2007
Electric Service
Reliability Monitoring
Annual Report

CONTENTS

Introduction

Pursuant to WAC 480-100-393 and WAC 480-100-398, Washington state investor-owned Electric companies must file a plan for monitoring and reporting electric service reliability information to the Commission annually.

This document reports Avista Utilities' reliability metrics for the calendar year 2007. All numbers in this document are based on system data. The Company's system includes eleven geographical divisions. Two of these divisions straddle the Washington and Idaho border and commingle jurisdictional customers. A map of Avista's operating area is included in a following section.

WAC 480-100-393 (3)(b) requires the establishment of baseline reliability statistics. The Company's baseline statistics are included in this report.

Avista continues to review its baseline reliability statistics in light of operational experience under this regulatory protocol. The Company may modify its baseline statistics as appropriate and will update the Commission accordingly.

New to this years report, is a new section which analyzes the areas where customers are experiencing multiple sustained outages. This new section will analyze a new reliability indice called $CEMI_n$, which implies Customers Experiencing Multiple sustained Interruptions more than n times.

Data Collection and Calculation Changes

WAC 480-100-398 (2) requires the Company to report changes made in data collection or calculation of reliability information after initial baselines are set. This section addresses changes that the Company has made to data collection.

Data Collection

- Since Avista's Electric Service Reliability Monitoring and Reporting Plan was filed in 2001, there have been several improvements in the methods used to collect outage data. In late 2001, centralizing the distribution trouble dispatch and data collection function for Avista's entire service territory began. The distribution dispatch office is located in the Spokane main complex. At the end of September 2005, 100% of the Company's feeders, accounting for 100% of the customers, are served from offices that employ central dispatching.

The data collected for 2007 represents the second full year of outage data collected through the Outage Management Tool (OMT). For 2007, all data was collected using the "Outage Management Tool" (OMT) based on the Company's Geographic Information System (GIS). The OMT system automates the logging of restoration times and customer counts.

Use of the OMT system and GIS data has improved the tracking of the numbers of customers without power, allowed for better prioritization of the restoration of service, and the improved dispatching of crews.

With the completion of the transition to the OMT system, there has been an increase in the variability of the data collected from 2001 to 2007. As described in the last three annual reports, the data that was most affected by moving to an OMT system is the number of customers associated with an outage. The OMT system improves the customer count accuracy because OMT uses the customer count from GIS, rather than an estimate. As the Company expected, the following reliability statistics were affected as a result of the areas being centralized:

- SAIFI and SAIDI – These statistics were expected to increase since the total number of customers affected by an outage will be used rather than the number of customers that have called in. The OMT system also significantly reduces the estimates made by the Distribution Dispatcher.
- CAIDI – This reliability index has not increased as much as anticipated due to the increases associated with both SAIFI and SAIDI. This is due to the better response time the Company can provide through the OMT system.
- MAIFI – This statistic is not expected to be effected by the implementation of OMT. The data for momentary outages is gathered from the System Operators log (not the Distribution Dispatchers). However, the MAIFI statistic may be increasing in the future as more of the distribution feeder Trips and Recloses are recorded through the SCADA system.

The Company believes that centralization will also provide better cause code classification. The improvement will be due to the concentration of dispatchers, associated increased training, and quality control.

Interruption Cause Codes

Cause code information is provided in this report to give readers a better understanding of outage sources. Further, the Company uses cause information to analyze past outages and, if possible, reduce the frequency and duration of future outages.

- The Company made several changes in the classification of outage causes for the reporting of 2005 outages and subsequent years. No change is being proposed for 2007.

Customers Experiencing Multiple Interruptions

The IEEE Standard 1366P-2003 provides for two methods to analyze data associated with customers experiencing multiple momentary interruptions and/or sustained interruptions. Avista's Outage Management Tool (OMT) and Geographical Information System (GIS) provide the ability to geospatially associate an outage to individual customer service points. This association allows for graphically showing Customers Experiencing Multiple sustained Interruptions ($CEMI_n$) with Major Event Day data included onto GIS produced areas. Data can be exported to MS Excel to also create graphs representing different values of n. A new section will be added to the report after the Areas of Concern Section to summarize the analysis Avista performed on the 2007 outage data. The calculation for $CEMI_n$ and Customers Experiencing Multiple Sustained and Momentary Interruptions $CEMSMI_n$ is provided in the Indices Section.

Definitions

Reliability Indices

SAIFI (System Average Interruption Frequency Indices), MAIFI (Momentary Average Interruption Frequency Indices), SAIDI (System Average Interruption Duration Indices), and CAIDI (Customer Average Interruption Duration Indices) are calculated consistent with industry standards as described below. Avista adopts these for purposes of tracking and reporting reliability performance. Further explanation and definitions are provided in the "Indices Calculation" section of this report. While these indices are determined using industry standard methods, it is important to note that differing utilities may use different time intervals for momentary and sustained outages. Avista defines momentary outages as those lasting five (5) minutes or less. Sustained outages are those lasting longer than five (5) minutes.

Baseline Reliability Statistics

WAC 480-100-393 (3) (b) requires the establishment of baseline reliability statistics. The Company's 2003 Electric Service Reliability Monitoring and Reporting Plan initially established Avista's Baseline Reliability Statistics. At that time, the Company selected these baseline statistics as the average of the 2001 through 2003 yearly indices plus two standard deviations (to provide 95% confidence level). Last year, the Company reviewed the calculation of the baseline statistics in light of the completion of the transition to the OMT in 2005 and the data collected in 2006. Calculating the baseline reliability statistics including the 2004 through 2006 data show an increase in the values, which the Company believes, represents better reporting using OMT. The Company proposed the latest calculated Baseline Statistic values to reflect the best available data collection. Because the Company believes that the OMT data collection has affected the SAIFI index the most, it used the years 2004 to 2006 for the SAIFI Baseline Statistic and the years 2002 to 2006 for the MAIFI and SAIDI Indices.

The baseline indices have been adjusted by removing Major Event Days, MED's, as defined in the following section.

The following table summarizes the baseline statistics by indices.

Indices	2004-2006 Average (Excluding Major Events)	Baseline Statistic (Ave + 2 Standard Deviations)
SAIFI	1.09	1.44

Indices	2002-2006 Average (Excluding Major Events)	Baseline Statistic (Ave + 2 Standard Deviations)
MAIFI	4.52	5.82
SAIDI	114	160

Additional comparison of the Baseline Indices is provided in the System Indices section of this report.

Avista is anticipating using the different years in the Baseline Statistics for SAIFI for at least a couple of years until a full five years of data is gathered using the current Outage Management Tool.

Major Events

Major Events and Major Event Days as used in this report are defined per the IEEE Guide for Electric Power Distribution Reliability Indices, IEEE P1366-2003. The following definitions are taken from this IEEE Guide.

> **Major Event** – Designates an event that exceeds reasonable design and or operation limits of the electric power system. A Major Event includes at least one Major Event Day (MED).
>
> **Major Event Day** – A day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

The Company will use the process defined in IEEE P1366 to calculate the threshold value of T_{MED} and to determine MED's. All indices will be reported both including and excluding MED's. The comparisons of service reliability to the baseline statistics in subsequent years will be made using the indices calculated without MED's.

The table below lists the major event days for 2007.

Major Event Days	SAIDI (Customer-Minutes)	Cause
2007 Major Event Day Threshold	8.017	
01-06-2007	9.98	Wind Storm
06-29-2007	32.64	Wind Storm
07-13-2007	12.79	Wind Storm
08-31-2007	21.30	Wind & Lightning Storm

Additional analysis of the 2007 Major Event Days is provided in this Annual Report starting on Page 52, section Major Event Days Causes.

Customer Complaints

The Company tracks reliability complaints in two areas, Commission complaints and Customer complaints. Commission complaints are informal complaints filed with and tracked by the Commission. Customer Complaints are recorded by our Customer Service Representatives when a customer is not satisfied with a resolution or explanation of their concern. See the Customer Complaints section on Page 36 for a summary of results for this year.

System Indices

The charts below show indices for Avista's Washington and Idaho ("system") electric service territory by year. Breakdown by division is included later in this report.

The Company continues to use the definition of major events as described above to be consistent with IEEE Standards. Therefore, the following charts show statistics including the effect of major events per this definition.

Chart 1.1 – SAIFI - Sustained Interruptions / Customer

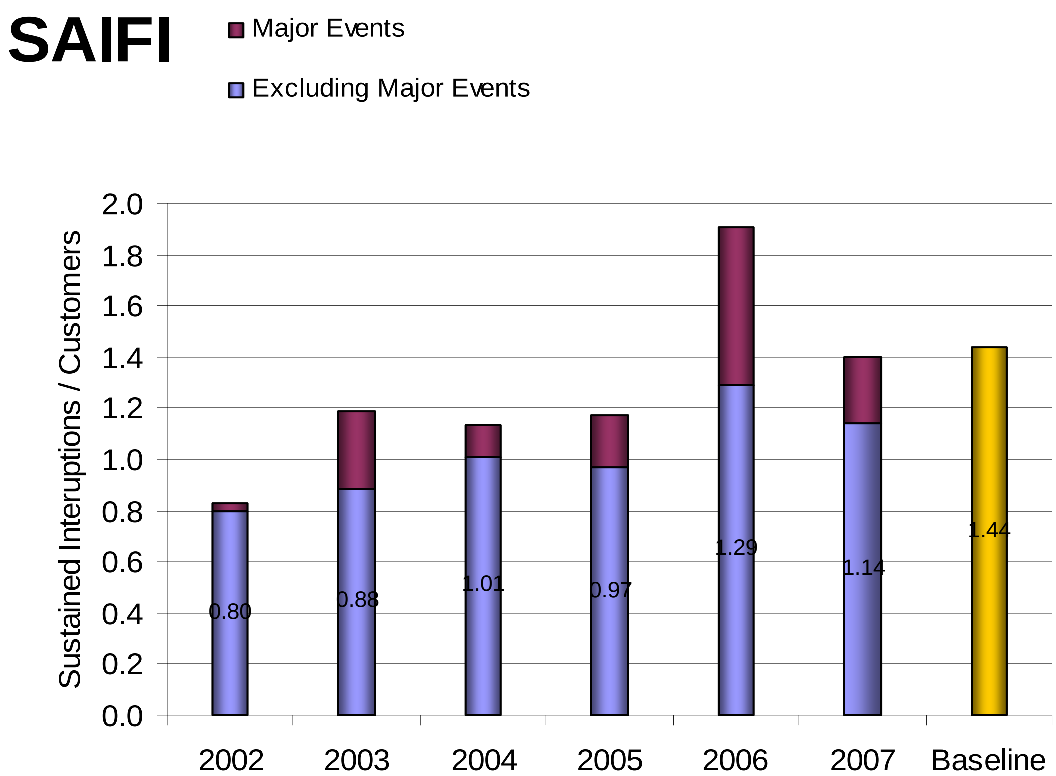
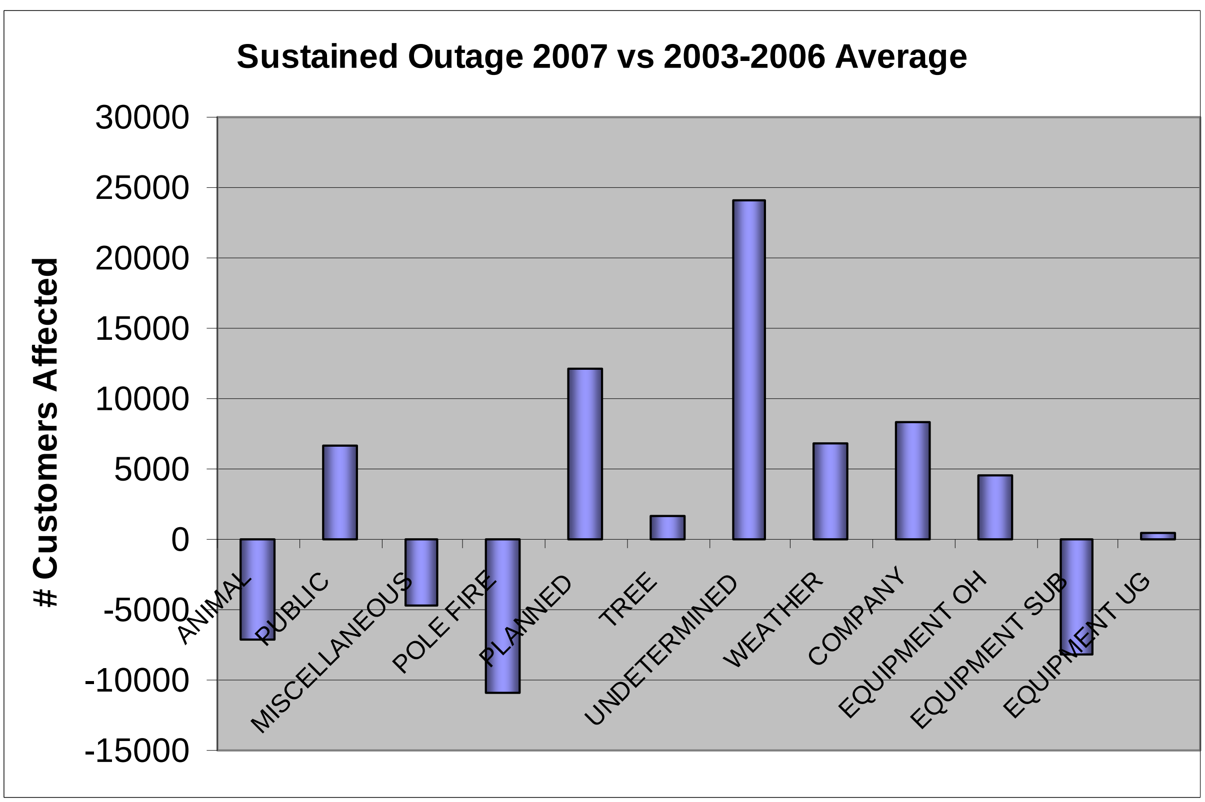


Chart 1.2 – Sustained Interruptions / Customer Historic Comparison



SAIFI for 2007 was within the existing baseline and 12% lower than 2006. Major contributors to this difference were lower weather, tree, public, and overhead equipment outages.

There were 71,949 customers affected by sustained outages caused by weather in 2007. This compares to the 2003–2006 average of 65,115 customers.

47,051 customers were affected by sustained outages associated with tree related incidents. This compares to the 2003-2006 average of 45,350 customers. The vast majority of the tree related reasons were associated with either tree fell or tree weather incidents.

Planned maintenance activities, and forced repairs affected 27,293 customers as compared to the 2003-2006 average of 15,164 customers. Additional maintenance activities associated with the Company cutout replacement program contributed to the increase in this cause and reduced the Overhead Equipment outage causes.

Equipment overhead (OH) failures resulted in outages to 53,397 customers as compared to the 2003-2006 average of 48,817. Major Equipment OH sub-categories were distribution fused cutouts, primary connector failures, arrester failures and other.

Cars hitting poles, felling trees and fires were a majority of the public caused outages.

A large increase in the number of Undetermined Causes occurred in 2007 as compared to the 2003-2006 average. 51,408 customer had undetermined causes as compared to the average of 27,250. A significant number of outages were associated with transformer fuses, but there was no known reason for the fuse to operate.

Chart 1.3 - MAIFI Momentary Interruption Events / Customer

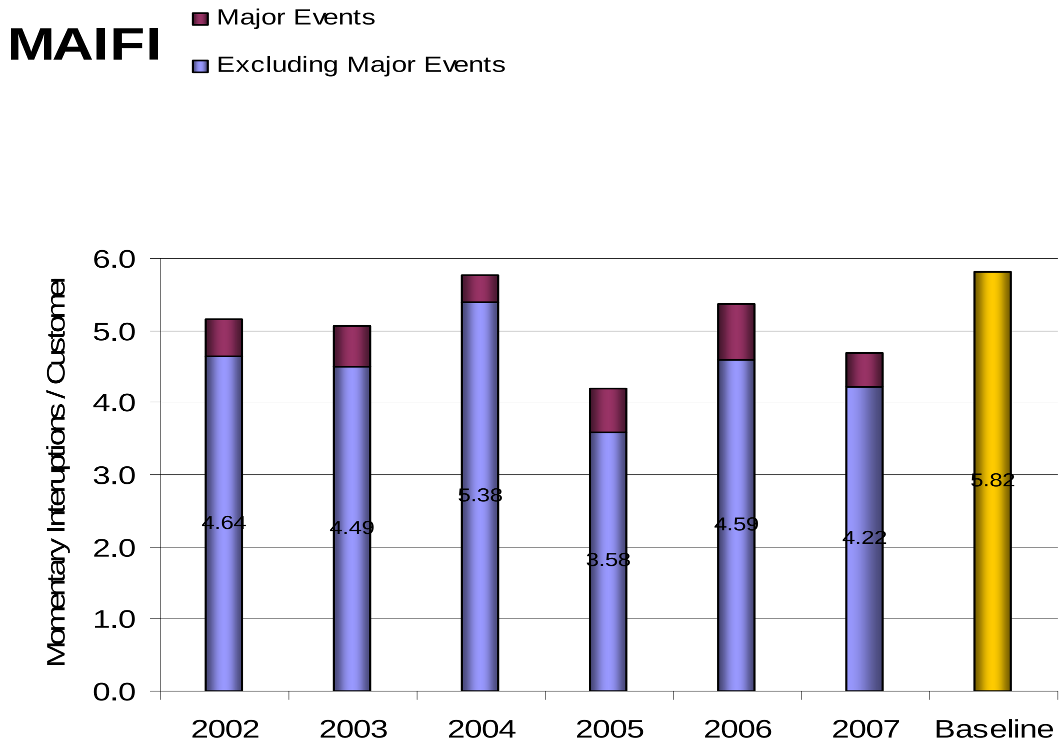
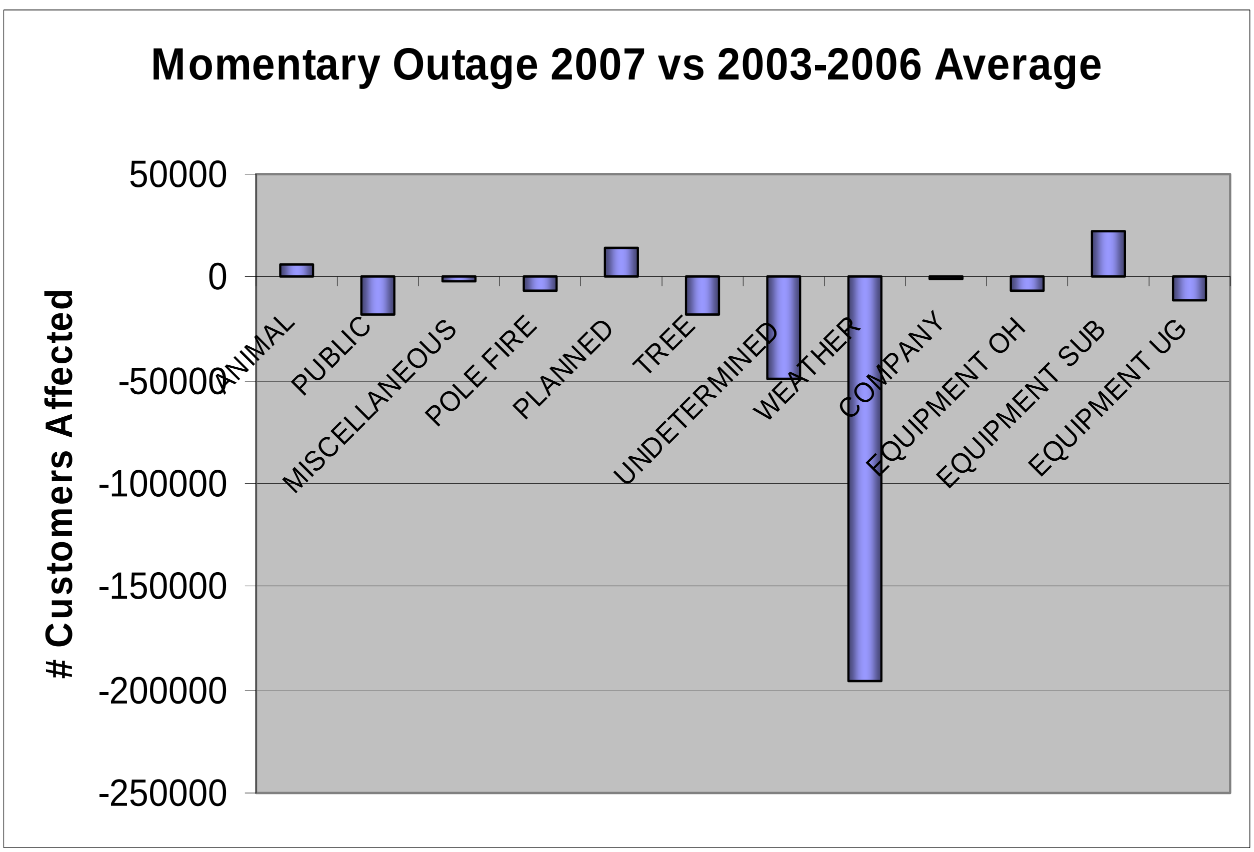


Chart 1.4 – Momentary Interruptions/ Customer Historic Comparison



The 2007 results for MAIFI show a small decrease in the number of incidents compared to the 2003 to 2006 average. There was a significant reduction in weather/undetermined related momentary outages, that were most likely due to the better overall weather conditions. Distribution Dispatch continues to make improvements in correlating the momentary outages with subsequent sustained outages, which reduces the undetermined causes. Wind contributed to 32,157 customers being impacted, Heavy Snow impacted 39,443 customers while Lightning accounted for impacts to 23,566 customers.

All other categories showed either a slight increase or slight decrease that would be consistent with previous years.

Chart 1.5 - SAIDI – Average Outage Time / Customer

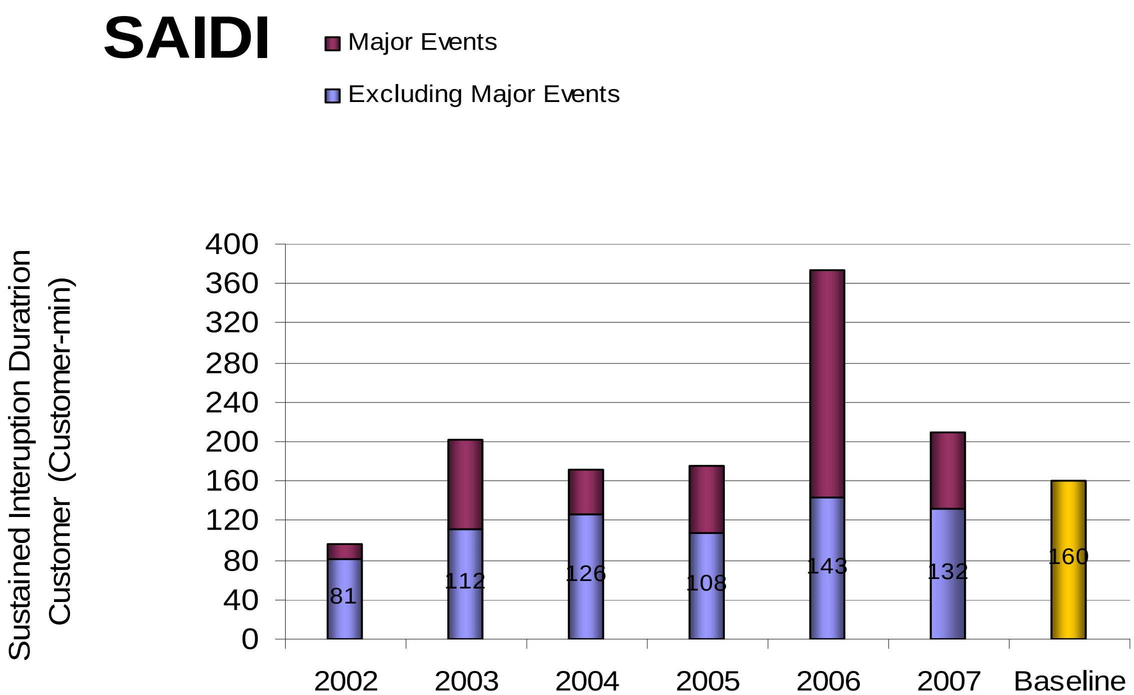
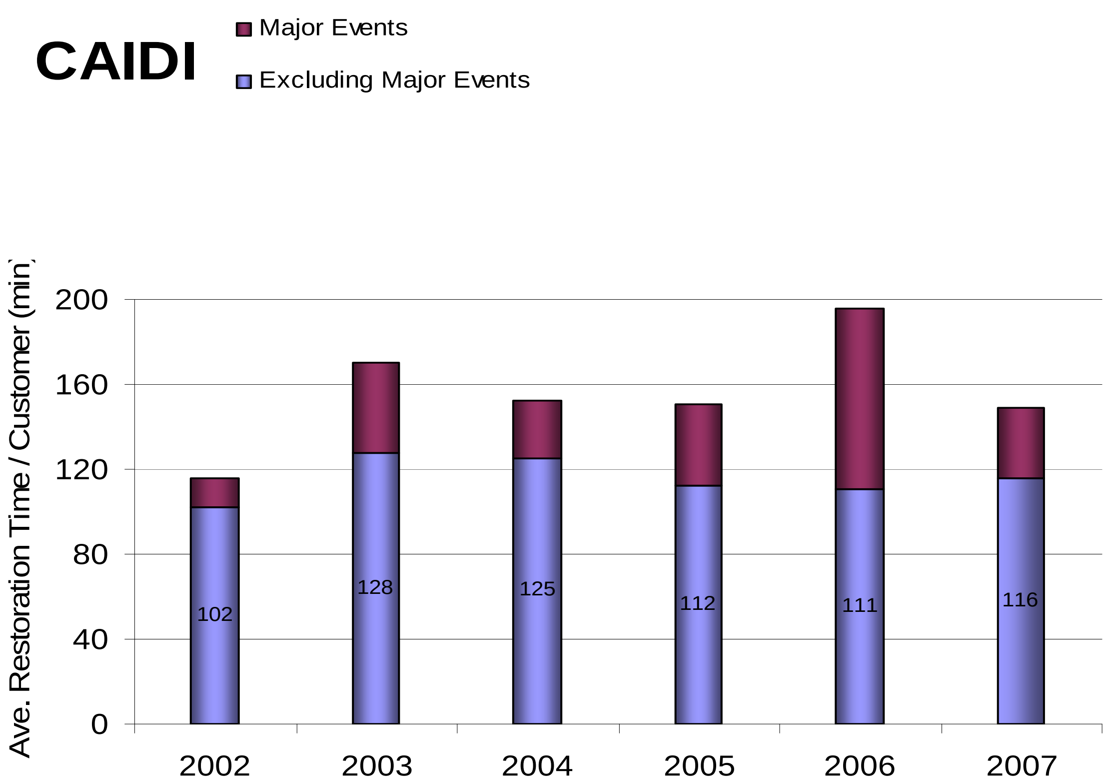


Chart 1.6 - CAIDI – Average Restoration Time



OFFICE Indices

Chart 2.1 – SAIFI - Sustained Interruptions / Customer

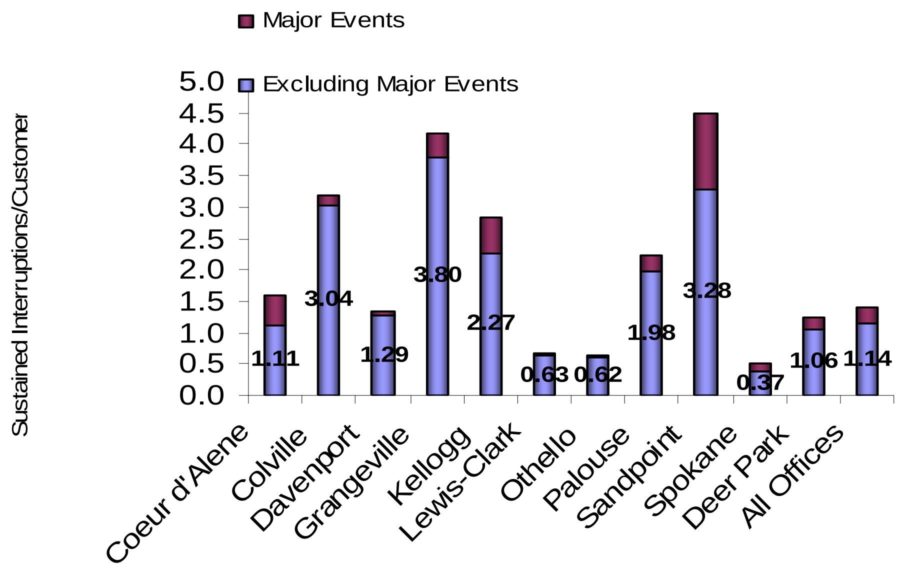


Chart 2.2 - MAIFI Momentary Interruption Events / Customer

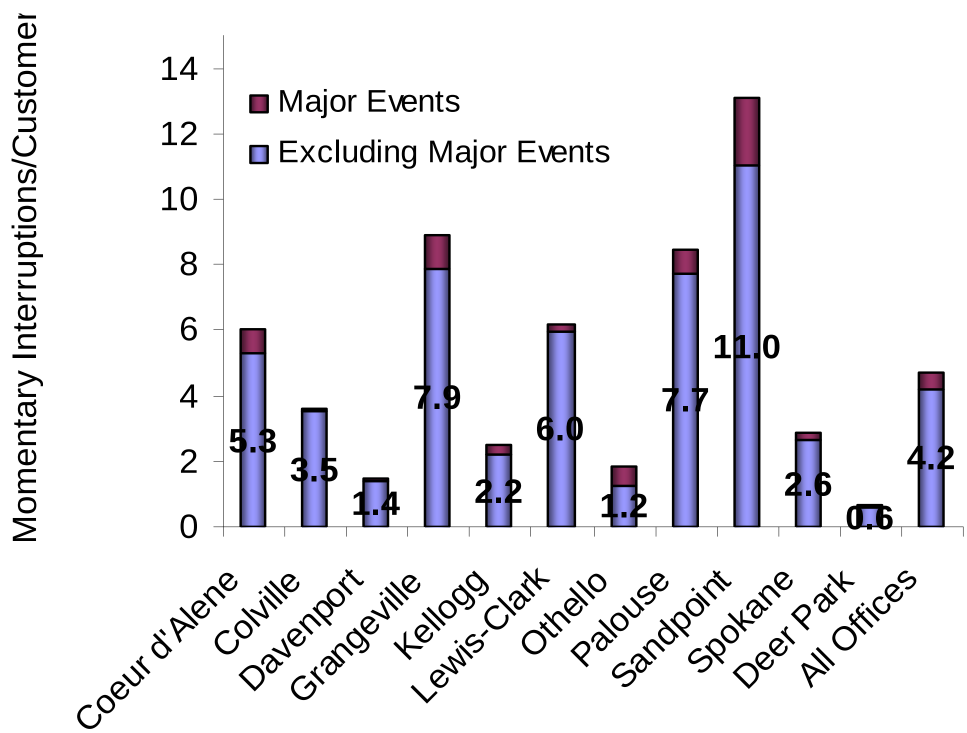


Chart 2.3 - SAIDI – Average Outage Time / Customer

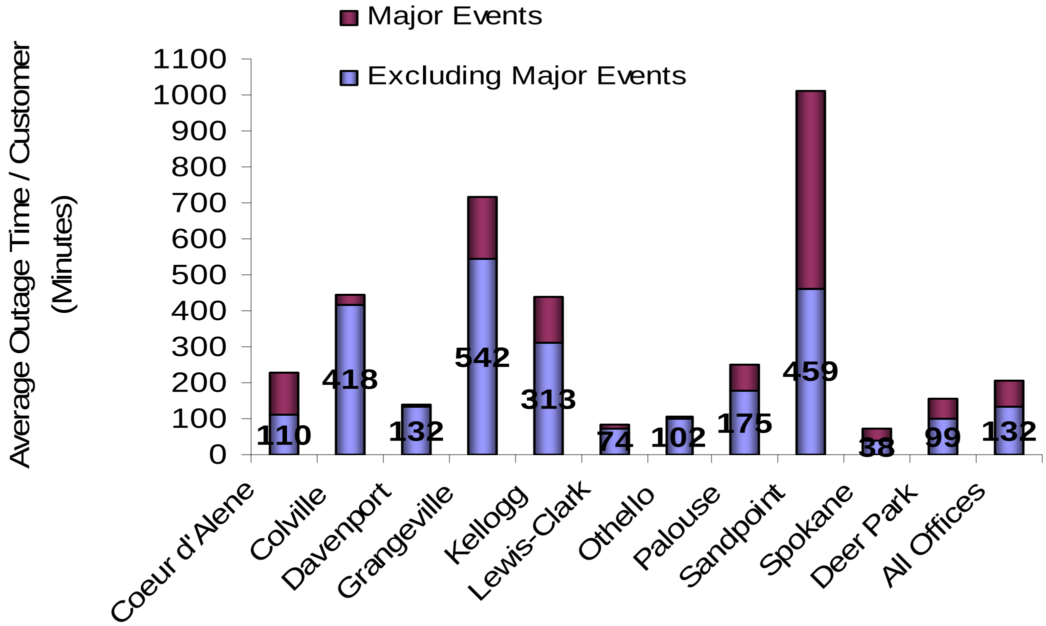
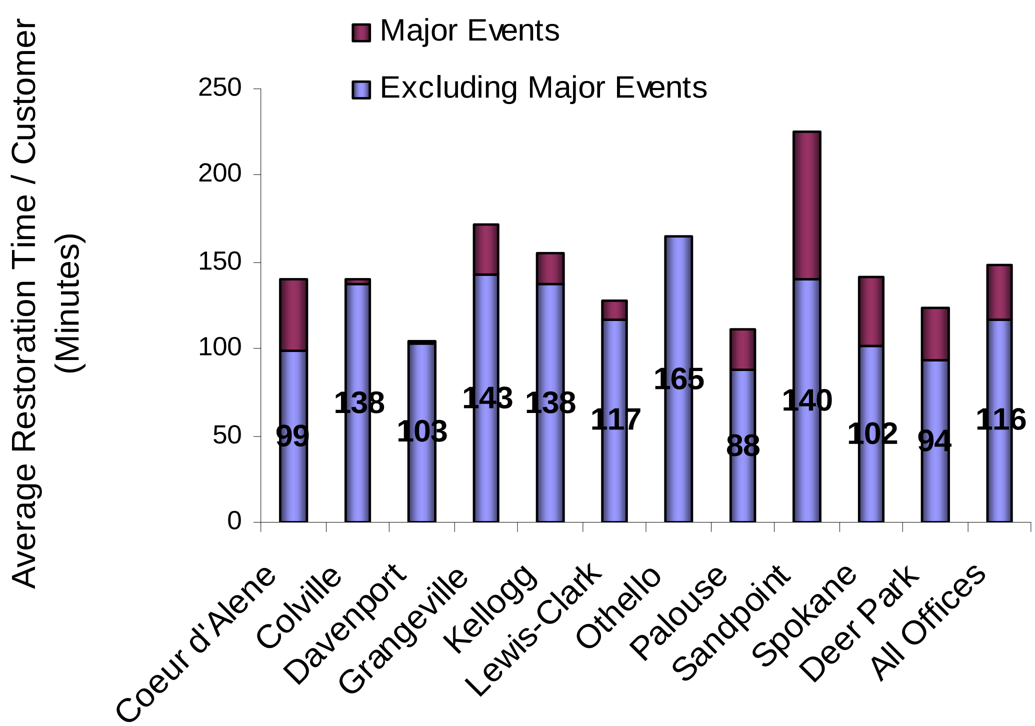


Chart 2.4 - CAIDI – Average Restoration Time



Areas of Concern

As in previous years, Colville has the lowest reliability of Washington's operating areas. However, the Colville area continues to show improvement over previous years as work plans are implemented. Colville was judged lowest based on its performance in the yearly indices for SAIFI, SAIDI, CAIDI, and MAIFI. Within the Colville area, five feeders (Gifford 34F1, Gifford 34F2, Colville 34F1, Colville 12F4, Chewelah 12F3 and Valley 12F1) were identified as areas of concern in 2006. For this report, six feeders are identified as the areas of concern for 2007. These feeders are Gifford 34F1, Gifford 34F2, Colville 34F1, Colville 12F4, Valley 12F3 and Valley 12F1.

Cause Information:

Generally rural areas have a greater number of outages per customer. Colville is a predominately rural and forested area. There are approximately 2342 miles of distribution line exposed to weather, underground cable failures and tree problems. Unlike most of the Company's system, lines in this area are built on the narrow, cross-country rights-of-way, typical of PUD construction practices prior to Avista acquiring the system. These conditions make patrolling, tree trimming, right of way clearing and other maintenance difficult. Over time and when cost effective Avista moves sections of these lines to road rights of way and/or converts them to underground.

Further, when outages occur in rural areas, the time required to repair damage is longer. More time is required for first responders to arrive and assess the damage and more time is required for the crew to reach the site. Often the damage is off road and additional time is required to transport materials and equipment to the site.

Listed below is a summary of the specific cause data for each feeder. This is a compilation of data from the Avista Outage Management Tool and the reporting from our local servicemen to Distribution Dispatch. Data from the reporting system is shown as a percentage of total customer-outages, (SAIFI) for that feeder.

Snow loading on green healthy trees growing beyond the rights-of-way often causes them to bend or break and contact distribution lines. These trees are not cut as part of our vegetation management program because they are outside our right of way and are considered healthy marketable timber.

The reliability of two of the Valley feeders has diminished over the last four years and will be added to the list for this year's report to reflect plans to improve the reliability in future years. Valley 12F3 has poorer reliability for 2007 than Valley 12F1 which was reported for the first time in the 2006 report.

Gifford 34F1

- 30.1% Weather: snow, wind and lightning storms
- 21.4% Equipment: poles, fused cutouts, & connectors
- 11.8% Pole fires
- 16.9% Trees
- 3.3% Planned outages

Colville 34F1

- 23.4% Weather; snow, wind and lightning storms
- 20.8% Equipment: crossarms and poles
- 0.1% Pole fires
- 34.1% Trees
- 10.7% Planned outages

Chewelah 12F3

- 3.7% Weather: snow, wind and lightning storms
- 35.7% Equipment: connector and arrester
- 23.0% Company
- 9.4% Trees
- 15.0% Planned outages
- 3.6% Animal: birds or squirrels

Gifford 34F2

- 14.0% Weather: Wind, snow, and lightning storms
- 0.1% Equipment: regulator failure
- 34.8% Pole Fires
- 37.5% Trees
- 6.3% Planned outages
- 2.6% Public: car hit pole, dig in

Valley 12F3

- 12.0% Weather: wind and lightning storms
- 33.5% Equipment: fused cutouts, insulator, and other
- 5.4% Trees
- 15.8% Public
- 15.5% Planned outages
- 0.5% Animal: birds or squirrels

Valley 12F1

- 3.6% Weather: snow, wind and lightning storms
- 42.6% Equipment: connector and arrester
- 0.3% Trees
- 9.2% Public
- 7.3% Planned outages
- 3.5% Animal: birds or squirrels

Work Plans:

The improvement work that has been accomplished or planned for each feeder is listed below. The Company's reliability working group is continuing to study these feeders to develop additional work plans. Each of the identified feeders also had planned outages that correspond to the maintenance and replacement activities in the area.

Gifford 34F1

- An engineering review was completed in 2006 and construction jobs drawn up to implement improvements to the feeder protection scheme which should break up the exposure on the long single phase laterals. Construction work was completed in the later part of 2007 to replace two reclosers and to add two additional reclosers to the feeder. In addition, adding 320 neutral extension racks should help address the ice unloading issue. However, the work on the extension racks has been delayed for a couple of years.
- No URD cable was replaced in 2007, but 7500' of cable has been identified to be replaced in 2008.
- Vegetation Management was scheduled to complete ROW clearing in 2007, but this was rescheduled to be completed in 2008. Work was rescheduled due to forest access restrictions last summer and completing work on other parts of the Avista system.

Colville 34F1

- No URD cable was replaced in 2007; however a 6620' section of new URD cable was installed to replace a section of overhead line that had a lot of poles that would need to be replaced.
- The remaining 50% of the feeder was re-cleared during 2007. No additional work planned for 2008.
- An engineering review was completed and construction jobs drawn up to implement improvements to the feeder protection scheme, eliminating a step-up transformer, and several 34.5 to 13.2 kV step-down transformers on the HWY 25N-Williams Lake section of the feeder to improve the level of service to customers. Construction work was completed in 2007, however the new recloser installed failed to perform properly and has been removed from service and has been returned to the factory for evaluation.

Chewelah 12F3

- Engineering analysis completed in 2006 and a budget item prepared. Higher priority budget items left these reliability improvements unfunded for 2007. In early 2007, budget money was approved to complete this project. Three reclosers were installed on the feeder to improve the temporary fault protection. Local personnel identified areas where turkeys roost and fly into the distribution facilities during early morning hours.
- Hazard tree patrol and mitigation work was completed during 2007. No work is planned for 2008.
- 3300' of URD cable was replaced in 2007.

Gifford 34F2

- Engineering analysis was completed in 2006 and a budget item prepared to implement improvements to the feeder protection scheme. Higher priority budget items left these reliability improvements unfunded for 2007 and 2008. Current planning is to begin work in 2009.
- No tree trimming work was planned for either 2007 or 2008.
- There is several planned replacement jobs of less than 1000' of URD cable scheduled in 2008.

Valley 12F1

- Engineering analysis was completed in 2006 and a budget item prepared to implement improvements to the feeder protection scheme that should reduce the exposure on long single phase laterals. Higher priority budget items left these reliability improvements unfunded for 2007 and 2008. Work is scheduled to be start in 2009.
- Hazard tree patrol and mitigation work was completed in 2007. No work planned for 2008, but work is planned for 2009.

Valley 12F3

- Engineering analysis was completed in 2007 after a car hit pole incident and subsequent line recloser failure to evaluate the overall protection scheme.
- No tree trimming work was planned or completed for 2007, but work is planned for 2008.
- No URD cable was replaced in 2007 or is planned to be replaced in 2008.

The Company typically uses several different protective devices on its feeders to isolate faulted or overloaded sections and also continue to serve the remaining customers. Generally, two different protection schemes are used to either "save" the lateral fuse or "blow" the lateral fuse by using or not using the instantaneous over current trip. Depending on the feeder, number of customers, types of faults, (temporary or permanent), customer type, time of year, etc. both of these schemes may be used on an individual feeder at different times at the discretion of the field personnel. With the better data and cause code collection that OMT provides and the customer growth on some of the Colville feeders, changes to the type of scheme used has been reviewed. In the last few years, new electronic fault indicators allow for quicker response to outages and help with restoration of customers. Fault indicators are being employed on some feeders to reduce the outage response times. Engineering reviews of some of the sections of the feeder(s) in the Colville area show that the addition of surge arrester protection should reduce outages on the feeder(s) due to lightning.

Avista develops a detailed annual budget for various improvements to the facilities it owns and operates. With the emphasis on Generation upgrades, Electric Transmission upgrades, Electric Substation capacity increases, and Electric Distribution capacity projects, the three projects described below were deferred until later years. Reliability specific projects were prioritized at a lower level than thermal capacity projects which is related to the recent economic growth in the Avista service territory. Many of these capacity projects have large capital expenditures associated with them and have taken the allocated capital budget resources. Also, as result of better data collection the analysis may show that these projects should have a higher priority over the next few years.

Feeder	Decisions/ basis	2008	2009 and beyond
Gifford 34F2	A small part of the initial budget item is being completed in 2008 on a portion of the feeder with the worst performance. The remaining portion of the budget item will be submitted again in 2009.	Planned	Planned
Valley 12F1	This feeder was first identified in mid 2006 as having areas that would be of concern. The priority of the projects identified for this feeder will be reviewed and resubmitted in future years.		Planned
Valley 12F3	A project has been identified to reconductor a section of this feeder near Waitts Lake to allow the addition of a third phase to a section of the feeder beyond the lake. Fusing protection will also be revised.	Planned	Planned

Besides the specific plans listed above, the Company performs ongoing maintenance activities in the Colville area that includes transmission aerial patrols, substation inspections and infrared surveys. Other maintenance activities occur daily as field personnel find and repair problems.

Porcelain cutout failures continue to contribute to outages and also have caused several pole fires on a system wide basis. As a result, Avista began purchasing a newer design of cutout with a polymer insulator beginning in January of 2005. Porcelain cutout failures tend to occur at a higher rate in areas with colder temperatures and wide temperature fluctuations, such as the Colville area. Avista started a system wide change out program in early 2007 to proactively replace problematic porcelain cutouts before this specific style fails. As of the end of February, 2008, 4400 out of about 8000 of this type of porcelain cutout have been replaced on the system. An additional 3600 are being planned to be replaced before year end 2008.

Avista has an annual vegetation management plan and budget to accomplish the plan. The budget is allocated into distribution, transmission, administration, and gas line reclearing.

Distribution

Our current plan for Avista's distribution system is managed by Asplundh Tree Expert Co. Every distribution circuit is scheduled to be line clearance pruned on a regular maintenance cycle of five years. Other distribution vegetation management activities include hazard tree patrol and herbicide application.

Transmission

The transmission system is managed by Avista's forester. All 230 kV lines are patrolled annually for hazard trees and other issues, and mitigation is done in that same year. Approximately one third of 115 kV transmission system is patrolled annually for hazard tree identification, and assessment of right of way clearing needs. Right of way clearing maintenance is scheduled and performed approximately every ten to fifteen years (for each line). Interim spot work is done as identified and needed. Engineering specifications for various voltages, line configurations are followed when clearing the right of way. Currently, the work is bid to a variety of contractors.

Customers Experiencing Multiple Interruptions

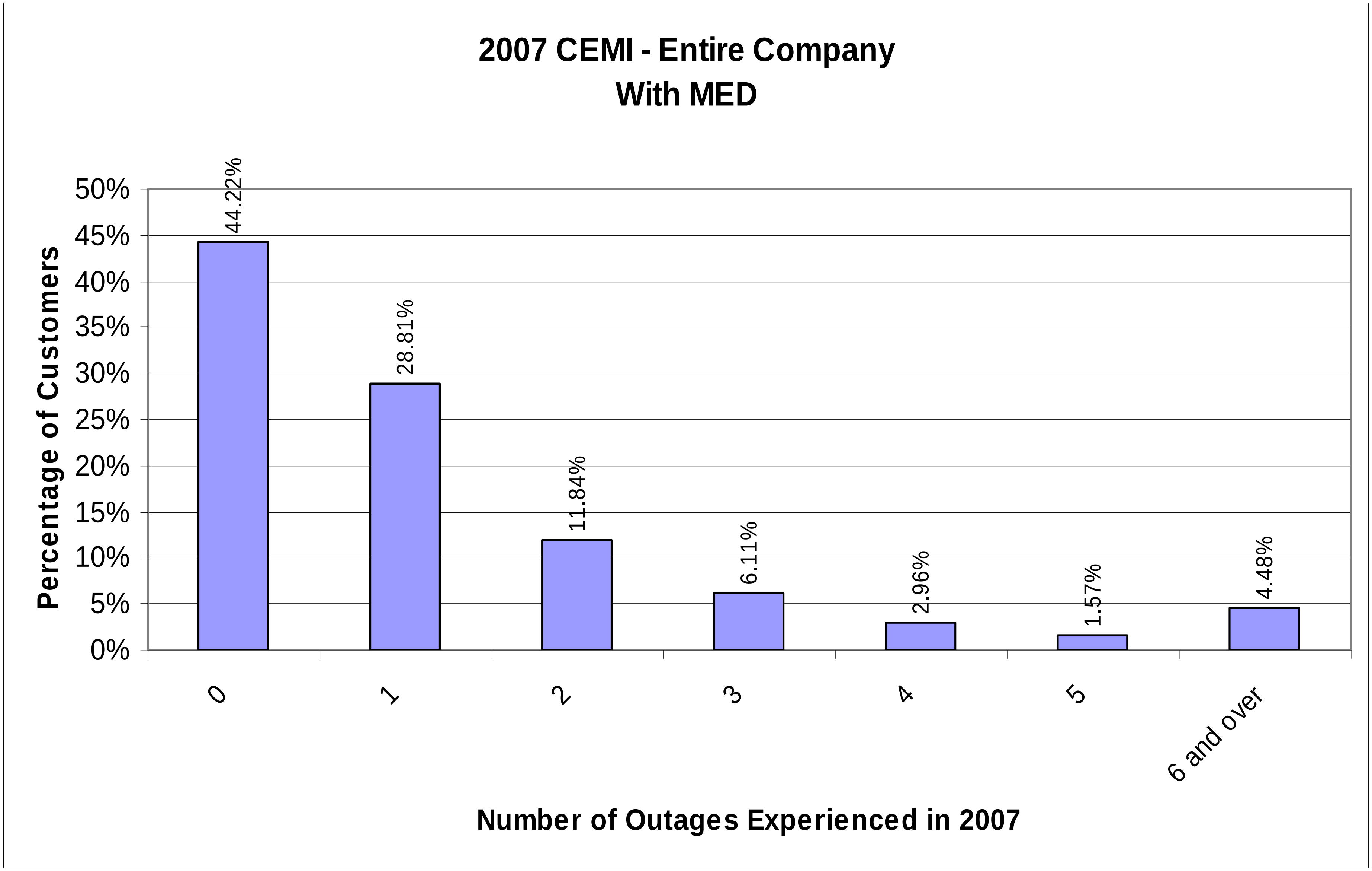
Avista has used the data from the OMT system integrated with the GIS system to geospatially display reliability data for specific conditions. The specific conditions imply looking at the number of sustained interruptions for each service point (meter point). This would be similar to the SAIFI indice, but would be related to a certain number of sustained interruptions. Avista includes all sustained interruptions including those classified under Major Event Days. This provides a view of what each customer on a specific feeder experiences on an annual basis. Momentary Interruptions are not included in the $CEMI_n$ indice, because of the lack of indication on many of the rural feeder reclosers.

The first chart below provides a view of the percentage of customers served from the Avista system that have sustained interruptions. 73 % of Avista customer had 1 or fewer sustained interruptions and 4.48% of Avista Customers had 6 or more sustained interruptions during 2007.

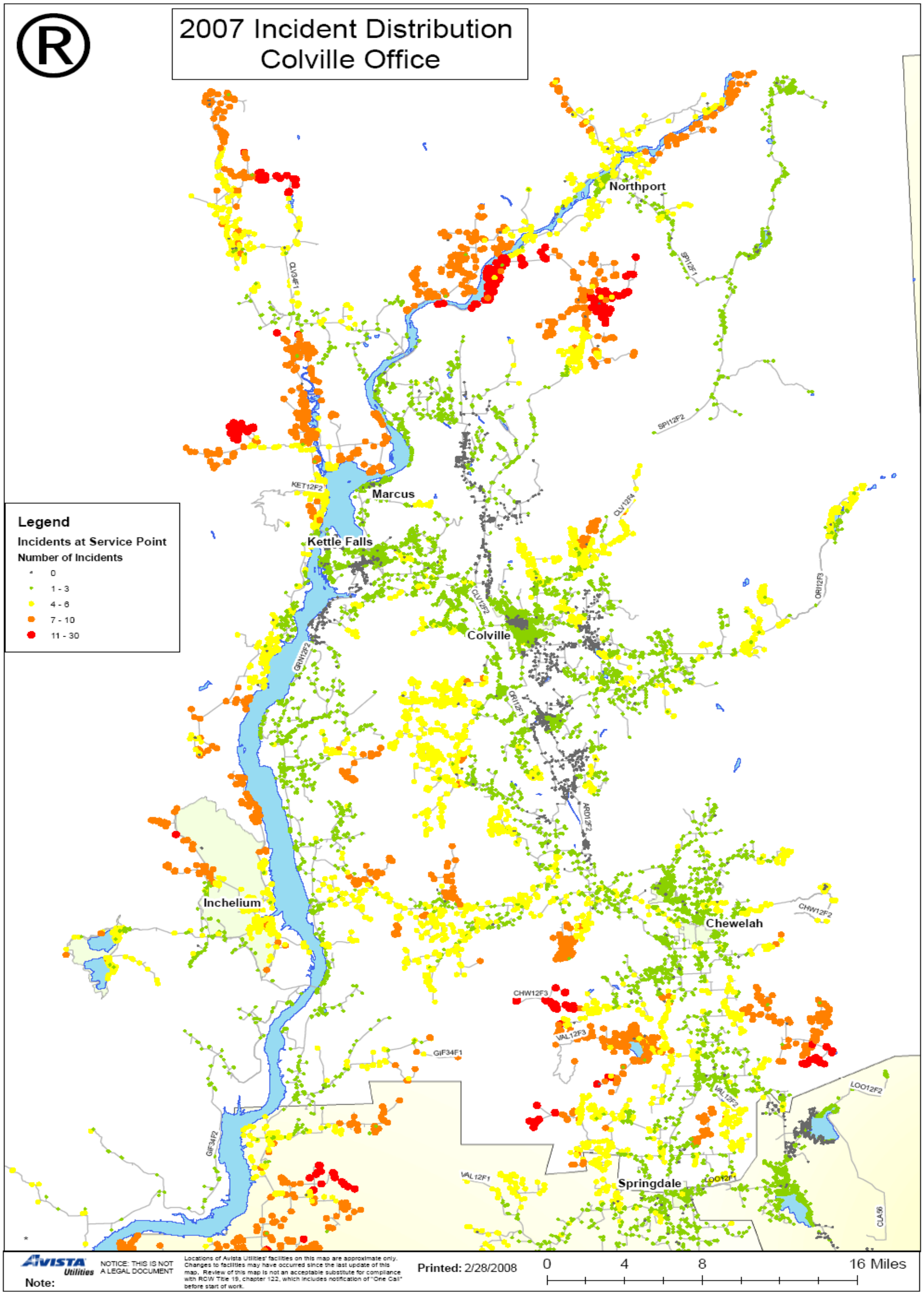
The remaining geographic plots show the sustained interruptions by color designation according to the legend on each plot for each office area. Note the office area is designated as the area in white for each plot and that there is overlap between adjacent office area plots. The adjacent office areas are shown in light yellow.

The plots provide a quick visual indication of varying sustained interruptions, but significant additional analysis is required to determine underlying cause(s) of the interruptions and potential mitigation.

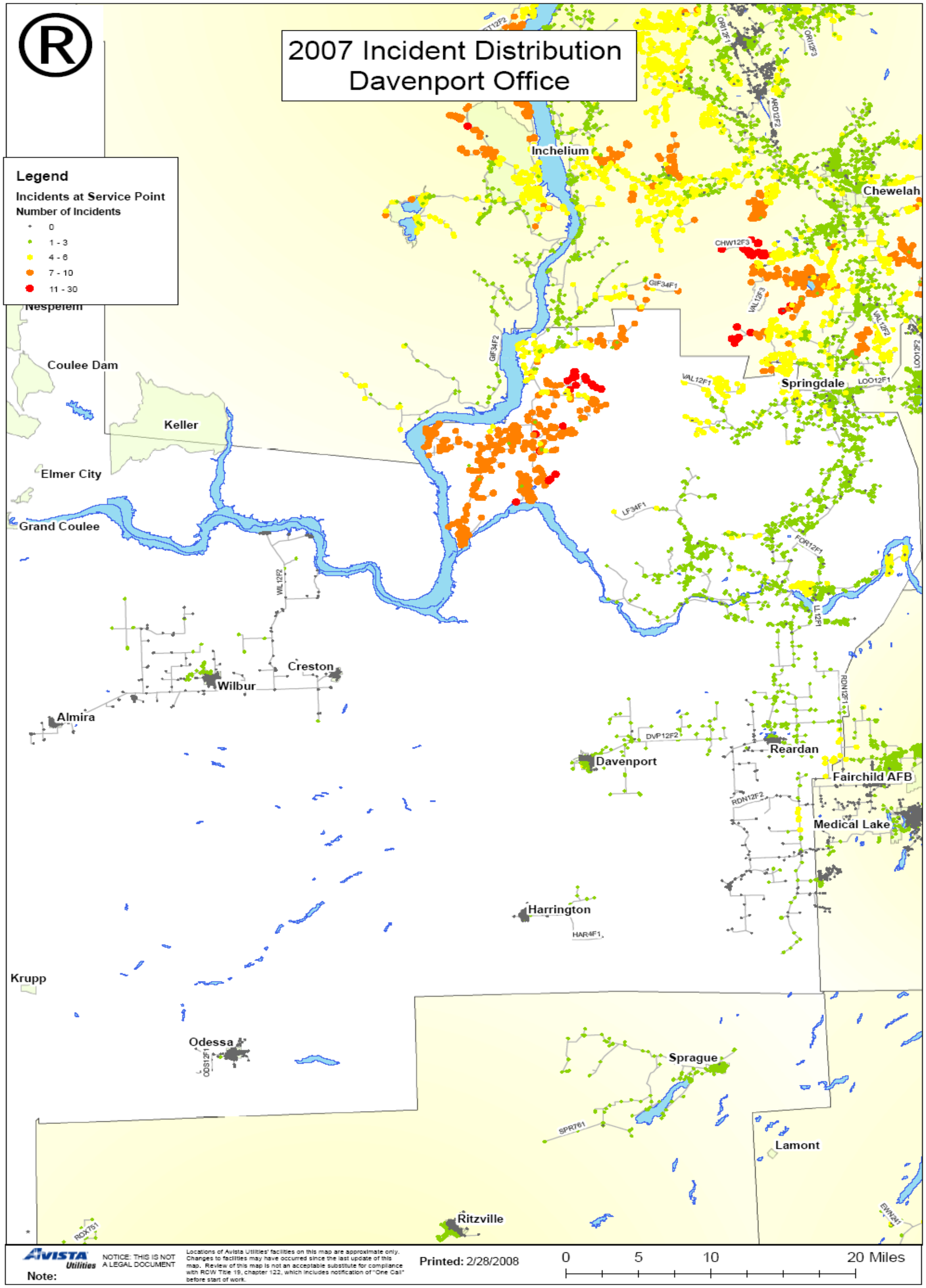
Avista Service Territory CEMI$_n$ Chart



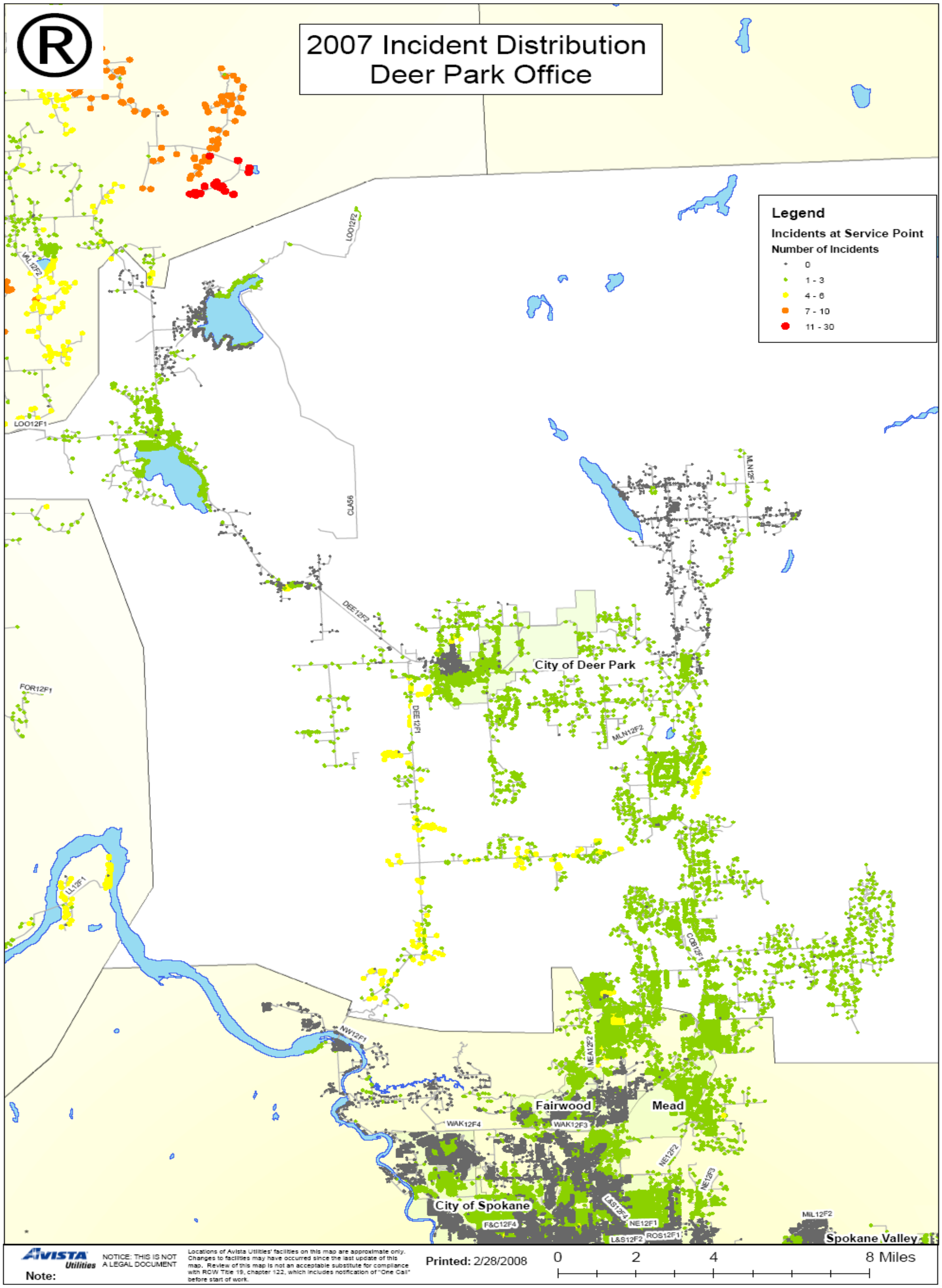
Colville Office - $CEMI_n$



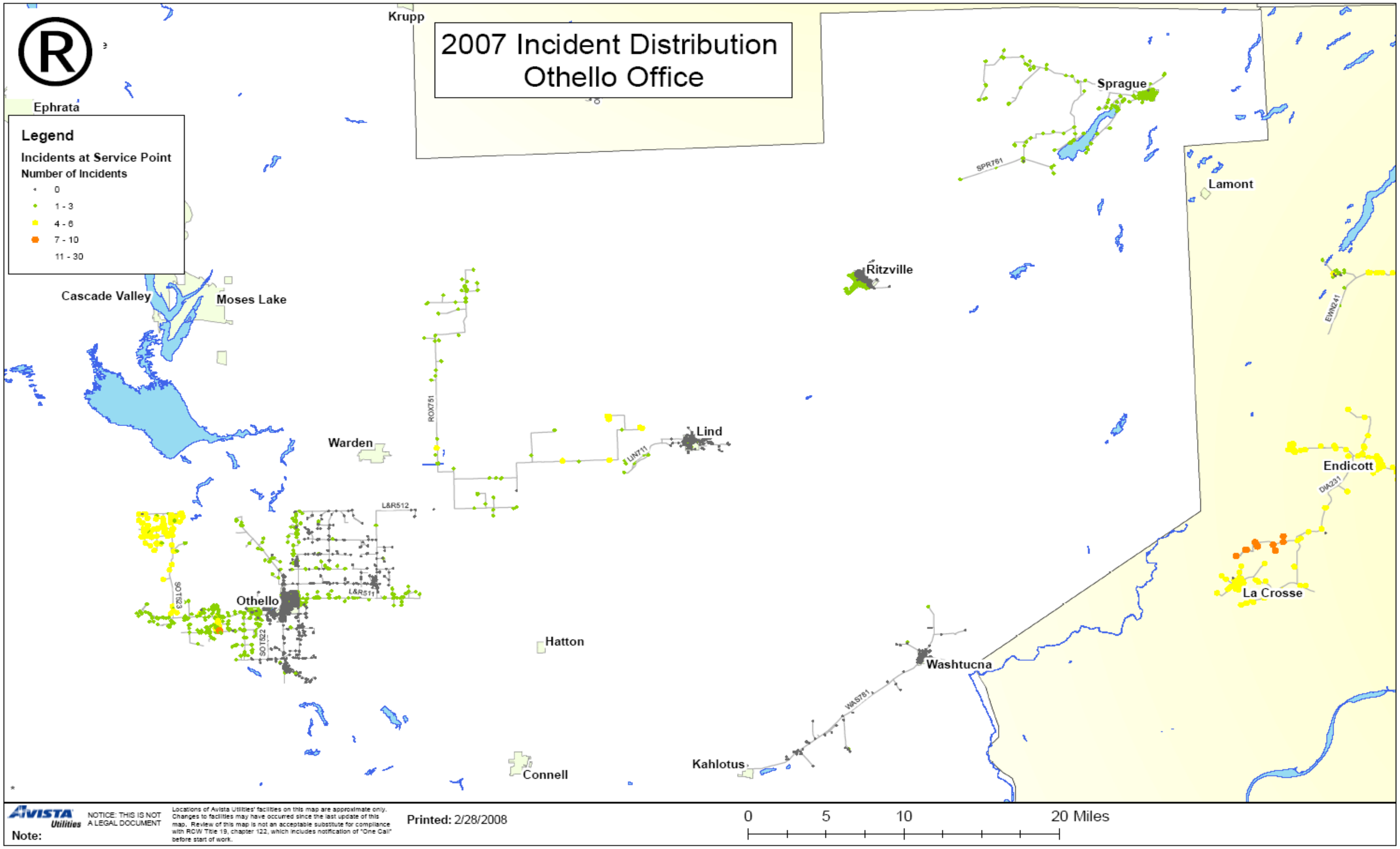
Davenport Office - CEMI$_n$



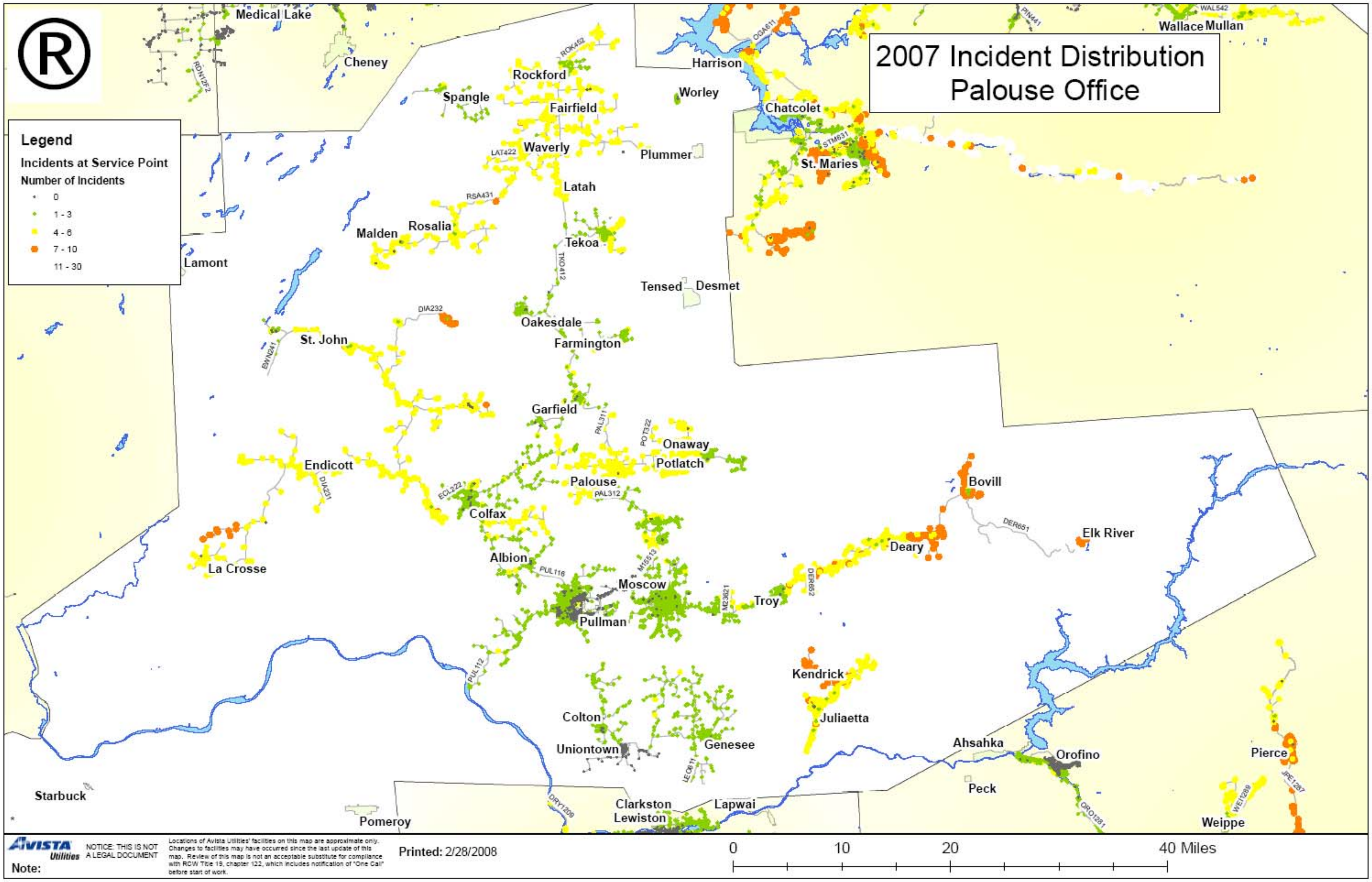
Deer Park Office - CEMI$_n$



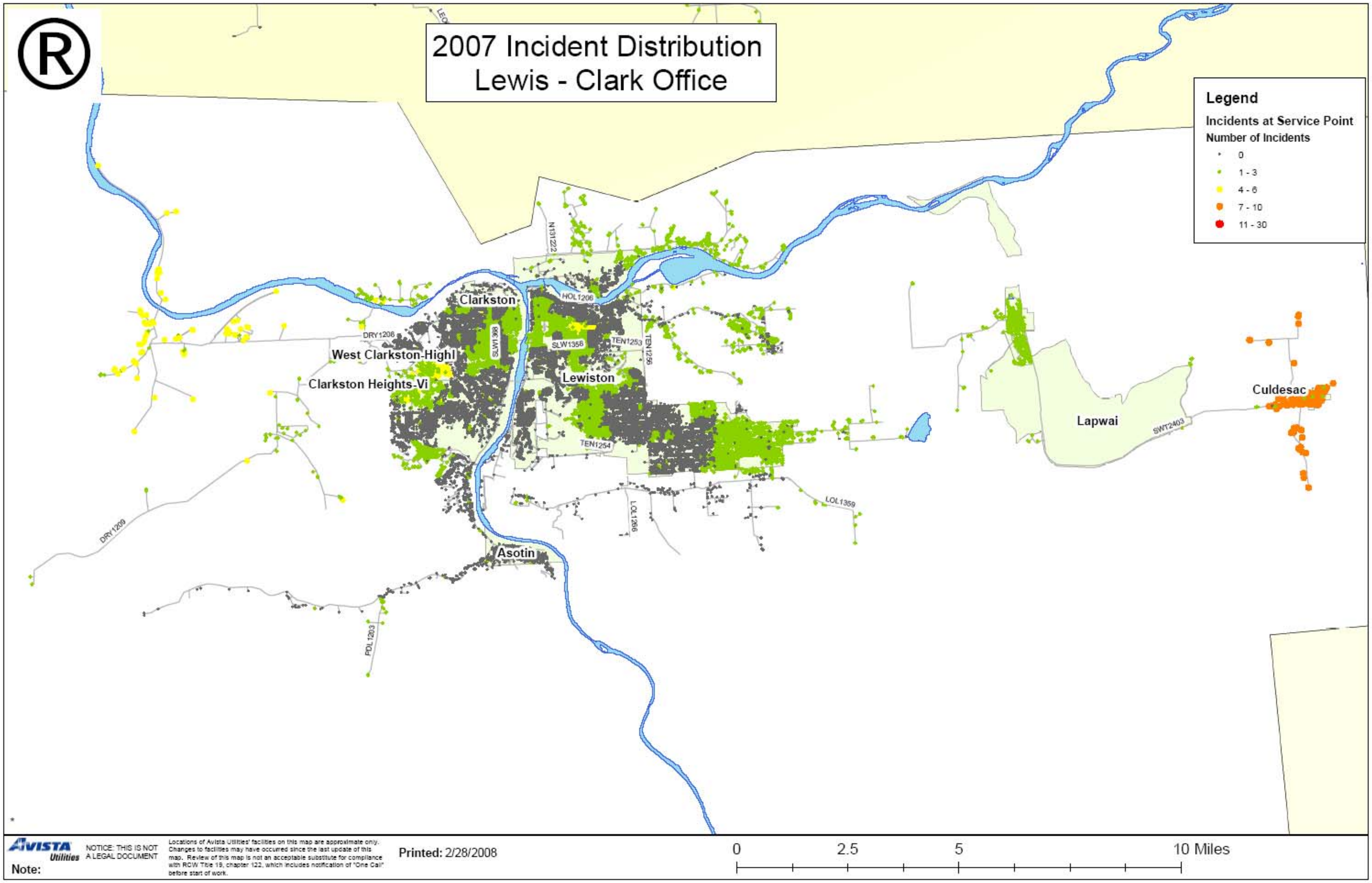
Othello Office - CEMI$_n$



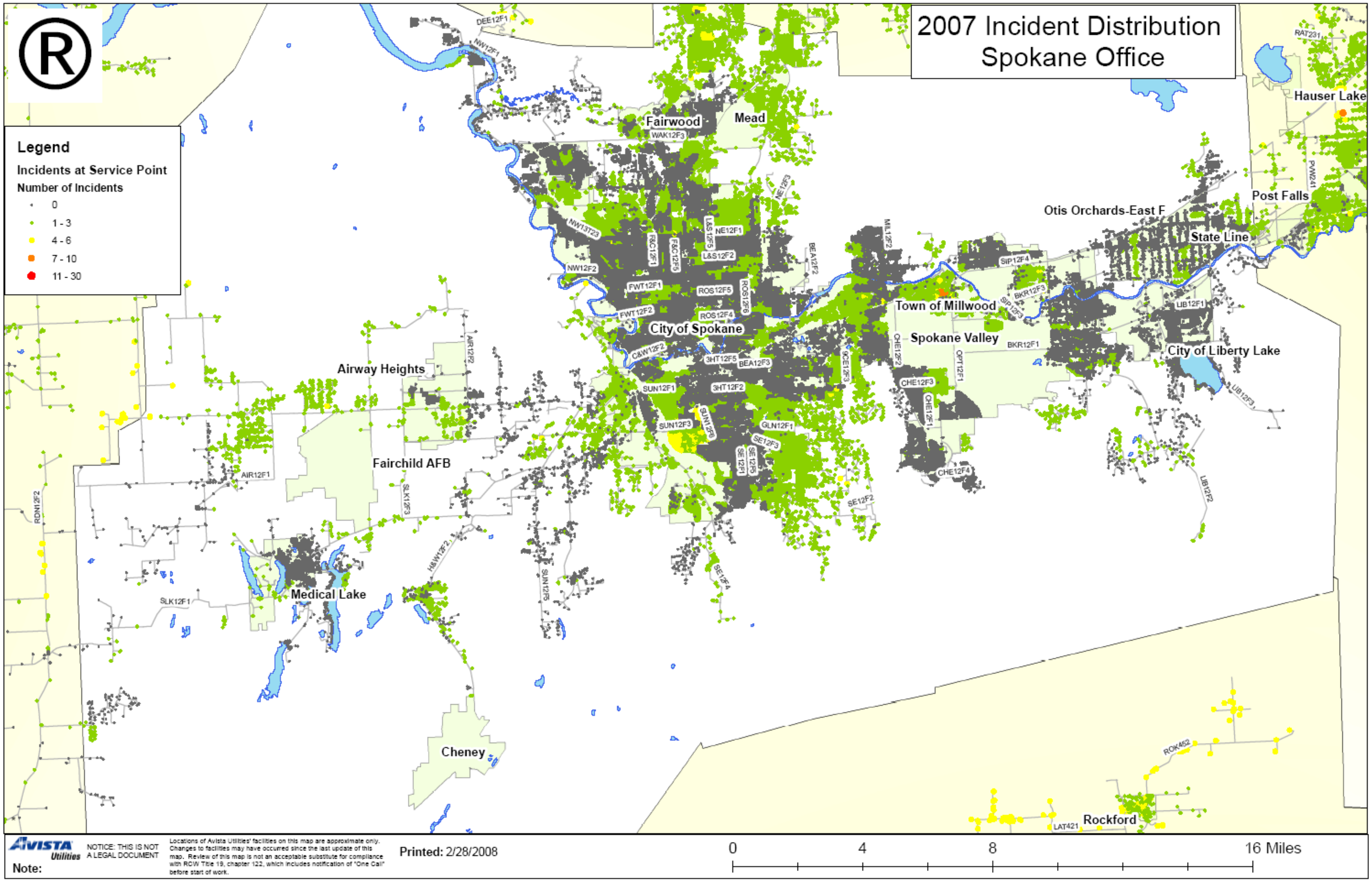
Palouse Office - CEMI$_n$



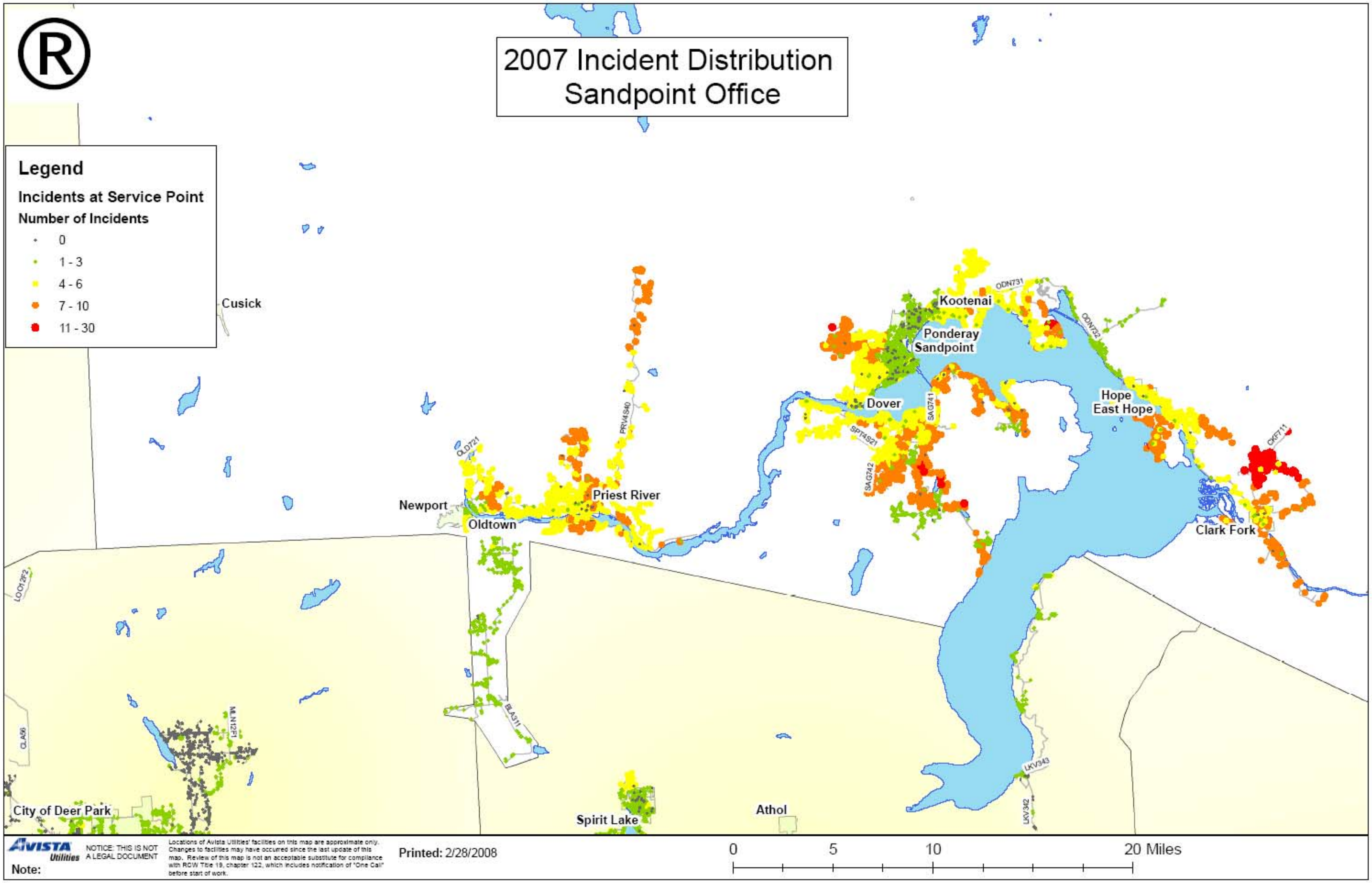
Lewis-Clark Office - $CEMI_n$



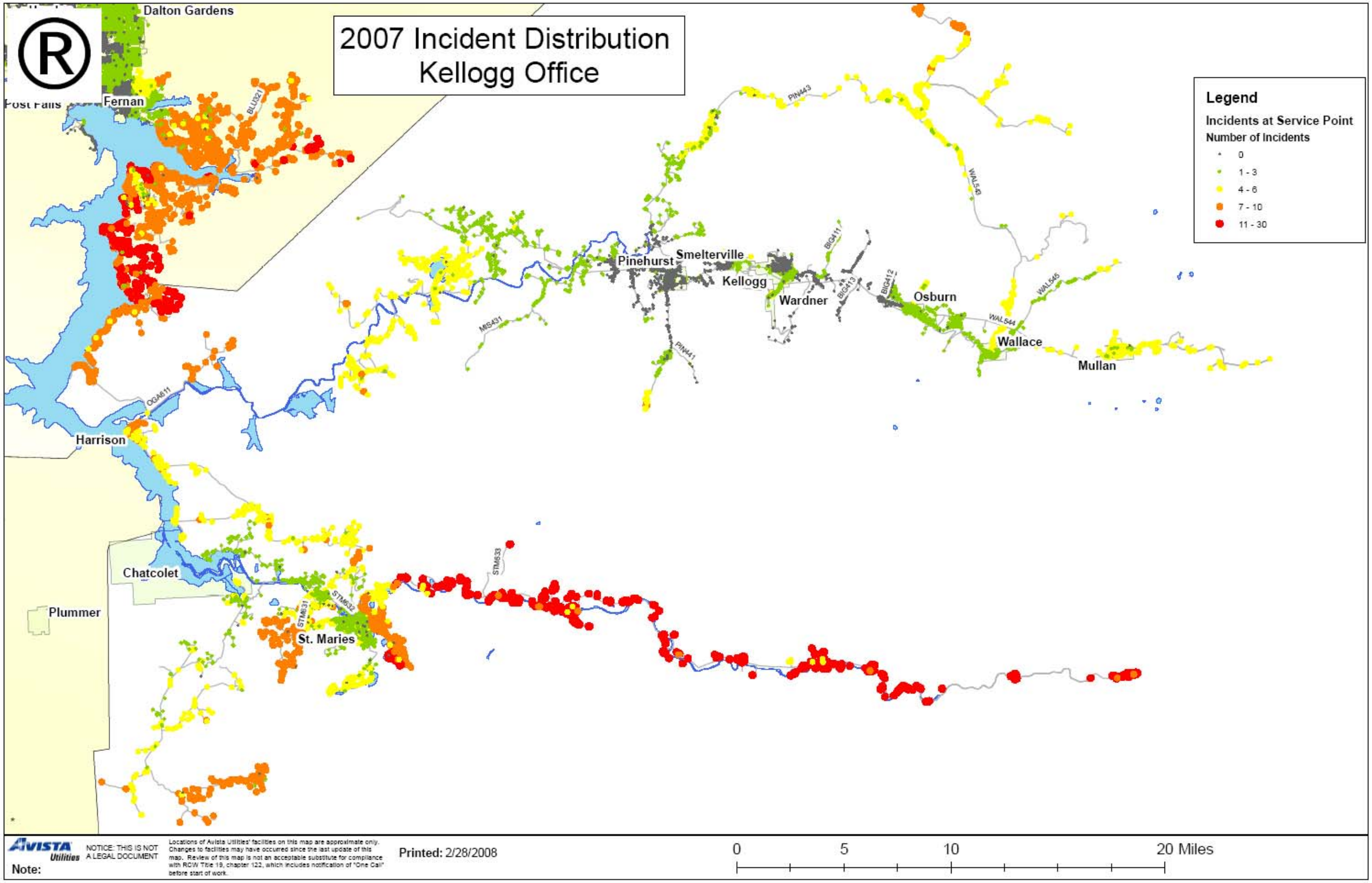
Spokane Office - CEMI$_n$



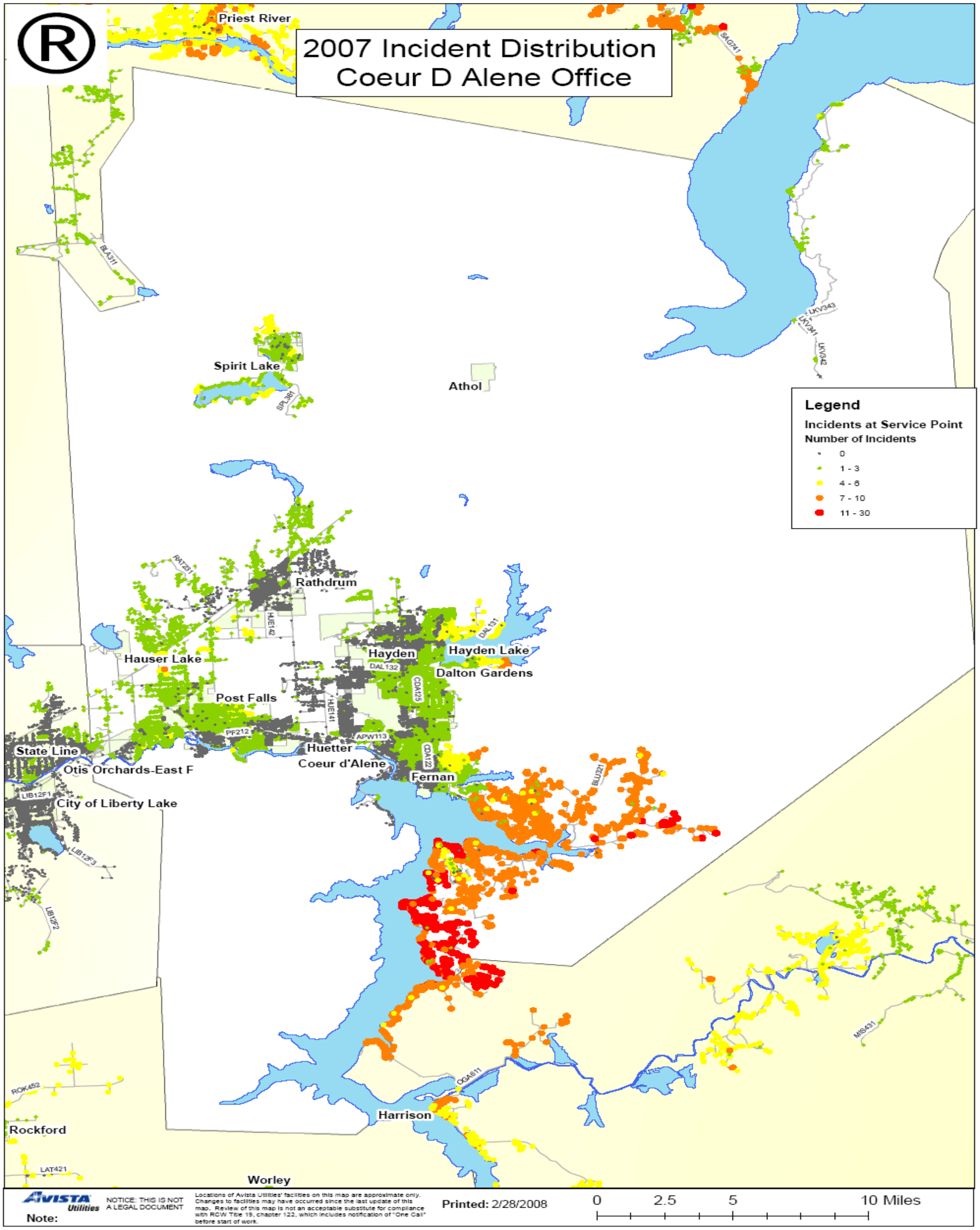
Sandpoint Office - CEMI$_n$



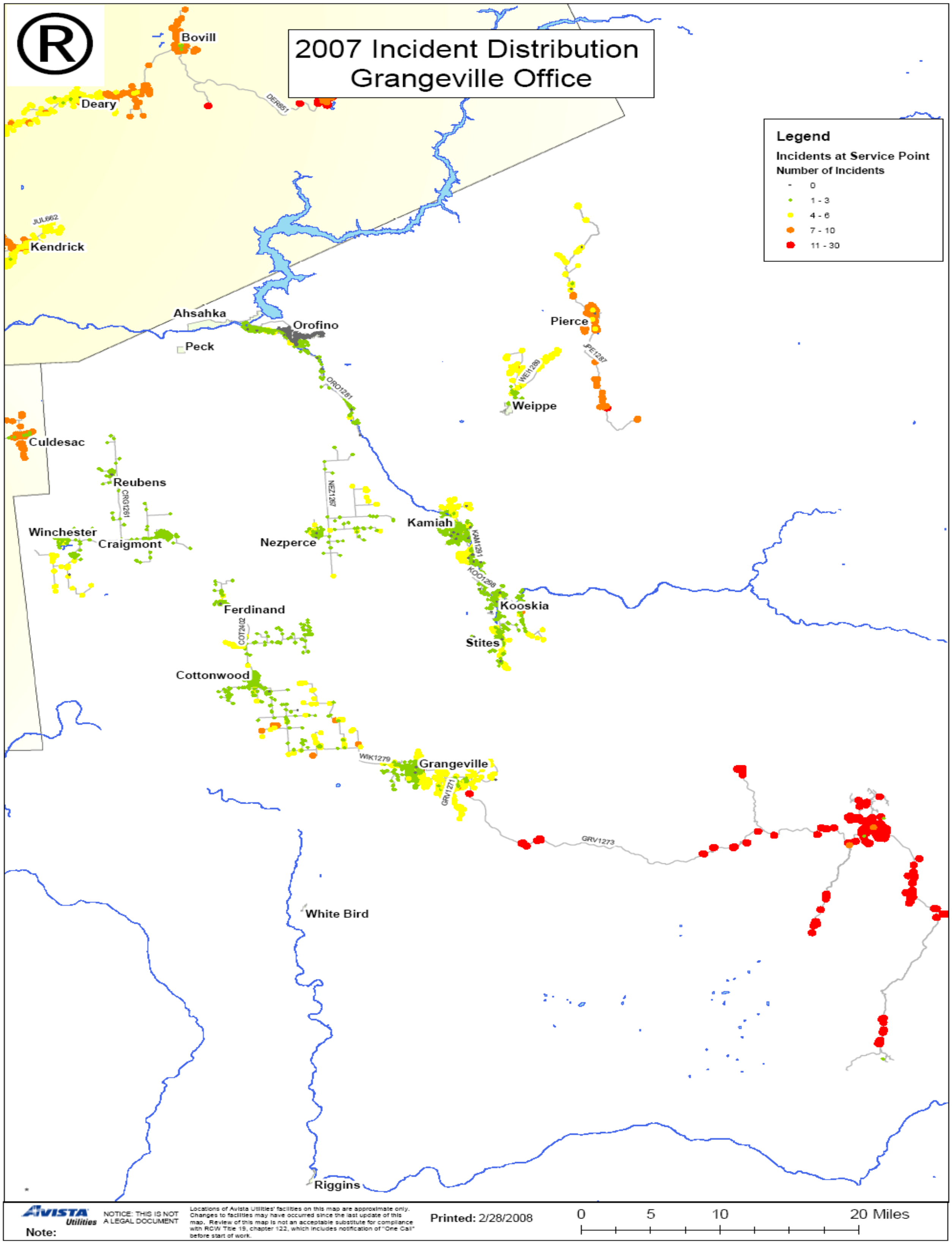
Kellogg Office - CEMI$_n$



Coeur d'Alene - CEMI$_n$



Grangeville Office - $CEMI_n$



Monthly Indices

Each of the following indices, reported by month, shows the variations from month to month. These variations are partially due to inclement weather and, in some cases, reflect incidents of winter snowstorms, seasonal windstorms, and in mid- and late summer lightning storms. They also reflect varying degrees of animal activity causing disruptions in different months of the year.

Chart 3.1 – SAIFI - Sustained Interruptions / Customer

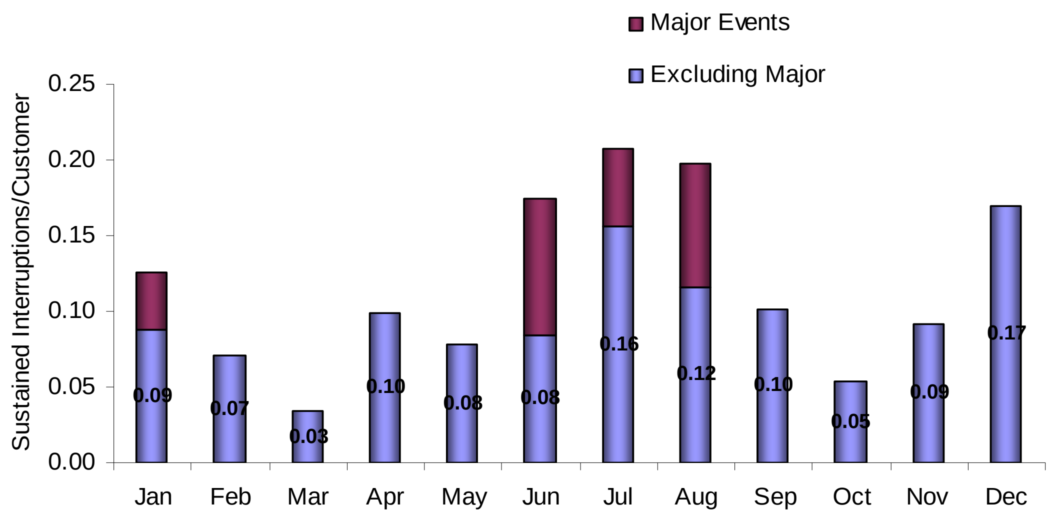


Chart 3.2 - MAIFI Momentary Interruption Events / Customer

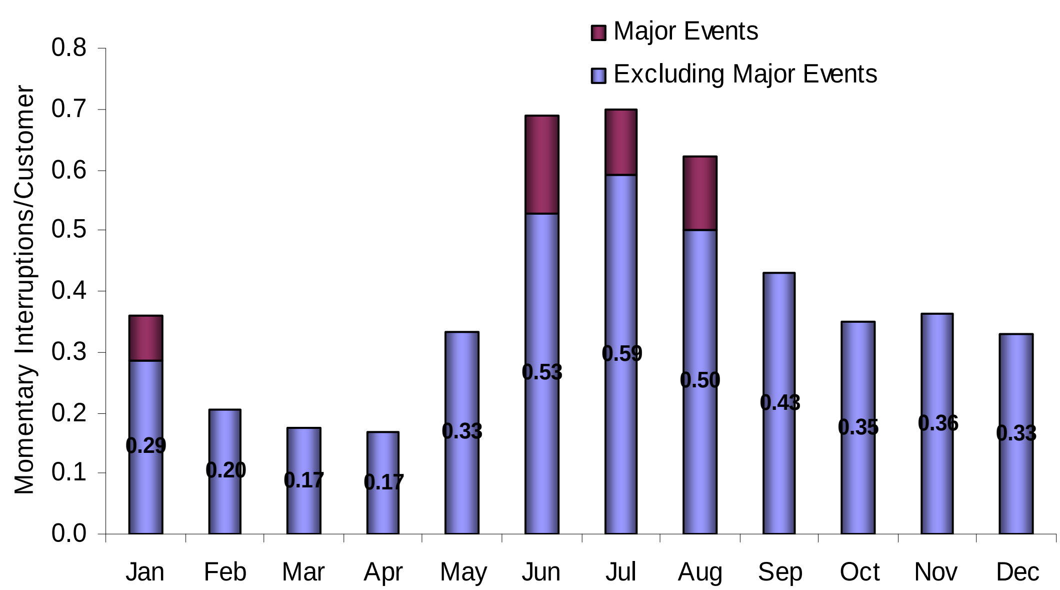


Chart 3.3 - SAIDI – Average Outage Time / Customer

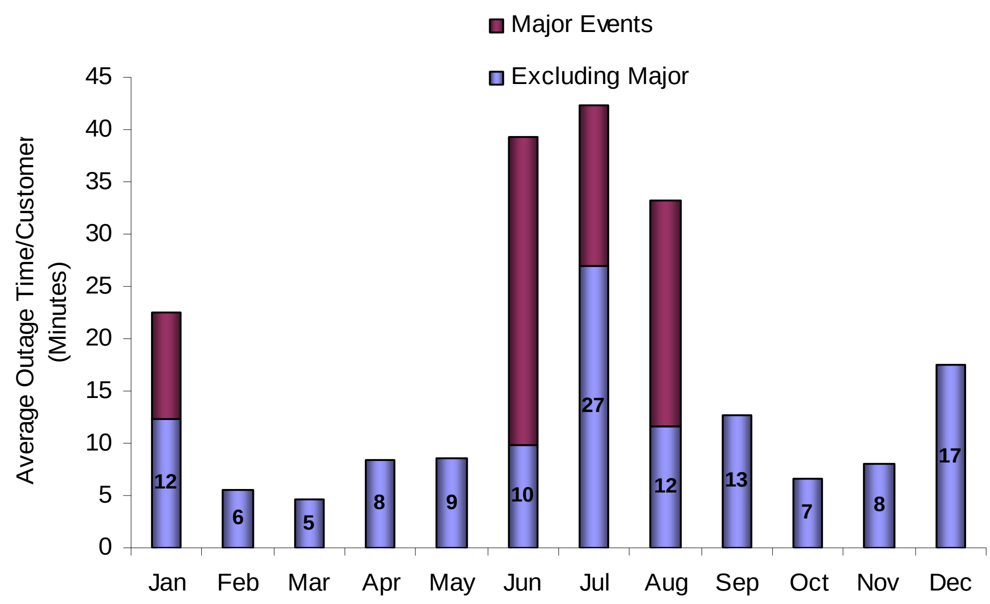
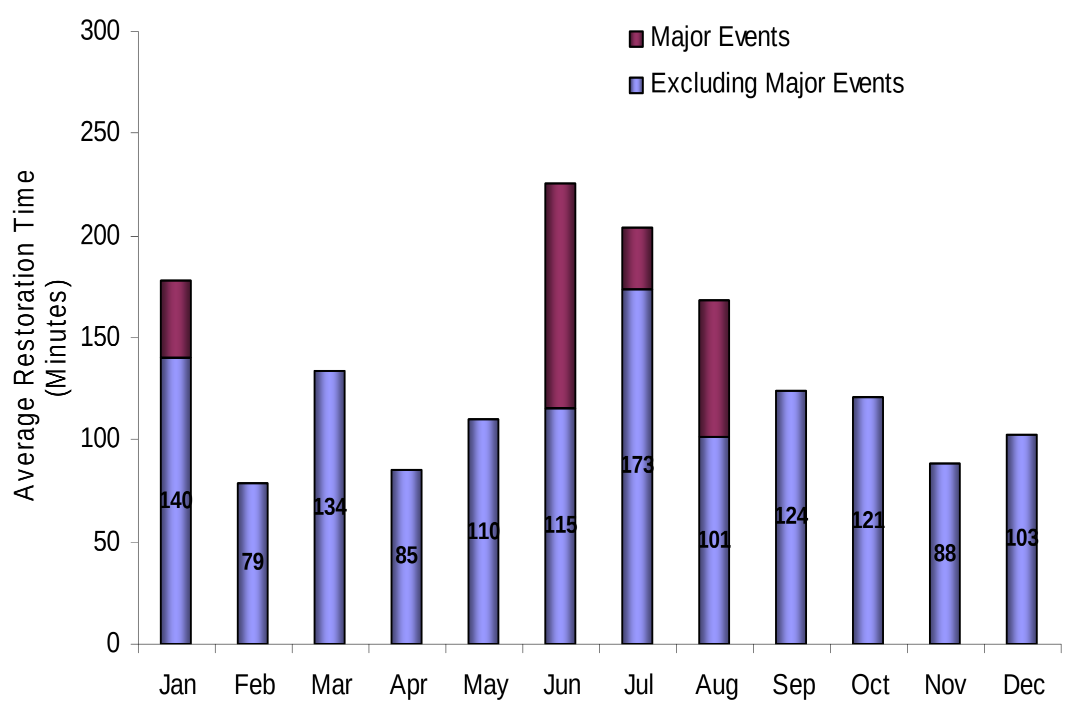


Chart 3.4 - CAIDI – Average Restoration Time



Customer Complaints

Commission Complaints

The following is a list of Complaints made to the Commission during this year.

Customer Address	Complaint	Resolution
Chewelah, WA Chewelah 12F2	The area in which customer lives experiences periodic power outages. Yesterday they were without power for 18 hours for no apparent reason – no bad weather, etc. Neighbors have purchased $3000 generators. Customer does not feel he should have to purchase as generator.	4 sustained outages and 1 momentary outage. 8/03/07 Complaint Closed – Company upheld.

Customer Complaints

The following is a list of complaints made to our Customer Service Representatives.

Customer / Feeder	Complaint	Resolution
Rice, WA Gifford 34F1	03/19/07 – Customer emailed Avista with a complaint about all of the outages in his area this year. Email forwarded on to the Colville office to answer his question.	Colville office sent Customer an email explaining that Avista was unaware that the customer was out of power. Apparently the customer does not live at this location and Avista is unaware when the power is out. Customer did not reply as of November 29, 2007.
Pullman, WA South Pullman 121	08/29/07 – Customer called to complain about several momentary outages over the past few days. Customer had counted 5 momentary outages in the last 4 days.	Electric Transmission Operations reported that this was a transmission problem that should be resolved now. 8/29/2007.
Rice, WA Gifford 34F1 or Gifford 34F2	07/17/07 - Customer called about power outage on July 22, 2007 that was scheduled.	Customer location could not be found, and call back phone number was not valid. No resolution.
Pullman, WA Pullman 112	10/02/07 –Customer called and is tired of coming home every day and having to reset all the clocks etc. due to Avista power surge issues or whatever is causing this in Pullman. Customer was told that if outage is less than 10 seconds it is not a big deal, but it happens constantly. Please get this fixed; customer doesn't have the option of choosing a different power company.	Complaint was forwarded to Pullman office. Customer was sent an apology letter after Avista left a message on his phone. Avista did experience some power outages about that time.
Hope, ID Clark Fork 711	08/14/07 – Customer unhappy power keeps going out. Would like someone to let him know what Avista is doing to fix this problem. Wants resolved before he goes out of town the 1st of September.	Sandpoint office made several attempts to contact the customer and never did talk to him directly. Hope area had numerous outages and momentary outages during the summer due to wind storms and lightning.

Sustained Interruption Causes

Table 4.1 - % SAIFI per Cause by Office

The following table lists the percentage SAIFI contribution by causes for outages excluding major event days.

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	0.9%	2.6%	1.5%	3.1%	8.0%	3.5%	5.0%	0.8%	12.6%	14.8%	8.9%	5.7%
MISCELLANEOUS	0.1%	0.9%	0.0%	1.7%	0.0%	0.0%	0.1%	0.0%	0.0%	0.2%	0.0%	0.3%
POLE FIRE	0.4%	6.5%	12.6%	14.0%	3.0%	12.1%	18.0%	8.1%	0.6%	2.2%	20.4%	6.0%
WEATHER	16.6%	16.7%	9.4%	30.0%	32.4%	1.9%	11.1%	27.7%	16.9%	4.3%	6.7%	18.4%
UNDETERMINED	24.4%	6.0%	10.8%	12.6%	22.3%	18.4%	4.2%	10.3%	8.4%	11.3%	13.7%	13.1%
TREE	5.9%	20.6%	9.7%	8.1%	13.8%	18.7%	0.2%	9.9%	22.5%	2.3%	30.7%	12.2%
PUBLIC	16.4%	8.0%	10.3%	1.7%	3.9%	35.0%	26.6%	16.6%	1.7%	24.1%	5.6%	12.8%
COMPANY	19.2%	3.6%	0.1%	5.1%	0.1%	0.0%	0.0%	3.8%	7.6%	7.7%	0.5%	6.2%
EQUIPMENT OH	8.4%	18.0%	29.2%	15.0%	8.6%	7.8%	9.1%	14.2%	13.3%	17.6%	2.2%	13.6%
EQUIPMENT UG	0.5%	2.5%	4.9%	2.4%	0.6%	1.0%	3.7%	1.8%	0.1%	3.8%	1.0%	1.8%
EQUIPMENT SUB	2.3%	0.0%	6.3%	1.0%	6.2%	0.0%	0.0%	0.0%	6.6%	6.6%	0.0%	2.8%
PLANNED	4.8%	14.6%	5.2%	5.3%	1.2%	1.6%	22.1%	6.7%	9.7%	5.3%	10.2%	7.0%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

Chart 4.1 – % SAIFI per Cause by Office

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.

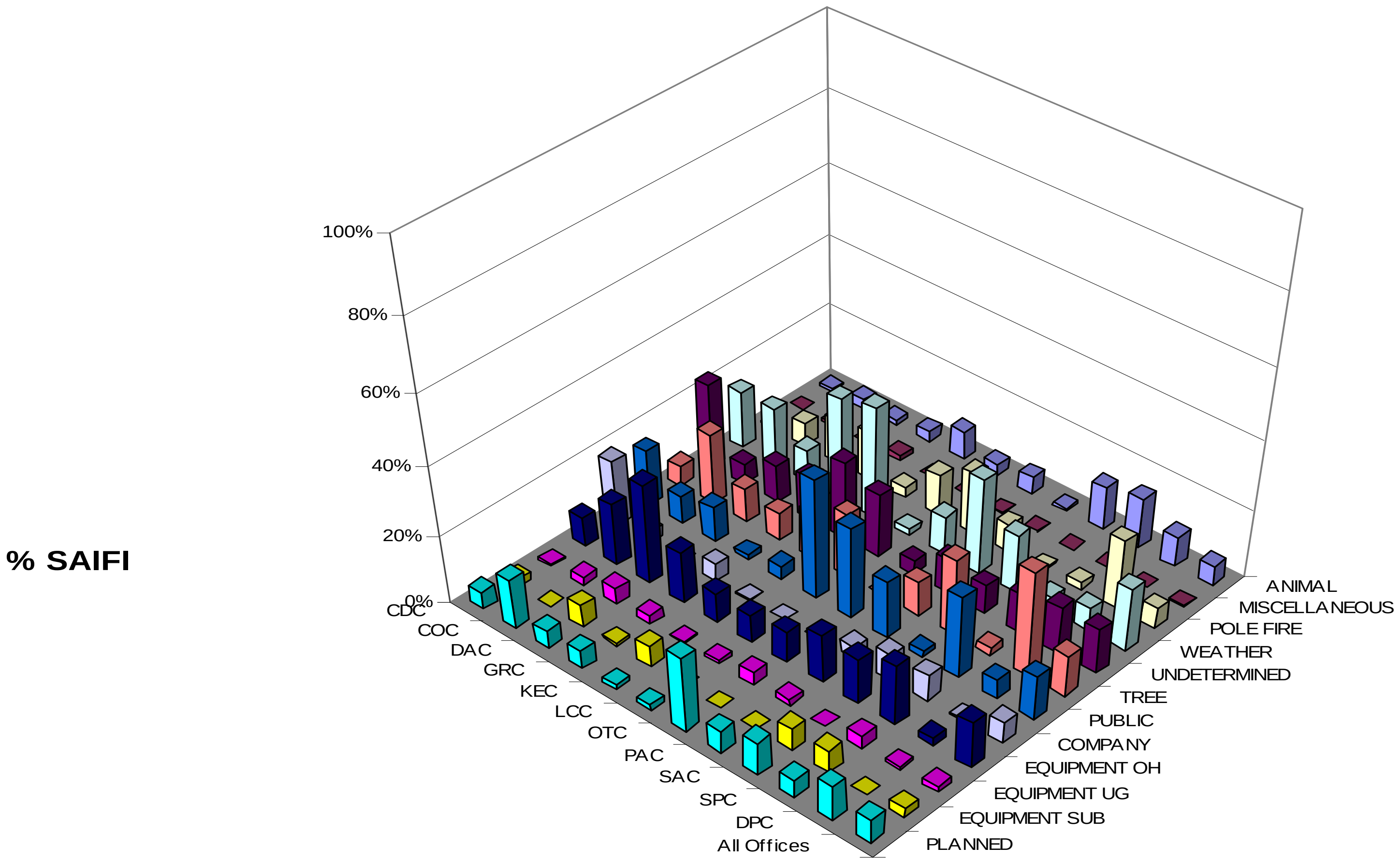


Table 4.2 - % SAIDI per Cause by Office

The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	1.1%	1.7%	1.9%	1.3%	4.0%	3.3%	2.8%	0.5%	7.4%	13.3%	6.1%	4.1%
MISCELLANEOUS	0.1%	0.5%	0.0%	1.2%	0.0%	0.0%	0.1%	0.2%	0.0%	0.1%	0.0%	0.3%
POLE FIRE	1.2%	7.3%	31.2%	25.0%	3.4%	20.6%	42.3%	11.4%	0.5%	3.3%	16.5%	9.2%
WEATHER	27.7%	23.4%	14.9%	18.7%	43.3%	4.3%	15.7%	18.0%	35.3%	11.7%	18.3%	23.3%
UNDETERMINED	15.5%	5.1%	16.5%	9.3%	13.7%	14.4%	2.0%	5.8%	7.9%	6.8%	15.9%	9.1%
TREE	9.8%	20.6%	14.0%	12.0%	23.0%	12.6%	0.1%	15.9%	36.3%	3.9%	25.6%	17.3%
PUBLIC	21.0%	6.8%	6.3%	1.9%	3.5%	33.6%	12.9%	17.3%	1.9%	20.9%	5.3%	11.4%
COMPANY	0.7%	1.3%	0.0%	0.6%	0.0%	0.0%	0.0%	4.1%	0.7%	1.6%	0.3%	1.3%
EQUIPMENT OH	16.4%	14.1%	10.4%	14.3%	5.6%	8.3%	10.9%	13.3%	5.5%	16.7%	4.2%	12.0%
EQUIPMENT UG	1.9%	3.0%	2.0%	2.9%	0.9%	2.3%	6.8%	3.8%	0.1%	11.7%	2.4%	3.5%
EQUIPMENT SUB	3.1%	0.0%	0.5%	6.0%	1.9%	0.0%	0.0%	0.0%	1.8%	6.9%	0.0%	2.4%
PLANNED	1.6%	16.5%	2.3%	6.8%	0.7%	0.7%	6.5%	9.7%	2.6%	3.1%	5.4%	6.1%

CDC	Coeur d'Alene
COC	Colville
DAC	Davenport
DPC	Deer Park
GRC	Grangeville
KEC	Kellogg/ St. Maries
LCC	Lewiston-Clarkston
OTC	Othello
PAC	Palouse
SAC	Sandpoint
SPC	Spokane

Chart 4.2 – % SAIDI per Cause by Office

The following chart shows the percentage SAIDI contribution by causes for outages excluding major event days.

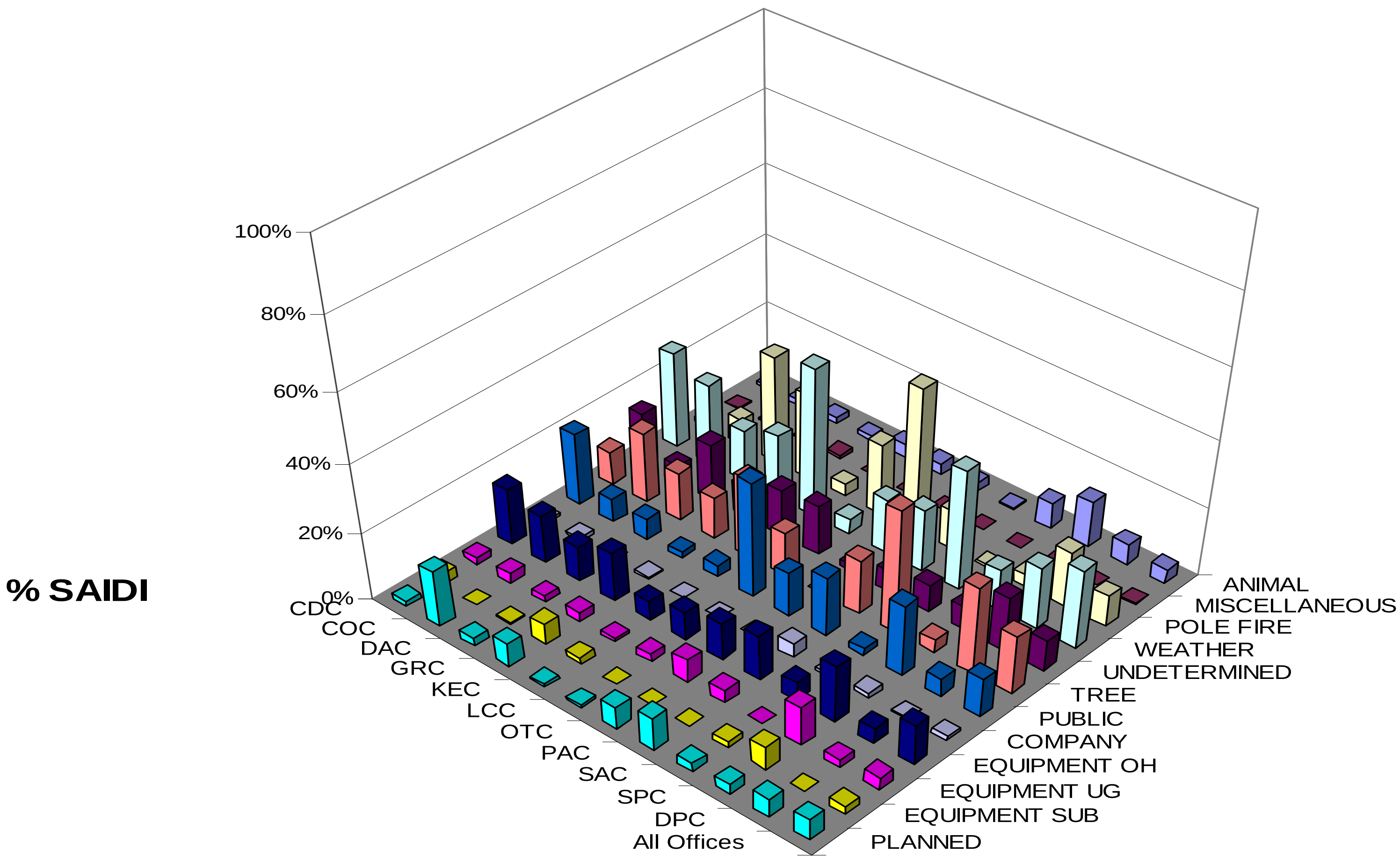


Table 4.3 - % SAIFI per Cause by Month

The following table lists the percentage SAIFI contribution by causes for all outages, excluding major event days.

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	2.9%	0.4%	5.0%	18.9%	2.6%	14.5%	8.9%	5.7%	3.7%	3.1%	1.0%	0.4%	5.7%
MISCELLANEOUS	0.1%	0.1%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.1%	0.1%	0.0%	0.8%	0.3%
POLE FIRE	0.0%	1.6%	12.0%	0.0%	0.6%	1.1%	14.0%	10.0%	24.0%	4.8%	1.4%	0.4%	6.0%
WEATHER	5.7%	16.7%	0.8%	0.1%	20.8%	15.5%	20.9%	3.1%	5.5%	0.3%	39.7%	50.0%	18.4%
UNDETERMINED	24.3%	20.4%	10.0%	11.1%	10.8%	2.7%	13.4%	14.2%	18.7%	21.5%	7.6%	8.3%	13.1%
TREE	33.1%	14.1%	8.9%	11.8%	11.3%	17.7%	2.3%	12.0%	17.0%	20.1%	5.0%	6.5%	12.2%
PUBLIC	18.1%	13.6%	33.6%	8.9%	8.3%	2.8%	18.6%	12.2%	10.1%	18.7%	3.6%	14.8%	12.8%
COMPANY	0.5%	0.0%	0.9%	8.0%	11.0%	4.2%	4.1%	13.1%	5.9%	0.2%	22.1%	1.6%	6.2%
EQUIPMENT OH	5.4%	8.2%	19.7%	32.4%	15.1%	27.6%	5.5%	18.9%	9.7%	16.4%	5.1%	10.4%	13.6%
EQUIPMENT UG	0.8%	0.2%	1.2%	0.1%	1.0%	3.8%	4.1%	2.0%	3.4%	4.1%	0.6%	0.3%	1.8%
EQUIPMENT SUB	4.3%	17.0%	3.3%	0.6%	0.0%	0.0%	0.0%	4.9%	0.0%	0.0%	9.2%	0.0%	2.8%
PLANNED	4.8%	7.7%	4.7%	8.1%	18.5%	10.0%	6.9%	3.8%	1.9%	10.7%	4.6%	6.5%	7.0%

Chart 4.3 – % SAIFI per Cause by Month

The following chart shows the percentage SAIFI contribution by causes for all outages, excluding major event days.

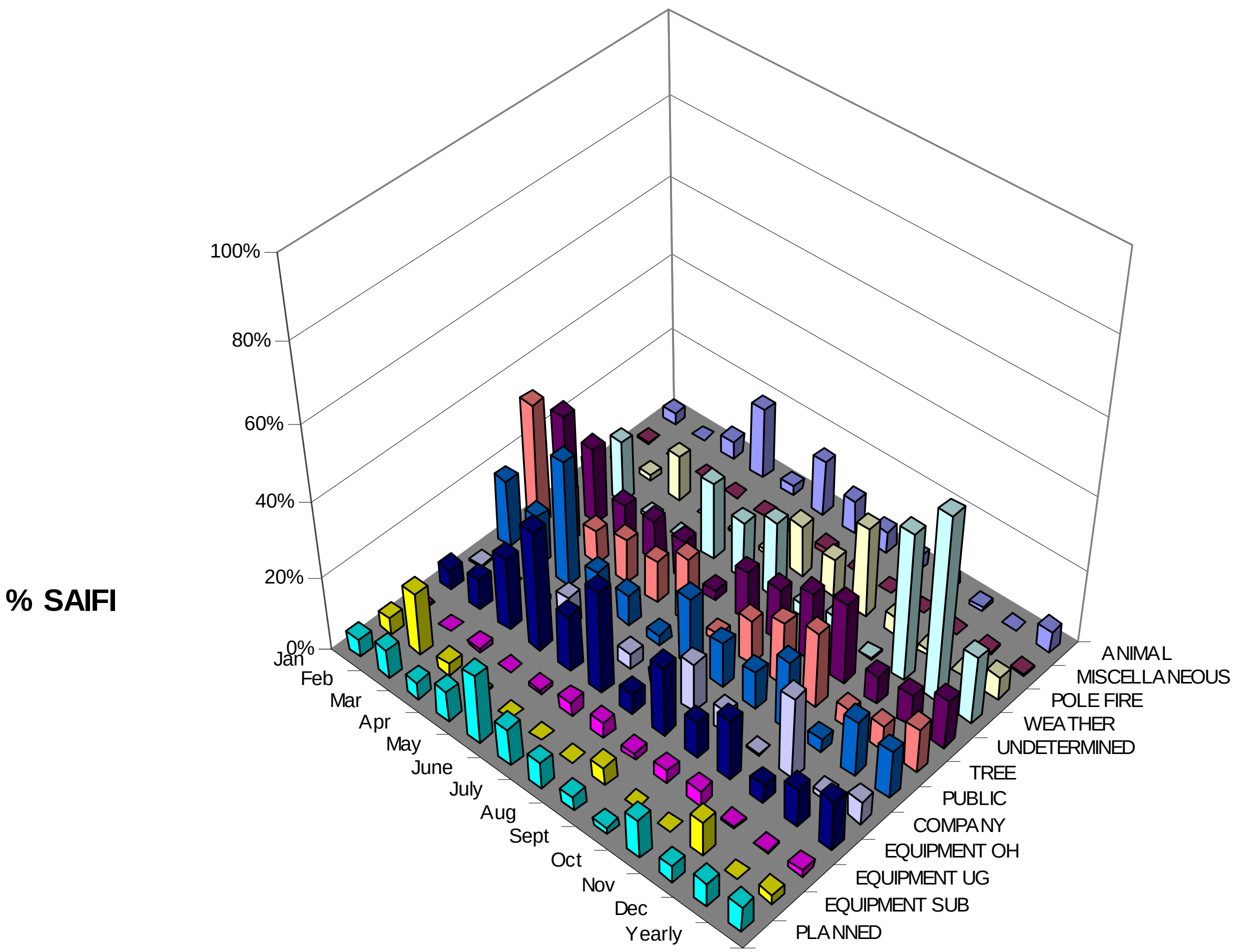


Table 4.4 - % SAIDI per Cause by Month

The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

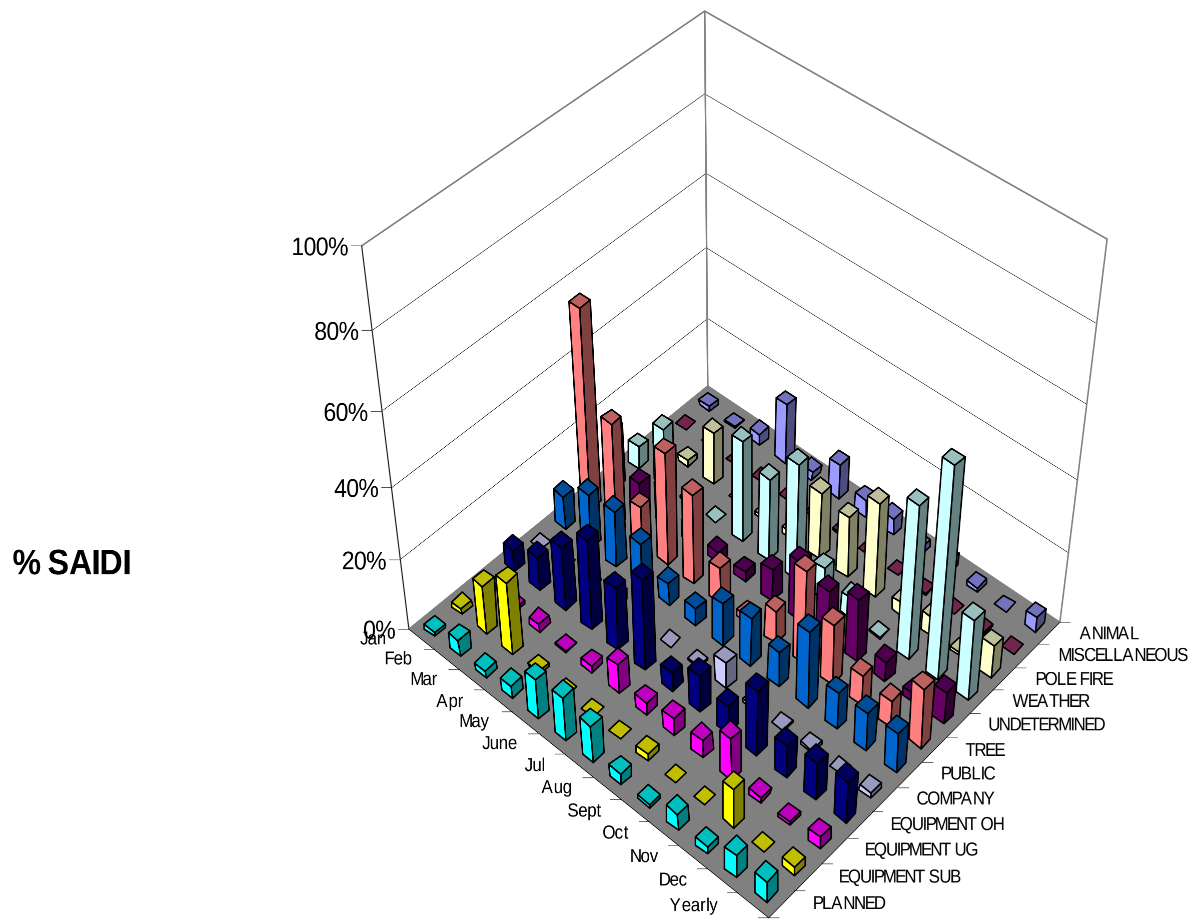
REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	1.5%	0.5%	3.1%	16.9%	2.4%	9.9%	4.9%	4.9%	2.0%	3.3%	1.4%	0.2%	4.1%
MISCELLANEOUS	0.1%	0.4%	0.0%	0.0%	0.0%	0.1%	0.7%	0.0%	0.0%	0.1%	0.0%	0.5%	0.3%
POLE FIRE	0.0%	1.7%	15.0%	0.0%	0.8%	1.6%	18.8%	17.3%	26.7%	3.6%	5.4%	0.7%	9.2%
WEATHER	6.4%	16.6%	0.8%	0.3%	28.6%	23.3%	32.8%	8.9%	5.8%	0.3%	43.1%	59.0%	23.3%
UNDETERMINED	16.9%	6.6%	10.6%	4.8%	3.0%	2.8%	9.0%	16.8%	14.4%	17.8%	5.9%	2.3%	9.1%
TREE	55.8%	29.6%	11.1%	31.8%	25.7%	10.2%	1.6%	9.3%	26.5%	17.3%	8.6%	7.3%	17.3%
PUBLIC	9.6%	15.4%	15.9%	12.3%	6.4%	4.9%	12.0%	13.9%	9.9%	21.8%	10.3%	11.0%	11.4%
COMPANY	0.3%	0.0%	0.5%	2.9%	1.9%	0.2%	0.4%	7.5%	0.7%	0.3%	0.9%	0.1%	1.3%
EQUIPMENT OH	5.9%	9.6%	18.1%	25.7%	17.9%	26.0%	5.3%	10.6%	7.9%	18.7%	9.3%	10.9%	12.0%
EQUIPMENT UG	1.0%	0.9%	2.1%	0.4%	2.0%	8.3%	3.6%	5.4%	5.0%	11.9%	1.6%	1.2%	3.5%
EQUIPMENT SUB	1.5%	14.0%	20.7%	1.1%	0.0%	0.0%	0.0%	2.1%	0.0%	0.0%	11.3%	0.0%	2.4%
PLANNED	1.1%	4.8%	2.0%	3.7%	11.4%	12.7%	10.8%	3.4%	1.1%	4.8%	2.3%	6.6%	6.1%

Table 4.4.1 Ave Outage Time (HH:MM)

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	1:33	1:37	1:41	1:37	1:45	1:59	1:57	1:46	1:48	1:44	1:25	1:24	1:48
MISCELLANEOUS	1:18	2:20	0:00	0:00	2:05	25:27	1:47	0:05	0:11	2:09	0:59	0:40	3:06
POLE FIRE	0:00	2:52	3:37	4:25	2:21	3:57	3:38	5:23	3:19	3:04	4:16	2:26	3:45
WEATHER	2:57	2:29	9:48	4:33	3:01	4:26	11:07	5:01	3:11	2:04	3:42	2:43	5:02
UNDETERMINED	2:00	1:54	1:54	2:05	2:01	2:58	2:26	1:44	1:50	1:46	1:40	1:42	2:03
TREE	4:19	3:24	2:25	7:40	3:01	2:34	3:02	2:34	3:18	3:06	2:33	2:37	3:20
PUBLIC	2:28	2:56	2:05	2:19	2:21	2:14	2:27	2:29	2:56	2:37	2:48	3:49	2:34
COMPANY	1:55	2:09	1:06	1:29	2:21	0:53	1:16	1:59	0:22	2:18	0:25	0:23	1:18
EQUIPMENT OH	2:51	2:40	2:23	1:55	2:41	3:00	4:45	2:56	3:09	2:59	3:10	2:55	2:59
EQUIPMENT UG	3:55	6:00	3:53	4:07	4:30	4:55	6:41	5:46	5:32	5:20	4:59	4:39	5:19
EQUIPMENT SUB	0:50	1:02	13:59	1:47	2:50	0:00	0:00	0:42	0:00	0:00	2:17	0:00	2:16
PLANNED	0:57	1:19	0:49	1:14	1:33	1:24	1:28	1:09	1:00	1:06	0:44	1:09	1:09

Chart 4.4 – % SAIDI per Cause by Month

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.



Momentary Interruption Causes

The cause for many momentary interruptions is unknown. Because faults are temporary, the cause goes unnoticed even after the line is patrolled. Momentary outages are recorded using our SCADA system (System Control and Data Acquisition). On average, about 88% of Avista's customers are served from SCADA controlled stations.

Table 5.1 - % MAIFI per Cause by Office

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	0.1%	4.6%	0.0%	1.3%	0.0%	7.5%	0.0%	0.6%	6.2%	12.6%	0.0%	5.5%
POLE FIRE	1.6%	0.0%	0.0%	0.0%	0.0%	0.7%	0.0%	0.0%	0.0%	2.8%	0.0%	1.1%
WEATHER	22.4%	22.7%	53.2%	36.6%	23.8%	5.5%	9.5%	13.9%	13.9%	5.9%	0.0%	14.2%
TREE	2.2%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	1.8%	5.3%	0.9%	0.0%	1.6%
PUBLIC	3.6%	0.0%	0.0%	0.0%	0.0%	1.1%	0.0%	3.9%	0.0%	4.5%	0.0%	2.8%
COMPANY	2.9%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.1%	3.0%	3.2%	0.0%	1.7%
UNDETERMINED	51.7%	68.7%	46.8%	61.0%	76.2%	81.1%	84.8%	71.2%	60.2%	58.8%	0.0%	63.8%
EQUIPMENT UG	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.8%	1.4%	5.1%	0.0%	1.7%
EQUIPMENT OH	5.6%	4.0%	0.0%	0.2%	0.0%	2.8%	0.0%	5.2%	6.9%	4.8%	0.0%	4.5%
PLANNED	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	5.8%	1.2%	3.0%	1.3%	0.0%	1.2%
EQUIPMENT SUB	8.2%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	1.6%
NOT OUR ROBLEM	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

Table 5.1.1 - % MAIFI per Cause by Office (Washington only)

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	COC	DAC	OTC	SPC	DPC	PAC-WA	LCC-WA	Grand Total
ANIMAL	0.0%	0.0%	0.0%	4.2%	0.0%	0.0%	4.4%	3.3%
POLE FIRE	1.4%	0.0%	0.0%	0.8%	0.0%	1.6%	5.2%	1.4%
WEATHER	26.7%	29.1%	29.8%	34.2%	100.0%	31.5%	19.1%	31.6%
TREE	1.8%	0.0%	0.0%	0.8%	0.0%	0.0%	0.0%	0.8%
PUBLIC	0.9%	0.0%	10.6%	2.7%	0.0%	0.0%	3.8%	2.6%
COMPANY	2.1%	0.0%	0.0%	2.1%	0.0%	0.7%	0.0%	1.7%
UNDETERMINED	63.0%	70.9%	59.6%	49.9%	0.0%	65.9%	52.0%	53.0%
EQUIPMENT UG	0.0%	0.0%	0.0%	2.1%	0.0%	0.3%	4.1%	1.9%
EQUIPMENT OH	3.9%	0.0%	0.0%	3.0%	0.0%	0.0%	8.9%	3.5%
PLANNED	0.1%	0.0%	0.0%	0.1%	0.0%	0.0%	0.0%	0.1%
EQUIPMENT SUB	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.6%	0.3%

COC	Colville	OTC	Othello
DAC	Davenport	PAC-WA	Palouse Washington
DPC	Deer Park	SPC	Spokane
LCC-WA	Lewiston-Clarkston Washington		

Chart 5.1 – % MAIFI per Cause by Office

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.

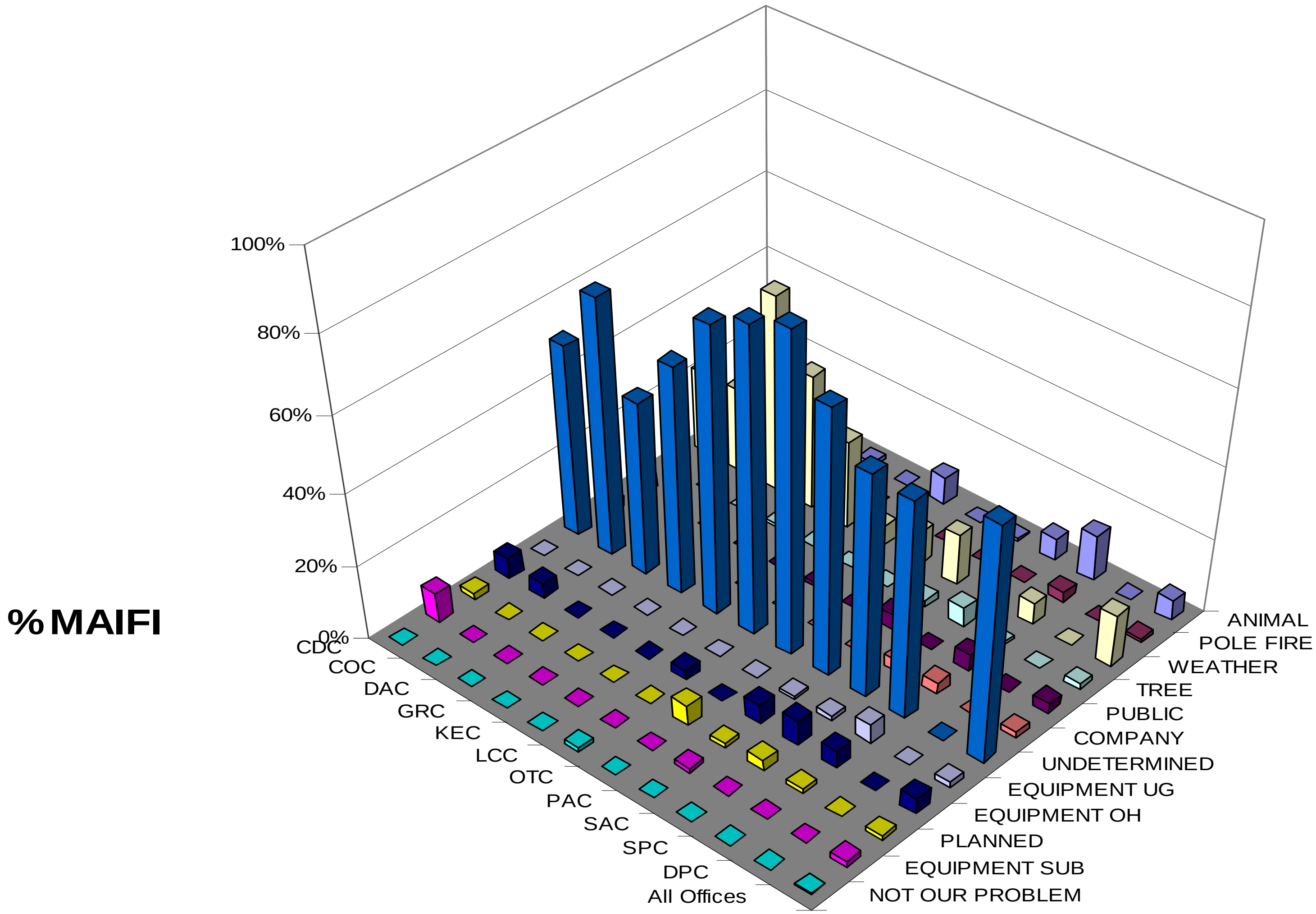


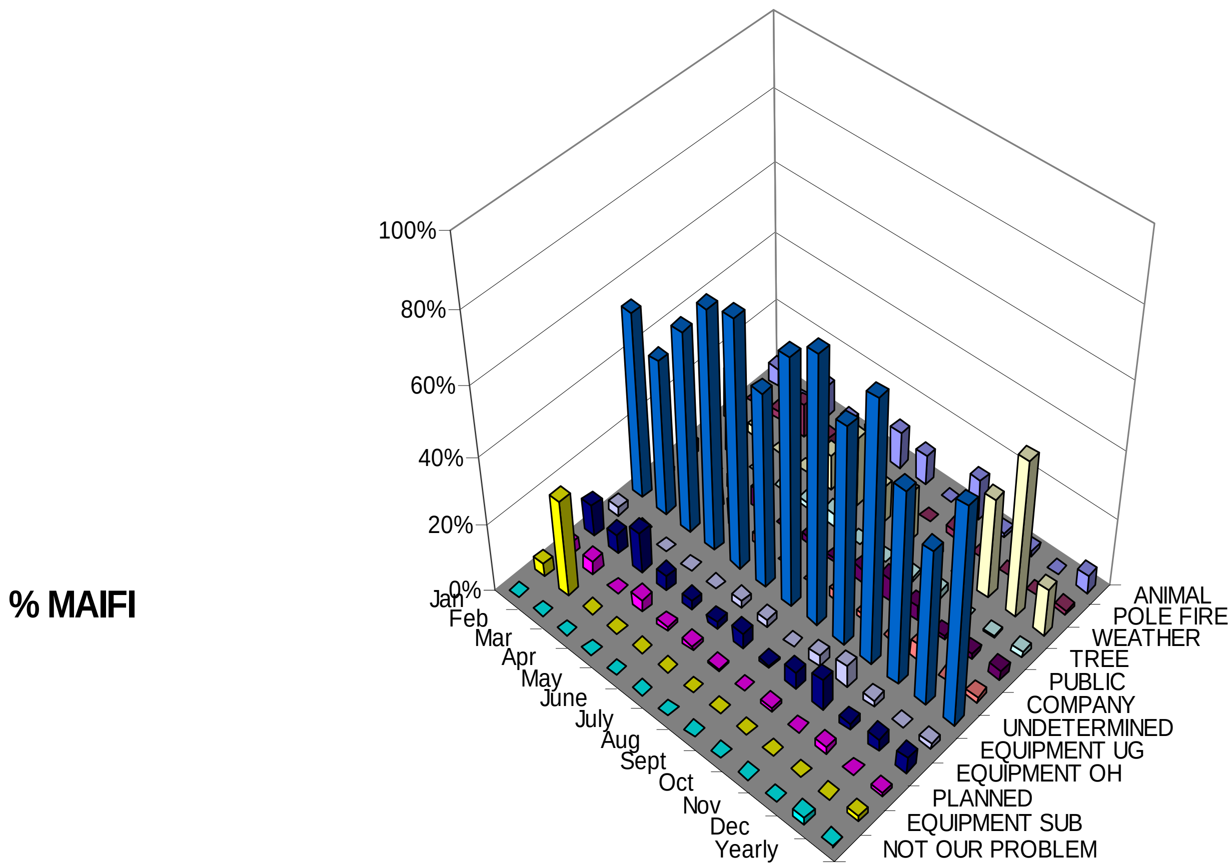
Table 5.2 - % MAIFI per Cause by Month

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	5.2%	0.0%	9.9%	4.2%	6.4%	10.8%	8.9%	0.2%	12.2%	1.6%	1.5%	0.0%	5.5%
POLE FIRE	0.0%	2.2%	9.6%	4.5%	2.7%	0.0%	0.1%	0.0%	2.5%	0.0%	0.0%	0.0%	1.1%
WEATHER	15.0%	2.9%	0.0%	0.0%	10.5%	20.9%	11.2%	14.7%	2.7%	0.0%	29.7%	46.2%	14.2%
TREE	1.3%	10.9%	0.0%	0.0%	1.6%	3.8%	0.0%	0.0%	1.1%	2.6%	0.0%	0.6%	1.6%
PUBLIC	3.3%	0.0%	4.1%	3.9%	2.2%	4.1%	2.3%	0.0%	1.3%	0.0%	8.8%	2.6%	2.8%
COMPANY	1.1%	0.0%	6.1%	7.6%	2.5%	0.0%	0.0%	2.8%	1.6%	0.0%	4.7%	0.0%	1.7%
UNDETERMINED	54.2%	45.7%	58.7%	69.7%	72.1%	56.9%	71.6%	77.5%	63.6%	76.1%	56.8%	45.7%	63.8%
EQUIPMENT UG	2.7%	0.0%	0.0%	0.0%	0.0%	2.0%	2.1%	0.0%	3.4%	6.2%	2.0%	0.0%	1.7%
EQUIPMENT OH	9.3%	5.8%	12.1%	4.6%	2.7%	2.2%	4.7%	0.9%	5.0%	8.9%	2.1%	3.8%	4.5%
PLANNED	3.5%	4.1%	0.0%	3.8%	1.4%	1.6%	0.5%	0.0%	1.1%	0.0%	2.1%	0.0%	1.2%
EQUIPMENT SUB	3.8%	28.5%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.6%
NOT OUR PROBLEM	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	2.0%	0.2%

Chart 5.2 – % MAIFI per Cause by Month

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.



Maintenance Plan Summary – Overhead Equipment with Sub Category Components

With the increasing quality of the SAIFI data, Avista has completed a preliminary analysis, based on our subject matter experts, indicating that performing a preventative maintenance or an inspection program will not provide the best value to our customers in all cases. As shown in the table, the projected failure rates impact on SAIFI do not justify the expenses of a preventative maintenance program on all of this equipment. However, we continue to evaluate and monitor these to determine if and when a preventative maintenance program would be in the best interest of our customers.

Visual Inspections of the poles and crossarms is being increased in 2008 to a 20 year cycle in order to maintain a reliable system. This visual inspection along with field personnel will identify some problem equipment during the course of their work and will get them repaired or replaced, but this is not part of a scheduled preventative maintenance program.

OH Equipment/Sub category component	Maintenance Plan Summary	Projected Average Annual SAIFI contribution
Arrestors	No Program	0.013
Capacitor	No Program	Not calculated
Conductor – Pri	No Program	0.013
Conductor – Sec	No Program	Very Small
Crossarm – Rotten	1-2% visually inspected annually but planning to move to 5% annually in 2008.	0.002
Cutout/Fuse	No specific program, but one vintage of cutout is being replaced on a planned basis.	0.073
Insulator	No Program	0.10
Insulator Pin	No Program	0.024
Other	No Program	Not calculated
Pole – Rotten	1-2% inspected annually but planning to move to 5% annually in 2008.	0.01
Recloser	Midline Reclosers – opportunistic or suspect, No defined cycle program. Substation Reclosers – 13 year maintenance cycle and planning to move to a 10 year cycle. Switchgear breakers – 7 year maintenance cycle.	0.025
Regulator	Substation Regulators inspected monthly with most midline regulators being inspected monthly.	0.003
Switch / Disconnect	No Program	0
Transformer - OH	No Program, but transformers that are removed from service for any reason and are older than 1980 are not refurbished and returned to service.	0.004

Major Event Day Causes

Chart 6.1 – % SAIFI by Cause Code for the Major Event Days

The following chart shows the percentage SAIFI contribution by causes for outages during major event days

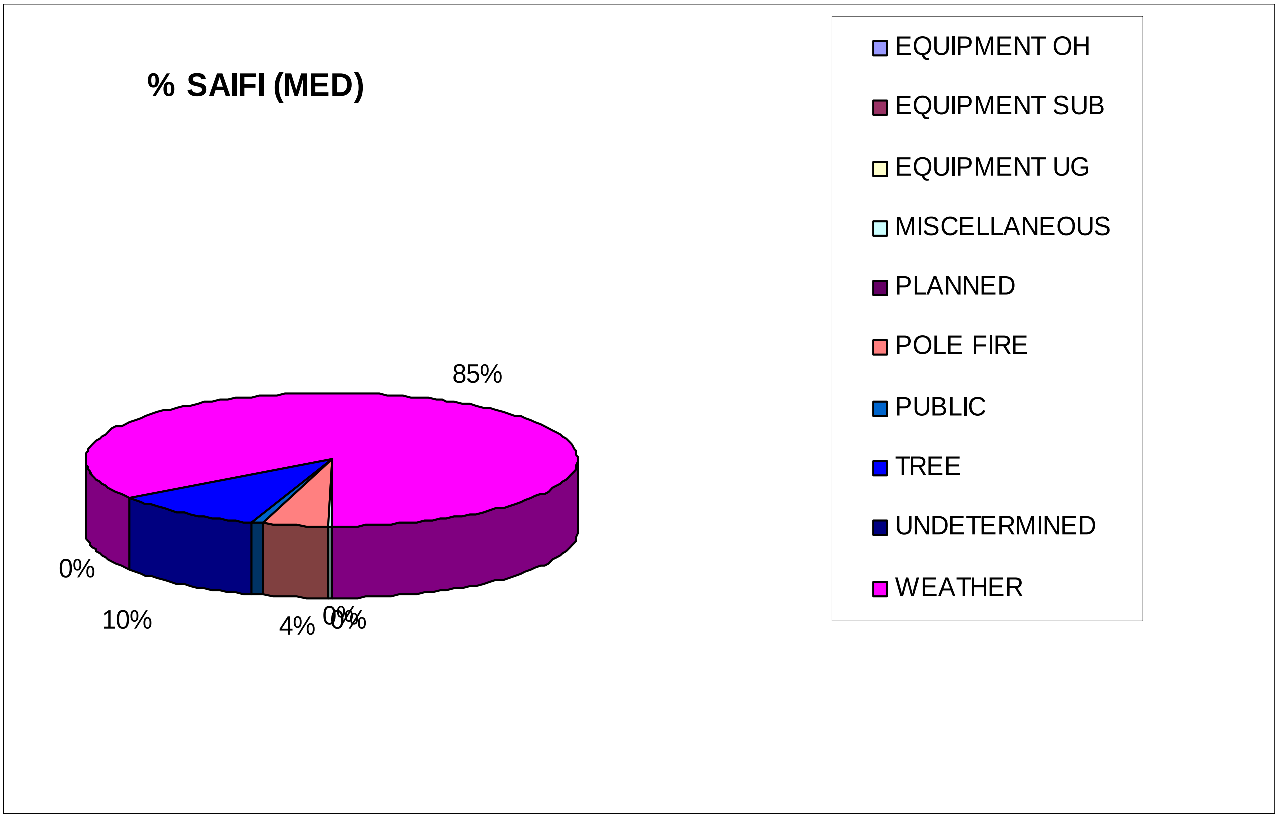


Table 6.1 – % SAIFI by Sub Cause Code for the Major Event Days

The following table shows the SAIFI contribution and Customer hours by sub causes code for the three main outage causes during major event days.

Cause Code	Sub reason	Sum of Ni	Sum of ri x Ni (hours)
Pole Fire	Pole Fire	3799	9005:24
Total		3799	9005:24
TREE	Tree Fell	71	320
	Tree Growth	6	7
	Weather	9018	50031
Total		9095	50359
WEATHER	Snow/Ice	1980	378
	Lightning	28484	120689
	Wind	44823	252280
Total		75287	373348

Table 6.2 – Yearly Summary of the Major Event Days

Table 6.2 is provided as an initial review of Major Event Day information. The main premise of the IEEE Major Event Day calculation is that using the 2.5bmethod should classify 2.3 days each year as MED's.

The following table shows the previous major event days, the daily SAIDI value and the relationship of the yearly T_{MED}.

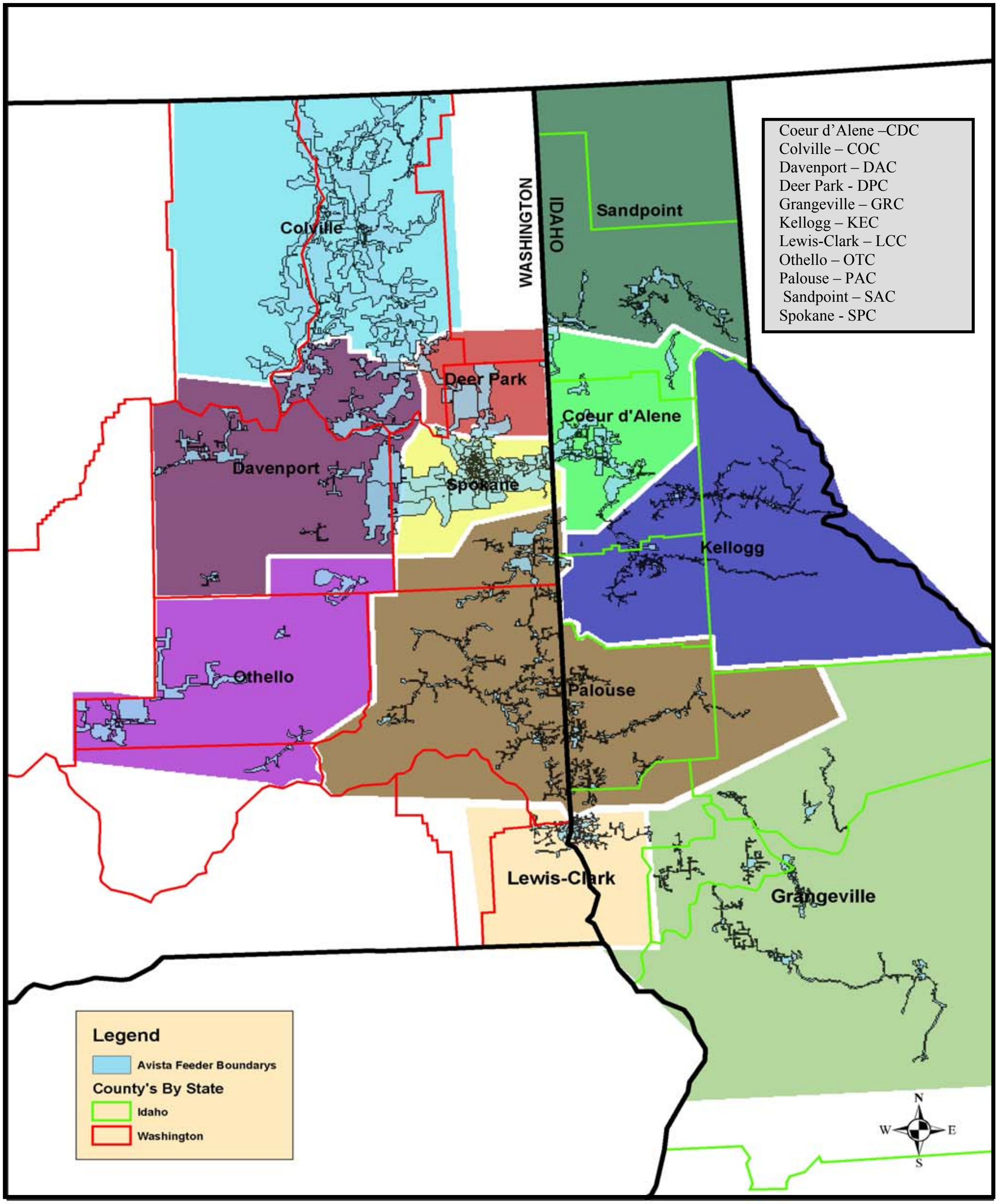
Year	Date	SAIDI	T_{MED}
2003	01-03-2003	5.38	4.96
	05-24-2003	5.11	
	09-08-2003	5.47	
	10-16-2003	6.62	
	10-28-2003	9.25	
	11-19-2003	57.06	
2004	05-21-2004	7.11	6.35
	08-02-2004	7.36	
	12-08-2004	31.00	
2005	06-21-2005	39.53	4.916
	06-22-2005	9.03	
	08-12-2005	19.60	
2006	01-11-2006	12.10	7.058
	03-09-2006	8.58	
	11-13-2006	30.79	
	12-14-2006	29.26	
	12-15-2006	158.31	
2007	01-06-2007	9.98	8.017
	06-29-2007	32.64	
	07-13-2007	12.79	
	08-31-2007	21.30	
2008			9.224

Interruption Cause Codes

MAIN CATEGORY	Proposed (Changes Only)	SUB CATEGORY	Proposed (Changes Only)	Definition
ANIMAL		Bird		Outages caused by animal contacts. Specific animal called out in sub category.
		Protected		
		Squirrel		
		Underground		
		Other		
PUBLIC		Car Hit Pad		Underground outage due to car, truck, construction equipment etc. contact with pad transformer, junction enclosure etc..
		Car Hit Pole		Overhead outage due to car, truck, construction equipment etc. contact with pole, guy, neutral etc.
		Dig In		Dig in by a customer, a customer's contractor, or another utility.
		Fire		Outages caused by or required for a house/structure or field/forest fire.
		Tree		Homeowner, tree service, logger etc. fells a tree into the line.
		Other		Other public caused outages
COMPANY		Dig in		Dig in by company or contract crew.
		Other		Other company caused outages
EQUIPMENT OH		Arrestors		Outages caused by equipment failure. Specific equipment called out in sub category.
		Capacitor		
		Conductor - Pri		
		Conductor - Sec		
		Connector - Pri		
		Connector - Sec		
		Crossarm- rotten		
		Cutout / Fuse		
		Insulator		
		Insulator Pin		
		Other		
		Pole - Rotten		
		Recloser		
		Regulator		
		Switch / Disconnect		
		Transformer - OH		
EQUIPMENT UG		URD Cable - Pri		Outages caused by equipment failure. Specific equipment called out in sub category.
		URD Cable- Sec		
		Connector - Sec		
		Elbow		
		Junctions		
		Primary Splice		
		Termination		
		Transformer - UG		
		Other		

MAIN CATEGORY	Proposed (Changes Only)	SUB CATEGORY	Proposed (Changes Only)	Definition
EQUIPMENT SUB		High side fuse Bus Insulator High side PCB High side Swt / Disc Low side OCB/Recloser Low side Swt / Disc Relay Misoperation Regulator Transformer Other		
MISCELLANEOUS		SEE REMARKS		For causes not specifically listed elsewhere
NOT OUR PROBLEM (*Outages in this category are not included in reported statistics*)		Customer Equipment SEE REMARKS		Customer equipment causing an outage to their service. If a customer causes an outage to another customer this is covered under Public.
		Other Utility		Outages when another utility's facilities cause an outage on our system.
POLE FIRE				Used when water and contamination causes insulator leakage current and fire. If insulator is leaking due to material failure list under equipment failure. If cracked due to gunfire use customer caused other.
PLANNED		Maintenance / Upgrade		Outage, normally prearranged, needed for normal construction work
		Forced		Outage scheduled to repair outage damage
TREE		Tree fell		For outages when a tree falls into distribution primary/secondary or transmission during normal weather
		Tree growth		Tree growth causes a tree to contact distribution primary/secondary or transmission during normal weather.
		Service		For outages when a tree falls or grows into a service.
		Weather		When snow and wind storms causes a tree or branch to fall into, or contact the line. Includes snow loading and unloading.
UNDETERMINED				Use when the cause can not be determined
WEATHER		Snow / Ice		Outages caused by snow or ice loading or unloading on a structure or conductor. Use weather tree for snow and ice loading on a tree.
		Lightning		Lightning flashovers without equipment damage. Equipment failures reported under the equipment type.
		Wind		Outages when wind causes conductors to blow into each other, another structure, building etc. (WEATHER/TREE) used for tree contacts.

Office Areas



Indices Calculations

Sustained Interruption

- An interruption lasting longer than 5 minutes.

Momentary Interruption Event

- An interruption lasting 5 minutes or less. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an interrupting device operates two, three, or four times and then holds, it is considered a single event.

SAIFI – System Average Interruption Frequency Index

- The average number of sustained interruptions per customer
- = $\dfrac{\text{The number of customers which had } \textbf{\textit{sustained interruptions}}}{\text{Total number of customers served}}$
- = $\dfrac{\sum N_i}{N_T}$

$MAIFI_E$ – Momentary Average Interruption Event Frequency Index

- The average number of momentary interruption events per customer
- = $\dfrac{\text{The number of customers which had } \textbf{\textit{momentary interruption events}}}{\text{Total number of customers served}}$
- = $\dfrac{\sum ID_E N_i}{N_T}$
- MAIFI can be calculated by one of two methods. Using the number of momentary interruptions or the number momentary events. This report calculates $MAIFI_E$ using momentary events. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an automatic interrupting device opens and then recloses two, or three times before it remains closed, it is considered a single event.

SAIDI – System Average Interruption Duration Index

- Average sustained outage time per customer
- = $\dfrac{\text{Outage duration multiplied by the customers effected for all } \textbf{\textit{sustained interruptions}}}{\text{Total number of customers served}}$
- = $\dfrac{\sum r_i N_i}{N_T}$

CAIDI – Customer Average Interruption Duration Index

- Average restoration time
- = $\dfrac{\text{Outage duration multiplied by the customers effected for all } \textbf{\textit{sustained interruptions}}}{\text{The number of customers which had } \textbf{\textit{sustained interruptions}}}$
- = $\dfrac{\sum r_i N_i}{\sum N_i}$

Quantities
i = An interruption event;
r_i *= Restoration time for each interruption event;*
T = Total;
ID_E *= Number of interrupting device events;*
N_i *= Number of interrupted customers for each interruption event during the reporting period;*
N_T *= Total number of customers served for the area being indexed;*

CEMI$_n$ – Customers Experiencing Multiple Sustained Interruptions more than n.

- CEMI$_n$
- = $\dfrac{\text{Total Number of Customers that experience more than } n \textbf{ sustained interruptions}}{\text{Total Number of Customers Served}}$
- = $\dfrac{CN_{(k>n)}}{N_T}$

CEMSMI$_n$ – Customers experiencing multiple sustained interruption and momentary interruption events.

- CEMSMIn
- = $\dfrac{\text{Total Number of Customers experiencing more than } n \textbf{ interruptions}}{\text{Total Number of Customers Served}}$
- = $\dfrac{CNT_{(k>n)}}{N_T}$

MED - Major Event Day

A major event day is a day in which the daily system SAIDI exceeds a threshold value. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events.

T_{MED} is calculated (taken from the IEEE 1366-2003 Standard)
The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period (typically one year) for use during the next reporting period as follows:

a) Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
b) Only those days that have a SAIDI/Day value will be used to calculate the T_{MED} (do not include days that did not have any interruptions).
c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.
d) Find ạ(Alpha), the average of the logarithms (also known as the log-average) of the data set.
e) Find ḅ(Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
f) Compute the major event day threshold, TMED, using equation (25).

$$T_{MED} = e^{\square\text{ạ}2.5\text{ ḅ}} \qquad (25)$$

g) Any day with daily SAIDI greater than the threshold value TMED that occurs during the subsequent reporting period is classified as a major event day. Activities that occur on days classified as major event days should be separately analyzed and reported.

Numbers of Customers Served

The following numbers of customers were based on the customers served at the beginning of the year. These numbers were used to calculate indices for this report.

Office	Customers	% of Total
Coeur d'Alene	46032	13.3%
Colville	17349	5.0%
Davenport	6759	2.0%
Deer Park	10001	2.9%
Grangeville	9981	2.9%
Kellogg/St. Maries	13978	4.0%
Lewis-Clark	28713	8.3%
Othello	5949	1.7%
Palouse	37454	10.9%
Sandpoint	13793	4.0%
Spokane	155186	45.0%
System Total	**345195**	

Avista Utilities

2009
Electric Service
Reliability Monitoring
Annual Report

CONTENTS

Introduction

Washington state investor-owned electric companies are to provide statements describing their reliability monitoring in an annual report pursuant to WAC 480-100-393 and WAC 480-100-398.

This document reports Avista Utilities' reliability metrics for the calendar year 2009. All numbers in this document are based on system data. The Company's system includes eleven geographical divisions. Two of these divisions straddle the Washington and Idaho border and commingle jurisdictional customers. A map of Avista's operating area is included in a following section.

WAC 480-100-393 (3)(b) requires the establishment of baseline reliability statistics. The Company's baseline statistics are included in this report.

Avista continues to review its baseline reliability statistics in light of operational experience under this regulatory protocol. Avista may modify its baseline statistics as appropriate and will update the Commission accordingly.

Avista added a new section to the 2007 annual report which analyzes the areas where customers are experiencing multiple sustained outages. This new section provides analysis of a reliability indice called $CEMI_n$, which implies Customers Experiencing Multiple sustained Interruptions more than n times.

Data Collection and Calculation Changes

WAC 480-100-398 (2) requires the Company to report changes made in data collection or calculation of reliability information after initial baselines are set. This section addresses changes that the Company has made to data collection.

Data Collection

- Since Avista's Electric Service Reliability Monitoring and Reporting Plan was filed in 2001, there have been several improvements in the methods used to collect outage data. In late 2001, centralizing the distribution trouble dispatch and data collection function for Avista's entire service territory began. The distribution dispatch office is located in the Spokane main complex. At the end of September 2005, 100% of the Company's feeders, accounting for 100% of the customers, are served from offices that employ central dispatching.

The data collected for 2009 represents the fourth full year of outage data collected through the Outage Management Tool (OMT). For 2009, all data was collected using the "Outage Management Tool" (OMT) based on the Company's Geographic Information System (GIS). The OMT system automates the logging of restoration times and customer counts.

Avista did discover a software coding error that has been within the OMT system since 2002 that will cause a small increase in the SAIDI and CAIDI for 2008. Previous years were also evaluated to determine the overall impact to the Avista baseline statistics and at this time Avista is not proposing a change to the baseline numbers. The software error only occurred during very specific outage conditions when a group of customers with an initial outage starting time were "rolled" up into another group of customers that were determined to be part of the first group outage. The second group may have had a later outage starting time. When the first group of customer outage information was rolled up, the original outage starting time was lost and the second group outage starting time was used for both groups of customers instead of using the first outage starting time. The number of customers was counted correctly.

Even as good as the OMT system is at quantifying the number of customers and duration of the outage duration, there still are areas where the data collection is not precise. Determining the exact starting time of an outage is dependent on when a customer calls in, how well the Avista Distribution Dispatcher determines where the outage is and defines the device that has opened to remove the faulted section.

As AMR/AMI metering is implemented in the future and the customer meter provides outage information to the OMT system through an interface, the SAIDI and CAIDI numbers are expected to increase. This is similar to the above discussion.

Use of the OMT system and GIS data has improved the tracking of the numbers of customers without power, allowed for better prioritization of the restoration of service and the improved dispatching of crews.

- Avista has reported in the previous annual reports that the completion of the transition to the OMT system had caused an increase in the variability of the data collected from 2001 to 2007. This Annual Report continues to show that a gradual increase in the SAIFI and SAIDI numbers that cannot be attributed to the transition to the OMT system. Review the charts, on pages 9 and 12 that provide a trend line for SAIFI and SAIDI historical data.

Continued scrutiny will be important over the next year or so to determine if the increase in SAIFI/SAIDI continues, or can be slowed or reversed by reliability improvement programs implemented in 2009 and underway in 2010. If it cannot be slowed or reversed to examine if this is driven by other sources or conditions not recognized yet. See SAIFI Linear Trend Line Chart later in this document.

Interruption Cause Codes

Cause code information is provided in this report to give readers a better understanding of outage sources. Further, the Company uses cause information to analyze past outages and, if possible, reduce the frequency and duration of future outages.

- The Company made several changes in the classification of outage causes for the reporting of 2005 outages and subsequent years.

Customers Experiencing Multiple Interruptions

The IEEE Standard 1366P-2003 provides for two methods to analyze data associated with customers experiencing multiple momentary interruptions and/or sustained interruptions. Avista's Outage Management Tool (OMT) and Geographical Information System (GIS) provide the ability to geospatially associate an outage to individual customer service points. This association allows for graphically showing Customers Experiencing Multiple sustained Interruptions ($CEMI_n$) with Major Event Day data included onto GIS produced areas. Data can be exported to MS Excel to also create graphs representing different values of n. 2009 information is provided in the new section added to the 2007 report after the Areas of Concern Section to summarize the analysis Avista performed on the 2009 outage data. The calculation for $CEMI_n$ and Customers Experiencing Multiple Sustained and Momentary Interruptions $CEMSMI_n$ is provided in the Indices Section.

Definitions

Reliability Indices

SAIFI (System Average Interruption Frequency Indices), MAIFI (Momentary Average Interruption Frequency Indices), SAIDI (System Average Interruption Duration Indices), and CAIDI (Customer Average Interruption Duration Indices) are calculated consistent with industry standards as described below. Avista adopts these for purposes of tracking and reporting reliability performance. Further explanation and definitions are provided in the "Indices Calculation" section of this report. While these indices are determined using industry standard methods, it is important to note that differing utilities may use different time intervals for momentary and sustained outages. Avista defines momentary outages as those lasting five (5) minutes or less. Sustained outages are those lasting longer than five (5) minutes.

Baseline Reliability Statistics

WAC 480-100-393 (3) (b) requires the establishment of baseline reliability statistics. The Company's 2003 Electric Service Reliability Monitoring and Reporting Plan initially established Avista's Baseline Reliability Statistics. At that time, the Company selected the baseline statistics as the average of the 2001 through 2003 yearly indices plus two standard deviations (to provide 95% confidence level). In 2006 the Company reviewed the calculation of the baseline statistics in light of the completion of the transition to the OMT in 2005 and the data collected in 2006. Calculating the baseline reliability statistics including the 2004 through 2006 data show an increase in the values, which the Company believes, represents better reporting using OMT. The Company proposed the latest calculated Baseline Statistic values to reflect the best available data collection. Because the Company believes that the OMT data collection has affected the SAIFI index the most it used the years 2004 to 2006 for the SAIFI Baseline Statistic and the years 2002 to 2006 for the MAIFI and SAIDI Indices.

The baseline indices have been adjusted by removing Major Event Days, MED's, as defined in the following section.

The following table summarizes the baseline statistics by indices.

Indices	2004-2006 Average (Excluding Major Events)	Baseline Statistic (Ave + 2 Standard Deviations)
SAIFI	1.09	1.44

Indices	2002-2006 Average (Excluding Major Events)	Baseline Statistic (Ave + 2 Standard Deviations)
MAIFI	4.52	5.82
SAIDI	114	160

Additional comparison of the Baseline Indices is provided in the System Indices section of this report.

Avista is anticipating using the different years in the Baseline Statistics for SAIFI for a few years until a full five years of data is gathered using the current Outage Management Tool.

Major Events

Major Events and Major Event Days as used in this report are defined per the IEEE Guide for Electric Power Distribution Reliability Indices, IEEE P1366-2003. The following definitions are taken from this IEEE Guide.

> **Major Event** – Designates an event that exceeds reasonable design and or operation limits of the electric power system. A Major Event includes at least one Major Event Day (MED).
>
> **Major Event Day** – A day in which the daily system SAIDI exceeds a threshold value, T_{MED}. For the purposes of calculating daily system SAIDI, any interruption that spans multiple calendar days is accrued to the day on which the interruption began. Statistically, days having a daily system SAIDI greater than T_{MED} are days on which the energy delivery system experienced stresses beyond that normally expected (such as severe weather). Activities that occur on major event days should be separately analyzed and reported.

The Company will use the process defined in IEEE P1366 to calculate the threshold value of T_{MED} and to determine MED's. All indices will be reported both including and excluding MED's. The comparisons of service reliability to the baseline statistics in subsequent years will be made using the indices calculated without MED's.

The table below lists the major event days for 2009.

Major Event Days	SAIDI (Customer-Minutes)	Cause
2009 Major Event Day Threshold	9.925	
No Major Event Days		

Additional analysis of the 2009 Major Event Days is not provided in this Annual Report as was done in previous years starting on Page 53, section Major Event Days Causes.

Customer Complaints

The Company tracks reliability complaints in two areas, Commission Complaints and Customer Complaints. Commission Complaints are informal complaints filed with and tracked by the Commission. Customer Complaints are recorded by our Customer Service Representatives when a customer is not satisfied with a resolution or explanation of their concern. See the Customer Complaints section on Page 36 for a summary of results for this year.

System Indices

The charts below show indices for Avista's Washington and Idaho ("system") electric service territory by year. Breakdown by division is included later in this report.

The Company continues to use the definition of major events as described above to be consistent with IEEE Standards. Therefore, the following charts show statistics including the effect of major events per this definition.

Chart 1.1 – SAIFI - Sustained Interruptions / Customer

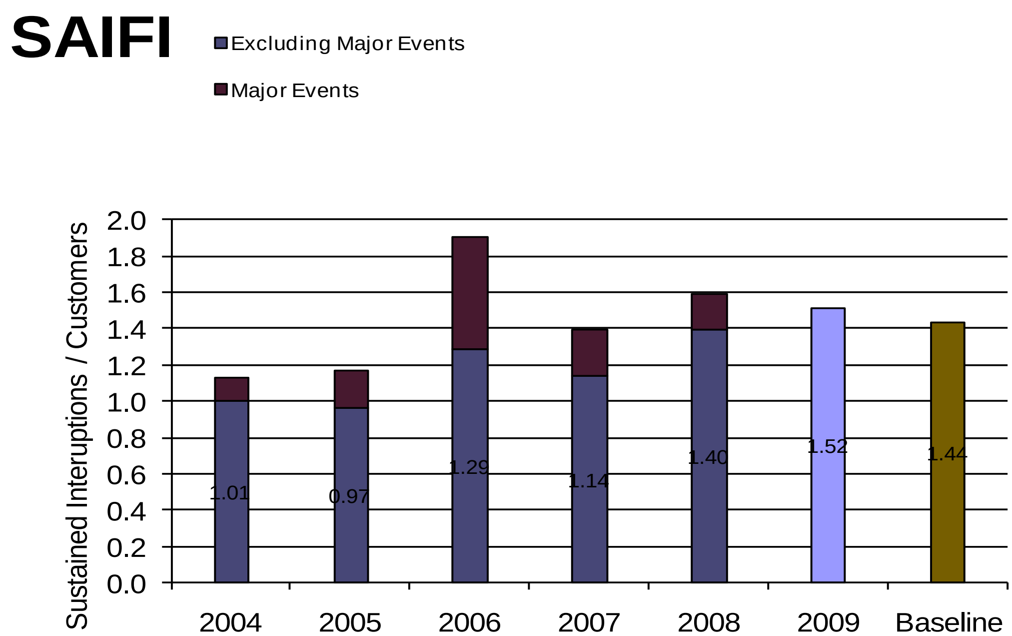
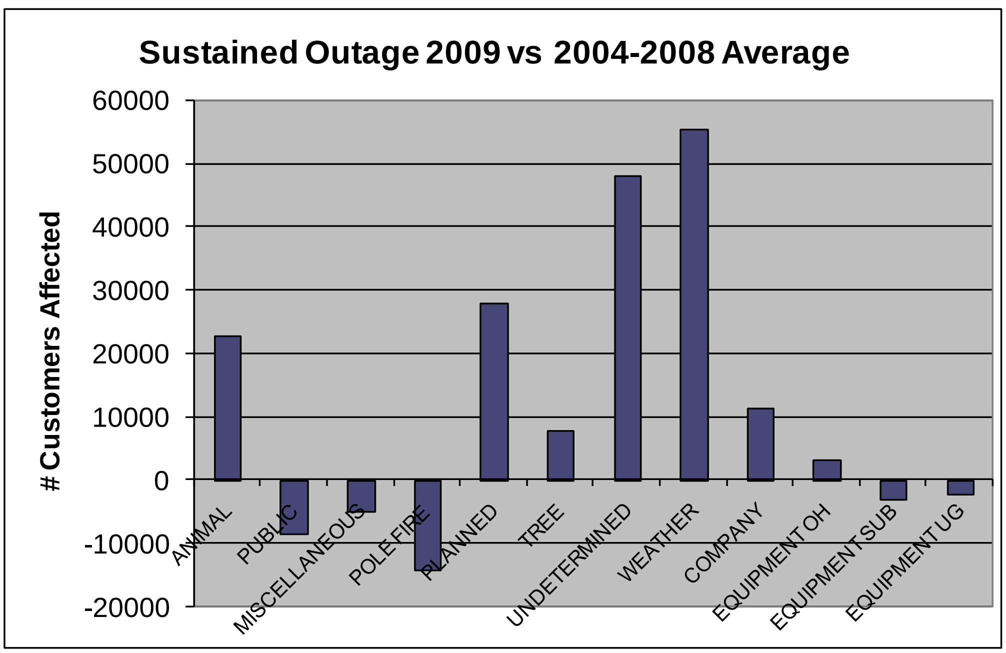


Chart 1.2 – Sustained Interruptions / Customer Historic Comparison



SAIFI for 2009 was over the existing baseline established in 2006 and represents the increasing trend. Using a simple linear regression to establish a trend line, it would look like about a 9.9% growth in number of customers affected. The R^2 coefficient of determination shows a much stronger correlation to the data than last year. A chart of this analysis has been provided just after this discussion. Major contributors to this higher number of customers affected were animals, planned outages, undetermined, and weather.

There were 138,951 customers affected by sustained outages caused by weather in 2009. This compares to the 2004–2008 average of 83,395 customers.

51,024 customers were affected by sustained outages associated with animal related incidents. This compares to the 2004-2008 average of 28,233 customers. The vast majority of the animal related reasons were associated with squirrel caused incidents.

Planned maintenance activities and also forced repairs affected 52,838 customers as compared to the 2004-2008 average of 24,845 customers. Continued maintenance activities associated with the Company equipment replacement program contributed to the increase in this cause and reduced the Overhead Equipment outage causes.

An increase in the number of Undetermined Causes occurred in 2009 as compared to the 2004-2008 average. 92,117 customers had undetermined causes as compared to the average of 43,835. A large number of outages were associated with transformer fuses, but there was no known reason for the fuse to operate. Additional analysis in 2009 along with discussions with local area personnel could only suspect these maybe animal caused as the common element that is suspected. No evidence can be contributed to these outages.

SAIFI Linear Trend Line Chart

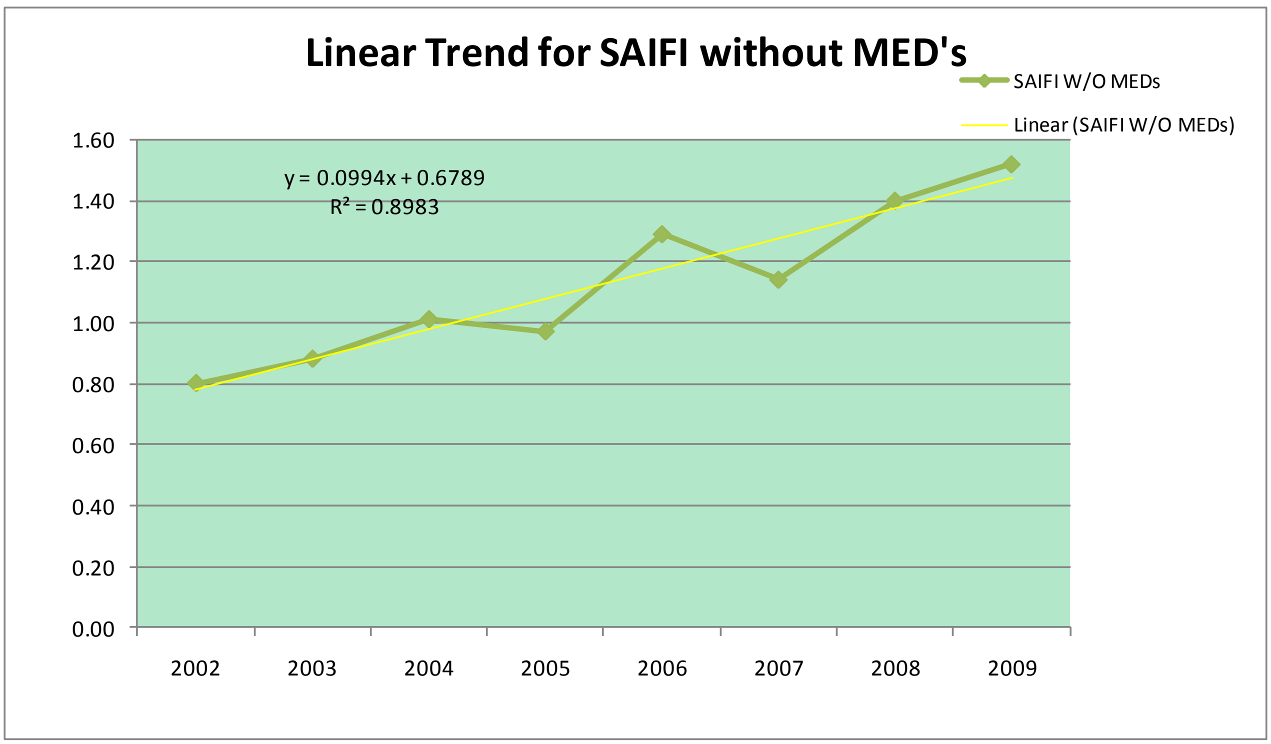


Chart 1.3 - MAIFI Momentary Interruption Events / Customer

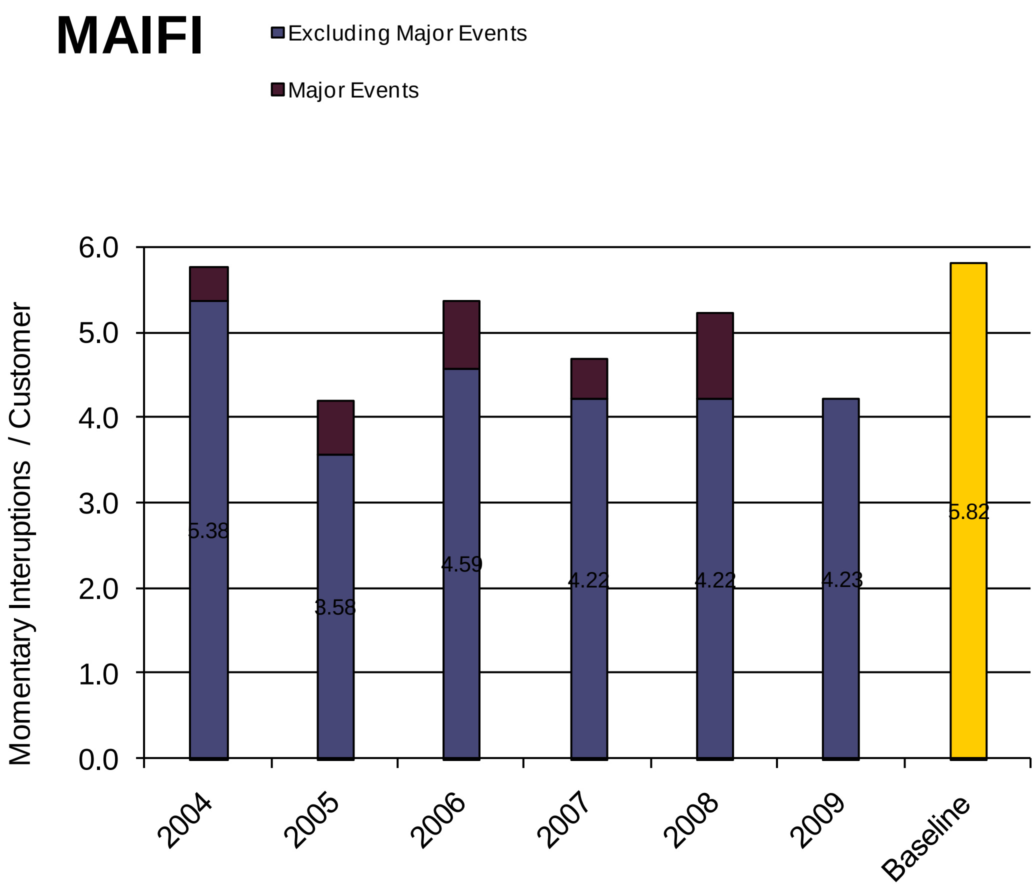
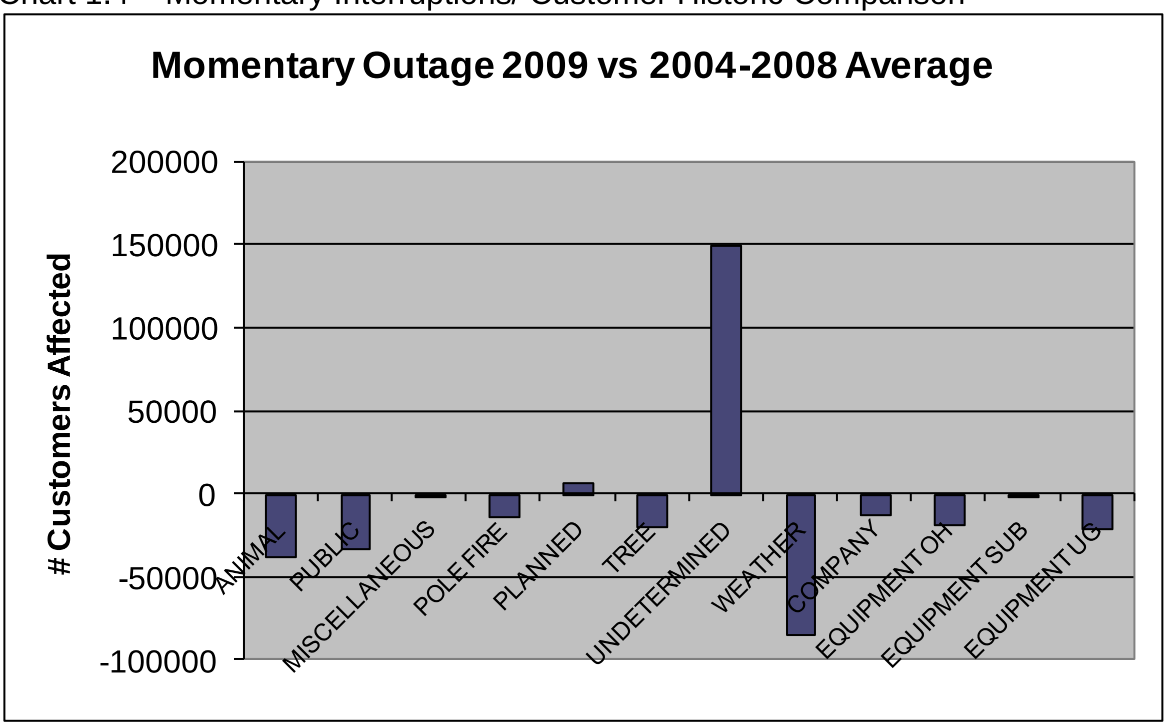


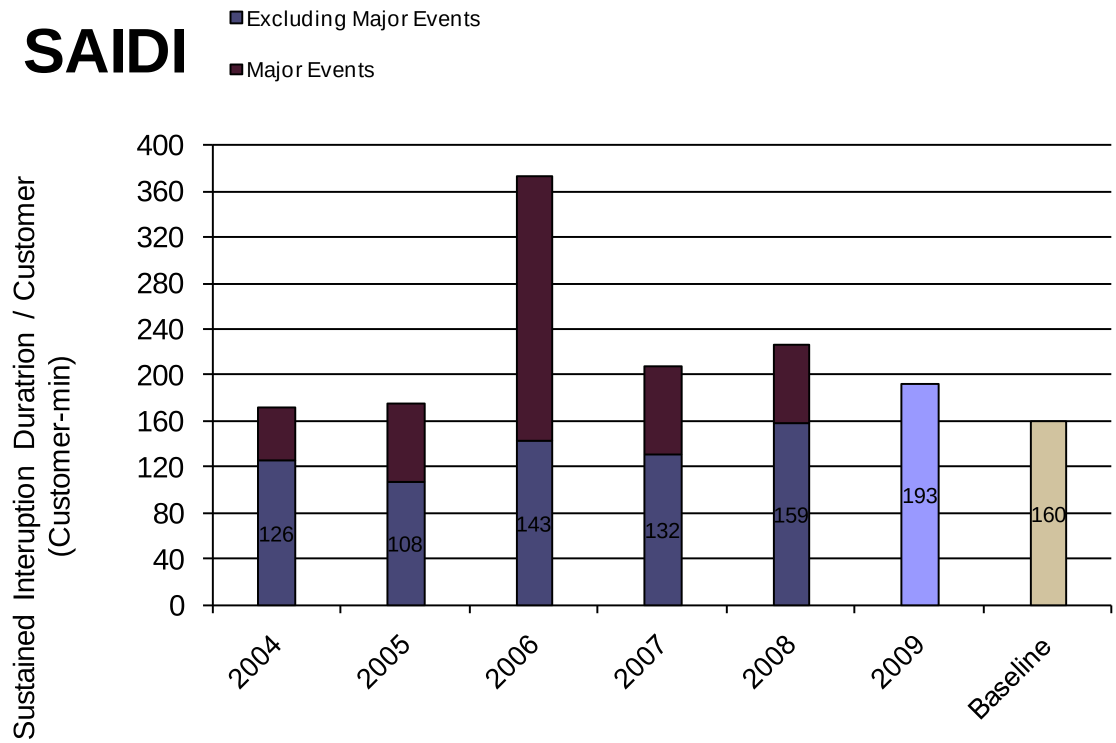
Chart 1.4 – Momentary Interruptions/ Customer Historic Comparison



The 2009 results for MAIFI show a large decrease over 2008 and about the same as 2007 levels. There was a reduction in weather related momentary outages that cannot be explained on weather conditions alone. There was a corresponding increase in the number of undetermined outages, which can reflect that weather conditions did cause outages. Distribution Dispatch continues to make improvements in correlating the momentary outages with subsequent sustained outages, which reduces the undetermined causes.

All other categories showed either a slight decrease that would be consistent with previous years.

Chart 1.5 - SAIDI – Average Outage Time / Customer



SAIDI Linear Trend Line Chart

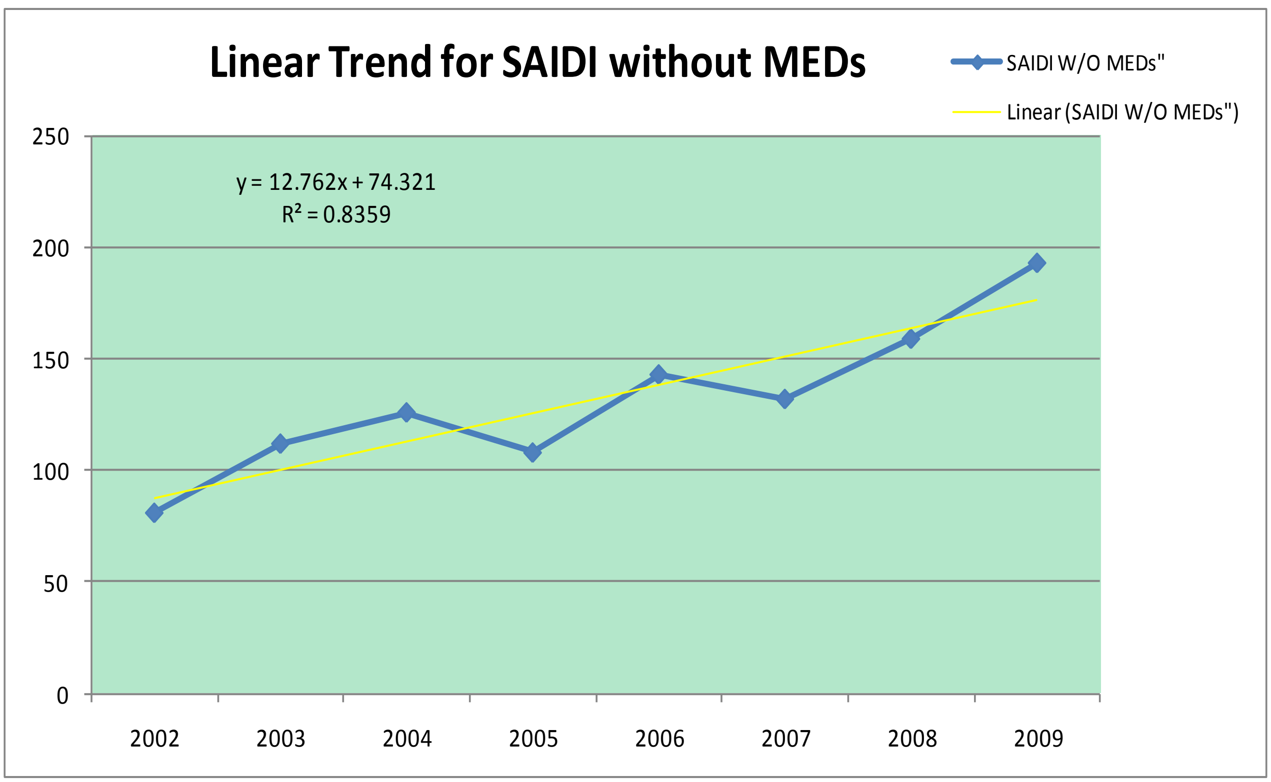
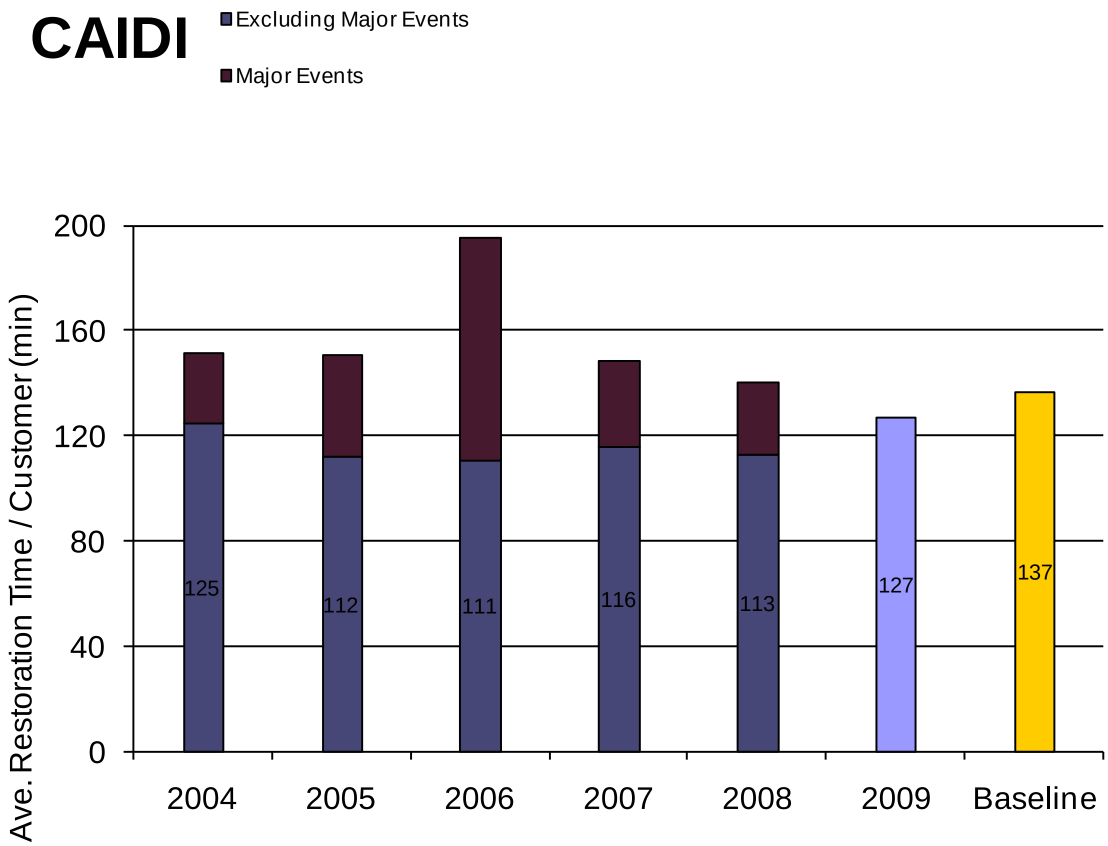


Chart 1.6 - CAIDI – Average Restoration Time



OFFICE Indices

Chart 2.1 – SAIFI - Sustained Interruptions / Customer

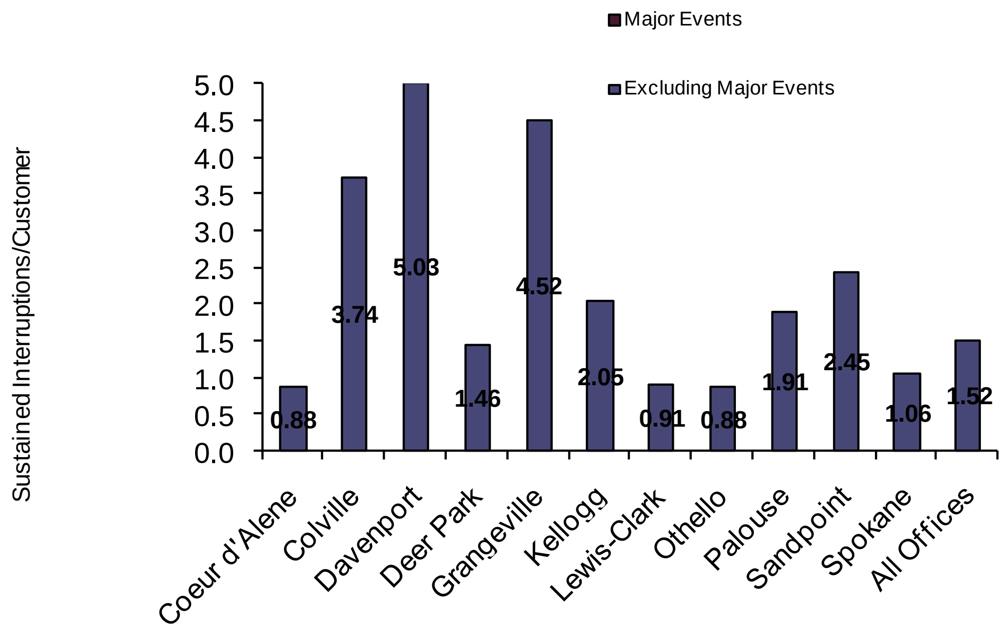


Chart 2.2 - MAIFI Momentary Interruption Events / Customer

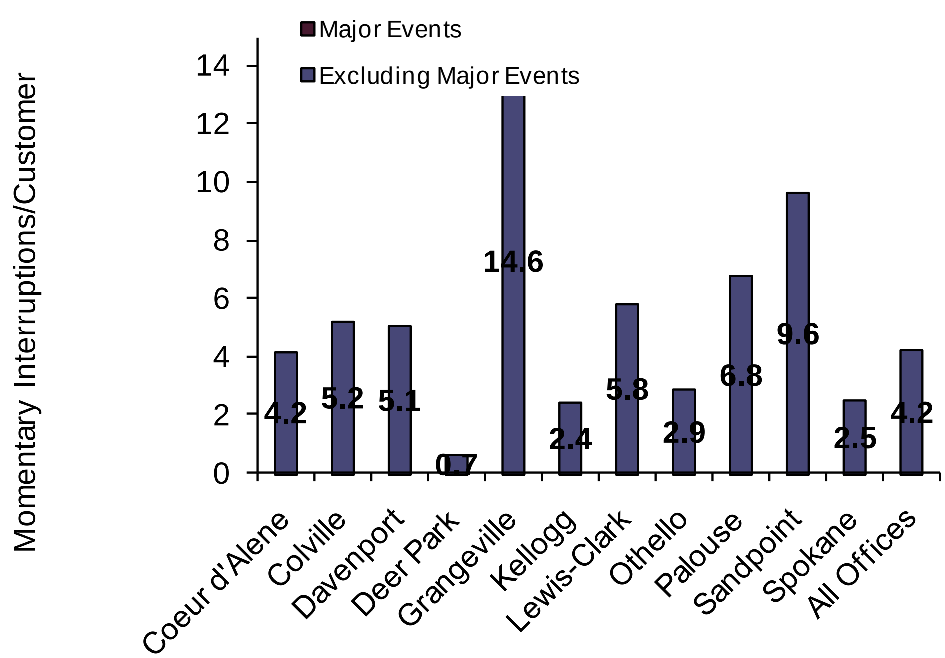


Chart 2.3 - SAIDI – Average Outage Time / Customer

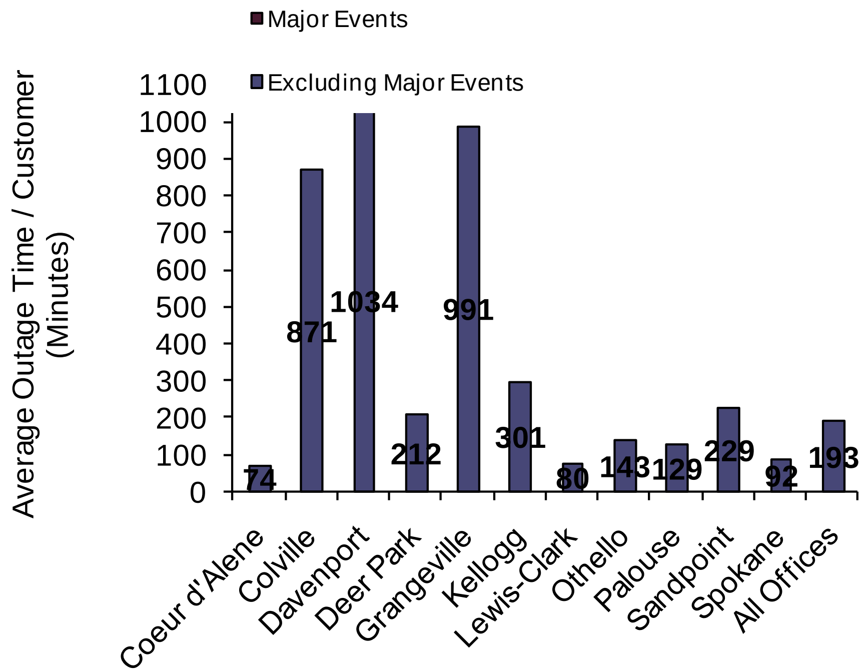
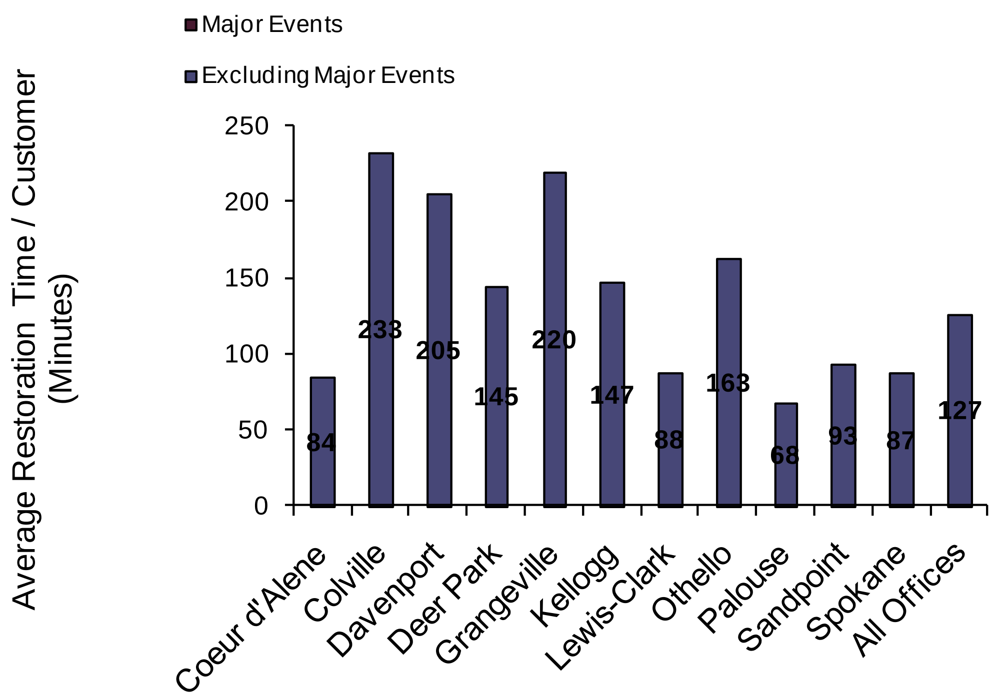


Chart 2.4 - CAIDI – Average Restoration Time



Areas of Concern

As in previous years, Colville continues to have the lowest reliability of Washington's operating areas. However, the Colville area continues to show improvement over previous years as work plans are implemented. Colville was judged lowest based on its performance in the yearly indices for SAIFI, SAIDI, CAIDI, and MAIFI. Within the Colville area, six feeders were identified as the areas of concern for 2009. These feeders are Gifford 34F1, Gifford 34F2, Colville 34F1, Colville 12F4, Valley 12F3 and Valley 12F1. For this report, these same six feeders are identified as the areas of concern for 2009.

Cause Information:

Generally rural areas have a greater number of outages per customer. Colville is a predominately rural and forested area. There are approximately 2342 miles of distribution line exposed to weather, underground cable failures and tree problems. Unlike most of the Company's system, lines in this area are built on the narrow, cross-country rights-of-way, typical of PUD construction practices prior to Avista acquiring the system. These conditions make patrolling, tree trimming, right of way clearing and other maintenance difficult. When cost effective, Avista moves sections of these overhead lines to road rights of way and/or converts them to underground.

Further, when outages occur in rural areas, the time required to repair damage is longer. More time is required for first responders to arrive and assess the damage and more time is required for the crew to reach the site. Often the damage is off road and additional time is required to transport materials and equipment to the site.

Listed below is a summary of the specific cause data for each feeder. This is a compilation of data from the Avista Outage Management Tool and the reporting from our local servicemen to Distribution Dispatch. Data from the reporting system is shown as a percentage of total customer-outages, (SAIFI) for that feeder.

Snow loading on green healthy trees growing beyond the rights-of-way often causes them to bend or break and contact distribution lines. These trees are not cut as part of our vegetation management program because they are outside our right of way and are considered healthy marketable timber.

Gifford 34F1

- 19.1% Weather: snow, wind and lightning storms
- 9.5% Equipment
- 0.0% Pole fires
- 2.4% Trees
- 19.1% Planned outages

Colville 34F1

- 35.7% Weather; snow, wind and lightning storms
- 11.4% Equipment
- 2.0% Pole fires
- 14.3% Trees
- 9.1% Planned outages

Chewelah 12F3

- 33.6% Weather: snow, wind and lightning storms
- 5.2% Equipment
- 3.5% Trees
- 15.5% Planned outages
- 7.8% Animal: birds or squirrels

Gifford 34F2

- 19.7% Weather: Wind, snow, and lightning storms
- 9.2% Equipment
- 1.3% Pole Fires
- 10.5% Trees
- 11.8% Planned outages
- 14.5% Animal: birds or squirrels

Valley 12F1

- 25.8% Weather: snow, wind and lightning storms
- 10.3% Equipment
- 11.3% Trees
- 7.2% Public
- 7.2% Planned outages
- 4.1% Animal: birds or squirrels

Valley 12F3

- 17.7% Weather: wind and lightning storms
- 5.9% Equipment
- 5.9% Trees
- 23.5% Public
- 23.5% Planned outages
- 0.0% Animal: birds or squirrels

Colville Area Work Plans:

The improvement work that has been accomplished or planned for each feeder is listed below. The Company's reliability working group is continuing to study these feeders to develop additional work plans. Each of the identified feeders also had planned outages that correspond to the maintenance and replacement activities in the area.

Gifford 34F1

- 10,300' of URD cable was replaced in 2009, and 12,850' of URD cable is planned for replacement in 2010.
- A reliability improvement project is scheduled for 2010 in the Pleasant Valley area of this feeder to replace (42) 1940 class poles with new poles and replace approximately 2.2 miles of 1-phase #6A, #6CW, and #9 1/2D wire (all in poor shape) with 2-phases of #2ACSR wire.
- Vegetation Management completed tree trimming of 698 trims and 522 tree removals in 2009. No work planned for 2010.

Colville 34F1

- 12,350 of URD cable was replaced in 2009. None is scheduled to be replaced on this feeder in 2010
- A capital improvement project was completed in 2009 to replace 2.2 miles of 3-phase #6 Crapo wire in poor condition in a difficult access area with 3-phases or URD cable.
- A reliability improvement project is planned for 2010 to perform an RF survey of the trunk of this feeder and perform follow-up work to address issues that are found.
- Vegetation Management completed 6 tree trims and 713 tree removals in 2009. No work planned for 2010.

Chewelah 12F3

- 7700' of URD cable was replaced in 2009, and 5200' of URD cable is planned for replacement in 2010.
- A reliability improvement project was completed in 2009 to split the Chewelah 12F3 into two feeders (Chewelah 12F3 and Chewelah 12F4). Also, another reliability project was completed to convert 2 miles of 1-phase overhead line with bad access with 2-phases of URD.
- Late December 2009 saw the completion of the new Chewelah 12F4 feeder, which split the existing 12F3 into two parts. The original 12F3 feeder was almost 66 miles in circuit miles and is now about 26 circuit miles. 12F4 will be about 40 circuit miles.

Gifford 34F2

- 2775' of URD cable was replaced in 2009, and 8510' of URD cable is planned for replacement in 2010.
- A reliability improvement project is planned for 2010 to convert 3.5 miles of 3-phase overhead line to URD in the Twin Lakes area near Inchelium.

Valley 12F1

- No URD cable was replaced in 2009, but 300' of URD cable is planned for replacement in 2010.

- A reliability improvement project was completed in 2009 to convert 1.9 miles of 1-phase overhead line to URD in the Hesseltine Rd. area.
- Another reliability improvement project is planned for 2010 to convert 3.2 miles of 2-phase overhead line to 1-phase URD in the Jepsen Rd area.

Valley 12F3

- 1300' of URD cable was replaced in 2009, and 700' of URD cable is planned for replacement in 2010.
- Vegetation Management completed 749 tree trims and 293 tree removals in 2009. A small amount of work is planned for 2010.

Avista typically uses several different protective devices on its feeders to isolate faulted or overloaded sections and also continue to serve the remaining customers. Generally, two different protection schemes are used to either "save" the lateral fuse or "blow" the lateral fuse by using or not using the instantaneous over current trip. Depending on the feeder, number of customers, types of faults, (temporary or permanent), customer type, time of year, etc. both of these schemes may be used on an individual feeder at different times at the discretion of the field personnel. With the better data and cause code collection that OMT provides and the customer growth on some of the Colville feeders, changes to the type of scheme used has been reviewed. Listed below are major reliability projects specifically identified by feeder. Three of these are in the State of Idaho.

Feeder	Decisions/ basis	2010	2011 and beyond
Gifford 34F1	Reliability improvements	Budgeted	Planned
Gifford 34F2	Reliability improvements	Budgeted	Planned
Colville 34F1	Reliability improvements	Budgeted	Planned
Valley 12F1	This feeder was first identified in mid 2006 as having areas that would be of concern. Capital dollars have been budgeted in 2010 to identify and implement some reliability improvement.	Budgeted	Planned
Valley 12F3	Fusing protection was revised and updated. Additional reliability improvements maybe budgeted in future years.		Planned
Wallace 542 New*	Reliability Improvement	Budgeted	
Grangeville 1273*	Engineering is on going along with Wood Pole Management related work to identify reliability improvements for this feeder.	Budgeted	Planned
Saint Maries 633*	Reliability Improvement	Budgeted	Planned

* Not included as an area of concern in this report.

Avista System Wide Work Plans:

Avista develops a detailed annual budget for various improvements to the facilities it owns and operates. For 2009, three reliability feeder projects (one has been deferred to 2010) were completed and described above. The reliability improvement should show up over the next couple of years. Additionally Asset Management has developed some specific projects that are expected to improve reliability on several feeders system wide. These projects are summarized in the table below.

Porcelain cutout replacements were completed at the end of 2009.

During 2009, Avista looked at the possibility of performing extensive construction and rehabilitation of the Ninth and Central 12F4 feeder in Spokane. This included reconductoring specific sections of line for loss improvement, changing transformers that were older than 1983, replacing many long secondary districts, and replacing many wood poles. Reliability in 2009 was degraded due to the many planned outages, however only two non planned outages have been reported in early 2010. Additional review will be done for the year end 2010.

Material records show that some wildlife guards were installed on new distribution transformers installations starting in the mid 1980's. With the recognition of increases in animal caused outages, new materials and improvements have been made in the construction standards for new distribution transformer installations to reduce these types of outages. Initial indications show that the outage reduction on a feeder after wildlife guards are installed is significant.

2009 was the start of the multiyear wildlife guard installation program to reduce the squirrel and bird related outages on approximately sixty feeders in Washington and Idaho. Most of the wildlife guards were installed with a hot stick on existing transformers that do not have an existing wildlife guard.

Avista installed a total of 4534 wildlife guards on 20 feeders in 2009. There were 2130 wildlife guards installed in Idaho on 9 feeders and 2404 wildlife guards installed in Washington on 11 feeders. One feeder (Orin 12F3) in the Colville area had wildlife guards installed last year.

Avista deferred plans to install wildlife guards on additional feeders in Washington for 2010 due to unfavorable pro-forma rate treatment of the program. Avista will continue with plans to install wildlife guards in the State of Idaho. 9 feeders are planned to have wildlife guards installed.

Asset Management in conjunction with the Wood Pole Management Program stubbed or replaced numerous poles and additionally replaced numerous pole top transformers and associated cutouts/arresters.

Avista System Wide Vegetation Management Plan:

Avista has an annual vegetation management plan and budget to accomplish the plan. The budget is allocated into distribution, transmission, administration, and gas line reclearing.

Distribution

Our current plan for Avista's distribution system is managed by Asplundh Tree Expert Co. Every distribution circuit is scheduled to be line clearance pruned on a regular maintenance cycle of four year urban and seven years rural. Other distribution vegetation management activities include hazard tree patrol and herbicide application.

Transmission

The transmission system is managed by Avista's forester. All 230 kV lines are patrolled annually for hazard trees and other issues, and mitigation is done in that same year. Approximately one third of 115 kV transmission system is patrolled annually for hazard tree identification, and assessment of right of way clearing needs. Right of way clearing maintenance is scheduled and performed approximately every ten to fifteen years (for each line). Interim spot work is done as identified and needed. Engineering specifications for various voltages, line configurations are followed when clearing the right of way. Currently, the work is bid to a variety of contractors.

Customers Experiencing Multiple Interruptions

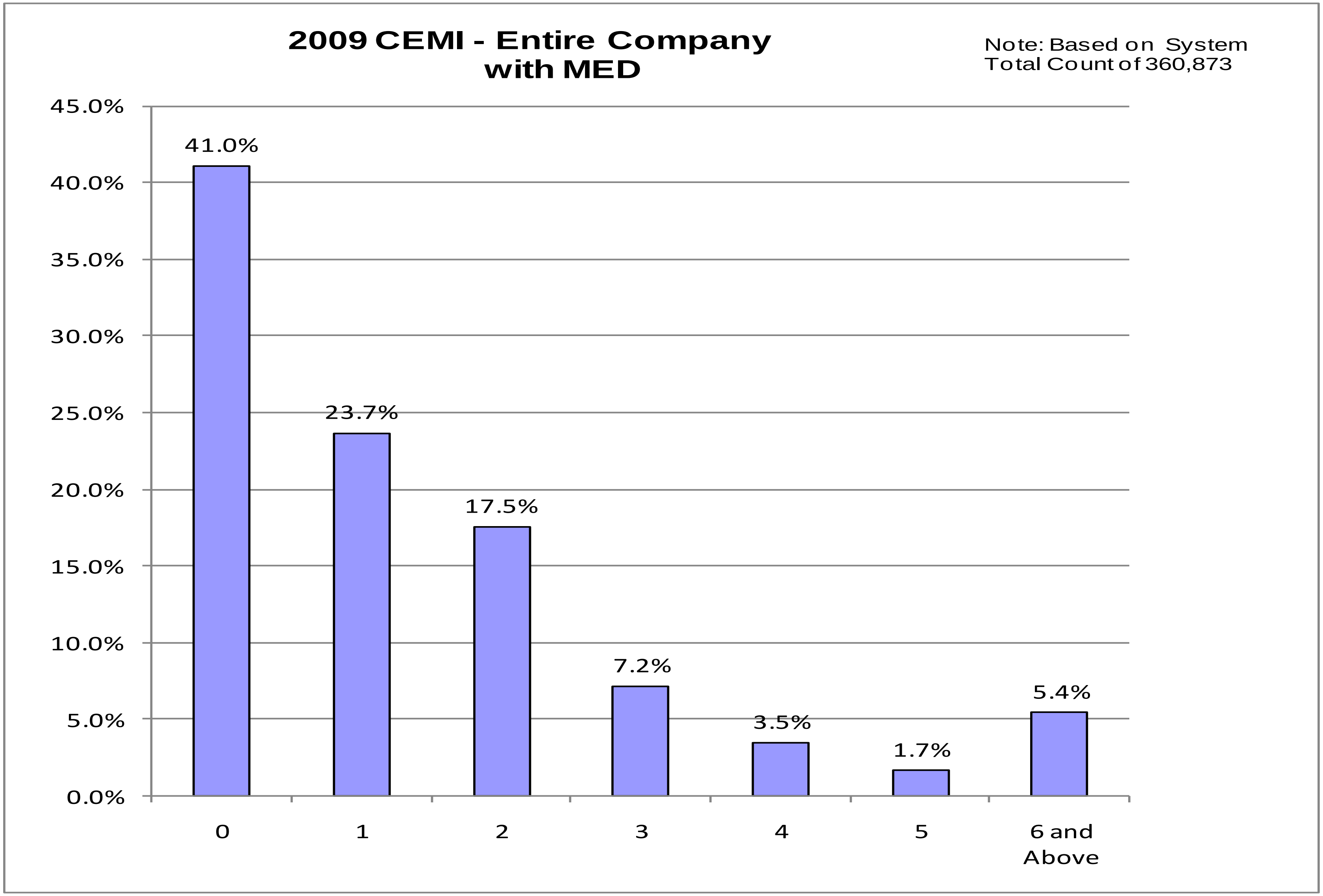
Avista has used the data from the OMT system integrated with the GIS system to geospatially display reliability data for specific conditions. The specific conditions imply looking at the number of sustained interruptions for each service point (meter point). This would be similar to the SAIFI indice, but would be related to a certain number of sustained interruptions. Avista includes all sustained interruptions including those classified under Major Event Days. This provides a view of what each customer on a specific feeder experiences on an annual basis. Momentary Interruptions are not included in the $CEMI_n$ indice, because of the lack of indication on many of the rural feeder reclosers.

The first chart below provides a view of the percentage of customers served from the Avista system that have sustained interruptions. 65 % of Avista customers had 1 or fewer sustained interruptions and 5.4% of Avista customers had 6 or more sustained interruptions during 2009.

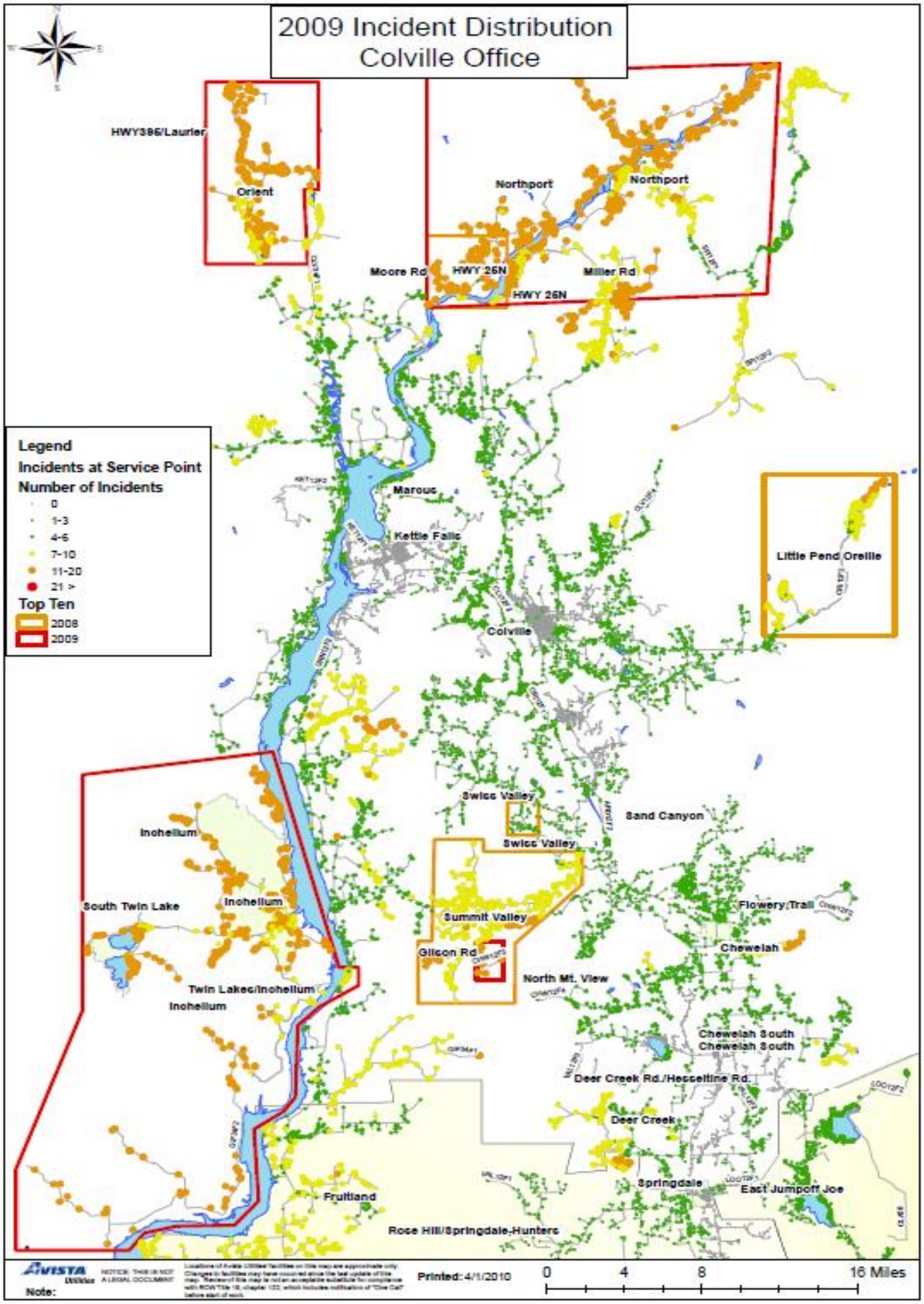
The remaining geographic plots show the sustained interruptions by color designation according to the legend on each plot for each office area. Note the office area is designated as the area in white for each plot and that there is overlap between adjacent office area plots. The adjacent office areas are shown in light yellow.

The plots provide a quick visual indication of varying sustained interruptions, but significant additional analysis is required to determine underlying cause(s) of the interruptions and potential mitigation.

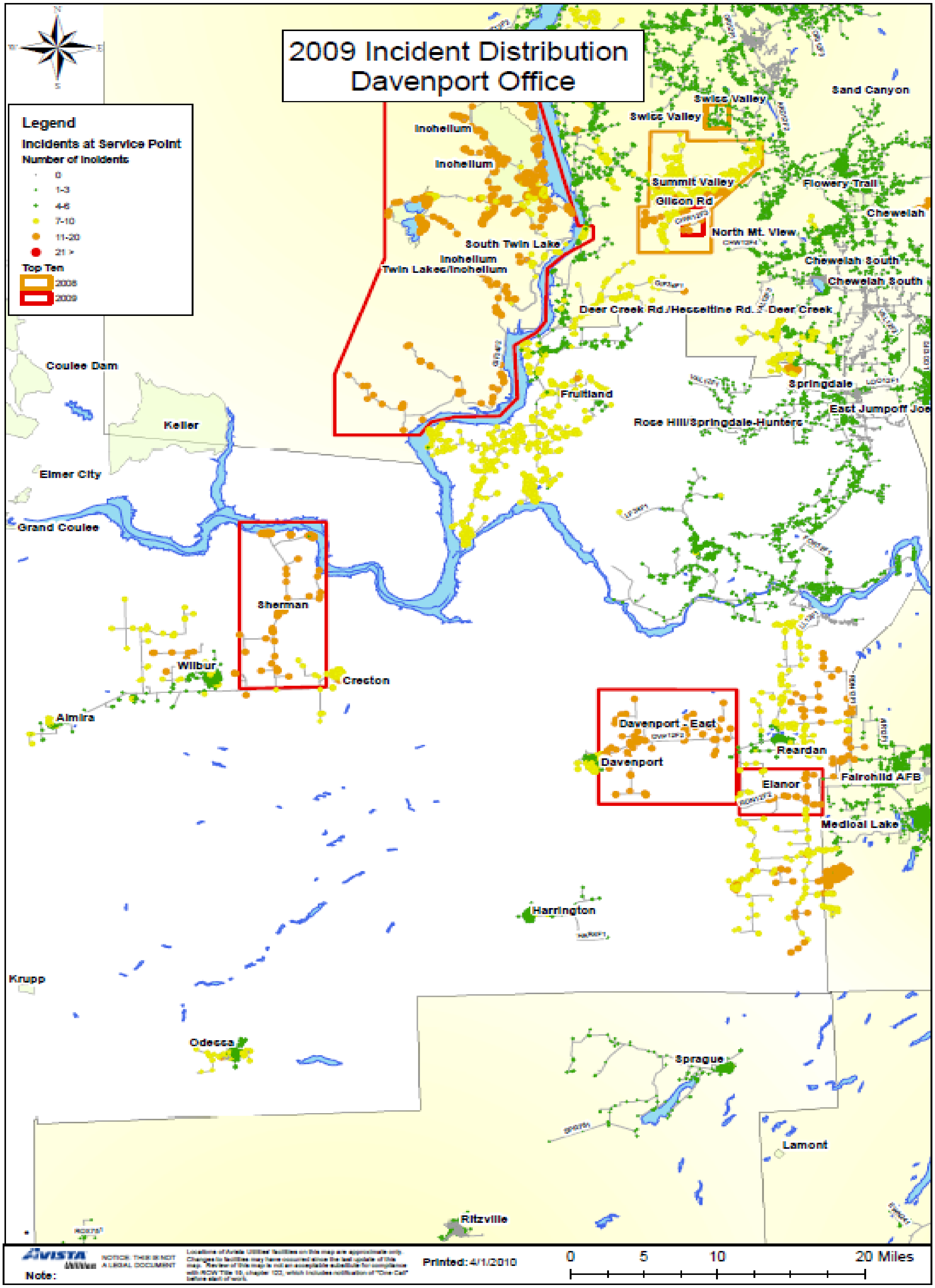
Avista Service Territory CEMI$_n$ Chart



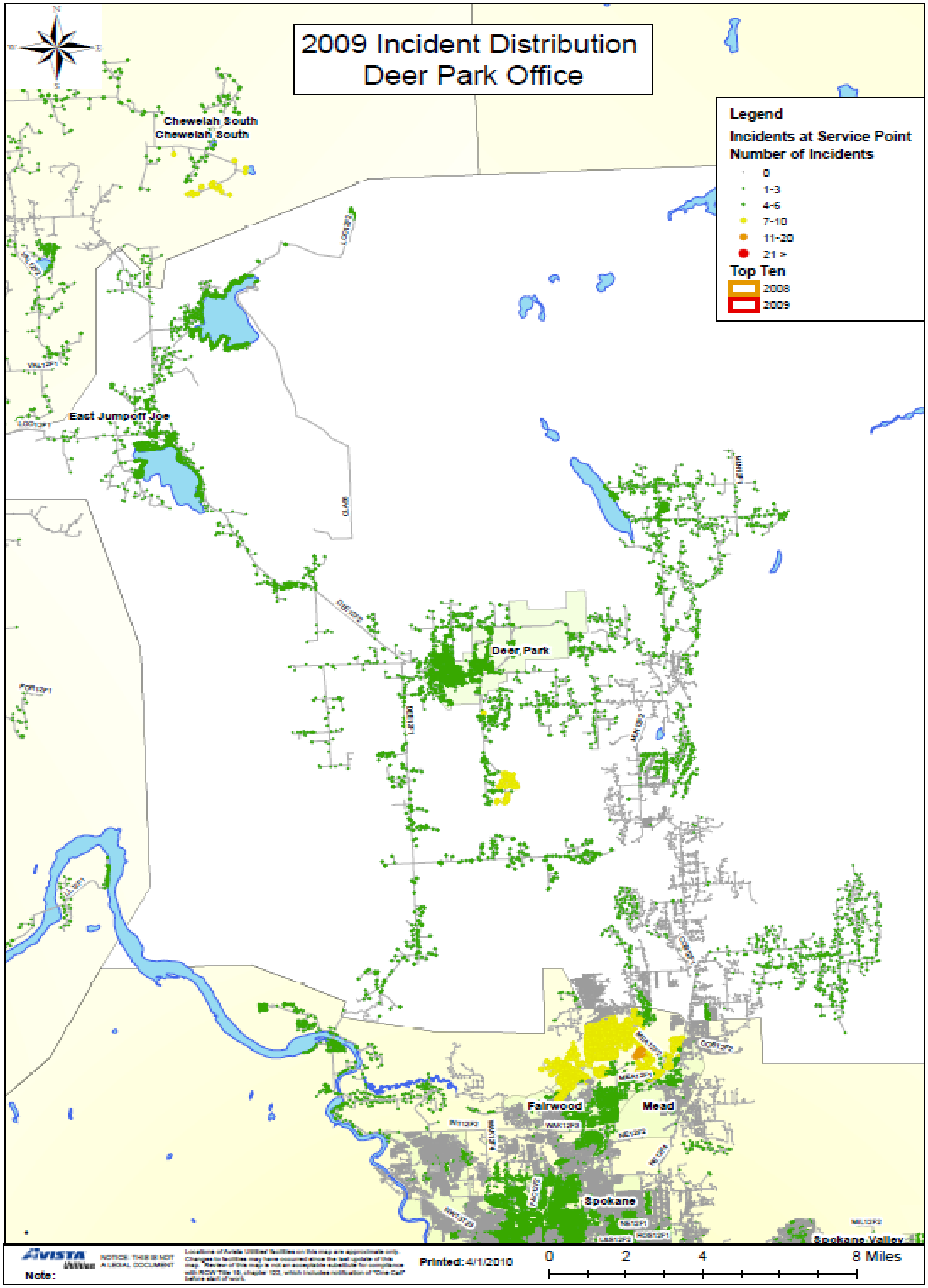
Colville Office - CEMI$_n$



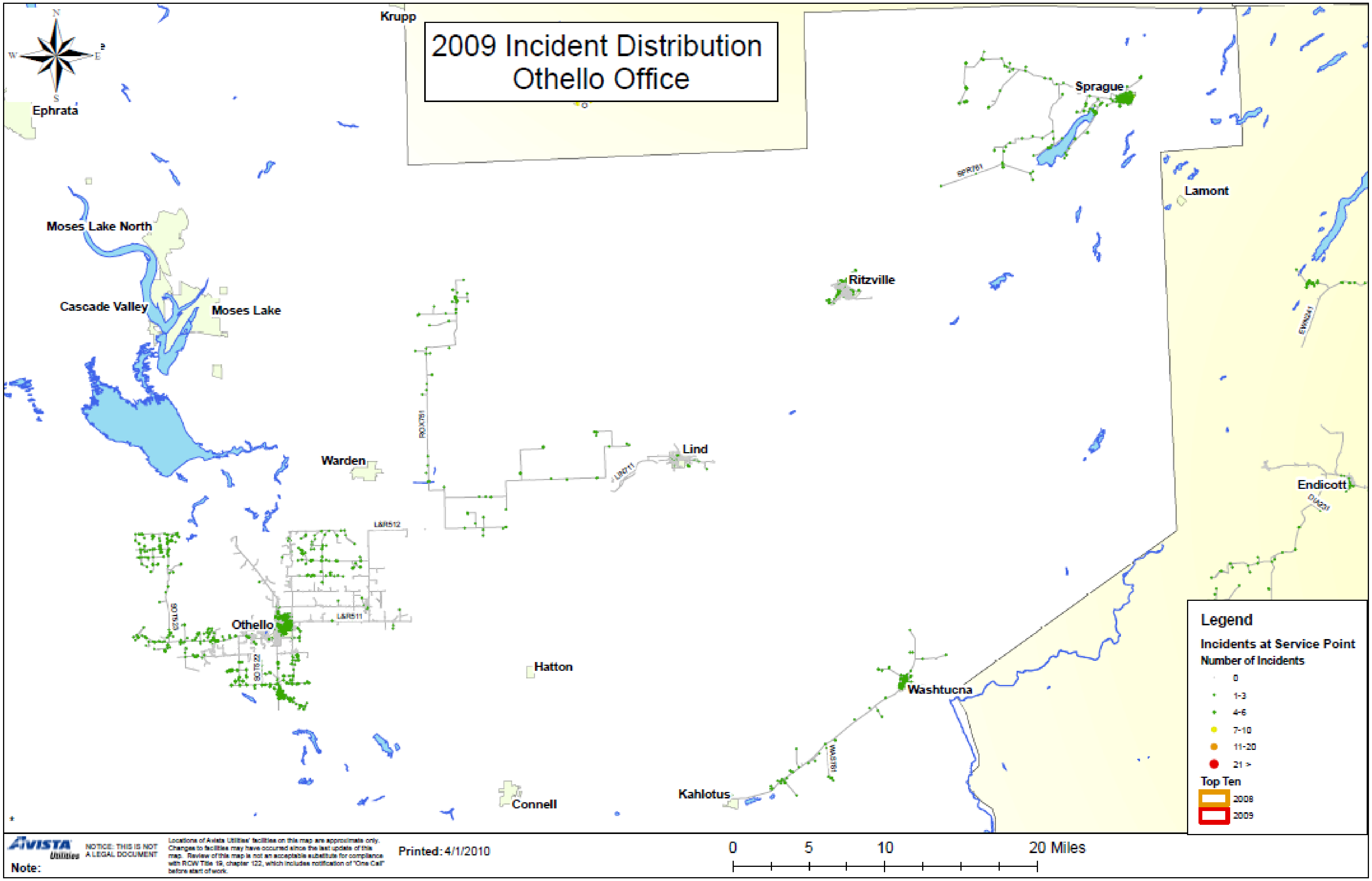
Davenport Office - CEMI$_n$



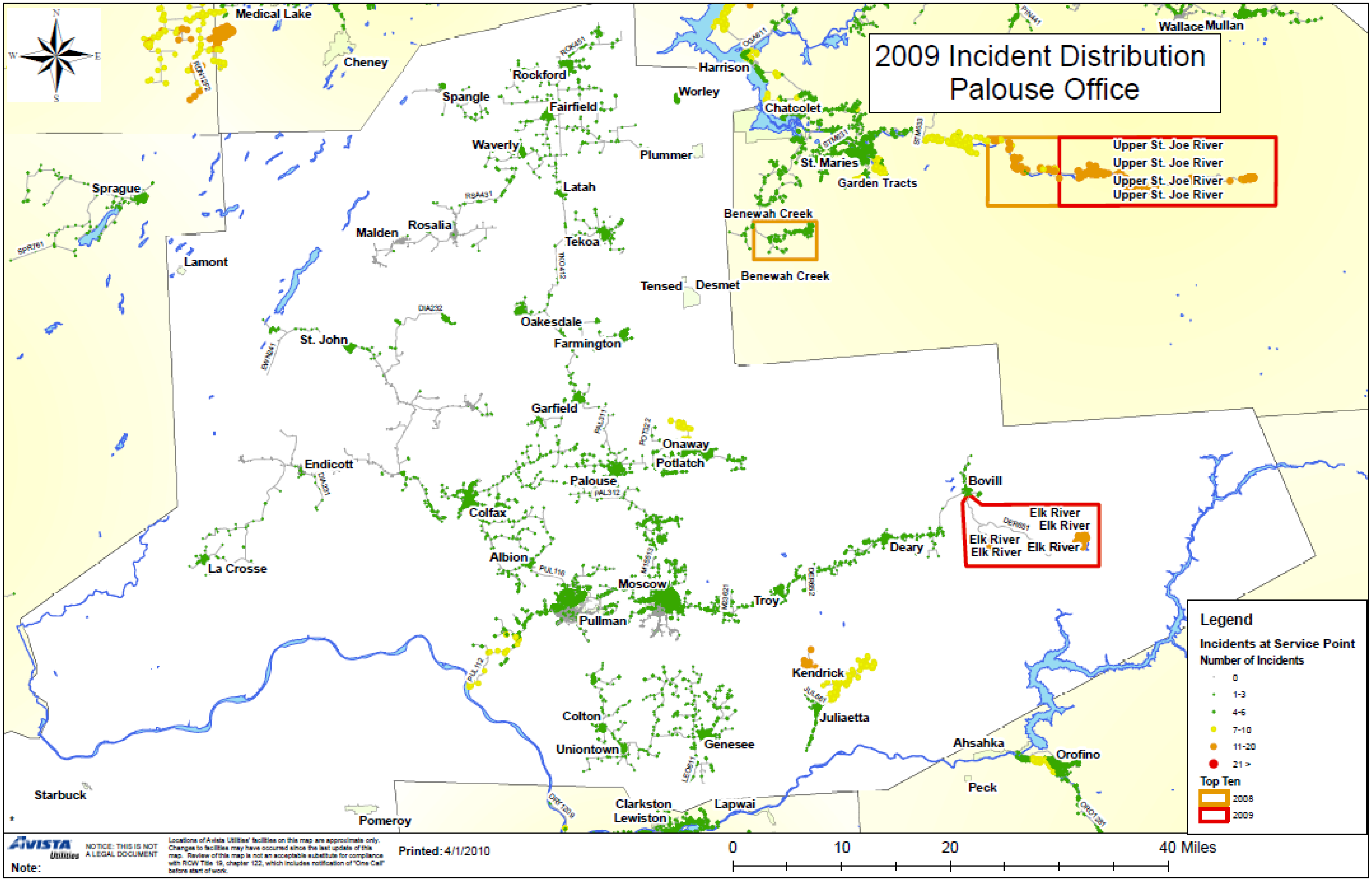
Deer Park Office - CEMI$_n$



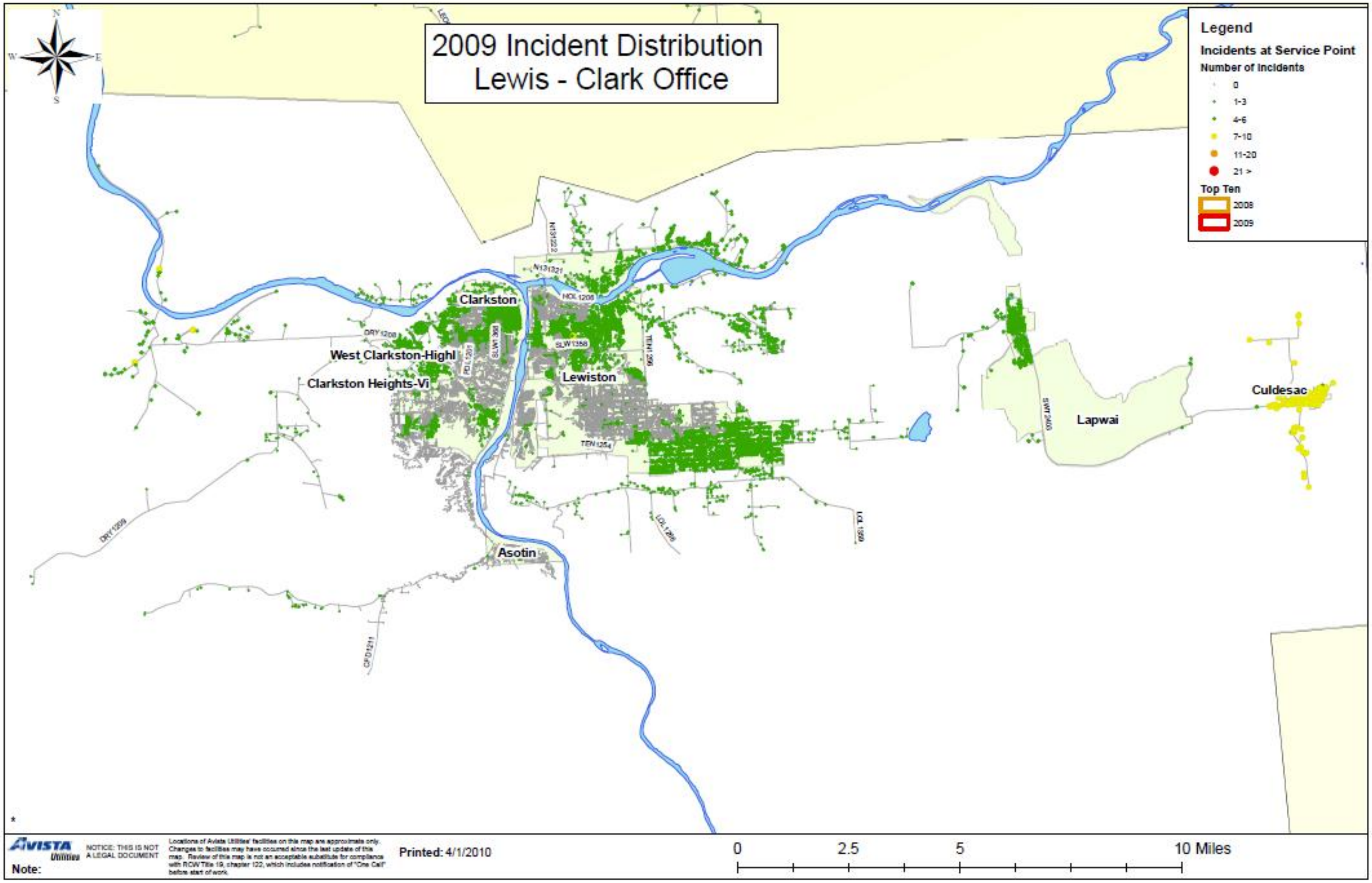
Othello Office - $CEMI_n$



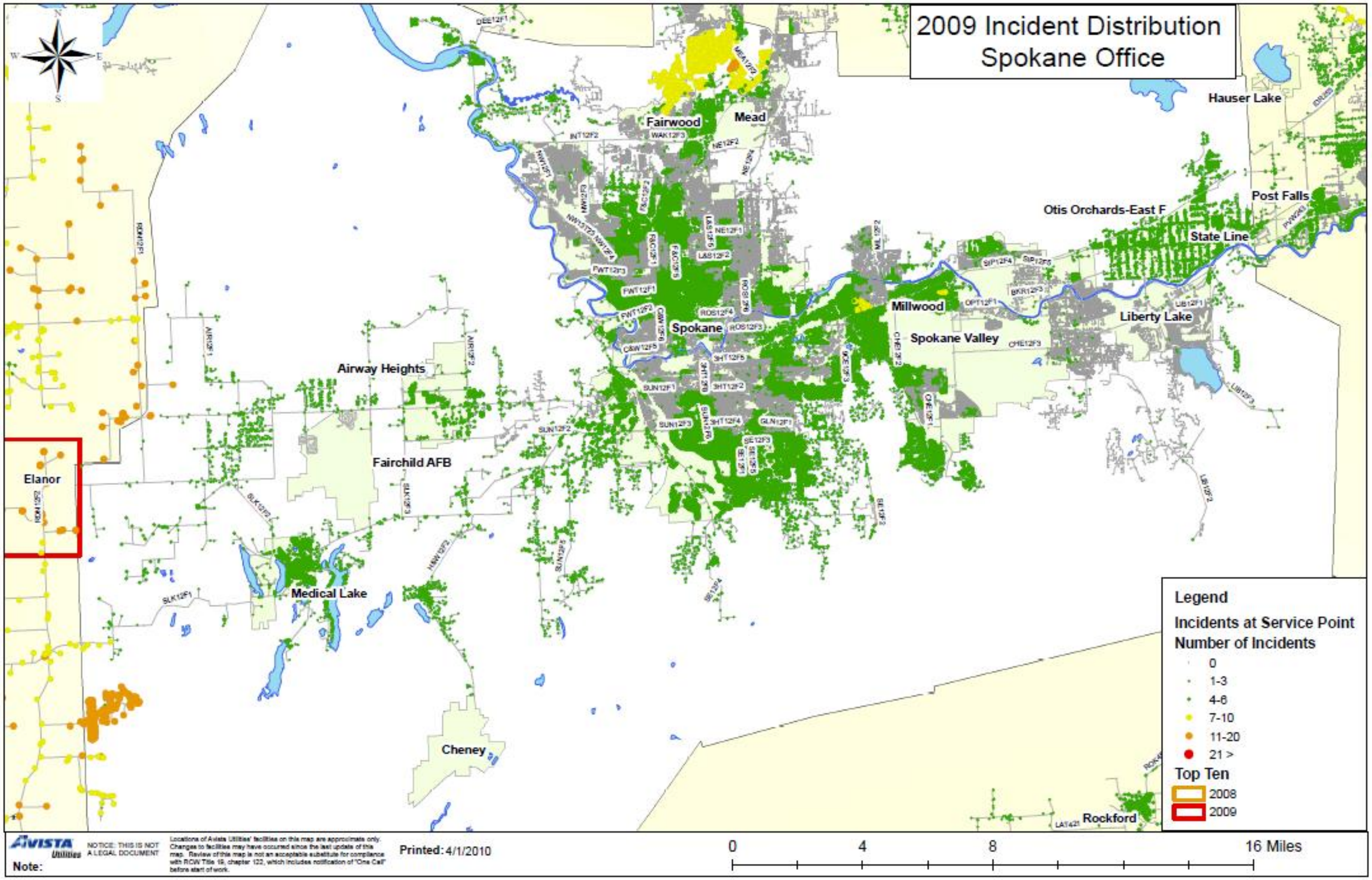
Palouse Office - CEMI$_n$



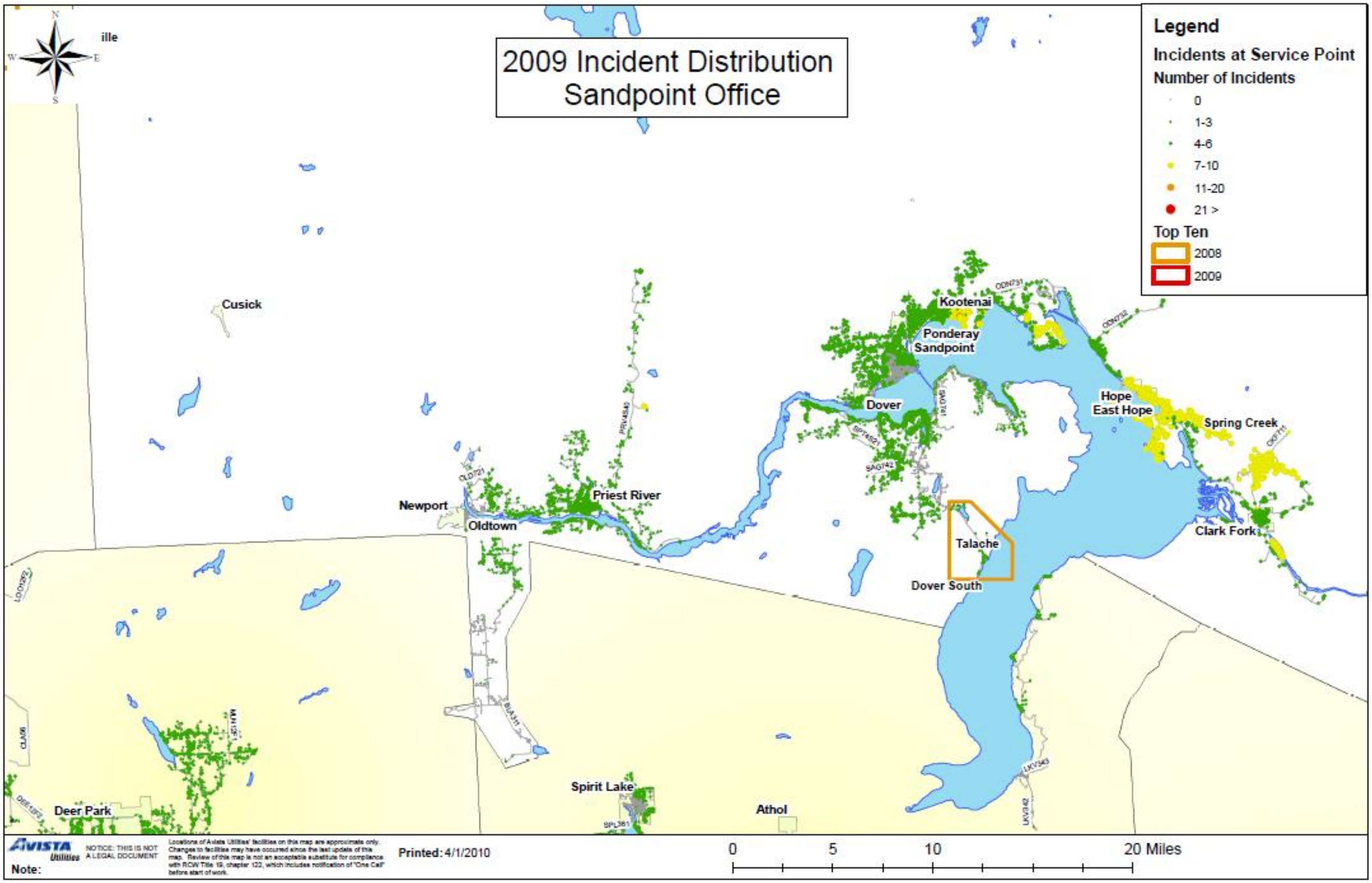
Lewis-Clark Office - CEMI$_n$



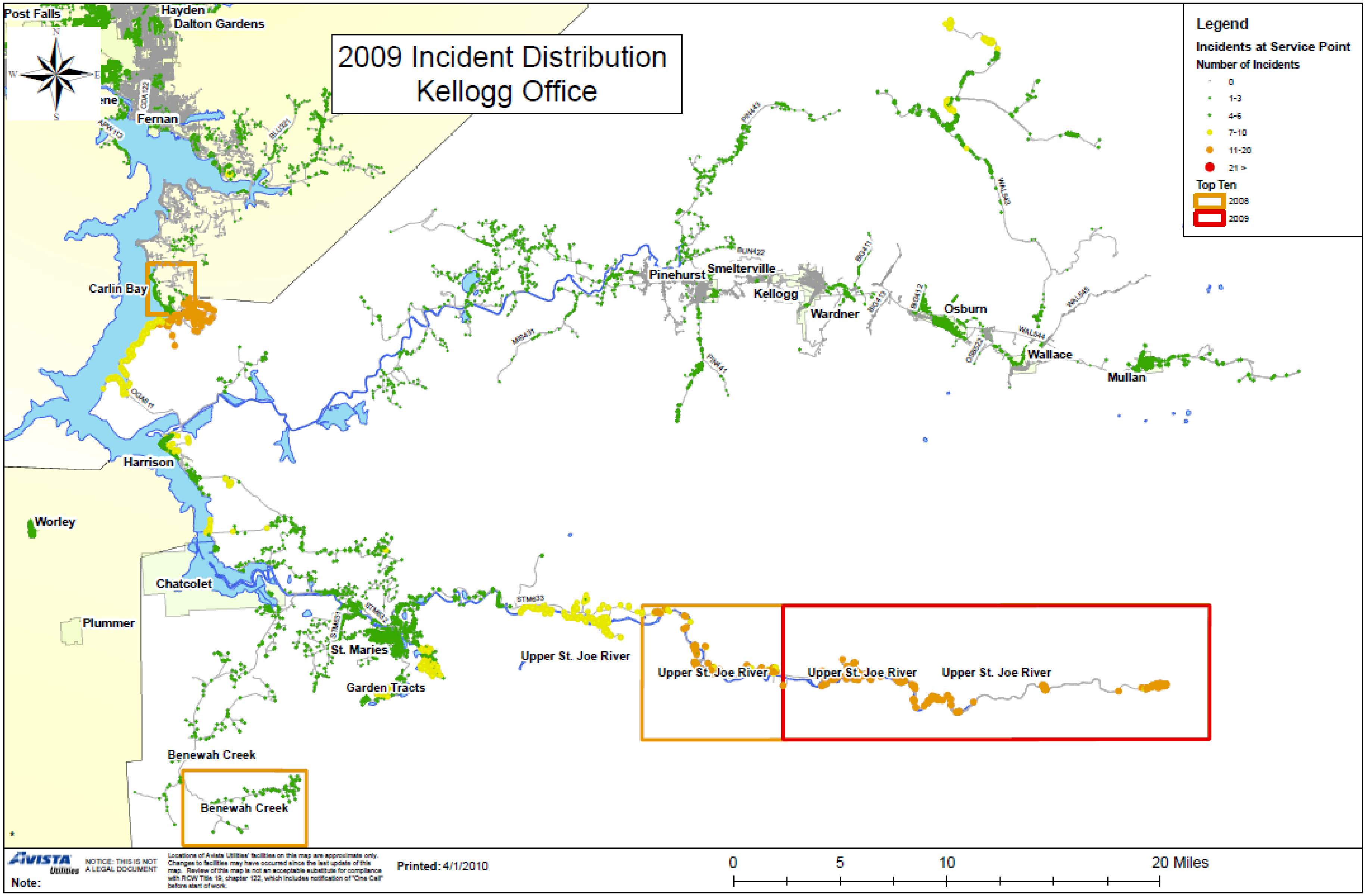
Spokane Office - CEMI$_n$



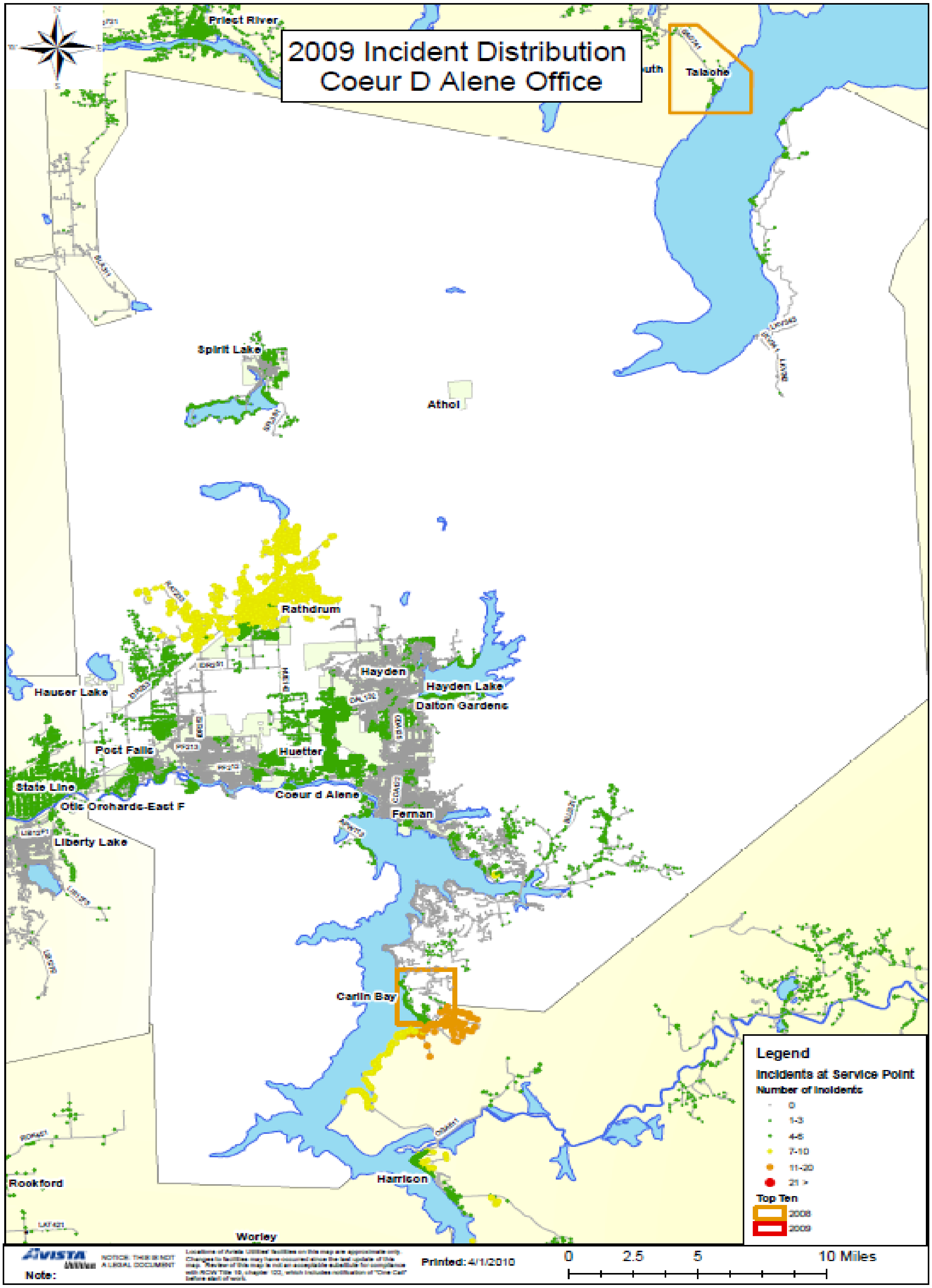
Sandpoint Office - CEMI$_n$



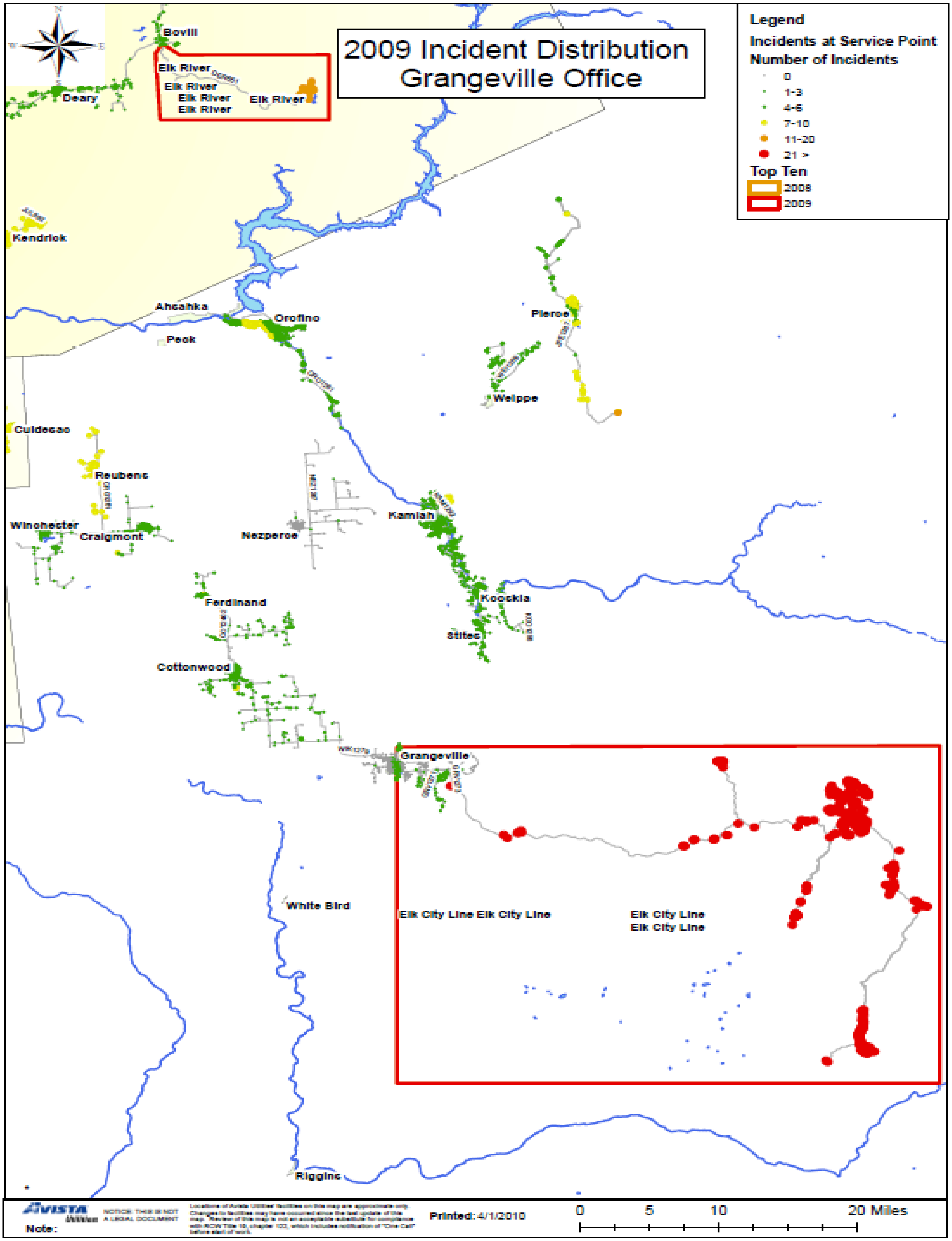
Kellogg Office - CEMI$_n$



Coeur d'Alene - CEMI$_n$



Grangeville Office - CEMI$_n$



Monthly Indices

Each of the following indices, reported by month, shows the variations from month to month. These variations are partially due to inclement weather and, in some cases, reflect incidents of winter snowstorms, seasonal windstorms, and in mid- and late summer lightning storms. They also reflect varying degrees of animal activity causing disruptions in different months of the year.

Chart 3.1 – SAIFI - Sustained Interruptions / Customer

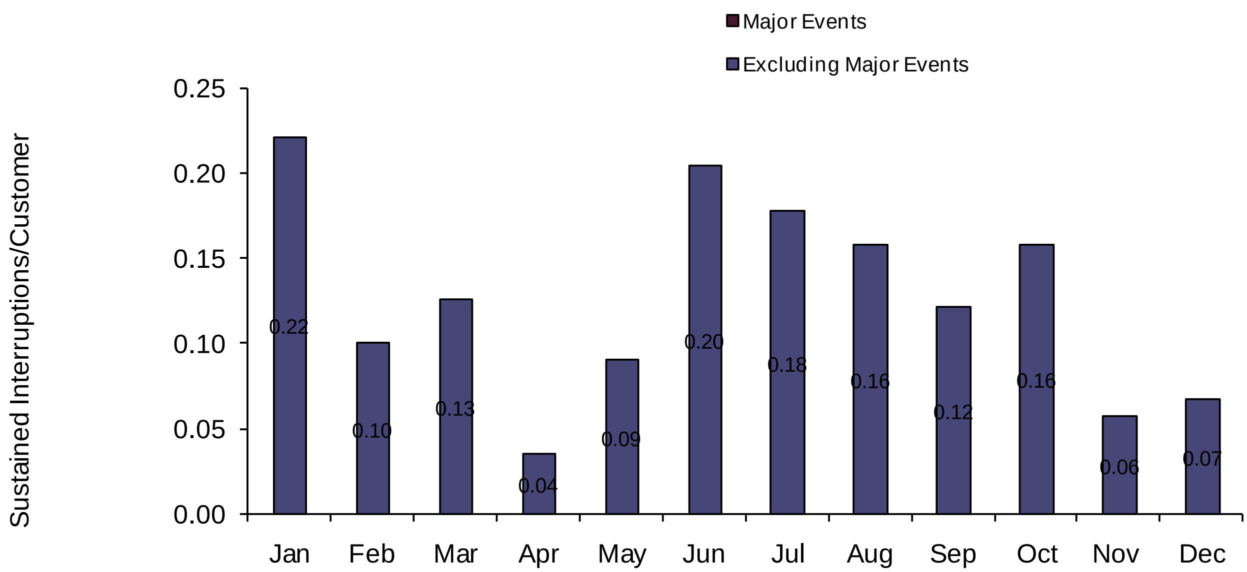


Chart 3.2 - MAIFI Momentary Interruption Events / Customer

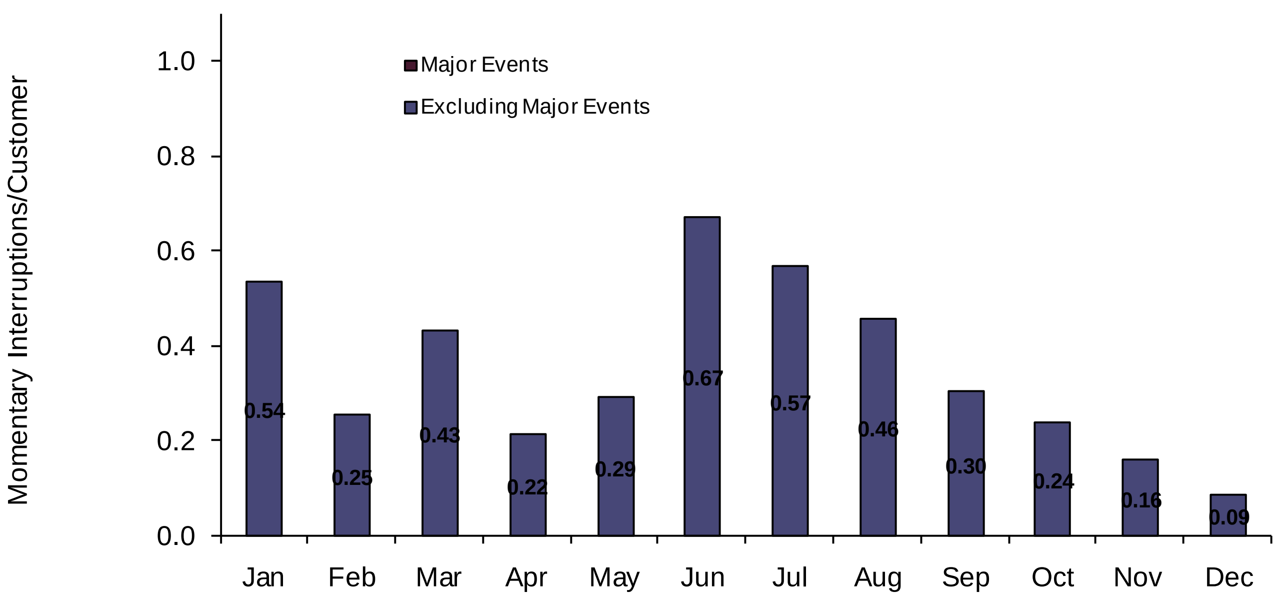


Chart 3.3 - SAIDI – Average Outage Time / Customer

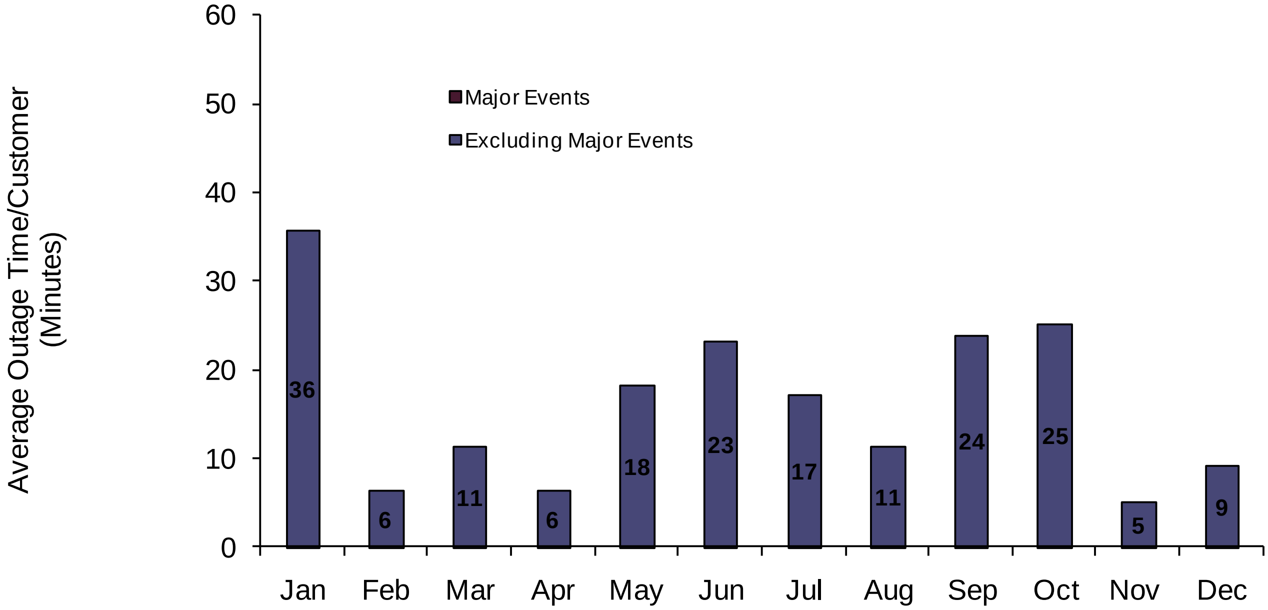
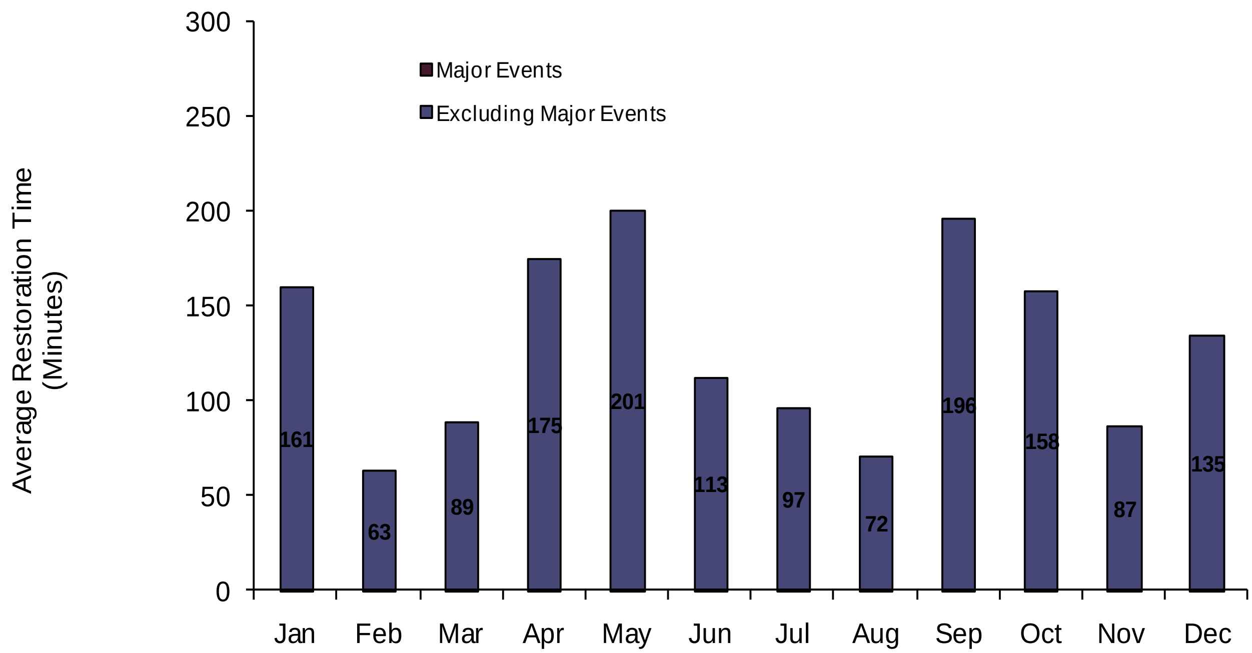


Chart 3.4 - CAIDI – Average Restoration Time



Customer Complaints

Commission Complaints

The following is a list of Complaints made to the Commission during this year.

Customer Address	Complaint	Resolution
Elk City ID Grangeville 1273	The power was to be off all week 9 to 3, which is fine. We had almost 4 feet of snow this week and it was taking the power out in the mornings and they still left it off. Thursday it went off at 6:30AM and was not restored until 7:30PM, we froze. We live in a very remote area if they would have turn it on so we could get our homes warm it would have been ok. Too cold for power to be out that long on purpose.	Avista responded to service complaint 4/9/2009. No resolution documented
Kettle Falls, WA Spirit 12F1	Since August 2008, customer has had 9-10 outages, one of which may have surged his TV. Many of the outages were not weather related and he wants to know what Avista is doing to ensure reliable service. One of the reps told him to buy a generator. Please supply information on circuit, outage causes, number of customers affected, SAIDI/SAIFI, Condition of circuit, any improvement projects, repair history.	Complaint Closed 1/13/2009 Company Upheld.
Springdale, WA Valley 12F1	Customer has had several power surges, brown outs, low voltage, trips and resets in his area and has been trying to get the company to fix the problem since about August 2009. She calls repair and the company asks if she has power and when she says yes, they say they will look into it. However, the company has not fixed the problem, nor have they told her when the problem will be fixed.	Avista responded to customer 11/2/2009 Construction office is investigating and will put repairs in place – is to be scheduled.

Customer Complaints

The following is a list of complaints made to our Customer Service Representatives.

Customer / Feeder	Complaint	Resolution
Spokane, WA Francis & Cedar 12F4	Customer is concerned about the frequent short power outages over the past. Says it is impacting his electronic equipment. Like to know if there is something that can be done.	No Resolution Documented.
Lewiston, ID Tenth & Stewart 1254	Lost Equipment Due to Outage	Claim Filed 6/22/09. Claim rejected, repairs made to service.
Spokane Valley, WA Beacon 12F1	Customer called to complain about recent outages, feels like she lives in 3rd world country and higher the rates go the worse the service. Wanted to file a formal complaint and believes we need to do something about this. Last week out for 5 hours and then off and on for next few days.	Customer did not want call back just wanted to have complaint on file. 7/9/2009
No Location Given	Customer feels should not be out for this long of time since went to underground. No one else on street is out.	No Resolution Documented.
Rathdrum, ID Rathdrum 231	Customer very unhappy power keeps going out in Rathdrum Area. Says she wants to take money off on what she pays due to lack of quality of service.	No Resolution Documented.
Harrison, ID Ogara 611	Customer called for estimated restoration on outage, thought was planned outage we decided to do early. Advised customer outage was unplanned and gave estimated restoration time. Customer said that we should not go ahead with planned outage since has been out of power since 1:30AM. Advised customer outage was not reported until 7:15AM. Believes Avista should have equipment that tells us of power outages.	Supervisor notified of comment. No action or callback required. 9/03/2009
Cataldo, ID Mission 431	Customer wasn't told about planned outage. Suggests notifying customers for planned outages.	No Resolution Documented.

Lincoln County WA Unknown Feeder	Customer was part of extended outages. Believes if Avista would have performed maintenance during summer that outages would not have occurred. Says maintenance should be priority over mgmt compensation.	No Resolution Documented.
No Location Information	Customer would like rebate on all the times service has been disrupted	No Resolution Documented.
Spokane Valley, WA Liberty Lake 12F2	Customer Complaint about rates, executive pay and repeated Power Outages.	No Resolution Documented.
Liberty Lake, WA Liberty Lake 12F3	Customer wanted us to change scheduled outage because of holiday and everyone home. Noted that next time to schedule for non-holiday and wanted frustrations noted.	Advised customer could not change outage time. No Resolution Documented.
Edwall, WA Reardan 12F2	Customer upset about scheduled outage and not personally notified.	Area Manager contacted customer 6/25/2009. No Resolution Documented.
Spokane, WA Millwood 12F2	Customer wants to know why clocks were flashing last night. Says this happens frequently	No outage reported in his area on 10/6/2009. Suggested to customer probably limbs on line, small animal etc. Customer not completely satisfied. No Resolution Documented.
Wilbur, WA Wilbur 12F2	1/15/09Customer not happy with the service. Power keeps going on and off steadily for the last 12 hours. 1/16/09 Customer upset he keeps getting same update when the service should be back up(1/17/09). States Avista should hire more crews to help in this outage.	No Resolution Documented.
Edwall, WA Reardan 12F2	Customer upset not notified about power outage.	No Resolution Documented.
Kettle Falls, WA Greenwood 12F1	Customer notified us that we shut off power to the trailer park while we changed transformer. Upset we did not notify them.	No Resolution Documented.
Kettle Falls, WA Spirit 12F1	Customer upset about planned outage. Knew about outage but Avista is late for turning power back on. Stated we need to work at night because of huge inconvenience.	No Resolution Documented.

Sustained Interruption Causes

Table 4.1 - % SAIFI per Cause by Office

The following table lists the percentage SAIFI contribution by causes for outages excluding major event days.

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	13.8%	2.2%	1.9%	2.5%	3.7%	4.6%	2.1%	2.1%	3.0%	21.1%	4.3%	9.3%
MISCELLANEOUS	0.2%	0.3%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.1%
POLE FIRE	9.8%	5.1%	0.6%	7.4%	7.1%	4.5%	10.0%	0.0%	0.9%	2.9%	0.8%	3.8%
WEATHER	3.4%	20.9%	80.6%	29.3%	26.6%	14.5%	31.4%	28.6%	22.2%	21.5%	22.0%	25.4%
UNDETERMINED	29.5%	9.5%	2.6%	18.9%	4.0%	25.2%	5.4%	29.5%	31.8%	10.5%	29.5%	16.8%
TREE	5.4%	11.4%	2.3%	7.8%	31.8%	11.4%	1.0%	12.4%	16.7%	7.1%	14.6%	10.2%
PUBLIC	17.9%	1.6%	0.4%	1.0%	0.2%	1.0%	1.7%	5.2%	6.2%	10.5%	14.1%	6.6%
COMPANY	0.0%	6.3%	0.0%	0.0%	5.2%	13.5%	0.0%	4.8%	7.4%	5.4%	0.0%	4.5%
EQUIPMENT OH	18.7%	5.8%	6.0%	4.9%	12.7%	23.1%	41.3%	6.6%	7.6%	9.3%	8.1%	9.7%
EQUIPMENT UG	0.4%	0.8%	0.2%	2.5%	0.3%	0.6%	0.1%	1.1%	1.0%	0.9%	1.8%	0.9%
EQUIPMENT SUB	0.0%	0.0%	0.0%	1.8%	0.0%	0.0%	0.0%	0.0%	0.0%	8.8%	0.0%	2.9%
PLANNED	0.9%	36.0%	5.3%	23.9%	8.4%	1.5%	7.0%	9.5%	3.0%	2.1%	4.8%	9.7%

CDC	Coeur d'Alene
COC	Colville
DAC	Davenport
DPC	Deer Park
GRC	Grangeville
KEC	Kellogg/ St. Maries
LCC	Lewiston-Clarkston
OTC	Othello
PAC	Palouse
SAC	Sandpoint
SPC	Spokane

Chart 4.1 – % SAIFI per Cause by Office

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.

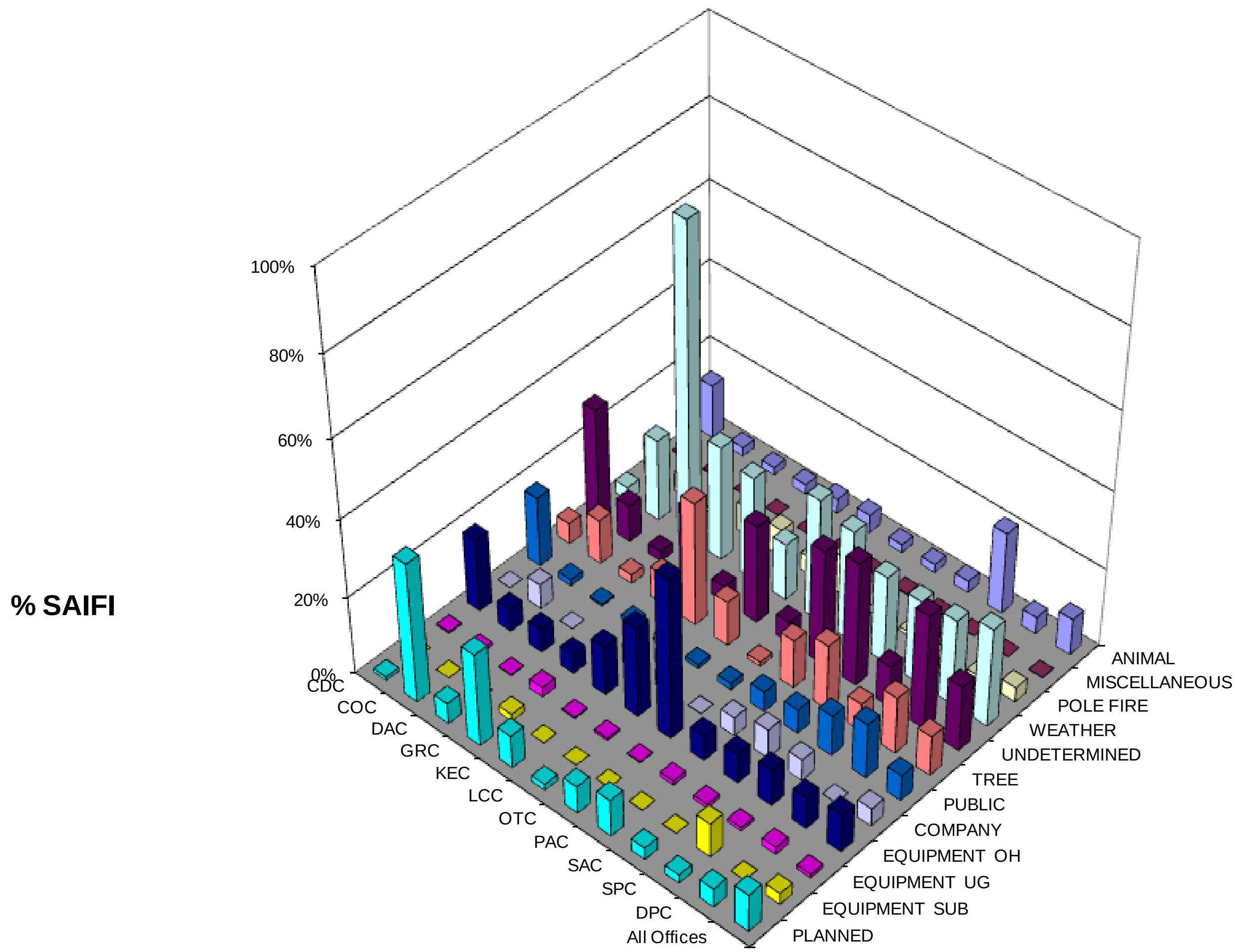


Table 4.2 - % SAIDI per Cause by Office

The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

Reason	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	6.8%	1.1%	3.2%	2.2%	4.9%	5.2%	2.8%	2.8%	5.8%	17.5%	3.8%	6.1%
MISCELLANEOUS	0.3%	0.1%	0.0%	0.0%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.1%
POLE FIRE	23.2%	6.1%	0.5%	8.6%	4.4%	4.9%	14.9%	0.0%	1.2%	3.7%	0.8%	5.4%
WEATHER	2.5%	19.8%	79.1%	46.2%	13.8%	29.0%	21.9%	33.5%	40.9%	26.7%	24.9%	32.4%
UNDETERMINED	17.8%	3.7%	1.8%	6.5%	2.6%	24.5%	7.7%	15.4%	10.1%	6.2%	22.8%	7.6%
TREE	12.3%	19.1%	3.7%	6.0%	55.2%	8.4%	1.1%	18.2%	21.2%	7.7%	15.7%	14.4%
PUBLIC	16.4%	1.7%	0.3%	0.3%	0.2%	1.8%	1.6%	6.3%	6.1%	10.7%	18.4%	5.0%
COMPANY	0.0%	0.5%	0.0%	0.0%	0.3%	1.0%	0.0%	1.6%	2.4%	1.3%	0.0%	0.7%
EQUIPMENT OH	19.2%	3.6%	3.5%	2.7%	10.5%	21.4%	45.7%	10.4%	7.1%	12.3%	9.1%	8.6%
EQUIPMENT UG	1.2%	1.1%	0.5%	1.3%	0.5%	2.3%	0.5%	3.8%	3.0%	2.2%	3.2%	1.7%
EQUIPMENT SUB	0.0%	0.0%	0.0%	3.6%	0.0%	0.0%	0.0%	0.0%	0.0%	10.1%	0.0%	2.7%
PLANNED	0.4%	43.1%	7.4%	22.6%	7.6%	1.5%	3.7%	7.7%	2.2%	1.6%	1.3%	15.4%

CDC	Coeur d'Alene	LCC	Lewiston-Clarkston
COC	Colville	OTC	Othello
DAC	Davenport	PAC	Palouse
DPC	Deer Park	SAC	Sandpoint
GRC	Grangeville	SPC	Spokane
KEC	Kellogg/ St. Maries		

Chart 4.2 – % SAIDI per Cause by Office

The following chart shows the percentage SAIDI contribution by causes for outages excluding major event days.

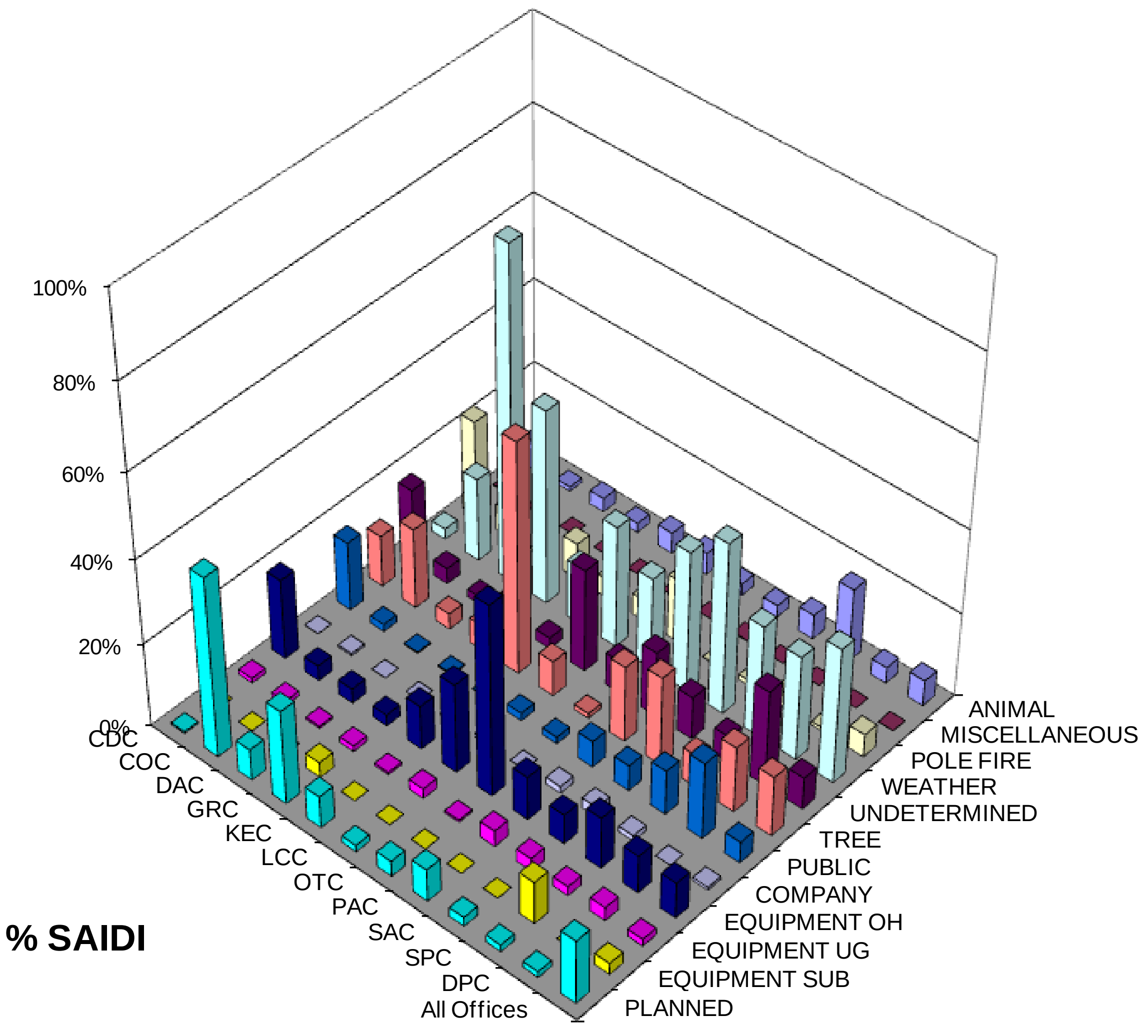


Table 4.3 - % SAIFI per Cause by Month

The following table lists the percentage SAIFI contribution by causes for all outages, excluding major event days.

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	0.5%	1.5%	0.4%	5.7%	4.5%	19.9%	11.3%	31.1%	12.1%	3.0%	4.7%	0.5%	9.3%
MISCELLANEOUS	0.0%	0.1%	0.0%	0.0%	0.5%	0.0%	0.0%	0.0%	0.2%	0.0%	0.0%	0.7%	0.1%
POLE FIRE	2.4%	0.3%	0.7%	5.6%	8.6%	0.3%	7.7%	5.1%	2.2%	1.4%	0.7%	19.2%	3.8%
WEATHER	63.4%	50.7%	36.9%	15.7%	8.2%	18.2%	11.1%	10.8%	12.7%	24.2%	7.4%	5.2%	25.4%
UNDETERMINED	13.0%	14.1%	25.3%	6.2%	15.6%	2.3%	34.0%	21.1%	24.5%	13.4%	13.6%	11.2%	16.8%
TREE	10.2%	3.1%	13.1%	6.0%	13.1%	6.8%	8.3%	5.0%	5.3%	25.3%	14.8%	11.7%	10.2%
PUBLIC	0.4%	9.1%	5.9%	30.9%	14.5%	10.3%	4.2%	9.1%	3.6%	2.2%	9.3%	3.2%	6.6%
COMPANY	0.7%	0.0%	0.3%	0.0%	6.0%	3.1%	11.0%	7.6%	0.9%	4.6%	23.0%	3.2%	4.5%
EQUIPMENT OH	6.4%	17.8%	9.0%	14.6%	3.8%	10.3%	6.9%	4.3%	12.2%	9.5%	8.1%	31.8%	9.7%
EQUIPMENT UG	0.6%	0.7%	0.8%	1.6%	1.1%	0.6%	0.9%	1.6%	2.5%	0.2%	0.8%	0.3%	0.9%
EQUIPMENT SUB	0.0%	0.0%	0.3%	0.0%	2.1%	15.8%	0.0%	0.0%	6.2%	1.2%	0.0%	0.0%	2.9%
PLANNED	2.5%	2.5%	7.3%	13.7%	22.0%	12.5%	4.6%	4.3%	17.6%	15.1%	17.7%	13.0%	9.7%

Chart 4.3 – % SAIFI per Cause by Month

The following chart shows the percentage SAIFI contribution by causes for all outages, excluding major event days.

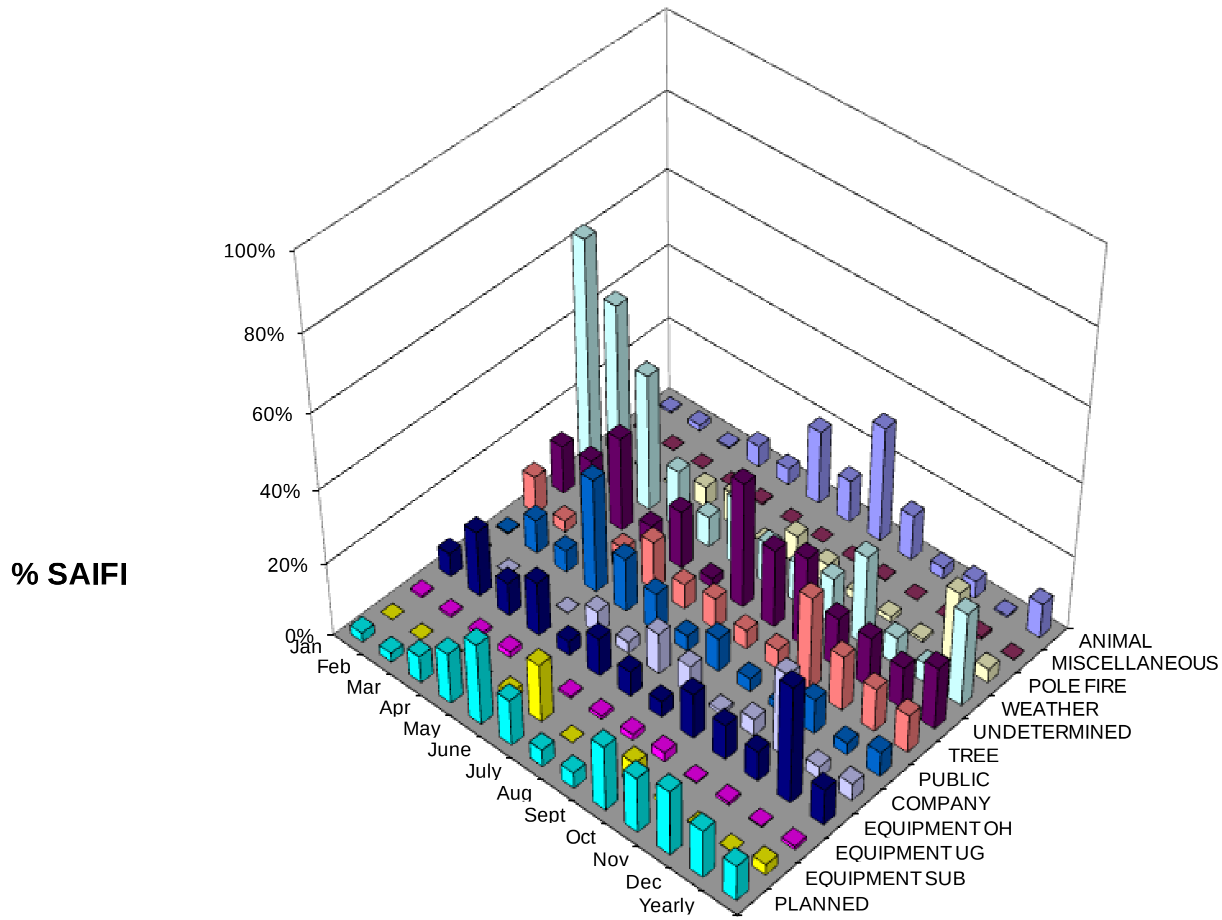


Table 4.4 - % SAIDI per Cause by Month

The following table lists the percentage SAIDI contribution by causes for outages excluding major event days.

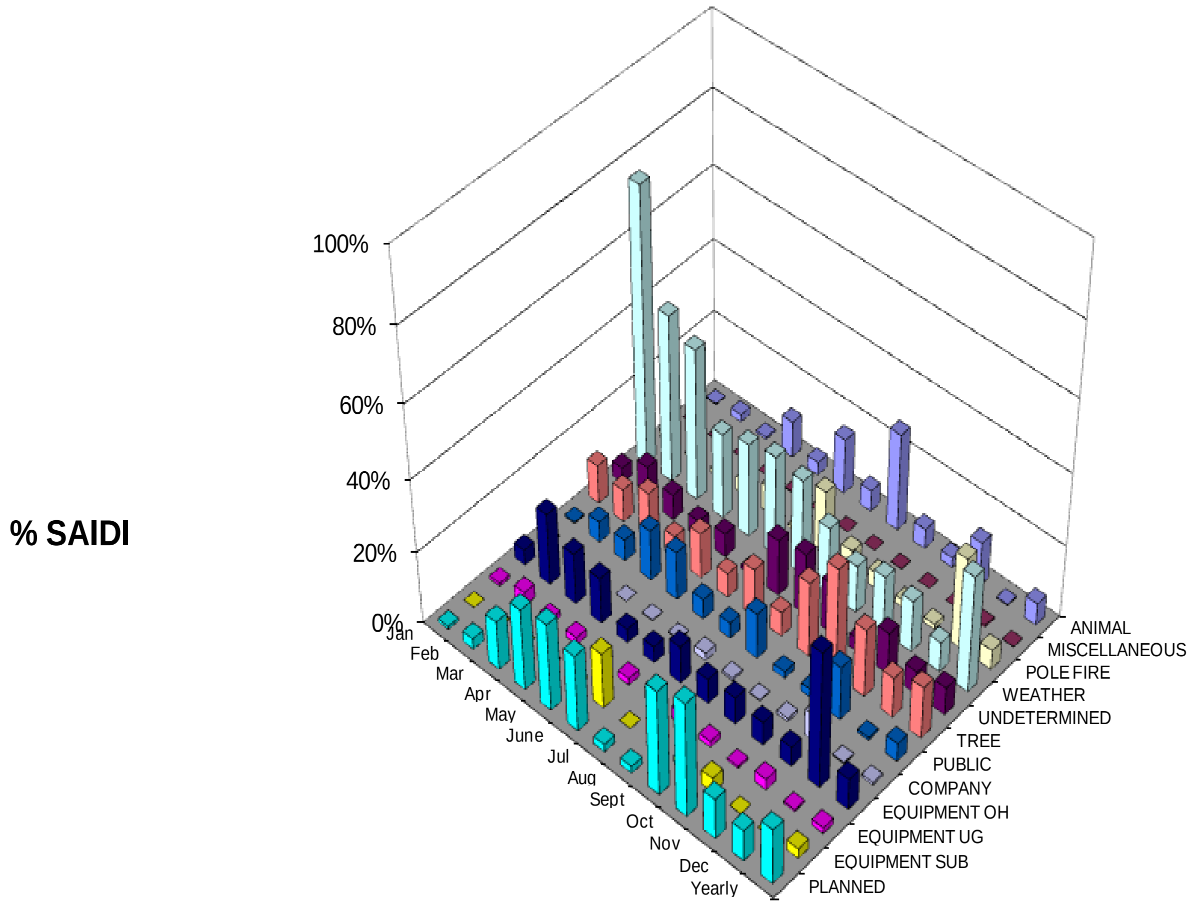
REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	0.3%	2.0%	0.6%	10.0%	3.6%	15.2%	5.8%	26.9%	5.5%	2.7%	12.4%	0.3%	6.1%
MISCELLANEOUS	0.0%	0.2%	0.0%	0.0%	0.2%	0.0%	0.0%	0.0%	0.1%	0.0%	0.0%	0.5%	0.1%
POLE FIRE	2.4%	0.7%	1.4%	4.1%	7.4%	0.8%	17.2%	5.8%	4.4%	2.0%	1.4%	25.6%	5.4%
WEATHER	76.0%	46.2%	41.9%	23.5%	25.8%	27.6%	26.3%	18.3%	13.1%	15.5%	14.3%	8.2%	32.4%
UNDETERMINED	4.2%	9.6%	7.0%	4.8%	6.5%	1.2%	15.5%	17.0%	14.0%	3.7%	11.5%	6.4%	7.6%
TREE	10.7%	9.0%	13.3%	6.3%	12.6%	6.7%	13.3%	6.7%	20.7%	30.2%	18.8%	11.1%	14.4%
PUBLIC	0.3%	5.8%	5.9%	14.0%	13.3%	5.5%	4.4%	12.6%	1.8%	2.3%	14.8%	0.7%	5.0%
COMPANY	0.1%	0.0%	0.5%	0.0%	0.2%	0.3%	2.0%	0.7%	0.2%	0.9%	7.2%	0.3%	0.7%
EQUIPMENT OH	4.3%	19.8%	14.1%	12.7%	3.8%	4.5%	10.3%	6.8%	7.4%	6.4%	5.4%	37.7%	8.6%
EQUIPMENT UG	0.8%	3.7%	1.6%	2.0%	1.5%	1.8%	3.2%	3.3%	1.6%	0.6%	3.0%	0.5%	1.7%
EQUIPMENT SUB	0.0%	0.0%	0.1%	0.0%	0.9%	15.3%	0.0%	0.0%	2.1%	4.0%	0.0%	0.0%	2.7%
PLANNED	0.9%	2.9%	13.6%	22.6%	24.2%	21.2%	2.0%	1.9%	29.1%	31.7%	11.2%	8.6%	15.4%

Table 4.4.1 Ave Outage Time (HH:MM)

Reason	Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	1:32	1:22	2:05	5:08	2:40	1:26	0:49	1:01	1:28	2:23	3:50	1:18	1:22
COMPANY	0:29	1:50	2:18	1:51	0:06	0:12	0:17	0:06	0:46	0:30	0:27	0:12	0:18
EQUIPMENT OH	1:46	1:10	2:19	2:32	3:19	0:49	2:24	1:54	1:59	1:47	0:57	2:39	1:51
EQUIPMENT SUB	1:52	0:00	0:21	0:00	1:24	1:49	0:00	0:00	1:06	8:41	0:00	0:00	1:58
EQUIPMENT UG	3:57	5:57	2:57	3:43	4:32	5:45	5:28	2:25	2:05	6:49	5:48	4:04	3:46
MISCELLANEOUS	1:29	1:52	2:23	0:13	1:46	0:00	0:00	0:00	1:38	3:41	0:00	1:32	1:40
PLANNED	0:55	1:12	2:47	4:48	3:40	3:12	0:42	0:31	5:24	5:32	0:55	1:29	3:21
POLE FIRE	2:37	2:29	3:09	2:08	2:53	4:12	3:37	1:21	6:27	3:44	2:47	2:59	3:02
PUBLIC	2:18	0:39	1:29	1:19	3:03	1:00	1:41	1:39	1:39	2:46	2:17	0:30	1:37
TREE	2:48	3:03	1:31	3:04	3:12	1:51	2:35	1:35	12:44	3:09	1:50	2:07	2:57
UNDETERMINED	0:51	0:43	0:24	2:16	1:23	0:56	0:44	0:57	1:52	0:43	1:13	1:17	0:57
WEATHER	3:12	0:57	1:41	4:21	10:28	2:51	3:48	2:01	3:22	1:41	2:48	3:34	2:41

Chart 4.4 – % SAIDI per Cause by Month

The following chart shows the percentage SAIFI contribution by causes for outages excluding major event days.



Momentary Interruption Causes

The cause for many momentary interruptions is unknown. Because faults are temporary, the cause goes unnoticed even after the line is patrolled. Momentary outages are recorded using our SCADA system (System Control and Data Acquisition). On average, about 88% of Avista's customers are served from SCADA controlled stations.

Table 5.1 - % MAIFI per Cause by Office

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	CDC	COC	DAC	GRC	KEC	LCC	OTC	PAC	SAC	SPC	DPC	All Offices
ANIMAL	0.0%	0.0%	0.0%	0.0%	0.0%	2.5%	0.0%	0.1%	1.8%	3.1%	0.0%	1.2%
POLE FIRE	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	6.1%	0.0%	0.0%	0.9%	0.0%	0.3%
WEATHER	13.5%	3.4%	7.8%	35.1%	21.4%	9.6%	5.9%	11.7%	16.9%	19.9%	0.0%	15.9%
TREE	0.0%	0.0%	1.3%	0.5%	0.0%	0.0%	6.9%	0.0%	1.1%	0.0%	0.0%	0.3%
PUBLIC	1.7%	2.6%	0.0%	0.0%	0.0%	1.4%	0.0%	0.6%	1.2%	0.6%	0.0%	0.9%
COMPANY	1.5%	0.0%	0.0%	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.7%	0.0%	0.5%
WEATHER	1.2%	1.8%	0.0%	4.5%	3.0%	1.1%	0.0%	0.0%	1.2%	1.1%	0.0%	1.3%
UNDETERMINED	79.8%	81.0%	90.8%	56.6%	75.6%	82.9%	74.2%	84.7%	75.3%	64.6%	0.0%	75.0%
EQUIPMENT UG	1.3%	0.0%	0.0%	0.0%	0.0%	0.3%	0.0%	0.0%	0.9%	0.0%	0.0%	0.3%
EQUIPMENT OH	1.0%	3.4%	0.0%	0.0%	0.0%	1.1%	6.9%	2.5%	0.9%	5.5%	0.0%	2.5%
PLANNED	0.0%	7.8%	0.0%	2.1%	0.0%	0.0%	0.0%	0.4%	0.9%	2.0%	0.0%	1.3%
EQUIPMENT SUB	0.0%	0.0%	0.0%	1.1%	0.0%	0.0%	0.0%	0.0%	0.0%	1.4%	0.0%	0.4%

CDC	Coeur d'Alene
COC	Colville
DAC	Davenport
DPC	Deer Park
GRC	Grangeville
KEC	Kellogg/ St. Maries
LCC	Lewiston-Clarkston
OTC	Othello
PAC	Palouse
SAC	Sandpoint
SPC	Spokane

Table 5.1.1 - % MAIFI per Cause by Office (Washington only)

The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	COC	DAC	OTC	SPC	DPC	PAC-WA	LCC-WA	All WA Offices
ANIMAL	2.25%	1.92%	2.05%	21.07%	4.30%	1.34%	11.31%	11.85%
COMPANY	6.27%	0.00%	0.02%	5.42%	0.00%	0.00%	0.00%	3.97%
MISCELLANEOUS	0.33%	0.00%	0.00%	0.01%	0.00%	0.00%	0.00%	0.07%
POLE FIRE	5.10%	0.64%	10.04%	2.89%	0.80%	0.00%	12.78%	2.97%
PUBLIC	1.60%	0.43%	1.69%	10.46%	14.10%	2.21%	0.13%	6.56%
TREE	11.42%	2.32%	1.04%	7.09%	14.55%	5.68%	34.65%	8.02%
UNDETERMINED	9.48%	2.61%	5.42%	10.53%	29.51%	40.85%	9.31%	13.80%
WEATHER	20.92%	80.59%	31.37%	21.47%	22.03%	36.90%	3.90%	29.06%
EQUIPMENT OH	5.84%	6.04%	41.25%	9.30%	8.12%	6.37%	24.59%	8.71%
EQUIPMENT UG	0.77%	0.18%	0.14%	0.86%	1.81%	1.04%	0.37%	0.82%
EQUIPMENT SUB	0.00%	0.00%	0.00%	8.76%	0.00%	0.01%	0.00%	4.42%
PLANNED	36.03%	5.27%	6.98%	2.13%	4.79%	5.59%	2.96%	9.76%

COC	Colville	OTC	Othello
DAC	Davenport	PAC-WA	Palouse Washington
DPC	Deer Park	SPC	Spokane
LCC-WA	Lewiston-Clarkston Washington		

Chart 5.1 – % MAIFI per Cause by Office

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.

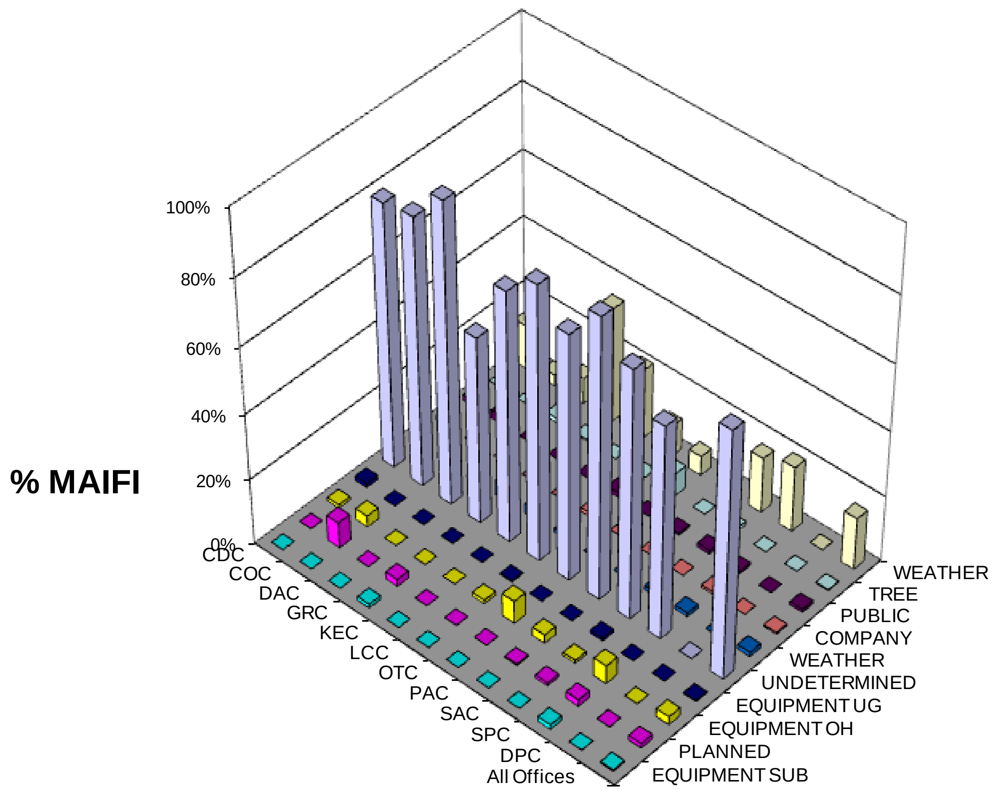


Table 5.2 - % MAIFI per Cause by Month

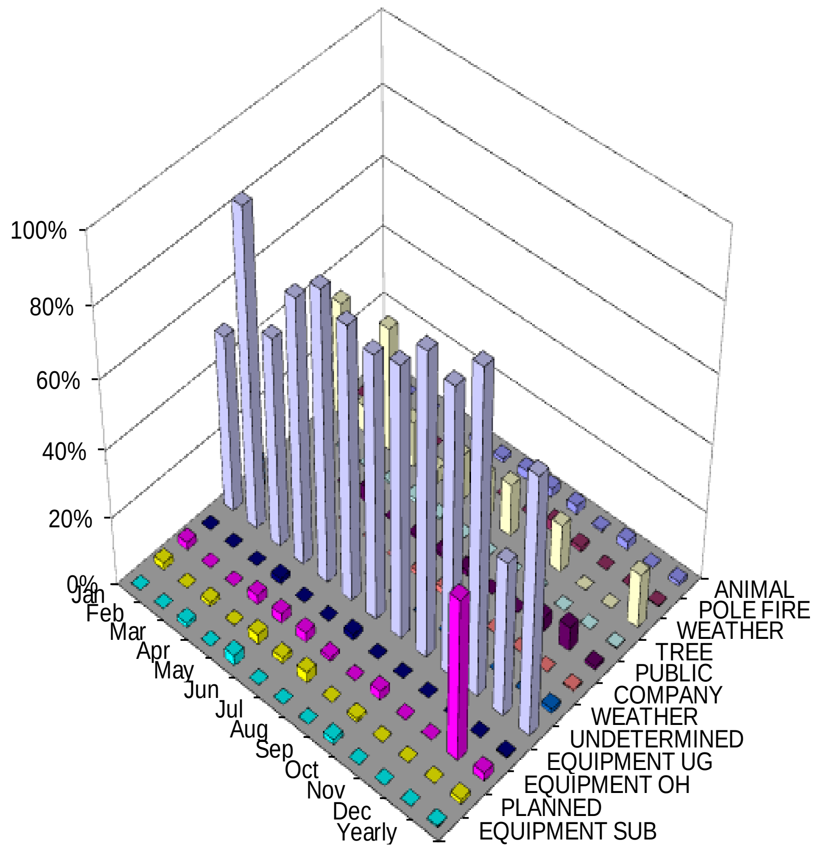
The following table lists the percentage MAIFI contribution by causes for outages excluding major event days.

REASON	Jan	Feb	Mar	Apr	May	June	Jul	Aug	Sept	Oct	Nov	Dec	Yearly
ANIMAL	0.0%	0.0%	0.0%	0.0%	1.6%	1.2%	2.6%	2.5%	2.6%	0.6%	2.5%	0.0%	1.2%
POLE FIRE	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	3.1%	1.3%	0.0%	0.0%	0.3%
WEATHER	34.3%	7.9%	36.5%	13.6%	4.4%	13.6%	13.0%	15.5%	0.0%	14.1%	0.0%	0.0%	15.9%
TREE	0.0%	0.0%	0.0%	0.6%	1.1%	0.7%	0.0%	0.0%	0.0%	0.8%	0.0%	0.0%	0.3%
PUBLIC	0.0%	0.0%	0.0%	4.5%	0.0%	0.7%	0.8%	1.5%	0.0%	0.0%	4.2%	7.1%	0.9%
COMPANY	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%	1.9%	1.9%	0.0%	0.0%	0.0%	0.5%
WEATHER	9.8%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	1.3%
UNDETERMINED	51.6%	92.1%	61.0%	77.0%	84.2%	79.4%	76.4%	78.6%	87.4%	83.2%	93.3%	45.3%	75.0%
EQUIPMENT UG	0.0%	0.0%	0.0%	1.6%	0.0%	0.0%	1.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.3%
EQUIPMENT OH	2.2%	0.0%	0.0%	2.8%	2.8%	2.8%	1.0%	0.0%	2.6%	0.0%	0.0%	47.6%	2.5%
PLANNED	2.1%	0.0%	1.3%	0.0%	2.9%	1.6%	3.1%	0.0%	0.9%	0.0%	0.0%	0.0%	1.3%
EQUIPMENT SUB	0.0%	0.0%	1.3%	0.0%	3.0%	0.0%	0.0%	0.0%	1.5%	0.0%	0.0%	0.0%	0.4%

Chart 5.2 – % MAIFI per Cause by Month

The following chart shows the percentage MAIFI contribution by causes for outages excluding major event days.

% MAIFI



Major Event Day Causes

Chart 6.1 – % SAIFI by Cause Code for the Major Event Days

The following chart shows the percentage SAIFI contribution by causes for outages during major event days

No Major events in 2009

Table 6.1 – % SAIFI by Sub Cause Code for the Major Event Days

The following table shows the SAIFI contribution and Customer hours by sub causes code for the three main outage causes during major event days.

Cause Code	Sub reason	Sum of Ni	Sum of ri x Ni (hours)
POLE FIRE	Pole Fire		
Total			
		No MED in 2009	
TREE	Tree Fell		
	Weather		
Total			
WEATHER	Snow/Ice		
	Lightning		
	Wind		
Total			

Table 6.2 – Yearly Summary of the Major Event Days

Table 6.2 is provided as an initial review of Major Event Day information. The main premise of the IEEE Major Event Day calculation is that using the 2.5bmethod should classify 2.3 days each year as MED's.
The following table shows the previous major event days, the daily SAIDI value and the relationship of the yearly T_{MED}.

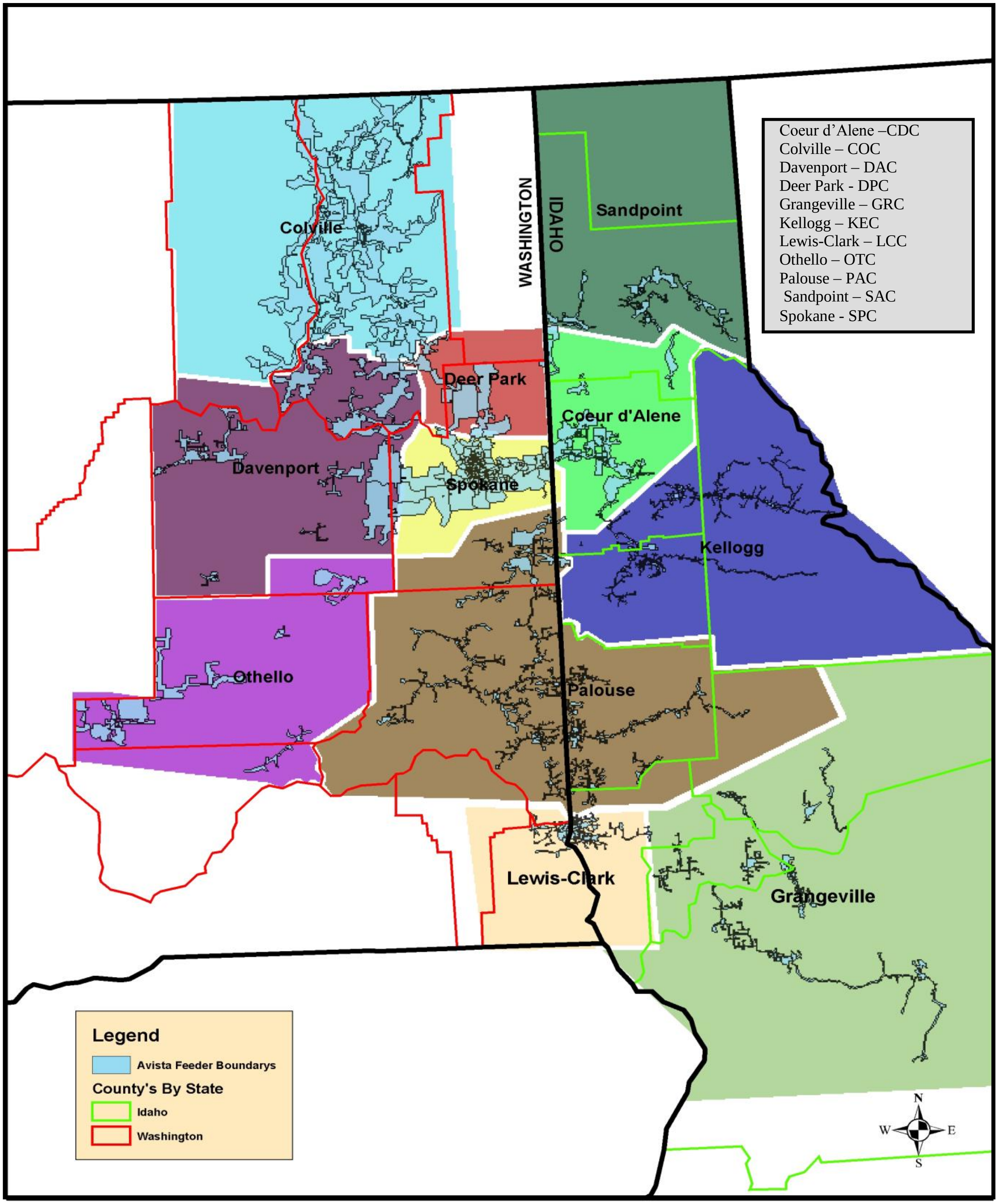
Year	Date	SAIDI	T_{MED}
2003	01-03-2003	5.38	4.96
	05-24-2003	5.11	
	09-08-2003	5.47	
	10-16-2003	6.62	
	10-28-2003	9.25	
	11-19-2003	57.06	
2004	05-21-2004	7.11	6.35
	08-02-2004	7.36	
	12-08-2004	31.00	
2005	06-21-2005	39.53	4.916
	06-22-2005	9.03	
	08-12-2005	19.60	
2006	01-11-2006	12.10	7.058
	03-09-2006	8.58	
	11-13-2006	30.79	
	12-14-2006	29.26	
	12-15-2006	158.31	
2007	01-06-2007	9.98	8.017
	06-29-2007	32.64	
	07-13-2007	12.79	
	08-31-2007	21.30	
2008	01-27-2008	17.57	9.224
	07-10-2008	36.74	
	08-18-2008	9.49	
2009	None		9.925
2010			11.110

Interruption Cause Codes

MAIN CATEGORY	Proposed (Changes Only)	SUB CATEGORY	Proposed (Changes Only)	Definition
ANIMAL		Bird		Outages caused by animal contacts. Specific animal called out in sub category.
		Protected		
		Squirrel		
		Underground		
		Other		
PUBLIC		Car Hit Pad		Underground outage due to car, truck, construction equipment etc. contact with pad transformer, junction enclosure etc..
		Car Hit Pole		Overhead outage due to car, truck, construction equipment etc. contact with pole, guy, neutral etc.
		Dig In		Dig in by a customer, a customer's contractor, or another utility.
		Fire		Outages caused by or required for a house/structure or field/forest fire.
		Tree		Homeowner, tree service, logger etc. fells a tree into the line.
		Other		Other public caused outages
COMPANY		Dig in		Dig in by company or contract crew.
		Other		Other company caused outages
EQUIPMENT OH		Arrestors		Outages caused by equipment failure. Specific equipment called out in sub category.
		Capacitor		
		Conductor - Pri		
		Conductor - Sec		
		Connector - Pri		
		Connector - Sec		
		Crossarm- rotten		
		Cutout / Fuse		
		Insulator		
		Insulator Pin		
		Other		
		Pole - Rotten		
		Recloser		
		Regulator		
		Switch / Disconnect		
		Transformer - OH		
		Wildlife Guard		Wildlife guard failed or caused an outage
EQUIPMENT UG		URD Cable - Pri		Outages caused by equipment failure. Specific equipment called out in sub category.
		URD Cable- Sec		
		Connector - Sec		
		Elbow		
		Junctions		
		Primary Splice		
		Termination		
		Transformer - UG		
		Other		

MAIN CATEGORY	Proposed (Changes Only)	SUB CATEGORY	Proposed (Changes Only)	Definition
EQUIPMENT SUB		High side fuse Bus Insulator High side PCB High side Swt / Disc Low side OCB/Recloser Low side Swt / Disc Relay Misoperation Regulator Transformer Other		
MISCELLANEOUS		SEE REMARKS		For causes not specifically listed elsewhere
NOT OUR PROBLEM (*Outages in this category are not included in reported statistics*)		Customer Equipment SEE REMARKS		Customer equipment causing an outage to their service. If a customer causes an outage to another customer this is covered under Public.
		Other Utility		Outages when another utility's facilities cause an outage on our system.
POLE FIRE				Used when water and contamination causes insulator leakage current and fire. If insulator is leaking due to material failure list under equipment failure. If cracked due to gunfire use customer caused other.
PLANNED		Maintenance / Upgrade		Outage, normally prearranged, needed for normal construction work
		Forced		Outage scheduled to repair outage damage
TREE		Tree fell		For outages when a tree falls into distribution primary/secondary or transmission during normal weather
		Tree growth		Tree growth causes a tree to contact distribution primary/secondary or transmission during normal weather.
		Service		For outages when a tree falls or grows into a service.
		Weather		When snow and wind storms causes a tree or branch to fall into, or contact the line. Includes snow loading and unloading.
UNDETERMINED				Use when the cause cannot be determined
WEATHER		Snow / Ice		Outages caused by snow or ice loading or unloading on a structure or conductor. Use weather tree for snow and ice loading on a tree.
		Lightning		Lightning flashovers without equipment damage. Equipment failures reported under the equipment type.
		Wind		Outages when wind causes conductors to blow into each other, another structure, building etc. (WEATHER/TREE) used for tree contacts.

Office Areas



Indices Calculations

Sustained Interruption

- An interruption lasting longer than 5 minutes.

Momentary Interruption Event

- An interruption lasting 5 minutes or less. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an interrupting device operates two, three, or four times and then holds, it is considered a single event.

SAIFI – System Average Interruption Frequency Index

- The average number of sustained interruptions per customer
- = The number of customers which had ***sustained interruptions*** / Total number of customers served
- = $\frac{\sum N_i}{N_T}$

MAIFI_E – Momentary Average Interruption Event Frequency Index

- The average number of momentary interruption events per customer
- = The number of customers which had ***momentary interruption events*** / Total number of customers served
- = $\frac{\sum ID_E N_i}{N_T}$
- MAIFI can be calculated by one of two methods. Using the number of momentary interruptions or the number momentary events. This report calculates MAIFI_E using momentary events. The event includes all momentary interruptions occurring within 5 minutes of the first interruption. For example, when an automatic interrupting device opens and then recloses two, or three times before it remains closed, it is considered a single event.

SAIDI – System Average Interruption Duration Index

- Average sustained outage time per customer
- = Outage duration multiplied by the customers effected for all ***sustained interruptions*** / Total number of customers served
- = $\frac{\sum r_i N_i}{N_T}$

CAIDI – Customer Average Interruption Duration Index

- Average restoration time
- = $\dfrac{\text{Outage duration multiplied by the customers effected for all } \textbf{\textit{sustained interruptions}}}{\text{The number of customers which had } \textbf{\textit{sustained interruptions}}}$
- = $\dfrac{\sum r_i N_i}{\sum N_i}$

Quantities
i = An interruption event;
r_i = Restoration time for each interruption event;
T = Total;
ID_E = Number of interrupting device events;
N_i = Number of interrupted customers for each interruption event during the reporting period;
N_T = Total number of customers served for the area being indexed;

CEMI$_n$ – Customers Experiencing Multiple Sustained Interruptions more than n.

- CEMI$_n$
- = $\dfrac{\text{Total Number of Customers that experience more than } n \textbf{ sustained interruptions}}{\text{Total Number of Customers Served}}$
- = $\dfrac{CN_{(k>n)}}{N_T}$

CEMSMI$_n$ – Customers experiencing multiple sustained interruption and momentary interruption events.

- CEMSMIn
- = $\dfrac{\text{Total Number of Customers experiencing more than } n \textbf{ interruptions}}{\text{Total Number of Customers Served}}$
- = $\dfrac{CNT_{(k>n)}}{N_T}$

MED - Major Event Day

A major event day is a day in which the daily system SAIDI exceeds a threshold value. Its purpose is to allow major events to be studied separately from daily operation, and in the process, to better reveal trends in daily operation that would be hidden by the large statistical effect of major events.

T_{MED} is calculated (taken from the IEEE 1366-2003 Standard)
The major event day identification threshold value, T_{MED}, is calculated at the end of each reporting period (typically one year) for use during the next reporting period as follows:

a) Collect values of daily SAIDI for five sequential years ending on the last day of the last complete reporting period. If fewer than five years of historical data are available, use all available historical data until five years of historical data are available.
b) Only those days that have a SAIDI/Day value will be used to calculate the T_{MED} (do not include days that did not have any interruptions).
c) Take the natural logarithm (ln) of each daily SAIDI value in the data set.
d) Find α (Alpha), the average of the logarithms (also known as the log-average) of the data set.
e) Find β (Beta), the standard deviation of the logarithms (also known as the log-standard deviation) of the data set.
f) Compute the major event day threshold, TMED, using equation (25).

$$T_{MED} = e^{(\alpha + 2.5\beta)} \qquad (25)$$

g) Any day with daily SAIDI greater than the threshold value TMED that occurs during the subsequent reporting period is classified as a major event day. Activities that occur on days classified as major event days should be separately analyzed and reported.

Numbers of Customers Served

The following numbers of customers were based on the customers served at the beginning of the year. These numbers were used to calculate indices for this report.

Office	Customers	% of Total
Coeur d'Alene	49531	13.8%
Colville	17906	5.0%
Davenport	6852	1.9%
Deer Park	10419	2.9%
Grangeville	10119	2.8%
Kellogg/St. Maries	14178	4.0%
Lewis-Clark	29055	8.1%
Othello	6672	1.9%
Palouse	38208	10.6%
Sandpoint	14422	4.0%
Spokane	161401	45.0%
System Total	**358763**	

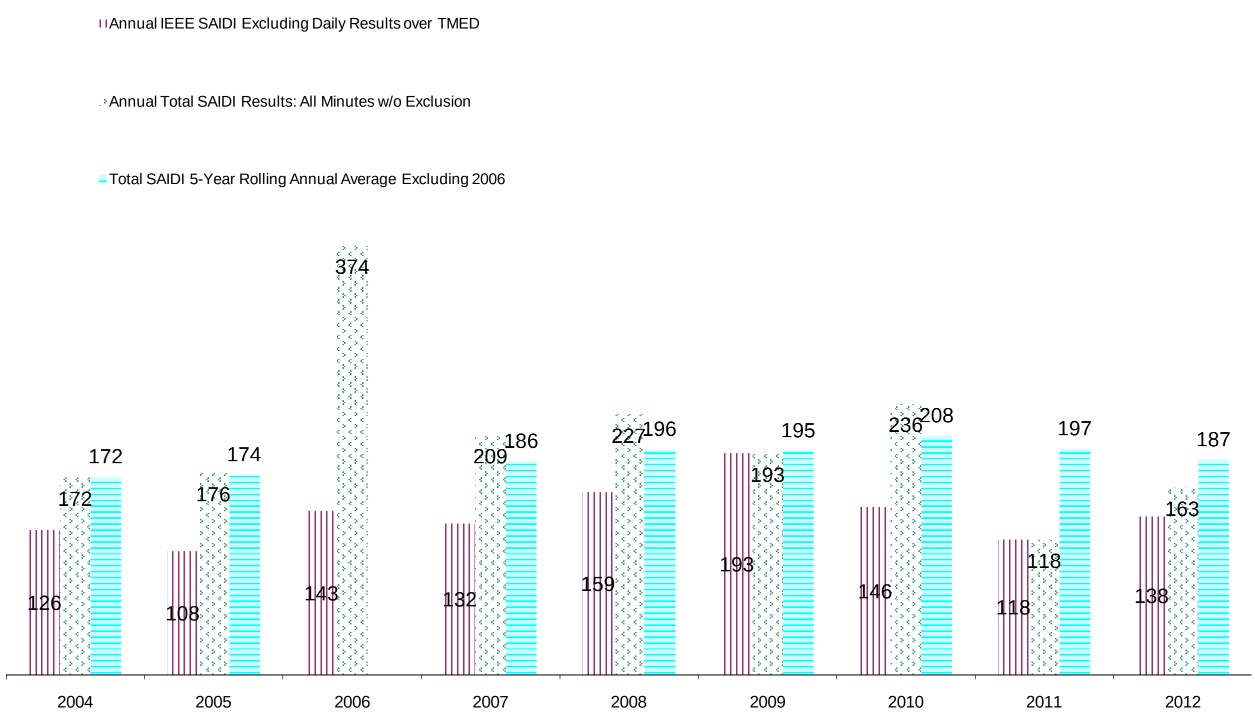
2004-2012 AVA SAIDI Performance in Different Measurements
(Average number of outage minutes per customer per year)

As of December 31, 2012

Table 1: 2004-2012 AVA SAIDI Performance by Measurement by Year

Year	Calendar Year	Annual IEEE SAIDI Excluding Daily Results over T_{MED}	Annual Total SAIDI Results: All Minutes w/o Exclusion	Annual Total SAIDI Results Excluding 2006	Total SAIDI 5-Year Rolling Annual Average Excluding 2006	
1	2004	126	172	172	172	
2	2005	108	176	176	174	Baseline
3	2006	143	374			
4	2007	132	209	209	186	
5	2008	159	227	227	196	
6	2009	193	193	193	195	
7	2010	146	236	236	208	
8	2011	118	118	118	197	
9	2012	138	163	163	187	
		171				Target

Chart 1: 2004-2012 AVA SAIDI Performance in Different Measurements by Year



2004 - 2012 AVA SAIFI Performance in Different Measurements
(Average number of interruptions per year per customer)

As of December 31, 2012

Table 1: 2004 - 2012 AVA SAIFI Performance by Measurement by Year

Year	Calendar Year	Annual IEEE SAIFI Excluding Daily Results over TMED	Annual Total SAIFI Results: All Minutes w/o Exclusion	Annual Total SAIFI Results Excluding 2006	Total SAIFI 5-Year Rolling Annual Average Excluding 2006	
1	2004	1.01	1.13	1.13	1.13	
2	2005	0.97	1.17	1.17	1.15	Baseline
3	2006	1.29	1.91			
4	2007	1.14	1.40	1.40	1.23	
5	2008	1.40	1.60	1.60	1.33	
6	2009	1.52	1.52	1.52	1.36	
7	2010	1.23	1.49	1.49	1.44	
8	2011	1.08	1.08	1.08	1.42	
9	2012	1.14	1.25	1.25	1.39	
		1.41				Target

Chart 1: 2004-2012 AVA SAIFI Performance in Different Measurements by Year

Baltimore Gas and Electric Company
COMAR 20.50.07.06 Reporting of Reliability Indices – CY 2005

(1) System-Wide Indices. A utility shall report SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

SAIFI – 1.56
SAIDI – 4.02
CAIDI – 2.57

Note: System-Wide Indices are calculated using IEEE Std. 1366-1998.

(b) All interruption data minus major event interruption data.

SAIFI – 1.56
SAIDI – 4.02
CAIDI – 2.57

BGE experienced no Major events in CY 2005.

(2) District Indices. A cooperatively-owned utility shall provide SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

(b) Major event interruption data excluded.

Requirements (a) & (b) are not applicable to BGE since BGE is an Investor Owned Utility.

(3) Feeder Indices. An investor-owned utility shall provide SAIDI, SAIFI, and CAIDI for 2% of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability. The indices shall be calculated and reported with 2 sets of input data.

(a) All interruption data;

13.8 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
7348	*LIPINS CORNER*	*8.06*	*10.04*	*13.89*	*1.38*
7711	*MEADOWS*	*6.82*	*8.31*	*8.33*	*1.00*
7107	*MOUNT WASHINGTON*	*6.46*	*7.79*	*14.00*	*1.80*
7015	*BROOKHILL*	*6.14*	*7.11*	*16.56*	*2.33*
8056	*WAKEFIELD*	*6.01*	*7.39*	*16.05*	*2.17*
7873	*HIGHLANDTOWN*	*5.43*	*5.69*	*10.57*	*1.86*
8474	*CROWNSVILLE*	*5.31*	*5.83*	*27.17*	*4.66*
7870	*HIGHLANDTOWN*	*4.85*	*6.42*	*10.39*	*1.62*
7420	*LEVITT*	*4.23*	*5.03*	*13.16*	*2.62*
7053	*VAN BIBBER*	*4.22*	*5.18*	*7.34*	*1.42*
7240	*FINKSBURG*	*4.16*	*4.71*	*20.50*	*4.35*
7838	*GREENE STREET*	*4.13*	*5.04*	*7.38*	*1.46*
7440	*MITCHELLVILLE*	*4.10*	*4.96*	*12.52*	*2.52*
8362	*BAY HILLS*	*4.08*	*4.77*	*18.50*	*3.88*
7845	*GREENE STREET*	*4.05*	*4.78*	*11.76*	*2.46*
7411	*GREENBURY POINT*	*4.02*	*4.49*	*23.54*	*5.24*
7735	*DORSEY RUN*	*3.95*	*4.79*	*6.44*	*1.34*
7683	*LAUREL*	*3.91*	*5.20*	*7.15*	*1.37*
7067	*FALLSTON*	*3.89*	*4.22*	*7.63*	*1.81*

4.4 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
4154	FORT AVENUE	*4.48*	*5.97*	*41.25*	*6.91*
4405	WOODBROOK	*4.10*	*4.32*	*8.80*	*2.04*
4069	PHILADELPHIA ROAD	*2.98*	*3.64*	*8.60*	*2.37*

(b) All interruption data minus major event interruption data:

BGE experienced no Major events in 2005.

BGE's "Worst Feeder Program" consists of plans to improve reliability performance for the top 2% of the 13.8 kV distribution feeders (19 out of 953 total 13.8 kV distribution feeders) and 2% of the 4.4 kV distribution feeders (3 out of 129 total 4.4 kV distribution feeders) based on all interruption data minus major event interruption data.

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
7348	LIPINS CORNER	8.06	10.04	13.89	1.38
7711	MEADOWS	6.82	8.31	8.33	1.00
7107	MOUNT WASHINGTON	6.46	7.79	14.00	1.80
7015	BROOKHILL	6.14	7.11	16.56	2.33
8056	WAKEFIELD	6.01	7.39	16.05	2.17
7873	HIGHLANDTOWN	5.43	5.69	10.57	1.86
8474	CROWNSVILLE	5.31	5.83	27.17	4.66
7870	HIGHLANDTOWN	4.85	6.42	10.39	1.62
7420	LEVITT	4.23	5.03	13.16	2.62
7053	VAN BIBBER	4.22	5.18	7.34	1.42
7240	FINKSBURG	4.16	4.71	20.50	4.35
7838	GREENE STREET	4.13	5.04	7.38	1.46
7440	MITCHELLVILLE	4.10	4.96	12.52	2.52
8362	BAY HILLS	4.08	4.77	18.50	3.88
7845	GREENE STREET	4.05	4.78	11.76	2.46
7411	GREENBURY POINT	4.02	4.49	23.54	5.24
7735	DORSEY RUN	3.95	4.79	6.44	1.34
7683	LAUREL	3.91	5.20	7.15	1.37
7067	FALLSTON	3.89	4.22	7.63	1.81

4.4 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
4154	FORT AVENUE	4.48	5.97	41.25	6.91
4405	WOODBROOK	4.10	4.32	8.80	2.04
4069	PHILADELPHIA ROAD	2.98	3.64	8.60	2.37

(c) Feeders shall not be included as having the poorest reliability in two consecutive reports.

No feeders listed in the CY 2004 report as having poor reliability are included in this report.

(4) The method used by a utility to identify the district and feeders with poorest reliability shall be approved by the Commission and be included in the report.

In order to determine which distribution feeders and areas having the poorest performance, BGE utilizes a Composite Reliability Index (CRI). In the event that two feeders have identical composite reliability indices, the feeders are then ranked based on the most recent year's feeder SAIFI. The formula for the index is:

$$CRI = 0.75 \times SAIFI_{2005} + 0.25 \times SAIFI_{2004}$$

As previously communicated with the Commission's Engineering Division, BGE changed to its current CRI methodology commencing with the CY 2004 report.
However, to be consistent, the old CRI formula was utilized in this report to assess the ordinal ranking of CY 2003's "worst feeders" in section 8 (b).

(5) Feeders included in the report, which serve customers in Maryland and one or more bordering jurisdiction, shall be identified. The report shall include the percentage of customers located in Maryland and the percentage of customers located in bordering jurisdictions.

Not applicable to BGE. BGE has no feeders outside Maryland.

(6) Major Event Interruption Data. The report shall include the time periods during which major event interruption data was excluded from the indices, along with a brief description of the interruption causes during each time period.

BGE experienced no Major events in 2005.

(7) Actions for Operating District and Feeders with Poorest Reliability.

(a) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under C.(3) of this regulation.

BGE will review the design for each feeder reported under this section to identify potential improvements. BGE will also trim the trees on feeders as needed, conduct a thorough equipment inspection on each feeder and correct any deficiencies found during the inspections. These inspections will permit the identification of potential outage causes, and will, as a result, reduce the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process, and have since been repaired or replaced. In some cases, underground cable replacement will be performed if the underground conductor experiences an excessive number of failures.

Feeder 7348

Feeder 7348 supplies approximately 2,250 customers in the Harundale area of Anne Arundel County. During 2005, 43% of the customer interruptions were caused by equipment failures, 21% were caused by unknown events (consisted mainly of 2 feeder lockouts where no system damage was identified), 20% were caused by underground conductor failures, 10% were the result of customer interferences (pole hits and dig-ins), 5% were caused by trees and 1% by other miscellaneous events. Tree trimming on this feeder was most recently completed in May 2004, and an inspection was performed which determined that localized tree trimming and overhang removals were needed which was completed in January 2005. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2006. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE identified cable replacement opportunities that were completed in November and December 2005. The design of this feeder was studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed with work being completed in December 2005.

Feeder 7711

Feeder 7711 supplies approximately 2,500 customers in the Security Square and Woodlawn areas of Baltimore County. During 2005, more than 99% of the customer interruptions were caused by underground conductor failures and the remainder caused by other miscellaneous events. Tree trimming on this feeder was most recently completed in October 2004, and a recent inspection has determined that no additional tree trimming is required at this time. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in November 2005. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006.

Feeder 7107

Feeder 7107 supplies approximately 1,200 customers in the Mount Washington area of Baltimore City. During 2005, 22% of the customer interruptions were caused by unknown events (vast majority were protective devices that operated where no system damage was identified), 18% were caused by trees, 18% were caused by underground conductor failures, 16% were caused by lightning, 12% were caused by wind or rain, 10% were the result of customer interferences (pole hits and dig-ins), and 4% were caused by equipment failures. Tree trimming on this feeder was most recently completed in May 2004, and an inspection was performed which determined that localized tree trimming and overhang removals were needed which was completed in January 2005. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2006. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. The design of this feeder was studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed with work being completed in January 2006.

Feeder 7015

Feeder 7015 supplies approximately 100 customers in the Seton Park area of Baltimore City. During 2005, 89% of the customer interruptions were caused by underground conductor failures, 10% were caused by equipment failures and 1% was caused by other miscellaneous events. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was most recently completed in February 2006. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in November 2005.

Feeder 8056

Feeder 8056 supplies approximately 1,500 customers in the Bel Air area of Harford County. During 2005, 53% of the customer interruptions were caused by underground conductor failures, 27% were caused by equipment failures, 17% were caused by trees, and 3% were caused by lightning. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was most recently completed in April 2005, and an inspection was performed which determined that additional overhang removals were needed which was completed in January 2006. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2006. The design of this feeder was studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed with work being completed in March 2006.

Feeder 7873

Feeder 7873 supplies approximately 1,600 customers in the Highlandtown area of Baltimore City. During 2005, 28% of the customer interruptions were caused by equipment failures, 27% were caused by wind or rain, 16% were caused by underground conductor failures, 14% were caused by wildlife, 14% were caused by lightning and 1% was caused by other miscellaneous events. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. Tree trimming on this feeder was most recently completed in February 2005. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2006. The design of this feeder has been studied and electronic resetable sectionalizing and additional fusing will be installed in 2006.

Feeder 8474

Feeder 8474 supplies approximately 680 customers in the Sherwood Forest area of Anne Arundel County. During 2005, 31% of the customer interruptions were caused by trees, 20% were the result of customer interferences (pole hits and dig-ins), 15% were caused by unknown events, 12% were caused by underground conductor failures, 11% were caused by equipment failures, 6% were caused by lightning, 4% were caused by wind or rain and 1% was caused by wildlife. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was last performed in February 2004, and an inspection performed in 2006 has determined that localized tree trimming and overhang removals are needed and will be performed in 2006. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing will be installed in 2006.

Feeder 7870

Feeder 7870 supplies approximately 2,150 customers in the Highlandtown area of Baltimore City. During 2005, 34% of the customer interruptions were the result of customer interferences (pole hits and dig-ins), 31% were caused by equipment failures, 19% were caused by unknown events, and 16% were caused by underground conductor failures. Each failed conductor was repaired or replaced during 2005as part of the service restoration and repair process. Tree trimming on this feeder was most recently completed in March 2005. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied and electronic resetable sectionalizing and fault indicators will be installed in 2006.

Feeder 7420

Feeder 7420 supplies approximately 1,350 customers in the Bowie area of Prince Georges County. During 2005, 66% of the customer interruptions were caused by unknown events (vast majority were protective devices that operated where no system damage was identified), 20% were caused by lightning, 9% were caused by trees, 4% were caused by equipment failures and 1% was caused by wildlife. Tree trimming on this feeder was most recently completed in July 2003, and an inspection performed in 2006 has determined that localized tree trimming and overhang removals are needed and will be performed in 2006. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in 2005.

Feeder 7053

Feeder 7053 supplies approximately 2,450 customers in the Edgewood area of Harford County. During 2005, 69% of the customer interruptions were caused by trees, 29% were caused by equipment failures and 2% were caused by other miscellaneous events. Tree trimming on this feeder was most recently completed in April 2006 and BGE performed aggressive tree and overhang removals along the 3 phase main. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2006. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing will be installed in 2006.

Feeder 7240

Feeder 7240 supplies approximately 1,300 customers in the Finksburg area of Carroll County and the Reisterstown area of Baltimore County. During 2005, 35% of the customer interruptions were caused by unknown events (vast majority were protective devices that operated during storms where no system damage was identified), 30% were caused by trees, 26% were the result of customer interferences (pole hits) and 9% were caused by lightning. Tree trimming on this feeder was most recently completed in May 2004, and an inspection performed in 2006 has determined that localized tree trimming and overhang removals are needed and will be performed in 2006. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in December 2005. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing will be installed in 2006.

Feeder 7838

Feeder 7838 supplies approximately 3,150 customers in the Druid Hill area of Baltimore City. During 2005, 55% of the customer interruptions were caused by underground conductor failures, 21% were caused by equipment failures, 13% were caused by unknown events, 9% were caused by wildlife and 2% were caused by other miscellaneous events. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. Tree trimming on this feeder was most recently completed in February 2006.

Feeder 7440

Feeder 7440 supplies approximately 1,150 customers in the Bowie area of Prince Georges County. During 2005, 42% of the customer interruptions were caused by unknown events (vast majority were protective devices that operated where no system damage was identified), 34% were caused by lightning, 19% were caused by trees, 2% were the result of customer interferences (dig-ins), 2% were caused by underground conductor failures and 1% was caused by equipment failure. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was most recently completed in July 2005 and BGE performed aggressive tree and overhang removals along the 3 phase main. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2006. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in 2005.

Feeder 8362
Feeder 8362 supplies approximately 1,200 customers in the Arnold area of Anne Arundel County. During 2005, 44% of the customer interruptions were caused by equipment failures, 25% were caused by underground conductor failures, 20% were caused by trees, 6% were the result of customer interferences (dig-ins), 4% were caused by unknown events and 1% was caused by other miscellaneous events. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was most recently completed in May 2005, and an inspection performed in 2006 has determined that localized tree trimming and overhang removals are needed and will be performed in 2006. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied and Distribution Automation reclosers and electronic resetable sectionalizing will be installed in 2006.

Feeder 7845
Feeder 7845 supplies approximately 4,150 customers in the Union Square area of Baltimore City. During 2005, 37% of the customer interruptions were caused by unknown events (consisted mainly of 1 feeder lockout where no system damage was identified), 35% were caused by equipment failures, 23% were caused by underground conductor failures, 4% were caused by lightning and 1% was caused by trees. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in September 2005. Tree trimming on this feeder was most recently completed in December 2002 and is scheduled for cycle trimming in 2006.

Feeder 7411
Feeder 7411 supplies approximately 1,475 customers in the Arnold and Greenbury Point areas of Anne Arundel County. During 2005, 35% of the customer interruptions were caused by trees, 31% were caused by unknown events (vast majority were protective devices that operated where no system damage was identified), 24% were caused by equipment failures, 8% were caused by lightning and 2% were caused by other miscellaneous events. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. Tree trimming on this feeder was most recently completed in December 2002, and is scheduled for cycle trimming in 2006 with aggressive tree and overhang removals being targeted. The design of this feeder has been studied and Distribution Automation reclosers will be installed in 2006.

Feeder 7735

Feeder 7735 supplies approximately 700 customers in the Severn area of Anne Arundel County. During 2005, 48% of the customer interruptions were the result of customer interferences (pole hits and dig-ins), 23% were caused by underground conductor failures, 23% were caused by unknown events (vast majority were protective devices that operated during storms where no system damage was identified), and 6% were caused by equipment failures. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was most recently completed in January 2003, and an inspection performed in 2006 has determined that no additional tree trimming is required at this time. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied and Distribution Automation reclosers and, electronic resetable sectionalizing will be installed in 2006.

Feeder 7683

Feeder 7683 supplies approximately 670 customers in the Laurel area of Prince George's County. During 2005, 78% of the customer interruptions were caused by underground conductor failures and 22% were caused by unknown events (consisted mainly of 1 feeder lockout where no system damage was identified). Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE replaced a portion of the feeder main that was completed in March 2006. Tree trimming on this feeder was most recently completed in July 2005, and a recent inspection has determined that no additional tree trimming is required at this time. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies.

Feeder 7067

Feeder 7067 supplies approximately 1,350 customers in the Fallston area of Harford County. During 2006, 50% of the customer interruptions were caused by underground conductor failures, 30% were caused by equipment failures, 12% were caused by trees, 5% were wind or rain related and 3% were caused by unknown events. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. In addition, BGE has identified cable replacement opportunities that will be completed in 2006. Tree trimming on this feeder was most recently completed in December 2005, and BGE performed aggressive tree and overhang removals along the 3 phase main. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing will be installed in 2006.

Feeder 4154

Feeder 4154 supplies approximately 350 customers in the South Baltimore area of Baltimore City. During 2005, 45% of the customer interruptions were caused by equipment failures, 39% were caused by underground conductor failures, and 16% were caused by unknown events. Each failed conductor was repaired or replaced during 2005 as part of the service restoration and repair process. BGE conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. Tree trimming on this feeder was most recently completed in December 2002 and is scheduled for cycle trimming in 2006.

Feeder 4405
Feeder 4405 supplies approximately 815 customers in the Mondawmin area of Baltimore City. During 2005, 53% of the customer interruptions were caused by unknown events (the major contributor was 1 lockout where no system damage was identified), 24% were caused by trees and 23% were caused by equipment failures. BGE conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2006. Tree trimming on this feeder was most recently completed in February 2006, and BGE performed aggressive tree and overhang removals along the 3 phase main.

Feeder 4069
Feeder 4069 supplies approximately 700 customers in the Clifton Park area of Baltimore City. During 2005, 47% of the customer interruptions were caused by equipment failures, 28% were the result of customer interferences (dig-ins) and 25% were caused by lightning. BGE conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2006. Tree trimming on this feeder was most recently completed in December 2002, and is scheduled for cycle trimming in 2006 with aggressive tree and overhang removals being targeted.

(b) Each utility shall briefly describe the actions taken or planned to improve reliability. When the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

BGE plans include remedial actions for all feeders identified as worst performers.

(8) Evaluation of Remedial Actions. For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports.

(a) The annual report for the year following the identification of the operating district and feeders as having the poorest performance shall provide a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions.

BGE reviewed the design for each feeder reported under this section to identify potential improvements. BGE also trimmed the trees on each feeder as needed, conducted a thorough equipment and conductor inspection on each feeder and corrected any deficiencies found during the inspections. Those inspections permitted the identification of potential outage causes, and, as a result, reduced the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process, and have since been repaired or replaced. In some cases, underground cable replacement was performed if the underground conductor experienced an excessive number of failures.

Feeder 7130

Feeder 7130 supplies approximately 1,000 customers in the Hereford area of Baltimore County. During 2004, 39% of the customer interruptions were caused by trees, 34% were caused by lightning, 13% were caused by unknown events, 9% were caused by equipment failures, 3% were caused by other miscellaneous events and 2% were caused by wind or rain. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in January 2006.

Feeder 7141

Feeder 7141 supplies approximately 1,090 customers in the Jacksonville area of Baltimore County. During 2004, 40% of the customer interruptions were caused by trees, 20% were the result of customer interferences (pole hits and dig-ins), 14% were caused by unknown events, 12% were caused by lightning, 12% were caused by equipment failures and 2% were caused by wind or rain. Tree trimming on this feeder was most recently completed in December 2003, and an inspection performed in 2005 determined that localized tree trimming and overhang removals were needed (Completed 5/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in March 2006.

Feeder 7419

Feeder 7419 supplies approximately 350 customers in the Bowie area of Prince George's County. During 2004, 74 % were caused by unknown events (consisted of 3 lockouts during minor storm where no system damage was identified), 25% were caused by lightning and 1% was caused by other miscellaneous events. Tree trimming on this feeder was most recently completed in March 2004, and an inspection performed in 2005 determined that no additional tree trimming was required. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in March 2005.

Feeder 8103

Feeder 8103 supplies approximately 700 customers in the Mt Washington and Roland Park areas of Baltimore City. During 2004, 52% of the customer interruptions were caused by trees, 15% were caused by equipment failures, 12% were caused by unknown events, 12% were caused by underground conductor failures, 7% were the result of customer interferences (pole hits and dig-ins) and 2% were caused by other miscellaneous events. Each failed conductor was repaired or replaced during 2004 as part of the service restoration and repair process. Tree trimming on this feeder was most recently completed in December 2004 and BGE performed aggressive tree and overhang removals along the 3 phase main. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in March 2005.

Feeder 8734

Feeder 8734 supplies approximately 1380 customers in the Ashton area of Montgomery County. During 2004, 46% were caused by unknown events (the majority were caused by 3 lockouts, 2 storm related, where no cause could be identified), 40% were caused by lightning, 9% were the result of customer interferences (pole hits and dig-ins), and 5% were caused by other miscellaneous events. Tree trimming on this feeder was most recently completed in March 2005, and BGE performed aggressive tree and overhang removals along the 3 phase main. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in March 2006.

Feeder 7105

Feeder 7105 supplies approximately 1,650 customers in the Pikesville and Brooklandville areas of Baltimore County. During 2004, 61% of the customer interruptions were caused by trees, 18% were caused by equipment failures, 17% were caused by unknown events and 4% were caused by other miscellaneous events. Tree trimming on this feeder was last performed in April 2004 and an inspection performed in 2005 determined that localized tree trimming and overhang removals were needed (Completed 7/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in May 2005.

Feeder 7132

Feeder 7132 supplies approximately 1,300 customers in the Hereford area of Baltimore County. During 2004, 27% of the customer interruptions were caused by trees, 27% were the result of customer interferences (pole hits and dig-ins), 25% were caused by unknown events, 10% were caused by lightning, 10% were caused by wind or rain and 1% was caused by other miscellaneous events. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05). BGE also conducted an overhead equipment and conductor inspection and corrected the related deficiencies in February 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in February 2006.

Feeder 7730

Feeder 7730 supplies approximately 90 customers in the Jessup areas of Howard and Anne Arundel Counties. During 2004, 96% of the customer interruptions were caused by equipment failures and 4% were caused by wildlife. Tree trimming on this feeder was most recently completed in April 2004, and an inspection performed in 2005 determined that localized tree trimming and overhang removals were needed (Completed 4/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in April 2006.

Feeder 7129

Feeder 7129 supplies approximately 1,213 customers in the Hereford area of Baltimore County. During 2004, 52% of the customer interruptions were caused by equipment failures, 25% were caused by unknown events, 10% were caused by trees, 7% were caused by wildlife, 4% were caused by lightning and 2% were caused by wind or rain. Tree trimming on this feeder was most recently completed in December 2003 and an inspection performed in 2005 determined that localized tree trimming and overhang removals were needed (Completed 5/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in July 2005.

Feeder 8421

Feeder 8421 supplies approximately 675 customers in the Wayson's Corner area of Anne Arundel County and the northern part of Calvert County. During 2004, 86% of the customer interruptions were due to equipment failures, 10% were the result of customer interferences (pole hits) and 4% were caused by lightning. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in December 2005.

Feeder 8010

Feeder 8010 supplies approximately 718 customers in the Roland Park area of Baltimore City. During 2004, 40% of the customer interruptions were caused by unknown events (consisted of 2 lockouts during where no system damage was identified), 24% were caused by underground conductor failures, 23% were caused by equipment failures, 9% were the result of customer interferences (dig-ins) and 4% were caused by other miscellaneous events. Each failed conductor was repaired or replaced during 2004 as part of the service restoration and repair process. In addition, BGE identified sections of underground cable on this feeder that had experienced an excessive number of failures. A cable replacement job was designed to replace more than 4,000 feet of cable with an expected cut in date of late 2005. However, right of way and customer issues in the Village of Cross Keys delayed the start of the job, which is now underway with an expected May 2006 completion. BGE most recently conducted an overhead equipment and conductor inspection in 2004 and corrected the related deficiencies. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 8/05). The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in April 2006.

Feeder 7072

Feeder 7072 supplies approximately 1,120 customers in the Joppatowne area of Harford County. During 2004, 61% of the customer interruptions were caused by trees, 37% were caused by equipment failure and 2% were caused by other miscellaneous events. Tree trimming on this feeder was most recently completed in December 2003 and an inspection performed in 2005 determined that localized tree trimming and overhang removals were needed (Completed 5/05) BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in December 2005.

Feeder 8783

Feeder 8783 supplies approximately 1,065 customers in the Crofton area of Anne Arundel County. During 2004, 59% of the customer interruptions were the result of customer interferences (pole hits and dig-ins), 24% were caused by unknown events, 16% were caused by equipment failures and 1% was caused by other miscellaneous events. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in January 2006.

Feeder 7123

Feeder 7123 supplies approximately 1,450 customers in the Towson area of Baltimore County. During 2004, 37% of the customer interruptions were caused by equipment failures, 24% were caused by lightning, 18% were caused by underground conductor failures, 11% were caused by trees, 8% were construction related, and 2% were caused by miscellaneous events. Each failed conductor was repaired or replaced during 2004 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2005. Tree trimming on this feeder was most recently completed in December 2004 and BGE performed aggressive tree and overhang removals along the 3 phase main. The design of this feeder has been studied and the installation of electronic resetable sectionalizing and additional fusing was completed in April 2006.

Feeder 7692

Feeder 7692 supplies approximately 1,105 customers in the Woodbine area of Howard County. During 2004, 62% of the customer interruptions were caused by equipment failures, 17% were caused by trees, 13% were the result of customer interferences (dig-ins), 6% were caused by underground conductor failures and 2% were caused by miscellaneous events. Each failed conductor was repaired or replaced during 2004 as part of the service restoration and repair process. In addition, BGE replaced sections of underground cable on this feeder that had experienced an excessive number of failures (Completed 9/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2005. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05). The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in February 2006.

Feeder 7257

Feeder 7257 supplies approximately 153 customers in the Ellicott City area of Howard County. During 2004, 90% of the customer interruptions were caused by trees, 6% were caused by unknown events and 4% were caused by miscellaneous events. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in February 2006.

Feeder 8158

Feeder 8158 supplies approximately 830 customers in the Timonium area of Baltimore County. During 2004, 51% of the customer interruptions were caused by equipment failures, 25% were the result of customer interferences (dig-ins), 22% were caused by unknown events, and 2% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in December 2004, and an inspection performed in 2005 determined that no additional tree trimming was required. BGE most recently conducted an overhead equipment and conductor inspection in 2004 and corrected the related deficiencies in May 2004. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in March 2006.

Feeder 7189

Feeder 7189 supplies approximately 1,190 customers in the Pikesville area of Baltimore County. During 2004, 58% of the customer interruptions were caused by equipment failures, 41% were caused by unknown events and 1% was wind or rain related. Tree trimming on this feeder was most recently completed in January 2004, and an inspection performed in 2005 determined that no additional tree trimming was required. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in December 2004.

Feeder 7075

Feeder 7075 supplies approximately 725 customers in the Joppatowne area of Harford County. During 2004, 65% of the customer interruptions were caused by trees, 33% were caused by equipment failure and 2% were caused by wildlife. Tree trimming on this feeder was most recently completed in December 2003 and an inspection performed in 2005 determined that localized tree trimming and overhang removals were needed (Completed 5/05). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2005. The design of this feeder has been studied and the installation of Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing was completed in April 2006.

Feeder 4931

Feeder 4931 supplies approximately 770 customers in the Cherry Hill area of Baltimore City. During 2004, 53% of the customer interruptions were caused by lightning, 18% were caused by unknown events, 18% were the result of customer interferences (pole hit), 10% were caused by wind or rain and 1% was caused by miscellaneous events. BGE conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2005. Tree trimming on this feeder was most recently completed in August 2003, and an inspection performed in 2005 determined that no additional tree trimming was required.

Feeder 4834

Feeder 4834 supplies approximately 395 customers in the Clifton Park area of Baltimore City. During 2004, 69% of the customer interruptions were caused by unknown events (consisted of 3 lockouts where no system damage was identified), 28% were caused by wind or rain, 2% were caused by trees, and 1% was caused by equipment failures. BGE conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2005. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05).

Feeder 4801

Feeder 4834 supplies approximately 560 customers in the Calverton area of Baltimore City. During 2004, 35% of the customer interruptions were caused by wind or rain, 32% were caused by unknown events, 31% were the result of customer interferences (pole hits), 1% was caused by trees, and 1% was caused by equipment failures. BGE conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2005. During 2005, BGE trimmed the entire length of the feeder as well as performing aggressive removals along the 3 phase mains (Completed 4/05).

(b) The annual report two years after the identification of the operating district or feeders as having the poorest performance shall include the ordinal ranking representing the feeder's reliability during the current reporting period.

BGE's poorest performing 2% of the 13.8 kV distribution feeders (19 out of 953 total 13.8 kV distribution feeders) and 2% of the 4.4 kV distribution feeders (3 out of 129 total 4.4 kV distribution feeders) in 2003 had the following ordinal rankings in 2005. Ordinals for 2005 range from 1 (worst) to 129 (best) for 4.4 kV feeders and from 1 (worst) to 953 (best) for 13.8 kV feeders, ranked by Composite Reliability Index. Ranking excludes major event data.

13.8 kV Feeder	***Substation***	***2005 Ordinal Ranking***
7806	*Carroll*	*44*
7808	*Carroll*	*46*
7614	*Wilde Lake*	*104*
8366	*Pleasant Hills*	*217*
7003	*Center*	*103*
7043	*Hillen Road*	*185*
7438	*Priest Bridge*	*291*
7495	*Cedar Park*	*309*
7531	*Middleborough*	*68*
7401	*NAJ*	*55*
7493	*Cedar Park*	*117*
7008	*Center*	*554*
7473	*Glenn Dale*	*315*
8301	*Round Bay Modular*	*68*
7501	*Cowenton*	*719*
7392	*Lansdowne*	*427*
7486	*Tyler Avenue*	*109*
8453	*NAJ*	*155*
8661	*Mount Wilson*	*272*

4.4 kV Feeder	***Substation***	***2005 Ordinal Ranking***
4414	*Woodbrook*	*118*
4703	*South Baltimore*	*58*
4823	*Clifton Park*	*21*

(9) Momentary Interruptions. A utility shall maintain information which it collects on momentary interruptions for five years.

BGE meets this requirement.

Baltimore Gas and Electric Company
COMAR 20.50.07.06 Reporting of Reliability Indices – CY 2008

(1) System-Wide Indices. A utility shall report SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

SAIFI – 1.83
SAIDI – 6.40
CAIDI – 3.50

Note: System-Wide Indices are calculated using IEEE Std. 1366-1998.

(b) All interruption data minus major event interruption data.

SAIFI – 1.68
SAIDI – 5.31
CAIDI – 3.17

Data in (b) excludes customer interruptions from one Major Event experienced during 2008, further detailed in Section 6.

(2) District Indices. A cooperatively-owned utility shall provide SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

(b) Major event interruption data excluded.

Requirements (a) & (b) are not applicable to BGE since BGE is an Investor Owned Utility.

(3) Feeder Indices. An investor-owned utility shall provide SAIDI, SAIFI, and CAIDI for 2% of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability. The indices shall be calculated and reported with 2 sets of input data.

(a) All interruption data

13.8 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
7440	*MITCHELLVILLE*	*8.53*	*8.70*	*43.79*	*5.03*
7633	*LONG REACH*	*8.42*	*10.16*	*29.61*	*2.91*
8102	*MOUNT WASHINGTON*	*7.80*	*9.12*	*15.31*	*1.68*
8420	*WAYSONS CORNER*	*7.69*	*9.52*	*23.46*	*2.46*
8734	*ASHTON*	*7.64*	*8.84*	*51.87*	*5.87*
7348	*LIPINS CORNER*	*7.39*	*8.91*	*8.69*	*0.98*
8450	*NAJ*	*6.81*	*6.90*	*9.33*	*1.35*
7616	*WILDE LAKE*	*6.74*	*7.72*	*41.15*	*5.33*
7617	*WILDE LAKE*	*6.49*	*8.04*	*55.60*	*6.91*
7257	*FREDERICK ROAD*	*6.27*	*7.40*	*44.98*	*6.08*
8103	*MOUNT WASHINGTON*	*6.13*	*7.44*	*34.41*	*4.63*
7130	*HEREFORD*	*5.82*	*6.86*	*21.34*	*3.11*
7710	*MEADOWS*	*5.53*	*6.74*	*16.57*	*2.46*
7381	*SOUTH BALTIMORE*	*5.46*	*6.59*	*18.45*	*2.80*
8604	*CONCORD STREET*	*5.40*	*6.59*	*8.61*	*1.31*
7138	*LUTHERVILLE*	*5.38*	*5.31*	*23.95*	*4.51*
7129	*HEREFORD*	*5.32*	*5.08*	*17.61*	*3.47*
7658	*COLUMBIA*	*5.23*	*6.40*	*7.10*	*1.11*
8472	*CROWNSVILLE*	*5.13*	*4.59*	*19.44*	*4.23*
7941	*LEVEL*	*5.10*	*4.22*	*6.15*	*1.46*

13000 Series Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
13971	*NEWGATE*	*2.58*	*1.67*	*2.33*	*1.40*
13302	*ERDMAN*	*2.54*	*2.33*	*2.17*	*0.93*
13921	*WESTPORT*	*2.54*	*3.00*	*72.67*	*24.22*

4.4 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
4430	*FOREST PARK*	*6.59*	*7.11*	*23.51*	*3.31*
4812	*CALVERTON*	*5.75*	*6.15*	*10.69*	*1.74*
4828	*CLIFTON PARK*	*5.42*	*7.22*	*18.08*	*2.50*

(b) All interruption data minus major event interruption data:

BGE's "Worst Feeder Program" consists of plans to improve reliability performance for the top 2% of the 13.8 kV distribution feeders (20 out of 993 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 126 total 13000 series distribution feeders) and 2% of the 4.4 kV distribution feeders (3 out of 124 total 4.4 kV distribution feeders) based on all interruption data excluding Major Event interruption data.

13.8 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
8102	*MOUNT WASHINGTON*	*7.76*	*9.10*	*14.98*	*1.65*
7633	*LONG REACH*	*7.56*	*9.02*	*23.04*	*2.55*
7348	*LIPINS CORNER*	*7.27*	*8.90*	*8.36*	*0.94*
8420	*WAYSONS CORNER*	*6.62*	*8.49*	*13.05*	*1.54*
7130	*HEREFORD*	*5.78*	*6.86*	*21.34*	*3.11*
7257	*FREDERICK ROAD*	*5.48*	*6.44*	*32.11*	*4.99*
7616	*WILDE LAKE*	*5.26*	*5.75*	*18.27*	*3.18*
7658	*COLUMBIA*	*5.23*	*6.40*	*7.07*	*1.11*
7382	*SOUTH BALTIMORE*	*5.08*	*6.49*	*18.54*	*2.86*
8052	*ROCK RIDGE*	*5.05*	*5.66*	*11.80*	*2.08*
8604	*CONCORD STREET*	*5.00*	*6.46*	*8.27*	*1.28*
8682	*TEN OAKS*	*4.95*	*5.88*	*7.11*	*1.21*
7381	*SOUTH BALTIMORE*	*4.78*	*5.70*	*13.52*	*2.37*
7617	*WILDE LAKE*	*4.64*	*5.57*	*30.93*	*5.55*
8101	*MOUNT WASHINGTON*	*4.63*	*5.71*	*11.77*	*2.06*
7710	*MEADOWS*	*4.62*	*5.53*	*11.20*	*2.02*
8103	*MOUNT WASHINGTON*	*4.61*	*5.43*	*29.57*	*5.44*
8272	*HOLLOFIELD*	*4.61*	*5.16*	*6.12*	*1.18*
8556	*WAUGH CHAPEL*	*4.41*	*5.61*	*14.73*	*2.63*
8141	*EAST TOWSON*	*4.44*	*4.89*	*15.07*	*3.08*

13000 Series Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
13602	*COLDSPRING*	*1.77*	*2.03*	*2.82*	*1.39*
13302	*ERDMAN*	*1.75*	*2.00*	*1.83*	*0.92*
13936	*MONUMENT STREET OUTDOOR*	*1.61*	*2.14*	*2.98*	*1.39*

4.4 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
4430	*FOREST PARK*	*6.59*	*7.11*	*23.51*	*3.31*
4812	*CALVERTON*	*5.75*	*6.15*	*10.67*	*1.74*
4828	*CLIFTON PARK*	*5.42*	*7.22*	*18.08*	*2.50*

(c) Feeders shall not be included as having the poorest reliability in two consecutive reports.

No feeders listed in the CY 2007 report as having poor reliability are included in this report.

(4) The method used by a utility to identify the district and feeders with poorest reliability shall be approved by the Commission and be included in the report.

In order to determine which distribution feeders and areas having the poorest performance, BGE utilizes a Composite Reliability Index (CRI). In the event that two feeders have identical composite reliability indices, the feeders are then ranked based on the most recent year's feeder SAIFI. The formula for the index is:

$$\boldsymbol{CRI = 0.75 \times SAIFI_{2008} + 0.25 \times SAIFI_{2007}}$$

(5) Feeders included in the report, which serve customers in Maryland and one or more bordering jurisdiction shall be identified. The report shall include the percentage of customers located in Maryland and the percentage of customers located in bordering jurisdictions.

Not applicable to BGE. BGE has no feeders outside Maryland.

(6) Major Event Interruption Data. The report shall include the time periods during which major event interruption data was excluded from the indices, along with a brief description of the interruption causes during each time period.

BGE experienced 1 Major Event in 2008.

At approximately 3:00 PM on Wednesday, June 4, 2008, a strong band of storms accompanied by high winds, heavy rain and frequent lightning moved through the BGE service territory. By 5:00 PM a major storm was declared on the BGE system with a peak of 105,660 sustained customer interruptions. Cumulatively, 192,071 customer interruptions were experienced, the majority of which were in Anne Arundel, Calvert and Howard Counties. In addition to the strong storms, the National Weather Service received reports of tornado touchdowns in Severna Park, Chesapeake Beach and near the Chesapeake Bay Bridge. A total of 576 BGE personnel and BGE contractors along with 88 external contractors were involved in the restoration effort. The storm was declared over and the Storm Center closed at 5:30 AM on Saturday, June 7, 2008.

(7) Actions for Operating District and Feeders with Poorest Reliability.

(a) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under C.(3) of this regulation.

BGE will review the design for each feeder reported under this section to identify potential improvements. BGE will also trim the trees on feeders as needed, conduct a thorough equipment inspection on each feeder and correct any deficiencies found during the inspections. These inspections will permit the identification of potential outage causes, and will, as a result, reduce the number of customer interruptions due to unknown causes. Where the feeder interruptions *were the result of underground conductor failures, the failed sections were isolated during the service restoration process, and have since been repaired or replaced. In some cases, underground cable replacement will be performed if the underground conductor experiences an excessive number of failures.*

Feeder 8102

Feeder 8102 supplies approximately 1,959 customers in the Mount Washington area of Baltimore. During 2008, 40% of the customer interruptions were caused by underground conductor failures, 24% were caused by weather (23% were caused by lightning, and 1% was caused by wind/rain), 15% were caused due to equipment failures, 11% were caused by public interference (foreign objects blown by wind), 6% were caused due to trees, 2% were caused by unknown events, 1% was caused by overhead conductor failure and 1% was caused by wildlife. Tree trimming on this feeder was most recently completed in December 2008. BGE has identified three cable replacement opportunities that are currently in design and are intended to be completed by the end of the third quarter of 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 7633

Feeder 7633 supplies approximately 225 customers in the Oakland Mills area in Howard County. During 2008, 54% of the customer interruptions were caused by underground conductor failures, 20% were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 13% were caused by weather, and 13% were caused by public interference (dig-ins). Tree trimming on this feeder was most recently completed in June 2008. BGE has identified two cable replacement opportunities that are currently in design and are intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 7348

Feeder 7348 supplies approximately 2,285 customers in the Marley Creek area of Anne Arundel County. During 2008, 68% of the customer interruptions were caused by underground conductor failures, 17% were caused by overhead conductor failures, 14% were caused by trees, and 1% was caused by wildlife. Tree trimming on this feeder was most recently completed in December 2008. BGE has identified a cable replacement opportunity that is currently in design and is intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 8420

Feeder 8420 supplies approximately 1,801 customers in the Harwood area of Anne Arundel County. During 2008, 34% of the customer interruptions were caused by trees, 24% were caused by weather (wind/rain), 17% were caused by equipment failures, 13% were caused by underground conductor failures, and 12% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified). Tree trimming on this feeder was most recently completed in July 2005. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, each of the *pieces of equipment that failed were repaired or replaced after failure. BGE has identified a cable replacement opportunity that is currently in design and is intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. In addition, BGE performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and corrected the deficiencies identified.*

Feeder 7130

Feeder 7130 supplies approximately 1,028 customers in the Monkton area of Baltimore County. During 2008, 50% of the customer interruptions were caused by trees, 26% were caused by weather (15% were caused by lightning, and 11% were caused by wind/rain), 20% were caused by equipment failures, 3% were caused by overhead conductor failure, and 1% was caused by public interference (pole hits). Tree trimming on this feeder was most recently completed in June 2005. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies.

Feeder 7257

Feeder 7257 supplies approximately 819 customers in the Ellicott City area of Howard County. During 2008, 74% of the customer interruptions were caused by trees, 14% were caused by underground conductor failures, 11% were caused by overhead conductor failures, and 1% was caused by unknown events. Tree trimming on this feeder was most recently completed in June 2005. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder was studied and Distribution Automation reclosers were installed in January 2008.

Feeder 7616

Feeder 7616 supplies approximately 1,739 customers in the Village of Hickory Ridge area of Howard County During 2008, 49% of the customer interruptions were caused by trees, 20% were caused by equipment failures, 13% were caused by public interference (pole hits), 12% were caused by weather (7% were caused by lightning and 5% were caused by wind/rain), 5% were caused by overhead conductor failures, and 1% was caused by underground conductor failures. Tree trimming on this feeder was most recently completed in October 2007. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied, and Distribution Automation reclosers and fault indicators will be installed in 2009.

Feeder 7658

Feeder 7658 supplies approximately 1,087 customers in the Village of Owen Brown area of Howard County. During 2008, 95% of the customer interruptions were caused by underground conductor failures, and 5% were caused by equipment failures. BGE identified a cable replacement opportunity that was completed in October 2008. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. Thermovision and visual *inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.*

Feeder 7382

Feeder 7382 supplies approximately 68 customers in the Fairfield area of Baltimore City. During 2008, 41% of the customer interruptions were caused by weather (40% were caused by wind/rain and 1% was caused by lightning), 36% were caused by overhead conductor failures, and 23% were caused by equipment failures. Tree trimming on this feeder was most recently completed in August 2005. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied, and Distribution Automation reclosers will be installed in 2009.

Feeder 8052

Feeder 8052 supplies approximately 1,528 customers in the Jarrettsville area of Harford County. During 2008, 55% of the customer interruptions were caused by underground conductor failures, 19% were caused by trees, 19% were caused by public interferences (18% were caused by pole hits and 1% was caused by foreign objects blown by wind), 6% were caused by weather, and 1% was caused by equipment failures. Tree trimming on this feeder was most recently completed in December 2005. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. BGE has identified a cable replacement opportunity that is currently in construction and is intended to be completed by the end of the second quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies.

Feeder 8604

Feeder 8604 supplies approximately 2,046 customers in the Federal Hill area of Baltimore City. During 2008, 29% of the customer interruptions were caused by public interferences (15% were caused by pole hits and 14% were caused by foreign objects blown by wind), 19% were caused by underground conductor failures, 19% were caused by equipment failures, 16% were caused by weather (wind/rain), 15% were caused by trees, and 2% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in September 2006. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. Each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. In addition, BGE identified a cable replacement opportunity that was completed in January 2009. The design of this feeder has been studied, and Distribution Automation reclosers will be installed in 2009. BGE also performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and corrected the deficiencies identified.

Feeder 8682

Feeder 8682 supplies approximately 902 customers in the Dayton area of Howard County. During 2008, 40% of the customer interruptions were caused by trees, 39% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 14% were caused by overhead conductor failures, 5% were caused by public interference and 2% were caused by equipment failures. Tree trimming on this feeder was most recently *completed in December 2006. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009.*

Feeder 7381

Feeder 7381 supplies approximately 561 customers in the Brooklyn area of Baltimore City. During 2008, 49% of the customer interruptions were caused by overhead conductor failures (vast majority occurring during storms), 19% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 18% were caused by trees, 8% were caused by weather, 5% were caused by miscellaneous events and 1% was caused by equipment failures. Tree trimming on this feeder was most recently completed in August 2005. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed in 2009.

Feeder 7617

Feeder 7617 supplies approximately 803 customers in the Villages of Hickory Ridge area of Howard County. During 2008, 49% of the customer interruptions were caused by trees, 39% were caused by equipment failures, 4% were caused by weather, 4% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 1% was caused by underground conductor failures, 1% was caused by animals and 1% was caused by miscellaneous events. Tree trimming on this feeder was most recently completed in October 2008. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. In addition, BGE also performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and is in the process of correcting the deficiencies identified.

Feeder 8101

Feeder 8101 supplies approximately 2,088 customers in the Rodgers Forge area of Baltimore County. During 2008, 37% of the customer interruptions were caused by trees, 22% were caused by public interference (19% were caused by pole hits and 3% were caused by foreign objects blown by wind), 21% were caused by weather (17% were caused by lightning and 4% were caused by wind/rain), 13% were caused by animals, 5% were caused by overhead conductor failures, and 2% were caused by equipment failures. Tree trimming on this feeder was most recently completed in Dec 2004. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. BGE has identified a cable replacement opportunity that is currently in design and is intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies.

Feeder 7710

Feeder 7710 supplies approximately 2,301 customers in the Chadwick area of Baltimore County. During 2008, 84% of the customer interruptions were caused by trees, 13% were caused by miscellaneous events, 2% were caused by equipment failures, and 1% was caused by weather. Tree trimming on this feeder was most recently completed in October 2008. BGE has identified *two cable replacement opportunities that are currently in design and are intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. The design of this feeder has been studied and Distribution Automation reclosers will be installed in 2009.*

Feeder 8103

Feeder 8103 supplies approximately 677 customers in the Ruxton area of Baltimore County. During 2008, 26% of the customer interruptions were caused by overhead conductor failures, 22% were caused by trees, 16% were caused weather (15% were caused by wind/rain and 1% was caused by lightning), 15% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 14% were caused by public interference (13% were caused by pole hits and 1% was caused by foreign objects blown by wind), 5% were caused by equipment failures, 1% was caused by underground conductor failures and 1% was caused by animals. Tree trimming on this feeder was most recently completed in September 2008. BGE has identified a cable replacement opportunity that is currently in design and is intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009. A portion of this feeder is currently being transferred to feeder 7101. This transfer of a group of customers at the end of the feeder will reduce their vegetation exposure and move them to a better performing feeder. The transfer and related work is expected to be completed prior to the summer 2009 storm season.

Feeder 8272

Feeder 8272 supplies approximately 1,356 customers in the Windsor Mill area of Baltimore County. During 2008, 42% of the customer interruptions were caused by trees, 36% were caused by underground conductor failures, 21% were caused equipment failures, and 1% was caused by unknown events. Tree trimming on this feeder was most recently completed in March 2006. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE has identified a cable replacement opportunity that is currently waiting to be released to construction and is intended to be completed by the end of the third quarter of 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 8556

Feeder 8556 supplies approximately 671 customers in the Gambrills area of Anne Arundel County. During 2008, 43% of the customer interruptions were caused by trees, 37% were caused by underground conductor failures, 18% were caused by overhead conductor failures, and 2% were caused by equipment failures. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, BGE identified a cable replacement opportunity that was completed in August 2008. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. The design of this feeder has been studied, and Distribution Automation reclosers will be installed in 2009.

Feeder 8141
Feeder 8141 supplies approximately 917 customers in the Hampton area fo Baltimore County. During 2008, 58% of the customer interruptions were caused by trees, 22% were caused by equipment failures, 17% were caused by underground conductor failures, 2% were caused by weather, and 1% was caused by animals. Tree trimming on this feeder was most recently completed in May 2007. An inspection performed earlier this year determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2008 with no reliability deficiencies being found.

Feeder 13602
Feeder 13602 supplies approximately 271 customers in the Hampden area of Baltimore City. During 2008, 50% of the customer interruptions were caused by underground conductor failures and 50% were caused by equipment failures. Each failed cable was replaced as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. Tree trimming on this feeder was most recently completed in April 2005 and localized tree trimming and overhang removals is scheduled to occur in May 2009. BGE is in the process of conducting overhead equipment and conductor inspections and will correct any related deficiencies. In addition, BGE also performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and is in the process of correcting the deficiencies identified.

Feeder 13302
Feeder 13302 supplies approximately 6 customers in the Highlandtown area of Baltimore City. During 2008, 50% of the customer interruptions were caused by equipment failures, and 50% were caused by weather (lightning). Tree trimming on this feeder was most recently completed in February 2008. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE is in the process of conducting overhead equipment and conductor inspections and will correct any related deficiencies.

Feeder 13936
Feeder 13936 supplies approximately 132 customers in the Little Italy area of Baltimore City. During 2008, 99% of the customer interruptions were caused by underground conductor failures and 1% was caused by equipment failure. Each failed cable was replaced during 2008 as part of the service restoration and repair process. BGE performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this in March 2009 and corrected the deficiencies identified.

Feeder 4430
Feeder 4430 supplies approximately 888 customers in the Forest Park area of Baltimore City. During 2008, 31% of the customer interruptions were caused by trees, 24% were caused by underground conductor failures, 24% were caused by equipment failures, 18% were caused by weather (17 % were caused by wind/rain and 1% was caused by lightning) and 3% were caused by unknown events. Tree trimming on this feeder was most recently completed in October 2008. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE is in the process of conducting overhead equipment and conductor inspections and will correct any related deficiencies.

Feeder 4812

Feeder 4812 supplies approximately 502 customers in the Calverton area of Baltimore City. During 2008, 36% of the customer interruptions were caused by trees, 17% were caused by underground conductor failures, 17% were caused by equipment failures, 17% were caused by weather (wind/rain) and 13% were caused by miscellaneous events. Each failed cable was replaced as part of the service restoration and repair process. Tree trimming on this feeder was most recently completed in December 2005 and localized tree trimming and overhang removals is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE is in the process of conducting overhead equipment and conductor inspections and will correct any related deficiencies.

Feeder 4828

Feeder 4828 supplies approximately 734 customers in the Clifton Park area of Baltimore City. During 2008, 48% of the customer interruptions were caused by equipment failures, 21% were caused by underground conductor failures, 20% were caused by weather (19% were caused by lightning and 1% was caused by wind/rain) and 11% were caused by trees. Tree trimming on this feeder was most recently completed in December 2005 and localized tree trimming and overhang removals is scheduled to occur in May 2009. In addition, each of the pieces of equipment that failed were repaired or replaced after failure. BGE is in the process of conducting overhead equipment and conductor inspections and will correct any related deficiencies. Thermovision and visual inspections of all 3 phase pad mounted equipment on this feeder were completed in March 2008 with no reliability deficiencies being found.

(b) Each utility shall briefly describe the actions taken or planned to improve reliability. When the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

BGE plans include remedial actions for all feeders identified as worst performers.

(8) Evaluation of Remedial Actions. For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports.

(a) The annual report for the year following the identification of the operating district and feeders as having the poorest performance shall provide a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions.

BGE reviewed the design for each feeder reported under this section to identify potential improvements. BGE also trimmed the trees on each feeder as needed, conducted a thorough equipment and conductor inspection on each feeder and corrected any deficiencies found during the inspections. Those inspections permitted the identification of potential outage causes, and, as a result, reduced the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process, and have since been repaired or replaced. In some cases, underground cable replacement was performed if the underground conductor experienced an excessive number of failures.

Feeder 7733

Feeder 7733 supplies approximately 160 customers in the Harmans Dorsey Avenue area of Anne Arundel County and the Santa Barbara Road area of Howard County. During 2007, 58% of the customer interruptions were caused by trees, 15% were caused by miscellaneous events (consisted mainly of a feeder lockout where no system damage was identified), 13% were caused by overhead conductor failures, 6% were caused by underground conductor failures, 8% were caused by public interference (6% cable dig-ins, 2% vehicle hits). Tree trimming on this feeder was most recently completed in February 2007. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in April 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. The design of this feeder was studied and a portion of this feeder was transferred to a new Meadowridge Substation feeder in June 2007 and midpoint protection was added to create a tie with Dorsey Run Substation Feeder 7735.

Feeder 7411

Feeder 7411 supplies approximately 1,460 customers in the Arnold area of Anne Arundel County. During 2007, 39% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 21% were caused by trees, 14% were caused by overhead conductor failures, 14% were caused by equipment failures, 6% were caused by animals, 5% were caused by wind/rain, and 1% was caused by lightning. Tree trimming on this feeder was most recently completed in March 2006. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in March 2008. BGE conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008.

Feeder 7440

Feeder 7440 supplies approximately 1,110 customers in the Bowie area of Prince George's County. During 2007, 38% of the customer interruptions were caused by weather (24% were caused by lightning, and 14% were caused by wind/rain), 29% of the customer interruptions were caused by trees, 26% were caused by public interference (vehicle hits), 6% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), and 1% was caused by other miscellaneous events. Tree trimming on this feeder was most recently completed in July 2005. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in April 2008. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2008. In addition, this feeder has been redesigned and is being addressed as part of the Bowie Electric Reliability Action Plan (BERAP) in 2009 from an infrastructure and vegetation management perspective.

Feeder 7474

Feeder 7474 supplies approximately 1,210 customers in the Greenbelt area of Prince George's County. During 2007, 56% of the customer interruptions were caused by underground conductor failures, 25% were caused by overhead conductor failures, 16% were caused by trees, 2% were caused by unknown events, and 1% was caused by weather. Tree trimming on this feeder was most recently completed in March 2006. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in February 2008. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in December 2007. BGE identified two cable replacement opportunities and *completed both in 2008 (August and November). The design of this feeder was studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in January 2007. In addition, BGE performed a Thermovision inspection and replaced two single phase pad mounted transformers as a result in February 2008.*

Feeder 7237

Feeder 7237 supplies approximately 1,280 customers in the Pleasant Valley Road area of Carroll County. During 2007, 40% of the customer interruptions were caused by weather (27% were caused by wind/rain, and 13% were caused by lightning), 38% were caused by overhead conductor failures, 17% were caused by equipment failures, 3% were caused by unknown events where the cause could not be identified, and 2% were caused by trees. Tree trimming on this feeder was most recently completed in April 2007. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in May 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in March 2006.

Feeder 7283

Feeder 7283 supplies approximately 1,050 customers mainly in the Montpelier area of Prince George's County. During 2007, 100% of the customer interruptions were caused by underground conductor failures. Each failed cable was repaired or replaced during 2007 as part of the service restoration and repair process. In addition, BGE identified a cable replacement opportunity and was completed in November 2008. The design of this feeder has been studied and a Vacuum Fault Interrupter (VFI) switchgear was installed in January 2007.

Feeder 8450

Feeder 8450 supplies approximately 2,660 customers in the Severn area of Anne Arundel County. During 2007, 38% of the customer interruptions were caused by underground conductor failures, 28% were caused by trees, 26% were caused by overhead conductor failures, and 8% were caused by public interference (dig-ins). Each failed cable was repaired or replaced during 2007 as part of the service restoration and repair process. In addition, BGE has identified three cable replacement opportunities; two of which have been completed and construction has recently begun on the third with the intent to be completed by the end of the third quarter of 2009. Tree trimming on this feeder was most recently completed in June 2007. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in March 2008. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2008. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in May 2007, and a VFI switchgear was installed in October 2007.

Feeder 7390

Feeder 7390 supplies approximately 340 customers in the Arbutus Avenue area of Baltimore City and the Rosemont area of Baltimore County. During 2007, 38% of the customer interruptions were caused by weather (37% were caused by wind/rain, and 1% was caused by lightning), 36% were caused by equipment failures, 16% were caused by public interference (vehicle-hits), and 10% were caused by miscellaneous other events. Tree trimming on this feeder was most recently completed in April 2005. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine *trimming standards; this trimming was completed in February 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed with work being completed in November 2008.*

Feeder 8463

Feeder 8463 supplies approximately 510 customers in the Bowie area of Prince George's County. During 2007, 53% of the customer interruptions were caused by overhead conductor failures, 21% were caused by unknown events where the cause could not be identified, 17% were caused by weather (wind/rain), and 9% were caused by underground conductor failures. Each failed cable was repaired or replaced during 2007 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2008. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in 2006, and a VFI switchgear was installed in November 2006. In addition, this feeder has been redesigned and is being addressed as part of the Bowie Electric Reliability Action Plan (BERAP) from an infrastructure perspective in 2009. Tree trimming on this feeder was most recently completed in April 2008 as part of the BERAP.

Feeder 7129

Feeder 7129 supplies approximately 1,150 customers in the Hereford area of Baltimore County. During 2007, 53% of the customer interruptions were caused by trees, 26% were caused by equipment failures, 13% were caused by miscellaneous events, 3% were caused by weather, 3% were caused by public interference (vehicle-hits), 1% was caused by animals, and 1% was caused by unknown events. Tree trimming on this feeder was last performed in August 2007, and an inspection performed determined that localized tree trimming and overhang removals were needed and completed in April 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. The design of this feeder has been studied and Distribution Automation reclosers and electronic resetable sectionalizing were installed with work being completed on mains in 2005 and on taps in 2007.

Feeder 7138

Feeder 7138 supplies approximately 1,000 customers in the Lutherville area of Baltimore County. During 2007, 76% of the customer interruptions were caused by trees, 10% were caused by unknown events where the cause could not be identified, 6% were caused by overhead conductor failures, 5% were caused by weather, 2% were caused by underground conductor failures, and 1% was caused by animals. Tree trimming on this feeder was last performed in December 2006. An additional inspection performed determined that localized tree trimming and overhang removals were needed and completed in May 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in May 2008. In addition, BGE completed the identified cable replacement opportunity in April 2008. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed with work being completed in 2007.

Feeder 7609

Feeder 7609 supplies approximately 1,810 customers in the Columbia area of Howard County. During 2007, 100% of the customer interruptions were caused by underground conductor failures. Each failed cable was repaired or replaced during 2007 as part of the service restoration and repair process . In addition, BGE has identified four cable replacement opportunities, two of which have been completed (May 2008 and March 2009) and the remaining are in various stages of the process and are intended to be completed by the end of the third *quarter of 2009. The design of this feeder has been studied, and a VFI switchgear was installed in October 2007. This feeder was scheduled for routine cycle trimming which was completed in April 2008. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2008.*

Feeder 7832

Feeder 7832 supplies approximately 1,980 customers in the Hollins Market and Union Square areas of Baltimore City. During 2007, 56% of the customer interruptions were caused by unknown events where the cause could not be identified, 17% were caused by underground conductor failures, 17% were caused by overload, 9% were caused by overhead conductor failures, and 1% was caused by animals. Tree trimming on this feeder was most recently completed in May 2006. An additional inspection performed determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this trimming was completed in February 2008. BGE conducted an overhead equipment and conductor inspection in March 2008 and related deficiencies were corrected in April 2008. The overload issue was resolved in August 2007 through a load transfer from C phase to A phase on feeder 7832.

Feeder 8072

Feeder 8072 supplies approximately 1,525 customers in the Glen Arm and Long Green areas of Baltimore County. During 2007, 39% of the customer interruptions were caused by trees, 33% were caused by weather (18% were caused by lightning, and 15% were caused by wind/rain), 14% were caused by equipment failures, 12% were caused by unknown events where the cause could not be identified, 1% was caused by animals, and 1% was caused by public interference. Tree trimming on this feeder was most recently completed in February 2006. An additional inspection performed determined that localized tree trimming and overhang removals were needed and completed in May 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. The design of this feeder has been studied and Distribution Automation reclosers, electronic resetable sectionalizing, and additional fusing were installed with work being completed in 2006.

Feeder 7003

Feeder 7003 supplies approximately 1,575 customers in the Baker Street area of Baltimore City. During 2007, 39% of the customer interruptions were caused by trees, 23% were caused by public interference (cable dig-ins), 20% were caused by foreign objects, 9% were caused by overhead conductor failures, 6% were caused by weather, 2% were caused by unknown events where the cause could not be identified, and 1% was caused by animals. Tree trimming on this feeder was most recently completed in September 2007. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in August 2008. The design of this feeder has been studied and Distribution Automation reclosers and additional fusing were installed in April 2008.

Feeder 7232

Feeder 7232 supplies approximately, 1,520 customers in the Hampstead area of Carroll County, and the Upperco area of Baltimore County. During 2007, 48% of the customer interruptions were caused by unknown events where the cause could not be identified, 19% were caused by conductor contact, 18% were caused by underground conductor failure, 7% were caused by overhead conductor failures, 3% were caused by public interference (vehicle-hits), 2% were caused by trees, 2% were caused by weather, and 1% was caused by animals. Tree trimming on this feeder was most recently performed in November 2007. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in November 2008.

The design of this feeder was studied and Distribution Automation reclosers and additional fusing were installed in November 2006.

Feeder 7123

Feeder 7123 supplies approximately 1,425 customers in the Campus Hills and Hampton areas of Baltimore County. During 2007, 44% of the customer interruptions were caused by trees, 28% were caused by overhead conductor failures, 13% were caused by unknown events where the cause could not be identified, 8% were caused by miscellaneous events, 5% were caused by underground conductor failures, 1% was caused by animal,s and 1% was caused by weather. This feeder was scheduled for routine cycle trimming which was completed in October 2008. BGE conducted an overhead equipment and conductor inspection and related deficiencies were corrected in August 2008. The design of this feeder has been studied and Distribution Automation reclosers and additional fusing were installed in June 2006.

Feeder 8425

Feeder 8425 supplies approximately 930 customers in the Highland Beach area of Anne Arundel County. During 2007, 53% of the customer interruptions were caused by trees, 21% were caused by animals, 19% were caused by overhead conductor failures, 5% were caused by weather, 1% was caused by equipment failures, and 1% was caused by miscellaneous events. Tree trimming on this feeder was most recently completed in July 2007. In addition, BGE inspected this feeder for enhanced trimming opportunities beyond the routine trimming standards and identified that no additional work is required. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in August 2008. The design of this feeder has been studied and Distribution Automation reclosers and additional fusing were installed in December 2007.

Feeder 7555

Feeder 7555 supplies approximately 2,780 customers in the Middle River and Victory Villa areas of Baltimore County. During 2007, 47% of the customer interruptions were caused by overhead conductor failures, 28% were caused by public interferences (vehicle-hits), 21% were caused by trees, 3% were caused by underground conductor failures, and 1% was caused by weather. Tree trimming on this feeder was most recently completed in May 2007. BGE conducted an overhead equipment and conductor inspection and related deficiencies were corrected in July 2008. The design of this feeder was studied, and Distribution Automation reclosers and additional fusing were recommended to be installed in 2008. However, the job was redesigned to resolve the permitting issues and will be completed in 2009.

Feeder 8734

Feeder 8734 supplies approximately 1,440 customers in the New Hampshire Avenue area of Montgomery County. During 2007, 49% of the customer interruptions were caused by trees, 25% were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 10% were caused by overload, 10% were caused by overhead conductor failures, 3% were caused by underground conductor failures, and 3% were caused by public interference. Tree trimming on this feeder was most recently completed in March 2005. An additional inspection performed determined that localized tree trimming and overhang removals were needed and completed in April 2008. BGE conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. The design of this feeder was studied and Distribution Automation reclosers, electronic resetable sectionalizing and additional fusing were installed in December 2006. A new feeder 8735 was completed in April 2009 to provide load relief to Feeder 8734 with cut-in pending. This new feeder also significantly reduces the exposure of feeder 8734 resulting in improved reliability.

Feeder 13330

Feeder 13330 supplies approximately 26 customers in the Highlandtown area of Baltimore City. During 2007, 100% of the customer interruptions were caused by underground conductor failures. Each failed cable was replaced during 2007 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2008. Thermovision and visual inspection of this feeder was completed in August 2007 with no reliability deficiencies being found.

Feeder 13971

Feeder 13971 supplies approximately 8 customers in the Dundalk area of Baltimore County and Point Breeze area of Baltimore City. During 2007, 50% of the customer interruptions were caused by underground conductor failures, and 50% were caused by unknown events where the cause could not be identified. Each failed cable was replaced during 2007 as part of the service restoration and repair process. Tree trimming on this feeder was completed in May 2006 and localized tree trimming and overhang removals were completed in February 2008. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008. Thermovision and visual inspection of this feeder was most recently completed in April 2008 with no reliability deficiencies being found.

Feeder 13928

Feeder 13928 supplies approximately 16 customers in the Front Street area of Baltimore City. During 2007, 100% of the customer interruptions were caused by underground conductor failures. Each failed cable was replaced during 2007 as part of the service restoration and repair process. Thermovision and visual inspection of this feeder was completed in January 2007 with no reliability deficiencies being found.

Feeder 4371

Feeder 4371 supplies approximately 535 customers in the Washington Hill area of Baltimore City. During 2007, 54% were caused by underground conductor failures, 29% of the customer interruptions were caused by weather (lightning), 12% were caused by miscellaneous events and 5% were caused by public interference. Each failed cable was repaired or replaced during 2007 as part of the service restoration and repair process. Tree trimming on this feeder was most recently completed in May 2006 and localized tree trimming and overhang removals were completed in February 2008 with BGE performing aggressive hazard tree removals along the three phase main. BGE also conducted an overhead equipment and conductor inspection and related deficiencies were corrected in April 2008.

Feeder 4405

Feeder 4405 supplies approximately 770 customers in the Mondawmin area of Baltimore City. During 2007, 59% of the customer interruptions were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 20% were caused by weather (wind/rain), 19% were the result of public interferences (conductor contact) and 2% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in February 2006 and localized tree trimming and overhang removals were completed in February 2008. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2008.

Feeder 4806

Feeder 4806 supplies approximately 215 customers in the Franklin and Calverton Street area of Baltimore City. During 2007, 74% of the customer interruptions were caused by weather events (wind/rain), 25% were caused by overhead conductor failures, and 1% was caused by unknown events. Tree trimming on this feeder was most recently completed in February 2008. BGE also *conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2008.*

(b) The annual report two years after the identification of the operating district or feeders as having the poorest performance shall include the ordinal ranking representing the feeder's reliability during the current reporting period.

BGE's poorest performing 2% of the 13.8 kV distribution feeders (19 out of 966 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 121 total 13000 series distribution feeders and 2% of the 4.4 kV distribution feeders (3 out of 128 total 4.4 kV distribution feeders) in 2006 had the following ordinal rankings in 2008. Ordinals for 2008 range from 1 (worst) to 124 (best) for 4.4 kV feeder, from 1 (worst) to 126 (best) for 13000 series feeders and from 1 (worst) to 993 (best) for 13.8 kV feeders, ranked by Composite Reliability Index. Ranking excludes major event data.

13.8 kV Feeder	Substation	2008 Ordinal Ranking
7610	WILDE LAKE	140
7776	HIGH RIDGE	815
7285	WILLIS SCHOOL	391
7236	UNION MILLS	282
7757	BEAR BRANCH	26
7443	MITCHELLVILLE	96
7446	MITCHELLVILLE	220
7434	PRIEST BRIDGE	62
7614	WILDE LAKE	49
7750	SANDY SPRING	904
8445	BESTGATE	452
8301	ROUND BAY MODULAR	64
7089	KINGSVILLE	344
7243	FINKSBURG	37
8074	GLENARM	136
7062	HAVRE DE GRACE	365
8462	PRIEST BRIDGE	313
8464	PRIEST BRIDGE	379
8413	LEVITT	644

13000 series Feeder	Substation	2008 Ordinal Ranking
13987	NEWGATE	61
13758	SOUTH BALTIMORE	10
13933	MONUMENT STREET OUTDOOR	174

4.4 kV Feeder	Substation	2008 Ordinal Ranking
4703	SOUTH BALTIMORE	Retired
4812	CALVERTON	2
4268	CENTER	57

Feeder 4812 on the above list did not register significant reliability improvements. Explanations of recent outage causes are listed below. Because BGE is committed to improving the reliability of this feeder, we will be more aggressive in our analysis to identify and correct the poor performance and will include its progress in future reports.

Feeder 4812

Feeder 4812 supplies approximately 502 customers in the Calverton area of Baltimore City. During 2008, 36% of the customer interruptions were caused by trees, 17% were caused by underground conductor failures, 17% were caused by equipment failures, 17% were caused by weather (wind/rain) and 13% were caused by miscellaneous events.

(9) Momentary Interruptions. A utility shall maintain information which it collects on momentary interruptions for five years.

BGE collects momentary outage information on devices that are monitored by SCADA (e.g., Distribution Automation reclosers, substation breakers, etc.). However, BGE does not routinely collect counter readings from hydraulic reclosers.

Baltimore Gas and Electric Company
COMAR 20.50.07.06 Reporting of Reliability Indices – CY 2009

(1) System-Wide Indices. A utility shall report SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

SAIFI – 1.28
SAIDI – 3.60
CAIDI – 2.81

Note: SAIFI, SAIDI and CAIDI are calculated using COMAR 20.50.01.03 Definitions.

(b) All interruption data minus major event interruption data.

SAIFI – 1.28
SAIDI – 3.60
CAIDI – 2.81

BGE experienced no major events during 2009; therefore, the data in (b) are the same as in (a).

(2) District Indices. A cooperatively-owned utility shall provide SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

(b) Major event interruption data excluded.

Requirements (a) & (b) are not applicable to BGE since BGE is an Investor Owned Utility.

(3) Feeder Indices. An investor-owned utility shall provide SAIDI, SAIFI, and CAIDI for 2% of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability. The indices shall be calculated and reported with 2 sets of input data.

(a) All interruption data

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
8783	SUMMERS RUN	6.19	7.33	17.12	2.34
8734	ASHTON MODULAR	6.00	6.09	8.15	1.34
8472	CROWNSVILLE	5.69	6.12	31.55	5.16
7903	SNOWDEN RIVER	5.40	5.80	21.80	3.76
7236	UNION MILLS	5.18	6.43	15.03	2.34
7351	MILL CREEK	4.79	6.34	9.78	1.54
7696	COOKSVILLE	4.43	4.78	15.24	3.19
7593	FULLERTON	4.41	5.42	9.85	1.82
7849	GREENE STREET	4.36	5.05	6.95	1.38
7446	MITCHELLVILLE	4.32	5.06	3.25	0.64
7534	BAYNESVILLE	4.22	4.75	12.29	2.58
8463	PRIEST BRIDGE	3.96	3.91	16.14	4.12
7844	GREENE STREET	3.93	4.55	7.62	1.67
7070	JOPPATOWNE	3.82	3.97	7.60	1.91
7555	MIDDLE RIVER	3.82	4.23	6.59	1.56
8521	BENGIES #10 MOBILE	3.72	3.52	8.65	2.46
7141	JACKSONVILLE	3.57	3.04	9.44	3.10
8451	NAJ	3.52	4.24	5.19	1.22
7352	MILL CREEK	3.52	4.60	22.38	4.87
8799	REISTERSTOWN	3.45	3.86	11.86	3.07
7693	COOKSVILLE	3.37	2.83	10.99	3.89

13000 Series Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
13758	SOUTH BALTIMORE	4.71	6.14	13.48	2.19
13946	WESTPORT BROOM FACTORY	2.88	3.33	16.33	4.90
13913	WESTPORT	2.80	3.30	74.00	22.42

4.4 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
4823	CLIFTON PARK	6.54	8.33	16.10	1.93
4416	WOODBROOK	5.20	5.28	11.22	2.12
4403	WOODBROOK	5.05	6.53	9.02	1.38

(b) All interruption data minus major event interruption data:

BGE's "Worst Feeder Program" consists of plans to improve reliability performance for the top 2% of the 13.8 kV distribution feeders (21 out of 1025 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 119 total 13000 series distribution feeders) and 2% of the 4.4 kV distribution feeders (3 out of 112 total 4.4 kV distribution feeders) based on all interruption data minus major event interruption data. There were no major events experienced during 2009.

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
8783	SUMMERS RUN	6.19	7.33	17.12	2.34
8734	ASHTON MODULAR	6.00	6.09	8.15	1.34
8472	CROWNSVILLE	5.69	6.12	31.55	5.16
7903	SNOWDEN RIVER	5.40	5.80	21.80	3.76
7236	UNION MILLS	5.18	6.43	15.03	2.34
7351	MILL CREEK	4.79	6.34	9.78	1.54
7696	COOKSVILLE	4.43	4.78	15.24	3.19
7593	FULLERTON	4.41	5.42	9.85	1.82
7849	GREENE STREET	4.36	5.05	6.95	1.38
7446	MITCHELLVILLE	4.32	5.06	3.25	0.64
7534	BAYNESVILLE	4.22	4.75	12.29	2.58
8463	PRIEST BRIDGE	3.96	3.91	16.14	4.12
7844	GREENE STREET	3.93	4.55	7.62	1.67
7070	JOPPATOWNE	3.82	3.97	7.60	1.91
7555	MIDDLE RIVER	3.82	4.23	6.59	1.56
8521	BENGIES #10 MOBILE	3.72	3.52	8.65	2.46
7141	JACKSONVILLE	3.57	3.04	9.44	3.10
8451	NAJ	3.52	4.24	5.19	1.22
7352	MILL CREEK	3.52	4.60	22.38	4.87
8799	REISTERSTOWN	3.45	3.86	11.86	3.07
7693	COOKSVILLE	3.37	2.83	10.99	3.89

13000 Series Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
13758	SOUTH BALTIMORE	4.71	6.14	13.48	2.19
13946	WESTPORT BROOM FACTORY	2.88	3.33	16.33	4.90
13913	WESTPORT	2.80	3.30	74.00	22.42

4.4 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
4823	CLIFTON PARK	6.54	8.33	16.10	1.93
4416	WOODBROOK	5.20	5.28	11.22	2.12
4403	WOODBROOK	5.05	6.53	9.02	1.38

(c) Feeders shall not be included as having the poorest reliability in two consecutive reports.

No feeders listed in the CY 2008 report as having poor reliability are included in this report.

(4) The method used by a utility to identify the district and feeders with poorest reliability shall be approved by the Commission and be included in the report.

In order to determine which distribution feeders and areas have the poorest performance, BGE utilizes a Composite Reliability Index (CRI). In the event that two feeders have identical composite reliability indices, the feeders are then ranked based on the most recent year's feeder SAIFI. The formula for the index is:

$$CRI = 0.75 \times SAIFI_{2009} + 0.25 \times SAIFI_{2008}$$

(5) Feeders included in the report, which serve customers in Maryland and one or more bordering jurisdiction shall be identified. The report shall include the percentage of customers located in Maryland and the percentage of customers located in bordering jurisdictions.

Not applicable to BGE. BGE has no feeders outside Maryland.

(6) Major Event Interruption Data. The report shall include the time periods during which major event interruption data was excluded from the indices, along with a brief description of the interruption causes during each time period.

BGE experienced no major events in 2009.

(7) Actions for Operating District and Feeders with Poorest Reliability.

(a) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under C.(3) of this regulation.

BGE will review the design for each feeder reported under this section to identify potential improvements. BGE will also trim the trees on feeders as needed, conduct a thorough equipment inspection on each feeder and correct any deficiencies found during the inspections. These inspections will permit the identification of potential outage causes and will, as a result, reduce the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process and have since been repaired or replaced. In some cases, underground cable replacement will be performed if the underground conductor experiences an excessive number of failures.

Feeder 8783

Feeder 8783 supplies approximately 1,109 customers in the Woodwardville area of Anne Arundel County. During 2009, 91% of the customer interruptions were caused by trees, 7% were caused by overhead conductor failures and 2% were caused by weather (wind/rain). Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an *overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.*

Feeder 8734

Feeder 8734 supplies approximately 529 customers in the Ashton area of Montgomery County. During 2009, 93% of the customer interruptions were caused by weather (47% were caused by wind/rain and 46% were caused by ice/snow), 5% were caused by trees, 1% were caused by overhead conductor failures and 1% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder was studied, and Distribution Automation reclosers and additional fusing were installed on a portion of the feeder in February 2010. Station relays were reset in April 2010 to coordinate with the Distribution Automation reclosers. In addition, a project completed in 2009 created a new feeder that reduced the length and exposure of this feeder.

Feeder 8472

Feeder 8472 supplies approximately 1,183 customers in the Severn Run area of Anne Arundel County. During 2009, 81% of the customer interruptions were caused by trees, 16% were caused by a vehicle-hit, 2% were caused by wildlife and 1% were caused by weather (lightning). Tree trimming on this feeder was most recently completed in October 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2010. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed in 2010.

Feeder 7903

Feeder 7903 supplies approximately 670 customers in the Dickinson area of Howard County. During 2009, 56% of the customer interruptions were caused by underground cable failures, 20% were caused by underground equipment failures, 20% were caused by trees and 4% were caused by a company dig-in. Tree trimming on this feeder was most recently completed in May 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE has identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the third quarter of 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed in 2010.

Feeder 7236

Feeder 7236 supplies approximately 1,352 customers in Union Mills in Carroll County. During 2009, 36% of the customer interruptions were caused by trees, 22% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 21% were caused by weather (wind/rain), 9% were caused by public interference (vehicle-hits), 8% were caused by overhead equipment failures and 4% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in April 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE has identified three cable replacement opportunities that are currently in design or construction and are scheduled for completion by *the end of the fourth quarter of 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed in 2010.*

Feeder 7351

Feeder 7351 supplies approximately 1,013 customers in Severna Park in Anne Arundel County. During 2009, 42% of the customer interruptions were due to unknown causes (consisted mainly of feeder lockouts where no system damage was identified), 35% were caused by overhead equipment failures, 18% were caused by trees and 5% were caused by overhead conductor failures. Tree trimming on this feeder was most recently completed in April 2008. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE has identified two cable replacement opportunities that are currently in initiation or design and are scheduled for completion by the end of the fourth quarter of 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in November 2009 and January 2010.

Feeder 7696

Feeder 7696 supplies approximately 1,077 customers in the Glenwood area of Howard County. During 2009, 81% of the customer interruptions were caused by trees, 10% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 7% were caused by public interference (vehicle-hits), 1% were caused by underground cable failures and 1% were caused by weather (lightning). Tree trimming on this feeder was most recently completed in 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE has identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the third quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 7593

Feeder 7593 supplies approximately 1,921 customers in Fullerton in Baltimore County. During 2009, 37% of the customer interruptions were caused by underground equipment failures, 35% were caused by weather (lightning), 17% were from an unknown cause (a feeder lockout where no system damage was identified) and 11% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in September 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. BGE has identified two cable replacement opportunities that are currently in construction and are scheduled for completion by the end of the second quarter of 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2010 and is in the process of correcting the deficiencies identified.

Feeder 7849

Feeder 7849 supplies approximately 1,231 customers in the Franklin Square area of Baltimore City. During 2009, 52% of the customer interruptions were caused by underground cable failures, 25% were caused by underground equipment failures, 21% were from an unknown cause (a feeder lockout where no system damage was identified), 1% were caused by trees and 1% were caused by public interference (foreign objects blown by wind). Tree trimming on this feeder was most recently completed in 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. Each failed cable was repaired or replaced during 2009 as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2010 and corrected the deficiencies identified.

Feeder 7446

Feeder 7446 supplies approximately 1,048 customers in the Pointer Ridge area of Prince George's County. During 2009, 28% of the customer interruptions were caused by trees, 21% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 20% were caused by weather (wind/rain), 20% were caused by overhead conductor failures, 9% were caused by public interference (vehicle-hit), 1% were caused by overhead equipment failures and 1% were due to other causes. Tree trimming on this feeder was most recently completed in April 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE has identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the fourth quarter of 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010.

Feeder 7534

Feeder 7534 supplies approximately 473 customers in the Cromwood area of Baltimore County. During 2009, 45% of the customer interruptions were caused by trees, 34% were caused by overhead equipment failures and 21% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in January 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder has been studied and Distribution Automation reclosers and additional fusing will be installed in 2010.

Feeder 8463

Feeder 8463 supplies approximately 551 customers in Bowie in Prince George's County. During 2009, 42% of the customer interruptions were caused by underground cable failures, 32% were from underground equipment failures and 26% were caused by weather (wind/rain). Tree trimming on this feeder was most recently completed in June 2008 as part of the Bowie Electric Reliability Action Plan (BERAP). BGE has identified one cable replacement opportunity that is currently in construction and is scheduled for completion by the end of the second quarter of 2010. This includes the replacement of a switchgear. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. A project that will reconfigure the feeder and create additional feeder tie capabilities is scheduled for completion in June 2010. BGE also conducted an overhead equipment and conductor inspection and all *related deficiencies were corrected in March 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.*

Feeder 7844

Feeder 7844 supplies approximately 1,137 customers in the Lexington Terrace area of Baltimore City. During 2009, 80% of the customer interruptions were caused by underground cable failures, 15% were caused by wildlife, 3% were caused by trees, 1% were caused by weather (wind/rain) and 1% were due to other causes. Each failed cable was repaired or replaced during 2009 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 7070

Feeder 7070 supplies approximately 1,727 customers in Edgewood in Harford County. During 2009, 55% of the customer interruptions were caused by trees, 31% were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 6% were caused by public interference (vehicle-hit), 5% were caused by underground cable failures and 3% were caused by weather. Tree trimming on this feeder was most recently completed in December 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 7555

Feeder 7555 supplies approximately 3,012 customers in Middle River in Baltimore County. During 2009, 28% of the customer interruptions were caused by underground cable failures, 24% were caused by weather (wind/rain), 24% were caused by underground equipment failures and 24% were caused by public interference (vehicle-hits and a dig-in). Tree trimming on this feeder was most recently completed in May 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE has identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the third quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed and overhead reconductoring will be completed in 2010.

Feeder 8521

Feeder 8521 supplies approximately 2,399 customers in Bowleys Quarters in Baltimore County. During 2009, 26% of the customer interruptions were caused by company interference (new pole was undermined and leaned into the feeder), 17% were due to miscellaneous causes (consisted mainly of an outage due to a crossarm fire), 15% were caused by trees, 15% were caused by overhead conductor failures, 13% were caused by public interference (vehicle-hit), 8% were caused by weather (lightning), 4% were caused by overhead equipment failures and 2% were *caused by wildlife. Tree trimming on this feeder was most recently completed in March 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.*

Feeder 7141
Feeder 7141 supplies approximately 1,056 customers in the Jacksonville area of Baltimore County. During 2009, 68% of the customer interruptions were caused by trees, 15% were caused by overhead equipment failures, 6% were due to unknown causes, 5% were caused by weather (lightning), 3% were caused by overhead conductor failures, 1% were caused by wildlife, 1% were caused by underground cable failures and 1% were due to other causes. Tree trimming on this feeder was most recently completed in December 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 8451
Feeder 8451 supplies approximately 1,285 customers in the Severn Run area of Anne Arundel County. During 2009, 71% of the customer interruptions were caused by public interference (vehicle-hit), 22% were caused by trees, 5% were caused by weather (lightning) and 2% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in June 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 7352
Feeder 7352 supplies approximately 803 customers in the Arnold area of Anne Arundel County. During 2009, 68% of the customer interruptions were caused by trees, 22% were caused by company interference (dig-in), 6% were caused by overhead equipment failures and 4% were caused by overhead conductor failures. Tree trimming on this feeder was most recently completed in March 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. BGE identified one cable replacement opportunity which was completed in April 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in December 2009 and February 2010. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed in 2010.

Feeder 8799
Feeder 8799 supplies approximately 1,134 customers in Glyndon in Baltimore County. During 2009, 33% of the customer interruptions were due to unknown causes (consisted mainly of a feeder lockout and a recloser lockout where no system damage was identified), 31% were caused by trees, 27% were caused by public interference (vehicle-hits and dig-ins), 5% were caused by weather (4% was caused by lightning and 1% were caused by wind/rain), 2% were caused by

underground cable failures, 1% were caused by wildlife and 1% were due to other causes. Tree trimming on this feeder was most recently completed in December 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. BGE has identified two cable replacement opportunities. One is currently in design and is scheduled for completion by the end of the fourth quarter of 2010. The other was completed in February 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 7693

Feeder 7693 supplies approximately 1,163 customers in the Woodbine area on the border between Carroll and Howard Counties. During 2009, 35% of the customer interruptions were caused by public interference (vehicle-hits and dig-ins), 30% were caused by trees, 26% were caused by overhead conductor failure, 6% were caused by weather (wind/rain), 2% were caused by underground cable failure and 1% were due to miscellaneous causes. Tree trimming on this feeder was most recently completed in July 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. BGE has identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the fourth quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 13758

Feeder 13758 supplies approximately 21 customers in the Brooklyn area of South Baltimore City. During 2009, 49% of the customer interruptions were caused by overhead cable failures, 43% were caused by wildlife, 7% were caused by weather (6% were caused by lightning and 1% were caused by wind/rain) and 1% were caused by overhead equipment failures. Poles and equipment were replaced in February 2010 to improve customer reliability. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 13946

Feeder 13946 supplies approximately 3 customers in the Carroll Park area of Baltimore City. During 2009, 50% of the customer interruptions were caused by overhead conductor failures, 40% were caused by public interference (vehicle-hit) and 10% were due to unknown causes (consisted of a blown fuse where no system damage was identified). Tree trimming on this feeder was most recently completed in July 2009. Failed overhead conductors were repaired or replaced during 2009 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies.

Feeder 13913

Feeder 13913 supplies approximately 10 customers in Mount Vernon in Baltimore City. During 2009, 100% of the customer interruptions were caused by underground cable failures in duct. Each failed cable was replaced during 2009 as part of the service restoration and repair process. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 4823

Feeder 4823 supplies approximately 546 customers in Broadway East in Baltimore City. During 2009, 50% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 13% were caused by weather (lightning), 13% were caused by wildlife, 12% were caused by underground cable failures and 12% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in July 2009. Each failed cable was replaced during 2009 as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder will be performed in May 2010 and any identified deficiencies will be corrected. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 4416

Feeder 4416 supplies approximately 865 customers in the Druid Heights area of Baltimore City. During 2009, 60% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 24% were caused by underground cable failures and 16% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in December 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder will be performed in May 2010 and any identified deficiencies will be corrected. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 4403

Feeder 4403 supplies approximately 672 customers in the Penn North area of Baltimore City. During 2009, 83% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified) and 17% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in December 2006 and is due for routine cycle trimming in 2010. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder will be performed in May 2010 and any identified deficiencies will be corrected. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

(b) Each utility shall briefly describe the actions taken or planned to improve reliability. When the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

BGE plans include remedial actions for all feeders identified as worst performers.

(8) Evaluation of Remedial Actions. For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports.

(a) The annual report for the year following the identification of the operating district and feeders as having the poorest performance shall provide a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions.

BGE reviewed the design for each feeder reported under this section to identify potential improvements. BGE also trimmed the trees on each feeder as needed, conducted a thorough equipment and conductor inspection on each feeder and corrected any deficiencies found during the inspections. Those inspections permitted the identification of potential outage causes and, as a result, reduced the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process and have since been repaired or replaced. In some cases, underground cable replacement was performed if the underground conductor experienced an excessive number of failures.

Feeder 8102

Feeder 8102 supplies approximately 1,959 customers in the Mount Washington area of Baltimore. During 2008, 40% of the customer interruptions were caused by underground conductor failures, 24% were caused by weather (23% were caused by lightning, and 1% were caused by wind/rain), 15% were caused due to equipment failures, 11% were caused by public interference (foreign objects blown by wind), 6% were caused due to trees, 2% were caused by unknown events, 1% were caused by overhead conductor failure and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in December 2008. BGE identified three cable replacement opportunities: one cable replacement job was completed in December 2009 and the other two are currently in construction to be completed by the end of the second quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 7633

Feeder 7633 supplies approximately 225 customers in the Oakland Mills area in Howard County. During 2008, 54% of the customer interruptions were caused by underground conductor failures, 20% were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 13% were caused by weather, and 13% were caused by public interference (dig-ins). Tree trimming on this feeder was most recently completed in June 2008. BGE identified two cable replacement opportunities: one is currently in construction and the other is currently in design and both are intended to be completed by the end of the second quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 7348

Feeder 7348 supplies approximately 2,285 customers in the Marley Creek area of Anne Arundel County. During 2008, 68% of the customer interruptions were caused by underground conductor failures, 17% were caused by overhead conductor failures, 14% were caused by trees, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in December 2008. BGE identified a cable replacement opportunity that is currently in construction and is intended to be completed by the end of the second quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found. The design of this feeder was studied, and Distribution Automation reclosers and additional fusing will be installed and reconductoring will occur in 2010.

Feeder 8420

Feeder 8420 supplies approximately 1,801 customers in the Harwood area of Anne Arundel County. During 2008, 34% of the customer interruptions were caused by trees, 24% were caused by weather (wind/rain), 17% were caused by equipment failures, 13% were caused by underground conductor failure, and 12% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified). An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder was trimmed during the routine maintenance schedule in April 2009 and trimming beyond routine trimming standards was performed. BGE identified a cable replacement opportunity that was completed in October 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. In addition, BGE also performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and corrected the deficiencies identified.

Feeder 7130

Feeder 7130 supplies approximately 1,028 customers in the Monkton area of Baltimore County. During 2008, 50% of the customer interruptions were caused by trees, 26% were caused by weather (15% were caused by lightning, and 11% were caused by wind/rain), 20% were caused by equipment failures, 3% were caused by overhead conductor failure, and 1% were caused by public interference. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder was trimmed during the routine maintenance schedule in July 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in May 2009. The design of this feeder was studied, and Distribution Automation reclosers and additional fusing will be installed in 2010.

Feeder 7257

Feeder 7257 supplies approximately 819 customers in the Ellicott City area of Howard County. During 2008, 74% of the customer interruptions were caused by trees, 14% were caused by underground conductor failures, 11% were caused by overhead conductor failures, and 1% were caused by unknown events. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder was trimmed during the routine maintenance schedule in May and November 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in

April 2009. The design of this feeder was studied and Distribution Automation reclosers were installed in January 2008.

Feeder 7616

Feeder 7616 supplies approximately 1,739 customers in the Village of Hickory Ridge area of Howard County During 2008, 49% of the customer interruptions were caused by trees, 20% were caused by equipment failures, 13% were caused by public interference (vehicle-hits), 12% were caused by weather (7% were caused by lightning and 5% were caused by wind/rain), 5% were caused by overhead conductor failures, and 1% were caused by underground conductor failures). An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in March and April 2009 and trimming beyond BGE's routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2009. The design of this feeder was studied and Distribution Automation reclosers and fault indicators were installed in May 2009.

Feeder 7658

Feeder 7658 supplies approximately 1,087 customers in the Village of Owen Brown area of Howard County. During 2008, 95% of the customer interruptions were caused by underground conductor failures, and 5% were caused by equipment failures. BGE identified a cable replacement opportunity that was completed in October 2008. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.

Feeder 7382

Feeder 7382 supplies approximately 68 customers in the Fairfield area of Baltimore City. During 2008, 41% of the customer interruptions were caused by weather (39% were caused by wind/rain and 1% were caused by lightning), 36% were caused by overhead conductor failures, and 23% were caused by equipment failures. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder was trimmed during the routine maintenance schedule in April 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009. The design of this feeder was studied and Distribution Automation reclosers were installed in August 2009.

Feeder 8052

Feeder 8052 supplies approximately 1,528 customers in the Jarrettsville area of Harford County. During 2008, 55% of the customer interruptions were caused by underground conductor failures, 19% were caused by trees, 19% were caused by public interferences (18% were caused by vehicle-hits and 1% were caused by foreign objects blown by wind), 6% were caused by weather, and 1% were caused by equipment failures. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder mains were trimmed during the routine maintenance schedule in May 2009 and trimming of the taps was completed in June. Trimming beyond routine trimming standards was performed. BGE identified a cable replacement opportunity and the job was completed in June 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in May 2009.

Feeder 8604

Feeder 8604 supplies approximately 2,046 customers in the Federal Hill area of Baltimore City. During 2008, 29% of the customer interruptions were caused by public interferences (15% were caused by vehicle-hits and 15% were caused by foreign objects blown by wind), 19% were caused by underground conductor failures, 19% were caused by equipment failures, 16% were caused by weather (wind/rain), 15% were caused by trees, and 2% were caused by miscellaneous events. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in March and April 2009 and trimming beyond BGE's routine trimming standards was performed. Two hazard trees were removed as part of the trimming effort. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2009. In addition, BGE identified a cable replacement opportunity that was completed in January 2009. The design of this feeder was studied and Distribution Automation reclosers were installed in July 2009. BGE also performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and corrected the deficiencies identified.

Feeder 8682

Feeder 8682 supplies approximately 902 customers in the Dayton area of Howard County. During 2008, 40% of the customer interruptions were caused by trees, 39% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 14% were caused by overhead conductor failures, 5% were caused by public interference and 2% were caused by equipment failures. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in May 2009 and trimming beyond BGE's routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009.

Feeder 7381

Feeder 7381 supplies approximately 561 customers in the Brooklyn area of Baltimore City. During 2008, 49% of the customer interruptions were caused by overhead conductor failures (vast majority occurring during storms), 19% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 18% were caused by trees, 8% were caused by weather, 5% were caused by miscellaneous events and 1% were caused by equipment failures. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder was trimmed during the routine maintenance schedule in April 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009. The design of this feeder was studied and Distribution Automation reclosers and additional fusing were installed in September 2009. Station relays were reset in April 2010 to coordinate with the new Distribution Automation reclosers.

Feeder 7617

Feeder 7617 supplies approximately 803 customers in the Villages of Hickory Ridge area of Howard County. During 2008, 49% of the customer interruptions were caused by trees, 39% were caused by equipment failures, 4% were caused by weather, 4% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 1% were caused by underground conductor failures, 1% were caused by animals and 1% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in October 2008. BGE also conducted an overhead equipment and conductor inspection and all related *deficiencies were corrected in April 2009. In addition, BGE also performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and corrected the deficiencies identified. The design of this feeder was studied, and Distribution Automation recloser installations and an underground main reconductoring project are currently in construction with expected completion in May 2010.*

Feeder 8101

Feeder 8101 supplies approximately 2,088 customers in the Rodgers Forge area of Baltimore County. During 2008, 37% of the customer interruptions were caused by trees, 22% were caused by public interference (19% were caused by vehicle-hits and 3% were caused by foreign objects blown by wind), 21% were caused by weather (17% were caused by lightning and 4% were caused by wind/rain), 13% were caused by animals, 5% were caused by overhead conductor failures, and 2% were caused by equipment failures. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. The feeder was trimmed during the routine maintenance schedule in February 2009 and trimming beyond routine trimming standards was performed. BGE identified a cable replacement opportunity and intends to be completed by the end of the third quarter of 2010 (construction will impact a school who requested a delay until summer). BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009.

Feeder 7710

Feeder 7710 supplies approximately 2,301 customers in the Chadwick area of Baltimore County. During 2008, 84% of the customer interruptions were caused by trees, 13% were caused by miscellaneous events, 2% were caused by equipment failures, and 1% were caused by weather. Tree trimming on this feeder was most recently completed in October 2008. BGE identified two cable replacement opportunities: one was completed in October 2009 and the second is currently in construction and is intended to be completed by the end of the third quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. The design of this feeder was studied, and Distribution Automation reclosers were installed in May 2009.

Feeder 8103

Feeder 8103 supplies approximately 677 customers in the Ruxton area of Baltimore County. During 2008, 26% of the customer interruptions were caused by overhead conductor failures, 22% were caused by trees, 16% were caused weather (15% were caused by wind/rain and 1% were caused by lightning), 15% were caused by unknown events (consisted mainly of a feeder lockout where no system damage was identified), 14% were caused by public interference (13% were caused by vehicle-hits and 1% were caused by foreign objects blown by wind), 5% were caused by equipment failures, 1% were caused by underground conductor failures and 1% were caused by animals. Tree trimming on this feeder was most recently completed in September 2008. BGE identified a cable replacement opportunity that is currently in scheduling and is intended to be completed by the end of the second quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009. A portion of this feeder was transferred to feeder 7101. This transfer of a group of customers at the end of the feeder reduces their vegetation exposure and moves them to a better performing feeder. The transfer and related work was completed prior to the 2009 storm season.

Feeder 8272

Feeder 8272 supplies approximately 1,356 customers in the Windsor Mill area of Baltimore County. During 2008, 42% of the customer interruptions were caused by trees, 36% were caused by underground conductor failures, 21% were caused equipment failures, and 1% were *caused by unknown events. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in May 2009 and trimming beyond BGE's routine trimming standards was performed. BGE identified a cable replacement opportunity that was completed in November 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2009 with no reliability deficiencies being found.*

Feeder 8556
Feeder 8556 supplies approximately 671 customers in the Gambrills area of Anne Arundel County. During 2008, 43% of the customer interruptions were caused by trees, 37% were caused by underground conductor failures, 18% were caused by overhead conductor failures, and 2% were caused by equipment failures. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in April 2009 and trimming beyond BGE's routine trimming standards was performed. In addition, BGE identified a cable replacement opportunity that was completed in August 2008. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2009. The design of this feeder was studied, and Distribution Automation reclosers were installed in September 2009.

Feeder 8141
Feeder 8141 supplies approximately 917 customers in the Hampton area of Baltimore County. During 2008, 58% of the customer interruptions were caused by trees, 22% were caused by equipment failures, 17% were caused by underground conductor failures, 2% were caused by weather, and 1% were caused by animals. An inspection performed in 2009 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in May 2009 and trimming beyond BGE's routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in May 2009. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in March 2008 with no reliability deficiencies being found.

Feeder 13602
Feeder 13602 supplies approximately 271 customers in the Hampden area of Baltimore City. During 2008, 50% of the customer interruptions were caused by underground conductor failures and 50% were caused by equipment failures. Each failed cable was replaced as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was replaced after failure. The feeder was trimmed during the routine maintenance schedule in February 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in September 2009. In addition, BGE performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2009 and corrected the deficiencies identified.

Feeder 13302
Feeder 13302 supplies approximately 6 customers in the Highlandtown area of Baltimore City. During 2008, 50% of the customer interruptions were caused by equipment failures, and 50% were caused by weather (lightning). Tree trimming on this feeder was most recently completed in February 2008. In addition, each of the pieces of equipment that failed was replaced after

failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2009.

Feeder 13936

Feeder 13936 supplies approximately 132 customers in the Little Italy area of Baltimore City. During 2008, 99% of the customer interruptions were caused by underground conductor failures and 1% were caused by equipment failure. Each failed cable was replaced during 2008 as part of the service restoration and repair process. BGE performed a Thermovision and visual inspections of all 3-phase pad mounted equipment on this in March 2009 and corrected the deficiencies identified.

Feeder 4430

Feeder 4430 supplies approximately 888 customers in the Forest Park area of Baltimore City. During 2008, 31% of the customer interruptions were caused by trees, 24% were caused by underground conductor failures, 24% were caused by equipment failures, 18% were caused by weather (17 % were caused by wind/rain and 1% were caused by lightning) and 3% were caused by unknown events. Tree trimming on this feeder was most recently completed in October 2008. Each failed cable was repaired or replaced during 2008 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2009.

Feeder 4812

Feeder 4812 supplies approximately 502 customers in the Calverton area of Baltimore City. During 2008, 36% of the customer interruptions were caused by trees, 17% were caused by underground conductor failures, 17% were caused by equipment failures, 17% were caused by weather (wind/rain) and 13% were caused by miscellaneous events. Each failed cable was repaired or replaced during 2008 as part of the service restoration and repair process. The feeder was trimmed during the routine maintenance schedule in February 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and no related deficiencies were found.

Feeder 4828

Feeder 4828 supplies approximately 734 customers in the Clifton Park area of Baltimore City. During 2008, 48% of the customer interruptions were caused by equipment failures, 21% were caused by underground conductor failures, 20% were caused by weather (19% were caused by lightning and 1% were caused by wind/rain) and 11% were caused by trees. The feeder was trimmed during the routine maintenance schedule in February 2009 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in July 2009. Thermovision and visual inspections of all 3 phase pad mounted equipment on this feeder were completed in March 2008 with no reliability deficiencies being found.

(b) The annual report two years after the identification of the operating district or feeders as having the poorest performance shall include the ordinal ranking representing the feeder's reliability during the current reporting period.

BGE's poorest performing 2% of the 13.8 kV distribution feeders (20 out of 979 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 123 total 13000 series distribution feeders and 2% of the 4.4 kV distribution feeders (3 out of 123 total 4.4 kV distribution feeders) in 2007 had the following ordinal rankings in 2009. Ordinals for 2009 range from 1 (worst) to 112 (best) for 4.4 kV feeder, from 1 (worst) to 119 (best) for 13000 series feeders and from 1 (worst) to 1025 (best) for 13.8 kV feeders, ranked by Composite Reliability Index. Ranking excludes major event data.

13.8 kV Feeder	***Substation***	***2009 Ordinal Ranking***
7733	*DORSEY RUN*	*639*
7411	*GREENBURY POINT*	*426*
7440	*MITCHELLVILLE*	*58*
7474	*GLENN DALE*	*423*
7237	*UNION MILLS MOD*	*536*
7283	*MONTPELIER*	*675*
8450	*NAJ*	*153*
7390	*LANSDOWNE*	*695*
8463	*PRIEST BRIDGE*	*12*
7129	*HEREFORD*	*167*
7138	*LUTHERVILLE*	*31*
7609	*WILDE LAKE*	*720*
7832	*GREENE STREET*	*62*
8072	*GLENARM*	*30*
7003	*CENTER*	*408*
7232	*HAMPSTEAD*	*333*
7123	*EAST TOWSON*	*354*
8425	*BAY RIDGE*	*268*
7555	*MIDDLE RIVER*	*15*
8734	*ASHTON MODULAR*	*2*

13000 Series Feeder	***Substation***	***2009 Ordinal Ranking***
13330	*HIGHLANDTOWN*	*4*
13971	*NEWGATE*	*7*
13928	*MONUMENT STREET OUTDOOR*	*115*

4.4 kV Feeder	***Substation***	***2009 Ordinal Ranking***
4371	*BROADWAY*	*8*
4405	*WOODBROOK*	*13*
4806	*CALVERTON*	*79*

Feeders 8463, 7555 and 8734 on the above list did not register significant reliability improvements. Explanations of recent outage causes are listed below. Because BGE is committed to improving the reliability of this feeder, we will be more aggressive in our analysis to identify and correct the poor performance and will include its progress in future reports.

Feeder 8463

Feeder 8463 supplies approximately 551 customers in Bowie in Prince George's County. During 2009, 42% of the customer interruptions were caused by underground cable failures, 32% were from underground equipment failures and 26% were caused by weather (wind/rain). Tree trimming on this feeder was most recently completed in June 2008 as part of the Bowie Electric Reliability Action Plan (BERAP). BGE has identified one cable replacement opportunity that is currently in construction and is scheduled for completion by the end of the second quarter of 2010. This includes the replacement of a switchgear. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. A project that will reconfigure the feeder and create additional feeder tie capabilities is scheduled for completion in June 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected.

Feeder 7555

Feeder 7555 supplies approximately 3,012 customers in Middle River in Baltimore County. During 2009, 28% of the customer interruptions were caused by underground cable failures, 24% were caused by weather (wind/rain), 24% were caused by underground equipment failures and 24% were caused by public interference (vehicle-hits and a dig-in). Tree trimming on this feeder was most recently completed in May 2007. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE has identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the third quarter of 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2010 and any identified deficiencies will be corrected. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed and overhead reconductoring will be completed in 2010.

Feeder 8734

Feeder 8734 supplies approximately 529 customers in the Ashton area of Montgomery County. During 2009, 93% of the customer interruptions were caused by weather (47% were caused by wind/rain and 46% were caused by ice/snow), 5% were caused by trees, 1% were caused by overhead conductor failures and 1% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder was studied, and Distribution Automation reclosers and additional fusing were installed on a portion of the feeder in February 2010. Station relays were reset in April 2010 to coordinate with the Distribution Automation reclosers. In addition, a project completed in 2009 created a new feeder that reduced the length and exposure of this feeder.

(9) Momentary Interruptions. A utility shall maintain information which it collects on momentary interruptions for five years.

BGE collects momentary outage information on devices that are monitored by SCADA (e.g., Distribution Automation reclosers, substation breakers, etc.). However, BGE does not routinely collect counter readings from hydraulic reclosers.

Baltimore Gas and Electric Company
COMAR 20.50.07.06 Reporting of Reliability Indices – CY 2010

(1) System-Wide Indices. A utility shall report SAIDI, SAIFI, and CAIDI for its system consisting of all feeders originating in Maryland. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

SAIFI – 1.58
SAIDI – 5.46
CAIDI – 3.45

Note: SAIFI, SAIDI and CAIDI are calculated using COMAR 20.50.01.03 Definitions.

(b) All interruption data minus major event interruption data.

SAIFI – 1.48
SAIDI – 4.52
CAIDI – 3.05

Data in (b) above exclude customer interruptions from one Major Event experienced during July 2010, further detailed in Section 6.

All interruption data minus July 2010 major event interruption data and interruption data from the February 2010 snow storms.[1]

SAIFI – 1.37
SAIDI – 3.60
CAIDI – 2.63

All interruption data minus interruption data for all weather events.

SAIFI – 0.77
SAIDI – 1.56
CAIDI – 2.04

Note: The data sets showing SAIFI, SAIDI and CAIDI excluding July 2010 major event interruption data and interruption data from the February 2010 snow storms as well as excluding interruption data for all weather events are provided to demonstrate the impact of weather events on system-wide reliability.

[1] While the two snow storms in February 2010 were separate events and neither met the Major Storm definition in COMAR 20.50.01.03, the Commission directed BGE to file a Major Storm report in Case No. 9220 providing the information set forth in COMAR 20.50.07.07 for both storms.

(2) District Indices. A cooperatively-owned utility shall provide SAIDI, SAIFI, and CAIDI for each operating district and identify the operating district with the poorest reliability. The indices shall be calculated and reported with two sets of input data.

(a) All interruption data;

(b) Major event interruption data excluded.

Requirements (a) & (b) are not applicable to BGE since BGE is an Investor Owned Utility.

(3) Feeder Indices. An investor-owned utility shall provide SAIDI, SAIFI, and CAIDI for 2% of feeders or 10 feeders, whichever is more, serving at least one Maryland customer that are identified by the utility as having the poorest reliability. The indices shall be calculated and reported with 2 sets of input data.

(a) All interruption data

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
7583	RIVERSIDE	6.52	8.33	13.70	1.64
8445	BESTGATE	6.02	7.20	20.66	2.87
7497	CEDAR PARK	5.29	6.23	32.77	5.26
8144	EAST TOWSON	5.00	5.73	13.95	2.43
7407	CEDAR PARK	4.99	6.48	33.11	5.11
8010	COLDSPRING	4.91	6.45	16.10	2.50
7483	HUNT CLUB	4.88	5.96	37.59	6.31
8475	CROWNSVILLE	4.74	5.60	24.42	4.36
8411	BEVERLY BEACH	4.60	5.73	13.53	2.36
8004	COLDSPRING	4.53	5.26	7.68	1.46
8152	TEXAS	4.46	5.05	27.48	5.44
7105	MOUNT WASHINGTON	4.41	5.58	11.28	2.02
8474	CROWNSVILLE	4.40	4.66	34.59	7.42
7423	TRACEYS LANDING	4.34	5.73	30.21	5.27
7656	COLUMBIA	4.32	5.29	6.31	1.19
8158	TEXAS	4.23	4.17	4.55	1.09
8556	WAUGH CHAPEL	4.11	4.55	23.73	5.21
8072	GLENARM	4.05	4.00	19.26	4.82
7481	HUNT CLUB	3.97	4.36	28.42	6.52
8387	RIVA ROAD	3.93	4.81	13.40	2.78
7111	MOUNT WASHINGTON	3.90	5.06	12.44	2.46

13000 Series Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
13991	*MIDDLE RIVER*	*3.75*	*5.00*	*9.50*	*1.90*
13947	*WESTPORT BROOM FACTORY*	*3.33*	*3.33*	*32.67*	*9.80*
13330	*HIGHLANDTOWN*	*2.35*	*2.08*	*10.16*	*4.88*

4.4 kV Feeder	***Substation***	***CRI***	***SAIFI***	***SAIDI***	***CAIDI***
4067	*PHILADELPHIA ROAD*	*6.79*	*9.05*	*22.27*	*2.46*
4816	*CALVERTON*	*4.28*	*5.10*	*52.89*	*10.37*
4068	*PHILADELPHIA ROAD*	*4.07*	*5.40*	*36.79*	*6.82*

(b) All interruption data minus major event interruption data:

BGE's "Worst Feeder Program" consists of the Company's plans to improve reliability performance for the top 2% of the 13.8 kV distribution feeders (21 out of 1048 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 133 total 13000 series distribution feeders) and 2% of the 4.4 kV distribution feeders (3 out of 107 total 4.4 kV distribution feeders) based on all interruption data minus major event interruption data. There was one major event experienced during July 2010.

13.8 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
7583	RIVERSIDE	6.34	8.09	13.10	1.62
8445	BESTGATE	5.77	6.87	14.90	2.17
7497	CEDAR PARK	5.29	6.22	32.59	5.24
8144	EAST TOWSON	5.00	5.73	13.95	2.43
8010	COLDSPRING	4.91	6.45	16.10	2.50
8004	COLDSPRING	4.53	5.26	7.68	1.46
7105	MOUNT WASHINGTON	4.41	5.58	11.28	2.02
8411	BEVERLY BEACH	4.32	5.37	12.32	2.30
7656	COLUMBIA	4.32	5.29	6.31	1.19
8475	CROWNSVILLE	4.28	4.99	11.33	2.27
8158	TEXAS	4.21	4.14	4.50	1.09
8474	CROWNSVILLE	4.12	4.28	24.00	5.61
8072	GLENARM	3.94	3.86	18.51	4.79
8387	RIVA ROAD	3.91	4.80	12.61	2.63
7111	MOUNT WASHINGTON	3.90	5.06	12.44	2.46
7972	HONEYGO	3.84	3.84	3.56	0.93
8425	BAY RIDGE	3.81	4.88	15.59	3.20
8074	GLENARM	3.78	4.07	21.79	5.35
8121	KAUFFMAN	3.76	3.81	12.28	3.22
8073	GLENARM	3.75	5.00	13.00	2.60
7483	HUNT CLUB	3.71	4.40	20.94	4.76

13000 Series Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
13991	MIDDLE RIVER	3.75	5.00	9.50	1.90
13947	WESTPORT BROOM FACTORY	3.33	3.33	32.67	9.80
13330	HIGHLANDTOWN	2.35	2.08	10.16	4.88

4.4 kV Feeder	Substation	CRI	SAIFI	SAIDI	CAIDI
4067	PHILADELPHIA ROAD	6.79	9.05	22.27	2.46
4816	CALVERTON	4.28	5.10	52.89	10.37
4262	CENTER	3.54	4.72	44.84	9.50

(c) Feeders shall not be included as having the poorest reliability in two consecutive reports.

Feeders listed in the CY 2009 report as having poor reliability are not included in this report, which allows time for reliability data to reflect corrective actions performed in 2009 and 2010.

(4) The method used by a utility to identify the district and feeders with poorest reliability shall be approved by the Commission and be included in the report.

In order to determine which distribution feeders and areas have the poorest performance, BGE utilizes a Composite Reliability Index (CRI). In the event that two feeders have identical composite reliability indices, the feeders are then ranked based on the most recent year's feeder SAIFI. The formula for the index is:

$$CRI = 0.75 \times SAIFI_{2010} + 0.25 \times SAIFI_{2009}$$

(5) Feeders included in the report, which serve customers in Maryland and one or more bordering jurisdiction shall be identified. The report shall include the percentage of customers located in Maryland and the percentage of customers located in bordering jurisdictions.

Not applicable to BGE. BGE has no feeders outside Maryland.

(6) Major Event Interruption Data. The report shall include the time periods during which major event interruption data was excluded from the indices, along with a brief description of the interruption causes during each time period.

BGE experienced one Major Event in 2010.

On Sunday, July 25, 2010, beginning approximately 3:30 PM, portions of the BGE territory were impacted by lightning, wind and rain. Localized heavy rains, wind gusts and lightning experienced were due to a few strong thunderstorms that moved through Anne Arundel, Prince George's, Baltimore, Howard, Montgomery, Howard, Harford, Carroll and Calvert Counties as well as Baltimore City. A major storm was declared on the BGE system at 1:45 PM on July 25 with a peak of 78,534 sustained customer interruptions occurring at 6:42 PM. Cumulatively, BGE experienced 122,234 customer interruptions. A total of 1,313 BGE personnel and BGE contractors along with 185 external contractors were involved in the restoration effort. The storm was declared over and the Storm Center closed at 6:00 PM on Tuesday, July 27, 2010.

While not a Major Event on BGE's system, BGE prepared and filed a Major Storm Report for the dual blizzards of February 2010 at the request of the Commission. Between February 5 and February 12, 2010, the BGE service territory was impacted by two significant snow storms. Between them, these storms dumped nearly four feet of snow on Central Maryland. Nearly 97,000 customers lost service during the first storm that began on Friday, February 5 and intensified rapidly in the early morning hours of Saturday, February 6. At 4:00 PM on Friday, February 5, a minor storm was declared on the BGE electric distribution system in anticipation of the impending blizzard. The peak number of sustained customer interruptions was 45,158 and occurred on February 6, 2010 at 11:11AM. By the late evening on Monday, February 8, all but 800 customers had been restored. The second storm started Tuesday, February 9 and caused *approximately 45,000 additional service interruptions. Most were restored by Thursday, February 11, with a very small number of customer outages extending into Friday, February 12. The storm was declared over and the Storm Center closed at 3:00 PM on Friday, February 12, 2010.Between the two storms, BGE experienced a total of 142,001 customer interruptions.*

(7) Actions for Operating District and Feeders with Poorest Reliability.

(a) An investor-owned utility shall report remedial actions taken or planned to improve reliability for all feeders reported under C.(3) of this regulation.

BGE will review the design for each feeder reported under this section to identify potential improvements. BGE will also trim the trees on feeders as needed, conduct a thorough equipment inspection on each feeder and correct any deficiencies found during the inspections. These inspections will permit the identification of potential outage causes and will, as a result, reduce the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process and have since been repaired or replaced. In some cases, underground cable replacement will be performed if the underground conductor experiences an excessive number of failures.

Feeder 7583

Feeder 7583 supplies approximately 1,403 customers in the Dundalk area on the Baltimore City/County line. During 2010, 37% of the customer interruptions were caused by weather (32% due to wind/rain, 5% due to lightning), 37% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 15% were caused by overhead conductor failures, 5% were caused by miscellaneous events, 4% were caused by overhead equipment failures, and 2% were caused by wildlife. Tree trimming on this feeder was most recently completed in May 2007 and the feeder is due for routine cycle trimming in May 2011. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE renewed poles and modified the design of a pole to improve overhead conductor tension and sag in December 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2011. The design of this feeder has been studied, and Distribution Automation reclosers will be installed in 2011.

Feeder 8445

Feeder 8445 supplies approximately 1,236 customers in the Heritage Harbour area of Anne Arundel County. During 2010, 35% of the customer interruptions were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 32% were caused by trees, 29% were caused by underground equipment failures, 3% were caused by underground cable failures, and 1% were caused by weather (wind/rain and ice/snow). Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. A project to reduce the length and exposure of this feeder and add Distribution Automation reclosers will be completed in 2013 in conjunction with expected load increases.

Feeder 7497

Feeder 7497 supplies approximately 1,103 customers in the Annapolis area of Anne Arundel County. During 2010, 61% of the customer interruptions were caused by weather (36% due to ice/snow, 25% due to wind/rain), 36% were caused by trees, 2% were caused by underground equipment failures, and 1% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified). Tree trimming on this feeder was most recently completed in December 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8144

Feeder 8144 supplies approximately 96 customers in the Towson area of Baltimore County. During 2010, 53% of the customer interruptions were caused by underground equipment failures, 40% were caused by underground cable splice failures, and 7% were caused by trees. Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the cable splices and each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8010

Feeder 8010 supplies approximately 892 customers in the Roland Park area of Baltimore City. During 2010, 56% of the customer interruptions were caused by trees, 18% were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 17% were caused by weather (wind/rain), 6% were caused by wildlife, and 3% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in January 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8004

Feeder 8004 supplies approximately 2,116 customers in the Roland Park area of Baltimore City. During 2010, 33% of the customer interruptions were caused by weather (wind/rain), 23% were caused by trees, 22% were caused by unknown reasons (consisted mainly of a feeder lockout where no system damage was identified), 20% were caused by a splice failure, and 2% were caused by wildlife. Tree trimming on this feeder was most recently completed in May 2009. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 7105

Feeder 7105 supplies approximately 1,484 customers in the Stevenson area of Baltimore County. During 2010, 32% of the customer interruptions were caused by trees, 27% were caused by *weather (wind/rain), 18% were caused by unknown reasons (consisted mainly of a feeder lockout where no system damage was identified), 14% were caused by underground cable failures, 7% were caused by public interference (vehicle-hits), and 2% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in February 2011. BGE completed one cable replacement job in October 2010 and one in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.*

Feeder 8411

Feeder 8411 supplies approximately 1,457 customers in the Mayo area of Anne Arundel County. During 2010, 61% of the customer interruptions were caused by weather (38% due to wind/rain, 20% due to lightning, and 3% due to ice/snow), 27% were caused by trees, 9% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 1% were caused by wildlife, 1% were caused by overhead conductor failures, and 1% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in June 2008. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. A project to reduce the length and exposure of this feeder and add Distribution Automation reclosers will be completed by the end of the second quarter of 2011.

Feeder 7656

Feeder 7656 supplies approximately 742 customers in the Columbia area of Howard County. During 2010, 88% of the customer interruptions were caused by underground cable failures, 9% were caused by a partial feeder lockout as a result of an overload, 2% were caused by underground equipment failures, and 1% were caused by a dig-in. BGE identified one cable replacement opportunity. The construction work is complete and an outage is pending for cut-in. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8475

Feeder 8475 supplies approximately 731 customers in the Crownsville area of Anne Arundel County. During 2010, 45% of the customer interruptions were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 30% were caused by trees, 21% were caused by weather (19% due to ice/snow and 2% due to wind/rain), 3% were caused by overhead equipment failures, and 1% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in October 2007 and is due for routine cycle trimming in 2011. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2011. BGE identified one cable replacement opportunity that was completed in March 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8158

Feeder 8158 supplies approximately 872 customers in the Timonium area of Baltimore County. During 2010, 23% of the customer interruptions were caused by a defective splice, 20% were caused by equipment failures, 15% were caused by overhead conductor failures, 14% were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 15% were caused by trees, 10% were caused by a defective underground cable, 1% were caused by a dig-in, 1% were caused by weather (wind/rain), and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in October 2008. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. BGE identified three cable replacement opportunities. One was completed in February 2011. Construction work on the remaining two is complete and outages are pending for cut-in. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8474

Feeder 8474 supplies approximately 634 customers in the Sherwood Forest area of Anne Arundel County. During 2010, 63% of the customer interruptions were caused by trees, 23% were caused by weather (wind/rain), 10% were caused by unknown reasons (consisted mainly of feeder lockouts where no system damage was identified), 2% were caused by wildlife, 1% were caused by a dig-in, and 1% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8072

Feeder 8072 supplies approximately 1,530 customers in the Baldwin area of Baltimore County. During 2010, 58% of the customer interruptions were caused by weather (28% due to lightning, 19% due to wind/rain and 11% due to ice/snow), 36% were caused by trees, 2% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 2% were caused by overhead equipment failures, 1% were caused by foreign objects blown by wind, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in April 2010. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. BGE identified two cable replacement opportunities. One was completed in February 2011. The other is currently in design and is scheduled for completion by the end of the fourth quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. The design of this feeder has been studied, and Distribution Automation reclosers will be installed and a portion of the feeder will be reconductored in 2011.

Feeder 8387

Feeder 8387 supplies approximately 664 customers in the Riva area of Anne Arundel County. During 2010, 64% of the customer interruptions were caused by trees, 28% were caused by weather (wind/rain), 7% were caused by underground equipment failures, and 1% were caused *by underground cable failures. Tree trimming on this feeder was most recently completed in December 2009. It has been determined that reliability gains can be achieved by performing enhanced trimming beyond BGE's routine trimming standards; this work will be completed in 2011. BGE identified one cable replacement opportunity that is currently in design and is scheduled for completion by the end of the fourth quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.*

Feeder 7111

Feeder 7111 supplies approximately 2,074 customers in the Mt. Washington area on the Baltimore City/County line. During 2010, 21% of the customer interruptions were caused by underground cable failures, 21% were caused by public interference (vehicle-hits), 20% were caused by overhead equipment failures, 16% were caused by weather (lightning), 15% were caused by overhead conductor failures, 5% were caused by trees, 1% were caused by wildlife, and 1% were caused by unknown reasons (consisted mainly of a blown fuse where no system damage was identified). Tree trimming on this feeder was most recently completed in January 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 7972

Feeder 7972 supplies approximately 81 customers in the White Marsh area of Baltimore County. During 2010, 51% of the customer interruptions were caused by underground cable failures and 49% were caused by underground equipment failures. BGE identified one cable replacement opportunity that was completed in March 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8425

Feeder 8425 supplies approximately 928 customers in the Highland Beach area of Anne Arundel County. During 2010, 34% of the customer interruptions were caused by unknown reasons (consisted mainly of a feeder lockout where no system damage was identified), 26% were caused by trees, 23% were caused by weather (ice/snow), 14% were caused by an overhead conductor failure, 2% were caused by overhead equipment failures, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in February 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8074

Feeder 8074 supplies approximately 1,178 customers in the Carney area of Baltimore County. During 2010, 69% of the customer interruptions were caused by trees, 17% were caused by weather (14% due to wind/rain and 3% due to lightning), 6% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 5% were caused by *public interference (vehicle-hit), 2% were caused by overhead conductor failures, and 1% were caused by overhead equipment failures. Tree trimming on this feeder was most recently completed in January 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. The design of this feeder has been studied, and Distribution Automation reclosers and additional fusing will be installed, a portion of the feeder will be reconductored, and an overhead portion will be relocated underground in 2011.*

Feeder 8121

Feeder 8121 supplies approximately 1,140 customers in the Freeland area of Baltimore County. During 2010, 37% of the customer interruptions were caused by weather (22% due to wind/rain and 15% due to lightning), 32% were caused by trees, 26% were caused by overhead equipment failures, 3% were caused by unknown reasons (consisted mainly of blown fuses where no system damage was identified), 1% were caused by foreign objects blown by wind, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in August 2007 and the feeder is due for routine cycle trimming in August 2011. To further improve reliability, enhanced trimming beyond BGE's routine trimming standards will be performed in 2011. BGE identified three cable replacement opportunities based on performance in 2009. One was completed in January 2011. The remaining two are currently in construction and are scheduled for completion by the end of the second quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 8073

Feeder 8073 supplies 2 customers in the Glen Arm area of Baltimore County. During 2010, 60% of the customer interruptions were caused by underground equipment failures and 40% were caused by underground cable failures. Tree trimming on this feeder was most recently completed in January 2011. BGE identified one cable replacement opportunity that is currently in construction and is scheduled for completion by the end of the third quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 7483

Feeder 7483 supplies approximately 1,148 customers in the Cape Saint Claire area of Anne Arundel County. During 2010, 72% of the customer interruptions were caused by trees, 18% were caused by unknown reasons (consisted mainly of blown fuses and a feeder lockout where no system damage was identified), 5% were caused by weather (3% due to ice/snow and 2% due to wind/rain), 3% were caused by overhead conductor failures, 1% were caused by underground cable failures, and 1% were caused by wildlife. Tree trimming on this feeder was most recently completed in January 2011. BGE identified one cable replacement opportunity that is currently in scheduling and is planned for completion by the end of the fourth quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase *pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.*

Feeder 13991

Feeder 13991 supplies 2 customers in the Middle River area of Baltimore County. During 2010, 40% of the customer interruptions were caused by wildlife in the substation, 40% were caused by unknown reasons (a feeder lockout where no system damage was identified), and 20% were caused by an underground cable failure. Each of the pieces of equipment and the underground cable segment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 13947

Feeder 13947 supplies 6 customers in the Westport area of Baltimore City. During 2010, 70% of the customer interruptions were caused by equipment failures and 30% were caused by weather (ice/snow). Each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies have been corrected except one correction that will be completed in May 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. Station relays were reset in March 2011 to coordinate with a commercial customer on the feeder.

Feeder 13330

Feeder 13330 supplies approximately 25 customers in the Highlandtown area of Baltimore City. During 2010, 48% of the customer interruptions were caused by wildlife in a customer substation, 48% were caused by an underground cable failure in duct, and 4% were caused by public interference (vandalism). Each of the pieces of equipment and the underground cable segment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 4067

Feeder 4067 supplies approximately 743 customers in the Highlandtown area of Baltimore City. During 2010, 88% of the customer interruptions were caused by an underground cable splice failure, 11% were caused by an unknown reason (consisted of a blown fuse where no system damage was identified), and 1% were caused by overhead conductor failures. Tree trimming on this feeder was most recently completed in November 2010. In addition, each splice and each of the pieces of equipment that failed were repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder will be performed in 2011 and any identified deficiencies will be corrected. A project to transfer all customers on feeder 4067 to 13 kV feeders was completed in March 2011. Customers previously supplied by #6 copper 4 kV cable and sections of 4/0 and 350 copper paper-lead 4 kV feeder main cable are now supplied by new sections of overhead or underground 13 kV cable. This project will improve the reliability of the feeder as well as increase the emergency load capacity.

Feeder 4816

Feeder 4816 supplies approximately 90 customers in the Shipley Hill area of Baltimore City. During 2010, 39% of the customer interruptions were caused by underground equipment failures, 20% were caused by unknown reasons (consisted mainly of a blown fuse where no system damage was identified), 20% were caused by weather (ice/snow), 20% were caused by an underground cable failure, and 1% were caused by overhead conductor failures. Each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder will be performed in 2011 and any identified deficiencies will be corrected.

Feeder 4262

Feeder 4262 supplies approximately 451 customers in the Station North area of Baltimore City. During 2010, 40% of the customer interruptions were caused by underground equipment failures, 37% were caused by weather (lightning), and 23% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified). Tree trimming on this feeder was most recently completed in August 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in December 2010 and the identified deficiencies are scheduled to be corrected in May 2011.

(b) Each utility shall briefly describe the actions taken or planned to improve reliability. When the utility determines that remedial actions are unwarranted, the utility shall provide justification for this determination.

BGE plans include remedial actions for all feeders identified as worst performers.

(8) Evaluation of Remedial Actions. For the operating district and feeders identified as having the poorest reliability in an annual reliability indices report, the utility shall provide the following information in the next two annual reports.

(a) The annual report for the year following the identification of the operating district and feeders as having the poorest performance shall provide a brief description of the actions taken, if any, to improve reliability and the completion dates of these actions.

BGE reviewed the design for each feeder reported under this section to identify potential improvements. BGE also trimmed the trees on each feeder as needed, conducted a thorough equipment and conductor inspection on each feeder and corrected any deficiencies found during the inspections. Those inspections permitted the identification of potential outage causes and, as a result, reduced the number of customer interruptions due to unknown causes. Where the feeder interruptions were the result of underground conductor failures, the failed sections were isolated during the service restoration process and have since been repaired or replaced. In some cases, underground cable replacement was performed if the underground conductor experienced an excessive number of failures.

Feeder 8783

Feeder 8783 supplies approximately 1,109 customers in the Woodwardville area of Anne Arundel County. During 2009, 91% of the customer interruptions were caused by trees, 7% were caused by overhead conductor failures, and 2% were caused by weather (wind/rain). Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 8734

Feeder 8734 supplies approximately 529 customers in the Ashton area of Montgomery County. During 2009, 93% of the customer interruptions were caused by weather (47% were caused by wind/rain and 46% were caused by ice/snow), 5% were caused by trees, 1% were caused by overhead conductor failures, and 1% were caused by miscellaneous events. Tree trimming on this feeder was most recently completed in July 2009. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder was studied, and Distribution Automation reclosers were installed on a portion of the feeder in February 2010. Station relays were reset in April 2010 to coordinate with the Distribution Automation reclosers. In addition, a project completed in 2009 created a new feeder that reduced the length and exposure of this feeder.

Feeder 8472

Feeder 8472 supplies approximately 1,183 customers in the Severn Run area of Anne Arundel County. During 2009, 81% of the customer interruptions were caused by trees, 16% were caused by a vehicle-hit, 2% were caused by wildlife, and 1% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in January 2010. The design of this feeder was studied and Distribution Automation reclosers were installed in April 2010.

Feeder 7903

Feeder 7903 supplies approximately 670 customers in the Dickinson area of Howard County. During 2009, 56% of the customer interruptions were caused by underground cable failures, 20% were caused by underground equipment failures, 20% were caused by trees, and 4% were caused by a dig-in. Tree trimming on this feeder was most recently completed in May 2007. An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in 2010 and trimming beyond BGE's routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in March 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found. The design of this feeder was studied and Distribution Automation reclosers were installed in May 2010.

Feeder 7236

Feeder 7236 supplies approximately 1,352 customers in Union Mills in Carroll County. During 2009, 36% of the customer interruptions were caused by trees, 22% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 21% were caused by weather (wind/rain), 9% were caused by public interference (vehicle-hits), 8% were caused by overhead equipment failures, and 4% were caused by underground cable failures. The feeder was trimmed during the routine maintenance schedule in December 2010 and trimming beyond *routine trimming standards was performed. BGE identified three cable replacement opportunities. One was completed in June 2010, one was completed in October 2010, and the third is currently in construction and is scheduled for completion by the end of the second quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found. The design of this feeder was studied and Distribution Automation reclosers were installed in May 2010.*

Feeder 7351

Feeder 7351 supplies approximately 1,013 customers in Severna Park in Anne Arundel County. During 2009, 42% of the customer interruptions were due to unknown causes (consisted mainly of feeder lockouts where no system damage was identified), 35% were caused by overhead equipment failures, 18% were caused by trees, and 5% were caused by overhead conductor failures. The feeder was trimmed during the routine maintenance schedule in July 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in April 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in November 2009 and January 2010.

Feeder 7696

Feeder 7696 supplies approximately 1,077 customers in the Glenwood area of Howard County. During 2009, 81% of the customer interruptions were caused by trees, 10% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 7% were caused by public interference (vehicle-hits), 1% were caused by underground cable failures, and 1% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in October 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in December 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in February 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 7593

Feeder 7593 supplies approximately 1,921 customers in Fullerton in Baltimore County. During 2009, 37% of the customer interruptions were caused by underground equipment failures, 35% were caused by weather (lightning), 17% were from an unknown cause (a feeder lockout where no system damage was identified), and 11% were caused by underground cable failures. The feeder was trimmed during the routine maintenance schedule in October 2010 and trimming beyond routine trimming standards was performed. BGE identified two cable replacement opportunities. One was completed in April 2010 and the second is currently in construction and is scheduled for completion by the end of the second quarter of 2011. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 7849

Feeder 7849 supplies approximately 1,231 customers in the Franklin Square area of Baltimore City. During 2009, 52% of the customer interruptions were caused by underground cable *failures, 25% were caused by underground equipment failures, 21% were from an unknown cause (a feeder lockout where no system damage was identified), 1% were caused by trees, and 1% were caused by public interference (foreign objects blown by wind). The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. Each failed cable was repaired or replaced during 2009 as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in March 2010 and corrected the deficiencies identified.*

Feeder 7446

Feeder 7446 supplies approximately 1,048 customers in the Pointer Ridge area of Prince George's County. During 2009, 28% of the customer interruptions were caused by trees, 21% were due to unknown causes (consisted mainly of a feeder lockout where no system damage was identified), 20% were caused by weather (wind/rain), 20% were caused by overhead conductor failures, 9% were caused by public interference (vehicle-hit), 1% were caused by overhead equipment failures, and 1% were due to other causes. Tree trimming on this feeder was most recently completed in April 2007. An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in 2010 and trimming beyond BGE's routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in October 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010.

Feeder 7534

Feeder 7534 supplies approximately 473 customers in the Cromwood area of Baltimore County. During 2009, 45% of the customer interruptions were caused by trees, 34% were caused by overhead equipment failures, and 21% were caused by weather (lightning). The feeder was trimmed during the routine maintenance schedule in January 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. The design of this feeder was studied and Distribution Automation reclosers were installed in November 2010.

Feeder 8463

Feeder 8463 supplies approximately 551 customers in Bowie in Prince George's County. During 2009, 42% of the customer interruptions were caused by underground cable failures, 32% were from underground equipment failures, and 26% were caused by weather (wind/rain). An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in April 2010 and trimming beyond BGE's routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in April 2010. This job included the replacement of a switchgear. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. A project to reconfigure the feeder and create additional feeder tie capabilities was completed in March 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 7844

Feeder 7844 supplies approximately 1,137 customers in the Lexington Terrace area of Baltimore City. During 2009, 80% of the customer interruptions were caused by underground cable failures, 15% were caused by wildlife, 3% were caused by trees, 1% were caused by weather (wind/rain), and 1% were due to other causes. Each failed cable was repaired or replaced during 2009 as part of the service restoration and repair process. The feeder was trimmed during the routine maintenance schedule in June 2010 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and the identified deficiencies are being corrected.

Feeder 7070

Feeder 7070 supplies approximately 1,727 customers in Edgewood in Harford County. During 2009, 55% of the customer interruptions were caused by trees, 31% were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 6% were caused by public interference (vehicle-hit), 5% were caused by underground cable failures, and 3% were caused by weather. Tree trimming on this feeder was most recently completed in December 2007. An inspection performed in 2010 determined that reliability gains could be achieved by performing enhanced trimming beyond BGE's routine trimming standards. "Hot-spot" trimming on this feeder was completed in April 2010 and trimming beyond BGE's routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 7555

Feeder 7555 supplies approximately 3,012 customers in Middle River in Baltimore County. During 2009, 28% of the customer interruptions were caused by underground cable failures, 24% were caused by weather (wind/rain), 24% were caused by underground equipment failures, 23% were caused by a vehicle-hit, and 1% were caused by dig-ins. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE identified one cable replacement opportunity that was completed in July 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found. The design of this feeder has been studied, and Distribution Automation reclosers will be installed and overhead reconductoring will be completed by the end of the second quarter of 2011.

Feeder 8521

Feeder 8521 supplies approximately 2,399 customers in Bowleys Quarters in Baltimore County. During 2009, 26% of the customer interruptions were caused by company interference (new pole was undermined and leaned into the feeder), 17% were due to miscellaneous causes (consisted mainly of an outage due to a crossarm fire), 15% were caused by trees, 15% were caused by overhead conductor failures, 13% were caused by public interference (vehicle-hit), 8% were caused by weather (lightning), 4% were caused by overhead equipment failures, and 2% were caused by wildlife. The feeder was trimmed during the routine maintenance schedule in April 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 7141
Feeder 7141 supplies approximately 1,056 customers in the Jacksonville area of Baltimore County. During 2009, 68% of the customer interruptions were caused by trees, 15% were caused by overhead equipment failures, 6% were due to unknown causes, 5% were caused by weather (lightning), 3% were caused by overhead conductor failures, 1% were caused by wildlife, 1% were caused by underground cable failures, and 1% were due to other causes. Tree trimming on this feeder was most recently completed in October 2009. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 8451
Feeder 8451 supplies approximately 1,285 customers in the Severn Run area of Anne Arundel County. During 2009, 71% of the customer interruptions were caused by public interference (vehicle-hit), 22% were caused by trees, 5% were caused by weather (lightning), and 2% were caused by underground cable failures. The feeder was trimmed during the routine maintenance schedule in September 2010 and trimming beyond routine trimming standards was performed. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in March 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 7352
Feeder 7352 supplies approximately 803 customers in the Arnold area of Anne Arundel County. During 2009, 68% of the customer interruptions were caused by trees, 22% were caused by a dig-in, 6% were caused by overhead equipment failures, and 4% were caused by overhead conductor failures. The feeder was trimmed during the routine maintenance schedule in March 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity which was completed in April 2010. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in December 2009 and February 2010. The design of this feeder was studied and Distribution Automation reclosers were installed in June 2010.

Feeder 8799
Feeder 8799 supplies approximately 1,134 customers in Glyndon in Baltimore County. During 2009, 33% of the customer interruptions were due to unknown causes (consisted mainly of a feeder lockout and a recloser lockout where no system damage was identified), 31% were caused by trees, 26% were caused by vehicle-hits, 5% were caused by weather (4% was caused by lightning and 1% were caused by wind/rain), 2% were caused by underground cable failures, 1% were caused by wildlife, 1% were caused by dig-ins, and 1% were due to other causes. The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. BGE identified two cable replacement opportunities. One was completed in February 2010. The second was completed in November 2010. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 7693

Feeder 7693 supplies approximately 1,163 customers in the Woodbine area on the border between Carroll and Howard Counties. During 2009, 30% of the customer interruptions were caused by trees, 27% were caused by a vehicle-hit, 26% were caused by overhead conductor failure, 8% were caused by dig-ins, 6% were caused by weather (wind/rain), 2% were caused by underground cable failure, and 1% were due to miscellaneous causes. The feeder was trimmed during the routine maintenance schedule in May 2010 and trimming beyond routine trimming standards was performed. BGE identified one cable replacement opportunity that was completed in February 2011. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in June 2010. In addition, BGE performed Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder in November 2010 and corrected the deficiencies identified.

Feeder 13758

Feeder 13758 supplies approximately 21 customers in the Brooklyn area of South Baltimore City. During 2009, 49% of the customer interruptions were caused by overhead cable failures, 43% were caused by wildlife, 7% were caused by weather (6% were caused by lightning, and 1% were caused by wind/rain) and 1% were caused by overhead equipment failures. Poles and equipment were replaced in February 2010 to improve customer reliability. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 13946

Feeder 13946 supplies approximately 3 customers in the Carroll Park area of Baltimore City. During 2009, 50% of the customer interruptions were caused by overhead conductor failures, 40% were caused by public interference (vehicle-hit), and 10% were due to unknown causes (consisted mainly of a blown fuse where no system damage was identified). Tree trimming on this feeder was most recently completed in July 2009. Failed overhead conductors were repaired or replaced during 2009 as part of the service restoration and repair process. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010.

Feeder 13913

Feeder 13913 supplies approximately 10 customers in Mount Vernon in Baltimore City. During 2009, 100% of the customer interruptions were caused by underground cable failures in duct. Each failed cable was replaced during 2009 as part of the service restoration and repair process.

Feeder 4823

Feeder 4823 supplies approximately 546 customers in Broadway East in Baltimore City. During 2009, 50% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 13% were caused by weather (lightning), 13% were caused by wildlife, 12% were caused by underground cable failures, and 12% were caused by underground equipment failures. Tree trimming on this feeder was most recently completed in July 2009. Each failed cable was replaced during 2009 as part of the service restoration and repair process. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in May 2010 with no reliability deficiencies being found. Thermovision and visual *inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.*

Feeder 4416

Feeder 4416 supplies approximately 865 customers in the Druid Heights area of Baltimore City. During 2009, 60% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), 24% were caused by underground cable failures, and 16% were caused by overhead equipment failures. The feeder was trimmed during the routine maintenance schedule in December 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and is in the process of correcting the related deficiencies. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in July 2010 with no reliability deficiencies being found. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

Feeder 4403

Feeder 4403 supplies approximately 672 customers in the Penn North area of Baltimore City. During 2009, 83% of the customer interruptions were caused by unknown events (consisted mainly of feeder lockouts where no system damage was identified), and 17% were caused by underground equipment failures. The feeder was trimmed during the routine maintenance schedule in December 2010 and trimming beyond routine trimming standards was performed. In addition, each of the pieces of equipment that failed was repaired or replaced after failure. BGE also conducted an overhead equipment and conductor inspection and all related deficiencies were corrected in April 2010. Thermovision and visual inspections of all underground oil switches and oil fuse cut-outs on this feeder were performed in September 2010 with no reliability deficiencies being found. Thermovision and visual inspections of all 3-phase pad mounted equipment on this feeder were completed in November 2010 with no reliability deficiencies being found.

(b) The annual report two years after the identification of the operating district or feeders as having the poorest performance shall include the ordinal ranking representing the feeder's reliability during the current reporting period.

BGE's poorest performing 2% of the 13.8 kV distribution feeders (20 out of 993 total 13.8 kV distribution feeders), 2% of the 13000 series 13.8 kV customer feeders (3 out of 126 total 13000 series distribution feeders and 2% of the 4.4 kV distribution feeders (3 out of 124 total 4.4 kV distribution feeders) in 2008 had the following ordinal rankings in 2010. Ordinals for 2010 range from 1 (worst) to 107 (best) for 4.4 kV feeder, from 1 (worst) to 133 (best) for 13000 series feeders and from 1 (worst) to 1048 (best) for 13.8 kV feeders, ranked by Composite Reliability Index. Ranking excludes major event data.

13.8 kV Feeder	*Substation*	*2010 Ordinal Ranking*
8102	*MOUNT WASHINGTON*	*151*
7633	*LONG REACH*	*126*
7348	*LIPINS CORNER*	*299*
8420	*WAYSONS CORNER*	*483*
7130	*HEREFORD*	*69*
7257	*FREDERICK ROAD*	*181*
7616	*WILDE LAKE*	*127*
7658	*COLUMBIA*	*835*
7382	*SOUTH BALTIMORE*	*166*
8052	*ROCK RIDGE*	*275*
8604	*CONCORD STREET*	*428*
8682	*TEN OAKS*	*624*
7381	*SOUTH BALTIMORE*	*742*
7617	*WILDE LAKE*	*157*
8101	*MOUNT WASHINGTON*	*270*
7710	*MEADOWS*	*399*
8103	*MOUNT WASHINGTON*	*31*
8272	*HOLLOFIELD*	*560*
8556	*WAUGH CHAPEL*	*68*
8141	*EAST TOWSON*	*32*

13000 Series Feeder	*Substation*	*2010 Ordinal Ranking*
13602	*COLDSPRING*	*68*
13302	*ERDMAN*	*57*
13936	*MONUMENT STREET OUTDOOR*	*50*

4.4 kV Feeder	*Substation*	*2010 Ordinal Ranking*
4430	*FOREST PARK*	*25*
4812	*CALVERTON*	*27*
4828	*CLIFTON PARK*	*56*

(9) Momentary Interruptions. A utility shall maintain information which it collects on momentary interruptions for five years.

BGE collects momentary outage information on devices that are monitored by SCADA (e.g., Distribution Automation reclosers, substation breakers, etc.). However, BGE does not routinely collect counter readings from hydraulic reclosers.

BEFORE THE

PUBLIC SERVICE COMMISSION

OF MARYLAND

REVIEW OF 2013 ANNUAL PERFORMANCE	*	
REPORTS ON ELECTIC SERVICE	*	**CASE NO. 9353**
RELIABILITY FILED PURSUANT TO	*	
COMAR 20.50.12.11	*	

STAFF REVIEW OF ANNUAL

ELECTRIC RELIABILITY REPORTS

RELIABILITY TEAM MEMBERS:

JOHN H. HELM JR., TEAM LEAD

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DEANDRE WILSON

STAFF OF THE

PUBLIC SERVICE COMMISSION OF MARYLAND

JULY 10, 2014

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I. Executive Summary

The 2013 reporting year is the first full year under the COMAR 20.50.12 standards. The reporting requirements were standardized to allow for each utility company to report information in the same format and in a manner that could be analyzed by the Commission Staff. All annual reports were received on or prior to the required filing date, and all subsequent data request to the utility companies submitted by Commission Staff were answered in a timely manner.

Five of the six utility company met all COMAR standards for 2013, with only Delmarva falling short of the system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) requirements. Delmarva filed a corrective action plan (CAP) as required by COMAR and is already taking action to improve overall system reliability immediately. The corrective actions being taken by Delmarva Power and Light Company (Delmarva) are identified in Appendix 7.

Looking at a trend emerging from two consecutive years, all utility companies are showing improvement. This is reflective of the utility companies beginning the implementation of the new COMAR standards during the 2011 calendar year. The current trend should continue with improvements in reliability for all utility companies.

The poorest performing feeder (PPF) program is in its first full year under the new COMAR, and second year overall. There were only three feeders from the previous year that would have been considered repeat feeders if there was no 12-month remediation period. Next year will be the first year to assess the PPF program and identify if there are any repeat feeders for all utility companies.

All six utility companies met the COMAR standards for multiple device activations, downed wire response, and communication response times. Baltimore Gas and Electric Company (BGE) and Potomac Edison Company (P.E.) improved their communication performance standard after missing one or two of the requirements from 2012. P.E. also improved the downed wire response time to meet the COMAR standard.

All utility companies are ahead of the required COMAR vegetation management trim cycle. All companies implemented the COMAR vegetation management standards during the 2012 calendar year and had at least 44% of their systems trimmed by the end of 2013. Southern Maryland Electric Cooperative (SMECO) is well ahead of the COMAR standard with 78% of the overhead vegetation trimmed. The aggressive approach from all utility companies is critical to overall reliability as vegetation is the leading cause of outages by all companies.

The leading causes of outages for all utility companies were vegetation and animals. The aggressive vegetation management programs and animal guards on the overhead and underground equipment will reduce the overall system outages. Automated reclosers will also have an impact on system reliability by resetting the faults caused by an animal in most cases, without having to send out a technician to reset the failed device.

The top two programs identified by the utility companies to improve overall reliability are vegetation management and distribution automation. Vegetation management has been addressed by COMAR and embraced by all six utility companies. All companies are also installing distribution automation devices and upgrading systems to allow for remote monitoring and activation of reclosers and other system devices. This improves response time to outages, isolates outages and reduces the amount of customers without power, and allows for quicker restoration of outages, many times restoring power directly from the control center.

All six Maryland utility companies showed improvements in system reliability, implemented reliability plans that will allow the utility to continue to improve the overall system, or filed a CAP to address shortfalls and increase the ability of the company to meet COMAR standards and improve reliability.

II. Introduction

A. **Background**

The Maryland's General Assembly enacted the Maryland Electricity Service Quality and Reliability Act requiring the Commission to adopt regulations by July 1, 2012 establishing service quality and reliability standards for the delivery of electricity to retail customers by electric companies. Codified at Pub. Utils. §7-213, the Act established the goal that "each electric company provides its customers with high levels of service quality and reliability in a cost-effective manner, as measured by objective and verifiable standards…"[1]

In 2012, the Commission established specific standards for reliability for each electric company in COMAR 20.50.12.02D(1). Each electric company serving a total number of 40,000 or more customers in Maryland must file an annual performance report pursuant to COMAR 20.50.12.11. The report is to include:[2]

- The reliability indices as defined COMAR 20.50.12, which includes, at a minimum, the reliability index information and results from the previous year, the actual values of the reliability indices for each of the preceding 3 calendar years.
- A table showing the annual year end and three year average performance results.[3]
- The time periods during which major outage event (MOE) interruption data and the outage data resulting from an outage event occurring on another utility's electric system (cooperatively owned utility) was excluded from the SAIFI, SAIDI, and customer average interruption duration index (CAIDI) indices and a brief description of each interruption cause.
- A description of the utility's reliability objectives, planned action and projects, and programs for providing reliable service.
- An assessment of the utility's reliability objectives, planned action and projects, and programs for achieving an acceptable reliability level, to include SAIFI, SAIDI, and CAIDI indices, other reliability index considered, and the method for estimating or determining any impact on any reliability index.[4]
- Current year expenditures, an estimate or budget amount for the following two calendar years, current year labor resource hours (if available), and progress measures for each capital and maintenance program designed to support the maintenance of reliable electric service.[5]
- The number of outages by outage type including planned outages, non-planned outages minus MOEs, and MOEs.[6]
- The number of outages by outage cause including, but not limited to, animals, overhead (OH) equipment failure, and underground (UG) equipment failure.[7]
- The total number of customers that experienced an outage.[8]

[1] Public Utilities Article, §7-213(b), Annotated Code of Maryland
[2] COMAR 20.50.12.11A
[3] Public Utilities Article, §7-213(g)(2)(i) and (ii), Annotated Code of Maryland
[4] Public Utilities Article, §7-213(g)(2)(iii), Annotated Code of Maryland
[5] Public Utilities Article, §7-213(g)(2)(iv)(1), Annotated Code of Maryland
[6] Public Utilities Article, §7-213(g)(2)(iv)(2), Annotated Code of Maryland
[7] Public Utilities Article, §7-213(g)(2)(iv)(3), Annotated Code of Maryland
[8] Public Utilities Article, §7-213(g)(2)(iv)(4), Annotated Code of Maryland

- The total number of customer minutes of outage time.[9]
- A breakdown of the number of customers that experienced an outage by the number of days each customer was without electric service (to the maximum extent practicable).[10]
- PPF information and results.
- Multiple device activation information and results.

Each utility is also required to file a supplemental annual performance report which shall include, at a minimum:[11]

- The actual operation and maintenance and capital expenditures for the past three calendar years for each of the utility's reliability programs, including, but not limited to UG and OH distribution plant inspection, maintenance, and replacement programs, vegetation management, sub-transmission maintenance programs, and distribution substation plant inspection and maintenance programs.
- Service restoration requirement information and results.
- Downed wire response performance information and results.
- Vegetation management information.
- Periodic equipment inspection information and results.
- For the preceding calendar year under normal operating conditions only:
  - o The number of downed electric utility wires to which the utility responded in:
    - Four hours or less
    - More than four hours but less than eight hours
    - Eight hours or more
  - o The total number of downed electric utility wires reported to the utility.
- Any CAP required.[12]

B. **Overview**

The review of the utility company annual reports for 2012 covered the period from July 1, 2012 – December 31, 2012 where the COMAR 20.50.12 standards were required, as well as the period from January 1, 2012 – June 30, 2012, where reporting was required but no specific standards to meet. This, 2013, was the first full year of the utility companies operating under the COMAR 20.50.12 standards. The results for 2013 were compared to the COMAR standard as well as the results from 2012, to analyze company trends associated with operating under the new standards. The data and results were analyzed to determine if each utility company was on track to meet the COMAR standards set for 2014 and 2015. As seen by Figures 1 and 2, if the utility companies continue to improve reliability at the same rate that has occurred over the past four years, all utility companies are projected to reduce their SAIFI and SAIDI index to meet COMAR 2014 and 2015 standards. One company, Delmarva, was on track to miss both SAIFI and SAIDI for 2014 and 2015, but with the implementation of the CAP, is now on track to meet the COMAR standards.

[9] Public Utilities Article, §7-213(g)(2)(iv)(5), Annotated Code of Maryland
[10] Public Utilities Article, §7-213(g)(2)(iv)(6), Annotated Code of Maryland
[11] COMAR 20.50.12.11.B
[12] Public Utilities Article, §7-213(e)(1)(iii), Annotated Code of Maryland

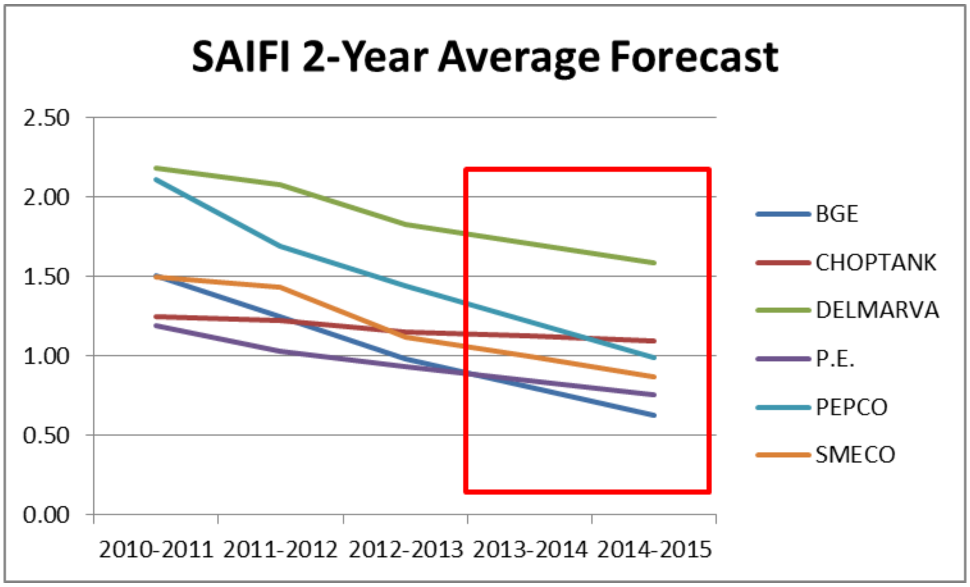

Figure 1: SAIFI 2-Year Average Forecast

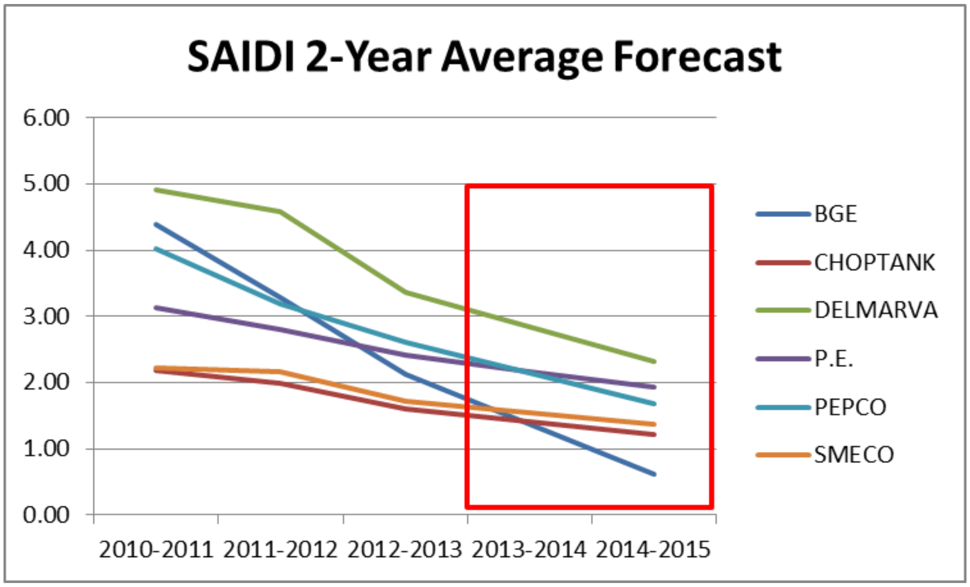

Figure 2: SAIDI 2-Year Average Forecast

For 2013, the only utility that failed to meet the COMAR SAIFI and SAIDI standards was Delmarva. Delmarva filed the required CAP which is addressed under the CAP analysis in Appendix 7. Potomac Edison failed to meet four COMAR standards from 2012 regarding response time to outages and customer call response. The company did meet the standards for 2013. BGE failed to meet the abandoned call standard for 2012, but met the standard in 2013.

Detailed analysis of utility performance in meeting each required standard in COMAR 20.50.12 are provided in the analysis section of the report.

	Utility											
	BGE		**Choptank**		**Delmarva**		**Potomac Edison**		**Pepco**		**SMECO**	
COMAR Standard	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013	2012	2013
SAIFI*												
SAIDI*												
Interruption restored within 8 hours												
MOE resotred within 50 hours**		N/A		N/A		N/A		N/A		N/A		N/A
Downed Wire Response												
% Calls answered within 30 sec												
% Annual Abandoned Calls												
% Vegetation Management Performed												
*2012 Pro-rated from July 1 - Dec 31		**No MOE for 2013					Met the standard				Did not meet the standard	

Figure 3: 2013 Overall Utility Performance Chart

III. Electric Company Service Reliability Standards, Results, and Analysis

A. **System-Wide Reliability Standards (20.50.12.02)**

COMAR 20.50.12.02D(1) outlines the minimum SAIFI and SAIDI standards that each utility is required to meet for each of the calendar years 2012-2015. The SAIFI represents the number of service outages experienced by the "average" customer of a group, or system, of customers over a period of time. SAIFI can also be calculated for a subset of customers, such as all the customers served by a particular distribution feeder. The SAIDI represents the total service outage time experienced by the "average" customer of a system of customers within an overall time period. As with the SAIFI, the SAIDI is typically calculated using the system of all Maryland customers served by the utility, but can also be calculated for a subset of customers such as those served by a particular feeder. CAIDI is a measure of duration that provides the average amount of time a customer is without power per interruption.

This was a unique year in that there were no MOEs. The analysis focuses on how the utility companies performed under normal operating conditions, and how the performance from 2013 compares to the COMAR standards, other Maryland utility companies, and past performance of the utility.

1. COMAR Reporting Standards

Five of the six reporting utilities, BGE, P.E., Potomac Electric Power Company (Pepco), Choptank Electric Cooperative (Choptank) and SMECO met the system-wide utility-specific reliability standards (SAIDI and SAIFI)[13] for 2013 while Delmarva fell short of the SAIDI and SAIFI for the standards. Delmarva filed a CAP as required by COMAR 20.50.12.2E. The analysis of Delmarva's CAP is in Appendix 7.

Utility	SAIFI (Interruptions)		SAIDI (Hours)		CAIDI (Hours)
	COMAR	Reported	COMAR	Reported	Reported
BGE	1.47	0.93	3.96	1.67	1.79
CHOPTANK	1.49	1.33	2.92	1.58	1.18
DELMARVA	1.65	1.95	2.99	3.54	1.82
P.E.	1.10	1.01	3.05	2.38	2.36
PEPCO	1.81	1.49	2.82	2.46	1.65
SMECO	1.38	0.93	2.35	1.36	1.46

Figure 4: 2013 System-Wide Reliability Standards

A three year average for SAIFI, SAIDI, and CAIDI for each utility is required for overall reliability and reliability minus MOEs and interruptions caused by other utility companies. The results of Figures 5 through 7 show the performance of each utility over the past three years under normal operating conditions. The three year average is used to determine how each utility

[13] The indices of SAIFI and SAIDI in COMAR are calculated using all interruption data excluding major outage event data and interruptions caused by other utility companies, which means these indices measure the system reliability under normal conditions.

performed this year compared to the average and what level of improvement was made or is needed to meet the future COMAR standards.

2. Three Year Analysis

The SAIFI performance chart shows that five of the six utility companies performed better than their three year average. Choptank performed 6% below the three year average due to a low SAIFI performance value for 2012, where the company had an exceptional performance. Two of the utilities, BGE and SMECO, showed an improvement in SAIFI over all three years.

Utility	SAIFI (All Interruptions: Minus MOE)			
	2011	2012	2013	3-Year Ave
BGE	1.46	1.03	0.93	**1.14**
CHOPTANK	1.46	0.98	1.33	**1.26**
DELMARVA	2.45	1.70	1.95	**2.03**
P.E.	1.21	0.85	1.01	**1.02**
PEPCO	2.00	1.39	1.49	**1.63**
SMECO	1.55	1.31	0.93	**1.26**

Figure 5: 3-Year Average SAIFI Performance (2011-2013)

The SAIFI performance chart shows that all six utility companies performed better than their three year average. Five of the six utility companies showed improvements over the entire three year period. One company, Delmarva, showed an increase for 2013, but did not exceed the three year average.

Utility	SAIDI (Hours: Minus MOE)			
	2011	2012	2013	3-Year Ave
BGE	3.98	2.58	1.67	**2.74**
CHOPTANK	2.35	1.64	1.58	**1.86**
DELMARVA	5.98	3.18	3.54	**4.23**
P.E.	3.19	2.43	2.38	**2.67**
PEPCO	3.60	2.77	2.46	**2.94**
SMECO	2.28	2.06	1.36	**1.90**

Figure 6: 3-Year Average SAIDI Performance (2011-2013)

The CAIDI performance chart shows that all six utility companies performed better than their three year average. Two of the utility companies, BGE and Delmarva, showed improvement over all three years.

Utility	CAIDI (Hours: Minus MOE)			
	2011	2012	2013	3-Year Ave
BGE	2.73	2.52	1.79	**2.35**
CHOPTANK	1.50	1.67	1.18	**1.45**
DELMARVA	2.45	1.87	1.82	**2.05**
P.E.	2.64	2.85	2.36	**2.62**
PEPCO	1.80	2.00	1.65	**1.82**
SMECO	1.47	1.57	1.46	**1.50**

Figure 7: 3-Year Average CAIDI Performance (2011-2013)

The trend for all utility companies over the past three years has been a steady improvement in SAIFI, SAIDI, and CAIDI performance, with the lone exception being Choptank which exceeded the three year SAIFI average by 6% in 2013. Staff determined that the overall trend for Maryland utilities is an improvement in reliability during normal operating conditions.

The full chart and analysis showing each utility's three year performance data which includes overall SAIFI, SAIDI, and CAIDI performance, performance minus MOEs, performance minus MOEs and outage data caused by other utilities (if cooperatively owned), and performance minus IEEE MOE data[14], 0are included in the individual company reports in Appendices 1-6. The charts include all data listed for both planned and unplanned outages.

3. Two Year Trend Analysis

Two-year trends are used to show the utility company average performance over the first two years of the new COMAR standards, and how the COMAR standards had an impact on reliability starting in 2010. The improvements in both SAIFI and SAIDI can be seen in the 2011-2012 two year period. Staff assessed that this is due to the utility company's preparing for the implementation of the new COMAR standard prior to 2012. Utility companies were working towards the new standards which are reflected in the performance trends for both SAIFI and SAIDI. Two consecutive years were analyzed and the data shown in Figure 6.

Utility	SAIFI (Interruptions: Minus MOE)			SAIDI (Hours: Minus MOE)		
	2010-2011	2011-2012	2012-2013	2010-2011	2011-2012	2012-2013
BGE	1.51	1.25	0.98	4.40	3.28	2.13
CHOPTANK	1.25	1.22	1.16	2.19	2.00	1.61
DELMARVA	2.19	2.08	1.83	4.92	4.58	3.36
P.E.	1.19	1.03	0.93	3.13	2.81	2.41
PEPCO	2.11	1.70	1.44	4.02	3.19	2.62
SMECO	1.50	1.43	1.12	2.22	2.17	1.71

Figure 8: 2-Year Trend on Average System-Wide Performance (2010-2013)

[14] IEEE Standard 1366TM – 2012.

The two year trend shows that all companies are improving reliability with SAIFI and SAIDI The two year analysis supports the three year trend that all utility companies are reducing the number outages and the duration of outages.

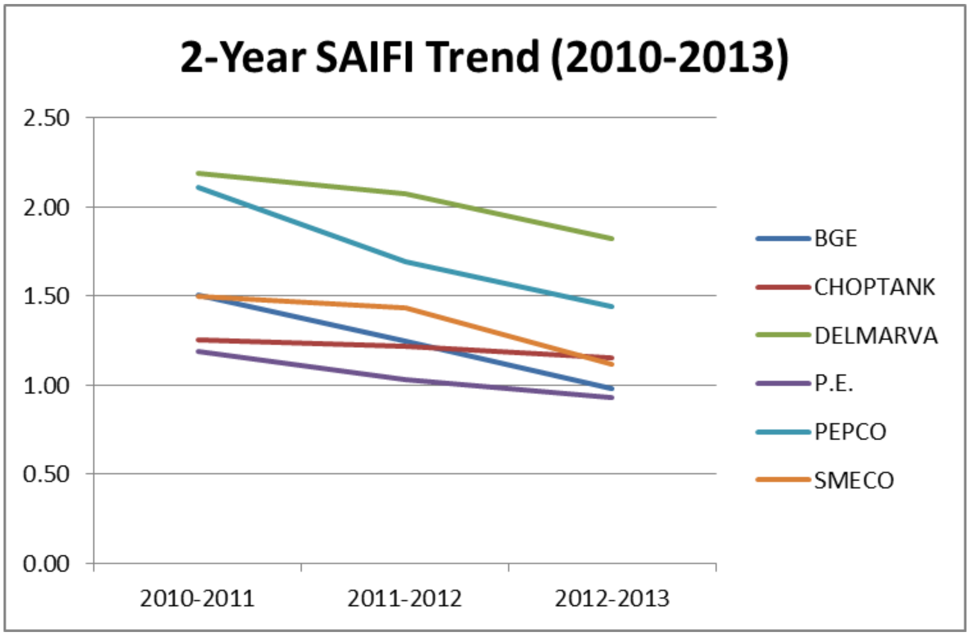

Figure 9: 2-Year SAIFI Trend

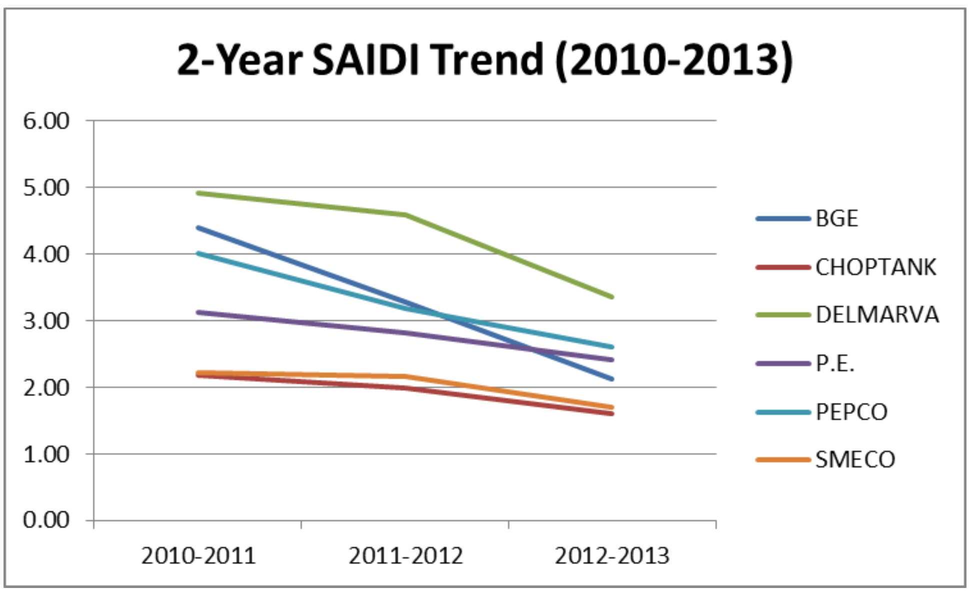

Figure 10: 2-Year SAIDI Trend

B. **Poorest Performing Feeder Standards (20.50.12.03)**

COMAR 20.50.12.03 outlines the PPF standard for feeders assigned to Maryland. Under this requirement, each electric company is required to report annual SAIDI, SAIFI and CAIDI indices for the 3% of feeders assigned to Maryland that have been identified by the Electric

Companies as having the poorest reliability. In calculating these indices, the "system" is limited to the group of customers served by the feeder circuits. Two sets of each index are reported for each least reliable feeder: 1) All Interruption Data; and 2) All Interruption Data (Minus MOEs). These two sets of data are used to give an overall evaluation of an electric company's system reliability during both normal and catastrophic events. The information used to determine the PPF list for each year is all interruption data minus MOEs. Prior to COMAR 20.50.12, electric cooperatives did not report these two sets of the SAIDI and the SAIFI for least reliable feeder circuits, but instead provided the two sets of indices for each operating district. In calculating these indices, the "system" is the group of customers served within each operating district.

1. Method to Determine PPF

Each utility company determines the method for identifying their PPFs based on their data collection methods and recommendations from the Commissioners from the 2012 Annual Report Review. To allow for year-to-year comparisons, COMAR 20.50.12.03A(4) does not allow a utility to change the method used to determine its PPF without Commission approval. The formula that each utility company uses is:

- BGE determines the bottom 3% of all feeders by first identifying the bottom 4% using individual feeder SAIFI performance values (minus MOEs). BGE selects the bottom 75% of the feeders based on the individual feeder SAIDI performance values (minus MOEs). This gives BGE the 3% PPFs for the year.[15]
- Choptank ranks all feeders by SAIFI and SAIDI separately. The company assigns a rank to each feeder, with #1 being the worst performance for each category. The rank of each feeder for SAIFI and SAIDI is added together to determine the PPF list.[16]
- Delmarva uses a feeder composite index, which is 75% of the feeder contribution to SAIFI plus 25% of feeder contribution to SAIDI to determine the PPF list.[17]
- P.E. takes the worst 20% of the feeders based on SAIFI (minus MOEs). The worst 15% of these feeders are selected based on SAIDI (minus MOEs) to get the 3% PPFs.[18]
- Pepco uses a feeder composite index, which is 75% of the feeder contribution to SAIFI plus 25% of feeder contribution to SAIDI to determine the PPF list.[19]
- SMECO determines the PPFs using a feeder index value which is equal to 50% of the SAIFI index for each feeder plus 50% of the SAIDI index for each feeder.[20]

This is the second year of the COMAR standards requiring the utility companies to report the 3% of their PPFs. COMAR states that:[21]

"No feeder ranked in the poorest performing 3 percent of feeders shall perform in the poorest performing 3 percent of feeders during either of the two subsequent 12-month reporting periods,

[15] BGE Annual Performance Report, pg. 18, Mail Log No: 153730
[16] Choptank Annual Performance Report, pg. 8, Mail Log No: 153648
[17] Delmarva Annual Performance Report, pg. 11, Mail Log No: 153728
[18] P.E. Annual Performance Report, pg. 12, Mail Log No: 153593
[19] Pepco Annual Performance Report, pg. 13, Mail Log No: 153734
[20] SMECO Annual Performance Report, pg. 6, Mail Log No: 153738
[21] COMAR 20.50.12.03A(5)

after allowing one 12-month reporting period for the utility to implement remediation measures, unless the utility has undertaken reasonable remediation measures to improve the performance of the feeder."

Currently three companies, BGE, Pepco, and Delmarva, have feeders that are in remediation and would have qualified for the PPF list this year. The corrective action plans for these feeders are identified in the individual company report Appendices. Next year will be the third year of the new COMAR PPF standard, meaning that there will be a basis to identify repeat PPFs.

2. Performance Comparison and Average

Figure 12 shows the 2013 performance for each utility company and the average performance for all. The overall SAIFI average for the Maryland utilities is high due to the extremely poor performance of two of Pepco's feeders. The complete list of each company PPFs is in the individual company Appendix.

Utility	# of PPF	Total # of Feeders in Maryland	Average # of Customers per PPF	2013 Interruption Data (Minus MOE)			% Above System Average	% Above System Average
				Average SAIFI (Interruptions)	Average SAIDI (Hours)	Average CAIDI (Hours)	SAIFI	SAIDI
BGE	39	1,265	918	3.02	6.48	2.13	240%	314%
CHOPTANK	4	112	453	3.01	4.68	1.62	240%	227%
DELMARVA	10	184	2937	2.56	3.98	1.50	204%	193%
P.E.	10	344	1152	2.67	9.26	3.65	213%	449%
PEPCO	21	697	1380	51.81	7.07	1.46	4123%	343%
SMECO	7	237	641	4.31	5.67	1.44	343%	275%
Summary	91	2839	1247	11.23	6.19	1.96	894%	300%

Figure 11: 2013 Poorest Performing Feeders (PPF)

Overall 91 feeders were chosen out of the 2,839 Maryland feeders as PPFs (3.2%). The average PPF SAIFI was 8.9 times higher than the overall average for all utility companies in Maryland. The average PPF SAIDI was 3 times higher than the overall average for all utility companies in Maryland. The average PPF CAIDI was 1.2 times higher than the overall average for all utility companies in Maryland. Staff noticed that the extreme difference in SAIFI was due to the few Pepco PPFs that raised the overall PPF SAIFI average.

C. **Multiple Device Activation Standards (20.50.12.04)**

COMAR 20.50.12.04 states that each utility shall report the number of protective devices that activated five or more times during the prior 12-month reporting period causing sustained interruptions in electric service to more than ten Maryland customers. The six utilities reported a total of 91 devices that were activated for five or more times during the prior 12-month time period. Utilities are required to implement remediation measures on all multiple activation devices reported in 2013. The information is provided in the individual company analysis in the Appendices.

Utility	Sum of Device (activated 5 or more times)	Protective Device Type				
		Line or Tap Fuse	Recloser	Circuit Breaker	Transformer	Substation
BGE	34	25	6	3	0	0
Choptank	3	1	0	0	0	2
DPL	7	4	1	2	0	0
PE	21	16	3	0	2	0
Pepco	26	14	0	11	1	0
SMECO	0	0	0	0	0	0
Total	**91**	**60**	**10**	**16**	**3**	**2**

Figure 12: Multiple Device Activations (October 1, 2012 - September 30, 2013)

The type of devices that has the highest number of multiple activations are line or tap fuses. There were multiple causes for the activations such as vegetation, circuit overloads, overhead and underground conductors, animals, and weather. Compared to 2012, there were 72 fewer multiple device activations in 2013, for a 44% improvement. The comparison shows that the remediation conducted by the utility companies for 2012 has made a positive impact and, along with the fact there were no MOEs for 2012, produced a reduction in multiple device activations for 2013.

D. **Additional Reliability Indices (20.50.12.05)**

COMAR 20.50.12.05 states that in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages for their entire system throughout Maryland from the previous calendar year (2012) and from the 3 previous calendar years, utilities are also required to calculate and report Customers Experiencing Multiple Interruptions (“$CEMI_n$”) and Momentary Average Interruption Frequency Index (“$MAIFI_E$”) information which also give a measure of electric service reliability from the customer’s perspective, unless it does not have the means to make the calculations, in which case the utility must provide an explanation of the reason why it cannot, and an estimate of the cost to provide this information in the future. Three of the six utility companies did not file $MAIFI_E$ reports for 2013, therefore a comparative analysis was not used in the review. The individual utility company $MAIFI_E$ analysis or reason for not filing is included in the individual utility Appendices.

$CEMI_n$ is the ratio of the total number of customers experiencing sustained interruptions equal to or greater than “n”, where **n** is equal to the number of interruptions, divided by the total number of customers served:

$$\boldsymbol{CEMI_n} = \frac{\boldsymbol{\#\ of\ customers\ experiencing\ sustained\ interruptions > "n"}}{\boldsymbol{Total\ \#\ of\ customers\ served\ on\ system}}$$

The overall trend for 2013 was an improvement with fewer multiple electric outages that customers experienced in Maryland. Four of the six utility companies, BGE, Choptank, Pepco, and SMECO, showed improvement from 2012 in almost every category. Delmarva and P.E. showed an increase in multiple customer interruptions, which correlates with the higher SAIFI numbers reported for 2013. The radial nature of both Delmarva and P.E. reduce the ability to provide redundancy in their systems, causing customers on isolated feeders to experience a higher number of repeat outages. Upgrading feeders and installing automated devices such as automated circuit reclosers will reduce the number of multiple outages.

Utility	2012: All Interruptions				2013 All Interruptions		2013 All Interruptions		
	$CEMI_2$	$CEMI_4$	$CEMI_6$	$CEMI_8$	$CEMI_2$	$CEMI_4$	$CEMI_4$	$CEMI_6$	$CEMI_8$
BGE	25.50%	7.10%	1.80%	0.50%	8.31%	1.30%	1.30%	23.00%	5.00%
CHOPTANK	9.07%	1.72%	0.35%	0.20%	6.77%	2.80%	2.80%	0.18%	0.00%
DELMARVA	38.90%	14.40%	5.46%	1.29%	47.30%	16.50%	16.50%	7.10%	2.50%
P.E.	7.02%	1.31%	0.12%	0.03%	12.25%	1.87%	1.87%	0.29%	0.03%
PEPCO	53.80%	22.80%	7.38%	2.52%	38.70%	10.10%	10.10%	2.20%	1.00%
SMECO	35.70%	10.70%	2.11%	0.51%	10.67%	1.75%	1.75%	0.38%	0.03%

Figure 13: 2012-2013 CEMI Performance Data

E. **Service Interruption Standards (20.50.12.06)**

COMAR 20.50.12.06 states that "an Electric Company shall restore service within 8 hours, measured from when the utility knew or should have known of the outage, to at least 92 percent of its customers experiencing sustained interruptions during normal conditions; within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers, and as quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the Electric Companies' total number of customers, whichever is less."

Utility	2012 Normal Conditions		2013 Normal Conditions	
	% of Interruptions Restored within 8 Hours	> 92% COMAR Standard	% of Interruptions Restored within 8 Hours	> 92% COMAR Standard
BGE	95.50%	Y	97.00%	Y
CHOPTANK	98.00%	Y	99.70%	Y
DELMARVA	99.28%	Y	98.92%	Y
P.E.	95.00%	Y	96.80%	Y
PEPCO	98.21%	Y	98.36%	Y
SMECO	99.31%	Y	99.71%	Y

Figure 14: 2012-2013 Service Interruption Standards

All utility companies met the COMAR standard for service interruption restoration under normal operating conditions for the second consecutive year. There were no MOEs reported for 2013, therefore no report on service restoration for MOEs.

F. **Downed Wire Response Standards (20.50.12.07)**

COMAR 20.50.12.07 states that each Electric Company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.

All utility companies are required to report on the total number of downed electric wires that are report by any source to the company. The utility is required to respond to all reported downed wires, although many of the reported wires are not electric. For Pepco only 34% of the wires reported belong to the utility, for Delmarva 49%, and BGE 80%.

Utility	Total Reported Downed Wires	Total Utility Responsible Wires	% of Reported Wires Belonging to the Utility	4 Hours or Less	More than 4 Hours but Less than 8 Hours	8 Hours or More	2013 % Responded to in 4 Hours or Less	Met COMAR Standard Guarded Wires 90%
BGE	8355	6677	80%	6020	519	138	90.16%	99.00%
CHOPTANK	3	3	100%	3	0	0	100.00%	100.00%
DELMARVA	809	393	49%	358	29	6	91.09%	100.00%
P.E.	240	240	100%	239	1	0	99.58%	99.58%
PEPCO	3401	1168	34%	801	215	152	68.58%	97.00%
SMECO	300	300	100%	247	39	14	82.33%	99.71%

Figure 15: 2013 Downed Wire Response Standards

All six utility companies were well above the COMAR standard of 90%, with the lowest performance being Pepco at 97%. Staff noted that there is a large difference in the response for guarded downed wires and downed wires reported from all sources for four of the six utility companies. The largest difference is Pepco, which responded to all downed wires in four hours or less 68.58% of the time, but to guarded downed wires 97% of the time. Two-thirds of the Pepco extended response times for downed wires occurred during low level storms: a small tornado that touched down in Rockville on June 13, 2013 and ice storm that occurred in December. SMECO responded to all downed wires in four hours or less 82.33% of the time, but to guarded downed wires 99.71% of the time. Staff noted that it was reasonable for the delay in response to the downed wires due to the severity of the storms that Pepco experienced during 2013.

G. **Customer Communication Standards (20.50.12.08)**

COMAR 20.50.12.08 states that each Electric Company shall answer a customer outage call within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each Electric Company shall achieve an annual average abandoned call percentage rate of 5 percent or less. Electric Companies are also required to provide:

- The percentage of calls that are answered within 30 seconds;
- The abandoned call percentage rate; and
- The average speed of answer.

In 2013, all utility companies met the COMAR standards for answering calls within 30 seconds and annual abandoned calls. For the percent of calls answered within 30 seconds, three companies, Choptank, P.E., and SMECO showed improvement from 2012. BGE showed a small decline of 1.4% from 2012. Delmarva and Pepco had the biggest decline in performance, with Delmarva dropping from 90.8% to 83.1% (7.7% decrease) and Pepco a drop from 89.7% to 78.6% (11.1% decrease). At the current rate of decline, if Pepco does not improve performance for 2014, they may not meet the COMAR standards. Delmarva is currently projected to just meet the COMAR standard for 2014. For the percent of abandoned calls, Pepco was close to the COMAR standard, dropping 4.3% of the calls (standard is >5%).

Utility	% of Calls Answered within 30 seconds (COMAR Standard 75%)		Met COMAR Standard 75% or Greater		% Annual Abandoned Calls		Met COMAR Standard < 5%		% of Calls Answered Within 30 Seconds by a Representative	% of Abandoned Calls Received by a Representative	Average Speed to Answer a Call (seconds)
	2012	2013	2012	2013	2012	2013	2012	2013			
BGE	89	87.6			6.8	2.11			76.1	3.46	25
CHOPTANK	91.2	95.9			1.4	0.79			94.3	1.1	11
DELMARVA	90.79	83.1			0.26	0.4			70.4	0.71	26
P.E.	70.87	80.34			6.93	3.19			61.18	6.3	45.5
PEPCO	89.66	78.55			1.93	4.31			57.96	8.44	74
SMECO	80.52	88.98			2.36	1.07			86.83	1.4	12
			Met the COMAR Standard			Did not Meet C	Did not Meet the COMAR Standard				

Figure 16: 2012-2013 Customer Communication Standards

H. **Vegetation Management Standards (20.50.12.09)**

Vegetation Management was the leading cause for system outages and system disruptions in 2013. All electric companies were scheduled to begin the vegetation management cycle in 2013. All companies took a proactive approach and began implementing their vegetation management programs in 2012. As seen in Figure 18, all companies exceeded the vegetation management requirement for 2013.

SMECO took the most proactive approach, trimming 37% of the overhead circuit vegetation for 2013 (12% required), for a total of 78% of the system trimmed over the past two years. The least amount of vegetation trimmed was P.E., with 22% for 2013 (15% required), and 46% over the past two years. P.E. is still way ahead of the required vegetation management trim cycle requirements. Vegetation management should result in significantly less outages occurring, though it is not expected to completely eliminate these likely occurrences.

Cost for vegetation management varies from $4,091 to $16,608 per mile. Compared to 2012, there was a slight increase in cost per mile for five of the six companies. The vast difference in cost is due to many factors such as the density of the vegetation, the type of vegetation, the amount of voltage for the power line, if the vegetation is located on a rural road or in a densely populated community within the city, and if the vegetation is located on a right of way for the utility or privately owned land. Each of these factors can have a significant impact on the personnel required, equipment required, and time required to properly trim the vegetation to meet the COMAR standard.

Utility	Overhead Circuit Miles		# of Miles of Vegetation Management Performed		% of Total System Trimmed to Standard	% of Total System Trimmed to Standard	Trim Cycle and Current Year (X of Y Years)	COMAR Minimum Required Trimming (%)	Vegetation Management Expenditures		Vegetation Management Cost Per Mile	
	2012	2013	2012	2013	2012	2013	2013	2013	2012	2013	2012	2013
BGE	9,404	9,404	2,863	2,338	30%	25%	1 of 4	15%	$28,605,626	$21,509,600	$ 9,991	$ 9,200
CHOPTANK	2,063	2,046	445	489	22%	24%	1 of 5	12%	$ 2,622,089	$ 3,291,292	$ 5,892	$ 6,731
DELMARVA	3,493	3,493	847	906	24%	26%	1 of 4	15%	$ 5,161,269	$ 7,077,726	$ 6,094	$ 7,812
P.E.	6,059	6,059	1,431	1,311	24%	22%	1 of 4	15%	$ 8,511,360	$10,318,072	$ 5,948	$ 7,870
PEPCO	3,990	3,966	1,550	1,011	39%	25%	1 of 4	15%	$24,642,714	$16,790,465	$ 15,899	$ 16,608
SMECO	3,576	3,576	1,451	1,310	41%	37%	1 of 5	12%	$ 5,686,399	$ 5,359,013	$ 3,919	$ 4,091

Figure 17: 2012-2013 Vegetation Management Activities

I. Outage Types & Causes

In order to improve overall system reliability for the utility systems, the causes of the outages needs to be determined. The greatest cause of non-planned outages for Maryland utility companies is vegetation. Animals are the second greatest cause on average for outages. For the companies that broke down the weather factors into lightning and non-lightning events, lightning strikes were a major cause of the outages. There was a significant drop in the amount of outages that Choptank reported caused by vegetation for 2013 from 2012 (down to 10.8% from 22%). This is a sign that the vegetation management plan Choptank is currently executing is having a positive effect on reliability.

Utility	Vegetation	OH Equipment Failure	UG Equipment Failure	Weather (not lightning)	Lightning Strike	Equipment Hit	Animals	Overload	Other*	Unknown
BGE	18.8%	5.5%	3.2%	4.9%	**	**	16.3%	**	3.6%	3.3%
CHOPTANK	10.8%	4.1%	17.7%	1.8%	8.2%	7.1%	14.7%	2.1%	21.7%	11.9%
DELMARVA	17.3%	16.5%	13.8%	11.7%	**	4.5%	12.4%	3.3%	7.1%	13.4%
P.E.	19.0%	10.0%	2.0%	**	**	3.0%	17.0%	**	1.0%	14.0%
PEPCO	18.1%	16.8%	28.6%	1.6%	3.4%	5.3%	13.2%	1.5%	5.9%	5.6%
SMECO	22.3%	13.4%	18.1%	0.8%	4.3%	2.5%	21.4%	**	0.1%	3.4%

* Includes employees, fire, source lost, loadshed, vandalism, other utility ** The information was requested but not provided by the utility

Figure 18: Non-Planned Outage Causes

IV. Expenditures

COMAR 20.50.12.11.A.(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11.B.(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

Individual company analyses for expenditures are listed in the company Appendices. A trend noted for all utility companies is the increase in capital expenditures to improve system reliability and a reduction in operation and maintenance cost to maintain and operate the systems. The only company that did not follow the same spending trend is Choptank, which decreased capital expenditure and increased operation and maintenance spending.

Utility	Capital Expenditures (designed to Support Maintenance of Reliable Electric Service)		Operating and Maintenance Expenditures (designed to Support Maintenance of Reliable Electric Service)		Projected Capital Expenditures		Projected Operation and Maintenance Expenditures	
	2012	2013	2012	2013	2014	2015	2014	2015
BGE	$138,996,410	$150,819,591	$141,661,372	$102,279,836	$122,283,325	$125,100,280	$109,931,404	$116,022,079
CHOPTANK	$6,048,731	$5,107,372	$3,037,066	$3,537,440	$5,415,000	N/A	$3,765,000	$3,765,000
DELMARVA	$27,153,576	$46,644,711	$49,630,296	$31,312,652	$48,080,829	$36,350,274	$33,060,567	N/A
P.E.	$6,877,294	$21,794,451	$18,841,781	$10,389,798	$27,770,507	$29,399,667	$8,514,905	$7,795,707
PEPCO	$125,598,029	$142,327,396	$119,797,033	$76,139,008	$131,160,520	$113,822,013	$74,797,240	N/A
SMECO	$38,058,996	$45,410,353	$28,555,168	$29,135,277	$82,776,108	$61,140,280	$9,434,409	N/A

Figure 19: Capital and Operation and Maintenance (O&M) Expenditures

V. Reliability Objectives, Planned Actions, Projects and Programs

COMAR 20.50.12.11(A)(4) states that each Electric Company is required to provide in its annual report a description of the reliability objectives, planned actions and projects, and programs which are designed to improve its electric service and system.

Individual company reports are located in the Appendices. Each company was asked by the Commission Staff to identify the three biggest programs that will have the greatest impact on long-term reliability. The purpose was to detect common trends for all utility companies. The common program for all six utility companies is vegetation management. The answers each utility company provided:

- BGE – Replace aging equipment, satisfy the regulatory requirements, maintain operating conditions, and minimize customer outages and durations. The critical programs for long-term reliability are vegetation management and cable replacement programs. BGE cannot rank the effectiveness of each program because each program compliments or supplement another.[22]
- Choptank – Choptank states the three programs that will have the greatest long-term reliability impact are selective undergrounding, vegetation management, and regular pole inspections. The company states that vegetation management will have a large impact on system reliability, but will take two to four year to accurately assess the vegetation management impacts on SAIFI and SAIDI.[23]
- Delmarva – The top three programs for Delmarva are vegetation management, feeder improvements, and distribution automation. The greatest impact projected on SAIFI and SAIDI is vegetation management. Feeder improvements are projected to eliminate faults and reinforce infrastructure with newer materials and standards. Distribution automation is designed to mitigate fault impact to decrease customers affected and durations of outages.[24]
- Pepco – The top three programs for Pepco are vegetation management, feeder improvements, and distributions automation. Feeder improvements are projected to eliminate faults and reinforce infrastructure with newer materials and standards. Distribution automation is designed to mitigate fault impact to decrease customers affected and durations of outages.[25]

[22] Case No. 9353 – Staff Data Request No. 1, BGE
[23] Case No. 9353 – Staff Data Request No. 1, Choptank
[24] Case No. 9353 – Staff Data Request No. 1, Delmarva
[25] Case No. 9353 – Staff Data Request No. 1, Pepco

- P.E. – P.E. states the top three programs impacting SAIFI and SAIDI are vegetation management, underground cable replacement, and overhead circuit inspections. Vegetation management will have the largest impact on overall system reliability. Underground cable replacement will provide long-term reliability replacing current cables that have reached the projected end of their service reliability. Overhead circuit inspections will identify deteriorating materials and components and enable these items to be repaired or replaced prior to causing outages.[26]
- SMECO – SMECO has three main components in the company interrelated system reliability programs: re-conductoring, vegetation management, and sectionalization. The re-conductoring program involves installing greater capacity wire, new stronger pole-line structures, fortification of circuit mechanical systems, and circuit right-of-way widening and clearing. The sectionalization program will reduce the number of customer affected by each outage. The program involves installing coordinated line protective devices to break up the long overhead circuit miles into smaller sections with fewer customers. The vegetation management program ties into all other programs and is designed to improve reliability throughout the service territory.[27]

VI. Assessment of Results and Effectiveness

Pursuant to COMAR 20.50.12.11A(5), each Electric Company must provide an assessment of the results and effectiveness of the programs, projects, or planned actions and their impact on the reliability indices, including CAIDI, SAIDI, and SAIFI and any other reliability indices. The assessments provided by each of the utilities in their respective annual reliability performance reports.

All utilities, with the exception of Delmarva, met all of the COMAR requirements for 2013. From a pure regulatory standpoint, the programs, projects, and planned actions of five of the six utility companies were effective for 2013. Delmarva did not meet the required COMAR SAIFI and SAIDI targets for 2013, but met all other annual requirements.

Each of the six utility companies stated the biggest challenges for reliability listed below:

- BGE – The frequency of the unpredictable nature of the weather has presented numerous challenges for BGE. The intensity of these storms has exposed the electric system to conditions that exceed the design limits. An example would be a tropical storm or a Derecho with high winds. Even though BGE trims vegetation to COMAR standards, under these weather conditions, tree limbs and branches that are normally situated outside the normal clearance zones could interfere with power lines. The erratic nature of these storms makes it extremely challenging to predict where and when a particular part of the electric system will be impacted, making it difficult to determine which portions of the system to harden.[28]
- Choptank – The challenges for overall system reliability for Choptank are power supply reliability, vegetation, and lightning. Choptank assesses that 17% of all vegetation management issues are required to be trimmed above and beyond the COMAR regulations, and continues to

[26] Case No. 9353 – Staff Data Request No. 1, P.E.
[27] Case No. 9353 – Staff Data Request No. 1, SMECO
[28] Case No. 9353 – Staff Data Request No. 1, BGE

address vegetation management by exceeding the required standards. Choptank is spending $1.0 million per year on selective undergrounding to improve reliability in high vegetation areas. Sectional ground rods and additional lightning arrestors are being installed as well as distribution automation equipment to reduce the number of outages and improve response time to outages.[29]

- Delmarva – The top three challenges for reliability are aging infrastructure, the lack of ties between feeders, and vegetation management. The company has addressed these issues in the CAP as well as in other reliability enhancement programs (Salisbury Plan, North East Plan) as well as economic alternatives in design such as under grounding strategies (extending the life of current underground cables by injecting silicon into the cables), advanced technologies (automated circuit reclosers (ACRs), and sturdier materials (fiberglass cross arms).[30]
- Pepco – The top three challenges for reliability are vegetation management, aging infrastructure, and the design and operational challenges of serving a high density urban/suburban environment. These issues are currently being addressed by Pepco in the Reliability Enhancement Plan (REP). The company routinely evaluates and employs economic alternatives in design such as under grounding strategies (extending the life of current underground cables by injecting silicon into the cables), advanced technologies (automated circuit reclosers (ACRs), and sturdier materials (fiberglass cross arms).[31]
- P.E. – The challenges for P.E. are the mountainous and rural nature of the service territory, the radial nature of the system, and high failures in underground cables. The company plans to use helicopters during major outage events to assist in patrolling rural feeders and determining outage points. P.E. is building circuit ties and a more robust system to allow for switching to alternate feeds during outages at peak loads. The company underground cable replacement program is addressing the aging and failing cables. Staff feels that under severe weather conditions, such as high winds and low visibility, helicopters will not be able to assess the outage points. The installation of distribution automation, if reasonably achievable, will allow for P.E. to identify and isolate outages in a timely manner.[32]
- SMECO – Unpredictable weather, long radial transmission and distribution circuits, and the nature of the rural electric system constructed in close proximity to properties with abundant trees (vegetation management).[33]

The utility companies identified the areas that need improvement in order to improve system reliability. The answer for each company:

- BGE – BGE states that all current programs are required in order to continue to improve in three critical areas: safety, reliability, and cost efficiency.[34]
- Choptank – The ability to accelerate selective undergrounding is limited by environmental permits and funding. Choptank is installing a fiber optic communication backbone for the company distribution automation system, but is limited by current staffing, contractors, and funds. The lack of an AMI system has slowed down response time to outages. The

[29] Case No. 9353 – Staff Data Request No. 1, Choptank
[30] Case No. 9353 – Staff Data Request No. 1, Delmarva
[31] Case No. 9353 – Staff Data Request No. 1, Pepco
[32] Case No. 9353 – Staff Data Request No. 1, P.E.
[33] Case No. 9353 – Staff Data Request No. 1, SMECO
[34] Case No. 9353 – Staff Data Request No. 1, BGE

installation of the AMI system late 2014 to early 2016 will help Choptank identify trouble areas and help prevent equipment failure and tree contacts.[35]

- Delmarva – Delmarva states that improvements in storm response and overall system reliability are the two areas to show improvement. Process changes in the area of storm response have improved customer communications, and system upgrades have reduced the number and duration of outages. The Delmarva webpage now keeps customers informed of outages and projected restoration times. Technicians and first responders are doing a better job of identifying the causes of the outages and reducing the amount of "unknown causes".[36]
- Pepco – Pepco states that improvements in storm response and overall system reliability are the two areas to show improvement. Process changes in the area of storm response have improved customer communications, and system upgrades have reduced the number and duration of outages. The Pepco webpage now keeps customers informed of outages and projected restoration times. Technicians and first responders are doing a better job of identifying the causes of the outages and reducing the amount of "unknown causes".[37]
- P.E. – P.E. has not identified any specific area that needs improving. P.E. states that addressing the mountainous and rural nature of the service territory, the radial nature of the system, and high failures in underground cables, the company will improve overall system reliability.[38]
- SMECO – The greatest need for improvement is providing redundant distribution circuits to the electric system. The service territory is peninsula shaped and creates a radial based electric distribution network. Improving response time to system outages and trouble issues is an aspect of SMECO that is being addressed. An AMI metering project will enable SMECO to get real-time feedback on system outages and improve response time to outages.[39]

Each company has a set of best business practices that enables the company to meet strategic and regulatory objectives. The best practices, as identified be each utility company, are:

- BGE – BGE has a wide variety of best practices in areas such as safety, reliability, environmental responsibility, energy conservation, cost efficiency, and community outreach. BGE does not rank their programs and the contribution to the industry.[40]
- Choptank – The best business practices for Choptank are selective undergrounding (proactive approach), enhanced vegetation management (going beyond the COMAR standard), and restoration speed by locating service personnel close to the area of the outage.[41]
- Delmarva – The top three best business practices for Delmarva are vegetation management, an automated provision of the estimated time of restoration to customers during outages, and a comprehensive safety program.[42]

[35] Case No. 9353 – Staff Data Request No. 1, Choptank
[36] Case No. 9353 – Staff Data Request No. 1, Delmarva
[37] Case No. 9353 – Staff Data Request No. 1, Pepco
[38] Case No. 9353 – Staff Data Request No. 1, P.E.
[39] Case No. 9353 – Staff Data Request No. 1, SMECO
[40] Case No. 9353 – Staff Data Request No. 1, BGE
[41] Case No. 9353 – Staff Data Request No. 1, Choptank
[42] Case No. 9353 – Staff Data Request No. 1, Delmarva

- Pepco - The top three best business practices for Delmarva are vegetation management, an automated provision of the estimated time of restoration to customers during outages, and a comprehensive safety program.[43]
- P.E. – Customer communication, storm handling process, and the customer contact center are the three best practices for P.E. P.E. has a 24/7 system for reporting system outages. Customers can also subscribe to receive alert notification when outage events occur. Customers can use text messages to report outages. In-house meteorologists, a new outage management system, and lessons learned reviews after each storm, allows P.E. to identify what worked and where to improve. Customer service representatives now have real-time information to share with customers during outage events to keep all in the service area informed.[44]
- SMECO – SMECO has a well-established electric system maintenance practices which greatly contribute to overall safety and reliability. Many of the inspection intervals established in COMAR 20.50.12.10.H are based on SMECO pre-existing maintenance practices. SMECO has a methodical systematic planning approach to developing capital improvement projects in tandem with on-going perpetual system review and configuration changes as necessary to best ensure the electric system can meet demanding normal and contingency situations. SMECO uses a four year vegetation management cycle as well as ground inspections of the transmission system by a contract Forester to identify vegetation issues before they arise.[45]

VII. Staff Comments & Conclusions

Since there were no MOEs for 2013, the reliability under major storms could not be assessed for 2013 and the performance could not be compared to 2012. There were several storms such as microburst thunderstorms, storms with large amount of lightning strikes, and high wind storms that occurred in various Maryland service territories, but were not large enough to cause enough outages to be considered MOEs. These storms had an impact on several of the Maryland utilities, with four of the six having a higher amount of outages than the year before. One of the utility companies, Delmarva, did not meet the COMAR standards for SAIFI and SAIDI, and filed a CAP as required. Staff concludes that the overall reliability of Maryland utilities is susceptible to significant storms that do not meet the COMAR standard for a MOE, but are large enough to cause sustained outages that directly impacts utility SAIFI and SAIDI indices. Staff notes that vegetation management, selective undergrounding, distribution automation, and upgrading aging feeders will enable Maryland utility companies to improve performance during such events.

All utility companies met the downed wire response standards. There was a large difference in the response time for two utility companies when the wires were reported and guarded by police, fire personnel, or reported by 911, and downed wires reported by all sources. Staff notes that there should not have been a large discrepancy in response time for guarded and non-guarded electric downed wires.

The vegetation management programs for all six utility companies are aggressive and ahead of the required vegetation management timeline as required by COMAR. All utility

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[43] Case No. 9353 – Staff Data Request No. 1, Pepco
[44] Case No. 9353 – Staff Data Request No. 1, P.E.
[45] Case No. 9353 – Staff Data Request No. 1, SMECO

companies began the vegetation management program in 2012, trimming vegetation according to the COMAR standard. The accelerated vegetation management has all utilities at 44% or above for current overhead vegetation trimming, well ahead of the 15% (4-year trim cycle) or 15% (5-year trim cycle) required by COMAR. Staff concludes that the accelerated vegetation management from all six utility companies should show a reduction in outages caused by vegetation and an improvement in system reliability.

The main causes of outages for all Maryland utility companies are vegetation and animals. Lightning was the major cause of weather outages, ahead of wind and other storm related causes. Staff notes that vegetation management, animal guards on overhead and underground equipment, and lightning arresters are all reliability improvements that may have a substantial impact on overall system reliability.

Programs that all six utility companies focus on for improving reliability are vegetation management and distribution automation. Vegetation management is the program that has been identified by all six utilities as the best way to improve system reliability. Distribution automation will have an impact on outages and the duration of outages. This program will allow for outages to be identified quickly, isolated, and power restored to customers faster. Staff notes that both the vegetation management program and distribution automation should have a positive impact on system wide reliability.

Several utility companies identify the radial nature of their service territory as a weakness in their systems. The utility companies are working on programs to tie current feeder into other existing feeders to improve reliability and provide redundancy in the system, allowing for outages or system overloads to be supported by other feeders while the outage is being addressed. Staff notes that the radial nature of three of the six Maryland utility systems (Delmarva, P.E., and SMECO) is a valid concern and a controlling factor in improving overall system reliability.

VIII. Observations and Recommendations

Based on the review of the six Electric Companies' 2013 performance reports, Staff renders the following observations and recommendations:

- Utilities made a commendable effort to structure a common reporting template that facilitates Staff evaluations and comparison of the annual report data. Staff will continue to work with the utilities to refine the template to include the data requests made to support the 2013 review. Staff will also work with the utilities to ensure there is a software format identified and process to submit data that the Staff needs to complete the analysis of the annual reports.
- Overall all six Maryland utility companies improved system reliability and implemented reliability plans that will allow the utility to continue to improve the overall system. The one utility, Delmarva, that did not meet the COMAR standards, has submitted a corrective action plan and is already taking steps to improve their system, and meet the COMAR standards in the future.

- Staff recommends that the Commission note the CAP filing and direct Delmarva to file mid-September, after the summer storm season, an assessment of the Delmarva's CAP including 2014 year to date SAIFI and SAIDI and updated 2014 SAIFI and SAIDI projections.

IX. Glossary of Terms

Term	Definition[46]
CAIDI – Customer Average Interruption Duration Index	A reliability indicator, usually measured in minutes or hours, used by electric companies to represent the average outage duration that any given customer would experience in a given year.
CEMI – Customers Experiencing Multiple Interruptions	A reliability indicator used by electric companies which represents the number of interruptions that a customer would experience in a given year.
CAP – Corrective Action Plan	A plan required by COMAR when a utility fails to meet one or more of the required standards, to remediate the system or systems that did not meet the standard or were a direct cause for the shortfall.
Cross Arm	A horizontal member attached to a pole, post, tower or other structure and equipped with means for supporting the conductors.
Cutout	An electric device used manually tor automatically to interrupt the flow of current though any particular apparatus or instrument.
Fuse	An overcurrent protective device with a circuit-opening fusible part that is heated and severed by the passage of overcurrent through it.
Lightning Arrestor[47]	A device for protecting an electrical apparatus from damage from lightning.
MAIFI – Momentary Average Interruption Frequency Index	A reliability indicator, measured in units of interruptions or events per customer, used by electric companies to represent the average number of momentary interruptions that a customer would experience during a given year.
MEO – Major Outage Event[48]	An event, defined by COMAR as Both: More than 10 percent or 100,000, whichever is less, of the electric utility's Maryland customers experience a sustained interruption of electric service; and restoration of electric service to any of these customers takes more than 24 hours; or the federal, State, or local government declares an official state of emergency in the utility's service territory and the emergency involves interruption of electric service.
PPF – Poorest Performing Feeder	An electric plant that emanates from a substation, serves customers, and is normally electrically isolated at all endpoints, that is performing in the bottom 3% for the utility.
Recloser (Reclosing Device)	A control device which initiates the reclosing of a circuit after it has been opened by a protective relay.
SAIDI – System Average Interruption Duration Index	A reliability indicator, usually measured in minutes or hours, used by electric companies to represent how much total time a customer may not have service in a given year.
SAIFI – System Average Interruption Frequency Index	A reliability indicator, usually measured in interruptions or events per customer, used by electric companies to represent how often a customer may experience an interruption in a given year.
Switch (or Switchgear)	A general term covering switching and interrupting devices and their combination with associated control, instrumentation, metering, protective and regulating devices.
Tap	An available connection that permits changing the active portion of the device in the circuit (i.e. voltage, current, ratio).
Tie (or Tie Feeder)	A feeder that connects together two or more independent sources of power and has no tapped load between the terminals.

[46] Frank, Jay; *IEEE Standard Dictionary of Electrical and Electronics Terms, Second Edition;* The Institute of Electrical and Electronics Engineers, Inc., Dec. 1, 1977. Print

[47] http://www.merriam-webster.com/dictionary/lightning%20arrester

[48] COMAR 20.50.01.03

X. Appendices

A. **Appendix 1: BGE**

Pursuant to COMAR 20.50.12.11, on or before April 1st of each year, BGE is required to file with the Commission their annual reliability performance report which reflects the company's reliability performance. This report marks the second annual report since the adoption of RM43.

BGE has met the system-wide reliability standards (SAIDI and SAIFI) in both 2012 and 2013. In comparison to 2012, BGE experienced improvements in their SAIFI, SAIDI, and CAIDI indexes for all interruption data minus major outage event data. BGE has implemented several distribution circuit reliability improvements that have resulted in a system wide decrease over the last three years in the SAIFI index for all interruption data.

1. 20.50.12.02 System-Wide Reliability Standards

COMAR 20.50.12.02 requires that each electric company shall collect and maintain reliability data and use system-wide indices SAIDI and SAIFI as performance measurements of system reliability. The SAIDI and SAIFI reliability standards set forth for BGE for the 2013 calendar year is 3.96 for SAIDI and 1.47 for SAIFI. BGE's annual SAIDI and SAIFI results are required to be equal to or less than these established numbers, and the indices are measured on all interruption data minus major outage event interruption data and minus outage data resulting from an outage event occurring on another utility's electric system.

BGE's system-wide SAIFI, SAIDI, and CAIDI indices for all interruption data minus major outage events, all showed a downward trend over the last three years. Since 2011, the SAIFI index has decreased by 0.53, the SAIDI index has decreased by 2.31, and the CAIDI index has decreased by 0.94. When looking at the SAIDI and CAIDI indices that include major outage event interruption data, BGE experienced a spike in these indices in 2012 due to the severity of the major events during that time period. Both BGE's SAIDI and SAIFI index met the system-wide reliability standards set forth in COMAR 20.50.12.02D(1)(a) and no corrective action plans were required.

Figure 1 outlines the reliability index results for SAIDI, SAIFI, and CAIDI for BGE.

		Reliability Index	2011	2012	2013	2013 COMAR Standard[4,5]	3 Year Average
Including Planned Outages	All Interruption Data	SAIFI[1] (Events)	2.26	1.92	0.93	N/A	1.70
		SAIDI[2] (Hours)	28.41	30.40	1.67	N/A	20.14
		CAIDI[3] (Hours)	12.59	15.84	1.79	N/A	11.83
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.46	1.03	0.93	1.47	1.14
		SAIDI (Hours)	3.98	2.58	1.67	3.96	2.74
		CAIDI (Hours)	2.73	2.52	1.79	N/A	2.41
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	1.29	1.04	0.93	N/A	1.09
		SAIDI (Hours)	3.07	2.48	1.67	N/A	2.41
		CAIDI (Hours)	2.38	2.40	1.79	N/A	2.22
Excluding Planned Outages	All Interruption Data	SAIFI (Events)	2.20	1.86	0.87	N/A	1.64
		SAIDI (Hours)	28.23	30.05	1.39	N/A	19.85
		CAIDI (Hours)	12.82	16.18	1.60	N/A	12.10
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.40	0.96	0.87	N/A	1.08
		SAIDI (Hours)	3.75	2.23	1.39	N/A	2.45
		CAIDI (Hours)	2.68	2.31	1.60	N/A	2.28
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	1.23	0.97	0.87	N/A	1.02
		SAIDI (Hours)	2.83	2.22	1.39	N/A	2.15
		CAIDI (Hours)	2.32	2.27	1.60	N/A	2.10

Figure 1: Reliability Index Information

2. 20.50.12.03 Poorest Performing Feeder Standard

COMAR 20.50.12.03 requires that electric companies report SAIDI, SAIFI, and CAIDI indices for the 3% of feeders identified as having the poorest reliability. BGE identified a total of 39 feeders as having the poorest reliability. BGE identified its poorest performing feeders by the following method:

- First, feeders were ranked by SAIFI, using all interruption data excluding major outage event interruption data, planned outage data, and substation event data for the twelve month period ending September 30, 2013.
- Next, the poorest performing 4% of feeders based on the SAIFI rankings, would then be ranked by SAIDI.
- Finally, the top 3% of the final rankings were selected as the poorest performing feeders, warranting remediation efforts.

BGE has completed, and in some cases scheduled, reasonable remediation efforts for the poorest performing feeders. BGE's remediation efforts include replacement or repair of conductor segments, vegetation trimming, installation of distribution automation reclosers, installation of sectionalizing switches, cable replacement, and undergrounding overhead circuitry.

COMAR 20.50.12.03A(5) states that no feeder identified as a poorest performing 3 percent of feeders shall perform in the poorest performing 3 percent of feeders during either or the two subsequent 12 month reporting periods unless reasonable remediation measures were taken to improve the performance of the feeder. This regulation also states that the electric company is allowed one 12-month reporting period to implement remediation measures. There were a few feeders that continued to rank low, however, BGE is still in the process of remediation efforts within the allowed 12-month period and therefore those feeders are not considered repeat feeders in the worst performing feeders category, and they were not included on the current list for worst performing feeders.

3. 20.50.12.04 Multiple Device Activation Standard

COMAR 20.50.12.04 requires that each electric company report all protective devices that activated five or more times causing sustained interruptions to at least ten customers during the reporting period. BGE had a total of thirty-four protective devices that were activated five or more times during the prior 12-month reporting period. Twenty-five of the protective devices were line or tap fuses, ranging from five to ten outage events each. Also, there were 6 reclosers that experienced five to six outage events each and three circuit breakers that experienced five to six outage events each. Approximately 50% of the remedial actions were completed in 2013. Remediation efforts includes, but is not limited to, the replacement or repair of conductor segments, vegetation trimming, installation of distribution automation reclosers, installation of sectionalizing switches, cable replacement, and undergrounding overhead circuitry. The remaining remedial actions are scheduled for completion in 2014 except for two feeders that will be converted to 13kV to increase system capacity, scheduled for completion in 2015 for one and 2016 for the other.

4. 20.50.12.05 Additional Reliability Indices Reporting Standard

COMAR 20.20.12.05 requires that each electric company use additional indices for reliability in its annual performance report for its Maryland service territory, in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages. Each electric company is also required to calculate and report Customers Experiencing Multiple Interruptions ("CEMIn") and Momentary Average Interruption Frequency Index ("MAIFIE") information which also give a measure of electric service reliability from the customer's perspective. If the electric company does not have the means to make the required calculations, then the utility must provide an explanation as to why it cannot supply this information, and an estimate of the cost to provide this information in the future.

BGE calculated that 8.31% of their customers experienced three or more sustained interruptions during the reporting period. This number has decreased from 25.5% reported for 2012. Consequently, they calculated 1.3% of their customers experienced five or more sustained interruptions, and 0.23% of their customers experienced seven or more sustained interruptions. Again, these numbers have also decreased from 2012. The number of customers that experienced five or more sustained interruptions last year was 7.1% and the number of customers that experienced seven or more sustained interruptions in 2012 was 1.8%. Finally, BGE calculated 0.05% of their customers experienced nine or more sustained interruptions during the reporting period, which decreased from 0.5% in 2012 for all interruption data.

BGE also calculated an annual MAIFIE index for its Maryland service territory of 4.13 for the reporting period. This index had a downward trend from 2012 where BGE calculated this index at 8.57 for all interruption data and 5.29 for all interruption data excluding major outage event interruption data.

5. 20.50.12.06 Service Interruption Standard

COMAR 20.50.12.06 states that an electric company shall restore service within 8 hours to at least 92 percent of its customers experiencing sustained interruptions during normal conditions and within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events (where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers). The required time duration for restoration is measured from when the utility knew or should have known of an outage. This standard also requires that service is restored quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the electric company's total number of customers, whichever is less.

BGE met this standard and restored service to 97% of their customers experiencing sustained interruptions during normal conditions within 8 hours. They did not experience any major outage events during the reporting period.

6. 20.50.12.07 Downed Wire Response Standard

COMAR 20.50.12.07 states that each electric company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.

BGE met the requirements of this standard and reported a 99% response rate within the required 4 hour time frame after notification of a guarded downed wire from a government emergency responder. There were a total of 8,355 downed wires reported to BGE during the reporting period, of which 6,677 belonged to the utility. BGE responded to 90% of these downed wires within 4 hours, 8% within 4 to 8 hours, and the remaining 2% had a greater than 8 hour response time.

7. 20.50.12.08 Customer Communications Standard

COMAR 20.50.12.08 states that each electric company shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each electric company shall achieve an annual average abandoned call percentage rate of 5 percent or less. For calls offered to the utility for customer service or outage reporting purposes, BGE met this requirement by answering 87.6% of the calls within 30 seconds with a 2.11% abandoned call rate. For calls solely offered to its customer service representatives, BGE met the requirement by answering 76.1% of calls within 30 seconds with a 3.46% abandoned call rate and an average answer speed of 25 seconds. This is a dramatic improvement from 2012, where BGE failed to meet the requirement by answering 58.5% of calls solely offered to its customer service representatives within 30 seconds with a 14.9% abandoned call rate and an average answer speed of 64 seconds.

8. 20.50.12.09 Vegetation Management Requirements

COMAR 20.50.12.09 outlines the scope, technical standards, record keeping, and reporting requirements for vegetation management. BGE has 9,404 miles of overhead distribution circuit lines for their system. This standard requires that within 12 months of the effective date of this regulation, an electric company on a 4 year trim cycle is required to perform vegetation management on at least 15% of its total distribution miles. BGE trimmed 2,338 miles of their distribution lines in 2013 and 2,353.02 miles in 2012 for a total of 4,691.02 distribution miles trimmed, which is more than the required 15% (see Figure 2).

BGE Distribution OH Circuit Miles	Trim Cycle	Distribution Miles Trimmed 2012	Distribution Miles Trimmed 2013	Total Distribution Miles Trimmed	% of System Trimmed To Date	COMAR Standard
9404	4-year	2,353.02	2338	4,691.02	49.9%	15%

Figure 2: Vegetation Management Requirements

BGE spent $32,767,011 in 2013 performing vegetation management duties resulting in an approximate cost per circuit mile trimmed of $9,200. BGE has projected a budget of $36,778,288 in 2014 for vegetation management.

9. Outage Types & Causes

During the reporting period, BGE experienced 18,572 outages, with 2,394 planned outages, 16,178 non-planned outages, and no major outage events. These outages affected 1,161,856 customers with 124,572,498 customer outage minutes. Vegetation accounted for approximately 18% of the outages, both underground and overhead (OH) equipment failure accounted for approximately 22% of the outages, and approximately 13% of the outages were planned. In comparison to 2012, BGE had a downward trend in total outages, planned outages, and non-planned outages excluding major outage events. Approximately 99.96% of the customers experienced an outage that was less than 24 hours in duration.

10. 20.50.12.11A(4) Reliability Objectives, Planned Actions, Projects and Programs

BGE's objective is to focus on minimizing the number and duration of electric service outages experienced by customers each year. As a result, BGE has established a variety of projects and programs that address outage issues at the system, feeder, community, and individual customer levels. These programs implemented for distribution circuit reliability improvements include, but are not limited to, cable replacement, electric system redesign, recloser replacement program, poorest performing feeders remediation, utility pole relocations, and multiple device activation remediation.

11. 20.50.12.11A(5) Assessment of Results and Effectiveness

Pursuant to COMAR 20.50.12.11A(5), each electric company must provide an assessment of the results and effectiveness of the programs, projects, or planned actions and their impact on the reliability indices, including CAIDI, SAIDI, and SAIFI and any other reliability indices.

BGE's reliability programs have supported their efforts to replace aging equipment and maintain operating conditions that minimize customer outages. To gauge the effectiveness of its reliability programs, BGE looked at feeders that had at least 12 months of data following the completion of reliability construction work, and found that there was an improvement in customer interruptions by approximately 63% and an improvement in customer minutes of interruption by approximately 75%.

12. Expenditures

COMAR 20.50.12.11.A.(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11.B(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

For distribution corrective and reliability improvement work, BGE had an upward trend in spending from 2012 to 2013, spending $110,102,576 in capital expenditures and $12,602,082 in operating and maintenance expenditures. The money spent on routine and reactive distribution work remained constant from 2012 to 2013 and money spent on storm work trended downward. The capital expenditures for substation inspection, maintenance, and repairs doubled from 2012 to 2013. The operating and maintenance expenditures for vegetation work in 2013 were $32,767,011. Projected amounts for 2014 and 2015 for vegetation management have a gradual upward trend. All other projected expenditures amounts for 2014 and 2015 are similar to either the actual or budgeted expenditures for 2013, except for the projected capital expenditures for planned distribution work and reliability improvement work which trends downward by approximately $30,000,000.

13. Conclusion

Overall, BGE showed an improvement in 2013 for reliability indices used for all interruption data, and all standards were met. BGE is continuing efforts in their reliability programs, vegetation management, and in implementing corrective measures to create a more resilient electric distribution system.

B. **Appendix 2: Choptank**

Pursuant to COMAR 20.50.12.11, on or before April 1st of each year, Choptank is required to file with the Commission their annual reliability performance report which reflects the company's reliability performance. This report marks the second annual report since the adoption of RM43.

Choptank has met the system-wide reliability standards (SAIDI and SAIFI) in both 2012 and 2013. In comparison to 2012, Choptank experienced improvements in their CAIDI and SAIDI indexes for all interruption data minus major outage event data and outage data resulting from another utility's electric system.

Choptank has implemented several reliability projects that have resulted in a system wide decrease in SAIDI and SAIFI indexes for all interruption data.

1. 20.50.12.02 System-Wide Reliability Standards

COMAR 20.50.12.02 requires that each electric company shall collect and maintain reliability data and use system-wide indices SAIDI and SAIFI as performance measurements of system reliability. The SAIDI and SAIFI reliability standards set forth for Choptank for the 2013 calendar year is 2.92 for SAIDI and 1.49 for SAIFI. Choptank's annual SAIDI and SAIFI results are required to be equal to or less than these established numbers, and the indices are measured on all interruption data minus major outage event interruption data and minus outage data resulting from an outage event occurring on another utility's electric system.

Choptank's system-wide SAIFI index for all interruption data for 2013 showed improvement from their numbers in 2012, going from 2.64 to 2.43. However, their SAIFI for all interruption data minus major outage events and outage events occurring on another utility's electric system did not follow that same trend. In looking at the preceding three years, Choptank experienced a dip in 2012 for their SAIFI index for this category and a downward trend for their SAIDI index. Both Choptank's SAIDI and SAIFI index met the system-wide reliability standards set forth in COMAR 20.50.12.02D(1)(b) and no corrective action plans were required.

Figure 1 was provided by Choptank, outlining the reliability index results for SAIDI, SAIFI, and CAIDI.

		Reliability Index	2011	2012	2013	2013 COMAR Standard[4,5]	3 Year Average
Including Planned Outages	All Interruption Data	SAIFI[1] (Events)	2.04	2.64	2.43	N/A	2.37
		SAIDI[2] (Hours)	3.02	10.68	5.47	N/A	6.39
		CAIDI[3] (Hours)	1.48	4.05	2.25	N/A	2.59
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	2.01	1.92	2.43	N/A	2.12
		SAIDI (Hours)	2.95	2.71	5.47	N/A	3.71
		CAIDI (Hours)	1.47	1.42	2.25	N/A	1.71
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occurring on Another Utility's Electric	SAIFI (Events)	1.46	0.98	1.33	1.49	1.26
		SAIDI (Hours)	2.35	1.64	1.58	2.92	1.86
		CAIDI (Hours)	1.50	1.67	1.18	N/A	1.45
		SAIFI (Events)	2.02	2.25	2.43	N/A	2.23

	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIDI (Hours)	2.96	5.52	5.18	N/A	4.55
		CAIDI (Hours)	1.47	2.45	2.13	N/A	2.02
Excluding Planned Outages	All Interruption Data	SAIFI (Events)	1.76	2.47	2.38	N/A	2.20
		SAIDI (Hours)	2.41	9.82	5.02	N/A	5.75
		CAIDI (Hours)	1.37	3.98	2.11	N/A	2.49
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.72	2.06	2.38	N/A	2.05
		SAIDI (Hours)	2.34	4.57	5.02	N/A	3.98
		CAIDI (Hours)	1.36	2.22	2.11	N/A	1.90
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occurring on Another Utility's Electric	SAIFI (Events)	1.17	0.93	1.13	N/A	1.08
		SAIDI (Hours)	1.75	1.52	2.30	N/A	1.86
		CAIDI (Hours)	1.50	1.64	2.02	N/A	1.72
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	1.72	2.06	2.33	N/A	2.04
		SAIDI (Hours)	2.34	4.57	4.63	N/A	3.85
		CAIDI (Hours)	1.36	2.22	1.99	N/A	1.86
**	There were no Major Events in 2013.						

Figure 1: Reliability Index Information

2. 20.50.12.03 Poorest Performing Feeder Standard

COMAR 20.50.12.03 requires that electric companies report SAIDI, SAIFI, and CAIDI indices for the 3% of feeders identified as having the poorest reliability. Since Choptank currently has 112 feeders, 3% of that total is approximately 4 feeders. Choptank identified the following feeders as having the poorest reliability: Feeder #131 (Barclay substation), Feeder #123 (Kennedyville substation), Feeder #312 (Hillsboro substation), and Feeder #112 (Clough substation). Choptank identified its poorest performing feeders by using the same method they used last year:

- First, a ranking number was assigned to each feeder using the SAIDI index for each feeder.
- Next, a ranking number was assigned to each feeder using the SAIFI index for each feeder.
- Both ranking numbers are added together for each feeder to determine the Total Rank.
- The 4 feeders with the highest Total Rank were chosen as the worst performing feeders.
- These calculations were performed using the indices that do not include outage data from major events or outage data from another utility's electric system.

Adequate remediation efforts have been performed where reasonable and have been summarized in Figure 2 submitted by Choptank.

Feeder Name/#	Substation	Remedial Action Description	Estimated Completion Date
131	Barclay	This circuit had 5 hot-line tag operations while a contractor was reconductoring a portion of the circuit. 1 Operation was caused by the contractor. The other operations were caused by downline faults that interrupted the entire circuit because it was in hot-line tag mode for the contractor. No remediation is necessary.	n/a

123	Kennedyville	Install additional reclosers at 123-62 so faults downline don't trip all the way back at the substation. Assess trouble areas for possible spot trimming.	1-Jun-14
312	Hillsboro	Circuit is mostly underground. The circuit had one cable splice failure. It also had 2 outages due to trees within the same area within a very short time span. That area was selectively undergrounded (312-59-566 to 312-59-566-9).	1-Dec-13
112	Clough	This circuit was interrupted 3 times for vehicular accidents. It was also interrupted due to imbalance by a large industrial customer twice. The breaker at the industrial site was reprogrammed after the second outage to trip just the industrial customer if they should cause a large imbalance again. The accident locations were not of the type that could be easily adjusted to minimize future accident possibilities.	n/a

Figure 2: Remediation For Poorest Performing Feeders

COMAR 20.50.12.03A(5) states that no feeder identified as a poorest performing 3 percent of feeders shall perform in the poorest performing 3 percent of feeders during either or the two subsequent 12 month reporting periods unless reasonable remediation measures were taken to improve the performance of the feeder. Choptank's Feeder #123 was identified as one of the poorest performing feeders in both the 2012 report and the 2013 report. Reasonable remediation measures were taken to improve the feeder's 2012 performance resulting in a section of the feeder being rebuilt underground and aggressive vegetation trimming. In Choptank's 2013 report, this feeder was identified as a poorest performing feeder for different reasons than that of 2012. This feeder contained no downstream devices, and a recloser at the substation along with fuses on the taps. There were vegetation issues along the second half of the feeder. Since there were no downstream devices on this feeder, the vegetation issues caused the recloser to open at the substation, resulting in many customers experiencing the outage although the vegetation issues were only in a small section of the feeder. As a result, Choptank installed a set of reclosers at the mid-point on this feeder so that vegetation near the end of the feeder will only affect that portion of the feeder and not the entire feeder. The reclosers were installed in May 2014. Also, the trees along the second half of this feeder were trimmed in March 2014.

Although Choptank experienced a repeat feeder in the poorest performing 3 percent of feeders category, the utility has shown that reasonable remediation measures were taken to improve the performance of the feeder and is therefore in compliance with COMAR 20.50.12.03A(5) and no corrective action plan is required.

3. 20.50.12.04 Multiple Device Activation Standard

COMAR 20.50.12.04 requires that each electric company report all protective devices that activated five or more times causing sustained interruptions to at least ten customers during the reporting period. Choptank had a total of three protective devices that were activated five or more times during the prior 12-month reporting period. Two of the protective devices at the substations experienced five outages each and the third device experienced six outages. All remedial actions were completed in 2013.

4. 20.50.12.05 Additional Reliability Indices Reporting Standard

COMAR 20.20.12.05 requires that each electric company use additional indices for reliability in its annual performance report for its Maryland service territory, in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages. Each electric company is also required to calculate and report Customers Experiencing Multiple Interruptions ("CEMIn") and Momentary Average Interruption Frequency Index ("MAIFIE") information which also give a measure of electric service reliability from the customer's perspective. If the electric company does not have the means to make the required calculations, then the utility must provide an explanation as to why it cannot supply this information, and an estimate of the cost to provide this information in the future.

Choptank calculated that 6.77% of their customers experienced three or more sustained interruptions during the reporting period. This number has decreased from 9% reported for 2012. Consequently, they calculated 2.8% of their customers experienced five or more sustained interruptions, and 0.18% of their customers experienced seven or more sustained interruptions. The number of customers that experienced five or more sustained interruptions increased slightly from last year, which was 1.72%. The number of customers that experienced seven or more sustained interruptions decreased from 0.35% reported for 2012. Choptank did not have any customers that experienced nine or more sustained interruptions during the reporting period.

Choptank did not provide calculations for 2013 MAIFIE data because the company would need to install and fully implement a system-wide automated metering information (AMI) system to accurately report this metric. Choptank is currently evaluating AMI systems/vendors and may begin implementation in the latter half of 2014. The Company estimates a cost of approximately $12 million for implementation.

5. 20.50.12.06 Service Interruption Standard

COMAR 20.50.12.06 states that an electric company shall restore service within 8 hours to at least 92 percent of its customers experiencing sustained interruptions during normal conditions and within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events (where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers). The required time duration for restoration is measured from when the utility knew or should have known of an outage. This standard also requires that service is restored quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the electric company's total number of customers, whichever is less.

Choptank met this standard and restored service to 99.7% of their customers experiencing sustained interruptions during normal conditions within 8 hours. They did not experience any major outage events during the reporting period.

6. 20.50.12.07 Downed Wire Response Standard

COMAR 20.50.12.07 states that each electric company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.

Choptank reported a 100% response rate within the required 4 hour time frame after notification from a government emergency responder of a guarded downed wire. There were a total of 3 downed wires reported to Choptank during the reporting period, all of which were found to belong to the utility. Choptank responded to all within 4 hours, therefore meeting the standard.

7. 20.50.12.08 Customer Communications Standard

COMAR 20.50.12.08 states that each electric company shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each electric company shall achieve an annual average abandoned call percentage rate of 5 percent or less. For calls offered to the utility for customer service or outage reporting purposes, Choptank met this requirement by answering 95.9% of the calls within 30 seconds with a 0.79% abandoned call rate. For calls solely offered to its customer service representatives, Choptank met the requirement by answering 94.3% of calls within 30 seconds with a 1.10% abandoned call rate and an average answer speed of 11 seconds.

8. 20.50.12.09 Vegetation Management Requirements

COMAR 20.50.12.09 outlines the scope, technical standards, record keeping, and reporting requirements for vegetation management. Choptank has 2,046 miles of overhead circuit lines for their system. This standard requires that within 24 months of the effective date of this regulation, an electric company on a 5 year trim cycle is required to perform vegetation management on at least 12% of its total distribution miles. Choptank trimmed 489 miles of their distribution lines in 2013 and 445.16 miles in 2012 for a total distribution miles of 934.16 miles trimmed, which is more than the required 12%.

Choptank set aside a budget of $3,400,000 for vegetation management in 2013, and they actually spent $3,291,292 performing this duty resulting in an average cost per circuit mile trimmed of $6,731. Choptank has projected 626.45 overhead circuit miles will be trimmed in 2014.

9. Outage Types & Causes

Choptank filed a corrected chart outlining their outage data under Mail Log No. 156132, dated June 20, 2014. During the reporting period, Choptank experienced 1,664 outages, with 66 planned outages, and no major outage events. These outages affected 134,888 customers with 17,371,428 customer outage minutes. Underground equipment failure led to 17% of the outages, and 14% of the outages were due to animals. Although there were more planned outages this year, Choptank had a downward trend in total number of outages for 2013 in comparison to 2012. There was also a downward trend in the total number of customers affected and the total customer outage minutes. All 134,888 customers were without electrical service for less than 24 hours.

10. 20.50.12.11A(4) Reliability Objectives, Planned Actions, Projects and Programs

Choptank's objective is to pursue reliability enhancements on multiple levels by performing more aggressive tree trimming to obtain larger clearances between trees and overhead conductors, having Osmose Utilities Services, Inc. (Osmose) perform system-wide inspections and implement a pole treatment program, and to have one employee solely dedicated to performing system inspections. Also, Choptank will be selectively undergrounding or relocating sections of line that are "repeat offenders". The company will focus on improvements that will have the most impact on the frequency of outages, number of customers affected, and outage durations.

11. 20.50.12.11A(5) Assessment of Results and Effectiveness

Pursuant to COMAR 20.50.12.11A(5), each electric company must provide an assessment of the results and effectiveness of the programs, projects, or planned actions and their impact on the reliability indices, including CAIDI, SAIDI, and SAIFI and any other reliability indices.

Choptank has chosen to focus on projects in areas that are prone to many outages and affect many customers. As a result, recently completed projects have reduced overall SAIDI by 0.10 minutes and SAIFI by 0.02.

12. Expenditures

COMAR 20.50.12.11.A.(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11.B.(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

In 2013, Choptank spent $220,971 on pole and padmount equipment inspections and treating utility poles with a preservative. The work was performed by Osmose, the utility services company which has been performing inspections on Choptank's system since 2010. The company abruptly lost their System Inspector, an employee who was solely responsible for inspecting poles and padmounted equipment for reliability and safety issues, which resulted in Choptank being under budget in 2013 for their operating and maintenance expenditures.

Figure 3 shows the actual operation and maintenance and capital expenditures for Choptank's reliability programs over the past 3 calendar years, and the projected budget for 2014.

	2011	2012	2013	2014 (Projected)
Pole and Padmount Equipment Inspection and Maintenance	$319,638	$300,535	$220,971	$300,000
Chief Lineman (System Inspector)	$112,563	$112,231	$25,177	$125,000
Vegetation Management	$2,248,554	$2,622,089	$3,291,292	$3,260,000
Recloser Replacement	$256,504	$208,208	$781,657	$560,000
Selective Undergrounding	$3,408,657	$5,557,198	$4,033,358	$4,575,000
Distribution Automation	$279,835	$283,325	$292,357	$280,000

Figure 3: Choptank's Expenditures

Choptank projects include:

- "Recloser Replacement involves replacing older hydraulic reclosers with electronic Distribution Automation (DA) capable reclosers.
- Selective Undergrounding involves line sections that are relocated underground to improve reliability and/or sections that are due for replacement/improvement and have a significant portion relocated underground.
- Distribution Automation involves the installation of communications equipment and reclosers at normal open points between feeders to facilitate DA."

Projected amounts for 2014 show a gradual upward trend for pole/padmount equipment inspection and maintenance, selective undergrounding, and for the System Inspector position. The projected amounts for vegetation management and distribution automation remain relatively constant, and there's a downward trend in the projected 2014 amounts for recloser replacements.

13. Conclusion

Overall, Choptank showed an improvement in 2013 for all interruption data for both frequency and duration, and all standards were met. Choptank is continuing efforts in their reliability programs, vegetation management, and in implementing corrective measures to create a more resilient electric distribution system.

C. Appendix 3: Delmarva

Pursuant to COMAR 20.50.12.11, on or before April 1st of each year, Delmarva is required to file with the Commission their annual reliability performance report which reflects the company's reliability performance. This report marks the second annual report since the adoption of COMAR 20.50.12.

Delmarva did not meet all COMAR required standards for 2013. Delmarva fell short of the SAIFI and SAIDI requirements set forth by COMAR, but was able to meet all other required COMAR standards for 2013. Delmarva filed a corrective action plan (CAP) as required by COMAR on April 1, 2014. The Staff analysis of the CAP is in Appendix 7.

	Annual Requirement	Actual Results	% Over COMAR
SAIDI	2.99	3.54	18.4%
SAIFI	1.65	1.95	18.2%

Figure 1: 2013 Delmarva SAIFI and SAIDI Performance

1. 20.50.12.02 System-Wide Reliability Standards

COMAR 20.50.12.02 requires that each electric company shall collect and maintain reliability data and use system-wide indices SAIDI and SAIFI as performance measurements of system reliability. The SAIFI and SAIDI reliability standards set forth for Delmarva for the 2013 calendar year are 1.65 for SAIFI and 2.99 for SAIDI. Delmarva's annual SAIFI and SAIDI results are required to be equal to or less than these established numbers, and the indices are measured on all interruption data minus major outage event interruption data and minus outage data resulting from an outage event occurring on another utility's electric system.

The system-wide performance data for Delmarva is listed below in Figure 1. The report for 2013 is unique in that it does not include any major outage events (MOEs). Delmarva did not meet the COMAR standard for 2013 for SAIFI (performing 18.2% worse than the standard), and SAIDI (performing 18.4% worse than the standard).

		Reliability Index	2011	2012	2013	2013 COMAR Standard[4,5]	3 Year Average
Including Planned Outages	All Interruption Data	SAIFI[1] (Events)	3.20	2.38	1.95	N/A	2.51
		SAIDI[2] (Hours)	16.20	9.73	3.54	N/A	9.83
		CAIDI[3] (Hours)	5.07	4.10	1.82	N/A	3.66
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	2.45	1.70	1.95	1.65	2.03
		SAIDI (Hours)	5.98	3.18	3.54	2.99	4.24
		CAIDI (Hours)	2.45	1.87	1.82	N/A	2.05
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Ocurring on Another Utility's Electric System	SAIFI (Events)	-	-	-		-
		SAIDI (Hours)	-	-	-		-
		CAIDI (Hours)	-	-	-	N/A	-
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	2.23	1.73	1.88	N/A	1.95
		SAIDI (Hours)	4.30	3.38	3.38	N/A	3.69
		CAIDI (Hours)	1.93	1.95	1.81	N/A	1.90
Excluding Planned Outages	All Interruption Data	SAIFI (Events)	3.17	2.37	1.92	N/A	2.49
		SAIDI (Hours)	16.15	9.72	3.50	N/A	9.79
		CAIDI (Hours)	5.10	4.10	1.82	N/A	3.67
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	2.42	1.69	1.92	N/A	2.01
		SAIDI (Hours)	5.93	3.17	3.50	N/A	4.20
		CAIDI (Hours)	2.45	1.87	1.82	N/A	2.05
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Ocurring on Another Utility's Electric System	SAIFI (Events)	-	-	-	N/A	-
		SAIDI (Hours)	-	-	-	N/A	-
		CAIDI (Hours)	-	-	-	N/A	-
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	2.20	1.73	1.85	N/A	1.93
		SAIDI (Hours)	4.25	3.38	3.35	N/A	3.66
		CAIDI (Hours)	1.93	1.95	1.81	N/A	1.90

Figure 2: Delmarva System-Wide Reliability Table 2011-2013

The Delmarva performance for SAIFI, SAIDI, and CAIDI were all better than the three year average from 2011-2013.

2. 20.50.12.03 Poorest Performing Feeder Standard

COMAR 20.50.12.03 requires that electric companies report SAIDI, SAIFI, and CAIDI indices for the 3% of feeders identified as having the poorest reliability. Delmarva identified a total of 10 feeders as having the poorest reliability. Delmarva identified its poorest performing feeders by the following method:

Delmarva[49] uses a feeder composite index, which is 75% of the feeder contribution to SAIFI plus 25% of feeder contribution to SAIDI to determine the PPF list.

Utility	# of PPF	Total # of Feeders in Maryland	Average # of Customers per PPF	2013 Interruption Data (Minus MOE)			2013 Interruption Data (Minus MOE)		
				Average SAIFI (Interruptions)	Average SAIDI (Hours)	Average CAIDI (Hours)	Average SAIFI (Interruptions)	Average SAIDI (Hours)	Average CAIDI (Hours)
DELMARVA	10	184	2937	2.56	3.98	1.50	2.56	3.98	1.50

Figure 3: Delmarva 2013 Poorest Performing Feeder Summary

The 10 selected PPF accounted for 24% of total Delmarva system SAIFI and 19% of system SAIDI. Delmarva had one feeder that was a repeat feeder from 2012, Feeder MD2245. No other feeder from 2012 fell into the bottom 3% for 2013.

[49] Delmarva Annual Performance Report, pg. 11, Mail Log No: 153728

Feeder MD245 is a long radial feeder in Delmarva Power, extending 164.38 miles. The backbone of this feeder, approximately 20 miles, is adjacent to the two-lane heavily travelled Chestertown - Rock Hall Road (MD Rte. 20). The information for Feeder MD2245 is listed in Figure 4.

					Reliability Indices			Feeder Miles			
District	Substation	Circuit	Customers Served	Number of Outages	SAIFI	SAIDI	CAIDI	OH	UG	TOTAL	REPEATED LAST 2 YEARS
Centreville	Chestertown	MD2245	3106	83	3.31	8.83	2.67	53%	47%	164.38	Yes

Figure 4: Feeder MD2245 Data

During the 2013 performance year (October 2012 to September 2013), this feeder experienced multiple outages due to poles hit from motor vehicle accidents (poles along Rte. 20) and lightning that caused a pole fire. Those outage causes (equipment hit, weather and the pole fire included in other) contributed to 91.7% of the 3.31 SAIFI. Vegetation only caused 6.2% of the outages associated with this feeder.

Outage cause by SAIFI	SAIFI	% of Feeder SAIFI
Equipment Hit	1.35	40.7%
Weather	1.10	33.1%
Other*	0.59	17.9%
Tree	0.21	6.2%
Equipment Failure	0.04	1.3%
Unknown	0.02	0.7%
Animal	0.00	0.1%

* Other includes employee, fire, source lost, vandalism, load shed

Figure 5: Feeder MD2245 Outage Causes

The remediation planned for Feeder MD2245 is as follows:

- Replace 41 poles at various vulnerable locations throughout the feeder.
- Install fused cutouts for coordination and sectionalization.
- Install reclosers for sectionalization.

3. 20.50.12.04 Multiple Device Activation Standard

COMAR 20.50.12.04 requires that each electric company report all protective devices that activated five or more times causing sustained interruptions to at least ten customers during the reporting period. Delmarva had a total of 7 protective devices that were activated five or more times during the prior 12-month reporting period. Four of the protective devices were line or tap fuses, two devices were circuit breakers, and one recloser.

Utility	Sum of Device (activated 5 or more times)	Protective Device Type				
		Line or Tap Fuse	Recloser	Circuit Breaker	Transformer	Substation
Delmarva	7	4	1	2	0	0

Figure 6: Multiple Device Activations

The number of devices was down 7 from 12 in 2012, a 42% reduction. The primary remediation actions for the devices are vegetation management, pole, cross arm, and cable replacement, animal guards, and conversion of overhead to underground lines to reduce vegetation-related outages.

4. 20.50.12.05 Additional Reliability Indices Reporting Standard

COMAR 20.20.12.05 requires that each electric company use additional indices for reliability in its annual performance report for its Maryland service territory, in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages. Each electric company is also required to calculate and report Customers Experiencing Multiple Interruptions ("$CEMI_n$") and Momentary Average Interruption Frequency Index ("$MAIFI_E$") information which also give a measure of electric service reliability from the customer's perspective.

	$CEMI_2$	$CEMI_4$	$CEMI_6$	$CEMI_8$
All Interruption Data	0.473	0.165	0.071	0.025
All Interruption Data Minus Major Outage Event Data	0.473	0.165	0.071	0.025

Figure 7: 2013 Delmarva CEMI Data

Delmarva showed a decrease in performance all CEMI categories compared to 2012. The number of customers experiencing multiple outages is up from 39% in 2012 to 47% in 2013. Delmarva has developed a negative trend that needs to be corrected to prevent customers from experiencing multiple outages in the future. The Delmarva CAP addresses programs and action to improve overall system reliability, therefore reducing the amount of multiple outages.

Delmarva also calculated an annual $MAIFI_E$ index for its Maryland service territory of 0.75, up slightly from 0.68 in 2012. Delmarva has remained steady in the amount of momentary outages for customers in their service territory.

	$MAIFI_E$
All Interruption Data	0.75
All Interruption Data Minus Major Outage Event Data	0.75

Figure 8: 2013 MAIFI Index

5. 20.50.12.06 Service Interruption Standard

COMAR 20.50.12.06 states that an electric company shall restore service within 8 hours to at least 92 percent of its customers experiencing sustained interruptions during normal conditions and within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events (where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers). The required time duration for restoration is measured from when the utility knew or should have known of an outage. This standard also requires that service is restored quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the electric company's total number of customers, whichever is less.

Normal Conditions		Major Outage Events[2]	
% of Customers Restored Within 8 Hours[1]		% Of Customers Restored Within 50 Hours[1]	
Actual	COMAR Standard	Actual	COMAR Standard
98.92%	≥ 92%	N/A	≥ 95%

Figure 9: 2013 Service Interruption Performance

Delmarva met the COMAR standard for restoration under normal conditions with 98.92%, similar to the 99.28% from 2012. Delmarva has performed well above the COMAR standard for the past two years. There were no MOEs for 2013, therefore no performance data for Delmarva for such events.

6. 20.50.12.07 Downed Wire Response Standard

COMAR 20.50.12.07 states that each electric company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time. Delmarva met the performance standard for guarded downed wires with a 100% response rate within 4 hours.

Government Emergency Responder Guarded Downed Wires	
% Responded to Within 4 Hours After Notification by a Fire Department, Police Department or 911 Emergency Dispatcher	COMAR Standard
100%	≥ 90%

Figure 10: 2013 Guarded Downed Wire Response Performance

There were a total of 809 downed wires reported to Delmarva during the reporting period, of which 393 belonged to the utility (49%). Delmarva responded to 91.1% of these downed wires within 4 hours, 7.4% within 4 to 8 hours, and the remaining 1.5% had a greater than 8 hour response time. Delmarva responded to all downed wire calls in a timely manner.

Utility	Total Reported Downed Wires	Total Utility Responsible Wires	% of Reported Wires Belonging to the Utility	4 Hours or Less	More than 4 Hours but Less than 8 Hours	8 Hours or More	2013 % Responded to in 4 Hours or Less	Met COMAR Standard Guarded Wires 90%
DELMARVA	809	393	49%	358	29	6	91.09%	100.00%

Figure 11: All Downed Wire Response Performance

7. 20.50.12.08 Customer Communications Standard

COMAR 20.50.12.08 states that each electric company shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each electric company shall achieve an annual average abandoned call percentage rate of 5 percent or less.

For calls offered to the utility for customer service or outage reporting purposes, Delmarva met this requirement by answering 83.1% of the calls within 30 seconds with a 0.4% abandoned call rate. This is a decrease in performance in 2012 where Delmarva answered 90.8% of the calls within 30 seconds and had 0.26% of calls abandoned. If Delmarva continues this performance trend, it will be possible for the company not to meet the call response time standard in COMAR for 2014.

Customer Telephone Call Answer Time[1]		Abandoned Call Rate[2]	
% of Calls Answered Within 30 Seconds	COMAR Standard	% Abandoned Calls	COMAR Standard
83.10%	≥ 75%	0.40%	≤ 5%

Figure 12: 2013 Customer Communication Performance

For calls solely offered to its customer service representatives, Delmarva answered 70.4% of calls within 30 seconds with a 0.71% abandoned call rate and an average answer speed of 26 seconds. These are non-outage related calls.

% of Calls Answered Within 30 Seconds[3]	% Abandoned Calls[3]	Average Speed of Answer[4] (Seconds)
70.40%	0.71%	26

Figure 13: 2013

8. 20.50.12.09 Vegetation Management Requirements

COMAR 20.50.12.09 outlines the scope, technical standards, record keeping, and reporting requirements for vegetation management. Delmarva has 3,493 miles of overhead distribution circuit lines for their system. This standard requires that within 12 months of the effective date of this regulation, an electric company on a 4 year trim cycle is required to perform vegetation management on at least 15% of its total distribution miles. Delmarva trimmed 906 miles of their distribution lines in 2013, or 26% of total distribution miles. Delmarva took an aggressive approach to the new COMAR standard and began vegetation management in 2012, trimming 847 distribution miles, or 24% of the service territory. Delmarva is well ahead of the required 15% vegetation management for 2013 by cutting a total of 50% over the past two years.

Utility	Overhead Circuit Miles		# of Miles of Vegetation Management Performed		% of Total System Trimmed to Standard	% of Total System Trimmed to Standard	Trim Cycle and Current Year (X of Y Years)	COMAR Minimum Required Trimming (%)	Vegetation Management Expenditures		Vegetation Management Cost Per Mile	
	2012	2013	2012	2013	2012	2013	2013	2013	2012	2013	2012	2013
DELMARVA	3,493	3,493	847	906	24%	26%	1 of 4	15%	$ 5,161,269	$ 7,077,726	$ 6,094	$ 7,812

Figure 14: 2012-2013 Vegetation Management

The cost per mile for vegetation management for Pepco is $7,812, up from the 2012 cost of $6,094 per mile. The high cost is due to long radial distribution feeders, the type of vegetation along the feeders, and the equipment and personnel required to perform the trimming.

9. Outage Types & Causes

During the reporting period, Delmarva experienced 4,542 outages, with 34 planned outages, 4,508 non-planned outages, and no major outage events. These outages affected 389,960 customers with 42,621,192 customer outage minutes, or 109 outage minutes per customer.

Outage Type	# of Outages	# of Customers Affected	Customer Outage Minutes
Planned	34	4,345	459,323
Non-Planned Minus Major Outage Event	4,508	385,615	42,161,869
Major Outage Event	0	0	0
TOTALS	4,542	389,960	42,621,192

Figure 15: 2013 Outages

Vegetation accounted for approximately 17.3% of the outages, overhead (OH) equipment accounted for 16.5% of the outages, underground (UG) equipment failure accounted for approximately 13.8% of the outages, and animals 12.4% of outages.

Utility	Vegetation	OH Equipment Failure	UG Equipment Failure	Weather (not lightning)	Lightning Strike	Equipment Hit	Animals	Overload	Other*	Unknown
DELMARVA	17.3%	16.5%	13.8%	11.7%	**	4.5%	12.4%	3.3%	7.1%	13.4%
* Includes employees, fire, source lost, loadshed, vandalism, other utility										

Figure 16: Types of Outages

10. Expenditures

COMAR 20.50.12.11.A(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11.B(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

	2011	2012	2013		2013	2014	2015
	Actual	Actual	Budget	Actual	Labor Hours (Utility)	Projected	Projected
Priority Feeder Upgrades	2,991,966	2,588,657	4,043,984	11,144,381	15,339	$7,138,445	$6,151,906
Underground Residential Distribution Cable Upgrades (URD)	7,372,645	9,401,269	5,363,738	6,433,622	7,923	6,235,800	5,527,765
Distribution Automation	214,896	2,632,331	9,088,904	9,788,286	20,854	12,877,536	7,674,018
Feeder Reliability Improvements	3,426,153	8,585,870	11,794,142	12,281,079	27,961	11,967,298	12,024,798
Conversions	-	-	375,921	228,590	595	382,659	387,836
Substation Reliability Improvements	-	1,273,127	3,049,135	3,274,066		4,531,395	2,511,839
Feeder Load Relief	5,027,348	2,672,323	1,545,115	3,494,688	1,413	4,947,696	2,072,112
TOTAL	$19,033,008	$27,153,576	$35,260,939	$46,644,711	74,085	$48,080,829	$36,350,274

Figure 17: 2013 Delmarva Capital Expenditures

The capital expenditure for priority feeder upgrades greatly exceeded the projected budget for 2013.This can be directly related to the new COMAR standard set in 2012 and the long-term objective of improving system reliability. Delmarva has struggled over the past two years meeting COMAR reliability standards, and took an aggressive approach to upgrading feeders in 2013 to improve reliability.

	2011	2012	2013		2013	2014	2015
	Actual	Actual	Budget	Actual	Labor Hours (Utility)	Projected	Projected
Transmission							
Scheduled Maintenance	$5,229,901	$4,213,286	$5,347,304	$3,200,286	15,557	$4,138,505	
Corrective Maintenance	$1,662,661	$1,209,629	$988,350	$1,137,248	7,262	$1,272,097	
Vegetation Management	$616,220	$501,453	$862,160	$630,783	111	$1,938,440	
Sub-total	$7,508,782	$5,924,368	$7,197,814	$4,968,317	22,930	$7,349,042	
Distribution							
Scheduled Maintenance	$6,006,441	$8,582,198	$7,026,851	$5,458,267	33,586	$8,646,345	
Corrective Maintenance	$31,059,323	$29,646,159	$15,634,479	$13,169,421	36,089	$16,841,894	
Vegetation Management	$4,522,062	$5,477,571	$5,995,775	$7,716,647	3,951	$7,572,328	
Sub-total	$41,587,826	$43,705,928	$28,657,105	$26,344,335	73,626	$33,060,567	
Total	$49,096,608	$49,630,296	**$35,854,919**	**$31,312,652**	96,556	**$40,409,609**	

Figure 18: 2013 Operation and Maintenance Expenditures

There are no real changes in the Delmarva operation and maintenance budget projections and execution. There was a slight savings in corrective maintenance, most likely due to no MOEs for 2013, and a slight increase in vegetation management spending which supports the aggressive program and the CAP.

11. 20.50.12.11A(4) Reliability Objectives, Planned Actions, Projects and Programs

COMAR 20.50.12.11(A)(4) states that each Electric Company is required to provide in its annual report a description of the reliability objectives, planned actions and projects, and programs which are designed to improve its electric service and system.

The top three programs for Delmarva are vegetation management, feeder improvements, and distribution automation. The greatest impact projected on SAIFI and SAIDI is vegetation management. Feeder improvements are projected to eliminate faults and reinforce infrastructure with newer materials and standards. Distribution automation is designed to mitigate fault impact to decrease customers affected and durations of outages.

12. 20.50.12.11A(5) Assessment of Results and Effectiveness

Pursuant to COMAR 20.50.12.11A(5), each electric company must provide an assessment of the results and effectiveness of the programs, projects, or planned actions and their impact on the reliability indices, including CAIDI, SAIDI, and SAIFI and any other reliability indices.

The top three challenges for reliability are aging infrastructure, the lack of ties between feeders, and vegetation management. The company has addressed these issues in the CAP as well as in other reliability enhancement programs (Salisbury Plan, North East Plan) as well as economic alternatives in design such as under grounding strategies (extending the life of current underground cables by injecting silicon into the cables), advanced technologies (automated circuit reclosers (ACRs), and sturdier materials (fiberglass cross arms).

Pepco states that improvements in storm response and overall system reliability are the two areas to show improvement. Process changes in the area of storm response have improved customer communications, and system upgrades have reduced the number and duration of outages. The Pepco webpage now keeps customers informed of outages and projected restoration times. Technicians and first responders are doing a better job of identifying the causes of the outages and reducing the amount of "unknown causes".

The top three best business practices for Delmarva are vegetation management, an automated provision of the estimated time of restoration to customers during outages, and a comprehensive safety program.

13. Conclusions

Delmarva did not meet all COMAR standards for 2013. Delmarva fell short of the SAIFI and SAIDI requirements set forth by COMAR, but was able to meet all other required COMAR standards for 2013. Delmarva filed a corrective action plan (CAP) as required by COMAR on April 1, 2014.Delmarva had one repeat feeder for 2013, and has a corrective action plan for the feeder to improve overall reliability and keep the feeder out of the bottom 3% in the future.

Delmarva has two major areas to focus on in the near future. The SAIFI and SAIDI performance indices were 18% above the COMAR standards. The CAP and the ongoing reliability enhancement programs that Delmarva is conducting need to be aggressive and provide immediate improvements to overall system reliability. Delmarva also needs to work on the customer communication performance, which dropped from 90% to 83% for customer outage calls answered within 30 seconds.

Delmarva has exceeded the requirements for vegetation management beginning in 2012 by cutting 24% of the required service territory. With the additional 26% cut in 2013, Delmarva is currently at 50% of the service territory cut to COMAR standards, will ahead of the required 15% by the end of 2013.

Delmarva is focused on vegetation management and distribution automation as the two programs that will have the greatest impact on long-term system-wide reliability. These programs along with replacing and upgrading aging infrastructure and undergrounding key vulnerable areas will improve system reliability.

D. **Appendix 4: P.E.**

1. System-Wide Reliability Standards (20.50.12.02)

PE's system-wide SAIFI, SAIDI, and CAIDI indices for all interruption data minus major outage events, showed a downward trend over the last three years. Since 2011, prior to RM43, PE's SAIFI index decreased by 0.26, and SAIDI by .96. PE experienced a spike in these indices in 2012 due to the major events which occurred during that time period. Both PE's SAIDI and SAIFI index met the system-wide reliability standards set forth in COMAR and are not required to provide a corrective action plan.

The following table provides the required reliability index results (SAIFI, SAIDI, and CAIDI) for PE's system.

		Reliability Index	2011	2012	2013	2013 COMAR Standard[4, 5]	3 Year Average
Including Planned Outages	All Interruption Data	SAIFI[1] (Events)	1.50	1.55	1.01	N/A	1.35
		SAIDI[2] (Hours)	5.89	23.71	2.38	N/A	10.64
		CAIDI[3] (Hours)	3.94	15.34	2.36	N/A	7.87
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.27	0.85	1.01	1.10	1.05
		SAIDI (Hours)	3.34	2.43	2.38	3.05	2.72
		CAIDI (Hours)	2.62	2.86	2.36	N/A	2.60
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occurring on Another Utility's Electric System	SAIFI (Events)	N/A	N/A	N/A	N/A	N/A
		SAIDI (Hours)	N/A	N/A	N/A	N/A	N/A
		CAIDI (Hours)	N/A	N/A	N/A	N/A	N/A
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	1.11	0.86	1.01	N/A	0.99
		SAIDI (Hours)	2.44	2.80	2.38	N/A	2.54
		CAIDI (Hours)	2.20	3.26	2.36	N/A	2.56
Excluding Planned Outages	All Interruption Data	SAIFI (Events)	1.50	1.51	0.95	N/A	1.32
		SAIDI (Hours)	5.89	23.66	2.17	N/A	10.55
		CAIDI (Hours)	3.94	15.66	2.30	N/A	8.02
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.27	0.81	0.95	N/A	1.01
		SAIDI (Hours)	3.34	2.38	2.17	N/A	2.63
		CAIDI (Hours)	2.62	2.92	2.30	N/A	2.60
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occurring on Another Utility's Electric System	SAIFI (Events)	N/A	N/A	N/A	N/A	N/A
		SAIDI (Hours)	N/A	N/A	N/A	N/A	N/A
		CAIDI (Hours)	N/A	N/A	N/A	N/A	N/A

	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	N/A	N/A	N/A	N/A	N/A
		SAIDI (Hours)	N/A	N/A	N/A	N/A	N/A
		CAIDI (Hours)	N/A	N/A	N/A	N/A	N/A

Figure 1: System Wide Reliability Indices

2. Poorest Performing Feeder Standards (20.50.12.03)

PE has a total of 344 distribution feeders serving at least one customer in Maryland and has identified 10 distribution feeders that have the poorest reliability based on their ranking method. An additional circuit (#11) was added to PE's lists for informational purposes. It was ranked in the poorest performing 3 percent of feeders during the prior 12-month period. Although it has been identified as a "repeater", PE states that it is not a true repeater. In accordance with 20.50.12.03 (B), PE did not have any poorest performing feeders not assigned to Maryland.

The methodology used by PE to identify its poorest performing feeders is based on both SAIFI and SAIDI indices and consists of the following steps:

1) For each feeder calculate a circuit SAIFI using only distribution-caused outages;

2) Select the worst 20% of feeders based on the highest circuit SAIFI;

3) Rank the selected feeders based on SAIDI using only distribution-caused customer minutes; and

4) Select the required number of feeders based on the highest customer minutes. These feeders are then identified as the poorest performing.

All remedial work planned for feeders identified as poorest performing are scheduled to be completed no later than September 30, 2014. The following table is a list of the Poorest Performing Feeders PE has listed by rank for 2013.

Rank	Feeder	Substation	# of Customers
1	Waverly	McCain	1,078
2	Turkey Neck	Thayerville	2,127
3	Hoyes Run Road	Garrett	820
4	Sugarloaf Center	Fairhill	924
5	Centertown	Frostburg #1	1,737
6	Poolesville	Beallsville	1,180
7	Zittlestown	Boonsboro	660
8	New Midway	Legore	967
9	Barkhill Road	Carroll	1,103
10	Howard Chapel	Damascus	1,119
11	CW-12	Carroll	1,439

Figure 2: 2013 Poorest Performing Feeders

The following table is a lists of PE's Poorest Performing Feeders and there reliability indices for 2013.

Feeder	All Interruption Data			All Interruption Data Minus Major Outage Events		
	SAIFI	SAIDI	CAIDI	SAIFI	SAIDI	CAIDI
Waverly	2.92	13.42	4.60	2.92	13.42	4.60
Turkey Neck	5.18	135.49	26.14	4.09	12.58	3.08
Hoyes Run Road	3.6	181.34	50.32	2.58	14.51	5.61
Sugarloaf Center	3.36	12.74	3.79	3.36	12.74	3.79
Centertown	4.53	63.24	13.97	1.81	4.51	2.49
Poolesville	4.53	9.30	2.05	4.48	7.41	1.66
Zittlestown	2.24	9.91	4.42	2.24	9.79	4.37
New Midway	1.67	31.36	18.79	1.26	6.62	5.27
Barkhill Road	1.73	5.78	3.33	1.73	5.78	3.33
Howard Chapel	2.29	6.33	2.77	2.27	5.22	2.30
CW-12	4.13	12.98	3.15	4.11	11.38	2.90

Figure 3: 2013 Poorest Performing Feeder Reliability Indices

3. Multiple Device Activation Standards (20.50.12.04)

Figure 4 provides a list of PE protective devices that activated five or more times resulting in sustained interruptions in electric service to more than 10 Maryland customers.

COMPANY	Protective Device Type				Total # of Devices that Activated Five or More Times	Total # of Activation Events
	Recloser	Circuit Breaker	Line Or Tap Fuse	Transformer		
PE	3	0	16	2	21	N/A

Figure 4: 2013 Multiple Device Activations

4. Additional Reliability Indices (20.50.12.05)

COMAR 20.50.12.05 states that in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages for their entire system throughout Maryland from the previous calendar year (2012) and from the 3 previous calendar years, utilities are also required to calculate and report Customers Experiencing Multiple Interruptions[50] ("$CEMI_n$") and Momentary Average Interruption Frequency Index[51] ("$MAIFI_E$") information which also give a measure of electric service reliability from the customer's perspective, unless it does not have the means to make the calculations, in which case the utility must provide an explanation of the reason why it cannot, and an estimate of the cost to provide this information in the future.

COMPANY	All Interruption Data				All Interruption Data Minus Major Outage Event Data			
	$CEMI_3$	$CEMI_5$	$CEMI_7$	$CEMI_9$	$CEMI_3$	$CEMI_5$	$CEMI_7$	$CEMI_9$
PE	12.1%	1.8%	0.3%	0.03%	12.1%	1.8%	0.3%	0.03%

Figure 5: 2013 CEMI Performance Data

PE reports that it does not have the ability to provide MAIFI results for its Maryland service territory, because the data required is not currently collected for other purposes, and collecting it in order to calculate MAIFI would be a new, entirely manual field process. The cost of providing this annually in the future would be approximately $32,000 and 400 man hours which includes time to obtain recloser readings, data entry and engineer review.

5. Service Interruption Standards (20.50.12.06)

COMAR 20.50.12.06 states that an Electric Company shall restore service within 8 hours, measured from when the utility knew or should have known of the outage, to at least 92 percent of its customers experiencing sustained interruptions during normal conditions; within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers, and as quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the Electric Companies' total number of customers, whichever is less.

[50] $CEMI_n$ is the ratio of the total number of customers experiencing sustained interruptions equal to or greater than "n" ", where **n** is equal to the number of interruptions, divided by the total number of customers served.
[51] $MAIFI_E$ is the ratio of the total number of customer momentary interruption events divided by the total number of customers served, where **E** is equal to the number of interruption events.

COMPANY	*Normal Conditions*		*Major Outage Events*[52]		*Corrective Action Plan Required?*
	% Of Interruptions Restored w/in 8 Hours	Meets COMAR Interruption Standard (92%)	% Of Interruptions Restored w/in 50 hours	Meets COMAR Interruption Standard (95%)	
PE	96.8%	Yes	N/A	N/A	No

Figure 6: 2013 Service Interruption Performance

During normal conditions, PE restored service to 96.8% of its customers that experienced a sustained outage within 8 hours or less. PE experienced no major outage events in 2013. PE satisfied this standard and does not need to provide a corrective action plan.

6. Downed Wire Response Standards (20.50.12.07)

COMAR 20.50.12.07 states that each Electric Company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.

PE exceeded the 90 percent within 4 hours standard by responding to 99.58 percent of government emergency responder guarded downed electric utility wire within 4 hours after notification.

COMPANY	*4 Hours Or Less*	*More Than 4 Hours But Less Than 8 Hours*	*8 Hours or More*	*Total Found to Be Electric Utility Wires*	*Total # of Downed Wires Reported*
PE	239	1	0	N/A	240

Figure 7: Guarded Downed Wire Response

COMPANY	*% Of Downed Wire Notifications Resulting In Responses w/in 4 Hours*	*Meets COMAR Downed Wire Response Standard (90%)*	*Corrective Action Plan Required?*
PE	99.58%	Yes	No

Figure 8: All Downed Wire Response

7. Customer Communications Standards (20.50.12.08)

COMAR 20.50.12.08 states that each Electric Company shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each Electric Company shall achieve an annual average abandoned call percentage rate of 5 percent or less. Electric Companies are also required to provide:

- The percentage of calls that are answered within 30 seconds;
- The abandoned call percentage rate; and

[52] PE reported no Major Outage Events occurring on its system in 2013.

- The average speed of answer.

PE's customer telephone call answer time and abandoned call rate includes calls offered to a customer service representative, IVR or the overflow system. In 2013, PE answered 80.34% of all calls offered within 30 seconds, with an abandoned call percentage rate of 3.19%.

Based solely upon those calls offered to its customer service representatives, PE answered 61.18% of calls within 30 seconds. PE also reported an abandoned call percentage rate of 6.30% with an average speed of answer of 45.5 seconds.

COMPANY	**% Of Calls Answered w/in 30 seconds**	**Meets COMAR Call Answer Time Standard (75%)**	**Annual Abandoned Call %[53]**	**Meets COMAR Annual Abandoned Call Standard (< 5%)**	**% Of Calls Answered w/in 30 seconds by Rep**	**% of Abandoned Calls Received by Rep**	**Average Speed of Answer (seconds)**
PE	80.34%	Yes	3.19%	Yes	61.18%	6.30%	45.5

Figure 9: Customer Communication Performance

8. Vegetation Management Standards (20.50.12.09)

When performing VM, PE physically performs the following methods: brush removal by cutting or mowing, brush control utilizing hydraulic foliage, low volume basal, and cut surface herbicide applications techniques, off and on corridor tree removal, including off corridor hazard trees, property owner notification, and the pruning of trees which can originate either from off or on the corridor.

Total circuit miles trimmed in 2013 were 1,310 miles with a total cost of approximately \$10,318,072. The average cost per circuit mile trimmed was \$7,876.

Company	Overhead Circuit Miles in MD	Total # of Miles of VM Performed	Trim Cycle (Years)	COMAR[54] Minimum Required Trimming 1^{st}- 12 Months	2013 VM Expenditures[55]	2013 Avg. VM Cost (\$/Mile)
PE	6,059	1,310	5	12%	\$10,318,072	\$7,876

Figure 10: 2013 Vegetation Management Completed

[53] The abandoned call rate is calculated by dividing the total number of abandoned calls by the total number of calls offered to the utility of customer service or outage reporting purposes.

[54] COMAR 20.50.12.09F (1) states that this regulation initially begins on January 1 of the year immediately following the effective date of the regulation (i.e. January 1, 2013).

[55] VM cost includes both Capital and O&M Expenditures for "Vegetation Management" work.

Company	# of Miles of Veg. Management Planned to be Trimmed	# of Substations Affected	# of Feeders/Circuits Affected	% of System	2014 Projected Vegetation Management Expenditures	2014 Planned Avg. VM Cost ($/Mile)
PE	1,305	30	98	22%	$10,024,196	$7,681

Figure 11: 2014 Projected Vegetation Management

PE uses a 5-year trim cycle when performing VM and has approximately 6,059 total OH circuit miles throughout Maryland on its system.

In 2013, PE trimmed a total of 1,310 OH circuit miles on feeders at 93 substations. 31 34.5kV Sub-Transmission Substations were also trimmed in 2013. Approximately 22% of its OH circuit miles were trimmed in 2013. PE's expenditures for VM in 2013 totaled $10,318,072.

For 2014, PE plans to trim 1,305 OH circuit miles at 97 substations, 21-34.5kV Sub-Transmission Substations are included. If completed, PE will have trimmed approximately 22% of its total system in 2014. PE proposes a budget of $10,024,196 to complete all planned VM for 2014.

9. Reliability Objectives & Planned Actions

Over the past two years, in order to improve system reliability, PE invested into all facets of its system such as new technologies, refurbishment or replacement of equipment, and rigorous inspection and maintenance activities such as: circuit and pole inspections, underground equipment inspections and vegetation management. As a result, the Company has improved its service reliability performance by 25% since 2011. In addition to those activities listed above, PE plans to pursue its overall reliability goals by placing focus on four specific COMAR requirements.

The first COMAR reliability requirement that PE is placing additional emphasis on in order to achieve its reliability goals is 20.50.12.09 (Vegetation Management Requirements). PE states that continuing to emphasis its rigorous vegetation management program will ensure continued and safe operation of the subtransmission and distribution systems. PE estimates a 8.5 minute reduction in SAIDI as a result of this work.

The second COMAR reliability requirement that PE is placing additional focus on in order to achieve its reliability goals is 20.50.12.03 (Poorest Performing Feeder Standard). PE is emphasizing this program because it estimates a 4.2 minute overall reduction in SAIDI as a result.

The third and fourth COMAR reliability requirement that PE is placing additional focus on in order to achieve its reliability goals are 20.50.12.10.D(2) & H(2) (Periodic Equipment Inspections). As required, PE conducts visual inspections of distribution circuits and equipment from the substation to the first protective device every two years, as well as a total circuit line and equipment inspection every six years. This program identifies, uncovers and addresses through appropriate preventative or corrective maintenance, problems that could impact service reliability and problems with equipment such as deterioration. PE is emphasizing these equipment inspections because it is estimated to produce a 4.3 minute overall reduction in SAIDI as a result.

In addition, PE also has plans to place additional emphasis on three reliability improvement programs in order to achieve its reliability goals moving forward:

Wood pole inspection: PE has a 10-year inspection program which identifies poles in need of repair or replacement prior to failure. Special emphasis is being placed on this program because PE estimates a 0.6 minute overall improvement in SAIDI;

CEMI: PE has a program that examines customers experiencing multiple interruptions ("CEMI"). In this program, reliability improvement teams, led by reliability engineers, meet to review poor performing circuits and devices, any device that has operated three or more times in the past twelve months and any circuit that has locked out two or more times in the past twelve months. PE estimates a 0.7 minute overall improvement in SAIDI;

Underground cable replacement: PE has a reactive program that replaces underground cable that show a history of failures. Projects are identified and ranked based on the number of customers affected, the number of failures and the impact on customer satisfaction. PE estimates a 5.8 minute overall improvement in SAIDI.

PE has also made significant improvements to the downed wire response process by installing supplementary monitors in its hazard dispatch room where an individual to monitor these calls.

When inquired by Staff, PE stated that the top three programs that will have the greatest impact on long-term reliability were:

- Vegetation Management
    - 8.5 minutes projected SAIDI impact
    - 0.06 projected SAIFI impact
    - $10,318,072 in 2013

- Underground Cable Replacement
    - 5.8 minutes projected SAIDI impact
    - 0.04 projected SAIFI impact
    - $348,005 in 2013

- Overhead Circuit Inspections
    - 3 minutes projected SAIDI impact
    - 0.03 projected SAIFI impact
    - $2,044,973 in 2013

10. Expenditures and Projects

COMAR 20.50.12.11.A.(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11B(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

The following are the actual capital and operation and maintenance expenditures for PE for 2013, including a historical overview of the money spent the previous 2 calendar years.

Investment Reason	2011[56]	2012	2013		2013	2014	2015
	Actual	Actual	Budget	Actual	Labor Hours[57] (Utility)	Projected	Projected
Condition		8,733,658	8,758,813	3,761,598	20,078	5,604,173	7,180,588
Forced		37,063,077	13,014,304	6,408,486	87,198	10,703,518	10,826,352
Miscellaneous		1,862,452	1,502,954	1,718,713	14,015	2,085,061	2,482,220
System Reinforcement		706,747	1,959,137	1,090,930	8,608	1,133,013	784,795
Vegetation Management		8,511,360	8,957,030	8,814,724	5,819	8,244,742	8,125,712
Total	29,747,118	56,877,294	34,192,238	21,794,451	135,718	27,770,507	29,399,667

Figure 12: Maintenance of Reliable Electric Service Capital Expenditures

PE defines each of its Capital expenditures investment reasons as such:

- Condition – Costs associated with the replacement of outdated and/or poor performing equipment and reliability related costs.
- Forced – Costs associated with storm outage restoration, failed substation or line equipment and devices, regulatory required and relocations of facilities associated with roadways and bridge projects.
- Miscellaneous – Costs associated with corrective maintenance, operations, lighting and meter.
- System Reinforcement – Costs associated with system reinforcement.
- Vegetation Management – Costs associated with planned and unplanned tree trimming and vegetation management programs.

[56] PE states that due to system conversion that took place as a result of the merger between Allegheny Energy and FirstEnergy in 2011, the 2011 actual capital and operations expenditures are only available as a total amount.
[57] Note that the hours worked in 2013 do not include contractor hours.

	2011	2012	2013		2013	2014	2015
	Actual	Actual	Budget	Actual	Labor Hours[58] (Utility)	Projected	Projected
Condition		2,053,444	952,014	1,739,376	18,549	2,306,982	1,847,219
Corrective Maintenance		1,599,895	414,720	2,069,178	19,002	447,360	447,360
Forced		11,601,584	3,306,974	3,620,298	22,166	2,935,321	2,712,420
Miscellaneous		1,241,577	536,488	1,457,598	17,648	1,045,188	1,006,072
Vegetation Management		2,345,231	2,704,934	1,503,348	1,845	1,779,454	1,782,636
Total	7,363,913	18,841,731	7,915,130	10,389,798	79,210	8,514,305	7,795,707

Figure 13: Reliable Electric Service Operating & Maintenance Expenditures

PE defines each of its Operation & Maintenance expenditures investment reasons as such:

- Condition – Costs associated with obsolete equipment, fix-it-now, and reliability
- Corrective Maintenance – Costs associated with corrective maintenance, operations and preventative maintenance
- Forced – Costs associated with failures, IPP/Municipal connect, relocations, storms and substation failures
- Miscellaneous – Costs associated with system reinforcement, lighting and meter.
- Operations – Costs associated with operations
- Preventative Maintenance – Costs associated with preventative maintenance
- Vegetation Management – Costs associated with planned and unplanned vegetation management activities.

[58] Note that the hours worked in 2013 do not include contractor hours.

E. Appendix 5: Pepco

Pursuant to COMAR 20.50.12.11, on or before April 1st of each year, Pepco is required to file with the Commission their annual reliability performance report which reflects the company's reliability performance. This report marks the second annual report since the adoption of COMAR 20.50.12.

Pepco has met all COMAR required standards for 2013, as it did in 2012. In comparison to 2012, Pepco experienced improvements in their SAIDI, and CAIDI indexes for all interruption data minus major outage event data, but had an increase in SAIFI.

Pepco has used the company's top three best business practices: vegetation management, an automated provision of the estimated time of restoration to customers during outages, and a comprehensive safety program, to improve overall system reliability. These practices along with system upgrades and distribution automation will improve Pepco system reliability.

1. 20.50.12.02 System-Wide Reliability Standards

COMAR 20.50.12.02 requires that each electric company shall collect and maintain reliability data and use system-wide indices SAIDI and SAIFI as performance measurements of system reliability. The SAIFI and SAIDI reliability standards set forth for Pepco for the 2013 calendar year is 1.81 for SAIFI and 2.82 for SAIDI. Pepco's annual SAIFI and SAIDI results are required to be equal to or less than these established numbers, and the indices are measured on all interruption data minus major outage event interruption data and minus outage data resulting from an outage event occurring on another utility's electric system.

The system-wide performance data for Pepco is listed below in Figure 1. The report for 2013 is unique in that it does not include any major outage events (MOEs). Pepco met the COMAR standard for 2013 for SAIFI (performing 17.7% better than the standard), and SAIDI (performing 12.8% better than the standard).

		Reliability Index	2011	2012	2013	2013 COMAR Standard[4,5]	3 Year Average
Including Planned Outages	All Interruption Data	SAIFI[1] (Events)	3.43	3.16	1.49	N/A	2.69
		SAIDI[2] (Hours)	23.95	43.07	2.46	N/A	23.16
		CAIDI[3] (Hours)	6.98	13.63	1.65	N/A	7.42
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	2.00	1.39	1.49	1.81	1.63
		SAIDI (Hours)	3.60	2.77	2.46	2.82	2.94
		CAIDI (Hours)	1.80	2.00	1.65	N/A	1.82
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Ocurring on Another Utility's Electric System	SAIFI (Events)	-	-	-	-	-
		SAIDI (Hours)	-	-	-	-	-
		CAIDI (Hours)	-	-	-	N/A	-
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	1.91	1.41	1.49	N/A	1.60
		SAIDI (Hours)	3.40	2.55	2.46	N/A	2.80
		CAIDI (Hours)	1.78	1.80	1.65	N/A	1.74
Excluding Planned Outages	All Interruption Data	SAIFI (Events)	3.43	3.12	1.43	N/A	2.66
		SAIDI (Hours)	23.93	42.95	2.26	N/A	23.05
		CAIDI (Hours)	6.98	13.75	1.59	N/A	7.44
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.99	1.36	1.43	N/A	1.59
		SAIDI (Hours)	3.58	2.65	2.26	N/A	2.83
		CAIDI (Hours)	1.80	1.95	1.59	N/A	1.78
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Ocurring on Another Utility's Electric System	SAIFI (Events)	-	-	-	-	-
		SAIDI (Hours)	-	-	-	-	-
		CAIDI (Hours)	-	-	-	N/A	-
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	1.91	1.38	1.43	N/A	1.57
		SAIDI (Hours)	3.38	2.42	2.26	N/A	2.69
		CAIDI (Hours)	1.78	1.75	1.59	N/A	1.71

Figure 1: Pepco System-Wide Reliability Table 2011-2013

The Pepco performance for SAIFI, SAIDI, and CAIDI were all better than the three year average from 2011-2013.

2. 20.50.12.03 Poorest Performing Feeder Standard

COMAR 20.50.12.03 requires that electric companies report SAIDI, SAIFI, and CAIDI indices for the 3% of feeders identified as having the poorest reliability. Pepco identified a total of 21 feeders as having the poorest reliability. Pepco identified its poorest performing feeders by the following method:

- Pepco[59] uses a feeder composite index, which is 75% of the feeder contribution to SAIFI plus 25% of feeder contribution to SAIDI to determine the PPF list.

Utility	# of PPF	Total # of Feeders in Maryland	Average # of Customers per PPF	2013 Interruption Data (Minus MOE)			2013 Interruption Data (Minus MOE)		
				Average SAIFI (Interruptions)	Average SAIDI (Hours)	Average CAIDI (Hours)	Average SAIFI (Interruptions)	Average SAIDI (Hours)	Average CAIDI (Hours)
PEPCO	21	697	1380	51.81	7.07	1.46	51.81	7.07	1.46

Figure 2: Pepco 2013 Poorest Performing Feeder Summary

The 21 selected PPF for Pepco accounted for 18% of total Pepco system SAIFI and 16% of system SAIDI. Pepco had one feeder that was a repeat feeder from 2012, Feeder No: 15238, but does not count as a repeat feeder due to the 12 month remediation period allowed the

[59] Pepco Annual Performance Report, pg. 13, Mail Log No: 153734

following reporting period after the feeder was identified. No other feeder from 2012 fell into the bottom 3% for 2013.

The information for Feeder No. 15238 is listed in Figure 3 below.

Feeder 15238

District	Substation	Circuit	Customers Served	Number of Outages	Reliability Indices (In Hours)			Feeder Miles			Repeated Last 2 Years?
					SAIFI	SAIDI	CAIDI	OH	UG	Total	
MC	Quince Orchard 118	15238	1,147	27	7.24	11.92	1.65	21%	79%	33.13	Yes

Figure 3: Feeder 15238 Data

The majority of the outages for Feeder 15238 were caused by vegetation (54%), 17% unknown, and 14% each for both equipment failure and weather.

Outage Cause by SAIFI	SAIFI	% of Feeder SAIFI
Tree	3.932	54.3%
Unknown	1.209	16.7%
Equipment Failure	1.017	14.1%
Weather	0.999	13.8%
Animal	0.072	1.0%
Equipment Hit	0.006	0.1%

Figure 4: Feeder 15238 Outage Causes

The remediation planned for Feeder 15238 is as follows:

- Perform vegetation management on the transmission right of way (ROW) for the feeder, which has been assessed as the most vulnerable part of the feeder.
- Replace the feeder wire with larger and stronger cables.

3. 20.50.12.04 Multiple Device Activation Standard

COMAR 20.50.12.04 requires that each electric company report all protective devices that activated five or more times causing sustained interruptions to at least ten customers during the reporting period. Pepco had a total of 26 protective devices that were activated five or more times during the prior 12-month reporting period. 14 of the protective devices were line or tap fuses, 11 devices were circuit breakers, and one transformer.

Utility	Sum of Device (activated 5 or more times)	Protective Device Type				
		Line or Tap Fuse	Recloser	Circuit Breaker	Transformer	Substation
Pepco	26	14	0	11	1	0

Figure 5: Multiple Device Activations

The number of devices was down 39 from 65 in 2012, a 40% reduction. The primary remediation actions for the devices are vegetation management, overhead and underground cable replacement, animal guards, lightning arrestors, and automatic closer reclosers (ACRs).

4. 20.50.12.05 Additional Reliability Indices Reporting Standard

COMAR 20.20.12.05 requires that each electric company use additional indices for reliability in its annual performance report for its Maryland service territory, in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages. Each electric company is also required to calculate and report Customers Experiencing Multiple Interruptions ("$CEMI_n$") and Momentary Average Interruption Frequency Index ("$MAIFI_E$") information which also give a measure of electric service reliability from the customer's perspective.

	$CEMI_2$	$CEMI_4$	$CEMI_6$	$CEMI_8$
All Interruption Data	0.387	0.101	0.022	0.010
All Interruption Data Minus Major Outage Event Data	0.387	0.101	0.022	0.010

Figure 6: 2013 Pepco CEMI Data

Pepco has shown improvement in all CEMI categories. The number of customers experiencing multiple outages is down from 54% in 2012 to 39% in 2013. Although the number is high, Pepco is moving in the right direction to correct the problem.

Pepco also calculated an annual $MAIFI_E$ index for its Maryland service territory of 0.23, down from 3.45 in 2012. Pepco has greatly reduced the momentary outages for customers in their service territory.

	$MAIFI_E$
All Interruption Data	0.23
All Interruption Data Minus Major Outage Event Data	0.23

Figure 7: 2013 MAIFI Index

5. 20.50.12.06 Service Interruption Standard

COMAR 20.50.12.06 states that an electric company shall restore service within 8 hours to at least 92 percent of its customers experiencing sustained interruptions during normal conditions and within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events (where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers). The required time duration for restoration is measured from when the utility knew or should have known of an outage. This standard also requires that service is restored quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the electric company's total number of customers, whichever is less.

Normal Conditions		Major Outage Events[2]	
% of Customers Restored Within 8 Hours[1]		% Of Customers Restored Within 50 Hours[1]	
Actual	COMAR Standard	Actual	COMAR Standard
98.36%	≥ 92%	N/A	≥ 95%

Figure 8: 2013 Service Interruption Performance

Pepco met the COMAR standard for restoration under normal conditions with 98.36%, similar to the 98.21% from 2012. Pepco has performed well above the COMAR standard for the past two years. There were no MOEs for 2013, therefore no performance data for Pepco for such events.

6. 20.50.12.07 Downed Wire Response Standard

COMAR 20.50.12.07 states that each electric company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time. Pepco met the performance standard for guarded downed wires with a 97% response rate within 4 hours.

Government Emergency Responder Guarded Downed Wires	
% Responded to Within 4 Hours After Notification by a Fire Department, Police Department or 911 Emergency Dispatcher	COMAR Standard
97%	≥ 90%

Figure 9: 2013 Guarded Downed Wire Response Performance

There were a total of 3401 downed wires reported to Pepco during the reporting period, of which 1,168 belonged to the utility (34%). Pepco responded to 68.5% of these downed wires within 4 hours, 18.4% within 4 to 8 hours, and the remaining 13.1% had a greater than 8 hour response time. Two-thirds of the Pepco extended response times for downed wires occurred during low level storms: a small tornado that touched down in Rockville on June 13, 2013 and ice storm that occurred in December.

	Total	Number Responded to in:		
		≤ 4 Hours	> 4 but < 8 Hours	≥ 8 Hours
Downed Wires Reported to the Utility	3401	N/A	N/A	N/A
Downed Wires Reported and Found to belong to the Utility	1168	801	215	152

Figure 10: All Downed Wire Response Performance

7. 20.50.12.08 Customer Communications Standard

COMAR 20.50.12.08 states that each electric company shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each electric company shall achieve an annual average abandoned call percentage rate of 5 percent or less. For calls offered to the utility for customer service or outage reporting purposes, Pepco met this requirement by answering 78.6% of the calls within 30 seconds with a 4.31% abandoned call rate. This is a decrease in performance in 2012 where Pepco answered 89.7% of the calls within 30 seconds and had 1.93% of calls abandoned. If Pepco continues this performance trend it will not meet the COMAR standards for 2014.

Customer Telephone Call Answer Time[1]		Abandoned Call Rate[2]	
% of Calls Answered Within 30 Seconds	COMAR Standard	% Abandoned Calls	COMAR Standard
78.55%	≥ 75%	4.31%	≤ 5%

Figure 11: 2013 Customer Communication Performance

For calls solely offered to its customer service representatives, Pepco answered 58% of calls within 30 seconds with a 8.4% abandoned call rate and an average answer speed of 74 seconds. These are non-outage related calls.

% of Calls Answered Within 30 Seconds[3]	% Abandoned Calls[3]	Average Speed of Answer[4] (Seconds)
57.96%	8.44%	74

Figure 12: 2013

8. 20.50.12.09 Vegetation Management Requirements

COMAR 20.50.12.09 outlines the scope, technical standards, record keeping, and reporting requirements for vegetation management. Pepco has 3,966 miles of overhead distribution circuit lines for their system. This standard requires that within 12 months of the effective date of this regulation, an electric company on a 4 year trim cycle is required to perform vegetation management on at least 15% of its total distribution miles. Pepco trimmed 1,011 miles of their distribution lines in 2013, or 25% of total distribution miles. Pepco took an aggressive approach to the new COMAR standard and began vegetation management in 2012, trimming 1,550 distribution miles, or 29% of the service territory. Pepco is well ahead of the required 15% vegetation management for 2013 by cutting a total of 54% over the past two years.

Utility	Overhead Circuit Miles		# of Miles of Vegetation Management Performed		% of Total System Trimmed to Standard	% of Total System Trimmed to Standard	Trim Cycle and Current Year (X of Y Years)	COMAR Minimum Required Trimming (%)	Vegetation Management Expenditures		Vegetation Management Cost Per Mile	
	2012	2013	2012	2013	2012	2013	2013	2013	2012	2013	2012	2013
PEPCO	3,990	3,966	1550	1011	39%	25%	1 of 4	15%	$24,642,714	$16,790,465	$ 15,899	$ 16,608

Figure 13: 2012-2013 Vegetation Management

The cost per mile for vegetation management for Pepco is $16,608, up slightly from the 2012 cost of $15,899 per mile. The high cost is due to thick vegetation, the type of vegetation along the feeders, the urban/suburban service area, and the equipment and personnel required to perform the trimming.

9. Outage Types & Causes

During the reporting period, BGE experienced 11,614 outages, with 3,982 planned outages, 7,632 non-planned outages, and no major outage events. These outages affected 801,925 customers with 79,371,340 customer outage minutes, or 99 outage minutes per customer. Although the number of unplanned outage was only twice as high as planned outages, the customer outage minutes was 12 times as high.

Outage Type	# of Outages	# of Customers Affected	Customer Outage Minutes
Planned	3,982	34,030	6,201,424
Non-Planned Minus Major Outage Event	7,632	767,895	73,169,916
Major Outage Event	0		
TOTALS	11,614	801,925	79,371,340

Figure 14: 2013 Outages

Vegetation accounted for approximately 18% of the outages, underground (UG) equipment accounted for 28.6% of the outages, overhead (OH) equipment failure accounted for approximately 16.8% of the outages, and animals 13.2% of outages.

Utility	Vegetation	OH Equipment	UG Equipment	Weather (not	Lightning Strike	Equipment Hit	Animals	Overload	Other*	Unknown
PEPCO	18.1%	16.8%	28.6%	1.6%	3.4%	5.3%	13.2%	1.5%	5.9%	5.6%
* Includes employees, fire, source lost, loadshed, vandalism, other utility										

Figure 15: Types of Outages

10. Expenditures

COMAR 20.50.12.11.A.(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11B(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

	2011	2012	2013		2013	2014	2015
	Actual	Actual	Budget	Actual	Labor Hours (Utility)	Projected	Projected
Priority Feeder Upgrades	8,830,164	26,898,369	21,455,655	23,958,170	11,736	$ 34,000,508	$ 34,001,981
Underground Residential Distribution Cable Upgrades (URD)	24,915,190	23,747,848	18,575,015	34,448,829	11,816	16,202,611	16,203,699
Distribution Automation	2,100,835	2,642,417	6,369,281	5,036,575	18,140	2	3,807,999
Selective Undergrounding	-	556	4,049,877	2,494,667	11,199	3	2,185,248
69kv and 34kv Feeder Upgrades	2,171,818	4,844,505	5,800,160	882,327	203	6,820,756	6,820,551
Feeder Reliability Improvements	16,581,603	55,563,251	43,077,780	71,350,764			35,000,000
Feeder Load Relief	3,585,022	11,901,083	4,571,957	4,156,065	3,055		16,820,936
	$ 58,184,634	$125,598,029	$ 103,899,725	$ 142,327,396	56,149	$ 131,160,520	$ 113,822,013
Hours (direct charged internal only)	43,687	63,765		56,149			

Figure 16: 2013 Pepco Capital Expenditures

Two capital expenditures greatly exceeded the projected budget for 2013: underground residential distribution cable upgrades and feeder reliability improvements. Both of these can be directly related to the new COMAR standard set in 2012 and the long-term objective of improving system reliability.

	2011	2012	2013		2013	2014	2015
	Actual	Actual	Budget	Actual	Labor Hours (Utility)	Projected	Projected
Transmission							
Scheduled Maintenance	$5,955,148	$4,783,673	$4,827,578	$4,150,443	37,803	37,803	
Corrective Maintenance	$8,844,462	$6,768,302	$5,042,815	$5,050,261	48,639	$5,529,467	
Vegetation Management	$1,373,109	$2,168,334	$2,019,386	$2,318,077	2,054	$2,191,356	
Sub-total	$16,172,719	$13,720,309	$11,889,779	$11,518,781	88,496	$7,758,626	
Distribution							
Scheduled Maintenance	$14,247,079	$14,483,504	$15,960,519	$13,169,277	99,140	$14,862,322	
Corrective Maintenance	$67,747,406	$66,950,506	$31,632,387	$32,302,603	292,562	$29,731,704	
Vegetation Management	$23,601,419	$24,642,714	$23,082,872	$19,148,347	6,729	$22,444,588	
Sub-total	$105,595,904	$106,076,724	$70,675,778	$64,620,227	398,431	$67,038,614	
Total	$121,768,623	$119,797,033	$82,565,557	$76,139,008	$486,927	$74,797,240	

Figure 17: 2013 Operation and Maintenance Expenditures

There are no real changes in the Pepco operation and maintenance budget projections and execution. There was a slight savings in scheduled maintenance and vegetation management, nothing noteworthy.

11. 20.50.12.11A(4) Reliability Objectives, Planned Actions, Projects and Programs

COMAR 20.50.12.11(A)(4) states that each Electric Company is required to provide in its annual report a description of the reliability objectives, planned actions and projects, and programs which are designed to improve its electric service and system.

The top three programs for Pepco are vegetation management, feeder improvements, and distributions automation. Feeder improvements are projected to eliminate faults and reinforce infrastructure with newer materials and standards. Distribution automation is designed to mitigate fault impact to decrease customers affected and durations of outages.

12. 20.50.12.11A(5) Assessment of Results and Effectiveness

Pursuant to COMAR 20.50.12.11A(5), each electric company must provide an assessment of the results and effectiveness of the programs, projects, or planned actions and their impact on the reliability indices, including CAIDI, SAIDI, and SAIFI and any other reliability indices.

The top three challenges for reliability are vegetation management, aging infrastructure, and the design and operational challenges of serving a high density urban/suburban environment. These issues were addressed by Pepco in the Reliability Enhancement Plan (REP). The company routinely evaluates and employs economic alternatives in design such as under grounding strategies (extending the life of current underground cables by injecting silicon into the cables), advanced technologies (automated circuit reclosers (ACRs), and sturdier materials (fiberglass cross arms).

Pepco states that improvements in storm response and overall system reliability are the two areas to show improvement. Process changes in the area of storm response have improved customer communications, and system upgrades have reduced the number and duration of outages. The Pepco webpage now keeps customers informed of outages and projected restoration times. Technicians and first responders are doing a better job of identifying the causes of the outages and reducing the amount of “unknown causes”.

The top three best business practices for Pepco are vegetation management, an automated provision of the estimated time of restoration to customers during outages, and a comprehensive safety program.

13. Conclusion

Pepco met all COMAR standards for 2013. Pepco had a slightly higher SAIFI value for 2013, but remained below the three year average for all three indices: SAIF, SAIDI, and CAIDI. Pepco had one feeder that would have been a repeat feeder if not for the 12 month remediation period. Pepco has a corrective action plan for the feeder to improve overall reliability and keep the feeder out of the bottom 3% in the future.

Pepco has two areas to focus on in the near future. The overall downed wire response time for wires reported by all sources is 68%, 29% lower than the guarded downed wire response time of 97%. Pepco also needs to work on the customer communication performance, which dropped from 89% to 78% for customer outage calls answered within 30 seconds. Pepco also rose to 4.31% for abandoned calls, which is slightly below the COMAR 5% standard.

Pepco has exceeded the requirements for vegetation management beginning in 2012 by cutting 29% of the required service territory. With the additional 25% cut in 2013, Pepco is currently at 54% of the service territory cut to COMAR standards, will ahead of the required 15% by the end of 2013.

Pepco is focused on vegetation management and distribution automation as the two programs that will have the greatest impact on long-term system-wide reliability. These programs along with replacing and upgrading aging infrastructure will improve system reliability.

F. Appendix 6: SMECO

1. System-Wide Reliability Standards (20.50.12.02)

SMECO's system-wide SAIFI, SAIDI, and CAIDI indices for all interruption data minus major outage events, showed a uniform downward trend over the last three years (2011-2013). Since 2011, prior to RM43, SMECO's SAIFI index decreased by 0.62, and SAIDI by .92. SMECO is one of two utilities that have shown an overall uniform improvement in SAIDI, SAIFI, and CAIDI in all three years (2011-2013). SMECO also performed better in SAIFI and SAIDI in 2013 (0.93 & 1.36) than its 3-Year Average (1.26 & 1.90). Both SMECO's SAIDI and SAIFI index met the system-wide reliability standards set forth in COMAR and are not required to provide a corrective action plan.

The following table provides the required reliability index results (SAIFI, SAIDI, and CAIDI) for SMECO's system (2011-2013 and 3-Year Average).

		Reliability Index	2011	2012	2013	2013 COMAR Standard	3 Year Average
Including Planned Outages	All Interruption Data	SAIFI (Events)	2.87	2.10	0.93	N/A	1.97
		SAIDI (Hours)	33.1	11.02	1.36	N/A	15.16
		CAIDI (Hours)	11.7	5.26	1.46	N/A	6.15
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	1.55	1.31	0.93	N/A	1.26
		SAIDI (Hours)	2.28	2.06	1.36	N/A	1.90
		CAIDI (Hours)	1.47	1.57	1.46	N/A	1.50
	All Interruption Data Minus Major Outage Event Interruption Data & Minus Outage Data Resulting from an Outage Event Occurring on Another Utility's Electric System	SAIFI (Events)	1.55	1.31	0.93	1.38	1.26
		SAIDI (Hours)	2.28	2.06	1.36	2.35	1.90
		CAIDI (Hours)	1.47	1.57	1.46	N/A	1.50
	All Interruption Data Minus IEEE Major Event Day Interruption Data	SAIFI (Events)	N/A	1.32	0.90	N/A	1.11
		SAIDI (Hours)	2.26	2.06	1.20	N/A	1.84
		CAIDI (Hours)	N/A	1.57	1.38	N/A	1.48
Excluding Planned Outages	All Interruption Data	SAIFI (Events)	N/A	N/A	0.93	N/A	0.93
		SAIDI (Hours)	33.08	11.00	1.33	N/A	15.14
		CAIDI (Hours)	N/A	N/A	1.43	N/A	1.43
	All Interruption Data Minus Major Outage Event Interruption Data	SAIFI (Events)	N/A	N/A	0.93	N/A	0.93
		SAIDI (Hours)	2.26	2.04	1.33	N/A	1.88
		CAIDI (Hours)	N/A	N/A	1.43	N/A	1.43
	All Interruption Data Minus Major Outage Event Interruption Data &	SAIFI (Events)	N/A	N/A	0.93	N/A	0.93
		SAIDI (Hours)	2.26	2.04	1.33	N/A	1.88

	Minus Outage Data Resulting from an Outage Event Occurring on Another Utility's Electric System	**CAIDI (Hours)**	N/A	N/A	1.43	N/A	1.43
	All Interruption Data Minus IEEE Major Event Day Interruption Data	**SAIFI (Events)**	N/A	1.30	0.88	N/A	1.09
		SAIDI (Hours)	2.26	2.05	1.12	N/A	1.81
		CAIDI (Hours)	N/A	1.57	1.39	N/A	1.48

Figure 1: System Wide Reliability Indices

2. Poorest Performing Feeder Standards (20.50.12.03)

SMECO has 237 distribution feeders serving customers in Maryland and has selected 7 feeders as its poorest performing for 2013. SMECO identifies its poorest performing feeders as those with the highest combined 50% of SAIDI plus 50% of SAIFI reliability index values, as follows:

- **Feeder Index Value = [(0.50 X SAIDI) + (0.50 X SAIFI)]**

The 7 feeders with the highest Index Values are considered SMECO's poorest performing feeders. None of SMECO's previous years' identified worse performing feeders fell within this year's three percent poorest performing feeder list; therefore, no corrective action plan is required to be filed at this time.

Of the 7 feeders identified on SMECO's poorest performing feeders list, 3 feeders had remedial work completed in 2013, 2 feeders were scheduled to be complete during the 2^{nd} Quarter 2014, and the remedial work for the remaining 2 feeders are on schedule to be completed in the 3^{rd} and 4^{th} Quarter 2014.

A complete list of SMECO's poorest performing feeders for 2013 are listed below.

Feeder	**All Interruption Data**			**All Interruption Data Minus Major Outage Events**		
	SAIFI	**SAIDI**	**CAIDI**	**SAIFI**	**SAIDI**	**CAIDI**
Valley Lee 1	3.2185	7.6361	2.6798	3.2155	7.5821	2.6606
Mason Springs 24	6.8642	17.0411	2.4784	4.6145	5.7671	1.2511
PRNAS 3-13	5.2476	5.3117	1.2156	5.0476	5.2077	1.2272
Redgate 12	4.3395	12.4189	2.8593	4.0082	5.7788	1.4418
Redgate 11	4.9440	8.7322	1.7751	4.6350	4.9703	1.0698
Leonardtown 24	4.0956	5.4704	1.3333	4.0941	5.4322	1.3242
Cedarville 1	4.5451	5.0313	1.1067	4.5236	4.9321	1.0901

Figure 2: 2013 Poorest Performing Feeders

3. Multiple Device Activation Standards (20.50.12.04)

SMECO identifies and reports protective devices that serves more than 10 customers and which activated five or more times during the prior 12-month reporting period. Major outage events are included when making this determination. SMECO did not have any devices meeting the multiple device activation criteria within this reporting period.

4. Additional Reliability Indices (20.50.12.05)

COMAR 20.50.12.05 states that in addition to providing SAIFI, SAIDI, and CAIDI system-wide index averages for their entire system throughout Maryland from the previous calendar year and from the 3 previous calendar years, utilities are also required to calculate and report Customers Experiencing Multiple Interruptions[60] ("$CEMI_n$") and Momentary Average Interruption Frequency Index[61] ("$MAIFI_E$") information which also give a measure of electric service reliability from the customer's perspective, unless it does not have the means to make the calculations, in which case the utility must provide an explanation of the reason why it cannot, and an estimate of the cost to provide this information in the future.

COMPANY	All Interruption Data				All Interruption Data Minus Major Outage Event Data[62]			
	$CEMI_3$	$CEMI_5$	$CEMI_7$	$CEMI_9$	$CEMI_3$	$CEMI_5$	$CEMI_7$	$CEMI_9$
SMECO	10.67%	1.75%	0.38%	0.03%	10.67%	1.75%	0.38%	0.03%

Figure 3: 2013 CEMI Data

SMECO has not provided $MAIFI_E$ data because it does not currently have the means to perform these calculations. The Cooperative anticipates having the ability to calculate these indices after full deployment of its AMI project. The estimated cost for the total project is $69.4 million.

5. Service Interruption Standards (20.50.12.06)

COMAR 20.50.12.06 states that an Electric Company shall restore service within 8 hours, measured from when the utility knew or should have known of the outage, to at least 92 percent of its customers experiencing sustained interruptions during normal conditions; within 50 hours to at least 95 percent of its customers experiencing sustained interruptions during major outage events where the total number of sustained interruptions is less than or equal to 400,000 or 40 percent of the utility's total number of customers, and as quickly and safely as permitted to its customers experiencing sustained interruptions during each major outage event in which the total number of sustained interruptions is greater than 400,000 or 40 percent of the Electric Companies' total number of customers, whichever is less.

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[60] $CEMI_n$ is the ratio of the total number of customers experiencing sustained interruptions equal to or greater than "n" ", where **n** is equal to the number of interruptions, divided by the total number of customers served.
[61] $MAIFI_E$ is the ratio of the total number of customer momentary interruption events divided by the total number of customers served, where **E** is equal to the number of interruption events
[62] The information is the same because no COMAR qualifying major events occurred on SMECO's electric system in 2013.

The following table details how well SMECO restored service to customers who experienced an interruption in 2013. No data is available for major outage conditions because no major events occurred on SMECO's electric distribution system in 2013.

	Normal Conditions		*Major Outage Events*[63]		
COMPANY	**% Of Interruptions Restored w/in 8 Hours**	**Meets COMAR Interruption Standard (92%)**	**% Of Interruptions Restored w/in 50 hours**	**Meets COMAR Interruption Standard (95%)**	***Corrective Action Plan Required?***
SMECO	99.71%	Yes	N/A	N/A	No

Figure 4: Service Interruption Standards

SMECO restored service to 99.71% of its customers who experienced sustained interruptions within 8 hours during normal conditions.

6. Downed Wire Response Standards (20.50.12.07)

COMAR 20.50.12.07 states that each Electric Company shall respond to a government emergency responder guarded downed electric utility wire within 4 hours after notification by a fire department, police department, or 911 emergency dispatcher at least 90 percent of the time.

SMECO exceeded the 90 percent within 4 hours standard by responding to 97 percent of government emergency responder guarded downed electric utility wire within 4 hours after notification.

COMPANY	***4 Hours Or Less***	***More Than 4 Hours But Less Than 8 Hours***	***8 Hours or More***	***Total Found to Be Electric Utility Wires***	***Total # of Downed Wires Reported***
SMECO	247	39	14	N/A[64]	300

Figure 5: Guarded Downed Wire Response

COMPANY	***% Of Downed Wire Notifications Resulting In Responses w/in 4 Hours***	***Meets COMAR Downed Wire Response Standard (90%)***	***Corrective Action Plan Required?***
SMECO	97%	Yes	No

Figure 6: Guarded Downed Wire Response (cont.)

7. Customer Communications Standards (20.50.12.08)

COMAR 20.50.12.08 states that each Electric Company shall answer within 30 seconds, on an annual basis, at least 75 percent of all calls offered to the utility for customer service or outage reporting purposes. It also states that each Electric Company shall achieve an annual average abandoned call percentage rate of 5 percent or less. Electric Companies are also required to provide:

[63] SMECO reported no Major Outage Events occurring on its system in 2013.
[64] SMECO's OMS system does not contain the data to distinguish between a SMECO or non-SMECO downed wire.

- The percentage of calls that are answered within 30 seconds;
- The abandoned call percentage rate; and
- The average speed of answer.

In 2013, SMECO answered 88.98% of all calls offered within 30 seconds, with an abandoned call percentage rate of 1.07%.

Based solely upon those calls offered to its customer service representatives, SMECO answered 86.83% of calls within 30 seconds. SMECO also reported an abandoned call percentage rate of 1.40% with an average speed of answer of 12 seconds.

SMECO's telecommunications systems are designed to accommodate expected volumes of customer calls with minimal, or no, customer busy signals during both normal conditions and major outage events. This includes the utilization of an automated off-site overflow IVR service to process the high volume of outage related telephone calls associated with storm events.

COMPANY	% Of Calls Answered w/in 30 seconds	Meets COMAR Call Answer Time Standard (75%)	Annual Abandoned Call %	Meets COMAR Annual Abandoned Call Standard (< 5%)	% Of Calls Answered w/in 30 seconds by Rep	% of Abandoned Calls Received by Rep	Average Speed of Answer (seconds)
SMECO	80.52%	Yes	2.36%	Yes	71.73%	3.60%	19

Figure 7: Customer Communication Performance

8. Vegetation Management Standards (20.50.12.09)

SMECO's total overhead circuit miles are 3,576 miles. SMECO is in the second year of a 4-year trim cycle and, as of December 31, 2013, has performed vegetation management on more than 33% of total distribution system in 2013.

In 2013, SMECO trimmed 1,207 circuit miles at 16 substations and mowed 292 miles at 4 substations, spending a total of $5,359,013 for VM on Distribution.[65] The average cost per circuit mile trimmed was $4,440, compared to $3,918 in 2012.

Figure 8 lists the vegetation management activities performed by SMECO in 2013.

[65] According to Table 3b on page 15 of SMECO's Annual Performance Report 2013 (ML# 153738).

Company	Overhead Circuit Miles in MD	Total # of Miles of VM Performed	Trim Cycle (Years)	COMAR[66] Minimum Required Trimming 1st- 12 Months	2013 VM Expenditures	2013 Avg. VM Cost ($/Mile)
SMECO	3,576	1,207	4	15%	$5,359,013	$4,440

Figure 8: 2013 Vegetation Management

For 2014, SMECO plans to trim 1,401 circuit miles at 20 substations and 422 miles of mowing at 6 substations. $4,757,397 has been budgeted to complete VM work in 2014.

The following table is a breakdown of SMECO's planned VM work for 2014.

Company	# of Miles of Veg. Management Planned to be Trimmed	# of Substations Affected	# of Feeders/Circuits Affected	% of System	2014 Projected Vegetation Management Expenditures	2014 Planned Avg. VM Cost ($/Mile)
SMECO	1,401	20	77	39.2%	$4,757,397	$3,396

Figure 9: 2014 Projected Vegetation Management

Over the past two years (2012-2013), SMECO has trimmed more than 78% of its system since the promulgation of RM43 on May 28, 2012.

9. Reliability Objectives & Planned Actions

In order to meet the electric system performance requirements specified in COMAR 20.50.12, Service Quality and Reliability Standards, SMECO's objective is to use modern technology in combination with a proactive customer-friendly approach. The key elements of SMECO's strategy include: (1) line and station inspections, (2) preventive and responsive system maintenance, (3) efficient operation utilizing energized work states whenever determined to be a safe method, and (4) methodical short-term and long-term system planning. SMECO feels that this approach will best ensure cost-effective reliable power is available to serve both existing and future customer-members.

SMECO plans to continue to provide reliable, high quality service to its customers, in part, by continuing to carry out the following programs:

- Visually inspecting the entire distribution system bi-annually and conducting quarterly aerial inspections of all 69 kV and 230 kV transmission lines.
- Systematic wood pole inspection, treatment, and replacement as needed.

[66] COMAR 20.50.12.09F (1) states that this regulation initially begins on January 1 of the year immediately following the effective date of the regulation (i.e. January 1, 2013).

- Aggressive distribution right-of-way maintenance on a four-year cycle and right-of-way widening as appropriate.
- Annual substation transformer and voltage regulator oil testing and analysis.
- Regularly scheduled testing and maintenance of substation reclosers, circuit breakers, and associated relays.
- Annually inspecting substations, switching stations, and major distribution lines with an infrared scanner.
- Continued use and enhancement of the Cooperative's implemented Outage Management System (OMS) in conjunction with the expansion of its mobile workforce computing capabilities.

SMECO will investigate expanding its existing preventative maintenance practices and continue to proactively look for opportunities to improve area reliability performance by:

- Developing requirements for an Asset Management System to better track existing maintenance programs, asset performance statistics, and to better identify aging infrastructure before it reaches its expired useful life.
- Initiating a program to proactively replace aging copper distribution lines with new aluminum cable or steel-reinforced aluminum conductor lines.
- Reviewing existing distribution circuit sectionalizing and protective coordination configuration.
- Continued advancement of the Cooperative's AMI initiative.
- Continuing with design and construction of the SMECO Western Charles County 69kV transmission line expansion project. This project will provide needed infrastructure to add two additional distribution substations and loop-fed 69 kV transmission infrastructures to better serve growing area loads and ensure alternate transmission feeds to serve area distribution substations during outage contingency situations.
- Completing the remaining phase of the SMECO 230 kV Southern Maryland Reliability Project.

SMECO develops its system Load Forecasts ("LF") using statistics provided by the Maryland State Office of Planning. The Company plans to provide its next LF in the second Quarter of 2014, which will be based on the more recent winter 2013-2014 and summer 2013 system load information. SMECO uses this LF as the basis for developing current and future construction work plans ("CWP"). Both SMECO's LF and CWP are supported by its Distribution Long Range Plan ("DLRP") and Transmission Long Range Plan ("TLRP"), completed January 2005 and 2006, respectively. The purpose of these programs are to examine SMECO's existing transmission and distribution systems and to provide a guide for making system improvements needed to reliably serve projected peak system loads for future years.

SMECO also uses software modeling on each of its distribution feeders to determine the worst-case voltage drop, maximum expected line amps, and the maximum line section loading percentage for projected peak loads.

10. Expenditures and Projects

COMAR 20.50.12.11.A(6) requires each of the electric companies to report current year expenditures and estimate or projected expenditures for the following two calendar years, current year labor hours if available, and progress measures for each capital and maintenance program. COMAR 20.50.12.11B(1) requires each of the utilities to report reliability program operation and maintenance and capital expenditures for the current year and the 2 previous years.

Figure 10 shows the actual capital and operation and maintenance expenditures for SMECO for 2013, including a historical overview of the money spent the previous 2 calendar years.

In 2013, SMECO spent approximately $45,410,353 on capital expenditures to support maintenance of reliable electric service. The following table provides more in-depth information regarding how these expenditures were disbursed among the various capital investment reasons.

Actual expenditures for the past three calendar years are also listed below:

Investment Reason	2011	2012	2013		2013		2014	2015
	Actual	Actual	Budget[67]	Actual	Labor Hours (Utility)	Labor Hours (Contractor)	Projected	Projected
T&D Capital Budget[68]	N/A	N/A	106,900,000	N/A	N/A	N/A	82,776,108	61,140,280
Substations & Switching Stations	3,522,907	0	N/A	678,589.8	N/A	N/A	N/A	N/A
Distribution –CWP	443,487	3,621,703	N/A	16,192,317	N/A	N/A	N/A	N/A
Ordinary Distribution Replacement	6,931,705	11,947,503	N/A	7,300,330	N/A	N/A	N/A	N/A
Miscellaneous Line and Station Changes	14,781,190	20,372,308	N/A	16,350,146	N/A	N/A	N/A	N/A
Miscellaneous Line and Station Changes	4,662,437	2,117,482	N/A	4,888,971	N/A	N/A	N/A	N/A
Utility Hours					**188227**	**N/A**		

Figure 10: SMECO Capital Expenditures[69]

In 2013, SMECO spent approximately $29,406,277 on operation & maintenance expenditures to support maintenance of reliable electric service. The following table provides more in-depth information regarding how these expenditures were disbursed among the various operation & maintenance investment reasons.

[67] This was SMECO's 2013 reported total capital budgeted. Had SMECO reported net the new service connection budget, total would have been $62,392,400.
[68] Transmission and Distribution Capital Budget: SMECO budgets all T&D capital as one account. When expensed, it is allocated to the appropriate work type/accounts.
[69] Capital expenditures include work required to add or replace real property associated with the distribution system that provides electrical service to SMECO customers. Real property is defined as construction units that are accounted for within the Continuing Property Records system. This includes all voltages.

Investment Reason	2011	2012	2013		2013		2014
	Actual	Actual	Budget	Actual	Labor Hours (Utility)	Labor Hours (Contractor)	Projected
Transmission Labor Hours	0	0	0	0	29118	N/A	0
Distribution Labor Hours	0	0	0	0	260405	N/A	0
Underground & Overhead Distribution Plant Inspection	85,176	88,570	649,253	761,992	0	N/A	663,263
Maintenance & Replacement Programs	13,594,064	12,011,542	8,343,779	10,596,336	0	N/A	10,311,994
Vegetation Management Distribution	4,219,910	4,773,005	4,335,602	5,359,013	0	N/A	4,757,397
Vegetation Management Sub-Transmission	928,765	1,038,884	1,035,105	1,094,922	0	N/A	1,287,232
Sub-transmission Inspection and Maintenance Programs	1,103,347	1,637,831	1,063,149	1,515,960	0	N/A	1,231,786
Distribution Substation Plant Inspection and Maintenance Programs	937,322	1,114,033	746,607	1,112,260	0	N/A	1,077,577
Miscellaneous Distribution Operation and Maintenance	8,448,462	7,891,303	10,577,069	8,965,794	0	N/A	9,434,409

Figure 11: SMECO Operation & Maintenance Expenditures

11. Conclusions

Based on its review of SMECO's 2013 reliability report, Staff believes SMECO is steadily improving its electric system reliability and is confident that, barring any unforeseen circumstances, SMECO will be able to meet the standard reliability benchmarks outlined in COMAR for 2014.

G. **Appendix 7: Delmarva 2013 Corrective Action Plan Review**

1. Background/Summary

In 2011, Maryland's General Assembly passed the Maryland Electricity Service Quality and Reliability Act (Chapter 168 of the Acts of 2011) which required the Commission to adopt regulations by July 1, 2012 establishing service quality and reliability standards for the delivery of electricity to retail customers by electric companies. The Act established the goal that "each electric company provides its customers with high levels of service quality and reliability in a cost-effective manner, as measured by objective and verifiable standards…"[70]

Effective May 28, 2012, the Commission established specific standards for reliability for each electric company in COMAR 20.50.12.02D(1)(c).

The 2013 annual reliability standards for Delmarva are as follows:[71]

SAIDI[72]	2.99
SAIFI[73]	1.65

According to Delmarva's annual Performance Report Corrective Action Plan dated April 1, 2014, the annual standards for 2013 were not met.[74]

2. Applicable Law

PUA § 7-213(e)(1)(iii) states:

> The regulations adopted under subsection (d) of this section shall: . . . (iii) for an electric company that fails to meet the applicable service quality and reliability standards, require the electric company to file a corrective action plan that details specific actions the company will take to meet the standards.

COMAR 20.50.12.02D(1)(c) sets forth the SAIDI and SAIFI reliability standards for Delmarva for calendar years 2012-2015.

COMAR 20.50.12.02D(4) states, "A utility's annual SAIDI result shall be equal to or less than its annual SAIDI reliability standard established in §D(1) of this regulation."

COMAR 20.50.12.02D(5) states, "A utility's annual SAIFI result shall be equal to or less than its annual SAIFI reliability standard established in §D(1) of this regulation."

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[70] PUA §7-213(b).
[71] COMAR 20.50.12.02D(1)(c).
[72] PUA §7-213(a)(2) defines "System-average interruption duration index" or "SAIDI" as the sum of the customer interruption hours divided by the total number of customers served.
[73] PUA §7-213(a)(3) defines "System-average interruption frequency index" or "SAIFI" as the sum of the number of customer interruptions divided by the total number of customers served.
[74] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 5; Mail Log No: 153722

COMAR 20.50.12.02(E) states, "If a utility fails to satisfy the standard in §D(4) or (5) of this regulation, it shall provide a corrective action plan, preferably in its annual performance report but by no later than April 1."

3. Acronyms:

ACR – Automatic Circuit Recloser
ASR - Automatic Sectionalization and Restoration
CAP – Corrective Action Plan
CEMI - Customers Experiencing Multiple Interruptions
CI – Customer Interruptions
CMI – Customer Minutes of Interruption
DA- Distribution Automation
DR – Data Request
GSRI - Greater Salisbury Reliability Improvement Project
IT – Information Technology
MOE – Major Outage Event
MOD – Motor Operated Devices
PPF – Poorest Performing Feeder
T&D – Transmission and Distribution
URD- Underground Residential Distribution

4. Analysis

a. Delmarva's Reliability

Staff reviewed the 2013 SAIDI and SAIFI standards results reported by Delmarva against the COMAR standards established by the Commission.

	Annual Requirement	Actual Results[75]	% Above COMAR Standard
SAIDI	2.99	3.54	18.4%
SAIFI	1.65	1.95	18.2%

Figure 1: 2013 SAIFI and SAIDI Targets and Results

The chart below shows the Delmarva SAIFI and SAIDI numbers for the past five years, comparing the company performance for 2012-2013 to the COMAR standards.

[75] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 5; Mail Log No: 153722

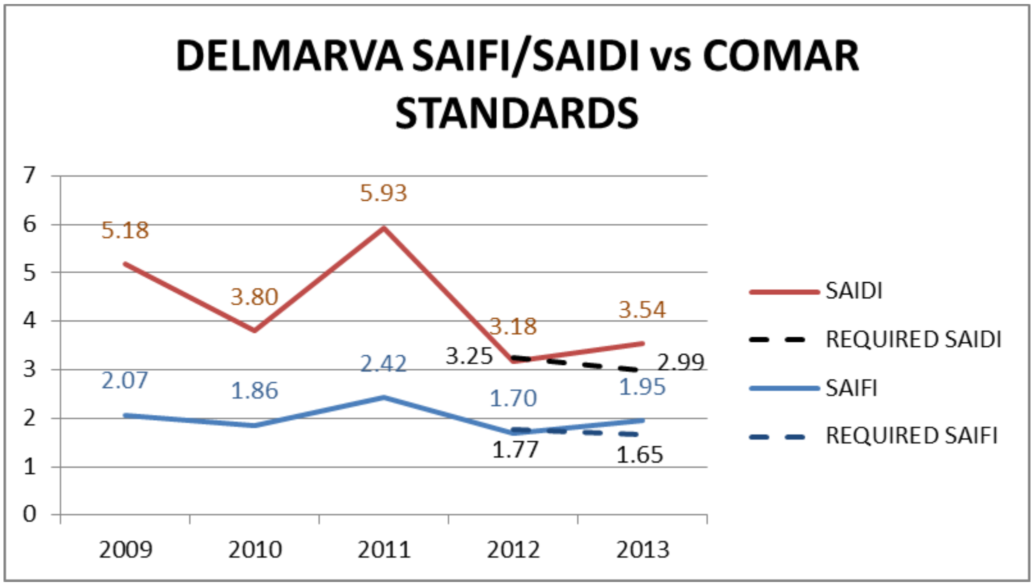

Figure 2: 2013 SAIFI and SAIDI 5 Year Trend

b. Customer Perspective

In examining the data, the increased interruptions and the outage time caused by the shortfall in SAIFI and SAIDI can be seen as follows:

Delmarva total customer count for 2013 = 199,956

Delmarva Actual SAIFI = 1.95
Delmarva Target SAIFI = 1.65

Target Number of Customer Interruptions = 199,956 * 1.65 = 329,927
Actual Number of Customer Interruptions = 199,956 * 1.95 = 389,914
Number of Additional Interruptions Caused by the Shortfall = 59,987
Percentage of Additional Interruptions Caused by the Shortfall = 59,987 / 329,927 = 18.1%

Delmarva Actual SAIDI = 3.54
Delmarva Target SAIDI = 2.99

Target Number of Outage Hours = 199,956 * 2.99 = 597,868
Actual Number of Outage Hours = 199.956 * 3.54 = 707,844
Number of Additional Outage Hours = 109,976
Percentage of Additional Customer Outage Hours = 18.4%

To put it these differences into perspective, if all of these outages occurred simultaneously in three of the largest cities in the Delmarva service area (Salisbury, Ocean City, and Elkton), all of the customers in the cities would have experience an outage of just under two hours.

Delmarva CAIDI (Shortfall)

Customer Minutes of Interruption (CMI) by Shortfall = 109,976 * 60 = 6,598,548
Average Outage Time of Customers Affected by Shortfall = 6,598,548 / 59,987 = 110 min or 1.83 hours

Delmarva did not meet he COMAR SAIFI and SAIDI standards for 2013. What this meant to a customer was that on average one out of every five Delmarva customers experienced an additional 1 hour and 50 minutes of additional outage time during 2013.

c. Delmarva Districts

Delmarva operates three districts in Maryland: North East (near Elkton), Centreville, and Salisbury, as seen in Figure 4. During significant storms and MOEs, Delmarva dispatches response and repair teams from each of the three district offices.

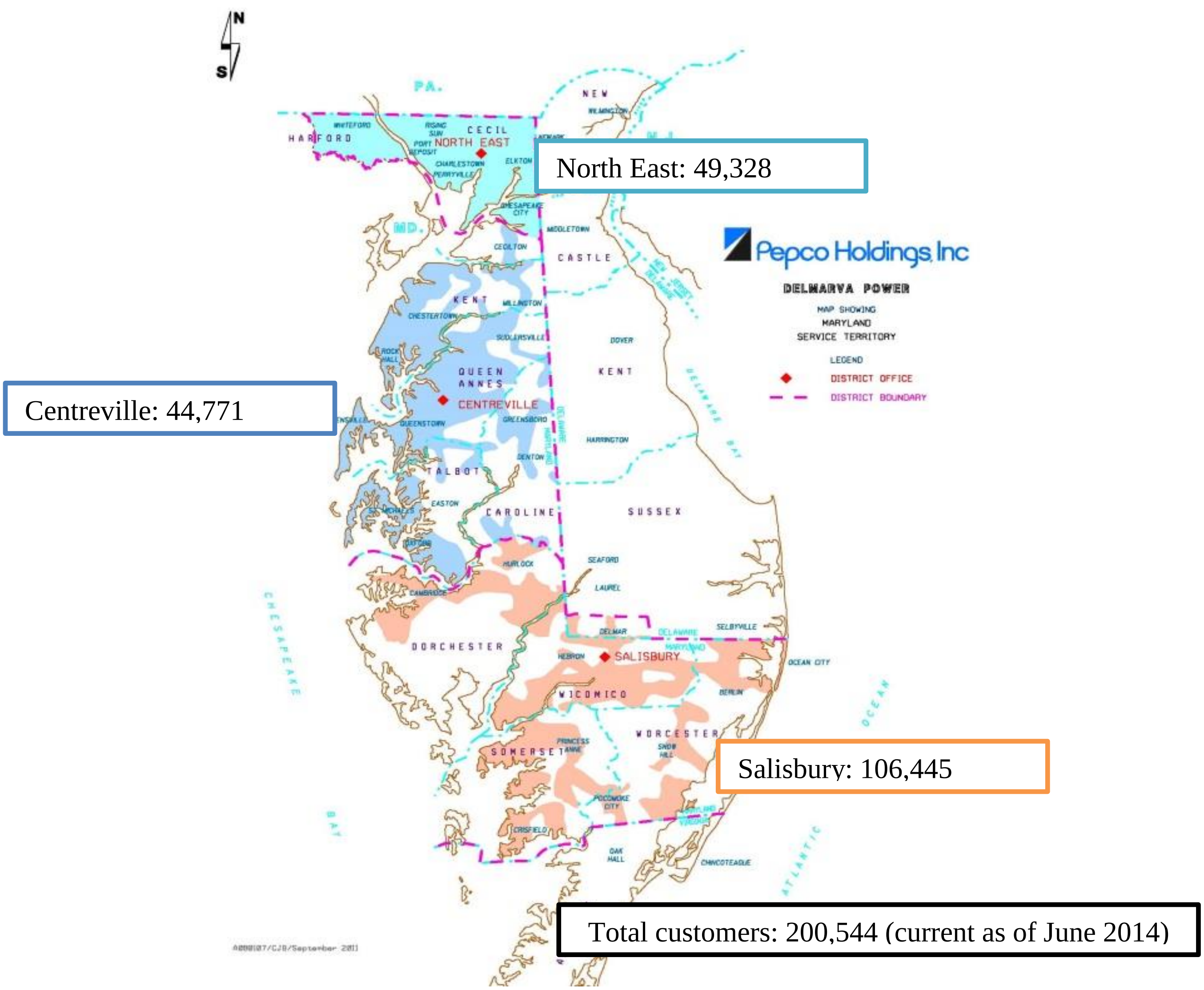

Figure 3: Delmarva Service Districts

d. Significant Storms

There were no major outages recorded for 2013. Delmarva stated that isolated events such as microburst thunderstorms have an effect on a large portion of their customers but not over 10% or 100,000 required to be considered a MOE.[76] Delmarva suggests that storms that have over 700 lightning strikes, microburst thunderstorms, or wind gusts of over 50 mph should be considered a significant storm and excluded from the SAIFI and SAIDI standards.[77] Storms with large winds cause extensive damage by blowing around vegetation which damages overhead equipment, as well as other objects that strike above ground equipment causing damage and outages. Lightning strikes can affect the systems in many ways, but generally result in one of the following:[78]

- Activation of a protective device (fuse, breaker, recloser) from an overcurrent caused by the lightning strike. These activations can be temporary or permanent requiring repairs.
- Activation of the lightning arrestor causing the high voltage to be grounded, causing no damage to the system.
- Catastrophic equipment damage or failure (transformer, voltage regulator, breakers, etc.) due to direct lightning strikes.

There were seven significant storms (thunderstorms with over 700 lightning strikes, microburst thunderstorms, or wind gusts of over 50 mph)[79] between March 2013 – August 2013 in the Salisbury district that were not considered major outage events, (MOEs), but were significant enough to cause large outages in a localized area. One microburst thunderstorm in Salisbury on June 13, 2013[80] contributed to 5% of the annual system-wide SAIDI total, or 5 ½ minutes of outage per customer. Within the Salisbury district, the district SAIDI increased 10%, or 11minutes of outage per customer as a result of the storm. The customers affected by each storm as well as the amount of hours that the customers were without power is listed in Figure 4. For example, the August 13, 2013 thunderstorm in the North East district of Delmarva impacted 12,782 customers for an average of 3.09 hours.

Significant Event	Date	Location	CI	CMI	CAIDI (Minutes)	CAIDI (Hours)
Thunderstorm (1000)Lightning Strikes	8/13/2013	North East	12782	2371509	186	3.09
Microburst Thunderstorm	6/13/2013	Salisbury	13914	1897942	136	2.27
Wind Storm (> 50 mph)	3/6/2013	North East	13942	1894738	136	2.27
Thunderstorm (1000)Lightning Strikes	6/24/2013	North East	8024	1834581	229	3.81
Microburst Thunderstorm	6/14/2013	Centreville	10523	1599053	152	2.53
Thunderstorm (700)Lightning Strikes	7/12/2013	North East	9529	1542856	162	2.70
Thunderstorm (700)Lightning Strikes	7/23/2013	Centreville	7485	1129205	151	2.51
Significant Storm Days			76199	12269884	164	2.74

Figure 4: Delmarva 2013 Significant Storm Events

76 COMAR 20.50.01B(27)(a).
77 Delmarva Power Corrective Action Plan MD (Helm) Data Request
78 John Helm DR Responses, June 17, 2014
79 Delmarva Power Corrective Action Plan MD (Helm) Data Request May 21, 2014
80 Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 4; Mail Log No: 153722

Delmarva states that the average daily SAIDI is .57 minutes. For the seven significant storms, the daily SAIDI was 10 to 21 times higher than the norm, and considers these as extremely abnormal days. If these significant storms were included as MOEs, the SAIFI for Delmarva would be 1.57 and SAIDI 2.52, allowing them to meet the COMAR standard.

	Outages[81]	MD Customers Affected	SAIFI	Customer Minutes	SAIDI
All Data	4,542	389,960	1.95	42,621,192	3.54
Significant Storms Excluded	4,058	313,715	1.57	30,200,770	2.52

Figure 5: Delmarva SAIDI and SAIFI minus Significant Storm Data

As shown in Figure 6, Delmarva performed very well during the significant storms. At least 92% of the customers were restored for every storm within 8 hours, meeting the required COMAR standard. The average time from the start of the storm until the last customer's power was restored was approximately 29 hours. There was only one storm where 0.01% percent of customers remained without power for more than 24 hours. Most customers had their power restored on average in under 12 hours.[82]

Weather	Date	Location	% Restored within 8 hours*	% of outage over 24 hours	Duration of the storm (hours)**	How long to restore the last 5% of the outage (hours)***
Thunderstorm (1000)Lightning Strikes	8/13/2013	North East	93%	0.00%	21.77	8.58
Microburst Thunderstorm	6/13/2013	Salisbury	98%	0.00%	34.63	14.13
Wind Storm (> 50 mph)	3/6/2013	North East	98%	0.00%	24.95	14.05
Thunderstorm (1000)Lightning Strikes	6/24/2013	North East	92%	0.01%	32	15.62
Microburst Thunderstorm	6/14/2013	Centreville	100%	0.00%	24.45	3.87
Thunderstorm (700)Lightning Strikes	7/12/2013	North East	94%	0.00%	36.87	8.08
Thunderstorm (700)Lightning Strikes	7/23/2013	Centreville	99%	0.00%	29.07	19.37
Significant Storm Days			96%	0.00%	29.11	11.96
* Calculated based on individual customer outage start time and not from the start of the storm						
**The storm duration is defined as from the onset of the storm to the last customer restored						
***Calculated based on the cumulative customers restored during the storm						

Figure 6: Significant Storm Restoration Times[83]

[81] Delmarva 2014 Annual Performance Report, Appendix 1, Table 4a; Mail Log No: 153728
[82] Staff Data Request #3 Delmarva CAP, June 30, 2014
[83] Staff Data Request #3 Delmarva CAP, June 30, 2014

If the same COMAR standard regarding MOEs applied to each district as it does to the entire Delmarva service territory, none of the significant storms would have met the criteria to be a MOE. Delmarva met all COMAR standards for service restoration during these significant storms.

e. Unique Distribution System

Delmarva's service area is composed of several different transmission and distribution (T&D) systems with different voltages and distribution patterns that have been merged together to form the Delmarva service territory, and has remained unchanged for the past 19 years. The separate subsystems operate on voltages of 34kV, 25kV, 12kV, and 4kV. Each subsystem has vulnerabilities that contribute to the challenge of improving the reliability of the system as a whole.

Key vulnerabilities are as follows:[84]

- 34kV system
  - Extremely lengthy feeders with high customer counts and heavy tree exposure
- 25kV system
  - Lengthy feeders with high customer counts (>500) and moderate tree exposure
  - Moderate lightning and animal exposure
- 12kV system
  - Medium to short feeders with moderate tree exposure
- 4kV system
  - Short feeders with small customer count and moderate to heavy tree exposure
  - Reliant on the 34kV systems

f. COMAR Standards

The radial nature of Delmarva's area of operations and the various transmission and distribution systems justify a higher Delmarva SAIDI and SAIFI standard compared to the other investor owned utilities in Maryland. Delmarva's distribution feeders are fed by four transmission lines running from north to south in the service territory. The Delmarva service territory is on a peninsula, and predominantly rural and radial.

Each utility company in Maryland must meet reliability standards that reflect the type of systems and equipment utilized for operations and maintenance. For 2013, BGE, Potomac Edison, and Pepco met the COMAR standards for both SAIFI and SAIDI. While each investor owned utility's reliability metrics in COMAR differs, BGE, Pepco, and P.E. all met their standards as shown in Figure 7.

[84] John Helm DR Responses, June 17, 2014

	SAIFI			SAIDI		
Utility	**Actual**	**COMAR**	**% Difference**	**Actual**	**COMAR**	**% Difference**
Delmarva	1.95	1.65	**18.2%**	3.54	2.99	**18.4%**
BGE	0.93	1.47	**-36.7%**	1.67	3.96	**-57.8%**
Potomac Edison	1.01	1.10	**-8.2%**	2.38	3.05	**-22.0%**
Pepco	1.49	1.81	**-17.7%**	2.46	2.82	**-12.8%**

Figure 7: 2013 Investor Owned Utility SAIFI and SAIDI Performance

Examining trending in annual SAIFI and SAIDI for the investor owned utilities, Figure 8 shows that Delmarva did not have a steady downward SAIFI trend over the past five years. From 2009-2011 Delmarva's SAIFI trended opposite to that of the three other investor owned utilities. Delmarva has trended with the other companies from 2011-2013.

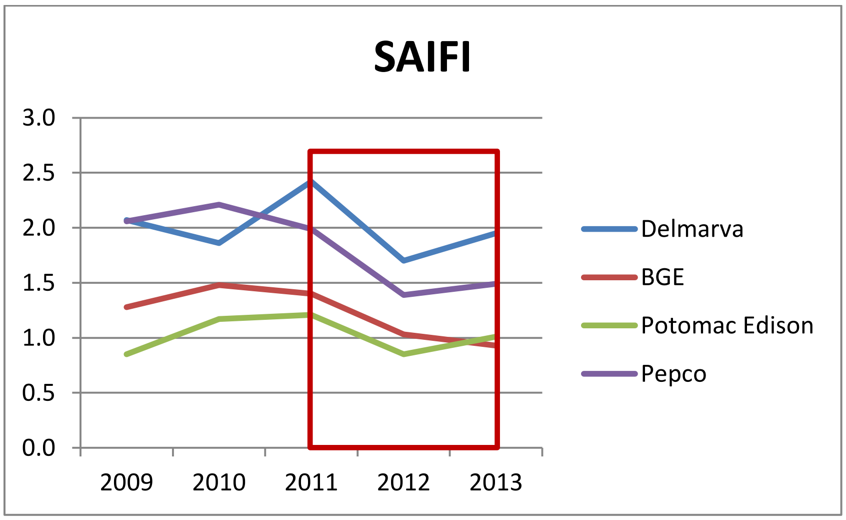

Figure 8: SAIFI Maryland Utility 5 Year Comparison 2009-2013

Similarly, Delmarva's SAIDI trended opposite to that of the other three investor owned utilities from 2009-2011. Delmarva did show an improvement from 2011-2012, it was the only utility to have an increase in SAIDI from 2012-2013, attributed to isolated, yet significant storms, which occurred in Delmarva's service area.[85]

[85] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 4; Mail Log No: 153722

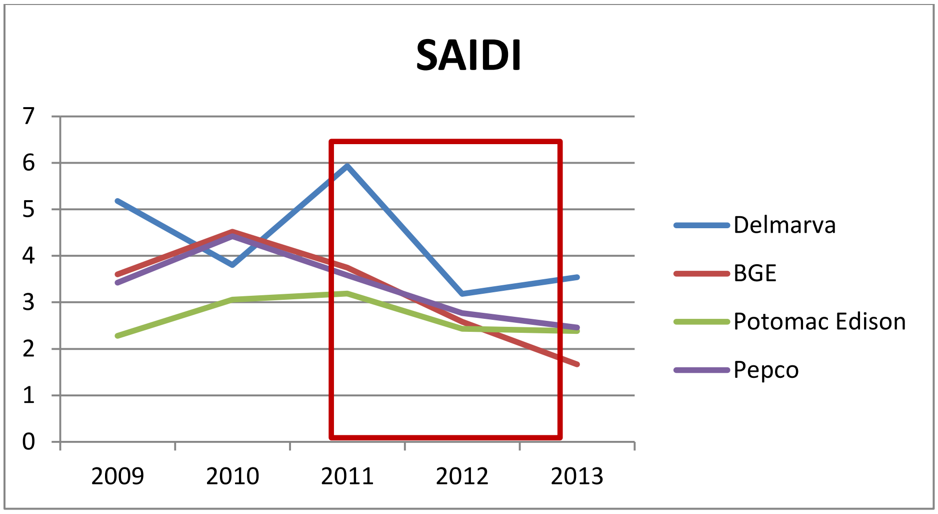

Figure 9: SAIDI Maryland Utility 5 Year Comparison 2009-2013

Post-2011 improvements in SAIFI and SAIDI for all Maryland investor owned utilities is likely attributed to the reliability improvement work utility companies began just prior to promulgation of RM43 in 2012.

COMAR standards have been set for almost two years, allowing for trend analysis to be expanded to cover this time period. When looking at two year trends, all four major utility companies are trending in a positive direction for both SAIFI and SAIDI. Delmarva has improved at the same rate as the other investment owned utilities over the past two years, but started at a higher baseline due to high SAIFI and SAIDI values for 2011. Delmarva is currently above the COMAR standard; however with the implementation of its Corrective Action Plan (CAP), Delmarva is working toward meeting or exceeding the standard from 2014 onward. Data for the two year trend charts represents the average for two consecutive years.

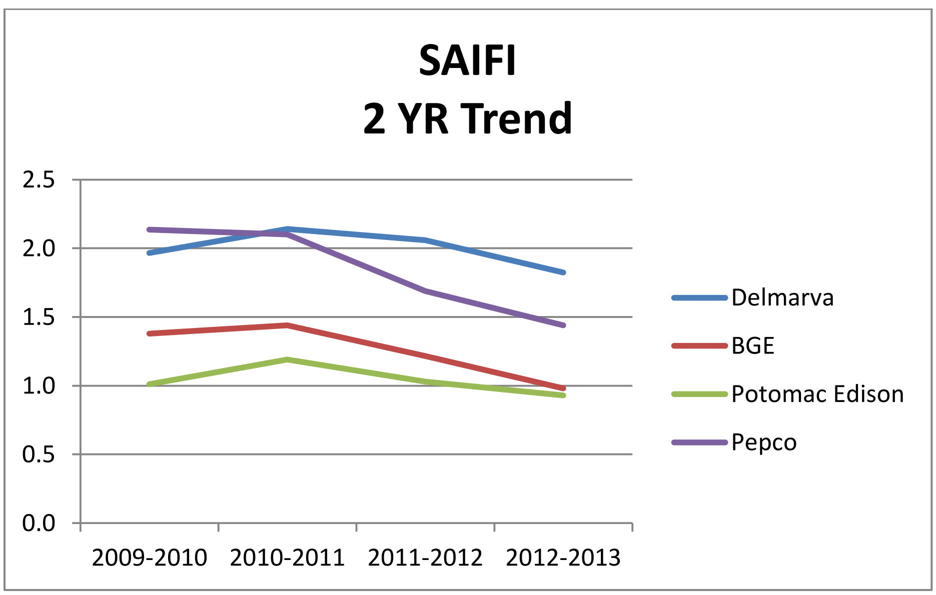

Figure 10: SAIFI Maryland Utility 2 Year Trend

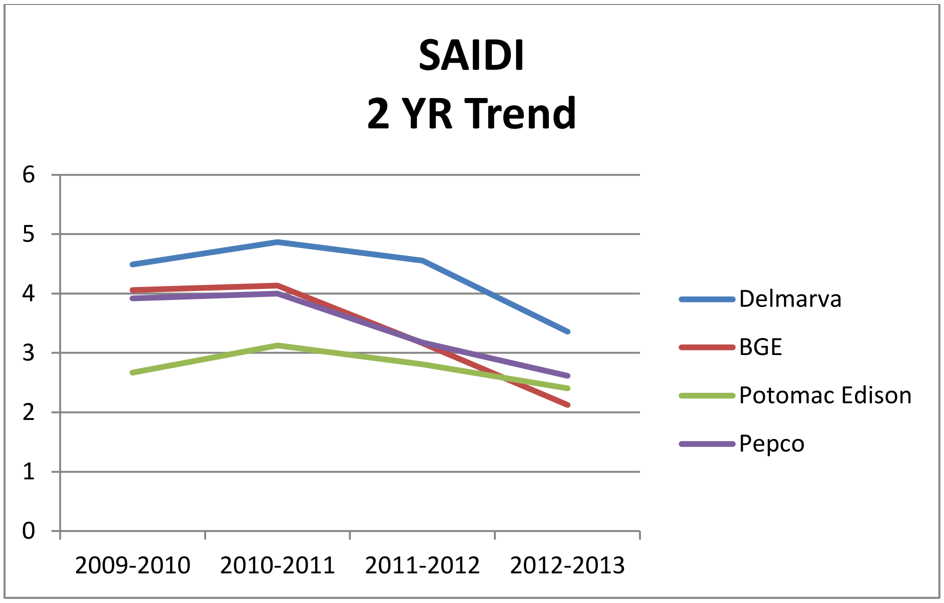

Figure 11: SAIDI Maryland Utility 2 Year Trend

g. Outage Causes

As seen in Figure 12, most customer outages and customer minutes of interruption during 2013 were caused by overhead equipment failure, weather and trees respectively.[86] In its response to Staff data requests about the filed CAP, Delmarva identified significant storms as driving factors for the missed targets in addition to overhead equipment failure and vegetation.[87]

Delmarva breaks down overhead equipment failure into several different sub categories.[88] The greatest percentage of outages caused by overhead equipment failure consists of cables (19.4%), cutouts (the device that holds the fuse link) (8.4%), transformers (7.7%), and fuses (5.7%). The greatest number of customers losing power that was caused by overhead equipment failure consists of bare wires (19.5%), insulators (11.6%), and cables (10%). The greatest number of total customer minutes lost caused by overhead equipment failure consists of bare wires (28.3%), cables (13.7%), loose connections (8.5%), and cross arms (8.4%). The unknown category covers outages that the assessment or repair crew could not accurately determine. Delmarva reports that the reason for the high amount of cable and bare wire failures (~40% of overhead failures) is faulty connections, causing the wires and cables to fail and burn.[89] Cable and bare wire failures typically occur at older facilities with small wire circuits. Failures occurring underneath (below the device on the pole or supporting structure) of the breaker or a recloser will cause the highest amount of outages.

[86] Delmarva 2014 Annual Performance Report, Appendix 1, Table 4b; Mail Log No: 153728
[87] Delmarva Power Corrective Action Plan MD (Helm) Data Request
[88] Delmarva Power Corrective Action Plan Follow-Up Questions, June 2, 2014
[89] John Helm DR Responses, June 17, 2014

Outage Cause	# of Outages	% of Outages	# of Customers Affected	Outage Minutes	% of Minutes
Animals	563	12.40%	21,834	2,179,881	5.11%
OH Equipment Failure	**748**	**16.47%**	**100,982**	**8,699,411**	**20.41%**
UG Equipment Failure	627	13.80%	11,807	1,759,727	4.13%
Equipment Hit	205	4.51%	36,624	4,550,436	10.68%
Other *	321	7.07%	51,592	4,113,785	9.65%
Overload	152	3.35%	3,830	608,404	1.43%
Tree **	**787**	**17.33%**	**74,717**	**10,387,600**	**24.37%**
Unknown	607	13.36%	34,871	2,725,466	6.39%
Weather	**532**	**11.71%**	**53,703**	**7,596,481**	**17.82%**
Total	4542	100.00%	389,960	42,621,192	100.00%

•Includes Employee, Fire, Source Lost, Vandalism, Loadshed, etc.
••Includes Inside of ROW and Outside of ROW Tree Outages

Figure 12: 2013 Delmarva Outage Causes

5. Corrective Action Measures

Delmarva has implemented several projects and accelerated other scheduled reliability improvement projects in order to improve the reliability of the Delmarva system and meet the COMAR standards for 2014 and beyond. Figure 13 depicts the strategies adopted by the company for reliability improvement. To address the reliability shortfall, Delmarva has broken down their CAP into two sections: current projects and additional projects. Delmarva has adjusted their previous strategies of focusing strictly on the poorest performing feeders (PPF), looking long-term at feeders that are aging and decreasing in performance. Delmarva is also implementing more distribution automation to increase reliability and reduce outage occurrences and times.

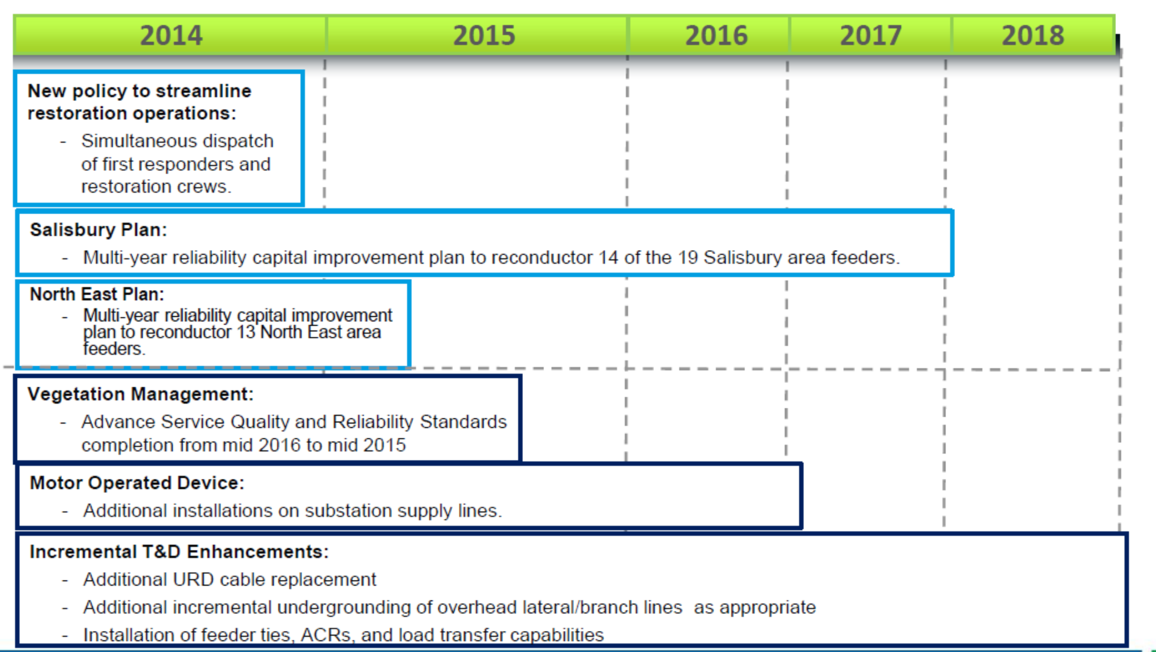

Figure 13: Delmarva CAP Strategies and Projects 2014-2018[90]

[90] RM-43 Delmarva MD Corrective Action Plan Discussion Document, March 2014

a. Strategy

The Delmarva CAP has addressed current reliability issues by changing strategies to include long range planning for feeders that are not included in the COMAR required poorest performing feeder list but are declining in performance and adding distribution automation to the network. Delmarva uses a combination of SAIFI, SAIDI, and CEMI (Customers Experiencing Multiple Interruptions) to determine which feeders outside of the bottom 3% are performing at a less than desirable level with regards to customer satisfaction or system reliability.[91] Staff determined that long term projections will improve overall reliability, but that this practice should have been occurring as part of normal operational and strategic planning.

b. Cost

Delmarva separates reliability enhancement into projects. Additional CAP funding integrates existing projects with new projects and projects that augment currently planned reliability enhancements. Examples of augmented projects are vegetation management, URD cable replacement and additional undergrounding, and substation improvements.

Delmarva plans on spending an additional $24 million on reliability for 2014, $23.5 million in 2015, and $20 million each year from 2016-2018.[92] The priority for spending is for transmission and distribution (T&D) feeder, source line, and substation improvements, with the additional spending for 2014 and 2015 on accelerated vegetation management. The currently scheduled project budget as well as the projected CAP budget is seen in Figure 14.

Corrective Action Plan (in millions)	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Vegetation Management Distribution (O&M)*	$4.0	$3.5					
URD Cable Replacement	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0
Additional Undergrounding	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0
MOD Installation (Transmission)	$2.0	$2.0	$2.0	$2.0	$2.0	$2.0	$2.0
T&D Feeder, Source Line & Substation	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0	$10.0
Total	**$24.0**	**$23.5**	**$20.0**	**$20.0**	**$20.0**	**$20.0**	**$20.0**

* Used to accelerate the vegatation cycle from 4 to 3 years. No acceleration projected from 2016-2020

Figure 14: 2013-2020 Delmarva Corrective Action Plan Spending[93]

[91] John Helm DR Responses, June 17, 2014
[92] Delmarva 2014 Annual Performance Report Corrective Action Plan; Table 3; Mail Log No: 153722
[93] Vegetation management spending is for the accelerated from a four to three year cycle from 2014-2015

Projects	2014 Approved Budget	2015 Approved Budget	2016 Approved Budget	2017 Approved Budget	2018 Approved Budget
Conversions	$ 0.92	$ 0.89	$ 0.84	$ 0.97	$ 0.40
Distribution Automation	$ 9.00	$ 5.62	$ 4.39	$ 3.94	$ 3.78
Vegetation Management O & M	$ 7.49	$ 7.64	$ 7.80	$ 7.95	$ 8.11
Feeder Improvement	$ 11.86	$ 12.02	$ 12.08	$ 12.38	$ 12.38
GRC Priority Feeder Work	$ -	$ 2.10	$ -	$ -	$ -
Load Growth	$ 5.21	$ 2.07	$ 8.66	$ 15.25	$ 10.60
Priority Feeder Work	$ 5.46	$ 4.05	$ 4.07	$ 4.10	$ 4.10
Sub Reliability Improvements	$ 4.59	$ 2.51	$ 2.43	$ 2.37	$ 2.37
UG Residential Distribution	$ 6.23	$ 5.53	$ 5.59	$ 5.65	$ 5.65
Dist Non REP Reliability	$ 31.41	$ 29.47	$ 27.90	$ 25.68	$ 28.01
Other	$ 61.61	$ 39.72	$ 34.00	$ 40.94	$ 108.80
Trans Non REP Reliability	$ 18.13	$ 29.41	$ 41.70	$ 25.75	$ 5.45
Sub Total	**$ 161.92**	**$ 141.04**	**$ 149.46**	**$ 144.99**	**$ 189.66**
CAP	$ 24.00	$ 24.00	$ 24.00	$ 24.00	$ 24.00
% of Additional Spending: CAP	12.9%	14.5%	13.8%	14.2%	11.2%
Grand Total	**$ 185.92**	**$ 165.04**	**$ 173.46**	**$ 168.99**	**$ 213.66**

Figure 15: 2013-2018 Delmarva Reliability Enhancement Plan Budget

With regards to the projects outlined in Figure 15, a source line is the transmission line or supply line which feeds the distribution stations. This line is often bundled together for better protection from weather and animal damage. Conversions included changing or upgrading feeder infrastructure to a higher voltage. Upgrades reduce system losses, replace aging infrastructure, and enable Delmarva to allow more feeders in the region to operate at one common voltage.[94] Sub reliability improvements are improvements to the equipment located inside a substation such as new breakers, new electronic relays, and remote terminal units. The other category consists of IT, fiber, radio, and facilities directly in support of supervisor control and data acquisition (SCADA).

c. Salisbury Plan[95]

Delmarva has accelerated the work in the Greater Salisbury Reliability Improvement Project (GSRI) from six to four years. Three feeders associated with GSRI have been deemed priority feeders by Delmarva, per COMAR standards, and will be funded from the poorest performing feeder program. The cost of upgrading and repairing the three feeders is $4.8 million and the work will be complete by September 2014.[96] Over the past four years, 14 of the 19 Salisbury feeders have accounted for 91 outages affecting over 118,000 customers. Delmarva projects that the upgrades to the existing feeders (original installation 1958-1968) and vegetation management will reduce the number and duration of power outages in the Salisbury region. The projected impacts on reliability are expected to be seen by 2017, reducing outages by 60%. This will cause a reduction in SAIFI of 0.34 and SAIDI by 0.58 for the Delmarva system, or a SAIFI

[94] John Helm DR Responses, June 17, 2014
[95] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 12; Mail Log No: 153722
[96] Delmarva Power Corrective Action Plan MD (Helm) Data Request, May 21, 2014

reduction of 0.68 and SAIDI 1.16 for the Salisbury district. Immediate impacts will be seen by the end of 2014 due to the accelerated installation of three feeders that were selected as priority feeders. Delmarva stated that the planned acceleration of the GSRI will have an immediate impact in 2014 and improve the reliability of the Delmarva system.

YEAR	Customers Impacted by Salisbury Project	Potential Reduction to Impacted Customer Interruptions	Potential Reduction to Impacted Customer Minutes Interruptions	Potential SAIFI Improvement for Affected Feeders	Potential SAIDI Improvement for Affected Feeders
2014	22,214	86,139	9,648,796	0.39	43
2015	4,104	18,399	1,633,998	0.08	7
2016	4,745	7,363	1,269,370	0.03	6
2017	1,477	3,157	714,560	0.01	3
Transmission	5,059	8,004	1,600,800	0.04	7
TOTAL	**37,599**	**123,062**	**14,867,524**	**0.55**	**67**

Figure 16: Salisbury Plan Projected SAIFI and SAIDI Improvements[97]

d. North East Plan[98]

The North East Plan is an existing plan to increase reliability. It is an automatic sectionalization and restoration (ASR) project to address outages caused by 34kV feeders. The project will implement a distribution automation (DA) system to allow for remote control of the reclosers and advanced monitoring capabilities. Delmarva projects that all 78 planned reclosers will be installed and operational by August 31, 2014. Delmarva estimates that the potential impact on SAIDI will be one to two hours, but is unable to model and project the exact impacts due to no historical data existing. Delmarva predicts an improvement in SAIDI and SAIFI for the district by a minimum of 5% each.[99] The impacts will be seen and assessed after the summer storm season. Data will be collected and reported in the 2014 Annual Report.

e. Installing Additional Reclosers[100]

The Delmarva power distribution system, illustrated by Figure 15, consists of 184 feeders, with 117 of these feeders operating above 4kV and servicing 89% of Delmarva's customers. By the end of 2014 Delmarva will have installed 28 additional reclosers on feeders that currently have at least one inline closer and 13 reclosers on feeders that do not have one currently installed, bringing the total to 104 feeders with reclosers (89% of the system). Reclosers on the additional 15 feeders will not provide any additional reliability due to their radial nature. The projected reduction in SAIFI and SAIDI is combined with all T&D feeders, source lines, and substation incremental enhancements and is expected to be 15% from 2015-2026 for SAIFI and 23% from 2015-2026 for SAIDI.[101] Delmarva's assessment is that the installation of the additional 57 reclosers that are functional and 16 reclosers that will be functional by August 2014 (currently completing the communication system and testing), will have an immediate impact on SAIDI for the 2014 summer season.[102]

[97] RM-43 Delmarva MD Corrective Action Plan Discussion Document, March 2014
[98] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 8; Mail Log No: 153722
[99] John Helm DR Responses, June 17, 2014
[100] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 14; Mail Log No: 153722
[101] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 22; Mail Log No: 153722
[102] Delmarva Power Corrective Action Plan Follow-Up Questions, June 22, 2014

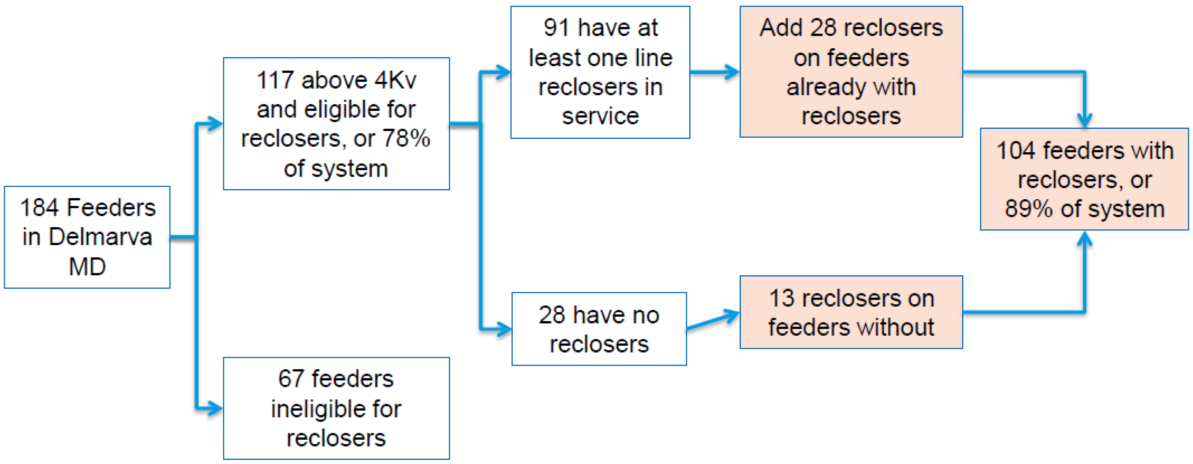

Figure 17: Additional Reclosures

f. Accelerated Vegetation Management[103]

Delmarva proposed to accelerate the tree trimming cycle from four to three years to improve the 17% of outages caused by vegetation in 2013. The report notes that 25% of outages were identified as weather or unknown, which Delmarva states may have been caused by tree related outages. The accelerated cycle will cover 1,909 miles of overhead lines which accounted for 14% of the tree-related SAIFI for 2013. Staff notes that the accelerated vegetation management cycle will reduce both the tree related and other category SAIFI and SAIDI numbers for 2014. Delmarva is confident that future reliability indices will improve as a result of these measures.

June 2012 - June 2013 Year 1: 26%	June 2013 - June 2014 Year 2: 27%	June 2014 - June 2015 Year 3: 25%	June 2015 - June 2016 Year 4: 22%

Figure 18: 4-Year Vegetation Management Timeline

June 2012 - June 2013 Year 1: 26%	June 2013 - June 2014 Accelerated Year 2: 41%	June 2014 - June 2015 Accelerated Year 3: 33%

Figure 19: 3-Year Accelerated Vegetation Management Timeline

g. Motor Operated Device (MOD) Installation[104]

The installation of MODs will enable isolation switching to occur remotely and identify where the fault occurred, increasing restoration time. This will be used in conjunction with distance-to-fault relaying, which is a system that can identify within a half mile in the system where the fault occurred by measuring the resistance in the power lines. Earlier identification of fault locations will allow crews to quickly arrive on scene to assess and begin repairs. This also allows for faults to be isolated and power restored to customers prior to where the fault occurred. The installation of the MODs is expected to lead to a drop in system outages with the intent of restoring an interruption within 5 minutes, which is not defined as an outage. The projected

[103] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 17; Mail Log No: 153722
[104] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 17; Mail Log No: 153722

SAIFI and SAIDI reduction on MOD system projects is 5% for SAIFI and 3% for SAIDI. Delmarva's assessment is that the MOD installation will have a gradual impact on SAIFI and SAIDI over the next ten years, and will improve overall reliability.

h. Underground Residential Distribution (URD) Cable Replacement[105]

Underground equipment failure accounted for just over 4% of the total failures for 2013. URD was installed in most of the Delmarva service areas in the 1970s. The current underground cables in the Delmarva service area are over 40 years old, exceeding the normal service life expectancy of 25-30 years. Due to the nature of the cables Delmarva is unable to provide service life extension by injecting silicon into the cables, a practice used in the Pepco service area. Over the past three years Delmarva has increased the number of underground cables, replaced faulty cables, and reduced the number of faults.[106]

	2009	2010	2011	2012	2013
Miles of cable	2727	2756	2966	3049	3163
Faults	361	410	414	308	267
URD Faults / Mile	0.132	0.149	0.14	0.101	0.084

Figure 20: 2009-2013 Delmarva Underground Cable Faults

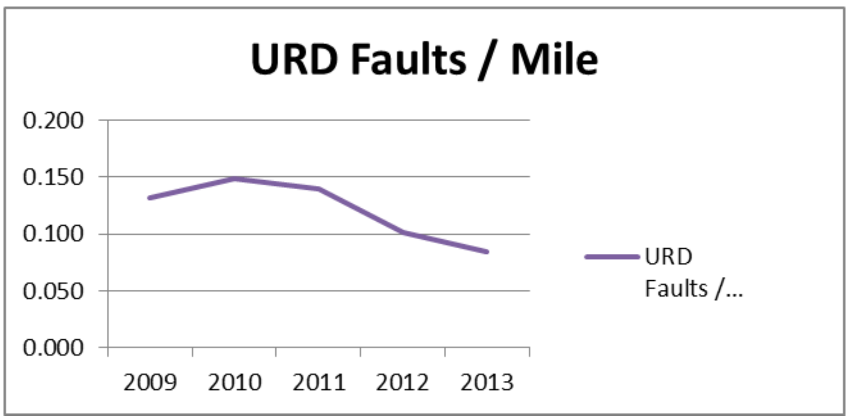

Figure 21: 2009-2013 Delmarva Underground Cable Fault Graph

Although the URD outages are a small portion of the overall SAIFI and SAIDI numbers, many of these customers experience multiple outages when the cables fail. Delmarva will increase the spending on the URD project to $4 million to accelerate replacement of aging and failing cables. The projected reduction in SAIFI and SAIDI is minimal. Staff noted that it is reasonable that these upgrades should be continued to avoid repeat outages to customers in the future.

i. Transmission and Distribution (T&D) Feeder Enhancements[107]

105 Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 19; Mail Log No: 153722
106 Delmarva Power Corrective Action Plan Follow-Up Questions, June 22, 2014
107 Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 20; Mail Log No: 153722

Currently Delmarva uses one of their 10 mobile transformers to restore power when one of the substation transformers fails. Currently two are in service while repairs to two substations are ongoing. The plan to improve reliability in the system is to install additional substations, automatic circuit reclosers, and increase the number of ties between feeders. Over the next seven years Delmarva will conduct several projects:

- Two new distribution substations and related land for future growth
- Fifteen new unit substations
- Thirteen miles of new transmission lines
- One new distribution feeder
- One mile of underwater feeder cable upgrades
- Two miles of overhead feeder reconductoring
- Seven distribution line voltage regulators
- 32 ACRs
- 23 new distribution feeder field switches.

The T&D feeder enhancements should improve the resiliency of the backbone of the Delmarva system. Delmarva stated that the T&D feeder enhancements will enable T&D systems to be back online faster and reduce multiple outages during a single event. SAIFI and SAIDI projected improvements are combined with source line, and substation incremental enhancements and is expected to be 15% from 2015-2026 for SAIFI and 23% from 2015-2026 for SAIDI.[108]

j. Streamlined Recovery Operations[109]

In 2014 Delmarva changed its standard operating procedure for assessing and repairing outages. It takes up to two hours to assemble a crew necessary to fix a 34kV feeder. These feeders typically service a large amount of customers having a large impact on SAIFI and SAIDI. In the past a first responder would be sent out to the scene to make an assessment, and make immediate safety-related corrections and, perform wire clearing, as appropriate. Once the initial assessment was made it took up to two hours for the proper crew to get on site to start making the corrections. In 2014, Delmarva began dispatching both a first responder and a crew for a feeder lockout. First responders historically are able to handle 80% of the outages, getting temporary service restored. The crew is able to immediately start repairs on the other 20% as well as conduct permanent repairs on the work initiated by the first responder. The change in strategy has minimal impacts on normal Delmarva operations. The additional crews, required during the day, will be pulled from low priority projects to assist with any emergency restoration. Delmarva stated that crews deployed after hours have no impact on manpower staffing.[110] Delmarva deploys its crews once it is determined it is safe for the crews to assess an outage situation. Staff notes that it is reasonable that the combined response team will reduce outage time and SAIDI.

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[108] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 20; Mail Log No: 153722
[109] Delmarva 2014 Annual Performance Report Corrective Action Plan; pg. 16; Mail Log No: 153722
[110] RM-43 Delmarva MD Corrective Action Plan Discussion Document, March 2014

6. Risks

There may be risks associated with the reliability of the Delmarva system while upgrades and repairs are being conducted. Delmarva has a predominantly radial system, with many of the feeders isolated and without redundancy in the systems. When repairs are being conducted on feeders, the system is set to maintenance mode. This provides a level of safety for the crews working on the systems. When a fault occurs under normal operating conditions, automatic circuit reclosers (ACR) activate, reducing outages that do not require maintenance crews to manually reset the faults. When the system is in maintenance mode, the ACRs are disabled to protect the workers. Faults experienced during maintenance activities will need to be addressed manually until the work is complete or the system is placed back into the normal mode of operation. As a result, customers could experience longer outage periods when faults occur during maintenance work.

Also, repairs on one feeder may have a direct impact on other feeders. If a feeder fails under normal operating conditions, a second feeder may be able to provide power to part of, or the entire downed feeder, depending on the location of the fault. When the redundant systems are taken off line, other systems on the network are more susceptible to outages. This is due to both a lack of a backup supply of power to the feeder and a higher voltage load on a feeder providing the backup support. Staff notes the necessary risk to improve the reliability of the Delmarva system.

7. Conclusions

Per COMAR 20.50.12.02D(1), Maryland utilities are required to meet reliability standards set for each year starting in 2012. Delmarva was unable to meet the 2013 year standards. Per COMAR 20.50.12.02E, Delmarva submitted a corrective action plan by April 1, 2014.

In the corrective action plan, Delmarva proposes to address reliability shortfalls by employing several reliability enhancing programs:

Regional Plans:
- Greater Salisbury Reliability Improvement (GSRI) project
- Installing ASRs and DA in the North East Plan

Entire Service Territory Plans:
- Installing additional reclosers
- Accelerating vegetation management from four to three years
- Install Motor Operated Devices (MOD)s to reduce outages
- Replace Underground Residential Distribution Cables (URD)s
- Install Transmission and Distribution (T&D) feeder enhancements
- Streamline recovery operations

While their enhancements should improve reliability, Delmarva stated that it may not meet its 2014 SAIDI and SAIFI targets in COMAR,[111] given a forecast of similar weather patterns and system performance to 2013. Delmarva stated that the system improvements and accelerated vegetation management will have an impact on the reliability of the system during the summer months, but will not know the extent of the benefits until the summer storm season is over.[112] However, the CAP has both long-term and short-term initiatives that Delmarva believes would allow the company to meet the COMAR targets in the future, if projected lineally. Delmarva stated that with the additional CAP programs and spending, separating the current service area into three zones to determine the category of outages, and the current ongoing reliability enhancement plans, they believe is heading in the right direction towards meeting COMAR standards for 2014 and 2015.

Prior to implementing the CAP, Delmarva predicted that the company would not meet the COMAR SAIFI standards for 2014 and 2015 and SAIDI standard for 2014.

Figure 22: Delmarva SAIFI and SAIDI Projections without the CAP[113]

With the implementation of the CAP, Delmarva is predicting with the revised estimate of SAIFI and SAIDI performance that the company will be able to meet the COMAR standards for 2014 and 2015.

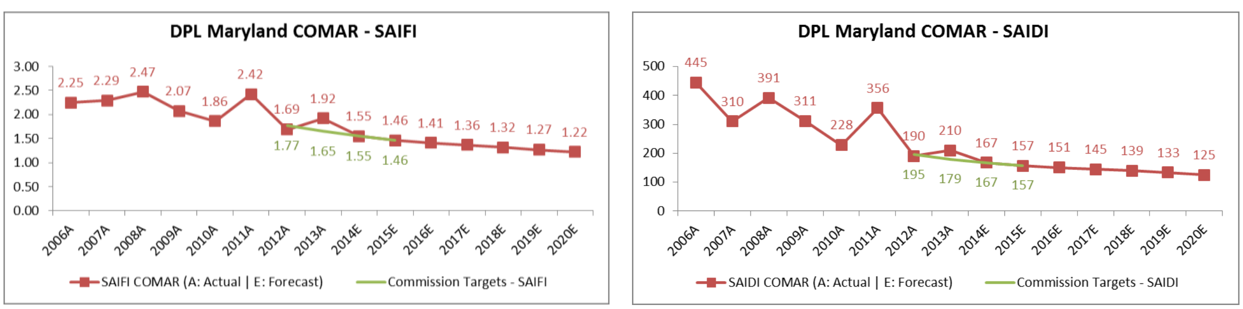

Figure 23: Revised Delmarva SAIFI and SAIDI Projections with the CAP[114]

Staff has reviewed the Delmarva CAP, which includes the Salisbury Plan, North East Plan, installing additional reclosers, accelerated vegetation management plan, motor operated device installation, underground residential distribution replacement and enhancement,

[111] John Helm DR Responses, June 17, 2014
[112] John Helm DR Responses, June 17, 2014
[113] RM-43 Delmarva MD Corrective Action Plan Discussion Document, March 2014
[114] RM-43 Delmarva MD Corrective Action Plan Discussion Document, March 2014

transmission and distribution feeder enhancements, and streamlined recovery operations plan. Staff believes the CAP is reasonable and that these programs should improve overall system reliability.

STATE OF NEW YORK

DEPARTMENT OF PUBLIC SERVICE

2008 ELECTRIC RELIABILITY PERFORMANCE REPORT

Electric Distribution Systems

Office of Electric, Gas, and Water

June 2009

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report presents Department of Public Service Staff's (Staff) assessment of electric reliability performance in New York State. As a means of monitoring the levels of service, utilities are required to submit detailed interruption data to the Public Service Commission (Commission). Staff relies on two primary metrics to measure reliability performance: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration).[1] By compiling the results of individual utilities, the average frequency and duration of interruptions can be reviewed to assess the overall reliability of electric service in New York State.

The statewide interruption frequency for 2008, excluding major storms, was considerably better than that recorded in 2007, where all companies except Orange and Rockland Utilities, Inc. (Orange and Rockland) showed improvement. The statewide duration in 2008 was slightly worse than in 2007. The year 2008 was the second-most affected by storms in five years and had 35 more storms than in 2007. Staff attributes some of the 2008 improvement in frequency to the high number of major storms (excludable events). Typical weather patterns result in less severe weather that lead to minor storms, which are included in the measures and thereby increase performance measures. Similar overall patterns exist for frequency and duration when analyzing the reliability data excluding Consolidated Edison Company of New York, Inc (Con Edison) performances.[2]

With respect to individual utilities' performances in 2008, Central Hudson Gas and Electric Corporation (Central Hudson), Niagara Mohawk Power Corporation d/b/a National Grid's (National Grid) and Rochester Gas and Electric Corporation (RG&E) performed at, or better than, their historic levels. Infrastructure improvements

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[1] SAIFI is the average number of times that a customer is interrupted during a year. CAIDI is the average interruption duration time for those customers that experience an interruption during the year.

[2] Con Edison's system includes many large, highly concentrated distribution networks. As a result, its interruption frequency is extremely low as compared to other utilities' interruption frequency and typically skews aggregated data measurements. Therefore, Staff examines statewide statistics both including and excluding Con Edison's data.

associated with National Grid's commitment to invest $1.47 billion over a five year period appears to positively affect its reliability performance.[3] Additionally, Central Hudson's revised tree trimming program seems to be helping in reducing tree caused interruptions. In 2008, Orange and Rockland was not as good as its 2007 performance for both frequency (slight change) and duration. Orange and Rockland attributes its change in duration to the installation of distribution automation; Staff is currently investigating the relationship between distribution automation and duration.

Con Edison performed satisfactorily on its radial system for both frequency and duration, and better than previous year with respect to its network frequency. The Company's performance in 2008 for network duration, however, was significantly worse than its historic performance. Based on a self-assessment conducted in response to Staff's report for 2007Con Edison identified strategies to improve its performance and is implementing several pilot programs this summer. It also formed a task force to continue to identify means to improve performances, especially on it network system. The programs involve predictive outage modeling, improvements to assist in crew allocation and deployment in order to improve both network and radial outage durations. In order to evaluate the effectiveness of Con Edison's actions, Staff is recommending that the Company file a report of the task force findings and results from its pilot programs by September 15, 2009. Staff is also recommending Con Edison perform a self-assessment to identify actions to improve its network duration performance and file the self-assessment with Staff by September 15, 2009.

Although NYSEG's overall reliability statistics improved compared with 2007, its performance with respect to tree related outages continues to decline. In last year's reliability report, Staff recommended NYSEG perform a self-assessment of its existing distribution tree trimming program based on its declining performance and reduced expenditures on tree trimming. The continued decline in performance with respect to tree related interruptions is not surprising because the Company's self-

[3] Case 06-M-0878, Joint Petition of National Grid PLC and KeySpan Corporation for Approval of Stock Acquisition and other Regulatory Authorizations.

assessment showed approximately half the circuit miles have been trimmed in 2007 and 2008 when compared to 2002 through 2005 levels. NYSEG's decision to reduce its tree trimming activities and expenditures despite declining performance in this area needs to be examined in detail and will be the focus of a newly established Case 09-E-0472.[4]

Electric utilities have reliability performance mechanisms (RPMs) in place as part of their rate plans. The reliability performance mechanisms are designed such that companies are subject to negative revenue adjustments for failing to meet electric reliability targets.[5] In 2008, Con Edison failed to achieve the duration target in its reliability performance mechanism for the network component of its distribution system and Orange and Rockland failed to achieve the duration target in its reliability performance mechanism for 2008. Combined, these failures resulted in about $5.4 million in negative revenue adjustments.

This report will be transmitted to an executive level operating officer of each electric utility with a letter from the Director of the Office of Electric, Gas, and Water. Con Edison is expected to comply with the recommendations and submit documentation by the dates indicated in the report.

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[4] Case 09-E-0472, In the Matter of Investigation of New York State Electric and Gas Corporation Expenditures Related to its Line Clearance Programs.

[5] NYSEG was the only utility not under an RPM in 2007 and 2008 because its mechanism expired in 2006. A new RPM is in place for the Company's 2009 performance.

INTRODUCTION

The following report is an overview of the electric reliability performance in New York State. As a means of monitoring the levels of service quality, the Commission's Rules and Regulations require utilities delivering electricity in New York State to collect and submit information to the Commission about electric service interruptions on a monthly basis.[6] Using the data, Staff calculates two primary performance metrics: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration). The information provided is also subdivided into 10 categories that reflect the nature of the cause of interruption (cause code).[7] By doing so, analysis of the cause code data can be used to highlight areas where increased capital investment or maintenance is needed. As an example, if a circuit were shown to be prone to lightning-caused interruptions, devices could be installed on that circuit to try to minimize the problem. In general, most of a utility's interruptions are a result of major storms, tree contacts, equipment failures, and accidents.[8] Staff maintains the interruption information in a database that dates back to 1989, which allows it to observe trends.

In addition, the Commission adopted standards addressing the reliability of electric service by establishing minimum acceptable levels for both the frequency and duration of service interruptions for each major electric utility's operating divisions. The utilities are required to submit a formal reliability report by March 31st of every year containing detailed assessments of performance, including outage trends in a utility's various geographic regions, reliability improvement projects, and analyses of worst-performing

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6 16 NYCRR Part 97, Notification of Interruption of Service requires utilities to keep detailed back-up data for six years.

7 16 NYCRR Part 97, Notification of Interruption of Service specifies and defines the following ten cause codes that reflect the nature of the interruptions: major storms, tree contacts, overloads, operating errors, equipment failures, accidents, prearranged interruptions, customers equipment, lightning, and unknown. There are an additional seven cause codes used exclusively for Con Edison's underground network system.

8 The accident cause codes cover events not typically in the utilities' control including vehicular accidents, sabotage, and animal contacts. Lightning is reported under a separate cause code.

feeders. There are no revenue adjustments for failure to meet a minimum level under the service standards; utilities are, however, required to include a corrective action plan as part of the annual report.[9] The service standards were last revised in 2004.

Interruption data is presented in two ways in this report – with major storms excluded and with major storms included. A major storm is defined by the Commission's regulations as any storm which causes service interruptions of at least 10 percent of customers in an operating area, and/or interruptions with duration of 24 hours or more.[10] Major storm interruptions are excluded from the data when calculating performance levels for service standards and reliability performance mechanisms. The purpose of this policy is to achieve a balance between service interruptions under a utility's control, such as equipment failures and line maintenance, and those over which a utility's control is more limited, such as severe ice storm or a heavy wet snowstorm. Performance inclusive of major storms shows the actual customer experience during a year.

[9] Revenue adjustments for inferior performances are implemented through individual Reliability Performance Mechanisms established in rate orders.

[10] Major storms do not include heat-related service interruptions.

2008 RELIABILITY PERFORMANCE

The following sections provide a summary discussion of the reliability performance statewide and for each of the major utilities. Each year, Staff also prepares an Interruption Report summarizing the monthly interruption data submitted by the utilities. The 2008 Interruption Report contains detailed interruption data for each utility and statewide statistics for the past five years. The Interruption Report for 2008 is attached as an Appendix. Individual company discussions identify issues or actions within each company that influenced performance levels for 2008 and indicates company-specific trends where applicable.

In addition, performances are compared to utilities' reliability performance mechanisms (RPMs) placed into effect as part of their rate orders. The reliability performance mechanisms are designed such that companies are subjected to negative revenue adjustments for failing to meet electric reliability targets. The targets are based on the indices used by the Commission's electric service standards.

Con Edison and Orange and Rockland each failed to achieve a target in their reliability performance mechanisms for 2008. Con Edison failed to achieve the duration target for its network system, resulting in a potential negative rate adjustment of \$5 million.[11] Orange and Rockland failed to achieve its duration target, which results in a negative revenue adjustment of approximately \$400,000.

STATEWIDE

For many years, Staff has been combining the individual utility performances into overall statewide statistics. By doing so, we evaluate the level of reliability provided and identify statewide trends. Because Con Edison's system includes many large, highly concentrated distribution networks, its interruption frequency is

[11] This rate adjustment is a preliminary assessment based on Con Edison's March 31, 2009 filing that detailed the Company's compliance with its RPM. Con Edison's rate adjustment has not been presented to the Commission for final action.

extremely low as compared with other utilities. This, combined with the fact that it serves the largest number of customers in the state, typically results in a skewing of the performance measures. As a result, we examine and present aggregated data including and excluding Con Edison's data.

Statewide, the frequency of interruptions when excluding major storms was 0.56 in 2008, which is considerably better than the five-year average of 0.63 and better than 2007's performance level of 0.65. All companies, except Orange and Rockland, had fewer customers affected by power outages, again when major storms are excluded, as shown in Figure 1. This improvement is amplified when Con Edison is excluded with the frequency performance for 2008 at 0.88, which is considerably better than the five-year average of 0.98.

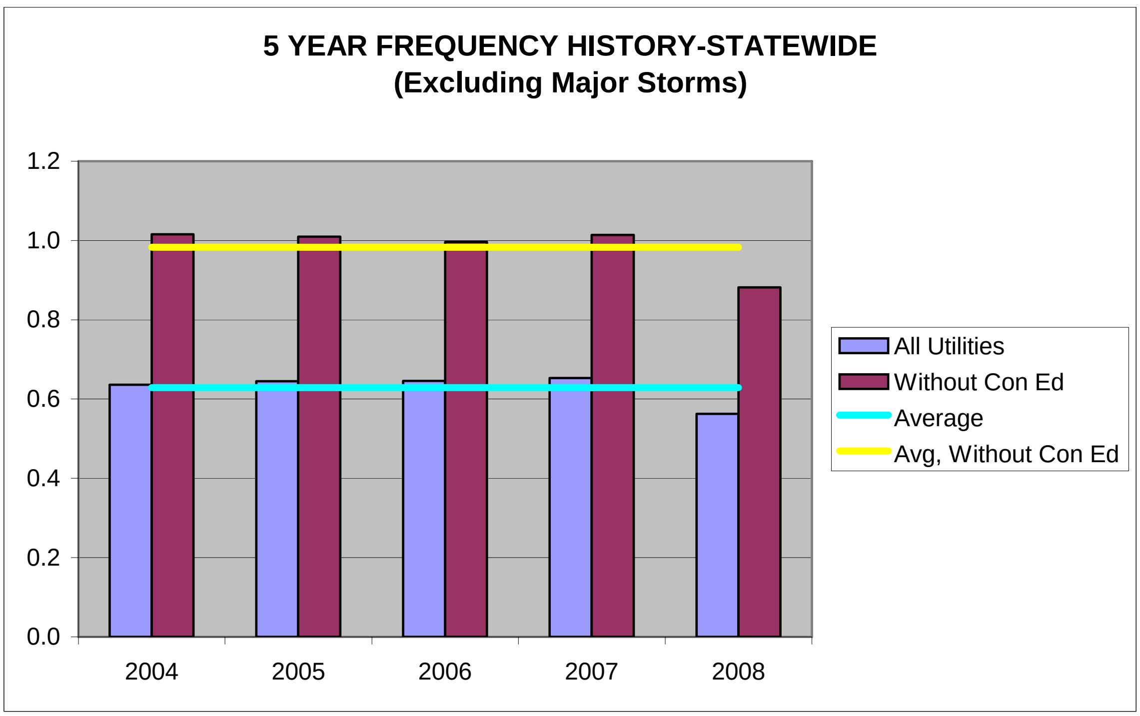

Figure 1: Statewide Frequency Performance

Figure 2 shows the statewide duration index for 2008, excluding major storms. The overall statewide duration index continues to be at a more normal level of 1.93 hours, as compared with 1.95 hours and 1.89 hours in 2005 and 2007, respectively. Con Edison's Long Island City network outages greatly affected the statewide duration in 2006. The statewide duration index, excluding Con Edison, was 1.89 hours in 2008, which is slightly better than 2007 and equal to the five-year average.

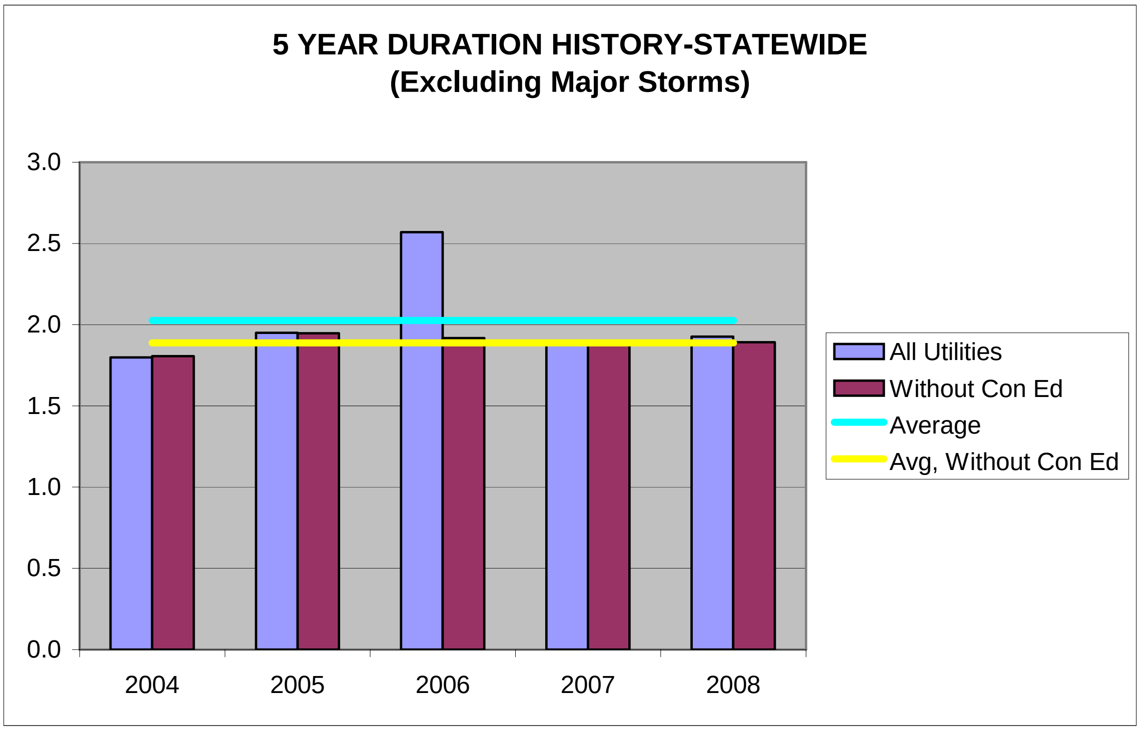

Figure 2: Statewide Duration Performance

In 2008, the weather during the winter and summer months was relatively severe, while there was a moderate amount of adverse weather activities in the spring. This pattern was apparent as numerous winter storms occurred during the early part of the year, culminating in a severe ice storm which significantly affected the Capital Region and Mid-Hudson in December 2008. Several fronts that traversed the State in June and July brought severe storms and/or damaging winds. In general, wind speeds and gusts were higher in 2008 than in prior years; National Grid reported the number of days with winds exceeding 30 miles per hour was 20% higher than the annual norm, and nearly twice the norm in two of its service areas. As a result, the total number of major storms experienced by utilities increased by 35 storms over last year (Table 1, below). National Grid and NYSEG each experienced more than 20 major storms in 2008.

Table 1: Major Storms in 2008

Company	2007	2008	Change in Major Storms
Con Edison	4	4	0
National Grid	10	24	+14
NYSEG	17	25	+8
RG&E	10	12	+2
Central Hudson	5	9	+4
Orange and Rockland	1	8	+7
Total	**47**	**82**	**+35**

The year 2008 was the second-worst year for severe weather effects in the last five years (Figure 3, below).[12] When including major storms, the 2008 statewide frequency and duration performances were 0.93 and 4.50, respectively. When excluding Con Edison, the 2008 statewide frequency and duration performances including major storms were 1.51 and 4.62, respectively. All four of these measures were worse than the five-year averages. Major storms in 2008 accounted for 71% of the overall customer-hours of interruptions and 39% of the overall number of customers affected.

[12] The Buffalo area experienced a massive ice storm in 2006.

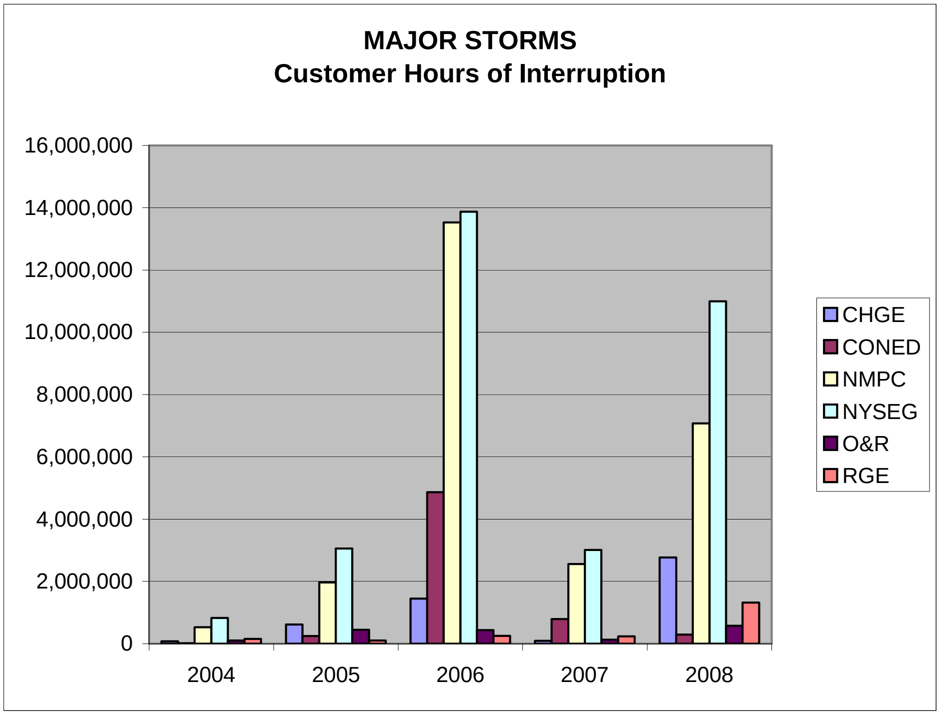

Figure 3: Major Storm Customer Hours

New York State investor-owned electric utilities must submit a report to the Commission addressing all facets of their restoration effort if the restoration period associated with significant storms lasts more than three days.[13] Overall, the utilities responded well to the major storms in 2008, restoring most customers affected within 24-72 hours from the end of a storm. In 2008, there were four reports submitted on major storms as listed in Table 2, below. These storms, especially the December ice storm, as well as the numerous other major storms mentioned earlier, had a greater than historic effect on the total number of hours that customers were without service.

Table 2: Storm reports filed in 2008

Date	Company	Areas Affected	Reason for Interruptions
October	NYSEG	Oneonta, Liberty	Wind and Snow Storm
December	Central Hudson, NYSEG, GRID	Capital District & Troy area	Ice Storm

<u>CON EDISON</u>

[13] 16 NYCRR Part 97, Part 105.4

Table 3: Con Edison's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Network Systems						
Frequency (SAIFI)	0.005	0.006	**0.021**	**0.075**	0.017	0.025
Duration (CAIDI)	3.64	**4.44**	**60.81**	1.79	**6.28**	15.39
Radial System						
Frequency (SAIFI)	0.39	0.51	**0.54**	0.38	0.42	0.45
Duration (CAIDI)	1.64	**1.91**	**2.66**	**2.07**	1.83	2.02

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Con Edison serves approximately 3.2 million customers in New York City and Westchester County. Electricity is supplied to 2.4 million customers using network systems. The remaining 900,000 customers are supplied by radial systems.

In 2008, the network frequency performances were significantly lower than its historical performances in 2006 and 2007. The Company radial frequency was slightly higher than in 2007 but lower than the five year average. In 2008, the Con Edison spent $562 million to improve the reliability on its electric system including $352 million on relief programs, $122 million on reliability programs, and $88 million on maintenance programs. In 2007 and 2008, the Company expanded its tree trimming budget and has seen a reduction in the number of interruption caused by trees as compared with previous years.

To minimize the frequency of customer outages, Con Edison's networks are designed with redundant supply paths. Individual service lines to customer premises, however, lack any supplemental supply. Given these design criteria and underground settings, the majority of interruptions (85%) are associated with the service portion of the network system, as shown in Figure 4. Equipment failures are the second highest (7%) cause for interruptions in 2008. Failures on parts of the network grid itself (secondary feeders or mains) are the third highest cause for interruptions at 6%.

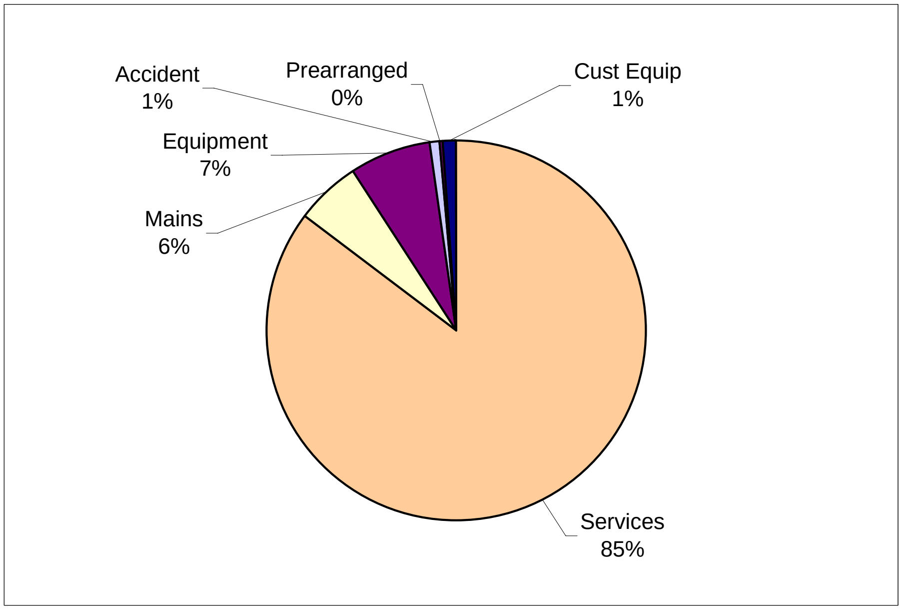

Figure 4: Con Edison's 2008 Network Interruptions by Cause

On its radial system, Con Edison's performance in 2008 was better than the five year average for both frequency and duration. Equipment failures are responsible for 71% of the interruptions on the radial system, followed by trees and accidents at 14% and 8%, respectively, as shown in Figure 5.

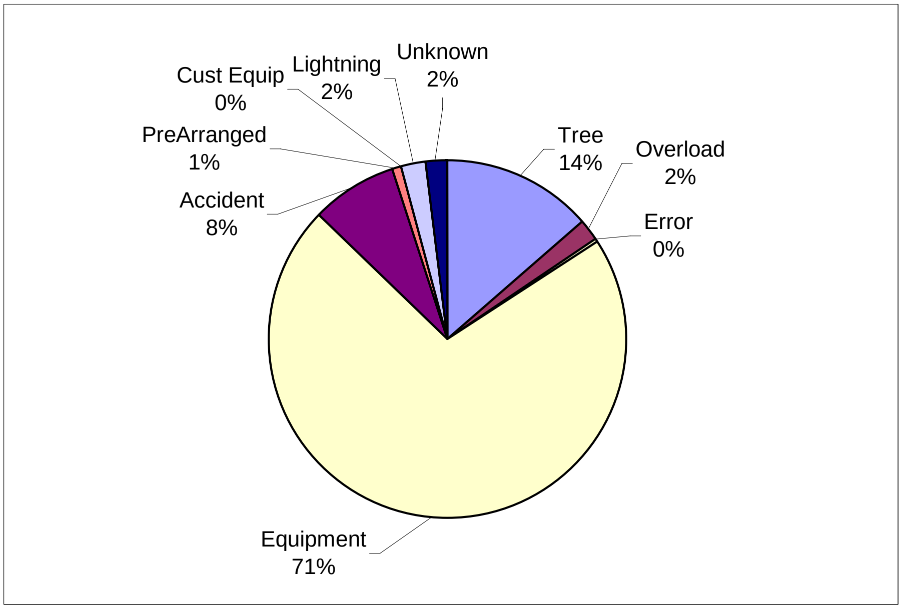

Figure 5: Con Edison's 2008 Radial Interruptions by Cause

Con Edison had one of its worst years for network duration in 2008. In recent years, Con Edison has missed its duration targets for both network and non-network.[14] As part of last year's report, Staff recommended that the Company conduct a detailed self assessment into why its duration performance associated with its radial systems had deteriorated. Con Edison responded by noting that nearly 40% of it longer duration outages are associated with weather events that typically occur in the late afternoon and early evening. As a result, the Company has initiated a study to correlate weather patterns to high duration events. Based on the results of the study, the Company expects to be able to better predict events and ensure sufficient staffing levels are on duty. For 2009, the Con Edison has established a program to experiment with length of shifts (8-hr vs. 12-hr) to determine which provides better coverage, and will be implementing an automated call system to improve crew response times. The Company is also considering dedicated crews to respond to specific outages and using electricians as first responders. In 2008, Con Edison established a new workplace in Westchester County to reduce travel time in that area.

Finally, Con Edison has recently assembled a task force to identify strategies to help improve its network and radial duration performances. Staff will be meeting with the task force in June to review new proposed actions. We are encouraged by the pilot programs and would like to see successful programs applied on a company-wide basis. Therefore, Staff recommends that Con Edison file a report by September 15, 2009 detailing information learned by the task force and during pilot programs. The report should include information on how Con Edison will implement successful programs on a permanent basis. Additionally, Staff recommends that Con Edison perform a self-assessment to identify strategies to improve its network performance and identify corrective actions that are unique to its network system. The self assessment should also be filed by September 15, 2009.

[14] In 2007, a short duration incident affecting a large number of customers resulted in a network duration

NATIONAL GRID

Table 4: National Grid's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	**1.02**	**0.98**	**1.01**	**0.96**	0.75	0.94
Duration (CAIDI)	2.04	**2.32**	2.05	2.01	1.96	2.08

Note: Data presented in red represents a failure to meet the RPM target for a given year.

National Grid serves approximately 1.59 million customers across upstate New York. The Company's territories include metropolitan areas such as the cities of Buffalo, Albany, and Syracuse. National Grid also serves many rural areas in northern New York and the Adirondacks.

Overall, National Grid improved in 2008 and achieved all of its reliability targets. Previously, National Grid missed the frequency target level of 0.93 for each year from 2004 until 2007. Results this year, however, significantly improved and the Company met the target with an end result of 0.75. Duration results were better in 2008 as well; the Company has performed better than the duration target for three consecutive years now. In general, the utility had improved service on a region by region basis.

The overall reliability improvements are partially due to the installation of 432 reclosers, of which most were identified and installed through the Engineering Reliability Review (ERR) process since 2006. The Company installed 234 out of the 432 reclosers during the calendar year of 2008. Results for both the frequency and duration categories were unusually low, due in part to the numerous interruptions resulting from major storms in 2008. Although the Company exhibited a significant reliability improvement through various efforts, it is not likely that results of this magnitude will continue in the future. Staff will encourage the utility to continue with efforts in order to sustain a reasonable level of reliability.

As a result of past reliability results, the Commission placed additional emphasis on National Grid's reliability performance in association with its acquisition of Keyspan, which provides electric distribution services to the Long Island Power

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that was well below historic performances.

Authority. Because of this acquisition, the Commission created an Order requiring the utility to file details of its capital expenditure spending. Staff actively reviews listed projects within this filing. Additionally, Staff provides input and recommendations on the justification and progress of the projects.

As seen in Figure 6, equipment failures are the leading cause of interruptions for National Grid, however, this has been improving over the past five years. The five year average number of interruptions in this category is approximately 4,000; yet this year, the utility reported around 3,500 such occurrences. Furthermore, results showed that the utility reduced the number of customers affected and customer hours for this cause code by almost one half compared to 2007. As evident in the equipment failure cause code results from 2008, the above noted programs appear to be useful methods for improving National Grid's reliability performance in association with equipment failures.

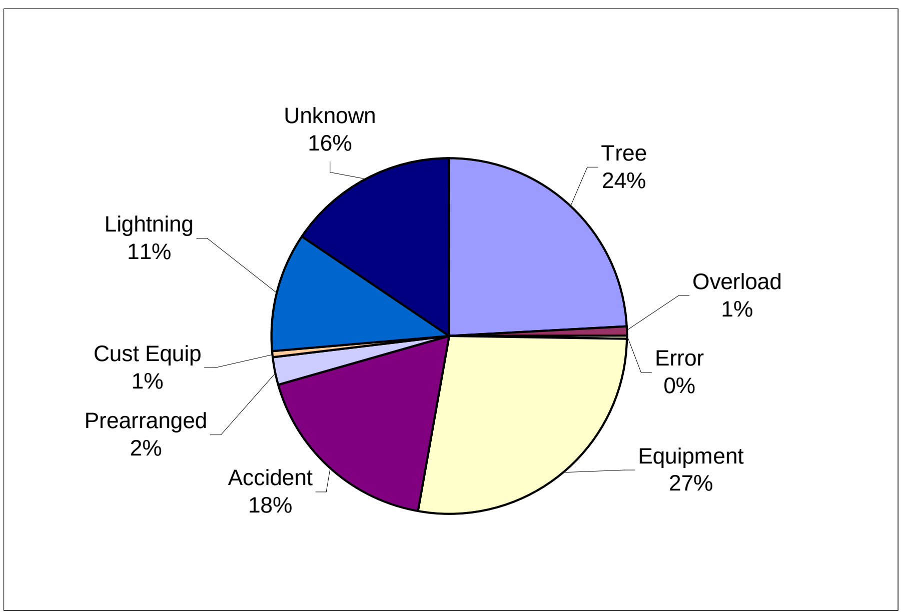


Figure 6: National Grid's 2008 Interruptions by Cause

National Grid made a commitment to spend $1.47 billion on capital improvements to its transmission and distribution system over a five year period from 2007 until 2011. The five-year investment plan contains proposed projects and strategies to upgrade and replace components on its electric system. In particular, the utility developed a Reliability Enhancement Plan (REP) to improve its performance by focused maintenance work on poor performing circuits and replacement of aging assets. This plan specifically includes a targeted program to enhance the performance of feeders, asset replacement, an improved inspection and maintenance program, and a tree trimming program. The REP also provides for the installation of sectionalizing equipment and animal guards that will help to minimize the number of customers affected when an outage occurs, or to avoid interruptions in general. In conjunction with other programs, National Grid has replaced 665 transformers which were deteriorated or overloaded. As noted above, the Company identified and installed 432 reclosers since 2006. Many of the deteriorated assets addressed by the REP were identified as a result of the utility's inspection program.

The second highest contributor to National Grid's interruption performance for 2008 was tree-related outages; however, the Company showed signs of improvement as compared with last year's results in this area as well. Although the number of interruptions in 2008 for this cause code was fairly close to results of 2007, the number of customers affected and customer hours were reduced from last year by approximately 15%. Prior performance had prompted the utility to shorten its trimming cycle from six years to a more traditional five year period in urban areas. National Grid has also expanded its program to remove "danger" trees outside of the standard clearance zone. With these amplified activities, the utility has gradually increased its spending on distribution tree trimming in recent years. National Grid spent approximately $33 million for distribution trimming during fiscal year 2008. The drop in tree-related interruptions in 2008 was mainly due to a reduced number of interruptions related to fallen trees. Outages caused by broken limbs and tree growth actually increased as compared with last years results. Furthermore, the majority of improvements within this cause code occurred in the Syracuse and Buffalo areas. Tree-related frequency results were actually up in five of National Grid's eight operating divisions.

The number of accident caused interruptions in 2008 as compared with 2007decreased by approximately 20% and yielded a reduction of approximate 25% for both customers affected and customer duration. The number of unknown causes of interruptions in 2008 was fairly equivalent to those of 2007, however, the number of customer affected and customer duration were higher than the 2007 results. The number of 2008 lightning caused interruptions was also close to those of 2007, but the customer affected and customer duration decreased by approximately one half compared to the previous results.

National Grid's capital investment program is having a positive affect. National Grid should continue to pursue infrastructure investments that relate reliability. As part of Case 06-M-0878, Staff will continue to closely monitor the Company's capital improvements.

NEW YORK STATE ELECTRIC AND GAS

Table 5: NYSEG's Historic Performance Excluding Major Storms

Metric	**2004**	**2005**	**2006**	**2007**	**2008**	**5-Year Average**
Frequency (SAIFI)	1.13	1.12	1.12	1.20	1.11	1.13
Duration (CAIDI)	1.96	1.96	2.01	2.22	2.08	2.05

Approximately 840,000 customers are served by NYSEG. The Company is primarily located in the Binghamton and Finger Lakes regions, but does have localized service regions, including areas near Plattsburgh, Brewster, Mechanicville, and Lancaster.

The year 2008 showed improvement over last year's poor reliability performance by the Company. NYSEG's 2008 frequency performance of 1.11 was better than both the previous year's performance and its five year average performance level. The 2008 duration performance of 2.08 was also better than both the previous year's performance, however, still slightly higher than the five year average. The two major contributors to NYSEG's interruptions were tree contacts (41%) and equipment failures (21%), as shown in Figure 7.

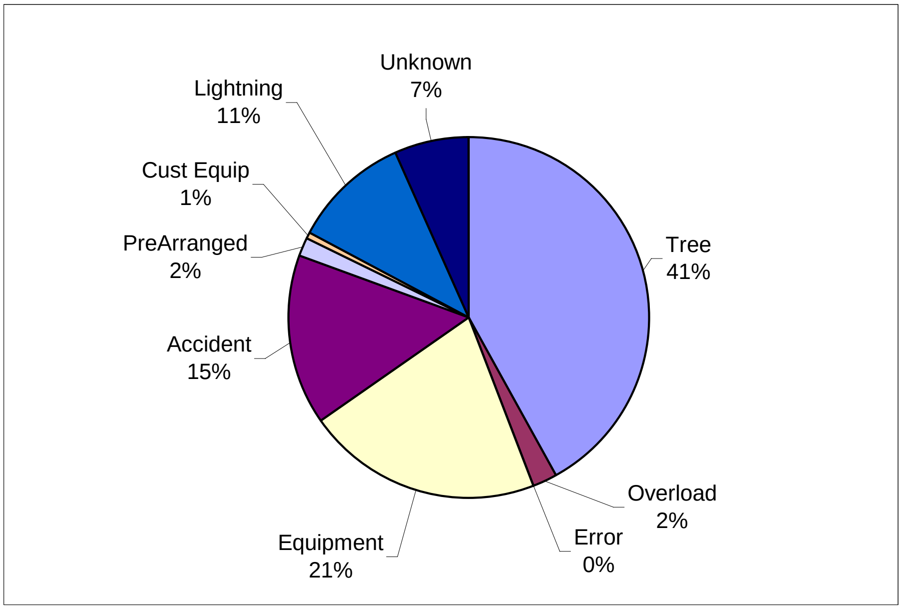


Figure 7: NYSEG's 2008 Interruptions by Cause

Tree related interruptions have consistently had the greatest impact on NYSEG's interruption performance. As shown in Table 6 below, NYSEG's performance has continuously declined with respect to tree caused interruptions. In last year's reliability report, Staff recommended that NYSEG perform a self-assessment of its existing distribution tree trimming program based on its declining performance and reduced expenditures on tree trimming. On January 7, 2009, NYSEG responded to Staff's recommendation stating that increased costs for tree trimming efforts per mile have reduced the number of overall miles completed each year. The report showed

Table 6: NYSEG's Reliability Performance with respect to Tree Caused Interruptions

Year	Customers Affected by Tree Interruptions	Customer Hours for Tree Interruptions	Number of Interruptions due to Trees
2004	205,245	477,623	3,002
2005	288,347	666,940	4,090
2006	297,893	735,250	3,779
2007	333,469	865,694	3,997
2008	349,065	886,543	4,215

approximately half the circuit miles have been trimmed in 2007 and 2008 when compared to 2002 through 2005 levels. The number of customers affected by tree events has increased by 32% compared to the average for the years 2002 through 2005.

In Case 05-E-1222, NYSEG was allowed $17.7 million in rates for tree trimming on an annual basis effective in 2007. The Company indicated, however, that it has spent less in tree trimming on its distribution system than what was allowed in rates.

NYSEG's existing tree trimming program requires cycle trimming on all of the 35 kV circuits, but only the three phase sections of its 12 kV and 5 kV circuits, and single phase sections of these circuits on an ad hoc basis. The Company recommended in its self-assessment that in order to reduce tree caused interruptions, the existing tree trimming program should be expanded to perform cycle trimming on all single phase portions of its circuits. Given that NYSEG has not completed its planned trimming in recent years, Staff has concerns about NYSEG's tree trimming program.

Even though both frequency and duration improved in 2008 as compared with 2007, Staff continues to be concerned with NYSEG's overall approach to managing its tree caused interruptions. NYSEG's decision to reduce its tree trimming activities despite declining performance in this area needs to be examined. As a result, Staff will be seeking detailed information and explanations of trimming activities performed, spending variances, and quality assurance as part of the newly established Case 09-E-0472.

Equipment failures are the second highest cause of interruptions. In the Iberdrola merger (Case 07-M-0906), NYSEG was required to submit a condition assessment report. This report was received by Staff on December 8, 2008, and provided information on all of the electrical equipment and assets within its service territory and identified how age is a continued concern on the entire electrical system. The report concluded that NYSEG's electrical system is in "sound" condition. Over the past five years, however, NYSEG's reliability data show a steady increase in the number of interruptions caused by the failure or poor performance of the system equipment.

To proactively address the Company's aging infrastructure and equipment failure issues, NYSEG started a Transmission and Distribution Infrastructure Replacement Program (TDIRP). This program has been in place since 2005 and is the principal funding source for projects that address overall system condition issues. Overall Staff views this program as beneficial; however, funding for the program has been on the decline, and Staff is concerned whether NYSEG is committing appropriate funding resources to making the necessary infrastructure investments through TDIRP.

Another concern noted in Staff's reliability report last year was a declining trend in field staffing/personnel levels. As required, NYSEG provided its self-assessment that stated cost pressures have diminished its ability to increase or even maintain the field personnel levels once held in previous years. The Company goes on to say that while it continues to maintain sufficient numbers of workers to achieve the established reliability performance targets, increasing the number of qualified field personnel by approximately 10% may support improved duration numbers. As shown in Table 7 below, NYSEG has increased in total field personnel number for 2008. The increases, however, are for apprentice workers and not the qualified workers the Company is seeking.[15]

Table 7: NYSEG's Field Personnel Information

	2004	2005	2006	2007	2008
Total Number of Field Personnel	646	651	619	608	662
Percent Change from Previous Year	----	+0.8%	-4.9%	-1.8%	+8.2%

ROCHESTER GAS AND ELECTRIC

Table 8: RG&E's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	0.86	0.79	0.79	0.83	0.78	0.81
Duration (CAIDI)	1.84	1.87	1.78	1.73	1.85	1.81

[15] It takes approximately 3 years for an apprentice to be considered a qualified worker.

RG&E serves approximately 360,000 customers. Although the Company is comprised of four service areas, its Rochester division accounts for approximately 80% of its customer base. As a result, its overall reliability statistics mirror that of the Rochester division.

With regard to service reliability, RG&E continues to be one of the better performing utilities within the state. The Company has not failed its RPM targets of 0.90 for frequency and 1.90 for duration as established in its rate orders. As shown in Table 8, above, RG&E's performance for frequency and duration continue to be fairly consistent with its five year average. In 2008, the Company's frequency performance of 0.78 is the lowest since 2004. RG&E's duration performance of 1.85 in 2008 was slightly higher than both the previous year's performance. Figure 8 shows that the two major contributors to interruptions continue to be equipment failures (31%) and tree contacts (21%). The levels are slightly higher than the five year averages of both equipment failures and tree contacts.

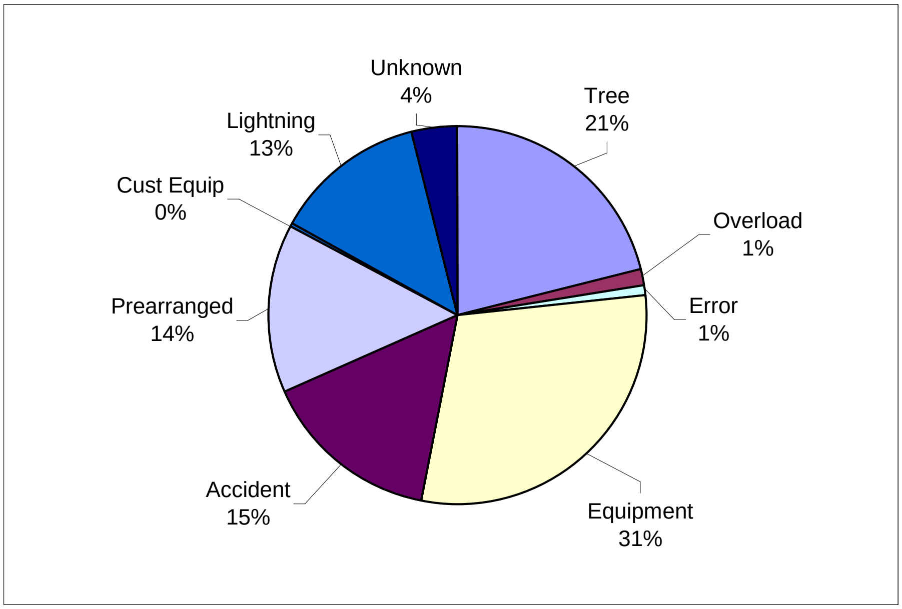


Figure 8: RG&E's 2008 Interruptions by Cause

Like NYSEG, RG&E was required to submit a conditions assessment report as part of the Iberdrola merger agreement. This report was received by Staff on December 8, 2008, and concluded that RGE's electrical system is in "sound" condition. Equipment failures, however, continues to be RG&E's highest contributor to its interruption performance. In 2007, RG&E implemented its own Transmission and Distribution Infrastructure Replacement Program (TDIRP), similar to that used by NYSEG, to address the Company's aging infrastructure and equipment failure issues. Staff encourages RG&E to make necessary infrastructure investments through TDIRP to ensure safe and reliable service to its customers.

CENTRAL HUDSON GAS AND ELECTRIC

Table 9: Central Hudson's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	**1.36**	1.44	**1.59**	1.42	1.27	1.42
Duration (CAIDI)	**2.35**	2.70	**2.58**	2.43	2.47	2.51

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Central Hudson serves approximately 298,000 customers in the Mid-Hudson Valley region. The Company's territory is mainly suburban and rural. Central Hudson does serve some urban regions, such as the cities of Poughkeepsie and Newburgh. Central Hudson's RPM targets were reestablished at 1.45 for frequency and 2.50 for duration in its most recent rate order, effective in 2007.[16]

Central Hudson' frequency performance of 1.27 in 2008 was its best in five years, considerably better than its five-year average (Table 9, above). The 2008 duration performance of 2.47 was better than the five-year average, but still close to the RPM target of 2.50, however. Figure 9 shows that 37% of customer interruptions are due to tree related issues, followed by accidents at 22%.

[16] As part of the joint agreement adopted in the last rate order, Central Hudson was not assessed revenue adjustments for 2005 performances.

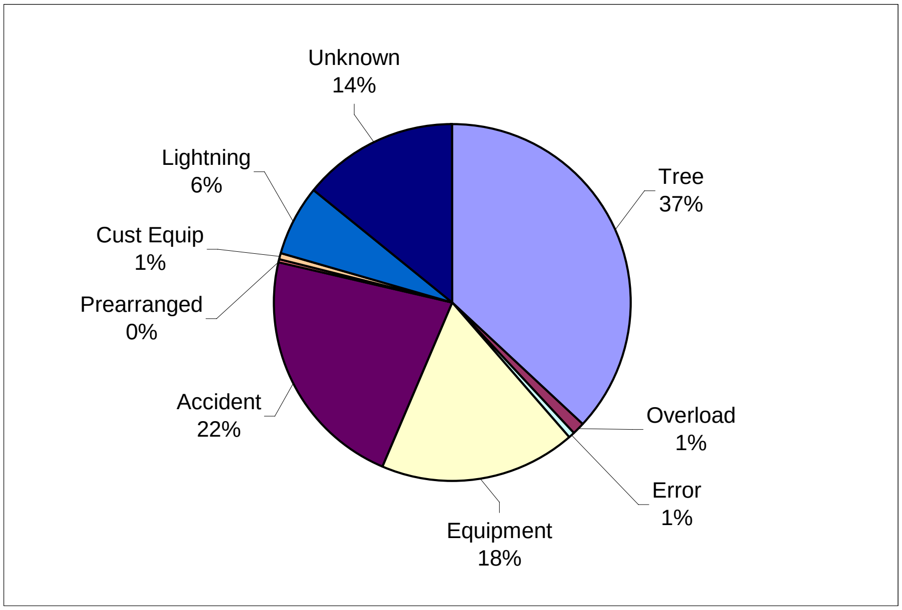


Figure 9: Central Hudson's 2008 Interruptions by Cause

Central Hudson has had a reduction in equipment failures resulting in customer outages since 2005 (see Table 10 below); in 2008, equipment failures were responsible for only 18% of the interruptions.

Table 10: Customers Affected by Service Interruptions

Year	Tree	Equipment
2004	136,933	89,177
2005	155,504	109,190
2006	172,850	104,263
2007	156,053	99,290
2008	137,170	86,115

In last year's report Staff directed that Central Hudson perform a self assessment of its line clearance program. Staff reviewed Central Hudson's report and found it satisfactory. It does appear that Central Hudson has been addressing tree caused interruptions in a logical way, expanding lessons learned in its enhanced clearance program to the rest of the system and positive results might have begun to be seen (see Table 10, above). In its current rate case proceeding, based on the recommendation of its consultant and actual experience, Central Hudson proposed (and Staff supported) expanding its enhanced tree trimming program of critical three-phase lines as well as the implementation of the modified enhanced program for the rest of the system, both single and multi-phase. A possible encouraging trend in reduced tree outages may also be seen in Table 9 (above) and will be something we will monitor.

Central Hudson's annual reliability report indicates one driver of outage duration is overloaded distribution transformers. Several districts noted they are replacing transformers before they fail using a combination of Transformer Load Management database and field checks with line foremen. This approach appears to have merit especially as preparation for warmer summers, such as was experienced in 2008.

ORANGE AND ROCKLAND

Table 11: O&R's Historic Performances Excluding Major Storms

Metric	2004	2005	2006	2007	2008	5-Year Average
Frequency (SAIFI)	1.30	1.36	1.23	1.03	1.19	1.22
Duration (CAIDI)	**1.61**	**1.71**	1.51	1.60	**1.83**	1.65

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Orange and Rockland is the smallest of the major investor-owned electric utilities. It serves approximately 217,000 customers in three New York counties along the New Jersey and Pennsylvania border. In 2008, the Company met its reliability performance mechanism target for frequency. The 2008 frequency performance, although higher than 2007, was still below the Company's five year average performance level. Orange and Rockland, however, failed its reliability performance mechanism for duration in 2008 with a performance of 1.83.

As shown in Figure 10 (below), equipment failures (34%) and trees (31%) caused the majority of interruptions in 2008. Orange and Rockland is addressing reliability issues due to equipment failures through capital improvement programs such as the Distribution Automation Program, the Underground Cable Maintenance and

Rebuild Program, and a number of service reliability improvement projects directed by the circuit priority-rating methodology.

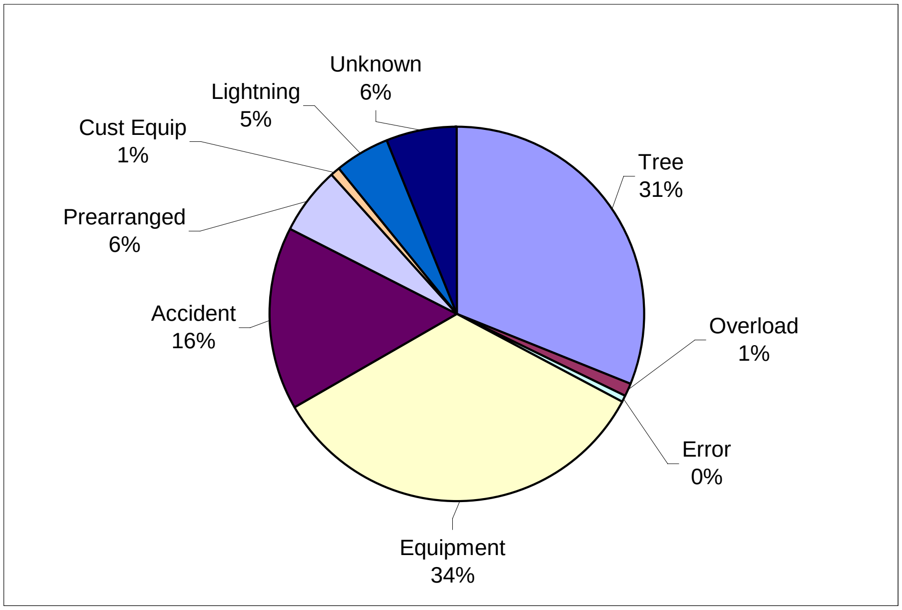


Figure 10: Orange and Rockland's 2008 Interruptions by Cause

The Company is addressing the tree concerns through increased efforts on its trimming programs. In addition to the four-year cycle based tree trimming program, the Company has continued to identify additional efforts to address key areas with recurring outages such as a recurring outage identification program and a "cycle buster" trimming program. These programs should help reduce the impact of tree contacts on the Company's electrical system through the coming years.

Orange and Rockland's duration performance in 2008 was slightly above its RPM target of 1.70. The Company had performed better than this target in both 2006 and 2007. Since its last rate filing (Case 07-0949), Orange and Rockland has been expressing concern that distribution automation equipment is negatively impacting its duration performance and recently made a presentation to Staff on the issue. As a result, Staff is working closely with the Company to determine the identifiable affects distribution automation has on the duration measure.

Staff believes that Orange and Rockland is appropriately installing more distribution automation equipment, increasing tree trimming efforts, and performing needed capital improvement projects to improve overall reliability. Equipment Failures and Tree Contacts continue to be the major causes of interruptions throughout the past five-years and this performance trend remains consistent throughout each operating division as well. Orange and Rockland's has been striving to control tree and equipment related interruptions for several years now. Even though immediate drastic changes are not anticipated due to the nature of the causes, small and steady improvements are expected in the years to come with the finalization of additional reliability projects.

RECOMMENDATIONS

The following is a summary of Staff recommendations based on our analysis of reliability performances in 2008. Additionally, NYSEG will have to respond to actions taken as part of Case 04-E-0472.

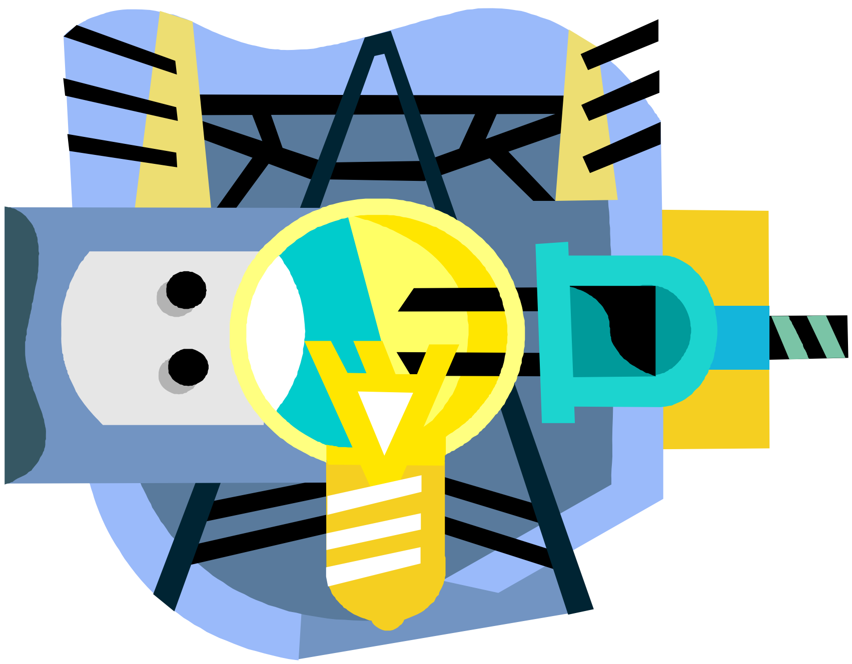
1. Con Edison should file a report no later than September 15, 2009 detailing information learned during pilot programs related to improving its duration performance and explaining how successful programs from the pilot programs would be implemented on a permanent basis.

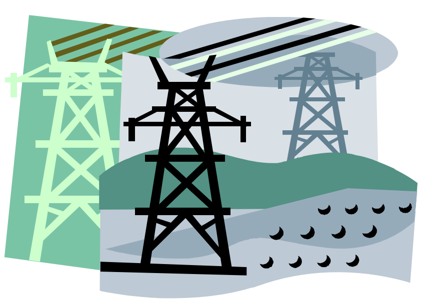
2. Con Edison should perform a self-assessment to identify strategies to improve its network duration performance and identify corrective actions that are unique to its network system. The self assessment should be filed no later than September 15, 2009.

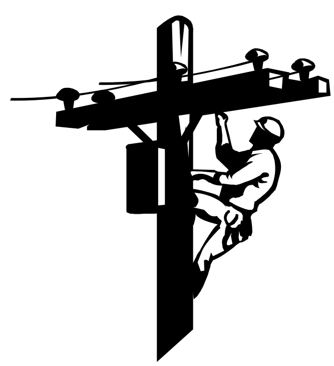
APPENDIX

2008 INTERRUPTON REPORT

The 2008 Interruption Report







Office of Electricity Gas and Water

June, 2009

ATTACHMENT
Definitions and Explanations of Terms Used in the 2008
Statewide Electric Service Interruption Report

Interruption is the loss of service for five minutes or more.

Customer hours is the time a customer is without electric service.

Customers affected is the number of customers without electric service.

Customers served is the number of customers as of the last day of the **current year.** For example, for the calendar year of **2008**, customers served is the number of customers as of 12/31/2008. For indices using customers served, the **previous** year is used.

Frequency (**SAIFI)** measures the average number of interruptions experienced by customers served by the utility. It is the customers affected divided by the customers served at the end of the **previous** year, i.e., 12/31/2007.

Duration (CAIDI) measures the average time that an affected customer is out of electric service. It is the customer hours divided by the customers affected.

Availability (SAIDI) is the average amount of time a customer is out-of-service during a year. It is the customer hours divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2007. Mathematically, it also is **SAIFI** multiplied by **CAIDI**.

Interruptions Per 1000 Customers Served is the number of interruptions divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2007, divided by 1,000.

Major Storm is defined as any storm which causes service interruptions of at least ten percent of customers in an operating area, or if the interruptions last for 24 hours or more.

Operating Area is a geographical subdivision of each electric utility's franchise territory. These areas are also called regions, divisions, or districts.

Most of the data is presented two ways, with major storms included and major storms excluded. Major storms tend to distort a utility's performance trend. Tables and graphs that exclude major storms illustrate interruptions that are more under the utility's control. It portrays a utility's system facilities under normal conditions, although this can be misleading because interruptions during "normal" bad weather are included and it is difficult to analyze from year to year.

The first two tables show frequency and duration indices for the last five years for each utility and Statewide with and without Con Edison data. Con Edison has by far the lowest frequency numbers and tends to distort the Statewide data. Much of Con Edison's distribution system consists of a secondary network. In a secondary network, a customer is fed from multiple supplies, making the probability of an interruption relatively rare.

COMPARISON OF SERVICE RELIABILITY INDICES
(EXCLUDING MAJOR STORMS)

	2004	2005	2006	2007	2008	5 YR AVG
CHGE						
FREQUENCY	1.36	1.44	1.59	1.42	1.27	1.42
DURATION	2.35	2.70	2.58	2.43	2.47	2.51
CONED						
FREQUENCY	0.11	0.14	0.16	0.16	0.13	0.14
DURATION	1.71	1.99	8.23	1.97	2.27	3.23
LIPA *						
FREQUENCY	0.83	0.85	0.75	0.90	0.77	0.82
DURATION	1.04	1.07	1.37	1.20	1.36	1.21
NAT GRID						
FREQUENCY	1.02	0.98	1.01	0.96	0.75	0.94
DURATION	2.04	2.32	2.05	2.01	1.96	2.08
NYSEG						
FREQUENCY	1.13	1.12	1.12	1.20	1.11	1.13
DURATION	1.96	1.96	2.01	2.22	2.08	2.05
O&R						
FREQUENCY	1.30	1.36	1.23	1.03	1.19	1.22
DURATION	1.61	1.71	1.51	1.60	1.83	1.65
RG&E						
FREQUENCY	0.86	0.79	0.79	0.83	0.78	0.81
DURATION	1.84	1.87	1.78	1.73	1.85	1.81
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.02	1.01	1.00	1.01	0.88	0.98
DURATION	1.81	1.95	1.92	1.88	1.89	1.89
STATEWIDE (WITH CONED)						
FREQUENCY	0.64	0.65	0.65	0.65	0.56	0.63
DURATION	1.80	1.95	2.57	1.89	1.93	2.03

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

COMPARISON OF SERVICE RELIABILITY INDICES
(INCLUDING MAJOR STORMS)

	2004	2005	2006	2007	2008	5 YR AVG
CHGE						
FREQUENCY	1.42	1.83	2.20	1.51	2.15	1.82
DURATION	2.45	3.27	4.12	2.51	5.76	3.62
CONED						
FREQUENCY	0.11	0.15	0.23	0.18	0.14	0.16
DURATION	1.74	2.32	12.31	3.12	2.71	4.44
LIPA *						
FREQUENCY	0.91	1.07	1.17	1.03	1.09	1.05
DURATION	1.12	1.42	1.99	1.37	1.65	1.51
NAT GRID						
FREQUENCY	1.12	1.28	1.48	1.31	1.37	1.31
DURATION	2.15	2.76	7.18	2.70	4.32	3.82
NYSEG						
FREQUENCY	1.41	1.77	1.79	1.71	2.14	1.76
DURATION	2.26	3.27	10.32	3.62	7.07	5.31
O&R						
FREQUENCY	1.46	1.83	1.81	1.17	1.64	1.58
DURATION	1.77	2.42	2.15	1.92	2.94	2.24
RG&E						
FREQUENCY	0.98	0.93	0.98	1.16	1.36	1.08
DURATION	2.04	1.90	2.14	1.80	3.77	2.33
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.15	1.36	1.48	1.31	1.51	1.36
DURATION	1.97	2.60	6.02	2.56	4.62	3.55
STATEWIDE (WITH CONED)						
FREQUENCY	0.71	0.85	0.96	0.83	0.93	0.86
DURATION	1.95	2.58	6.65	2.61	4.50	3.66

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

June, 2009

STATEWIDE (WITHOUT CON ED)

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	50,242	54,434	55,211	55,425	53,758	53,814
Number of Customer-Hours	8,015,041	8,631,869	8,439,916	8,439,464	7,399,179	8,185,094
Number of Customers Affected	4,439,677	4,433,386	4,400,072	4,495,428	3,910,426	4,335,798
Number of Customers Served	4,392,363	4,415,079	4,434,324	4,436,307	4,429,635	4,421,542
Average Duration Per Customer Affected (CAIDI)	1.81	1.95	1.92	1.88	1.89	1.89
Average Duration Per Customers Served	1.83	1.97	1.91	1.90	1.67	1.86
Interruptions Per 1000 Customers Served	11.49	12.39	12.51	12.50	12.12	12.20
Number of Customers Affected Per Customer Served (SAIFI)	1.02	1.01	1.00	1.01	0.88	0.98

STATEWIDE (WITH CON ED)

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	59,458	65,019	65,752	66,746	65,403	64,476
Number of Customer-Hours	8,596,012	9,506,355	12,603,322	9,429,452	8,326,562	9,692,341
Number of Customers Affected	4,779,817	4,873,534	4,905,844	4,996,967	4,319,550	4,775,142
Number of Customers Served	7,553,747	7,602,291	7,652,745	7,681,104	7,701,361	7,638,250
Average Duration Per Customer Affected (CAIDI)	1.80	1.95	2.57	1.89	1.93	2.03
Average Duration Per Customers Served	1.14	1.26	1.66	1.23	1.08	1.28
Interruptions Per 1000 Customers Served	7.91	8.61	8.65	8.72	8.51	8.48
Number of Customers Affected Per Customer Served (SAIFI)	0.64	0.65	0.65	0.65	0.56	0.63

* LIPA is not regulated by the NYS PSC.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

STATEWIDE (WITHOUT CON ED)
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	53,535	66,767	70,872	61,753	73,150	65,215
Number of Customer-Hours	9,852,887	15,493,419	39,413,242	14,848,512	30,962,269	22,114,066
Number of Customers Affected	5,009,438	5,960,730	6,548,910	5,808,516	6,705,414	6,006,602
Number of Customers Served	4,392,363	4,415,079	4,434,324	4,436,307	4,429,635	4,421,542
Average Duration Per Customer Affected (CAIDI)	1.97	2.60	6.02	2.56	4.62	3.55
Average Duration Per Customers Served	2.25	3.53	8.93	3.35	6.98	5.01
Interruptions Per 1000 Customers Served	12.24	15.20	16.05	13.93	16.49	14.78
Number of Customers Affected Per Customer Served (SAIFI)	1.15	1.36	1.48	1.31	1.51	1.36

STATEWIDE (WITH CON ED)
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	62,806	77,937	86,734	74,261	85,548	77,457
Number of Customer-Hours	10,454,054	16,612,929	48,437,221	16,630,252	32,188,186	24,864,528
Number of Customers Affected	5,355,101	6,442,863	7,282,114	6,379,276	7,158,329	6,523,537
Number of Customers Served	7,553,747	7,602,291	7,652,745	7,681,104	7,701,361	7,638,250
Average Duration Per Customer Affected (CAIDI)	1.95	2.58	6.65	2.61	4.50	3.66
Average Duration Per Customers Served	1.39	2.20	6.37	2.17	4.19	3.27
Interruptions Per 1000 Customers Served	8.36	10.32	11.41	9.70	11.14	10.18
Number of Customers Affected Per Customer Served (SAIFI)	0.71	0.85	0.96	0.83	0.93	0.86

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CENTRAL HUDSON
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	6,514	6,911	7,538	6,386	6,857	6,841
Number of Customer-Hours	917,136	1,125,389	1,201,109	1,021,859	933,993	1,039,897
Number of Customers Affected	389,969	416,547	464,765	420,769	377,564	413,923
Number of Customers Served	289,080	292,816	295,368	298,386	300,621	295,254
Average Duration Per Customer Affected (CAIDI)	2.35	2.70	2.58	2.43	2.47	2.51
Average Duration Per Customers Served	3.21	3.89	4.10	3.46	3.13	3.56
Interruptions Per 1000 Customers Served	22.77	23.91	25.74	21.62	22.98	23.40
Number of Customers Affected Per Customer Served (SAIFI)	1.36	1.44	1.59	1.42	1.27	1.42

CENTRAL HUDSON
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	6,756	8,309	10,066	6,681	9,887	8,340
Number of Customer-Hours	994,057	1,735,705	2,649,690	1,117,802	3,705,277	2,040,506
Number of Customers Affected	405,534	530,319	643,778	444,813	642,949	533,479
Number of Customers Served	289,080	292,816	295,368	298,386	300,621	295,254
Average Duration Per Customer Affected (CAIDI)	2.45	3.27	4.12	2.51	5.76	3.62
Average Duration Per Customers Served	3.47	6.00	9.05	3.78	12.42	6.95
Interruptions Per 1000 Customers Served	23.62	28.74	34.38	22.62	33.13	28.50
Number of Customers Affected Per Customer Served (SAIFI)	1.42	1.83	2.20	1.51	2.15	1.82

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (SYSTEM)
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	9,216	10,585	10,541	11,321	11,645	10,662
Number of Customer-Hours	580,971	874,487	4,163,407	989,988	927,383	1,507,247
Number of Customers Affected	340,140	440,148	505,772	501,539	409,124	439,345
Number of Customers Served	3,161,384	3,187,212	3,218,421	3,244,797	3,271,726	3,216,708
Average Duration Per Customer Affected (CAIDI)	1.71	1.99	8.23	1.97	2.27	3.23
Average Duration Per Customers Served	0.18	0.28	1.31	0.31	0.29	0.47
Interruptions Per 1000 Customers Served	2.93	3.35	3.31	3.52	3.59	3.34
Number of Customers Affected Per Customer Served (SAIFI)	0.11	0.14	0.16	0.16	0.13	0.14

CON ED (SYSTEM)
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	9,271	11,170	15,862	12,508	12,398	12,242
Number of Customer-Hours	601,167	1,119,510	9,023,979	1,781,740	1,225,917	2,750,463
Number of Customers Affected	345,663	482,133	733,204	570,760	452,915	516,935
Number of Customers Served	3,161,384	3,187,212	3,218,421	3,244,797	3,271,726	3,216,708
Average Duration Per Customer Affected (CAIDI)	1.74	2.32	12.31	3.12	2.71	4.44
Average Duration Per Customers Served	0.19	0.35	2.83	0.55	0.38	0.86
Interruptions Per 1000 Customers Served	2.95	3.53	4.98	3.89	3.82	3.83
Number of Customers Affected Per Customer Served (SAIFI)	0.11	0.15	0.23	0.18	0.14	0.16

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (NETWORK)

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	4,360	4,967	4,274	5,571	5,485	4,931
Number of Customer-Hours	44,195	59,566	2,947,306	316,477	252,964	724,101
Number of Customers Affected	12,138	13,406	48,467	176,430	40,301	58,148
Number of Customers Served	2,319,321	2,339,622	2,363,897	2,361,145	2,385,760	2,353,949
Average Duration Per Customer Affected (CAIDI)	3.64	4.44	60.81	1.79	6.28	15.39
Average Duration Per Customers Served	0.02	0.03	1.26	0.13	0.11	0.31
Interruptions Per 1000 Customers Served	1.89	2.14	1.83	2.36	2.32	2.11
Number of Customers Affected Per Customer Served (SAIFI)	0.005	0.006	0.021	0.075	0.017	0.025

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (RADIAL)
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	4,856	5,618	6,267	5,750	6,160	5,730
Number of Customer-Hours	536,776	814,921	1,216,101	673,511	674,419	783,146
Number of Customers Affected	328,002	426,742	457,305	325,109	368,823	381,196
Number of Customers Served	842,063	847,590	854,524	883,652	885,966	862,759
Average Duration Per Customer Affected (CAIDI)	1.64	1.91	2.66	2.07	1.83	2.02
Average Duration Per Customers Served	0.64	0.97	1.43	0.79	0.76	0.92
Interruptions Per 1000 Customers Served	5.81	6.67	7.39	6.73	6.97	6.72
Number of Customers Affected Per Customer Served (SAIFI)	0.39	0.51	0.54	0.38	0.42	0.45

CON ED (RADIAL)
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	4,911	6,203	11,588	6,937	6,913	7,310
Number of Customer-Hours	556,972	1,059,944	6,076,673	1,465,264	972,954	2,026,361
Number of Customers Affected	333,525	468,727	684,737	394,330	412,614	458,787
Number of Customers Served	842,063	847,590	854,524	883,652	885,966	862,759
Average Duration Per Customer Affected (CAIDI)	1.67	2.26	8.87	3.72	2.36	3.78
Average Duration Per Customers Served	0.67	1.26	7.17	1.71	1.10	2.38
Interruptions Per 1000 Customers Served	5.88	7.37	13.67	8.12	7.82	8.57
Number of Customers Affected Per Customer Served (SAIFI)	0.40	0.56	0.81	0.46	0.47	0.54

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

LIPA

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	15,423	17,728	18,634	18,736	18,135	17,731
Number of Customer-Hours	942,669	999,412	1,129,275	1,190,411	1,166,613	1,085,676
Number of Customers Affected	908,253	931,276	823,396	995,077	856,405	902,881
Number of Customers Served	1,096,472	1,103,162	1,108,540	1,110,853	1,114,716	1,106,749
Average Duration Per Customer Affected (CAIDI)	1.04	1.07	1.37	1.20	1.36	1.21
Average Duration Per Customers Served	0.87	0.91	1.02	1.07	1.05	0.98
Interruptions Per 1000 Customers Served	14.16	16.17	16.89	16.90	16.33	16.09
Number of Customers Affected Per Customer Served (SAIFI)	0.83	0.85	0.75	0.90	0.77	0.82

LIPA

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	15,956	21,317	24,905	20,077	20,471	20,545
Number of Customer-Hours	1,105,002	1,675,011	2,564,134	1,564,559	1,998,270	1,781,395
Number of Customers Affected	986,170	1,177,059	1,289,698	1,142,365	1,208,292	1,160,717
Number of Customers Served	1,096,472	1,103,162	1,108,540	1,110,853	1,114,716	1,106,749
Average Duration Per Customer Affected (CAIDI)	1.12	1.42	1.99	1.37	1.65	1.51
Average Duration Per Customers Served	1.01	1.53	2.32	1.41	1.80	1.62
Interruptions Per 1000 Customers Served	14.65	19.44	22.58	18.11	18.43	18.64
Number of Customers Affected Per Customer Served (SAIFI)	0.91	1.07	1.17	1.03	1.09	1.05

* LIPA is not regulated by the NYS PSC.
* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NATIONAL GRID

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	13,917	13,680	13,665	14,606	12,939	13,761
Number of Customer-Hours	3,274,229	3,598,884	3,289,340	3,045,363	2,334,754	3,108,514
Number of Customers Affected	1,602,708	1,551,448	1,607,461	1,518,634	1,188,585	1,493,767
Number of Customers Served	1,580,131	1,585,383	1,589,949	1,594,179	1,583,311	1,586,591
Average Duration Per Customer Affected (CAIDI)	2.04	2.32	2.05	2.01	1.96	2.08
Average Duration Per Customers Served	2.08	2.28	2.07	1.92	1.46	1.96
Interruptions Per 1000 Customers Served	8.82	8.66	8.62	9.19	8.12	8.68
Number of Customers Affected Per Customer Served (SAIFI)	1.02	0.98	1.01	0.96	0.75	0.94

NATIONAL GRID

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	14,760	16,211	16,279	16,222	18,301	16,355
Number of Customer-Hours	3,800,127	5,568,127	16,813,162	5,605,931	9,410,833	8,239,636
Number of Customers Affected	1,766,092	2,020,066	2,341,235	2,075,480	2,177,786	2,076,132
Number of Customers Served	1,580,131	1,585,383	1,589,949	1,594,179	1,583,311	1,586,591
Average Duration Per Customer Affected (CAIDI)	2.15	2.76	7.18	2.70	4.32	3.82
Average Duration Per Customers Served	2.41	3.52	10.61	3.53	5.90	5.19
Interruptions Per 1000 Customers Served	9.35	10.26	10.27	10.20	11.48	10.31
Number of Customers Affected Per Customer Served (SAIFI)	1.12	1.28	1.48	1.31	1.37	1.31

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NYSEG
Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	8,946	10,190	9,682	10,317	10,027	9,832
Number of Customer-Hours	1,866,112	1,872,868	1,913,315	2,299,142	1,980,213	1,986,330
Number of Customers Affected	952,258	955,009	953,941	1,034,113	953,105	969,685
Number of Customers Served	849,335	854,508	859,440	859,963	857,517	856,153
Average Duration Per Customer Affected (CAIDI)	1.96	1.96	2.01	2.22	2.08	2.05
Average Duration Per Customers Served	2.21	2.21	2.24	2.68	2.30	2.32
Interruptions Per 1000 Customers Served	10.59	12.00	11.33	12.00	11.66	11.48
Number of Customers Affected Per Customer Served (SAIFI)	1.13	1.12	1.12	1.20	1.11	1.13

NYSEG
Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	10,269	14,364	12,835	12,928	17,008	13,481
Number of Customer-Hours	2,687,162	4,926,508	15,787,602	5,314,914	12,974,501	8,338,137
Number of Customers Affected	1,188,998	1,504,612	1,529,247	1,469,825	1,836,251	1,505,787
Number of Customers Served	849,335	854,508	859,440	859,963	857,517	856,153
Average Duration Per Customer Affected (CAIDI)	2.26	3.27	10.32	3.62	7.07	5.31
Average Duration Per Customers Served	3.18	5.80	18.48	6.18	15.09	9.75
Interruptions Per 1000 Customers Served	12.15	16.91	15.02	15.04	19.78	15.78
Number of Customers Affected Per Customer Served (SAIFI)	1.41	1.77	1.79	1.71	2.14	1.76

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

O&R

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	2,546	2,718	2,688	2,596	2,993	2,708
Number of Customer-Hours	440,617	493,591	397,977	356,514	470,431	431,826
Number of Customers Affected	274,124	289,022	264,121	222,895	256,943	261,421
Number of Customers Served	212,352	214,546	216,268	215,694	217,373	215,247
Average Duration Per Customer Affected (CAIDI)	1.61	1.71	1.51	1.60	1.83	1.65
Average Duration Per Customers Served	2.09	2.32	1.85	1.65	2.18	2.02
Interruptions Per 1000 Customers Served	12.10	12.80	12.53	12.00	13.88	12.66
Number of Customers Affected Per Customer Served (SAIFI)	1.30	1.36	1.23	1.03	1.19	1.22

O&R

Including Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	2,729	3,123	3,546	2,738	3,655	3,158
Number of Customer-Hours	542,652	942,127	836,046	483,938	1,043,235	769,600
Number of Customers Affected	307,396	388,553	388,164	252,650	354,315	338,216
Number of Customers Served	212,352	214,546	216,268	215,694	217,373	215,247
Average Duration Per Customer Affected (CAIDI)	1.77	2.42	2.15	1.92	2.94	2.24
Average Duration Per Customers Served	2.58	4.44	3.90	2.24	4.84	3.60
Interruptions Per 1000 Customers Served	12.97	14.71	16.53	12.66	16.95	14.76
Number of Customers Affected Per Customer Served (SAIFI)	1.46	1.83	1.81	1.17	1.64	1.58

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

RG&E

Excluding Major Storms

	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	2,896	3,207	3,004	2,784	2,807	2,940
Number of Customer-Hours	574,278	541,725	508,899	526,175	513,175	532,850
Number of Customers Affected	312,365	290,084	286,388	303,940	277,824	294,120
Number of Customers Served	364,993	364,664	364,759	357,232	356,097	361,549
Average Duration Per Customer Affected (CAIDI)	1.84	1.87	1.78	1.73	1.85	1.81
Average Duration Per Customers Served	1.58	1.48	1.40	1.44	1.44	1.47
Interruptions Per 1000 Customers Served	7.96	8.79	8.24	7.63	7.86	8.10
Number of Customers Affected Per Customer Served (SAIFI)	0.86	0.79	0.79	0.83	0.78	0.81

RG&E

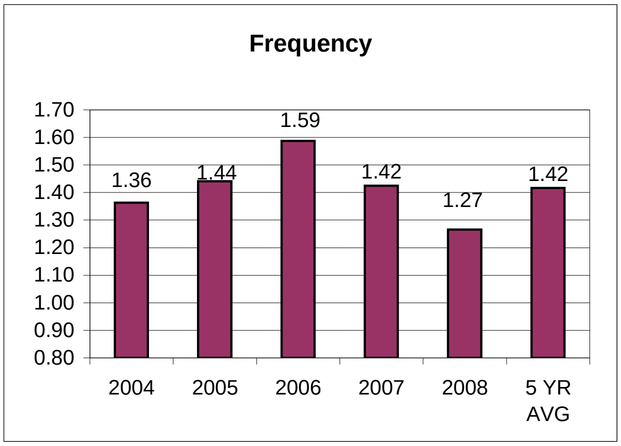
Including Major Storms

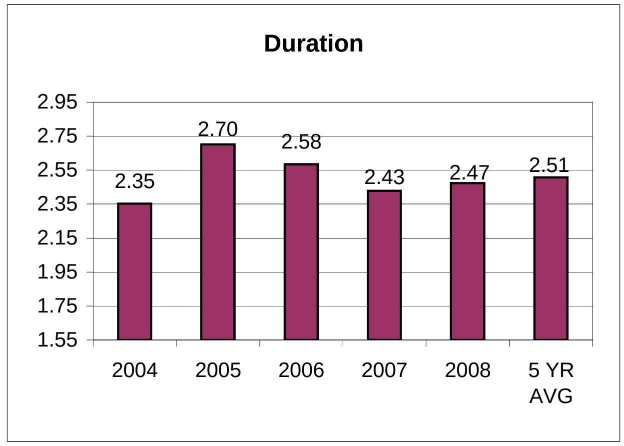
	2004	2005	2006	2007	2008	5 YR AVG
Number of Interruptions	3,065	3,443	3,241	3,107	3,828	3,337
Number of Customer-Hours	723,887	645,940	762,609	761,368	1,830,153	944,791
Number of Customers Affected	355,248	340,121	356,788	423,383	485,821	392,272
Number of Customers Served	364,993	364,664	364,759	357,232	356,097	361,549
Average Duration Per Customer Affected (CAIDI)	2.04	1.90	2.14	1.80	3.77	2.33
Average Duration Per Customers Served	1.99	1.77	2.09	2.09	5.12	2.61
Interruptions Per 1000 Customers Served	8.43	9.43	8.89	8.52	10.72	9.20
Number of Customers Affected Per Customer Served (SAIFI)	0.98	0.93	0.98	1.16	1.36	1.08

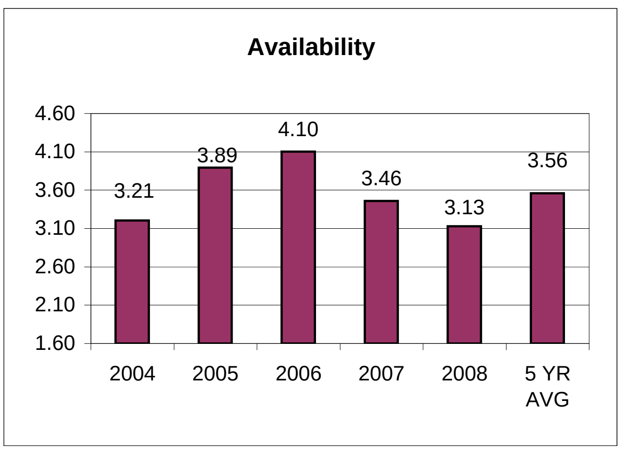
* Customers Served is the number of customers served at the end of the current year.

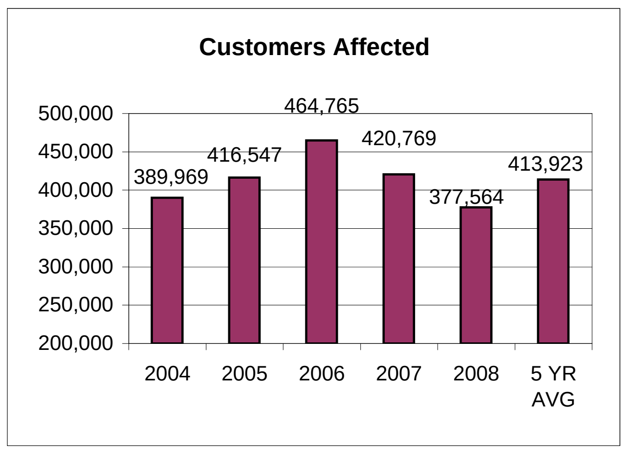
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

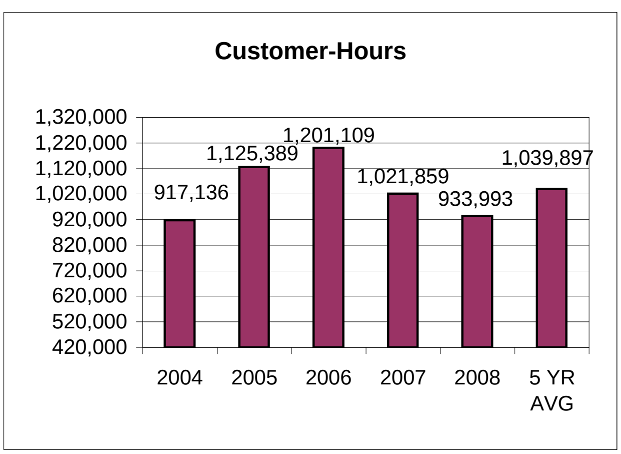
Central Hudson Gas and Electric
(Excluding Major Storms)

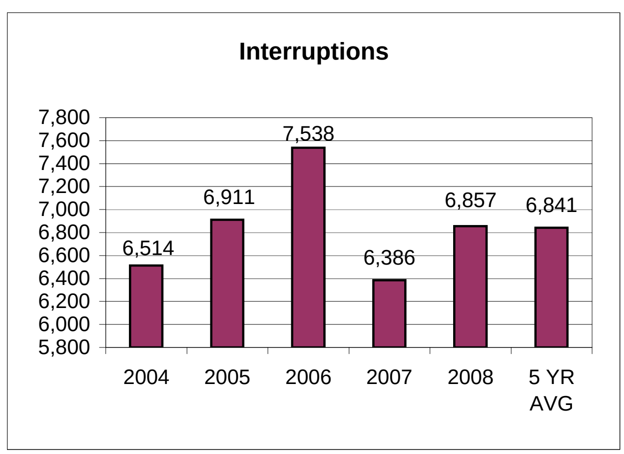






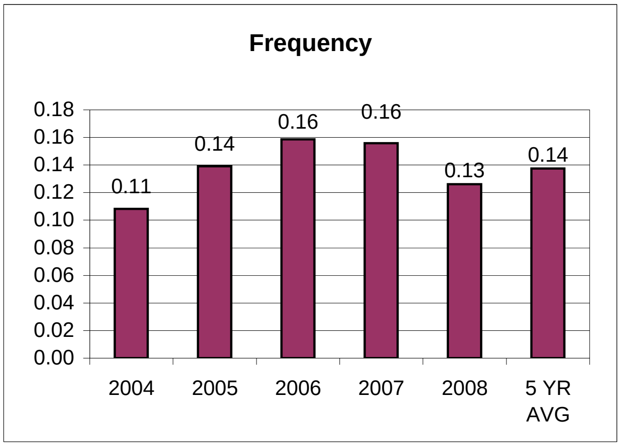


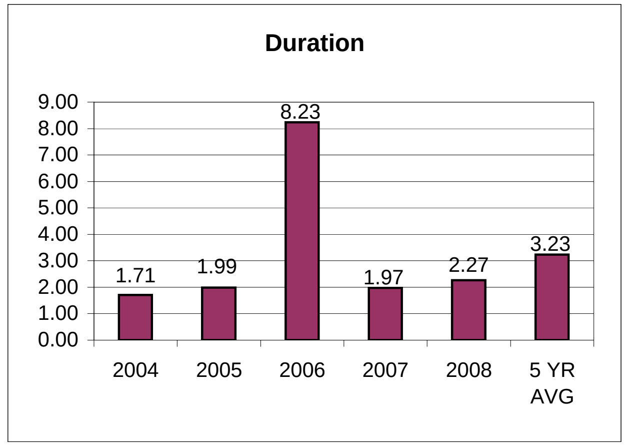


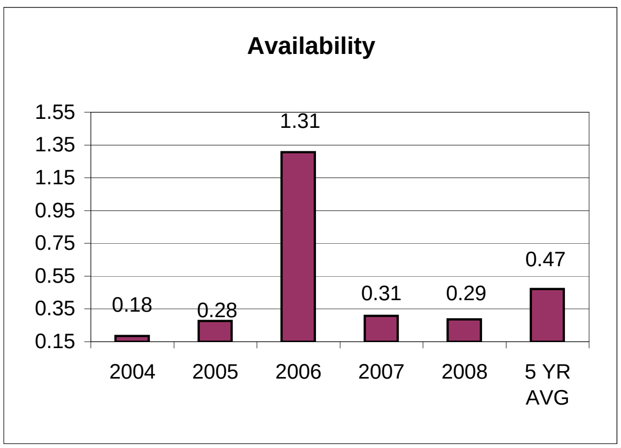


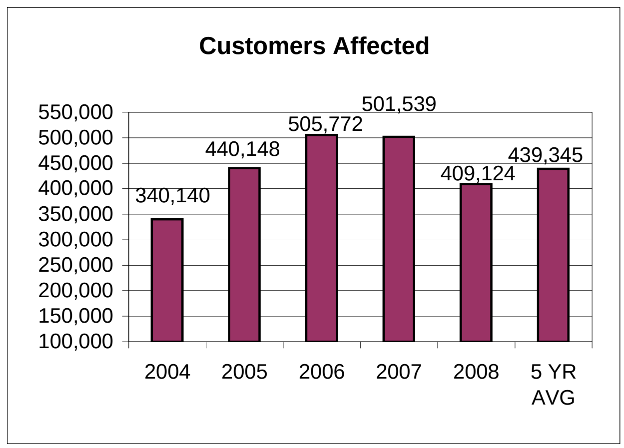
June, 2009

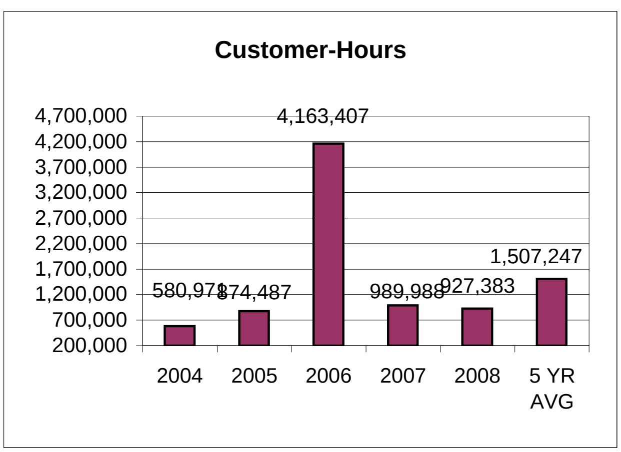
Consolidated Edison - System
(Excluding Major Storms)

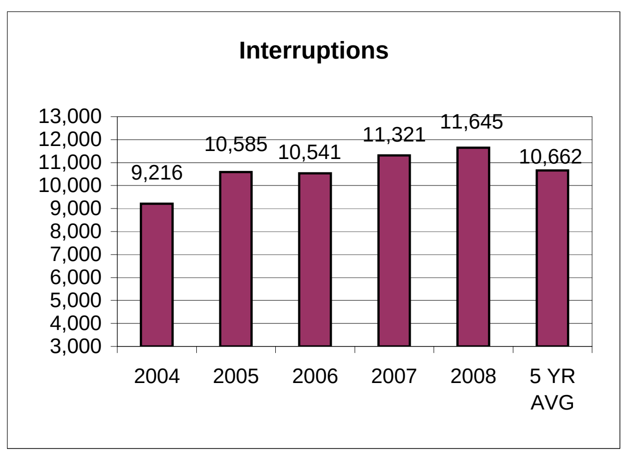




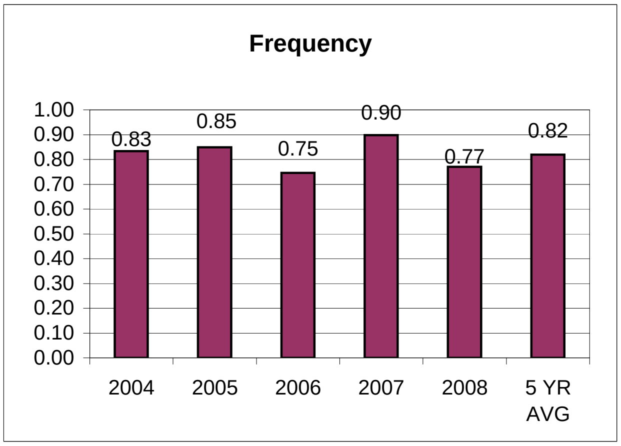


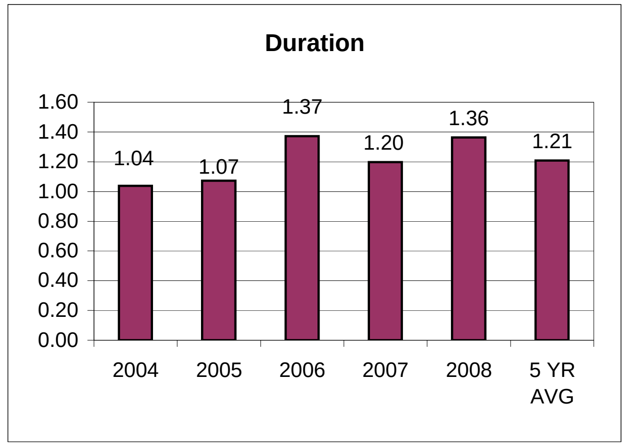


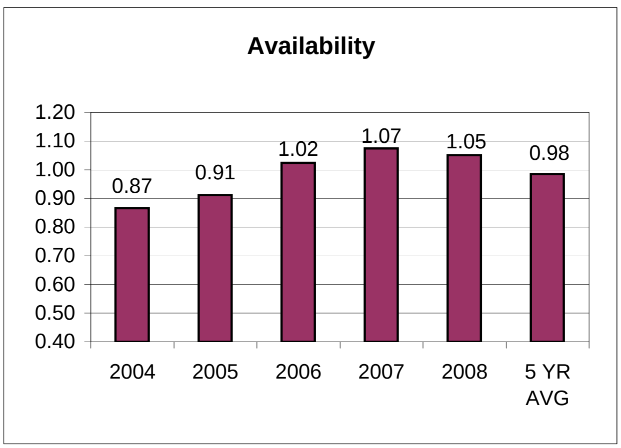


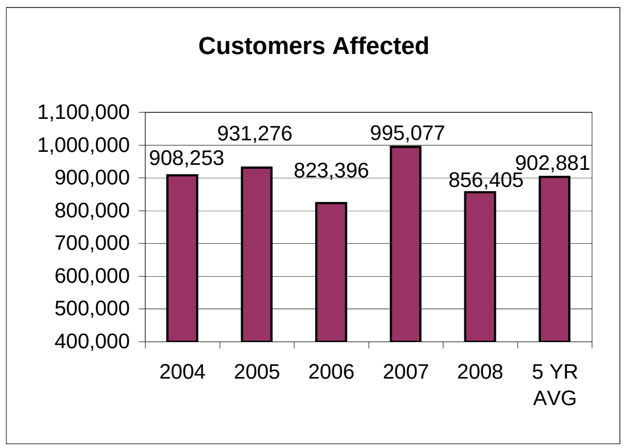


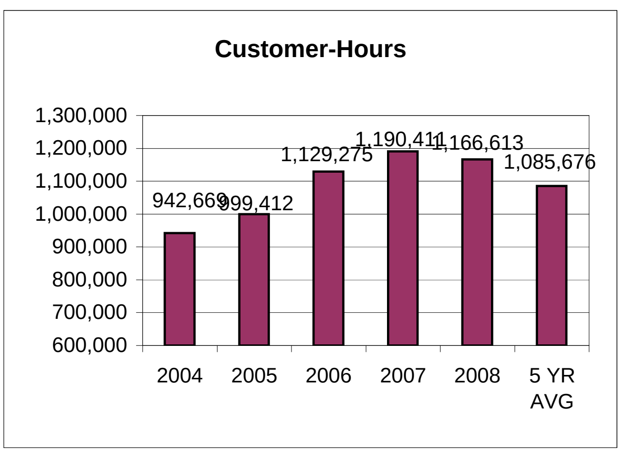
Long Island Power Authority
(Excluding Major Storms)

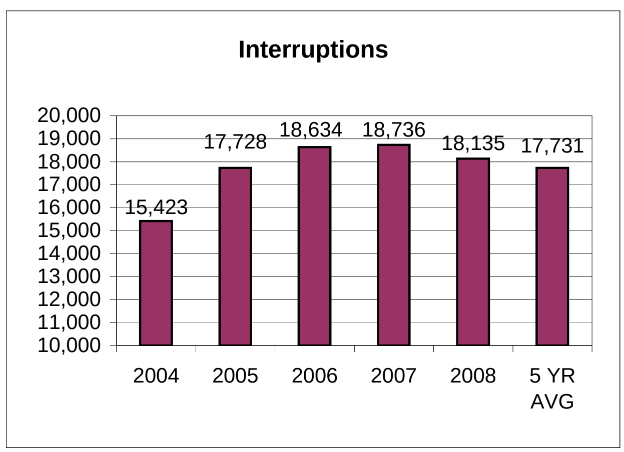






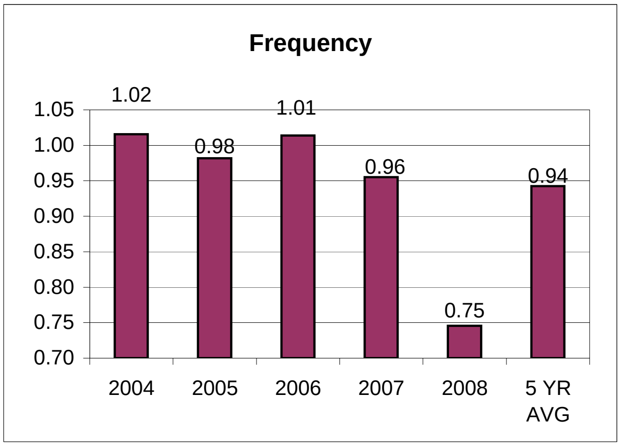


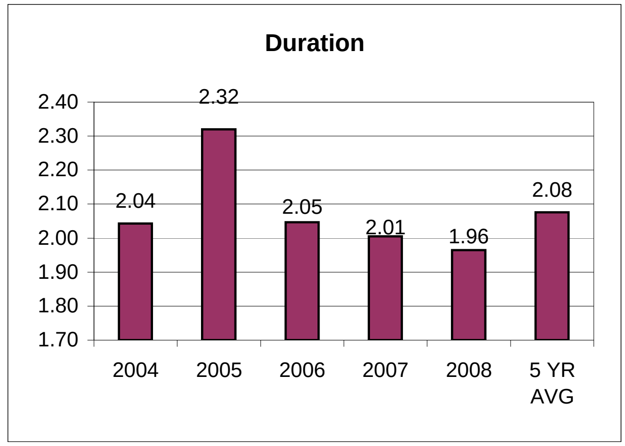


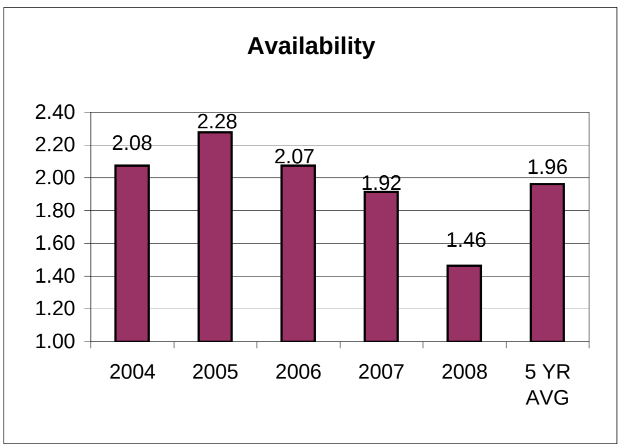


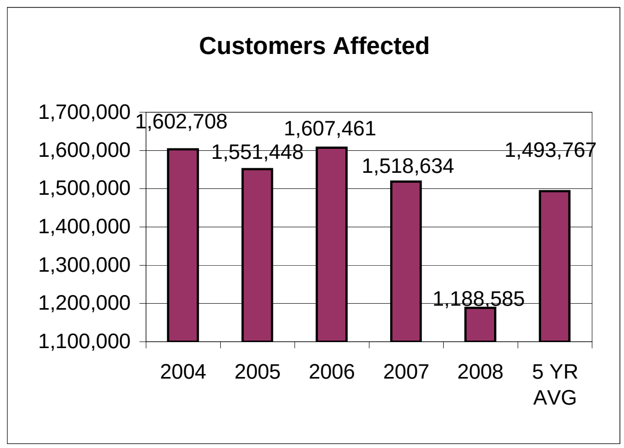
* LIPA is not regulated by the NYS PSC.

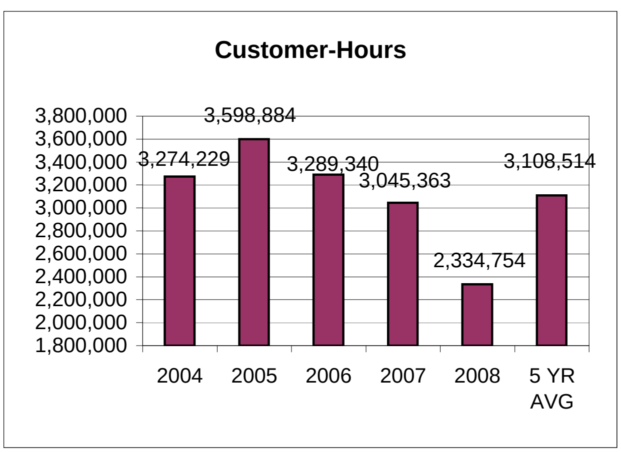
National Grid
(Excluding Major Storms)

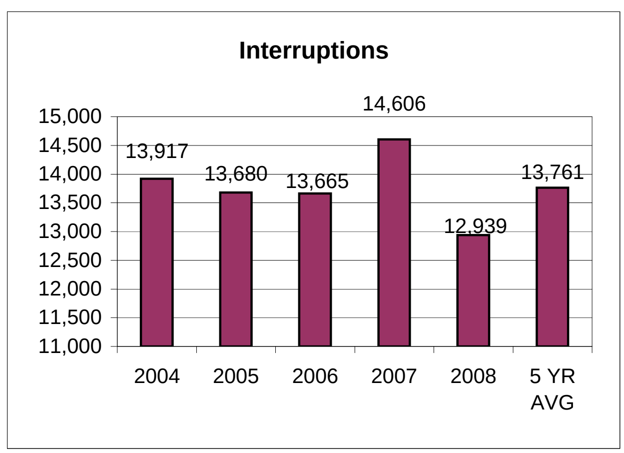




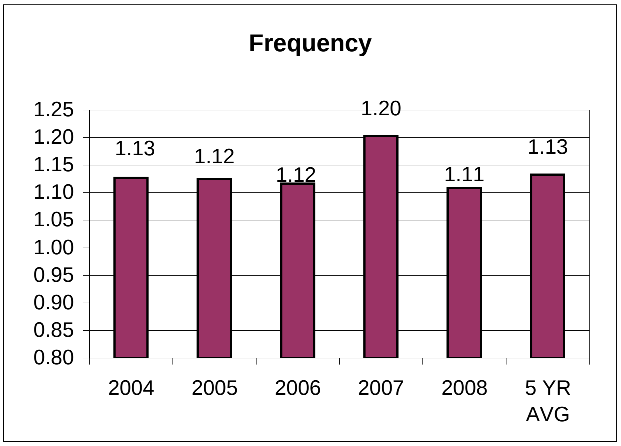


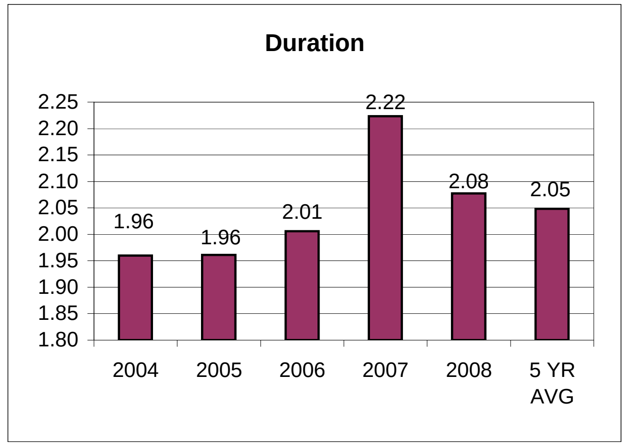


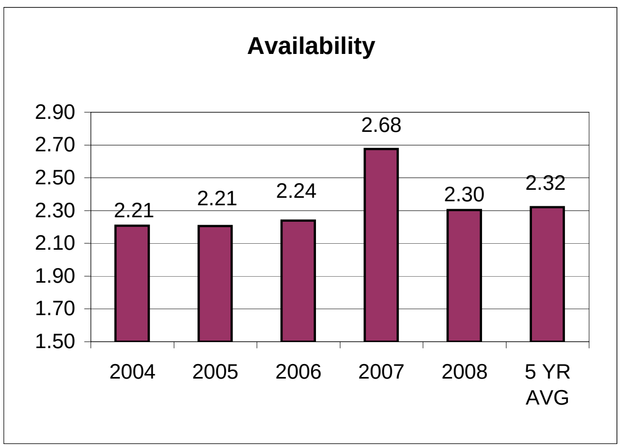


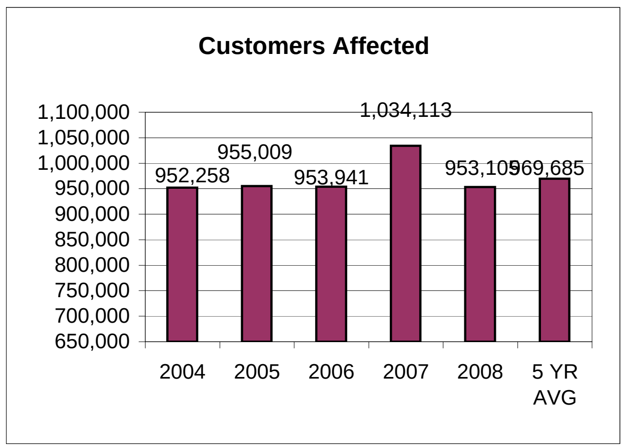


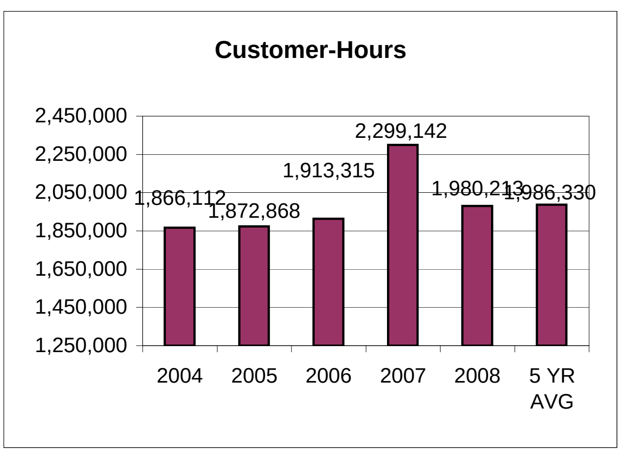
New York State Electric and Gas
(Excluding Major Storms)

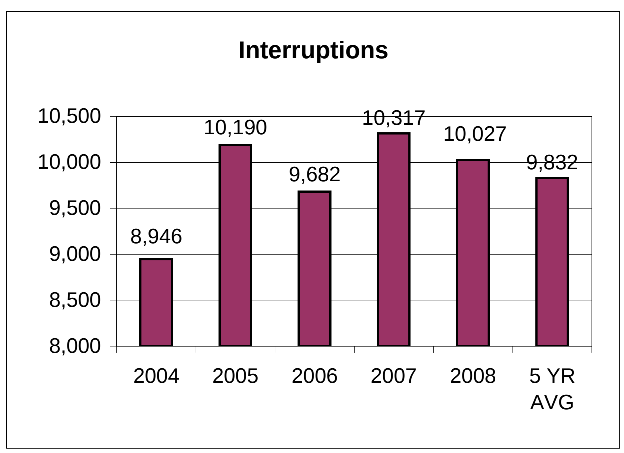




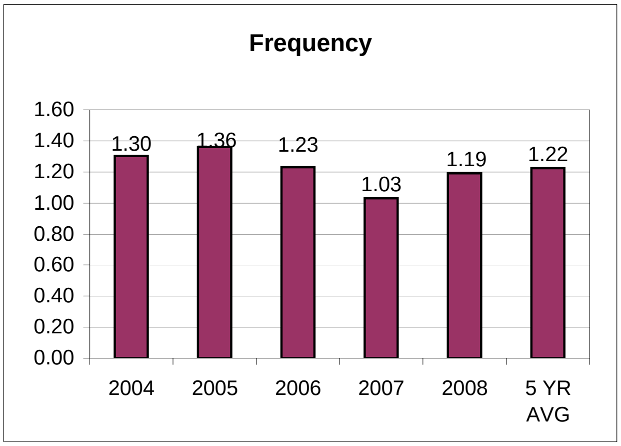


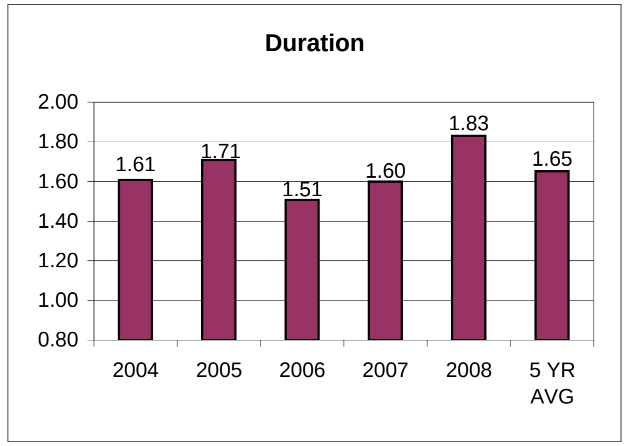


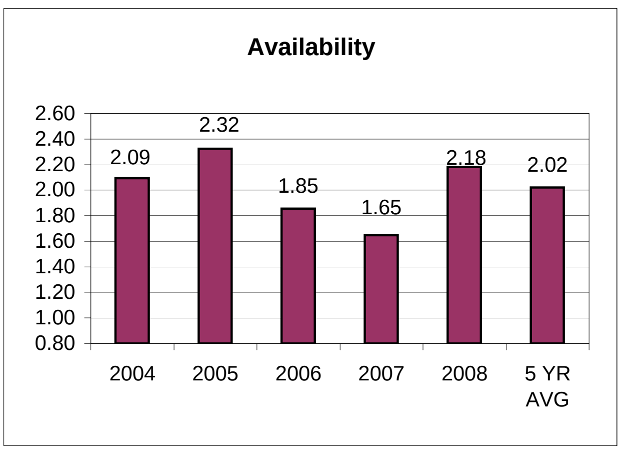


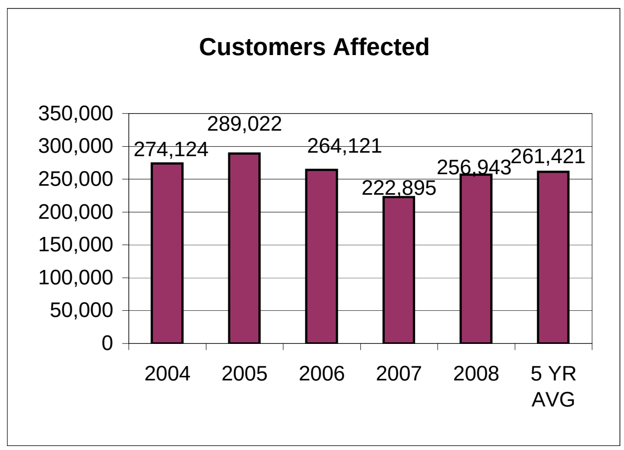


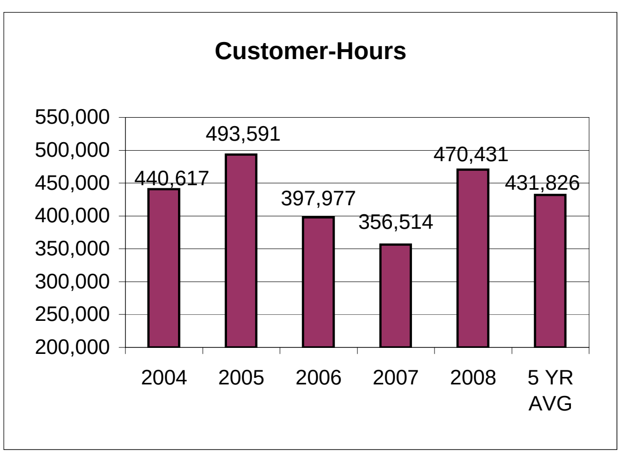
Orange and Rockland Utilities
(Excluding Major Storms)

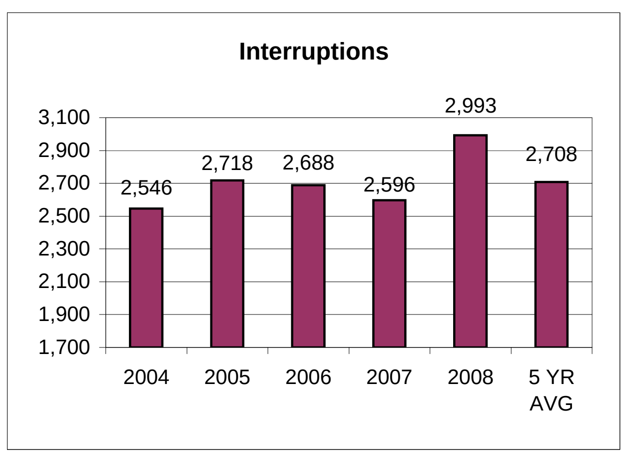




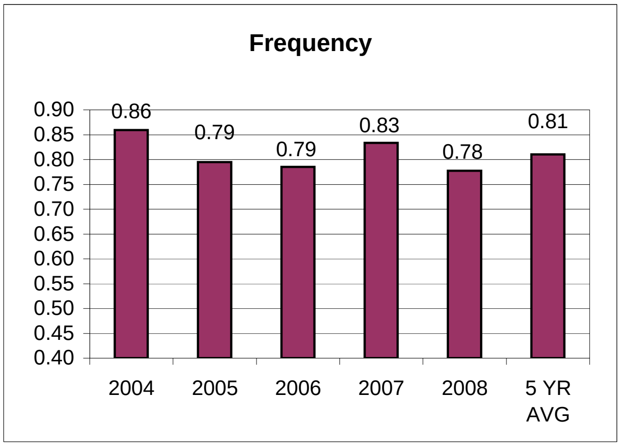


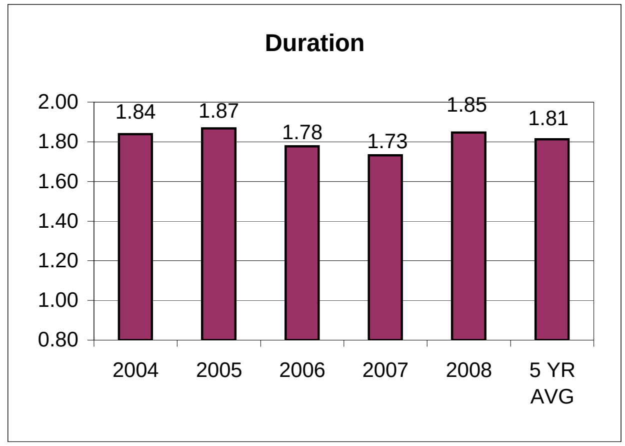


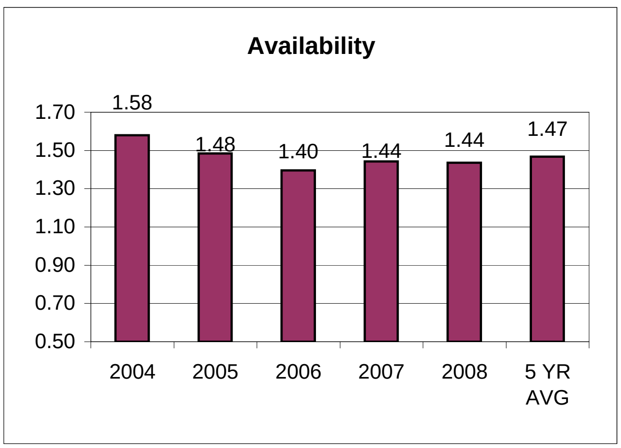


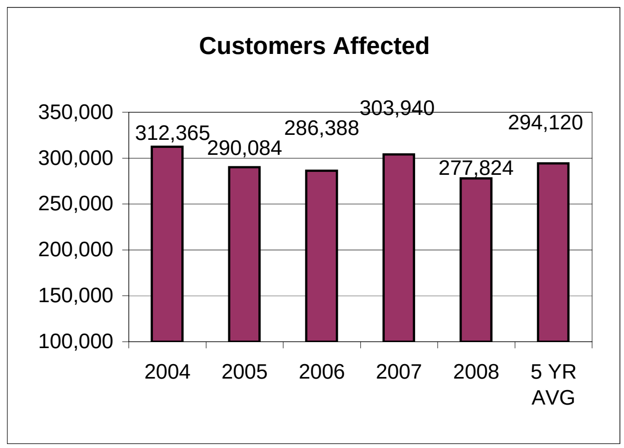


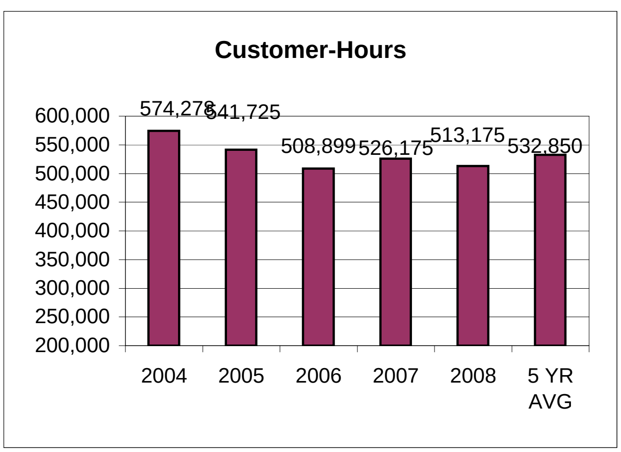
Rochester Gas and Electric
(Excluding Major Storms)

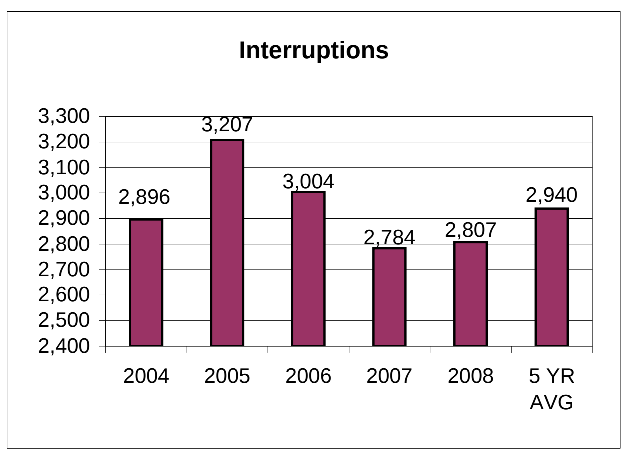












Filed Session of June 16, 2011

STATE OF NEW YORK

DEPARTMENT OF PUBLIC SERVICE

2010 ELECTRIC RELIABILITY PERFORMANCE REPORT

Electric Distribution Systems

Office of Electric, Gas, and Water

June 2011

TABLE OF CONTENTS

EXECUTIVE SUMMARY

This report presents Department of Public Service Staff's (Staff) assessment of electric reliability performance in New York State for 2010. As a means of monitoring the levels of service, utilities are required to submit detailed monthly interruption data to the Public Service Commission (Commission). Staff primarily relies on two metrics commonly used in the industry to measure reliability performance: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration).[1] Frequency is influenced by factors such as system design, capital investment, maintenance, and weather.[2] Decisions made by utilities today on capital expenditures and maintenance policies, however, can take several years before being fully reflected in the frequency measure. Duration, on the other hand, is affected by work force levels, management of the workforce, and geography. By compiling the interruption data provided by the individual utilities, the average frequency and duration of interruptions can be reviewed to assess the overall reliability of electric service in New York State. Recent data is also compared with historic performances to identify positive or negative trends. Finally, Staff reviews several other specific metrics that vary by utility to gauge electric reliability.

The statewide interruption frequency for 2010, excluding major storms, has been nearly identical for the past three years, and better than the five year average. Central Hudson Gas and Electric Corporation (Central Hudson) and Niagara Mohawk Power Corporation d/b/a National Grid's (National Grid) improved when compared with 2009. While the performances of the remaining four of the major electric companies were not as good as 2009 levels, they still performed satisfactorily and met the criteria in the performance mechanisms to which they were subject. For these companies, calendar year 2009 was also one of their best performing years in recent history.

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[1] SAIFI is the average number of times that a customer is interrupted during a year. CAIDI is the average interruption duration time for those customers that experience an interruption during the year.

[2] To help achieve a balance between service interruptions under a utility's control, such as equipment failures, and those which a utility's control is more limited, such as an ice storm, we review reliability data both including and excluding severe weather events.

For the most part, duration performances were acceptable. Although, the statewide duration in 2010 was slightly worse than 2009, it was better than the five year average. In 2010, New York State Electric and Gas (NYSEG)'s and Rochester Gas and Electric (RG&E)'s duration was its best performance in the past five years.

Calendar year 2010 was historically one of the worst with respect to major storm effects. Three significant storms in the Hudson Valley and Downstate contributed to the entire State having the fifth-most hours of customer electric service interruption (including major storms) in the past twenty years.

With respect to individual utility performance in 2010, Consolidated Edison Company of New York's (Con Edison) generally performed satisfactorily. Due to concerns regarding the accuracy of the number of customers that were affected by an interruption in a network, we are now measuring network performance using two alternate measures: the number of interruptions per 1000 customers[3] and the average interruption duration. In 2010, Con Edison's network interruption performance was better than its 2009 performance, however, the Company's network interruption duration was worse in 2010 when compared to its 2009 performance. With regard to its radial system, Con Edison's radial system interruption frequency was nearly the same as its five year average. The radial system interruption duration performance declined compared to prior years, but was better than the five year average.

While NYSEG and RG&E had worse frequency performances in 2010 as compared with 2009, they are still much better than the Companies' respective performance targets. Outages associated with tree contacts and equipment failures continue to be a concern relative to NYSEG. In 2010, the companies have resumed investing in and maintaining their systems at more appropriate levels after low spending levels in 2009. As previously stated, the companies achieved their best duration performances of the past five years in 2010.

[3] An interruption is the loss of service for five minutes or more, for one or more customers. For example, a blown fuse that affects twelve customers is one interruption.

National Grid continues to perform well. The Company's recent infrastructure improvement and reliability focused programs are having a positive impact. Central Hudson's performance was better or consistent with its five year averages. Because of continuing tree issues, Central Hudson implemented a more rigorous tree trimming specification several years ago. Staff will perform field reviews of electric lines that are at or near the end of the first four-year trimming cycle. Orange and Rockland Utilities, Inc. (Orange and Rockland) performed satisfactorily with regard to interruption frequency, but not with respect to interruption duration. The Company has lacked consistency in its performances and Staff will be working with the Company to help reduce this variability.

All investor-owned electric utilities have reliability performance mechanisms (RPMs) in place as part of their rate plans. The RPMs are designed such that companies are subject to negative revenue adjustments for failing to meet electric reliability targets. In 2010, Con Edison achieved the network outage duration metric and the remote monitoring system metric in its RPM only if the exclusions it is asserting are accepted by the Commission. Failure to achieve the performance levels set forth in these metrics may result in negative revenue adjustments of $5 million and $10 million, respectively. Con Edison is seeking exclusion of storm related outages and extraordinary circumstances in its Long Island City network, as permitted under certain circumstances in its RPM. If the exclusion is allowed, this would result in the Company meeting all RPM targets.[4] Orange and Rockland failed to achieve its interruption duration target in 2010, which would result in a negative revenue adjustment of $800,000. On March 16, 2011, Orange and Rockland filed a request for exemption for outages experienced during a storm on July 19, 2010. The request, if granted, improves the duration performance such that the Company would meet its target and not be subject to any negative revenue adjustments.[5] All of the other companies met their RPM targets.

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4 Con Edison filed a request for exemption on March 31, 2010 which has yet to be presented to the Commission for final action.

5 Orange and Rockland's request for exemption has yet to be presented to the Commission for final action.

Overall, we are generally pleased with the steady electric reliability performance across the State. There are, however, individual concerns that are being addressed through various Staff efforts. This report will be transmitted to an executive level operating officer of each electric utility with a letter from the Director of the Office of Electric, Gas, and Water.

INTRODUCTION

This report provides an overview of the electric reliability performance in New York State. As a means of monitoring the levels of service reliability, the Commission's Rules and Regulations require utilities delivering electricity in New York State to collect and submit information to the Commission regarding electric service interruptions on a monthly basis.[6] The utilities provide interruption data that enables Staff to calculate two primary performance metrics: the System Average Interruption Frequency Index (SAIFI or frequency) and the Customer Average Interruption Duration Index (CAIDI or duration). The information is grouped into 10 categories that delineate the nature of the cause of interruption (cause code).[7] Analysis of the cause code data enables the utilities and Staff to identify areas where increased capital investment or maintenance is needed. As an example, if a circuit were shown to be prone to lightning-caused interruptions, arrestors could be installed on that circuit to try to minimize the effect of future lightning strikes. In general, most of a utility's interruptions are a result of major storms, tree contacts, equipment failures, and accidents.[8] Staff maintains the interruption information in a database that dates back to 1989, which enables it to observe trends.

The Commission also adopted electric service standards addressing the reliability of electric service. The standards contain minimum acceptable performance levels for both the frequency and duration of service interruptions for each major electric utility's operating divisions. The utilities are required to submit a formal reliability report by March 31 of each year containing detailed assessments of performance, including outage trends in a utility's various geographic regions, reliability improvement projects, and analyses of worst-performing feeders. There are no revenue adjustments for failure

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[6] 16 NYCRR Part 97, Notification of Interruption of Service requires utilities to keep detailed back-up data for six years.

[7] 16 NYCRR Part 97, Notification of Interruption of Service specifies and defines the following ten cause codes that reflect the nature of the interruptions: major storms, tree contacts, overloads, operating errors, equipment failures, accidents, prearranged interruptions, customers equipment, lightning, and unknown. There are an additional seven cause codes used exclusively for Con Edison's underground network system.

[8] The accident cause code covers events not entirely within in the utilities' control including vehicular accidents, sabotage, and animal contacts. Lightning is reported under a separate cause code.

to meet a minimum level under the service standards; utilities are, however, required to include a corrective action plan as part of the annual report. The service standards were last revised in 2004.

In addition, utility performance is compared with utilities' RPMs established as part of the utilities' rate orders. RPMs are designed such that companies are subjected to negative revenue adjustments for failing to meet electric reliability targets. The RPMs typically include targets for frequency and duration; some RPMs have additional measures to address specific concerns within an individual company.

2010 RELIABILITY PERFORMANCE

The following sections provide a summary discussion of the reliability performance statewide and for each of the major utilities.[9] Interruption data is presented in two ways in this report – with major storms excluded and with major storms included. A major storm is defined by the Commission's regulations as any storm which causes service interruptions of at least 10 percent of customers in an operating area, and/or interruptions with duration of 24 hours or more. Major storm interruptions are excluded from the data used in calculating performance levels for service standards and reliability performance mechanisms. The purpose of this policy is to achieve a balance between service interruptions under a utility's control, such as equipment failures and line maintenance, and those over which a utility's control is more limited, such as severe ice storm or a heavy wet snowstorm. Reliability performance data inclusive of major storms reflects the actual customer experience during a year.

Each year, Staff prepares an Interruption Report summarizing the monthly interruption data submitted by utilities. The 2010 Interruption Report contains detailed interruption data for each utility and statewide statistics for the past five years. The Interruption Report for 2010 is attached as an Appendix. Individual company discussions identify issues or actions within each company that influenced performance levels for 2010 and indicate company-specific trends where applicable.

Revenue adjustments for inadequate performance are implemented through individual RPMs which have been established in the utilities' rate orders.[10] Con Edison and Orange and Rockland failed to achieve targets in their reliability performance mechanisms for 2010. Con Edison failed to achieve the average interruption duration target for its network system and also failed its Remote Monitoring System target, resulting in a negative rate adjustment of $15 million. Orange and Rockland failed to achieve its interruption duration target, which results in a negative revenue adjustment of $800,000. The rate adjustments are preliminary assessments because both companies are

[9] Although LIPA is not regulated by the Commission, it supplies interruption data that is used to calculate statewide performance in this report.

[10] Revenue adjustments for inferior performances are implemented through individual Reliability Performance Mechanisms established in rate orders.

requesting exemptions, which are permitted under certain circumstances, and with which the companies would meet their targets and avoid any negative revenue adjustments.[11]

STATEWIDE

For many years, Staff has been combining individual utility performance statistics into overall statewide statistics. By doing so Staff is able to evaluate the level of reliability provided statewide and identify statewide trends. Because Con Edison's system includes many large, highly concentrated distribution networks that are generally less prone to interruptions than overhead systems, its interruption frequency is extremely low (i.e., better) as compared with other utilities. This, combined with the fact that it serves the largest number of customers in the state, typically results in a skewing of the performance measures. As a result, Staff examines and presents aggregated data both including and excluding Con Edison's data.

Statewide, as may be seen in Figure 1, the frequency of interruptions excluding major storms was 0.57 in 2010; this is generally equivalent to the previous two years' performances and better than the five-year average. National Grid and Central Hudson had fewer customers affected by power outages in 2010 when major storms are excluded, while NYSEG, Con Edison, RG&E, and O&R had more customers affected. The frequency performance in 2010 for utilities other than Con Edison is 0.89, which is substantially the same as their frequency performance of 0.88 in 2008 and .090 in 2009, and better than the five-year average of 0.94.

[11] The requests have not been presented to the Commission for final action.

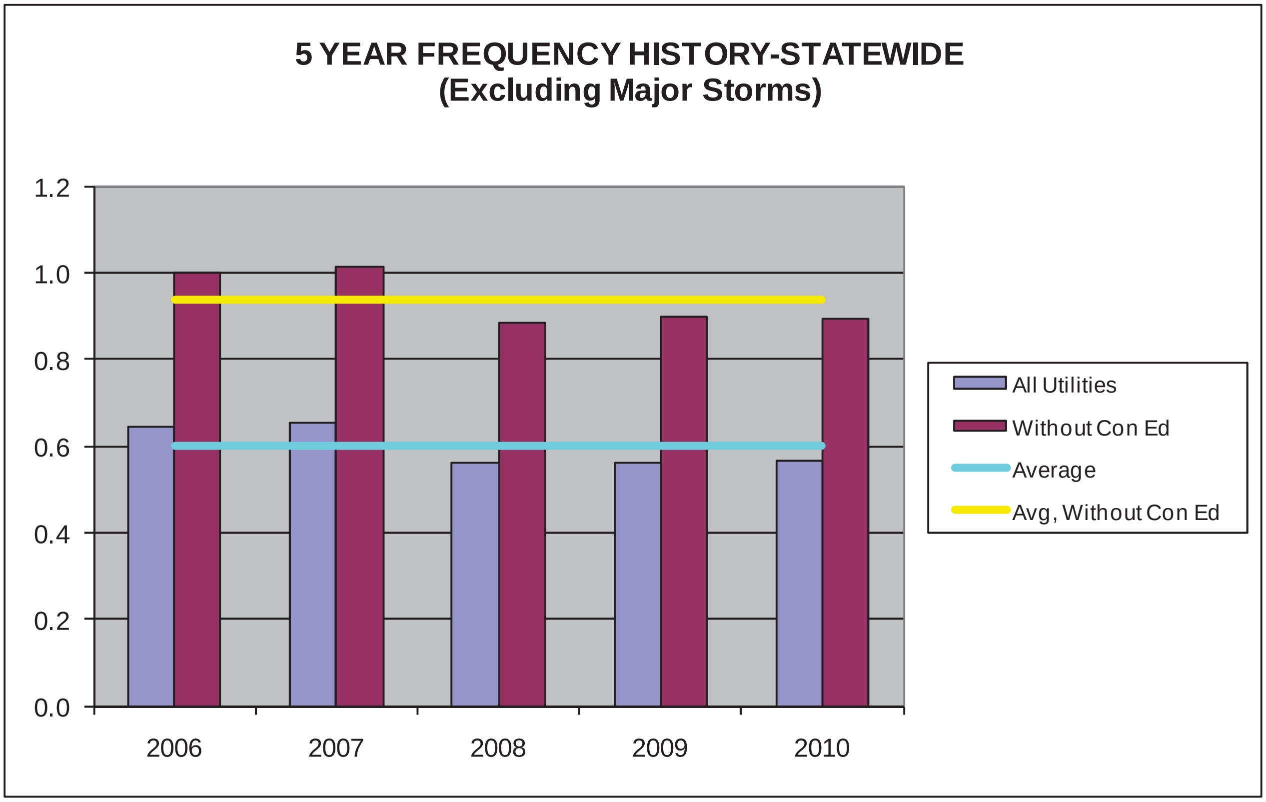


Figure 1: Statewide Frequency Performance

Figure 2 shows the historical statewide interruption duration index, excluding major storms. The 2010 overall statewide interruption duration index of 1.89 is slightly worse than 2009's 1.83, but is still consistent with the history of the past four years. When examining the chart, it should be kept in mind that Con Edison's Long Island City network outages in 2006 are still in the five year average. The statewide interruption duration index, excluding Con Edison, was 1.82 hours in 2010, which is the second best of the past five years.

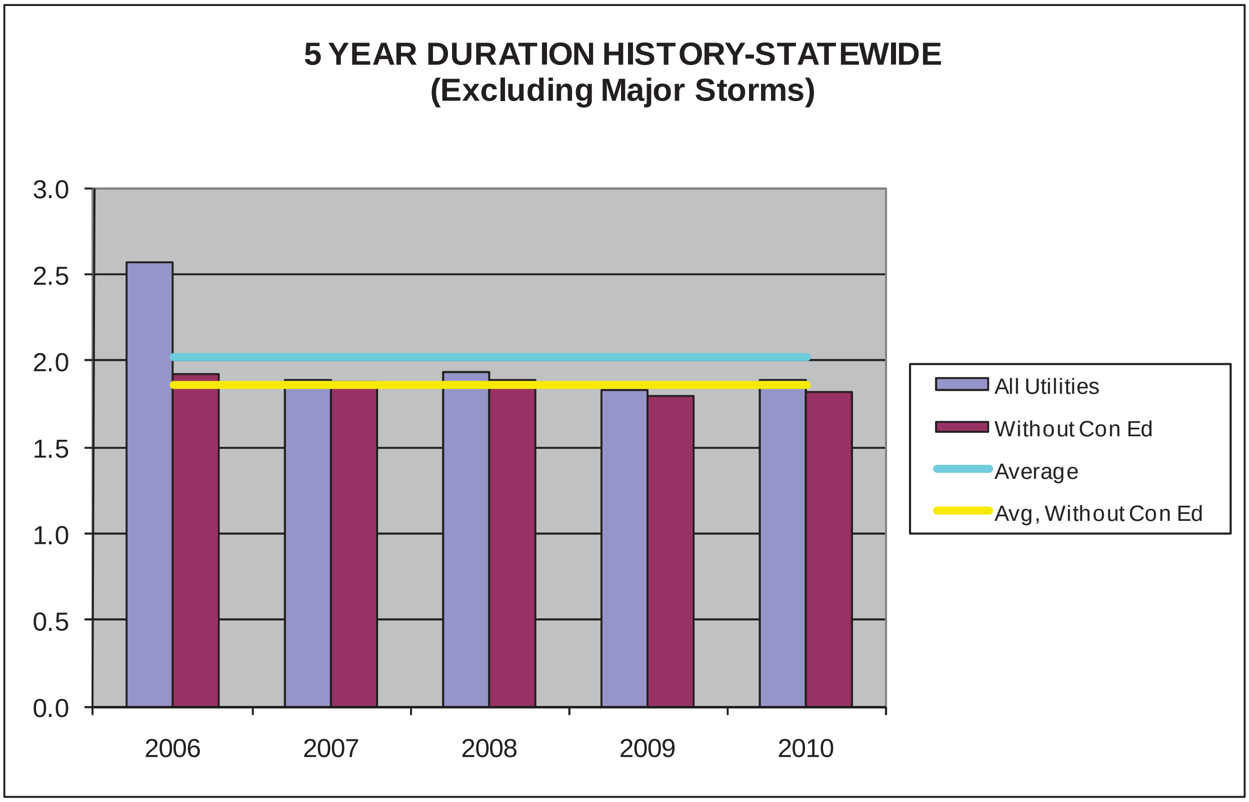


Figure 2: Statewide Duration Performance

While the overall number of major storms in 2010 was not atypical, three significant storms occurred in the Hudson Valley and Downstate. The three storms, summarized below, contributed to 2010 having the fifth-most hours of customer electric service interruption (including major storms) in the past twenty years (Figures 3 and 4, below). Because of the extended restoration times associated with these storms, the Commission requires the companies to file storm reports detailing restoration activities. [12] These reports were reviewed during the course of the year and determined that, in general, the utilities responded well.

- On February 23rd and 25th, heavy wet snow hit the Hudson Valley causing 300,000 customers to lose power. Central Hudson, Con Edison, NYSEG, and O&R were affected with overall restoration time exceeding a week. For Central Hudson, it was the worst storm in Company history since 1991, causing twice as much hours of customer interruption as Hurricane Floyd in 1999.

[12] 16 NYCRR Part 97, Part 105.4, requires utilities to file storm reports for outages lasting longer than three days.

- A March nor'easter swept the downstate area on March 3rd and affected 475,000 customers. Companies primarily affected were Con Edison, O&R, and LIPA. For Con Edison, it was the largest storm with respect to customer hours of interruption in Company history, with more than three times the amount experienced in Tropical Storm Ernesto in 2006.

- On September 16th, Tornados/Macrobursts hit downstate and affected Con Edison, O&R and LIPA, causing Con Edison 31,000 customers, mostly in Staten Island, Brooklyn and Queens, to lose power, some for extended times. The storms, while narrow in this geography, were notable in the magnitude of their destructiveness.

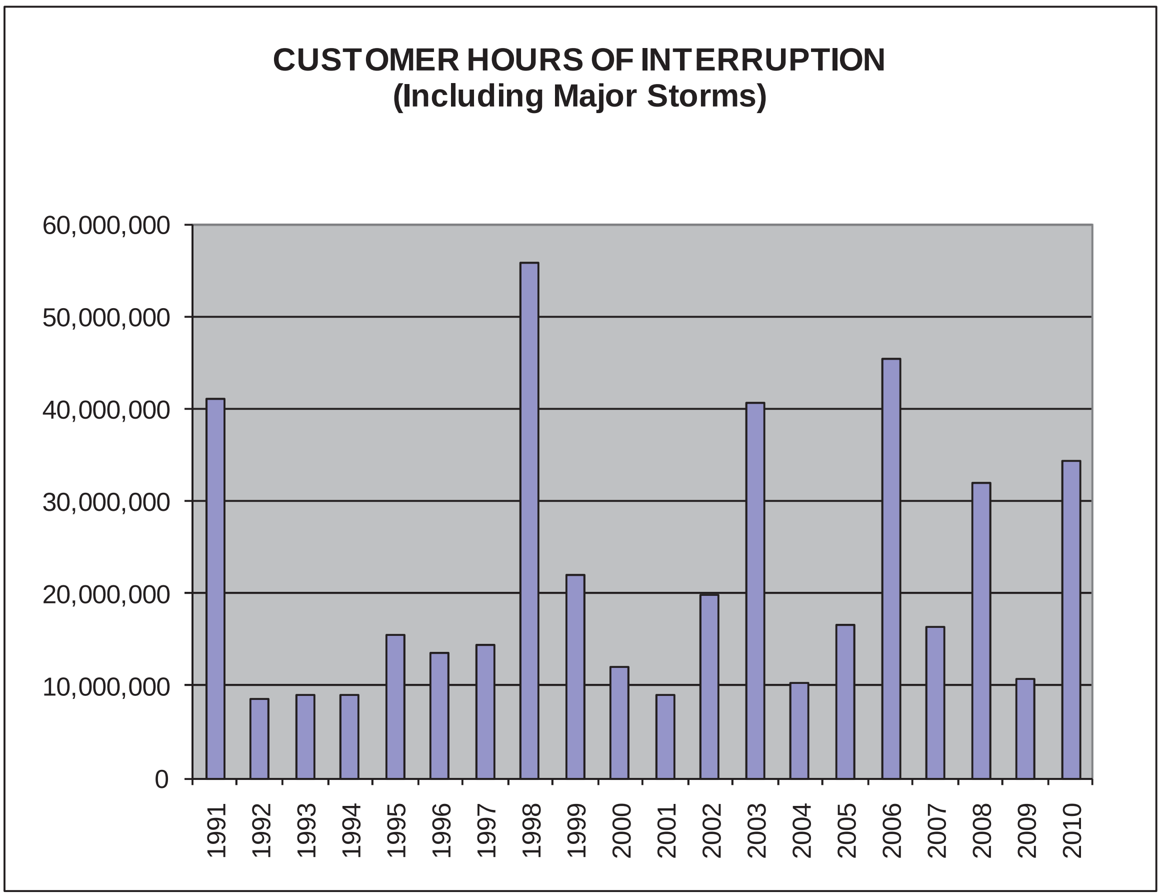


Figure 3: Customer Hours of Interruption (Including Major Storms)

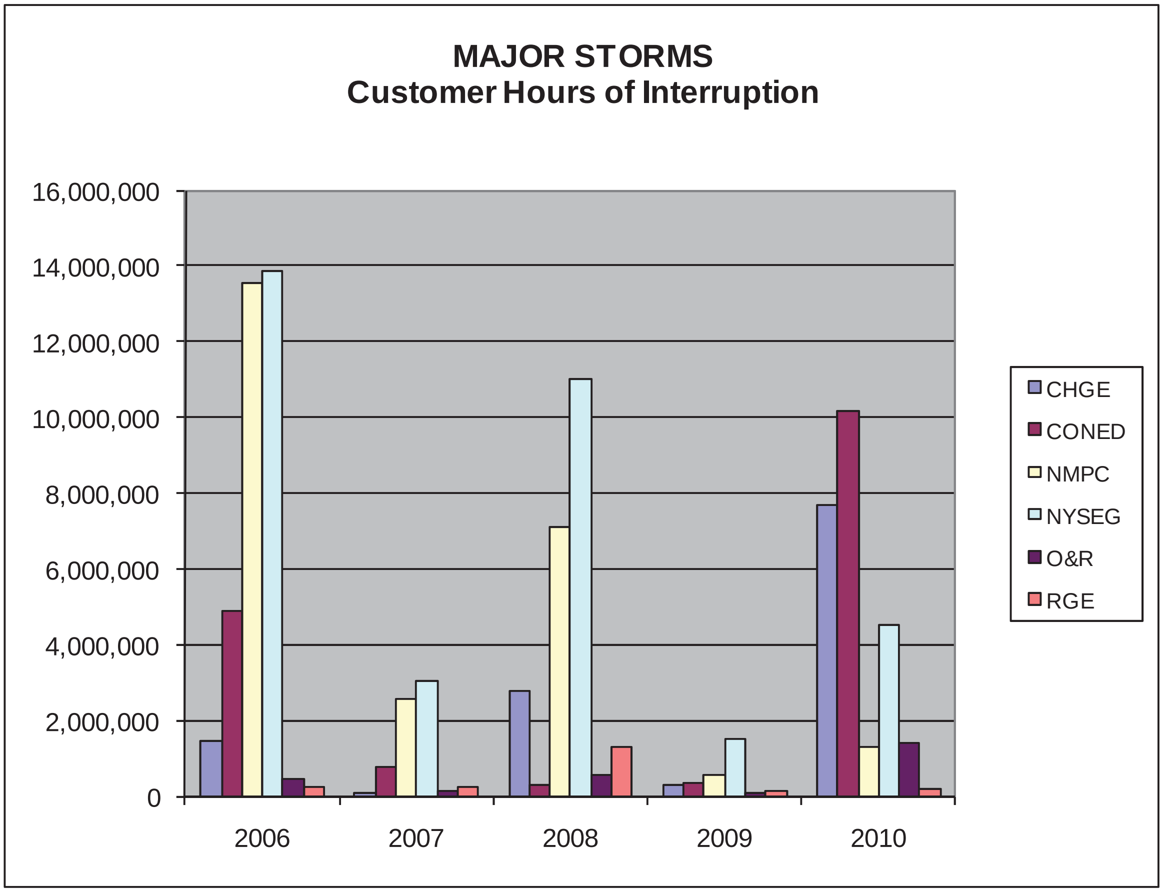


Figure 4: Major Storm Customer Hours

CON EDISON

Table 1: Con Edison's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Network Systems[13]						
Frequency				3.63	3.09	---
Duration				4.63	5.89	---
Radial System						
Frequency (SAIFI)	**0.54**	0.38	0.42	0.32	0.41	0.42
Duration (CAIDI)	**2.66**	**2.07**	1.83	1.74	1.95	2.05

Note: Data presented in red represents a failure to meet the RPM target for a given year.

[13] The duration and frequency metrics to measure network performance were replaced for 2009 with other measures.

Con Edison serves approximately 3.3 million customers in New York City and Westchester County. Electricity is supplied to 2.4 million customers using network systems. The remaining 900,000 customers are supplied by radial systems.

To minimize the frequency of customer outages, Con Edison's networks are designed with redundant supply paths. Individual service lines to customer premises, however, lack any supplemental supply. Given these design characteristics and underground settings, the majority of interruptions (78%) are associated with the service portion of the network system, as shown in Figure 5. Equipment failures (8%) are the next highest causes for interruptions in 2010 followed by Mains (7%).

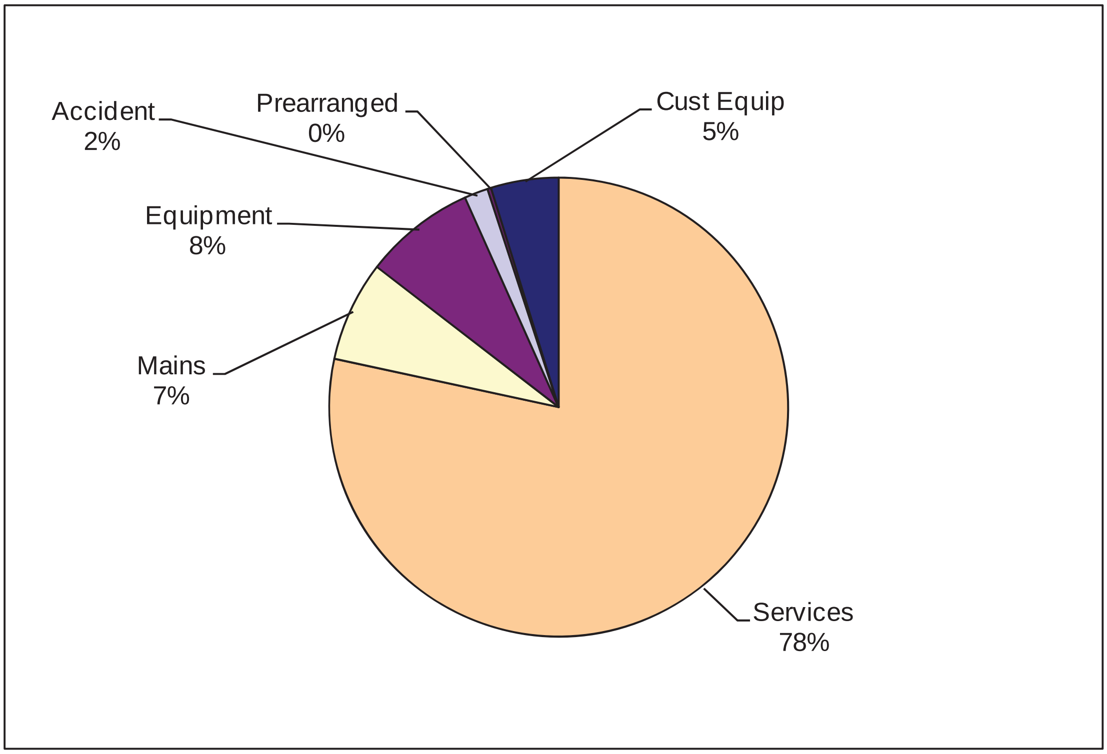


Figure 5: Con Edison's 2010 Network Interruptions by Cause

Due to concerns regarding the accuracy of the number of customers affected by an interruption in a network, we are now measuring network performance using two measures: the number of interruptions per 1000 customers and the average interruption duration. By using measures that are not based on the number of customers affected, we are able to monitor and trend network reliability performances without questioning the validity of the measures. In 2010, Con Edison's network interruptions metric was better than its 2009 performance. The Company also achieved its RPM network interruption target for the past two years. With regard to duration, Con Edison performed worse in 2010 when compared to its 2009 performance. The Company did not meet its RPM target for average interruption duration in 2010. Con Edison is seeking exclusion of storm related outages from its interruption performance levels. It also failed to achieve the remote monitoring system metric in its RPM, but is seeking an exclusion due to extraordinary circumstances with regard to the Remote Monitoring System (RMS) criteria for its Long Island City network. If these exclusions are granted, the Company would meet the targets and not incur any negative revenue adjustment.[14]

On its radial system, Con Edison's frequency in 2010 of 0.41 was worse than 2009's performances and nearly equal to its five year average. The Company met its RPM frequency target of 0.495 for 2010. Equipment failures are responsible for 75% of the interruptions on the radial system, followed by trees and accidents at 9% and 8%, respectively, as shown in Figure 6.

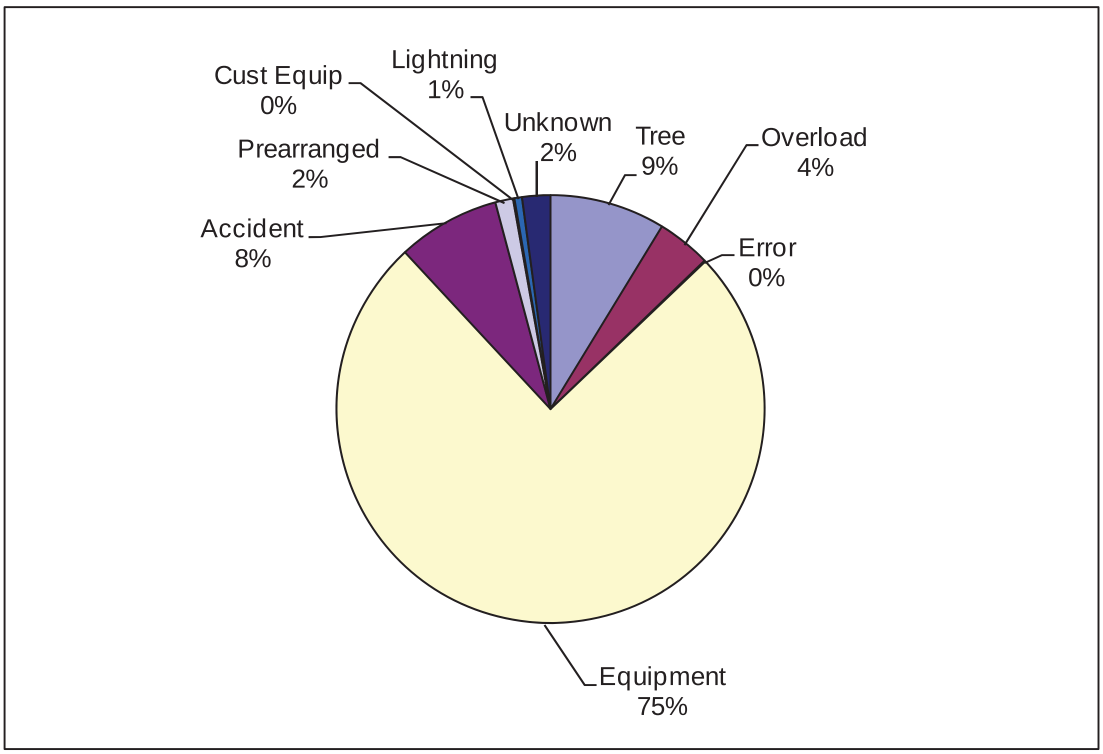


Figure 6: Con Edison's 2010 Radial Interruptions by Cause

[14] Con Edison filed a request for exemption on March 31, 2010 which has yet to be presented to the Commission for final action.

With respect to duration, Con Edison's radial performance in 2010 was worse than the previous two years. While the Company passed its RPM target of 2.04, duration performance is something we and the Company are monitoring closely. In response to a self-assessment recommended by Staff, Con Edison developed and implemented duration improvement strategies for both its radial and network system. To improve crewing efficiency and reduce outage duration, the Company has increased use of first responder staffing, increased the ability to mobile dispatch work to crews, and improve training resources. Con Edison stated that enhancements have been made to the process utilized for its outage management system to flag large outage jobs, and it now employs an automatic call out process for additional crews. The Company also continues to improve the reliability of its system by installing switches and other rapid restoration technologies. Given the focus and efforts Con Edison has put into place regarding duration, we believe 2010's performance is acceptable.

NATIONAL GRID

Table 2: National Grid's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	**1.01**	**0.96**	0.75	0.88	0.80	0.88
Duration (CAIDI)	2.05	2.01	1.96	1.91	1.98	1.98

Note: Data presented in red represents a failure to meet the RPM target for a given year.

National Grid serves approximately 1.59 million customers across upstate New York. The Company's 25,000 square mile territory includes metropolitan areas, such as the cities of Buffalo, Albany, and Syracuse, as well as many rural areas in northern New York and the Adirondacks.

In 2010, National Grid achieved both its reliability targets, comprising three consecutive years of positive performance. The Company's frequency level of 0.80 in 2010 improved as compared with 0.88 in 2009, and is well below its frequency target level of 0.93. The duration performance for 2010 was worse than 2009, but equal to its historic five-year average, and better than its duration target of 2.07 for five consecutive years. National Grid also provided consistent service on a region by region basis. In 2010, the Company's Northeast division failed to achieve its duration expectation and the Capital Region barely missed its frequency expectation. As previously discussed, the divisional expectations are defined by our Electric Service Standards.

Historically, equipment failures were National Grid's leading cause of interruptions. Aged equipment, leading to poor frequency performances in mid 2000 necessitated the Company's significant investment in capital improvement projects aimed at improving reliability. As a result of the upgrades and modifications to its distribution system, the percentage of interruptions caused by equipment failures is now less than tree related electric service interruptions for 2010 (see Figure 7, below). It should be noted, however, that tree-related outages were worse in 2009 and 2010 when compared to historic interruption rates. Analysis of the data indicates that the increase in tree related interruptions is attributable to increased broken limb conditions. Interruptions caused by re-growth and danger trees, however, were both lower in 2010 than in 2009. As a result, National Grid is not recommending changes to its five year trimming cycle or hazard tree removal program. To help reduce it tree-related outages, National Grid is doing additional off-cycle trimming and trimming on worst performing circuits in 2011.

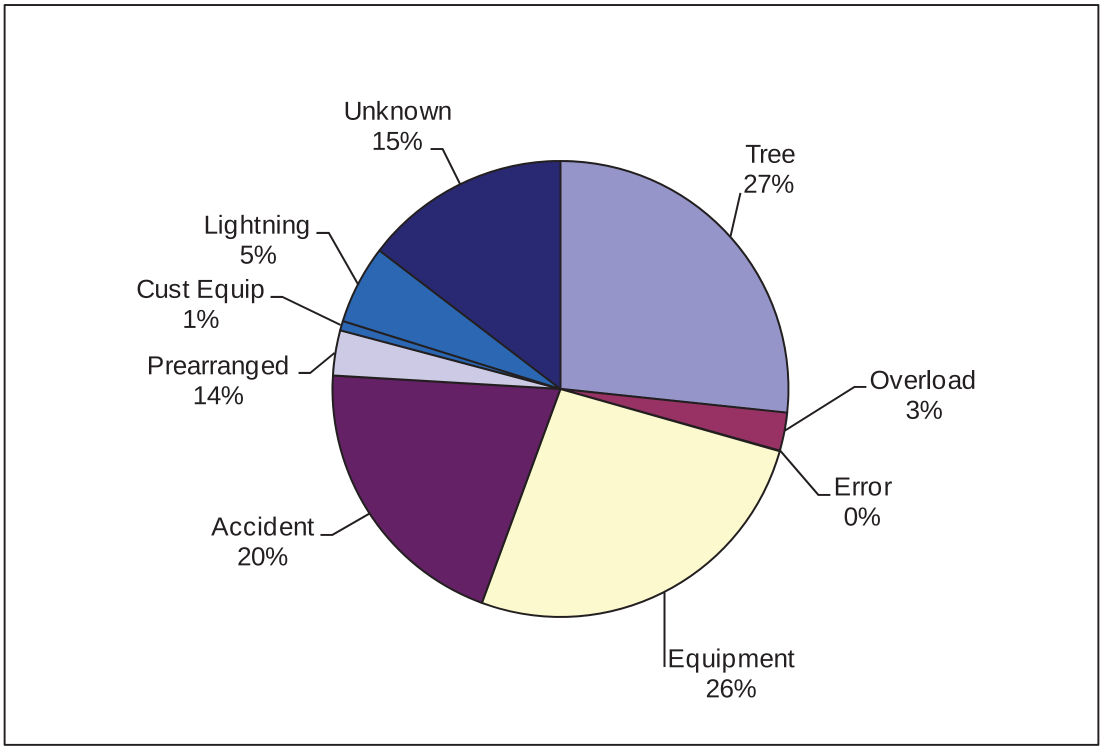


Figure 7: National Grid's 2010 Interruptions by Cause

In addition to improved performance on equipment failures, National Grid has decreased the number of customers affected when a failure occurs (see Table 3). The average number of customers affected by an interruption has been reduced from over 100 customers per interruption to approximately 90 customers per interruption in each of the last three years. National Grid credits the reduction to its effort to sectionalize lines via recloser and side tap fuse installations. National Grid's Line Recloser Program installs 100 additional reclosers per year and is expected to continue to limit the number of customers affected by a single interruption.

Table 3: National Grid's Historic Customers Affected per Interruption

	2006	**2007**	**2008**	**2009**	**2010**
Average number of customers affected per interruption	118	104	92	87	92

National Grid now uses a system that establishes repair work orders in direct response to inspection findings. Based on its success in repairing deteriorated items under its inspection and maintenance, National Grid will be discontinuing focused programs, such as the Pole Replacement Program and Feeder Hardening Program in 2011. While these programs were helpful in reducing National Grid's frequency performance over the past years, it is appropriate for the Company to consolidate its efforts in the interest of prioritizing and scheduling efficiencies. We expect that National Grid will continue to address reliability concerns on worst performing feeders, either through engineering reliability reviews or alternate methods, and maintain at least the current level of performance in future years.

NEW YORK STATE ELECTRIC AND GAS

Table 4: NYSEG's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	1.12	1.20	1.11	1.08	1.14	1.13
Duration (CAIDI)	2.01	2.22	2.08	2.00	1.98	2.06

Approximately 858,269 customers are served by NYSEG. The Company is primarily located in the Binghamton and Finger Lakes regions, but does have localized service regions, including areas near Plattsburgh, Brewster, Mechanicville, and Lancaster.

NYSEG's frequency performance of 1.14 was worse when compared with 2009's performance of 1.08, but nearly the same as the five year average. The 2010 duration performance of 1.98 was the best in the past five years. Overall, NYSEG's performance is satisfactory and the Company was able to meet its RPM reliability targets of 1.20 for frequency and 2.08 for duration.

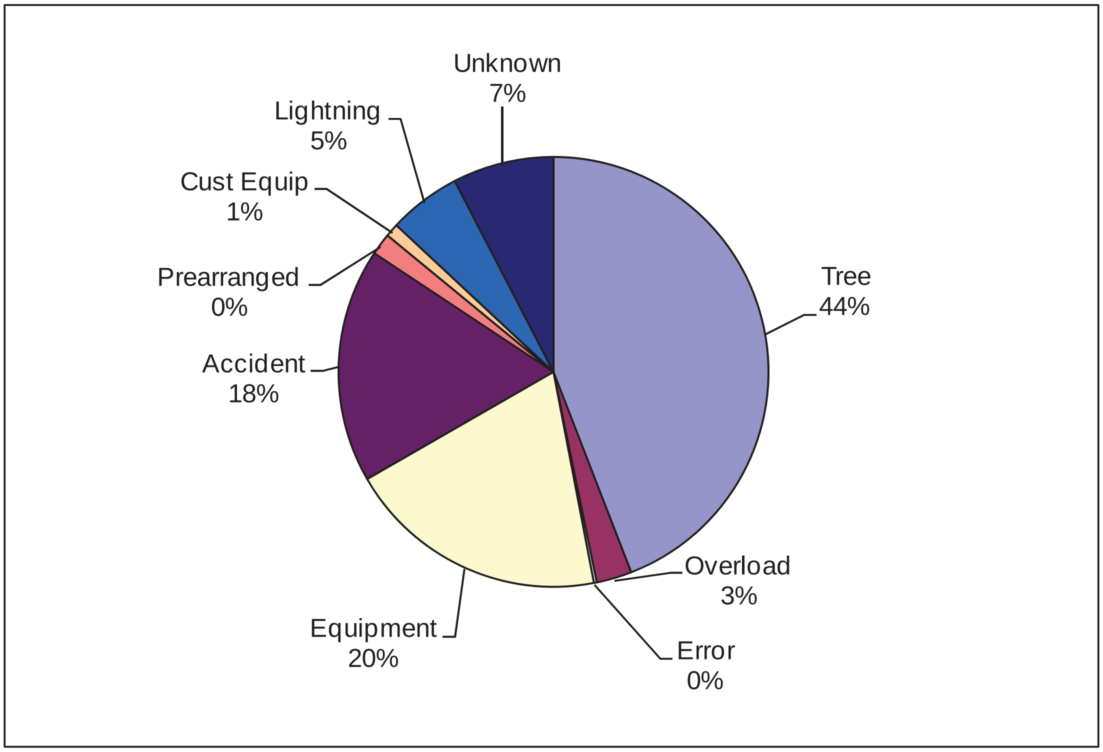


Figure 8: NYSEG's 2010 Interruptions by Cause

As shown in Figure 8, tree contacts (44%), equipment failures (20%), and accidents (18%) remain the predominant causes of interruption throughout NYSEG's twelve operating divisions in 2010. NYSEG has one of the worst frequency rates which is caused primarily by customers affected by tree interruptions. As a result, NYSEG needs to continue to focus on improving its distribution vegetation management program and reducing tree related outages. The Commission approved increased funding for distribution vegetation management activities as part of its last 2010 rate case agreement to help move NYSEG towards full cycle trimming activities. Therefore, Staff expects NYSEG to address the issue of tree trimming more aggressively and undertake measures to identify and perform trimming in areas where tree related outages are more frequent.

Equipment failures are NYSEG's second major cause for interruption. For the past two years, it accounted for 20% of the total number of interruptions. NYSEG has been addressing equipment failures under its Transmission and Distribution Infrastructure Replacement Program (TDIRP) program. The TDIRP program replaces electrical T&D equipment based on the condition, age, and failure characteristics of the specific item based on the Company's experience and knowledge. Funding for the

TDIRP program was reduced significantly in 2009 to approximately $6.0 million from historical levels of approximately $23 million annually.[15] In 2010, NYSEG began to invest in its system at close to or higher than historic levels. The most recent rate case supported $25 million in expenditures for the TDIRP efforts annually, to bring the Company back up to pre 2009 spending levels. The reinvestment into this program is expected to help reduce outages related to equipment failures and improve the system reliability on a going forward and proactive basis. Staff will continue to monitor the Company's performance on these issues.

ROCHESTER GAS AND ELECTRIC

Table 5: RG&E's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	0.79	0.83	0.78	0.59	0.71	0.74
Duration (CAIDI)	1.78	1.73	1.85	1.80	1.71	1.77

RG&E serves approximately 358,109 customers. Although the Company is comprised of four service areas, its Rochester division accounts for approximately 80% of its customer base. As a result, its overall reliability statistics mirror that of the Rochester division.

With regard to service reliability, RG&E continues to be one of the better utilities in the state by continually performing better than its RPM targets of 0.90 for frequency and 1.90 for duration, as established in its rate orders. As shown in Table 5, RG&E's performance for frequency and duration is fairly consistent with its five year average. The Company's frequency performance of 0.71 in 2010 was an increase from 0.59 in 2009; however, the 2009 performance was the best in the past five years. RG&E's duration performance of 1.71 in 2010 was better than in 2009 and better than the five-year average.

[15] In 2009, the Company reduced all expenditures to essential needs only while stating financial issues within the Company as the reasoning behind the reduced spending.

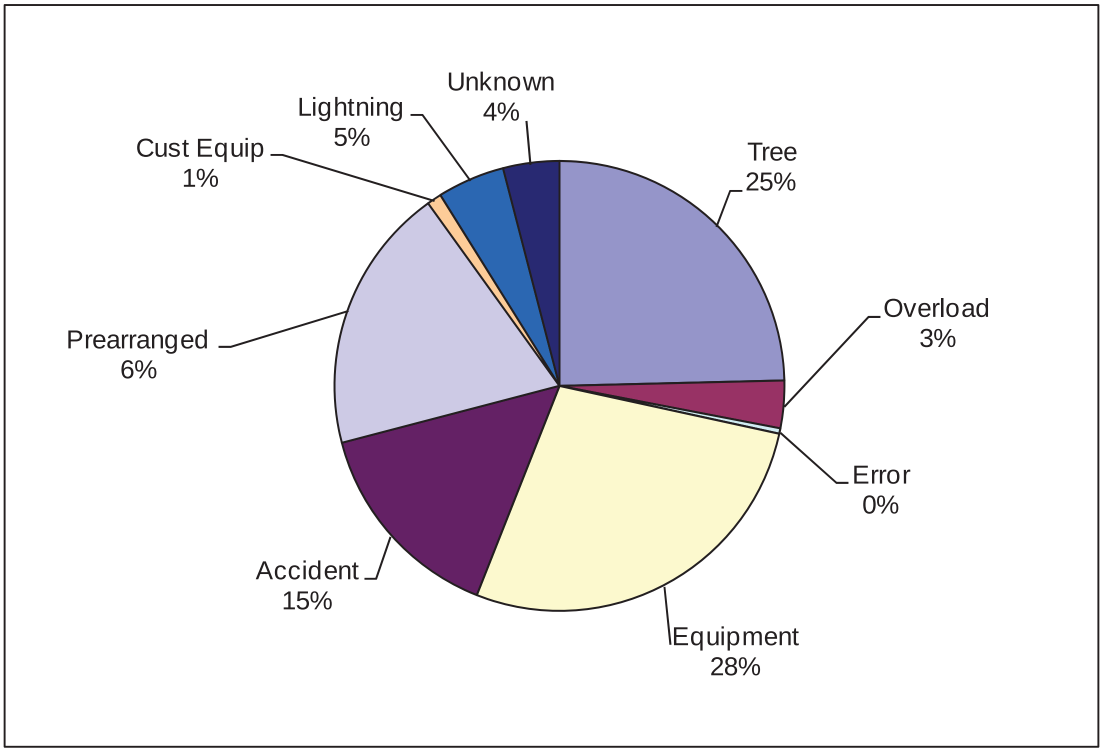


Figure 9: RG&E's 2010 Interruptions by Cause

Figure 9 shows that the two major contributors to interruptions in 2010 continue to be equipment failures (28%) and tree contacts (25%). Similar to NYSEG, funding for RG&E's Transmission and Distribution Infrastructure Replacement Program (TDIRP) was reduced due to Company financial issues in 2009 and the beginning of 2010. In the last rate case, the Commission supported expenditures for the TDIRP efforts, in the amount of $15 million annually, to bring the Company back up to pre 2009 spending levels. Likewise, the Commission also supported increased expenditures for vegetation management, in the amount of $6.6 million annually, allowing the Company to implement a full system vegetation management (tree trimming) cycle program. Staff believes that these two programs and associated expenditures will help reduce outages and improve the system reliability going forward on proactive basis.

CENTRAL HUDSON GAS AND ELECTRIC

Table 6: Central Hudson's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	**1.59**	1.42	1.27	1.37	1.27	1.38
Duration (CAIDI)	**2.58**	2.43	2.47	2.22	2.42	2.43

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Central Hudson serves approximately 298,000 customers in the Mid-Hudson Valley region. The Company's territory is mainly suburban and rural. Central Hudson does serve some urban regions, such as the cities of Poughkeepsie and Newburgh.

Central Hudson's frequency performance of 1.27 in 2010 was better than 2009 and ties its five-year best. The Company's duration performance of 2.42 in 2010, on the other hand, was slightly better than average. Figure 10 shows that 38% of customer interruptions were due to tree related issues, followed by accidents which comprised 25%. In 2010, the Company achieved its RPM targets of 1.45 for frequency and 2.50 for duration.

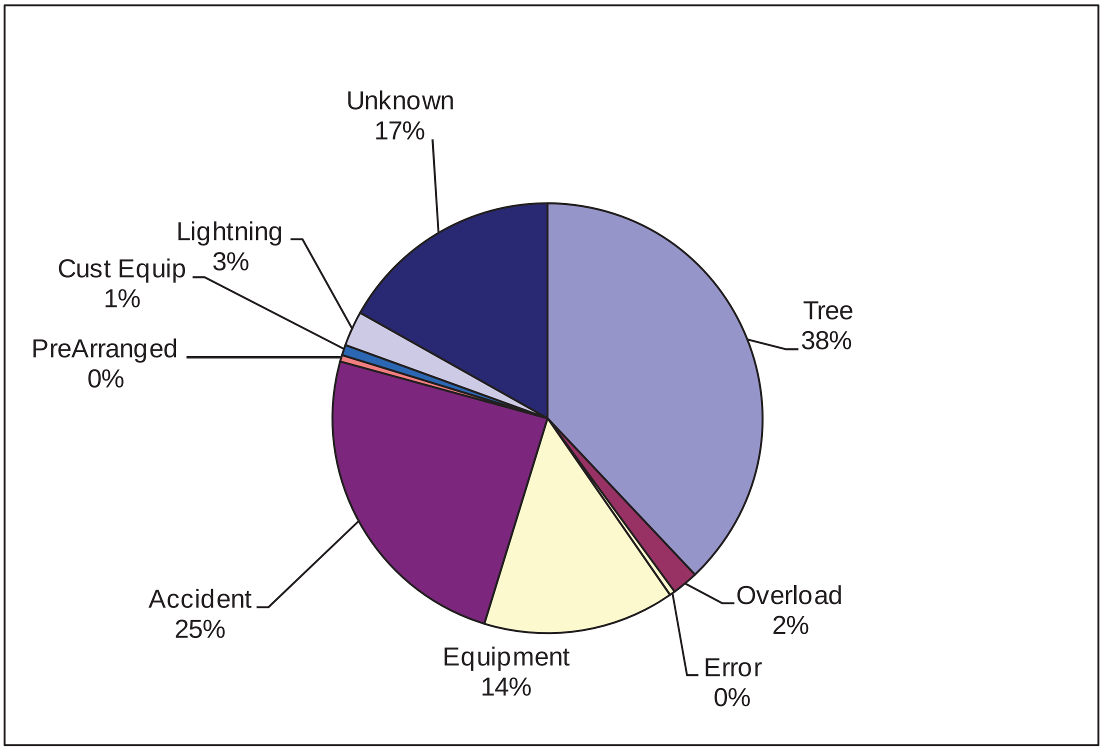


Figure 10: Central Hudson's 2010 Interruptions by Cause

As is the case with most overhead distribution utilities, trees are a primary cause of outages (Figure 10, above). The Company as a whole suffers more tree interruptions per customer served than any other major New York electric utility. Since 2007 Central Hudson has done vegetation line clearance in accordance with a new, improved specification. Using greater level of detail available to it, the Company reports a trend of decreasing interruptions resulting from trees falling inside its trimming zone. Staff will follow-up this summer with the Company and perform field reviews of electric lines that are at or near the end of the four-year trimming cycle.

The Unknown and Accident categories historically make up large portions of electric interruptions for all New York utilities, and this is the case for Central Hudson as well. Staff will be looking more closely with the Company at these classifications of outages to see if the Company's performance can be improved.

Equipment failures cause a large number of electric interruptions as is the case with most electric utility companies. Central Hudson is continuing several programs to decrease the number of these interruptions, including programs for substation breaker replacement, porcelain cutout replacement, 14kV paper and lead cable replacement, automatic load transfer switch installation, and aging recloser replacement (including remote communication). In addition, the Company has a program to upgrade individual circuits.

ORANGE AND ROCKLAND

Table 7: O&R's Historic Performance Excluding Major Storms

Metric	2006	2007	2008	2009	2010	5-Year Average
Frequency (SAIFI)	1.23	1.03	1.19	0.96	1.21	1.13
Duration (CAIDI)	1.51	1.60	**1.83**	1.66	**1.79**	1.68

Note: Data presented in red represents a failure to meet the RPM target for a given year.

Orange and Rockland serves approximately 218,000 customers in three New York counties along the New Jersey and Pennsylvania border. In 2010, the

Company met its reliability performance mechanism target of 1.36 for frequency with a frequency of 1.21; however, it failed to achieve the duration target of 1.70 with a 1.79 performance.[16] As the table above shows, the 2010 frequency and duration performance levels were both much worse than last years and continue ORU's sporadic performance trend from year to year. The 2010 results were worse than the 5 year averages and are similar to those in 2008 when the Company again failed to achieve its duration target. Staff will continue to work with the Company to help reduce the variability in performances.

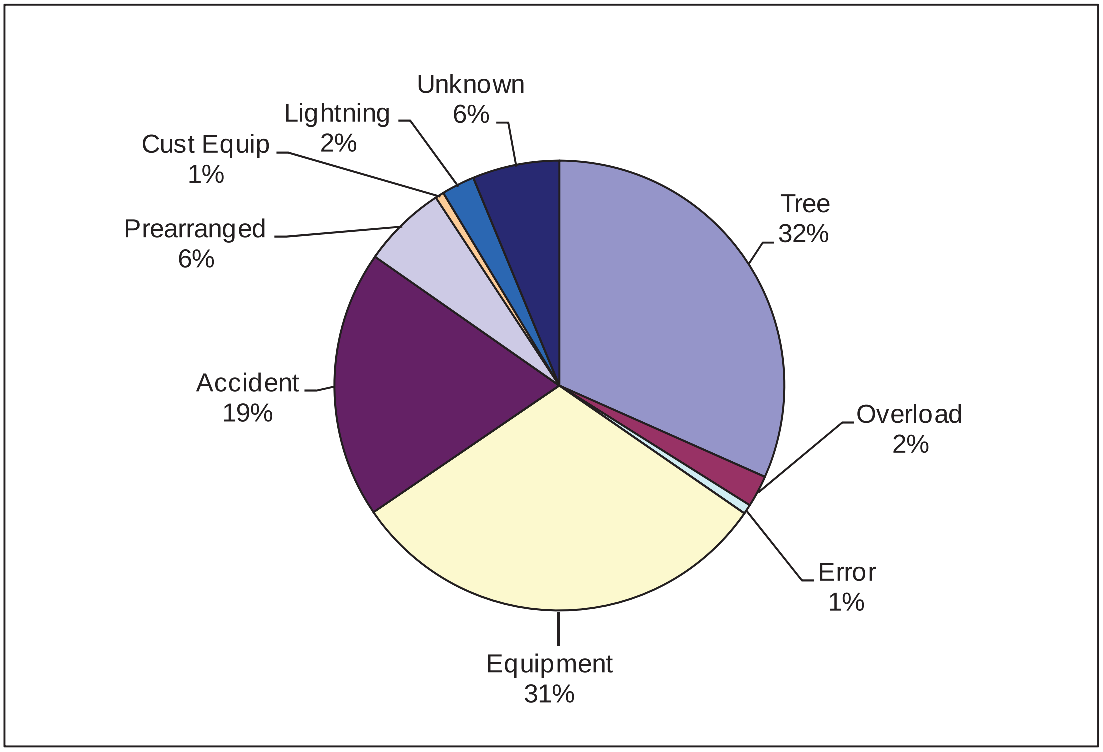


Figure 11: Orange and Rockland's 2010 Interruptions by Cause

As shown in Figure 11, tree contacts (32%) and equipment failures (31%) caused the majority of interruptions in 2010. Orange and Rockland is addressing reliability issues resulting from equipment failures through capital improvement programs such as the Distribution Automation Program, the Underground Cable

[16] The Company has filed a petition to the Commission for exemption from the RPM revenue adjustment, related to a storm that affected its Eastern Division on July 19, 2010. This petition has not been acted on by the Commission.

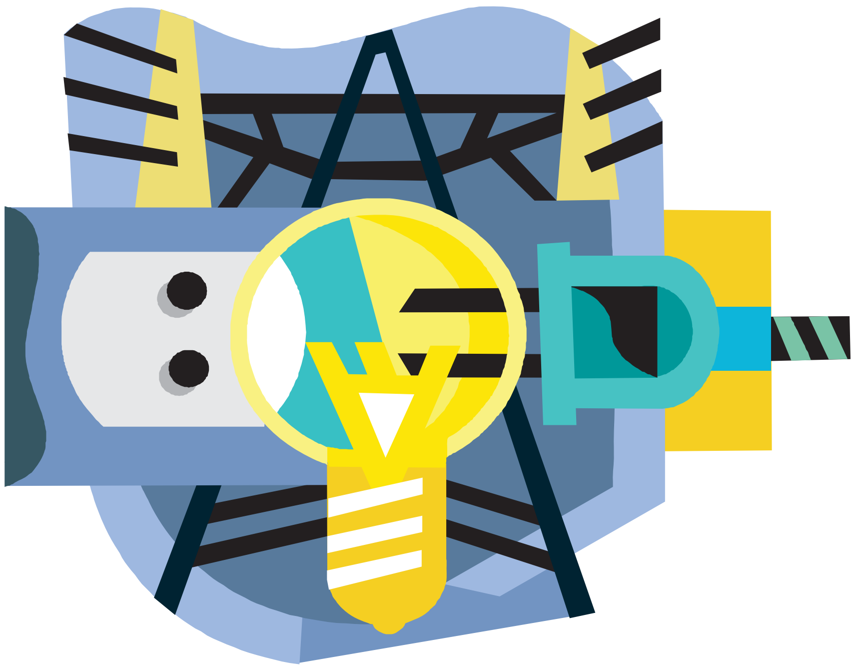
Maintenance and Rebuild Program, and a number of service reliability improvement projects directed by the circuit priority-rating methodology.

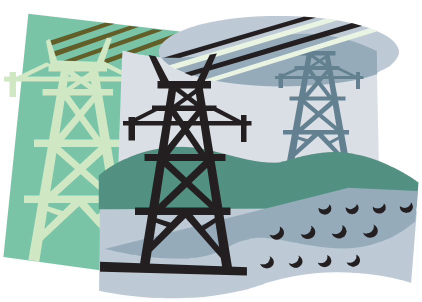
The Company continues to address concerns regarding tree-related outages through increased efforts on its line clearance programs. In addition to the four-year cycle based tree trimming program, the Company has continued to identify and perform supplemental trimming to address areas with recurring tree related outages. These programs are expected to reduce the impact of tree contacts on the Company's electrical system through the coming years.

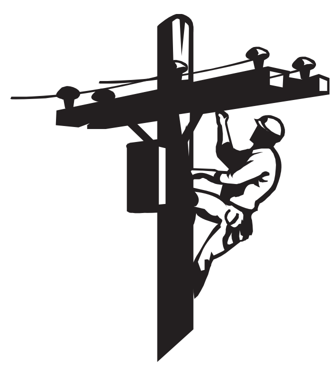
APPENDIX

2010 INTERRUPTON REPORT

The 2010 Interruption Report







Office of Electricity, Gas, and Water

June 2011

June 2011

ATTACHMENT
Definitions and Explanations of Terms Used in the 2010 Statewide Electric Service Interruption Report

Interruption is the loss of service for five minutes or more.

Customer hours is the time a customer is without electric service.

Customers affected is the number of customers without electric service.

Customers served is the number of customers as of the last day of the **current year.** For example, for the calendar year of **2010**, customers served is the number of customers as of 12/31/2010. For indices using customers served, the **previous** year is used.

Frequency (**SAIFI)** measures the average number of interruptions experienced by customers served by the utility. It is the customers affected divided by the customers served at the end of the **previous** year, i.e., 12/31/2009.

Duration (CAIDI) measures the average time that an affected customer is out of electric service. It is the customer hours divided by the customers affected.

Availability (SAIDI) is the average amount of time a customer is out-of-service during a year. It is the customer hours divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2009. Mathematically, it also is **SAIFI** multiplied by **CAIDI**.

Interruptions Per 1000 Customers Served is the number of interruptions divided by the number of customers served at the end of the **previous** year, i.e., 12/31/2009, divided by 1,000.

Major Storm is defined as any storm which causes service interruptions of at least ten percent of customers in an operating area, or if the interruptions last for 24 hours or more.

Operating Area is a geographical subdivision of each electric utility's franchise territory. These areas are also called regions, divisions, or districts.

Most of the data is presented two ways, with major storms included and major storms excluded. Major storms tend to distort a utility's performance trend. Tables and graphs that exclude major storms illustrate interruptions that are more under the utility's control. It portrays a utility's system facilities under normal conditions, although this can be misleading because interruptions during "normal" bad weather are included and it is difficult to analyze from year to year.

The first two tables show frequency and duration indices for the last five years for each utility and Statewide with and without Con Edison data. Con Edison has by far the lowest frequency numbers and tends to distort the Statewide data. Much of Con Edison's distribution system consists of a secondary network. In a secondary network, a customer is fed from multiple supplies, making the probability of an interruption relatively rare.

COMPARISON OF SERVICE RELIABILITY INDICES
(EXCLUDING MAJOR STORMS)

	2006	2007	2008	2009	2010	5 YR AVG
CHGE						
FREQUENCY	1.59	1.42	1.27	1.37	1.27	1.38
DURATION	2.58	2.43	2.47	2.22	2.42	2.43
CONED						
FREQUENCY	0.16	0.16	0.13	0.10	0.13	0.13
DURATION	8.23	1.97	2.27	2.27	2.57	3.46
LIPA *						
FREQUENCY	0.75	0.90	0.77	0.74	0.73	0.78
DURATION	1.37	1.20	1.36	1.17	1.11	1.24
NAT GRID						
FREQUENCY	1.01	0.96	0.75	0.88	0.80	0.88
DURATION	2.05	2.01	1.96	1.91	1.98	1.98
NYSEG						
FREQUENCY	1.12	1.20	1.11	1.08	1.14	1.13
DURATION	2.01	2.22	2.08	2.00	1.98	2.06
O&R						
FREQUENCY	1.23	1.03	1.19	1.03	1.21	1.14
DURATION	1.51	1.60	1.83	1.67	1.79	1.68
RG&E						
FREQUENCY	0.79	0.83	0.78	0.59	0.71	0.74
DURATION	1.78	1.73	1.85	1.80	1.71	1.77
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.00	1.02	0.88	0.90	0.89	0.94
DURATION	1.92	1.88	1.89	1.79	1.82	1.86
STATEWIDE (WITH CONED)						
FREQUENCY	0.65	0.65	0.56	0.56	0.57	0.60
DURATION	2.57	1.89	1.93	1.83	1.89	2.02

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

COMPARISON OF SERVICE RELIABILITY INDICES
(INCLUDING MAJOR STORMS)

	2006	2007	2008	2009	2010	5 YR AVG
CHGE						
FREQUENCY	2.20	1.51	2.15	1.63	2.62	2.02
DURATION	4.12	2.51	5.76	2.48	10.94	5.16
CONED						
FREQUENCY	0.23	0.18	0.14	0.11	0.23	0.18
DURATION	12.31	3.12	2.71	3.06	15.05	7.25
LIPA *						
FREQUENCY	1.18	1.04	1.09	0.81	1.04	1.03
DURATION	1.99	1.37	1.65	1.25	1.84	1.62
NAT GRID						
FREQUENCY	1.48	1.31	1.37	1.01	0.98	1.23
DURATION	7.18	2.70	4.32	2.01	2.46	3.74
NYSEG						
FREQUENCY	1.79	1.71	2.14	1.47	1.84	1.79
DURATION	10.32	3.62	7.07	2.68	4.09	5.55
O&R						
FREQUENCY	1.81	1.17	1.64	1.15	1.79	1.51
DURATION	2.15	1.92	2.94	1.89	4.76	2.73
RG&E						
FREQUENCY	0.98	1.16	1.36	0.74	0.79	1.01
DURATION	2.14	1.80	3.77	2.03	2.18	2.38
STATEWIDE (WITHOUT CONED)						
FREQUENCY	1.49	1.31	1.51	1.07	1.29	1.34
DURATION	6.02	2.56	4.62	2.09	4.09	3.87
STATEWIDE (WITH CONED)						
FREQUENCY	0.96	0.83	0.93	0.67	0.84	0.85
DURATION	6.65	2.61	4.50	2.16	5.35	4.25

* LIPA is not regulated by the NYS PSC.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

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STATEWIDE (WITHOUT CON ED)
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	55,211	55,425	53,758	55,995	54,310	54,940
Number of Customer-Hours	8,439,916	8,439,464	7,399,179	7,116,848	7,197,156	7,718,512
Number of Customers Affected	4,400,072	4,495,428	3,910,426	3,976,492	3,962,829	4,149,049
Number of Customers Served	4,428,946	4,433,994	4,425,772	4,437,856	4,446,105	4,434,535
Average Duration Per Customer Affected (CAIDI)	1.92	1.88	1.89	1.79	1.82	1.86
Average Duration Per Customers Served	1.91	1.91	1.67	1.61	1.62	1.74
Interruptions Per 1000 Customers Served	12.52	12.51	12.12	12.65	12.24	12.41
Number of Customers Affected Per Customer Served (SAIFI)	1.00	1.02	0.88	0.90	0.89	0.94

STATEWIDE (WITH CON ED)
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	65,752	66,746	65,403	70,930	68,221	67,410
Number of Customer-Hours	12,603,322	9,429,452	8,326,562	7,891,155	8,284,480	9,306,994
Number of Customers Affected	4,905,844	4,996,967	4,319,550	4,316,932	4,385,672	4,584,993
Number of Customers Served	7,647,367	7,678,791	7,697,498	7,729,599	7,766,918	7,704,035
Average Duration Per Customer Affected (CAIDI)	2.57	1.89	1.93	1.83	1.89	2.02
Average Duration Per Customers Served	1.66	1.23	1.08	1.03	1.07	1.21
Interruptions Per 1000 Customers Served	8.66	8.73	8.52	9.21	8.83	8.79
Number of Customers Affected Per Customer Served (SAIFI)	0.65	0.65	0.56	0.56	0.57	0.60

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** For those indices that use Customers Served, Customers Served is the December

STATEWIDE (WITHOUT CON ED)
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	70,872	61,753	73,150	61,841	72,135	67,950
Number of Customer-Hours	39,413,242	14,848,512	30,962,269	9,923,723	23,466,391	23,722,827
Number of Customers Affected	6,548,910	5,808,516	6,705,414	4,752,148	5,741,806	5,911,359
Number of Customers Served	4,428,946	4,433,994	4,425,772	4,437,856	4,446,105	4,434,535
Average Duration Per Customer Affected (CAIDI)	6.02	2.56	4.62	2.09	4.09	3.87
Average Duration Per Customers Served	8.94	3.35	6.98	2.24	5.29	5.36
Interruptions Per 1000 Customers Served	16.08	13.94	16.50	13.97	16.25	15.35
Number of Customers Affected Per Customer Served (SAIFI)	1.49	1.31	1.51	1.07	1.29	1.34

STATEWIDE (WITH CON ED)
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	86,734	74,261	85,548	77,181	91,471	83,039
Number of Customer-Hours	48,437,221	16,630,252	32,188,186	11,046,399	34,693,862	28,599,184
Number of Customers Affected	7,282,114	6,379,276	7,158,329	5,118,841	6,487,588	6,485,230
Number of Customers Served	7,647,367	7,678,791	7,697,498	7,729,599	7,766,918	7,704,035
Average Duration Per Customer Affected (CAIDI)	6.65	2.61	4.50	2.16	5.35	4.25
Average Duration Per Customers Served	6.38	2.17	4.19	1.44	4.49	3.73
Interruptions Per 1000 Customers Served	11.42	9.71	11.14	10.03	11.83	10.83
Number of Customers Affected Per Customer Served (SAIFI)	0.96	0.83	0.93	0.67	0.84	0.85

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CENTRAL HUDSON
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	7,538	6,386	6,857	6,705	7,762	7,050
Number of Customer-Hours	1,201,109	1,021,859	933,993	910,250	922,392	997,921
Number of Customers Affected	464,765	420,769	377,564	410,516	380,489	410,821
Number of Customers Served	295,368	298,386	300,621	299,557	299,971	298,781
Average Duration Per Customer Affected (CAIDI)	2.58	2.43	2.47	2.22	2.42	2.43
Average Duration Per Customers Served	4.10	3.46	3.13	3.03	3.08	3.36
Interruptions Per 1000 Customers Served	25.74	21.62	22.98	22.30	25.91	23.71
Number of Customers Affected Per Customer Served (SAIFI)	1.59	1.42	1.27	1.37	1.27	1.38

CENTRAL HUDSON
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	10,066	6,681	9,887	7,609	11,994	9,247
Number of Customer-Hours	2,649,690	1,117,802	3,705,277	1,211,827	8,597,567	3,456,433
Number of Customers Affected	643,778	444,813	642,949	488,732	785,806	601,216
Number of Customers Served	295,368	298,386	300,621	299,557	299,971	298,781
Average Duration Per Customer Affected (CAIDI)	4.12	2.51	5.76	2.48	10.94	5.16
Average Duration Per Customers Served	9.05	3.78	12.42	4.03	28.70	11.60
Interruptions Per 1000 Customers Served	34.38	22.62	33.13	25.31	40.04	31.10
Number of Customers Affected Per Customer Served (SAIFI)	2.20	1.51	2.15	1.63	2.62	2.02

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (SYSTEM)
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	10,541	11,321	11,645	14,935	13,911	12,471
Number of Customer-Hours	4,163,407	989,988	927,383	774,307	1,087,325	1,588,482
Number of Customers Affected	505,772	501,539	409,124	340,440	422,843	435,944
Number of Customers Served	3,218,421	3,244,797	3,271,726	3,291,743	3,320,813	3,269,500
Average Duration Per Customer Affected (CAIDI)	8.23	1.97	2.27	2.27	2.57	3.46
Average Duration Per Customers Served	1.31	0.31	0.29	0.24	0.33	0.49
Interruptions Per 1000 Customers Served	3.31	3.52	3.59	4.56	4.23	3.84
Number of Customers Affected Per Customer Served (SAIFI)	0.16	0.16	0.13	0.10	0.13	0.13

CON ED (SYSTEM)
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	15,862	12,508	12,398	15,340	19,336	15,089
Number of Customer-Hours	9,023,979	1,781,740	1,225,917	1,122,677	11,227,471	4,876,357
Number of Customers Affected	733,204	570,760	452,915	366,693	745,782	573,871
Number of Customers Served	3,218,421	3,244,797	3,271,726	3,291,743	3,320,813	3,269,500
Average Duration Per Customer Affected (CAIDI)	12.31	3.12	2.71	3.06	15.05	7.25
Average Duration Per Customers Served	2.83	0.55	0.38	0.34	3.41	1.50
Interruptions Per 1000 Customers Served	4.98	3.89	3.82	4.69	5.87	4.65
Number of Customers Affected Per Customer Served (SAIFI)	0.23	0.18	0.14	0.11	0.23	0.18

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** For those indices that use Customers Served, Customers Served is the December value from the previous year.

CON ED (NETWORK)

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	4,274	5,571	5,485	8,650	7,434	6,283
Number of Customer-Hours	2,947,306	316,477	252,964	273,705	370,405	832,171
Number of Customers Affected	48,467	176,430	40,301	52,994	54,555	74,549
Number of Customers Served	2,363,897	2,361,145	2,385,760	2,403,818	2,439,565	2,390,837
Average Duration Per Customer Affected (CAIDI)	60.81	1.79	6.28	5.16	6.79	16.17
Average Duration Per Customers Served	1.26	0.13	0.11	0.11	0.15	0.35
Interruptions Per 1000 Customers Served	1.83	2.36	2.32	3.63	3.09	2.64
Number of Customers Affected Per Customer Served (SAIFI)	0.021	0.075	0.017	0.022	0.023	0.031

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CON ED (RADIAL)

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	6,267	5,750	6,160	6,285	6,477	6,188
Number of Customer-Hours	1,216,101	673,511	674,419	500,602	716,920	756,310
Number of Customers Affected	457,305	325,109	368,823	287,446	368,288	361,394
Number of Customers Served	854,524	883,652	885,966	887,925	881,248	878,663
Average Duration Per Customer Affected (CAIDI)	2.66	2.07	1.83	1.74	1.95	2.05
Average Duration Per Customers Served	1.43	0.79	0.76	0.57	0.81	0.87
Interruptions Per 1000 Customers Served	7.39	6.73	6.97	7.09	7.29	7.10
Number of Customers Affected Per Customer Served (SAIFI)	0.54	0.38	0.42	0.32	0.41	0.42

CON ED (RADIAL)

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	11,588	6,937	6,913	6,690	11,902	8,806
Number of Customer-Hours	6,076,673	1,465,264	972,954	848,971	10,857,066	4,044,185
Number of Customers Affected	684,737	394,330	412,614	313,699	691,227	499,321
Number of Customers Served	854,524	883,652	885,966	887,925	881,248	878,663
Average Duration Per Customer Affected (CAIDI)	8.87	3.72	2.36	2.71	15.71	6.67
Average Duration Per Customers Served	7.17	1.71	1.10	0.96	12.23	4.63
Interruptions Per 1000 Customers Served	13.67	8.12	7.82	7.55	13.40	10.11
Number of Customers Affected Per Customer Served (SAIFI)	0.81	0.46	0.47	0.35	0.78	0.57

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

LIPA
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	18,634	18,736	18,135	17,795	17,180	18,096
Number of Customer-Hours	1,129,275	1,190,411	1,166,613	958,679	905,031	1,070,002
Number of Customers Affected	823,396	995,077	856,405	821,723	811,969	861,714
Number of Customers Served	1,103,162	1,108,540	1,110,853	1,114,716	1,117,281	1,110,910
Average Duration Per Customer Affected (CAIDI)	1.37	1.20	1.36	1.17	1.11	1.24
Average Duration Per Customers Served	1.03	1.08	1.05	0.86	0.81	0.97
Interruptions Per 1000 Customers Served	16.99	16.98	16.36	16.02	15.41	16.35
Number of Customers Affected Per Customer Served (SAIFI)	0.75	0.90	0.77	0.74	0.73	0.78

LIPA
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	24,905	20,077	20,471	19,003	22,867	21,465
Number of Customer-Hours	2,564,134	1,564,559	1,998,270	1,121,723	2,125,507	1,874,839
Number of Customers Affected	1,289,698	1,142,365	1,208,292	894,595	1,153,884	1,137,767
Number of Customers Served	1,103,162	1,108,540	1,110,853	1,114,716	1,117,281	1,110,910
Average Duration Per Customer Affected (CAIDI)	1.99	1.37	1.65	1.25	1.84	1.62
Average Duration Per Customers Served	2.34	1.42	1.80	1.01	1.91	1.70
Interruptions Per 1000 Customers Served	22.71	18.20	18.47	17.11	20.51	19.40
Number of Customers Affected Per Customer Served (SAIFI)	1.18	1.04	1.09	0.81	1.04	1.03

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* Customers Served is the number of customers served at the end of the current year.
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NATIONAL GRID

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	13,665	14,606	12,939	15,915	13,822	14,189
Number of Customer-Hours	3,289,340	3,045,363	2,334,754	2,645,775	2,529,126	2,768,872
Number of Customers Affected	1,607,461	1,518,634	1,188,585	1,387,131	1,277,727	1,395,908
Number of Customers Served	1,589,949	1,594,179	1,583,311	1,589,810	1,593,830	1,590,216
Average Duration Per Customer Affected (CAIDI)	2.05	2.01	1.96	1.91	1.98	1.98
Average Duration Per Customers Served	2.07	1.92	1.46	1.67	1.59	1.74
Interruptions Per 1000 Customers Served	8.62	9.19	8.12	10.05	8.69	8.93
Number of Customers Affected Per Customer Served (SAIFI)	1.01	0.96	0.75	0.88	0.80	0.88

NATIONAL GRID

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	16,279	16,222	18,301	17,060	15,571	16,687
Number of Customer-Hours	16,813,162	5,605,931	9,410,833	3,214,148	3,824,438	7,773,703
Number of Customers Affected	2,341,235	2,075,480	2,177,786	1,599,090	1,553,727	1,949,464
Number of Customers Served	1,589,949	1,594,179	1,583,311	1,589,810	1,593,830	1,590,216
Average Duration Per Customer Affected (CAIDI)	7.18	2.70	4.32	2.01	2.46	3.74
Average Duration Per Customers Served	10.61	3.53	5.90	2.03	2.41	4.89
Interruptions Per 1000 Customers Served	10.27	10.20	11.48	10.77	9.79	10.50
Number of Customers Affected Per Customer Served (SAIFI)	1.48	1.31	1.37	1.01	0.98	1.23

* Customers Served is the number of customers served at the end of the current year.

** For those indices that use Customers Served, Customers Served is the December value from the previous year.

NYSEG

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	9,682	10,317	10,027	9,643	9,777	9,889
Number of Customer-Hours	1,913,315	2,299,142	1,980,213	1,848,599	1,934,747	1,995,203
Number of Customers Affected	953,941	1,034,113	953,105	922,448	975,375	967,796
Number of Customers Served	859,440	859,963	857,517	858,712	856,474	858,421
Average Duration Per Customer Affected (CAIDI)	2.01	2.22	2.08	2.00	1.98	2.06
Average Duration Per Customers Served	2.24	2.68	2.30	2.16	2.25	2.32
Interruptions Per 1000 Customers Served	11.33	12.00	11.66	11.25	11.39	11.52
Number of Customers Affected Per Customer Served (SAIFI)	1.12	1.20	1.11	1.08	1.14	1.13

NYSEG

Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	12,835	12,928	17,008	11,948	14,976	13,939
Number of Customer-Hours	15,787,602	5,314,914	12,974,501	3,369,824	6,445,599	8,778,488
Number of Customers Affected	1,529,247	1,469,825	1,836,251	1,257,464	1,576,105	1,533,778
Number of Customers Served	859,440	859,963	857,517	858,712	856,474	858,421
Average Duration Per Customer Affected (CAIDI)	10.32	3.62	7.07	2.68	4.09	5.55
Average Duration Per Customers Served	18.48	6.18	15.09	3.93	7.51	10.24
Interruptions Per 1000 Customers Served	15.02	15.04	19.78	13.93	17.44	16.24
Number of Customers Affected Per Customer Served (SAIFI)	1.79	1.71	2.14	1.47	1.84	1.79

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

O&R
Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	2,688	2,596	2,993	2,987	2,897	2,832
Number of Customer-Hours	397,977	356,514	470,431	375,064	472,939	414,585
Number of Customers Affected	264,121	222,895	256,943	223,976	263,752	246,337
Number of Customers Served	216,268	215,694	217,373	217,884	218,393	217,122
Average Duration Per Customer Affected (CAIDI)	1.51	1.60	1.83	1.67	1.79	1.68
Average Duration Per Customers Served	1.85	1.65	2.18	1.73	2.17	1.92
Interruptions Per 1000 Customers Served	12.53	12.00	13.88	13.74	13.30	13.09
Number of Customers Affected Per Customer Served (SAIFI)	1.23	1.03	1.19	1.03	1.21	1.14

O&R
Including Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	3,546	2,738	3,655	3,111	3,646	3,339
Number of Customer-Hours	836,046	483,938	1,043,235	471,941	1,857,491	938,530
Number of Customers Affected	388,164	252,650	354,315	249,064	389,937	326,826
Number of Customers Served	216,268	215,694	217,373	217,884	218,393	217,122
Average Duration Per Customer Affected (CAIDI)	2.15	1.92	2.94	1.89	4.76	2.73
Average Duration Per Customers Served	3.90	2.24	4.84	2.17	8.53	4.33
Interruptions Per 1000 Customers Served	16.53	12.66	16.95	14.31	16.73	15.44
Number of Customers Affected Per Customer Served (SAIFI)	1.81	1.17	1.64	1.15	1.79	1.51

* Customers Served is the number of customers served at the end of the current year.
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

RG&E

Excluding Major Storms

	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	3,004	2,784	2,807	2,950	2,872	2,883
Number of Customer-Hours	508,899	526,175	513,175	378,481	432,921	471,930
Number of Customers Affected	286,388	303,940	277,824	210,698	253,517	266,473
Number of Customers Served	364,759	357,232	356,097	357,177	360,156	359,084
Average Duration Per Customer Affected (CAIDI)	1.78	1.73	1.85	1.80	1.71	1.77
Average Duration Per Customers Served	1.40	1.44	1.44	1.06	1.21	1.31
Interruptions Per 1000 Customers Served	8.24	7.63	7.86	8.28	8.04	8.01
Number of Customers Affected Per Customer Served (SAIFI)	0.79	0.83	0.78	0.59	0.71	0.74

RG&E

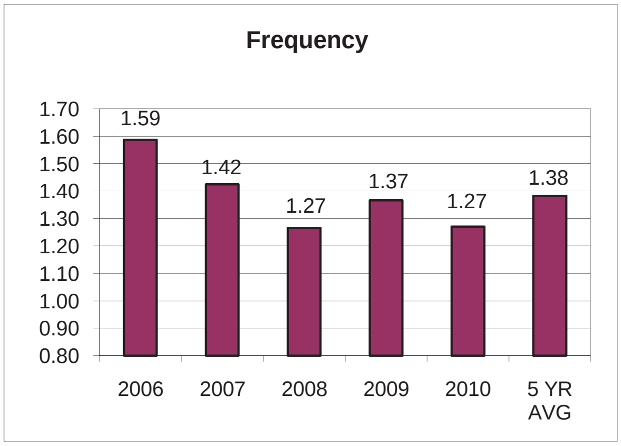
Including Major Storms

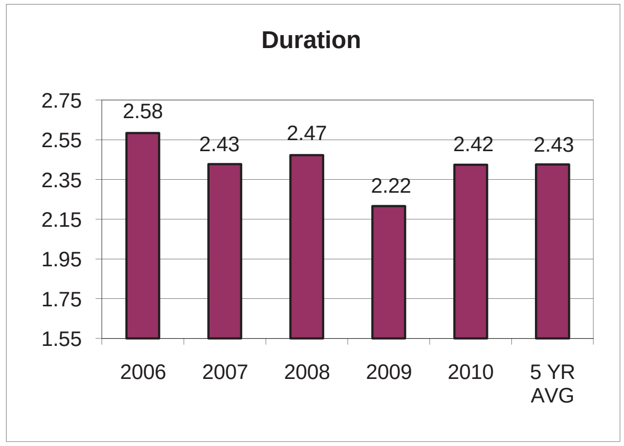
	2006	2007	2008	2009	2010	5 YR AVG
Number of Interruptions	3,241	3,107	3,828	3,110	3,081	3,273
Number of Customer-Hours	762,609	761,368	1,830,153	534,259	615,789	900,835
Number of Customers Affected	356,788	423,383	485,821	263,203	282,347	362,308
Number of Customers Served	364,759	357,232	356,097	357,177	360,156	359,084
Average Duration Per Customer Affected (CAIDI)	2.14	1.80	3.77	2.03	2.18	2.38
Average Duration Per Customers Served	2.09	2.09	5.12	1.50	1.72	2.51
Interruptions Per 1000 Customers Served	8.89	8.52	10.72	8.73	8.63	9.10
Number of Customers Affected Per Customer Served (SAIFI)	0.98	1.16	1.36	0.74	0.79	1.01

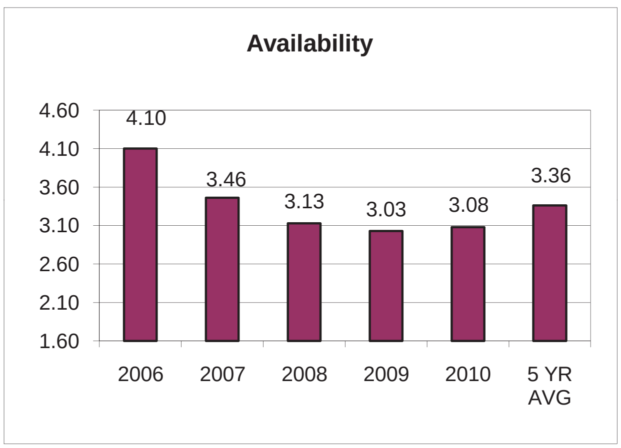
* Customers Served is the number of customers served at the end of the current year.

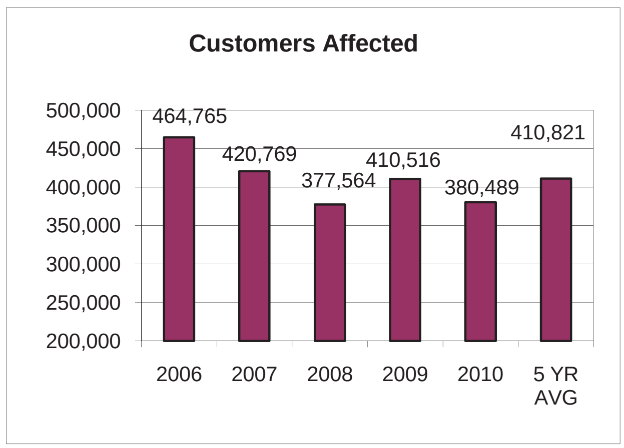
** For those indices that use Customers Served, Customers Served is the December value from the previous year.

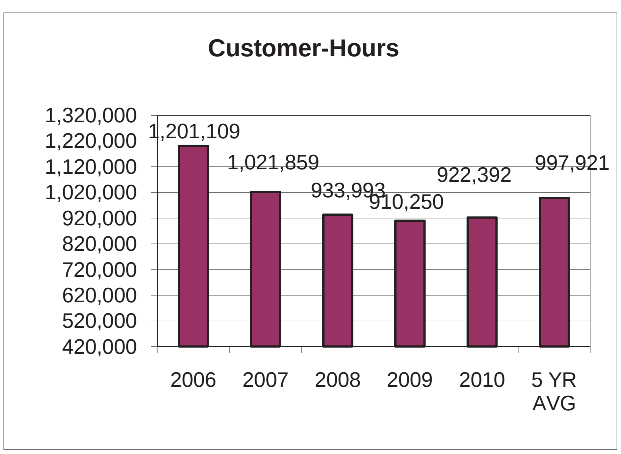
Central Hudson Gas and Electric
(Excluding Major Storms)

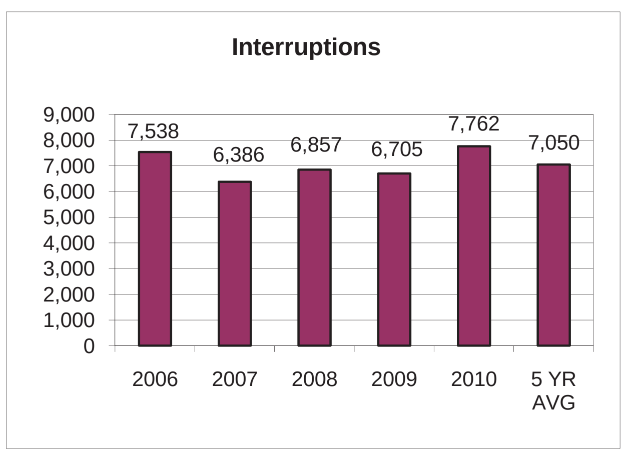




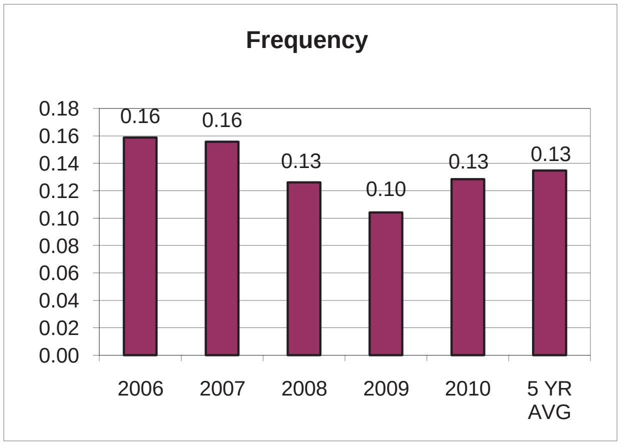


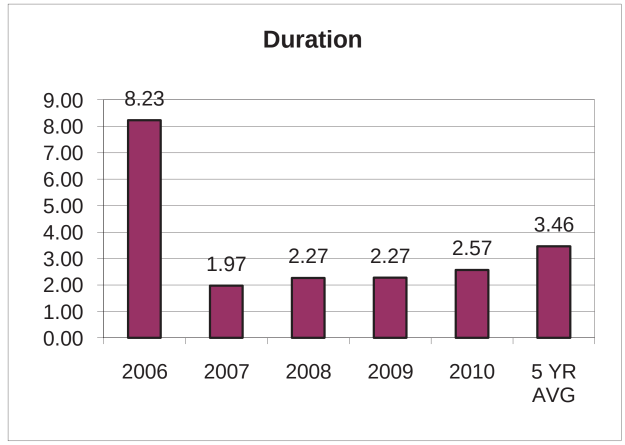


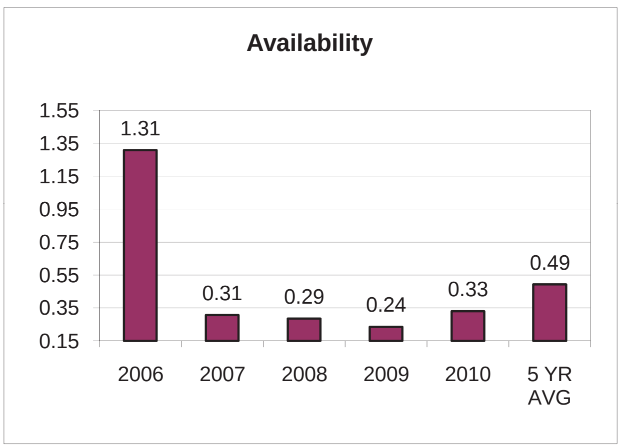


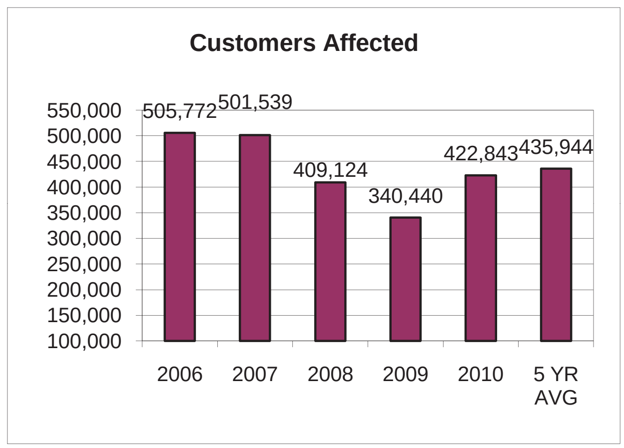


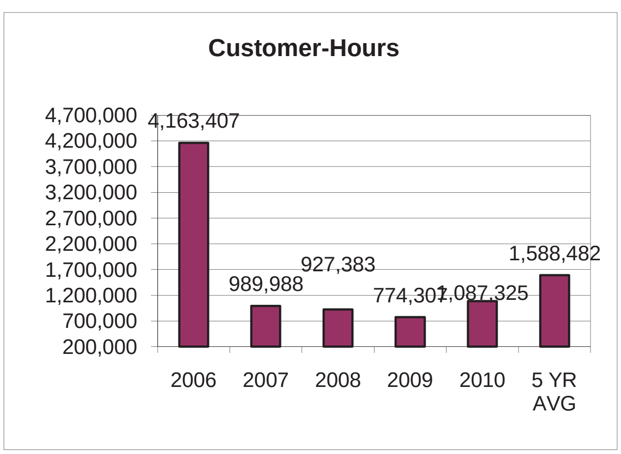
Consolidated Edison - System
(Excluding Major Storms)

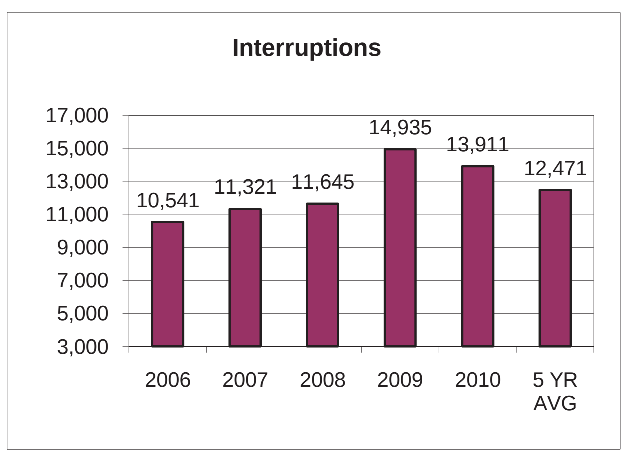






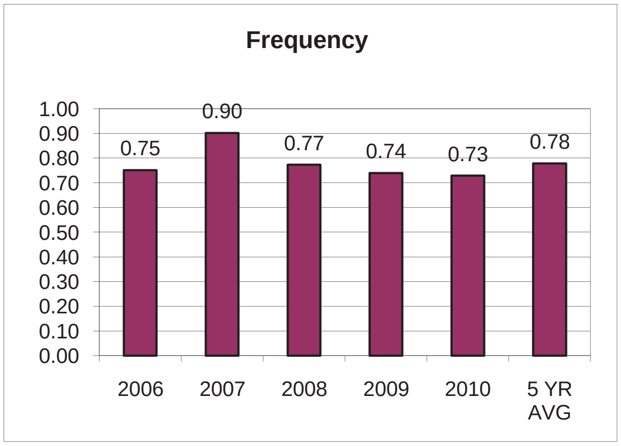


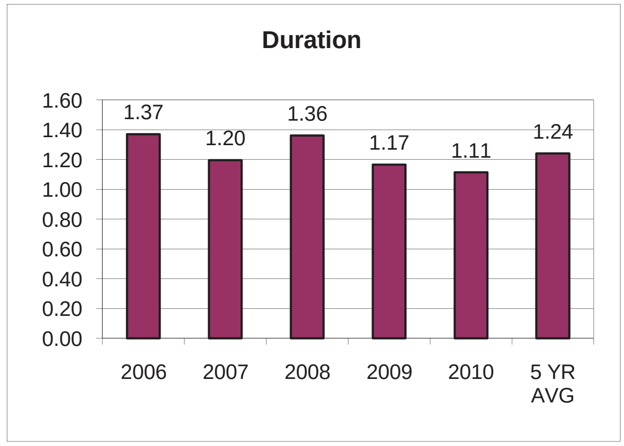


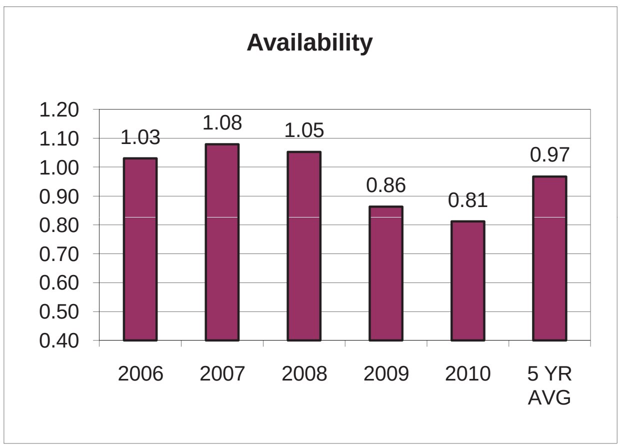


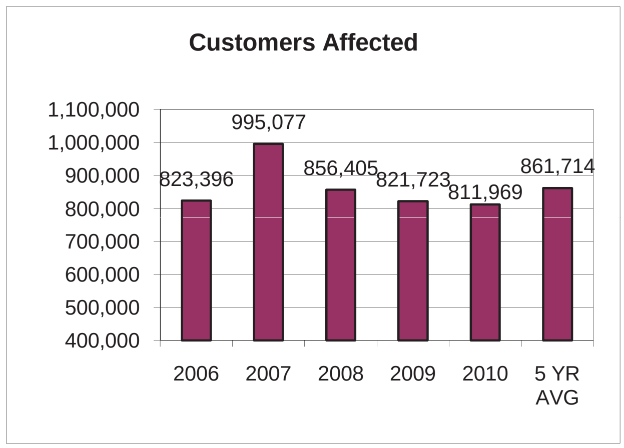
June 2011

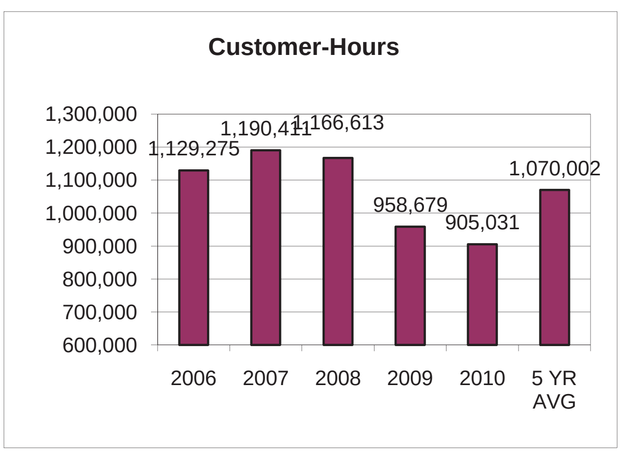
Long Island Power Authority
(Excluding Major Storms)

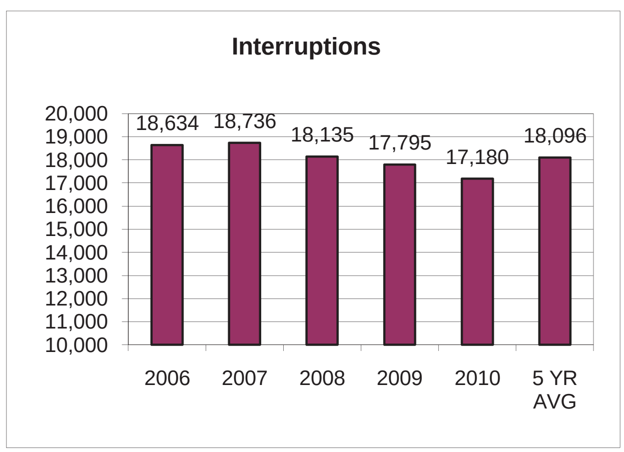






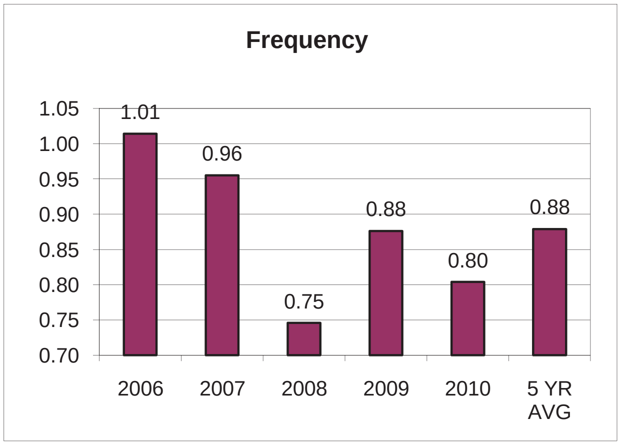


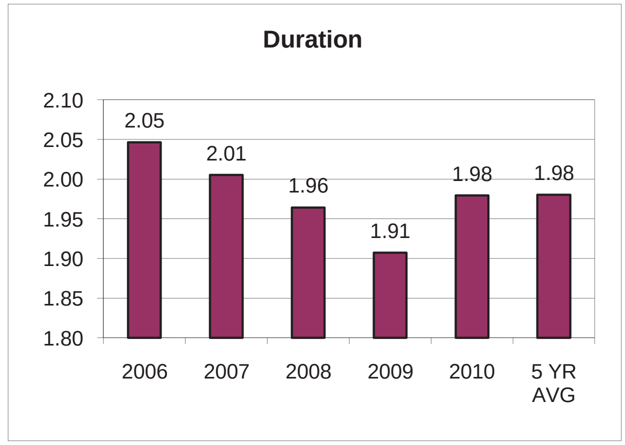


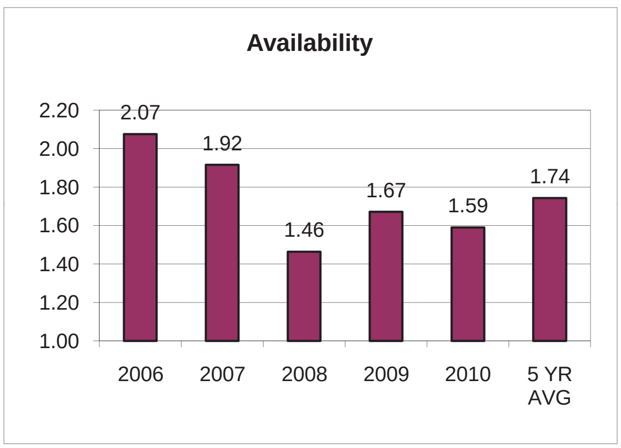


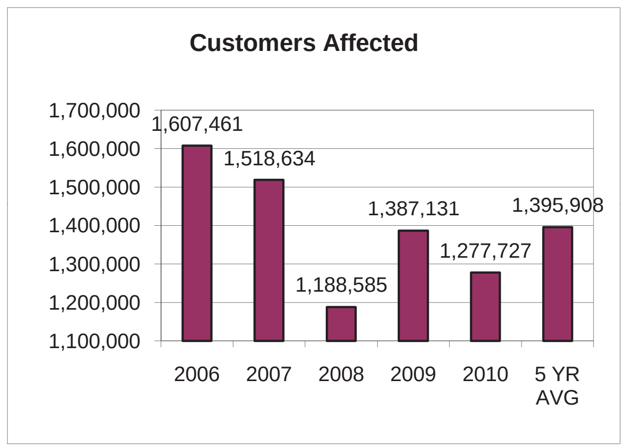
* LIPA is not regulated by the NYS PSC.

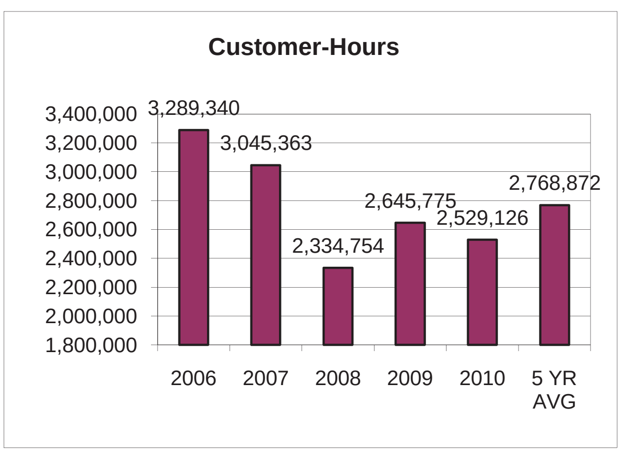
National Grid
(Excluding Major Storms)

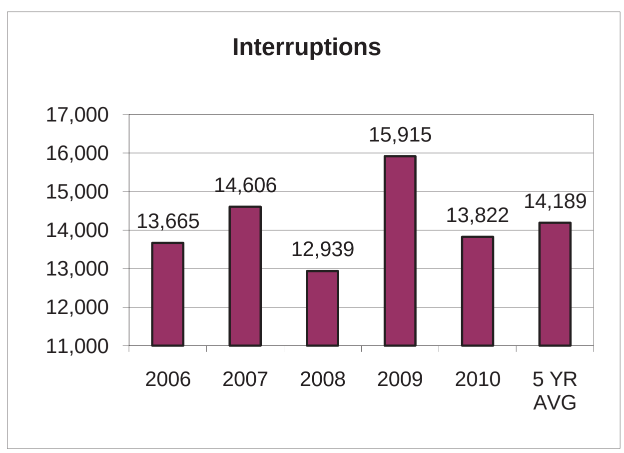






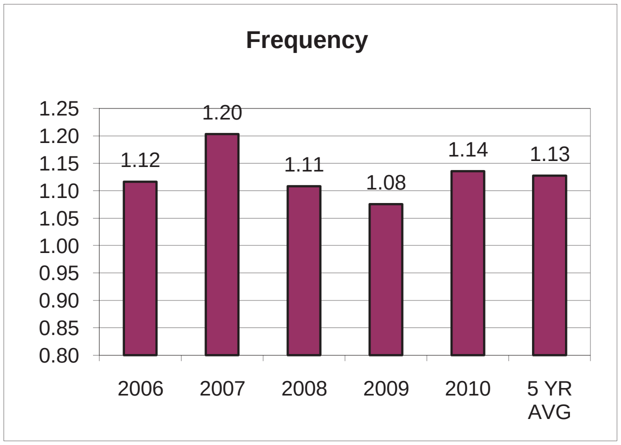


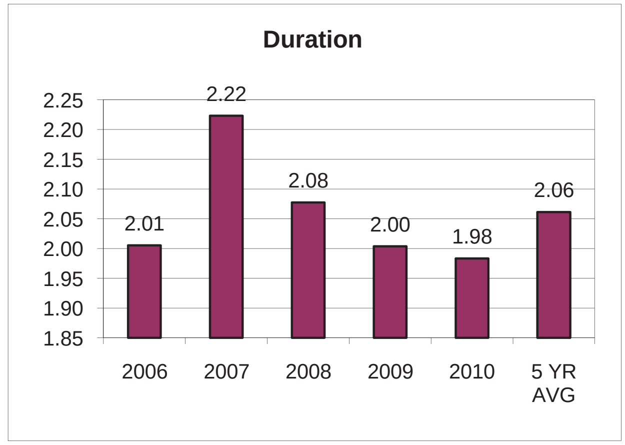


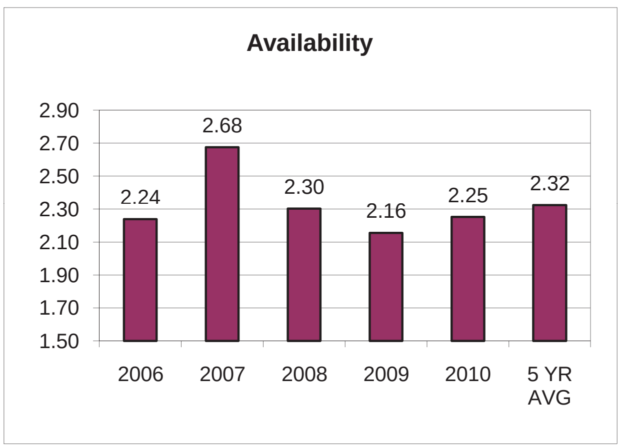


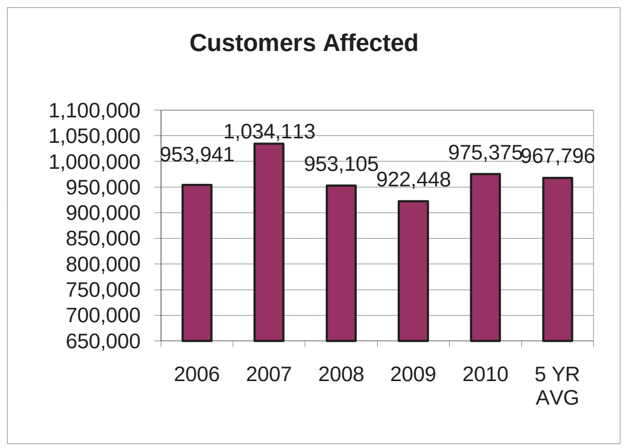
June 2011

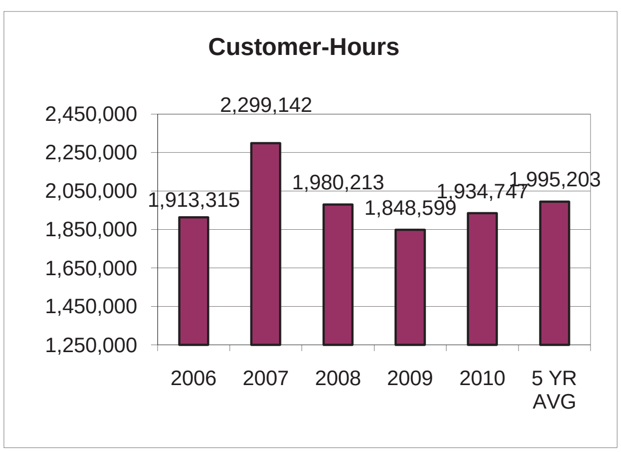
New York State Electric and Gas
(Excluding Major Storms)

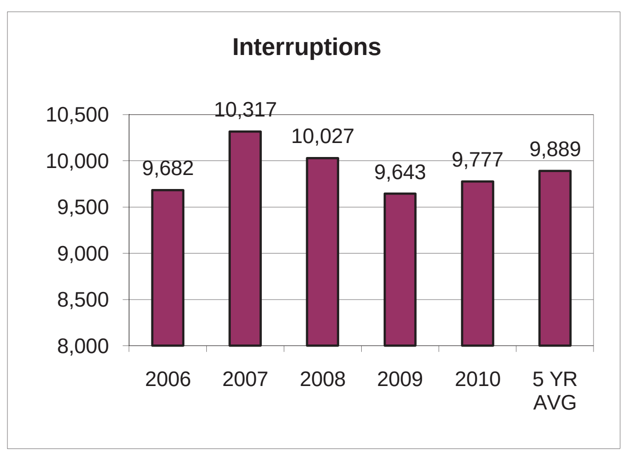




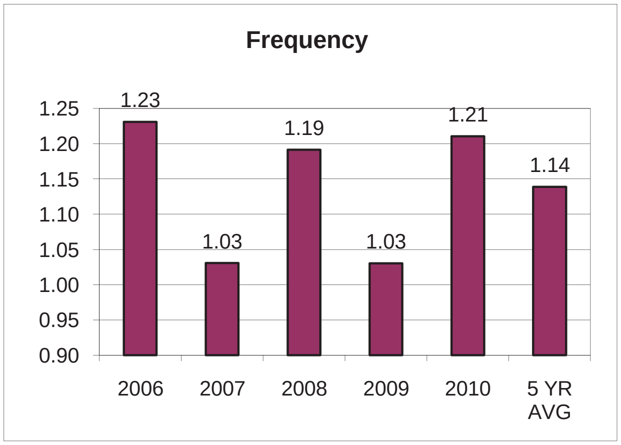


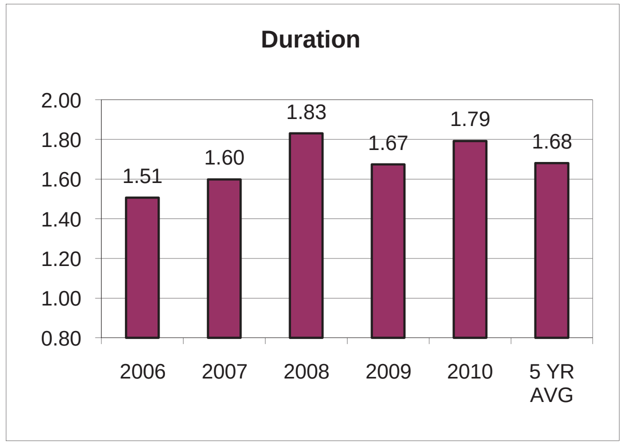


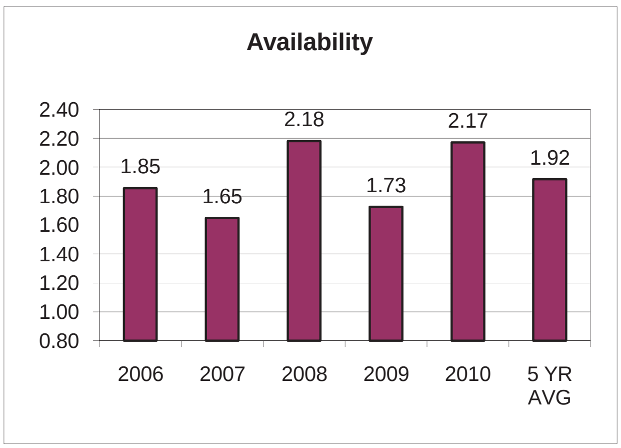


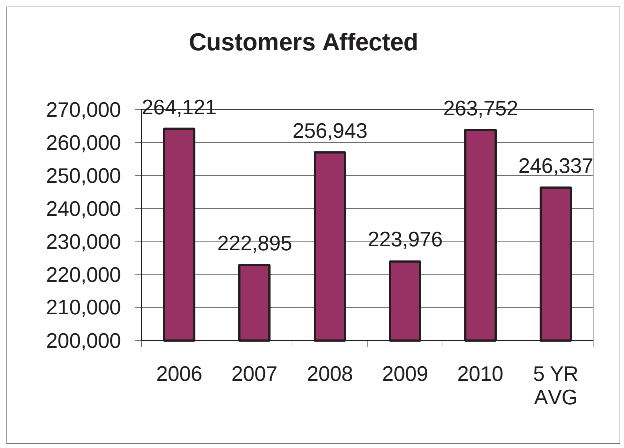


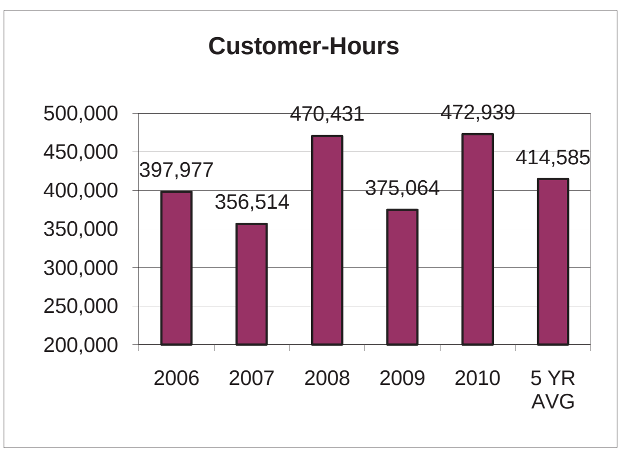
Orange and Rockland Utilities
(Excluding Major Storms)

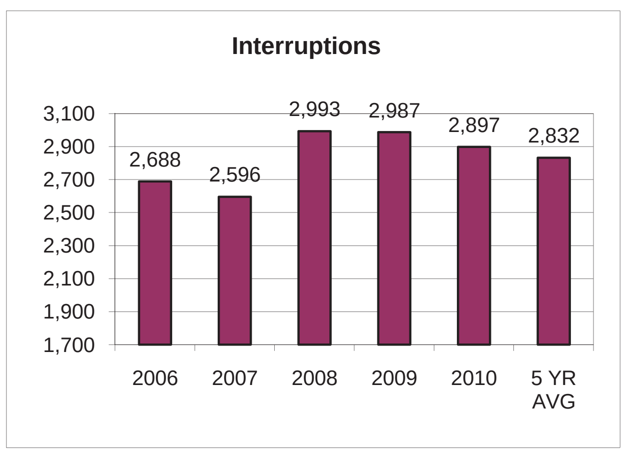




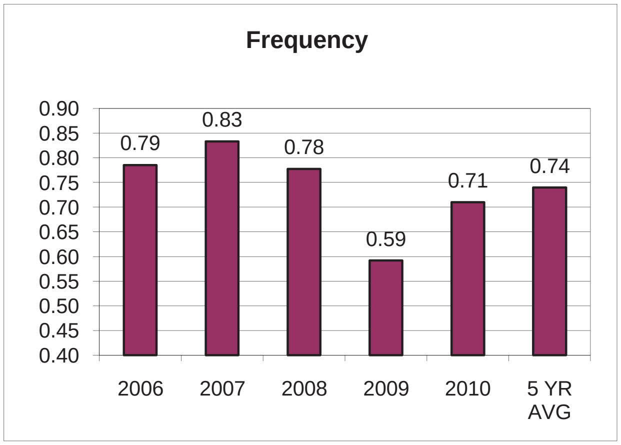


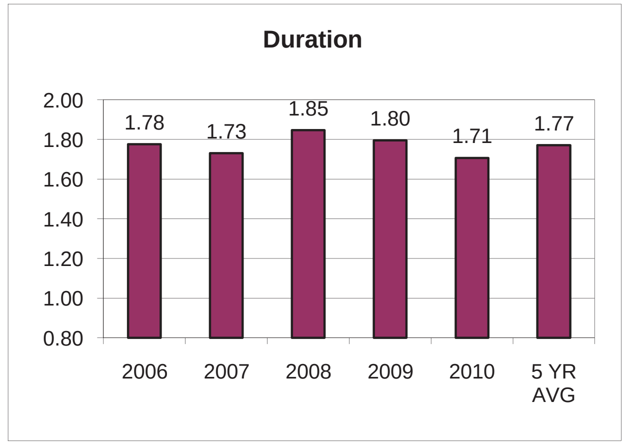


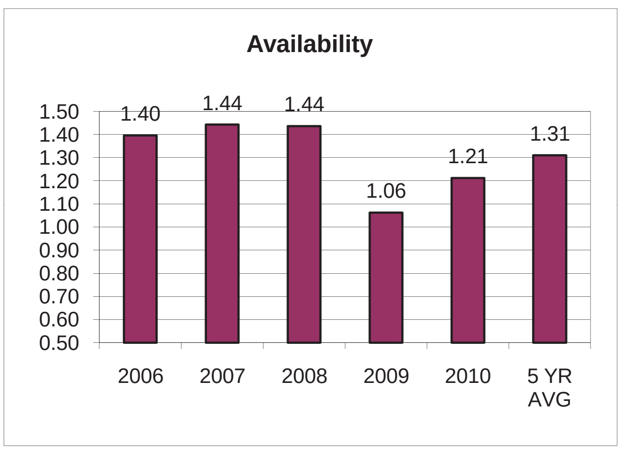


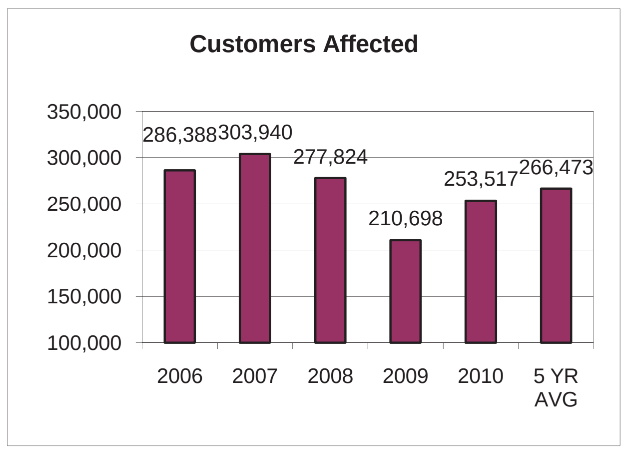


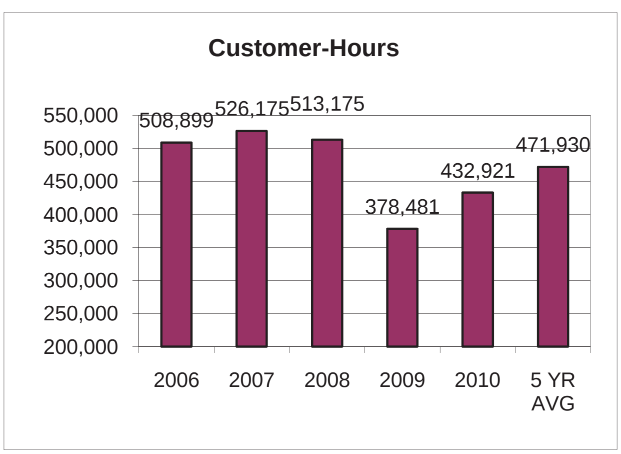
Rochester Gas and Electric
(Excluding Major Storms)

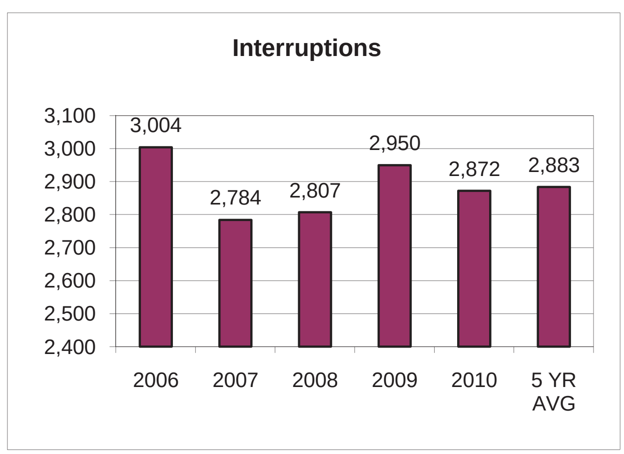












Central Maine Power

July 3, 2007

Ms. Karen Geraghty
Administrative Director
Maine Public Utilities Commission
242 State Street
18 State House Station
Augusta, ME 04330

Re: CENTRAL MAINE POWER COMPANY,
Chapter 120 Information (Post ARP 2000),
Transmission and Distribution Utility Revenue Requirement
And Rate Design, and Request for Alternative Rate Plan,
Docket No. 2007-215

Dear Ms. Geraghty:

Enclosed for filing in the above-captioned proceeding are Central Maine Power Company's responses to the following data requests:

- **EX-02-02, 03, 04, 06, 12, 18, 19, 20, 25, and 26.**

Sincerely,

Amy Leeman

Amy Leeman
Analyst, Central Maine Power

cc: Service List

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-02

Q. Referencing the WCI Report at pg. 63. Please fully describe how CMP's program is designed to address the catch-up required to address the current vegetation encroachment issues noted in the WCI Report.

A. In 2006, CMP deployed an alternate vegetation management practice to clear conductors that were in contact as identified in the WCI report. CMP instructed their contractors to clear fifteen feet above the conductor, eight feet to the side and nothing closer than 10 feet under the conductor. Using this method of trim, CMP cleared the vegetation from the conductors on 6,811 spans (approximately 258 miles). In addition to the initiative described above and as shown in Exhibit MLW-03, CMP proposes to spend an additional $2 million in 2008 above current levels of vegetation management spending and an additional $2 million in 2009 above the five year cycle amount to address lines in contact and worst performing circuits. Exhibit MLW-4B provides the circuits that will have additional $2 million of vegetation management spending for 2008 during the transition to the full cycle program. Exhibit MLW-4A provides the proposed annual work plan by service center and circuit beginning in 2008.

Response Prepared and Submitted by:
Michael L. Watson
Director Maintenance Engineering.

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 03, 2007

EX-02-03

Q. Please provide all analyses memoranda, etc. related to what amount would be needed to be spent by CMP to catch up for past under-funding of its vegetation program.

A. In the testimony, CMP has presented a plan to establish a five year vegetation management cycle where all of the distribution system gets trimmed. At the end of 2013, all of CMP's distribution system will have been trimmed in the past five years and the cycle will begin again in 2014. For CMP's plans to address vegetation currently in danger of contact with conductors, please see the response to EX-02-02.

CMP's current vegetation management approach is not under-funded. The funding is consistent with the program in place for CMP over the past ten or more years and is consistent with the level of vegetation management expense provided for in its revenue requirement. CMP has been successful in increasing the productivity of its vegetation management spending. For example and as noted in the WCI report Section 3.6.1 on page 45, CMP has increased the number of spans trimmed by 20% while spending the same amount, moving from 50,000 spans to 60,000 spans per year in 2003.

Response Prepared and Submitted By:
Michael L. Watson
Director Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-04

Q. Re: Watson Direct Testimony, pg. 13, lines 12-14. Please provide all backup for Mr. Watson's statement that the number of trees removed by CMP will increase from 175,000 to 300,000.

A. CMP has maintained an aggressive tree removal program in order to help reduce extended power outages due to tree damage. Tree removals are part of the specification that the contractors are required to follow as they complete vegetation activity in CMP's system. The totally blended unit rate requires ground cutting and edge trees as part of the unit work. The contract with Lucas Tree also has a component for off right of way tree removals (Schedule B, paragraph 7 on page B-6) to keep them focused on tree removals outside of the clear zone that may impact service reliability. The expectation is that if the budget is increased from $8.7 million to $15 million the tree removals associated with that work will increase proportionally.

Response Prepared and Submitted By:
Michael L. Watson
Director Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-06

Q. Please provide all support, including references to the WCI Report, to go to a five-year inspection program.

A. There are several references in the WCI Report that indicate that CMP can improve its distribution system reliability. In the WCI Report, Section 4.1 Conclusions, item 1 states: " [i]mplementing stretch goals for reliability indices, with gradual improvement targets set year by year, will provide an incentive to continue efforts to improve performance." In the WCI Report in Section 5.1.3 Goals, the report indicates: "[t]herefore, a realistic goal for CMP might be to improve its reliability performance into the third quartile of national reliability performance within a period of three years. Obviously, this will require CMP to fund expanded tree trimming and other reliability improvement programs.'

While the WCI Report did not specifically recommend that CMP move to a five year inspection cycle, it did say that CMP would need to expand reliability programs. One of the programs CMP chose to expand was the distribution inspection program in order to improve service reliability and to achieve the new service quality targets proposed in the testimony. Through the inspection process CMP will identify problems in the distribution system and correct them before they impact service to customers. CMP is also proposing additional distribution betterments to improve service reliability. As stated in the testimony, it takes this three pronged approach (including a five year cycle trim program) to achieve the new service reliability levels, as measured by CAIDI and SAIFI. CMP agrees with the WCI report that the improved service reliability levels recommended in the WCI Report cannot be achieved with only an enhanced trim program.

Response Prepared and Submitted By:
Michael L. Watson
Director Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-12

Q. What is the test year amount of pole replacement spending?

A. CMP does not currently have a pole replacement program and did not have such a program in place during 2006. Consequently, there is no test year spending for pole replacement. As part of the system improvement proposal, CMP used a work order design to estimate the cost to change out a pole and estimated doing approximately 400 pole replacements per year. As stated in Exhibit MLW-07, CMP will focus on poles installed prior to 1937.

Response Prepared and Submitted By:
Michael L. Watson
Director Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-18

Q. Please fully describe how the betterments, especially those in the 2010-2014 period were identified.

A. The Distribution Engineer for each area worked closely with Service Center Operations personnel to develop the project list. For each of the years included, they prioritized projects for each area based on their experience with their circuits.

Response Prepared By:
Gary Ricci
Manager, Distribution Engineering

Response Submitted By:
Michael L Watson
Director, Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-19

Q. Please confirm if CMP has ever calculated and or used for its own use, the System Average Interruption Duration Index (SAIDI). If so, please provide both pre & post exclusion, the historical annual SAIDI figures for the years 1995 through 2006.

A. CMP does not calculate the System Average Interruption Duration Index for its own use. CMP measures its performance using the service quality indicators under ARP 2000, namely the System Average Interruption Frequency Index (SAIFI) and the Customer Average Interruption Duration Index (CAIDI). However, CMP does provide the SAIDI calculation as part of the Annual Reliability Report included with its ARP 2000 annual compliance filing. These SAIDI calculations are post exclusion, using outage exclusion criteria in effect at the time.

YEAR	1995	1996	1997	1998	1999
SAIDI	3.71	3.09	2.80	3.85	2.65
SAIFI	1.41	1.30	1.29	1.88	1.47
CAIDI	2.63	2.38	2.01	2.05	1.80
Interruptions	6,597	5,690	5,456	5,892	5,528
Cust. Hrs	2,432,072	2,760,520	1,881,916	2,662,710	2,318,989
Cust. Interrupted	864,308	1,040,186	852,545	993,884	1,020,669
Cust. Served	518,285	523,267	528,121	533,593	539,845

YEAR	2000	2001	2002	2003	2004
SAIDI	4.20	2.90	3.38	3.14	4.17
SAIFI	1.75	1.45	1.72	1.72	1.98
CAIDI	2.40	2.01	1.97	1.82	2.11
Interruptions	4,702	6,635	7,481	7,756	7,655
Cust. Hrs	2,662,710	1,626,688	1,911,814	1,793,608	2,424,422
Cust. Interrupted	957,545	804,549	969,035	982,906	4,148,230
Cust. Served	546,835	556,617	564,076	571,888	581,059

YEAR	2005	2006			
SAIDI	4.24	4.79			
SAIFI	1.94	2.18			
CAIDI	2.18	2.14			
Interruptions	7,188	7604			
Cust. Hrs	2,497,920	2,860,014			
Cust. Interrupted	1,144,991	1,297,753			
Cust. Served	588,820	596,030			

CMP calculated pre exclusion SAIDI numbers and they are as follows:

1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006
8.76	7.74	3.55	69.28	4.27	5.48	5.83	9.03	8.11	4.14	5.31	10.00

Response Prepared and Submitted by:
Michael L. Watson
Director Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-20

Q. Please confirm if CMP is familiar with and or has the capability to recalculate its CAIDI & SAIFI measures using the IEEE Beta 2.5 method for exclusions. If so, please provide a similar table as the MLW-1 in Mr. Watson's testimony showing only the actual historic pre and post SAIFI and CAIDI figures excluding any baseline targets for each year that is represented.

A. CMP has had very little experience with the IEEE 2.5 beta methodology. Since 1995, CMP has used SAIFI and CAIDI with various exclusion criteria but never the 2.5 beta methodology. Attachment 1 is a table similar to MLW-1 showing the CAIDI, SAIFI and SAIDI calculations with no exclusions, with 10% company wide exclusion, and with the 2.5 beta method.

From 1995 through 2006 there were three different methods for calculating outage exclusions. CMP ran the 10% company wide exclusion approach (the method used beginning in 2004) for 1995 through 2006 for consistent comparison purposes. Because the 2.5 beta methodology needs five years of data in order to calculate statistics, reliability statistics using this method begin in 2000.

Response Prepared By:
Randall C. Butler
Lead Analyst-Maintenance Engineering

Response Submitted By:
Michael L. Watson
Director Maintenance Engineering

Attachment(s):
Attachment #1 System Performance Comparison

System Performance Index Comparison

Various Exclusion Methods

	CAIDI				SAIFI				SAIDI			
		Exclusion Criteria				Exclusion Criteria				Exclusion Criteria		
Yr	Target	None	10%	2.5Beta	Target	None	10%	2.5Beta	Target	None	10%	2.5Beta
1995	3.00	4.00	2.21		2.00	2.19	1.50		6.00	8.76	3.32	
1996	3.00	2.93	1.98		2.00	2.64	1.79		6.00	7.74	3.54	
1997	3.00	2.19	2.07		2.00	1.62	1.48		6.00	3.55	3.06	
1998	3.00	14.93	4.67		2.00	4.64	1.91		6.00	69.28	8.92	
1999	3.00	2.27	2.17		2.00	1.88	1.78		6.00	4.27	3.86	
2000	3.00	2.78	2.27	2.33	2.00	1.97	1.65	1.70	6.00	5.48	3.75	3.96
2001	2.58	3.05	2.40	2.20	1.80	1.91	1.66	1.68	4.64	5.83	3.98	3.71
2002	2.58	3.57	2.05	2.11	1.80	2.53	2.01	2.10	4.64	9.03	4.12	4.43
2003	2.58	3.48	1.96	1.76	1.80	2.33	2.03	1.97	4.64	8.11	3.98	3.47
2004	2.32	2.09	2.09	1.94	2.10	1.98	1.98	1.77	4.87	4.14	4.14	3.42
2005	2.32	2.38	2.19	2.09	2.10	2.23	1.95	1.95	4.87	5.31	4.27	4.07
2006	2.32	3.28	2.14	2.03	2.10	3.05	2.24	2.26	4.87	10.00	4.79	4.58

Targets for CAIDI and SAIFI are as defined in ARP agreements

SAIDI (Cust Hrs / Cust Srv) can be calculated as CAIDI * SAIFI

"None" shows calculations where no exclusions are considered

"10%" shows calculation after excluding events where 10% of Customers Served are impacted

"2.5Beta" shows indices after exclusions calculated by the 2.5 Beta method

5 years of historical data are used to develop 2.5Beta criteria.

Therefore, no 2.5Beta entries are shown prior to 2000.

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-25

Q. Referencing page 12 of Mr. Watson's testimony please provide any analysis or back up information that would support CMP estimates that approximately 19% of the distribution system is open and does not require any trim.

A. CMP determined that 19% of its distribution system was open spans in 2003 using the assumption that if a span was not trimmed or completed over a period of time, then it must be an open span. The open spans were then compared to the total spans. The 19% is also consistent on anecdotal information provided through CMP's arborists.

As a result of the WCI assessment, CMP has added a field in the handheld devices for the contractors to report if a span is open or not. CMP hopes to capture better information about open versus treed spans which will be helpful for future management of vegetation activity and contract negotiations.

It should also be noted that treed versus open spans will be dynamic. Spans that were considered open on one cycle may be a treed span five years later as trees grow and encroach on the clear zone. Alternately, spans that were treed on one cycle may be open on the next five year cycle due to betterments, road jobs, landowners cutting their trees, etc.

Response Prepared and Submitted By:
Michael L. Watson
Director, Maintenance Engineering

CENTRAL MAINE POWER COMPANY
RESPONSE TO THE EXAMINER'S 2nd SET OF DATA REQUESTS
DOCKET No. 2007-215

July 3, 2007

EX-02-26

Q. Please provide a copy of any report/documentation used by the arborists to record any non compliance or completed work during the inspection process for the 40% of completed work by the vegetation contractors.

A. Attachment 1 is the Distribution Line Clearance form (2932) used by CMP arborists in the inspection process. This form is used to document their inspection results. Attachment 2 is the summary of the 2006 inspections completed by the arborists with notice of rework needed. In 2007, CMP built a report for the arborist to use to manage the audit process with contractors. Attachment 3 is the January through May audit results.

Response Prepared and Submitted by:
Michael L Watson
Director Maintenance Engineering

Attachment(s):
Attachment #1 Central Maine Power Distribution Line Clearance inspection form
Attachment #2 2006 Crew Work Audits
Attachment #3 2007 Audit Results January through May

Form 2932
1/94

Central Maine Power Company
Distribution Line Clearance

Evaluator Int. (3) ______ Date of Review __/__/__	Audit-Eval. Date (Mo./Yr.) ____/____	(Check One) Monthly Eval. ________ W.O. Audit ________ Other Audit ________

Site No.	Dist. Code	Contr. Code	Crew Code	Wk. Ending Date	Order No.	Town Code	Road Code	Unit $	T/M $	Estimate $
1.				/ /						
2.				/ /						
3.				/ /						
4.				/ /						
5.				/ /						

Site No.	Pole # From To	Comply Code	Act. Code	No. Units	Hrs.	Herb Code	Len	Wid	Comments

TOTAL NO. OF SECTIONS REVIEWED ______
Detail Corrected? Y N
Rework Necessary? Y N
Date Rework Completed? ____________

Codes:
B — Brush not chipped
C — Clearance less than required
D — Directional trim
F — Flushcuts (stubs too long)
G — Good
H — Hangers left
S — Stumps too high
T — Treatment not used
R — Recording tm/cd

CONTRACT

Dist.

CMP VEGETATION MANAGEMENT

Audit By : Reviwed Date: Number of re-do :

Crew # Week ending : Spans Reviewed :

Town/Sect Code	Town Name	Road Code	Road Name	From Pole	To Pole	Comply	Unit Code	Should Crew Claim Span	Coments

B - Brush not chipped, C - Clearance less than required, D - Directional trim, F - Flushcuts (stubs too long), H - Hangers left, S - Stumps too high, T - Treatment not used, R - Recording tm/cd, GNR- Ground cut, PR5 - Hazard Trees, PR6 - Hazard tree missed, SEC - secondary missed, SER - Service missed

2006 Crew Work Audit

	Jan	Feb	Mar	Total	April	May	June	Total	July	Aug	Sept	Total	Oct	Nov	Dec	Total	Totals	Count 3/26/2007
Alfred	461	180	344	**985**	103	649	339	**1091**	50	124	686	**860**	612	1077		**1689**	**4625**	
Rework	110	7	36	**153**	2	43	10	**55**	1	22	72	**95**	48	107		**155**	**458**	**405**
Augusta	64	205	102	**371**	240	15	43	**298**	46	83	151	**280**	284	119	215	**618**	**1567**	
Rework	2	6	33	**41**	19	5		**24**	4	4	3	**11**	14	3	3	**20**	**96**	**118**
Bridgton	219	310	506	**1035**	189	27	129	**345**	412	653	794	**1859**	293	131	823	**1247**	**4486**	
Rework	11	30	10	**51**	12	3	19	**34**	28	3	8	**39**	2	25	19	**46**	**170**	**214**
Brunswick	72			**72**	216	72	768	**1056**	380		56	**436**		337	3	**340**	**1904**	
Rework	12			**12**	97	43	306	**446**	145		20	**165**		122	3	**125**	**748**	**748**
Dover		2		**2**	2	101	47	**150**	109	204	214	**527**	175	319		**494**	**1173**	
Rework				**0**		6	2	**8**	7	2	28	**37**	3	28		**31**	**76**	**95**
Fairfield	14	116	3	**133**		95	113	**208**		140	103	**243**	107	2		**109**	**693**	
Rework	1	17		**18**		45	32	**77**		6	22	**28**	5	2		**7**	**130**	**114**
Farmington			134	**134**	30	388	1109	**1527**	21	546		**567**	213	364		**577**	**2805**	
Rework			43	**43**	17	70	108	**195**	13	176		**189**	15	33		**48**	**475**	**475**
Lewiston	84	62	282	**428**	109	182	87	**378**	46	65	215	**326**	330	141	97	**568**	**1700**	
Rework	3	3	15	**21**	9	22	13	**44**	3	3	9	**15**	8	4	1	**13**	**93**	**93**
Portland	358	180	319	**857**	184	552	253	**989**	154	596	160	**910**	484	489	616	**1589**	**4345**	
Rework	25	11	12	**48**	8	111	42	**161**	25	31	17	**73**	22	22	36	**80**	**362**	**362**
Rockland				**0**				**0**				**0**				**0**	**0**	
John				**0**		310		**310**				**0**				**0**	**310**	
Corey				**0**				**0**		18	91	**109**	18	929		**947**	**1056**	
Tom/Wes			44	**44**			263	**628**	364			**364**				**0**	**1036**	
Rework			11	**11**		106	35	**141**	60	10		**70**	10	8		**18**	**240**	**230**
Skowhegan	112	129	53	**294**	41			**41**				**0**		44		**44**	**379**	
Rework	16	15	5	**36**	1			**1**				**0**		14		**14**	**51**	**51**
Transmission	98	131	62	**291**	19	2	2	**23**	2	1	1	**4**	6			**6**	**324**	
Rework				**0**				**0**				**0**	17			**17**	**17**	**17**
													Total Rework				**2916**	**2922**
													Total Spans				**26403**	

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRIDGTON | **Cotiaux** | **1/11/2007** | **5 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2130	Fryeburg	008	Bridgton Rd.	701	702		M	D	38	3/30/2007	1/25/2007
	Less than 8' side clearance - smaller pines, see arborcultur										
2130	Fryeburg	008	Bridgton Rd.	702	701		M	D	38	3/30/2007	1/25/2007
	less that 8' side										
2130	Fryeburg	008	Bridgton Rd.	703	702		M	D	38	3/30/2007	1/25/2007
	Remove stubbed pine (6"dbh) @ 703 - less than 8' side cleara										
2130	Fryeburg	008	Bridgton Rd.	703	704		M	D	38	3/30/2007	1/25/2007
	stubs										

BRIDGTON | **Cotiaux** | **1/11/2007** | **19 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5230	Sebago	045	Kimball Corner Rd.	13	14		M	D	139	3/30/2007	
	hardwoods - need g/c - knee hi beech										
5230	Sebago	045	Kimball Corner Rd.	3	4		M	D	139	3/30/2007	1/18/2007
	Read maple stubs										
5230	Sebago	045	Kimball Corner Rd.	4	House		M	D	139	3/30/2007	
	n/d - less than 2 feet										
5230	Sebago	045	Kimball Corner Rd.	6	serv		M	D	139	3/30/2007	
	w.p. leader hard on serv										
5230	Sebago	045	Kimball Corner Rd.	7	serv		M	D	139	3/30/2007	
	n/done - white house # 45										
5230	Sebago	045	Kimball Corner Rd.	9	10		M	D	139	3/30/2007	
	a few dead pines PR6										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRIDGTON Cotiaux 1/30/2007 57 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2130	Fryeburg	088	River Road	024	025	S	M	D	196/24	3/30/2007	3/30/2007
	stumps										
2130	Fryeburg	088	River Road	026	027	S	M	D	196/24	3/30/2007	3/30/2007
	Hi stumps - 196										
2130	Fryeburg	088	River Road	027	028	S	M	D	196/24	3/30/2007	3/30/2007
	Hi stumps - 196										
2130	Fryeburg	088	River Road	09	010	C	M	D	196/24	3/30/2007	
	Some stubs - 24										

BRIDGTON Cotiaux 1/12/2007 75 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5230	Sebago	054	Mack Corner	22.1	meter pol		M	D	85	3/30/2007	
	n/d										
5230	Sebago	054	Mack Corner	28	28.1	B	M	D	85	3/30/2007	
	Brush (whole line) done 1/22 ??										
5230	Sebago	054	Mack Corner	31	32	S	M	D	85	3/30/2007	
	Stubs, brush & need cut topped trees										
5230	Sebago	054	Mack Corner	38	38.1		M	D	85	3/30/2007	
	not done - sec.										
5230	Sebago	054	Mack Corner	501	02	S	M	D	85	3/30/2007	
	stubs - on little trees										
5230	Sebago	054	Mack Corner	562	03	S	M	D	85	3/30/2007	
	Stubs										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRIDGTON Cotiaux 2/9/2007 2 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1580	DENMARK	079	STANLEY HILL ROAD	22	23	S	M	D	20/4/158	3/30/2007	
	Stubs										
1580	DENMARK	079	STANLEY HILL ROAD	25	1	PR6	M	D	20/4/158	3/30/2007	
	Pole 1 - Harnden Rd - PR6 poplar										

BRIDGTON Cotiaux 2/6/2007 45 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5503	STANDISH	068	JOHNSON ROAD	3	4	S	M	D	85 super	3/30/2007	3/23/2007
5503	STANDISH	074	LAKEVIEW LANE SOUT	6	7	S	M	D	85 super	3/30/2007	3/22/2007
	lower hemlock stubs										
5503	STANDISH	100	PERIMETER AVENUE	9	10	C	M	D	85 super	3/30/2007	3/22/2007
	>2' pone on service										

BRIDGTON Cotiaux 2/23/2007 46 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1060	CASCO	052	LIBBY ROAD	11	11.1	C	M	D	85 Super	3/30/2007	3/23/2007
	Look at 11- 11.1 >2' clearance near road - not sure what happened here										
1060	CASCO	052	LIBBY ROAD	13	14	C	M	D	85 Super	3/30/2007	
	Listed both sections "man. -cut brush"										
1060	CASCO	052	LIBBY ROAD	14	15	B	M	D	85 Super	3/30/2007	
	Brush all over; listed as full clearance										
1060	CASCO	052	LIBBY ROAD	17	18	C	M	D	85 Super	3/30/2007	3/23/2007
	2 topped trees, please cut down										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

1060	CASCO	052	LIBBY ROAD	21	22	C	M	D	85 Super	3/30/2007	3/23/2007
	6" w.p. has been hard trimmed to a "no crown" less that 1'3 status -cut down										
1060	CASCO	052	LIBBY ROAD	5	6	PR6	M	D	85 Super	3/30/2007	3/23/2007
	PR6 - 8" w.p. opposite single phase line has holes in butt on bank										

BRIDGTON Cotiaux 2/23/2007 47 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5503	STANDISH	118	PRIDE LINE	4	5	H	M	D	85	3/30/2007	3/23/2007
	> 15' aerial percarious wp leader										
5503	STANDISH	143	SUCKER BROOK ROAD	18	19	F	M	D	85	3/30/2007	3/23/2007
	Listed as "f" cut oak 9" from singe phase										
5503	STANDISH	143	SUCKER BROOK ROAD	19	20		M	D	85	3/30/2007	3/23/2007
	> 15' aerial over building - check side										
5503	STANDISH	143	SUCKER BROOK ROAD	2	3	PR6	M	D	85	3/30/2007	3/23/2007
	PR6 - 8" dbh nectria infester poplar										
5503	STANDISH	143	SUCKER BROOK ROAD	4	4.1	SER	M	D	85	3/30/2007	3/23/2007
	Serv 1 pt. pole - not done										

BRIDGTON Cotiaux 2/1/2007 49 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2130	Fryeburg	008	Bridgton Road	568	569	S	M	D	various	3/30/2007	
	Stubs = F										
2130	Fryeburg	008	Bridgton Road	569	570	C	M	D	various	3/30/2007	2/19/2007
	Pop top on hazard maple										
2130	Fryeburg	008	Bridgton Road	570	571	S	M	D	various	3/30/2007	
	Stubs										
2130	Fryeburg	008	Bridgton Road	600	601	C	M	D	various	3/30/2007	2/19/2007
	Cut down poorly topped 6' maple										
2130	Fryeburg	008	Bridgton Road	603	604	C	M	D	various	3/30/2007	2/19/2007
	PR6 unit - flagged poplar										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRIDGTON | Cotiaux | 2/8/2007 | 58 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0365	BALDWIN	015	CRAM ROAD	509	510		M	D	85	3/30/2007	
	Cut pines at pole										
0365	BALDWIN	060	MOUNTAIN ROAD	3	3.1		M	D	85	3/30/2007	3/22/2007
	Not done										

BRIDGTON | Cotiaux | 2/9/2007 | 82 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1580	DENMARK	036	HARNDEN ROAD	11	12	S	M	D	24/20	3/30/2007	
	Stubs										
1580	DENMARK	036	HARNDEN ROAD	14	15	S	M	D	24/20	3/30/2007	
	Stubs & W.P. w 1/4 crown left										
1580	DENMARK	036	HARNDEN ROAD	5	6	S	M	D	24/20	3/30/2007	
	Stubs										
2130	FRYEBURG	095	STANLEY HILL ROAD	14	15	S	M	D	20/4/158	3/30/2007	
	Stubbing										
2130	FRYEBURG	095	STANLEY HILL ROAD	15	16	PR6	M	D	20/4/158	3/30/2007	2/16/2007
	not infested w/o 18" dbh- it it at mid-span point- 75' needed										
2130	FRYEBURG	095	STANLEY HILL ROAD	4	5	C	M	D	20/4/158	3/30/2007	
	Beech & brush left (brush to be cut)										
2130	FRYEBURG	095	STANLEY HILL ROAD	605	1	S	M	D	20/4/158	3/30/2007	
	605 Bridgton rd (rt 302) stubs & small tree toping issues										

BRIDGTON | Cotiaux | 2/8/2007 | 126 Sections Reviewed

Town	Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

0365	BALDWIN	015	CRAM ROAD	503		F	M	D	85 super	3/30/2007	
	Cut pine at pole (shows F clearance)										
0365	BALDWIN	015	CRAM ROAD	506	507	C	M	D	85 super	3/30/2007	
	no g/c in front of house, but "F" clearance, 2 birches for 75" s/b PR6										
0365	BALDWIN	040	HARRY MURCH ROAD	7	8	PR6	M	D	85 super	3/30/2007	
	PR 6, leaning disfigured topped poplar										
0365	BALDWIN	040	HARRY MURCH ROAD	72	1		M	D	85 super	3/30/2007	
	p. 72 So Bridgton Rd to p.1 Harry Murch >8' PF5 poplar - ROW										
0365	BALDWIN	040	HARRY MURCH ROAD	9	10	S	M	D	85 super	3/30/2007	
	Stubs & brush in thr ROW										
0365	BALDWIN	061	MURCH ROAD	13	14	PR6	M	D	85 super	3/30/2007	3/22/2007
	PR6 poplar w/dark hypox, there are two										
0365	BALDWIN	061	MURCH ROAD	4	5	S	M	D	85 super	3/30/2007	3/22/2007
	Stubs										
0365	BALDWIN	212	SOUTH BRIDGTON ROA	52	serv	C	M	D	85 super	3/30/2007	
	>2 feet										
0365	BALDWIN	212	SOUTH BRIDGTON ROA	70	70.1	C	M	D	85 super	3/30/2007	3/22/2007
	Cut out maple leader ' "hard"										

BRIDGTON Cotiaux 3/15/2007 35 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1580	DENMARK	089	WARREN ROAD	22	23	PR6	M	D	20	4/5/2007	
	PR6 - Big poplar,birch, peach, cankor; each at butt										

BRIDGTON Cotiaux 3/26/2007 41 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0690	BRIDGTON	063	INGALLS HILL ROAD	30	30H	S	M	D	20-24	4/5/2007	
	Hi stumps - need cut in front of house										
0690	BRIDGTON	063	INGALLS HILL ROAD	31	32	S	M	D	20-24	4/5/2007	
	Hi Stumps - nned cut in front of house										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0690	BRIDGTON	063	INGALLS HILL ROAD	32	33	S	M	D	20-24	4/5/2007	
	Hi Stumps - nned cut in front of house										

BRIDGTON — Cotiaux — 3/8/2007 — 45 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5503	STANDISH	079	LONG POINT LINE	44	45	PR6	M	D	8	4/5/2007	
	PR6 - very visible defective w.p. w/several signs on it										
5503	STANDISH	079	LONG POINT LINE	44	44.1	C	M	D	8	4/5/2007	
	> 8' (10' w/ pine) clamimd as full										

BRIDGTON — Cotiaux — 3/12/2007 — 79 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1060	CASCO	076	QUAKER RIDGE ROAD				M	D	85	4/5/2007	
1060	CASCO	076	QUAKER RIDGE ROAD	06	Serv	C	M	D	85	4/5/2007	
	Service not done										
1060	CASCO	113	WATKINS SHORE ROAD	6	6.1	SER	M	D	85	4/5/2007	
	Service not done										
1060	CASCO	113	WATKINS SHORE ROAD	8	9	C	M	D	85	4/5/2007	
	Stubs and the like										

BRIDGTON — Cotiaux — 3/1/2007 — 104 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1580	DENMARK	047	LAKE ROAD	503	503.1	C	M	D	20 etal	4/5/2007	
	single phase not done										
1580	DENMARK	047	LAKE ROAD	503 1/2	504	PR6	M	D	20 etal	4/5/2007	
	Poplars - nectria PR6										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

1580	DENMARK	047	LAKE ROAD	514	serv	C	M	D	20 etal	4/5/2007	
	<2' - pine 4"										

BRIDGTON | Cotiaux | 3/7/2007 | 143 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1060	CASCO	004	CONE ROAD	034	serv		M	D	85 super	4/5/2007	
	Service not done										
1060	CASCO	004	CONE ROAD	046	serv	C	M	D	85 super	4/5/2007	
	Not done										
1060	CASCO	004	CONE ROAD	047	1	C	M	D	85 super	4/5/2007	
	(1 Ekland), no ground cut										
1060	CASCO	004	CONE ROAD	051	serv	C	M	D	85 super	4/5/2007	
	not done >2'										
1060	CASCO	004	CONE ROAD	061	serv	C	M	D	85 super	4/5/2007	
	Not done										
1060	CASCO	004	CONE ROAD	064	065	C	M	D	85 super	4/5/2007	
	Flagg - hit poplar										
1060	CASCO	004	CONE ROAD	066	066.1	C	M	D	85 super	4/5/2007	
	>8 >15										

BRIDGTON | Cotiaux | 4/10/2007 | 56 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0690	BRIDGTON	108	NORTH BAY ROAD	5	6	GRN	M	D	85	5/8/2007	
	Ground cut by pole 6										
0690	BRIDGTON	108	NORTH BAY ROAD	6	7	C	M	D	85	5/8/2007	
	Topped trees needs to finish										
0690	BRIDGTON	108	NORTH BAY ROAD	7	8	B	M	D	85	5/8/2007	
	Brush needs to be chipped										
0690	BRIDGTON	127	PONDICHERRY ROAD	16	17	GRN	M	D	85	5/8/2007	
	Neesds more ground cut - beech										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

0690	BRIDGTON	127	PONDICHERRY ROAD	3 1/2	4	PF5	M	D	85	5/8/2007	
	PR 5 - maple tree inches from 2 phase, cut										
0690	BRIDGTON	127	PONDICHERRY ROAD	6	6.1	SER	M	D	85	5/8/2007	
	Service not done at pole 6.1										
0690	BRIDGTON	127	PONDICHERRY ROAD	8	9	SER	M	D	85	5/8/2007	
	servcie not done at pole 9										

BRIDGTON Cotiaux 4/2/2007 59 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0690	BRIDGTON	049	HILLSIDE DRIVE	5	6	C		D	24/158	5/8/2007	
	> 8ft - ash need to be cut; listed as full clearance										
5640	SWEDEN	049	MASCIA ROAD	7	7.1	C		D	24/158	5/8/2007	
	> 2 ft; not done; crew 158										

BRIDGTON Cotiaux 4/11/2007 89 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4900	RAYMOND	020	DEEP COVE ROAD	24	25	C	M	D	85	5/8/2007	
	> 15 ft dead oak leader - no PR6 birch recorded										
4900	RAYMOND	020	DEEP COVE ROAD	5	5.1	SEC	M	D	85	5/8/2007	
	Secondary off pole5 (5.1 & 5.2)										
4900	RAYMOND	082	PINE LEDGES LINE	10	10.1	GRN	M	D	85	5/8/2007	
	Need more ground cut by pole 10										
4900	RAYMOND	082	PINE LEDGES LINE	2	3	C	M	D	85	5/8/2007	
	> 15 ft pines										
4900	RAYMOND	082	PINE LEDGES LINE	7	8	PR6	M	D	85	5/8/2007	
	PR6 dead pine										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRIDGTON | **Cotiaux** | **5/24/2007** | **25 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0690	BRIDGTON	058	HIO RIDGE ROAD	1	2	GRN	M	D	20	6/13/2007	
	Needs ground cut; stubs too high										
0690	BRIDGTON	058	HIO RIDGE ROAD	10	11	GRN	M	D	20	6/13/2007	
	Needs ground cut; stubs too high										
0690	BRIDGTON	058	HIO RIDGE ROAD	16	17	GRN	M	D	20	6/13/2007	
	Needs ground cut										
0690	BRIDGTON	058	HIO RIDGE ROAD	2	4	S	M	D	20	6/13/2007	
	stubs too high										
0690	BRIDGTON	058	HIO RIDGE ROAD	33	34	Haz	M	D	20	6/13/2007	
	Hazard tree										
0690	BRIDGTON	058	HIO RIDGE ROAD	38	39	C	M	D	20	6/13/2007	
	Dead ask top - remove										
0690	BRIDGTON	058	HIO RIDGE ROAD	4	5	GRN	M	D	20	6/13/2007	
	Needs ground cut; stubs too high										
0690	BRIDGTON	058	HIO RIDGE ROAD	42	43	GRN	M	D	20	6/13/2007	
	Knee-high pines - need ground cut										
0690	BRIDGTON	058	HIO RIDGE ROAD	5	6	GRN	M	D	20	6/13/2007	
	Needs ground cut; stubs too high										
0690	BRIDGTON	058	HIO RIDGE ROAD	9	10	GRN	M	D	20	6/13/2007	
	Needs ground cut; stubs too high										

Service Center Totals: ***103 Sections for Rework*** ***1693 Sections Reviewed*** ***6.08%***

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

PORTLAND | **Cotiaux** | **1/16/2007** | **114 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1280	Cumberland	039	Methodist Road	2	3	S	M	D	73	3/30/2007	1/22/2007
	Hugh stub & stubletts - crew 58										
1280	Cumberland	039	Methodist Road	3	4	S	M	D	73	3/30/2007	1/22/2007
	Hugh pine stub										
1280	Cumberland	039	Methodist Road	8	8.01		M	D	73	3/30/2007	
	Need more g/c (full clerance listed)>8'Maple - crew 73										
1280	Cumberland	039	Methodist Road	8.01	8.02		M	D	73	3/30/2007	
	Needs more g/c (full clearance listed) - crew 73										
1280	Cumberland	039	Methodist Road	8.03	8.04		M	D	73	3/30/2007	
	Needs more g/c (full clearance listed) - crew 73										
1280	Cumberland	511	Forest Lane	10	11		M	D	73/173	3/30/2007	
	sev @ 11 - less than 2' - crew 173										
1280	Cumberland	511	Forest Lane	5	5.1		M	D	73/173	3/30/2007	1/22/2007
	Tree (3" dhb) on wire- live tree - remove 9 cre 73										
1280	Cumberland	511	Forest Lane	5	6	S	M	D	73/173	3/30/2007	
	stubs-limbs on tel (10' nelow rule) full clear - crew 73										
1280	Cumberland	511	Forest Lane	8	9	S	M	D	73/173	3/30/2007	
	stubs & rips - crew 173										
1280	Cumberland	511	Forest Lane	9	10	S	M	D	73/173	3/30/2007	
	stubs & rips - crew 173										
2305	Gray	031	Forest Lake West Shore	26	27	PR6	M	D	173/73	3/30/2007	2/28/2007
	PR6 -birch & defective beech - crew 73										
2305	Gray	031	Forest Lake West Shore	27	28	PR6	M	D	173/73	3/30/2007	2/28/2007
	PR6 - maple w/butt damage & dead birch - crew 73										
2305	Gray	031	Forest Lake West Shore	30	31		M	D	various	3/30/2007	
	PR6 - or top dead hemlock w/in 8' - crew 173										
2305	Gray	031	Forest Lake West Shore	33	34		M	D	various	3/30/2007	
	birch rubbing on secondary - crew 173										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

2305	Gray	031	Forest Lake West Shore	37	38		M	D	various	3/30/2007	
	cuts should be made to branch collars - crew 173										
2305	Gray	031	Forest Lake West Shore	44	45		M	D	various	3/30/2007	
	on topping trees - cuts not straight cut										
2305	Gray	031	Forest Lake West Shore	49	50		M	D	various	3/30/2007	
	ROW needs more clearance - crew 58										
2305	Gray	031	Forest Lake West Shore	51	52	S	M	D	173/73	3/30/2007	
	stubs - poorly topped evergreen - crew 73										
6390	Windham	054	Critter Drive	6	7		M	D	69	3/30/2007	
	Hazard Tree										
6390	Windham	171	Maynards Rogers Road	26			M	D	various	3/30/2007	
	> 15' aerial= w pine										
6390	Windham	171	Maynards Rogers Road	28			M	D	various	3/30/2007	
	> 8' oak on 1phase + op.3 wire										
6390	Windham	171	Maynards Rogers Road	29	30	S	M	D	various	3/30/2007	
	stubs										

PORTLAND　Cotiaux　2/26/2007　20 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1280	CUMBERLAND	081	SKILLINGS ROAD	22	23	C	M	D	73	3/30/2007	4/10/2007
	Brush needs cut & treat for "F" clearance -red maple										

PORTLAND　Cotiaux　2/17/2007　36 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2305	GRAY	050	HYDE ROAD	1	2	C	M	D	69	3/30/2007	
	PR6- dead elm (or top)										
2305	GRAY	118	WHITNEY ROAD	32	34	C	M	D	73	3/30/2007	
	Large pine stubs - take back to bole										
2305	GRAY	118	WHITNEY ROAD	32	33	C	M	D	73	3/30/2007	
	Less than 15" (not sure which crew) ash leader										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

PORTLAND | Cotiaux | 2/23/2007 | 38 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2305	GRAY	057	LONG HILL ROAD	44	46	PR6	M	D	73,58,173,46	3/30/2007	4/10/2007
	dead tree - why left?										

PORTLAND | Cotiaux | 2/7/2007 | 39 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1280	CUMBERLAND	081	SKILLINGS ROAD	19	20	C	M	D	58/73	3/30/2007	4/10/2007
	Some stubbing on upper crown, shade tree maple										
1280	CUMBERLAND	081	SKILLINGS ROAD	9	10	C	M	D	58/73	3/30/2007	4/10/2007
	Dead pine leader left - pine										
2010	Falmouth	225	Gristmill Road	3	4	C	M	D	various	3/30/2007	4/12/2007
	Stubs - conifer; watch small stublets										
2010	Falmouth	225	Gristmill Road	4	5	C	M	D	various	3/30/2007	4/12/2007
	Narley looking										
2010	Falmouth	225	Gristmill Road	5	6	C	M	D	various	3/30/2007	
	Also stubs										
2305	GRAY	013	COTTON ROAD	4	5	C	M	D	73	3/30/2007	4/12/2007
	Big stubs in oak over single phase										

PORTLAND | Cotiaux | 2/2/2007 | 43 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2010	FALMOUTH	016	BLACKSTRAP ROAD	162	163	C	M	D	58/46	3/30/2007	
	stubs poor topped-maple by stream										
2010	FALMOUTH	016	BLACKSTRAP ROAD	162	161	C	M	D	58/46	3/30/2007	
	Hang										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

2010	FALMOUTH	016	BLACKSTRAP ROAD	167	168	C	M	D	58/46	3/30/2007	
	Maple leader by 167 - poor-need out PR6										
2010	FALMOUTH	016	BLACKSTRAP ROAD	173	174	C	M	D	58/46	3/30/2007	
	"Pop top" dead pine-PR6										
2010	FALMOUTH	016	BLACKSTRAP ROAD	174	175	C	M	D	58/46	3/30/2007	4/11/2007
	Maple stubs										

PORTLAND Cotiaux 3/20/2007 34 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2010	FALMOUTH	105	MERRILL ROAD	18	18.1	C	M	D	73	4/5/2007	
	Point pole to serv, n/d										

PORTLAND Cotiaux 3/22/2007 46 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2010	FALMOUTH	144	PLEASANT HILL ROAD	8	9	C	M	D	73	4/5/2007	
	>8 feet - listd as "F"										
4730	PORTLAND - EAS	419	PARSONS ROAD	6	5	C	M	D	69	4/5/2007	4/10/2007
	Listed as "F"-curved Norway Maple leader is >15,could be removed & tree trained away from 1phase										

PORTLAND Cotiaux 3/15/2007 50 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4730	PORTLAND - EAS	405	OCEAN AVENUE	100	101	C	M	D	58	4/5/2007	4/10/2007
	Cut but no chemical - high stumps										
4730	PORTLAND - EAS	419	PARSONS ROAD	8	8H	C	M	D	173	4/5/2007	
	> 15" ariel @ pole										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

PORTLAND Cotiaux 3/6/2007 71 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2010	FALMOUTH	106	MIDDLE ROAD	133.3	133.4	C	M	D	73/173	4/5/2007	
	Crew 58 noted w.pine w/woodpecker holes tree is PR5/cose at lead PF6										
2010	FALMOUTH	106	MIDDLE ROAD	210	H	C	M	D	73/173	4/5/2007	
	House 226 - Service not done										

PORTLAND Cotiaux 3/27/2007 92 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2010	FALMOUTH	155	FALMOUTH ROAD	54	55	C	M	D	73/58	4/5/2007	4/10/2007
	Pole 55 - service not done - house 20										
2010	FALMOUTH	155	FALMOUTH ROAD	88	89	PF5	M	D	73/58	4/5/2007	
	PF5 - Dying: or dead oak - 18" dhb, need permission - >8" lsites as full										
4730	PORTLAND - EAS	018	AUSTIN STREET	6	7	C	M	D	69	4/5/2007	
	Parsons - > 8'; need to get this 1phase leader										
4730	PORTLAND - EAS	075	CHENERY STREET	8	9	SER	M	D	69	4/5/2007	4/10/2007
	Pole 8 to service > 2 feet										
4730	PORTLAND - EAS	724	RAINBOW MALL ROAD	1	2		M	D	37	4/5/2007	
4730	PORTLAND - EAS	724	RAINBOW MALL ROAD	5H	1	SER	M	D	27	4/5/2007	
	5H (Rainbow Mall Rd-724); service not done on pole 1 on Ledgewood Dr (729).										

Service Center Totals: 51 Sections for Rework 995 Sections Reviewed 5.13%

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

ROCKLAND Cummings 1/24/2007 15 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0970	Camden	033	Carle Farm Rd.	1	2	C	M	D	70/47	3/30/2007	
	Topped hemlock-PR6										
0970	Camden	033	Carle Farm Rd.	2	3	C	M	D	70/47	3/30/2007	
	Dead oak in ROW										
0970	Camden	033	Carle Farm Rd.	5	5.01	C	M	D	70/47	3/30/2007	
	Service not done										
0970	Camden	033	Carle Farm Rd.	5.2	5.1	C	M	D	70/47	3/30/2007	
	Watch shelves, dead maple-PF6, topped hemlock-PR6										
0970	Camden	033	Carle Farm Rd.	5.3	5.31	C	M	D	70/47	3/30/2007	
	Service not done										
0970	Camden	033	Carle Farm Rd.	7	8	C	M	D	70/47	3/30/2007	
	Service deflecting										

ROCKLAND Cummings 1/23/2007 19 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4580	Penobscot	012	Brooksville Rd.(Deans Rd	22	22.1	C	M	D	96	3/30/2007	
	Not 2' on secondary										
4580	Penobscot	012	Brooksville Rd.(Deans Rd	23	23 1/2	C	M	D	96	3/30/2007	
	Service - overhead on oak										
4580	Penobscot	012	Brooksville Rd.(Deans Rd	23 1/2	24	C	M	D	96	3/30/2007	
	Service - spruce										
4580	Penobscot	012	Brooksville Rd.(Deans Rd	24	25	C	M	D	96	3/30/2007	
	Why pine shelf?										
4580	Penobscot	012	Brooksville Rd.(Deans Rd	27	28	C	M	D	96	3/30/2007	
	2 services										
4580	Penobscot	034	Nute Line	1	1.1	C	M	D	96	3/30/2007	
	Service										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4580	Penobscot	034	Nute Line	8	9	C	M	D	96	3/30/2007	
	Service										

ROCKLAND Cummings 1/24/2007 24 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0970	Camden	082	Frankel Line	10	11	C	M	D	72/45	3/30/2007	
	Remove pine in ROW										
0970	Camden	082	Frankel Line	13	14	C	M	D	72/45	3/30/2007	
	Remove birch leaning over lines										
0970	Camden	082	Frankel Line	9	9.1	C	M	D	72/45	3/30/2007	
	Service to yellow house - not done										

ROCKLAND Cummings 2/2/2007 25 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0970	CAMDEN	238	START ROAD	503	504	S	M	D	70	3/30/2007	
	Small stubs near driveway - too tall										
0970	CAMDEN	238	START ROAD	508	509	SER	M	D	70	3/30/2007	
	Service										
0970	CAMDEN	238	START ROAD	519.02	519.03	C	M	D	70	3/30/2007	
	Oak limb too close to primary										

ROCKLAND Cummings 2/22/2007 52 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3300	LINCOLNVILLE	100	MARTINS CORNER ROA	502	503	GRN	M	D	45/70	3/30/2007	
	Ground cut needed										
3300	LINCOLNVILLE	102	MOODY MOUNTAIN RO	4	5	SER	M	D	45/70	3/30/2007	
	Services not done										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

ROCKLAND Cummings 2/23/2007 60 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3300	LINCOLNVILLE	191	WILEYS CORNER ROAD	18	19	SER	M	D	70/45	3/30/2007	
	Trim Service										
3300	LINCOLNVILLE	191	WILEYS CORNER ROAD	22	22.1	PR5	M	D	70/45	3/30/2007	
	Cut down topped hemlock in ROW										
3300	LINCOLNVILLE	191	WILEYS CORNER ROAD	22.1	22.2	PR6	M	D	70/45	3/30/2007	
	Finsih taking down pine that was topped										

ROCKLAND Cummings 3/21/2007 58 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0970	CAMDEN	167	MOUNTAIN STREET	90	90H	PR6	M	D	70	4/5/2007	
	Remove cherry tree										

ROCKLAND Cummings 3/13/2007 78 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0970	CAMDEN	025	BEAUCAIRE ROAD	35	36	C	M	D	70	4/5/2007	
	Limb on service										

ROCKLAND Cummings 4/24/2007 37 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5965	UNITY	206	STEVENS ROAD	38	39	B	M	D		5/8/2007	
	Brush										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

ROCKLAND Cummings 4/12/2007 106 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5965	UNITY	090	HUNTER ROAD	1	2	G	M	D	110	5/8/2007	
	Need to ground cut										
5965	UNITY	090	HUNTER ROAD	21	22	G	M	D	110	5/8/2007	
	Need to ground cut										
5965	UNITY	090	HUNTER ROAD	34	35	PR6	M	D	110	5/8/2007	
	PR 6										
5965	UNITY	090	HUNTER ROAD	9	10	G	M	D	110	5/8/2007	
	Need to ground cut										

Service Center Totals: 31 Sections for Rework 474 Sections Reviewed 6.54%

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FARMINGTON Drake 2/22/2007 12 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4610	PERU	290	RIDGE ROAD	13	13.1	SER	M	D	55	3/30/2007	
	Service off 13.1										
4610	PERU	290	RIDGE ROAD	13	14	S	M	D	55	3/30/2007	
	Stubs										
4610	PERU	290	RIDGE ROAD	14	15	C	M	D	55	3/30/2007	
	Remove topped pine										
4610	PERU	290	RIDGE ROAD	8	9	S	M	D	55	3/30/2007	
	Stubs										

FARMINGTON Drake 2/1/2007 44 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0155	Anson	019	Hallbrook	1	2	C	M	D	1,87	3/30/2007	4/2/2007
	Leaning fir										
0155	Anson	019	Hallbrook	18	serv	C	M	D	1,87	3/30/2007	
	Serv										
0155	Anson	019	Hallbrook	20	serv	C	M	D	1,87	3/30/2007	
	serv										
0155	Anson	019	Hallbrook	22	23	C	M	D	1,87	3/30/2007	2/9/2007
	Cut fir/box alder										
0155	Anson	019	Hallbrook	4	5	C	M	D	1,87	3/30/2007	3/15/2007
	Leaning fir										
0155	Anson	019	Hallbrook	5	6	C	M	D	1,87	3/30/2007	
	PR6 - poplar										
0155	Anson	019	Hallbrook	8	9	C	M	D	1,87	3/30/2007	
	Trim not 8 feet										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FARMINGTON Drake 2/21/2007 49 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5580	STRONG *Ground cut*	107	SPAULDING ROAD	1	2	GRN	M	F		3/30/2007	
5580	STRONG *Dieihg Maple*	107	SPAULDING ROAD	13	14		M	F		3/30/2007	4/26/2007
5580	STRONG *Not 15"*	107	SPAULDING ROAD	2	3	C	M	F		3/30/2007	4/26/2007

FARMINGTON Drake 2/22/2007 93 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2030	FARMINGTON *Ground cut*	010	BACK FALLS ROAD	02	03	GRN	M	D	55	3/30/2007	
2030	FARMINGTON *PR6 poplar*	114	LUCY KNOWLES ROAD	25H	26	PR6	M	D	55	3/30/2007	
2030	FARMINGTON *Not 8" cut & trim*	114	LUCY KNOWLES ROAD	27	28	C	M	D	55	3/30/2007	
2030	FARMINGTON *Not 8" cut & trim*	114	LUCY KNOWLES ROAD	28	29	C	M	D	55	3/30/2007	
2030	FARMINGTON *Not 8" - fir*	114	LUCY KNOWLES ROAD	44	46	C	M	D	55	3/30/2007	
2030	FARMINGTON *cut*	114	LUCY KNOWLES ROAD	48	49		M	D	55	3/30/2007	
2030	FARMINGTON *Cut*	114	LUCY KNOWLES ROAD	49	50		M	D	55	3/30/2007	
2030	FARMINGTON *not 15'*	114	LUCY KNOWLES ROAD	50	51	C	M	D	55	3/30/2007	
2030	FARMINGTON *Cut*	114	LUCY KNOWLES ROAD	51	55		M	D	55	3/30/2007	

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

2030	FARMINGTON	114	LUCY KNOWLES ROAD	55	56		M	D	55	3/30/2007	
	Cut										
2030	FARMINGTON	114	LUCY KNOWLES ROAD	57	58	C	M	D	55	3/30/2007	
	Not 15'										
2030	FARMINGTON	114	LUCY KNOWLES ROAD	67	68	PR6	M	D	55	3/30/2007	
	PR 6 dead fir										
2030	FARMINGTON	114	LUCY KNOWLES ROAD	68	69	PR6	M	D	55	3/30/2007	
	PR 6 dead fir										
2030	FARMINGTON	185	ROBBINS LINE	2	3		M	D	55	3/30/2007	
	Fir not 8' and cut topped maple										
2030	FARMINGTON	185	ROBBINS LINE	3	4		M	D	55	3/30/2007	
	Not 8'										
2030	FARMINGTON	185	ROBBINS LINE	5	6		M	D	55	3/30/2007	
	Cut fir										
2030	FARMINGTON	185	ROBBINS LINE	7	8		M	D	55	3/30/2007	
	Not 8'										

FARMINGTON Drake 2/5/2007 131 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2835	Industry	185	West Mills Rd.	101	102	C	M	D	9	3/30/2007	
	Cut fir										
2835	Industry	185	West Mills Rd.	104	105	C	M	D	9	3/30/2007	
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	25	26	C	M	D	154	3/30/2007	3/20/2007
	Front leaders in maple										
4075	New Sharon	053	West Mills Road	52	53	C	M	D	154	3/30/2007	3/20/2007
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	53	54	C	M	D	154	3/30/2007	3/20/2007
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	59	59.01	C	M	D	154	3/30/2007	
	Cut fir										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4075	New Sharon	053	West Mills Road	59	60	C	M	D	154	3/30/2007	3/20/2007
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	69	70	C	M	D	154	3/30/2007	3/20/2007
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	70	71	C	M	D	154	3/30/2007	3/20/2007
	PR6 - 3 leaning birch trees										
4075	New Sharon	053	West Mills Road	71	72	C	M	D	154	3/30/2007	
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	73	74	C	M	D	154	3/30/2007	
	Cust 2 fir near pole 74										
4075	New Sharon	053	West Mills Road	93	94	C	M	D	154	3/30/2007	3/20/2007
	Trim apple tree										
4075	New Sharon	053	West Mills Road	95	96	C	M	D	154	3/30/2007	3/20/2007
	Cut birch tree										
4075	New Sharon	053	West Mills Road	96	97	C	M	D	154	3/30/2007	3/20/2007
	Pine not 8 feet										
4075	New Sharon	053	West Mills Road	97	98	C	M	D	154	3/30/2007	
	Trim not 8 feet										
4075	New Sharon	053	West Mills Road	98	99	C	M	D	154	3/30/2007	3/20/2007
	Trim not 8 feet										

FARMINGTON Drake 2/22/2007 159 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4610	PERU	020	CANTON-LEWISTON RO	31	32	S	M	D	55	3/30/2007	
	Stubs										
4610	PERU	020	CANTON-LEWISTON RO	33	34	PR6	M	D	55	3/30/2007	
	PR6 - yellow birch										
4610	PERU	020	CANTON-LEWISTON RO	34H	36	PR6	M	D	55	3/30/2007	
	PR6 - leaning birch										
4610	PERU	020	CANTON-LEWISTON RO	38	39	PR6	M	D	55	3/30/2007	
	PR6 - pine near pole 39										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4610	PERU	020	CANTON-LEWISTON RO	50	51	PR6	M	D	55	3/30/2007
	PR6 - dead pine									
4610	PERU	020	CANTON-LEWISTON RO	51	52	PR6	M	D	55	3/30/2007
	2 PR6 - pines with split seam									
4610	PERU	020	CANTON-LEWISTON RO	52	53		M	D	55	3/30/2007
	Birch under wires									
4610	PERU	020	CANTON-LEWISTON RO	54	55		M	D	55	3/30/2007
	Pines under wires									
4610	PERU	080	DICKVALE ROAD	12	13		M	D	55	3/30/2007
	Remove maple - bad trim job									
4610	PERU	080	DICKVALE ROAD	2	2.01	GRN	M	D	55	3/30/2007
	Ground cut									
4610	PERU	080	DICKVALE ROAD	2.1	2.2	GRN	M	D	55	3/30/2007
	Ground cut									
4610	PERU	080	DICKVALE ROAD	5	7		M	D	55	3/30/2007
	Cut									
4610	PERU	080	DICKVALE ROAD	7	8		M	D	55	3/30/2007
	Cut									
4610	PERU	080	DICKVALE ROAD	8	9	C	M	D	55	3/30/2007
	Remove trees within 8'									
4610	PERU	080	DICKVALE ROAD	9	10		M	D	55	3/30/2007
	Cut									
4610	PERU	230	MAIN STREET	505	1	S	M	D	55	3/30/2007
	Oak stub									
4610	PERU	230	MAIN STREET	516	516.1		M	D	55	3/30/2007
	Not 15" cut									
4610	PERU	230	MAIN STREET	516.1	516.2	C	M	D	55	3/30/2007
	Cut/trim									
4610	PERU	230	MAIN STREET	516.2	516.3	C	M	D	55	3/30/2007
	Cut/trim									
4610	PERU	230	MAIN STREET	516.3	516.4	C	M	D	55	3/30/2007
	Cut/trim									

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

5020	RUMFORD	130	DIXFIELD ROAD	14	15	S	M	D	55	3/30/2007	
	Stubs										
5020	RUMFORD	130	DIXFIELD ROAD	15	16	S	M	D	55	3/30/2007	
	Stubs										
5020	RUMFORD	130	DIXFIELD ROAD	16	17	S	M	D	55	3/30/2007	
	Stubs										
5020	RUMFORD	273	INDUSTRIAL PARK RD (	7	7.1		M	D	55	3/30/2007	
	Cut hemlock										
5020	RUMFORD	500	SMITHVILLE ROAD	64	Serv		M	D	55	3/30/2007	
	Service										
5020	RUMFORD	500	SMITHVILLE ROAD	65	serv	C	M	D	55	3/30/2007	
	Service										
5020	RUMFORD	500	SMITHVILLE ROAD	72	73		M	D	55	3/30/2007	
	Bad leader on popler										
5020	RUMFORD	500	SMITHVILLE ROAD	74	75	C	M	D	55	3/30/2007	
	not 15'										
5020	RUMFORD	500	SMITHVILLE ROAD	75	76	PR6	M	D	55	3/30/2007	
	3 PR6 - maples										
5020	RUMFORD	500	SMITHVILLE ROAD	80	1	C	M	D	55	3/30/2007	
	Pole 1 Dixfield rd.- Dead limbs in pine										

FARMINGTON **Drake** **3/23/2007** **127 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0155	ANSON	032	ANSON VALLEY ROAD	533	534	SER	m	D	87	4/5/2007	4/26/2007
	Service not done										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	42	43	C	m	D	170/1	4/5/2007	4/26/2007
	Overhead not 15 feet										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	503	504	C	m	D	170/1	4/5/2007	4/26/2007
	Ground cut										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	504	505	C	m	D	170/1	4/5/2007	4/26/2007
	Ground cut										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	507	508	C	m	D	170/1	4/5/2007	4/26/2007
	Ground cut										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	513	514	C	m	D	170/1	4/5/2007	4/26/2007
	Ground cut										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	514	515	C	m	D	170/1	4/5/2007	4/26/2007
	Ground cut										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	51H	52	PR6	m	D	170/1	4/5/2007	4/26/2007
	PR6 - 2 poplar										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	66	67	C	m	D	170/1	4/5/2007	4/26/2007
	Cut birch										
4080	NEW VINEYARD	001	ANSON VALLEY ROAD	69	70	C	m	D	170/1	4/5/2007	
	Cut fir										

FARMINGTON Drake 3/22/2007 226 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4075	NEW SHARON	024	GLENN HARRIS ROAD	2	2.1	C	M	D	9	4/5/2007	
	Secondary n/d										
4075	NEW SHARON	024	GLENN HARRIS ROAD	4	5	C	M	D	9	4/5/2007	
	Veins										
4075	NEW SHARON	024	GLENN HARRIS ROAD	5	6	C	M	D	9	4/5/2007	
	Not 8' and service off pole 6										
4075	NEW SHARON	025	GRAY ROAD	327	328	C	M	D	9	4/5/2007	4/23/2007
	Beech with dead top										
4075	NEW SHARON	025	GRAY ROAD	330H	331	C	M	D	9	4/5/2007	4/23/2007
	Veins										
4075	NEW SHARON	025	GRAY ROAD	336	336	PR6	M	D	9	4/5/2007	
	PR6 - 2 firs and 1 yellow birch PR5										
4075	NEW SHARON	025	GRAY ROAD	337	338	PR6	M	D	9	4/5/2007	4/23/2007
	PR6's 2 poplar										
4075	NEW SHARON	025	GRAY ROAD	339H	340	C	M	D	9	4/5/2007	4/23/2007
	2 poplar										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4075	NEW SHARON	025	GRAY ROAD	357	357.1	SER	M	D	9	4/5/2007	4/23/2007
	Service										
4075	NEW SHARON	025	GRAY ROAD	357H	358	C	M	D	9	4/5/2007	
	Split ash										
4075	NEW SHARON	025	GRAY ROAD	359	359.1	SEC	M	D	9	4/5/2007	4/23/2007
	Secondary not done										
4075	NEW SHARON	042	STARKS ROAD	187	188	C	M	D	9	4/5/2007	
	Cut cherry										
4075	NEW SHARON	042	STARKS ROAD	189	190	PR6	M	D	9	4/5/2007	
	PR6 leaner										
4075	NEW SHARON	042	STARKS ROAD	190	191	PR6	M	D	9	4/5/2007	
	PR6 - 2 leaning poplar										
4075	NEW SHARON	042	STARKS ROAD	215	216	C	M	D	9	4/5/2007	
	Trim not 8'										
4075	NEW SHARON	042	STARKS ROAD	222	223	C	M	D	9	4/5/2007	
	Trim not 8'										
4075	NEW SHARON	042	STARKS ROAD	223	227	PR6	M	D	9	4/5/2007	
	PR6 - 2 leaning poplar & service at pole 227										
4075	NEW SHARON	042	STARKS ROAD	227	228	C	M	D	9	4/5/2007	
	Leaning birch										
4075	NEW SHARON	042	STARKS ROAD	228	229	C	M	D	9	4/5/2007	
	2 leaning birch										
4075	NEW SHARON	042	STARKS ROAD	239	239.1	SER	M	D	9	4/5/2007	
	Service										
4075	NEW SHARON	042	STARKS ROAD	239	240	C	M	D	9	4/5/2007	
	Ground cut hardwoods										
4075	NEW SHARON	042	STARKS ROAD	243	244	C	M	D	9	4/5/2007	
	Ground cut hardwoods										
4075	NEW SHARON	042	STARKS ROAD	247	247.1	C	M	D	9	4/5/2007	4/23/2007
	Ground cut hardwoods										
4075	NEW SHARON	042	STARKS ROAD	249	250	S	M	D	9	4/5/2007	
	Stumps										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4075	NEW SHARON	042	STARKS ROAD	250	251	S	M	D	9	4/5/2007	
	Stumps										
4075	NEW SHARON	042	STARKS ROAD	252	266	PR6	M	D	9	4/5/2007	
	PR6 - leaning birch										
4075	NEW SHARON	042	STARKS ROAD	267	268	C	M	D	9	4/5/2007	
	Overhead not 15'										
4075	NEW SHARON	042	STARKS ROAD	280	290	C	M	D	9	4/5/2007	
	Veins										
4075	NEW SHARON	042	STARKS ROAD	311	312	C	M	D	9	4/5/2007	4/23/2007
	Not 8'										
4075	NEW SHARON	042	STARKS ROAD	312	312.1	SEC	M	D	9	4/5/2007	4/23/2007
	Secondary not done										
5515	STARKS	052	GRAY ROAD	352	353	C	M	D	9	4/5/2007	
	Maple double top with bad seam										
5515	STARKS	052	GRAY ROAD	355	356	C	M	D	9	4/5/2007	4/23/2007
	Poplar										

FARMINGTON Drake 5/8/2007 158 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2030	FARMINGTON	012	BARKER ROAD	1	2	PR6		D	9	6/13/2007	
	Cut poplar PR6										
4080	NEW VINEYARD	010	BARKER ROAD	17	18	PR6		D	9	6/13/2007	
	PR6 - poplar										
4080	NEW VINEYARD	010	BARKER ROAD	37.4	37.41	C		D	9	6/13/2007	
	Trim not 8 feet										
4080	NEW VINEYARD	010	BARKER ROAD	55	56	PR6		D	9	6/13/2007	
	2 PR6 - maple and basswood										
4080	NEW VINEYARD	010	BARKER ROAD	7	8	C		D	9	6/13/2007	
	Cut birches										
4080	NEW VINEYARD	132	WITHEY ROAD	2	3	C		D	9	6/13/2007	
	Trim not 8 feet by 15 feet										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FARMINGTON **Drake** **5/9/2007** **349 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2030	FARMINGTON *Service*	010	BACK FALLS ROAD	039	039.1	SER	M	D	55/9	6/13/2007	
2030	FARMINGTON *Secondary*	010	BACK FALLS ROAD	049	049.1	SEC	M	D	55/9	6/13/2007	
2030	FARMINGTON *Trim not 8 feet*	129	MARWICK ROAD	12	13	C	M	D	55/9	6/13/2007	
2030	FARMINGTON *Cut 6 pines under lines*	129	MARWICK ROAD	9	10	C	M	D	55/9	6/13/2007	
2030	FARMINGTON *Service needs trim*	135	NEW SHARON ROAD	10	11	SER	M	D	55/9	6/13/2007	
2030	FARMINGTON *Stumps*	135	NEW SHARON ROAD	17	18	S	M	D	55/9	6/13/2007	
2030	FARMINGTON *Veins*	135	NEW SHARON ROAD	9	10	V	M	D	55/9	6/13/2007	
4075	NEW SHARON *Stumps*	035	NEW SHARON ROAD	58	59	S	M	D	55/9	6/13/2007	
4075	NEW SHARON *Stumps*	035	NEW SHARON ROAD	59	60	S	M	D	55/9	6/13/2007	
4075	NEW SHARON *Secondary*	035	NEW SHARON ROAD	68	68.1	SEC	M	D	55/9	6/13/2007	

Service Center Totals: ***135 Sections for Rework*** ***1348 Sections Reviewed*** ***10.01%***

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

DOVER Hammond 1/26/2007 37 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1610	Dexter	161	Old Newport Rd.	30	31	C	M	D	various	3/30/2007	
	s/c to trim off 31										
1610	Dexter	161	Old Newport Rd.	39	40	R	M	D	various	3/30/2007	
	claimed - no work found (pond)										
1610	Dexter	161	Old Newport Rd.	41	42	R	M	D	various	3/30/2007	
	claimed - no work found (pond)										
1610	Dexter	161	Old Newport Rd.	42	43	R	M	D	various	3/30/2007	
	claimed - no work found (pond)										
1610	Dexter	161	Old Newport Rd.	44	45	C	M	D	various	3/30/2007	
	S/c to trim off 45										
1610	Dexter	161	Old Newport Rd.	45	45.1	C	M	D	various	3/30/2007	
	Skipped secondary										
1610	Dexter	161	Old Newport Rd.	59	60	R	M	D	various	3/30/2007	
	*fon found *1-223) only work claimed*										
1610	Dexter	161	Old Newport Rd.	61	62	C	M	D	various	3/30/2007	
	1 pr6 to cut (22) leaning fir in r/w										

DOVER Hammond 2/2/2007 2 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4520	PARKMAN	190	STONEBRIDGE LANE	11	12	C	m	D	137	3/30/2007	
	Cut 1 tall cedar & pine brush (flagged)										
4520	PARKMAN	190	STONEBRIDGE LANE	12	13	C	m	D	137	3/30/2007	
	Cut flagged brush on curve (per line dept request)										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

DOVER **Hammond** **3/7/2007** **62 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1220	CORINNA	053	FIVE CORNERS ROAD	28	29	C	M	D	various	4/5/2007	
	Dead limb near pole 28										
1220	CORINNA	053	FIVE CORNERS ROAD	35	36	C	M	D	various	4/5/2007	
	Apple trees/bursh left - cut or tim										
1220	CORINNA	053	FIVE CORNERS ROAD	36	37	C	M	D	various	4/5/2007	
	Apple trees/bursh left - cut or tim										
1220	CORINNA	053	FIVE CORNERS ROAD	37	38	C	M	D	various	4/5/2007	
	Apple trees/bursh left - cut or tim										
1220	CORINNA	142	OLD NEWPORT ROAD	68	69	C	M	D	various	4/5/2007	
	Skipped - cut brush & trim s/c - road crossing span										
1220	CORINNA	142	OLD NEWPORT ROAD	69	70	C	M	D	various	4/5/2007	
	Cut hardwood brush in cedar screen										

DOVER **Hammond** **3/7/2007** **118 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1220	CORINNA	172	RIPLEY ROAD	503	504	C	M	D	116	4/5/2007	
	Cut small flagged maple - 6' from line										
1610	DEXTER	202	RAND HILL ROAD	06	06.1	C	M	D	various	4/5/2007	
	Skipped secondary and s/c span										
5105	ST ALBANS	056	FIVE CORNERS ROAD	102	103	F	M	D	various	4/5/2007	
	Stubbing on small maple										
5105	ST ALBANS	056	FIVE CORNERS ROAD	110	111	C	M	D	various	4/5/2007	
	remove maple leader w/hole by pole 110										
5105	ST ALBANS	056	FIVE CORNERS ROAD	40	41	C	M	D	various	4/5/2007	
	Skipped section off pole 41										
5105	ST ALBANS	056	FIVE CORNERS ROAD	61.1	61.2	C	M	D	various	4/5/2007	
	Cut flagged ash beside driveway;remove dead ash overhead limbs-mid span										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5105	ST ALBANS	056	FIVE CORNERS ROAD	75	76	C	M	D	various	4/5/2007	
	cut birch brush (among alders)										

DOVER Hammond 4/11/2007 3 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2470	HAMPDEN	131	NEW COLDBROOK ROA	18.01	58	C	M	D	8/155	5/8/2007	
	58 Coldbrook Rd., more ground uct to to in r/w span										

DOVER Hammond 4/11/2007 81 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1020	CARMEL	031	DYER ROAD	1	701	C		D	varous	5/8/2007	
	Trim overhead - maple by pole 1										
1020	CARMEL	151	PARTRIDGE ROAD	14	15	C		D	various	5/8/2007	
	Cut flagged brush (ash) by pole 14 and one PR6 (223) flagged										
1020	CARMEL	151	PARTRIDGE ROAD	3	4	B		D	various	5/8/2007	
	Pine limb to chip and more trim										
1020	CARMEL	153	PLYMOUTH ROAD	24	25	PR6		D	various	5/8/2007	
	Cut flagged PF6 (223)										
1020	CARMEL	153	PLYMOUTH ROAD	26	27	C		D	various	5/8/2007	
	More overhead trim										
1020	CARMEL	153	PLYMOUTH ROAD	27	27.1	C		D	various	5/8/2007	
	Cut rtipped pine										
1020	CARMEL	153	PLYMOUTH ROAD	29	30	C		D	various	5/8/2007	
	Shelf on oak										
1020	CARMEL	153	PLYMOUTH ROAD	35	35.01	C		D	various	5/8/2007	
	Cut brush by pole 35										
1020	CARMEL	153	PLYMOUTH ROAD	36	37	C		D	various	5/8/2007	
	shelf on pine - woodlot										
1020	CARMEL	153	PLYMOUTH ROAD	45	46	C		D	various	5/8/2007	
	Cut topped spruce										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1020	CARMEL	153	PLYMOUTH ROAD	46	47	C		D	various	5/8/2007	
	Cut topped fir at pole 46										
1020	CARMEL	153	PLYMOUTH ROAD	48	49	C		D	various	5/8/2007	
	Cut brush at pole 49 and trim service										
1020	CARMEL	153	PLYMOUTH ROAD	49	50	C		D	various	5/8/2007	
	Cut dead maple (this is now done)										
1020	CARMEL	153	PLYMOUTH ROAD	51	51H	C		D	various	5/8/2007	
	Cut toped conifers and recut tall stumps										

DOVER **Hammond** **4/11/2007** **138 Sections Reviewed**

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1890	ETNA	023	CENTER ROAD	755	756	C		D	various	5/8/2007	
	Remove leader with woodpecker hole										
1890	ETNA	023	CENTER ROAD	767	701	C		D	various	5/8/2007	
	Pole 701 (Dixmont Rd) cut birch under line										
1890	ETNA	023	CENTER ROAD	768	769	C		D	various	5/8/2007	
	Cut topped brush										
1890	ETNA	031	DIXMONT ROAD	36	36.01	C		D	various	5/8/2007	
	Cut topped hardwoods										
1890	ETNA	031	DIXMONT ROAD	41	42	C		D	various	5/8/2007	
	Cut pine at pole 42										
1890	ETNA	241	YOUNG ROAD	12	13	C		D	various	5/8/2007	
	Fir hedge not trimmed										

DOVER **Hammond** **4/11/2007** **146 Sections Reviewed**

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1637	DIXMONT	055	ETNA ROAD	01	02	C		D	various	5/8/2007	
	Cut topped pines and ash brush										
1637	DIXMONT	135	MEADOW ROAD	65	66	S		D	various	5/8/2007	
	Cut brush and high stumps										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

1637	DIXMONT	135	MEADOW ROAD	66	67	C	D	various	5/8/2007
	Cut brush and high stumps								
1637	DIXMONT	135	MEADOW ROAD	67	68	S	D	various	5/8/2007
	Cut high stumps								
1637	DIXMONT	135	MEADOW ROAD	72	73	S	D	various	5/8/2007
	Cut high stumps and trim overhead								
1637	DIXMONT	135	MEADOW ROAD	73	74	S	D	various	5/8/2007
	Cut high stumps								
1637	DIXMONT	138	MOORE ROAD				D	various	5/8/2007
1637	DIXMONT	202	SOUTH ETNA ROAD	2	3	PR6	D	various	5/8/2007
	Cut PR6 (223) poplar - flagged by pole 3								
1637	DIXMONT	244	WHITE SCHOOL ROAD	1	2	PR6	D	various	5/8/2007
	Cut PR6 (223) flagged poplar and chip it								
1637	DIXMONT	244	WHITE SCHOOL ROAD	14	14.1	C	D	various	5/8/2007
	Cut elm brush by road								
1637	DIXMONT	244	WHITE SCHOOL ROAD	46	47	C	D	various	5/8/2007
	Chip at pole 46 and trim on poles 47 - 471. (Secondary)								
1637	DIXMONT	244	WHITE SCHOOL ROAD	47	1	SER	D	various	5/8/2007
	Pole 1 on So. Etna Rd - Trim service off pole 1								

Service Center Totals: ***56 Sections for Rework*** ***587 Sections Reviewed*** ***9.54%***

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FAIRFIELD Hammond 1/5/2007 28 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5210	Waterville	382	Thomas Drive	1	2	C	M	D	119	3/30/2007	
	Pine limbs at pole 1										
5210	Waterville	382	Thomas Drive	2	3	C	M	D	119	3/30/2007	
	Too close										
5210	Waterville	382	Thomas Drive	3	4	C	M	D	119	3/30/2007	
	Leaner should be cut										
5325	Sidney	184	West River Road	0223	0224	C	M	D	115	3/30/2007	
	Pines to cut										

FAIRFIELD Hammond 1/24/2007 78 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1155	China	149	Stanley Road	75	76	C	M	D		3/30/2007	3/19/2007
	1 pine to cut										
1155	China	149	Stanley Road	76	76.1	C	M	D		3/30/2007	
	side clearance in R/W < 8'										
6035	Vassalboro	011	Brann Road	2	3	C	M	D		3/30/2007	3/21/2007
	Limb by pole 3										
6035	Vassalboro	011	Brann Road	25	27	C	M	D		3/30/2007	3/21/2007
	retrim s/c off 27										
6035	Vassalboro	011	Brann Road	27H	28	C	M	D		3/30/2007	3/21/2007
	Cut leaning ash (flagged) PR5										
6035	Vassalboro	011	Brann Road	3	4	C	M	D		3/30/2007	3/21/2007
	2 pines to cut -OROW-code 223 (flagged)										
6035	Vassalboro	011	Brann Road	5	6	R	M	D		3/30/2007	
	no work found										
6035	Vassalboro	021	China Road	25	26	C	M	D		3/30/2007	3/19/2007
	Cut stubbed hardwoods										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6035	Vassalboro	021	China Road	53	54	C	M	D		3/30/2007	3/19/2007
	Side trim - ash (too close)										
6035	Vassalboro	058	Gray Road	702	703	C	M	D		3/30/2007	3/21/2007
	Trim s/c- spruces										

FAIRFIELD **Hammond** **1/24/2007** **79 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6035	Vassalboro	064	Hussey Hill Road	509	1-Masse	C	M	D		3/30/2007	
	Cut flagged maple - OROW - Code 223										
6035	Vassalboro	100	Lombard Dam Road	19	20	C	M	D		3/30/2007	3/22/2007
	Cut leaner - OROW - code 223										
6035	Vassalboro	110	Masse Ln	3	4	C	M	D		3/30/2007	3/22/2007
	Cut 2 plagged maples (PR5)										
6035	Vassalboro	110	Masse Ln	4	5	C	M	D		3/30/2007	3/22/2007
	Cut tipped firs by pole 4 - brush size										
6035	Vassalboro	115	Nelson Road	704	705	C	M	D		3/30/2007	3/22/2007
	Recut brush										
6035	Vassalboro	115	Nelson Road	705	706	C	M	D		3/30/2007	3/22/2007
	Cut stubbed trees (PR5)										
6035	Vassalboro	131	Priest Hill Road	012	013	C	M	D		3/30/2007	3/23/2007
	Cut pine (+ brush under it)										
6035	Vassalboro	131	Priest Hill Road	03	04	C	M	D		3/30/2007	3/23/2007
	Sec to trim off 04										
6035	Vassalboro	131	Priest Hill Road	04	05	C	M	D		3/30/2007	3/23/2007
	2 sec to trim off 05										
6035	Vassalboro	131	Priest Hill Road	05	06	C	M	D		3/30/2007	3/23/2007
	Sec to trim off 06										
6035	Vassalboro	137	Quaker Lane	502	503	C	M	D		3/30/2007	3/23/2007
	Ash to cut - PR5										
6035	Vassalboro	137	Quaker Lane	503	503.1	C	M	D		3/30/2007	
	No work found										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

6035	Vassalboro	137	Quaker Lane	503.2	503.3	C	M	D		3/30/2007	
	Cut hardwood, at least										
6035	Vassalboro	137	Quaker Lane	503.3	503.4	C	M	D		3/30/2007	
	Change to lim clr; if can not get more										
6035	Vassalboro	137	Quaker Lane	512	513	C	M	D		3/30/2007	3/23/2007
	Cut topped fir										
6035	Vassalboro	149	So. China Road	293	294	C	M	D		3/30/2007	3/22/2007
	Trim sec to garage (off 294)										
6035	Vassalboro	149	So. China Road	295	296	C	M	D		3/30/2007	3/22/2007
	Retrim sec - spruces (off 296)										
6035	Vassalboro	149	So. China Road	325	326	C	M	D		3/30/2007	3/22/2007
	Retrim sec off 326										
6035	Vassalboro	149	So. China Road	327	328	C	M	D		3/30/2007	3/22/2007
	Cut topped hardwoods										
6035	Vassalboro	149	So. China Road	329	330	C	M	D		3/30/2007	3/22/2007
	Cut flagged leaner - OROW (code 225)										
6035	Vassalboro	149	So. China Road	329	329.1	C	M	D		3/30/2007	
	No work here - road crossing only										

FAIRFIELD Hammond 2/7/2007 73 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4300	OAKLAND	056	EAST SIDE TRAIL	11	11.1	C	M	D	115,119	3/30/2007	3/23/2007
	Needs more side trim (<8') in R/W										
4300	OAKLAND	056	EAST SIDE TRAIL	4	5	C	M	D	115,119	3/30/2007	3/23/2007
	Ash brush by road										
4300	OAKLAND	056	EAST SIDE TRAIL	7	8	C	M	D	115,119	3/30/2007	3/23/2007
	Skipped s/c off 8										
4300	OAKLAND	078	GAGE ROAD	01	02	B	M	D	115,119	3/30/2007	3/23/2007
	Chip (and danger tree)										
4300	OAKLAND	078	GAGE ROAD	2	3	C	M	D	115,119	3/30/2007	3/23/2007
	More timr on cedars										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4300	OAKLAND	078	GAGE ROAD	t/o 47	01	C	M	D	115,119	3/30/2007	
	More ash brush to cut (and danger tree)										
4300	OAKLAND	100	JOLICOEUR LINE	1	2		M	D	115,119	3/30/2007	3/23/2007
	Skipped s/c off pole 2										
4300	OAKLAND	100	JOLICOEUR LINE	2	3		M	D	115,119	3/30/2007	3/23/2007
	Skipped s/c off pole 3										
4300	OAKLAND	222	SUMMER STREET	57	57.1	C	M	D	115,119	3/30/2007	
	Skipped sec & s/c - not billable 308										
4300	OAKLAND	222	SUMMER STREET	t/o 09	57	R	M	D	115,119	3/30/2007	
	No work found										
4300	OAKLAND	226	SIERRA TRAIL	6	7	C	M	D	115,119	3/30/2007	3/23/2007
	Cut brush on curve										

FAIRFIELD Hammond 2/7/2007 114 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4300	OAKLAND	067	FAIRFIELD STREET	25	24	C	M	D	115,119	3/30/2007	3/23/2007
	Skipped s/c off 24 (across road)										
4300	OAKLAND	067	FAIRFIELD STREET	50	49H	C	M	D	115,119	3/30/2007	3/23/2007
	Skipped s/c off 49H - not billable 309										
4300	OAKLAND	067	FAIRFIELD STREET	57	57.1	C	M	D	115,119	3/30/2007	3/26/2007
	Skipped sec. & s/c										
4300	OAKLAND	091	HIGH STREET	1	1.1	C	M	D	115,119	3/30/2007	
	Skipped sec										
4300	OAKLAND	091	HIGH STREET	16	16.1	C	M	D	115,119	3/30/2007	3/23/2007
	Skipped sec										
4300	OAKLAND	091	HIGH STREET	24.01	24.02	C	M	D	115,119	3/30/2007	
	More side trim needed (<8')										
4300	OAKLAND	091	HIGH STREET	27	28	C	M	D	115,119	3/30/2007	
	No work seen										
4300	OAKLAND	091	HIGH STREET	31	31.1	C	M	D	115,119	3/30/2007	
	Skipped sec - not billable 308										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4300	OAKLAND	091	HIGH STREET	39	39.01	C		M	D	115,119	3/30/2007	3/23/2007
	Topped birches s/b cut											
4300	OAKLAND	091	HIGH STREET	39.01	39.02	C		M	D	115,119	3/30/2007	3/23/2007
	Topped birches s/b cut											

FAIRFIELD Hammond 3/16/2007 6 Sections Reviewed

	Town		Road	From	To	Compliance Issue		Class	Contractor	Crew	Notify Date	Fix Date
4650	PITTSFIELD	011	BATES STREET	5	6	C		M	D	89	4/5/2007	3/20/2007
	Needs cut; hardwood brush topped											
4650	PITTSFIELD	011	BATES STREET	7	8	C		M	D	89	4/5/2007	3/20/2007
	Needs cut, stump treatment and topped brush											

FAIRFIELD Hammond 3/9/2007 44 Sections Reviewed

	Town		Road	From	To	Compliance Issue		Class	Contractor	Crew	Notify Date	Fix Date
6420	WINSLOW	060	DALLAIRE STREET	3	4	C		M	D	137	4/5/2007	
	Stubs left & should remvoe front leader (Boxfeder)											
6420	WINSLOW	060	DALLAIRE STREET	6	7	C		M	D	137	4/5/2007	
	Shelf left - town tree											
6420	WINSLOW	110	HALLOWELL STREET	4	1	C		M	D	166	4/5/2007	
	1 (St. John) retirm s/c - still rubbing (paid 5/6)											
6420	WINSLOW	110	HALLOWELL STREET	8	9	F		M	D	166	4/5/2007	
	Stubs											
6420	WINSLOW	186	POULIN STREET					M	D	89	4/5/2007	
6420	WINSLOW	186	POULIN STREET	01	3	C		M	D	89	4/5/2007	
	3 (Rancourt) cut brush behind pole 3											
6420	WINSLOW	186	POULIN STREET	26	1	C		M	D	89	4/5/2007	
	26 (Halifax) stubs & shelf & more trim on s/c											
6420	WINSLOW	260	WHIPPLE STREET	9	10	R		M	D	89	4/5/2007	
	Charged for 305 - s/b (2) 308 billable											

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FAIRFIELD   Hammond   3/23/2007   58 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0460	BENTON	213	WINSLOW ROAD	0165	0166	C	M	D	various	4/5/2007	
	S/c to trim off pole 0166										
0460	BENTON	213	WINSLOW ROAD	0170	0171	S	M	D	various	4/5/2007	
	High stumps										
6420	WINSLOW	048	CLINTON AVENUE	159	160	S	M	D	various	4/5/2007	
	Brush to chip and high stumps										
6420	WINSLOW	048	CLINTON AVENUE	160	161	C	M	D	various	4/5/2007	
	Ash brush to cut at pole 160										
6420	WINSLOW	228	SMILEY AVENUE	503	504	C	M	D	various	4/5/2007	
	Cut brush by pole 504										
6420	WINSLOW	228	SMILEY AVENUE	504	505	C	M	D	various	4/5/2007	
	Cut brush by pole 505										
6420	WINSLOW	228	SMILEY AVENUE	505	505H	C	M	D	various	4/5/2007	
	Cut brush by pole 505										
6420	WINSLOW	228	SMILEY AVENUE	508	509	C	M	D	various	4/5/2007	
	Cut brush by pole 509										

FAIRFIELD   Hammond   3/27/2007   70 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0050	ALBION	014	BESSEY RIDGE ROAD	21H	22	B	M	D	various	4/5/2007	
	Small brush pile to chip @ pole 22										
0050	ALBION	014	BESSEY RIDGE ROAD	507	508	C	M	D	various	4/5/2007	
	Ash brush to cut by pole 508										
0050	ALBION	014	BESSEY RIDGE ROAD	519	520	C	M	D	various	4/5/2007	
	Ash brush to cut										
0050	ALBION	040	DANFORTH ROAD	1	2	S	M	D	various	4/5/2007	
	Cut/treat high stumps										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

0050	ALBION	080	HUSSEY ROAD	58	59	B	M	D	various	4/5/2007	
	Brush piles in ROW - chip or dice/windrow										
0050	ALBION	080	HUSSEY ROAD	61	62	C	M	D	various	4/5/2007	
	Brush to cut										
0050	ALBION	080	HUSSEY ROAD	79	80	C	M	D	various	4/5/2007	
	More overhead tirm in yard										
0050	ALBION	080	HUSSEY ROAD	81	83	C	M	D	various	4/5/2007	
	More side teim to do										
0050	ALBION	080	HUSSEY ROAD	85	86	C	M	D	various	4/5/2007	
	Missed s/c across road										
0050	ALBION	145	NOYES ROAD	20	21	C	M	D	various	4/5/2007	
	More trim needed - weak limbs										

FAIRFIELD Hammond 3/21/2007 96 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0050	ALBION	015	BOG ROAD	1	2	S	M	D	various	4/5/2007	
	Recut stumps and spray										
0050	ALBION	015	BOG ROAD	20	21	C	M	D	various	4/5/2007	
	Not open -stubs on maple										
0050	ALBION	015	BOG ROAD	22	24	S	M	D	various	4/5/2007	
	Recut stumps										
0050	ALBION	015	BOG ROAD	27	28	S	M	D	various	4/5/2007	
	Recut stumps and spray										
0050	ALBION	015	BOG ROAD	28	29	S	M	D	various	4/5/2007	
	Recut stumps and spray										
0050	ALBION	015	BOG ROAD	44	46	C	M	D	various	4/5/2007	
	Trim s/c to red house										
0050	ALBION	015	BOG ROAD	51	52	C	M	D	various	4/5/2007	
	Cut birch by pole 52										
0050	ALBION	015	BOG ROAD	72	73	C	M	D	various	4/5/2007	
	Cut flagged fir and spruce by pole 73										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

				From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0050	ALBION	015	BOG ROAD	80	81	C	M	D	various	4/5/2007	
	High pine stumps and cut brush										
0050	ALBION	015	BOG ROAD	81	82	C	M	D	various	4/5/2007	
	High pine stumps and cut brush										

FAIRFIELD — Hammond — 3/27/2007 — 101 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0050	ALBION	120	LIBBY HILL ROAD	18	19	B/C	M	D	various	4/5/2007	
	Chip and flagged maple to cut										
0050	ALBION	120	LIBBY HILL ROAD	2	2.1	B	M	D	various	4/5/2007	
	Chip by pole l2/1										
0050	ALBION	120	LIBBY HILL ROAD	20	21	F	M	D	various	4/5/2007	
	Stubs on willow										
0050	ALBION	120	LIBBY HILL ROAD	28	29	Han	M	D	various	4/5/2007	
	hanger in pine										
0050	ALBION	260	YORK TOWN ROAD	10	11	C	M	D	various	4/5/2007	
	Brush to cut by pole 10										
0050	ALBION	260	YORK TOWN ROAD	4	5	S	M	D	various	4/5/2007	
	High stumps - cut/treat										
0050	ALBION	260	YORK TOWN ROAD	5	6	S	M	D	various	4/5/2007	
	High stumps - cut/treat										
0050	ALBION	260	YORK TOWN ROAD	6	7	S	M	D	various	4/5/2007	
	High stumps - cut/treat										
0050	ALBION	260	YORK TOWN ROAD	7	8	S	M	D	various	4/5/2007	
	High stumps - cut/treat										
0050	ALBION	260	YORK TOWN ROAD	8	9	S	M	D	various	4/5/2007	
	High stumps - cut/treat										
0050	ALBION	260	YORK TOWN ROAD	9	10	S	M	D	various	4/5/2007	
	High stumps - cut/treat										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FAIRFIELD Hammond 3/21/2007 103 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4300	OAKLAND	029	CRAIG DRIVE	16	17	C	M	D	various	4/5/2007	
	1 birch top - woodlot										
4300	OAKLAND	206	RICE RIPS ROAD	501	502	C	M	D	various	4/5/2007	
	More brush to cut										
4300	OAKLAND	206	RICE RIPS ROAD	510	511	C	M	D	various	4/5/2007	
	Missed s/c off pole 511 - fir										
4300	OAKLAND	206	RICE RIPS ROAD	516	517	C	M	D	various	4/5/2007	
	Missed s/c to yellow house off pole 517										
4300	OAKLAND	206	RICE RIPS ROAD	519	520	C	M	D	various	4/5/2007	
	More to cut (clump - maple)										
4300	OAKLAND	206	RICE RIPS ROAD	520	521	C	M	D	various	4/5/2007	
	Two to cut (per Ara Cookson)										
6210	WATERVILLE	228	MARSTON ROAD	H	1	C	M	D	various	4/5/2007	
	Recut high stumps and spray										
6210	WATERVILLE	259	NORTH STREET	503	504	C	M	D	various	4/5/2007	
	Cut ash closest to pole 504 - 4 ft from pole										

FAIRFIELD Hammond 3/23/2007 120 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6420	WINSLOW	048	CLINTON AVENUE	40H	41	C	m	D	various	4/5/2007	
	Cut flagged elms (small)										
6420	WINSLOW	048	CLINTON AVENUE	43H	44	S	m	D	various	4/5/2007	
	Cut flagged elm and high stumps										
6420	WINSLOW	048	CLINTON AVENUE	91	91.1	C	m	D	various	4/5/2007	
	Cut limb off pole										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FAIRFIELD **Hammond** **4/25/2007** **61 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0440	BELGRADE	165	PINKHAM COVE EXTEN	13	14	C		D	various	5/8/2007	
	Cut ash brush by pole 13 and consult with customer off pole 12										
0440	BELGRADE	165	PINKHAM COVE EXTEN	15	16	C		D	various	5/8/2007	
	Cut ash brush by pole 15										
0440	BELGRADE	165	PINKHAM COVE EXTEN	17	17.1	SEC		D	various	5/8/2007	
	Secondary not done & check s/c										
0440	BELGRADE	165	PINKHAM COVE EXTEN	19	20	C		D	various	5/8/2007	
	Cut oak brush by pole 19										
0440	BELGRADE	165	PINKHAM COVE EXTEN	20	21	C		D	various	5/8/2007	
	Cut oak brush by pole 20										
0440	BELGRADE	165	PINKHAM COVE EXTEN	21	21.1	SEC		D	various	5/8/2007	
	Secondary not done										
0440	BELGRADE	165	PINKHAM COVE EXTEN	24	24.1	SEC		D	various	5/8/2007	
	Secondary and s/c not done										
0440	BELGRADE	165	PINKHAM COVE EXTEN	25	26	B		D	various	5/8/2007	
	Chip hardwood pole by pole 25 and windrow limbs in r/w										
0440	BELGRADE	165	PINKHAM COVE EXTEN	26	27	B		D	various	5/8/2007	
	Windrow limbs in r/w										
0440	BELGRADE	165	PINKHAM COVE EXTEN	27	28	C		D	various	5/8/2007	
	Remove shelf on hemlocks in r/w										
0440	BELGRADE	165	PINKHAM COVE EXTEN	28	29	C		D	various	5/8/2007	
	Trim s/c off pole 29										
0440	BELGRADE	165	PINKHAM COVE EXTEN	29	30	C		D	various	5/8/2007	
	Trim s/c off pole 30										
0440	BELGRADE	165	PINKHAM COVE EXTEN	30	31	C		D	various	5/8/2007	
	Cut one Orow birch (code 223) flagged										
0440	BELGRADE	165	PINKHAM COVE EXTEN	32	33	C		D	various	5/8/2007	
	Cut hemlock brush by pole 33 and remove shelf in r/w										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

0440	BELGRADE	165	PINKHAM COVE EXTEN	33	34	C	D	various	5/8/2007
	Trim ash for primary and s/c off pole 33								
0440	BELGRADE	165	PINKHAM COVE EXTEN	34	35	C	D	various	5/8/2007
	More side trim - hemlock								
0440	BELGRADE	165	PINKHAM COVE EXTEN	35	36	C	D	various	5/8/2007
	More side trim - maple								
0440	BELGRADE	165	PINKHAM COVE EXTEN	36	36.1	SEC	D	various	5/8/2007
	Secondary and 2 s/c to trim (not done)								
0440	BELGRADE	165	PINKHAM COVE EXTEN	45	46	C	D	various	5/8/2007
	Cut small brush by pole 45 in r/w								
0440	BELGRADE	165	PINKHAM COVE EXTEN	47	47H	C	D	various	5/8/2007
	Trim beech by pole 47, cut brush by pole 47H, trim cedars s/c off pole 47H								
0440	BELGRADE	165	PINKHAM COVE EXTEN	48	48.1	SEC	D	various	5/8/2007
	Secondary not done								
0440	BELGRADE	165	PINKHAM COVE EXTEN	50	51	C	D	various	5/8/2007
	Trim beech by pole 50 - shelf								
0440	BELGRADE	165	PINKHAM COVE EXTEN	51	52	C	D	various	5/8/2007
	Trim s/c off pole 52 - rubbing								
0440	BELGRADE	165	PINKHAM COVE EXTEN	52	53	C	D	various	5/8/2007
	Cut Orow tree (code 223) flagged in r/w								
0440	BELGRADE	165	PINKHAM COVE EXTEN	55	56	C	D	various	5/8/2007
	Cut Orow tree (code 225) flagged in r/w; trim hemlock by pole 56								
0440	BELGRADE	165	PINKHAM COVE EXTEN	56	57	C	D	various	5/8/2007
	Cut and trim for s/c off pole 57 - flagged								
0440	BELGRADE	165	PINKHAM COVE EXTEN	57	58	C	D	various	5/8/2007
	Remove shelf and trim s/c off pole 58								
0440	BELGRADE	165	PINKHAM COVE EXTEN	57	57.1	SEC	D	various	5/8/2007
	Secondary and 2 s/c to do - not done								
0440	BELGRADE	165	PINKHAM COVE EXTEN	60	61	C	D	various	5/8/2007
	Cut brush by pole 60								

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

FAIRFIELD **Hammond** **5/18/2007** **59 Sections Reviewed**

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0440	BELGRADE	061	FOSTER POINT ROAD	28	30	GRN	M	D	various	6/13/2007	
	Cut brush in r/w by pole 28 and trim										
0440	BELGRADE	061	FOSTER POINT ROAD	30	31	GRN	M	D	various	6/13/2007	
	Poplar to cut										
0440	BELGRADE	061	FOSTER POINT ROAD	32	33	C	M	D	various	6/13/2007	
	OH on ash										
0440	BELGRADE	061	FOSTER POINT ROAD	5	6	GRN	M	D	various	6/13/2007	
	oak/maple brush to cut										
0440	BELGRADE	061	FOSTER POINT ROAD	57	58	C	M	D	various	6/13/2007	
	Needs more cut & trim in r/w										
0440	BELGRADE	061	FOSTER POINT ROAD	64	65	C	M	D	various	6/13/2007	
	Skipped span & cut split leaning maple										
0440	BELGRADE	061	FOSTER POINT ROAD	66	67	C	M	D	various	6/13/2007	
	Recut by pole 67										
0440	BELGRADE	061	FOSTER POINT ROAD	69	70	C	M	D	various	6/13/2007	
	Dying pine by pole 70 - too close										
0440	BELGRADE	061	FOSTER POINT ROAD	70	71	C	M	D	various	6/13/2007	
	Dying hemlock - too close										
0440	BELGRADE	165	PINKHAM COVE EXTEN	3	4	SER	M	D	various	6/13/2007	
	s/c off pole 4 to trim										
6420	WINSLOW	052	CORBETT LANE	3	4	SER	M	D	various		
	Retrim s/c to house #8										
6420	WINSLOW	052	CORBETT LANE	5	6	S	M	D	various		
	Stubbed branch										
6420	WINSLOW	052	CORBETT LANE	6	7	SER	M	D	various		
	Retrim s/c off pole 7										
6420	WINSLOW	090	FRANKWOOD DRIVE	1	2	C	M	D	various		
	More trim needed at pole 2										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

6420	WINSLOW	228	SMILEY AVENUE	11	12	C	M	D	various		
	More cut at pole 12										

FAIRFIELD — Hammond — 5/1/2007 — 75 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4300	OAKLAND	023	BLAKE EXTENSION	1	2	B	M	D	various	6/13/2007	
	Recut and chop by pole 2										
4300	OAKLAND	023	BLAKE EXTENSION	2	3	C	M	D	various	6/13/2007	
	Retrim pine shelf										
4300	OAKLAND	221	SMITHFIELD ROAD	47H	48	C	M	D	various	6/13/2007	
	Cut topped hardwood brush and brush by box trailer										
4300	OAKLAND	221	SMITHFIELD ROAD	49	50	C	M	D	various	6/13/2007	
	Cut ash brush - flagged										
4300	OAKLAND	235	TOWN FARM ROAD	515	515.1	C	M	D	various	6/13/2007	
	Clained but not done (secondary										
4300	OAKLAND	235	TOWN FARM ROAD	533	534	B	M	D	various	6/13/2007	
	Chip by pole 534										
4300	OAKLAND	235	TOWN FARM ROAD	534	535	C	M	D	various	6/13/2007	
	Cut rush at pole 534										
4300	OAKLAND	235	TOWN FARM ROAD	537	539	B	M	D	various	6/13/2007	
	Chip by pole 537										
4300	OAKLAND	235	TOWN FARM ROAD	550.1	550.1H	C	M	D	various	6/13/2007	
	Retrim shelf and hanger										
4300	OAKLAND	235	TOWN FARM ROAD	550.1H	550.2	C	M	D	various	6/13/2007	
	Retrim shelf										
4300	OAKLAND	235	TOWN FARM ROAD	553	555	B	M	D	various	6/13/2007	
	Chip brush										
4300	OAKLAND	235	TOWN FARM ROAD	555	557	C	M	D	various	6/13/2007	
	Retrim shelf - beech by pole 551 & S/R off pole 557										
4300	OAKLAND	235	TOWN FARM ROAD	562	563	C	M	D	various	6/13/2007	
	Cut hardwood brush out of conifer screen										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4300	OAKLAND	235	TOWN FARM ROAD	572	574	C	M	D	various	6/13/2007
	Trim limb over road									

Service Center Totals:	**174 Sections for Rework**	**1386 Sections Reviewed**	**12.55%**

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

SKOWHEGAN Hammond 1/25/2007 45 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0200	Athens	243	W. Athens Road	13	14	R	M	D	various	3/30/2007	
	claimed, no work found										
0200	Athens	243	W. Athens Road	25	25.1	C	M	D	various	3/30/2007	
	Skipped secondary										
0200	Athens	243	W. Athens Road	34	35	R	M	D	various	3/30/2007	
	claimed, no work found										
0200	Athens	243	W. Athens Road	38	39	C	M	D	various	3/30/2007	3/29/2007
	Leaning fir - PR6 (223) to cut										
0200	Athens	243	W. Athens Road	41	41.1	C	M	D	various	3/30/2007	
	Skipped secondary										
0200	Athens	243	W. Athens Road	42	43	R	M	D	various	3/30/2007	
	claimed, no work found										
0200	Athens	243	W. Athens Road	43	44	R	M	D	various	3/30/2007	
	claimed, no work found										

SKOWHEGAN Hammond 2/1/2007 98 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5330	Skowhegan	063	E. Front Street	19	20	C	M	D	various	3/30/2007	4/12/2007
	Claimed, not done (PR20)										
5330	Skowhegan	063	E. Front Street	29	30	C	M	D	various	3/30/2007	4/12/2007
	Fir to wire (or top)										
5330	Skowhegan	367	Waterville Road	57	57.01	C	M	D	various	3/30/2007	4/12/2007
	Retrim secondary										
5330	Skowhegan	367	Waterville Road	59	59.1	C	M	D	various	3/30/2007	4/12/2007
	Skipped - 2 sections to do (309)										
5330	Skowhegan	367	Waterville Road	70	70.1	C	M	D	various	3/30/2007	4/12/2007
	Primary - cut/trim										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5330	Skowhegan	367	Waterville Road	72	72.1	C	M	D	various	3/30/2007	
	Primary - cut/trim										
5330	Skowhegan	367	Waterville Road	80	80.1	C	M	D	various	3/30/2007	4/12/2007
	Skipped secondary spay - cut/trim										
5330	Skowhegan	367	Waterville Road	84	84.1	C	M	D	various	3/30/2007	4/12/2007
	Cut 1 pine in ROW										
5330	Skowhegan	367	Waterville Road	87	87.1	C	M	D	various	3/30/2007	4/12/2007
	Skipped - trim section off 87.1 (309)										

SKOWHEGAN Hammond 3/9/2007 5 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3510	MADISON	152	RUSSELL ROAD	509	509H	C	M	D	88	4/5/2007	3/14/2007
	Left one poplar uncut										
3510	MADISON	152	RUSSELL ROAD	509H	510	C	M	D	88	4/5/2007	3/14/2007
	Left shelf (resprout limbs)										
3510	MADISON	152	RUSSELL ROAD	509H	509H.1	C	M	D	88	4/5/2007	3/14/2007
	Left one maple uncut										
5330	SKOWHEGAN	373	WEST RIDGE ROAD	128	129	C	M	D	88	4/5/2007	
	Left dead limbs on pine by pole 129 & shelf left by pole 128										

SKOWHEGAN Hammond 5/23/2007 50 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0200	ATHENS	191	SKOWHEGAN ROAD	392	391	S	M	D	62,88,154		
	Pole 392 on Skowhegan to pole 291 on Cornville Rd.- recut stumps										
1250	CORNVILLE	180	SHADAGEE ROAD	30	31	S	M	D	62,88,154		
	Confier stumps										
1250	CORNVILLE	180	SHADAGEE ROAD	4	5	S	M	D	62,88,154		
	Confier stumps										
1250	CORNVILLE	185	SKOWHEGAN ROAD	386	386.1	C	M	D	62,88,154		
	Not full clearance										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

SKOWHEGAN Hammond 5/9/2007 54 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4150	NORRIDGEWOCK	020	CHILDS ROAD	14	15	C	M	D	62,154,88	6/13/2007	
	Remove shelft; pines woodlot & add 2 PF6 (222) done- not claimed										
4150	NORRIDGEWOCK	020	CHILDS ROAD	3	4	C	M	D	62,154,88	6/13/2007	
	new shelf										
4150	NORRIDGEWOCK	020	CHILDS ROAD	30	31	B	M	D	62,154,88	6/13/2007	
	Chip pine limbs										
4150	NORRIDGEWOCK	020	CHILDS ROAD	4	5	C	M	D	62,154,88	6/13/2007	
	New shelf										
4150	NORRIDGEWOCK	020	CHILDS ROAD	5	H	C	M	D	62,154,88	6/13/2007	
	Childs Rd to Pine St.- trim hardwoods										
4150	NORRIDGEWOCK	020	CHILDS ROAD	7	8	C	M	D	62,154,88	6/13/2007	
	Remove shelf										
4150	NORRIDGEWOCK	155	REBECCA STREET	4	5	C	M	D	62,154,88	6/13/2007	
	Cut hardwoods under wires & shelf										

Service Center Totals: 31 Sections for Rework 296 Sections Reviewed 10.47%

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

AUGUSTA | Irwin | 1/17/2007 | 8 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6450	Winthrop	023	Case Road	14	15		M	D	663	3/30/2007	

Trim service

AUGUSTA | Irwin | 1/17/2007 | 19 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6450	Winthrop	003	Augusta Road	78	79	C	M	D	663	3/30/2007	

Not enough clearance

AUGUSTA | Irwin | 1/2/2007 | 21 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0240	Augusta	254	Mt. Vernon Road	26	26.1	R	M	D	157	3/30/2007	

trim service

AUGUSTA | Irwin | 1/17/2007 | 22 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6450	Winthrop	023	Case Road	5	6		M	D	667	3/30/2007	

trim service so service hangs free

AUGUSTA | Irwin | 1/30/2007 | 31 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1150	China	004	Augusta Road	23	24	C	M	D	4	3/30/2007	4/4/2007

Pole 24-see if you can cut dead tree - beware of dog

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

3540	Manchester	003	Appletree Lane	1		C	M	D		3/30/2007	
	Trim sevice										

AUGUSTA — Irwin — 1/15/2007 — 36 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6300	West Gardiner	023	Davis Cobb	6	6.1		M	D	662	3/30/2007	
	Trim service and secondary										

AUGUSTA — Irwin — 2/5/2007 — 12 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1150	CHINA	002	ALDER PARK ROAD	13	14	PR6	M	D	157	3/30/2007	2/27/2007
	PR6										
1150	CHINA	002	ALDER PARK ROAD	17	18	PR6	M	D	157	3/30/2007	2/27/2007
	PR6										
1150	CHINA	002	ALDER PARK ROAD	4	5	C	M	D	157	3/30/2007	2/27/2007
	clearance - lower shelf										

AUGUSTA — Irwin — 2/20/2007 — 15 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3540	MANCHESTER	140	ROLLINS ROAD	10	11	GRN	M	D	663	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	11	12	GRN	M	D	662	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	2	1	GRN	M	D	662	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	3	2	GRN	M	D	662	3/30/2007	
	Ground cut										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

3540	MANCHESTER	140	ROLLINS ROAD	3	4	GRN	M	D	667	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	4	5	GRN	M	D	663	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	5	6	GRN	M	D	667	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	6	7	GRN	M	D	663	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	7	8	GRN	M	D	667	3/30/2007	
	Ground cut										
3540	MANCHESTER	140	ROLLINS ROAD	9	10	GRN	M	D	662	3/30/2007	
	Ground cut										

AUGUSTA Irwin 2/6/2007 18 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6450	WINTHROP	030	COBB LINE	2	2.1	B	M	D	663	3/30/2007	
	Need to cut major white birch leader rubbing on secondary										
6450	WINTHROP	128	NORTH SHORE ROAD	pole 5		PR6	M	D	663	3/30/2007	
	Need to cut spruce w/top broken out of it in yard										

AUGUSTA Irwin 2/5/2007 32 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1150	CHINA	004	AUGUSTA ROAD	14	14.1	C	M	D	4	3/30/2007	4/4/2007
	Would like to see spruce on corner "stripped" of lower shelf										
1150	CHINA	004	AUGUSTA ROAD	9	11	C	M	D	4	3/30/2007	4/4/2007
	Must do "point poles" to claim span										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

AUGUSTA Irwin 2/6/2007 37 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6450	WINTHROP	047	FOSTER ROAD	7	8	PR6	M	D	662	3/30/2007	
	Must cut top our of birch										
6450	WINTHROP	075	ISLAND PARK ROAD	3	4	PR6	M	D	662	3/30/2007	
	Need to cut popple w/dead top, tree bowing towards line										
6450	WINTHROP	138	PACKARD CAMP LINE	5	5.1	C	M	D	662	3/30/2007	
	Not 2' clearance on service from 5.1										

AUGUSTA Irwin 3/5/2007 27 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6300	WEST GARDINER	007	BENSON ROAD	25	26	C	M	D	662	4/5/2007	
	Need to cut										
6300	WEST GARDINER	007	BENSON ROAD	28	29	C	M	D	662	4/5/2007	
	Need to cut small spruce near pole 29 (woodlot)										
6300	WEST GARDINER	007	BENSON ROAD	32	33	C	M	D	662	4/5/2007	
	Need to trim secondary off pole 33										
6300	WEST GARDINER	007	BENSON ROAD	7	8	C	M	D	662	4/5/2007	
	Cut ask tree at pole										

AUGUSTA Irwin 4/27/2007 112 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5380	SOMERVILLE PL	126	PALERMO ROAD	2	3	SEC		D	super	5/8/2007	
	Trim section 3 - 3.1										
5380	SOMERVILLE PL	126	PALERMO ROAD	5	6	SEC		D	super	5/8/2007	
	Trim section 36- 6.1										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

5380	SOMERVILLE PL	143	ROUTE 105	16	17	PF6		D	super	5/8/2007	
	Cut leaning popple										
5380	SOMERVILLE PL	143	ROUTE 105	39	40	SEC		D	super	5/8/2007	
	Trim section 40 to 40-1										
5380	SOMERVILLE PL	143	ROUTE 105	47	48	B		D	super	5/8/2007	
	Brush on ground										
5380	SOMERVILLE PL	143	ROUTE 105	49	50	B		D	super	5/8/2007	
	Brush on ground										
5380	SOMERVILLE PL	143	ROUTE 105	60	61	H		D	super	5/8/2007	
	Huge pone over primaries										
5380	SOMERVILLE PL	185	WEEKS MILLS ROAD	7	8	B		D	super	5/8/2007	
	Brush on ground										

AUGUSTA Irwin 4/4/2007 182 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6185	WASHINGTON	193	WEST WASHINGTON RI	143	144	SER	M	D	super crew	5/8/2007	
	Service off pole 144										
6185	WASHINGTON	193	WEST WASHINGTON RI	145	146	C	M	D	super crew	5/8/2007	
6185	WASHINGTON	193	WEST WASHINGTON RI	146	146.1	SEC	M	D	super crew	5/8/2007	
	Secondary and service										
6185	WASHINGTON	193	WEST WASHINGTON RI	148	149	SER	M	D	super crew	5/8/2007	
	Service										
6185	WASHINGTON	193	WEST WASHINGTON RI	171	172	SER	M	D	super crew	5/8/2007	
	Service off pole 172										
6185	WASHINGTON	193	WEST WASHINGTON RI	176	177	SER	M	D	super crew	5/8/2007	
	Service off pole 177										

AUGUSTA Irwin 5/14/2007 20 Sections Reviewed

Town	Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2045	FAYETTE	119	OAK HILL ROAD	25	26	C	M	D	663/667	6/13/2007	
	Overhead clearance										
2045	FAYETTE	119	OAK HILL ROAD	28	29	PR6	M	D	663/667	6/13/2007	
	Cut birch tree										
2045	FAYETTE	119	OAK HILL ROAD	30	31	SEC	M	D	663/667	6/13/2007	
	Trim secondary & cut brush near pole										
2045	FAYETTE	153	SANDERSON ROAD	5	4	PR6	M	D	663/667	6/13/2007	
	Cut 2 tagged maples										

AUGUSTA Irwin 5/11/2007 64 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4910	READFIELD	037	FAYETTE ROAD	22	23	PR6	M	D	663	6/13/2007	
	Cut bad popple - tagged										

AUGUSTA Irwin 5/9/2007 91 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2045	FAYETTE	146	READFIELD ROAD	57	57.1	SER	M	D	663/667	6/13/2007	
	Service off pole 57.1 not done										
6400	WINDSOR	135	SOUTH BELFAST ROAD	24	25	F	M	D	super	6/13/2007	
	Trim nasty stubs on pine										
6400	WINDSOR	135	SOUTH BELFAST ROAD	29	30	SER	M	D	super	6/13/2007	
	Trim service at pole 30										

AUGUSTA Irwin 5/23/2007 119 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5380	SOMERVILLE PL	040	FRYE LINE	6H	6	SER	M	D	supercrew	6/13/2007	
	trim service										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

5380	SOMERVILLE PL	185	WEEKS MILLS ROAD	23	24	PR6	M	D	superc	6/13/2007
	Cut tagged red pine									
5380	SOMERVILLE PL	185	WEEKS MILLS ROAD	6	7	C	M	D	superc	6/13/2007
	More side trim and ground cut									
6400	WINDSOR	133	SAMPSON ROAD	16	17	SER	M	D	superc	6/13/2007
	Trim service									
6400	WINDSOR	133	SAMPSON ROAD	17	18	PR6	M	D	superc	6/13/2007
	Cut popples									

Service Center Totals: ***58 Sections for Rework*** ***936 Sections Reviewed*** ***6.20%***

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

LEWISTON Irwin 1/30/2007 13 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3710	Minot	032	Harris Road	40(098)	1 (032)	S	M	D	196	3/30/2007	
	Stubs										
3710	Minot	068	Pottle School Road	12	13		M	D	79	3/30/2007	
	Cut PR6 - big ash tree										

LEWISTON Irwin 1/24/2007 21 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3710	Minot	032	Harris Road	Take off	1	S	M	D		3/30/2007	
	Stubs - pruning; remove dead stub										

LEWISTON Irwin 2/22/2007 10 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6140	WALES	042	THE AVENUE ROAD	11	11 1/2	PR6	M	D	784	3/30/2007	
	Need to cut danger tree										
6230	SABATTUS	005	BOWDOIN ROAD	507	508	S	M	D	784	3/30/2007	4/10/2007
	Need to cut 4 foot stump										

LEWISTON Irwin 2/1/2007 55 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0230	Auburn	064	Court Street	102	103	C	M	D	774	3/30/2007	
	Clearance underneath										
0230	Auburn	228	Manley Road	4	5	C	M	D	784	3/30/2007	4/10/2007
	Clearance on service										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

0230	Auburn	228	Manley Road	5	6	S	M	D	784	3/30/2007	
	stubs										

LEWISTON **Irwin** **2/23/2007** **79 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3610	MECHANIC FALLS	061	NORWAY ROAD	31	32	C	M	D	79	3/30/2007	
	Need to trim secondary 32 - 36.1										
3610	MECHANIC FALLS	061	NORWAY ROAD	35	36	C	M	D	79	3/30/2007	
	Need to trim secondary 36 - 36.1										
3610	MECHANIC FALLS	061	NORWAY ROAD	48	49	C	M	D	196	3/30/2007	
	Need to prune dead limb over primary										
3610	MECHANIC FALLS	061	NORWAY ROAD	49	50	C	M	D	196	3/30/2007	
	Need to trim limb over primary										
3610	MECHANIC FALLS	061	NORWAY ROAD	55	56	C	M	D	196	3/30/2007	
	Need to trim Secondary 56 - 56.1										
3610	MECHANIC FALLS	061	NORWAY ROAD	61	62	C	M	D	79	3/30/2007	
	Need to trim secondary 62 - 62.1										
3610	MECHANIC FALLS	061	NORWAY ROAD	64	65	C	M	D	79	3/30/2007	
	Need to trim secondary 65 - 65.1										
3610	MECHANIC FALLS	061	NORWAY ROAD	69	70	C	M	D	79	3/30/2007	
	Need to trim secondary 70 - 70.1										
3710	MINOT	010	CENTER MINOT HILL R	011	012	PR6	M	D	79	3/30/2007	
	PR6 -need to cut popple - danger tree										
4425	OXFORD	102	MECHANIC FALLS ROA	75	76	C	M	D	196	3/30/2007	
	Need to trim secondary 76 - 76.1										

LEWISTON **Irwin** **3/20/2007** **19 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6140	WALES	001	ANDREWS ROAD	11	12	C	M	D	784	4/5/2007	
	Trim service off pole 12										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

6140	WALES	001	ANDREWS ROAD	12	13	C	M	D	784	4/5/2007	
	Trim service off pole 13										
6140	WALES	001	ANDREWS ROAD	13	14	C	M	D	784	4/5/2007	
	Take dead leader out of maple near pole 14										

LEWISTON Irwin 3/29/2007 29 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6140	WALES	001	ANDREWS ROAD	18	19	H	M	D	784		
	Knock broken branch out of tree										
6140	WALES	001	ANDREWS ROAD	2	3	SEC	M	D	784		
	Secondary										
6140	WALES	001	ANDREWS ROAD	20	21	C	M	D	784		
	Take more out of big maple										

LEWISTON Irwin 3/5/2007 30 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6140	WALES	023	LEWISTON-AUGUSTA R	70	71	C	M	D	784	4/5/2007	
	Cut small apple sapling										
6140	WALES	023	LEWISTON-AUGUSTA R	96	96.1	C	M	D	784	4/5/2007	
	Trim 96.1 to service pole										

LEWISTON Irwin 3/30/2007 35 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5880	TURNER	101	TORY HILL ROAD	5	6	PR6	M	D	196	4/5/2007	
	Cut 1 more PF6 - popple										
6230	SABATTUS	040	LONE PINE DRIVE	2	3	C	M	D	774	4/5/2007	
	Cut hawthorne sapling										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6230	SABATTUS	062	PLEASANT HILL CORNE	14	15	C	M	D	774	4/5/2007	
	Trim service to service pole										

LEWISTON Irwin 3/6/2007 39 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
3610	MECHANIC FALLS	061	NORWAY ROAD	23	23.1	C	M	D	79	4/5/2007	
	Need to trim tree off pole 23										
3610	MECHANIC FALLS	061	NORWAY ROAD	32	32.1	C	M	D	79	4/5/2007	
	Trim secondary										
4425	OXFORD	170	VERRILL ROAD	2	3	C	M	D	79	4/5/2007	
	Trim service off pole 2										
4425	OXFORD	170	VERRILL ROAD	4	4.01	C	M	D	79	4/5/2007	
	Cut dead maple next to secondary										
6230	SABATTUS	056	OLD LISBON ROAD	85	86	SEC	M	D	774		
	Re-record this span as 305-0, record sec span as 308-0										

LEWISTON Irwin 3/20/2007 58 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5880	TURNER	061	MUD STREET	4	5	C	M	D	196	4/5/2007	
	Cut tree on service - okay with customer										

LEWISTON Irwin 4/3/2007 10 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6140	WALES	023	LEWISTON-AUGUSTA R				M	D	784	5/8/2007	
6140	WALES	023	LEWISTON-AUGUSTA R	101	102	C	M	D	784	5/8/2007	
	Trim maples after sap season										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

LEWISTON Irwin 4/3/2007 13 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0780	BUCKFIELD	005	BEAR POND ROAD	018	019	PR6	M	D	196	5/8/2007	
	cut 1 PR6 missed										

LEWISTON Irwin 5/25/2007 17 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6230	SABATTUS	020	FURBUSH ROAD	5	5.1	SEC	M	D	784	6/13/2007	
	Record as 308-1, span complete yes										

LEWISTON Irwin 5/12/2007 57 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
6230	SABATTUS	056	OLD LISBON ROAD	10	11	SER	M	D	774	6/13/2007	
	Snip service at pole 11										
6230	SABATTUS	056	OLD LISBON ROAD	13	13.01	SER	M	D	774	6/13/2007	
	Trim for servcie										
6230	SABATTUS	056	OLD LISBON ROAD	20	20.01	SER	M	D	774	6/13/2007	
	Service										
6230	SABATTUS	056	OLD LISBON ROAD	30	31	PF6	M	D	774	6/13/2007	
	PR6										

Service Center Totals: 43 Sections for Rework 655 Sections Reviewed 6.56%

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

ALFRED **Lessard** **1/11/2007** **688 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4160	North Berwick *Cut vine*	046	Hammond Raod	1			M	D		3/30/2007	2/13/2007
4160	North Berwick *Cut vine*	046	Hammond Raod	4			M	D		3/30/2007	2/13/2007
4160	North Berwick *Secondary needs trim*	060	Linscott Road	2	2.1		M	D		3/30/2007	2/13/2007
4160	North Berwick *Secondary needs trim*	060	Linscott Road	3	3.1		M	D		3/30/2007	2/13/2007
4160	North Berwick *Secondary needs trim*	060	Linscott Road	4	4.1		M	D		3/30/2007	2/13/2007
4160	North Berwick *Serv needs trim*	119	Turkey Street	503.1	serv		M	D		3/30/2007	2/13/2007
4160	North Berwick *Serv needs trim*	119	Turkey Street	512.1	serv		M	D		3/30/2007	2/13/2007
4160	North Berwick *Hazard Tree*	119	Turkey Street	519	520		M	D		3/30/2007	2/13/2007
4160	North Berwick *Hazard Tree*	119	Turkey Street	524	525		M	D		3/30/2007	2/13/2007
4160	North Berwick *Tree on secondary*	124	Valley Road	34.1			M	D		3/30/2007	2/13/2007
4160	North Berwick *Cut vine*	302	Fox Farm Hill Road	15			M	D		3/30/2007	2/13/2007
4160	North Berwick *Cut vine*	302	Fox Farm Hill Road	20			M	D		3/30/2007	2/13/2007
4160	North Berwick *Cut vine*	302	Fox Farm Hill Road	22			M	D		3/30/2007	2/13/2007
4160	North Berwick *Cut vine*	302	Fox Farm Hill Road	23			M	D		3/30/2007	2/13/2007

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4160	North Berwick	302	Fox Farm Hill Road	32			M	D	3/30/2007	2/13/2007
	Service needs trim									
4160	North Berwick	302	Fox Farm Hill Road	37			M	D	3/30/2007	2/13/2007
	Cut vine									
4160	North Berwick	302	Fox Farm Hill Road	48	48.1		M	D	3/30/2007	2/13/2007
	Secondary needs trim									
4160	North Berwick	302	Fox Farm Hill Road	6	7	C	M	D	3/30/2007	2/13/2007
	poor clearance									
4160	North Berwick	305	Ford Quint Road	013	013.1		M	D	3/30/2007	2/13/2007
	Secondary needs trim									
4160	North Berwick	307	Oak Woods Road	102	103		M	D	3/30/2007	2/13/2007
	Hazard tree									
4160	North Berwick	307	Oak Woods Road	104	105		M	D	3/30/2007	2/13/2007
	Hazard tree									
4160	North Berwick	307	Oak Woods Road	91	92		M	D	3/30/2007	2/13/2007
	Hazard tree									
4160	North Berwick	307	Oak Woods Road	98	99		M	D	3/30/2007	2/13/2007
	Hazard tree									
4160	North Berwick	308	Bauneg Bea Hill Road	511	512		M	D	3/30/2007	2/13/2007
	Hazard Tree									
4160	North Berwick	308	Bauneg Bea Hill Road	702	703		M	D	3/30/2007	2/13/2007
	Hazard tree									
4160	North Berwick	308	Bauneg Bea Hill Road	703	703.1		M	D	3/30/2007	2/13/2007
	Secondary needs trim									
4160	North Berwick	308	Bauneg Bea Hill Road	706	706.01		M	D	3/30/2007	2/13/2007
	Secondary needs trim									
4160	North Berwick	308	Bauneg Bea Hill Road	707	707.1		M	D	3/30/2007	2/13/2007
	Secondary needs trim									
4160	North Berwick	308	Bauneg Bea Hill Road	708	708.1		M	D	3/30/2007	3/16/2007
	Secondary needs trim									
4160	North Berwick	308	Bauneg Bea Hill Road	716	716.1		M	D	3/30/2007	3/16/2007
	Secondary needs trim									

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5170	Sanford	204	Javica Lane	20.1	20.2		M	D		3/30/2007	
	Hazard tree										

ALFRED Lessard 1/11/2007 963 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5170	Sanford	139	Grammar Road	58	60		M	D		3/30/2007	
	Service need trim - pole 60										
5170	Sanford	158	Hansom Ridge Road	25	26	H	M	D		3/30/2007	1/24/2007
	Hazard tree - pine - code 241										
5170	Sanford	158	Hansom Ridge Road	55	56		M	D		3/30/2007	3/27/2007
	Cut vine on pole 56										
5170	Sanford	158	Hansom Ridge Road	92	93	H	M	D		3/30/2007	1/24/2007
	Hazard tree - pine										
5170	Sanford	171	Harvey House Road	010	011		M	D		3/30/2007	1/24/2007
	Secondary needs trim										
5170	Sanford	171	Harvey House Road	011	012		M	D		3/30/2007	1/24/2007
	Secondary needs trim										
5170	Sanford	241	Main Street	165	166	H	M	D		3/30/2007	1/24/2007
	Hazard tree										
5170	Sanford	294	Oak Street	95	95.1		M	D		3/30/2007	1/24/2007
	Secondary needs trim										
5170	Sanford	332	Rankin Street	5	6		M	D		3/30/2007	3/27/2007
	Service needs trim at pole 6										
5170	Sanford	332	Rankin Street	7	8		M	D		3/30/2007	1/24/2007
	Service needs trim at pole 8										
5170	Sanford	370	Sherburne Street	3	4		M	D		3/30/2007	1/24/2007
	Service needs trim - pole 4										

ALFRED Lessard 2/1/2007 1 Sections Reviewed

Town	Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

4160	NORTH BERWICK	060	LINSCOTT HILL ROAD	7	8	SER	M	D		3/30/2007	
	Service need trim pole 8										

ALFRED **Lessard** **2/1/2007** **197 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
5410	SOUTH BERWICK	012	BENNETT LOT ROAD	3	3.1	Haz	M	D		3/30/2007	3/20/2007
	Dead tree on service and several hazard trees										
5410	SOUTH BERWICK	012	BENNETT LOT ROAD	5	6	Haz	M	D		3/30/2007	3/30/2007
	Hazard trees										
5410	SOUTH BERWICK	016	CHICKS HILL ROAD	10	11	Haz	M	D		3/30/2007	
	Hazard tree										
5410	SOUTH BERWICK	016	CHICKS HILL ROAD	108	1	H	M	D		3/30/2007	
	Dead limbs over primary										
5410	SOUTH BERWICK	016	CHICKS HILL ROAD	8	9	Haz	M	D		3/30/2007	
	Hazard tree										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	105	106	Haz	M	D		3/30/2007	3/30/2007
	Hazard tree										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	106	107	H	M	D		3/30/2007	
	Deal Limbs over primary										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	109	110	Haz	M	D		3/30/2007	3/30/2007
	Hazard tree										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	115	115.1	SEC	M	D		3/30/2007	3/22/2007
	Secondary needs trim										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	115	115.01	SEC	M	D		3/30/2007	3/22/2007
	Secondary needs trim										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	115	1	SEC	M	D		3/30/2007	3/30/2007
	Chicks Hill Tap - secondary needs trim										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	117	118	H	M	D		3/30/2007	
	Rubbing hard on service										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	119	120	C	M	D		3/30/2007	3/21/2007
	Dead limbs over primary										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	120	121	C	M	D	3/30/2007	3/20/2007
	Service needs trim									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	123	124	Haz	M	D	3/30/2007	
	Hazard tree									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	125	126	Haz	M	D	3/30/2007	3/21/2007
	Hazard tree									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	126	127	Haz	M	D	3/30/2007	3/30/2007
	Hazard tree									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	127	1 (john G	Haz	M	D	3/30/2007	3/30/2007
	2 Hazard trees									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	129	129.1	SEC	M	D	3/30/2007	
	Secondary need trim									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	136	135	Haz	M	D	3/30/2007	
	3 Hazard trees									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	142	141	SEC	M	D	3/30/2007	3/21/2007
	Secondary needs trim									
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	143	142	SEC	M	D	3/30/2007	3/21/2007
	Secondary needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	14	14S	SEC	M	D	3/30/2007	3/28/2007
	Secondary needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	14	14.01	SEC	M	D	3/30/2007	3/28/2007
	Secondary needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	15	15H	Haz	M	D	3/30/2007	3/21/2007
	Hazard tree									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	16	17	SER	M	D	3/30/2007	3/28/2007
	Service needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	3	4	Haz	M	D	3/30/2007	
	2 hazard trees									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	3	3.1	Haz	M	D	3/30/2007	
	Hazard tree- maple									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	3.1	3.2	Haz	M	D	3/30/2007	
	4 Hazard trees									

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5410	SOUTH BERWICK	065	JOHN GRAY ROAD	3.4	3.5	SER	M	D	3/30/2007	3/22/2007
	Service needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	4	5	Haz	M	D	3/30/2007	3/21/2007
	2 hazard trees									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6	7	Haz	M	D	3/30/2007	3/21/2007
	2 Hazard trees									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6	6.1	SER	M	D	3/30/2007	3/22/2007
	Service needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6.1	6.11	SER	M	D	3/30/2007	
	Servcie needs trim									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6.1	6.2	H	M	D	3/30/2007	3/26/2007
	Dead limb over primary									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6.2	6.3	C	M	D	3/30/2007	3/26/2007
	Overhead clearance									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6.3	6.4	C	M	D	3/30/2007	3/26/2007
	Overhead clearance & dead limb									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	6.4	6.5	C	M	D	3/30/2007	3/26/2007
	Overhead clearancq									
5410	SOUTH BERWICK	065	JOHN GRAY ROAD	8	9	C	M	D	3/30/2007	3/21/2007
	Dead limbs over primary									
5410	SOUTH BERWICK	127	THURELL ROAD	503	503.1	C	M	D	3/30/2007	3/20/2007
	Dead trim by service									
5410	SOUTH BERWICK	127	THURELL ROAD	504	505	Haz	M	D	3/30/2007	3/20/2007
	Hazard tree									
5410	SOUTH BERWICK	127	THURELL ROAD	507	507H	B	M	D	3/30/2007	
	Brush left									
5410	SOUTH BERWICK	127	THURELL ROAD	507	507.1	B/C	M	D	3/30/2007	3/20/2007
	Secondary & service needs trim - brust left									
5410	SOUTH BERWICK	127	THURELL ROAD	507H	588	B	M	D	3/30/2007	
	Brush left									
5410	SOUTH BERWICK	127	THURELL ROAD	510	511	Haz	M	D	3/30/2007	
	Hazard tree									

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ALFRED Lessard 2/1/2007 649 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	20H	21	Haz	M	D		3/30/2007	3/30/2007
	Hazard tree										
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	24	25	Haz	M	D		3/30/2007	2/2/2007
	Hazard tree pole 25.1										
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	26	27	Haz	M	D		3/30/2007	2/2/2007
	Hazard tree										
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	27H	28	Haz	M	D		3/30/2007	
	Hazard tree										
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	508	507	SER	M	D		3/30/2007	
	Service needs trim pole 508.1										
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	520	521	Haz	M	D		3/30/2007	2/2/2007
	Hazard tree										
4160	NORTH BERWICK	010	BEECH RIDGE ROAD	7	7.01	C	M	D		3/30/2007	3/20/2007
	Dead tree										
4160	NORTH BERWICK	058	LEBANON ROAD	73	74	Haz	M	D		3/30/2007	3/30/2007
	Hazard tree - code 241										
4160	NORTH BERWICK	058	LEBANON ROAD	96	97	SEC	M	D		3/30/2007	3/30/2007
	Secondary needs trim 97.1										
4160	NORTH BERWICK	062	LOWER MAIN STREET	30	31	SER	M	D		3/30/2007	3/28/2007
	Service needs trim pole 31										
4160	NORTH BERWICK	062	LOWER MAIN STREET	34	35	SEC	M	D		3/30/2007	
	Secondary neds trim 35.1										
4160	NORTH BERWICK	062	LOWER MAIN STREET	38	39	SER	M	D		3/30/2007	
	Service need trim pole 39										
5410	SOUTH BERWICK	012	BENNETT LOT ROAD	48	47	SER	M	D		3/30/2007	3/22/2007
	Dead pine by serv pole 47										
5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	166	165	Haz	M	D		3/30/2007	
	2 hazard trees										

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5410	SOUTH BERWICK	033	EMERYS BRIDGE ROAD	167.3	167.4	Haz	M	D		3/30/2007	3/30/2007
	Hazard tree										
6273	WELLS	125	HAMILTON ROAD	501	502	Haz	M	D		3/30/2007	3/30/2007
	Hazard tree										

ALFRED Lessard 4/1/2007 806 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
1830	ELIOT	002	BEECH RIDGE ROAD	1	2	GRN	M	D		5/8/2007	
	Ground cut & stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	10	11	S	M	D		5/8/2007	
	Stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	11	12	S	M	D		5/8/2007	
	Stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	12	13	S	M	D		5/8/2007	
	Stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	2	3	GRN	M	D		5/8/2007	
	Ground cut & stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	3	4	GRN	M	D		5/8/2007	
	Ground cut										
1830	ELIOT	002	BEECH RIDGE ROAD	4	5	Haz	M	D		5/8/2007	
	Hazard tree, ground cut & stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	5	6	S	M	D		5/8/2007	
	Stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	6	7	GRN	M	D		5/8/2007	
	Ground cut & stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	7	8	S	M	D		5/8/2007	
	Stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	8	9	Haz	M	D		5/8/2007	
	Hazard tree & stubs										
1830	ELIOT	002	BEECH RIDGE ROAD	9	10	S	M	D		5/8/2007	
	Stubs										

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	015	BAYBERRY DRIVE	1	2	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	015	BAYBERRY DRIVE	2	3	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	015	BAYBERRY DRIVE	2	1	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	015	BAYBERRY DRIVE	3	4	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	015	BAYBERRY DRIVE	4	5	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	11	11.1	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	018	BEECH ROAD	11	11H	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	11H	12	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	12	13	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	13	14	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	14.1	14.2	SER	M	D	5/8/2007
	Service needs trim at pole 14.2 & clearance								
1830	ELIOT	018	BEECH ROAD	14.2	14.3	C	M	D	5/8/2007
	Clearance & cut vine								
1830	ELIOT	018	BEECH ROAD	14.3	14.4	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	018	BEECH ROAD	14.4	14.5	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	018	BEECH ROAD	14.5	14.51	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	018	BEECH ROAD	14.5	14.6	C	M	D	5/8/2007
	Clearance								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	018	BEECH ROAD	14.51	14.52	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	018	BEECH ROAD	16	16.1	SEC	M	D	5/8/2007
	Secondary & service needs trim								
1830	ELIOT	018	BEECH ROAD	18	18.1	SER	M	D	5/8/2007
	Service needs trim at pole 18.1								
1830	ELIOT	018	BEECH ROAD	21	22	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	22H	23	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	23	24	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	25H	26	SER	M	D	5/8/2007
	Service needs trim at pole 2 & ground cut								
1830	ELIOT	018	BEECH ROAD	3	4	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	36	36.1	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	018	BEECH ROAD	36.2	36.3	SER	M	D	5/8/2007
	Service needs trim at pole 36.3								
1830	ELIOT	018	BEECH ROAD	4	5	Haz	M	D	5/8/2007
	Hazard tree & stubs								
1830	ELIOT	018	BEECH ROAD	4.	4.1	SEC	M	D	5/8/2007
	Seconardy needs trim								
1830	ELIOT	018	BEECH ROAD	4.1	4.2	SEC	M	D	5/8/2007
	Seconardy needs trim								
1830	ELIOT	018	BEECH ROAD	40	41	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	41	42	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	42	43	Haz	M	D	5/8/2007
	Hazard tree & stubs								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	018	BEECH ROAD	43	44	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	44	44H	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	44H	45	Haz	M	D	5/8/2007
	Hazard tree & stubs								
1830	ELIOT	018	BEECH ROAD	47	48	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	48	1	GRN	M	D	5/8/2007
	Ground cut & clearance								
1830	ELIOT	018	BEECH ROAD	48	49	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	49	49.1	S	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	018	BEECH ROAD	50	51	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	51	51.1	SEC	M	D	5/8/2007
	Secondary need trim								
1830	ELIOT	018	BEECH ROAD	51.1	51.2	SEC	M	D	5/8/2007
	Secondary need trim								
1830	ELIOT	018	BEECH ROAD	54	55	SER	M	D	5/8/2007
	Service needs trim								
1830	ELIOT	018	BEECH ROAD	55	56	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	58	58.1	SEC	M	D	5/8/2007
	Secondary & service needs trim								
1830	ELIOT	018	BEECH ROAD	58	59	S	M	D	5/8/2007
	Stubs & service needs trim at pole 61								
1830	ELIOT	018	BEECH ROAD	6	7	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	60	61	GRN	M	D	5/8/2007
	Ground cut & service needs trim at pole 61								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	018	BEECH ROAD	62	61	GRN	M	D	5/8/2007
	Ground cut & stubs								
1830	ELIOT	018	BEECH ROAD	63	62	Haz	M	D	5/8/2007
	Hazard								
1830	ELIOT	018	BEECH ROAD	64	63	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	64	64.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	018	BEECH ROAD	65	64	S	M	D	5/8/2007
	Stubs & service needs trim at pole 65								
1830	ELIOT	018	BEECH ROAD	65	65.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	018	BEECH ROAD	67	66	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	69	68	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	69	69.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	018	BEECH ROAD	7	8	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	018	BEECH ROAD	70	69	GRN	M	D	5/8/2007
	Ground cut & stubs								
1830	ELIOT	018	BEECH ROAD	70.1	70.2	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	018	BEECH ROAD	71	70	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	72	73	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	018	BEECH ROAD	72	71	GRN	M	D	5/8/2007
	Ground cut (selective cut)								
1830	ELIOT	018	BEECH ROAD	9	10	SER	M	D	5/8/2007
	Service needs trim at pole 10								

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1830	ELIOT	027	BRADSTREET LANE	6	7	SER	M	D	5/8/2007
	Service needs trim								
1830	ELIOT	027	BRADSTREET LANE	7	8	Haz	M	D	5/8/2007
	Hazard trim								
1830	ELIOT	031	BUNKER LINE	2	3	Haz	M	D	5/8/2007
	3 hazard trees								
1830	ELIOT	068	DEPOT ROAD	15	16	Haz	M	D	5/8/2007
	Hazard tree & ground cut								
1830	ELIOT	068	DEPOT ROAD	16	16.1	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	068	DEPOT ROAD	16	18	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	068	DEPOT ROAD	16.1	16.2	Haz	M	D	5/8/2007
	Hazard tree & clearance								
1830	ELIOT	068	DEPOT ROAD	16.3	16.4	Haz	M	D	5/8/2007
	Hazard tree & clearance								
1830	ELIOT	068	DEPOT ROAD	16.5	16.51	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	068	DEPOT ROAD	16.51	16.52	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	068	DEPOT ROAD	18	19	SER	M	D	5/8/2007
	Service nees trim								
1830	ELIOT	068	DEPOT ROAD	19	20	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	068	DEPOT ROAD	26	27	SER	M	D	5/8/2007
	Service needs trim								
1830	ELIOT	068	DEPOT ROAD	28	29	SER	M	D	5/8/2007
	Service needs trim & ground cut								
1830	ELIOT	068	DEPOT ROAD	39	40	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	068	DEPOT ROAD	41	42	GRN	M	D	5/8/2007
	Ground cut								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	068	DEPOT ROAD	42	43	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	068	DEPOT ROAD	43	44	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	068	DEPOT ROAD	51	52	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	068	DEPOT ROAD	55	56	v	M	D	5/8/2007
	Cut vine on pole								
1830	ELIOT	068	DEPOT ROAD	56	57	C	M	D	5/8/2007
	Clearance & ground cut								
1830	ELIOT	068	DEPOT ROAD	57	58	GRN	M	D	5/8/2007
	Ground cut & selective cut								
1830	ELIOT	068	DEPOT ROAD	58	59	GRN	M	D	5/8/2007
	Ground cut & selective cut								
1830	ELIOT	068	DEPOT ROAD	59	60	SER	M	D	5/8/2007
	Service needs trim at pole 60 & selective ground cut								
1830	ELIOT	068	DEPOT ROAD	6	7	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	068	DEPOT ROAD	7	8	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	090	FERNALD LANE	1	2	GRN	M	D	5/8/2007
	Ground cut & clearance								
1830	ELIOT	090	FERNALD LANE	2	3	C	M	D	5/8/2007
	Overhead clearance								
1830	ELIOT	094	FORE ROAD	1	3	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	094	FORE ROAD	11	12	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	094	FORE ROAD	12	13	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	094	FORE ROAD	13	14	GRN	M	D	5/8/2007
	Ground cut								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	094	FORE ROAD	14	15	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	094	FORE ROAD	15	16	Haz	M	D	5/8/2007
	Hazard tree & ground cut								
1830	ELIOT	094	FORE ROAD	22	23	Haz	M	D	5/8/2007
	Hazard tree & ground cut								
1830	ELIOT	094	FORE ROAD	27	28	SER	M	D	5/8/2007
	Service needs trim								
1830	ELIOT	094	FORE ROAD	28	29	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	094	FORE ROAD	34	36	Haz	M	D	5/8/2007
	4 hazard trees								
1830	ELIOT	094	FORE ROAD	6	7	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	1	2	GRN	M	D	5/8/2007
	Ground cut & stubs								
1830	ELIOT	110	GOODWIN ROAD	1	1.1	SEC	M	D	5/8/2007
	Secondary & service needs trim								
1830	ELIOT	110	GOODWIN ROAD	10	11	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	15	16	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	16	1	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	19	20	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	20	21	SER	M	D	5/8/2007
	Service needs trim & stubs								
1830	ELIOT	110	GOODWIN ROAD	21	22	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	22	23	S	M	D	5/8/2007
	Stubs								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	110	GOODWIN ROAD	4	5	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	110	GOODWIN ROAD	5	6	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	110	GOODWIN ROAD	6	7	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	110	GOODWIN ROAD	7	8	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	8	9	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	110	GOODWIN ROAD	9	10	SER	M	D	5/8/2007
	Service needs trim & stubs								
1830	ELIOT	124	K GROVER LINE	3	4	SER	M	D	5/8/2007
	Servcie neets trim & cut								
1830	ELIOT	171	KEITH LANE	3	4	SER	M	D	5/8/2007
	Service needs trim								
1830	ELIOT	171	KEITH LANE	3	3.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	171	KEITH LANE	5.	5.1	SEC	M	D	5/8/2007
	Secondary need trim								
1830	ELIOT	171	KEITH LANE	5.1	5.2	SEC	M	D	5/8/2007
	Secondary need trim								
1830	ELIOT	188	LAUREL LANE	2	3	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	188	LAUREL LANE	4	5	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	188	LAUREL LANE	5	1	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	205	MAIN STREET	104	105	S	M	D	5/8/2007
	Stubs & improper cut								
1830	ELIOT	205	MAIN STREET	105	106	S	M	D	5/8/2007
	Stubs & improper cut								

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Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	205	MAIN STREET	117	118	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	205	MAIN STREET	121	122	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	205	MAIN STREET	123	124	SER	M	D	5/8/2007
	Service needs trim at pole 124 & stubs								
1830	ELIOT	205	MAIN STREET	128	129	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	205	MAIN STREET	131	131.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	205	MAIN STREET	132	133	Haz	M	D	5/8/2007
	Hazard tree & service needs trim at pole 133								
1830	ELIOT	205	MAIN STREET	134	135	SER	M	D	5/8/2007
	Service needs trim at pole 134								
1830	ELIOT	205	MAIN STREET	135	136	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	205	MAIN STREET	136	137	H	M	D	5/8/2007
	Dead limb over three phase								
1830	ELIOT	205	MAIN STREET	139.1	139.2	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	205	MAIN STREET	140	140.1	SER	M	D	5/8/2007
	Service needs trim								
1830	ELIOT	205	MAIN STREET	142	143	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	143	143.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	205	MAIN STREET	148	148.1	Haz	M	D	5/8/2007
	Hazard tree								
1830	ELIOT	205	MAIN STREET	152	153	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	155	156	GRN	M	D	5/8/2007
	Ground cut								

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	205	MAIN STREET	156	157	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	161	162	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	165	166	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	166	167	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	173	174	vin	M	D	5/8/2007
	Cut vine at pole 174								
1830	ELIOT	205	MAIN STREET	174	1	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	205	MAIN STREET	259	260		M	D	5/8/2007
	Remove shelf								
1830	ELIOT	205	MAIN STREET	265	266		M	D	5/8/2007
	Remove shelf								
1830	ELIOT	205	MAIN STREET	268	269	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	210	MARSHALL FARM	23	24	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	210	MARSHALL FARM	25	26	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	210	MARSHALL FARM	26	27	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	210	MARSHALL FARM	27	73	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	210	MARSHALL FARM	5	6	GRN	M	D	5/8/2007
	Ground cut								
1830	ELIOT	212	MARSHWOOD ESTATE	504	505	C	M	D	5/8/2007
	Clearance								
1830	ELIOT	228	NORTH CRESCENT DRI	1	2	S	M	D	5/8/2007
	Stubs								

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	228	NORTH CRESCENT DRI	3	1	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	1	1.1	C	M	D	5/8/2007
	Cut vines on pole 1.1								
1830	ELIOT	255	OLD ROAD	10	11	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	11	12	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	23	24	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	25	26	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	26	27	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	27	28	Haz	M	D	5/8/2007
	Hazard tree & stubs								
1830	ELIOT	255	OLD ROAD	28	29	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	29	29.1	SEC	M	D	5/8/2007
	Secondary needs trim								
1830	ELIOT	255	OLD ROAD	29	30	S	M	D	5/8/2007
	Stubs & improper cuts								
1830	ELIOT	255	OLD ROAD	30	31	S	M	D	5/8/2007
	Stubs & improper cuts								
1830	ELIOT	255	OLD ROAD	4	5	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	255	OLD ROAD	6	7	S	M	D	5/8/2007
	Stubs								
1830	ELIOT	286	RIVER ROAD	1	2	H	M	D	5/8/2007
	Hangers & Stubs								
1830	ELIOT	286	RIVER ROAD	4	5	S	M	D	5/8/2007
	Stubs & improper cuts								

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

1830	ELIOT	302	ROUTE 236	29	1	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	29H	30	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	37	37	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	37	38	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	44H	45	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	45H	1	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	50	50.1	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	302	ROUTE 236	51	51.1	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	401	GREAT CREEK DRIVE	1	2	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	401	GREAT CREEK DRIVE	3	4	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	406	AGGREGATE RECYCLIN	1	2	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	406	AGGREGATE RECYCLIN	2	3	GRN	M	D	5/8/2007
1830	ELIOT *Brush left*	406	AGGREGATE RECYCLIN	7	8	B	M	D	5/8/2007
1830	ELIOT *Ground cut*	412	LIBBEY ROAD	1	2	GRN	M	D	5/8/2007
1830	ELIOT *Ground cut*	412	LIBBEY ROAD	2	3	GRN	M	D	5/8/2007
1830	ELIOT *Hazard tree*	412	LIBBEY ROAD	3	4	Haz	M	D	5/8/2007

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

3100	KITTERY	385	PICKERNELL LANE	1	2	GRN	M	D	5/8/2007
	Ground cut & service trim pole 2								
3100	KITTERY	385	PICKERNELL LANE	2	3	GRN	M	D	5/8/2007
	Ground cut & stubs								
3100	KITTERY	385	PICKERNELL LANE	3	4	GRN	M	D	5/8/2007
	Ground cut & stubs								
3100	KITTERY	385	PICKERNELL LANE	5	5.1	GRN	M	D	5/8/2007
	Ground cut & stubs								
3100	KITTERY	516	WILSON ROAD	24	25	GRN	M	D	5/8/2007
	Ground Cut								
3100	KITTERY	516	WILSON ROAD	25	26	GRN	M	D	5/8/2007
	Ground Cut								
3100	KITTERY	516	WILSON ROAD	26	27	GRN	M	D	5/8/2007
	Ground Cut								
3100	KITTERY	516	WILSON ROAD	27	28	GRN	M	D	5/8/2007
	Ground Cut								
3100	KITTERY	516	WILSON ROAD	28	29	S/G	M	D	5/8/2007
	Ground Cut & stubs								
3100	KITTERY	516	WILSON ROAD	29	30	S/G	M	D	5/8/2007
	Ground Cut & stubs								
3100	KITTERY	516	WILSON ROAD	30	31	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	31	32	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	32	33	Haz	M	D	5/8/2007
	Hazard tree & stubs								
3100	KITTERY	516	WILSON ROAD	33	34	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	34	35	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	35	36	S	M	D	5/8/2007
	Stubs & directional								

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

3100	KITTERY	516	WILSON ROAD	36	37	S		M	D	5/8/2007
	Stubs & directional									
3100	KITTERY	516	WILSON ROAD	37	37.1	GRN		M	D	5/8/2007
	Ground cut									
3100	KITTERY	516	WILSON ROAD	37	38	S		M	D	5/8/2007
	Stubs									
3100	KITTERY	516	WILSON ROAD	37.1	37.2	GRN		M	D	5/8/2007
	Ground cut									
3100	KITTERY	516	WILSON ROAD	37.4	37.5	GRN		M	D	5/8/2007
	Ground cut & fir balson by pole									
3100	KITTERY	516	WILSON ROAD	66	67	S		M	D	5/8/2007
	Stubs									
3100	KITTERY	516	WILSON ROAD	67	68	S		M	D	5/8/2007
	Stubs									
3100	KITTERY	516	WILSON ROAD	68	1	GRN		M	D	5/8/2007
	Ground Cut									
3100	KITTERY	516	WILSON ROAD	69	70	Haz		M	D	5/8/2007
	Hazard tree									
3100	KITTERY	516	WILSON ROAD	70	71	S		M	D	5/8/2007
	Broken top over 3 phase & stubs									
3100	KITTERY	516	WILSON ROAD	71	1	GRN		M	D	5/8/2007
	Ground cut									
3100	KITTERY	516	WILSON ROAD	71	72	Haz		M	D	5/8/2007
	Hazard tree & stubs									
3100	KITTERY	516	WILSON ROAD	72	73	Haz		M	D	5/8/2007
	Hazard tree & stubs									
3100	KITTERY	516	WILSON ROAD	73	74	S		M	D	5/8/2007
	Stubs									
3100	KITTERY	516	WILSON ROAD	75	76	S		M	D	5/8/2007
	Stubs									
3100	KITTERY	516	WILSON ROAD	76	77	S		M	D	5/8/2007
	Stubs									

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

3100	KITTERY	516	WILSON ROAD	77	78	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	82	82H	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	83	85	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	85	86	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	87	88	S	M	D	5/8/2007
	Stubs								
3100	KITTERY	516	WILSON ROAD	89	1	GRN	M	D	5/8/2007
	Ground cut								
3100	KITTERY	540	PATTEN LANE	1	2	GRN	M	D	5/8/2007
	Ground cut								
3100	KITTERY	540	PATTEN LANE	45	5	GRN	M	D	5/8/2007
	Ground cut (selective cut)								

Service Center Totals: ***348 Sections for Rework*** ***3304 Sections Reviewed*** ***10.53%***

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRUNSWICK Randall 1/9/2007 2 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2933	Jefferson	071	Hinks Road	28.1	28.2		M	D	182	3/30/2007	1/10/2007
	Clearance secondary										

BRUNSWICK Randall 2/23/2007 32 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
0710	BRISTOL	062	FOSSETT LINE	1	2	C	m	D		3/30/2007	
	Clearance >8										
0710	BRISTOL	062	FOSSETT LINE	8	8.1	C	m	D		3/30/2007	3/14/2007
	Clerance >8										
0710	BRISTOL	062	FOSSETT LINE	9	8	C	m	D		3/30/2007	3/14/2007
	Clearance >8 fir behind pole 9										
0710	BRISTOL	076	HANLEY LINE	1	1.01	SER	m	D		3/30/2007	3/14/2007
	Missed service off 1.01										
0710	BRISTOL	076	HANLEY LINE	3	2	GRN	m	D		3/30/2007	3/14/2007
	Need more gound cut										
0710	BRISTOL	076	HANLEY LINE	4	3	GRN	m	D		3/30/2007	
	Need more ground cut, stubs, and hangers										
0710	BRISTOL	076	HANLEY LINE	5	6	C/F	m	D		3/30/2007	3/14/2007
	Need more ground cut, stubs, and hangers										
0710	BRISTOL	076	HANLEY LINE	5	4	GRN	m	D		3/30/2007	3/14/2007
	Need more ground cut										
0710	BRISTOL	174	SPRING LANE ROAD	11	10	SER	m	D		3/30/2007	3/14/2007
	Missed service off pole 10 & 11, brush not chipped										
0710	BRISTOL	174	SPRING LANE ROAD	3	4	PR6	m	D		3/30/2007	
	Missed dead spruce behind pole 4, hazard										
0710	BRISTOL	214	WEST ROAD	13	13.1	SEC	m	D		3/30/2007	
	Missed secondary										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRUNSWICK Randall 2/9/2007 41 Sections Reviewed

Town		Road		From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2110	FREEPORT	066	DUMP ROAD	2	3	C	M	D		3/30/2007	4/9/2007
	Clearance overhead										
2110	FREEPORT	066	DUMP ROAD	4	5	C	M	D		3/30/2007	4/9/2007
	Missed ground cut										
2110	FREEPORT	066	DUMP ROAD	44-powe	1 Dump r	PR6	M	D		3/30/2007	
	Missed hazard tree -marked, from pole 44 Pownal Rd to pole 1 Dump Rd.										
2110	FREEPORT	066	DUMP ROAD	6	7	C	M	D		3/30/2007	4/9/2007
	Missed ground cut										
2110	FREEPORT	221	LANDING ROAD	10	10.1	C	M	D		3/30/2007	
	Clearance side & overhead										
2110	FREEPORT	221	LANDING ROAD	11	13	SER	M	D		3/30/2007	4/12/2007
	Missed service off pole 11										
2110	FREEPORT	221	LANDING ROAD	13	14	F	M	D		3/30/2007	4/12/2007
	Stubs & hazard tree										
2110	FREEPORT	221	LANDING ROAD	8	9	PR6	M	D		3/30/2007	
	Missed PR6 poplar (marked)										
2110	FREEPORT	221	LANDING ROAD	8	8.1	SEC	M	D		3/30/2007	
	Missed secondary										
2110	FREEPORT	221	LANDING ROAD	8.1	8.2	SEC	M	D		3/30/2007	
	Missed secondary & service										
2110	FREEPORT	221	LANDING ROAD	8.2	8.3	SEC	M	D		3/30/2007	
	Missed secondary & service										
2110	FREEPORT	245	MAST LANDING ROAD	09	010	PR6	M	D		3/30/2007	4/9/2007
	Missed PR6 - marked										

BRUNSWICK Randall 2/23/2007 45 Sections Reviewed

Town	Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

0710	BRISTOL	139	PEMAQUID POINT LIGH	10	11	SER	M	D		3/30/2007	3/14/2007
	Missed service off pole 11										
0710	BRISTOL	139	PEMAQUID POINT LIGH	13	14	B	M	D		3/30/2007	3/14/2007
	Brushed not chipped										
0710	BRISTOL	139	PEMAQUID POINT LIGH	19	20	C	M	D		3/30/2007	
	Clerance & ground cut										
0710	BRISTOL	139	PEMAQUID POINT LIGH	20	21	SER	M	D		3/30/2007	
	Missed service off pole 21										
0710	BRISTOL	139	PEMAQUID POINT LIGH	20	20.1		M	D		3/30/2007	
	No such span - wants credit										
0710	BRISTOL	139	PEMAQUID POINT LIGH	8	9	B	M	D		3/30/2007	3/14/2007
	Brush not chipped -piled by pole 9										
0710	BRISTOL	139	PEMAQUID POINT LIGH	9.01	9.02	B	M	D		3/30/2007	3/14/2007
	Brush not chippled & missed service off 9.01										
0710	BRISTOL	214	WEST ROAD	10	10.1	SEC	M	D		3/30/2007	
	Missed secondary										
0710	BRISTOL	214	WEST ROAD	12	13	PR6	M	D		3/30/2007	
	Remove dead birch										
0710	BRISTOL	214	WEST ROAD	13	14	GRN	M	D		3/30/2007	
	Ground cut 3 softwood close to pole 13										
0710	BRISTOL	214	WEST ROAD	3	3H	SER	M	D		3/30/2007	
	Missed service off pole 3										
0710	BRISTOL	214	WEST ROAD	3	3.1	SER	M	D		3/30/2007	
	Missed secondary & Service										
0710	BRISTOL	214	WEST ROAD	4	5	GRN	M	D		3/30/2007	
	Missed some softwood ground cut										
0710	BRISTOL	214	WEST ROAD	8	9	C	M	D		3/30/2007	
	Remove tree mark & little more side cleam on spruce near house										

BRUNSWICK **Randall** **3/22/2007** **5 Sections Reviewed**

Town	Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

2510	HARPSWELL	064	CUNDY'S HARBOR ROA	44	44H	PR5	M	D	28	4/5/2007	
	Remove hazard pine PF5 - 3' from primary, tree is marked										

BRUNSWICK Randall 3/30/2007 16 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2110	FREEPORT	400	TORREY RANGE ROAD	19	1	C	M	D		4/5/2007	
	Pole 19 South St to pole 1 Torrey Range rd. under clearance										
2110	FREEPORT	400	TORREY RANGE ROAD	5.4	5.5	Haz	M	D		4/5/2007	
	Remove several dead oak - hazard tree										

BRUNSWICK Randall 3/29/2007 33 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2110	FREEPORT	001	ALLEN RANGE ROAD	1	2	PR6	M	D		4/5/2007	
	Remove dying hemlock PR6 22inches										
2110	FREEPORT	001	ALLEN RANGE ROAD	12	12.1	SEC	M	D		4/5/2007	
	Secondary - left 6 ft stumps and 20 ft stump; remove hanger										
2110	FREEPORT	001	ALLEN RANGE ROAD	120	1	C	M	D		4/5/2007	
	Pole 120 Brunswick Rd. to pole 1 Allen Range Rd - removed bad maple eladher heading to primary										
2110	FREEPORT	001	ALLEN RANGE ROAD	4	5	R	M	D		4/5/2007	
	Remove bad beech tree - rotten at bottom; clearance in hemlock										
2110	FREEPORT	001	ALLEN RANGE ROAD	5	6	C	M	D		4/5/2007	
	Remove topped p ine - 5 inches										
2110	FREEPORT	001	ALLEN RANGE ROAD	7	8	PR6	M	D		4/5/2007	
	Brush not chipped & remove bad maple behind mail boxes PR6										
2110	FREEPORT	001	ALLEN RANGE ROAD	9	10	PF6	M	D		4/5/2007	
	Remove bad fir tree PR6 - 15 inches										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

BRUNSWICK Randall 3/29/2007 38 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2110	FREEPORT	041	CUSHING BRIGGS ROA	7	8	PR6	M	D		4/5/2007	
	Badly leaning 1/2 dead poplar PR6										
2110	FREEPORT	041	CUSHING BRIGGS ROA	9.2	9.3	SEC	M	D		4/5/2007	
	Missed secondary										
2110	FREEPORT	273	NOBLE DRIVE	4	5	SER	M	D		4/5/2007	
	Missed service off pole 4										
2110	FREEPORT	375	SANDY BEACH ROAD	5.2	5.3	C	M	D		4/5/2007	
	Clearance at pole 5.2 and missed service at 5.2										

BRUNSWICK Randall 3/23/2007 56 Sections Reviewed

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2110	FREEPORT	105	FERNALD ROAD	3	3H	SER	M	D	174	4/5/2007	
	Missed service off pole 3										
2110	FREEPORT	251	MURCH ROAD	1	2	SER	M	D		4/5/2007	
	Missed service off pole 1										
2110	FREEPORT	251	MURCH ROAD	1	1.1	SEC	M	D		4/5/2007	
	Missed secondary										
2110	FREEPORT	251	MURCH ROAD	2	2.01	SEC	M	D		4/5/2007	
	Missed secondary										
2110	FREEPORT	251	MURCH ROAD	3	3.1	SEC	M	D		4/5/2007	
	Missed secondary										
2110	FREEPORT	350	RANGE "E" ROAD	4	5	SER	M	D	174	4/5/2007	
	Missed service off pole 4 - stubs, maple										
2110	FREEPORT	350	RANGE "E" ROAD	5	6	SER	M	D	174	4/5/2007	
	Missed service off pole 6										
2110	FREEPORT	350	RANGE "E" ROAD	5	5.1	SEC	M	D	174	4/5/2007	
	Missed secondary										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

2110	FREEPORT	350	RANGE "E" ROAD	6	6.1	SEC	M	D	174	4/5/2007	
	Missed secondary										
2110	FREEPORT	350	RANGE "E" ROAD	9	10	S	M	D	174	4/5/2007	
	Bad stubbing maple										
2110	FREEPORT	400	TORREY RANGE ROAD	16	15	C	M	D		4/5/2007	
	Remove front oak closed to pole 16										
2110	FREEPORT	400	TORREY RANGE ROAD	17	16	C	M	D		4/5/2007	
	Ground cut small fir next to pole 16										
2110	FREEPORT	400	TORREY RANGE ROAD	18	17	C	M	D		4/5/2007	
	Clearance under										
2110	FREEPORT	400	TORREY RANGE ROAD	20	20.1	PR5	M	D		4/5/2007	
	Remove bad fir - 50 ft before pole 20.1 PR5										
2110	FREEPORT	400	TORREY RANGE ROAD	20	19	C	M	D		4/5/2007	
	Remove small topped out oak										
2110	FREEPORT	400	TORREY RANGE ROAD	25	26	C	M	D		4/5/2007	
	Remove fir tree behind pole 125 - permission										
2110	FREEPORT	400	TORREY RANGE ROAD	31	32	C	M	D		4/5/2007	
	Side clearnace, under clearance, topped softwood										
2110	FREEPORT	400	TORREY RANGE ROAD	34	34.1	SEC	M	D		4/5/2007	
	Missed secondary										
2110	FREEPORT	400	TORREY RANGE ROAD	5.2	5.3	C	M	D		4/5/2007	
	Remove small topped pine										
2110	FREEPORT	400	TORREY RANGE ROAD	5.3	5.4	C	M	D		4/5/2007	
	Removed dead oak 6 inches										

BRUNSWICK **Randall** **4/3/2007** **6 Sections Reviewed**

	Town		Road	From	To	Compliance Issue	Class	Contractor	Crew	Notify Date	Fix Date
2510	HARPSWELL	064	CUNDY'S HARBOR ROA	66	67	B	M	D		5/8/2007	
	Chip brush & finish removing topped trees										
2510	HARPSWELL	064	CUNDY'S HARBOR ROA	67	68	B	M	D		5/8/2007	
	Chip brush & finish removing topped trees										

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

2510	HARPSWELL	064	CUNDY'S HARBOR ROA	68	69	B	M	D		5/8/2007
	Chip brush & finish removing topped trees									
2510	HARPSWELL	064	CUNDY'S HARBOR ROA	69	70	B	M	D		5/8/2007
	Chip brush & finish removing topped trees									
2510	HARPSWELL	064	CUNDY'S HARBOR ROA	70	71	S	M	D		5/8/2007
	Re-cut high stumps									
2510	HARPSWELL	064	CUNDY'S HARBOR ROA	71	72	C	M	D		5/8/2007
	Finish removing topped pine									
6490	WOOLWICH	068	MIDDLE ROAD	66	66.1	B	M	D	174	5/8/2007
	Brush never chipped - asap									
6490	WOOLWICH	068	MIDDLE ROAD	66.1	66.2	B	M	D	174	5/8/2007
	Brush never chipped - asap									
6490	WOOLWICH	093	OLD COUNTY ROAD	134	134.1	B	M	D	150	5/8/2007
	Brush never chipped - asap									
6490	WOOLWICH	093	OLD COUNTY ROAD	134.1	134.2	B	M	D	150	5/8/2007
	Brush never chipped - asap									
6490	WOOLWICH	093	OLD COUNTY ROAD	134.2	134.3	B	M	D	150	5/8/2007
	Brush never chipped - asap									

Service Center Totals:	83 Sections for Rework	336 Sections Reviewed	24.70%

CMP Vegetation Management

Audit Results for 1/1/2007 thru 5/31/2007

Corporate Totals:	**1129 Sections for Rework**	**12460 Sections Reviewed**	**9.06%**

Central Maine Power Company
July 2009 Distribution Rate Design Excluding One-Year Adjustment
ARP 2008 Docket No. 2010-051
July 2010 ARP Price Change

	2009 Core Rate Billing Units 1/	Distribution Rates 7/1/09 Including One Year Adjustments 2/	Distribution Revenue 3/	Distribution Rates 7/1/09 Less One Year Adjustments	Distribution Revenue Check
	(1)	(2)	(3)	(4)	(5)
			(1)*(2)	(2)*% Change	(1)*(4)
ARP Increase July 2009 less one year adjustments			3.72%		
RATES A & R					
Minimum Charge	6,394,164	$ 5.21	$ 33,313,594	$ 5.02	$ 32,098,703
kWh 100 or less	586,505,456				
kWh Charge for kWh > 100	2,741,797,508	0.040160	110,110,588	$ 0.038666	106,014,342
Total kWh and Revenue	3,328,302,964		143,424,182		138,113,046
Increase in Distribution Revenue			(5,335,380)		(5,311,137)
					24,243
A & R-TOU					
Service Charge	69,805	6.99	487,937	6.73	469,788
kWh-On Winter	8,551,357	0.068193	583,143	0.065656	561,448
kWh-Sh Winter	3,222,358	0.056162	180,974	0.054073	174,243
kWh-Off Winter	20,891,886	0.017965	375,323	0.017297	361,367
kWh-On Other	11,190,257	0.068193	763,097	0.065656	734,708
kWh-Sh Other	4,373,531	0.056162	245,626	0.054073	236,490
kWh-Off Other	25,019,103	0.017965	449,468	0.017297	432,755
Total kWh and Revenue	73,248,492		3,085,568		2,970,798
Increase in Distribution Revenue			(114,783)		(114,770)
					13
A-LM					
Service Charge	2,639	9.13	24,094	8.79	23,197
kWh Winter	648,292	0.001303	845	0.001255	814
kWh Other	349,117	0.001303	455	0.001255	438
Total kWh and Revenue	997,409		25,394		24,449
Increase in Distribution Revenue			(945)		(945)
					(0)
SGS (0 - 20 kW)					
Service Charge - Single Phase	510,315	10.47	5,342,998	10.08	5,143,975
Service Charge - Three Phase	92,160	17.39	1,602,662	16.74	1,542,758
kWh Winter	189,318,599	0.029927	5,665,738	0.028814	5,455,026
kWh Other	354,931,336	0.029927	10,622,030	0.028814	10,226,992
Total kWh and Revenue	544,249,935		23,233,428		22,368,751
Increase in Distribution Revenue			(864,284)		(864,677)
					(393)
MGS-S					
Service Charge - Single Phase	41,045	25.87	1,061,834	24.91	1,022,431
Service Charge - Three Phase	89,151	33.72	3,006,172	32.47	2,894,733
kW Winter	1,792,274	3.92	7,025,713	3.77	6,756,872
kW Other	3,898,000	2.91	11,343,180	2.80	10,914,400
kWh Winter	586,984,020	-	-	-	-
kWh Other	1,202,237,651	-	-	-	-
KVAR	206,077	0.66	136,011	0.64	131,889
Total kWh and Revenue	1,789,221,671		22,572,909		21,720,325
Increase in Distribution Revenue			(839,712)		(852,585)
					(12,872)
MGS-P					
Service Charge - Single Phase	405	73.31	29,691	70.58	28,585
Service Charge - Three Phase	1,538	113.47	174,517	109.25	168,027
kW Winter	69,589	3.49	242,867	3.36	233,820
kW Other	146,588	2.10	307,835	2.02	296,108
kWh Winter	23,709,450	-	-	-	-
kWh Other	45,412,096	-	-	-	-
KVAR	88,917	0.66	58,686	0.64	56,907
Total kWh and Revenue	69,121,546		813,594		783,446
Increase in Distribution Revenue			(30,266)		(30,148)
					118

Central Maine Power Company
July 2009 Distribution Rate Design Excluding One-Year Adjustment
ARP 2008 Docket No. 2010-051
July 2010 ARP Price Change

	2009 Core Rate Billing Units 1/	Distribution Rates 7/1/09 Including One Year Adjustments 2/	Distribution Revenue 3/	Distribution Rates 7/1/09 Less One Year Adjustments	Distribution Revenue Check
	(1)	(2)	(3)	(4)	(5)
			(1)*(2)	(2)*% Change	(1)*(4)
ARP Increase July 2009 less one year adjustments			3.72%		
IGS-S					
Service Charge	2,486	99.42	247,158	95.72	237,960
kW-On Winter	341,907	1.96	670,139	1.89	646,205
kW-Sh Winter	336,732	1.11	373,773	1.07	360,304
kW-On Other	770,324	1.70	1,309,551	1.64	1,263,332
kW-Sh Other	768,763	1.11	853,327	1.07	822,576
kWh-On Winter	43,701,780	-	-	-	-
kWh-Sh Winter	34,303,420	-	-	-	-
kWh-Off Winter	67,327,670	-	-	-	-
kWh-On Other	98,225,460	-	-	-	-
kWh-Sh Other	48,825,200	-	-	-	-
kWh-Off Other	168,841,740	-	-	-	-
KVAR	117,044	0.66	77,249	0.64	74,908
Total kWh and Revenue	461,225,270		3,531,196		3,405,285
Increase in Distribution Revenue			(131,361)		(125,912)
					5,449
IGS-P					
Service Charge	726	144.36	104,805	138.99	100,907
kW-On Winter	111,696	3.80	424,444	3.66	408,807
kW-Sh Winter	110,936	1.18	130,905	1.14	126,467
kW-On Other	242,408	1.70	412,094	1.64	397,550
kW-Sh Other	241,799	1.18	285,322	1.14	275,650
kWh-On Winter	13,896,450	0.002890	40,161	0.002782	38,660
kWh-Sh Winter	10,832,322	0.002359	25,553	0.002271	24,600
kWh-Off Winter	22,400,858	0.000905	20,273	0.000871	19,511
kWh-On Other	30,033,260	0.001717	51,567	0.001653	49,645
kWh-Sh Other	15,246,772	0.001623	24,746	0.001563	23,831
kWh-Off Other	50,491,286	0.000354	17,874	0.000341	17,218
KVAR	53,277	0.66	35,163	0.64	34,097
Total kWh and Revenue	142,900,948		1,572,907		1,516,943
Increase in Distribution Revenue			(58,512)		(55,965)
					2,548
LGS-S					
Service Charge	134	492.31	65,970	474.00	63,516
kW-On Winter	46,384	2.86	132,657	2.75	127,555
kW-Sh Winter	45,285	1.45	65,664	1.40	63,399
kW-On Other	98,275	2.27	223,084	2.19	215,222
kW-Sh Other	98,209	1.45	142,403	1.40	137,493
kWh-On Winter	6,157,234	-	-	-	-
kWh-Sh Winter	4,839,263	-	-	-	-
kWh-Off Winter	10,673,535	-	-	-	-
kWh-On Other	13,999,378	-	-	-	-
kWh-Sh Other	6,888,940	-	-	-	-
kWh-Off Other	26,850,344	-	-	-	-
KVAR	18,926	0.66	12,491	0.64	12,113
Total kWh and Revenue	69,408,694		642,269		619,298
Increase in Distribution Revenue			(23,892)		(22,971)
					921
LGS-P					
Service Charge	589	535.78	315,574	515.85	303,836
kW-On Winter	332,948	4.85	1,614,798	4.67	1,554,868
kW-Sh Winter	328,236	1.36	446,401	1.31	429,989
kW-On Other	698,386	1.96	1,368,836	1.89	1,319,949
kW-Sh Other	696,269	1.23	856,411	1.18	821,597
kWh-On Winter	44,944,306	-	-	-	-
kWh-Sh Winter	34,877,582	-	-	-	-
kWh-Off Winter	77,540,261	-	-	-	-
kWh-On Other	99,290,729	-	-	-	-
kWh-Sh Other	48,675,302	-	-	-	-
kWh-Off Other	183,911,290	-	-	-	-
KVAR	220,186	0.66	145,323	0.64	140,919
Total kWh and Revenue	489,239,470		4,747,343		4,571,157
Increase in Distribution Revenue			(176,601)		(176,185)
					416

Central Maine Power Company
July 2009 Distribution Rate Design Excluding One-Year Adjustment
ARP 2008 Docket No. 2010-051
July 2010 ARP Price Change

	2009 Core Rate Billing Units 1/	Distribution Rates 7/1/09 Including One Year Adjustments 2/	Distribution Revenue 3/	Distribution Rates 7/1/09 Less One Year Adjustments	Distribution Revenue Check
	(1)	(2)	(3)	(4)	(5)
			(1)*(2)	(2)*% Change	(1)*(4)
ARP Increase July 2009 less one year adjustments			3.72%		
LGS-ST-TOU					
Service Charge	624	521.01	325,110	501.63	313,017
kW-On Winter	444,780	-	-	-	-
kW-Sh Winter	454,081	-	-	-	-
kW-On Other	850,147	-	-	-	-
kW-Sh Other	831,904	-	-	-	-
kWh-On Winter	55,993,527	-	-	-	-
kWh-Sh Winter	48,313,588	-	-	-	-
kWh-Off Winter	108,424,203	-	-	-	-
kWh-On Other	113,553,616	-	-	-	-
kWh-Sh Other	52,865,563	-	-	-	-
kWh-Off Other	253,982,393	-	-	-	-
KVAR	301,657	-	-	-	-
	633,132,890		325,110		313,017
			(12,094)		(12,093)
					1
LGS-T-TOU					
Service Charge	208	727.96	151,416	700.88	145,783
kW-On Winter	344,599	-	-	-	-
kW-Sh Winter	346,792	-	-	-	-
kW-On Other	979,003	-	-	-	-
kW-Sh Other	843,070	-	-	-	-
kWh-On Winter	25,573,777	-	-	-	-
kWh-Sh Winter	24,714,260	-	-	-	-
kWh-Off Winter	65,270,882	-	-	-	-
kWh-On Other	74,234,154	-	-	-	-
kWh-Sh Other	31,319,593	-	-	-	-
kWh-Off Other	199,644,775	-	-	-	-
KVAR	554,533	-	-	-	-
	420,757,441		151,416		145,783
			(5,633)		(5,633)
					0
AL 4/	9,554,110	0.161587	1,543,820	0.155576	1,486,390
SL 4/	27,380,923	0.203709	5,577,740	0.196131	5,370,248
Total	8,058,741,763		$ 211,246,878		$ 203,408,935
Total Increase			$ (7,858,384)		$ (7,837,942)
					$ 20,442
					-3.71%

Notes:
1/ Adjusted 2009 core billing units.
2/ See Compliance Attachment 4, ARP Filing, June 10, 2009, Docket No. 2009-071
3/ See Compliance Attachment 1, Page 2, ARP Filing, June 10, 2009, Docket No. 2009-071
4/ Individual fixture prices will be provided in the compliance filing.

Central Maine Power Company
Distribution Rate Design
ARP 2008 Docket No. 2010-051
July 2010 Price Change

	2009 Core Rate Billing Units 1/	Distribution Rates 7/1/09 Less One Year Adjustments 2/	Distribution Revenue 3/	Distribution Rates 7/1/10 2/	Distribution Revenue Check
	(1)	(2)	(3)	(4)	(5)
			(1)*(2)	(2)*% Change	(1)*(4)
ARP Decrease July 2010			1.93000%		
RATES A & R					
Minimum Charge	6,394,164	$ 5.02	$ 32,098,703	$ 5.12	$ 32,738,120
kWh 100 or less	586,505,456				
kWh Charge for kWh > 100	2,741,797,508	0.038666	106,014,342	0.039412	108,059,723
Total kWh and Revenue	3,328,302,964		138,113,046		140,797,843
Increase in Distribution Revenue			2,665,582		2,684,797
					19,216
A & R-TOU					
Service Charge	69,805	6.73	469,788	6.86	478,862
kWh-On Winter	8,551,357	0.065656	561,448	0.066923	572,282
kWh-Sh Winter	3,222,358	0.054073	174,243	0.055117	177,607
kWh-Off Winter	20,891,886	0.017297	361,367	0.017631	368,345
kWh-On Other	11,190,257	0.065656	734,708	0.066923	748,886
kWh-Sh Other	4,373,531	0.054073	236,490	0.055117	241,056
kWh-Off Other	25,019,103	0.017297	432,755	0.017631	441,112
Total kWh and Revenue	73,248,492		2,970,798		3,028,150
Increase in Distribution Revenue			57,336		57,352
					15
A-LM					
Service Charge	2,639	8.79	23,197	8.96	23,645
kWh Winter	648,292	0.001255	814	0.001279	829
kWh Other	349,117	0.001255	438	0.001279	447
Total kWh and Revenue	997,409		24,449		24,921
Increase in Distribution Revenue			472		473
					1
SGS (0 - 20 kW)					
Service Charge - Single Phase	510,315	10.08	5,143,975	10.27	5,240,935
Service Charge - Three Phase	92,160	16.74	1,542,758	17.06	1,572,250
kWh Winter	189,318,599	0.028814	5,455,026	0.029366	5,559,530
kWh Other	354,931,336	0.028814	10,226,992	0.029366	10,422,914
Total kWh and Revenue	544,249,935		22,368,751		22,795,628
Increase in Distribution Revenue			431,717		426,877
					(4,840)
MGS-S					
Service Charge - Single Phase	41,045	24.91	1,022,431	25.38	1,041,722
Service Charge - Three Phase	89,151	32.47	2,894,733	33.09	2,950,007
kW Winter	1,792,274	3.77	6,756,872	3.84	6,882,331
kW Other	3,898,000	2.80	10,914,400	2.85	11,109,300
kWh Winter	586,984,020	-	-	-	-
kWh Other	1,202,237,651	-	-	-	-
KVAR	206,077	0.64	131,889	0.65	133,950
Total kWh and Revenue	1,789,221,671		21,720,325		22,117,309
Increase in Distribution Revenue			419,202		396,985
					(22,218)
MGS-P					
Service Charge - Single Phase	405	70.58	28,585	71.94	29,136
Service Charge - Three Phase	1,538	109.25	168,027	111.36	171,272
kW Winter	69,589	3.36	233,820	3.42	237,995
kW Other	146,588	2.02	296,108	2.06	301,971
kWh Winter	23,709,450	-	-	-	-
kWh Other	45,412,096	-	-	-	-
KVAR	88,917	0.64	56,907	0.65	57,796
Total kWh and Revenue	69,121,546		783,446		798,170
Increase in Distribution Revenue			15,121		14,724
					(396)

Central Maine Power Company
Distribution Rate Design
ARP 2008 Docket No. 2010-051
July 2010 Price Change

	2009 Core Rate Billing Units 1/	Distribution Rates 7/1/09 Less One Year Adjustments 2/	Distribution Revenue 3/	Distribution Rates 7/1/10 2/	Distribution Revenue Check
	(1)	(2)	(3)	(4)	(5)
			(1)*(2)	(2)*% Change	(1)*(4)
ARP Decrease July 2010			1.93000%		
IGS-S					
Service Charge	2,486	95.72	237,960	95.81	238,184
kW-On Winter	341,907	1.89	646,205	1.93	659,881
kW-Sh Winter	336,732	1.07	360,304	1.09	367,038
kW-On Other	770,324	1.64	1,263,332	1.67	1,286,441
kW-Sh Other	768,763	1.07	822,576	1.09	837,951
kWh-On Winter	43,701,780	-	-	-	-
kWh-Sh Winter	34,303,420	-	-	-	-
kWh-Off Winter	67,327,670	-	-	-	-
kWh-On Other	98,225,460	-	-	-	-
kWh-Sh Other	48,825,200	-	-	-	-
kWh-Off Other	168,841,740	-	-	-	-
KVAR	117,044	0.64	74,908	0.65	76,079
Total kWh and Revenue	461,225,270		3,405,285		3,465,575
Increase in Distribution Revenue			65,722		60,290
					(5,432)
IGS-P					
Service Charge	726	138.99	100,907	141.67	102,852
kW-On Winter	111,696	3.66	408,807	3.73	416,626
kW-Sh Winter	110,936	1.14	126,467	1.16	128,686
kW-On Other	242,408	1.64	397,550	1.67	404,822
kW-Sh Other	241,799	1.14	275,650	1.16	280,486
kWh-On Winter	13,896,450	0.002782	38,660	0.002824	39,244
kWh-Sh Winter	10,832,322	0.002271	24,600	0.002303	24,947
kWh-Off Winter	22,400,858	0.000871	19,511	0.000876	19,623
kWh-On Other	30,033,260	0.001653	49,645	0.001673	50,246
kWh-Sh Other	15,246,772	0.001563	23,831	0.001581	24,105
kWh-Off Other	50,491,286	0.000341	17,218	0.000336	16,965
KVAR	53,277	0.64	34,097	0.65	34,630
Total kWh and Revenue	142,900,948		1,516,943		1,543,232
Increase in Distribution Revenue			29,277		26,289
					(2,988)
LGS-S					
Service Charge	134	474.00	63,516	488.20	65,419
kW-On Winter	46,384	2.75	127,555	2.80	129,874
kW-Sh Winter	45,285	1.40	63,399	1.43	64,758
kW-On Other	98,275	2.19	215,222	2.23	219,153
kW-Sh Other	98,209	1.40	137,493	1.43	140,439
kWh-On Winter	6,157,234	-	-	-	-
kWh-Sh Winter	4,839,263	-	-	-	-
kWh-Off Winter	10,673,535	-	-	-	-
kWh-On Other	13,999,378	-	-	-	-
kWh-Sh Other	6,888,940	-	-	-	-
kWh-Off Other	26,850,344	-	-	-	-
KVAR	18,926	0.64	12,113	0.65	12,302
Total kWh and Revenue	69,408,694		619,298		631,945
Increase in Distribution Revenue			11,952		12,647
					695
LGS-P					
Service Charge	589	515.85	303,836	525.81	309,702
kW-On Winter	332,948	4.67	1,554,868	4.76	1,584,833
kW-Sh Winter	328,236	1.31	429,989	1.34	439,836
kW-On Other	698,386	1.89	1,319,949	1.93	1,347,885
kW-Sh Other	696,269	1.18	821,597	1.20	835,522
kWh-On Winter	44,944,306	-	-	-	-
kWh-Sh Winter	34,877,582	-	-	-	-
kWh-Off Winter	77,540,261	-	-	-	-
kWh-On Other	99,290,729	-	-	-	-
kWh-Sh Other	48,675,302	-	-	-	-
kWh-Off Other	183,911,290	-	-	-	-

Central Maine Power Company
Distribution Rate Design
ARP 2008 Docket No. 2010-051
July 2010 Price Change

	2009 Core Rate Billing Units 1/	Distribution Rates 7/1/09 Less One Year Adjustments 2/	Distribution Revenue 3/	Distribution Rates 7/1/10 2/	Distribution Revenue Check
	(1)	(2)	(3)	(4)	(5)
			(1)*(2)	(2)*% Change	(1)*(4)
ARP Decrease July 2010			1.93000%		
KVAR	220,186	0.64	140,919	0.65	143,121
Total kWh and Revenue	489,239,470		4,571,157		4,660,899
Increase in Distribution Revenue			88,223		89,742
					1,518
LGS-ST-TOU					
Service Charge	624	501.63	313,017	511.31	319,057
kW-On Winter	444,780	-	-		-
kW-Sh Winter	454,081	-	-		-
kW-On Other	850,147	-	-		-
kW-Sh Other	831,904	-	-		-
kWh-On Winter	55,993,527	-	-		-
kWh-Sh Winter	48,313,588	-	-		-
kWh-Off Winter	108,424,203	-	-		-
kWh-On Other	113,553,616	-	-		-
kWh-Sh Other	52,865,563	-	-		-
kWh-Off Other	253,982,393	-	-		-
KVAR	301,657	-	-		-
Total kWh and Revenue	633,132,890		313,017		319,057
Increase in Distribution Revenue			6,041		6,040
					(1)
LGS-T-TOU					
Service Charge	208	700.88	145,783	714.41	148,597
kW-On Winter	344,599	-	-		-
kW-Sh Winter	346,792	-	-		-
kW-On Other	979,003	-	-		-
kW-Sh Other	843,070	-	-		-
kWh-On Winter	25,573,777	-	-		-
kWh-Sh Winter	24,714,260	-	-		-
kWh-Off Winter	65,270,882	-	-		-
kWh-On Other	74,234,154	-	-		-
kWh-Sh Other	31,319,593	-	-		-
kWh-Off Other	199,644,775	-	-		-
KVAR	554,533	-	-		-
Total kWh and Revenue	420,757,441		145,783		148,597
Increase in Distribution Revenue			2,814		2,814
					1
AL 4/	9,554,110	0.155576	1,486,390	0.158579	1,515,081
SL 4/	27,380,923	0.196131	5,370,248	0.199916	5,473,885
Total	8,058,741,763		$ 203,408,935		$ 207,320,293
Total Increase			$ 3,925,792		$ 3,911,357
					$ (14,435)
					1.92%

Notes:
1/ Adjusted 2009 core billing units.
2/ See Attachment 17
3/ Distribution Rate change from Attachment 1 - July 2010 Price Change applied to revenue, by class, to detemined the expected r
4/ Individual fixture prices will be provided in the compliance filing.

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	Distribution Rates 7/1/2010 1/	ELP Assessment 7/1/2010	Conservation and Solar Assessment 7/1/2010	Stranded Cost Rates 7/1/2009 2/	Transmission Rates 7/1/2009 3/	Total Rates Effective 7/1/2010	Total Rates Effective 7/1/2009	% Change in Component
RATES A & R								
Minimum Charge	$ 5.12	$ 0.08	$ 0.14	$ 1.51	$ 1.42	$ 8.27	$ 8.36	-1.12%
kWh Charge kWh > 100	0.039412	0.000882	0.001500	-	0.015475	0.057269	0.058017	-1.29%
A & R-TOU								
Customer Charge	6.86					6.86	6.99	-1.86%
Winter On-Peak	0.066923	0.000882	0.001500	0.006113	0.015475	0.090893	0.092163	-1.38%
Winter Shoulder	0.055117	0.000882	0.001500	0.005067	0.015475	0.078041	0.079086	-1.32%
Winter Off-Peak	0.017631	0.000882	0.001500	0.001746	0.015475	0.037234	0.037568	-0.89%
Other On-Peak	0.066923	0.000882	0.001500	0.006113	0.015475	0.090893	0.092163	-1.38%
Other Shoulder	0.055117	0.000882	0.001500	0.005067	0.015475	0.078041	0.079086	-1.32%
Other Off-Peak	0.017631	0.000882	0.001500	0.001746	0.015475	0.037234	0.037568	-0.89%
A-LM								
Customer Charge	8.96					8.96	9.13	-1.86%
Energy Winter	0.001279	0.000882	0.001500	0.002188	0.004701	0.010550	0.010574	-0.23%
Energy Other	0.001279	0.000882	0.001500	0.002188	0.004701	0.010550	0.010574	-0.23%
SGS (0 - 20 kW)								
Customer - Single Phase	10.27	-				10.27	10.47	-1.91%
Customer - Three Phase	17.06	-				17.06	17.39	-1.90%
Energy Winter	0.029366	0.000882	0.001500	0.003047	0.015166	0.049961	0.050522	-1.11%
Energy Other	0.029366	0.000882	0.001500	0.003047	0.015166	0.049961	0.050522	-1.11%
MGS-S								
Customer - Single Phase	25.38	-				25.38	25.87	-1.89%
Customer - Three Phase	33.09	-				33.09	33.72	-1.87%
Demand Winter	3.84	-		0.49	4.74	9.07	9.15	-0.87%
Demand Other	2.85	-		0.49	4.74	8.08	8.14	-0.74%
Energy Winter	-	0.000882	0.001500	0.002402		0.004784	0.004784	0.00%
Energy Other	-	0.000882	0.001500	0.002402		0.004784	0.004784	0.00%
KVAR	0.65	-				0.65	0.66	-1.52%
MGS-P								
Customer - Single Phase	71.94	-				71.94	73.31	-1.87%
Customer - Three Phase	111.36	-				111.36	113.47	-1.86%
Demand Winter	3.42	-		0.41	4.49	8.32	8.39	-0.83%
Demand Other	2.06	-		0.41	4.49	6.96	7.00	-0.57%
Energy Winter	-	0.000882	0.001500	0.002467		0.004849	0.004849	0.00%
Energy Other	-	0.000882	0.001500	0.002467		0.004849	0.004849	0.00%
KVAR	0.65					0.65	0.66	-1.52%

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	Distribution Rates 7/1/2010 1/	ELP Assessment 7/1/2010	Conservation and Solar Assessment 7/1/2010	Stranded Cost Rates 7/1/2009 2/	Transmission Rates 7/1/2009 3/	Total Rates Effective 7/1/2010	Total Rates Effective 7/1/2009	% Change in Component
IGS-S								
Customer Charge	95.81	-				95.81	99.42	-3.63%
kW-On Winter	1.93	-		0.41	6.09	8.43	8.46	-0.35%
kW-Sh Winter	1.09	-		0.41		1.50	1.52	-1.32%
kW-On Other	1.67	-		0.41	6.09	8.17	8.20	-0.37%
kW-Sh Other	1.09	-		0.41		1.50	1.52	-1.32%
kWh-On Winter	-	0.000882	0.001500	0.003086		0.005468	0.005468	0.00%
kWh-Sh Winter	-	0.000882	0.001500	0.003086		0.005468	0.005468	0.00%
kWh-Off Winter	-	0.000882	0.001500	0.003086		0.005468	0.005468	0.00%
kWh-On Other	-	0.000882	0.001500	0.003086		0.005468	0.005468	0.00%
kWh-Sh Other	-	0.000882	0.001500	0.003086		0.005468	0.005468	0.00%
kWh-Off Other	-	0.000882	0.001500	0.003086		0.005468	0.005468	0.00%
KVAR	0.65	-				0.65	0.66	-1.52%
IGS-P								
Customer Charge	141.67	-				141.67	144.36	-1.86%
kW-On Winter	3.73	-		0.23	5.51	9.47	9.54	-0.73%
kW-Sh Winter	1.16	-		0.23		1.39	1.41	-1.42%
kW-On Other	1.67	-		0.23	5.51	7.41	7.44	-0.40%
kW-Sh Other	1.16	-		0.23		1.39	1.41	-1.42%
kWh-On Winter	0.002824	0.000882	0.001500	0.002691		0.007897	0.007963	-0.83%
kWh-Sh Winter	0.002303	0.000882	0.001500	0.002691		0.007376	0.007432	-0.75%
kWh-Off Winter	0.000876	0.000882	0.001500	0.002691		0.005949	0.005978	-0.49%
kWh-On Other	0.001673	0.000882	0.001500	0.002691		0.006746	0.006790	-0.65%
kWh-Sh Other	0.001581	0.000882	0.001500	0.002691		0.006654	0.006696	-0.63%
kWh-Off Other	0.000336	0.000882	0.001500	0.002691		0.005409	0.005427	-0.33%
KVAR	0.65	-	-	-		0.65	0.66	-1.52%

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	Distribution Rates 7/1/2010 1/	ELP Assessment 7/1/2010	Conservation and Solar Assessment 7/1/2010	Stranded Cost Rates 7/1/2009 2/	Transmission Rates 7/1/2009 3/	Total Rates Effective 7/1/2010	Total Rates Effective 7/1/2009	% Change in Component
LGS-S								
Customer Charge	488.20	-		-		488.20	492.31	-0.83%
kW-On Winter	2.80	-		0.36	6.15	9.31	9.37	-0.64%
kW-Sh Winter	1.43	-		0.36		1.79	1.81	-1.10%
kW-On Other	2.23	-		0.36	6.15	8.74	8.78	-0.46%
kW-Sh Other	1.43	-		0.36		1.79	1.81	-1.10%
kWh-On Winter	-	0.000882	0.001500	0.003512		0.005894	0.005894	0.00%
kWh-Sh Winter	-	0.000882	0.001500	0.003512		0.005894	0.005894	0.00%
kWh-Off Winter	-	0.000882	0.001500	0.003512		0.005894	0.005894	0.00%
kWh-On Other	-	0.000882	0.001500	0.003512		0.005894	0.005894	0.00%
kWh-Sh Other	-	0.000882	0.001500	0.003512		0.005894	0.005894	0.00%
kWh-Off Other	-	0.000882	0.001500	0.003512		0.005894	0.005894	0.00%
KVAR	0.65	-		-		0.65	0.66	-1.52%
LGS-P								
Customer Charge	525.81	-		-		525.81	535.78	-1.86%
kW-On Winter	4.76	-		0.28	6.18	11.22	11.31	-0.80%
kW-Sh Winter	1.34	-		0.28		1.62	1.64	-1.22%
kW-On Other	1.93	-		0.28	6.18	8.39	8.42	-0.36%
kW-Sh Other	1.20	-		0.28		1.48	1.51	-1.99%
kWh-On Winter	-	0.000882	0.001500	0.002987		0.005369	0.005369	0.00%
kWh-Sh Winter	-	0.000882	0.001500	0.002987		0.005369	0.005369	0.00%
kWh-Off Winter	-	0.000882	0.001500	0.002987		0.005369	0.005369	0.00%
kWh-On Other	-	0.000882	0.001500	0.002987		0.005369	0.005369	0.00%
kWh-Sh Other	-	0.000882	0.001500	0.002987		0.005369	0.005369	0.00%
kWh-Off Other	-	0.000882	0.001500	0.002987		0.005369	0.005369	0.00%
KVAR	0.65	-				0.65	0.66	-1.52%
LGS-ST-TOU								
Customer Charge	511.31	-		-		511.31	521.01	-1.86%
kW-On Winter	-	-		0.43		0.43	0.43	0.00%
kW-Sh Winter	-	-		0.43		0.43	0.43	0.00%
kW-On Other	-	-		0.43	Note 4	0.43	0.43	0.00%
kW-Sh Other	-	-		0.43		0.43	0.43	0.00%
kWh-On Winter	-	-	0.000050	0.001015		0.001065	0.001065	0.00%
kWh-Sh Winter	-	-	0.000050	0.001015		0.001065	0.001065	0.00%
kWh-Off Winter	-	-	0.000050	-		0.000050	0.000050	0.00%
kWh-On Other	-	-	0.000050	-		0.000050	0.000050	0.00%
kWh-Sh Other	-	-	0.000050	-		0.000050	0.000050	0.00%
kWh-Off Other	-	-	0.000050	-		0.000050	0.000050	0.00%
KVAR	-	-		0.19		0.19	0.19	0.00%

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	Distribution Rates 7/1/2010 1/	ELP Assessment 7/1/2010	Conservation and Solar Assessment 7/1/2010	Stranded Cost Rates 7/1/2009 2/	Transmission Rates 7/1/2009 3/	Total Rates Effective 7/1/2010	Total Rates Effective 7/1/2009	% Change in Component
LGS-T-TOU								
Customer Charge	714.41	-		-		714.41	727.96	-1.86%
kW-On Winter	-	-		0.40		0.40	0.40	0.00%
kW-Sh Winter	-	-		0.40		0.40	0.40	0.00%
kW-On Other	-	-		0.40	Note 4	0.40	0.40	0.00%
kW-Sh Other	-	-		0.40		0.40	0.40	0.00%
kWh-On Winter	-	-	0.000050	0.001210		0.001260	0.001260	0.00%
kWh-Sh Winter	-	-	0.000050	0.001210		0.001260	0.001260	0.00%
kWh-Off Winter	-	-	0.000050	-		0.000050	0.000050	0.00%
kWh-On Other	-	-	0.000050	-		0.000050	0.000050	0.00%
kWh-Sh Other	-	-	0.000050	-		0.000050	0.000050	0.00%
kWh-Off Other	-	-	0.000050	-		0.000050	0.000050	0.00%
KVAR	-	-		0.19		0.19	0.19	0.00%
AL	0.158579	0.000882	0.001500	0.002284	0.011524	0.174769	0.177777	-1.69%
SL	0.199916	0.000882	0.001500	0.002289	0.011524	0.216111	0.219904	-1.72%
Total								

Notes:
1/ Distribution Rates from Docket No. 2010-051
2/ Stranded Cost Rates from Docket No. 2009-090
3/ Transmission rates for distribution level customers, effective July 1, 2009. Will be updated later in this proceeding
4/ Transmission level customers purchase transmission services in accordance with the ISO Transmission Market and Services Tariff, and as a result, the prices are not included here.

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	2009 Core Rate Billing Units	Revenues July 1, 2010 Distribution	ELP Assessment	Conservation Assessment	Stranded Costs	Transmission	Total Delivery	7/1/2010 Avg kWh	Total Delivery Revenue 7/1/2009	7/1/2009 Avg kWh	Total Delivery Change
RATES A & R											
Minimum Charge	6,394,164	32,738,120	511,533	895,183	9,655,188	9,076,758	52,876,782		53,476,995		
	586,505,456										
kWh Charge kWh > 100	2,741,797,508	108,059,723	2,418,265	4,112,696	-	42,429,316	157,020,001		159,070,866		
	3,328,302,964	140,797,843	2,929,799	5,007,879	9,655,188	51,506,075	209,896,783	0.063064	212,547,861	0.063861	-1.25%
A & R-TOU											
Customer Charge	69,805	478,862	-	-	-	-	478,862		487,937		
Winter On-Peak	8,551,357	572,282	7,542	12,827	52,274	132,332	777,258		788,119		
Winter Shoulder	3,222,358	177,607	2,842	4,834	16,328	49,866	251,476		254,843		
Winter Off-Peak	20,891,886	368,345	18,427	31,338	36,477	323,302	777,888		784,866		
Other On-Peak	11,190,257	748,886	9,870	16,785	68,406	173,169	1,017,116		1,031,328		
Other Shoulder	4,373,531	241,056	3,857	6,560	22,161	67,680	341,315		345,885		
Other Off-Peak	25,019,103	441,112	22,067	37,529	43,683	387,171	931,561		939,918		
	73,248,492	3,028,150	64,605	109,873	239,329	1,133,520	4,575,477	0.062465	4,632,896	0.063249	-1.24%
A-LM											
Customer Charge	2,639	23,645	-	-	-	-	23,645		24,094		
Energy Winter	648,292	829	572	972	1,418	3,048	6,839		6,855		
Energy Other	349,117	447	308	524	764	1,641	3,683		3,692		
	997,409	24,921	880	1,496	2,182	4,689	34,168	0.034257	34,641	0.034731	-1.36%
SGS (0 - 20 kW)											
Customer - Single Phase	510,315	5,240,935	-	-	-	-	5,240,935		5,342,998		
Customer - Three Phase	92,160	1,572,250	-	-	-	-	1,572,250		1,602,662		
Energy Winter	189,318,599	5,559,530	166,979	283,978	576,854	2,871,206	9,458,547		9,564,754		
Energy Other	354,931,336	10,422,914	313,049	532,397	1,081,476	5,382,889	17,732,724		17,931,841		
	544,249,935	22,795,628	480,028	816,375	1,658,330	8,254,095	34,004,456	0.062479	34,442,256	0.063284	-1.27%
MGS-S											
Customer - Single Phase	41,045	1,041,722	-	-	-	-	1,041,722		1,061,834		
Customer - Three Phase	89,151	2,950,007	-	-	-	-	2,950,007		3,006,172		
Demand Winter	1,792,274	6,882,331	-	-	878,214	8,495,377	16,255,922		16,399,304		
Demand Other	3,898,000	11,109,300	-	-	1,910,020	18,476,519	31,495,839		31,729,719		
Energy Winter	586,984,020	-	517,720	880,476	1,409,936	-	2,808,132		2,808,132		
Energy Other	1,202,237,651	-	1,060,374	1,803,356	2,887,775	-	5,751,505		5,751,505		
KVAR	206,077	133,950	-	-	-	-	133,950		136,011		
	1,789,221,671	22,117,309	1,578,094	2,683,833	7,085,945	26,971,897	60,437,077	0.033778	60,892,676	0.034033	-0.75%
MGS-P											
Customer - Single Phase	405	29,136	-	-		-	29,136		29,691		
Customer - Three Phase	1,538	171,272	-	-	-	-	171,272		174,517		
Demand Winter	69,589	237,995	-	-	28,532	312,456	578,983		583,854		
Demand Other	146,588	301,971	-	-	60,101	658,180	1,020,252		1,026,116		
Energy Winter	23,709,450	-	20,912	35,564	58,491	-	114,967		114,967		
Energy Other	45,412,096	-	40,053	68,118	112,032	-	220,203		220,203		
KVAR	88,917	57,796	-	-	-	-	57,796		58,686		

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	2009 Core Rate Billing Units	Revenues July 1, 2010 Distribution	ELP Assessment	Conseration Assessment	Stranded Costs	Transmission	Total Delivery	7/1/2010 Avg kWh	Total Delivery Revenue 7/1/2009	7/1/2009 Avg kWh	Total Delivery Change
	69,121,546	798,170	60,965	103,682	259,156	970,636	2,192,609	0.031721	2,208,033	0.031944	-0.70%
IGS-S											
Customer Charge	2,486	238,184	-	-	-	-	238,184		247,158		
kW-On Winter	341,907	659,881	-	-	140,182	2,082,216	2,882,280		2,892,537		
kW-Sh Winter	336,732	367,038	-	-	138,060	-	505,098		511,833		
kW-On Other	770,324	1,286,441	-	-	315,833	4,691,274	6,293,548		6,316,658		
kW-Sh Other	768,763	837,951	-	-	315,193	-	1,153,144		1,168,519		
kWh-On Winter	43,701,780	-	38,545	65,553	134,864	-	238,961		238,961		
kWh-Sh Winter	34,303,420	-	30,256	51,455	105,860	-	187,571		187,571		
kWh-Off Winter	67,327,670	-	59,383	100,992	207,773	-	368,148		368,148		
kWh-On Other	98,225,460	-	86,635	147,338	303,124	-	537,097		537,097		
kWh-Sh Other	48,825,200	-	43,064	73,238	150,675	-	266,976		266,976		
kWh-Off Other	168,841,740	-	148,918	253,263	521,046	-	923,227		923,227		
KVAR	117,044	76,079	-	-	-	-	76,079		77,249		
	461,225,270	3,465,575	406,801	691,838	2,332,609	6,773,490	13,670,313	0.029639	13,735,934	0.029781	-0.48%
IGS-P											
Customer Charge	726	102,852	-	-	-	-	102,852		104,805		
kW-On Winter	111,696	416,626	-	-	25,690	615,444	1,057,760		1,065,579		
kW-Sh Winter	110,936	128,686	-	-	25,515	-	154,201		156,420		
kW-On Other	242,408	404,822	-	-	55,754	1,335,670	1,796,246		1,803,518		
kW-Sh Other	241,799	280,486	-	-	55,614	-	336,100		340,936		
kWh-On Winter	13,896,450	39,244	12,257	20,845	37,395	-	109,740		110,657		
kWh-Sh Winter	10,832,322	24,947	9,554	16,248	29,150	-	79,899		80,506		
kWh-Off Winter	22,400,858	19,623	19,758	33,601	60,281	-	133,263		133,912		
kWh-On Other	30,033,260	50,246	26,489	45,050	80,820	-	202,604		203,926		
kWh-Sh Other	15,246,772	24,105	13,448	22,870	41,029	-	101,452		102,092		
kWh-Off Other	50,491,286	16,965	44,533	75,737	135,872	-	273,107		274,016		
KVAR	53,277	34,630	-	-	-	-	34,630		35,163		
	142,900,948	1,543,232	126,039	214,351	547,119	1,951,114	4,381,856	0.030664	4,411,531	0.030871	-0.67%

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	2009 Core Rate Billing Units	Revenues July 1, 2010: Distribution	ELP Assessment	Conseration Assessment	Stranded Costs	Transmission	Total Delivery	7/1/2010 Avg kWh	Total Delivery Revenue 7/1/2009	7/1/2009 Avg kWh	Total Delivery Change
LGS-S											
Customer Charge	134	65,419	-	-	-	-	65,419		65,970		
kW-On Winter	46,384	129,874	-	-	16,698	285,260	431,832		434,615		
kW-Sh Winter	45,285	64,758	-	-	16,303	-	81,061		81,966		
kW-On Other	98,275	219,153	-	-	35,379	604,391	858,923		862,854		
kW-Sh Other	98,209	140,439	-	-	35,355	-	175,794		177,758		
kWh-On Winter	6,157,234	-	5,431	9,236	21,624	-	36,291		36,291		
kWh-Sh Winter	4,839,263	-	4,268	7,259	16,995	-	28,523		28,523		
kWh-Off Winter	10,673,535	-	9,414	16,010	37,485	-	62,910		62,910		
kWh-On Other	13,999,378	-	12,347	20,999	49,166	-	82,512		82,512		
kWh-Sh Other	6,888,940	-	6,076	10,333	24,194	-	40,603		40,603		
kWh-Off Other	26,850,344	-	23,682	40,276	94,298	-	158,256		158,256		
KVAR	18,926	12,302	-	-	-	-	12,302		12,491		
	69,408,694	631,945	61,218	104,113	347,498	889,650	2,034,425	0.029311	2,044,749	0.029460	-0.50%
LGS-P											
Customer Charge	589	309,702	-	-	-	-	309,702		315,574		
kW-On Winter	332,948	1,584,833	-	-	93,225	2,057,619	3,735,678		3,765,643		
kW-Sh Winter	328,236	439,836	-	-	91,906	-	531,742		538,307		
kW-On Other	698,386	1,347,885	-	-	195,548	4,316,024	5,859,457		5,880,408		
kW-Sh Other	696,269	835,522	-	-	194,955	-	1,030,478		1,051,366		
kWh-On Winter	44,944,306	-	39,641	67,416	134,249	-	241,306		241,306		
kWh-Sh Winter	34,877,582	-	30,762	52,316	104,179	-	187,258		187,258		
kWh-Off Winter	77,540,261	-	68,391	116,310	231,613	-	416,314		416,314		
kWh-On Other	99,290,729	-	87,574	148,936	296,581	-	533,092		533,092		
kWh-Sh Other	48,675,302	-	42,932	73,013	145,393	-	261,338		261,338		
kWh-Off Other	183,911,290	-	162,210	275,867	549,343	-	987,420		987,420		
KVAR	220,186	143,121	-	-	-	-	143,121		145,323		
	489,239,470	4,660,899	431,509	733,859	2,036,993	6,373,644	14,236,904	0.029100	14,323,348	0.029277	-0.60%
LGS-ST-TOU											
Customer Charge	624	319,057	-	-	-	-	319,057		325,110		
kW-On Winter	444,780	-	-	-	191,255	-	191,255		191,255		
kW-Sh Winter	454,081	-	-	-	195,255	-	195,255		195,255		
kW-On Other	850,147	-	-	-	365,563		365,563		365,563		
kW-Sh Other	831,904	-	-	-	357,719	-	357,719		357,719		
kWh-On Winter	55,993,527	-	-	2,800	56,833	-	59,633		59,633		
kWh-Sh Winter	48,313,588	-	-	2,416	49,038	-	51,454		51,454		
kWh-Off Winter	108,424,203	-	-	5,421	-	-	5,421		5,421		
kWh-On Other	113,553,616	-	-	5,678	-	-	5,678		5,678		
kWh-Sh Other	52,865,563	-	-	2,643	-	-	2,643		2,643		
kWh-Off Other	253,982,393	-	-	12,699	-	-	12,699		12,699		
KVAR	301,657	-	-	-	57,315	-	57,315		57,315		

Central Maine Power Company
Rate Summary
For Rates Effective July 1, 2010

	2009 Core Rate Billing Units	Revenues July 1, 2010 Distribution	ELP Assessment	Conservation Assessment	Stranded Costs	Transmission	Total Delivery	7/1/2010 Avg kWh	Total Delivery Revenue 7/1/2009	7/1/2009 Avg kWh	Total Delivery Change
	633,132,890	319,057	-	31,657	1,272,979	7,482,647	9,106,340	0.014383	7,891,315	0.012464	15.40%
LGS-T-TOU											
Customer Charge	208	148,597	-	-	-	-	148,597		151,416		
kW-On Winter	344,599	-	-	-	137,840	-	137,840		137,840		
kW-Sh Winter	346,792	-	-	-	138,717	-	138,717		138,717		
kW-On Other	979,003	-	-	-	391,601		391,601		391,601		
kW-Sh Other	843,070	-	-	-	337,228	-	337,228		337,228		
kWh-On Winter	25,573,777	-	-	1,279	30,944	-	32,223		32,223		
kWh-Sh Winter	24,714,260	-	-	1,236	29,904	-	31,140		31,140		
kWh-Off Winter	65,270,882	-	-	3,264	-	-	3,264		3,264		
kWh-On Other	74,234,154	-	-	3,712	-	-	3,712		3,712		
kWh-Sh Other	31,319,593	-	-	1,566	-	-	1,566		1,566		
kWh-Off Other	199,644,775	-	-	9,982	-	-	9,982		9,982		
KVAR	554,533	-	-	-	105,361	-	105,361		105,361		
	420,757,441	148,597	-	21,038	1,171,595	1,773,027	3,114,258	0.007402	2,910,682	0.006918	6.99%
AL	9,554,110	1,515,081	8,427	14,331	21,822	110,102	1,669,762	0.174769	1,698,501	0.177777	-1.69%
SL	27,380,923	5,473,885	24,150	41,071	62,675	315,538	5,917,319	0.216111	6,021,174	0.219904	-1.72%
Total	8,058,741,763	207,320,293	6,172,514	10,575,396	26,693,420	114,510,123	365,271,747	0.045326	367,795,598	0.045639	-0.69%

Docket No. 2010-051
March 12, 2010
Attachment 20

REDACTED

Central Maine Power Company
Effect of Targeted Programs and Contracts on T&D Sales and Revenue
March 11, 2010

January 25, 2010

Karen Geraghty
Administrative Director
Maine Public Utilities Commission
242 State Street, State House Station 18
Augusta, ME 04333-0018

RE: Docket No. 2007-355 Reorganization/Acquisition of Energy East by IBERDROLA. S. A.
Docket Nos. 2007-215 and 2008-111 Post Merger Alternative Rate Plan (ARP 2008) and Annual Price Change for Remaining Items from ARP 2000 - Revised

Dear Ms. Geraghty:

Pursuant to 1) Paragraph 40 of the January 10, 2008 Stipulation in Docket No. 2007-355 which was approved by Commission Order dated February 7, 2008, 2) Paragraph 38 of the June 6, 2008 Stipulation in Docket Nos. 2007-215 and 2008-111, which was approved by Commission Order dated July 1, 2008, and 3) Attachment 1 to the Stipulation in Docket No. 2008-294, which was approved by Commission Order dated March 31, 2009, CMP hereby files its quarterly report including service quality metrics and other miscellaneous items. The indicators below are reported on a year-to-date basis. Graphs of these metrics are contained in Attachment 1.

	Indicator	YTD October	YTD November	YTD December	2009 Target
1.	New Service Installation (on-time delivery; this target is effective April 1, 2009)	99%	99%	99%	85%
2.	Business Calls Answered (within 30 seconds)	82%	82%	82%	80%
3.	Meters Read	95%	95%	95%	94%
4.	Call Center Service Quality (on knowledgeability & customer satisfaction)	88%	89%	89%	85%
5.	MPUC Customer Complaints (per 1,000 customers)	2.26	2.43	2.47	1.00
6.	SAIFI (using IEEE 2.5 Beta approach)	1.67	1.88	2.04	2.10
7.	CAIDI (using IEEE 2.5 Beta approach)	1.95	2.10	1.87	2.18

Attachment 2 shows that for the fourth quarter, ten of CMP's distribution circuits exceeded the Circuit Average Interruption Frequency Index ("CAIFI") of 6.3. The O & M activities report, required by Paragraph 40(a), is provided in Attachment 3. There have not been any changes to CMP's O & M practices and no material change in technical operations staffing levels in the fourth quarter 2009.

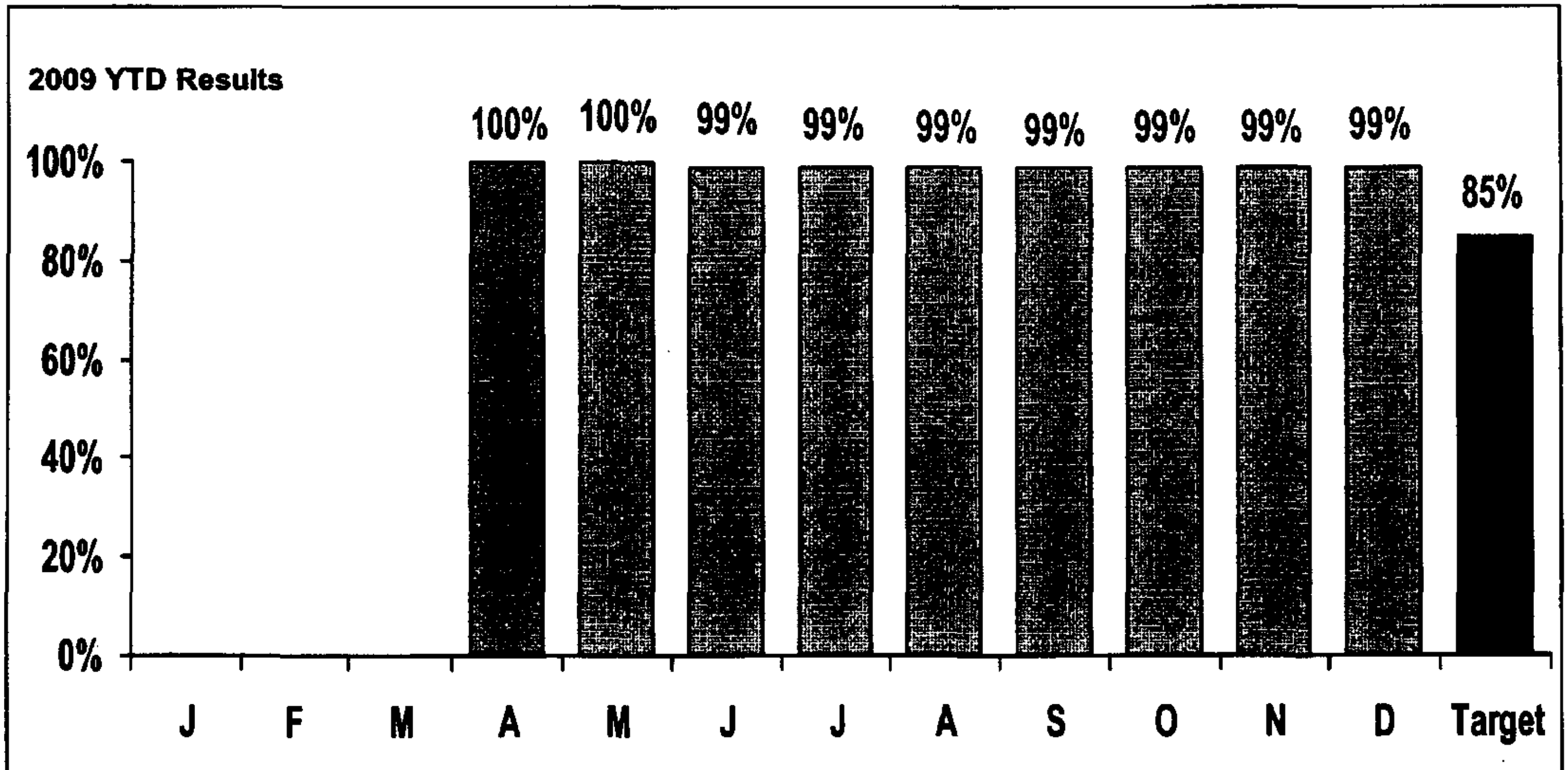
Please contact me if you have questions.

Sincerely,

Paul A. Dumais
Director of Regulatory Services

New Service Installation

Definition: Percent new services installed and energized within the time periods agreed to in Docket No. 2008-294.

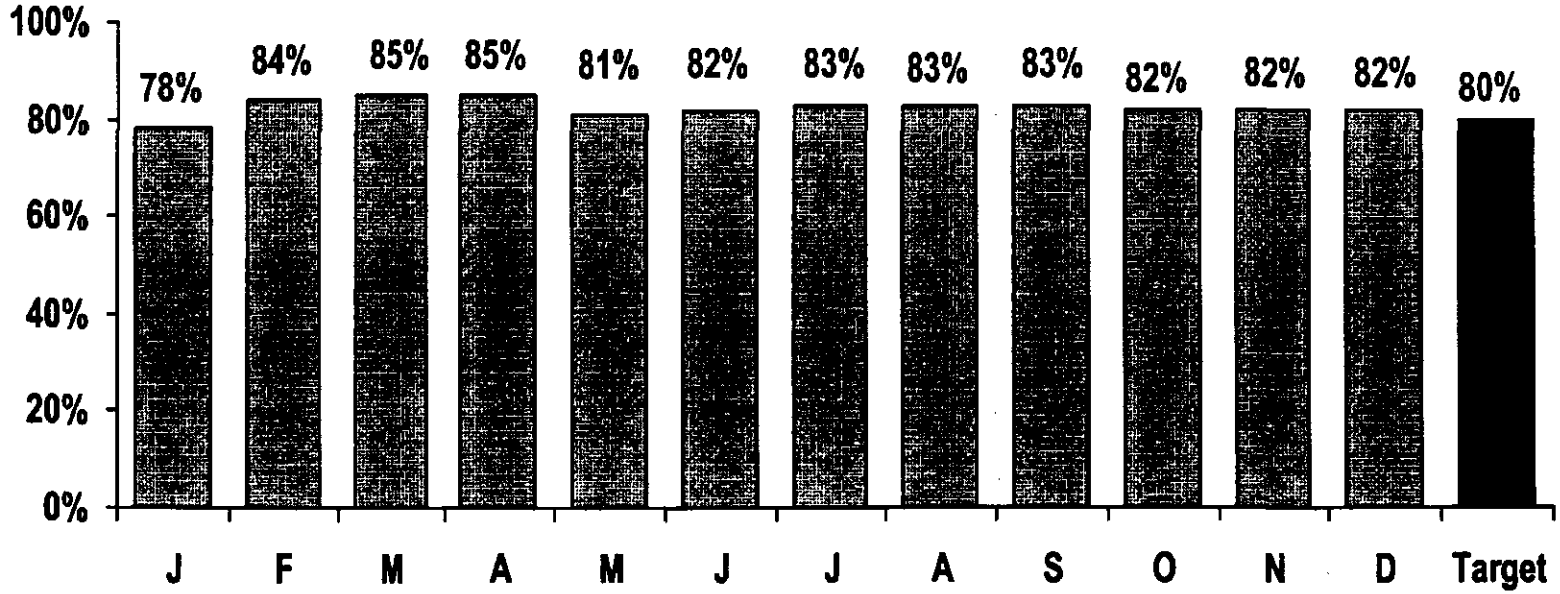


Source: M. Coates, Farmington-Field Customer Service

Business Calls Answered

Definition: Percent of calls answered within 30 seconds, CMP may exclude from this calculation the days that are excluded from the CAIDI and SAIFI calculations which are determined using the IEEE 2.5 Beta approach.

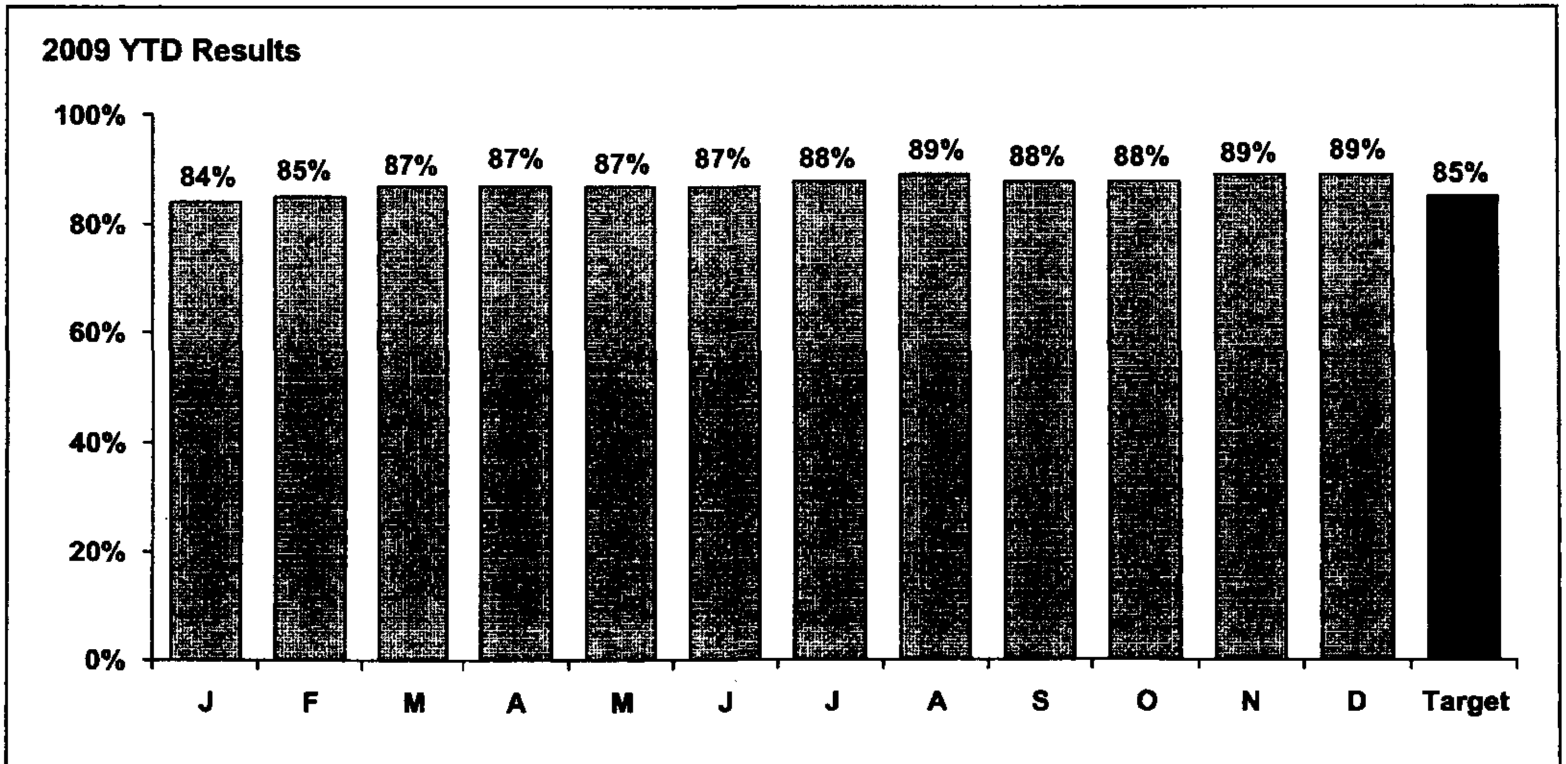
2009 YTD Results



Source: D. Houston, Customer Relations Center

Call Center Service Quality

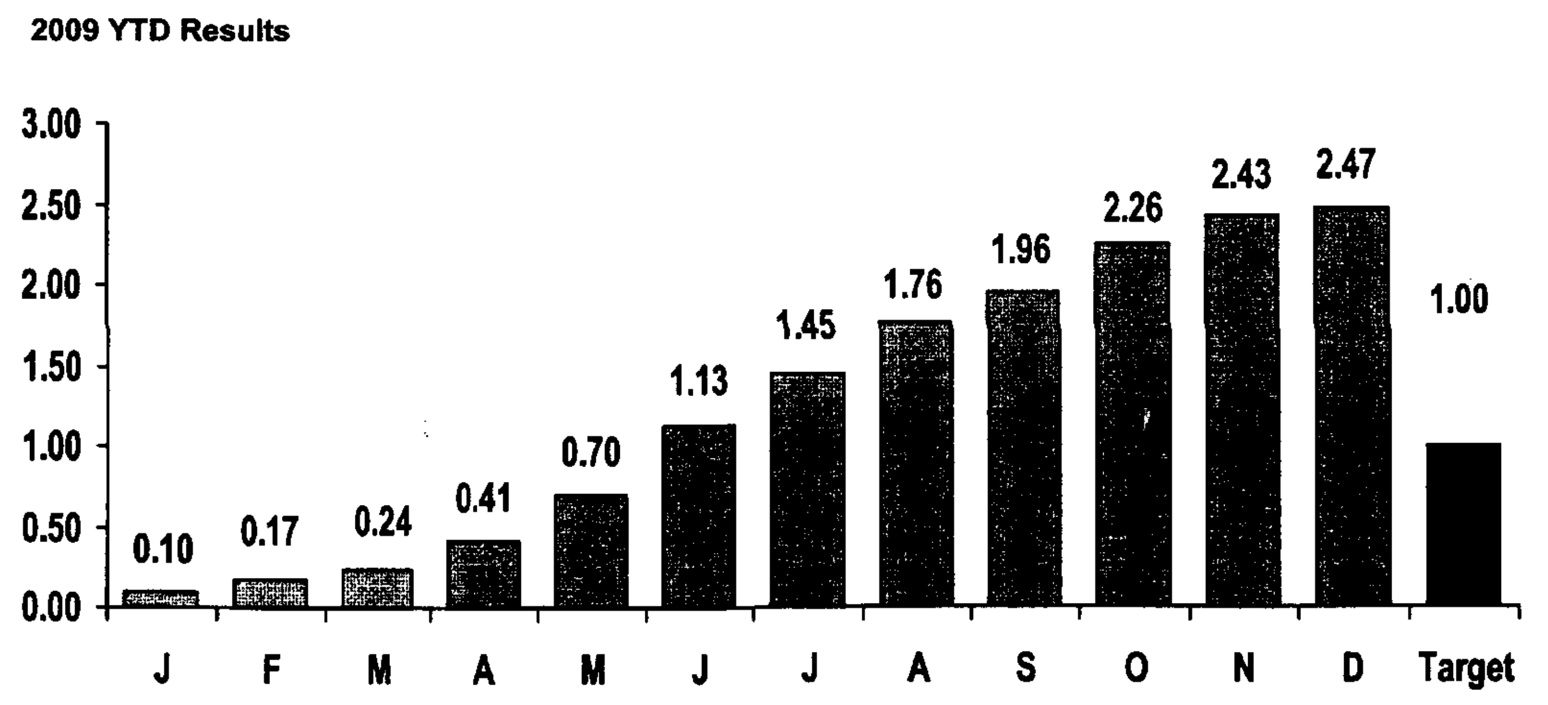
Definition: Percent favorable survey response on the Rep's knowledgeability and customer satisfaction with call.



Source: K. Duplessis, Marketing & Sales

MPUC Customer Complaints

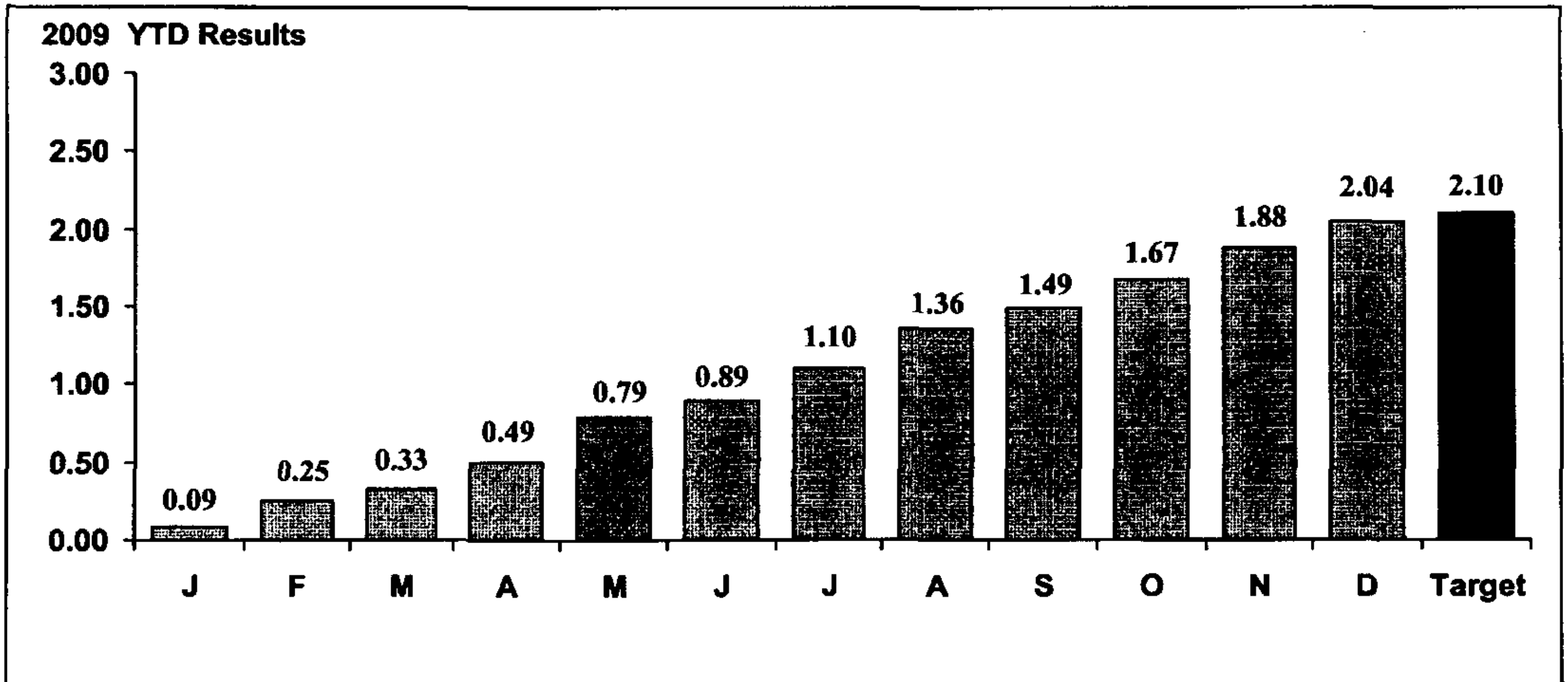
Definition: Complaints per 1,000 customers per year.



Source: A. Brooks, Customer Service Quality

System Average Interruption Frequency Index (SAIFI)

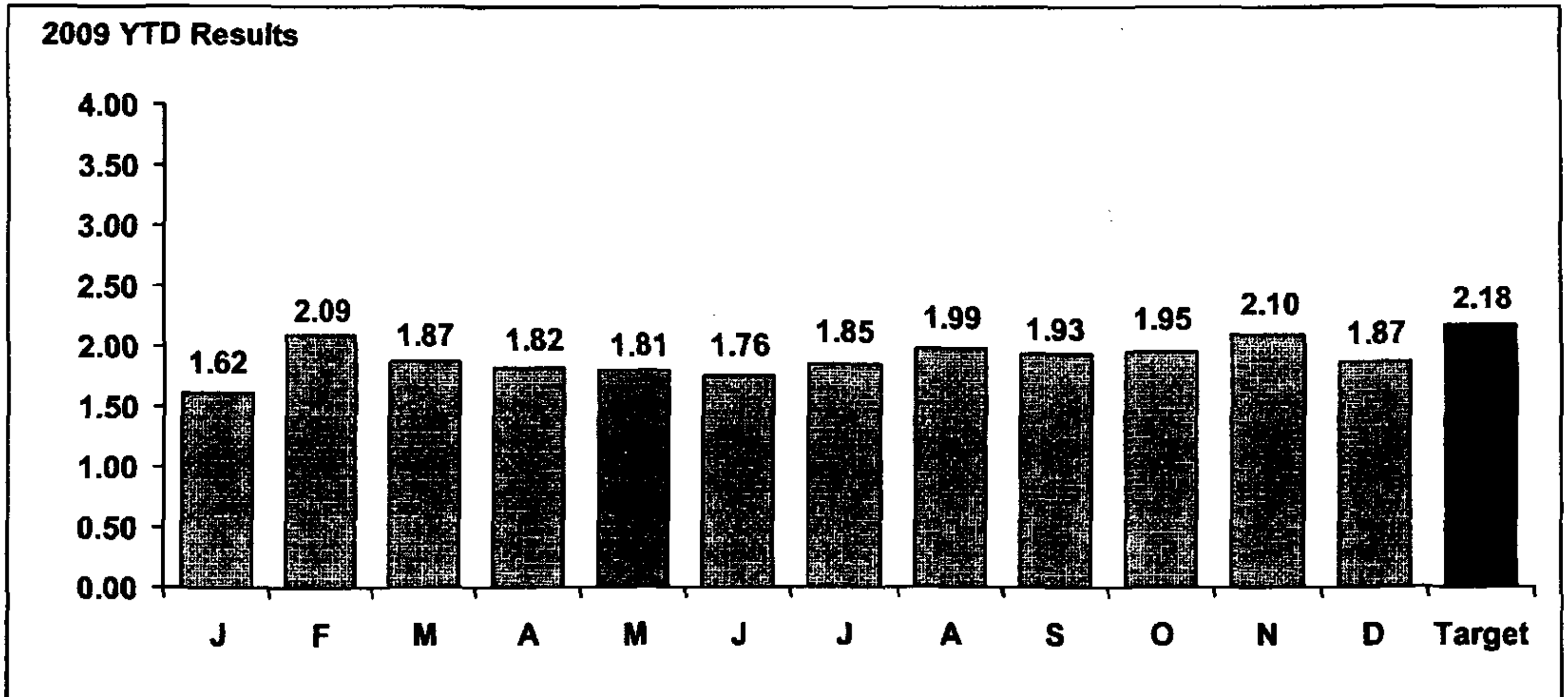
Definition: Average interruptions per customer. CMP excludes outages from the calculation of this indicator using the IEEE 2.5 Beta approach described in IEEE Standard 1366.



Source: R. Butler, Electric Maintenance Engineering

Customer Average Interruption Duration Index (CAIDI)

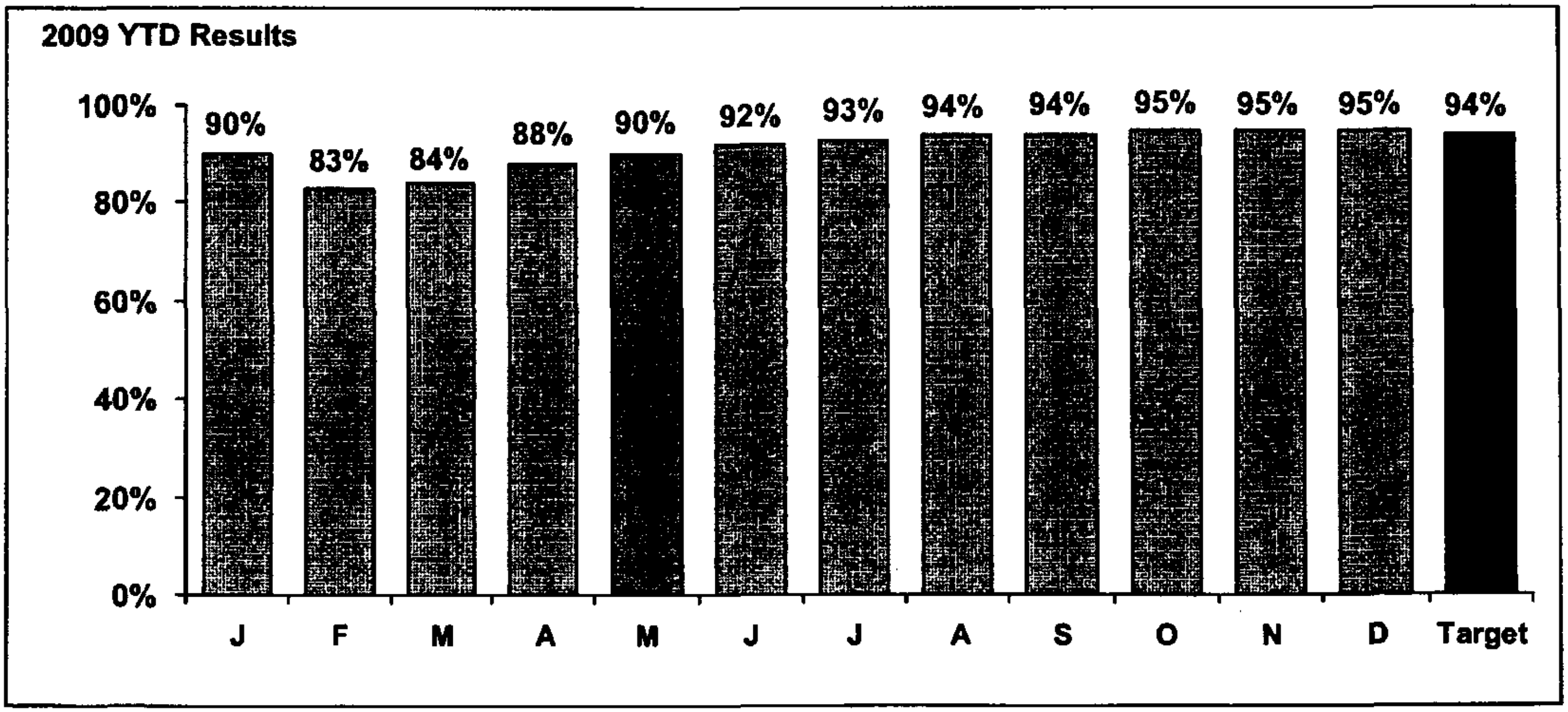
Definition: Average interruption duration for customers whose service is interrupted. CMP excludes outages from the calculation of this indicator using the IEEE 2.5 Beta approach described in IEEE Standard 1366.



Source: R. Butler, Electric Maintenance Engineering

Meters Read

Definition: Percentage of Meters Read. CMP will exclude from this calculation the estimated reads on days that are excluded from the CAIDI and SAIFI calculations which are determined using the IEEE 2.5 Beta approach.



Source: B. Benner, Regional Operations - Lewiston

[illegible]

	Total 2009 Hours	% of Hours for T&D
[illegible]		
(560) Operation - Supervision and Engineering	16,880.69	
(561) Load Dispatching - FERC 561.0	5,817.00	
(561.1) Load Dispatch - Reliability	9,987.50	
(561.2) Load Dispatch - Monitor and Operate Trans System	44,054.50	
(561.5) Reliability, Planning and Stndards Development	859.50	
(561.6) Transmission Service Studies	-	
(561.7) Generation Interconnection Studies	1,172.40	
(562) Station Expenses	14,392.65	
(563) Overhead Lines Expenses	3,459.50	
(564) Underground Line Expenses	27.50	
(566) Miscellaneous Transmission Expenses	26,728.09	
[illegible]	123,379.33	
[illegible]		
(568) Maintenance - Supervision and Engineering	4,551.60	
(569) Maintenance of Structures	3,029.75	
(570) Maintenance of Station Equipment	39,194.25	
(571) Maintenance of Overhead Lines	5,053.28	
(572) Maintenance of Overhead Lines	2,420.50	
(573) Maintenance of Miscellaneous Transmission Plant	72.24	
[illegible]	54,321.62	
[illegible]	177,700.95	17.8%
[illegible]		
(580) Operation - Supervision Engineering	17,912.81	
(5801) Substation - Operation and Supervision	-	
(581) Load Dispatching	37.60	
(582) Station Expenses	22,474.60	
(583) Overhead Line Expenses	70,411.15	
(584) Underground Line Expenses	4,396.69	
(585) Street Lighting and Signal System Expenses	5,372.50	
(586) Meter Expenses	148,053.75	
(587) Customer Installations Expense	18,585.75	
(588) Miscellaneous Expenses	224,529.96	
(589) Rents	-	
[illegible]	511,774.81	
[illegible]		
(590) Maintenance Supervision Engineering	35,197.03	
(591) Maintenance of Structures	1,654.25	
(592) Maintenance of Station Equipment	22,195.25	
(593) Maintenance of Overhead Lines	203,403.89	
(594) Maintenance of Underground Lines	13,871.46	
(595) Maintenance of Line Transformers	2,283.29	
(596) Maintenance of Street Lighting and Signal Systems	10,531.11	
(597) Maintenance of Meters	20,098.75	
(598) Maintenance of Miscellaneous Distribution Plant	2,210.76	
[illegible]	311,445.78	82.2%
[illegible]	823,220.59	
[illegible]	1,000,921.54	

Circuits with FAIFI Greater than 6.3

ARP Reportable Outages

01/01/09 to 12/31/09

Dst	Dist	Ckt	Rank	Customer Hours	Impacted	CAIDI	SAIFI	FAIFI
014	BRUNSWICK	204D6	6	39172.3	22246	1.7609	0.0368	7.5385
014	BRUNSWICK	217D3	8	40304.8	26074	1.5458	0.0432	6.9401
021	FAIRFIELD	237D1	5	2204.30	2528	0.8720	0.0042	8.0767
024	FARMINGTON	875D1	4	20231.3	15288	1.3233	0.0253	8.9039
024	FARMINGTON	881D1	9	750.800	632	1.1880	0.0010	6.7234
046	ALFRED	603D2	10	23102.4	12025	1.9212	0.0199	6.6290
046	ALFRED	691D1	3	2694.27	2126	1.2673	0.0035	9.7972
051	LEWISTON	220D1	1	7838.28	3734	2.0992	0.0062	18.3039
054	BRIDGTON	463D1	7	21004.3	7855	2.6740	0.0130	7.0575
054	BRIDGTON	692D1	2	2388.27	3185	0.7498	0.0053	10.1433

Docket No. 2010-051
March 12, 2010
Attachment 22

REDACTED
Central Maine Power Company
2009 Annual Reliability Improvement Report

Central Maine Power

SAIDI, CAIDI, SAIFI, and Meters Read with and without Excluded Events
2009 Monthly Year To Date

	With Excluded Events				Without Excluded Events			
	SAIDI	CAIDI	SAIFI	Meters Read	SAIDI	CAIDI	SAIFI	Meters Read
January	0.15	1.62	0.09	90%	0.15	1.62	0.09	90%
February	4.93	8.85	0.56	81%	0.52	2.09	0.25	83%
March	5.04	7.81	0.64	83%	0.63	1.87	0.33	84%
April	5.35	6.53	0.82	87%	0.90	1.82	0.49	88%
May	5.73	5.59	1.02	89%	1.27	1.81	0.70	90%
June	6.02	4.96	1.21	91%	1.57	1.76	0.89	92%
July	6.56	4.59	1.43	92%	2.03	1.85	1.10	93%
August	7.24	4.28	1.69	93%	2.71	1.99	1.36	94%
September	7.41	4.07	1.82	94%	2.88	1.93	1.49	94%
October	7.78	3.89	2.00	94%	3.25	1.95	1.67	95%
November	*8.47*	*3.84*	*2.21*	*95%*	*3.94*	*2.10*	*1.88*	*95%*
December	8.92	3.62	2.46	95%	3.80	1.87	2.04	95%

Central Maine Power
Excluded Events
For the Year 2009

Event	Dates	Customers Impacted	Customer Hours	Number Outages
1	2/22/2009	37,922	566,651	100
2	2/23/2009	167,265	2,241,485	970
3	11/28/2009	51,453	274,315	408
	3	256,640	3,082,451	1,478

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
EQUIPMENT	Cable Failure	10620	32	13956.2
	Connector or Splice Failure	6855	17	12049.8
	Crossarm Failure	5974	6	8525.9
	Cutout Broken, Burned, etc.	15908	121	22124.1
	Guy/Anchor Failure	33	1	23.1
	Hot Line Clamp-(Specify)	263	4	738.2
	Hot Line Clamp-Burned Conducto	4435	17	3607.1
	Insulator Broken or Defective	58195	173	96666.4
	Lightning Arrestor Failure	18190	104	20963.7
	Other Equipment Failure	44727	88	72757.1
	Pole Failure	9866	24	28101.6
	Recloser Failure	5657	6	16933.7
	Terminator Failure	42	3	182.0
	Tie Wire Failure	8326	25	14907.3
	Transformer Failure	21860	110	75089.8
	Total	210951	731	386626.1
GENERAL	Fire	11801	23	15460.7
	Overload	6160	25	5663.9
	Planned	17189	34	28991.4
	Unknown	197882	2632	299075.8
	Total	233032	2714	349191.9
HUMAN ERROR	Auto Accident	117420	296	294906.5
	Cable Dig In	393	4	528.0
	CMP Cont. Error	15	1	17.0
	CMP Crew Error	8040	5	854.2
	CMP Tree Cont. Error	119	1	107.1
	Crane Contact	40	2	36.4
	Customer Error	522	11	842.0
	Other Human Error	14562	21	17504.0
	Road Cont. Error	1889	4	393.2
	Snowplow Damage	1965	6	6160.3
	Telephone Crew Error	97	1	111.5
	Tree Cont. Error	9358	45	9962.3
	Total	154420	397	331422.6

CATEGORY	*CAUSE*	*Customers Interrupted*	*Number of Interruptions*	*Customer Hours*
NATURAL	Animal or Bird Contact	97916	2290	121386.6
	Ice or Snow Broken Conductors	3294	3	5045.4
	Lightning	20022	141	36765.4
	Other Natural Cause	2033	6	2561.5
	Storm	53672	385	283821.1
	Tree Condition	381875	2813	735086.1
	Wind or Snow Crossed Conductor	2390	38	8185.6
	Total	561202	5676	1192851.8
SUPPLY	Station Outage	11711	5	17132.9
	Transmission	60883	15	87974.8
	Total	72594	20	105107.7
	Corporate Totals	***1232199***	***9538***	***2365200.1***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Alfred	EQUIPMENT	Cable Failure	74	2	334.2
		Connector or Splice Failure	33	1	66.5
		Cutout Broken, Burned, etc.	3822	25	5429.7
		Hot Line Clamp-(Specify)	125	1	487.5
		Hot Line Clamp-Burned Conducto	344	2	459.1
		Insulator Broken or Defective	3658	54	7455.2
		Lightning Arrestor Failure	4640	19	5462.2
		Other Equipment Failure	9246	16	9365.0
		Pole Failure	238	5	1296.0
		Recloser Failure	236	2	370.7
		Terminator Failure	4	1	5.0
		Tie Wire Failure	3015	5	5629.0
		Transformer Failure	1324	15	2910.4
		Total	26759	148	39270.6
Alfred	GENERAL	Fire	36	1	17.4
		Overload	1062	10	1062.7
		Planned	1209	3	247.0
		Unknown	31646	377	54186.3
		Total	33953	391	55513.5
Alfred	HUMAN ERROR	Auto Accident	13646	33	29459.3
		Customer Error	43	1	91.0
		Other Human Error	6573	11	3133.4
		Snowplow Damage	622	1	3918.6
		Tree Cont. Error	2438	10	2692.7
		Total	23322	56	39295.0
Alfred	NATURAL	Animal or Bird Contact	21386	519	33002.9
		Ice or Snow Broken Conductors	251	1	681.9
		Lightning	69	7	188.4
		Other Natural Cause	1859	1	2385.7
		Tree Condition	78135	421	142507.0
		Wind or Snow Crossed Conductor	635	1	105.8
		Total	102335	950	178871.8
Alfred	SUPPLY	Station Outage	2218	1	4022.7
		Transmission	3276	1	3494.4
		Total	5494	2	7517.1

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
	Alfred District Total	**191863**	**1547**	**320468.1**

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Augusta	EQUIPMENT	Cable Failure	1046	1	882.1
		Cutout Broken, Burned, etc.	385	4	665.4
		Insulator Broken or Defective	3541	5	3527.9
		Lightning Arrestor Failure	452	9	1188.1
		Other Equipment Failure	2963	7	5759.6
		Pole Failure	128	1	657.1
		Tie Wire Failure	2621	11	6292.0
		Transformer Failure	6113	11	47198.8
		Total	17249	49	66170.9
Augusta	GENERAL	Fire	333	3	434.6
		Overload	290	1	910.0
		Planned	94	3	138.6
		Unknown	25339	322	41222.4
		Total	26056	329	42705.6
Augusta	HUMAN ERROR	Auto Accident	4581	13	7961.7
		Cable Dig In	33	1	57.8
		CMP Crew Error	1329	1	132.9
		Customer Error	11	1	46.4
		Other Human Error	22	1	82.1
		Tree Cont. Error	56	3	560.3
		Total	6032	20	8841.2
Augusta	NATURAL	Animal or Bird Contact	6571	220	7668.4
		Lightning	683	14	3367.5
		Other Natural Cause	76	2	92.9
		Storm	4025	27	33314.5
		Tree Condition	24947	269	57232.7
		Wind or Snow Crossed Conductor	18	1	29.4
		Total	36320	533	101705.4
Augusta	SUPPLY	Station Outage	0	0	0.0
		Transmission	13815	3	11022.8
		Total	13815	3	11022.8
		Augusta District Total	**99472**	**934**	**230445.9**

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Bridgton	EQUIPMENT	Cutout Broken, Burned, etc.	1082	9	1331.5
		Insulator Broken or Defective	1243	14	1857.5
		Lightning Arrestor Failure	3934	8	6922.7
		Other Equipment Failure	15652	28	39990.4
		Recloser Failure	615	1	2501.0
		Terminator Failure	7	1	35.9
		Tie Wire Failure	35	1	239.7
		Transformer Failure	212	4	457.2
		Total	22780	66	53336.0
Bridgton	GENERAL	Fire	1196	3	1586.3
		Overload	1777	1	473.9
		Planned	386	5	160.1
		Unknown	12340	359	19636.0
		Total	15699	368	21856.3
Bridgton	HUMAN ERROR	Auto Accident	19533	27	33167.6
		CMP Crew Error	191	1	19.1
		Other Human Error	1	1	0.7
		Road Cont. Error	14	1	15.9
		Tree Cont. Error	1184	7	1187.6
		Total	20923	37	34390.9
Bridgton	NATURAL	Animal or Bird Contact	3572	191	5269.1
		Ice or Snow Broken Conductors	29	1	43.5
		Lightning	4898	28	6466.7
		Storm	7512	72	92765.4
		Tree Condition	48418	408	120326.9
		Wind or Snow Crossed Conductor	283	12	5008.6
		Total	64712	712	229880.2
Bridgton	SUPPLY	Transmission	5928	1	1580.8
		Total	5928	1	1580.8
		Bridgton District Total	***130042***	***1184***	***341044.2***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Brunswick	EQUIPMENT	Cable Failure	7252	10	7938.3
		Connector or Splice Failure	1362	3	892.2
		Crossarm Failure	1310	1	436.7
		Cutout Broken, Burned, etc.	1173	18	2196.6
		Hot Line Clamp-(Specify)	1	1	1.5
		Hot Line Clamp-Burned Conducto	76	2	195.9
		Insulator Broken or Defective	7791	18	12601.1
		Lightning Arrestor Failure	1415	14	2238.3
		Other Equipment Failure	4823	2	2624.8
		Pole Failure	372	8	1312.3
		Tie Wire Failure	936	1	1201.2
		Transformer Failure	4992	17	5819.9
		Total	31503	95	37459.0
Brunswick	GENERAL	Fire	7654	4	6655.0
		Overload	487	3	481.8
		Planned	4847	5	14640.7
		Unknown	38973	463	67400.1
		Total	51961	475	89177.6
Brunswick	HUMAN ERROR	Auto Accident	16803	59	55852.8
		CMP Crew Error	2666	1	355.5
		Customer Error	187	2	284.4
		Snowplow Damage	884	1	1473.3
		Tree Cont. Error	3426	7	2697.3
		Total	23966	70	60663.3
Brunswick	NATURAL	Animal or Bird Contact	11461	382	15466.1
		Lightning	754	17	2282.6
		Storm	12504	57	53203.0
		Tree Condition	39433	290	54406.1
		Total	64152	746	125357.8
Brunswick	SUPPLY	Station Outage	1639	1	1311.2
		Transmission	5063	1	16639.7
		Total	6702	2	17950.9
		Brunswick District Total	***178284***	***1388***	***330608.5***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Dover	EQUIPMENT	Connector or Splice Failure	11	1	35.2
		Cutout Broken, Burned, etc.	169	2	281.9
		Hot Line Clamp-(Specify)	137	2	249.2
		Insulator Broken or Defective	1728	7	3752.7
		Lightning Arrestor Failure	2491	12	1322.2
		Other Equipment Failure	134	1	129.5
		Recloser Failure	115	1	130.3
		Terminator Failure	31	1	141.0
		Transformer Failure	62	4	100.0
		Total	4878	31	6142.1
Dover	GENERAL	Fire	20	1	22.7
		Overload	232	1	726.9
		Planned	3489	7	4073.0
		Unknown	4195	83	6428.5
		Total	7936	92	11251.1
Dover	HUMAN ERROR	Auto Accident	825	10	3236.0
		Snowplow Damage	409	2	741.8
		Tree Cont. Error	153	1	165.8
		Total	1387	13	4143.6
Dover	NATURAL	Animal or Bird Contact	4629	46	5116.2
		Lightning	3478	1	4753.3
		Other Natural Cause	23	1	30.3
		Tree Condition	37627	254	91900.8
		Wind or Snow Crossed Conductor	69	4	327.7
		Total	45826	306	102128.3
		Dover District Total	***60027***	***442***	***123665.1***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Fairfield	EQUIPMENT	Cutout Broken, Burned, etc.	123	3	312.4
		Hot Line Clamp-Burned Conducto	149	1	37.3
		Insulator Broken or Defective	7046	3	10096.5
		Lightning Arrestor Failure	15	2	49.5
		Other Equipment Failure	6	1	14.0
		Transformer Failure	520	7	5141.7
		Total	7859	17	15651.4
Fairfield	GENERAL	Planned	49	1	219.7
		Unknown	15580	130	21291.6
		Total	15629	131	21511.3
Fairfield	HUMAN ERROR	Auto Accident	6477	22	9133.0
		Tree Cont. Error	1211	3	776.0
		Total	7688	25	9909.1
Fairfield	NATURAL	Animal or Bird Contact	4838	131	5409.5
		Lightning	2	1	4.8
		Storm	219	8	459.8
		Tree Condition	18100	106	37744.5
		Total	23159	246	43618.5
		Fairfield District Total	***54335***	***419***	***90690.3***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Farmington	EQUIPMENT	Cable Failure	31	4	223.8
		Connector or Splice Failure	5	1	9.9
		Cutout Broken, Burned, etc.	32	4	59.4
		Hot Line Clamp-Burned Conducto	673	1	684.2
		Insulator Broken or Defective	8241	16	8235.9
		Lightning Arrestor Failure	142	5	282.2
		Other Equipment Failure	2690	5	5651.0
		Pole Failure	7484	3	18720.2
		Recloser Failure	3554	1	12813.6
		Tie Wire Failure	252	1	567.0
		Transformer Failure	659	10	2415.3
		Total	23763	51	49662.6
Farmington	GENERAL	Fire	1139	2	2314.1
		Overload	443	2	254.5
		Planned	4035	3	6857.6
		Unknown	20229	196	30957.5
		Total	25846	203	40383.6
Farmington	HUMAN ERROR	Auto Accident	5767	19	13166.5
		CMP Crew Error	1541	1	308.2
		Crane Contact	3	1	3.1
		Customer Error	140	2	152.9
		Other Human Error	3863	2	4379.7
		Snowplow Damage	14	1	3.7
		Total	11328	26	18014.2
Farmington	NATURAL	Animal or Bird Contact	1719	80	2204.3
		Ice or Snow Broken Conductors	3014	1	4320.1
		Lightning	7157	23	8365.9
		Other Natural Cause	71	1	33.1
		Storm	1059	13	4823.7
		Tree Condition	31703	309	56917.0
		Wind or Snow Crossed Conductor	1017	8	1782.8
		Total	45740	435	78446.9
Farmington	SUPPLY	Station Outage	4670	2	5324.8
		Transmission	18868	4	20079.5
		Total	23538	6	25404.4

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
	Farmington District Total	**130215**	**721**	**211911.6**

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Lewiston	EQUIPMENT	Cable Failure	775	3	1184.2
		Connector or Splice Failure	302	4	601.6
		Crossarm Failure	156	1	332.8
		Cutout Broken, Burned, etc.	1224	21	1776.0
		Hot Line Clamp-Burned Conducto	2725	4	1591.9
		Insulator Broken or Defective	16315	18	34154.6
		Lightning Arrestor Failure	186	12	269.0
		Other Equipment Failure	2162	9	1530.6
		Pole Failure	46	1	114.2
		Recloser Failure	1137	1	1118.0
		Tie Wire Failure	1389	4	857.3
		Transformer Failure	1716	10	3800.8
		Total	28133	88	47331.1
Lewiston	GENERAL	Fire	505	5	1574.4
		Overload	406	1	521.0
		Planned	62	1	16.5
		Unknown	10056	223	11969.4
		Total	11029	230	14081.3
Lewiston	HUMAN ERROR	Auto Accident	3344	22	9412.9
		Cable Dig In	68	1	182.5
		CMP Cont. Error	15	1	17.0
		Customer Error	33	2	21.9
		Road Cont. Error	1791	2	236.0
		Snowplow Damage	0	0	0.0
		Telephone Crew Error	97	1	111.5
		Tree Cont. Error	6	2	5.3
		Total	5354	31	9987.1
Lewiston	NATURAL	Animal or Bird Contact	6903	193	6820.6
		Lightning	1146	34	7008.6
		Storm	3284	7	28142.7
		Tree Condition	20628	172	33528.5
		Wind or Snow Crossed Conductor	213	5	532.8
		Total	32174	411	76033.1

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE		Customers Interrupted	Number of Interruptions	Customer Hours
Lewiston	SUPPLY	Station Outage		3184	1	6474.1
		Transmission		5916	1	7690.8
			Total	9100	2	14164.9
		Lewiston District Total		***85790***	***762***	***161597.6***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE		Customers Interrupted	Number of Interruptions	Customer Hours
Portland	EQUIPMENT	Cable Failure		1442	12	3393.6
		Connector or Splice Failure		4440	2	9682.9
		Crossarm Failure		113	2	160.9
		Cutout Broken, Burned, etc.		5259	21	8505.2
		Guy/Anchor Failure		33	1	23.1
		Hot Line Clamp-Burned Conducto		353	5	502.3
		Insulator Broken or Defective		4846	23	7523.7
		Lightning Arrestor Failure		4196	11	1539.0
		Other Equipment Failure		5093	10	4353.2
		Tie Wire Failure		72	1	108.0
		Transformer Failure		1629	16	2964.2
			Total	27476	104	38756.0
Portland	GENERAL	Fire		512	1	2449.1
		Overload		1429	5	1192.9
		Unknown		20701	213	21717.1
			Total	22642	219	25359.1
Portland	HUMAN ERROR	Auto Accident		18119	38	23300.5
		Cable Dig In		292	2	287.8
		CMP Tree Cont. Error		119	1	107.1
		Crane Contact		37	1	33.3
		Other Human Error		61	2	53.0
		Tree Cont. Error		84	2	84.9
			Total	18712	46	23866.7
Portland	NATURAL	Animal or Bird Contact		31059	314	32912.3
		Lightning		699	5	839.9
		Storm		11528	39	23136.2
		Tree Condition		24337	118	27255.6
			Total	67623	476	84143.9
Portland	SUPPLY	Transmission		1541	1	4164.4
			Total	1541	1	4164.4
		Portland District Total		***137994***	***846***	***176290.1***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Rockland	EQUIPMENT	Connector or Splice Failure	281	3	248.1
		Crossarm Failure	4395	2	7595.5
		Cutout Broken, Burned, etc.	367	9	621.8
		Hot Line Clamp-Burned Conducto	115	2	136.4
		Insulator Broken or Defective	2245	8	4353.1
		Lightning Arrestor Failure	603	8	1164.2
		Other Equipment Failure	1893	7	3195.7
		Pole Failure	1548	4	5524.0
		Tie Wire Failure	6	1	13.1
		Transformer Failure	3653	15	4183.6
		Total	*15106*	*59*	*27035.4*
Rockland	GENERAL	Fire	154	1	46.2
		Planned	925	4	418.9
		Unknown	15970	227	19264.8
		Total	17049	232	19729.9
Rockland	HUMAN ERROR	Auto Accident	23226	36	91642.1
		Customer Error	96	2	232.1
		Road Cont. Error	84	1	141.4
		Snowplow Damage	36	1	22.8
		Tree Cont. Error	800	10	1792.3
		Total	24242	50	93830.7
Rockland	NATURAL	Animal or Bird Contact	4197	160	4902.6
		Lightning	573	6	1800.1
		Other Natural Cause	4	1	19.5
		Storm	8518	103	30670.7
		Tree Condition	36331	266	58180.3
		Wind or Snow Crossed Conductor	138	6	341.9
		Total	49761	542	95915.2
Rockland	SUPPLY	Transmission	5116	2	23075.7
		Total	5116	2	23075.7
		Rockland District Total	***111274***	***885***	***259586.9***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

	CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
Skowhega	EQUIPMENT	Connector or Splice Failure	421	2	513.3
		Cutout Broken, Burned, etc.	2272	5	944.2
		Insulator Broken or Defective	1541	7	3108.2
		Lightning Arrestor Failure	116	4	526.3
		Other Equipment Failure	65	2	143.2
		Pole Failure	50	2	477.8
		Tie Wire Failure	0	0	0.0
		Transformer Failure	980	1	98.0
		Total	5445	23	5811.0
Skowhega	GENERAL	Fire	252	2	361.1
		Overload	34	1	40.2
		Planned	*2093*	*2*	*2219.3*
		Unknown	2853	39	5002.1
		Total	5232	44	7622.6
Skowhega	HUMAN ERROR	Auto Accident	5099	17	18574.0
		CMP Crew Error	2313	1	38.6
		Customer Error	12	1	13.4
		Other Human Error	4042	4	9854.9
		Total	11466	23	28480.9
Skowhega	NATURAL	Animal or Bird Contact	1581	54	2614.8
		Lightning	563	5	1687.6
		Storm	5023	59	17305.2
		Tree Condition	22216	200	55086.7
		Wind or Snow Crossed Conductor	17	1	56.4
		Total	29400	319	76750.6
Skowhega	SUPPLY	Transmission	1360	1	226.7
		Total	*1360*	*1*	*226.7*
		Skowhegan District Total	***52903***	***410***	***118891.8***

Central Maine Power

2009 Interruption Summary by Cause

(Exclusions Removed)

CATEGORY	CAUSE	Customers Interrupted	Number of Interruptions	Customer Hours
	CompanyTotal	**1232199**	**9538**	**2365200.1**

Central Maine Power Company
Summary of Distribution Plant Ages
2009

Type	Unit of Measure	Count/Length	Average Age
Poles	Each	643,406	29.1
Conductor	Feet	281,244,714	36.8
Transformers	Each	256,088	20.9
Regulators	Each	1,434	15.4
Capacitors	Each	502	20.1
Reclosers	Each	1,305	2.7

Central Maine Power Company
Number of Poles and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1900	13	109.5	1,423.5		
1901	4	108.5	434.0		
1902	3	107.5	322.5		
1903	3	106.5	319.5		
1905	3	104.5	313.5		
1907	1	102.5	102.5		
1908	4	101.5	406.0		
1909	1	100.5	100.5		
1910	1	99.5	99.5		
1911	12	98.5	1,182.0		
1912	1	97.5	97.5		
1914	3	95.5	286.5		
1915	2	94.5	189.0		
1917	7	92.5	647.5		
1918	4	91.5	366.0		
1919	12	90.5	1,086.0		
1920	37	89.5	3,311.5		
1921	12	88.5	1,062.0		
1922	18	87.5	1,575.0		
1923	15	86.5	1,297.5		
1924	19	85.5	1,624.5		
1925	49	84.5	4,140.5		
1926	81	83.5	6,763.5		
1927	121	82.5	9,982.5		
1928	172	81.5	14,018.0		
1929	271	80.5	21,815.5		
1930	481	79.5	38,239.5		
1931	389	78.5	30,536.5		
1932	144	77.5	11,160.0		
1933	169	76.5	12,928.5		
1934	188	75.5	14,194.0		
1935	317	74.5	23,616.5		
1936	301	73.5	22,123.5		
1937	506	72.5	36,685.0		
1938	562	71.5	40,183.0		
1939	630	70.5	44,415.0		
1940	832	69.5	57,824.0		
1941	967	68.5	66,239.5		
1942	413	67.5	27,877.5		
1943	411	66.5	27,331.5		
1944	374	65.5	24,497.0		
1945	949	64.5	61,210.5		
1946	1,509	63.5	95,821.5		

Central Maine Power Company
Number of Poles and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1947	3,967	62.5	247,937.5		
1948	4,590	61.5	282,285.0		
1949	3,398	60.5	205,579.0		
1950	4,198	59.5	249,781.0		
1951	5,426	58.5	317,421.0		
1952	6,891	57.5	396,232.5		
1953	7,458	56.5	421,377.0		
1954	8,444	55.5	468,642.0		
1955	8,996	54.5	490,282.0		
1956	9,876	53.5	528,366.0		
1957	8,251	52.5	433,177.5		
1958	8,631	51.5	444,496.5		
1959	7,933	50.5	400,616.5		
1960	6,788	49.5	336,006.0		
1961	8,023	48.5	389,115.5		
1962	8,054	47.5	382,565.0		
1963	8,877	46.5	412,780.5		
1964	9,321	45.5	424,105.5		
1965	9,403	44.5	418,433.5		
1966	8,301	43.5	361,093.5		
1967	6,773	42.5	287,852.5		
1968	7,273	41.5	301,829.5		
1969	7,274	40.5	294,597.0		
1970	8,431	39.5	333,024.5		
1971	9,938	38.5	382,613.0		
1972	10,440	37.5	391,500.0		
1973	11,657	36.5	425,480.5		
1974	12,719	35.5	451,524.5		
1975	10,009	34.5	345,310.5		
1976	10,794	33.5	361,599.0		
1977	10,204	32.5	331,630.0		
1978	12,744	31.5	401,436.0		
1979	12,561	30.5	383,110.5		
1980	12,332	29.5	363,794.0		
1981	10,170	28.5	289,845.0		
1982	9,439	27.5	259,572.5		
1983	11,036	26.5	292,454.0		
1984	11,378	25.5	290,139.0		
1985	12,590	24.5	308,455.0		
1986	13,923	23.5	327,190.5		
1987	18,853	22.5	424,192.5		
1988	19,477	21.5	418,755.5		
1989	17,653	20.5	361,886.5		
1990	16,693	19.5	325,513.5		

Central Maine Power Company
Number of Poles and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1991	13,870	18.5	256,595.0		
1992	13,411	17.5	234,692.5		
1993	11,856	16.5	195,624.0		
1994	10,137	15.5	157,123.5		
1995	10,650	14.5	154,425.0		
1996	11,043	13.5	149,080.5		
1997	11,284	12.5	141,050.0		
1998	13,866	11.5	159,459.0		
1999	12,513	10.5	131,386.5		
2000	11,034	9.5	104,823.0		
2001	9,901	8.5	84,158.5		
2002	10,437	7.5	78,277.5		
2003	12,838	6.5	83,447.0		
2004	8,214	5.5	45,177.0		
2005	6,614	4.5	29,763.0		
2006	9,757	3.5	34,149.5		
2007	8,434	2.5	21,085.0		
2008	8,554	1.5	12,831.0		
2009	7,795	0.5	3,897.5		
	643,406		18,748,493.0		
Average Age			29.1		

Central Maine Power Company
Conductor Footage and Age
2009

YEAR	TOTAL	AGE	TOTAL AGE		
1901	230	108.5	24,955.0		
1902	3,436	107.5	369,370.0		
1904	1,268	105.5	133,774.0		
1905	8,330	104.5	870,485.0		
1906	348	103.5	36,018.0		
1907	218	102.5	22,345.0		
1908	5,543	101.5	562,614.5		
1909	1,269	100.5	127,534.5		
1910	119,023	99.5	11,842,788.5		
1911	27,387	98.5	2,697,619.5		
1912	10,312	97.5	1,005,420.0		
1913	80,691	96.5	7,786,681.5		
1914	4,931	95.5	470,910.5		
1915	57,103	94.5	5,396,233.5		
1916	6,387	93.5	597,184.5		
1917	70,192	92.5	6,492,760.0		
1918	47,711	91.5	4,365,556.5		
1919	39,884	90.5	3,609,502.0		
1920	228,761	89.5	20,474,109.5		
1921	212,600	88.5	18,815,100.0		
1922	145,364	87.5	12,719,350.0		
1923	175,037	86.5	15,140,700.5		
1924	293,884	85.5	25,127,082.0		
1925	555,994	84.5	46,981,493.0		
1926	773,192	83.5	64,561,532.0		
1927	981,952	82.5	81,011,040.0		
1928	1,204,579	81.5	98,173,188.5		
1929	2,037,345	80.5	164,006,272.5		
1930	2,082,404	79.5	165,551,118.0		
1931	1,431,458	78.5	112,369,453.0		
1932	713,632	77.5	55,306,480.0		
1933	323,969	76.5	24,783,628.5		
1934	554,854	75.5	41,891,477.0		
1935	825,147	74.5	61,473,451.5		
1936	1,042,164	73.5	76,599,054.0		
1937	1,753,528	72.5	127,130,780.0		
1938	2,697,484	71.5	192,870,106.0		
1939	2,005,881	70.5	141,414,610.5		
1940	2,893,635	69.5	201,107,632.5		
1941	4,121,305	68.5	282,309,392.5		
1942	471,987	67.5	31,859,122.5		
1943	339,436	66.5	22,572,494.0		
1944	431,474	65.5	28,261,547.0		

Central Maine Power Company
Conductor Footage and Age
2009

YEAR	TOTAL	AGE	TOTAL AGE		
1945	1,217,382	64.5	78,521,139.0		
1946	3,449,696	63.5	219,055,696.0		
1947	7,473,341	62.5	467,083,812.5		
1948	7,265,903	61.5	446,853,034.5		
1949	4,623,265	60.5	279,707,532.5		
1950	3,641,897	59.5	216,692,871.5		
1951	3,070,177	58.5	179,605,354.5		
1952	2,995,813	57.5	172,259,247.5		
1953	2,912,680	56.5	164,566,420.0		
1954	3,511,231	55.5	194,873,320.5		
1955	4,012,310	54.5	218,670,895.0		
1956	4,003,509	53.5	214,187,731.5		
1957	3,228,688	52.5	169,506,120.0		
1958	3,648,583	51.5	187,902,024.5		
1959	3,323,490	50.5	167,836,245.0		
1960	2,790,970	49.5	138,153,015.0		
1961	2,924,162	48.5	141,821,857.0		
1962	2,823,726	47.5	134,126,985.0		
1963	3,384,440	46.5	157,376,460.0		
1964	4,027,258	45.5	183,240,239.0		
1965	3,279,954	44.5	145,957,953.0		
1966	3,119,481	43.5	135,697,423.5		
1967	2,746,845	42.5	116,740,912.5		
1968	3,281,125	41.5	136,166,687.5		
1969	2,777,330	40.5	112,481,865.0		
1970	3,416,681	39.5	134,958,899.5		
1971	4,149,847	38.5	159,769,109.5		
1972	4,091,445	37.5	153,429,187.5		
1973	4,986,487	36.5	182,006,775.5		
1974	4,999,358	35.5	177,477,209.0		
1975	3,559,344	34.5	122,797,368.0		
1976	4,015,569	33.5	134,521,561.5		
1977	3,623,718	32.5	117,770,835.0		
1978	4,339,419	31.5	136,691,698.5		
1979	4,601,434	30.5	140,343,737.0		
1980	4,205,364	29.5	124,058,238.0		
1981	3,394,571	28.5	96,745,273.5		
1982	3,187,525	27.5	87,656,937.5		
1983	3,425,275	26.5	90,769,787.5		
1984	3,335,610	25.5	85,058,055.0		
1985	3,880,192	24.5	95,064,704.0		
1986	4,675,581	23.5	109,876,153.5		
1987	7,661,423	22.5	172,382,017.5		
1988	7,475,418	21.5	160,721,487.0		

Central Maine Power Company
Conductor Footage and Age
2009

YEAR	TOTAL	AGE	TOTAL AGE		
1989	5,961,764	20.5	122,216,162.0		
1990	6,044,866	19.5	117,874,887.0		
1991	4,723,010	18.5	87,375,685.0		
1992	4,505,393	17.5	78,844,377.5		
1993	3,987,656	16.5	65,796,324.0		
1994	3,075,828	15.5	47,675,334.0		
1995	3,444,461	14.5	49,944,684.5		
1996	3,661,651	13.5	49,432,288.5		
1997	3,729,627	12.5	46,620,337.5		
1998	3,793,246	11.5	43,622,329.0		
1999	4,036,197	10.5	42,380,068.5		
2000	3,690,647	9.5	35,061,146.5		
2001	3,502,444	8.5	29,770,774.0		
2002	3,622,375	7.5	27,167,812.5		
2003	4,949,973	6.5	32,174,824.5		
2004	2,398,036	5.5	13,189,198.0		
2005	2,693,766	4.5	12,121,947.0		
2006	3,763,198	3.5	13,171,193.0		
2007	3,018,458	2.5	7,546,145.0		
2008	2,928,262	1.5	4,392,393.0		
2009	2,375,010	0.5	1,187,505.0		
	281,244,714		10,347,671,260.0		
Average Age			36.8		

Central Maine Power Company
Number of Transformers and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1900	88	109.5	9,636.0		
1910	4	99.5	398.0		
1911	2	98.5	197.0		
1912	3	97.5	292.5		
1913	7	96.5	675.5		
1914	2	95.5	191.0		
1915	8	94.5	756.0		
1916	3	93.5	280.5		
1917	6	92.5	555.0		
1918	1	91.5	91.5		
1919	7	90.5	633.5		
1920	3	89.5	268.5		
1921	10	88.5	885.0		
1922	10	87.5	875.0		
1923	15	86.5	1,297.5		
1924	9	85.5	769.5		
1925	10	84.5	845.0		
1926	31	83.5	2,588.5		
1927	10	82.5	825.0		
1928	18	81.5	1,467.0		
1929	50	80.5	4,025.0		
1930	15	79.5	1,192.5		
1931	18	78.5	1,413.0		
1932	6	77.5	465.0		
1933	22	76.5	1,683.0		
1934	10	75.5	755.0		
1935	13	74.5	968.5		
1936	47	73.5	3,454.5		
1937	24	72.5	1,740.0		
1938	19	71.5	1,358.5		
1939	42	70.5	2,961.0		
1940	48	69.5	3,336.0		
1941	99	68.5	6,781.5		
1942	16	67.5	1,080.0		
1943	8	66.5	532.0		
1944	17	65.5	1,113.5		
1945	77	64.5	4,966.5		
1946	75	63.5	4,762.5		
1947	208	62.5	13,000.0		
1948	367	61.5	22,570.5		
1949	114	60.5	6,897.0		
1950	296	59.5	17,612.0		
1951	594	58.5	34,749.0		

Central Maine Power Company
Number of Transformers and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1952	451	57.5	25,932.5		
1953	441	56.5	24,916.5		
1954	478	55.5	26,529.0		
1955	832	54.5	45,344.0		
1956	875	53.5	46,812.5		
1957	394	52.5	20,685.0		
1958	912	51.5	46,968.0		
1959	842	50.5	42,521.0		
1960	675	49.5	33,412.5		
1961	941	48.5	45,638.5		
1962	966	47.5	45,885.0		
1963	1,005	46.5	46,732.5		
1964	1,557	45.5	70,843.5		
1965	1,175	44.5	52,287.5		
1966	1,428	43.5	62,118.0		
1967	867	42.5	36,847.5		
1968	1,511	41.5	62,706.5		
1969	2,107	40.5	85,333.5		
1970	2,945	39.5	116,327.5		
1971	4,405	38.5	169,592.5		
1972	4,919	37.5	184,462.5		
1973	5,797	36.5	211,590.5		
1974	6,823	35.5	242,216.5		
1975	3,958	34.5	136,551.0		
1976	5,133	33.5	171,955.5		
1977	4,156	32.5	135,070.0		
1978	5,180	31.5	163,170.0		
1979	4,312	30.5	131,516.0		
1980	3,834	29.5	113,103.0		
1981	3,965	28.5	113,002.5		
1982	3,365	27.5	92,537.5		
1983	5,093	26.5	134,964.5		
1984	5,523	25.5	140,836.5		
1985	5,340	24.5	130,830.0		
1986	6,582	23.5	154,677.0		
1987	8,164	22.5	183,690.0		
1988	9,544	21.5	205,196.0		
1989	9,720	20.5	199,260.0		
1990	6,304	19.5	122,928.0		
1991	4,492	18.5	83,102.0		
1992	6,319	17.5	110,582.5		
1993	4,998	16.5	82,467.0		
1994	5,023	15.5	77,856.5		
1995	5,696	14.5	82,592.0		

Central Maine Power Company
Number of Transformers and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1996	5,832	13.5	78,732.0		
1997	5,971	12.5	74,637.5		
1998	7,674	11.5	88,251.0		
1999	7,183	10.5	75,421.5		
2000	7,344	9.5	69,768.0		
2001	7,804	8.5	66,334.0		
2002	7,451	7.5	55,882.5		
2003	7,332	6.5	47,658.0		
2004	7,315	5.5	40,232.5		
2005	7,813	4.5	35,158.5		
2006	7,043	3.5	24,650.5		
2007	6,749	2.5	16,872.5		
2008	5,285	1.5	7,927.5		
2009	3,813	0.5	1,906.5		
	256,088		5,355,967.0		
Average Age			20.9		

Central Maine Power Company
Number of Regulators and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1948	2	61.5	123.0		
1956	4	53.5	214.0		
1960	1	49.5	49.5		
1962	1	47.5	47.5		
1963	1	46.5	46.5		
1964	8	45.5	364.0		
1965	2	44.5	89.0		
1966	5	43.5	217.5		
1967	8	42.5	340.0		
1968	6	41.5	249.0		
1969	14	40.5	567.0		
1970	7	39.5	276.5		
1971	5	38.5	192.5		
1972	7	37.5	262.5		
1973	12	36.5	438.0		
1974	7	35.5	248.5		
1975	14	34.5	483.0		
1976	6	33.5	201.0		
1977	15	32.5	487.5		
1978	33	31.5	1,039.5		
1979	32	30.5	976.0		
1980	8	29.5	236.0		
1981	3	28.5	85.5		
1982	14	27.5	385.0		
1983	15	26.5	397.5		
1984	17	25.5	433.5		
1985	25	24.5	612.5		
1986	33	23.5	775.5		
1987	40	22.5	900.0		
1988	35	21.5	752.5		
1989	65	20.5	1,332.5		
1990	111	19.5	2,164.5		
1991	6	18.5	111.0		
1992	25	17.5	437.5		
1993	45	16.5	742.5		
1994	38	15.5	589.0		
1995	54	14.5	783.0		
1996	9	13.5	121.5		
1997	11	12.5	137.5		
1998	35	11.5	402.5		
1999	29	10.5	304.5		
2000	31	9.5	294.5		
2001	126	8.5	1,071.0		

Central Maine Power Company
Number of Regulators and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
2002	68	7.5	510.0		
2003	76	6.5	494.0		
2004	65	5.5	357.5		
2005	47	4.5	211.5		
2006	75	3.5	262.5		
2007	47	2.5	117.5		
2008	49	1.5	73.5		
2009	42	0.5	21.0		
	1,434		22,029.0		
Average Age			15.4		

Central Maine Power Company
Number of Capacitors and Age
2009

YEAR	COUNT	AGE	TOTAL AGE		
1962	1	47.5	47.5		
1966	3	43.5	130.5		
1968	1	41.5	41.5		
1976	6	33.5	201.0		
1977	1	32.5	32.5		
1978	23	31.5	724.5		
1979	5	30.5	152.5		
1980	21	29.5	619.5		
1981	12	28.5	342.0		
1982	7	27.5	192.5		
1983	8	26.5	212.0		
1984	41	25.5	1,045.5		
1985	37	24.5	906.5		
1986	39	23.5	916.5		
1987	33	22.5	742.5		
1988	19	21.5	408.5		
1989	30	20.5	615.0		
1990	38	19.5	741.0		
1991	20	18.5	370.0		
1992	10	17.5	175.0		
1993	7	16.5	115.5		
1994	7	15.5	108.5		
1995	15	14.5	217.5		
1996	9	13.5	121.5		
1997	12	12.5	150.0		
1998	8	11.5	92.0		
1999	12	10.5	126.0		
2000	14	9.5	133.0		
2001	7	8.5	59.5		
2002	10	7.5	75.0		
2003	23	6.5	149.5		
2004	17	5.5	93.5		
2005	1	4.5	4.5		
2007	1	2.5	2.5		
2008	3	1.5	4.5		
2009	1	0.5	0.5		
	502		10,070.0		
Average Age			20.1		

Central Maine Power Company						
Number of Reclosers and Age						
2009						
YEAR	COUNT	AGE	TOTAL AGE			
1996	1	13.5	13.5			
1997	2	12.5	25.0			
1998	1	11.5	11.5			
1999	14	10.5	147.0			
2000	3	9.5	28.5			
2001	14	8.5	119.0			
2002	7	7.5	52.5			
2003	27	6.5	175.5			
2004	55	5.5	302.5			
2005	134	4.5	603.0			
2006	226	3.5	791.0			
2007	292	2.5	730.0			
2008	295	1.5	442.5			
2009	234	0.5	117.0			
	1,305		3,558.5			
Average Age			2.7			

Central Maine Power Company

Answer Time Distribution

Seconds	Percentage of calls answered within specified seconds
<30	81%
30	82%
60	87%
90	91%
>90	100%

Docket No. 2010-051
March 12, 2010
Attachment 27

REDACTED

Central Maine Power Company
Customer Relation Center Statistics
For the Period Ending December 31, 2009

Docket No. 2010-051
March 12, 2010
Attachment 28

REDACTED

Central Maine Power Company
Total Answered and Abandoned Business Calls

Docket No. 2010-051
March 12, 2010
Attachment 29

REDACTED

Central Maine Power Company
Customer Information Systems ("CIS")
Investment per Customer
For the Period Ended December 31, 2009

Docket No. 2010-051
March 12, 2010
Attachment 30

REDACTED

Central Maine Power Company
Customers Served per Customer Information System
Full Time Employees ("FTE")
For the Period Ended December 31, 2009

Central Maine Power Company
Reliability Improvement Program
Trees in Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
** Service Center: 11				
200D2	T	3	3	317.76
200D3	T	4	4	595.80
207D1	T	1	1	834.12
207D2	T	8	8	4,591.52
208D2	T	14	14	983.15
208D3	T	13	13	2,653.96
211D1	T	14	14	912.49
211D2	T	8	8	8,709.02
215D3	T	2	2	1,055.72
215D5	T	1	1	-
216D1	T	26	26	4,272.96
216D2	T	11	11	1,458.04
216D3	T	1	1	-
220D1	T	170	170	68,801.68
226D2	T	5	5	982.42
233D1	T	1	1	343.08
233D2	T	91	91	29,319.42
236D1	T	7	7	-
237D1	T	5	5	2,085.76
240D1	T	18	18	2,784.83
242D1	T	2	2	1,023.93
244D1	T	7	7	4,229.83
255D1	T	57	57	18,708.45
255D2	T	81	81	10,659.50
256D1	T	2	2	304.13
256D2	T	19	19	7,290.29
256D3	T	16	16	2,939.21
262D1	T	29	29	7,704.61
263D1	T	10	10	3,251.72
272D4	T	88	88	23,816.11
11 Subtotal		714	714	210,629.51
** Service Center: 14				
204D6	T	12	12	1,952.27
206D1	T	10	10	1,581.41
209D1	T	11	11	1,510.16
209D2	T	3	3	228.02
209D3	T	4	4	583.68
210D1	T	37	37	13,257.99
213D1	T	39	39	7,567.08
213D2	T	5	5	788.90
213D4	T	1	1	114.01
217D1	T	5	5	342.04
217D2	T	3	3	570.06
217D3	T	64	64	10,713.30

Central Maine Power Company
Reliability Improvement Program
Trees In Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
218D1	T	12	12	4,167.59
219D1	T	7	7	4,407.15
219D2	T	12	12	2,496.69
223D1	T	9	9	941.86
225D2	T	55	55	10,405.95
225D3	T	73	73	20,077.03
225D4	T	9	9	2,434.86
231D1	T	2	2	114.01
231D2	T	1	1	684.06
231D3	T	1	1	114.01
232D1	T	4	4	263.13
232D2	T	4	4	1,367.53
238D1	T	88	88	36,348.54
241D1	T	102	102	48,793.00
245D2	T	5	5	1,467.52
249D1	T	3	3	1,409.86
249D2	T	3	3	-
250D1	T	7	7	548.14
250D2	T	2	2	-
252D2	T	9	9	1,087.44
257D1	T	6	6	-
258D1	T	121	121	30,727.88
261D3	T	33	33	-
263D1	T	52	52	5,718.32
273D4	T	49	49	8,718.08
273D5	T	12	12	4,264.25
274D1	T	54	54	12,643.77
620D1	T	1	1	-
620D2	T	5	5	1,447.69
14 Subtotal		935	935	239,857.28
** Service Center: 21				
810D1	T	8	8	2,202.22
812D1	T	26	26	6,655.23
812D2	T	6	6	1,652.49
817D2	T	2	2	1,087.43
817D3	T	12	12	3,530.34
839D1	T	15	15	6,169.21
839D2	T	5	5	1,053.80
842D1	T	2	2	1,047.15
852D1	T	15	15	5,165.36
855D1	T	68	68	17,521.75
855D2	T	1	1	302.06
860D1	T	43	43	12,312.33
861D9	T	4	4	1,481.22
865D1	T	39	39	7,907.78

Central Maine Power Company
Reliability Improvement Program
Trees in Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
865D2	T	12	12	2,440.54
865D5	T	5	5	3,610.41
870D1	T	1	1	-
873D1	T	21	21	11,282.12
873D2	T	1	1	-
21 Subtotal		286	286	85,421.44
** Service Center: 22				
120D1	T	8	8	1,101.68
808D1	T	2	2	143.09
811D1	T	29	29	5,429.43
813D1	T	78	78	7,153.41
813D3	T	99	99	16,354.93
815D2	T	4	4	594.07
820D1	T	37	37	7,100.30
821D1	T	11	11	2,810.98
821D2	T	2	2	176.02
821D3	T	3	3	429.27
834D2	T	1	1	161.37
22 Subtotal		274	274	41,454.55
** Service Center: 24				
400D1	T	21	21	-
407D1	T	17	17	1,882.03
428D2	T	3	3	-
428D3	T	2	2	972.66
429D1	T	1	1	464.50
435D1	T	1	1	-
447D1	T	6	6	156.87
447D2	T	14	14	278.70
449D2	T	21	21	582.30
453D1	T	132	132	15,413.60
816D1	T	4	4	469.86
818D1	T	249	249	51,087.63
835D1	T	9	9	-
836D1	T	2	2	227.23
841D1	T	7	7	1,031.86
841D2	T	23	23	5,519.81
844D1	T	1	1	-
858-D4	T	1	1	184.63
858D1A	T	4	4	1,510.70
858D1B	T	3	3	1,347.72
858D3	T	39	39	5,784.24
858D4	T	401	401	62,156.61
875D1	T	1	1	358.60
877D1	T	19	19	2,578.17
882D2	T	1	1	-

Central Maine Power Company
Reliability Improvement Program
Trees In Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
885D1	T	13	13	7,253.50
24 Subtotal		995	995	159,261.22
** Service Center: 25				
822D1	T	276	276	23,829.97
823D2	T	58	58	20,876.09
824D1	T	26	26	7,830.40
824D2	T	1	1	244.48
832d2	T	1	1	198.51
853D1	T	152	152	10,005.27
853D2	T	4	4	481.18
854D1	T	2	2	254.19
866D1	T	234	234	27,713.46
866D2	T	1	1	240.68
868D1	T	101	101	30,331.96
25 Subtotal		856	856	122,006.19
** Service Center: 31				
214D1	T	5	5	3,398.62
214D2	T	20	20	2,878.32
214D3	T	41	41	2,582.28
214D4	T	47	47	15,173.41
239D5	T	4	4	785.00
239D6	T	12	12	8,348.88
239D7	T	12	12	-
239D9	T	2	2	401.25
245d1	T	3	3	1,721.17
246D1	T	47	47	8,639.79
246D2	T	1	1	785.00
251D1	T	12	12	-
253D1	T	5	5	1,038.75
800D	T	4	4	530.36
800D1	T	5	5	1,897.19
803D4	T	1	1	-
803D5	T	1	1	-
803D6	T	6	6	2,380.93
805D1	T	31	31	8,799.11
806D1	T	184	184	45,981.91
806D2	T	160	160	35,485.93
814D2	T	4	4	-
846D1	T	5	5	2,977.89
850D1	T	64	64	35,575.34
850D2	T	24	24	4,920.93
860D2	T	151	151	51,377.56
874D1	T	1	1	-
31 Subtotal		852	852	235,679.62
** Service Center: 41				

Central Maine Power Company
Reliability Improvement Program
Trees in Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
218D1	T	17	17	3,728.40
416D3	T	1	1	-
607D2	T	3	3	339.73
607D5	T	197	197	32,305.91
610D2	T	7	7	2,492.18
61163	T	1	1	661.43
611D2	T	1	1	689.14
611D3	T	3	3	689.19
613D1	T	27	27	5,402.28
613D2	T	8	8	3,545.72
613D3	T	4	4	573.48
617D1	T	2	2	631.30
617D2	T	5	5	-
618D1	T	1	1	186.35
618D2	T	4	4	661.02
618D3	T	2	2	415.53
620D1	T	9	9	3,729.23
620D4	T	93	93	14,943.84
622D2	T	23	23	8,461.16
623D4	T	2	2	319.42
624D1	T	1	1	277.08
624D2	T	10	10	2,666.58
631D2	T	3	3	228.03
631D3	T	73	73	14,971.56
635D1	T	18	18	4,917.69
635D2	T	4	4	774.16
636D1	T	1	1	273.82
639D1	T	2	2	789.66
639D2	T	8	8	1,254.16
639D3	T	1	1	278.70
644D1	T	1	1	232.25
644D2	T	9	9	-
645D4	T	3	3	472.49
646D1	T	2	2	804.88
647D1	T	2	2	1,914.48
647D2	T	1	1	185.80
650D1	T	3	3	698.71
650D4	T	46	46	12,623.62
653D2	T	1	1	486.90
653D3	T	1	1	324.60
659D13	T	7	7	2,234.96
659D8	T	2	2	1,340.92
659D9	T	2	2	609.21
660D1	T	2	2	3,552.04
668D1	T	1	1	167.22

Central Maine Power Company
Reliability Improvement Program
Trees in Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
674D1	T	1	1	743.20
674D2	T	1	1	154.83
675D3	T	3	3	689.19
678D1	T	6	6	636.43
682D1	T	2	2	242.40
682D2	T	2	2	836.10
690D1	T	4	4	836.10
690D2	T	2	2	338.11
690D3	T	66	66	11,820.47
691D1	T	2	2	-
693D1	T	7	7	4,402.51
693D2	T	2	2	2,007.78
41 Subtotal		712	712	154,561.95
** Service Center: 46				
603D2	T	4	4	677.76
605D1	T	114	114	28,099.34
612D1	T	7	7	-
612D2	T	4	4	969.97
617D2	T	69	69	15,803.96
621D1	T	5	5	1,504.29
621D2	T	2	2	-
626D5	T	1	1	84.72
629D1	T	1	1	169.44
629D2	T	9	9	598.90
629D3	T	2	2	254.16
632D1	L	1	1	222.30
632D1	T	2	2	1,131.56
633D1	T	3	3	729.90
634D1	T	2	2	-
634D2	T	18	18	353.98
638D1	T	11	11	1,524.91
640D1	T	144	144	47,398.90
640D2	T	3	3	423.60
640D3	T	38	38	10,487.70
641D1	T	1	1	-
641D3	T	3	3	671.06
641D4	T	1	1	-
656D2	T	5	5	1,089.25
657D3	T	1	1	169.44
661D2	T	62	62	4,335.06
663D1	T	81	81	1,245.92
670D1	T	1	1	221.58
671D1	T	71	71	12,079.85
671D2	T	13	13	1,462.89
676D2	T	56	56	13,449.78

Central Maine Power Company
Reliability Improvement Program
Trees in Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
677D1	T	14	14	4,387.74
678D1	T	123	123	24,840.58
684D1	T	3	3	423.60
685D1	T	72	72	11,619.02
685D2	T	96	96	18,785.64
687D1	T	1	1	1,130.31
688D1	T	36	36	7,643.52
688D2	T	172	172	44,614.56
689D1	T	29	29	5,512.81
691D1	T	70	70	31,352.47
692D1	T	24	24	4,671.61
46 Subtotal		1375	1375	300,142.08
** Service Center: 51				
411D1	T	3	3	531.18
412.D3	T	1	1	296.19
412D1	T	5	5	340.63
412D2	T	1	1	-
412D3	T	12	12	5,090.42
412D4	T	7	7	1,140.25
416D1	T	21	21	5,805.28
416D2	T	16	16	1,220.87
420D1	T	33	33	8,665.43
420D2	T	9	9	-
420D3	T	1	1	-
420D4	T	2	2	492.10
420D6	T	2	2	247.73
420D7	T	3	3	1,243.38
421D1	T	1	1	96.87
421D2	T	84	84	13,728.51
424D2	T	1	1	-
424D4	T	34	34	5,851.70
424D5	T	1	1	297.28
424D6	T	1	1	278.70
426D6	T	1	1	-
431D1	T	11	11	3,245.71
431D2	T	6	6	1,793.46
436D1	T	2	2	-
436D2	T	1	1	278.70
436D3	T	1	1	306.30
436D6	T	9	9	2,266.34
436D7	T	1	1	-
450D1	T	39	39	9,424.04
450D2	T	21	21	6,325.26
454D1	T	6	6	646.53
454D2	T	91	91	11,691.54

Central Maine Power Company
Reliability Improvement Program
Trees in Contact

Circuit	W/T	Lines in contact Spans	Totals Spans	Totals Costs
456D1	T	2	2	1,245.66
456D2	T	113	113	17,616.77
467D1	T	21	21	4,207.03
51 Subtotal		563	563	104,373.86
** Service Center: 54				
405D1	T	2	2	369.45
405D2	T	4	4	936.36
406D1	T	11	11	4,306.71
406D2	T	92	92	18,349.23
406D3	T	1	1	277.08
413D1	T	3	3	3,223.96
413D2	T	2	2	1,208.14
415D1	T	2	2	234.09
415D2	T	2	2	529.05
415D3	T	1	1	-
419D1	T	4	4	1,868.35
430D1	T	5	5	2,028.16
435D1	T	2	2	-
435D2	T	5	5	346.36
435D3	T	1	1	138.55
435D4	T	30	30	9,369.84
437D1	T	1	1	-
437D2	T	3	3	311.89
438D1	T	31	31	6,071.25
439D1	T	3	3	-
444D1	T	17	17	2,526.61
444D2	T	6	6	2,491.96
444D3	T	4	4	1,131.47
445D1	T	25	25	4,731.40
445D2	T	6	6	2,698.24
458D1	T	7	7	964.09
458D2	T	3	3	796.97
463D1	T	64	64	14,697.47
691D1	T	2	2	893.48
692D1	T	2	2	994.53
54 Subtotal		341	341	81,494.69
Subtotal		7903	7903	1,734,882.39
Dollars / old system				435,074.03
Total				2,169,956.42

Central Maine Power Company
Capital Budget Requests
by Department $000's

Department	Property Description	2010 Budget	2009 Budget	2009 Actuals
Power Delivery	Distribution & Substation Construction	$ 3,114	$ 958	$ 91
	Metering	1,731	1,236	1,103
	Large Power Transfmrs	4,991	23,036	21,320
	Dist Regulator Purchases	261	250	248
	Transmission Construction	309,823	71,978	60,836
	Land Purchase & Sale			
	Major Betterment Projects			
	General Equipment	1,547	1,500	1,252
	Subtotal	321,467	98,958	84,851
Field Operations	Substation Construction	984	1,065	891
	New Business Blankets	1,741	1,829	2,194
	Line Extensions	1,495	1,613	1,244
	Road Job Construction	2,612	2,303	2,302
	Major Betterment Projects	4,178	3,056	3,043
	Minor Betterment Projects	11,604	11,125	11,550
	Disposal Blanket	450	450	455
	Transmission Construction	1,350	1,070	965
	Misc. Projects	5,026	4,007	5,233
	General Property	350	100	53
	Subtotal	29,791	26,617	27,930
Information Technology	General Property	663	424	326
	Subtotal	663	424	326
Other	Distribution Line Transformers	12,106	12,248	8,995
	Transportation	5,151	735	568
	Miscellaneous	260	130	38
	Subtotal	17,517	13,113	9,601
Administrative Services	General Property	146		
	Facilities	3,253	1,900	1,449
	Subtotal	3,399	1,900	1,449
Corporate, including AMI	General Property	29,829	402	2,049
	Grand Total	$ 402,667	$ 141,413	$ 126,206

Central Maine Power Company
Capital Spending
2010 Budget to 2009 Budget Comparison

CMP's construction budget for 2010 totals $402.6M, approximately $261M higher than the 2009 Budget. Actual expenditures for 2009 were approximately $126.2M. The increase in the 2010 budget relative to 2009 is due primarily to the Maine Power Reliability project ($257M) and the Automated Meter Infrastructure project ($29M).

2009 Budget to Actual Comparison

CMP's construction budget for 2009 totaled $141.4M, while actual expenditures for 2009 were approximately $126.2M. Actual spending included decreases over plan in transmission projects, mainly the Maine Power Reliability Project in Power Delivery and increases over plan in General Property from the Advanced Meter Infrastructure project included in Corporate.

Exhibit 1

AmerenUE 4 CSR 240-23.010 Electric Utility System Reliability Monitoring and Reporting Submission Requirements – Annual Reliability Report

Introduction

This report details Union Electric Company dba AmerenUE's annual reliability metrics and worst performing circuits for calendar year 2008 as required by Missouri Public Service Commission Rule 4 CSR 240-23.010, Electric Utility System Reliability Monitoring and Reporting Submission Requirements (referred to in the remainder of this document as "the Rule"). This report is required by Sections (2) and (7) of the Rule which state, "*The information required by section (1) shall be filed annually by the last business day of April of the calendar year following the calendar year for which the information was accumulated…. The information developed in accordance with section (6) shall be reported as part of the annual report required by section (2)….*" This report will provide the reliability measures requested by the Rule, the list of Worst Performing Circuits (WPCs), and the actions taken or planned to improve the performance of these circuits.

Definitions

For the purposes of this report, the following definitions shall apply:

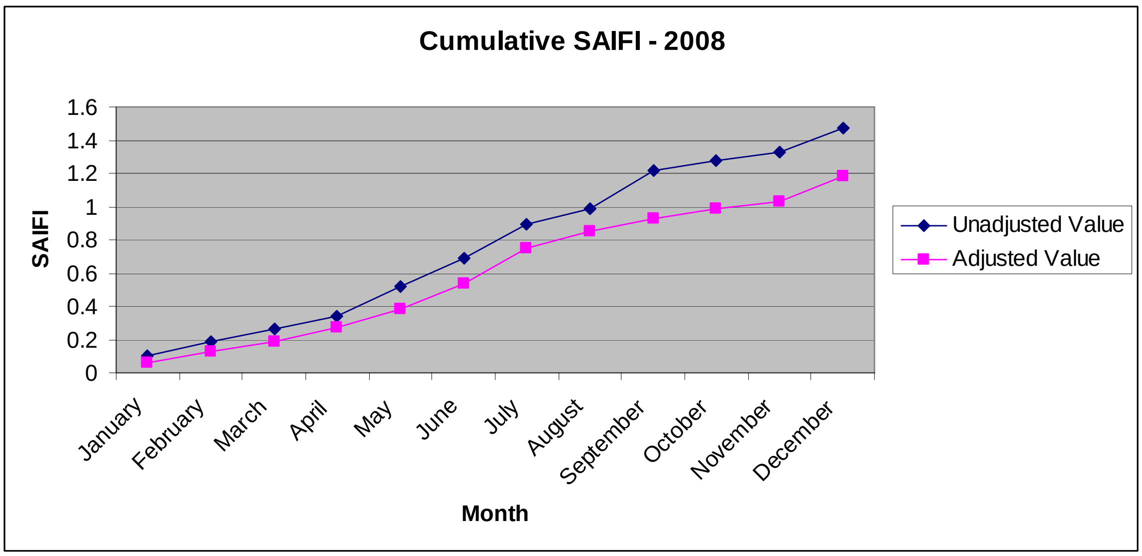
1. System Average Interruption Frequency Index (SAIFI) – The average frequency of service interruptions in number of occurrences per customer (total number of customer interruptions divided by the total number of customers served).
2. Customer Average Interruption Frequency Index (CAIFI) – The average number of interruptions per customer interrupted (total number of customer interruptions divided by the total number of customers affected).
3. System Average Interruption Duration Index (SAIDI) – The average interruption in hours or minutes per customer served (sum of all customer interruption durations divided by the total number of customers served).
4. Customer Average Interruption Duration Index (CAIDI) – The average interruption duration (sum of all customer interruption durations divided by the total number of customers interrupted).
5. Worst Performing Circuit (WPC) – A distribution circuit whose SAIFI value, adjusted to exclude major storm events per IEEE Standard 1366-2003, when compared to the SAIFI values for the other circuits in the AmerenUE system places it among the 5% of circuits with the highest SAIFI values in the AmerenUE system.

Reliability Metrics

The following tables and graphs show AmerenUE's unadjusted and adjusted[1] reliability metrics for calendar year 2008:

SAIFI:

Month	Unadjusted Value	Adjusted Value
January	0.10	0.06
February	0.19	0.13
March	0.26	0.19
April	0.34	0.27
May	0.52	0.38
June	0.69	0.54
July	0.89	0.75
August	0.99	0.85
September	1.22	0.93
October	1.28	0.99
November	1.33	1.03
December	1.47	1.18



[1] Data has been adjusted in accordance with 4 CSR 240-23.010(5).

CAIFI:

Month	Unadjusted Value	Adjusted Value
January	1.17	1.12
February	1.33	1.17
March	1.37	1.23
April	1.38	1.26
May	1.50	1.35
June	1.66	1.52
July	1.83	1.70
August	1.91	1.77
September	2.12	1.83
October	2.16	1.88
November	2.19	1.91
December	2.27	2.00

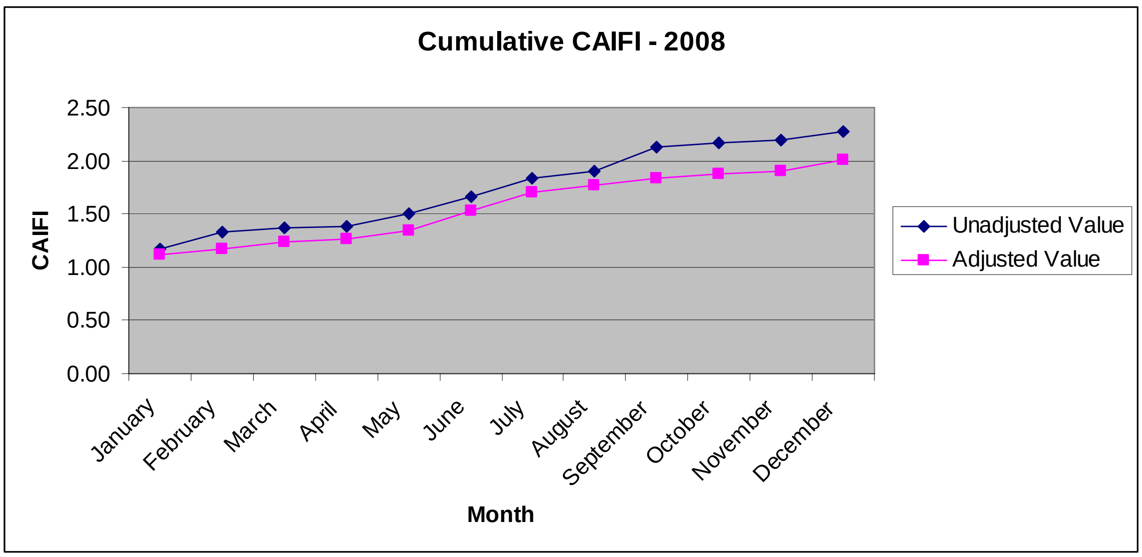
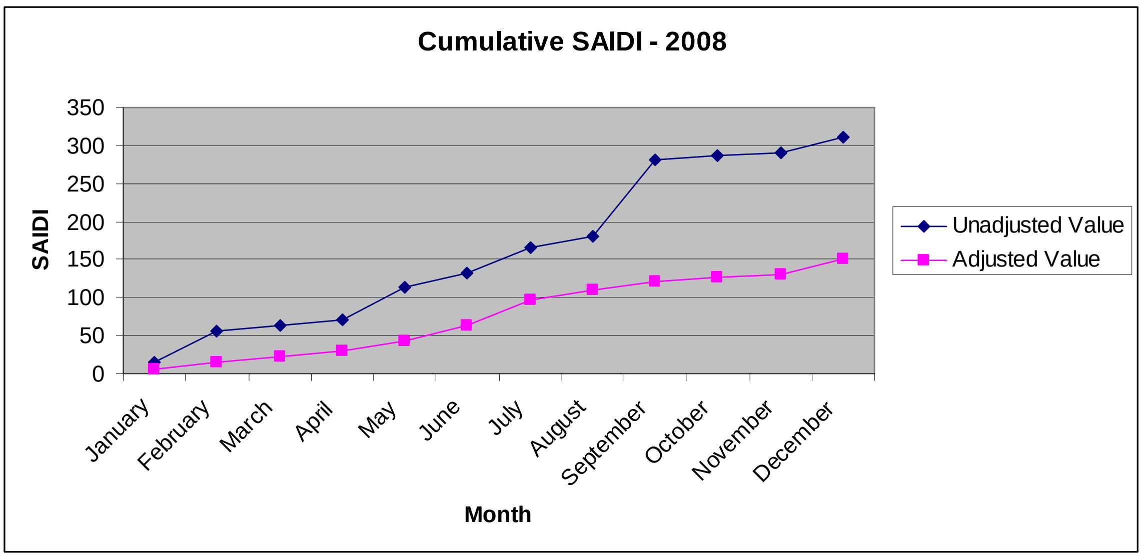


Exhibit 1

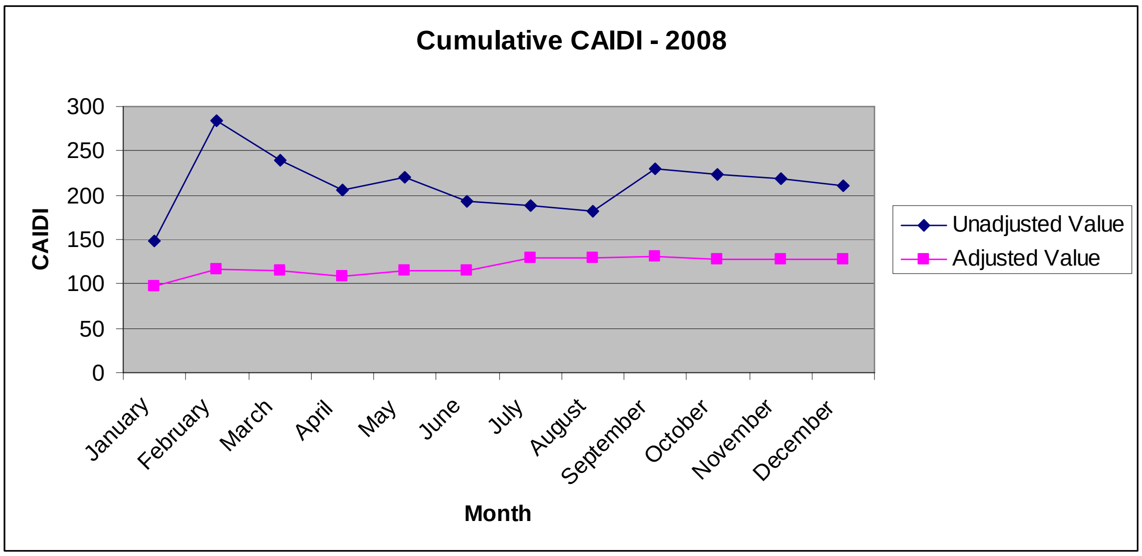
SAIDI:

Month	Unadjusted Value	Adjusted Value
January	14.85	5.71
February	55.01	14.85
March	62.62	22.46
April	70.03	29.87
May	113.95	43.48
June	133.01	62.54
July	166.53	96.06
August	181.00	110.54
September	280.90	121.67
October	286.13	126.89
November	290.47	131.24
December	310.13	150.89



CAIDI:

Month	Unadjusted Value	Adjusted Value
January	149.03	97.22
February	283.68	116.33
March	239.97	115.36
April	205.78	109.00
May	219.66	115.43
June	193.86	114.96
July	187.68	128.90
August	182.29	129.91
September	230.19	131.37
October	222.79	128.16
November	218.72	126.93
December	210.61	128.05



Worst Performing Circuits

AmerenUE has performed SAIFI calculations on all of its distribution circuits in accordance with section (6) of the Rule. The circuits have been ranked in order of descending SAIFI value and the 5 percent of the circuits with the highest SAIFI values have been designated as Worst Performing Circuits (WPCs). The list of WPCs based on 2008 SAIFI values has been included in Appendix A.

AmerenUE has analyzed each of these WPCs and the reasons why the circuit qualifies as a WPC and the actions planned or taken to improve the WPC's performance have been included in Appendix B.

Conclusion

This report details AmerenUE's annual reliability metrics and provides a list of AmerenUE's worst performing circuits and the actions planned and/or taken to improve the reliability of these circuits. The report clearly demonstrates that AmerenUE is aware of those circuits considered "worst performers" and has either taken or planned aggressive actions to improve the reliability of these circuits in order to better serve our customers.

AmerenUE 4 CSR 240-23.010 Electric Utility System Reliability Monitoring and Reporting Submission Requirements – Annual Reliability Report

Introduction

This report details Union Electric (dba AmerenUE) Company's annual reliability metrics and worst performing circuits for calendar year 2009 as required by Missouri Public Service Commission Rule 4 CSR 240-23.010, Electric Utility System Reliability Monitoring and Reporting Submission Requirements (referred to in the remainder of this document as "the Rule"). This report is required by Sections (2) and (7) of the Rule which state, "*The information required by section (1) shall be filed annually by the last business day of April of the calendar year following the calendar year for which the information was accumulated…. The information developed in accordance with section (6) shall be reported as part of the annual report required by section (2)….*" This report will provide the reliability measures requested by the Rule, the list of Worst Performing Circuits (WPCs), and the actions taken or planned to improve the performance of these circuits.

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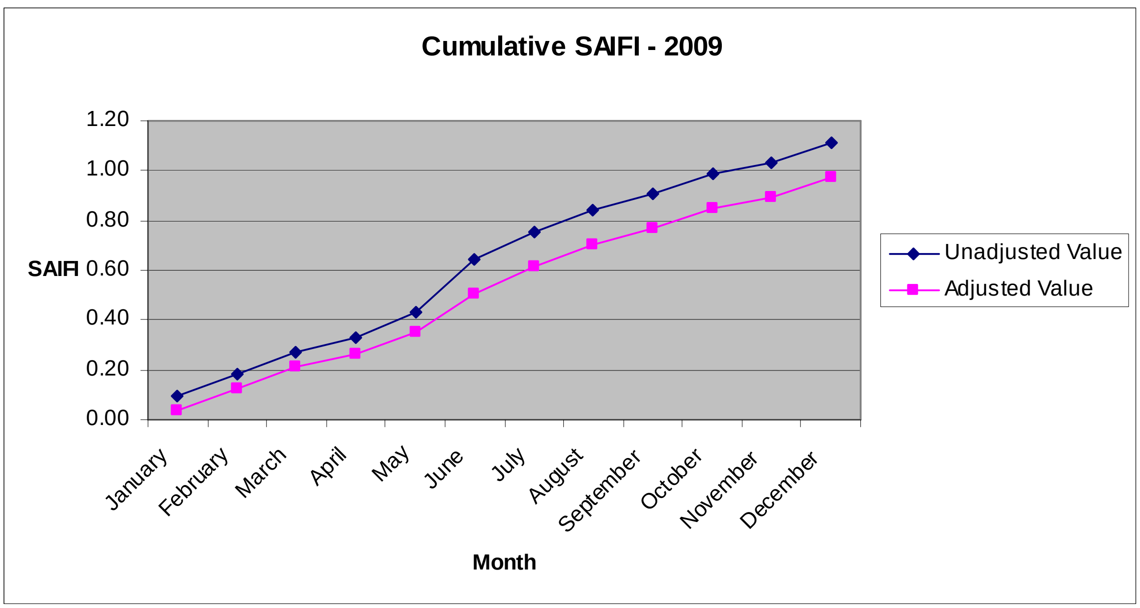
Reliability Metrics

The following tables and graphs show AmerenUE's unadjusted and adjusted reliability metrics for calendar year 2009:

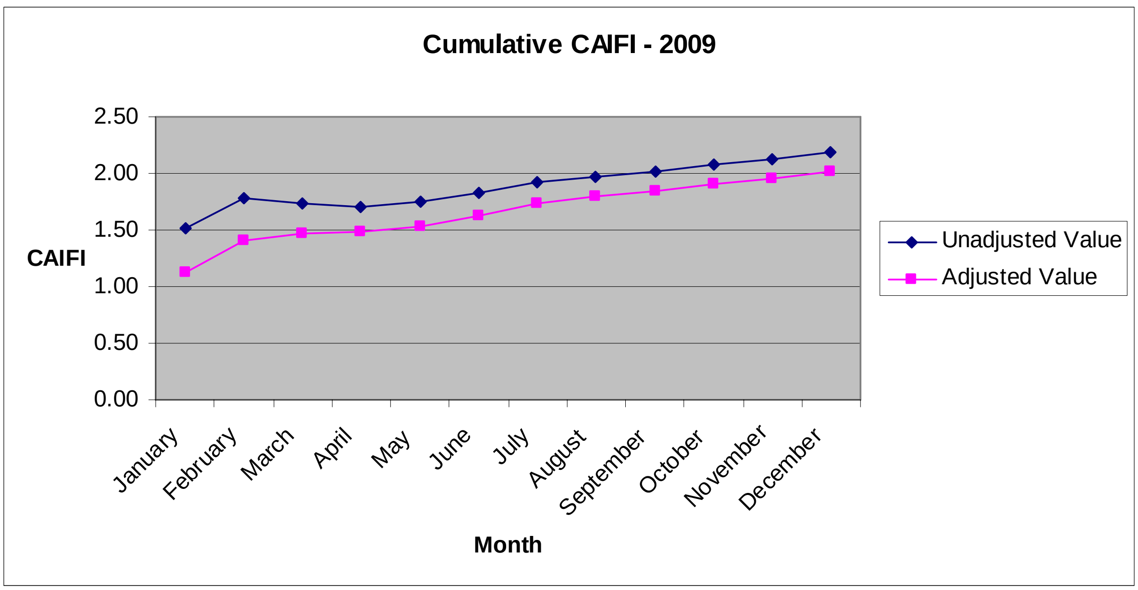
SAIFI:

Month	Unadjusted Value	Adjusted Value
January	0.10	0.04
February	0.19	0.12
March	0.27	0.21
April	0.33	0.27
May	0.43	0.35
June	0.64	0.51
July	0.75	0.61
August	0.84	0.71
September	0.91	0.77
October	0.98	0.85
November	1.03	0.89
December	1.11	0.98



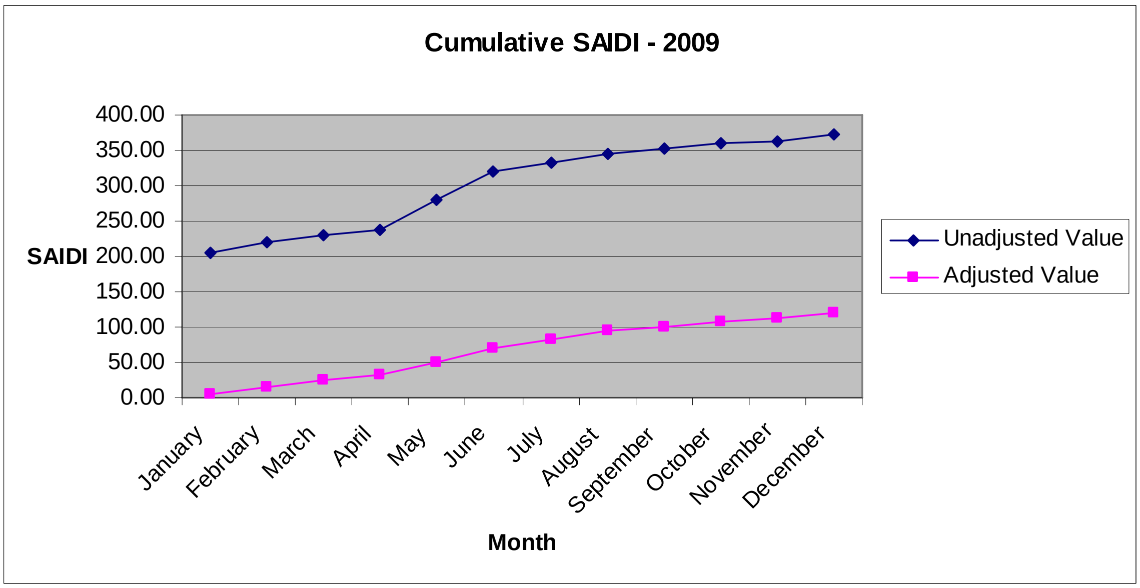
CAIFI:

Month	Unadjusted Value	Adjusted Value
January	1.52	1.13
February	1.79	1.40
March	1.73	1.47
April	1.71	1.48
May	1.75	1.53
June	1.83	1.63
July	1.92	1.73
August	1.98	1.80
September	2.02	1.85
October	2.08	1.91
November	2.12	1.95
December	2.18	2.02



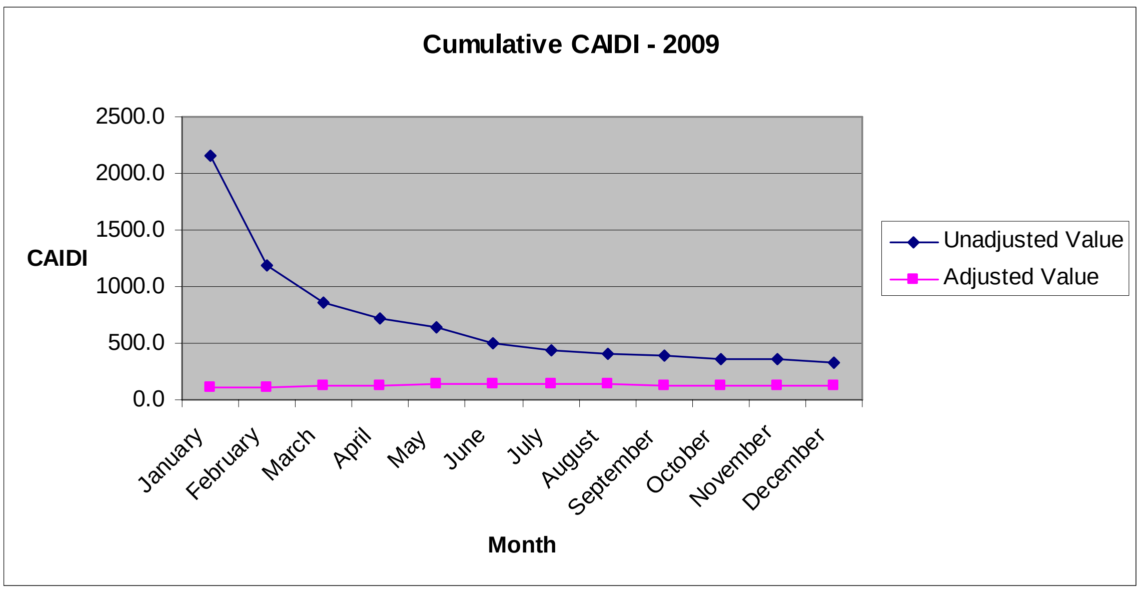
SAIDI:

Month	Unadjusted Value	Adjusted Value
January	205.62	4.4
February	219.62	14.2
March	231.21	25.8
April	237.13	31.7
May	280.05	49.4
June	320.92	70.0
July	332.71	81.8
August	345.25	94.3
September	351.77	100.8
October	358.96	108.0
November	362.90	112.0
December	372.09	121.1



CAIDI:

Month	Unadjusted Value	Adjusted Value
January	2157.4	113.8
February	1184.5	113.5
March	855.3	122.8
April	726.3	119.1
May	646.7	141.8
June	500.4	138.6
July	443.6	133.2
August	410.0	133.6
September	388.4	131.1
October	364.7	127.4
November	352.7	125.4
December	334.3	124.1



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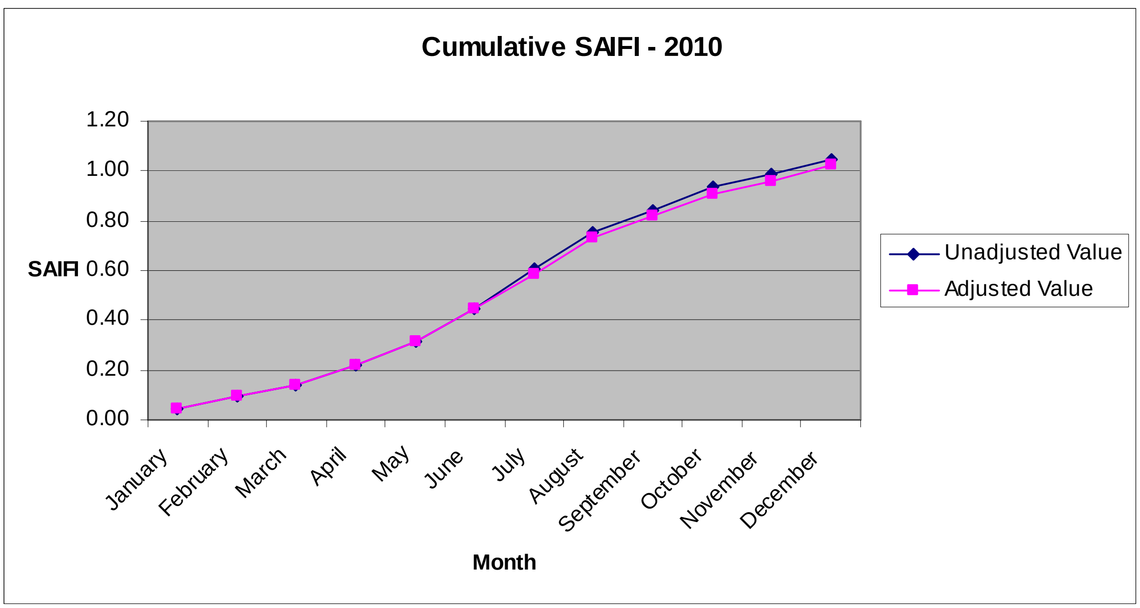
4. Customer Average Interruption Duration Index (CAIDI) – The average interruption duration (sum of all customer interruption durations divided by the total number of customers interrupted).
5. Worst Performing Circuit (WPC) – A distribution circuit whose SAIFI value, adjusted to exclude major storm events per IEEE Standard 1366-2003, when compared to the SAIFI values for the other circuits in the Ameren Missouri system places it among the 5% of circuits with the highest SAIFI values in the Ameren Missouri system.

Reliability Metrics

The following tables and graphs show Ameren Missouri's unadjusted and adjusted reliability metrics for calendar year 2010:

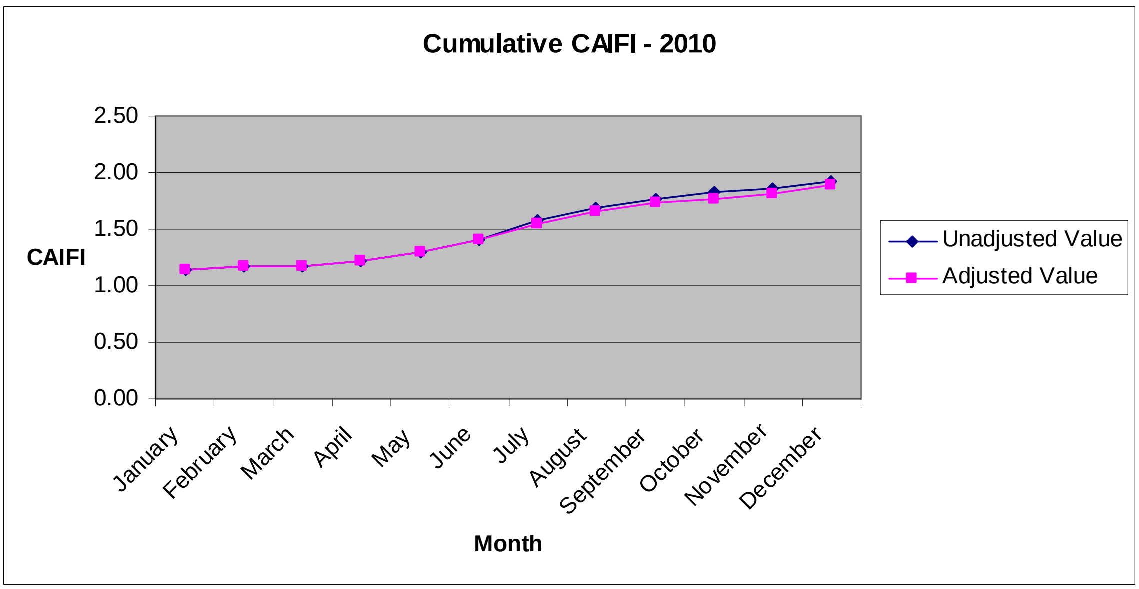
SAIFI:

Month	Unadjusted Value	Adjusted Value
January	0.05	0.05
February	0.09	0.09
March	0.14	0.14
April	0.22	0.22
May	0.31	0.31
June	0.44	0.44
July	0.61	0.58
August	0.76	0.73
September	0.85	0.82
October	0.93	0.91
November	0.99	0.96
December	1.05	1.02



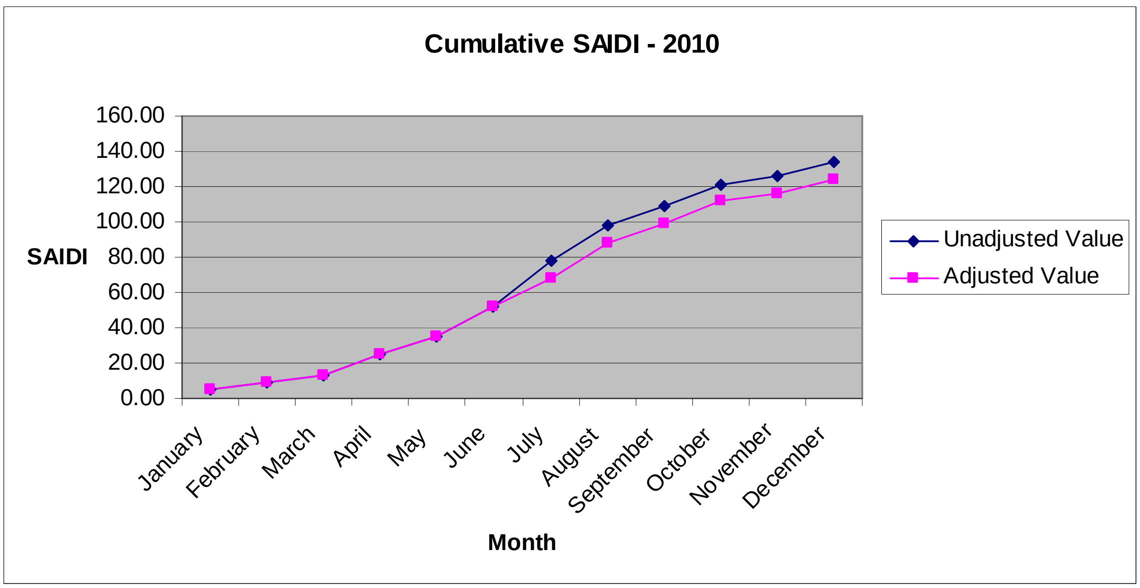
CAIFI:

Month	Unadjusted Value	Adjusted Value
January	1.15	1.15
February	1.17	1.17
March	1.17	1.17
April	1.23	1.23
May	1.30	1.30
June	1.40	1.40
July	1.58	1.54
August	1.69	1.65
September	1.76	1.73
October	1.82	1.77
November	1.86	1.81
December	1.92	1.89



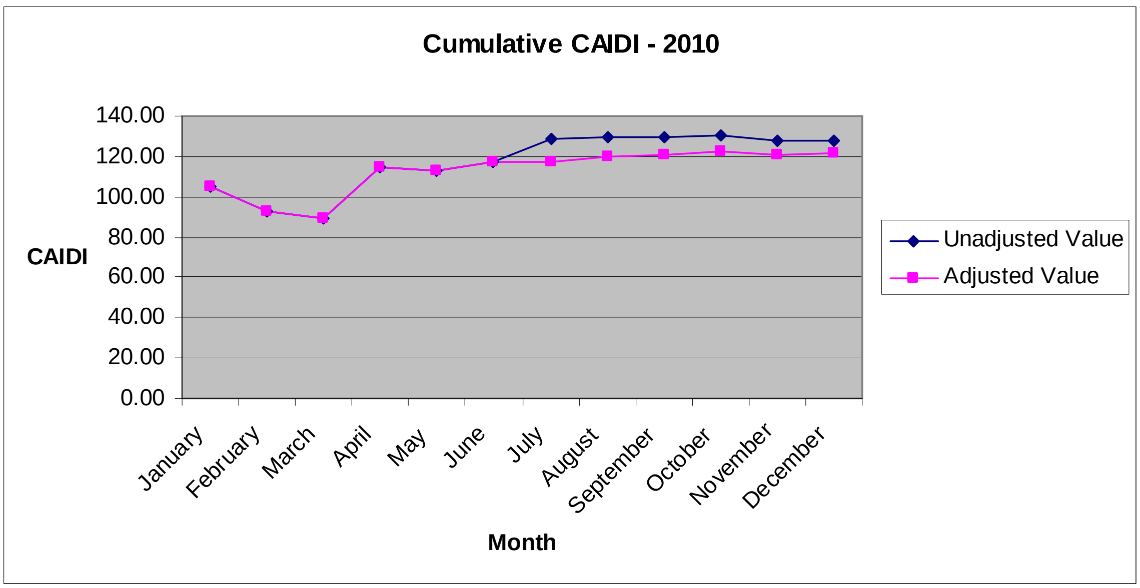
SAIDI:

Month	Unadjusted Value	Adjusted Value
January	4.85	4.85
February	8.65	8.65
March	12.60	12.60
April	25.12	25.12
May	35.34	35.34
June	52.11	52.11
July	78.25	68.40
August	97.62	87.78
September	109.19	99.34
October	121.50	111.65
November	126.25	116.41
December	134.12	124.27



CAIDI:

Month	Unadjusted Value	Adjusted Value
January	104.62	104.62
February	93.18	93.18
March	89.01	89.01
April	114.92	114.92
May	113.20	113.20
June	117.61	117.61
July	128.45	117.10
August	129.25	120.19
September	129.21	121.15
October	130.13	122.88
November	128.05	121.14
December	128.18	121.68



Worst Performing Circuits

Ameren Missouri has performed SAIFI calculations on all of its distribution circuits in accordance with section (6) of the Rule. The circuits have been ranked in order of descending SAIFI value and the 5 percent of the circuits with the highest SAIFI values have been designated as Worst Performing Circuits (WPCs). The list of WPCs based on 2010 SAIFI values has been included in Appendix A.

Ameren Missouri has analyzed each of these WPCs and the reasons why the circuit qualifies as a WPC and the actions planned or taken to improve the WPC's performance have been included in Appendix B.

Conclusion

This report details Ameren Missouri's annual reliability metrics as well as providing a list of Ameren Missouri's worst performing circuits and the actions planned and/or taken to improve the reliability of these circuits. The report clearly demonstrates that Ameren Missouri is aware of those circuits considered "worst performers" and has either taken or planned aggressive actions to improve the reliability of these circuits in order to better serve our customers.

Ameren Missouri 4 CSR 240-23.010 Electric Utility System Reliability Monitoring and Reporting Submission Requirements – Annual Reliability Report

Introduction

This report details Union Electric (dba Ameren Missouri) Company's annual reliability metrics and worst performing circuits for calendar year 2011 as required by Missouri Public Service Commission Rule 4 CSR 240-23.010, Electric Utility System Reliability Monitoring and Reporting Submission Requirements (referred to in the remainder of this document as "the Rule"). This report is required by Sections (2), (7), and (8) of the Rule which state, *"The information required by section (1) shall be filed annually by the last business day of April of the calendar year following the calendar year for which the information was accumulated…. The information developed in accordance with section (6) shall be reported as part of the annual report required by section (2)…. If on or after the time the annual report required by section (7) for calendar year 2011 is filled, a circuit has been on the worst performing circuit list for two (2) of the three (3) most recent consecutive calendar years the electrical corporation shall include detailed plans and schedules for improving the performance of that circuit in addition to the other information required by section (7)."* This report will provide the reliability measures requested by the Rule, the list of Worst Performing Circuits (WPCs), including Multi-Year Worst Performing Circuits (MWPCs), and the actions taken or planned to improve the performance of these circuits.

Definitions

For the purposes of this report, the following definitions shall apply:

1. System Average Interruption Frequency Index (SAIFI) – The average frequency of service interruptions in number of occurrences per customer (total number of customer interruptions divided by the total number of customers served).
2. Customer Average Interruption Frequency Index (CAIFI) – The average number of interruptions per customer interrupted (total number of customer interruptions divided by the total number of customers affected).
3. System Average Interruption Duration Index (SAIDI) – The average interruption in minutes per customer served (sum of all customer interruption durations divided by the total number of customers served).
4. Customer Average Interruption Duration Index (CAIDI) – The average interruption duration (sum of all customer interruption durations divided by the total number of customers interrupted).

5. Worst Performing Circuit (WPC) – A distribution circuit whose SAIFI value, adjusted to exclude major storm events per IEEE Standard 1366-2003, when compared to the SAIFI values for the other circuits in the Ameren Missouri system places it among the 5% of circuits with the highest SAIFI values in the Ameren Missouri system.
6. Multi-Year Worst Performing Circuit (MWPC) – A distribution circuit whose SAIFI value has ranked it as a Worst Performing Circuit for any two (2) of the three (3) most recent consecutive calendar years.

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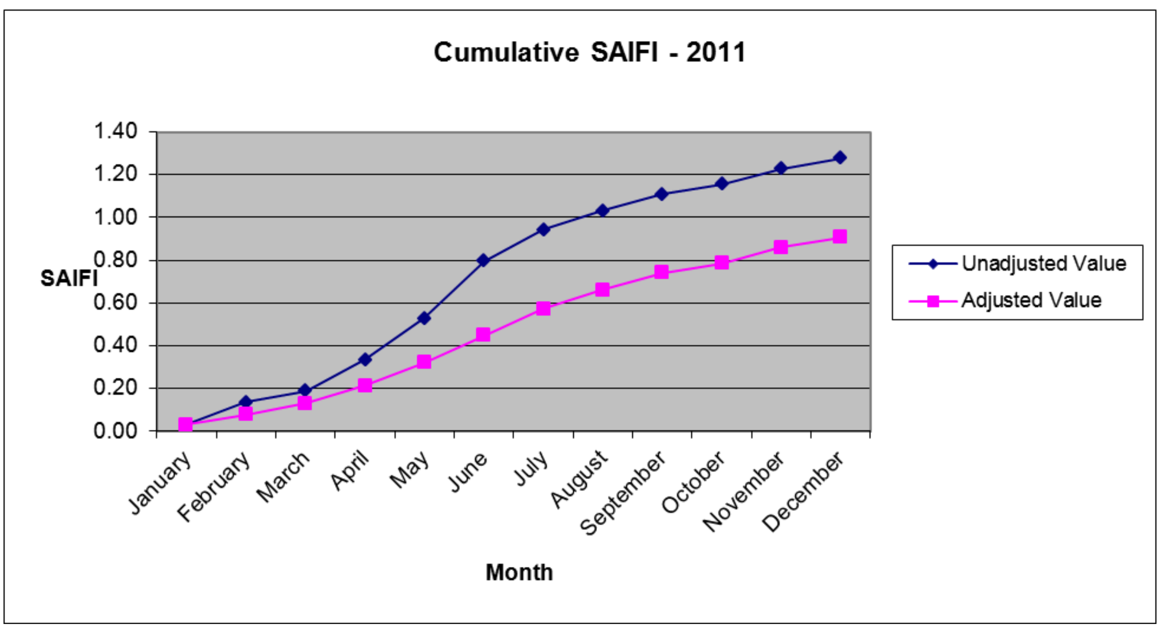
Reliability Metrics

4 CSR 240-23.010, section 3 states "The information required by section (1) shall be filed both unadjusted and adjusted to exclude major storm events per IEEE Standard 1366-2003, Guide for Electric Power Distribution Reliability Indices." The following tables and graphs show Ameren Missouri's unadjusted and adjusted reliability metrics for calendar year 2011:

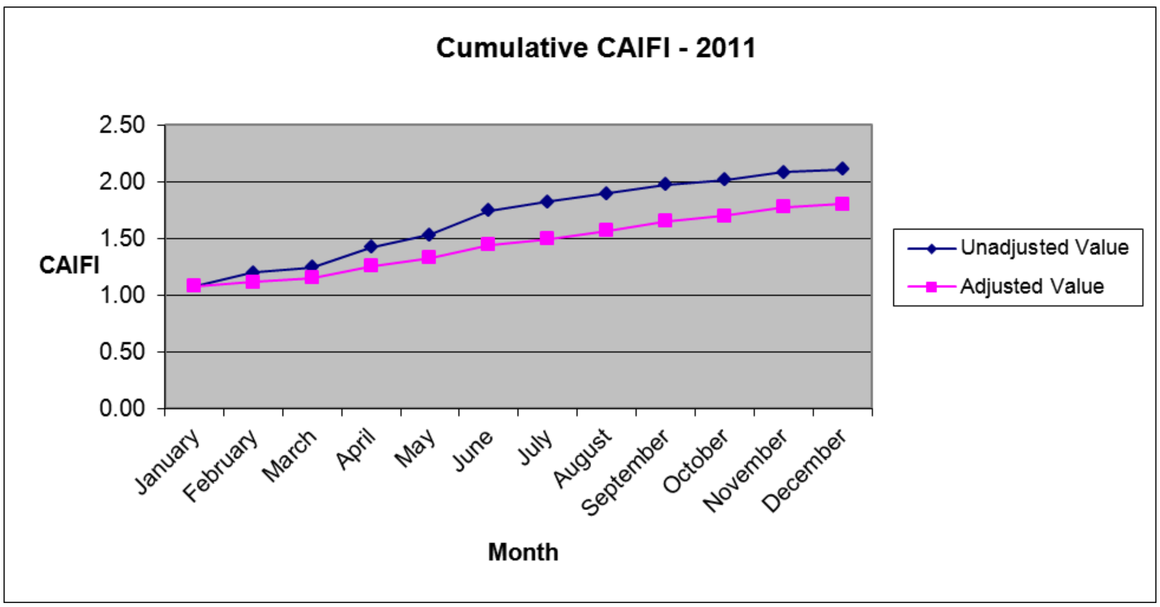
SAIFI:

Month	Unadjusted Value	Adjusted Value
January	0.03	0.03
February	0.14	0.08
March	0.19	0.13
April	0.34	0.21
May	0.53	0.32
June	0.80	0.45
July	0.94	0.57
August	1.03	0.66
September	1.11	0.74
October	1.16	0.79
November	1.23	0.86
December	1.28	0.91



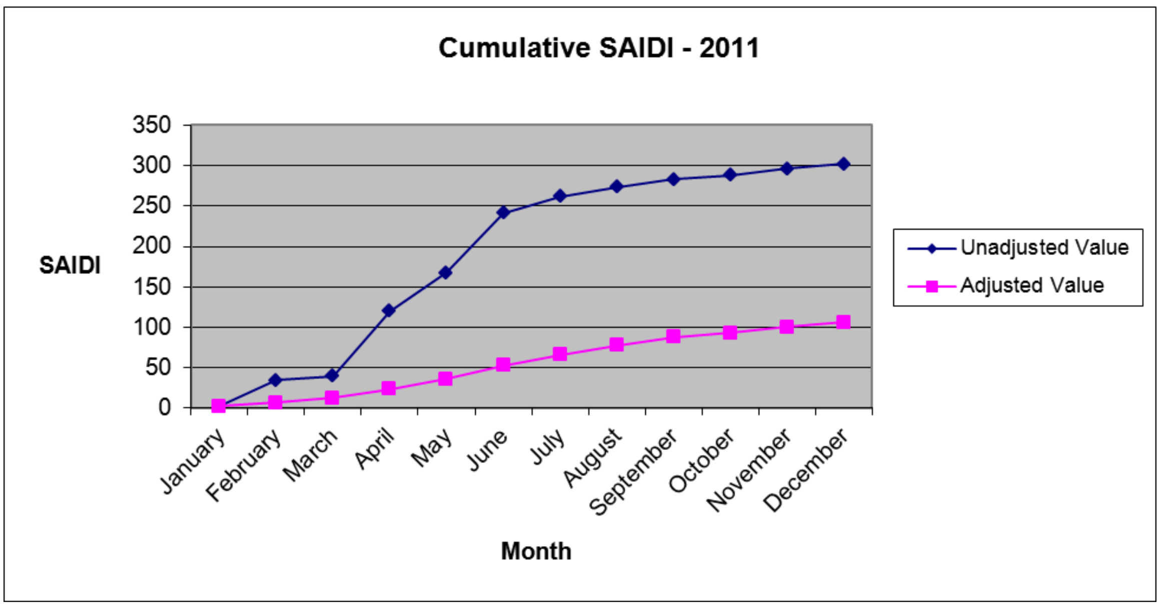
CAIFI:

Month	Unadjusted Value	Adjusted Value
January	1.08	1.08
February	1.20	1.11
March	1.25	1.15
April	1.43	1.26
May	1.53	1.33
June	1.75	1.44
July	1.83	1.50
August	1.90	1.57
September	1.98	1.65
October	2.02	1.70
November	2.09	1.78
December	2.11	1.80



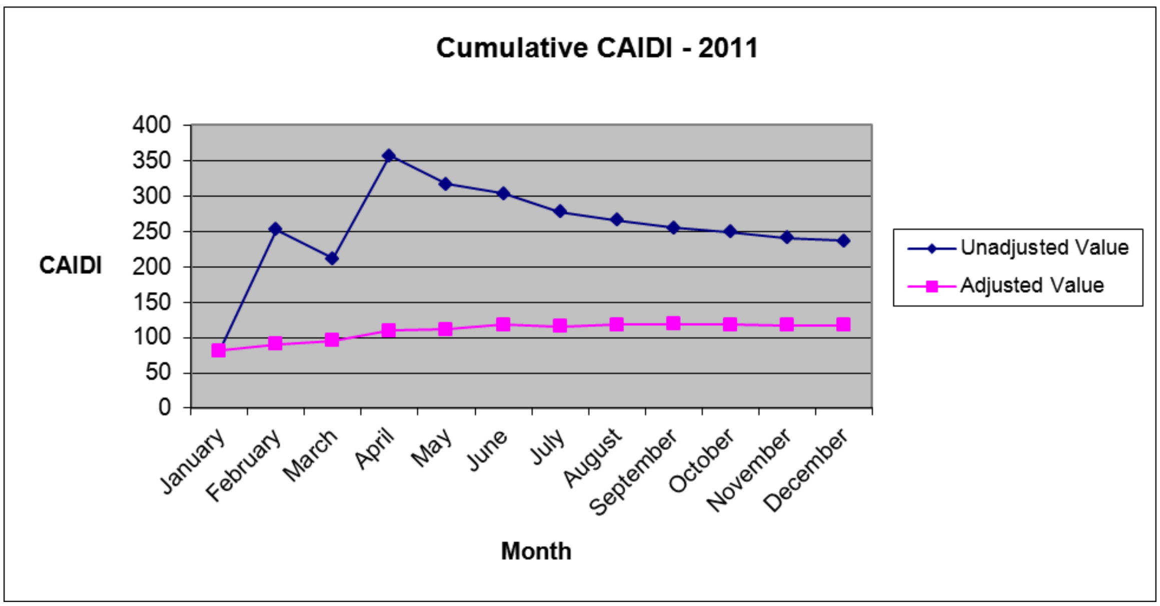
SAIDI:

Month	Unadjusted Value	Adjusted Value
January	3	3
February	35	7
March	40	12
April	120	24
May	168	36
June	242	53
July	262	66
August	273	78
September	283	88
October	288	93
November	296	101
December	302	106



CAIDI:

Month	Unadjusted Value	Adjusted Value
January	81	81
February	252	90
March	212	96
April	357	110
May	317	111
June	304	118
July	278	116
August	265	118
September	255	119
October	249	118
November	241	117
December	236	117



Ameren Missouri 2011 Worst Performing Circuits

Ameren Missouri has performed SAIFI calculations on all of its distribution circuits in accordance with section (6) of the Rule. The circuits have been ranked in order of descending 2011 SAIFI and the 5 percent of the circuits with the highest SAIFI values have been designated as Worst Performing Circuits (WPCs). Multi-Year Worst Performing Circuits (MWPCs) have also been identified. The 2011 WPCs, including those designated as MWPCs are listed in Appendix A. The circuit numbers for the MWPCs have been highlighted in red.

Ameren Missouri has analyzed each of the WPCs for the reasons the circuit qualifies as a WPC and the actions planned or taken to improve the WPC's performance have been included in Appendix B. Each of the MWPCs in Appendix B is identified with the title "Multi-Year WPC Analysis and Remedial Action Report". The MWPC reports contain detailed information regarding work completed or planned to improve the performance of each of the MWPCs as required by the Rule.

Multi-year Worst Performing Circuits not on the 2011 WPC list

The MWPCs circuits not identified as WPCs in 2011 but which were WPCs in 2009 and 2010 are listed in Appendix C. Appendix D details the actions taken and/or planned to improve the performance of these circuits.

Conclusion

This report satisfies the reporting requirements of 4 CSR 240-23.010 for the calendar year 2011. The reported reliability metrics demonstrate continued improvement in the reliability of Ameren Missouri's electric distribution system. With an adjusted SAIFI value of .91, Ameren Missouri's customers now experience, on average, less than one extended outage per year. The reported analyses and corrective actions for the Worst Performing Circuits also demonstrate Ameren Missouri's high level of focus on improving reliability and our full commitment to satisfying both the intent and the requirements of this rule.

Appendix A
Ameren Missouri 2011 Worst Performing Circuits

DIVISION	OPERATING AREA	CIRCUIT	VOLT	CUSTOMERS	CI	CMI	SAIDI	SAIFI	2009	2010	2011	Years WPC
SEMO	CAPE GIRARDEAU	635007	4	49	1,616	149,533	3052	32.98			WPC	1
GATEWAY	ST CHARLES	564051	12	250	4,692	173,038	692	18.77			WPC	1
SEMO	DEXTER	879006	4	344	2,859	387,268	1126	8.31		WPC	WPC	2
BOONE TRAILS	WENTZVILLE	659051	12	295	1,978	152,130	516	6.71			WPC	1
SEMO	ST FRANCOIS	161054	12	407	2,460	329,892	811	6.04			WPC	1
BOONE TRAILS	MOBERLY	797008	4	14	72	4,186	299	5.14			WPC	1
BOONE TRAILS	BOONEVILLE	708004	4	1	5	336	336	5.00			WPC	1
SEMO	CAPE GIRARDEAU	835002	4	138	659	117,475	851	4.78		WPC	WPC	2
BOONE TRAILS	WENTZVILLE	655058	12	1064	4,563	308,033	290	4.29			WPC	1
ARCHVIEW	GERALDINE	188008	4	176	714	171,099	972	4.06			WPC	1
ARCHVIEW	GERALDINE	083002	4	31	124	35,425	1143	4.00			WPC	1
SEMO	POTOSI	483052	12	874	3,461	306,765	351	3.96	WPC		WPC	2
SEMO	DEXTER	620055	12	219	849	86,943	397	3.88			WPC	1
SEMO	CAPE GIRARDEAU	828056	12	328	1,271	129,955	396	3.88			WPC	1
SEMO	DEXTER	690057	12	619	2,350	346,776	560	3.80	WPC	WPC	WPC	3
SEMO	HAYTI	456057	12	134	507	82,624	617	3.78	WPC	WPC	WPC	3
GATEWAY	BERKELEY	281054	12	1302	4,777	316,383	243	3.67			WPC	1
SEMO	HAYTI	456055	12	97	353	83,512	861	3.64			WPC	1
SEMO	HAYTI	466055	12	151	543	55,214	366	3.60		WPC	WPC	2
CENTRAL OZARKS	CAPITAL	836051	12	295	1,013	133,241	452	3.43			WPC	1
GATEWAY	BERKELEY	215053	12	1337	4,587	1,017,294	761	3.43		WPC	WPC	2
SEMO	HAYTI	455053	12	817	2,747	242,629	297	3.36	WPC	WPC	WPC	3
SEMO	HAYTI	454055	12	1103	3,664	379,062	344	3.32	WPC	WPC	WPC	3
SEMO	POTOSI	451054	12	403	1,332	350,589	870	3.31			WPC	1
MERAMEC VALLEY	JEFFERSON	546054	12	155	491	51,068	329	3.17		WPC	WPC	2
GATEWAY	BERKELEY	134051	12	1374	4,308	296,403	216	3.14			WPC	1
SEMO	HAYTI	452053	12	288	895	213,061	740	3.11	WPC	WPC	WPC	3
GATEWAY	DORSETT	203058	12	811	2,472	425,846	525	3.05			WPC	1
SEMO	DEXTER	824003	4	421	1,251	92,116	219	2.97			WPC	1
ARCHVIEW	GERALDINE	120003	4	202	575	398,116	1971	2.85			WPC	1
GATEWAY	BERKELEY	134054	12	1858	5,284	989,496	533	2.84			WPC	1
UNDERGROUND	UNDERGROUND	082051	12	366	1,036	285,059	779	2.83		WPC	WPC	2
MERAMEC VALLEY	FRANKLIN	585052	12	280	790	191,888	685	2.82			WPC	1
SEMO	ST FRANCOIS	561053	12	765	2,155	355,812	465	2.82			WPC	1
BOONE TRAILS	MEXICO	800001	4	90	241	28,914	321	2.68			WPC	1
BOONE TRAILS	WENTZVILLE	672053	12	287	760	94,205	328	2.65	WPC		WPC	2
GATEWAY	DORSETT	209055	12	245	642	42,151	172	2.62			WPC	1
GATEWAY	BERKELEY	131005	4	577	1,479	916,223	1588	2.56			WPC	1
GATEWAY	BERKELEY	167054	12	1598	4,090	705,641	442	2.56	WPC		WPC	2
SEMO	HAYTI	465055	12	989	2,492	257,101	260	2.52	WPC		WPC	2
GATEWAY	DORSETT	256054	12	1637	4,103	334,091	204	2.51			WPC	1
GATEWAY	BERKELEY	272053	12	405	998	118,137	292	2.46			WPC	1
SEMO	CAPE GIRARDEAU	871057	12	268	654	108,607	405	2.44			WPC	1
MERAMEC VALLEY	FRANKLIN	503052	12	403	981	66,771	166	2.43			WPC	1
BOONE TRAILS	WENTZVILLE	674052	12	424	1,031	123,615	292	2.43		WPC	WPC	2
SEMO	DEXTER	688007	4	228	546	116,924	513	2.39			WPC	1
CENTRAL OZARKS	CAPITAL	854051	12	452	1,079	287,977	637	2.39			WPC	1
ARCHVIEW	GERALDINE	128004	4	89	210	18,158	204	2.36			WPC	1
MERAMEC VALLEY	FRANKLIN	506051	12	716	1,687	168,082	235	2.36			WPC	1
SEMO	DEXTER	628053	12	601	1,412	145,268	242	2.35			WPC	1
BOONE TRAILS	WENTZVILLE	645052	12	59	138	13,729	233	2.34			WPC	1
MERAMEC VALLEY	ELLISVILLE	169053	12	184	423	105,188	572	2.30			WPC	1
GATEWAY	BERKELEY	269004	4	819	1,879	106,539	130	2.29			WPC	1
GATEWAY	BERKELEY	265052	12	803	1,832	169,496	211	2.28			WPC	1
GATEWAY	BERKELEY	167056	12	722	1,640	654,479	906	2.27			WPC	1
BOONE TRAILS	MOBERLY	939053	12	572	1,299	69,111	121	2.27			WPC	1
GATEWAY	BERKELEY	153006	4	736	1,669	109,782	149	2.27			WPC	1
SEMO	CAPE GIRARDEAU	607054	12	271	613	86,263	318	2.26	WPC		WPC	2
GATEWAY	DORSETT	203051	12	1426	3,221	641,569	450	2.26			WPC	1
MERAMEC VALLEY	JEFFERSON	560053	12	1469	3,309	540,329	368	2.25			WPC	1
SEMO	CAPE GIRARDEAU	607055	12	272	612	111,306	409	2.25			WPC	1
CENTRAL OZARKS	EXCELSIOR SPRINGS	917051	12	575	1,265	58,714	102	2.20			WPC	1
BOONE TRAILS	WENTZVILLE	629051	12	484	1,058	155,184	321	2.19		WPC	WPC	2
BOONE TRAILS	KIRKSVILLE	703001	4	588	1,278	90,411	154	2.17			WPC	1
ARCHVIEW	GERALDINE	160001	4	470	1,021	106,888	227	2.17			WPC	1
CENTRAL OZARKS	CAPITAL	847001	4	112	243	45,361	405	2.17			WPC	1
BOONE TRAILS	MOBERLY	745053	12	226	490	44,431	197	2.17			WPC	1
GATEWAY	ST CHARLES	577051	12	1098	2,380	204,757	186	2.17			WPC	1
ARCHVIEW	MACKENZIE	271055	12	1687	3,646	355,530	211	2.16			WPC	1
GATEWAY	DORSETT	256059	12	1063	2,290	334,462	315	2.15	WPC		WPC	2
SEMO	DEXTER	622054	12	389	837	78,434	202	2.15	WPC		WPC	2
SEMO	CAPE GIRARDEAU	646052	12	949	2,038	483,236	509	2.15	WPC		WPC	2
GATEWAY	BERKELEY	096003	4	666	1,424	60,932	91	2.14			WPC	1
ARCHVIEW	GERALDINE	083006	4	71	151	10,482	148	2.13			WPC	1
ARCHVIEW	MACKENZIE	015011	4	357	759	61,554	172	2.13			WPC	1
ARCHVIEW	GERALDINE	255001	4	730	1,549	246,726	338	2.12			WPC	1
SEMO	POTOSI	487051	12	58	123	7,213	124	2.12			WPC	1
ARCHVIEW	MACKENZIE	020003	4	61	129	11,301	185	2.11			WPC	1

Appendix A
Ameren Missouri 2011 Worst Performing Circuits

DIVISION	OPERATING AREA	CIRCUIT	VOLT	CUSTOMERS	CI	CMI	SAIDI	SAIFI	2009	2010	2011	Years WPC
GATEWAY	BERKELEY	181003	4	693	1,457	702,091	1013	2.10			WPC	1
MERAMEC VALLEY	ELLISVILLE	295052	12	854	1,794	270,368	317	2.10			WPC	1
MERAMEC VALLEY	JEFFERSON	185053	12	644	1,350	262,948	408	2.10			WPC	1
ARCHVIEW	MACKENZIE	245051	12	1318	2,752	174,086	132	2.09			WPC	1
GATEWAY	BERKELEY	260053	12	407	845	93,989	231	2.08			WPC	1
ARCHVIEW	GERALDINE	044006	4	165	342	40,548	246	2.07			WPC	1
ARCHVIEW	MACKENZIE	105005	4	674	1,397	225,715	335	2.07			WPC	1
UNDERGROUND	UNDERGROUND	285054	12	318	658	200,609	631	2.07			WPC	1
GATEWAY	ST CHARLES	583051	12	992	2,049	60,529	61	2.07			WPC	1
GATEWAY	BERKELEY	210051	12	1289	2,647	193,468	150	2.05			WPC	1
SEMO	CAPE GIRARDEAU	803053	12	58	118	21,027	363	2.03			WPC	1
SEMO	DEXTER	623003	4	284	577	82,445	290	2.03			WPC	1
CENTRAL OZARKS	EXCELSIOR SPRINGS	717051	12	1116	2,267	179,775	161	2.03			WPC	1
ARCHVIEW	MACKENZIE	194052	12	1199	2,433	405,902	339	2.03			WPC	1
BOONE TRAILS	KIRKSVILLE	705001	4	330	664	34,728	105	2.01			WPC	1
GATEWAY	DORSETT	266052	12	92	185	40,512	440	2.01			WPC	1
BOONE TRAILS	KIRKSVILLE	858052	12	1	2	99	99	2.00			WPC	1
UNDERGROUND	UNDERGROUND	082052	12	172	343	91,415	531	1.99	WPC		WPC	2
BOONE TRAILS	WENTZVILLE	647052	12	308	613	118,770	386	1.99			WPC	1
GATEWAY	ST CHARLES	544055	12	868	1,720	229,612	265	1.98	WPC		WPC	2
GATEWAY	BERKELEY	163003	4	507	1,003	74,166	146	1.98			WPC	1
GATEWAY	BERKELEY	039004	4	386	757	88,401	229	1.96			WPC	1
ARCHVIEW	GERALDINE	083008	4	41	80	2,280	56	1.95			WPC	1
GATEWAY	BERKELEY	259054	12	2031	3,920	276,332	136	1.93			WPC	1
GATEWAY	DORSETT	264060	12	854	1,618	133,538	156	1.89			WPC	1
ARCHVIEW	MACKENZIE	253052	12	1563	2,955	245,717	157	1.89			WPC	1
SEMO	POTOSI	473053	12	625	1,175	408,646	654	1.88			WPC	1
BOONE TRAILS	WENTZVILLE	627051	12	589	1,100	59,066	100	1.87	WPC		WPC	2
MERAMEC VALLEY	ELLISVILLE	279054	12	1123	2,096	162,798	145	1.87			WPC	1
SEMO	ST FRANCOIS	161051	12	997	1,839	244,259	245	1.84			WPC	1
ARCHVIEW	GERALDINE	104008	4	748	1,374	506,530	677	1.84			WPC	1

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 635007
Division – SEMO
Area Served – Cape Girardeau, MO
SAIFI Value – 32.98

Analysis Results:

The high SAIFI value for this circuit is misleading due to a change in customer count from 800 to 49 at the end of the year, and also due to two large outages that were incorrectly recorded in 2011. In reviewing the first outage it was discovered that a reporting error improperly attributed this event as an outage when the customers were actually in service. In reviewing the second outage it was discovered that customers had been transferred to the Midtown 621003 circuit and no actual customer interruptions had occurred. When the CI associated with these reported outages are removed, the overall SAIFI calculation for this circuit would have been 0.88. Therefore, no corrective actions are necessary for this circuit.

Corrective Actions:

No work is planned on this circuit in 2012.

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APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 564051
Division – Gateway
Area Served – St. Charles, MO
SAIFI Value – 18.77

Analysis Results:

This circuit serves 250 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by underground cable faults and a tree failure resulting in 4,639 of the total 4,692 CI. Circuit 564051 experienced three significant outages in 2011 which resulted in 99% of the CI experienced on this circuit. Two of the outages occurred when the direct buried primary cable on the circuit backbone failed. The other outage occurred when a tree branch broke and contacted the overhead lines.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Both primary cable failures were repaired. The existing sections of direct buried primary cable were replaced with new primary cable installed in conduit under DOJM Work Request number 25SC051861. This work was completed in March 2012.

The circuit will be patrolled in 2012 to determine if any additional spot tree trimming is required.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of this inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 879006
Division – SEMO
Area Served – Lilbourn, MO
SAIFI Value – 8.31

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were: 3.18 in 2010 and 8.31 in 2011. This circuit serves 344 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather, heat loading, overloads, and overhead equipment failures. Circuit 879006 experienced ten significant outages in 2011. Two outages occurred when the substation breaker tripped due to lightning. Two outages occurred when reclosers tripped due to excessive heat loading on the circuit. Three outages occurred as a result of the primary phases contacting each other during heavy wind. Two outages occurred as a result of the substation breaker tripping due to an overload from the new Pioneer Plant. Lastly, one outage occurred as a result of a lightning arrester failure.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2010.

A project to re-conductor and add lightning arrestors to a portion of the circuit running towards Ristine was performed under DOJM Work Request numbers 2TSE095450 and 2TSE095451. This work was completed in August 2011 and November 2011 respectively.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of this inspection was performed under DOJM Work Request numbers 2TSE097308, 2TSE097708, and 2TSE098621 which were completed in July 2011, October 2011, and November 2011 respectively.

Wire spacers were added to the circuit near the substation to prevent the primary phases from contacting each other. In addition, the substation breaker was upgraded to eliminate overload conditions. This work was performed in 2011.

Planned MWPC reliability improvement work:

A new substation is being built with a capacity of 7MVA, SCADA switchgear, and a third circuit which will serve the new Pioneer Plant load. The feeder exits will be undergrounded which will eliminate the primary phase contact problem. This project is expected to be completed in June 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 659051
Division – Boone Trails
Area Served – Wentzville, MO
SAIFI Value – 6.71

Analysis Results:

This circuit serves 295 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and overhead equipment failures. Circuit 659051 experienced three significant outages in 2011. The first outage occurred when an insulator failed. The second outage occurred when a cross arm twisted in the wind. The third outage occurred when an insulator failed and caused the primary to fall.

Corrective Actions:

Both insulators and the cross arm were replaced.

Several transformers on the circuit backbone and several taps were fused in 2011.

Several old insulators on the circuit backbone were replaced in 2011.

Division engineering personnel will review the circuit in 2012 to determine where lightning arrestors should be installed to limit outages caused by lightning strikes.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 161054
Division – SEMO
Area Served – Farmington, MO
SAIFI Value – 6.04

Analysis Results:

This circuit originally served 1,073 customers. However, in November of 2011 666 of these customers were transferred to new circuit 161056, reducing the customer count on circuit 161054 to 407. This reduced number of customers was used to calculate the SAIFI value which placed this circuit on the WPC list. If the original customer count were included, the overall SAIFI calculation for this circuit would have been 2.29.

The customer interruptions (CI) experienced on this circuit in 2011 were caused by storms and equipment failures. Circuit 161054 experienced four circuit outages in 2011. Two outages were caused by storms, which caused wire failures and tree damage. A third outage was caused by faulty insulators on the circuit backbone. The fourth outage was caused by a capacitor bank failure.

Corrective Actions:

Circuit 161054 was modified in 2011. A new feeder exit project, the Farmington 161056 circuit, moved nine miles of circuit 161054 to new circuit 161056. This reduced the three phase exposure on circuit 161054 to five miles, which will greatly improve its reliability. This project was performed under DOJM Work Request numbers 28SF034583 and 28SF034295, which were completed in November 2011 and January 2012 respectively.

Tree trimming will be performed on this circuit in 2012.

Circuit protection projects, including additional fuses and insulators, will be performed under DOJM Work Request numbers 28SF035489 and 28SF035919 in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 797008
Division – Boone Trails
Area Served – Moberly, MO
SAIFI Value – 5.14

Analysis Results:

This circuit serves 14 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment malfunctions and weather. Circuit 797008 experienced several significant outages in 2011. The outages occurred when fuses blew during adverse weather conditions. This circuit is being reconfigured to 12kV.

Corrective Actions:

This circuit's load was transferred to circuit 914055 in 2011. Circuit 797008 will be removed and the substation retired.

No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 708004
Division – Boone Trails
Area Served – Boonville, MO
SAIFI Value – 5.00

Analysis Results:

This circuit serves 1 customer. The customer interruptions (CI) experienced on this circuit in 2011 were caused by hardware failures. Circuit 708004 experienced five significant outages in 2011. These five outages occurred due to hardware failures on the circuit. This circuit is being reconfigured to 12kV.

Corrective Actions:

This circuit will be retired this year and the load will be transferred to an adjacent 12kV circuit with greater capacity.

No work is planned on this circuit in 2012.

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APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 835002
Division – SEMO
Area Served – Chaffee, MO
SAIFI Value – 4.78

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were: 2.58 in 2010 and 4.78 in 2011. This circuit serves 138 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by public vehicle accidents and a primary wire failure. Circuit 835002 experienced three significant outages in 2011. Two of these outages were caused by public vehicle accidents. The other outage occurred when a primary wire failed due to excessive heat loading and caused the substation breaker to trip.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed a mid-cycle patrol of this circuit in 2011.

A major substation project to replace the existing substation and switchgear was completed in 2011.

New 34kV and 3-4160V feeder exits were installed on this circuit along with regaining the third feeder position lost in 2007 when the existing switchgear failed. This work was performed under DOJM Work Request numbers 2TSE095580, 2TSE095461, 2TSE095460, and 2TSE095456, which were completed in September and October 2011.

A special visual inspection was performed on this circuit in 2011 which inspected for animal guarding, tap fusing, and maintenance issues. Repairs were performed under DOJM Work Request number 2TSE097993 which was completed in September 2011.

Planned MWPC reliability improvement work:

Normally scheduled tree trimming will be performed on this circuit in 2012. No further reliability work is needed.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 655058
Division – Boone Trails
Area Served – Saint Peters, MO
SAIFI Value – 4.29

Analysis Results:

This circuit serves 1,064 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and cable failures. Circuit 655058 experienced four significant outages in 2011. The first outage occurred when a tree broke and fell onto the primary during a thunderstorm. The second outage occurred when a tree limb fell onto the primary during a thunderstorm. The last two outages occurred when the direct buried feeder exit cable failed.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

The direct buried feeder exit cable that failed is being replaced with cable in conduit. This work will be performed in 2012 under DOJM Work Request number 2WWZ146467.

Division engineering personnel will patrol the circuit in 2012 to verify that all backbone transformers are fused and to determine if any additional opportunities for circuit sectionalizing exist.

Division engineering personnel will perform an Infrared (IR) inspection of the circuit. Repair work identified as a result of this inspection will be completed in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 188008
Division – Archview
Area Served – University City, MO
SAIFI Value – 4.06

Analysis Results:

This circuit originally served 516 customers. However, in 2011 this circuit was reconfigured to eliminate overload concerns, which reduced the customer count to 176. This reduced number of customers was used to calculate the SAIFI value which placed this circuit on the WPC list. If the original customer count were to be included, the overall SAIFI calculation for this circuit would have been 1.38.

The customer interruptions (CI) experienced on this circuit in 2011 were caused by an underground cable failure and a wire fault. Circuit 188008 experienced two significant outages in 2011. The first outage occurred due to an underground cable fault. The second outage occurred when a 34kV circuit sagged into circuit 188008 and caused it to trip.

Corrective Actions:

The underground cable that failed was replaced in 2011.

Circuit 188008 was lowered to prevent future clearance problems with the 34kV circuit. This work was performed in 2011.

An overhead visual and ground line inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 083002
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 4.00

Analysis Results:

This circuit serves approximately 31 primarily commercial/industrial customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a public vehicle accident and overhead equipment failures resulting in 124 CI. Circuit 083002 experienced two significant outages in 2011 which resulted in 99% of the CI experienced on this circuit. The first outage occurred when a vehicle hit a pole on private property, which resulted in a circuit outage to make repairs. The second outage occurred when the jumpers on a tie switch failed during abnormal switching.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009.

A portion of the circuit was rebuilt in 2011 to accommodate the facility expansion at ADM Company. This work also improved and re-configured the secondary portion of the circuit where the wires were shorting together.

No further work is planned on this circuit in 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 483052
Division – SEMO
Area Served – Ironton, MO
SAIFI Value – 3.96

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the last three years were: 2.27 in 2009, 0.18 in 2010, and 3.96 in 2011. This circuit serves 874 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by tree contacts, switching errors, faulty overhead equipment, weather, and animal intrusions. Circuit 483052 experienced multiple outages in 2011. Outages were caused by a tree contact on a three phase circuit, a switching error inside a substation, and a faulty lightning arrester on the circuit backbone. Device level outages were also caused by wire failures during thunderstorms and animal intrusions in equipment.

Corrective Actions:

Previous reliability work performed on this circuit:

Seven miles of this circuit were rebuilt and re-conductored which eliminated most aging hardware and voltage problem concerns. This work was performed under DOJM Work Request numbers 28IR031993, 28IR031994, and 28IR031995, completed in September and December of 2009, and February of 2010.

Line reclosers and fuses were installed on the radial section of this circuit. This work was performed under DOJM Work Request numbers 28IR030744 and 28IR033264, completed in June and April of 2010

Animal guards and line spinners were installed on substation line components to reduce future substation outages caused by animal intrusions under DOJM Work Request number 28IR034555 which was completed in December 2010.

In 2011, the 6 year cycle tree trimming was completed for this circuit. This action should reduce the amount of tree caused outages in 2012.

Planned MWPC reliability improvement work:

Additional protection was installed on unprotected backbone devices under DOJM Work Request number 28IR036154, which was completed in February 2012.

Additional switch labels were installed at the Pilot Knob substation to ensure correct switch identification, thereby eliminating future switching errors. This work was performed under OAS Order Number 120243636 in January 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 620055
Division – SEMO
Area Served – Parma, MO
SAIFI Value – 3.88

Analysis Results:

This circuit serves 219 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 620055 experienced four significant outages in 2011. Two outages occurred when the substation breaker tripped as a result of high winds and snow. Two other outages occurred when the substation breaker tripped following primary conductor failures during storms

Corrective Actions:

A visual inspection of this circuit will be performed by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099725.

An overhead visual and ground line inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 828056
Division – SEMO
Area Served – Blodgett, MO
SAIFI Value – 3.88

Analysis Results:

This circuit serves 328 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures and weather. Circuit 828056 experienced seven significant outages in 2011. Two outages occurred when the primary failed during a thunderstorm. Two outages occurred when lightning arresters failed. Lastly, three outages occurred when the primary conductor failed due to load which caused the reclosers to trip.

Corrective Actions:

An overhead visual and ground line inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 690057
Division – SEMO
Area Served – Richland, MO
SAIFI Value – 3.80

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009, 2010, and 2011. The SAIFI values for this circuit in the last three years were: 3.92 in 2009, 5.11 in 2010, and 3.80 in 2011. This circuit serves 619 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and underground cable failures. Circuit 690057 experienced seven significant outages in 2011. Two outages occurred when the 34kV subtransmission primary failed during storms. Another outage occurred when the substation high side fuses blew during a thunderstorm. Two more outages occurred when the primary failed during storms. Lastly, two outages occurred when the substation feeder exit cable failed.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2008.

A special overhead visual inspection was performed on this circuit in 2010. The inspection identified needed animal guarding, tap-fusing, and other maintenance items. Tap fusing was performed under DOJM Work Request number 2TSE092583 which was completed in December 2010. The remaining circuit inspection work was performed under DOJM Work Request number 2TSE093548 which was completed in November 2010.

Three sets of reclosers were installed to sectionalize the circuit. This work was performed under DOJM Work Request number 2TSE092584 and was completed in December 2010.

The substation underground feeder exit cable was replaced under DOJM Work Request number 2TSE097309 in August 2011.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of this inspection was completed in accordance with Ameren Missouri’s infrastructure inspection policy. This work was performed under DOJM Work Request numbers 2TSE097992 and 2TSE097095 which were completed in October 2011 and December 2011 respectively.

Planned MWPC reliability improvement work:

A normally scheduled underground detailed inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 456057
Division – SEMO
Area Served – Deering, MO
SAIFI Value – 3.78

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009, 2010, and 2011. The SAIFI values for this circuit in the last three years were: 2.37 in 2009, 3.17 in 2010, and 3.78 in 2011. This circuit serves 134 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and overhead equipment failures. Circuit 456057 experienced six significant outages in 2011. One outage occurred when the 34kV subtransmission primary failed during a storm. A second outage occurred when a recloser tripped during a thunderstorm. A third outage occurred when a transformer failed which resulted in a fused switch failure. The remaining three outages occurred when the primary on this circuit failed during inclement weather.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2010.

An overhead visual inspection was done on this circuit in 2010. The repair work identified as a result of this inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy. This work was performed under DOJM Work Request number 2TSE093555 which was completed in October 2010.

A special overhead visual inspection was performed on this circuit in 2011 which inspected for animal guarding, tap fusing, maintenance issues, and performed an infrared scan of the circuit. Repairs were performed under DOJM Work Request numbers 2TSE097298, 2TSE097705, and 2TSE097099 which were completed in July 2011, August 2011, and September 2011 respectively.

A 34kV Viper recloser was installed at the Hayti West substation to replace the old OCB. This 34kV substation serves the 12kV Deering substation. This work was performed under DOJM Work Request number 2TSE093963 which was completed in October 2011.

Planned MWPC reliability improvement work:

The previously completed reliability work is expected to improve the performance of this circuit to an acceptable level. No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 281054
Division – Gateway
Area Served – Berkeley, MO
SAIFI Value – 3.67

Analysis Results:

This circuit serves 1,302 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees and underground equipment failures. Circuit 281054 experienced three significant outages in 2011 which resulted in 71% of the total CI experienced on this circuit. The first two outages occurred when high winds caused tree damage on the circuit. The third outage occurred when an underground cable failed.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These include fusing the transformers on the circuit backbone. This work was performed under DOJM Work Request number 21MT546198 which was completed in March 2012. In addition, two overhead transformers and a pole will be replaced under DOJM Work Request number 21MT546241.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of this inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 456055
Division – SEMO
Area Served – Deering, MO
SAIFI Value – 3.64

Analysis Results:

This circuit serves 97 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and an overhead equipment failure. Circuit 456055 experienced four significant outages in 2011. The first outage occurred when trees fell into the primary during a thunderstorm. Two other outages occurred when the substation breaker tripped when trees contacted the primary during storms. The last outage occurred when a 34kV jumper failed.

Corrective Actions:

A 34kV Viper recloser was installed at the Hayti West substation to replace the old OCB. This 34kV substation serves the 12kV Deering substation. This work was performed under DOJM Work Request number 2TSE093963 which was completed in October 2011.

A visual inspection of this circuit will be performed by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099736.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 466055
Division – SEMO
Area Served – Wardell, MO
SAIFI Value – 3.60

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were 2.48 in 2010 and 3.60 in 2011. This circuit serves 151 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and overhead equipment failures. Circuit 466055 experienced four significant outages in 2011. The first outage occurred when a fuse blew during calm weather. The second outage occurred when a fuse blew during a thunderstorm. The two other outages occurred when the substation breaker tripped as a result of lightning strikes during thunderstorms.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2010.

A special overhead visual inspection was performed on this circuit in 2011. The inspection identified needed animal guarding, tap-fusing, and other maintenance items. Repairs were performed under DOJM Work Request number 2TSE097100 which was completed in August 2011. Additional work to install reclosers, replace poles, and replace cross arms was performed under DOJM Work Request number 2TSE097706 which was completed in August 2011.

Planned MWPC reliability improvement work:

The previously completed reliability work is expected to improve the performance of this circuit to an acceptable level. No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 836051
Division – Central Ozark
Area Served – Marys Home, Eugene, Henley, MO
SAIFI Value – 3.43

Analysis Results:

This circuit serves 295 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a transmission line failure and tree failures. Circuit 836051 experienced three significant outages in 2011. One outage occurred when the 138kV transmission line which supplies this circuit's substation failed, causing the circuit to fail. Two other outages occurred when tree limbs fell into the lines during two different storms.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012. This work is expected to resolve the only recurring reliability problem on this circuit.

There are no other repetitive causes of the outages experienced on this circuit. Therefore, no other work is planned for this circuit in 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 215053
Division – Gateway
Area Served – Black Jack, MO
SAIFI Value – 3.43

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were: 2.09 in 2010 and 3.43 in 2011. This circuit serves 1,339 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather which resulted in 3,966 CI. Circuit 215053 experienced four significant outages in 2011 which resulted in 83% of the CI experienced on this circuit. The first outage occurred in May 2011 when a pole broke during a thunderstorm and required the circuit to be de-energized while repairs were made. The outage resulted in 893 CI. The second outage occurred in June 2011 when a tree branch broke and fell into the primary during a thunderstorm. The third outage occurred in September 2011 when a tree branch broke and fell into the primary during a thunderstorm. These two storms resulted in 2,052 CI. The fourth outage occurred in September 2011 when a cross arm broke during a thunderstorm and resulted in 1,019 CI.

Corrective Actions:

Previous reliability work performed on this circuit:

Tree trimming was last performed on this circuit in 2009.

Engineering personnel patrolled the circuit in 2010. This patrol identified the need for fusing and animal guarding. This work was performed under DOJM Work Request number 21MT523706 which was completed in April 2011.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Division engineering personnel performed an overhead inspection of the circuit and several improvement opportunities were identified. These included replacement of insulators, lightening arrestors, and deteriorated poles, as well as the installation of animal guards and the coordination and relocation of fuses. The need for additional tree trimming was identified and coordinated with the Vegetation Management Department. The repair work identified as a result of this inspection will be performed under DOJM Work Request number 21MT546755 which will be completed in December 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 455053
Division – SEMO
Area Served – Caruthersville, MO
SAIFI Value – 3.36

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009, 2010, and 2011. The SAIFI values for this circuit in the last three years were: 3.56 in 2009, 2.21 in 2010, and 3.36 in 2011. This circuit serves 817 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather, overhead equipment malfunctions, substation failures, and public vehicle accidents. Circuit 455053 experienced seven significant outages in 2011. The first outage occurred when the Hayti 71 34kV circuit tripped the Hayti Bulk substation during a lightning storm. The second outage occurred when a switch burned during a thunderstorm. The third outage occurred when a jumper burned as a result of a failed connection. Two other outages occurred due to substation faults. The last two outages occurred as a result of public vehicle accidents.

Corrective Actions:

Previous reliability work performed on this circuit:

A major rebuild and re-conductor project was performed on this circuit in 2010. This work was performed under DOJM Work Request numbers 2TSE090495, 2TSE090496, and 2TSE090784 which were completed in November 2010, December 2010, and December 2010 respectively.

A project to build a new 34kV loop to serve the previously radial fed Caruthersville West substation was performed under DOJM Work Request numbers 2TSE090497 and 2TSE091155. This work was completed in August 2010 and September 2010 respectively.

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2011.

The following upgrades were made to the substation in 2011: Animal spinners were added to the overhead line and a Viper recloser was installed.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of this inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy. This work was performed under DOJM Work Request number 2TSE097988 which was completed in September 2011.

Planned MWPC reliability improvement work:

An Intellirupter recloser will be installed on this circuit in 2012 to establish a tie with the Caruthersville West (455055) circuit. This work will be performed under DOJM Work Request number 2TSE100085 which will be completed in December 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 454055
Division – SEMO
Area Served – Caruthersville, MO
SAIFI Value – 3.32

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009, 2010, and 2011. The SAIFI values for this circuit in the past three years were: 5.55 in 2009, 3.41 in 2010, and 3.32 in 2011. This circuit serves 1,103 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and overhead equipment failures. Circuit 454055 experienced five significant outages in 2011. The first outage occurred when the Hayti 71 34kV circuit tripped the Hayti Bulk substation during a lightning storm. A second outage occurred when the substation breaker tripped as a result of a lightning strike. A third outage occurred when a jumper burned as a result of a failed connection. The remaining two outages occurred when trees contacted the line during storms and caused the substation breaker to trip.

Corrective Actions:

Previous reliability work performed on this circuit:

A major rebuild and re-conductor project was performed on this circuit in 2010. This work was performed under DOJM Work Request numbers 2TSE090495, 2TSE090496, and 2TSE090784 which were completed in November 2010, December 2010, and December 2010 respectively.

Tree trimming was performed on this circuit in 2011.

A special overhead visual inspection was performed on this circuit in 2011 which inspected for animal guarding, tap fusing, and maintenance issues. Repairs were performed under DOJM Work Request number 2TSE097702 which was completed in December 2011.

Planned MWPC reliability improvement work:

An Intellirupter recloser will be installed on this circuit in 2012 to establish a tie with the Caruthersville West (455053) circuit. This work will be performed under DOJM Work Request number 2TSE100086 which will be completed in December 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 451054
Division – SEMO
Area Served – Viburnum, MO
SAIFI Value – 3.31

Analysis Results:

This circuit serves 403 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees, pole hardware failures, and wire failures. Circuit 451054 did not experience significant outages in 2011, but did experience a number of smaller device outages that together resulted in enough CI to place this circuit on the WPC list. The majority of these outages occurred on three different reclosers which tripped on multiple occasions. These failures were caused by tree contacts, overhead equipment failures, and primary failures.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009 in accordance with the 6 year rural schedule.

Additional reclosers, fuses, and switches were installed on various sections of this circuit to improve reliability and increase fault isolation during outages. This work was performed under DOJM Work Request numbers 28IR034384 and 28IR034193 in December 2010 and January 2011, respectively.

An overhead visual inspection and a ground line inspection were performed on this circuit in 2011. These inspections identified approximately 150 pole replacements and various other hardware repairs. The repair work identified as a result of the inspection is in progress and will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

The Vegetation Management Department will perform a mid-cycle patrol of this circuit in 2012 to identify and remove tree hazards.

Automated switch installations on single phase circuit taps will be performed under DOJM Work Request number 28IR036322 in 2012.

The substation 451054 circuit breaker will be replaced with a new SCADA controlled Viper circuit breaker with single phase trip capability in 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 546054
Division – Meramec Valley
Area Served – House Springs, MO
SAIFI Value – 3.17

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were: 2.80 in 2010 and 3.17 in 2011. This circuit serves 155 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by equipment malfunctions and public vehicle accidents, resulting in 335 CI. Circuit 546054 experienced three significant outages in 2011. Two outages were caused by underground feeder exit cable failures near the circuit substation. The third outage occurred as a result of a public vehicle hitting a pole.

Corrective Actions:

Previous reliability work performed on this circuit:

A recloser which caused an outage due to a cold load pickup failure was replaced under DOJM Work Request number 26JF110855. This job was completed in February 2010.

The Vegetation Management Department performed spot tree trimming on the circuit in 2011.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Two jobs were created to address problems identified in 2011. Animal guards will be installed on the circuit under DOJM Work Request number 26JF119050 and fuses will be installed on un-fused taps along the circuit backbone under DOJM Work Request number 26JF119359. These jobs will be completed in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 134051
Division – Gateway
Area Served – Florissant, MO
SAIFI Value – 3.14

Analysis Results:

This circuit serves 1,377 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by an operator error and weather. Circuit 134051 experienced five significant outages in 2011. The first outage occurred when a pole broke during a storm. The second outage occurred due to a lightning strike during a thunderstorm. The third outage occurred when a thunderstorm caused a tree branch to fall into the line. The fourth outage also occurred when a thunderstorm caused a tree branch to fall into the line. The last outage occurred when an operator made a switching error on the circuit.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 452053
Division – SEMO
Area Served – Braggadocio, MO
SAIFI Value – 3.11

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009, 2010, and 2011. The SAIFI values for this circuit in the last three years were: 3.04 in 2009, 2.32 in 2010, and 3.11 in 2011. This circuit serves 288 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 452053 experienced five significant outages in 2011. The first outage occurred when the Hayti 72 34kV circuit tripped the Hayti Bulk substation during a lightning storm. Two other outages occurred when the primary failed during storms. The remaining two outages occurred when trees contacted the line during storms and caused the substation breaker to trip.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2010.

A project to coordinate and add fuses to this circuit was performed in 2010. The work was performed under DOJM Work Request number 2TSE092735 which was completed in October 2010.

An overhead visual inspection was performed on this circuit in 2011 which inspected for animal guarding, tap fusing, and maintenance issues. Repairs were performed under DOJM Work Request numbers 2TSE096750 and 2TSE097700 which were completed in June 2011 and October 2011 respectively.

Planned MWPC reliability improvement work:

The previously completed reliability work is expected to improve the performance of this circuit. No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 203058
Division – Gateway
Area Served – Bridgeton, MO
SAIFI Value – 3.05

Analysis Result

This circuit serves 811 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather, an underground cable fault, and unknown causes. Circuit 203058 experienced three significant outages in 2011. The first outage occurred for unknown reasons as no cause was found at the time. The second outage occurred when a tornado caused a tree contact. The third outage occurred when an underground cable faulted.

Corrective Actions:

The faulted cable was repaired under DOJM Work Request number 21MT532814 which was completed in July 2011.

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 824003
Division – SEMO
Area Served – Bernie, MO
SAIFI Value – 2.97

Analysis Results:

This circuit serves 421 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 824003 experienced three significant outages in 2011. Two of these outages occurred when the substation breaker tripped during high winds and storms. The other outage occurred when a tree made contact with the primary during a storm which caused the substation breaker to trip.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

A visual inspection of this circuit will be performed by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099753.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 120003
Division – Archview
Area Served – Pine Lawn, North St. Louis County, MO
SAIFI Value – 2.85

Analysis Results:

The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure. Circuit 120003 experienced a significant outage during a storm when a large limb fell on the overhead primary and broke a pole and the wire. The outage was partially restored and following the partial restoration the number of customers affected was miscounted. Instead of 374 customers, only 38 customers remained out of service following the partial restoration. This would have resulted in an overall circuit SAIFI value of 1.43. Therefore, no corrective actions are necessary for this circuit.

Corrective Actions:

No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 134054
Division – Gateway
Area Served – Florissant, MO
SAIFI Value – 2.84

Analysis Results:

This circuit serves 1,857 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather, animal intrusions, operator errors, overhead equipment failures, and unknown causes. Circuit 134054 experienced five significant outages in 2011. The first outage occurred when a lightning arrestor failed. The second outage occurred for an unknown reason, but did occur on a day with high winds and thunderstorms. The third outage occurred due to a lightning strike on the circuit. The fourth outage occurred due to the improper calibration of the substation relays. The fifth outage occurred when an animal intrusion into the substation caused the substation to trip.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

The relay settings at the substation where the outage occurred have been re-calibrated.

Line guards will be installed on the overhead lines into the Shackelford substation to prevent animal intrusions. This work will be performed under DOJM Work Request number 21MT548008.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 082051
Division – Underground
Area Served – Saint Louis, MO
SAIFI Value – 2.83

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the past two years were: 2.99 in 2010 and 2.83 in 2011. This circuit serves 371 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by an underground cable failure, customer equipment failures, and a substation equipment failure. Circuit 082051 experienced four significant outages in 2011. The first outage occurred in April when a water main break flooded the Sigma-Aldrich primary switchgear. The resulting fault tripped the entire Cole 51 circuit. The second outage occurred in October when a cable splice in the manhole at 15th and Washington failed. The third outage occurred in November when a fault in the CPI Building primary switchgear tripped the entire Cole 51 circuit. The fault at the CPI Building appeared to have been caused by a lightning arrester failure. Due to the Cole 51 damage at the CPI Building, the Cole 51 load was switched to the Cole 52 circuit until Cole 51 repairs could be made. The fourth outage occurred when a Traveling Substation Operator performing an inspection on the Cole Substation opened the bus tie cabinet door to record breaker operation counts and substation equipment malfunctioned causing the Cole 52 circuit to trip. Cole 51 customers switched to Cole 52 experienced this additional outage.

The Cole circuit has unique features that do not exist at other locations, including high fault currents that cause coordination problems. The underground Cole 51 circuit has no sectionalizing devices because they cannot coordinate with the instantaneous trip settings on the Cole 51 circuit. The instantaneous trip setting is set at 4500 Amperes to limit the amount of fault current, and resulting damage, to the circuit. The Cole Substation has no reactors so the low instantaneous trip setting cannot be raised. In addition, the System Relay Department has indicated that there are no known devices that can coordinate with the required instantaneous settings at the Cole substation.

A second issue with the Cole 51 circuit is the circuit exposure length. There are essentially two sections of the circuit: the area east of Jefferson Ave. and the area west of Jefferson Ave. In addition, there are no available feeder spaces at the Cole substation. Between the inability to sectionalize the circuit, and the large amount of exposure on the circuit, there are challenges with the reliability of the Cole circuit.

Corrective Actions:

Previous reliability work performed on this circuit:

An automated switchgear tie between Cole 51 and Cole 52 was installed at switch pad 18414 in 2011. This equipment will transfer customers to alternative circuits following feeder lockout. It will not prevent circuit outages but it will reduce customer minutes out.

Planned MWPC reliability improvement work:

Distribution automation equipment will be installed at Beaumont and Market Streets in 2012.

The Cole substation will be eliminated and circuits will transfer to the new Martin Luther King (MLK) switching station in 2014. The customers will ultimately be fed from new Ashley circuits via the new MLK switching station. Much of the cable for the area will be replaced as customers transition to the new feed. Route diversity for the supplies has been incorporated into the designs. These system improvements should help the overall reliability of this circuit.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 585052
Division – Meramec Valley
Area Served – Franklin District, MO
SAIFI Value – 2.82

Analysis Results:

This circuit serves 280 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by animal intrusions, trees, and a substation malfunction, resulting in 790 CI. Circuit 585052 experienced two significant outages in 2011 which resulted in 65% of the CI experienced on this circuit. The first outage occurred when a tree contacted the line and a substation breaker failed. The tree was cleared and the substation breaker auxiliary switch was replaced. A second outage was caused by a tree falling onto the circuit during a major storm. In addition to these outages, smaller outages on this circuit were caused by animal intrusions. Animal intrusions caused 30% of the CI experienced on this circuit.

Corrective Actions:

Animal guards were added to three transformers in 2011. This work was performed under DOJM Work Request numbers 21MT524424, 21MT529542, and 21MT538804 which were completed March 2011, June 2011, and October 2011 respectively.

Division engineering personnel performed an inspection of the circuit in 2012 and several improvement opportunities were identified. Animal guards will be added to six transformers on the circuit under DOJM Work Request number 21MT546972.

The taps off of this circuit serve wooded residential areas and many of the trees are much taller than the poles and wires. Several of these locations were provided to the Vegetation Management Department for detailed review.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 561053
Division – SEMO
Area Served – Terre Du Lac, MO
SAIFI Value – 2.82

Analysis Results:

This circuit serves 765 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by sub-transmission outages, wire problems, and faulty pole hardware. Circuit 561053 experienced significant outages in 2011 due to outages on sub-transmission circuit ESTR-74, which is the single supply to the Terre Du Lac substation, caused by trees and an unknown outage (possibly ground wire theft). Other circuit outages were caused by excess slack in the phase wires and faulty pole hardware.

Corrective Actions:

Tree trimming was last performed on this circuit and sub-transmission circuit ESTR-74 in 2010.

Additional tap fusing was performed on this circuit to protect the 3 phase backbone. This work was performed under DOJM Work Request number 28SF033326 which was completed in March of 2010.

Additional Lightning protection and grounding were installed on sub-transmission circuit ESTR-74. This work was performed under DOJM Work Request number 28SF034579 which was completed in February of 2011.

Substation relay settings were adjusted on circuit 561053 in 2011 to reduce momentary outages.

Line voltage regulators were installed on B & C phases of the circuit to eliminate low voltage complaints. This work was performed under DOJM Work Request numbers 28SF034748 and 28SF035853, which were completed in May 2011 and January 2012 respectively.

An overhead visual inspection and a ground line inspection will be performed on sub-transmission circuit ESTR-74 in 2012. The repair work identified as a result of these inspections will be completed in accordance with Ameren Missouri’s infrastructure inspection policy.

A project to install fuses on long single phase taps under DOJM Work Request number 28SF035921 will be performed in 2012.

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APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 800001
Division – Boone Trails
Area Served – Benton City, Audrain County, MO
SAIFI Value – 2.68

Analysis Results:

This circuit serves 90 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and unknown causes resulting in 241 CI. Circuit 800001 experienced three significant outages in 2011. The first outage occurred when a tree fell into the lines during a thunderstorm. The second outage occurred when a fuse blew at the substation two hours after the first outage was restored. No cause was found for this outage. The third outage occurred when the subtransmission conductor failed during a thunderstorm.

Corrective Actions:

Tree trimming is not scheduled for this circuit until 2014. However, several tree issues were identified and reported to the Vegetation Management Department for spot tree trimming.

Division engineering personnel performed an Infrared (IR) inspection on the Benton City Substation and significant components on the circuit backbone. No thermal problems were found.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacement of cracked or distorted cross arms, insulators, lightening arrestors, un-fused transformers, and deteriorated poles. This work will be performed under DOJM Work Request number 2DLD075107 and will be completed in June 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 672053
Division – Boone Trails
Area Served – Wentzville, MO
SAIFI Value – 2.65

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the last three years were: 2.66 in 2009, 0.69 in 2010, and 2.65 in 2011. This circuit serves 287 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by vegetation, trees, and weather. Circuit 672053 experienced three significant outages in 2011. Two of the outages occurred due to a vine which caused the circuit neutral and primary to contact each other during a storm. The third outage occurred when a tree limb fell on the primary.

Corrective Actions:

Previous reliability work performed on this circuit:

Tree trimming was last performed on this circuit in 2009.

The tap on Highway UU experienced multiple outages in 2009. Fuses and reclosers were added to the circuit under DOJM Work Request number 2WWZ133177, which was completed in September 2009. In addition, a third phase was extended to balance the load and allow better coordination between fuses and reclosers. This work was performed under DOJM Work Request number 2WWZ134219 which was completed in July 2010.

Almost a mile of this circuit along Highway NN and Pike Rd 269 was rebuilt. This work was performed under DOJM Work Request numbers 2WWZ138595 and 2WWZ141786 which were completed in November 2010.

The vine which caused the circuit neutral and primary to contact each other in 2011 has been removed. In addition, the wire spacing in this area has been improved.

Planned MWPC reliability improvement work:

The rest of this circuit will be moved to Highway D and Pike Rd 251 under DOJM Work Request number 2WWZ136674.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 209055
Division – Gateway
Area Served – Bridgeton, MO
SAIFI Value – 2.62

Analysis Results:

This circuit serves 245 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees and overhead malfunctions resulting in 642 CI. Circuit 209055 experienced two significant outages in 2011. The first outage occurred when a tree contacted the lines. The second outage occurred due to an overhead malfunction.

Corrective Actions:

An underground visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Tree trimming will be performed on this circuit in 2012.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of this inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 131005
Division – Gateway
Area Served – Ferguson, MO
SAIFI Value – 2.56

Analysis Results:

This circuit serves 581 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by severe weather. Circuit 131005 experienced four significant outages in 2011. Three of these outages occurred over a three day period in April 2011 when this circuit experienced a tornado and severe winds. The fourth outage occurred when a tree branch fell into the primary during a thunderstorm.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

Division engineering personnel performed an analysis of circuit protection coordination. Three fuses were identified as not coordinating properly and were corrected.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 167054
Division – Gateway
Area Served – Northern Bellefontaine Neighbors, MO
SAIFI Value – 2.56

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the past three years were: 2.12 in 2009, 0.27 in 2010, and 2.56 in 2011. This circuit serves 1,601 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 167054 experienced four significant outages in 2011, all occurring during adverse weather conditions and resulting in 80% of the total CI experienced on this circuit. All four of these outages occurred when the primary failed during bad weather.

Corrective Actions:

Previous reliability work performed on this circuit:

A project to install animal guards, fuses, replace damaged hardware, and relocate transformers was performed in 2009.

Tree trimming was last performed on this circuit in 2009.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Division engineering personnel performed an overhead inspection of the circuit and several improvement opportunities were identified. These included replacement of cracked or distorted cross arms, insulators, lightening arrestors, and deteriorated poles, as well as the installation of animal guards and the coordination and relocation of fuses. The need for additional tree trimming was identified and coordinated with the Vegetation Management Department. The repair work identified as a result of this inspection will be performed under DOJM Work Request number 21MT547212 which will be completed in August 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 465055
Division – SEMO
Area Served – Steele, MO
SAIFI Value – 2.52

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the past three years were: 7.05 in 2009, 0.48 in 2010, and 2.52 in 2011. This circuit serves 989 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 465055 experienced four significant outages in 2011. Two outages occurred when the primary failed during storms. The remaining two outages occurred when the Hayti 72 34kV subtransmission circuit tripped due to lightning and storms.

Corrective Actions:

Previous reliability work performed on this circuit:

A project to re-conductor 8.6 miles of this circuit was performed under DOJM Work Request numbers 2TSE086706, 2TSE086705, and 2TSE086295 which were completed in October 2009, November 2009, and December 2009 respectively.

The Vegetation Management Department performed mid-cycle maintenance tree trimming on this circuit in 2010.

Tap fuses were added to un-fused taps on this circuit under DOJM Work Request number 2TSE090755 which was completed in January 2010.

A special overhead visual inspection was performed on this circuit in 2010. The inspection identified needed animal guarding, tap-fusing, and other maintenance items. Repairs were performed under DOJM Work Request number 2TSE093496 which was completed in October 2010.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2011 which inspected for animal guarding, tap fusing, and other maintenance issues. Repairs will be performed under DOJM Work Request number 2TSE099556 which will be completed in 2012.

An overhead visual and ground line inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 256054
Division – Gateway
Area Served – Maryland Heights, MO
SAIFI Value – 2.51

Analysis Results:

This circuit serves 1,639 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees and overhead equipment malfunctions. Circuit 256054 experienced three smaller outages in 2011. The first outage occurred when the phases contacted each other during windy conditions. The second outage occurred due to a tree contact. The third outage occurred when the primary failed. All of these outages occurred on a portion of the circuit downstream of automatic switch R1081.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

The primary failure was replaced under DOJM Work Request number 21MT527755, which was completed in April 2011.

Two overhead connectors which overheated were repaired under DOJM Work Request numbers 21MT534111 and 21MT534113, both of which were completed in August 2011.

Fiberglass spacers were installed on the circuit to prevent momentary outages or recloser trips. This work was performed under DOJM Work Request number 21MT544819 which was completed in February 2012.

Decayed poles located on private property were replaced under DOJM Work Request numbers 21MT537058, 21MT537174, 21MT537176, 21MT537175, 21MT537172, 21MT537173, 21MT537177, and 21MT537171 which were completed in October 2011, December 2011, January 2012, January 2012, February 2012, February 2012, February 2012, and March 2012 respectively.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 272053
Division – Gateway
Area Served – Spanish Lake, MO
SAIFI Value – 2.46

Analysis Results:

This circuit serves 409 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 272053 experienced two significant outages in 2011 which resulted in over 80% of the total CI experienced on this circuit. The first outage occurred when a pole broke during a thunderstorm. The second outage occurred when a tree limb fell into the primary during inclement weather.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacement of failed lightening arrestors, fusing of transformers, installation of animal guards, and coordination and relocation of fuses. This work will be performed under DOJM Work Request number 21MT548400 and will be completed in 2012.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

<u>WPC Analysis and Remedial Action Report</u>

Circuit Number – 871057
Division – SEMO
Area Served – Scott City, MO
SAIFI Value – 2.44

Analysis Results:

This circuit serves 268 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by tree failures and weather. Circuit 871057 experienced two significant outages in 2011. The first outage occurred due to tree contact on the lines during high winds. The second outage occurred when the substation breaker tripped following a lightning strike.

Corrective Actions:

The Vegetation Management Department performed a mid-cycle patrol of this circuit in 2011.

A visual inspection of this circuit will be performed by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099754.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 503052
Division – Meramec Valley
Area Served – Franklin District, MO
SAIFI Value – 2.43

Analysis Results:

This circuit serves 403 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a substation malfunction and an operating error, resulting in 981 CI. Circuit 503052 experienced two significant outages in 2011 which resulted in 82% of the CI experienced on this circuit. The first outage occurred when a circuit relay at the substation failed. The second outage was caused by an operating error on the circuit.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

A project to extend a 34.5kV circuit and replace one mile of existing 3/0ACSR conductor on this 12kV circuit with 556AAA conductor was completed in 2011. In addition, the existing transformers on this section of the circuit had fused switches and animal guards installed. This work was performed under DOJM Work Request number DOJM 23FR049411 and completed in September 2011.

Division engineering personnel performed an inspection of the circuit in 2012 and several improvement opportunities were identified. Animal guards will be added to one transformer and fused switches will be added to nine transformers on the circuit backbone under DOJM Work Request number 23FR051911.

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APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 674052
Division – Boone Trails
Area Served – Wentzville, MO
SAIFI Value – 2.43

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were: 3.53 in 2010 and 2.43 in 2011. This circuit serves 424 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by public vehicle accidents, trees, and overhead equipment failures. Circuit 674052 experienced three significant outages in 2011. The first outage occurred when a public vehicle accident broke a pole and caused the primary to fail. The second outage occurred when an overhead jumper burned. The third outage occurred when a tree limb fell on the primary and broke it.

Corrective Actions:

Previous reliability work performed on this circuit:

Fuses and animal guards were added to the circuit under DOJM Work Request number 2WWZ137084. This work was completed in March 2010.

The overhead circuits on Highway BB, Mackville Road, and Paris Branch Road were improved under DOJM Work Request number 2WWZ134867 which was completed in August 2010.

A circuit tie was built along Hwy K to tie circuit 674052 with circuit 691052. This work was performed under DOJM Work Request numbers 2WWZ137265 and 2WWZ141067 which were completed in July 2011 and October 2011 respectively.

A special overhead visual inspection was performed on this circuit in 2011. Defective cross arms, insulators, and broken down guys were repaired or replaced. Animal guards and fuses were installed and some poles were replaced. This work was performed under DOJM Work Request numbers 2WWZ143423, 2WWZ145477, and 2WWZ146226 which were completed in May 2011, August 2011, and November 2011 respectively.

A section of 2400V was converted to 7200V and a step down transformer was eliminated under DOJM Work Request number 2WWZ146227 which was completed in September 2011.

Planned MWPC reliability improvement work:

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 688007
Division – SEMO
Area Served – Morehouse, MO
SAIFI Value – 2.39

Analysis Results:

This circuit serves 228 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and flooding. Circuit 688007 experienced two significant outages in 2011. The first outage occurred as a result of unusual spring flooding in the substation. The second outage occurred when the substation breaker tripped following a lightning strike.

Corrective Actions:

An overhead visual and ground line inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 854051
Division – Central Ozark
Area Served – Port Hudson, MO
SAIFI Value – 2.39

Analysis Results:

This circuit serves 452 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures. Circuit 854051 experienced two significant outages in 2011 which resulted in 83% of the CI experienced on this circuit. Both of the circuit outages occurred on the same day and were caused by the separate failure of two 34kV insulators. After the first insulator failure, customers were restored by switching the looped 34kV circuit to the backup supply. When the insulator failed on the backup supply, the second customer outage resulted. The outage was restored when the insulators were replaced. The 34kV insulators are thought to have failed because of lightning damage from a severe storm which occurred a week earlier.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009.

The 34kV insulators responsible for the circuit outage were replaced as part of the outage restoration. The circuit was also patrolled to identify any other damaged insulators.

One set of 12kV reclosers located outside the circuit substation are operating near their rated load. These reclosers will be replaced in 2012 with a new radio controlled Viper recloser. This new recloser will provide greater capacity, enhanced circuit protection, and quicker restoration capability in the event of an outage.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 128004
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 2.36

Analysis Results:

This circuit serves 89 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by an underground cable failure, public damage, unknown causes, and trees, resulting in 210 CI. Circuit 128004 experienced two major outages in 2011 which resulted in 95% of the CI experienced on this circuit. The first outage occurred when an underground feeder exit cable failed. The second outage occurred when a contractor broke the primary while demolishing a building, requiring a circuit outage to facilitate repairs. In addition to these two major outages, smaller outages were caused by tree contact and unknown causes.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

The feeder exit cable that failed was replaced under DOJM Work Request number 21MT537316 in September 2011.

No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 506051
Division – Meramec Valley
Area Served – Franklin District, MO
SAIFI Value – 2.36

Analysis Results:

This circuit serves 716 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment malfunctions, an underground cable failure, and animal intrusions, resulting in 1,687 CI. Circuit 506051 experienced two significant outages in 2011 which resulted in 84% of the CI experienced on this circuit. The first outage occurred when an underground feeder exit cable failed. The second outage occurred when a transformer on the circuit backbone failed. In addition to the two outages, approximately 11% of the CI experienced on this circuit was caused by animal intrusions.

Corrective Actions:

Animal guards were installed on three transformers on this circuit under DOJM Work Request number 23FR050653. This work was completed in December 2011.

Tree trimming will be performed on this circuit in 2012. In addition, several locations were provided to the Vegetation Management Department for detailed review.

Division engineering personnel performed an inspection of the circuit in 2012 and several improvement opportunities were identified. Animal guards will be added to five transformers and two fused switches will be installed on single-phase taps off the circuit backbone under DOJM Work Request numbers 23FR051854 and 23FR051855.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 628053
Division – SEMO
Area Served – Dexter, MO
SAIFI Value – 2.35

Analysis Results:

This circuit serves 601 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 628053 experienced three significant outages in 2011. One outage occurred when trees fell into the primary during a storm. The other two outages occurred when trees fell into the lines during high winds.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

A visual inspection of this circuit will be performed by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099756.

An underground visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 645052
Division – Boone Trails
Area Served – Saint Charles, MO
SAIFI Value – 2.34

Analysis Results:

This circuit serves 54 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by animal intrusions, weather, and overhead equipment failures. Circuit 645052 experienced five significant outages in 2011. The first outage occurred when an animal contacted the overhead circuit. The second outage occurred when a tree fell into the primary during a thunderstorm. The third outage occurred when a substation transformer bushing failed. The fourth outage occurred when a lightning strike cause a fuse to fail. The fifth outage occurred when a cross arm located on a pole near the substation failed during a thunderstorm.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Division engineering personnel will perform an Infrared (IR) inspection of the circuit. Any repair work identified as a result of this inspection will be completed in 2012.

Division engineering personnel will patrol the circuit in 2012 to verify that all backbone transformers are properly fused and to determine if any additional opportunities for circuit sectionalizing exist.

A circuit extension project which will improve reliability in the area as well as increase the number of customers served by the circuit will be completed in 2012. This work will be performed under DOJM Work Request number 2WWZ148513.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 169053
Division – Meramec Valley
Area Served – Ellisville, MO
SAIFI Value – 2.30

Analysis Results:

This circuit serves 184 customers. The area served by this circuit is rural and runs predominately along MO highway 100, Wild Horse Creek Road, and Ossenfort Road within the right-of-way. Wild Horse Creek and Ossenfort Roads are narrow, winding, two lane roads with large trees lining both sides of the road in most areas.

The customer interruptions (CI) experienced on the circuit in 2011 were caused by trees, overhead and underground malfunctions, and unknown causes which resulted in 423 CI. Circuit 169053 experienced one major outage in 2011 which was caused by a broken tree which fell across the lines and broke a pole. This event accounted for approximately 76% of the total CI experience by this circuit. Other tree issues and contacts resulted in an additional 8% of the CI. Another 6% of the CI was the result of overhead malfunctions, underground malfunctions, or unknown causes.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009.

An underground visual inspection was performed on the circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

The Vegetation Management Department will perform a mid-cycle patrol along Wild Horse Creek and Ossenfort Roads in 2012 to identify and remove tree hazards.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 269004
Division – Gateway
Area Served – Berkeley, MO
SAIFI Value – 2.29

Analysis Results:

This circuit serves 819 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by operator error, overhead equipment failures, and trees. Circuit 269004 experienced three significant outages in 2011 which resulted in 73% of the CI experienced on this circuit. The first outage occurred due to tree failures. The second outage occurred due to an operator error. The third outage occurred when a pole broke.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These include fusing the transformers on the circuit backbone. This work will be performed under DOJM Work Request number 21MT549238.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 265052
Division – Gateway
Area Served – Eastern Florissant, MO
SAIFI Value – 2.28

Analysis Results:

This circuit serves 803 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by public damage and overhead equipment malfunctions. Circuit 265052 experienced two significant outages in 2011 which resulted in over 85% of the CI experienced on this circuit. The first outage occurred when balloons became entangled in the phases. The second outage occurred when a lightning arrestor failed and burned.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 167056
Division – Gateway
Area Served – Bellefontaine Neighbors, MO
SAIFI Value – 2.27

Analysis Results:

This circuit serves 723 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees and a switchgear fault. Circuit 167056 experienced two significant outages in 2011 which resulted in over 85% of the CI experienced on this circuit. The first outage occurred when a tree branch failed and fell into the primary. The second outage occurred due to a switchgear fault.

Corrective Actions:

The Vegetation Management Department performed out of cycle tree trimming on the circuit backbone in 2011 to address the tree caused outage.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Division engineering personnel performed a circuit protection coordination analysis and corrected protection schemes as needed.

Division engineering personnel patrolled two circuit taps which had experienced multiple device interruptions. These patrols identified deficiencies such as excessive brush, unused primary, bad poles, missing animal guards, bad lightning arrestors, un-fused transformers, transformers needing re-sizing, and non-standard clearances. This work will be performed under DOJM Work Request number 21MT528503 and will be completed in December 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 939053
Division – Boone Trails West
Area Served – Moberly, MO
SAIFI Value – 2.27

Analysis Results:

This circuit serves 577 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures, trees, and a public vehicle accident resulting in 1,303 CI. Circuit 939053 experienced one significant outage in 2011, and the 577 CI incurred on this outage resulted in 45% of the total CI experienced on this circuit. Smaller outages were caused by overhead transformer failures and fuse operations, as well as tree obstructions.

Corrective Actions:

Tree trimming was performed on this circuit in 2012.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacement of cracked or distorted cross arms, insulators, lightening arrestors, and deteriorated poles.

An overhead visual inspection was performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 153006
Division – Gateway
Area Served – Castle Point, MO
SAIFI Value – 2.27

Analysis Results:

This circuit serves 741 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by wire failures and underground cable faults. Circuit 153006 experienced two significant outages in 2011 which resulted in over 85% of the total CI experienced on this circuit. The first outage occurred when the primary failed. The second outage occurred when one of the phases of the substation feeder exit cable faulted.

Corrective Actions:

Tree trimming was last performed on this circuit in 2011.

Division engineering personnel performed a circuit protection coordination analysis and corrected protection schemes as needed.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 607054
Division – SEMO
Area Served – Benton, MO
SAIFI Value – 2.26

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values on this circuit in the last three years were: 9.53 in 2009, 1.81 in 2010, and 2.26 in 2011. This circuit serves 271 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and animal intrusions. Circuit 607054 experienced five significant outages in 2011. Four of these outages occurred when storms caused the recloser west of I55 to trip. The other outage occurred due to an animal intrusion.

Corrective Actions:

Previous reliability work performed on this circuit:

Tree trimming was last performed on this circuit in 2010.

Reclosers and spacers were installed on this circuit to prevent substation breaker outages. This work was performed under DOJM Work Request number 2TSE086476 which was completed in August 2009.

A special overhead visual inspection was performed on this circuit in 2010 which inspected for animal guarding, tap-fusing, and maintenance issues. Repairs were performed under DOJM Work Request number 2TSE093454 which was completed in August 2010.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2011 which inspected for animal guarding, tap fusing, and other maintenance issues. Repairs will be performed under DOJM Work Request number 2TSE099528. This work will be completed in December 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 203051
Division – Gateway
Area Served – Bridgeton, MO
SAIFI Value – 2.26

Analysis Results:

This circuit serves 1,434 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and relay problems. Circuit 203051 experienced three significant outages in 2011. The first outage occurred when the circuit was struck by a tornado in April 2011. The second outage occurred when the circuit was struck by a wind storm. The third outage occurred as a result of a relay problem.

Corrective Actions:

All damage caused by the tornado was repaired at the time. The majority of the damage was caused by broken trees and poles. These have since been repaired.

The relaying issue has been resolved.

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 560053
Division – Meramec Valley
Area Served – High Ridge and Fenton, MO
SAIFI Value – 2.25

Analysis Results:

This circuit serves 1,469 customers. The largest customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and unknown causes, resulting in 2,936 CI (89%) of the total 3,309 CI experienced on the circuit. Circuit 560053 experienced two significant outages in 2011. The first outage occurred when lightning caused a switch malfunction. The second outage occurred due to unknown causes.

Corrective Actions:

Installation of a backbone recloser is being pursued by the Division based on the nature of the reported outages. District personnel are working with the System Protection Department and other departments to identify a suitable location for the recloser. This work will be tracked under DOJM Work Request number 26JF119753.

APPENDIX B

<u>WPC Analysis and Remedial Action Report</u>

Circuit Number – 607055
Division – SEMO
Area Served – Benton, MO
SAIFI Value – 2.25

Analysis Results:

This circuit serves 278 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by animal intrusions and weather. Circuit 607055 experienced three significant outages in 2011. The first outage occurred as a result of an animal intrusion into the substation. The other two outages occurred as a result of trees falling and breaking the primary during storms.

Corrective Actions:

An overhead visual inspection will be performed on this circuit by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance issues. Repairs will be performed under DOJM Work Request number 2TSE099757.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 917051
Division – Central Ozark
Area Served – Excelsior Springs, MO
SAIFI Value – 2.20

Analysis Results:

This circuit serves 575 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure and public damage. Circuit 917051 experienced two significant outages in 2011 which resulted in 84% of the CI experienced on this circuit. The first outage occurred when a contractor dug into the substation underground exit cable. The second outage occurred when a broken tree limb fell across the wires during a storm.

Corrective Actions:

Tree trimming was performed on this circuit in 2010.

The outages experienced on this circuit were not due to a common cause. Therefore, no work is planned for this circuit in 2012.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 629051
Division – Boone Trails
Area Served – Clarksville, MO
SAIFI Value – 2.19

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2010 and 2011. The SAIFI values for this circuit in the last two years were: 2.92 in 2010 and 2.19 in 2011. This circuit serves 484 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather and an overhead equipment failure resulting in 968 CI. Circuit 629051 experienced two significant outages in 2011 resulting in 91% of the total CI experienced on this circuit. The first outage occurred when a tornado/straight line winds hit the town of Clarksville causing extensive damage to the circuit. The second outage occurred when a recloser on a circuit tap failed.

Corrective Actions:

Previous reliability work performed on this circuit:

A special overhead visual inspection was performed on this circuit in 2011. Defective cross arms, insulators, and broken down guys were repaired or replaced. Animal guards and fuses were installed and some poles replaced. This work was performed under DOJM Work Request numbers 2WWZ146067 and 2WWZ147718 which were completed in November 2011.

Planned MWPC reliability improvement work:

Division engineering personnel will perform an inspection of the circuit in 2012. This inspection will identify un-fused backbone transformers and deteriorated guy wires.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 703001
Division – Boone Trails West
Area Served – Brookfield, MO
SAIFI Value – 2.17

Analysis Results:

This circuit serves 1,183 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures and trees, resulting in 1,595 CI. Circuit 703001 experienced several significant outages in 2011. 37% of the CI were caused by trees contacting the lines. Another 43% of the CI were cause by overhead equipment malfunctions. The overhead equipment malfunctions consisted of transformer failures and switch failures. Other overhead equipment malfunctions or failures constituted less than 20% of the CI and resulted from animal intrusions and fuses blowing in adverse weather conditions.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

The Vegetation Management Department will perform a mid-cycle patrol of this circuit in 2012 to identify and remove tree hazards.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacement of cracked or distorted cross arms, insulators, lightening arrestors, and deteriorated poles.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 160001
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 2.17

Analysis Results:

This circuit serves 470 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment malfunctions, circuit overloads, a public vehicle accident, and trees, resulting in 1,021 CI. Circuit 160001 experienced one significant outage and several smaller outages in 2011 which resulted in 97% of the CI experienced on this circuit. The significant outage was caused by a public vehicle accident. The smaller outages were caused by broken cross arms, failed transformers, overloaded transformers, broken tree limbs, and a failed switch.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

Division personnel repaired the failed equipment at the time of the outage.

In 2011 portions of this circuit were reconfigured and placed underground as a result of the construction of the new Mississippi River Bridge by MODOT. These new facilities should enhance future circuit reliability.

Additional engineering evaluations and field inspections will be performed in 2012 to check circuit loading and equipment conditions. Corrective measures to address overloads and deteriorated equipment and facilities will be performed as required.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 847001
Division – Central Ozark
Area Served – Morrison, MO
SAIFI Value – 2.17

Analysis Results:

This circuit serves 112 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by tree failures. Circuit 847001 experienced several significant outages in 2011 which resulted in 97% of the CI experienced on this circuit. The outages were caused by trees being blown into the wires during storms which occurred during one particularly windy week of the year.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

A portion of this circuit will be re-conductored in 2012 to provide better voltage support and increase system capacity. New conductor and several new poles will be installed as a part of this project under DOJM Work Request number 2JCP082697.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 745053
Division – Boone Trails
Area Served – Moberly, MO
SAIFI Value – 2.17

Analysis Results:

This circuit serves 226 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by animal intrusions and overhead equipment failures resulting in 490 CI. Circuit 745053 experienced several significant outages in 2011 which were broken down as follows: 24% of the CI occurred during adverse weather conditions, 47% of the CI were caused by animal intrusions, and 43% of the CI were caused by overhead equipment malfunctions or failures.

Corrective Actions:

Tree trimming was performed on this circuit in 2011. The circuit is currently being spot tree trimmed.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacement of cracked or distorted cross arms, insulators, lightening arrestors, and deteriorated poles.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 577051
Division – Gateway
Area Served – St. Peters, MO
SAIFI Value – 2.17

Analysis Results:

This circuit serves 1,098 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by underground cable faults resulting in 2,181 of the total 2,378 CI. Circuit 577051 experienced two significant outages in 2011 which resulted in 92% of the CI experienced on this circuit. Both circuit outages occurred when the direct buried primary backbone cable faulted.

Corrective Actions:

Both primary cable failures were repaired. Fuses were installed to isolate the section of the circuit where the underground cable failed from the rest of the circuit. This work was performed under DOJM Work Request number 25SC051497 which was completed in June 2011.

A project to replace the existing sections of direct buried primary cable with new primary cable installed in conduit will be performed under DOJM Work Request number 25SC052105. This work will be completed in 2012.

An overhead visual inspection and ground line inspection was performed on this circuit in 2011. The repair work identified as a result of these inspections will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 271055
Division – Archview
Area Served – Fenton, MO
SAIFI Value – 2.16

Analysis Results:

This circuit serves 1,687 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a public vehicle accident and an outage of unknown cause resulting in 3,268 CI (90%) of the total 3,646 CI experienced on the circuit. The first outage was caused by a public truck hitting and breaking a pole which did not immediately cause an outage, however, work to repair the pole required that all but 317 customers on the circuit be taken out of service while repairs were made. The second outage was caused by a fault on the circuit resulting in the breaker incorrectly locking out after only one trip instead of going through its full reclosing sequence. Since no physical circuit problem was found and the breaker held upon manual reclose, it is likely that a temporary condition caused the trip. Had the reclose sequence operated correctly it is likely that this event would have been only a momentary outage. The outages on this circuit were not due to a common cause.

Corrective Actions:

An overhead visual inspection was performed on the circuit in 2010. The repair work identified as a result of the inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

The public vehicle accident was not realistically avoidable and further action to mitigate this problem was not identified.

The circuit outage resulting from the breaker lockout was reviewed and it was determined that the outage would likely have been a momentary outage had the breaker functioned properly. However, it was determined that the vacuum breaker MOC switch bounced during the reclose sequence causing the relay to lock out too quickly. The Substation Maintenance Department completed a job to eliminate this bounce issue shortly after the incident. This work should limit future problems with the reclose sequence.

The Vegetation Management Department performed a mid-cycle patrol of this circuit in 2011 to identify any spot trim locations requiring attention prior to the four year cycle trim scheduled for 2013.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 256059
Division – Gateway
Area Served – Maryland Heights, MO
SAIFI Value – 2.15

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the past three years were: 3.08 in 2009, 0.18 in 2010, and 2.15 in 2011. This circuit serves 1,063 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by tree failures, overhead equipment failures, and weather. Circuit 256059 experienced four significant outages in 2011. The first outage occurred when a tree failure caused an outage on circuit 283056 while this circuit and circuit 256059 were abnormally switched. The second outage occurred when the primary broke during windy conditions. The third outage occurred when an overhead jumper burned. The fourth outage occurred when the primary broke during windy conditions.

Corrective Actions:

Previous reliability work performed on this circuit:

Tree trimming was last performed on this circuit in 2010.

The burned jumper was replaced under DOJM Work Request number 21MT532352 which was completed in July 2011.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 622054
Division – SEMO
Area Served – Charleston, MO
SAIFI Value – 2.15

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the past three years were: 4.71 in 2009, 0.08 in 2010, and 2.15 in 2011. This circuit serves 389 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 622054 experienced two significant outages in 2011. These two outages were caused by tree contacts with the primary during storms which resulted in the substation breaker tripping.

Corrective Actions:

Previous reliability work performed on this circuit:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2009.

Un-fused taps were corrected and fuse coordination verified on this circuit in 2010 to minimize future outages. This work was performed under DOJM Work Request number 2TSE092582 which was completed in December 2010.

A special overhead visual inspection was performed on this circuit in 2010. This inspection focused on animal guarding, tap-fusing, and maintenance items. Repairs were performed under DOJM Work Request number 2TSE093546 which was completed in December 2010.

Planned MWPC reliability improvement work:

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 646052
Division – SEMO
Area Served – Cape Girardeau, MO
SAIFI Value – 2.15

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit based on its performance in 2009 and 2011. The SAIFI values for this circuit in the last three years were: 2.51 in 2009, 0.86 in 2010, and 2.15 in 2011. This circuit serves 949 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 646052 experienced six significant outages in 2011. Three outages occurred due to the substation tripping as a result of tree contacts during storms. Another outage occurred when the primary failed during a storm. Lastly, two outages occurred when the primary failed during high winds.

Corrective Actions:

Previous reliability work performed on this circuit:

Tree trimming was last performed on this circuit in 2009.

Five miles of this circuit were re-conductored under DOJM Work Request numbers 2TSE090516, 2TSE090515, and 2TSE090514, which were completed in November 2010.

A special overhead visual inspection was performed on this circuit in 2010. This inspection focused on animal guards, tap-fusing, and maintenance items. Repairs were performed under DOJM Work Request number 2TSE093453 which was completed in August 2010.

Planned MWPC reliability improvement work:

An overhead visual inspection was performed on this circuit in 2010. This inspection identified needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099527.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

An underground visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 096003
Division – Gateway
Area Served – Berkeley, MO
SAIFI Value – 2.14

Analysis Results:

This circuit serves 666 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by underground equipment failures. Circuit 096003 experienced two significant outages in 2011 which resulted in 84% of the total CI experienced on this circuit. Both of the outages occurred when underground cables failed.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These include fusing the transformers on the circuit backbone. This work will be performed under DOJM Work Request number 21MT549022.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 083006
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 2.13

Analysis Results:

This circuit serves 71 predominantly light industrial and commercial customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees, overhead equipment failures, and unknown causes resulting in 151 CI. Circuit 083006 experienced two significant outages in 2011 which resulted in 96% of the CI experienced on this circuit. The first outage occurred when a tree failure caused a circuit outage. The second outage occurred as a result of unknown causes. In addition, other smaller outages were caused by jumper and connection failures, public vehicle accidents, and localized flooding.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009.

The Vegetation Management Department performed a mid-cycle patrol of this circuit in 2011 and appropriate additional trimming was completed.

A circuit inspection was performed on this circuit in 2011, and repairs initiated on appropriate facilities.

Developers are reconfiguring the landscape of part of the area served by this circuit. As a result, there is a major relocation of part of this circuit's backbone in progress. This new construction on part of the circuit backbone should improve circuit reliability.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 015011
Division – Archview
Area Served – South St. Louis City, MO
SAIFI Value – 2.13

Analysis Results:

This circuit serves 357 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure and an underground cable failure resulting in 729 CI (96%) of the total 759 CI experienced on the circuit. Circuit 015011 experienced two circuit outages in 2011. The first circuit outage occurred when a tree broke and fell on the wire. The second circuit outage occurred when the underground primary cable failed at Dip GRAV-8.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

The cable failure was corrected at the time of the outage. There are no repetitive outage causes on this circuit so no further work is planned for 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 255001
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 2.12

Analysis Results:

This circuit serves 730 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees, overhead equipment failures, and unknown causes resulting in 1,549 CI. Circuit 255001 experienced two significant outages in 2011 which resulted in 97% of the CI experienced on this circuit. The first outage occurred as a result of tree failures. The second outage occurred as a result of primary failures during high winds.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Repairs to malfunctioning equipment were performed at the time of the outage.

There are no repetitive outage causes on this circuit so no further work is planned for 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 487051
Division – SEMO
Area Served – Richwoods, MO
SAIFI Value – 2.12

Analysis Results:

This circuit serves 123 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a number of single phase circuit tap outages. This long single phase tap comprises approximately 33% of the total circuit load and experienced seven device outages in 2011. Patrols of this tap never found any definitive causes for the fuse failures experienced on this tap.

Corrective Actions:

Tree trimming was performed on sub-transmission circuit ESTR-73, which supplies this circuit, in 2009.

An overhead visual inspection was performed on this circuit in 2010. The repair work identified as a result of the inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

Tree trimming was last performed on this circuit in 2010.

A project to address multiple device outages on the Kingston Rd. circuit tap and address circuit balancing will be performed in 2012 under DOJM Work Request number 28IR035900. This work request includes recloser installation for Kingston Rd. tap protection, and animal guarding.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 020003
Division – Archview
Area Served – South St. Louis City, MO
SAIFI Value – 2.11

Analysis Results:

This circuit serves 61 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by an overhead equipment failure and an outage of unknown cause resulting in 126 CI (98%) of the total 129 CI experienced on the circuit. Circuit 020003 experienced two circuit outages in 2011**.** The first circuit outage occurred during an ice storm when ice loading caused a pin insulator to fail which resulted in two conductors contacting each other. The second circuit outage occurred when the substation breaker tripped four times and then locked out. The substation exit cable was inspected and no faults were found. The circuit was also patrolled and no problems were found. The circuit was then manually reclosed and the substation breaker held.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

An underground visual inspection was performed on this circuit in 2011. The repair work identified as a result of this inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

Circuit 020003 was patrolled in 2011. As a result of this patrol, a missing cross arm brace was installed under DOJM Work Request number 21MT532873. This work was completed in July 2011.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of this inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 181003
Division – Gateway
Area Served – Dellwood, MO
SAIFI Value – 2.10

Analysis Results:

This circuit serves 696 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 181003 experienced three significant outages in 2011 which resulted in over 83% of the CI experienced on this circuit. The three outages were related and occurred on the same day. The outages occurred when a tree branch contacted the line during a thunderstorm.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

Division engineering personnel performed a circuit protection coordination analysis and corrected protection schemes as needed.

A project which will enlarge a tie and provide improved access to switching will be performed under DOJM Work Request number 21MT482935.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 295052
Division – Meramec Valley
Area Served – Ellisville, MO
SAIFI Value – 2.10

Analysis Results:

This circuit serves 854 customers. The area serviced by this circuit is rural with several tract lot subdivisions. The subdivisions in the area are predominately serviced by single phase underground laterals. The terrain is rocky, heavily wooded, with rolling hills, and the roadways (outside of MO 109 and the improved tract lot subdivisions) are narrow two lane winding roadways. The circuit predominantly runs cross country and along narrow rural roadways to provide service to individual customers and customers in the tract developments.

The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures, trees, and public vehicle accidents resulting in 1,794 CI. The circuit experienced two major outages resulting from public vehicle accidents which accounted for approximately 45% of the CI. A recloser just outside the substation failed and prior to the failure it opened due to an unknown cause. These two outages resulted in 41% of the CI. Tree limbs on the line and tree contacts resulted in 9% of the CI. Other causes, including animal intrusions or unknown causes accounted for approximately 1.5% of the total CI in 2011.

Corrective Actions:

The recloser outside the substation was replaced in late 2011.

Tree trimming will be performed on this circuit in 2012. This work should address the tree contacts.

An underground detailed inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 185053
Division – Meramec Valley
Area Served – Imperial, MO
SAIFI Value – 2.10

Analysis Results:

This circuit serves 644 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by an overhead equipment failure. Circuit 185053 experienced two significant outages in 2011 which occurred on the same day and resulted in 95% of the CI experienced on this circuit. The first outage occurred when a primary phase failed on the three phase tap and tripped the circuit. When the fault cleared itself the circuit was placed back in service. Later that day, the fault re-occurred and tripped the circuit a second time. The circuit was patrolled and the failed primary phase was discovered and repaired.

Corrective Actions:

Fuses will be installed on two taps on this circuit in 2012 under DOJM Work Request number 26JF119638.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 245051
Division – Archview
Area Served – Affton, MO
SAIFI Value – 2.09

Analysis Results:

This circuit serves 1,318 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a public vehicle accident and an Ameren crew error resulting in 2,643 CI (96%) of the total 2,752 CI experienced on the circuit. Circuit 245051 experienced two circuit outages in 2011. The first outage occurred when Ameren crews inadvertently contacted a new energized conductor with the neutral while performing relocation work. The second circuit outage occurred when a public vehicle ran into a pole and broke it.

The outages experienced on this circuit were not the result of a common cause. The first circuit outage was due to an error by Ameren crews performing work and would not occur under typical circumstances. The second outage, due to a public vehicle accident, has not been a typical occurrence on this circuit and further action to mitigate this problem was not identified.

Corrective Actions:

An overhead visual inspection was performed on this circuit in 2010. The repair work identified as a result of the inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

The Vegetation Management Department performed a mid-cycle patrol of this circuit in 2011 to identify any spot trim locations requiring attention prior to the four year cycle trim scheduled for 2013.

An underground detailed inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 260053
Division – Gateway
Area Served – Florissant, MO
SAIFI Value – 2.08

Analysis Results:

This circuit serves 404 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 260053 experienced two significant outages in 2011 which resulted in over 95% of the total CI experienced on this circuit. The first outage occurred when a lightning strike caused the primary to fail. The second outage occurred when vines on the primary caused a recloser lock out during a thunderstorm.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacing cracked or distorted insulators, lightening arrestors, and deteriorated poles, installation of animal guards, and coordination and relocation of fuses. This work will be performed under DOJM Work Request number 21MT535388 and will be completed by December 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 044006
Division – Archview
Area Served – Ladue, MO
SAIFI Value – 2.07

Analysis Results:

This circuit serves 165 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure and a storm. Circuit 044006 experienced two significant outages in 2011 which resulted in 99% of the CI experienced on this circuit. The first outage occurred when a tree fell into the overhead wire resulting in an outage. The second outage occurred during a storm when the primary wire failed, causing an outage.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

<u>WPC Analysis and Remedial Action Report</u>

Circuit Number – 105005
Division – Archview
Area Served – Affton, MO
SAIFI Value – 2.07

Analysis Results:

This circuit serves 674 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure and an overhead equipment failure resulting in 1,344 CI (96%) of the total 1,397 CI experienced on the circuit. Circuit 105005 experienced two circuit outages in 2011. The first outage was caused by a tree, 30 feet from the circuit, breaking and falling into a second tree as well as into the overhead lines. The second outage occurred when an overhead line broke at an existing splice, causing the line to fall. The outages on this circuit were not due to a common cause.

Corrective Actions:

An overhead visual inspection, an overhead ground line inspection, and an underground detailed inspection were performed on this circuit in 2010. The repair work identified as a result of these inspections was completed in accordance with Ameren Missouri's infrastructure inspection policy.

The tree which broke, and along with a second tree, caused a circuit failure was located outside of the normally trimmed easement. Both of these trees were removed.

Tree trimming will be performed on this circuit in 2012.

The line failure due to the failed splice was repaired at the time of the incident. The circuit has experienced very few other hardware problems.

In January 2012 the Division Engineer inspected the first 2,000 feet of this circuit's backbone. This line runs along private property rear lots and includes the areas associated with the two circuit outages which occurred in 2011. No obvious hardware issues were found.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 285054
Division – Underground
Area Served – St. Louis, MO
SAIFI Value – 2.07

Analysis Results:

This circuit serves 318 customers. This circuit experienced 658 customer interruptions (CI) in 2011. The CI experienced on this circuit in 2011 were caused by animal intrusions and cable faults. Circuit 285054 experienced two significant outages in 2011. The first outage occurred on April 11, when an animal entered switchpad 26363 in the Cupples Station and caused a failure of the entire circuit. The second outage occurred on June 26, when a fault occurred between manholes 63 and 64 in the Blue Cross-Blue Shield parking lot. This outage also affected the entire circuit. A third outage occurred at the building at 2020 Washington on September 27. This building, The Sporting Goods Lofts, is a condominium complex with 106 customers. When Ameren personnel arrived at the building to make repairs, they discovered that the outage was due to building maintenance arranged by building management. The outage was therefore the result of a customer equipment outage and not due to Ameren equipment. Therefore, the 106 CI associated with this outage were not attributable to Ameren equipment. The actual CI for this circuit should have been 552 CI which would have resulted in an overall SAIFI value of 1.74. Therefore no corrective actions are necessary for this circuit.

Corrective Actions:

No work is planned on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 583051
Division – Gateway
Area Served – St. Charles, MO
SAIFI Value – 2.07

Analysis Results:

This circuit serves 992 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a public vehicle accident and a tree failure resulting in 2,005 of the total 2,049 CI. Circuit 583051 experienced two significant outages in 2011 which resulted in 98% of the CI experienced on this circuit. The first outage occurred when a car hit a pole and broke it. The second outage occurred when a tree branch broke and contacted the lines.

Corrective Actions:

The circuit will be patrolled in 2012 to determine if any additional spot tree trimming is required.

An overhead visual inspection, an overhead ground line inspection, and an underground visual inspection were performed on this circuit in 2011. The repair work identified as a result of these inspections will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

This circuit will be patrolled in 2012 to determine if any additional protection devices must be installed.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 210051
Division – Gateway
Area Served – Berkeley, MO
SAIFI Value – 2.05

Analysis Results:

This circuit serves 1,289 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures. Circuit 210051 experienced two significant outages in 2011 which resulted in 97% of the CI experienced on this circuit. The first outage occurred when overhead primary conductors touched during windy conditions. The second outage occurred due to a damaged solid blade switch.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These include fusing the transformers on the circuit backbone and installing animal protection. This work will be performed under DOJM Work Request number 21MT548360. In addition, a damaged transformer and pole will be replaced under DOJM Work Request number 21MT548368.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 803053
Division – SEMO
Area Served – Nash Road, MO
SAIFI Value – 2.03

Analysis Results:

This circuit serves 58 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures and weather. Circuit 803053 experienced two significant outages in 2011. The first outage occurred when the primary fell following a splice failure. The second outage occurred when the primary failed during a thunderstorm.

Corrective Actions:

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 623003
Division – SEMO
Area Served – Charleston, MO
SAIFI Value – 2.03

Analysis Results:

This circuit serves 284 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 623003 experienced two significant outages in 2011. The first outage occurred when high winds broke a pole. The second outage occurred when a tree fell on the primary during a thunderstorm and caused the substation breaker to trip.

Corrective Actions:

The Vegetation Management Department performed mid-cycle maintenance tree trimming in 2011.

A visual inspection of this circuit will be performed by division personnel in 2012. This inspection will identify needed animal guarding, tap fusing, and other maintenance items. Repairs will be performed under DOJM Work Request number 2TSE099768.

APPENDIX B

<u>WPC Analysis and Remedial Action Report</u>

Circuit Number – 717051
Division – Central Ozark
Area Served – Wood Heights, Excelsior Springs, MO
SAIFI Value – 2.03

Analysis Results:

This circuit serves 1,116 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure and an overhead equipment failure. Circuit 717051 experienced two significant outages in 2011 which resulted in 99% of the CI experienced on this circuit. The first outage occurred when a tree broke and fell into the circuit backbone. The second outage occurred when a circuit phase sagged into a loose guy wire during a wind/ice storm.

Corrective Actions:

The loose guy which caused an outage has been repaired. There are no other repetitive causes of the outages experienced on this circuit.

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 194052
Division – Archview
Area Served – South St. Louis County, MO
SAIFI Value – 2.03

Analysis Results:

This circuit serves 1,199 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by tree failures and equipment failures in bad weather, resulting in 2,351 CI (97%) of the total 2,433 CI experienced on the circuit. Circuit 194052 experienced three circuit outages in 2011. The first circuit outage occurred when a tree fell across all three phases of primary wire. The second outage occurred when a storm knocked down several trees which broke the primary and secondary wires. In addition, several fuses blew and transformers tripped. The third outage occurred when high winds caused a deadend to fail at a pole which caused primary to fall on Kock Road.

Corrective Actions:

Tree trimming was performed in select locations on this circuit following the first outage. This work was initially performed by a Troubleman to re-energize the circuit. Additional spot trimming was then performed on this circuit by the Vegetation Management Department.

Overhead and underground visual inspections were performed on this circuit in 2011. The repair work identified as a result of the inspections was completed in accordance with Ameren Missouri's infrastructure inspection policy.

The circuit was patrolled and an animal guard installed at 4345 Bordeaux Dr. under DOJM Work Request number 21MT536636. This work was completed in September 2011.

APPENDIX B

<u>WPC Analysis and Remedial Action Report</u>

Circuit Number – 705001
Division – Boone Trails
Area Served – Kirksville, MO
SAIFI Value – 2.01

Analysis Results:

This circuit serves 330 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by feeder exit cable failures and overhead equipment failures resulting in 664 CI. Circuit 705001 experienced two significant outages in 2011, resulting in 98% of the total CI experienced on the circuit. The two outages occurred when the feeder exit cables failed. Additional smaller outages occurred due to overhead equipment failures and resulted in less than 2% of the total CI experienced on this circuit.

Corrective Actions:

Tree trimming will be performed on this circuit in 2012.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacement of cracked or distorted cross arms, insulators, lightening arrestors, and deteriorated poles.

An overhead visual and thermal inspection will be performed on this circuit in 2012 by Division engineering personnel. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 266052
Division – Gateway
Area Served – Earth City, MO
SAIFI Value – 2.01

Analysis Results:

This circuit serves 92 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by underground cable faults and a tree failure, resulting in 185 total CI. Circuit 266052 experienced two significant outages in 2011. The first outage occurred when a cable failed. The second outage occurred when a tree failed.

Corrective Actions:

The cable fault was repaired under DOJM Work Request number 21MT534828 which was completed in September 2011.

Tree trimming was performed on this circuit in 2011.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 858052
Division – Boone Trails
Area Served – Canton, MO
SAIFI Value – 2.00

Analysis Results:

This circuit serves 1 customer, Culver Stockton College. The customer interruptions (CI) experienced on this circuit in 2011 were caused by customer equipment problems downstream of their primary meter. Circuit 858052 experienced two significant outages in 2011. Both outages occurred due to customer equipment problems.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

Significant animal guarding work was completed at the Canton Substation in 2011. This animal guarding included installation of Zapshield Wildlife Guards, Critter Line Guards for overhead feeder exit lines, metal flashing around poles and an electric fence inside the substation fence. There were no animal caused circuit outages at the Canton Substation after this work was completed in 2011.

Division engineering personnel are scheduled to perform an infrared (IR) inspection of the circuit backbone and the Canton Substation in 2012. The general condition of the overhead equipment and tree conditions will also be inspected. Any thermal, general maintenance or tree trimming issues found as a result of this inspection will be addressed.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 082052
Division – Underground
Area Served – Saint Louis, MO
SAIFI Value – 1.99

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the past three years were: 2.38 in 2009, 0.02 in 2010 and 1.99 in 2011. This circuit serves 170 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by an underground cable failure, customer equipment failures, and a substation equipment failure. Circuit 082052 experienced four significant outages in 2011. The first outage occurred in April when a water main break flooded the Sigma-Aldrich primary switchgear. The resulting fault tripped the entire Cole 52 circuit. The second outage occurred in June when a cable splice in the manhole at 20th and Martin Luther King failed. The third outage to the Cole 52 circuit occurred in November as a result of damage to the Cole 51 circuit at the CPI Building. When Cole 51 repairs were made at the CPI Building a pin hole in the cable was missed by the Underground crew. When the Cole 51 circuit was re-energized it faulted at the CPI Building, tripping both the Cole 51 and Cole 52 circuits. The fourth outage occurred when a Traveling Substation Operator performing an inspection on the Cole Substation opened the bus tie cabinet door to record breaker operation counts and substation equipment malfunctioned, causing the Cole 52 circuit to trip.

The Cole circuit has unique features that do not exist at other locations, including high fault currents that cause coordination problems. The underground Cole 52 circuit has no sectionalizing devices because they cannot coordinate with the instantaneous trip settings on the Cole 52 circuit. The instantaneous trip setting is set at 4500 Amperes to limit the amount of fault current, and resulting damage, to the circuit. The Cole Substation has no reactors so the low instantaneous trip setting cannot be raised. In addition, the System Relay Department has indicated that there are no known devices that can coordinate with the required instantaneous settings at the Cole substation.

A second issue with the Cole 52 circuit is the circuit exposure length. There are essentially two sections of the circuit: the area east of Jefferson Ave. and the area west of Jefferson Ave. In addition, there are no available feeder spaces at the Cole substation. Between the inability to sectionalize the circuit, and the large amount of exposure on the circuit, there are challenges with the reliability of the Cole circuit.

Corrective Actions:

Previous reliability work performed on this circuit:

An automated switchgear tie between Cole 51 and Cole 52 was installed at switch pad 18414 in 2011. This equipment will transfer customers to alternative circuits following feeder lockout. It will not prevent circuit outages but it will reduce customer minutes out.

Planned MWPC reliability improvement work:

Distribution automation equipment will be installed at Beaumont and Market Streets in 2012.

The Cole substation will be eliminated and circuits will transfer to the new Martin Luther King (MLK) switching station in 2014. The customers will ultimately be fed from new Ashley circuits via the new MLK switching station. Much of the cable for the area will be replaced as customers transition to the new feed. Route diversity for the supplies has been incorporated into the designs. These system improvements should help the overall reliability of this circuit.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 647052
Division – Boone Trails
Area Served – Defiance, MO
SAIFI Value – 1.99

Analysis Results:

This circuit serves 308 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 647052 experienced two significant outages in 2011. The first outage occurred when a thunderstorm caused a large tree limb to fall into the primary, damaging it in multiple locations. The second outage occurred when a tree uprooted by a thunderstorm tore down a span of primary.

Corrective Actions:

Tree trimming was performed on this circuit in 2011. Since the completion of this trimming cycle, no major outages have occurred on this circuit.

Division engineering personnel will patrol the circuit in 2012 to verify that all backbone transformers are properly fused and to determine if any additional opportunities for circuit sectionalizing exist.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 544055
Division – Gateway
Area Served – St. Charles, MO
SAIFI Value – 1.98

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the last three years were: 2.19 in 2009, 0.26 in 2010 and 1.98 in 2011. This circuit serves 869 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by tree failures and overhead equipment failures which resulted in 865 CI. Circuit 544055 experienced one significant outage in 2011 which resulted in 50% of the CI experienced on this circuit. The outage occurred when a tree limp broke and contacted the line. Other minor outages occurred due to overhead equipment malfunctions and tree contacts. A large portion of this circuit is of overhead construction which runs through heavily wooded areas and behind private homes.

Corrective Actions:

Previous reliability work performed on this circuit:

Spot tree trimming was performed near Briarcliff Dr. and Principia Ave. where tree contacts occurred in 2009. This circuit was also patrolled in 2010 to identify any additional areas requiring trimming. All spot tree trimming work performed in 2010 was completed under DOJM Work Request number 25SC048559 in December 2010.

Intellirupter reclosers were installed on this circuit to isolate some of the circuit while still maintaining circuit capacity. This work was performed under DOJM Work Request number 25SC049357 which was completed in September 2010.

An overhead visual inspection and an underground detailed inspection were performed on this circuit in 2010. The repair work identified as a result of these inspections was completed in 2011.

Tree trimming was performed on this circuit in 2011.

Planned MWPC reliability improvement work:

This circuit will be patrolled in May 2012 to determine whether any additional spot tree trimming is required.

This circuit will be patrolled by division personnel in May 2012. Any repair work identified as a result of this inspection will be addressed. Other small device outages due to equipment malfunctions and tree contacts will be reviewed to determine whether any further action is required.

APPENDIX B

<u>WPC Analysis and Remedial Action Report</u>

Circuit Number – 163003
Division – Gateway
Area Served – Dellwood, MO
SAIFI Value – 1.98

Analysis Results:

This circuit serves 522 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather, operator errors, and unknown causes. Circuit 163003 experienced five significant outages in 2011. The first outage occurred when an operator error caused a subtransmission outage. The second outage occurred when tree limbs contacted the primary during a storm. The third outage occurred due to an unknown cause. The remaining two outages occurred when tree limbs contacted the primary during storms.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

The Vegetation Management Department performed an additional patrol of the entire circuit in May 2011 and removed any hazards.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included replacing transformers, insulators, lightening arrestors, and deteriorated poles, installation of animal guards, and coordination and relocation of fuses. This work will be performed under DOJM Work Request number 21MT548932 and will be completed by December 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 039004
Division – Gateway
Area Served – Berkeley, MO
SAIFI Value – 1.96

Analysis Results:

This circuit serves 386 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures and trees, resulting in 437 CI. Circuit 039004 experienced one major outage and numerous smaller outages in 2011 which resulted in 96% of the total CI experienced on this circuit. The major outage occurred when a tree failed. The smaller outages occurred when overhead equipment malfunctioned.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Division engineering personnel performed an inspection of the circuit and several improvement opportunities were identified. These included fusing the transformers on the circuit backbone. This work will be performed under DOJM Work Request number 21MT548793.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 083008
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 1.95

Analysis Results:

This circuit serves 40 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by overhead equipment failures resulting in 80 CI. Circuit 083008 experienced two significant outages in 2011 which resulted in 100% of the CI experienced on this circuit. The two outages occurred within an hour of each other and were caused by loose primary connections that caused the unbalanced circuit to trip.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009.

An overhead visual inspection was performed on the circuit in 2011. The repair work identified as a result of the inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

No further work is planned for this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 259054
Division – Gateway
Area Served – Florissant, MO
SAIFI Value – 1.93

Analysis Results:

This circuit serves 2,030 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a wire failure. Circuit 259054 experienced two significant outages in 2011 which resulted in 94% of the CI experienced on this circuit. The first outage occurred when the primary failed. The second outage occurred when the circuit tripped a second time following restoration of the first outage.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

There are no repetitive outage causes on this circuit so no further work is planned for 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 264060
Division – Gateway
Area Served – Creve Coeur, MO
SAIFI Value – 1.89

Analysis Results:

This circuit serves 854 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a circuit overload, trees, overhead equipment failures, and animal intrusions. Circuit 264060 experienced two major outages and a number of smaller outages in 2011. The first major outage occurred when this circuit was overloaded while it was abnormally switched to supply another circuit while the other circuit was repaired. The second major outage occurred when a switch burned. Other smaller outages occurred due to tree contacts and animal intrusions along a section of the three phase overhead primary which is heavily wooded and located on private property.

Corrective Actions:

All three phases of the burned switch were replaced in September 2011.

An overhead visual inspection and an underground detailed inspection were performed on this circuit in 2011. The repair work identified as a result of these inspections will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Animal guards will be installed at two transformers under DOJM Work Request numbers 21MT526442 and 21MT541710.

Tree trimming will be performed on this circuit in 2012.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 253052
Division – Archview
Area Served – South St. Louis County, MO
SAIFI Value – 1.89

Analysis Results:

This circuit serves 1,563 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a tree failure and an overhead equipment failure resulting in 2,656 CI (90%) of the total 2,955 CI experienced on the circuit. Circuit 253052 experienced two significant outages in 2011. The first outage occurred during a thunderstorm when a tree limb broke and broke the primary. The second outage occurred when an A phase jumper on the backbone near the circuit terminal pole burned due to a bad connection.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

Circuit 253052 was patrolled in 2011. As a result of this patrol, a lightning arrestor was replaced at 5147 Harth Lodge Dr. under DOJM Work Request number 21MT531089. This work was completed in July 2011.

Overhead and underground visual inspections will be performed on this circuit in 2012. The repair work identified as a result of these inspections will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 473053
Division – SEMO
Area Served – Bismarck, MO
SAIFI Value – 1.88

Analysis Results:

This circuit serves 625 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by two long duration outages, equipment failures, trees, animals, and overhead hardware. The two largest outages were caused by regulator failures from lightning, and tree limb caused damage during a storm. Other outages were caused by multiple device failures which occurred on a section of three phase circuit downstream from a recloser at Bismarck Ridge Rd and Highway 32. In addition, smaller outages were caused by trees, animals, and faulty overhead pole hardware.

Corrective Actions:

An automated SCADA controlled 34.5 kV Viper recloser was installed in the circuit substation to allow for faster transfer to a contingent 34.5 kV supply during an outage on the circuit. This work was performed under DOJM Work Request number 28IR033316 which was completed in July of 2010.

A new tie was established between circuits 473053 and 475052 which will enable switching operations and improve reliability for the southern half of circuit 473053. This work was performed under DOJM Work Request number 28IR035635 which was completed in November of 2011.

The Vegetation Management Department will perform a mid-cycle patrol of this circuit in 2012 to identify and remove tree hazards.

An overhead visual and ground line inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

Reliability projects at Bismarck Ridge Rd. and Highway 32 will be performed under DOJM Work Request numbers 28IR035949 and 28IR036217 in 2012. These projects will replace poles, add animal guards, and add fuses in this area.

APPENDIX B

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 627051
Division – Boone Trails
Area Served – St. Peters, MO
SAIFI Value – 1.87

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2011. The SAIFI values for this circuit in the last three years were: 6.02 in 2009, 0.49 in 2010, and 1.87 in 2011. This circuit serves 589 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather, animal intrusions, and trees. Circuit 627051 experienced six significant outages in 2011. The first outage occurred due to an unknown cause during a thunderstorm. The second outage occurred when a fuse on a three phase tap blew. The third outage occurred when a 140T fuse blew due to a lightning strike during a thunderstorm. The fourth outage occurred when a tree contacted a single phase tap during a thunderstorm. The fifth outage occurred when an animal contacted the line at a single phase terminal pole. The sixth outage occurred when a tree contacted a single phased tap.

Corrective Actions:

Previous reliability work performed on this circuit:

Tree trimming was last performed on this circuit in 2010.

Planned MWPC reliability improvement work:

Division engineering personnel will patrol this circuit in 2012 to determine whether mid-cycle tree trimming is required, to verify that all backbone transformers are properly fused, and to determine if any additional opportunities for circuit sectionalizing exist.

An overhead visual inspection of this circuit will be performed in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 279054
Division – Meramec Valley
Area Served – Ellisville, MO
SAIFI Value – 1.87

Analysis Results:

This circuit serves 1,123 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused primarily by overhead malfunctions, primary wire failures, and underground malfunctions which caused two major outages and resulted in 2,096 CI. The first major outage resulted from a primary fault on a three phase 750 Al cable which accounted for 53% of the CI. The second major outage was the result of an overhead malfunction which was caused by a 600 amp switch failing and causing the primary wire to fail, which resulted in 40% of the CI. These two major outages resulted in 93% of the CI experienced on this circuit. The remaining CI were the result of underground malfunctions (5%), and other causes (less than 1%).

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

The 600 amp switch was replaced and the primary wire repaired following the circuit outage in 2011.

The 3-750 Al cable which failed was located in a conduit system. A new section of cable was pulled in to the conduit to replace the failed section. In addition, two smaller manholes on this Dip were replaced to provide better access for future maintenance of the cable. This work was completed in 2011.

APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 161051
Division – SEMO
Area Served – Farmington, MO
SAIFI Value – 1.84

Analysis Results:

This circuit serves 997 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by storms, device outages, and animal intrusions. Circuit 161051 experienced one circuit outage and two large device outages due to storm damage, and multiple device outages on fused taps 2070 and 1635 due to animals.

Corrective Actions:

A new feeder exit and re-conductor project was completed along Highway H and Highway AA which relieved heavy loading on circuit 161051 and transferred five miles of circuit 161051 to circuit 161055. This project greatly reduced exposure on circuit 161051 and was performed under DOJM Work Request numbers 28SF033814, 28SF033813, 28SF034575, and 28SF034574, which were completed in October 2010, November 2010, and January 2011, respectively.

Tree trimming was last performed on this circuit in 2010.

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APPENDIX B

WPC Analysis and Remedial Action Report

Circuit Number – 104008
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 1.84

Analysis Results:

This circuit serves 748 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees, public vehicle accidents, and equipment malfunctions resulting in 1,374 CI. Circuit 104008 experienced several outages in 2011 which resulted in 98% of the CI experienced on this circuit. The majority of the CI experienced on this circuit were caused by tree contacts and broken limbs. The second largest cause of outages experienced on this circuit was public vehicle accidents. The third largest cause of outages experienced on this circuit was equipment malfunctions.

Corrective Actions:

Tree trimming was last performed on this circuit in 2010.

The Vegetation Management Department will perform a mid-cycle patrol of this circuit in 2012 to identify and remove tree hazards.

No further work is planned on this circuit in 2012.

Appendix A
Ameren Missouri 2011 Worst Performing Circuits

DIVISION	OPERATING AREA	CIRCUIT	VOLT	CUSTOMERS	CI	CMI	SAIDI	SAIFI	2009	2010	2011	Years WPC
ARCHVIEW	GERALDINE	159003	4	63	89	17,487	278	1.41	WPC	WPC		2
GATEWAY	ST CHARLES	193051	12	396	484	127,044	321	1.22	WPC	WPC		2
BOONE TRAILS	WENTZVILLE	638052	12	2	1	11	6	0.50	WPC	WPC		2
SEMO	POTOSI	475052	12	239	105	19,997	84	0.44	WPC	WPC		2
GATEWAY	DORSETT	147057	12	961	308	54,684	57	0.32	WPC	WPC		2
SEMO	POTOSI	488052	12	444	116	19,051	43	0.26	WPC	WPC		2
BOONE TRAILS	WENTZVILLE	795051	12	140	7	1,496	11	0.05	WPC	WPC		2

APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 159003
Division – Archview
Area Served – North City of St. Louis, MO
SAIFI Value – 1.41

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 2.33 in 2009, 3.25 in 2010, and 1.41 in 2011. This shows that reliability has greatly improved in 2011. This circuit now serves 63 customers. A major portion of the customers on this circuit were transferred to the new Gimblin Substation (317007) in 2010. The customer interruptions (CI) experienced on this circuit in 2011 were caused by trees, and lightning strikes resulting in 89 CI. Circuit 159003 experienced several weather related outages in 2011 which resulted in 93% of the CI experienced on this circuit. The majority of the outages were caused by lightning strikes. The second largest cause of outages on this circuit was tree contacts.

Corrective Actions:

Tree trimming was last performed on this circuit in 2009.

A failed underground cable which resulted in a circuit outage in 2009 was replaced under DOJM Work Request number 21MT480720, which was completed in June, 2009.

Portions of this circuit were re-conductored in 2010 to facilitate load relief for the Humboldt Substation. Several new poles, switches, conductors, and other equipment were installed, replacing deteriorated facilities. In addition, a portion of circuit 159003 was transferred to a new circuit 317007 in late 2010 as part of the installation of an additional unit at the Gimblin Substation.

Tree trimming for individual outages was performed as part of the outage restoration. Although tree related outages were a large portion of the CI in 2011, these multiple small occurrences constituted only 37 CI.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed under DOJM Work Request number 21MT525759 in July 2012.

Division engineering personnel will perform reviews of circuit 159003 in 2012. These will include reviews of potential additional tap fusing, increased lightning protection, grounding reviews, increased sectionalizing, fuse coordination, phase balancing, and adverse equipment loading.

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APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 193051
Division – Gateway
Area Served – St. Charles, MO
SAIFI Value – 1.22

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 2.31 in 2009, 2.06 in 2010, and 1.22 in 2011. This shows that reliability has greatly improved in 2011. This improvement is a result of the corrective actions taken in 2009 and 2010**.** This circuit serves 396 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by a public vehicle accident resulting in 396 CI. Circuit 193051 experienced one significant outage in 2011 which resulted in 82% of the CI experienced on this circuit. This outage occurred when a car struck a pole and broke it. There were some smaller outages in 2011 which were the result of overhead equipment malfunctions and underground cable failures, which resulted in the remaining CI incurred on this circuit.

Corrective Actions:

A single phase underground primary cable failure was repaired under DOJM Work Request number 25SC047487 which was completed in December 2009.

Device outages due to equipment malfunctions in 2009 and 2010 were inspected at the time and no further action was required.

Tree trimming was last performed on this circuit in 2010. However, this circuit was recently reclassified from a rural circuit to an urban circuit. As a result, tree trimming will be performed on this circuit on a 4 year cycle instead of a 6 year cycle. As a result, this circuit is now scheduled for tree trimming in 2014.

Underground cable failures were repaired under DOJM Work Request numbers 25SC051754 and 25SC052894 which were completed in July 2011 and December 2011 respectively.

An overhead visual inspection and an underground visual inspection will be performed on this circuit in 2012. The repair work identified as a result of these inspections will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 638052
Division – Boone Trails
Area Served – Wentzville, MO
SAIFI Value – 0.50

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 136.0 in 2009, 19.0 in 2010, and 0.50 in 2011. However these SAIFI values were misleading as described in the following paragraphs.

This circuit was on the WPC list in 2009. However, the majority of the customers associated with this circuit were moved to a new Legion Trails substation, which was energized in December 2009. The customer count on this circuit was 712 when the outages recorded on this circuit occurred. At the end of 2009 only 1 customer remained on this circuit. If the original customer count were included, the overall SAIFI calculation for this circuit would have been 0.19.

At the beginning of 2010, 325 customers were moved to this circuit. However, at the end of 2010 this circuit was reconfigured, which reduced the customer count from 325 to 1. This reduced number of customers was used to calculate the SAIFI value which placed this circuit on the 2010 WPC list. If the original customer count were to be included, the overall SAIFI calculation for this circuit would have been 0.06. Therefore, no corrective actions are necessary for this circuit.

Corrective Actions:

No work is planned on this circuit in 2012.

APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 475052
Division – SEMO
Area Served – Graniteville, MO
SAIFI Value – 0.44

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 4.55 in 2009, 4.52 in 2010, and 0.44 in 2011. This shows that reliability has greatly improved in 2011. In 2011 there was one 14 minute circuit outage which was caused by a tree contact on the sub-transmission circuit. After a review of this circuit, no further action is required in 2012.

Corrective Actions:

An overhead visual and ground line inspection was performed on this circuit in 2009. This inspection identified poles which needed repair or replacement. These poles have been repaired or replaced in accordance with Ameren Missouri's infrastructure inspection policy.

Six miles of circuit 475052 were re-conductored in 2010, replacing aging pole hardware and conductors. Tap fusing was completed on the circuit under DOJM Work Request numbers 28IR033579, 28IR034453, and 28IR033581, all of which were completed in October and November of 2010.

A special overhead visual and infrared inspection was performed in 2010 which identified work that was repaired in 2010.

An overhead visual inspection was performed on this circuit in 2011. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

A new circuit tie was also established between the Graniteville 475052 and the Bismarck 473053 circuit allowing for switching operations during outages. This will reduce outage duration for some customers on this circuit. This work was performed under DOJM Work Request number 28IR035635 and completed in November 2011.

No additional reliability actions will be required for this circuit in 2012.

APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 147057
Division – Gateway
Area Served – Creve Coeur, MO
SAIFI Value – 0.32

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 3.53 in 2009, 2.92 in 2010, and 0.32 in 2011. This shows that reliability has greatly improved in 2011. This improvement is a result of the corrective actions taken in 2009 and 2010**.** This circuit serves 960 customers. The customer interruptions (CI) experienced on this circuit in 2011 were caused by weather. Circuit 147057 experienced one significant outage in 2011. This outage occurred when a tree broke during a wind storm which occurred on a day classified as a major event day.

Corrective Actions:

Tree trimming was performed on this circuit in 2011.

Risers, down guys, and overhead guys were replaced under DOJM Work Request number 21MT535589 which was completed in February 2012.

Overheated connectors were replaced under DOJM Work Request number 21MT531571 which was completed in March 2012.

An overhead visual inspection was performed on the circuit in 2011. The repair work identified as a result of the inspection will be performed in 2012 under DOJM Work Request numbers 21MT535583, 21MT535584, 21MT535585, 21MT535586, 21MT535587, 21MT535588, 21MT531572, 21MT531573, and 21MT543050.

APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 488052
Division – SEMO
Area Served – Sunnen, MO
SAIFI Value – 0.26

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 2.41 in 2009, 2.98 in 2010, and 0.26 in 2011. This shows that reliability has greatly improved in 2011.

Corrective Actions:

Reclosers were installed in 2009 at two locations on the circuit identified by the Multiple Device Interruption (MDI) program.

Tree trimming was last performed on this circuit in 2010.

Fuses were installed along the three phase backbone of the circuit in 2010. In addition, animal guards and reclosers were installed on various circuit taps in 2010.

An overhead visual inspection was performed on the circuit in 2011. The repair work identified as a result of the inspection was completed in accordance with Ameren Missouri's infrastructure inspection policy.

A new circuit tie was established between the Sunnen 488052 and the Potosi 484052 circuits allowing for switching operations during outages. This will reduce outage duration for some customers on this circuit. This work was performed under DOJM Work Request number 28IR034957 which was completed in September 2011.

A new SCADA controlled Viper recloser was installed in the circuit substation to replace the old 3 phase breaker in 2010. This improvement will eliminate 3 phase outages during single phase fault conditions.

An overhead visual inspection will be performed on this circuit in 2012. The repair work identified as a result of the inspection will be completed in accordance with Ameren Missouri's infrastructure inspection policy.

APPENDIX D

Multi-Year WPC Analysis and Remedial Action Report

Circuit Number – 795051
Division – Boone Trails
Area Served – Wentzville, MO
SAIFI Value – 0.05

Analysis Results:

This circuit is a Multi-Year Worst Performing Circuit (MWPC) based on its performance in 2009 and 2010. This circuit was not a WPC in 2011. The SAIFI values for this circuit in the most recent three year period were: 4.71 in 2009, 3.72 in 2010, and 0.05 in 2011. This shows that reliability has greatly improved in 2011. This improvement is a result of the corrective actions taken in 2009 and 2010. These are described below.

Corrective Actions:

An Intellirupter recloser was installed midway on this radial circuit in September 2009.

Tree trimming was performed on this circuit in 2010, which greatly reduced the number of outages caused by tree related problems.

17,000 feet of the distribution circuit was re-conductored and the associated poles replaced as part of a circuit reliability improvement project. This project was completed in September 2010.

The seven mile 34kV subtransmission line which serves Saverton was rebuilt over the last three years. The last section of this line was completed in 2011.

A project to replace poles and re-conductor the last 12,000 feet of the distribution circuit to eliminate splices in the #4 and #6 copperweld wire will be completed in 2012 under DOJM Work Request number 2WWZ144303.

Ameren Missouri 4 CSR 240-23.010 Electric Utility System Reliability Monitoring and Reporting Submission Requirements – Annual Reliability Report

Introduction

This report details Union Electric (dba Ameren Missouri) Company's annual reliability metrics and worst performing circuits for calendar year 2012 as required by Missouri Public Service Commission Rule 4 CSR 240-23.010, Electric Utility System Reliability Monitoring and Reporting Submission Requirements (referred to in the remainder of this document as "the Rule"). This report is required by Sections (2), (7), and (8) of the Rule which state, "*The information required by section (1) shall be filed annually by the last business day of April of the calendar year following the calendar year for which the information was accumulated…. The information developed in accordance with section (6) shall be reported as part of the annual report required by section (2)…. If on or after the time the annual report required by section (7) for calendar year 2011 is filled, a circuit has been on the worst performing circuit list for two (2) of the three (3) most recent consecutive calendar years the electrical corporation shall include detailed plans and schedules for improving the performance of that circuit in addition to the other information required by section (7).*" This report will provide the reliability measures requested by the Rule, the list of Worst Performing Circuits (WPCs), including Multi-Year Worst Performing Circuits (MWPCs), and the actions taken or planned to improve the performance of these circuits.

Definitions

For the purposes of this report, the following definitions shall apply:

1. System Average Interruption Frequency Index (SAIFI) – The average frequency of service interruptions in number of occurrences per customer (total number of customer interruptions divided by the total number of customers served).
2. Customer Average Interruption Frequency Index (CAIFI) – The average number of interruptions per customer interrupted (total number of customer interruptions divided by the total number of customers affected).
3. System Average Interruption Duration Index (SAIDI) – The average interruption in minutes per customer served (sum of all customer interruption durations divided by the total number of customers served).
4. Customer Average Interruption Duration Index (CAIDI) – The average interruption duration (sum of all customer interruption durations divided by the total number of customers interrupted).

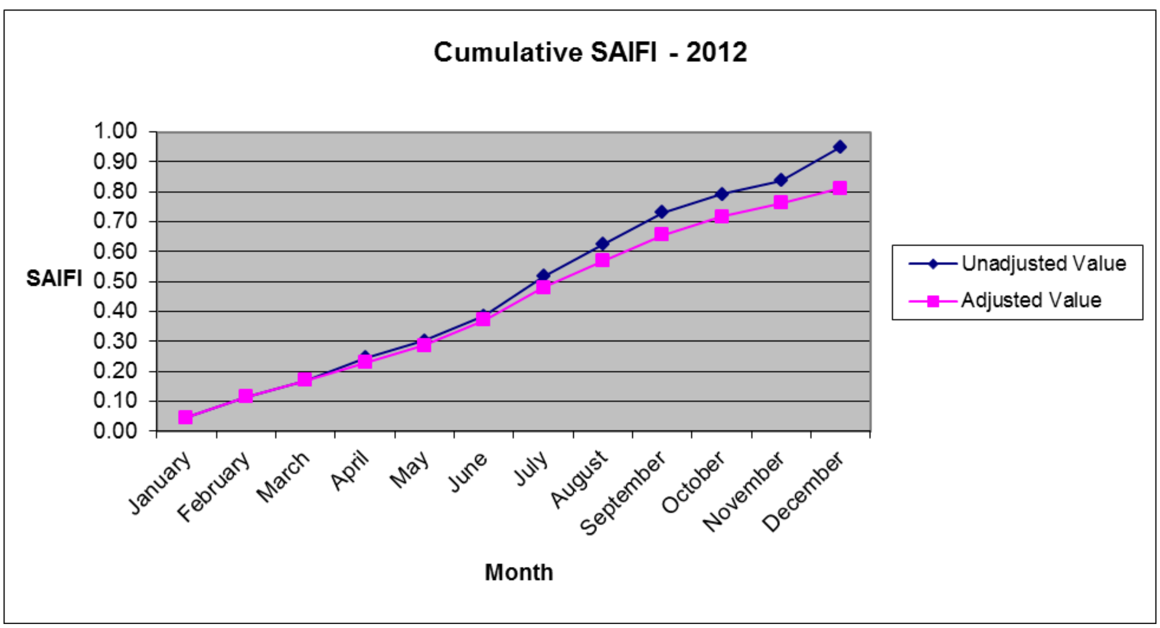
5. Worst Performing Circuit (WPC) – A distribution circuit whose SAIFI value, adjusted to exclude major storm events per IEEE Standard 1366-2003, when compared to the SAIFI values for the other circuits in the Ameren Missouri system places it among the 5% of circuits with the highest SAIFI values in the Ameren Missouri system.
6. Multi-Year Worst Performing Circuit (MWPC) – A distribution circuit whose SAIFI value has ranked it as a Worst Performing Circuit for any two (2) of the three (3) most recent consecutive calendar years.

Reliability Metrics

4 CSR 240-23.010, section 3 states "The information required by section (1) shall be filed both unadjusted and adjusted to exclude major storm events per IEEE Standard 1366-2003, Guide for Electric Power Distribution Reliability Indices." The following tables and graphs show Ameren Missouri's unadjusted and adjusted reliability metrics for calendar year 2012:

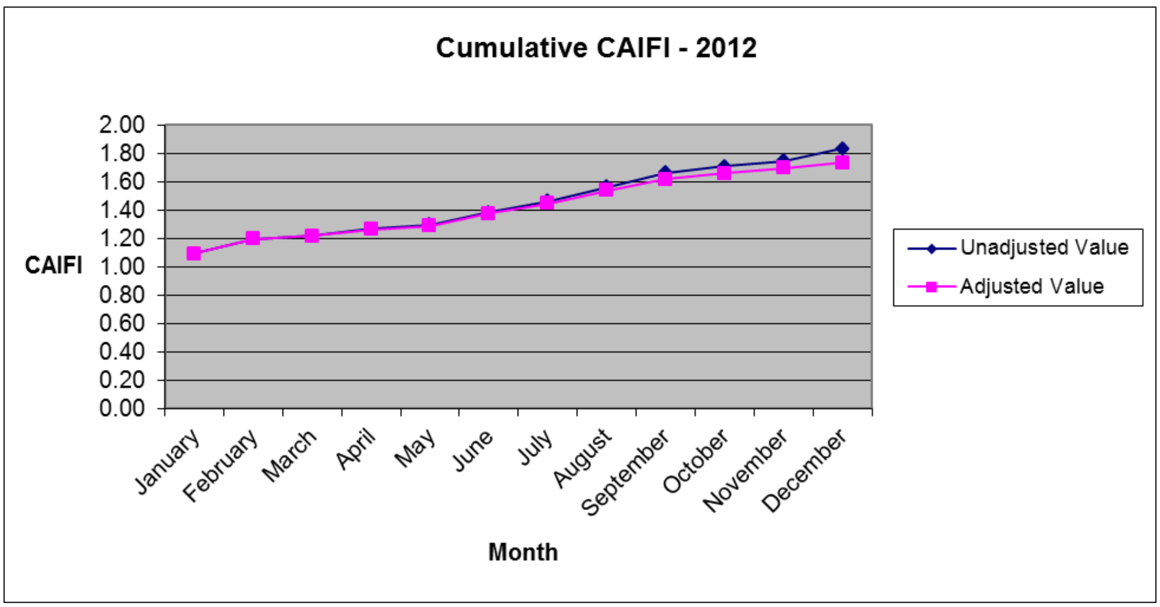
SAIFI:

Month	Unadjusted Value	Adjusted Value
January	0.05	0.05
February	0.11	0.11
March	0.17	0.17
April	0.24	0.23
May	0.30	0.29
June	0.39	0.37
July	0.52	0.48
August	0.62	0.57
September	0.73	0.66
October	0.79	0.72
November	0.84	0.76
December	0.95	0.81



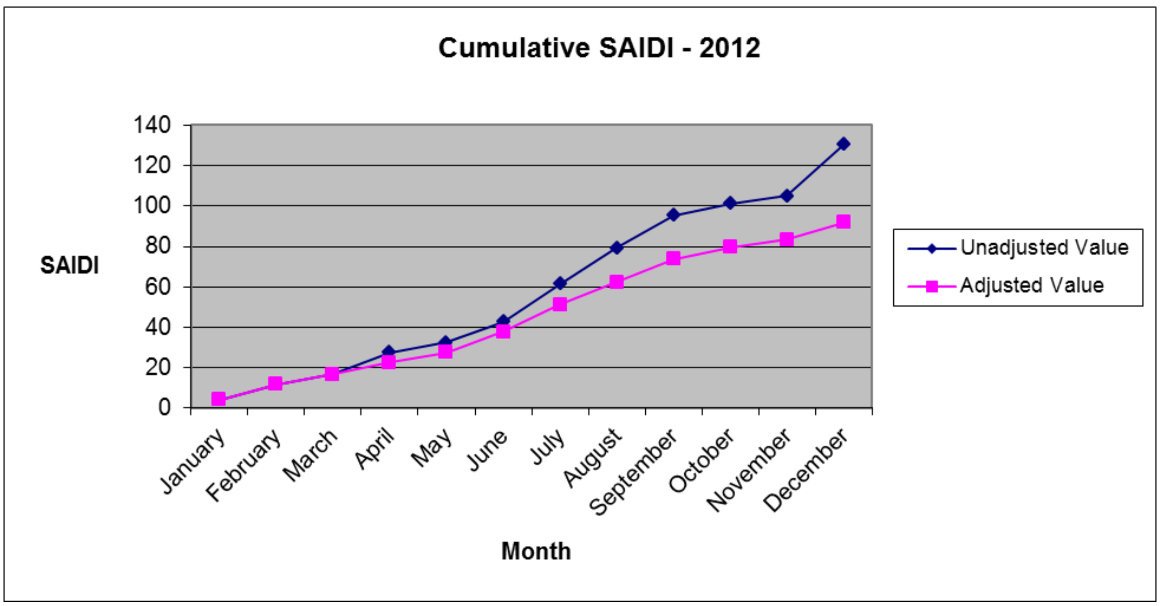
CAIFI:

Month	Unadjusted Value	Adjusted Value
January	1.09	1.09
February	1.20	1.20
March	1.22	1.22
April	1.27	1.26
May	1.30	1.29
June	1.38	1.38
July	1.46	1.45
August	1.57	1.54
September	1.66	1.62
October	1.71	1.66
November	1.75	1.70
December	1.84	1.74



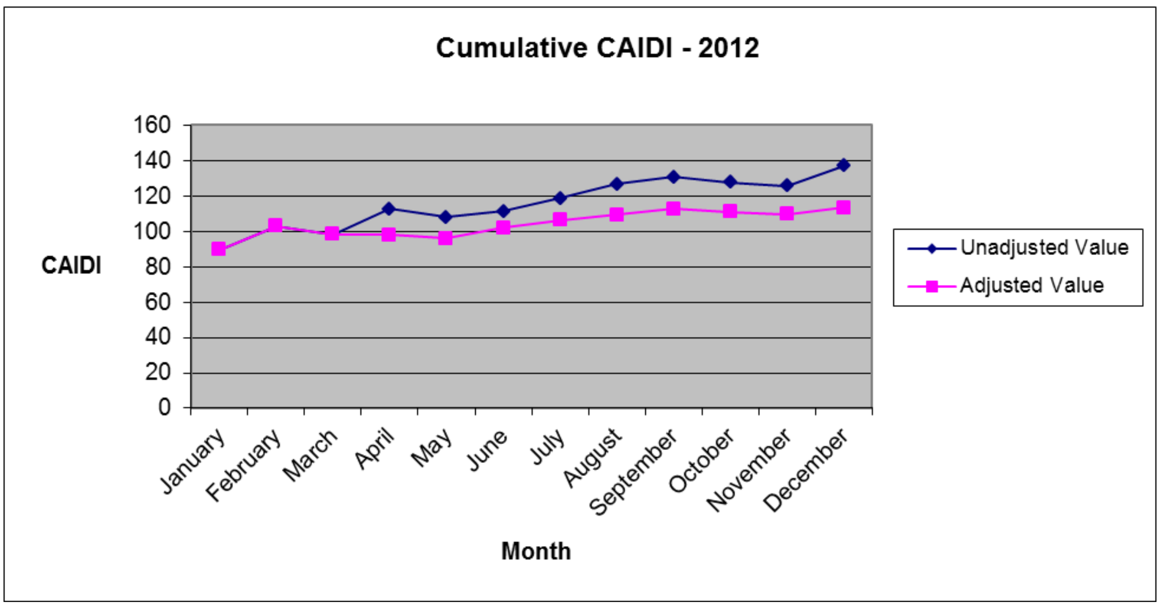
SAIDI:

Month	Unadjusted Value	Adjusted Value
January	4	4
February	12	12
March	17	17
April	28	23
May	33	28
June	43	38
July	61	51
August	79	62
September	95	74
October	101	79
November	105	83
December	130	92



CAIDI:

Month	Unadjusted Value	Adjusted Value
January	89	89
February	103	103
March	98	98
April	113	98
May	108	96
June	111	102
July	119	106
August	127	109
September	131	113
October	128	111
November	126	110
December	137	113



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Ameren Missouri 2012 Worst Performing Circuits

Ameren Missouri has performed SAIFI calculations on all of its distribution circuits in accordance with section (6) of the Rule. The circuits have been ranked in order of descending 2012 SAIFI and the 5 percent of the circuits with the highest SAIFI values have been designated as Worst Performing Circuits (WPCs). Multi-Year Worst Performing Circuits (MWPCs) have also been identified. The 2012 WPCs, including those designated as MWPCs are listed in Appendix A. The circuit numbers for the MWPCs have been highlighted in red.

Ameren Missouri has analyzed each of the WPCs for the reasons the circuit qualifies as a WPC and the actions planned or taken to improve the WPC's performance have been included in Appendix B. Each of the MWPCs in Appendix B is identified with the title "Multi-Year WPC Analysis and Remedial Action Report". The MWPC reports contain detailed information regarding work completed or planned to improve the performance of each of the MWPCs as required by the Rule.

Multi-year Worst Performing Circuits not on the 2012 WPC list

The MWPCs circuits not identified as WPCs in 2012 but which were WPCs in 2010 and 2011 are listed in Appendix C. Appendix D details the actions taken and/or planned to improve the performance of these circuits.

Conclusion

This report satisfies the reporting requirements of 4 CSR 240-23.010 for the calendar year 2012. The reported reliability metrics demonstrate continued improvement in the reliability of Ameren Missouri's electric distribution system. With an adjusted SAIFI value of .81, Ameren Missouri's customers now experience, on average, less than one extended outage per year. The reported analyses and corrective actions for the Worst Performing Circuits also demonstrate Ameren Missouri's high level of focus on improving reliability and our full commitment to satisfying both the intent and the requirements of this rule.