State of Florida

Public Service Commission

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-M-E-M-O-R-A-N-D-U-M-

DATE: August 17, 2006

TO: Director, Division of the Commission Clerk & Administrative Services (Bayó)

FROM: Division of Economic Regulation (Breman, Daniel, Jopling, Kummer, Lee, Matlock, McNulty, Redemann, Rieger, Swearingen, Trapp)
Office of the General Counsel (Gervasi, Helton)

RE: Docket No. 060198-EI – Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.

AGENDA: 08/29/06 – Regular Agenda – Proposed Agency Action Except Issue 10 – Interested Persons May Participate

COMMISSIONERS ASSIGNED: All Commissioners

PREHEARING OFFICER: Administrative

CRITICAL DATES: None

SPECIAL INSTRUCTIONS: None

FILE NAME AND LOCATION: S:\PSC\ECR\WP\060198.RCM.DOC

Case Background

On January 23, 2006, Commission staff conducted a workshop to discuss damage to electric utility facilities resulting from recent hurricanes and to explore ways of minimizing future storm damages and customer outages. State and local government officials, independent technical experts, and Florida's electric utilities participated in the workshop. On January 30, 2006, some participants filed post-workshop comments.

At the February 27, 2006, Internal Affairs, staff briefed the Commission on recommended actions to address the effects of extreme weather events on electric infrastructure. The Commission also heard comments from interested persons and Florida's electric utilities regarding staff's recommended actions. The Commission modified various aspects of staff's proposal. In brief, the Commission decided the following:

1) All Florida electric utilities, including municipal utilities and rural electric cooperative utilities, would provide a 2006 Hurricane Preparedness Briefing at the Internal Affairs on June 5, 2006.

2) Staff would file a proposed agency action recommendation for the April 4, 2006, Agenda requiring each investor-owned electric utility to file plans and estimated implementation costs for ongoing storm preparedness initiatives.

3) A docket would be opened to initiate rulemaking to adopt distribution construction standards that are more stringent than the minimum safety requirements of the National Electrical Safety Code.

4) A docket would be opened to initiate rulemaking to identify areas and circumstances where distribution facilities should be required to be constructed underground.

On April 25, 2006, in this docket, the Commission issued Order No. PSC-06-0351-PAA-EI, requiring the investor-owned electric utilities to file plans and estimated implementation costs for ten ongoing storm preparedness initiatives on or before June 1, 2006. The ten ongoing initiatives are:

1) A Three-year Vegetation Management Cycle for Distribution Circuits,
2) An Audit of Joint-Use Attachment Agreements,
3) A Six-year Transmission Structure Inspection Program,
4) Hardening of Existing Transmission Structures,
5) A Transmission and Distribution Geographic Information System,
6) Post-Storm Data Collection and Forensic Analysis,
7) Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems,
8) Increased Utility Coordination with Local Governments,
9) Collaborative Research on Effects of Hurricane Winds and Storm Surge, and
10) A Natural Disaster Preparedness and Recovery Program.

The initiatives listed above are not intended to encompass all reasonable ongoing storm preparedness initiatives. Rather, the Commission viewed these initiatives as the starting point of an ongoing process. The docket was kept open for the Commission to address the adequacy of the utility's plans.

On June 1, 2006, each investor-owned electric utility filed plans addressing each of the ten ongoing storm initiatives.

This recommendation addresses the adequacy of the investor-owned electric utility plans for implementing the ten initiatives for ongoing storm preparedness identified in Order No. PSC-

06-0351-PAA-EI. The plans filed by the investor-owned electric utilities are discussed in Issues 1 through 8 and in Attachment A. In Issue 9, staff presents a method for monitoring each utility's ongoing storm hardening initiatives.

Staff informally asked each municipal electric utility and rural electric cooperative utility to voluntarily file plans regarding the ten initiatives identified in the Order. A summary of the filed plans of the municipal electric utilities and rural electric cooperative utilities are discussed in Issue 10 and in Attachments B and C.

The Commission has jurisdiction pursuant to Sections 366.04(2)(c), (2)(f), and (5), 366.05(7), Florida Statutes.

Discussion of Issues

Issue 1: Are each of the investor-owned electric utility plans for vegetation management for distribution equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms?

Recommendation: The plans filed by Tampa Electric Company and Florida Public Utilities Company comply with the three-year trim cycle requirement of Order No. PSC-06-0351-PAA-EI. Staff believes the proposed alternative plan filed by Florida Power & Light Company is reasonably consistent with the compliance options provided by the Order. In addition, staff believes the phase-in approach proposed by Tampa Electric Company and Florida Power & Light Company is reasonable for initial implementation. The alternative plans filed by Progress Energy Florida and Gulf Power Company are based on their current vegetation management programs and do not contain a method or sufficient data for staff to conduct the necessary ongoing review to ensure that the alternative plans are equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms. Staff believes their current plans should be revised and staff will work with the companies to bring their plans to full compliance with the Order. Staff recommends that all plans and plan implementation should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issues 5 and 9. (Lee, Breman, Gervasi)

Staff Analysis:

Initiative 1 –Three-Year Vegetation Management Cycle for Distribution Circuits.

In Order No. PSC-06-0351-PAA-EI, the Commission found that “[t]he vegetation management practices of the investor-owned electric utilities do not provide adequate assurance that tree clearances for overhead distribution facilities are being maintained in a manner that is likely to reduce vegetation related storm damage. We (the Commission) believe that utilities should develop more stringent distribution vegetation management programs.”

Consequently, the Commission required each investor-owned electric utility to provide plans, a timeline for implementation, and cost estimates to implement a three-year trim cycle for all distribution circuits unless shown to be cost prohibitive. The plan should enumerate minimum performance requirements. The Commission provided for utility specific flexibility. The Order states that any “alternatives proposed by the utility shall be compared to a three-year trim cycle and must be shown to be equivalent or better in terms of cost and reliability for purposes of preparing for future storms.”

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, staff met informally with the utilities to seek clarifications and additional information. Staff’s review of each investor-owned electric utility’s plans for vegetation management for distribution circuits is provided below and in summary form on page 1 of Attachment A (page 32 of this recommendation).

Individual Plans

As shown by the summary on page 1 of Attachment A, Tampa Electric Company (TECO) and Florida Public Utilities Company (FPUC) plan to comply with the three-year tree trim cycle for all distribution circuits. Florida Power & Light Company (FPL), Progress Energy Florida (PEF), and Gulf Power Company (GULF) proposed alternatives to a standard three-year tree trim cycle for all distribution circuits. Among the concerns cited by the companies, the potential cost impact associated with the supply and demand of the tree-trimming contractor resources is the most common. FPL, PEF, and GULF provided reasons for their individually recommended alternatives; however, only FPL provided a quantitative analysis of the costs of more frequent trimming compared to estimated benefits of reduced storm restoration costs due to avoided storm outages.

FPL: FPL proposes a three-year average tree trim cycle for feeders and a six-year average cycle for distribution laterals. FPL currently achieves a three-year average trim cycle on its feeders. The proposed six-year average for lateral circuits is an increase of 63 increase in historically achieved tree trimming for lateral circuits. FPL estimates in 2013, FPL will complete its transition to an average six-year cycle for lateral circuits. Table 1 is a summary of the options FPL reviewed.

Table 1

Summary of Vegetation Management Options Considered by FPL

Vegetation Management Initiative	Average Annual Costs ($millions)	Average Annual Incremental Costs ($millions)	Annual Avoided Storm Outages (measured by Customer Interruption or "CI"	Average Cost per Avoided CI
Recommended 3-year cycle for all distribution circuits	$102.5	$43.5	155,000	$280
FPL's proposed 3-year feeder cycle and 6-year Lateral cycle	$71.9	$12.9	100,000	$129
FPL's current program	$59.0	N/A	N/A	N/A

Compared with its current tree trimming practice, FPL estimates that moving to a three-year tree trim cycle for all distribution circuits would result in an average incremental annual cost of $43.5 million, while providing a potential incremental benefit of 155,000 fewer storm-related Customer Interruptions (CI). Therefore, the cost per avoided storm CI to implement a three-year trim cycle for all distribution circuits would be approximately $280. FPL estimates its proposed alternative would result in an average incremental annual cost of $12.9 million, while providing a potential incremental benefit of 100,000 fewer storm-related CI. Therefore, the cost per avoided storm CI would be approximately $129 for the alternative. FPL asserts that the additional spending to comply with a three-year tree trim cycle for distribution laterals would result in a diminishing return measured by storm cost savings. FPL also presented a 10-year total cost analysis which demonstrates its proposed alternative to be more cost effective. FPL proposes that its plan be re-evaluated annually to assess lessons learned and ensure continued effectiveness.

Staff believes FPL's plan is reasonably consistent with the compliance options provided by the Order. FPL has provided more extensive data and analysis than the other two companies that proposed alternative plans. However, FPL's analysis is based on various assumptions such as the potential incremental benefit in reduced customer interruptions during storm events. At this time there is no substantive forensic data supporting such assumptions. Therefore, staff is uncertain at this time whether FPL's proposed plan is equivalent to or better than a three-year trim cycle for all circuits in terms of cost and reliability for purposes of preparing for future storms. Staff believes FPL's proposed plan is reasonable for initial implementation because it is an improvement over its current program and it contains a method for staff to conduct the necessary ongoing review to ensure that it is equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms.

FPL's analytical approach appears to be sound. As more data become available, FPL's plan and plan implementation should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issues 5 and 9. In particular, to ensure that the level of vegetation management is achieving the Commission's goal of reducing future storm impact, the company needs to collect forensic data to evaluate the correlation between the storm-related CI and the frequency of the trim cycles.

PEF: As shown by the summary on page 1 of Attachment A, PEF's plan is an alternative to a three-year tree trim cycle for all distribution circuits. PEF calls for a fully integrated vegetation management program using a number of prioritization ranking factors for targeted trimming to balance the cycle trimming approach. PEF believes its program is better than a three-year tree trim cycle for all distribution circuits. PEF estimates that a three-year cycle for all circuits would immediately increase costs by approximately $7 million in the first year and could increase its overall budget by more than 3% per year.

PEF's plan includes a goal of a three-year average trim cycle. However, PEF has not shown whether it has achieved that goal or whether it will increase the trim frequency to move toward that goal. PEF provided reasons why it believes its alternative is better. However, its plan provides no quantitative comparisons of the costs and benefits similar to FPL's analysis. Nor does PEF's plan contain a method for staff to conduct the necessary ongoing review to ensure that it is equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms. Therefore, staff believes PEF's current plan should be revised to address these concerns. Staff will work with the company to bring its plan to full compliance with the Order.

As more data becomes available, PEF's plan should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issues 5 (Data Collection) and 9 (Annual Review). In particular, to ensure the level of vegetation management is achieving the Commission's goal of reducing future storm impact, the company needs to collect forensic data to evaluate the correlation between the storm-related CI and the frequency of the trim cycles.

TECO: As shown by the summary on page 1 of Attachment A, TECO's plan calls for targeted tree trimming. The company will ensure that every circuit is trimmed every three years. TECO alleges contractor resource constraints due to increased demand. TECO is planning a phased-in approach to transition from the current vegetation management program to the three year program. A two to three year transition period is planned to stabilize costs and conduct training. Staff believes that TECO's plan complies with the three-year trim cycle recommended in the Order when fully implemented. As more data becomes available, TECO's plan should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issues 5 and 9.

GULF: As shown by the summary on page 1 of Attachment A, GULF's plan is an alternative to a three-year tree trim cycle for all distribution circuits. Its plan is to continue its current reliability-based program. GULF's reliability-based program targets vegetation based on the following priorities: Trouble Ticket Pruning, Targeted Hot Spot Pruning, and Full Maintenance Pruning. Gulf described its Full Maintenance Pruning as follows: If the field patrol determines that reliability is deteriorating due to the overall condition of vegetation on the entire circuit, then the entire circuit will be scheduled for pruning. In full maintenance pruning, the main feeder as well as all taps and laterals will be pruned to establish a minimum of three-years of clearance on the entire circuit. In addition, small trees on the right-of-way that will present future problems will be removed.

GULF does not believe a cyclical approach is better with respect to the impact on storm hardening. GULF asserts that the vast majority of tree caused outages during storms have historically been caused by trees falling into the road right-of-way. GULF believes neither cyclical nor reliability based programs would have a significant impact on these trees. GULF estimates that a three-year cycle for all circuits would require an annual budget of $7.4 million, representing an annual incremental cost of $4.2 million.

In its response to staff's data request, GULF states that it is evaluating a process that will ensure each distribution circuit is evaluated on a cyclical basis. An appropriate cycle will be established for each circuit to insure it is evaluated with respect to potential for storm damage. Circuits with a high customer count and heavy forest cover will be evaluated on a shorter cycle than will circuits with no forest cover. The entire circuit, main feeder lines and laterals, will be evaluated and vegetation concerns will be corrected. Critical circuits in heavily forested areas may be evaluated for trimming annually while circuits on the beach may not require evaluation on a regular basis. It is conceivable that the frequency of circuit specific trim cycles could range from one to ten years. GULF estimates the annual incremental cost of this program would be approximately $1,000,000.

Staff notes that GULF is the only company that does not incorporate a cyclical approach in its plan. While staff believe GULF's assumption regarding outages caused by trees falling into the road right-of-way may be valid for major storms with extreme winds, staff also believes cyclical trimming should result in fewer storm-related customer interruptions for named storms with wind speeds less than 100 miles per hour, as indicated by FPL's data. Gulf did not offer any data to support its argument.

The Order requires that "alternatives proposed by the utility shall be compared to a three-year trim cycle and must be shown to be equivalent or better in terms of cost and reliability for purposes of preparing for future storms." GULF's responses to staff's data request stated reasons why it believes its alternative is better. However, GULF provided no quantitative comparisons of the costs and benefits similar to FPL's analysis. Nor does GULF's vegetation management plan contain a method for staff to conduct the necessary ongoing review to ensure that it is equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms. Therefore, staff believes GULF's current plan should be revised. Staff will work with the company to bring its plan to full compliance with the Order.

FPUC: As shown by the summary on page 1 of Attachment A, FPUC's plan calls for a three-year trim cycle for all feeders. For laterals, FPUC plan includes a three-year trim cycle for the NE division and an alternative of a five-year trim cycle for its NW division. Subsequent to its filing, FPUC provided additional clarification that the company will implement the three-year tree trim cycle for all distribution circuits. Based on FPUC's clarifications, staff believes FPUC's plan complies with the order requirement of a three-year trim cycle. As more data becomes available, FPUC's plan should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issues 5 and 9.

Conclusion

Based on the forgoing, staff believes the plans filed by Tampa Electric Company and Florida Public Utilities Company comply with the three-year trim cycle required in Order No. PSC-06-0351-PAA-EI. Staff believes the proposed alternative plan filed by Florida Power & Light Company is reasonably consistent with the compliance options provided by the Order. FPL's analytical approach appears to be sound and staff believes the method can be used to determine whether the proposed plan is equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms. In addition, staff believes the phase-in approach proposed by TECO and FPL is reasonable for initial implementation.

The alternative plans filed by PEF and GULF are based on their current vegetation management programs. They do not contain a method or data for staff to conduct the necessary ongoing review to ensure that they are equivalent to or better than a three-year trim cycle in terms of cost and reliability for purposes of preparing for future storms. Staff believes their current plans should be revised. Staff will work with the two companies to bring their plans to full compliance with the Order.

Staff recommends that all plans should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issues 5 and 9.

Issue 2: Does each investor-owned electric utility's plans for auditing its joint-use attachment agreements include pole strength assessments and attachment verification?

Recommendation: Yes. Each utility's plan for auditing its joint-use attachment agreements includes pole strength assessments, but plans should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issue 9. (Swearingen, Gervasi)

Staff Analysis:

Initiative 2 –Audit of Joint-Use Attachment Agreements.

In Order No. PSC-06-0351-PAA-EI, the Commission found that "Florida's utilities have not provided adequate assurance that their practices and procedures governing joint-use facilities avoid storm damages and customer outages."

Consequently, the Commission required each investor-owned electric utility to provide plans, a timeline for implementation, costs, and rate impacts to audit joint-use agreements that include pole strength assessments. The plans should enumerate minimum performance requirements. The Commission provided for utility specific flexibility.

Staff' Review

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, staff informally met with the utilities seeking clarifications and additional information. Staff's review of each investor-owned electric utility's plans for an audit of joint-use attachment agreements is provided below and in summary form on pages 2 and 3 of Attachment A (pages 33 and 34 of this recommendation).

FPL: Currently, FPL partners with CATV and telecommunication companies to complete system wide pole attachment surveys on a five-year cycle. The system wide attachment surveys focus on compliance issues associated with existing pole attachment agreements for all FPL-owned and third-party-owned poles. The current attachment surveys do not explicitly include pole strength assessments. Prospectively, FPL proposes to include pole strength assessments addressing the impacts of existing pole attachments in conjunction with its eight-year wooden pole inspection program. Data on the poles will be collected and stored in an information database. FPL will continue to verify all attachments have been made pursuant to a current joint-use agreement on a five-year cycle system-wide pole attachment survey. FPL's plan will be implemented in January 2007 at an estimated incremental annual cost of $1.2 to 2.5 million.

PEF: PEF currently performs a pole agreement compliance audit on a five-year cycle. The current pole attachment compliance audit does not explicitly address pole strength assessments. PEF has developed a plan that includes pole strength assessment for all PEF-owned and third-party-owned poles in conjunction with its eight-year wood pole inspection cycle. Data on the poles will be collected and stored in electronic format. PEF will continue to verify all attachments have been made pursuant to a current joint-use agreement on a five-year cycle. PEF initiated this plan in 2006 with completion cycles of eight years and an estimated incremental annual cost of $80,000.

TECO: Currently, TECO performs periodic inspections and/or audits of all joint-use attachments to its facilities. TECO has proposed a plan to audit all joint-use agreements including pole strength assessment for all TECO-owned and third-party-owned poles. This audit will be performed in conjunction with its eight-year wood pole inspection cycle. Stress calculation will also be performed on poles during the eight-year inspection cycle. Data on the poles will be collected and stored in a GIS database. TECO will verify all attachments have been made pursuant to a current joint-use agreement including strength assessments during the eight-year pole inspection cycle. TECO's plan will be implemented in January 2007 with a completion cycle of eight-years at an estimated annual cost of $5 million. TECO's cost estimate associated with Initiative 2 does not appear comparable to estimates of the other utilities because TECO's cost estimate of $5 million is commingled with its cost to perform pole inspections.

GULF: Since 1991, GULF has conducted field audits of joint-use poles every five years. GULF has proposed a plan to audit all joint-use agreements of GULF-owned poles and third-party-owned poles on a five-year cycle. Pole strength assessments and stress calculations will be performed on a 5% random sample of GULF-owned poles that are 20 years old or more and have three or more attachments. Data on poles will be collected and stored in a database. GULF will verify all attachments have been made pursuant to a current joint-use agreement on a five-year cycle. GULF will use results of its 2006 survey to revise its cost estimates and scope of work for 2007. Preliminary cost estimates for 2007 show a $5.375 million increase relative to 2005. GULF's cost estimate associated with just Initiative 2 appears to include activities and costs to perform pole inspections on an eight-year cycle.

FPUC: FPUC's plan was silent on how the utility currently audits joint-use attachment agreements. FPUC has proposed a plan to audit all joint-use agreements including pole strength assessment for all FPUC-owned and third-party-owned poles. This audit will be performed in conjunction with its eight-year wood pole inspection cycle. Stress calculation will also be performed on poles during the eight-year inspection cycle. Data on the poles will be collected and stored in a database. FPUC's plan will be implemented in January 2007 with a completion cycle of eight-years at an estimated annual cost of $20,300.

Conclusion

Staff recommends that each of the utilities' plans for auditing joint-use attachment agreements include strength assessments and are consistent with the intent of Order No. PSC-06-0351-PAA-EI. All plans should be re-evaluated annually to assess the need for any adjustment. This annual assessment should be conducted consistent with the discussion in Issue 9.

Issue 3: Is each investor-owned electric utility's plan for a transmission structure inspection program equivalent to a six-year inspection cycle methodology in terms of cost and reliability?

Recommendation: Yes, each utility's transmission structure inspection plan is consistent with the intent of the Order Staff recommends continued monitoring of each utility's transmission structure inspection program. This annual assessment should be conducted consistent with the discussion in Issue 9. (Breman, McRoy, Gervasi)

Staff Analysis:

Initiative 3 – A Six-year Transmission Structure Inspection Program

In Order No. PSC-06-0351-PAA-EI, the Commission was "not convinced that current utility transmission facility inspections are adequate to prepare for future storms."

Consequently, the Commission required each investor-owned electric utility to provide plans, a timeline for implementation, costs, and rate impacts to implement a plan for fully inspecting all transmission towers and other transmission line supporting equipment on a six-year cycle. The Commission provided for utility specific flexibility. The Order states that any "alternatives shall be compared to a six-year inspection cycle methodology and must be shown to be equivalent or better in terms of cost and reliability for purposes of preparing for future storms."

The Commission noted that Order No. PSC-06-0144-PAA-EI[1] does not address whether an eight year inspection cycle for all transmission facilities is adequate to prepare for future storms. Also, Order No. PSC-06-0144-PAA-EI does not address the full inspection of all transmission poles, towers, and other line supporting structures. Therefore, the Commission required each investor-owned electric utility to develop a plan to fully inspect on a six-year cycle all transmission structures, substations, and all hardware associated with these facilities that are not already addressed by Order No. PSC-06-0144-PAA-EI.

Individual Plans

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, staff informally met with the utilities seeking clarifications and additional information. Staff's review of each investor-owned electric utility's plan for a six-year transmission inspection program is provided below and in summary form on page 4 of Attachment A (page 35 of this recommendation).

FPL: FPL's prior transmission structure inspection program focused on performing detailed inspections on ten percent of its transmission structures every four years and fully inspecting substations every three months. FPL is now increasing its sample and inspection methodology to achieve what it believes to be "the equivalent of a non-sample six-year inspection cycle." The

[1] Issued February 27, 2006, in Docket No. 060078-EI, In re: Proposal to require investor-owned electric utilities to implement ten-year wood pole inspection program.

estimated increase in annual inspection costs is $2.3 million. FPL is currently implementing upgrades to its transmission structure inspection program this year.

PEF: PEF's existing transmission structure inspection program is indexed to a five-year cycle for structures. PEF completes a full inspection of its substations once per year. PEF is not proposing any changes to its current program. PEF will not incur any incremental costs associated with transmission structure inspections.

TECO: TECO's plan establishes a six-year transmission structure inspection program consistent with the requirements of the Order. The estimated increase in annual inspection costs and additional maintenance is $2.97 million. TECO currently completes a full inspection of its substations once per year and no enhancements of substation inspection activities are planned.

GULF: GULF fully inspects its substations annually and schedules inspections of its transmission structures based on achieving a six-year inspection cycle for all of its facilities. GULF will not incur any incremental costs associated with transmission structure inspections.

FPUC: FPUC is developing a program for inspecting its transmission structures on a six-year cycle. The program includes coordination with customers who own transmission structures. The estimated increase in annual inspection costs is $18,000. FPUC currently fully inspects its substations at least once per year and no enhancements of substation inspection activities are planned.

<u>Conclusion</u>

Staff recommends that the Commission find that each of the utility's transmission structure inspection plan is consistent with the intent of Order No. PSC-06-0351-PAA-EI. Over time, as each utility collects and reviews its storm performance data, each utility will become better able to address the adequacy of its efforts to prepare for future storms. Staff recommends continued monitoring of each utility's transmission structure inspection program consistent with the discussion in Issue 9.

Issue 4: Is each investor-owned electric utility's plan for hardening existing transmission structures adequate for purposes of preparing for future storms?

Recommendation: Yes. Based on the available information, the Commission should find that each utility's transmission plan for hardening existing transmission structures is consistent with the intent of Order No. PSC-06-0351-PAA-EI. As utilities implement their forensic data collection procedures, each utility will become better able to address the adequacy of its efforts to prepare for future storms. Staff recommends continued monitoring of each utility's plans for hardening existing transmission structures consistent with the discussion in Issue 9. (Breman, McRoy, Gervasi)

Staff Analysis:

Initiative 4 – Hardening of Existing Transmission Structures.

In Order No. PSC-06-0351-PAA-EI, the Commission concluded that the electric utilities "have not shown the extent of utility efforts in this area nor the criteria used to select which transmission structures are upgraded or replaced."

Consequently, the Commission required each investor-owned electric utility to provide a plan, a timeline for implementation, costs, and rate impacts to implement a plan to upgrade and replace existing transmission structures. The Commission provided for utility specific flexibility. The Order states that "the plan shall include the scope of activity, any limiting factors, and the criteria used for selecting transmission upgrades and replacements."

Individual Plans

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, staff informally met with the utilities seeking clarifications and additional information. Staff's review of each investor-owned electric utility's plans for hardening existing transmission structures is provided below and in summary form, on page 5 of Attachment A (page 36 of this recommendation).

FPL: FPL currently upgrades its existing transmission structures during road-way relocation projects and as other maintenance activities provide cost-efficient opportunities. Two specific activities included in its program include upgrading un-guyed single wood pole transmission structures and replacement of ceramic post line insulators with a type of polymer insulators to ensure the structures meet extreme wind load criteria. FPL estimates these two activities will be completed within 10 to 15 years. FPL projects an increased level of transmission upgrade activities relative to 2005 resulting in additional annual expenses between $3.3 and $6 million beginning in 2007.

PEF: PEF currently upgrades its existing transmission structures during road-way relocation projects and as other maintenance activities provide cost-efficient opportunities. A primary component in its plan includes changing out existing wooden transmission poles with either concrete or steel. Over the next ten years, PEF estimates the program will reduce the percentage of wooden transmission poles from 75 percent to 50 percent. PEF does not plan to expand its existing program at this time. Consequently, PEF is not expected to incur any costs associated with any incremental changes to its plan relative to 2005.

TECO: TECO currently upgrades its existing transmission structures during road-way relocation projects and as other maintenance activities provide cost-efficient opportunities. TECO's plan includes the systematic replacement of wooden transmission structures with non-wooden structures based primarily on pole inspection results. TECO does not plan to expand its existing program at this time. Consequently, TECO is not expected to incur any costs associated with any incremental changes to its plan relative to 2005.

GULF: GULF currently upgrades its existing transmission structures during road-way relocation projects, and as other maintenance activities provide cost-efficient opportunities. GULF's plan includes a five-year program to install storm guys on H-frame transmission structures not currently guyed. In addition, GULF began a ten-year program to replace all wooden cross-arms with steel. For new construction beginning in 2007, GULF will implement a "loss of conductor" contingency design standard. A "loss of conductor" contingency is a design standard directed at avoiding cascading transmission tower failures. In 2007, GULF will begin incurring approximately $600,000 in incremental annual capital construction costs relative to 2005.

FPUC: FPUC plans to replace 180 wooden transmission poles on its system with concrete poles as necessary and economically practicable. The total project costs are estimated to be $4.5 million for replacement of all 180 wooden transmission poles. To date, FPUC has not established a timeline for completing the pole change outs because the poles are currently sound, and transmission line upgrades that may require stronger poles have not been scheduled at this time.

<u>Conclusion</u>

Based on the available information, staff believes the Commission should find that each utility's transmission plans for hardening existing transmission structures is consistent with the intent of Order No. PSC-06-0351-PAA-EI. Utilities are in the process of implementing forensic data collection. Over time, as each utility collects and reviews its storm performance data, each utility will become better able to address the adequacy of its efforts to prepare for future storms. Staff recommends continued monitoring of each utility's plans for hardening existing transmission structures consistent with the discussion in Issue 9.

Issue 5: Are each investor-owned electric utility's plans for a transmission and distribution geographic information system (Initiative 5), post-storm data collection, and forensic reviews (Initiative 6), and assessing performance of overhead and underground systems (Initiative 7) adequate for purposes of improving its storm restoration activities and evaluation of its storm hardening options?

Recommendation: Yes. The Commission should find that each utility's plans are consistent with the Order. Each utility's implementation of its plan should be monitored consistent with the discussion in Issue 9. (Matlock, Gervasi)

Staff Analysis: The following three initiatives are addressed together because effective implementation of anyone initiative is dependent on effective implementation of the other two initiatives.

Initiative 5 – A Transmission and Distribution Geographic Information System

Initiative 6 – Post-Storm Data Collection and Forensic Analysis,

Initiative 7 – Collection of Detailed Outage Data Differentiating Between Overhead and Underground Systems.

In Order No. PSC-06-0351-PAA-EI, the Commission concluded that the electric utilities should develop a transmission and distribution geographic information system (GIS) adequate to provide assurance "that sufficiently detailed data is collected to conduct forensic reviews, assess performance of overhead and underground systems, determining whether appropriate maintenance has been performed and evaluation of storm hardening options."

The Order also states "[i]n addition to the general need to increase post-storm data collection, utilities shall collect specific storm performance data that differentiates between overhead and underground system. Data regarding overhead and underground system performance is needed to adequately inform customers and communities who are considering their options. The same data is needed by the utility to address storm hardening options that reduce storm damage, storm restoration costs, and customer outages."

Consequently, the Commission required each investor-owned electric utility to provide a plan, timeline for implementation, costs, and rate impacts to implement plans to develop a GIS program, collect post-storm data on competing technologies, perform forensic analysis, and assess the reliability of overhead and underground systems on an ongoing basis. The Commission intended for the utilities to have the flexibility to propose plans that are efficient and cost-effective.

Individual Plans

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, staff informally met with the utilities seeking clarifications and additional information. Staff's review of each investor-owned electric utility's plans for storm hardening initiatives 5, 6 and 7 is provided below and in summary form on pages 6 through 9 of Attachment A (pages 37 through 40 of this recommendation).

FPL: FPL has initiated GIS programs for its distribution and transmission systems and is in the process of fully representing its facilities in the electronic model. To comply with Initiative 5, FPL plans to purchase a new maintenance management system to complement its GIS and other information systems. This will allow better information on equipment maintenance and performance. FPL already has a GIS and an asset management system for its transmission system.

For forensic data collection and analysis, FPL proposes that post-storm performance data be collected from a randomly selected sample of locations. The specific method of sampling is yet to be determined. Staff needs to better understand how sampling will be done and will work with FPL on this. FPL contends that immediately following a destructive storm, personnel qualified for gathering storm damage data are in limited supply and complete enumeration of all damaged facilities to determine a statistically valid sample of the affected area would take too long. FPL proposes that while storm damage data are being gathered from a sample of locations, it is important for restoration crews to begin their work in the other areas. This will allow the collection of sample observations for forensic analysis without restricting early restoration work. Inclusion of overhead and underground performance will be included in FPL's plan for managing its assets and performing forensic analyses. FPL's proposed plans will have an incremental cost of $6.3 million for adding additional pole attribute information to its GIS and an annual maintenance cost of $0.5 million. FPL's proposed alternatives for Initiatives 6 and 7 require no additional costs.

PEF: Although PEF's present GIS is not capable of providing the information necessary to comply with the Order, PEF plans is to make the necessary changes to its GIS so that it will be in compliance with the Order. For distribution, PEF's GIS will need to be enhanced to include specific information about distribution asset performance. For transmission, PEF's GIS does not contain maintenance information.

PEF has established procedures for gathering post-storm performance data for the 2006 hurricane season. The goal of PEF's data gathering procedures is to be able to provide the PEF Forensic Assessor (distribution) and a consultant (transmission) with the data gathered so that each will be able to make recommendations for improvements in its system. PEF's plans include assessing differences in damage sustained between underground and overhead facilities and determining whether customer outages are caused by failures in underground or overhead components. PEF plans estimated cost to comply with Initiatives 5, 6, and 7 will be $8.8 million initially for developing its computer system and inspecting its facilities, with an annual maintenance cost of $0.3 million and a per storm cost of $0.9 million.

TECO: TECO began to implement a new distribution and transmission GIS in the Fall of 2005 and implementations will be completed by the Summer of 2007. This system along with TECO's outage management system, will provide a variety of functions with information about system performance. Following major storms, TECO will use information from these systems, along with information collected from a representative sample of storm damaged areas, to determine the causes of equipment failure and to determine preventive measures to harden these systems. TECO currently categorizes equipment-failure outages into underground and overhead equipment. The present information systems will be amended as necessary to provide reliability-performance comparisons between underground and overhead systems. The cost for TECO to make changes necessary to comply with Initiatives 5, 6, and 7 is $1.1 million with an additional forensic analysis cost of $ 0.1 million per storm.

GULF: GULF presently has a GIS, excluding complete transmission information, for its distribution and transmission structures. At the present rate of processing, the GIS will include all transmission-system information within six years. For post-storm performance data gathering, Gulf intends to employ contractors to survey a percentage of the lines in the damaged areas. Crews will cover inland and coastal areas and overhead and underground outages. The cost for GULF to continue developing its GIS and use the system according to the initiatives is $75,000 initially and $125,000 per storm.

FPUC: FPUC, NW Florida Division, presently has a GIS capable of collecting all of the necessary information. Additional procedures will be developed to enable the division to track all specific hurricane outages, identify the causes of the outages, and count the numbers of customer outages. The utility now has the ability to report performance information differentiating between overhead and underground facilities. FPUC, NE Florida Division, presently has only limited GIS capabilities. FPUC has plans to upgrade NE Florida's GIS to have the same capabilities as NW Florida's and then also develop the additional procedures pertaining to the performance of its electric infrastructure. FPUC states that it will make changes necessary for both divisions to be in compliance with the Order. The initial cost for FPUC to upgrade it system is $207,000, and after the upgrades are implemented in 2007, there will be a per storm cost of $10,000.

Conclusion

Staff recommends that the Commission find the utilities" filed plans adequate for carrying out Initiatives 5, 6, and 7. Staff further recommends that utility implementation of the plans be monitored consistent with the discussion in Issue 9.

Issue 6: Are the utility plans for increased coordination with local governments adequate to foster better communication between the utilities and the cities and counties they serve, not only prior to and immediately after a storm, but year-round to identify and address issues of common concern?

Recommendation: Yes. While no objective metrics exist to quantify community coordination, the investor-owned electric utilities have filed draft plans which appear to inform and encourage joint participation with cities and counties and resolve common issues. Staff recommends continued monitoring of the implementation of the plans as discussed in Issue 9. (Jopling, Kummer, Gervasi)

Staff Analysis:

Initiative 8 – Increased Coordination with Local Governments

Order No. PSC-06-0351-PAA-EI noted that the electric utilities needed to develop "better communication between the utilities and the cities and counties they serve." The goal of this better communications is to promote on-going dialogue, in addition to the general need to increase pre-and post-storm coordination. The increased coordination and communication will also facilitate the collection and analysis of more detailed information on the operational characteristics of underground and overhead systems. This additional data is also necessary to more fully inform customers and communities who are considering undergrounding as an option, as well as to assess the most cost effective storm hardening.

One example of better coordination was suggested at the Commission's January 23, 2006 infrastructure hardening workshop. Mayor Anne Castro of the City of Dania Beach suggested that a more integrated partnership between local governments and utilities could assist utilities in better serving customers. Mayor Castro explained:

> We want to be the eyes and ears for FPL. We have offered…[to] … train our public service people, our public safety people, especially after a hurricane or even on an ongoing basis during the year, as to what to look for in their infrastructure. If they could teach us what to look for as far as poles being bad or wires being bad or fuses hanging or loose ends hanging, our folks as they routinely do this through code enforcement, through the fire department, through the police department, are happy to go out there and take a look. Even our citizens on patrol…turn in half of the code violations anyway…they can report all that, they can create a list…

To facilitate increased governmental interaction, the Commission required each IOU to provide a plan, detailing activities, a timeline for implementation, and associated cost and rate impacts for expanding any existing program or initiating new utility/local government liaison programs. The goal of increased discussion is to reach some accommodation or agreement on mutual concerns and to prioritize needs, within the given time and financial constraints. This could include not only optimal system planning or upgrades such as undergrounding or expansion of facilities but also tree trimming and storm restoration priorities.

Individual Plans

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, Staff informally met with the utilities to seek clarifications and additional information on the plans submitted. A discussion of each utility's plans for increased coordination with local governments is provided below and in table format on pages 10 through 11 of Attachment A (pages 41 and 42 of this recommendation). Staff cautions, however, that plans are only as good as their implementation and follow-through procedures. Even an ambitious plan can be inadequate if not timely implemented with adequate resources to achieve the desired results. Therefore, staff is recommending in Issue 9 that the approval of the plans be the first step and that the Commission continue to monitor the implementation and any subsequent modifications of the plans.

FPL: FPL's plan consists of three subsections, each addressing a different mode of operation: (1) Storm Mode, (2) Storm Recovery Mode, and (3) Normal Operations. The plan subsections addressing Storm Mode and Storm Recovery Mode include the traditional pre-storm planning and post-storm restoration activities and indicate that FPL is increasing the level of pre/post storm related information shared with local governments. Noted in the plan is an annual campaign to identify special needs customers under the Medically Essential Program to alert local officials to customers who may need extra care in relocation and service restoration. FPL will continue to coordinate with each local emergency operation center (EOC) before and after storms and has pledged to have FPL representatives in County EOCs during storm activity. FPL has also pledged to coordinate local restoration efforts with local officials to better meet critical local needs. FPL also plans to expand the timeliness and extent of the information available to the local community during both pre-and post-storm activities.

Under its plan for Normal Operations, FPL will expand its existing "Right Tree, Right Place" program, and enhance its community outreach teams to improve local communication. FPL also pledges to develop a program to allow local governments to alert the utility when facilities appear in need of repair. Similar to the approach described by Mayor Castro, the program will train public works departments and other governmental departments to report conditions observed during their normal work activities and receive feedback from FPL on its response to their concerns. FPL plans to continue its current External Affairs Support efforts to work with local officials throughout the year to identify problem areas and potential solutions. It has also recently implemented an e-mail distribution network that can target messages to specific audiences to share breaking news and important updates.

The costs associated with FPL's planned enhancements are for program startup as well as training local governmental participants. Initial startup costs are estimated to be $125,000 and the ongoing annual expense associated with training is estimated to be $12,000. FPL provided supplemental data addressing training of local governmental volunteers to find and report potential reliability concerns. FPL states its plan will not be fully operational until the first part of 2007.

PEF: While PEF did not propose any additional programs, it did note planned improvements in its storm preparedness coordination and its information update activities associated with storm restoration. Improvements include more efficient process and reporting mechanisms to facilitate easier use by city and county governments. PEF also plans to enhance its educational efforts to prepare customers for storm related activities and coordinate with local governments on prioritizing local restoration activities.

As part of its response to the July 14 meeting, PEF provided a detailed list of activities envisioned for a cross functional team to improve staff training and communications. This team will include representatives in the areas of public policy, community relations and commercial/industrial and governmental accounting. As part of the implementation of this cross functional team, PEF notes that more than 70 employees will be utilized to support these communication efforts. An in-house improvement to facilitate better communication includes a task specific electronic site to insure that information is timely updated. Continuing interaction with community representatives will provide feedback on the effectiveness of existing programs and form the basis for changes. Communications with local governments will be through mailings, coordination meetings, update calls, e-mails and workshops. In addition, PEF states it is in the process of revising its existing underground conversion tariff to offer more flexibility to local governments in managing project costs. PEF also plans to continue its vegetation management education as well as its street lighting reporting and repair program.

Because the plans initially anticipate primarily a continuing of current efforts or redirection of existing staff and resources, PEF did not provide incremental cost impacts. It did note, however, that as the programs are refined, additional costs may be incurred.

TECO: TECO asserts it has very good relationships with local governments within its service territory. TECO plans to continue its ongoing discussions with local officials regarding issues such as storm preparedness and storm restoration activities. TECO notes that it currently hosts a storm preparation workshop with local government officials and safety personnel each year prior to storm season. Based on their experience in 2004, TECO plans to place additional personnel in local EOC's during storms to facilitate timely communication. TECO also assists in training local EOC participants which allows establishment of personal relationships with local participants and encourages cooperation.

As part of its on-going activities, TECO plans to increase its efforts in vegetation management coordination and develop educational material related to overhead-to-underground conversion projects. Part of this effort is working with local governments to develop viable tree ordinances that meet both the local and utility needs. In addition, TECO also plans to develop a program to train local government representatives in the identification and reporting of damaged or unsafe system conditions to expedite repairs.

Since many of the activities are already in place, there are minimal incremental costs. Preliminary estimates to develop the educational and training materials for this new program are $75,000 annually. TECO will implement its plan in the first part of 2007.

GULF: GULF believes it enjoys very positive relationships with local governments within its service territory. Storm related activities include notifying all local governments when a storm becomes imminent and providing a single point of contact for governments to call for additional information. It also staffs local EOC's on a 24 hour basis, if necessary. These GULF representatives also provide updated restoration information after storms. GULF also sets up temporary customer service in or near government facilities to expedite the handling of customer issues.

On an ongoing basis, GULF conducts Community Leader Forums where government and civic leaders are invited to discuss critical issues, including storm related matters and overhead-to-underground conversion projects, and other matters of common interest. GULF also indicated that it will create a website for county building and electrical inspectors as a central information source on the electric system, planned improvements and storm preparation and restoration. GULF assigns designated employees to maintain active relationships with local governments, including Line Clearing Specialists which serve a single point of contact for vegetation management issues for local governments. To facilitate underground conversions, GULF indicated that it works to identify and involve all affected parties early on to facilitate cost effective planning and construction. It also stresses the need for a single point of coordination and contact with the authority to make timely decisions.

Since many of these activities are being conducted today, GULF states that there are no incremental costs associated with its plan. To the extent programs or initiatives are expanded or modified, additional costs may be incurred.

FPUC: FPUC is in the unique position of serving two small compact service territories which enables it to maintain an ongoing close relationship with local governments as a regular business practice. Since FPUC employees often live and work in the communities it serves, they bring a different perspective to the process of local government communications. The utility has received no complaints about the level or timeliness or coordination of information from its local governments.

FPUC notes that, due to limited resources, it is not able to have employees at all government locations throughout storm related activities; however, staff can be relocated from undamaged areas to assist in areas hit hardest by weather activity. The cost of additional personnel is estimated at $9,700 per activity. In lieu of a physical presence at local EOC's, FPUC suggests that it may be more cost effective to institute daily communication procedure to ensure that necessary information is received in a timely manner at EOC's during storms.

Conclusion

Based on the available information, staff concludes that each investor-owned electric utility's plan is consistent with the requirements of the Order. There are, however, no objective metrics to judge whether any of the plans will accomplish the desired level of coordination. How the plans are implemented and ultimately perceived by the local governments will determine their effectiveness. Staff recommends continued monitoring of the implementation of the plans as discussed in Issue 9.

Issue 7: Is each investor-owned electric utility's plan for collaborative research on effects of hurricane winds and storm surge adequate to further the development of storm resilient electric utility infrastructure and technologies that reduce storm restoration costs and outages to customers reasonable?

Recommendation: While efforts are underway, the collaborative research plans of the investor-owned electric utilities are incomplete at this time The plans do not establish a sufficiently detailed schedule for selecting collaborative research activities and establishing funding levels. Staff will keep the Commission informed on the progress of these activities. (McNulty, Gervasi)

Staff Analysis:

Initiative 9 – Collaborative Research on Effects of Hurricane Winds and Storm Surge

In Order No. PSC-06-0351-PAA-EI, the Commission noted that "the utilities appeared to be unaware of work being done by universities to study the effects of hurricane winds and storm surge within Florida. Each utility appeared engaged in independent efforts to gather its own data with little, if any, coordination of resources and information." The Commission concluded that "Florida would be better served by consolidating utility resources through a centrally coordinated research and development effort with universities as well as research organizations. The same data is needed by the utility to address storm hardening options that reduce storm damage, storm restoration costs, and customer outages."

Consequently, the Commission required each investor-owned electric utility to establish a plan that increases collaborative research, establishes continuing collaboration, identifies objectives, promotes cost sharing, and funds necessary work. The investor-owned electric utilities were required to solicit participation from the municipal electric utilities and rural electric cooperative electric utilities in addition to available educational and research organizations.

Individual Plans

Each investor-owned electric utility filed plans supporting a non-profit, member supported organization to coordinate all research efforts directed at better understanding storm effects on utility infrastructure and development of technologies that reduce storm restoration costs and outages to customers. On June 9, 2006, a workshop was held at the Public Utility Research Center, located in the Warrington College of Business at the University of Florida (PURC) to discuss collaborative research efforts. The June 9 PURC workshop on research in electric infrastructure hardening provided a forum where utilities expressed their specific interests and various research organizations described their abilities and resources. On July 19, 2006, the Florida electric utilities, including municipal electric utilities and cooperative electric utilities, provided a copy of a Memorandum of Understanding (MOU) that establishes the administrative requirements for creating a statewide collaborative research effort. As of August 9, 2006, Lee County Electric Cooperative is the only Florida electric utility not participating in the MOU and statewide collaborative research effort.

Pursuant to the MOU, a statewide collaborative research effort will be coordinated through PURC. Each research project will be approved by a steering committee comprised of experienced electric utility engineering staff. However, the MOU is silent regarding the frequency of steering committee meetings and whether any research project would be pursued by a time certain. On June 9, and on July 14, several potential research activities were identified for review by the steering committee, including efforts to gather better wind data associated with failed poles. As of August 8, 2006, the steering committee had not established a schedule for selecting research activities and setting funding levels. At this time, estimated costs associated with funding the organization and resultant joint research have not been projected.

<u>Conclusion</u>

Staff recommends that the Commission find each of the investor-owned electric utility plans for collaborative research to be incomplete at this time because the plans do not establish a sufficiently detailed schedule for selecting collaborative research activities and establishing project funding levels. Each investor-owned electric utility has made progress in establishing a plan that may increase collaborative research, establish continuing collaboration, identify objectives, promote cost sharing, and fund necessary work. All investor-owned electric utilities, all municipal electric utilities, and most rural electric cooperative utilities have participated in establishing a cost allocation methodology and an administrative structure. Staff will monitor the utilities continued efforts on collaborative research and will keep the Commission informed on the progress of these activities.

<u>Issue 8</u>: Is each of the investor-owned electric utility's natural disaster preparedness and recovery plan adequate?

<u>Recommendation</u>: The Commission should find that each utility natural disaster preparedness and recovery plan is consistent with the intent of Order No. PSC-06-0351-PAA-EI. The plans are "living documents" and subject to constant revision as new lessons are learned. They will be reviewed and updated annually with lessons learned from storms and forensics data that is collected and analyzed. The plans will be relied on by EOC and PSC staff during training and actual emergencies. (Swearingen, Gervasi)

<u>Staff Analysis</u>:

<u>Initiative 10 – A Natural Disaster Preparedness and Recovery Program</u>

In Order No. PSC-06-0351-PAA-EI, the Commission noted that "[a] key element in minimizing storm-caused outages is having a natural disaster preparedness and recovery plan. A formal disaster plan provides an effective means to document lessons learned, improve disaster recovery training, pre-storm staging activities, and post-storm recovery."

Consequently, the Commission required each investor-owned electric utility "to develop, if it has not already, a formal disaster preparedness and recovery plan that outlines its disaster recovery procedures. Each utility shall maintain a current copy of its utility disaster plan with the Commission on a going-forward basis."

<u>Individual Plans.</u>

Each investor-owned electric utility filed plans on June 1, 2006. On July 14, 2006, staff informally met with the utilities seeking clarifications and additional information. Staff reviewed the plans for content such as safety procedures, pre/post storm procedures, forensic data collection, and for frequency of updates to their respective plans. Staff's review of each investor-owned electric utility's plans for natural disaster preparedness and recovery is provided below and in summary form on page 13 of Attachment A (page 44 of this recommendation).

Staff notes that each of the natural disaster preparedness and recovery plans will be available to the EOC staff and PSC staff during training and actual emergencies.

FPL: FPL has a formal disaster preparedness and recovery plan. The plan is reviewed and updated by FPL on an annual basis. The plan contains pre/post emergency procedures and safety procedures for natural disasters. The plan has a procedure for collecting forensics data after a disaster.

PEF: PEF has a formal disaster preparedness and recovery plan. The plan is reviewed and updated by PEF on an annual basis. The plan contains pre/post emergency procedures and safety procedures for natural disasters. The plan has a procedure for collecting forensics data after a disaster.

TECO: TECO has a formal disaster preparedness and recovery plan. The plan is reviewed and updated by TECO on an annual basis. The plan contains pre/post emergency procedures and safety procedures for a wide scope of natural and man made disasters.

GULF: GULF has a formal disaster preparedness and recovery plan that has been filed with the Commission. The plan is reviewed and updated by GULF on an annual basis. The plan contains pre/post emergency procedures and safety procedures for natural disasters.

FPUC: FPUC has a formal disaster preparedness and recovery plan. The plan is reviewed and updated by FPUC on an annual basis. The plan contains pre/post emergency procedures and safety procedures for natural disasters. FPUC will develop a procedure for gathering forensic data per their response to Initiative 6 “Post-Storm Data Collection and Forensic Analysis” discussed in this recommendation.

Conclusion

The plans for all investor-owned electric utilities satisfy the intent of initiative 10 of Order No. PSC-06-0351-PAA-EI. The plans are “living documents” and subject to constant revision as new lessons are learned. They will be reviewed and updated annually with lessons learned from storms and forensics data that is collected and analyzed. The plans will be relied on by EOC and PSC staff during training and actual emergencies.

Issue 9: Should the Commission authorize staff to monitor and report on the investor-owned electric utility storm hardening plans?

Recommendation: Yes. The storm hardening initiatives should be monitored and reported in the following manner:

- Initiatives 1 through 7 – These initiatives should be monitored through the Commission's annual review of distribution service reliability performance because the storm hardening initiatives involve reliability performance activities.

- Initiative 8 – This initiative for increased coordination with local governments should be monitored through Commission's review of electric utilities' dialogue with local governments and selected review of utility activities in this area.

- Initiative 9 – This initiative for collaborative research on effects of hurricane winds and storm surge should be monitored by the Commission by reviewing the electric utilities' participation in studies and projects undertaken by the collaborative research efforts.

- Initiative 10 – This initiative regarding the electric utilities' natural disaster preparedness and recovery plans should be monitored by the Commission by reviewing and maintaining current copies of the plans.

Each utility should file updates of its storm hardening plans by March 1, 2007. Staff's 2007 review of investor-owned electric utility reliability performance should include an additional section addressing utility ongoing storm hardening initiatives. (McNulty, Gervasi)

Staff Analysis: In Order No. PSC-06-0351-PAA-EI, the Commission noted that the ten listed ongoing storm preparedness initiatives "are not intended to encompass all reasonable ongoing storm preparedness initiatives. We view these initiatives as the starting point of an ongoing process. Utilities and interested persons are encouraged to identify additional initiatives and to suggest alternative plans so long as the same objectives are achieved in a cost effective manner."

The plans that have been developed and discussed in prior issues are based on the prevailing utility management views and the data that is available at this time. As experience reveals new information, utility management can be expected to change and improve their implementation strategy and even identify new storm hardening initiatives. Thus, the investor-owed electric utilities need to provide periodic updates and status reports on their ongoing storm hardening initiatives in order for the Commission to effectively monitor utility programs.

Staff inquired whether the investor-owned electric utilities would be willing to provide status reports and updates on their respective storm hardening initiatives by March 1. The March 1 date was suggested because it is the filing date for the Annual Distribution Service Reliability Report pursuant to Rule 25-6.0455, Florida Administrative Code. All investor-owned electric utilities have indicated that they can provide annual updates of their storm hardening initiatives on or before March 1. However, additional dialogue is necessary to address details regarding the content and format of such updates. Assuming there is no protest to this PAA Order, staff will schedule a staff workshop in October addressing the format and summary information to be reported on or before March 1, 2007.

Staff believes that the most effective method to monitor each utility's ongoing storm hardening initiatives is in conjunction with the Commission's annual review of distribution reliability performance because the storm hardening initiatives are primarily reliability performance activities. Staff intends to include an additional section in its 2007 review of electric utility reliability performance addressing the ten listed ongoing storm preparedness initiatives and any additional storm hardening initiatives proposed by either the utilities or the Commission.

Issue 10: What information has been provided to the Commission regarding each municipal electric utility's and each rural electric cooperative utility's ongoing storm hardening plans?

Recommendation: INFORMATIONAL ISSUE ONLY – NO DECISION REQUIRED. (Redemann, Rieger, Gervasi)

Staff Analysis: In order to gauge the level of storm preparation throughout the State of Florida, staff solicited storm hardening plans consistent with the requirements of Order PSC-06-0351-PAA-EI from the electric municipal utilities and the electric cooperative utilities. There are 34 electric municipal utilities and 18 electric cooperative utilities operating in Florida. A summary of each municipal electric utility's plan filed is included in Attachment B on pages 45 through 49 of this recommendation. A summary of each rural electric cooperative utility's plan filed is included in Attachment C on pages 50 through 52. Staff is continuing its efforts to collect information on plans and plan implementation from all such utilities.

Staff's initial assessment of the electric municipal utilities' and the electric cooperative utilities' plans are summarized below by initiative in a generalized format.

<u>Initiative 1 – Three-Year Vegetation Trim Cycle</u>

The electric municipal utilities' and the electric cooperative utilities' vegetation management programs are consistent with the intent of the Order. Electric cooperative utilities using trim cycles greater than three years in rural areas assert that their vegetation trim clearance practices are more aggressive for these areas and provide better overall performance in terms of cost and customer outages than what would be achieved on a three-year cycle.

<u>Initiative 2 – Joint-Use Pole Attachment Audits</u>

At this time, most electric municipal (24) and cooperative (12) utilities perform field audits of the attachments. Most of these utilities have not provided information regarding their practices for concluding pole strength assessments associated with joint-use poles. However, these utilities design poles to the NESC safety standards and indicate they have experienced few pole failures due to overloading. On August 8, 2006, staff had a meeting with the Florida Electric Cooperatives Association, Inc. (FECA) and the Florida Municipal Electric Association, Inc. (FMEA) and the Associations indicated they will provide the information shortly.

<u>Initiative 3 – Six-Year Inspection Cycle for Transmission Structures</u>

Many electric municipal utilities (16) do not have transmission structures. Most electric cooperative utilities (10) with transmission facilities reported inspection cycles of less than six years.

Initiative 4 – Storm Hardening Activities Associated with Wooden Transmission Structures

Of the electric municipal utilities and electric cooperative utilities which have wooden transmission facilities, some utilities plan to replace wood transmission poles with non-wood poles (9) while others do not (10).

Initiative 5 – Geographic Information System (GIS)

Most larger municipal (16) and most cooperative (9) electric utilities have an electronic GIS system. Some municipal (6) and cooperative (4) electric utilities are in the process of implementing a GIS system. Many of the smaller utilities only have a paper system and do not plan to implement a GIS system.

Initiative 6 – Post-Storm Data Collection and Forensic Analysis

Most electric municipal utilities (28) and electric cooperative utilities (18) indicate that their current post-storm data collection programs meet the needs of the utility. The post-storm reviews generally focus on identifying lessons learned.

Initiative 7 – Outage Data Differentiating Between Overhead and Underground Systems

Almost all the municipal and cooperative electric utilities reported that detailed outage data is routinely collected. The electric municipal utilities and cooperative electric utilities are capable of providing overhead and underground performance data.

Initiative 8 – Increase Coordination with Local Governments

This initiative is primarily directed at increasing dialog and coordination regarding vegetation management issues and underground issues. Municipal electric utilities tend to address these local issues through their governance process that includes public meetings. The cooperative electric utilities assert their historical level of dialogue and interaction with local governments regarding vegetation management issues and undergrounding projects has been effective.

Initiative 9 – Collaborative Research

In Order No. PSC-06-0351-PAA-EI the IOUs were directed to solicit participation from municipal and cooperative electric utilities. As discussed in Issue 7, through FMEA and FECA, each electric municipal and cooperative utility is participating in such a statewide collaborative research effort. Lee County Electric Cooperative is the only Florida electric utility not participating in the collaborative research effort through FECA. Staff notes that Lee County Electric Cooperative did not sign the memorandum of understanding discussed in Issue 7.

Initiative 10 – Disaster Preparedness and Recovery Plan

As of August 8, 2006, most municipal electric utilities did not indicate they have a natural disaster preparedness and recovery plan. Most cooperative electric utilities indicated they have such a plan. On August 8, 2006, staff had a meeting with FECA and FMEA to clarify this initiative, and staff requested that the member utilities to file their natural disaster preparedness and recovery plan with the Commission. FECA and FMEA agreed to solicit such plans from their members and file the plans with the Commission by August 22, 2006.

Issue 11: Should this docket be closed?

Recommendation: No. If no timely protest is filed by a person whose substantial interests are affected by the proposed agency action portions of the order arising from this recommendation, a consummating order will be issued. If the Commission approves staff recommendation in Issue 1, the docket should remain open for PEF and GULF to file an updated vegetation management plan which includes appropriate means of evaluating the effectiveness of their programs. (Gervasi)

Staff Analysis: If no timely protest is filed by a person whose substantial interests are affected by the proposed agency action portions of the order arising from this recommendation, a consummating order will be issued. If the Commission approves staff recommendation in Issue 1, the docket should remain open for PEF and GULF to file an updated vegetation management plan which includes appropriate means of evaluating the effectiveness of their programs.

Initiative 1 – A Three-year Vegetation Management Cycle for Distribution Circuits

Order Requirement: 1. 3 Year Tree Trim Cycle for Primary Feeders (minimum). 2. 3 year cycle for laterals as well, if not cost prohibitive. 3. Utilities may propose alternatives to the requirements described below. Any alternatives must include a complete description of the alternative as well as the reason why the alternative is equivalent or better in terms of cost and avoiding future storm damages. 4. Timeline for implementation.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)*	Utility Alternative Incremental Cost Impact ($ million)*
FPL	1. Average 3 year trim cycle for feeders. 2. Average 6 year trim cycle for laterals, instead of 3 year cycle. 3. FPL's analysis of its alternative focused on the lateral trimming program. FPL believes that its analysis, demonstrates that its proposed alternative is more cost effective. (The 3 year cycle would cost average $30.3 million per year more than the 6 year cycle, while providing a potential incremental benefit of 55,000 fewer storm-related Customer Interruptions.) 4. Year One for implementation is 2007.	Year One – $88.9 Annual - $43.4	Year One – $15.5 Annual - $12.9
PEF	1. Targeted feeder trim based on prioritization (3 year weighted average trim cycle). 2. Not specified for laterals. 3. PEF provided reasons why it believes its alternative is better; however, there are no quantitative comparisons of the costs and benefits. 4. Year One for implementation is 2007.	Year One - $7 Annual – 3% minimum increase in tree trim budget	Year One – Annual – N/R
TECO	1. Feeder trim based on prioritization (All trimmed every 3 years). 2. Every circuit including open secondaries, cabled secondaries, and appropriate services is trimmed every 3 years. 3. TECO's program is a three-year trim-cycle program. 4. Year One for implementation is 2007. Assuming 2 to 3 year transition allowed to stabilize costs, conduct training, etc.	Year One – N/R Annual $3.4	Not applicable.
GULF	1. Reliability based trimming instead of cycle based. 2. Not based on fixed year cycle. 3. GULF provided reasons why it believes its alternative is better; however, there are no quantitative comparisons of the costs and benefits. 4. Year One for implementation is 2007.	Year One – Annual - $4.2	Year One – NR Annual – N/R
FPUC	1. All feeders on a three-year trim cycle. 2. Laterals may be on a three-year trim cycle or an alternative 5-year trim cycle in the NW service area. 3. The 5-year trim cycle is less expensive. 4. Year One for implementation is 2007.	Year One – N/R Annual - $.342	Year One – N/R Annual - $.228

* The incremental cost impact is based on comparisons with the existing trimming program forward. "N/R" No Response. Not Applicable.: Not Applicable. "Year One" First Year of Implementation. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 2 – Audit of Joint-Use Attachment Agreements

Order Requirement: 1. (a) Each investor-owned electric utility shall develop a plan for auditing joint-use agreements that includes pole strength assessments. (b) These audits shall include both poles owned by the electric utility and poles owned by other utilities to which the electric utility has attached its electrical equipment. 2. The location of each pole, the type and ownership of the facilities attached and the age of the pole and the attachments to it should be identified. 3. Each investor-owned utility shall verify that such attachments have been made pursuant to a current joint-use agreement. 4. Stress calculations shall be made to ensure that each joint-use pole is not overloaded or approaching overloading for instances not already addressed by Order No. PSC-06-0144-PAA-EI. 5. Provide compliance cost estimate and cost estimate for alternative action if any. 6. Provide a timeline for implementation.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all FPL owned and third-party poles during eight-year wood pole inspection cycle. 2. All required data will be collected during inspections and stored in the attachment information database. 3. Will verify attachments have been made pursuant to current joint-use agreement through a 5 year system wide pole attachment survey. 4. Stress calculations will be performed during eight-year wood pole inspection cycle. 5. See columns to the right. 6. Plan will be initiated January 2007 with completion cycles of eight-years.	Annual - $1.2 – 1.5	Not Applicable
PEF	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all PEF owned and third-party poles during eight-year wood pole inspection cycle. 2. All required data will be collected on <u>select</u> poles and stored in electronic format. 3. Will verify attachments have been made pursuant to a current joint-use agreement during eight-year wood pole inspection cycle. 4. Stress calculations will be performed on <u>select</u> poles during eight-year wood pole inspection cycle. 5. See columns to the right. 6. Plan initiated 2006 with completion cycles of eight-years.	Annual - $.080	Not Applicable
TECO	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all TECO owned poles and third-party poles per Joint-Use contract agreements on a eight-year cycle. 2. All required data will be collected during the eight-year wood pole inspection cycle and stored in GIS database. 3. Will verify attachments have been made pursuant to a current joint-use agreement during eight-year	Annual - $5	Not Applicable

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
	wood pole inspection cycle. 4. Stress calculations will be performed during eight-year wood pole inspection cycle. 5. See columns to the right. 6. Plan will be initiated January 2007 with completion cycles of eight-years.		
Gulf	1. (a) Plan proposes to do pole strength assessment on 5% random sample of Gulf owned poles that are 20 years old or more and with 3 or more attachments. (b) Plan includes auditing all Gulf owned poles and third-party poles per Joint-Use contract agreements on a 10 year cycle. 2. All required data will be collected and stored during 10 year inspection cycle. 3. Will verify attachments have been made pursuant to current joint-use agreement through a 10 year cycle. 4. Stress assessment will be performed on 5% random sample of Gulf owned poles that are 20 years old or more and with 3 or more attachments. 5. See columns to the right. 6. Plan will be initiated January 2007 with completion cycles of 10 years.	Annual - $5.375	Not Applicable
FPUC	1. (a) Plan includes performing pole strength assessment during eight-year wood pole inspection cycle. (b) Plan includes auditing all FPUC owned and third-party poles during eight-year wood pole inspection cycle. 2. All required data will be collected during inspections and stored in a database. 3. Will verify attachments have been made pursuant to a current joint-use agreement during eight-year wood pole inspection cycle. 4. Stress calculations will be performed during eight-year wood pole inspection cycle. 5. See columns to the right 6. Plan will be initiated January 2007 with completion cycles of eight-years.	Annual - $.020	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 3 – Six-year Transmission Inspection Program

Order Requirement:
1. Develop a plan to fully inspect all transmission towers and other transmission supporting equipment (such as insulators, guying, grounding, splices, cross-braces, bolts etc.). 2. Develop a plan to fully inspect all substations (including relay, capacitor, and switching stations). 3. Provide a timeline for implementation. 4. Provide compliance cost estimate and cost estimate for alternative actions if any.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). Circuits with structures containing wood cross-arm structures inspected at least every 4 years. Steel and/or concrete structures (no wood) inspection activities 10% sample every 4-year program will be augmented to achieve equivalent of a non-sample six-year inspection cycle. Inspection of insulators, wires, etc., are included in the augmented efforts. 2. Substations fully inspected quarterly. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $12.9 million, annually.	Annual - $2.3	Not Applicable
PEF	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). Structures on a 5-year inspection cycle. All other portions of the system: inspected on a three-year cycle. 2. Monthly visual substation inspection. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $0.	Annual - $ 0	Not Applicable
TECO	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). Structures on a 6 year cycle, All other portions of the system: inspected annually. 2. Substations fully inspected at least annually. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $0.	Annual - $2.97	Not Applicable
Gulf	1. Wood pole inspection activities (PSC-06-0144-PAA-EI Docket No. 060078-EI). All other portions of the system: Gulf does not hold itself to a rigid number of annual inspections. Period of 12 years will show that on average a six-year cycle is achieved. 2. Substations at least annually. Structures inside new substations built to withstand wind speed in excess of 150MPH. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $0.	Annual - $ 0	Not Applicable
FPUC	1. Will develop procedures for climbing inspections of owned 69 and 138 KV structures. Coordination/process for customer-owned 69 KV line will be developed. 2. No plan provided for substations. 3. Plan already implemented. 4. Estimated incremental costs relative to 2005 is $18,000, annually.	Annual - $.018	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 4 – Hardening of Existing Transmission Structures

Order Requirement:
1. Develop a plan to upgrade and replace existing transmission structures. Provide scope of activity, limiting factors, and criteria for selecting structure to upgrade and replace. 2. Provide a timeline for implementation. 3. Provide compliance cost estimate and cost estimate for alternative actions if any.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Company Alternative Incremental Cost Impact ($ million) *
FPL	1. Incremental upgrades during relocations and other maintenance. Upgrade un-guyed single wood pole structures. Ceramic post line insulator replacements. 2. Plan completed in 10-15 years. 3. Estimated incremental costs relative to 2005 is between $3.3 and 6 million, annually.	One Time - $0 Annual - $3.3-6	Not Applicable
PEF	1. Incremental upgrades during relocations and other maintenance. 2. Plan completed in 10 or more years. 3. Estimated incremental costs relative to 2005 are $0.	One Time - $0 Annual - $2.8	Not Applicable
TECO	1. Incremental phase out of wood transmission structures during all new construction, relocations, and other maintenance. 2. Plan is on-going with no completion date. 3. Estimated incremental costs relative to 2005 are a one time cost of $2.5 million.	One Time - $2.5 Annual - $0	Not Applicable
GULF	1. Storm guy H-Frames. Replace wood cross-arms with steel cross-arms and other activities. 2. Plan completed in 10-15 years. 3. Estimated incremental costs relative to 2005 are $0.6 million.	One Time - $0.2 Annual - $0.6	Not Applicable
FPUC	1. Replacement of 180 wood poles on 69 KV line with concrete as necessary and when economically practical. 2. Plan is on-going with no completion date. 3. Estimated total cost is $4.5 million.	One Time - $4.5 Annual - $0	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. "One Time" refers to total project costs. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 5 - A Transmission and Distribution Geographic Information System

Order Requirement: Develop a program that collects data - 1. To conduct forensic reviews; 2. To assess the performance of underground systems relative to overhead systems; 3. To determine whether appropriate maintenance has been performed; and 4. To evaluate storm hardening options. 5. Provide a timeline for implementation. The utilities have the flexibility to propose a methodology that is efficient and cost effective

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	Transmission: FPL currently has its transmission lines and structures identified by geographic area and sub-area, and GPS location. 1. FPL's proposed alternative does not include forensic reviews. 2. FPL's proposed alternative does not include underground versus overhead. 3. FPL's proposed alternative does not include determination of appropriate maintenance. 4. FPL's proposed alternative does not include evaluation of storm hardening options. 5. None. Distribution: Combine existing analytical systems to have all facilities in a GIS platform, being able to identify performance of circuits and certain devices, providing a good forensic analysis of FPL's facilities after a hurricane, identifying maintenance and providing a separate view of hardened facilities. 1. Combine existing analytical systems to have all facilities in a GIS platform, being able to identify performance of circuits and certain devices, providing a good forensic analysis of FPL's facilities after a hurricane, identifying maintenance and providing a separate view of hardened facilities. 2. FPL's proposed alternative does not include underground versus overhead. 3. FPL's proposed alternative does not include determination of appropriate maintenance. 4. FPL's proposed alternative does not include evaluation of storm hardening options. 5. Three years.	One Time - $14.55 Annual - $3.13	One Time – $6.3 Annual - $.5
PEF	Transmission: PEF plans to "populate" the system (present GIS system) with maintenance data that will be captured in PEF's Transmission Line Inspection Plan. 1. PEF's plan does not include forensic reviews. 2. PEF's plan does not include underground versus overhead performance assessment. 3. PEF's plan does not include determination of appropriate maintenance. 4. PEF's plan does not include evaluation of storm hardening options. 5. Six years.	One Time - $8.8 Annual - $.30	Not Applicable

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
	Distribution: PEF plans to create an environment that contains all the elements referenced by the order, change its current GIS system from location driven to asset driven, and thereby be able to collect data from many sources which would provide it with the ability to look for trends in performance of individual assets. 1. PEF's plan does not include forensic reviews 2. PEF's plan does not include underground versus overhead. 3. PEF's plan does not include determination of appropriate maintenance. 4. PEF's plan does not include evaluation of storm hardening options 5. 6 years		
TECO	TECO is in the process of implementing a new GIS system. The field assets that will be incorporated in the GIS will include all distribution, transmission, substation and lighting facilities for TECO's entire system. GIS, in conjunction with current OMS, will provide information on location and system performance. 1. TECO's plan includes forensic reviews on a statistical sampled basis. 2. TECO's plan includes forensic reviews with regard to types of materials and construction, and location 3. TECO's plan does not include determination of appropriate maintenance. 4. TECO's plan includes assessment of future preventive measures where possible. 5. Not Applicable.	One time - $.4 Annual – Not Applicable.	Not Applicable
Gulf	Gulf describes its GIS system, but does not mention location or performance data. 1. Gulf's plan does include forensic reviews 2. Gulf's plan does include underground versus overhead. 3. Gulf's plan does include determination of appropriate maintenance. 4. Gulf's plan does include evaluation of storm hardening options 5. 6 Years	One Time - $0 Annual - $.075	Not Applicable
FPUC	1-4. NW Fl Division currently has in place GIS system capable of collecting all of the necessary information. Additional procedures will be developed to ensure that NW Fl can use the data as ordered. 1-4. NE Florida Division does not have this capability but will upgrade its present system 5. Not Applicable.	One Time - $.19 Annual - $.0	Not Applicable

* The incremental cost impact is based on comparisons with the existing trimming program going forward. "Year One" refers to First Year of Implementation. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 6 – Post-Storm Data Collection and Forensic Analysis

Order Requirement: 1. Develop a program that collects post-storm information for performing forensic analyses. 2. Provide a timeline for implementation. The utilities have the flexibility to propose a methodology that is efficient and cost effective.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Utility Alternative Incremental Cost Impact ($ million) *
FPL	1. Distribution: Divide a sample of damaged poles among forensics teams, observations will be made on all damaged samples. Capture information such as location, attachments, and area wind speed. Transmission: For the 2004 and 2005 storm season FPL used the storm management system called Orion Storm. The system captures 100% of the damaged impacted lines. Forty-one percent of the lines imported included detailed data collected with the Orion Storm Program. Fifty-nine percent of the lines impacted did not involve damaged facilities. FPL proposes to collect data for these transmission facilities to meet the Commission initiative. 2. Distribution: Available for 2006 storm season. Transmission: Currently activated program.	One Time - $0 Annual - $.050-.10	Not Applicable
PEF	1. Distribution: PEF has implemented the Forensic Assessment process for the upcoming 2006 storm season. Transmission: PEF will hire a contractor. The contractor will collect detailed post storm data necessary to perform storm damage and forensic analysis. 2. Available for 2006 storm season.	One Time - $0 Annual $.9/ per storm	Not Applicable
TECO	1. Distribution & Transmission: TECO plans to implement a formal process to randomly sample system damage following a major weather event in a statistically significant manner. This information will be used to perform forensic analysis in an attempt to categorize the root cause of equipment failure. 2. 1 Year.	One time - $.2 Annual - $.1 per storm	Not Applicable
Gulf	1. Distribution & Transmission: Concurrent with storm restoration, crews of contractors will survey a sample of the lines affected by the storm. Inland and coastal areas will be surveyed. 2. No Response.	One time - $0 Annual - $.125/per storm	Not Applicable
FPUC	1. Distribution & Transmission: FPUC will develop a procedure to better track specific hurricane outages, identify outage causes, and count the numbers of customers affected. 2. No Response.	One Time - $.017 Annual - $.010/per storm	Not Applicable

* The incremental cost impact is based on comparisons with the existing trimming program going forward. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 7 – Collection of Detailed Outage Data Differentiating between the Reliability Performance of Overhead and Underground Systems

Order Requirement:
1. Collect specific storm performance data that differentiates between overhead and underground systems, to determine the percentage of storm caused outages that occur on overhead and underground systems, and to assess the performance and failure mode of competing technologies such as direct bury cable versus cable-in-conduit, and concrete poles versus wooden poles, and location factors such as front-lot versus back-lot, and pad-mounted versus vault.
2. Provide a timeline for implementation.

The utilities have the flexibility to propose a methodology that is efficient and cost effective.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)	Company Alternative Incremental Cost Impact ($ million)
FPL	1. FPL proposes analyzing storm specific *samples* of locations (feeders, laterals, etc.) based on identifying GIS information established in compliance with initiatives #5 and #6. FPL does not plan to hold up storm restoration in order to ensure complete enumerations or adequate sample sizes for making valid inferences. FPL stresses that this would be particularly true of smaller storms, from which recovery is typically more rapid. Feeders tend to be hybrids with regard to underground and overhead. Forensics teams will be augmented to assess the damages to the various locations. Laterals tend to be either one or the other, so assessments with regard to overhead or underground will be available by knowing a lateral's location. 2. No Response.	One Time - $0 Annual - $.05-.1/per storm	Not Applicable
PEF	1. The implementation of the new GIS system would enhance PEF's ability to collect data relevant to assess performance, and PEF would use this data to analyze and compare the performance of its overhead and underground systems. 2. No Response.	Response One Time – No Response Annual – No Response	Not Applicable
TECO	1 TECO currently collects outage data. TECO will implement to fully comply with the Commission initiative for the collection of detailed outage data differentiating between the reliability performance of overhead and underground systems. 2. 1 Year.	One Time - $.5 Annual - $0	Not Applicable
GULF	1 Gulf will record numbers of overhead and underground customers and calculate SAIDI and SAIFI for each outage. As outages occur, Gulf will also collect data by type of buried cable and type of pole. 2. ¾ Year	One time - $0 Annual – minimal	Not Applicable
FPUC	1. FPUC is currently able to carry out this initiative. 2. Available now.	One Time - $0 Annual - $0	Not Applicable

* The incremental cost impact is based on comparisons with the existing trimming program going forward. "One Time" refers to first year set-up costs.. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 8 – Increased Coordination with Local Governments

Order Requirement: 1. Each utility should actively work with local communities year-round to identify and address issues of common concern, including the period following a severe storm like a hurricane and also ongoing, multihazard infrastructure issues such as flood zones, areas prone to wind damage, development trends in land use and coastal development, joint use of public right-of-way, undergrounding facilities, tree trimming, and long range planning and coordination. 2. Provide a timeline for implementation. 3. Incremental plan costs.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)*	Company Alternative Incremental Cost Impact ($ million)*
FPL	1, The FPL Plan focuses initially on storm preparation, coordination and communication with External Affairs representatives working with county planners and post-storm communications FPL plans to implement: ▪ On-going planning programs with External Affairs representatives working with local government officials. ▪ A special e-mail program oriented to government officials and special audiences. ▪ A new government update website. ▪ A program called "community trouble reporting. ▪ Community outreach teams to brief local government and customer groups. 2. No specific timeline for implementation of the entire plan is provided except for a general reference to May 2006 marking the start date for some programs. 3. Incremental costs are only provided for the training ($25k) and Wire Down/Priority 1 ($12k) and Communications ($100k). No methodology for cost estimates are provided.	One Time - $.1 Annual - $.012	Not Applicable
PEF	1. The PEF Plan provides an internal team composed of community relations, regulatory affairs and account management to coordinate Company planning with governmental activities. The activities include assigning specific staff to work with individual communities to identify opportunities throughout the year for improved preparedness, developing enhanced organization and planning, providing support and information for storm preparation and restoration, conducting an annual storm drill, conducting on-going activities such as planning workshops and town-hall type meetings at both state and county levels. 2. No specific timeline for implementation of the entire plan is provided except for a general reference 2006 marking the start date for the programs. 3. Incremental costs for the Plan are not provided. No methodology for estimating cost are provided.	One Time – No Response Annual – No Response	Not Applicable
TECO	1. TECO's Plan calls for building on past community involvement by including local government, fire, police and water officials in storm preparation workshops, including local government in local Emergency Operations Centers, increased vegetation management including government and consumer education, undergrounding planning and education, and damage reporting prior, during and after storms. 2. No specific timeline for implementation of the entire plan is provided except for a general reference to some of the programs having already started in 2006. 3. Only a general incremental cost for the overall plan is provided ($75,000). No methodology for estimating	One time - $0 Annual - $.075	Not Applicable

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)*	Company Alternative Incremental Cost Impact ($ million)*
	costs is provided.		
GULF	1. The Gulf Plan builds on existing programs of year round activities like workshops with community leaders, pre-hurricane planning with participation in all local government hurricane preparedness drills, exercises, information fairs by line clearing specialists and post hurricane programs to include timely news announcements to government officials, single point-of-contact personnel and a standing Emergency Operations Center staffed 24 hours a day. 2. Gulf's Programs are currently ongoing. 3. No incremental costs are provided since the programs are considered already ongoing. No methodology for estimating costs is provided.	One Time - $0 Annual - $0	Not Applicable
FPUC	1. The FPUC Plan calls for interacting with local governments in each of the separate divisions of the Company, having personnel at local Emergency Operations Centers after each storm, and engaging in discussions with local government on both undergrounding and tree trimming issues as they arise. 2. No specific timeline for implementation of the entire plan since the program is simply a continuation of the activities that were carried out in 2005. 3 No incremental cost were listed with the exception of an estimated cost of $7,500 per event that FPUC staff attended. No methodology for estimating costs were provided.	One Time - $0 Annual - $0	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. "One Time" refers first year set-up costs. "Annual" refers to annual incremental cost impact incurred each year beginning with the first year of implementation.

Initiative 9 – Collaborative Research

Order Requirement:
1. IOUs must establish a plan that increases collaborative research
2. IOUs must identify collaborative research objective
3. IOUs must develop collaborative plans that promote cost sharing
4. IOUs must solicit munies, coops, educational and research institutions.
5. IOUs must establish timeline for implementation.
6. IOUs must identify their incremental costs necessary to fund the organization and perform the research.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million) *	Company Alternative Incremental Cost Impact ($ million) *
FPL	1. FPL Indicates support for the creation of a non-profit, member supported organization that coordinates all research efforts in the area of storm effects on utility infrastructures. 2. FPL did not enumerate research objectives. FPL did not identify any specific research projects. 3. FPL proposed a non-profit, member supported organization for researching storm effects on utility infrastructure with PURC as the host. FPL suggested a single coordinator of research efforts from each member utility, and proposes an organization which would pursue two types of research; membership funded research voted on by the majority of members, and individually funded research (not voted or funded by other utilities). 4. FPL states the IOUs will solicit participation from the municipal and rural electric cooperative utilities in addition to available educational and research organizations. 5. No timeline for implementation was provided. 6. For cost requirements, see column to the right.	One Time - $0 Annual - $05-$.10	Not Applicable
PEF	Same as FPL.	One Time - TBD Annual – TBD	Not Applicable
TECO	Same as FPL.	One Time - TBD Annual – TBD	Not Applicable
GULF	Same as FPL. In addition, Gulf plans on continuing to participate as appropriate within Southern Company and its own R&D efforts. Gulf may also engage in R&D through a local university in Northwest Florida.	One Time - TBD Annual – TBD	Not Applicable
FPUC	Same as FPL. Commitment to fund research regarding hurricane winds and storm surge. Requires reasonable allocation of costs based on customers, net load, etc.	One Time - $0 Annual - $.025	Not Applicable

* Incremental cost impact is calculated using 2005 as a base year. “One Time” refers first year set-up costs. “Annual” refers to annual incremental cost impact incurred each year beginning with the first year of implementation. “TBD”“ is abbreviation for “To Be Determined.”

Initiative 10 – A Natural Disaster Preparedness and Recovery Program

Develop a formal Natural Disaster Preparedness and Recovery Plan that outlines the utility's disaster recovery procedures if the utility does not already have one.

Utility	Investor-Owned Electric Utility Plan to Comply with Order	PSC Incremental Cost Impact ($ million)	Company Alternative Incremental Cost Impact ($ million)
FPL	Disaster Preparedness/Recovery Plan already developed and filed .	Not Applicable	Not Applicable
PEF	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
TECO	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
GULF	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable
FPUC	Disaster Preparedness/Recovery Plan already developed and filed.	Not Applicable	Not Applicable

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative

		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord . with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
JEA	387,685	3-Yr All	Audit in 2002 No stress calc	4-Yr	No new wood, No plan existing	Migrating to electronic system +1-yr	Done	Collected - Not reported	Yes	See MOU	No Response
Orlando Utilities Commission	194,081	4-Yr Feeders, N/A Lat	Audit Plan No stress calc	6-Yr	Phase out wood trans poles	Electronic system for 100% assets	In future plans	Collected - Not reported	Yes	See MOU	After 2004 entire plan rewrote
Lakeland Electric	120,000	5-Yr All	Audit in 2005. Stress calc as needed	1-Yr	Phase out wood trans poles	Electronic system of 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Tallahassee, City of	109,000	1.5 -Yr All	Audit Fall 2006. Plan to stress calc	5-Yr; 8-yr for wood poles	Phase out wood trans poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Gainesville Regional Utilities	87,700	3-Yr All	Audit only. No stress calc	1-Yr	No plans to replace wood poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Kissimmee Utility Authority	62,000	4-Yr All	Audit not discussed. Plan to stress calc	5-Yr; 8-yr for wood poles	Phase out wood trans poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Ocala Electric Utility	48,300	4-Yr All	5-Yr Audit. Stress calc	6-Yr	No plan to replace wood poles	Electronic from Substation to Service	Done	Collected - Plan to report	Yes	See MOU	No Response

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative

		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord . with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Vero Beach, City of	32,500	2-3 Yr All	5-Yr Audit cycle. Stress calc for new poles	1-Yr (River crossing @10 yrs)	No plan to replace wood poles	Electronic system for 100% assets	May install system	Collected - Not reported	Yes	See MOU	No Response
Beaches Energy Services	32,000	3-Yr All	Plan to Audit. No stress calc	1-Yr Visual 69 Kv, Plan aerial 138 Kv	None	Migrating to electronic + ? yr	Done	Collected - Not reported	Yes	See MOU	No Response
Lake Worth Utilities Dept.	27,400	2-Yr All	Plan to Audit 2006. No stress calc	1-Yr	None	Electronic system for 100% assets	Partial implemen t	Plan to collect - Not reported	Yes	See MOU	No Response
Keys Energy Services	27,000	2-Yr All	No Audit. No stress calc	2 Yr Aerial, 3-4 Yr Foundations	None	Electronic system for 100% assets	Done	Upgrade in progress	Yes	See MOU	No Response
Fort Pierce Utilities Authority	26,500	3-Yr All	Audit 2006. No stress calc	1-Yr Trans, 3-Yr Line Hardware	Class 2 wood poles, Reviewing	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
New Smyrna Beach	24,000	Ongoing All	Audit includes stress calc	4-5 Yr	Phase out wood trans poles	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Leesburg, City of	21,500	4-Yr All	5-Yr Audit cycle. Plan stress calc	Not Applicable	None	Electronic system for 100% assets	Plan more detail	Collected - Reported	Yes	See MOU	No Response

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative

		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord . with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Homestead, City of	19,500	Less than 3 Yr for all	5-Yr Audit cycle with stress calc	6-Yr, 2-Yr Thermo	None	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Winter Park, City of	14,000	2-3-Yrs	Plan to Audit. No stress calc	Not Applicable	Not Applicable	Migrating to electronic system + 1 yr	Done	Collected - Plan to report	Yes	See MOU	No Response
Bartow, City of	10,500	4-Yr All	No Audit cycle. Stress calc for big cables	Not Applicable	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Mount Dora, City of	5,800	1-Yr All	Audits regularly. No stress calc	Not Applicable	Not Applicable	Paper system for 100% of assets Plan for GIS	Done	Collected - Not reported	No mentio n of EOC	See MOU	No Response
Quincy, City of	4,580	1-Yr All	No Audit cycle. No stress calc	6-Yr, 2-Yr Thermo	None	Paper system for 100% assets	Done	Not currently	Yes	See MOU	No Response
Clewiston Utilities, City of	4,135	1-Yr Feed Removal by Request Dist	5-Yr Audit cycle. No stress calc	2-Yr	None	Migrating to electronic system +7-yrs	Partial implemen t	Collected - Not reported	Yes	See MOU	No Response
Alachua, City of	3,600	3-Yr All	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Migrating to electronic system +2 yr	Done	Collected - Not reported	Yes	See MOU	No Response

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative

		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord . with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Green Cove Springs, City of	3,600	1-Yr All	No Audit cycle. No stress calc	Not Applicable	None	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Starke, City of	3,000	1-Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Wauchula, City of	2,773	3-Yr	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Migrating to electronic system + ? yr	Done	Collected - Not reported	Yes	See MOU	No Response
Fort Meade, City of	2,647	3-4 Yr All	2-3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets Plan GIS	Done	Collected - Not reported	Yes	See MOU	No Response
Williston, City of	1,390	1-Yr All	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Blountstown, City of	1,333	3-Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Havana, Town of	1,310	3-Yr All	2-3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets Plan GIS	Done	Collected - Not reported	Yes	See MOU	No Response

Summary of Municipal Electric Utility Responses and Plans for Each Ongoing Storm Hardening Initiative

		1	2	3	4	5	6	7	8	9	I0
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord . with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Newberry, City of	1,300	1-1.5 Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets Plan GIS	Done	Collected - Not reported	Yes	See MOU	No Response
Chattahoochee, City of	1,298	1-Yr All	3-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Reedy Creek Improvement District	1,213	Not applicable. 99% UG.	No overhead attachments.	Monthly	None	Electronic system for 100% assets	Done	99% UG	Yes	See MOU	No Response
Bushnell, City of	1,132	1-Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
Moore Haven, City of	842	1-1.5 Yr All	1-Yr Audit cycle. No stress calc	Not Applicable	Not Applicable	Paper system for 100% assets	Done	Collected - Not reported	Yes	See MOU	No Response
St. Cloud, City of		See Orlando Utilities Commission.									
Done = Post-storm damage review process in place in the nature of lessons learned.											

Summary of Rural Electric Cooperative Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Withlacoochee River Electric Coop., Inc.	177,972	4-5 Yr cycle all	5-Yr Audit cycle. No stress calc	1-Yr cycle	Replace wood poles 3-5 Yrs	Electronic system for 100% assets	Done	Collected - and reported.	Yes	See MOU	Yes
Lee County Electric Coop., Inc.	168,749	3-6 Yr cycle all	Audit 2001. No stress calc	1-2 Yr cycle	No new wood poles. Phase-out wood poles	Electronic system for 100% assets	Done	No collection – Not Reported	Yes	No	Yes
Clay Electric Coop., Inc.	164,000	3-5-Yr cycles based on city/rural criteria Avg. 3.9 all	Audit 2008 Some stress calc	6-Yr cycle 4X-Yr Thermo	No plan to replace wood poles	Non-GPS electronic system	Done	Collected – Plan to report	Yes	See MOU	Yes
Sumter Electric Coop., Inc.	152,000	3-Yr cycle all Not Adequate New Plan	Audit for un-notified attachments. Stress calc	5-Yr cycle 1.5-Yr Thermo	No new wood poles. Phase-out some wooden structures	Electronic system for 100% assets	Done	Collected-Not Reported – No value.	Yes	See MOU	Yes
Talquin Electric Coop., Inc.	52,838	Target 3-Yr cycle all achieved 3.7- Yr	5-Yr Audit cycle. No stress calc	8-Yr cycle	Phase out wood poles	Considering whether need exists	Done	Not Collected - Not reported.	Yes	See MOU	Yes
Choctawhatchee Electric Coop., Inc.	36,987	5-Yr cycle all	3-Yr Audit cycle. Stress calc	Not Applicable	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
Peace River Electric Coop., Inc.	34,500	3-Yr cycle all Not Adequate	No Audit. No stress calc	6-Yr cycle	No new wood poles. Phase out wood poles	Electronic system for 100% assets	Done	Plan to Collect - Plan to report	Yes	See MOU	Yes
Central Florida Electric Coop.,	31,702	4-Yr cycle all	5-Yr Audit cycle. No	Targets 1-Yr Cycle	No plan to replace wood	Paper system	Done	Few UG facilities.	Yes	See MOU	Yes

Summary of Rural Electric Cooperative Utility Responses and Plans for Each Ongoing Storm Hardening Initiative

		1	2	3	4	5	6	7	8	9	10
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Inc.			stress calc		poles						
Florida Keys Electric Coop. Ass., Inc.	31,000	3-Yr cycle all	3-Yr Audit cycle. No stress calc	1-Yr cycle	None	Migrating to electronic system	Done	Collected - Not reported.	Yes	See MOU	No Response
West Florida Electric Coop. Ass., Inc.	27,000	4.5-Yr cycle all	5-Yr Audit cycle. No stress calc	Not Applicable	None	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
Suwannee Valley Electric Coop., Inc.	24,000	4 Yr cycle all	Audit 2007. No stress calc	8-Yr, Own 5	Not Applicable	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	Yes
Gulf Coast Electric Coop., Inc.	20,098	5-Yr cycle all	8-Yr Audit cycle. No stress calc	Not Applicable	None at this time.	Electronic system for 100% assets	Done	Collected - Not reported.	Yes	See MOU	No Response
Tri-County Electric Coop., Inc.	17,200	5-Yr cycle all	Audits are current. No stress calc	1-Yr cycle	No plan to replace wood poles.	Some Electric Some Paper	Done	Collected - Not reported 95% OH.	Yes	See MOU	Yes
Glades Electric Coop., Inc.	16,063	3-Yr cycle all	2-Yr Audit cycle. No stress calc	1-Yr cycle	No plan to replace wood poles. Harding	Migrating to electronic system 2007	Done	Collected - Not reported.	Yes	See MOU	Yes
Escambia River Electric Coop., Inc.	10,100	5-Yr cycle all	Plan Audit. No stress calc	Not Applicable	None at this time	Migrating to electronic system	Done	Collected - Reported	Yes	See MOU	Yes
Okefenoke Rural Electric Membership Corporation	8,883	3-Yr cycle all	Start 5-Yr Audit cycle. Some stress calc	Not Applicable	None at this time	Electronic system for 100% assets	Done	Collected – Not Reported.	Yes	See MOU	Yes
Alabama Electric Coop.,	No Retail Customers	Not Applicable	No Audit No stress calc	4-Yr cycle	No plan to replace wood	Migrating to electronic	Done	No UG facilities.	Yes	See MOU	Yes

Summary of Rural Electric Cooperative Utility Responses and Plans for Each Ongoing Storm Hardening Initiative											
		1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
Utility	**Approx. Customer Count**	**Vegetation Clearing - 3-Yr Cycle for Feeders 3-Yr Cycle for Laterals**	**Joint-Use Pole Audit & Stress Calc.**	**6-Yr Transmission Inspection Cycle**	**Hardening of Existing Transmission**	**A Geographic Information System**	**Post-Storm Data and Forensic Analysis**	**OH/UG Reliab. Data**	**Coord. with Local Gov.**	**Research Wind & Surge**	**Disaster Plan**
Inc.*					poles	system					
Seminole Electric Coop., Inc.*	No Retail Customers	Not Applicable	No Audit No stress calc	Unknown	No Plan – Not Cost Effective	No GIS system planned	Done. Limited history.	No UG facilities.	Yes	See MOU	Yes
1* Alabama Electric is a generating and transmission cooperative providing wholesale service in Florida to 4 rural electric cooperative utilities. 2* Seminole Electric is a generating and transmission cooperative providing wholesale service in Florida to rural electric cooperative utilities.											
Done = Post-storm damage review process in place in the nature of lessons learned.											