2012
STORM IMPLEMENTATION PLAN
&
ANNUAL RELIABILITY PERFORMANCE REPORTS

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EXECUTIVE SUMMARY

A) Initiative 1: Four-year Vegetation Management

Tampa Electric's Vegetation Management Program incorporates a balanced approach to electrical safety and reliability while adhering to the American National Standards Institute ("ANSI") A300 pruning standards. The company manages approximately 6,300 miles of distribution and 1,300 miles of transmission lines over five counties within Florida. Tampa Electric's current vegetation management plan calls for trimming its distribution system on a four-year cycle approved by the Commission in Docket No. 120038-EI, Order PSC-12-0303-PAA-EI, issued June 12, 2012. The plan incorporates the flexibility to change circuit prioritization utilizing the company's reliability based methodology.

B) Initiative 2: Joint Use Pole Attachments Audit

In 2012, Tampa Electric conducted comprehensive loading analyses and continued to streamline processes to better manage attachment requests from attaching entities. A comprehensive loading analysis is being performed on 2,558 poles and all poles determined to be overloaded will be corrected. For 2013, Tampa Electric will continue conducting comprehensive load analyses where necessary and evaluate when to initiate the next system wide pole attachment audit. In addition, Tampa Electric performed an internal audit of the Joint Use Department and the department was found to be operating in compliance.

C) Initiative 3: Transmission Structure Inspection Program

The Tampa Electric transmission system inspection program is a multi-pronged approach that identifies potential transmission system issues. In 2012, the ground line inspections exceeded program expectations. Due to an aggressive inspection schedule Tampa Electric completed the eight-year cycle of inspections one year before scheduled. A portion of the scheduled above ground inspections were performed in 2012, with the remainder to be completed with the 2013 yearly inspections. Since the 2011 aerial infrared patrol identified minimal issues, Tampa Electric omitted the patrol from its 2012 inspection program. The company intends to initiate the aerial infrared patrol again in 2013.

D) Initiative 4: Hardening of Existing Transmission Structures

Tampa Electric is hardening the existing transmission system in a prudent, cost-effective manner utilizing its inspection and maintenance program to systematically replace wood structures with non-wood structures. In 2012, Tampa Electric hardened 808 structures that included 639 structure replacements utilizing steel or concrete poles and 169 sets of insulators replaced with polymer insulators.

Additionally, as part of the LiDAR surveying (in response to NERC's October 7, 2010 alert) Tampa Electric performed corrective procedures by reconfiguring and hardening 79 structures consisting of 68 structure replacements and 11 sets of insulators.

Combining the totals from both programs Tampa Electric hardened 887 structures including 707 structure replacements and 180 sets of insulators.

For 2013, Tampa Electric's goal is to harden 875 transmission structures as part of the pole inspection and maintenance program and 98 structures as a part of the LiDAR corrective maintenance.

E) Initiative 5: Geographic Information System

Tampa Electric's Geographic Information System ("GIS") continues to serve as the foundational database for all transmission, substation and distribution facilities. Development and improvement of the GIS continues. In 2012, a project to enhance the GIS was initiated to expand the use of Tampa Electric's legacy grid numbering system for facilities in the field. In 2013, a major upgrade of the system is scheduled to begin, which will include updating the computing hardware running the system, updating the software version to the most current available, updating the database to the most current available and implementing a number of user improvements.

F) Initiative 6: Post-Storm Data Collection

Tampa Electric's process for post storm forensic data collection and analysis has been in place for approximately five years. The company has continued its relationship with its outside contractor to perform the multiple components of the plan that include the establishment of a field asset database, forensic measurement protocol, integration of forensics activity with overall system restoration, forensics data sampling and reporting format. Should a storm impact Tampa Electric's service area, the overall process will facilitate post-storm data collection and analysis that will be used to determine the root cause of damage occurring to the company's transmission and distribution system. As Tampa Electric's GIS continues to evolve, the forensics process will leverage that system through implementation of damage assessment.

G) Initiative 7: Outage Data - Overhead and Underground Systems

Tampa Electric was minimally impacted by two weather events in 2012. Due to the lack of severity of the weather events, meaningful performance data of overhead vs. underground systems was not available to the company. An established process is in place for collecting post-storm data and forensic analysis. The company also has appropriate measures in place to manage outage performance data of the two systems should a major weather event occur.

H) Initiative 8: Increase Coordination with Local Governments

In 2012, Tampa Electric's communication efforts focused on maintaining vital governmental contacts and participation on standing disaster recovery planning committees. Tampa Electric was invited to participate in several Hillsborough County led initiatives, focusing on joint efforts to identify temporary housing, rebuilding infrastructure and reviving the area's economy in the aftermath of a disaster. These committees are standing committees and will continue to meet. Prior to the 2012 hurricane season, Tampa Electric also participated in joint mock exercises with Hillsborough and Polk County Emergency Management personnel.

I) Initiative 9: Collaborative Research

Tampa Electric is participating in a collaborative research effort with the state's other investor-owned electric utilities and several municipals and cooperatives to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers. This research is being facilitated by the Public Utility Research Center ("PURC") at the University of Florida. A steering

committee comprised of one member from each of the participating utilities is providing the direction for research initiatives. For 2021, continued refinement of the undergrounding model occurred. Additionally, PURC worked with advanced degree candidates in the engineering department of the University of Florida to assess some of the inter-relationships between wind speed and other environmental factors on utility equipment damage.

J) Initiative 10: Disaster Preparedness and Recovery Plan

TECO Energy and Tampa Electric Emergency Management plans address all hazards, including extreme weather events. In 2012, TECO Energy companies continued to participate in internal and external preparedness exercises and collaborated with government emergency management agencies, at local, State and Federal levels. Specifically, 2012 preparedness included in-depth coordination with local, state and federal emergency management in the following areas:

- Preparation for the Republican National Convention, held in Tampa the week of August 17, 2012.
- Major contributor in the Hillsborough County Post Disaster Redevelopment Plan update; created job descriptions, ICS chart, and exercise.
- Major contributor to the Florida Reliability Coordination Council committee on Crisis Response plan; plan development and ICS draft.

For 2013, Tampa Electric will continue in a leadership role in county and national preparedness groups: Hillsborough County Post Disaster Redevelopment Plan, Hillsborough County Local Mitigation Strategy Group,

Tampa Bay Regional Planning Council-small business preparedness, Edison Electric Institute, and the National Fire Protection 1600 Committee on Emergency Management, Business Continuity and Disaster Recovery.

K) Wood Pole Inspection Program

Tampa Electric's Ground-line Inspection Program for its distribution, lighting, and transmission poles is based on the requirements of the National Electrical Safety Code ("NESC") and is designed to inspect 12.5 percent or one-eighth of the pole population each year. The company manages approximately 393,400 distribution and lighting poles and 24,000 transmission poles appropriate for inspection for a total pole population of approximately 417,400 over five counties within Florida. In 2012, Tampa Electric performed 52,518 pole inspections. For 2013, the company plans to inspect over 49,000 poles on its system.

SECTION I - Storm Preparedness Plans

A) Initiative 1: Four-Year Vegetation Management

1) Program Overview

Tampa Electric's Vegetation Management Program provides a balanced approach to vegetation management and currently calls for a four-year tree trim cycle, which will improve the quality of line clearance while increasing system reliability related to system hardening activities. Tampa Electric began ramping up its vegetation management program at the end of 2005, with an emphasis on critical trimming needed in areas identified by the company's reliability based methodology. For 2012, the company trimmed over one-fourth of the system. Results for the year, on a system-wide basis as well as by specific region, are provided in various tables contained in Section D of the Appendix. In 2012, the Commission approved Tampa

Electric's request to modify its trim cycle to four years (Docket No. 120038-EI).

2) Description of Vegetation Management Program

In 2012, Tampa Electric's Vegetation Management Program utilized nine full time company employees and approximately 159 contracted tree trim personnel to manage the company's distribution tree trimming requirements. The company's Vegetation Management Program utilizes the American National Standards Institute ("ANSI") A300 standards which are implemented through Tampa Electric's Transmission and Distribution Line Clearance Specification. This comprehensive document covers specifications related to operations, notification guidelines, tree trimming and removal, chemical application, targeted completion dates, overtime, and non-compliance. In addition, Tampa Electric updated its Transmission Vegetation Management Program ("TVMP") to address the North American Electric Reliability Corporation FAC-003-1 standard. In November 2011, the Florida Reliability Coordinating Council completed an audit of Tampa Electric's compliance with FAC-003-1. Tampa Electric was found to be fully compliant.

In 2012, Tampa Electric utilized approximately 24 contracted tree trim personnel to manage the company's transmission tree trimming requirements.

3) Summary of Past and Future Activities

During 2012, Tampa Electric's System Reliability and Line Clearance Departments utilized a third party vegetation management software application. Using this application, an analysis was completed which took

into consideration multi-year circuit performance data, trim cycles, and cost. The analysis has resulted in the development of a multi-year vegetation management plan which optimizes activities from both a reliability based and cost-effective standpoint within the company's overall plan. For 2013, Tampa Electric will continue to review current reliability-based information and pertinent field and customer information along with its annual trimming plan, in order to maximize the overall effectiveness of its vegetation management program.

4) Tree-related Terms and Definitions

Tampa Electric defines a "hazard tree" as any tree that is dead, diseased, or damaged with the potential to impact the distribution or transmission facilities. All reactive or "hot-spot" trimming is defined as any internal or external customer driven request for tree trimming. Therefore, all tree trim requests outside of full circuit trimming activities are categorized as hot-spot trims.

5) Criteria Used to Select a Vegetation Management Response

Tampa Electric's Line Clearance and Inspection right-of-way supervisors, in conjunction with a contracted tree trim general foreman, evaluate whether or not to remove a tree, hot-spot trim, or execute full circuit trimming based on several variables. These variables include the date the circuit was last trimmed, circuit reliability data, and visual inspection of the circuit. Specific to tree removal, if the trunk of the tree is growing underneath or nearly underneath the electrical conductor and cannot be trimmed in accordance with the ANSI A300 standard, the tree is removed. On occasion, Tampa Electric has replaced a tree with a more suitable tree at Tampa Electric's expense. The company promotes the Right Tree, Right Place Program,

whereby customers are encouraged to plant trees that will not interfere with electrical facilities. Tampa Electric operates and maintains a customer information web site which allows any customer to review the recommended set back distances for planting from electrical facilities.

6) Vegetation Management Practices - Utility Easements and Rights-of-Way

Tampa Electric's tree clearing practices within and outside utility easements and rights-of-way utilize a variety of methods to determine the corrective actions to be taken on a case-by-case basis. On private properties, where tree and/or brush removal is required to complete the maintenance activity, the contractor or company representative is required to make every reasonable effort to secure permission of property owners prior to removing and/or chemically treating any trees or brush.

Tampa Electric's tree trimming practices, for trees that abut or intrude into easements and authorized rights-of-way, also utilize a variety of methods to determine corrective actions to be taken on a case-by-case basis. Specific to trees that intrude into easements and authorized rights-of-way, the contractor is required to make every reasonable effort to secure permission to trim these trees.

7) Relevant Utility Tariffs

Tampa Electric is not limited in terms of tariff language pertaining to vegetation management within easements and rights-of-way.

8) Company Practices Regarding Trimming Requests

Most external based requests for tree trimming are routed to representatives in the company's Customer Service - One Source Department for input into the work order management system. Work orders are received by line clearance personnel or assigned to tree trim contractors for a field inspection. Once the field review is complete, proper action is taken to satisfy the customer request. These actions include communicating directly with the customer on-site or leaving a door hanger with detailed tree trimming information. In 2012, approximately 77 percent of all customer driven tree trim requests resulted in some form of tree trimming. The balance of the requests did not require immediate action or they impacted other utilities.

9) 2013 Projected Activities

For 2013, Tampa Electric has 140 dedicated distribution tree trim personnel throughout its seven service areas. These dedicated resources are broken out into two categories: proactive and reactive tree trim crews. The proactive tree trim crews are utilized for circuit tree trimming activities and consist of 125 personnel. The reactive tree trim crews consist of 15 tree trim personnel and are employed for hot spot trims, customer requested work, and work orders associated with circuit improvement process.

10) Local Community Participation

Tampa Electric has increased its efforts toward effective vegetation management as part of a coordinated plan with local governments and communities. The relationship between tree conservation and appropriate utility line clearance preservation is a delicate balance. Tampa Electric, in conjunction with its local government and community partners, has developed tree-planting guides, which minimizes company trim activities.

Moreover, Tampa Electric's Line Clearance Department holds periodic meetings with local governments and communities related to vegetation management.

During the fourth quarter 2012, Tampa Electric submitted its renewal application to the National Arbor Day Foundation's Tree Line USA Program and received endorsement in the first quarter 2013. This is the fifth consecutive year Tampa Electric has received the National Arbor Day Foundation's Tree Line USA Program designation.

In addition, Tampa Electric participated in an Arbor Day/Earth Day event hosted by the University of South Florida. This educational presentation focused on a general overview of Tampa Electric's line clearance program and Right Tree, Right Place Program. Tampa Electric also participated in the City of Tampa's Urban Forest Sustainability Steering Committee as well as the Hillsborough County Tree and Landscape Advisory Committee.

11) Hazard Tree Program and Related Information

Data collection related to hazard tree and "top for removal" program was incorporated into Tampa Electric's work order management system effective January 2007 to enhance future reporting capabilities. During 2012, Tampa Electric evaluated 173 potential hazard trees and "top for removals," resulting in the trees either being removed or trimmed.

12) Comparison with a Three-Year Program

Tampa Electric's Vegetation Management Program began its transition from a three-year program to a four-year program subsequent to the Commission's decision in Docket No. 120038-EI, Order No. PSC-12-0303-PAA-EI issued June 12, 2012. As such, the company is unable to make a

2012 annual comparison of its current program to a three-year program. For 2013, the company will have exercised the first full year of its four-year program and will be in position to make the required comparison.

13) Conclusion

Tampa Electric has set forth an aggressive program to effectively operate and manage its overall Vegetation Management Program. Tampa Electric has continued to enhance the level of communication and coordination with local governments and communities. In 2012, Tampa Electric began the transition to a four-year trim cycle. For 2013, the company will have exercised the first full year of its four-year program.

B) Initiative 2: Joint Use Pole Attachments Audit

1) Overview

In 2012, Tampa Electric's Joint Use Department continued to streamline processes in order to better manage attachment requests from attaching entities. A comprehensive pole loading analysis on all poles with joint use attachments that failed an initial load screening is being performed on 2,558 poles. In addition, Tampa Electric performed an internal audit of the Joint Use Department and the department was found to be operating in compliance.

2) Joint Use Agreements

There is an opportunity for unknown foreign attachments to exist on facilities and thereby place additional loading on the facility which may, in fact, create an overload situation. To help mitigate potential overload situations, all Tampa Electric joint use agreements have provisions that allow for periodic inspections and/or audits of all joint use attachments to Tampa Electric facilities. In addition, all agreements have provisions that require the

attaching party to build and maintain attachments within NESC guidelines or Tampa Electric specifications, whichever are more stringent. All of Tampa Electric's existing joint use agreements require attaching parties to receive authorization from the company prior to attaching any cable to its facilities. During 2012, Tampa Electric reviewed all known attachment records and verified that the company has joint use agreements with all attaching entities. Tampa Electric has a total of 37 joint use agreements with attaching entities.

3) Tampa Electric's Joint Use Department

The Joint Use Department streamlined processes to better manage attachment requests from attaching entities. The best way to mitigate storm related issues on poles with joint use attachments is to ensure the poles are not overloaded and meet the requirements of the NESC or Tampa Electric Standards, whichever is more stringent. All joint use agreements require attaching entities to apply for and gain permission to make attachments to Tampa Electric's poles. Tampa Electric implemented a process for receiving, reviewing and authorizing pole attachment applications in 2001. The company also made improvements in its notification processes through the National Joint Utilities Notification System. Tampa Electric's permit application process requires a thorough review of the application, an engineering assessment of every pole where attachments are being proposed which includes comprehensive loading analysis and compliance with NESC or Tampa Electric's construction standards, the completion of any necessary construction to ensure poles are ready for attachments, Tampa Electric's permission to attach to the poles requested and a post inspection and authorization of the attachments that have been placed in the field.

During 2012, the Joint Use Department processed 40 pole attachment applications for 547 poles. As a result, the company identified 39 distribution poles that were overloaded due to joint use attachments and no poles were overloaded due to Tampa Electric's attachments. Out of the 2,857 poles that were assessed through the pole attachment application process and the comprehensive loading analysis, there were 140 poles that had NESC violations due to joint use attachments and 54 poles with NESC violations due to Tampa Electric attachments. All poles with NESC violations were either corrected by adjustments to attachments, pole replacements or joint use entities' removal of the attachments in violation.

One area of concern has been the practice of over-lashed attachments (i.e., attaching to an existing attachment) being added to Tampa Electric's poles without prior engineering and authorization. In 2012, a significant effort was made by third party "attachers" to notify Tampa Electric of poles planned for over-lashing. This is in alignment with the 2010 stipulation agreement between Tampa Electric and its attaching entities whereby the attaching entities agreed to submit notification of all proposed overlashed attachments.

4) Initiatives that Align with Tampa Electric's Pole Inspection Program

In 2008, two initiatives associated with Tampa Electric's pole inspection program were implemented. These initiatives are the Comprehensive Loading Analysis and the Pole Attachment Audit. For 2012, comprehensive loading analysis was performed on all joint use poles that were screened as being potentially overloaded during the pole inspection program. If the comprehensive loading analysis determined a pole was overloaded, the pole was assigned to the engineering department for work request creation and design. Corrective action was accomplished using various methods

including a replacement of the pole, guying or the pole could be upgraded to the appropriate level of strength by installing an Osmose® E-T Truss.

A Pole Attachment Audit was completed in the last quarter of 2008. The company is evaluating when to initiate the next audit. The main benefit of performing the audit is the identification of unauthorized attachments. This allows Tampa Electric to perform the engineering and loading analysis on these poles to ensure that all loading requirements are met.

5) Conclusion:

In 2012, Tampa Electric's Joint Use Department continued improving the processes necessary for attaching entities to attach to its poles as well as the Comprehensive Loading Analysis initiatives.

C) Initiative 3: Six-Year Inspection Cycle for Transmission Structures

1) Overview

The Tampa Electric Transmission System Inspection Program identifies potential system issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. The inspection program is a multi-pronged approach with inspection cycles of one, six or eight years depending on the goals or requirements of the individual inspection activity. Formal inspection activities included in the program are ground line inspection, ground patrol, aerial infrared patrol, above ground inspection and substation inspections. Typically, the ground patrol, aerial infrared patrol and substation inspections are performed on one-year cycles. The above ground inspection is performed on a six-year cycle and the ground line inspection is performed

on an eight-year cycle. Additionally, pre-climb inspections are performed prior to commencing work on any structure.

The 2013 budget for the ground line inspection, ground patrol, and above ground inspection is $380,000.

2) Ground Line Inspection

Tampa Electric has implemented a ground line inspection program that complies with the Commission's order requiring ground line inspection of wooden transmission structures. In addition, Tampa Electric included provisions in the ground line inspection program to identify deficiencies with non-wood structures. Ground line inspections are performed on an eight-year cycle. At a minimum, each year approximately 12.5 percent of all transmission structures are scheduled for inspection.

In 2012, ground line inspections were performed on 4,762 transmission poles at a cost of $89,000. This represents approximately 21 percent of the transmission system. Since Tampa Electric inspected 1,900 more structures than scheduled for 2012, the company was able to complete the ground line inspections ahead of the required eight-year cycle.

Having completed the ground line inspection of the system ahead of schedule, there will be no money budgeted for these inspections in 2013. The ground line inspections will resume in 2014.

The 2006 initial pole count for transmission ground line inspections was approximately 26,000 poles. Subsequent to that count, Tampa Electric has determined that certain categories of transmission poles were included that

should not have been. For example, certain steel towers that were a part of other inspection protocols were inadvertently included in wood pole counts. Having completed the inspection of transmission poles in accordance with the company's approved wood pole inspection program, ground line inspections of transmission poles will resume in 2014.

3) Ground Patrol

The ground patrol is a visual inspection for deficiencies with poles, insulators, switches, conductors, static wire and grounding provisions, cross arms, guying, hardware and encroachment.

In 2012, all 230 kV, 138 kV and 69 kV circuits were patrolled by ground at least once. The cost for the 2012 ground patrol was $151,500.

For 2013, ground patrol is planned for all transmission circuits. All 230 kV, 138 kV and all critical 69 kV circuits will be ground patrolled prior to the peak of hurricane season with the remaining transmission circuits being completed by the end of 2013. Transmission circuits are typically scheduled to be patrolled by level of criticalness, with the most critical circuits patrolled first.

4) Aerial Infrared Patrol

The aerial infrared patrol is typically performed on the entire transmission system. It is performed by helicopter with a contractor specializing in thermographic power line inspections and a company employee serving as navigator and observer. This inspection identifies areas of concern that are not readily identifiable by normal visual methods as well as splices and other connections that are heating abnormally and may result in premature failure of the component. This inspection also identifies system deficiencies

such as broken cross arms and visibly damaged poles. Since many of these structures are on limited access rights-of-way, this aerial inspection provides a frequent review of the entire transmission system and helps identify potential reliability issues in a timely manner.

Since the 2011 aerial infrared patrol identified minimal issues, Tampa Electric omitted the patrol from its 2012 inspection program. The Company intends to initiate the aerial infrared patrol again in 2013.

5) Above Ground Inspection

Above ground inspections are performed on transmission structures on a six year cycle; therefore, each year approximately 17 percent or one-sixth of transmission structures are scheduled for inspection. This inspection is performed by a contractor specializing in above ground power pole inspection and may be performed by climbers, bucket truck or helicopter. The above ground inspection is a comprehensive inspection that includes assessment of poles, insulators, switches, conductors, static wire, grounding provisions, cross arms, guying, hardware, and encroachment issues. This program provides a detailed review of the above ground condition of the structure.

For Tampa Electric, 2012 marked the beginning of the second six-year above ground inspection cycle. In 2012, above ground inspections were performed on 1,035 structures, or approximately five percent of the system, comprising five circuits. The cost for the 2012 above ground inspection was $66,000.

The remainder of the 17 percent of the system that was scheduled to be inspected in 2012 will be added to the 2013 above ground inspection schedule.

6) Substation Inspections

Substation inspections consist at a minimum of an annual inspection of all transmission substations as well as dissolved gas analyses. These inspections identify equipment deficiencies and the information is entered into a maintenance database. The database is reviewed by management for prioritization and facilitation of the remediation process across Tampa Electric's system.

In 2012, substation inspections were performed on all transmission substations.

For 2013, substation inspections are planned on all transmission substations.

7) Pre-Climb Inspections

While not a part of the formal inspection program outlined above, Tampa Electric construction crews are required to inspect poles prior to climbing. As part of these inspections, the employee is required to visually inspect each pole prior to climbing and sound each pole with a hammer if deemed necessary. These pre-climbing inspections provide an additional integrity check of poles prior to the employee ascending the pole and may also result in the identification of any structural deterioration issues.

8) Reporting

Standardized reports are provided for each of the formal inspections. Deficiencies identified during the inspections are entered into a database.

This maintenance database is used to prioritize and manage required remediation. Deficiencies identified during the pre-climb inspections are assessed by the on-site crew and reported to supervisory personnel for determination of corrective action.

D) Initiative 4: Storm Hardening Activities for Transmission Structures

1) Overview

Tampa Electric is hardening the existing transmission system in a prudent, cost-effective manner utilizing its inspection and maintenance program. This plan includes the systematic replacement of wood transmission structures with non-wood structures during the company's annual maintenance of the transmission system. Additionally, the company will utilize non-wood structures for all new transmission line construction projects as well as system rebuilds and line relocations. The company is also actively replacing insulators that have deteriorated over time with new polymer insulators.

2) 2012 Activity

In 2012, Tampa Electric hardened 808 structures at a cost of $11.2 million. This included 639 structure replacements with steel or concrete poles and 169 sets of insulators replaced with polymer insulators.

Additionally, as part of the LiDAR surveying (in response to NERC's October 7, 2010 alert) Tampa Electric performed corrective procedures by reconfiguring and hardening 79 structures at a cost of $3.1 million. This consisted of 68 structure replacements and 11 sets of insulators.

3) 2013 Activity

For 2013, Tampa Electric plans to harden 875 transmission structures as a part of the pole inspection and maintenance program with a budget of $12.8 million. This includes 775 structure replacements with steel or concrete poles and 100 sets of insulators replaced with polymer insulators.

Tampa Electric also plans to harden 98 structures as a part of the LiDAR corrective maintenance program with a budget of $3.7 million. This includes replacing 78 structures and an additional 20 sets of insulators.

E) Initiative 5: Geographic Information System

1) Overview

GIS is fully integrated into Tampa Electric's process as the foundational database for all transmission, substation and distribution facilities. All new computing technology requests are evaluated with an emphasis on full integration with GIS. Development and improvement of the GIS for users continues. In 2013, a major upgrade of the system is scheduled to begin and will include updating the computing hardware running the system, updating the software version to the most current available, updating the database to the most current available and implementing a number of user improvements.

Technology that may be implemented to ensure compliance with FAC 003-2 is being evaluated based on how much integration into GIS is possible. Phase II of the GIS system upgrade, discussed in more detail below, includes an interface between GIS and a third party pole inspection database to facilitate Tampa Electric's compliance with the pole inspection program. Both of these initiatives are being evaluated with the goal to

eliminate redundant, exclusive and difficult to update databases, further cementing GIS as the foundational database for Tampa Electric.

In 2012, a project to enhance the GIS was initiated to expand the use of Tampa Electric's legacy grid numbering system for facilities in the field. The original GIS vendor was engaged to perform this project. This enhancement is expected to be moved into production in 2013.

Beginning in the fourth quarter of 2012, work began on a major upgrade of the GIS. The work in 2012 consisted of reviewing, analyzing and assessing the current system. The original GIS vendor was engaged to provide Tampa Electric with an assessment of the current GIS and environment. This assessment is being used to plan and schedule the overall upgrade project, expected to take all of 2013 and into 2014.

Due to the size and scope of the GIS upgrade project, Tampa Electric plans to execute the project in two phases. Phase I of the upgrade project will be to perform the actual upgrade to the computing hardware, the software and the database to bring these components up to the most current versions available. Phase II will be to implement a significant number of user improvements consisting of configuration changes as well as usability enhancements.

An ongoing activity is the improvement of the functionality of the GIS. User improvement requests are forwarded to the GIS User's Group, which meets regularly to review, evaluate and recommend enhancements for implementation.

2) Conclusion

Tampa Electric has fully integrated GIS into its business processes. All technology requests are evaluated with a goal of full integration into GIS. Development and improvement of the GIS for users continues. In 2013, a major upgrade of the system is scheduled to begin.

F) Initiative 6: Post-Storm Data Collection

1) Establishment of a Forensics Team

Tampa Electric has continued its relationship with its outside consultant to perform the post-storm forensic analysis. Its purpose is to determine the root cause of storm damage after a major storm.

2) Establishment of Forensics Measurements

The consultant used the company's existing data sources and built a database of distribution and transmission structures and facilities on a geographic basis (service areas). It was the responsibility of the consultant to collect the data, catalog and produce the database prior to Tampa Electric's 2007 storm season. This was needed to have a complete understanding of the total facilities exposed to storm conditions in a given area in order to effectively analyze the extent of damage.

Pole damage compared to damage on other overhead components, such as conductors and equipment, generally have the biggest impacts on the system reliability, restoration and resource allocation. Therefore, Tampa Electric's forensic analysis will look at pole damage during storm events. Pole damage during hurricanes can be categorized into two major categories: pole leaning and pole breaking. Recommendations on pole setting depth in different soil types will be provided, if needed.

Contributing factors to pole breakages during hurricanes can include trees, debris, presence of deterioration and wind. Although these factors may seem independent, they will result in additional stress on poles causing breakage to occur. Therefore, the impacts of these external factors will be examined and analyzed. Meanwhile, internal factors such as pole material (e.g., concrete, wood, metal), pole height/class, framing types, conductors, attachments and equipment will also be considered to determine the current pole loading profile. The company's consultant will take both external and internal factors into account and evaluate pole loading in both normal conditions (based on design criteria) and hurricane conditions.

Breakage rates (defined as the proportion of pole breakages to the total pole population) as opposed to absolute breakage counts will be considered in forensic analysis. Breakage rate analysis will be applied to every category of pole structures. Categories of pole structures are classified by each pole structure's unique combination of features including pole height/class, framing type, conductors, attachments and equipment and presence of deterioration, etc. Each category of pole structure will be studied in each wind region (region that has unique range of wind speed) to determine the breakage rate in each region.

3) Establishment of Forensics Database Format

In 2007, Tampa Electric and its consultant established a database of the company's transmission and distribution assets that will be used for post-storm forensic analysis. Tampa Electric provided initial raw data to the consultant for construction of the pole database.

The pole database includes such information as pole size, average age, pole population by type of treatment, pole inspection and maintenance data such as last inspection or treatment, types of conductor, foreign utility attachment size and quantity, tree trimming cycles by area and a number of other important factors and variables used for forensic analysis.

The database was built from Tampa Electric's pole inventory, pole inspection records and joint use attachment records. To address additional infrastructure installed in the company's system since the raw data was collected, all data collected during the forensic analysis process will be cross checked against the database and any missing data will be added. This will allow for all data collected during a storm event to be evaluated.

4) Forensics and Restoration Process Integration

As a severe storm approaches, the consultant will be put on notice when Tampa Electric activates its Incident Command System. This will likely occur when the storm is within three days of landfall. The consultant is required to mobilize data gathering personnel and equipment no later than one day prior to landfall to be ready for data gathering as soon as it is safe after the storm passes. The decision to mobilize the consultant will be made by the company in conjunction with the decision to mobilize foreign crews for restoration work.

Prior to data collection, the consultant will work with Tampa Electric to determine the geographical areas to be patrolled for data collection. This will be done using storm path and wind strength information, flood/surge information, initial damage assessment reports and other relevant data.

Scheduling of the data collection effort will be done in conjunction with the company's restoration effort.

The consultant will be responsible for patrolling a representative sample of the damaged areas of the electrical system following a major storm event and perform the data collection process. At a minimum, the following types of information will be collected:

- Pole/Structure – type of damage, size and type of pole, age (birth mark), and likely cause of damage
- Conductor – type of damage, conductor or joint use size and type, and likely cause of damage
- Equipment - type of damage, overhead or underground, size and type, and likely cause of damage
- Hardware - type of damage, size and type, and likely cause of damage

To collect post-storm field data, a data collection model will be used by field personnel doing the damage assessments. This data collection model will exist electronically for use on laptop computers in the field. The electronic spreadsheet will be based on the available information from the initial data inventory and the additional information required from field collection. The input form of an electronic collection tool will include many drop down selections based on all the possible alternatives found on Tampa Electric's system to facilitate easy data entry for field personnel and ensure consistent information for later analysis.

5) Forensics Data Sampling Methodology

Tampa Electric will work with the consultant to perform the initial assessment of the storm damage area to determine the data sample to be collected. This initial assessment will provide information on the size of the area(s) impacted by the storm and the level of damage in the area(s).

From the damage assessment and initial data inventory, the consultant will make a correlation between size of damage area and the number of facilities exposed to storm force winds. This analysis will then lead to an estimated sample size to be collected and also direct the areas in which samples should be collected. The consultant will use weather reports and wind data from throughout the storm area to analyze the wind forces Tampa Electric facilities encountered during the storm.

6) Reporting Format Used to Report Forensics Results

Following a storm event and the subsequent forensic analysis, Tampa Electric's consultant will provide a full report containing the data collected and resulting findings. The data collected will be an electronic database, Excel or Access format, with accompanying analyses, charts and diagrams.

Reporting for this project will include a detailed written report of findings, analyses, conclusions and recommendations for improvement in system performance. The report format will typically include the following sections:

- Summary of Findings
- Available Data
- Analysis and Findings

- Integral Analysis and Interpretation
- Conclusions

7) Conclusion

Tampa Electric has developed a process to gather the necessary data following a significant storm. This data will be used to determine the root cause of damage after a storm event. In 2012, no dollars were spent on forensic analysis due to an inactive hurricane season in Tampa Electric's service area. In 2013, depending upon the number of storm events, the company will incur costs based upon the category of storm and level of activation upon the forensic analysis contractor.

G) Initiative 7: Outage Data - Overhead and Underground Systems

1) Overview

Tampa Electric was minimally impacted by two weather events in 2012. Due to the lack of severity of the weather events, meaningful performance data of overhead vs. underground systems was not available to the company. An established process is in place for collecting post-storm data and forensic analysis. The company also has appropriate measures in place to manage outage performance data of the two systems should a major weather event occur.

H) Initiative 8: Increase Coordination with Local Governments

The following is a summary of Tampa Electric's 2012 activities with local governments in support of ongoing programs, storm preparation and plans for 2013. This information is also represented in the matrix provided in the Appendix D.

1) Communication Efforts

Tampa Electric strives daily to maintain excellent communications with the local governments within its service territory. These communications are carried out by specifically assigned personnel from the Company's Community Relations Department to each of the local governments served. These Community Relations representatives engage in ongoing discussions with local officials regarding critical issues such as storm restoration, underground conversions and vegetation management. Tampa Electric is committed to improving these relationships even further and will increase coordination in a number of key areas.

In 2012, Tampa Electric's communication efforts focused on working with local governments in preparing for emergency situations as well as preparing for major events. Tampa Electric was invited to participate in several local government drills, as well as partnering in preparations for the Republican National Convention in Tampa. Other communication topics in 2012 included updating governmental officials of the company's transmission line inspections and structural upgrades.

Community focused communications for 2012 included hurricane season news releases at the beginning of hurricane season to all the major media outlets in the service area. All releases were also posted on Tampa Electric's web site. Hurricane guides were published in our major newspapers – the Tampa Tribune, Lakeland Ledger and Winter Haven News Chief.

2) Storm Workshop and Training with Local Government

In 2012, Tampa Electric continued to have excellent opportunities to train alongside local government Emergency Management personnel new to their positions.

Joint workshops and training with governmental officials and Tampa Electric included joint storm exercises with Hillsborough and Polk County's Emergency Management teams. Also in 2012, Tampa Electric participated with Hillsborough County in their Post Disaster Redevelopment Plan Project which involved both government and businesses who have major roles in recovery after a disaster. These committees cover topics such as temporary housing, economic recovery and infrastructure repair and replacement.

3) Emergency Operation Centers – Key Personnel Contact

The Emergency Operations Centers ("EOC") for the City of Tampa and Hillsborough County were activated three times in 2012: Tropical Storm Debby, Republican National Convention ("RNC") and Tropical Storm Isaac. Tampa Electric activated its Incident Command System ("ICS"), deploying Emergency Response personnel to activated EOCs and the Multi Agency Coordination/Communication Center (during the RNC only). After the event, lessons learned were captured and Tampa Electric worked closely with different stakeholders to improve the Emergency Response Team plan for EOCs. Tampa Electric continues to work with local governments to streamline the flow of information that is helpful to both the company's and local government's efforts to restore all services as quickly as possible. Prior to June 1 of each year, the company's ICS plan is reviewed and

updated to insure that company representatives to local EOCs are in place and trained in the event of EOC activation.

4) Search and Rescue Teams – Assistance to Local Government

There was no activity to report in 2012, but the company's Safety Liaison Team was briefly activated in August as a result of flooding due to Tropical Storm Isaac. Tampa Electric maintains a staff of lineman and vehicles ready to assist local Fire Departments with Search and Rescue Activities when called upon. The team was ready to support in advance of Tropical Storm Isaac.

5) Tree Ordinances, Planting Guides and Trim Procedures

In 2012, Tampa Electric Line Clearance personnel communicated with municipal officials on several projects. Some of these projects include providing guidance to Plant City's Planning Board on changes to their landscaping ordinance, and covered issues including Rights-of-Way landscaping issues.

In 2013, the company's Manager of Vegetation Management and Inspections will continue to work with Community Relations staff to offer meetings with local government's Public Works supervisory staff on how Tampa Electric can best work with city staff in pre- and post-storm events and to better coordinate the company's tree trimming procedures with governmental ordinances.

6) Underground Conversions

In 2012, the Dana Shores Civic Association requested detailed estimates on underground conversions throughout their community. Employees of

Tampa Electric attended several meetings with officers of the association, county officials, as well as regular association meetings to provide assistance. Estimates for the project were presented jointly by the association's officers and Tampa Electric employees to the County Planning Commission Staff. Efforts are still underway to pursued Hillsborough County to set up a special taxing district specifically for funding this project.

7) Planned Activities in 2013

Tampa Electric will continue to train its EOC representatives and designated search and rescue personnel should the need arise. In 2013, Tampa Electric will refocus its government communications efforts on connecting governmental officials with the company's Emergency Response contacts and reviewing its Emergency Response Plan. Workshops with municipal Emergency Response Officials are planned at the company's Energy Control Center and will include all company personnel involved in communicating with governmental agencies as related to the Emergency Response Plan. Tampa Electric will continue communicating storm preparedness information to customers through the annual media pre-hurricane season press release. For 2013, workshops and open dialogue among stakeholders are planned.

I) Initiative 9: Collaborative Research

1) PURC Collaborative Research Report

Report on Collaborative Research for Hurricane Hardening

Provided by

The Public Utility Research Center
University of Florida

To the

Utility Sponsor Steering Committee

February 2013

I. Introduction

The Florida Public Service Commission (FPSC) issued Order No. PSC-06-00351-PAA-EI on April 25, 2006 (Order 06-0351) directing each investor-owned electric utility (IOU) to establish a plan that increases collaborative research to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers. This order directed IOUs to solicit participation from municipal electric utilities and rural electric cooperatives in addition to available educational and research organizations. As a means of accomplishing this task, the IOUs joined with the municipal electric utilities and rural electric cooperatives in the state (collectively referred to as the Project Sponsors) to form a Steering Committee of representatives from each utility and entered into a Memorandum of Understanding (MOU) with the University of Florida's Public Utility Research Center (PURC).

PURC manages the work flow and communications, develops work plans, serves as a subject matter expert, conducts research, facilitates the hiring of experts,

coordinates with research vendors, advises the Project Sponsors, and provides reports for Project activities. The collaborative research has focused on undergrounding, vegetation management, hurricane-wind speeds at granular levels, and improved materials for distribution facilities.

This report provides an update on the activities of the Steering Committee since the previous report dated February 2012.

II. Undergrounding

The collaborative research on undergrounding has been focused on understanding the existing research on the economics and effects of hardening strategies, including undergrounding, so that informed decisions can be made about undergrounding policies and specific undergrounding projects.

The collaborative has refined the computer model developed by Quanta Technologies and there has been a collective effort to learn more about the function and functionality of the computer code. PURC and the Project Sponsors have worked to fill information gaps for model inputs and significant efforts have been invested in the area of forensics data collection. Since the state has not been affected by any hurricanes since the database software was completed, there is currently no data. Therefore, future efforts to refine the undergrounding model will occur when such data becomes available.

In addition, PURC has worked with doctoral and master's candidates in the University of Florida Department of Civil and Coastal Engineering to assess some of the inter-relationships between wind speed and other environmental factors on utility equipment damage. PURC has also been contacted by engineering researchers at other universities with an interest in the model, though no additional relationships have been established. The researchers that contact PURC all cite the model as the only non-proprietary model of its kind.

The research discussed in last year's report on the relationship between wind speed and rainfall is still under review by the engineering press. Further results of this and related research can likely be used to further refine the model.

III. Wind Data Collection

The Project Sponsors entered into a wind monitoring agreement with WeatherFlow, Inc. Currently, WeatherFlow's Florida wind monitoring network includes 50 permanent wind monitoring stations around the coast of Florida. The wind, temperature, and barometric pressure data being collected at these stations has been made available to the Project Sponsors.

There have been no major impacts from hurricanes since the wind monitoring network was established. Once such an event does occur and wind data is captured, it is expected that forensic investigations of utilities' infrastructure failure will be conducted and overlaid with wind observations to correlate failure modes to wind speed and turbulence characteristics. Project Sponsors and PURC will analyze such data at that time.

IV. Public Outreach

In last year's report we discussed the impact of Hurricane Irene on greater interest in storm preparedness. PURC researchers discussed the collaborative effort in Florida with the engineering departments of the state regulators in Pennsylvania and Maryland. In addition, PURC researchers testified on the collaborative effort in a special session before the office of the Governor of Connecticut. While all of the regulators and policymakers showed great interest in the genesis of the collaborative effort, and the results of that effort, they have not, at this point, shown further interest in participating in the research effort. However, the impact of Hurricane Sandy has sparked interest in the research in the states of New York and New Jersey, and representatives of regulatory and consumer organizations in both states have contacted PURC regarding the research and Florida's collaborative effort.

In August, PURC Director of Energy Studies Ted Kury participated in a teleseminar for state utility regulators sponsored by the National Regulatory Research Institute. During the seminar, he joined other participants in discussing the costs and benefits of relocating power lines underground. He also discussed the state's response to the 2004-05 hurricane seasons and shared lessons from the collaborative experience. In March of 2013, the Wall Street Journal will be publishing a special section on pressing energy issues where Kury will be contributing an essay on the costs and benefits of undergrounding.

V. Conclusion

In response to the FPSC's Order 06-0351, IOUs, municipal electric utilities, and rural electric cooperatives joined together and retained PURC to coordinate research on electric infrastructure hardening. The steering committee has taken steps to extend the research collaboration MOU so that the industry will be in a position to focus its research efforts on undergrounding research, granular wind research and vegetation management when significant storm activity affects the state.

J) Initiative 10: Disaster Preparedness and Recovery Plan

1) 2012 Emergency Management Summary

In 2012, Tampa Electric worked with the local governments it serves to further enhance dialogue and seek opportunities to partner in training. As in the past, the company provided its communities with public service information at the beginning of storm season via local news media. During the Hillsborough County storm exercise, the Tampa Electric Emergency Response and Corporate Public Information Officers tested the response and communication plan.

Prior to June 1, 2012, all emergency support functions were reviewed, personnel trained and ICS Logistics and Planning Section plans were tested.

In January 2013, the company Emergency Contingency Response and Business Continuity Plan was reviewed and updated. A copy is provided in Appendix D.

2) 2013 Emergency Management Activities & Budget

The 2013 Emergency Management budget of $410,000 will be used on internal and external training and exercises to test plans. In addition, Tampa Electric will continue the following initiatives:

- Hold a Tampa Electric Emergency Preparedness Fair with representation from government agencies
- Continue training over 40 Tampa Electric certified emergency response team members

- Participate in local, state and national emergency management and business continuity forums
- Continue supporting Hillsborough County in communicating the national flood insurance to county residents
- Lead the Hillsborough County Post Disaster Recovery Plan ("PDRP") Exercise Planning Team and facilitate the 2013 PDRP Leadership Exercise; State Division of Emergency Management and Department of Homeland Security ("DHS") in participation
- Participate in the DHS Protective Security Advisor Program by working through the local Urban Area Security Initiative
- Support community preparedness through participation in various government committees (e.g., Maritime Security, Florida Department of Law Enforcement, Regional Domestic Security Task Force), and activate as necessary during major community events
- Continue planning with the Hillsborough County Department of Health on the Cities Readiness Initiative; pandemic and bio-terrorism emergency response
- Continue to provide leadership (Vice Chair) in the Hillsborough County Local Mitigation Strategy group
- Continue to chair the Hillsborough County PDRP Infrastructure Technical Advisory Committee
- Participate in public/ private storm related exercises
- Continue to conduct all-hazards internal preparedness exercises and training sessions using the company ICS model to test plans

Tampa Electric has not identified any barriers to success in the above mentioned areas.

3) 2012 Energy Delivery Emergency Management

In 2012, the Energy Delivery department of Tampa Electric was involved in many activities throughout the entire storm season. The department facilitated training sessions in various locations to include roles and responsibilities before, during and after storm activation. The Emergency Management Coordinator visited various safety meetings throughout Energy Delivery to discuss employee preparedness and storm assignments.

In May 2012, Energy Delivery facilitated a decentralized functional exercise consisting of a review of functional requirements and three storm interval scenarios. The eight-hour event was based on a Category 3 hurricane with sustained winds of 100 - 115 mph with a storm surge of two to four feet which impacted Hillsborough County. Each scenario was preceded by an Energy Delivery conference call that included other key employees across the company. As a result of the exercise, 65 actions items were identified for follow-up and lessons learned. All action items were followed up on and implemented.

In 2012, Tampa Electric reviewed sites for incident bases and staging sites which ensure primary and backup locations for distribution, transmission and materials. Throughout Tampa Electric's service territory, the company is constantly developing and maintaining relationships with property owners for potential incident bases and staging sites. Additionally, logistical needs and equipment requirements were reviewed for each incident base site.

Energy Delivery reviewed existing purchase orders and contacted contractors who would assist the company with restoration efforts.

In 2012, Energy Delivery participated in numerous conference calls with other Southeastern Electric Exchange utilities regarding rain, wind and ice events. The company's participation in these calls was to offer mutual assistance to a requesting company needing restoration support. Tampa Electric resources were deployed through mutual assistance groups three times in 2012 to assist other electric utilities as a result of ice storms, tornadoes and hurricanes.

Finally, prior to hurricane season, Energy Delivery management reviewed all employees' storm assignments and communicated roles and expectations. Meetings and training were held as needed.

4) 2013 Planned Activities

Energy Delivery will continue to pursue additional incident base and staging sites as backup locations. Service area managers and incident base leaders will maintain relationships with property owners of existing sites and locations.

Energy Delivery will conduct a mock storm drill in the second quarter of 2013 to include key employees across all levels of the company. The plan is to practice a hurricane making landfall on peninsular Florida. Various scenarios will be injected throughout the exercise. Follow-up items and lessons learned will be recorded.

Prior to hurricane season, Energy Delivery management will review all employees' storm assignments and communicate roles and expectations. Meetings, training and exercises will be scheduled at various locations.

Additionally, employee preparedness will be emphasized prior to storm season via training materials and presentations.

K) Storm Hardening Plan Update

1) Undergrounding Distribution Interstate Crossings

This activity focused on hardening limited access highway crossings which will prevent the hindrance of first responders, emergency vehicles and others due to fallen distribution lines blocking traffic. The restoration of downed overhead power lines over interstate highways can be lengthy because of heavy traffic congestion. Tampa Electric's current preferred construction standard requires all distribution line interstate crossings to be underground. Therefore, the company's hardening plan called for converting several overhead distribution line crossings on interstates I-75, I-4 and the East-West section of I-275 to underground. The three-year plan was to underground 12 distribution line crossings at a total estimated cost of $600,000, or four crossings each year, has been completed. Through 2012 a total of 14 distribution crossings have been converted at a cost of $827,000. Any remaining distribution interstate highway crossings will be converted to underground as construction and maintenance activities present opportunities.

2) Testing Network Protectors

The Tampa downtown network is a small area of dense loads made up mostly of high-rise office buildings. This area is considered critical infrastructure because of the high concentration of business and governmental buildings in this area. The types of businesses include telecommunications switching center, banking, city and county governmental offices, federal and county courthouses as well are approximately 2,500 hotel rooms and 6.5 million square foot of office space.

The Marion Street substation serves the downtown network with six underground distribution circuits.

The downtown network consists of 361 manholes and 56 network vaults. Most contain two network transformers and two network protectors. Although network protectors are designed to be waterproof, Tampa Electric has pressure tested the 18 network protectors located in the 10 low lying manholes and vaults. The results of the tests required multiple gaskets to be replaced. In 2012 forty-nine (49) network protectors were tested and 3 units were replaced. Tampa Electric will continue to remotely monitor the network protectors daily and address any issues that arise and each unit will be visually inspected at least once bi-annually. Further analysis will be conducted on the network protectors to determine the benefit of these hardening efforts in the unfortunate event of a hurricane impacts the downtown network.

3) 4 kV Conversions

Tampa Electric has converted all 4 kV distribution circuits as part of its hardening plan. The benefits are in the form of standardizing the distribution voltage to only 13.2 kV. This has eliminated the confusion of dual distribution voltages and the need to have different construction standards and critical spare material which has resulted in faster restoration.

4) Extreme Wind Pilot Projects

a) Port of Tampa

The Port of Tampa is a critical facility as it serves 10 petroleum distribution customers that deliver 40 percent of the gasoline in the state of Florida. Approximately six miles of transmission and

distribution feeder have been rebuilt to meet the extreme wind requirements. Tampa Electric will monitor the behavior of this hardened location before and after a hurricane event to determine the effectiveness of these types of hardening efforts and their appropriateness for broader system deployment.

b) Saint Joseph's Hospital

While there are several hospitals in Tampa Electric's service territory that are considered critical customers, Saint Joseph's Hospital was chosen for this pilot program because of its Level 2 Trauma Center status, central location, high elevation and the cost effectiveness of the hardening activities. The distribution feeder serving the hospital is approximately one-mile in length and was rebuilt to meet the extreme wind requirements. The hardening measures included replacing 37 distribution poles with a stronger class wood pole and six wood transmission poles with non-wood poles.

Tampa Electric will monitor the behavior of this hardened location before and after a hurricane event to determine the effectiveness of these types of hardening efforts and their appropriateness for broader system deployment.

5) Underground Equipment Construction Standard

In 2008, Tampa Electric removed the mild steel underground transformers as a standard and established stainless steel transformers as the new standard for all underground transformers. This action aligns well with the company's previously established standard of stainless steel switchgear. Tampa Electric will continually evaluate and implement economical options

that will improve all underground installation performance during and after saturated conditions.

6) Coordination with Third Party Attachers

Tampa Electric has met with third party attachers to discuss the hardening projects identified in the company's Three-Year Storm Hardening Plan. Meetings have taken place in the field and coordination discussions have been ongoing. Documentation and follow-up are integral to the process. Conflicts that have been brought to Tampa Electric's attention are being reviewed and addressed. Overall, the coordination with third party attachers has been positive and productive.

SECTION II - Storm Season Ready Status

A) Storm Season Ready Status: 2012 Accomplishments

1) Transmission

In 2012, Tampa Electric completed ground patrols on the transmission system including all 230 kV, 138 kV circuits and 69 kV circuits. The ground patrols identified access, encroachment and vegetation management issues and facilitated a visual review of the system.

The company continued to execute its six-year transmission structure inspection program with priority given to critical facilities and coastal facilities with progression to inspection of older inland circuits. As inspections were completed, the inspections moved to interconnection circuits, circuits serving co-generators and other inland circuits. The transmission structure inspections took into consideration the condition of each pole and span of wire, including issues with structural hardware such

as nuts that have backed off their bolts, corroded equipment, deteriorated appurtenance arms, unbraided conductors and woodpecker holes. This inspection work is completed when the system is under load.

Also in 2012, Tampa Electric hardened 808 structures that included 639 structure replacements utilizing steel or concrete poles and 169 sets of insulators replaced with polymer insulators.

Additionally, as part of the LiDAR surveying (in response to NERC's October 7, 2010 alert) Tampa Electric performed corrective procedures by reconfiguring and hardening 79 structures consisting of 68 structure replacements and 11 sets of insulators.

Combining the totals from both programs Tampa Electric hardened 887 structures including 707 structure replacements and 180 sets of insulators.

2) Vegetation Management

In 2012, Tampa Electric continued to maximize the effectiveness of its vegetation management efforts relative to storm season. All 230 kV and 138 kV transmission lines as well as priority 69 kV tie lines were patrolled twice for vegetation management. Any vegetative conditions identified from those patrols were either resolved immediately or scheduled for full circuit maintenance.

These efforts, along with the company's ongoing, aggressive trimming of the distribution system in 2012, have better prepared Tampa Electric for future storm seasons.

3) Updated and Reviewed Circuit Priority

In 2013, Tampa Electric will continue working with all the EOCs in the review and update of the restoration priorities following the established procedures.

4) Capacitor Maintenance Program

In support of maintaining balanced voltage to both the transmission and distribution systems and in maintaining the interconnection with Tampa Electric's neighbors, the company continued its capacitor maintenance program in 2012. The company remotely monitored capacitor banks and when apparent problems were identified, a Tampa Electric field crew was dispatched to resolve any operational problems. In 2012, the company conducted field visits for 629 capacitor banks and made repairs as needed.

5) Increased Equipment Inventory

The company reviewed and increased its storm inventory prior to the 2012 hurricane season. The stock increase secured a full four-day supply of overhead distribution materials such as splices, fuses, connectors, service clamps, brackets, wire, poles, transformers, etc. The company has procurement contracts in place that provide for additional supplies being delivered within four days of landfall and it will replenish required stock for the duration of a major restoration event.

6) Communication and Coordination with Key EOC and Governmental Organizations

In 2012, Tampa Electric's communication efforts focused on maintaining vital governmental contacts and participation on standing disaster recovery planning committees. Tampa Electric was invited to participate in several

Hillsborough County led initiatives, focusing on joint efforts to identify temporary housing, rebuilding infrastructure and reviving the area's economy in the aftermath of a disaster. These committees are standing committees and will continue to meet. Tampa Electric also participated in joint mock exercises with Hillsborough and Polk County Emergency Management personnel prior to the 2012 hurricane season.

7) Secured and Expanded Incident Bases

Tampa Electric worked with local business owners and officials to make sure that the company had incident bases in each service area. In 2012, the company renewed existing agreements for primary sites and secured back-up locations as an additional contingency. Incident bases are needed to provide logistical bases for visiting crew operations including staging of material, trucks, meals and work order assignments.

8) Hurricane Preparedness Exercises

In May 2012, Energy Delivery facilitated a functional exercise which included key employees from all levels and departments across the company. The eight-hour event was based on a Category 3 hurricane with winds of 100-115 mph and a tidal surge of two to four feet which impacted Hillsborough County. As a result of the exercise, 65 action items were addressed and lessons learned were implemented.

9) Post-Storm Data Collection and Forensic Analysis Implemented

In 2012, Tampa Electric continued its relationship with its outside consultant for performing post storm forensic analysis. This analysis will be completed to gather a statistically significant representative sample of damage and using this sample to determine root causes of failure during major storms.

10) Storm Hardening

All proposed projects in section K of this report have been completed.

B) Storm Season Ready Status: 2013 Planned Activities

1) Program Summary

Tampa Electric's Storm Season Readiness preparation focuses on a number of areas including pre-storm transmission inspections and maintenance, wood pole inspections and replacements, vegetation management, capacitor maintenance, local government interaction, increased equipment inventory, circuit priority reviews and hurricane preparation exercises.

2) Transmission Inspections and Maintenance

In preparation for the 2013 storm season, Tampa Electric will perform above ground inspection of approximately 6,500 transmission structures. Additionally, all 230 kV, 138 kV and 69 kV circuits will be patrolled by ground at least once prior to the peak of hurricane season. Tampa Electric plans to change out approximately 775 wood transmission poles throughout the year with steel or concrete structures. Also, Tampa Electric intends to replace approximately 100 sets of insulators with polymer insulators with much of this work being completed prior to the peak of hurricane season.

Tampa Electric also plans to harden 98 structures as a part of the LiDAR corrective maintenance program. This work will be completed throughout 2013 and includes the replacement of 78 structures and an additional 20 sets of insulators.

3) Pole Inspections

The 2013 Ground-line Pole Inspection Program goal includes 49,000 distribution and lighting pole inspections. The future inspections coupled with the company's pole replacement program will enhance the storm resiliency of Tampa Electric's distribution system.

4) Capacitor Maintenance Program

For 2013, the company will continue monitoring and maintaining capacitor banks. In preparation for summer peak loads, and in anticipation of the significant impact of summer storms on workforce availability and capacitor failure rates, Tampa Electric is taking an aggressive effort to make capacitor bank repairs during the spring of 2013. Repairs during the summer are generally limited to an as needed basis. Regularly scheduled repairs will continue in the fall as the need and weather permits. In 2013, the company estimates that approximately 650 capacitor banks will be field visited and repaired, as needed.

5) Communication with Local Governments

Tampa Electric has and will continue to meet with various governmental agencies to enhance communication and coordination of emergency and vegetation management as well as provide education on coordinating and facilitating underground conversions.

6) Increase Equipment Inventory

As was the case in 2012, the company will review and increase storm stock in 2013 to ensure a four-day supply of overhead distribution materials such as splices, fuses, connectors, service clamps, brackets, wire, poles, transformers, etc., as well as transmission and substation materials. The

company will also ensure that procurement contracts are in place to support additional supplies being delivered within four days of landfall and it will replenish required stock for the duration of a major restoration event.

7) Circuit Priority Review

In 2013, Tampa Electric will continue working with all the EOCs in the review and update of the restoration priorities for the areas the company serves.

8) Hurricane Preparedness Exercises

Energy Delivery will conduct a mock storm drill in the second quarter of 2013 to include key employees across all levels of the company. The plan is to practice a hurricane making landfall on peninsular Florida. Various scenarios will be injected throughout the exercise. Follow-up items and lessons learned will be recorded.

9) Storm Hardening Plan

All proposed projects in Section K of this report have been completed. Should a severe weather event strike Tampa Electric's service area, the company will evaluate the performance of the pilot projects to determine next steps to be taken. For 2013, the company will file its 2013-2015 Storm Hardening Plan.

SECTION III - Wood Pole Inspection Program

A) Wood Pole Inspection Program

1) Program Summary

Tampa Electric's Wood Pole Ground-line Inspection Program is part of a comprehensive program initiated by the Florida Public Service Commission for Florida investor-owned electric utilities to harden the electric system

against severe weather and unauthorized and unnoticed non-electric pole attachments which affect the loadings on poles.

This inspection program complies with Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI which requires each investor-owned electric utility to implement an inspection program of its wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the NESC. This program provides a systematic identification of poles that require repair or replacement to meet strength requirements of NESC.

2) Inspection Cycle

Tampa Electric performs inspections of all wood poles on an eight-year cycle. Tampa Electric has approximately 393,400 distribution and lighting poles and 24,000 transmission poles appropriate for inspection for a total pole population of approximately 417,400. Approximately 12.5 percent of the known system will be targeted for inspections annually although the actual number of poles may vary from year to year due to recently constructed circuits, de-energized circuits, reconfigured circuits, etc.

3) Inspection Method and Procedure

Tampa Electric will utilize three basic inspection procedures for determining the condition of wooden poles. These procedures include a visual inspection, sound and bore, and excavation if required.

a) Inspection in Conjunction with Other Field Work

As part of day-to-day operations, personnel are sometimes required to climb poles to perform different types of field work. Prior to climbing

any pole, personnel will make an assessment of the condition of the pole. This will include a visual check and may include sounding to determine pole integrity. This type of inspection will supplement the systematic inspection approach otherwise outlined in this pole inspection program.

b) Visual Inspection

An initial visual inspection shall be made on all poles from the ground-line to the pole top to determine the condition of the pole before any additional inspection work is completed. The visual inspection shall include a review of the pole condition itself and any attachments to the pole for conditions that jeopardize reliability and are in need of replacement, repair or minor follow-up. After a pole has passed the initial visual inspection, the balance of the required inspection method will be performed.

c) Sound and Bore

After passing the visual inspection, the pole shall be sounded to a minimum height of seven feet above the ground-line to locate any rotten conditions or pockets of decay inside the pole. Borings shall be made to determine the location and extent of internal decay or voids. All borings shall be plugged with preservative treated wooden dowels. After the pole has passed the sound and bore inspection, an excavation inspection will be performed, if required.

d) Excavation

For poles requiring excavation, the pole shall be excavated to a minimum depth of 18 inches below the ground-line. Any external

decay shall be removed to expose the remaining sound wood. The remaining pole strength shall be determined.

For a pole in concrete or pavement where excavation is not possible, Tampa Electric will utilize the Osmose Utility Services, Inc. shell boring technique. This will consist of boring two 3/8 inch holes at a 45-degree angle to a depth of 16 to 18 inches below ground level. The technician will determine the pole strength by the resistance while drilling. Upon withdrawing the drill bit, the technician will examine the condition of the wood shavings to determine whether decay is present. All borings shall be plugged as previously described.

e) Hardware Inspection

The inspector shall inspect all of Tampa Electric's guying, grounding provisions, and hardware that is visible from the ground.

f) Inspection and Treatment Labeling

After completion of the ground-line inspection, an aluminum tag identifying the contractor and date of inspection shall be attached to the pole above the birthmark. Additionally, a tag shall be attached identifying any preservative treatments applied and the date of application.

g) Pole Attachment/Loading Analysis

In some circumstances, Tampa Electric will conduct a pole loading data collection and analysis as part of the ground-line inspection. The analysis will ensure that the condition of the pole meets the requirements in Table 261-1A of the NESC. The analysis will not be

performed on poles having only Tampa Electric attachments since these facilities were addressed in the original design.

h) Data Collection

The collected data shall be managed in a database and include information related to pole class, material, vintage, location, joint use attachments, and any pole deficiencies that required follow-up actions, if any.

4) Disposition of Poles

Poles with early stage decay that do not require remediation to meet the NESC strength requirements shall be treated with an appropriate preservative treatment. Poles with moderate decay that have substantial sound wood shall be considered for reinforcement. Analysis shall be performed to determine if reinforcement will bring the deficient pole into compliance with the requirements of the NESC. If it is determined that the pole can be reinforced, the pole shall be treated with an appropriate preservative treatment and reinforced. Poles with advanced decay shall fail the inspection and be replaced.

5) Routing of Inspections

a) Distribution

Tampa Electric's distribution system is a radial system with many laterals and service drops. The company has determined the most cost-effective and reasonable approach for routing the work of the annual inspection program is by geographic location. Therefore, inspectors will be given an area that is defined by specific boundaries

and distribution and lighting poles within that area will be systematically inspected.

b) Transmission

Tampa Electric's transmission system is primarily a network system with few laterals. The company has determined the most cost-effective and reasonable approach for routing the inspection work to be on a circuit basis. Therefore, annual inspections will be performed sequentially from substation to substation completing an entire circuit in the process.

6) Shared Poles

Tampa Electric supports the Commission's effort to establish pole inspection requirements on the owners of all utility poles. Tampa Electric will coordinate with third party owners of utility poles that carry the company's facilities. With regard to the third party's inspection process, the company will rely upon the third party's inspection requirements and share data requested by the third party to be utilized in their inspection procedure. Tampa Electric will cooperate, as requested, in the work associated with pole replacement where joint use exists.

7) Standards Superseding NESC Requirements

Tampa Electric's Wood Pole Ground-line Inspection Program complies with NESC requirements.

8) Pole Inspection Program Performance Verification

Qualified Tampa Electric personnel or an independent contractor will conduct a quality control audit on the pole inspection work to verify

compliance with the pole inspection services contract. This quality control audit shall consist of selecting random poles, determining the proper course of action per the inspection services contract, and comparing the independent audit recommendation against the proposed recommendation by the pole inspection service.

9) Reporting

Tampa Electric will file an annual Pole Inspection Report by March 1 of each year in full accordance with the reporting requirements set forth in Docket No. 070634-EI, Order No. PSC-07-0918-PAA-PU, issued November 14, 2007. The report will contain the methods used to determine the strength and structural integrity of wooden poles, the selection criteria for inspected poles, a summary of the results of the inspections, the cause(s) of inspection failures, and the corrective action taken for the failures.

10) 2012 Accomplishments

Tampa Electric's Ground-line Pole Inspection Program was conducted by three contracted crews and one supervisor who inspected a total of 53,974 poles which was 1,456 inspections above plan. The pole failure rate for distribution and lighting was 16.8 percent due to the vintage of poles inspected. Of these failures, 0.30 percent was reinforced; therefore, the overall distribution and lighting wooden pole replacement rate was 16.5 percent. The ground-line pole failure rate for transmission poles was 10 percent. Tampa Electric's spending levels for the Ground-line Pole Inspection Program, which included distribution and lighting pole reinforcements, exceeded $1.4 million.

The 2012 Ground-line Pole Inspection Program results include:

- 49,176 planned distribution and lighting pole inspections with 49,212 completed.
- 3,342 planned transmission poles inspections with 4,762 completed.
- 52,518 planned distribution, lighting, and transmission ground-line pole inspections with a total of 53,974 completed.

Expenditures for the 2012 Ground-line Pole Inspection Program include:

- Distribution and lighting ground-line pole inspections - $1.4 million.
- Transmission ground-line pole inspections - $89,000.
- Distribution and lighting pole reinforcements - $77,300.
- Inspection-related distribution and lighting maintenance - $52,300.

11) 2013 Activities and Budget Levels

For 2013, Tampa Electric will start the year with three contractor crews and one supervisor in place. Pole inspection targets by service area are established with a goal of completing approximately 12.5 percent of the system.

The 2013 Ground-line Pole Inspection Program goals include:

- 49,176 distribution and lighting pole inspections
- 0 transmission pole inspections (goal accomplished in 2012)
- 49,176 total distribution, lighting, and transmission ground-line pole inspections

Established funding levels for the 2013 Ground-line Pole Inspection Program are:

- Distribution and lighting ground-line pole inspections - $1.5 million.
- Transmission ground-line pole inspections - $0.
- Distribution and lighting pole reinforcements - $125,000.
- Inspection-related distribution and lighting maintenance - $28,800.

Tampa Electric's Ground-line Inspection Program strategy takes a balanced approach and has produced excellent results in a cost effective manner. The future inspections coupled with its pole replacement program will enhance the storm resilience of Tampa Electric's distribution, lighting, and transmission poles.

12) Chromated Copper Arsenate Pole Inspections

In Docket No. 080219-EI, Order No. PSC-08-0615-PAA-EI, issued September 28, 2008 the Florida Public Service Commission approved a modification to Tampa Electric's Wood Pole Inspection Program involving chromated copper arsenate ("CCA") poles. Specifically, the modification requires CCA treated poles less than 16 years of age to be sound and selectively bored. Selective boring shall be performed on poles suspected of internal decay. Additionally, one percent of the annual number of CCA treated poles inspected less than 16 years of age shall be excavated to validate this inspection method. Finally, all CCA treated poles over 16 years of age shall be excavated.

SECTION IV - Rule 25-6.0455 F.A.C.

A) 2012 Reliability Performance

1) Overview

Tampa Electric's 2012 distribution reliability indices, both adjusted and actual, represented mixed results in comparison to 2011. While the

company saw an improved performance in the customer average interruption duration and in the momentary average interruption frequency, there was an increase in the system average interruption duration and the system average interruption frequency.

2) Summary

Tampa Electric's Adjusted 2012 System Average Interruption Duration Index ("SAIDI") increased by 2.11 minutes over 2011 representing a 2.78 percent increase (40.52 minutes or 28.44 percent decrease – 2012 actual). Customer Average Interruption Duration Index ("CAIDI") decreased by 1.28 minutes over 2011 representing a 1.5 percent decrease (34.43 minutes or 28.41 percent decrease – 2012 actual). System Average Interruption Frequency Index ("SAIFI") increased by 0.04 average events or 4.6 percent (0 average events or 0 percent increase – 2012 actual), and the Momentary Average Interruption Frequency Index Event ("MAIFIe") decreased by 1.89 events or 14.26 percent from 2011 (1.94 events or 13.14 percent decrease – 2012 actual).

The modest fluctuations in SAIDI, SAIFI and MAIFIe are attributed to Tampa Electric's use of its Schweitzer relays and controls in substations. During non-storm months these relays were temporarily disabled to reduce the number of momentary events customers would experience. However, this slightly increased the frequency of outages customers experienced due to faults being cleared by other protective fusing. CAIDI remained relatively unchanged due to the company's level of resources used for restoration efforts.

The primary causes associated with a total outage increase of 325 were attributed as follows:

Down Wire – 200
Bad Connection – 57
Other Weather – 38
Vehicle – 30

The primary causes associated with a total decrease of 812 attributed as follows:

Animals – 421
Vegetation – 129
Electrical – 104
Unknown outages – 70
Lightning related - 65
Defective Equipment – 15
Remaining Causes - 8

When these primary causes are considered together, the net decrease of 487 outages is realized.

Overall outages were down in 2012 in comparison to 2011; the total number of outages in comparison to the last five-year average is also down by 7.34 percent or 713 outage events. Five-year average outage causes in all categories are down in comparison to 2012 totals with the exception of bad connection, unknown, vehicle, and down wire which are up by 0.38 percent, 2.37 percent, 21.25 percent and 49.91 percent, respectively.

Tampa Electric currently tracks outage records in its outage database according to date, duration, customers affected, cause, equipment-type,

associated field reports, breakers operations, etc., and uses this information to track and report inter-departmental, inter-company and external regulatory requests as required.

Tampa Electric management continues reviewing system performance and related metrics on a daily basis. Primary areas of focus include incremental and year-to-date semi-weekly SAIDI performance for transmission, substation and distribution, year-to-date MAIFIe and associated breaker operations, customer outages by system and region and major unplanned outages. In addition, management reviews the status of de-energized underground cables, oil circuit reclosers, online capacitor banks and street lights previously identified as needing maintenance.

In 2012, Tampa Electric management continued its increased focus on feeder restoration activity. As part of the semi-weekly review, feeder outage activity was reported and reviewed. Where outage duration exceeded acceptable thresholds, management reviewed incidents in pursuit of continued improvements with response time.

In addition to reviewing semi-weekly performance as noted above, the company analyzes distribution circuit performance, including feeders represented on the three percent feeder list, through a number of different ongoing processes. These processes include tree trimming analysis and circuit analysis.

3) Conclusion

In 2012, Tampa Electric customers experienced a decrease in the number of outages, the average interruption duration and the momentary average interruption frequency compared to previous years. The company attributes

some decrease to shorter interruption duration along with a decreased number of outages as reported.

B) Generation Events – Adjustments

Tampa Electric experienced no outages due to generation events that would have impacted distribution reliability; as a result, there were no exclusions in the company's 2012 Annual Distribution Reliability Report related to generation outage events.

C) Transmission Events – Adjustments

1) Transmission Outage Summary

In 2012, there were 10 transmission outages that affected customers. This included seven outages that were due to equipment failures, two outages due to vehicle collisions, and one outage due to animals. A total of 4,736,341 Customer Minutes of Interruption and 67,305 Customer Interruptions were excluded from the 2012 Annual Distribution Reliability Report per Rule 25-6.0455.

2) Equipment Failure Outages

There were seven outages attributed to ground wire, switch or pole failures. The repair or replacement of deficient ground wire, switches and poles has been identified and prioritized.

There was one outage attributed to a static wire failure. Above ground inspections will continue to identify static wire deficiencies so that repairs can be made prior to failure.

3) Vehicle Collision Outages

There were two outages attributed to structure failure due to vehicle collisions. No action items were identified.

4) Human Error Outage

There were no outages due to human error in 2012.

5) Vegetation Related Outages

There were no vegetation related outages 2012.

6) Clearance Outages

There were no outages due to insufficient clearance in 2012.

7) Cause Not Determined Outages

There were no outages due to an undetermined cause in 2012.

8) Transmission Outage Detail

69 KV Circuit

February 2012

Date: 2/05/12 **Circuit:** 66652

Customers Affected: 2,353 **SAIDI Impact:** 4 seconds

Discussion: Service was interrupted when a pole was hit by a vehicle. The damaged pole was replaced and the circuit was returned to service.

Event: Localized

March 2012

Date: 3/01/12 **Circuit:** 66051
Customers Affected: 7,176 **SAIDI Impact:** 2 seconds
Discussion: Service was interrupted when a pole was hit by a vehicle. The damaged pole was replaced and the circuit was returned to service.
Event: Localized

Date: 3/30/12 **Circuit:** 66838
Customers Affected: 15,041 **SAIDI Impact:** 25 seconds
Discussion: Service was interrupted when a buzzard got into the transmission conductor. The circuit was patrolled and switched back in.
Event: Localized

June 2012

Date: 6/24/12 **Circuit:** 66833
Customers Affected: 11,033 **SAIDI Impact:** 202 seconds
Discussion: Service was interrupted when a pole was broken due to Tropical Storm Debby. The pole was replaced and the circuit was returned to service.
Event: Localized

Date: 6/25/12 **Circuit:** 66833
Customers Affected: 5,481 **SAIDI Impact:** 127 seconds
Discussion: Service was interrupted when a pole was broken due to Tropical Storm Debby. The pole was replaced and the circuit was returned to service.
Event: Localized

August 2012

Date: 8/10/12 **Circuit:** 66011

Customers Affected: 2,098 **SAIDI Impact:** 32 seconds

Discussion: A span of static wire broke and fell into the energized lines which caused an interruption in service. The static wire was repaired and the circuit was returned to service.

Event: Localized

Date: 8/14/12 **Circuit:** 66419

Customers Affected: 2,342 **SAIDI Impact:** 1 second

Discussion: Service was interrupted when a ground wire was struck by lighting and fell into energized lines. The ground wire was repaired and the circuit was returned to service.

Event: Localized

October 2012

Date: 10/12/12 **Circuit:** 66004

Customers Affected: 4,116 **SAIDI Impact:** 15 seconds

Discussion: Service was interrupted when a ground wire was struck by lighting and fell into energized lines. The ground wire was repaired and the circuit was returned to service.

Event: Localized

Date: 10/20/12 **Circuit:** 66026

Customers Affected: 17,197 **SAIDI Impact:** 4 seconds

Discussion: Service was interrupted due to a planned outage to perform switch maintenance on an inoperable switch. The switch was repaired and the circuit was returned to service.

Event: Localized

November 2012

Date: 11/19/12 **Circuit:** 66004

Customers Affected: 468 **SAIDI Impact:** 1 second

Discussion: Service was interrupted when a wood pole broke. The pole was replaced and the circuit was returned to service.

Event: Localized

138 kV Circuit

None.

230 kV Circuit

None.

D) Extreme Weather

Tampa Electric experienced two extreme weather events during 2012 which affected customers in all seven divisions. Tropical Storm Debby began impacting the company's electric system on June 24, 2012 at 11:00 and continued to affect customers until June 26, 2012 at 23:59. Tropical Storm Isaac began impacting the company's electric system on August 26, 2012 at 12:00 and continued to affect customers until August 28, 2012 at 06:00.

This weather systems caused 675 outage events resulting in 69,361 Customer Interruptions and 14,176,134 Customer Minutes of Interruption impacting the electric system over the two three-day periods.

Of the 675 outage events experienced, 656 were attributed to the overhead system and the balance of 19 were attributed to the underground system.

System outage duration (L-Bar) during this event was 535.08 (523.77 and 925.32 overhead and underground, respectively).

Methods used to determine exclusions for the thunderstorm were the same used in the 2004, 2005, 2007 and 2011 Annual Distribution Reliability Reports.

See Appendix for specific data pursuant to Rule 25-6.0455.

E) Other Distribution – Adjustments

In 2012, there were 571 Other Distribution outages that affected customers. A total of 2,279,541 Customer Minutes of Interruption and 111,700 Customer Interruptions were excluded from the 2012 Annual Distribution Reliability Report per Rule 25-6.0455. All outages were attributed to planned events as noted within the 2012 Adjustments: Other Distribution in Appendix.

F) Distribution Substation

1) 2012 Distribution Substation Adjustments

In 2012, there were 148 Distribution Substation outages that affected customers. A total of 7,345,241 Customer Minutes of Interruption and 138,506 Customer Interruptions were excluded from the 2012 Annual Distribution Reliability Report per Rule 25-6.0455. All outages were attributed to substation equipment as noted within the 2012 Adjustments: Distribution Substation in Appendix.

2) Patterns and Trends - Distribution Substation Reliability Performance

In 2012, breaker mechanism problems contributed the most to SAIDI, but these issues continue to be significantly lower than the five-year average. Breakers that miss-operate are inspected, cleaned, lubricated and tested before being returned to service. The reclosing relays are then tested in the breaker. The most common causes of breaker miss-operations have been sticky mechanisms, defective closing coils and faulty reclosing relays. Outage analysis has revealed intermittent reclosing problems in specific types of breaker mechanisms and as a result, a Breaker Reliability program has been initiated to remove unreliable breakers from the system.

Since 2008, the total number of 13 kV circuit breakers that have been replaced through the program is 103. In 2012, 21 breakers were replaced as part of the Breaker Reliability program.

In 2012, outages due to protective relay failure/miss-operation were the second leading contributor to SAIDI. Most existing system relays are electromechanical. Failed electromechanical reclosing relays resulted in a majority of the relay related SAIDI impact. New installations use multifunction microprocessor based feeder relays for reclosing and under frequency protection. The new relays are more reliable than the older electromechanical relays. Self-diagnostic features allow earlier detection of failures in new relays. Moving from a common station under frequency relay to feeder based under frequency protection minimizes the effect of a relay miss-operation to a single feeder instead of an entire substation.

In 2012, animals were the third largest cause of SAIDI related outages. All new substations incorporate extensive animal protection into their design,

and Tampa Electric has been actively retrofitting existing substations with the latest in animal protection equipment. As a result, animal related outages have been trending downward over the past several years.

3) Tracking Distribution Substation Reliability

All major substation equipment nameplate data and maintenance activities are tracked in an asset management database. All work orders, findings and corrective actions related to substation outages are added to the asset management database. Substation operations supervisors review the maintenance and outage history of equipment involved in outages on a daily basis.

4) Process to Promote Substation Reliability

The following are used to determine the actions to promote substation reliability:

- Quarterly inspections of all substations
- Root cause analysis of each outage
- Annual review of all substation outages

Tampa Electric findings support the following ongoing activities:

- Review of all breaker misoperations
- Installation of animal protection in substations
- Change out breaker mechanisms identified with chronic problems
- Install microprocessor based relays for reclosing in all new construction and upgrade projects

- Replace station wide static under frequency relays with feeder based microprocessor under frequency relays in all new construction projects
- Program to replace 13kV circuit breakers that have been identified as problem breakers

In addition to the above activities, Tampa Electric has implemented automatic bus restoration schemes in select stations with multiple transformers.

The tables and exhibits that follow provide the performance results for distribution substations.

Table 1: Distribution Substation Inspections by Year

Year	Number of Distribution Substation Inspections
2008	378
2009	389
2010	542
2011	271
2012	520

Exhibit 1: 2012 Distribution Substation Outages

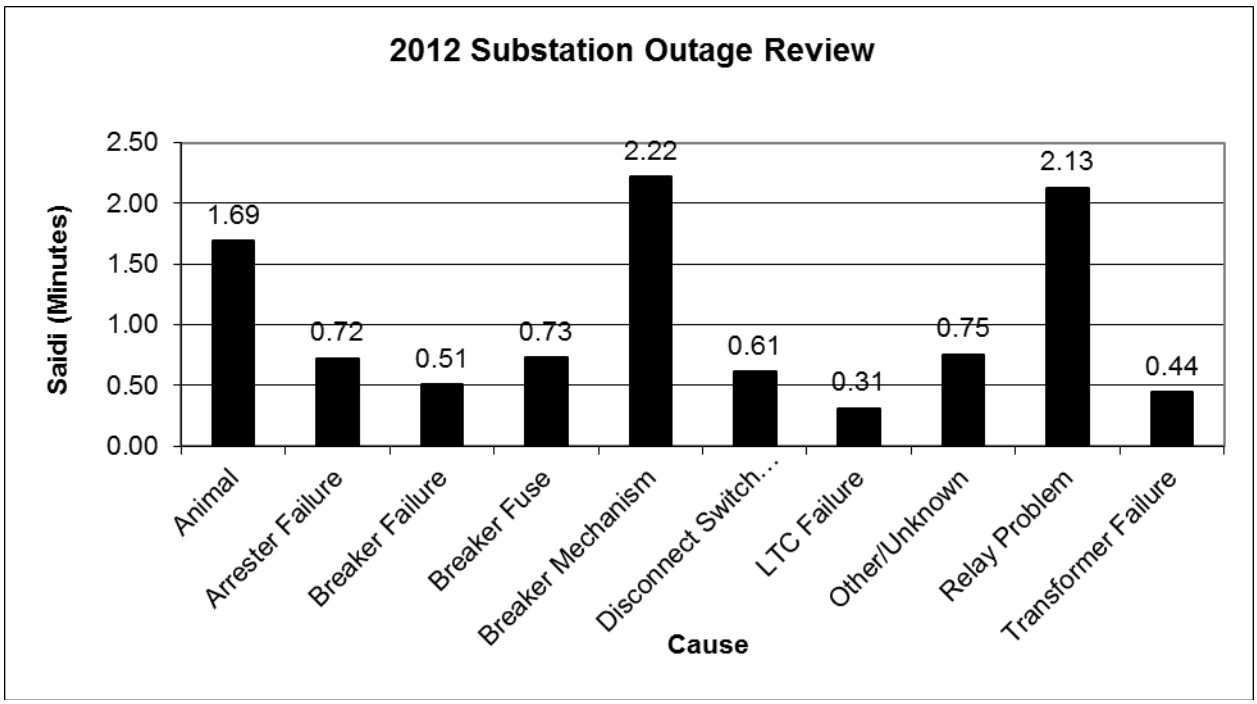


Exhibit 2: 2011 Distribution Substation Outages

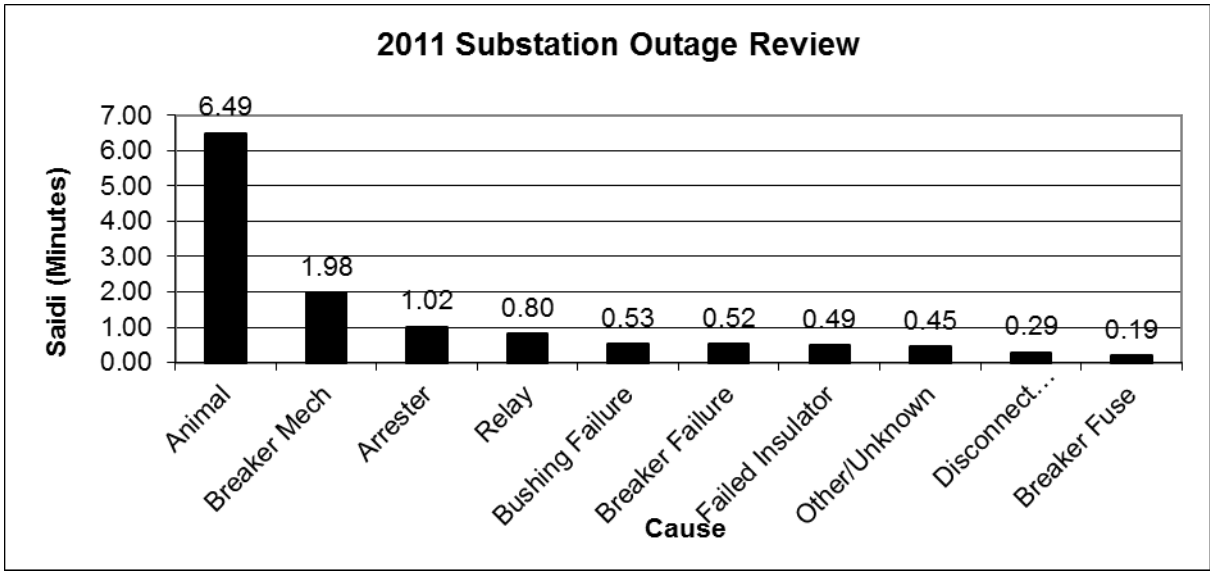


Exhibit 3: 2010 Distribution Substation Outages

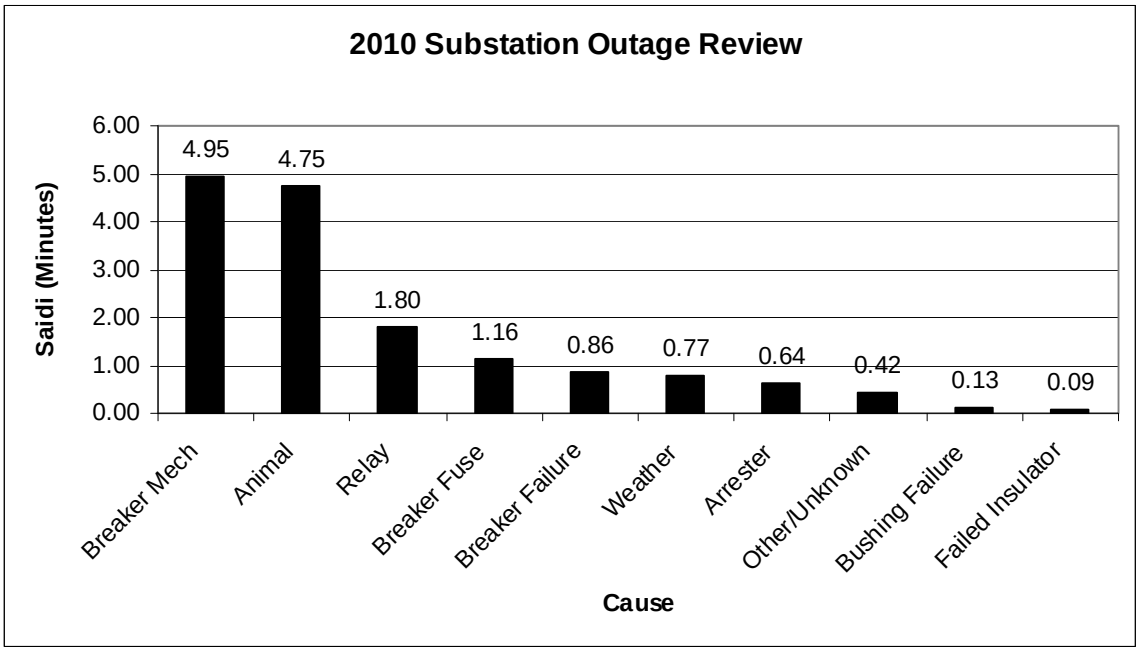


Exhibit 4: 2009 Distribution Substation Outages

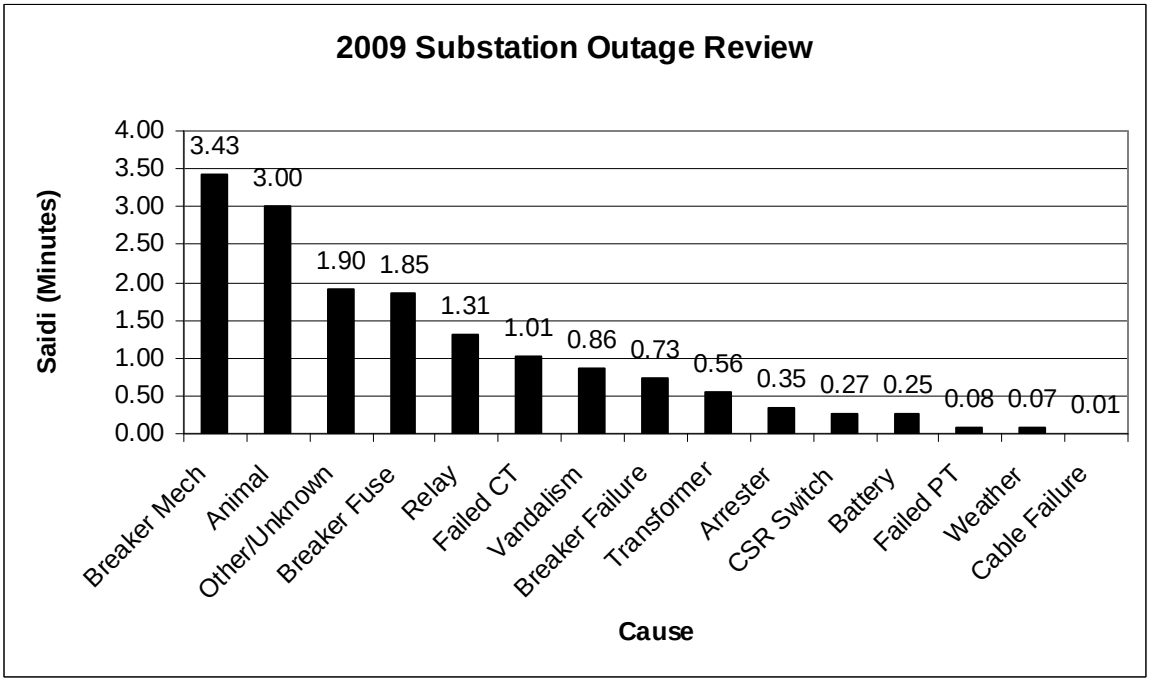


Exhibit 5: 2008 Distribution Substation Outages

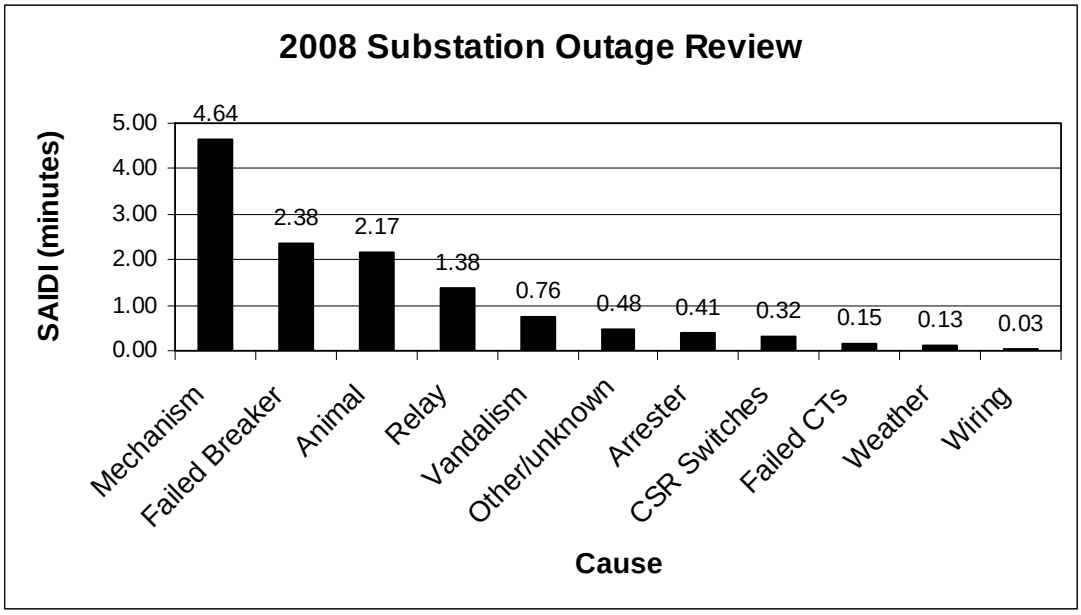


Exhibit 6: Substation Outages due to Animal Contact

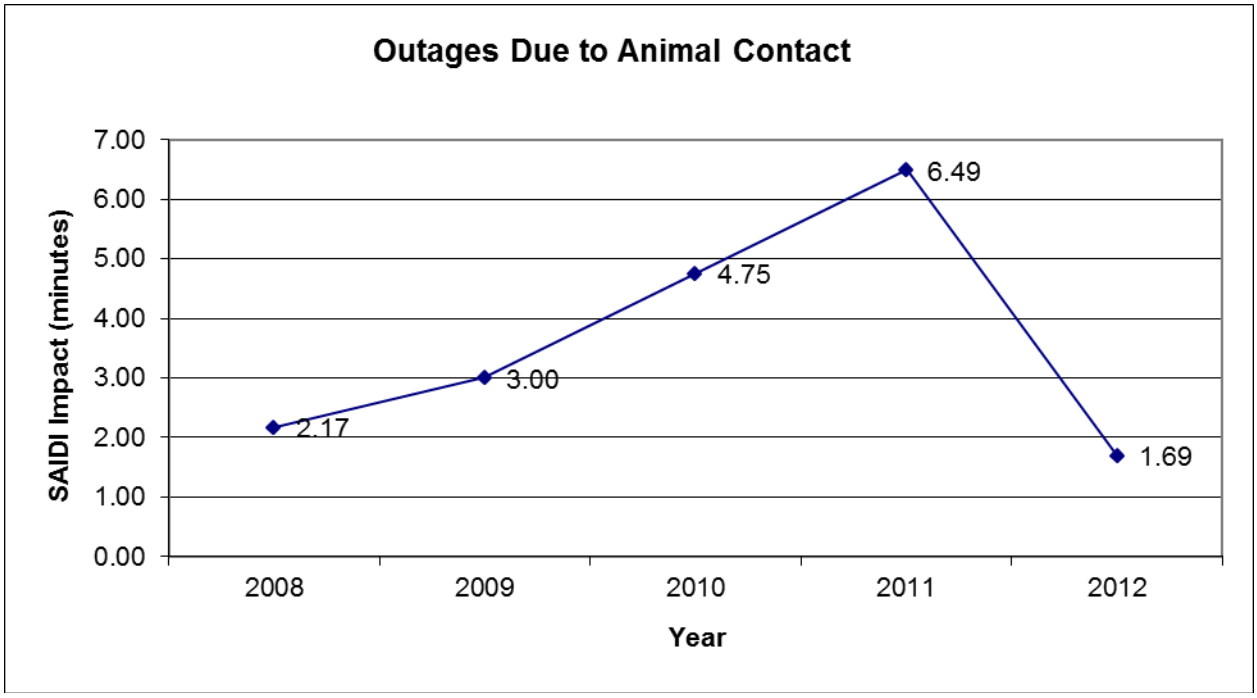


Exhibit 7: Substation Outages due to Breaker Mechanism Problem

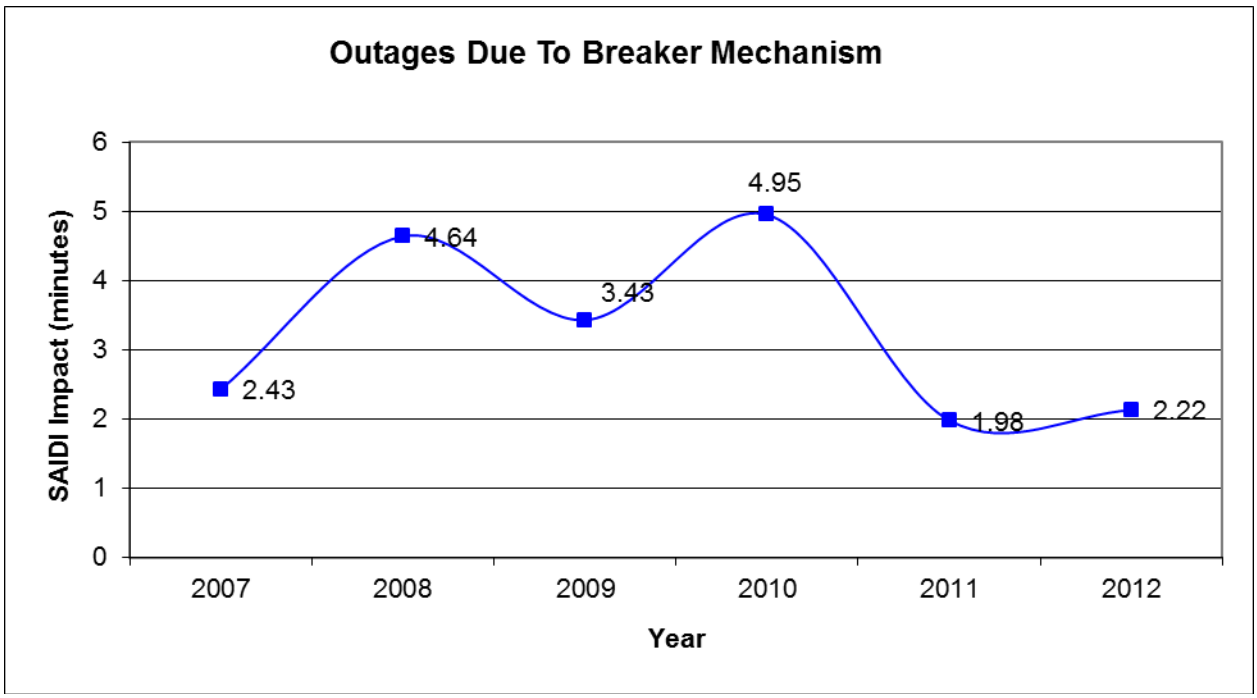
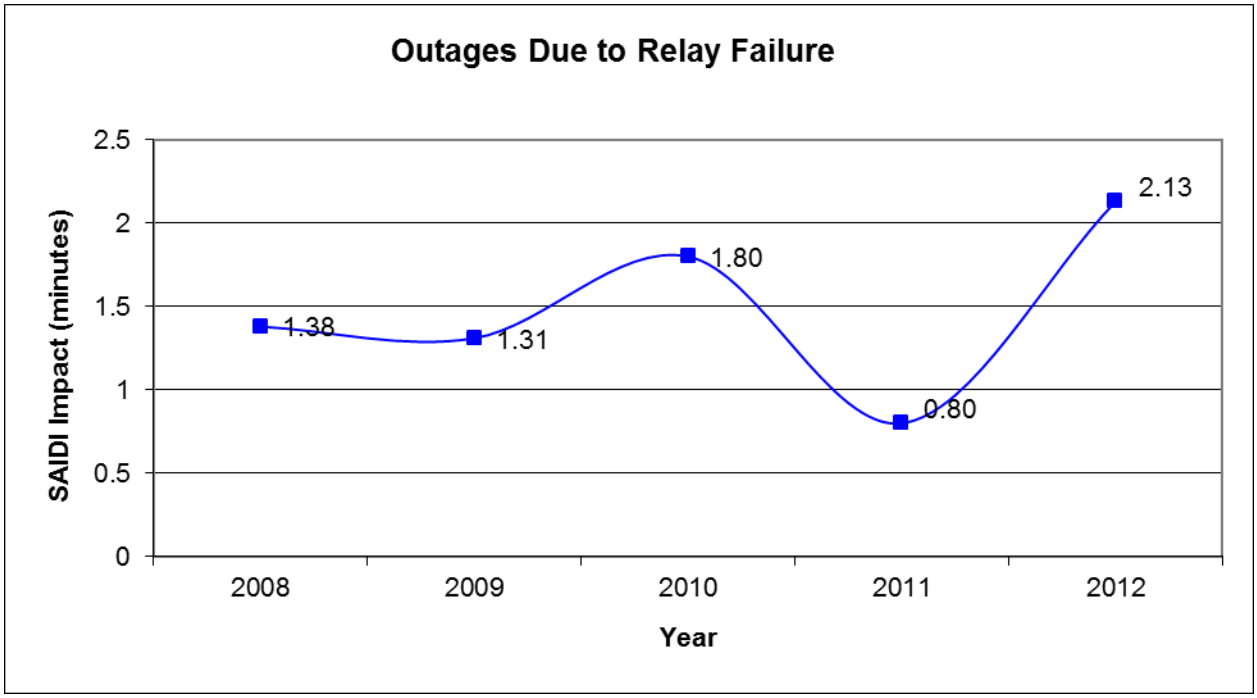


Exhibit 8: Substation Outages due to Relay Failure



G) 2012 Adjusted Distribution Reliability

1) Causes of Outages

Table 2: Cause of Outage Events by Year

Cause of Outage Events	2008	2009	2010	2011	2012
Animals	2,252	1,555	2,040	2,157	1,736
Vegetation	2,035	2,059	1,975	1,806	1,677
Lightning	1,570	1,498	1,226	1,392	1,327
Electrical	864	1,204	1,380	1,172	1,068
Unknown	703	721	753	849	779
Bad Connection	785	880	1,090	848	905
Down Wire	264	301	336	325	525
Vehicle	220	234	245	285	315
Other Weather	645	636	727	222	260
All Remaining Causes	249	235	206	223	215
Defective Equipment	511	396	245	196	181
System Totals	10,098	9,719	10,223	9,475	8,988

2) Three Percent Feeder

In reviewing both actual and adjusted Three Percent Feeder Lists (Forms 102 and 103, Part II) included within the Appendix of this report, six circuits have been identified to have been listed once before 2012. These circuits include Turkey Ford 13679, 30th Street 13160, Double Branch 13191, Habana 13220, Mulberry 13008 and Mulberry 13009.

Actual events for Turkey Ford 13679 included six circuit outages as reported. The company completed corrective activities on this circuit in

2012 including the replacement of padmounted equipment, overhead feeder, fused cutouts, switches and lightning arresters.

Actual events for 30th Street 13160 included three circuit outages as reported. The company completed corrective activities on this circuit in 2012 including hotspot tree trimming, the replacement of defective transformers and poles, the replacement of primary and the replacement of failing services.

Actual events for Double Branch 13191 included three circuit outages as reported. The company completed corrective activities on this circuit in 2012 including the replacement of lightning arresters, padmount equipment and switches.

Actual events for Habana 13220 included three circuit outages as reported. The company completed corrective activities on this circuit in 2012 including replacing lightning arresters, connections and fused cutouts.

Actual events for Mulberry 13008 included two circuit outages as reported. The company completed corrective activities on this circuit in 2012 including the installation of avian protection, replacement of lightning arrester, replacement of distribution poles and full circuit tree trimming.

Actual events for Mulberry 13009 included two circuit outages as reported. The company completed corrective activities on this circuit in 2012 including the installation of avian protection, replacement of lightning arrester and the replacement of distribution poles.

Other circuits identified in both “Actual” and “Adjusted” reports have had maintenance activities performed as noted on the Three Percent Feeder Report. The company will continue to monitor circuit outage performance as part of its daily and ongoing review of system reliability and will respond accordingly at a regional level.

H) Regional Reliability Indices

1) Summary

Table 4 represents customers by division over the period. Dade City, Plant City and South Hillsborough have the fewest customers and represent the most rural, lowest customer density per line mile in comparison to the other four Tampa Electric divisions. Actual reliability indices for the rural areas have varied from those of the more urban, densely populated areas for this period. This is due to the much greater distance traveled for service restoration in rural areas.

In 2012, SAIDI by division decreased over 2011 in all divisions except for Central, South Hillsborough and Plant City as represented in Table 5. 2012 SAIDI performance for all divisions but Central, Dade City, and South Hillsborough, was above the five-year average. Actual results by division and year have varied for the five-year period.

Table 6 data represents an increase in the 2012 CAIDI performance in comparison to 2011 for all divisions except Plant City, South Hillsborough and Winter Haven. 2012 CAIDI performance for all divisions but Central, Dade City, and Western, was above the five-year average. Actual results by division and year have varied for the five-year period.

In 2012, SAIFI performance for Western, Winter Haven, Eastern and Dade City improved over 2011 as noted in Table 7. SAIFI performance in Central, South Hillsborough and Plant City declined over 2011 results. All divisions performed better than the five-year average except Central, South Hillsborough and Winter Haven.

In 2012, MAIFIe performance improved in 2012 over 2011 in all divisions except Dade City and Plant City. All divisions had better MAIFIe performance than the five-year average except for Dade City and Plant City as noted in Table 8.

2) Improving Regional Reliability Trends

Tampa Electric focuses on divisional reliability through its operational management structure, which includes a divisional Operations Manager and Engineer. Planned and corrective maintenance is engineered and coordinated to completion by divisional operations staff. The divisional management teams receive daily reports on outage activity, including date and time of outage, duration, cause, and customers affected, etc., and identify any discrepancies in the data. This daily outage reporting also affords each divisional staff with key performance information and opportunities to identify and improve any trends that might have developed on feeders or laterals in their respective areas. It is expected that feeder and lateral performance will continue to be tracked in support of improving regional reliability.

Table 4: Number of Customers by Service Area per Year

	2008	2009	2010	2011	2012
Central	179,224	179,160	179,810	181,797	185,005
Dade City	13,806	13,686	13,692	13,700	13,822
Eastern	107,495	108,206	109,383	109,876	111,069
Plant City	53,925	54,103	54,470	54,725	55,472
South Hillsborough	59,540	60,356	61,530	62,761	64,530
Western	186,062	186,960	187,932	189,200	191,083
Winter Haven	67,243	66,979	67,560	67,222	67,735
System	667,295	669,450	674,377	679,281	688,716

Table 5: SAIDI by Service Area per Year

	2008	2009	2010	2011	2012
Central	46.61	61.53	64.06	54.40	75.88
Dade City	127.30	137.96	134.55	170.11	161.12
Eastern	69.02	63.53	66.90	60.95	56.76
Plant City	108.01	141.26	143.61	99.39	109.73
South Hillsborough	65.41	84.97	101.07	66.77	89.70
Western	69.99	79.31	88.91	91.22	77.48
Winter Haven	51.66	59.11	79.24	86.24	66.76
System	65.55	76.69	84.20	75.96	78.07

Table 6: CAIDI by Service Area per Year

	2008	2009	2010	2011	2012
Central	76.31	74.59	87.48	85.32	88.10
Dade City	63.62	74.53	81.73	85.06	96.56
Eastern	73.51	70.22	96.07	75.93	78.07
Plant City	78.91	76.39	97.36	87.87	82.02
South Hillsborough	73.04	95.13	113.70	88.77	84.83
Western	78.33	78.30	99.23	93.92	95.79
Winter Haven	53.01	69.99	80.08	82.93	66.14
System	73.28	76.53	94.53	86.83	85.55

Table 7: SAIFI by Service Area per Year

	2008	2009	2010	2011	2012
Central	0.61	0.82	0.73	0.64	0.86
Dade City	2.00	1.85	1.65	2.00	1.67
Eastern	0.94	0.90	0.70	0.80	0.73
Plant City	1.37	1.85	1.48	1.13	1.34
South Hillsborough	0.90	0.89	0.89	0.75	1.06
Western	0.89	1.01	0.90	0.97	0.81
Winter Haven	0.97	0.84	0.99	1.04	1.01
System	0.89	1.00	0.89	0.87	0.91

Table 8: MAIFIe by Service Area per Year

	2008	2009	2010	2011	2012
Central	12.36	8.79	10.01	11.23	10.17
Dade City	16.88	13.41	16.51	15.64	15.76
Eastern	15.33	11.97	12.99	14.38	10.85
Plant City	19.02	19.93	14.78	17.61	19.84
South Hillsborough	15.26	13.28	14.20	13.56	11.21
Western	12.59	10.40	11.79	12.57	10.58
Winter Haven	14.18	11.16	11.55	14.47	9.98
System	13.97	11.39	12.04	13.25	11.36

Table 9: CEMI5 by Service Area per Year

	2008	2009	2010	2011	2012
Central	0.29%	1.22%	0.37%	0.60%	0.44%
Dade City	5.12%	11.50%	0.58%	0.67%	3.66%
Eastern	0.23%	0.59%	1.60%	0.69%	0.37%
Plant City	3.84%	11.27%	1.22%	0.85%	0.90%
South Hillsborough	1.20%	2.47%	1.04%	0.30%	3.49%
Western	0.82%	1.74%	0.69%	0.58%	0.26%
Winter Haven	1.00%	1.69%	3.56%	0.80%	0.71%
System	0.97%	2.45%	1.11%	0.62%	0.79%

I) Overhead – Underground Reliability

1) Five-Year Trends - Reliability Performance

Examining a five-year trend from 2008 to 2012 in overall outages presented in Table 10, 2012 represented the lowest number of total outages during the period. Overhead outages represented the majority of outages ranging from 83 to 89 percent of the total outages for the period. Underground outages represented 11 to 17 percent annually compared against total outages.

Table 10: Outages per Year

System Totals	2008	2009	2010	2011	2012
Number of Outages Events (N)	10,098	9,719	10,223	9,475	8,988
System Average Duration (L-Bar)	143.78	159.00	172.51	169.47	177.24
Average Restoration Time (CAIDI)	73.28	76.53	94.53	86.83	85.55

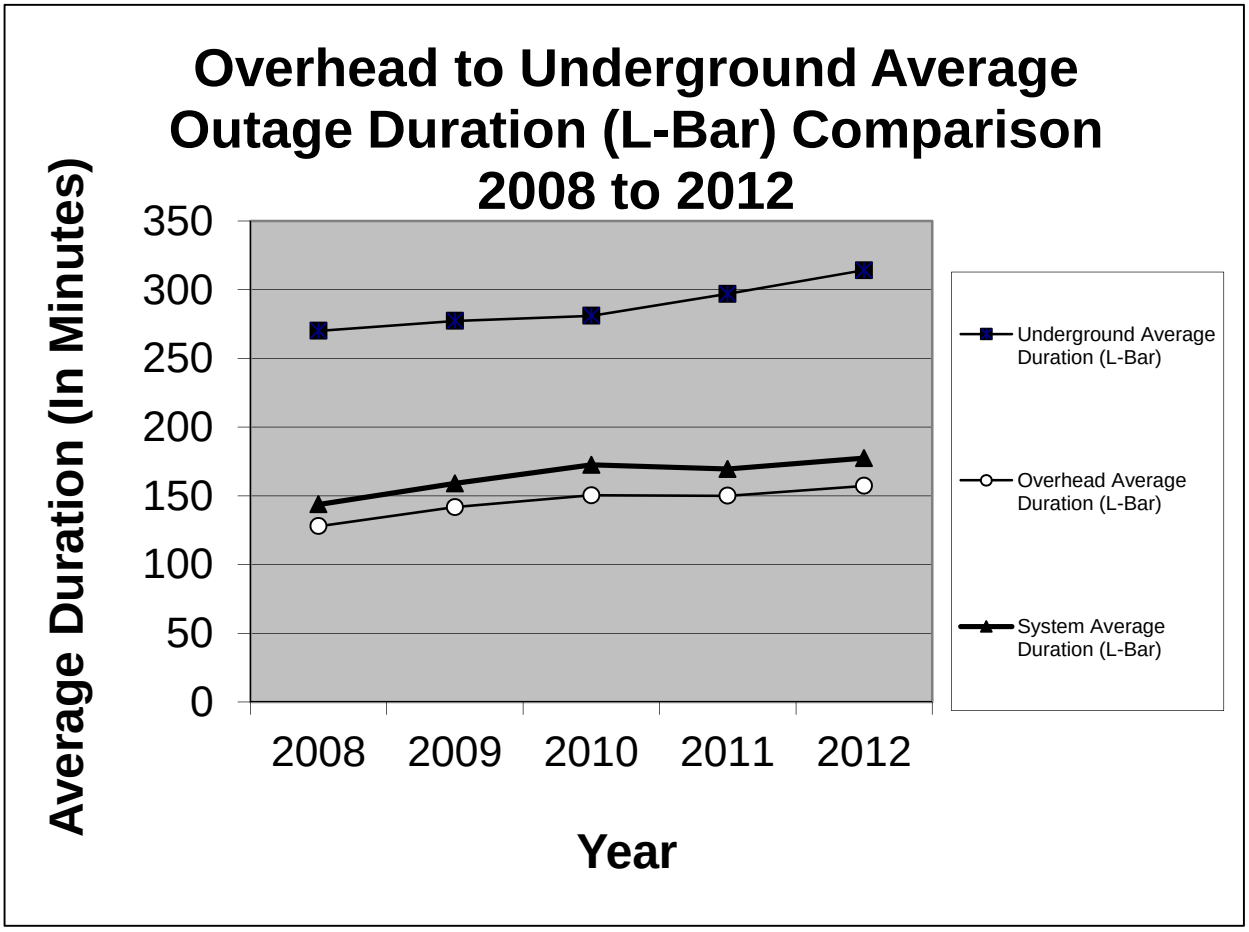
Overhead	2008	2009	2010	2011	2012
Number of Outages Events (N)	8,977	8,484	8,495	8,226	7,838
Overhead Average Duration (L-Bar)	128.01	141.76	150.43	150.11	157.12
Average Restoration Time (CAIDI)	69.41	72.84	86.80	82.65	80.87

Underground	2008	2009	2010	2011	2012
Number of Outages Events (N)	1,121	1,235	1,728	1,249	1,150
Underground Average Duration (L-Bar)	270.07	277.38	281.08	296.94	314.37
Average Restoration Time (CAIDI)	266.54	210.33	237.89	246.51	277.23

Tampa Electric miles of distribution through 2011 include 6,301 miles of overhead and 4,762 miles of underground for a total of 11,063 miles. The ratio of overhead and underground miles to total miles equates to 57 percent and 43 percent, respectively.

The overhead distribution system characteristically provides advantages for quicker troubleshooting, fault identification and shorter outage duration. Exhibit 9 below represents average outage duration (L-Bar) for the past five years. Overhead L-Bar increased in 2012 and has a five-year average of 145.49 minutes, while underground L-Bar has a five-year average of 287.97 minutes which also increased in 2012. The five-year system L-Bar average is 164.40 minutes.

Exhibit 9: Overload to Underground Outage Duration



2) Tracking Overhead to Underground Reliability Performance

Tampa Electric tracks outage records in its outage database according to cause and equipment type. These equipment types are designed and associated with the overhead and underground systems. Reporting capability allows the company to track CMI, CI, Number of Outages, Average Duration and CAIDI as referenced in Section C – Overhead to Underground in the Appendix. In addition, separate reporting was undertaken in order to align miles and customers for overhead and underground distribution.

The company tracks and reports MAIFIe by system and circuit. Interruption data is electronically captured, recorded and tracked at each individual distribution circuit breaker. As a result, a momentary interruption occurring down-line from the circuit breaker and whether it's associated with overhead or underground equipment as noted above, is not currently captured and cannot be reported.

The company currently measures CEMI5 through a query that is run through its OMS. There is no option to run the query for overhead or underground systems. Therefore, the company is not able to provide CEMI5 as previously requested by Commission Staff.

3) Underground Distribution System Conversions

For 2012, there was no activity associated with underground distribution system conversions.

J) Reliability-Related Customer Complaints

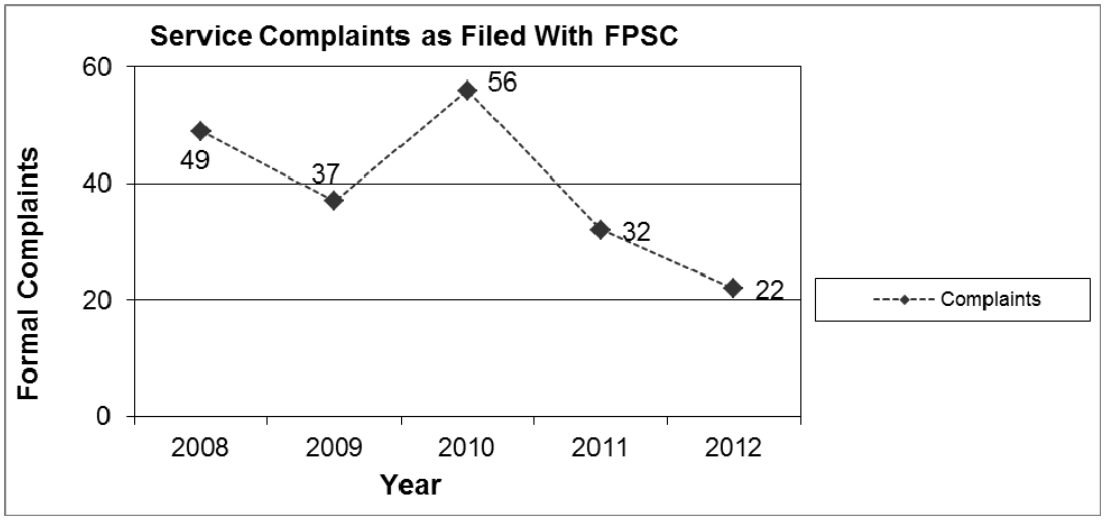
During 2012, Tampa Electric experienced a decrease of 10 formal service-related complaints as logged by the Florida Division of Consumer Affairs and noted in Exhibit 10 below. In addition, service-related complaints as tracked by the company and including FPSC Formal, Three-Day, Transfer-Connect, eWarm Transfer and Executive Level decreased by 24 complaints in 2012 as noted in Exhibit 11 below. In comparison to the five-year average, overall complaints were 17.91 percent less in 2012.

When comparing formal complaints logged against the company to reliability performance (Exhibits 12 and 13) over the last five years, it is apparent that as reliability performance has varied, complaints have tracked accordingly. The company believes that increased activity on vegetation management over the last five years, circuit review activity and resulting line improvements and other maintenance activities will continue to contribute toward minimizing service-related complaints in 2013.

Tampa Electric's current process for responding to all service related complaints includes the central intake and coordination of complaint resolution through the Quality Assurance Department and extends out to Operations Engineers who are responsible for the daily oversight of feeders in their respective service area. Operations Engineers are involved in customer interactions, identifying needs and corrective measures, and are responsible for coordination through to completion. Working through and responding to complaints at a regional level affords the company an opportunity to be aware of any trends that may occur for a given feeder or lateral.

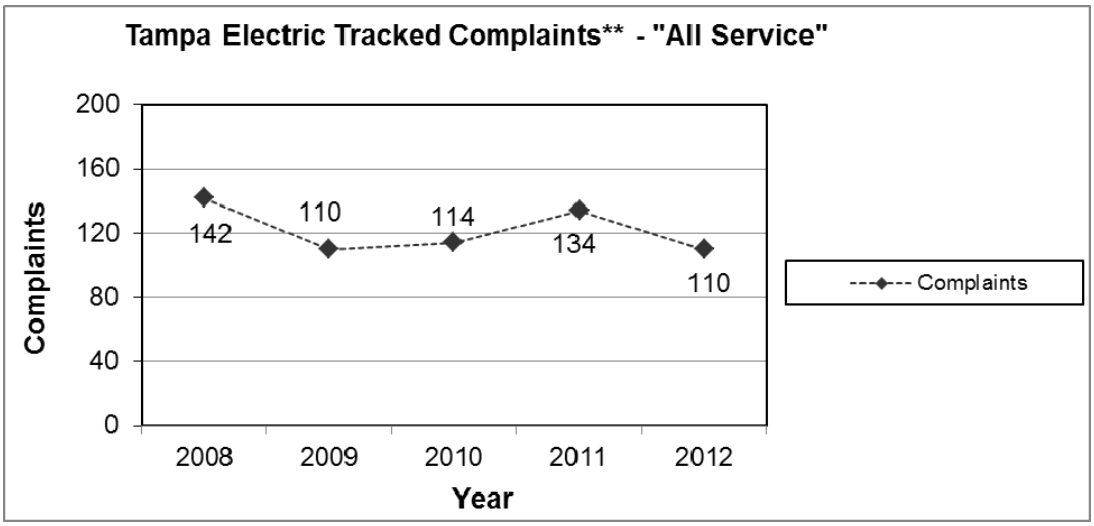
In addition, the group of Operations Engineers and System Reliability meet on a monthly basis to review common areas of concern across the system and identifies opportunities for improvement.

Exhibit 10: Tampa electric Service Formal Complaints Filed with the FPSC by Year



Source: FPSC Consumer Activity Reports

Exhibit 11: Tampa Electric Service Complaints by Year



Source: Tampa Electric FPSC Tracking System Reports

Notes: **Consists of all "Service" complaints logged by the company including FPSC Formal, three-day, Transfer-Connect, eWarm Transfer and Executive Level.

Exhibit 12: Formal Complaints *vs.* SAIDI by Year

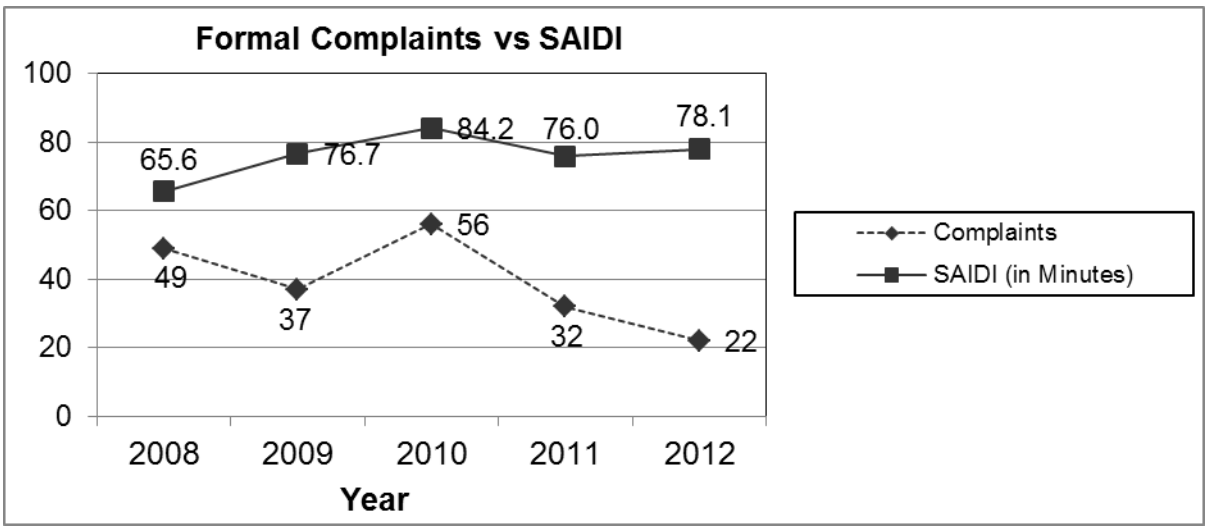
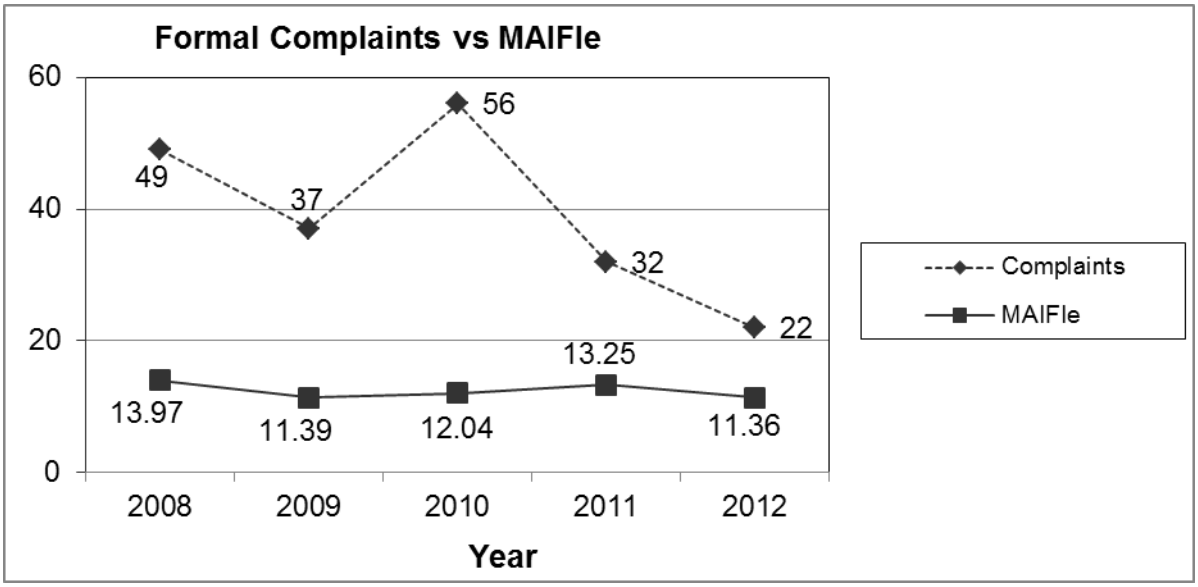


Exhibit 13: Formal Complaints *vs.* MAIFIe by Year



APPENDIX

2012
STORM IMPLEMENTATION PLAN
&
ANNUAL RELIABILITY PERFORMANCE REPORTS

Tampa Electric Company **March 2013**

Appendix A) Form 102 – Part I –Actual

PART I

Primary Causes of Outage Events - Actual

Utility Name: Tampa Electric **Year: 2012**

Cause (a)	Number of Outages Events (N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Vegetation	2,090	270.41	129.10
2. Animals	1,741	87.22	64.37
3. Lightning	1,366	236.14	122.97
4. Electrical	1,140	196.59	79.28
5. Bad Connection	959	233.52	121.14
6. Unknown	791	137.66	98.43
7. Other Weather	549	164.43	77.02
8. Down Wire	406	334.12	138.58
9. Vehicle	346	212.91	76.17
10. Human Interference	250	91.21	17.55
All Remaining Causes	596	153.32	42.47
System Totals	10,234	196.43	86.74

Form PSC/ECR 102-1, Docket No. 011351-EI, Rule 25-6.0455(a)

Form 102 – Part II –Actual

3 Percent Feeder List

Utility Name: Tampa Electric — Year: 2012

Primary Circuit Id. No. or Name (a)	Substation Origin (b)	Location (c)	Number of Customers: Residential (d)	Commerical (e)	Industrial (f)	Other (g)	Total (h)	Outage Events "N" (i)	Avg. Duration "L-Bar" (j)	CAIDI (k)	Listed Last Year? (l)	Years in the Last 5 (m)	Action Completion Date (n)
CB_13679	Turkey Ford	Western	1,036	53	5		1,094	6	58.17	56.77	No	1	01/2012
CB_13118	Lake Alfred	Winter Haven	1,225	128	14		1,367	4	46.50	46.45	No	0	02/2012, 05/2012, 06/2012, 09/2012, 12/2012
CB_13298	Polk City	Winter Haven	1,008	118	5		1,131	4	51.75	58.72	No	0	02/2012, 03/2012, 04/2012, 05/2012, 07/2012, 09/2012, 10/2012
CB_13406	Keystone	Western	195	23	8		226	4	68.75	57.50	No	0	07/2012
CB_13817	Ruskin	South Hillsborough	1,551	145	15		1,711	4	55.50	50.54	No	0	03/2012, 04/2012, 05/2012, 06/2012, 10/2012, 12/2012
CB_14023	Riverview	South Hillsborough	729	28	5		762	4	69.00	66.29	No	0	01/2012, 06/2012
CB_13003	Ruskin	South Hillsborough	779	139	19		937	3	38.33	37.49	No	0	01/2012, 06/2012, 07/2012, 09/2012, 11/2012
CB_13010	Mulberry	Plant City	1,418	146	31		1,595	3	97.00	105.03	No	0	03/2012
CB_13011	Mulberry	Plant City	1,775	65	9		1,849	3	69.33	69.26	No	0	04/2012
CB_13098	Sunset Lane	Central	884	213	21		1,118	3	45.67	46.41	No	0	01/2012, 02/2012, 03/2012, 04/2012, 05/2012, 06/2012, 06/2012, 07/2012, 08/2012, 09/2012, 10/2012, 11/2012, 12/2012
CB_13125	Plant City	Plant City	773	69	21		863	3	77.00	70.39	No	0	09/2012
CB_13160	30th Street	Central	931	14	2		947	3	43.33	43.35	No	1	01/2012, 03/2012, 04/2012, 05/2012, 06/2012, 07/2012, 08/2012, 09/2012, 10/2012
CB_13191	Double Branch	Western	301	252	58		611	3	36.00	33.84	Yes	1	05/2012
CB_13220	Habana	Western	625	104	13		742	3	11.67	9.09	Yes	1	08/2012
CB_13370	Dairy Road	Winter Haven	1,373	213	40		1,626	3	10.67	9.61	No	0	05/2012, 06/2012
CB_13442	Lake Region	Winter Haven	1,695	71	6		1,772	3	42.00	36.96	No	0	03/2012, 06/2012, 07/2012, 09/2012
CB_13661	Lake Winterset	Winter Haven	1,384	76	3		1,463	3	47.67	45.73	No	0	02/2012, 04/2012, 05/2012, 08/2012, 10/2012
CB_13798	St. Cloud	Eastern	1,036	124	29		1,189	3	33.33	32.25	No	0	03/2012, 04/2012, 06/2012, 07/2012, 08/2012, 11/2012, 12/2012
CB_13815	Blanton	Dade City	625	120	7		752	3	41.67	40.57	No	0	07/2012
CB_13910	Peach Avenue	Eastern	1,052	50	4		1,106	3	44.33	44.33	No	0	01/20012, 06/2012, 07/2012, 08/2012
CB_13924	Lake Gum	Winter Haven	449	106	7		562	3	41.67	42.46	No	0	02/2012, 05/2012, 09/20012
CB_14011	GTE-Collier	Central	601	48	28		677	3	64.33	63.21	No	0	06/2012, 07/2012, 11/2012
CB_13008	Mulberry	Plant City	316	88	24		428	2	49.50	49.51	Yes	2	01/2012, 04/2012
CB_13009	Mulberry	Plant City	40	68	23		131	2	60.50	60.71	Yes	1	05/2012
CB_13017	Gibsonton	South Hillsborough	1,472	66	2		1,540	2	49.00	49.00	No	0	03/2012, 05/2012, 06/2012, 12/2012
CB_13019	Gibsonton	South Hillsborough	1,324	171	31		1,526	2	45.00	45.02	No	0	03/2012, 06/2012, 07/2012, 11/2012
CB_13036	Belmont Heights	Central	1,071	98	21		1,190	2	88.00	84.44	No	0	01/2012, 02/2012, 03/2012, 05/2012, 06/2012, 06/2012, 07/2012, 08/2012, 09/2012, 10/2012, 11/2012, 12/2012

Form PSC/ECR 102-2, Docket No. 011351-EI, Rule 25-6.0455(b)

Notes:
L-Bar and CAIDI are based on the entire circuit.
L-Bar and CAIDI are expressed in minutes

Form 102 – Part III –Actual

ANNUAL DISTRIBUTION RELIABILITY REPORT - 2012

Utility Name: Tampa Electric

SAIDI: System Average Interruption Duration Index		
= Sum of All Customer Minutes Interrupted (CMI)	70,226,090	101.97
Total number of Customers Served (C)	688,716	
CAIDI: Customer Average Interruption Duration Index		
= Sum of All Customer Minutes Interrupted (CMI)	70,226,090	86.74
Total number of Customer Interruptions (CI)	809,584	
SAIFI: System Average Interruption Frequency Index		
= Total number of Customer Interruptions (CI)	809,584	1.18
Total number of Customers Served (C)	688,716	
MAIFIe: Momentary Average Interruption Event		
= Sum of All Customer Momentary Interruption Events (CME)	8,828,494	12.82
Total number of Customers Served (C)	688,716	
LBar:		
= Minutes of Interruption	2,010,301	196.43
Total number of Outages	10,234	

District	C	CMI	CI	CME	# Cust > 5
Central	185,005	19,970,121	199,475	2,142,398	1,196
Dade City	13,822	3,042,071	38,914	264,769	806
Eastern	111,069	8,354,138	113,595	1,353,880	943
Plant City	55,472	7,010,263	96,935	1,192,942	809
South Hillsborough	64,530	7,048,732	90,705	842,363	2,408
Western	191,083	17,974,659	193,055	2,278,367	767
Winter Haven	67,735	6,826,106	76,905	753,775	810
System Totals	688,716	70,226,090	809,584	8,828,494	7,741

Form 102 – Part III continued – Actual

PART III

Service Reliability Indices – Actual

Utility Name: Tampa Electric **Year: 2012**

District or Service Area (a)	SAIDI (b)	CAIDI (c)	SAIFI (d)	MAIFIe (e)	CEMI5 (f)
Central	107.94	100.11	1.08	11.58	0.65%
Dade City	220.09	78.17	2.82	19.16	5.83%
Eastern	75.22	73.54	1.02	12.19	0.85%
Plant City	126.37	72.32	1.75	21.51	1.46%
South Hillsborough	109.23	77.71	1.41	13.05	3.73%
Western	94.07	93.11	1.01	11.92	0.40%
Winter Haven	100.78	88.76	1.14	11.13	1.20%
System	101.97	86.74	1.18	12.82	1.12%

Form PSC/ECR 102-3, Docket No. 011351-EI, Rule 25-6.0455(c)

Appendix B) Form 103 – Part I – Adjusted

PART I

Primary Causes of Outage Events – Adjusted

Utility Name: Tampa Electric **Year: 2012**

Cause (a)	Number of Outages Events (N) (b)	Average Duration (L-Bar) (c)	Average Restoration Time (CAIDI) (d)
1. Animals	1,736	87.01	67.11
2. Vegetation	1,677	217.67	106.51
3. Lightning	1,327	224.89	121.48
4. Electrical	1,068	184.45	79.32
5. Unknown	905	225.32	108.76
6. Bad Connection	779	135.13	86.77
7. Down Wire	525	165.30	77.36
8. Vehicle	315	220.97	83.37
9. Other Weather	260	190.81	92.50
10. Defective Equipment	181	182.27	147.88
All Remaining Causes	215	155.24	45.04
System Totals	8,988	177.24	85.55

Form PSC/ECR 102-1, Docket No. 011351-EI, Rule 25-6.0455(a)

FORM 103 - PART II – Adjusted

3 Percent Feeder List

Utility Name: Tampa Electric — Year: 2012

Primary Circuit Id. No. or Name (a)	Substation Origin (b)	Location (c)	Number of Customers: Residential (d)	Commerical (e)	Industrial (f)	Other (g)	Total (h)	Outage Events "N" (i)	Avg. Duration "L-Bar" (j)	CAIDI (k)	Listed Last Year? (l)	Years in the Last 5 (m)	Action Completion Date (n)
CB_13118	Lake Alfred	Winter Haven	1,225	128	14		1,367	4	46.50	46.45	No	0	02/2012, 05/2012, 06/2012, 09/2012, 12/2012
CB_13298	Polk City	Winter Haven	1,008	118	5		1,131	4	51.75	58.72	No	0	02/2012, 03/2012, 04/2012, 05/2012, 07/2012, 09/2012, 10/2012
CB_13817	Ruskin	South Hillsborough	1,551	145	15		1,711	4	55.50	50.54	No	0	03/2012, 04/2012, 05/2012, 06/2012, 10/2012, 12/2012
CB_14023	Riverview	South Hillsborough	729	28	5		762	4	69.00	66.29	No	0	01/2012, 06/2012
CB_13003	Ruskin	South Hillsborough	779	139	19		937	3	38.33	37.49	No	0	01/2012, 06/2012, 07/2012, 09/2012, 11/2012
CB_13010	Mulberry	Plant City	1,418	146	31		1,595	3	97.00	105.03	No	0	03/2012
CB_13011	Mulberry	Plant City	1,775	65	9		1,849	3	69.33	69.26	No	0	04/2012
CB_13098	Sunset Lane	Central	884	213	21		1,118	3	45.67	46.41	No	0	01/2012, 02/2012, 03/2012, 04/2012, 05/2012, 06/2012, 06/2012, 07/2012, 08/2012, 09/2012, 10/2012, 11/2012, 12/2012
CB_13125	Plant City	Plant City	773	69	21		863	3	77.00	70.39	No	0	09/2012
CB_13370	Dairy Road	Winter Haven	1,373	213	40		1,626	3	10.67	9.61	No	0	05/2012, 06/2012
CB_13442	Lake Region	Winter Haven	1,695	71	6		1,772	3	42.00	36.96	No	0	03/2012, 06/2012, 07/2012, 09/2012
CB_13661	Lake Winterset	Winter Haven	1,384	76	3		1,463	3	47.67	45.73	No	0	02/2012, 04/2012, 05/2012, 08/2012, 10/2012
CB_13798	St. Cloud	Eastern	1,036	124	29		1,189	3	33.33	32.25	No	0	03/2012, 04/2012, 06/2012, 07/2012, 08/2012, 11/2012, 12/2012
CB_13815	Blanton	Dade City	625	120	7		752	3	41.67	40.57	No	0	07/2012
CB_13910	Peach Avenue	Eastern	1,052	50	4		1,106	3	44.33	44.33	No	0	01/20012, 06/2012, 07/2012, 08/2012
CB_13924	Lake Gum	Winter Haven	449	106	7		562	3	41.67	42.46	No	0	02/2012, 05/2012, 09/20012
CB_14011	GTE-Collier	Central	601	48	28		677	3	64.33	63.21	No	0	06/2012, 07/2012, 11/2012
CB_13159	30th Street	Central	1,078	75	24		1,177	2	30.00	24.11	No	0	06/2012, 07/2012
CB_13040	Bloomingdale	Eastern	988	70	27		1,085	2	48.50	47.37	No	0	02/2012, 05/2012
CB_13045	Fern Street	Central	975	85	18		1,078	2	45.00	46.09	No	0	04/2012, 07/2012, 08/2012, 09/2012, 12/2012
CB_13096	Sunset Lane	Central	1,102	122	19		1,243	2	45.50	45.52	No	0	01/2012, 03/2012, 04/2012, 09/2013
CB_13223	56th Street	Central	230	188	51		469	2	40.00	40.40	No	0	,02/2012, 03/2012, 06/2012, 10/2012
CB_13229	Brandon	Eastern	1,063	187	18		1,268	2	31.00	22.36	No	0	01/2012, 02/2012, 03/2012, 04/2012,05/2012,06/2012, 08/2012, 09/2012
CB_13187	Pine Lake	Central	1,185	88	7		1,280	2	68.50	67.20	No	0	01/2012, 02/20012, 05/2012, 08/2012, 11/2012
CB_13017	Gibsonton	South Hillsborough	1,472	66	2		1,540	2	49.00	49.00	No	0	03/2012, 05/2012, 06/2012, 12/2012
CB_13019	Gibsonton	South Hillsborough	1,324	171	31		1,526	2	45.00	45.02	No	0	03/2012, 06/2012, 07/2012, 11/2012
CB_13036	Belmont Heights	Central	1,071	98	21		1,190	2	88.00	84.44	No	0	01/2012, 02/2012, 03/2012, 05/2012, 06/2012, 06/2012, 07/2012, 08/2012, 09/2012, 10/2012, 11/2012, 12/2012

Form PSC/ECR 102-2, Docket No. 011351-EI, Rule 25-6.0455(b)

Notes:
L-Bar and CAIDI are based on the entire circuit.
L-Bar and CAIDI are expressed in minutes

Form 103 – Part III – Adjusted

PART III

ANNUAL DISTRIBUTION RELIABILITY REPORT - 2012

Utility Name: Tampa Electric

SAIDI: System Average Interruption Duration Index

= Sum of All Customer Minutes Interrupted (CMI)	53,770,415	78.07
Total number of Customers Served (C)	688,716	

CAIDI: Customer Average Interruption Duration Index

= Sum of All Customer Minutes Interrupted (CMI)	53,770,415	85.55
Total number of Customer Interruptions (CI)	628,523	

SAIFI: System Average Interruption Frequency Index

= Total number of Customer Interruptions (CI)	628,523	0.91
Total number of Customers Served (C)	688,716	

MAIFIe: Momentary Average Interruption Event

= Sum of All Customer Momentary Interruption Events (CME)	7,825,550	11.36
Total number of Customers Served (C)	688,716	

LBar:

= Minutes of Interruption	1,593,055	177.24
Total number of Outages	8,988	

District	C	CMI	CI	CME	# Cust > 5
Central	185,005	14,037,306	159,340	1,881,055	808
Dade City	13,822	2,227,053	23,063	217,856	506
Eastern	111,069	6,304,541	80,758	1,204,706	413
Plant City	55,472	6,086,762	74,215	1,100,480	497
South Hillsborough	64,530	5,788,179	68,230	723,262	2,255
Western	191,083	14,804,551	154,548	2,022,394	495
Winter Haven	67,735	4,522,023	68,369	675,797	484
System Totals	688,716	53,770,415	628,523	7,825,550	5,458

Form 103 – Part III continued – Adjusted

PART III

Service Reliability Indices – Adjusted

Utility Name: Tampa Electric **Year: 2012**

District or Service Area (a)	SAIDI (b)	CAIDI (c)	SAIFI (d)	MAIFIe (e)	CEMI5 (f)
Central	75.88	88.10	0.86	10.17	0.44%
Dade City	161.12	96.56	1.67	15.76	3.66%
Eastern	56.76	78.07	0.73	10.85	0.37%
Plant City	109.73	82.02	1.34	19.84	0.90%
South Hillsborough	89.70	84.83	1.06	11.21	3.49%
Western	77.48	95.79	0.81	10.58	0.26%
Winter Haven	66.76	66.14	1.01	9.98	0.71%
System	78.07	85.55	0.91	11.36	0.79%

Form PSC/ECR 102-3, Docket No. 011351-EI, Rule 25-6.0455(c)

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0456	6/24/2012 11:02	50	1
PLF	FPSC Commission Rule 25-6.0457	6/24/2012 11:06	24	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0458	6/24/2012 11:10	980	14
TX Repaired (OH)	FPSC Commission Rule 25-6.0459	6/24/2012 11:13	420	5
TX Repaired (OH)	FPSC Commission Rule 25-6.0460	6/24/2012 11:14	504	3
PLF	FPSC Commission Rule 25-6.0461	6/24/2012 11:22	400	2
PLF	FPSC Commission Rule 25-6.0462	6/24/2012 11:43	272	16
Circuit Out	FPSC Commission Rule 25-6.0463	6/24/2012 11:57	61194	1974
TX Repaired (OH)	FPSC Commission Rule 25-6.0464	6/24/2012 11:58	704	4
TX Repaired (OH)	FPSC Commission Rule 25-6.0465	6/24/2012 12:12	1528	8
Primary Wire	FPSC Commission Rule 25-6.0466	6/24/2012 12:16	464	1
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0467	6/24/2012 12:19	4158	6
TX Repaired (OH)	FPSC Commission Rule 25-6.0468	6/24/2012 12:37	3558	6
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0469	6/24/2012 12:38	712	8
Primary Wire	FPSC Commission Rule 25-6.0470	6/24/2012 12:38	181	1
PLF	FPSC Commission Rule 25-6.0471	6/24/2012 12:48	3180	12
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0472	6/24/2012 12:53	4140	23
PLF	FPSC Commission Rule 25-6.0473	6/24/2012 13:00	26569	163
Primary Wire	FPSC Commission Rule 25-6.0474	6/24/2012 13:02	4796	11
Circuit Out	FPSC Commission Rule 25-6.0475	6/24/2012 13:02	14235	1095
Service - Crew	FPSC Commission Rule 25-6.0476	6/24/2012 13:03	2709	7
Primary Wire	FPSC Commission Rule 25-6.0477	6/24/2012 13:04	760	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0478	6/24/2012 13:07	38	1
Secondary Wire	FPSC Commission Rule 25-6.0479	6/24/2012 13:10	290	1
Circuit Out	FPSC Commission Rule 25-6.0480	6/24/2012 13:29	124733	1211
Cross Arm	FPSC Commission Rule 25-6.0481	6/24/2012 13:29	49476	217
PLF	FPSC Commission Rule 25-6.0482	6/24/2012 13:31	5474	46
TX Replaced (OH)	FPSC Commission Rule 25-6.0483	6/24/2012 13:35	1356	6
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0484	6/24/2012 13:37	5229	63
PLF	FPSC Commission Rule 25-6.0485	6/24/2012 13:42	128030	413
PLF	FPSC Commission Rule 25-6.0486	6/24/2012 14:06	3375	15
PLF	FPSC Commission Rule 25-6.0487	6/24/2012 14:07	1104	6
TX Repaired (OH)	FPSC Commission Rule 25-6.0488	6/24/2012 14:19	9776	16

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Primary Wire	FPSC Commission Rule 25-6.0489	6/24/2012 14:30	18225	81
PLF	FPSC Commission Rule 25-6.0490	6/24/2012 14:34	13090	70
TX Repaired (OH)	FPSC Commission Rule 25-6.0491	6/24/2012 14:35	7865	11
Circuit Out	FPSC Commission Rule 25-6.0492	6/24/2012 14:36	37050	975
Primary Wire	FPSC Commission Rule 25-6.0493	6/24/2012 14:37	2681	7
TX Repaired (OH)	FPSC Commission Rule 25-6.0494	6/24/2012 14:45	1068	6
PLF	FPSC Commission Rule 25-6.0495	6/24/2012 14:48	69	1
PLF	FPSC Commission Rule 25-6.0496	6/24/2012 14:49	48	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0497	6/24/2012 14:51	2124	4
TX Repaired (OH)	FPSC Commission Rule 25-6.0498	6/24/2012 14:51	1197	3
Service - Crew	FPSC Commission Rule 25-6.0499	6/24/2012 15:01	580	1
Primary Wire	FPSC Commission Rule 25-6.0500	6/24/2012 15:05	22750	91
Step Restoration	FPSC Commission Rule 25-6.0501	6/24/2012 15:13	6102	339
Pole	FPSC Commission Rule 25-6.0502	6/24/2012 15:14	3003	7
PLF	FPSC Commission Rule 25-6.0503	6/24/2012 15:17	3860	20
OH Other	FPSC Commission Rule 25-6.0504	6/24/2012 15:27	609	3
Service - Crew	FPSC Commission Rule 25-6.0505	6/24/2012 15:29	1440	8
OH Other	FPSC Commission Rule 25-6.0506	6/24/2012 15:38	82	1
PLF	FPSC Commission Rule 25-6.0507	6/24/2012 15:40	7150	10
PLF	FPSC Commission Rule 25-6.0508	6/24/2012 15:42	2107	49
Secondary Wire	FPSC Commission Rule 25-6.0509	6/24/2012 15:58	32294	67
OH Other	FPSC Commission Rule 25-6.0510	6/24/2012 16:11	3626	14
Circuit Out	FPSC Commission Rule 25-6.0511	6/24/2012 16:21	57379	1171
Circuit Out	FPSC Commission Rule 25-6.0512	6/24/2012 16:33	27183	697
PLF	FPSC Commission Rule 25-6.0513	6/24/2012 16:35	744	6
Pole	FPSC Commission Rule 25-6.0514	6/24/2012 16:38	112560	168
Primary Wire	FPSC Commission Rule 25-6.0515	6/24/2012 16:39	711	1
PLF	FPSC Commission Rule 25-6.0516	6/24/2012 16:40	170	1
OH Other	FPSC Commission Rule 25-6.0517	6/24/2012 16:40	63	1
Circuit Out	FPSC Commission Rule 25-6.0518	6/24/2012 16:57	77682	726
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0519	6/24/2012 17:08	7170	10
Step Restoration	FPSC Commission Rule 25-6.0520	6/24/2012 17:10	8379	441
Primary Wire	FPSC Commission Rule 25-6.0521	6/24/2012 17:12	8	1
OCR, Sec.	FPSC Commission Rule 25-6.0522	6/24/2012 17:14	4770	45
Service - Crew	FPSC Commission Rule 25-6.0523	6/24/2012 17:28	491	1

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
URD Outage	FPSC Commission Rule 25-6.0524	6/24/2012 17:31	4256	28
TX Repaired (OH)	FPSC Commission Rule 25-6.0525	6/24/2012 17:33	72	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0526	6/24/2012 17:34	212	2
TX Repaired (OH)	FPSC Commission Rule 25-6.0527	6/24/2012 17:37	143	1
OH Other	FPSC Commission Rule 25-6.0528	6/24/2012 17:39	104	1
Primary Wire	FPSC Commission Rule 25-6.0529	6/24/2012 17:45	1190	2
PLF	FPSC Commission Rule 25-6.0530	6/24/2012 18:01	1500	15
TX Repaired (OH)	FPSC Commission Rule 25-6.0531	6/24/2012 18:18	1605	15
TX Replaced (OH)	FPSC Commission Rule 25-6.0532	6/24/2012 18:25	2235	3
PLF	FPSC Commission Rule 25-6.0533	6/24/2012 18:25	448	1
PLF	FPSC Commission Rule 25-6.0534	6/24/2012 18:27	50142	274
Step Restoration	FPSC Commission Rule 25-6.0535	6/24/2012 18:30	1314	219
TX Repaired (OH)	FPSC Commission Rule 25-6.0536	6/24/2012 18:31	249	1
URD Outage	FPSC Commission Rule 25-6.0537	6/24/2012 18:39	2890	5
Primary Wire	FPSC Commission Rule 25-6.0538	6/24/2012 18:40	54272	128
Step Restoration	FPSC Commission Rule 25-6.0539	6/24/2012 18:43	1134	42
Step Restoration	FPSC Commission Rule 25-6.0540	6/24/2012 18:43	5335	97
Service - Non Crew	FPSC Commission Rule 25-6.0541	6/24/2012 18:48	191	1
Pole	FPSC Commission Rule 25-6.0542	6/24/2012 19:00	839	1
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0543	6/24/2012 19:01	989	1
Primary Wire	FPSC Commission Rule 25-6.0544	6/24/2012 19:03	3297	3
TX Repaired (OH)	FPSC Commission Rule 25-6.0545	6/24/2012 19:17	4596	6
Service - Non Crew	FPSC Commission Rule 25-6.0546	6/24/2012 19:31	629	1
PLF	FPSC Commission Rule 25-6.0547	6/24/2012 19:33	122	1
PLF	FPSC Commission Rule 25-6.0548	6/24/2012 19:52	22200	30
Primary Wire	FPSC Commission Rule 25-6.0549	6/24/2012 19:56	634	1
Circuit Out	FPSC Commission Rule 25-6.0550	6/24/2012 19:57	94464	984
Tap or Riser	FPSC Commission Rule 25-6.0551	6/24/2012 19:57	1986	6
Primary Wire	FPSC Commission Rule 25-6.0552	6/24/2012 20:03	262	1
Primary Wire	FPSC Commission Rule 25-6.0553	6/24/2012 20:07	378	1
PLF	FPSC Commission Rule 25-6.0554	6/24/2012 20:09	6955	65
Step Restoration	FPSC Commission Rule 25-6.0555	6/24/2012 20:10	51813	57
Step Restoration	FPSC Commission Rule 25-6.0556	6/24/2012 20:10	738185	1127
Step Restoration	FPSC Commission Rule 25-6.0557	6/24/2012 20:10	678776	1054
Circuit Out	FPSC Commission Rule 25-6.0558	6/24/2012 20:12	247250	215

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Primary Wire	FPSC Commission Rule 25-6.0559	6/24/2012 20:26	56550	75
Pole	FPSC Commission Rule 25-6.0560	6/24/2012 20:26	593	1
OCR, Sec.	FPSC Commission Rule 25-6.0561	6/24/2012 20:28	60480	630
Primary Wire	FPSC Commission Rule 25-6.0562	6/24/2012 20:28	60368	154
Circuit Out	FPSC Commission Rule 25-6.0563	6/24/2012 20:31	115872	426
PLF	FPSC Commission Rule 25-6.0564	6/24/2012 20:35	18525	39
Primary Wire	FPSC Commission Rule 25-6.0565	6/24/2012 20:44	886	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0566	6/24/2012 20:50	1305	9
TX Repaired (OH)	FPSC Commission Rule 25-6.0567	6/24/2012 20:51	1309	1
PLF	FPSC Commission Rule 25-6.0568	6/24/2012 20:59	168276	222
PLF	FPSC Commission Rule 25-6.0569	6/24/2012 21:09	10842	13
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0570	6/24/2012 21:15	498	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0571	6/24/2012 21:20	11100	10
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0572	6/24/2012 21:20	5560	5
Secondary Wire	FPSC Commission Rule 25-6.0573	6/24/2012 21:21	919	1
PLF	FPSC Commission Rule 25-6.0574	6/24/2012 21:23	165426	237
Circuit Out	FPSC Commission Rule 25-6.0575	6/24/2012 21:23	74636	794
Secondary Wire	FPSC Commission Rule 25-6.0576	6/24/2012 21:24	6756	6
Circuit Out	FPSC Commission Rule 25-6.0577	6/24/2012 21:25	51194	286
PLF	FPSC Commission Rule 25-6.0578	6/24/2012 21:25	106140	87
Circuit Out	FPSC Commission Rule 25-6.0579	6/24/2012 21:25	18894	141
PLF	FPSC Commission Rule 25-6.0580	6/24/2012 21:25	10906	38
TX Repaired (OH)	FPSC Commission Rule 25-6.0581	6/24/2012 21:26	2114	7
Circuit Out	FPSC Commission Rule 25-6.0582	6/24/2012 21:26	70930	410
Pole	FPSC Commission Rule 25-6.0583	6/24/2012 21:26	29700	5
Circuit Out	FPSC Commission Rule 25-6.0584	6/24/2012 21:26	16512	192
Circuit Out	FPSC Commission Rule 25-6.0585	6/24/2012 21:26	21549	653
Circuit Out	FPSC Commission Rule 25-6.0586	6/24/2012 21:26	54208	847
Circuit Out	FPSC Commission Rule 25-6.0587	6/24/2012 21:26	52260	670
PLF	FPSC Commission Rule 25-6.0588	6/24/2012 21:27	94054	82
TX Repaired (OH)	FPSC Commission Rule 25-6.0589	6/24/2012 21:28	3685	11
Primary Wire	FPSC Commission Rule 25-6.0590	6/24/2012 21:28	158	79
OH Other	FPSC Commission Rule 25-6.0591	6/24/2012 21:29	2136	12
Circuit Out	FPSC Commission Rule 25-6.0592	6/24/2012 21:29	17862	229
Primary Wire	FPSC Commission Rule 25-6.0593	6/24/2012 21:30	3364	116

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Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	FPSC Commission Rule 25-6.0594	6/24/2012 21:30	689	1
Primary Wire	FPSC Commission Rule 25-6.0595	6/24/2012 21:32	61824	128
Primary Wire	FPSC Commission Rule 25-6.0596	6/24/2012 21:33	24219	27
Primary Wire	FPSC Commission Rule 25-6.0597	6/24/2012 21:34	65095	47
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0598	6/24/2012 21:34	696	6
OH Other	FPSC Commission Rule 25-6.0599	6/24/2012 21:34	11791	13
Primary Wire	FPSC Commission Rule 25-6.0600	6/24/2012 21:34	39440	40
PLF	FPSC Commission Rule 25-6.0601	6/24/2012 21:36	13104	21
Primary Wire	FPSC Commission Rule 25-6.0602	6/24/2012 21:36	21456	24
Circuit Out	FPSC Commission Rule 25-6.0603	6/24/2012 21:36	538852	1259
PLF	FPSC Commission Rule 25-6.0604	6/24/2012 21:38	44380	35
TX Repaired (OH)	FPSC Commission Rule 25-6.0605	6/24/2012 21:38	5061	7
TX Repaired (OH)	FPSC Commission Rule 25-6.0606	6/24/2012 21:39	4260	10
PLF	FPSC Commission Rule 25-6.0607	6/24/2012 21:40	544	2
Primary Wire	FPSC Commission Rule 25-6.0608	6/24/2012 21:40	370	2
PLF	FPSC Commission Rule 25-6.0609	6/24/2012 21:42	4600	8
PLF	FPSC Commission Rule 25-6.0610	6/24/2012 21:43	2912	13
Step Restoration	FPSC Commission Rule 25-6.0611	6/24/2012 21:43	1878	6
OH Other	FPSC Commission Rule 25-6.0612	6/24/2012 21:43	4627	7
OH Other	FPSC Commission Rule 25-6.0613	6/24/2012 21:45	8646	22
TX Repaired (PM)	FPSC Commission Rule 25-6.0614	6/24/2012 21:45	886230	1145
Pole	FPSC Commission Rule 25-6.0615	6/24/2012 21:47	10032	11
TX Repaired (OH)	FPSC Commission Rule 25-6.0616	6/24/2012 21:49	44574	34
Secondary Wire	FPSC Commission Rule 25-6.0617	6/24/2012 21:55	497	1
Primary Wire	FPSC Commission Rule 25-6.0618	6/24/2012 21:57	401	1
PLF	FPSC Commission Rule 25-6.0619	6/24/2012 21:59	3726	9
Primary Wire	FPSC Commission Rule 25-6.0620	6/24/2012 22:01	4176	4
OH Other	FPSC Commission Rule 25-6.0621	6/24/2012 22:01	239	1
OH Other	FPSC Commission Rule 25-6.0622	6/24/2012 22:03	7185	5
Primary Wire	FPSC Commission Rule 25-6.0623	6/24/2012 22:10	2874	2
TX Repaired (OH)	FPSC Commission Rule 25-6.0624	6/24/2012 22:11	1898	2
Service - Crew	FPSC Commission Rule 25-6.0625	6/24/2012 22:19	1346	2
Secondary Wire	FPSC Commission Rule 25-6.0626	6/24/2012 22:23	1100	1
OH Other	FPSC Commission Rule 25-6.0627	6/24/2012 22:34	339	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0628	6/24/2012 22:44	4936	8

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Primary Wire	FPSC Commission Rule 25-6.0629	6/24/2012 22:48	21472	22
OH Other	FPSC Commission Rule 25-6.0630	6/24/2012 22:48	712	1
Circuit Out	FPSC Commission Rule 25-6.0631	6/24/2012 22:55	191835	1421
OH Other	FPSC Commission Rule 25-6.0632	6/24/2012 23:03	687	1
Primary Wire	FPSC Commission Rule 25-6.0633	6/24/2012 23:04	208	8
Pole	FPSC Commission Rule 25-6.0634	6/24/2012 23:11	917	1
Primary Wire	FPSC Commission Rule 25-6.0635	6/24/2012 23:17	163	1
OH Other	FPSC Commission Rule 25-6.0636	6/24/2012 23:27	4344	4
Step Restoration	FPSC Commission Rule 25-6.0637	6/24/2012 23:38	4628	89
Primary Wire	FPSC Commission Rule 25-6.0638	6/25/2012 0:04	382160	272
Pole	FPSC Commission Rule 25-6.0639	6/25/2012 0:14	33578	206
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0640	6/25/2012 0:17	1213	1
Pole	FPSC Commission Rule 25-6.0641	6/25/2012 0:17	44881	37
Primary Wire	FPSC Commission Rule 25-6.0642	6/25/2012 0:19	736	1
Circuit Out	FPSC Commission Rule 25-6.0643	6/25/2012 0:40	13725	305
TX Repaired (OH)	FPSC Commission Rule 25-6.0644	6/25/2012 0:51	1120	8
Pole	FPSC Commission Rule 25-6.0645	6/25/2012 1:14	12474	11
Primary Wire	FPSC Commission Rule 25-6.0646	6/25/2012 1:54	552	2
Primary Wire	FPSC Commission Rule 25-6.0647	6/25/2012 2:03	957	1
Circuit Out	FPSC Commission Rule 25-6.0648	6/25/2012 2:20	69099	743
Circuit Out	FPSC Commission Rule 25-6.0649	6/25/2012 2:29	51615	333
Pole	FPSC Commission Rule 25-6.0650	6/25/2012 3:15	7110	6
OH Other	FPSC Commission Rule 25-6.0651	6/25/2012 3:40	13158	258
PLF	FPSC Commission Rule 25-6.0652	6/25/2012 3:53	1053	9
Circuit Out	FPSC Commission Rule 25-6.0653	6/25/2012 4:01	1131	29
Primary Wire	FPSC Commission Rule 25-6.0654	6/25/2012 4:08	17592	24
PLF	FPSC Commission Rule 25-6.0655	6/25/2012 4:08	202050	225
PLF	FPSC Commission Rule 25-6.0656	6/25/2012 4:08	17424	66
Circuit Out	FPSC Commission Rule 25-6.0657	6/25/2012 4:11	24598	1757
OH Other	FPSC Commission Rule 25-6.0658	6/25/2012 4:11	2	1
Circuit Out	FPSC Commission Rule 25-6.0659	6/25/2012 4:11	29369	683
PLF	FPSC Commission Rule 25-6.0660	6/25/2012 4:15	23232	44
OH Other	FPSC Commission Rule 25-6.0661	6/25/2012 4:15	18	1
PLF	FPSC Commission Rule 25-6.0662	6/25/2012 4:20	120000	200
PLF	FPSC Commission Rule 25-6.0663	6/25/2012 4:20	1692	2

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Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
TX Repaired (OH)	FPSC Commission Rule 25-6.0664	6/25/2012 4:30	27870	30
PLF	FPSC Commission Rule 25-6.0665	6/25/2012 4:30	9449	11
PLF	FPSC Commission Rule 25-6.0666	6/25/2012 4:38	78750	126
Circuit Out	FPSC Commission Rule 25-6.0667	6/25/2012 4:45	199764	1611
OH Other	FPSC Commission Rule 25-6.0668	6/25/2012 4:47	1174	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0669	6/25/2012 4:48	1674	3
PLF	FPSC Commission Rule 25-6.0670	6/25/2012 4:49	18788	61
Step Restoration	FPSC Commission Rule 25-6.0671	6/25/2012 4:52	48609	99
Primary Wire	FPSC Commission Rule 25-6.0672	6/25/2012 4:55	24672	32
Primary Wire	FPSC Commission Rule 25-6.0673	6/25/2012 4:57	1004	4
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0674	6/25/2012 4:59	511	1
PLF	FPSC Commission Rule 25-6.0675	6/25/2012 5:05	69466	94
PLF	FPSC Commission Rule 25-6.0676	6/25/2012 5:08	4490	5
PLF	FPSC Commission Rule 25-6.0677	6/25/2012 5:11	14014	22
PLF	FPSC Commission Rule 25-6.0678	6/25/2012 5:25	8298	6
PLF	FPSC Commission Rule 25-6.0679	6/25/2012 5:39	1081	1
Service - Non Crew	FPSC Commission Rule 25-6.0680	6/25/2012 5:43	7494	6
Primary Wire	FPSC Commission Rule 25-6.0681	6/25/2012 5:46	64124	164
Primary Wire	FPSC Commission Rule 25-6.0682	6/25/2012 5:48	7808	8
Service - Non Crew	FPSC Commission Rule 25-6.0683	6/25/2012 5:56	1828	4
OCR, Sec.	FPSC Commission Rule 25-6.0684	6/25/2012 5:58	48642	121
Primary Wire	FPSC Commission Rule 25-6.0685	6/25/2012 6:09	26100	20
PLF	FPSC Commission Rule 25-6.0686	6/25/2012 6:22	38614	86
OH Other	FPSC Commission Rule 25-6.0687	6/25/2012 6:36	1072	1
PLF	FPSC Commission Rule 25-6.0688	6/25/2012 6:44	1203	3
OH Other	FPSC Commission Rule 25-6.0689	6/25/2012 7:04	11084	17
OH Other	FPSC Commission Rule 25-6.0690	6/25/2012 7:07	58032	18
PLF	FPSC Commission Rule 25-6.0691	6/25/2012 7:08	7968	6
TX Repaired (OH)	FPSC Commission Rule 25-6.0692	6/25/2012 7:13	7320	6
Primary Wire	FPSC Commission Rule 25-6.0693	6/25/2012 7:20	2480	2
PLF	FPSC Commission Rule 25-6.0694	6/25/2012 7:26	344	1
Service - Crew	FPSC Commission Rule 25-6.0695	6/25/2012 7:36	696	4
Circuit Out	FPSC Commission Rule 25-6.0696	6/25/2012 7:40	220665	939
OH Other	FPSC Commission Rule 25-6.0697	6/25/2012 7:42	648	1
Pole	FPSC Commission Rule 25-6.0698	6/25/2012 7:44	436	1

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Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Pole	FPSC Commission Rule 25-6.0699	6/25/2012 7:52	578	1
PLF	FPSC Commission Rule 25-6.0700	6/25/2012 7:54	889	7
Service - Crew	FPSC Commission Rule 25-6.0701	6/25/2012 7:55	4249	7
PLF	FPSC Commission Rule 25-6.0702	6/25/2012 7:56	20242	29
PLF	FPSC Commission Rule 25-6.0703	6/25/2012 7:59	2150	5
Primary Wire	FPSC Commission Rule 25-6.0704	6/25/2012 8:03	984	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0705	6/25/2012 8:03	803	1
Pole	FPSC Commission Rule 25-6.0706	6/25/2012 8:04	596	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0707	6/25/2012 8:05	1268	1
Service - Crew	FPSC Commission Rule 25-6.0708	6/25/2012 8:12	2424	4
Primary Wire	FPSC Commission Rule 25-6.0709	6/25/2012 8:18	396	1
Pole	FPSC Commission Rule 25-6.0710	6/25/2012 8:19	2067	3
Primary Wire	FPSC Commission Rule 25-6.0711	6/25/2012 8:20	316	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0712	6/25/2012 8:22	306	2
Connections	FPSC Commission Rule 25-6.0713	6/25/2012 8:24	1003	1
Riser	FPSC Commission Rule 25-6.0714	6/25/2012 8:27	569	1
OH Other	FPSC Commission Rule 25-6.0715	6/25/2012 8:31	4088	4
PLF	FPSC Commission Rule 25-6.0716	6/25/2012 8:37	8943	11
OH Other	FPSC Commission Rule 25-6.0717	6/25/2012 8:39	3938	11
OH Other	FPSC Commission Rule 25-6.0718	6/25/2012 8:40	883	1
Secondary Wire	FPSC Commission Rule 25-6.0719	6/25/2012 8:41	470	1
Primary Wire	FPSC Commission Rule 25-6.0720	6/25/2012 8:43	15216	48
PLF	FPSC Commission Rule 25-6.0721	6/25/2012 8:49	28990	26
Pole	FPSC Commission Rule 25-6.0722	6/25/2012 8:56	639	1
PLF	FPSC Commission Rule 25-6.0723	6/25/2012 9:00	216	27
TX Repaired (OH)	FPSC Commission Rule 25-6.0724	6/25/2012 9:02	512	1
Pole	FPSC Commission Rule 25-6.0725	6/25/2012 9:20	329	1
Primary Wire	FPSC Commission Rule 25-6.0726	6/25/2012 9:26	261	1
Pole	FPSC Commission Rule 25-6.0727	6/25/2012 9:34	246	1
Service - Crew	FPSC Commission Rule 25-6.0728	6/25/2012 9:37	704	1
Secondary Wire	FPSC Commission Rule 25-6.0729	6/25/2012 9:41	5940	1
Service - Non Crew	FPSC Commission Rule 25-6.0730	6/25/2012 9:42	754	1
PLF	FPSC Commission Rule 25-6.0731	6/25/2012 9:44	1655	5
Pole	FPSC Commission Rule 25-6.0732	6/25/2012 9:45	190	1
Primary Wire	FPSC Commission Rule 25-6.0733	6/25/2012 9:48	3528	3

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Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Pole	FPSC Commission Rule 25-6.0734	6/25/2012 9:50	633	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0735	6/25/2012 9:57	806	2
TX Replaced (OH)	FPSC Commission Rule 25-6.0736	6/25/2012 9:59	6812	26
Service - Non Crew	FPSC Commission Rule 25-6.0737	6/25/2012 10:02	1237	1
PLF	FPSC Commission Rule 25-6.0738	6/25/2012 10:13	457	1
OH Other	FPSC Commission Rule 25-6.0739	6/25/2012 10:15	2376	3
Primary Wire	FPSC Commission Rule 25-6.0740	6/25/2012 10:18	17187	17
TX Repaired (OH)	FPSC Commission Rule 25-6.0741	6/25/2012 10:22	632	4
OH Other	FPSC Commission Rule 25-6.0742	6/25/2012 10:25	1848	7
OH Other	FPSC Commission Rule 25-6.0743	6/25/2012 10:28	342	1
Primary Wire	FPSC Commission Rule 25-6.0744	6/25/2012 10:42	742	1
PLF	FPSC Commission Rule 25-6.0745	6/25/2012 10:48	18414	54
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0746	6/25/2012 10:54	804	1
Circuit Out	FPSC Commission Rule 25-6.0747	6/25/2012 10:59	292030	2755
OH Other	FPSC Commission Rule 25-6.0748	6/25/2012 10:59	1328	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0749	6/25/2012 11:04	951	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0750	6/25/2012 11:07	153	17
Circuit Out	FPSC Commission Rule 25-6.0751	6/25/2012 11:10	33770	614
Primary Wire	FPSC Commission Rule 25-6.0752	6/25/2012 11:13	3642	6
Pole	FPSC Commission Rule 25-6.0753	6/25/2012 11:18	444	2
Secondary Wire	FPSC Commission Rule 25-6.0754	6/25/2012 11:27	603	1
Secondary Wire	FPSC Commission Rule 25-6.0755	6/25/2012 11:41	16788	12
Service - Crew	FPSC Commission Rule 25-6.0756	6/25/2012 11:50	1932	6
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.0757	6/25/2012 11:54	1048	4
OH Other	FPSC Commission Rule 25-6.0758	6/25/2012 12:12	409	1
TX Replaced (OH)	FPSC Commission Rule 25-6.0759	6/25/2012 12:16	3240	8
Circuit Out	FPSC Commission Rule 25-6.0760	6/25/2012 12:26	16200	300
Step Restoration	FPSC Commission Rule 25-6.0761	6/25/2012 12:26	102600	1368
Tap or Riser	FPSC Commission Rule 25-6.0762	6/25/2012 12:33	54855	115
Pole	FPSC Commission Rule 25-6.0763	6/25/2012 12:39	5940	1
Circuit Out	FPSC Commission Rule 25-6.0764	6/25/2012 12:45	112726	359
OH Other	FPSC Commission Rule 25-6.0765	6/25/2012 12:47	1205	1
Primary Wire	FPSC Commission Rule 25-6.0766	6/25/2012 12:52	98	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0767	6/25/2012 12:54	10144	8
TX Repaired (OH)	FPSC Commission Rule 25-6.0768	6/25/2012 13:01	331	1

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Primary Wire	FPSC Commission Rule 25-6.0769	6/25/2012 13:03	272	1
Pole	FPSC Commission Rule 25-6.0770	6/25/2012 13:08	653	1
Connections	FPSC Commission Rule 25-6.0771	6/25/2012 13:15	555	1
URD Outage	FPSC Commission Rule 25-6.0772	6/25/2012 13:16	11753	23
PLF	FPSC Commission Rule 25-6.0773	6/25/2012 13:18	460655	373
Service - Crew	FPSC Commission Rule 25-6.0774	6/25/2012 13:24	672	1
OH Other	FPSC Commission Rule 25-6.0775	6/25/2012 13:24	165	1
Primary Wire	FPSC Commission Rule 25-6.0776	6/25/2012 13:24	995	1
Primary Wire	FPSC Commission Rule 25-6.0777	6/25/2012 13:30	1110	3
Primary Wire	FPSC Commission Rule 25-6.0778	6/25/2012 13:39	18074	14
PLF	FPSC Commission Rule 25-6.0779	6/25/2012 13:41	656	2
Secondary Wire	FPSC Commission Rule 25-6.0780	6/25/2012 13:42	5840	10
Primary Wire	FPSC Commission Rule 25-6.0781	6/25/2012 13:42	4086	9
TX Replaced (OH)	FPSC Commission Rule 25-6.0782	6/25/2012 13:43	6944	14
TX Repaired (OH)	FPSC Commission Rule 25-6.0783	6/25/2012 13:44	3619	11
Service - Crew	FPSC Commission Rule 25-6.0784	6/25/2012 14:08	13662	11
PLF	FPSC Commission Rule 25-6.0785	6/25/2012 14:14	-696	1
PLF	FPSC Commission Rule 25-6.0786	6/25/2012 14:18	2784	16
Pole	FPSC Commission Rule 25-6.0787	6/25/2012 14:35	11920	16
TX Repaired (OH)	FPSC Commission Rule 25-6.0788	6/25/2012 14:37	10620	15
TX Repaired (OH)	FPSC Commission Rule 25-6.0789	6/25/2012 14:44	346	1
OH Other	FPSC Commission Rule 25-6.0790	6/25/2012 14:47	447	1
OH Other	FPSC Commission Rule 25-6.0791	6/25/2012 14:55	2540	4
Primary Wire	FPSC Commission Rule 25-6.0792	6/25/2012 14:55	935	1
Circuit Out	FPSC Commission Rule 25-6.0793	6/25/2012 14:57	362355	1421
Primary Wire	FPSC Commission Rule 25-6.0794	6/25/2012 15:05	1420	4
Primary Wire	FPSC Commission Rule 25-6.0795	6/25/2012 15:12	308	1
UG Other	FPSC Commission Rule 25-6.0796	6/25/2012 15:14	7337	23
Secondary Wire	FPSC Commission Rule 25-6.0797	6/25/2012 15:15	26100	20
Service - Crew	FPSC Commission Rule 25-6.0798	6/25/2012 15:16	6340	10
Pole	FPSC Commission Rule 25-6.0799	6/25/2012 15:18	1286	1
Service - Crew	FPSC Commission Rule 25-6.0800	6/25/2012 15:33	1908	4
OH Other	FPSC Commission Rule 25-6.0801	6/25/2012 15:36	50594	82
OH Other	FPSC Commission Rule 25-6.0802	6/25/2012 15:39	542	1
Service - Crew	FPSC Commission Rule 25-6.0803	6/25/2012 15:40	191	1

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Primary Wire	FPSC Commission Rule 25-6.0804	6/25/2012 15:43	40535	55
OH Other	FPSC Commission Rule 25-6.0805	6/25/2012 15:57	3459	3
TX Repaired (OH)	FPSC Commission Rule 25-6.0806	6/25/2012 16:11	401	1
Service - Crew	FPSC Commission Rule 25-6.0807	6/25/2012 16:17	475	1
Service - Crew	FPSC Commission Rule 25-6.0808	6/25/2012 16:17	251	1
Secondary Wire	FPSC Commission Rule 25-6.0809	6/25/2012 16:23	5735	5
Pole	FPSC Commission Rule 25-6.0810	6/25/2012 16:27	1355	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0811	6/25/2012 16:34	3845	5
Secondary Wire	FPSC Commission Rule 25-6.0812	6/25/2012 16:37	8771	7
OH Other	FPSC Commission Rule 25-6.0813	6/25/2012 16:37	2464	2
Circuit Out	FPSC Commission Rule 25-6.0814	6/25/2012 16:37	37380	1068
Primary Wire	FPSC Commission Rule 25-6.0815	6/25/2012 16:37	5410	5
Circuit Out	FPSC Commission Rule 25-6.0816	6/25/2012 16:37	4800	192
Circuit Out	FPSC Commission Rule 25-6.0817	6/25/2012 16:44	48960	612
TX Repaired (OH)	FPSC Commission Rule 25-6.0818	6/25/2012 16:44	6624	8
Secondary Wire	FPSC Commission Rule 25-6.0819	6/25/2012 16:44	37231	31
OH Other	FPSC Commission Rule 25-6.0820	6/25/2012 16:47	218	1
PLF	FPSC Commission Rule 25-6.0821	6/25/2012 16:55	9600	30
OH Other	FPSC Commission Rule 25-6.0822	6/25/2012 16:58	5268	12
Secondary Wire	FPSC Commission Rule 25-6.0823	6/25/2012 16:58	2536	8
Primary Wire	FPSC Commission Rule 25-6.0824	6/25/2012 17:03	32205	57
Primary Wire	FPSC Commission Rule 25-6.0825	6/25/2012 17:05	1307	1
PLF	FPSC Commission Rule 25-6.0826	6/25/2012 17:08	50688	99
PLF	FPSC Commission Rule 25-6.0827	6/25/2012 17:10	7222	23
PLF	FPSC Commission Rule 25-6.0828	6/25/2012 17:20	111540	143
Service - Non Crew	FPSC Commission Rule 25-6.0829	6/25/2012 17:25	1298	2
Service - Non Crew	FPSC Commission Rule 25-6.0830	6/25/2012 17:28	449	1
Primary Wire	FPSC Commission Rule 25-6.0831	6/25/2012 17:30	13480	20
OH Other	FPSC Commission Rule 25-6.0832	6/25/2012 17:31	5940	1
Primary Wire	FPSC Commission Rule 25-6.0833	6/25/2012 17:34	5940	1
Circuit Out	FPSC Commission Rule 25-6.0834	6/25/2012 17:45	7231	1033
TX Repaired (OH)	FPSC Commission Rule 25-6.0835	6/25/2012 17:47	1337	1
Primary Wire	FPSC Commission Rule 25-6.0836	6/25/2012 17:49	17871	21
Secondary Wire	FPSC Commission Rule 25-6.0837	6/25/2012 17:50	369	1
TX Replaced (OH)	FPSC Commission Rule 25-6.0838	6/25/2012 17:54	5940	1

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Step Restoration	FPSC Commission Rule 25-6.0839	6/25/2012 18:03	82419	993
TX Repaired (OH)	FPSC Commission Rule 25-6.0840	6/25/2012 18:13	2416	2
PLF	FPSC Commission Rule 25-6.0841	6/25/2012 18:38	86	1
OH Other	FPSC Commission Rule 25-6.0842	6/25/2012 18:38	1017	1
Circuit Out	FPSC Commission Rule 25-6.0843	6/25/2012 18:57	43250	865
Service - Non Crew	FPSC Commission Rule 25-6.0844	6/25/2012 19:07	5120	10
PLF	FPSC Commission Rule 25-6.0845	6/25/2012 19:09	2520	15
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0846	6/25/2012 19:10	460	2
Circuit Out	FPSC Commission Rule 25-6.0847	6/25/2012 19:11	67912	1306
Primary Wire	FPSC Commission Rule 25-6.0848	6/25/2012 19:12	78323	67
Primary Wire	FPSC Commission Rule 25-6.0849	6/25/2012 19:25	19515	15
URD Outage	FPSC Commission Rule 25-6.0850	6/25/2012 19:35	11815	17
Service - Crew	FPSC Commission Rule 25-6.0851	6/25/2012 19:37	5621	7
PLF	FPSC Commission Rule 25-6.0852	6/25/2012 19:47	981	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0853	6/25/2012 19:49	990	5
Circuit Out	FPSC Commission Rule 25-6.0854	6/25/2012 19:59	36330	865
Primary Wire	FPSC Commission Rule 25-6.0855	6/25/2012 20:07	40500	225
OH Other	FPSC Commission Rule 25-6.0856	6/25/2012 20:13	11740	20
Circuit Out	FPSC Commission Rule 25-6.0857	6/25/2012 20:52	24128	754
PLF	FPSC Commission Rule 25-6.0858	6/25/2012 21:09	3717	7
Service - Crew	FPSC Commission Rule 25-6.0859	6/25/2012 21:26	732	1
Circuit Out	FPSC Commission Rule 25-6.0860	6/25/2012 21:41	26628	634
Primary Wire	FPSC Commission Rule 25-6.0861	6/25/2012 21:55	2294	2
Circuit Out	FPSC Commission Rule 25-6.0862	6/25/2012 22:00	267246	2646
Step Restoration	FPSC Commission Rule 25-6.0863	6/25/2012 22:00	109312	976
PLF	FPSC Commission Rule 25-6.0864	6/25/2012 22:17	4833	27
TX Repaired (OH)	FPSC Commission Rule 25-6.0865	6/25/2012 22:22	2908	4
Primary Wire	FPSC Commission Rule 25-6.0866	6/25/2012 22:22	22980	30
Primary Wire	FPSC Commission Rule 25-6.0867	6/25/2012 22:29	47912	53
PLF	FPSC Commission Rule 25-6.0868	6/25/2012 22:33	666	9
OH Other	FPSC Commission Rule 25-6.0869	6/25/2012 22:35	1383	1
OH Other	FPSC Commission Rule 25-6.0870	6/25/2012 22:37	1317739	1219
TX Repaired (OH)	FPSC Commission Rule 25-6.0871	6/25/2012 22:53	550	5
TX Repaired (OH)	FPSC Commission Rule 25-6.0872	6/25/2012 22:59	1794	2
Primary Wire	FPSC Commission Rule 25-6.0873	6/25/2012 23:17	8368	16

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Primary Wire	FPSC Commission Rule 25-6.0874	6/25/2012 23:19	31716	36
Primary Wire	FPSC Commission Rule 25-6.0875	6/25/2012 23:35	3896	4
Primary Wire	FPSC Commission Rule 25-6.0876	6/25/2012 23:45	33858	81
OH Other	FPSC Commission Rule 25-6.0877	6/25/2012 23:50	80	1
TX Replaced (OH)	FPSC Commission Rule 25-6.0878	6/25/2012 23:56	1328	2
TX Repaired (OH)	FPSC Commission Rule 25-6.0879	6/26/2012 0:03	5663	7
TX Repaired (OH)	FPSC Commission Rule 25-6.0880	6/26/2012 0:19	194	1
Secondary Wire	FPSC Commission Rule 25-6.0881	6/26/2012 0:27	1776	6
TX Repaired (OH)	FPSC Commission Rule 25-6.0882	6/26/2012 0:53	912	2
TX Repaired (OH)	FPSC Commission Rule 25-6.0883	6/26/2012 1:38	3366	3
OH Other	FPSC Commission Rule 25-6.0884	6/26/2012 1:39	65	1
Service - Crew	FPSC Commission Rule 25-6.0885	6/26/2012 2:15	5940	1
PLF	FPSC Commission Rule 25-6.0886	6/26/2012 2:41	325	13
PLF	FPSC Commission Rule 25-6.0887	6/26/2012 3:10	12359	17
Secondary Wire	FPSC Commission Rule 25-6.0888	6/26/2012 3:11	10524	12
TX Repaired (OH)	FPSC Commission Rule 25-6.0889	6/26/2012 3:22	666	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0890	6/26/2012 3:49	2455	5
PLF	FPSC Commission Rule 25-6.0891	6/26/2012 4:06	76140	270
PLF	FPSC Commission Rule 25-6.0892	6/26/2012 5:12	15720	131
Primary Wire	FPSC Commission Rule 25-6.0893	6/26/2012 5:14	1288	2
PLF	FPSC Commission Rule 25-6.0894	6/26/2012 5:41	4964	4
OH Other	FPSC Commission Rule 25-6.0895	6/26/2012 5:57	40880	56
Pole	FPSC Commission Rule 25-6.0896	6/26/2012 6:24	621	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0897	6/26/2012 6:31	13650	30
PLF	FPSC Commission Rule 25-6.0898	6/26/2012 6:47	11041	61
Tap or Riser	FPSC Commission Rule 25-6.0899	6/26/2012 6:53	5262	6
Secondary Wire	FPSC Commission Rule 25-6.0900	6/26/2012 6:59	6188	7
Primary Wire	FPSC Commission Rule 25-6.0901	6/26/2012 7:07	906	1
Primary Wire	FPSC Commission Rule 25-6.0902	6/26/2012 7:13	22997	61
Primary Wire	FPSC Commission Rule 25-6.0903	6/26/2012 7:19	2444	4
Service - Crew	FPSC Commission Rule 25-6.0904	6/26/2012 7:20	640	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0905	6/26/2012 7:39	656	1
PLF	FPSC Commission Rule 25-6.0906	6/26/2012 7:51	10780	20
Service - Non Crew	FPSC Commission Rule 25-6.0907	6/26/2012 7:53	3330	5
TX Repaired (PM)	FPSC Commission Rule 25-6.0908	6/26/2012 7:56	1275	1

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
TX Repaired (OH)	FPSC Commission Rule 25-6.0909	6/26/2012 8:02	3136	7
Primary Wire	FPSC Commission Rule 25-6.0910	6/26/2012 8:04	205	1
Service - Crew	FPSC Commission Rule 25-6.0911	6/26/2012 8:06	5724	6
Secondary Wire	FPSC Commission Rule 25-6.0912	6/26/2012 8:10	327	1
PLF	FPSC Commission Rule 25-6.0913	6/26/2012 8:11	1869	3
Pole	FPSC Commission Rule 25-6.0914	6/26/2012 8:14	1085	1
OH Other	FPSC Commission Rule 25-6.0915	6/26/2012 8:15	816	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0916	6/26/2012 8:19	3880	8
Service - Crew	FPSC Commission Rule 25-6.0917	6/26/2012 8:24	5940	1
Service - Non Crew	FPSC Commission Rule 25-6.0918	6/26/2012 8:26	495	1
Service - Crew	FPSC Commission Rule 25-6.0919	6/26/2012 8:35	325	1
Secondary Wire	FPSC Commission Rule 25-6.0920	6/26/2012 8:35	1225	7
Tap or Riser	FPSC Commission Rule 25-6.0921	6/26/2012 8:37	1053	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0922	6/26/2012 8:39	2772	12
Crab/Secondary	FPSC Commission Rule 25-6.0923	6/26/2012 8:43	6318	13
PLF	FPSC Commission Rule 25-6.0924	6/26/2012 8:44	129	1
Cross Arm	FPSC Commission Rule 25-6.0925	6/26/2012 8:44	286	1
Pole	FPSC Commission Rule 25-6.0926	6/26/2012 8:59	5940	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0927	6/26/2012 9:01	667	1
PLF	FPSC Commission Rule 25-6.0928	6/26/2012 9:16	19495	35
Tap or Riser	FPSC Commission Rule 25-6.0929	6/26/2012 9:19	982	2
Service - Crew	FPSC Commission Rule 25-6.0930	6/26/2012 9:25	1018	1
Primary Wire	FPSC Commission Rule 25-6.0931	6/26/2012 9:28	1222	1
Connections	FPSC Commission Rule 25-6.0932	6/26/2012 9:40	581	1
PLF	FPSC Commission Rule 25-6.0933	6/26/2012 9:42	3720	6
TX Repaired (OH)	FPSC Commission Rule 25-6.0934	6/26/2012 9:44	8487	23
TX Replaced (OH)	FPSC Commission Rule 25-6.0935	6/26/2012 9:44	4660	10
OH Other	FPSC Commission Rule 25-6.0936	6/26/2012 9:46	820	1
PLF	FPSC Commission Rule 25-6.0937	6/26/2012 9:48	4092	22
OH Other	FPSC Commission Rule 25-6.0938	6/26/2012 9:50	689	1
OH Other	FPSC Commission Rule 25-6.0939	6/26/2012 9:52	129	1
OH Other	FPSC Commission Rule 25-6.0940	6/26/2012 9:54	700	1
OH Other	FPSC Commission Rule 25-6.0941	6/26/2012 10:02	820	1
PLF	FPSC Commission Rule 25-6.0942	6/26/2012 10:02	10080	60
Primary Wire	FPSC Commission Rule 25-6.0943	6/26/2012 10:14	5940	1

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	FPSC Commission Rule 25-6.0944	6/26/2012 10:14	788	1
OH Other	FPSC Commission Rule 25-6.0945	6/26/2012 10:18	192	1
Pole	FPSC Commission Rule 25-6.0946	6/26/2012 10:24	307	1
Pole	FPSC Commission Rule 25-6.0947	6/26/2012 10:25	333	1
Primary Wire	FPSC Commission Rule 25-6.0948	6/26/2012 10:46	306	1
PLF	FPSC Commission Rule 25-6.0949	6/26/2012 10:47	11017	23
Tap or Riser	FPSC Commission Rule 25-6.0950	6/26/2012 11:01	373	1
Service - Non Crew	FPSC Commission Rule 25-6.0951	6/26/2012 11:03	902	1
Circuit Out	FPSC Commission Rule 25-6.0952	6/26/2012 11:06	27132	798
PLF	FPSC Commission Rule 25-6.0953	6/26/2012 11:08	662	2
PLF	FPSC Commission Rule 25-6.0954	6/26/2012 11:10	15180	33
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.0955	6/26/2012 11:18	2049	3
OH Other	FPSC Commission Rule 25-6.0956	6/26/2012 11:19	336	1
PLF	FPSC Commission Rule 25-6.0957	6/26/2012 11:26	1053	3
TX Repaired (OH)	FPSC Commission Rule 25-6.0958	6/26/2012 11:26	154	1
Circuit Out	FPSC Commission Rule 25-6.0959	6/26/2012 11:27	83768	1132
OH Other	FPSC Commission Rule 25-6.0960	6/26/2012 11:27	248	1
Service - Crew	FPSC Commission Rule 25-6.0961	6/26/2012 11:31	414	1
Service - Crew	FPSC Commission Rule 25-6.0962	6/26/2012 11:33	724	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0963	6/26/2012 11:41	904	1
PLF	FPSC Commission Rule 25-6.0964	6/26/2012 12:01	2280	5
Secondary Wire	FPSC Commission Rule 25-6.0965	6/26/2012 12:07	38	1
Service - Crew	FPSC Commission Rule 25-6.0966	6/26/2012 12:15	3105	5
OH Other	FPSC Commission Rule 25-6.0967	6/26/2012 12:19	451	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0968	6/26/2012 12:21	155	1
Primary Wire	FPSC Commission Rule 25-6.0969	6/26/2012 12:35	9152	32
TX Replaced (OH)	FPSC Commission Rule 25-6.0970	6/26/2012 12:36	1602	3
Primary Wire	FPSC Commission Rule 25-6.0971	6/26/2012 12:45	357	1
OH Other	FPSC Commission Rule 25-6.0972	6/26/2012 12:55	88	1
Primary Wire	FPSC Commission Rule 25-6.0973	6/26/2012 13:02	2202	3
Service - Crew	FPSC Commission Rule 25-6.0974	6/26/2012 13:12	669	1
Pole	FPSC Commission Rule 25-6.0975	6/26/2012 13:19	1928	4
OH Other	FPSC Commission Rule 25-6.0976	6/26/2012 13:26	57	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0977	6/26/2012 13:28	62	1
PLF	FPSC Commission Rule 25-6.0978	6/26/2012 13:55	2080	32

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
TX Repaired (OH)	FPSC Commission Rule 25-6.0979	6/26/2012 13:57	2807	7
Pole	FPSC Commission Rule 25-6.0980	6/26/2012 13:57	1042	2
Service - Crew	FPSC Commission Rule 25-6.0981	6/26/2012 14:06	294	1
PLF	FPSC Commission Rule 25-6.0982	6/26/2012 14:20	137	1
PLF	FPSC Commission Rule 25-6.0983	6/26/2012 14:31	3427	23
Service - Non Crew	FPSC Commission Rule 25-6.0984	6/26/2012 14:34	1236	3
Primary Wire	FPSC Commission Rule 25-6.0985	6/26/2012 14:37	514	1
OH Other	FPSC Commission Rule 25-6.0986	6/26/2012 14:39	71	1
PLF	FPSC Commission Rule 25-6.0987	6/26/2012 14:49	3290	10
TX Repaired (OH)	FPSC Commission Rule 25-6.0988	6/26/2012 14:55	1157	1
PLF	FPSC Commission Rule 25-6.0989	6/26/2012 14:57	322	1
Primary Wire	FPSC Commission Rule 25-6.0990	6/26/2012 15:01	149	1
Primary Wire	FPSC Commission Rule 25-6.0991	6/26/2012 15:24	18048	94
PLF	FPSC Commission Rule 25-6.0992	6/26/2012 15:26	178	1
PLF	FPSC Commission Rule 25-6.0993	6/26/2012 15:37	7668	54
Primary Wire	FPSC Commission Rule 25-6.0994	6/26/2012 15:41	836	4
Tap or Riser	FPSC Commission Rule 25-6.0995	6/26/2012 15:48	4878	9
Secondary Wire	FPSC Commission Rule 25-6.0996	6/26/2012 15:54	1724	4
Service - Crew	FPSC Commission Rule 25-6.0997	6/26/2012 16:03	207	1
TX Repaired (OH)	FPSC Commission Rule 25-6.0998	6/26/2012 16:12	1035	3
Circuit Out	FPSC Commission Rule 25-6.0999	6/26/2012 16:15	42274	1838
PLF	FPSC Commission Rule 25-6.1000	6/26/2012 16:29	5070	13
OH Other	FPSC Commission Rule 25-6.1001	6/26/2012 16:37	494	1
Pole	FPSC Commission Rule 25-6.1002	6/26/2012 16:55	598	1
PLF	FPSC Commission Rule 25-6.1003	6/26/2012 16:57	5880	35
TX Repaired (OH)	FPSC Commission Rule 25-6.1004	6/26/2012 17:09	5310	6
Step Restoration	FPSC Commission Rule 25-6.1005	6/26/2012 17:11	31350	190
Step Restoration	FPSC Commission Rule 25-6.1006	6/26/2012 17:11	11730	69
URD Outage	FPSC Commission Rule 25-6.1007	6/26/2012 17:11	1587	3
Service - Crew	FPSC Commission Rule 25-6.1008	6/26/2012 17:16	631	1
Service - Crew	FPSC Commission Rule 25-6.1009	6/26/2012 17:33	84	1
Service - Non Crew	FPSC Commission Rule 25-6.1010	6/26/2012 17:35	508	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1011	6/26/2012 17:43	111	1
Pole	FPSC Commission Rule 25-6.1012	6/26/2012 17:43	107	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1013	6/26/2012 18:01	1076	2

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	FPSC Commission Rule 25-6.1014	6/26/2012 18:05	768	2
TX Repaired (OH)	FPSC Commission Rule 25-6.1015	6/26/2012 18:07	1448	4
PLF	FPSC Commission Rule 25-6.1016	6/26/2012 18:16	708	3
OH Other	FPSC Commission Rule 25-6.1017	6/26/2012 18:27	372	1
Primary Wire	FPSC Commission Rule 25-6.1018	6/26/2012 18:33	6144	32
Primary Wire	FPSC Commission Rule 25-6.1019	6/26/2012 18:35	385	1
OH Other	FPSC Commission Rule 25-6.1020	6/26/2012 18:44	1808	8
TX Replaced (OH)	FPSC Commission Rule 25-6.1021	6/26/2012 18:44	586	1
Circuit Out	FPSC Commission Rule 25-6.1022	6/26/2012 19:22	7952	56
Service - Non Crew	FPSC Commission Rule 25-6.1023	6/26/2012 19:44	465	1
OH Other	FPSC Commission Rule 25-6.1024	6/26/2012 19:46	1768	2
Tap or Riser	FPSC Commission Rule 25-6.1025	6/26/2012 19:47	740	2
Service - Crew	FPSC Commission Rule 25-6.1026	6/26/2012 20:32	169	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1027	6/26/2012 20:50	48	1
PLF	FPSC Commission Rule 25-6.1028	6/26/2012 21:03	1428	4
OH Other	FPSC Commission Rule 25-6.1029	6/26/2012 21:10	720	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1030	6/26/2012 21:32	58	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1031	6/26/2012 22:02	135	3
OH Other	FPSC Commission Rule 25-6.1032	6/26/2012 22:43	726	6
Service - Non Crew	FPSC Commission Rule 25-6.1033	6/26/2012 23:30	680	5
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.1034	6/26/2012 23:43	584	8
TX Repaired (OH)	FPSC Commission Rule 25-6.1035	8/26/2012 13:21	468	3
Service - Crew	FPSC Commission Rule 25-6.1036	8/26/2012 14:11	174	6
Circuit Out	FPSC Commission Rule 25-6.1037	8/26/2012 14:42	115463	1957
Primary Wire	FPSC Commission Rule 25-6.1038	8/26/2012 14:55	483	1
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.1039	8/26/2012 15:31	149	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1040	8/26/2012 15:51	72	2
PLF	FPSC Commission Rule 25-6.1041	8/26/2012 15:56	2820	60
Circuit Out	FPSC Commission Rule 25-6.1042	8/26/2012 17:26	43632	808
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.1043	8/26/2012 17:36	46	1
Primary Wire	FPSC Commission Rule 25-6.1044	8/26/2012 17:52	248	1
Primary Wire	FPSC Commission Rule 25-6.1045	8/26/2012 17:55	875	5
TX Replaced (OH)	FPSC Commission Rule 25-6.1046	8/26/2012 18:39	1164	4
TX Repaired (OH)	FPSC Commission Rule 25-6.1047	8/26/2012 19:43	118	2
OH Other	FPSC Commission Rule 25-6.1048	8/26/2012 21:29	9920	64

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	FPSC Commission Rule 25-6.1049	8/26/2012 21:59	2338	7
PLF	FPSC Commission Rule 25-6.1050	8/26/2012 23:02	962	13
Primary Wire	FPSC Commission Rule 25-6.1051	8/26/2012 23:03	548	2
Tap or Riser	FPSC Commission Rule 25-6.1052	8/26/2012 23:28	1196	13
Primary Wire	FPSC Commission Rule 25-6.1053	8/27/2012 0:45	4770	6
OH Other	FPSC Commission Rule 25-6.1054	8/27/2012 0:46	516	2
OH Other	FPSC Commission Rule 25-6.1055	8/27/2012 1:00	840	4
TX Repaired (OH)	FPSC Commission Rule 25-6.1056	8/27/2012 1:16	545	5
OH Other	FPSC Commission Rule 25-6.1057	8/27/2012 1:37	658	2
TX Repaired (OH)	FPSC Commission Rule 25-6.1058	8/27/2012 1:50	70	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1059	8/27/2012 1:51	126	3
PLF	FPSC Commission Rule 25-6.1060	8/27/2012 1:54	154	1
Switch 600 amp	FPSC Commission Rule 25-6.1061	8/27/2012 2:35	456	1
PLF	FPSC Commission Rule 25-6.1062	8/27/2012 2:45	2054	26
Circuit Out	FPSC Commission Rule 25-6.1063	8/27/2012 2:53	680	340
OH Other	FPSC Commission Rule 25-6.1064	8/27/2012 2:53	231	33
PLF	FPSC Commission Rule 25-6.1065	8/27/2012 2:53	679	7
TX Repaired (OH)	FPSC Commission Rule 25-6.1066	8/27/2012 2:56	2176	4
TX Repaired (OH)	FPSC Commission Rule 25-6.1067	8/27/2012 3:11	38	1
Primary Wire	FPSC Commission Rule 25-6.1068	8/27/2012 3:29	259	1
Service - Crew	FPSC Commission Rule 25-6.1069	8/27/2012 3:42	369	1
Circuit Out	FPSC Commission Rule 25-6.1070	8/27/2012 4:43	42549	1091
URD Outage	FPSC Commission Rule 25-6.1071	8/27/2012 5:11	515	1
PLF	FPSC Commission Rule 25-6.1072	8/27/2012 5:32	1254	19
PLF	FPSC Commission Rule 25-6.1073	8/27/2012 5:40	342	2
TX Repaired (OH)	FPSC Commission Rule 25-6.1074	8/27/2012 5:55	294	2
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.1075	8/27/2012 5:55	424	4
TX Replaced (OH)	FPSC Commission Rule 25-6.1076	8/27/2012 6:00	485	1
TX Replaced (OH)	FPSC Commission Rule 25-6.1077	8/27/2012 6:13	4164	12
PLF	FPSC Commission Rule 25-6.1078	8/27/2012 6:22	3968	62
TX Repaired (OH)	FPSC Commission Rule 25-6.1079	8/27/2012 6:22	512	4
Primary Wire	FPSC Commission Rule 25-6.1080	8/27/2012 6:26	194	1
Circuit Out	FPSC Commission Rule 25-6.1081	8/27/2012 6:28	53818	758
OH Other	FPSC Commission Rule 25-6.1082	8/27/2012 6:41	67	1
Primary Wire	FPSC Commission Rule 25-6.1083	8/27/2012 6:41	2190	10

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
TX Repaired (OH)	FPSC Commission Rule 25-6.1084	8/27/2012 6:43	2429	7
TX Repaired (OH)	FPSC Commission Rule 25-6.1085	8/27/2012 6:46	272	2
Primary Wire	FPSC Commission Rule 25-6.1086	8/27/2012 6:52	158	1
OH Other	FPSC Commission Rule 25-6.1087	8/27/2012 7:02	235	1
Secondary Wire	FPSC Commission Rule 25-6.1088	8/27/2012 7:12	311	1
OH Other	FPSC Commission Rule 25-6.1089	8/27/2012 8:07	125	1
OH Other	FPSC Commission Rule 25-6.1090	8/27/2012 8:15	96	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1091	8/27/2012 8:22	456	6
PLF	FPSC Commission Rule 25-6.1092	8/27/2012 8:47	133	1
OH Other	FPSC Commission Rule 25-6.1093	8/27/2012 8:50	483	1
Secondary Wire	FPSC Commission Rule 25-6.1094	8/27/2012 8:52	790	5
OH Other	FPSC Commission Rule 25-6.1095	8/27/2012 8:52	240	3
TX Repaired (OH)	FPSC Commission Rule 25-6.1096	8/27/2012 9:31	225	5
TX Repaired (OH)	FPSC Commission Rule 25-6.1097	8/27/2012 9:39	450	5
TX Repaired (OH)	FPSC Commission Rule 25-6.1098	8/27/2012 9:53	64	1
TX Replaced (PM)	FPSC Commission Rule 25-6.1099	8/27/2012 9:59	2365	11
TX Repaired (OH)	FPSC Commission Rule 25-6.1100	8/27/2012 11:01	870	10
TX Repaired (OH)	FPSC Commission Rule 25-6.1101	8/27/2012 11:03	50	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1102	8/27/2012 11:26	82	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1103	8/27/2012 11:40	190	1
Primary Wire	FPSC Commission Rule 25-6.1104	8/27/2012 12:31	1892	11
TX Repaired (OH)	FPSC Commission Rule 25-6.1105	8/27/2012 13:00	94	1
PLF	FPSC Commission Rule 25-6.1106	8/27/2012 13:44	91	1
PLF	FPSC Commission Rule 25-6.1107	8/27/2012 13:53	1728	24
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.1108	8/27/2012 14:14	298	2
Cut Out 100 amp - Tx	FPSC Commission Rule 25-6.1109	8/27/2012 14:35	55	1
OH Other	FPSC Commission Rule 25-6.1110	8/27/2012 14:39	103	1
Primary Wire	FPSC Commission Rule 25-6.1111	8/27/2012 14:53	728	4
Primary Wire	FPSC Commission Rule 25-6.1112	8/27/2012 15:16	9932	52
TX Repaired (OH)	FPSC Commission Rule 25-6.1113	8/27/2012 16:18	208	1
PLF	FPSC Commission Rule 25-6.1114	8/27/2012 16:34	3410	55
TX Repaired (OH)	FPSC Commission Rule 25-6.1115	8/27/2012 16:50	5280	24
Circuit Out	FPSC Commission Rule 25-6.1116	8/27/2012 16:54	74620	1148
OH Other	FPSC Commission Rule 25-6.1117	8/27/2012 16:55	128	1
TX Repaired (OH)	FPSC Commission Rule 25-6.1118	8/27/2012 17:05	392	4

2012 Adjustments: Extreme Weather Outage Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
TX Repaired (OH)	FPSC Commission Rule 25-6.1119	8/27/2012 17:11	240	4
OH Other	FPSC Commission Rule 25-6.1120	8/27/2012 17:24	50	1
Service - Crew	FPSC Commission Rule 25-6.1121	8/27/2012 18:22	648	3
OH Other	FPSC Commission Rule 25-6.1122	8/27/2012 18:52	98	1
PLF	FPSC Commission Rule 25-6.1123	8/27/2012 19:26	1426	23
URD Outage	FPSC Commission Rule 25-6.1124	8/27/2012 22:57	522	1
Cut Out 100 amp - PLF	FPSC Commission Rule 25-6.1125	8/28/2012 1:48	82	1
PLF	FPSC Commission Rule 25-6.1126	8/28/2012 3:59	2160	20
PLF	FPSC Commission Rule 25-6.1127	8/28/2012 4:27	9471	77
Secondary Wire	FPSC Commission Rule 25-6.1128	8/28/2012 4:39	2106	6
TX Replaced (OH)	FPSC Commission Rule 25-6.1129	8/28/2012 5:26	2849	11
Primary Wire	FPSC Commission Rule 25-6.1130	8/28/2012 6:00	2250	9

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Circuit Out	Planned Outage	1/3/2012 5:44	152	152
Service - Non Crew	Planned Outage	1/3/2012 8:13	69	1
OH Other	Planned Outage	1/3/2012 9:44	162	6
OH Other	Planned Outage	1/3/2012 9:58	120	1
OH Other	Planned Outage	1/3/2012 17:02	4030	403
Customer Breaker	Planned Outage	1/3/2012 17:28	53	1
UG Other	Planned Outage	1/4/2012 8:53	133	1
OH Other	Planned Outage	1/4/2012 15:51	196	1
Circuit Out	Planned Outage	1/5/2012 4:59	7428	1857
Customer Breaker	Planned Outage	1/5/2012 8:48	221	1
UG Other	Planned Outage	1/5/2012 21:12	192	1
Circuit Out	Planned Outage	1/9/2012 2:09	19880	1420
OH Other	Planned Outage	1/9/2012 8:14	113	1
OH Other	Planned Outage	1/9/2012 8:48	18	1
OH Other	Planned Outage	1/9/2012 9:57	122	2
OH Other	Planned Outage	1/10/2012 12:24	360	8
OH Other	Planned Outage	1/10/2012 13:12	572	11
Circuit Out	Planned Outage	1/11/2012 12:55	52785	621
Circuit Out	Planned Outage	1/11/2012 12:57	15720	1048
Circuit Out	Planned Outage	1/11/2012 15:05	585	117
OH Other	Planned Outage	1/12/2012 7:51	37	1
Customer Breaker	Planned Outage	1/12/2012 8:11	134	1
UG Other	Planned Outage	1/12/2012 10:52	479	1
Circuit Out	Planned Outage	1/13/2012 15:51	13157	223
OH Other	Planned Outage	1/13/2012 15:51	49206	834

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Customer Breaker	Planned Outage	1/16/2012 9:06	156	1
OH Other	Planned Outage	1/16/2012 9:54	417	3
OH Other	Planned Outage	1/16/2012 12:46	65	1
UG Other	Planned Outage	1/17/2012 8:56	34	1
OH Other	Planned Outage	1/17/2012 13:09	53	1
Customer Breaker	Planned Outage	1/18/2012 13:00	137	1
UG Other	Planned Outage	1/18/2012 15:11	155	1
Circuit Out	Planned Outage	1/18/2012 19:23	6300	420
Circuit Out	Planned Outage	1/18/2012 22:46	11431	1633
Circuit Out	Planned Outage	1/19/2012 7:41	10542	1757
UG Other	Planned Outage	1/19/2012 8:35	4680	15
OH Other	Planned Outage	1/19/2012 12:27	141	1
Customer Breaker	Planned Outage	1/19/2012 14:09	123	1
Circuit Out	Planned Outage	1/19/2012 17:56	1676	838
OH Other	Planned Outage	1/20/2012 11:43	297	1
OH Other	Planned Outage	1/24/2012 7:37	314	2
OH Other	Planned Outage	1/24/2012 15:22	213	1
UG Other	Planned Outage	1/25/2012 7:42	68	1
OH Other	Planned Outage	1/26/2012 17:58	10	1
UG Other	Planned Outage	1/26/2012 22:25	204	1
Circuit Out	Planned Outage	1/27/2012 10:34	4310	431
OH Other	Planned Outage	1/27/2012 12:04	36	1
Customer Breaker	Planned Outage	1/28/2012 14:12	155	1
OH Other	Planned Outage	1/28/2012 22:14	58	1
OH Other	Planned Outage	1/31/2012 11:55	137	1
Customer Breaker	Planned Outage	1/31/2012 15:23	131	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Customer Breaker	Planned Outage	2/1/2012 8:00	80	1
OH Other	Planned Outage	2/1/2012 10:42	106	1
Customer Breaker	Planned Outage	2/2/2012 12:19	78	1
UG Other	Planned Outage	2/4/2012 7:22	61	1
UG Other	Planned Outage	2/4/2012 8:09	50	1
Circuit Out	Planned Outage	2/4/2012 16:05	836	418
Circuit Out	Planned Outage	2/5/2012 15:46	43	43
Service - Crew	Planned Outage	2/9/2012 14:16	109	1
UG Other	Planned Outage	2/10/2012 15:31	249	1
OH Other	Planned Outage	2/12/2012 7:10	4740	474
UG Other	Planned Outage	2/12/2012 9:57	2128	112
OH Other	Planned Outage	2/13/2012 10:00	96	1
Circuit Out	Planned Outage	2/13/2012 14:34	9495	211
OH Other	Planned Outage	2/14/2012 10:21	82	1
OH Other	Planned Outage	2/15/2012 12:46	40500	324
OH Other	Planned Outage	2/15/2012 13:57	1700	10
OH Other	Planned Outage	2/15/2012 14:01	11850	237
OH Other	Planned Outage	2/15/2012 14:11	58	1
Circuit Out	Planned Outage	2/16/2012 18:24	14823	549
Step Restoration	Planned Outage	2/16/2012 18:24	18984	339
Circuit Out	Planned Outage	2/16/2012 23:03	1328	1328
Circuit Out	Planned Outage	2/17/2012 6:42	17847	661
Circuit Out	Planned Outage	2/18/2012 4:06	6804	486
Step Restoration	Planned Outage	2/18/2012 4:06	708	59
Step Restoration	Planned Outage	2/18/2012 4:06	20828	508
Step Restoration	Planned Outage	2/18/2012 4:06	32096	59

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Circuit Out	Planned Outage	2/18/2012 16:09	2949	983
OH Other	Planned Outage	2/19/2012 17:05	37	1
OH Other	Planned Outage	2/20/2012 9:08	56	1
UG Other	Planned Outage	2/22/2012 10:10	63	1
UG Other	Planned Outage	2/23/2012 14:32	63	1
Circuit Out	Planned Outage	2/24/2012 9:29	1696	1696
UG Other	Planned Outage	2/24/2012 14:24	7	1
Cut Out 100 amp - PLF	Planned Outage	2/24/2012 15:54	1488	48
Step Restoration	Planned Outage	2/26/2012 3:13	22475	145
Circuit Out	Planned Outage	2/26/2012 4:03	18694	719
Circuit Out	Planned Outage	2/28/2012 13:35	69	23
Circuit Out	Planned Outage	2/28/2012 13:35	147	49
OH Other	Planned Outage	2/28/2012 15:14	55	1
Step Restoration	Planned Outage	3/1/2012 2:05	11935	341
Circuit Out	Planned Outage	3/2/2012 6:08	11200	1600
UG Other	Planned Outage	3/3/2012 18:41	37	1
Step Restoration	Planned Outage	3/4/2012 7:19	9174	1529
OH Other	Planned Outage	3/4/2012 8:17	153	1
OH Other	Planned Outage	3/4/2012 18:40	539	7
OH Other	Planned Outage	3/5/2012 13:30	115	1
OH Other	Planned Outage	3/6/2012 10:43	1050	175
UG Other	Planned Outage	3/6/2012 15:13	36	1
OH Other	Planned Outage	3/6/2012 21:39	8712	132
OH Other	Planned Outage	3/8/2012 10:45	39	1
OH Other	Planned Outage	3/9/2012 10:56	125	1
OH Other	Planned Outage	3/9/2012 11:27	21	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OCR, Sec.	Planned Outage	3/10/2012 7:05	31845	579
Circuit Out	Planned Outage	3/11/2012 18:59	10600	1325
OH Other	Planned Outage	3/12/2012 12:10	120	2
UG Other	Planned Outage	3/14/2012 10:01	28	1
Circuit Out	Planned Outage	3/15/2012 12:34	5726	818
Handhole	Planned Outage	3/15/2012 16:21	177	1
Handhole	Planned Outage	3/15/2012 16:23	171	1
UG Other	Planned Outage	3/16/2012 8:10	324	1
Customer Breaker	Planned Outage	3/19/2012 12:06	73	1
Service - Crew	Planned Outage	3/19/2012 16:35	400	1
UG Other	Planned Outage	3/20/2012 9:10	85	1
OH Other	Planned Outage	3/20/2012 10:08	36	1
OH Other	Planned Outage	3/21/2012 8:08	92	1
Circuit Out	Planned Outage	3/21/2012 14:56	83468	1897
Circuit Out	Planned Outage	3/21/2012 17:37	690	69
Service - Non Crew	Planned Outage	3/21/2012 18:59	288	1
OH Other	Planned Outage	3/21/2012 22:40	5000	625
Circuit Out	Planned Outage	3/22/2012 7:34	5544	504
Circuit Out	Planned Outage	3/22/2012 7:34	8173	743
Circuit Out	Planned Outage	3/22/2012 11:37	5944	743
UG Other	Planned Outage	3/22/2012 12:57	175	1
OH Other	Planned Outage	3/23/2012 7:33	95	1
UG Other	Planned Outage	3/23/2012 15:27	40	1
Service - Crew	Planned Outage	3/26/2012 13:47	128	1
OH Other	Planned Outage	3/26/2012 15:55	25	1
TX Replaced (OH)	Planned Outage	3/26/2012 16:40	3796	13

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Service - Crew	Planned Outage	3/27/2012 18:31	237	1
OH Other	Planned Outage	3/28/2012 8:03	242	1
OH Other	Planned Outage	3/28/2012 11:37	47	1
UG Other	Planned Outage	3/28/2012 15:04	88	1
Circuit Out	Planned Outage	3/28/2012 20:02	14000	1400
Customer Breaker	Planned Outage	3/29/2012 8:05	58	1
OH Other	Planned Outage	3/29/2012 8:36	272	1
OH Other	Planned Outage	3/29/2012 10:30	115	1
Customer Breaker	Planned Outage	3/29/2012 17:51	60	1
OH Other	Planned Outage	3/30/2012 9:59	39	1
OH Other	Planned Outage	3/30/2012 15:36	38	1
OH Other	Planned Outage	4/1/2012 16:23	31	1
Customer Breaker	Planned Outage	4/1/2012 18:56	178	1
OH Other	Planned Outage	4/2/2012 8:58	189	1
OH Other	Planned Outage	4/2/2012 9:33	94	1
OH Other	Planned Outage	4/2/2012 10:47	58	1
OH Other	Planned Outage	4/3/2012 7:58	60	1
Service - Non Crew	Planned Outage	4/8/2012 17:21	121	1
Circuit Out	Planned Outage	4/9/2012 8:24	3585	239
Circuit Out	Planned Outage	4/10/2012 9:01	4680	585
OH Other	Planned Outage	4/10/2012 9:29	55	1
OH Other	Planned Outage	4/10/2012 9:30	55	1
OH Other	Planned Outage	4/10/2012 12:06	46	1
OH Other	Planned Outage	4/10/2012 16:15	80	1
OH Other	Planned Outage	4/12/2012 19:21	148	1
OH Other	Planned Outage	4/14/2012 15:17	75	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	4/15/2012 15:26	40	1
OH Other	Planned Outage	4/15/2012 19:55	31	1
TX Repaired (OH)	Planned Outage	4/16/2012 7:44	66	1
UG Other	Planned Outage	4/16/2012 8:18	179	1
UG Other	Planned Outage	4/16/2012 8:19	184	1
Switchgear	Planned Outage	4/16/2012 10:50	130314	587
OH Other	Planned Outage	4/16/2012 15:13	34	1
Meter Damaged	Planned Outage	4/17/2012 12:59	194	1
UG Other	Planned Outage	4/17/2012 13:08	119	1
Circuit Out	Planned Outage	4/18/2012 2:30	184	92
Circuit Out	Planned Outage	4/18/2012 8:26	8340	1668
Circuit Out	Planned Outage	4/18/2012 13:33	468	156
Customer Breaker	Planned Outage	4/18/2012 16:20	284	4
PLF	Planned Outage	4/18/2012 17:04	315	15
OH Other	Planned Outage	4/19/2012 9:35	41	1
Customer Breaker	Planned Outage	4/19/2012 15:44	52	1
Handhole	Planned Outage	4/20/2012 8:00	509	1
Circuit Out	Planned Outage	4/21/2012 3:02	1852	463
OH Other	Planned Outage	4/21/2012 12:19	102	2
Circuit Out	Planned Outage	4/21/2012 16:06	22088	1004
Circuit Out	Planned Outage	4/21/2012 16:15	1941	647
OCR, Sec.	Planned Outage	4/22/2012 3:17	17139	197
Circuit Out	Planned Outage	4/22/2012 6:05	1916	958
Step Restoration	Planned Outage	4/22/2012 6:08	7360	460
OH Other	Planned Outage	4/23/2012 9:26	57	1
TX Repaired (PM)	Planned Outage	4/23/2012 10:44	155	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Service - Crew	Planned Outage	4/23/2012 11:59	1406	1
OH Other	Planned Outage	4/24/2012 13:49	500	10
OH Other	Planned Outage	4/24/2012 21:55	65	1
OH Other	Planned Outage	4/25/2012 2:50	9975	665
OH Other	Planned Outage	4/25/2012 3:09	17861	337
Service - Crew	Planned Outage	4/25/2012 7:09	441	1
OH Other	Planned Outage	4/25/2012 8:19	59	1
OH Other	Planned Outage	4/25/2012 11:46	104	1
Circuit Out	Planned Outage	4/26/2012 8:28	1634	817
OH Other	Planned Outage	4/27/2012 2:19	7500	250
OH Other	Planned Outage	4/27/2012 14:39	129	1
Circuit Out	Planned Outage	4/27/2012 19:49	34250	1370
UG Other	Planned Outage	4/30/2012 7:35	103	1
OH Other	Planned Outage	4/30/2012 7:51	223	1
OH Other	Planned Outage	4/30/2012 9:52	220	1
TX Replaced (PM)	Planned Outage	4/30/2012 17:34	326	1
Service - Crew	Planned Outage	5/1/2012 14:07	233	1
Meter Damaged	Planned Outage	5/2/2012 14:05	72	1
Customer Breaker	Planned Outage	5/4/2012 6:47	112	1
OH Other	Planned Outage	5/4/2012 10:23	103	1
Customer Breaker	Planned Outage	5/7/2012 11:52	93	1
Service - Non Crew	Planned Outage	5/8/2012 5:53	140	1
Service - Non Crew	Planned Outage	5/8/2012 8:33	168	1
UG Other	Planned Outage	5/8/2012 11:33	770	10
Service - Non Crew	Planned Outage	5/9/2012 7:52	40	1
Service - Non Crew	Planned Outage	5/9/2012 11:51	67	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	5/10/2012 10:27	84	3
OH Other	Planned Outage	5/10/2012 10:44	22	1
UG Other	Planned Outage	5/11/2012 9:11	55	1
OH Other	Planned Outage	5/11/2012 18:51	112	1
Circuit Out	Planned Outage	5/12/2012 5:52	6957	773
Connections	Planned Outage	5/14/2012 10:43	560	8
OH Other	Planned Outage	5/14/2012 12:16	65	1
Service - Non Crew	Planned Outage	5/15/2012 7:39	232	1
Service - Non Crew	Planned Outage	5/15/2012 12:23	90	1
Service - Crew	Planned Outage	5/16/2012 8:18	207	1
Circuit Out	Planned Outage	5/16/2012 13:23	5796	828
Circuit Out	Planned Outage	5/16/2012 19:36	47150	2050
Circuit Out	Planned Outage	5/16/2012 19:49	13410	894
UG Other	Planned Outage	5/16/2012 23:55	122	1
OH Other	Planned Outage	5/17/2012 8:16	616	8
Service - Non Crew	Planned Outage	5/17/2012 17:04	54	1
TX Repaired (PM)	Planned Outage	5/18/2012 12:30	1050	7
UG Other	Planned Outage	5/18/2012 15:02	96	1
OH Other	Planned Outage	5/21/2012 10:13	40188	2364
Circuit Out	Planned Outage	5/22/2012 9:48	2628	1314
UG Other	Planned Outage	5/22/2012 12:31	63	1
OH Other	Planned Outage	5/23/2012 20:13	1568	49
Circuit Out	Planned Outage	5/24/2012 3:00	1814	907
OH Other	Planned Outage	5/24/2012 10:47	282	6
UG Other	Planned Outage	5/24/2012 15:05	900	5
OH Other	Planned Outage	5/24/2012 20:51	363	33

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	5/25/2012 15:06	44	4
Customer Breaker	Planned Outage	5/25/2012 17:00	556	2
OH Other	Planned Outage	5/25/2012 17:40	370	37
UG Other	Planned Outage	5/28/2012 15:07	40	1
UG Other	Planned Outage	5/29/2012 20:26	119	1
Circuit Out	Planned Outage	5/30/2012 7:20	20	1
UG Other	Planned Outage	5/30/2012 7:30	630	18
UG Other	Planned Outage	5/30/2012 12:31	7511	37
OH Other	Planned Outage	5/31/2012 5:39	2156	44
PLF	Planned Outage	6/1/2012 12:56	50	1
Customer Breaker	Planned Outage	6/1/2012 14:53	213	1
UG Other	Planned Outage	6/3/2012 7:25	92	1
OH Other	Planned Outage	6/4/2012 17:41	179	1
OH Other	Planned Outage	6/5/2012 10:43	82	1
Circuit Out	Planned Outage	6/5/2012 14:22	158746	667
Step Restoration	Planned Outage	6/5/2012 14:22	16704	232
OH Other	Planned Outage	6/6/2012 19:46	5612	244
OH Other	Planned Outage	6/7/2012 10:02	127	1
OH Other	Planned Outage	6/8/2012 9:12	196	2
OH Other	Planned Outage	6/8/2012 12:23	2112	176
OH Other	Planned Outage	6/9/2012 7:47	59	1
OH Other	Planned Outage	6/9/2012 9:40	30	1
OH Other	Planned Outage	6/10/2012 20:59	440	10
OH Other	Planned Outage	6/11/2012 8:08	75	1
Service - Non Crew	Planned Outage	6/11/2012 8:22	90	1
OH Other	Planned Outage	6/12/2012 16:30	714	6

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
UG Other	Planned Outage	6/12/2012 22:26	65	1
OH Other	Planned Outage	6/14/2012 3:03	43	1
OH Other	Planned Outage	6/15/2012 15:52	85	1
OH Other	Planned Outage	6/16/2012 9:21	92	1
OH Other	Planned Outage	6/16/2012 10:50	77	1
OH Other	Planned Outage	6/18/2012 11:55	146	1
OH Other	Planned Outage	6/18/2012 13:05	98	1
Connections	Planned Outage	6/19/2012 8:26	134	1
OH Other	Planned Outage	6/19/2012 9:45	194	1
OH Other	Planned Outage	6/19/2012 10:44	119	1
Circuit Out	Planned Outage	6/19/2012 11:10	4276	1069
Service - Non Crew	Planned Outage	6/19/2012 16:12	119	1
Circuit Out	Planned Outage	6/20/2012 8:36	9480	790
Circuit Out	Planned Outage	6/20/2012 21:21	60270	1722
Circuit Out	Planned Outage	6/21/2012 8:02	858	429
Circuit Out	Planned Outage	6/21/2012 11:34	5692	1423
OH Other	Planned Outage	6/21/2012 12:23	34	1
Service - Non Crew	Planned Outage	6/23/2012 8:28	82	1
OH Other	Planned Outage	6/23/2012 12:56	42	1
Step Restoration	Planned Outage	6/27/2012 6:20	35226	342
OH Other	Planned Outage	6/27/2012 8:34	230	1
OH Other	Planned Outage	6/27/2012 9:14	109	1
OH Other	Planned Outage	6/27/2012 10:02	215	1
OH Other	Planned Outage	6/27/2012 11:16	64	1
UG Other	Planned Outage	6/27/2012 11:41	600	4
OH Other	Planned Outage	6/27/2012 14:30	127	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	6/27/2012 17:30	177	1
OH Other	Planned Outage	6/28/2012 10:34	36	1
OH Other	Planned Outage	6/28/2012 10:44	67	1
OH Other	Planned Outage	6/28/2012 11:20	42	1
OH Other	Planned Outage	6/28/2012 13:42	804	1
OH Other	Planned Outage	6/28/2012 14:19	333	3
Service - Crew	Planned Outage	6/28/2012 23:47	323	1
TX Repaired (OH)	Planned Outage	6/29/2012 11:03	448	8
UG Other	Planned Outage	6/29/2012 11:06	3565	155
OH Other	Planned Outage	6/29/2012 12:16	65	1
OH Other	Planned Outage	6/29/2012 12:16	47	1
OH Other	Planned Outage	6/29/2012 12:29	42	1
OH Other	Planned Outage	6/29/2012 12:38	28	1
OH Other	Planned Outage	6/29/2012 13:00	17	1
UG Other	Planned Outage	7/2/2012 9:11	116	4
UG Other	Planned Outage	7/3/2012 12:18	33	1
Service - Non Crew	Planned Outage	7/4/2012 13:09	48	1
Customer Breaker	Planned Outage	7/5/2012 13:58	35	1
OH Other	Planned Outage	7/6/2012 10:19	38	1
Service - Non Crew	Planned Outage	7/7/2012 10:13	58	1
OH Other	Planned Outage	7/9/2012 12:52	35	1
OH Other	Planned Outage	7/9/2012 13:44	440	8
OH Other	Planned Outage	7/9/2012 16:56	21	1
Circuit Out	Planned Outage	7/10/2012 20:09	2324	581
Meter Damaged	Planned Outage	7/11/2012 8:43	120	1
OH Other	Planned Outage	7/11/2012 8:57	247	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	7/11/2012 9:51	741	1
Circuit Out	Planned Outage	7/12/2012 1:45	24932	1084
Service - Crew	Planned Outage	7/12/2012 18:18	56	1
UG Other	Planned Outage	7/12/2012 19:58	590	5
Circuit Out	Planned Outage	7/14/2012 3:26	20664	504
Circuit Out	Planned Outage	7/15/2012 5:58	2640	440
OH Other	Planned Outage	7/16/2012 7:53	51	1
OH Other	Planned Outage	7/16/2012 12:56	98	2
OH Other	Planned Outage	7/16/2012 13:56	79	1
OH Other	Planned Outage	7/16/2012 19:00	28	1
OH Other	Planned Outage	7/17/2012 8:15	46	1
OH Other	Planned Outage	7/17/2012 8:37	57	1
Service - Non Crew	Planned Outage	7/17/2012 21:48	82	1
UG Other	Planned Outage	7/18/2012 0:31	59	1
Circuit Out	Planned Outage	7/18/2012 8:38	6050	1210
OH Other	Planned Outage	7/18/2012 9:22	70	1
Circuit Out	Planned Outage	7/18/2012 11:58	3528	1764
Service - Non Crew	Planned Outage	7/18/2012 17:46	58	1
OH Other	Planned Outage	7/19/2012 12:34	226	1
Service - Crew	Planned Outage	7/19/2012 14:21	263	1
TX Replaced (PM)	Planned Outage	7/23/2012 6:54	139	1
OH Other	Planned Outage	7/23/2012 11:42	600	8
Circuit Out	Planned Outage	7/23/2012 14:23	14319	1591
UG Other	Planned Outage	7/23/2012 14:29	35	1
UG Other	Planned Outage	7/23/2012 16:20	45	1
Circuit Out	Planned Outage	7/23/2012 19:13	8298	1383

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	7/27/2012 9:51	710	10
UG Other	Planned Outage	7/27/2012 11:59	108	1
OH Other	Planned Outage	7/30/2012 6:06	4572	18
OH Other	Planned Outage	7/30/2012 12:57	145	1
OH Other	Planned Outage	7/31/2012 7:34	139	1
Service - Crew	Planned Outage	7/31/2012 13:32	242	1
OH Other	Planned Outage	8/1/2012 10:18	60	1
UG Other	Planned Outage	8/1/2012 14:50	30	1
Service - Non Crew	Planned Outage	8/4/2012 5:22	120	1
Step Restoration	Planned Outage	8/4/2012 23:45	1218	174
OH Other	Planned Outage	8/6/2012 9:01	105	1
UG Other	Planned Outage	8/6/2012 20:51	25	1
Service - Non Crew	Planned Outage	8/8/2012 20:09	85	1
UG Other	Planned Outage	8/10/2012 8:15	52	1
OH Other	Planned Outage	8/10/2012 16:57	127	1
Circuit Out	Planned Outage	8/11/2012 8:46	2094	698
Circuit Out	Planned Outage	8/11/2012 14:48	4669	667
OH Other	Planned Outage	8/13/2012 7:34	94	1
OH Other	Planned Outage	8/13/2012 7:34	156	1
OH Other	Planned Outage	8/13/2012 10:06	191	1
OH Other	Planned Outage	8/13/2012 15:40	76	1
OH Other	Planned Outage	8/14/2012 8:03	88	2
OH Other	Planned Outage	8/14/2012 8:30	76	1
Circuit Out	Planned Outage	8/14/2012 15:51	9729	1081
Circuit Out	Planned Outage	8/15/2012 2:20	22050	225
Circuit Out	Planned Outage	8/15/2012 2:31	260120	1858

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	8/15/2012 10:08	48	1
OH Other	Planned Outage	8/15/2012 12:35	126	1
OH Other	Planned Outage	8/16/2012 8:04	205	1
Circuit Out	Planned Outage	8/16/2012 8:12	6620	1655
Circuit Out	Planned Outage	8/16/2012 17:24	3522	1174
Circuit Out	Planned Outage	8/19/2012 22:44	8922	1487
UG Other	Planned Outage	8/20/2012 4:06	1168	8
OH Other	Planned Outage	8/20/2012 8:07	53	1
Service - Non Crew	Planned Outage	8/20/2012 9:06	308	1
OH Other	Planned Outage	8/20/2012 12:50	43	1
UG Other	Planned Outage	8/21/2012 9:52	56	1
TX Repaired (PM)	Planned Outage	8/22/2012 9:00	205	1
Customer Breaker	Planned Outage	8/22/2012 16:26	126	1
Circuit Out	Planned Outage	8/22/2012 19:04	4035	1345
OH Other	Planned Outage	8/23/2012 19:04	1128	24
UG Other	Planned Outage	8/25/2012 9:44	79	1
Service - Non Crew	Planned Outage	8/28/2012 14:35	43	1
Circuit Out	Planned Outage	8/29/2012 17:29	48672	936
OH Other	Planned Outage	8/29/2012 17:29	28652	551
Service - Non Crew	Planned Outage	8/30/2012 11:56	41	1
Service - Non Crew	Planned Outage	8/31/2012 11:03	119	1
OH Other	Planned Outage	8/31/2012 11:35	127	1
OH Other	Planned Outage	9/2/2012 0:39	13536	376
OH Other	Planned Outage	9/2/2012 1:27	76	19
UG Other	Planned Outage	9/3/2012 10:38	175	1
OH Other	Planned Outage	9/4/2012 8:32	65	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Service - Crew	Planned Outage	9/4/2012 13:54	41	1
Service - Crew	Planned Outage	9/4/2012 14:53	23	1
UG Other	Planned Outage	9/4/2012 19:39	80	1
OH Other	Planned Outage	9/5/2012 6:51	159	1
UG Other	Planned Outage	9/5/2012 16:59	53	1
Service - Non Crew	Planned Outage	9/6/2012 12:07	48	1
Service - Crew	Planned Outage	9/6/2012 16:06	254	1
TX Repaired (PM)	Planned Outage	9/7/2012 5:53	1008	8
LBC Cabinet	Planned Outage	9/7/2012 5:58	1930	10
Service - Non Crew	Planned Outage	9/7/2012 7:34	194	1
OH Other	Planned Outage	9/8/2012 12:24	410	10
OH Other	Planned Outage	9/9/2012 16:04	84	1
Circuit Out	Planned Outage	9/10/2012 5:27	114	38
Customer Breaker	Planned Outage	9/10/2012 13:20	67	1
OH Other	Planned Outage	9/10/2012 16:43	47	1
Service - Non Crew	Planned Outage	9/11/2012 8:47	69	1
Service - Non Crew	Planned Outage	9/11/2012 12:01	95	1
Service - Non Crew	Planned Outage	9/11/2012 13:25	279	3
Customer Breaker	Planned Outage	9/11/2012 14:32	495	1
Service - Crew	Planned Outage	9/11/2012 15:58	826	1
Circuit Out	Planned Outage	9/12/2012 1:36	6168	1542
Service - Non Crew	Planned Outage	9/12/2012 15:20	131	1
UG Other	Planned Outage	9/12/2012 19:37	1633	71
OH Other	Planned Outage	9/13/2012 8:06	102	1
Customer Breaker	Planned Outage	9/14/2012 8:02	47	1
Service - Non Crew	Planned Outage	9/14/2012 14:17	70	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Service - Non Crew	Planned Outage	9/14/2012 20:24	87	1
OH Other	Planned Outage	9/17/2012 18:06	107	1
PLF	Planned Outage	9/18/2012 2:21	4539	17
OH Other	Planned Outage	9/19/2012 10:57	66	1
Customer Breaker	Planned Outage	9/21/2012 9:41	44	1
OH Other	Planned Outage	9/21/2012 11:09	61	1
OH Other	Planned Outage	9/21/2012 11:23	83	1
UG Other	Planned Outage	9/21/2012 11:39	163	1
Customer Breaker	Planned Outage	9/21/2012 13:39	26	1
Circuit Out	Planned Outage	9/21/2012 15:29	10696	764
UG Other	Planned Outage	9/25/2012 11:39	152	1
OH Other	Planned Outage	9/25/2012 20:50	102	1
OH Other	Planned Outage	9/26/2012 9:35	267	1
OH Other	Planned Outage	9/26/2012 12:37	108	1
OH Other	Planned Outage	9/26/2012 14:05	43	1
OH Other	Planned Outage	9/26/2012 15:44	27	1
UG Other	Planned Outage	9/27/2012 9:06	169	1
Customer Breaker	Planned Outage	9/27/2012 10:42	156	1
Customer Breaker	Planned Outage	9/27/2012 11:58	150	1
OH Other	Planned Outage	9/27/2012 13:55	107	1
Circuit Out	Planned Outage	9/28/2012 7:19	5	5
UG Other	Planned Outage	9/28/2012 8:25	188	1
UG Other	Planned Outage	10/1/2012 8:11	155	1
OH Other	Planned Outage	10/1/2012 9:13	41	1
OH Other	Planned Outage	10/2/2012 10:20	72	1
OH Other	Planned Outage	10/2/2012 10:31	252	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	10/3/2012 10:35	53	1
OH Other	Planned Outage	10/3/2012 12:56	26	1
OH Other	Planned Outage	10/4/2012 9:46	32	1
OH Other	Planned Outage	10/4/2012 10:56	131	1
OH Other	Planned Outage	10/4/2012 17:08	109	1
Circuit Out	Planned Outage	10/4/2012 20:30	7925	1585
Service - Crew	Planned Outage	10/4/2012 20:41	402	1
OH Other	Planned Outage	10/5/2012 13:28	106	1
Customer Breaker	Planned Outage	10/5/2012 15:38	127	1
OH Other	Planned Outage	10/6/2012 3:44	30	1
OH Other	Planned Outage	10/6/2012 4:56	66	1
OH Other	Planned Outage	10/6/2012 8:45	244	1
Circuit Out	Planned Outage	10/6/2012 18:09	140	20
OH Other	Planned Outage	10/7/2012 3:50	44	1
Step Restoration	Planned Outage	10/7/2012 20:34	1250	125
Circuit Out	Planned Outage	10/7/2012 20:51	1153	1153
OH Other	Planned Outage	10/9/2012 14:16	102	2
Customer Breaker	Planned Outage	10/9/2012 16:02	429	1
OH Other	Planned Outage	10/11/2012 5:53	37	1
OH Other	Planned Outage	10/11/2012 11:43	338	1
Service - Crew	Planned Outage	10/12/2012 13:08	75	1
OH Other	Planned Outage	10/12/2012 15:42	98	2
OH Other	Planned Outage	10/12/2012 23:41	57	1
OH Other	Planned Outage	10/13/2012 6:52	126	1
OH Other	Planned Outage	10/16/2012 13:19	5680	40
TX Replaced (OH)	Planned Outage	10/16/2012 17:43	182	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Circuit Out	Planned Outage	10/17/2012 21:30	12249	1361
OH Other	Planned Outage	10/23/2012 8:03	48	1
UG Other	Planned Outage	10/23/2012 8:40	46	1
Step Restoration	Planned Outage	10/23/2012 17:11	368	23
OH Other	Planned Outage	10/24/2012 7:50	101	1
OH Other	Planned Outage	10/24/2012 9:22	20	1
UG Other	Planned Outage	10/24/2012 14:50	149	1
Customer Breaker	Planned Outage	10/24/2012 16:19	130	1
Customer Breaker	Planned Outage	10/24/2012 16:48	215	1
OH Other	Planned Outage	10/25/2012 10:31	71	1
UG Other	Planned Outage	10/25/2012 10:52	208	1
OH Other	Planned Outage	10/25/2012 19:32	590	10
Circuit Out	Planned Outage	10/25/2012 23:20	2164	541
Circuit Out	Planned Outage	10/26/2012 16:48	26352	976
Circuit Out	Planned Outage	10/26/2012 18:38	23881	1837
OH Other	Planned Outage	10/26/2012 23:35	174	1
OH Other	Planned Outage	10/27/2012 10:34	79	1
TX Pad	Planned Outage	10/27/2012 19:29	125	1
OH Other	Planned Outage	10/29/2012 10:31	506	2
OH Other	Planned Outage	10/29/2012 11:32	140	1
Circuit Out	Planned Outage	10/30/2012 8:15	4824	536
UG Other	Planned Outage	10/30/2012 8:52	358	1
OH Other	Planned Outage	10/30/2012 12:07	1236	6
OH Other	Planned Outage	10/30/2012 13:29	39	1
UG Other	Planned Outage	10/30/2012 14:30	70	1
OH Other	Planned Outage	10/31/2012 9:20	158	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	11/1/2012 9:52	50	1
Service - Non Crew	Planned Outage	11/1/2012 13:49	372	1
TX Repaired (PM)	Planned Outage	11/2/2012 10:49	1122	6
OH Other	Planned Outage	11/5/2012 7:41	73	1
OH Other	Planned Outage	11/5/2012 10:17	57	1
OH Other	Planned Outage	11/5/2012 13:00	3750	25
Circuit Out	Planned Outage	11/6/2012 7:49	20670	689
OH Other	Planned Outage	11/6/2012 10:09	101	1
Service - Non Crew	Planned Outage	11/6/2012 11:17	80	1
Service - Crew	Planned Outage	11/6/2012 14:36	72	1
Circuit Out	Planned Outage	11/6/2012 14:46	17280	720
OH Other	Planned Outage	11/8/2012 14:51	61	1
Service - Non Crew	Planned Outage	11/8/2012 19:33	54	1
OH Other	Planned Outage	11/9/2012 7:47	155	1
Service - Non Crew	Planned Outage	11/13/2012 8:50	34	1
Circuit Out	Planned Outage	11/14/2012 6:37	3360	336
Circuit Out	Planned Outage	11/14/2012 6:37	4710	471
Cut Out 100 amp - Tx	Planned Outage	11/16/2012 7:36	60	1
UG Other	Planned Outage	11/16/2012 8:24	605	1
OH Other	Planned Outage	11/16/2012 19:49	50	1
OH Other	Planned Outage	11/19/2012 10:45	118	1
OH Other	Planned Outage	11/19/2012 10:59	324	9
Circuit Out	Planned Outage	11/20/2012 10:40	15752	1432
OH Other	Planned Outage	11/20/2012 10:51	74	1
OH Other	Planned Outage	11/20/2012 12:27	35	1
Circuit Out	Planned Outage	11/23/2012 3:16	708	236

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	11/23/2012 3:50	700	4
OH Other	Planned Outage	11/23/2012 3:50	19728	48
Circuit Out	Planned Outage	11/23/2012 3:52	1425	285
Circuit Out	Planned Outage	11/23/2012 4:48	1102	1102
Circuit Out	Planned Outage	11/25/2012 9:56	11245	865
Circuit Out	Planned Outage	11/26/2012 1:16	10913	1559
Service - Crew	Planned Outage	11/26/2012 8:18	252	1
Service - Non Crew	Planned Outage	11/26/2012 10:31	258	1
Circuit Out	Planned Outage	11/26/2012 14:28	1710	114
Service - Non Crew	Planned Outage	11/26/2012 14:36	38	1
OH Other	Planned Outage	11/27/2012 4:51	119	1
TX Repaired (OH)	Planned Outage	11/27/2012 5:00	4850	10
UG Other	Planned Outage	11/27/2012 9:25	37	1
OH Other	Planned Outage	11/28/2012 10:11	159	1
OH Other	Planned Outage	11/28/2012 14:37	87	1
Step Restoration	Planned Outage	11/30/2012 8:31	1526	14
Circuit Out	Planned Outage	11/30/2012 19:24	3105	621
Circuit Out	Planned Outage	12/1/2012 22:26	3158	1579
OH Other	Planned Outage	12/3/2012 14:15	22	1
UG Other	Planned Outage	12/3/2012 14:17	106	1
UG Other	Planned Outage	12/3/2012 15:09	47	1
Circuit Out	Planned Outage	12/7/2012 8:23	1102	1102
OH Other	Planned Outage	12/7/2012 8:24	61	1
OH Other	Planned Outage	12/8/2012 9:24	200	1
Circuit Out	Planned Outage	12/8/2012 16:56	6484	1621
OH Other	Planned Outage	12/12/2012 14:25	52	1

2011 Adjustments: Other Distribution Outage Events

Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
OH Other	Planned Outage	12/13/2012 7:50	78	1
OH Other	Planned Outage	12/15/2012 8:27	240	1
Service - Non Crew	Planned Outage	12/15/2012 12:23	97	1
Circuit Out	Planned Outage	12/16/2012 8:12	2352	294
UG Other	Planned Outage	12/17/2012 9:59	334	1
Circuit Out	Planned Outage	12/17/2012 11:36	645	5
OH Other	Planned Outage	12/18/2012 7:41	76	1
OH Other	Planned Outage	12/18/2012 9:17	1036	7
UG Other	Planned Outage	12/19/2012 7:56	42	1
OH Other	Planned Outage	12/20/2012 9:29	34224	186
OH Other	Planned Outage	12/20/2012 10:29	70	1
Customer Breaker	Planned Outage	12/21/2012 9:20	312	1
Circuit Out	Planned Outage	12/22/2012 1:16	8748	729
Service - Crew	Planned Outage	12/22/2012 22:56	314	1
Customer Breaker	Planned Outage	12/23/2012 12:25	55	1
Circuit Out	Planned Outage	12/23/2012 17:35	1374	687
Circuit Out	Planned Outage	12/23/2012 23:43	2408	1204
Circuit Out	Planned Outage	12/25/2012 6:32	1935	387
OH Other	Planned Outage	12/26/2012 10:59	241	1
Circuit Out	Planned Outage	12/26/2012 22:29	6924	1154
OH Other	Planned Outage	12/27/2012 6:38	60	1
Customer Breaker	Planned Outage	12/28/2012 0:55	243	1
Circuit Out	Planned Outage	12/29/2012 5:25	9580	958
UG Other	Planned Outage	12/29/2012 7:43	212	2
OH Other	Planned Outage	12/31/2012 10:07	27	1
UG Other	Planned Outage	12/31/2012 10:41	43090	310

2012 Adjustments: Substation Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Substation	Short\Primary	1/3/2012 7:08	64740	996
Substation	Short\Primary	1/3/2012 7:08	80826	1418
Substation	Short\Primary	1/3/2012 7:08	171132	2194
Substation	Short\Primary	1/3/2012 7:09	140346	2599
Substation	Substation Transformer Failure	1/19/2012 17:21	11820	197
Substation	Substation Transformer Failure	1/19/2012 17:21	32472	451
Substation	Substation Transformer Failure	1/19/2012 17:21	57597	789
Substation	Substation Transformer Failure	1/19/2012 17:21	13280	160
Substation	Circuit Breaker	1/28/2012 15:26	77926	1658
Substation	Circuit Breaker	2/7/2012 8:48	305	305
Substation	Substation Equipment	2/14/2012 10:20	2219	2219
Substation	Substation Equipment	2/18/2012 2:00	24752	1456
Substation	Substation Equipment	2/28/2012 18:18	40275	895
Substation	Substation Equipment	2/28/2012 18:18	47	1
Substation	Substation Equipment	2/28/2012 18:18	22140	410
Substation	Circuit Breaker	2/29/2012 4:48	1572	786
Substation	Other Substation	3/1/2012 19:01	2606	1303
Substation	Relay and Controls	3/18/2012 10:37	42498	787
Substation	Relay and Controls	3/18/2012 10:37	86127	1511
Substation	Relay and Controls	3/18/2012 10:37	105154	1421
Substation	Relay and Controls	3/18/2012 10:37	142575	1901
Substation	Circuit Breaker	3/21/2012 23:26	163666	1387
Substation	Substation Equipment	3/25/2012 9:50	25398	747
Substation	Circuit Breaker	3/26/2012 17:11	28449	981
Substation	Circuit Breaker	3/26/2012 17:12	22484	803
Substation	Circuit Breaker	3/26/2012 17:12	77941	1901
Substation	Rain	3/31/2012 15:19	31278	802
Substation	Bus Fault\13KV	4/3/2012 8:18	50002	1087
Substation	Bus Fault\13KV	4/3/2012 8:18	57523	943

2012 Adjustments: Substation Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Substation	Circuit Breaker	4/7/2012 14:54	1685	1685
Substation	Other Substation	4/8/2012 8:45	36176	476
Substation	Other Substation	4/8/2012 8:45	20757	561
Substation	Bus Fault\13KV	4/18/2012 16:32	127088	2704
Substation	Bus Fault\13KV	4/18/2012 16:32	98605	1517
Substation	Bus Fault\13KV	4/18/2012 16:32	98670	1518
Substation	Substation Equipment	4/22/2012 1:03	79130	1930
Substation	Substation Equipment	4/22/2012 1:03	35917	733
Substation	Substation Equipment	4/22/2012 1:03	56168	826
Substation	Squirrel	4/23/2012 7:52	24540	818
Substation	Squirrel	4/23/2012 7:52	45056	1408
Substation	Squirrel	4/23/2012 7:52	2420	55
Substation	Squirrel	4/23/2012 8:59	51578	1517
Substation	Squirrel	4/23/2012 8:59	43430	1010
Substation	Squirrel	4/23/2012 8:59	48018	906
Substation	Squirrel	4/23/2012 8:59	33208	593
Substation	Squirrel	4/24/2012 8:44	28866	849
Substation	Squirrel	4/24/2012 8:44	30786	733
Substation	Squirrel	5/1/2012 7:35	52560	1314
Substation	Squirrel	5/1/2012 7:35	77616	1386
Substation	Squirrel	5/1/2012 7:35	43384	748
Substation	Substation Equipment	5/3/2012 5:59	46800	650
Substation	Substation Equipment	5/3/2012 5:59	75518	619
Substation	Substation Equipment	5/3/2012 6:03	37000	370
Substation	Substation Equipment	5/3/2012 6:03	37584	432
Substation	Animal (other)	5/20/2012 1:59	62	1
Substation	Animal (other)	5/20/2012 1:59	45880	740
Substation	Animal (other)	5/20/2012 1:59	56052	692
Substation	Animal (other)	5/20/2012 1:59	3348	27
Substation	Circuit Breaker	5/20/2012 6:35	612	3
Substation	Bus Fault\13KV	5/22/2012 9:38	21580	332
Substation	Bus Fault\13KV	5/22/2012 9:38	108780	1470
Substation	Bus Fault\13KV	5/22/2012 9:38	56208	1171

2012 Adjustments: Substation Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Substation	Bus Fault\13KV	5/22/2012 9:38	33800	676
Substation	Bus Fault\13KV	5/22/2012 9:38	42276	813
Substation	Bus Fault\13KV	5/22/2012 9:42	17178	409
Substation	Substation Equipment	5/28/2012 17:04	1972	986
Substation	Bus Fault\13KV	5/29/2012 11:09	44424	617
Substation	Bus Fault\13KV	5/29/2012 11:09	139500	1860
Substation	Bus Fault\13KV	5/29/2012 11:09	85728	893
Substation	Bus Fault\13KV	5/29/2012 11:09	86415	823
Substation	Switch	6/2/2012 15:10	97152	2024
Substation	Switch	6/2/2012 15:10	62802	1163
Substation	Squirrel	6/6/2012 9:59	18560	640
Substation	Squirrel	6/6/2012 9:59	39240	981
Substation	Squirrel	6/6/2012 9:59	62000	1550
Substation	Squirrel	6/6/2012 9:59	47212	1073
Substation	Bus Fault\13KV	6/7/2012 1:43	48672	936
Substation	Bus Fault\13KV	6/7/2012 1:43	49105	805
Substation	Bus Fault\13KV	6/7/2012 1:43	6208	97
Substation	Bus Fault\13KV	6/7/2012 1:43	405	5
Substation	Unknown	6/9/2012 19:45	81200	2320
Substation	Unknown	6/9/2012 19:46	117299	1289
Substation	Unknown	6/9/2012 19:49	38068	614
Substation	Substation Equipment	6/11/2012 11:32	63104	986
Substation	Substation Equipment	6/11/2012 11:32	4810	65
Substation	Substation Equipment	6/11/2012 11:32	28576	304
Substation	Substation Equipment	6/11/2012 11:32	47806	451
Substation	Switch	6/11/2012 15:54	126	1
Substation	Circuit Breaker	6/25/2012 16:38	68704	904
Substation	Substation Equipment	6/28/2012 15:44	54684	868
Substation	Substation Equipment	6/28/2012 15:44	63872	998
Substation	Substation Equipment	6/28/2012 15:44	23240	280
Substation	Substation Equipment	6/28/2012 15:44	31356	268
Substation	Substation Equipment	7/18/2012 7:11	11570	445
Substation	Substation Equipment	8/3/2012 16:32	5028	1676

2012 Adjustments: Substation Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Substation	Vines	8/9/2012 6:34	11505	295
Substation	Circuit Breaker	8/11/2012 21:36	30573	387
Substation	Circuit Breaker	8/11/2012 21:36	49140	540
Substation	Circuit Breaker	8/12/2012 14:17	55944	1036
Substation	Substation Equipment	8/15/2012 21:45	55878	834
Substation	Substation Equipment	8/15/2012 21:45	111399	1569
Substation	Substation Equipment	8/15/2012 21:45	85702	1174
Substation	Substation Equipment	8/15/2012 21:45	69090	705
Substation	Substation Equipment	8/23/2012 12:42	16800	350
Substation	Substation Equipment	8/23/2012 12:45	26332	908
Substation	Substation Equipment	8/24/2012 12:18	23746	766
Substation	Substation Equipment	8/24/2012 12:18	15392	416
Substation	Substation Equipment	8/27/2012 19:17	62764	1207
Substation	Substation Equipment	8/27/2012 19:17	40992	672
Substation	Substation Equipment	8/27/2012 19:17	2912	56
Substation	Substation Equipment	8/27/2012 19:17	23214	318
Substation	Unknown	8/28/2012 11:51	13446	747
Substation	Circuit Breaker	8/28/2012 11:52	33852	1209
Substation	Substation Equipment	8/28/2012 21:20	15190	245
Substation	Circuit Breaker	9/9/2012 11:32	1376	344
Substation	Squirrel	10/2/2012 9:20	32472	792
Substation	Squirrel	10/2/2012 9:20	40795	995
Substation	Squirrel	10/2/2012 9:20	23364	354
Substation	Unknown	10/7/2012 10:09	9008	2252
Substation	Circuit Breaker	10/8/2012 7:27	91278	2766
Substation	Substation Equipment	10/21/2012 8:09	37816	652
Substation	Substation Equipment	10/24/2012 17:50	114750	1530
Substation	Substation Equipment	10/24/2012 17:51	18300	366
Substation	Substation Equipment	10/24/2012 17:51	35350	707
Substation	Substation Equipment	10/24/2012 17:51	50900	1018
Substation	URD Cable\Fault	10/25/2012 10:34	87892	2044
Substation	URD Cable\Fault	10/25/2012 10:34	62234	1073
Substation	Substation Equipment	10/28/2012 15:33	81920	1280

2012 Adjustments: Substation Events
Outage Event Description

Outage Event	Reason For Exclusion	Outage Date	CMI Excluded	CI Excluded
Substation	Substation Equipment	10/28/2012 15:33	46788	1114
Substation	Substation Equipment	10/28/2012 15:33	42432	884
Substation	Substation Equipment	10/28/2012 15:33	51370	934
Substation	Substation Equipment	10/31/2012 6:25	72688	1232
Substation	Circuit Breaker	11/8/2012 8:27	86580	1665
Substation	Short\Primary	11/19/2012 7:47	40824	648
Substation	Substation Equipment	11/23/2012 17:57	109944	1527
Substation	Substation Equipment	11/23/2012 17:57	150900	1509
Substation	Substation Equipment	11/23/2012 18:02	164263	1507
Substation	Substation Equipment	11/23/2012 18:33	50456	901
Substation	Unknown	11/25/2012 10:19	468	52
Substation	Substation Equipment	11/26/2012 0:25	26270	185
Substation	Substation Equipment	11/26/2012 0:25	53648	479
Substation	Substation Equipment	11/26/2012 0:25	110200	950
Substation	Substation Equipment	12/7/2012 10:20	47658	1222
Substation	Short\Primary	12/12/2012 16:17	29516	628
Substation	Squirrel	12/15/2012 8:42	2940	49
Substation	Squirrel	12/15/2012 8:42	5472	114
Substation	Squirrel	12/15/2012 8:42	127950	2559
Substation	Squirrel	12/15/2012 8:42	69224	1018

2012 Adjustments: Transmission Events

Outage Event Description

Outage Event	Reason for Exclusion	Outage Date	CMI Excluded	CI Excluded
Transmission	CIRCUIT BREAKER	2/5/2012 7:31	15318	666
Transmission	CIRCUIT BREAKER	2/5/2012 7:31	26992	1687
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	690	230
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	900	300
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	2007	669
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	2265	755
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	2289	763
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	2421	807
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	3303	1101
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	3612	1204
Transmission	CIRCUIT BREAKER	3/1/2012 5:28	4041	1347
Transmission	CIRCUIT BREAKER	3/30/2012 1:49	9174	1529
Transmission	CIRCUIT BREAKER	3/30/2012 1:49	8058	1343
Transmission	CIRCUIT BREAKER	3/30/2012 1:49	210	42
Transmission	CIRCUIT BREAKER	3/30/2012 1:49	5530	1106
Transmission	CIRCUIT BREAKER	3/30/2012 1:49	6780	1130
Transmission	CIRCUIT BREAKER	3/30/2012 1:49	6205	1241
Transmission	HUMAN SWITCHING	3/30/2012 1:49	42126	413
Transmission	HUMAN SWITCHING	3/30/2012 1:49	160	2
Transmission	HUMAN SWITCHING	3/30/2012 1:49	216	2
Transmission	HUMAN SWITCHING	3/30/2012 1:49	1288	14
Transmission	HUMAN SWITCHING	3/30/2012 1:49	63531	543
Transmission	HUMAN SWITCHING	3/30/2012 1:49	101907	871
Transmission	HUMAN SWITCHING	3/30/2012 1:49	7782	1297
Transmission	HUMAN SWITCHING	3/30/2012 1:49	6560	1312
Transmission	HUMAN SWITCHING	3/30/2012 1:49	6720	1120
Transmission	LIGHTNING	3/30/2012 1:49	9906	1651
Transmission	LIGHTNING	3/30/2012 1:49	7125	1425
Transmission	LIGHTNING	6/24/2012 20:10	24780	210
Transmission	LIGHTNING	6/24/2012 20:10	464877	471
Transmission	OTHER TRANSMISSION	6/24/2012 20:10	87261	493
Transmission	OTHER TRANSMISSION	6/24/2012 20:13	300117	1409
Transmission	OTHER TRANSMISSION	6/24/2012 20:13	163880	680
Transmission	OTHER TRANSMISSION	6/24/2012 20:13	277020	1710
Transmission	OTHER TRANSMISSION	6/24/2012 20:15	128193	741

2012 Adjustments: Transmission Events

Outage Event Description

Outage Event	Reason for Exclusion	Outage Date	CMI Excluded	CI Excluded
Transmission	OTHER TRANSMISSION	6/24/2012 20:16	345920	1472
Transmission	OTHER TRANSMISSION	6/24/2012 20:20	6864	39
Transmission	OTHER TRANSMISSION	6/24/2012 21:21	38160	720
Transmission	OTHER TRANSMISSION	6/24/2012 21:21	59356	836
Transmission	OTHER TRANSMISSION	6/24/2012 21:21	123919	1493
Transmission	OTHER TRANSMISSION	6/24/2012 23:53	303600	759
Transmission	OTHER TRANSMISSION	6/25/2012 1:31	624180	2060
Transmission	OTHER TRANSMISSION	6/25/2012 2:27	358925	1465
Transmission	OTHER WEATHER	6/25/2012 2:29	296704	1216
Transmission	OTHER WEATHER	6/25/2012 2:31	9477	39
Transmission	OTHER WEATHER	6/25/2012 2:32	169642	701
Transmission	OTHER WEATHER	8/10/2012 14:13	41976	477
Transmission	OTHER WEATHER	8/10/2012 14:13	327442	1621
Transmission	OTHER WEATHER	8/14/2012 16:07	1551	517
Transmission	OTHER WEATHER	8/14/2012 16:07	2163	721
Transmission	OTHER WEATHER	8/14/2012 16:07	3312	1104
Transmission	OTHER WEATHER	10/12/2012 8:42	36995	755
Transmission	OTHER WEATHER	10/12/2012 8:42	42032	1136
Transmission	OTHER WEATHER	10/12/2012 8:42	61740	1260
Transmission	OTHER WEATHER	10/12/2012 8:46	34740	965
Transmission	OTHER WEATHER	10/20/2012 10:41	1365	455
Transmission	OTHER WEATHER	10/20/2012 10:41	1815	605
Transmission	OTHER WEATHER	10/20/2012 10:41	1938	646
Transmission	PLANNED OUTAGE	10/20/2012 10:41	2073	691
Transmission	PLANNED OUTAGE	10/20/2012 10:41	2391	797
Transmission	PLANNED OUTAGE	10/20/2012 10:41	2982	994
Transmission	PLANNED OUTAGE	10/20/2012 10:41	3222	1074
Transmission	PLANNED OUTAGE	10/20/2012 10:41	3270	1090
Transmission	PLANNED OUTAGE	10/20/2012 10:41	3477	1159
Transmission	PLANNED OUTAGE	10/20/2012 10:41	4653	1551
Transmission	PLANNED OUTAGE	10/20/2012 10:41	5046	1682
Transmission	PLANNED OUTAGE	10/20/2012 10:41	5232	1744
Transmission	PLANNED OUTAGE	10/20/2012 10:41	6516	2172
Transmission	PLANNED OUTAGE	10/20/2012 10:41	7611	2537
Transmission	PLANNED OUTAGE	11/19/2012 4:56	6	1
Transmission	PLANNED OUTAGE	11/19/2012 4:56	498	83

2012 Adjustments: Transmission Events

Outage Event Description

Outage Event	Reason for Exclusion	Outage Date	CMI Excluded	CI Excluded
Transmission	PLANNED OUTAGE	11/19/2012 4:56	534	89
Transmission	WIRE DOWN	11/19/2012 4:56	1770	295

Appendix C) Pole Inspection Summary

The following page contains the Annual Wood Pole Inspection Report.

ORDER NO. PSC - 07 - 0918 - PAA - PU
DOCKET NOS. 070634-EI, 070635-TL

ATTACHMENT 1

TAMPA ELECTRIC COMPANY
Annual Wood Pole Inspection Report
2012

a	b	c	d	e	f	g	h	i	j	k	l	m
Total # of Wooden Poles in the Company Inventory	# of Pole Inspections Planned this Annual Inspection	# of Poles Inspected this Annual Inspection	# of Poles Failing Inspection this Annual Inspection	Pole Failure Rate (%) this Annual Inspection	# of Poles Designated for Replacement this Annual Inspection	Total # of Poles Replaced this Annual Inspection	# of Poles Requiring Minor Follow-up this Annual Inspection (Anchors / Guys)	# of Poles Overloaded this Annual Inspection	Methods(s) V = Visual E = Excavation P = Prod S = Sound B = Bore R = Resistograph	# of Pole Inspections Planned for Next Annual Inspection Cycle	Total # of Poles Inspected (Cumulative) in the 8-Year Cycle to Date	% of Poles Inspected (Cumulative) in the 8-Year Cycle To Date
Distribution, Lighting, and Transmission				Distribution and Lighting Reinforcement 0.30%	Distribution and Lighting Reinforcement 148	Distribution and Lighting Reinforcement 148						
				Distribution and Lighting Replacement 16.51%	Distribution and Lighting Replacement 8,126	Distribution and Lighting Replacement 4,957						
* TOTAL POLE POPULATION												
Distribution and Lighting 393,404	Distribution and Lighting 49,176	Distribution and Lighting 49,212	Distribution and Lighting 8,274	Distribution and Lighting 16.81%	Distribution and Lighting 8,274	Distribution and Lighting 4,957	Distribution and Lighting 350	Distribution and Lighting Poles Overloaded 2,558	Visual Sound Bore Excavation	Distribution and Lighting 49,176	Distribution and Lighting 292,088	Distribution and Lighting 74.25%
Transmission 25,530	Transmission 3,342	Transmission 4,762	Transmission 476	Transmission 10.00%	Transmission 476	Transmission 683	Transmission 4	Transmission 7		Transmission 0	Transmission 23,958	Transmission 100.00%
Total Poles 418,934	Total 52,518	Total 53,974	Total 8,750		Total 8,750	Total 5,640	Total 354	Total 2,565		Total 49,176	Total 316,046	Total 75.72%

If b - c > 0, provide explanation
If d - g > 0, provide explanation

Description of selection criteria for inspections
* Total Pole Population Includes Wood and Non-Wood.

Appendix D) Storm Hardening Metrics

1) Initiative 1: Four-year Vegetation Management

2012 - System Vegetation Management Performance Metrics - SYSTEM

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer interruptions							
(C) Miles Cleared		435.3			1282.1		1717.4
(D) Remaining Miles		1274.6			3308.9		4583.5
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		99			3856		3955
(H) All Vegetation Management Costs							$10,428,301
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							$11,359,299
(L) Vegetation Goal (current year)		426.1			1152.0		1578.1
(M) Vegetation Budget (next year)							$10,293,112
(N) Vegetation Goal (next year)		425.3			1149.9		1575.2
(O) Trim-Back Distance							10’

Notes:
(H) All Vegetation Management Costs - SERVICE AREA - include ONLY contractor costs
(H) All Vegetation Management Costs - SYSTEM - include ALL costs
(L) & (N) Vegetation Goal shown in miles
(O) 10' Represents an average, however to comply with ANSI A300, actual trim distances may vary

2012 - System Vegetation Management Performance Metrics - CSA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		106.0			195.6		301.7
(D) Remaining Miles		228.6			519.0		747.6
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		25			990		1015
(H) All Vegetation Management Costs							$1,576,411
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		70.8			191.5		262.4
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		70.8			191.5		262.3
(O) Trim-Back Distance							10'

2012 - System Vegetation Management Performance Metrics - DCA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		14.3			95.2		109.6
(D) Remaining Miles		39.9			222.0		259.8
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		2			95		97
(H) All Vegetation Management Costs							$242,491
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		25.0			67.5		92.5
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		24.9			67.4		92.4
(O) Trim-Back Distance							10’

2012 - System Vegetation Management Performance Metrics - ESA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		87.6			151.3		238.9
(D) Remaining Miles		204.1			400.3		604.4
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		13			489		502
(H) All Vegetation Management Costs							$1,262,729
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		57.0			154.1		211.1
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		56.9			153.9		210.8
(O) Trim-Back Distance							10’

2012 - System Vegetation Management Performance Metrics - PCA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		52.5			292.8		345.3
(D) Remaining Miles		187.2			706.0		893.2
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		13			515		528
(H) All Vegetation Management Costs							$1,445,778
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		83.8			226.5		310.2
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		83.6			226.0		309.6
(O) Trim-Back Distance							10’

2012 - System Vegetation Management Performance Metrics - SHA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		47.1			173.7		220.8
(D) Remaining Miles		144.5			382.9		527.4
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		7			266		273
(H) All Vegetation Management Costs							$679,730
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		50.7			137.0		187.7
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		50.5			136.5		187.0
(O) Trim-Back Distance							10’

2012 - System Vegetation Management Performance Metrics - WSA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		71.6			151.2		222.7
(D) Remaining Miles		281.7			617.2		898.9
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		29			1113		1142
(H) All Vegetation Management Costs							$1,697,864
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		75.9			205.2		281.1
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		75.7			204.7		280.4
(O) Trim-Back Distance							10’

2012 - System Vegetation Management Performance Metrics - WHA

	Feeders			Laterals			Total
	Unadjusted	Adjusted	Diff.	Unadjusted	Adjusted	Diff.	
(A) Number of Outages							
(B) Customer Interruptions							
(C) Miles Cleared		56.3			222.3		278.5
(D) Remaining Miles		188.6			463.6		652.3
(E) Outages per Mile [A ÷ (C + D)]							
(F) Vegetation CI per Mile [B ÷ (C + D)]							
(G) Number of Hotspot trims		10			388		398
(H) All Vegetation Management Costs							$585,085
(I) Customer Minutes of Interruption							
(J) Outage restoration costs							
(K) Vegetation Budget (current year)							
(L) Vegetation Goal (current year)		62.9			170.2		233.1
(M) Vegetation Budget (next year)							
(N) Vegetation Goal (next year)		62.8			169.9		232.7
(O) Trim-Back Distance							10’

2) Initiative 2: Joint-Use Pole Attachments Audit

Describe the extent of the audit and results pertaining to pole reliability and NESC safety matters. The intent is to assure the Commission that utilities know the status of their facilities and that reasonable efforts are taken to address pole reliability and NESC safety matters.

a) Percent of system audited.
0% feeders :_N/A___ laterals :_N/A___

b) Date audit conducted?

c) Date of previous audit? Total system-wide audit completed 2008.

d) List of audits conducted annually
- Through Tampa Electric's Pole Attachment Audit Application process, the company performed the following audits: attachment verification, NESC violation analysis, and pole loading assessment.

e) State whether pole rents are jurisdictional or non-jurisdictional. If pole rents are jurisdictional, then provide an estimate of lost revenue and describe the company's efforts to minimize the lost revenue.
- Tampa Electric does not have any non-jurisdictional distribution poles.

Joint-Use Attachment Data Table

(A) Number of company owned distribution poles.	307,573
(B) Number of company distribution poles leased.	13,733[1]
(C) Number of owned distribution pole attachments	205,418
(D) Number of leased distribution pole attachments.	13,733[2]
(E) Number of authorized attachments.	352,060
(F) Number of unauthorized attachments.	Unknown[3]
(G) Number of distribution poles strength tested.	2,857
(H) Number of distribution poles passing strength test.	516
(I) Number of distribution poles failing strength test (overloaded).	39
(J) Number of distribution poles failing strength test (other reasons).	8,274 [4]
(K) Number of distribution poles corrected (strength failure).	358[5]
(L) Number of distribution poles corrected (other reasons).	148 [6]
(M) Number of distribution poles replaced.	4,988
(N) Number of apparent NESC violations involving electric infrastructure.	54
(O) Number of apparent NESC violations involving 3rd party facilities.	140

Notes:

(1) These are the number of poles where Tampa Electric leases space on foreign owned poles.
(2) Each attachment is counted as one per pole on leased poles.
(3) Tampa Electric did not conduct a pole attachment audit; therefore, the company did not identify any unauthorized attachments in 2012.
(4) These 8,274 poles were identified for replacement during Tampa Electric's Pole Inspection Program and failed the strength test due to wood damage at groundline or other locations on the pole.
(5) These poles were re-guyed or re-configured to pass strength loading.
(6) The company reinforced these poles with trusses.

3) Initiative 3: Six-Year Inspection Cycle for Transmission Structures

Transmission Circuit, Substation and Other Equipment Inspections

		Activity		Current Budget		Next Year	
		Goal	Actual	Budget	Actual	Goal	Budget
(A)	Total transmission circuits.		187			187	
(B1)	Planned transmission circuit inspections – Groundline (Structures)	24 (2,862)		$110,523		0	
(B2)	Planned transmission circuit inspections – Above Ground (Structures).	31 (3,784)		$180,000		29% of System	$314,000
(C1)	Completed transmission circuit inspections – Groundline (Poles)		59 (4,762)		$88,672		
(C2)	Completed transmission circuit inspections – Above Ground (Structures)		5 (1,035)		$65,790		
(D1)	Percent of transmission circuit inspections completed - Groundline		166%				
(D2)	Percent of transmission circuit inspections completed – Above Ground.		27%				
(E)	Planned transmission substation inspections.	71				71	
(F)	Completed transmission substation inspections		71				
(G)	Percent transmission substation inspections completed.		100%				
(H)	Planned transmission equipment inspections (other equipment). – Ground Patrol/ IR Patrol	187/0				187/187	
(I)	Completed transmission equipment inspections (other equipment) – Ground Patrol/ IR Patrol		187/0		$151,514		
(J)	Percent of transmission equipment inspections completed (other equipment) – Ground Patrol/ IR Patrol		100%				

Transmission Pole Inspections

	Activity		Current Budget		Next Year	
	Goal	Actual	Budget	Actual	Goal	Budget
(A) Total number of transmission poles		25,530 [1]				
(B) Number of transmission poles strength tested		4,762	Note 2	Note 2		Note 2
(C) Number of transmission poles passing strength test		4,755				
(D) Number of transmission poles failing strength test (overloaded)		7				
(E) Number of transmission poles failing strength test (other reasons)		0				
(F) Number of transmission poles corrected (strength failure)		0				
(G) Number of transmission poles corrected (other reasons)		0				
(H) Total transmission poles replaced (Structures)		707			853	Note 3

Note 1: The transmission pole count on the entire system is 25,530, of this number 1,478 were excluded from the inspections due to co-ownership of lines, de-energized circuits, circuit construction and additions, and steel tower structures.

Note 2: The transmission pole strength test is budgeted as part of the groundline inspection. This information is included in the Transmission Circuit, Substation and Other Equipment Inspections section.

Note 3: The budget information for this table is included in the information supplied in the Hardening of Existing Transmission Structures section.

4) Initiative 4: Storm Hardening Activities for Transmission Structures

	Activity		Current Budget		Next Year	
	Goal	Actual	Budget	Actual	Goal	Budget
(A) Transmission structures scheduled for hardening.		887	$13.6M		973	$16.5M
(B) Transmission structures hardening completed.		920		$14,308,906		
(C) Percent transmission structures hardening completed.		96.4%				

Tampa Electric is hardening the existing transmission system in a prudent, cost-effective manner utilizing its inspection and maintenance program. This plan includes the systematic replacement of wood transmission structures with non-wood structures during the company's annual maintenance of the transmission system. Additionally, the company will utilize non-wood structures for all new transmission line construction projects as well as system rebuilds and line relocations.

In the early 1990s, Tampa Electric made the decision to begin building all new transmission circuits with non-wood structures. This was based on a life-cycle cost analysis for new construction. Tampa Electric also decided to modify its transmission maintenance practices to a program of non-wood replacements for all transmission pole replacements.

Tampa Electric does not reinforce wood transmission structures as is allowed by the NESC; if a transmission structure requires reinforcement or replacement due to its condition, Tampa Electric changes out the pole to a non-wood structure. In most cases, this new pole provides strength in excess of the original strength of the wood transmission pole.

The criteria used to select poles for upgrades and replacement is straightforward. First, all new transmission circuits are constructed with steel or concrete poles. Over time, this new construction will result in a higher percentage of structures being non-wood across the Tampa Electric system. Second, whenever a transmission line is relocated due to a road widening or customer-driven relocation, the new poles installed are non-wood. Third, all poles replaced due to deterioration are replaced and maintained with non-wood structures.

Tampa Electric strongly believes that the replacement of sound wood transmission structures is not a cost-effective use of resources. The company estimates that it would cost in excess of $250 million to replace all its wood transmission structures. Wood structures that are in good condition and can meet NESC extreme wind requirements will not be replaced. The company believes that its approach to hardening the transmission system is an appropriate cost-effective program that provides a good balance of system hardening and prudent spending.

5) Initiative 5: Geographic Information System

See Section I – Storm Preparedness Plans, item E) Initiative 5: See Geographic Information System on pages 26 through 28 for a detailed discussion.

6) Initiative 6: Post-Storm Data Collection

See Section I – Storm Preparedness Plans, item F) Initiative 6: Post-Storm Data Collection on pages 28 through 33 for a detailed discussion.

7) Initiative 7: Outage Data - Overhead and Underground Systems

See Section I – Storm Preparedness Plans, item G) Initiative 7: Outage Data – Overhead and Underground Systems on page 33 for a detailed discussion.

8) Initiative 8: Increase Coordination with Local Governments

See attached page 167 for a matrix of Tampa Electric's activities involving its coordination with local governments.

Gov't Entities		Communication Efforts Presentations, Material, Etc.	Storm Workshop, Planning and Training With Local Gov't Officials and Fire and Police Personnel	Emergency Operation Centers Key Personnel Contact	Search and Rescue Teams Assistance to Local Gov't	Vegetation Management Tree Ordinances, Planting Guides, and Trim Procedures	Undergrounding Share Information, Estimates, and Materials
FEDERAL			NFPA 1600 Committee meeting - emergency management, business continuity, and disaster recovery standard		SALT Team (safety liaison team) activation during TS Debby flooding in Fowler area		
			DHS training on secret clearance	One activation - RNC Multi-Agency Coordination Center			
STATE		Communications to state and local officials aerial inspection of transmission facilities	FRCC - Crisis Response Task Force				
			Met with DOS regarding election day preparations for voting location				
Hillsborough County		Geomagnetic Exercise - Three with one being face-to-face	Consequence Management Committee meetings	Three activations: TS Debby, TS Isaac and the Republican National Convention		Meet with Hillsborough County Engineering	Working with Dana Shores Civic Assn. to provide costs to underground entire neighborhood
		LMS governance meeting - Mitigation	DS7 training with urban area security group			Hillsborough County Tree and Landscape Advisory Committee	
		LMS governance meeting - Mitigation	PDRP planning, including conference			TECO participation in the Hillsborough County Neighborhood Conference	
		Emergency Mgmt presentation	Critical Facility Index Working Group			Earth Day at USF	
		LMS governance meeting - Mitigation	HC EOC training			USF - Study of urban trees	
		Working with Dana Shores Civic Assn. to establish a special taxing district to finance neighborhood Undergrounding project	HURREVAC training				
			RNC EOC training				
			Consequence Management workshop at HCEOC				
	City of Tampa		TAMPA Host Exercise	Three activations: TS Debby, TS Isaac and the Republican National Convention		City of Tampa Planning Department/ TECO TGR Demonstration on Sports Authority property, Raymond James Stadium	
						City of Tampa Planning Department/ Wilderness Project review	
	Plant City	Met with Mayor, City Mgr., Police Chief on EOC power switching options		No activations in 2012		Met with City officials to discuss changes in City landscaping ordinance	
	Temple Terrace	Interaction regarding preparation and updates related to TS Debby and TS Isaac	Participated in hurricane season briefing and planning	No activations in 2012		Tree ordinance meeting	
Polk County			Monthly mock EM reporting exercise	No activations in 2012			
Pasco County		Call to advise of Tampa Electric activation	Participated in PASCO County, EOC activation drill	Activations: June (Debby) and August (Isaac) – No Tampa Electric personal required at EOC; Communications via phone			
		Meeting w/Pasco EOC Coordinator					
	Dade City	Call to advise of Tampa Electric activation	Partial activation for TS Debby due to flooding	No activations in 2012		Tree ordinance meetings	Requested bid on underground telecommunications line
	San Antonio	Call to advise of Tampa Electric activation		No activations in 2012		Requested information on responsibility of debris cleanup in 2012	City of San Antonio- Hazard tree removal program
	St. Leo	Call to advise of Tampa Electric activation		No activations in 2012		Requested information on responsibility of debris cleanup in 2012	
Pinellas County				No activations in 2012			
	Oldsmar			No activations in 2012			

9) Initiative 9: Collaborative Research

See Section I – Storm Preparedness Plans, item I) Initiative 9: Collaborative Research on pages 38 through 40 for a detailed discussion and related data.

10) Initiative 10: Disaster Preparedness and Recovery Plan

See attached pages 169 through 233.

Emergency Contingency Response and Business Continuity Plan

(ECRP- BC)

EMERGENCY CONTINGENCY RESPONSE AND BUSINESS CONTINUITY PLAN

Contents

TABLE OF CONTENTS

To view this plan online, go to:

Internet Explorer, "My TECOnet" homepage.
At the top right of the page, click on the "Emergency Management" red button.
Once there click on the "Unified Command" blue button located on the left-hand column of the page. The plan can be found under the subheading titled "Documents and Additional Attachments to Plan" on the Unified Command page. The complete plan is secured using Sharepoint.

Page 0

SSI CEII DOCUMENT - TECO ECRP BC

FIRST STEPS – RESPONDING TO AN EMERGENCY

1. INTRODUCTION

When an emergency occurs, Tampa Electric (Electric and Gas), and TECO Energy, Inc. (TEC/TECO) emergency management personnel are activated in accordance with the Incident Command System (ICS) call out roster or hazard specific call-out rosters.

Remove the *First Steps* Section and personalize with the emergency documents used during an emergency.

The *First Steps* is an emergency response notebook organized for ease of use during an activation. All the documents are available for printing from the intranet Emergency Management (EM) Website, Activation/Notification webpage, and also from applicable Company / Department Command (i.e., facility drawings), Logistics, Planning or Finance webpages.

The following list includes the types of documents that may be organized as part of the *First Steps*. *First Steps* responder notebooks are personalized and therefore each notebook may not include all listed documents. The list of documents may be expanded by user, as needed. The words storm and hurricane are used interchangeably for Natural Events in various plans.

Activation and Notification – ICS All Hazards

- TECO Schedule of Meetings and Reports
- Storm Activation and Notification Flowchart
- TECO Energy Sabotage Reporting Guidelines
- Threat Alert Level – Elevation and Communication
- NERC Emergency Notification Tree (and form)
- All Hazards Notification Flowchart – Energy Supply
- DOE EIS OE-417 Report Form

Meetings and Contact Information

- ICS Organizational Charts
- ICS Rosters
- Satellite Phones
- Company/Department Command -Telephone Numbers
- Checklists and Agendas

Response Checklists

- Department or Company Business Continuity Checklists
- Physical Security Emergencies (Annex 1)

Revised: 1/9/2013

Ver:6

Document security group: SSI for original plan

Health and Safety Emergencies (Annex 2)
Environmental Emergencies (Annex 3)
Energy Emergencies (Annex 4)
Natural Emergencies (Hurricanes) Emergencies (Annex 5)
Cyber Security Emergencies (Annex 6)
Telecom Emergencies (Annex 7)
Facility Emergencies (Annex 8)
Telephone Roll Call

Reports

Pre-Storm Company / Department Summary Dashboard
Post-Storm Company/ Department Summary Dashboard
Post-Storm Emergency Function Dashboard
Generic Company/Department Summary Dashboard

Facility MAP/Drawings

TECO Facilities
Other Facilities

Reference Data

Circuit Priorities
Command / Department Plans
Corporate Directory
Critical Facilities
Critical Functions
Driving Directions
Emergency Response Team Scenarios
Evacuation Maps
Facility Elevations
Function Relocation List
GETS Card Information
Hospital Listing
How to use a Satellite Phone
Incident Bases
Message One Notification System Recipient Instructions
Priority Definitions
Re-entry letter
Relocation of Functions – excerpt
Satellite Phones (including how to use)
Schedule of Meetings – excerpt
SLOSH Maps
TECO Planning and Logistics Response Timeline
TECO Sabotage Reporting Guidelines
Telephone Numbers (other)
Weather Information
Zip code maps

Revised: 1/9/2013

Ver:6

Document security group: SSI for original plan

SSI CEII DOCUMENT - TECO ECRP BC

2. ACTIVATION

Reporting and activation follow specific reporting and activation charts (e.g., NERC Notification Tree, BB Station Physical Security Plan, etc.).

- At the onset of an emergency, the first team member on the scene calls 911(if needed) and then calls the Central Monitoring Center (CMS) [phone number not included for security purpose].

  A call to 911 deploys Fire Department Response teams including HAZMAT. In the case of a chemical or biological attack, the Fire Department will manage/control the situation. If they are not able to respond they will obtain support from surrounding counties. If this response does not provide sufficient man-power, the Fire Department will contact the National Guard. **The closest National Guard HAZMAT unit can arrive in two hours**.

  TEC/TECO is not equipped to respond to a chemical or a biological attack.

  In the case of a Homeland Security – National Terrorism Advisory System threat alert level change, the TECO Corporate Security Department will alert the Emergency Response Officer and ICS will be activated in response to the threat.

- CMS will contact Law Enforcement agencies and TECO Security.
- Upon receipt of the initial emergency communication, the TECO Security Director follows the TECO ICS activation procedure to report the emergency and activate ICS, if necessary.
- The Department/Facility Safety Coordinator is responsible for protection of life and coordinates with Facility Management, HR, Emergency Medical Services (EMS), Department and TECO Security personnel; Department and TEC Environmental Coordinators; Department Emergency Manager; Peer Support Liaison; and hospitals during an emergency, following the department safety plan.
- TEC HR Critical Incident Stress Management Leader may activate the TECO Peer Support team on location or off-site.
- The Department Environmental Coordinator is responsible for the protection of the environment and communication with the TEC Environmental Health and Safety Department; HAZMAT teams; and Department Security, Safety, and Emergency Management personnel.

- The Department Emergency Manager/Coordinator is responsible for coordinating ICS activation at Department level. The Department Emergency Manager/Coordinator contacts TECO Emergency Management and Business Continuity (EM-BC) closes the communication loop with the TECO Security Director.

IF THE EMERGENCY IS OF A CONFIDENTIAL NATURE

The Director of TECO Security and EM contacts the applicable Company Officers in accordance with the TECO Security Plan.

IF THE EMERGENCY IS NOT OF A CONFIDENTIAL NATURE

1. Once notified by TECO Security and EM or a Company/Department Commander, the TECO Emergency Response Officer:
    a. Informs/discusses emergency with impacted Company Officer and Unified Commander to determine level of ICS activation.
    b. Asks EM-BC Group to schedules the first meeting. Subsequent meetings are scheduled by Telecom. The ICS meeting will only include the areas impacted by the emergency.
2. The TEC President, acting as the TECO Unified Commander, activates the Department Commands and other ICS sections and Legal, as appropriate.
3. Each Department Commander activates ICS structures, as necessary, and follows their Emergency Contingency Response and Business Continuity (ECRP BC) plan (ECRP and BC plans may be separate), as necessary. ICS functions not activated before the ICS conference call may be activated after the ICS conference call.
4. The TECO Unified Commander activates TECO Logistics and Planning support functions, if they have not already been activated by the TECO EM-BC Group as a result of specific department emergency needs.

IF THE EMERGENCY IS LOCALIZED

1. In a localized event, the Department Emergency Manager /Department determines if the event can be managed using established emergency operating procedures (i.e., summer storms and stages of activation protocol). If ICS need to be activated the Department Emergency Manager/Coordinator places a call to TECO EM-BC for guidance and support.
2. TECO EM-BC assumes the function of TECO Logistics and Planning until more resources are needed to support the event, in which case TECO EM-BC activates the appropriate functions, including the Logistics Support Unit (LSU).
    a. Once the department announces a partial activation, a logistics liaison will be activated to support the affected Department Command.
    b. If the Planning, Logistics and Finance Sections are activated, the Section Chiefs will call-out their personnel using the Emergency Management conference call rosters; updated on a weekly basis through SAP to the emergency notification system.
3. TECO EM-BC contacts, the TECO Public Information Officer or back-up and the Community Relations Officer. TECO EM-BC communicates with all emergency functions at corporate level to ensure that everyone has been notified of the event. Specific hazard checklists for the applicable facilities are used for emergency response in conjunction with the emergency notification trees mentioned above (i.e., Annex 1 Checklist – Physical Security Emergencies, Annex 2 Checklist – Health and Safety Emergencies, Annex 3 Checklist – Environmental Emergencies, etc.)

3. EMERGENCY NOTIFICATION AND ICS ACTIVATION

- In the event of an emergency at TEC/TECO, team members will act immediately to assure the health and safety of team members, the stabilization of any victims, and the administration of first aid by qualified personnel. As soon as it is reasonably possible, the TECO Security Central Monitoring Center (CMS) at [phone number not included for security purpose], is contacted by the first responder on the scene and the applicable emergency response notification charts / trees are used for the balance of notifications. In the event of a hurricane or other emergency which causes widespread outages to the TEC system, the ICS will be activated and the conference call bridge will be used for meetings [phone number and access code not included for security purpose] (bridge is maintained open). Hazard specific

emergency checklists are used to streamline response. Checklists are based on existing plans and procedures.

SCHEDULE OF MEETINGS AND REPORTS

During a "planned" emergency (i.e., hurricane) and prior to a storm landfall, Unified Command calls occur daily at 9:00am and 6:30pm. After storm landfall, Unified Command calls occur daily at 9:00am and 8:30pm to allow each command and response team to assess daily situation, develop command objectives and strategies, and compile impact reports. Media updates are scheduled throughout the day in accordance with the schedule of meetings (See Attachment 5 – TECO Schedule of Meetings and Reports).

TEAM MEMBER AND FUNCTION RELOCATION

When ICS is activated, personnel report to work according to their ICS assignments. Upon activation, facility floor plans are posted at occupied primary and alternate facilities.

[REMOVE THIS SECTION FROM THE REST OF THE PLAN AND INSERT INTO ITS OWN NOTEBOOK]

[INSERT HERE THE LIST OF DOCUMENTS USED IN YOUR PERSONALIZED FIRST STEPS AND ADD YOUR EMERGENCY DOCUMENTS BEHIND THIS PAGE]

TECO Emergency Contingency Response and Business Continuity Plan

1. INTRODUCTION

All Department Commands in TEC/TECO have Emergency Contingency/Response plans (emergency plans), and use the Incident Command System (ICS) to manage emergencies. The emergency plans are used to respond to various types of hazards or emergencies (i.e., physical security, health and safety, environmental, etc.) See Attachment 1 – EM-BC Map of Plans/Manuals and Procedures and Appendix 1 – ICS.

TECO ICS Logistics, Planning and Finance sections support TEC and TECO Energy, Inc. This Emergency Response and Business Continuity plan (ECRP-BC) (Plan) supports global emergency response plans (i.e., hurricane, pandemic, etc.), specific facility ECRPs and Business Continuity plans.

Figure 1 - Modified Burtles Hierarchy of Plans - Mueller

2. PURPOSE

The purpose of this Plan is to:

- Ensure the business continuity of TEC/TECO critical functions during an emergency (see Attachment 2 – Critical Functions);
- Have a current, reliable, emergency plan with an ICS structure that is on stand-by and ready for activation;
- Place the plan responsibility and authority for plan implementation under the individuals/groups most competent to deal with the situation;
- Document the ICS structure as the incident management system;
- Document how Unified Command is activated in the event of a disaster; and

- Document how communication protocols are implemented during an emergency.

This Plan is intended to serve as a guide for ICS leadership and personnel responding to a disaster or the threat of a disaster that will impact systems (e.g., computing, generation, transmission and distribution) or a facility. Disasters can range in size from a local emergency (e.g., power failure), to a major regional event (e.g., hurricane). Therefore, this plan is designed to be flexible enough to address any size situation or potential event that threatens the people, property, and systems within the company. This plan details the ICS structure that will be used to prepare for or to respond to such an event.

The Plan can be activated to address an event that impacts a single TEC/TECO Department or facility, such as a fire, chemical spill, local flooding, or a cyber-attack. In such a situation, the ICS structure would have the President of TEC as the TECO Unified Company Commander or the Vice President / Director (as applicable) of the impacted area as the Department Commander.

3. TYPES OF EMERGENCIES

For the purpose of this plan, the emergencies referred to might be localized or company-wide in scope, and are grouped into two categories:

Natural emergencies
Other emergencies

These two categories are further subdivided to identify specific threat/hazard categories as follows:

Type 1 – Physical Security Emergencies

Type 2 – Health and Safety Emergencies

Type 3 – Environmental Emergencies

Type 4 – Energy Emergencies

Type 5 - Natural Emergencies

Type 6 – Cyber Security Emergencies

Type 7 - Telecom Emergencies

Type 8 – Facility Emergencies

Natural Emergencies

Natural emergencies include weather related emergencies, but are not limited to:

- Storms which include hurricanes, tornados, thunderstorms, or any violent combination of wind and precipitation. See Annex 5 – Natural Emergencies – Company or Department Command specific plans.
- Floods may be in conjunction with or as a result of, other storm activity and may threaten the integrity of company facilities and/or services. See Annex 5 – Natural Emergencies - Company or Department Command specific plans.
- Weather Extremes that are not necessarily storm related, but are hot or cold, wet or dry, or may impact the ability of the company to conduct business in a normal fashion. See Annex 5 – Natural Emergencies – Company or Department Command specific and/or Annex 4 – Energy Emergencies – Load Curtailment Plans.
- Sink Holes or other types of natural environmental or geological emergencies.
    - Pandemics. See Annex 2 – Health and Safety Plan – TECO Pandemic Plan

Other Emergencies

Other types of emergencies may be caused by the combination of unusual circumstances or may be caused by individuals, such as crimes against the corporation:

- Terrorism, Kidnapping, Hostage Situation, or Extortion. See Annex 1 – TECO Security Department Plan.
- TECO Unified Command will coordinate response to potential or real terrorist attacks. Confidentiality of those response actions is essential to the success of the plan. The Emergency Response Officer (or his designee) will serve as the single point of contact to complete necessary response actions.
- Bombing, Explosions, and Major Fires which also may be an act of sabotage. See Annex 1 – Physical Security Department Plan, Annex 2 – Health and Safety Plan – Fire Evacuation plans, and Annex 8 – Facility Emergencies – Department Command specific plans. Bomb threats will be handled in accordance with company policy as defined in the TECO Energy security policies that can be found on myTECOnet.
- Civil Disorders such as riots or demonstrations against the company or its facilities (i.e., strikes, criminal acts, etc.). See Annex 1 – Physical Security Plans.

- Plane Crashes, which has either company personnel implications and/or facility damage. See Annex 1, 2 and 3 for specific response measures.
- Medical Emergencies. See Annex 2 – Health and Safety Plan.
- Chemical Spills which can have serious environmental impacts. See Annex 3 – Integrated Contingency Plans or in the case where a facility does not have an ICP, this annex will contain other environmental related documents for use during response activities.
- Fuel Shortages for any number of reasons. See Annex 4 – Energy Emergencies – Load Curtailment Plans.
- Cyber Attacks, Virus Infections, DOS Attacks. See Annex 6 – Cyber Security Emergencies – Department Command specific plans.
- Telecom System Malfunctions or loss of Telecom System. See Annex 7 – Cyber Security and Telecom Emergencies – Department Command specific plans.
- Facility Emergencies. See Annex 8 – Facility Services Emergency Plan
- Bioterrorism Response See Annex 1 – Physical Security

The above mentioned emergency situations have extreme ranges of effects on the ability of the company to conduct its business. Some emergencies may impact structures (i.e., natural disasters), other may impact personnel (i.e., pandemics), or impact the Company finances (i.e., cyber-attack on the national financial infrastructure).

While every possible emergency scenario cannot be addressed in the plan, this plan serves as a solid guideline to deal proficiently with any emergency situation.

4. APPLICABILITY AND SCOPE

This plan is applicable to the following TEC Departments: Electric and Gas Delivery, Energy Supply and Customer Service, and applicable supporting TECO Energy functions (i.e., Finance, HR, etc.).

Using an all-hazards approach, this plan is based on an impact analysis that determined the potential for detrimental impacts to TEC facilities. The viability of this plan is predicated on:

The Company:

- Has financial and administrative procedures to support all departments before, during and after an emergency and review processes periodically to ascertain vulnerabilities.

- Develops and maintains mitigation documents to establish interim and long term actions to eliminate hazards or to reduce the impact of those hazards that have been identified but cannot be eliminated.
- Performs training/education to cover ICS, *Get Ready!,* and specific plans (Annexes 1, 2…9).
- Documents training.
- Has non-security critical portions of the plan available to all team members via myTECOnet.
- Department leadership assigns personnel familiar with business operations that can implement plans.
- Evaluates program plans, procedures, and capabilities through periodic reviews, testing, post–incident reports, performance evaluations and exercises. Conducts exercises designed to test individual essential elements, interrelated elements, or the entire plan.
- Ensures that corrective action is taken on any deficiency identified in the evaluation process and to revise the appropriate program plan.
- Ensures that there are procedures in place to disseminate and respond to requests for pre-disaster, disaster, and post disaster information, including procedures to provide information to the media and deal with their inquiries.
- Continues to provide public safety information regarding electric hazards during any emergency, as applicable.

5. CRITICAL FUNCTIONS

Critical Corporate Functions
[Critical functions not included for security purpose].

Critical Company Functions – See Attachment 2

Critical functions are depicted in the ICS Unified Command organizational chart (See Attachment 3). At first glance the above mentioned functions are critical to support tactical response and are required to effectively respond to an emergency.

- Other corporate critical functions are embedded in ICS Sections [not included for security purpose].

AUTHORITIES AND REFERENCES

Responsibility and concurrent authority is provided to the Company and Department Command ICS general staff to manage an emergency situation in accordance with the approved plans. In the absence of clearly defined action or direction, each team member

shall follow established company guidelines, policies, and procedures as closely as possible.

However, the Prudential Rule (as defined directly below) shall remain in effect throughout the duration of the declared emergency. TEC is regulated under the Public Service Commission and is impacted by a variety of regulatory bodies: Department of Homeland Security (DHS), OSHA, and the Environmental Protection Agency, among others. DHS regulations do not require TEC to have a business continuity plan.

All gender references using "he," "him," and "his" are for editorial purposes only and shall be deemed to also include "she," "her," "hers" and/or "they," "them," and "theirs."

- Safe Work Practices

  All emergency response actions taken by team members shall strictly adhere to the Safe Work Practices and procedures in order to ensure the Health and Safety of TECO team members and the public. THE SAFETY OF LIFE SHALL CONTINUE TO OUTWEIGH ALL OTHER CONSIDERATION.

- Corporate Policies

  All existing company policies will be followed to the extent that timeliness in reacting to an emergency situation is not affected. The Company / Department Command general staff has the authority to make exception to company policies, if needed.

- Prudential Rule

  Situations may arise that could necessitate a responsible team member to assume authority, and if necessary, lay aside company policies and/or procedures in order to respond appropriately to the circumstance. However, in doing so the team member shall not violate the Corporate Compliance Plan or the Safe Work Practices.

- Corporate Compliance

  All emergency response actions taken by team members, including those in the following sections, Safe Work Practices and Prudential Rule, shall comply with the standards and ethical guidelines as specified within the Corporate Compliance Plan.

6. CONCEPT OF OPERATIONS

This section details activation and relocation protocols, alerts, notifications, implementation of ICS, daily reporting schema, and details about leadership and authority issues.

WIDESPREAD EVENT ACTIVATION

[Information not included for security purpose].

ISOLATED OR LOCALIZED EVENT ACTIVATION

[information not included for security purpose].

Specific hazard checklists for the applicable facilities are used for emergency response in conjunction with the emergency notification trees mentioned above (i.e., Annex 1 Checklist – Physical Security Emergencies, Annex 2 Checklist – Health and Safety Emergencies, Annex 3 Checklist – Environmental Emergencies, etc.)

7. LEADERSHIP, ORDERS OF SUCCCESION AND DELEGATIONS OF AUTHORITY

In the case of loss of key personnel, the TECO Succession Plan will be used to determine order of succession outside ICS. Authority will be delegated in accordance with pre-established ICS organizational charts and the TECO Succession Plan, as applicable.

8. DECISION PROCESS

Tampa Electric (Electric and Gas) and TECO Energy use the Incident Command System as the management and decision process vehicle during an emergency.

For concurrent emergencies (i.e., a generating plant emergency, which would cause implementation of the Firm Load Curtailment Plan and a transformer failure at one of the plants) the emergency coordinator, along with the vice president and/or appropriate company officer, will implement the appropriate plan(s).

9. DEVOLUTION

Each Company and Department Commander has authority over their area and report to the Unified Commander. In the case of an isolated event, if there are no means of communication, the Company and Department Commanders have authority to continue electric or gas restoration.

10. ALERT, NOTIFICATION, DAILY REPORTING SCHEDULE

Message One, the emergency notification system for TEC/TECO Energy may be used to alert and notify activation to Unified Command and all response personnel Leadership will implement the applicable hazard response plan and will use a daily reporting schedule upon activation.

All tactical meetings between TECO Operations, Logistics, Planning and Finance Sections within each Company and Department Command occur throughout the day, as well as Joint Chief of Staff meetings.

Meeting and report schedules follow Attachment 5 – Schedule of Meetings and Reports.

11. ALTERNATE FACILITIES

Functions are performed from alternate facilities according to Attachments 6.

12. EMERGENCY RESPONSE

Once the initial emergency assessment phase is complete, the appropriate plan (annex) is activated. It is imperative that the team take this action in the most decisive and timely manner possible.

When an emergency occurs, the emergency contingency response plans are used and the Department/Facility Management, Physical Security personnel, Safety Coordinator, Environmental Coordinator, and Emergency Management personnel are activated in accordance with the applicable call-out roster.

Once the Department ICS is activated, all emergency communications follow the established Department ICS organizational charts. Initial situation reporting and activation is done through the above mentioned channels.

An ICS reporting schedule is followed during emergencies, as delineated above. From emergency services (i.e., meal coordination, lodging services, etc.) to Department Response Teams all information is gathered and presented, at a minimum, twice a day to TECO Unified Command.

- The Unified Commander activates the Company Commands and other ICS sections, following the appropriate emergency checklist located in the ***First Steps*** portion of this plan in support of TEC.

- Each Company or Department Commander activates ICS structures as necessary and follows their Department ECRP. ICS functions not activated before the ICS conference call may be activated after the ICS conference call.
- The Department/Facility Safety Coordinator is responsible for protection of life and coordinates with Facility Management; Human Resources; Department and TECO Security personnel; Department and TECO Environmental Coordinators; Department Emergency Coordinator/Manager; Peer Support Liaison; EMS and Hospitals during an emergency.
- The TECO Critical Incident Stress Management - Peer Support team may be activated on location or off-site by the TECO HR Critical Incident Stress Management Leader.
- The Department Environmental Coordinator is responsible for the protection of the environment and communication with the TECO Environmental Health and Safety Department; HAZMAT teams; and Department Physical Security, Safety, and Emergency Management personnel.
- The Department Emergency Manager/Coordinator is responsible for coordinating ICS activation at Department level. The Department Emergency Manager/Coordinator contacts the TEC EM Group reports the situation to the TECO Emergency Response Officer. The TECO Emergency Response Officer may request an ICS conference or discuss situation with appropriate Officers.
- The TECO Unified Commander activates, if necessary, TECO logistics support functions. If the emergency is localized, the Department Logistics would be activated by the Department Emergency Manager/Coordinator with support from the Logistics Support Unit (LSU) offsite. LSU functions include: Facility Services, Telecom, IT, etc. TECO EM activates TECO Logistics, Planning and Finance to support localized events.
- The TECO EM Group communicates with all emergency functions at corporate level to ensure that everyone has been notified of the event and is activated. The TECO Unified Commander is ultimately responsible for activating, the TECO Public Information Officer or back-up and the Community Relations Officer.
- Specific Hazard checklists are used for emergency response according to the pre-assigned categories. Checklists are included in the ***First Steps*** above.

If the Planning, Logistics and Finance Sections are activated, the Section Chiefs would call-out their personnel using the Emergency Management conference call rosters which are

updated on a daily basis through SAP (the HR system), and uploaded to Message One weekly.

13. ALTERNATE FACILITY OPERATIONS

MISSION CRITICAL SYSTEMS

Mission critical systems are listed in the Information Technology disaster recovery plans. The IT emergency plans detail system names, current location, backup locations and system restoration protocols. See Attachments 4 and 5, as well as Annex 6 – IT ECRP, for additional document and plans.

VITAL FILES, RECORDS, AND DATABASES

The Legal Department is responsible for the corporation vital files. Their emergency plan details location of record, type of record, form of record, movement of records to alternate locations and the procedure and Chain of Custody when records or evidence have to be moved to an alternate location. See Legal Department Response plan. Other critical records are maintained by each Department Command and information is included in the Department/Region ECRP. Production databases are backed up following automated IT processes.

14. LOGISTICS AND PLANNING

ALTERNATE LOCATION

[Information not included for security purpose].

INTEROPERABILITY

Modes of established communications include:

[Information not included for security purpose].

Each Department Command establishes a mode of communication that is compatible with the rest of the corporation. The TECO EM Group reviews each department plan to identify the modes of communication used are compatible with other parts of the corporation/company.

Communications between corporate representatives at the various government operations center use a mix of communications equipment; wireless laptops, cell phones and some may

also use satellite phones.

CORPORATE COMMUNICATIONS

- The TECO Unified Commander activates the Company Commands, Department Commands, other ICS sections and Legal, as appropriate.
- Each Department Commander activates their ICS structures as necessary and follows this plan.
- An e-mail to "ALL" is sent out by the TECO EM Group to TECO team members informing activation status.
- Changes in National Terrorism Advisory Levels are also communicated to the company in the same manner.

INCIDENT MAILBOX

The off – hours TECO emergency phone is used by the TECO EM Group, TECO Planning Section or the TECO Unified Command to leave recorded messages for specific groups. An e-mail to "ALL" is sent out when this phone is activated.

An intelligent voice recognition system is used in the case a general broadcast or activation needs to be made to our team members.

15. DEACTIVATION

ICS functions are deactivated as the emergency is resolved. After the company emergency response effort is officially deactivated, all sections and Company and Department Commands return to normal. The last function to remain in operations is the TECO Logistics and Planning Sections since they return resources to vendors or corporate warehouses and compile logistics and planning records.

- Leadership will notify their Section or Department Command that the emergency has ended;
- Direct all groups, teams and units to compile a post emergency assessment report for leadership;
- Evaluate the report for the purpose of making any necessary modifications to the emergency plan(s);

- Direct emergency coordinators to compile reports and lessons learned; and
- Emergency Coordinators will forward report to the TECO EM Group for compilation of lessons learned into a corporate After Action Report.

16. PLAN MAINTENANCE

It is the responsibility of the TECO EM Group, TECO Security to ensure that this Plan is maintained. In addition, each Department Command Emergency Coordinator is responsible for ensuring the maintenance and testing of their ECRPs.

17. RESPONSIBILITITES – TECO EMERGENCY RESPONSE OFFICER

Assure that the plan is updated, reviewed, and approved by May 15th of each year to reflect any changes in operating requirements. Support the coordination of emergency plans throughout TECO.

18. RESPONSIBILITIES- TECO EMERGENCY MANAGEMENT AND BUSINESS CONTINUITY (EM-BC) DIRECTOR

Review and update the Plan by May 1st of each year to reflect any changes in operating requirements. Assure the coordination of emergency plans throughout TECO.

19. RETENTION

The Plan is maintained and secured in the TECO EM Sharepoint site. Plan is available through the EM website and backed-up at other critical locations. Copies of the Plan and all supporting documentation are distributed to affected team members through the EM Website whenever significant changes are made.

20. PLAN TESTING

The objective of testing plans is to ensure that all identified personnel can respond to the emergency as stated in the various departmental plan(s).

Emergency Contingency Response and Business Continuity plans are tested through exercises, plan reviews and personnel training in accordance with the TECO Energy Comprehensive Exercise plan. See Appendix 3.

21. PLAN TEST EVALUATION

The TECO EM-BC Director or the Department Command Emergency Coordinator oversee and critique the simulation and also prepare a report to include:

- Outline of the sequence of test events
- Comments on deviations from the published plans
- Overall evaluation as to the effectiveness of the plan(s), and
- Appropriate recommendations for plan revision.

22. MULTI-YEAR STRATEGY AND PROGRAM MANAGEMENT PLAN

The TECO Energy Emergency Management Program Five Year plan addresses the multi year emergency management strategies that includes TEC strategies. ECRPs and hazard category plans are available on the TECO Emergency Management (EM) intranet Website. ICS Leadership has a copy of this plan. ICS generic forms and Department Response Teams (DRT) specific forms are available online on the TECO Energy Intranet, Emergency Management website.

This plan follows the NFPA 1600 guidelines - Standard on Disaster/Emergency Management and Business Continuity and the Homeland Security Guidance regarding Continuity of Operations plans.

23. DEFINITIONS

BC – Business Continuity
ECRP – Emergency Contingency Response plan
ICS – Incident Command System
DRT - Department Response Team
Devolution – “Home Rule” is the statutory granting of powers from the central government of a state to government at national, regional or local level. For this plan it is used within the scope of granting power from the unified commander to other parts of the TECO command.

[Some of the following attachments, appendices and annexes are not included for security reasons].

- ATTACHMENT 1 - EM BC Map of Plans/Manuals and Procedures [Not included for security reason].
- ATTACHMENT 2 – TECO Critical Functions [Not included for security reason].
- ATTACHMENT 3 – UNIFIED COMMAND ORG CHART AND ROSTER [Attached – without names]
- ATTACHMENT 4 - TECO CRITICAL FACILITIES [Not included for security reason].
- ATTACHMENT 5 - TECO Schedule of Meetings and Reports [Not included for security reason].
- ATTACHMENT 6 – TECO Relocation of Functions [Not included for security reason].
- ATTACHMENT 7 – Satellite Phone List [Not included for security reason].
- APPENDIX 1 – ICS [Attached]
- APPENDIX 2 – GET READY! [Attached].
- APPENDIX 3 – COMPREHENSIVE EXERCISE PLAN [Attached].
- APPENDIX 4 – POST DISASTER REDEVELOPMENT PLAN [Not included for security reason].
- ANNEX 1 – Department Command Physical Security Plans (for applicable locations) [Not included for security reason].
- ANNEX 2 – Department / Facility Command HEALTH AND Safety Plans, including Pandemic (for applicable locations) [Not included for security reason].
- ANNEX 3 – Department Command Environmental Plans (for applicable locations) [Not included for security reason].
- ANNEX 4 – Energy / Gas Emergency Plans (TECO Fuels Dept and PGS Ops) [Not included for security reason].
- ANNEX 5 – Department Command Storm Plans [Not included for security reason].
- ANNEX 6 – CYBER SECURITY Emergency Plans (for applicable locations/systems) [Not

included for security reason].

- ANNEX 7 – Telecom Department Command Plans [Not included for security reason].
- ANNEX 8 – Facilities Emergency Plans (for applicable locations/Departments) [Not included for security reason].
- ANNEX 9 – PERSONNEL Emergency Plans (for applicable locations/Departments) [Not included for security reason].

Document History
Version 2, February 2008, Reformatted First Steps
Version 3, July 2009, S. Mueller, Changes in Schedule of Meeting
Version 4, January 4, 2010, S. Mueller, changes in company and local government leadership and functions
Version 5 – April 29, 2011, S. Mueller changes in functions, change of title from COOP to BC. Clarification of Agility Trailer use, clarification of partial activation.
June 22 – updating Schedule of Meetings and Reports section
Version 6 - January 9, 2013 Added relocation of functions as separate attachments with new information regarding TECO Plaza functions, as well as the Schedule of Meetings and Reports, ICS, Get Ready, etc. Changed the TECO Emergency Response Officer.

APPENDIX 1 - TECO ECRP BC
Incident Command System

APPENDIX 1 - TECO INCIDENT COMMAND SYSTEM

I. INTRODUCTION

The Incident Command System (ICS) is a modular organization with a manageable span of control. The ICS modular organization allows the commander of a structure to manage any type and size of emergency. ICS uses consistent terminology and an integrated approach to communications and resources.

The TECO Energy (TECO) ICS is comprised of a Unified Commander, Staff and General Staff. The Staff includes an Emergency Response Officer, Regulatory Officer, Environmental Officer, Corporate Communications Officer, Public Information Officer, Legal Officer, and Community Relations Officer.

TECO Unified Commander and Staff are responsible for crisis management in support of the General Staff incident tactical response. General Staff includes four sections: Operations (Company and Department Commands), Planning, Logistics and Finance.

The Operations Section is responsible for the incident tactical response and it includes Electric and Gas Delivery (E&G), Fuels and Customer Services, Energy Supply, and Information technology and Telecom Department Commands.

The Company or Department Planning Sections are responsible for developing the Incident Response plan (IRP) also known as the General Plan[1]; establishing the logistics and planning response at the Incident Bases and Incident Command Centers. Communication between the different Planning Sections ensures an effective incident response. The TECO Planning Section houses several units: Documentation, Resource Situation, Legal, and Risk Management.

The Logistics Section is responsible for economizing and acquiring resources. Resources can be economized by prioritizing the use of emergency and non-routine resources. The TECO Logistics Section includes a Logistics Support Unit (LSU), Purchasing Department Response Team (DRT), Lodging Services Team, Emergency Services team, and Incident Base (IB) setup Team.

[1] For storm response purposes, the Storm Plan is considered the Incident Response Plan

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Like the Planning Section, the different Department Command Logistics Sections have a line of communication to the TECO Logistics Section. The LSU houses representatives from many TECO support Departments (i.e., HR Benefits, Physical Security, Environmental, Risk Management, etc.) and Emergency Services (i.e., Meal Coordination, Lodging Services, Family Assistance, etc.).

The TECO Finance Section is responsible for streamlining payroll, accounts payable, documenting expenses and other financial functions during an emergency. Each department is responsible for communicating with the ICS Staff and General Staff, as necessary. Although communication can be free flowing, decisions are made in accordance with the implemented ICS line of authority. The above mentioned functional Departments will be activated based on the incident management needs. The five functional Departments are repeated throughout each ICS level and can be differentiated by the use of a modifier (i.e., *TECO* Planning Section, *ES* Planning Section, etc.).

Crisis Management

A. Unified Commander

The TECO Unified Commander is responsible for the activation of the ICS in response to a business disruption crisis. He is also responsible for the uninterrupted operation of a specific company, as determined during an emergency. The TECO Unified Commander is dedicated to supporting the General staff to ensure prompt and effective tactical incident response.

The Unified Commander is the President of TECO Energy or the President of the company most impacted by the emergency.

B. Environmental Officer

The Environmental Officer is responsible for ensuring precise environmental response to an incident or multiple incidents. During the course of the emergency he will also identify the global environmental issues that could impair the operations of the company.

The TECO Unified Commander, Staff and General Staff will be informed of the existing environmental hazards and the status of the response operations as it relates to all

APPENDIX 1 - TECO ECRP BC
Incident Command System

environmental releases or potential releases. In addition, the Environmental Officer maintains communication with the various internal and external environmental agencies to ascertain compliance with all environmental regulations.

C. Emergency Response Officer

The Emergency Response Officer is responsible for ensuring safe response to an incident or multiple incidents. During the course of the emergency he will also identify the global safety and security issues that could impair the operations of the company, and is responsible for high level communications and representation of the utility at the local emergency operation centers.

The TECO Unified Commander, Staff and General Staff will be informed of the existing safety hazards and the status of the response operations as it relates to the incident. In addition, the Emergency Response Officer shall maintain communications with the various internal and external safety and security managers to ascertain compliance with all regulations and to ensure the safety of all our team members and contractors.

This function is also responsible for the communication with county and municipal emergency operations centers. The local TECO Emergency Response Team reports to this function during an emergency. The Emergency Response Officer maintains communication with the Emergency Response Team Leadership; resolves global or high level response issues with other Company Officers (i.e. Visits local EOC with the Emergency Response Officer).

Other functions reporting to the Emergency Response Officer are: Human Resources (Critical Incident Stress Management and Peer Support), Physical Security, and Emergency Management.

The TECO EM-BC Director

The TECO EM-BC Director supports the TECO Emergency Response Officer, facilitates the use of ICS throughout the structure and works with outside agencies (e.g., Homeland Security – FEMA and USCG, EOCs, Local Mitigation Strategy group, etc.).

This function trains, during an event, personnel in new Logistics assignments and maintains communication supporting the Operations Planning Sections in other

APPENDIX 1 - TECO ECRP BC
Incident Command System

ways.

TECO Emergency Response Team Function

In 2006, the EOC function was moved from Energy Delivery to Unified Command, reporting to the TECO Emergency Response Officer during Incident Command System (ICS) activation. Since then, the EOC function has grown to encompass other types of TECO county emergency management jobs outside of the EOCs. The EOC Team Leader and Backup are now the TECO Emergency Response Leader and Backup respectively. This change was necessary to encompass the following new functions that were added in late 2006 early 2007 timeframe:

- TECO ESF3 Representative (to ESF-3) to the Public Works Command.
- TECO EOC Logistics Coordinator to the Hillsborough County EOC. This function will be responsible for high level communications from Hillsborough County EOC to the Emergency Response Team.
- Wire down Liaison within the Emergency Response team at the ECC. This function was added in conjunction with Energy Delivery.
- Wire Down Team within Energy Delivery supporting the Emergency Response Team in the field for wire down responses.
- TECO Disaster Recovery Center (DRC) Customer Service Liaison at the FEMA Hillsborough County Disaster Recovery Center located at Faulkenburg. Other centers will open during an emergency but these have not been pre-identified. The EOCs can be activated as a result of a hurricane, terrorist attack, pandemic, or a large environmental event (i.e., an oil spill under the Oil Pollution Act of 1990). Hurricanes, a terrorist attack or pandemic may have an impact on power and gas distribution and generate customer complaints.

  The response goal is to deploy the right combination of “matter experts” to each activated site to match the emergency response required from TECO Energy. Depending on the service territory we may have both PGS and TEC

APPENDIX 1 - TECO ECRP BC
Incident Command System

personnel sitting at the various sites.

The TECO EOC Reps (2 per desk) at the EOCs may represent the following departments: Customer Service, Energy Delivery, Environmental, Security, and Human Resources – all companies. Community Relations personnel will be visiting the EOCs and working the field. In the City of Tampa, On Scene Command reps will be deployed as necessary.

The EOC Representative Responsibility (personnel from different depts. and companies)

E&G, Customer Service or Community Relations EOC Rep:

1. Keeps the EOC appraised of the electrical power situation
    a. Areas and numbers of people without power
    b. Projections on power restoration
    c. Public safety information on downed power lines
2. Processes all power restoration requests generated at the EOC.
3. Provides information to the TECO Public Information Officer (PIO will be physically at the EOC)
4. Reports to the EOC Leader

HR, Security or Environmental/Safety EOC Rep:

1. Coordinates response with other EOC reps (i.e., FEMA, DEP, EPCHC, HCSO - land and marine units, FBI, Health Dept, etc.)
2. Processes matter specific questions generated at the EOC
3. Shares information with E&G, Customer Service, or Community Relations EOC Regional Rep and the assigned TECO PIO.

The Emergency Response Team Leader

1. Maintains communication with the EOCs reps prior and post storm landfall
2. Maintains communication with the State EOC Representative
3. Participates in E&G Dept. Command Calls to obtain information regarding:
    a. Areas and numbers of people without power
    b. Projections of power restoration
    c. Public safety information on downed power lines

APPENDIX 1 - TECO ECRP BC
Incident Command System

4. Participates in Emergency Management Calls
5. Participates in Unified Command Calls
    a. Reports on the EOC status
    b. Reports on EOC pertinent questions
6. During an emergency coordinates with PGS, Energy Delivery, Community Relations, Customer Service, Environmental, HR, Security and Emergency Management Departments to solve complaints and issues.
7. Is the sole contact of the TECO EOC and Public Works Representatives.
8. Is the sole contact to the TECO EOC Logistics Coordinator
9. Escalates all high level problems to the Emergency Response Officer

TECO EOC Logistics Coordinator

This function is activated when the TECO Energy Incident Command System is activated and is deployed after an emergency event (i.e., storm, terrorist attack, etc.) by the TECO Energy EOC Leader. This position is responsible for providing logistics support to the Hillsborough County EOC/ESF3 TECO Energy representatives.

Activities include staying connected to the EOC/ ESF3 reps to ensure that their basic necessities are being met; IT equipment is functioning and they have cyber connectivity to the Emergency Management website and have a means of communication (i.e., satellite phone, cell phone, etc.).

This position is the primary conduit of information from the HCEOC to the EOC Leader regarding HCEOC flyovers; responsible for preparing reports and communicating with the TECO Emergency Response Team Leader; and participating in annual emergency management training and exercises. Please note: The remaining EOCs located in the balance of our service areas will be contacted to ensure we can apply the same protocols.

If a frequency has not been pre-assigned to this function, at the time of the event, the Hillsborough County will assign an 800 MHz frequency to this function

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Incident Command System

through the TELC. This frequency will be outside Energy Delivery's and Energy Supply's operations range.

ESF3 Representative

This function is activated when the TECO Energy Incident Command System is activated and is deployed after an emergency event (i.e., storm, terrorist attack, etc.) by TECO Energy EOC Leader. This position supports the restoration activities by operating as a TECO representative at Public Works.

This position is responsible for coordinating with ESF3 debris clearance function to open roads and facilitate usage of TECO facilities and power restoration; participating in "after flyover" meetings in conjunction with ESF3 leadership; serving as an energy / gas liaison; communicating with the EOC Team at the ECC in person or via a communication device to ensure that ESF3 field problems are assessed – by phone /radio or in person in a timely manner in order to have line(s) de-energized or left for prioritization for line crew intervention; and participating in annual emergency management training and exercises.

D. Corporate Communications Officer

The Corporate Communications Officer is responsible for ensuring accurate and timely dissemination of information. The primary role of this office during an incident is to strategize the dissemination of current information on TEC system status to team members, as well as customers, the news media and other external constituencies.

E. Public Information Officer

The primary role of the TECO Public Information Officer (PIO) during an incident is to gather current information on the impacted company status (i.e. storm damage reports, gas restoration updates, etc.) and other information of interest and importance to team members, customers and the news media. This information is disseminated as summaries to critical news media, team members and customers at regular intervals during and following an emergency.

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The Public Information Officer also obtains information from the various Commands and Department Commands. The Department Commands may be asked, as communication needs warrant during an incident, to serve as subject matter experts, and on occasion convey system status and power restoration updates to the media with Corporate Communications' counsel, assistance and coordination.

The TECO PIO is responsible for keeping communication within the Department Commands to facilitate the visit of news media, where warranted, to the companies Incident Bases for the purpose of obtaining broadcast footage or photography.

F. Legal Officer

The primary role of this office during an incident is to support crisis management.

G. Regulatory Officer

The Regulatory Officer is responsible for high level communications and representation of the utility at State level. The TECO Regulatory Officer is responsible for maintaining contact with state EOC to ensure the uninterrupted operation of our company and is also responsible for maintaining the TECO ICS Staff and General Staff informed of the status of applicable government declarations.

H. Community Relations Officer

The TECO Community Relations Officer is responsible for maintaining contact with local government officials. Community Relations has liaisons to local EOCs which also serve as a communication conduit during infrastructure restoration.

The TECO Community Relations Officer is responsible for maintaining the TECO ICS Staff and General Staff informed of the status of applicable government declarations. This function is back-up to the company Emergency Response Officer.

Tactical Response

A. Operation Section

Each operation Department is classified as a Company Command or a Department Command (i.e. Tampa Electric, Energy Supply, E&G Delivery, Customer Services, etc.). Company Commands and Department Commands have developed comprehensive plans

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Incident Command System

and are activated by their Commanders. Copies of these plans are available on the Intranet, the office of each of the Company Commands or Department Commands, or the office of the TEC Emergency Manager.

B. Planning Section

The TECO Planning Section Chief activates the TECO Planning Section. The TECO Planning Section is responsible for preparing the General Plan for the Logistics response. This plan is presented to the TECO Staff and General Staff daily in preparation for the next operating shift.

The section is comprised of four units (Documentation, Resource Situation, Legal and Risk Management) and two staff positions (IT Technical Support and Workforce Coordination and Planning).

The Documentation Unit is responsible for compiling the reports received from the Incident Base Logistics response and the TECO Logistics Section. The Resource Situation Unit is responsible for maintaining the "storyboard" and ensuring that the status of the Logistics response is updated in an organized and timely manner, whether on the walls of the Unified Command or the Emergency Management website. This unit is responsible for establishing the status of personnel.

The Legal Unit provides council to the Section as it pertains to Real Estate and other topics, as necessary. The Risk Management Unit provides guidance regarding Worker's Comp. and other related issues. The Documentation Unit supports all the Planning units. The TECO Planning Section is responsible for preparing daily activity section summaries and providing a status update to the TECO Unified Command Staff and General Staff in preparation for the next operating shift. The Generic Plan ICS Form can be used for this purpose. See Section below for specific responsibilities.

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Responsibilities

The following is a list of responsibilities for the TECO Planning Section by function.

Section Chief or Backup	Attending the TECO Unified Command Meetings
	Upon activation, contacting the Planning Section Personnel and setting-up the Section at the designated location.
	Upon activation, establishing conference call frequency for the section.
	In the case of a storm, prior to landfall, verifying personnel emergency assignments and preparing the org charts that will be used at the UC Post, LSU and the Incident Bases. The Planning Section team members will print org charts and ensure they are delivered to the ECC prior to storm landfall. See Rapid Activation wall in Security Dept.
	Communicating updates to the TECO Unified Command during scheduled meetings.
	Documenting decisions regarding prioritization of common resources (logistics) formulated during TECO Unified Command meetings and presenting information to the TECO Planning Section.
	Operating the TECO Planning Section and providing support to the different Department Command Planning Sections, as necessary.
	Communicating with the TECO Unified Command Logistics section to determine resource availability and provide support as necessary.

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	Overseeing the Logistics IB Section Incident Bases set-up. Equipment is kept in the ***EM Storm Room***, First floor, ECC building.
	Planning for the next operational period.
	Training new personnel, as necessary.
	Participating in the Department Command Tactics meetings, depending on the emergency.
Documentation Unit	Keeping a log of the personnel present in the Section by shift.
	Compiling information for the daily Unified Command call. Including alternate Logistics strategies.
	Sending out broadcast messages using intelligent voice recognition system and daily reports.
	At the end of the emergency, collecting reports from the LSU and the IB Logistics. Organizing the document box and delivering box to Planning Section Chief.
	Updating the EM website (e.g., Emergency Services reports, Operations reports used by logistics).
	Working with IT to maintain the EM website.
	Duplicating media articles and posting on main entrance and hallways as requested by Officers.
	Maintaining records and activity logs.
Resource Situation Unit	Setting up the UC Post (ECC2) prior to storm landfall. (See ECC drawings).

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	Maintaining the LSU and ECC2 org charts – post changes in a timely manner – daily or more frequently.
	Setting up the Message Board and posts the ECC emergency drawings.
	Working with Corporate Communications to release communication to team members.
	Recording and Maintaining the 24 hour emergency message line and the LSU recorded line.
Legal Unit	Providing council to the Section, as necessary, pertaining to Real Estate, Environmental, Security, Safety and other issues.
	Communicating pertinent issues to the Legal Department.
Risk Management Unit	Providing guidance to the Section regarding Workers Compensation and other risk issues affecting the company during the restoration effort.
	Communicating with the Risk Management Department to obtain status of the Logistics Support Unit – Risk Management Desk. Maintaining abreast of new issues encountered through the LSU.

See TECO Planning Section Manual

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C. LOGISTICS SECTION

The TECO Logistics Section Chief activates the Logistics Section. This section is comprised of several units and one DRT, as mentioned above.

The LSU includes an Operations Team, a Phone Bank, and a Resource Bank. The LSU also communicates with the Department Response Teams (DRTs). The purpose of this unit is to assist the different Company and Department Commands in their restoration efforts by streamlining the TECO resource request process to ensure prompt service restoration before or after a business disruption crisis.

The Logistics Section Chief is activated during the Unified Command meeting. If the section Chief or back-up are not present, they will be activated using the external IVR (intelligent voice recognition system). This activation will be initiated by the TECO Energy/TEC Sr. Emergency Coordinator or backup, or EM Group.

The TECO Logistics Chief is responsible for activating the LSU Leader and initiating the setup of the LSU; activating the IB Set-up Team, Emergency Services, Logistics Liaisons and Logistics Coordinators.

Department Command Logistics sections are activated by the appropriate Department Commander as necessary and may be activated in advance of TECO Logistics Chief. TECO Logistics is responsible for preparing a resource status exception report twice a day. This status report is a compilation of the exception status reports from the different Department Commands and the LSU. Report is presented daily to the TECO Unified Command Staff and General Staff in preparation for the next operating shift.

The Emergency Management Website is used during response as a bulletin board (the EM Dashboard) and as a repository of emergency response plans, org charts, rosters, etc.

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Emergency Services

There are a few emergency services worth expounding on; Laundry, Mobile Asset Support System (MASS), Meals, Lodging, TECO Retiree Task Force and Transportation. These services are crucial to response and are managed through the LSU.

Laundry Services

The TECO Energy (TECO) Laundry Services Coordination Plan is a plan for supplying laundry services to foreign crews, displaced home crews, critical team members and support personnel at TECO Incident Bases (IB) during an emergency.

The TECO Emergency Coordinator manages the Laundry Services Coordination function. The TECO Laundry Services Coordination Team has been formed to provide corporate laundry services coverage during an emergency.

When the service is activated, the Laundry Services process begins the day after the first crews arrive at an IB or the day after emergency response personnel arrive at the emergency response support scene. At the IB, the dirty laundry is picked up in the morning, cleaned and returned in the evening. Turn-around time is 1-2 days maximum. For more information see the Laundry Services Plan.

Lodging Services

The TECO Energy Lodging Services Coordination Plan is a procedure for securing hotel rooms and supplying laundry services to critical team members and support personnel at TEC facilities during an emergency. This procedure can include securing hotel space for families of critical team members.

The Lodging Services Coordination function is managed by the TECO Emergency Management in conjunction with the TECO Lodging Services Coordinator and Backup. The TECO Lodging Services Coordination Team and the Facility Lodging Services Coordination Teams have been formed to provide corporate/company - wide coverage during an emergency. For more information see the Lodging Services Plan.

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MASS Management

MASS Management is a logistics tracking and barcode ID card system. This system is used to establish official registration and safety training point for incoming mutual assistance crews. This function is used to track emergency services provided to the mutual assistance crews, as well as the crewmembers.

Meal Services

The TECO Energy Meal Coordination Plan is a procedure for acquiring and supplying meals to all team members and support personnel at TECO facilities during an emergency. For the purpose of this plan, twenty-seven (27) facilities have been identified for meal coordination.

The meal coordination function is managed by the TECO Emergency Management in conjunction with the TECO Meal Coordinator and Back-up. The TECO Meal Coordination Team and the Facility Meal Coordination Teams have been formed to provide corporate / company - wide coverage during an emergency. For more information see the Meal Services Plan.

TECO Retiree Task Force

The TECO Retiree Task Force is a group of retirees from different TECO Energy and TEC departments who can fill selected entry level positions during an emergency, allowing TECO team members to be deployed to the field on emergency assignments. In addition, TECO retirees with operations experience can be utilized in Energy Delivery (gas and electric) and Energy Supply.

Transportation Services

The TECO Energy Transportation Service Coordination Plan is a procedure for securing transportation for Foreign Crews, to and from hotels and Incident Bases or Incident Command Centers in support of power restoration within TECO service area during an emergency. This function also includes transportation of team members from all incident bases. Bus service includes day through evening service.

The TECO EM Coordinator manages this function. The TECO Transportation Services Coordinator, LSU – Transportation Resource Planners, and IB

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Transportation Coordinators make up the *Transportation Services Coordination Team*. The Transportation Services Coordination team also works together to provide transportation such as amphibious vehicles, van, helicopter, taxi, limousine, and watercraft transportation. For more information see the Transportation Services Plan.

See TECO Logistics Section Manual

D. FINANCE SECTION

The TECO Finance Section Chief activates the TECO Finance Section. The function of this section is to assist Operations, Planning and Logistics in their restoration efforts by streamlining payroll, accounts payable, and other financial functions during an emergency.

See TECO Finance Section Manual

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INTRODUCTION

TECO Energy, specifically Tampa Electric Company (TEC) is an integral part of lifeline services to the community. TEC has a critical relationship with other emergency service agencies in our community, such as Fire, Police and Emergency Management Service.

Our quick response in an emergency:

- Helps us fulfill our civic responsibility to protect our families, the community and the environment;
- Enhances our ability to recover from damages to equipment or business interruptions;
- Facilitates our compliance with regulatory requirements; and
- Enhances our company image and credibility with team members, Customers and the community.

To respond efficiently during an emergency situation, TECO has established a comprehensive Emergency Contingency Response plan. Planning is mandatory and it is an annual effort to ensure our activities are effective and up to date. Although TECO is responsible for assuring business continuity, team members have the responsibility of working together during an emergency situation to ensure that the business is restored efficiently. For that reason, it is critical that every team member develop a family emergency plan before an emergency situation arises. It is the team member's responsibility to be prepared.

We recognize that all of us are concerned foremost about the safety and well-being of our families during an emergency situation and fully understand the need to take care of family matters first.

This guide contains information that will assist every team member in their planning efforts. Literature such as the annual *Get Ready! Guide*, *the Critical Worksheet, Stay Safe During this Storm Season Guide,* the Family Plan template and the *Hurricane Guides* are made available to team members by TECO as planning tools.

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Team members are responsible for developing a Family Preparedness Plan that includes information on team member, family and home preparation. The plan should cover the actions that would be taken to keep they family safe and ensure the team member's prompt return to work.

TEAM MEMBER PREPAREDNESS

TECO Energy Emergency Management (EM) Assignment

All team members are expected to report to work in accordance with their primary emergency job assignment and their Department's Emergency Contingency Response plan. EM Assignments are activated whenever the Incident Command System (ICS) is activated.

If your emergency assignment location is at a secure location, remember that you need clearance and training. Contact your Emergency Coordinator for assistance.

ICS does not have to be fully activated in order for you to be activated. Therefore, it is important to know your EM Assignment at all times. Your EM Assignment tells you what your responsibility will be during or after an emergency and also tells you where you report in case of an emergency. Update or develop your Family Preparedness Plan. If you have changed your address, phone number or emergency contact, please update your ESS personal information through the HR Department as soon as possible.

If the company needed to contact your family, are the right numbers on file?

You can view your assignment on the intranet and can change your skill inventory through MyTeconet.

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In case of a storm situation, team members will be released as follows:

Team members may be released in several stages, based on the situation and individual needs. The overriding considerations for team member release is the balance of protecting life and property against the need to serve our customers. Final decisions on the sequence and timing of releasing team members will be made by each Department Head or Department Commander.

Release times will be based in part on the following considerations:

- Severity of the wind. Everyone must be released in time to reach his or her destination before sustained winds reach 40 m.p.h.
- Severity of approaching storm. Larger storms may require longer lead times for evacuation. Team members closer to the coast will require additional time.
- Severity of incident.
- Time of day and day of week of the possible storm strike. Weekend and night strike times will impact the timing of releasing team members to prepare.
- Emergency Managers will declare evacuation orders, both voluntary and mandatory to Department Commanders. Team members responsible for family members in evacuation zones may need time to prepare and/or evacuate.
- Road and bridge closures. Bridges may be closed before evacuation orders are issued. Team members who traverse bridges need time to adjust schedules.
- The ability of a facility to withstand the approaching storms. Severe storms will mandate the evacuation of the facility.

Transportation

Transportation after a major storm or hurricane may be difficult because of road conditions and other limitations brought on by the storm. Team members in remote areas are encouraged to take into consideration the road conditions between their homes and work locations, the amount of trees on the route that may block transportation, and their personal vehicle availability and readiness. Special plans should be made in advance to minimize the potential of being stranded.

- Evaluate vehicles before storm season and make any necessary arrangements to reduce the risk or exposure to severe damage.

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- Additional materials, equipment, and alternate arrangements should be made to expedite repairs after a storm or emergency.
- Remember to contact the insurance company in order to learn more about the requirements and restrictions of the policy after an emergency. This inquiry should include such questions as:
    - In the event my vehicle is damaged by a storm, what am I required to do to protect/secure the vehicle until it can be properly inspected and repaired?
    - Can I use and/or make repairs to my vehicle prior to an inspection by the claims adjuster?
    - Are there any restrictions or requirements for the company that will repair my vehicle? (i.e., licensed, bonded, prior approval by insurance company, etc.)

FAMILY PREPAREDNESS

Before developing this section of the Family Preparedness plan, each team member should learn about the emergency management plans and activities in their community in order to know:

- How the local government is protecting the community from possible hazards;
- How to coordinate your plan with those of the community; and
- How to use resources available in the community.

Informational brochures are available to citizens from numerous agencies to help guide home and family preparation. These guides are available through merchants, printed in newspapers, and are generally found throughout the community and on our Emergency Management web site. Please refer to all Emergency Planning information distributed by Emergency Agencies before finalizing your plans.

TYPE OF INFORMATION

- Alternate shelter for the team member and dependents ("dependents" are defined here as those for whom the team member is directly responsible)

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- Missing Persons
- Medical Information
- Cash & Scarce Resources
- Pet Care
- Evacuation zones and flood zones
- Geographic conditions that may affect your home (i.e., trees, rivers, creeks, remote area, etc.)

To create an emergency plan you can use the Get Ready! Critical Worksheet. You should have two additional contingency plans on hand in case the situation changes and the primary plan is no longer effective.

Note: Early evacuation to emergency shelters is strongly recommended.

DEPENDENT CARE

Family is a top priority for all of us. The well-being and safety of our families during an emergency dictates our prompt return to work for service restoration efforts.

- Each team member is responsible for planning emergency dependent care in advance for children, elderly dependent(s) and ill family members. Prepare one plan with two additional contingency plans for dependent care needs. The plan should include a family emergency meeting location (primary and secondary). Male sure all contact numbers are up to date and programmed in cell phones.
- If a team member's family member (adult/special needs dependents) requires supplemental shelter care the team member is encouraged to pre-register their dependent for care at one of the "special needs" shelters listed below. Hillsborough County Emergency Planning Operations sponsors Special Needs Shelters below: the latest shelters are listed on the EM Website/Get Ready.

Note: An emergency shelter should be your last option. You should plan ahead by arranging emergency housing with friends or family members.

MEDICAL/DENTAL

All the TEC medical and dental providers will have methods in place to deal with an influx of

calls during emergency situations. Team members should call the established local phone numbers for their medical or dental provider during an emergency situation.

Your Plan should include the following information:

1. Determine which substitute physician, if any should be contacted in an emergency situation if the primary physician is unavailable.
2. Have available a copy of medical records for each family member. Records should include current prescription dosages. Keep an address and telephone number of the nearest hospital.
3. In the case of a medical emergency, team members should seek immediate care at the nearest health care facility.
4. Your Get Ready! Critical Worksheet, with the primary care physician's phone number, should be kept handy. If time permits, call the primary care physician before going to the emergency room. Or, if a prior call is not possible, contact the primary care physician from the emergency room for further direction.
5. Team members with special medical needs or those who are taking prescription drugs should consult with their physician or pharmacist for such details as storage of prescription or non-prescription medications (i.e. baby formula, insulin, heart medication, etc.) in the event of an emergency situation.

CASH AND SCARCE RESOURCES

1. Cash

   Consider a plan to obtain cash. Cash requirements may greatly increase for everyone during an emergency situation. The potential exists for the local economy to resort to a "cash base society".

b. Regular Payroll
   - It is the intent of the Payroll Department to maintain the normal payroll schedule. This includes normal direct deposit processing.
   - If the mainframe is not available, all team members will be issued checks.

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- Payroll checks and direct deposit pay stubs will be delivered to normal work locations if mail is being processed or held for pickup at the main office or where payroll is located.

EMERGENCY CASH ADVANCES & TEAM MEMBER PURCHASES

Depending upon the nature and severity of the disaster, Accounts Receivable Miscellaneous (ARM) purchases will be provided for team members, handled via departmental approvals and based upon emergency availability for purchases. Approval will depend on verification of hardship.

PAYROLL CASH ADVANCE

IF FUNDS ARE AVAILABLE, DEPARTMENTS WILL BE ABLE TO PROVIDE CASH ADVANCES TO TEAM MEMBERS, WITH AN APPROVED REQUEST, FOR THEIR EMERGENCY NEEDS. A VOUCHER REQUEST FOR THIS WILL BE PROCESSED THROUGH PAYROLL. AFTER A DELAY OF TWO MONTHS, THIS ADVANCE WILL BE DEDUCTED OVER A SIX-MONTH PERIOD.

Departments requiring emergency cash shall designate a representative who will be responsible for acquiring a check from Accounts Payable. The representative may have back-ups. At the onset of each storm season, representatives shall submit an approved cash advance request to Accounts Payable in the name of the person who will be responsible for cashing the check (include back-up names if not sure).

Upon activation of the Incident Command System, the representative will contact Accounts Payable (extension 34793, 31356, 34825, 34829) to activate the cash advance in the appropriate name.

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MISSING PERSONS

The Red Cross handles requests for locating missing persons in the event of an emergency. Team members should contact their local Red Cross Chapter if a family member or friend needs to be located.

PET CARE

It is the team member's responsibility to make plans well in advance for the safety and emergency care of their pet(s). The company is not prepared to provide pet care. Hillsborough County may open owner/pet shelters.

FAMILY SAFETY

The STAY SAFE this Storm Season brochure provides many steps to assist you in preparation before, during, and after a storm.

Authorities will tell you if you need to evacuate. Leave early if you must evacuate.

- Before leaving your house, disconnect electrical appliances except for refrigerator and freezers. Secure and lock your house.
- Follow instructions carefully offered by local authorities and travel with care. Watch for flooding and avoid crossing flooded areas.

TECO - Comprehensive Exercise Plan (CEP)

Prepared by S. Mueller, FPEM

Update: May 5, 2011
By: S. Mueller
Ver: 5

Emergency Management

Overall Preparedness
Susan Mueller

EM Logistics
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EM Planning
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EM Services
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EM Coordinators
See EM Coordinator Org Chart

Table of Contents

TECO ENERGY - CEP

I. INTRODUCTION

The focus of this document is to provide TECO Energy exercise planners and other interested parties with a synopsis of the current TECO Energy exercise-related activities; exercise plan goals; exercise methodology; and a three-year timeline depicting exercise planning and execution cycles.

The exercise matrix included in this plan is reviewed on an annual basis. Also included is a list of the local and state annual exercises in which TECO Energy BC-EM participates in various capacities.

The BC-EM Group uses the Homeland Security, Federal Emergency Management Agency Exercise Guidance on exercise management. Exercises and drills have been conducted since 1990. These drills and exercises have met their regulatory definition of a drill (testing one portion of a plan) or exercise (testing the complete plan).

As EM evolves and aligns itself with FEMA standards, the exercise building block approach found on page 11 is merged with the regulatory requirements to ensure a streamlined approach to exercise management.

II. CURRENT TECO ENERGY EMERGENCY MANAGEMENT EFFORTS

Annually, the EM Group conducts exercises that serve to review plans and play out scenarios to expose different levels of vulnerability, known as “Lessons Learned” (LL).

LL are captured in After Action Reports which serve to identify and provide a timeline for mitigation, as necessary. Exercise budget responsibility fall under the jurisdiction of each Emergency Coordinator and it is augmented with monies from the EM-BCM Group.

III. EXERCISE PLAN GOALS

Based on the current TECO Energy efforts or exercise activities, the EM-BC Group finds that participation and commitment to preparedness is strength for the corporation. From the participation of the Officer team to Staff and tactical response departments, to emergency services personnel, there is a dedication to "exercise as we would respond".

Some of the exercises conducted at TECO Energy are required by law and the rest are required by our corporate sense of responsibility. Each type of exercise is thought through taking into consideration what goals and objectives will need to be achieved to have a stronger plan.

Exercise goals are realistic and provide an opportunity to measure success throughout the process. The initial plan was written in 2007, and is updated annually to reflect changes in exercise schedules. All After Action Reports are kept electronically as pdf portfolios in the 2010 EM Sharepoint site.

IV. EXERCISE METHODOLOGY

The exercise methodology used at TECO Energy reflects a cycle of activity that meets the corporations' specific needs and includes exercises of increasing levels of complexity (building-block approach – as described below on page 11).

Exercises:

- Are threat-based, realistic, and use accurate exercise scenarios;
- Involve players from multiple disciplines to test interagency relationships and agreements;
- Provide a means to improve planning for each exercise;
- Provide a method to share best practices and lessons learned with local and corporate partners.

Type and Compliance	Quantity	Frequency	Locations	Responsible
Security 33CFR105 Security Exercises	4 drills / location *1 exercise / location (an exercise can replace a drill, an event can replace an exercise)	4 / year	Big Bend Station	EM-BC
Health and Safety Fire and Building Code	1 / location	1 / year	**TECO Plaza, Power Stations	Location Safety Function or Facility Services
Environmental Oil Pollution Act of 1990 Exercises (OPA)	1 / location	1 / year	Big Bend Station Polk Power Station	EM-BC
Storm – not mandated by law	***Various	Minimum 1 / year	All Departments , Emergency Functions, ICS Functions	EM and EM Coordinators from different Departments
Cyber Security North American Electric Reliability Corporation (NERC) Exercises	1	1 / year / in accordance with CIP-008-3 and CIP-009-3	Ybor Secure Center ECC Bayside	EM- BC
Cyber Security Disaster Recovery Exercises	1/system	Annually	Ybor Data Center, ECC, and Secure Center	IT EM - BC Coordinator
Private Breach Under corporate Admin policy 1.15	1	Annually	Corporate	EM-BC
Pandemic	1 company exercise	Every 3 years, a response constitutes a plan test	All Departments	EM-BC
Bio-Terrorism Response	1 company exercise	Every 3 years, a response constitutes a plan test	Physical Security and EM BC	EM-BC
ICS ICS is "tested" in all exercises				

*IN ACCORDANCE WITH 33CFR105 AN EXERCISE CAN COUNT AS A DRILL
**ONLY BUILDING THAT HAVE MORE THAN 3 FLOORS ARE REQUIRED TO HAVE A FIRE DRILL, AT TEC ALL BUILDINGS HAVE FIRE DRILLS
***THE LOGISTICS SUPPORT UNIT ALTERNATES FUNCTIONAL EXERCISES AND TABLETOP EXERCISES EVERY OTHER YEAR

V. EXERCISE TYPES[1]

Below are listed the seven available exercise types that may be used at TECO Energy.

Seminars
Seminars are generally employed to orient participants to, or provide an overview of, authorities, strategies, plans, policies, procedures, protocols, response resources, or concepts and ideas. Seminars provide a good starting point for jurisdictions that are developing or making major changes to their plans and procedures. They offer the following attributes:

- Low-stress environment employing a number of instruction techniques (i.e., lectures, multimedia presentations, panel discussions, case study discussions, expert testimony, decision support tools, etc.)
- Informal discussions led by a seminar leader
- Atmosphere that is not constrained by real-time portrayal of events
- Effectiveness with both small and large groups

Workshops
Workshops usually focus on development of a product by the attendees. Organization of attendees into functional groups, aided by facilitators and the use of breakout sessions, are common. Final results are often presented and approved in a plenary session. In conjunction with exercise development, workshops are most useful in planning specific aspects of exercise design, such as:

- Determining program or exercise objectives
- Developing exercise scenario and key events listings
- Determining evaluation elements and standards of performance

Drills
A drill is a coordinated, supervised activity usually employed to test a single specific operation, single part of a plan for a facility, or function in a single department. Drills are commonly used to provide training in the use of new equipment, to develop or test new policies or procedures, or to practice and maintain current skills.

[1] *Homeland Security Exercise and Evaluation Program, Volume 1: Overview and Doctrine*, U.S. Department of Homeland Security, Office for Domestic Preparedness.

Typical attributes include:

- A narrow focus, measured against established standards
- Instant feedback
- Realistic environment
- Performance in isolation
- Performance as a subset of full-scale exercises (FSEs)

Games

A game is a simulation of operations that often involves two or more teams, usually in a competitive environment, using rules, data, and procedures designed to depict an actual or assumed real-life situation. It does not involve the use of actual resources, but the sequence of events affects, and is in turn affected by, the decisions made by the players.

Players are commonly presented with scenarios and asked to perform a task associated with the scenario episode. Each episode then moves to the next level of detail or complexity, taking into account the players' earlier decisions. The decisions made by game participants determine the flow of the game. The goal is to explore decision-making processes and the consequences of decisions. In a game, the same situation can be examined from different perspectives by changing variables and parameters that guide player actions. Large-scale games may be inter departmental or multijurisdictional, if in conjuction with the public sector, and can include active participation from local to national levels of government. Games stress the importance of the planners' and players' understanding and comprehension of interrelated processes.

With the evolving complexity and sophistication of current simulations, there are increased opportunities to provide enhanced realism for game participants. The use of computer-generated scenarios and simulations can provide a more realistic and time-sensitive method of introducing situations for analysis. Planner decisions can be input and models run to show the effect of decisions made during a game. Games are excellent vehicles for the following:

- Gaining policy or process consensus
- Conducting "what-if" analyses of existing plans
- Developing new plans

Tabletop Exercises

Tabletop exercises (TTXs) involve senior staff, Directors, or other key staff in an informal setting to discuss simulated situations. This type of exercise is intended to stimulate discussion of various issues regarding a hypothetical situation. It can be used to assess plans, policies, and procedures, or to assess the types of systems needed to guide the prevention of, response to, and recovery from the defined event. TTXs are typically aimed at facilitating the understanding of concepts, identifying strengths and shortfalls, and/or achieving a change in attitude. Participants are encouraged to discuss issues in depth and develop decisions through slow-paced problemsolving, rather than rapid, spontaneous decisionmaking that occur under actual

or simulated emergency conditions. In contrast to the scale and cost of exercises and games, TTXs can be a cost-effective tool when used in conjunction with more complex exercises. The TTX's effectiveness is derived from the energetic involvement of participants and their assessment of recommended revisions to current policies, procedures, and plans.

There are two categories of TTXs: basic and advanced. In a basic TTX, the scene set by the scenario materials remains constant. The scene describes an event or emergency incident, and brings participants up to the simulated present time. Players apply their knowledge and skills to a list of problems presented by the leader/moderator. Problems are discussed as a group, and resolution is generally agreed upon, and then summarized by the leader. In an advanced TTX, play revolves around delivery of prescripted messages to players that alter the original scenario. The exercise controller (moderator) usually introduces problems one at a time, in the form of a written message, simulated telephone call, videotape, or other means. Participants discuss the issues raised by the problem, using appropriate plans and procedures. Activities in a TTX may include:

- Practicing group problemsolving
- Familiarizing senior officials
- Conducting a specific case study
- Examining personnel contingencies
- Testing group message interpretation
- Participating in information sharing
- Assessing interagency coordination
- Achieving limited or specific objectives

Functional Exercises

The functional exercise (FE) is designed to test and evaluate individual capabilities, multiple functions or activities within a function, or interdependent groups of functions. It is generally focused on exercising the plans, policies, procedures, and staffs of the direction and control nodes of Incident Command and Unified Command. Events are usually projected through an exercise scenario, with event updates that drive activity at the management level. The movement of equipment and personnel is simulated.

The objective of the FE is to execute specific plans and procedures and apply established policies, plans, and procedures under crisis conditions, within a particular function or by a specific team. The FE simulates the reality of operations in a functional area by presenting complex and realistic problems that require rapid and effective responses by trained personnel in a highly stressful environment. Activities in an FE include:

- Evaluating functions
- Evaluating EOCs, headquarters, and staff
- Reinforcing established policies and procedures
- Measuring the adequacy of resources

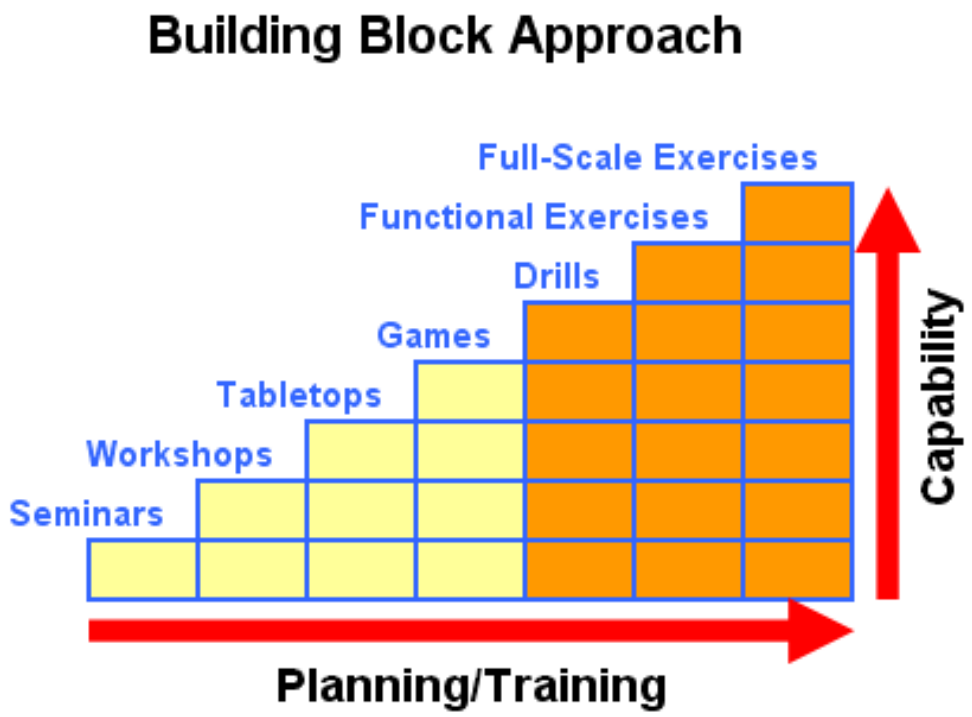
- Examining interjurisdictional relationships

Full-Scale Exercises

In a full-scale exercise (FSE), response elements are required to mobilize and deploy to a designated site or locate in response to a simulated attack, generally for an extended period. Actual mobilization and movement of personnel and resources are required to demonstrate coordination and response capability. EOCs and field command posts are activated. The FSE is the largest, costliest, and most complex exercise type and may involve participation at the State, local, regional, and Federal levels. Although prescripted events may be used, the exercise is primarily driven by player actions and decisions.

The FSE is used to evaluate the operational capabilities of systems, functional interfacing, and interaction during an extended period. It involves testing a major portion of operations plans and overall organization under field conditions. Activities in an FSE may include:

- Assessing organizational or individual performance
- Demonstrating interagency cooperation
- Allocating resources and personnel
- Assessing equipment capabilities
- Activating personnel and equipment locations
- Assessing interjurisdictional cooperation
- Exercising public information systems
- Testing communications systems and procedures
- Analyzing memoranda of understanding (MOUs), standard operating procedures (SOPs), plans, policies, and procedures


Building Block Approach
Full-Scale Exercises
Functional Exercises
Drills
Games
Tabletops
Workshops
Seminars
Capability
Planning/Training

VI. EXERCISE LOGISTICS PROCEDURES

The following procedure explains how to prepare and execute an exercise. The procedure is found on 2010 EM Sharepoint/EM Admin and Projects/EM Procedures

http://teams/sites/corpsvcs/emer/_layouts/WordViewer.aspx?id=/sites/corpsvcs/emer/EM%20Projects/EM%20Procedures/EXERCISES%20-%20How%20to%20Prepare%20and%20Execute%20an%20Exercise.docx&Source=http%3A%2F%2Fteams%2Fsites%2Fcorpsvcs%2Femer%2FEM%2520Projects%2FForms%2FAllItems%2Easpx%3FRootFolder%3D%252Fsites%252Fcorpsvcs%252Femer%252FEM%2520Projects%252FEM%2520Procedures%26FolderCTID%3D0x012000B5E892E9894418468AEA90019F13C5CC%26View%3D%7B677B4FB8%2D3C3C%2D40F1%2D97E7%2D006727BDA6E9%7D&DefaultItemOpen=1

VIII. EM and ICS TRAINING PROGRAM

The purpose of ICS training is to ensure that team members understand their role during an emergency.

- When do I report?
- Where do I report to?
- Who do I report to?
- What is my job and how do I perform my job?
- Where do I fit in the Incident Command System?

These are all questions that are answered during training.

A special focus of all training is to ensure that EM or the responsible function provides team members with safety information and the proper personal protective equipment that will be needed to perform their emergency job.

All ICS functions under the scope of EM are trained on an annual or bi-annual basis. Emergency communication drills are performed using the Emergency Notification System an external intelligent voice recognition system several times a year. The Planning Section is responsible for the use and deployment of the emergency notification system.

Emergency Services training includes cross functional training for Meal Coordination, Transportation, Lodging, and Laundry.

Traffic control personnel, is included in the Emergency Services cross training to enhance communication between this team and the logistics team that will be deployed.

TECO Logistics, Planning and Finance Sections are all trained on their specific functions as well, at a minimum of once a year.

Company Commands, Department Commands and Department Response Teams (i.e., Purchasing, Facility Services, Fuels, Environmental, etc.) are responsible for their own training. EM may be present at these training opportunities depending on the nature and scope of training.

2013 LIST OF TRAINING AND EXERCISES

2/6	New EM Response Officer - ICS
2/21	MASS Management
2/27	New EM Response Officer - ICS
3/5	IB Logistics Central
3/6	IB Logistics S. Hills
3/7	IB Logistics Western
3/12	IB Logistics PC/DC/WH
3/14	IB Logistics Eastern
3/20	New EM Response Officer – ICS
3/27	New EM Response Officer – ICS
4/2	New EM Response Officer Backup – ICS and new function
4/3	New EM Response Officer – ICS
4/3	EM Response Team Exercise
4/9,10, and 11	Emergency Notification System test
4/17	New EM Response Officer – ICS
4/23	CERT Activation Exercise
4/24	New EM Response Officer – ICS
4/25	LSU Exercise
4/25	Exercise IB Logistics Checkout
4/30	Lodging Services Emergency Response Plan Review
5/7	Family Assistance
5/9	ICC – Facility Meals
5/14	Phase 1 – ICC Meals
5/15	Phase 2 – ICC Facility Meals
5/16	Phase 3 – ICC Facility Meals
6/6	BB Drill
8/28	Privacy breach Exercise
9/1	BB Annual OPA / Security Exercise (Planning will be tested as well)
10/24	Polk OPA Exercise
11/13-14	Annual Cyber Security Exercise

11) Feeder Specific and Attached Laterals Data

See attached pages 235 through 278.

(A) Circuit	(B) Service Area	(C) Number of OH Lateral Lines	(D) Number of OH Lateral Miles	(E) Number of Customers Served on OH Lateral Lines	(F) CMI for OH Lateral Lines	(G) CI for OH Lateral Lines	(H) Number of URD Lateral Lines	(I) Number of URD Lateral Miles	(J) Number of Customers Served on URD Lateral Lines	(K) CMI for URD Lateral Lines	(L) CI for URD Lateral Lines	(M) Number of Automatic Line Sectionalizing Devices on the Lateral
13001	SH	N/A	12.99	821	26169	125	N/A	4.56	567	0	0	0
13002	SH	N/A	5.51	407	2393	22	N/A	4.43	469	0	0	0
13003	SH	N/A	27.42	656	168119	1134	N/A	3.38	233	0	0	0
13004	DC	N/A	11.03	547	44381	193	N/A	8.49	421	3686	9	0
13005	DC	N/A	6.39	279	10693	114	N/A	1.61	195	2058	14	0
13006	DC	N/A	23.07	801	176489	2408	N/A	9.64	879	6738	14	0
13007	PC	N/A	32.03	477	40009	293	N/A	2.97	44	0	0	0
13008	PC	N/A	17.32	367	90786	694	N/A	1.38	17	966	3	0
13009	PC	N/A	3.33	94	1160	7	N/A	0.99	40	0	0	0
13010	PC	N/A	7.93	517	98363	1122	N/A	9.58	1030	233	1	0
13011	PC	N/A	27.65	1432	73387	657	N/A	4.25	336	94	2	0
13012	WSA	N/A	0.80	97	5961	40	N/A	0.52	14	0	0	0
13013	WSA	N/A	0.22	65	180	30	N/A	1.39	227	12168	26	0
13016	WSA	N/A	0.78	89	2376	11	N/A	0.45	91	0	0	0
13017	SH	N/A	9.40	361	42551	400	N/A	12.41	1138	1437	18	0
13019	SH	N/A	15.54	975	45293	128	N/A	5.38	507	930	2	0
13020	SH	N/A	13.10	915	12468	113	N/A	1.32	87	0	0	0
13021	CSA	N/A	3.88	290	9694	58	N/A	4.64	1037	15048	72	0
13022	CSA	N/A	4.03	427	3171	24	N/A	0.71	281	0	0	0
13023	CSA	N/A	8.31	1001	16423	66	N/A	1.85	332	0	0	0
13024	CSA	N/A	8.43	818	32748	259	N/A	1.30	173	0	0	0
13026	CSA	N/A	3.04	261	27609	200	N/A	4.77	1255	0	0	0
13027	CSA	N/A	9.25	702	136660	747	N/A	1.84	299	4540	10	0
13028	CSA	N/A	5.56	548	37774	621	N/A	4.60	1373	7752	56	0
13029	CSA	N/A	6.14	503	53775	286	N/A	3.04	639	0	0	0
13030	WH	N/A	31.09	995	22537	276	N/A	9.58	619	4736	16	0
13031	WH	N/A	14.46	547	4461	64	N/A	1.65	87	0	0	0
13034	CSA	N/A	9.69	1156	94910	351	N/A	0.74	165	0	0	0
13035	CSA	N/A	5.29	537	13162	88	N/A	0.70	88	0	0	0
13036	CSA	N/A	9.37	885	197438	763	N/A	1.99	234	645	1	0
13037	CSA	N/A	5.89	588	10728	120	N/A	1.72	333	0	0	0
13038	ESA	N/A	6.20	374	34223	172	N/A	3.01	166	0	0	0
13039	ESA	N/A	7.62	469	14560	88	N/A	5.76	531	4044	25	0
13040	ESA	N/A	0.28	8	55523	690	N/A	14.37	1073	0	0	0
13041	ESA	N/A	5.79	353	10032	61	N/A	13.93	895	5983	37	0

(A) Circuit	(B) Service Area	(C) Number of OH Lateral Lines	(D) Number of OH Lateral Miles	(E) Number of Customers Served on OH Lateral Lines	(F) CMI for OH Lateral Lines	(G) CI for OH Lateral Lines	(H) Number of URD Lateral Lines	(I) Number of URD Lateral Miles	(J) Number of Customers Served on URD Lateral Lines	(K) CMI for URD Lateral Lines	(L) CI for URD Lateral Lines	(M) Number of Automatic Line Sectionalizing Devices on the Lateral
13042	CSA	N/A	12.58	1542	172220	477	N/A	0.05	2	0	0	0
13043	CSA	N/A	12.19	1640	356221	587	N/A	1.23	392	0	0	0
13044	CSA	N/A	11.76	1618	100877	230	N/A	0.26	8	0	0	0
13045	CSA	N/A	7.16	988	209878	786	N/A	0.05	18	0	0	0
13046	CSA	N/A	7.91	1170	43789	294	N/A	0.05	4	0	0	0
13047	CSA	N/A	3.90	557	6545	47	N/A	0.31	165	0	0	0
13048	CSA	N/A	8.15	1181	54449	363	N/A	0.32	25	0	0	0
13049	CSA	N/A	5.51	613	9030	61	N/A	2.22	485	0	0	0
13050	CSA	N/A	0.22	3	0	0	N/A	0.91	45	0	0	0
13051	CSA	N/A	1.33	139	9189	62	N/A	4.12	926	0	0	0
13052	CSA	N/A	0.89	52	3474	30	N/A	0.60	129	714	2	0
13053	CSA	N/A	9.23	1223	22934	137	N/A	1.98	302	8127	27	0
13054	CSA	N/A	0.27	5	0	0	N/A	1.16	439	0	0	0
13055	CSA	N/A	0.14	6	0	0	N/A	0.65	27	0	0	0
13057	CSA	N/A	4.21	602	87776	1137	N/A	1.03	192	0	0	0
13059	WSA	N/A	7.04	892	52021	208	N/A	0.70	119	342	6	0
13060	WSA	N/A	4.54	620	35052	377	N/A	1.00	451	0	0	0
13061	WSA	N/A	3.45	509	83680	638	N/A	0.39	42	0	0	0
13062	WSA	N/A	4.80	589	3687	34	N/A	0.15	15	0	0	0
13063	WSA	N/A	5.65	503	17570	99	N/A	6.86	1377	5298	30	0
13064	WSA	N/A	8.97	903	10377	81	N/A	4.89	772	2646	6	0
13065	WSA	N/A	8.83	893	96634	759	N/A	2.05	457	2925	8	0
13066	WSA	N/A	2.88	496	9365	53	N/A	0.00	10	0	0	0
13067	WSA	N/A	5.24	646	18437	72	N/A	0.23	322	0	0	0
13068	WSA	N/A	5.46	753	2118	22	N/A	1.38	158	866	1	0
13069	WSA	N/A	4.10	601	68210	189	N/A	0.51	339	0	0	0
13070	WSA	N/A	17.01	395	77785	482	N/A	15.41	1165	3678	27	0
13071	WSA	N/A	7.52	192	53763	469	N/A	15.40	37	121	1	0
13072	WSA	N/A	6.49	663	20867	105	N/A	0.31	345	13520	80	0
13073	WSA	N/A	3.57	466	30419	157	N/A	6.84	116	1364	4	0
13076	WSA	N/A	2.09	108	12048	79	N/A	1.44	47	8650	25	0
13077	WSA	N/A	8.09	654	11212	64	N/A	1.75	89	0	0	0
13078	WSA	N/A	7.25	987	49497	221	N/A	0.29	751	6446	22	0
13079	WSA	N/A	4.58	552	412	2	N/A	2.49	540	0	0	0
13080	WSA	N/A	8.00	1122	149370	1281	N/A	1.28	499	140	1	0

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13081	WSA	N/A	3.09	404	32026	154	N/A	1.14	296	0	0	0
13082	WSA	N/A	6.28	780	56946	457	N/A	0.46	76	0	0	0
13084	ESA	N/A	3.87	180	806	9	N/A	1.37	5	606	1	0
13085	ESA	N/A	2.05	56	2395	7	N/A	0.23	65	256	1	0
13086	ESA	N/A	3.10	245	27922	177	N/A	1.33	311	0	0	0
13087	ESA	N/A	3.05	261	49929	127	N/A	2.20	318	0	0	0
13088	CSA	N/A	3.53	386	5843	45	N/A	1.22	656	0	0	0
13089	CSA	N/A	7.73	696	68795	465	N/A	2.15	382	0	0	0
13090	CSA	N/A	4.69	679	11213	62	N/A	1.53	6	1836	3	0
13091	CSA	N/A	9.03	1299	47432	144	N/A	0.43	56	0	0	0
13092	CSA	N/A	5.33	626	36463	170	N/A	0.29	1	0	0	0
13093	CSA	N/A	7.47	1119	154126	453	N/A	0.03	384	0	0	0
13094	CSA	N/A	6.05	637	43941	352	N/A	1.70	495	12900	129	0
13096	CSA	N/A	19.91	676	77194	670	N/A	10.45	529	0	0	0
13097	CSA	N/A	14.55	632	31057	139	N/A	12.96	500	6372	30	0
13098	CSA	N/A	10.17	528	140985	1038	N/A	8.99	734	12485	22	0
13099	CSA	N/A	11.77	409	28472	265	N/A	18.92	83	18820	64	0
13100	CSA	N/A	6.75	527	95464	1070	N/A	0.87	179	0	0	0
13101	CSA	N/A	3.19	348	16829	86	N/A	0.67	18	0	0	0
13102	CSA	N/A	2.25	375	16520	73	N/A	0.44	12	0	0	0
13103	CSA	N/A	3.75	660	15593	129	N/A	0.43	243	0	0	0
13104	CSA	N/A	5.04	515	46845	504	N/A	1.54	338	389	1	0
13105	CSA	N/A	6.81	626	169639	630	N/A	2.01	1966	0	0	0
13106	CSA	N/A	3.61	406	75689	1033	N/A	5.53	923	33467	109	0
13107	CSA	N/A	4.10	540	20661	205	N/A	5.79	1208	3308	11	0
13109	WSA	N/A	5.49	679	56396	434	N/A	2.40	65	5817	21	0
13110	WSA	N/A	1.18	64	135	3	N/A	1.54	319	0	0	0
13111	WSA	N/A	4.17	554	22171	170	N/A	1.25	527	15084	36	0
13112	WSA	N/A	10.45	998	14553	214	N/A	5.10	3	0	0	0
13113	WSA	N/A	3.22	490	9644	166	N/A	0.08	1939	0	0	0
13114	WSA	N/A	6.38	534	36598	92	N/A	7.94	411	0	0	0
13115	WH	N/A	9.21	639	29755	267	N/A	7.12	479	570	6	0
13117	WH	N/A	11.57	721	4046	61	N/A	21.79	698	0	0	0
13118	WH	N/A	10.24	600	99949	1254	N/A	9.39	625	25940	56	0
13119	PC	N/A	1.65	35	630	3	N/A	2.10	831	0	0	0

(A) Circuit	(B) Service Area	(C) Number of OH Lateral Lines	(D) Number of OH Lateral Miles	(E) Number of Customers Served on OH Lateral Lines	(F) CMI for OH Lateral Lines	(G) CI for OH Lateral Lines	(H) Number of URD Lateral Lines	(I) Number of URD Lateral Miles	(J) Number of Customers Served on URD Lateral Lines	(K) CMI for URD Lateral Lines	(L) CI for URD Lateral Lines	(M) Number of Automatic Line Sectionalizing Devices on the Lateral
13120	PC	N/A	2.64	71	25233	181	N/A	10.20	656	7870	55	0
13121	PC	N/A	3.26	105	0	0	N/A	7.16	66	0	0	0
13122	PC	N/A	3.97	357	30383	278	N/A	1.05	123	318	1	0
13123	PC	N/A	7.70	659	4753	20	N/A	1.32	506	0	0	0
13124	PC	N/A	17.94	636	83123	572	N/A	5.04	355	3655	43	0
13125	PC	N/A	4.19	437	84415	439	N/A	3.07	1007	8899	11	0
13127	ESA	N/A	2.08	105	14262	339	N/A	14.89	516	9085	54	0
13128	ESA	N/A	9.50	566	71933	2719	N/A	6.79	409	2676	12	0
13129	ESA	N/A	2.82	279	31313	105	N/A	5.43	450	17357	85	0
13130	ESA	N/A	6.00	392	14840	99	N/A	4.16	84	12319	36	0
13132	ESA	N/A	1.66	55	444	4	N/A	1.76	177	0	0	0
13133	ESA	N/A	8.34	856	27547	188	N/A	1.64	201	0	0	0
13134	ESA	N/A	2.06	162	2014	7	N/A	2.68	7	25348	103	0
13136	WSA	N/A	4.24	481	57557	213	N/A	0.29	527	0	0	0
13137	WSA	N/A	0.89	152	25657	194	N/A	1.58	865	0	0	0
13138	WSA	N/A	3.98	430	95792	684	N/A	2.54	885	0	0	0
13139	WSA	N/A	5.86	545	27111	97	N/A	3.35	410	15689	29	0
13140	WSA	N/A	4.08	378	11769	60	N/A	0.82	447	0	0	0
13141	WSA	N/A	2.87	625	18213	51	N/A	0.93	517	0	0	0
13142	WSA	N/A	2.87	486	28347	677	N/A	1.34	38	41717	76	0
13143	WSA	N/A	1.97	391	35298	211	N/A	0.35	16	0	0	0
13146	PC	N/A	20.04	486	62308	341	N/A	0.85	289	0	0	0
13147	PC	N/A	32.38	773	44664	480	N/A	5.97	39	0	0	0
13148	PC	N/A	30.95	643	3391	27	N/A	1.09	194	0	0	0
13150	WH	N/A	4.35	394	1679	17	N/A	4.92	1027	0	0	0
13151	WH	N/A	1.86	53	20006	172	N/A	9.99	549	7421	29	0
13152	WH	N/A	3.70	361	90611	298	N/A	8.15	391	309	1	0
13153	WH	N/A	11.37	1116	10958	135	N/A	5.34	1418	3930	5	0
13154	WSA	N/A	3.67	388	10290	34	N/A	8.55	1244	46473	107	0
13155	WSA	N/A	3.78	384	83206	732	N/A	12.05	857	1901	13	0
13156	WSA	N/A	2.21	253	73299	247	N/A	3.81	551	14101	25	0
13157	WSA	N/A	0.82	85	14462	107	N/A	10.02	787	39551	367	0
13158	CSA	N/A	7.19	738	60198	259	N/A	3.06	305	0	0	0
13159	CSA	N/A	8.35	797	158314	916	N/A	1.94	390	381	1	0
13160	CSA	N/A	5.91	529	216670	332	N/A	2.15	56	8074	22	0

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13161	WSA	N/A	3.49	411	6769	37	N/A	0.18	257	0	0	0
13162	WSA	N/A	5.67	600	46265	545	N/A	0.95	121	0	0	0
13163	WSA	N/A	5.61	848	20682	153	N/A	0.52	46	0	0	0
13164	WSA	N/A	5.82	786	97264	464	N/A	0.82	55	0	0	0
13165	WSA	N/A	1.90	247	6022	24	N/A	0.51	439	0	0	0
13166	WSA	N/A	6.34	954	17264	136	N/A	1.11	220	0	0	0
13167	WSA	N/A	7.47	1228	15186	132	N/A	0.75	748	0	0	0
13169	ESA	N/A	1.07	10	56684	733	N/A	10.34	1210	5239	13	0
13170	ESA	N/A	0.22	10	34817	369	N/A	15.75	772	3909	10	0
13171	ESA	N/A	9.35	597	108423	1435	N/A	9.26	107	7029	43	0
13172	ESA	N/A	2.95	224	33987	288	N/A	1.46	453	146	1	0
13173	ESA	N/A	3.23	444	1692	25	N/A	3.69	2121	0	0	0
13174	ESA	N/A	1.57	23	12563	200	N/A	10.03	31	224	8	0
13175	CSA	N/A	17.71	1736	106808	848	N/A	0.55	45	0	0	0
13176	CSA	N/A	8.51	827	107870	1216	N/A	1.12	44	0	0	0
13177	CSA	N/A	3.40	326	413	7	N/A	0.43	40	0	0	0
13178	CSA	N/A	3.11	138	9017	24	N/A	0.55	70	0	0	0
13180	CSA	N/A	2.25	246	6663	28	N/A	0.46	602	0	0	0
13181	CSA	N/A	4.13	310	7577	27	N/A	1.32	25	0	0	0
13183	CSA	N/A	6.92	340	43952	171	N/A	0.36	32	0	0	0
13184	CSA	N/A	1.65	116	653	11	N/A	0.42	1012	0	0	0
13185	CSA	N/A	2.54	242	134057	405	N/A	7.81	109	1520	6	0
13186	CSA	N/A	4.02	442	26636	108	N/A	0.37	620	185	1	0
13187	CSA	N/A	6.07	596	62774	361	N/A	4.40	584	8569	19	0
13188	CSA	N/A	5.25	480	48085	181	N/A	4.88	58	6511	17	0
13189	WSA	N/A	2.59	222	4989	26	N/A	1.44	342	0	0	0
13190	WSA	N/A	8.06	580	156239	1002	N/A	7.27	178	0	0	0
13191	WSA	N/A	4.07	388	71058	446	N/A	3.48	775	1708	4	0
13192	WSA	N/A	4.27	238	652	8	N/A	7.72	841	498	2	0
13193	WSA	N/A	0.00	0	0	0	N/A	10.08	200	10836	21	0
13194	WSA	N/A	6.16	240	7071	23	N/A	1.92	12	0	0	0
13195	WSA	N/A	0.45	56	0	0	N/A	0.37	187	0	0	0
13198	WSA	N/A	4.13	718	11787	92	N/A	2.41	135	0	0	0
13199	WSA	N/A	4.86	725	20294	92	N/A	0.75	5	0	0	0
13200	WSA	N/A	0.37	61	0	0	N/A	0.39	8	0	0	0

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13201	WSA	N/A	2.85	391	20298	38	N/A	0.32	1290	0	0	0
13204	CSA	N/A	5.29	522	135019	836	N/A	4.21	461	4899	30	0
13205	CSA	N/A	4.01	309	58123	267	N/A	2.05	27	11264	80	0
13206	WSA	N/A	10.43	1397	40605	176	N/A	0.17	31	0	0	0
13207	WSA	N/A	9.46	940	77475	414	N/A	0.52	45	0	0	0
13208	WSA	N/A	4.51	504	36902	119	N/A	0.87	3	0	0	0
13210	WSA	N/A	7.38	823	6489	61	N/A	0.08	772	0	0	0
13211	ESA	N/A	2.05	87	8921	48	N/A	6.83	452	5888	9	0
13213	ESA	N/A	21.64	951	233315	1857	N/A	9.34	253	786	7	0
13214	ESA	N/A	6.22	441	17128	70	N/A	5.21	184	44392	62	0
13217	WSA	N/A	3.10	324	23766	137	N/A	1.44	753	0	0	0
13218	WSA	N/A	6.05	587	13748	81	N/A	2.14	358	0	0	0
13219	WSA	N/A	8.87	1200	160698	1377	N/A	2.08	288	4959	58	0
13220	WSA	N/A	4.53	456	32806	829	N/A	1.44	984	81	1	0
13221	CSA	N/A	2.44	117	9716	51	N/A	4.24	16	4027	35	0
13222	CSA	N/A	1.92	167	25475	139	N/A	1.36	99	0	0	0
13223	CSA	N/A	5.43	351	108783	376	N/A	1.51	211	0	0	0
13224	CSA	N/A	10.11	896	334965	2563	N/A	1.17	365	0	0	0
13225	ESA	N/A	5.85	420	23690	121	N/A	4.56	1170	11633	32	0
13226	ESA	N/A	6.79	473	105254	2577	N/A	9.94	492	0	0	0
13227	ESA	N/A	6.28	435	52336	417	N/A	5.51	770	0	0	0
13228	ESA	N/A	3.99	282	16060	77	N/A	4.61	555	513	2	0
13229	ESA	N/A	8.37	643	107509	799	N/A	4.15	837	3317	11	0
13230	ESA	N/A	3.77	296	8704	59	N/A	5.21	736	9324	9	0
13231	ESA	N/A	5.14	495	126649	940	N/A	8.25	158	0	0	0
13233	SH	N/A	4.67	70	3561	22	N/A	1.55	1832	0	0	0
13235	SH	N/A	0.41	6	0	0	N/A	26.11	590	376	1	0
13236	SH	N/A	73.85	671	226359	1780	N/A	11.41	115	0	0	0
13237	SH	N/A	0.00	2	0	0	N/A	3.11	1714	0	0	0
13238	SH	N/A	5.04	71	2244	4	N/A	19.71	587	463	1	0
13241	PC	N/A	11.62	923	65291	378	N/A	4.72	356	8177	17	0
13242	PC	N/A	10.81	364	10365	50	N/A	3.04	364	732	2	0
13243	PC	N/A	10.41	853	11187	121	N/A	2.36	805	0	0	0
13253	CSA	N/A	0.09	1	0	0	N/A		779	0	0	0
13254	SH	N/A	24.61	535	189761	1367	N/A	11.52	5	30318	58	0

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13256	SH	N/A	22.42	437	23101	202	N/A	6.97	5	9769	70	0
13258	CSA	N/A	0.00	0	0	0	N/A	0.58	3	0	0	0
13259	CSA	N/A	0.00	0	0	0	N/A	1.37	720	0	0	0
13260	CSA	N/A	0.00	0	0	0	N/A	0.20	3	0	0	0
13261	CSA	N/A	0.00	0	0	0	N/A	1.23	420	0	0	0
13263	CSA	N/A	0.00	1	0	0	N/A	0.05	1	0	0	0
13264	CSA	N/A	0.00	1	0	0	N/A	1.36	8	0	0	0
13265	CSA	N/A	0.00	0	0	0	N/A	0.46	86	0	0	0
13270	WSA	N/A	0.41	33	20100	406	N/A	3.36	34	0	0	0
13275	WSA	N/A	0.00	0	0	0	N/A	1.87	1	0	0	0
13276	WSA	N/A	0.00	1	0	0	N/A	2.27	63	0	0	0
13278	WH	N/A	7.51	712	1354	16	N/A	0.80	9	0	0	0
13279	WH	N/A	2.77	366	6439	63	N/A	1.04	41	3888	11	0
13280	WH	N/A	0.01	0	0	0	N/A	0.12	247	0	0	0
13281	WH	N/A	0.00	2	0	0	N/A	0.05	329	0	0	0
13282	WH	N/A	12.06	471	4654	89	N/A	2.12	470	2196	12	0
13283	WH	N/A	0.45	4	453	1	N/A	0.31	113	0	0	0
13288	WH	N/A	1.10	114	174	6	N/A	1.67	353	0	0	0
13289	WH	N/A	4.03	319	7693	115	N/A	1.94	159	0	0	0
13290	WH	N/A	5.08	638	21498	142	N/A	1.39	857	2496	16	0
13291	WH	N/A	3.88	311	2918	34	N/A	3.47	861	761	10	0
13292	WH	N/A	2.79	335	3638	28	N/A	1.72	683	0	0	0
13293	WH	N/A	8.37	887	21766	384	N/A	2.44	37	0	0	0
13294	WH	N/A	14.32	1256	14426	147	N/A	2.01	528	0	0	0
13295	WH	N/A	2.85	245	9618	83	N/A	11.12	1291	4200	14	0
13296	WH	N/A	9.53	445	29742	458	N/A	10.35	408	0	0	0
13297	WH	N/A	6.01	545	38257	308	N/A	5.87	1000	37439	164	0
13298	WH	N/A	135.99	1079	279861	2328	N/A	3.41	62	0	0	0
13299	WH	N/A	17.45	537	10707	119	N/A	14.51	508	0	0	0
13302	SH	N/A	2.99	212	49357	384	N/A	17.80	35	2679	57	0
13303	SH	N/A	113.47	1541	482491	2629	N/A	5.61	104	0	0	0
13304	SH	N/A	0.70	11	2305	8	N/A	12.63	102	6279	21	0
13305	SH	N/A	24.50	543	74027	497	N/A	6.38	382	641	1	0
13308	WH	N/A	6.92	675	10770	117	N/A	3.39	105	3375	15	0
13309	WH	N/A	3.64	395	2320	8	N/A	0.32	293	0	0	0

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13310	WH	N/A	2.06	323	10251	72	N/A	0.51	18	0	0	0
13311	WH	N/A	5.73	647	11835	85	N/A	0.54	1030	0	0	0
13312	WH	N/A	4.91	509	23480	136	N/A	2.29	1	0	0	0
13313	WH	N/A	3.60	313	3980	25	N/A	1.37	1	0	0	0
13314	WH	N/A	3.03	159	215	2	N/A	2.02	5	0	0	0
13315	WH	N/A	0.00	0	0	0	N/A	0.49	5	0	0	0
13317	WSA	N/A	0.74	4	0	0	N/A	5.19	502	12742	23	0
13318	WSA	N/A	0.00	0	0	0	N/A	0.40	49	0	0	0
13319	WSA	N/A	0.00	0	0	0	N/A	0.33	13	0	0	0
13320	WSA	N/A	0.00	0	0	0	N/A	2.39	9	0	0	0
13321	WSA	N/A	0.00	0	0	0	N/A	1.57	46	0	0	0
13322	WSA	N/A	0.10	0	83	1	N/A	1.56	5	0	0	0
13323	WSA	N/A	1.79	273	2014	17	N/A	0.96	25	0	0	0
13324	ESA	N/A	6.33	244	16591	145	N/A	0.44	59	0	0	0
13325	ESA	N/A	2.66	34	162	1	N/A	0.64	395	0	0	0
13326	ESA	N/A	8.43	309	87067	825	N/A	2.26	143	0	0	0
13327	ESA	N/A	2.40	18	379	2	N/A	0.41	1460	0	0	0
13328	DC	N/A	6.21	521	11088	66	N/A	0.55	337	0	0	0
13329	DC	N/A	8.12	662	16224	128	N/A	0.51	205	0	0	0
13330	DC	N/A	35.34	1234	65729	453	N/A	7.96	27	182	2	0
13331	DC	N/A	27.42	1106	277854	1806	N/A	3.12	192	0	0	0
13332	WSA	N/A	2.70	101	2808	27	N/A	8.23	1783	13500	50	0
13333	WSA	N/A	1.70	182	1049	6	N/A	2.52	213	0	0	0
13334	WSA	N/A	4.32	623	4110	29	N/A	1.07	1268	0	0	0
13335	WSA	N/A	2.01	38	3117	42	N/A	2.57	423	0	0	0
13336	WSA	N/A	2.50	63	24655	206	N/A	2.84	1226	2500	15	0
13337	WSA	N/A	2.84	285	6434	29	N/A	4.64	723	0	0	0
13338	WSA	N/A	3.43	150	11925	99	N/A	1.92	1281	0	0	0
13339	WSA	N/A	0.48	0	147624	1128	N/A	5.47	997	133	1	0
13340	SH	N/A	3.91	47	4861	49	N/A	8.60	1665	0	0	0
13341	SH	N/A	8.21	153	33894	359	N/A	11.62	350	0	0	0
13342	SH	N/A	9.40	405	12460	67	N/A	7.65	350	0	0	0
13343	SH	N/A	0.53	9	0	0	N/A	15.47	1508	342	1	0
13344	SH	N/A	2.13	43	294	4	N/A	9.43	1311	0	0	0
13348	CSA	N/A	3.76	555	4670	93	N/A	5.67	61	5712	12	0

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13349	CSA	N/A	1.29	18	2157	18	N/A	1.99	1376	0	0	0
13350	CSA	N/A	0.14	62	49439	247	N/A	1.66	264	2112	8	0
13351	CSA	N/A	3.25	456	88511	431	N/A	6.59	68	0	0	0
13352	CSA	N/A	0.99	109	12090	88	N/A	5.06	45	9925	33	0
13353	CSA	N/A	0.00	0	0	0	N/A	0.68	193	0	0	0
13354	CSA	N/A	2.12	147	0	0	N/A	6.23	1953	0	0	0
13355	CSA	N/A	0.00	2	0	0	N/A	0.06	1476	0	0	0
13358	WSA	N/A	4.25	1047	230763	1129	N/A	1.01	899	0	0	0
13359	WSA	N/A	6.21	852	96867	1316	N/A	1.84	4	0	0	0
13360	WSA	N/A	0.10	10	0	0	N/A	0.05	2158	0	0	0
13362	CSA	N/A	0.00	6	6501	110	N/A	1.35	245	6000	43	0
13363	CSA	N/A	0.63	32	10484	196	N/A	5.36	567	37005	95	0
13364	CSA	N/A	0.55	30	19234	107	N/A	5.39	47	12100	25	0
13365	CSA	N/A	2.01	337	516	11	N/A	7.48	233	0	0	0
13366	CSA	N/A	0.00	4	0	0	N/A	0.64	5	0	0	0
13367	CSA	N/A	1.13	43	4878	35	N/A	8.92	161	5016	12	0
13368	CSA	N/A	0.00	0	0	0	N/A	0.02	116	0	0	0
13369	CSA	N/A	0.00	0	0	0	N/A	0.12	4	0	0	0
13370	WH	N/A	11.97	1284	27331	621	N/A	4.11	1	0	0	0
13371	WH	N/A	10.48	644	47080	380	N/A	8.49	158	6908	36	0
13372	WH	N/A	2.43	226	2691	36	N/A	0.89	48	0	0	0
13373	WH	N/A	11.08	909	96259	1332	N/A	2.26	377	0	0	0
13375	WSA	N/A	0.00	0	0	0	N/A		287	0	0	0
13376	WSA	N/A	0.00	0	0	0	N/A	0.28	411	0	0	0
13377	WSA	N/A	4.12	985	156687	1275	N/A	2.04	965	0	0	0
13378	WSA	N/A	0.00	0	0	0	N/A		14	0	0	0
13379	WSA	N/A	6.24	827	83639	1318	N/A	1.20	227	0	0	0
13381	WSA	N/A	0.00	2	0	0	N/A	0.89	107	0	0	0
13382	WSA	N/A	0.00	0	0	0	N/A	0.18	161	0	0	0
13383	WSA	N/A	0.00	0	0	0	N/A		28	0	0	0
13384	WSA	N/A	0.00	0	0	0	N/A	0.01	114	0	0	0
13388	PC	N/A	17.70	514	31571	190	N/A	6.34	55	250	1	0
13389	PC	N/A	17.01	925	36379	220	N/A	1.45	174	0	0	0
13390	PC	N/A	33.45	1213	184214	3559	N/A	4.62	70	672	7	0
13391	PC	N/A	48.46	1178	265010	4210	N/A	6.42	1415	17536	69	0

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13397	CSA	N/A	2.42	207	46785	325	N/A	1.40	469	0	0	0
13398	CSA	N/A	1.10	28	54532	305	N/A	0.88	427	0	0	0
13399	CSA	N/A	0.43	46	66	1	N/A	0.13	928	0	0	0
13400	CSA	N/A	1.92	209	1095	15	N/A	1.49	1306	0	0	0
13405	WSA	N/A	9.06	190	28082	220	N/A	1.77	275	0	0	0
13406	WSA	N/A	1.42	59	14912	198	N/A	5.95	1085	0	0	0
13412	PC	N/A	4.48	302	4757	43	N/A	0.76	282	0	0	0
13414	PC	N/A	9.34	759	7299	66	N/A	1.67	524	0	0	0
13417	CSA	N/A	5.06	637	48066	475	N/A	1.18	231	286	1	0
13418	CSA	N/A	9.62	1095	60865	353	N/A	0.62	547	1104	24	0
13419	CSA	N/A	10.68	1347	44461	251	N/A	0.44	343	493	1	0
13420	CSA	N/A	3.92	417	12376	80	N/A	5.21	179	558	1	0
13422	DC	N/A	44.43	1025	207283	1601	N/A	10.01	2758	90	1	0
13423	DC	N/A	27.03	622	8609	89	N/A	2.99	448	0	0	0
13425	WSA	N/A	0.01	7	22340	107	N/A	9.31	423	2648	7	0
13426	WSA	N/A	5.73	365	117360	958	N/A	11.98	1126	40135	237	0
13427	WSA	N/A	0.00	0	6490	30	N/A	3.98	662	6096	28	0
13428	WSA	N/A	1.31	62	31465	194	N/A	8.96	160	552	1	0
13431	DC	N/A	16.08	471	13406	153	N/A	7.90	35	0	0	0
13432	DC	N/A	4.35	75	5409	13	N/A	16.84	50	0	0	0
13433	ESA	N/A	9.08	306	8362	40	N/A	3.42	459	3458	14	0
13434	ESA	N/A	9.89	887	12660	114	N/A	4.28	165	2749	7	0
13435	ESA	N/A	5.64	285	33984	72	N/A	1.78	65	0	0	0
13436	ESA	N/A	7.77	464	20671	108	N/A	2.49	93	140	1	0
13438	SH	N/A	0.40	101	65603	239	N/A	21.03	5	674	1	0
13439	SH	N/A	2.87	413	34607	197	N/A	6.52	21	0	0	0
13440	SH	N/A	5.45	22	644	2	N/A	6.54	1354	0	0	0
13442	WH	N/A	13.82	609	85216	979	N/A	20.72	616	0	0	0
13443	WH	N/A	5.49	196	46950	896	N/A	6.54	799	28112	114	0
13444	WH	N/A	3.97	425	9480	146	N/A	1.56	621	1240	4	0
13446	WSA	N/A	0.00	0	629	37	N/A	0.68	74	0	0	0
13447	WSA	N/A	1.42	67	6117	31	N/A	0.93	448	218	1	0
13448	WSA	N/A	1.29	119	5436	36	N/A	1.84	152	0	0	0
13449	WSA	N/A	2.63	238	325	5	N/A	1.16	209	0	0	0
13450	WSA	N/A	0.65	56	222	9	N/A	3.55	561	0	0	0

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13451	WSA	N/A	0.18	14	996	3	N/A	2.40	15	0	0	0
13452	WSA	N/A	0.25	33	606	3	N/A	0.18	160	0	0	0
13453	WSA	N/A	0.36	19	4383	41	N/A	4.91	35	1760	5	0
13454	ESA	N/A	4.48	223	23453	293	N/A	11.55	247	150	1	0
13455	ESA	N/A	3.02	184	88780	720	N/A	2.83	692	8729	19	0
13456	ESA	N/A	1.81	140	3420	42	N/A	2.82	628	0	0	0
13457	ESA	N/A	2.29	142	39420	109	N/A	5.10	138	2010	3	0
13458	ESA	N/A	14.78	473	8539	84	N/A	4.12	249	0	0	0
13459	ESA	N/A	11.35	394	18137	113	N/A	10.87	164	2304	22	0
13460	ESA	N/A	37.90	923	165091	1020	N/A	3.13	233	410	1	0
13461	ESA	N/A	27.12	943	210564	1365	N/A	6.09	1562	0	0	0
13462	PC	N/A	4.45	251	12697	118	N/A	8.59	741	5906	10	0
13463	PC	N/A	1.62	235	5365	28	N/A	0.19	1511	0	0	0
13464	PC	N/A	3.67	297	73911	811	N/A	1.08	1250	0	0	0
13466	CSA	N/A	2.30	216	8582	9	N/A	0.43	1374	0	0	0
13467	CSA	N/A	1.29	45	0	0	N/A	1.18	697	0	0	0
13468	CSA	N/A	5.63	643	40381	118	N/A	2.71	2446	0	0	0
13469	CSA	N/A	2.04	131	152719	1692	N/A	7.13	213	3780	36	0
13470	WH	N/A	17.97	738	25026	122	N/A	4.92	385	0	0	0
13471	WH	N/A	3.63	382	12937	94	N/A	2.56	1586	0	0	0
13473	WH	N/A	9.63	542	88222	1156	N/A	2.26	219	15120	35	0
13479	WH	N/A	9.66	527	2534	75	N/A	3.42	308	0	0	0
13480	WSA	N/A	0.84	15	74016	338	N/A	11.21	409	10052	25	0
13481	WSA	N/A	0.00	5	51508	516	N/A	7.12	688	0	0	0
13482	WSA	N/A	0.88	12	38289	216	N/A	15.28	211	7863	20	0
13483	WSA	N/A	4.84	397	79947	521	N/A	14.99	493	392	1	0
13484	WSA	N/A	0.20	10	22435	130	N/A	10.27	44	12684	42	0
13485	WSA	N/A	2.90	135	160045	1365	N/A	6.56	57	0	0	0
13488	SH	N/A	0.94	85	18066	175	N/A	18.88	1331	10500	42	0
13489	SH	N/A	9.41	305	22476	300	N/A	4.35	8	0	0	0
13490	WSA	N/A	2.85	410	4629	25	N/A	3.59	764	10932	36	0
13491	WSA	N/A	2.80	120	53297	756	N/A	9.60	530	4598	13	0
13492	WSA	N/A	5.24	486	42270	404	N/A	2.37	25	0	0	0
13493	WSA	N/A	2.17	281	192538	565	N/A	3.69	1057	7794	39	0
13494	SH	N/A	0.30	9	108	1	N/A	3.44	906	0	0	0

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13495	ESA	N/A	19.03	1174	78254	479	N/A	5.99	280	2720	10	0
13496	CSA	N/A	1.13	72	11033	46	N/A	2.17	1368	0	0	0
13497	CSA	N/A	0.82	156	27421	682	N/A	2.48	93	0	0	0
13498	CSA	N/A	0.00	1	0	0	N/A	0.45	343	0	0	0
13499	CSA	N/A	0.09	3	0	0	N/A	0.99	367	0	0	0
13501	ESA	N/A	0.90	24	7144	32	N/A	1.68	1009	0	0	0
13502	ESA	N/A	5.08	175	82476	900	N/A	8.21	5	0	0	0
13504	ESA	N/A	0.18	5	0	0	N/A	1.29	406	0	0	0
13505	ESA	N/A	3.30	198	13562	155	N/A	5.01	15	0	0	0
13506	ESA	N/A	2.67	79	123735	646	N/A	4.09	207	14828	13	0
13507	ESA	N/A	0.02	0	1002	6	N/A	1.75	2	0	0	0
13509	ESA	N/A	6.89	314	103527	1602	N/A	10.56	225	16356	64	0
13510	WSA	N/A	3.62	386	93457	570	N/A	8.30	143	6551	32	0
13511	WSA	N/A	3.34	439	25575	56	N/A	4.00	65	7898	108	0
13512	WSA	N/A	3.50	384	48582	240	N/A	7.80	1475	70714	156	0
13513	WSA	N/A	0.86	35	410	5	N/A	1.60	1740	0	0	0
13514	WSA	N/A	2.07	256	125314	355	N/A	3.42	909	6703	82	0
13516	WSA	N/A	3.87	474	72981	399	N/A	3.71	974	4034	31	0
13517	WSA	N/A	4.21	373	104737	875	N/A	3.35	668	0	0	0
13518	WSA	N/A	0.38	80	808	5	N/A	0.86	987	0	0	0
13519	WSA	N/A	0.01	3	1020	3	N/A	0.00	601	0	0	0
13520	WSA	N/A	1.31	160	72137	393	N/A	2.42	42	331715	496	0
13521	WSA	N/A	0.00	9	0	0	N/A	1.80	19	0	0	0
13522	WSA	N/A	10.98	1283	308654	1627	N/A	0.70	9	0	0	0
13523	WSA	N/A	4.51	647	71600	382	N/A	0.05	1	0	0	0
13524	WSA	N/A	1.06	143	15781	96	N/A	1.98	912	21072	16	0
13530	WSA	N/A	5.51	838	16521	75	N/A	0.00	1029	0	0	0
13531	WSA	N/A	2.71	92	3585	22	N/A	3.96	575	0	0	0
13532	WSA	N/A	4.37	352	5641	36	N/A	0.66	567	18	1	0
13533	WSA	N/A	2.41	277	39581	193	N/A	6.02	1274	21108	56	0
13535	WSA	N/A	5.32	298	93895	897	N/A	14.88	672	20249	27	0
13538	WSA	N/A	0.22	13	24512	159	N/A	13.31	975	23774	98	0
13539	WSA	N/A	0.86	11	3992	17	N/A	11.76	850	6713	19	0
13540	WSA	N/A	0.20	5	18658	151	N/A	6.74	356	0	0	0
13541	WSA	N/A	0.00	0	21489	189	N/A	14.52	931	7730	17	0

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13544	WSA	N/A	0.88	65	899	2	N/A	4.23	1389	0	0	0
13546	CSA	N/A	8.14	393	6167	74	N/A	2.15	909	568	1	0
13547	CSA	N/A	3.69	281	1688	18	N/A	1.35	2120	0	0	0
13551	CSA	N/A	0.05	1	0	0	N/A	0.01	772	0	0	0
13552	CSA	N/A	2.63	53	374	2	N/A	0.51	1023	0	0	0
13553	CSA	N/A	0.00	0	0	0	N/A	1.88	8	0	0	0
13554	CSA	N/A	1.28	0	0	0	N/A		39	0	0	0
13560	CSA	N/A	0.00	0	0	0	N/A	0.92	83	0	0	0
13561	CSA	N/A	0.00	0	0	0	N/A	0.99	398	0	0	0
13562	CSA	N/A	0.00	0	0	0	N/A	1.45	290	0	0	0
13563	CSA	N/A	0.00	0	0	0	N/A	0.91	194	0	0	0
13564	CSA	N/A	0.00	0	0	0	N/A	0.92	668	0	0	0
13565	CSA	N/A	0.00	0	0	0	N/A	0.94	395	0	0	0
13572	WSA	N/A	0.76	68	14302	47	N/A	9.27	329	5247	54	0
13573	WSA	N/A	1.29	24	21314	175	N/A	10.06	281	6064	16	0
13574	WSA	N/A	3.00	272	23393	170	N/A	5.48	345	0	0	0
13575	WSA	N/A	0.45	23	0	0	N/A	5.43	347	2695	11	0
13576	ESA	N/A	3.00	271	20640	102	N/A	13.83	253	1995	5	0
13577	ESA	N/A	3.00	264	5300	28	N/A	8.47	295	366	1	0
13579	ESA	N/A	4.29	158	33330	206	N/A	12.55	873	8665	34	0
13582	WSA	N/A	6.25	189	45567	233	N/A	11.12	115	10336	27	0
13583	WSA	N/A	4.55	113	874	10	N/A	6.45	1056	0	0	0
13584	WSA	N/A	0.21	3	12603	123	N/A	10.43	30	3248	16	0
13585	WSA	N/A	0.55	26	20317	150	N/A	7.21	8	46120	60	0
13586	WSA	N/A	8.50	249	78868	680	N/A	11.06	90	18642	33	0
13587	WSA	N/A	1.69	14	13498	66	N/A	13.76	114	3013	8	0
13589	WSA	N/A	0.47	9	19680	176	N/A	8.99	87	4894	14	0
13590	CSA	N/A	3.24	377	8989	69	N/A	2.80	1844	49633	131	0
13591	CSA	N/A	7.27	965	32660	187	N/A	0.07	994	0	0	0
13592	CSA	N/A	16.12	2353	238065	1526	N/A	0.86	229	13722	27	0
13593	CSA	N/A	5.49	666	174490	478	N/A	1.15	36	0	0	0
13600	CSA	N/A	6.41	563	15683	82	N/A	1.67	898	298	1	0
13605	WSA	N/A	2.58	300	30817	236	N/A	1.75	1338	0	0	0
13606	WSA	N/A	0.74	40	462	7	N/A	0.38	1324	0	0	0
13610	WSA	N/A	5.81	565	13242	130	N/A	1.43	417	3179	11	0

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13611	WSA	N/A	3.27	318	32304	222	N/A	0.21	361	0	0	0
13612	WSA	N/A	7.49	1018	62901	429	N/A	1.02	254	0	0	0
13613	WSA	N/A	5.45	742	12087	83	N/A	0.86	763	6480	36	0
13621	WSA	N/A	14.12	387	221268	851	N/A	7.45	144	0	0	0
13622	WSA	N/A	22.75	697	252349	1301	N/A	7.55	1078	2244	4	0
13624	WSA	N/A	17.38	363	60223	514	N/A	9.13	1095	4593	13	0
13630	CSA	N/A	6.07	734	82637	337	N/A	1.41	909	0	0	0
13631	CSA	N/A	5.70	440	62180	207	N/A	9.31	572	5924	39	0
13632	CSA	N/A	5.29	483	65125	346	N/A	0.56	1570	3372	12	0
13633	CSA	N/A	3.57	195	20749	148	N/A	6.87	2050	83	1	0
13635	WSA	N/A	0.21	20	0	0	N/A	2.93	1001	0	0	0
13636	WSA	N/A	0.04	5	138	1	N/A	0.57	1206	0	0	0
13637	WSA	N/A	1.20	60	1332	11	N/A	0.67	812	0	0	0
13638	WSA	N/A	2.20	203	7864	159	N/A	0.77	2063	0	0	0
13639	WSA	N/A	0.65	67	0	0	N/A	0.05	698	0	0	0
13640	WSA	N/A	0.00	0	0	0	N/A	0.00	1021	0	0	0
13641	WSA	N/A	0.00	0	0	0	N/A	0.00	1112	0	0	0
13642	WSA	N/A	0.00	0	0	0	N/A	0.00	747	0	0	0
13645	SH	N/A	8.86	176	36777	297	N/A	19.37	721	0	0	0
13646	SH	N/A	1.24	65	112	1	N/A	14.02	834	37	1	0
13648	SH	N/A	19.19	416	42235	288	N/A	5.37	600	0	0	0
13649	SH	N/A	4.81	290	63166	725	N/A	0.84	793	0	0	0
13650	SH	N/A	0.00	0	0	0	N/A	9.89	311	0	0	0
13651	SH	N/A	4.00	162	347066	1374	N/A	12.08	22	11946	66	0
13652	SH	N/A	4.59	192	36272	355	N/A	17.47	2	0	0	0
13655	PC	N/A	7.68	345	4529	38	N/A	4.35	12	0	0	0
13656	PC	N/A	40.24	1078	295433	2024	N/A	8.27	980	840	2	0
13657	PC	N/A	35.11	717	184435	1499	N/A	7.65	893	9254	14	0
13659	WH	N/A	9.26	443	33980	341	N/A	9.12	1356	1719	8	0
13660	WH	N/A	21.67	1009	22252	236	N/A	1.09	1084	0	0	0
13661	WH	N/A	7.89	388	95143	2035	N/A	16.50	1325	27305	245	0
13668	PC	N/A	9.19	249	2930	28	N/A	15.73	315	7409	30	0
13669	WSA	N/A	2.51	161	15352	125	N/A	7.43	2214	101	1	0
13670	WSA	N/A	1.21	5	86960	360	N/A	7.16	2349	580	5	0
13671	WSA	N/A	0.10	5	8082	71	N/A	11.64	470	3289	11	0

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13672	WSA	N/A	3.94	252	12008	162	N/A	10.56	2037	23557	79	0
13673	WSA	N/A	1.07	14	145255	1423	N/A	10.40	1793	158474	443	0
13674	WSA	N/A	1.04	13	770	16	N/A	9.99	1182	0	0	0
13677	WSA	N/A	4.00	87	64497	541	N/A	16.24	316	129536	368	0
13678	WSA	N/A	5.30	113	110831	925	N/A	15.61	551	49108	115	0
13679	WSA	N/A	9.47	344	107263	752	N/A	15.10	957	20990	179	0
13685	ESA	N/A	2.38	115	77087	1653	N/A	12.76	788	2443	7	0
13686	ESA	N/A	3.10	135	12101	80	N/A	14.74	56	896	4	0
13687	ESA	N/A	16.35	571	137820	696	N/A	10.36	721	12346	32	0
13690	ESA	N/A	1.70	88	737	5	N/A	11.42	256	173	1	0
13691	ESA	N/A	0.85	29	8310	40	N/A	10.81	947	21248	129	0
13692	ESA	N/A	1.25	31	265	1	N/A	6.58	857	0	0	0
13693	ESA	N/A	4.91	203	12051	99	N/A	11.39	1222	5121	9	0
13695	WH	N/A	17.50	1048	9553	148	N/A	3.73	275	29463	56	0
13696	WH	N/A	12.78	1224	8626	55	N/A	0.63	99	0	0	0
13697	WH	N/A	0.52	38	1368	12	N/A	0.18	335	0	0	0
13698	WH	N/A	16.94	995	16790	200	N/A	1.75	121	0	0	0
13699	WH	N/A	5.80	259	4654	51	N/A	9.83	3	0	0	0
13705	ESA	N/A	8.63	525	42258	478	N/A	11.09	1750	1066	6	0
13706	ESA	N/A	3.79	198	86800	1035	N/A	10.00	286	2904	10	0
13707	ESA	N/A	1.32	68	3194	25	N/A	8.35	745	22851	96	0
13708	ESA	N/A	1.64	72	15474	118	N/A	12.38	1166	39037	103	0
13709	ESA	N/A	6.24	540	76323	569	N/A	4.75	583	1831	25	0
13710	ESA	N/A	6.92	355	39368	187	N/A	14.29	6	8270	13	0
13711	ESA	N/A	1.80	15	0	0	N/A	14.07	249	177	1	0
13712	ESA	N/A	8.81	476	17685	156	N/A	5.37	890	0	0	0
13713	CSA	N/A	0.00	2	52840	320	N/A	25.46	372	73862	746	0
13714	CSA	N/A	0.02	2	16184	71	N/A	10.34	16	10965	15	0
13715	CSA	N/A	0.08	3	8238	67	N/A	14.88	296	0	0	0
13716	CSA	N/A	0.02	3	1020	6	N/A	6.12	7	0	0	0
13717	CSA	N/A	2.09	18	0	0	N/A	20.95	725	0	0	0
13718	CSA	N/A	0.01	0	32476	391	N/A	18.47	1382	585	1	0
13719	CSA	N/A	0.01	4	0	0	N/A	4.44	579	306	2	0
13722	PC	N/A	9.91	438	49791	685	N/A	1.76	688	0	0	0
13723	PC	N/A	16.64	552	14834	127	N/A	12.79	724	5877	41	0

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13724	PC	N/A	26.06	705	25376	215	N/A	6.06	1806	0	0	0
13729	ESA	N/A	2.41	48	644	4	N/A	12.29	52	9000	23	0
13731	ESA	N/A	0.08	5	1355	6	N/A	10.82	16	33459	97	0
13732	ESA	N/A	0.14	18	1417	12	N/A	16.29	77	5688	24	0
13733	ESA	N/A	1.59	5	10765	74	N/A	7.78	1357	0	0	0
13737	WSA	N/A	3.91	613	3861	58	N/A	0.57	1598	3672	18	0
13738	WSA	N/A	1.98	188	27761	115	N/A	1.28	1027	0	0	0
13739	WSA	N/A	0.83	75	112	2	N/A	0.85	1271	0	0	0
13740	WSA	N/A	10.48	1171	38782	313	N/A	0.17	996	0	0	0
13745	WSA	N/A	1.64	39	18383	145	N/A	16.57	1379	59149	153	0
13747	WSA	N/A	0.74	90	3516	48	N/A	1.91	54	4896	34	0
13748	WSA	N/A	4.41	394	62637	296	N/A	7.78	76	5888	28	0
13749	WSA	N/A	2.05	220	29379	346	N/A	9.03	96	860	10	0
13750	WSA	N/A	1.53	66	43737	178	N/A	5.93	77	5225	5	0
13753	WSA	N/A	3.71	650	27026	81	N/A	0.08	90	0	0	0
13754	WSA	N/A	7.38	1095	212715	1206	N/A	1.03	879	0	0	0
13756	WSA	N/A	3.32	840	17294	234	N/A	1.23	607	0	0	0
13761	WSA	N/A	0.54	23	4553	21	N/A	1.34	1377	0	0	0
13762	WSA	N/A	0.15	5	186	2	N/A	1.36	371	0	0	0
13763	WSA	N/A	0.00	0	0	0	N/A	0.03	865	0	0	0
13764	WSA	N/A	0.16	11	1002	3	N/A	1.27	783	0	0	0
13765	WSA	N/A	0.00	0	0	0	N/A	0.22	295	0	0	0
13769	WH	N/A	16.73	389	56163	726	N/A	13.68	1057	0	0	0
13770	WH	N/A	4.03	224	28943	186	N/A	21.80	151	4398	13	0
13772	WH	N/A	18.80	739	5680	87	N/A	9.95	677	2160	6	0
13777	SH	N/A	2.18	261	30483	136	N/A	13.07	340	43649	83	0
13780	SH	N/A	7.09	612	78585	493	N/A	9.92	605	20113	42	0
13781	SH	N/A	2.18	73	66696	424	N/A	18.42	890	8680	14	0
13785	PC	N/A	16.44	274	71347	401	N/A	2.72	688	0	0	0
13786	PC	N/A	43.28	743	121536	968	N/A	1.54	1509	459	1	0
13787	PC	N/A	41.15	853	85965	537	N/A	6.72	531	0	0	0
13793	ESA	N/A	3.69	184	31106	154	N/A	12.28	598	302	2	0
13795	ESA	N/A	8.49	284	159917	764	N/A	24.73	1276	10078	73	0
13796	ESA	N/A	5.79	186	89677	491	N/A	7.04	1229	2898	6	0
13797	ESA	N/A	4.71	200	23126	96	N/A	16.26	954	0	0	0

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13798	ESA	N/A	3.46	177	91729	286	N/A	9.68	686	6906	27	0
13799	ESA	N/A	2.80	125	7234	47	N/A	10.81	253	0	0	0
13805	PC	N/A	46.98	990	221076	1193	N/A	3.75	1393	0	0	0
13807	PC	N/A	34.78	1005	55788	915	N/A	2.61	297	2902	8	0
13808	PC	N/A	102.43	1757	194610	2128	N/A	4.41	80	453	1	0
13813	DC	N/A	43.49	705	122864	320	N/A	5.35	546	0	0	0
13815	DC	N/A	45.20	635	119721	1022	N/A	7.50	1597	1455	3	0
13817	SH	N/A	20.31	782	516357	3612	N/A	14.41	954	0	0	0
13825	CSA	N/A	7.08	748	49351	384	N/A	2.13	853	0	0	0
13826	CSA	N/A	3.60	242	7355	57	N/A	7.09	1618	2583	9	0
13827	CSA	N/A	4.06	361	27473	154	N/A	3.47	1398	1792	4	0
13828	CSA	N/A	6.10	438	8092	36	N/A	3.25	2235	1494	3	0
13829	CSA	N/A	1.11	57	6014	73	N/A	8.26	1227	6653	45	0
13830	CSA	N/A	3.73	314	14304	147	N/A	5.83	114	2630	5	0
13831	CSA	N/A	0.62	137	26812	304	N/A	5.38	104	4576	8	0
13832	CSA	N/A	3.00	232	980	19	N/A	1.45	1354	0	0	0
13835	CSA	N/A	5.51	511	14494	37	N/A	2.96	1527	0	0	0
13836	CSA	N/A	1.02	34	7708	55	N/A	7.92	1162	11478	48	0
13837	CSA	N/A	4.04	427	68607	786	N/A	7.30	1113	20706	58	0
13838	CSA	N/A	9.37	650	72710	1055	N/A	6.44	1139	0	0	0
13839	CSA	N/A	6.81	396	20161	163	N/A	15.92	1389	3478	13	0
13840	CSA	N/A	7.75	339	92240	343	N/A	10.20	641	7386	36	0
13844	CSA	N/A	0.23	5	351	1	N/A	2.54	1332	0	0	0
13845	CSA	N/A	0.00	0	0	0	N/A	3.94	857	0	0	0
13850	PC	N/A	0.07	3	9880	91	N/A	11.33	227	2375	5	0
13853	PC	N/A	1.99	25	223422	1207	N/A	26.94	761	3292	11	0
13854	PC	N/A	17.21	1031	34590	156	N/A	16.07	720	26350	133	0
13858	CSA	N/A	0.00	0	0	0	N/A	0.25	1567	0	0	0
13860	WSA	N/A	1.85	42	25690	209	N/A	7.89	112	14522	53	0
13863	WSA	N/A	0.77	19	11563	107	N/A	7.37	1177	0	0	0
13864	WSA	N/A	2.29	138	39262	578	N/A	1.73	338	1632	6	0
13865	WSA	N/A	5.30	224	71843	217	N/A	13.27	53	2670	8	0
13866	WSA	N/A	3.60	154	758	6	N/A	4.63	673	337	1	0
13867	WSA	N/A	2.32	142	520	4	N/A	1.71	675	0	0	0
13869	WSA	N/A	0.19	11	0	0	N/A	5.71	1581	4368	7	0

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13870	WSA	N/A	3.65	75	336454	2078	N/A	13.28	612	4928	16	0
13871	WSA	N/A	0.32	4	100	1	N/A	8.08	31	13988	52	0
13872	WSA	N/A	0.08	1	8745	53	N/A	9.68	1405	7048	44	0
13873	WSA	N/A	4.22	64	75399	201	N/A	16.15	581	2128	16	0
13878	ESA	N/A	2.06	51	6096	48	N/A	8.28	1515	2816	26	0
13879	ESA	N/A	0.27	6	4800	30	N/A	8.61	30	9131	31	0
13880	ESA	N/A	0.14	4	8226	52	N/A	6.26	949	0	0	0
13881	ESA	N/A	0.00	2	73	1	N/A	1.42	1	0	0	0
13882	ESA	N/A	0.00	0	1000	8	N/A	1.12	440	0	0	0
13883	ESA	N/A	1.24	58	84	1	N/A	4.81	1104	0	0	0
13884	ESA	N/A	0.33	8	11354	113	N/A	11.47	303	46330	127	0
13885	ESA	N/A	0.61	9	39	1	N/A	9.91	984	1620	5	0
13886	WSA	N/A	0.00	1	15201	91	N/A	11.82	759	42528	85	0
13888	WSA	N/A	0.82	20	12126	92	N/A	11.64	13	34730	83	0
13889	WSA	N/A	6.89	290	25060	235	N/A	13.51	3	1736	8	0
13890	WSA	N/A	0.70	31	14708	87	N/A	7.02	1	10361	71	0
13891	WSA	N/A	0.01	3	24892	152	N/A	17.78	390	2856	6	0
13892	WSA	N/A	1.69	71	142960	438	N/A	7.28	100	3388	3	0
13895	WSA	N/A	0.86	72	357	7	N/A	2.14	91	0	0	0
13896	SH	N/A	8.05	601	35556	174	N/A	6.84	207	0	0	0
13897	SH	N/A	4.66	86	43111	456	N/A	11.10	90	2778	6	0
13898	SH	N/A	1.61	20	50	1	N/A	24.32	2132	60	1	0
13899	SH	N/A	2.00	116	3952	30	N/A	1.06	1499	449	1	0
13900	SH	N/A	5.60	62	1402	5	N/A	16.86	191	0	0	0
13906	ESA	N/A	6.77	361	31720	114	N/A	3.42	1369	0	0	0
13909	ESA	N/A	7.57	559	43363	436	N/A	2.74	224	0	0	0
13910	ESA	N/A	7.98	349	66717	645	N/A	8.92	101	11544	24	0
13911	ESA	N/A	6.71	440	58444	708	N/A	6.11	3	0	0	0
13916	WH	N/A	2.41	129	3315	49	N/A	12.45	1301	1667	9	0
13918	WH	N/A	1.89	91	9865	73	N/A	10.43	443	0	0	0
13919	WH	N/A	0.01	11	0	0	N/A	1.04	6	0	0	0
13920	WH	N/A	1.96	59	387405	2259	N/A	10.67	1332	0	0	0
13921	WH	N/A	2.46	152	7048	70	N/A	6.24	1808	0	0	0
13922	WH	N/A	0.82	11	19964	237	N/A	27.11	6	259	1	0
13924	WH	N/A	41.50	512	10404	262	N/A	1.42	164	0	0	0

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13927	WH	N/A	26.42	703	66899	1428	N/A	11.27	334	197	1	0
13929	SH	N/A	0.46	0	0	0	N/A	0.05	2077	0	0	0
13930	SH	N/A	0.00	0	0	0	N/A	0.00	1038	0	0	0
13932	CSA	N/A	4.03	167	15812	112	N/A	7.18	892	0	0	0
13934	CSA	N/A	1.44	33	2672	11	N/A	8.36	1227	25332	54	0
13935	CSA	N/A	1.86	138	14292	248	N/A	3.67	1543	1595	11	0
13939	CSA	N/A	2.66	142	29389	209	N/A	10.60	1635	0	0	0
13942	CSA	N/A	0.32	151	25978	258	N/A	0.89	614	28495	391	0
13943	CSA	N/A	1.22	51	2378	21	N/A	0.96	856	251	1	0
13944	CSA	N/A	0.06	16	1423	13	N/A	0.03	374	0	0	0
13946	CSA	N/A	0.00	0	0	0	N/A		42	0	0	0
13947	CSA	N/A	6.43	898	86282	451	N/A	0.15	806	0	0	0
13948	CSA	N/A	6.44	695	29197	343	N/A	2.61	2	0	0	0
13951	ESA	N/A	0.92	49	4213	155	N/A	1.58	53	528	2	0
13952	ESA	N/A	0.39	12	0	0	N/A	2.66	668	559	1	0
13953	ESA	N/A	4.10	161	811	7	N/A	5.38	446	0	0	0
13954	ESA	N/A	0.41	21	0	0	N/A	2.82	307	0	0	0
13955	ESA	N/A	3.50	118	18757	92	N/A	8.08	954	0	0	0
13956	ESA	N/A	1.28	55	635	7	N/A	6.99	816	360	4	0
13959	PC	N/A	12.74	439	67267	383	N/A	2.65	854	0	0	0
13961	PC	N/A	22.18	587	147772	955	N/A	14.58	279	20565	85	0
13962	PC	N/A	19.20	742	59334	435	N/A	5.26	1102	1375	8	0
13963	ESA	N/A	4.50	342	60804	360	N/A	2.52	1701	12351	23	0
13964	ESA	N/A	7.30	444	27222	101	N/A	0.35	273	0	0	0
13967	WH	N/A	3.66	208	6349	51	N/A	13.97	1814	17388	54	0
13968	WH	N/A	5.31	597	5334	55	N/A	1.45	1403	0	0	0
13971	WH	N/A	0.18	1	142	1	N/A	1.17	54	0	0	0
13972	WH	N/A	3.93	58	17020	307	N/A	18.47	351	4200	40	0
13973	WH	N/A	1.36	34	205686	2283	N/A	16.28	38	0	0	0
13980	PC	N/A	0.00	1	0	0	N/A	0.00	1916	0	0	0
13982	PC	N/A	2.16	47	502	6	N/A	0.89	1427	310	2	0
13983	PC	N/A	18.65	595	46109	278	N/A	4.48	255	0	0	0
13984	PC	N/A	9.23	339	11124	63	N/A	6.45	1058	0	0	0
13985	CSA	N/A	0.00	12	0	0	N/A	21.85	10	28458	54	0
13986	CSA	N/A	1.17	8	29442	220	N/A	14.20	993	2872	8	0

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13987	CSA	N/A	0.05	5	103101	670	N/A	10.08	5	89422	248	0
13988	CSA	N/A	0.00	0	10851	89	N/A	11.90	422	29636	96	0
13989	CSA	N/A	0.00	21	4107	18	N/A	19.58	1345	67495	169	0
13990	CSA	N/A	0.59	7	0	0	N/A	21.68	1	6936	39	0
13991	CSA	N/A	0.00	2	0	0	N/A	6.77	753	11584	29	0
13993	CSA	N/A	4.95	191	26914	166	N/A	11.27	1153	2216	8	0
14000	PC	N/A	16.41	551	89940	1318	N/A	6.20	1131	0	0	0
14001	PC	N/A	3.42	51	318	1	N/A	1.04	1691	267	1	0
14002	PC	N/A	0.52	8	35535	240	N/A	14.60	1376	23997	150	0
14004	PC	N/A	0.05	3	0	0	N/A	0.22	1508	0	0	0
14010	CSA	N/A	0.00	2	0	0	N/A	2.40	1030	0	0	0
14011	CSA	N/A	0.86	5	12708	69	N/A	4.90	1008	0	0	0
14012	CSA	N/A	11.42	668	103563	1268	N/A	4.36	1123	0	0	0
14014	CSA	N/A	0.74	0	290	1		1.10	1828	0	0	o
14020	SH	N/A	5.09	261	26055	246	N/A	9.24	660	381	1	0
14021	SH	N/A	8.61	325	65998	412	N/A	11.43	1013	5993	13	0
14022	SH	N/A	1.23	9	83	1	N/A	12.98	1392	0	0	0
14023	SH	N/A	16.13	424	40457	460	N/A	4.88	851	0	0	0
14024	SH	N/A	8.54	566	34419	192	N/A	13.08	1272	0	0	0
14025	SH	N/A	9.40	249	154908	1967	N/A	17.85	535	0	0	0
14026	SH	N/A	3.36	52	5125	13	N/A	4.67	1848	1855	5	0
14030	WSA	N/A	6.66	245	240554	3107	N/A	24.43	1483	12966	21	0
14031	WSA	N/A	7.53	346	31050	280	N/A	11.51	1793	1715	7	0
14032	WSA	N/A	1.42	41	180	2	N/A	1.53	631	0	0	0
14035	WSA	N/A	1.04	77	1160	19	N/A	2.16	664	0	0	0
14036	WSA	N/A	0.00	0	0	0	N/A	0.81	642	174	1	0
14037	WSA	N/A	0.80	2	6444	36	N/A	18.56	658	15756	78	0
14040	CSA	N/A	5.97	339	99143	486	N/A	11.92	1047	18775	76	0
14041	CSA	N/A	19.39	761	89335	541	N/A	5.21	133	437	1	0
14042	CSA	N/A	4.98	420	35474	110	N/A	13.29	330	55241	139	0
14050	PC	N/A	31.57	419	22763	158	N/A	1.88	87	367	1	0
14051	PC	N/A	1.66	0	0	0	N/A	0.07	1915	0	0	0
14059	CSA	N/A	0.07	1	1236	22	N/A	2.02	963	641	3	0
14060	CSA	N/A	0.00	0	0	0	N/A	0.53	1133	0	0	0
14064	CSA	N/A	0.00	1	0	0	N/A	0.53	1411	0	0	0

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14065	CSA	N/A	0.00	0	31104	216	N/A	8.36	828	31947	78	0
14066	CSA	N/A	0.00	0	0	0	N/A	0.39	956	0	0	0
14069	WSA	N/A	5.63	215	58532	408	N/A	17.03	629	2457	6	0
14070	WSA	N/A	0.07	14	19718	148	N/A	18.93	1	222	1	0
14071	WSA	N/A	8.66	316	44959	251	N/A	20.01	44	7452	16	0
14079	WSA	N/A	0.00	0	39244	396	N/A	15.91	239	45525	113	0
14080	WSA	N/A	0.03	0	0	0	N/A	15.92	19	30914	164	0
14081	WSA	N/A	0.00	0	18663	101	N/A	10.42	1	49099	742	0
14082	WSA	N/A	0.00	0	10227	61	N/A	13.52	1303	18620	38	0
14083	WSA	N/A	1.34	94	4796	58	N/A	15.44	552	3212	11	0
14084	WSA	N/A	0.11	5	2076	12	N/A	15.45	670	0	0	0
14089	CSA	N/A	0.08	7	57813	201	N/A	24.49	277	58760	560	0
14090	CSA	N/A	0.12	11	150069	2562	N/A	9.05	1189	0	0	0
14091	CSA	N/A	0.21	5	9903	121	N/A	11.35	16	4345	15	0
14094	CSA	N/A	0.03	9	11100	54	N/A	11.34	0	23176	75	0
14095	CSA	N/A	0.00	1	0	0	N/A	14.78	0	3276	6	0
14096	CSA	N/A	0.00	0	0	0	N/A	14.05	0	0	0	0
14099	CSA	N/A	2.60	44	50533	572	N/A	9.01	0	1866	6	0
14100	CSA	N/A	0.00	0	0	0	N/A	19.04	0	25735	166	0
14101	CSA	N/A	0.00	0	12405	93	N/A	20.68	0	29714	73	0
14102	CSA	N/A	2.32	45	150723	2187	N/A	19.97	0	36887	88	0
14109	ESA	N/A	0.47	17	6424	64	N/A	5.23	0	2880	9	0
14110	ESA	N/A	4.21	152	19916	129	N/A	14.79	0	4707	11	0
14111	ESA	N/A	7.54	495	30349	269	N/A	7.72	0	3660	30	0
14112	ESA	N/A	3.56	122	11707	95	N/A	10.43	0	5600	14	0
14114	ESA	N/A	6.02	287	47125	358	N/A	12.26	0	9100	40	0
14115	ESA	N/A	0.92	29	2258	33	N/A	3.00	0	0	0	0
14116	ESA	N/A	1.13	91	10016	62	N/A	1.68	0	5030	10	0
14117	ESA	N/A	0.76	102	234	3	N/A	1.66	0	0	0	0
14119	PC	N/A	0.33	4	56589	304	N/A	25.43	0	12515	26	0
14120	PC	N/A	2.45	41	5560	40	N/A	14.70	0	644	7	0
14121	PC	N/A	17.22	315	116142	1014	N/A	22.32	0	206	1	0
14122	PC	N/A	0.01	0	0	0	N/A	25.29	0	168	3	0
14123	PC	N/A	5.80	167	13519	50	N/A	14.35	0	0	0	0
14144	SH	N/A	7.03	521	92040	1534	N/A	10.34	0	3267	9	0

(A) Circuit	(B) Service Area	(C) Number of OH Lateral Lines	(D) Number of OH Lateral Miles	(E) Number of Customers Served on OH Lateral Lines	(F) CMI for OH Lateral Lines	(G) CI for OH Lateral Lines	(H) Number of URD Lateral Lines	(I) Number of URD Lateral Miles	(J) Number of Customers Served on URD Lateral Lines	(K) CMI for URD Lateral Lines	(L) CI for URD Lateral Lines	(M) Number of Automatic Line Sectionalizing Devices on the Lateral
14145	SH	N/A	0.18	3	353	2	N/A	12.52	0	92734	202	0
14196	ESA	N/A	0.00	0	0	0	N/A	0.08	0	0	0	0
14197	ESA	N/A	2.05	44	1526	6	N/A	0.77	0	460	2	0
14198	ESA	N/A	2.06	59	0	0	N/A	4.09	0	0	0	0
14199	ESA	N/A	1.13	64	804	3	N/A	0.80	0	0	0	0
14200	SH	N/A	0.00	0	0	0	N/A	0.00	0	0	0	0
14201	SH	N/A	0.00	0	0	0	N/A	0.00	0	0	0	0
14207	ESA	N/A	0.17	2	0	0	N/A	0.00	0	0	0	0
14208	ESA	N/A	0.00	0	0	0	N/A	0.02	0	0	0	0
14209	ESA	N/A	0.00	1	0	0	N/A	0.00	0	0	0	0
14216	CSA	N/A	7.59	0	8577	91	N/A	18.00	0	0	0	0
14217	CSA	N/A	5.12	26	2108	16	N/A	6.72	0	0	0	0
14218	CSA	N/A	0.05	0	36218	157	N/A	9.94	0	9605	25	0
14274	WSA	N/A	27.41	519	79624	321	N/A	5.85	0	0	0	0
14275	WSA	N/A	2.53	25	12224	44	N/A	23.32	0	19830	49	0
14306	DC	N/A	17.01	415	57140	668	N/A	1.23	0	0	0	0
14310	ESA	N/A	0.00	0	0	0	N/A	0.00	0	0	0	0
14341	ESA	N/A	6.43	22	0	0	N/A	0.00	0	0	0	0

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	21.47	0.09	0	0	0	3.83	61	18480	440	5.7%	5.9
0	YES	12.80	0.05	0	0	0	2.81	14	0	0	3.9%	4.6
0	YES	40.12	0.59	0	0	0	8.73	52	116443	3106	-25.2%	4.0
0	YES	22.87	0.00	0	0	0	3.35	32	37430	985	0.4%	5.4
0	YES	9.59	0.51	0	0	0	1.08	34	0	0	-9.8%	3.5
0	YES	38.68	0.05	0	0	0	5.93	68	105294	1770	-32.0%	5.4
0	YES	38.25	0.19	0	0	0	3.06	15	39858	546	3.5%	7.2
0	YES	19.55	0.00	0	0	0	0.86	46	42723	863	-9.4%	2.8
0	YES	6.31	0.09	0	0	0	1.90	0	15603	257	-25.9%	2.4
0	YES	22.34	0.20	0	0	0	4.63	47	394931	3760	-2.3%	7.4
0	YES	38.85	0.54	0	0	0	6.41	102	386217	5576	-1.6%	7.9
0	YES	2.15	0.32	0	0	0	0.51	0	5184	108	-12.6%	4.0
0	YES	3.06	0.82	0	0	0	0.63	14	0	0	-9.6%	4.3
0	YES	2.09	0.15	0	0	0	0.70	0	0	0	-10.6%	1.4
0	YES	25.53	0.50	0	0	0	3.22	59	147098	3002	1.2%	6.4
0	YES	25.14	0.46	0	0	0	3.77	43	134416	2986	1.6%	7.7
0	YES	18.28	0.00	0	0	0	3.86	60	0	0	-2.4%	3.9
0	YES	11.56	0.08	0	0	0	2.96	43	25289	1331	-1.3%	6.5
0	YES	4.96	0.11	0	0	0	0.11	7	0	0	10.9%	2.2
0	YES	12.30	0.10	0	0	0	2.05	66	0	0	-1.7%	5.5
0	YES	10.79	0.12	0	0	0	0.94	45	0	0	-0.4%	4.1
0	YES	9.11	0.04	0	0	0	1.25	75	0	0	-3.4%	4.9
0	YES	12.21	0.41	0	0	0	0.71	22	40139	979	-3.5%	4.3
0	YES	11.63	0.02	0	0	0	1.45	51	22800	1425	-0.6%	5.2
0	YES	10.51	0.29	0	0	0	1.04	25	0	0	2.6%	4.9
0	YES	45.90	0.09	0	0	0	5.14	74	0	0	-2.3%	7.3
0	YES	19.58	0.00	0	0	0	3.47	38	0	0	-0.9%	2.8
0	YES	12.48	0.04	0	0	0	2.02	32	45764	1346	-1.2%	4.4
0	YES	8.00	0.00	0	0	0	2.02	36	0	0	-2.1%	5.6
0	YES	13.94	0.73	0	0	0	1.85	93	169807	2011	32.8%	8.6
0	YES	10.00	0.00	0	0	0	2.39	97	0	0	-3.2%	4.4
0	YES	11.35	0.13	0	0	0	2.01	36	0	0	-2.1%	3.5
0	YES	16.46	0.08	0	0	0	3.00	36	0	0	-2.5%	5.2
0	YES	15.92	0.60	0	0	0	0.66	3	75798	1600	-2.8%	6.6
0	YES	23.96	0.00	0	0	0	4.24	56	0	0	2.6%	6.8

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	15.09	0.05	0	0	0	2.41	136	563011	3127	3.0%	6.1
0	YES	15.53	0.05	0	0	0	2.06	139	126614	2183	1.4%	7.9
0	YES	13.54	0.03	0	0	0	1.49	116	204253	3425	-0.5%	7.0
0	YES	8.93	0.11	0	0	0	1.61	79	81630	1771	-0.9%	4.6
0	YES	11.13	0.00	0	0	0	3.17	94	2522	1261	2.6%	4.7
0	YES	5.59	0.04	0	0	0	1.33	27	0	0	2.5%	2.6
0	YES	10.90	0.15	0	0	0	2.29	95	38730	1291	-2.9%	5.1
0	YES	9.47	0.05	0	0	0	1.70	69	0	0	-1.1%	4.0
0	YES	3.06	1.49	0	0	0	0.44	0	0	0	-5.7%	5.4
0	YES	7.48	0.14	0	0	0	1.88	17	0	0	0.2%	4.8
0	YES	3.04	0.08	0	0	0	1.47	0	6125	175	-19.1%	6.0
0	YES	13.66	0.23	0	0	0	2.23	67	0	0	-0.4%	6.0
0	YES	3.18	0.67	0	0	0	1.08	5	0	0	-11.2%	3.6
0	YES	4.24	1.17	0	0	0	2.29	0	0	0	6.5%	3.4
0	YES	7.47	0.00	0	0	0	2.22	0	6821	793	-3.2%	7.2
0	YES	9.12	0.00	0	0	0	1.38	123	0	0	5.2%	4.9
0	YES	7.53	0.00	0	0	0	1.98	33	0	0	-1.8%	5.5
0	YES	6.05	0.00	0	0	0	2.21	101	43576	1216	0.0%	3.1
0	YES	6.71	0.00	0	0	0	1.77	63	0	0	-0.8%	2.4
0	YES	15.59	0.00	0	0	0	3.08	76	0	0	-6.2%	6.9
0	YES	15.83	0.00	0	0	0	1.98	126	0	0	-3.8%	7.6
0	YES	11.53	0.00	0	0	0	0.65	175	0	0	-2.1%	5.3
0	YES	3.50	0.09	0	0	0	0.52	10	0	0	6.8%	2.0
0	YES	6.69	0.06	0	0	0	1.16	57	0	0	-1.6%	4.3
0	YES	8.14	0.03	0	0	0	1.27	121	0	0	4.7%	4.9
0	YES	7.28	0.13	0	0	0	2.53	50	0	0	-0.2%	5.1
0	YES	35.97	0.69	0	0	0	2.86	28	2259	753	-3.6%	5.1
0	YES	25.30	0.06	0	0	0	2.31	4	0	0	6.7%	8.8
0	YES	7.48	0.32	0	0	0	0.35	37	9152	416	0.4%	5.6
0	YES	12.47	0.19	0	0	0	1.86	50	0	0	-1.8%	5.7
0	YES	5.13	0.00	0	0	0	1.60	12	0	0	9.3%	4.9
0	YES	13.03	0.09	0	0	0	3.09	70	0	0	-7.3%	5.8
0	YES	8.61	0.06	0	0	0	1.02	11	0	0	-0.1%	6.0
0	YES	9.55	0.26	0	0	0	2.22	71	0	0	1.5%	5.9
0	YES	11.50	0.16	0	0	0	2.06	104	0	0	-3.4%	7.2

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	4.68	0.19	0	0	0	0.25	53	0	0	-8.6%	4.4
0	YES	7.29	0.00	0	0	0	0.52	25	0	0	-9.1%	5.3
0	YES	7.64	0.12	0	0	0	2.29	10	0	0	-5.5%	3.8
0	YES	3.50	0.37	0	0	0	0.85	0	0	0	-3.7%	3.4
0	YES	7.85	0.37	0	0	0	3.05	25	20398	329	12.4%	6.0
0	YES	6.63	0.03	0	0	0	1.36	30	0	0	-1.0%	2.1
0	YES	5.91	0.04	0	0	0	1.11	19	0	0	10.7%	2.8
0	YES	10.21	0.00	0	0	0	0.33	46	0	0	2.1%	5.1
0	YES	8.86	0.37	0	0	0	2.28	41	0	0	7.8%	5.4
0	YES	11.91	0.10	0	0	0	2.34	65	0	0	5.9%	5.6
0	YES	7.10	0.19	0	0	0	1.30	92	32214	767	5.2%	3.2
0	YES	9.11	0.21	0	0	0	1.40	72	41140	1210	2.2%	4.4
0	YES	11.25	0.89	0	0	0	2.62	74	0	0	-3.1%	6.0
0	YES	33.71	0.08	0	0	0	3.27	73	112885	2480	-8.9%	7.2
0	YES	32.75	0.54	0	0	0	4.70	0	0	0	-8.3%	5.3
0	YES	23.63	0.07	0	0	0	4.39	95	137127	2954	0.0%	6.6
0	YES	37.14	0.07	0	0	0	6.38	0	61236	1134	-14.4%	5.8
0	YES	9.49	0.02	0	0	0	1.84	55	0	0	-19.4%	5.7
0	YES	5.05	0.00	0	0	0	1.19	85	0	0	3.0%	3.9
0	YES	5.27	0.13	0	0	0	2.46	65	19479	453	5.7%	2.2
0	YES	6.29	0.16	0	0	0	1.95	42	6770	677	6.8%	3.8
0	YES	8.73	0.00	0	0	0	2.15	47	83332	1288	-10.5%	4.9
0	YES	10.49	0.00	0	0	0	1.67	57	89676	636	1.9%	5.7
0	YES	10.37	0.09	0	0	0	1.15	203	80988	2382	-5.3%	4.9
0	YES	13.08	0.00	0	0	0	3.20	69	0	0	-8.2%	6.3
0	YES	8.85	0.22	0	0	0	0.74	165	0	0	-5.0%	4.6
0	YES	4.47	0.08	0	0	0	1.67	0	0	0	-13.0%	5.8
0	YES	6.69	0.33	0	0	0	0.94	12	0	0	-2.2%	5.0
0	YES	19.57	0.21	0	0	0	3.81	107	73600	1600	18.3%	6.5
0	YES	4.34	0.06	0	0	0	0.98	17	29884	482	-1.8%	2.1
0	YES	15.90	0.89	0	0	0	0.69	57	0	0	-2.9%	8.3
0	YES	19.45	0.60	0	0	0	2.52	62	0	0	-3.9%	5.0
0	YES	38.95	2.48	0	0	0	3.12	34	0	0	-5.9%	4.0
0	YES	26.07	0.52	0	0	0	5.91	72	207696	4471	-10.3%	5.2
0	YES	5.59	0.08	0	0	0	1.76	0	88046	662	9.6%	4.6

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	15.76	0.74	0	0	0	2.17	13	0	0	-2.9%	5.4
0	YES	13.57	0.26	0	0	0	2.90	33	0	0	3.3%	7.2
0	YES	6.47	0.09	0	0	0	1.36	21	0	0	-1.4%	5.6
0	YES	11.10	0.00	0	0	0	2.08	68	0	0	12.2%	4.4
0	YES	26.91	0.14	0	0	0	3.79	68	37820	1220	-5.6%	7.1
0	YES	10.64	0.86	0	0	0	2.52	68	173087	2183	-2.5%	6.2
0	YES	19.53	0.00	0	0	0	2.56	53	0	0	-0.9%	5.3
0	YES	19.71	0.03	0	0	0	3.39	70	0	0	59.1%	5.2
0	YES	10.25	0.13	0	0	0	1.87	6	0	0	-3.1%	4.3
0	YES	13.74	0.07	0	0	0	3.51	55	0	0	-4.5%	4.9
0	YES	3.98	0.00	0	0	0	0.57	0	0	0	14.9%	2.6
0	YES	11.41	0.00	0	0	0	1.43	64	0	0	-33.3%	4.0
0	YES	5.88	0.07	0	0	0	1.07	49	0	0	3.3%	1.6
0	YES	6.04	0.10	0	0	0	1.41	26	0	0	19.7%	2.9
0	YES	4.26	0.42	0	0	0	1.38	70	39326	742	2.8%	3.8
0	YES	7.76	0.03	0	0	0	1.21	80	0	0	-4.3%	4.6
0	YES	10.93	0.05	0	0	0	1.68	38	0	0	4.1%	7.9
0	YES	5.01	0.08	0	0	0	0.03	45	23520	672	2.0%	2.8
0	YES	5.08	0.38	0	0	0	0.90	36	0	0	-4.0%	5.6
0	YES	5.04	0.29	0	0	0	0.53	135	0	0	-4.6%	4.5
0	YES	3.74	0.39	0	0	0	1.03	25	0	0	1.8%	9.1
0	YES	29.39	0.31	0	0	0	8.19	13	21197	517	-7.2%	1.4
0	YES	43.88	0.02	0	0	0	5.51	35	0	0	-6.5%	3.0
0	YES	36.22	0.00	0	0	0	4.19	41	127908	1385	-13.7%	2.2
0	YES	12.90	0.33	0	0	0	3.30	48	17836	637	40.3%	6.8
0	YES	15.41	0.05	0	0	0	3.51	4	0	0	-10.0%	5.6
0	YES	14.76	0.14	0	0	0	2.77	85	72420	1750	-2.4%	5.8
0	YES	19.05	0.04	0	0	0	2.30	47	0	0	-5.4%	6.4
0	YES	13.60	0.00	0	0	0	1.38	77	0	0	-0.8%	7.2
0	YES	19.01	1.12	0	0	0	2.06	56	0	0	2.7%	6.9
0	YES	8.19	0.07	0	0	0	2.10	28	127680	1064	5.3%	4.7
0	YES	12.09	0.39	0	0	0	0.87	22	16308	302	-4.0%	3.4
0	YES	12.34	0.06	0	0	0	2.03	105	0	0	-7.0%	4.2
0	YES	13.60	0.10	0	0	0	3.21	68	80380	3334	3.2%	5.1
0	YES	8.08	0.02	0	0	0	0.00	21	121112	2794	-2.0%	5.3

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	3.95	0.05	0	0	0	0.23	21	0	0	0.3%	2.7
0	YES	8.13	0.00	0	0	0	1.51	110	34018	466	-8.1%	7.1
0	YES	7.66	0.06	0	0	0	1.47	95	0	0	-2.3%	6.8
0	YES	8.23	0.32	0	0	0	1.27	10	0	0	-2.6%	5.5
0	YES	2.72	0.21	0	0	0	0.11	19	0	0	-9.1%	3.4
0	YES	11.65	0.15	0	0	0	4.06	104	0	0	-0.5%	8.7
0	YES	9.69	0.00	0	0	0	1.48	143	7885	1577	-2.0%	7.1
0	YES	14.85	1.72	0	0	0	1.72	1	0	0	7.2%	8.8
0	YES	21.19	2.64	0	0	0	2.57	3	0	0	-5.9%	7.0
0	YES	22.64	0.15	0	0	0	3.88	48	9450	378	-6.9%	7.0
0	YES	5.90	0.02	0	0	0	1.47	11	0	0	1.4%	1.6
0	YES	10.65	0.74	0	0	0	2.99	2	0	0	-1.7%	2.5
0	YES	14.24	0.22	0	0	0	2.42	3	0	0	8.1%	5.3
0	YES	21.61	0.23	0	0	0	3.13	63	0	0	1.2%	8.1
0	YES	13.39	0.38	0	0	0	3.38	73	76953	1263	-17.5%	7.3
0	YES	5.49	0.20	0	0	0	1.46	62	0	0	53.5%	4.5
0	YES	6.56	0.38	0	0	0	2.52	19	6596	194	-21.8%	5.6
0	YES	3.80	0.27	0	0	0	0.82	40	35604	989	3.1%	4.3
0	YES	7.25	0.19	0	0	0	1.62	25	0	0	-8.6%	6.4
0	YES	8.69	0.22	0	0	0	1.19	32	0	0	-8.2%	2.5
0	YES	4.06	0.40	0	0	0	1.58	0	0	0	-12.4%	1.8
0	YES	11.62	0.06	0	0	0	1.21	43	0	0	5.4%	3.9
0	YES	6.66	0.00	0	0	0	2.26	123	0	0	-4.8%	2.8
0	YES	12.75	0.07	0	0	0	2.21	67	162702	2421	1.7%	5.1
0	YES	12.80	0.00	0	0	0	2.67	60	0	0	1.0%	5.6
0	YES	5.89	0.01	0	0	0	1.85	16	386	2	-1.6%	8.2
0	YES	19.49	0.34	0	0	0	3.81	123	0	0	9.7%	6.6
0	YES	10.59	0.30	0	0	0	2.74	49	51038	1508	-12.7%	5.8
0	YES	16.18	0.40	0	0	0	3.79	7	0	0	-10.2%	7.7
0	YES	14.97	1.81	0	0	0	3.08	2	0	0	-1.5%	3.8
0	YES	9.43	0.12	0	0	0	1.23	11	0	0	-6.5%	2.7
0	YES	2.90	1.43	0	0	0	0.65	0	0	0	-2.6%	7.3
0	YES	9.46	0.34	0	0	0	2.58	32	22584	941	0.6%	4.8
0	YES	5.95	0.10	0	0	0	0.25	75	0	0	3.4%	3.9
0	YES	1.41	0.05	0	0	0	0.60	0	25515	405	2.7%	4.4

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	5.45	0.72	0	0	0	1.56	33	0	0	-9.7%	4.8
0	YES	12.08	0.24	0	0	0	2.34	95	75185	1367	-6.2%	4.0
0	YES	7.17	0.37	0	0	0	0.73	44	88368	2104	-17.9%	2.3
0	YES	11.54	0.15	0	0	0	0.79	97	0	0	0.2%	6.8
0	YES	10.70	0.17	0	0	0	0.55	45	0	0	-4.4%	6.2
0	YES	6.58	0.25	0	0	0	0.95	36	0	0	-0.1%	3.9
0	YES	9.92	0.40	0	0	0	2.05	63	0	0	-4.5%	5.1
0	YES	11.11	0.30	0	0	0	1.93	0	0	0	2.4%	6.7
0	YES	34.81	0.75	0	0	0	3.09	93	0	0	-7.8%	7.5
0	YES	14.89	0.56	0	0	0	2.91	45	0	0	4.8%	4.2
0	YES	7.39	0.72	0	0	0	2.13	68	0	0	2.0%	4.8
0	YES	9.88	0.28	0	0	0	1.41	57	0	0	0.7%	4.4
0	YES	13.48	0.00	0	0	0	2.53	147	88438	3324	-0.8%	6.5
0	YES	7.58	0.19	0	0	0	1.42	7	26856	2622	0.8%	3.2
0	YES	8.26	0.16	0	0	0	1.43	12	0	0	-5.1%	3.7
0	YES	5.48	0.37	0	0	0	1.82	27	0	0	35.2%	8.7
0	YES	9.85	0.00	0	0	0	2.90	13	59393	1675	-12.2%	4.2
0	YES	14.30	0.75	0	0	0	2.28	76	101280	1586	-9.4%	7.4
0	YES	11.04	0.06	0	0	0	0.55	25	0	0	-1.2%	3.6
0	YES	20.71	0.13	0	0	0	3.85	44	0	0	-0.1%	9.9
0	YES	14.69	0.03	0	0	0	2.87	61	0	0	1.0%	5.4
0	YES	12.11	0.14	0	0	0	3.37	56	54900	1098	-4.3%	7.0
0	YES	14.85	0.10	0	0	0	2.23	71	62344	2788	-0.3%	5.8
0	YES	11.54	0.21	0	0	0	2.36	18	0	0	4.1%	5.1
0	YES	16.89	0.20	0	0	0	3.30	26	4207	601	3.0%	5.8
0	YES	7.70	0.05	0	0	0	1.44	5	0	0	-20.8%	0.7
0	YES	34.80	3.12	0	0	0	5.16	1	0	0	-8.5%	7.0
0	YES	93.63	1.73	0	0	0	6.68	35	40581	501	-49.5%	4.8
0	YES	6.23	2.22	0	0	0	0.90	0	318	106	-45.0%	0.4
0	YES	29.47	2.74	0	0	0	1.98	1	0	0	329.6%	7.9
0	YES	18.28	0.00	0	0	0	1.93	38	0	0	-5.5%	6.2
0	YES	17.44	0.10	0	0	0	3.50	17	12064	754	-13.1%	3.4
0	YES	15.22	0.00	0	0	0	2.45	79	0	0	-6.2%	5.2
0	YES	0.56	0.05	0	0	0	0.43	0	0	0	0.0%	7.4
0	YES	48.80	0.28	0	0	0	12.39	133	121152	2352	-6.7%	4.6

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	31.41	0.28	0	0	0	1.73	35	71460	1191	0.3%	2.7
0	YES	0.87	0.29	0	0	0	0.00	0	0	0	-1.8%	5.7
0	YES	2.14	0.77	0	0	0	0.00	0	0	0	5.0%	4.9
0	YES	1.27	1.07	0	0	0	0.00	0	0	0	-15.0%	0.3
0	YES	1.99	0.76	0	0	0	0.00	0	1891	61	-52.8%	1.9
0	YES	0.20	0.15	0	0	0	0.00	0	0	0	1.1%	0.8
0	YES	2.54	1.17	0	0	0	0.00	0	39590	370	-5.4%	6.4
0	YES	0.99	0.53	0	0	0	0.00	0	0	0	-23.7%	3.3
0	YES	5.15	0.06	0	0	0	1.32	1	0	0	4.6%	2.4
0	YES	3.86	1.99	0	0	0	0.00	0	0	0	-9.6%	2.5
0	YES	3.98	1.71	0	0	0	0.00	0	0	0	-5.7%	3.3
0	YES	11.53	0.07	0	0	0	3.15	81	0	0	1.5%	3.2
0	YES	7.58	0.29	0	0	0	3.49	15	0	0	-20.4%	3.8
0	YES	1.00	0.70	0	0	0	0.18	0	0	0	-50.6%	5.9
0	YES	1.14	0.58	0	0	0	0.51	0	0	0	-11.9%	8.5
0	YES	20.48	0.30	0	0	0	5.99	16	0	0	7.1%	7.8
0	YES	2.05	0.51	0	0	0	0.79	0	0	0	-9.9%	6.1
0	YES	3.91	0.00	0	0	0	1.13	0	0	0	-7.9%	4.6
0	YES	8.88	0.16	0	0	0	2.76	15	0	0	-4.6%	3.6
0	YES	9.47	0.14	0	0	0	2.87	58	0	0	-2.1%	3.3
0	YES	8.72	0.00	0	0	0	1.37	15	0	0	-4.3%	4.5
0	YES	6.87	0.00	0	0	0	2.36	60	23569	481	-6.4%	2.8
0	YES	14.30	0.07	0	0	0	3.42	119	0	0	-8.6%	4.0
0	YES	20.05	0.27	0	0	0	3.45	119	0	0	96.0%	7.8
0	YES	17.71	0.62	0	0	0	3.11	34	0	0	-4.2%	5.3
0	YES	24.26	0.20	0	0	0	4.17	65	0	0	-16.9%	5.2
0	YES	15.70	0.12	0	0	0	3.69	113	0	0	-5.4%	4.9
0	YES	163.43	0.00	0	0	0	24.03	24	203008	3467	-0.3%	7.0
0	YES	39.25	1.79	0	0	0	5.50	60	2192	1096	-14.0%	4.6
0	YES	23.71	1.44	0	0	0	1.48	3	0	0	-6.3%	5.6
0	YES	124.46	0.09	0	0	0	5.28	133	0	0	0.8%	7.5
0	YES	16.83	1.52	0	0	0	1.97	3	0	0	-10.1%	3.7
0	YES	36.10	0.09	0	0	0	5.13	38	0	0	-13.8%	2.3
0	YES	13.54	0.05	0	0	0	3.18	81	86181	1249	6.4%	5.6
0	YES	5.80	0.04	0	0	0	1.79	4	0	0	119.0%	3.9

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	3.93	0.05	0	0	0	1.30	11	0	0	-1.0%	2.8
0	YES	9.25	0.06	0	0	0	2.92	54	0	0	10.7%	4.1
0	YES	9.80	0.04	0	0	0	2.55	15	0	0	-5.7%	6.9
0	YES	5.88	0.22	0	0	0	0.69	28	9982	434	-6.2%	5.4
0	YES	6.46	0.32	0	0	0	1.10	20	6356	454	-7.2%	3.8
0	YES	0.87	0.38	0	0	0	0.00	0	0	0	7.1%	1.8
0	YES	9.45	2.52	0	0	0	1.00	4	0	0	-4.1%	4.7
0	YES	2.24	1.84	0	0	0	0.00	0	0	0	14.3%	4.0
0	YES	3.07	2.73	0	0	0	0.00	0	0	2	0.1%	4.7
0	YES	4.65	2.26	0	0	0	0.00	0	0	0	0.2%	6.0
0	YES	3.44	1.87	0	0	0	0.00	0	0	0	1.9%	3.2
0	YES	4.34	2.30	0	0	0	0.38	1	0	0	9.4%	3.7
0	YES	4.67	0.81	0	0	0	1.11	7	0	0	-4.5%	1.8
0	YES	10.80	0.10	0	0	0	3.94	19	0	0	33.5%	4.7
0	YES	5.13	0.11	0	0	0	1.73	0	0	0	6.5%	4.5
0	YES	16.31	0.00	0	0	0	5.63	16	0	0	2.8%	6.4
0	YES	3.27	0.00	0	0	0	0.47	0	0	0	-7.6%	1.8
0	YES	8.17	0.07	0	0	0	1.35	14	54611	563	-6.6%	3.1
0	YES	11.48	0.06	0	0	0	2.80	21	0	0	-6.1%	4.4
0	YES	48.12	0.20	0	0	0	4.62	131	92644	1748	-4.4%	5.9
0	YES	34.43	0.11	0	0	0	3.79	87	68856	1208	-25.8%	3.2
0	YES	12.78	0.06	0	0	0	1.80	65	0	0	-10.0%	4.8
0	YES	6.40	0.19	0	0	0	1.99	21	0	0	0.4%	4.5
0	YES	7.59	0.13	0	0	0	2.07	45	0	0	3.2%	3.8
0	YES	5.50	0.20	0	0	0	0.72	0	460	20	0.5%	4.3
0	YES	6.90	0.18	0	0	0	1.38	1	0	0	-13.8%	5.0
0	YES	10.17	0.14	0	0	0	2.55	80	0	0	-0.5%	6.2
0	YES	8.71	0.14	0	0	0	3.23	6	0	0	-15.2%	4.3
0	YES	7.40	1.04	0	0	0	0.41	3	0	0	-6.3%	7.5
0	YES	19.52	1.54	0	0	0	5.47	1	0	0	-7.3%	2.8
0	YES	26.49	0.39	0	0	0	6.26	53	0	0	-8.3%	9.4
0	YES	22.03	0.12	0	0	0	4.86	11	0	0	-15.3%	5.2
0	YES	18.35	0.70	0	0	0	1.64	5	0	0	-0.7%	6.5
0	YES	16.03	1.18	0	0	0	3.30	6	0	0	35.3%	7.6
0	YES	12.16	0.32	0	0	0	2.41	173	0	0	-6.2%	6.2

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	4.54	0.84	0	0	0	0.43	11	0	0	3.1%	5.9
0	YES	2.51	0.40	0	0	0	0.31	5	0	0	-36.0%	4.2
0	YES	11.24	0.30	0	0	0	1.10	24	0	0	-6.6%	5.3
0	YES	7.92	0.86	0	0	0	1.01	19	6970	1394	-10.4%	3.9
0	YES	2.15	1.47	0	0	0	0.00	0	0	0	-18.3%	1.7
0	YES	10.54	0.07	0	0	0	2.13	26	0	0	-3.0%	6.8
0	YES	0.57	0.24	0	0	0	0.28	0	0	0	-29.9%	3.6
0	YES	7.45	0.25	0	0	0	1.95	90	37044	588	-2.5%	7.1
0	YES	11.56	1.48	0	0	0	2.04	20	0	0	-6.3%	5.8
0	YES	1.72	0.76	0	0	0	0.82	0	0	0	-4.5%	0.1
0	YES	2.63	0.62	0	0	0	0.66	0	0	0	-5.3%	7.1
0	YES	7.38	0.08	0	0	0	1.31	8	68438	1801	-20.1%	3.5
0	YES	7.43	0.09	0	0	0	1.41	1	44609	1439	-9.6%	3.3
0	YES	14.86	1.67	0	0	0	3.70	23	0	0	-12.6%	4.8
0	YES	2.33	1.16	0	0	0	0.54	0	0	0	-3.1%	5.6
0	YES	11.66	0.12	0	0	0	1.48	4	0	0	-7.2%	6.9
0	YES	0.27	0.25	0	0	0	0.00	0	0	0	17.7%	5.0
0	YES	0.37	0.25	0	0	0	0.00	0	0	0	-31.5%	3.9
0	YES	20.77	0.18	0	0	0	4.51	105	42583	4432	29.9%	6.9
0	YES	23.23	0.39	0	0	0	3.87	30	62985	1235	-9.8%	5.8
0	YES	4.64	0.11	0	0	0	1.22	9	0	0	-5.7%	5.8
0	YES	17.43	0.84	0	0	0	3.24	72	6174	126	-7.8%	4.8
0	YES	0.80	0.80	0	0	0	0.00	0	0	0	14.5%	2.0
0	YES	1.12	0.84	0	0	0	0.00	0	0	0	7.1%	1.6
0	YES	9.24	0.83	0	0	0	2.24	37	106640	2370	3.1%	6.1
0	YES	0.02	0.02	0	0	0	0.00	0	0	0	0.0%	0.0
0	YES	8.59	0.58	0	0	0	0.57	181	69839	1955	-9.5%	4.4
0	YES	1.88	0.99	0	0	0	0.00	0	0	0	22.6%	3.9
0	YES	1.03	0.85	0	0	0	0.00	0	0	0	-16.1%	4.1
0	YES	0.00	0.00	0	0	0	0.00	0	0	0	0.7%	0.0
0	YES	0.75	0.74	0	0	0	0.00	0	0	0	-13.9%	3.2
0	YES	28.93	0.85	0	0	0	4.04	50	18400	736	-2.6%	5.0
0	YES	24.76	0.04	0	0	0	6.26	131	33976	1096	-5.0%	4.2
0	YES	44.57	0.30	0	0	0	6.20	158	0	0	-4.4%	5.9
0	YES	64.91	1.47	0	0	0	8.56	91	179157	3091	-2.0%	6.8

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	5.75	1.01	0	0	0	0.93	9	13407	625	17.8%	3.9
0	YES	3.89	1.31	0	0	0	0.60	5	24764	604	-16.8%	3.5
0	YES	1.23	0.23	0	0	0	0.43	0	1952	61	-47.3%	0.9
0	YES	5.00	0.25	0	0	0	1.34	41	27877	457	-12.8%	2.5
0	YES	13.90	0.67	0	0	0	2.41	2	0	0	7.1%	1.7
0	YES	11.86	0.28	0	0	0	4.20	0	40193	699	6.6%	4.1
0	YES	9.87	0.05	0	0	0	4.57	26	13845	355	19.5%	3.3
0	YES	13.73	0.04	0	0	0	2.67	31	34352	904	-7.3%	5.1
0	YES	9.38	0.25	0	0	0	2.89	101	25536	456	-1.7%	5.1
0	YES	11.67	0.13	0	0	0	1.31	171	226885	2848	4.4%	5.6
0	YES	12.72	0.14	0	0	0	1.46	105	66612	3017	-3.9%	6.6
0	YES	11.35	0.11	0	0	0	2.10	107	0	0	-2.8%	6.2
0	YES	62.35	0.14	0	0	0	7.78	78	460181	2913	26.9%	5.6
0	YES	32.68	0.18	0	0	0	2.48	46	35454	933	-23.3%	3.8
0	YES	10.32	0.14	0	0	0	0.85	0	0	0	4.6%	4.6
0	YES	18.86	0.07	0	0	0	1.07	31	0	0	-0.1%	6.7
0	YES	4.14	0.07	0	0	0	0.09	0	0	0	1.7%	1.2
0	YES	12.87	0.05	0	0	0	2.55	52	0	0	-12.5%	4.4
0	YES	28.62	0.78	0	0	0	3.86	45	0	0	-18.4%	3.5
0	YES	23.57	0.08	0	0	0	2.30	24	35910	630	-9.8%	5.6
0	YES	15.93	0.25	0	0	0	3.18	13	0	0	12.8%	6.0
0	YES	18.44	0.10	0	0	0	4.17	108	0	0	8.7%	4.4
0	YES	10.37	0.12	0	0	0	2.83	3	0	0	55.8%	3.3
0	YES	13.50	0.12	0	0	0	3.12	44	37620	684	-11.4%	5.3
0	YES	26.58	3.26	0	0	0	1.88	3	138572	2828	69.4%	7.5
0	YES	13.43	0.65	0	0	0	3.39	47	77120	964	-2.6%	5.0
0	YES	18.54	0.57	0	0	0	5.98	4	29882	446	-23.6%	4.1
0	YES	37.45	0.14	0	0	0	2.76	51	166252	4498	-9.7%	6.6
0	YES	14.25	0.04	0	0	0	2.18	22	0	0	-5.4%	3.2
0	YES	8.01	0.23	0	0	0	2.25	18	0	0	-3.7%	2.6
0	YES	1.93	1.25	0	0	0	0.00	0	2100	70	-12.7%	3.2
0	YES	3.65	0.11	0	0	0	1.19	0	0	0	-11.9%	6.2
0	YES	4.27	0.68	0	0	0	0.47	5	0	0	-5.5%	3.5
0	YES	5.56	0.89	0	0	0	0.87	22	0	0	-0.2%	5.1
0	YES	6.97	1.51	0	0	0	1.26	0	0	0	0.2%	5.9

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	3.79	0.29	0	0	0	0.92	0	3480	87	-7.8%	4.5
0	YES	1.13	0.14	0	0	0	0.55	0	1036	37	-0.3%	1.3
0	YES	8.64	2.90	0	0	0	0.47	0	1100	20	-10.7%	6.9
0	YES	18.34	0.12	0	0	0	2.19	40	49879	1609	1.0%	6.4
0	YES	8.00	0.13	0	0	0	2.02	50	14280	280	3.9%	4.4
0	YES	7.15	0.74	0	0	0	1.77	19	0	0	0.2%	4.9
0	YES	9.93	0.07	0	0	0	2.48	21	24024	728	1.3%	4.2
0	YES	27.21	0.61	0	0	0	7.70	36	0	0	6.4%	3.1
0	YES	27.87	1.68	0	0	0	3.98	59	102938	1761	-6.7%	4.1
0	YES	48.26	0.07	0	0	0	7.16	49	57018	1118	-7.2%	4.7
0	YES	40.31	0.19	0	0	0	6.90	61	57504	1198	-5.0%	6.5
0	YES	16.97	0.20	0	0	0	3.72	29	0	0	3.9%	8.8
0	YES	4.84	0.00	0	0	0	3.03	60	0	0	9.3%	7.6
0	YES	6.57	0.10	0	0	0	1.73	18	2160	18	-11.7%	2.2
0	YES	4.53	0.12	0	0	0	1.68	15	5628	268	-12.8%	3.6
0	YES	4.04	0.08	0	0	0	1.49	0	0	0	-5.2%	1.3
0	YES	11.01	0.14	0	0	0	2.51	70	43642	2502	-14.2%	3.7
0	YES	13.27	0.55	0	0	0	3.55	8	15441	733	-10.3%	7.3
0	YES	24.32	0.06	0	0	0	1.37	38	146877	1343	-50.5%	3.6
0	YES	9.55	0.22	0	0	0	3.14	25	0	0	-58.2%	2.0
0	YES	14.32	0.02	0	0	0	2.42	36	0	0	-7.0%	3.1
0	YES	17.93	0.05	0	0	0	4.79	38	0	0	-8.9%	4.2
0	YES	12.98	0.03	0	0	0	0.90	1	0	0	-8.5%	4.7
0	YES	11.98	1.88	0	0	0	2.99	0	9196	121	7.6%	3.6
0	YES	18.72	0.64	0	0	0	1.92	5	0	0	-8.5%	6.2
0	YES	21.57	1.49	0	0	0	0.25	75	0	0	-6.2%	6.7
0	YES	14.22	0.70	0	0	0	3.05	7	0	0	-5.4%	5.0
0	YES	12.02	0.08	0	0	0	2.48	8	0	0	2.1%	6.1
0	YES	23.23	0.83	0	0	0	2.57	197	252880	2767	-2.8%	6.5
0	YES	17.51	0.82	0	0	0	2.93	16	0	0	-47.3%	4.0
0	YES	8.37	0.07	0	0	0	1.86	38	0	0	0.3%	3.9
0	YES	15.18	0.13	0	0	0	2.64	26	41615	1189	-1.3%	5.1
0	YES	9.65	0.28	0	0	0	1.77	86	28296	786	-1.9%	5.9
0	YES	7.84	0.38	0	0	0	1.60	50	28468	647	0.5%	2.8
0	YES	6.15	0.80	0	0	0	1.60	0	0	0	-15.0%	2.2

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	31.41	0.01	0	0	0	6.38	30	0	0	-5.1%	9.0
0	YES	6.73	1.41	0	0	0	2.02	10	0	0	-3.0%	5.2
0	YES	7.95	2.53	0	0	0	2.13	3	0	0	23.3%	9.0
0	YES	1.17	0.72	0	0	0	0.00	0	0	0	-14.8%	2.9
0	YES	4.30	1.63	0	0	0	1.59	0	0	0	-21.0%	4.4
0	YES	4.41	0.12	0	0	0	1.71	0	2900	50	-4.0%	3.2
0	YES	15.54	1.12	0	0	0	1.13	74	66654	1587	3.1%	7.4
0	YES	3.33	1.02	0	0	0	0.84	0	0	0	-12.0%	4.3
0	YES	10.84	1.04	0	0	0	1.49	28	0	0	0.1%	5.9
0	YES	9.08	0.80	0	0	0	1.52	19	0	0	13.1%	4.7
0	YES	3.30	1.36	0	0	0	0.17	0	0	0	26.8%	3.2
0	YES	21.70	0.91	0	0	0	3.35	18	128301	2629	-6.9%	6.3
0	YES	14.04	0.07	0	0	0	2.05	18	0	0	-1.3%	5.8
0	YES	9.68	0.39	0	0	0	1.95	12	0	0	-2.6%	5.6
0	YES	13.60	0.28	0	0	0	2.02	53	296034	3605	-7.8%	5.5
0	YES	3.40	0.50	0	0	0	0.44	0	0	0	-4.1%	5.5
0	YES	8.80	0.11	0	0	0	3.21	3	15072	471	-12.9%	5.0
0	YES	9.27	0.12	0	0	0	1.56	46	0	0	-4.7%	4.8
0	YES	9.34	0.07	0	0	0	1.70	58	33784	824	-5.1%	6.6
0	YES	2.34	0.14	0	0	0	0.97	0	0	0	0.2%	7.2
0	YES	0.14	0.02	0	0	0	0.11	0	0	0	100.0%	7.6
0	YES	5.97	0.44	0	0	0	1.80	18	17919	543	-0.7%	4.7
0	YES	2.26	0.15	0	0	0	0.31	0	0	0	151.5%	3.4
0	YES	12.96	0.27	0	0	0	1.01	117	98169	1764	0.4%	6.5
0	YES	6.17	0.20	0	0	0	1.41	118	0	0	16.9%	3.5
0	YES	4.64	0.39	0	0	0	1.21	30	0	0	-0.3%	8.7
0	YES	6.33	0.18	0	0	0	0.64	11	0	0	1.2%	3.6
0	YES	9.74	0.60	0	0	0	2.47	4	0	0	9.8%	4.0
0	YES	6.95	0.04	0	0	0	1.88	37	0	0	-12.0%	5.2
0	YES	11.28	0.02	0	0	0	2.82	53	149234	1798	-1.2%	6.4
0	YES	22.36	0.08	0	0	0	2.08	98	0	0	4.7%	8.5
0	YES	16.02	1.07	0	0	0	1.42	7	0	0	-2.5%	6.4
0	YES	14.67	0.12	0	0	0	1.94	8	0	0	-10.3%	4.8
0	YES	8.91	0.17	0	0	0	1.80	3	0	0	2.9%	3.1
0	YES	16.21	1.69	0	0	0	0.00	0	0	0	-3.0%	5.5

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	7.22	0.06	0	0	0	2.05	1	0	0	-5.1%	3.1
0	YES	14.94	0.59	0	0	0	4.07	8	0	0	-6.8%	6.3
0	YES	8.48	0.15	0	0	0	3.29	49	7920	110	-19.6%	2.6
0	YES	0.40	0.10	0	0	0	0.23	0	57	1	87.0%	0.6
0	YES	5.01	0.24	0	0	0	1.62	0	0	0	-54.8%	2.9
0	YES	1.88	0.00	0	0	0	0.00	0	0	0	-65.9%	1.5
0	YES	1.59	0.31	0	0	0	0.00	0	0	0	-12.2%	4.4
0	YES	2.40	1.48	0	0	0	0.00	0	0	0	-4.9%	2.4
0	YES	3.93	2.94	0	0	0	0.00	0	0	0	-1.3%	3.2
0	YES	3.89	2.44	0	0	0	0.00	0	0	0	-5.3%	3.3
0	YES	2.61	1.70	0	0	0	0.00	0	0	0	-3.6%	2.8
0	YES	2.49	1.57	0	0	0	0.00	0	0	0	-8.9%	3.3
0	YES	2.93	1.99	0	0	0	0.00	0	0	0	-12.4%	2.2
0	YES	11.17	0.23	0	0	0	0.91	5	0	0	150.2%	3.7
0	YES	12.63	0.30	0	0	0	0.98	4	0	0	-7.6%	4.5
0	YES	10.37	0.16	0	0	0	1.73	11	0	0	-8.8%	3.8
0	YES	6.93	0.12	0	0	0	0.94	12	0	0	-4.1%	2.6
0	YES	21.63	0.40	0	0	0	4.40	61	53856	1584	-3.2%	6.9
0	YES	14.81	0.00	0	0	0	3.34	43	0	0	-0.9%	4.2
0	YES	19.29	0.15	0	0	0	2.30	31	24104	3013	-33.0%	4.9
0	YES	23.10	1.85	0	0	0	3.88	4	0	0	-7.6%	6.7
0	YES	14.15	0.09	0	0	0	3.06	6	0	0	-20.3%	5.4
0	YES	12.79	0.05	0	0	0	2.10	5	0	0	-4.6%	4.6
0	YES	9.03	0.11	0	0	0	1.16	0	0	0	-12.1%	5.6
0	YES	22.95	0.50	0	0	0	2.90	4	48636	1158	-6.8%	6.4
0	YES	17.88	0.62	0	0	0	1.82	1	0	0	-5.1%	7.2
0	YES	14.13	1.72	0	0	0	2.96	0	47926	773	-24.8%	4.9
0	YES	9.11	0.03	0	0	0	3.04	141	0	0	-4.6%	6.3
0	YES	10.08	0.14	0	0	0	2.61	114	82456	2174	-6.1%	3.8
0	YES	21.69	0.13	0	0	0	4.59	150	0	0	-2.7%	9.2
0	YES	9.34	0.14	0	0	0	2.55	45	31720	793	1.0%	4.3
0	YES	9.52	0.12	0	0	0	1.31	22	0	0	4.0%	5.7
0	YES	5.25	0.25	0	0	0	0.66	51	0	0	1.7%	2.6
0	YES	2.57	0.05	0	0	0	1.41	58	13110	285	-23.5%	1.9
0	YES	8.55	0.23	0	0	0	1.08	54	0	0	0.5%	5.8

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	4.39	0.16	0	0	0	0.75	38	50028	758	-2.3%	2.2
0	YES	9.86	0.14	0	0	0	1.21	43	78126	1347	0.1%	5.0
0	YES	7.67	0.26	0	0	0	1.10	49	0	0	15.6%	3.7
0	YES	23.95	0.03	0	0	0	2.35	40	24544	767	-2.4%	5.9
0	YES	33.29	0.06	0	0	0	2.94	63	0	0	3.3%	5.9
0	YES	29.76	0.00	0	0	0	3.25	53	21504	672	-0.6%	4.0
0	YES	11.01	0.33	0	0	0	3.19	116	0	0	-4.7%	4.6
0	YES	17.24	0.31	0	0	0	1.92	45	58805	2603	0.2%	6.7
0	YES	7.80	0.06	0	0	0	1.89	81	0	0	1.3%	2.7
0	YES	14.04	0.15	0	0	0	3.44	69	111198	1293	-2.2%	7.7
0	YES	5.84	1.04	0	0	0	1.66	0	0	0	0.5%	4.1
0	YES	2.50	0.74	0	0	0	1.14	0	0	0	-5.3%	6.3
0	YES	3.90	0.10	0	0	0	1.94	11	16200	162	0.0%	1.8
0	YES	4.64	0.41	0	0	0	1.26	13	0	0	1.5%	2.0
0	YES	1.90	0.30	0	0	0	0.90	0	0	0	1085.7%	6.6
0	YES	1.92	1.92	0	0	0	0.00	0	0	0	0.0%	0.0
0	YES	1.90	1.90	0	0	0	0.00	0	0	0	0.0%	0.0
0	YES	1.92	1.92	0	0	0	0.00	0	0	0	0.0%	0.0
0	YES	33.57	1.22	0	0	0	4.12	9	19380	228	-13.2%	6.9
0	YES	19.20	3.23	0	0	0	0.72	0	0	0	1.2%	4.1
0	YES	29.22	0.05	0	0	0	4.61	62	126941	2654	0.3%	5.0
0	YES	7.31	0.09	0	0	0	1.57	59	0	0	-10.9%	1.5
0	YES	12.37	1.25	0	0	0	1.23	0	16236	2706	-10.1%	3.9
0	YES	21.38	1.12	0	0	0	4.18	24	59989	239	-6.9%	7.2
0	YES	28.95	1.43	0	0	0	5.45	31	23751	2639	-19.3%	7.4
0	YES	15.23	0.08	0	0	0	3.13	38	0	0	-14.6%	2.7
0	YES	56.89	0.34	0	0	0	8.04	140	101975	2279	-4.6%	7.0
0	YES	46.12	0.17	0	0	0	3.19	120	50024	1204	-2.4%	4.9
0	YES	21.25	0.03	0	0	0	2.84	34	21888	1216	313.4%	8.5
0	YES	27.09	0.10	0	0	0	4.22	74	124134	1217	9.2%	4.8
0	YES	29.21	1.24	0	0	0	3.58	15	138590	2535	-2.7%	7.3
0	YES	28.03	1.92	0	0	0	1.18	37	0	0	-7.8%	6.7
0	YES	12.23	0.18	0	0	0	2.11	35	121401	2187	-0.8%	4.2
0	YES	9.27	0.11	0	0	0	0.79	2	29008	592	-10.8%	2.8
0	YES	14.92	1.73	0	0	0	1.45	15	238201	4795	-6.9%	5.7

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	18.86	0.82	0	0	0	3.54	11	134343	2277	-15.4%	6.7
0	YES	14.70	1.04	0	0	0	2.18	2	32637	759	-3.5%	5.4
0	YES	15.32	1.45	0	0	0	2.84	2	0	0	-2.4%	5.6
0	YES	26.40	3.46	0	0	0	2.72	1	0	0	1.5%	6.6
0	YES	24.02	0.28	0	0	0	2.82	2	322419	3623	-2.6%	6.7
0	YES	29.42	0.18	0	0	0	4.68	50	346194	6098	-8.0%	7.6
0	YES	19.82	1.89	0	0	0	2.80	42	0	0	-6.4%	6.4
0	YES	20.80	0.13	0	0	0	2.83	20	0	0	0.8%	7.4
0	YES	33.14	0.17	0	0	0	6.26	104	97614	957	1.3%	8.4
0	YES	16.00	1.28	0	0	0	1.60	23	0	0	2.5%	5.7
0	YES	14.82	0.72	0	0	0	2.45	10	50112	864	10.7%	5.6
0	YES	9.99	0.16	0	0	0	2.01	7	0	0	-6.6%	2.7
0	YES	20.03	1.00	0	0	0	2.73	44	0	0	2.4%	6.4
0	YES	23.36	0.00	0	0	0	2.13	74	38668	1381	-4.4%	6.0
0	YES	16.55	0.11	0	0	0	3.03	84	74256	1326	-2.1%	6.0
0	YES	3.04	0.36	0	0	0	1.97	2	0	0	9.5%	0.5
0	YES	24.14	0.69	0	0	0	4.76	93	78029	1099	-9.3%	6.4
0	YES	17.64	0.34	0	0	0	1.67	7	0	0	-5.1%	4.0
0	YES	22.91	0.14	0	0	0	3.05	26	29856	1244	-4.1%	6.8
0	YES	16.60	0.23	0	0	0	2.59	40	13167	627	-7.6%	6.6
0	YES	13.10	0.92	0	0	0	2.51	11	0	0	-3.1%	4.9
0	YES	18.05	0.73	0	0	0	3.31	13	84120	1402	3.0%	7.7
0	YES	13.58	0.12	0	0	0	2.47	37	0	0	-5.5%	3.3
0	YES	24.34	0.27	0	0	0	2.85	24	0	0	-3.0%	9.1
0	YES	19.97	1.05	0	0	0	3.05	3	0	0	-3.3%	8.3
0	YES	19.40	0.51	0	0	0	4.70	52	0	0	-7.5%	5.1
0	YES	29.25	3.12	0	0	0	0.67	2	0	0	-3.9%	9.5
0	YES	14.28	2.09	0	0	0	1.83	0	174336	1816	-13.0%	5.2
0	YES	17.31	0.30	0	0	0	2.05	1	72828	1156	-6.4%	5.4
0	YES	10.39	0.64	0	0	0	3.60	1	14445	321	-11.4%	3.1
0	YES	27.72	0.49	0	0	0	4.20	3	0	0	20.3%	5.4
0	YES	22.11	2.54	0	0	0	1.09	0	0	0	-11.9%	5.4
0	YES	7.67	2.04	0	0	0	1.18	3	0	0	-5.7%	3.4
0	YES	15.16	0.02	0	0	0	3.47	5	11050	442	19.2%	5.5
0	YES	35.24	0.07	0	0	0	5.74	33	0	0	-8.7%	5.7

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	38.33	0.06	0	0	0	6.14	73	0	0	-10.3%	5.3
0	YES	17.22	0.17	0	0	0	2.35	3	0	0	-6.3%	6.6
0	YES	13.20	0.99	0	0	0	1.31	0	0	0	11.6%	4.7
0	YES	18.39	1.82	0	0	0	0.15	0	0	0	-2.7%	8.0
0	YES	12.64	0.53	0	0	0	2.74	1	0	0	-8.8%	3.5
0	YES	6.93	0.17	0	0	0	2.29	42	0	0	0.4%	4.8
0	YES	5.58	0.69	0	0	0	1.62	33	27145	445	-2.2%	5.3
0	YES	3.54	0.21	0	0	0	1.66	0	0	0	5.8%	4.0
0	YES	12.05	0.28	0	0	0	1.12	96	0	0	-4.3%	5.7
0	YES	19.93	0.00	0	0	0	1.72	12	121590	1737	0.3%	7.4
0	YES	3.82	0.22	0	0	0	0.95	7	0	0	0.8%	1.9
0	YES	16.06	0.39	0	0	0	3.48	25	101682	2311	1.6%	7.4
0	YES	13.27	0.30	0	0	0	1.88	17	0	0	-2.8%	5.0
0	YES	9.19	0.31	0	0	0	1.42	12	0	0	-9.8%	4.2
0	YES	5.67	0.05	0	0	0	1.84	91	0	0	-0.9%	4.6
0	YES	9.23	0.14	0	0	0	0.68	126	55272	1128	-3.6%	6.2
0	YES	5.34	0.14	0	0	0	0.65	76	0	0	-0.8%	5.2
0	YES	3.63	0.66	0	0	0	1.08	0	1131	377	-25.1%	2.9
0	YES	3.95	1.92	0	0	0	0.52	0	0	0	-2.3%	4.8
0	YES	0.54	0.52	0	0	0	0.00	0	0	0	-17.3%	3.2
0	YES	2.32	0.12	0	0	0	0.77	0	0	0	-8.1%	5.8
0	YES	1.08	0.86	0	0	0	0.00	0	0	0	-68.7%	1.0
0	YES	37.24	1.20	0	0	0	5.63	16	16932	498	-1.4%	4.5
0	YES	29.83	0.40	0	0	0	3.60	64	73692	1602	-2.7%	7.9
0	YES	38.15	3.06	0	0	0	6.34	6	0	0	-5.6%	5.7
0	YES	19.78	2.18	0	0	0	2.34	85	0	0	-7.0%	5.1
0	YES	19.23	0.55	0	0	0	1.68	91	0	0	-6.5%	6.8
0	YES	25.79	0.19	0	0	0	5.00	7	0	0	31.2%	10.5
0	YES	21.11	0.39	0	0	0	1.55	32	0	0	-11.1%	1.7
0	YES	50.35	0.56	0	0	0	4.96	38	59139	1167	-1.7%	3.4
0	YES	56.80	0.24	0	0	0	8.70	84	55496	991	31.2%	7.6
0	YES	19.23	0.72	0	0	0	2.54	49	143080	1460	-5.5%	6.1
0	YES	37.72	0.07	0	0	0	4.43	54	0	0	-6.1%	8.9
0	YES	16.95	0.54	0	0	0	3.58	17	0	0	-10.4%	4.2
0	YES	23.84	0.06	0	0	0	2.81	32	0	0	-0.4%	8.9

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	15.23	0.25	0	0	0	1.84	27	110243	3418	-18.4%	7.2
0	YES	16.43	0.29	0	0	0	2.54	38	75460	1540	1.1%	6.1
0	YES	55.45	0.03	0	0	0	4.69	85	0	0	-0.7%	5.4
0	YES	43.76	0.11	0	0	0	6.25	113	41028	789	-7.1%	5.4
0	YES	121.76	0.25	0	0	0	14.67	110	27150	905	-1.6%	7.5
0	YES	53.90	0.03	0	0	0	5.02	12	89270	790	-7.7%	3.0
0	YES	59.69	0.26	0	0	0	6.73	27	77324	1906	-6.3%	2.7
0	YES	42.44	1.69	0	0	0	6.03	72	262716	5198	1.1%	6.2
0	YES	11.76	0.00	0	0	0	2.55	138	0	0	3.2%	6.1
0	YES	13.91	0.57	0	0	0	2.65	80	263646	3995	-6.1%	4.7
0	YES	8.58	0.00	0	0	0	1.06	23	0	0	-0.3%	3.2
0	YES	10.67	0.15	0	0	0	1.18	35	0	0	-3.0%	6.3
0	YES	12.58	0.05	0	0	0	3.16	2	0	0	-6.2%	3.5
0	YES	12.45	0.00	0	0	0	2.89	39	50301	621	-1.3%	3.9
0	YES	7.47	0.03	0	0	0	1.45	82	0	0	-5.7%	3.2
0	YES	5.93	0.85	0	0	0	0.62	27	0	0	-7.2%	2.1
0	YES	9.89	0.02	0	0	0	1.40	42	0	0	-5.3%	5.0
0	YES	10.20	0.07	0	0	0	1.19	10	52188	745	-18.2%	2.7
0	YES	14.02	0.53	0	0	0	2.15	34	94606	1506	-4.0%	4.9
0	YES	20.37	0.16	0	0	0	4.41	134	35203	2387	-11.8%	5.3
0	YES	28.34	0.12	0	0	0	5.48	18	0	0	-8.3%	7.1
0	YES	22.47	0.07	0	0	0	4.46	130	0	0	-12.7%	6.2
0	YES	5.20	0.53	0	0	0	1.91	4	0	0	-17.8%	3.8
0	YES	4.49	0.55	0	0	0	0.00	0	0	0	-30.9%	1.5
0	YES	12.22	0.41	0	0	0	0.40	0	0	0	-2.0%	2.7
0	YES	33.42	2.85	0	0	0	1.64	3	13560	113	4.1%	8.0
0	YES	40.37	0.81	0	0	0	6.27	57	116250	2325	-0.2%	9.1
0	YES	0.80	0.55	0	0	0	0.00	0	0	0	44.0%	7.3
0	YES	11.26	0.05	0	0	0	1.46	10	48192	1004	1.8%	5.9
0	YES	9.98	0.92	0	0	0	0.93	9	0	0	5.7%	3.4
0	YES	6.68	0.19	0	0	0	2.47	22	184	4	-3.3%	4.8
0	YES	23.21	0.70	0	0	0	3.94	17	0	0	-17.8%	8.2
0	YES	11.59	0.21	0	0	0	3.16	6	14144	442	10.4%	8.0
0	YES	5.72	0.19	0	0	0	1.50	0	0	0	-3.6%	5.4
0	YES	7.05	0.17	0	0	0	0.98	3	0	0	-5.2%	6.0

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	19.27	0.06	0	0	0	2.28	10	77547	1725	-2.8%	6.4
0	YES	10.15	0.33	0	0	0	1.42	6	3820	955	-3.3%	4.0
0	YES	11.11	0.81	0	0	0	0.53	0	3316	829	-5.1%	3.2
0	YES	21.70	0.18	0	0	0	1.15	45	6980	1745	1.0%	8.4
0	YES	12.99	0.43	0	0	0	2.22	14	89609	1469	-2.7%	5.5
0	YES	11.66	1.76	0	0	0	1.01	2	0	0	-7.8%	6.6
0	YES	9.23	1.64	0	0	0	1.18	3	0	0	-2.9%	6.5
0	YES	3.36	1.30	0	0	0	0.64	0	0	0	-12.0%	4.4
0	YES	2.40	1.28	0	0	0	0.00	0	0	0	-17.7%	3.3
0	YES	8.03	0.29	0	0	0	1.69	4	17530	1753	-4.9%	5.9
0	YES	14.06	0.31	0	0	0	1.95	2	0	0	-2.8%	6.6
0	YES	13.04	0.79	0	0	0	1.72	10	0	0	-3.9%	5.1
0	YES	13.66	1.43	0	0	0	0.41	0	0	0	1.3%	5.0
0	YES	15.03	0.45	0	0	0	2.13	2	0	0	-6.3%	5.6
0	YES	23.69	0.31	0	0	0	2.99	31	162645	3424	7.5%	9.7
0	YES	8.89	0.07	0	0	0	1.10	26	0	0	-2.2%	3.7
0	YES	19.45	0.96	0	0	0	0.71	8	0	0	-3.0%	7.0
0	YES	11.90	0.12	0	0	0	2.82	4	18185	1823	-6.6%	6.1
0	YES	4.89	0.07	0	0	0	1.81	2	0	0	1.8%	4.9
0	YES	18.85	1.73	0	0	0	2.23	58	65472	1364	-3.7%	4.6
0	YES	21.28	2.90	0	0	0	2.62	5	9828	378	-21.3%	2.8
0	YES	35.57	4.80	0	0	0	4.84	2	0	0	1.0%	7.7
0	YES	5.05	0.05	0	0	0	1.94	0	0	0	-3.7%	1.8
0	YES	29.80	0.88	0	0	0	6.46	4	0	0	-19.9%	4.3
0	YES	12.81	0.11	0	0	0	2.51	22	0	0	-11.3%	3.7
0	YES	12.95	0.25	0	0	0	2.39	31	35899	1303	-1.8%	6.0
0	YES	19.51	0.07	0	0	0	2.54	87	146805	3312	-3.6%	5.2
0	YES	14.91	0.13	0	0	0	1.97	112	82056	1052	-1.0%	4.7
0	YES	16.10	0.00	0	0	0	1.23	17	0	0	-0.7%	5.6
0	YES	14.83	0.18	0	0	0	2.33	7	0	0	-20.8%	3.1
0	YES	1.90	0.26	0	0	0	0.58	0	0	0	-17.2%	1.5
0	YES	14.64	0.32	0	0	0	1.69	13	73920	660	-3.4%	4.9
0	YES	10.26	0.00	0	0	0	1.56	34	18531	261	-6.0%	2.6
0	YES	33.47	2.31	0	0	0	3.24	2	55080	1530	-0.4%	5.5
0	YES	71.03	0.00	0	0	0	28.11	24	57744	1360	-14.5%	3.2

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	42.92	0.32	0	0	0	4.91	87	164635	1733	-16.8%	6.1
0	YES	0.55	0.05	0	0	0	0.00	0	0	0	0.0%	0.0
0	YES	0.04	0.04	0	0	0	0.00	0	0	0	0.0%	0.0
0	YES	13.28	0.05	0	0	0	2.01	38	21556	634	-4.6%	4.0
0	YES	12.23	0.12	0	0	0	2.30	9	36480	1140	-1.8%	6.7
0	YES	8.06	0.33	0	0	0	2.20	33	10471	283	4.0%	2.7
0	YES	16.00	0.08	0	0	0	2.67	24	0	0	-3.1%	5.7
0	YES	2.56	1.10	0	0	0	0.26	7	0	0	-15.9%	2.3
0	YES	4.43	1.28	0	0	0	0.98	0	1020	34	-6.9%	3.3
0	YES	1.19	0.82	0	0	0	0.28	0	11941	897	-54.1%	0.0
0	YES	0.06	0.06	0	0	0	0.00	0	0	0	-99.8%	0.0
0	YES	7.67	0.00	0	0	0	1.09	100	0	0	-0.3%	2.7
0	YES	11.12	0.00	0	0	0	2.07	76	34680	1156	-4.4%	6.4
0	YES	4.79	0.55	0	0	0	1.74	0	0	0	3.0%	3.9
0	YES	4.17	0.15	0	0	0	0.97	0	0	0	2.4%	3.5
0	YES	12.00	0.15	0	0	0	2.38	8	1950	390	-1.6%	8.6
0	YES	5.49	0.31	0	0	0	1.94	0	0	0	1.4%	5.0
0	YES	15.87	1.65	0	0	0	2.64	12	0	0	0.1%	7.1
0	YES	11.70	0.80	0	0	0	2.64	7	0	0	3.6%	6.3
0	YES	21.46	0.02	0	0	0	6.04	41	0	0	-0.8%	2.7
0	YES	40.58	0.00	0	0	0	3.82	31	0	0	-9.3%	7.4
0	YES	28.92	0.25	0	0	0	4.21	88	0	0	2.8%	7.2
0	YES	10.60	0.81	0	0	0	2.77	19	0	0	30.8%	9.5
0	YES	9.66	0.20	0	0	0	1.82	25	0	0	-1.6%	2.7
0	YES	21.23	0.06	0	0	0	3.54	148	0	0	-9.9%	6.0
0	YES	9.72	0.06	0	0	0	2.91	76	0	0	-3.9%	3.4
0	YES	1.75	0.21	0	0	0	0.19	0	0	0	-0.7%	1.9
0	YES	25.57	0.06	0	0	0	3.11	10	0	0	3.8%	5.3
0	YES	21.49	1.48	0	0	0	2.37	31	28056	1002	-3.5%	5.6
0	YES	0.98	0.06	0	0	0	0.92	0	8	1	-88.4%	0.3
0	YES	9.27	0.50	0	0	0	5.72	0	1920	64	44.1%	7.1
0	YES	28.70	0.15	0	0	0	5.43	57	44178	1632	-25.5%	3.5
0	YES	21.87	1.10	0	0	0	5.09	35	4236	706	-7.2%	6.3
0	YES	30.60	5.47	0	0	0	3.29	1	0	0	-9.5%	8.5
0	YES	18.66	2.28	0	0	0	1.00	2	0	0	-10.6%	6.7

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	16.26	2.87	0	0	0	3.26	2	34671	889	-11.8%	4.7
0	YES	15.07	3.17	0	0	0	0.00	0	0	0	4.2%	5.6
0	YES	23.09	1.47	0	0	0	2.05	7	0	0	-8.1%	6.2
0	YES	29.52	5.10	0	0	0	2.15	0	0	0	-2.2%	8.4
0	YES	8.11	0.76	0	0	0	0.58	1	0	0	-7.7%	3.1
0	YES	21.17	0.14	0	0	0	4.80	46	84315	1095	-11.4%	4.9
0	YES	26.70	0.56	0	0	0	3.53	25	19905	617	-5.3%	5.8
0	YES	5.76	0.13	0	0	0	1.18	0	3201	97	-19.5%	1.8
0	YES	18.25	1.98	0	0	0	1.15	1	0	0	-4.4%	4.2
0	YES	0.72	0.04	0	0	0	0.41	0	0	0	27.6%	0.2
0	YES	3.96	1.57	0	0	0	0.00	0	0	0	21.4%	9.1
0	YES	7.74	1.52	0	0	0	0.46	2	121357	1920	18.8%	7.4
0	YES	23.22	0.77	0	0	0	6.67	30	10106	326	-11.5%	5.9
o	YES	2.18	0.07	0	0	0	0.28	0	0	0	-78.6%	0.9
0	YES	18.30	0.21	0	0	0	3.76	11	75740	1690	-2.6%	7.4
0	YES	22.35	0.00	0	0	0	2.32	27	0	0	-6.6%	6.2
0	YES	16.82	0.32	0	0	0	2.29	1	0	0	-4.1%	5.1
0	YES	25.44	0.03	0	0	0	4.40	64	247741	3737	-2.0%	5.1
0	YES	26.50	0.14	0	0	0	4.74	53	0	0	-2.7%	7.6
0	YES	32.43	1.61	0	0	0	3.56	20	5304	78	0.4%	8.1
0	YES	10.17	0.50	0	0	0	1.64	17	23843	351	-3.1%	2.1
0	YES	33.66	0.24	0	0	0	2.33	40	99630	1122	-2.2%	9.9
0	YES	21.92	0.77	0	0	0	2.12	26	0	0	1.8%	8.3
0	YES	4.87	0.79	0	0	0	1.13	8	0	0	-2.5%	3.0
0	YES	4.87	0.95	0	0	0	0.71	0	0	0	-7.8%	4.6
0	YES	2.11	1.25	0	0	0	0.05	0	0	0	-9.5%	2.9
0	YES	22.71	1.89	0	0	0	1.45	0	0	0	-3.2%	7.6
0	YES	21.71	0.03	0	0	0	3.79	43	97570	1774	5.0%	6.7
0	YES	29.13	0.31	0	0	0	4.22	28	28888	1256	-6.5%	6.4
0	YES	22.98	0.07	0	0	0	4.63	26	0	0	6.9%	8.8
2	YES	48.23	4.82	0	0	0	9.96	8	3066	438	-15.8%	1.7
0	YES	1.72	0.00	0	0	0	0.00	0	0	0	85.3%	0.4
0	YES	3.97	1.89	0	0	0	0.00	0	110288	976	-9.0%	5.8
0	YES	1.37	0.84	0	0	0	0.00	0	0	0	-9.1%	4.0
0	YES	2.76	2.24	0	0	0	0.00	0	0	0	-7.8%	7.8

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	8.75	0.38	0	0	0	0.00	0	132759	1341	-4.8%	5.0
0	YES	1.09	0.70	0	0	0	0.00	0	0	0	-100.0%	0.0
0	YES	27.83	3.99	0	0	0	1.18	9	0	0	-4.8%	6.1
0	YES	22.15	0.80	0	0	0	2.34	6	0	0	-1.9%	7.5
0	YES	36.91	4.65	0	0	0	3.58	39	199686	1447	-5.6%	7.6
0	YES	20.34	4.17	0	0	0	0.26	1	0	0	-0.8%	8.1
0	YES	18.64	2.23	0	0	0	0.47	0	7740	3187	-1.8%	6.8
0	YES	13.35	2.92	0	0	0	0.00	0	3948	564	-0.3%	5.4
0	YES	16.41	2.88	0	0	0	0.00	0	0	0	-0.8%	6.6
0	YES	23.29	3.65	0	0	0	2.85	0	167897	1731	-5.0%	7.8
0	YES	18.90	1.39	0	0	0	1.96	2	0	0	0.0%	7.9
0	YES	31.31	4.21	0	0	0	2.52	3	80215	1315	3.1%	9.3
0	YES	13.39	2.92	0	0	0	1.30	2	4400	712	-1.8%	6.3
0	YES	15.40	2.08	0	0	0	1.75	0	0	0	-6.3%	6.3
0	YES	15.23	2.25	0	0	0	1.60	0	0	0	-2.1%	8.0
0	YES	17.69	2.91	0	0	0	0.00	0	0	0	-4.0%	6.1
0	YES	18.93	4.03	0	0	0	0.84	0	0	0	2.5%	6.5
0	YES	17.91	1.95	0	0	0	4.35	4	2450	49	-14.3%	3.9
0	YES	23.47	4.43	0	0	0	0.00	0	0	0	-10.1%	6.7
0	YES	26.28	5.61	0	0	0	0.00	0	0	0	-3.7%	7.8
0	YES	27.10	2.75	0	0	0	2.06	31	9114	217	-3.0%	8.5
0	YES	7.42	0.28	0	0	0	1.44	3	0	0	-10.6%	2.6
0	YES	21.57	0.17	0	0	0	2.40	28	0	0	-7.5%	5.5
0	YES	18.23	0.06	0	0	0	2.92	28	0	0	-4.2%	6.2
0	YES	17.09	0.23	0	0	0	2.87	18	0	0	-7.3%	6.0
0	YES	21.27	0.15	0	0	0	2.84	25	0	0	4.7%	6.7
0	YES	6.85	1.64	0	0	0	1.28	0	9656	136	-10.5%	6.3
0	YES	4.76	0.15	0	0	0	1.80	36	0	0	4.0%	3.7
0	YES	4.54	0.21	0	0	0	1.91	11	0	0	2.3%	5.4
0	YES	30.83	3.77	0	0	0	1.31	0	0	0	6.5%	9.5
0	YES	21.70	3.07	0	0	0	1.48	0	0	0	1.9%	8.7
0	YES	47.21	2.19	0	0	0	5.48	19	53048	1396	0.6%	8.3
0	YES	28.71	3.20	0	0	0	0.22	0	0	0	-0.7%	9.0
0	YES	26.31	2.47	0	0	0	3.67	31	68326	2022	-9.6%	6.4
0	YES	19.00	0.14	0	0	0	1.49	73	182016	2156	-15.9%	4.1

(N) Number of Automatic Line Sectionalizing Devices on the Feeder	(O) Feeder Looped?	(P) Total Length of Feeder	(Q) Length of URD Portion of Feeder Circuit	(R) Number of Customers Served by URD Feeders	(S) CMI for URD Feeders	(T) CI for URD Feeders	(U) Length of Overhead Portion of the Feeder Circuit	(V) Number of Customers Served by Overhead Feeders	(W) CMI for Overhead Feeders	(X) CI for Overhead Feeders	(Y) % Load Growth Since December 31 2010	(Z) Recorded Peak Load Recorded through December 31 2011
0	YES	15.74	0.89	0	0	0	2.16	0	0	0	-15.1%	3.1
0	YES	0.08	0.00	0	0	0	0.00	0	0	0	1.7%	6.2
0	YES	4.89	0.00	0	0	0	2.07	0	0	0	-11.5%	2.2
0	YES	9.19	0.61	0	0	0	2.43	5	0	0	-7.7%	6.0
0	YES	4.29	0.25	0	0	0	2.12	0	0	0	-3.0%	5.4
0	YES	0.08	0.08	0	0	0	0.00	0	0	0	-0.9%	5.5
0	YES	0.12	0.12	0	0	0	0.00	0	0	0	-33.5%	4.9
0	YES	0.41	0.03	0	0	0	0.21	0	0	0	-7.7%	4.0
0	YES	0.28	0.08	0	0	0	0.18	0	0	0	41.5%	3.0
0	YES	0.50	0.07	0	0	0	0.42	0	0	0	-26.5%	5.3
0	YES	29.83	0.42	0	0	0	3.83	0	0	0	-100.0%	0.0
0	YES	14.93	1.22	0	0	0	1.87	0	0	0	250.1%	2.5
0	YES	12.70	0.30	0	0	0	2.40	0	0	0	-100.0%	0.0
0	YES	38.52	0.32	0	0	0	4.95	19	0	0	7.5%	3.6
0	YES	31.30	3.05	0	0	0	2.39	1	0	0	1.8%	7.5
0	YES	21.88	0.51	0	0	0	3.13	46	18801	539	-23.1%	2.7
0	YES	0.40	0.10	0	0	0	0.30	0	0	0	7743.5%	13.3
0	YES	7.53	0.09	0	0	0	1.01	0	0	0	-10.8%	0.1