ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH

SERVICE QUALITY

REVIEW

January 1 – June 30, 2012

Report

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EXECUTIVE SUMMARY

Rocky Mountain Power has had 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.

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] On May 15, 2012 the Public Service Commission of Utah filed proposed rules R746-313 with the Utah Division of Administrative Rules and opened Docket No. 11-999-05 to take comments on the proposed rule. The Company, Commission and other stakeholders have been working to develop rules 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)	No goal at this time. Modification is pending rulemaking.
Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	No goal at this time. Modification is pending rulemaking.
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]On May 15, 2012 the Public Service Commission of Utah filed proposed rules R746-313 with the Utah Division of Administrative Rules and opened Docket No. 11-999-05 to take comments on the proposed rule. The Company, Commission and other stakeholders have been working to develop rules 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 interruptions which occur within a 5 minute time period, as long as the interruption event did not result in a device experiencing a sustained interruptions. This sequence of events typically occurs when the system is

[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.

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 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 1366-2003) based on the 2.5 beta methodology.

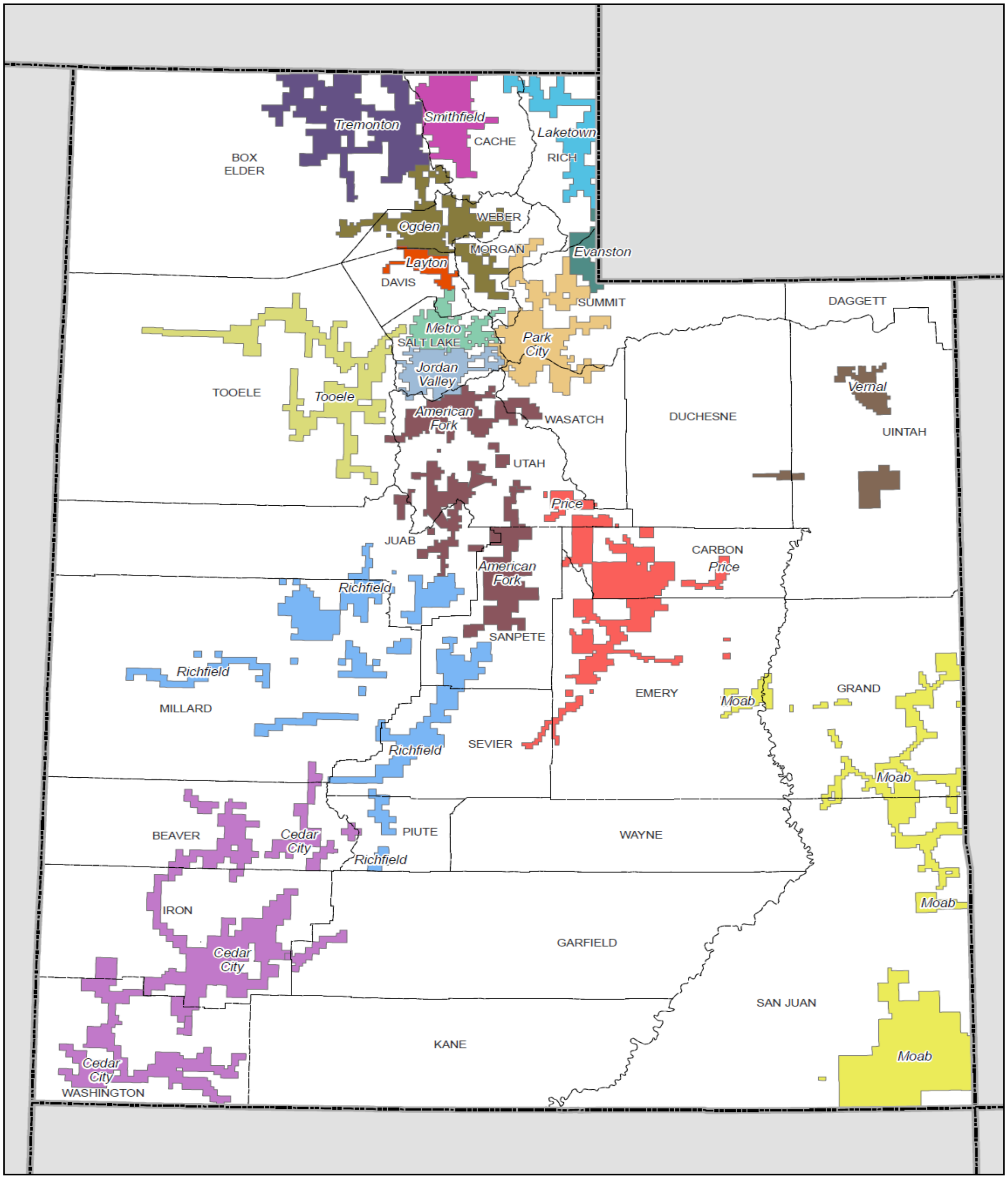
Underlying Events
Within the industry, there has been a great need to develop methodologies to evaluate year-on-year performance. This has led to the development of methods for segregating outlier days, via the approaches described above. Those days which fall below the statistically derived threshold represent "underlying" performance, and are valid (with some minor considerations for changes in reporting practices) for establishing and evaluating meaningful performance trends over time.

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.

1.4 Utah Service Territory Map with Operating Areas/Districts



2 RELIABILITY PERFORMANCE

As can be seen in the charts under subsections 2.1 and 2.2 below, the company's 2012 reliability results show steady performance through the period. While there is no plan to which comparisons are made, if the second half matches current performance, results at year-end would be at an all-time best for the state in both SAIDI and SAIFI.

During the period, two major events and two significant event days[3] were recorded, all were related to weather. The major events excluded 13 minutes from total performance during the period, and the significant event days account for approximately 11 minutes (14%) of the period's underlying results.

MAJOR EVENTS		
Date	Cause	SAIDI
January 18-19, 2012	Thunderstorms/Pole Fires	6
January 21, 2012	Thunderstorms/Pole Fires	7
	TOTAL	13

Major Event General Description

A Pacific storm system coming up through California into Utah from January 18-21, 2012 caused substantial damage to facilities and significant customer interruptions in Rocky Mountain Power service territories, particularly in the above-noted operating areas. The storm impacted operations in two waves with a temporary lull (January 20) having very little activity. The first wave of the storm resulted primarily in pole fires due to light rain or snow mixing with accumulated dust or salt contamination on facilities, and the second wave was snow-, wind- and tree-related outages with another round of pole fires. Several insulators from burned structures were collected by the company for study.

Interruptions occurred on 171 substations serving 239 circuits. The longest interruption of the event occurred on Jordan Valley's Herriman #11 circuit, affecting 5 customers for 1,628 minutes (27 hours) due to pole fire. Facilities damage in Utah included replacement of 33 distribution poles, 2 transmission poles, 53 crossarms, 11 transformers, and approximately 7,000 line feet of conductor.

Since the storm occurred in two waves, the company filed a single major event report for all three days, noting the normal day between them (January 20). In Docket No. 12-035-70, the Commission acknowledged the filing and recognized the Division's recommendation for approval of the filing but as separate major events, thereby designating the events as two Approved Major Events.

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

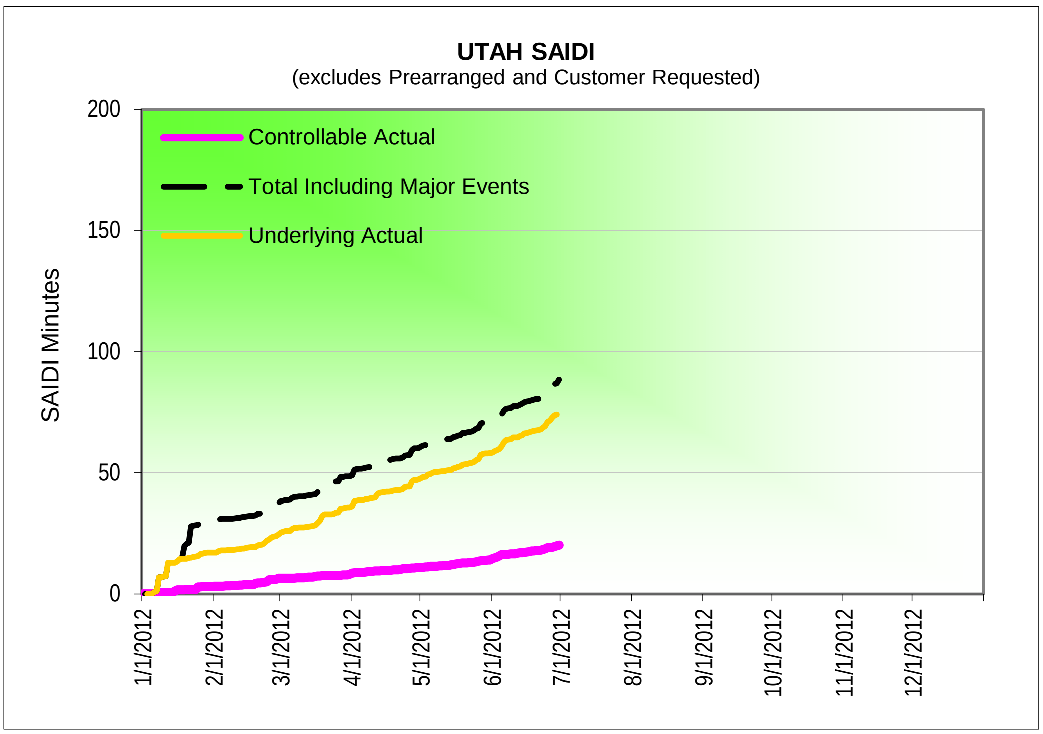
SIGNIFICANT EVENT DAYS						
Date	Underlying SAIDI	Percent of Total Underlying SAIDI (76 min)	CD SAIDI	Percent of Total CD SAIDI (20 min)	CD Percent of Day	Primary Cause
1/7/2012	5.5	7%	0.47	2.4%	8.5%	Loss of Supply
1/11/2012	5.5	7%	0.04	0.2%	0.7%	Loss of Supply
TOTAL	**11**	**14%**	**0.51**	**2.6%**	**4.6%**	

Significant Event General Descriptions

- On 1/7/12 – snowstorms and loss of Tooele to Terminal 138kV line
- On 1/11/12 – loss of 138kV due to conductor down between Praxair tap and Pine Canyon

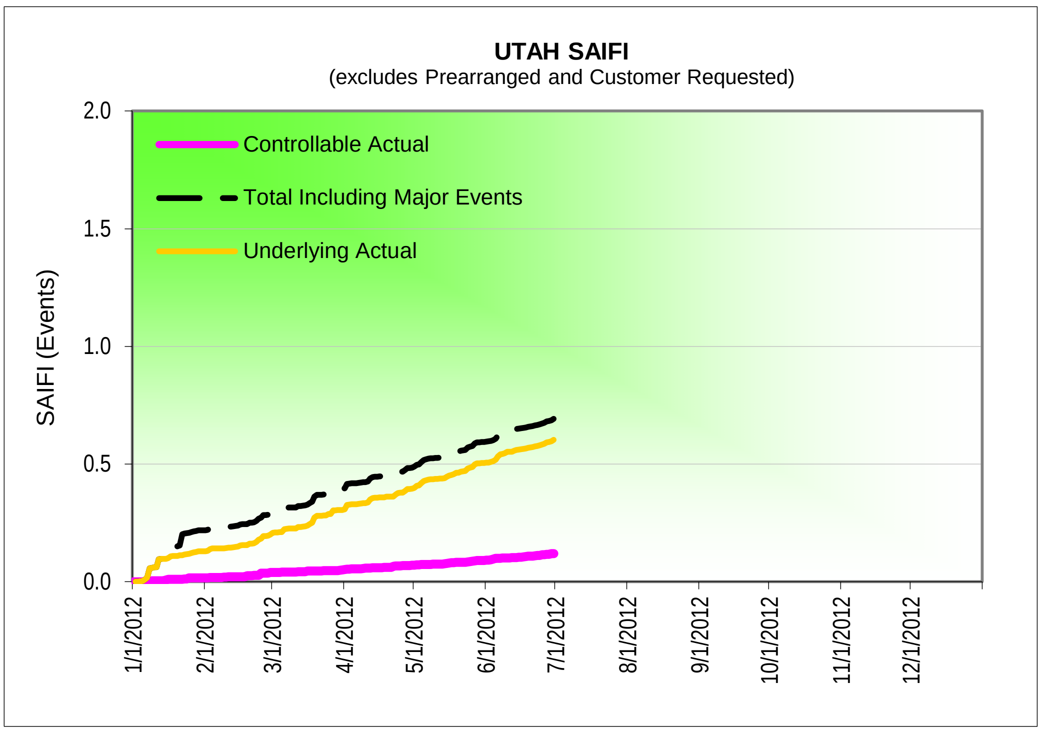
2.1 System Average Interruption Duration Index (SAIDI)

UTAH	January 1 through June 30, 2012
	SAIDI Actual
Total	89
Underlying	76
Controllable Distribution	20



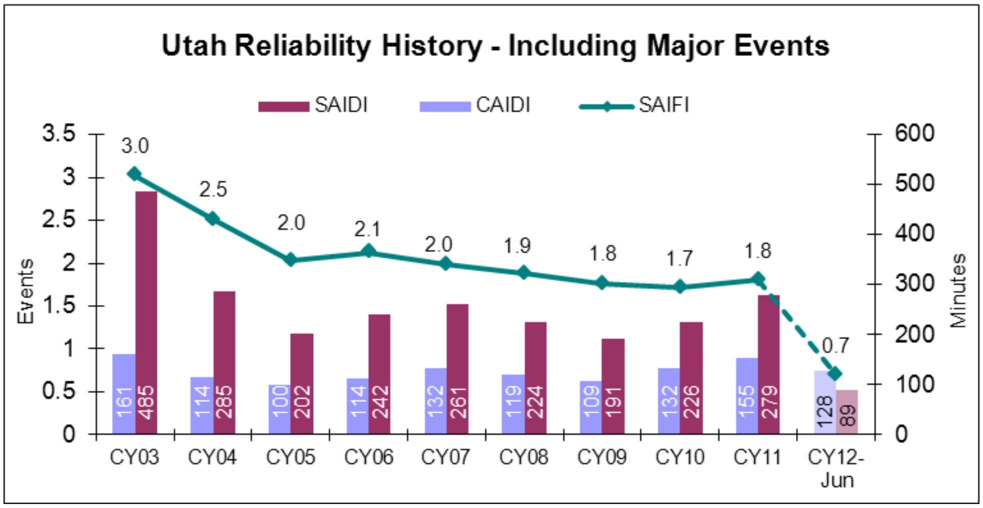
2.2 System Average Interruption Frequency Index (SAIFI)

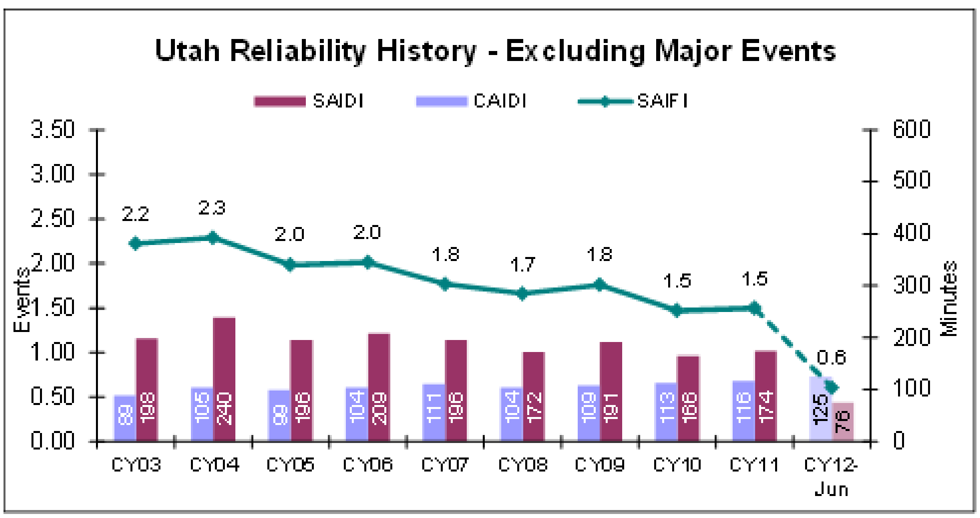
UTAH	January 1 through June 30, 2012
	SAIFI Actual
Total	0.69
Underlying	0.61
Controllable Distribution	0.12



2.3 Reliability History

Historically the company has significantly improved reliability as measured by all key reliability indices. These are shown below, and demonstrate the efficacy of the long-term improvement strategies undertaken since early in the decade. It is particularly noteworthy that reliability has been improved for both underlying and major event performance within the state.



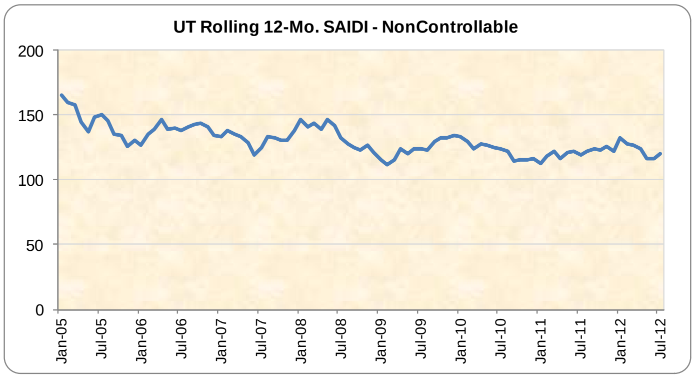


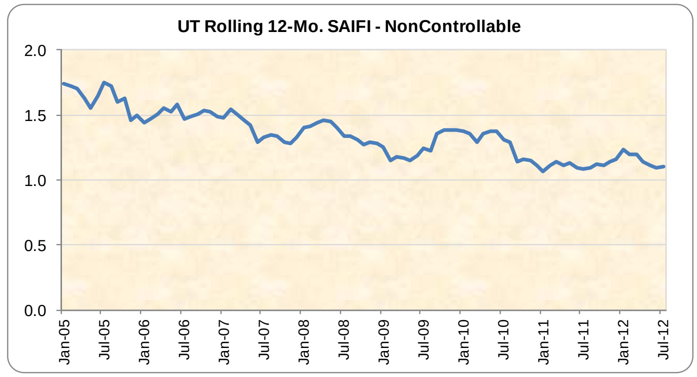
2.4 Controllable, Non-Controllable and Underlying Performance Review

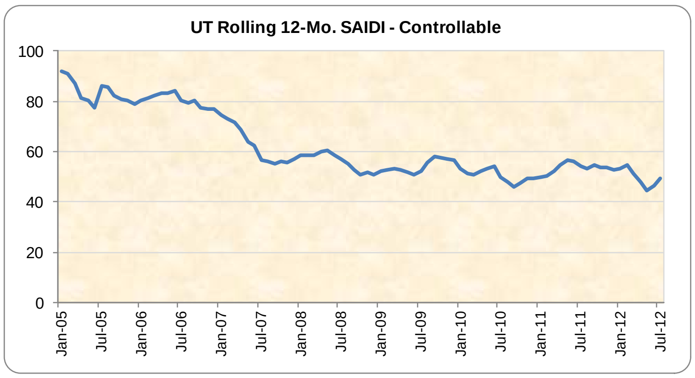
In 2008 the Company introduced a further categorization of outage causes, which it subsequently used to develop improvement programs as deployed by engineering resources. This categorization was titled Controllable Distribution outages and recognizes that certain types of outages can be cost-effectively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

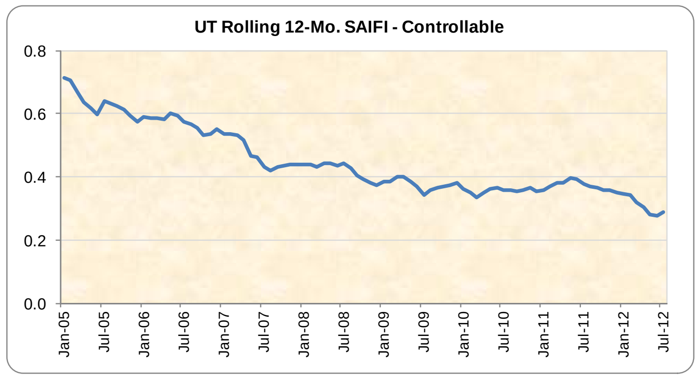
The graphic history demonstrates controllable, non-controllable and underlying performance on a rolling 12-month basis. Analysis of the trends displayed in the charts below shows a general improving trend for all charts. In order to also focus on non-controllable outages, the Company has continued to 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.

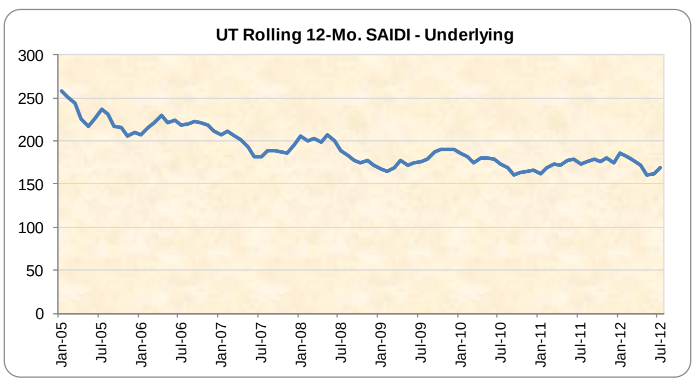
[4] 3.The Company shall provide, as an appendix to its Service Quality Review reports, information regarding non-controllable outages, including, when applicable, descriptions of efforts made by the Company to improve service quality and reliability for causes the Company has identified as not controllable.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

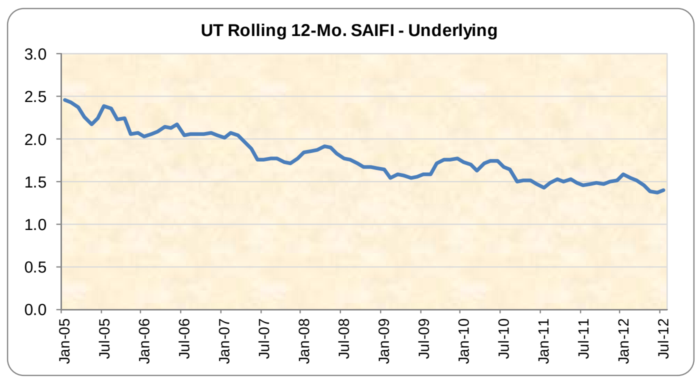












2.5 Cause Analysis

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.

[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 837,545 (2012 Utah frozen customer count).

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 DISTRIBUTION					
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	407,066.72	3,947	182	0.5	0.005
BIRD MORTALITY (NON-PROTECTED SPECIES)	433,026.38	4,101	71	0.5	0.005
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	164,636.17	1,049	27	0.2	0.001
BIRD NEST (BMTS)	90,020.63	267	15	0.1	0.000
BIRD SUSPECTED, NO MORTALITY	135,567.18	1,172	57	0.2	0.001
ANIMALS	**1,230,317.09**	**10,536**	**352**	**1.5**	**0.013**
B/O EQUIPMENT	2,629,158.70	13,042	352	3.1	0.016
DETERIORATION OR ROTTING	11,672,504.65	60,788	2,037	13.9	0.073
OVERLOAD	414,831.94	2,805	49	0.5	0.003
EQUIPMENT	**14,716,495.29**	**76,635**	**2,438**	**17.6**	**0.091**
FAULTY INSTALL	30,434.08	1,012	15	0.0	0.001
IMPROPER PROTECTIVE COORDINATION	25,946.80	293	11	0.0	0.000
INCORRECT RECORDS	126,442.63	3,318	27	0.2	0.004
INTERNAL CONTRACTOR	40,972.09	312	6	0.0	0.000
PACIFICORP EMPLOYEE - FIELD	16,236.02	1,103	10	0.0	0.001
PACIFICORP EMPLOYEE - SUB	0.00	0	0	0.0	0.000
OPERATIONAL	**240,031.62**	**6,038**	**69**	**0.3**	**0.007**
TREE - TRIMMABLE	336,432.67	5,819	94	0.4	0.007
TREES	**336,432.67**	**5,819**	**94**	**0.4**	**0.007**
UTAH CONTROLLABLE DISTRIBUTION	**16,523,276.67**	**99,028**	**2,953**	**19.7**	**0.118**

UTAH

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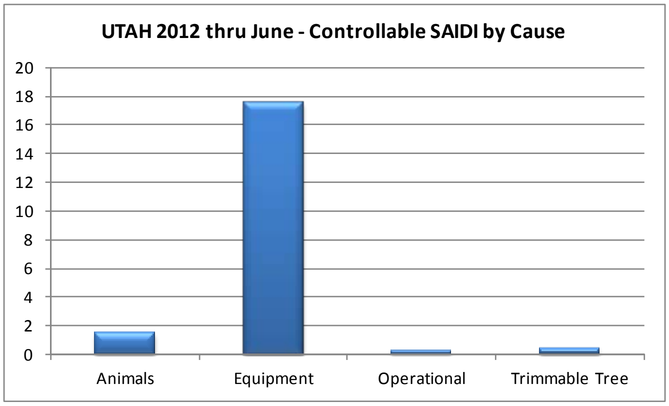
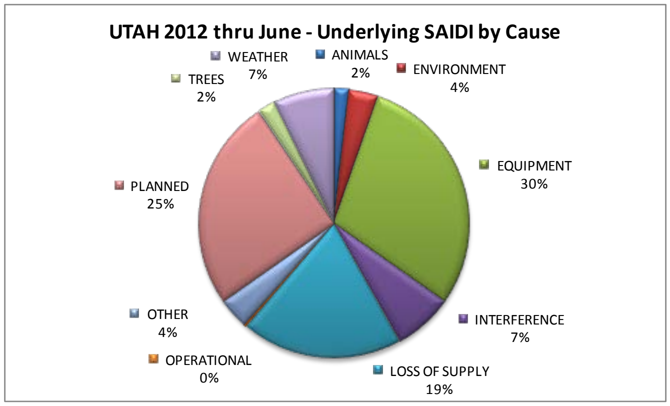
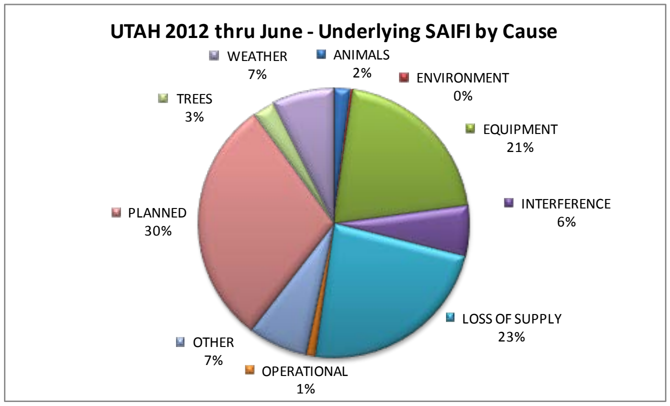
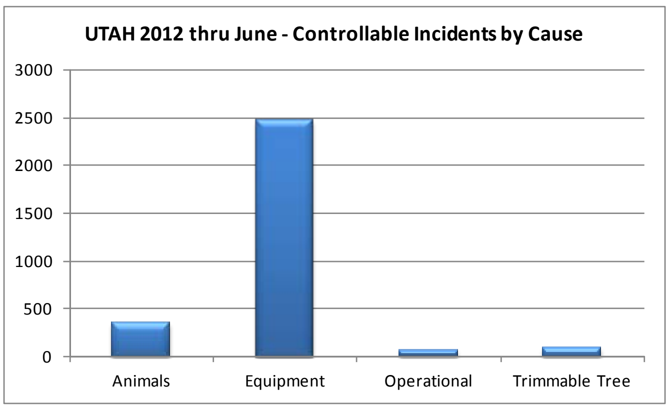
UTAH CAUSE ANALYSIS - UNDERLYING					
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	407,066.72	3,947	182	0.5	0.005
BIRD MORTALITY (NON-PROTECTED SPECIES)	433,026.38	4,101	71	0.5	0.005
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	164,636.17	1,049	27	0.2	0.001
BIRD NEST (BMTS)	90,020.63	267	15	0.1	0.000
BIRD SUSPECTED, NO MORTALITY	135,567.18	1,172	57	0.2	0.001
ANIMALS	**1,230,317.09**	**10,536**	**352**	**1.5**	**0.013**
FIRE/SMOKE (NOT DUE TO FAULTS)	2,483,848.16	1,932	22	3.0	0.002
ENVIRONMENT	**2,483,848.16**	**1,932**	**22**	**3.0**	**0.002**
B/O EQUIPMENT	2,629,158.70	13,042	352	3.1	0.016
DETERIORATION OR ROTTING	11,672,504.65	60,788	2,037	13.9	0.073
NEARBY FAULT	136,772.32	601	5	0.2	0.001
OVERLOAD	414,831.94	2,805	49	0.5	0.003
POLE FIRE	5,806,779.87	33,724	163	6.9	0.040
TRANS STRUCTURES, INSULATORS, CONDUCTOR	344.98	4	33	0.0	0.000
EQUIPMENT	**20,660,392.46**	**110,964**	**2,639**	**24.7**	**0.132**
DIG-IN (NON-PACIFICORP PERSONNEL)	712,820.94	3,936	128	0.9	0.005
OTHER INTERFERING OBJECT	142,002.17	1,325	37	0.2	0.002
OTHER UTILITY/CONTRACTOR	245,127.35	1,388	49	0.3	0.002
VANDALISM OR THEFT	68,489.70	3,804	24	0.1	0.005
VEHICLE ACCIDENT	3,823,056.32	22,533	145	4.6	0.027
INTERFERENCE	**4,991,496.48**	**32,986**	**383**	**6.0**	**0.039**
FAILURE ON OTHER LINE OR STATION	0.00	0	5	0.0	0.000
LOSS OF FEED FROM SUPPLIER	5,886.85	141	2	0.0	0.000
LOSS OF SUBSTATION	960,114.73	12,797	16	1.1	0.015
LOSS OF TRANSMISSION LINE	12,523,502.34	112,666	207	15.0	0.135
SYSTEM PROTECTION	62.13	1	1	0.0	0.000
LOSS OF SUPPLY	**13,489,566.05**	**125,605**	**231**	**16.1**	**0.150**
FAULTY INSTALL	30,434.08	1,012	15	0.0	0.001
IMPROPER PROTECTIVE COORDINATION	25,946.80	293	11	0.0	0.000
INCORRECT RECORDS	126,442.63	3,318	27	0.2	0.004
INTERNAL CONTRACTOR	40,972.09	312	6	0.0	0.000
PACIFICORP EMPLOYEE - FIELD	16,236.02	1,103	10	0.0	0.001
PACIFICORP EMPLOYEE - SUB	0.00	0	0	0.0	0.000
UNSAFE SITUATION	681.30	18	1	0.0	0.000
OPERATIONAL	**240,712.92**	**6,056**	**70**	**0.3**	**0.007**
OTHER, KNOWN CAUSE	286,267.99	4,622	69	0.3	0.006
UNKNOWN	2,317,922.68	33,880	547	2.8	0.040
OTHER	**2,604,190.66**	**38,502**	**616**	**3.1**	**0.046**
CONSTRUCTION	392,099.44	3,913	415	0.5	0.005
CUSTOMER NOTICE GIVEN	6,308,831.23	33,463	1,286	7.5	0.040
CUSTOMER REQUESTED	560,917.15	1,774	364	0.7	0.002
EMERGENCY DAMAGE REPAIR	8,698,860.79	101,574	768	10.4	0.121
INTENTIONAL TO CLEAR TROUBLE	1,287,563.57	10,491	32	1.5	0.013
TRANSMISSION REQUESTED	519,059.77	8,376	30	0.6	0.010
PLANNED	**17,767,331.93**	**159,591**	**2,895**	**21.2**	**0.191**
TREE - NON-PREVENTABLE	1,145,204.21	8,507	132	1.4	0.010
TREE - TRIMMABLE	336,432.67	5,819	94	0.4	0.007
TREES	**1,481,636.88**	**14,326**	**226**	**1.8**	**0.017**
ICE	27,344.85	230	4	0.0	0.000
LIGHTNING	655,254.70	5,073	49	0.8	0.006
SNOW, SLEET AND BLIZZARD	1,254,739.13	9,535	142	1.5	0.011
WIND	3,189,159.36	24,982	282	3.8	0.030
WEATHER	**5,126,498.04**	**39,820**	**477**	**6.1**	**0.048**
UTAH including Prearranged	**70,075,990.67**	**540,318**	**7,911**	**83.7**	**0.645**
UTAH excluding Prearranged	**63,206,242.30**	**505,081**	**6,261**	**75.5**	**0.603**

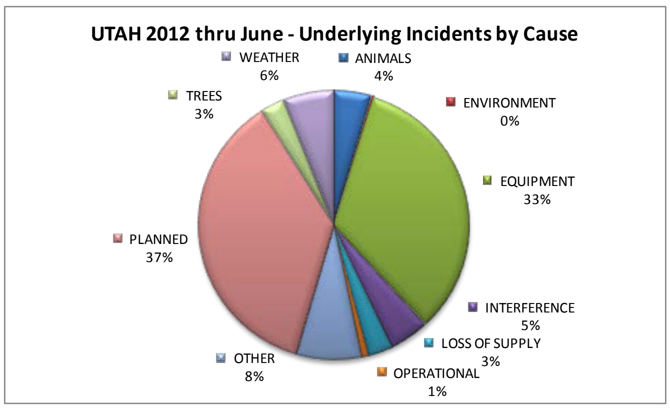

UTAH 2012 thru June - Controllable SAIDI by Cause
20
18
16
14
12
10
8
6
4
2
0
Animals
Equipment
Operational
Trimmable Tree


UTAH 2012 thru June - Underlying SAIDI by Cause
WEATHER 7%
ANIMALS 2%
ENVIRONMENT 4%
TREES 2%
EQUIPMENT 30%
PLANNED 25%
OTHER 4%
INTERFERENCE 7%
OPERATIONAL 0%
LOSS OF SUPPLY 19%


UTAH 2012 thru June - Controllable SAIFI by Cause
0.1
0.09
0.08
0.07
0.06
0.05
0.04
0.03
0.02
0.01
0
Animals
Equipment
Operational
Trimmable Tree


UTAH 2012 thru June - Underlying SAIFI by Cause
WEATHER 7%
ANIMALS 2%
ENVIRONMENT 0%
TREES 3%
EQUIPMENT 21%
INTERFERENCE 6%
PLANNED 30%
LOSS OF SUPPLY 23%
OTHER 7%
OPERATIONAL 1%


UTAH 2012 thru June - Controllable Incidents by Cause
3000
2500
2000
1500
1000
500
0
Animals
Equipment
Operational
Trimmable Tree


UTAH 2012 thru June - Underlying Incidents by Cause
WEATHER 6%
ANIMALS 4%
TREES 3%
ENVIRONMENT 0%
EQUIPMENT 33%
PLANNED 37%
INTERFERENCE 5%
LOSS OF SUPPLY 3%
OTHER 8%
OPERATIONAL 1%

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). B/O refers to bad order equipment.
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 Rocky Mountain Power or Rocky Mountain Power'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.
Trans Line Failure	(Transmission Line Failure) Failure of transmission line
Trans Term Equip	(Transmission Termination Equipment) Failure of equipment at either end of a transmission line, such as at the transmission or distribution substation

2.6 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).

WORST PERFORMING CIRCUITS	STATUS	BASELINE	Performance 6/30/2012
Program Year 12: (CY2011)			
Lincoln 15	IN PROGRESS	192	146
Huntington City 12	IN PROGRESS	371	513
Magna 15	IN PROGRESS	233	258
Gunnison 12	IN PROGRESS	246	348
Capitol 11	IN PROGRESS	143	126
TARGET SCORE = **190**		**237**	**278**
Program Year 11: (CY2010)			
Decker Lake 12	IN PROGRESS	112	194
North Bench 13	IN PROGRESS	105	285
Newgate 14	IN PROGRESS	178	128
Newton 12	IN PROGRESS	194	108
St Johns 11	IN PROGRESS	755	817
TARGET SCORE = **215**		**269**	**306**

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

2.7 Supply Restoration

The table below shows the percent of customers restored within three hours for each month in the reporting period, cumulative year to date and cumulative program to date (measured across 3 years). The cumulative 3-year program goal is 80%; the company's internal stretch goal is 85% annually.

UTAH RESTORATIONS WITHIN 3 HOURS					
Cumulative January 1 – June 30, 2012					**79%**
January	February	March	April	May	June
70%	84%	85%	82%	86%	72%
July	August	September	October	November	December

2.8 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).

2.9 Utah State Customer Guarantee Summary Status

customer*guarantees*

January to June 2012

Utah

		2012				2011			
	Description	Events	Failures	%Success	Paid	Events	Failures	%Success	Paid
CG1	Restoring Supply	503,078	0	100%	$0	609,167	1	99.9%	$50
CG2	Appointments	3,381	9	99.7%	$450	3,272	4	99.9%	$200
CG3	Switching on Power	5,318	4	99.9%	$200	4,930	2	99.9%	$100
CG4	Estimates	806	0	100%	$0	758	2	99.7%	$100
CG5	Respond to Billing Inquiries	803	0	100%	$0	1,017	0	100%	$0
CG6	Respond to Meter Problems	272	0	100%	$0	360	0	100%	$0
CG7	Notification of Planned Interruptions	31,598	30	99.9%	$1,500	41,840	33	99.9%	$1,650
		545,256	**43**	**99.9%**	**$2,150**	**642,868**	**40**	**99.9%**	**$2,000**

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

One reconnect for credit that had been disconnect 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.)

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.

Transmission and Distribution lines have a combination of preventive maintenance programs.

- Visual assurance inspections are designed to identify damage or defects that may endanger public safety or adversely affect the integrity of the electric system. (2 year cycle distribution and sub-transmission, 1 year cycle main grid)
- Detailed inspections are careful visual inspections of each structure and the spans between each structure.[8]
- Pole test and treat includes intrusive tests performed on wood poles to determine the strength of the pole, with subsequent application of chemicals or other measures to maximize the lifespan of the pole. (20 year cycle)

Substations and Major Equipment

- Rocky Mountain Power inspects all substations to ascertain all components within the substation are operating as expected. These components can include breaker counters or target levels, which are critical information in monitoring the equipment. Abnormal conditions that are identified are prioritized for repair (corrective maintenance). (Monthly cycle)
- Rocky Mountain Power also performs minor maintenance or overhauls on major substation equipment based on elapsed time or number of equipment operations, also to maximize the lifespan of this major equipment. (Based upon type of equipment)

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.

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[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 an immediate hazard to the public or employees, or that risk immediate 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 an immediate hazard.

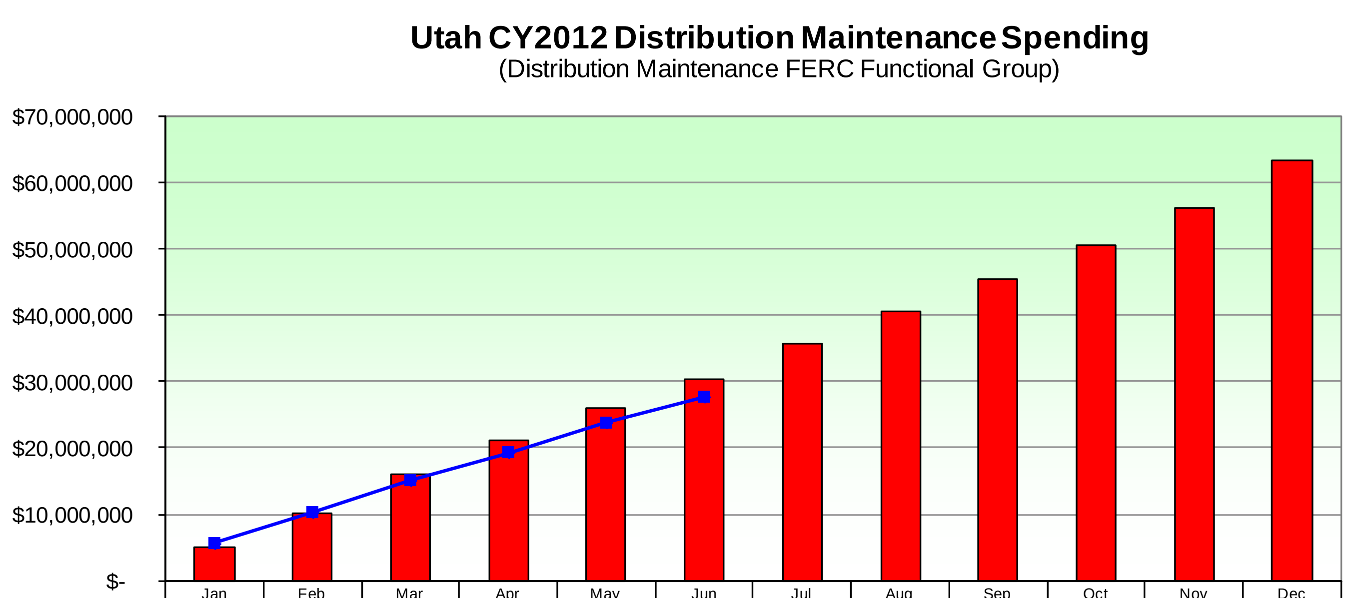
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

Priority D: Conditions that conform to the NESC and are not reportable to the associated State Commission. These conditions do not have a regulatory timeline for correction.

Priority G: Conditions that conform to the NESC, GO95, or GO128 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.

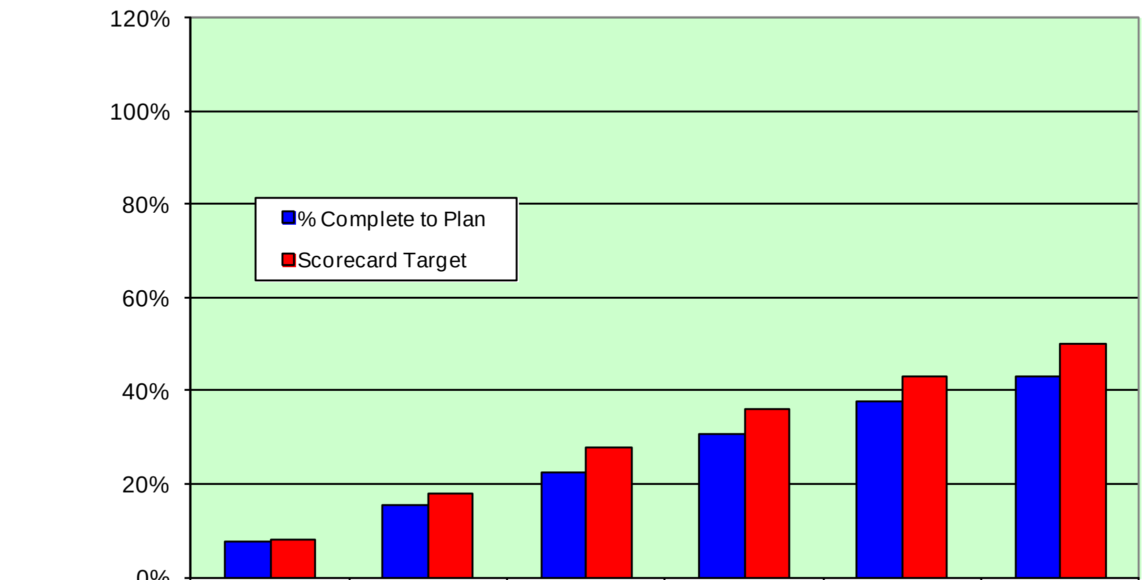
[8] Effective 1/1/2007, Rocky Mountain Power modified its reliability & preventive planning methods to utilize repeated reliability events to prioritize localized preventive maintenance activities, using its Reliability Work Planning methodology. At this time, repeated outage events experienced by customers 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



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$5,106,510	$10,225,67	$15,988,28	$21,218,79	$25,969,51	$30,430,87	$35,646,87	$40,484,80	$45,516,16	$50,615,55	$56,035,48	$63,274,56
Actual	$5,651,029	$10,349,33	$15,153,08	$19,354,91	$23,849,96	$27,747,47						

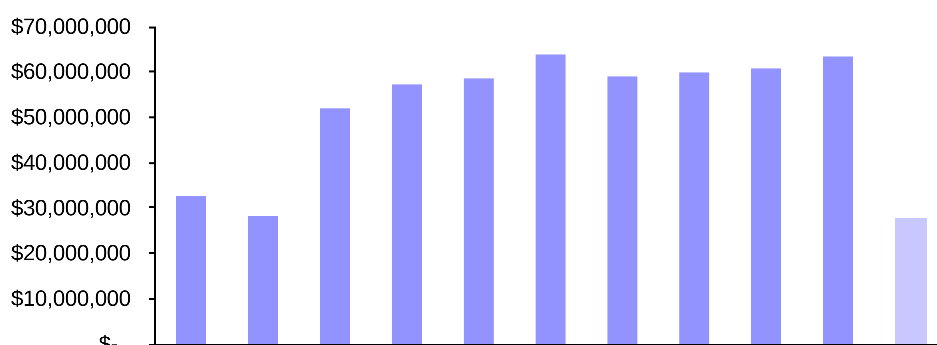
CY2012-June Utah Maintenance Percent Complete
(Corrective & Preventive Maintenance)



	Jan	Feb	Mar	Apr	May	Jun
% Complete to Plan	7.7%	15.2%	22.4%	30.8%	37.9%	43.1%
Scorecard Target	8.0%	18.0%	28.0%	36.0%	43.0%	50.0%

3.2.1 Maintenance Historical Spending

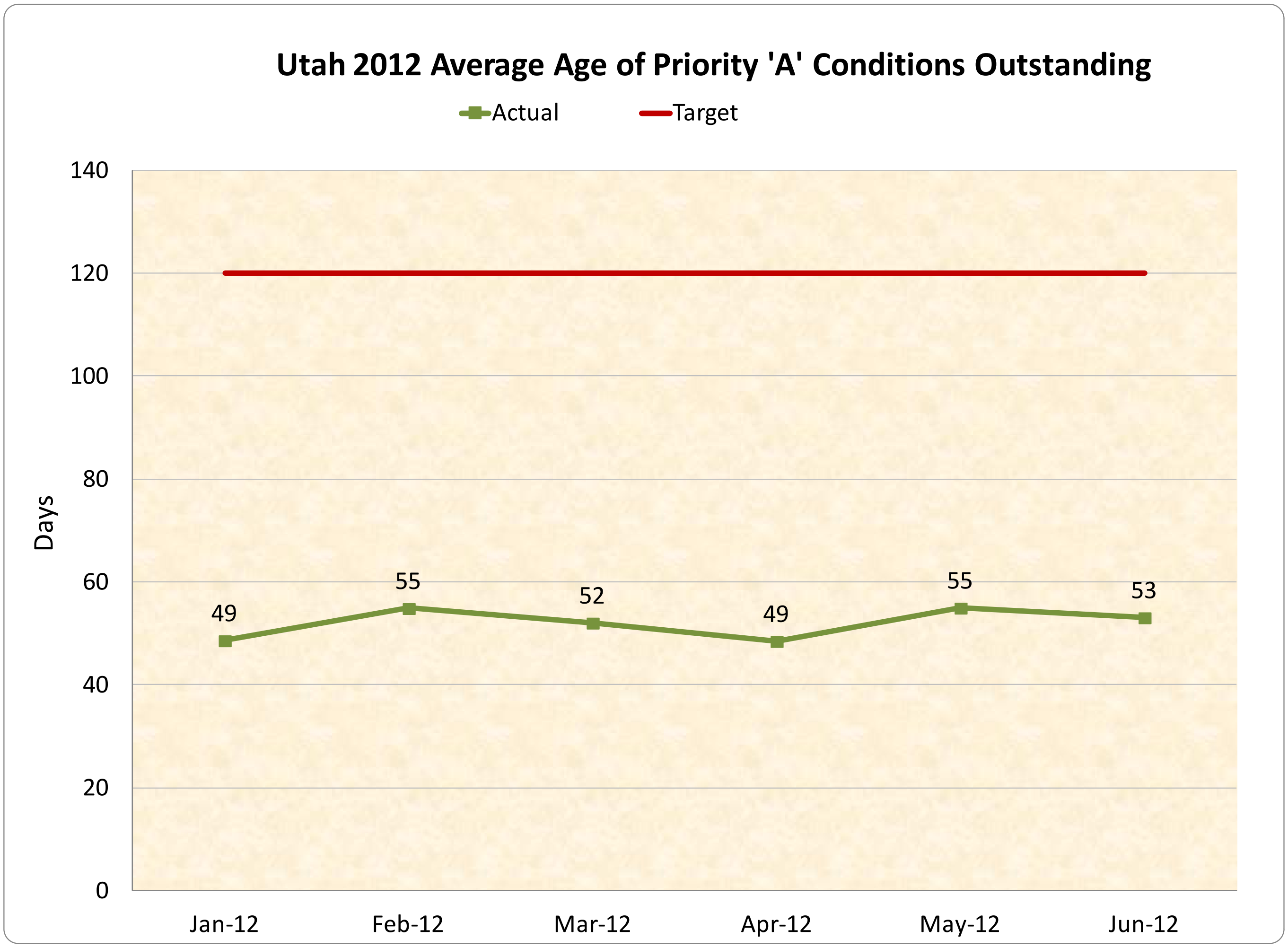
Utah Inspections & Maintenance Spending



	CY2002	CY2003	CY2004	CY2005	CY2006	CY2007	CY2008	CY2009	CY2010	CY2011	CY2012-Jun
Actual	32,560,1	28,022,0	51,831,0	57,327,6	58,758,2	63,886,5	58,875,9	59,955,4	60,648,2	63,432,8	27,747,4

3.3 T&D Priority "A" Conditions Correction History & Compliance

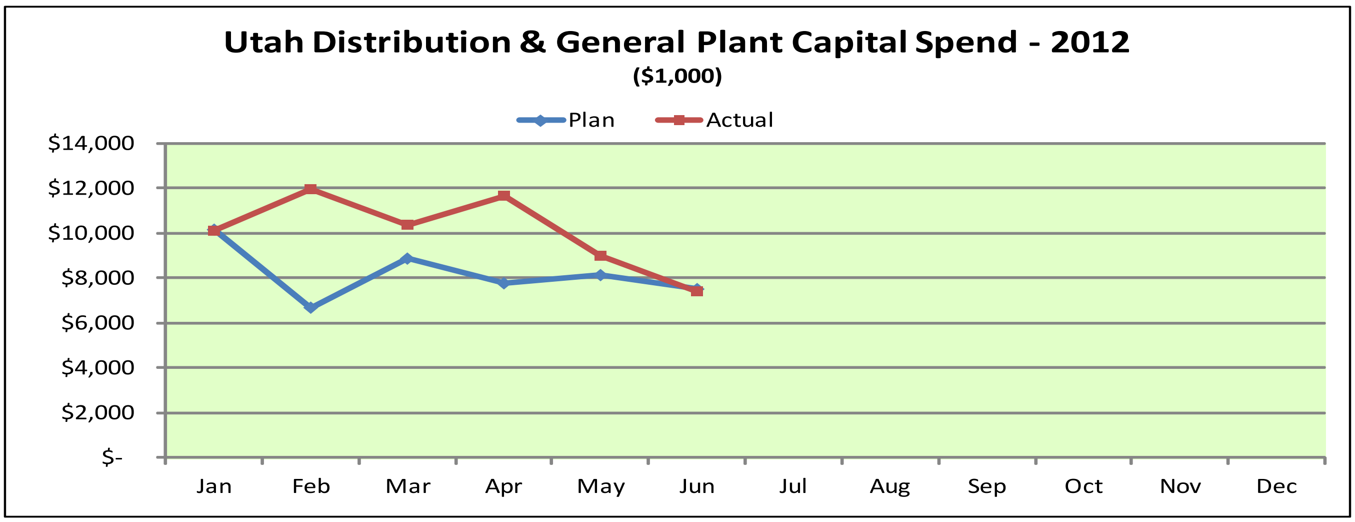
The company reports its compliance for the average age of "A" priority corrections. As can be seen in the chart below, compliance to the target has been consistently delivered.

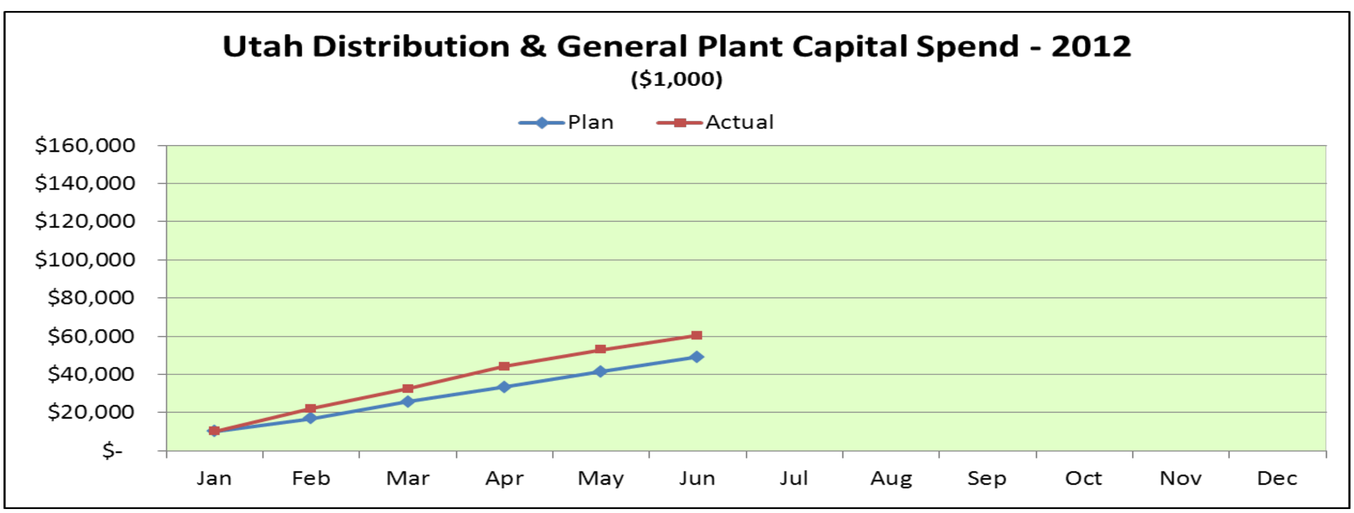


4 CAPITAL INVESTMENT

4.1 Capital Spending - Distribution and General Plant

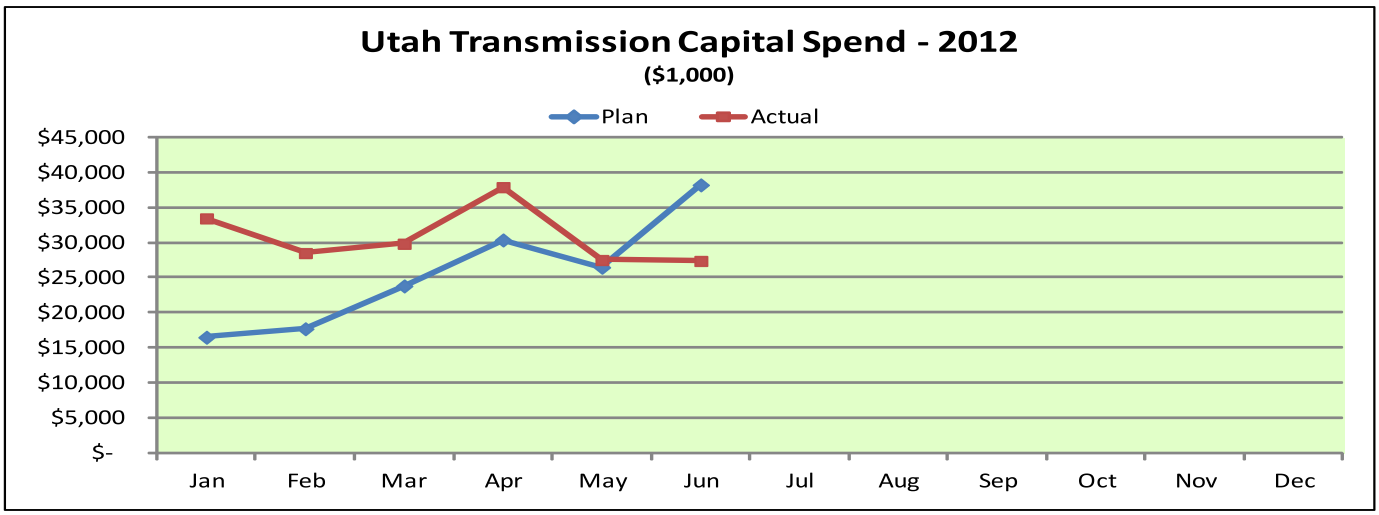
Investment	Actuals ($M)	Plan ($M)	Variance Explanation
1. Mandated	$7.9	$6.7	Road relocations, environmental/avian protection and public accommodations over plan; partially offset by regional & national regulatory.
2. New Connects	$30.5	$25.0	Residential, commercial and irrigation over plan; partially offset by industrial.
3. System Reinforcement	$8.7	$6.5	Feeder and subtransmission over plan; partially offset by substation.
4. Replacements	$12.0	$9.0	Underground vaults & equipment, storm & casualty, meters, substation bushings & glass, and abandoned facilities removal over plan; partially offset by substation transformers and tools.
5. Upgrade & Modernize	$1.3	$1.9	Economically justified (automated meter reading) under plan; partially offset by feeder and substation improvements.
Total	**$60.5**	**$49.1**	

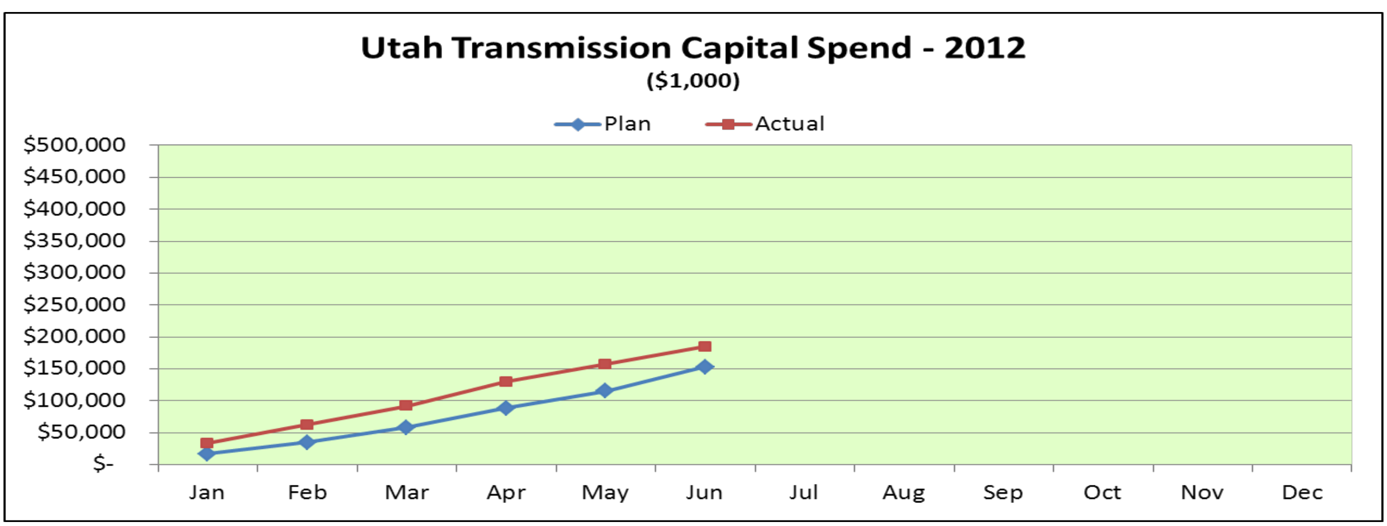




4.2 Capital Spending - Transmission

Investment	Actuals ($M)	Plan ($M)	Variance Explanation
1. Mandated	7.4	6.8	Road relocations, right-of-way renewals and environmental/avian protection over plan; partially offset by non-conforming code issues.
2. New Connects	0.5	0.0	Commercial over plan; partially offset by industrial.
3. Local Transmission System Reinforcements	9.4	7.2	Subtransmission, substation and feeder over plan.
4. Main Grid Reinforcements / Interconnections	22.2	30.7	Main grid and generation/municipal interconnections under plan.
5. Energy Gateway Transmission	135.6	101.4	Mona-Oquirrh line and Sigurd Red Butte-Crystal line over plan; partially offset by Oquirrh-Terminal line, Clover sub and Populus-Terminal line.
6. Replacements	8.2	6.5	Substation meters & relays, storm & casualty and overhead transmission poles and equipment over plan; partially offset by substation transformers, substation switchgear/breakers/reclosers and abandoned facilities removal.
7. Upgrade & Modernize	1.3	0.6	Substation and transmission over plan.
Total	**184.6**	**153.1**	





4.3 New Connects

UTAH	Jan - Dec 2011	Jan	Feb	Mar	Q1 Total	Apr	May	Jun	Q2 Total	Jan - Jun 2012
Residential										
UT South	539	21	32	112	165	51	57	58	166	331
UT North/Metro	2,138	178	277	260	715	189	385	293	867	1,582
UT Central	4,077	478	307	323	1,108	390	450	457	1,297	2,405
Total Residential	**6,754**	**677**	**616**	**695**	**1,988**	**630**	**892**	**808**	**2,330**	**4,318**
Commercial										
UT South	180	22	13	19	54	15	14	22	51	105
UT North/Metro	608	86	111	86	283	67	45	108	220	503
UT Central	795	63	72	97	232	88	107	136	331	563
Total Commercial	**1,583**	**171**	**196**	**202**	**569**	**170**	**166**	**266**	**602**	**1,171**
Industrial										
UT South	14	-	-	1	1	-	-	-	-	1
UT North/Metro	3	2	1	-	3	1	-	-	1	4
UT Central	6	-	-	-	-	-	-	-	-	-
Total Industrial	**23**	**2**	**1**	**1**	**4**	**1**	**-**	**-**	**1**	**5**
Irrigation										
UT South	46	1	1	8	10	14	11	5	30	40
UT North/Metro	6	-	-	-	-	-	1	1	2	2
UT Central	20	2	3	1	6	3	11	3	17	23
Total Irrigation	**72**	**3**	**4**	**9**	**16**	**17**	**23**	**9**	**49**	**65**
TOTAL New Connects										
UT South	779	-	-	-	230	-	-	-	247	477
UT North/Metro	2,755	-	-	-	1,001	-	-	-	1,090	2,091
UT Central	4,898	-	-	-	1,346	-	-	-	1,645	2,991
TOTAL New Connects	**8,432**	**853**	**817**	**907**	**2,577**	**818**	**1,081**	**1,083**	**2,982**	**5,559**

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, 2012 through June 30, 2012
Distribution: Three Year Cycle 1/1/2011-12/31/2013

	3 Year Program/Total Line Miles *column a*	1/1/2012-6/30/2012 Miles Planned *column b*	1/1/2012-6/30/2012 Actual Miles *column c*	1/1/2012-6/30/2012 Ahead/Behind *column d*	1/1/2012-6/30/2012 % Ahead/Behind *column e*	1/1/2011-6/30/2012 Miles Planned *column f*	1/1/2011-6/30/2012 Actual Miles *column g*	1/1/2011-6/30/2012 Ahead/Behind *2*	1/1/2011-6/30/2012 % Ahead/Behind *column i*
UTAH	11,491	1,915	2,150	235	112.3%	5,691	5,976	285	105.0%
AMERICAN FORK	858	143	175	32	122.4%	426	357	-69	83.8%
CEDAR CITY	1,338	223	108	-115	48.4%	671	764	93	113.9%
JORDAN VALLEY	846	141	152	11	107.8%	410	518	108	126.3%
LAYTON	386	64	88	24	137.5%	195	152	-43	77.9%
MOAB	963	161	538	377	334.2%	481	703	222	146.2%
OGDEN	1,051	175	123	-52	70.3%	525	392	-133	74.7%
PARK CITY	541	90	55	-35	61.1%	272	275	3	101.1%
PRICE	641	107	90	-17	84.1%	321	350	29	109.0%
RICHFIELD	1,418	236	229	-7	97.0%	703	381	-322	54.2%
SL METRO	1,133	189	143	-46	75.7%	528	692	164	131.1%
SMITHFIELD	848	141	81	-60	57.4%	424	440	16	103.8%
TOOELE	480	80	73	-7	91.3%	238	164	-74	68.9%
TREMONTON	705	118	220	102	186.4%	355	635	280	178.9%
VERNAL	283	47	75	28	159.6%	142	153	11	107.7%

Distribution cycle $/tree:	$65.20
Distribution cycle $/mile:	$2,652
Distribution cycle removal %	28.13%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,295	1,107	501	(606)	5,689	90%

Transmission $/mile: $4,696

Notes:

Column a: Total overhead distribution pole miles by district
Column b: Total overhead distribution pole miles planned for the period January 1, 2012 through June 30, 2012
Column c: Actual overhead distribution pole miles worked during the period January 1 2012 through June 30, 2012
Column d: Miles ahead or behind for the period January 1, 2012 through June 30, 2012 (column c-column b)
Column e: Percent of actual compared to planned for the period January 1, 2012 through June 30, 2012 ((column c÷b)×100)
Column f: Total overhead distribution pole miles planned for the period January 1, 2011 through June 30, 2012
Column g: Actual overhead distribution pole miles worked during the period January 1 2011 through June 30, 2012
Column h: Miles ahead or behind for the period January 1, 2011 through June 30, 2012 (column g-column f)
Column i: Percent of actual compared to planned for the period January 1, 2011 through June 30, 2012 ((column g÷f)×100).

5.2 Budget

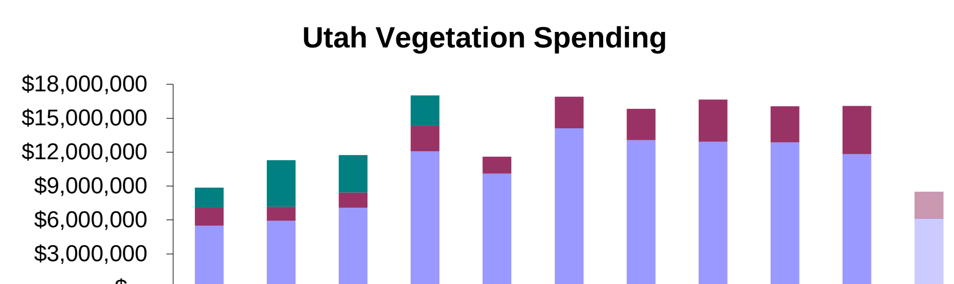
UTAH
Tree Program Reporting

	CY2013	CY2014	CY2015
Distribution			
Tree Budget	$12,396,709	$12,396,709	$12,396,709
Transmission			
Tree Budget	$3,642,292	$3,642,292	$3,642,292
Total Tree Budget	$16,039,001	$16,039,001	$16,039,001

	Distribution			Transmission		
	Actuals	Budget	Variance	Actuals	Budget	Variance
Calendar year 2012						
Jan	$1,132,018	$1,032,948	$99,070	$393,385	$270,455	$122,929
Feb	$1,042,051	$983,759	$58,291	$365,245	$270,734	$94,510
Mar	$1,131,420	$1,082,136	$49,284	$460,356	$306,349	$154,006
Apr	$935,990	$1,032,948	-$96,958	$393,679	$316,640	$77,039
May	$1,176,148	$1,082,136	$94,012	$379,183	$333,156	$46,026
Jun	$724,190	$1,032,948	-$308,758	$360,846	$293,763	$67,083
Jul			$0			$0
Aug			$0			$0
Sep			$0			$0
Oct			$0			$0
Nov			$0			$0
Dec			$0			$0
Total	$6,141,816	$6,246,875	-$105,059	$2,352,693	$1,791,099	$561,594

Average # Tree Crews on Property (YTD) 71

5.2.1 Vegetation Historical Spending



	FY03	FY04	FY05	FY06	Apr-Dec'06	CY07	CY08	CY09	CY10	CY11	CY12-Jun
Miscellaneous	1,719,069	4,127,062	3,306,952	2,666,318							
Transmission	1,646,644	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	2,352,693
Distribution	5,503,859	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	6,141,816

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