



REVIEW OF

Data Accuracy in Electric Reliability Reporting by Florida Electric IOUs

JULY 2015

BY AUTHORITY OF

The Florida Public Service Commission
Office of Auditing and Performance Analysis

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1.0 Executive Summary

1.1 Purpose and Objectives

In January 2015, the Office of Auditing and Performance Analysis initiated an audit to assess the processes investor-owned utilities (IOUs) employ to ensure the accuracy of the data provided to the Florida Public Service Commission (Commission) in their Distribution Service Reliability Reports. The IOUs examined were:

- ◆ Duke Energy Florida, Inc. (DEF)
- ◆ Florida Power & Light Company (FPL)
- ◆ Florida Public Utilities Company (FPUC)
- ◆ Gulf Power Company (Gulf)
- ◆ Tampa Electric Company (TEC)

Rather than analyzing the quality of *distribution service* provided (trends, weaknesses, improvements) this audit focuses on the quality of the *data reported* and the adequacy of processes by which each IOU compiles and validates this information.

Specific information contained in the annually-filed Service Reliability Reports includes results for the set of Commission-approved service quality performance metrics (e.g. CAIDI, SAIDI, SAIFI), and status updates on various Commission-required system preparedness initiatives.

In summary, the primary objectives of the audit were to:

- ◆ Document and evaluate processes and systems used to capture service reliability index data.
- ◆ Document and evaluate controls and processes to ensure service reliability index data is reported in the Distribution Service Reliability Report in compliance with Rule 25-6.0455, Florida Administrative Code (F.A.C.)
- ◆ Document and evaluate data collection processes for wood pole inspection/replacement, vegetation management, and other Commission-required reliability initiatives and activities.
- ◆ Document and evaluate controls and processes to ensure the accuracy of data reported regarding wood pole inspection, vegetation management, and other Commission-required reliability initiatives are correctly reported in the Distribution Service Reliability Report.

1.2 Methodology and Scope

The information compiled in this audit report was gathered through responses to document requests and onsite interviews with key employees accountable for directing, developing, and implementing each IOU's annual distribution reliability report. Specific information collected and reviewed from each utility included:

- ◆ Policies and procedures used to assess the effectiveness of reliability data
- ◆ Processes and systems used in the collection of reliability data
- ◆ Management reports used to evaluate systems used to capture reliability data
- ◆ Internal review processes to ensure accuracy of reliability data

In general, the audit sought to focus on systems and processes currently in use. Where necessary, differences between present and formerly-used methodologies were examined to understand changes made over time and their impact.

Audit staff specifically focused upon portions of the Distribution Service Reliability Report that present potential risk of data accuracy problems. Accurate data is essential for the Commission's use in rate cases, evaluations of service quality, and other Commission decisions. Key processes involve outage data capture and analysis, planning and tracking of targeted hardening and maintenance activities, and the verification of completed work unit data reported by contractors.

The tracking and gathering of data used to calculate the service quality metrics of SAIDI, CAIDI, SAIFI, etc. received close attention from commission audit staff due to their importance as key indicators of reliable electric service. These metrics require complex tracking and compilation of innumerable data points. Though much of metrics calculation is programmed and automated, some degree of operator discretion and human judgement exists in various processes.

Finally, some elements of the annual Distribution Service Reliability Report are largely qualitative or narrative in nature. Since no specified annual data reporting is required for initiatives such as forensic pole damage analysis, storm recovery planning, and coordination with emergency response agencies/law enforcement, no data validity issues needed to be examined.

1.3 Background and Perspective

To gather uniform information on electric service reliability, the Commission requires Florida investor-owned utilities (IOUs) to file an annual Distribution Service Reliability Report pursuant to Rule 25-6.0455, Florida Administrative Code (F.A.C.). The Commission and staff rely upon the data provided in the annual reports in annual assessments of overall service quality. For degradation in service, the Commission may request remedial action.

In early 2006, Commission dockets addressed wood pole inspection programs. The Commission ordered¹ annual reporting on each IOU's activities and results. In a subsequent docket, specified

¹ Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, Docket No. 060078-EI.

storm-preparedness initiatives were introduced by the Commission.² These initiatives were implemented by IOU's beginning in 2006 to explore ways of minimizing future storm damage and customer outages. The annual Distribution Service Reliability Reports provide the Commission with the status of wood pole inspections and storm-preparedness initiatives including:

- ◆ Vegetation Management Program
- ◆ Audit of Joint-Use Pole Attachment Agreements
- ◆ Transmission Structure Inspection Program
- ◆ Hardening of Existing Transmission Structures
- ◆ Transmission and Distribution Geographic Information System
- ◆ Post-storm Data Collection and Forensic Analysis
- ◆ Reliability Performance of Overhead and Underground Systems

Another key requirement of the Distribution Service Reliability Reports is the reporting of a set of reliability performance measurements or indices. These service reliability indices are used by the IOUs and the Commission to measure present performance against past history. The following indices are widely used in the electric industry as measures of outage duration, outage frequency, system availability, and response performance.

- ◆ **SAIDI:** The average minutes of service interruption duration per retail customer served with a specific area of service over a given period of time.
- ◆ **CAIDI:** The average time to restore service to interrupted retail customers within a specified area of service over a given period of time.
- ◆ **SAIFI:** The average number of service interruptions per retail customer within a specified area of service over a given period of time.
- ◆ **MAIFIe:** The average number of momentary interruption events recorded on primary circuits for a specified area of service over a given period of time.
- ◆ **CEMI5:** The number of retail customers that sustain more than five service interruptions for a specified area of service over a given period of time.
- ◆ **L-BAR:** Average length of outage; the sum of durations for all outage events occurring during a given time period, divided by the number of outage events over the same time period within a specific area of service.

The Commission requires the IOUs to track both “adjusted” and “actual” or “absent adjustments” service reliability indices and to report the results in the annual distribution reliability reports. “Absent adjustments” service reliability indices provide an indication of the distribution system performance *including* hurricanes and other infrequent and unusual events.

² Order Nos. PSC-06-0351-PAA-EI, issued April 25, 2006, PSC-06-0781-PAA- EI, issued September 19, 2006, PSC-06-0947-PAA-EI, issued November 13, 2006, and PSC-07-0468-FOF-EI, issued May 30, 2007, all in Docket No. 060198-EI.

“Adjusted” service reliability indices provide an indication of the distribution system performance on a normal day-to-day basis to avoid data skewing due to events beyond the control of the utility. Per Rule 25-6.0455, the adjusted reliability data removes the impact of the following events from reliability performance indices:

- ◆ Planned Service Interruption
- ◆ Storm named by the National Hurricane Center
- ◆ Tornado recorded by the National Weather Service
- ◆ Ice on lines
- ◆ Planned load management event
- ◆ Electric generation or transmission event not governed by subsection 25-6.018(2) and (3), F.A.C.
- ◆ Extreme weather or fire event causing activation of the county emergency operation center

While reliability indices provide a common system for evaluation of distribution system performance, any inter-utility reliability index comparisons should be performed with caution since no two distribution systems are alike. Variations, including service territory make-up, customer base size, system design, and degree of automation can impact the value of such cross-comparisons based solely upon these metrics.

In 2003, the Institute of Electrical and Electronic Engineering (IEEE) developed a calculation methodology to employ statistical five-year performance norms as the basis for offsetting abnormal system impacts and events such as named-storm outages. Often referred to as the “2.5 Beta” methodology, it is now codified in IEEE standard 1366-2012. As a consistent methodology available to all utilities, it provides comparable benchmarking of reliability metrics (CAIDI, SAIDI, SAIFI, etc.) In contrast, the Commission’s current exclusion methodology was developed internally and is unique to Florida.

Florida’s IOUs are aware of the IEEE 2.5 Beta calculation methodology. However, at this time, no interest has been expressed in amending present Commission-prescribed calculation methods. To the extent some Florida utilities believe the 2.5 Beta results do add value, they are also tracked internally and reported to management.

1.4 Commission Audit Staff Observations

Commission audit staff identified the following observations regarding the adequacy of processes by which each IOU compiles and validates information reported in the annual Distribution Service Reliability Reports:

1. **Extensive efforts are made by all five companies reviewed to accurately capture reliability data both electronically and manually. The internal use of reliability data for operation management purposes inherently drives the need for data accuracy.**

- 2. Quality assurance reviews are conducted by distribution operations work units to verify the validity of reliability records and data captured.**
- 3. Central staff positions exist at all five companies to perform validation and correction of the data that is ultimately reported to the Commission.**
- 4. Supervisory and managerial review provides an additional layer of verification and correction of data.**
- 5. Though reliability data is often gathered via complex and reliable computer systems, a significant degree of human judgement and analysis is still necessary to maximize accuracy.**
- 6. The degree of manual versus computerized data collection varies among the five companies reviewed, depending upon the capabilities of the systems in use.**
- 7. Currently-prescribed calculation methodologies for reliability index calculations are generally viewed as adequate and well-understood. Instances of corrections by the companies of results reported to the Commission are rare.**

2.0 Duke Energy Florida

2.1 Reliability Indices

The reliability of electric distribution systems is critically important to both utilities and customers. Reliability indices are used to provide a quantitative and objective basis for judging the effectiveness of Duke Energy Florida's (DEF) efforts to maintain or improve performance. DEF's Power Quality, Reliability & Integrity and Grid solutions Reporting business organizations are responsible for monitoring, reporting, and ensuring the accuracy of all the reliability indices as required by the FPSC's Annual Distribution Reliability Report.

Quantifying reliability is a complex data intensive effort which presents numerous opportunities to make errors. It is important for DEF to accurately track and evaluate reliability metrics to ensure the reliable distribution of electricity and to identify areas for improvement.

2.1.1 Data Collection Process

Duke Energy Florida has implemented a multi-layered system to capture reliability index data from the time an outage occurs to final calculations. DEF's Outage Management System (OMS) acts as the central point of capturing outage information. All outage restoration work is also tracked and coordinated through the OMS system. Other programs such as the company's Geographic Information System (GIS), the Supervisory Control and Data Acquisition (SCADA) application, and the Customer Service system (CSS) feed information into OMS to allow the company to identify and restore outages in an efficient manner.

Outages are identified by either customer calls or by SCADA at the substation level. Customers report outages by calling the company and utilizing the Customer Service System (CSS), Integrated Voice Response (IVR), a corporate call center, or a third-party back-up call center used for overflow calls. Start times for outages are recorded as soon as the first customer calls.

Customer calls reporting outages trigger the automatic creation of work tickets in the OMS system. However, as shown in **Exhibit 1**, SCADA communications can also automatically create a work ticket in the OMS. SCADA provides DEF with two-way telemetry to monitor outages at a substation level. When an outage occurs at this level, the SCADA application at the control center immediately records the outage and creates a work ticket in the OMS system.

While DEF has a small deployment of Advanced Metering Infrastructure (AMI) technology, DEF does not currently use this technology to obtain outage information. The deployment is part of a small pilot program geared towards understanding the technology and the billing information it provides.

Dispatchers monitor incoming outage work tickets and dispatch them to available field technicians. OMS prediction models use GIS information to identify the device causing the outage. Using these maps, OMS can prioritize outages by equipment type, customer count, and resources needed and available.

Once the outage is dispatched, the field technician utilizes the Mobile Outage Management System (MOMS) on their truck laptop to record the failed device type, cause code, and any comments pertaining to the restoration activities as shown in **Exhibit 1**. The technician enters the restoration time once he has completed fixing the problem device.

Duke Energy Florida Reliability Data Collection Process		
Step	Process / Input	Description
Collecting Outage Information	<pre> graph TD SCADA[SCADA] --> OMS[OMS] CC[Customer Calls] --> OMS </pre>	Outages are identified through the SCADA system or through calls from customers experiencing outages.
Creating Outage Ticket	<pre> graph TD OMS1[OMS] --> OMS2[OMS] GIS[GIS] --> OMS2 </pre>	Work tickets are automatically created in the Outage Management system (OMS). GIS maps and information is used by the OMS prediction models to identify the device and customer count.
Working Ticket	<pre> graph TD FT[Field Tech] --> MOMS[MOMS] ASC[Automated system checks] --> MOMS </pre>	Field technician enters all outage information and changes into the Mobile OMS (MOMS) using the truck laptop. Automated systems checks ensure that required fields on the ticket are completed before allowing the field technician to submit and close the ticket.
Completing Ticket	<pre> graph TD OMS1[OMS] --> OMS2[OMS] </pre>	Once an outage has been restored, the field technician completes the ticket, and the outage information is stored in OMS.
Outage Data Review	<pre> graph TD OA[Outage Auditor] --> OMSR[OMSR] </pre>	OMS data is transferred nightly to the Outage Management System Reconciliation application (OMSR). Outage auditors review and reconcile outage data to ensure accurate reporting.
Indices Calculations	<pre> graph TD OHD[Outage History Datamart] </pre>	All reconciled outage data is transferred to the Outage History Datamart, where reports calculate all reliability indices reported to the Commission.

Exhibit 1

Source: Document Request Response 1.33

Exhibit 1 illustrates DEF’s process of identifying, tracking, collecting, validating, calculating, and reporting reliability data.

As illustrated in **Exhibit 1**, OMS daily publishes all outage information to the Outage Management System Reconciliation application (OMSR). Once in OMSR, outage data is reviewed and reconciled by outage auditors. These comments give outage auditors key information if the need to investigate an outage later arises. Once the data has been reconciled, the outage data is extracted from OMSR into the Outage History Datamart, which is DEF's system of record for reliability data. DEF's Reporting team runs the reports which calculate the reliability indices used in internal reports as well as the Commission's Annual Distribution Reliability Report.

DEF creates weekly internal status reports of the reliability indices for review by upper management. DEF calculates the reliability indices using the required FPSC exclusions.

To assess overhead and underground reliability data, DEF runs a query in the Outage History Datamart. During the outage restoration process, overhead and underground outages are automatically classified by the restored device type identified by the field technician in the Mobile Outage Management System (MOMS). It is possible for a multi-step outage to have both overhead and underground Customers Interrupted (CI) and Customer Minutes of Interruption (CMI). OMS is able to properly allocate the CI and CMI to overhead and underground devices. DEF's GIS can also identify which lines and devices are overhead or underground. DEF does not routinely review overhead and underground reliability indices data internally, but rather the company reviews reliability data holistically and takes corrective actions or re-directs investments geared at improving overall reliability accordingly.

In 2011, Duke Energy Florida implemented an upgraded version of its Intergraph OMS system. This upgraded software allows for more stability and better outage predictions to ensure more accurate outage information. OMS was originally implemented in 1999.

Additionally, the company calculates the reliability indices in accordance with IEEE 1366 2.5 Beta methodology for all internal reports and goals. DEF also uses IEEE calculations of the reliability indices to benchmark with other utilities.

FPSC exclusions are performed by an analyst in the Power Quality, Reliability & Integrity Governance group. The analyst reviews historical NOAA website data to obtain the location and time of severe weather events that qualify under the FPSC exclusion method. Using this data, they identify the operation center(s) that were affected, and the proposed FPSC exclusion is documented. After the Director of Power Quality, Reliability and Integrity approves the exclusions, all events for that operating center for that time period are flagged for exclusion from all FPSC indices in the OMSR application.

DEF states that the IEEE 1366 Standard and 2.5 Beta calculations provide the best normalized reliability data for benchmarking purposes. This standard would improve the validity, accuracy, and usefulness of the reported reliability data. The IEEE 1366 standard allows for a more statistical approach to calculating exclusion than the current FPSC exclusion method.

2.1.2 Data Accuracy Validation

DEF uses a combination of automated system edits and several levels of verification and validation to ensure the accuracy of outage data. OMS automated system checks require all fields of a trouble ticket to be completed by field technicians during outage restoration.

DEF's multi-layered outage system, implements several controls to ensure the accuracy of data. GIS publishes updated maps to OMS twice per week to reflect any new additions or changes. This increases the accuracy of the OMS prediction models and helps dispatchers allocate resources more efficiently to restore outages.

Outage information is extracted from OMS into the Outage Management System Reconciliation Application (OMSR) every night. DEF has performed an outage auditing function for more than 10 years. DEF has 3 to 5 outage auditors in Florida. Outage auditors are responsible for reviewing outages and reconciling any discrepancies in the cause, restore time, or type of equipment found.

Auditors are assigned geographic areas and prioritize outages by reconciling those with the largest CMI first. Service outages impacting one customer or outages caused by transformers impacting a small customer count are auto-reconciled by the program. Auditors review all outage tickets created from SCADA and all tickets caused by fuses or larger devices. Also reconciled are step outages, which progressively restore groups of customers until the repairs are completed.

Auditors also research and investigate outages with field technicians. The auditors perform monthly self-checks using a checklist of 24 tests ensuring they do not miss something and validating the quality of the data. The GIS manager who oversees the outage auditors reviews weekly internal reconciliation goals to ensure timely completion of reconciliations. After this data has been scrubbed and extracted from OMSR, it is used to update customer records to help facilitate future outage predictions. At the end of the year, once all the outages have been reconciled, the data is locked down and cannot be changed.

As an additional accuracy check, DEF's Outage Follow-up process involves field verification by field personnel of any large customer-count outages. This helps the field technicians to help prevent future outages by similar devices. After the follow-up, any discrepancies are corrected in the OMSR database.

Once reconciled, outage data is entered in the Outage History Datamart. DEF's IT organization monitors the Datamart and all the equations embedded in the program ensuring that they are used correctly to calculate the reliability indices.

In 2012, the Performance Support organization performed an audit of the accuracy of the Datamart equations. To verify the accuracy of the reliability index equations, the Performance Support organization dismantled and reconstructed the Datamart to validate the original Datamart. No discrepancies were found. The IT organization has also set up notifications to monitor the communication between all of these programs that collect and report the reliability indices data as indicated in **Exhibit 1**.

2.2 Wood Pole Inspections

DEF has approximately 763,079 distribution and lighting wood poles and 25,370 transmission poles. The Commission requires each IOU to implement an inspection program of wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the National Electric Safety Code.³ Approximately one-eighth of the poles are inspected annually. DEF's first inspection cycle was completed in 2014.

The data accuracy issue related to wood pole inspection is accurate planning and tracking to ensure all poles are accounted for during the inspection cycle. Poles missing from plant records or GIS listings could become weak links that negatively impact reliability.

2.2.1 Data Collection Process

DEF uses Osmose to perform all wood pole inspections. The company tracks all wood pole inspections by overlaying a print of the completed inspections over the company's Geographic Information System (GIS). DEF's GIS database holds the location of all poles and allows the company to track poles that have not been inspected. After the company determines the workload for that year, it provides the contractor a GIS map, including the pole numbers and GPS coordinates for all poles in that year's workload.

Osmose performs visual inspections and sound and bore inspections of most poles. If any surface decay is visible, the contractor removes it as part of the inspection process. Chromated Copper Arsenate (CCA) poles less than 16 years old only receive visual inspections, and a sample of CCA poles is also used to conduct a sound/bore inspection.

Osmose sends DEF weekly email reports detailing a list of high priority poles in need of replacement. The rest of the pole inspection results are reported to DEF monthly. The contractor provides DEF with an Excel file of inspection results, which are used to prioritize pole replacements. Replacement targets are processed and tracked using Excel and Access files, then added to the Facilities Management Data Repository (FMDR). Using FMDR, engineers create a work order in the Work Management System (WMS). Completion of pole replacement is tracked in FMDR and Excel and Access databases. DEF uses both in-house crews and contractors to perform pole replacements.

The contractor performs internal post-inspection audits to ensure the quality of inspections. These audits are performed using a random sample with no prescribed schedule. These internal audits are performed by the contractor's general foreman, and audit results are shared with DEF during semi-annual business reviews.

Duke Energy Florida has developed a Forensic Analysis program that is in place to capture data of storm and weather damage to the power delivery system. Following a storm, DEF will determine whether the forensic data analysis will be performed internally or by a third-party. In 2008, 2011, 2012, and 2013, DEF collected data from storms and mid-level events, but no analysis of the data has been performed. DEF's forensics team participated in DEF's 2014 and 2015 storm season preparatory activities.

³ See Commission Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI.

2.2.2 Data Accuracy Validation

DEF's field inspectors perform quality audits on the contractor's wood pole inspections. Inspectors check for performance, work quality, safety, and accuracy of inspection results. The contractor also provides daily work location reports to DEF's Wood Pole Inspector and Senior Engineering Technologist. A random sample of one percent of the poles inspected for each contractor crew foreman is audited by DEF each year. The audit results are captured in paper forms. Any deficiencies found by the audit must be corrected by the contractor within 15 business days. DEF has also implemented Quality Assurance audits for pole replacement. Construction inspectors review a sample of work for both the quality of the work as well as safety.

DEF uses a contractor to perform a structural load analysis of approximately 1/8th of all joint-use poles each year in addition to the wood pole inspections. Structural load analysis is tracked in an Excel database. If a pole is found to be overloaded, the contractor is required to provide a remedy to correct that pole. Load analysis results are entered into FMDR. DEF uses its FMDR to track completion of pole replacement work. There, the line crew and supervisor have access to the analysis results in case discrepancies arise regarding the load analysis results before the pole replacement work begins.

2.3 Vegetation Management

The single largest cause of electric power outage occurs when trees, or portions of trees, grow or fall into overhead power lines. Keeping trees and vegetation from conflicting with overhead conductors and triggering power outages is critical to service reliability.

It is imperative that DEF ensures adequate and consistent vegetation management practices through accurate tracking of workloads and schedules. Inaccurate records could allow lines to remain uninspected, leading to preventable outages.

2.3.1 Data Collection Process

DEF's Vegetation Management (VM) program employs stricter inter cycles, addressing feeder backbone circuitry within a three year period and lateral circuitry within a five year period. DEF's VM program uses a cycle-based approach and a reliability-based prioritization model to plan trimming work. The model assesses reliability and historical data and factors such as equipment type, year, and phase. This model is an Excel spreadsheet maintained by the DEF Manager and Business Consultant. The targets identified by the prioritization model become the annual work plan allowing the company to allocate the appropriate resources and project time requirements.

DEF employs five different contractors to conduct vegetation management activities. Prior to beginning any trimming work, the contractor rides each targeted circuit with a utility employee to determine the type of trimming and clearing necessary. After the field observation is complete, the agreed-upon work types are stored in the Vegetation Management Specialist tracking tool. This manual tracking tool, maintained by the DEF foresters, allows management to track all completed work, quality assurance scores, and mileage. All annual work plan targets and mileage are reviewed weekly.

Hot-spot tree trimming is monitored and tracked separately in an Excel file reviewed weekly by VM management. After the completion of the current feeder and lateral circuit cycles, DEF evaluates the vegetation management program to identify opportunities for further optimization of reliability and cost. The 2015-2017 DEF distribution clearing specifications will expand to include right of way floor clearing activities. There are also future plans to increase the scope of the herbicide program to manage right of way floors long term.

2.3.2 Data Accuracy Validation

DEF conducts a quality audit on all circuits completed by its contractors to ensure clearing specifications, contract terms, and contract conditions have been met. Vegetation Management inspectors conduct audits on 100 percent of all circuit work. Inspectors use a form containing weighted factors such as:

- ◆ Clean-out around poles and removal of vegetation
- ◆ Pruning quality
- ◆ Floor clean-up and stump removal
- ◆ Clearances
- ◆ Danger trees
- ◆ Yard brush handled properly

If any findings are found, the contractor has 10 days to correct the problem and resubmit for confirmation. Prior to 2012, DEF conducted field observations of a minimum of two locations of the circuit. Post 2012, circuits are not completed until an audit has been performed and all findings have been corrected.

DEF's VM Governance group along with the VM Program Manager and foresters conduct a quarterly meeting with the contractor to review and validate all work performed. DEF combines all audit scores into a score card and reviews it with the contractor. Score card categories include safety, quality, productivity and cost, and customer service. These score cards are calculated by area and are contractor specific.

An internal audit was completed by Duke Energy's Corporate Audit Services on the Vegetation Management Clearing Activities on Distribution Lines. No major findings were found.

2.4 Transmission Structure Inspections and Storm Hardening

DEF's annual reliability report updates the status of inspecting and storm hardening transmission structures. The transmission structure inspection program identifies specific issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. DEF's storm hardening activities for transmission structures primarily focuses on the systematic replacement of wood transmission structures with non-wood structures.

2.4.1 Data Collection Process

Investor-Owned Utilities are required by the Commission to inspect all transmission structures and substations on a six-year cycle. However, Duke Energy Florida has developed shorter inspection cycles. DEF inspects all wood transmission structures every three years and all concrete and steel structures every five years. These inspections are done in conjunction with aerial patrols, which are conducted twice a year.

DEF utilizes the Cascade Data and Work Order Management tool, implemented in 2003, to store and maintain all transmissions structure data as well as work orders. All transmission employees have access to the Cascade database; however, input rights are restricted to a limited number of employees. Inspections are planned and performed by geographical areas determined by the company.

DEF uses a contractor and DEF crews to perform its transmission pole inspections. The contractor is responsible for looking at the whole structure including the poles and the hardware. DEF provides the contractor with an Excel spreadsheet with the work to be performed extracted from the Cascade database. As the work is completed, the contractor provides DEF an Excel spreadsheet with inspection results, which are entered into Cascade to track progress and identify any pole replacement.

The contractor supervisors also perform Quality Control inspections to ensure safety, quality of work, and accuracy of reporting. These Quality Control inspections are reviewed by DEF's management.

There is an initiative to standardize pole inspection criteria throughout the Duke Energy enterprise to adopt best practices across the system. This effort is projected to be completed by 2015.

Since 2013, transmission pole replacement work orders have been created through the Cascade database and the Work Management System. DEF utilizes in-house crews and contractors to perform pole replacements. Work orders identify the structure needing replacement as well as the condition of the pole. DEF prioritize pole replacement by the inspection results. The worst poles are replaced first. Once the work order is completed by transmission engineers, it is scheduled. A field review occurs prior to pole replacement, verifying the pole inspection results. Any discrepancies found during the field observation are provided to the contractor who performed the initial pole structure inspection.

Any storm hardening of existing transmission structures occurs at the same time as pole replacements. DEF assigns an oversight inspector to oversee the storm hardening and pole replacement activities and monitor the quality of the work. After the work is complete, the Cascade database and GIS are updated to reflect the storm hardening work.

2.4.2 Data Accuracy Validation

Currently, DEF does not perform internal quality assurance inspections or audits on its transmission pole inspection program. DEF is planning to implement internal quality assurance inspections to complement the contractor's quality control inspections by the end of 2015.

As aerial inspections are performed, the helicopter pilot checks the transmission structure and the accuracy of the Cascade structural data. The pilot is equipped with a handheld device loaded with the GPS coordinates from the Cascade database and a paper map. If there is any discrepancy between the GPS coordinates from the Cascade database and the physical transmission system, he notes this on the paper map for later correction by DEF engineers in the Cascade database.

During the pole replacement process, an oversight inspector oversees the construction process and ensures the quality of each pole replaced. There is no formal documentation for these quality assurance inspections. However, if any discrepancy or changes occur during construction, an Equipment Change Request form is completed by the DEF oversight personnel. The completed Equipment Change Request form is sent to the line engineers who manually update the Cascade database and the hard copy records.

2.5 Geographic Information System

A geographic information system (GIS) allows DEF to collect, organize, maintain, manage, and analyze spatial and geographical data. The GIS is the foundational database for DEF's facilities records and is fully integrated with 100 percent of DEF's distribution and transmission systems. The GIS provides critical support to the distribution operations. Inaccurate GIS data would negatively impact the location of system components in need of repair and delay restoration efforts.

2.5.1 Data Collection Process

DEF's GIS is managed by the GIS Florida Engineering and Construction organization. DEF restricts access by employees to minimize accuracy issues. The GIS specialists also perform the outage audit function mentioned in section 2.1.1.

All new construction or changes to the company's assets are reflected in the company's GIS. The engineer's design specifications are entered into the Work Management System (WMS) and GIS. Only GIS technicians have the authority to add or modify the GIS infrastructure. Changes are published to OMS as a "proposed facility" until the work is complete. This allows OMS to be as up-to-date as possible. If there are any changes throughout the process, the GIS organization would be contacted through the Mobile Work Management System to increase the accuracy of GIS maps.

GIS is the repository for all distribution power delivery system assets and lines, which feeds those maps to other programs. GIS publishes its most current maps and asset lists to other programs on a regular basis. Engineering planning uses an engineering program, which receives updated information from GIS weekly. The Work Management System (WMS) and the mobile WMS also use GIS maps. Most importantly, GIS publishes updates to DEF's OMS system twice a week. GIS receives customer records from the Customer Service System allowing it to tie customers to specific equipment in its inventory. This allows OMS to predict the outage device and the number of customers tied to that device. For example, if a transformer stops working, OMS runs models using GIS data to identify the customers tied to that specific transformer. DEF can then calculate the number of customers affected.

An initiative at the Duke Energy enterprise level will consolidate the various GIS systems across all the operating companies into one centralized GIS system. This initiative is expected to be completed by 2017.

2.5.2 Data Accuracy Validation

DEF has implemented several controls to validate GIS data since it is vital to OMS and other distribution operations programs. GIS produces a daily report which identifies any design errors in the GIS data that could hinder the OMS predictions. If GIS identifies more than 100 design errors, it will not publish updates to OMS or any other programs. GIS also publishes a report reviewing whether any circuit is looped. The IT organization has also blocked any other program to write into GIS.

To check the accuracy of the GIS map accuracy, DEF has developed the Fix My Map system. It allows field technicians or dispatchers to flag issues they encounter. If a field technician performing restoration work encounters a discrepancy in the GIS maps, the tech uses the Fix My Map system to alert GIS technicians of the discrepancy. Dispatchers also have the capability to tag errors within OMS. The emails and tags are compiled into a queue and addressed by the GIS technicians. This allows DEF to constantly increase the accuracy of the GIS mapping data by utilizing field personnel.

DEF's Internal Audit department performed an audit of the company's GIS in 2009 and a follow-up audit in 2012. All audit findings were addressed and corrected.

3.0 Florida Power & Light Company

3.1 Reliability Indices

The reliability of electric distribution systems is critically important to both utilities and customers. Reliability indices are used to provide quantitative and objective judgement of Florida Power & Light Company (FPL) efforts to maintain and improve performance. FPL's Power Delivery business organization is responsible for monitoring, reporting, and ensuring the accuracy of all reliability indices reported in the Annual Distribution Reliability Report.

Quantifying reliability is a complex data intensive process, potentially allowing opportunities to make errors. It is important for FPL to accurately track and evaluate reliability metrics to ensure efficient distribution performance and identify potential areas for improvement.

3.1.1 Data Collection Process

Data collected to calculate reliability indices is captured in FPL's Data Warehouse. The data warehouse interfaces with FPL field systems, which gather outage ticket and other reliability data used to calculate metrics and report Florida Public Service Commission (Commission) required information.

FPL's Supervisory Control and Data Acquisition (SCADA) system located in System Control Centers captures data relevant to substation level outages to initiate a feeder level interruption ticket. The feeder and substation location, outage type, outage cause, customers re-routed, and timing of service restoration are captured for these outages.

The Trouble Call Management System (TCMS) receives data from SCADA and other systems to initiate lower level outage tickets. The outage ticket provides the location, estimated number of customers impacted, and a suspected cause of the outage. FPL's Customer Information System (CIS) provides TCMS with data that identifies the estimated number of customers served within the outage area identified.

The outage ticket is dispatched to field technicians for service restoration. Upon arriving at the outage site, field technicians input the time into their portable computer. Technicians begin verifying outage details to assess the outage cause and restore service. The field technician confirms the system-generated outage cause, or inputs another cause code more specifically identifying the true outage cause.

Exhibit 2 provides a basic flowchart of the FPL outage data collection process for reliability data reported to the Commission.

Florida Power & Light Company Reliability Data Collection Process		
Step	Process / Input	Description
Collecting Outage Information		Outage identified by AMI smart devices and SCADA signals TCMS. Customer outages reported via CIS are also identified through phone and FPL website.
Creating Outage Ticket		TCMS creates outage ticket with estimated customer count.
Working Ticket		Dispatchers assign field crew for repair activity and coordinate restoration with crew; crew verifies outage details; crew enters time arrived on-site, time work completed, service restored, and any equipment changes to TCMS through the portable computer.
Completing Ticket		TCMS and/or field personnel complete outage ticket, review details, make notes on the ticket when needed, and close the ticket in TCMS. Nightly uploads to Data Warehouse update outage data.
Ticket Review And verification		Daily verification of outage ticket is completed by Control Center Operators and/or field personnel; Every 2-3 days Control Center Supervisors review outage tickets; Monthly random samples of approximately 500 outage tickets are completed by Delivery Assurance staff to ensure outage ticket accuracy and completeness. Data Warehouse retains outage and other reliability data used for FPL management reports and Commission reporting.

Exhibit 2

Source: Document Request Response DR-1.25

To ensure all customers impacted by the outage have been restored, technicians can request the Distribution Control Center (DCC) to electronically confirm, or “ping” customer meters in the outage area. Pinging the meter confirms that service to the meter was restored. This can prevent a second field call due to overlooking a customer whose service was not restored during the initial dispatch trip. Meter pinging is carried out through FPL’s Advanced Metering Infrastructure technology, implemented as part of its Energy Smart Florida program.

Once service has been restored to all customers impacted, the technician reports the completion time through the portable computer. TCMS collects information regarding the outage location, outage type, number of customers interrupted, dispatched resources, timing of the dispatch, and restoration completion time. Ticket information from TCMS, is used to compute FPL’s SAIDI, CAIDI, and SAIFI indices. MAIFI is determined through operations in SCADA.

Information fed from FPL’s systems is extracted from the Data Warehouse to calculate reliability indices established by the Commission. Reliability performance is measured monthly for each of FPL’s sixteen management areas.

Though not required by the Commission, FPL internally tracks the Institute of Electrical and Electronics Engineers (IEEE) 2.5 Beta methodology to calculate SAIDI, CAIDI, SAIFI and MAIFI. The company captures the data internally to benchmark its reliability results against other electric industry participants using the same methodology.

Unlike required Commission indices, the 2.5 beta methodology defines all outages less than five minutes as momentary events and excludes them from SAIDI, CAIDI, and SAIFI calculations. IEEE 2.5 Beta uses a five-year average for the threshold applied for Major Event Days, and combines Transmission and Distribution to assess total company reliability performance. In the 2.5 Beta methodology, planned exclusions such as those allowed by Commission rule, are not excluded. Instead, a five-year Major Event Threshold is used as a daily limit to outages.

For FPL reporting purposes, FPL is not aware of any increase in benefit or usefulness of the 2.5 Beta methodology over the current Commission reliability measurements. The company states that the methodology would provide different results than the current Commission reliability indices. These results would not necessarily be more or less accurate in measuring performance, just different. FPL suggests that, if in the future, the Commission considers adopting the IEEE 2.5 Beta methodology for reporting purposes, a workshop to discuss the pros and cons of the measurement would be beneficial.

For many years FPL has built more underground facilities than overhead, due to customer and local government aesthetic preferences. Measurement of FPL’s overhead and underground reliability performance begins with its electric feeder design. Almost all of its feeders are a hybrid design, comprised of both underground and overhead construction throughout the feeder. Lateral lines further distribute electric power from feeders to customer locations, and are usually of a single type of construction, either underground or overhead.

Forensic lateral data is collected daily from statistically valid random samples of both overhead and underground lateral outage tickets. Post-restoration review of available lateral ticket comments is performed for underground damage, since problems with buried equipment may not be easily observed in the field.

FPL has established metrics to measure overhead and underground performance. The metrics used are the Percent of Overhead Laterals With Damage versus Total Overhead Laterals in Storm Impacted Areas and the Percent of Underground Laterals With Damage versus Total Underground Laterals in Storm Impacted Areas. If statistically valid counts of overhead facilities are damaged, overhead measurement includes the total quantities stratified by pole type, location on lot, underground total quantities of cable construction, and estimated repair time.

FPL states that its processes, systems, and tools for overhead and underground forensic data collection have been tested to ensure they perform appropriately and accurately. FPL continues to test and evaluate the forensic overhead and underground process during the annual company-wide storm preparedness dry-run.

3.1.2 Data Accuracy Validation

To ensure accuracy of reliability data, FPL uses a combination of automated system edits, several levels of verification and validation, and periodic internal audits. Automated system edits require all fields to be completed, and prevent certain types of data entry errors from being completed. These edits make corrections before allowing data entry personnel to complete the entry, or hold the error until it can be resolved for final entry.

Frequent data uploads ensure the most current and accurate reliability data is captured and stored in FPL's data warehouse. Essential data is reviewed daily and weekly by company management. Monthly management reports are also provided through back-end systems for further analysis and reporting.

FPL Distribution Control Centers receive notification of electric system interruptions and complete outage tickets to document outage details. As a first level of data verification, Control Center Operators review ticket information daily to validate the accuracy of each ticket. Ticket errors, such as outage coding or timing, are corrected with supervisor approval, and notes are made on the ticket to document why the change was made. The Control Center Supervisor completes a second level of data verification through ticket reviews every two to three days. These reviews ensure outage tickets are complete, accurate, and properly coded.

A third key level of data verification is completed monthly by FPL's Delivery Assurance Group at Jupiter West and the Distribution South Campus. As discussed in **Exhibit 2**, this group completes a random sample from the data warehouse of approximately 500 outage tickets monthly. These tickets are reviewed for accuracy and completeness of outage information including:

- ◆ Start and stop times
- ◆ Type of outage
- ◆ Outage cause

- ◆ Outage coding
- ◆ Equipment code
- ◆ Ticket notes

If necessary, the Delivery Assurance reviewer may access SCADA to determine whether an automated feeder switch (AFS) was activated during the outage. AFS equipment may limit the actual number of customers impacted by an outage by automatically re-directing the electrical service to another circuit for continued service. This reduces the number of customers out of service during an outage.

Delivery Assurance sample verifications are usually completed within 15-25 days after the outage has occurred. The ticket event log captures everything coded on the ticket, and the single login identifier shows the individual making any change in customer interruptions or customer minutes of interruption on the outage ticket. Additionally, ticket notes explain any changes made or critical information relative to completing the outage and restoring service.

To assist in the sample review, Delivery Assurance may make inquiries to the control centers regarding specific tickets. The Control Center Manager provides feedback to Delivery Assurance to resolve any questions uncovered by the sampling review. These responses are maintained with the sample file results in Delivery Assurance.

During the period 2010-2015, FPL's Internal Audit department regularly conducted audits of the processes related to reliability measurement data and Commission-ordered storm hardening initiatives.

3.2 Wood Pole Inspections

The Commission requires each IOU to implement an inspection program of wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the National Electric Safety Code. FPL inspects its distribution wood poles on an eight-year cycle. Transmission wood pole structures are inspected through climbing and bucket truck inspections over a six-year cycle. FPL completed its first eight-year pole inspection cycle in 2014.

Accurate planning and tracking is essential to ensure all poles are accounted for during the inspection cycle. Poor inspection records, missing plant records, or inaccurate Geographical Information System listings can allow poles to go uninspected, and become weak links that may negatively impact pole reliability.

3.2.1 Data Collection Process

FPL uses Osmose as its wood pole inspection contractor to annually inspect approximately one eighth of the total 1.2 million distribution wood poles in its electric system. FPL has established nine management areas for pole inspections, and completes annual inspections and necessary follow-up remediation in each zone. FPL and AT&T partner with the pole inspection contractor

to ensure FPL and AT&T joint-use poles are also inspected and load tested on an eight year cycle.

Pole Inspection metrics tracked by FPL include:

- ◆ Total number of poles in the company inventory
- ◆ Number of pole inspections planned
- ◆ Number of poles inspections completed
- ◆ Number of poles failing inspection
- ◆ Pole failure rate as a percentage
- ◆ Number of poles designated for replacement
- ◆ Total number of poles replaced
- ◆ Number of poles requiring minor follow-up
- ◆ Number of poles overloaded
- ◆ Total number of poles inspected cumulative for the eight-year cycle
- ◆ Percent of poles inspected cumulative for the eight-year cycle

FPL's Work Management System (WMS) tracks assigned pole inspection work activity. Weekly status updates of pole inspections, follow-up work, and re-work is monitored to ensure activities are completed as required.

Osmose uses mobile computing technology to record inspection results and calculate pole strength and loading conditions. Weekly inspection results are reviewed by contractor supervisors prior to submitting completed work, timesheet data, and invoices to FPL. Approved inspection information is uploaded via a direct transfer to FPL's Asset Management System/Geographic Information System (AMS/GIS) to update pole inspection records.

The FPL Pole Inspection Group uses Osmose raw data results to update Central Maintenance Excel files, and upload to the data warehouse. Updated pole inspection information from the data warehouse, is used to complete monthly pole inspection reports to management.

As a result of the first eight-year pole inspection cycle, FPL requested the Commission to modify requirements for its chromium copper arsenate (CCA) pole inspection excavations and loading calculations due to the low failure rate experienced for CCA poles. Commission Order PSC-14-0594-PAA-EI approved an extension of the exemption for CCA poles from 16 to 28 years, and limited load calculation requirements during the second inspection cycle. FPL estimated cost savings of approximately \$4.2 million over the second eight-year inspection cycle due to the change.

In response to Commission Order PSC-06-0144-PAA-EI, FPL began strengthening its forensic data collection and analysis process for storm-related wood pole damage. FPL's forensic process is designed to obtain information regarding the storm's expected path and wind bands prior to the storm making windfall, and follow-up with analysis of the storm-damaged assets.

FPL has trained 45 individuals, backed-up by contractor resources to conduct post-storm data collection of storm damaged assets. The company plans to position teams as near to the projected storm damage path and ride the storm out in category-5 rated buildings.

Using FPL's mobile mapping and field automation software a random sample of poles from the path of the storm damage is created. The random pole locations are used to design forensic team patrol routes for observation and collection. The forensic team uses portable field computers to collect data including:

- ◆ GIS coordinates
- ◆ Facility information
- ◆ Wind speed and loading
- ◆ Construction and framing
- ◆ Debris and soil conditions
- ◆ Impact of flying debris
- ◆ Equipment failure
- ◆ Cascading pole failures and events
- ◆ Pictures of damaged equipment and facilities

The forensic team is required to capture data for both hardened and non-hardened assets in the most severely damaged areas. This data will be analyzed and evaluated for improved hardening and storm-preparedness.

Testing to ensure the processes, systems, and tools are performing appropriately and accurately has already been completed. FPL tested and verified the readiness of its forensic process during the annual company-wide storm dry run and after actual tornado conditions.

3.2.2 Data Accuracy Validation

FPL uses several levels of validation checks to ensure the accuracy of pole inspections. Initially, Osmose supervisors review the inspection results for accuracy prior to submitting completed work. FPL Quality Assurance inspectors review Osmose completed work prior to approving payment for inspections. Monthly, FPL's Quality Assurance group also completes a random sample of approximately 500 pole inspections submitted by the contractor to:

- ◆ Verify and validate contractor inspection results
- ◆ Ensure FPL agrees with inspection assessments
- ◆ Address any safety hazards identified
- ◆ Ensure inspection data is properly recorded
- ◆ Assess whether contractor invoicing is accurate

Questionable results identified by the sample are returned to the contractor for clarification and correction. Any corrective re-work necessary is performed at the expense of the contractor.

Random sample surveys of inspection results are conducted by FPL after Osmose has completed pole inspection work. Additionally, a third-party audit of attachments is conducted on a five year cycle, and verified for accuracy by a multi-participant joint-use verification team.

To ensure new joint-use requests will not overload existing poles, FPL uses a third-party vendor to complete joint-use pole loading evaluations. This contractor completes assessments of joint-use pole strength and loading requirements, and ensures proper clearances are maintained for new attachments. This ensures new joint-use requests will not overload existing poles.

3.3 Vegetation Management

Trees and vegetation are among the largest causes of electric system outages annually. Electric power outages occur when trees, or portions of trees, grow or fall into overhead power lines. Keeping trees and vegetation from conflicting with overhead conductors and triggering power outages is critical to service reliability.

It is imperative that electric utilities implement adequate and consistent vegetation management practices through accurate tracking of workloads and schedules. Vegetation management is essential to maintaining tree clearances from distribution lines, and ensuring sustained electric reliability during high wind and storm conditions.

3.3.1 Data Collection Process

Annually, FPL trims approximately one third of its feeders and one sixth of its lateral lines. FPL also conducts a mid-cycle trimming program, to address fast-growing vegetation requiring additional trimming prior to the next scheduled cycle.

FPL's vegetation management plan is loaded into the Work Management System (WMS) annually and contractor trimming progress is tracked continually. A weighted index considering customer interruptions and customer momentary interruptions is developed for each circuit. Each circuit has a unique identifier and weighted index to establish trim priorities.

As FPL's three tree contractors complete planned trimming, WMS is updated to reflect trim progress. The miles trimmed are compared to the planned trim to ensure miles actually trimmed are tracked and completed.

All trimming work is captured in WMS. The system allows contractors to input completed work directly through a system interface. Contractors input their vegetation trim work start date, percent complete, and complete date. This information is used to track and document whether work is completed on time. Through WMS, FPL vegetation managers track trimming work requests, including data regarding:

- ◆ Feeder number
- ◆ Type of line (feeder or lateral)
- ◆ Miles of line
- ◆ Start date and finish date
- ◆ Percent complete

3.3.2 Data Accuracy Validation

FPL vegetation management Quality Control & Compliance employees inspect 100 percent of completed feeder trim work, within 30 days of contractor notification that the work is complete. These inspections are completed to ensure work is consistent with FPL's vegetation plan standards, and is appropriately recorded. FPL selects, inspects, and validates a sample of completed lateral line trimming to ensure conformance and compliance with FPL's plan and standards. Quality Control & Compliance survey results are also tracked in WMS.

Upon inspection, contractor re-work may be necessary. If re-work is required, the inspector documents the work to be completed on the existing work request. Contractors are notified of re-work conditions through WMS with an attached re-work notice. The contractor is required to complete the re-work at no cost to FPL.

3.4 Transmission Structure Inspections and Storm Hardening

The Commission requires investor-owned electric utilities to develop a plan for inspecting all transmission towers and other line-supporting equipment based on at least a six-year inspection cycle. At year end 2014, FPL's transmission system consists of approximately 11,550 wood and 53,300 steel and concrete structures.

FPL's annual reliability report updates the status of inspection and storm hardening actions for transmission structures. The transmission structure inspection program identifies potential issues along the entire transmission circuit by analyzing structural conditions at the ground line and above.

3.4.1 Data Collection Process

FPL's Transmission Group builds, operates, and maintains transmission substations and structures. A pole inspection contractor is used to perform all FPL transmission wood pole inspections within the six-year cycle. Cyclical inspections are performed by line section, sequentially from substation to substation. Prioritization for annual inspections of poles within a line section is based on the framing configuration, structural loading, transmission components, system importance, inspection history, and economic efficiencies within the same corridor.

Inspection data results collected by FPL's contract inspectors are captured in portable field computers. Contractor field computers are linked to the transmission Asset Management Program (AMP) on a work order level. Cyclical inspections often generate follow-up tasks for poles inspected, requiring additional work orders to be issued for corrective actions. Within the AMP system, work activities are created to ensure necessary follow-up work is tracked and completed.

FPL employees also complete annual ground inspections and maintenance for transmission lines and structures. On average, FPL's Transmission Group generates work tasks for approximately 10,000 transmission structures each year. The AMP system lists all FPL transmission and substation assets. The system provides detailed data of the transmission system, by line section, and generates work tasks for climbing and bucket cyclical inspections.

FPL's Commission-approved transmission hardening efforts have consisted of three planned primary hardening actions. The first action is to replace all transmission wood structures by 2022. The number of annual replacements completed each year is scheduled in concert with FPL's plan approved by the Commission. In 2014, the plan scheduled the replacement of 1,100 wood structures. At year end 2014, FPL had reduced its transmission wood pole structures to 11,550. Annual progress toward the 2022 completion is consistent with the hardening plan.

The second planned hardening action was to replace ceramic post insulators on square concrete transmission poles with polymer insulators. FPL reports that this project was completed as scheduled by the end of 2014. The third hardening action is to implement storm flood initiatives to better protect certain transmission facilities and expedite restoration efforts.

Transmission storm hardening is tracked by project in the AMP system. Measurements of the Number of Transmission Structures Hardened and Percent of Planned Transmission Structures Hardening Completed are tracked for the replacement of transmission wood structures and ceramic post transmission line insulator projects. Measurements of the Number of Substation Flood Monitoring Equipment Installations and Percent of Flood Monitoring Installations Completed to Plan are tracked for the storm surge/flood project. The individual projects are audited upon completion to verify and document the work is completed as planned.

Transmission hardening work is prioritized by three levels after it has been inspected:

- ◆ Level 1 requires immediate attention
- ◆ Level 2 requires attention within the next year
- ◆ Level 3 will require attention in the near future

The hardening priority for Transmission/Distribution substations is to complete non-wood pole sections, or sections with the fewest number of wood poles, since wood poles will eventually be replaced by steel and concrete. Inspection validation is completed by transmission field crews and updated into AMP.

3.4.2 Data Accuracy Validation

To ensure the accuracy of inspection results and contractor-completed work input to AMP, the Technical Services Group and local work centers validate the data submitted and identify necessary corrections. Global positioning system coordinates for each structure are loaded into AMP, along with the structure's detail. Pole replacements and as-built changes are also included with contractor completed work and entered into AMP. A final sign-off on the purchase order is completed by Technical Services to ensure changes are reflected accurately into AMP.

3.5 Geographic Information System

Investor-owned electric utilities are required by the Commission to implement a Transmission and Distribution Geographic Information System (GIS). The system must maintain facility data with sufficient detail to conduct forensic reviews, assess the performance of underground

systems compared to overhead systems, determine whether proper maintenance is performed, and evaluate storm hardening options.

A GIS allows FPL to collect, organize, maintain, manage, and analyze spatial and geographical data relative to its assets and territory. GIS is one of the foundational databases for FPL's facilities records and is integrated with FPL's distribution and transmission systems to provide critical support data. Inaccurate GIS data negatively impacts location information and system component data used in repair and restoration efforts.

3.5.1 Data Collection Process

FPL's Commission-approved plan for GIS included developing mobile electronic survey and inspection tools to gather data for post-hurricane forensic analyses and adding certain distribution facility attributes to its Distribution GIS information. FPL's geographical information system is integrated with the Asset Management System (AMS), and referred to as AMS/GIS. The data collected within AMS/GIS includes: pole data, joint-use facilities, hardening data, and street light data.

Prior to FPL finalizing its GIS processes, systems testing was completed to ensure data was appropriately captured and recorded. At the end of 2011, FPL reported completing all Commission-required system changes.

Ongoing field changes made to work orders are documented by the crew on an "as-built" print and forwarded to the local service center for processing. As-built prints are reviewed and forwarded to the AMS/GIS services group, to update and match the field changes. This process of correcting discrepancies and changes made during daily work activities contributes to maintaining data integrity between field data and AMS/GIS.

3.5.2 Data Accuracy Validation

FPL's AMS/GIS employs built-in system safeguards to help validate the integrity of the data. Automated validation prevents unauthorized users from gaining network connectivity. If invalid data is entered into the system, or all fields are not completed, the system automatically identifies and flags the entry with an error message, and will not post the information to the system until proper correction is made.

There are three levels of checks to ensure FPL AMS/GIS data accuracy. Level one is in FPL's Operations Centers, where Operation Technicians are responsible for reviewing all proposed work packages. These technicians compare and verify records and drawings within the Design Management System to ensure work packages reflect existing GIS data, before releasing designed work to the field. Any discrepancies identified are corrected prior to field assignment.

Level two checks are made by FPL Quality Assurance inspectors in the field upon completion of a project. These inspections help ensure field changes are accurately reflected in the as-built drawings. Quality Assurance reviews completed for pole inspections, joint-use pole inspections, and vegetation management also help ensure that accurate data is reflected in the AMS/GIS.

Level three checks are completed by the AMS/GIS service group, making corrections to discrepancies identified in daily work activities. This check ensures that changes in daily work activities are accurately reflected in data uploaded to the AMS/GIS and Design Management Systems.

4.0 Florida Public Utilities Company

4.1 Reliability Indices

The reliability of electric distribution systems is critically important to both utilities and customers. Reliability indices are used to provide a quantitative and objective basis for judging the effectiveness of Florida Public Utilities Company's (FPUC) efforts to maintain or improve performance. The company's engineering group is responsible for monitoring, reporting, and ensuring the accuracy of all the reliability indices as required by the Commission's Annual Distribution Reliability Report.

Quantifying reliability is a complex data intensive effort which presents numerous opportunities to make errors. It is important for the company to accurately track and evaluate reliability metrics to ensure the reliable distribution of electricity and to identify areas for improvement.

4.1.1 Data Collection Process

FPUC implemented a new centralized Outage Management System (OMS) in 2013 to allow both its Northeast and Northwest divisions to manually manage and track outages. The company oversight uses this system to assist with collecting and calculating its reliability indices. This data is reported by the company yearly in its Annual Distribution Reliability Report to the Commission.

The company is notified of an outage through customer calls to its call center or after-hour answering service. When a customer reports an outage, the customer service representative (CSR) collects and enters the pertinent outage information into its OMS. From this point, the company tracks the outage for reliability calculations. The company relies solely on customer calls for outage notification.

After the outage is entered into the OMS, the system generates an automated text notification to the dispatcher who then notifies a technician. The technician locates the trouble site, assesses the issue, and makes the necessary repairs to restore service. Once service is restored, the technician calls the dispatcher to provide the supporting information necessary to close out the outage in the OMS system. This includes information such as restoration time, outage cause code, an estimated number of customers impacted, above ground or underground impact, etc. The final outage cause may require interpretation of several factors. This is common with events involving equipment, vegetation, or animals. Once this information is documented into the system, the data serves as the source information for reporting.

OMS assesses and tracks outage calls in real time. If the system receives multiple entries, the system, using algorithmic coding, will compile and combine related events to predict the device that is causing the outage. The system is designed to notify managers, via text messaging, when outages occur. Based on the information sent through the system alerts, service management can respond accordingly.

Florida Public Utilities Company Reliability Data Collection Process		
Step	Process / Input	Description
Collecting Outage Information	<div style="border: 1px solid black; padding: 5px; text-align: center;">Outage Call received to Company</div> <p style="text-align: center;">↓</p>	All outage calls are received directly by company staff or an after-hours answering service. This information is submitted to a dispatcher for processing.
Creating Outage Ticket	<div style="display: flex; justify-content: space-around; align-items: center;"> <div style="border: 1px solid black; padding: 5px; text-align: center;">Outage is documented in OMS</div> <div style="border: 1px solid black; padding: 5px; text-align: center;">GIS</div> </div> <p style="text-align: center;">↓</p>	Once an outage is documented in OMS by the CSR, the system issues an electronic text notification is sent to the authorized employee for dispatch. The OMS and GIS work in tandem to identify and document the outage location
Working Ticket	<div style="display: flex; justify-content: space-around; align-items: center;"> <div style="border: 1px solid black; padding: 5px; text-align: center;">Service Technician Dispatched to Outage Event through the OMS system</div> <div style="border: 1px solid black; padding: 5px; text-align: center;">GIS</div> </div> <p style="text-align: center;">↓</p>	The service technician responds to an outage via the information provided through the OMS. Using this information, the technician assesses and resolves any issue, or utilizes additional resources to resolve event. The GIS system continues to work with OMS to assist the technician with location accuracy.
Completing Ticket	<div style="border: 1px solid black; padding: 5px; text-align: center;">Service Technician Creates a Manual Close out Ticket and Notifies Dispatcher for Documenting in the OMS</div> <p style="text-align: center;">↓</p>	Once restoration occurs, the technician notifies the dispatcher with the permanent close-out data. This includes restoration time, event cause, estimated number of customers impacted. The dispatcher enters this information into the OMS system. The information is also documented on the written work-order ticket.
Outage Data Review	<div style="border: 1px solid black; padding: 5px; text-align: center;">Assistant Operations Manager Manually Reviews Manual Outage Ticket and verifies to the OMS Records</div> <p style="text-align: center;">↓</p>	All outage tickets are submitted to the Assistant Operations Manager for review. Each ticket is reviewed for accuracy and verified against OMS to ensure that the correct information was documented in the database. Any discrepancies are reviewed by management and adjusted in OMS and recorded on the manual documentation.
Indices Calculations	<div style="border: 1px solid black; padding: 5px; text-align: center;">Engineering Manager manually formulates the Reliability Indices</div>	The Engineering Manager collects the outage data for both districts through the OMS and transfers to an Excel document. The indices are calculated using Excel formula and verified by the Engineering Manager. This data is transferred to the Company's Annual Reliability Report.

Exhibit 3

Source: Interview with Company Management

The company's calculation of reliability indices is performed by the Engineering Manager. The Engineering Manager collects and transfers the data manually from the OMS into an Excel

spreadsheet, which performs the necessary calculations of reliability indices. **Exhibit 3** outlines the tracking of an outage event within the company from initial report to final close-out.

Currently, this process is performed on a monthly basis. Prior to 2013, the company performed this quarterly. Company management maintains this reliability database, and employee access to this spreadsheet is restricted. Both divisions collect this data separately, and the two are combined to create the overall company results. The company believes adequate controls exist to prevent outage manipulation. The outage spreadsheet is maintained on the off-site server, and the raw outage data is stored in the off-site OMS system. If need be, the company could re-create the Excel spreadsheet using this raw data.

FPUC management states that when collecting its reliability data, the company only calculates and evaluates the indices required under the current Commission requirements. The company does not calculate its reliability indicators using IEEE's 2.5 Beta methodology. Management states that due to its limited staffing, doing such would create a resource burden on the company.

4.1.2 Data Accuracy Validation

The new 2013 OMS system upgrade allowed the company to track and compile outage data in an efficient process. Prior to implementation of this new system, the process for collecting and evaluating of outage data utilized an OMS that required more manual handling of data. The updated system increases the company's ability to analytically assess outages as they occur and respond more timely.

The company relies on manual verifications of outage tickets. Once the technician successfully restores an outage, a completed work order ticket is provided to the supervisor for quality assurance verification. The supervisor reviews all work orders for accuracy and documentation. If a concern is identified on the work order documentation, the outage event is reviewed in more detail by management and any adjustments are made to the event's entry in OMS.

In addition to routine outage events, the company has a process for evaluating larger, multi-customer outages. For this process, the supervisors and engineering management evaluate multi-outage events to examine the outage cause, assess the restoration time for the customers impacted, and ensure that the outage and cause are appropriately tied together in OMS. The company does not have a looped 69kV transmission system, limiting its ability quickly restore power through re-routing. When management identifies an error on an outage entry, the supervisor notes the manual adjustment on the ticket. It is the company's process to group multiple notifications into one outage and cause. After this point, management adjusts the data in the OMS to accurately reflect the overall outage event and restoration time for reporting purposes.

Each outage has a discreet outage number for tracking. Changes to any ticket are trackable via the operator's ID number. The number of customers impacted transfers from a manual estimation to an automated process using the OMS and GIS systems. Once the correct information is entered into the OMS system, any correction is documented on the manual ticket. This provides the company a redundant source of verification.

In addition to outage causes and restoration timelines, the company tracks outages by underground service or overhead service. This data is collected by the restoration technician at time of repair. The technician reports to the dispatch employee whether the outage occurred on an overhead or underground line and this information is recorded in OMS. Outage information provided monthly to the outage reports in Excel, gives management the ability to query this information for reporting and tracking.

4.2 Wood Pole Inspections

The company has 21,279 wood distribution poles in its Northwest division and 4,872 in its Northeast division. The Commission requires each IOU to implement an inspection program of wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the National Electrical Safety Code.⁴ Approximately one-eighth of the poles are inspected annually. The company completed its first eight-year inspection cycle in early 2015. It will initiate its second-cycle in 2016.

4.2.1 Data Collection Process

FPUC uses the contractor Osmose to perform its wood pole inspections for both the Northeast and Northwest territories. The current contract is on a three-year reviewed cycle. Management in each territory determines the geographic inspection cycle necessary to comply with the Commission inspection requirements. The company's goal is to inspect roughly the same number of poles annually to ensure all required poles are inspected within the cycle. The contractor inspects the prescribed number of poles as outlined in the contract and agreed-upon annual cycle.

The cycle inspection breakdown is documented in the company's mapping system and is provided to the contractor. The company uses this data to monitor and verify that all required poles are inspected on schedule. All inspections are updated through this process to verify completion. Due to the limited number of poles to be inspected annually, FPUC is able to complete this process within a small window of time each year.

Depending on the pole type and age, the inspections include visual, sounding and boring, and treatment. A load calculation may be performed by the contractor if their initial inspections results identify strength issues. This allows the contractor and company to analyze pole strength under the pressures of all attachments on the pole. The contractor provides this information to the company for review by the overseeing engineer, who also performs contractor spot-checks for inspection verifications.

The company receives two inspection reports from the contractor. The individual pole inspection results are provided to FPUC via the contractor's website. To ensure accuracy, the contractor uses the company's GIS interface as its tracking mechanism for documenting each pole inspection. Satellite images are also used to verify the pole and location. An inspection summary is provided to the manager for each division. This report contains the number of poles inspected, the number of poles rejected, and the number of poles treated by the contractor.

⁴ See Commission Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI.

Once pole inspection data is received from the contractor, FPUC inputs the data into OMS for data tracking and reliability monitoring. The company recently centralized its process for distribution information under its engineering group. The company tracks inspection results, pole history, class and height of pole, and percentage of strength remaining for each pole. The company GIS database interfaces with the centralized pole records for mapping purposes.

The company's policy is to replace, rather than brace, all poles that do not pass the inspection criteria. Management enters all rejected poles into a Decayed Pole Database which records and tracks the status of its wood pole replacement. This database is used by both divisions to track the status for replacing necessary poles.

In addition, FPUC has a forensic analysis process to monitor and assess pole damage after a significant damage event. If a larger storm damage event occurs, the company uses its pole-inspection vendor to assist with root-cause assessments of pole damage. The contractor will provide results to the company's operational management. This information would be reviewed and analyzed by company management and provided to the Commission after review. To date, the company has implemented this process in its Northwest division after an identified tornado event. The company did not calculate any outlying results through this analysis.

As part of the wood pole inspection process, the company should maintain accurate records of its Joint-Use pole attachments. An internal audit performed by the company during 2013 identified issues with the accuracy of its pole inventory records. The audit noted that the company's joint-use data was not accurate and the company did not have a process in place to ensure the records were updated appropriately. Company management states it is in the process of updating all joint-use agreements with all providers in both service territories. Once complete, the company will conduct a joint-use audit of all poles to ensure that all facilities are recorded accurately. The company estimates for this to be complete in 2016.

4.2.2 Data Accuracy Validation

The company performs quality checks and monitoring of contractor pole inspections. During the inspection cycle, FPUC employees monitor the contractor work schedule and review the inspection locations. Onsite inspections and spot verification of inspection tags are performed by the company. Inspected poles are marked with an updated Osmose inspection tag and the company considers the pole as inspected per contract. FPUC states that the contract is designed to financially incent the contractor to identify damaged poles; therefore, the company does not perform any reviews of a pole that passed inspection.

The company requires all contractor rejected poles be reviewed by a manager. If the engineering group concludes that the pole meets the rejection criteria, the company will re-analyze the structure. Any discrepancies identified between the reported results and re-evaluations are addressed and resolved with the contractor through an agreed-upon process. The company prioritizes its replacement schedule based on risk.

4.3 Vegetation Management

The single largest cause of electric power outage occurs when trees, or portions of trees, grow or fall into overhead power lines. Keeping trees and vegetation from conflicting with overhead conductors and triggering power outages is critical to service reliability.

It is imperative that FPUC ensures adequate and consistent vegetation management practices through accurate tracking of workloads and schedules. Inaccurate records could allow lines to remain uninspected, leading to preventable outages.

FPUC follows the Commission-required trimming cycle for its overhead circuits for vegetation management. The company is required to maintain its feeder circuits on a three-year cycle and a six-year cycle for its lateral circuits. This work is performed continuously in both the company's Northwest and Northeast divisions.

4.3.1 Data Collection Process

The company currently employs Davey Tree to perform its vegetation management program for both divisions. As with pole inspections, the company employs a three-year contract cycle for its vegetation management vendor. This contract is competitively bid for each cycle. The contractor performs work supporting both the lateral and main feeder trim schedule, along with any hotspot and spraying work.

The company provides the contractor detailed maps of the assigned trimming requirements on a monthly basis, and assigns hotspots as needed. The contractor maintains constant stations crews in both the Northwest and Northeast division. Per the contract, the vendor provides FPUC monthly worksheets detailing the mileage trimmed and the man-hours accumulated. Once verified by the engineering staff, the information is compiled for the annual reliability report to the Commission.

Each division develops and reports its yearly cycle target goals and year-end completion. Each division's cycle is developed on a simple total miles per year calculation (total territory miles/eight years.) Each division reports to the Engineering Manager its total vegetation results for reporting purposes. This information is compiled and verified using Excel spreadsheets. The contractor and company management conduct an annual meeting to assess the performance for the previous year.

4.3.2 Data Accuracy Validation

FPUC assigns an Assistant Operations Manager in each division to oversee, monitor, and verify the vegetation management work performed by the contractor. This employee receives weekly reports from the contractor and hosts weekly meetings with contractor personnel to discuss the previous week's work and current schedule expectations.

The FPUC supervisor verifies all contractor timesheets and miles trimmed calculations. The Assistant Operations Manager conducts trim-site visits and drive-by verifications on the contractor's work crews. Examples of monitoring protocol include the Assistant Operations

Manager placing markers at prescribed starting and ending points of the trimming schedule to monitor the contractor's timeline. Since trimming is an ongoing, annual program, this is monitored daily.

The contractor reports its trim results daily. It is the responsibility of the Assistant Operations Manager to verify all contractor documentation is correct for both the feeder cycle and lateral cycle. If the company identifies a problem, the contractor is notified and is required to adjust the official trim maps. If the contractor is not maintaining the trim schedule, the Assistant Operations Manager will monitor the time and day cycle to maintain the long-term cycle goal.

The Assistant Operations Manager signs-off on each invoice and forwards to the Warehouse Manager for verification. Finally, the Operations Manager will review and approve. Once approved, the invoice is forwarded to account payable for payment.

An FPUC internal audit was performed on the company's vegetation management program in July 2012. The audit identified, from a reporting perspective, issues related to maintaining documentation of monthly meetings with vendor and the verification of payment invoices. Company management appropriately responded to the audit findings.

4.4 Transmission Structure Inspections and Storm Hardening

The company's annual reliability report updates the status of inspecting and storm hardening transmission structures. The transmission structure inspection program identifies specific issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. FPUC's storm hardening approach for its limited transmission structures primarily includes the systematic replacement of wood transmission structures with non-wood structures.

4.4.1 Data Collection Process

The company maintains two 138 kV and three 69 kV transmission line in the Northeast division, and none in the Northwest district. FPUC performs a transmission pole structural inspection, which includes climbing all its poles, every six years. Due to the limited number of poles, the company is able to complete inspections within a few months. The last inspection cycle in the Northeast district was completed in 2012.

The company uses a vendor—currently Pike Electric, Inc.—to perform a climbing assessment on each transmission pole. This is done in accordance with the Commission's six-year review requirement. The vendor climbs and inspects each pole to ensure all attachments and facilities are maintained in accordance with Commission requirements. Any issues identified by the contractor are processed through a work order for repairs through FPUC's engineering group. Division management monitors and evaluates contract work quality and accuracy using the same process used for distribution pole inspections.

As part of this inspection process, the company maintains a focus on potential hardening of its transmission facilities. When the contractor identifies issues with an existing transmission pole—whether through the ground strength or climbing inspection, the company uses its storm-

hardening criteria as the basis for resolution. Depending on the identified issue, the company will repair or replace the facilities in accordance with its hardening standards. This includes concrete poles for any replacement. The company states that approximately 30 percent of its poles have been replaced through this approach.

4.4.2 Data Accuracy Validation

The company utilizes the same verification approach for its transmission inspection vendor as it does for its ground pole inspection vendor. The work performed by the transmission climb vendor is a short-term, limited initiative performed over a few months every six years. Company management states that, when performed, the verification process is similar to the group pole inspection process.

A technical supervisor is responsible for monitoring and verifying the vendor's inspection activities. As with ground pole inspections, any issues identified via the pole climbing inspections are reported to FPUC. The company's engineering staff reviews all repair requests and authorizes necessary work. The vendor makes repairs once approved by the company.

4.5 Geographic Information System

A geographic information system (GIS) allows the company to collect, organize, maintain, manage, and analyze spatial and geographical data. The GIS is the foundational database for FPUC's facilities records and is fully integrated with 100 percent of its distribution and transmission systems. The GIS provides critical support to the distribution operations. Inaccurate GIS data would negatively impact the location of system components in need of repair and delay restoration efforts.

4.5.1 Data Collection Process

In recent years FPUC created and installed a GIS database of its infrastructure. This included mapping locations of all main and lateral feeders. The company collected the necessary data via historical data, current mapping, and external resources. The company has incorporated this application into its OMS, with plans to expand the resource into additional tracking and monitoring tools.

The vegetation management contractor and the pole inspection contractor use the company's GIS system for tracking and verification. Each vendor reports any discrepancies to the company. FPUC uses an outside vendor to assist in maintaining and verifying the accuracy of its GIS.

4.5.2 Data Accuracy Validation

To ensure accuracy, the company works closely with its GIS contractor to maintain current information. The company conducts weekly calls with its vendor to discuss accuracy and quality of data. With the completion of the first pole inspection cycle, the company has been able to monitor and adjust the accuracy of its pole inventory in its GIS.

5.0 Gulf Power Company

5.1 Reliability Indices

The reliability of electric distribution systems is critically important to both utilities and customers. Reliability indices are used to provide a quantitative and objective basis for judging the effectiveness of Gulf Power Company (Gulf) efforts to maintain or improve performance.

Quantifying reliability is a complex, data intensive effort which presents numerous opportunities to make errors. It is important for Gulf to accurately track and evaluate reliability metrics to ensure the reliable distribution of electricity and to identify areas for improvement. Quantitative measurement of service performance to consumers is captured in reliability indices, measuring the frequency and duration of electric system and customer outages.

5.1.1 Data Collection Process

Gulf tracks service reliability indices through its Distribution Control Center (DCC) using the Trouble Call Management System (TCMS). Outage notifications arrive in TCMS from Automated Metering Infrastructure (AMI; smart meters), Distribution Supervisory Control and Data Acquisition (DSCADA), or the Customer Service System (CSS) through a Customer Care Center representative or automated voice response unit. Notifications may also enter the system via the online customer care website, manual entries by field personnel, customer texting, and the Gulf Power mobile application.

TCMS uses outage notifications from these sources to predict outage type, device involved, and to determine a precise outage start time. The system can also calculate the number of customers impacted by an outage without receiving reports from all customers downstream of the failed device.

Reliability index information is gathered by:

- ◆ TCMS – an Oracle database that is the primary database for storage of reliability data
- ◆ Transmission Reliability Data – gathers outage verification, cause, and resolution
- ◆ Customer Counts – year-end customer count for reliability reporting
- ◆ Industrial Customers – year-end list of industrial customers for reliability reporting
- ◆ DSCADA (Distribution Supervisory Control & Data Acquisition) Tools – an application that reduces outage times by permitting remote monitoring and control of distribution line devices

Since 2010, Gulf has made several key changes to its reliability process. The system is now 100 percent AMI, providing automatic outage notification when power is interrupted for one minute. Gulf has also installed smart reclosers that segment long or critical distribution feeders, minimizes sustained outages from temporary faults (e.g. lightning or branches brushing against lines), provide additional segmenting for quicker restoration, limiting the numbers of customers impacted. Automated circuit fault indicators reduce the time required to locate outages, isolate problems, and reduce the total customer minutes of interruption.

Gulf Reliability Data Collection Process		
Step	Process / Input	Description
Collecting Outage Information	<pre> graph TD AMI --> TCMS[TCMS in DCC] DMS --> TCMS OutageApp[Outage App] --> TCMS CSS --> TCMS Website --> TCMS Texting --> TCMS DSCADA --> TCMS TCMS --> TicketCreation[Ticket Creation] </pre>	<p>AMI and smart devices automatically alert TCMS in the DCC, the central point for data collection, prediction, and verification.</p> <p>Customers may also report outages via phone, text, or online.</p>
Creating Outage Ticket	<pre> graph TD TicketCreation[Ticket Creation] --> WorkingTicket[Working a Ticket] </pre>	<p>Outage ticket is created, with estimated customer count.</p>
Working Ticket	<pre> graph TD WorkingTicket[Working a Ticket] <--> CrewVerification[Crew Verification] WorkingTicket --> TicketCompletion[Ticket Completion] </pre>	<p>Crews in the field verify outage details using a truck mounted laptop during the restoration effort, report corrections taken to the DCC.</p>
Completing Ticket	<pre> graph TD TicketCompletion[Ticket Completion] <--> OperatorReview[Operator Review] TicketCompletion --> DataAccuracyReview[Data Accuracy Review] </pre>	<p>Distribution Operations Techs and Distribution Systems Operators in the DCC manually verify details of every outage ticket during the completion and approval process.</p>
Ticket Review and Verification	<pre> graph TD DataAccuracyReview[Data Accuracy Review] <--> TCMS[TCMS, DSCADA, GIS; possible field review] </pre>	<p>TCMS, DSCADA, and GIS provide data needed for ticket completion and validation; technical personnel review 90 percent manually. Automatic SQL queries are run weekly.</p> <p>Field personnel may be dispatched to verify customer counts or other details.</p>

Exhibit 4

Source: Document Request Response 2.1

Collecting outage information, creating the outage ticket, and completing the process are all functions within the Distribution Control Center, as shown in **Exhibit 4**.

The Gulf measurement of overhead and underground reliability relies on its Distribution Geographic Information System (DistGIS), completed system wide in 2009. All transmission facilities have been mapped in the Transmission GIS database.

DistGIS differentiates between construction types, overhead or underground, as indicated by the Trouble Call Management System (TCMS) and the TCMS operator includes this data as

part of the event ticket. Outages are then separated into overhead and underground categories for reporting to the Commission.

DistGIS and Transmission GIS are continually updated from maintenance, repair, replace, and new business work orders. Gulf states that this repeated and continual updating of DistGIS and Transmission GIS provides the company with adequate information that, combined with forensic data following a major storm, allow a comprehensive and accurate analysis of overhead and underground performance.

5.1.2 Data Accuracy Validation

Gulf uses a layered approach to verification of input data, combining automated system edits with manual and automated reviews. Automated system edits require all fields to be properly completed and helps prevent erroneous data from being entered. Automated system edits prompt corrections by data entry personnel or are held by the system until an error can be resolved before final entry. Gulf technical personnel also review approximately 90 percent of all outage tickets each month. Monthly reports to management provide validation, insight, analysis, and trending information.

Gulf runs two sets of exclusion data, one set based on the rule criteria and allowable exclusions for Commission reliability reporting and a second set based on rule criteria and allowable exclusions for Southern Company reliability reporting. In each set, Gulf states that the company is looking for discrepancies in interruption cause codes and outage start and stop times among the many other data checks performed.

Gulf produces data using the 2.5 Beta IEEE criteria for both the Southern Company Distribution Benchmarking and Southeastern Electric Exchange groups. Gulf states that it discerns no value added from the use of the 2.5 Beta method, and that Commission-mandated use would impose an additional burden on finite validation resources.

The Distribution System Operations Engineer is responsible for conducting reviews of customer minutes of interruption and outage duration, the number of customers effected, the total tickets produced, and outage start and stop times. On a daily basis, operators verify the number of tickets, that outages are separately caused and not double counted. The Distribution Control Center checks that outage causes and durations match what was recorded on the ticket. Operators correct outage cause codes, duration times, or add clarifying notes to tickets with identified issues.

From 2010 to date, Gulf has not conducted an audit of data accuracy validation but believes its layered combination of automated systems and regular manual verification is sufficient. During the same period, no audits were conducted of overhead and underground forensic comparisons because there have been no major recent storms impacting the service area. Gulf believes that its tests and evaluations of the forensic capture processes, systems, and tools during its annual company-wide storm season practice runs adequately substitute for such audits.

In 2011, Southern Company (Gulf's parent company) conducted a reliability audit on data accuracy and the validation process of its subordinate utilities, with no findings specific to Gulf.

5.2 Wood Pole Inspections

Gulf has approximately 203,000 wooden poles in its fleet. The Commission requires each IOU to implement an inspection program of wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the National Electric Safety Code.⁵ Approximately one-eighth of the poles are inspected annually.

The Gulf inspection program was approved by Commission Order No. PSC-07-1022-FOF-EI. Gulf Power Company completed its first eight-year cycle ahead of schedule and began the second iteration in 2014.

In 2014, Gulf inspected 27,204 poles with a rejection rate of 2.48 percent. All poles identified as deficient in pre-2014 inspections have been replaced. Those identified in 2014 have been reinforced or replaced in 2015.

The data accuracy issue related to wood pole inspection is accurate planning and tracking to ensure all poles are accounted for during the inspection cycle. Poles missing from plant records or GIS listings could negatively impact reliability.

5.2.1 Data Collection Process

Gulf uses a recognized industry vendor, Osmose, to perform its wood pole inspections. The wood pole inspection program and process is managed by Gulf's Asset Management Coordinator.

Inspections are organized, sequenced, and accomplished using a grid system overlaid on the Gulf service area. The Asset Management Coordinator systematically moves the assigned work from west to east, one-eighth of the fleet per year, through the entire Gulf service area. Results are tracked manually using an Excel spreadsheet.

Gulf DistGIS pole data is loaded into Osmose hand held computers for locating poles scheduled for inspection. The contractor inspects poles against the strength and soundness specifications found in the Gulf Power Storm Hardening Plan. For poles over 16 years of age, inspections and tests include performing visual evaluation of the pole, sounding by hammer, ground line boring samples, and excavation to a depth of 18 inches for inspection. Chromated copper arsenate poles less than 16 years old require only a visual inspection.

Inspections are managed using a database which provides a virtual geographic web-based reporting and mapping capability providing Gulf personnel with the ability to manage inspection data. A variety of information is available, including pole class, material, age location, joint-use attachments, and previous problems or remediation. Having this historical information readily available shortens and simplifies the pole inspection process.

Poles found to have minor decay are either repaired or reinforced. Decayed areas found are stripped from the pole and the decayed debris removed from the excavation. A preservative is then applied, the treated area is wrapped, and the wrap is secured to the pole. Non-restorable

⁵ See Commission Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI.

poles are designated for replacement and the information provided to Gulf for replacement sequencing.

Primary responsibility for coordinating post-storm forensic data collection and analysis belongs to the Power Delivery Project Manager. Immediately following a major storm, contractors will collect forensics on hand-held computers containing Gulf DistGIS with distribution facilities and a template for capturing damage information (e.g. location, pole age, height, class, species, manufacturer and third party attachers). The data collectors will be spread throughout the service area to ensure a thorough sampling of damage caused by varying wind strengths.

Gulf states that its goal is to collect as much post-storm forensic data as possible without hindering restoration, that the efforts will occur simultaneously and independent of one another, and field data will be uploaded nightly to a secure off-site location. After field collection is completed, the data will be provided to a consultant for statistical analysis and preparation of a final damage assessment report.

Gulf reviews its data collection and transfer process plans annually prior to storm season. While no significant storms have occurred since inception of the plan and the process has not been utilized, it has been tested during these annual storm response exercises.

Overloading of joint-use poles can also become a reliability issue if the joint-use program is not properly managed and poles are not regularly maintained. To help safeguard the pole fleet, Gulf personnel perform a load analysis as part of new construction and replacement. Gulf performs this analysis using an application called “Pole Foreman” which calculates various pole loading and potential forces, determining the proper class of pole to use and guy wire tensioning for the proposed attachments. As a further safeguard, Gulf requires that an additional load analysis is performed as part of every third-party attachment permitting process.

5.2.2 Data Accuracy Validation

For wood pole inspections, when a pole is found deficient by Osmose, information is sent to the Gulf Asset Management Coordinator (AMC) for validation. The information is then forwarded to Power Delivery and updated in GIS. The AMC visits the field weekly, selecting 5 to 10 poles randomly for reinspection with the Osmose inspection supervisor. Inspection results are then compared to the original inspection documentation.

If a pole is selected for replacement, the Asset Management Coordinator assigns that rejected pole to an engineer who creates a replacement order. Upon completion of the replacement, the work order is returned to AMC and closed out. The AMC tracks every rejected pole and conducts a back end work order recheck to ensure replacements occurred timely.

The company states that the quality assurance inspections and regular, random sampling of completed inspections provides adequate assurance that the program is working. For joint-use load analysis, Gulf joint-use permit administrators make field visits to examine attachments. Based on their field examination and notes, along with the original load analysis results, a determination is made whether attached equipment meets the National Electric Safety Code criteria but does not exceed pole loading capacity.

5.3 Vegetation Management

One of the largest causes of electric power outages occurs when trees, or portions of trees, grow or fall into overhead power lines. Keeping trees and vegetation properly trimmed, and away from overhead conductors where they might trigger power outages, is critical to service reliability.

It is imperative that Gulf ensures adequate and consistent vegetation management practices through accurate tracking of workloads and schedules. Inaccurate records could allow lines to remain uninspected, leading to preventable outages.

5.3.1 Data Collection Process

Gulf complies with its three-year trim schedule for overhead main line feeders and lateral circuits on a four-year recurring cycle. The company completes its annual mainline schedule prior to the start of storm season. The two-thirds of main line feeders not scheduled for trimming each year are visually inspected. Gulf states that it achieves a four-year average cycle for lateral distribution lines. Last year, Gulf trimmed 241 mainline miles, pruned 1,294 miles of lateral primary lines, and inspected (pruning as required) nearly 500 miles of main line primary.

The vegetation management program is managed by the Gulf Forestry Services Department. This department consists of a supervisor, three Line Clearing Specialists, and two Forestry Technicians, all certified arborists. All vegetation management work is done by contractors.

Every mainline feeder gets one trimming and two annual inspections during each three-year period. Annual inspections identify and remediate dead or dying vegetation which could fall into the conductor, as well as fast growing trees that may encroach the conductor prior to the next scheduled trim.

Lateral lines are selected for vegetation management activities based on observation of field conditions by Gulf Forestry Services staff, analysis of reliability outages caused by vegetation, the last time the lateral line was maintained, feedback from field engineers, and input from Gulf customers.

5.3.2 Data Accuracy Validation

Gulf Forestry Services Department employees schedule and monitor the activities in the field, with Forestry Services personnel making routine field visits to review work in progress. Trimming is performed by independent contractors. Gulf believes hands on interaction with contractors ensures standards remain high, scheduled work is verified, and required subtasks are performed safely, efficiently, completely, and timely. In turn, this contributes to the accuracy of reported data.

Contractors turn in a weekly performance results using the Contract Activities Management Program, reporting labor, equipment usage, and hours. Gulf Forestry Services Department staff verifies the incremental work. When a contractor certifies that trimming in an area is complete, Forestry Services Department personnel accompany the contractor to inspect the work, ensuring compliance and satisfactory completion. Forestry Services employees also conduct additional, random quality assurance field visits to assess progress and results.

Using the process shown in **Exhibit 4**, Gulf conducts weekly reviews of vegetation management related reliability data. This data is provided to the Commission annually as part of its Reliability and Storm Hardening Initiatives Report.

Gulf conducted an internal audit of vendor vegetation management contracting and billing practices in 2012. The audit reviewed actions and activities impacting vegetation management reliability, such as whether miles billed equaled the number of miles actually trimmed. There were no findings.

5.4 Transmission Structure Inspections and Storm Hardening

The Gulf Power Company annual *Reliability and Storm Hardening Initiatives Report* updates the status of inspecting and storm hardening transmission structures. The transmission structure inspection program identifies specific issues along the entire transmission circuit by analyzing structural conditions at the ground line, above ground, and in conductor spans.

Florida investor-owned utilities are required to inspect transmission structures and substations on a six-year cycle. Gulf's transmission inspection program is based on alternating 12-year cycles with structures being inspected at least every six years. Gulf uses an overlapping combination of three separate programs:

- ◆ A ground line treatment inspection (contractor line crews)
- ◆ A comprehensive walking inspection (Gulf and contractor line crews)
- ◆ Aerial inspections (at least four times annually)

In 2014, Gulf inspected all 56 of its substations with transmission equipment in service.

Gulf's storm hardening plan consists of two primary transmission system activities. The first included adding storm guys to all wooden H-frame structures on its transmission system. This was completed on the entire inventory in 2012. The second activity, replacing all wooden cross arms on transmission system structures with steel cross arms, is ongoing with an estimated completion date in 2017.

5.4.1 Data Collection Process

For transmission structure inspections, Gulf uses an in-house database application called the Southern Transmission Operating and Maintenance Program (STOMP) to schedule inspections of its transmission lines. STOMP is populated with field structure information such as pole size, type (e.g. wood, concrete, etc.), cross arm type, and cross arm dimensions. Inspections are regularly recurring, so upon completing an inspection and entering the completion date into STOMP, the system automatically schedules the next regularly recurring inspection.

From STOMP, the Transmission Line Maintenance System receives and manages the work orders. It identifies lines due for inspection from STOMP and creates work orders for each one. This data is exported for use in a field inspection application called the Transmission Line Inspection System. The Transmission Line Inspection System is a handheld, portable GIS-based field application allowing field inspectors to record data captured during inspection. Upon

completion of the field inspection the Transmission Line Maintenance System imports the data, processes it, and imports it back to STOMP.

For storm hardening, information on the type of cross arm for each structure is stored in the Common Transmission Database. The information is updated for each structure as wooden arms are replaced, maintaining an accurate count and allowing Gulf to know the number of remaining wooden cross arms in real time.

5.4.2 Data Accuracy Validation

As part of its quality control for transmission structure inspections, Gulf personnel review and verify information in the Transmission Line Maintenance System prior to it being repopulated into the STOMP database. Once verified and imported back into STOMP, the work order is closed and STOMP automatically schedules the next inspection. Once imported back into the database, any inspection issues can be tracked and prioritized by Transmission Line Maintenance System.

For storm hardening data validation, a Gulf inspector is assigned to each contractor work crew. That inspector is responsible for making sure that cross arms scheduled for replacement get replaced correctly and timely. When work is completed and satisfactory, the inspector communicates completion information back to the Transmission Line Maintenance Engineer. The Common Transmission Database is updated to reflect the work done in the field.

Gulf relies on the inspector assigned to each contract work crew to provide quality assurance oversight. Transmission Line Maintenance Engineers also make random field visits to verify work has been completed timely, as directed, and to standard.

5.5 Geographic Information System

A geographic information system (GIS) allows Gulf to capture, organize, maintain, manage, and analyze spatial and geographical data. GIS is the foundational database for facilities records and is fully integrated with 100 percent of the distribution and transmission systems, providing critical support to distribution operations. Gulf uses GIS for mapping, asset inventory, and tracking of all devices and lines deployed in the Gulf Power Company system. Inaccurate GIS data would negatively impact the location of system components in need of repair and delay restoration efforts.

5.5.1 Data Collection Process

Gulf states that the transmission system, including substations, lines, structures, and switches, has been documented using GIS to an accuracy of better than one meter. This accuracy was achieved and is maintained by using LiDAR⁶, survey data, aerial imagery, construction/maintenance design documentation, and field inspections using electronic devices.

⁶ LiDAR (for *Light Detection and Ranging*) is a [remote sensing](#) methodology using a pulsed laser to measure ranges, usually from an airborne system. These light pulses are combined with other data to create precise, three-dimensional information about terrain surface characteristics.

The Gulf Distribution GIS procedures set requirements for documenting changes made to the distribution system. Reporting discrepancies and ensuring that changes made in the field are communicated accurately to the GIS department is accomplished through specific processes addressing Change of Field Equipment, work order processes, and the Customer Job Order process.

5.5.2 Data Accuracy Validation

Transmission GIS data is subjected to continuous quality assurance validation through field verification by line maintenance engineers, line specialists, line design engineers and transmission control center operations whenever a field inspection, maintenance/design engineering project, or control center operation is conducted. The GIS Analyst uses LiDAR, survey, and aerial imagery data to validate and update the system in a near real-time, ongoing manner.

Gulf Distribution GIS maintains data accuracy of GIS by several methods. GIS quality assurance reviews, monitors, and provides feedback to Power Delivery on accuracy and precision of the GIS database. These reviews focus on the quality of the mapping entries completed by the GIS Department.

An automated review and data validation is run nightly, with results in a daily management report. A monthly work order quality review examines GIS accuracy, helps establish best practices, and promotes consistency in engineering, mapping and construction company-wide. The Gulf Power Validation Tools is a collection of queries run nightly within GIS looking for anomalies such as phasing mismatches and mapping errors on any device such as switch gear. Depending on the anomaly, remediation can be either automated or require a GIS Mapping Specialist to make a manual repair.

6.0 Tampa Electric Company

6.1 Reliability Indices

The reliability of electric distribution systems is critically important to both utilities and customers. Reliability indices are used to provide a quantitative and objective basis for judging the effectiveness of Tampa Electric Company's (TEC) efforts to maintain or improve performance. TEC's System Reliability business organization is responsible for monitoring, reporting, and ensuring the accuracy of all the reliability indices as required by the FPSC's Annual Distribution Reliability Report.

Quantifying reliability is an intensive effort using complex data that has numerous opportunities to make errors. It is important for TEC to accurately track and evaluate reliability metrics to ensure the reliable distribution of electricity and to identify areas for improvement.

6.1.1 Data Collection Process

TEC deploys a network of multi-layered systems to communicate outage information and centralize the capturing of data for reliability reporting. To effectively communicate outage information, it is necessary to integrate communications networks, control systems, and field devices. **Exhibit 5** depicts TEC's key system interfaces and the workflow process for tracking, managing, and reporting system reliability data.

The heart of reliability data collection is TEC's Outage Management System (OMS). In capturing data, OMS reduces human error and provides critical analytical tools used by TEC's Dispatchers to determine the scope of outages and the likely source location of problems. OMS compiles information on the times and locations of customer calls and fault data from substations and monitoring devices on feeder lines. OMS tracks, identifies, and manages customer outages by generating outage tickets for field personnel. OMS also helps the utility inform the customer of the outage situation and restoration status (rather than the customer informing the utility).

As shown on **Exhibit 5**, TEC's OMS works in conjunction with Computer Aided Dispatch (CAD), Supervisory Control and Data Acquisition (SCADA) communications systems, Geographic Information Systems (GIS), the utility's Customer Information System (CIS), the Work Management System (WMS), and High-Volume Call Answering Interactive Voice Response (HVCA IVR) system. By filtering and analyzing outage information from multiple sources, OMS can provide TEC's distribution operations and repair crews with specific and actionable information to manage outages and restorations more precisely and cost-effectively. Major functions usually found in TEC's OMS include:

- ◆ Prediction of location of fuse or breaker that opened upon failure
- ◆ Prioritizing restoration efforts and managing resources based upon criteria such as locations of emergency facilities, size of outages, and duration of outages
- ◆ Providing information on extent of outages and number of customers impacted to management, media and regulators

- ◆ Calculation of estimated restoration times
- ◆ Management of crews assisting in restoration

Outages are automatically identified by TEC's SCADA's system and customer calls received via the interactive voice response system. The SCADA system provides TEC with a means of real-time monitoring and control of the electric power grid, particularly generation and transmission systems. SCADA allows TEC to have two-way telepathy with substation breakers and will automatically trigger an outage ticket in OMS. Customer calls received in TEC's HVCA IVR are integrated with CIS and permit trouble call entry into OMS without dispatcher interaction. TEC's current meters presently do not have the capability to communicate outages to the company.

A key component of TEC's OMS is its use of GIS connectivity. OMS, using GIS data, provides Dispatchers with electronic maps and an inventory of equipment and lines to aid with outage management, including partial restorations and detection of isolated outages. OMS can prioritize outages by equipment type, customer count, and resources needed and available. It also provides the Dispatcher with the following real-time information for each outage throughout the restoration process:

- ◆ Estimated restore time
- ◆ Trouble analysis of outage area
- ◆ Customer count
- ◆ Call count

TEC's field personnel use mobile laptops to tap into real-time information streaming from OMS. At the time of an outage, Troublemens are required to fill out a field report maintained in TEC's CAD system. Troublemens record outage information such as failed device type, cause code, restoration time, overhead versus underground, and any additional comments pertaining to the restoration activities.

6.1.2 Data Accuracy Validation

To ensure accuracy of reliability data, TEC uses a combination of automated system edits, and multiple levels of verification and validation, including an internal assessment of 100 percent of customer outages. All of TEC's data pertinent to electric outage reporting is centrally stored in the Distribution Outage Database (DOD) which connects to a variety of sources. DOD is linked to and gets outage data from the Emergency Management System (EMS) and OMS Oracle databases. The database tracks outage records according to cause and equipment type and is capable of supporting the following functionality:

Tampa Electric Company Reliability Data Collection Process		
Step	Process / Input	Description
Collecting Outage Information		Outages identified by HVCA IVR and SCADA. CIS interface facilitates dispatching and provides real-time status on service requests. WMS delivers process automation for work order management.
Creating Outage Ticket		Outage ticket created in OMS. OMS integrated with GIS and CIS data provides estimated customer outage counts and to assist field crews with accurate mapping information of outage.
Working Ticket		Dispatchers use OMS/CAD to assign field personnel for repair activity and coordinate restoration with field crews; field personnel verifies outage details; using mobile laptops field personnel enters time arrived on-site, time work completed, and time service restored and any equipment changes.
Completing Ticket		Daily verification of outage tickets in OMS is completed by Distribution Service Operations; Nightly uploads to Distribution Outage Database. Typically within 72 hours of an occurring outage, TEC's Distribution System Operator Supervisor verifies the accuracy of the outage data.
Outage Data Review		TEC's Distribution Reliability Coordinator reviews every outage for data accuracy in OMS and DOD. The Reliability Coordinator reviews the previous week's outages to validate the reliability indices impacted.
Indices Calculations		Service reliability data mart warehouse retains outage and reliability data used for TEC management reports and Commission reporting.

Exhibit 5

Source: Document Request 1-28.

- ◆ Centralized capture of outage related data
- ◆ Analysis and clean-up of outage-related data
- ◆ Maintenance and adjustment to distribution outage database data
- ◆ Automatic Generation and distribution of canned reliability reports
- ◆ Generating ad hoc operational and managerial reports

The Distribution Outage Database is further programmed to distinguish between overhead and underground systems and is specifically designed to generate distribution service reliability reports that comply with Rule 25-6.0455, Florida Administrative Code. To create and generate reliability reports that conform to the correct 2.5 Beta methodology of IEEE standard 1366, data tables must be manually extracted from the database.

TEC's System Reliability organization administers the Distribution Outage Database and uses it to extract numerous reliability reports, including management reports and those filed with the Commission. The Distribution Outage Database was upgraded in 2014 to be compatible with Windows 7. According to TEC, the change provided for supportable data integration and made for a more accurate reporting system that supports the needs of the end user. TEC further stated that the reliability data in the new Distribution Outage Database was carefully analyzed, compared, and verified against the old Distribution Outage Database before full switch-over of systems.

TEC's Distribution Operations audits and assess the indices daily to ensure that reliability indices are being implemented as prescribed. Typically within 72 hours of an outage, TEC's Distribution System Operator Supervisor verifies the accuracy of the outage data. TEC's Distribution Reliability Coordinator's sole responsibility is to review every outage for data accuracy in OMS and DOD. The Coordinator is responsible for reviewing the previous week's outage to validate the reliability indices impacted.

6.2 Wood Pole Inspections

TEC has approximately 316,000 distribution and lighting wood poles and 26,000 transmission poles. The Commission requires each IOU to implement an inspection program of wooden transmission, distribution and lighting poles on an eight-year cycle based on the requirements of the National Electric Safety Code.⁷ Approximately one-eighth of the poles are inspected annually. TEC's first inspection cycle was completed in 2014.

The data accuracy issue related to wood pole inspection is accurate planning and tracking to ensure all poles are accounted for during the inspection cycle. Poles missing from plant records or GIS listings could become weak links that negatively impact reliability.

6.2.1 Data Collection Process

⁷ See Commission Order No. PSC-06-0144-PAA-EI, issued February 27, 2006 in Docket No. 060078-EI.

According to TEC, the most reasonable and cost-effective approach for planning and routing the work of the annual distribution pole inspection program is by geographic location. However, the transmission pole inspection program is planned by circuit. TEC's wood pole inspection program requires all poles over 16 years of age to be fully excavated to a minimum depth of 18 inches below the ground-line for inspection. For chromated copper arsenate poles less than 16 years old, TEC performs visual, sound, and selective bore inspections. One percent of these poles are fully excavated as mandated by the Commission. A list of non-restorable poles for replacement is sent to TEC planning for engineering and scheduling. Restorable poles are reinforced by the contractor, Osmose.

TEC presently has 216,101 poles with attachments under 31 joint-use agreements. Because there is an opportunity for unknown foreign attachments to create an overload situation on TEC's poles, TEC performs a pole loading analysis as part of the pole inspection program. Pole loading analysis is performed on any joint-use pole with an attachment of one-half inch in diameter cable or greater.

Wood pole inspections are managed via an online database provided by the contractor, Osmose. The Osmose database is a virtual geographic web-based reporting and mapping solution that provides TEC personnel with the ability to manage inspection data. The database is accessed by TEC and Osmose personnel whose duties require access.

For mapping purposes, TEC's pole locations are downloaded from TEC's GIS into the Osmose database for each pole in the Osmose database, TEC records pole inspection and maintenance activities performed, on each pole. Data captured includes pole class, material, vintage, location, joint-use attachments, and pole deficiencies. The Osmose database provides TEC with the ability to shorten and simplify the pole inspection process by having all the history of pole inspection information available at any time.

Weekly inspection results are queried from the online database and given to the Supervisor of Right-of-Way Maintenance for coordination of action items and internal filing of the actual inspections. Annual inspection summaries are also queried from the online database for purposes of filing in the company's annual reliability report to the Commission.

Additionally, an outside consultant, KEMA, is readily available upon TEC's request to perform forensic analysis or root cause of infrastructure failures that result from storm damage. Although TEC has not experienced any major storms requiring forensic analysis over the first eight-year pole inspection cycle, the consultant constructed a database of the company's distribution structures and facilities that can be used for post-storm forensic analysis. The database, created from data provided by TEC, includes pole information such as categories of poles structures, foreign utility attachment size and quantity and tree trimming cycles by area. As a storm approaches, TEC will activate its Incident Command System which includes putting the consultant on notice. The consultant is required to mobilize data gathering personnel and equipment no later than one day prior to storm landfall to be ready for data gathering as soon as it is safe after the storm passes. The consultant will patrol a statistically valid sample of the damaged areas of the electrical system following a major storm event and perform the data collection process.

6.2.2 Data Accuracy Validation

TEC asserts that the ongoing engagement process between TEC supervisors, field staff, and the contractor provide data accuracy controls for its pole inspection program. TEC field personnel along with a contractor supervisor perform quality assurance audits of the prior week's pole inspection work to verify compliance with the pole inspections services contract. Quality assurance audits are conducted by three inspectors who each randomly select ten poles to check against the previous week's inspection report for each pole. If four poles are found to disagree with the report, the identified work is rejected and corrective work is proposed. All quality control corrective work is performed with the contractor's supervisor and crew and documented in a written report and signed by the contractor and TEC supervisors.

TEC's joint-use department is also responsible for identifying and performing load analysis on all new joint-user pole attachments. Load analysis is captured in a geographic, web-based software called Spida Min, maintained by IJUS. IJUS is a joint-use contractor that provides pole attachment administrative and consulting resources to TEC. Spida Min provides TEC with the ability to analyze many structures and organize them as one pole attachment project through a map view. Information stored in Spida Min includes attachment heights of all cables and equipment, pole age, pole type, pole number, pole size, and span lengths and size of all cables and wires.

6.3 Vegetation Management

The single largest cause of electric power outage occurs when trees, or portions of trees, grow or fall into overhead power lines. Keeping trees and vegetation from conflicting with overhead conductors and triggering power outages is critical to service reliability.

It is imperative that TEC ensures adequate and consistent vegetation management practices through accurate tracking of workloads and schedules. Inaccurate records could allow lines to remain uninspected, leading to preventable outages.

6.3.1 Data Collection Process

TEC's distribution vegetation management program operates on a four-year trim cycle.⁸ In 2014, TEC's vegetation management program utilized nine full time employees and approximately 160 contracted personnel to manage the company's tree trimming requirements. The results of TEC's vegetation management program are tracked primarily in the form of circuit miles maintained annually.

The company's reliability and line clearance departments employ a third-party vegetation management software application which takes into consideration multi-year circuit performance data, trim cycles, and cost. The application provides TEC's line clearance department an objective method for optimizing tree-trimming schedules by determining the impact of tree trimming costs on system reliability. The software takes into account TEC's historical outage

⁸ See Commission Order No. PSC-12-0303-PAA-EI, issued June 12, 2012, in Docket 120038-EI.

and trim data and analyzes the impact of different spending levels on vegetation management efforts. Furthermore, the software is used to estimate the minimum investment required to meet specific tree-related SAIDI or SAIFI performance targets.

TEC's vegetation management program is primarily split into two activities, proactive (planned preventative maintenance) and reactive (hot spot). The circuits selected for annual proactive maintenance are assigned to tree trim contractors throughout the year. Reactive work is driven by the volume of internal and external customer requested work and new construction, which may vary year to year.

For proactive vegetation management activities, contractors are required to submit weekly reports for all work completed in the previous week. The weekly reports include information such as date, substation name, circuit number, trees trimmed, trees removed, brush removed, acres mowed, debris disposed, and the related man hours and trim miles. TEC's Line Clearance Right-of-Way Supervisors review, reconcile, and manually upload the weekly data submitted by the contractors into Excel spreadsheets. At the conclusion of each circuit and various times throughout the year, the data is used to generate circuit closeout and performance reports. These reports are used to measure vegetation density, evaluate contractor performance, and validate overall circuit condition. Data in the reports supports the third-party vegetation management software application.

The company's reactive vegetation management activities are driven by internal or external customer requests. Most external requests are routed to representatives in TEC's Customer Service department for input into the work order management system. Work orders are assigned to either a right of way supervisor or tree trim contractor for a field inspection and any necessary corrective action.

6.3.2 Data Accuracy Validation

TEC states the weekly reviews and reconciliation of the data submitted by the contractors provide adequate data validation to ensure trimming completed is recorded accurately. Additionally, TEC audits the field activities performed through a series of site visits. These site audits, while largely informal with no set schedule, key in on number of miles trimmed, quality of clearance and trimming, and safe work practices. Vegetation management results are also validated through a series of regular meetings between TEC and its tree trim contractors.

6.4 Transmission Structure Inspections and Storm Hardening

TEC's annual reliability report updates the status of inspecting and storm hardening transmission structures. The transmission structure inspection program identifies specific issues along the entire transmission circuit by analyzing the structural conditions at the ground line and above ground as well as the conductor spans. TEC's storm hardening activities for transmission structures primarily focuses on the systematic replacement of wood transmission structures with non-wood structures.

6.4.1 Data Collection Process

In December 2014, the Commission approved TEC's petition to increase its transmission structure inspection cycle from six to eight years.⁹ Since many repairs and replacements had been performed during the first complete cycle, the Commission agreed that increasing the transmission structure inspection cycle from six to eight years would not appear to be a detriment to overall system reliability, and provides a cost savings to the company.

The company executes its transmission structure inspection program with priority given to critical facilities and coastal facilities with progression to inspection of older inland circuits. All transmission substations, capacitor stations, relay stations, switching stations, and other supporting equipment such as insulators, guying, grounding, and cross-arms are included in the inspection program. The primary methods of inspection are:

- ◆ Above ground inspections
- ◆ Ground line inspections
- ◆ Infrared inspections
- ◆ Ground patrol inspections

TEC's above ground inspection program is performed by a contractor using a helicopter or bucket trucks. The program provides a detailed assessment of above ground conditions of TEC's transmission structures. Ground line inspections primarily focus on identifying deficiencies with transmission wood poles. Both above-ground and ground line inspections follow the inspection priority as listed above, with the most critical circuits patrolled first. The above-ground and ground line inspections are tracked and scheduled in an Excel spreadsheet to ensure the entire transmission system is inspected within the defined cycles.

The aerial infrared inspections are performed in a helicopter by a contractor using thermal imaging to detect weak points before they impact the power grid. The inspection process is divided into six geographical grids, with each grid inspected in its entirety before moving on to the next grid. The circuits in each grid are patrolled by the contractor and a TEC representative. All six geographical grid areas are inspected annually. Aerial inspections are tracked in Excel spreadsheets.

The ground patrol inspections are visual inspections for pole and equipment deficiencies, such as insulators, switches, and conductors. Ground patrol inspections of TEC's entire transmission system are performed annually by TEC lineman. In 2014, TEC began tracking ground patrol inspection results using tablet technology with the aid of a mobile application. The mobile application allows lineman to have all circuit maps in one handheld device without using paper maps in the field. Prior to 2014, inspection results were captured in an Excel spreadsheet.

Once transmission inspection results are compiled, the operations engineer addresses storm hardening initiatives. After the remediation activities are engineered, the work is planned based on the same priority, with most critical areas coming first. Once the higher priority failures are addressed the remaining failures are addressed based on failure date. Specific storm hardening activities for TEC's transmission structures include upgrading wooden poles to steel or concrete

⁹See Commission Order No. PSC-14-0684-PAA-EI, issued December 10, 2014, in Docket 140122-EI.

material, upgrading aluminum lattice to steel or concrete, and replace ceramic insulators with fiberglass polymer insulators. For the year 2015, TEC plans to harden 548 transmission structures.

When the work is completed in the field, the job documents are signed by the Crew Leader and returned to the Transmission Operations staff. The Transmission Operations staff reviews the job activities, material issued, and related work requests to ensure proper remediation of the structure. TEC utilizes GIS, work management programs, and a maintenance database to track the transmission job packages from design through completion.

6.4.2 Data Accuracy Validation

TEC relies on its Transmission Operations Engineers and Patrolmen to work closely throughout the year to maintain a consistent level of quality assurance. All transmission structure inspection results are imported into an Access database and monitored by TEC's Senior Engineer of Transmission. Quality assurance activities include reviewing procedures with contractors, ride-alongs with contractors and crew to monitor their performance and results, and implementing corrective actions if necessary. If corrective actions are warranted, TEC supervisory personnel may request additional follow up with the field crew and a follow-up email is sent to the contractor's office.

TEC internally reviews completion of storm hardening projects for existing transmission structures. During this project review, the materials specified for installation are compared to the actual material installed through a reconciliation and project closeout process. This detailed review process along with supervisory oversight provides for validating the overall process of storm hardening of existing transmission structures. This is performed at the closeout of each storm hardening project.

6.5 Geographic Information System

A geographic information system (GIS) allows TEC to collect, organize, maintain, manage, and analyze spatial and geographical data. The GIS is the foundational database for TEC's facilities records and is fully integrated with 100 percent of TEC's distribution and transmission assets. The GIS provides critical support to the distribution operations. Inaccurate GIS data would negatively impact the location of system components in need of repair and delay restoration efforts.

6.5.1 Data Collection Process

TEC's Work Management System with GIS technology, allows TEC to efficiently schedule and dispatch services. GIS provides TEC the ability to follow the life cycle of jobs in the Work Management System, from job designs to construction prints, to automatic updates of facilities (services installed or removed).

TEC is considering several changes to the company's GIS processes and activities. Distribution System Designers create changes to the electric system directly within GIS today. The company is embarking on implementation of Itron's Distribution Design Studio product as the primary

tool for the company's Distribution System Designers. Once implemented, users will have a design tool available to provide them with the ability to design changes or additions to the distribution system in an effective, yet cost efficient manner. This tool will upload changes to the facility data directly into the GIS database without requiring reentry of data after design is complete.

Other changes to GIS processes and activities are also anticipated during 2015 and beyond, including enhanced training and a new process to directly update the GIS database with results from field audits of poles. The goal is to have GIS serve as the system of record for all transmission and facility information.

6.5.2 Data Accuracy Validation

TEC employs an ongoing process for auditing and validating the accuracy of the GIS database. A contracted vendor provided quality control checking software, known as the "QC Tool", which is used to check the GIS database for errors. There are 51 separate rules that check for data issues related to connectivity, phasing, attribution, and more in accordance with business requirements. This software is run against portions of the GIS database many times every day to ensure the integrity of the data.

In addition to the software-aided process for auditing the accuracy of the electric GIS database, TEC's work order creation process allows for designers to update the GIS database anytime it is determined that field conditions differ from the database. Users are sent weekly reports concerning cancelled work orders and job conflicts to make corrections as needed. The GIS group requests designers to perform field checks when questions arise about facilities or data in the GIS database. Other sources of information such as Google Maps and aerial photography are also used by the GIS group to aid in determining actual conditions in the field.

All aspects of GIS are reviewed on a regular basis through the GIS Users Group. This group meets several times per year and is charged with suggesting new enhancements, correcting issues and sharing tips or tricks to improve the overall GIS process. TEC notes it made efforts during the first eight-year cycle to improve the GIS experience for the user by providing additional improved tools.