Review of Florida's Investor-Owned Electric Utilities' Service Reliability in 2006

Florida Public Service Commission

Division of Economic Regulation
Division of Regulatory Compliance and Consumer Assistance
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Terms and Acronyms

CAIDI	Customer Average Interruption Duration Index
CI	Customer Interruption
CME	Customer Momentary Events
CMI	Customer Minutes of Interruption
EOC	Florida's Emergency Operation Center
F.A.C.	Florida Administrative Code
FPL	Florida Power & Light Company
FPUC	Florida Public Utilities Company
GIS	Geographic information system
GULF	Gulf Power Company
IOU	The five investor-owned electric utilities: FPL, PEF, TECO, GPC, and FPUC
MAIFIe	Momentary Average Interruption Event Frequency Index
PEF	Progress Energy Florida, Inc.
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
TECO	Tampa Electric Company

Reliability Metrics Used in this Review

1. *Customer Minutes of Interruption* (CMI) is the number of minutes that a customer's electric service was interrupted for one minute or longer.

2. *Customer Interruption* (CI) is the number of customer service interruptions which lasted one minute or longer.

3. *Customer Momentary Events* (CME) is the number of customer momentary service interruptions which lasted less than one minute measured at the primary circuit breaker in the substation.

4. *Customer Average Interruption Duration Index* (CAIDI) is an indicator of average interruption duration, or the time to restore service to interrupted customers. CAIDI is calculated by dividing the total system customer minutes of interruption by the number of interrupted customers. (CAIDI = CMI ÷ CI, also CAIDI = SAIDI ÷ SAIFI)

5. *System Average Interruption Frequency Index* (SAIFI) is an indicator of average service interruption frequency experienced by customers on a system. It is calculated by dividing the number of service interruptions by the number of customers served. (SAIFI = CI ÷ C, also SAIFI = SAIDI ÷ CAIDI)

6. *System Average Interruption Duration Index* (SAIDI) is a composite indicator of outage frequency and duration and is calculated by dividing the customer minutes of interruptions by the number of customers served on a system. (SAIDI = CMI ÷ C, also SAIDI = SAIFI x CAIDI)

7. *Momentary Average Interruption Event Frequency Index* (MAIFIe) is an indicator of average frequency of momentary interruptions or the number of times there is a loss of service of less than one minute. MAIFIe is calculated by dividing the number of momentary interruption events recorded on primary circuits by the number of customers served. (MAIFIe = CME ÷ C)

8. *Customers Experiencing More Than Five Interruptions* (CEMI5) measures the percent of customers that have experienced more than five service interruptions. (CEMI5 is a customer count often shown as a percentage of total customers.)

9. *Number of Outage Events* (N) measures the primary causes of outage events and identifies feeders with the most outage events.

10. *Average Duration of Outage Events* (L-Bar) is the simple average of customer service outage events lasting a minute or longer.

Executive Summary

The purpose of this review is to assess trends in the reliability of service provided by Florida's investor owned electric utilities. Throughout this review, emphasis is placed on observations that suggest declines in service reliability and thus reveal areas where additional scrutiny or remedial action may be required by the company.

Assessing Service Reliability

The assessment of an investor-owned electric utility's (IOU) service reliability is made primarily through a detailed review of established service reliability metrics pursuant to Rule 25-6.0455, Florida Administrative Code (F.A.C.).[1] Reliability metrics are intended to reflect changes over time in system average performance, regional performance, and sub-regional performance. For a given system, increases in the value of a given reliability metric denote declining reliability in the service being provided. Comparison of the year-to-year levels of the reliability metrics may reveal changes in performance which indicate the need for additional work in one or more areas. A utility's level of storm hardening activity is reviewed to gain insight into factors contributing to the observed trends in the performance metrics.[2, 3] Additional insight into potential changes in service reliability can be found through inter-utility comparisons of reliability data and reliability related complaints addressed by the Commission. Finally, audits are performed where additional scrutiny is needed based on the observed patterns and to ensure the reported data are reliable.

Prior to 2006, Rule 25-6.0455, F.A.C., required the IOUs to file distribution reliability metrics to track adjusted performance that excluded events such as planned outages for maintenance, generation disturbances, transmission disturbances, wildfires, and extreme acts of nature such as tornadoes and hurricanes. The "adjusted" data provides an indication of the distribution system performance on a normal day-to-day basis but does not reveal the impact of excluded events on reliability performance.

With the active hurricane years of 2004 and 2005, the importance of collecting reliability data that would reflect the total or "actual" reliability experience from the customers' perspective became apparent. Complete unadjusted service reliability data was needed to assess service performance during hurricanes. In June 2006, Rule 25-6.0455, F.A.C., was revised to require each IOU to provide both "actual" and "adjusted" performance data for the prior year. The scope of the IOUs' Annual Distribution Service Reliability Report was expanded to include

[1]The Commission does not have rules requiring municipal electric utilities and rural electric cooperative utilities to file service reliability metrics.
[2]Rule 25-6.0342, F.A.C., effective February 5, 2007, requires investor-owned electric utilities to file comprehensive storm hardening plans at least every three years.
[3]Rule 25-6.0343, F.A.C., effective December 12, 2006, requires municipal electric utilities and rural electric cooperative utilities to report annually, by March 1, the extent to which their construction standards, policies, practices, and procedures are designed to storm-harden their transmission and distribution facilities.

status reports on the various storm hardening initiatives required by the Commission.[4] Staff held a workshop with the IOUs and interested parties in October 2006 to discuss the expected content of the more comprehensive reports which would be due on March 1, 2007.

The reports filed on March 1, 2007, included: (1) actual 2006 service reliability data; (2) adjusted distribution service reliability data; (3) actual and adjusted performance assessments in five areas: system-wide, operating region, feeder, cause of outage events; and (4) complaints. The reports also summarized the storm hardening activities for the IOU.

Conclusions

The comprehensive March 1 reports of Florida Power & Light Company (FPL), Progress Energy Florida, Inc.,(PEF), Tampa Electric Company (TECO), and Gulf Power Company (GULF) were sufficient to perform this review. Florida Public Utilities Company's (FPUC) storm hardening activities are not addressed by this review. Instead, FPUC's storm hardening activities will be addressed in Docket No. 070304-EI, FPUC's 2007 request for a general rate increase. FPUC's comprehensive March 1 report was sufficient to assess normal day-to-day service reliability.

Storm hardening activities are new programs for each IOU. As a result, the data collected for 2006 may not be representative of future levels of storm hardening activities. Based on the filed data, Staff has not observed any trends in service reliability requiring an increased level of investigation such as a focused audit, investigation or other formal proceeding before the Commission. Staff will continue to monitor and engage each company on service reliability matters. The following company specific summaries provide highlights of the observed patterns.

Service Reliability of Florida Power & Light Company

FPL reported a customer-initiated type of outage event for exclusion that is not specifically provided by Rule 25-6.0455, F.A.C. In 2006, customer-initiated outage events comprised approximately 0.8 percent of all customer interruptions. These types of outage events are typically requested by the customer or site developer for construction or site maintenance purposes. Customer outage events can also be triggered by electrical problems on the customers' premises. Staff believes a "By Customer" outage event can be excluded because the reliability data from such events is not indicative of a utility allowing its system to become less reliable.

The 2006 omitted data for outage events allowed by the rule and customer-initiated outage events are 30 percent of all customer interruptions. FPL's report documented how the

[4]Wooden Pole Inspection Orders: Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI; and Order Nos. PSC-06-0778-PAA-EU, issued September 18, 2006, PSC-07-0078-PAA-EU, issued January 29, 2007, in Docket No. 060531-EU.
Storm Hardening Initiative Orders: PSC-06-0351-PAA-EI, issues April 25, 2006; PSC-06-0781-PAA- EI, issued September 19, 2006; PSC-06-0947-PAA-EI, issued November 13, 2006; and PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 060198-EI.

omitted outage data impacted some but not all reliability metrics. FPL has committed to improving subsequent Annual Distribution Reliability Reports.

On an adjusted basis, the 2006 average frequency of service interruptions (SAIFI) increased (11 percent) and the average duration of service interruptions (SAIDI) increased (7 percent) relative to 2005 levels. FPL continues to show increases in the time to recover from an outage event (L-Bar) and, on average, exceeds the recovery time of other IOUs. During 2006, there was a 43 percent increase in the group of customers experiencing more than 5 interruptions. FPL attributes the recent declines in service reliability to long-term effects of the 2004 and 2005 storm damages.

FPL's average number of reliability related complaints per customer served increased, a pattern that began in 2001. However, during 2006, on a per customer basis, FPL received the equivalent of one reliability complaint for every 2.8 filed against PEF. Compared to GULF, FPL received the equivalent of seven reliability complaints for every one filed against GULF.

Service Reliability of Progress Energy Florida, Inc.

PEF's 2006 omitted data for outage events allowed by the rule are 20 percent of all customer interruptions. PEF excluded an additional 17 percent of customer interruptions without explanation. Thus, PEF's omitted data totals 37 percent of all 2006 customer interruptions. Additionally, PEF's report documented how the omitted outage data impacted some but not all reliability metrics. PEF has committed to improving subsequent Annual Distribution Reliability Reports.

Much of PEF's adjusted data supports a conclusion that average service reliability in recent years is stable and may be improving. This trend suggests little potential exits for lingering problems stemming from the 2004 and 2005 storm damages in PEF's service area to cause future declines in service reliability. Nevertheless, PEF's data includes indication of factors detrimental to continued improvement in service reliability. The L-Bar (average length of outage events) is increasing, a sign that PEF is spending more time recovering from outage events. Additionally, PEF is reporting increased multiple occurrences on the Three Percent Feeder Report which can suggest localized problems that have not been fully addressed.

On a per customer basis, more of PEF's customers tend to lodge reliability related complaints than customers served by other IOUs. Further review is required to address the tension between the service reliability improvement claimed by PEF and the increasing volume of reliability related complaints.

Service Reliability of Tampa Electric Company

TECO's 2006 omitted data for outage events allowed by the rule are 38 percent of all customer interruptions. TECO's report documented how the omitted outage data impacted some but not all reliability metrics. TECO has committed to improving subsequent Annual Distribution Reliability Reports.

A widening difference is emerging between the levels of service reliability TECO provides in each of its seven regions. The average length of outage events (L-Bar) has increased relative to 2002 and 2003 levels, resulting in TECO spending more time recovering from outage events. Also, the length of TECO's primary feeder outages has increased.

For the second consecutive year, TECO's average number of reliability related complaints per customer served declined, but not dramatically. During 2006, on a per customer basis, TECO received the equivalent of two reliability complaints for every 2.99 lodged against PEF, 13.3 reliability for every one filed against GULF, and 1.9 for every one filed against FPL.

Service Reliability of Gulf Power Company

GULF's 2006 omitted data for outage events allowed by the rule are 32 percent of all customer interruptions. GULF's report documented how the omitted outage data impacted some but not all reliability metrics. GULF has committed to improving subsequent Annual Distribution Reliability Reports.

For 2006, all eight reliability metrics showed increased values, denoting decreasing service reliability. The more significant declines are shown by a 58 percent increase in system average service restoration time (CAIDI), a 68 percent increase in customers experiencing more than five interruptions (CEMI5), and a 102 percent increase in system average customer minutes of interruptions (SAIDI). Some of these increases may be attributed to the possible lingering storm damages of 2004 and 2005 or weather events during 2006 that GULF did not exclude.

The number of reliability related complaints filed against GULF in 2006 is unchanged from 2005 levels. During 2006, on a per customer basis, GULF received the equivalent of one reliability complaint for every 19.8 filed against PEF, 13.3 filed against TECO, and 7 filed against FPL.

Service Reliability of Florida Pubic Utilities Company

The adequacy of FPUC's service reliability is expected to be addressed in Docket No. 070304-EI, FPUC's 2007 request for a general rate increase. This review does not opine on what actions, if any, should be pursued in FPUC's rate case based on the observations noted below.

FPUC, like FPL, reported a customer-initiated type of outage event for exclusion that is not explicitly specifically provided by Rule 25-6.0455, F.A.C. In 2006, customer-initiated outage events comprised approximately 0.1 percent of all customer interruptions. These types of outage events are typically requested by the customer or site developer for construction or site maintenance purposes. Customer outage events can also be triggered by electrical problems on the customers' premises. Staff believes a "By Customer" outage event can be excluded because the reliability data from such events is not indicative of a utility allowing its system to become less reliable. The 2006 omitted outage data allowed by the rule and customer-initiated outage events totals 21 percent of all customer interruptions.

FPUC's adjusted data shows increased 2006 values for many of the metrics. The largest increases were (1) a 35 percent increase in the average number outage events per customer, (2) a 69 percent increase in the average service restoration time (CAIDI), and (3) a 126 percent increase in the system average service interruption duration (SAIDI). The total number of outage events per customer continued to increase during 2006. Outage events caused by vegetation increased 90 percent, by animals increased by 68 percent, and by unknown causes increased by 79 percent from 2005 to 2006.

Reliability related complaints against FPUC are infrequent, in part, because FPUC has less than 50,000 customers. However, based on the average number of such complaints per customer for the period 1999 through 2006, FPUC received the equivalent of one for every 0.6 lodged against GULF, 4.8 lodged against TECO, 5.6 lodged against PEF, and 2.1 lodged against FPL.

Introduction

The Florida Public Service Commission (Commission) has the jurisdiction to monitor the quality and reliability of electric service provided by Florida's investor-owned electric utilities (IOUs) for maintenance, operational and emergency purposes.[5]

Monitoring service reliability is achieved through a review of service reliability metrics provided by the IOUs pursuant to Rule 25-6.0455, Florida Administrative Code (F.A.C.).[6] Service reliability metrics are intended to reflect changes over time in system average performance, regional performance, and sub-regional performance. For a given system, increases in the value of a given reliability metric denote declining reliability in the service being provided. Comparison of the year-to-year levels of the reliability metrics may reveal changes in performance which indicate the need for additional work in one or more areas.

A utility's level of storm hardening activity contributes to both day-to-day service reliability and emergency response. Thus, a review of a utility's storm hardening activities can provide insight into factors contributing to the observed trends in the performance metrics. Additional insight into potential changes in service reliability can be found through inter-utility comparisons of reliability data and reliability related complaints addressed by the Commission. Finally, audits are performed where additional scrutiny is needed based on the observed patterns and to ensure the reported data are reliable.

Throughout this review, emphasis is placed on observations that suggest declines in service reliability and areas where additional scrutiny or remedial action may be required by the company.

Background

Prior to 2006, Rule 25-6.0455, F.A.C., required the IOUs to file distribution reliability metrics to track adjusted performance that excluded events such as planned outages for maintenance, generation disturbances, transmission disturbances, wildfires, and extreme acts of nature such as tornadoes and hurricanes. The "adjusted" data provides an indication of the distribution system performance on a normal day-to-day basis but does not reveal the impact of excluded events on reliability performance.

With the active hurricane years of 2004 and 2005, the importance of collecting reliability data that would reflect the total or "actual" reliability experience from the customers' perspective became apparent. Complete unadjusted service reliability data was needed to assess service performance during hurricanes. In June 2006, Rule 25-6.0455, F.A.C., was revised to require each IOU to provide both "actual" and "adjusted" performance data for the prior year. The

[5] Sections 366.04(2)c and 366.05, Florida Statutes
[6] The Commission does not have rules requiring municipal electric utilities and rural electric cooperative utilities to file service reliability metrics.

scope of the IOUs' Annual Distribution Service Reliability Report was expanded to include status reports on the various storm hardening initiatives required by the Commission.[7] Staff held a workshop with the IOUs and interested parties in October 2006 to discuss the expected content of the more comprehensive reports which would be due on March 1, 2007.

The reports filed on March 1, 2007, included: (1) actual 2006 service reliability data; (2) adjusted distribution service reliability data; (3) actual and adjusted performance assessments in five areas: system-wide, operating region, feeder, cause of outage events; and (4) complaints. The reports also summarized the storm hardening activities for the IOU.

Review Outline

This review relies primarily on the March 1, 2007, reports for recent reliability performance data and storm hardening activities. A section addressing trends in reliability related complaints is also included. Staff's review consists of five sections.

Section 1: Addresses storm hardening activities such as pole strength inspections, vegetation management, and other initiatives.

Section 2: Addresses each utility's actual 2006 service reliability and support for each of its adjustments to the actual service reliability data.

Section 3: Addresses each utility's 2006 distribution service reliability based on adjusted service reliability data.

Section 4: Addresses inter-utility comparisons and the volume of reliability related customer complaints.

Section 5: Appendices containing detailed utility specific data.

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[7]Wooden Pole Inspection Orders: Order No. PSC-06-0144-PAA-EI, issued February 27, 2006, in Docket No. 060078-EI; and Order Nos. PSC-06-0778-PAA-EU, issued September 18, 2006, PSC-07-0078-PAA-EU, issued January 29, 2007, in Docket No. 060531-EU.
Storm Hardening Initiative Orders: PSC-06-0351-PAA-EI, issues April 25, 2006; PSC-06-0781-PAA- EI, issued September 19, 2006; PSC-06-0947-PAA-EI, issued November 13, 2006; and PSC-07-0468-FOF-EI, issued May 30, 2007, in Docket No. 060198-EI.

Section I. Storm Hardening Activities

The hurricanes of 2004 and 2005 caused extensive damage resulting in significant storm restoration costs and long-term electric service interruptions to millions of Florida's electric utility customers. On January 23, 2006, the Florida Public Service Commission (Commission) conducted a workshop to discuss the damage to electric utility facilities resulting from the 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 February 7, 2006, the Commission voted to require the investor-owned electric utilities and local exchange companies to begin implementing an eight-year inspection cycle of their respective wooden poles.[8, 9] On February 27, 2006, at an internal affairs conference, the Commission was briefed on recommended additional 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. Ultimately, the Commission decided the following:

(1) All Florida electric utilities, including municipal utilities and rural electric cooperative utilities, would provide an annual Hurricane Preparedness Briefing.

(2) Staff would file a proposed agency action recommendation for the April 4, 2006, agenda conference 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 (NESC).

(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, 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 (Ten Initiatives) on or before June 1, 2006.[10]

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[8]Order No. PSC-06-0144-PAA-EI, 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. Order No. PSC-06-0168-PAA-TL, issued March 1, 2006, in Docket No. 060077-TL, In re: Proposal to require local exchange telecommunications companies to implement ten-year wood pole inspection program.

[9]Rule 25-6.0343, F.A.C., effective December 12, 2006, requires municipal electric utilities and rural electric cooperative utilities to report annually, by March 1, their standards, policies, practices, and procedures regarding storm hardening inclusive of wooden pole inspections.

[10]Docket No. 060198-EI, In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.

The Ten 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
(10) A natural disaster preparedness and recovery program

These Ten Initiatives were not intended to encompass all reasonable ongoing storm preparedness activities. Rather, the Commission viewed these initiatives as the starting point of an ongoing process.[11, 12]

Separate from the Ten Initiatives, the Commission established rules addressing storm hardening of transmission and distribution facilities for all of Florida's electric utilities.[13, 14, 15] The IOUs, pursuant to Rule 25-6.0342, F.A.C., are required to file a storm hardening plan for review and approval at least every three years. On June 7, 2007, the four major IOUs filed storm hardening plans that included the wooden pole inspection program and the Ten Initiatives. Florida Public Utilities Company (FPUC) requested and received a waiver because its storm hardening plan is a matter to be addressed in Docket No. 070304-EI, FPUC's request for a general rate increase. Consequently, this review does not address FPUC's storm hardening plan.

A consolidated public hearing was held on October 3-4, 2006, addressing the storm hardening plans of the four major IOUs. On December 4, 2006, the Commission voted to approve the storm hardening plans and required the next storm plan filing by May 1, 2010.[16]

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[11]See page 2 of Order No. PSC-06-0947-PAA-EI, issued November 13, 2006, in Docket No. <u>060198-EI, In re: Requirement for investor-owned electric utilities to file ongoing storm preparedness plans and implementation cost estimates.</u>

[12]The Commission addressed the adequacy of the IOUs' plans for implementing the Ten Initiatives by Order Nos. PSC-06-0781-PAA-EI, PSC-06-0947-PAA-EI, and PSC-07-0468-FOF-EI. In 2006, the municipal and rural electric cooperative utilities voluntarily provided summary statements regarding their implementation of the Ten Initiatives. Prospectively, reporting from these utilities is required pursuant to Rule 25-6.0343, F.A.C.

[13]Order No. PSC-06-0556-NOR-EU, issued June 28, 2006, in Docket No. 060172-EU, <u>In re: Proposed rules governing placement of new electric distribution facilities underground, and conversion of existing overhead distribution facilities to underground facilities, to address effects of extreme weather events</u>, and Docket No. 060173-EU, <u>In re: Proposed amendments to rules regarding overhead electric facilities to allow more stringent construction standards than required by National Electric Safety Code.</u>

[14]Order Nos. PSC-07-0043-FOF-EU and PSC-07-0043A-FOF-EU.

[15]Order No. PSC-06-0969-FOF-EU, issued November 21, 2006, in Docket No. 060512-EU, <u>In re: Proposed adoption of new Rule 25-6.0343, F.A.C., Standards of Construction - Municipal Electric Utilities and Rural Electric Cooperatives.</u>

[16]Vote Sheet: Document No. 10676-07, Docket Nos. 070297-EI, 070298-EI, 070299-EI, and 070301-EI.

This review, however, relies on each IOU's annual status report filed March 1, 2007 and not their storm hardening plans.

The following eight pages give a summary of each IOU's programs addressing an eight-year wooden pole inspection program and the Ten Initiatives.

Eight-Year Wooden Pole Inspection Program

Order Nos. PSC-06-0144-PAA-EI and PSC-07-0078-PAA-EI require each IOU to inspect 100 percent of the installed wooden poles every eight years. FPUC's implementation of the eight-year wooden pole inspection program is a matter to be addressed in Docket No. 070304-EI, FPUC's request for a general rate increase. Consequently, this review does not address FPUC's wooden pole inspection activities.

Table 1-1 shows a summary of the volume of wooden poles inspected compared to the average annual volume of inspections required to achieve an eight-year inspection cycle. In 2006, PEF achieved the expected average annual volume of inspections necessary to meet the eight-year cycle while FPL, TECO, and GULF did not.

Table 1-1. 2006 Wooden Pole Inspection Activity Summary

	2006 Installed Wooden Poles	Avg. Annual Inspections to meet 8-Yr Cycle	2006 Pole Inspections					2006 Variance From 8-Yr Cycle	
			Planned		Completed		Variance		
			Volume	% of 8-Yr	Volume	% of 8-Yr	% of Planned	Volume	% of 8-Yr
FPL	1,118,673	139,834	85,000	60.8%	96,090	68.7%	7.93%	-43,744	-31.3%
PEF	513,660	64,208	63,749	99.3%	79,369	123.6%	24.33%	15,162	23.6%
TECO	307,000	38,375	23,771	61.9%	17,700	46.1%	-15.82%	-20,675	-53.9%
GULF	243,993	30,499	12,800	42.0%	12,745	41.8%	-0.18%	-17,754	-58.2%

On a 2007 projected basis, shown in Table 1-2 on page 11, PEF will achieve the expected average annual volume of inspections necessary to complete the eight-year cycle while FPL, TECO, and GULF will not.

Table 1-2. Projected 2007 Wooden Pole Inspection Activity Summary

	2006 Installed Wooden Poles	2007 Planned Inspections		2006-2007 Cumulative			
		Volume	% of 8-Yr	Avg. Volume to meet 8-Yr Cycle	Planned Volume	Estimated Variance from 8-Yr Cycle Volume	%
FPL	1,118,673	127,000	60.8%	279,668	223,090	-56,578	-20.2%
PEF	513,660	95,000	99.3%	128,415	174,369	45,954	35.8%
TECO	307,000	41,617	108.4%	76,750	59,317	-17,433	-22.7%
GULF	243,993	32,000	42.0%	60,998	44,745	-16,253	-26.6%

Annual variances as seen in Tables 1-1 and 1-2 are allowable so long as each utility achieves 100 percent inspection within an eight-year period. Staff will continue to monitor each utility's performance.

Ten Initiatives

Three-Year Vegetation Management Cycle for Distribution Circuits

Since feeder circuits are the main arteries from the substations to the local communities, these circuits are targeted for frequent vegetation management. The approved plans of all IOUs require a three-year trim cycle for overhead feeder circuits. Table 1-3 is a summary of 2006 and projected 2007 feeder vegetation management activities.

Table 1-3. Vegetation Clearing from Feeder Circuits

	Plan Trim Cycle	Total Miles	Avg. Annual Miles	2006 Miles		Projected 2007 Miles	
				Miles Trimmed	% of Annual Cycle	Estimated Trim Miles	% of Annual Cycle
FPL	3	13,333	4,444	10,094	227%	4,400	99%
PEF	3	3,800	1,267	723	57%	1,267	100%
TECO	3	1,734	578	268	46%	N/A	N/A
GULF	3	N/A	N/A	N/A	N/A	NA	N/A

At the time GULF filed its March 1, 2007, report, GULF did not have detailed vegetation management data identifying solely feeder circuit activities. In aggregate, for 2007, GULF plans to clear 1,844 miles of distribution circuits, which is approximately 30 percent of its system.

TECO did not estimate miles to be trimmed for feeder or lateral circuits during 2007. Instead, TECO provide an estimated 2007 budget equal to its 2006 expenses. Consequently, TECO's 2007 trimmed miles are expected to be approximately 46-57 percent of the average annual requirements of its plan consistent with its 2006 level of activity. A summary of vegetation activities on overhead lateral circuits is shown in Table 1-4.

Table 1-4. Vegetation Clearing from Lateral Circuits

	Plan Trim Cycle	Total Miles	Plan Avg. Annual Miles	2006 Miles: Miles Trimmed	2006 Miles: % of Annual Cycle	Projected 2007 Miles: Estimated Trim Miles	Projected 2007 Miles: % of Annual Cycle
FPL	6	22,262	3,710	825	22.2%	1,900	51.2%
PEF	5	14,200	2,840	2,703	95.2%	2,840	100.0%
TECO	3	4,400	1,467	840	57.3%	NA	N/A
GULF	6	N/A	N/A	N/A	N/A	NA	N/A

In addition to the planned cycle trimming, each IOU also performs hot-spot trimming and mid-cycle trimming to address rapid growth problems. Table 1-3 and 1-4 do not reflect hot-spot trimming and mid-cycle trimming activities. An additional factor to consider is that not all miles of overhead distribution circuits require vegetation clearing. Factors such as hot-spot trimming and open areas contribute to the apparent variances from the approved plans. Annual variances as seen in Tables 1-3 and 1-4 are allowable so long as each utility achieves 100 percent completion within the cycle-period stated in the approved Plan for feeder and lateral circuits.

Audit of Joint Use Agreements

The Commission requires each IOU to actively monitor the impact of attachments by other parties to ensure such attachments conform to the IOU's strength requirements without compromising storm performance. All IOU's perform pole strength assessments in conjunction with the eight-year wooden pole inspection program. Additionally, field surveys are performed to verify that the third-party attachments in the field comply with the terms and conditions of existing joint use agreements. These field surveys typically focus on discovering attachments that were previously not known or are inconsistent with the joint use agreements. On average, such field surveys occur on a five-year cycle. The following are some 2006 highlights and projected 2007 activities for each utility.

√ FPL: Audits approximately 20% of jointly used poles annually. The 2006 audits revealed minimal unauthorized attachments or overloaded facilities.

√ PEF: In 2006, PEF audited its entire system of jointly used transmission and distribution poles. The audit identified a total of 72,321 previously unknown attachments and one overloaded distribution pole.

- √ TECO: In 2006, TECO found 1,633 overloaded poles. By the end of 2007 TECO will have completely audited 25 percent of its system.

- √ GULF: In 2006, GULF's survey estimates a total of 6,090 previously unknown attachments existed system wide. No overloaded poles were found. GULF's report did not state how many sites were used in its survey.

Six-Year Transmission Inspections

The Commission required each IOU to develop a plan to fully inspect, on a six-year cycle, all transmission structures, substations, and all hardware associated with these facilities. Approval of any alternative to a six-year cycle must be shown to be equivalent or better than a six-year cycle in terms of cost and reliability in preparing for future storms. The approved plans for FPL, TECO, and GULF require full inspection of all transmission facilities within a six-year cycle. On an annual average basis, a full inspection means inspecting 16.7 percent of the system. PEF, which already had a program indexed to a five-year cycle, continues with its five-year program. Annual program variances for TECO and GULF are discussed below. However, such variances are allowable so long as each utility achieves 100 percent completion within a six-year period.

- √ FPL: FPL inspected in excess of 16 percent of each type of transmission facility meeting the average annual program requirements. The 2007 projections show an expectation that FPL will continue to meet the average annual program requirements.

- √ PEF: PEF reported inspection of more than 20 percent of each type of transmission facility meeting average annual program requirements. PEF's 2007 projections show a continued expectation of meeting the average annual program requirements.

- √ TECO: In 2006, TECO completed ground-line inspection on 7.3 percent of the transmission structures. However, no wind loading analysis was performed. All other transmission inspections were performed as scheduled. TECO asserted difficulties in acquiring contractor resources for completing this work. For 2007, TECO has secured contractor resources to meet the program requirements of inspecting and assessing the strength of 12.5 percent of the transmission structures.

- √ GULF: In 2006, GULF inspected 5.2 percent of its transmission tower structures, less than the average annual program requirements of 16.7 percent. For 2007, GULF plans to complete 12.9 percent, also less than the average annual program requirement. The estimated cumulative variance through 2007 is a -15.2 percent for inspecting transmission tower structures. All other transmission inspections were performed as scheduled. GULF's report does not address factors that are contributing to its program variances.

Hardening of Existing Transmission Structures

The Commission required IOUs to show the extent of utility efforts in this area including the scope of activity and the criteria used for selecting transmission upgrades and replacements. No specific activity was ordered other than developing a plan and reporting on storm hardening of existing transmission structures. In general, all IOUs' plans continued pre-existing programs that focus on upgrading older wooden transmission poles. Below are some 2006 highlights and projected 2007 activities for each utility.

- √ FPL: FPL's primary focus is on upgrading un-guyed wooden transmission structures. These upgrades include using replacement with round spun concrete poles. Additionally, older pole-mounted facilities, such as ceramic post insulators are being replaced with a new polymer type. These activities will be completed within 10 to 15 years.

- √ PEF: PEF is systematically 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.

- √ TECO: TECO's plan includes the replacement of wooden transmission structures with non-wooden structures based primarily on the eight-year wooden pole inspection results and ground line inspections of transmission facilities. No specific time frame has been set for completing this effort because the program is based on continual strength assessment of existing facilities rather than simply changing out wooden poles for non-wooden poles.

- √ GULF: GULF's plan includes a five-year program to install storm guys on H-frame transmission structures not currently guyed. In addition, in 2006, GULF began a ten-year program to replace all wooden cross-arms with steel. For new construction beginning in 2007, GULF implemented a "loss of conductor" contingency design standard directed at avoiding cascading transmission tower failures.

A Transmission and Distribution Geographic Information System

Post-Storm Data Collection and Forensic Analysis

Collection of Detailed Outage Data Differentiating Between the Reliability Performance of Overhead and Underground Systems

These three initiatives are addressed together because effective implementation of any one initiative is dependent on effective implementation of the other two initiatives. The four major IOUs have geographic information system (GIS) programs and programs to collect post-storm data on competing technologies, perform forensic analysis, and assess the reliability of overhead and underground systems on an ongoing basis. Differentiating between overhead and underground reliability performance and costs is still problematic because underground facilities are typically connected to overhead facilities and the interconnected systems that the IOUs address on a total basis for reliability and managing costs. Below are some 2006 highlights and projected 2007 activities for each utility.

- √ FPL: FPL is increasing the pole data, such as height, class, brand date, and installation date, that are linked to its GIS resources and asset management system. In 2007, FPL's upgrades will include details regarding joint use attachments, streetlights, feeder sections, equipment replacement, and post-storm forensic analyses. Site specific forensic analysis and other post-storm analysis remain key programs in FPL's assessment of overhead and underground storm performance. FPL's report suggests various metrics for program monitoring purposes and reporting overhead and underground performance data on a system and regional basis. FPL's suggestions, which may be adequate for annual reporting purposes and averaged data, will not address site specific matters that may be unique to local communities.

- √ PEF: During 2006, PEF added distribution facility data to its GIS. In 2007, PEF will complete populating its GIS with transmission facility data. PEF's approach to differentiating between overhead and underground facility performance includes assessing GIS, outage management, and customer service information systems. Assumptions will still be required because PEF's system is interconnected and comprised of both overhead and underground facilities.

- √ TECO: Implementation of a GIS resource by June 2007 was expected to be delayed due to problems rising from migrating existing data to the new system. TECO continues to test and expand the requirements of its system to meet the objectives of the plan. TECO's GIS resources will ultimately replace and consolidate two existing information systems. In 2007, a forensic database element, with detailed data similar to FPL's, will be added. TECO reported limitations regarding the calculation of reliability metrics such as SAIDI and SAIFI.

- √ GULF: All major overhead and underground distribution equipment data is in GULF's new GIS resource. GULF's report did not discuss efforts to further expand its GIS resource with non-major distribution equipment. Beginning in the first quarter of 2007, GULF plans to add additional record keeping enabling GULF to more directly calculate reliability metrics such as SAIDI and SAIFI as experienced by overhead and underground customers.

Increased Utility Coordination with Local Governments

The Commission's goal with this program is to promote ongoing dialogue between IOUs and local governments on matters such as vegetation and underground construction in addition to the general need to increase pre- and post-storm coordination. The increased coordination and communication is intended to promote IOU 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 converting existing overhead facilities to underground facilities (undergrounding) as an option, as well as to assess the most cost-effective storm hardening options.

Each IOU's external affairs representatives or designated liaisons are responsible for engaging in dialog with local governments on issues pertaining to underground issues, vegetation management, public rights-of-way use, critical infrastructure projects, other storm related topics, and day-to-day matters. Additionally, each IOU assigns staff to each county emergency operation center to participate in joint training exercises and actual storm restoration efforts. The IOUs now have outreach and educational programs addressing underground construction, tree placement, tree selection, and tree trimming practices. Below are some 2006 highlights and projected 2007 activities for each utility.

√ FPL: FPL relies on its external affairs representatives. In 2006, FPL began an e-mail distribution network to share breaking news and important updates with public officials in a timely and consistent manner. A dedicated Web site was established for governmental leaders to facilitate storm recovery efforts. FPL continues to meet with county and municipal leaders requesting information on vegetation management and conversion of existing overhead electric facilities to underground facilities. FPL also advertises its "Right Tree Right Place" educational program.

√ PEF: PEF has 17 full time employees assigned to liaison activities with local governments. PEF reported 18 active projects converting existing overhead to underground, and in 2006, PEF created a dedicated team to engineer and manage such conversion projects. A total of 47 underground construction projects are in various stages of review. Tree trimming information packets and a Web page were developed during 2006 to facilitate customer and municipal decisions regarding tree selection, placement of trees, and trimming practices.

√ TECO: TECO established workshops with local, regional, and state agencies outlining TECO's emergency preparedness plan, vegetation management strategy, and underground construction of electric facilities. For 2007, a brochure would be developed, made available on TECO's Web site, and handed out at meetings with customers seeking additional information on converting existing overhead facilities to underground. Also, during 2007, TECO plans to offer workshops and training to local governments on recognizing damaged electrical facilities and how best to report such information to TECO.

√ GULF: GULF reported seven active overhead-to-underground conversion projects and ten additional projects in preliminary phases. GULF's three district managers and at least four local area managers interact with city and county personnel on a daily and weekly basis on various issues, not just emergency preparedness.

Collaborative Research on Effects of Hurricane Winds and Storm Surge

Prior to 2006, the Commission observed 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 found 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.

In response to Commission directives, the electric utilities established a non-profit, member financed organization to coordinate all research efforts through the Public Utility Research Center, located in the Warrington College of Business at the University of Florida. The members include all electric municipal utilities, retail electric cooperative utilities, and IOUs within Florida. The administrative requirements were codified in a memorandum of understanding. The resultant collaborative research programs address three areas: hurricane wind effects, vegetation management, and undergrounding of electric utility infrastructure.

<u>Hurricane Wind Effects:</u> The wind research project is a long-term effort that will collect data on hurricane force wind impacts on electric facilities through actual events and experimentation. The wind information is needed to fill a gap in the current utility knowledge base. Absent the research effort, each utility would have very little objective wind data which is essential for effective forensic assessments. The knowledge developed through wind research will enable future utility planners to evaluate storm hardening alternatives before implementation, thereby avoiding a potentially costly trial-by-error approach. No end date for the wind research program has been set. By year-end 2007, an interim report will be filed with the Commission for review.

<u>Vegetation Management:</u> The vegetation management research project is directed at improving vegetation management practices so that outages, post-storm restoration efforts, and overall vegetation management costs are reduced. An industry workshop addressing best practices in vegetation management was held on March 5-6, 2007, in Orlando and was attended by 30 electric utilities. A report summarizing results the from the best practice workshop was completed April 17, 2007.[17] The top five best practices ranked by number of votes received are:

- √ State law (referenced the law in California) giving utility right to trim/remove (26 votes)
- √ Adequate financial resources to maintain vegetation management cycles (13 votes)
- √ City partnership to work with homeowner associations/city foresters (10 votes)
- √ Using herbicides to control growth on vegetation and in ground (8 votes)
- √ Directional pruning (7 votes)

[17]"Report on the Workshop for Best Practices in Vegetation Management," April 17, 2007, <http://www.floridapsc.com/utilities/electricgas/EIProject/docs/VegetationManagementWorkshopReport.pdf>.

Additionally, the workshop addressed areas where utilities believed improvements could be made. The top five areas for improvement in vegetation management programs ranked by the number of votes received are:

- √ Better education of customers and public (22 votes)
- √ State laws to support tree removals (18 votes)
- √ Maintenance of some circuits from station to the end of the line (3 votes)
- √ Access (3 votes)
- √ Chemical applications (3 votes)

The report on the best vegetation management practices does not discuss any future plans for additional review. The report notes a suggested role for the Commission in providing regular public service announcement campaigns.

<u>Undergrounding of Electric Utility Infrastructure:</u> The undergrounding research project is a shorter term research effort with a final report due March 30, 2008. The research program is structured in three phases: Phase 1 is a meta-analysis of existing research, reports, and case studies; Phase 2 consists of Florida specific case studies of actual projects in which overhead facilities have been converted to underground; and Phase 3 is the development and testing of a methodology to identify and evaluate the costs and benefits of underground specific facilities in Florida. Phase 1 was completed on February 28, 2007,[18] and Phase 2 was completed on August 6, 2007.[19] Both the Phase 1 and 2 reports noted that the initial costs to convert overhead distribution to underground distribution are high and insufficient data is available to show that the high initial costs are completely justifiable by quantifiable benefits such as reduced operation and maintenance cost savings and reduced hurricane damage. Increased data collection can potentially increase the amount of quantifiable benefits, but it is unlikely that these benefits will entirely justify the high initial cost of undergrounding, except potentially in a situation where an underground system is struck by multiple severe hurricanes. The dominate reason for undergrounding is to improve the aesthetics of the area. Phase III is projected to be completed March 30, 2008 and will result in a report being filed with the Commission.

A Natural Disaster Preparedness and Recovery Program

Each IOU is required to maintain a current copy of its formal disaster preparedness and recovery plan with the Commission. A formal disaster plan provides an effective means to document lessons learned, improve disaster recovery training, pre-storm staging activities, post-storm recovery, facility performance data, and forensic analysis. Additionally, the IOUs participated in the Commission's annual pre-storm preparedness briefing which focuses on the extent to which all Florida electric utilities and telecommunications companies are prepared for potential hurricane events.

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[18]Undergrounding Assessment Phase 1 Report, *Literature Review and Analysis of Electric Distribution Overhead to Underground Conversion,* issued February 28, 2007, <http://www.psc.state.fl.us/utilities/electricgas/EIProject/docs/InfraSourcePhase1FinalReport20070228.pdf>.

[19]Undergrounding Assessment Phase 2 Report, *Undergrounding Case Studies,* issued August 6, 2007, < http://www.psc.state.fl.us/utilities/electricgas/EIProject/docs/InfraSourcePhase2FinalReport6AUG07.pdf>.

Section II. Actual Distribution Service Reliability and Exclusions of Individual Utilities

Retail customers are affected by all outage events and momentary events regardless of where problems originate. For example, generation events and transmission events, while electrically remote from the distribution system serving a retail customer, impact the distribution service reliability experience of customers. This total service reliability experience is intended to be captured by the "actual" reliability data.

The actual reliability data includes two subsets of outage data: the excludable data and data pertaining to normal day-to-day activities. Rule 25-6.0455(4), F.A.C., explicitly lists outage events that may be excluded:

(1) Planned service interruptions
(2) A storm named by the National Hurricane Center
(3) A tornado recorded by the National Weather Service
(4) Ice on lines
(5) A planned load management event
(6) Any electric generation or transmission event not governed by subsections 25-6.018(2) and (3), F.A.C.
(7) An extreme weather or fire event causing activation of the county emergency operation center

This section of the review provides an overview of each IOU's actual 2006 performance data and focuses on the exclusions allowed by the rule. Assessment of trends in the actual reliability data was not possible because 2007 is the first reporting year of such data.

Florida Power & Light Company: Actual Data

Table 2-1, shown on the following page, provides an overview of the key metrics Customer Minutes of Interruption (CMI) and Customer Interruptions (CI) for FPL for 2006. FPL's actual values are calculated because FPL did not included transmission events in their calculation of the actual reliability data. Excluded outage events accounted for 30 percent of the service interruptions experienced by FPL's customers in 2006. FPL reported no outage events caused by generation problems.

FPL excluded "By Customer" outage events which is an additional type of outage event that is not explicitly provided by Rule 25-6.0455, F.A.C. The "By Customer" category are those requested by the customer or site developer for construction or site maintenance purposes. Customer outage events can also be triggered by electrical problems on the customers' premises. Staff believes a "By Customer" outage event can be excluded because the reliability data from such events is not indicative of a utility allowing its system to become less reliable.

Table 2-1. FPL's 2006 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	**% of Actual**	**Value**	**% of Actual**
Calculated Actual Data	388,312,305		8,149,402	
Documented Exclusions				
Transmission Events	24,126,973	6.2%	2,019,162	24.8%
Named Storm Outages	12,734,527	3.3%	198,811	2.4%
Planned Outages	10,562,985	2.7%	108,236	1.3%
Tornadoes	8,280,788	2.1%	83,057	1.0%
By Customer	4,692,607	1.2%	64,535	0.8%
Reported Adjusted Data	347,914,425	84.4%	5,675,601	69.6%

FPL's report did not fully document how the excluded events impacted reliability metrics for momentary events (CME and MAIFIe), the number of outage events (N and L-Bar), the duration of outage events (Minutes and L-Bar) and the customers experiencing more than five outage events (CEMI5). The extent of FPL's incomplete documentation within its report is shown in Table 2-2. FPL has committed to improving future Annual Distribution Reliability Reports.

Table 2-2. Differences Between FPL's 2006 System Adjusted Distribution Reliability Data and Explained Adjustments

	Minutes	N	CEMI5
Value	-1,185,446	-389	-53,254
% of Actual	5%	0.4%	31%

Progress Energy Florida, Inc: Actual Data

Table 2-3, provides an overview of the key metrics CMI and CI for PEF in 2006. The data shown was updated after PEF's review and response to the draft report. Their response provided recategorization of exclusions and updated numbers. The updated information shows excluded events comprised 37 percent of the service interruptions experienced by PEF's customers during 2006.

Table 2-3. PEF's 2006 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data	180,929,753		2,818,189	
Documented Exclusions				
Transmission	21,024,940	11.6%	345,756	12.3%
Severe Weather	24,370,391	13.5%	203,036	7.2%
Emergency Shutdowns	6,643,830	3.7%	414,032	14.7%
Prearranged & Dispatch Resolved	7,830,917	4.3%	88,939	3.2%
Reported Adjusted Data	121,059,675	66.9%	1,766,426	62.7%

PEF excluded a generation event that occurred on August 2, 2006 due to an electrical fault at the Bartow Fossil Units 1 and 2 auxiliary load distribution network. This fault occurred at a peak load time resulting in low system voltage in the southern half of Pinellas County. Load shedding on several feeder circuits kept the problem localized. PEF's efforts to avoid or minimize any similar future events included replacement of all Bartow Fossil Unit electrical components associated with the event, installation of distribution line capacitors during 2007, and creation of an employee goal directed at avoiding low system voltage conditions.

PEF's report, while providing substantial detail on some events, did not adequately discuss the events noted by "Prearranged and Dispatch Resolved" in Table 2-3, above. The extent of PEF's incomplete support for all exclusions within its report is shown in Table 2-4. PEF has committed to improving future Annual Distribution Reliability Reports.

Table 2-4. Differences Between PEF's 2006 System Adjusted Distribution Reliability Data and Explained Adjustments

	CMI	CI	Minutes	N	CEMI5
Value	-13,811,581	-482,908	-665,395	-6,534	9,208
% of Actual	8%	17%	12%	14%	50%

Tampa Electric Company: Actual Data

TECO did not include its reported transmission and substation events in its calculation of the actual reliability data. In response to staff inquiry, TECO also noted several minor errors in its supporting data. The errors are minor because the reliability indices used to track annual distribution reliability performance are not affected by the changes to the supporting data. Table 2-5 provides TECO's corrected CMI and CI for 2006. Excluded outage events account for 38 percent of the outage events experienced by TECO's customers.

Table 2-5. TECO's Corrected 2006 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	**% of Actual**	**Value**	**% of Actual**
Calculated Actual Data	60,502,954		947,247	
Documented Exclusions				
Substation Events	7,135,977	11.8%	151,089	16.0%
Named Storm Outages	4,745,116	7.8%	54,459	5.7%
Transmission Events	2,395,855	4.0%	132,916	14.0%
Planned Outages	407,336	0.7%	18,977	2.0%
Reported Adjusted Data	45,818,670	75.7%	589,806	62.3%

Additionally, TECO excluded outage events without fully documenting how those events impacted performance metrics for momentary events (CME and MAIFIe), duration of outage events (Minutes and L-Bar) and CEMI5. The extent of TECO's incomplete documentation within its report is shown in Table 2-6. TECO has committed to improving future Annual Distribution Reliability Reports.

Table 2-6. Differences Between TECO's 2006 System Adjusted Distribution Reliability Data and Explained Adjustments

	Minutes	CEMI5
Value	-98,711	-1,754
% of Actual	6%	10%

Gulf Power Company: Actual Data

Table 2-7 provides an overview of the key metrics CMI and CI for GULF for 2006. Excluded outage events account for 32 percent of the outage events experienced by GULF's customers. Twenty percent of these service interruptions were due to planned events necessary for GULF to perform maintenance and service to its facilities. GULF did not identify any generation events or extreme weather events for exclusion.

Table 2-7. GULF's 2006 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	% of Actual	Value	% of Actual
Reported Actual Data	100,261,757		785,791	
Documented Exclusions				
Transmission Events	4,233,088	4.2%	91,644	11.7%
Planned Outages	10,103,683	10.1%	158,807	20.2%
Reported Adjusted Data	85,924,986	85.7%	535,340	68.1%

GULF did, however, exclude outage events without fully documenting how those events impacted performance metrics for the duration of outage events (Minutes and L-Bar) and CEMI5. The extent of GULF's incomplete documentation within its report is shown in Table 2-8. GULF has committed to improving future Annual Distribution Reliability Reports.

Table 2-8. Differences Between GULF's 2006 System Adjusted Distribution Reliability Data and Explained Adjustments

	Minutes	CEMI5
Value	-49,864	-5,626
% of Actual	3%	40%

Florida Public Utilities Company: Actual Data

Table 2-9 provides an overview of the key metrics CMI and CI for FPUC for 2006. The actual data in Table 2-9 is the sum of "as reported" data because FPUC's report did not explicitly state FPUC's actual reliability metrics.

FPUC excluded "By Customer" outage events which is an additional type of outage event that is not explicitly provided by Rule 25-6.0455, F.A.C. The "By Customer" category are those outages requested by the customer or site developer for construction or site maintenance purposes. Customer outage events can also be triggered by electrical problems on the customers' premises. Staff believes a "By Customer" outage event can be excluded because the reliability data from such events is not indicative of a utility allowing its system to become less reliable.

Table 2-9. FPUC's 2006 Customer Minutes of Interruption and Customer Interruptions

	Customer Minutes of Interruption (CMI)		Customer Interruptions (CI)	
	Value	**% of Actual**	**Value**	**% of Actual**
Calculated Actual Data	6,818,113		52,071	
Documented Exclusions				
Transmission	1,997,669	29.3%	5,811	11.2%
Substation	393,235	5.8%	5,074	9.7%
Planned	13	0.0002%	1	0.002%
By Customer	4,216	0.1%	65	0.1%
Reported Adjust.	4,422,980	65.9%	41,120	79.0%

During 2006, excluded outage events were 21 percent of the service interruptions experienced by FPUC's customers. FPUC does not have generation resources on which to report. FPUC did not report any excluded extreme weather events.

For utilities with fewer than 50,000 customers, Rule 25-6.0344(3)(d), F.A.C., waives the requirement to report statistics for indices MAIFIe and CEMI5. FPUC reported that it served 28,793 customers in 2006, which qualifies FPUC for this reporting waiver. Nevertheless, FPUC is proceeding with installation of information systems that will allow it to gather and remit such data.

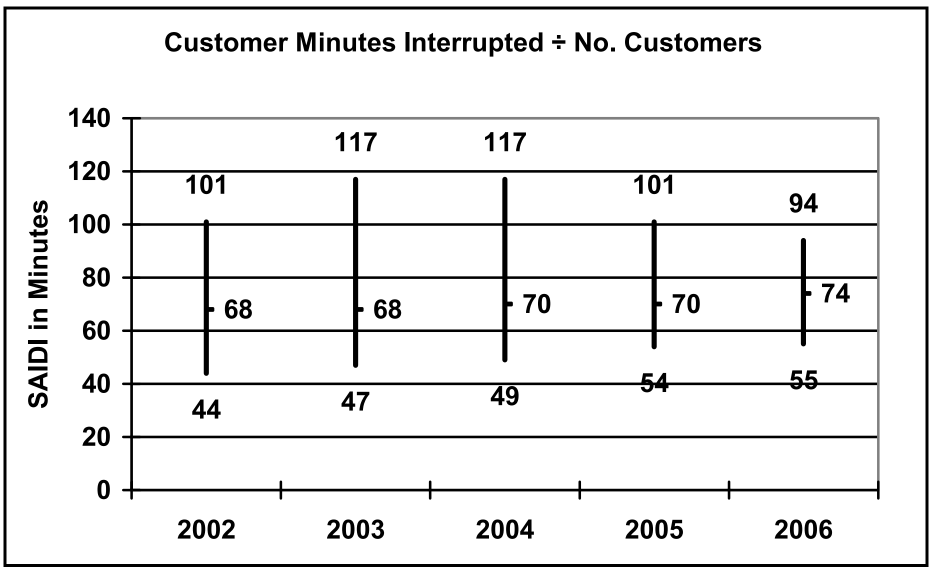
Section III. Adjusted Distribution Service Reliability Review of Individual Utilities

Review of the adjusted distribution reliability metrics provides insight into potential trends in a utility's daily practices and maintenance of its distribution facilities. This section of the review is based on each utility's as reported adjusted data.

Florida Power & Light Company: Adjusted Data

Figure 3-1 shows the maximum, average, and minimum adjusted SAIDI (minutes of interruptions per customer) recorded across FPL's system. While Figure 3-1 shows a general increase in the minimum SAIDI, there is also a general decline in the maximum SAIDI recorded across FPL's system. FPL reported a declining SAIDI for the Treasure Coast region which historically has had high SAIDI values. This trend change suggests a general improvement in FPL's Treasure Coast region. Since 2002, FPL's system average has increased slightly from 68 minutes to 74 minutes. FPL attributes the 2006 decreases in reliability to lingering effects from the 2004 and 2005 hurricane season.

Figure 3-1. SAIDI Across FPL's 16 Regions (Adjusted)



Figures 3-2 and 3-3, shown on the following page, are charts of the maximum, average, and minimum adjusted SAIFI (number of interruptions per customer) and adjusted CAIDI (outage restoration time) across FPL's system. FPL achieved its best SAIFI in 2005, with a system average of 1.15 service interruptions per customer. FPL's best CAIDI was 50 minutes in 2003. Unlike regional data for other indices no specific patterns were observed concerning the regional CAIDI values. The absence of a discernable pattern implies FPL's outage response process and location of service centers relative to affected customers are comparable for all regions. FPL reported a declining SAIFI for the Treasure Coast region, suggesting a general improvement in the Treasure Coast area which historically has received less reliable service compared to other FPL regions.

Figure 3-2. SAIFI Across FPL's 16 Regions (Adjusted)

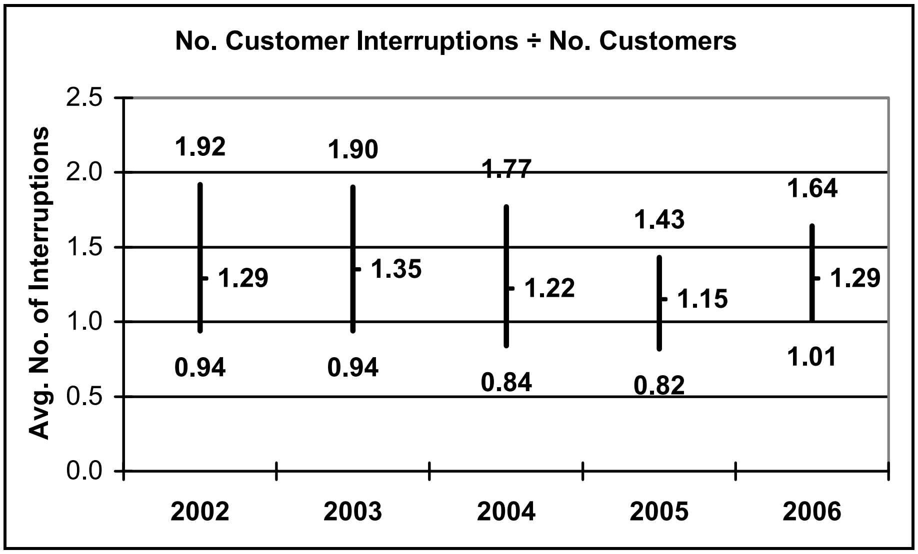
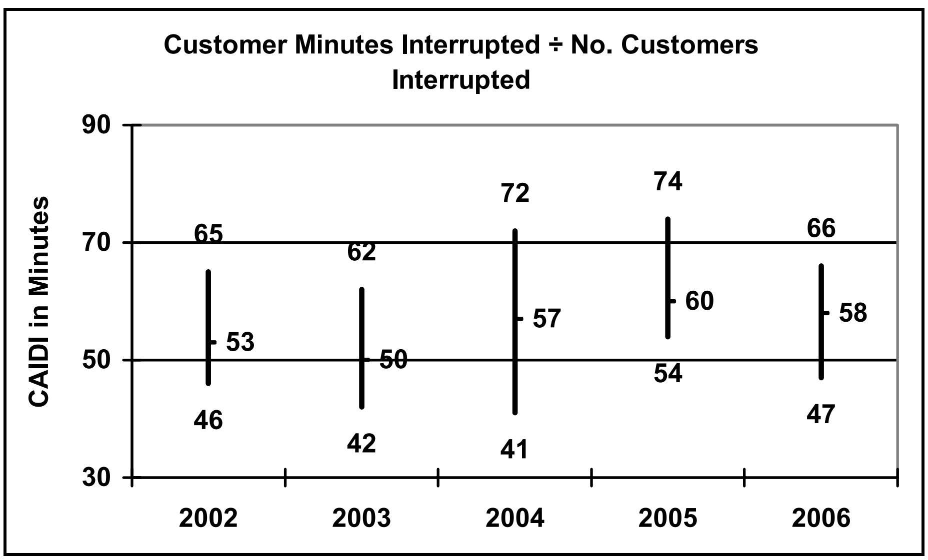


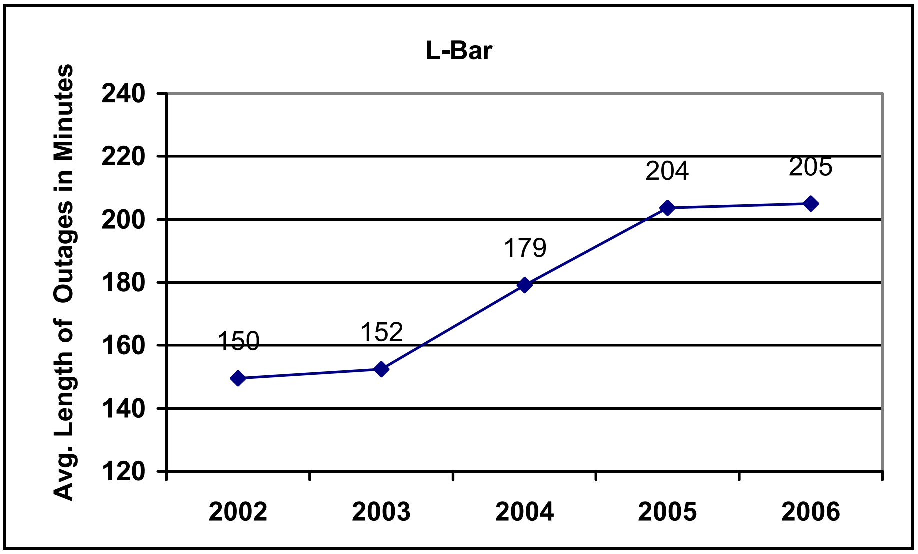
Figure 3-3. CAIDI Across FPL's 16 Regions (Adjusted)



The average length of time FPL's spends recovering from outage events, excluding hurricanes and other extreme outage events, is the index L-Bar shown in Figure 3-4. Even with adjustments, FPL has spent more time restoring service every year since 2002.

Many factors contribute to increases in L-Bar, including increased number of underground outages, the cause and location of the outage event, the amount of distribution facilities needing replacement or repair, and the number of available trained and equipped personnel. FPL offered no explanation for the increasing outage recovery time.

Figure 3-4. FPL's Avg. Duration of Outages (Adjusted)



Frequent outage problems experienced by a subset of customers indicate an opportunity for improvement. Such outage problems can be masked by the previously discussed indices of SAIDI, SAIFI, CAIDI, and L-Bar.

Figure 3-5, shown on the following page, is the maximum, average, and minimum adjusted MAIFIe (frequency of momentary events on primary circuits per customer) recorded across FPL's system. FPL's 2006 performance is comparable to its performance in 2002/2003, prior to the hurricane seasons of 2004 and 2005. For its Treasure Coast region, FPL reported a declining MAIFIe which suggests a general improvement in the Treasure Coast region which historically received less reliable service compared to other FPL regions. Isolated momentary events also occur on segments of the distribution circuit remote from the substation where the MAIFIe data is measured. These remote momentary events often impact a small group of customers or even just one customer. At this time, no efforts are underway to capture all momentary events that occur because of the high costs to do so.

Figure 3-5. MAIFIe Across FPL's 16 Regions (Adjusted)

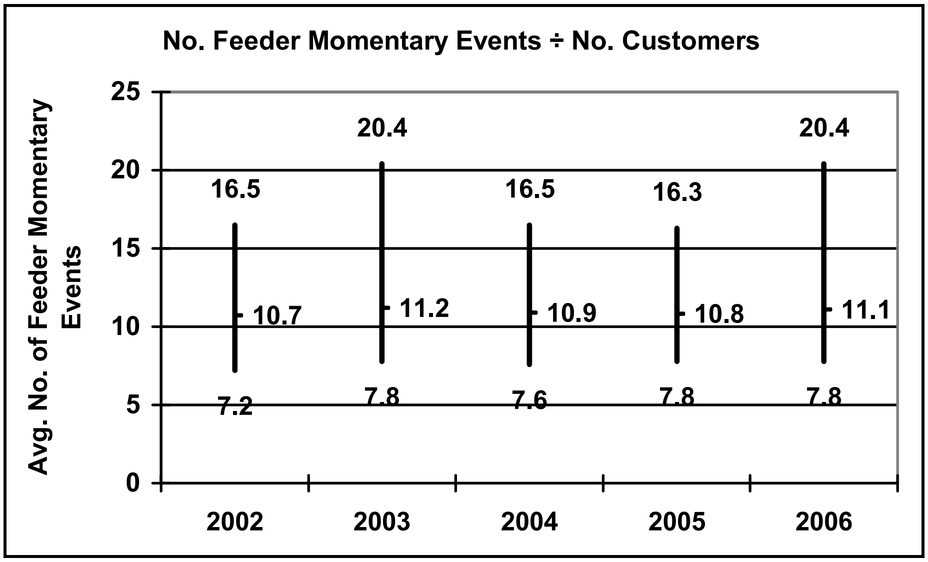
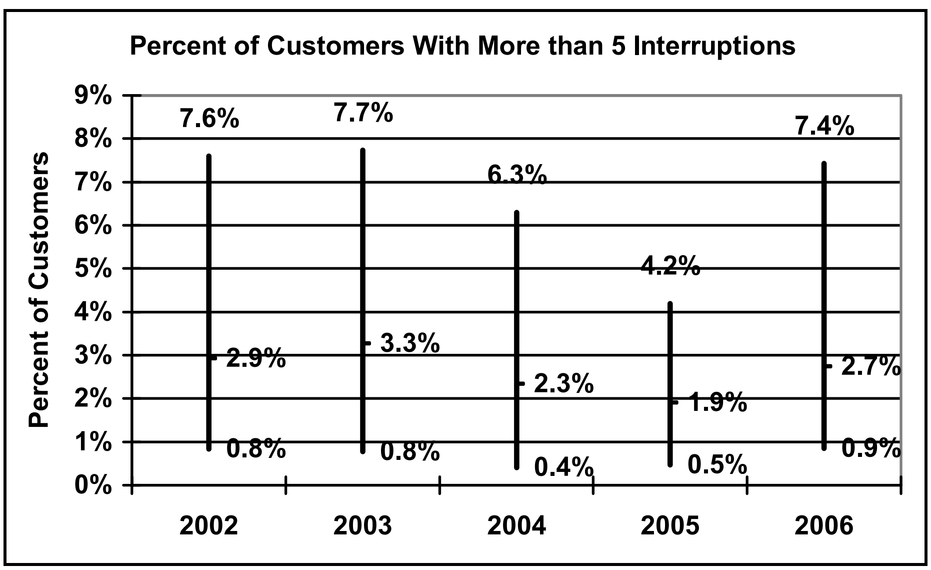


Figure 3-6 shows the maximum, average, and minimum adjusted CEMI5 (percent of customers experiencing more than five interruptions). FPL's 2006 performance is comparable to its performance in 2002/2003, prior to the hurricane seasons of 2004 and 2005.

Figure 3-6. CEMI5 Across FPL's 16 Regions (Adjusted)



FPL reported a declining CEMI5 for FPL's Treasure Coast region which suggests improvement in the Treasure Coast area which historically received less reliable service compared to other FPL regions.

The Three Percent Feeder Report is a listing of the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences, Figure 3-7, is calculated from the number of recurrences divided by the number of feeders reported on a three-year and five-year basis. While it appears that FPL may have made improvements, FPL's 2006 report listed only 67 feeders compared to 87 feeders in 2005. This drop in reported feeders is unexplained and contributes to the reduction in fraction of multiple occurrences shown in Figure 3-7.

Figure 3-7. FPL's Three Percent Feeder Report (Adjusted)

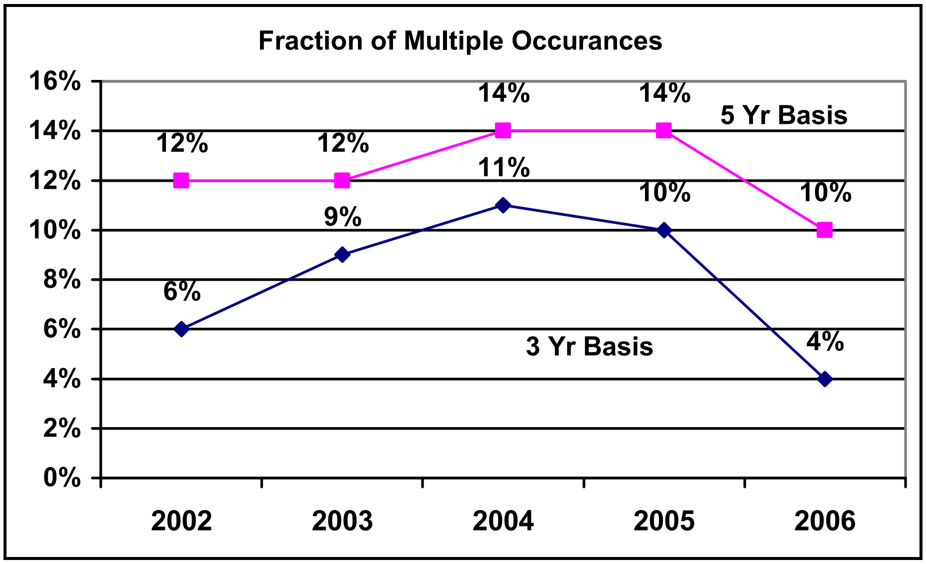


Figure 3-8. FPL's Top Five Outage Causes (Adjusted)

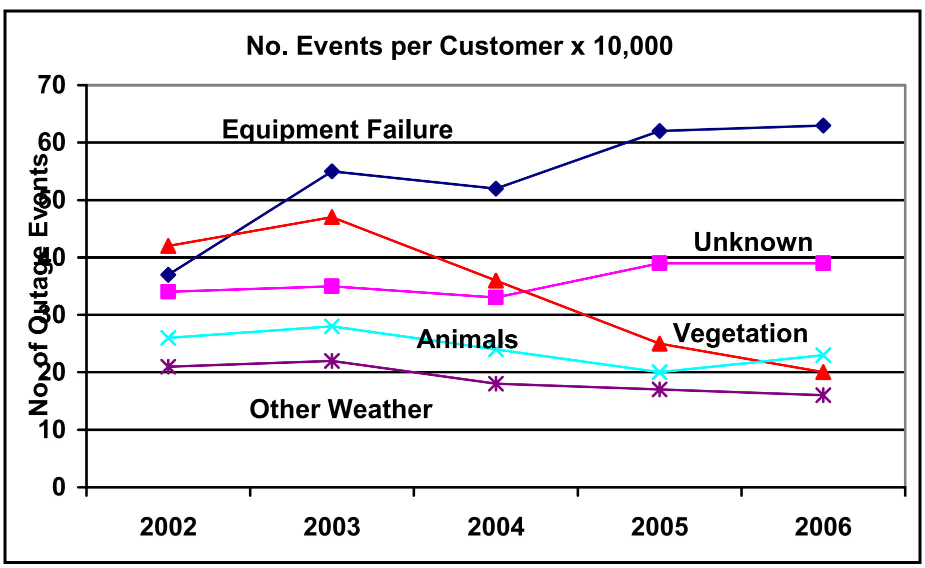


Figure 3-8, shown on the previous page, shows the top five causes of outage events on FPL's distribution system normalized to a 10,000 customer base. The figure is based on FPL's adjusted data of the top ten causes of outage events and represents 74 percent of the outage events that occurred between December 31, 2001, and January 1, 2007. For the five-year period the five top causes of outage event included equipment failures (24 percent), unknown (16 percent), vegetation (15 percent), animals (11 percent), and weather (eight percent) on a cumulative basis. The data shows an increasing trend in outage events caused by equipment failure and those which occur due to unknown factors.

The review of FPL's supporting data, adjusted for customer growth, shows a decreasing trend in the total number of outage events over the five-year period. The average annual decrease is 5 outage events per year on a 10,000 customer basis. These results suggest FPL is implementing proactive measures that avoid outage events to its customers despite recent increases in other service reliability metrics.

Observations: FPL' s Adjusted Data

The service relibilty provided by FPL in recent years has declined in spite of its efforts to avoid customer outage events. The recent decline in service reliability appears related to the hurricane impacts of 2004 and 2005. Nevertheless, FPL achieved service reliability improvements in specific regions which historically have had less reliability compared to FPL's other regions. Future Annual Distribution Reliability Reports are expected to more completely address year-to-year changes that impact assessment of service reliability, such as an explanation of the 20 feeder decrease in the 2006 Three Percent Feeder Report.

Progress Energy Florida, Inc: Adjusted Data

Figure 3-9, shown on the following page, charts the maximum, average, and minimum adjusted SAIDI recorded across PEF's system. While Figure 3-7 shows a general increase in the minimum SAIDI, a general decline also appears in the maximum SAIDI recorded across PEF's system. PEF reported a declining SAIDI for the North Coastal region which has historically had higher SAIDI values compared to other regions. This change suggests a general improvement in PEF's North Coastal region. Additionally, PEF appears to be providing increasingly similar level of reliability across its entire service area. On a system average basis, PEF has reduced the average minutes of service interruptions per customer from 88 minutes to 75 minutes.

Figure 3-9. SAIDI Across PEF's 4 Regions (Adjusted)

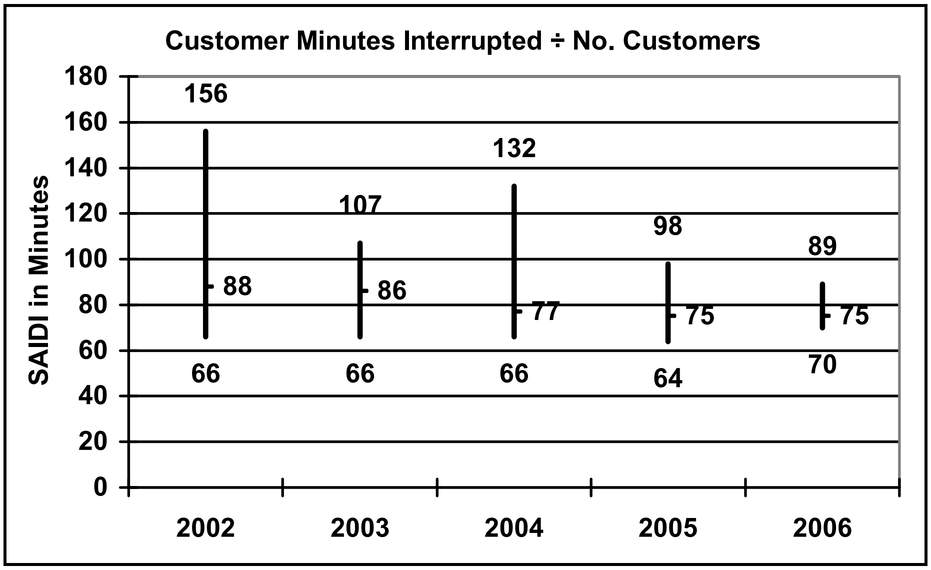


Figure 3-10 below shows the maximum, average, and minimum adjusted SAIFI across PEF's system. Figure 3-11, shown on the following page, is the adjusted CAIDI. Relative to 2002, PEF achieved improvement in SAIFI without a significant change in CAIDI. The review of supporting data shows PEF's North Coastal region continued to have the longest restoration time while PEF's South Coastal region continued to have the shortest outage restoration time. The presence of a discernable pattern implies PEF's outage response process and location of service centers relative to affected customers may not be comparable across its service area

Figure 3-10. SAIFI Across PEF's 4 Regions (Adjusted)

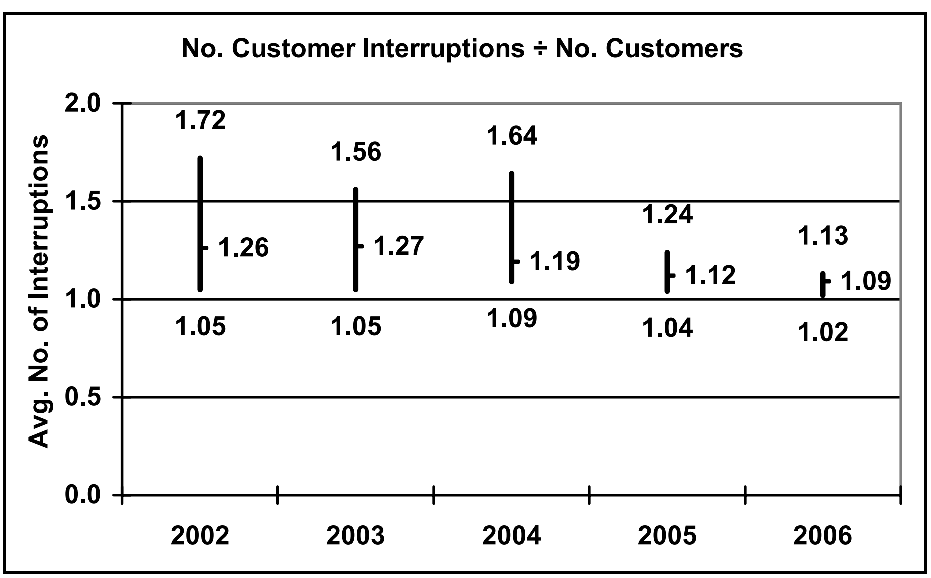
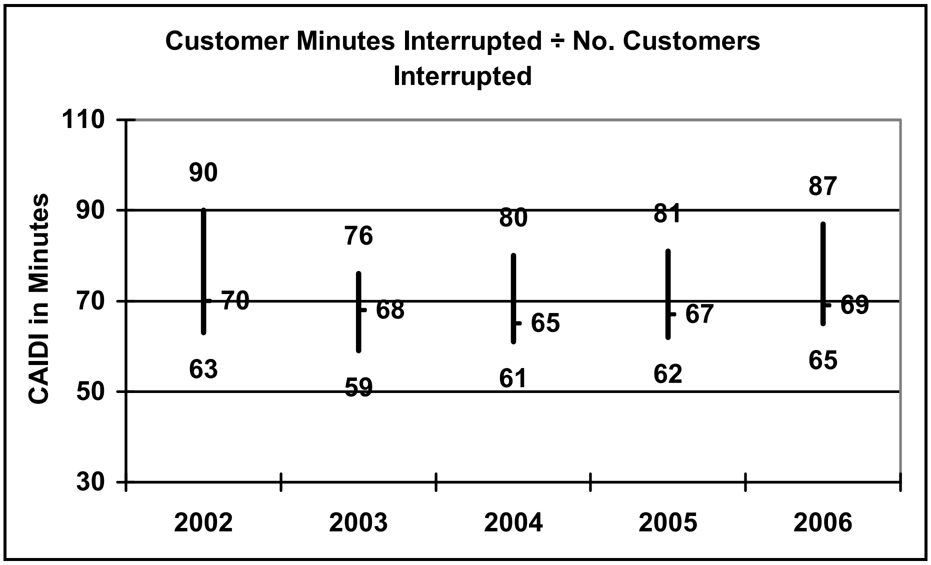
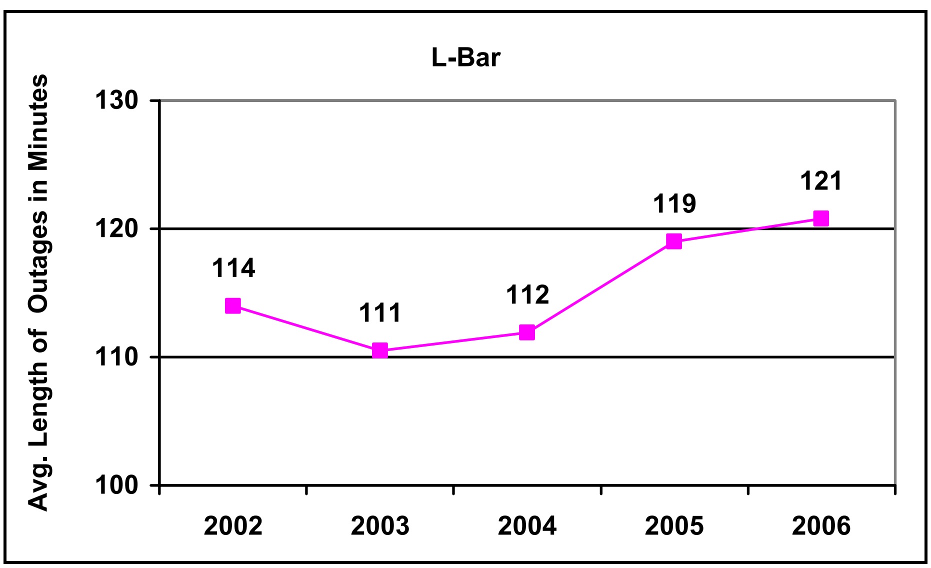


Figure 3-11. CAIDI Across PEF's 4 Regions (Adjusted)



The average length of time PEF's spends recovering from outage events, excluding hurricanes and other extreme outage events, is the index L-Bar shown in Figure 3-12. The data demonstrates a general increase of outage durations for the period reviewed. Many factors contribute to increases in L-Bar, including increased number of underground outages, the cause and location of the outage event, the amount of distribution facilities needing replacement or repair, and the number of available trained and equipped personnel. PEF's report did not address the increasing outage recovery time.

Figure 3-12. PEF's Avg. Duration of Outages (Adjusted)



Frequent outage problems experienced by a subset of customers indicate an opportunity for improvement. Such outage problems can be masked by the previously discussed indices of SAIDI, SAIFI, CAIDI, and L-Bar.

Figure 3-13 shows the maximum, average, and minimum adjusted MAIFIe (frequency of momentary events on primary circuits per customer) recorded across PEF's system. PEF's 2006 performance is improved compared to its performance in 2002/2003, prior to the hurricane seasons of 2004 and 2005. A review of supporting data shows that PEF's South Coastal region typically has the largest MAIFIe while PEF's North Coastal region has the lowest MAIFIe. Isolated momentary events also occur on segments of the distribution circuit remote from the substation where the MAIFIe data is measured. These remote momentary events often impact a small group of customers or even just one customer. At this time, no efforts are underway to capture all momentary events that occur because of the high costs to do so.

Figure 3-13. MAIFIe Across PEF's 4 Regions (Adjusted)

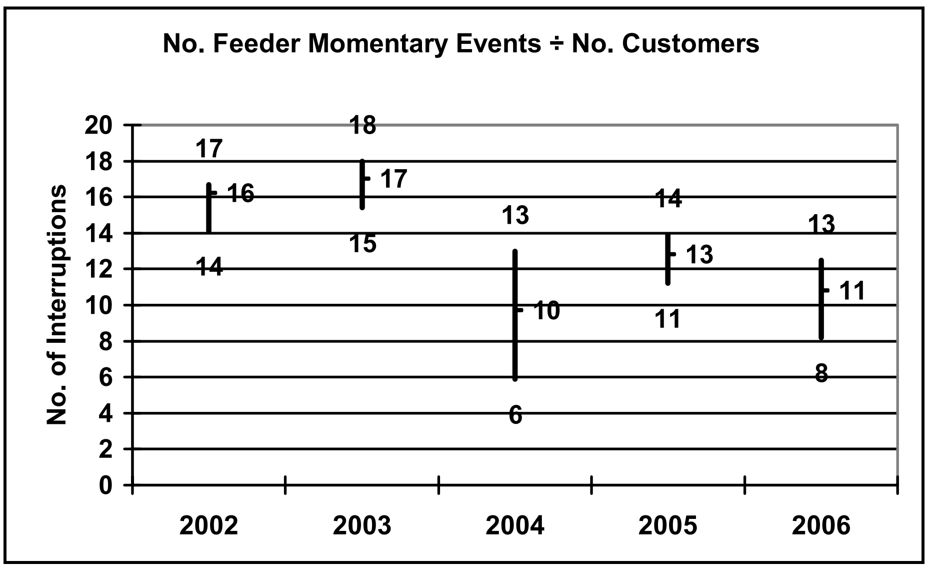
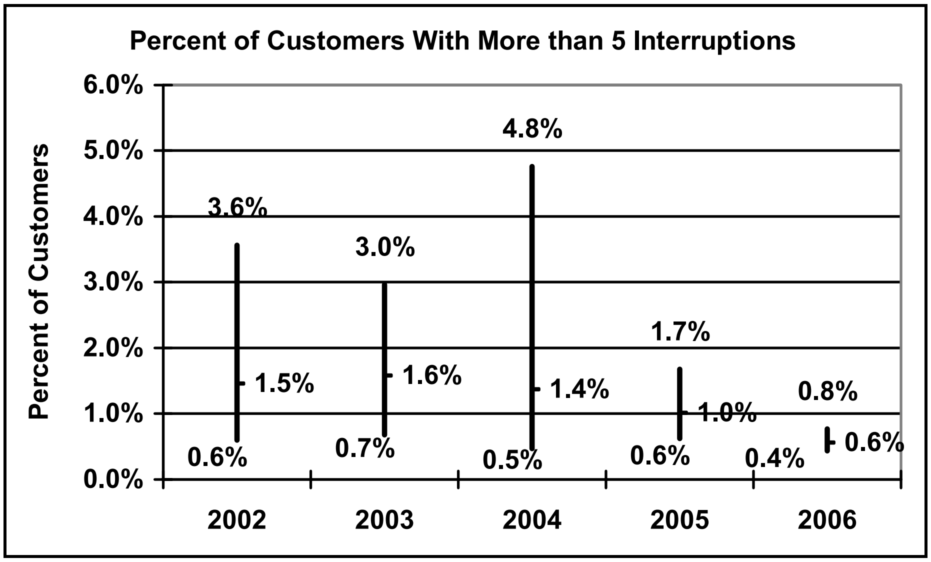


Figure 3-14, shown on the following page, charts the maximum, average, and minimum adjusted CEMI5. PEF's 2006 performance is improved compared to its performance in 2002/2003, prior to the hurricane seasons of 2004 and 2005. PEF reported declining CEMI for its North Coastal region over the entire period, suggesting general improvement in the North Coastal region.

Figure 3-14. CEMI5 Across PEF's 4 Regions (Adjusted)



The Three Percent Feeder Report lists the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences, Figure 3-15, is calculated from the number of recurrences divided by the number of feeders reported. Figure 3-15 shows the fraction of multiple occurrences of feeders using a three-year and five-year basis. In both cases, for the period reviewed, PEF's data shows an increasing trend for the same feeders to be reported. The increasing trend of recurring feeders suggests PEF has localized problems along certain feeders that have not yet been fully addressed.

Figure 3-15. PEF's Three Percent Feeder Report (Adjusted)

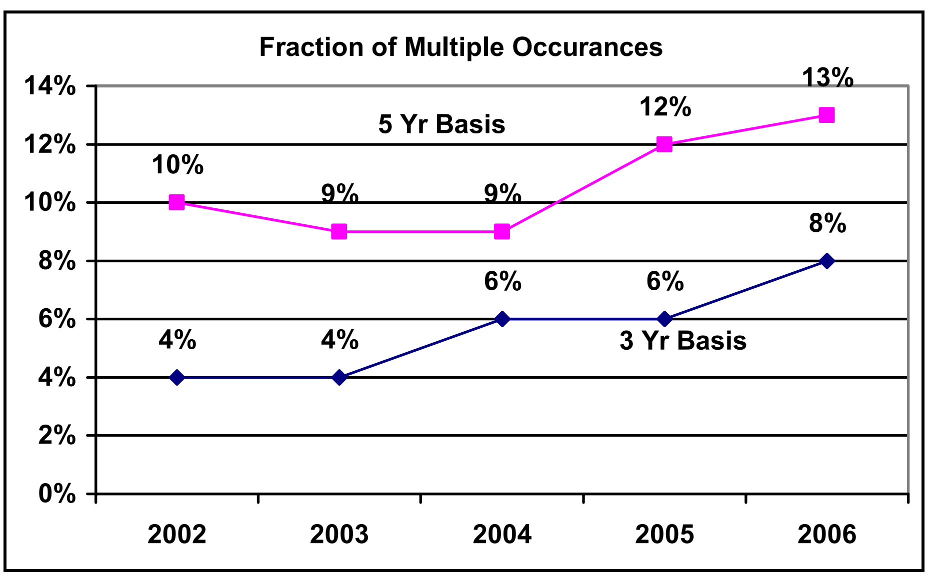
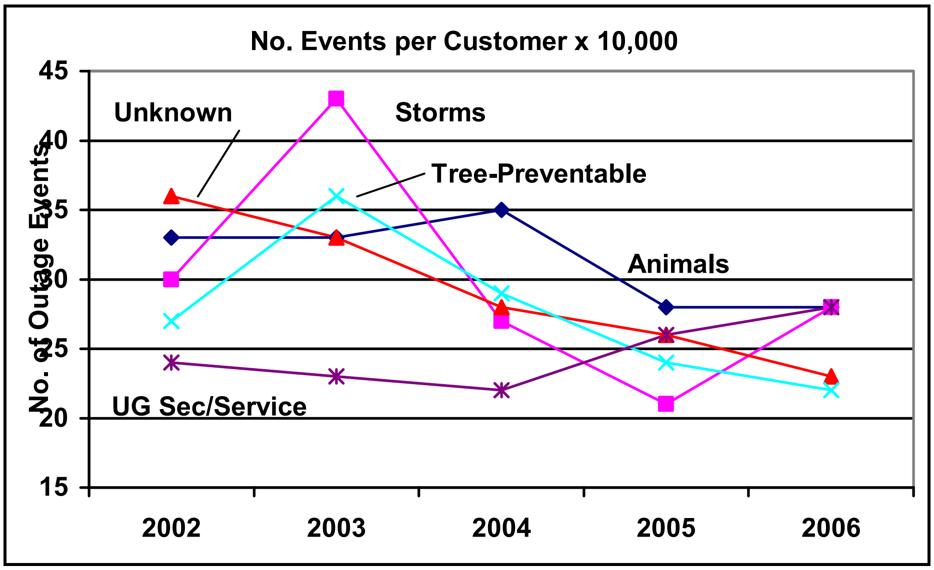


Figure 3-16 shows the top five causes of outage events on PEF's distribution system normalized to a 10,000 customer base. The figure is based on PEF's adjusted data of the top ten causes of outage events and represents 57 percent of the outage events that occurred between December 31, 2001, and January 1, 2007. For the five-year period, the top five causes of outage events were: animals (12.6 percent), storms (11.8 percent), unknown (11.6 percent), tree-preventable (10.9 percent), underground service failures and underground secondary cable failures (9.8 percent) on a cumulative basis. PEF uses its "Tree-Preventable" code to denote instances where it believes additional tree trimming could have avoided the outage event.

Figure 3-16. PEF's Top Five Outage Causes (Adjusted)



In 2005 and 2006, there was an increase in the number of outage events on underground services and underground secondary cable. A review of PEF's supporting data and adjusted for customer growth shows a sustained decreasing trend in the total number of outage events over the five-year period. The average annual decrease is 14 outage events per year on a 10,000 customer basis. Taken together, these results suggest PEF is implementing proactive measures that avoid outage events to its customers.

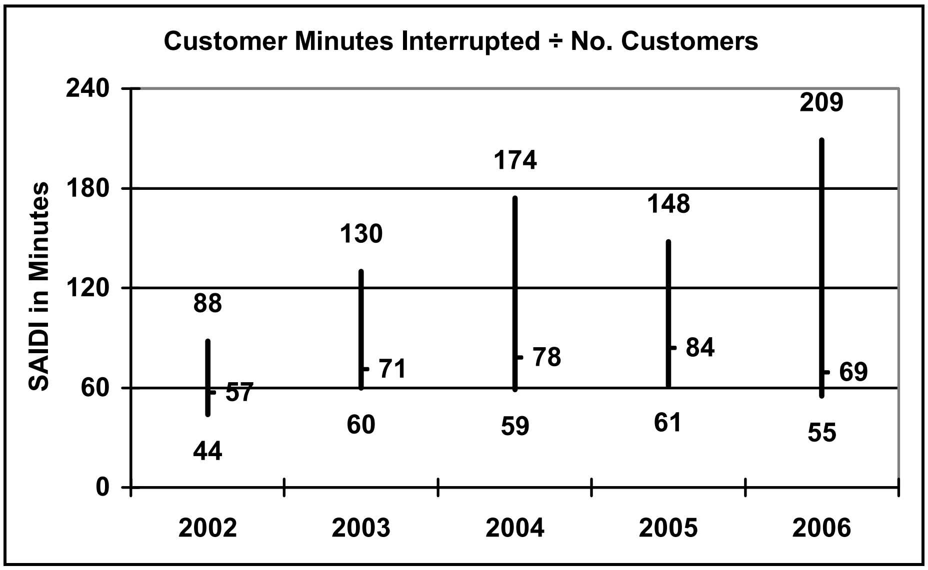
Observations: PEF' s Adjusted Data

In general, the service reliabilty provided by PEF in recent years is not declining, which possibly indicates minimal lingering effects of the 2004 and 2005 hurricanes. However, a small group of customers are experiencing a decline in service reliability because an increasing trend for certain feeders appears repeatedly on the Three Percent Feeder Report. PEF should consider efforts to reverse the increasing outage trend of certain feeders.

Tampa Electric Company: Adjusted Data

Figure 3-17 shows the maximum, average, and minimum adjusted SAIDI recorded across TECO's system. While TECO's average performance improved in 2006, Figure 3-13 shows a general increase in the maximum SAIDI recorded for all of TECO's regions combined. The supporting data confirms that TECO's Dade City region continues to show reliability declines while TECO's Central Region continues to show better overall performance. This tendency suggests that TECO's focus may need to change if TECO is attempting to provide comparable reliability to all of its service regions.

Figure 3-17. SAIDI Across TECO's 7 Regions (Adjusted)



Figures 3-18 and 3-19, shown on the following page, graph the maximum, average, and minimum adjusted SAIFI (number of interruptions per customer) and adjusted CAIDI (outage restoration time) across TECO's system. TECO's data shows both improvement and decline in SAIFI. As previously noted, TECO's regions do not experience comparable reliability. TECO's Dade City region, while representing only two percent of TECO's total customers, historically has more service interruptions than TECO's other regions. TECO has maintained that the long circuits serving the Dade City region contribute to the increased number of service interruptions relative to other regions. Unlike the regional data for other reliability indices, no specific patterns were observed concerning the regional CAIDI values. The absence of a discernable pattern implies TECO's outage response process and location of service centers relative to affected customers are comparable across its service area.

Figure 3-18. SAIFI Across TECO's 7 Regions (Adjusted)

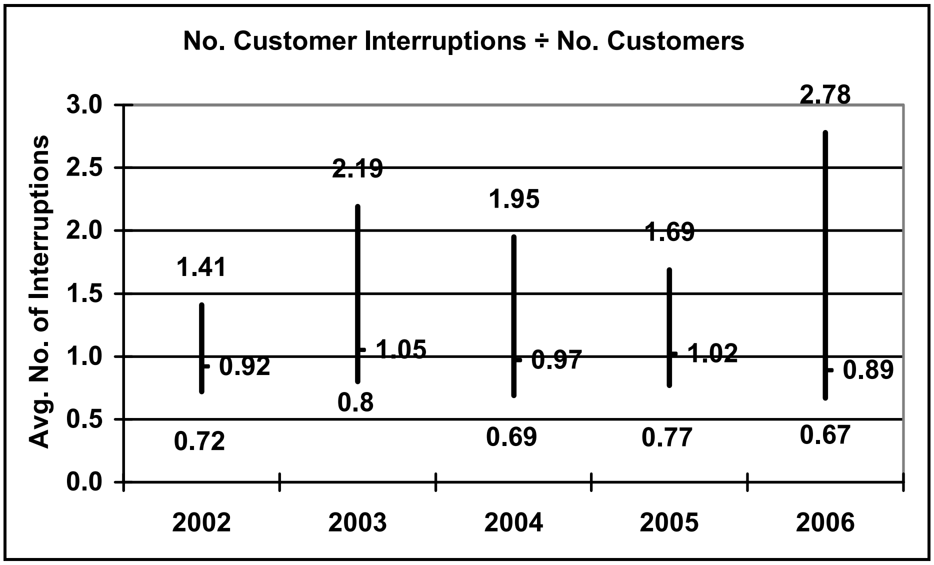
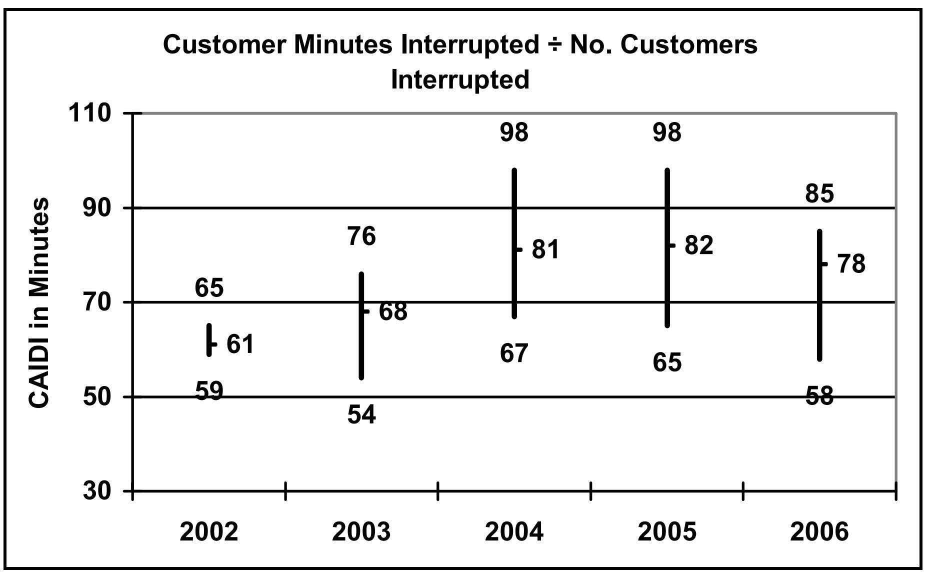
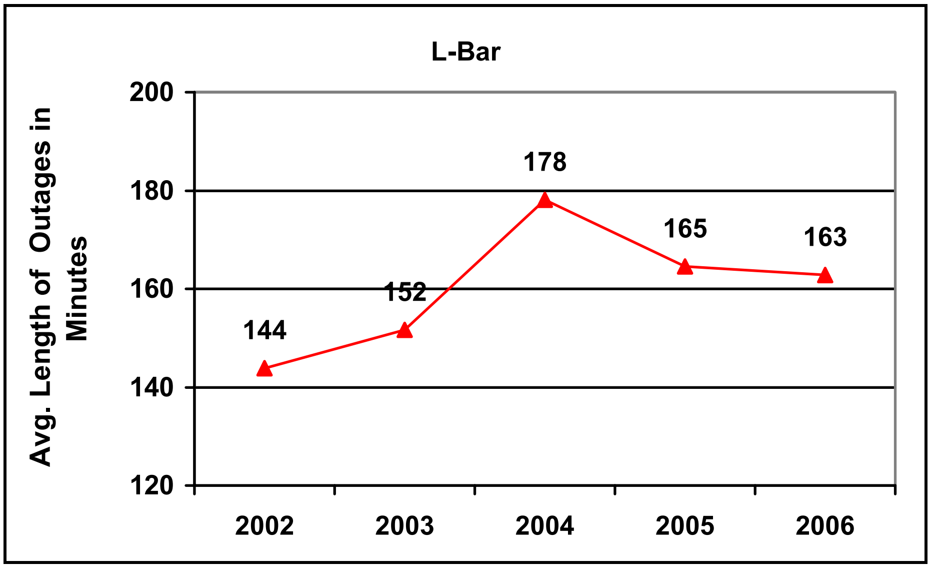


Figure 3-19. CAIDI Across TECO's 7 Regions (Adjusted)



The average length of time TECO's spends recovering from outage events, excluding hurricanes and other extreme outage events, is the index L-Bar shown in Figure 3-20 on the next page. The data demonstrates a general increase in outage durations for the period reviewed. Many factors contribute to increases in L-Bar, including increased number of underground outages, the cause and location of the outage event, the amount of distribution facilities needing replacement or repair, and the number of available trained and equipped personnel. TECO's report did not address any reasons for the observed increase in outage recovery time.

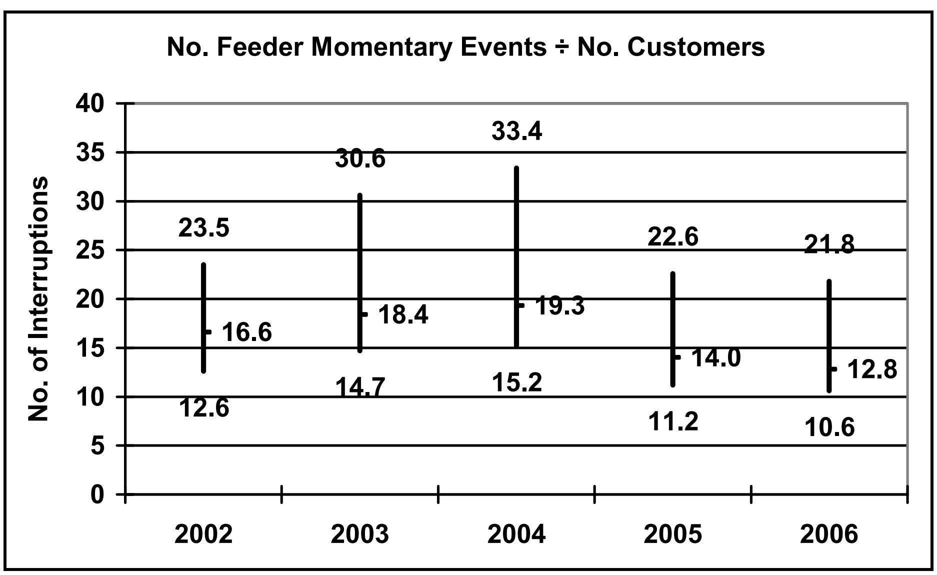
Figure 3-20. TECO's Avg. Duration of Outages (Adjusted)



Frequent outage problems experienced by a subset of customers indicate an opportunity for improvement. Such outage problems can be masked by the previously discussed indices of SAIDI, SAIFI, CAIDI, and L-Bar.

Figure 3-21 shows the maximum, average, and minimum adjusted MAIFIe recorded across TECO's system. TECO reported a declining MAIFIe in 2005 and 2006, a trend suggesting a general improvement compared to the prior four years.

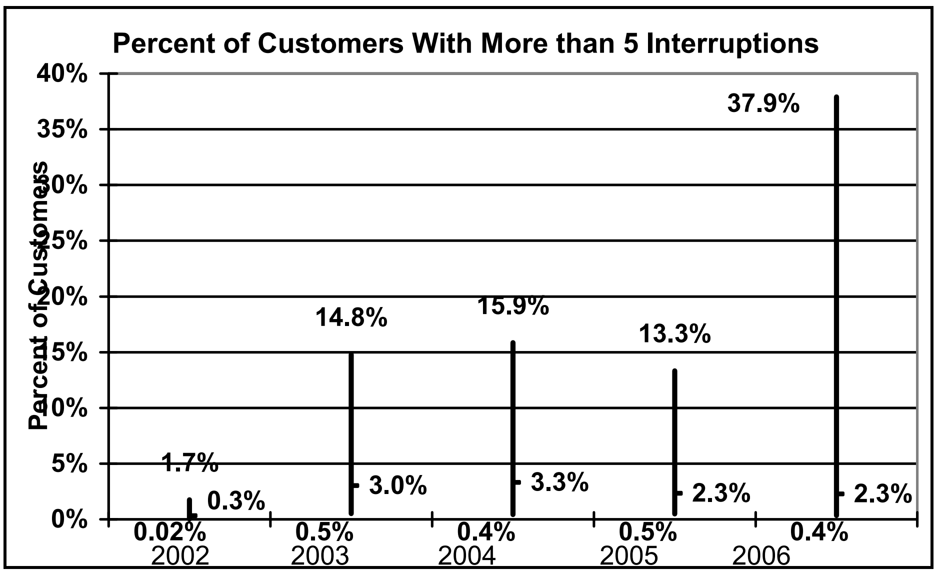
Figure 3-21. MAIFIe Across TECO's Regions (Adjusted)



Isolated momentary events also occur on segments of the distribution circuit remote from the substation where the MAIFIe data is measured. These remote momentary events often impact a small group of customers or even just one customer. At this time, no efforts are underway to capture all momentary events that occur because of the high costs to do so.

Figure 3-22 shows the maximum, average, and minimum adjusted CEMI5. Figure 3-22 shows an increasing difference in the level of reliability to pockets of customers throughout TECO's system. The three peak CEMI5 values were recorded for TECO's Dade City region which means small groups of customers in the Dade City are more likely to have outage events than small groups of customers located elsewhere in TECO's service area.

Figure 3-22. CEMI5 Across TECO's 7 Regions (Adjusted)



The Three Percent Feeder Report is a listing of the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences, Figure 3-23, is calculated from the number of recurrences divided by the number of feeders reported. Figure 3-23 shows the fraction of multiple occurrences of feeders using a three-year and five-year basis. In both cases, TECO's data shows a decreasing trend, implying improved performance. However, TECO's supporting data shows that the duration of reported feeder outage events (5,211 minutes in 2006) has increased to 163 percent of the reported duration of feeder outage events during 2002 (3,194 minutes). This increase in the duration of feeder outage events means the performance of TECO's primary circuits declined.

Figure 3-23. TECO's Three Percent Feeder Report (Adjusted)

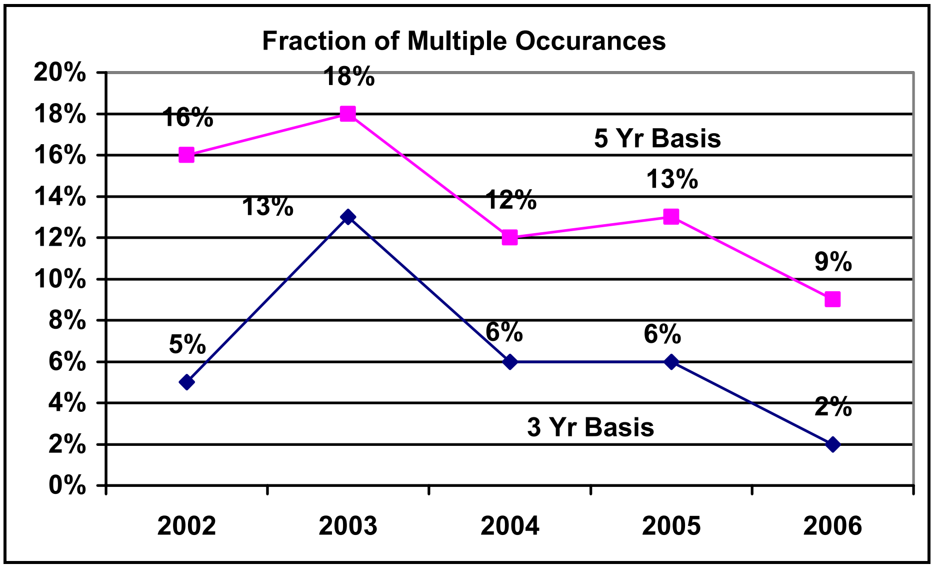
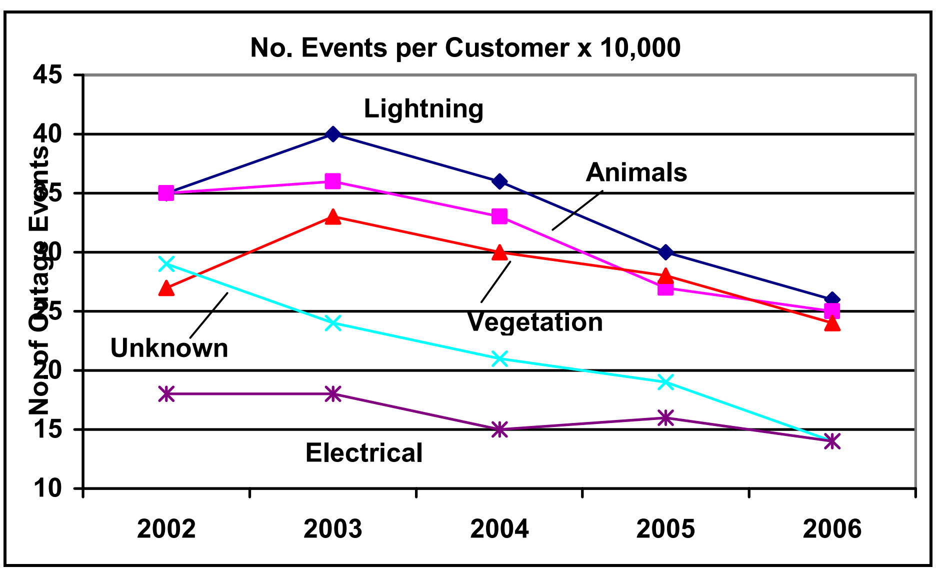


Figure 3-24 shows the top five causes of outage events on TECO's distribution system normalized to a 10,000 customer base. The figure is based on TECO's adjusted data of the top ten causes of outage events and represents 74 percent of the outage events that occurred between December 31, 2001, and January 1, 2007. For the five-year period, the five top causes of outages were: lightning (19 percent), animals (18 percent), vegetation (16 percent), unknown (12 percent), and electrical failures (9 percent) on a cumulative basis.

Figure 3-24. TECO's Top 5 Outage Causes (Adjusted)



There is no discernable increase in the causes of outage events by any causation. Review of TECO's supporting data, adjusted for customer growth, shows a sustained decreasing trend in the total number of outage events over the five-year period. The average annual decrease is 13 outage events per year on a 10,000 customer basis. Taken together, these results suggest TECO is implementing proactive measures that avoid outage events to its customers.

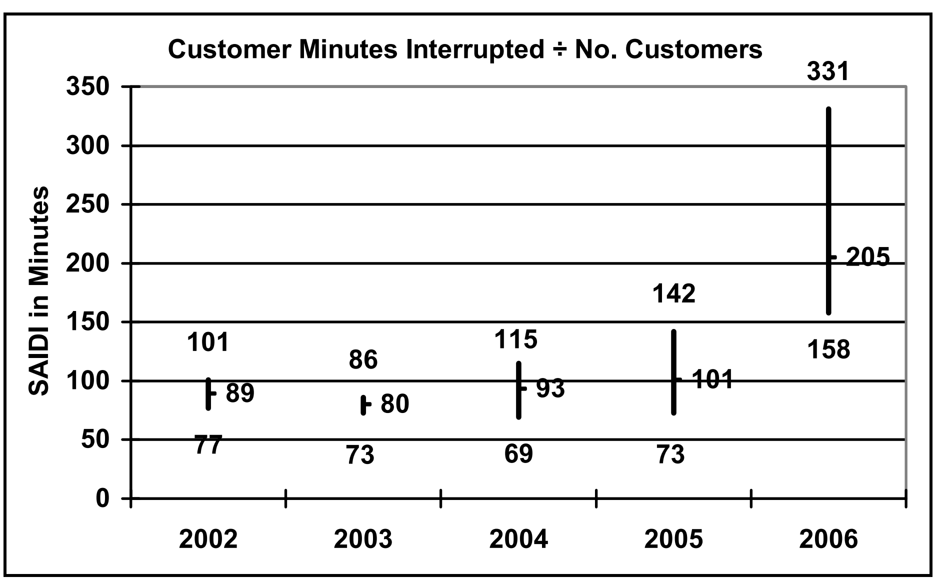
Observations: TECO' s Adjusted Data

Service reliaiblty in specific regions has declined in spite of recent improvements TECO has made on a system average basis. While TECO has long maintained that remote, rural areas with long feeders typically have lower service reliability; the growing disparity in service reliability between regions suggests other factors may be involved. TECO should consider measures to reverse these observed trends.

Gulf Power Company: Adjusted Data

Figure 3-25 shows the maximum, average, and minimum adjusted SAIDI recorded across GULF's system. The data clearly shows a significant increasing trend in SAIDI. GULF attributes the 2006 decline in reliability to lingering problems due to the effects of the hurricanes during 2004 and 2005. Additionally, GULF identifies several weather events that were not excluded because the events were not documented tornadoes or named weather systems. A review of supporting data for the period does not indicate that one of GULF's regions typically receives the lowest or highest SAIDI values. GULF's Western region, impacted by Hurricane Ivan in 2004 and Hurricane Katrina in 2005, had the lowest 2006 SAIDI of 158 minutes.

Figure 3-25. SAIDI Across GULF's 3 Regions (Adjusted)



Figures 3-26 and 3-27 show the maximum, average, and minimum adjusted SAIFI and adjusted CAIDI across GULF's system. Again, GULF's data shows marked increases in the 2006 reliability indices relative to the 2005 values. For 2006, GULF's Western region had the lowest SAIFI value of 1.27 and the lowest CAIDI value of 124 minutes. Nevertheless, these best 2006 regional values are substantial increases relative to prior years and demonstrate decreased reliability.

Figure 3-26. SAIFI Across GULF's 3 Regions (Adjusted)

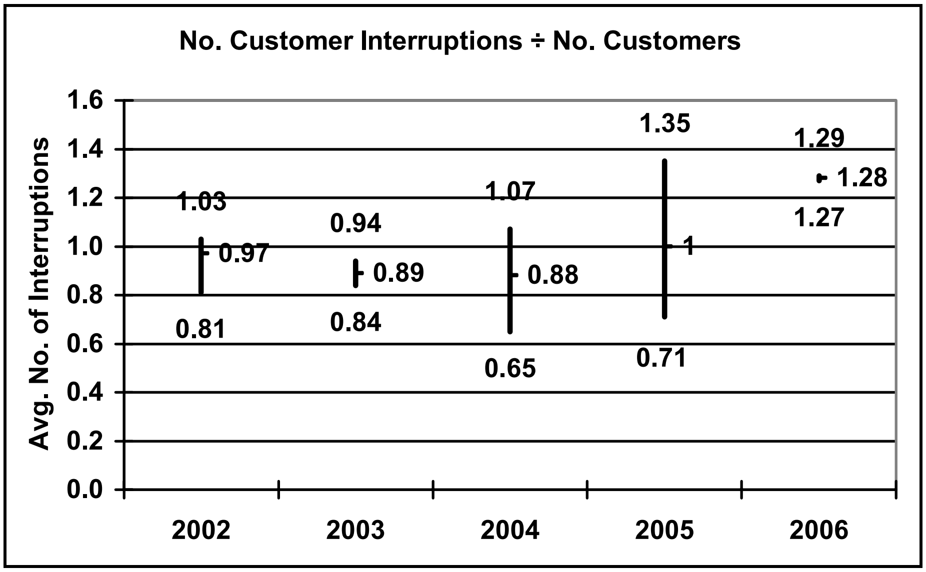
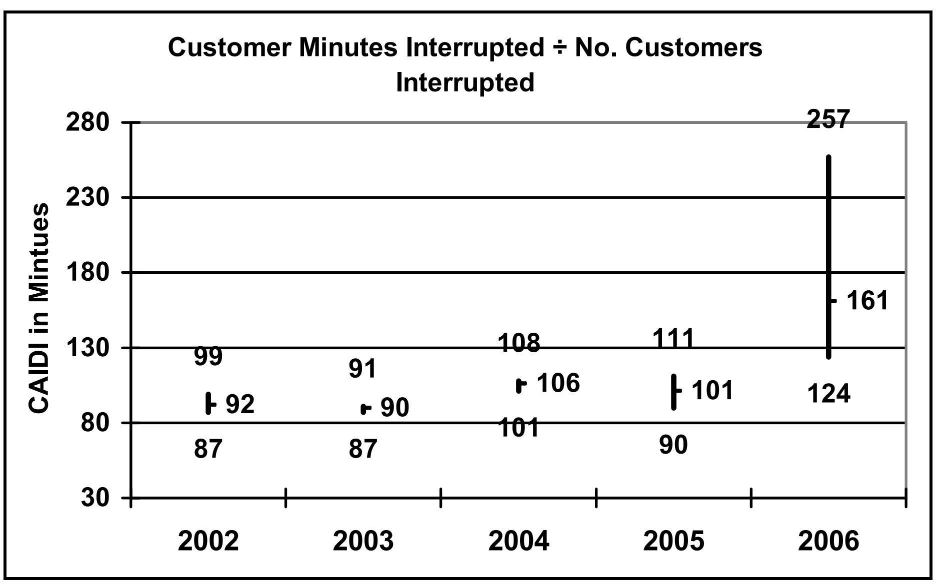
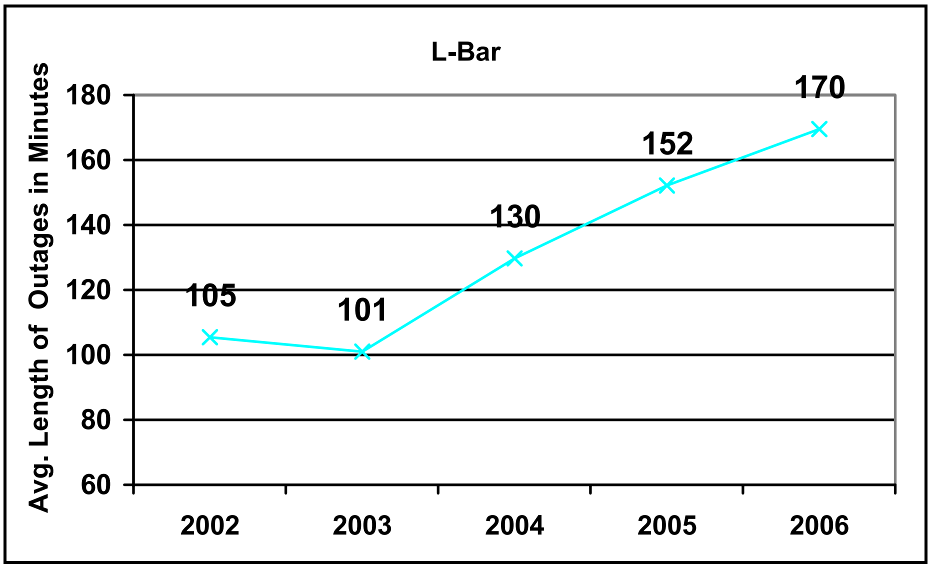


Figure 3-27. CAIDI Across GULF's 3 Regions (Adjusted)



The average length of time GULF's spends recovering from outage events, excluding hurricanes and other outage events, is the index L-Bar shown in Figure 3-28. Even with adjustments, GULF is spending more time restoring service every year since 2002. Many factors contribute to the increases in L-Bar, including increased number of underground outages, the cause and location of the outage event, the number of distribution facilities needing replacement or repair, and the number of available trained and equipped personnel. GULF's report did not address reasons for GULF's increasing outage recovery time.

Figure 3-28. GULF's Avg. Duration of Outages (Adjusted)



Frequent outage problems experienced by a subset of customers indicate an opportunity for improvement. Such outage problems can be masked by the previously discussed indices of SAIDI, SAIFI, CAIDI, and L-Bar.

Figure 3-29, shown on the following page, is the maximum, average, and minimum adjusted MAIFIe recorded across GULF's system. From 2002 through 2004, GULF reported an improving reliability trend that has now begun to deteriorate. At this time, it is unclear whether recent changes in GULF's MAIFIe is due to lingering problems due to the effects of storm damages during the 2004/2005 hurricane seasons. Isolated momentary events also occur on segments of the distribution circuit remote from the substation where the MAIFIe data is measured. These remote momentary events often impact a small group of customers or even just one customer. At this time, no efforts are underway to capture all momentary events that occur because of the high costs to do so.

Figure 3-29. MAIFIe Across GULF's 3 Regions (Adjusted)

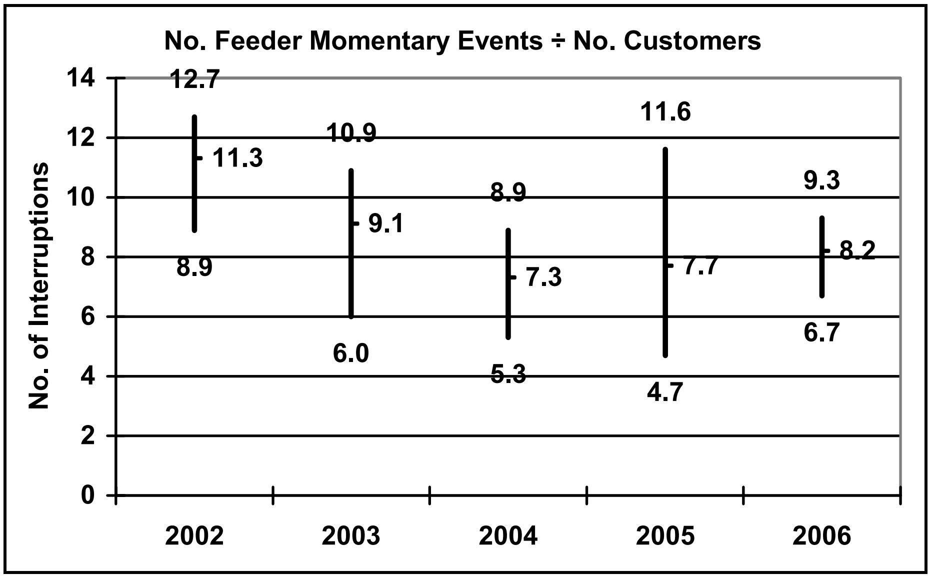
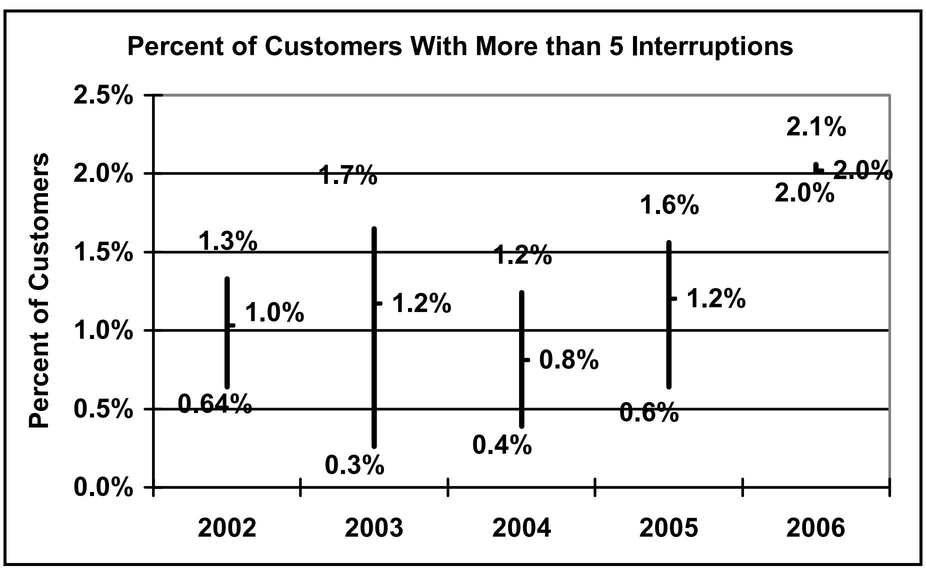


Figure 3-30 shows the maximum, average, and minimum adjusted CEMI5. In 2006, all of GULF's regions reported a general increase in the number of customers experiencing more than five outage events consistent with GULF's MAIFIe data.

Figure 3-30. CEMI5 Across GULF's 3 Regions (Adjusted)



The Three Percent Feeder Report is a listing of the top three percent of feeders with the most feeder outage events. The fraction of multiple occurrences, Figure 3-31, is calculated from the number of recurrences divided by the number of feeders reported. Figure 3-31 shows the fraction of multiple occurrences of feeders using a three-year and-five year basis. In both cases, GULF's data shows a decreasing trend which implies improved performance. However, the supporting data shows the duration of feeder outage events (2,670 minutes in 2006) increased by 169 percent from the values reported for 2002 (1,581 minutes). This increase in the duration of feeder outage events means the performance of GULF's primary circuits declined.

Figure 3-31. GULF's Three Percent Feeder Report (Adjusted)

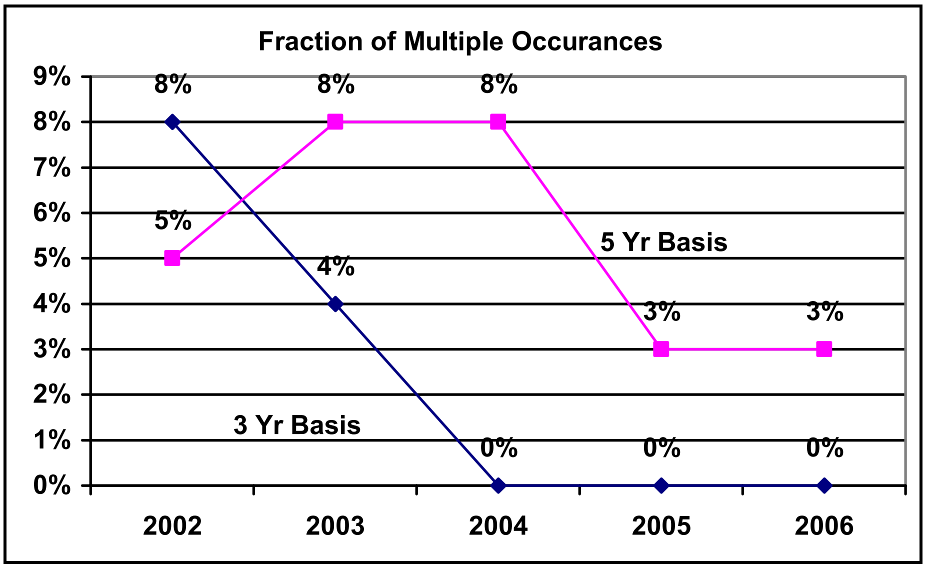
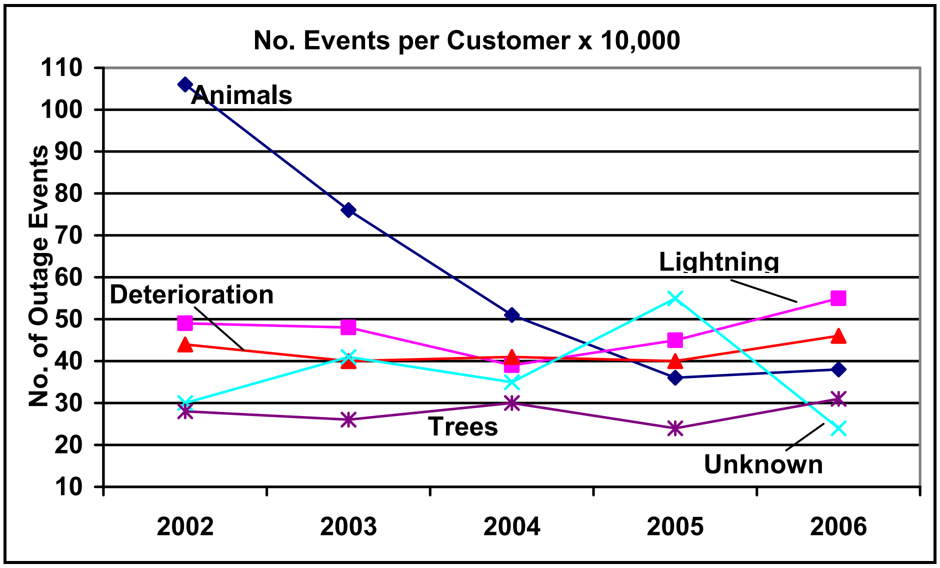


Figure 3-32, shown on the following page, is a graphic of the top five causes of outage events on GULF's distribution system normalized to a 10,000 customer base. The figure is based on GULF's adjusted data of the top ten causes of outage events and represents 87 percent of the outage events that occurred between December 31, 2001, and January 1, 2007. For the five-year period, the top five causes of outage events were: animals (25 percent), lightning (19 percent), deterioration (17 percent), unknown (15 percent), and trees (11 percent) on a cumulative basis. Relative to 2005, there is an increase in the number outage events caused by lightning (24.6 percent), deterioration (17.1 percent) and animals (8.3 percent). The total number of outage events in 2006 increased by 11.2 percent compared to 2004.

Figure 3-32. GULF's Top 5 Outage Causes (Adjusted)



Nevertheless, GULF's supporting data, adjusted for customer growth, shows a decreasing trend in the total number of outage events over the five-year period. The average annual decrease is 12 outage events per year on a 10,000 customer basis.

Observations: GULF' s Adjusted Data

The service reliabilty provided by GULF has recently declined. The frequency of customer service interruptions, the duration of service interruptions, and the length of outage events have increased for GULF's customers. Some of these increases may be attributed to the potential lingering effects from the storms of 2004 and 2005 and other weather related events in 2006.

Florida Public Utilities Company: Adjusted Data

Figure 3-33, shown on the following page, is the maximum, average, and minimum adjusted SAIDI recorded across FPUC's system. The data clearly shows an increasing trend in SAIDI and potentially an increasing difference in the level of reliability FPUC provides to its customers in each of FPUC's two regions. FPUC's report notes the recent decline in reliability but does not attribute the decline to any specific cause or causes. A review of supporting data for the period does not indicate that one of FPUC's regions typically receives the lowest or highest SAIDI values. Rather, a general trend of increasing customer interruption minutes suggests a general decline in reliability.

Figure 3-33. SAIDI Across FPUC's 2 Regions (Adjusted)

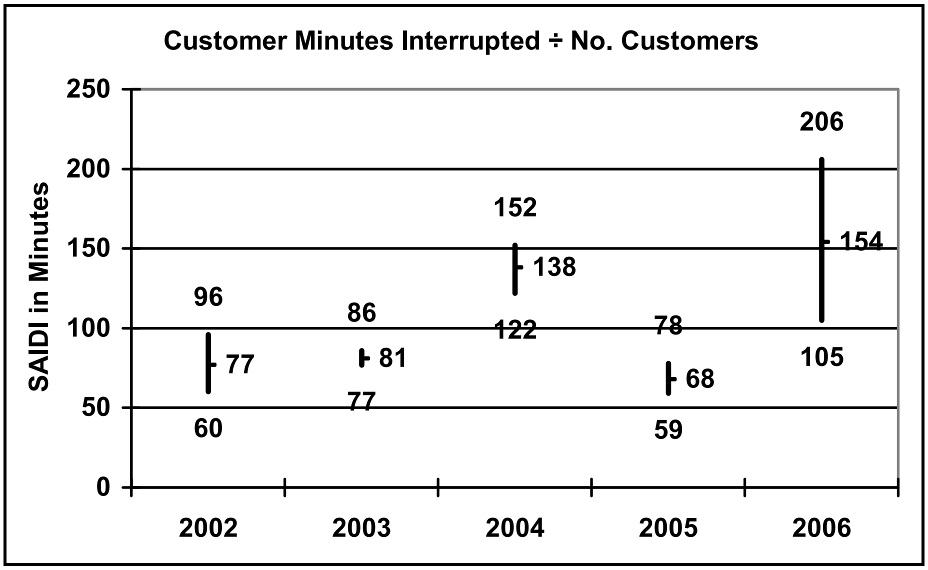


Figure 3-34 shows the maximum, average, and minimum adjusted SAIFI (number of interruptions per customer) across FPUC's system. FPUC's data shows marked increases in the 2006 reliability indices relative to 2005 values. FPUC supporting data shows FPUC's northeastern (Fernandina) region historically achieves fewer customer interruptions than FPUC's northwestern (Marianna) region.

Figure 3-34. SAIFI Across FPUC's 2 Regions (Adjusted)

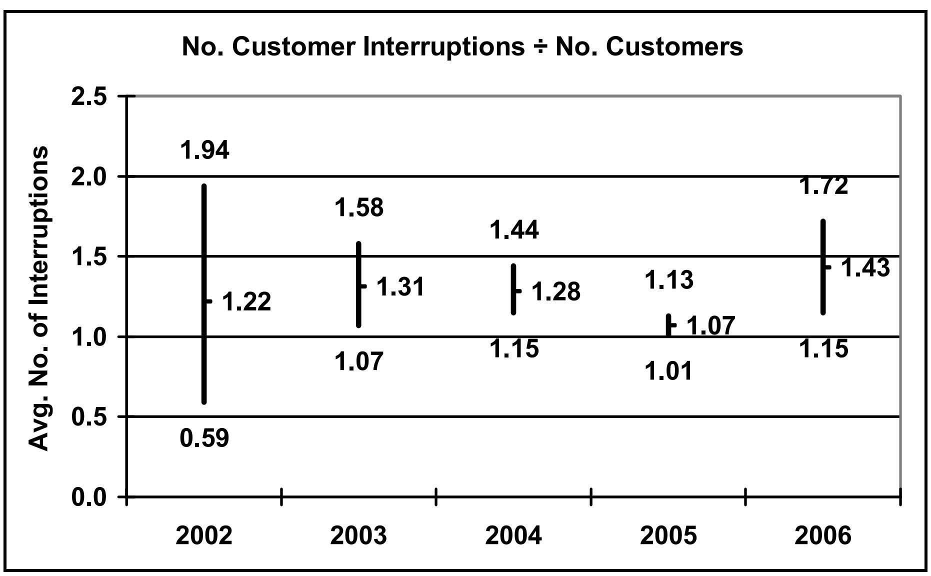


Figure 3-35 shows the maximum, average, and minimum adjusted CAIDI across FPUC's system. Again, FPUC's data shows marked increases in the 2006 reliability indices relative to 2005 values. Unlike regional data for other indices, no specific patterns were observed concerning the regional CAIDI values. The absence of a discernable pattern implies FPUC's outage response process and location of service centers relative to affected customers are comparable in both regions.

Figure 3-35. CAIDI Across FPUC's 2 Regions (Adjusted)

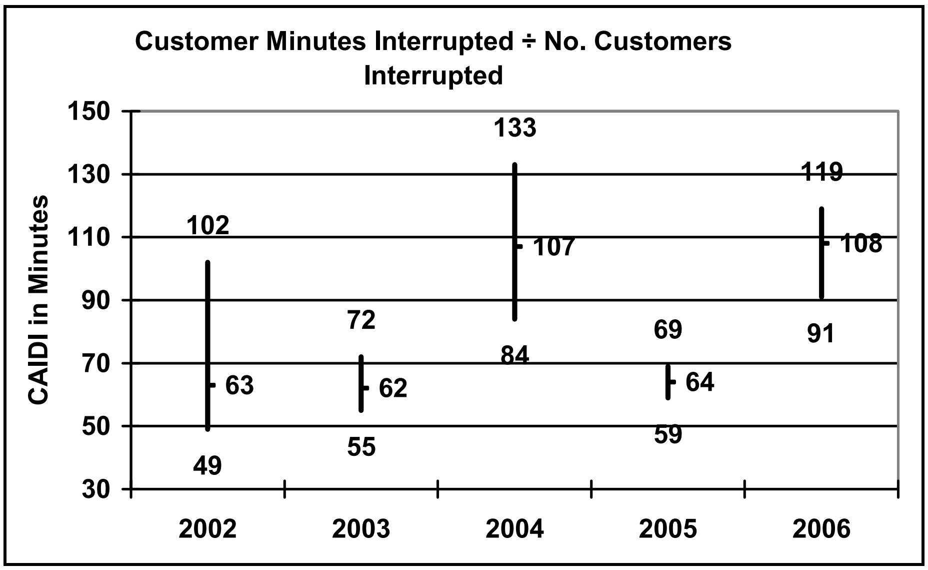
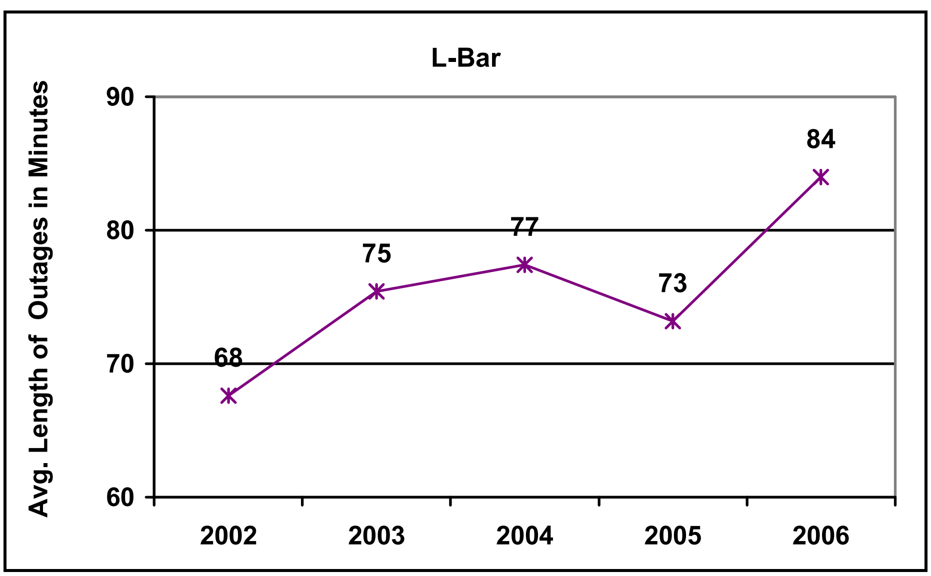


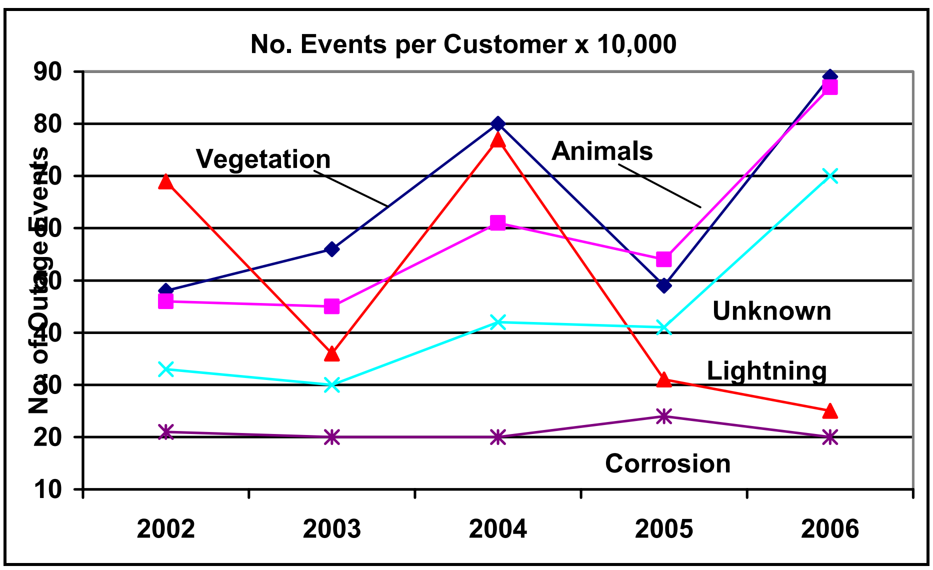
Figure 3-36. FPUC's Avg. Duration of Outages (Adjusted)



The average length of time FPUC spends recovering from outage events (adjusted L-Bar), is shown in Figure 3-36, on the previous page. The data demonstrates variability and a general increasing trend of longer outage recovery times. While variability is expected because FPUC is small, general increases in L-Bar are not expected. Many factors contribute to increases in L-Bar, including increased number of underground outages, the cause and location of the outage event, the number of distribution facilities needing replacement or repair, and the number of available trained and equipped personnel. FPUC's report does not address reasons for increases in outage recovery time.

Figure 3-37 shows the top five causes of outage events on FPUC's distribution system normalized to a 10,000 customer base. The figure is based on FPUC's adjusted data of the top ten causes of outage events and represents 80 percent of the outage events that occurred between December 31, 2001, and January 1, 2007. For the five-year period, the top five causes of outage event were: vegetation (22 percent), animals (20 percent), lightning (16 percent), unknown (15 percent) and corrosion (7 percent) on a cumulative basis. Relative to 2005, there is an increase in the number outage events caused by vegetation (90 percent), unknown causes (79 percent), and animals (68 percent). FPUC's supporting data, adjusted for customer growth, shows an increasing trend for the total number of outage events for the five-year period. The average annual increase is 18 outage events per year on a 10,000 customer basis.

Figure 3-37. FPUC's Top 5 Outage Causes (Adjusted)



These trends in the causes of outages are materially impacted by the large number of outage events FPUC reported for 2004 and 2006 compared to other years. Additionally, large variations are expected for a utility FPUC's size. However, for a larger utility increases in outages due to three causations (animals, vegetation and unknown) at the same time, as demonstrated by FPUC's data, are commonly associated with a decrease in vegetation management activities.

FPUC filed a Three Percent Feeder Report listing the top three percent of feeders with the most feeder outage events. However, FPUC has so few feeders (30 in 2005) that the data in the report has not been statistically significant. Beginning with FPUC's 2007 performance data filed in March 2008, an effort will be made to assess FPUC's Three Percent Feeder Report consistent with review of the Three Percent Feeder Reports provide by other utilities.

Rule 25-6.0455, F.A.C., waives the requirement to report information associated with metrics MAIFIe and CEMI5 for any utility with less than 50,000 customers. FPUC qualifies for this waiver and did not file any data pertaining to metrics MAIFIe and CEMI5. FPUC's size probably affords its management immediate knowledge of where problems are and the nature of such problems. Additionally, the cost for the information systems necessary to measure MAIFIe and CEMI5 has a higher impact on small utilities compared to large utilities on a per customer basis. Nevertheless, FPUC is implementing system improvement one region at a time, improvements which will enable its management to review detailed performance data such as MAIFIe and CEMI5 for the entire FPUC system. Beginning in 2007, FPUC will have the capability to report MAIFIe and CEMI5 for its Northwestern (Marianna) region. Typically, implementation of automated reliability performance information systems can cause reported data to show apparent declines in reliability. Such apparent changes range from a 10 to 30 percent increase in reliability statistics.

Observations: FPUC' s Adjusted Data

The service relibilty provided by FPUC in 2006 declined relative to prior years. The frequency of customer service interruptions, the duration of service interruptions, service restoration time, and the number of outage events increased for FPUC's customers. Significant effort by FPUC is required if the uility is to reduce its distribution reliability metrics to the levels achieved in 2002 and 2003.

Section IV. Inter-Utility Reliability Comparisons

Inter-Utility Reliability Trend Comparisons: Adjusted Data

Throughout the following comparative discussion it is important to remember that FPUC is a very small utility compared to the other IOUs. FPUC's size contributes to volatility in annual reliability data. Also, FPUC is exempt from reporting certain indices (MAIFIe and CEMI5) because FPUC has less than 50,000 customers. Nevertheless, FPUC is gradually implementing information system upgrades that will enable data collection and reporting of the MAIFIe and CEMI5 reliability metrics.

Figure 4-1 is a ten-year graph of the adjusted SAIDI (system average minutes of interruptions per customer) for each IOU. The increases in SAIDI for GULF prior to 2000, and for TECO prior to 2003, are associated with upgrades to their information systems that began capturing more detailed outage data. Both GULF and FPUC show an increasing trend in SAIDI relative to the other IOUs.

Figure 4-1. Avg. Interruption Duration (Adjusted SAIDI)

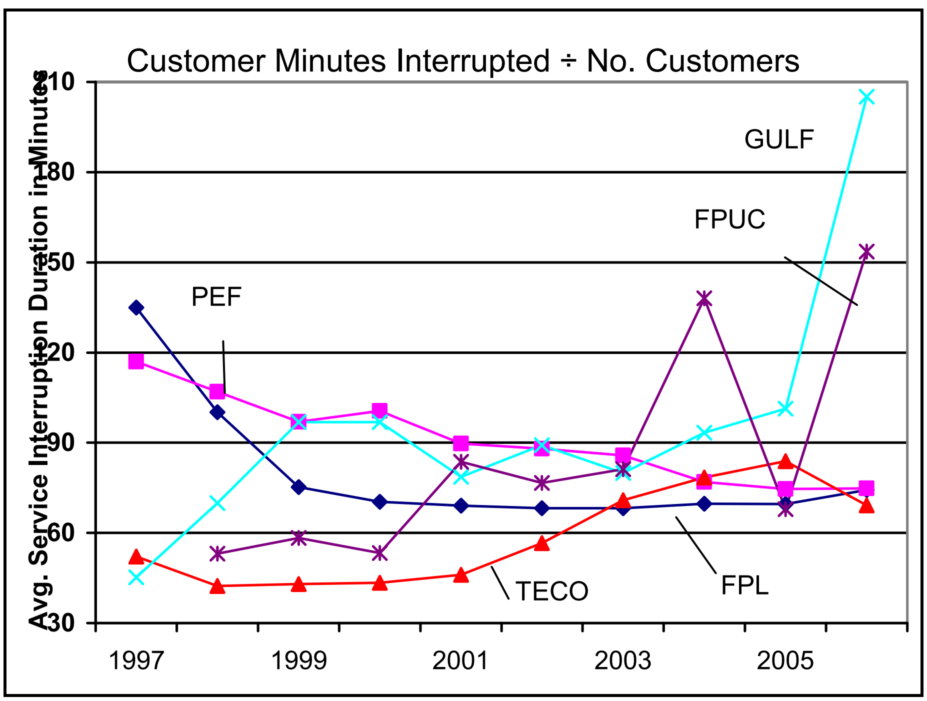


Figure 4-2 is a ten-year graph of the adjusted SAIFI (system average frequency of interruptions per customer) for each IOU. In 2006, FPUC recorded significantly higher values compared to the other IOUs.

Figure 4-2. Avg. Number of Service Interruptions (Adjusted SAIFI)

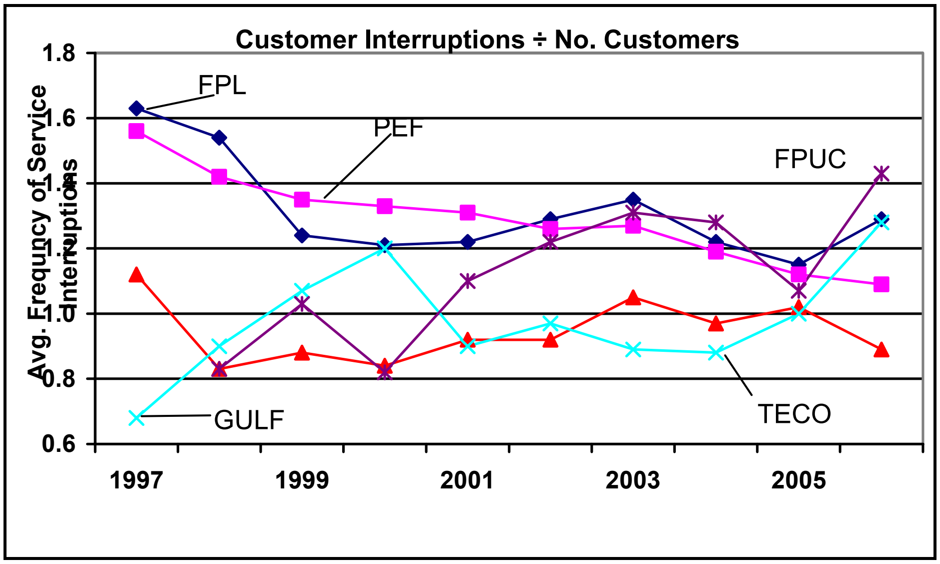


Figure 4-3. Avg. Service Restoration Time (Adjusted CAIDI)

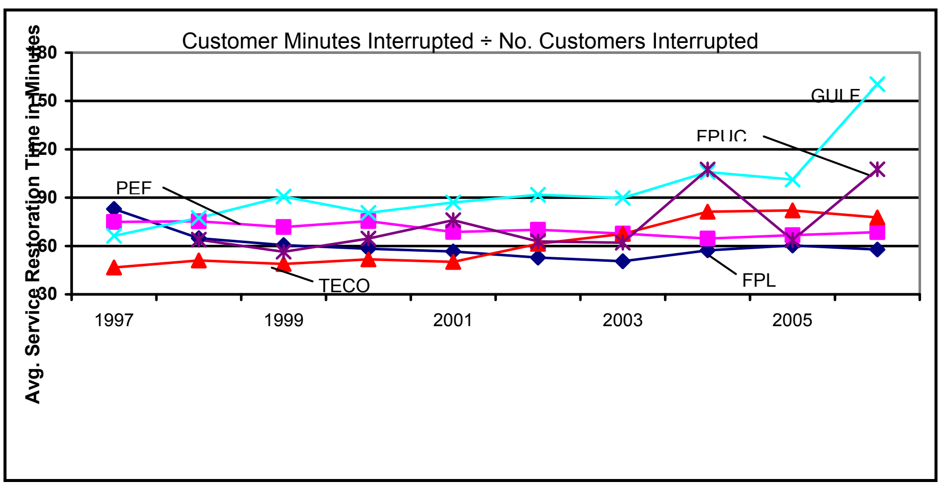


Figure 4-3 is a ten-year graph of the adjusted CAIDI (system average customer interruption duration) for each IOU. Through 2006, GULF allowed its CAIDI values, which are greater than those of other IOUs, to continue increasing. FPUC and TECO also allowed CAIDI to increase over time, although not as significantly as GULF.

Figure 4-4. Avg. Number of Feeder Momentary Events (Adjusted MAIFIe)

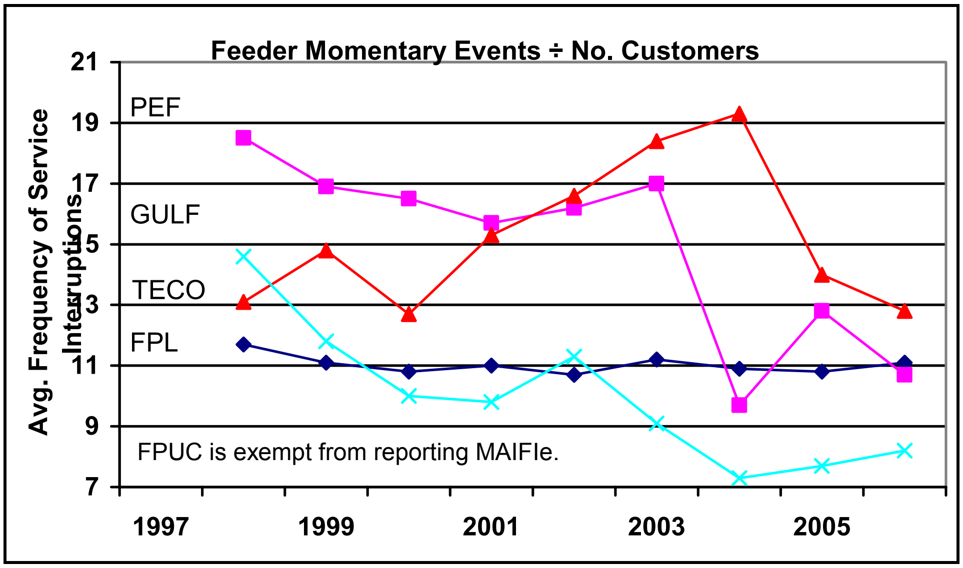


Figure 4-4 is a nine-year graph of the adjusted MAIFIe (system average frequency of momentary events on primary circuits per customer) for FPL, PEF, TECO and GULF. Prior to 2002, reporting MAIFIe data was voluntary. TECO, PEF, and GULF show lower values compared to performance in 2002. FPL remains relatively unchanged for the 2002 through 2006 year period.

Figure 4-5 Percent of Customers With More Than 5 Interruptions (Adjusted CEMI5)

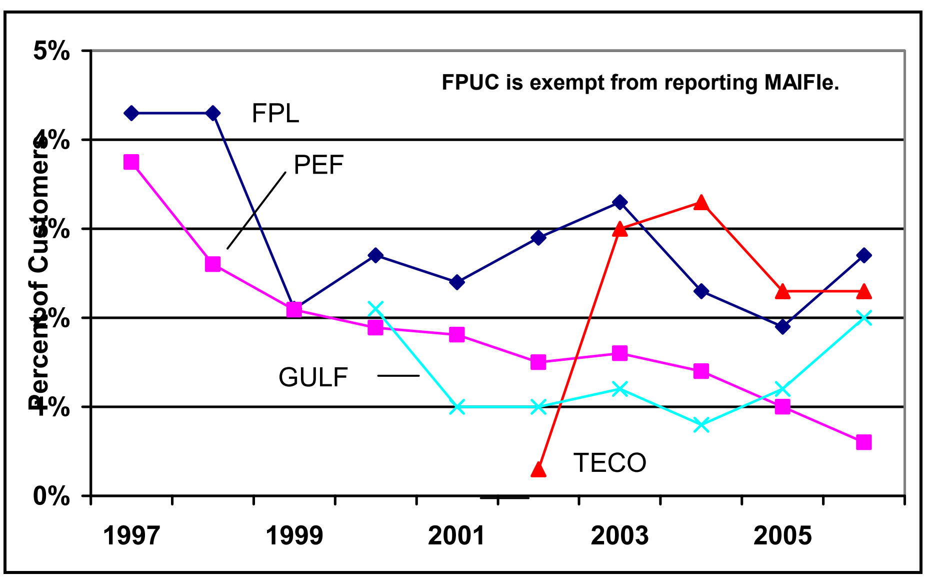


Figure 4-5, shown on the prior page, is a ten-year graph of the adjusted CEMI5 (percentage of customers experiencing more than five service interruptions) for FPL, PEF, TECO and GULF. Prior to 2002, reporting was voluntary. IOUs with less than 50,000 customers are not required to report. FPUC qualifies for this reporting waiver. The Adjusted CEMI5 increased in 2006 for FPL and GULF relative to 2005, indicating that groups of customers experienced more outages in 2006 than in 2005 on a hurricane adjusted basis. PEF, for the second year, reported the lowest adjusted CEMI5. TECO's increase in CEMI5 between 2002 and 2003 is attributed to the implementation of a new information system.

Figure 4-6. Avg. Number of Outages to 10,000 Customers (Adjusted N)

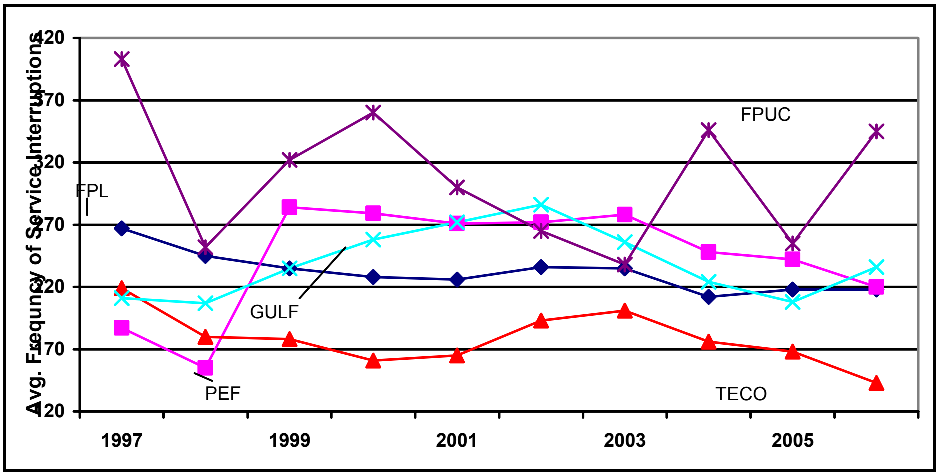
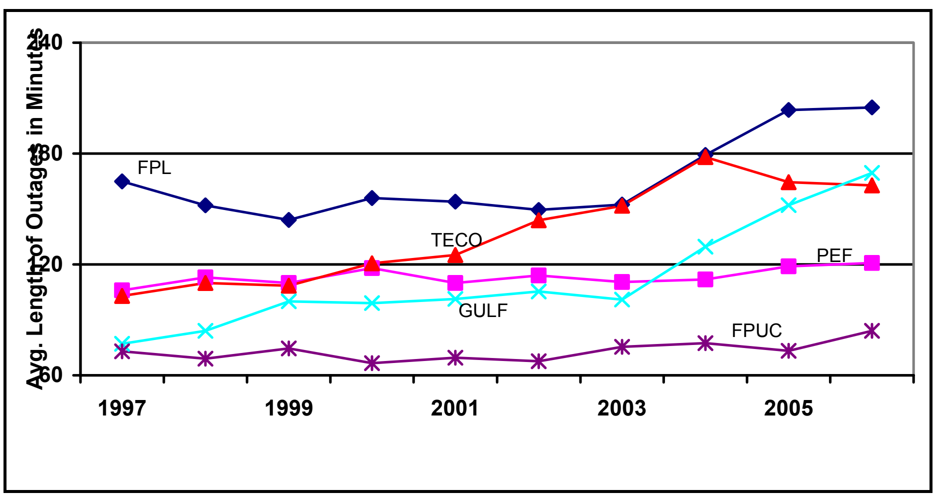


Figure 4-7. Avg. Duration of Outage Events (Adjusted L-Bar)



The average duration of outage events (Adjusted L-Bar) for each IOU is graphed in Figure 4-7. On average, FPL now spends in excess of three hours recovering from outage events, which is 2.44 times longer that FPUC. The outage recovery time for both TECO and

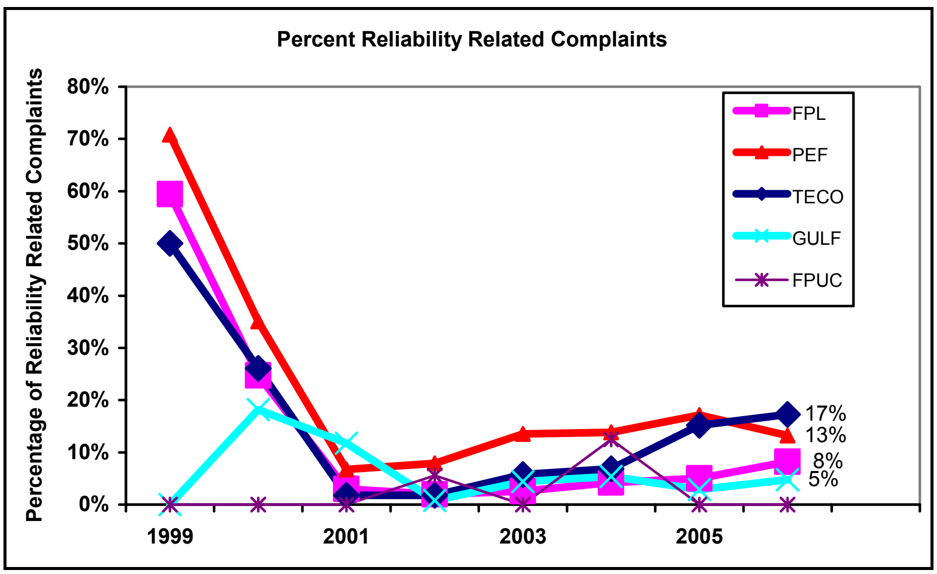
GULF has also increased over time. Both PEF and FPUC have remained relatively constant over the period and show slight increases in recent years.

Inter-Utility Comparisons of Reliability Related Complaints

Each customer complaint received by the Commission is assigned a category after the complaint is resolved. Reliability related complaints are those pertaining to trees, safety, repairs, quality of service, and service interruptions. Tracking complaints in concert with reliability performance began in 1999.

As shown in Figure 4-8, the percentage of reliability related customer complaints dropped from 1999 levels but is now trending upwards for FPL, PEF, TECO. and GULF. The apparent volatility in FPUC's reliability related customer complaints is due to FPUC's small customer base which exaggerates the significance of one complaint in years 2002 and 2004.

Figure 4-8. Percent of Complaints That Are Reliability Related



The gradual increase in reliability related complaints from 2002 to current levels is exceeding customer growth rates for the major IOUs. TECO has experienced the highest increase in percentage of reliability complaints (59 percent), followed by FPL (27 percent), and PEF and Gulf (both 19 percent) relative to year-end customer growth rates.

Figure 4-9. Service Reliability Related Complaints

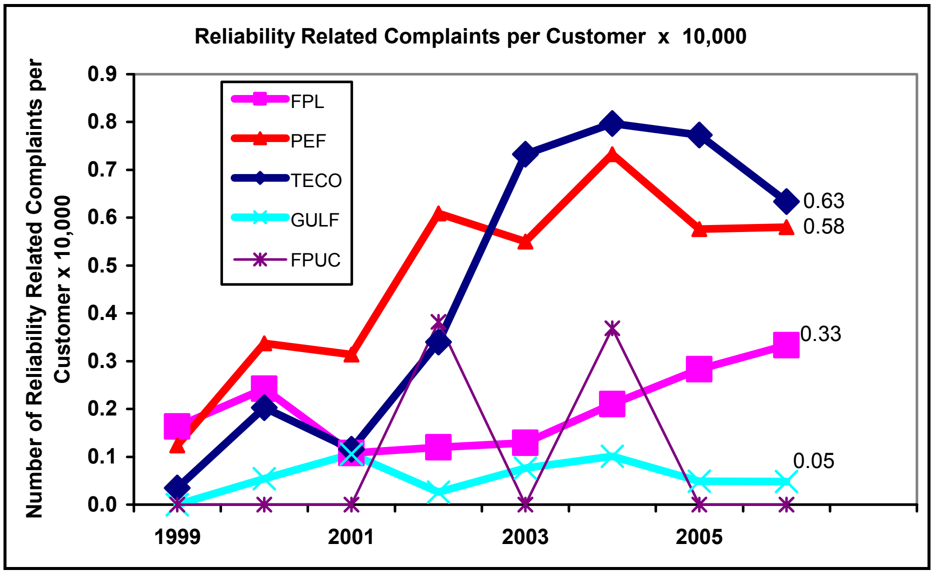


Figure 4-9 provides the volume of reliability related complaints per customer normalized to a 10,000 customer basis for each utility. The data is normalized because utility size impacts both the volume of complaints and the significance of trends. Due to FPUC's small size, in 2006, one FPUC complaint had the equivalent impact on the data in Figure 4-9 as 153 FPL complaints, 56 PEF complaints, 23 TECO complaints and 15 GULF complaints. Figure 4-9 demonstrates that, on an equivalent basis, both FPUC and GULF have significantly fewer reliability related customer complaints compared to the other IOUs.

Additionally, no sustained increase in the volume of reliability related customer complaints exists, since 2002, for FPUC and GULF, unlike the increasing volume of reliability related customer complaints recorded for the other IOUs for the same period. The most significant increases since 1999 were noted for TECO (17 times) and PEF (4 times).

Section V. Appendices

Appendix A. Adjusted Service Reliability Data

Florida Power & Light Company:

Table A-1. FPL's Number of Customers (Year End)

	2002	2003	2004	2005	2006
Gulf Coast	342,679	357,399	374,578	393,653	414,519
Manasota	330,072	336,408	342,322	351,134	358,098
Boca Raton	317,286	337,025	340,279	343,569	347,030
West Palm	316,623	314,635	322,670	332,194	337,612
Gulf Stream	298,737	304,203	310,684	313,158	316,390
Pompano	291,116	293,716	296,961	298,740	299,874
S.Dade	267,763	272,793	278,713	286,995	293,656
Brevard	251,973	259,357	264,851	272,758	281,090
Treasure Coast	219,945	229,436	237,794	252,063	264,835
C. Florida	223,787	230,764	241,517	253,134	261,990
Wingate	248,234	249,639	251,910	253,775	254,358
Central Dade	224,891	228,043	231,185	235,400	242,649
N. Dade	211,500	215,306	216,609	218,848	222,019
W. Dade	208,586	211,497	214,338	218,097	221,686
Toledo Blade	141,285	145,814	144,993	154,821	164,917
N. Florida	111,720	115,386	120,285	127,860	134,688
FPL System	4,006,197	4,101,421	4,189,689	4,306,199	4,415,411

Table A-2. FPL's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
Gulf Coast	86.4	80.2	64.2	71.0	79.7	1.54	1.63	1.22	1.26	1.53	56.2	49.3	52.7	56.4	52.2
Manasota	69.4	58.5	61.1	54.0	66.4	1.06	1.06	0.84	0.83	1.01	65.2	55.0	72.4	65.2	66.0
Boca Raton	67.1	65.7	61.5	77.8	74.7	1.38	1.37	1.23	1.35	1.39	48.6	48.0	49.9	57.8	53.9
West Palm	59.4	62.8	66.1	76.2	83.5	1.08	1.19	1.16	1.27	1.27	54.8	52.9	56.7	59.9	65.7
Gulf Stream	57.0	54.1	49.9	55.7	59.7	1.15	1.29	1.06	1.04	1.28	49.7	42.0	47.0	53.6	46.6
Pompano	43.9	53.7	53.5	55.2	67.7	0.94	1.19	0.86	0.88	1.16	46.5	45.2	62.4	62.8	58.2
S.Dade	62.7	67.8	65.6	74.2	83.1	1.13	1.30	1.25	1.27	1.25	55.3	52.3	52.3	58.6	66.2
Brevard	68.1	66.2	80.8	63.3	55.4	1.41	1.32	1.32	1.02	1.03	48.2	50.1	61.2	61.9	53.9
Treasure Coast	100.7	100.3	116.7	101.1	80.9	1.92	1.90	1.77	1.43	1.41	52.3	52.8	65.9	70.7	57.5
C. Florida	81.8	99.5	107.0	74.4	69.8	1.52	1.89	1.73	1.31	1.27	53.9	52.6	61.9	56.9	54.9
Wingate	67.3	68.1	55.0	74.6	82.7	1.45	1.54	1.33	1.39	1.51	46.5	44.1	41.2	53.8	54.6
Central Dade	59.6	46.7	49.1	55.2	63.6	1.22	0.94	0.91	1.02	1.05	49.0	49.7	54.2	53.9	60.8
N. Dade	60.3	63.3	74.0	75.8	77.8	1.07	1.10	1.13	1.03	1.19	56.4	57.5	65.2	73.6	65.2
W. Dade	62.4	55.7	64.3	72.2	94.4	1.14	1.20	1.10	1.30	1.64	54.9	46.3	58.4	55.7	57.4
Toledo Blade	76.1	61.4	93.3	61.4	81.8	1.53	1.00	1.44	0.82	1.42	49.8	61.5	64.7	74.5	57.6
N. Florida	89.1	117.4	96.3	79.6	74.4	1.46	1.90	1.61	1.10	1.14	61.2	61.9	59.9	72.2	65.2
FPL Sys.	68.2	68.2	69.7	69.6	74.3	1.29	1.35	1.22	1.15	1.29	52.8	50.5	57.3	60.4	57.8

Table A-3. FPL's Adjusted Regional Indices MAIFIe and CEMI5

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
Gulf Coast	10.8	10.6	8.8	8.7	9.8	6.2%	5.5%	1.6%	2.4%	3.1%
Manasota	8.1	8.3	8.1	8.5	9.3	1.8%	1.4%	1.1%	1.0%	1.2%
Boca Raton	9.1	8.1	9.7	8.2	8.8	2.5%	2.8%	1.2%	1.1%	2.1%
West Palm	12.5	14.1	11.3	11.4	11.7	1.5%	2.4%	1.2%	2.5%	2.5%
Gulf Stream	10.1	10.9	11.1	9.8	8.9	1.1%	2.1%	1.8%	1.6%	5.4%
Pompano	7.6	8.2	7.6	7.8	7.8	1.0%	2.8%	0.4%	0.6%	2.3%
S.Dade	11.2	12.9	11.5	11.9	10.3	2.9%	3.2%	2.1%	3.1%	2.3%
Brevard	15.3	15.3	13.9	14.1	15.8	5.6%	1.7%	2.2%	0.5%	0.8%
Treasure Coast	16.5	20.4	16.5	15.6	14.6	7.6%	7.3%	6.3%	4.2%	4.6%
C. Florida	11.1	10.9	13.3	15.1	12.8	2.5%	6.9%	5.3%	2.8%	2.0%
Wingate	11.7	8.3	11.2	12.0	12.8	2.4%	3.1%	2.7%	2.2%	2.3%
Central Dade	7.8	7.8	9.0	7.8	8.9	2.9%	0.8%	2.0%	2.1%	1.2%
N. Dade	9.6	9.5	9.4	8.8	9.7	1.4%	3.2%	3.1%	1.1%	2.5%
W. Dade	9.9	14.4	11.2	9.8	10.6	0.8%	2.0%	2.1%	2.0%	7.4%
Toledo Blade	13.3	12.5	13.9	16.3	20.4	3.3%	1.9%	4.6%	1.9%	2.9%
N. Florida	7.2	8.3	12.8	13.2	12.5	4.9%	7.7%	3.6%	1.9%	1.4%
FPL System	10.7	11.2	10.9	10.8	11.1	2.9%	3.3%	2.3%	1.9%	2.7%

Table A-4. FPL's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2002	2003	2004	2005	2006	Cumulative Percentages	2002	2003	2004	2005	2006
Equip. Failure	14,696	22,728	21,633	26,752	27,692	24.2%	203	200	217	249	255
Unknown	13,678	14,469	13,811	16,970	17,273	16.2%	126	128	149	149	183
Vegetation	16,906	19,307	15,225	10,571	8,911	15.1%	149	155	174	199	192
Animal	10,490	11,445	10,153	8,711	10,006	10.8%	74	74	79	113	113
All Other	18,479	4,296	6,261	5,842	5,318	8.6%	160	149	287	223	203
Other Weather	8,281	9,083	7,413	7,250	7,148	8.3%	108	106	132	144	156
Other	3,077	4,956	6,575	8,865	10,165	7.2%	141	155	178	184	193
Lightning	4,625	5,074	4,212	4,682	4,575	4.9%	227	233	262	289	301
Equip. Connect	1,875	2,339	1,932	2,288	2,925	2.4%	160	163	171	217	227
Vehicle	1,645	1,791	1,751	1,905	2,181	2.0%	191	194	204	236	231
Dig-in	807	767				0.3%	225	207			
FPL System	94,559	96,255	88,966	93,836	96,194	100.0%	150	150	179	204	205

Notes:
(1) "Other" category is a sum of outage events that require a detailed explanation.
(2) "All Other" category is the sum of many diverse causes of outage events which individually are not among the top ten causes of outage events and excludes those identified as "Other".
(3) Blanks are shown for years where the number of outages was too small to be among the top ten causes of outage events

Progress Energy Florida, Inc:

Table A-5. PEF's Number of Customers (Year End)

	2002	2003	2004	2005	2006
S. Coastal	628,228	530,387	638,170	647,997	651,800
S. Central	324,916	344,656	360,327	384,292	401,943
N. Central	416,604	421,595	366,161	363,656	371,357
N. Coastal	107,376	211,999	176,744	183,861	190,414
PEF System	1,477,124	1,508,637	1,541,402	1,579,806	1,615,514

Note: PEF changed the boundaries of its regions in 2002-2003.

Table A-6. PEF's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
S. Coastal	66	66	66	64	70	1.05	1.13	1.09	1.04	1.07	62.6	58.8	60.7	61.8	65.2
S. Central	86	78	68	82	75	1.18	1.05	1.10	1.24	1.12	72.5	74.1	62.0	66.7	66.5
N. Central	106	107	77	73	77	1.50	1.56	1.22	1.09	1.13	70.7	68.8	63.2	67.2	68.1
N. Coastal	156	104	132	98	89	1.72	1.38	1.64	1.21	1.02	90.4	75.8	80.3	80.7	86.9
PEF Sys.	88	86	77	75	75	1.26	1.27	1.19	1.12	1.09	70.1	67.7	64.7	66.7	68.6

Table A-7. PEF's Adjusted Regional Indices MAIFIe and CEMI5

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
S. Coastal	16.7	18.0	13.0	12.8	12.5	0.60%	0.68%	1.14%	0.62%	0.51%
S. Central	15.7	17.4	8.3	13.9	10.6	1.62%	0.90%	0.47%	1.68%	0.44%
N. Central	16.2	15.4	7.3	12.3	9.1	2.10%	2.56%	1.00%	0.78%	0.77%
N. Coastal	14.1	17.4	5.9	11.2	8.2	3.56%	2.96%	4.76%	1.48%	0.60%
PEF System	16.2	17.0	9.7	12.8	10.7	1.46%	1.58%	1.37%	1.01%	0.56%

Table A-8. PEF's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2002	2003	2004	2005	2006	Cumulative Percentages	2002	2003	2004	2005	2006
Animals	4,871	5,044	5,422	4,430	4,602	12.6%	63	60	58	65	140
Storm	4,400	6,472	4,208	3,337	4,534	11.8%	114	104	106	111	158
Tree-preventable	4,013	5,380	4,546	3,814	3,552	11.0%	113	112	113	107	109
Unknown	5,326	4,964	4,362	4,058	3,685	11.5%	78	73	73	74	74
All Other	3,589	3,748	3,285	3,946	3,064	9.1%	107	107	107	115	138
Defective Equip.	3,674	3,382	3,289	3,694	3,317	8.9%	164	169	165	180	181
UG Sec. / Service	3,492	3,522	3,450	4,139	4,464	9.8%	154	139	156	156	158
Connector Failure	2,885	2,923	2,830	2,853	2,967	7.4%	97	92	95	102	106
Tree Non-preventable	2,993	2,757	2,247	2,044	1,823	6.1%	122	125	116	112	119
UG Primary	2,805	2,578	2,323	2,586	2,735	6.7%	163	173	176	198	184
Lightning	2,145	1,103	2,287	3,277	875	5.0%	122	157	125	116	189
PEF System	40,193	41,873	38,249	38,178	35,618	100%	114	111	112	119	121

Note: "All Other" category is the sum of diverse causes of outage events which individually are not among the top ten causes of outage events.

Tampa Electric Company:

Table A-9. TECO's Number of Customers (Year End)

	2002	2003	2004	2005	2006
Western	181,194	181,164	182,791	184,826	185,868
Central	171,507	168,119	171,187	175,919	179,020
Eastern	95,339	95,517	98,326	102,328	105,687
Winter Haven	63,673	62,015	63,013	64,981	67,362
S. Hillsborough	43,838	45,837	49,271	53,627	57,675
Plant City	49,436	48,885	50,032	51,633	53,081
Dade City	13,174	12,644	13,000	13,421	13,818
TECO System	618,161	614,181	627,620	646,735	662,511

Table A-10. TECO's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
Western	57	66	59	75	64	0.93	0.86	0.69	0.88	0.75	62	76	85	85	85
Central	44	60	82	61	55	0.72	0.80	0.84	0.77	0.67	61	74	98	79	83
Eastern	53	62	81	97	62	0.81	1.14	1.02	1.13	0.87	65	54	80	86	71
Winter Haven	58	65	71	65	58	0.97	1.16	1.04	1.01	1.00	60	56	68	65	58
S. Hills.	79	90	89	127	96	1.34	1.21	1.33	1.38	1.15	59	75	67	92	84
Plant City	73	120	105	130	96	1.25	1.83	1.58	1.69	1.25	59	66	67	77	77
Dade City	88	130	174	148	209	1.41	2.19	1.95	1.50	2.78	63	59	90	98	75
TECO	57	71	78	84	69	0.92	1.05	0.97	1.02	0.89	61	68	81	82	78

Table A-11. TECO's Adjusted Regional Indices MAIFIe and CEMI5

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
Western	15.9	17.9	15.2	11.4	12.6	0.21%	0.52%	0.44%	0.57%	0.61%
Central	12.6	14.7	16.3	11.2	10.6	0.09%	3.81%	1.17%	0.52%	0.35%
Eastern	17.9	17.8	20.7	15.5	12.6	0.13%	0.99%	3.57%	1.20%	0.66%
Winter Haven	16.0	17.8	23.4	15.8	12.3	0.02%	1.55%	5.16%	0.49%	1.19%
S. Hillsborough	23.5	25.7	26.6	19.4	15.4	1.74%	7.28%	3.69%	8.52%	1.05%
Plant City	23.0	24.5	26.3	19.6	17.3	0.85%	8.35%	14.45%	13.31%	11.05%
Dade City	23.0	30.6	33.4	22.6	21.8	0.10%	14.78%	15.85%	0.63%	37.90%
TECO System	16.6	18.4	19.3	14.0	12.8	0.32%	3.02%	3.30%	2.33%	2.26%

Table A-12. TECO's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2002	2003	2004	2005	2006	Cumulative Percentages	2002	2003	2004	2005	2006
Lightning	2,148	2,481	2,283	1,962	1723	19.0%	191	241	246	220	224
Animal	2,133	2,192	2,083	1,742	1656	17.6%	81	79	93	91	82
Vegetation	1,668	2,003	1,880	1,797	1564	16.0%	158	172	202	157	153
Unknown	1,783	1,487	1,335	1,243	895	12.1%	124	191	146	130	123
Other Weather	976	1,009	911	930	703	8.1%	147	160	187	161	163
Electrical	1,125	1,122	955	1,065	954	9.4%	164	154	180	190	189
Bad Connection	752	841	694	917	704	7.0%	149	158	179	182	186
Human Interference	349		222	266		1.5%	145		193	200	
Vehicle	331	348	235	349	334	2.9%	171	163	169	182	180
Defective Equip.	290	317	210	291	441	2.8%	154	182	207	217	209
All Other	345	276	235	311	264	2.6%	152	138	187	174	177
Down Wire		265			237	0.9%		177			197
TECO System	11,900	12,341	11,043	10,873	9,475	100.0%	144	167	178	164	163

Notes:

(1) "All Other" category is the sum of many diverse causes of outage events which individually are not among the top ten causes of outage events.

(2) Blanks are shown for years where the number of outages was too small to be among the top ten causes of outage events.

Gulf Power Company:

Table A-13. GULF's Number of Customers (Year End)

	2002	2003	2004	2005	2006
Western	192,924	197,690	194,705	184,826	205,779
Central	97,753	100,660	97,849	175,919	108,859
Eastern	93,246	95,508	103,220	102,328	104,254
GULF System	383,923	393,858	395,774	463,073	418,892

Table A-14. GULF's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
Western	89	86	115	142	158	1.02	0.94	1.07	1.35	1.27	87	91	108	105	124
Central	101	73	69	73	174	1.03	0.84	0.65	0.81	1.28	99	87	105	90	136
Eastern	77	75	75	78	331	0.81	0.84	0.75	0.71	1.29	95	90	101	111	257
GULF	89	80	93	101	205	0.97	0.89	0.88	1.00	1.28	92	90	106	101	161

Table A-15. GULF's Adjusted Regional Indices MAIFIe and CEMI5

	Average Frequency of Momentary Events on Feeders (MAIFIe)					Percentage of Customers Experiencing More than 5 Service Interruptions (CEMI5)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
Western	12.7	10.9	8.9	11.6	9.3	1.07%	1.65%	1.24%	1.17%	2.01%
Central	10.8	8.5	5.3	4.7	7.5	1.33%	0.26%	0.39%	1.56%	2.01%
Eastern	8.9	6.0	6.4	5.8	6.7	0.64%	1.13%	0.39%	0.64%	2.06%
GULF System	11.3	9.1	7.3	7.7	8.2	1.03%	1.17%	0.81%	1.20%	2.02%

Table A-16. GULF's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2002	2003	2004	2005	2006	Cumulative Percentages	2002	2003	2004	2005	2006
Animal	4,074	3,000	2,012	1,486	1,609	24.6%	69	67	81	92	163
Lightning	1,865	1,885	1,541	1,851	2,307	19.1%	143	123	151	192	170
Deterioration	1,677	1,594	1,611	1,634	1,914	17.1%	139	134	162	188	174
Unknown	1,150	1,616	1,390	980	987	12.4%	99	96	136	141	157
Trees	1,075	1,016	1,193	254	1,292	9.8%	118	106	129	139	157
Vehicle	246	227	303	2,239	284	6.7%	140	147	162	171	381
All Other	306	217	264	288	299	2.8%	127	132	126	110	139
Wind/Rain	126	100	118	235	680	2.5%	138	145	125	146	219
Overload	221	201	212	129	223	2.0%	107	93	125	108	156
Vines	103	128	117	424		1.6%	85	87	98		
Other	125	85	121	129		0.9%	102	100	124	217	
Contamination / Corrosion				118	137	0.5%				194	182
Dig-In					144	0.3%					109
GULF System	10,968	10,069	8,882	9,638	9,876	100%	105	101	130	152	114

Notes:

(1) "All Other" category is the sum of many diverse causes of outage events which individually are not among the top ten causes of outage events.

(2) Blanks are shown for years where the number of outages was too small to be among the top ten causes of outage events.

Florida Public Utilities Company:

Table A-17. FPUC's Number of Customers (Year End)

	2002	2003	2004	2005	2006
Fernandina(NE)	14,000	14,448	14,566	14,731	14,859
Marianna (NW)	12,198	12,598	12,528	12,661	13,934
FPUC System	26,198	27,046	27,094	27,392	28,793

Table A-18. FPUC's Adjusted Regional Indices SAIDI, SAIFI, and CAIDI

	Average Interruption Duration Index (SAIDI)					Average Interruption Frequency Index (SAIFI)					Average Customer Restoration Time Index (CAIDI)				
	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006	2002	2003	2004	2005	2006
NE	60	77	152	59	105	0.59	1.07	1.15	1.01	1.15	102	72	133	59	91
NW	96	86	122	78	206	1.94	1.58	1.44	1.13	1.72	49	55	84	69	119
FPUC	77	81	138	68	154	1.22	1.31	1.28	1.07	1.43	63	62	107	64	108

Table A-19. FPUC's Primary Causes of Outage Events

	Adjusted Number of Outage Events						Adjusted L-Bar - Length of Outages				
	2002	2003	2004	2005	2006	Cumulative Percentages	2002	2003	2004	2005	2006
Vegetation	126	153	216	135	257	22.4%	74	72	80	83	95
Animal	121	124	164	149	250	20.4%	45	44	48	49	50
Lightning	181	100	208	84	72	16.3%	56	65	81	72	99
Unknown	87	82	113	113	202	15.0%	46	50	55	49	69
Corrosion	54	56	53	66	59	7.3%	140	157	115	116	124
All Other	30	30	45	40	33	4.5%	79	87	86	75	73
Other Weather	28	31	49	20	50	4.5%	80	82	124	69	103
Trans. Failure	43	37	27	38	32	4.5%	117	142	161	154	170
Vehicle	10	11	16	14	28	2.0%	69	73	91	68	162
Cut-Out Failure	13	13	26	12	5	1.7%	67	70	71	74	55
Fuse Failure			21	27	6	1.4%			49	47	95
Dig-in		6				0.2%		92			
Salt Spray	1					0.03%	61				
FPUC Sys	694	643	938	698	994	100%	68	75	77	73	84

Notes:

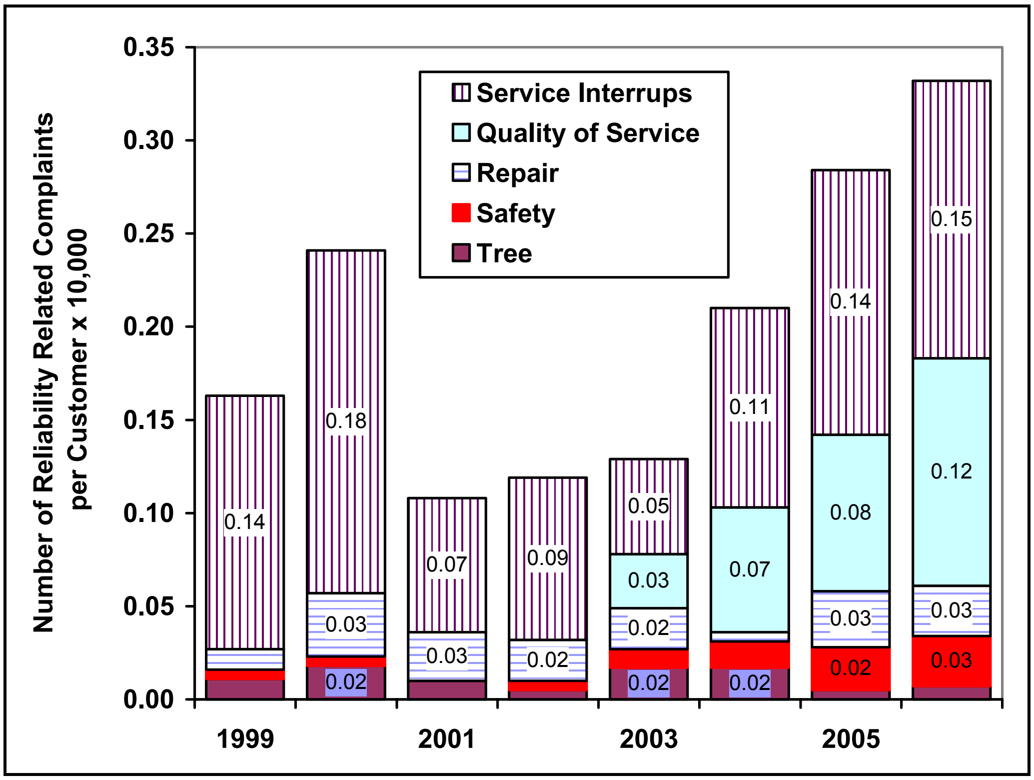
(1) "All Other" category is the sum of many diverse causes of outage events which individually are not one of the top ten causes of outage events.

(2) Blanks are shown for years where the quantity of outages was less than one of the top ten causes of outage events.

Appendix B. Service Reliability Customer Complaints

Each customer complaint received by the Commission is assigned a category after the complaint is resolved. Reliability related complaints are those pertaining to trees, safety, repairs, quality of service, or service interruptions.[20] The "quality of service" category was established in July 2003, resulting in a shift of some complaints that previously would have been coded in another complaint category. The volume of service reliability related complaints is normalized to a 10,000 customer basis for comparative purposes.

Figure B-1. FPL's Service Reliability Complaints



[20] A quality of service customer complaint typically includes one or more aspect of service reliability (i.e., momentary events, service interruptions, trees, safety, or repairs) and possibly other matters such as a high bill.

Figure B-2. PEF's Service Reliability Complaints

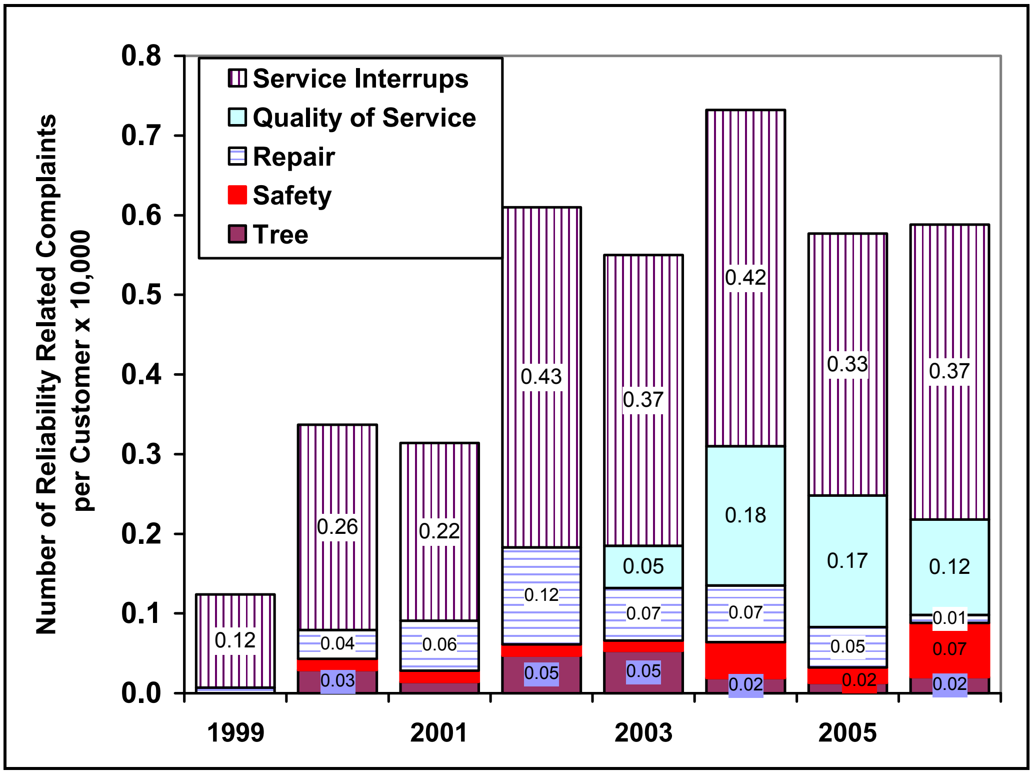


Figure B-3. TECO's Service Reliability Complaints

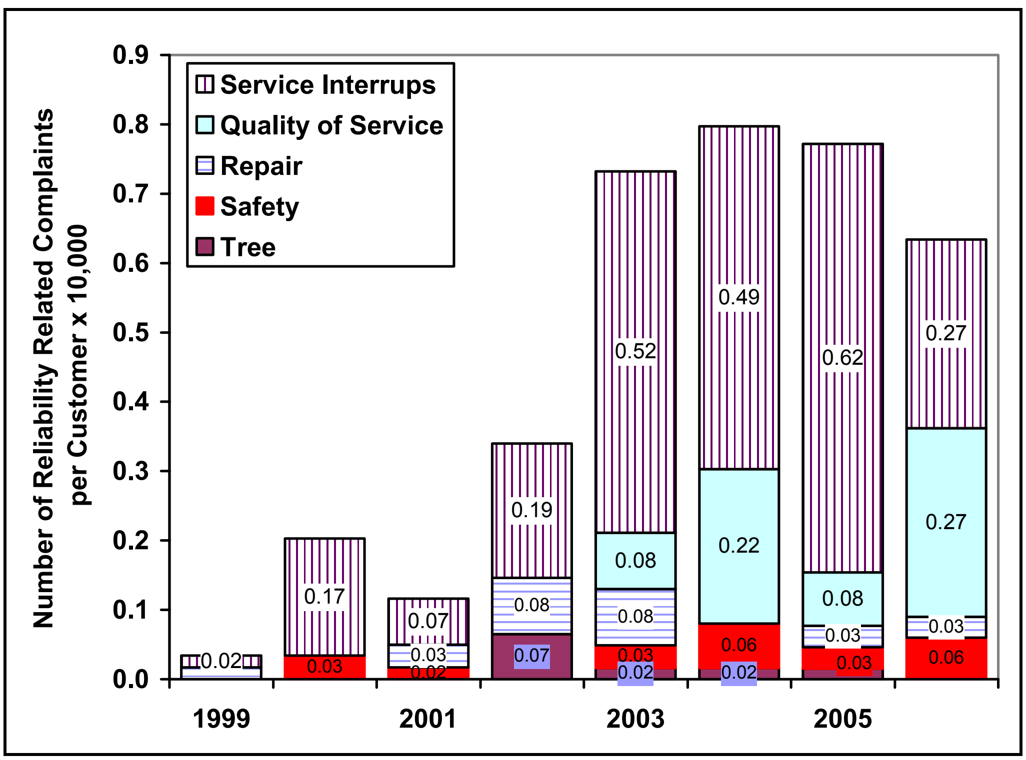


Figure B-4. GULF's Service Reliability Complaints

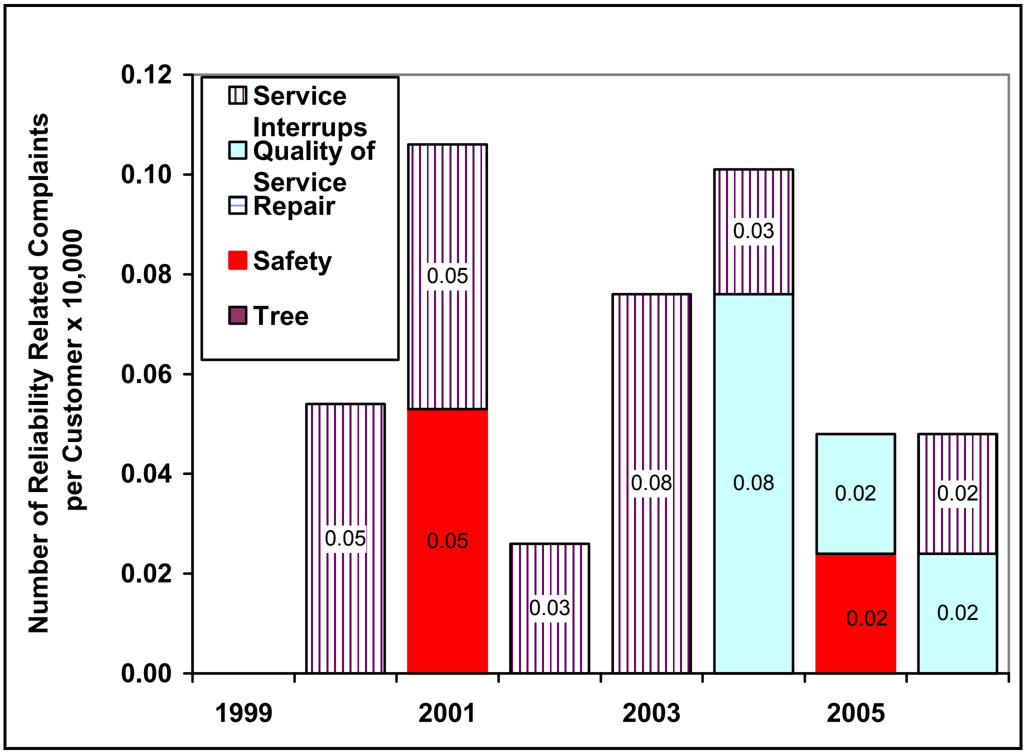


Figure B-5. FPUC's Service Reliability Complaints