ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH

SERVICE QUALITY

REVIEW

January 1 – June 30, 2013

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 some cases, Rocky Mountain Power has decided to exceed these industry standards. 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. Many elements of this report were supplemented or modified to reflect changes that occurred in 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 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[2] 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).

$MAIFI_E$
$MAIFI_E$ (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

[2] IEEE 1366-2003 was adopted by the IEEE on December 23, 2003. 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.

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.

<u>Performance Types</u>

Rocky Mountain Power recognizes two categories of performance: underlying performance and major events. Major events represent the atypical, with extraordinary numbers and durations for outages beyond the usual. Ordinary outages are incorporated within underlying performance. These types of events are further defined below.

Major Events

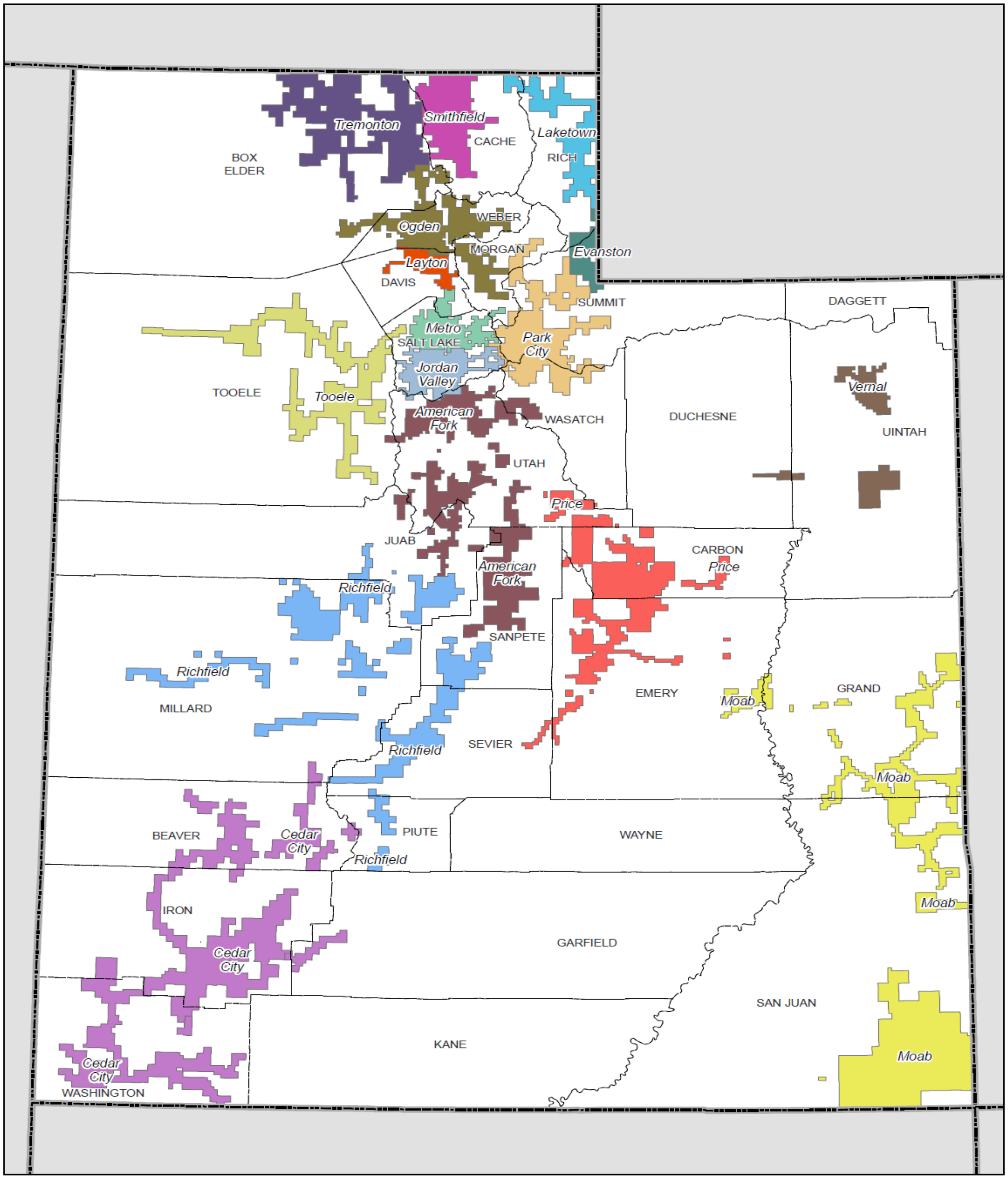
A Major Event is defined as a 24-hour period where SAIDI exceeds a statistically derived threshold value (Reliability Standard IEEE 1366-2012) based on the 2.5 beta methodology. For the time period January 1 through December 31, 2013, the major event threshold calculated is 5,554,098 customer minutes interrupted, calculated using a frozen customer count for the year of 856,927 customers, which equates to 6.48 Utah SAIDI minutes.

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 includes all sustained interruptions, whether of a controllable or non-controllable cause, exclusive of major events, prearranged and customer requested interruptions.

Controllable 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). 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.

1.4 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

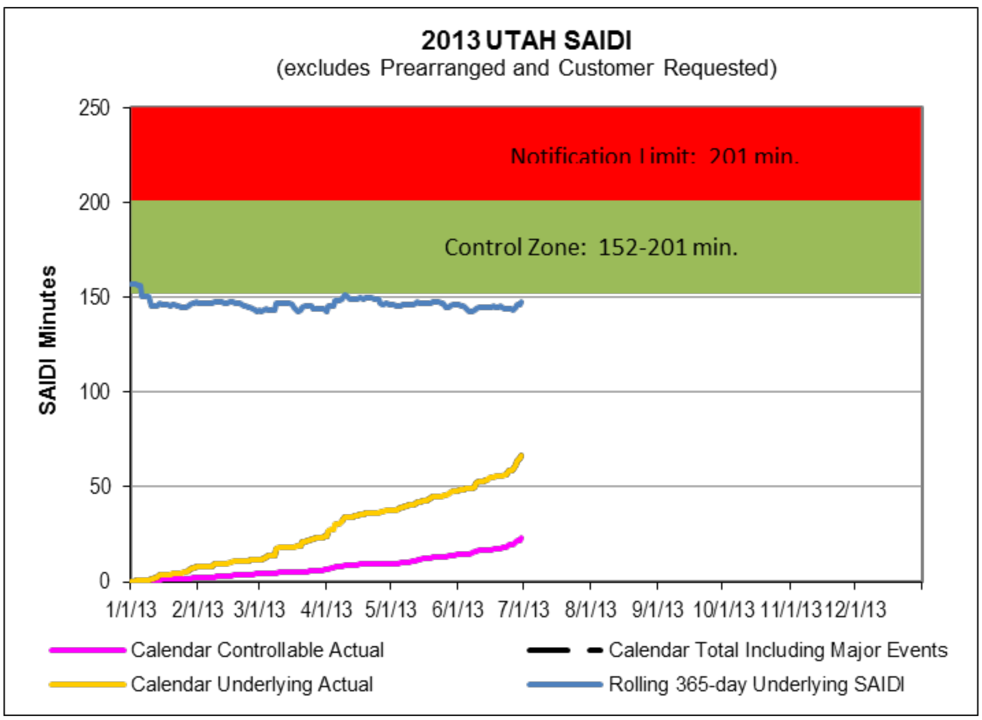
As shown in charts under subsections 2.1 and 2.2 below, the Company's 2013 year to date underlying reliability results continue to demonstrate improvements as measured by both SAIDI and SAIFI. History reflecting these metrics is displayed in Sections 2.3 and 2.4. A newly-added section discussing baselines are contained 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 that is consistent with features proscribed in Utah Title 746.313.

During the semiannual period, there were no major events or significant event days[3] recorded.

2.1 System Average Interruption Duration Index (SAIDI)

UTAH	Semiannual Period	365-day Rolling Year
SAIDI	January 1 through June 30, 2013	July 1, 2012 through June 30, 2013
Total	66	180
Underlying	66	147
Controllable Distribution	23	50

Note: The chart below represents the semiannual period.

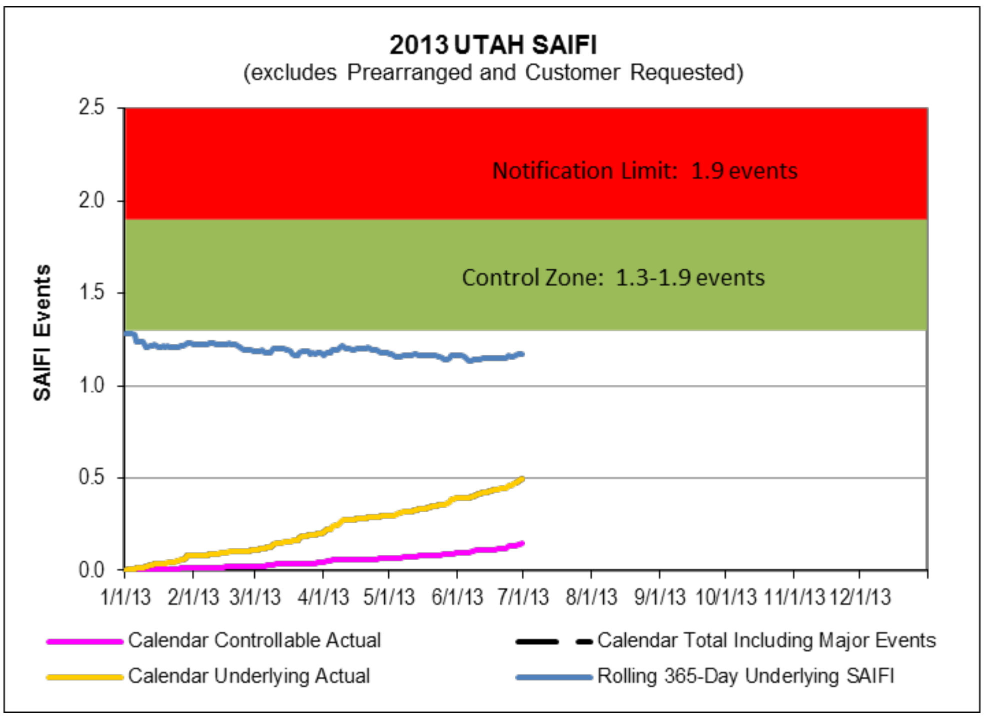


[3] Significant event days are 1.75 times the standard deviation of the company's natural log daily SAIDI results (by state).

2.2 System Average Interruption Frequency Index (SAIFI)

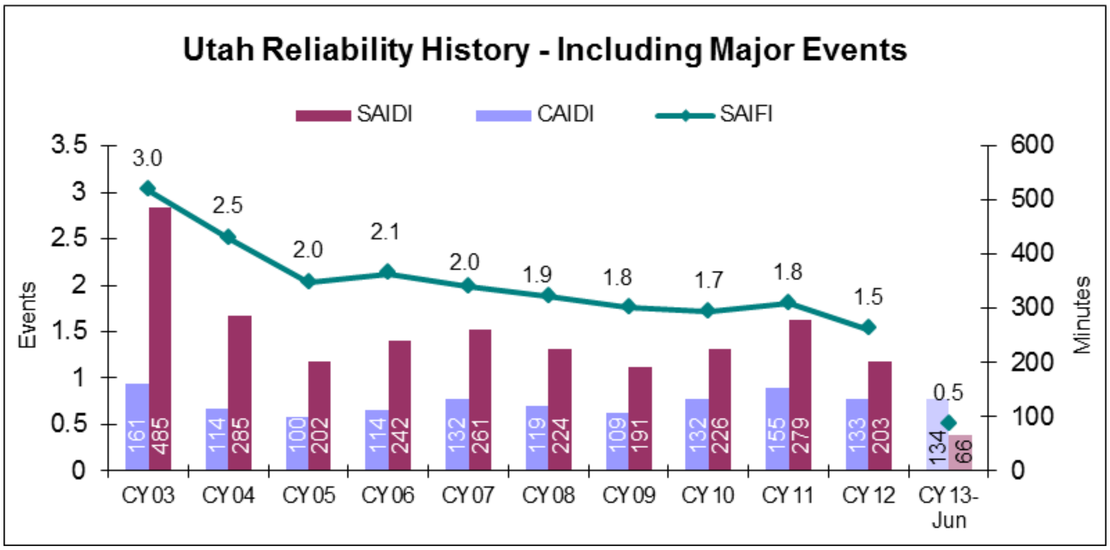
UTAH	Semiannual Period	365-day Rolling Year
SAIFI	January 1 through June 30, 2013	July 1, 2012 through June 30, 2013
Total	0.495	1.328
Underlying	0.495	1.173
Controllable Distribution	0.149	0.305

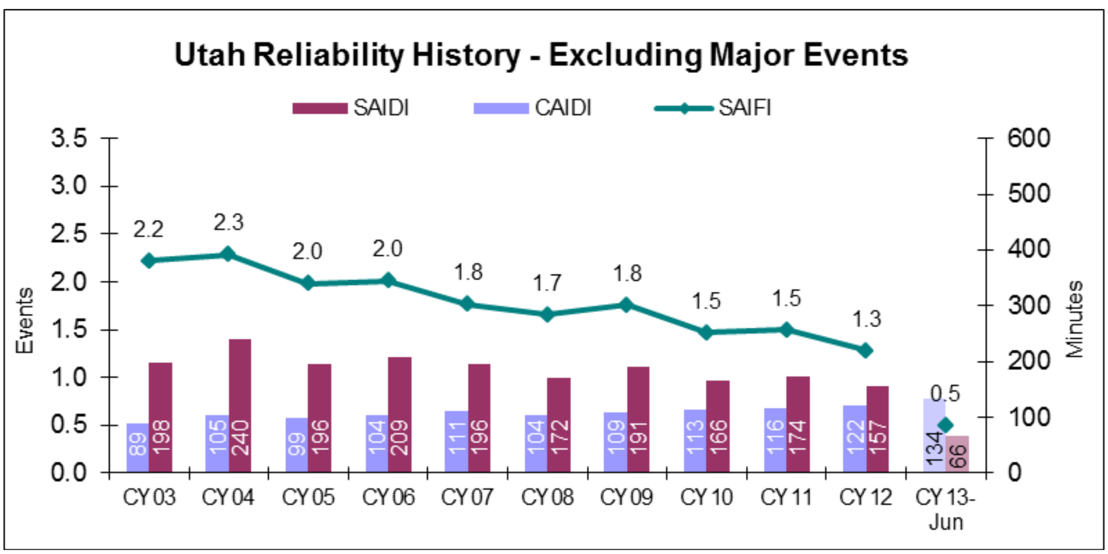
Note: The chart below represents the semiannual period.



2.3 Reliability History

Historically the Company has improved reliability as measured by SAIDI and SAIFI reliability indices; at the same time outage duration excluding major events has eroded slightly. These indices (shown in the history charts below) demonstrate the efficacy of the long-term improvement strategies targeted toward reducing the frequency of interruptions that the company undertook early in the decade. It is particularly noteworthy that these two metrics show improvement for both underlying and major event performance within the state.

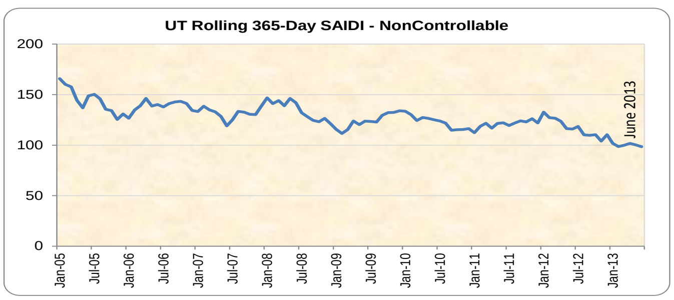


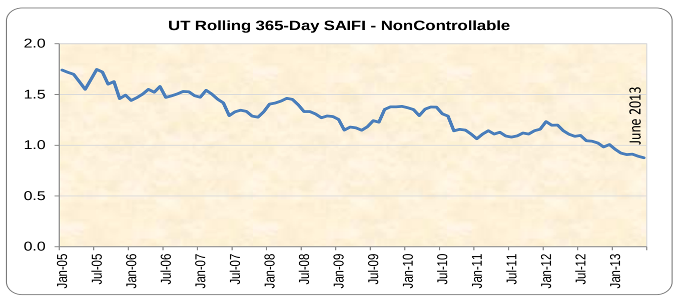


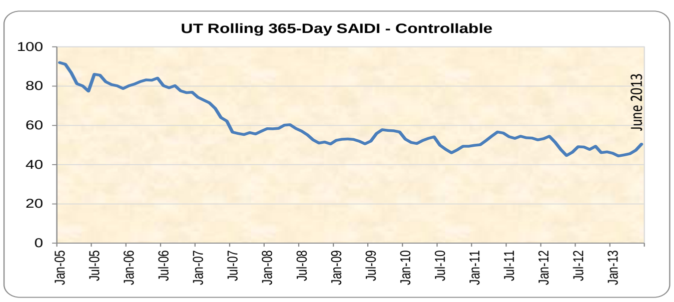
2.4 Controllable, Non-Controllable and Underlying Performance Review

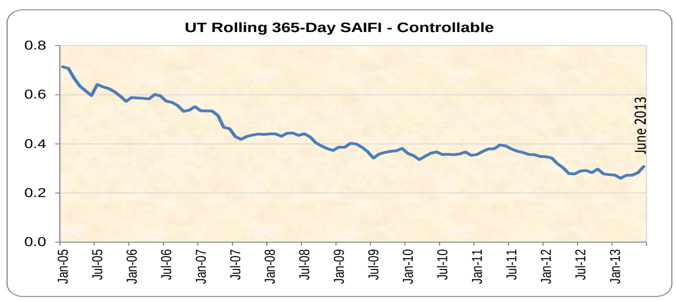
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as deployed by engineering resources. This categorization was titled Controllable Distribution outages and recognizes that certain types of outages can be cost-effectively 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 implement 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].

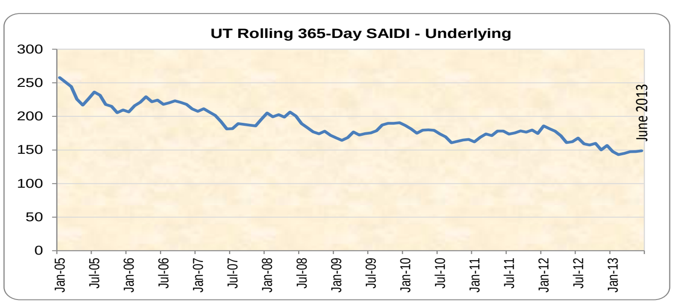
The graphic history demonstrates controllable, non-controllable and underlying performance on a rolling 12-month basis. Analysis of the trends displayed in the charts below shows a general improving trend for all charts. In order to also focus on non-controllable outages, the Company has continued to 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. Further, it has recently deployed a new web-based notification tool for alerting field engineering and operational resources when devices have exceeded performance thresholds. These notifications are conducted regardless of whether the outage cause was controllable or non-controllable.

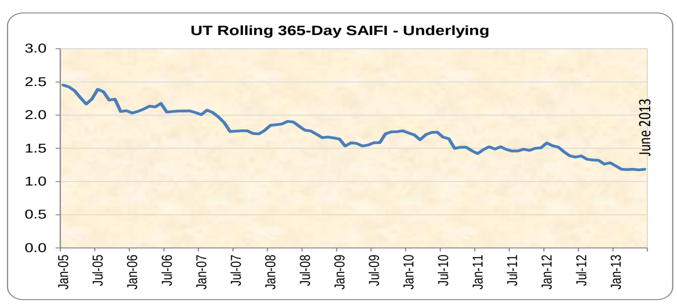












[4] 3. The Company shall provide, as an appendix to its Service Quality Review reports, information regarding non-controllable outages, including, when applicable, descriptions of efforts made by the Company to improve service quality and reliability for causes the Company has identified as not controllable.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

2.5 Cause Analysis Tables

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.

UTAH CAUSE ANALYSIS - CONTROLLABLE					
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	213,398.47	2,062	213	0.25	0.002
BIRD MORTALITY (NON-PROTECTED SPECIES)	307,395.13	4,159	94	0.36	0.005
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	465,357.37	4,459	46	0.54	0.005
BIRD NEST (BMTS)	199,688.65	1,810	26	0.23	0.002
BIRD SUSPECTED, NO MORTALITY	375,545.08	1,974	52	0.44	0.002
ANIMALS	**1,561,384.69**	**14,464**	**431**	**1.82**	**0.017**
B/O EQUIPMENT	2,811,791.42	22,223	357	3.28	0.026
DETERIORATION OR ROTTING	13,807,760.96	67,290	2,473	16.11	0.079
OVERLOAD	564,506.26	5,236	75	0.66	0.006
STRUCTURES, INSULATORS, CONDUCTOR	1,461.82	8	20	0.00	0.000
RELAYS, BREAKERS, SWITCHES	423.00	8	6	0.00	0.000
EQUIPMENT FAILURE	**17,185,943.46**	**94,765**	**2,931**	**20.06**	**0.111**
FAULTY INSTALL	72,089.02	390	21	0.08	0.000
IMPROPER PROTECTIVE COORDINATION	740,038.67	8,415	11	0.86	0.010
INCORRECT RECORDS	22,265.75	338	31	0.03	0.000
PACIFICORP EMPLOYEE - FIELD	281,001.14	6,158	6	0.33	0.007
PACIFICORP EMPLOYEE - SUB	11,567.00	1,345	1	0.01	0.002
OPERATIONAL	**1,126,961.57**	**16,646**	**70**	**1.32**	**0.019**
TREE - TRIMMABLE	143,423.78	1,428	39	0.17	0.002
TREES	144,605.63	1,437	40	**0.17**	**0.002**
UTAH CONTROLLABLE DISTRIBUTION	**20,018,895.35**	**127,312**	**3,472**	**23.36**	**0.149**

[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 856,927 (2013 Utah frozen customer count).

UTAH

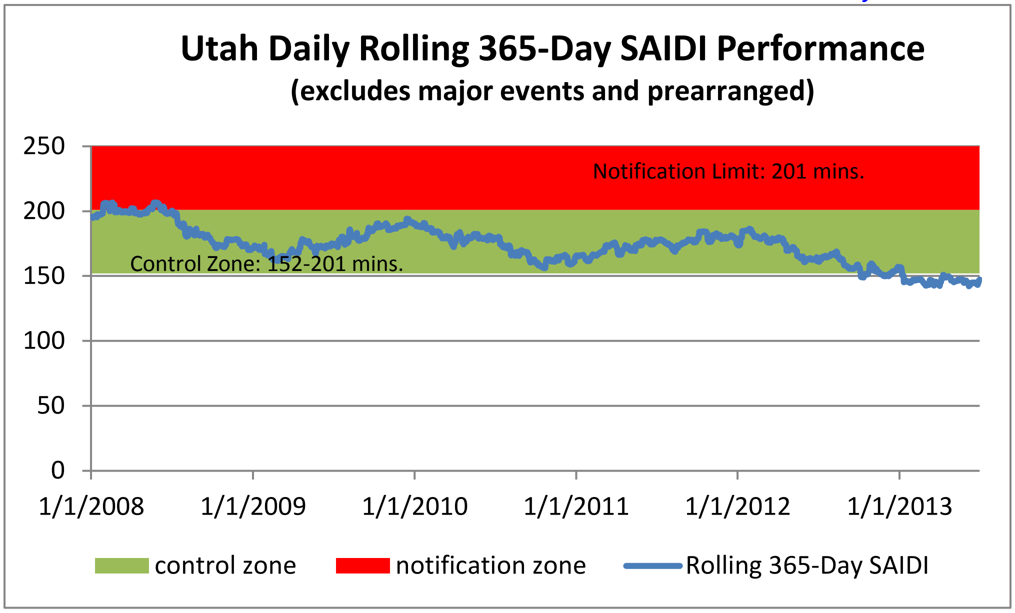
January 1 – June 30, 2013

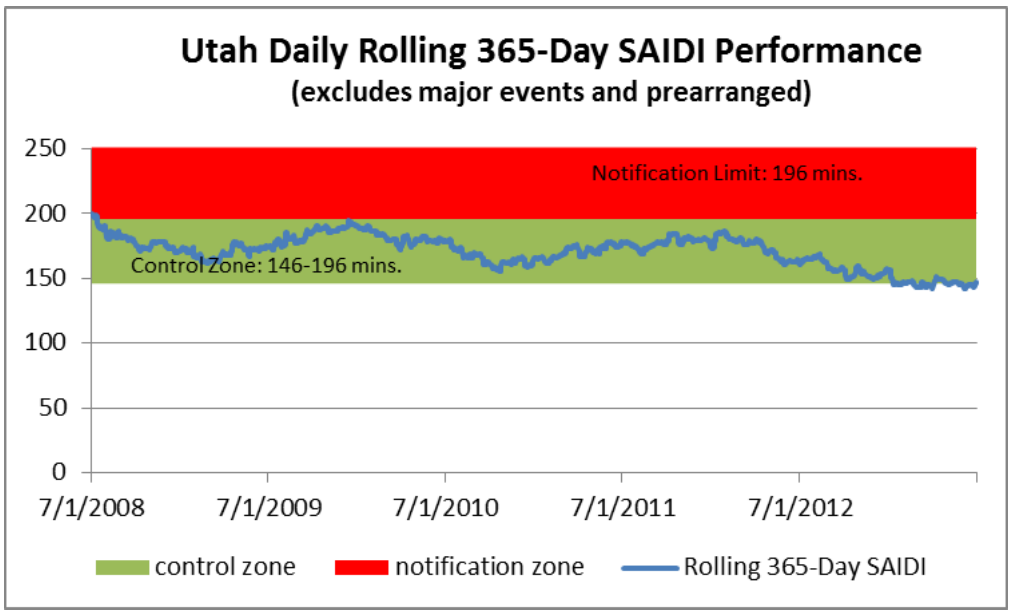
UTAH CAUSE ANALYSIS - UNDERLYING					
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	213,398.47	2,062	213	0.25	0.002
BIRD MORTALITY (NON-PROTECTED SPECIES)	307,395.13	4,159	94	0.36	0.005
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	465,357.37	4,459	46	0.54	0.005
BIRD NEST (BMTS)	199,688.65	1,810	26	0.23	0.002
BIRD SUSPECTED, NO MORTALITY	375,545.08	1,974	52	0.44	0.002
ANIMALS	**1,561,384.69**	**14,464**	**431**	**1.82**	**0.017**
CONDENSATION / MOISTURE	2,447.32	7	1	0.00	0.000
CONTAMINATION	91.60	2	1	0.00	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	33,523.10	118	10	0.04	0.000
FLOODING	247.92	2	2	0.00	0.000
ENVIRONMENT	**36,309.93**	**129**	**14**	**0.04**	**0.000**
B/O EQUIPMENT	2,811,791.42	22,223	357	3.28	0.026
DETERIORATION OR ROTTING	13,807,760.96	67,290	2,473	16.11	0.079
NEARBY FAULT	3,195.69	56	2	0.00	0.000
OVERLOAD	564,506.26	5,236	75	0.66	0.006
POLE FIRE	5,332,379.82	26,594	102	6.22	0.031
STRUCTURES, INSULATORS, CONDUCTOR	1,461.82	8	20	0.00	0.000
RELAYS, BREAKERS, SWITCHES	423.00	8	6	0.00	0.000
EQUIPMENT FAILURE	**22,521,518.97**	**121,415**	**3,035**	**26.28**	**0.142**
DIG-IN (NON-PACIFICORP PERSONNEL)	468,364.44	3,072	108	0.55	0.004
OTHER INTERFERING OBJECT	740,714.21	7,403	43	0.86	0.009
OTHER UTILITY/CONTRACTOR	455,331.48	3,920	44	0.53	0.005
VANDALISM OR THEFT	35,162.72	201	12	0.04	0.000
VEHICLE ACCIDENT	4,266,577.66	22,954	181	4.98	0.027
INTERFERENCE	**5,966,150.50**	**37,550**	**388**	**6.96**	**0.044**
FAILURE ON OTHER LINE OR STATION	0.00	0	2	0.00	0.000
LOSS OF FEED FROM SUPPLIER	13,866.10	113	6	0.02	0.000
LOSS OF SUBSTATION	1,474,317.02	10,591	36	1.72	0.012
LOSS OF TRANSMISSION LINE	4,442,380.61	42,950	105	5.18	0.050
SYSTEM PROTECTION	83.00	1	1	0.00	0.000
LOSS OF SUPPLY	**5,930,646.73**	**53,655**	**150**	**6.92**	**0.063**
FAULTY INSTALL	72,089.02	390	21	0.08	0.000
IMPROPER PROTECTIVE COORDINATION	740,038.67	8,415	11	0.86	0.010
INCORRECT RECORDS	22,265.75	338	31	0.03	0.000
PACIFICORP EMPLOYEE - FIELD	281,001.14	6,158	6	0.33	0.007
PACIFICORP EMPLOYEE - SUB	11,567.00	1,345	1	0.01	0.002
UNSAFE SITUATION	103.27	1	1	0.00	0.000
OPERATIONAL	**1,127,064.84**	**16,647**	**71**	**1.32**	**0.019**
OTHER, KNOWN CAUSE	133,975.02	1,902	57	0.16	0.002
UNKNOWN	2,947,200.72	31,200	532	3.44	0.036
OTHER	**3,081,175.73**	**33,102**	**589**	**3.60**	**0.039**
CONSTRUCTION	523,908.26	7,647	210	0.61	0.009
CONSTRUCTION SCHEDULED SWITCHING	271,103.50	42	108	0.32	0.000
CUSTOMER NOTICE GIVEN	6,168,288.80	34,448	1,279	7.20	0.040
CUSTOMER REQUESTED	94,991.46	934	427	0.11	0.001
EMERGENCY DAMAGE REPAIR	7,447,580.67	95,410	785	8.69	0.111
INTENTIONAL TO CLEAR TROUBLE	113,875.90	2,060	33	0.13	0.002
TRANSMISSION REQUESTED	347,109.68	2,408	7	0.41	0.003
PLANNED	**14,966,858.28**	**142,949**	**2,849**	**17.47**	**0.167**
TREE - NON-PREVENTABLE	2,078,013.81	11,141	190	2.42	0.013
TREE - TRIMMABLE	144,605.63	1,437	40	0.17	0.002
TREES	**2,222,619.44**	**12,578**	**230**	**2.59**	**0.015**
FREEZING FOG & FROST	9,957.88	13	5	0.01	0.000
ICE	22,776.80	118	28	0.03	0.000
LIGHTNING	298,796.53	4,869	49	0.35	0.006
SNOW, SLEET AND BLIZZARD	3,547,884.67	9,497	118	4.14	0.011
WIND	2,084,565.21	12,894	146	2.43	0.015
WEATHER	**5,963,981.09**	**27,391**	**346**	**6.96**	**0.032**
UTAH - INCLUDING PREARRANGED	**63,377,710.19**	**459,880**	**8,103**	**73.96**	**0.537**
UTAH - UNDERLYING DISTRIBUTION	**56,843,326.43**	**424,456**	**6,289**	**66.33**	**0.495**

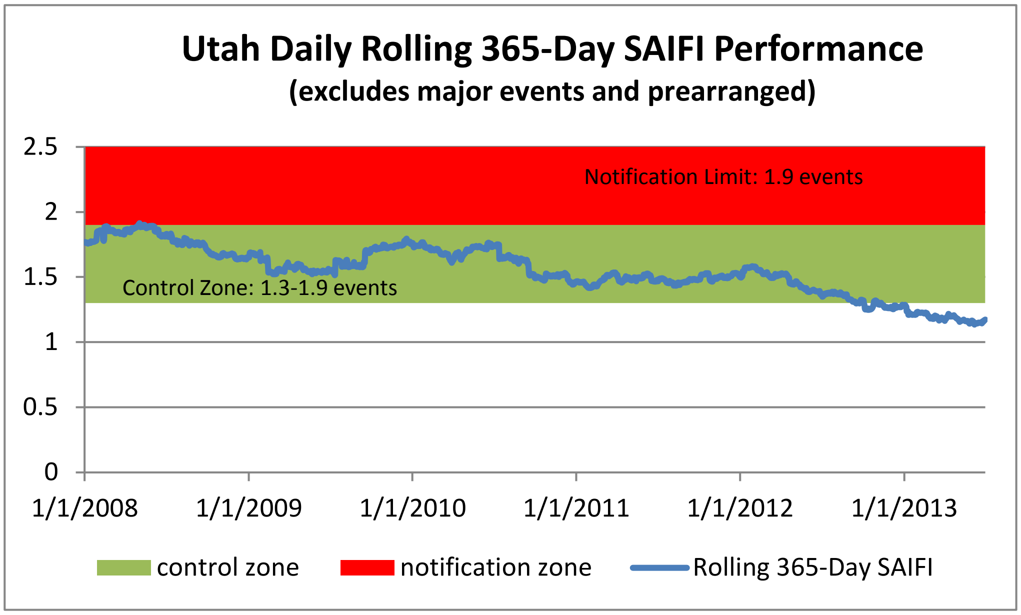
2.6 Baseline Performance

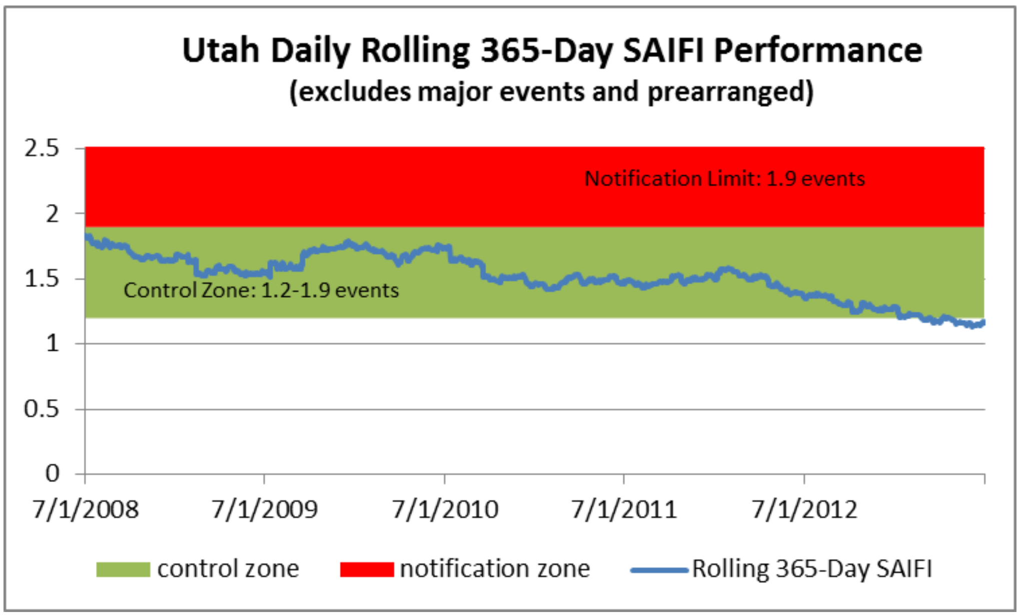
In compliance with Utah Reliability Reporting Rules, the Company developed performance baselines that it subsequently filed for approval (based on 2008-2012 history). These baselines were approved, but stakeholders advocated annually refreshing baseline levels using the methods that resulted in the approved baselines; refreshing through June 30, 2013 yields the values shown below. 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% confidence interval and resulted in a SAIDI range of 152-201 minutes and a SAIFI range of 1.3-1.9 events. The same methods applied with the most recent six months of performance result in an average of 171 minutes and 1.52 events, with a SAIDI range of 146-196 minutes and a SAIFI range of 1.2-1.9 events. These values are shown in the table below.

Baseline	As Filed (history through December 31, 2012)			Current Period (through June 30, 2013)		
	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	171 minutes	146 minutes	196 minutes
SAIFI	1.59 events	1.3 events	1.9 events	1.52 events	1.2 events	1.9 events


Utah Daily Rolling 365-Day SAIDI Performance
(excludes major events and prearranged)
Notification Limit: 201 mins.
Control Zone: 152-201 mins.
250
200
150
100
50
0
1/1/2008
1/1/2009
1/1/2010
1/1/2011
1/1/2012
1/1/2013
control zone
notification zone
Rolling 365-Day SAIDI


Utah Daily Rolling 365-Day SAIDI Performance
(excludes major events and prearranged)
Notification Limit: 196 mins.
Control Zone: 146-196 mins.
250
200
150
100
50
0
7/1/2008
7/1/2009
7/1/2010
7/1/2011
7/1/2012
control zone
notification zone
Rolling 365-Day SAIDI


Utah Daily Rolling 365-Day SAIFI Performance
(excludes major events and prearranged)
Notification Limit: 1.9 events
Control Zone: 1.3-1.9 events
2.5
2
1.5
1
0.5
0
1/1/2008
1/1/2009
1/1/2010
1/1/2011
1/1/2012
1/1/2013
control zone
notification zone
Rolling 365-Day SAIFI


Utah Daily Rolling 365-Day SAIFI Performance
(excludes major events and prearranged)
Notification Limit: 1.9 events
Control Zone: 1.2-1.9 events
2.5
2
1.5
1
0.5
0
7/1/2008
7/1/2009
7/1/2010
7/1/2011
7/1/2012
control zone
notification zone
Rolling 365-Day SAIFI

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

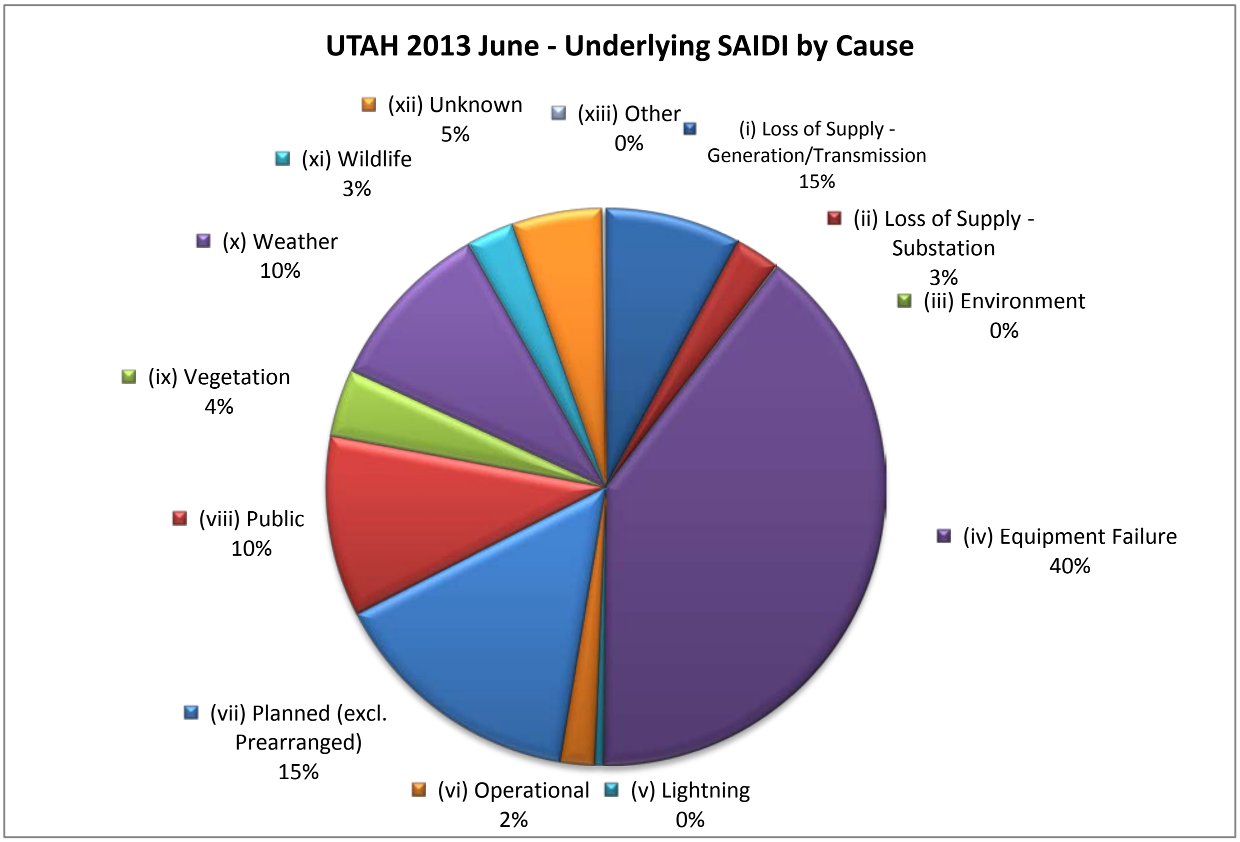
In 2012 the Company and stakeholders developed reliability reporting rules that are codified in Utah Rule R 746.313. Certain reliability reporting details were outlined in these rules that had not been previously required in the Company's Service Quality Review Report. Certain elements may be at least partially redundant or segmented differently than has been provided in the past. Thus, in order to include both the new required segmentation and the pre-reporting rule segmentation was considered the ideal reporting approach. As this report evolves, certain of these redundancies may be eliminated.

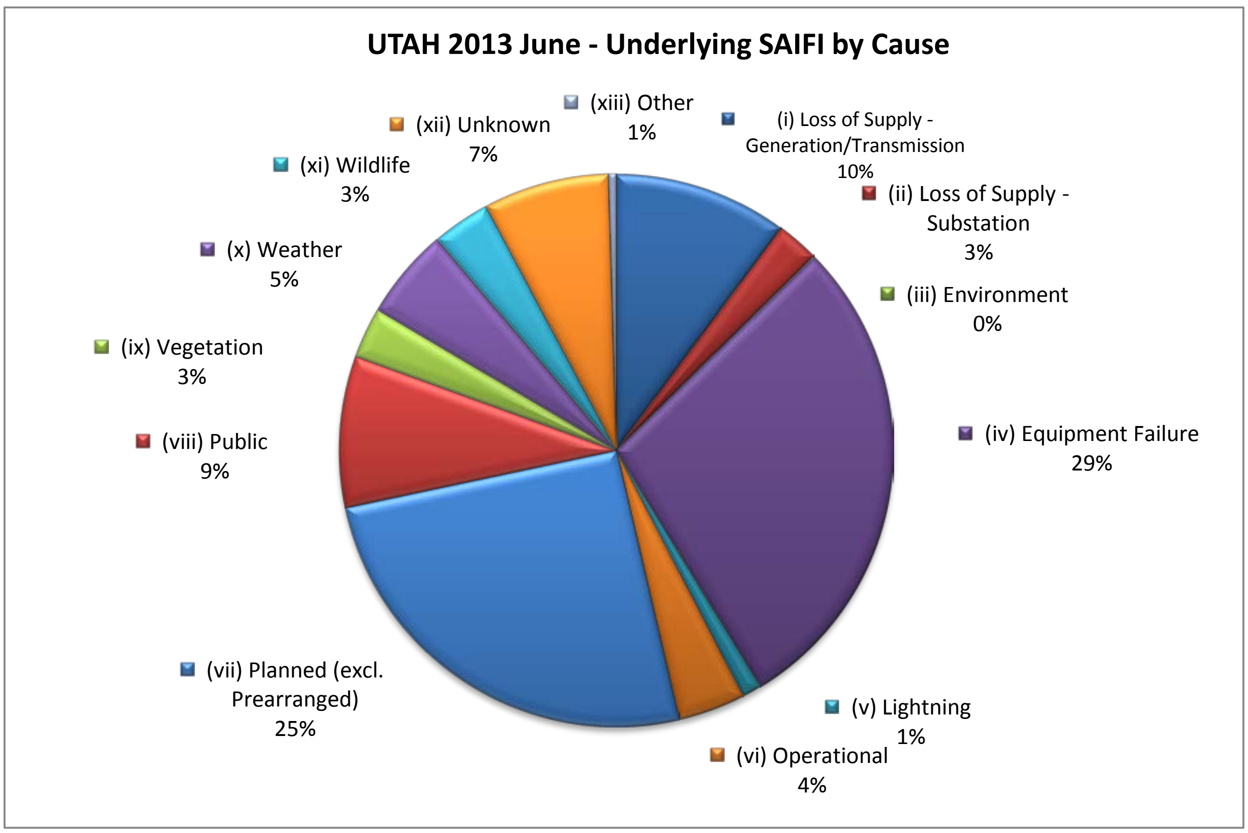
The final rule required five year history at an operating area level of SAIDI, SAIFI and CAIDI. At a state level these metrics, in addition to $MAIFI_{e,}$ are required.

Major Events and Prearranged Excluded*	2008				2009				2010				2011				2012				2013-June			
STATE	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe	SAIDI	SAIFI	CAIDI	MAIFIe
Utah	172	1.7	104	2.31	191	1.8	108	1.70	166	1.5	113	1.33	174	1.5	116	1.10	157	1.3	122	0.72	66	0.5	134	0.32
OP AREA																								
AMERICAN FORK	148	1.4	107		130	1.5	87		148	1.2	124		132	1.3	106		101	0.8	135		26	0.3	79	
CEDAR CITY	267	2.7	100		219	2.3	97		296	2.5	118		218	1.7	131		279	1.8	154		78	0.4	183	
CEDAR CITY (MILFORD)	1,129	5.7	199		590	5.4	110		389	2.1	183		980	8.1	121		363	2.8	129		160	0.9	171	
JORDAN VALLEY	142	1.3	106		146	1.2	120		112	1.0	116		113	0.9	121		106	0.8	129		42	0.3	143	
LAYTON	93	1.1	89		135	1.0	130		151	1.1	142		155	1.3	124		105	0.8	131		52	0.5	108	
MOAB	215	2.5	85		526	5.2	101		286	2.6	111		151	1.8	86		375	3.1	122		102	0.6	166	
OGDEN	209	2.1	101		208	2.8	74		171	1.8	96		204	1.8	116		153	1.3	117		66	0.5	137	
PARK CITY	220	2.2	99		327	2.4	137		251	2.2	116		186	1.6	116		184	1.8	100		113	0.5	212	
PRICE	243	3.9	62		218	2.3	94		505	3.4	150		421	2.5	166		133	1.4	97		141	0.4	402	
RICHFIELD	258	2.2	119		224	1.5	151		255	2.9	87		369	3.2	114		200	2.0	100		291	1.5	194	
RICHFIELD (DELTA)	285	3.0	95		400	5.8	69		189	2.5	76		316	3.6	89		329	2.9	113		149	2.5	59	
SLC METRO	164	1.5	107		165	1.4	116		144	1.3	107		178	1.5	117		129	1.2	112		78	0.6	122	
SMITHFIELD	172	1.5	116		277	2.1	134		229	1.7	135		174	1.6	106		267	2.6	102		67	0.4	155	
TOOELE	263	2.5	107		438	3.8	116		178	1.3	134		329	3.0	110		595	3.7	163		60	0.4	158	
TREMONTON	259	2.5	103		561	2.6	214		346	3.4	102		255	2.2	115		447	3.0	147		117	1.5	76	
VERNAL	70	0.9	80		116	0.7	156		105	0.9	115		117	2.2	54		236	2.9	82		28	0.4	69	

* except MAIFIe

Utah Cause Category	2008		2009		2010		2011		2012		2013- June	
	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI
Environment	0	0.0	0	0.0	1	0.0	0	0.0	4	0.0	0	0.0
Equipment Failure	55	0.4	59	0.4	53	0.3	52	0.3	53	0.3	26	0.1
Lightning	3	0.0	10	0.1	7	0.1	9	0.1	4	0.0	0	0.0
Loss of Supply - Generation/Transmission	29	0.3	28	0.4	21	0.3	26	0.3	25	0.3	5	0.1
Loss of Supply - Substation	6	0.0	10	0.1	7	0.1	6	0.1	5	0.1	2	0.0
Operational	1	0.0	1	0.0	1	0.0	1	0.0	0	0.0	1	0.0
Other	0	0.0	0	0.0	0	0.0	1	0.0	0	0.0	0	0.0
Planned (excl. Prearranged)	22	0.4	24	0.3	17	0.3	23	0.3	22	0.3	10	0.1
Public	20	0.1	16	0.1	15	0.1	15	0.1	16	0.1	7	0.0
Unknown	10	0.2	8	0.1	10	0.1	7	0.1	7	0.1	3	0.0
Vegetation	8	0.0	10	0.1	10	0.1	13	0.1	5	0.1	3	0.0
Weather	13	0.1	22	0.2	21	0.1	19	0.1	11	0.1	7	0.0
Wildlife	3	0.0	4	0.0	4	0.0	4	0.0	4	0.0	2	0.0
UTAH Underlying	**172**	**1.7**	**191**	**1.8**	**166**	**1.5**	**174**	**1.5**	**157**	**1.3**	**66**	**0.5**


UTAH 2013 June - Underlying SAIDI by Cause
(xii) Unknown 5%
(xiii) Other 0%
(i) Loss of Supply - Generation/Transmission 15%
(xi) Wildlife 3%
(ii) Loss of Supply - Substation 3%
(x) Weather 10%
(iii) Environment 0%
(ix) Vegetation 4%
(viii) Public 10%
(iv) Equipment Failure 40%
(vii) Planned (excl. Prearranged) 15%
(vi) Operational 2%
(v) Lightning 0%


UTAH 2013 June - Underlying SAIFI by Cause
(xiii) Other 1%
(xii) Unknown 7%
(i) Loss of Supply - Generation/Transmission 10%
(xi) Wildlife 3%
(ii) Loss of Supply - Substation 3%
(x) Weather 5%
(iii) Environment 0%
(ix) Vegetation 3%
(viii) Public 9%
(iv) Equipment Failure 29%
(vii) Planned (excl. Prearranged) 25%
(v) Lightning 1%
(vi) Operational 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). Annually the company will update the history of all circuits improved as part of the Worst Performing Circuits program.

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 6/30/2013
Program Year 13: (CY2012)			
Fielding 11	IN PROGRESS	264	259
East Bench 12	IN PROGRESS	263	226
Clinton 11	IN PROGRESS	143	139
Redwood 16	IN PROGRESS	182	214
Orangeville 11	IN PROGRESS	190	143
TARGET SCORE = **166**		208	**196**
Program Year 12: (CY2011)			
Lincoln 15	IN PROGRESS	192	112
Huntington City 12	IN PROGRESS	371	466
Magna 15	IN PROGRESS	233	175
Gunnison 12	IN PROGRESS	246	270
Capitol 11	IN PROGRESS	143	110
TARGET SCORE = **190**		**237**	**227**
Program Year 11: (CY2010)			
Decker Lake 12	IN PROGRESS	112	234
North Bench 13	IN PROGRESS	105	63
Newgate 14	IN PROGRESS	178	106
Newton 12	IN PROGRESS	194	137
St Johns 11	IN PROGRESS	755	673
TARGET SCORE = **215**		**269**	**242**

Note: Goals were met for Program Years 1 through 10 and filed in prior reporting periods.

2.9 CAIDI Performance

The table below shows the average time, during the reporting period, for outage restoration. This replaces previous reporting for the percent of customers whose power was restored within 3 hours of notification of an outage event, and transitions the Company's outage response reporting toward industry indices.

UTAH CAIDI (Average Outage Duration)	
Underlying Performance	134 minutes
Total Performance	134 minutes

2.10 Telephone Service and Response to Commission Complaints

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

[6] 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).

2.11 Utah State Customer Guarantee Summary Status

customer*guarantees*

January to June 2013

Utah

		2013				2012			
	Description	Events	Failures	%Success	Paid	Events	Failures	%Success	Paid
CG1	Restoring Supply	421,659	0	100%	$0	503,078	0	100%	$0
CG2	Appointments	3,269	3	99.9%	$150	3,381	9	99.7%	$450
CG3	Switching on Power	5,287	2	99.9%	$100	5,318	4	99.9%	$200
CG4	Estimates	682	2	99.7%	$100	806	0	100%	$0
CG5	Respond to Billing Inquiries	808	1	99.9%	$50	803	0	100%	$0
CG6	Respond to Meter Problems	429	0	100%	$0	272	0	100%	$0
CG7	Notification of Planned Interruptions	34,448	30	99.9%	$1,500	31,598	30	99.9%	$1,500
		466,582	**38**	**99.9%**	**$1,900**	**545,256**	**43**	**99.9%**	**$2,150**

Overall Customer Guarantee performance remains above 99%, demonstrating Rocky Mountain Power's continued commitment to customer satisfaction.

One reconnect for credit that had been disconnected for non-payment was not reconnected within twenty-four hours and is not included in the above numbers. (Credit customers are exempt from Customer Guarantee 3; however, the Company attempts to connect these customers within twenty-four hours and reports them separately in this report.)

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[7], 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. Certain of these activities were initiated during 2012 which resulted in lower costs for maintenance work items that were delivered.

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 padmounted distribution equipment.[8]
- 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

- 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.

[7] 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.

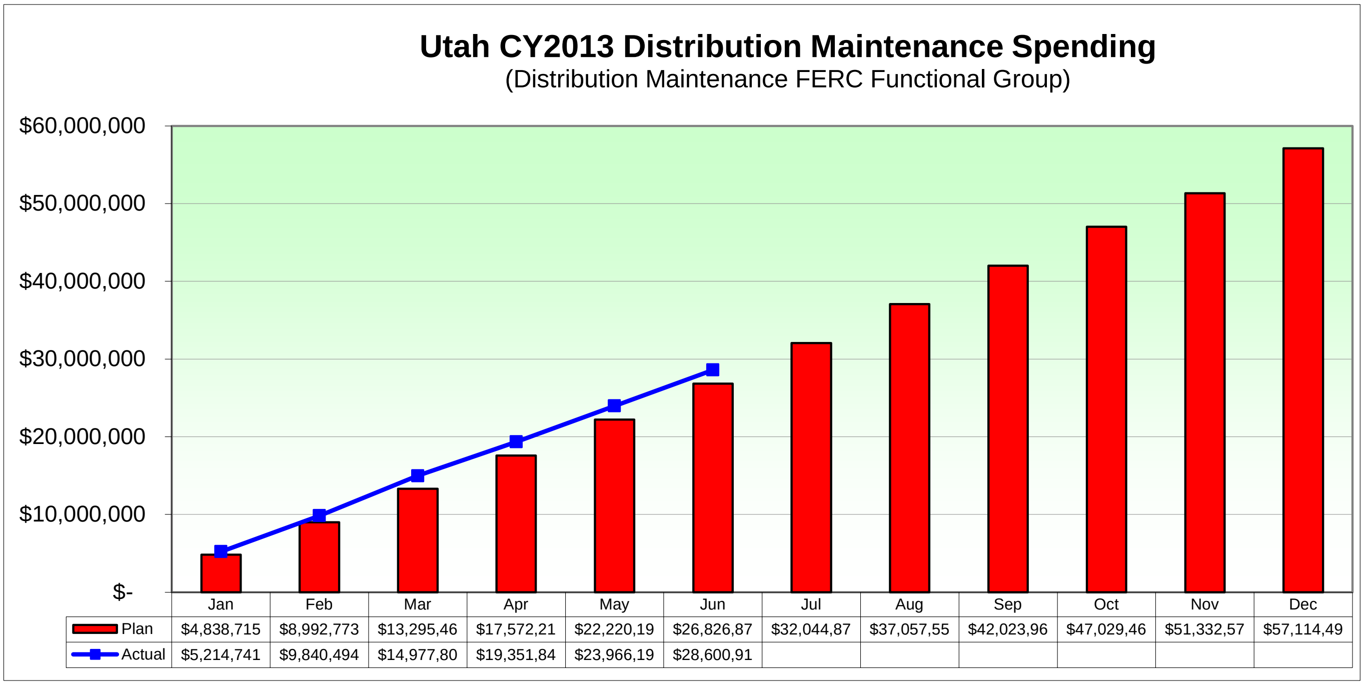
Priority B: Conditions that are nonconforming, but that in the opinion of the inspector do not pose a hazard.

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.

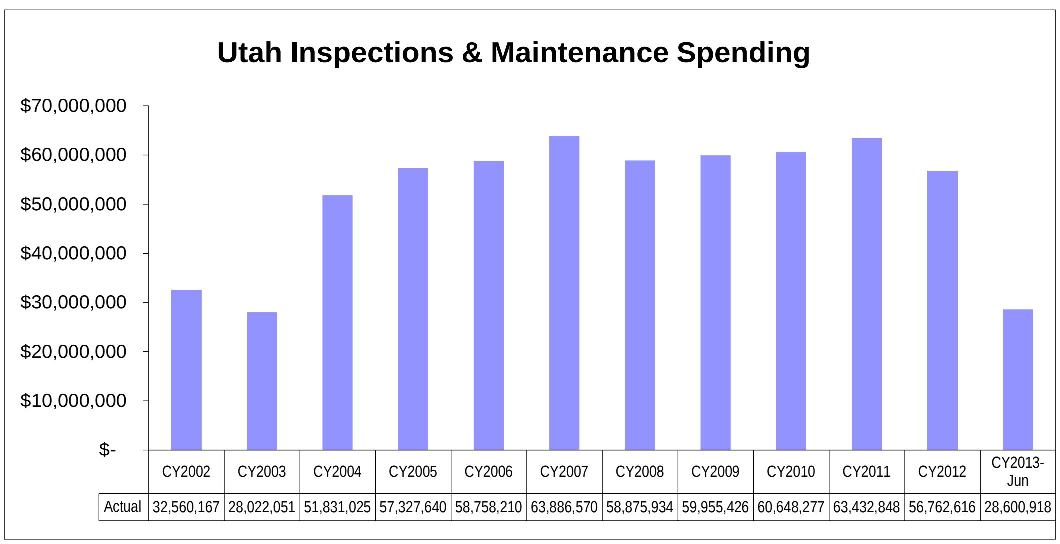
Priority D: Conditions that conform to the NESC and are not reportable to the associated State Commission. Priority G: Conditions that conform to the regulations requirement that was in place when construction took place but do not conform to more recent code adoptions. These conditions are "grandfathered"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

[8] 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.

3.2 Maintenance Spending

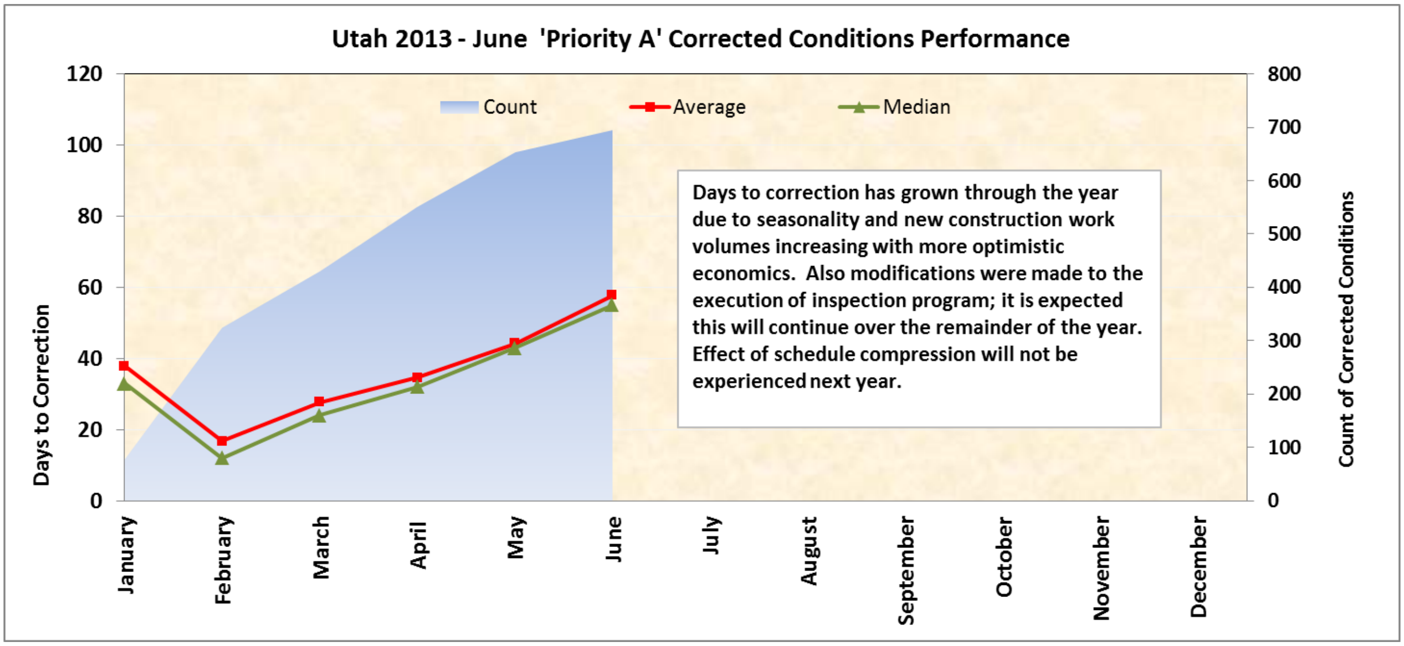


3.2.1 Maintenance Historical Spending



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, performance well below the target average of 120 days has been consistently delivered, however as noted it has grown with the changes in new construction activities and with adjustments to the execution of the inspection program.



In its July 10, 2013 correspondence in the matter Docket No. 13-035-70, "In the Matter of Rocky Mountain Power's Service Quality Review Report" the Company was directed to list the longest five A priority conditions as of the report date[9]. Below is the information that was contained in the Facility Point Inspection (FPI) system as of the end of June.

TYPE	Map String/High Level Name	Facility Point/Low Level Name	Structure Type	Priority	Condition	Remark	Inspection Date	Number of Days	Corrected Date	Days Upon Correction	COMMENTS
DETAIL	'082104	'501 '	OHTRANS	A	BOPOLE	POLE IS SPLIT; REPLACE	9/19/2012	414	6/24/2013	278	Condition corrected - replaced 6/24/2013 w/o 5720642
DETAIL	'11319001.0	'265700	OHDIST	A	BOXARM	REPLACE HEAVY ANGLE XARM_16071057	1/18/2013	293	8/1/2013	195	Condition corrected - replaced 8/1/2013 w/o 16071057
DETAIL	'11329003.0	'325200	OHDIST	A	BOXARM	REPLACE XARM W/O 16068311	1/18/2013	293	7/10/2013	173	Condition corrected - replaced 07/10/2013 w/o 1606831
DETAIL	'11403001.0	'221806	OHDIST	A	BORISER	CLIMBABLE RISER - CUSTOMER FENCE_16074015	2/5/2013	275	8/20/2013	196	Condition corrected - Replaced 8/20/2013 w/o 16074015
SAFETY	'11403001.0	'329500	OHDIST	A	BORISER	CLIMBABLE RISER - POWER_16073992	2/5/2013	275	8/20/2013	196	Condition corrected - Replaced 8/20/2013 w/o 16073992

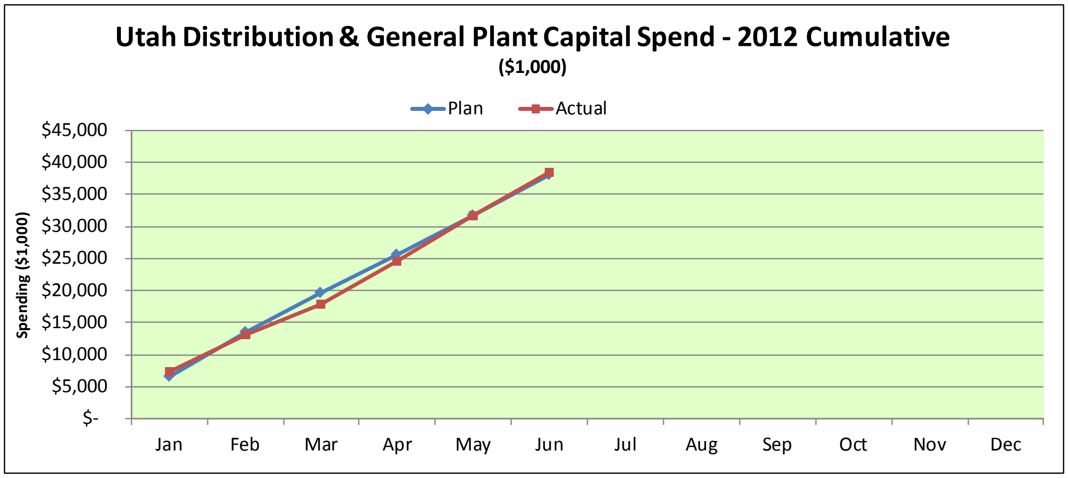
[9] The company was requested to provide the number of A priorities as of report date, which tally 2,227 conditions. This excludes those conditions that are the responsibility of joint pole users.

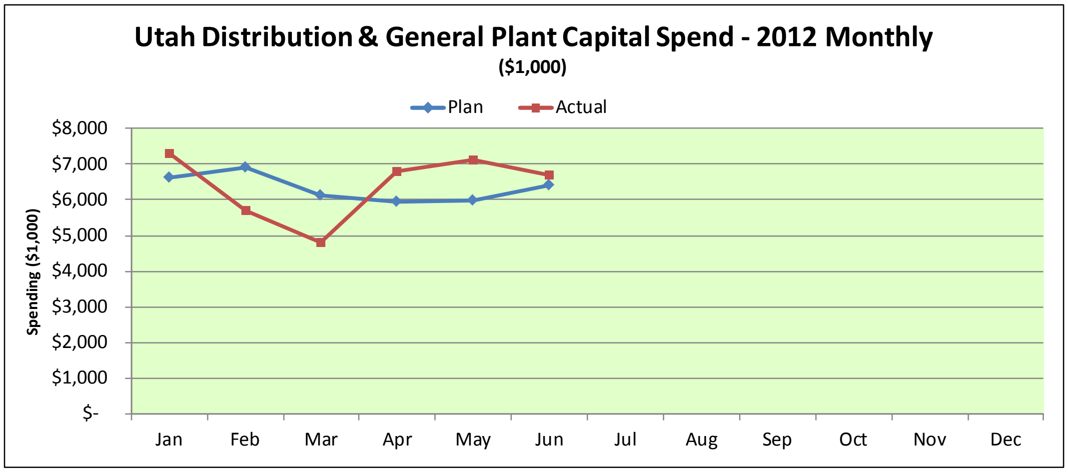
4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

Utah Capital Spending*
January - June 2013
Distribution and General Plant

Investment	Actuals ($M)	Plan ($M)	Significant Variances
1. Mandated	$3.4	$4.1	Mandated environmental/avian protection under plan, (-$0.4M).
2. New Connects	$16.6	$16.4	Industrial new connections over plan, (+$1.7M); commercial new connections under plan, (-$1.2M).
3. System Reinforcement	$5.0	$5.4	Substation reinforcement under plan, (+$1.2M); feeder and subtransmission reinforcement over plan, (+0.7M).
4. Replacements	$13.1	$11.5	Replacements for substation transformers, microwave/fiber communications, and substation bushings/glass/etc over plan, (+$3.2M); storm & casualty, overhead distribution poles and distribution lines/other under plan, (-$1.9M).
5. Upgrade & Modernize	$0.3	$0.6	
Total	**$38.4**	**$38.0**	



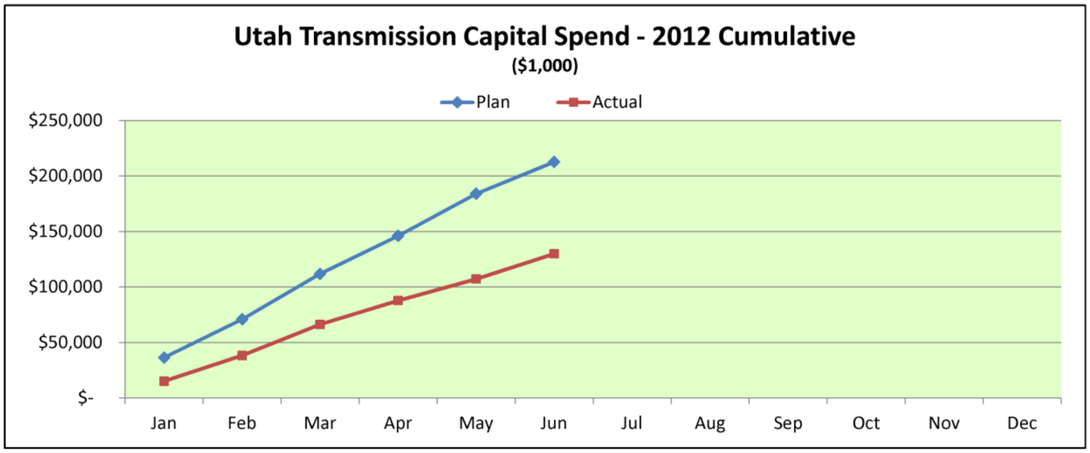


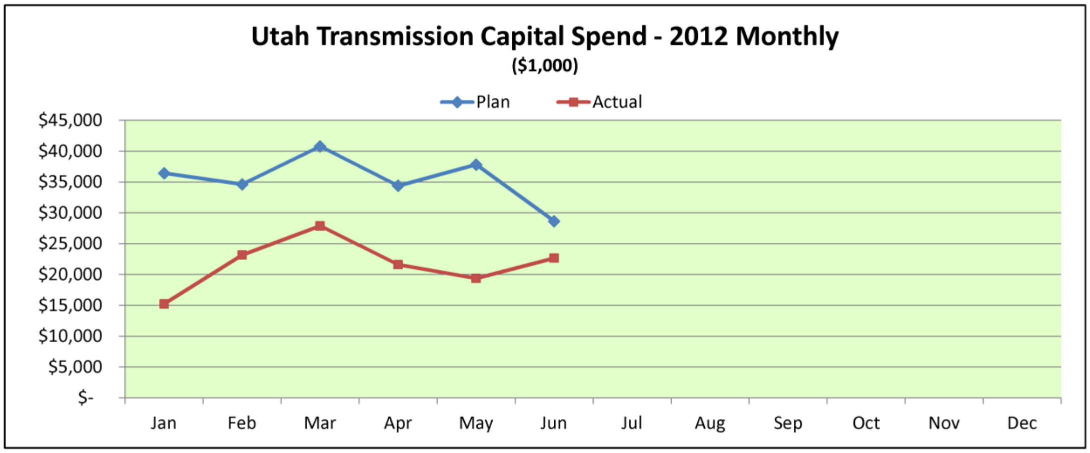
* Actual costs shown are expenditure values, not plant placed in service (PPIS) values. Actual expenditures are not directly tied to PPIS values.

4.2 Capital Spending - Transmission

Utah Capital Spending*
January - June 2013
Transmission

Investment	Actuals ($M)	Plan ($M)	Significant Variances
1. Mandated	4.9	9.2	Mandated NERC reliability (non-conforming code issues) and road relocations under plan, (-$5.5M); mandated right of way renewals and environmental/avian protection over plan, (+$1.2M).
2. New Connects	0.0	0.8	Industrial new connections under plan, (-$0.7M).
3. Local Transmission System Reinforcements	8.4	11.2	Local subtransmission reinforcement under plan (-$3.3M).
# Main Grid Reinforcements / Interconnections	26.4	48.3	Lake Side 2 Interconnect Q0301 (-9.3M), Black Rock Sub (-$4.1M), Mona Sub Series Reactor (-$4.0M), TSR Q1256 Lakeside II Transmission Svc (-$2.5M), Pinto 3rd Ph Shifting Transformer (-$2.0M) under plan.
**5. Energy Gateway Transmission	87.2	138.0	Mona-Oquirrh Line (-$29.4M), Sigurd Red Butte Crystal Line (-$14.1M), Clover Sub & Lines (-$5.7M) under plan.
6. Replacements	3.1	5.2	Replacements for overhead transmission poles, meters & relays, storm & casualty, and substation switchgear/breakers/reclosers under plan, (-3.1M); substation transformer replacements over plan, (+1.4M).
7. Upgrade & Modernize	0.0	0.0	
Total	**130.0**	**212.7**	





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

4.3 New Connects

	2012	2013								
	Jan - Dec 2012	Jan	Feb	Mar	Q1 Total	Apr	May	Jun	Q2 Total	Jan - Jun 2013
Residential										
UT South	605	36	48	43	127	59	75	50	184	311
UT North/Metro	3,672	395	316	310	1,021	528	366	303	1,197	2,218
UT Central	4,606	381	290	416	1,087	515	499	392	1,406	2,493
Total Residential	**8,883**	**812**	**654**	**769**	**2,235**	**1,102**	**940**	**745**	**2,787**	**5,022**
					-				-	-
Commercial					-				-	-
UT South	195	15	11	22	48	30	23	26	79	127
UT North/Metro	845	53	33	34	120	49	95	60	204	324
UT Central	838	50	41	55	146	63	119	108	290	436
Total Commercial	**1,878**	**118**	**85**	**111**	**314**	**142**	**237**	**194**	**573**	**887**
					-				-	-
Industrial					-				-	-
UT South	2	-	-	-	-	-	1	-	1	1
UT North/Metro	5	1	-	-	1	-	-	-	-	1
UT Central	-	1	-	-	1	-	-	-	-	1
Total Industrial	**7**	**2**	**-**	**-**	**2**	**-**	**1**	**-**	**1**	**3**
					-				-	-
Irrigation					-				-	-
UT South	56	1	2	10	13	11	13	6	30	43
UT North/Metro	6	-	-	-	-	-	1	1	2	2
UT Central	28	1	1	2	4	1	2	1	4	8
Total Irrigation	**90**	**2**	**3**	**12**	**17**	**12**	**16**	**8**	**36**	**53**
					-				-	-
TOTAL New Connects					-				-	-
UT South	856	52	61	75	188	100	111	82	293	481
UT North/Metro	4,523	448	349	344	1,141	577	462	364	1,403	2,544
UT Central	5,472	432	332	473	1,237	579	620	501	1,700	2,937
TOTAL New Connects	**10,851**	**932**	**742**	**892**	**2,566**	**1,256**	**1,193**	**947**	**3,396**	**5,962**

Utah South region includes Moab, Price, Cedar City and Richfield

Utah North/Metro region includes SLC Metro, Ogden and Layton

Utah Central region includes American Fork, Vernal, Tooele, Jordan Valley and Park City

Region areas are subject to change for operational purposes and may differ from historical reporting

New Connects report reflects the volume of all new connections in the system in the reporting period, which may include temporary connections that are subsequently removed in future periods; therefore, it is not necessarily an auditable count of new permanent connections for the reporting period.

5 VEGETATION MANAGEMENT

5.1 Production

UTAH
Tree Program Reporting
January 1, 2013 through June 30, 2013
Distribution

	Total	Calendar Year Reporting				Cycle Reporting			
	3 Year Program/Total Line Miles	1/1/2013-6/30/2013 Miles Planned	1/1/2013-6/30/2013 Actual Miles	01/01/2013-6/30/2013 Ahead/Behind	1/1/2013-6/30/2013 % Ahead/Behind	1/1/2011-12/31/2013 Miles Planned	1/1/2011-12/31/2013 Actual Miles	01/01/2011-12/31/2013 Ahead/Behind	1/1/2011-12/31/2013 % Ahead/Behind
	column a	*column b*	*column c*	*column d*	*column e*	*column f*	*column g*	*column h*	*column i*
UTAH	10,832	1,805	1,643	-162	91.0%	9,027	9,159	132	101.5%
AMERICAN FORK	807	135	152	18	113.0%	673	660	-13	98.1%
CEDAR CITY	1,333	222	208	-14	93.6%	1,111	1034	-77	93.1%
JORDAN VALLEY	773	129	55	-74	42.7%	644	625	-19	97.0%
LAYTON	281	47	102	55	217.8%	234	311	77	132.8%
MOAB	887	148	103	-45	69.7%	739	921	182	124.6%
OGDEN	883	147	184	37	125.0%	736	718	-18	97.6%
PARK CITY	528	88	66	-22	75.0%	440	452	12	102.7%
PRICE	613	102	55	-47	53.8%	511	474	-37	92.8%
RICHFIELD	1,332	222	125	-97	56.3%	1,110	918	-192	82.7%
SL METRO	1,188	198	192	-6	97.0%	990	1,067	77	107.8%
SMITHFIELD	756	126	128	2	101.6%	630	629	-1	99.8%
TOOELE	485	81	229	148	283.3%	404	468	64	115.8%
TREMONTON	727	121	44	-77	36.3%	606	712	106	117.5%
VERNAL	239	40	0	-40	0.0%	199	170	-29	85.4%

Distribution cycle $/tree:	$55.07
Distribution cycle $/mile:	$3,385
Distribution cycle removal %	40.36%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,379	1,260	575	(685)	5,694	89%

Transmission $/mile: $3,338

Current distribution cycle begain January 1, 2011 and extends until December 31, 2013.

Notes:
Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2013 through June 30, 2013
Column c: Actual overhead distribution pole miles worked during the period January 1 2013 through June 30, 2013
Column d: Miles ahead or behind for the period January 1, 2013 through June 30, 2013 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2013 through June 30, 2013 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2011 through December 31, 2013
Column g: Actual overhead distribution pole miles worked during the period January 1 2011 through December 31, 2013
Column h: Miles ahead or behind for the period January 1, 2011 through December 31, 2013 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2011 through December 31, 2013 ((column g÷f)×100). Max = 100%

5.2 Budget

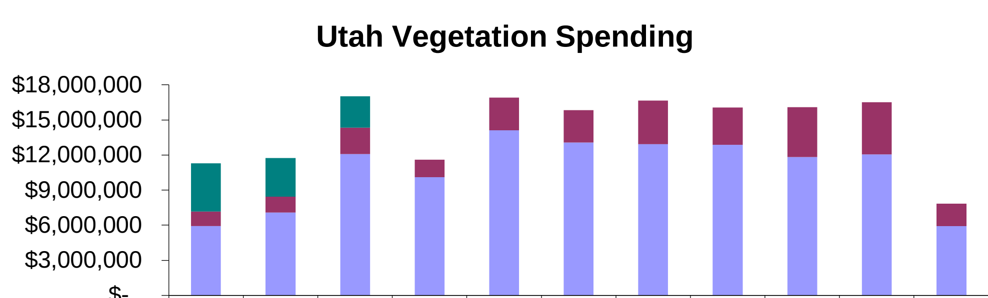
Tree Program Reporting

	CY2014	CY2015	CY2016
Distribution			
Tree Budget	$11,595,374	$11,595,374	$11,595,374
Transmission			
Tree Budget	$3,681,515	$3,681,515	$3,681,515
Total Tree Budget	$15,276,889	$15,276,889	$15,276,889

	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Calendar year 2013						
Jan	$1,090,506	$1,032,948	$57,558	$203,359	$275,591	-$72,232
Feb	$898,631	$983,759	-$85,129	$287,739	$299,635	-$11,896
Mar	$1,016,021	$982,136	$33,885	$297,764	$311,535	-$13,771
Apr	$978,950	$932,948	$46,002	$405,139	$316,640	$88,499
May	$1,020,289	$1,080,801	-$60,512	$353,017	$333,156	$19,861
Jun	$959,395	$1,032,948	-$73,553	$323,478	$293,763	$29,715
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	$5,963,791	$6,045,540	-$81,749	$1,870,497	$1,830,322	$40,175

Average # Tree Crews on Property (YTD) 66

5.2.1 Vegetation Historical Spending



	FY04	FY05	FY06	Apr-Dec'06	CY07	CY08	CY09	CY10	CY11	CY12	CY13-Jun
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	1,870,497
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	5,963,791

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