Unitil Energy Systems, Inc.
May 1, 2014 Step Adjustment

Explanation of Filing

REP and VMP Annual Report 2013

Pursuant to Section 7 of the Settlement Agreement, UES shall file an annual report showing actual REP and VMP activities and costs for the previous calendar year and its planned activities and costs for the current calendar year. Actual and planned REP and VMP costs shown in the report will be reconciled with the revenue requirements associated with the actual planned capital additions and expenses. UES' report for 2013 is attached hereto.

Changes in Non-REP Net Plant in Service

Pursuant to Section 6 of the Settlement Agreement, UES shall file financial documentation showing the actual changes to Net Plant in Service, which is included in the Step Adjustment as described below. Schedule 1 shows the calculation of the change in Non-REP Net Plant in Service. Page 1 shows the actual net book value by plant account at December 31, 2013 while page 2 provides the same information at December 31, 2012. Page 3 provides the change between periods, less the net book cost of 2013 REP projects. Page 4 provides additional supporting detail for the 2013 REP projects.

Step Adjustment Revenue Requirement

The Company has calculated a total revenue requirement of $1,537,205 for the May 1, 2014 Step Adjustment as shown in Schedule 2. The 2014 Step Adjustment reflects 75 percent of the actual change to Non-REP net plant in service between December 31, 2012 and December 31, 2013, adjustments for the change in REP net plant in service, and a reversal of the prior year VMP and REP reconciliation amount.

Non-REP Net Plant in Service: As provided for in Section 6 of the Settlement Agreement, the 2014 Step Adjustment reflects the revenue requirement associated with 75% of the actual change in non-REP net plant in service during 2013. The actual change in non-REP net plant in service during 2013 was $6,128,839, and 75% of that amount is $4,596,629. In Attachment 1 of the Settlement Agreement, the Company forecasted the change in non-REP net plant in service to be $5,929,492 during 2013. The difference between the forecasted and actual change in non-REP net plant in service primarily results from the difference in the long-term capital spending forecast model that used at the time to prepare Attachment 1 and the final approved Capital Budget for 2013, which is prepared with more detail and specificity using current information and data at the start of each budget year. The revenue requirement reflected in the 2014 Step Adjustment is $1,038,215 which was calculated based on 75% of the change in non-REP net plant in service of $4,596,629 during 2013. The amount $4,596,629, or 75% of the change in non-REP net plant in service during 2013, is below the recoverable limits established in Section 6.5 of the Settlement Agreement which specifies an annual maximum change for 75% of non-REP net plant in service of $8 million and a cumulative change of $20 million.

REP Net Plant in Service: As provided for in Sections 2 of the Settlement Agreement, the 2014 Step Adjustment also reflects a revenue requirement of $335,028 associated with $1,730,953 of REP net plant in service additions during 2013.

VMP & REP Reconciliation: In the step effective May 1, 2013, the Company had an over-collection balance of $163,962. Since this will have been collected over the 12 months from May 1, 2013 to May 1, 2014, this amount has been removed from the reconciliation calculation. This permanently removes any over/under collection from base rates. The Company proposes to move all current and future over/under collection of VMP and REP revenue to the Company's External Delivery Charge ("EDC") mechanism since May 1, 2014 is the last step adjustment under the Settlement Agreement. Since the EDC is a reconciling mechanism, the full amount will be returned to customers with interest. Since the step adjustments are effective May 1, the Company will credit the over/under collection to the EDC mechanism on May 1 of the following year where it will accrue interest.

The total revenue requirement for all of the above components of the 2014 Step Adjustment is $1,537,205.

Proposed EDC Reconciliation: As required by Section 7 of the Settlement Agreement, UES has reconciled its VMP and REP program Costs. From December 31, 2012 through December 31, 2013, the Company has collected $4,262,739 in VMP revenue, and will collect an additional $296,000 for the additional four months of the Storm Hardening Program, for a total of $4,558,739 in VMP revenue (Table 1, Page 5). Additionally the Company has collected $200,000 in REP revenue related to VMP (Table 15, Page 28) and $861,886 in revenue from Fairpoint Communications[1], for a grand total of $5,620,625. During that same period, the Company spent $4,723,843 in VMP expense (Table 1, Page 5) and $108,674 of REP expenses related to VMP (Section 3.2.1., Page 28) for a total of $4,832,517, leading to an over-collection of $788,108.

The Company also collected $100,000 in REP revenue related to reliability inspection and maintenance (Table 15 Page 28) from December 31, 2012 to December 31, 2013. During that same period, the Company spent $128,000 (Section 3.2.2, Page 29), for an under-collection of $28,000.

These two components result in an over collection amount of $760,108. As discussed above, this amount will be credited to the EDC mechanism effective May 1, 2014.

Rate Design

Schedule 3 shows the rate design from current rates to the rates proposed in this filing. Columns 2 demonstrates the May 1, 2013 effective rates for all rate classes. Columns 3-5 demonstrate the rate design for the May 1, 2014 Step Adjustment of $1,537,205 following the methodology approved in Section 9 of the Settlement Agreement. The overall percentage increase due to the May 1, 2014 Step Adjustment is 3.15%. Pursuant to the Settlement Agreement, the residential class will receive 115% of this increase, or 3.63% with residential customer charges to remain unchanged and the block difference remaining at $0.00500 per kWh. The remaining revenue requirement is

[1] The Settlement Agreement did not consider payments from FairPoint Communications for tree trimming. UES proposes to credit these payments to its External Delivery Charge.

to be collected from other rate classes on a uniform percentage basis through customer, kWh, demand, and luminaire charges as appropriate. This is a 2.66% increase for non-residential rate classes.

Bill Impacts

Bill impacts are computed and shown in Schedule 4. These reflect rates as proposed in this filing versus currently effective rates. As a result of this filing, a typical 600 kWh residential customer on default service will see a monthly bill increase of $1.13 or 1.1%. Impacts to other rate classes will be similar, but may vary based on size and consumption pattern. These bill impacts do not reflect the proposed credit to the External Delivery Charge which changes on August 1.

Earnings Sharing

In accordance with Section 5 of the Settlement Agreement, UES has calculated its earned return on equity on Form F-1 for the calendar year ending December 31, 2013. Schedule 5 contains UES's Form F-1 for the year ending December 31, 2013 which shows an earned return on equity of 7.7%. Since its return on equity is not greater than 10 percent, UES is not subject to a sharing of earnings for the 2013 calendar year reporting period.

Exogenous Events

In accordance with Section 11 of the Settlement Agreement, UES certifies that no exogenous events occurred during calendar year 2013 which caused changes in excess of the Exogenous Events Rate Adjustment Threshold.

Report and Schedules:

REP and VMP Annual Report 2013
Schedule 1: Changes in Non-REP Net Plant in Service
Schedule 2: Step Adjustment Revenue Requirement
Schedule 3: Rate Design
Schedule 4: Bill Impacts
Schedule 5: Earnings Sharing Calculation
2013 Storm Resiliency Pilot Program Results

THE STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

Unitil Energy Systems, Inc.

RELIABILITY ENHANCEMENT PROGRAM AND VEGETATION MANAGEMENT PROGRAM ANNUAL REPORT 2013

1. Introduction

Pursuant to the Settlement Agreement approved by the New Hampshire Public Utilities Commission ("Commission") in Docket No. DE 10-055[1] , Unitil Energy Systems, Inc. ("UES" or "Company") is submitting the results of the Reliability Enhancement Plan ("REP") and Vegetation Management Plan ("VMP") for Fiscal Year 2013 ("FY 2013"), representing the period, January 1, 2013 – December 31, 2013.

The Settlement Agreement provides that Unitil should implement a REP beginning in calendar year 2011 and allowed Unitil to spend a target amount of $1,750,000 annually and is subject to a cap of $2,000,000 on REP capital spending in any given year. The Step Adjustments for REP capital spending were limited to the years May 1st of the years 2012, 2013, and 2014 to recover the revenue requirements attributable to REP capital expenditures of the preceding year. Unitil is also to increase its annual REP operation and maintenance expense by $300,000 effective May 1, 2012. The Settlement Agreement also provides that Unitil implement an augmented VMP. The revenue requirement for the permanent rates effective May 1, 2011 included $200,000 of augmented VMP spending above the test year amount and the Step Adjustment effective May 1, 2011 provided for an additional increase of $1,250,000 for annual VMP spending. The Step Adjustment effective May 1, 2012 provided for a further increase of $950,000.

The Settlement Agreement also provides that on or before the last day of February of each year following approval, Unitil will provide an annual report to the Commission, Staff and OCA showing actual REP and VMP activities and costs for the previous calendar year, and its planned activities and costs for the current calendar year. Actual and planned REP and VMP costs shown in the report will be

[1] Order 25,214 dated April 26, 2011

reconciled along with the revenue requirements associated with the actual and planned capital additions and expenses. This report includes the following information:

(A) A description of Unitil's VMP;
(B) A comparison of FY2013 actual to budgeted spending on O&M activities related to the VMP
(C) Detail on the O&M spending related to the FY2014 VMP estimated expenditures and work to be completed;
(D) A summary of the reliability performance tracking for pruning, hazard tree and storm pilot program components;
(E) A summary of the Vegetation Management Storm Hardening Pilot Program results;
(F) Detail on the O&M spending related to Exacter Inspection survey;
(G) Detail on the O&M spending related to Enhanced Tree Trimming;
(H) Detail on the REP capital spending for 2013 and 2014 budget; and
(I) Reliability performance of the UES Capital and UES Seacoast systems.

2. Vegetation Management Plan

The Settlement Agreement provides that Unitil will implement an augmented Vegetation Management Program (VMP). The VMP shall be based upon the recommended program provided in the report of Unitil's consultant Environmental Consultants, Inc. ("ECI")[2], modified to incorporate a 5-year multi-phase and 5-year single phase trim cycle with 10-foot side and 15-foot top trim zones. In addition, the VMP will be conducted in a manner that addresses fast growing species, and will provide that deadwood will be removed above the primary, and that deadwood outside the trim zone will be removed if service could be impacted. The VMP shall also comply with the requirements of NESC Rule 218.B regarding overhanging vegetation at railroad and limited access highway crossings[3].

2.1. Plan Description

Unitil's Vegetation Management Program ("VMP") is comprised of six components; 1) circuit pruning; 2) hazard tree mitigation; 3) mid-cycle review; 4) forestry reliability assessment; 5) brush removal; and 6) storm resiliency work. This program is designed to support favorable reliability

[2] A copy of the ECI report, originally provided in response to data request Staff 1-29 (Confidential), was made part of the record in DE 10-055 as a Confidential Exhibit, accompanied by a public redacted version, during the hearing before the Commission.
[3] Reference Settlement Agreement Section 7.3 Page 14 of 26

performance, reduce damage to lines and equipment, as well as provide a measure of public safety. The main benefits and risks addressed by these programs are reliability, regulatory, efficiency, safety and customer satisfaction.

2.1.1. Circuit Pruning

Vegetation maintenance pruning is done on a cyclical schedule by circuit. The optimal cycle length was calculated by balancing five important aspects: 1) clearance to be created at time of pruning; 2) growth rates of predominant species; 3) risk to system performance; 4) aesthetics / public acceptance of pruning; and 5) cost to implement. For New Hampshire, this optimal cycle length was calculated as 5 years for all lines.

2.1.2. Hazard Tree Mitigation

The Hazard Tree Mitigation program ("HTM") consolidates tree removal activities into a formalized program with risk tree assessment. This program is aimed at developing a more resistant electrical system that is more resilient under the impacts of typical wind, rain and snow events. The intention is to accomplish this through minimizing the incidence and resulting damage of large tree and limb failures from above and alongside the conductors through removal of biologically unhealthy or structurally unstable trees and limbs.

HTM circuits are identified and prioritized through reliability assessment risk ranking, identification as a worst performing circuit, field problem identification, and time since last worked. Once circuits are identified they are scheduled in two ways: 1) while the circuit is undergoing cycle pruning; or 2) scheduled independently of cycle pruning. In New Hampshire, HTM circuit selection corresponds closely with cycle pruning, as both pruning and HTM are on a 5 year cycle.

In order to produce the greatest reliability impact quickly and cost effectively, HTM circuit hazard tree assessment and removal is focused primarily on the three phase only, with most emphasis on the portion of the circuit from the substation to the first protection device.

2.1.3. Mid-Cycle Review

The mid-cycle review program targets circuits for inspection and pruning based on time since last circuit pruning and forecasted next circuit pruning. The aim of this program is to address the fastest growing tree species that will grow into the conductors prior to the next cyclic pruning, potentially causing reliability, restoration and safety issues. As the first full circuit pruning cycle is underway, mid-cycle review will be used to address only 13.8kV and above, three-phase portions of selected circuits. Circuit selection is based on number of years since last prune and field assessment.

2.1.4. Forestry Reliability Assessment

The Forestry Reliability Assessment program targets circuits for inspection, pruning, and hazard tree removal based on recent historic reliability performance. The goal of this program is to allow reactive flexibly to address immediate reliability issues not addressed by the scheduled maintenance programs. Using recent historic interruption data, poor performing circuits are selected for analysis of tree related interruptions. Circuits or portions of circuits showing a high number of tree related events per mile, customers interrupted per event, and/or customer minutes interrupted per event are selected for field assessment. After field assessment, suitable circuits are scheduled and a forestry work prescription is written for selected circuits or areas.

2.1.5. Brush Removal

The Brush Removal program targets removal of healthy trees growing under or directly adjacent to conductors to realize benefits of avoided cost of future pruning and future hazard limb or tree removal. Tree removal will be paired with a selective stump treatment program to inhibit sprouting and re-growth and provide short and long-term benefits. The program targets small diameter trees to maximize cost effectiveness.

Due to program prioritization in relation to the VMP ramp up of funding, this program was not selected for implementation in 2013.

2.1.6. Storm Resiliency Work

The Storm Resiliency program targets critical sections of circuits for tree exposure reduction by removing all overhanging vegetation or pruning "ground to sky", as well as performing intensive hazard tree review and removal along these critical sections and the remaining three phase of the circuit. The goal of this program is to reduce tree related incidents and resulting customers interrupted along these portions in minor and major weather events. In turn, the aim is to reduce the overall cost of storm preparation and response, and improve restoration.

2.2. 2013 Actual Expenditures and Work Completed

Table 1 depicts the 2013 VMP expenditures by activity in relation to the anticipated budget expenditures. As the program progressed in 2013 there were some deviations in the anticipated expenditures. The Hazard Tree Mitigation and the Core Work activity required the most deviation in spending relative to anticipated costs. Core work cost was above the anticipated level. Increases were driven by customer requests and emergency work. An additional cost for VMP Planning was also incurred for software to more efficiently and effectively schedule, manage, implement and monitor the VM program components. Due to these unanticipated costs, Hazard Tree Mitigation spending was below the level anticipated. As shown in the table below, total spending was above the budget by $64,668.

Table 1

2013 VMP O&M Activities			
VM Activity	**2013 Cost Proposal**	**2013 Actual Cost**	**2013 Revised Cost***
Cycle Prune	$ 1,156,000	$ 1,202,972	$ 1,123,452
Hazard Tree Mitigation	$ 880,000	$ 695,326	$ 689,154
Forestry Reliability Work	$ 112,000	$ 60,250	$ 60,250
Mid-Cycle Review	$ 81,845	$ 166,330	$ 166,330
Police / Flagger	$ 546,094	$ 638,658	$ 628,035
Core Work	$ 40,000	$ 160,342	$ 156,220
VMP Planning	$ -	$ 11,581	$ 11,581
Distribution Total	**$ 2,815,939**	**$ 2,935,459**	**$ 2,835,023**
Sub-T	$ 100,000	$ 153,699	$ 153,699
VM Staff	$ 219,800	$ 282,709	$ 282,709
Program Total	**$ 3,135,739**	**$ 3,371,867**	**$ 3,271,431**
Storm Pilot Program	$ 1,423,000	$ 1,351,976	$ 1,351,976
Grand Total	**$ 4,558,739[4]**	**$ 4,723,843**	**$ 4,623,407**

*Removed invoices processed after Dec. 2012 cut-off date for work completed in 2012

[4] Test year amount of $735,739 + $200,000 augmented VMP spending in permanent rates + $2,200,000 ($1,250,000 + $950,000) included in step adjustments.

The following tables detail the 2013 VMP work completed by activity. Table 2 details the cycle pruning work. All circuits were completed as planned. A total of 238.7 miles of cycle pruning was completed in 2013.

Table 2

2013 VMP Planned Cycle Pruning Details

District	Feeder	Overhead Miles	Scheduled Miles	Completed Miles
Capital	C13W2	72.9	72.9	72.9
Capital	C34X4	0.2	0.2	0.2
Capital	C33X4	2.0	2.0	2
Capital	C2H1	3.2	3.2	3.2
Capital	C2H2	8.6	8.6	8.6
Capital	C2H4	1.8	1.8	1.8
Capital	C24H1	1.9	1.9	1.9
Capital	C24H2	1.9	1.9	1.9
Capital	16H1	3.8	3.8	3.8
Capital	16H3	4.4	4.4	4.4
Capital	16X4	6.5	6.5	6.5
Capital	16X5	0.5	0.5	0.5
Capital	16X6	0.1	0.1	0.1
Seacoast	E51X1	30.0	30.0	30
Seacoast	E17W2	4.8	4.8	4.8
Seacoast	E2H1	2.3	2.3	2.3
Seacoast	E15X1	9.8	9.8	9.8
Seacoast	E27X1	17.4	17.4	17.4
Seacoast	E13W2	29.4	24.4	24.4
Seacoast	E56X2	2.4	2.4	2.4
Seacoast	E13X3	4.0	4.0	4
Seacoast	E5H1	3.3	3.3	3.3
Seacoast	E5H2	6.9	6.9	6.9
Seacoast	E58X1	31.5	25.6	25.6
Total			**238.7**	**238.7**

Table 3 details the hazard tree mitigation work. A total of 99.8 miles of line across 15 circuits were mitigated for hazard tree risk. Unitil had estimated approximately 1,760 hazard tree removals in the budget. The actual results indicate 2,128 total hazard trees were removed on these circuits and various other circuits as found through the course of work over the year.

Table 3

2013 VMP Planned Hazard Tree Mitigation Details					
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**	**Completed Miles**	**# of Removals**
Capital	C4X1	34.3	7.7	25.6	114
Capital	C18W2	33.6	5.0	5.0	146
Capital	C13W3	15.4	8.2	0.2	2*
Capital	C2H2	8.6	5.2	5.2	2
Capital	C16X4	6.5	3.7	3.7	2
Capital	Various				730
Seacoast	E2X2	20.2	13.0	13.0	37
Seacoast	E46X1	3.9	2.0	0	0
Seacoast	E19X2	2.8	1.7	1.7	8
Seacoast	E11X1	12.1	6.8	6.8	25
Seacoast	E54X1	30.7	7.9	7.9	95
Seacoast	E56X1	17.0	3.7	3.7	52
Seacoast	E18X1	18.1	8.5	8.5	193
Seacoast	E23X1	27.5	10.6	1.5	13*
Seacoast	E47X1	15.3	6.2	6.2	29
Seacoast	E15X1	9.8	6.2	6.2	9
Seacoast	E27X1	17.4	4.6	4.6	96
Seacoast	Various				575
Total			**101**	**99.8**	**2,128**

* All hazard trees identified, marked, and approved for removal but not yet completed in the field – removals to carry over to 2014

Tables 4 and 5 detail the forestry reliability work and mid-cycle work respectively. A total of 28.2 miles of line underwent forestry reliability work and 23 miles of line were completed for mid-cycle work.

Table 4

2013 VMP Planned Reliability Analysis Details				
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**	**Completed Miles**
Capital	C13W1	33.5	6.2	6.2
Capital	C3H1	2.8	1.9	1.9
Seacoast	E22X1	53.5	11.4	11.4
Seacoast	E21W1	28.5	8.7	8.7
Seacoast	E21W2	21.9	8.5	0
Total			**36.7**	**28.2**

Table 5

2013 VMP Planned Mid-Cycle Review Details				
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**	**Completed Miles**
Capital	C15W2	5.7	4.4	4.4
Capital	C22W3	4.5	3.2	3.2
Seacoast	E19X3	37.8	15.4	15.4
Seacoast	E6W1	26.8	5.7	0
Seacoast	E6W2	19.0	4.9	0
Total			**33.6**	**23.0**

Table 6 details the sub-transmission right-of-way clearing work. A total of 189 acres were cleared.

Table 6

2013 Sub Transmission Planned Clearing Details				
District	**Feeder**	**Scheduled Miles**	**Scheduled Acres**	**Completed Acres**
Capital	35	3.6	44	44
Capital	34	3.5	44	44
Seacoast	3343/3354	7.9	101	101
Total		**15.0**	**189**	**189**

2.3. 2014 VMP Estimated Expenditures and Work To Be Completed

Table 7 depicts the 2014 VMP expenditures by activity and the proposed VMP activity details. Unitil proposes to spend $3,135,739[5] on VMP activities and another $1,423,000 on vegetation storm resiliency, explained in more detail below, for a total of $4,558,739.

Table 7

2014 VMP O&M Activities Cost Proposal		
VM Activity		**2014 Cost Proposal**
Cycle Prune	$	1,156,000
Hazard Tree Mitigation	$	800,000
Forestry Reliability Work	$	81,845
Mid-Cycle Review	$	112,000
Brush Control	$	-
Police / Flagger	$	526,094
Core Work	$	100,000
Distribution Total	**$**	**2,775,939**
Sub-T	$	140,000
VM Staff	$	219,800
Program Total	**$**	**3,135,739**
Storm Resiliency Work	$	1,423,000
Grand Total	**$**	**4,558,739**

[5] Test year amount of $735,739 + $200,000 augmented VMP spending in permanent rates + $1,250,000 included in step adjustments + $950,000 increase to step adjustment effective May 1, 2012.

Tables 8 through 12 provide more detail on each of the VMP activities planned for 2014. The activities include 242 miles of cycle pruning (Table 8), 89.4 miles of hazard tree mitigation (Table 9) which estimates 1,942 hazard tree removals, 16.3 miles of forestry reliability work (Table 10), 49.8 miles of mid-cycle pruning (Table 11), and 186 acres of sub-transmission clearing.

Table 8

2014 VMP Planned Cycle Pruning Details			
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**
Capital	C13W1	33.5	29
Capital	C4X1	34.4	30.6
Capital	C4W4	14.2	14.2
Capital	C22W1	4.4	4.4
Capital	C22W2	0.9	0.9
Capital	C7W4	7.4	7.4
Capital	C8H1	1.2	1.2
Capital	C8H2	4.7	4.7
Capital	C8X5	7.3	7.3
Capital	C38E	4.1	4.1
Capital	C38W	3.7	3.7
Seacoast	E21W1	28.5	28.5
Seacoast	E21W2	21.6	21.6
Seacoast	E13W1	18.5	18.5
Seacoast	E7X2	19.1	19.1
Seacoast	E18X1	18	18
Seacoast	E17W1	8.7	8.7
Seacoast	E47X1	15.4	15.4
Seacoast	E19H1	4.7	4.7
Total			**242**

Table 9

2014 VMP Planned Hazard Tree Mitigation Details			
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**
Capital	C13W3	7.0	3.2
Capital	C6X3	15.1	4.7
Capital	C14H2	3.9	1.6
Capital	C4W4	14.2	4.0
Capital	C22W1	4.4	3.2
Capital	C7W4	7.4	4.2
Capital	C8H2	4.7	2.3
Capital	C8X5	7.3	6.8
Capital	C38E	4.1	2.3
Capital	C38W	3.7	3.0
Seacoast	E23X1	27.5	10.6
Seacoast	E6W1	26.9	5.8
Seacoast	E6W2	18.9	4.9
Seacoast	E21W1	28.5	8.9
Seacoast	E13W1	18.5	4.6
Seacoast	E7X2	19.1	6.3
Seacoast	E17W1	8.7	3.5
Seacoast	E47X1	15.4	6.2
Seacoast	E19H1	4.7	3.3
Total			**89.4**

Table 10

2014 VMP Planned Reliability Analysis Details			
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**
Capital	C22W3	39.7	11.3
Capital	C15W1	16.7	5.0
Total			**16.3**

Table 11

2014 VMP Planned Mid-Cycle Review Details			
District	**Feeder**	**Overhead Miles**	**Scheduled Miles**
Capital	C6X3	15.1	4.7
Capital	C13W3	82.9	7.4
Capital	C37X1	6.3	1.1
Seacoast	E19X3	37.8	15.4
Seacoast	E6W1	26.8	5.7
Seacoast	E6W2	19.0	4.9
Seacoast	E23X1	27.5	10.6
Total			**49.8**

Table 12

2014 Sub Transmission Planned Clearing Details			
District	**Feeder**	**Scheduled Miles**	**Scheduled Acres**
Capital	34/36	3.5	43.5
Capital	37	3.6	44.5
Seacoast	3359	7.7	61.9
Seacoast	3348/3350	4.5	36.1
Total		**19.3**	**186.0**

2.4. Vegetation Management Storm Hardening Pilot Program Results

In 2012, Unitil embarked on a pilot project that targeted specific circuits in communities in the Seacoast area which underwent extensive tree exposure reduction. In 2013, Unitil continued this pilot project in communities in the Capital area. In both years these circuits were selected through analysis of tree related reliability performance. The 2013 circuits are shown below in Table 13. In 2013, 32.3 miles of critical three phase line had all overhanging vegetation removed (pruned “ground-to-sky”) and 2,271 hazard trees were removed along this portion as well as 16.7 additional miles of three phase.

Table 13

2013 Storm Pilot Work Details			
Circuit	**Scheduled Miles**	**Completed Miles**	**# of Removals**
C13W1	6.2	6.2	657
C18W2	5.0	5.0	823
C4X1	6.9[6]	6.9	253
C7W3	14.2	14.2	538
Total	**32.3**	**32.3**	**2,271**

This program was met with huge success in both years. All pilot program work in 2013 was completed within 5% of the estimated budget, with final expenditures (excluding spring tree replanting costs) totaling $1,351,976, just below the $1,423,000 budget estimate. For the second year in a row, the planned pruning and removals were obtained with very limited customer opposition or complaints.

During the course of the 2013 pilot pruning and removal work, Unitil was able to see the work's response to a minor storm event. On November 24-25, 2013 the company's Capital region experienced a wind event that was forecasted as an EII 4 event with wind gusts of 40-50mph. At this time, the Company's 2013 storm resiliency pilot program circuit, C13W1 was complete. During this event, 4 tree related outages were sustained on the C13W1 circuit on the laterals only, and no tree related events on the portions that underwent storm resiliency work.

As designed, the critical portions of this circuit did not experience and interruption and many customers served off this circuit did not experience an electrical outage. It is difficult to tell if an event on the critical portion was avoided. However, by looking at the tree related events on the surrounding lines, an estimate of events that would have been seen on the critical portions can be determined.

By looking at the number of events on the unworked portion, an event per mile calculation can be determined. Assuming that the portion of circuit that was worked would have had the same tree failure rate, this event per mile calculation can be used to determine the avoided events on the storm resiliency circuit miles. There were 4 events along the 27.3 miles not under the storm resiliency program; 0.146 events per mile. Apply this to the storm resiliency area worked and assume this work avoided 0.146

[6] C4X1 scheduled mileage adjusted from 7.7 miles to 6.9 miles before work planning, due to circuit configuration and isolating device changes.

events per mile over the entire 6.2 miles of area worked; then ~1 event on the critical portions of line was avoided during this wind event.

The Unitil Seacoast Pilot area from 2012 continued to maintain favorable reliability throughout 2013, even while experiencing minor snow events in January / February 2013 and minor rain and wind event over this time frame. Again, the Storm Pilot circuits performed well with no major events.

From this pilot over the last two years, it is apparent that the Storm Resiliency work has the ability to prevent tree related failures and subsequent electric incidents. This reduction in incidents reduces damage to the electric infrastructure and the need for crews to respond, in turn reducing overall storm costs.

As the Company has explained more fully in the Storm Resiliency Pilot Program Cost Benefit Analysis report, there are also a number of additional benefits associated with a tree exposure reducing Storm Resiliency program, including:

- Preserving municipal critical infrastructure
- Minimizing the dependence on mutual aid and off system resources
- Minimizing the total number of resources required to restore service
- Shortening the duration of major events
- Minimizing the overall cost of restoration
- Reducing economic loss to municipals, businesses, and customers
- Most cost effective solution vs. other alternatives
- Minimal bill impact on a per-customer basis

2.5. Vegetation Management Storm Resiliency Program Recommendation

After reviewing the results of the Storm Hardening Pilot program, Unitil found that the reliability effects, the avoided interruptions and costs, and the positive public acceptance more than offsets the cost to implement. For this reason, Unitil is proposing to add a Vegetation Management Storm Resiliency companion program to the current Vegetation Management Program.

This program builds on the pilot and proposes to perform VM Resiliency work on 298 miles of line in the New Hampshire service territory over the remaining 9 year period for an annual cost of $1.423 million. This work will mirror the pilot program in specifications where critical sections of the circuit, from the substation out to the first protection device, will have tree exposure reduced by removing all

overhanging vegetation or pruning "ground to sky." Intensive hazard tree review and removal will also be conducted on these critical sections. In cases where the customer count is either over 500 customers or over 1/3 the total customers served at the first protection device (if less than 500), overhang and hazard tree removal will continue to the second protection device. From that point, hazard tree inspection and removal will be conducted out to the third protection device or along remaining three phase lines.

For 2014, resiliency work on 34.7 miles of line in the Seacoast service area is proposed, at a total cost of $1,423,000. These circuits, shown in Table 14, were chosen for their recent historic reliability performance, number of customers served, field conditions, and location.

Table 14

2014 Storm Pilot Planned Work Details		
Circuit	**Overhead Miles**	**Scheduled Miles**
E22X1	53.5	11.4
E43X1	30.6	7.9
E19X3	37.8	15.4
Total		**34.7**

2.6. Vegetation Management Reliability Performance Tracking

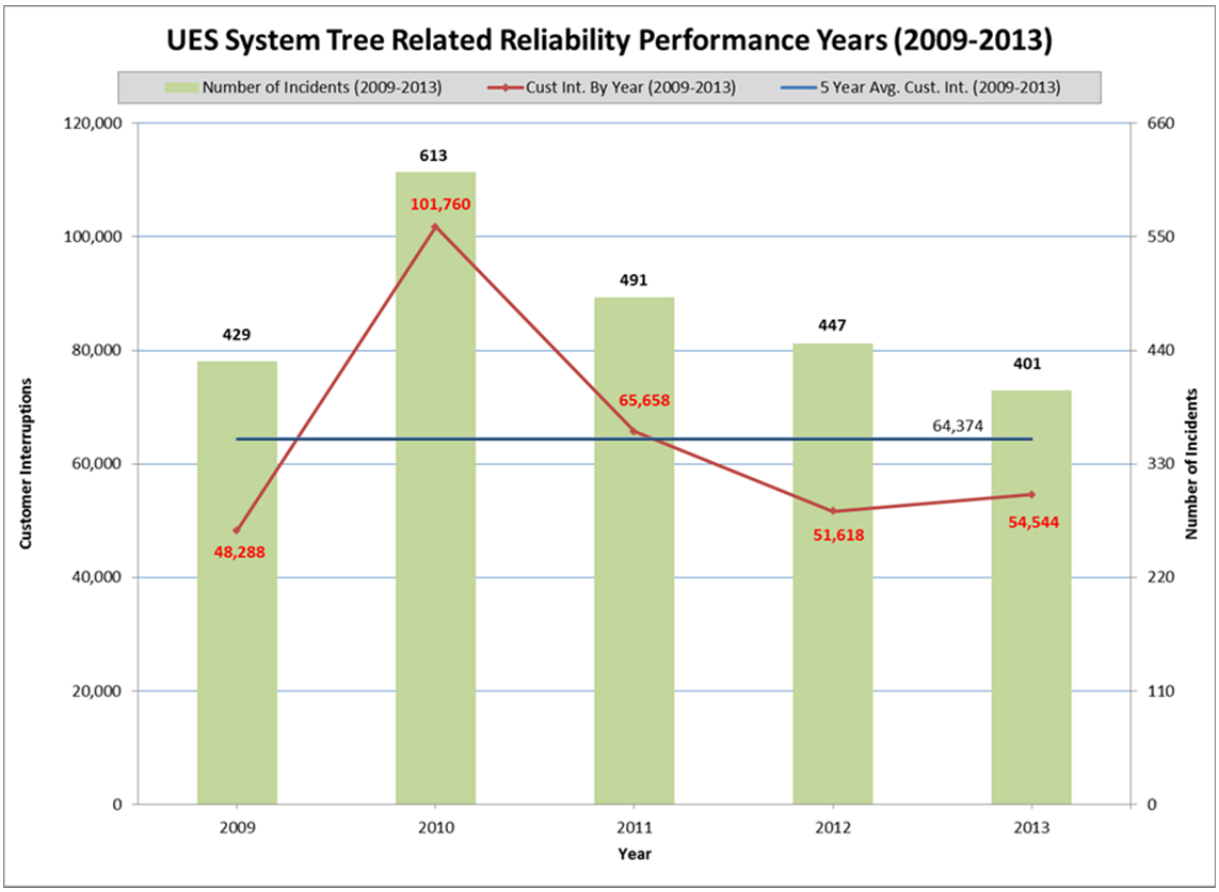
As the Vegetation Management Program progresses through its first five year prune and hazard tree cycles, the effects of these programs on reliability have begun to emerge. In order to study the results of these programs and the combination of VM components that have the largest reliability effect, the Company has developed VM Program reliability analysis[7]. Overall New Hampshire system tree related reliability performance was reviewed, as well as the individual circuits and program components that were undertaken. Chart 1, shown below, displays the number of customers interrupted per year from tree related incidents from 2009 to 2013 against the 5 year average of tree related incidents from 2009 to 2013.

2.6.1.System Overview

[7] Data errors were found in the graphs included with the previous year's filing. These graphs represent the corrected data with the inclusion of 2013 performance.

Chart 1 shows a declining trend in customers interrupted as well as a decline in tree related incidents from 2010 through 2013. It also shows the number of customers interrupted in 2013 is below the historic 5 year average for the second year in a row. Although the VM program is still in its infancy, the Company believes this trend is indicative of overall positive program results.

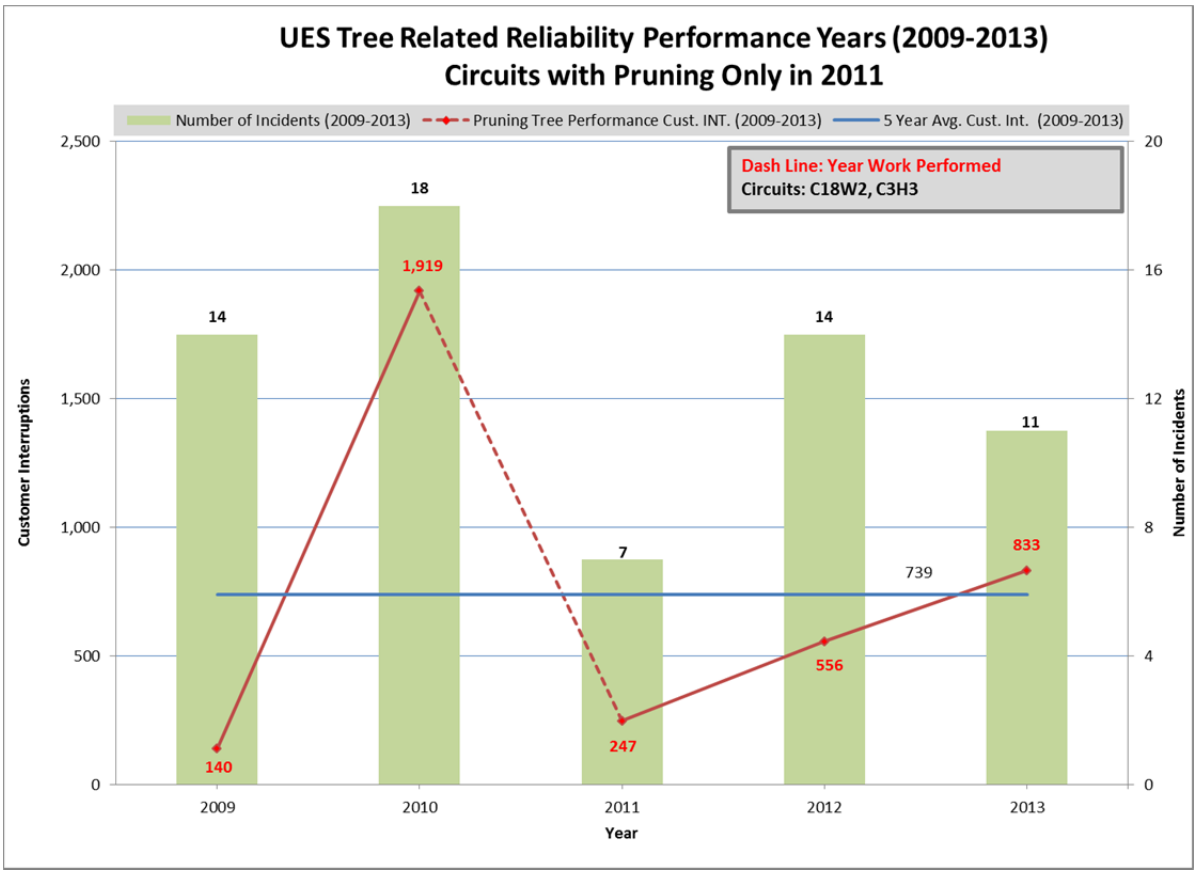
Chart 1



2.6.2.Pruning Only – Done in Years 2011 to 2013

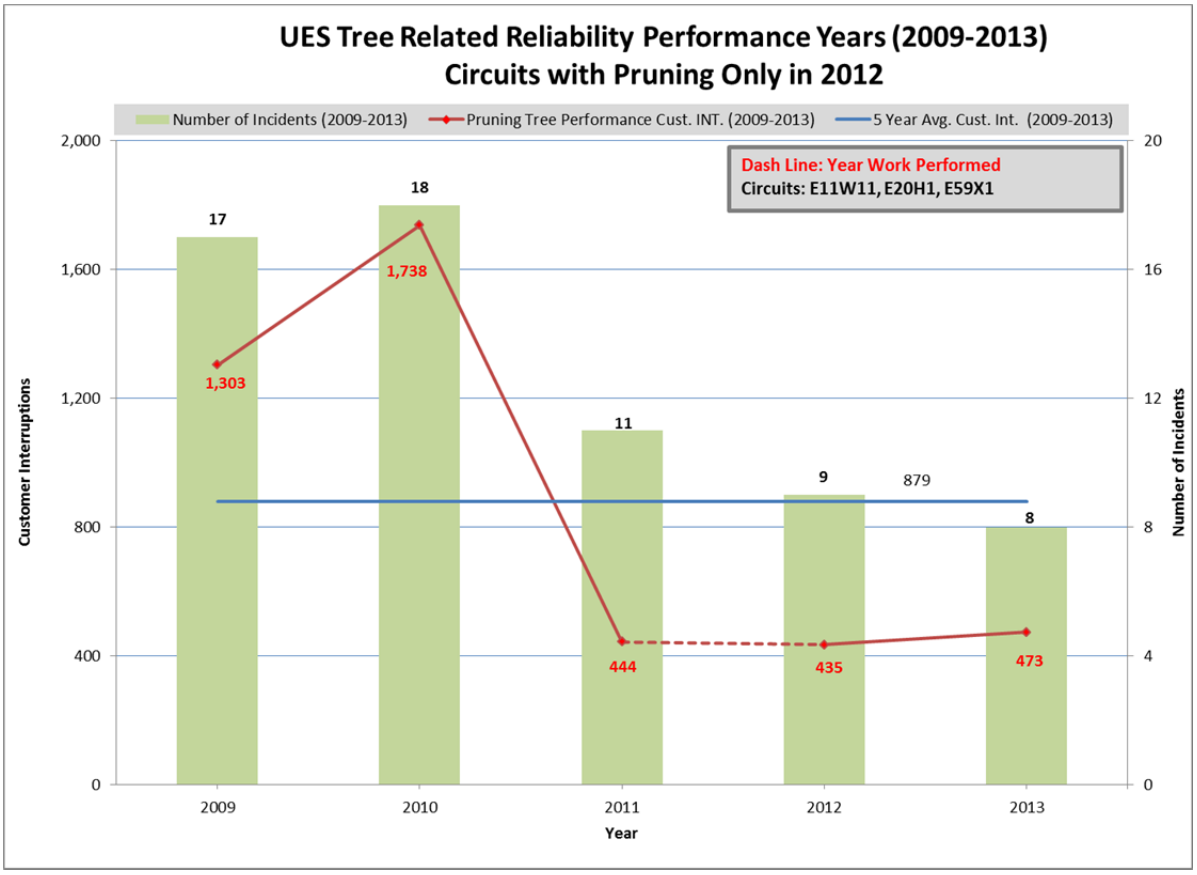
Chart 2, Chart 3, and Chart 4 shown below, display the tree related reliability performance of the individual circuits that underwent pruning only in 2011, 2012, and 2013 respectively. The dashed line represents the year pruning occurred. It is important to note that pruning could have occurred at any point during that year from January through December, and includes a combination of before and after pruning results.

Chart 2



5 Year Avg Cust-Int (2009-2013)	5 Year Avg # of Incidents (2009-2013)		Avg After Trimming Cust-Int (2011)	Year After Trimming # of Incidents (2011)		Cust-Int Percentage Change	No of Incidents Percentage Change
739	12.8		695	12.5		-6.0%	-2.3%

Chart 3



5 Year Avg Cust-Int (2009-2013)	5 Year Avg # of Incidents (2009-2013)		Avg After Trimming Cust-Int (2012)	Year After Trimming # of Incidents (2012)		Cust-Int Percentage Change	No of Incidents Percentage Change
879	12.6		473	8.0		-46.2%	-36.5%

Charts 2 and 3 show reliability results in the years after pruning. Both charts show that the average customers interrupted and the average incidents is lower than the historic 5 year average – indicating reliability improvement. Chart 2 shows a 6% improvement in customers interrupted over the 2 years since pruning, even though the number of customers interrupted each year since 2011 has risen slightly. Chart 3 shows a 46% improvement in customers interrupted over the year since pruning. Both charts show a decrease in incidents in every year since pruning, showing that the actual number of tree related events on these circuits has declined.

Chart 4

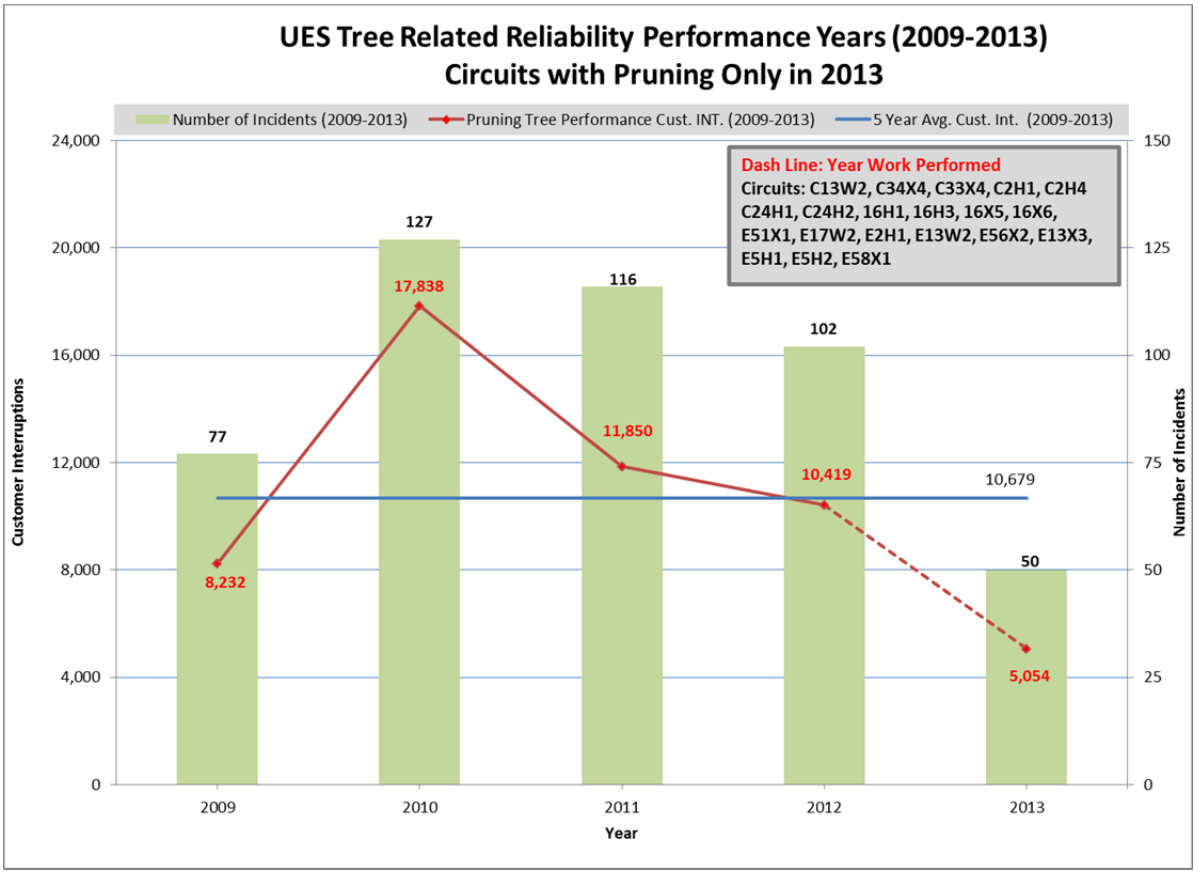
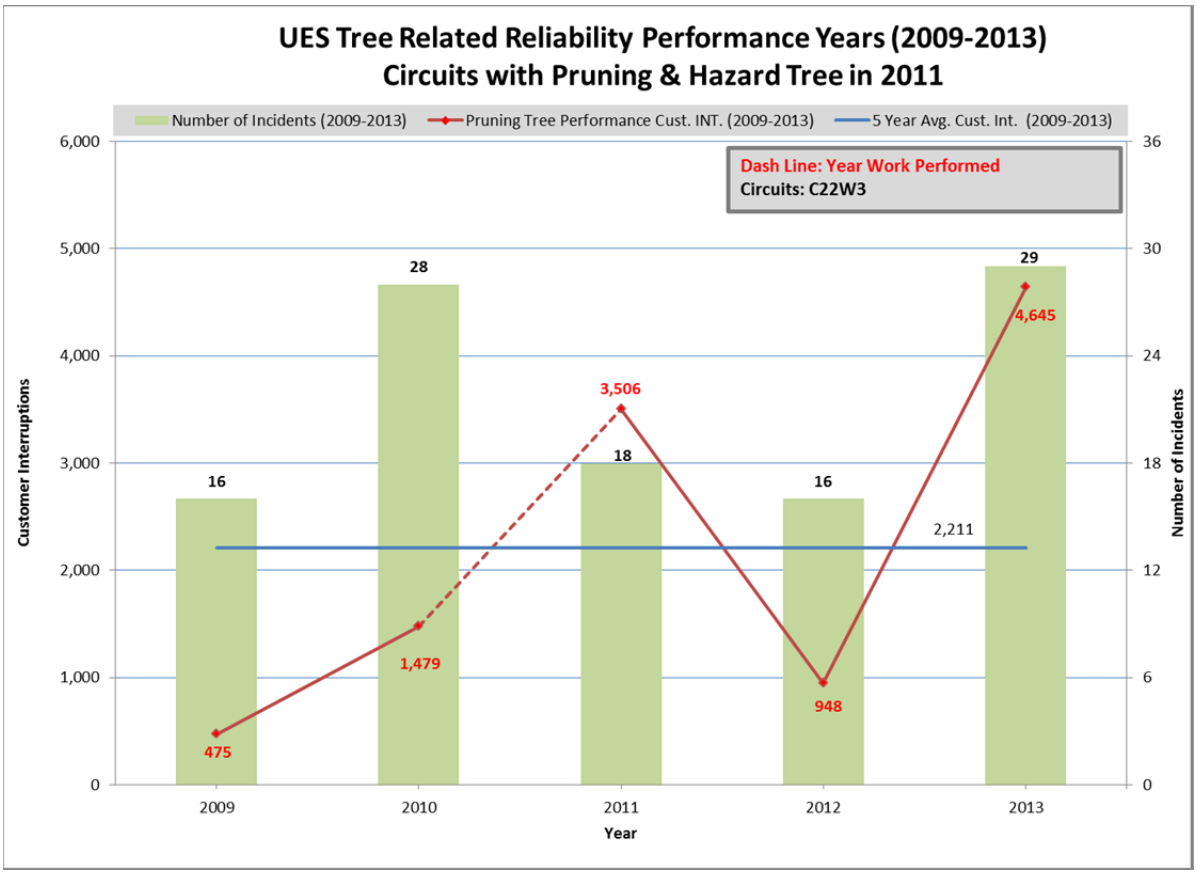


Chart 4 shows the pruning only work that was done in 2013 and the reliability results that occurred last year during pruning. The number of customers interrupted and the incidents decreased. It is important to note that work could have occurred at any point during the year and the reliability information includes a combination of reliability results from before and after work was completed.

2.6.3.Pruning & Hazard Tree – Done in Years 2011 to 2013

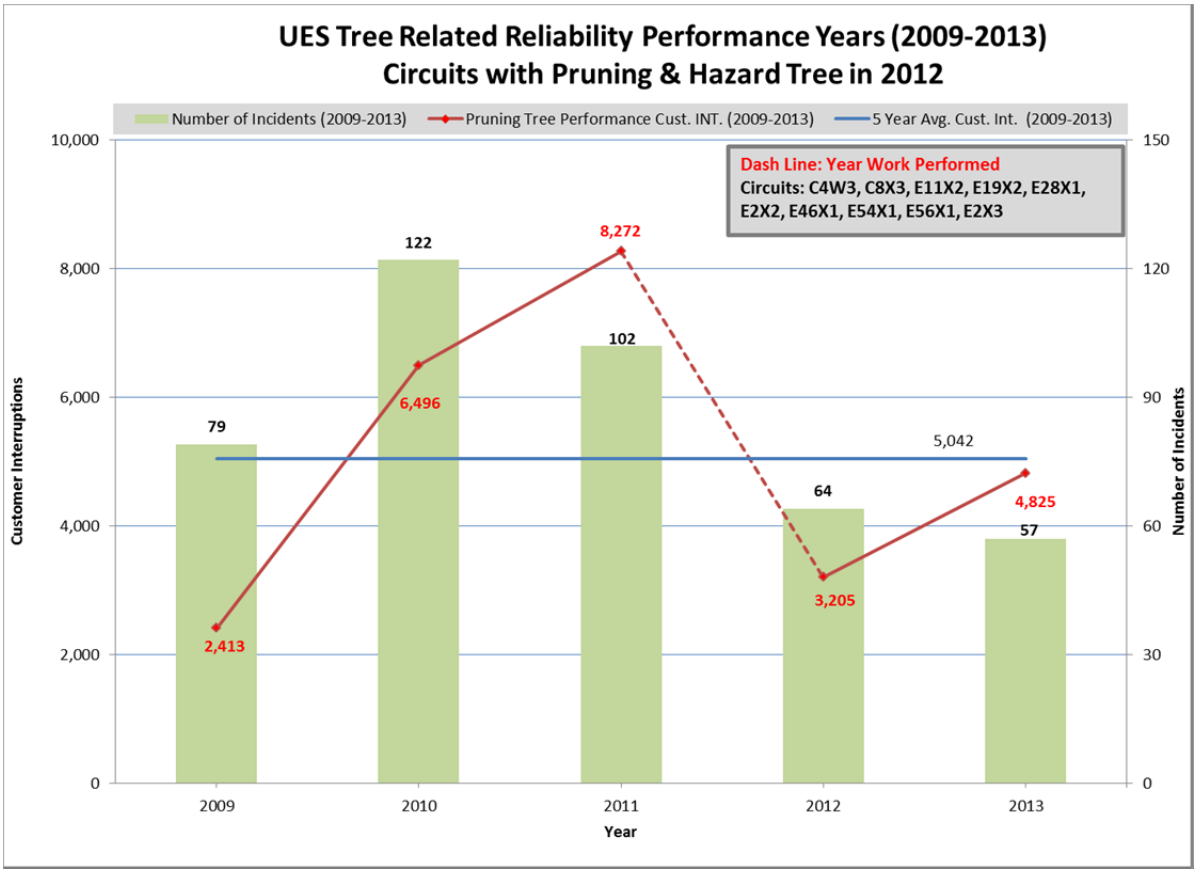
Chart 5 and Chart 6, and Chart 7 shown below, display the tree related reliability performance of the individual circuit(s) that underwent pruning and hazard tree together in 2011, 2012, and 2013 respectively. The dashed line represents the year work occurred.

Chart 5



5 Year Avg Cust-Int (2009-2013)	5 Year Avg # of Incidents (2009-2013)		Avg After Trimming Cust-Int (2011)	Year After Trimming # of Incidents (2011)		Cust-Int Percentage Change	No of Incidents Percentage Change
2,211	21.4		2,797	22.5		26.5%	5.1%

Chart 6



5 Year Avg Cust-Int (2009-2013)	5 Year Avg # of Incidents (2009-2013)	Avg After Trimming Cust-Int (2012)	Year After Trimming # of Incidents (2012)	Cust-Int Percentage Change	No of Incidents Percentage Change
5,042	84.8	4,825	57.0	-4.3%	-32.8%

Charts 5 and 6 show reliability results in the years after pruning and hazard tree work. Chart 5 shows a decrease in incidents and customers interrupted the first year after work was done but an increase incidents and customers interrupted the second year after. It is important to note that only one circuit underwent both pruning and hazard tree in 2011 making the study population very small. Upon further analysis as to the large spike in customers interrupted and incidents in the second year following work, it was found that there were three days of minor storm that caused multiple outages on this circuit. This may allude to the limitations of the normal vegetation management program and help support a case for storm resiliency work aimed at reducing damage from storm events.

Contrary to Chart 5, Chart 6 shows a decrease in customers interrupted and incidents after pruning and hazard tree removal versus the 5 year historic average. The number of customers interrupted

improved by 4% and the number of incidents improved by 33%. It is important to note that many more circuits; ten (10), underwent both pruning and hazard tree in 2012.

Chart 7

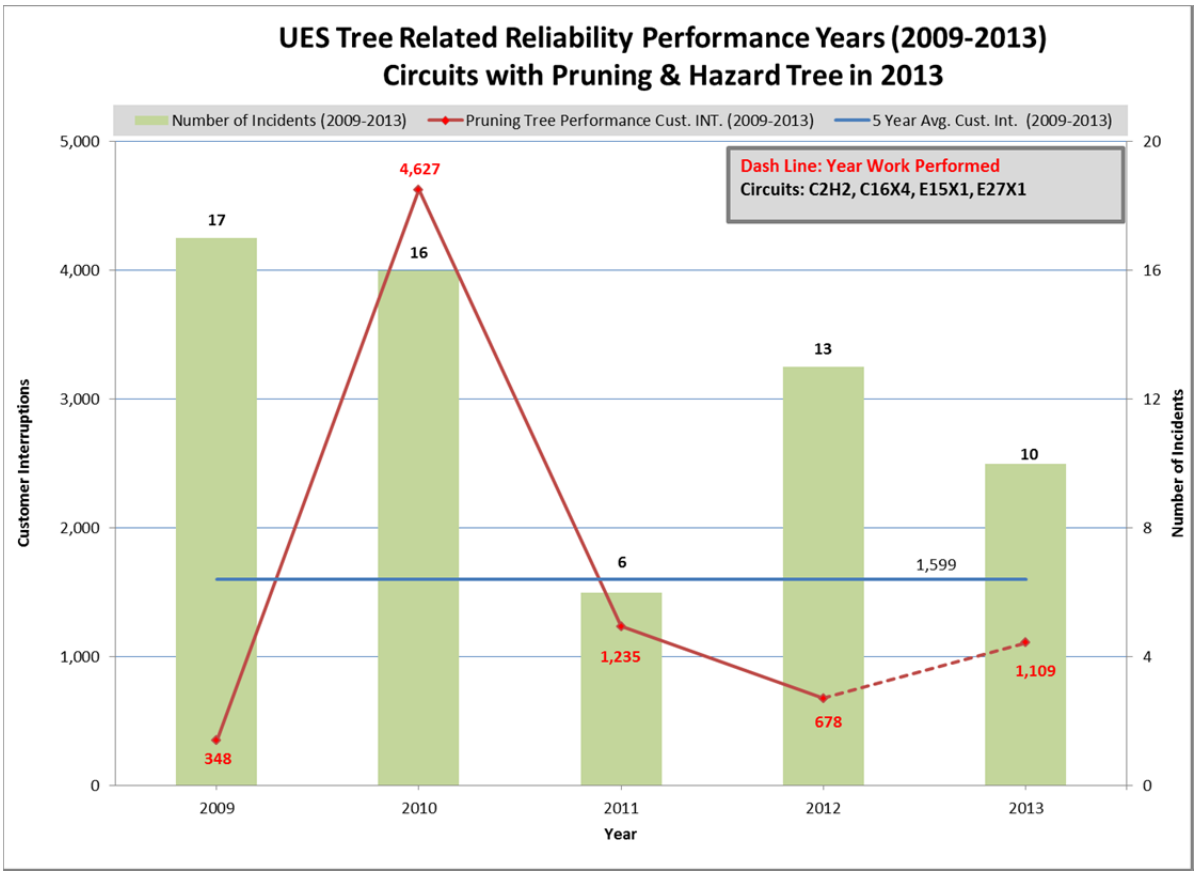
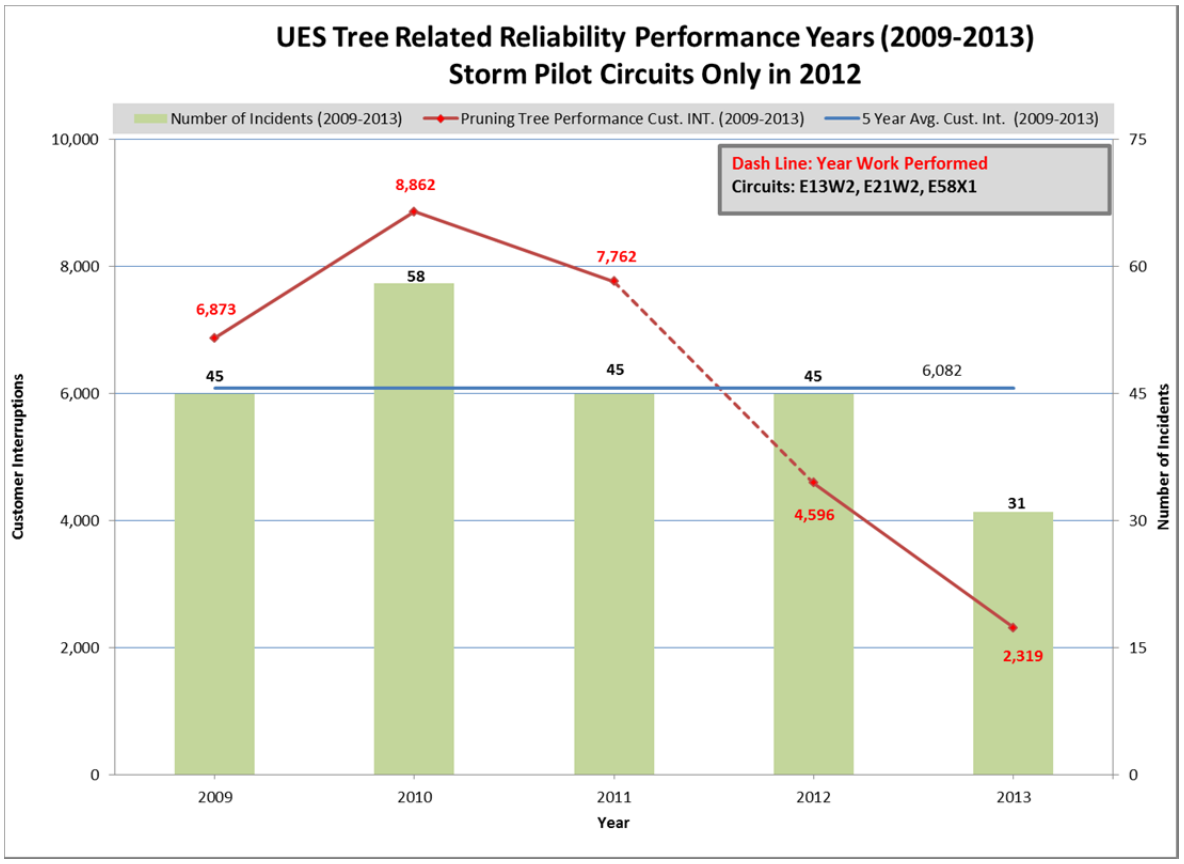


Chart 7 shows the work that was done in 2013. In the year that work was completed, customer interruptions rose slightly (still under the 5 year average) while the number of incidents decreased. It is important to note that work could have occurred at any point during the year and the reliability information includes a combination of reliability results from before and after work was completed.

2.6.4. Storm Resiliency Work – Done in 2012 and 2013

Chart 8, shown below, displays the tree related reliability performance of the individual circuits that underwent Storm Hardening Pilot work in 2012. The dashed line represents the year work occurred.

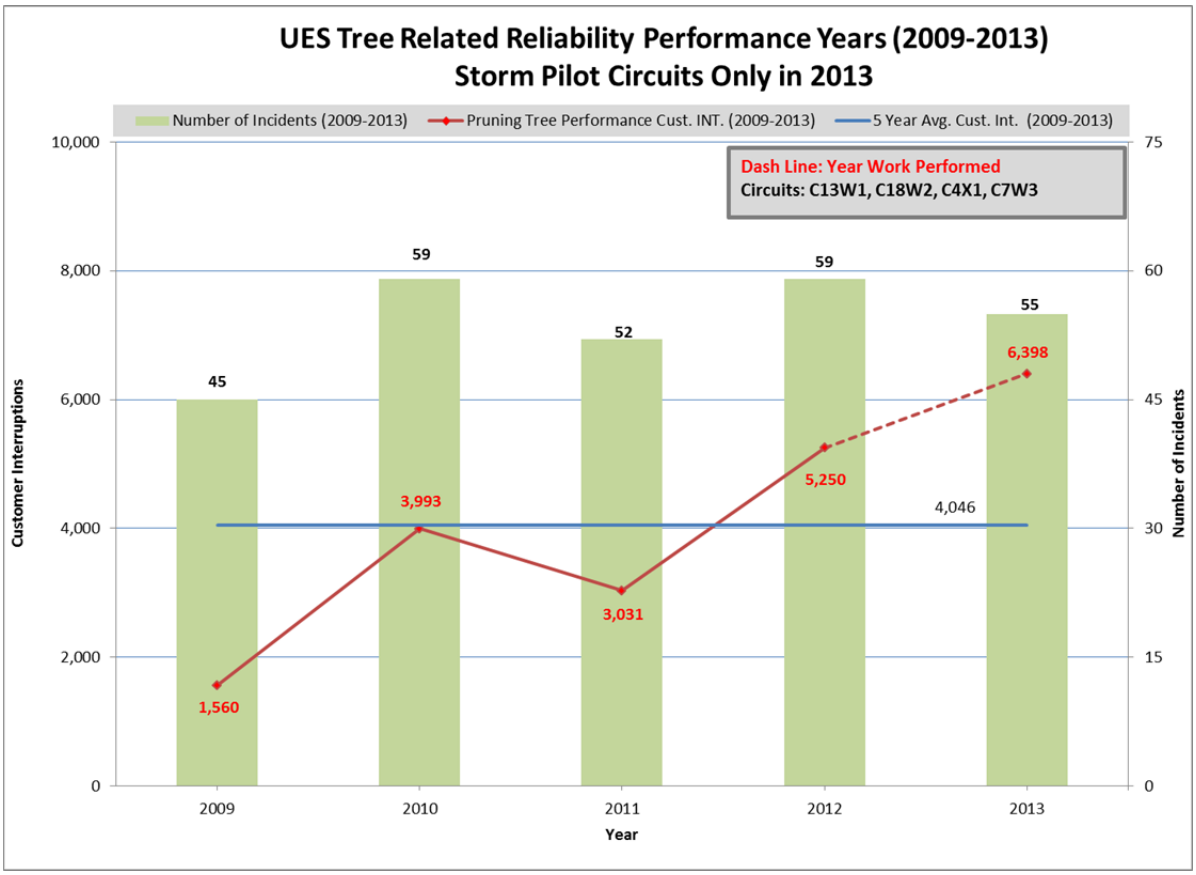
Chart 8



5 Year Avg Cust-Int (2009-2013)	5 Year Avg # of Incidents (2009-2013)		Avg After Trimming Cust-Int (2012)	Year After Trimming # of Incidents (2012)		Cust-Int Percentage Change	No of Incidents Percentage Change
6,082	44.8		2,319	31.0		-61.9%	-30.8%

The Storm Resiliency Pilot work, show in Chart 8, indicates no change in incidents and a decrease in customers interrupted during the year work was done. It is important to note that due to work planning and implementation need, most of the work occurred in the last quarter of 2012 so the information for that year includes a combination of reliability results from before and after work was completed. In the first full year after work was completed the number of incidents and the number of customers interrupted decreased. Versus the historic 5 year average, there was a 62% improvement in customers interrupted and a 31% improvement in incidents, showing very good reliability results for this work.

Chart 9



The Storm Pilot work, show in Chart 9, shows the reliability results for 2013 - the year in which the work was done. There was a slight reduction in incidents, yet an increase in customers interrupted during this year. Like the 2012 pilot, it is important to note that due to work planning and implementation need, most of the work occurred in the last quarter of 2013 so the information displayed above includes a combination of reliability results from before and after work was completed. It is our hope that 2014 reliability results will be similar to the 2012 pilot for the first full year after work is completed, and display a large improvement.

The Company will continue to monitor those circuits which have undergone Pruning, Hazard Tree and Storm Resiliency work, and barring any unforeseen items such as weather or pest infestations, expect to see a continuing trend in reliability improvement.

3. Reliability Enhancement Plan

The Settlement Agreement provides that Unitil should implement a Reliability Enhancement Program. Pursuant to the Agreement and beginning in 2011, the Company has planned to spend a target amount of $1,750,000 annually and is subject to a cap of $2,000,000 in REP capital expenditures in a given year and $300,000 in operation and maintenance expense effective May 1, 2012.[8]

As described in Mr. Meissner's Direct Testimony in Docket DE 10-055[9], the REP covers capital and O&M activities and projects intended to maintain or improve the reliability of the electric system including: (1) system hardening measures, i.e., equipment upgrades; installation of additional fuses, sectionalizers and reclosers; SCADA and automation projects; improvements to lightning protection; installation of animal guards; and other activities to mitigate the specific causes of outages; (2) enhanced tree trimming, i.e., aggressive trimming and clearing involving an expanded trim zone or more aggressive removal beyond what is normally included in maintenance trimming, typically in localized areas of poor reliability; (3) asset replacement, which targets aging electrical components at increased risk of failure, including porcelain cutouts and insulators, transformers, circuit breakers, underground cable, wood poles and other equipment, and includes conductor replacement and reconductoring of select mainlines with spacer cable; and (4) reliability-based inspections and maintenance, which will include enhanced inspection methods to detect and mitigate outage causes before they occur, including surveys using new or improved technology such as thermography (IR) and radiofrequency (RF) sensor technology to identify and mitigate failing electrical equipment, as well as software applications to better manage inspection, maintenance, and reliability programs and data.

3.1. Reliability Studies

The Settlement Agreement provides that the Company will complete the following fuse and recloser studies and reviews: 1) Un-fused Lateral Study; 2) Fuse Coordination Studies; and 3) Recloser Studies[10]. Each of these studies is described below.

[8] Reference Settlement Agreement Section 7.1 Page 14 of 26
[9] Direct Testimony of Thomas P. Meissner, Jr., DE 10-055, pages 20-29.
[10] Reference Settlement Agreement Section 7.6.1 Page 15 of 26

3.1.1. Un-fused Lateral Study

The Settlement Agreement provides that the Company would complete a review of un-fused lateral on distribution circuits.

In 2011, the Company completed a review of all distribution circuits in order to identify laterals tapped directly to the main line of distribution circuits without fusing or some other type of protective device. [11] The study was provided as part of the Reliability Enhancement Program and Vegetation Management Program Annual Report 2011.

Distribution Engineering developed a prioritized list of unprotected laterals based upon number of customers which could be affected by an outage event. As identified in the 2011 Annual Report, the Company plans to issue Engineering Work Requests (EWRs) to address all the identified locations over a three year period or as other work is performed on these circuits as part of planned system upgrades or modifications. In 2013, EWR's were issued to install fusing at 24 locations on eleven circuits. In 2014, there will be forty-three potential locations reviewed during circuit analysis. This should complete the mainline unfused lateral locations.

3.1.2. Fuse Coordination Studies

The Settlement Agreement provides that the Company complete fuse coordination studies on distribution circuits where they are out of date and ensure that fuses are coordinated and of the proper size.

The Company conducts distribution planning studies on an annual basis. The purpose of this study is to identify when system load growth is likely to cause main elements of the distribution system to reach their operating limits, and to prepare plans for the most cost-effective system improvements.

Circuit analysis provides the basis for the distribution planning study. Circuit analysis is completed on a three year rotating cycle with the objective to review one-third of the entire system each year. The Milsoft WindMil software application is used to perform circuit analysis to identify potential problem areas and to evaluate available alternatives for system improvements. Circuit analysis includes the following: 1) update of circuit model from GIS; 2) circuit diagnostics; 3) load allocation and overload analysis; 4) voltage drop analysis; 5) fault current and coordination analysis. Engineering work requests

[11] Reference Unitil Energy Systems Unprotected Lateral Study, November 29, 2011.

are initiated for any apparent miscoordination identified during this analysis. Protection device coordination analysis is an automated function within the WindMil application. This function is included each year as part of the circuit analysis performed on the circuits evaluated.

In addition to the fuse coordination completed as part of circuit analysis, the Company reviews trouble interruption reports on a daily basis. Any outage in which the fuse did not appear to operate correctly is further analyzed to determine the cause. Engineering Work Requests are issued to implement upgrades or changes on the system identified by the circuit analysis or an evaluation of an outage. In 2013, twenty-one Engineering Work Requests were initiated specific to fuse installation or fuse size changes due to the coordination analysis performed.

3.1.3. Recloser Studies

The Settlement Agreement provides that the Company would complete a review of locations on distribution circuits where reclosers could be applied in an economic manner to improve reliability.

Each year, Unitil completes annual reliability studies for each of its operating areas. The purpose of these studies is to report on the overall reliability performance of the electric systems from January 1 through December 31 of the previous year (12 months total). The scope of this report also evaluates substation, subtransmission and individual circuit reliability performance over the same time period. The analysis also identifies common trends or themes based upon type of outage (i.e. tree, equipment failure, etc.). The Annual Reliability Analysis and Recommendations report for the UES Capital Operating Area and UES Seacoast Operating Area are attached to this report as Attachment 1 and Attachment 2 respectively.

The recommendations provided in the study are focused on improving the worst performing circuits as well as the overall system reliability. These recommendations are provided for budget consideration and will be further developed with the intention of incorporation into the capital budget development process. In response to these studies, projects have been approved for 2014 construction to install reclosers and/or breakers in five locations.

There are several common solutions which can improve reliability depending upon the circumstance: 1) installation of reclosers or sectionalizers; 2) addition of fusing locations; 3) tree trimming; and 4) installation of tree wire or spacer cable. These solutions are recommended quite regularly. For instance, in 2013, there were five projects implemented to add reclosers or sectionalizers to improve fault isolation

and a project to replace spacer cable to improve the circuit reliability. In addition, projects have been approved in the 2014 capital budget to install reclosers or breakers in four locations and installation of remote fault indication.

3.2. REP O&M Expenditures

The Settlement Agreement provides that Unitil will increase its annual REP O&M expense by $300,000 effective May 1, 2012.[12] The order does not specify, however, the allocation of the expense. The Company is allocating: 1) $200,000 for Enhanced Tree Trimming and 2) $100,000 for Reliability Inspections and Maintenance. The Enhanced Tree Trimming funding is intended to target "problem" areas identified through engineering analysis.

The annual budget year increases over the test year amounts for the Company are shown in Table 15 below:

Table 15

REP O&M Category	Spending Above Test Year Amounts		
	2012[13]	2013	2014
Enhanced Tree Trimming	$133,333	$200,000	$200,000
Reliability Inspection and Maintenance	$ 66,667	$100,000	$100,000
Totals	$200,000	$300,000	$300,000

3.2.1. Enhanced Tree Trimming

Each year, the Company completes reliability analysis on the distribution and subtransmission system. The reliability analysis (as shown in Attachments 1 and 2) identifies areas of the system which have experienced an abnormal or increasing amount of tree related outages in 2013. Distribution Engineering provides the System Arborist a prioritized list of recommended subtransmission lines and/or distribution circuits which would benefit the most from enhanced tree trimming.

In 2013, Distribution Engineering recommended two subtransmission lines to receive enhanced tree trimming: 1) Line 375 in Concord and 2) Line 37 in Penacook. In total, $108,674 was spent on Enhanced Tree Trimming on these lines. The 375 line underwent enhanced risk tree assessment, and 399

[12] Reference Settlement Agreement Section 7.1 Page 14 of 26
[13] Prorated annual amounts assuming May 1, 2012 increase

hazard tree removals were completed along with sideline clearing on selected portions. The northern portion of the 37 line underwent enhanced risk tree assessment and 247 hazard tree removals were completed along with sideline clearing.

For 2014, Distribution Engineering is recommending one sub-transmission line to receive enhanced tree trimming: Line 3359 in Hampton Falls and Seabrook. Since 2010, the 3359 Line has experienced an average of almost one incident per year involving tree contact or outages where no apparent cause was found. These outages have accounted for more than 12,000 customer interruptions and almost 1.1 million customer minutes of interruption. The trimming on this subtransmission line will be prioritized and is budgeted not to exceed $100,000 in 2014.

3.2.2. Reliability Inspection and Maintenance

In 2013, Unitil, working with Davey Resource Group, implemented a first year pilot project to identify degraded facilities prior to equipment failure. The survey itself cost approximately $100,000 and the repairs cost approximately $28,000. A summary of the pilot project is provided below.

3.2.2.1. Exacter Overview

Exacter Technology is deployed by electric utilities to locate overhead distribution equipment showing signs of degradation and possible failure, thereby increasing overall system reliability by preventing failures before they occur. Exacter's technology identifies and locates "radio frequency (RF) failure signatures" on overhead equipment. The process and technology allows for the survey of large geographic areas by simply driving the circuitry at posted speed limits.

Once the circuit surveys are completed, the collected field data is overlaid with Unitil's existing GIS and outage data to provide the basis for predictive analytics. This information allows Unitil to prioritize repairs and/or replacement based up several criteria including number of customers affected in the event of failure, or location of equipment in relation to critical infrastructure such as emergency shelters, hospitals, or other critical municipal facilities. As a result, Unitil is able to develop accurate estimates of SAIDI minutes saved or avoided in repairing or replacing the equipment before it fails and causes an outage.

3.2.2.2. 2013 Pilot Objectives

Unitil, working with Davey Resource Group, implemented a first year pilot project to identify degraded facilities prior to equipment failure. The objective of the initial deployment of the Exacter technology was to inspect our facilities along all of our three-phase distribution circuits, encompassing approximately 428 circuit miles at both our Capital and Seacoast operating centers. The circuits were inspected for conditions where equipment is likely to fail, and where partial discharge or electromagnetic interference is present. The intent was to utilize the technology in combination with our GIS system to provide a targeted tool to prioritize critical preventative maintenance. The combination of this technology and customer location information would provide a "customer impact" rating," i.e. the number of potential customers affected by equipment failure, allowing for a targeted replacement of degraded equipment. This integrated data approach provides the means to prioritize replacement and proactively improve reliability for UES customers. The cost of the 2013 pilot was $100,000, not including cost to repair identified equipment (see below).

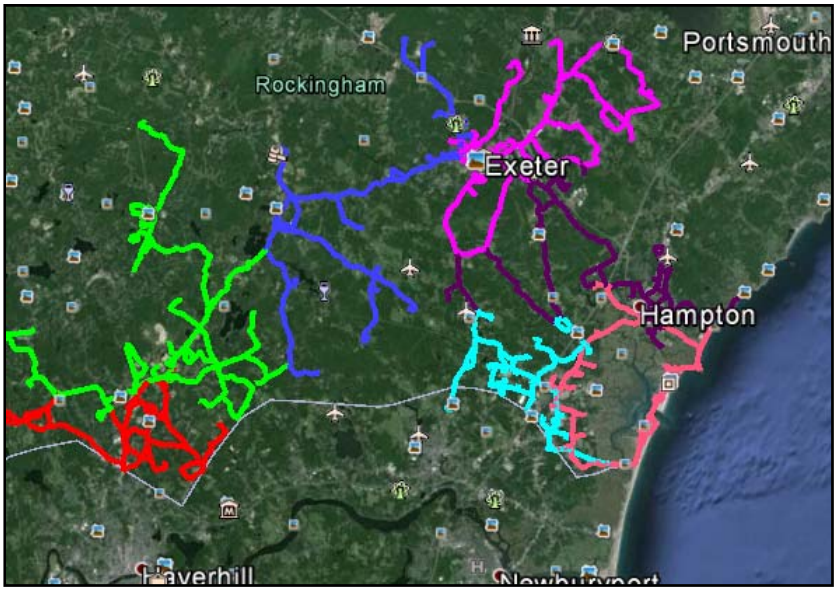
Pilot Objectives:

- Identify degraded equipment and validate technology
- Integrate Exacter data into Unitil GIS
- Develop processes and prioritization for replacement of degraded equipment
- Analyze results and estimate effect on overall system reliability
- Program and technology assessment and recommendation

3.2.2.3. Pilot Process Deployment

In August of 2013, a system scan of all three phase-overhead distribution circuits was performed using the Exacter Technology. Approximately 428 circuit miles of three-phase overhead were inspected in both the Seacoast and Capital operating centers. Data acquisition lasted approximately three weeks and utilized Unitil GIS information as the foundation of the circuit selection. Reference Graphic 1 below.

Graphic 1

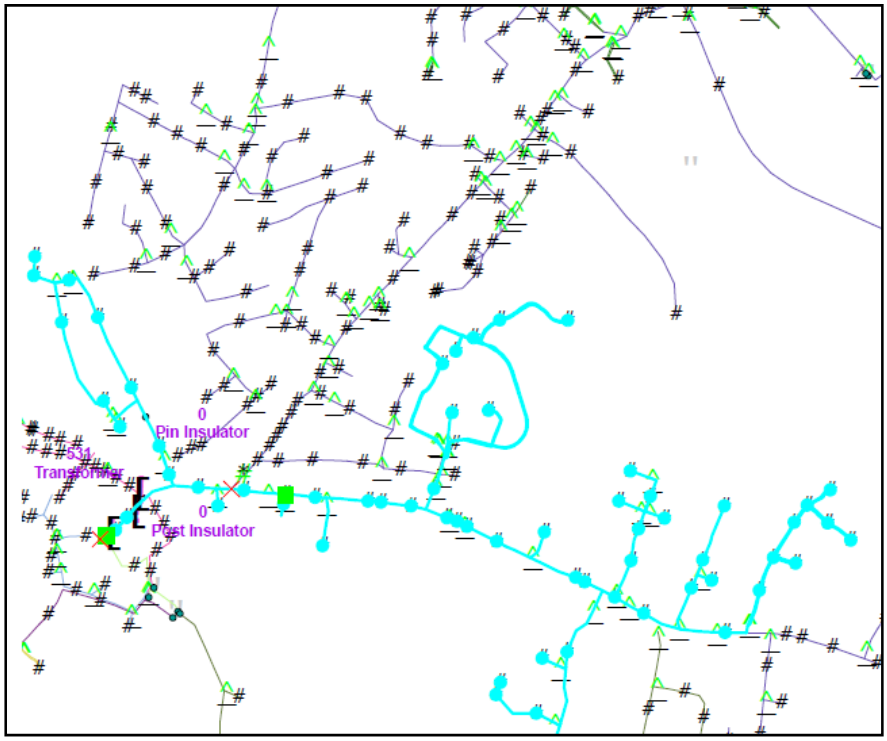


The data acquired was processed through the Exacter signature library to identify the specific locations for secondary field visit where acoustical devices were utilized to pinpoint the exact piece of equipment creating the partial discharge. Once the individual pieces of equipment were identified for replacement, a link was built to the Unitil GIS system. This link was used to determine the number of customers impacted downstream from the point of equipment failure and the isolating protective device. Based on the customers impacted, a priority level was assigned to the replacement, and replacement was scheduled. The entire survey and analysis process took approximately ten weeks, providing specific locations of facilities recommended for replacement and a clear prioritization of spending.

3.2.2.4. Project Results

The circuit survey identified 56 specific locations where facilities required repair, including a failure signature on the main circuit feed to Exeter Hospital, an example of a potential critical infrastructure impact. The types of facilities identified included transformers, insulators, lightning arrestors, bushings, and cutouts. Reference Attachment 3 for sample field photos and specific information developed for replacement. Graphic 2 illustrates Unitil GIS maps with specific equipment identified.

Graphic 2



Utilizing Unitil's GIS maps for customer counts and protective devices, we are able to develop potential system reliability impacts. The pilot identified a repair every 7.6 miles, and an average of 559 customers impacted by each failure event if it occurred. The estimated number of customers impacted by potential failures of all identified locations would be 31,275. The estimated customer minutes of interruption would be 2,980,508 (calculated using the most recent 10-year average system CAIDI (2004-2013) of 95.3 minutes). The total opportunity for avoided system SAIDI would be 39.4 minutes, which represents 24.2 % of UES' most recent 10-year average SAIDI of 162.7 minutes.

3.2.2.5. Repairs and Findings

To date, 26 of the 56 facilities identified during the survey have been repaired. The repairs were performed in accordance with established priority levels and schedule efficiencies. The findings have identified a number of clearly visible items in need of repair, where failure was imminent (example at right showing a cracked insulator). In addition, a location identified for replacement during the survey failed between the time of identification and prior to repair crews accessing the site, demonstrating the effectiveness of the technology. The remaining repairs are scheduled for 2014.

The 26 repairs were completed for a total cost of approximately $28,000. Another benefit of the program is that the repairs were scheduled during normal work hours, under non-emergency situations. Should the identified equipment fail and cause an outage, it is possible that some of the repairs would have been completed during premium work hours, greatly increasing overall labor costs.

In terms of avoided customer interruptions, these 26 repairs alone represent 14,520 avoided customer interruptions and, utilizing UES' 10-year average CAIDI, and provides an opportunity to avoid 1,393,952 customer minutes of interruptions. In terms of system reliability, the repairs represent an opportunity to avoid approximately 18.4 SAIDI minutes, or 15.5 % of UES' 2013 reported SAIDI of 119.07 minutes.

3.2.2.6. Summary

The survey identified 56 different components of the distribution system that were in need of repair. Absent this technology, this faulty equipment would have been discovered only after it failed, and in addition, resulted in an outage to customers. The Exacter program is a preventative maintenance program that allows for identification and replacement of equipment before failure, resulting in a reduction in customer outages due to equipment failure. The 2013 pilot program avoided 26 outages, and saved an average of 1,393,952 customer minutes of interruption and resulted in an avoided 18.4 SAIDI minutes. Unitil's proactive use of this technology reduces interruptions to customers, as well as improves the reliability and resiliency of the UES distribution system.

3.2.2.7. 2014 Plan Proposal

Based upon the success of the program, Unitil is recommending a continuation of the Exacter preventative maintenance program. The design of the program will be to perform an annual survey of all three-phase circuit miles of the UES distribution system, as failures of this equipment has the greatest impact on customer interruptions. In the future, the program will also perform targeted single-phase circuitry based upon expected reliability benefits. The estimated cost to perform the annual survey and provide the analytics is $202,500, and the repair work to replace the identified equipment is expected to be approximately $45,000 annually. Given the potential impact on system SAIDI, UES believes these expenditures are prudent and beneficial to customers.

Unitil is also planning to investigate performing a survey of our 34.5 kV sub-transmission system which is predominantly off road in rights-of-way. Davey Resource Group stated that a helicopter mounted survey unit is being developed and will be available in the near future.

3.3. REP Capital Expenditures

As described above, beginning in 2011 the Company planned on spending a target amount of $1,750,000, subject to a cap of $2,000,000 in REP capital expenditures in a given year annually. The breakdown of the spending by category is shown in Table 16 below:

Table 16

REP Capital Category	Target Spending Above Test Year Amounts		
	2011	2012	2013
System Hardening/Reliability	$ 750,000	$ 750,000	$ 750,000
Asset Replacement	$1,000,000	$1,000,000	$1,000,000
Totals	$1,750,000	$1,750,000	$1,750,000

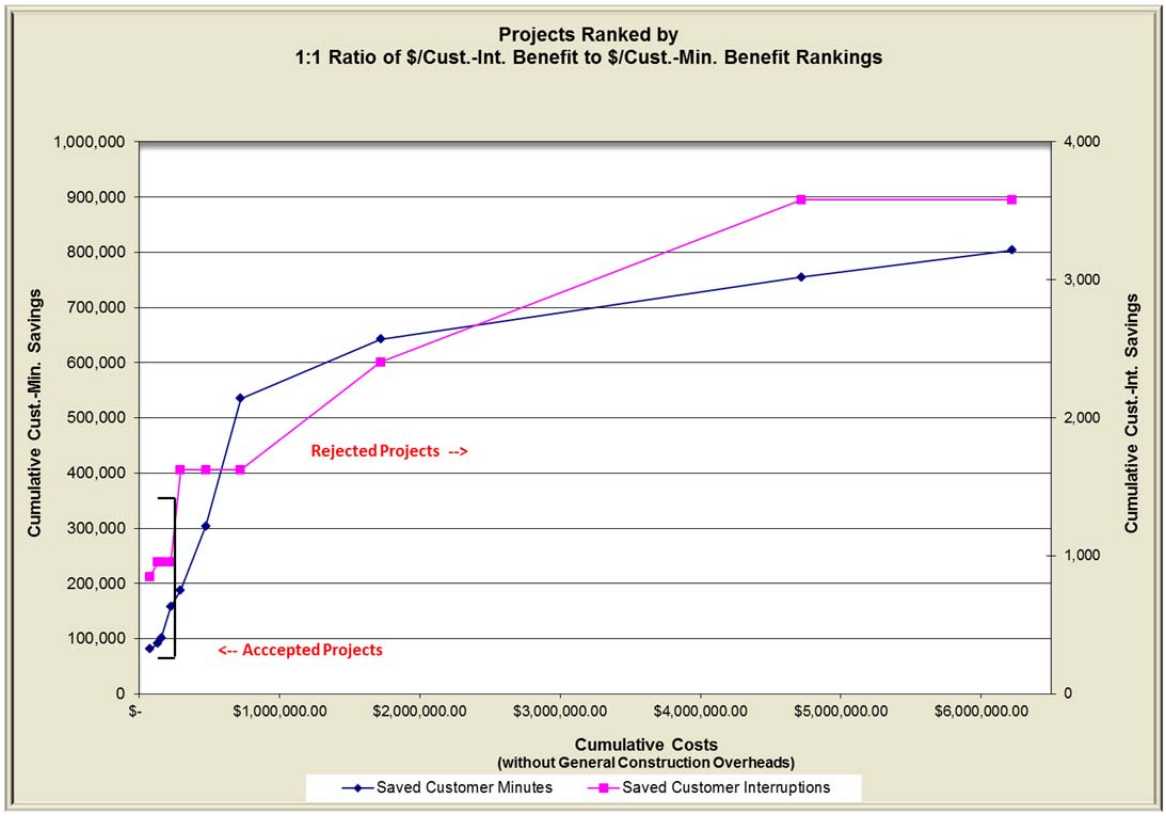
As described above, each year, Unitil completes annual reliability studies for each of its operating areas. The recommendations provided in the study are focused on improving the worst performing circuits as well as the overall system reliability. These REP projects count for the majority or all of the "System Hardening/Reliability" spending for each year.

The REP projects recommended for the budget include a project scope, construction cost estimate and estimated reliability improvements (annualized saved customer minutes and saved customer interruptions). All of the recommended projects are ranked against each other based upon two cost benefit comparisons (cost per saved customer minute and cost per saved customer interruption).

An overall project rank is the derived from the sum of these two cost benefit rankings. In general, projects with low construction cost and high saved customer minutes or high saved customer interruptions are ranked highest on the list while those projects with high construction cost and low saved customer minutes or saved customer interruptions are ranked low on the list. Another way these projects are analyzed by Distribution Engineering is shown in Chart 10 below. This chart displays the cumulative project cost compared to the anticipated reliability benefits of all projects. Each data point pair represents a specific project and its associated reliability benefits (saved customer minutes and saved customer

interruptions). This chart is used to determine when there is a diminishing return of reliability benefits associated with project cost as indicated by the "knee" of the curve. Proposed projects to the left of the cutoff line are accepted into the Capital Budget and those to the right have been rejected.

Chart 10



The REP projects for 2014 presented in Table 17 below provide an illustration of the process used to identify REP projects. Table 17 is a listing of REP projects recommended by Distribution Engineering as part of the 2013 annual reliability studies for the UES system which have been accepted into the 2014 Capital Budget. This project listing details the overall project ranking, scope, cost, and anticipated reliability benefits.

Table 17

Project Ranking	DOC / Budget No.	Description	Project Cost	Cumulative Cost	Customer Interruptions Saved Annually	Customer Minutes Saved Annually
1	DRBE01	Replace 59X1 Recloser at Stard Road Tap	$73,513	$73,513	849	81,520
2	DRBE03	13W1 - Install Recloser and Sectionalizer Crystal Hill	$59,563	$133,076	103	9,893
3	DRBC01	33 Line - Wireless FCI at Pleasant St	$23,889	$156,965	0	10,775
4	DRBE02	3359 Line Remote Fault Indication at Mill Lane Tap	$68,824	$225,789	0	55,797
PROPOSED NH REP PROJECTS			**$225,789**		**4,980**	**477,788**

Note the project list above has been sorted by project rank in ascending order beginning with the project having the best composite cost benefit ranking. This list is used by Distribution Engineering as a guide for recommending projects to be included in the Capital Budget as REP projects. However, it should be noted that not all projects identified in the annual reliability analysis are accepted in the Capital Budget.

3.3.1. 2013 Actual REP Expenditures

The 2013 capital expenditures for the Company total $1,737,368, or $12,635 less than the targeted amount of $1,750,000[14]. The spending below the targeted amount was mainly due to projects that were completed for less than original budget estimate in 2013. Table 18 is a list of projects completed in the field and closed to plant as of December 31, 2013 and the final expenditures.

[14] Reference Attachment 4 for schedule of 2013 REP project spending

Table 18 - Projects initiated in 2013

Project	**Description/Comment**	**Total Expenditures**
Distribution Pole Replacement	Replacement of distribution poles which were identified during pole inspections completed in 2011. (Various Towns)	$1,168,561
Circuit 4W4 – Install Recloser on Lakeview	Install recloser to improve reliability. (Concord & Penacook)	$ 14,597
Circuit 11W1 &11W2 – Portsmouth Ave S/S Install Reclosers	Install reclosers to separate one large circuit into two smaller circuits. (Exeter & Stratham)	$ 204,077
Hampton S/S – Install Breakers on 3342, 3353 and 3348 Lines	Install reclosers on 34.5kV lines which serve other substations to reduce the size of potential outages. (Hampton and Seabrook)	$332,154
Fusing Changes	This project consists of installing a new fuse locations to address mainline unfused laterals and sensitivity concerns. (Various Towns)	$ 27,976
Total		**$1,737,365**

3.3.2. 2014 REP Estimated Capital Expenditures and Work To Be Completed

The Settlement Agreement provides for Step Adjustments on May 1st of 2012, 2013, and 2014 for REP capital expenditures in the preceding years. Therefore, the Company understands that REP capital expenditures initiated in 2014 will not be included in a May 1st Step Adjustment in 2015. Regardless, the company has included its 2014 REP capital spending plan in the same manner as if it were part of a Step Adjustment.

The 2014 REP capital spending plan was developed from the recommendations identified in the annual reliability planning studies. The projects shown below provide the best cost benefit ratio based upon project cost and estimated reliability improvement. The proposed 2014 REP capital spending is $1,595,693. The proposed projects are identified below.

The Asset Replacement projects identified for 2013 include distribution pole replacement of $1,369,904. Distribution pole replacements are based upon field inspections and are defined as poles that are not expected to last until the next inspection cycle. Distribution pole replacements are prioritized based upon their condition. Other smaller projects may be identified throughout the year such as insulator or cutout replacements identified during normal inspections. At this time, the cost of those replacements is unknown.

The 2014 System Hardening/Reliability projects are shown below in order of the ranking described in section 3.3 and total $225,789. Other System Hardening/Reliability projects may be identified throughout the year which may provide a better cost benefit than the projects presently identified. If such projects are identified, the Company generally attempts to maintain flexibility and complete the project with the better cost benefit ratio.

(1) *Replace 59X1 Recloser at Stard Road Tap* – This project consists of replacing the 59X1 recloser at Stard Road Tap. This type and vintage of recloser is known for premature failure due to insulation breakdown.

(2) *13W1 - Install Recloser and Sectionalizer Crystal Hill* – This project will consist of installing a single-phase electronic recloser on Cottonwood Road and replacing the existing fuse at Crystal Hill Circle with a cutout mounted sectionalizer. This will allow for the installation of a new fuse locations along the circuit. This project is estimated to save 9,893 customer minutes and 103 customer interruptions on an annual basis.

(3) *33 Line Remote Fault Indication at Pleasant Street* - Install three SCADA monitored fault indicating devices on the source side of the 33J2 and 33J1 switches. This will require communication to the RTU which is included in the price of this project. This project is estimated to save 10,775 customer minutes on an annual basis.

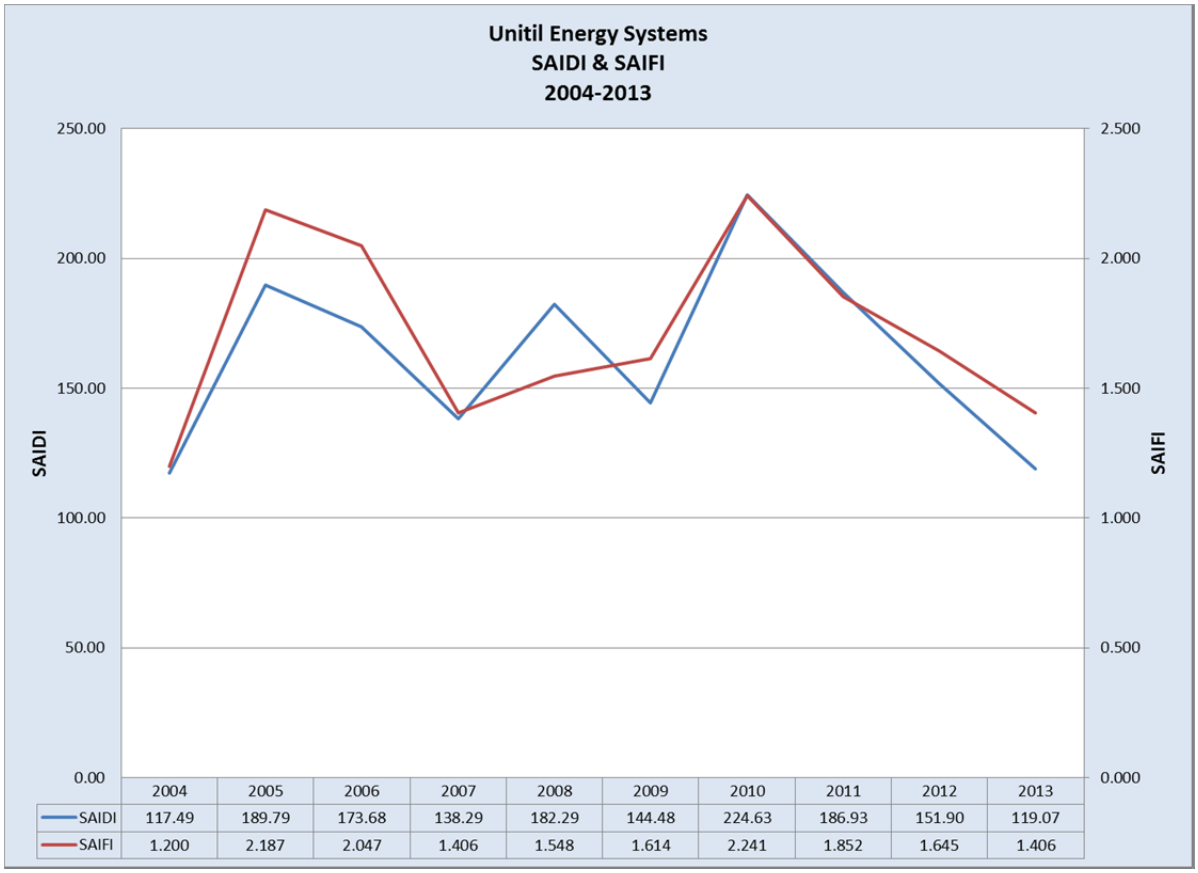
(4) *3359 Line Remote Fault Indication at Stard Rd Tap* - This project will consist of installing two wireless fault indicators at Stard Rd Tap. The indicators will be integrated into the existing RTU at this location to provide status via SCADA. This project is estimated to save 55,797 customer minutes on an annual basis.

4. 2012 Reliability Performance

4.1. Historical Performance (2004-2013)

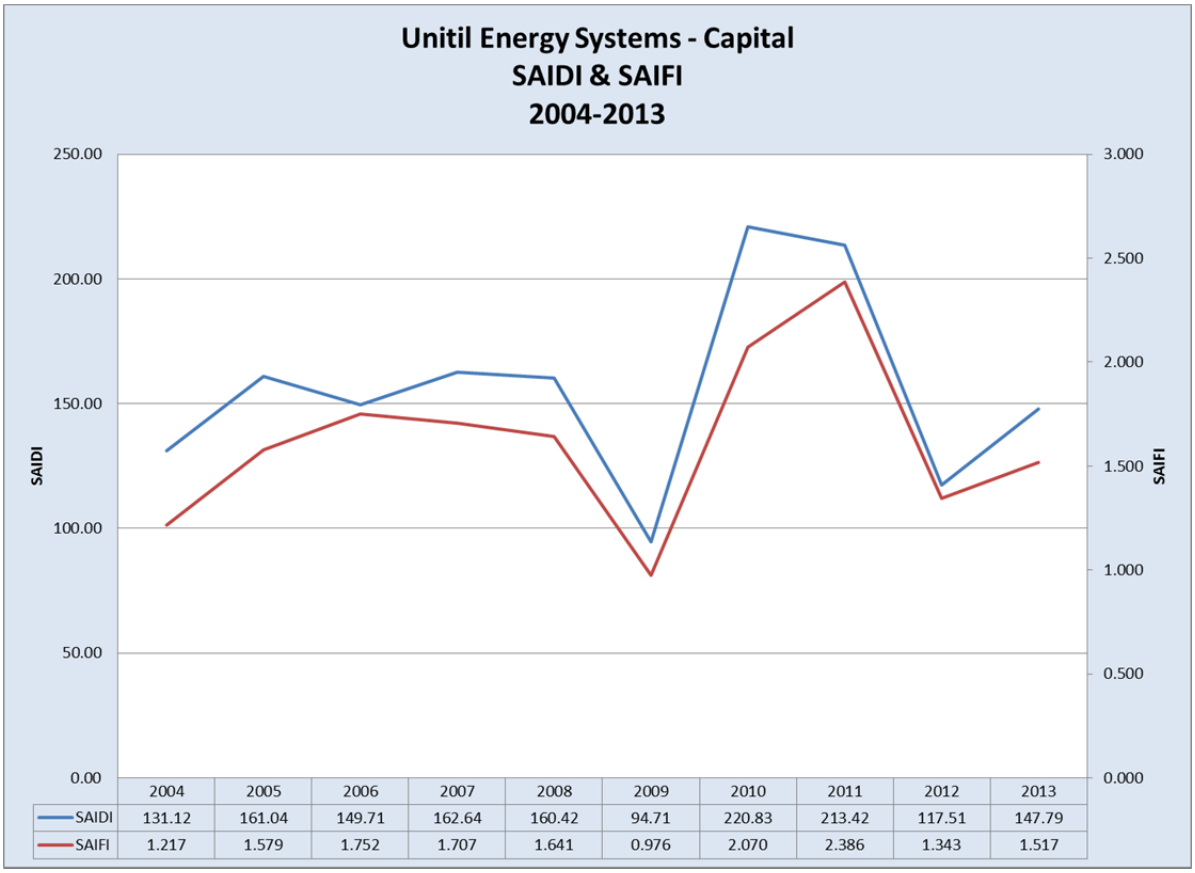
The historical reliability performance for the UES system for the time period from 2004-2013 is outlined in Charts 11-13 below. These charts display annual SAIDI and SAIFI for the combined UES systems as well as separate charts for each of the UES-Capital and UES-Seacoast service territories.

Chart 11



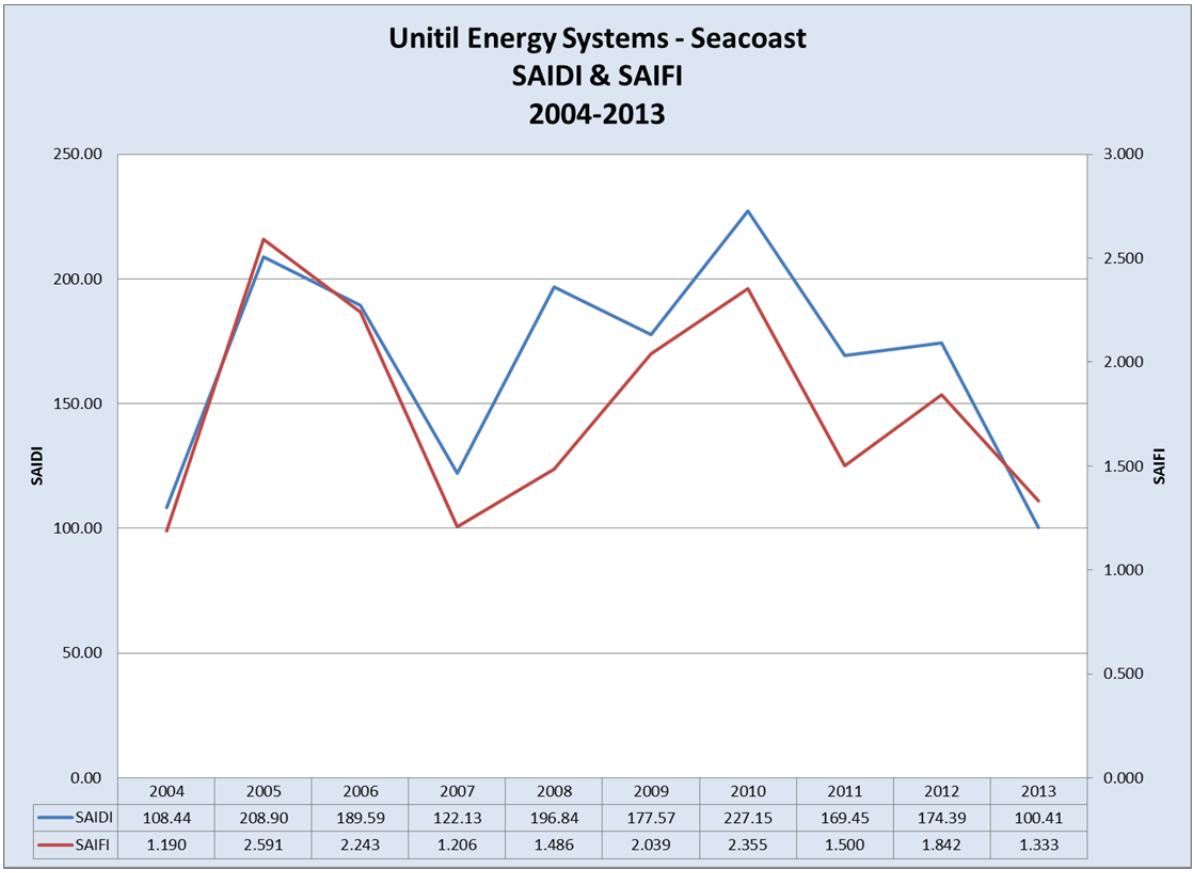
	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
SAIDI	117.49	189.79	173.68	138.29	182.29	144.48	224.63	186.93	151.90	119.07
SAIFI	1.200	2.187	2.047	1.406	1.548	1.614	2.241	1.852	1.645	1.406

Chart 12



	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
SAIDI	131.12	161.04	149.71	162.64	160.42	94.71	220.83	213.42	117.51	147.79
SAIFI	1.217	1.579	1.752	1.707	1.641	0.976	2.070	2.386	1.343	1.517

Chart 13



NOTE: Only those events causing an outage to 1 or more customers and lasting more than 5 minutes in duration are included in the calculation of these indices. In addition, events meeting any of the following criteria have also been excluded from these calculations:

- PUC Major Storm: Any event where the number of customers interrupted exceeds 15 % of customers served with 16 concurrent outage events or 22 concurrent outage events regardless of the number of customers interrupted.
- Scheduled Outages
- Off system power supply interruptions

4.2. Summary of 2013 Performance

The reported reliability performance of the UES systems in 2013 (after taking PUC exclusions) was the best since 2004 and much better than the 10 year average. The combined UES system SAIDI of 119.07 minutes is roughly 27% lower than the 10 year average of 162.86 minutes and the total UES system SAIFI of 1.406 interruptions is 18% lower than the 10 year average of 1.715. The

total number of troubles recorded in 2013, not including exclusionary events, was 949. This is lower than any year since 2004 and almost 12% below the 10 year average of 1,079.

In 2013, there were several events that met the exclusionary criteria described in Section 4.1 which were therefore not included in the calculation of UES SAIDI and SAIFI. The excluded events are listed below:

- March 19th – 3342/3353 Line Outage (Seacoast Region)
- July 19th – Lightning & Rain Storm (Capital Region)
- September 11th – Loss of Supply to Hollis Substation (Capital Region Due to PSNH 318 Line Outage)
- November 24th – Windstorm (Capital Region)

Table 19 below shows the reliability performance of the UES system by individual cause codes.

Table 19

Cause of Outage	No of Trouble	Cust-Hrs	Cust-Int	SAIDI	% of Total	SAIFI	% of Total
Broken Tree/Limb	315	76,859	50,838	61.09	51%	0.673	48%
Equipment Failure - Company	150	24,007	21,459	19.08	16%	0.284	20%
Patrolled, Nothing Found	112	10,093	4,390	8.02	7%	0.058	4%
Other	24	7,571	5,103	6.02	5%	0.068	5%
Tree/Limb Contact - Growth into Line	86	7,009	3,706	5.57	5%	0.049	3%
Loose/Failed Connection	43	6,911	4,067	5.49	5%	0.054	4%
Vehicle Accident	53	5,682	4,866	4.52	4%	0.064	5%
Squirrel	68	4,047	3,726	3.22	3%	0.049	4%
Bird	22	2,916	3,007	2.32	2%	0.040	3%
Overload	26	1,813	1,106	1.44	1%	0.015	1%
Equipment Failure - Customer	3	1,631	3,054	1.30	1%	0.040	3%
Lightning Strike	10	599	201	0.48	0%	0.003	0%
Action by Others	12	227	132	0.18	0%	0.002	0%
Improper Installation	3	223	104	0.18	0%	0.001	0%
Animal - Other	4	101	58	0.08	0%	0.001	0%
Corrosion/Contamination/Decay	16	81	86	0.06	0%	0.001	0%
Operating Error/System Malfunction	1	48	206	0.04	0%	0.003	0%
Civil Emergency (fire, etc.)	1	1	2	0.00	0%	0.000	0%
Total:	**949**	**149,818**	**106,111**	**119.07**	**100.0%**	**1.406**	**100.0%**

As observed from the preceding table, tree related outages and equipment failures had the greatest impact on UES system SAIDI and SAIFI performance in 2013. Table 20 below shows how the top three causes during 2013 have trended over the last three years.

Table 20

	SAIDI (% Total)				**SAIFI (% Total)**		
Cause	**2013**	**2012**	**2011**		**2013**	**2012**	**2011**
Tree Related	56%	39%	48%		51%	42%	47%
Equipment Failure	16%	21%	21%		20%	14%	23%
Patrolled, Nothing Found	7%	9%	3%		4%	9%	4%