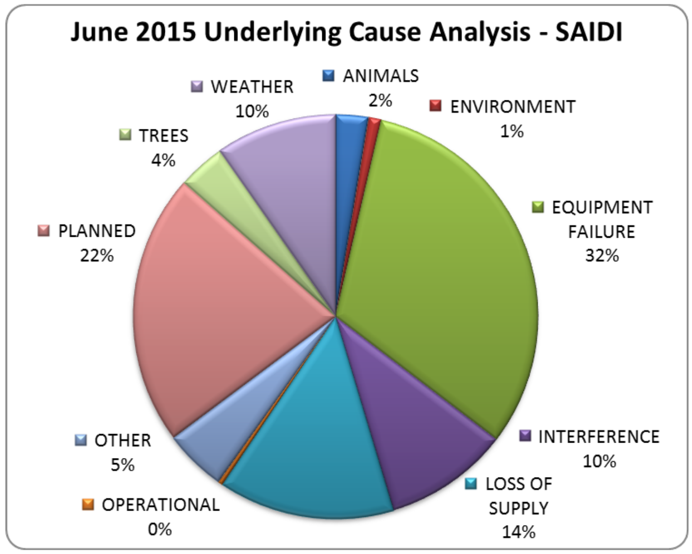
Utah Cause Analysis - Underlying 01/01/2015 - 06/30/2015

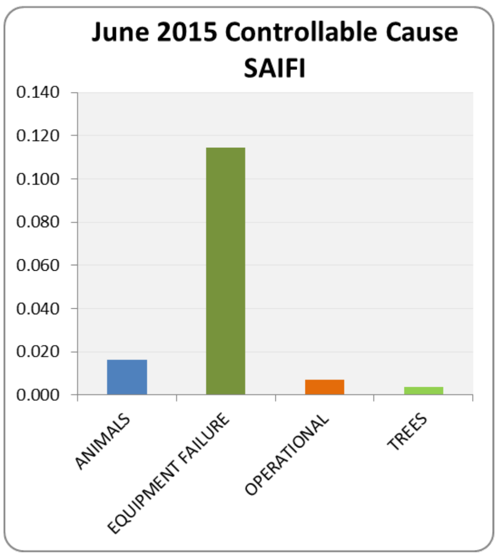
Direct Cause	Customer Minutes Lost for Incident	Customers in Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	701,196	4,737	179	0.81	0.005
BIRD MORTALITY (NON-PROTECTED SPECIES)	620,661	5,761	113	0.71	0.007
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	160,633	935	37	0.18	0.001
BIRD NEST (BMTS)	272,420	1,260	37	0.31	0.001
BIRD SUSPECTED, NO MORTALITY	178,255	1,412	45	0.21	0.002
ANIMALS	**1,933,165**	**14,105**	**411**	**2.22**	**0.016**
CONDENSATION / MOISTURE	52,036	216	2	0.06	0.000
CONTAMINATION	6,677	64	4	0.01	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	668,251	1,947	19	0.77	0.002
FLOODING	653	3	1	0.00	0.000
ENVIRONMENT	**727,616**	**2,230**	**26**	**0.84**	**0.003**
B/O EQUIPMENT	2,465,813	16,717	306	2.84	0.019
DETERIORATION OR ROTTING	15,699,863	70,377	2,497	18.06	0.081
NEARBY FAULT	382	1	1	0.00	0.000
OVERLOAD	1,677,137	12,449	145	1.93	0.014
POLE FIRE	3,439,295	19,594	130	3.96	0.023
RELAYS, BREAKERS, SWITCHES	279	6	21	0.00	0.000
STRUCTURES, INSULATORS, CONDUCTOR	22,148	9	27	0.03	0.000
EQUIPMENT FAILURE	**23,304,917**	**119,153**	**3,127**	**26.81**	**0.137**
DIG-IN (NON-PACIFICORP PERSONNEL)	1,041,391	7,827	142	1.20	0.009
OTHER INTERFERING OBJECT	521,441	8,794	61	0.60	0.010
OTHER UTILITY/CONTRACTOR	375,061	2,308	38	0.43	0.003
VANDALISM OR THEFT	610,203	5,845	23	0.70	0.007
VEHICLE ACCIDENT	4,770,336	31,245	182	5.49	0.036
INTERFERENCE	**7,318,432**	**56,019**	**446**	**8.42**	**0.064**
FAILURE ON OTHER LINE OR STATION	-	-	3	-	-
LOSS OF FEED FROM SUPPLIER	413	3	2	0.00	0.000
LOSS OF SUBSTATION	2,946,784	27,371	47	3.39	0.031
LOSS OF TRANSMISSION LINE	7,380,936	76,420	166	8.49	0.088
SYSTEM PROTECTION	81	2	3	0.00	0.000
LOSS OF SUPPLY	**10,328,214**	**103,796**	**221**	**11.88**	**0.119**
FAULTY INSTALL	78,361	647	17	0.09	0.001
IMPROPER PROTECTIVE COORDINATION	22,259	207	9	0.03	0.000
INCORRECT RECORDS	54,005	2,573	28	0.06	0.003
INTERNAL CONTRACTOR	1,286	119	2	0.00	0.000
PACIFICORP EMPLOYEE - FIELD	112,335	2,386	13	0.13	0.003
PACIFICORP EMPLOYEE - SUB	-	-	-	-	-
OPERATIONAL	**268,246**	**5,932**	**69**	**0.31**	**0.007**
OTHER, KNOWN CAUSE	252,631	2,165	113	0.29	0.002
UNKNOWN	3,386,633	41,028	531	3.90	0.047
OTHER	**3,639,264**	**43,193**	**644**	**4.19**	**0.050**
CONSTRUCTION	179,809	1,632	143	0.21	0.002
CONSTRUCTION - SCHEDULED SWITGHING	26,413	37	70	0.03	0.000
CUSTOMER NOTICE GIVEN	9,353,443	45,486	1,489	10.76	0.052
CUSTOMER REQUESTED	147,203	706	431	0.17	0.001
EMERGENCY DAMAGE REPAIR	5,409,666	93,520	711	6.22	0.108
INTENTIONAL TO CLEAR TROUBLE	676,554	19,088	29	0.78	0.022
MAINTENANCE	76,125	34	110	0.09	0.000
TRANSMISSION REQUESTED	75,814	217	10	0.09	0.000
PLANNED	**15,945,028**	**160,720**	**2,993**	**18.35**	**0.185**
TREE - NON-PREVENTABLE	2,094,367	13,859	185	2.41	0.016
TREE - TRIMMABLE	701,636	3,253	57	0.81	0.004
TREES	**2,796,004**	**17,112**	**242**	**3.22**	**0.020**
FREEZING FOG & FROST	1,010	5	1	0.00	0.000
LIGHTNING	2,977,758	26,335	239	3.43	0.030
SNOW, SLEET AND BLIZZARD	1,390,747	6,821	135	1.60	0.008
WIND	2,726,357	15,752	134	3.14	0.018
WEATHER	**7,095,873**	**48,913**	**509**	**8.16**	**0.056**
Utah Including Prearranged	**73,356,758**	**571,173**	**8,688**	**84.40**	**0.657**
Utah Excluding Prearranged	**63,829,698**	**524,944**	**6,698**	**73.44**	**0.604**

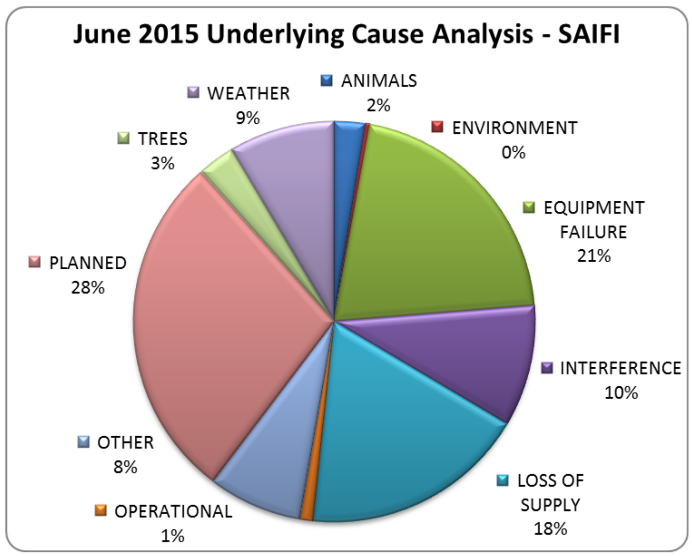
UTAH

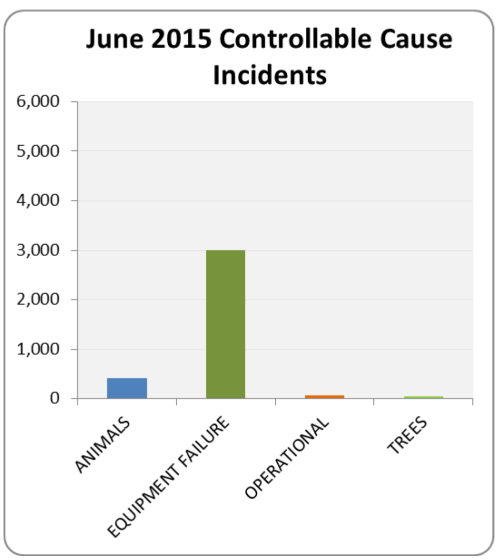
January 1 – June 30, 2015

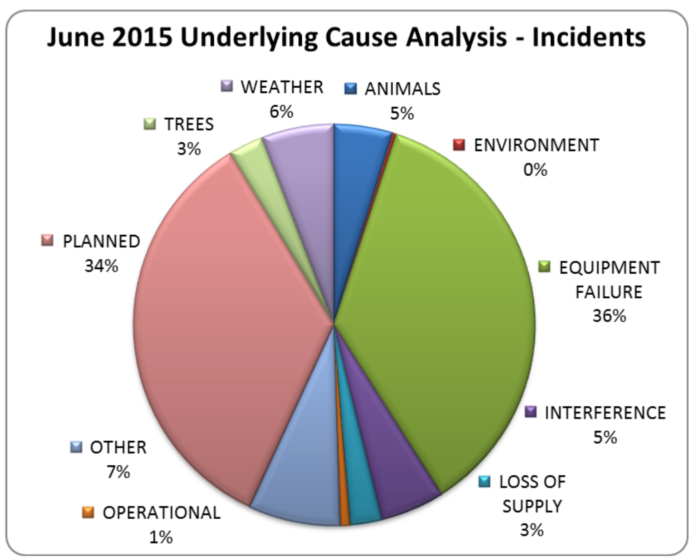


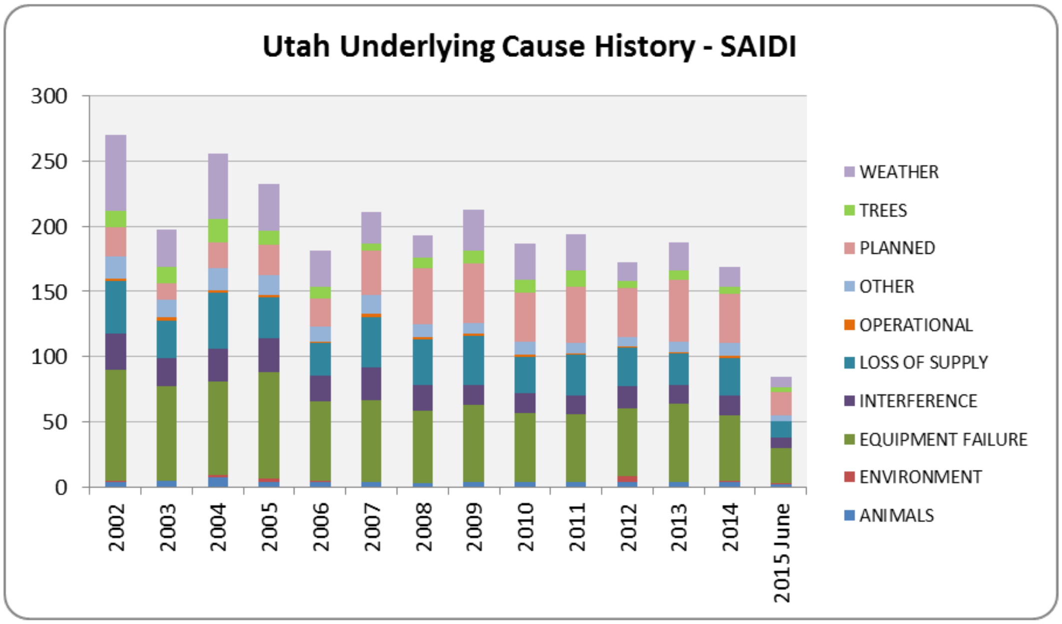


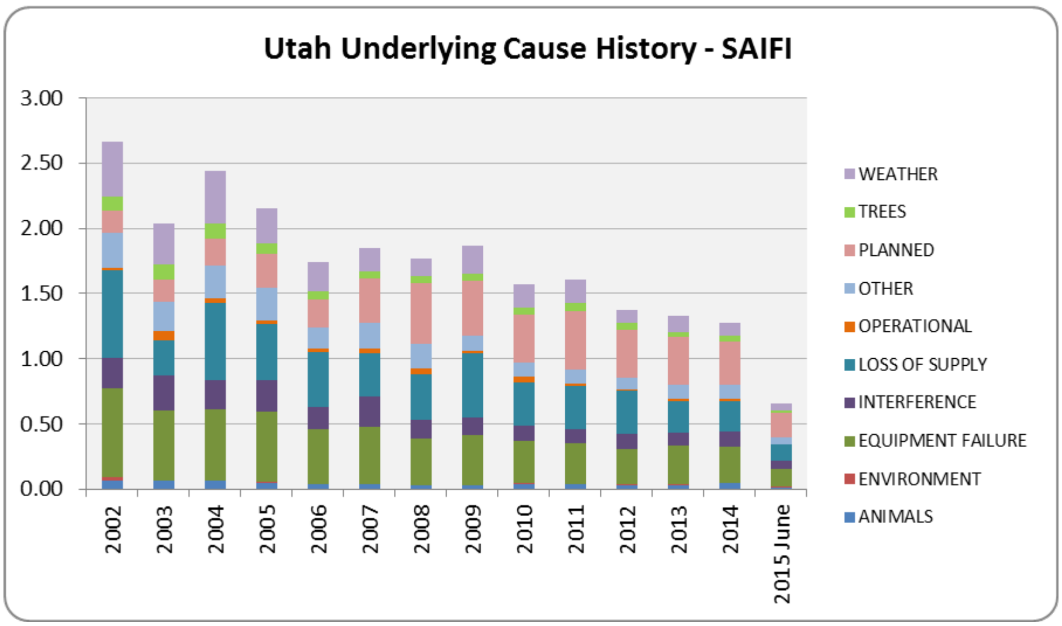









Utah Underlying Cause History - SAIDI
300
250
200
150
100
50
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015 June
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS


Utah Underlying Cause History - SAIFI
3.00
2.50
2.00
1.50
1.00
0.50
0.00
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
2014
2015 June
WEATHER
TREES
PLANNED
OTHER
OPERATIONAL
LOSS OF SUPPLY
INTERFERENCE
EQUIPMENT FAILURE
ENVIRONMENT
ANIMALS

Cause Category	Description and Examples
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).
Weather	Wind (excluding windborne material); snow, sleet or blizzard; ice; freezing fog; frost; lightning.
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 (i.e. broken conductor hits another line).
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.
Animals and Birds	Any problem nest that requires removal, relocation, trimming, etc; any birds, squirrels or other animals, whether or not remains found.
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.
Loss of Supply	Failure of supply from Generator or Transmission system; failure of distribution substation equipment.
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.
Trees	Growing or falling trees
Other	Cause Unknown; use comments field if there are some possible reasons.

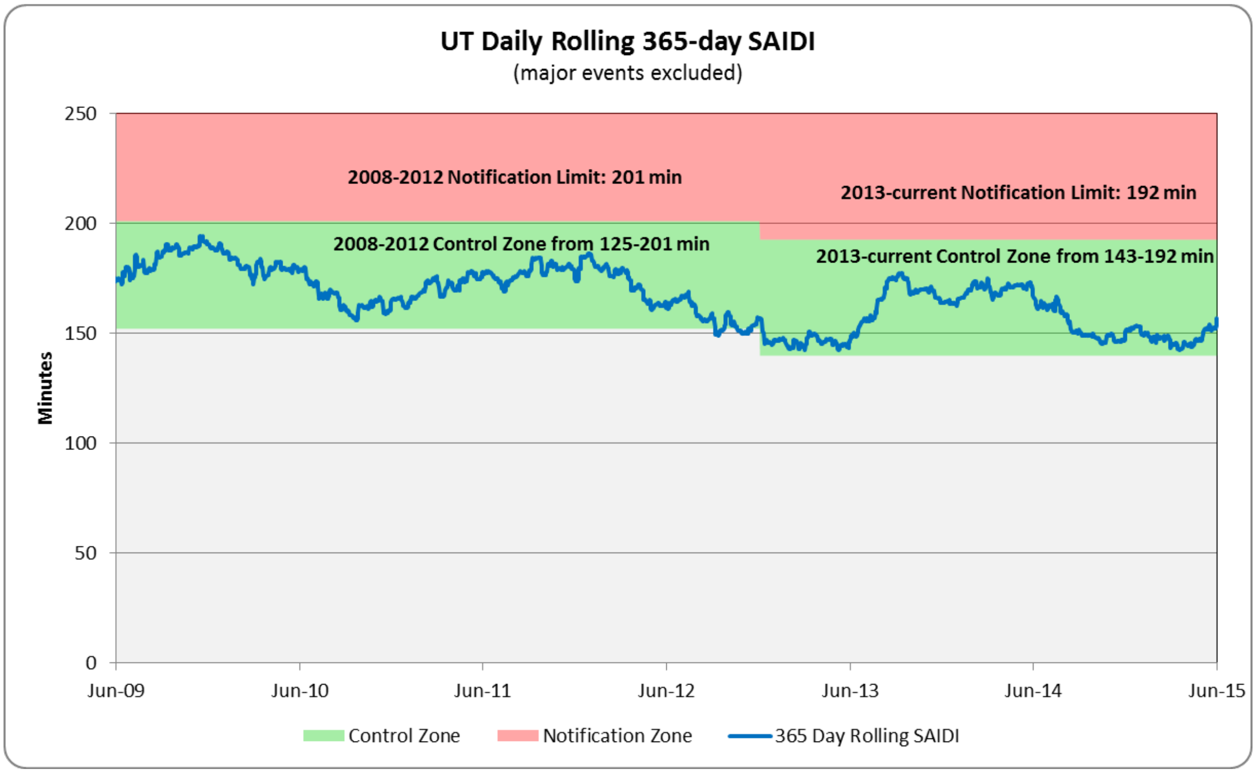
2.6 Baseline Performance

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 this section of the report is updated using the methods that resulted in the approved baselines; refreshing through June 30, 2015 yields the values shown below. In spite of performing this recalculation the Company is not advocating modifications to these baselines.

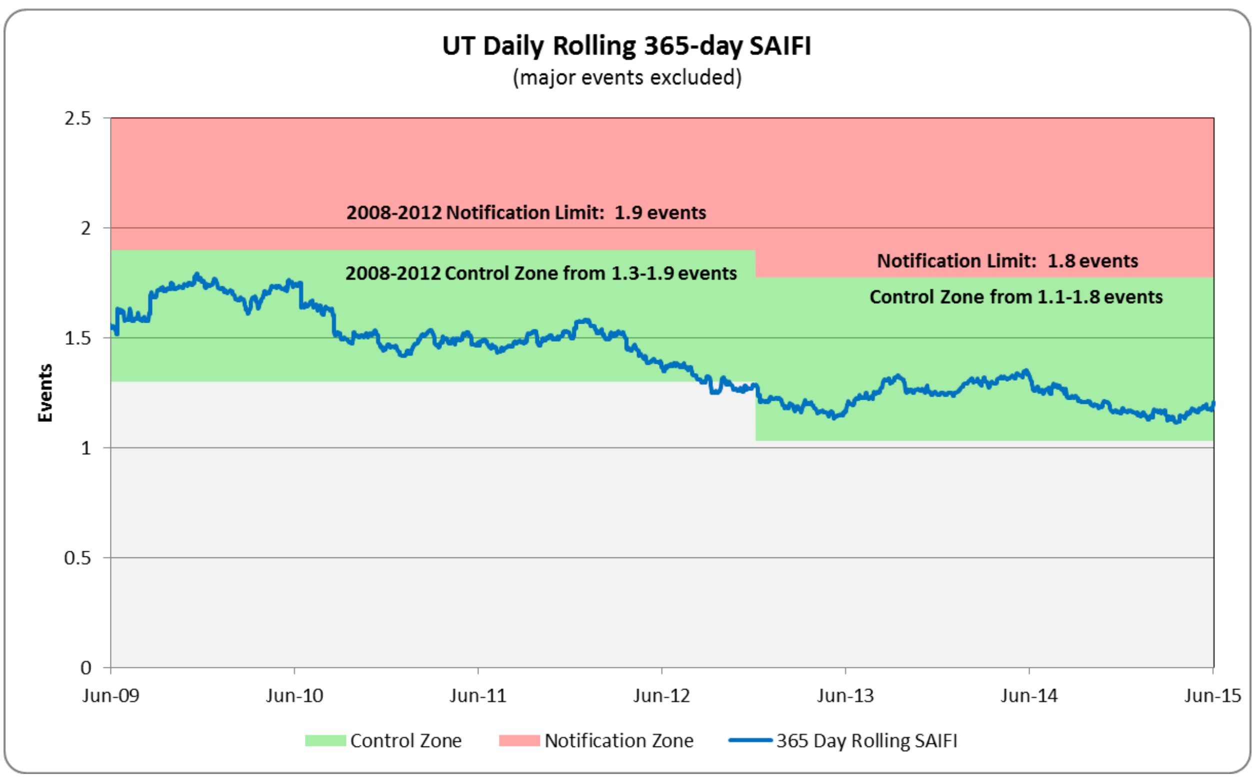
The Company refreshed the dataset and calculated using the last six years of daily reliability data, which was selected to align with major event calculations, but required the addition of the prior 365 days in order to construct the daily rolling 365-days curves used for these calculations. The 365-day average performance was 176 minutes and 1.59 events. The baselines filed were based on a 95% probability and resulted in a SAIDI range of 152-201 minutes and a SAIFI range of 1.3-1.9 events. The same methods applied through June 30, 2015 result in an average of 157 minutes and 1.21 events, with a SAIDI range of 144-192 minutes and a SAIFI range of 1.1-1.8 events. These values are shown in the table below.

Baseline	**As Filed (history through December 31, 2012)**			**Current Period (June 2015)**		
	365-Day Average	Lower Value Control Zone	Upper Value Control Zone (Notification Limit)	365-Day Average	Lower Value Control Zone	Upper Value Control Zone (Notification Limit)
SAIDI	176 minutes	152 minutes	201 minutes	157 minutes	144 minutes	192 minutes
SAIFI	1.59 events	1.3 events	1.9 events	1.21 events	1.1 events	1.8 events

Baseline Summary SAIDI



Baseline Summary SAIFI



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

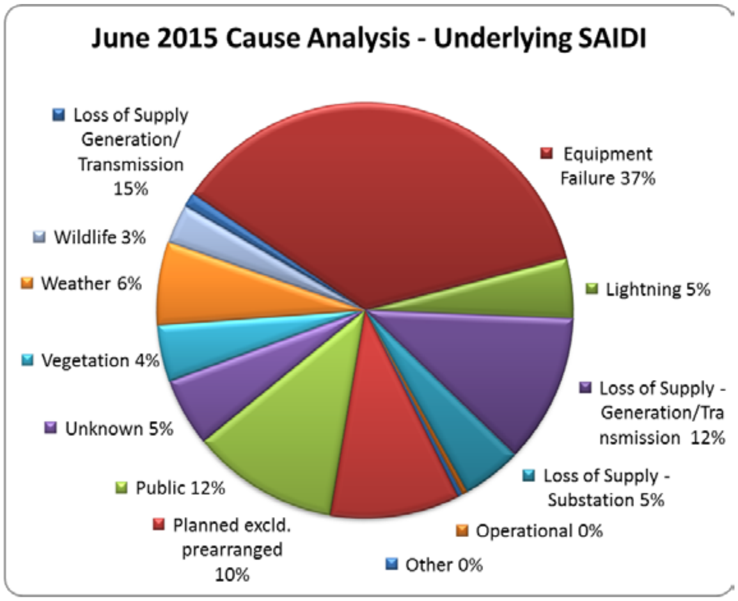
In 2012, the Company and stakeholders developed reliability reporting rules that are codified in Utah Rule R 746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least 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.

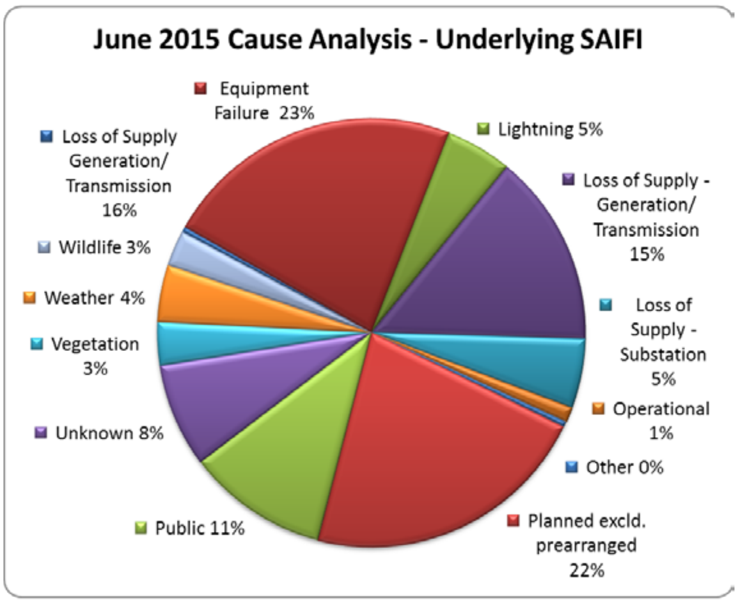
The final rule required five-year history at an operating area level for SAIDI, SAIFI and CAIDI. At a state level, these metrics in addition to $MAIFI_e$ are required.

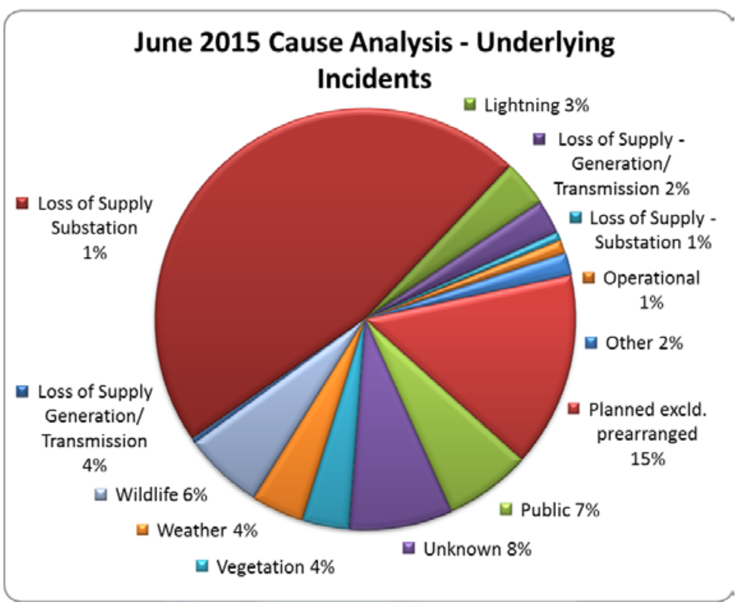
Major Events and Prearranged Excluded*	2011				2012				2013				2014				June - 2015			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	174	1.5	116	1.10	157	1.3	122	0.72	164	1.2	132	0.81	152	1.2	129	1.21	73	0.6	122	0.69
OP AREA																				
AMERICAN FORK	132	1.3	106		101	0.8	135		126	1.3	99		113	1.0	109		56	0.5	121	
CEDAR CITY	218	1.7	131		279	1.8	154		225	1.8	127		170	1.1	151		146	1.0	140	
CEDAR CITY (MILFORD)	980	8.1	121		363	2.8	129		707	3.3	213		891	3.3	271		212	1.1	194	
JORDAN VALLEY	113	0.9	121		106	0.8	129		106	0.7	145		103	0.7	141		53	0.5	102	
LAYTON	155	1.3	124		105	0.8	131		105	1.0	109		108	0.8	127		76	0.7	105	
MOAB	151	1.8	86		375	3.1	122		284	1.9	147		412	2.3	181		96	1.0	100	
OGDEN	204	1.8	116		153	1.3	117		168	1.4	122		218	1.9	113		75	0.6	120	
PARK CITY	186	1.6	116		184	1.8	100		232	1.5	155		147	1.1	140		59	0.4	151	
PRICE	421	2.5	166		133	1.4	97		514	1.8	293		394	2.2	180		96	1.1	89	
RICHFIELD	369	3.2	114		200	2.0	100		469	3.4	138		181	1.7	104		232	1.1	203	
RICHFIELD (DELTA)	316	3.6	89		329	2.9	113		316	3.7	85		202	1.9	108		409	2.3	180	
SLC METRO	178	1.5	117		129	1.2	112		170	1.2	139		145	1.1	129		54	0.4	130	
SMITHFIELD	174	1.6	106		267	2.6	102		81	0.7	117		114	0.9	126		149	0.7	202	
TOOELE	329	3.0	110		595	3.7	163		137	1.3	103		239	2.1	115		72	0.9	80	
TREMONTON	255	2.2	115		447	3.0	147		335	3.3	102		216	2.0	111		270	2.5	106	
VERNAL	117	2.2	54		236	2.9	82		160	2.1	75		119	1.2	101		26	0.4	61	

* except MAIFIe

Utah Cause Category	2011		2012		2013		2014		June 2015	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	0	0.0	4	0.0	0	0.0	1	0.0	1	0.0
Equipment Failure	52	0.3	53	0.3	60	0.3	51	0.3	27	0.1
Lightning	9	0.1	4	0.0	9	0.1	7	0.1	3	0.0
Loss of Supply - Generation/Transmission	26	0.3	25	0.3	19	0.2	23	0.2	8	0.1
Loss of Supply - Substation	6	0.1	5	0.1	6	0.0	6	0.0	3	0.0
Operational	1	0.0	0	0.0	1	0.0	1	0.0	0	0.0
Other	1	0.0	0	0.0	0	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	23	0.3	22	0.3	24	0.3	20	0.2	7	0.1
Public	15	0.1	16	0.1	14	0.1	15	0.1	8	0.1
Unknown	7	0.1	7	0.1	8	0.1	10	0.1	4	0.0
Vegetation	13	0.1	5	0.1	7	0.0	6	0.0	3	0.0
Weather	19	0.1	11	0.1	12	0.1	8	0.0	5	0.0
Wildlife	4	0.0	4	0.0	4	0.0	4	0.0	2	0.0
UTAH Underlying	**174**	**1.5**	**157**	**1.3**	**164**	**1.2**	**151**	**1.2**	**73**	**0.6**


June 2015 Cause Analysis - Underlying SAIDI
Loss of Supply Generation/ Transmission 15%
Equipment Failure 37%
Wildlife 3%
Weather 6%
Lightning 5%
Vegetation 4%
Loss of Supply - Generation/Transmission 12%
Unknown 5%
Loss of Supply - Substation 5%
Public 12%
Planned excld. prearranged 10%
Operational 0%
Other 0%


June 2015 Cause Analysis - Underlying SAIFI
Equipment Failure 23%
Lightning 5%
Loss of Supply Generation/ Transmission 16%
Loss of Supply - Generation/ Transmission 15%
Wildlife 3%
Weather 4%
Loss of Supply - Substation 5%
Vegetation 3%
Operational 1%
Unknown 8%
Other 0%
Public 11%
Planned excld. prearranged 22%


June 2015 Cause Analysis - Underlying Incidents
Lightning 3%
Loss of Supply - Generation/ Transmission 2%
Loss of Supply Substation 1%
Loss of Supply - Substation 1%
Operational 1%
Other 2%
Loss of Supply Generation/ Transmission 4%
Planned excld. prearranged 15%
Wildlife 6%
Public 7%
Weather 4%
Unknown 8%
Vegetation 4%

2.8 Reduce CPI for Worst Performing Circuits by 20%

On a routine basis, the Company reviews circuits for performance. One of the measures that it uses is called circuit performance indicator (CPI), which is 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 selects a set of Worst Performing Circuits for improvements, which are to be completed within two years of selection. Within five years of selection, the average performance of the five-selection set must improve by at least 20% (as measured by comparing current performance against baseline performance).

2.8.1 Circuit Performance Score Updates for Prior-Year Selections

Annually, the company tracks the performance of circuits designated in the Worst Performing Circuits program, until the Program Year has successfully met the target score. Goal Met is reported and then that program year removed from future Service Quality Reports.

WORST PERFORMING CIRCUITS	STATUS	BASELINE[6]	Performance 6/30/2015
Program Year 15: (CY2014)			
Skull Valley 11	IN PROGRESS	468	441
Fort Douglas 13	IN PROGRESS	417	172
Parowan Valley 25	IN PROGRESS	408	402
Brighton 21	IN PROGRESS	364	184
Bush 12	IN PROGRESS	281	287
TARGET SCORE = **248**		**310**	**297**
Program Year 14: (CY2013)			
Snyderville 16	COMPLETE	72	78
Eden 11	COMPLETE	116	235
Bush 11	COMPLETE	228	231
Pioneer 12	COMPLETE	177	56
Grantsville 12	COMPLETE	250	135
TARGET SCORE = 108		**135**	**147**

Program Year 13: (CY2012)

[6] 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 on each of the circuits. The application of CPI99 proved to demonstrate more consistently how performance comparisons could be made.

Fielding 11	COMPLETE	207	275
East Bench 12	COMPLETE	112	76
Clinton 11	COMPLETE	133	34
Redwood 16	COMPLETE	145	60
Orangeville 11	COMPLETE	114	19
TARGET SCORE = **114**	**Target Met**	**142**	**93**
Program Year 12: (CY2011)			
Lincoln 15	COMPLETE	173	70
Huntington City 12	COMPLETE	285	78
Magna 15	COMPLETE	140	55
Gunnison 12	COMPLETE	110	71
Capitol 11	COMPLETE	129	72
TARGET SCORE = **134**	**Target Met**	**167**	**69**
Program Year 11: (CY2010)			
Decker Lake 12	COMPLETE	102	164
North Bench 13	COMPLETE	95	55
Newgate 14	COMPLETE	164	65
Newton 12	COMPLETE	105	90
St Johns 11	COMPLETE	547	270
TARGET SCORE = **162**	**Target Met**	**203**	**129**
Program Year 10: (CY2009)			
Fruit Heights 12	COMPLETE	113	62
Mathis 12	COMPLETE	132	78
Parrish 11	COMPLETE	137	43
Valley Center 11	COMPLETE	169	42
Hammer 15	COMPLETE	95	48
TARGET SCORE = **104**	**Target Met**	**129**	**55**

Note: Goals were met for Program Years 1 through 12 and filed in prior reporting periods; however, data for Program Years 10-12 are retained in this report in order to show circuit selections of the past 6 program years for discussion purposes.

2.9 Restore Service to 80% of Customers within 3 Hours

RESTORATIONS WITHIN 3 HOURS					
CUMULATIVE January – June 2015 = 84%					
January	February	March	April	May	June
90%	91%	87%	91%	80%	73%
July	August	September	October	November	December
-	-	-	-	-	-

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.

June 2015 CAIDI (Average Outage Duration)	
Underlying Performance	122 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[7] complaints within 30 days	100%	100%

[7] 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.

Since June 30, 2015, there were three dates identified as a wide-scale outage days; call statistics are shown in the table below. The outage event on January 29th was a Loss of supply at the Granger substation in Utah, resulting in approximately 9,100 customers out of service for approximately 1 hour. The outage events on February 9th were due to a winter storm which affected customers in Wyoming, California, Oregon, and Washington, and met major event thresholds for Wyoming, California and Oregon. On April 21st a loss of supply event in Oregon cause an 8 minute outage to 29,258 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
1/29/2015	15:00	15:14	1262	216	61	530	89
	15:15	15:29	1195	101	19	221	62
	15:30	15:44	834	0	11	99	19
	15:45	15:59	714	2	1	63	10
2/9/2015	10:30	10:44	541	0	7	149	61
	10:45	10:59	924	74	17	123	51
	11:00	11:14	2094	256	20	160	70
	11:15	11:29	1224	35	71	740	128
	11:30	11:44	976	0	59	414	66
	11:45	11:59	849	0	2	44	5
	12:00	12:14	991	0	1	68	8
	12:15	12:29	1050	1	1	70	8
	12:30	12:44	960	0	0	56	8
	12:45	12:59	1037	3	3	86	8
	13:00	13:14	990	2	2	34	3
	13:15	13:29	966	0	6	151	13
	13:30	13:44	846	0	7	148	19
	13:45	13:59	794	0	9	84	18
	14:00	14:14	1239	0	20	189	51
	14:15	14:29	1525	0	10	134	31
	14:30	14:44	1990	94	15	223	43
	14:45	14:59	1431	32	28	212	60
	15:00	15:14	1292	17	32	233	60
	15:15	15:29	1429	9	10	132	23
	15:30	15:44	1422	0	15	139	32
	15:45	15:59	1091	49	20	227	52
	16:00	16:14	936	11	7	226	24
	16:15	16:29	1112	126	24	224	68

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
4/21/2015	15:30	15:44	2510	287	290	433	59
	15:45	15:59	465	0	8	172	29
	16:00	16:14	395	0	7	174	71
	16:15	16:29	394	0	13	136	50

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 2015

Utah

	Description	2015 Events	2015 Failures	2015 % Success	2015 Paid	2014 Events	2014 Failures	2014 % Success	2014 Paid
CG1	Restoring Supply	525,996	1	99.90%	$50	495,632	0	100%	$0
CG2	Appointments	3,664	3	99.92%	$150	3,418	16	99.53%	$800
CG3	Switching on Power	3,793	1	99.90%	$50	4,306	2	99.95%	$100
CG4	Estimates	649	1	99.85%	$50	582	0	100%	$0
CG5	Respond to Billing Inquiries	873	2	99.77%	$100	704	0	100%	$0
CG6	Respond to Meter Problems	375	1	99.90%	$50	387	0	100%	$0
CG7	Notification of Planned Interruptions	45,486	16	99.96%	$800	39,603	13	99.97%	$650
		580,836	**25**	**99.9%**	**$1,250**	**544,632**	**31**	**99.9%**	**$1,550**

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[8], 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.[9]
- 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.

Substations and Major Equipment

[8] 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.

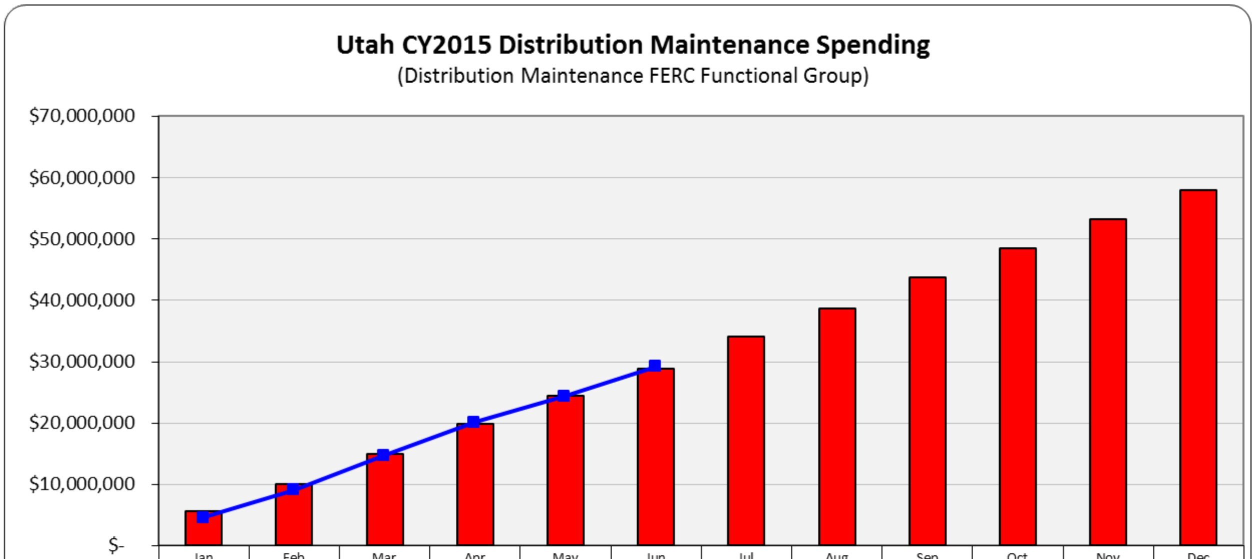
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

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.

[9] 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.

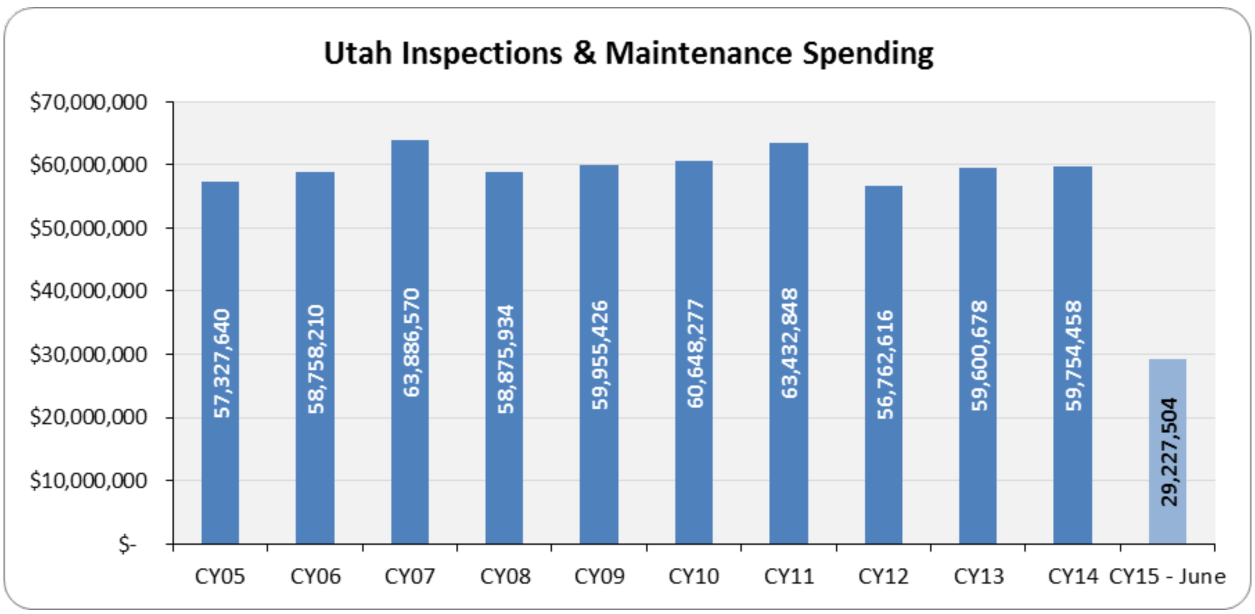
- Correctable conditions are identified through the preventive maintenance process, often associated with actions performed on major equipment.
- Corrections consist of repairing equipment or responding to a failed condition.

3.2 Maintenance Spending [10]



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,564,355	$10,072,615	$14,964,978	$19,878,075	$24,372,257	$28,900,729	$34,135,921	$38,721,204	$43,670,616	$48,420,725	$53,189,196	$57,946,129
Actual	$4,598,421	$9,108,312	$14,741,711	$20,110,720	$24,427,827	$29,227,504						

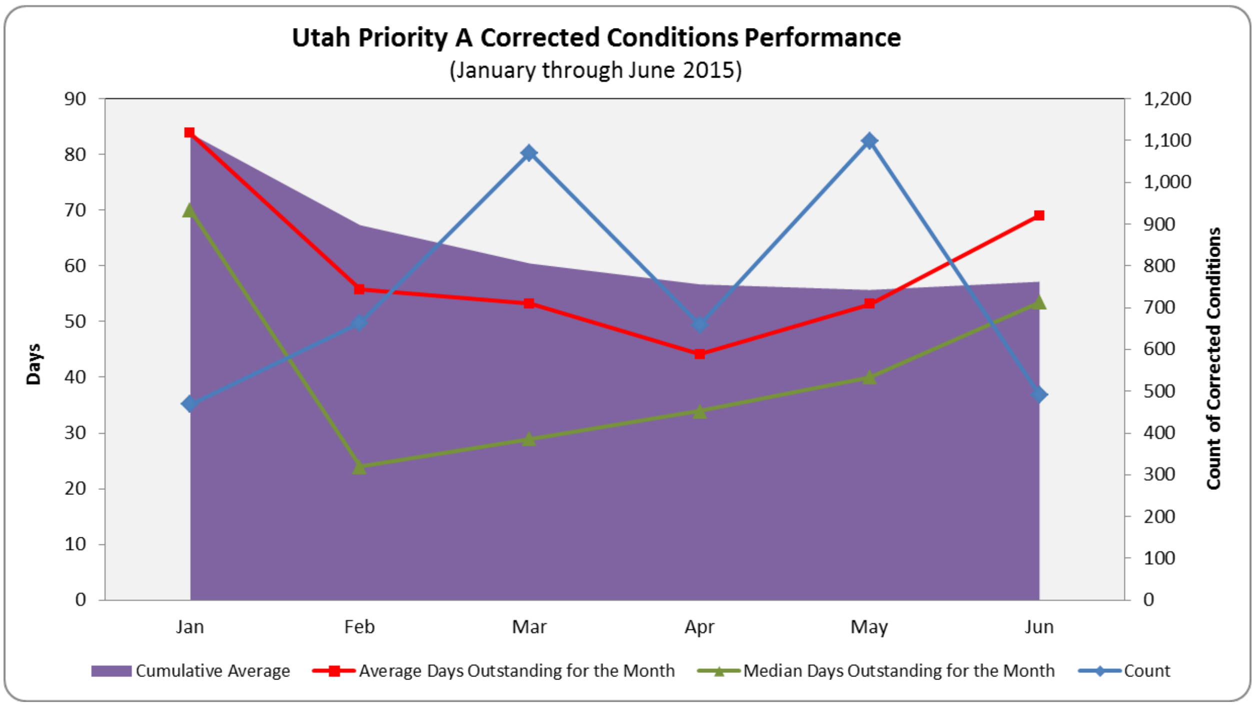
3.2.1 Maintenance Historical Spending



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

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.



Oldest Outstanding Priority A Conditions In Utah

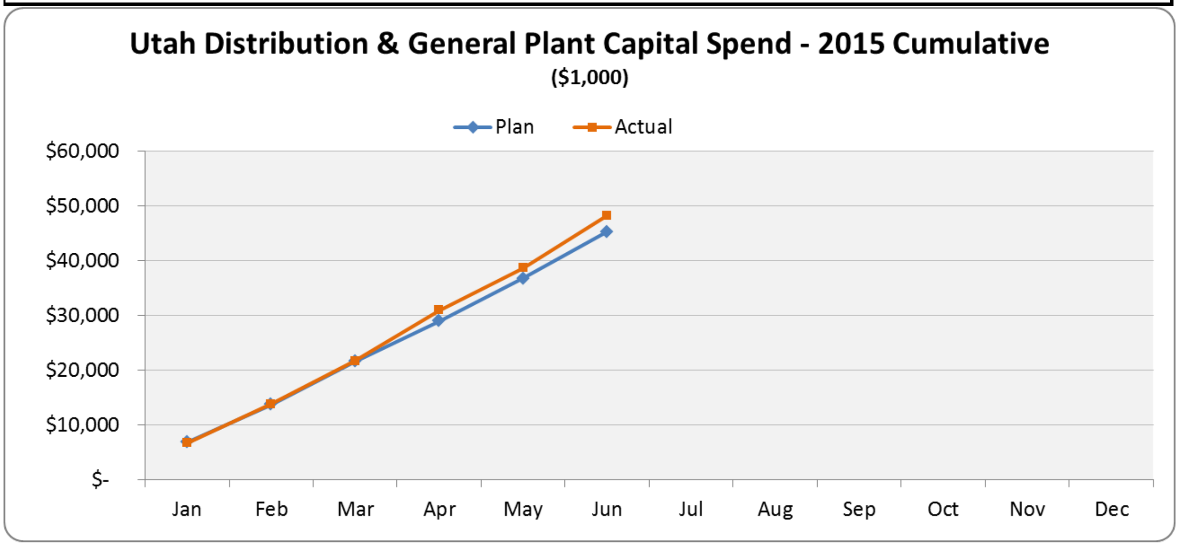
District	Mapstring	Pole	Condition	Inspection Remarks	Inspection Date	Completion Date	Days to Correct	Circuit	Explanation
Jordan Valley	11403001	163106	BOPOLE	DECAY REJECT RESTORE_HR 0.5_HEART ROTT	11/8/2014			DMP13	The pole replacement was scheduled in February, 2015. The customer would not allow our contractor to access her property to replace the pole. Several attempts have been made to accommodate the customer with a schedule that would work for her. The customer has been uncooperative. We are continuing to work with the customer to have the pole replaced.
Metro	11401001	359700	BOPOLE	DECAY REJECT REPLACE_SRA_SHELL ROT ABOVE /NOT RESTORABLE	11/13/2014			OLY13	The property owner built a large shed/garage around the pole. The pole sticks through the roof. The pole is in Metro Water's ROW. Metro Water wants the facility removed from their ROW. We are working with the customer to obtain ROW to move the pole to their property and out of Metro Water's ROW.
Moab	11426022	84300	CLEARSVC	CLEARANCE OF SERVICE OVER YARD_7FT 11IN 16307078	11/1/2014			MOA12	The customer refused to let RMP install a service pole on his property to acquire the required clearance. The customer agreed to update his service mast, which will correct the issue.
Price	11414010	263306	CLEARSVC	CLEARANCE OF SERVICE OVER ROADWAY OR COMMERCIAL DRIVEWAY_12" E OF POLE	8/29/2014			MAT11	RMP is working with the homeowners because it will take the installation of a new pole to correct the condition. The proposed location of the pole would interfere with an irrigation line, so RMP has proposed two alternate locations and is negotiating the locations with the homeowner.
Richfield	11322003	314901	BOPOLE	LEANING POLE_#16292915	9/29/2014	7/1/2015	275	RCH14	This pole is on top of a mountain and feeds a cellular site. Access was restricted due to snow and weather and the permit from the U.S. Forest Service required that RMP make a minimal footprint to correct the condition.

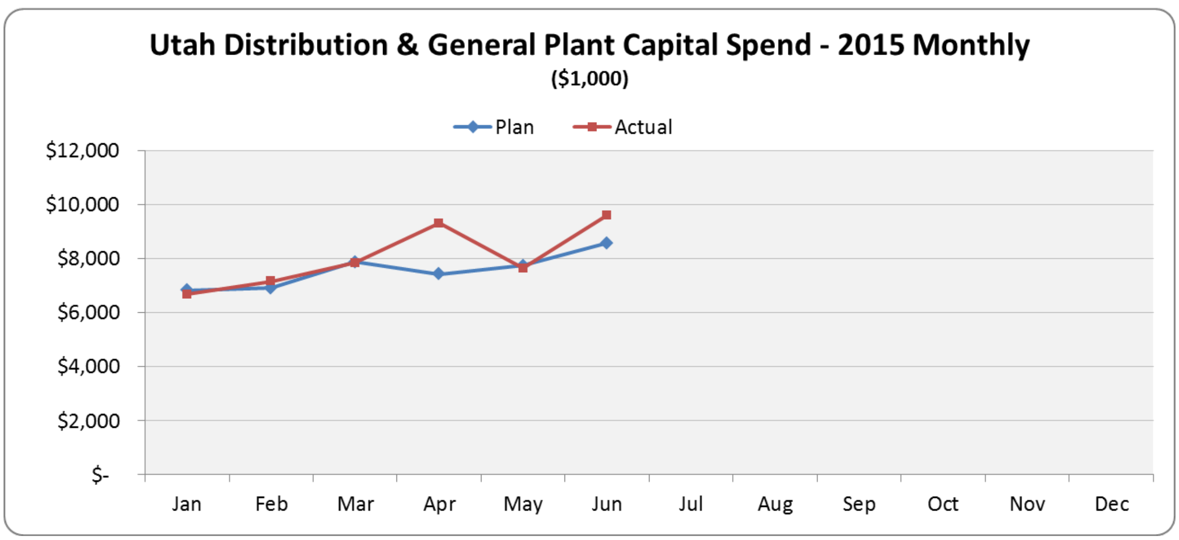
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

January – June 2015

Investment	Actuals ($M)	Plan ($M)	Significant Variances
1. Mandated	$4.4	$3.3	Mandated road relocations over plan, (+$0.7M).
2. New Connect	$20.1	$19.8	Commercial new connects over plan, (+$1.0M); residential new connects under plan, (-$0.4M).
3. System Reinforcement	$4.7	$3.4	Feeder and substation reinforcements over plan, (+$1.2M).
4. Replacement	$17.9	$17.2	Replacements for underground cable, vaults/equipment and customer meters over plan, (+$3.5M); replacements for vehicles (transport), microwave/fiber communications, overhead distribution lines/other and substation transformers under plan, (-$3.2M).
5. Upgrade & Modernize	$1.2	$1.5	
Total	**$48.3**	**$45.4**	



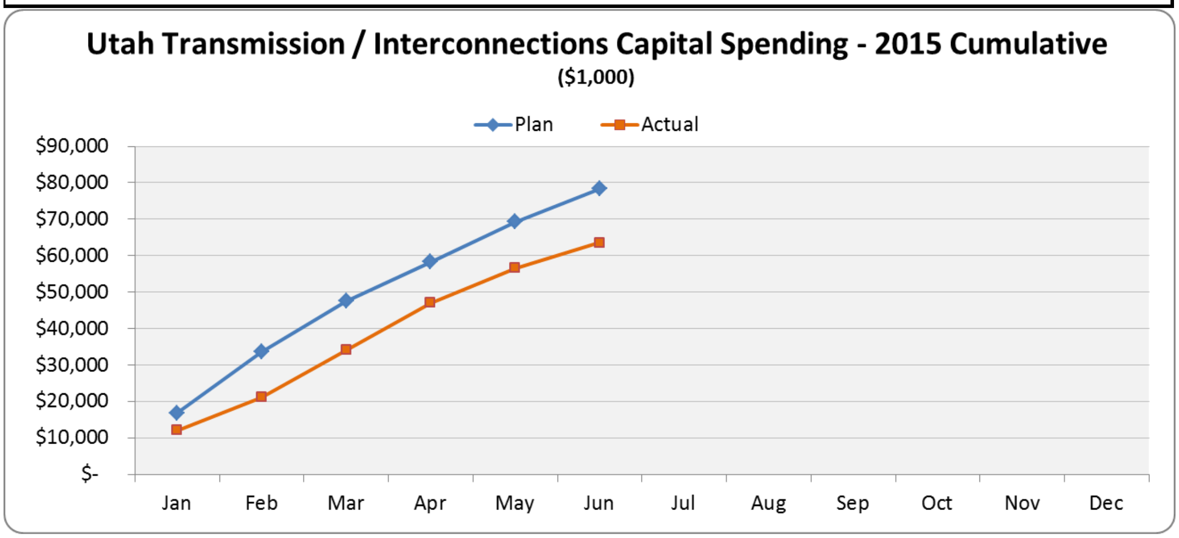


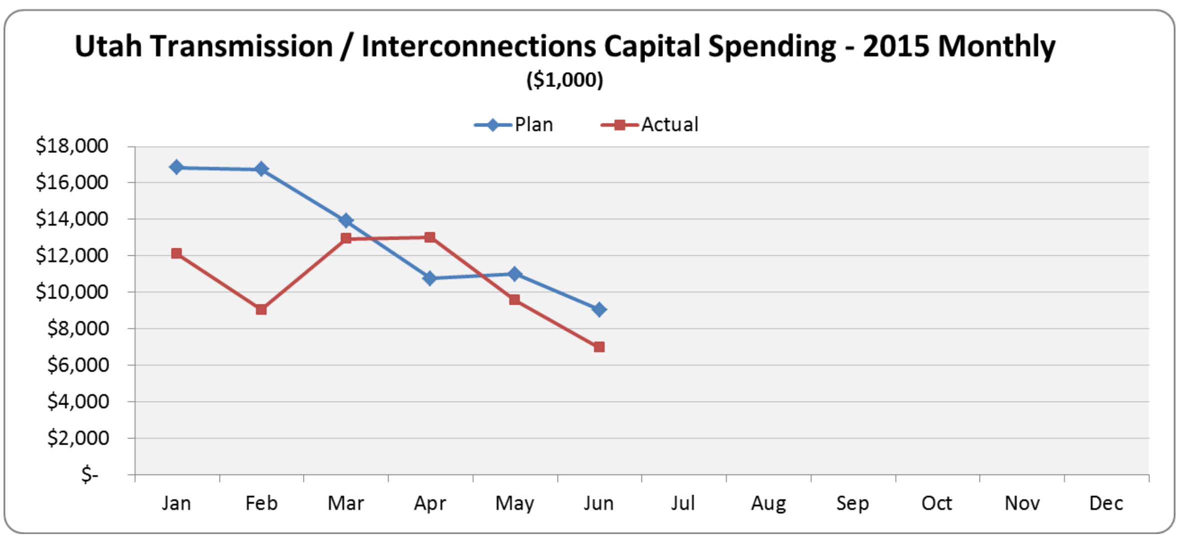
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending – Transmission/Interconnections

January –June 2015

	Investment	Actuals ($M)	Plan ($M)	Significant Variances
1.	Mandated	4.0	3.0	Mandated NERC reliability over plan, (+$1.8M); mandated right-of-way renewals under plan, (-$0.4M).
2.	New Connect	0.3	0.5	
3.	Local Transmission System Reinforcements	12.9	13.2	Local subtransmission substation reinforcement over plan, (+$0.6M); local subtransmission line reinforcement under plan, (-$1.2M).
**4.	Main Grid Reinforcements / Interconnections	13.8	21.4	Pinto 3rd Ph Shifting Transfmr (-$5.2M) and Hurricane West 138kV Net Deliv Pt-UAMPS (-$1.3M) under plan.
**5.	Energy Gateway Transmission	22.7	31.8	Populus-Terminal 345kV Line (+$1.0M) over plan; Sigurd Red Butte Crystal 345kV Line (-$10.1M) under plan. *(Note: Populus-Terminal Line project crosses state line--plan $ assigned to ID; $1M 2015 UT expenditures.)*
6.	Replacement	9.8	8.2	Replacements for storm & casualty and substation meters/relays over plan, (+$1.1M).
7.	Upgrade & Modernize	0.2	0.2	
	Total	**63.6**	**78.3**	





4.3 New Connects

	2014	2015																	
	Jan - Dec 2014	Jan	Feb	Mar	Q1 Total	Apr	May	Jun	Q2 Total	Jan - Jun 2015	Jul	Aug	Sep	Q3 Total	Oct	Nov	Dec	Q4 Total	YEAR TO DATE
Residential																			
UT South	676	43	47	31	121	41	44	43	128	249	-	-	-	-	-	-	-	-	249
UT North/Metro	3,985	287	171	222	680	249	476	253	978	1,658	-	-	-	-	-	-	-	-	1,658
UT Central	6,837	567	483	766	1,816	416	487	634	1,537	3,353	-	-	-	-	-	-	-	-	3,353
Total Residential	**11,498**	**897**	**701**	**1,019**	**2,617**	**706**	**1,007**	**930**	**2,643**	**5,260**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**5,260**
					-				-	-				-				-	-
Commercial					-				-	-				-				-	-
UT South	181	16	17	17	50	17	12	19	48	98	-	-	-	-	-	-	-	-	98
UT North/Metro	554	67	44	41	152	56	35	46	137	289	-	-	-	-	-	-	-	-	289
UT Central	639	53	35	70	158	70	68	64	202	360	-	-	-	-	-	-	-	-	360
Total Commercial	**1,374**	**136**	**96**	**128**	**360**	**143**	**115**	**129**	**387**	**747**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**747**
					-				-	-				-				-	-
Industrial					-				-	-				-				-	-
UT South	3	-	-	1	1	-	-	-	-	1	-	-	-	-	-	-	-	-	1
UT North/Metro	2	2	-	-	2	-	-	-	-	2	-	-	-	-	-	-	-	-	2
UT Central	9	-	-	1	1	1	-	1	2	3	-	-	-	-	-	-	-	-	3
Total Industrial	**14**	**2**	**-**	**2**	**4**	**1**	**-**	**1**	**2**	**6**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**6**
					-				-	-				-				-	-
Irrigation					-				-	-				-				-	-
UT South	45	2	2	3	7	13	5	3	21	28	-	-	-	-	-	-	-	-	28
UT North/Metro	4	-	2	1	3	-	1	3	4	7	-	-	-	-	-	-	-	-	7
UT Central	14	-	2	1	3	1	2	2	5	8	-	-	-	-	-	-	-	-	8
Total Irrigation	**63**	**2**	**6**	**5**	**13**	**14**	**8**	**8**	**30**	**43**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**43**
					-				-	-				-				-	-
TOTAL New Connects					-				-	-				-				-	-
UT South	905	61	66	52	179	71	61	65	197	376	-	-	-	-	-	-	-	-	376
UT North/Metro	4,545	356	217	264	837	305	512	302	1,119	1,956	-	-	-	-	-	-	-	-	1,956
UT Central	7,499	620	520	838	1,978	488	557	701	1,746	3,724	-	-	-	-	-	-	-	-	3,724
TOTAL New Connects	**12,949**	**1,037**	**803**	**1,154**	**2,994**	**864**	**1,130**	**1,068**	**3,062**	**6,056**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**6,056**

Utah South region includes Moab, Price, Cedar City and Richfield
Utah North/Metro region includes SLC Metro, Odgen 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 permeant connection for the reporting period.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH
Tree Program Reporting
January 1, 2015 through June 30, 2015
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2015-6/30/2015 Miles Planned	1/1/2015-6/30/2015 Actual Miles	01/01/2015-6/301/2015 Ahead/ Behind	1/1/2015-6/30/2015 % 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	10,964	1,757	2,281	524	129.8%	5,411	6,274	863	115.9%
AMERICAN FORK	817	131	108	-23	82.4%	403	282	-121	70.0%
CEDAR CITY	1,363	218	62	-156	28.4%	673	770	97	114.4%
JORDAN VALLEY	772	124	136	12	109.7%	381	469	88	123.1%
LAYTON	304	49	58	9	118.4%	150	85	-65	56.7%
MOAB	970	155	616	461	397.4%	479	788	309	164.5%
OGDEN	933	150	205	55	136.7%	461	484	23	105.0%
PARK CITY	535	86	0	-86	0.0%	264	218	-46	82.6%
PRICE	588	94	169	75	179.8%	290	490	200	169.0%
RICHFIELD	1,342	215	557	342	259.1%	662	804	142	121.5%
SL METRO	1,192	191	190	-1	99.5%	588	704	116	119.7%
SMITHFIELD	766	123	68	-55	55.3%	378	379	1	100.3%
TOOELE	482	77	31	-46	40.3%	238	123	-115	51.7%
TREMONTON	651	104	0	-104	0.0%	321	519	198	161.7%
VERNAL	249	40	81	41	202.5%	123	159	36	129.3%

Distribution

Distribution cycle $/tree:	$103.29
Distribution cycle $/mile:	$2,413
Distribution cycle removal %	17.46%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,471	1,114	682	(432)	6,039	0.933

Transmission $/mile:	$2,882

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, 2015 through June 30, 2015
Column c: Actual overhead distribution pole miles worked during the period January, 2015 through June 30, 2015
Column d: Miles ahead or behind for the period January 1, 2015 through June 30, 2015 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2015 through June 30, 2015 ((column c÷b)×100)
Column f: Planned miles cycle to date (April 1, 2005 through April 1, 2008)
Column g: Actual miles cycle to date (April 1, 2005 through April 1, 2008) - Cycle to date
Column h: Miles ahead or behind for the period April 1, 2005 through April 1, 2008 (column j-column i) - cycle to date
Column i: Percent of actual compared to planned for the period April 1, 2005 through April 1, 2008 ((column j÷i)×100) - cycle progress to date

5.2 Budget

UTAH

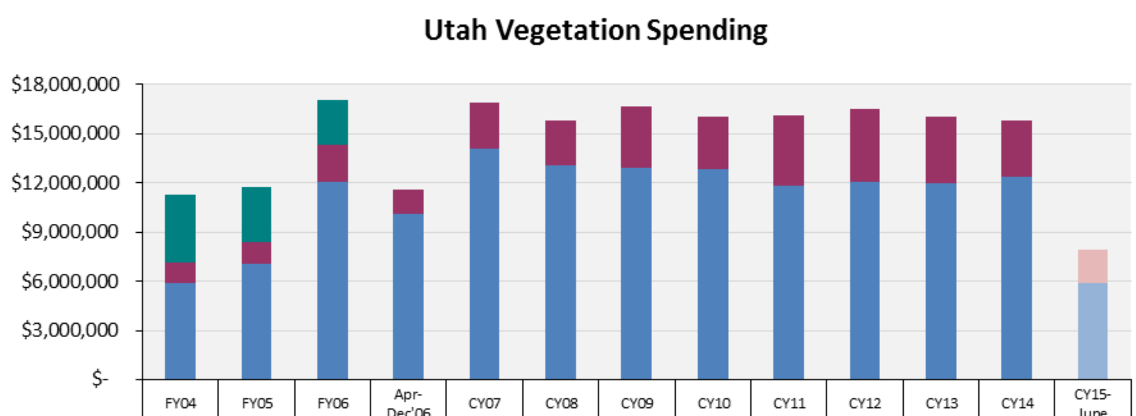
Tree Program Reporting

	CY2016	CY2017	CY2018
Distribution			
Tree Budget	$12,068,854	$12,068,854	$12,068,854
Transmission			
Tree Budget	$3,886,696	$3,886,696	$3,886,696
Total Tree Budget	**$15,955,550**	**$15,955,550**	**$15,955,550**

Calendar year 2015	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Jan	$1,010,180	$992,500	$17,680	$286,010	$323,499	-$37,489
Feb	$841,991	$899,236	-$57,245	$323,296	$292,693	$30,603
Mar	$1,025,831	$1,039,132	-$13,301	$357,325	$338,878	$18,447
Apr	$1,020,727	$1,039,132	-$18,405	$352,993	$338,908	$14,085
May	$1,001,463	$945,868	$55,595	$295,792	$308,097	-$12,305
Jun	$1,025,092	$1,039,132	-$14,040	$405,858	$338,908	$66,950
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	**$5,925,284**	**$5,955,000**	**-$29,716**	**$2,021,274**	**$1,940,983**	**$80,291**

Average # Tree Crews on Property (YTD) **65**

5.2.1 Vegetation Historical Spending



	FY04	FY05	FY06	Apr-Dec'06	CY07	CY08	CY09	CY10	CY11	CY12	CY13	CY14	CY15-June
Miscellaneous	4,127,062	3,306,952	2,666,318										
Transmission	1,235,702	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	2,021,274
Distribution	5,934,507	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	5,925,284

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[11] 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).

$MAIFI_E$

[11] 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.

$MAIFI_E$ (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.

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 and customer requested interruptions.

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.