ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

UTAH

Reliability Review

xx – xx, 20xx

Report

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Discussion about program and plan elements over the reporting period….

Reliability Reporting Program

1 Reliability Definitions and Cause Categories

2 Utah Service Territory Map with Operating Areas/Districts

3 Internal Processes to Collect, Monitor and Analyze Interruption Events

4 Reliability Performance

5 Major Events and Significant Events during Reporting Period

6 Reliability History

7 Cause Analysis

8 Improvement Plan: Areas of Concern

1 Service Standards Program Summary

Effective April 1, 2008 through December 31, 2011[1,2]

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:	The Company will switch on power within 24 hours of the

[1] On November 10, 2011 the Company extended its Service Quality Standards Program pending ongoing Service Reliability Informal Rulemaking. Upon completion of this rulemaking any required program modifications will be incorporated as appropriate.

[2] In its June 11, 2009 Order in Docket 08-35-55, the Commission approved modifications to the Service Standards Program wherein network performance improvement targets are developed based upon Controllable Distribution causes, extending through December 31, 2011.

Switching on Power	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.

1.2 Rocky Mountain Power Performance Standards

Network Performance Standard 1: Improve System Average Interruption Duration Index (SAIDI)	The Company will improve Controllable Distribution SAIDI by 29% by December 31, 2011.
Network Performance Standard 2: Improve System Average Interruption Frequency Index (SAIFI)	The Company will improve Controllable Distribution SAIFI by 27% by December 31, 2011.
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 Reliability Definitions

Interruption Types

Below are the definitions for interruption events. For further details, refer to IEEE 1366-2003[3] Standard for Reliability Indices.

Sustained Outage
A sustained outage is defined as an outage of greater than 5 minutes in duration.

Momentary Outage
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.

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).

CEMI
CEMI is an acronym for Customers Experiencing Multiple (Sustained and Momentary) 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

[3] 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.

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 * 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: 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 * 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.

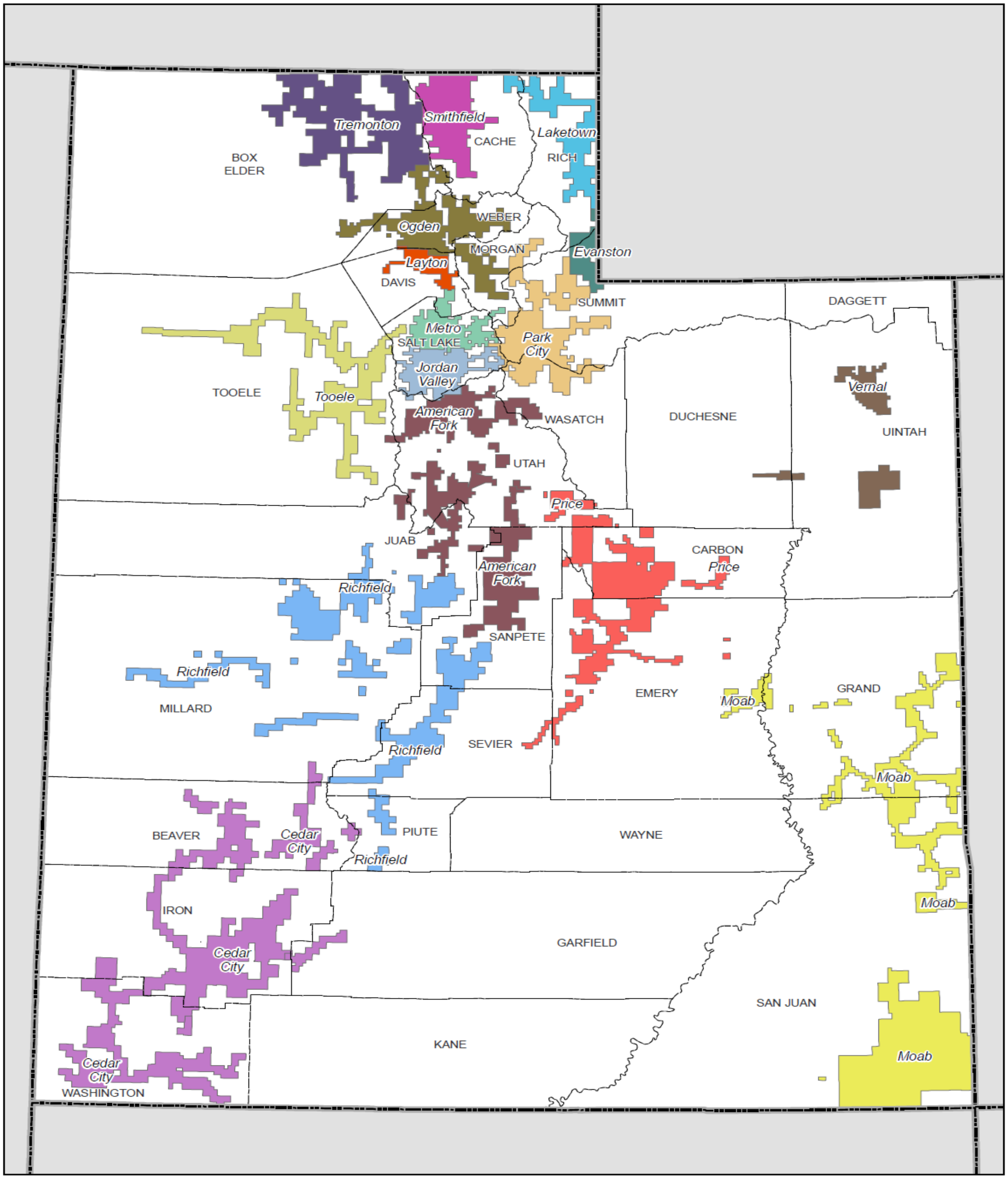
Underlying Events
Within the industry, there has been a great need to develop methodologies to evaluate year-on-year performance. This has led to the development of methods for segregating outlier days, via the approaches described above. Those days which fall below the statistically derived threshold 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.

CATEGORY	DESCRIPTION AND EXAMPLES
Loss of Supply - Transmission	
Loss of Supply - Substation	
Distribution - Equipment	
Distribution - Lightning	
Distribution - Planned	
Distribution - Public	
Distribution - Vegetation	
Distribution – Weather (other than lightning)	
Distribution - Wildlife	
Distribution - Unknown	
Distribution - Other	

2 Utah Service Territory Map with Operating Areas/Districts



3 Internal Processes to Collect, Monitor and Analyze Interruption Events

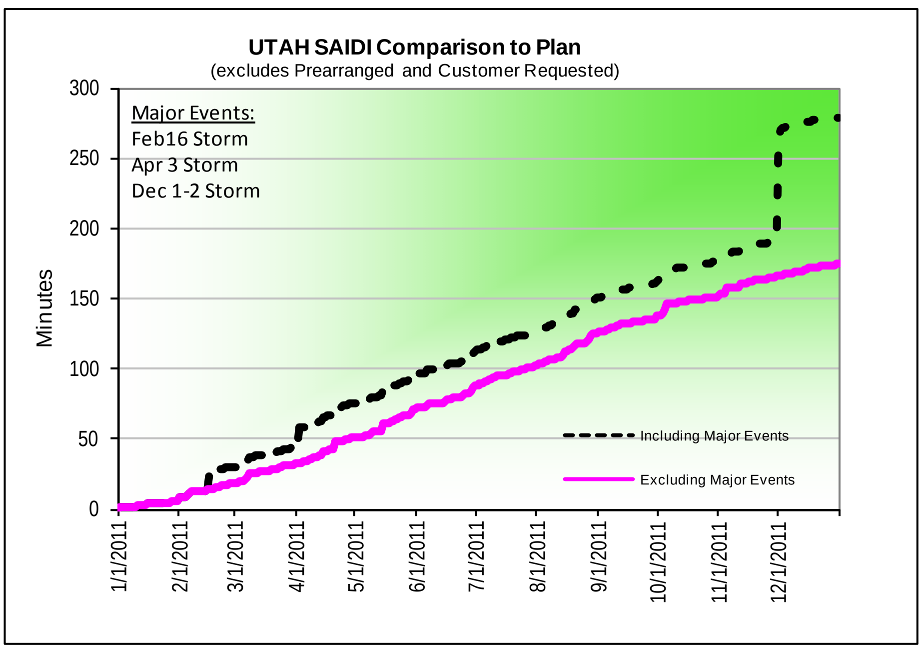
Discussion about the Company's processes and systems to evaluate system reliability.

4 Reliability Performance

As can be seen in the charts under subsections 2.1 and 2.2 below, the company's 2011 reliability results for controllable distribution outage duration and outage frequency[4] consistently tracked very closely to plan throughout the entire year, missing the goal by 2 SAIDI minutes at year end while SAIFI results finished the year at 0.03 events better than plan. For its underlying SAIDI and SAIFI performance, year-end results are better than the company's internal operating plan levels.

System Average Interruption Duration Index (SAIDI)

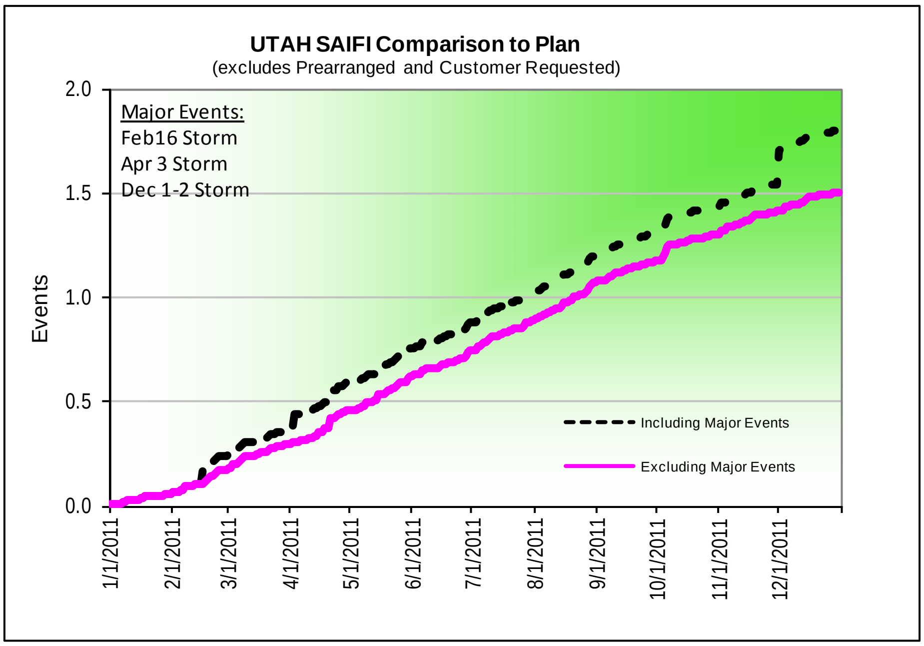
UTAH	January 1 through December 31, 2011
	SAIDI Actual
Total	279
Underlying	174



[4] For the period 7/1/2008- 6/30/2009 the Company successfully delivered its controllable distribution targets of SAIDI, 50.8 minutes (actual of 50.61 minutes) and SAIFI, 0.383 events (actual of 0.369 events).

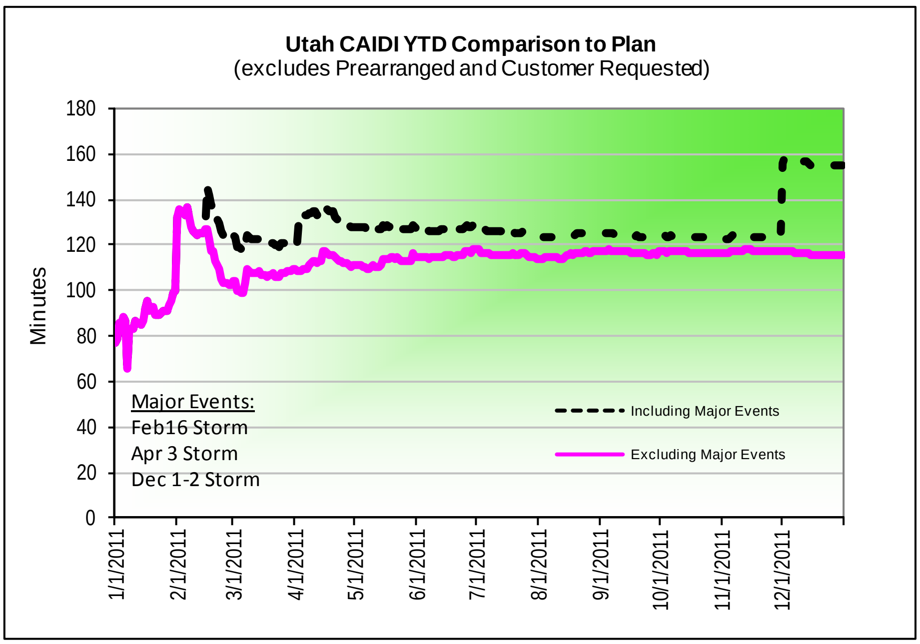
System Average Interruption Frequency Index (SAIFI)

UTAH	January 1 through December 31, 2011
	SAIFI Actual
Total	1.80
Underlying	1.50



Customer Average Interruption Duration Index (CAIDI)

UTAH	January 1 through December 31, 2011
	SAIFI Actual
Total	155
Underlying	116



5 Major Events and Significant Events during Reporting Period

During the period, three major events and eleven significant event days[5] were recorded; most were related to weather. The major events excluded 105 minutes from total performance during the period, and the significant event days account for approximately 38 minutes (22%) of the period's underlying results.

MAJOR EVENTS		
Date	Cause	SAIDI
February 16, 2011	Snow and Wind	12
April 3, 2011	Snow	13
December 1-2, 2011	Wind	80
	TOTAL	105

Major Event General Description

- On 2/16/11 – a winter storm caused numerous outages throughout the company's service territory in Utah, most significantly in the company's SLC Metro, Richfield, Jordan Valley and Ogden operating areas, due to high winds, heavy snow, and lightning. Sustained interruptions were caused by blown fuses, downed primary, broken crossarms, objects blown into lines, burned or broken jumpers, pulled apart connections, and loss of transmission. The 46 kV bus at Sigurd substation lost voltage when a switch insulator failed, de-energizing downstream substations. At the height of the event, more than 20,000 Rocky Mountain Power customers were without power. In Docket No. 11-035-91 the Commission acknowledged the filing and recognized the Division's recommendation for approval, designating the event as an Approved Major Event.
- On 4/3/11 – a storm passing through Utah's Wasatch Front caused numerous outages due to high winds, heavy rain and wet snow, most significantly in the company's Salt Lake City Metro and Jordan Valley operating areas. Sustained interruptions were caused by blown fuses, downed primary, broken crossarms, unloading snow or wind slapping conductor together, tree contacts, and loss of transmission. At the height of the event, more than 31,000 Rocky Mountain Power customers were without power. In Docket No. 11-035-75 the Commission acknowledged the filing and recognized the Division's recommendation for approval, designating the event as an Approved Major Event.
- On 12/1/11-12/2/11 – a severe windstorm blowing through Utah created numerous momentary and sustained outages in Rocky Mountain Power's service territory, most significantly in the company's Salt Lake City Metro, Jordan Valley, Ogden and Layton operating areas. Sustained wind speeds averaged 65mph with gusts exceeding 100mph. The destructive wind forces uprooted hundreds of trees, tore roofs off structures, destroyed traffic signals, sent all manner of debris airborne into facilities, toppled high-profile vehicles, and snapped utility poles and crossarms like matchsticks. Concern for public safety led to temporary closures of public rail and highways. Sustained interruptions were caused by blown fuses, tree contacts, slapping conductor, broken crossarms, and downed poles and wire. At the height of the event,

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

more than 66,000 Rocky Mountain Power customers were without power. In Docket No. 12-035-03 the Commission acknowledged the filing and recognized the Division's recommendation for approval, designating the event as an Approved Major Event.

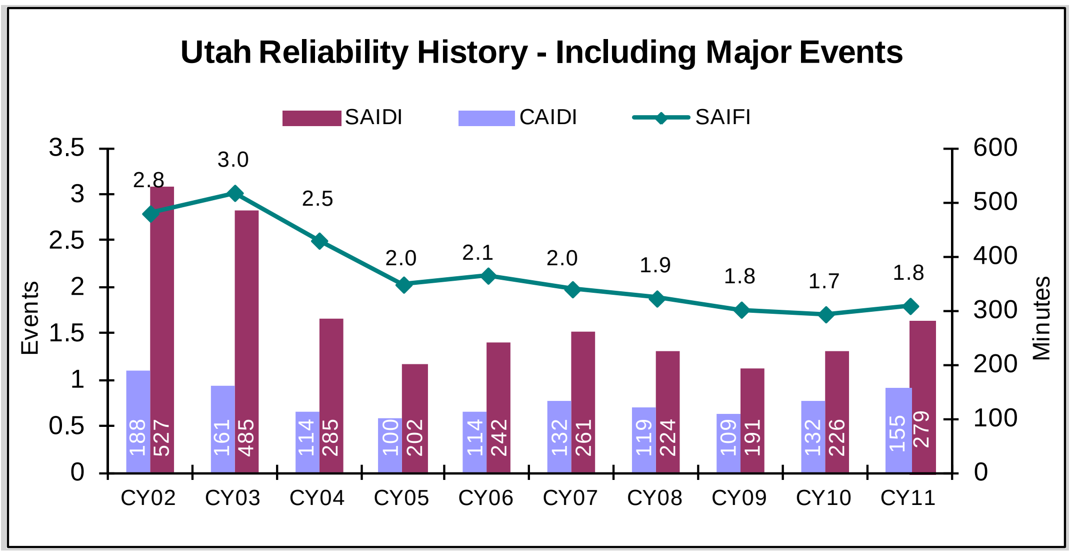
SIGNIFICANT EVENTS						
Date	Underlying SAIDI	Percent of Annual Underlying SAIDI (174)	CD SAIDI	Percent of Annual CD SAIDI (53)	CD Percent of Day	Primary Cause
February 1, 2011	2.71	1.6%	0.07	0.1%	2.5%	Loss of Transmission
April 15, 2011	2.83	1.6%	2.80	5.3%	99.1%	Equipment
April 21, 2011	4.65	2.7%	0.14	0.3%	3.1%	Windstorm
May 15, 2011	4.74	2.7%	1.03	2.0%	21.8%	Windstorm
May 30, 2011	3.84	2.2%	0.46	0.9%	11.9%	Loss of Substation
June 29, 2011	3.26	1.9%	0.26	0.5%	8.1%	Thunderstorms
August 15, 2011	2.68	1.5%	0.23	0.4%	8.5%	Thunderstorms
August 28, 2011	2.97	1.7%	0.30	0.6%	10.0%	Thunderstorms
October 5, 2011	2.79	1.6%	0.17	0.3%	6.2%	Thunderstorms
October 6, 2011	3.31	1.9%	0.10	0.2%	3.1%	Vehicle Interference
November 5, 2011	3.86	2.2%	1.69	3.2%	43.8%	Snowstorm/Trimmable Trees
TOTAL	37.62	21.6%	7.26	13.7%	19.3%	

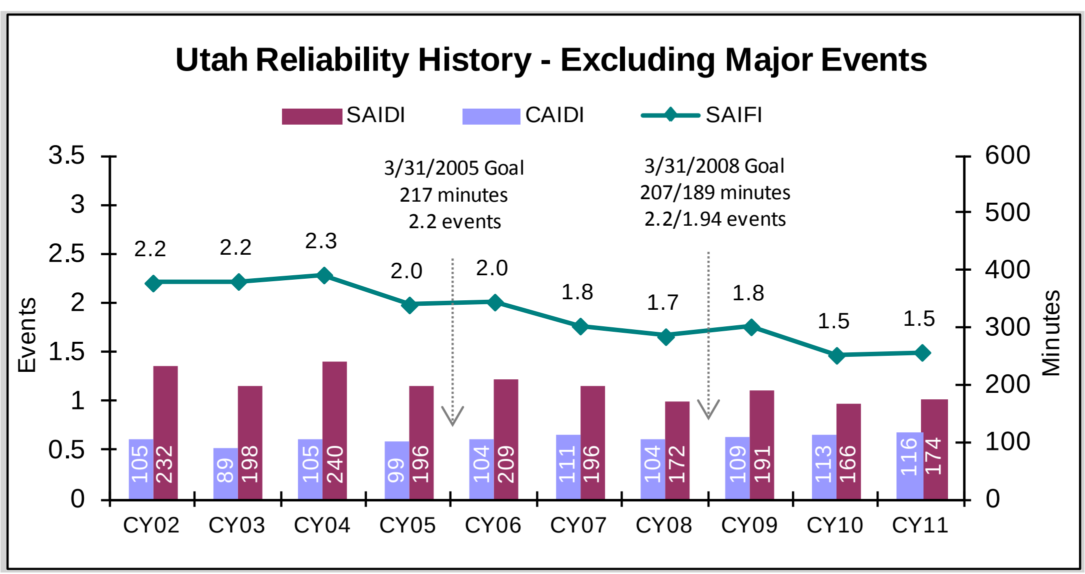
Significant Event General Descriptions

- On 2/1/11 – wind and loss of 34.5 kV line Brian Head substation in Cedar City
- On 4/15/11 – switch burned up at Granger substation in SLC Metro
- On 4/21/11 – windstorm outages in Wasatch area with some loss of transmission lines due to slapping conductor
- On 5/15/11 – windstorm outages in Wasatch area with loss of substations at Pioneer and East Millcreek due to downed trees
- On 5/30/11 – loss of substation due to conductor down inside Sigurd substation and double circuit 46kV pole fire
- On 6/29/11 – thunderstorms caused outages due to wind, lightning, trees and pole fires
- On 8/15/11 – widespread thunderstorms caused outages due to lightning and pole fires
- On 8/28/11 – widespread thunderstorms caused outages due to lightning and pole fires
- On 10/5/11 – widespread thunderstorms caused outages due to lightning and pole fires
- On 10/6/11 – vehicle interference on Tooele #11 affected 2700 customers for 11 hours; some wind and tree-related outages due to stormy weather
- On 11/5/11 – snowstorms caused numerous tree-related outages

6 Reliability History

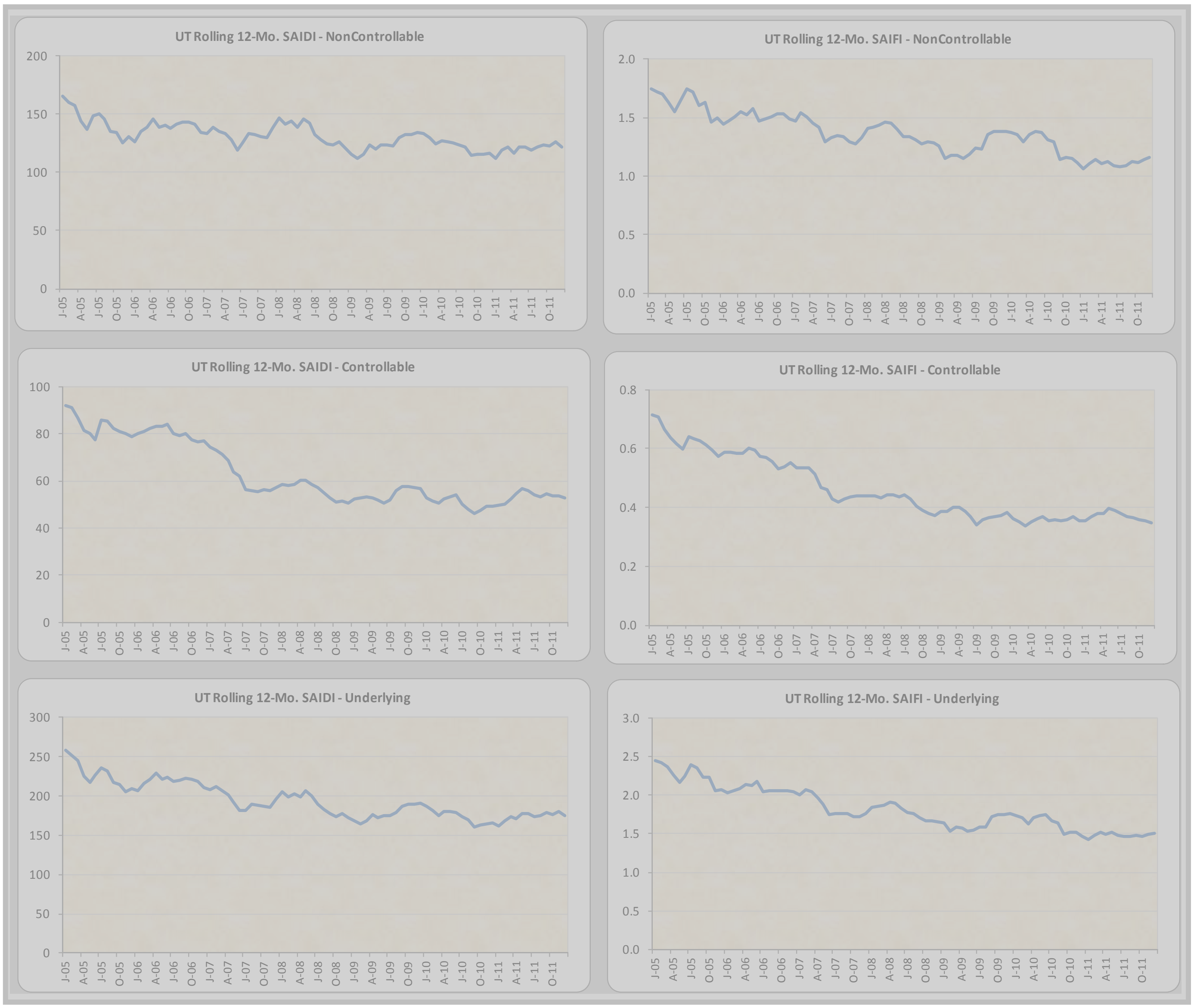
Historically the company has significantly improved reliability as measured by all key reliability indices. These are shown below, and demonstrate the efficacy of the long-term improvement strategies undertaken since early in the decade. It is particularly noteworthy that reliability has been improved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





6.1 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[6].



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

The graphic history demonstrates controllable, non-controllable and underlying performance on a rolling 12-month basis which depicts improvements in all areas. 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.

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

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

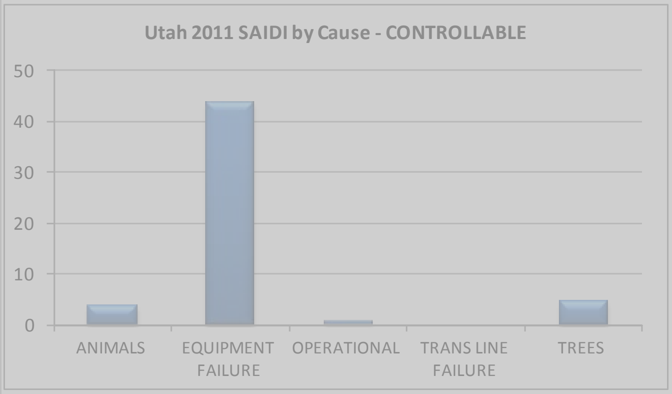
[7] To convert SAIDI (Outage Duration) and SAIFI (Outage Frequency) to Customer Minutes Lost and Sustained Customer Interruptions, respectively, multiply the SAIDI or SAIFI value by 830,483 (2011 Utah frozen customer count).

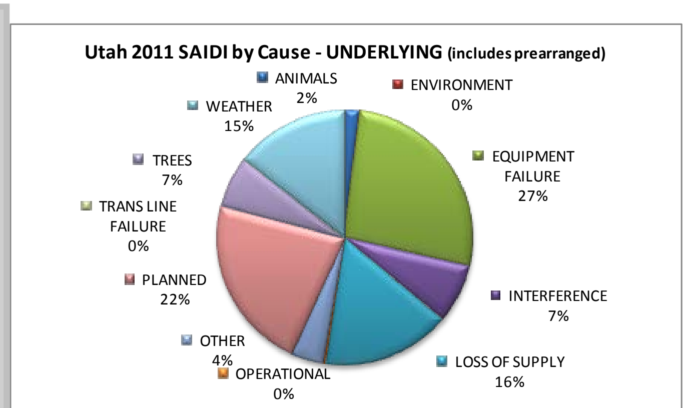
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	975,721.51	10,329	506	1.2	0.012
BIRD MORTALITY (NON-PROTECTED SPECIES)	858,088.57	12,061	297	1.0	0.015
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	423,845.84	4,802	62	0.5	0.006
BIRD NEST (BMTS)	10,963.97	63	17	0.0	0.000
BIRD SUSPECTED, NO MORTALITY	708,271.96	4,902	142	0.9	0.006
ANIMALS	**2,976,891.84**	**32,157**	**1,024**	**3.6**	**0.039**
B/O EQUIPMENT	8,740,943.50	55,924	830	10.5	0.067
DETERIORATION OR ROTTING	26,954,147.07	155,333	5,104	32.5	0.187
OVERLOAD	639,179.97	7,614	114	0.8	0.009
EQUIPMENT FAILURE	**36,334,270.54**	**218,871**	**6,048**	**43.8**	**0.264**
FAULTY INSTALL	41,758.14	397	57	0.1	0.000
IMPROPER PROTECTIVE COORDINATION	71,793.43	721	28	0.1	0.001
INCORRECT RECORDS	44,759.12	888	43	0.1	0.001
INTERNAL CONTRACTOR	148,526.42	4,051	9	0.2	0.005
INTERNAL TREE CONTRACTOR	26,114.62	108	4	0.0	0.000
PACIFICORP EMPLOYEE - FIELD	44,799.33	1,087	19	0.1	0.001
PACIFICORP EMPLOYEE - SUB	136,856.02	7,575	9	0.2	0.009
SWITCHING ERROR	16,091.90	2,327	3	0.0	0.003
OPERATIONAL	**530,698.97**	**17,154**	**172**	**0.6**	**0.021**
STRUCTURES, INSULATORS, CONDUCTOR	6,511.62	3	47	0.0	0.000
TRANS LINE FAILURE	**6,511.62**	**3**	**47**	**0.0**	**0.000**
TREE - TRIMMABLE	3,818,884.47	21,736	480	4.6	0.026
TREES	**3,818,884.47**	**21,736**	**480**	**4.6**	**0.026**
UTAH Controllable Distribution	**43,667,257.43**	**289,921**	**7,771**	**52.6**	**0.349**

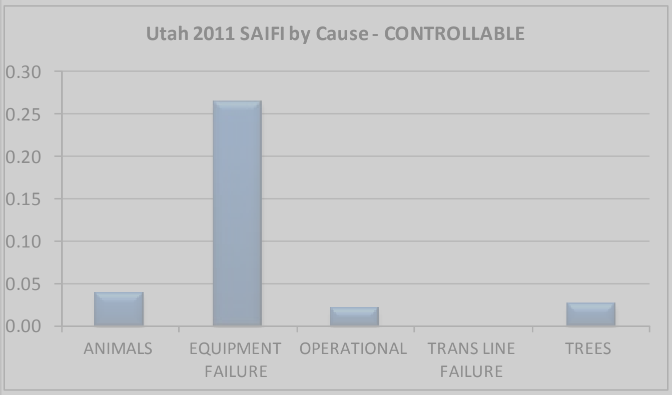
UTAH

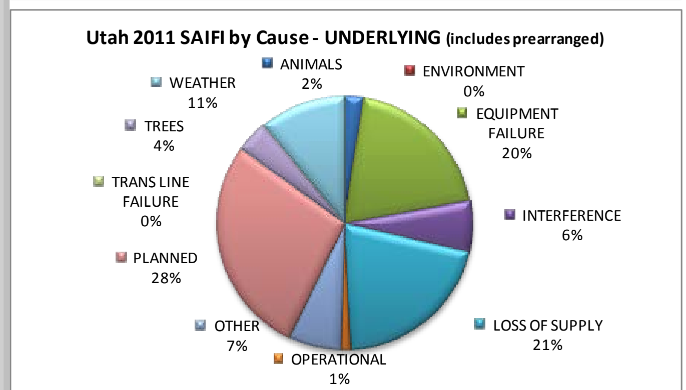
January 1 – December 31, 2011

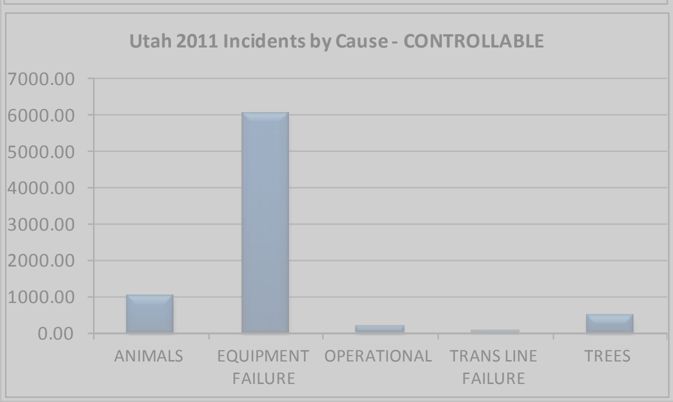
Direct Cause	Customer Minutes Lost for Incident	Customers In Incident Sustained	Sustained Incident Count	SAIDI	SAIFI
ANIMALS	975,721.51	10,329	506	1.2	0.012
BIRD MORTALITY (NON-PROTECTED SPECIES)	858,088.57	12,061	297	1.0	0.015
BIRD MORTALITY (PROTECTED SPECIES) (BMTS)	423,845.84	4,802	62	0.5	0.006
BIRD NEST (BMTS)	10,963.97	63	17	0.0	0.000
BIRD SUSPECTED, NO MORTALITY	708,271.96	4,902	142	0.9	0.006
ANIMALS	2,976,891.84	32,157	1,024	3.6	0.039
CONDENSATION / MOISTURE	11,662.32	112	3	0.0	0.000
CONTAMINATION	6,624.83	56	4	0.0	0.000
FIRE/SMOKE (NOT DUE TO FAULTS)	164,623.90	677	19	0.2	0.001
FLOODING	9,545.53	95	6	0.0	0.000
ENVIRONMENT	192,456.58	940	32	0.2	0.001
B/O EQUIPMENT	8,740,943.50	55,924	830	10.5	0.067
DETERIORATION OR ROTTING	26,954,147.07	155,333	5,104	32.5	0.187
NEARBY FAULT	56,982.22	466	8	0.1	0.001
OVERLOAD	639,179.97	7,614	114	0.8	0.009
POLE FIRE	6,531,761.25	42,929	217	7.9	0.052
EQUIPMENT FAILURE	42,923,014.01	262,266	6,273	51.7	0.316
DIG-IN (NON-PACIFICORP PERSONNEL)	1,844,459.93	13,910	295	2.2	0.017
OTHER INTERFERING OBJECT	980,913.43	12,871	66	1.2	0.015
OTHER UTILITY/CONTRACTOR	439,598.77	2,973	105	0.5	0.004
VANDALISM OR THEFT	697,992.49	5,158	50	0.8	0.006
VEHICLE ACCIDENT	8,086,604.78	52,380	348	9.7	0.063
INTERFERENCE	12,049,569.39	87,292	864	14.5	0.105
FAILURE ON OTHER LINE OR STATION	24.72	1	6	0.0	0.000
LOSS OF FEED FROM SUPPLIER	22,556.32	220	7	0.0	0.000
LOSS OF SUBSTATION	4,917,474.40	56,768	54	5.9	0.068
LOSS OF TRANSMISSION LINE	21,356,192.94	217,524	562	25.7	0.262
SYSTEM PROTECTION	9.00	1	7	0.0	0.000
LOSS OF SUPPLY	26,296,257.38	274,514	636	31.7	0.331
FAULTY INSTALL	41,758.14	397	57	0.1	0.000
IMPROPER PROTECTIVE COORDINATION	71,793.43	721	28	0.1	0.001
INCORRECT RECORDS	44,759.12	888	43	0.1	0.001
INTERNAL CONTRACTOR	148,526.42	4,051	9	0.2	0.005
INTERNAL TREE CONTRACTOR	26,114.62	108	4	0.0	0.000
PACIFICORP EMPLOYEE - FIELD	44,799.33	1,087	19	0.1	0.001
PACIFICORP EMPLOYEE - SUB	136,856.02	7,575	9	0.2	0.009
SWITCHING ERROR	16,091.90	2,327	3	0.0	0.003
UNSAFE SITUATION	177.83	2	2	0.0	0.000
OPERATIONAL	530,876.80	17,156	174	0.6	0.021
OTHER, KNOWN CAUSE	412,035.30	4,586	123	0.5	0.006
UNKNOWN	6,195,604.92	84,359	1,309	7.5	0.102
OTHER	6,607,640.22	88,945	1,432	8.0	0.107
CONSTRUCTION	561,817.71	7,449	467	0.7	0.009
CUSTOMER NOTICE GIVEN	16,030,812.29	80,677	3,013	19.3	0.097
CUSTOMER REQUESTED	379,752.33	3,093	368	0.5	0.004
EMERGENCY DAMAGE REPAIR	17,335,491.83	255,708	1,735	20.9	0.308
INTENTIONAL TO CLEAR TROUBLE	588,651.75	11,080	66	0.7	0.013
TRANSMISSION REQUESTED	996,686.98	12,166	41	1.2	0.015
PLANNED	35,893,212.90	370,173	5,690	43.2	0.446
STRUCTURES, INSULATORS, CONDUCTOR	6,511.62	3	47	0.0	0.000
TRANS LINE FAILURE	6,511.62	3	47	0.0	0.000
TREE - NON-PREVENTABLE	6,623,463.16	33,489	590	8.0	0.040
TREE - TRIMMABLE	3,818,884.47	21,736	480	4.6	0.026
TREES	10,442,347.63	55,225	1,070	12.6	0.066
FREEZING FOG & FROST	105,145.27	1,330	5	0.1	0.002
ICE	7,432.65	51	14	0.0	0.000
LIGHTNING	7,282,198.67	51,445	790	8.8	0.062
SNOW, SLEET AND BLIZZARD	5,793,679.21	33,286	684	7.0	0.040
WIND	10,185,030.83	61,055	748	12.3	0.074
WEATHER	23,373,486.63	147,167	2,241	28.1	0.177
UTAH including Prearranged	**161,292,265**	**1,335,838**	**19,483**	**194.2**	**1.609**
UTAH Underlying	**144,881,700**	**1,252,068**	**16,102**	**174.4**	**1.508**

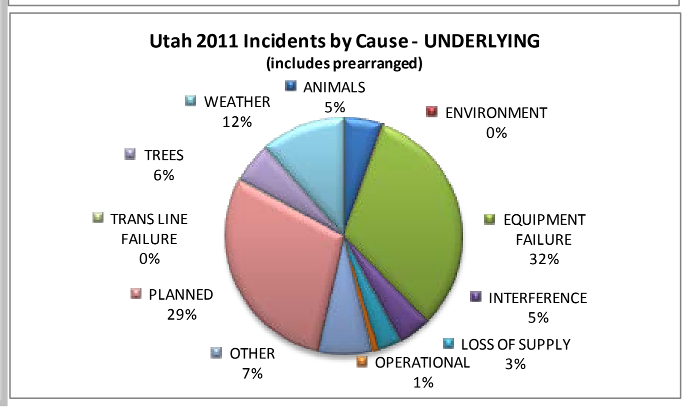

Utah 2011 SAIDI by Cause - CONTROLLABLE
50
40
30
20
10
0
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TRANS LINE FAILURE
TREES


Utah 2011 SAIDI by Cause - UNDERLYING (includes prearranged)
ANIMALS 2%
ENVIRONMENT 0%
EQUIPMENT FAILURE 27%
INTERFERENCE 7%
LOSS OF SUPPLY 16%
OPERATIONAL 0%
OTHER 4%
PLANNED 22%
TRANS LINE FAILURE 0%
TREES 7%
WEATHER 15%


Utah 2011 SAIFI by Cause - CONTROLLABLE
0.30
0.25
0.20
0.15
0.10
0.05
0.00
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TRANS LINE FAILURE
TREES


Utah 2011 SAIFI by Cause - UNDERLYING (includes prearranged)
ANIMALS 2%
ENVIRONMENT 0%
EQUIPMENT FAILURE 20%
INTERFERENCE 6%
LOSS OF SUPPLY 21%
OPERATIONAL 1%
OTHER 7%
PLANNED 28%
TRANS LINE FAILURE 0%
TREES 4%
WEATHER 11%


Utah 2011 Incidents by Cause - CONTROLLABLE
7000.00
6000.00
5000.00
4000.00
3000.00
2000.00
1000.00
0.00
ANIMALS
EQUIPMENT FAILURE
OPERATIONAL
TRANS LINE FAILURE
TREES


Utah 2011 Incidents by Cause - UNDERLYING (includes prearranged)
ANIMALS 5%
ENVIRONMENT 0%
EQUIPMENT FAILURE 32%
INTERFERENCE 5%
LOSS OF SUPPLY 3%
OPERATIONAL 1%
OTHER 7%
PLANNED 29%
TRANS LINE FAILURE 0%
TREES 6%
WEATHER 12%

CATEGORY	~~DESCRIPTION AND EXAMPLES~~Modified Per Rules
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

8 Reduce CPI for Improvement Plan: Areas of Concern 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).

Discussion about plans to improve reliability performance

IMPROVEMENT AREAS ~~WORST PERFORMING CIRCUITS~~	STATUS	BASELINE	Performance 12/31/2011
Program Year 12: (CY2011)			
Lincoln 15	IN PROGRESS	192	185
Huntington City 12	IN PROGRESS	371	554
Magna 15	IN PROGRESS	233	249
Gunnison 12	IN PROGRESS	246	319
Capitol 11	IN PROGRESS	143	136
TARGET SCORE = **190**		**237**	**289**
Program Year 11: (CY2010)			
Decker Lake 12	IN PROGRESS	112	206
North Bench 13	IN PROGRESS	105	295
Newgate 14	IN PROGRESS	178	137
Newton 12	IN PROGRESS	194	108
St Johns 11	IN PROGRESS	755	643
TARGET SCORE = **215**		**269**	**278**

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

8.1 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 3-Year Program-to-date					**84%**
Cumulative January 1 – December 31, 2011					**82%**
January	February	March	April	May	June
85%	87%	83%	82%	83%	72%
July	August	September	October	November	December
83%	77%	83%	87%	82%	88%

8.2 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[8] complaints within 30 days	100%	100%

[8] 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).

8.3 Utah State Customer Guarantee Summary Status

customer*guarantees*

January to December 2011

Utah

	Description	2011 Events	2011 Failures	2011 % Success	2011 Paid	2010 Events	2010 Failures	2010 % Success	2010 Paid
CG1	Restoring Supply	1,239,102	1	99.9%	$50	1,191,689	1	99.9%	$50
CG2	Appointments	6,559	6	99.9%	$300	6,630	9	99.9%	$450
CG3	Switching on Power	10,563	8	99.9%	$400	10,965	14	99.9%	$700
CG4	Estimates	1,561	4	99.7%	$200	1,461	2	99.9%	$100
CG5	Respond to Billing Inquiries	2,243	0	100%	$0	2,858	3	99.9%	$150
CG6	Respond to Meter Problems	796	0	100%	$0	900	0	100%	$0
CG7	Notification of Planned Interruptions	80,677	54	99.9%	$2,700	89,132	74	99.9%	$3,700
		1,341,501	**73**	**99.9%**	**$3,650**	**1,303,635**	**103**	**99.9%**	**$5,150**

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

One reconnect for credit 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.

9 MAINTENANCE COMPLIANCE TO ANNUAL PLAN

9.1 T&D Preventive and Corrective Maintenance Programs

Preventive Maintenance

The primary focus of the preventive maintenance plan is to inspect facilities, identify abnormal conditions[9], 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.[10]
- 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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[9] 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.

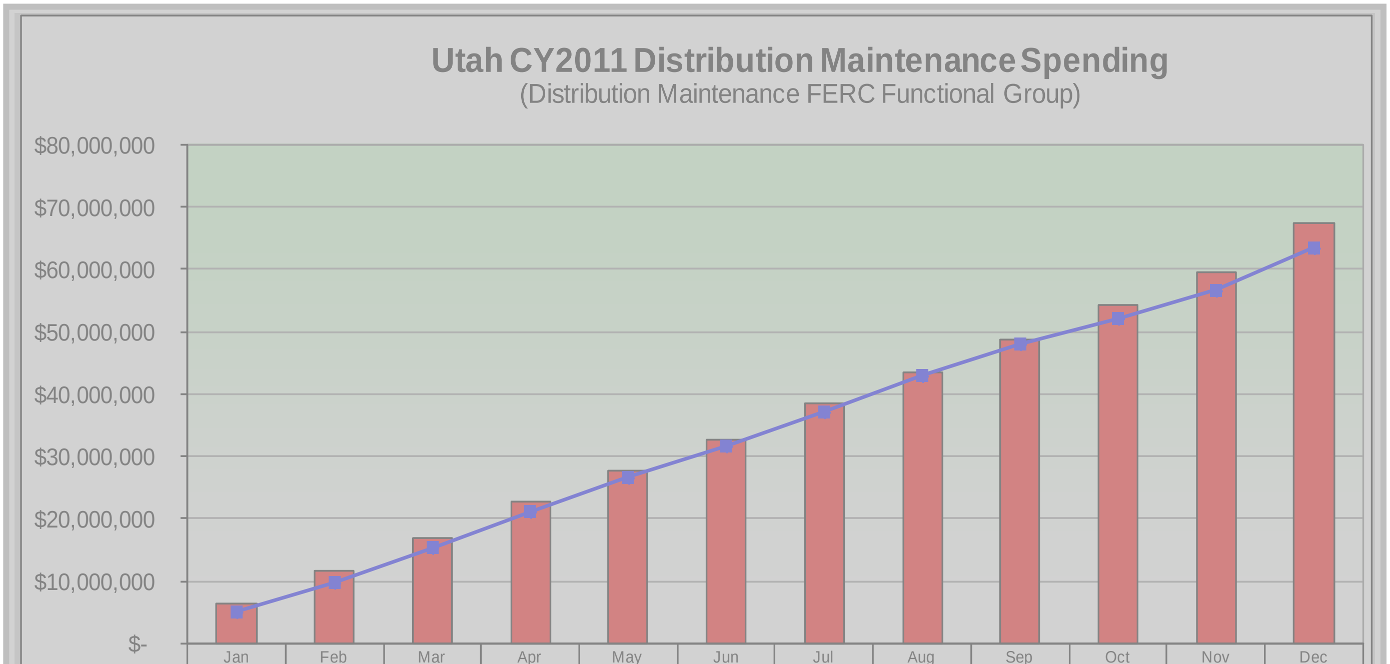
Priority C: Conditions that are nonconforming, but that in the opinion of the inspector do not need to be corrected until the next scheduled work is performed on that facility point.

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.

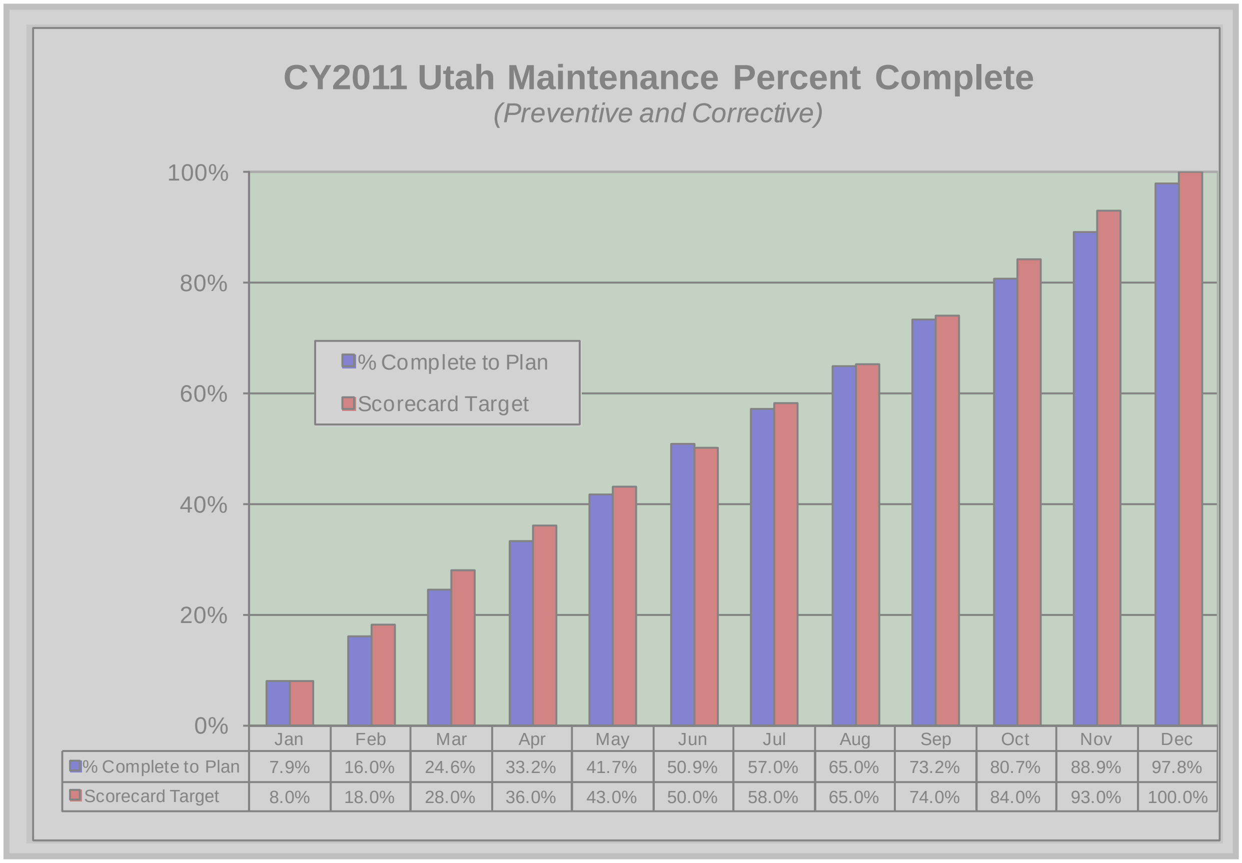
Priority G: Conditions that conform to the NESC, GO95, or GO128 requirement that was in place when construction took place but do not conform to more recent code adoptions. These conditions are "grandfathered" and are considered conforming.

[10] 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.

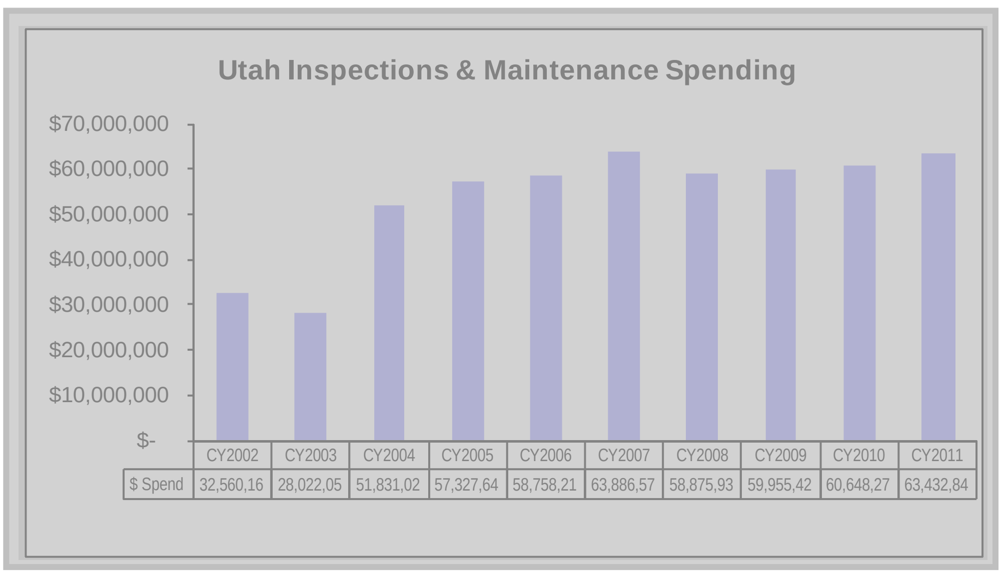
9.2 Maintenance Spending



	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Plan	$6,234,253	$11,499,53	$16,841,76	$22,695,01	$27,679,78	$32,534,22	$38,463,05	$43,320,69	$48,645,45	$54,223,99	$59,536,59	$67,419,85
Actual	$5,031,488	$9,737,017	$15,307,97	$21,104,79	$26,583,70	$31,634,21	$37,108,15	$42,917,68	$48,022,38	$52,111,25	$56,599,98	$63,432,84

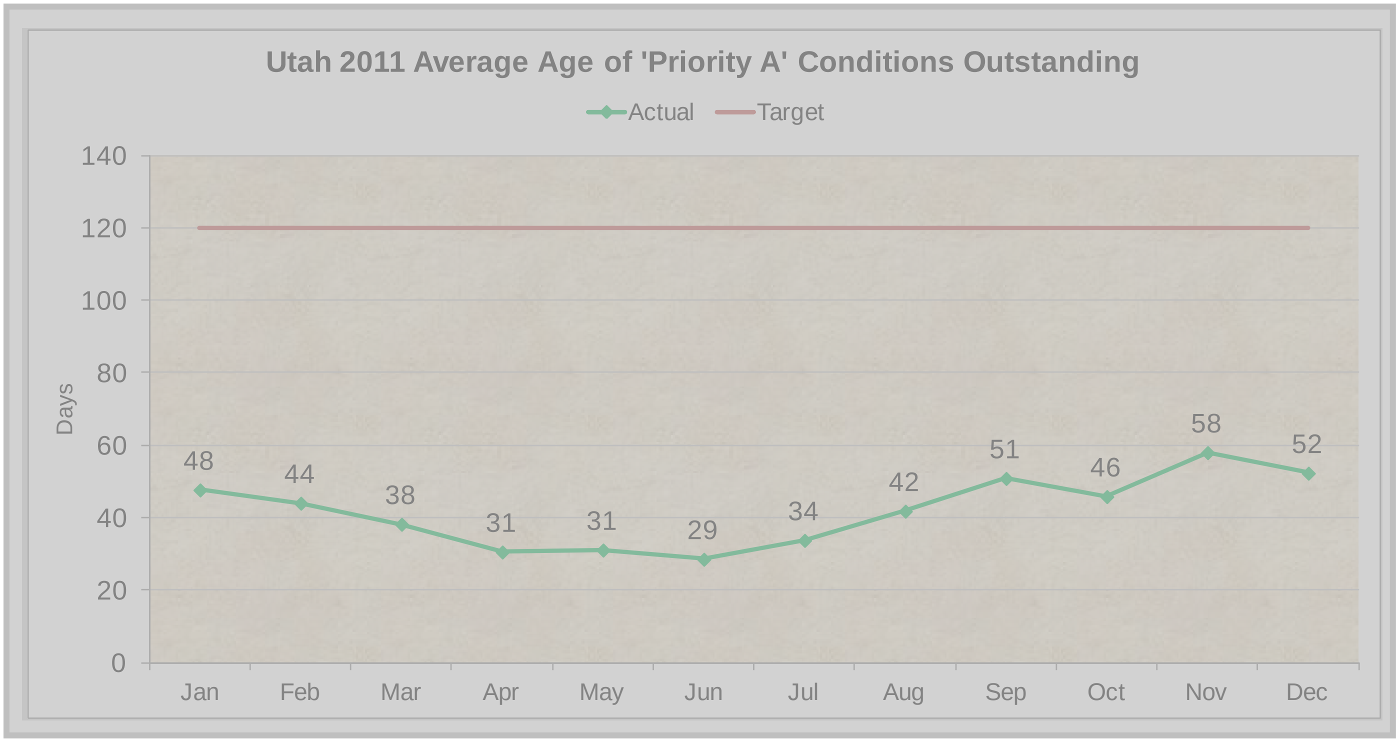


9.2.1 Maintenance Historical Spending



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

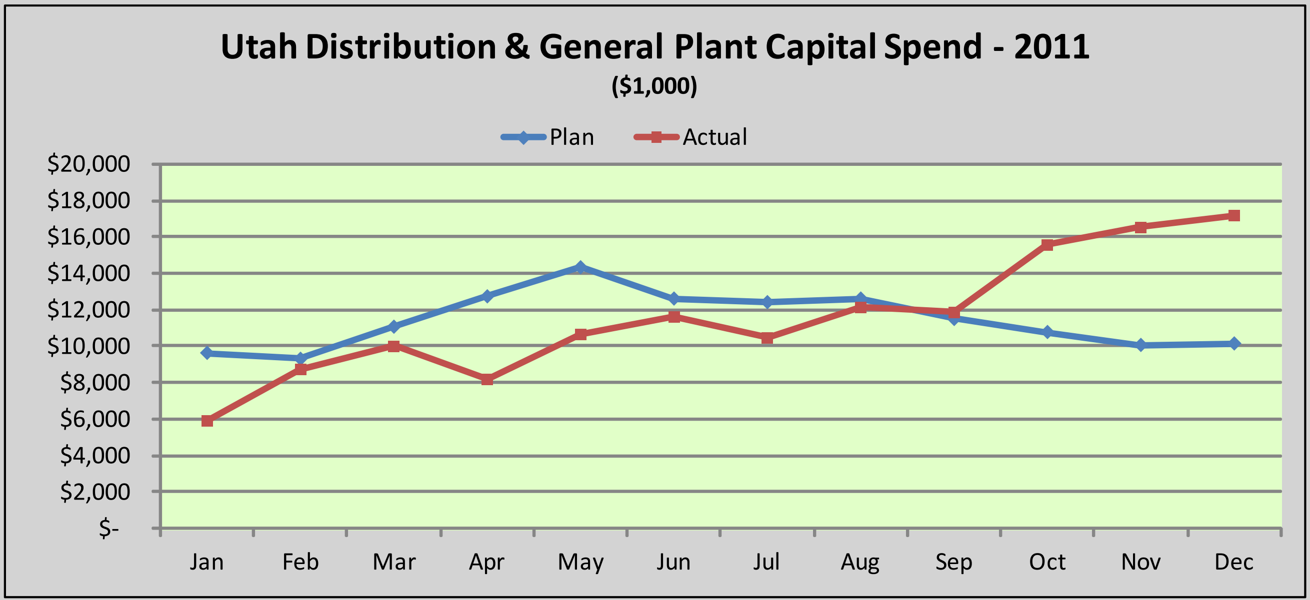
The company reports its compliance for the average age of "A" priority corrections. As can be seen in the chart below, compliance to the target has been consistently delivered.



10 CAPITAL INVESTMENT

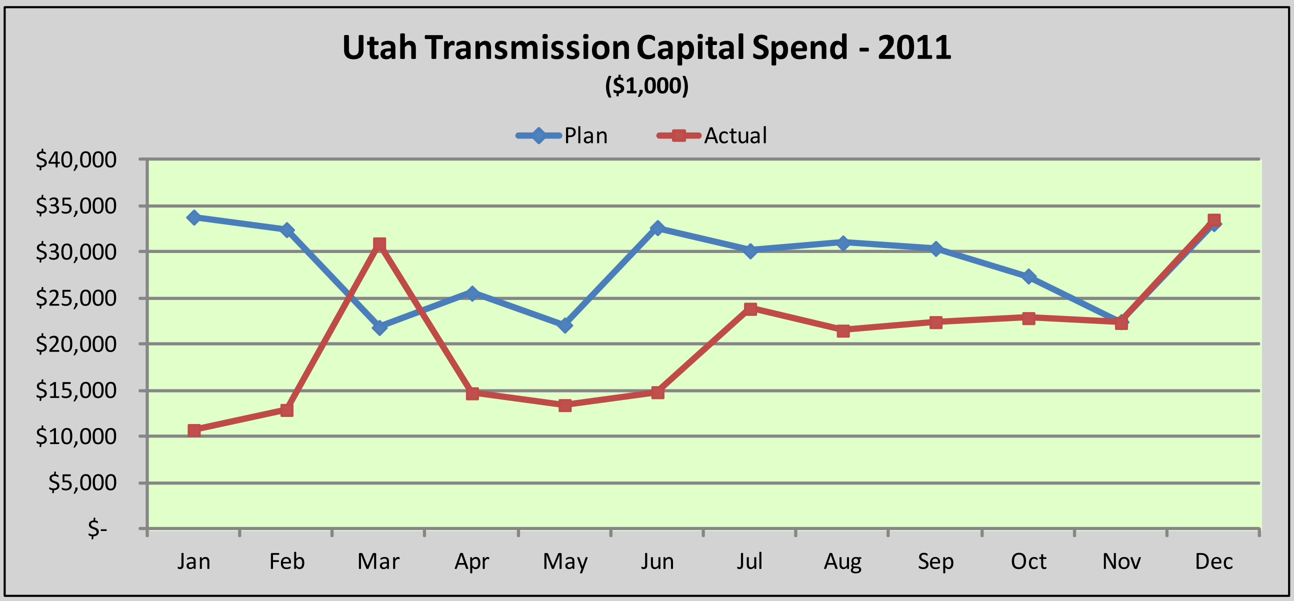
10.1 Capital Spending - Distribution and General Plant

Investment	Actuals ($M)	Plan ($M)	Variance Explanation
1. Mandated	$26.6	$24.5	Highway relocations $3.9m over plan, environmental/avian protection $3.3m over plan, neutral extensions $0.7m over plan, right of way renewals $0.7m over plan; partially offset by regional & national regulatory $6.5m under plan.
2. New Connects	$42.8	$49.6	Residential $4.8m under plan, commercial $4.9m under plan; partially offset by industrial $2.0m over plan and other $0.9m over plan.
3. System Reinforcement	$26.2	$33.0	Substation $13.8 under plan; partially offset by feeder $3.8m over plan, subtransmission $1.9m over plan and other $1.3m over plan.
4. Replacements	$35.9	$29.2	Underground cable $1.1m over plan, overhead distribution poles $1.0m over plan, storm & casualty $3.9m over plan, facilities $1.5m over plan, tools $1.3m over plan; partially offset by meters $1.1m under plan and other $1m under plan.
5. Upgrade & Modernize	$7.2	$1.1	Feeder $2.3m over plan, economically justified (automated meter reading) $3m over plan and other $0.8m over plan.
Total	**$138.7**	**$137.2**	



10.2 Capital Spending - Transmission

Investment	Actuals ($M)	Plan ($M)	Variance Explanation
1. Mandated	9.7	7.7	Non-conforming code issues $3.2m over plan, right of way renewals $1.1m over plan; partially offset by public accommodations $1.7m under plan and other $0.6m under plan.
2. New Connects	(0.1)	0.1	
3. Local Transmission System Reinforcements	39.8	38.3	Substation $15.2m over plan; partially offset subtransmission $12.7m under plan and other $1.0m under plan.
4. Main Grid Reinforcements / Interconnections	51.3	61.6	Main grid $3.5m under plan and generation/municipal interconnections $6.8m under plan.
5. Energy Gateway Transmission	130.3	226.2	Clover sub $11m under plan, Mona-Oquirrh line $38.1m under plan, Oquirrh-Terminal line $15.6m under plan and Sigurd Red Butte-Crystal line $31.2m under plan.
6. Replacements	12.6	8.9	Overhead transmission poles $2.0m over plan, storm & casualty $1.6m over plan and other $0.1m over plan.
7. Upgrade & Modernize	0.6	0.3	Transmission $0.2m over plan and other $0.1m over plan.
Total	**244.1**	**343.1**	



10.3 New Connects

UTAH	2010	Jan	Feb	Mar	Q1 Total	Apr	May	Jun	Q2 Total	Jul	Aug	Sep	Q3 Total	Oct	Nov	Dec	Q4 Total	2011
Residential																		
UT South	578	37	36	37	110	44	41	67	152	46	76	54	176	49	47	42	138	576
UT North/Metro	2,896	269	101	159	529	137	122	216	475	186	209	250	645	190	346	204	740	2,389
UT Central	4,376	330	212	289	831	244	288	387	919	211	567	344	1,122	582	571	446	1,599	4,471
Total Residential	**7,850**	**636**	**349**	**485**	**1,470**	**425**	**451**	**670**	**1,546**	**443**	**852**	**648**	**1,943**	**821**	**964**	**692**	**2,477**	**7,436**
Commercial																		
UT South	223	15	15	10	40	23	20	25	68	14	22	14	50	8	15	18	41	199
UT North/Metro	731	31	39	43	113	40	39	60	139	68	84	64	216	50	88	51	189	657
UT Central	886	63	47	57	167	56	54	87	197	60	88	110	258	96	104	113	313	935
Total Commercial	**1,840**	**109**	**101**	**110**	**320**	**119**	**113**	**172**	**404**	**142**	**194**	**188**	**524**	**154**	**207**	**182**	**543**	**1,791**
Industrial																		
UT South	6	-	-	-	-	-	1	-	1	1	1	8	10	-	3	-	3	14
UT North/Metro	2	-	-	-	-	-	-	-	-	-	-	1	1	-	-	3	3	4
UT Central	2	-	-	-	-	-	-	2	2	1	2	1	4	-	-	-	-	6
Total Industrial	**10**	**-**	**-**	**-**	**-**	**-**	**1**	**2**	**3**	**2**	**3**	**10**	**15**	**-**	**3**	**3**	**6**	**24**
Irrigation																		
UT South	40	1	2	2	5	11	5	9	25	3	4	3	10	4	-	1	5	45
UT North/Metro	5	-	-	-	-	-	-	3	3	-	1	2	3	-	-	-	-	6
UT Central	19	-	-	1	1	-	2	7	9	3	5	1	9	1	-	-	1	20
Total Irrigation	**64**	**1**	**2**	**3**	**6**	**11**	**7**	**19**	**37**	**6**	**10**	**6**	**22**	**5**	**-**	**1**	**6**	**71**
TOTAL New Connects																		
UT South	847	53	53	49	155	78	67	101	246	64	103	79	246	61	65	61	187	834
UT North/Metro	3,634	300	140	202	642	177	161	279	617	254	294	317	865	240	434	258	932	3,056
UT Central	5,283	393	259	347	999	300	344	483	1,127	275	662	456	1,393	679	675	559	1,913	5,432
TOTAL New Connects	**9,764**	**746**	**452**	**598**	**1,796**	**555**	**572**	**863**	**1,990**	**593**	**1,059**	**852**	**2,504**	**980**	**1,174**	**878**	**3,032**	**9,322**

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.

11 VEGETATION MANAGEMENT

11.1 Production

UTAH
Tree Program Reporting
January 1, 2011 through December 31, 2011
Distribution

	3 Year Program/Total Line Miles *column a*	1/1/2011-12/31/2011 Miles Planned *column b*	1/1/2011-12/31/2011 Actual Miles *column c*	01/01/2011-12/31/2011 Ahead/Behind *column d*	1/1/2011-12/31/2011 % Ahead/Behind *column e*	1/1/2011-12/31/2013 Miles Planned *column f*	1/1/2011-12/31/2011 Actual Miles *column g*	01/01/2011-12/31/2011 Ahead/Behind *column h*	1/1/2011-12/31/2011 % Ahead/Behind *column i*
UTAH	11,377	3,792	3,828	36	100.9%	3,792	3,828	36	100.9%
AMERICAN FORK	852	284	183	-101	64.4%	284	183	-101	64.4%
CEDAR CITY	1,342	447	656	209	146.8%	447	656	209	146.8%
JORDAN VALLEY	820	273	366	93	134.1%	273	366	93	134.1%
LAYTON	390	130	64	-66	49.2%	130	64	-66	49.2%
MOAB	962	321	166	-155	51.7%	321	166	-155	51.7%
OGDEN	1,050	350	269	-81	76.9%	350	269	-81	76.9%
PARK CITY	543	181	220	39	121.5%	181	220	39	121.5%
PRICE	641	214	260	46	121.5%	214	260	46	121.5%
RICHFIELD	1,406	469	152	-317	32.4%	469	152	-317	32.4%
SL METRO	1,056	352	549	197	156.0%	352	549	197	156.0%
SMITHFIELD	847	282	359	77	127.3%	282	359	77	127.3%
TOOELE	475	158	91	-67	57.6%	158	91	-67	57.6%
TREMONTON	709	236	415	179	175.8%	236	415	179	175.8%
VERNAL	284	95	78	-17	82.1%	95	78	-17	82.1%

Distribution cycle $/tree:	$53.53
Distribution cycle $/mile:	$2,846
Distribution cycle removal %	42.27%

Transmission

Total Line Miles	Line Miles Scheduled	Line Miles Worked	Miles Ahead(behind) Schedule	Miles on Schedule	% of miles on/behind Schedule
6,076	1,652	1,817	165	6,076	100%

Transmission $/mile: $2,251

Note that 2011 represented the first year of the current cycle, so YTD and cycle to date are the identical.

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

11.2 Budget

UTAH

Tree Program Reporting

	CY2012	CY2013	CY2014
Distribution			
Tree Budget	$12,395,373	$12,395,373	$12,395,373
Transmission			
Tree Budget	$3,642,292	$3,642,292	$3,642,292
Total Tree Budget	$16,037,665	$16,037,665	$16,037,665

	Distribution Actuals	Distribution Budget	Distribution Variance	Transmission Actuals	Transmission Budget	Transmission Variance
Calendar year 2011						
Jan	$888,155	$1,057,948	-$169,793	$314,144	$274,622	$39,522
Feb	$815,076	$957,191	-$142,115	$276,523	$262,186	$14,337
Mar	$1,027,049	$1,158,705	-$131,656	$356,927	$323,231	$33,696
Apr	$1,089,619	$1,057,948	$31,671	$302,123	$320,807	-$18,684
May	$1,061,453	$1,057,948	$3,505	$288,227	$325,006	-$36,779
Jun	$1,114,425	$1,108,326	$6,099	$354,929	$310,446	$44,483
Jul	$1,096,106	$957,191	$138,915	$350,102	$329,688	$20,414
Aug	$1,051,583	$1,158,705	-$107,122	$363,996	$355,636	$8,360
Sep	$913,430	$1,057,948	-$144,518	$406,801	$336,095	$70,706
Oct	$963,050	$1,057,948	-$94,898	$364,913	$309,826	$55,087
Nov	$1,095,425	$1,007,569	$87,856	$340,785	$271,903	$68,882
Dec	$722,050	$1,057,948	-$335,898	$525,619	$272,845	$252,774
Total	$11,837,421	$12,695,375	-$857,955	$4,245,089	$3,692,291	$552,798

Average # Tree Crews on Property (YTD) 72

11.2.1 Vegetation Historical Spending